-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	**<u>Docket No. 01-035-01</u>** Utah Division of Public Utilities Exhibit No. DPU 8.0 Rebuttal

Rebuttal Testimony of Rebecca L. Wilson

For The

Division of Public Utilities

Department of Commerce

State of Utah

July 16, 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. Are you the same Rebecca Wilson who filed direct testimony on behalf of the Utah Division of Public Utilities in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. To amend my direct testimony in response to PacifiCorp's June 8, 2001 filing and in response to the stipulation in this case filed July 13, 2001. Specifically, I recalculate the Division's recommended long-term firm revenue increase. Additionally, I respond to CCS Witness Yankel's recommendation that the Commission establish a task force to investigate line losses allocated to Utah loads for determination of system peak.

Q. What did PacifiCorp file on June 8, 2001?

A. PacifiCorp filed replacement pages to their February direct testimony. The replacement pages reflect five adjustments to correct errors in PacifiCorp's filed position on net power costs. The five errors were: 1) The actual power costs noted in Exhibit No. UP&L (DDL-), Tab 5, page 5.1.1 were understated which overstated PacifiCorp's recommended normalized net power cost adjustment. 2) $59 million of test period purchase power costs were mistakenly allocated situs to Oregon rather than to the system generation allocator in the unadjusted results of operations. 3) The Utah loads included in PacifiCorp's net power cost model were incorrect for the test period. 4) PacifiCorp's capacity share in the Colstrip Plant was understated. 5) The San Diego Gas & Electric wholesale contract was mistakenly identified and modeled as a short term rather than long-term firm sale. The sum total net impact to PacifiCorp's filed net power cost position of correcting these five errors is to increase the test period Utah revenue requirement by $23 million.

Q. Has the Division reviewed these errors and corrections?

A. Yes, we have confirmed the errors as follows:

1) Comparison of unadjusted account 555 with the “Actual Cost” column in Exhibit No. UP&L (DDL-), Tab 5, page 5.1.1 shows that the exhibit was in error. Correction of this error decreases PacifiCorp’s filed position on net power cost by $7 million in Utah.

2) Division auditors reviewed prior semi-annual reports and note that Oregon situs allocation of purchase power costs typically reflects a relatively small credit associated with BPA entitlements. The $59 million appears to be a simple accounting error. Correction of this error increases the Utah test period revenue requirement by $22 million.

3) Witness Herz representing the United States Executive Agencies in this case is credited with discovering the Utah load error. This error was confirmed by Division and Committee Witness Hayet and included in Mr. Hayet’s adjustments in our direct filed net power cost position. Correction of this error, assuming PacifiCorp’s filed net power cost position, decreases Utah’s revenue requirement by $7.5 million.

4) Division and Committee Witness Falkenberg identified the Colstrip capacity errors and this adjustment is included in the Division’s direct filed net power cost position. Correction of this error assuming PacifiCorp’s filed net power cost position reduces Utah’s revenue requirement by $2.5 million.

5) Review of the San Diego Gas & Electric wholesale contract reveals that PacifiCorp signed

an obligation to provide San Diego with 100 MW at a 100% capacity factor dated March 24, 1997 that began January 1, 1998 and continues through to December 31, 2001 at a fixed price of $16.45 per megawatt hour. A short term contract is one that has a term, and therefore obligation, of less than one year. The contract does not state that PacifiCorp has a unilateral right to end the contract prior to its full term is completed. We therefore conclude that the contract is not a short term firm transaction as currently modeled by PacifiCorp. Correction of this error increases Utah's revenue requirement by $17 million assuming PacifiCorp's filed net power cost position.

Q. How does the Division incorporate these corrections in its filed position on net power costs in this case?

A. The first four corrections are made in the stipulation. The last correction I address now. As a long-term wholesale contract, the San Diego Gas & Electric wholesale contract should meet the criteria set by the Commission in Docket 90-035-06 discussed in my direct filed testimony, including that it cover its marginal cost and expire after a short time or cover its embedded cost. The contract clearly does not cover PacifiCorp's test year marginal cost[1] and additionally does not cover its embedded cost even though it is in its final year. Therefore, I recommend that the Commission increase its revenues for the test year up to embedded cost. The Division will file in surrebuttal a revised Exhibit No. DPU 8.3 (the summary of all Division recommended net power cost adjustments) to reflect the stipulated changes and the change proposed in my testimony today.

Q. Have you prepared an exhibit which shows the increase in revenues required for the San

[1] Calculation of PacifiCorp's Realized Marginal Energy Cost for the twelve months ending September 2000 was $42.48 per megawatt hour.

Diego contract to recover embedded cost and the impact of the addition of this contract on your overall long term wholesale revenue increase adjustment?

A. Yes. Exhibit No. DPU 8.2 Revised is attached. This six page exhibit provides four tables, each which shows the adjustment under different calculations of embedded cost. The exhibit also includes workpapers for the adjustment.

Table 1 is a reproduction of the information provided in my original Exhibit No. DPU 8.2. It shows a Utah revenue requirement decrease of $25 million assuming PacifiCorp's filed embedded generation and transmission cost and the interjurisdictional allocation factors recommended in the Division's direct testimony.

Table 2 shows the result on Table 1 of adding the San Diego contract bringing the total number of contracts affected to fifteen. It shows a Utah revenue requirement decrease of $32 million, again assuming PacifiCorp's filed embedded generation and transmission cost and the interjurisdictional allocation factors recommended by the Division in direct testimony.

Table 3 shows the sum total recommended revenue increase for long term wholesale contracts, including San Diego, using embedded cost results which include stipulated cost adjustments and PacifiCorp's filed net power costs. It shows a Utah revenue requirement decrease of $31 million using the stipulated interjurisdictional allocation factor. At this lower embedded cost, the number of contracts affected drops down to fourteen as the Deseret Supplemental contract is not less than embedded cost.

Table 4 shows the Division's recommended revenue increase for wholesale contracts, including San Diego, using embedded cost results which reflect stipulated costs but with an adjustment to reflect actual net power cost rather than PacifiCorp's modeled net power cost. For actual net power cost, the three net power cost adjustments included in the stipulation which were computed based on PacifiCorp's filed net power cost position have been removed. Only the $22 million Oregon situs error is included since this affected unadjusted actual net power cost. Table 4 shows a Utah revenue requirement decrease of $23 million assuming stipulated interjurisdictional allocation factors. The number of contracts affected drops to thirteen as the WAPA and Deseret Supplemental contracts are no longer less than embedded cost.

Q. Which Table shows the Division's recommended adjustment?

A. Table 4 or Table 3 depending on which net power cost adjustments the Commission adopts. Since the Division recommends that the Commission adopt Mr. Falkenberg's adjustment to use actual short term purchase and sales prices, it is the $23 million in Table 4 that represents the Division's recommendation. This is about $1.5 million less than recommended in my direct testimony. However, if the Commission adopts PacifiCorp's proposed price adjustments to short term firm sales and purchases, the correct calculation of my recommended adjustment is the $31 million shown in Table 3. This is about $5.9 million more than recommended in my direct testimony.

Q. Do you have an exhibit which shows how you calculated embedded generation and transmission cost for the four Tables in Exhibit No. DPU 8.2 Revised?

A. Yes. Exhibit No. DPU 8.11 is a five page exhibit which summarizes the results of my embedded cost calculations and provides the detail from the model runs I used to calculate embedded cost. I used the model created by Commission staff Jim Logan called 03_IFA_stip.xls. It replicates PacifiCorp's cost of service study which functionally unbundles costs. In order to gain confidence in modeling embedded cost under different revenue requirement inputs, I successfully benchmarked the model to produce Mr. Taylor's results shown in Exhibit No. UP&L (DLT), PacifiCorp's cost of service study.

Q. Could you describe the generation and transmission embedded cost results for each case modeled?

Yes. Including stipulated cost adjustments and PacifiCorp's proposed net power costs in the Utah revenue requirement results in an embedded generation and transmission cost of $37.25 per megawatt hour. This is slightly lower than the embedded generation and transmission cost of $37.60 per megawatt hour calculated from Mr. Taylor's study due to the stipulated cost adjustments.

Adjusting further to account for the stipulation but removing three of the stipulated net power cost adjustments associated with PacifiCorp's filed case and using the Division's cost of service study changes noted by Division witness Dr. Nelson,[2] produces an embedded generation and transmission cost of $33.72. The effect of removing the stipulated net power cost adjustments (except for the $22 million Oregon situs allocation error) essentially produces an embedded cost based on the stipulated revenue requirement and actual net power cost.

[2] The Division uses the Commission approved method for calculating line losses which differs from the loss factors used by PacifiCorp. The Divison allocates certain overhead accounts on a plant allocator rather than the labor allocator used by PacifiCorp.

To summarize, it is now appropriate to use either the $33.72 or $37.25 embedded cost per megawatt hour as the basis for increasing revenues rather than the $37.60 per megawatt hour used in my direct testimony because of the stipulated cost adjustments to revenue requirement. The $37.60 should only be used if the stipulation is not adopted and PacifiCorp's net power cost position is adopted. The $37.25 per megawatt hour should only be used if the Commission chooses to adopt the stipulation and PacifiCorp's short term firm power price adjustments. If the Commission adopts the stipulation and the Division's recommended net power cost adjustments, the $33.72 per megawatt hour embedded cost would be appropriate.

Q. CCS witness Mr. Yankel recommends that the Commission establish a task force to investigate the Company's line loss adjustments to Utah's peak loads. Do you support this recommendation?

A. No. We are very concerned by the issues raised by Mr. Yankel in his direct testimony and have decided to investigate the issue on our own as soon as possible. We do not think it is an issue that requires a workgroup or task force. We consider it important and do not wish to wait for the conclusion of this rate case. We support his recommendation that the Commission order PacifiCorp to provide the loss study they have been working on for years in whatever stage of completion it is in. However, we recommend that this study or draft study be provided to the Commission or regulators rather than a task force.

Q. Does this conclude your rebuttal testimony?

A. Yes.