- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Investigation into the Reasonableness of Rates and Charges of PacifiCorp, dba Utah Power & Light Company	))))	DOCKET NO. 99-035-10 REPORT AND ORDER

ISSUED: May 24, 2000

SHORT TITLE

PacifiCorp 1999 General Rate Case

SYNOPSIS

The Commission changes Pacificorp's annual revenue requirement by $17.04 million, based on an adjusted 1998 test year and an allowed rate of return on equity of 11 percent. The Commission also adopts a Lifeline rate for customers who qualify and establishes a new line extension policy. The percent revenue increase to residential, irrigation, small commercial, and lighting customers is 4.24 percent. The percent revenue increase to large commercial and industrial customers is less than 1 percent.

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I. PROCEDURAL HISTORY

On September 20, 1999, PacifiCorp, d.b.a. Utah Power and Light (Utah Power, PacifiCorp, or Company) filed an application to increase revenues by $67 million or 9.9 percent. PacifiCorp has recently completed a merger with ScottishPower, and this name may appear in the text of this Report and Order.

Interveners were: Salt Lake Community Action Program ("CAP") and Crossroads Urban Center ("Crossroads"), Nucor Steel, a Division of Nucor Corporation ("Nucor"), Magnesium Corporation of America ("Magcorp"), Utah Farm Bureau Federation ("Farm Bureau"), the Utah Industrial Energy Consumers (Abbott Critical Care, Fairchild Semiconductor Corporation, Holnam, Inc., Kennecott Utah Copper Corporation, Kimberly-Clark Corporation, Micron Technology, Inc., Praxair, Inc., and Westinghouse/Western Zirconium Division, "UIEC"), the Large Customer Group (Alliant Aerospace Company, Chevron Company, Cordant Technologies - Thiokol Propulsions, E. A. Miller, Inc., Geneva Steel, Hexcel Corporation, Intermountain Health Care, Thatcher Chemical Company, and Western Electrochemical Company, "LCG"), the Land and Water Fund of the Rockies ("LAW Fund"), and the Office of Energy and Resource Planning ("OERP").

On December 16, 1999, a technical conference was held on the Company's proposed changes to its Line Extension Regulation and General Line Extension Policy.

On January 10, 2000, the Company filed a motion with the Commission seeking an extension of the schedule in this docket. The Company agreed that, as a condition of the Commission approving the proposed schedule extension, the deadline for the final order in this docket be extended to May 24, 2000, and the Commission issued an Amended Scheduling Order to this effect.

On February 1, 2000, the Large Customer Group filed a motion with the Commission to extend by one week, through February 11, 2000, the filing of the prefiled direct testimony of its witness. On February 3, 2000, a hearing was held on the motion filed by the LCG. On February 15, 2000, the Commission issued an order extending the LCG filing deadline for prefiled direct testimony, exhibits, and workpapers from February 4 to February 11, 2000, with the LCG to respond to data requests from the Company relating to its prefiled direct testimony within one week of service of a data request.

The Company, the Division, the Committee, the Large Customer Group, the Utah Industrial Energy Consumers, the Land and Water Fund, Utah Office of Energy and Resource Planning, and the Salt Lake Community Action Program/Crossroads Urban Center filed testimony in this proceeding. The Commission held hearings March 27-31, and April 3-7, 2000. Public witnesses were heard March 29, 2000. On April 28, 2000, Utah Power, the Division, the Committee, the Large Customer Group, the Utah Industrial Energy Consumers of the Large Customer Group, and the Salt Lake Community Action Program/Crossroads Urban Center filed post-hearing briefs.

II. ADJUSTED 1998 TEST YEAR REVENUE REQUIREMENT

A. COST OF CAPITAL

Using a hypothetical capital structure, with component weights for long-term debt, preferred equity and common equity of 47.4 percent, 3.8 percent, and 48.8 percent, respectively, and undisputed costs of long-term debt and preferred equity of 7.231 percent and 6.017 percent, respectively, and an allowed rate of return on common equity of 11 percent, we conclude that a rate of return on investment of 9.0241 percent is fair and reasonable.

1. Capital Structure

The Company recommends a hypothetical capital structure consisting of 47.4 percent long-term debt, 3.85 percent preferred stock, and 48.8 percent common equity. This was derived from the average capitalization of comparable electric utilities used to develop the Company's return on equity recommendation. The Division agrees with this recommendation because the debt-to-equity ratio falls within the range recommended by Standard and Poors for utilities with similar risk. The Committee recommends a capital structure of 47.9 percent long-term debt, 5.95 percent preferred stock, and 46.3 percent common equity, derived from the average capital structure of the firms used in its sample. Under cross examination, the Committee witness acknowledges that some of the firms in this sample received less than 75 percent of their revenues from electric operations, and of these, some are highly leveraged.

We find that the Company's sample of comparable firms is a reasonable basis upon which to determine a hypothetical capital structure. It presents a consistency between recommended return on equity and capital structure. We therefore accept the capital structure recommended by the Company and supported by the Division.

2. Cost of Common Equity

The authorized rate of return on common equity, the Company's profit rate, is determined by the return necessary to attract investment in the Company's common stock. This determination is as much an art as it is a science. The authorized rate of return set in this case will help determine the level of just and reasonable prices charged for electric services and will provide the Company with the opportunity to earn a fair and reasonable return on its investment. There is no guarantee that the Company will earn that return. Rather the intent is to give the Company a legitimate opportunity to earn this return, assuming competent management and normal market conditions. The authorized rate of return is not designed to insulate the Company from business and financial risks, but is set in recognition of the financial and business risks it faces.

a. Positions of Parties

Three parties present testimony and recommendations on a fair and reasonable rate of return for the Company. Each applies a variety of financial models to the data of the Company and a group of comparable companies, and obtains a range of reasonable estimates from which a recommendation is drawn. Each uses judgment to select inputs and assumptions for the models, and to reach conclusions. Each acknowledges that the Commission must use judgment and discretion to determine a fair and reasonable rate of return for the Company.

PacifiCorp. PacifiCorp recommends an allowed rate of return on equity of 11.25 percent, and a range of reasonable returns it places at 10.2 to 13.2 percent. The Company uses a variety of Discounted Cash Flow (DCF) models as well as risk premium analyses to present a range of reasonable estimates for its of return on common equity. Its recommendation depends upon capital market conditions as well as factors affecting both the electric utility industry and the Company.

The Company applies DCF analyses to a group of comparable companies that have attributes similar to PacifiCorp. Although it discounts the results of the constant growth DCF model because of recent volatility in dividend policy, the Company nonetheless uses the model to produce an average and median estimate of 10.2 percent and 10.3 percent respectively. The more cumbersome but theoretically sophisticated non-constant growth version of the DCF produces a higher and broader range of 11.0 percent to 11.6 percent. A variant of this method uses a ten-year transition period between growth periods and produces a range of 11.2 percent to 11.3 percent.

To buttress DCF results, Utah Power performs a risk premium analysis which compares the authorized returns on equity for electric utilities during the period 1980-1998 with contemporaneous long-term utility debt rates. The difference between the two is said to be the risk premium. An empirical analysis of this history, states the Company, reveals an inverse relationship between the level of interest rates and the size of the risk premium; i.e., as interest rates rise, the risk premium gets smaller. Regression analysis is used to quantify the relationship such that a one percent increase in the interest rate leads to a .55 percent increase in rate of return on common equity. Applying this to interest rates the Company uses in direct testimony yields estimates of 12.92 percent to 13.19 percent.

The Company points out changes in economic conditions since the filing of direct testimony, most importantly an increase in utility bond rates of about 35 basis points (one hundred basis points equal one percentage point). Since Docket No. 97-035-01, interest rates have climbed from 7 percent to 8 percent. The Company believes short-term interest rates will continue to climb, due to actions some expect of the Federal Reserve Board (Fed). While the impact of Fed policy on long-term rates is uncertain, interest rates generally move together. Thus, the Company stresses that the cost of capital has increased since the last rate case. In short, the Company points to the recent rise in utility bond rates, the added uncertainty associated with the transition of the industry to a more competitive structure, and Company-specific factors such as its merger with Scottish Power, as key considerations supporting its 11.25 percent rate-of-return recommendation.

The Division. The Division advocates a range of reasonable returns of 10.8 to 11.2 percent, from which a midpoint estimate of 11 percent is recommended for the allowed return on equity. This Division recommendation relies primarily on estimation results from its DCF modeling, using Capital Asset Pricing Model (CAPM) analysis plus Standard and Poor's single-A utility bond rating criteria to establish the reasonableness of the DCF results. Since the Division's recommended return on equity of 10 percent in Docket No. 97-035-01, it suggests that changes in both interest rates and stock prices indicate a higher return recommendation today. In its direct testimony, the Division recommends an allowed return of 10.5 percent, but revised this during hearings for an updated analysis which corrects a data timing mismatch and a computational error. The Division concludes that the criteria used by the Company to select a sample of comparable companies is correct if the sample is revised to exclude outliers having anomalously low or high growth rates. The Company removed only those companies having negative growth rates from its sample.

With these factors in mind, the Division reruns its constant-growth DCF model with an 11 percent return result. The Division employs both constant-growth and non-constant-growth forms of this model and averages the results. In response to Company arguments about the merit of these forms, the Division testifies that the non-constant growth model is more elegant but the assumptions either requires are equally uncertain or arbitrary. It criticizes the range of inputs the Company employs in its non-constant DCF model to produce a higher rate of return as too restricted. The Division supports a broad range for the DCF analysis and argues that averaging the results of model runs mitigates the impact of assumptions and analyst judgments. This analysis indicates a return of approximately 11 percent.

The Division performs a CAPM analysis to check the validity of its DCF results. This model adds a risk premium, determined to be the risk of a company's stock relative to the risk of the stock market as a whole, to the risk-free interest rate. The Division uses the midpoint of a 13-week average of 30-year treasury bonds for its measure of the risk-free interest rate. The betas, a measure of correlation between the stock's risk and the market's risk, range from a low of .45 to a high of .65 . The risk premium can be estimated in a variety of ways, including reliance on published sources. The Division uses a long-run average and end-point of a standard confidence interval of U.S. stock returns to estimate rate of return. With an 8 percent premium, the appropriate ROE for the sample is 10.4 percent, states the Division.

A further check on the reasonableness of DCF results used by the Division is Standard and Poor's bond-rating criteria. One important criterion is the times-interest-earned ratio, which is the ratio of a utility's profit before taxes, plus interest charges, divided by interest charges. This is accepted as a measure of a company's ability to meet fixed debt obligations. With its recommended rate of return and capital structure, the ratio is 3.63, within the range required to maintain a single-A bond rating. Higher rates of return have little impact on the ratio results and are not, in the Division's opinion, justified. In its opinion, an authorized rate of return of 11 percent is fair and reasonable to investors and ratepayers.

The Committee. The range of reasonable returns found by the Committee is 10 to 11 percent, and its recommended return on equity is the midpoint of that range, 10.5 percent. The Committee reviews three financial models and the comparable earnings approach, but prefers the constant-growth DCF model for its simplicity and because it is the version most used by investors. The model is applied to a group of companies the Committee believes are reasonably comparable to PacifiCorp. This sample group differs from the Company's in that it contains only companies having a single-A bond rating but includes firms that derive less than 75 percent of their revenues from electric operations. Otherwise, states the Committee, the sample would contain fewer firms than is appropriate for the analysis. So while the Company expands its sample by including firms with bond ratings of single A or better, the Committee includes firms with more diversified operations.

Selection of DCF inputs, such as stock prices and earnings growth rates, greatly influence the results, emphasizes the Committee. It therefore employs a variety of estimates of growth rates and average prices of stocks to obtain a rate of return estimate. A three-month average of the stock price is recommended to smooth daily price fluctuations, and a near-term growth rate, based on Value Line's forecasted dividend growth rate, and a long-term growth rate, based on a retention growth rate, are used. This approach to non-constant dividend growth, according to the Committee, avoids both economic forecasts and an unsupported relationship between utility dividend growth and economic growth. The Committee argues estimating average expected return on equity using near- and long-term growth rates and average prices is reasonable. Its analysis supports a range of reasonable returns between 10 percent and 11 percent.

A risk-premium, or bond yield plus risk premium, method is used by the Committee to check the reasonableness of its DCF results. This method is based on the theory that the required rate of return on equity will be higher than the return on bonds because equities are inherently more risky. The equity investor stands last in line as a claimant on the earnings of the firm. The Committee notes, however, that bonds do carry an interest rate risk, independent of a firm's financial or business risk, that arises because interest rates may change while a fixed-yield bond is held. Interest rates are inversely related to the market price of a bond. Interest rate risk, the Committee asserts, upsets the assumption that a risk premium is constant over time and means that the risk premium method is not reliable as a primary return estimation method. Nevertheless, the Committee calculates a 1978 to 1999 risk premium for PacifiCorp as an average of 3.01 percent over utility bond rates and 4.45 percent over Treasury bond rates. When applied to current bond yields, this produces a rate-of-return range of 10.95 percent to 11.41 percent.

The CAPM model is, in the Committee's opinion, a subset of the risk premium approach. Applying it, the Committee derives a rate-of-return range of 7.30 percent to 10.10 percent for PacifiCorp and 8.10 percent to 10.74 percent for the Company's sample of comparable firms. More weight is given in the Committee's analysis to the results of the DCF model, however, to support its return recommendation of 10.5 percent.

b. Discussion, Findings and Conclusions

The range of point rate-of-return estimates found in testimony is 10.5 percent to 11.25 percent. In the March 4, 1999 Report and Order in Docket No. 97-035-01, the Commission found a return of 10.5 percent fair and reasonable. Since that time, however, economic conditions have changed as shown by increasing interest rates and single-A-rated utility bond rates. In the present proceeding, utility bonds yield an average of 8.22 percent, approximately 100 basis points higher than during the preceding Docket. There is, however, conflicting evidence on the present record about interest rates, since 30-year Treasury bonds have a lower yield than they did a year ago. Short- and long-term interest rates apparently are not moving in concert, contrary to normal expectations. The recent decline in the 30-year bond yield may be an anomaly. Unusual recent volatility in the NASDAQ and the New York Stock Exchange may be leading investors to less risky investments in long-term government bonds. An increase in demand could raise the price of these bonds, decreasing their yields.

Under normal circumstances, the costs of debt and equity move together. Regression analyses performed by the Company attempt to quantify the relationship between interest rates and return on equity. This analysis indicates that rate of return increases about 55 basis points per 100 basis points increase in utility bond yield. If this relationship is valid, PacifiCorp's return would increase to 11.05 percent, given recent interest rate changes. The Division casts doubt on this analysis, however, repeating points it made in the previous Docket, No. 97-035-01, particularly its opinion that no theoretical basis exists to support it. Without a theoretical basis, the Division recommends against reliance on the purported relationship.

Nevertheless, the evidence on the cost of debt permits a finding that utility bond rates have increased since the previous Docket. In the Company's opinion, this supports a return of at least 11 percent. Financial model results indicate that the reasonable range for rate of return varies with the particular model employed and the input assumptions each analyst makes. As in the past, we continue to rely on DCF analyses, but, as the witnesses suggest, use the risk-premium and CAPM analyses as reasonableness checks. We believe the constant growth model of the DCF is adequate for estimating return, but look to the non-constant growth model for support.

A representative sample of comparable companies is important. The Committee's use of firms that derive a relatively small proportion of their revenues from electric operations causes us to discount its analysis somewhat, because the record provides better support for the sample firms selected by the Company and the Division. We are aware, however, that the elimination from the Company's sample of only those firms having low or negative growth rates, while retaining those having abnormally high ones may lead to biased results. We accept as more reasonable the sample recommended by the Division, in which both high and low growth rate outliers have been removed.

The Company's non-constant growth DCF gives slightly higher return estimates than those derived from the constant growth form. On this record, we cannot adequately explain or accept the difference, and continue to interpret results based on knowledge that each analyst subjectively chooses model assumptions and inputs. These can greatly influence modeling outcomes. At times in the past, this has led us, when the record is inadequate to do otherwise, to seek an allowed return by averaging model results. In this Docket, the range of return recommendations is narrow. Only 75 basis points separates them. This makes a decision much more apparent. Financial modeling results support an allowed return of 11 percent, and the same conclusion may be drawn when these results are averaged and the sample of comparable firms recommended by the Division is employed. This result is further supported by the increase in cost of capital that the record shows has occurred since our last rate order in Docket No. 97-035-01. We conclude an allowed rate of return on equity of 11 percent is fair and reasonable for both stockholders and ratepayers.

B. INTERJURISDICTIONAL ALLOCATION ISSUES

1. Normalization of Firm Retail Peak Loads

One of the primary influences in the allocation of costs among jurisdictions is the System Generation (SG) factor. The SG factor is a weighted average of the System Capacity (SC) factor, a measure of peak load responsibility, and the System Energy (SE) factor, a measure of annual use. The weights are 75 percent for the SC factor and 25 percent for the SE factor. The SG factor is used to allocate, among other costs, the investment and non-fuel expenses associated with the Company's production and transmission functions. To construct the SC factor, the hour when the combined firm retail loads of all jurisdictions attain a maximum is identified for every month of the test year. Each jurisdiction's load is measured in megawatts at the identified peak hour of the month. The monthly peak loads for each jurisdiction are then added together to obtain an annual jurisdictional figure. The SC factor is the ratio of a jurisdiction's annual figure to the total for all jurisdictions. This is known as the 12-coincident peak method.

In the Division's judgment, the growth in Utah's SC factor was abnormal and should be normalized, due in part to the shift in the system winter peak loads from the morning to the evening. The SC factor is relatively sensitive to changes in the time of day used to identify the monthly peak. In 1998, all four monthly system winter peaks occurred during the evening. In contrast, there were no system winter evening peaks in 1990, 1991 1993, or 1994, one in 1992, 1995 and 1996, and two in 1997 and 1999. In the Division's judgment, 1998 peak loads are abnormal, resulting in higher than normal SC and SG factors for Utah. To compensate for the anomalous four peaks, the Division recommends increasing the 1997 SC factor by its 1992 to 1996 average annual growth rate of four percent to obtain a normalized 1998 SC factor. This growth rate is supported by statistical analysis. Relative to the Company, the Division's adjustment reduces the SC factor from 34.9593 percent to 34 percent and reduces the SG factor from 34.8781 percent to 34.1587 percent. Using Utah's unadjusted results of operations and the Commission's 11 percent allowed rate of return on equity, determined previously, these changes in allocation factors, along with related changes in deferred income tax factors, reduce revenue requirement by $3,698,481 relative to the Company.[(1)] Neither the Committee nor the Large Customer Group (LCG) took a position on this issue.

The Company opposes the Division's normalizing adjustment because it believes the1998 SC and SG factors are consistent with general load growth trends during 1992-1998. It explains the shift to system winter evening peaks as a result of load growth in Utah relative to other states. Prior to the 1989 merger, Utah Power peaked in the evening during three and sometimes all four of the winter months. In addition, the use of electricity for space heating is declining in the Pacific northwest. The Utah jurisdiction's, as distinct from the system's, winter peaks during 1992-1999 have all occurred during the evening.

The Division demonstrates to our satisfaction that the occurrence in 1998 of four winter peaks is an anomaly. If our own observation of the pattern of system winter evening peaks were not enough, the Division's statistical analysis is persuasive. We conclude from the record that the dispute over the number of winter evening peaks does not alone explain the deviation of the SC factor from the 1993 through 1997 trend line. In the absence of an appropriate explanation, we find it reasonable to apply to the 1997 SC factor the growth rate derived by the Division from historical data.

2. Time Of Peak For The Measurement Of Firm Retail Loads

The assumption underlying the Company's method of interjurisdictional cost allocations is that wholesale transactions provide an overall benefit to retail customers. In this approach, the costs of wholesale service are borne by firm retail customers and the revenues from wholesale transactions are allocated to firm retail customers as a credit to offset these costs. This is the revenue credit treatment of wholesale activity. Due to recent moves toward competition and the growth in the Company's wholesale activity, the Committee is concerned that retail customers may be subsidizing wholesale transactions. In 1998, retail and wholesale each were approximately 50 percent of total Company sales.

In the Committee's view, because the Company has a firm obligation to meet both retail and wholesale loads (both are included in the Company's RAMPP integrated resource plans), and wholesale sales are of a relatively significant size, the time of the system peak should be defined by the hour in which the combination of firm retail and firm wholesale loads peak, not when firm retail loads alone peak. The Committee recommends basing the SC allocation factor on each jurisdiction's peak demand at the time when the combination of retail and wholesale loads peak each month. This adjustment reduces revenue requirement by about $4.2 million. In addition, the Committee recommends establishing a forum to address the treatment of jurisdictional revenue responsibility, both retail and wholesale, in the wake of recent changes in Company direction and wholesale markets, and possible future changes in the electric utility industry.

The Division opposes the Committee's adjustment because it may produce volatile results and is inconsistent with the revenue credit approach to retail ratemaking, which the Division supports in this Docket. The Division, however, does support the Committee's recommendation to establish a forum to investigate the jurisdictional revenue requirement responsibility between wholesale and retail customers. They suggest the issue of loads to be used in determining the time of system peak could be studied in such a forum.

The Company opposes the Committee's recommendations. A change in the measurement of peak load responsibility affects all states and should first be discussed at the Pacificorp Interjurisdictional Task Force on Allocations (PITA), the Company argues. It also points to treatment of wholesale loads at the Federal Energy Regulatory Commission (FERC), where they are excluded from the reporting requirement used to determine the hour of system peak. The Company further argues that the long-term obligation to serve wholesale contracts differs from the obligation to serve retail and FERC requirement service loads, and wholesale contracts are included in the RAMPP planning process for their contract period only and not beyond. Volatility of wholesale sales can distort the hour of system peak, such that outside influences produce changes in retail cost allocation.

We will not accept the Committee's recommendation to base the time of peak on both retail and wholesale loads. The reasons to reject it given by the Company and the Division are convincing on this record. We will, however, order the establishment of a forum, as recommended by the Committee and the Division, for the purposes they have identified.

3. Treatment Of 1997 And 1998 Retail Special Contracts

The loads and revenues from firm retail special contracts signed before 1997 are assigned to the jurisdiction in which the customer is located and where the contract is approved. An agreement was reached among the staff representatives of the states participating in PITA to use the revenue credit approach to allocate, rather than assign, the revenues from firm special retail contracts signed beginning in 1997. The load from these recent contracts is removed from the calculation of a jurisdiction's load-based allocation factors, so the cost of serving these contract customers is borne by remaining firm retail customers, and the revenues are allocated to all jurisdictions as a credit to offset the allocated costs.

This treatment disadvantages Utah since Utah has relatively few of these special contracts relative to other states. The Committee recommends assignment of the loads and revenues from firm retail special contracts signed in 1997 and 1998 to the jurisdiction in which the contract was approved. The effect of this adjustment is to reduce revenue requirement by slightly less than $4.7 million.

The Committee's adjustments for the time of system peak and the treatment of firm retail special contracts affect deferred income taxes, and the allocation factors based on deferred taxes. The Committee did not address this issue when it made its adjustment, and agrees that the deferred tax allocation factors should be adjusted, but does not agree with the Company's correction of the tax factors necessary to implement the Committee's adjustment. The effect of the Committee's two adjustments, discussed here and above, is not independent. Relative to the Company, the combined effect of both of the Committee's adjustments reduces the SC factor from 34.9593 percent to 33.4855 percent, reduces the SE factor from 34.6347 percent to 33.5118 percent, and reduces the SG factor from 34.8781 percent to 33.4921 percent. Using Utah's unadjusted results of operations and the Commission's allowed rate of return on rate base, determined previously, these changes in allocation factors reduce revenue requirement by $8,778,274 relative to the Company's allocation factors.(2) The effect of the time of peak adjustment is just slightly less than the effect of the special contract adjustment.

Initially the Division supported a similar adjustment, but withdrew its proposal and recommends that the Commission defer this issue for discussion at PITA before taking independent action.

The Company argues that assigning firm retail special contracts to the jurisdiction in which the contract is approved, the "host" jurisdiction, raises the host's revenue requirement and delivers more of the contribution to fixed costs to non-host jurisdictions. This provides an incentive for the host jurisdiction to reject special contracts that may benefit the entire system. The Company states it is indifferent as to whether these contracts are assigned to the respective host jurisdictions or allocated to all jurisdictions. Its interest is that all states adopt the same treatment. Otherwise, it is exposed to the risk of being unable to recover all of its costs, and will be forced to discontinue special contracts as they expire. The Company maintains that the Utah Commission should accept the commitment the Division made at PITA to allocate these contracts. If the Commission wishes to revert back to assigning special contracts, this should be done for new contracts rather than those the states have agreed to allocate.

For the purposes of this case, we do not accept the Committee's adjustment. The future treatment of special contracts is not resolved by this Order. For the present, we make no change in treatment of special contracts. We do not accept the Division's recommendation to have PITA examine the issue before we take independent action. Only the staffs of commissions are members of that group; other concerned parties are not represented there. Nor are the decisions reached at PITA in any way binding on this Commission, but are simply a potential basis for Division recommendations here.

4. Account 903 Allocation Factors

Prior to 1996, the Company used local offices, scattered throughout its service territory, to interact with customers either face-to-face or by telephone for a full variety of service and billing purposes. Since then, two new regional business centers have replaced the local offices, which have been closed. The Division has been seeking an appropriate way to allocate the customer service costs, booked to FERC Account 903, associated with these new business centers. It has disagreed with the allocation treatment recommended by the Company. The Division recommends using a general allocation factor called System Overheads (SO) on an interim basis until further analysis establishes, if indeed it can, a better cost-causal relationship for choice of the allocation factor. The Company recommends a customer-related factor reflecting the number or count of customers (CN). No other party expresses a recommendation.

Before the local offices were closed some 74 percent of Account 903 expense was directly assigned to jurisdictions. Together with the remaining 26 percent that was allocated to states, the result was 33 to 35 percent of Account 903 expenses apportioned to Utah. In this Docket, the Company proposes to directly assign only 20 percent of Account 903 expenses and to allocate 80 percent, using a customer-related allocation factor, thus apportioning a significantly larger share of the expenses to Utah than before. Alerted by this increase in share, the Division searched for a cost-causal relationship which might explain it. Using the techniques of statistical analysis, it both tested the proposal to use a customer-related factor and tried to identify other candidate allocation factors which track cost-causal relationships. No correlation between the incurrence of customer service costs and the number of customers exists, states the Division, leading it to recommend against use of customer-related allocation factors like CN. In the absence of a suitable cost-causal relationship, the Division recommends the general allocator, SO, to preserve a share of customer service expenses for Utah roughly equivalent to that experienced previously. The Company disagrees and faults this analysis for its dependence on information from the local office rather than the business center period of time, and for a failure to recognize the depth of change represented by the switch from local offices to regional business offices.

In any cost-of-service analysis, the most difficult choice is the adoption of appropriate allocation factors. This choice turns on informed judgment, and draws deeply on information about the engineering economics of service-delivery systems or processes. Identification of cost-causal relationships is the key concern. In this regard, the Division is quite correct to seek an explanation for a sudden increase in costs apportioned to Utah for the customer service function. That the move from local offices to regional centers is intended to increase the efficiency of service delivery is all the more reason to explain why Utah's share of these costs should increase. We might better expect the opposite. This is the context within which we examine the arguments of the Division and the Company.

Evidence suggests Utah is a growing share of PacifiCorp's electric operations because its population is increasing more rapidly than is that of the other states in the Company's service territory. The larger number of customers, in turn, creates a larger "potential" to place service calls to a phone center, the Company asserts, and relies on this to explain why the costs of customer service apportioned by its method to Utah show a large increase. The Company would not support an allocation factor based on the relative number of calls, however, because just 60 percent of business center work involves answering calls. These Company arguments are answered by the Division's statistical analysis which fails to reveal a cost-causal relationship between number of customers and the incurrence of customer service expense. A number of possible explanations are offered, including the importance of the random impact of weather events on electric service and a relationship between customer contacts with the Company and the relative size of bills (the larger the bill, the more the expense for serving the customer). Utah customers, the Division shows, have significantly smaller bills than do customers in the other states.

Choice of an appropriate allocation factor turns on technical disputes which the record is insufficient to resolve. We find that the Company and the Division each make important points, but neither offers a complete analysis. The use by the Division of information from the local office period to seek a cost-causal relationship for allocation of expenses may pay insufficient attention to the changes in method of service delivery implied by the new regional phone center operations, as the Company alleges. But the Division's insistence that this period provides the only information reasonably of use is telling. Moreover, its analysis is deeper and further reaching than is the Company's, and not all of the points raised by the Division have evoked an informed response from the Company. Thus on this record a basis for allocation other than number of customers is realistic. It follows that the Division's recommendation to use the general allocation factor, SO, pending further study is acceptable to us. This will extend the historical pattern of Account 903 cost apportionment through the present Docket, a reasonable result under these circumstances. We will expect the Division to work closely with the Company and other interested parties to resolve the technical points raised here so that an appropriate allocation factor may be adopted in the next general rate case. This decision reduces revenue requirement by $2,102,618.

5. Special Contract Revenue Allocation Change

By staff agreement through PITA, special retail contracts signed beginning in 1997 are allocated on a system basis. In its unadjusted results of operation, the Company separates revenues booked from both firm and non-firm retail special contracts into components related to demand and energy. It then allocates the demand-related revenues using a System Generation (SG) allocation factor and allocates the energy-related revenues with a System Energy (SE) allocation factor. The Division recommends using the SG factor for both components of retail firm contracts and the SE factor for both components of non-firm contracts. This is consistent with the treatment applied to wholesale contracts, where firm sales and purchases are allocated on the SG factor and non-firm sales and purchases are allocated on the SE factor. The Division applies this allocation treatment to the unadjusted contract revenues, as well as to the Company's normalizing and annualizing adjustments made to these contract revenues. This treatment, the Division argues, will better match revenue with cost allocation.

The general approach we employ to determine cost-of-service involves classifying revenues and costs into components related to demand and energy. However, the treatment given to wholesale transactions, the Company states, is due to their complexity, as well as to the difficulty of identifying demand-related and energy-related components of such contracts. If the cost of serving these retail special contracts were solely from wholesale purchases, we would accept the Division's recommendation. Lacking such evidence, we decline at this time to accept the Division's recommendation.

C. UNDISPUTED ADJUSTMENTS

A number of proposed adjustments to revenue requirement are undisputed. It is our practice to accept adjustments, whether proposed by the Applicant or the parties, which all agree should be adopted. The active presence of the Division as a party assures us the public interest aspects of each has been considered. Collectively, these adjustments increase revenue requirement by $34,554,674. We describe each adjustment in Appendix 1.

D. REGULATORY POLICY ADJUSTMENTS

Regulatory policy adjustments are adjustments for decisions made by the Commission in prior proceedings which remain effective.

1. Long-Term Incentive Compensation

The Company claims that incentive compensation is part of a "total compensation package" and is therefore reasonable and necessary for the Company to attract and retain qualified employees. Incentive compensation programs at issue place a part of total remuneration at risk. If employee performance is less than desired, remuneration should be less than market average. The Company testifies that total cash compensation for employees in 1998 was about 96 percent of the competitive average total cash compensation. In addition, it states that all of the incentive awards paid in 1998 were based on line-of-sight goals designed to benefit ratepayers rather than on measures of financial performance.

An adjustment made by the Company removes the cost of the long-term executive

incentive compensation plan in accordance with Commission Order in Docket No. 97-035-01. Both the Division and Committee agree to this adjustment. However, the Committee testifies that the Company fails to show that performance targets were met in the key areas of customer service and operational efficiency. It adds that ratepayers should not be saddled with the full amount of incentive compensation expense because management was not focused on its core utility business during 1998. The Committee recommends disallowing 62.5 percent of the incentive compensation expense.

On the basis of the record, we conclude that incentive plan expenses were only associated with non-financial goals which benefit ratepayers. Consequently, we do not accept the adjustment

proposed by the Committee. This decision decreases revenue requirement by $501,913.

2. Stock-Based Incentive Compensation

The Committee proposes an adjustment to disallow recovery of costs which it

characterizes as "stock-based incentive compensation." This proposal is based on its view that

the stock compensation is incentive compensation given for the Company's financial performance, contrary to Commission policy on rate recovery for incentive plans.

We find that the costs the Committee refers to as stock-based incentive compensation actually relate to specialized retention agreements the Company has with certain executives and

key employees. These employees were eligible for an early retirement program, but the Board of Directors determined that it would be detrimental to lose some of them. Restricted stock therefore was issued to 10 individuals in a successful bid to retain them. They have remained with the Company during the test year. Therefore, inasmuch as none of this stock was a performance-based incentive payment, and the retention of key employees was beneficial to ratepayers, we do not accept the proposed Committee adjustment.

3. Customer Service System Software Maintenance

During 1995 and 1996, the Company closed its many local service offices and in their place opened two regional service centers. Some $75 million of new computer software to implement this consolidation was purchased. In addition to regulated utility purposes, the software is capable of functions corresponding to the global aspirations and assumptions about competitive positioning, including pursuit of unregulated business activity, held by PacifiCorp at that time. In Docket No. 97-035-01, the Division presented a study questioning the prudence of the software investment. A stipulation entered in that Docket removed one-third of the investment and associated test-year maintenance expense. In the present Docket, the Company removes one-third of the investment but argues for full recovery of test-year maintenance expense. The Division and the Committee propose adjustments to remove one-third of maintenance expense. The Large Customer Group supports the Division and Committee adjustment.

Since the decision to purchase the software, changes in the Company's objectives and direction yield a focus on the core electric business in the western U. S. This forms the basis of its argument to fully recover test-year maintenance expense. Over 95 percent of the function served during the test year is regulated utility business, it asserts. But the Division claims the regulatory and non-regulatory functions the software can perform are so interlaced that maintenance upon the one serves the other. For the Company to assert that maintenance results almost wholly from regulatory service requirements is, according to the Division, "self-serving." The Committee agrees, adding that the system failed to perform adequately during the test year, producing inaccurate bills, a suspension of normal collections procedures, and increased maintenance costs. Under cross-examination by the Large Customer Group, the Company's witness indicated that to his knowledge the Company had undertaken no study to show that the customer service system software is best given the new focus on domestic electric operations and knew nothing about the maintenance costs that might be incurred for a system having this more narrowly defined purpose.

Our responsibility is to permit recovery in rates only of expenditures that are both legitimate and reasonable. We know the customer service system did not operate properly during the test year. The Committee asserts, and the Company did not show otherwise, that additional costs were incurred to fix problems. The record leaves no doubt that the software was intended for purposes much beyond the requirements of a regulated public utility, and supports a conclusion that maintenance expenses cannot easily be segregated by regulated versus non-regulated function. We are impressed as well that the Company can offer us no assurance that its maintenance costs are those that would be experienced by a system focused on the requirements of a public utility only. On this record, the recommendation to remove one-third of test-year maintenance expense is reasonable. We adopt it. The small difference in the magnitude of the Division and the Committee proposals appears to result from the Division's emphasis on test-year expenses associated with a terminated maintenance contract, which it reasons produces an acceptable proxy for both contract-related and internal employee expenses, and the Committee's adjustment to remove one-third of all maintenance expense, whether related to the contract or incurred in-house. For this reason, we accept the Committee's adjustment. It reduces revenue requirement by $532,765.

4. Merger Cost Sharing

Organization costs for the 1989 merger between Utah Power and Light and Pacific Power and Light Companies were by Commission order split equally between ratepayers and shareholders. That portion to be recovered from ratepayers was amortized over 15 years, and the unamortized amount was excluded from ratebase (costs are recovered but no return is earned). The Company now proposes to recover the present value of remaining expense amortization over three years, in its view thus corresponding to the Commission's recent Order in Docket No. 97-035-04 requiring movement over a specified phase-in period to an interjurisdictional allocation of total system revenue requirement based on a fully rolled-in method. The Company believes the Commission's move to fully rolled-in allocations "has accelerated the recognition of merger benefits," and with this as rationale proposes to shorten the organization cost amortization period. The Division and the Committee oppose the adjustment because the allocation decision eliminates a merger fairness adjustment but does not address the recovery period for merger organization costs.

In the Order in Docket No. 87-035-27 approving the Utah Power - Pacific Power merger, the Commission warned against using hypothetical merger benefits to fashion an allocation method. A benefit-sharing test was specifically rejected in Docket No. 90-035-06, a general rate case. As the Report and Order in Docket No. 97-035-04, adopting the fully rolled-in allocation method following a phase-in period, makes clear, merger benefits play no cost-of-service role in this jurisdiction. The Company's view that the Order to move to a fully rolled-in allocation method was intended "[to accelerate] . . . the recognition of merger benefits" is mistaken.

With respect to merger organization costs, the Commission concluded in Docket No. 87-035-27 that a fifty-fifty sharing between ratepayers and shareholders was appropriate because the merger would equally benefit both. That the merger would be beneficial supported the approval decision; it had nothing whatever to do with a consideration of merger benefits in a cost-of-service allocation context. Treatment of merger organization costs was and is a separate issue. The Order in that Docket required the Division to submit a proposal for ratemaking treatment of the organization costs within 30 days of its date of issuance. In the following general rate case, Docket No. 90-035-06, a stipulation was submitted which covered, without comment, the ratemaking treatment of organization costs. Because the Company's proposed adjustment is based on a misunderstanding of Commission orders, and has no other rationale, it is rejected. The Division adjustment is accepted, reducing revenue requirement by $186,846.

5. Solar Two Amortization

Prior to the test year, PacifiCorp participated in a solar thermal research project, known as Solar II, to gain experience in alternative generation technologies, consistent, in its view, with the requirements of its approved integrated resource planning process. Recovery of the expense is now proposed. The Committee, whose position is supported by the Division, recommends removal of Solar II expenses from the test year.

The record shows that project expenses were incurred between 1992 and 1995, and that the Company neither sought nor received approval from the Commission to defer recovery of them. Moreover, the Company removed an amortization of project expense from Docket No. 97-035-01, stating that Solar II "is an experimental R&D project, the deferred costs and amortization expense should not have been included in electric utility operations." In a change of mind, the Company now claims consistency with the purposes of integrated resource planning as grounds for recovery of project costs. We believe the Company must do more than merely point to consistency if recovery is to be allowed. But more to the point, the time for recovery appears to have passed and the costs have been fully amortized. We conclude the expense is not properly part of 1998 test-year revenue requirement and will not accept the Company's proposed adjustment. We accept the Committee's adjustment, decreasing revenue requirement by $150,922.

6. Outside Services: Price Waterhouse Study

During the test year, PacifiCorp incurred a $500,000 expense for the consulting services of Price Waterhouse to assist the Company in resolving revenue collection problems. Recovery of this amount is now sought by the Company on grounds of benefits realized in the form of increased collections in the test year and that acquiring outside expertise from time to time is normal. The Division takes no position, but the Committee opposes recovery because the cost is non-recurring and the collections problem is of the Company's own making, it having arisen as a difficulty of implementing customer service software associated with closing local service offices and replacing them with two regional business centers.

While it is true on this record that the Company has experienced collections difficulties during the test year, it is not beyond expectation that a comprehensive reorganization of customer service functions made possible by new technology might cause difficulties or that outside expertise might prove useful in resolving them. We determine a normal level of uncollectible expense in Section G. We agree with the Company that provision for acquisition of outside services is normal. For these reasons, we reject the proposed adjustment.

7. Miscellaneous General Expenses, Dues

On grounds that the adjustment is consistent with previous Commission decisions, the Division asks for removal of an expense for dues paid to two organizations, the Utah Taxpayers Association and the Utah Manufacturers Association. PacifiCorp considers the dues a legitimate test-year expense because membership in these Associations provides it with tax and other information permitting it to keep rates for service low, thereby benefitting ratepayers. The Committee takes no position.

We excluded the dues for these organizations from revenue requirement in PacifiCorp's last general rate case and do so again in the present Docket. Both organizations engage in political lobbying. The ratepayer benefit assertion is neither supported nor new. It has been considered and rejected before. We accept the Division's adjustment, reducing revenue requirement $5,339.

8. WAPA Wheeling Imputation

In 1962, Utah Power and Light Company entered into a fixed-rate contract of 80 years duration with the United States Bureau of Reclamation (later the Western Area Power Administration, WAPA), to wheel Colorado River Storage Project (CRSP) power over the Company's transmission system to public power "preference" customers. Some years later, Utah Power purchased CP National Corporation's Utah system, and thereby acquired a wheeling contract between CP National and the Bureau of Reclamation, having the same purpose and wheeling rate as the Utah Power contract. The wheeling rate in these contracts is $4.20 per kiloWatt-year; neither permits escalation.

In Docket No. 82-035-13, Report and Order issued May 23, 1983, this Commission recognized that the contracts were not compensatory and ordered an imputation of revenues, based on the then-current Federal Energy Regulatory Commission (FERC) wheeling rate of $24.12, to prevent the subsidy that otherwise would flow from Utah Power's retail customers to CRSP preference customers. Revenue imputation for these WAPA contracts has been the Commission's policy since then.

At some point in the mid-1990s, the Company on its own volition stopped recording a revenue imputation in its semi-annual reports on operations. Though this change in Company behavior was not reported to the Commission, the Division testifies that it routinely restored the imputation during its audits of annual operations. In Docket No. 97-035-01, the last general rate case for this Company, Utah Power did not impute revenues for the contracts, but the Committee proposed it as an adjustment. The adjustment was dropped in negotiations among the Company, the Division, and the Committee leading to a stipulation. This prevented the issue from coming to the Commission's attention until now. In the present Docket, the Division, supported by the Committee but opposed by the Company, seeks to restore the imputation.

The basis for the Company's opposition to the proposed imputation is its assertion that the WAPA contracts enable a flow of transmission-related benefits to retail customers. In 1962, it states, the federal government stood ready to build an all-federal transmission system to deliver electricity to preference customers from federal hydroelectric projects. This, however, would interfere with Utah Power and Light Company's strategy to build a transmission system permitting it to conduct wholesale transactions between Pacific Northwest generators of inexpensive hydro-power and lucrative power markets in the Southwest. Controlling the transmission pathway would allow the Company to purchase power cheap and sell it dear, and to serve its retail load with its own thermal baseload generation system while relying on the transmission system to meet peaking requirements on favorable terms. A federal system was perceived as a threat to this strategy. Thus Utah Power negotiated an 80-year, fixed rate contract which the Company believes prevented construction of the federal transmission system, much, in its view, to the benefit of its retail customers. Peaking power requirements were effectively satisfied and margins on wholesale transactions were passed directly to customers by operation of the then-existing energy balancing account. Such benefits, the Company argues, make a revenue imputation an unnecessary correction for the noncompensatory contracts.

In addition, the Company argues that the Commission has altered the imputation requirement. Following the 1989 merger of Pacific Power and Light and Utah Power and Light Companies, a "transmission endowment" meant to preserve for customers of the former Utah Power and Light Company the benefits of the "strategic" transmission system was built into a proposed post-merger interjurisdictional allocation procedure. Benefits of the transmission system that the Company now argues offset the need for imputation were thus, it contends, recognized by the Commission at that time. By incorporating transmission system benefits into jurisdictional revenue requirement, Utah Power argues the Commission has altered the imputation policy.

We reject the argument that a Commission regulatory policy can be changed in this indirect way. First, the Company is obligated, if it seeks to change existing regulatory policy, to bring to our attention any new considerations it believes may warrant the change. This is to be done in an open, public proceeding, where the sworn, cross-examined testimony and evidence, not just of the Company but of all parties, forms an evidentiary record. See, Salt Lake Citizens Congress v. Mountain States Telephone and Telegraph, et.al, 846 P.2d 1245 (Utah 1992). Second, the cited allocation procedure was not accepted in this jurisdiction. A reading of the Report and Order in Docket No. 90-035-06, wherein the procedure was proposed and rejected, will reveal that the Commission chose to use a revenue requirement number generated by it because it was a product of a multi-state staff task force's open deliberation and the best that appeared on the record. The Commission did not countenance, and indeed did not know of, the many judgments and assumptions that were part of the rejected method. The claim that the Commission has recognized the value of the "strategic" transmission system as a ratepayer benefit because it was factored into that method, thus indirectly changing the imputation requirement, is rejected. The revenue imputation policy stands unless we decide otherwise.

In the present Docket, the Company's opposition to imputation rests on its assertion that the WAPA contracts played a role in the development of a transmission system that has benefitted retail customers. But Utah Power was imprudent, testifies the Division, because it did not build escalation factors into contracts of 80 years duration. The Division's witness, who in 1962 was a Utah Power and Light Company employee, testifies that he was tasked to calculate a wheeling rate that would cover marginal costs but be low enough to prevent construction of a federal transmission system. He further testifies that the contract wheeling rate achieved these objectives, that to his knowledge no analyses were conducted to show that the rate would be compensatory in later years, and that Utah Power could have built its transmission system and realized benefits even if the federal system had been constructed. After the Commission ordered the imputation in Docket No. 82-035-13, the Division supported the Company's 1984 appeal to FERC to void or alter the noncompensatory WAPA contracts. FERC refused to do so, and opined that in any event the State had jurisdiction to ameliorate the subsidy effect on its own. This forms the basis for the Division's revenue imputation proposal. In support, the Committee argues that imputation remains Commission policy because the Stipulation which removed it in Docket No. 97-035-01 establishes no precedent.

We assess a request to reconsider a standing regulatory policy on the basis of testimony and evidence not previously considered in reaching the policy or which alleges new or changed circumstances. The Company argues that the benefits of the strategic transmission system more than compensate ratepayers for the burden imposed by below-cost WAPA contracts. This is not new. In Docket No. 82-035-13, the Commission rejected a similar Utah Power argument. There, Utah Power asserted that the Commission ought not impute revenues to the below-cost WAPA contract acquired with the CP National transaction because the "transaction taken as a whole is advantageous to the Company and its customers." (Report and Order, page 7.) Instead, the Commission concluded that failure to impute revenues, based on the difference between the contract wheeling rate of $4.20 and the then-current FERC wheeling rate of $24.12, would constitute subsidization of non-jurisdictional preference customers by retail customers. The Commission observed that prevention of such a subsidy was consistent with the intent of its allocation of CP National's transmission investment and expenses between retail and preference customer classes in previous CP National general rate cases.

The Company's argument lacks quantitative support. In this key respect it is similar to the Division's testimony that the Company could have achieved its objectives without the WAPA contracts by building its own system in the face of a newly constructed federal one. Both are interesting, and both might bear analysis. But the analysis has not been performed. We are unable to agree that the benefits allegedly enabled by these contracts outweigh costs ratepayers, in the absence of an imputation of revenues, would bear because of them. Without explicitly ruling on the Division's testimony that the Company behaved imprudently by entering long-term contracts having no escalation provisions, we conclude that the record contains no basis upon which to adopt the Company's rationale for abandoning the imputation policy, and we will not do so. The imputation policy is reaffirmed, and the Division - Committee adjustment is accepted. This decision reduces revenue requirement by $1,257,655.

E. AFFILIATE RELATIONS AND INVESTMENTS IN OTHER PROPERTIES

1. Business Postage

PacifiCorp often includes messages about its unregulated activities and advertisements promoting sale of unregulated goods and services along with the bills it mails monthly to electric service customers. The messages and advertisements are either separate sheets (called "bill stuffers") or part of the regulated Company's newsletter, "Voices." Though included in the same envelope as the monthly electric service bill, required postage is not increased. The Division proposes to share postage cost between the Company's regulated and unregulated activities. The Company opposes the adjustment.

In support of its adjustment, the Division relies on "Guidelines for Cost Allocations and Affiliate Transactions" advocated by the National Association of Regulatory Utility Commissioners (NARUC Guidelines) for authoritative suggestions on how to correct a subsidy flowing from regulated to unregulated Company activities. A good or service provided by the regulated utility to an unregulated affiliate should be priced at the higher of fully distributed, embedded cost or an appropriate price prevailing in the marketplace, states the Division, following the Guidelines. A fifty-fifty sharing of postage costs is the Division's proposal, based on its review of bill stuffer and "Voices" content during the test year. In response, the Company asserts that incremental, not fully distributed, cost is the relevant benchmark; that it is not the Commission's role to protect competition, which might be the practical effect of the Division's proposal; and that the Division is mistaken both on the shares of regulated and unregulated messages mailed during the test year and the relevant price of postage.

We begin by observing that the NARUC Guidelines have not been adopted in this jurisdiction. Certain affiliate relations issues which arose in Docket No. 97-035-01 could not be resolved on the basis of the record there, and were assigned for analysis to a task force after the rate case concluded. The task force considered the Guidelines but reached no consensus about them, with the result that affiliate relations or transactions issues in the present Docket cannot be considered in the context of a task force recommendation. Be this as it may, this Commission has employed "asymmetric pricing" in previous cases. This is the Guidelines' preferred regulatory approach to affiliate transactions. The higher-of-cost-or-market guideline proposed by the Division is an example of asymmetric pricing. We are prepared to follow this pricing prescription again here, if the facts call for it.

In opposing the adjustment, the Company quotes a popular saying from another arena: "no harm, no foul." Because postage costs are not increased by the inclusion of materials about unregulated matters ("the incremental cost is zero"), the Company argues, first, there is no subsidy provided by the utility or its ratepayers to unregulated activities, and second, if the Commission makes the recommended adjustment, it does so to protect competition, a matter beyond its jurisdiction. The Division generally responds to these points with the assertion that if the mailing service provided to unregulated activities were properly priced, rates for electric service would be reduced by that amount; in short, there is a subsidy and it is a proper matter of Commission concern. We believe the Division's view is correct.

The NARUC Guidelines posit a sensible definition of subsidization, to wit: "the recovery of costs from one class of customers or business unit that are attributable to another." No party, including the Company, disputes the fact that unregulated activities receive value, for which they pay nothing, from the mailing of messages and materials along with the customer's bill. Absent a close relationship with the regulated utility, this mailing would not be free. We find there is a subsidy and therefore the higher-of-cost-or-market guideline applies.

We first examine cost, and find on this record that it may be of two forms: fully distributed embedded cost, or incremental cost. The Division advocates use of the former, and the Company, should the Commission decide postage costs must be shared, the latter. Since in its view the incremental cost is zero, one leg of the either-or guideline is eliminated, the Company argues. This is relevant, however, only if we permit substitution of incremental cost for fully distributed cost. In our view, the substitution may be permissible, but only when a transaction which would benefit both the Company or affiliates *and ratepayers* would not occur if a fully-distributed-cost test were employed. Since ratepayers receive no benefit, and none is claimed, when free mailing is provided unregulated activities, the proper test remains fully distributed cost. We return below to the Company's assertion that the Division improperly calculates the fully distributed cost burden.

The guideline is the higher of cost or market. In this case, cost is market (the price of postage), in the Division's view. But the market price is really only about a tenth that of first-class postage, asserts the Company, citing a bulk mailing rate to which it claims access. The bulk mailing rate is not disputed. We find, nevertheless, that the relevant measure, both under the guideline and as we have addressed affiliate transactions pricing in previous dockets, is the higher, not the lower, of cost or market. The relevant cost is the postage on the billing envelope.

Equal sharing of postage costs is the Division proposal, but the Company testifies that the Division overestimates, and therefore gives too great a weight to, messages about unregulated matters. In response, the Division testifies that this dispute boils down to a difference of opinion about whether a message conveys regulated or unregulated information. We agree, and find that the Division's documentation of the results of its review not only of the "Voices" newsletter but the bill stuffers as well is convincing.

We therefore conclude a subsidy is occurring which should be corrected by application of the higher-of-cost-or-market guideline. The relevant cost is the billing envelope postage. We adopt the Division's recommendation that unregulated activities bear fifty percent of test-year postage costs. This decision reduces revenue requirement by $808,035.

2. Bridger Coal Company Accounts Receivable

All parties agree to an adjustment to include the Company's investment in the Bridger Coal Company in ratebase. (See Appendix 1, Section C, number 8.) Included in the average ratebase, however, is Bridger's accounts receivable balance relating to the early retirement program and coal sales. The Company, supported by the Division, proposes to remove the accounts receivable balance of $3,165,280 that is associated with the early retirement program. In addition, the Committee proposes to remove the amounts related to the coal sales of $7,640,258.

In the Committee's view, the Company should not be allowed ratebase treatment of amounts it owes others. Neither in testimony nor in hearing did the Company challenge the Committee's recommendation. Following close of hearings, a joint narrative exhibit was filed by the parties. In this exhibit, the Company claims that the accounts payable balance for Bridger Coal Company was included in the lead - lag study used to calculate cash working capital. The Bridger Coal receivable balance, in the Company's view, must be included in ratebase to offset the lower cash working capital that results from including Bridger's payable balance. The Division disagrees with the Committee adjustment, stating that if the accounts receivable is removed from ratebase it should be removed from the lead - lag study.

The Company had ample opportunity to challenge the Committee's proposal and to provide evidence proving the Committee wrong. It did not do so. Furthermore, the cash working capital study is based on a lead - lag study that dates from December 1991. The record does not show how the current $7 million balance associated with Bridger coal sales is treated in the 1991 study being used in this Docket. In short, we have no basis upon which to reject the Committee's recommendation. This decision reduces revenue requirement by $546,517.

F. NET POWER COST ADJUSTMENTS

1. Net Power Cost Studies

Net power costs are defined to be the costs of fuel at Company generating plants, plus the costs of wholesale power purchases and wheeling, less sales for resale (wholesale) revenues. The Company calculates net power costs using its Production Dispatch for the MacIntosh (PD/Mac) model. This model simulates the operation of the power supply portion of the Company on a monthly average basis. One of the most significant features of the model is its use of fifty years of data covering monthly hydroelectric generation for Company-owned hydro plants in the Northwest and Mid-Columbia purchased resources. The model is run for each of the fifty different water years (August 1928 through July 1979), the results are averaged, cost data is applied, and expected net power costs are obtained reflecting normal conditions. Among the important inputs are weather normalized retail loads, the prices and volumes specified in wholesale firm sale and purchase contracts, firm wheeling contracts, wholesale non-firm sale and purchase prices, and thermal plant data including coal prices. In addition, prices of resources, and prices and volumes of wholesale firm sale and purchase contracts are annualized. The model also uses data relating to the Pacific Northwest regional non-firm load and resource balance, as well as four non-firm wholesale sales markets: the Pacific Northwest, California, the Desert Southwest, and Nevada. The model determines, among other outputs, the monthly quantity of coal to be used at the Company's thermal generating plants, and the monthly quantity of wholesale non-firm sales and purchases for the 1998 test year under conditions reflecting normal water and weather conditions. The Wyodak, Naughton, and Bridger plants all have contracts which provide a reduction in cost per ton when certain tonnage levels are attained. These discounts are not quantified in PD/Mac studies, so the cost of fuel is adjusted to reflect discounts on the normalized tons of coal.

Following the net power cost study adjustments discussed below, the adjustments with respect to the prices of specific wholesale sales contracts proposed by the Division and Committee, and the adjustment concerning coal stockpiles proposed by the Division, are addressed.

The Company initially filed adjustments to normalize and annualize net power costs, and to quantify the coal tonnage discount. The Committee identified various adjustments, some of which were subsequently adopted by the Company and the Division, and some of which were withdrawn by the Committee. The Large Customer Group also filed net power cost studies using PD/Mac. The positions of the parties are summarized in the tables below.(3)

These tables, for comparison purposes, include actual 1997 net power costs and the stipulated 1997 net power costs accepted in Docket No. 97-035-01. The first table presents the positions of the parties with respect to system net power costs. The second table presents net power costs allocated to Utah. The allocation factors used for all parties are those previously accepted by the Commission in this Order. Also included in the second table is the determination of Utah's average net power cost.

Table 1: System Net Power Cost Sudy Results ($Million)

	1997 Actual	1997 Stip'd	1998 Actual	1998 Co.	1998 DPU	1998 CCS	1998 LCG
Fuel Expense	481.9	477.3	521.8	490.1	491.9	489.7	469.2
Purchased Power Expense	1,239.4	938.4	1,100.0	876.0	1,008.5	1,004.8	1,033.5
Wheeling Expense	70.5	72.4	74.2	73.5	74.8	74.8	73.5
Power Cost	**1,791.9**	**1,488.1**	**1,696.1**	**1,439.6**	**1,575.2**	**1,569.3**	**1,576.1**
less Sales for Resale Revenue	(1,421.9)	(1,113.8)	(1,251.3)	(1,003.4)	(1,147.5)	(1,148.9)	(1,248.8)
Net Power Cost	**$369.9**	**$374.3**	**$444.8**	**$436.1**	**$427.7**	**$420.4**	**$327.3**

In 1997, actual system net power costs totaled $369.9 million. In 1998, actual system net power costs totaled $444.8 million, an increase of nearly $75 million, or approximately 20 percent, relative to 1997. While power costs, i.e., the costs of fuel, power purchases, and wheeling, decreased by almost $96 million in 1998 relative to 1997, sales for resale revenue fell by almost $171 million. It is this relatively large decrease in sales for resale revenue that accounts for the increase in actual net power costs in 1998 relative to 1997.

Three adjustments proposed by the Committee have been accepted by the Company and Division. First, the dispatch of the Hermiston plant reflects PD/Mac model logic instead of being forced to operate according to environmental constraints. Second, a 30 megawatt derate on the Cholla #4 unit is used for spinning reserve purposes. Third, upgrades of turbine capacity at Company thermal generating units that occurred during 1998 are incorporated. These adjustments are consistent with the Stipulation of Net Power Cost Issues in Docket No. 97-035-01. These three adjustments, together with its initial adjustments, result in the Company's proposal to decrease system net power costs from the 1998 actual amount of $444.8 million to $436.1 million, a decrease of $8.7 million.

Two further adjustments proposed by the Committee have been accepted by the Division. Actual market prices for non-firm (secondary) and short-term firm sales and purchases are used rather than those the Company terms as normalized prices. As a result, the Division proposes to decrease system net power costs to $427.7 million, a decrease from the 1998 actual amount of $17.1 million.

The Committee also proposes an adjustment to the Wyodak fuel contract price to bring it in line with market levels. As a result, the Committee proposes to decrease system net power costs to $420.4 million, a decrease from the actual 1998 amount of $24.4 million. Neither the Company nor the Division accepts this adjustment.

The Large Customer Group proposes three adjustments to actual system net power costs. First, the LCG uses actual prices and volumes for short-term firm sales rather than the Company's normalized prices and the model's determination of normalized volumes of short-term firm sales. In effect, short-term firm sales revenues are maintained at actual 1998 levels. Second, the LCG allows spot prices to vary with each of the fifty water years used to establish normal hydro conditions whereas the Company uses the same spot prices for every water year. Third, the LCG removes the value by which short-term firm purchase costs exceeded short-term firm sales revenues during the months of July, August and September in 1998, ensuring profitability of short-term firm transactions throughout the year. As a result of these adjustments, the LCG proposes to decrease system net power costs to $327.3 million, a decrease from the actual 1998 amount of $117.5 million.

Using the System Generation (SG) allocation factor determined previously in this order, which for Utah is 34.1587 percent, and the System Energy (SE) allocation factor, which for Utah is 34.6347 percent, the positions of the parties with respect to the share of net power costs allocated to Utah are presented in the table below.

Table 2: Utah-Allocated Share of System Net Power Costs ($Million)

	1997 Actual	**1997 Stip'd**	**1998 Actual**	**1998 Co.**	**1998 DPU**	**1998 CCS**	**1998 LCG**
Fuel Expense	160.9	159.4	180.7	169.7	170.4	169.6	162.5
Purchased Power Expense	408.8	309.1	376.7	299.9	345.1	343.8	354.4
Wheeling Expense	23.2	23.8	25.4	25.1	25.6	25.6	25.1
Power Cost	**593.0**	**492.3**	**582.8**	**494.7**	**541.1**	**539.1**	**542.0**
less Sales for Resale Revenue	(468.3)	(366.3)	(427.8)	(342.8)	(392.1)	(392.6)	(426.6)
Net Power Cost	**$124.7**	**$126.1**	**$155.0**	**$151.9**	**$149.0**	**$146.5**	**$115.4**
Adjustment to '98 Actual				**($3.059)**	**($5.972)**	**($8.503)**	**($39.534)**
Megawatt Hours (million)		13.801		14.235	14.235	14.235	14.235
Average Cost ($NPC/Mwh)		$9.1339		$10.6711	$10.4665	$10.2886	$8.1088
Percent Change, '98 vs '97				**16.8%**	**14.6%**	**12.6%**	**-11.2%**

In 1997, actual net power costs allocated to Utah were $124.7 million. In 1998, actual net power costs allocated to Utah were $155 million, an increase of nearly $30 million, or approximately 24 percent. Again, this increase is due principally to the decrease in sales for resale (wholesale) revenue. Relative to the 1998 actual net power costs included in the results of operations for the 1998 test period, and subsequently allocated to Utah, the decreases proposed by the parties are: Company, $3.059 million; the Division, $5.972 million; the Committee, $8.503 million; and the LCG, $39.534 million.

Since the number of megawatt hours generally increased by slightly more than 3 percent from 1997 to 1998, a useful comparison of the parties' positions is the change in average cost. Relative to the average net power costs included in current Utah rates as a consequence of Docket No. 97-035-01, the percent increases proposed by the parties are: the Company, 16.8 percent; the Division, 14.6 percent; the Committee, 12.6 percent; with the LCG proposing a decrease of 11.2 percent.

This is the first case since the merger of Pacific Power & Light and Utah Power & Light that net power costs issues have been contested. In Docket No. 90-035-06, revenue requirement issues, including net power costs, were stipulated. In Docket No. 97-035-10, the Commission accepted the Stipulation on Net Power Costs Issues.

a. Prices for Non-Firm Sales and Purchases

In the past, non-firm sale and purchase prices were based on actual data, then adjusted by the Company's power marketing group. In this case, the Company for the first time uses a Market Clearing Price (MCP) model which develops an annual price based on an economic dispatch of Western System Coordinating Council (WSCC) resources under normal conditions, i.e, excluding excesses and deficiencies that take place in the market as a result of, among others, unplanned outages, water conditions, temperature extremes, and transmission outages. Next, the Company uses its forward price curve to shape the price over the months of the test period. The forward price curve is a forecast of future monthly prices created by the Company's marketing department based on a series of quotes of electric energy prices the Company obtains from a group of independent brokers. Finally, the Company assumes a half mill margin of sale over purchase prices, for both non-firm and short-term firm transactions. The margin was derived from conversations with the Company's traders in the wholesale marketing department. These monthly prices, for both non-firm and short-term firm wholesale sales and purchases, are then input into PD/Mac, which then determines, among other outputs, the volumes of non-firm sales and purchases. The MCP model was developed by the Monitor Group exclusively for PacifiCorp so the Company would have the capability of forecasting or evaluating market prices. It was also used to develop stranded cost evaluations that were presented to a Utah legislative task force. This model has not been scrutinized by any regulatory body.

The Committee, supported by the Division, recommends using actual prices for non-firm sales and purchases. The Committee objects to the MCP model for the following reasons: the model is unproven, un-audited, and potentially unreliable; market prices are quite volatile and difficult to model, involving subjective and disputable assumptions; the logic of the MCP model, which generates prices based on average hydro conditions, is inconsistent with the logic of PD/Mac, in which 50 different years of hydro conditions are simulated, with the result that market prices in the PD/Mac runs are not influenced by changes in hydro conditions; the Company did not show that 1998 was an abnormal year for market prices, thus a departure from the use of actual prices is not justified; the Company offered no compelling evidence demonstrating that the prices generated by the MCP model were reasonable for ratemaking purposes; actual information is readily available, thus reliance upon information developed by a model is unnecessary; and, consistent with Commission preference for historical test years, actual information is known and measurable whereas modeling results are speculative and uncertain. The Committee proposal reduces system Net Power Costs by approximately $1.79 million relative to the Company's proposal.

The Company opposes the Committee's proposal because: mixing actual prices and normalized volumes reflects neither the actual supply and demand relationships that existed during the test period nor those reflected in the normalization modeling; all net power cost items are interrelated and have a corresponding impact on other inputs - the use of actual non-firm prices, based on only a single observation, and normalized information for other components of net power costs such as thermal and hydro generation and normal temperatures creates an inappropriate mismatch because other inputs are based on normal information and not actual information; and, it is only appropriate to use actual information when a net power cost balancing account is used to set customer prices.

The purpose of normalization in the context of an historical test year is to adjust actual information for known and measurable events occurring during the test year, establishing a normal and recurring level of costs and revenues. Determining regional market prices is complex, risky, inherently subjective, and prone to error. The WSCC "normalized" price, as is the case in any model, is the product of assumptions. It is in large part subjective. The assumptions underlying the MCP model have not been examined on this record. Market conditions in the western region are highly fluid. With deregulation and electric industry restructuring, and the entry of new entities, competition is increasing. The whole process of using a complex regional dispatch model to obtain an annual price, shaping that annual price into monthly values, assuming a margin to differentiate sales from purchase prices, requires a large number of subjective judgments. In such circumstances we have little confidence in what constitutes known and measurable changes. This is precisely why we have a preference for the use of historical test years. Moreover, in terms of hydro conditions, 1998 was 98 percent of normal. In our judgment, there is no reason not to use actual information.

Further, we agree with the Committee's criticism that the use of market prices obtained from the MCP model is at odds with the hydro normalizing logic of PD/Mac. While it may be true that market prices are less sensitive to changes in hydro conditions, it does not justify ignoring the influence of hydro conditions. Changes in hydro conditions are the heart of the PD/Mac modeling process.

We also reject the Company claims that if actual information is used, then an energy balancing account (EBA) is necessary. An EBA is an inappropriate means of sharing risk when half of all the Company's sales are in the wholesale market. An EBA simply puts all risk of the Company's performance in the wholesale market on firm retail ratepayers. Some form of establishing the appropriate degree of risk to be borne by firm retail ratepayers remains. We therefore conclude the use of actual prices for non-firm sales and purchases, rather than the Company's normalized prices, is appropriate.

The Company assumes that variations in the quantity of hydro power on the Columbia River have no impact on market prices. The Company implements this assumption in the PD/Mac model by using one set of monthly normalized prices for all 50 years of hydro conditions. The LCG proposes to let non-firm prices vary with each of the 50 years. The LCG accomplishes this by turning on the PD/Mac code designed to permit power prices to vary with hydro conditions, which the Company has turned off in its running of PD/Mac. The Company claims the LCG's revision to the subroutine that causes prices to vary with hydro conditions has the effect of forcing market prices to their lowest level during period of poor water conditions, a contradictory result. When corrected, the Company states net power costs show a slight increase, rather than the large decrease quantified by the LCG. The Company also objects to the LCG's approach on other grounds. The Company claims that when the LCG adjusts the MCP model to include 50 years of hydro information, only the changes in the energy component of the hydro system are reflected, with the effects on hydro capacity omitted. The LCG also assumes prices in all regions of the WSCC are correlated with hydro conditions in the Northwest. Finally, as stated previously, the Company contends market prices are not as correlated with water levels as in the past due to environmental constraints on the use of the hydro system.

Since we have accepted the Committee proposal to use actual prices for non-firm sales and purchases, the proposal of the LCG is unnecessary.

b. Prices and Volumes of Short-Term Firm Sales and Purchases

Both the monthly prices and volumes of short-term transactions are treated as inputs in the PD/Mac model. The Company uses the same prices for short-term firm wholesale sales and purchases that it uses for non-firm wholesale transactions, described above. Again, a half mill margin is assumed on all short-term firm transactions, ensuring there are no losses associated with these transactions. The Company uses, as it has for several years, a two-year weighted average of volumes in order to smooth out or normalize the volatile levels of short-term firm transactions.

First, the Committee recommends using actual prices for short-term firm sales and purchases. The same logic expressed with respect to prices of non-firm sales and purchases, discussed previously, pertains to short-term firm prices. In addition, the Company uses the prices developed by the MCP model for both non-firm and short-term firm sales and purchases, yet these are different products, and since firm service has more value than non-firm service, short-term firm prices should be higher than non-firm prices.

Second, the Committee also recommends using actual volumes of short-term firm sales and purchases. The Committee again asserts the Company's adjustments are speculative, claiming the Company's development of normalized 1998 transaction volumes based on an arbitrary weighting of the 1997 and 1998 actual sales volumes cannot be considered known and measurable.

Finally, the Committee recommends removing losses from short-term firm transactions that occurred in the Utah division during 1998, stating that shareholders rather than ratepayers should bear the risk of the Company's trading losses in the wholesale market. In those months for which purchase prices exceeded sales prices in the Utah division for short-term firm service, the Committee reduces purchase prices to sale prices. This they claim is consistent with the assumptions of a half mill margin of sale over purchase prices made by the Company to prevent any losses. The Committee's proposal for the treatment of short-term firm transactions reduces system net power costs by approximately $6.7 million relative to the Company's proposal.

The Division supports the Committee proposal. Use of actual prices for short-term firm sales and purchases follows the same logic expressed with respect to prices of non-firm sales and purchases, discussed previously. In addition, the Division supports the Committee proposal to use actual 1998 volumes of short-term firm transactions. The Division states that in this case, the Company reduces 1997 volumes by two-thirds before the two-year average volumes are computed. This adjustment is undertaken in order to remove an estimated amount of book-outs, or purely financial transactions, that may have occurred in 1997. The Division claims the Company didn't keep records and has no evidence regarding the actual level of book-outs. The Division terms the Company's reduction unsupported and unacceptable, and points to the data response the Division received indicating that no evidence supports this reduction. The Division believes actual 1998 volumes are reasonable given that 1998 was a normal hydro year, concluding that actual data represent a normalized volume better than the two-year average as computed by PacifiCorp. Finally, the Division points out that the Company incurred a $39 million third quarter loss on its wholesale transactions.

The Company's argument for the use of normalized prices for short-term firm sales and purchases is the same as that expressed with respect to prices of non-firm sales and purchases, discussed previously. In addition, the Company claims removing losses is inappropriate because a substantial portion of the purchases were made to serve retail load and not to cover short-term firm wholesale sales, looking at monthly results fails to recognize that a one-year sale may appear to be losing money in any given month yet is profitable on an annual basis. In addition, the Company buys energy on the eastside that serves westside sales and vice versa. Finally, the Company states that since they operate an integrated system, the proper way to determine the profitability of short-term firm transactions would be to remove them entirely from the study and rerun the model, which would increase net power costs.

As we have previously discussed, we find it appropriate to use actual monthly prices. Furthermore, we agree with the Committee that firm service has a greater value than does non-firm service, a distinction not recognized in the Company's development of normalized prices. The Company did not respond to the Division's criticism of the Company's construction of normalized test period volumes. There is no evidentiary basis for accepting the Company's test-period volume adjustments as known and measurable. We conclude that it is appropriate to use actual monthly volumes.

While we agree that it is not wholly appropriate to view wholesale transactions in isolation, identifying the benefits of wholesale transactions is more complex than simply eliminating them from net power cost studies. The Company testified that about 5 to 10 percent of the supply for wholesale sales comes from the Company's thermal resources and 5 to 10 percent from non-firm purchases. This leaves 80 to 90 percent of the supply for wholesale sales to be provided from firm wholesale purchases. Therefore, a comparison of wholesale sales and purchases does provide useful, though incomplete, information. It is clear that the Company's performance in the wholesale market declined from 1997 to 1998, particularly during the third quarter of 1998 when the average purchase price, $33.99 per megawatt hour, exceeded the average sales price, $33.71 per megawatt hour. The Division testifies that 1998 was the worst year for the net revenue credit since 1990. We agree with the Committee that ensuring monthly purchase prices do not exceed sale prices is consistent with a similar assumption made by the Company with respect to its use of normalized prices, where a half mill margin is assumed. We conclude the Committee's proposal to remove losses is appropriate.

The LCG proposes that actual short-term firm sale prices and volumes be used in the PD/Mac model rather than the Company's normalized sales prices and volumes. This adjustment accounts for roughly 70 percent of the difference in the positions of the LCG and the Company. The Company claims this creates an extreme mismatch between revenues and expenses associated with wholesale transactions. The effect of the LCG proposal is to match actual 1998 revenues from short-term firm sales, which are much higher than the Company's normalized amounts, with the Company's normalized costs of short-term firm purchases, the latter having been greatly reduced from actual levels. The Company makes additional criticisms as well. Consistency would dictate that sales and purchases be treated on the similar basis. This we believe we have done in accepting the Committee's proposal.

The LCG states that regional power markets have undergone a single significant change due to the introduction of the California Independent System Operator and Power Exchange. This has produced a major shift in prices in the summer months, one not anticipated by the Company, and appears to explain the Company's losses in the summer of 1998. During the nine non-summer months of 1998, the margin between the average prices for short-term firm sales and purchases was .76 mills. During the summer months of July, August, and September of 1998, the margin fell to a negative 1.26 mills. The LCG recommends eliminating the Company's losses during the summer months.

Since we have accepted the Committee's proposal to use short-term firm sale prices where they exceed short-term firm purchase prices, this proposal is unnecessary.

The effect of accepting the Committee's proposals with respect to non-firm and short-term firm sales and purchases reduces Utah-allocated net power costs and the necessary change in revenue requirement by $5,972,013.

c. Wyodak Coal Contract Prices

The Committee's final net power cost study proposal is to bring the Wyodak fuel contract price in line with market levels. The Committee offers three justifications for its recommendation. First, the 1991 Coal Audit Report by Energy Venture Analysis, Inc. recommended that the Company pursue a buyout of the Wyodak coal supply contract to reduce fuel prices. Second, the Company's own fuel supply analysis confirms that the Wyodak fuel cost has been substantially above market levels since 1987 on a mine price basis, and has exceeded market levels since 1992 if transportation and handling costs are included in total fuel costs. Third, the Wyodak fuel price continues to exceed market levels in 1998.

With the commercial operation of the Wyodak plant in 1978, a long-term contract was entered into for the supply of coal. The Company states this contract is similar to other contracts signed during this time in the Powder River Basin. In addition, coal is delivered by conveyor thereby avoiding transportation and stockpiling costs. If the Company were to receive coal from other Powder River Basin mines by either rail or truck, then an unloading facility would be required at the plant. From the inception of the contract in 1978 through 1992, coal costs have been below-market. The Company testifies that the plant ranks as the fifth lowest cost thermal power plant in the WSCC. Finally, the Company states it is engaged in ongoing discussions with Black Hills, the entity holding the contract. The Division does not support this adjustment.

There has been no showing that this contract was entered into imprudently. Both the Company and Committee agree that the current contract prices exceed market levels. Yet the Company claims it has tried to buy out this contract, but to date its efforts have proved unsuccessful. We will continue to review Company efforts in this regard. Given that the total costs of currently operating the Wyodak plant, including coal costs, are reasonable, we find no adjustment is necessary at this time.

d. Confidentiality of Net Power Cost Studies

LCG recommends that the Commission eliminate confidentiality protection from all documents not specifically shown to have commercial value and not currently in the public record. When information is treated as confidential without substantial reason to do so existing, the regulatory process becomes needlessly difficult and time-consuming for all parties. We therefore concur with this recommendation, and will require that PacifiCorp make as much of its information open, available, and non-proprietary.

e. Format of the Production Dispatch Model

LCG recommends recasting the PD/Mac model using Microsoft Excel to make the methods and performance of the model easier to understand. In this Docket, LCG provides an Excel version of PD/Mac. This record not only shows that the change can be accomplished, but the report of the Committee's consultant, who participated in the last rate case and provided a report to the Division and the Committee, recommends the same. Moreover, it is clear to us that the tool can be transported from a MacIntosh format to an IBM-compatible format such as Excel. The Committee and other intervenors do not have ready access to MacIntosh equipment, and this reduces their ability to continually evaluate the logic of the model and its assumptions. The issue of net power costs was one of the least understood in this Docket. This change will help to address that problem. Therefore, we order that a Microsoft Excel version of PD/Mac be made available to the Division, the Committee, and any intervenor who requests it. This must be accomplished well before the next general rate case occurs.

In summary, our experience with PD/Mac in this Docket has been unsatisfactory and convinces us that the regulatory treatment of net power costs must be re-evaluated before the next general rate case for this Company. The record shows that the primary source of the increase in revenue requirement in this Docket is the result of the increase in net power costs. Although the Company listed certain causes from the witness stand for the increase, no party evaluated them in written testimony. It also shows that parties, with the exception of hired consultants, lack the expertise to fully evaluate net power cost issues. The model itself is a major contributing factor to such difficulties. This complex subject warrants further discussion outside the time-limited confines of a general rate proceeding, including this one. We desire the Division and interested parties to undertake an evaluation of alternative approaches to the normalization of net power costs.

2. SMUD Revenue Imputation

In 1987, the Company entered into a long-term (through 2014) contract with the Sacramento Municipal Utility District (SMUD) under the terms of which SMUD acquires electricity from the Company at a rate of $16.85 per MWH. This rate was below-market in 1987, but the contract, according to the Company, results from a complex set of transactions which, among other things, yielded for the Company an up-front payment from SMUD of $94 million. That amount, however, was retained by the Company rather than benefitting ratepayers through reduced rates. Imputing revenues to compensate for the below-market contract therefore has been common in several states since 1987. A partial history permitted by the record shows imputations in Oregon, Idaho, and Utah. The Division now proposes a revenue imputation adjustment which is adopted by the Company but opposed as inadequate by the Committee.

For its imputation proposal, the Division diverges from the basis it has employed in previous years and accepts a $19 per MWH basis recently adopted by the Idaho Public Utilities Commission. The Division reasons that the basis adopted in a sister state is appropriate here as well because, unlike recent imputations in Oregon, it is not the product of a stipulation. Stipulations, all agree, establish no precedent. Here in Utah, a revenue imputation was proposed by the Division for the general rate case postponed by the Utah Legislature in 1997, but when that case proceeded as Docket No. 97-035-01, the proposal was not included. The basis for imputations in Oregon and previously in Utah is a contemporaneous contract, said to indicate a market rate, the Company has with Southern California Edison Company (SCE). That contract rate until a recent renegotiation has been about $42 per MWH. Renegotiation resulted in a lower rate, about $37 per MWH. It no longer provides, in the Division's opinion, a relevant contemporaneous comparison.

The Committee disagrees. Noting that no reason is given by the Division to explain why the mere fact of renegotiation should render the SCE contract rates useless as a basis for imputation, the Committee nevertheless develops a different basis for imputation. It suggests use of the price used by this Commission to determine whether the terms of firm special retail contracts are compensatory. This price is about $30 per MWH, and the Committee advocates it both because it has been approved by the Commission and is properly based on the Company's incremental costs.

As noted, the Company accepts the revenue imputation amount proposed by the Division. It does so without significant comment.

A price contemporaneous with the date of the SMUD contract is proposed by the Division as the basis for revenue imputation. As the contract price was below-market when the contract was entered, a contemporaneous basis for regulatory correction is appropriate since the imputation amounts to a judgment about the Company's decision to enter the contract. As we have said elsewhere, such a judgment should be made in light of circumstances existing at the time. This view continues to be appropriate and we will apply it in this Docket. Since the contract was below-market when signed, the task before us is to find a rate, contemporaneous with the contract date, to use as the basis for revenue imputation.

On this record, rates which fit this description are associated with the SCE contract and the Idaho amount recommended by the Division. That proposed by the Committee is not acceptable because it is an amount calculated at a later date. As noted, the Division has used the SCE contract in previous years for the imputation, but abandons it now because the contract has been renegotiated. Instead, the Division offers a rate accepted by a sister state. This rate is inappropriate because it is a non-firm rate. The SMUD contract is a firm contract. This difference caused the Division witness to express no objection to use of an appropriate firm rate instead, agreeing on cross-examination that a suggested $23 per MWH was reasonable. Though we believe the proper basis for the imputation is a firm rate, we reject the suggested $23 because it is not contemporaneous. The record shows that it is a 1998 average firm sales price from COB and Palo Verde Electricity Price Indexes.

What remains on the record are the prices from the original and the renegotiated SCE contracts. No reason appears on this record to reject these prices as the basis for imputation other than the mere fact of contract renegotiation, which the Division believes removes it from consideration. This is not reasonable. The original contract rate of $42 per MWH remains a contemporaneous one whether or not the contract is later altered. The fact of renegotiation is an entirely unrelated, later event. We could easily choose this amount as the basis for a permissible revenue imputation, just as it has been in the past. This record, however, makes clear that, due to changes in the wholesale market, prices of wholesale sales have been declining. We surmise that the reduction of the price in the SCE contract reflects these changes, which result, we believe, not merely from temporary realignment of the forces of supply and demand but from institutional alterations in part due to government requirements. The latter fact inclines us to accept the renegotiated SCE contract rate of about $37 per MWH as the basis for a proper imputation of revenues for the under-market SMUD contract, and we so order. This decision reduces revenue requirement by $2,876,216.

3. Sales for Resale / Firm Wholesale Contracts Revenue Imputation

The Division and the Committee recommend a revenue imputation for long-term wholesale contracts (2-5 years) as an appropriate regulatory means to prevent harm to firm retail ratepayers. Revenue imputation is required because the Company entered into contracts that sell power for less than the cost to serve them. The Division concentrates on four intermediate-term contracts (2-4 years) and two long-term contracts (5 years), while the Committee's standard for judgment requires revenue imputation for a greater number of contracts. The difference between the Division's and Committee's adjustments centers on the appropriate price floor on which to base the revenue imputation. The Committee provides two options for establishing a price floor, both of which are derived from retail contracts which the Committee maintains are appropriate measures of the opportunity costs of the wholesale sales. The first option is determined by the prices associated with four interruptible contracts which average $24.19 per MWh. The second floor is derived by averaging the rates approved for the economic incentive 'special' contracts for four firm retail customers. These price floor recommendations result in revenue requirement adjustments of approximately $8 million and $20 million, respectively.

The Division uses avoided costs which were applicable in Utah at the time the contracts were signed as the basis for calculating the revenue imputation. Two different avoided costs are used by the Division to recognize that during the time period, the Company filed a new avoided cost application in this jurisdiction. The Division refers to this as the "Filed in Utah standard." To these avoided costs, the Division adds transmission losses and a sales for resale credit when such information is available.

The contracts in question have normalized prices that range from approximately $15 per MWh to $17.5 per MWh and were signed between June 1996 and December 1997. The Division maintains that its proposed "filed in Utah standard" is fair and appropriate because the Company has complete control over when it files its avoided costs in its jurisdictions, but has less control over Commission approval of these rates. The first avoided cost proposed by the Division as a measure for revenue imputation is that filed in Docket No. 95-2035-03 and approved on March 4, 1997. The price floor is $19.64 and includes an adder for transmission losses. It is based on a RAMPP-3 Integrated Resource Plan that is updated to include known and measurable changes to loads and resources, and price assumptions that would affect avoided costs. The second measure of a price floor is $16.70, and includes an adder for both transmission losses and a sales for resale credit. This figure is based on information filed in Docket No. 97-2035-02 and is used to evaluate the appropriateness of contracts filed in 1997. The request for approval of these 1997 avoided costs was ultimately rejected by the Commission in an order issued in October 20,1999. The Division's adjustment would reduce Utah revenue requirement by $1,516,107.

The Company argues that it is inappropriate to single out a few contracts for special treatment and that the overall performance, with respect to impact on retail customers, of the entire wholesale portfolio instead should be evaluated. The Company maintains that revenue credit ratemaking treatment for wholesale sales has been beneficial to ratepayers over the years. If, however, the Commission deems that revenue imputation is required, then an appropriate price floor, not those recommended by the Division or the Committee, should be used for imputing revenues.

The Company claims the Committee's use of retail contract rates, whether for economic incentive or interruptible contracts, is inappropriate. The wholesale market is more competitive than the retail market. This results in lower prices and margins because wholesale customers have more options than do retail customers. The provision of power to retail customers connotes a longer-term commitment to provide power than a wholesale contract, and thus requires higher margins.

The Company stresses that the Division's filed-in-Utah standard for imputation could produce conflicting prudence tests between jurisdictions which might result in fewer wholesale contracts, to the detriment of firm retail customers. It argues that a price floor based on avoided costs approved in Docket No. 95-2035-03 would use information from 1993 and 1994, too old for contracts signed in mid-1996. In its view, a proper comparison would link contract prices to the best information available to the Company at the time contracts were signed. This, the Company avers, would be its 1996 avoided costs submitted for approval to the Oregon Commission and approved there in July 1996. Market prices prevalent at the time might also be used. This would produce price floors of $14.44 and $13.74, respectively, and, the Company argues, would show that all contracts cover costs.

The Company also criticizes the Division's use of the sales for resales credit in its calculation, which the Company contends is a measure to assess the value of the energy if it were not sold on the open market. The Company asserts that the actual sales price on a wholesale contract is the opportunity cost, and it represents the best deal that was available at the time the deal was struck.

We recognize the difficulty of assessing the prudence of the wholesale contracts, and are aware that wholesale sales can benefit retail customers. Though the Company is not required to seek Commission approval of such sales, we must, as a matter of statutory responsibility, make sure that retail customers are not harmed by them. We reject the Company's argument that we should not judge specific contracts but only look at the overall impact of wholesale sales on retail customers. This is too lenient a criteria for standard and one that would send the wrong message to the Company. We do not judge, for example, the prudence of generation plant in that way.

Thus, the issue before us is the determination of a method to evaluate these contracts. We agree with the Company that the Committee's suggestion of using retail contracts as a measure of the wholesale price floor is inappropriate. Wholesale sales should not be judged solely on prices secured in the retail market. We also reject the Company's proposal to use prices for firm sales found in the spot market at the time these long-term contracts were signed. It is inappropriate to judge long-term contracts by short-term prices. What remains on this record for determining the basis for revenue imputation is the most appropriate avoided cost estimate.

In spite of the Company's argument that the most current information available when the contracts were signed is the avoided cost filed and approved in another jurisdiction, which has some appeal, we will not substitute another body's determinations for our own. The record shows that contemporaneous avoided cost actually was significantly higher than that approved in another jurisdiction, though we do not use it here, buttresses our contention that we cannot rely on another Commission's avoided cost decisions for the present purpose. We rely on the Division's expertise in the field of avoided cost determination, and on the basis of its testimony reject the Company's contention that the avoided costs the Division proposes are outdated.

We find that the Division's proposal to use the avoided cost rate that has been filed in Utah is reasonable for the purposes of revenue imputation in this Docket. We further find that its proposed adjustment for transmission losses is appropriate. It is not opposed by any party. With regard to the sales for resale adjustment, we find the Company's argument against it unpersuasive. We understand the sales for resale credit as an adjustment to account for a problem in modeling avoided costs. To calculate avoided costs, two model runs are compared, one with known loads and available resources and another which includes an addition to the resource mix of 10 average megawatts of zero-cost resources. The difference in total energy costs of two runs, divided by the 10 average megawatts, yields the avoided energy costs on a dollars per MWh basis. The sales for resale credit is an attempt to calculate the opportunity cost of the 10 average megawatts of the zero-cost resource based on the margin the Company could earn on power it generates and sells in the open market. The Company maintains that it could only get the price that it had just negotiated and thus the credit would be zero. The Division argues that this credit is required to calculate the avoided costs for Qualifying Facilities and is required here as well. The avoided cost is an independently determined measure of the opportunity cost of the wholesale sale. We accept this, and therefore adopt the Division's recommended wholesale revenue imputation. This adjustment reduces revenue requirement by $1,516,107.

4. Excess Coal Inventory

Coal inventories exceeded maximum target levels at the Hayden, Hunter, Huntington, and Dave Johnston plants during the test year. Inventories were based on recorded book values rather than normalized to coincide with reports and

PD/Mac requirements. The Division proposes an adjustment to reduce the excess inventory and to normalize coal costs. The adjustment would give PacifiCorp two years to meet the targets in order not to disturb the relationship between mine production levels and coal costs (coal costs can rise when production levels fall). Corrections to Division calculations were offered by PacifiCorp and accepted by the Division. Nevertheless, the Company contends no adjustment should be made. The Committee does not take a position.

If coal production at PacifiCorp mines were reduced as proposed, the Company asserts that coal costs borne by ratepayers would rise by about $2 million, as recovery of fixed costs over a smaller volume raises the cost per ton. This is a potential increase the Division's proposed adjustment does not reflect. In recommending the inventory reduction, the Division relies on a recommendation of a 1991 study of Company coal operations performed by the consulting firm Energy Ventures Analysis, Inc., the coal stockpile targets of which, the Company witness agrees, had been adopted by the Company. Though the record shows the Company has not been in compliance with the targets for years, it intends to reach target levels at an indefinite point in the future when doing so does not raise the cost of coal.

This record suggests that a coal stockpile is intended not simply to meet fuel requirements at a generation station but to do so in a manner permitting effective operation of the supplying coal mine, thus minimizing production costs. This rationale is presented by the Company and not disputed by the Division. The rationale appears to be a good one, as does the accompanying Company intention to move toward the targets when doing so minimizes the costs of generating electricity. On this basis, we reject the proposed Division adjustment.

G. NORMALIZING ADJUSTMENTS

Normalizing adjustments are those which remove the effects of abnormal or nonrecurring conditions such as weather.

1. Uncollectible Expense

The Company proposes two adjustments to uncollectible expense. The first, which is uncontested, corrects an improper allocation of bad debt expense to jurisdictions by directly assigning each jurisdiction's bad debt expense. The second adjustment, which is contested, reverses the provision for bad debt expense and calculates a three-year (1996, 1997 and 1998) average of bad debt write-off as a percent of average receivables. The Division and the Committee recommend similar adjustments, the Division employing a four-year 1993 through 1996 average, and the Committee a three-year 1994 through 1996 average. The Large Customer Group supports the Division's adjustment.

In Docket No. 97-035-01, the Commission decided this issue using the three-year average 1994 through 1996, rejecting the Company's proposal to include test-year 1997, which was found to be anomalous. The Company now proposes a three-year period beginning with 1996 and including the formerly rejected 1997. Results for 1998, asserts the Company, make what formerly seemed an anomaly look like a trend. Evidence for an upward trend in uncollectible expense is found, PacifiCorp testifies, in a growing number of bankruptcy filings in Utah in recent years.

We reject the Company position and adopt that of the Committee. The evidence on the record leaves little doubt that the rise in uncollectible expense is due to internal Company problems. Confidential internal reports reviewed by the Committee and an internal audit report reviewed by the Division point to problems associated with the implementation of a new customer service system in two regional centers and the closure of numerous local service offices (". . . management is working with a cross organizational task force to address the many customer collection process issues that have contributed to the significant increase in customer account write off.") Failure to produce correct bills led the Company to suspend collection efforts in late 1997 through early 1998. According to these reports, and to Division and Committee witnesses, this led to increases in uncollectible expense. Write-offs as a percent of receivables were 4.1 percent for 1994 through 1996, rose to 8.5 percent in 1997, and to 10.2 percent in 1998. As a result of its on-going efforts, PacifiCorp expects uncollectibles to decline. Because 1997 and 1998 are problematic and do not represent a normal, on-going ratio of write-offs to receivables, we adopt the three-year period proposed by the Committee. It is the same period used in the previous Docket. The Division would add 1993, but does not explain why a four-year period might be superior.

After close of hearings, the Company discovered an error which overstates the revenue requirement decrease of this adjustment by $2.4 million. The proposals of the Division and the Committee begin with the Company's adjustment and are therefore overstated by the same amount. PacifiCorp filed an exhibit on April 24, 2000, presenting a correction with which the parties agree. We adopt the correction. These decisions reduce revenue requirement by $4,797,671.

2. 1998 Early Retirement and Associated Pension Expense

During 1998, the Company offered an early retirement program to its employees. The Company proposed an adjustment to annualize the effect of the early retirement program for the selected test year and to amortize the cost of the program over five years. The Division accepted the Company's proposed adjustment. The Committee did not concur. The Committee asserted that the Company's calculations for the adjustment were in error and did not correctly account for the impact of the retirement program. During discovery, the exchange of information between the parties did cause the Company to revise its calculations and to propose an additional adjustment, in addition to the originally proposed adjustment. The Division accepted the Company's second, additional adjustment as well. The Committee continued in its objection that, even with the revisions, the Company's calculations still incorrectly adjust the test year for the 1998 retirement program's impact and improperly reflect the program's impact on pension expenses for the test year. In this latter aspect, the Committee objected to the Company's treatment of pension expenses on an accrual basis instead of a pay-as-you-go basis.

Previously, the Company had been on a pay-as-you-go reporting basis for both financial and regulatory reporting purposes. In 1997, the Company changed its financial reporting to an accrual basis for pension expenses. The Company's results of operations, which form the basis for the test year, reflect pension expenses on an accrual basis rather then a pay-as-you-go-basis. The Company requests regulatory treatment of pension expenses on an accrual basis. The Company maintains that accrual treatment results in a reduction in the level of these expenses to be included in this and future ratemaking proceedings.

Pension expenses under pay-as-you-go are recorded on the level of pension costs calculated to be necessary during the reporting period, compared the pension expenses accrued by employees under an accrual reporting basis, in order to have sufficient funds available to make present and future pension payments. Pension expenses recorded under a pay-as-you-go basis may have greater inter-period volatility than those recorded under an accrual basis. This occurs because the investment performance (both actual and projected) of the pension fund, which is used to provide funds for payment of pension expenses, varies as financial market conditions change and as actuarial calculations for pension expenses change. Differences between the level of pension expenses that would be recorded on a pay-as-you-go basis and that under an accrual basis are reflected through a deferred pension asset.

The Committee critiques the Company's filing as insufficiently supporting the adoption of accrual accounting for pension expenses, as opposed to remaining with the pay-as-you-go basis. The Committee maintains that the Commission must be adequately informed with a sufficiently detailed analysis to make reasoned conclusions that would support a decision to make this regulatory accounting change. The Committee argues that the burden is upon the Company to show that the accounting change would result in some benefit to ratepayers (a lower level of costs in determining the Company's revenue requirement) and that the Company has not met its burden. The Committee presented its analysis under which the retention of the pay-as-you-go basis could result in lower pension expenses. The Company responds to the Committee's analysis by noting alleged errors in Committee calculations and the Committee's reliance upon information outside the test year. The Committee's objection to the 1998 early retirement pension adjustment is based on its view that the Company has erred in attributing far too little of the test year's pension costs to the early retirement program and attributed far too much to the pension liability incurred from the service of retained employees during the test year. The Company responds to the Committee's position with the expected complement; the Committee errs by attributing far too much to the early retirement program and far too little to the retained employees' expense.

The choice between pay-as-you-go or accrual accounting treatment of pension costs for regulatory purposes and concomitant treatment of pension costs has been a vexing matter. Our ability to consider the matter in other dockets has been hampered by the lack of a well developed record upon which we could make an informed decision. It has been treated by parties based on the expediency of the limited term impact a particular choice may have on the determination of a utility's revenue requirement and, seemingly, without much thought on developing a record by which an objective third party could examine the regulatory decision to adopt one method or another and insure proper application of the decision. We recognize that in examining the matter, the analysis is sensitive to the underlying assumptions or projections given for the performance of the pension fund and in determining the life expectancy of covered employees. We also note that the manner in which the proposed change in regulatory treatment of pension costs was raised and treated by the parties had an impact upon the quality and quantity of the evidence submitted to us.

We conclude that the record provides sufficient evidence to determine that adoption of accrual treatment of pension expenses for regulatory purposes is reasonable. We will adopt the accrual treatment, not so much upon a determination of the revenue effect portrayed by the Company as definitively more probable and reasonable than that of the Committee, but also upon our general approval of accrual accounting principles and their application to pension expenses. We also conclude that there is no need for further adjustment beyond the Company's proposed two adjustments. The Company's adjustments properly account for the application of an accrual basis for pension expenses in conjunction with the 1998 early retirement program. This decision reduces revenue requirement by $49,601,814.

H. ACCOUNTING ADJUSTMENTS

This section considers adjustments to true-up accrual accounts for actual test-year experience and to reflect changes in accounting procedures.

1. Property Insurance

The Company allowed its property insurance reserve to be depleted because of claims during

recent years. This self-insurance reserve is used to cover the deductible on property damage

losses. PacificCorp made an adjustment to increase this reserve from $157,000 to $8,000,000

in 1998. The Committee is proposing to buildup the reserve to a cap of $6 million over 5 years, stating that the over accrual in 1998 is due to under-accruing to this reserve for more than 5 years. The Division agrees that the accruals in 1998 were increased too rapidly, and spreads the increase over two years, instead of one. We find that the Division correctly interprets our annualization policy. This adjustment reduces revenue requirement by $849,159.

2. Worker's Compensation

The Company made an adjustment during 1998 to increase the worker's compensation expense accrual by $1 million to compensate for under accruals during previous years. It states that the process of determining the appropriate annual accrual is, by necessity, a process of estimation and these estimates are trued up as actual experience becomes available. The Committee disagrees with this adjustment and proposes that it be removed in its entirety because it was caused by under accrual in prior years. The Division reduces the Company adjustment by half to recover the costs over two years, which we accept. This adjustment reduces revenue requirement by $150,552.

3. Pension Cost Write Off

When the Company changed its financial accounting to incorporate accrual treatment of pension expenses in 1997, the Company wrote off the deferred pension asset associated with the pay-as-you-go treatment of these expenses. In its 1997 Report to Stockholders, the Company represented that with the changes occurring in electric utility regulation, the Company believed that regulatory recovery of the deferred pension asset was not probable. For regulatory purposes, however, the Company (and Utah regulators) continued to use the pay-as-you-go method and continued to recognize the deferred pension asset. We did so in the Company's last general rate case proceeding, Docket No. 97-035-01. With the proposed change to accrual treatment of pension expenses in this proceeding, the Company requests recovery of the deferred pension asset as part of the change in regulatory treatment of pension expenses. The Company proposes an adjustment to amortize the recovery of the deferred pension asset over five years. Like its position on other pension expense issues, the Division accepts the Company's proposed adjustment.

The Committee objects to the Company's proposed amortization adjustment for the deferred pension asset. The Committee argues that the Company has not provided an acceptable explanation for its regulatory recovery, given that the Company's shareholder report noted that it would not seek recovery and wrote off the deferred pension asset in 1997 for financial purposes. The Committee noted that the Company failed to identify that recovery of the asset would include a deferred compensation plan from the 1980s and early retirement plans of 1987 and 1990. The Committee continues its argument that the manner by which the Company's presentation has co-mingled the pension costs without sufficient explanation or detail of the component parts and the attendant confounding procedural process the parties have had to follow warrant rejection of the Company's adjustment. The Large Customer Group opposes the Company's position and supports the position and arguments of the Committee. The Large Customer Group's position is not supported by record evidence introduced by the Large Customer Group, but relies upon that of the Committee. The Large Customer Group argues that the Company's position is an effort to "claw back" savings from Scottish Power's acquisition/merger of Pacificorp, approved in Docket No 99-2035-04.

In making a transition from pay-as-you-go to accrual treatment of pension costs, one would normally expect some treatment of the deferred pension asset to be expressed. Its general treatment would be to allow recovery, since it represents the deferral of the actual payment of liabilities which arose in prior periods, but which would not have to be paid until some future period. We do not believe that the Company's write off of the pension asset for financial purposes is sufficient to preclude recovery when regulatory accounting treatment of pensions changes as well. The distinction maintained between regulatory accounting treatment and financial accounting treatment incorporates the understanding that what occurs in one does not necessarily control what occurs in the other. In past dockets, when the Commission approved pay-as-you-go treatment of pension costs, our orders specifically identified that the regulatory treatment of the deferred aspect of that treatment was to be resolved in a future rate case.[(4)] We conclude that the record in this rate proceeding provides no reasonable basis to prevent recovery of the deferred pension asset as part of the change to accrual accounting. The amortization period proposed by the Company is not accepted. When dealing with other expenses associated with post-employment compensation and amortization of deferred amounts due to accounting changes, we have used a longer amortization period than the five years proposed here; e.g. post-retirement benefits other than pensions expenses. We have done so, in part, in consideration of the period over which ex-employees will receive the compensation in relation to the amortization period. We conclude that an appropriate amortization period for the deferred pension asset involved here is ten years. The pension asset itself arose over a period longer than five years. We conclude that a ten-year amortization results in an appropriate result to be reflected in determining a reasonable revenue requirement and attendant rate impact.

We are concerned with the aspect of the Committee's evidence which raises some question on the component parts that make up the pension asset, in light of our prior orders. We direct the Division and invite the Committee to conduct an audit of the deferred pension asset to determine whether the level represented by the Company properly reflects the accounting and deferral treatment intended in our prior orders. If the audit identifies that adjustment to the deferred pension asset itself is warranted, as well as adjustment to the amortization, modification may be made in subsequent regulatory reports and the rate effect in the next rate proceeding.

The conclusion we make on this issue requires an increase in revenue requirement of $3,258,432.

4. SERP Reserve

The Company accrues Supplemental Executive Retirement Plan (SERP) expense each year in accordance with the actuarial report. The excess of this accrual over cash payouts under the plan is recorded as a liability. The SERP reserve liability account was not identified as a ratebase deduction in the Company's unadjusted results, so the Company has accordingly adjusted rate base by $562,946. The Division and Committee both agree to this adjustment.

In addition, the Committee has proposed an adjustment disallowing all SERP expense for the test year. It argues that this plan is a non-qualified plan available to a select group of executives, is excessive, and the costs should not be passed on to ratepayers. The Company presented evidence that SERP is a part of the total remuneration package provided in order to attract and retain qualified executives. Most companies offer similar programs in order to make up the difference in the retirement gap for executives.

Although it has been argued that the SERP plan is extra compensation to executives who did not perform well during the test year, it is our opinion that a SERP plan is an essential part of executive compensation in recruiting and retaining qualified executives, and we therefore reject the Committee's adjustment and accept the Company's. This adjustment reduces revenue requirement by $548,338.

5. Executive Severance

The Division reverses the executive severance of Mr. Frederick Buckman, CEO and President, who terminated employment with PacificCorp on

September 25, 1998. The general

perception is that Mr. Buckman terminated his employment at the behest of the Company

Board of Directors as a direct result of sizeable financial losses in recent years to the non-regulated side of the business and a focus on global pursuits. The Division believes that shareholders should bear the responsibility for Mr. Buckman's severance package, and reduces expenses by $183,039 per year, which is Utah's allocated share amortized over five years. The Committee takes no position on this adjustment. We conclude that the Division's adjustment is appropriate. This adjustment reduces revenue requirement by $314,597.

6. Relocation Expense

The Company made an adjustment for the accounting department relocation expense during the test year, and amortized the associated cost over a five-year period. It asserts that this move was the only unusual employee relocation project in 1998. The Committee, however, states that even after this adjustment, the amount left in relocation expense is high and not reflective of normal cost levels. It proposes an adjustment that sets the relocation expense account at the 1993-97 average, plus one-fifth of the difference between the five-year average and the 1998 balance after the Company's adjustment.

We conclude that the relocation costs remaining after the Company adjustment are at a level expected to be ongoing, and therefore reject the additional adjustment proposed by the Committee.

7. Rent Expense

The Committee requests disallowance of certain 1998 rental expenses and the imputation of sublease revenue that will be earned in 2000 in order to promote a better matching of the costs and benefits of the Company's employee reduction program known as BSIP. Specifically, the Committee and the Division recommend annualizing $204,651 in rental expense associated with the Public Service Building in Portland because the lease expired in December 1998. Employees were moved to the Lloyd Center Tower where, the witness alleges, the Company had excess space which the Company had the opportunity to sublease. The Committee maintains that the Company provided conflicting information in data responses, raising doubts about possible rental income from the Lloyd Center property.

The Committee's second recommendation concerns imputing sublease income from renting the eighth floor of the One Utah Center (the lease begins early in 2000) which it alleges was vacated as a result of BSIP employee reductions. According to the Committee, a test-year imputation will promote a better matching of benefits of future employee reductions with the opportunity costs of the vacancy. In rebuttal, the Company states that PacifiCorp BSIP employees occupied the eighth floor for the entire 1998 test year, even though the eighth-floor accounting department was relocated to Portland. There is no evidence to the contrary on the record.

We find that the rental expense associated with the Public Service Building in Portland meets the criteria for annualization of test-year data stated in R746-407-3. The rental reduction occurred during the test year, is expected to be on-going, and is a volume change in the level of Company operations which has minimal interdependent investment/revenue/cost relationships. We therefore accept the Division's proposed adjustment to annualize the rent reduction for the Public Service Building. The Committee's proposal to impute revenue for the sublease of the eighth floor space in One Utah Center mismatches expenses and revenues. PacifiCorp employees occupied the space throughout the test year. Revenue from a post-test-year lease is not admissible and the rationale on the record is insufficient for a departure from the Commission's test-year rules. We do not accept the Committee's proposed adjustment. These decisions reduce revenue requirement by $71,022.

8. Noell Kempf Climate Action Project

Noell Kempf is an environmental risk mitigation project aimed at gaining experience in and the estimation of the cost of securing offsets to potential carbon dioxide taxes or emissions restrictions. It is a partnership between utilities and the Bolivian government to create a forest preserve. The project will prevent the logging and clearing of approximately 3.6 million acres of forest. The Company has committed $1.75 million dollars to this project and has booked approximately 44 percent or $763,500 (company-wide) as a test-year expense. The objective is to offset carbon dioxide emissions from PacifiCorp thermal generation plants. The Committee notes that the Company's newsletter, "Network," concedes the emission credits are uncertain at this time. The Committee argues that collecting 44 percent of the costs of a project whose uncertain benefits stretch over thirty years is a mismatch of benefits and costs. The Committee recommends that no cost recovery be allowed in this rate case.

The Company testifies that the Noell Kempf Project will sequester CO_2 and is being explored as a means to offset CO_2 emissions from burning fossil fuels. The cost of Noell Kempf is expected to be $0.30 to $0.60 per ton. This compares to $10 to $40 per ton assumed as a tax on CO_2 in the Company's integrated resource plan. The Company believes that this expense is prudent. It points to the Commission's Report and Order on Standards and Guidelines for Integrated Resource Planning which found that changing environmental regulations can increase the internal costs of the utility. This may occur through changes in plant operation, the addition of control technology, or purchase of emission permits. These costs will ultimately be borne by either ratepayers or stockholders. The Commission also found that prudent business planning must evaluate the consequences of risk and uncertainty for business strategy since a requirement to "internalize" external environmental costs poses risk. Should the

Commission disallow the Project expense, the Company recommends that it treat any future gains from the trading of CO2 credits symmetrically, so the value of the credits flows solely to the shareholders who funded the original research project.

We find that participation in the Noell Kempf climate Action Project is reasonable. Environmental risk mitigation is important. We will allow recovery of Utah's share of the $1.75 million total project expenditure, but will spread it over five years in order to better match benefits and costs. Any further investment in CO2 credits must explicitly be evaluated in the integrated resource planning process, and acknowledged by us, before future rate recovery will be allowed. The revenue requirement effect is a decrease of $89,333.

I. INFORMATION TECHNOLOGY ISSUES

1. Y2K Expenses

In order to prevent interruptions in electric utility service in the changeover from the year 1999 to 2000, PacifiCorp spent approximately $10.3 million, company-wide, in the 1998 test year. The Company proposes to allow the entire sum in the revenue requirement in this case to ensure quick recovery. The Division and the Committee both recommend that we amortize Utah's portion of the $10.3 million over five years to mitigate the effects of that one-time expense on customer rates. The Company argues that amortization "will result in tremendous under-recovery of those costs." We disagree. Amortization ensures recovery of prudently incurred costs at a sustainable pace without causing jerks and jolts in customers' rates. Those amounts not immediately expensed are left in rate base on which PacifiCorp earns a fair return until the entire sum is amortized. The Company, therefore, is assured of both a return and full cost recovery.

Although Y2K costs are one-time expenses and could be excluded from the test year, the Company in fact incurred them in each of four successive years beginning in 1997. In addition, given the importance of the effort to avoid short- and long-term power outages and the pressure imposed on PacifiCorp from the Commission and others to solve the Y2K problem, it would be unreasonable to exclude them. Including Utah's allocated share of the entire $10.3 million in this test year as the Company proposes, however, would cause a spike in customer rates that amortization avoids. We accept amortization as a fair way for the Company to recover these costs, but believe five years is too long a period under the circumstances presented in this case. Instead, we adopt a three-year amortization to reflect the unique nature and importance of these particular expenses to the public generally. We have never before and will never again face this problem. This adjustment will be calculated on the basis of an average annual rate base. This decision decreases revenue requirement by $1,947,885.

2. Re-Engineering

In 1996, PacifiCorp implemented the Business System Integration Project (BSIP) to review the Company's business processes and to implement more efficient means of conducting its business. This led to a new integration of software systems, and to reductions in inventories and staff. As part of this project, the Company acquired new comprehensive business software called Systems Applications and Products (SAP) and incurred expenses in 1997, 1998 and 1999 for re-engineering business processes and employee training. The Company proposes to amortize the re-engineering and training costs over five years, beginning in the test year. The Division supports the Company's proposal. In the Committee's view, re-engineering costs are those incurred to analyze the current flow of financial and other internal Company information used to manage the Company. Re-engineering is therefore an initial step in determining how SAP is to be used. These costs, asserts the Committee, cannot be beneficial to ratepayers until SAP is fully implemented. As this happened only in one generation station, the Naughton plant, during the test year, the Committee opposes the Company's adjustment as out-of-period. The Large Customer Group also opposes the adjustment as an out-of-period SAP-related one, and argues that these costs must be allocated between regulated and non-regulated activity. As the Committee does, LCG proposes to begin the amortization of re-engineering costs only when SAP is fully implemented.

Typically, when the Commission analyzes a request to amortize an expenditure a showing of roughly proportional benefits and costs over time and beginning in the test year is necessary for approval. Expenditures proposed for amortization by the Company total about $16 million, Company-wide, for the test year. This amount, it claims, is offset by test-year benefits of $30.6 million, Company-wide, associated with re-engineering, as part of BSIP and the implementation of SAP. These benefits, it asserts, arose both from use of SAP at the Naughton plant and from a new understanding of business processes leading to savings in employee levels and elimination of certain actions that would have been required had the older processes been expected to continue.

Though the Committee does not dispute implementation of SAP at the Naughton Plant, it argues that the potential benefits of re-engineering cannot be realized until SAP is fully implemented throughout the Company. It also asserts that no party has shown that SAP produced any benefit in the form of improvements in productivity during the test year. This Committee statement is correct insofar as the benefits claimed by the Company depend on assertions about actions not taken. We are more interested in measurable and sustainable gains in productivity. No evidence of this sort exists on the record.

This leads to the position advocated by LCG, which asserts that the evidence of benefits in the test year is shaky enough to warrant complete audit of all SAP-related expenditures before any are declared prudent and recovery is permitted. Moreover, given the time in which the entire project arose, the Company's then global objectives and emphasis on development of non-regulated business opportunities requires an allocation of these expenditures between regulated and non-regulated activity. LCG proposes an allocation of any SAP-related costs allowed recovery in this case on the basis of relative regulated and non-regulated revenues.

It appears on this record that re-engineering and training expenditures precede and are necessary to a change in internal business operations that are intended to result in future productivity gains. They are only part of total project expenditures. Other expenditures include those for hardware and software, which we take up below. We wish to encourage the Company in these efforts and expect attention to operational efficiency as part of effective management. If successful, expenditures for re-engineering and training will produce future, recurring productivity gains. For this reason, amortization may be an appropriate method of cost recovery.

Though the Committee disputes the assertion that benefits occur in the test year, its testimony does underscore the relationship between up-front expenditure and a future flow of project benefits. As a concept, this relationship is recognized by all parties. We adopt the recommendation of LCG, which is independently recommended by the Committee, to require a performance audit of the entire project. One aspect of this audit should inform us how an allocation of these expenditures should be performed. We await receipt of the imminent semi-annual report on operations for 1999 and the ScottishPower merger transition plan before stating more clearly the audit requirements. Suffice it to say here, we expect such an audit to be limited, focused, and directly on the points raised herein by its proponents. We believe the record in this Docket is sufficient to begin an amortization in this test year because SAP was installed in one generation station and we give some weight to the Company's claim that benefits were realized. Should the audit indicate otherwise, appropriate adjustments can be made. We therefore accept the proposal of the Company and the Division to amortize re-engineering and training expenditures over five years. This adjustment reduces revenue requirement by $464,539.

3. Computer Mainframe Write-Down

The Company replaced its mainframe computer during the test year. The old mainframe, it testifies, was taken out of service in January 1998 because of insufficient capacity. The Company proposes a three-year amortization of the write off, beginning in 1998. Since the old mainframe was removed from service in the test year, the Division proposes to amortize the write off over five years, beginning in 1998. No such write off should be allowed in the test year, recommends the Committee, because it is related to the implementation of SAP which provided but insignificant benefits in the test year. LCG recommends that any SAP-related costs allowed in this Docket should be allocated between regulated and non-regulated activities based on 1998 revenues, but all such expenditures should be subjected to thorough audit.

In 1997, the depreciable life of the old mainframe was shortened from 10 to five years, and the remaining net book value was written off. The Company sought recovery of the write off in Docket No. 97-035-01, but the Commission did not allow it on grounds that the old mainframe remained in service throughout the 1997 test year.

The record permits us to conclude that the mainframe was replaced during the test year because of insufficient capacity to perform necessary Company functions. There is a dispute, however, over what exactly led to the need to replace it, and how we resolve this bears directly on whether amortization of the write off should begin in the test year.

The Company argues the replacement was due only in part to acquisition of SAP, had other causes, and therefore amortization of the write off should begin in the test year. The Committee argues replacement was directly related to SAP and since but insignificant SAP-related benefits appear in the test year, amortization should not begin yet. The record shows that SAP runs on a client/server, not the mainframe, and that additional capacity was needed to run other vital software, including new customer service system software (CSS). Therefore, we conclude that test-year amortization of the write off need not proceed on the basis of a match with the presumed benefits associated with the implementation of SAP. Because replacement is indirectly due to SAP, however, and the primary benefits of that will occur beyond the test year, we conclude that an amortization period of five years, proposed by the Division, is more appropriate than the three-year period proposed by the Company, and it is therefore adopted. This adjustment increases revenue requirement by $1,607,717.

4. Computer Software Write-Down

In 1997, the Company wrote down its "legacy" software systems in anticipation of replacement by SAP. In Docket No. 97-035-01, the Company's proposal to amortize the write down over a three-year period was denied because the old systems were in service throughout the 1997 test year. The Company renews this proposal in the present Docket. The Division also proposes amortization beginning in the test year but recommends a five-year amortization period. The Committee opposes recognition of the write off in the test year, as does LCG.

All parties agree, and we therefore conclude, that the software was in use throughout the test year. The Company acknowledges that, though for only certain purposes, it will continue in use well beyond the test year. Its rationale for proposing recognition of the write off in the test year rests on the assertion that because the decision was made to implement SAP, certain maintenance and Y2K expenditures were avoided. In the Company's view, these benefits make recovery of the write off appropriate now.

We do not agree. The old software was in use throughout the test year. As the Committee states, SAP was not fully implemented during the test year so expected productivity enhancements have not yet occurred. As stated in the March 4, 1999 Report and Order in Docket No. 97-035-01, "inclusion of the write down, a non-cash expenditure, in the test year would saddle ratepayers with additional costs of obsolescence even though the benefits new programs make possible would not yet be present. This would mismatch costs and benefits, and inappropriately inflate test-year costs."

Circumstances have not changed, and these conclusions still apply. We therefore accept the Committee's recommendation to reverse the Company's proposed adjustment. This increases revenue requirement by $351,993.

5. Systems Applications and Products Software (SAP)

In December 1998 the Company recorded its investment in SAP software on the books of Electric Operations. This investment totaled $80,198,104. Since an average-of-year rate base is used for ratemaking purposes, one half or $40,099,052 of the SAP software investment is included in the Company's unadjusted results of operations for the 1998 test year. The Company's investment in legacy systems of $1,242,528 and an equal expense amount, fully amortizing the legacy systems, is also included in the 1998 test year.

The Company proposes an acceleration of the recovery of its SAP software investment by assuming, for ratemaking purposes, that the SAP software replaced the legacy systems at the beginning of the test year. The Company's adjustment includes adding the remaining half of the SAP software investment to the test year and removing the remaining investment in the legacy systems from the test year. Its adjustment also includes adding the expense associated with amortizing the SAP software investment over its expected useful life and removing the amortization expense associated with the legacy systems. The Division supports this proposal.

The Committee proposes to remove all costs associated with the SAP software investment from the test year. In its view, amortization of costs should not begin until benefits flow to ratepayers that are at least equal to the costs the Company has incurred to implement the programs. In addition, the Committee recommends undertaking an audit of the SAP programs, including a determination of the used and usefulness of the programs and the proper allocation of costs between regulated and non-regulated operations.

The LCG supports the Committee's proposal. Additionally, the LCG proposes that any SAP-related costs allowed in this case should be allocated between regulated and non-regulated activities on the basis of 1998 revenues, which they claim results in a 59 percent allocation to regulated services. Like the Committee, the LCG recommends subjecting all SAP-related expenditures to an audit. Finally, prudently incurred costs properly allocable to regulated services should be amortized over a period of at least five years, beginning in a test period no earlier than 1999 when the SAP system and related assets are shown to have become used and useful for regulated services.

The Company argues that SAP was fully implemented at the Naughton generation plant, allowing SAP-related benefits to be realized there. In total, it claims total SAP-related benefits of $30.6 million were achieved in the test year as opposed to costs of $25.5 million. It further argues that the BSIP project began to provide benefits before the roll-out of SAP to all Company locations was complete, and that cost reductions were realized in preparation for SAP which would not have been sustainable without SAP. The Division agrees that SAP-related benefits began in the test year, but the Committee does not. The Committee argues that SAP was not fully implemented until late in 1999, so only insignificant benefits might arise in the 1998 test year, and the Naughton plant pilot program, initiated in September 1998, cannot be the justification for including an $80 million investment in test-year ratebase.

We will allow neither the accelerated recovery of this investment proposed by the Company and supported by the Division, nor a deferral until a later test year as proposed by the Committee and LCG. Accelerated recovery is based on a Company argument that benefits in the test year, in the form of employee reductions and avoided costs associated with the legacy software systems, exceed the costs of SAP, re-engineering and the software write off, for a total, company-wide, net benefit of approximately $5 million. We do not rely on this argument. The claimed benefits are estimates of what the Company might have experienced absent the decision to implement SAP. What is important, however, is sustainable improvement in efficiency, measured over time as productivity gains, resulting in lower costs per customer and increases in the quality of service. These normally follow from the implementation of the new system, not its anticipated deployment. An example of a useful measure, presented both in the current Docket and the just-completed ScottishPower merger approval Docket, No. 98-2035-04, is non-production operation and maintenance expense per customer. The evidence about this on the record is disputed. It is not strong enough to warrant accelerated recovery. We look forward to presentation of measures such as this in the imminent ScottishPower Transition Plan.

On the other hand, the evidence shows that the Company is transforming its internal processes through the implementation of SAP, and that some beneficial effect has been achieved during the test year. The record shows that half the Company's SAP investment is already in ratebase; next year, the total amount will be there. We do not believe a reasonable basis exists to accept the recommendations of the Committee and the LCG to remove the investment from the test year. We rely, as well, on the decision stated above to accept the Committee and LCG recommendation to perform a comprehensive audit.

Because the proposals of the parties to either accelerate or defer cost recovery are rejected, these decisions require no adjustment to revenue requirement. Test-year revenue requirement properly includes half the SAP investment.

J. POST-TEST-YEAR ADJUSTMENTS

1. Glenrock Mine Closure

During 1997, a decision was made to close the Dave Johnston coal mine, operated by the Glenrock Coal Company, and the Company wrote off the mine in its entirety to expense. To reduce the risk of under recovery, a three-year amortization of mine closure costs (for unrecovered plant, reclamation, and severance), beginning in 1998, is proposed by the Company. Final reclamation work, the Company states, began at the mine during the test year. The Company claims its proposal will match a savings in fuel costs with the additional costs caused by early closure. The Division accepts a Company statement that the change in the mine operation plan resulted in some savings and that final reclamation work began during the test year. It proposes a five-year, rather than three-year, amortization of mine closure costs because the longer period is the same as that approved by the Commission for other amortizations; it mitigates the effect on rates; and it better matches cost recovery with fuel cost reductions that closing the mine makes possible. Thus, the Division believes amortization should begin in 1998. The Committee opposes any amortization of mine closure costs in this test year because the closure of the mine did not occur until October 1999, which is beyond the test year; argues that any coal cost savings in the test year were related to the early retirement program and not the mine closure; and considers the proposed write-off of reclamation costs to be retroactive ratemaking. The Large Customer Group agrees that the costs should be amortized over five years, but should begin with a test year no earlier than 1999, which in its view will more properly match costs and benefits of mine closure.

The record shows that the mine was fully operational during the test year. Since a rail contract was not signed during the test year and rail facilities to permit the substitution of an alternative source of coal did not exist then, the mine did not close until October 1999. For these reasons, we will restore the mine to ratebase, as used and useful during the test period, and will not permit its amortization as unrecovered plant. By restoring the mine to ratebase, we are deferring the write off and allowing a return to be earned on the remaining mine investment. We intend no disallowance. Because the mine was not closed during the test year, we will not consider employee severance costs in this Docket.

The Company points to a decline in coal price from $8.44 per ton to $8.02 during the test year as evidence of fuel cost savings resulting from a changed mining plan owing to the decision to close the mine. These savings, the Company argues, justify recovery of mine closure costs, beginning in 1998. In response, the Committee asserts that any savings come from the change in mine operations and not from replacing its coal production with a more economical alternative source of fuel. The Committee believes the claimed savings are primarily due to the Company's early retirement program, and when removed from mine savings a Utah jurisdictional savings of but $100,000 remains. In the Committee's view, this tiny amount cannot be justification for including the full amortization of the write off in the test year.

To permit the full amortization of the unrecovered mine investment in the test year without the presence there of a significant amount of savings is to create a potential for over earnings. For this reason, in past dockets we have looked to a rough equivalence of costs and related savings in the test year to warrant cost recovery. Clearly, the primary savings permitted by mine closure, estimated by the Company to be $15 million annually, do not arise until coal is obtained from a Powder River Basin alternative source. This does not occur in the test year. Absent the primary savings, a write-off of the mine investment in this test year is inappropriate.

Reclamation is a different matter. The Committee asserts that the proposed write-off of reclamation costs is retroactive ratemaking because these costs were known and could have been accrued by the Company as early as 1984, yet the Company did not raise accrual rates. The Company denies that reclamation costs were under accrued in the past. The reclamation write-off results from a change in accounting estimate and is not, as the Committee claims, an abandonment loss. In a further response to the Committee, the Company states that final reclamation work began at the mine during the test year.

We find the reclamation cost to be legitimate for recovery in rates. It began during the test year, and involved actual Company expenditures. We will therefore permit recovery, but rather than the three-year amortization proposed by the Company, will permit a five-year period beginning this test year. Our conclusions result in an increase in revenue requirement of $4,090,012.

2. Condit Dam Removal

Condit is a dam on the White Salmon River in Washington State used for many years by the Company to generate hydro-electric power. Recently, in response to newly imposed federal licensing requirements, the Company has determined continued operations there are uneconomic. It therefore has entered an agreement, signed in September 1999, and now awaiting approval by the Federal Energy Regulatory Commission, to begin removing the dam in October 2006. The Company proposes to accrue dam removal costs beginning in the test year. This is opposed by the Division, the Committee, and the Large Customer Group.

The accrual should commence in this Docket in order that customers who benefit from the electricity produced at the dam contribute to its removal costs, according to the Company. The Company asserts that failure to initiate the accrual in this Docket will produce an increase in depreciation rates in the future. Moreover, the Company believes its proposal is consistent with established depreciation policies that provide for recovery of plant-removal costs.

In the Committee's view, this is an event occurring outside the test year, and the final agreement, when approved, may result in other parties bearing a portion of removal costs. The Committee also relies on a December 1999 settlement in PacifiCorp's Utah depreciation case, Docket No. 98-2035-04, which provides for recovery of increased removal costs as part of stipulated depreciation expense, with new depreciation rates taking effect in April 2000. Dates associated with the removal agreement and the depreciation settlement are beyond the test year.

The Division relies on the depreciation settlement which calls for increased depreciation expense beginning in April 2000, and terms the Company's proposal a post-test-year adjustment, as well as a "a violation of common sense." The Large Customer Group also opposes the Company proposal for reasons similar to those the Committee and the Division provide.

The Company argues that its proposal is not an effort to implement the depreciation rates from the recently approved stipulation in advance of the April 2000 implementation date but instead is intended to make full use of the nine years spanning January 1998 to October 2006 to recover removal costs from customers who benefit from the dam's hydroelectric power.

We view the proposal as an impermissible post-test-year adjustment for the following reasons. First, the removal agreement was signed after the test year. Second, the agreement is not yet approved. Third, the agreement may change in ways including the distribution among parties of dam removal costs. Fourth, the depreciation stipulation, to which the Company was a party, provides for new rates beginning April 2000. Finally, although Condit dam depreciation expense may increase in the future, there may be offsetting depreciation rate changes such that overall depreciation expense may not rise as a result of this one event. We believe the Committee's adjustment correctly removes the full amount of accumulated depreciation recorded on its books by the Company in the test year for dam removal, and therefore accept it. This decision decreases revenue requirement by $533,530.

K. UPDATING ADJUSTMENTS

1. Interest Synchronization

Interest synchronization imputes interest expense for income tax purposes equal to the product of the weighted cost of debt (average long-term debt cost times its share in capital structure) and adjusted rate base. An adjustment must be made to account for the difference between imputed interest expense and the interest expense associated with Utah's share of unadjusted test-year results of operations. The adjusted rate base used to calculate imputed interest expense includes cash working capital (discussed below). As calculated in the Joint Numerical Exhibit on Revenue Requirement, the interest synchronization adjustment increases revenue requirement by $5,769,131. The method of calculation is not in dispute.

2. Cash Working Capital

In prior cases for all utilities, the Commission has approved the cash method to calculate the cash working capital included in rate base. The cash method focuses on the cash inflows and outflows during the test period needed to maintain daily operations. As a component of rate base, cash working capital thus reflects the Company's need for cash to conduct day-to-day operations. It represents investor-supplied capital the Company must have on hand during the interval between incurrence of expenses to provide service and receipt of revenues from ratepayers.

Lead/lag studies compare the difference in the timing lead or the timing lag between cash inflows and outflows. A net lag of 8.9 days is obtained from the Company's December 1991 Lead/Lag study and is the difference between the Utah jurisdiction net revenue lag of 44 days and net expense lag of 35.1 days. On average, it takes 44 days to collect revenues from the date service is provided and 35.1 days to pay expenses.

Cash working capital is calculated by totaling operations and maintenance (O&M) expenses, taxes other than income, federal income taxes, and state income taxes. This total is divided by the number of days in the year to determine the adjusted daily cost of service. The adjusted daily cost of service is then multiplied by the 8.9 net lag days to derive the cash working capital requirement.

An adjustment must be made to account for the difference between cash working capital calculated on the basis of results of operations adjusted by the decisions reached in this Docket and the amount that is based on the unadjusted test-year results of operations. Adjusted income taxes used to calculate cash working capital include the imputed interest expense discussed above. As calculated in the Joint Numerical Exhibit on Revenue Requirement, the cash working capital adjustment reduces revenue requirement by $2,025,408. The method of calculation is not in dispute.

L. SUMMARY

The adjusted test-year revenue requirement is $708,368,738. This requires a change in firm retail revenues of $17,043,480. The allowed rate of return on equity is 11 percent, and the rate of return on rate base is 9.0241 percent.

III. PRICING OF TARIFFED RATE SCHEDULES

Our practice is to employ an acceptable class cost-of-service study to guide the apportionment or spread of adjusted jurisdictional revenue requirement to classes of service. The design of rates in each class follows established ratemaking principles.

A. COST OF SERVICE

In this Docket, the Company submits a "functionalized" class cost-of-service study. Functionalized takes on a special meaning here, somewhat different than the functionalization step common to all cost-of-service studies. The Company now proposes five functions: production, transmission, distribution, retail services, and miscellaneous, which includes costs associated with demand-side management, franchise taxes, regulatory expenses, and other. This new approach is said to be the basis for "functional unbundling" of services, first introduced by the Company in Docket No. 97-035-01. There, we were unable to adopt it due to lack of an appropriate record. Nevertheless, certain changes to such a study were ordered in that Docket. These are functionalizing and allocating administrative and general expenses other than employee pensions and benefits on the basis of plant, not labor, and allocating sales for resales revenues consistent with the allocation of purchased power. These changes are incorporated in the study filed herein. To them, the Company adds the results of a new study of customer weighting factors, which revised weighting to reflect customers in Utah rather than system-wide, for meter reading (Account 902), and customer records and collections (Account 903). Further, no service-drop costs have been allocated to the irrigation class. In addition to other changes, an update to demand allocation factors to reflect a refinement to the load research calibration process used to tie hourly class loads to total Utah jurisdiction load is made. Weather normalization of class coincident peak loads also is incorporated for the first time in the study. Revised unbilled revenue calculations are made.

The parties identify several problems with the submitted cost-of-service study. First, the number of winter evening peaks, and the sensitivity of class-level results to changes in the number of such peaks, is in dispute. Second, the Committee proposes to determine the time of system peak based on the total of firm and wholesale loads rather than just firm retail loads as the Company study does. It notes that study results may be sensitive to the time of the peaks used for cost allocation. We have rejected this proposal. Third, the load research data is claimed by the Committee to be flawed.

The Committee asserts that residential coincident peak data are adjusted upward by a full 7 percent above the level actually measured by the Company load research program in order to compensate for shortcomings either in load research data or elsewhere in the Company's measuring system. In addition to similar problems, the load research sample for the irrigation class is said by the Committee to be out of date and based on data gathered between 1991 and 1993. The Company recognizes this problem and has undertaken new sampling for the irrigation class.

The Company adjusts sampled classes such as residential Schedule 1 to jurisdictional load, given the demand-metered load of other classes (termed "census" data), when the summation of all the census and load research data does not equal the Utah jurisdiction load. The jurisdictional and census loads are assumed by the Company to be correct. Nevertheless, the Committee asserts that the Company made changes both to census and jurisdictional loads, and as a result made further changes to the load research sampled schedules' loads to ensure that the sum of schedule loads equals jurisdictional load. The Company responds that indeed one, but only one, adjustment was made to a demand-metered (census) load. It also asserts that the shift in residential class load that the Committee identifies is explained by a change in the treatment of special retail contract loads. Formerly, these firm loads were assigned to the jurisdiction in which the customer was located; in the present study, as a result of an agreement reached among the staffs of the several states at PITA, these contracts are allocated systemwide. The result is these loads do not appear in the measurement of loads in both jurisdiction and class cost-of-service studies. The loads are no longer included in the determination of allocation factors.

The most significant problem with the results of the new cost-of-service study is the influence of a change in the number of winter evening peaks. In January 1997, when system peak occurred in the morning, the Utah residential class accounted for 31 percent of Utah's share of system peak, but in January 1998, when the system peak occurred in the evening, the Utah residential class accounted for 42 percent of Utah's share of system peak. The consequence of this change in the time of system peak is to greatly increase the cost responsibility of the residential class.

This shift in cost responsibility poses a fundamental problem for cost-of-service analysis. Such analyses presuppose stable underlying cost relationships because lack of stability would cause unpredictable swings in jurisdiction and class cost responsibility, a violation of ratemaking principles. It has always been known, for example, that a change in the time of peak, measured at a single hour in a month, can cause large shifts in cost responsibility among classes. For that reason, acceptable cost-of-service studies will allocate costs not on the basis of a simple peak allocator, prone to such volatility, but on an allocator that better recognizes a cost-causal basis for determining jurisdictional and class cost responsibility. Since the Company's 1998 study is vulnerable to just such a shift, it responds by providing study results using the average of 1996 through 1998 peak load data to mitigate the effect of a change in the hour of system peak.

The Division supports a mitigation step. In the runs it performs of the Company's cost-of-service model, using 1996, 1997 and 1998 demand data, the Division illustrates the need for mitigation due to the substantial difference in class allocation results when different demand data are used. It recommends that the revenue change be apportioned to classes using 1996 and 1997 study results only, because the number of 1998 winter evening peaks is anomalous and not likely to be repeated. The large industrial customer parties accept the Company's proposal to mitigate the effect of the shift in time of peak. Owing to its dissatisfaction with the quality of load data as well as the shift in cost responsibility caused by the claimed shift in the time of peak, the Committee opposes using even a mitigated cost-of-service study to achieve a disproportionate sharing of the change in revenue requirement. The Committee recommends recovery of any change in revenue requirement on an equal percentage basis among all classes.

In spite of the load data difficulties identified by the Committee, we believe the use of the cost-of-service studies, when mitigated as proposed by the Company and the Division, is sufficient for use in this case as a general guide to the spread of revenues. We do recognize, however, that problems identified by the Committee, both in Docket No. 97-035-01 and the present one, have been or are being addressed by the Company. The result of those raised in the previous Docket produced changes, for example, revised customer weighting factors, that are now included in the cost-of-service study filed by the Company in the present Docket.

B. SPREAD OF THE GENERAL REVENUE CHANGE

We consider here the mitigated cost-of-service results as a general guide to the spread of the revenue change. We reject the Committee's recommendation to spread the change on an equal percentage basis. We also reject the Division's proposal to spread the increase only to Schedules 1, 10, 23, 25, and the lighting schedules. The Company proposes a revenue spread that involves the use of a cap on the amount spread to certain under earning schedules as a mitigation measure because its proposed revenue change was so large. Given the change in revenue requirement we determine herein, this mitigation step is unnecessary.

The cost-of-service studies on this record are not completely reliable. In the last case, cost-of-service studies also showed a wide divergence of earnings results across classes, but we spread the rate reductions on an equal percent basis because the studies were not reliable. There, as here, the studies, if followed directly, would lead to an abrupt shift in revenue requirement responsibility among schedules. We do, however, reflect in the following spread decision a consideration of cost-of-service study results.

The primary source of the change in revenue requirement ordered herein is due to the increase in net power costs. In our view, this justifies all classes sharing in the revenue requirement increase. As we state above, the results of the cost-of-service studies here are sensitive to the time of system peak, which causes us to temper the conclusions we draw from them, particularly with respect to excluding some classes from any revenue change. The problems with load data also lead us to temper our cost-of-service study conclusions insofar as study results would spread the revenue requirement change solely to Schedules 1,10, 23, 25 and the lighting schedules. Finally, the Company's proposed spread did not exclude Schedules 6 and 9.

The spread we approve is provided in detail in Appendix II. It results in less than one percent increase in revenues to Schedules 6 (large commercial) and 9 (industrial). It also results in a 4.2 percent increase to Schedules 1 (residential), 10 (irrigation), 23 (small commercial), 25 (mobile homes and trailer parks), and 7, 11, and 12 (the lighting schedules, including traffic signal systems and metered outdoor lighting).

C. DESIGN OF RATES

1. Lifeline Rate

As in our last rate case, Salt Lake Community Action Program and Crossroads Urban Center (SLCAP/CUC) propose a lifeline rate for low-income residential customers. This program would give an $8 per month credit for eligible participants. That case contained an extended discussion and analysis of the proposal, which we will not repeat here but reference and again rely on, in addition to evidence introduced in this case, as basis for our decision here.

In the prior case, this Commission found that we have the authority to implement a lifeline rate; that a real need exists and is not otherwise being met by other programs; that the program as proposed in that case was successfully targeted and would not overly burden other customers; that the benefits offset negative impacts; and the proposed program was administratively simple and inexpensive to administer. Despite these findings, we declined to institute the lifeline rate in that case because of several concerns and unanswered questions, which were explained fully in that Order. We requested that a Low-Income Task Force be established to investigate these issues further. In brief, we asked for more information on what we characterized as primarily "practical concerns," asking for a Lifeline Plan which would include clear and specific proposals and information on the following: (1) a proposed cap on the total amount the program would raise and spend annually; (2) how to calculate charges, and on which users; (3) targeting eligible customers; (4) experience of other states; (5) proposed measurements and standards by which we could judge the success of a program; and (6) any future studies which might be appropriate.

Members of the Task Force issued a "Report to the Utah Public Service Commission" on December 17, 1999. The Task Force, acknowledging that "the diversity of economic and ideologic interests prevent the Task Force from recommending a low-income energy assistance program," could not reach agreement on all of the issues. However, SLCAP/CUC proposes that we effect a lifeline rate in this case nevertheless. Its proposal here is substantially the same one as proposed in the prior case with some additions in response to our Order, and some additional information from the Task Force Report. It argues that, considering the evidence and findings in the prior rate case, the Task Force Report, and additional evidence on the record in this case, it has answered the Commission's concerns and we should institute the lifeline rate.

The following discussion examines the items as to which we requested more information. We continue to rely on and incorporate the findings and conclusions from the earlier Order and add to them the analysis from this case.

Cap. SLCAP/CUC's proposal, set forth fully in the exhibits to the direct testimony of the three SLCAP/CUC witnesses, estimates that the program would cost approximately $1.8 million per year plus administrative costs totaling approximately $50,000 per year. These costs would be divided among the rate classes in proportion to class revenue. For example, Schedule 1 (individual) customers would be capped at $0.13 per month, possibly rising to $0.19 per month assuming a higher participation level. In contrast, Schedules 6, 9, and 31 customers, the largest users, would pay $6.25 per month, to a maximum of $75 per year. This approach, at least for residential customers, would constitute a much smaller percentage of the average monthly bill of $40.04 (0.32%) than comparable lifeline programs for telephone assistance.

Targeting Eligible Customers. The proposal indicates that to qualify, a customer must be qualified for the Utah Home Energy Assistance (HEAT) Program (which we examined in our prior order and found that by itself it is inadequate to meet the needs of eligible customers); or earn no more than 125% of the federal poverty level. The Utah Department of Community and Economic Development would administer the program in conjunction with its HEAT program.

Experience in Other States. The Task Force Report contains a discussion of its findings in this area. It tells us that many other states have low-income assistance programs and that they vary in range, cost, and design. Whether they offer real benefits was a hotly contested issue among Task Force participants. Some possible benefits identified are to society at large and thus, it is argued by some, this decision properly belongs to the legislature and not the commission. The Division asserts that there are no benefits to nonparticipants from direct assistance programs. It cautions the Commission against "effectuating social policy by means of altered electricity rates." During the hearing we learned that in most states with similar programs, they were adopted by commissions in those states, and then the legislatures generally codified them.

Proposed Standards of Measures of Success. The task force report indicated some confusion as to what the Commission intended with its questions in this area. "If the Commission's intention were to provide assistance to a given number of customers, or a percentage of low-income households, measurement would likely be quite simple . . . ." The Task Force identified some problems in trying to measure effectiveness of any low-income assistance program. It asserted that some of the information needed is not currently tracked by PacifiCorp and it would be cost prohibitive to do so. It recommended that we ask the Division to develop a set of standards and measures.

Future Studies. The Task Force recommended that a major review should be undertaken no later than three years after implementation of this, or any, program, to make sure the program is effective and to suggest changes or an end to the program. Beyond that, the Task Force members had differing opinions.

We conclude that, considering the additional information provided in this case, it is in the public interest to have a Lifeline program in Utah as proposed and we are ordering that it be implemented. We find sufficient benefits to the intended beneficiaries, to the utility, and to utility customers in general through reduced cost to the utility of collections, terminations, reconnections, and arrearages. As for arguments that the program would benefit one class of customers only, and thus should be paid by them only, we note that it is not done in other arguably similar areas and we decline to do so here. One specific example is that each class of service does not pay precisely its "share" of costs. This is true, for example, of the large customer groups, or special contract customers, according to some views of allocations. Yet they do not agree with any allegations that they are being subsidized by residential customers. Examples abound to demonstrate that one person's improper "social welfare" program is another person's legitimate regulation of utilities in the "public interest".

Nor has the Commission's current rules on a lifeline rate for telephones, enacted under our general authority in Section 54-4-1 and 54-4-4 of the Utah Code, ever been challenged. We find that the program proposed here is a rather simply-designed program with relatively modest goals and is analogous to the lifeline program for telephone service. We expect that experience in administering the telephone lifeline program will provide guidance as the Company, the Division, and others work to effect, and monitor, the Lifeline program we now institute. Although the large customer group questioned whether taxation of the amounts raised and spent for the Lifeline program might diminish its efficacy, it pointed to no evidence that that actually is happening with respect to the Lifeline program in the telephone arena. If that in fact turns out to be a problem, we expect to be advised of that, as the program is monitored.

Accordingly, we order the Division, the Committee, and SLC/CAP to work with the Company to implement, within 90 days following the effective date of this Order, the Lifeline program as proposed in the last case and as discussed herein. We anticipate that the program be capped at no more than $1.8 million per year; that it continue to be monitored by the Division and that it be thoroughly audited within three years.

2. Line Extension Tariff Change

The Company proposes a new tariff for line extension which would require new customers to pay more to extend electric service to their homes and businesses. The Division supports this change; the Committee does not oppose it, but proposes a ratemaking adjustment for the tariff change. This ratemaking adjustment is opposed by the Company and the Division.

The Commission questions the public policy merit of certain provisions in both the current and proposed tariffs. We address the request for tariff changes, the tariff provisions, and the proposed ratemaking adjustment.

The proposed tariff tightens current line extension policy to both residential and non-residential customers because, the Company claims, current policy is both overly generous to and subsidizes new customers. The current tariff provides residential customers with a transformer, a meter and three hundred feet of line, while non-residential customers currently receive a credit of three years of estimated revenues. The Company argues that residential line extensions cost on average $1400 for a home in a subdivision and $1900 outside a subdivision. For existing residential ratepayers, the average investment for line extension is $730 and approximately $18,348 for non-residential. The proposed tariff provides residential customers a $700 extension allowance and non-residential customers an allowance equal to their estimated annual revenue. Costs greater than the allowance will be borne by customers. The Division supports the tariff change because it eliminates subsidies and is more in line with policies of Utah's municipal utilities and rural electric cooperatives. The Committee did not comment on the merit of the tariff change.

Public witnesses testify that the proposed line extension is poor public policy, contradicts a Commission policy of gradual rate changes, increases the cost of new homes, limits economic growth, and should be rejected. The Utah Farm Bureau also argues against its adoption.

We rejected this same request in the last rate case for lack of a record on the social and public policy effects of the change. The Commission found in the former Docket, and reaffirms here, that electricity, for which there are no substitutes in many uses, is of critical importance in today's world. In the present Docket, the Company touches on these issues, and its comments were merely echoed by the Division, which apparently agreed with them. In response to the Division statement that the new policy would be in line with that of other utilities we do not regulate, we note that PacifiCorp is an investor-owned utility, not a municipal or rural-cooperative one. Its customers have no voice in management and can only express their displeasure with policy change to the Commission. Customers of municipals and cooperatives can vote out the board of directors or change city management. The Company's desire to reduce subsidies is not per se a reason to accept the proposed tariff; though we are sensitive to cross-subsidy issues, all subsidies cannot be removed from rates. Finally, we do rely on the ratemaking principle of gradualism, and we know the importance to society of the widespread availability of electric service. Nevertheless, the Company presents some evidence that line extensions are being subsidized by the general body of ratepayers and, left unabated, will put upward pressure on rates. In order to mitigate this pressure, but in recognition of our belief that the elimination of all subsidy is unwarranted for this service, we will permit a compromise revision of the line extension tariff to include, not the Company's proposed $700, but an allowance of $1,100 per residential customer. For non-residential customers, a line extension allowance equal to two years of estimated annual revenue is appropriate.

Though the record does not sufficiently air it, we are concerned about the tariff's annual recurring charge, the facilities charge. This is a monthly charge that certain customers who exceed the line extension allowance must pay in perpetuity. The charge is intended for remote residential and recreational property, as well as non-residential property. The Company proposes to reduce this charge from 2.0 percent to 1.67 percent per month based on the construction costs of the extension if the line is built and financed by the Company and from 1 percent to .67 percent if it is customer-financed. The charge is intended to collect all costs associated with the Company taking ownership of the line, including taxes, operation and maintenance, administrative and general, capital replacement annuity, and return of and on capital (when Company financed). The facilities charge is also used to calculate the minimum bill. Several parties question the propriety of a charge that goes on as long as electric service is provided to the property. Neither the Division nor the Committee addressed the issue. Testimony indicates that the components of the facilities charge are based on the average rather than the incremental cost of line extension.

We find that some of the costs, such as administrative and general expense and capital replacement annuity, cannot be justified in a facilities charge. General rates do not include the latter charge. In the case of line extension, however, we find that some additional cost is placed on the utility, or the general body of ratepayers, and thus will allow a facilities charge, but not at the rate the Company proposes. We find that 0.25 percent per month for the customer-financed line extensions is fair and reasonable. This recognizes that a subsidy may exist but it will take place over the life of the new plant and will have minimal impact on general rates. A rate of 1.25 percent per month may be charged for company-financed line extension. This new charge will also be used to calculate the minimum bill. Given the economic growth of the state and the utility system, the Commission finds that a perpetual charge is unwarranted. New extensions become part of the system. Therefore, we find that the charge may be collected only for a term of 15 years. This revision to the proposed tariff is just and reasonable and in the public interest.

The Committee states that a rate adjustment is required as a result of implementing the tariff change. Greater customer contribution for line extension will occur under the new tariff, and a ratebase adjustment will reflect the fact. The Company counters that the Committee is confusing the level of ratebase with the future growth of ratebase. The Division, in a reversal of position during hearings, now agrees with the Company's position. We conclude the 1998 test year will not see a decline in ratebase as a result of implementing this tariff, so no ratebase adjustment is required. We believe the Committee recommendation would violate test-year policy.

3. System Benefits Charge

The Utah Office of Energy and Resource Planning (OERP) and the Land and Water Fund of the Rockies (LAW Fund) propose in their written testimony the adoption an alternative funding mechanism for public-purposes programs. These include: energy efficiency, renewable energy, and low-income programs. They specifically recommend the System Benefit Charge (SBC), which would collect funds as a separate line item on a customers bill, as their preferred funding mechanism. These funds would be held in a separate account and would not be part of the regular ratemaking process.

The OERP and the LAW Fund do not ask for additional funding, but ask for a change in the way the money is collected and accounted for. They argue that a separate recovery mechanism for energy efficiency programs would provide advantages to PacifiCorp, service and technology vendors, and the people of Utah. It would also allow a more seamless transition if and when competition is introduced in Utah. The current funding mechanism for energy efficiency causes problems for the small vendors who supply and install the bulk of energy efficiency technologies because resource planning process leads to large swings in the need for such resources. A SBC will provide assurance of funding for these programs and will help minimize costs and lead to savings.

In rebuttal testimony, a number of the parties acknowledge that the Commission has approved and customers already pay for a number of public purposes programs in their current rates. However, the Large Customer Group (LCG), Utah Industrial Energy Consumers (UIEC) and the Division (DPU) expressed objections to the Commission ordering a new funding mechanism that has not been sufficiently studied and analyzed. There may be better ways to address the issues at hand and an SBC may have unintended consequences.

During hearing, the OERP and LAW Fund parties change their recommendation and agree that studying the issue would lead to better public policy. They request that the Commission direct the parties to form a stakeholder advisory committee to study the issue and report their findings and recommendations back to the Commission. After Commission review, the recommendation could then be implemented in an appropriate proceeding. All parties agreed that this is a prudent course of action.

The Commission orders the Company to convene and manage a stakeholder advisory group that would systematically review and evaluate PacifiCorp's current energy efficiency and renewable programs. The stakeholder advisory group would then make recommendations to the Commission and the Company on changes to increase the effectiveness of these programs in Utah. Issues the advisory group should address include, but not be limited to: program design, appropriate cost-effectiveness tests, funding levels, alternative funding mechanisms, evaluating cost-shifting, market transformation issues and equity issues of program delivery among customer classes. We further direct the Division to participate in this process and invite the Committee's and the Industrial customers' participation as well. The advisory committee should be open to all stakeholders and the general public. We appoint the Company and the OERP as co-chairs of this committee and hold them responsible for reporting the committee's findings and recommendations back to us by December 1, 2000.

4. Residential Customer Charge and Minimum Bill

Customer charges are designed to recover costs which are related to the number of customers and do not vary with usage. Without an explicit customer charge, customer-related costs are recovered through the energy charge which puts high-use customers at a disadvantage. A minimum bill amount, on the other hand, collects customer costs through a usage charge. It is intended to ensure that even customers whose monthly energy use is very low pay something to recover customer-related costs, when a specific customer charge does not do so.

For residential customers, the Company proposes to increase the customer charge from the current charge of $.98 to $2.50 to better reflect its cost-of-service results. The Company recommends keeping the minimum bill at its current level of $3.54. According to the Company, its fully embedded cost study justifies an approximate $6.00 per month charge for all customer-related costs. In a previous decision the Commission deemed the costs of meters, service drops, meter reading, and billing and collection as eligible for recovery via a customer charge. The Company calculates this at $2.60 using the Commission's criteria. The Company's proposal is a move towards its desire to increase the customer charge to fully embedded cost of service. The Company proposes to eliminate the minimum bill in a future rate case once the customer charge exceeds the minimum bill.

The Division proposes to increase the customer charge to $2.00 per month as a significant step towards recovery in the charge of the customer-related costs of $2.78 which it calculates. In addition, the Division recommends a reduction in the minimum bill to $2.75. The Committee calls for the elimination of the customer charge and proposes a minimum bill of $2.75 to cover customer-related costs. The Committee urges the Commission to weigh the benefits of energy conservation in making its decision. Eliminating the customer charge will result in slightly higher energy charges which, in turn, will promote conservation, particularly among high-use customers.

The Commission rejected a similar proposal to increase the customer charge in the last rate case, Docket No. 97-035-01, citing the lack of an acceptable cost-of-service study and the inequities associated with raising rates for particular customers when general rates were decreasing. Even with the cost-of-service study filed in the present Docket, which incorporates refinements and changes ordered previously, we are reticent to increase the customer charge. This charge is one of the most misunderstood components of the residential tariff. Customer understanding and acceptance is a ratemaking objective of long standing. Customers perceive that they are being charged unjustly and resent the fact that there is no way to avoid this charge, barring discontinuing service. Plainly speaking, customers hate this charge.

In determining public policy, we must balance conflicting regulatory objectives. In this case, administrative simplicity and customer understanding conflict with our ratemaking objective to set tariff prices on a cost basis. Weighed against the cost-based objective are the objectives of conservation, equity, and customer understanding. We permit no change in customer charges. The combination of a small customer charge and a minimum bill allows the Company to collect a significant share of the customer-related costs while minimizing the ratepayer misunderstanding of these charges. In addition, a smaller customer charge promotes energy conservation and its associated social benefits which are enjoyed by all. These considerations lead us to conclude that this policy is in the public interest.

5. General Increase

The change in schedule revenues will be implemented by a change in energy rates due in part to the role of the change in net power costs. Final rates are shown in Appendix III. For Schedules 6 and 9, the energy rate is increased by 1.5 percent. Indications in the filed cost-of-service studies are that the peak load responsibility of 6 and 9 are declining. Therefore, we find no basis to increase the demand charges of these Schedules. The remaining revenue requirement increase is spread to Schedules 1, 10, 23, 25, traffic signal systems, and metered outdoor nighttime lighting, by means of increasing energy charges. All rate elements in the security area and street lighting schedules are increased by 4.24 percent. No customer charge is changed.

These rate changes meet the Company's proposed pricing objectives of revenue requirement recovery, rate stability, and moving classes toward cost-of-service based rates. It also satisfies the Division's objectives of stability and gradualism. These are the objectives commonly employed in this jurisdiction.

IV. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order:

1. PacifiCorp to file appropriate tariff revisions increasing Utah jurisdictional revenues by $17,043,480.

2. The tariff revisions to reflect the Commission's determinations regarding rate increases, charges and other rate design aspects for service schedules and other changes in rates, fees or charges designated and discussed in this Report and Order. The Division of Public Utilities shall review the tariff revisions for compliance with this Report and Order. The tariff revisions may become effective as designated by the PacifiCorp, but not earlier than the date of this Order.

3. The Division of Public Utilities to audit the deferred pension asset accounting, as directed herein, and thereafter file a report of its findings with the Commission.

4. The Division of Public Utilities and PacifiCorp to prepare, with the participation of the Committee of Consumer Services and the Salt Lake Community Action Program and any other interested party, a Lifeline rate and program, as discussed herein, to be implemented within 90 days after this report and order. We further direct the Division of Public Utilities to monitor and audit the program, submitting, at a minimum, annual reports over an initial three-year period.

5. PacifiCorp to inform the Commission and the Division of Public Utilities of the anticipated date for completion of its studies concerning the weather normalization procedure and shall file with the Commission a report, with supporting material, containing recommendations for maintenance of, or modifications to, the weather normalization procedure. Interested parties may thereafter submit their comments to the filed report. We do not intend, by this requested procedural sequence, to preclude the participation, as determined appropriate by PacifiCorp, of any interested party in the development of the report and the inclusion of their views and recommendations in the report.

6. The Division of Public Utilities to submit to the Commission a report, with supporting material, containing recommendations for maintenance of, or modifications to, the corporate management fee methodology used to allocate corporate overhead expenses; particularly with consideration of the ScottishPower merger/acquisition of PacifiCorp. Interested parties may thereafter submit their comments to the filed report. We do not intend, by this requested procedural sequence, to preclude in the participation, as determined appropriate by the Division of Public Utilities, of any interested party in the development of the report and the inclusion of their views and recommendations in the report.

7. PacifiCorp to convene an advisory group to review and evaluate current energy efficiency and renewable programs as discussed in the Report and Order. The advisory group shall file a report containing any recommendations with the Commission.

8. To the extent the Commission has inadvertently omitted from the ordering provisions of this Order any duty or obligation intended to be imposed, which duty or obligation is otherwise clear from the language of this Report and Order, it is hereby incorporated herein by this reference and made a part hereof.

This Report and Order constitutes final agency action on PacifiCorp's September 20, 1999, Application. Pursuant to U.C.A. §63-46b-13, an aggrieved party may file, within 20 days after the date of this Report and Order, a written request for rehearing/reconsideration by the Commission. Pursuant to U.C.A. §54-7-15, failure to file such a request precludes judicial review of the Report and Order. If the Commission fails to issue an order within 20 days after the filing of such request, the request shall be considered denied. Judicial review of this Report and Order may be sought pursuant to the Utah Administrative Procedures Act (U.C.A. §§63-46b-1 et seq.).

DATED at Salt Lake City, Utah, this 24th day of May, 2000.

/s/ Constance B. White, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary

CONCURRING AND DISSENTING STATEMENT OF
COMMISSIONER STEPHEN F. MECHAM

I concur in all of the decisions in this order with the exception of two: the Lifeline Rate and the Line Extension Policy. I do not challenge the

Commission's authority to establish the lifeline rate because UCA 54-3-1 permits the Commission to consider the economic impact of utility rates on every category of customers. In addition, in 1986 the Commission adopted a lifeline rate for qualifying telecommunications customers without any more explicit statutory language. The difference is that the benefits for non-lifeline rate telecommunications customers are more identifiable than those suggested in this docket for non-lifeline electric customers. There are also federal offsets that enhance the benefits for telecommunications customers on the lifeline rate not available to electric customers who qualify. I do not personally oppose the lifeline proposal, but without concrete, identifiable benefits to all customers, I believe the legislature should specifically address this issue during its debate of electric industry deregulation before the proposal is implemented.

I also disagree with the Line Extension Policy established in this order. I am concerned that the policy may lead to double counting of parts of the system, like the transformer for example, and therefore result in double recovery. It also strikes me that the policy shifts more costs to the distribution system and the end use customer as the industry is preparing for restructuring. Many of the customers who cover those costs will be the last to benefit from a restructured electric industry. We should be wary of that movement. Lastly, though I prefer the new 15 year term for the facilities charge compared to the perpetual charge permitted today by tariff, that charge and how it is treated needs much more thorough analysis.

/s/ Stephen F. Mecham, Chairman

CONCURRING AND DISSENTING STATEMENT OF
COMMISSIONER CLARK D. JONES

I concur in all of the decisions in this order with the exception of the Computer Software Write-Down issue. I agree with the Company position regarding the remaining balance of the "legacy" software, which should be written down in 1998 using a five-year amortization period, as recommended by the Division. In Docket No. 97-035-01, the Company proposal to amortize the write-down over a three-year period was denied because the legacy software was in service throughout the 1997 test year and the new software called Systems Applications and Products (SAP) was not yet in service.

During the new test year (1998), the new software (SAP) was functional and useful. While the old software also remained in use, it was used for record inquiry purposes, and should not be the basis for not beginning the amortization of SAP. Benefits from the new system have begun to occur in the test year. The computer main-frame system was retired. Benefits associated with the re-engineering began to occur during the test year. The Commission needs to be consistent in accounting for these events and with its order in 97-035-01. The adjustment approved by the majority in not consistent and is wrong in my opinion.

/s/ Clark D. Jones, Commissioner

APPENDIX I: UNDISPUTED REVENUE REQUIREMENT ISSUES

A. INTERJURISDICTIONAL ALLOCATION ISSUES

1. USBR/Klamath Discount

Under contract with PacifiCorp, the U. S. Bureau of Reclamation (USBR) and the Klamath Basin Water Users' Protective Association (UKRB) receive a reduced price compared to fully tariffed customers for water rights. The difference in revenues derived from otherwise applicable tariff rates versus the contract rates is treated as a cost of the Company's entire hydro system, rather than a state-specific cost, and is allocated to all jurisdictions. This adjustment was accepted as an undisputed issue in Docket No. 97-035-01. The adjustment increases revenue requirement by $1,828,521.

2. Pilot Revenue

During 1998, the Company received revenues for sales of energy into the pilot programs of both Puget Power in Washington and Portland General Electric in Oregon. This adjustment reassigns those revenues from Washington and Oregon to a system-wide allocation consistent with the revenue credit treatment of off-system retail sales. The adjustment decreases revenue requirement by $3,859,434.

3. FAS 106 Deferred Charges

The Oregon and the Wyoming Commissions authorized deferral of the Financial Accounting Standard (FAS) 106 costs that exceed pay-as-you-go (cash) until 1996 rate cases were concluded. The deferred costs are now being amortized to account 929 and allocated to all jurisdictions based on a system overhead (SO) factor. These costs should be directly assigned to Oregon and Wyoming. This adjustment, accepted as an undisputed adjustment in Docket No. 97-035-01, reverses the amount being allocated system wide and directly assigns these costs to the appropriate jurisdiction. This adjustment decreases revenue requirement by $557,099.

4. Uncollectible Accounts

This adjustment has two components, one of which is undisputed. The disputed component normalizes the accrual for bad debt expense. The undisputed component corrects uncollectible allocation. During 1998, most of the Company's bad debt expense was recorded using a general office accounting location. Use of this location caused the jurisdictional allocation reporting system to allocate these costs based on the number of customers (a CN factor) rather than directly assigning them to the appropriate jurisdiction. This adjustment corrects that allocation error, reversing the customer-based allocation and directly assigning each jurisdiction's bad debt expense. The adjustment decreases revenue requirement by $520,023.

5. Materials Allocation

The cost of some store rooms associated with steam and hydro generating plants were being directly assigned to the state in which they were located instead of being allocated system-wide. This adjustment reverses the situs assignment of these Materials & Supplies costs and instead allocates them to all jurisdictions based on appropriate allocation factors. The adjustment increases revenue requirement by $614,885.

6. Other Revenues Allocation Correction

During the course of an audit, the Company identified $2,413,233 of revenues which were allocated on a system overhead (SO) factor, but should have been directly assigned to Oregon. This amount consists of two items; the first is Oregon Hassle Free Water Heater, $1,680,448; the second item is Oregon Deferred Revenues, $732,785. The direct assignment to Oregon of these revenues properly matches the assignment to Oregon of program costs. The adjustment increases revenue requirement by $837,490.

B. REGULATORY POLICY ADJUSTMENTS

1. SO2 Emission Allowances

This adjustment adjusts sales of excess SO2 emission allowances to reflect a four-year amortization as approved in the stipulation dated February 26, 1999 (October 8, 1998) by the Commission in Docket No. 97-035-01. The significant gains realized by the Company from the sale of emission allowances in recent years, $20.652 million in 1997 and $11.528 million in 1998, are normalized down to a level more reflective of future ongoing operations. The adjustment removes the actual gain from allowances sold in 1998 from the test period and replaces it with a four-year amortization of the actual gains from 1998, and continues the four-year amortization of the actual gains from 1997, totaling about $8.045 million company-wide. The adjustment also includes rate base treatment of the associated deferred income taxes and unamortized sales revenue. In addition, this adjustment has been modified by removing an accounts receivable balance related to prior period sales. The adjustment increases revenue requirement by $698,776.

2. Institutional Advertising

This adjustment removes the costs of institutional advertising from electric operations results consistent with prior Commission orders. A similar adjustment was uncontested in Docket No. 97-035-01. The adjustment fully removes the cost of institutional advertising from the test year and decreases revenue requirement by $12,682.

3. Customer Service Deposit Interest

The Company pays customers interest on their deposits per Utah's Electric Service Regulation No. 9. The Company was ordered by the Commission in Docket No. 97-035-01 to change the interest rate paid to customers to 6%. In compliance with Commission policy for all utilities, the customer service deposits are deducted from rate base as customer-supplied capital and operating expenses are increased to recognize the interest the Company pays to customers on their deposits. A similar adjustment was uncontested in Docket No. 97-035-01. This adjustment decreases revenue requirement by $183,892.

4. Customer Service System

In the stipulation approved by the Commission in Docket No. 97-035-01, one-third of the software investment, maintenance contract, and enhancement expenses were removed from the 1997 test year. This adjustment removes one-third of the Company's investment in its Customer Service System (CSS) software from the 1998 test period. The removal of one-third of the CSS development investment was based on the premise that the CSS system would be used by both regulated and non-regulated areas of the Company, but the costs associated with the maintenance contract remain in dispute. This adjustment decreases revenue requirement by $2,368,046.

5. Outside Services

This adjustment removes non-utility and prior period expenses booked to Account 923, Outside Services, which should be charged below-the-line.

A similar adjustment was one of several which were stipulated in Docket No. 97-035-01. This adjustment decreases revenue requirement by $567,569.

6. Strategic Consulting

This adjustment removes the costs of consultants for certain strategic and financial projects. It decreases revenue requirement by $369,532.

7. Miscellaneous General Expenses - Sponsorships

Certain sponsorships were included in expense and should be charged below-the-line. This adjustment removes these expenses, decreasing revenue requirement by $57,737.

C. AFFILIATE RELATIONS AND INVESTMENTS IN OTHER PROPERTIES

1. Non-Regulated Pension Expense

PacifiCorp bills its non-regulated subsidiaries for benefits provided to their employees. Certain pension expenses and post-retirement benefits billable to subsidiaries were inadvertently left in Administrative and General expense in 1998. This adjustment removes those expenses from the test period. It decreases revenue requirement by $210,044.

2. Corporate Aircraft Allocation

This adjustment reallocates the aircraft residual costs based on nautical miles. Residual costs are the direct operating costs not recovered from commercial equivalent fares as well as other operating costs, such as return, taxes, and operating expenses which cannot be assigned to specific aircraft. A similar adjustment was undisputed in Docket No. 97-035-01. The adjustment decreases revenue requirement by $186,400.

3. Expense Changes Due to the Sale of Corporate Aircraft

During the test year N206PC was sold and N208PC was replaced, resulting in a reduction to PacifiCorp Trans' fleet. The Division proposes as adjustment to remove the depreciation and interest recorded during the test year for N206PC and adjusts depreciation expense to reflect the replacement of N208PC with N208XL. This adjustment decreases revenue requirement by $250,566.

4. Gain on the Sale of Corporate Aircraft

The gain on the sale of N206PC was included in PacifiCorp Trans' billing for December 1998. Because users of corporate aircraft are billed one month in arrears, this gain was not reflected on the books of Electric Operations until January 1999. The Division proposes an adjustment to recognize the gain in 1998, the year in which the sale occurred. This adjustment decreases revenue requirement $91,800.

5. Corporate Shareholder Expenses

PacifiCorp charges all expenses of the Corporate Shareholder Services Department to electric operations. This adjustment uses a three-factor allocation formula to remove from the test year those shareholder services expenses that are related to PacifiCorp subsidiaries. A similar adjustment was undisputed in Docket No. 97-035-01. The adjustment decreases revenue requirement by $143,950.

6. PERCO Environmental Settlement

In 1996 PacifiCorp received an insurance settlement of $33 million for environmental clean-up projects. These funds were transferred to a subsidiary called PacifiCorp Environmental Remediation Company (PERCO). In 1998, PERCO received an additional $5 million of insurance proceeds. This adjustment is necessary to reflect the insurance proceeds in the test period as a reduction in rate base. The rate base amount will be reduced or amortized over time as PERCO expends dollars on clean-up costs. This gives ratepayers full credit for use of the environmental insurance proceeds. A similar adjustment was stipulated in Docket No. 97-035-01. The adjustment decreases revenue requirement by $1,560,651.

7. DSR, Inc. and Third-Party Financing of Demand-Side Management

In February 1995, PacifiCorp transferred its weatherization loans to its wholly owned subsidiary, DSR, Inc., following which Citibank purchased 72.27% of these loans from the subsidiary. In 1995, 1996, and 1997 an adjustment reflected the interest expense paid to Citibank on the transferred loans and adjusted rate base to include weatherization loan balances that remained on DSR, Inc.'s books. The adjustment was undisputed in Docket No. 97-035-01. By 1998 it had become apparent that new DSM investment was [not?] meeting the Company's volume expectations, and the expected advantages of the program were not being realized. Therefore, in November 1998, DSR, Inc., purchased all the loans back from Citibank, and in December 1998, they were transferred to the Company. An adjustment is necessary to reflect the loan amounts as though they had been on the Company's books since January 1, 1998. The adjustment increases revenue requirement by $158,978.

8. Garfield Coal Negotiation

This adjustment removes the deferred cost associated with Garfield coal negotiations from rate base. A similar undisputed adjustment was made in Docket No. 97-035-01. The adjustment decreases revenue requirement by $49,955.

9. Trapper Mine

The Company's investment in the Trapper Mine is accounted for in Account 123.1, Investment in Subsidiary Company, and is not in rate base. The normalized coal costs for Trapper Mine include the coal costs and operating and maintenance costs, but do not include a return on investment. This adjustment adds the Company's net investment in Trapper Mine to rate base. A similar undisputed adjustment was made in Docket No. 97-035-01. The adjustment increases revenue requirement by $272,711.

10. Bridger Coal Company

An investment in Bridger Coal Company has been recorded on the books of Pacific Minerals, Inc., a PacifiCorp subsidiary, rather than on the books of Electric Operations. The normalized costs for Bridger Coal Company are included the operations and maintenance costs of mining, but do not include a return on rate base. This adjustment adds the investment in the Bridger Coal Company to rate base. A similar undisputed adjustment was made in Docket No. 97-035-01. The adjustment increases revenue requirement by $2,253,644, but inclusion of Bridger's Accounts Receivable balance in rate base remains a subject of dispute.

D. NET POWER COSTS

All issues are considered in the body of the Report and Order.

E. NORMALIZING ADJUSTMENTS

1. Weather Normalization

Weather normalization adjusts weather-sensitive loads to correspond to weather and temperature patterns defined as normal on the basis of 30-year historical studies by the National Oceanic and Atmospheric Administration. Only residential and commercial sales are considered weather sensitive. Industrial sales are more sensitive to specific economic factors. A similar adjustment was accepted as undisputed in Docket No. 97-035-01. This adjustment decreases revenue requirement by $117,717.

The Division has concerns about the validity of the current weather normalization procedure, but recommends that the present weather normalization process for energy sales be adopted for this case without implying approval of the approach for future cases. The Division recommends current Company studies on an improved method should be concluded and reported to the Division and Commission before the next case.

2. Corporate Management Fee

The Company uses a three-factor formula to allocate corporate overhead expense to subsidiaries and to Electric Operations. In December, when the final billing for corporate overheads was made, 1997 three-factor formula data was used. This adjustment updates the allocation to electric operations based on December 1998 three-factor formula information. A similar adjustment was approved in Docket No. 97-035-01. This adjustment increases revenue requirement by $264,649.

The Committee argues that the three-factor formula is too simplistic to rely on for allocating corporate costs, particularly given the ScottishPower Merger and the additional layer of shared executive costs across a broader business enterprise it entails. While the Committee accepts the Company's adjustment in this case, it recommends detailed study of corporate cost allocation issues prior to the next PacifiCorp rate case.

3. Market Position and Futures

This adjustment removes the impact of losses from market position trading and futures contracts from the test period. Since the Company has greatly curtailed its involvement in these types of transactions, the 1998 losses are not indicative of on-going expense. The Large Customer Group supports this adjustment, but does not believe that it has been shown to effectively insulate customers from the Company's market position trading and futures contracts. The adjustment decreases revenue requirement by $2,495,300.

F. ANNUALIZING ADJUSTMENTS

1. Service Price Changes

Existing contracts and tariff changes are annualized to reflect a full year of revenues based on the rates currently in effect. A similar adjustment annualizing revenues was approved in Docket No. 97-035-01. This adjustment is the difference between the revenues calculated by applying the new rates in the contracts and tariffs to 1998 test-period energy usage from the actual revenues in the 1998 test period. It includes the price reduction, effective March 1, 1999, ordered in Docket No. 97-035-01, which reduced 1997 test-year revenues by $85.36 million. An adjustment, similar in principle, was accepted as undisputed in Docket No. 97-035-01. The adjustment increases revenue requirement by $88,013,741.

2. Tariff 300 Changes

In Docket No. 97-035-01, the Commission approved changes to Tariff 300 customer charges. These changes are for interest on customer service deposits, interest charged on late payments, returned check charges, and other miscellaneous service fees. The change in interest on customer service deposits is reflected above, in the adjustment entitled Customer Service Deposit Interest. The interest rate the Company is authorized to charge on past due accounts was reduced from 1.5% to 1% per month. The returned check charge was increased from $4 to $15. Except for customer service deposit interest, this adjustment annualizes the Tariff 300 changes ordered in Docket No. 97-035-01. The adjustment increases revenue requirement by $1,356,813.

3. 1988 Wage Increase

PacifiCorp has several labor groups, each with different contract renewal dates. The Company negotiated wage increases with each of these groups throughout the year. This adjustment annualizes the effective wage increase received during 1998 for labor charges to operation and maintenance accounts. A similar adjustment was stipulated in Docket No. 97-035-01. The adjustment increases revenue requirement by $462,689.

4. FICA Adjustment for the 1988 Wage Increase

This adjustment reflects the FICA tax increase associated with the larger payroll base that results from the annualized 1998 wage increase. The general wage increase is based on direct labor only and does not include overheads. A similar adjustment was stipulated in Docket No. 97-035-01. The adjustment increases revenue requirement by $30,438.

5. Depreciation Expense

For part of 1998, the Company recorded depreciation expense using rates from a 1996 depreciation study filed with the Commission for approval and subsequently withdrawn. The current authorized depreciation rates were applied to 1998 beginning/end of year average plant balances to calculate the on-going level of depreciation expense. The annualized depreciation expense was compared to the actual expense booked to account 403 for the same period. The adjustment to booked depreciation expense is necessary to reflect on-going depreciation expense based on current depreciation rates and the depreciable plant balances reflected in the test period. A similar adjustment was made in the Depreciation Stipulation approved by the Commission on June 18, 1998, in Docket No. 97-035-01. This adjustment decreases revenue requirement by $772,477.

6. Accumulated Depreciation

The previous adjustment annualizes depreciation expense based on current depreciation rates and test-period average plant balances. Any change made to depreciation expense has a direct impact on the accumulated depreciation reserve balance. This adjustment is necessary to reflect the impact of the adjustment to depreciation expense on the accumulated depreciation reserve. It adjustment increases revenue requirement by $34,855.

7. Accumulated Depreciation Correction

In December 1997, PacifiCorp booked an entry to adjust depreciation expense to reflect the proposed rates for its 1996 depreciation study. This entry increased the current year expense by $15,953,898. In addition, the Hermiston generation plant was being depreciated using a twenty-year life rather than the typical thirty five-year life for this type of facility, which had the impact of increasing depreciation expense by $3,565,255. The impact of the 1996 depreciation study was removed from the 1997 test period and the use of a 35-year life for Hermiston was included under the terms of the Depreciation Stipulation approved by the Commission on June 18, 1998, in Docket No. 97-035-01. On the Company's books, however, the depreciation reserve is still over-stated by the amount of additional depreciation expense recorded in 1997. This adjustment reduces the amount of accumulated depreciation included in 1998 test-period ratebase to a balance that is consistent with the 1997 Stipulation. The adjustment increases revenue requirement by $592,857.

G. ACCOUNTING ADJUSTMENTS

1. Miscellaneous Revenue

This adjustment normalizes test-period revenues by removing non-recurring or out-of-period adjustments. By far the largest component of this adjustment is the removal of the effect of the rate refund ordered in Docket No. 97-035-01, approximately $37 million of which was recorded in 1998. This adjustment accurately reflects nonrecurring revenue changes which occurred during the test year. An adjustment, similar in principle, was accepted as undisputed in Docket No. 97-035-01. This adjustment decreases revenue requirement by $39,055,020.

2. Unbilled Revenue

An error understating state loads in the test year in turn understates unbilled revenues. This adjustment restates test-year retail revenues to correct the calculation of unbilled revenues included in the original 1998 results. This adjustment decreases revenue requirement by $6,109,000.

3. APS Combustion Turbine

In December 1996, the Company recorded a $20 million payment to Arizona Public Service Company pursuant to a combustion turbine construction agreement arising from the August 1991 purchase of the Cholla 4 generating station. The payment is recorded as a deferred debit and is amortized over the 26-year life of the plant beginning August 1991. This adjustment is consistent with the undisputed treatment accepted by the Commission in Docket No. 97-035-01, which reflected a June 1997 agreement between the Company and the Division. This adjustment removes Utah's allocated share of the average balance of the deferred debit, or $4.93 million, from rate base. The adjustment decreases revenue requirement by $720,478.

4. QF Contract Buyouts

During 1998, PacifiCorp negotiated an early exit to two Qualifying Facilities (QF) contracts. The effective dates of the contract buyouts were July 1997 and June 1998. These buyouts are being amortized over the remaining lives of the QF contracts. The contract buyouts were recorded on the Company's books during 1998, including several months of catch-up amortization. This adjustment removes out-of-period amortization expense and annualizes the amortization expense. Ratebase is adjusted to reflect the buyouts as if they occurred January 1, 1998. A similar adjustment was accepted as undisputed in Docket No. 97-035-01 for contracts bought-out in 1997. The adjustment increases revenue requirement by $78,542.

5. Plant Held For Future Use

Plant held for future use related to steam plant was written-off in 1998. This adjustment removes the average balance from the test period. It is consistent with a treatment of plant held for future use in the Stipulation of Certain Revenue Requirement Issues in Docket No. 97-035-01. The adjustment decreases revenue requirement by $60,519.

6. Prior Year Incentive Accrual

In 1998, an additional amount of expense for 1997 incentive awards was accrued to properly reflect the amount accrued to the amount paid out. This adjustment removes this prior period accrual. It decreases revenue requirement by $987,583.

7. FAS 112 Post-Employment Benefits

PacifiCorp accrued a liability for post-employment benefits at the end of 1998. In part due to early retirement, the actuarial liability was less than anticipated. This adjustment removes from the test period the excess of the accrued liability at the end of the year over the actuarial liability. The adjustment also removes the 1998 portion of the under funded December 1996 balance in accordance with the Commission order in Docket No. 97-035-01 that approved the Company's request to change from pay-as-you-go to accrual accounting but denied its request to amortize over three years the under funded December 1996 balance. The adjustment also reverses the rate base reduction for FAS 112 reserve amounts not paid by Utah customers. The adjustment decreases revenue requirement by $1,503,976.

8. Pension and Benefit Reserve Correction

In October 1998, a new account was set up for Pension and Benefits Reserve - Termination Pay. The account was not identified as a rate base reduction in the Company's reported unadjusted results. The Company proposes an adjustment to include this account as a rate base reduction. In addition, the Company corrects a minor error in its original adjustment and properly reflects the rate base balance. While the Committee accepts the Company's original adjustment, it takes no position on the correction. Nevertheless, we treat this issue as undisputed. This adjustment decreases revenue requirement by $133,462.

APPENDIX II. SPREAD OF REVENUE CHANGE

Schedule	Current Revenue	Percent Change	Revenue Increase
1, Residential	$263,012,287	4.24%	$11,153,594
2, Residential Time-of-Day	$5,411	3.56%	$193

25, Mobile Home and House Trailer Park	$548,479	4.24%	$23,257
10, Irrigation, Non-Time-of-Day	$4,230,405	4.29%	$181,449
10, Irrigation, Time-of-Day	$442,606	3.78%	$16,711
23, General Service, Distribution, Small	$53,361,238	4.24%	$2,262,645
7, Security Area Lighting	$2,418,409	4.25%	$102,750
11, Company-Owned Street Lighting	$3,682,061	4.24%	$156,050
12, Customer-Owned Street Lighting	$1,797,499	4.24%	$76,203
12, Traffic Signal Systems	$569,919	4.24%	$24,171
12, Metered Outdoor Nighttime Lighting	$416,347	4.24%	$17,637
6, General Service, Distribution	$258,657,075	0.83%	$2,149,351
6A, Energy Time-of-Day	$7,927,081	0.90%	$71,135
6B, Demand Time-of-Day	$338,556	0.85%	$2,865
9, General Service, Transmission	$80,508,123	0.97%	$780,330
9A, Energy Time-of-Day	$575,168	1.07%	$6,179
9B, Energy Time-of-Day	$1,790,321	0.86%	$15,366
31, Back-Up, Maint. & Supplem. @6/9	$275,475	1.26%	$3,463
Total			$17,043,348

APPENDIX III. PRICING OF ENERGY RATE ELEMENTS

Schedule	Current Energy Rate	New Energy Rate
1, Residential	$0.058753	$0.061273
2, Residential T-of-D, On-Peak	$0.104606	$0.109093
2, Residential T-of-D, Off-Peak	$0.031275	$0.032616
25, Mobile Home and House Trailer Park	$0.039578	$0.041612
10, Irrigation, Non-T-of-D, 1st 30,000 kWh	$0.037673	$0.039776
10, Irrigation, Non-T-of-D, Additional kWh	$0.027749	$0.029298
10, Irrigation, T-of-D, On-Peak	$0.075116	$0.079310
10, Irrigation, T-of-D, Off-Peak	$0.021413	$0.022608
10, Irrigation, Post-Season	$0.025825	$0.027267
23, Gen Svc, Distri., Small, 1st 1,500 kWh	$0.069872	$0.073106
23, Gen Svc, Distri., Small, Additional kWh	$0.039175	$0.040988
23, Gen Svc, Distri., Small, Flat Rate kWh	$0.074057	$0.077485
12, Traffic Signal Systems	$0.046255	$0.048461
12, Metered Outdoor Nighttime Lighting	$0.046294	$0.049535
6, General Service, Distribution	$0.025900	$0.026289
6A, Energy T-of-D, On-Peak	$0.061097	$0.062013
6A, Energy T-of-D, Off-Peak	$0.018392	$0.018668
6B, Energy T-of-D	$0.025900	$0.026289
9, General Service, Transmission	$0.019863	$0.020161
9A, Energy T-of-D, On-Peak	$0.044119	$0.044781
9A, Energy T-of-D, Off-Peak	$0.018956	$0.019240
9B, Energy T-of-D	$0.019863	$0.020161

Schedule 7, Security Area Lighting: All rates increased by 4.216 percent.

Schedule 11, Company-Owned Street Lighting: All rates increased by 4.23 percent.

Schedule 12, Customer-Owned Street Lighting: All rates increased by 4.22 percent.

Rates for these schedules are rounded to the second decimal place.

1. The Company's unadjusted results of operations for Utah require revenues be increased by $48,960,798 to earn the Commission-authorized 11 percent rate of return on equity. Using the Division's allocation factors to obtain Utah unadjusted results, revenues must be increased by $45,262,317 to earn an 11 percent rate of return on equity.

2. As stated previously, the Company's unadjusted results of operations for Utah require revenues be increased by $48,960,798 to earn the Commission-authorized 11 percent rate of return on equity. Using the Committee's allocation factors to obtain Utah unadjusted results, revenues must be increased by $40,182,074 to earn an 11 percent rate of return on equity.

3. Actual 1997 Net Power Cost values are from the 1997 Semi-Annual Report, Tab 5, page 5.1.1. Stipulated 1997 Net Power Cost values are the actual 1997 values plus the sum of the 1997 adjustments (PC-5.1, PC-5.2, PC-9.2, and PC-9.19) contained in the 1997 Joint Numerical Exhibit on Revenue Requirement in Docket No. 97-035-01. Megawatt hours are Utah normalized values, excluding non-firm special contracts, obtained from Company witness William R. Griffith's rebuttal exhibit WRG-R1 in Docket No. 97-035-01.

Actual 1998 Net Power Cost values are from the 1998 Semi-Annual Report, Tab 5, page 5.1.1, reproduced in Company witness Jeffrey K. Larsen's exhibit JKL-1, page 5.1.1 in this case. Adjusted 1998 Net Power Cost values of the parties are the actual 1998 values plus the sum of the 1998 adjustments contained in the 1998 Joint Numerical Exhibit on Revenue Requirement. Megawatt hours are Utah normalized values, excluding non-firm special contracts, obtained from Company witness William R. Griffith's rebuttal exhibit WRG-2R in this case.

4. See orders in Dockets 87-035-16 and 90-035-08. The latter raises an perplexing conundrum as it orders the amortization of the deferred portion over a five year period beginning with the inception of the Voluntary Severance Program. The Committee alleges that the deferred pension asset is composed, in part, of deferrals from the 1990 program.