Q. Are you the same C. Craig Paice who has previously testified in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony I present PacifiCorp's 2008 Class Cost of Service Study based on the twelve month future test period ending December 31, 2008 that has been updated to correspond with the revenue requirement ordered by the Utah Public Service Commission on August 13, 2008. Additionally, I respond to the testimony of CCS witness Mr. Paul Chernick, UIEC witness Mr. Maurice Brubaker, UAE witness Mr. Kevin Higgins, and WRA/UCE witness Mr. Richard Collins.

Summary of Results

Q. Please identify Exhibit RMP___(CCP-1R-COS) and explain what it shows.

A. Exhibit RMP___(CCP-1R-COS) is the summary table from PacifiCorp's December 31, 2008 Class Cost of Service Study for the State of Utah. It is based on PacifiCorp's revised annual results of operations for the State of Utah presented in the rebuttal testimony of Company witness Steven McDougal as modified by the Commission's final revenue requirement order in this case. Page 1 of Exhibit RMP___(CCP-1R-COS) presents results at the Company's December 2008 rate of return assuming current rate levels. Page 2 shows the results using the return provided by the Commission ordered price increase of $36.2 million. It also reflects changes to the distribution substations peaks per the analysis presented by Company witness Mr. Lowell E. Alt.

Q. Please identify Exhibit RMP___(CCP-2R-COS) and explain what it shows.

A. Exhibit RMP___(CCP-2R-COS) shows the cost of service results in more detail by class and by function. Page 1 summarizes the total cost of service summary by class and pages 2 through 6 contain a summary by class for each major function.

Rebuttal of Mr. Paul Chernick & Mr. Maurice Brubaker

Q. Do you agree with Mr. Chernick that the cost of service study filed in this docket understates the energy-related cost of generation?

A. No, I do not. The cost of service study employs the Utah Public Service Commission approved 75 percent demand and 25 percent energy classification methodology for generation and transmission costs. No generation related costs (including seasonal resources) are classified 100 percent demand-related as Mr. Chernick claims. Exhibit RMP___(CCP-3S), Tab 1, Page 8 explains in detail the use of the 75 percent demand and 25 percent energy methodology to classify generation and transmission costs and Tab 4, Pages 1-18 of the same exhibit identifies all the allocation factors employed in the cost of service study.

Q. Mr. Brubaker also argues for a change in the classification of generation and transmission costs. Do you agree with his recommendation that generation and transmission fixed costs should be classified as 100 percent demand related?

A. No. PacifiCorp's generation portfolio includes different types of resources including coal fired steam plants, hydro facilities, simple and combined cycle gas combustion turbines, wind turbines, and purchases. Although it may be reasonable to classify the fixed costs of simple cycle combustion turbines and other peaking resources 100 percent demand related (which are designed to run during peak load hours only) such a classification would not be appropriate for the majority of PacifiCorp's portfolio. The Company's resource fleet is heavily skewed toward base load plants that were constructed not only to meet peak load, but also to produce low cost kilowatt-hours 24 hours per day, 7 days per week as needed to provide the energy requirements of all customers. The capital investment of a coal fired steam plant and other base load plants is greater than the capital investment of a peaking turbine. This additional investment was made, not to meet the peaking needs of the Company, but to generate lower cost kilowatt hours. Therefore, it would seem reasonable that some of the additional capital investment be classified as energy related.

Classification of Generation and Transmission Costs

Q. Please explain why the current methodology employed in the Company's cost of service study is appropriate for the state of Utah?

A. This classification issue was one of the first raised at the time of the Utah Power - Pacific Power merger because both companies previously utilized different generation fixed cost classification methodologies. Since the newly merged company created a combined system involving seven states it was necessary to find a common methodology suitable to all parties. Studies were conducted by the Division of Public Utilities (DPU) to determine the cause of production capacity costs with their conclusions being adopted by the Commission staffs of the states served by the Company to allocate jurisdictional costs. This methodology was also used in Docket 90-035-06, the first post-merger case to allocate cost of service. Several years following this docket, the DPU studies were updated and the same conclusions were reached. Since it was first introduced, the mix of 75 percent demand and 25 percent energy has been considered by the Commission to be reasonable. The Commission's position, as stated in Section IV. A.2. of the order issued in Docket 97-035-01, provides the basis for use of this allocation methodology:

> "We conclude that twelve monthly coincident peaks, with a 75 percent demand-related and 25 percent energy-related mix, is the appropriate basis for allocating production and transmission costs to classes in the Utah jurisdiction."

The classification of generation and transmission costs was addressed at length during the Multi-State Process (MSP) discussions. Several approaches were discussed, including those recommended in this case by Mr. Chernick and Mr. Brubaker. As with the earlier PacifiCorp Interjurisdictional Taskforce on Allocations (PITA) analysis, no clearly superior demand/energy classification split emerged from analyses conducted during the Multi-State Process. Because the 75 percent demand and 25 percent energy classification of generation fixed costs currently used by PacifiCorp falls in the middle of the range of reasonable approaches, the Company found no compelling reason to change the approach.

Q. Have changes to the 75 percent demand and 25 percent energy allocation method been proposed in previous rate cases?

A. Yes. In Docket 01-035-01, USEA (United States Executive Agencies) witness Mr. Joseph Herz argued in support of 100 percent demand classification of generation fixed costs. He concluded that the 75 percent demand and 25 percent energy classification was inappropriate "in that a portion of its demand related costs are allocated according to energy use." The Company provided testimony in support of the 75 percent demand and 25 percent energy classification in this same docket. RMP witness Mr. David L. Taylor stated:

> "PacifiCorp classifies production and transmission plant and non-fuel related expenses as 75 percent demand and 25 percent energy related. The Company's goal is to supply the lowest total cost generation resources to meet our customers' needs." (Docket 01-035-01, Taylor rebuttal, page 8).

In addition Dr. George Compton, of the DPU, also responded to Mr. Herz' recommendations and conducted additional analysis on the classification question.

Q. What were the results of Dr. Compton's analysis?

A. The analysis performed by Dr. Compton determined that a portion of the fixed costs associated with generation plants are energy-related and that it is entirely appropriate to allocate some of these costs in proportion to energy consumption. Regarding the quantity of energy-related of fixed costs, Dr. Compton's rebuttal testimony in the aforementioned docket illustrates continued support for the approved methodology where he stated that "… the 25% figure is reasonable." (Docket 01-035-01, Compton Rebuttal, page 3)

Q. Are the peaker and new generation plant approaches presented by Mr. Chernick appropriate methods of determining energy-related generation plant costs?

A. No. The intended objective is to allocate production costs to customer classes consistent with the cost impacts imposed on the system. While classifying some portion of generation fixed as energy-related is appropriate, Mr. Chernick's methods, in my view, reflect a bias toward classifying an excessive portion of generation costs as energy-related. The 1992 *Electric Utility Cost Allocation Manual* published by the National Association of Regulatory Utility Commissioners (NARUC) states that using the peaker method generally results in significant portions (between 40 to 75 percent) of generation costs being classified as energy-related. Mr. Chernick's testimony validates this concern stating that his approaches suggest generation costs should be 32 to 80 percent energy-related.

In addition, neither is appropriate because they apply simple calculations to a very complex issue. The complexities involved in determining a proper allocation cannot be underestimated. Perhaps this is best summarized by Dr. Compton, again in rebuttal testimony in Docket 01-035-01, where he referenced the difficulty involved in calculating an appropriate demand and energy classification mix. His expert opinion provides guidance on this subject:

> "To perform a definitive analysis employing all (or even a large portion of) the elements of the PacifiCorp demand/profile and resources would be horrendously complex." (Docket 01-035-01, Compton Rebuttal, page 3)

Lack of complexity suggests that neither approach presented by Mr. Chernick meets the qualifications of a definitive analysis.

Q. How should we view Mr. Chernick's recommended changes in the energy allocation of generation-related costs?

A. These recommended changes should be rejected for the following reasons:

- This subject has received significant attention throughout the years following the Utah Power - Pacific Power merger. The PacifiCorp Interjurisdictional

Task Force on Allocations (PITA), the Multi-State Process (MSP) and the 2005 Cost of Service and Rate Design Taskforce have all discussed this subject at length with no resulting changes.

- The Utah PSC gave approval for use of this allocation method in cost of service studies.
- Various analyses have been performed validating reasonableness of the 75 percent demand and 25 percent energy allocation.
- Approaches lacking objectivity and based on simple mathematical computations undermine the importance of determining an appropriate generation cost allocation method. Selection of an appropriate allocation method should be based on costs imposed on the system. They should also require extensive analysis as recommended by Dr. Compton.
- Section III.A.1 of Mr. Chernick's testimony references the impact of changing Factor 10 from 75 percent to 50 percent demand causing a shift of "about $8.5 million off of Schedules 1, 6, and 23 and about $3.8 million onto Schedule 8 and 9." The final sentence in this same section states "The demand-related portion of PacifiCorp owned generation, weighted across PacifiCorp's generation mix, <u>may be</u> much lower than 50 percent, so the effects may be much larger." It remains evident from these statements that Mr. Chernick's approaches to increase the energy allocation will create significant cost shifts between the various rate schedules. Since the revenue requirement spread to schedules is generally dependent upon cost-of-service information, a large or abrupt change in cost allocations could ultimately produce large rate

variations and would violate the principle of gradualism. The principle of gradualism has been held by the Utah PSC to be significant in order to avoid significant changes in rates within schedules.

Q. What is Mr. Chernick's position regarding the classification of transmission plant?

A. He is also critical of the 75 percent demand and 25 percent energy allocation of transmission-related costs stating it is <u>likely</u> that over half of the Company's transmission revenue requirement is attributable to energy. The basis for this statement is a simple review of PacifiCorp's 2006 FERC Form 1. In addition, he recommends to the Commission that PacifiCorp be required to undertake a comprehensive analysis of the factors driving transmission investment.

Q. Do you agree with his conclusion regarding energy-related classification of transmission plant?

A. No. RMP allocates transmission costs similar to the allocation of generation costs. This practice is consistent with guidelines cited in the NARUC *Electric Utility Cost Allocation Manual* which states:

> "In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other." (page 75).

RMP's position is in concert with this statement. This position plus the aforementioned reasons cited for maintaining use of the 75 demand and 25 energy allocation for generation costs support the current allocation method.

Additionally, the basis of Mr. Chernick's position is a review of the Company's

FERC Form 1 which he admits did not represent a comprehensive analysis of transmission costs.

Q. Should the Utah PSC consider his recommendation for RMP to undertake a thorough analysis of transmission investment?

A. No. This perspective is contrary to the "burden of proof" argument necessary when recommending allocation changes. As explained by Dr. Compton:

> "The burden of 'proof' to come up with some kind of definitive study incorporating the specifics of PacifiCorp's loads and resources would lie with whomever sought to depart from the established 25%/75% ratio." (Docket 01-035-01, Compton Rebuttal, page 5).

As such, the responsibility to prove the necessity of departing from the approved methodology rests with the recommending party.

Allocation of Firm Purchases and Sales

Q. What is the basis for allocating sales for resale revenue and purchased power expenses as presented in the cost of service study?

A. The basis is the *Allocations Task Force Report to the Utah Public Service Commission* (December 16, 1999, page 21) which states:

> "The PSC indicated in their Order in the last PacifiCorp rate case their desire for consistent application of cost-causal principles in both jurisdictional and class allocation studies. Consistency implies that the same methodology would be used in both the jurisdictional allocation and class cost of service models to allocate similar types of costs."

Sales for Resale revenue / Purchased Power expense allocations presented in the cost-of-service study are consistent with allocations presented in the Jurisdictional Allocation Model (JAM) and comports with the Commission's perspective.

Q. Do you agree with Mr. Chernick's position that Sales for Resale revenue and Purchased Power expenses are inappropriately allocated?

A. No. I disagree with Mr. Chernick's positions for at least two reasons. First of all, Mr. Chernick proposes different allocation procedures for Sales for Resale revenues and Purchased Power expenses. Second, his Sales for Resale revenue allocation proposal is inconsistent with his proposal for the allocation of the cost of the resources supporting those revenues. This allocation issue was raised in Docket 97-035-01 and addressed by the Company and the Division at that time. The Allocation Taskforce arising from that case also addressed this issue. Discussion of this subject contained in the *Allocations Task Force Report to the Utah Public Service Commission* (December 16, 1999, page 13) stated:

> "Early in the task force discussions, the parties agreed with the principle that the sales for resale revenue should be allocated on the same basis as the cost of making the sales. The issue then became how this principle would be implemented. The Division's analysis in the last rate case was based on 1997 data. For task force discussion, the Division updated their analysis using 1998 data (see Appendix). In the meantime, the Company had slightly changed the way the sales for resale revenue were allocated in the class cost of service study. The net result was that both the Division's 1998 analysis and the Company's 1998 cost study results were very similar (60/40 versus 63/47demand/energy split respectively). The Division now believes that the Company's current method is reasonable since the results are close and neither method is entirely accurate."

The cost of service study maintains this proportional perspective when comparing the percent of <u>total</u> sales for resale revenues to <u>total</u> purchased power expenses for all classes. Comparison results are:

Schedules	Sales for Resale	Purchased Power	Variance
Sch 1	30.5%	31.0%	0.5%
Sch 6	29.2%	28.9%	-0.3%
Sch 8	9.2%	9.1%	-0.1%
Sch. 7,11,12	0.2%	0.2%	0.0%
Sch 9	17.6%	17.5%	-0.1%
Sch 10	0.6%	0.6%	0.1%
Sch 12	0.0%	0.0%	0.0%
Sch 12	0.0%	0.0%	0.0%
Sch 23	6.6%	6.6%	0.0%
Sch 25	0.1%	0.1%	0.0%
Cust A	0.9%	0.9%	0.0%
Cust B	2.5%	2.5%	0.0%
Cust C	2.5%	2.5%	0.0%

There is a slight difference of 0.5 percent for Residential Schedule 1. A few other schedules show even smaller differences with no variation for most schedules.

Q. What conclusion can be drawn from this comparison?

A. Cost of service study results maintain a consistent allocation between sales for resale revenues and purchased power expenses as expected by the Utah PSC. From my analyses I also conclude that as long as the classification and allocation of sales for resale revenues and purchased power expenses are consistent, the methodology will have very little net impact on the cost of service results.

Q. Why are his approaches for allocating sales for resale revenues particularly inappropriate?

A. Mr. Chernick proposed to allocate sales for resale revenue in a manner that is totally inconsistent with his proposal for the allocation of the cost of the resources supporting those revenues. In the cost of service study all costs are first allocated to retail customers. Any revenues that the Company receives from sources other than retail customers (revenue credits), such as sales for resale revenues, are then used to reduce the level of costs that are ultimately collected from those retail customers. As such, revenue credits should be allocated to customer classes in a manner consistent with the costs that support those revenues.

Mr. Chernick's approaches, on the other hand, are predicated on the assumption that customer classes have the right to generation resources proportional to their July peak contribution. These approaches may be acceptable if each class were allocated the cost of generation based on only the July peak. However neither RMP's generation allocation method, which utilizes all 12 coincident peaks, nor Mr. Chernick's proposal for generation costs use this method. Mr. Chernick's proposal is a gross mismatch between how the underlying generation costs are allocated among customer classes and how the sales for resale revenues made possible from those resources are allocated. For example Mr. Chernick's "unused energy/peak" method, as shown in the work papers provided in response to RMP DR 1.4, assumes that during the month of February the residential class is entitled to 66 percent, of the Company's generation resources, but is only responsible for 24 percent of the February generation costs.

Q. What other concerns do you have with Mr. Chernick's proposals for the allocation of sales for resale revenues and purchased power expenses?

A. His proposal would create significant shifts among the classes. It appears that incorporating his recommendations would have significant consequences similar to those for generation and transmission costs. His testimony states that by changing the allocation of the firm non-seasonal purchases component of purchased power expenses to 25 percent demand from 75 percent demand results in a shift of approximately $13 million away from Schedules 1, 6, and 23. Then, a review of his three approaches to allocate sales for resale revenues demonstrates large differences from the cost study. The least variable approach would increase allocation of these revenues to Schedule 1 by a net difference of 27.44 percent. The other approaches illustrate even greater variations for this same schedule. He concludes with the observation that significant allocation changes (i.e., cost shifting) would occur and is supported by his final comment that the "effects on other classes could be material." However, there is no analysis presented to illustrate precisely how significantly these changes would impact all customer classes. Also, there is no attempt to determine if the accepted practice of flowing revenue credits to customer classes in proportion to the share of costs would be maintained.

Q. Please summarize your findings regarding current cost of service study allocation methodologies.

A. The cost of service study filed by the Company is a reasonable representation of cost functionalization, classification, and allocation of the Utah revenue requirement. The 75 percent demand / 25 percent energy allocation accepted by the Utah PSC and used in this study is an appropriate methodology which has been significantly discussed and analyzed. The sales for resale revenue allocation flows to customer classes in proportion to the share of generation costs assigned to them. Mr. Chernick's recommended allocation changes to the cost study would induce cost shifts among customer classes potentially creating large rate change variations across classes. No analyses are provided illustrating 1) total potential class revenue requirement shifts or 2) support for consistent allocations between sales for resale revenue and purchased power expenses. Absent cost movement indication it is impossible to ascertain if gradualism would be preserved.

Rebuttal of Mr. Brubaker concerning 12 CP allocation

Q. Do you agree with Mr. Brubaker's observation that because of growth in summer peak compared to loads in other seasons that it is time to revisit the appropriateness of the 12 coincident peaks (CP) allocation?

A. I agree with his observation that summer peak loads are growing. For this reason, the Company introduced modifications to the allocation of generation fixed costs and net power costs (introduced in Docket 06-035-21) to reflect the impact of seasonal costs and load differences. These modifications represent a first step toward meeting the objective of recognizing seasonal load and cost differences in the cost of service study without causing significant cost shifts between customer classes. However, I do not agree with the appropriateness of revisiting the 12 CP cost allocation methodology for two reasons. First, although RMP is a summer-peaking utility, costs are allocated based on the entire integrated system because that is how the system is planned and dispatched. A 12 CP allocation for system demand costs has been used since the Utah Power - Pacific Power merger in 1989 and continues to be used because it represents actual system operations. It recognizes that each of the monthly peaks is important. Second, it is appropriate for allocation methods to be consistent between interjurisdictional and class cost of service allocations. These two positions comport with Utah PSC findings (see order in Docket 97-035-01, Section IV.A.2, 4 respectively). Mr. Brubaker references revisiting the use of 12 coincident peaks to allocate generation among classes but presents no analysis in support of his statement. As discussed earlier in my testimony, deviation from the presently accepted methodology should be accompanied by "definitive analysis" from the recommending party.

Rebuttal of Mr. Kevin Higgins

Q. Do you agree with Mr. Higgins assessment that the Company's treatment of the MSP Rate Mitigation Cap in the class cost of service approach is incorrect?

A. No. While I agree there may be alternative approaches, I do not believe the method employed in our filed study produced a conceptual error. The Company's cost of service treatment of the MSP Rate Mitigation Cap is consistent with our representations before the Utah Commission in the hearing to approve the MSP Stipulation held on July 19, 2004.

Q. Why does Mr. Higgins feel the Company's approach is incorrect?

A. Rather than view the impacts of the Rate Mitigation Cap as a reduction in the Company's return on rate base, he views the Cap as a reduction in the allocation of generation costs to Utah. He recommends that the impact of the Rate Mitigation Cap be reflected as a reduction to generation expense so that the Company return is unaffected.

Q. Do you agree with the way he has portrayed the impact of the Rate Mitigation Cap?

A. No. The Rate Mitigation Cap does not reduce the allocation of costs to Utah. The MSP Revised Protocol as stipulated by the Utah parties, including those represented by Mr. Higgins, and approved by the Utah Commission is the methodology used to allocate costs to Utah. As such, Utah is allocated its full proportional share of total Company costs. The Rate Mitigation Cap does not limit the allocation of generation costs; it limits the level of revenues the Company is allowed to collect. This lowers the rate of return the Company will actually realize in Utah. The Company's cost of service study reflects the impact of the Rate Mitigation Cap by incorporating the lower "effective" return on rate base it produces.

Q. Are there other alternatives to the cost of service treatment of the Rate Mitigation Cap?

A. Yes. A possible alternative to the current cost of service treatment would be to lower the target return for the generation function only producing a different return for them when compared to the rates of return for other functions. The Company is not opposed to exploring this or other alternatives. Such an approach, however, would be a departure from the Company's traditional view that all business functions are producing the same rate of return.

Planning Margin Adjustment

Q. Mr. Higgins recommends that a portion of costs associated with the Company's planning margin requirement be added to the peak loads for classes that are traditionally temperature normalized. Do you agree with his proposal?

A. No, I do not. Mr. Higgins proposes an adjustment that allocates a percentage of planning margin to the CP for those rate schedules whose loads are traditionally temperature-adjusted by the Company. No data or calculations are presented that support this recommendation. The only basis for his recommendation is that he believes that a planning margin is reasonable. This recommendation has very little foundation and should be rejected.

Rebuttal of Mr. Richard Collins

Q. Do you agree with Mr. Collins that the Commission should order the Division to investigate cost of service based on marginal costs?

A. The Company believes that Mr. Collins' proposal should be investigated in the marginal cost/load growth collaborative proposed by Mr. Griffith in his rebuttal testimony and by other parties in their direct testimonies.

Workpapers

Q. Have you included your workpapers?

A. Yes. Exhibit RMP___(CCP-3R-COS) includes the cost of service study underlying the summary tables in RMP___(CCP-1R-COS). Both of these exhibits are being provided on CD in both PDF and working models.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.