Edward A. Hunter
John M. Eriksson
Gregory B. Monson
STOEL RIVES LLP
201 South Main St., Suite 1100
Salt Lake City, Utah 84111
Telephone: (801) 328-3131
Facsimile: (801) 578-6999

George M. Galloway
STOEL RIVES LLP
900 SW Fifth Ave., Suite 2300
Portland, Oregon 97204-1268
Telephone: (503) 294-9306
Facsimile: (503) 220-2480

Attorneys for PacifiCorp

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rates Schedules and Electric Service Regulations

))))))

DOCKET NO. 99-035-10

PACIFICORP'S POST-HEARING BRIEF

PacifiCorp, doing business as Utah Power & Light Company ("PacifiCorp" or the "Company") submits the following brief on certain issues raised in this case. The Company has not addressed all of the issues raised. The failure to address any particular issue is not to be construed as acquiescence to any other party's position.

I. THE COMMISSION SHOULD FIND THE RETURN ON EQUITY FOR PACIFICORP TO BE 11.25%, AND AN EQUITY RATIO OF 48.8%.

The cost of capital is comprised of the weighted cost of debt, preferred stock and equity. There is no dispute in the record regarding the cost of debt and the cost of preferred stock. Therefore, the issues remaining for decision by the

Commission are the cost of equity or return on equity ("ROE") and the capital structure or weighting of the three components.

In considering expert opinion evidence on cost of capital, certain legal requirements apply. For example, Utah Code Ann. § 54-4a-6(4)(a) states that just, reasonable and adequate rates are those that "maintain the financial integrity of public utilities by assuring a sufficient and fair rate of return." With respect to ROE, the accepted standard was set forth in *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923) and reaffirmed in *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944):

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.

320 U.S. at 603 (citations omitted).

A. Rate of Return on Equity

PacifiCorp witness Dr. Samuel C. Hadaway filed testimony in September 1999 based on data from June through August 1999. He recommended an ROE range from 11.00% to 11.80%, with a point estimate of 11.25%. Ex. UP&L 5 at 3, 29 In his rebuttal testimony and in his live testimony, Dr. Hadaway noted the substantial increase in capital costs since the last PacifiCorp rate case, which became a clear trend after he filed his direct testimony. Ex. UP&L 5R at 2-3; Tr. 252-55. He testified that based on more current data, his recommended point estimate of 11.25% was near the very bottom of a reasonable range. Tr. 252. He testified that a reasonable range based on current data through February 2000 was 11.25% through 12.25% with a point estimate of 11.75%. *Id.* at 253. He testified that interest rates had continued to rise and that the expectation was that the Federal Reserve System would increase interest rates again later this year. *Id.* at 253-54. Accordingly, it was his view that his recommended point estimate of 11.25% was extremely conservative. *Id.* at 254.

Dr. William A. Powell testified on cost of capital for the Division. In his direct testimony filed on February 4, 2000, he recommended an ROE of 10.50%. Ex. DPU 7 at 17-18. However, based upon updates, including use of more current data and correction of errors pointed out in Dr. Hadaway's rebuttal testimony, Dr. Powell revised his estimate in his live testimony to 11.00%. Ex. DPU 7.8 and Tr. 355. Dr. Hadaway had pointed out that there was an error in a reference in Dr. Powell's spreadsheet, that there was a mismatch of data and that Dr. Powell had failed to exclude companies with zero or negative growth projections from his analysis as both Drs Hadaway and Legler had. Ex. UP&L 5R at 10-14. Dr. Powell accepted the first two points and corrected his analysis to reflect them. Tr. 352-53. He also made a change based on the third point, but it was not the change Dr. Hadaway recommended. He not only excluded companies with zero or negative growth projections, he excluded companies at the high end of ROE results. *Id.* at 353-55. Had he made the correction consistent with the approach of Drs. Hadaway and Legler, his recommended ROE would have been above 11.00%. Ex. UP&L 5R at 14.

Dr. John B. Legler testified for the Committee on cost of capital in both this case and in the last PacifiCorp general rate case. Dr. Legler's methods and testimony are almost identical from case to case, making it relatively easy to compare his analysis and positions. Legler, Tr. 315-16. In September of 1998, Dr. Legler recommended an ROE of 10.25%. Cross Ex. 23 at 41. Using essentially identical methods, in February of 2000 he recommended an ROE of 10.50%. Ex. CCS 4 at 40. Dr. Hadaway pointed out that this small change in recommendation was inconsistent with the substantial increase in interest rates since the last rate case. Ex. UP&L 5R at 15; Tr. at 255. This problem was illustrated on cross examination of Dr. Legler. His average constant growth DCF results for single-A electrics increased from 82 to 87 basis points between the last case and this one. Legler, Tr. at 332-33. *Compare* Cross Ex. 23 at 40 and Legler Direct (Ex. CCS 4) at 39. The utility bond yield included in his risk premium analysis increased 140 basis points between the cases while his risk premium, the difference between utility bond rates and ROE, remained essentially the same. Tr. at 319-21. *Compare* Cross Ex. 23 at 32-33 and Legler Direct (Ex. CCS 4) at 32, 34. His rate for 30-year treasury bonds, used in another approach to the risk premium analysis, increased 90 basis points and, again, the risk premium, the difference between long-term U.S. Government Securities and ROE, remained essentially unchanged. *Compare* Cross Ex. 23 at 32-33 and Legler Direct (Ex. CCS 4) at 32, 34. The risk premium method estimates ROE by adding appropriate risk premiums to current yields on utility bonds and long-term U.S. Government securities. *Id.* Thus, one would have expected an increase of 85 to 140 basis points in Dr. Legler's recommended ROE, not the 25 basis points he actually recommended.

All witnesses agreed that ROE moves in the same direction as interest rates and that changes in interest rates are very relevant in determining ROE. Hadaway, Tr. at 254; Legler, Tr. 323, Cross Ex. 24; W. Powell, Tr. at 355. The Commission has previously acknowledged this relationship. See Docket No. 97-035-01, Report and Order ("1997 Order") at 50. The record is clear that interest rates, both short and long term have increased substantially since the last PacifiCorp rate case when the Commission found 10.50% to be the proper ROE. *See, e.g.*, Ex. DPU 7.8 (showing increases of 97 to 195 basis points during the past year); Legler, Tr. 319-21, 328-330 (showing increases of 90 and 140 basis points on long-term government securities and utility bonds, respectively, since the last rate case and increases of 124 and 125 basis points in industrial bond yields and mortgage interest rates, respectively, during the past year). When the Commission set the 10.50% ROE in the last case, interest rates were at their lowest levels in over 30 years. Hadaway, Tr. at 255. In light of these facts, the Commission should feel confident in adopting the Company's recommended 11.25% ROE. This result provides a return to equity owners that is at the low end of the range of returns required by law.

B. Capital Structure

All parties agree that PacifiCorp's capital structure should be determined on the basis of the average capital structures of comparable companies. Ex. UP&L 4 at 5-7; Ex. DPU 7 at 23; Ex. CCS 4 at 6. The Commission has previously accepted this position. *See, e.g.*1997 Order at 47. The only difference between the parties is in the group of comparable companies used to determine the hypothetical capital structure.

Dr. Hadaway used a group of comparable companies similar to that used in prior cases. It was composed of electric utilities with a bond rating of single-A or higher for which complete and adequate data was available that derived at least 75% of their total revenue from U.S. regulated electric utility operations. Ex. UP&L 4 at 5. PacifiCorp derives over 80% of its revenues from domestic electric sales. Ex. UP&L 5R at 8. Companies involved in mergers or restructurings were excluded. Hadaway, Tr. 284. Dr. Hadaway employed these screens to avoid inclusion of holding companies with totally dissimilar operations and to avoid use of companies involved in mergers or restructurings that might have skewed data. Ex. UP&L 5R at 7-8, 18. He also did so at least in part to be responsive to questions raised in the last general rate case regarding the use of companies engaged in a wide variety of diversified businesses with only a small percentage of their revenues from electric utility operations. *Id.* at 8-9; Tr. at 306. He included companies with ratings higher than single-A to avoid too small a sample. Tr. at 283-84, 306. The average capitalization of the group of companies was 47.4% debt, 3.8% preferred stock and 48.8% common equity. Ex. UP&L 4 at 5. Dr. Hadaway testified that this capital structure reflected the capitalization of the electric utility industry which was moving toward higher equity ratios. *Id.* at 6; Tr. at 258.

Dr. Powell accepted the hypothetical capital structure recommended by Dr. Hadaway. He testified that it was reasonable based upon Standard & Poor's suggested benchmarks for utilities of comparable risk to PacifiCorp. Ex. DPU 7 at 23.

Dr. Legler used a larger group of companies. He included all single-A rated electric companies without application of any screen. Legler, Tr. at 337-38. As a result, his recommended capital structure was 47.9% debt, 5.9% preferred stock and 46.3% common equity. Ex. CCS 4 at 6-7. The fact that Dr. Legler's overall cost of capital actually declined slightly from the last rate case is indicative of the bias in his approach, including his selection of unscreened companies. Legler, Tr. at 334-35.

The major problem with Dr. Legler's group is that it includes companies that are not comparable and skew the result. For example, his group included Northwestern Corp. which derives only 5% of its total revenues from domestic electric operations, Avista which derives only 15% of its total revenues from domestic electric operations, Reliant at 29%, and NiSource at 45%. Each of these companies had equity ratios far below the average, thus lowering the average. Overall, 15 of Dr. Legler's "comparables" derived less than 75% of their total revenue from domestic electric operations and 10 were involved in mergers or acquisitions. *Id.* at 338-45. Dr. Hadaway testified that if these non-comparable companies were removed from Dr. Legler's group, his recommended capital structure would have included a larger equity component than the one recommended by PacifiCorp and the Division. Ex. UP&L 5R at 18-19.

PacifiCorp and the Division have used a group of comparables in this case that is more reasonable and consistent with prior Commission orders for determining a hypothetical capital structure. The Commission should adopt their recommended capital structure of 47.4% debt, 3.8% preferred stock and 48.8% equity.

C. Overall Cost of Capital

Based upon a 7.231% cost of debt, 6.017% cost of preferred stock and 11.25% cost of equity, and a capital structure containing 47.4% debt, 3.8% preferred stock and 48.8% equity, the Commission should adopt an overall cost of capital of 9.15%.

II. THE COMMISSION SHOULD ACCEPT THE COMPANY'S NET POWER COSTS ADJUSTMENTS.

The Company's net power costs consist of its fuel, purchased power and transmission expenses netted against its wholesale sales revenues. For purposes of establishing retail rates, the Company calculates net power costs on a normalized basis using its production cost model, PD/Mac. This model is used to simulate the operation of the Company's power system under a variety of stream flow and associated energy market conditions. The model permits a determination of expected net power costs under "normal" conditions for the test period. 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 on the Company. Ex. UP&L 6 at 2.

As part of the Company's last Utah rate proceeding, the Division and Committee retained consultants to perform a comprehensive evaluation of the PD/MAC model. One of those consultants, Committee witness Randall J. Falkenberg, testified at length concerning his investigation. Tr. 1540-1547. His report, a product of 40-50 days of analysis, concluded that PD/MAC is not difficult to run and continues to represent a reasonable tool for ratemaking purposes. Tr. 1545-46.

Notwithstanding his general level of comfort with the PD/MAC model, Mr. Falkenberg proposed some adjustments to the Company's net power cost calculations. Some of these have been accepted by the Company and others are very much in dispute.

Mr. Falkenberg proposed adjustments to the expected output of the Hermiston generating plant, the capacity of the Cholla generating plant and the amount of spinning reserves appropriately assigned to the Cholla generating plant. These adjustments are uncontroverted.

Mr. Falkenberg also proposed adjustments with respect to both the assumed price (but not the assumed volume) of non-firm transactions and the assumed price and volume of short-term firm purchases. The Company believes that these adjustments are asymmetrical and unreasonable.

In the case of non-firm purchases and sales, Mr. Falkenberg proposes to use the actual prices that prevailed during the 1998 test period. This adjustment is inappropriate for each of the following reasons:

1. As acknowledged by Mr. Falkenberg, it is contrary to the Commission's long-standing policy of relying upon normalized prices in lieu of actual prices in order to insulate customers from short-term market fluctuations. Ex. CCS 6 at p. 7.

2. It is contrary to Mr. Falkenberg's position in the Company's last Utah rate proceeding that normalized prices are preferable to actual prices. Ex. UP&L 7R at 31-32.

3. It is unfair and asymmetrical because, it seeks to set rates based upon *actual* test period non-firm prices, but *normalized* volumes of non-firm transactions. Mr. Falkenberg testified that "in the short run, supply and demand factors greatly influence price levels." Ex. CCS 6 at 21; Tr. 1554. Yet, his proposed adjustment effectively ignores this relationship. While the Company continues to believe that the use of normalized prices and volumes is the best approach, it is agreeable to using actual net power costs in total. However, it is inappropriate to cherry pick some elements of net power costs on an actual basis and some on a normalized basis. Tr. 719.

In respect to short-term firm purchases, Mr. Falkenberg's adjustment appears even more tortured and results driven. Here, he proposes to use *actual* purchase volumes, *actual* sale volumes, *actual* purchase prices, but *adjusted* purchase prices for some, but not all, months. Mr. Falkenberg's justification for not consistently using actual short-term firm purchase prices is his belief that during some months of the test period, the Company "lost money" on short-term firm sales because its actual short-term firm purchase prices were in excess of its actual short-term firm sale prices. Tr. 1559. His adjustment would effectively remove this "loss."

Mr. Falkenberg's approach is misplaced because it assumes that an appropriate means of assessing the "profitability" of short-term firm purchases is to compare them to contemporaneous short-term firm sales. This would only be reasonable if:

1. Short-term firm purchases were always made to supply short-term firm sales.

2. Short-term firm purchases were always made in the same market as short-term firm sales.

3. The duration of each short-term purchase is the same as that of the short-term sale with which it is being "matched".

4. The load factor of each short-term firm purchase is the same as that of the short-term sale with which it is being “matched.”

The record in this proceeding demonstrates that none of these assumptions are warranted. Often, high-priced short-term firm purchases are required to serve retail load because of unit outages and transmission constraints and often short-term firm sales are covered from off-peak energy available from the Company's thermal plants. Tr. 673. At times, due to transmission constraints, the Company is required to make short-term firm purchases to serve retail load in markets where prices are inflated because of the transmission constraints into them. Tr. 1688. Finally, focusing only on those months during which short-term firm purchase prices exceeded short-term firm sales prices, ignores those months in which the opposite occurred. For example, the Company could have sold a six-month block of energy that was covered with three two-month purchases. If one block of purchased energy was higher than the sale price of the six-month block, but the other two blocks were priced lower, the overall transaction could be profitable if all the blocks are netted together. Tr. 673-74. Mr. Widmer demonstrated that even if one were to assume that all short-term firm purchases were made to serve short-term firm purchases, overall, the purchases were "profitable" if considered as a whole. Ex. UP&L 7SR at 5-6.

Mr. Falkenberg's attempts to "pick and choose" among actual and adjusted data should therefore be rejected. *See* Tr. 1566.

On behalf of the Large Customer Group, Mr. McCullough proposes the same sort of selective adjustments to the Company's net power cost calculations. Mr. McCullough's adjustments require even more extreme mismatches and result in patently absurd conclusions. For example, Mr. McCullough proposes to combine *actual* short-term firm sales volumes and *actual* short-term firm sales prices and assume that the resulting increased sales can be assumed to be covered by purchases made at *normalized* prices generated by the PD/MAC model. Among other difficulties, this gives rise to an assumption that a substantial additional volume of firm high-priced sales can be made on the west side of the Company's system which are "covered" by low-priced normalized purchases in the Pacific Northwest. Ex. UP&L 7SR at 2.

Mr. McCullough also proposes adjustments that effectively assume that the *lowest* market prices will prevail at times when the availability of hydroelectric power is at the *lowest* possible level. A series of errors like this drives Mr. McCullough to conclusions that are absurd on their face. Mr. McCullough is highly critical of the PD/MAC model and suggests that it does not accurately replicate actual conditions. Ex. LCG 2 at 4. In fact, the Company is proposing normalized net power costs in this proceeding that are within $600,000 of 1998 actual power costs. Tr. 1652. Mr. McCullough has made adjustments that result in proposed net power costs that are $102,000,000 lower than 1998 actual figures and materially lower than the Company has experienced in any year since the Utah Power/PacifiCorp merger. Tr. 1644 . If Mr. McCullough is correct in characterizing the match between PacifiCorp's actual and normalized results as "poor", his work would have to be considered laughable by comparison.

Several of the parties to this proceeding have attempted in various ways to suggest that difficulties and distractions somehow caused the Company to "lose" money in its Western wholesale marketing activities during 1998, thereby justifying adjustments to net power costs. The Company has described how wholesale markets are increasingly competitive and how wholesale sales margins are growing correspondingly narrower. Notwithstanding parties' various attempts at innuendo, the record in this proceeding does not support a conclusion either that the Company's responses to 1998 wholesale market conditions were other than appropriate, or that its wholesale sale activities were in fact unprofitable. Tr. 1620-21. Most importantly, even if 1998 was an aberrational year, the whole purpose of normalizing net power costs is to protect customers from any anomalies that did occur. Tr. 596, 1641. The Company prefers the continued use of normalized data, but can accept the use of actual data for net power cost as a whole. However, it should not be subjected to opportunistic adjustments that pick and choose between the two.

III. THE COMMISSION SHOULD REJECT THE WHOLESALE CONTRACT REVENUE IMPUTATION ADJUSTMENTS PROPOSED BY THE COMMITTEE AND THE DIVISION.

A. <u>The Commission has established standards that the Division and Committee must meet to support their adjustments.</u>

Division witness Wilson and Committee witness Yankel have proposed adjustments to impute additional revenue to certain wholesale sales contracts. The Division's adjustment is based on its conclusion that certain wholesale sales contracts are imprudent, as defined by the Division. Tr. 1173. While the Committee adopted the "general methodology" of the Division, its adjustment is apparently based on its assertion that retail customers are "subsidizing", as defined by the Committee, the Company's wholesale power business. Yankel Rebuttal Testimony at 4; Tr. 891.

In its September 10, 1993, Order, in *In the Matter of the Application of Mountain Fuel Supply to Adjust Rates for Natural Gas Service in Utah,* Dockets No. 91-057-11 and 91-057-17 ("Mountain Fuel Order"), the Commission established the standards the Division and the Committee must meet to support their proposed adjustments. In that case, Mountain Fuel Supply Company ("Mountain Fuel") had filed applications for rate reductions in two gas cost adjustment cases. The Committee alleged that Mountain Fuel had made imprudent gas supply decisions and requested additional rate reductions to reflect the hypothetical cost savings associated with the "prudent" gas supply decisions. In reaching its determination to reject the Committee's proposal, the Commission found that:

> In considering whether Mountain Fuel's gas acquisition decisions were prudent, we are bound to consider Mountain Fuel's decisions in light of the circumstances which existed at the time the decisions were made. The decisions must be judged in light of what Mountain Fuel knew or reasonably should have known. We must consider that Mountain Fuel was making its decisions prospectively rather than in reliance on hindsight. Prudence recognizes that reasonable persons can have honest differences of opinion without one or the other being imprudent.
>
> An issue arose regarding whether Mountain Fuel had the burden of demonstrating that its actions were prudent or the Committee had the burden of demonstrating that Mountain Fuel's actions were imprudent. We recognize that a public utility has the burden to justify rate relief that it seeks. (Citation Omitted) However, here the "rate relief" Mountain Fuel sought was approval of rate reductions of $8,332,000 . It is the Committee that is claiming that these rate reductions should be substantially larger. In these circumstances, the Committee has the burden of establishing a reasonable basis upon which we could conclude that Mountain Fuel acted imprudently.

Id. at 49-50.

B. <u>The Committee has not met its burden to establish that the Company has acted imprudently.</u>

The Committee has proposed an adjustment to impute additional revenue to fourteen of the Company's wholesale sales agreements. However, the Committee has made no attempt to establish a reasonable basis upon which to conclude that the Company has acted imprudently in entering into any of those agreements. Indeed, the Committee has made no attempt to analyze the prudence of any of those agreements.

The sole support for the Committee's proposed revenue imputation adjustment is Mr. Yankel's assertion that retail customers are subsidizing wholesale transactions. Mr. Yankel's subsidization argument is based on his comparison of the average cost of all the Company's existing purchased power contracts with the average price of post-1993 wholesale sales contracts. Ex. CCS 8 at 26. Tr. 892-894. By including pre-1993 purchased power contracts (including decades old high cost PURPA-mandated QF contracts like the Sunnyside Cogeneration Associates agreement) in the average cost side of his comparison, while excluding highly profitable pre-1993 wholesale sales contracts from the average price side of his comparison, Mr. Yankel is able to reach the conclusion he wants. Tr. 893-894; 504-505. However, that conclusion is not supported by the facts.

In reality, as Mr. Steinberg testified, the wholesale power market has changed over the last several years and both the costs of purchased power and the prices for wholesale sales have decreased. Ex. UP&L 6R at 12-13. As a result, under any reasonable power supply assumptions, the Company's wholesale sales are profitable and continue to provide benefits to retail customers. Ex. UP&L 6R at 13; Tr. 505-506.

The Committee has failed to meet its burden to establish that the Company has acted imprudently and the Committee's adjustment should be rejected.

C. <u>While the Division has provided a more reasonable analysis than the Committee, the Division has also failed to meet its burden to show that the Company has been imprudent.</u>

The Division has proposed an adjustment to impute revenue to six wholesale sales agreements. That adjustment is based on the Division's erroneous conclusion that the Company was imprudent when it entered into those agreements. In order to reach its conclusion, the Division has replaced the prudence standard previously adopted by the Commission with its own standard.

The Commission's prudence standard requires that decisions be judged "in light of the circumstances which existed at the time the decisions were made." Mountain Fuel Order at 49-50. Under that standard, the prudence analysis for these wholesale sales agreements should be based on the Company's RAMPP 4 avoided costs. Those RAMPP 4 avoided costs were filed and approved in Oregon in 1996 and reflected the most recent information available to the Company at the time it made its decision to execute the agreements. Tr. 2213-14.

In contrast, under the Division's prudence standard, the decision to enter into these six contracts is not judged on the basis of the then current circumstances, but on the basis of the "avoided costs filed in Utah by PacifiCorp at the time the contracts were signed." Tr. 2196. As a result, the Division has analyzed the prudence of 1996 contract decisions using 1995 avoided costs which reflect load and resource data from the years 1992 through 1994. Tr. 1173-76. That exercise has not and could not provide a reasonable basis for the conclusion that, based on what it knew at the time, the Company was imprudent when it entered into the six agreements.

In addition to violating established Commission policy, the Division's proposal for a jurisdiction dependent prudence standard is both unreasonable and unwise. The Commission currently determines prudence based on evidence of the actual circumstances facing the Company at the time a decision was made. Under the Division's proposed standard, evidence of the actual circumstances would become irrelevant. Prudence would instead be determined based upon a retroactive review of the state of the Company's regulatory filings in each jurisdiction. Tr. 1193. While Division witness Wilson acknowledged that the new prudence standard "definitely poses a challenge", that understates the problem. Tr. 1185. The standard is unworkable for a multi-jurisdictional utility. The abandonment of a system-wide standard would subject the Company to potentially conflicting standards for each jurisdiction and could result in the elimination of wholesale transactions, to the detriment of retail customers. Tr. 2217-18.

A final problem with the Division's prudence analysis is its use of a sales for resale credit. The sales for resale credit has been used in this and other jurisdictions as an opportunity cost in the analysis of retail special contracts. It has not been used, and should not be used in the analysis of wholesale agreements. The wholesale agreements already reflect the opportunities, and margin, that were available at the time they were executed.

IV. THE COMMISSION SHOULD REJECT THE DIVISION'S PROPOSED CHANGE TO THE ACCOUNT 903 ALLOCATION FACTOR.

The costs charged to Account 903 are primarily the labor and expenses associated with customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints. Costs incurred by the

Company's Salt Lake and Portland Business Centers are charged primarily to Account 903. About 20% of the Account 903 costs included in the Company's proposed revenue requirement relate to work done at local Utah offices, and were directly assigned to Utah. The other 80% are common costs allocated among the states using the CN factor, which is based on the number of customers in each state. The Division proposes to instead allocate such common costs among the states using the SO factor, which is based on utility plant investment. Ex. UP&L 2R at 6-7. The Division's proposal is unreasonable and should be rejected.

The foundation of the Division's proposal is an analysis in which the Division's witness, Mr. Kenneth Powell, purports to show that there is no statistical correlation between Account 903 costs and the number of customers. Because he is unable to find such a correlation, he concludes that Account 903 costs should not be allocated using the CN factor. Ex. DPU 4 at 5-6. However, a fundamental flaw in Mr. Powell's analysis is his use of 1991-1996 historical data that is irrelevant to the proper allocation of Business Center and other common costs, because that historical data is based on the costs of operating in a totally different manner. During that time frame, the Company had numerous local offices throughout its service territories to handle functions that are now handled by the Business Centers. There is simply no reason to expect that the portion of the Business Center-related costs should track the historical cost of operating local customer offices in each of the states in which the Company operated, nor has the Division established the existence of such a relationship. Rather, Mr. Powell simply used the 1991-1996 data because it was the "most consistent, reliable data," notwithstanding his recognition that it was inconsistent with the prior years' operations. Ex. UP&L 2R at 9-10, quoting Ex. DPU 4 at 6. A fitting analogy to the Division's comparison is an attempt to predict personal computer costs by reviewing typewriter maintenance records.

When Mr. Powell's statistical analyses leave him admittedly lost (Ex. DPU 4 at 11), he proposes a default allocator, SO. In sur-rebuttal, he attempts to support the use of SO by saying that it is used for allocating a lot of other things, and if it's "bad," we need to take another look at the use of SO. Tr. at 2244. That is not a reasonable basis for adopting the SO factor for the allocation of Account 903. On the other hand, using customer count (CN) for allocating customer service costs does have a reasonable basis, because such costs are driven by the need to provide all customers with bills, convenient access to information, and other customer services. Ex. UP&L 2R at 17.

The Division has proved neither a sound basis for the rejection of the use of the CN factor, nor a sound basis for the adoption of the SO factor for allocating Account 903 costs. The 1998 customer service costs in general, including those in Account 903 allocated using the CN factor, are consistent with historical trends for Utah, and should not be adjusted as proposed by the Division.

V. THE COMMISSION SHOULD REJECT THE COMMITTEE'S PROPOSED DISALLOWANCE OF INCENTIVE COMPENSATION COSTS.

The Company's revenue requirement in this case includes employee compensation expenses consisting in part of incentive compensation payments, a substantial portion of which the Committee proposes to disallow. As it did in the 1997 rate case, the Company has established the appropriateness of its incentive compensation costs, and the Committee's proposed disallowance should be rejected.

The Company's incentive compensation programs are one part of a compensation policy designed to attract and retain qualified employees. Incentive compensation is part of the employee's total remuneration, which is set at a level equal to the average total remuneration provided by competitors for employees when performance is at desired levels. The incentive compensation programs at issue are designed to put some of the total remuneration at risk. Thus, if employee performance is less than desired levels, employees should receive less than market average remuneration. On the other hand, the programs also provide upside opportunity for exceptional performance. All of the incentive awards paid in 1998 were based on line of sight goals designed to benefit ratepayers, rather than measures of financial performance, such as earnings per share. In 1998, the Company's workforce was paid about 96% of the competitive average total cash compensation. Thus, the total cash compensation paid to employees for 1998 is at or below the competitive average and is appropriately included in the Company's revenue requirement. Exhibit UP&L 9R, pp. 3-6.

As in the 1997 rate case, the Committee's proposal to remove 62.5% ($3.7 million on a Utah basis) of the Company's incentive compensation costs is without basis. Notwithstanding the evidence that the Company's total remuneration is at or below the competitive average, the Committee continues to hang onto the view that the incentive compensation is "extra compensation" and therefore inappropriate. To the contrary, the Company has taken specific steps to avoid the incentive compensation being "extra" compensation, and absent the guideline incentive that employees were eligible to earn under the programs, the Company's total cash compensation would be below the competitive level necessary to attract, retain and motivate qualified employees. Ex. UP&L 9R, p. 16. This is not rebutted. Indeed, the Committee did not even perform a comparison of the Company's total remuneration to the market.

In its challenge, the Committee also mischaracterizes a number of goals as being "financial," when in fact those goals are not based upon some corporate measure of financial performance such as earnings per share, but are directed at containing costs, which cannot be denied is beneficial to customers. Ex. UP&L 9R, p. 7.

The Company has shown that its incentive compensation payments for which recovery is sought in this case are consistent with the policies previously established by this Commission. Indeed, the Committee acknowledges that there are no significant differences between the 1997 incentive plans (for which the Commission granted cost recovery) and the 1998 incentive plans. The Committee has not put forth a basis for disallowance of the incentive compensation payments, and the Committee's adjustment must be rejected.

VI. THE COMMISSION SHOULD REJECT THE COMMITTEE'S ADJUSTMENT FOR STOCK-BASED COMPENSATION.

The Committee proposes that the Commission disallow recovery of costs which the Committee erroneously characterizes as "stock-based incentive compensation." Ex. CCS 5.4. The Committee's proposal is based on its view that the stock compensation was incentive compensation given for the Company's financial performance, which is contrary to the Commission's policy on rate recovery for incentive plans. The Committee's position is based on an erroneous view of the stock-based compensation which the Company has included in this case.

The costs which the Committee has referred to as stock-based incentive compensation actually relate to specialized retention agreements the Company put in place for certain executives and key employees. *None* of the costs of that stock compensation was a performance based incentive payment. Ex. UP&L 9R at 19. In fact, the Company made an adjustment to specifically remove all the costs associated with its long-term incentive compensation plan. The costs associated with the granting of stock for retention purposes is a normal, recurring cost, not triggered by the Company's financial performance, and should not be disallowed.

VII. THE COMMISSION SHOULD REJECT THE COMMITTEE'S AND DIVISION'S ADJUSTMENTS TO THE COMPANY'S PROPERTY INSURANCE EXPENSE.

The Division and Committee propose adjustments to reduce the Company's property insurance accrual for 1998. The Company's self-insurance reserve – meant to cover the deductible on property damage losses – was mostly consumed by the end of 1997, and had to be built up. Recovery of this expense in the test year is reasonable. What is certainly unreasonable, in light of the fact that it took less than 5 years to deplete the reserve, is the Committee's proposal to spread the buildup of the reserve over 5 years. Such delayed recovery would be inadequate and should be rejected. Further, the Committee's proposed $6 million cap is unreasonable, because the Company's deductible is not $6 million per year, but $6 million per incident. Ex. UP&L 1R at 26-27. The Company should be allowed to recovery its property insurance expense at the level included in its filing.

VIII. THE COMMISSION SHOULD REJECT THE COMMITTEE'S AND DIVISION'S ADJUSTMENTS RELATED TO THE COMPANY'S UNCOLLECTIBLE EXPENSE.

The Company included in its filing an adjustment to reduce its uncollectible expense to a level based on the average of the years 1996 through 1998, consistent with the approach adopted by the Commission in the 1997 Order. Ex. UP&L 3 at 13. The Division and Committee propose to further reduce the Company's uncollectible expense by excluding the expense levels for the years 1997 and 1998, and including earlier years in calculating averages. For calculating their averages, the Division reaches back to 1994, and the Committee goes even further, to 1993. The Committee and Division exclude 1997 and 1998 uncollectible expenses because they think they are too high, but neither party presents substantial evidence that their calculated averages, reaching back to the early '90s, are representative of the level of uncollectible expense that can be expected for the Company.

There is simply no reason to believe that the Company's uncollectible expense will return to the pre-1997 levels, particularly with the increasing incidence of bankruptcy filings occurring in the State. Ex. UP&L 1R at 14. The Committee's and Division's proposed adjustments lack adequate factual support, unreasonably disregard current expense levels, and should be rejected. The Committee also recommends disallowance of consulting fees paid to Price Waterhouse Coopers for help in improving the Company's collection policies and procedures. That proposal, based on

Ms. DeRonne's opinion that the Company shouldn't have to hire expert consultants on an annual basis to address such issues, is unreasonable and punitive and should be rejected. The Company will typically hire experts to assist it in becoming more efficient, to the benefit of all stakeholders, and such practice should not be discouraged. The work of Price Waterhouse Coopers resulted in savings greatly in excess of the fees which Ms. DeRonne proposes to disallow. Ex. UP&L 1R at 16-18. The Company's efforts in this regard should be recognized, and the Committee's adjustment should be rejected.

IX. THE COMMISSION SHOULD REJECT THE COMMITTEE'S ADJUSTMENTS RELATED TO RENTAL EXPENSES.

The Committee proposes two adjustments regarding rental expenses and revenues: a disallowance of lease expenses for the Public Service Building ("PSB") in Portland, and an imputation of revenues attributable to subleasing two floors of the Company's space in One Utah Center. Ex. CCS 3. Denial of the PSB lease expense is based on the termination of the lease on December 20, 1998. Thus, notwithstanding that the Company had use of the premises for more than 95 percent of the test year, the Committee recommends disallowing recovery. The proposed disallowance of the PSB lease cost would deny the Company recovery of an actual, legitimate test-year expense and should be rejected.

The Committee takes one of its most extreme steps outside the bounds of the Commission's test year rules with it proposal to impute revenues related to the Company subleasing two floors of the One Utah Center. The Committee's witness acknowledges that the revenues which she proposes to impute are associated with a sublease that just became effective January 1, 2000, well after the end of the test year. Tr. 1392. The Committee's imputation is clearly contrary to the Commission's policy on post-test-year adjustments and must be rejected.

X. THE COMMISSION SHOULD REJECT THE COMMITTEE'S LINE EXTENSION ADJUSTMENT.

PacifiCorp proposes changes to its Electric Service Regulation No. 12, including a reduction in the amount of customer line extension allowances. The Committee proposes an adjustment which would reduce the Company's existing Utah rate base by $6.4 million. The Committee argues that failure to make such an adjustment would allow the Company to earn a rate of return greater than that authorized by the Commission. Ex. CCS 1, p. 47. To the contrary, adoption of the Committee’s proposed adjustment would preclude the Company from earning a return of and a return on its actual investment in distribution property as though it had never happened.

The Committee’s proposed adjustment is based on the estimated annual increase in future residential contributions resulting from the proposed change in the line extension allowance. Ex. CCS 1, p. 47. By receiving a higher level of contribution from customers toward the cost of constructing line extensions, the Company’s investment in those line extensions will be lower than what it would be absent the adoption of the proposed change in the line extension allowance. However, a reduction in the growth in the Company’s distribution rate base will not reduce the Company’s actual existing rate base. That fact is undeniable and unrebutted. The approval of the proposed line extension policy will not reduce the amount of the Company’s investment in distribution plant, change the status of the plant that was built with that investment, or otherwise justify the removal of the plant from rate base.

The plain and simple truth of the matter is that the Committee’s proposed adjustment would deny the Company an opportunity to receive a return of and return on the $6.4 million of rate base that the Committee proposes to remove. While one Committee witness proposing the reduction of rate base as “fair and reasonable” was unable to answer the question of how the Company would receive a return of and return on that rate base amount, the other Committee witness, Mr. Larkin, avoided the question by claiming that the Committee’s proposal is a "change in relationship." Tr. 2074. Mr. Larkin went so far as to deny that the $6 million in rate base he is removing represents real money the Company has spent, claiming "it represents a relationship... And you can’t keep going back and saying, you took out $6 million of actual investment. What I took out – what I changed was a relationship." Tr. 2075. Yet, Mr. Larkin then again acknowledges that the Committee’s proposal reduces rate base by $6 million. Tr. 2076. The Committee is also misguided in its attempt to liken the line extension policy change to a tariff change which provides for increased revenues, such as an increase in a late check fee. Tr. 1992. The Committee fails to recognize that the line extension proposal would not result in additional revenues to the Company, but will only reduce the amount of capital that the Company will expend in the future for line extension. Exhibit UP&L 12R, p. 18. Further, the Committee’s proposal fails to account for the increase in the Company’s rate base to reflect that the Company would have to spend additional dollars on new line extensions in order to receive the additional contributions under the proposed policy. As such, the Committee's proposal violates matching principles adopted by this Commission. The Commission should recognize the Committee's argument for what it is, obfuscation and a plain and simple attempt to avoid the truth that its proposed adjustment would deny the Company's shareholders the ability to receive a return of and return on the $6.4 million of rate base which the Committee proposes to remove.

XI. THE COMMISSION SHOULD REJECT THE COMMITTEE'S PROPOSAL TO INCLUDE WHOLESALE LOAD IN THE DETERMINATION OF THE POWER SYSTEM PEAK.

Committee witness Yankel proposes to include the firm wholesale load in the determination of the Company's hour of system peak. Ex. CCS 8, pp. 49-51. The hour of system peak is used in the allocation of generation and transmission costs to all the retail jurisdictions served by PacifiCorp. Including firm wholesale load in their determination is inappropriate and should be rejected.

The Company set forth several reasons demonstrating the inappropriateness of Mr. Yankel's proposal. For instance, the Company does not assume the same long term obligations to serve wholesale contracts as it does for retail and FERC requirements service. Accordingly, the Company does not include non-requirements wholesale contracts in its system resource planning. Mixing wholesale loads for which the Company does not have an ongoing obligation to serve, with retail loads for which the Company does have an ongoing obligation to serve, would distort the contribution to system peak which is used in the allocation of costs to retail customers. Further, volatility in the magnitude of wholesale sales from hour to hour and from day to day would further distort the allocation of costs to retail customers with influences that are unrelated to retail load. Ex. UP&L 12R, pp. 4-7.

Including firm wholesale load in the determination of time of system peak would also work against the objective of rate stability because, as acknowledged by Mr. Yankel, including the wholesale loads would sometimes help Utah (by allocating less costs to the state) and sometimes hurt Utah (by causing a greater allocation of costs to the state). Tr. 927. The Committee's proposal is contrary to the determination of system peak as reported to and used by the Federal Energy Regulatory Commission, has never been made by Mr. Yankel before, and has not been discussed by the Committee or the Division with PITA. For all the above reasons, the Commission should not adopt the Committee's proposal to include wholesale load in the determination of system peak.

XII. THE COMMISSION SHOULD APPROVE THE COMPANY'S PROPOSED TREATMENT OF THE GLENROCK MINE CLOSURE COSTS AND RECOVERY OF RE-ENGINEERING, COMPUTER HARDWARE AND COMPUTER SOFTWARE COSTS

In the Company's last Utah rate proceeding, the Commission disallowed recovery of a number of costs that were recorded on the Company's books of account during the 1997 test period applicable to the proceeding. *See* 1997 Order at pages 33 through 42. The circumstances that gave rise to the Commission's decision to disallow these costs in the 1997 Order have now changed such that recovery is clearly warranted in this proceeding. Notwithstanding these changed circumstances, the Committee continues to oppose recovery based upon standards that this Commission has never imposed.

A. Dave Johnston Coal Mine Closure

In late 1997, the Company decided to close the Dave Johnston Coal Mine (also referred to as the Glenrock Mine) and utilize outside coal purchases for the Dave Johnston plant. This action was taken to achieve substantial reductions in fuel costs and was consistent with the recommendations made by the Division and its consultant, Energy Ventures Analysis, Inc. To properly reflect the mine's shortened life, the Company recorded an expense for the majority of the undepreciated plant balance in 1997 ($29 million) and also $33 million in reclamation expense and $3 million in employee severance expense. The Company sought amortization of these expenses in the 1997 rate case, but was denied recovery. In this case, the Company is seeking a three year amortization of these costs beginning with calendar year 1998, along with rate base treatment for the unamortized portion of the mine asset. The Division supports the inclusion of the Dave Johnston mine closure costs in this case, although recommending that they be amortized over five years rather than three. The Committee, on the other hand, recommends complete disallowance of the closure costs.

The Commission in the 1997 Order disallowed the Dave Johnston closure costs as a post-test-period adjustment, pointing to the mismatch in costs and benefits. In this case, however, both costs and benefits associated with the decision to close the mine existed within the test period, although the actual closure did not occur until 1999. For instance, the Company incurred approximately $4 million in final reclamation expenses in 1998 and achieved coal cost savings in the range of $1.8 million to $2.5 million attributable to the decision to close the mine. Ex. UP&L 1R, pp. 20-

21; UP&L 1.7R, 1.8R. Contrary to Mr. Larkin's belief that the majority of the savings was due to early retirements, the greatest part of the savings was attributable to

elimination of rehandling of overburden, due to the knowledge that the mine would be closing. Tr. p. 2164.

To no surprise, now that the Company has shown the existence of both costs and benefits within the test year, the Committee still proposes a disallowance of the Dave Johnston Mine costs, but this time because of an asserted "gross mismatch" of costs and benefits. Mr. Larkin would have the Commission require that for the Company to receive recovery, there must be benefits at least matching costs in the test period–that there be at least an equivalency. Tr. 2012-13, 2085. Mr. Larkin's proposed equivalency requirement is not only unworkable, it is unsupported by this Commission's decisions. It is unworkable because with the front-end costs of large projects, savings rarely, if ever, match costs in the early years of the project. Ex. UP&L 1R, p. 21. Notwithstanding substantial economic benefits over the life of a project with high front-end costs, Mr. Larkin's equivalency standard would deny recovery in almost every circumstance.

Mr. Larkin's equivalency requirement is also not supported by Commission orders. Mr. Larkin interprets the Commission's order in Docket No. 92-049-05 as imposing such a requirement, although there is no specific language suggesting such a standard. Tr. 2013. However, there is specific language in a later U S WEST case, Docket No. 95-049-05, reflecting that the equivalency requirement is <u>not</u> the standard adopted by this Commission:

> The Division recommends that recovery of the costs incurred by the Company in this area should be deferred, based upon its analysis indicating that the majority of the benefits which could be expected would occur, if at all, several years into the future. The Commission was asked to defer recovery until such time as these benefits can be ascertained, matched with the costs, and then offset against the costs.
> . . . .
>
> We will require that the restructuring and re-engineering costs be amortized over a period of five years. We believe it is appropriate to amortize the amounts, but over a definite period of time, as opposed to an open-ended period as proposed by the Division. We find that this is reasonably calculated to spread recovery over the period in which benefits to ratepayers will <u>at least begin to occur</u>.

November 27, 1995 Order, pp. 42, 44 (emphasis added).

Further, in granting rehearing on the re-engineering issue in the Company's 1997 rate case, the Commission stated its "intent that recovery should begin coincident with ratepayer benefit." April 13, 1999 Order on Requests for

Reconsideration and Rehearing. Consistent with its order in the U S WEST case, the Commission did not state that recovery should begin only when the benefits are equivalent to the costs within the test period.

The Committee also challenges the Dave Johnston mine closure costs with an argument that the recovery of the unaccrued final reclamation costs would amount to retroactive ratemaking, asserting that the Company underaccrued final reclamation costs in past years. However, the facts are otherwise. Had the mine stayed open, the remaining 53 million tons of coal would have been mined, and the Company would have accrued the final reclamation related to those tons to arrive at the approximate $54 million final reclamation cost. Tr. pp. 469-70; 2163. However, since the mine was closed in 1999, rather than in 2012, the $33 million (the difference between the $54 million and the $21 already accrued) has not yet been recovered from customers. The unrecovered reclamation costs are the result of the decision to close the mine early and should be included for cost recovery associated with the Dave Johnston mine closure.

B. Re-engineering Costs

As described in Mr. Meier's rebuttal testimony (Ex. UP&L 3R), commencing in 1996, the Company commenced a series of re-engineering initiatives in order to bring a corporate-wide focus to making the most of developments in information technology and increasing efficiency and productivity. Collectively, these initiatives came to be known as the Business System Integration Project ("BSIP"). The BSIP project resulted in a number of conclusions and recommendations including the decisions to implement an enterprise resource planning system (SAP), to stop remediation and maintenance work on systems that would be replaced by SAP, and to substantially reduce employee levels in anticipation of SAP efficiencies. These initiatives resulted in system-wide savings during the 1998 test period in excess of $30.6 Million (See Ex. UP&L 3R at page 17 and Tr. 372). These test period initiatives and savings would not have been obtainable in the absence of the BSIP process.

In the 1997 Order, the Commission found that customers had received *no* benefits from the Company's re-engineering efforts during the test period and denied recovery on that basis. It distinguished the Company's 1997 circumstances from those of US WEST on the grounds that: 1) benefits from U S WEST's re-engineering efforts *although small* began in the test period, 2) the US WEST record contained an analysis of the costs and benefits of the re-engineering program and 3) the U S WEST record (unlike the Company's 1997 record) showed that U S WEST would be continuing to incur expenses associated with re-engineering for the next several years. *See* 1997 Order at pages 38-39. The record in this case demonstrates that the Company's basis for recovering its re-engineering costs is at least as compelling as that relied upon by the

Commission in allowing the recovery of re-engineering costs by U S WEST. There are not just "small", but substantial test period benefits. The Company presented an analysis of the test period costs and benefits associated with its BSIP/SAP initiatives and the Company demonstrated that it has and will be continuing to incur costs for BSIP/SAP in the years following the test period. Under these circumstances, the Company's proposal to amortize BSIP costs over five years and to begin their recovery in this proceeding is clearly reasonable.

While the Division opposed recovery of re-engineering costs in the last proceeding, it supports recovery in this case. The Committee remains opposed, on the basis of Mr. Larkin's view that re-engineering, in and of itself, produces no benefits for customers and that it cannot produce customer benefits until SAP is fully functional. Mr. Larkin is wrong from a factual standpoint as evidenced by Mr. Meier's testimony regarding the savings that were obtained during 1998 as a result of BSIP, even before the SAP system became functional in the latter part of that year. Ex. UP&L 3R at 25.

C. Software Write-Down and SAP Cost Recovery

In the Company's last proceeding, the Company sought recovery of costs associated with writing down software that was to be replaced by the SAP system. Even though the Company had recorded these costs on its books during 1997, the Commission denied recovery of them. Again, changed circumstances dictate a different result in this case.

In the 1997 Order, the Commission denied recovery on the grounds that during the test period, the old software was still in use and the new software was not yet in service. In the present case, Mr. Meier testified that during the test period the new software (SAP) was functional, used and useful. While the old software also remained in use, this should not be the basis for not beginning the amortization of its costs because, for record "inquiry" purposes, the Company will continue to require use of the old software. It would not be cost effective to replace the record function performed by the old software. Tr. 437.

Again, while the Division opposed recovery of costs associated with the obsolete software in the last case, it supports recovery in this proceeding. The Committee, through Mr. Larkin, would continue to deny recovery because the old software remains useable and is relied upon for some functions and because the replacement SAP software was not in use throughout the Company during the test period. Neither of these factors should be determinative. As a practical matter, some use of the old software will be made for many years to come. The critical point, as observed in the 1997 Order, is whether the replacement SAP software was in use during the 1998 test period. Mr. Meier testified that the SAP software was fully functional during 1998. Although SAP was not installed throughout the Company until early 1999, the Company is not seeking to recover in this proceeding the cost of company-wide distribution of the system, but only a portion of the costs associated with causing SAP to be functional in 1998. Tr. 436.

Therefore, recovery of both a portion of the cost of the old software and a portion of its replacement SAP software in this case is both timely and appropriate.

D. <u>Mainframe Computer Writedown</u>

In the 1997 Order, the Commission denied recovery of costs associated with the retirement of the Company's mainframe computer on the grounds that the old mainframe computer was in use throughout the 1997 test period and its replacement was not yet in service. *See* 1997 Order at page 35. The Company's new mainframe computer was installed and the old mainframe was retired during 1998, thereby satisfying the Commission's standard for recovery in this proceeding. Again, the Division now supports recovery of the costs of the retired mainframe while the Committee continues to oppose it. Committee witness Larkin argues that because the new mainframe was required by the SAP system and because the SAP system was not in use throughout the Company during 1998, recovery of costs associated with the old mainframe is still premature, notwithstanding that it was actually taken out of service during the test period. Mr. Larkin's conclusion is based upon two erroneous premises. The new mainframe was principally required because the old mainframe was running out of capacity. Ex. UP&L 3R at 31. The new mainframe was not required by the SAP system and in fact, the SAP system does not even run on a mainframe. Tr. 2125-26.

XIII. THE COMMISSION SHOULD APPROVE THE COMPANY'S PROPOSED TREATMENT OF PENSION EXPENSES.

A. The Commission should allow the amortization of the deferred pension asset.

The Company has historically accounted for pension expense on a cash funding basis, and in 1987 obtained from the Commission an accounting order pursuant to Financial Accounting Standard (FAS) 71, authorizing it to establish a regulatory asset to defer the excess of FAS 87/88 (accrual based) pension cost above cash funding. Accordingly, since 1987 the Company has expensed for financial books and ratemaking the amount of cash funded to the pension plan and has deferred the difference between the amount funded and total pension cost as a regulatory pension asset. In this case, the Company seeks to discontinue the FAS 71-modified treatment of pension costs for ratemaking, and recover the deferred pension asset over a 5-year amortization period. Ex. UP&L 1R, at 2-5. The Committee seeks to deny the Company's recovery of those costs.

The Committee's argument against recovery of the deferred pension asset is largely based on the Company having written-off in 1997 the $87 million deferred regulatory pension asset, noting in its 1997 Annual Report that it had determined that recovery of these costs was not probable. However, as Mr. Dalley testified, the Company's view of the matter changed, as reflected in the 1998 Annual Report. The fact that the Company expensed the deferred pension asset in 1997 for financial reporting purposes should not pre-determine how this Commission treats the costs for regulatory purposes. As Mr. Peel for the Division stated: "What you do on the books and what you do for regulatory purposes can be different. . . . You can have two separate treatments for books and for regulatory accounting." Tr. 1470.

Absent a change to the accrual method, the deferred pension costs would normally be recovered through higher cash funding levels in the future. Ex. UP&L 1R, at 3-6. Just as the fact that a cost is left on the Company's books for financial reporting purposes does not dictate that the Company should receive recovery from customers, the fact that an item is removed from the books for financial reporting purposes should not preclude recovery. The fact still remains that these pension costs that were incurred for its electric operations have not been recovered. Consistent with the Commission's prior approval of amortization of early retirement costs and FAS 106 transition obligations, the Commission should allow the Company's requested amortization of the deferred pension asset.

B. The Commission should reject the Committee's proposed current period pension expense.

The Company established that the accrual-based pension costs in its filing are less expensive than the cash funding method proposed by Mr. Schultz for the Committee when properly calculated. Ex. UP&L 1R at 6; 1.4R. This is well-reflected in UP&L Summary Exhibit 1. The Division concurs that the Company's proposal is the lowest cost approach. Tr. 1464-65. Indeed, Mr. Peel for the Division calculated that using the cash funding method would cause a $12-13 million increase in revenue requirement. Tr. 1465.

A critical flaw in the Committee's proposal is that it arbitrarily attributes $88.6 million of the $94 million pension funding in 1998 to early retirement and allows only the difference of $5.4 million for current period expense. Such an approach unreasonably reduces current period pension expense and flies in the face of the fact that the Company simply did not fund that amount of early retirement-related pension cost in 1998, as the Division recognizes. Ex. UP&L 1R, at 11; Tr. 1480-81. A more reasonable approach shared by the Company and the Division is to reflect that the Company funded its current period pension expense first, and that the remainder of the 1998 funding went to early retirement-related pension cost. This approach assigns the "normal" pension cost (that which would have existed in the absence of the early retirement program) of $51 million to current period expense and the balance ($43 million) to the 1998 early retirement. Ex. UP&L 1R, at 9-11. If the Commission wishes the Company to stay on a cash basis for pension expense, this is the approach which should be followed.

Mr. Schultz attempts to support his assignment of $88 million in pension expense to the early retirement program by taking the nonsensical position that by doing so, there is somehow created some sort of "guarantee" that the pensions will be paid. Tr. 1947. Mr. Schultz did not explain, nor could he, how the drastically reduced recovery of pension expenses which he proposes could possibly provide greater assurance that the Company will be able to pay the pensions for the early retirees. His position is also flawed in that it is based on the erroneous belief that the early retirees' pensions were funded in 1998 at that level.

Mr. Schultz also seems to be opposed to the change to accrual due to an October 1999 Company publication that stated the plan's assets exceeded its retirement liabilities, as calculated by an independent accounting firm. Tr. 1945. However, as Mr. Dalley explained, different groups use different computations for analyzing the pension plan, leading to different results. What is relevant for purposes of this case are the Company's financial statements filed with the Securities and Exchange Commission (Form 10-K, Footnote 15), which show that for 1998, the pension plan was not fully funded. Tr. 88-89; 2121-22. Ultimately, Mr. Schultz acknowledges that his opposition is not really based on the merits, but on his perception that there's somehow been some impropriety in how the issue has been presented–that it was "slid under the door." Tr. 1964. That criticism is unfounded and unwarranted, in light of the Company's explicit discussion in its direct testimony of the change to FAS 87/88 for accounting and ratemaking purposes. Ex. UP&L 3 at 14.

The Committee's proposal is a hybrid of cash and accrual accounting treatment, because its current period pension expense is based on a cash concept and its early retirement-related pension expense is based on a 5-year accrual. The Committee's proposal would deny the Company an opportunity to recover its full and reasonable cost of service, and should be rejected. Under no circumstances can the Committee's proposal be considered a fair cash basis proposal. If the Commission requires the Company to remain on the cash basis for pension expenses, basic considerations of fairness and consistency require that the Company be allowed to recover in accordance with either of the funding scenarios presented in UP&L Summary Ex. 1, notwithstanding that either of those would cause a higher revenue requirement than under the Company's accrual proposal.

XIV. THE COMMISSION SHOULD REJECT THE DIVISION'S PROPOSED ADJUSTMENT TO THE SC/SG FACTORS.

The System Generation (SG) factor for each state is comprised of the system energy and system capacity factors for that state. The System Capacity (SC) factor is based on the measurement of each jurisdiction's contribution tot he sum of the 12 monthly coincident peaks (loads) on the PacifiCorp system. The System Energy (SE) factor for a state is the sum of energy consumed by all states over the 12-month period, divided into the total energy consumed by the state. These factors are used to allocate production and transmission costs. Ex. UP&L 10 R at 3-4. Division witness Powell concludes that the 1998 SC and SG factors are unrepresentative because of an increase in the number of winter peaks. Based on that conclusion, he "normalizes" 1998 by using the historic growth pattern of the Utah SC factor from 1992-

1996. Ex. DPU 4 at 16.

There are a number of problems with the Division's proposed adjustment. The first is the Division's assumption that the trend toward winter system peaks is an anomaly. Utah has been a winter evening peak jurisdiction for at least the last twenty years. As Utah becomes a larger proportion of the total system load, the system increasingly reflects the winter evening peak characteristics of the Utah jurisdiction. Ex. UP&L 10.5R; Ex. UP&L 10R at 5-6; Tr. 2288-91.

A second problem is the way in which Mr. Powell has performed his adjustment. Mr. Powell takes the 1997 temperature adjusted SC factor and multiplies it by a growth rate based on 1992 through 1996 weather and hydro endowment adjusted loads. Since the 1997 temperature adjustment was more than double the average temperature adjustment over the last seven years, and since Mr. Powell failed to make the necessary corresponding changes to Utah revenues and power costs, he has artificially reduced 1998 load while using 1998 revenues. Ex. UP&L 10R at 8.

A third problem is Mr. Powell's failure to consider the impact of temperature normalization and the hydro endowment on his growth rate calculation. If those factors are considered, it becomes apparent that the 1998 SC growth rate is not anomalous. Ex. UP&L 10R at 11.

The final problem with Mr. Powell's adjustment is that it is wildly overstated and doesn't address the issue he identified. The issue, as stated by Mr. Powell, is that 1998 is an abnormal year because it had four, rather than two, winter evening peaks and that resulted in an increase in Utah's SC and SG factors. Ex. DPU 4 at 16. Thus, if the Commission believes, as the Company does not, that the 1998 SC and SG factors should be normalized as a result of the four winter evening peaks, that normalization should be accomplished by reducing the number of winter evening peaks from four to two. As Mr. Larson testified, that adjustment would reduce Utah's SC factor from 35.3750% to 35.1018%, resulting in approximately a $2 million decrease in the Utah revenue requirement. Ex. UP&L 10R at 7; Ex. UP&L 10.1R. Additionally, the calculation would need to normalize the revenues and power costs, which would tend to lower the overall revenue requirement impact of the adjustment.

XV. THE COMMISSION SHOULD REJECT THE DIVISION'S AND COMMITTEE'S PROPOSALS TO AMORTIZE Y2K COSTS.

Both the Division and the Committee propose that the Commission amortize the Company's 1998 Y2K costs over 5 years, based on the premise that the Y2K expense was a one-time expense that does not extend beyond the test period. As pointed out by Company witness Larson, that premise is incorrect. The Company has been incurring Y2K costs since 1997, and continues to incur such costs into the year 2000. That fact–that the costs have been spread over 4 years–has a smoothing effect on the amount included in the test year, thereby eliminating any perceived need to amortize the test year expenses over 5 years. Ex. UP&L 10R at 12.

The proposals by Mr. Powell and Mr. Larkin would provide the Company delayed recovery only for its 1998 Y2K costs, which amortized over 5 years provides the Company only $2 million per year. However, that recovery is for an issue that has already cost the Company over $21 million, and which was seen as critical not only by the federal government and the Utah Legislature, but also by this Commission. It would be unreasonable to so severely limit the Company's recovery of these prudently incurred costs.

XVI. THE COMMISSION SHOULD REJECT THE COMMITTEE'S PROPOSAL TO DISALLOW A PORTION OF WYODAK COAL COSTS.

Committee witness Cardwell proposes an adjustment to reduce the Company's 1998 fuel cost in the amount of $6,785,612 related to coal purchases for the Wyodak generation plant. Mr. Cardwell proposes the adjustment on the basis that the coal being purchased by the Company under a long-term contract is above market price. Specifically, Mr. Cardwell compares the Company's Wyodak coal price to the price of coal for Black Hills Power & Light Company's Neil Simpson #2 plant, an 80 MW plant that went into service in 1995. The Commission should reject the proposed adjustment.

Mr. Cardwell's adjustment is based on an erroneous comparison: a 1978 long-term coal supply agreement, providing for a secure, long-term supply of coal, compared initially to prices under a 1995 contract between affiliates, and later to spot prices. As established by the Company's witness Getzelman, the Powder River Basin (PRB) coal production in 1978 was vastly different than it is today, having gone from 29 million tons produced annually to over 290 million tons. The decline in coal prices that accompanied that increase in production were not foreseen in 1978. Rather, coal pricing was projected to remain flat on a real cost basis over this period of time. Ex. UP&L 4.2R. Mr. Cardwell's adjustment is based on the premise that the Company could have, and should have, gone forward with the Wyodak plant in 1978 on something less than a firm, long-term coal supply agreement. There is no basis for such a premise. In fact, Mr. Cardwell acknowledged he has no evidence the Wyodak plant could have been built without entering into the long-term contract which he now attacks. Tr. 1528. On the other hand, the Company presented evidence that it was reasonable to enter into this type of contract in 1978, and that it was similar to other coal supply contracts entered into during that period in the PRB. Ex. UP&L 4R at 2.

Is the Company presently paying more than the spot price for coal at Wyodak? Sure. Does that mean that the Wyodak coal supply contract was imprudent? No. The fact that at a point in time the costs being incurred by the Company under a long-term contract may be higher than the spot market is not a basis for denying cost recovery. What Mr. Cardwell is seeking is for the Commission to look at the prudence of a 22-year old contract with 20/20 hindsight, and assume that the Wyodak plant, having the fifth lowest cost of plants in the WSCC region purchasing at least 1.5 million tons of coal per year (Ex. UP&L 4R at), could have prudently been built without the firm, long-term coal supply contract. Yet, Mr. Cardwell admittedly has no support for that position. The Committee's proposed adjustment must be rejected.

XVII. THE COMMITTEE'S PROPOSED ADJUSTMENTS RELATED TO EARLY RETIREMENTS SHOULD BE REJECTED.

In its rebuttal testimony, the Company set forth several changes related to the early retirement and workforce reduction programs, which results in decreases to Utah operating expense and rate base. Specifically, the revisions were made with respect to the number of backfill positions, the timing of the backfill and the average salary of backfill positions, and also remove a component of severance costs associated with an accrual related to 1999. Ex. UP&L 2R at 40-42; 2.1R revised, at 9.13. The Committee, through Mr. Schultz, proposes several further adjustments related to the Company's early retirement and workforce reduction programs that are based on erroneous facts, result in double counting, and reach beyond the test year, and accordingly, should be rejected.

First, the Committee seeks to disallow $600,598 of additional severance and $1,150,000 of non-qualified lump sum expense that were not paid or booked until 1999, notwithstanding that the savings associated with those employees are fully reflected in the Company's early retirement adjustment. Ex. UP&L 2R at 42. The Committee quite willingly takes the benefits, but doesn't want to pay the costs of achieving those benefits. Consistent with the principle of matching costs and benefits, the Commission should reject the Committee's adjustment, and include these costs along with the other early retirement costs to be amortized.

Next, out of apparent confusion over the difference between the early retirement program and the $30 million cost reduction program, the Committee recommends an adjustment for post-1998 retirement savings. There was no "post-1998 retirement" program. Instead, what Mr. Schultz is trying to have the Commission do is pull cost savings from 1999 budget reductions and severed employees into the 1998 test period. The Company has now already captured the savings attributed to 82 positions that were not backfilled in 1999, and Mr. Schultz wants to count another 75 positions eliminated in 1999. Tr. 2159-60. Aside from violating the Commission's policy against post-test-year adjustments, Mr. Schultz also double counts the elimination of budgeted positions. Ex. UP&L 2R at 43-44; Tr. 2158-59.

Finally, Mr. Schultz recommended a higher labor overhead rate for the calculation of early retirement savings. There were at least two serious flaws in Mr. Schultz' proposed overhead rate. First, Mr. Schultz failed to take into account that it is the <u>incremental</u> labor overhead, that is, the extra cost of hiring an employee, that should be used. Certain overhead costs, such as past pension costs, should not be considered as additional costs of hiring new employees or additional savings of eliminating employees, because those costs remain regardless of the number of current employees. Ex. UP&L 2R at 45. The next critical flaw in Mr. Schultz' proposed overhead rate is that it is based on mismatched comparisons that do not properly account for labor costs being split between expense and capitalization. Specifically, Mr. Schultz arrived at erroneous numbers by mismatching the components of numerators and denominators, such as by dividing a number made up of both capital and expense by a number that only includes expense. Tr. 2146-47; Ex. UP&L 2.7R. The Company established that Mr. Schultz' proposed overhead rate is flawed and, like his other proposed adjustments, should be rejected.

XVIII. THE COMMISSION SHOULD ALLOW RECOVERY OF SERP COSTS.

Included in the Company's proposed revenue requirement is an approximate $800,000 expense for the Company's Supplemental Executive Retirement Plan (SERP). The Committee, through its witness Schultz, proposes to disallow recovery entirely. The Committee's proposal lacks any sound basis and should be rejected.

The Company presented evidence that its SERP is a necessary form of compensation considered to be a part of the total remuneration package provided by the Company in order to attract and retain qualified executives. Most companies, including utilities, offer similar programs, the purpose of which is to make up a retirement benefit "gap" for executive employees. That gap results from legal limitations that have the effect of precluding such employees from obtaining retirement benefits (comprised of defined benefit pension and social security) of 60 - 70 percent of final average pay. Failure to offer SERP would make it more difficult for the Company to attract and retain qualified executives. Ex. UP&L 9R at 21-22.

True to form, the Committee views SERP expense as "extra compensation" and a "discretionary cost that should be the responsibility of shareholders," and accordingly recommends no recovery in this case. Ex. CCS 2 at 27. Rather than attempting to set forth some evidence that the SERP provides benefits that are unreasonably high compared to market, or that it is not usual for companies to provide such a benefit, the Committee simply makes the conclusory allegation, like it does with respect to incentive compensation, that the SERP provides "extra compensation." There is no valid basis on this record to deny the Company recovery of its costs associated with providing the SERP benefit, and the Committee's proposed adjustment must be rejected.

XIX. THE COMMISSION SHOULD REJECT THE PROPOSED DISALLOWANCE OF CEO SEVERANCE COSTS.

The Division recommends that the Commission deny recovery of the severance costs associated with the departure of the Company's former CEO, Mr. Frederick Buckman, in 1998. The Division's proposal to disallow the entire amount of Mr. Buckman's severance costs is unreasonable and should be rejected.

The Division bases its adjustment in part on some unspecified "unique circumstances" surrounding Mr. Buckman's termination of employment with the Company. Tr. 1465. Whatever "unique circumstances" the Division had in mind, it is likely that unique circumstances exist with respect to many executive departures. That alone cannot be a valid basis for denying recovery of costs of severance, which is a very common component of executive benefits and a necessary cost of doing business. Ex. UP&L 9R at 23.

The Division also points to the fact that Mr. Buckman's severance was higher than other officers' severance. Ex. DPU 2 at 8. Of course it was higher – CEOs' salaries are higher than other officers' salaries, and the marketplace requires that their severance packages are similarly higher. Tr. 1466. The fact that the cost of severance for the CEO was higher than the cost for other officers is no reason to deny recovery of the entire cost.

Finally, the Division attempts to justify the denial of recovery with a comparison to other officers' severance being connected with the Company's early retirement adjustment, which provides savings to customers. Reliance on a comparison to early retirement is misplaced in light of the fact that severance costs have been allowed by the Commission outside the context of an early retirement program. *See,* 1997 Order at 11. Thus, the Division has failed to establish a basis for its proposed denial of the CEO severance costs, and the adjustment should be rejected.

XX. THE COMMISSION SHOULD ALLOW RECOVERY OF THE CONDIT DAM DEPRECIATION EXPENSE.

PacifiCorp recorded $2 million of depreciation expense in 1998 to accrue for the cost of removing the Condit hydroelectric plant dam and related facilities. Mr. Powell for the Division and Mr. Larkin for the Committee propose removal of that expense from the test period. That proposed removal of the Condit expense disregards sound accounting principles and should be rejected.

The issuance of an environmental impact statement by the FERC, making the continued operation of the Condit plant uneconomic, led to the execution of a Settlement Agreement between the Company and the Yakima Nation, the U.S. Department of the Interior, and a number of other parties, which provides for the removal of the Condit facilities in 2006. Removal cost is estimated to be $16 million, while the Settlement Agreement limits the Company's cost at approximately $17 million. Ex. UP&L 11R at 3-5.

The Condit removal expense has been characterized as a post-test-year adjustment, given that the Settlement Agreement was not signed until 1999 and the facilities will not be removed until 2006. The Company disagrees with that characterization, because depreciation expense, which properly includes removal costs, is by its very nature forward looking. Providing for the recovery of the Condit removal accrual in this case, rather than deferring it, promotes intergenerational equity to the maximum extent possible by having the customers that are receiving the benefit of the Condit plant pay for the cost of the energy produced by the plant. Contrary to Mr. Larkin's claim that recovery of these costs in this case would violate the Commission's "policies which match costs to benefits for the period they are provided," (Ex. CCS 1 at 30), it is his proposed deferral of recovery that would violate the matching principle, since after removal of the dam, the benefits of the hydro generation will no longer exist.

In an apparent attempt to disassociate the cost of removing the Condit dam from depreciation expense (notwithstanding that the Committee signed the depreciation case stipulation that includes Condit removal cost as a component of depreciation), Mr. Larkin refers to the removal of Condit as an "abandonment loss." Such a characterization flies in the face of the fact that the costs are going to be incurred to remove the dam, not abandon it, and simply appears to be a semantic exercise directed at avoiding consideration of the true nature of the costs. Mr. Larkin's proposal to disallow the Condit removal costs is also inconsistent with his acknowledgment that a utility should not expect to recover the costs of an extraordinary retirement if the utility hasn't previously made a good faith attempt to recover the depreciation expense on the asset. Tr. 2037-38.

Failure to begin cost recovery in this case for the removal of the Condit dam will require dramatic increases in the Condit plant depreciation expenses that will be included in the next depreciation study to be effective in 2002. Ex. UP&L 11R at 11-12. The proposal by the Committee and the Division is contrary to sound accounting and common sense and should be rejected.

XXI. THE COMMISSION SHOULD REJECT THE COMMITTEE'S PROPOSED REDUCTION TO RELOCATION EXPENSES.

The Committee, through its witness Ms. DeRonne, recommends a reduction in the Company's relocation expenses through the use of a five-year average. The Committee's proposal is based on erroneous analysis and assumptions and should be rejected.

The Committee's proposed adjustment is based largely on its position that the Company undertook numerous relocation projects in 1998 including the Accounting Department relocation, a data center relocation and a Lloyd Center

Tower relocation project. Ex. CCS 3 at 4. However, the latter two projects were primarily capital projects and neither had *any* charges to Account 921.6, which is a sub-account used to track employee relocation expenses and is the account that is the focus of Ms. DeRonne's adjustment. Ex. UP&L 3 at 34-35. Further, the Accounting Department relocation expenses is already the subject of a Company adjustment which amortizes those costs over five years. In fact, the Accounting Department relocation was the *only* unusual employee relocation project in 1998.

Aside from the other errors in Ms. DeRonne's proposed adjustment, probably the greatest flaw is her unfounded use of 1993 and 1994 relocation expense levels in her attempt to arrive at a "normalized level." What evidence does she have that those six and seven year old expense levels (which she did not adjust for inflation) will ever again be experienced by the Company? None. Tr. 1387-88. Instead, she "presumes" the Company will not continue to have the "significant reorganizations" it has had in the past few years. Tr. 1388. Not only was it shown that Ms. DeRonne lacked any basis for presuming that there were significant reorganizations within the last few years that had any significant impact on relocation expense (other than the Accounting Department, for which the Company has already made an adjustment), her presumption still provides no basis for using such dated expense levels. Tr. 1384-87. The Committee's proposed adjustment is unreasonable and should be rejected.

XXII. THE COMMISSION SHOULD REJECT THE DIVISION'S PROPOSAL TO DISALLOW A PORTION OF THE POSTAGE COSTS NECESSARILY INCURRED IN MAILING BILLS TO THE COMPANY'S CUSTOMERS.

Along with the bills mailed to its electric customers, the Company includes a Company newsletter, and occasionally also includes advertising materials for non-regulated products and services. Notwithstanding the fact that inclusion of those materials does not impose any incremental cost on the Company's electric customers, the Division, through Mr. Powell, proposes to disallow nearly half of the postage cost associated with mailing utility bills. That proposal should be rejected for a number of reasons.

First, the Company's electric customers are only being asked to pay the normal postage cost for mailing their bills – any incremental postage cost associated with the inclusion of the non-regulated materials is charged to non-regulated expense. The Division's interpretation of certain NARUC guidelines so as to require the Company's non-regulated operations (or the Company's shareholders) to pay a portion of the normal postage cost of mailing electric bills to its customers is unreasonable and not required by the guidelines. Ex. UP&L 11R at 13-15. In fact, Mr. Powell's definition of a subsidy is not supported by the guidelines. He states that "A cross-subsidy exists whenever a partnership between two businesses, one of the businesses ends up having less costs than it would have had without the partnership." Tr. 2246-47. However, under the NARUC guidelines, subsidization is "The recovery of costs from one class of customers or business unit that are attributable to another." Tr. 2259. What became absolutely clear at the hearing is that Mr. Powell is using bootstrapping to create a subsidy argument:

> Mr. Larson [sic] goes on to say that the inclusion of these nonregulatory materials has no effect on the price customers pay for electricity. Well, that's up to this Commission to decide. If we determine nonregulatory concerns should pay the fair share of postage, rates will be lower than they would have been without that decision. So it does have an impact on the price the customers pay.

Tr. 2247. It is only with such bootstrapping that Mr. Powell was able to testify that, "The customers end up paying more than they would have otherwise." Tr. 2262.

The Division also bases its opposition to "free advertising" on complaints from contractors related to an asserted competitive disadvantage. Yet, as the Commission has previously recognized, "unfair competition" type claims are not for this Commission to resolve. Docket No. 95-035-14.

For the above reasons, as well as those further set forth in the Company's testimony, the Division's postage adjustment must be rejected.

XXIII. THE COMMISSION SHOULD REJECT THE WAPA WHEELING ADJUSTMENT PROPOSED BY THE DIVISION AND THE COMMITTEE.

The Company entered into a long-term wheeling agreement with WAPA in 1962. At that time, WAPA's predecessor was considering the construction of an all federal transmission system. The wheeling agreement between the Company and WAPA prevented the construction of that duplicative system and allowed the Company to achieve resource planning and off-system sales benefits that would not otherwise have been available. Ex. UP&L 10R at 16; Tr. at 2266-67.

There has been no serious challenge of the fact that the benefits from the transmission system have been substantial. Division witness Powell testified that the profits from the Company's off-system sales were in the multiple millions in some energy balancing account cases. Tr. 2272. Mr. Powell also agreed that, as a result of the transmission system, the Company did not have to build peaking resources and that also was a benefit to customers. Tr. 2267.

However, the Division contends that those benefits could have been achieved even if the Company had not entered into the WAPA agreement or that the Company could have negotiated a different WAPA agreement. The Division has provided no evidence to support either contention. Indeed, the Division was unable to provide any information about the scope of the federal system, the impact of the construction of the federal system, the way those benefits could have been achieved or how the Company could have achieved a different agreement. Tr. at 2267-2275.

In reality the execution of the WAPA agreement was a prudent decision which has provided and continues to provide substantial benefits to retail customers. The Commission should reject the proposed adjustment.

XXIV. THE COMMISSION SHOULD REJECT THE COMMITTEE'S PROPOSAL FOR SITUS TREATMENT OF FIRM RETAIL SPECIAL CONTRACTS.

Since 1997, the costs and revenues of the Company's post-1997 firm retail special contracts have been allocated among all the Company's jurisdictions. That system-wide revenue credit treatment, which was reviewed and approved by PITA, is the treatment previously accorded Utah interruptible retail special contracts. Ex. UP&L 8R at 4-5.

Committee witness Yankel has proposed a change in the allocation treatment of retail special contracts. Under Mr. Yankel's proposal, the costs and revenues from firm retail special contracts would be assigned to the jurisdiction in which the customer is located, while the Utah interruptible retail special contracts would continue to receive system-wide revenue credit treatment. Ex. CCS 8 at 47-48.

There are only two arguments raised by Mr. Yankel as support for his proposal. Ex. CCS 8 at 43. The first is that his proposal would result in a reduction (apparently approximately $4.8 million) in the Utah revenue requirement. In order to reach that result, Mr. Yankel has found it necessary to ignore the terms of two existing contracts, refuse to make a deferred tax adjustment, and fail to recognize system operation changes.

In the case of the two contracts, Mr. Yankel has decided that, although he agrees the two contracts provide for interruption, they are really firm contracts which can be assigned situs. Tr. 925. In the case of the deferred tax adjustment, Mr. Yankel has decided that, although a deferred tax adjustment should be made, he isn't going to make one. Tr. 888. If those leaps of logic by Mr. Yankel are corrected, his adjustment becomes a $0.8 million reduction. Ex.

UP&L 8R at 23-24; Ex. UP&L 8.5R.

In the case of the system operation changes, Mr. Yankel has failed to recognize changes in the rules of the Northwest Power Pool which affect the rationale for a different treatment of interruptible contracts. Historically, the Utah interruptible customers were given system revenue credit treatment because they could be treated as part of the system operating reserve. Under current Northwest Power Pool rules, that is no longer true. The system benefit rationale for allocation differences between interruptible and firm retail special contracts has disappeared. If that change is recognized, Mr. Yankel's proposal to assign special contracts to the host jurisdiction raises the Utah revenue requirement by approximately $9 million. Tr 863-870.

Mr. Yankel's second argument in support of his adjustment is that it protects Utah customers against what might transpire in other jurisdictions. Ex. CCS 8 at 43. However, Mr. Yankel agreed that, irrespective of the allocation method, the Commission has the ability to protect customers against special contract treatment in other jurisdictions. Tr. 923.

There is neither a sound factual or policy basis for adopting Mr. Yankel's proposal and it should be rejected by the Commission.

XXV. THE COMMISSION SHOULD ADOPT THE LIFELINE PROPOSAL OF SLCAP/CUC.

SLCAP/CUC proposes a well-defined lifeline rate to be made available to low-income customers, which the Company and the Committee support. The per customer costs of implementing the lifeline rate are minimal and have intentionally been capped to avoid any significant price impact to customers.

The Division's opposition to the lifeline proposal is based largely on its view that "utility rates should not include social or welfare programs." Ex. DPU 10 at 2. Yet, the Division witness on this issue at the same time agrees with the statement by the Utah Supreme Court that, "In all events, it can hardly be gainsaid that utility pricing policies do directly affect a multitude of social as well as economic problem–whether so intended or not." Tr. 1816-17 (quoting <u>Mtn. States Legal Foundation v. Utah Public Service Comm'n</u>, 636 P.2d 1047, 1057 (Utah 1981). Why the Division in this instance feels it is inappropriate to affect a social and economic problem through a pricing policy is simply unexplained. The Commission has previously found that it has the authority (1997 Order, pp. 97-99), and the Division has not established a policy basis for rejecting the adoption of the lifeline proposal.

PacifiCorp believes SLCAP/CUC has presented sufficient evidence demonstrating the reasonableness of its proposed lifeline rate and recommends that the Commission adopt the proposal.

XXVI. THE COMMISSION SHOULD ADOPT THE COMPANY'S RATE SPREAD RECOMMENDATION AS FAIR AND REASONABLE.

In the interest of minimizing price volatility and customer impacts, the Company's proposed rate spread was guided by a three-year average (1996, 1997 and 1998) of cost of service results and a proposed cap by which no customer class will receive more than 1.5 times the overall price increase. For the major classes, based on a price increase of 8.1 percent, the Company proposes the following rate spread:

Customer Class	Price Change
Residential	12.0%
Small General Service (Schedule 23)	11.5%
General Service -- Distribution Voltage (Schedule 6)	4.1%
General Service -- High Voltage (Schedule 9)	5.9%
Irrigation (Schedule 10)	11.2%
Public Street Lighting	8.1%

The 1.5 times cap minimizes the proposed residential price increase in this case. The three-year average of cost of service results was utilized to provide cost support for the 1.5 times cap. The three-year average alone indicated that residential prices should have increased by 12.8 percent. If the rate spread were based on single year cost of service results for 1998, the results indicated that residential prices should have increased by 16.4%.

Adoption of the Company's proposed rate spread will result in prices for residential, irrigation, and medium and large general service customers that remain lower than they were before the March 1999 price decrease. If the proposed rate spread is implemented, Utah customers will still see prices over 14 percent lower than they were at the time of the PacifiCorp/Utah Power merger in 1989; including the effects of inflation, prices will be at least 37 percent lower than in

1989. The Company's proposed rate spread is fair and moves customers toward paying full cost of service while minimizing bill impacts on customers.

Respectfully submitted this 28th day of April, 2000.

____

Edward A. Hunter
Stoel Rives LLP
Attorneys for PacifiCorp

CERTIFICATE OF SERVICE

I hereby certify that on this ____ day of April, 2000, I caused to be mailed, first class, postage prepaid, a true and correct copy of the foregoing PacifiCorp's Post-Hearing Brief to the following:

Michael Ginsberg
Assistant Attorney General
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, Utah 84111

Lee R. Brown
Vice President, Contracts, Human Resources, Public & Government Affairs
Magnesium Corporation of America
238 North 2200 West
Salt Lake City, Utah 84116

Doug Tingey
Assistant Attorney General
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, Utah 84111

Peter J. Mattheis
Matthew J. Jones
Brickfield, Burchette & Ritts, P.C.
1025 Thomas Jefferson Street, N.W.
800 West Tower
Washington, D.C. 20007

F. Robert Reeder
Williams J. Evans
Parsons Behle & Latimer
201 South Main Street, Suite 1800
Salt Lake City, Utah 84111

Jeff Burks - Director
Office of Energy & Resource Planning
Utah Department of Natural Resources
1594 West North Temple, Suite 3610
Salt Lake City, Utah 84114-6480

Glen E. Davies
PARSONS DAVIES KINGHORN & PETERS
185 South State Street, Suite 700
Salt Lake City, Utah 84111

Eric Blank
LAW Fund Energy Project
2260 Baseline Road, Suite 200
Boulder, CO 80302-7740

Stephen R. Randle
RANDLE, DEAMER, MCCONKIE & LEE
139 East South Temple, Suite 330
Salt Lake City, Utah 84111-1169

Betsy Wolf
SLCAP/CUC
764 South 200 West
Salt Lake City, Utah 84101

Gary Dodge
Parr, Waddoups, Brown, Gee & Loveless
185 South State Street, Suite 1300
Salt Lake City, Utah 84111-1536

____