Edward A. Hunter (Utah Bar No. 1592)
John M. Eriksson (Utah Bar No. 4827)
STOEL RIVES LLP
201 South Main Street, Suite 1100
Salt Lake City, Utah 84111
Telephone: (801) 328-3131
Fax: (801) 578-6999

James M. Van Nostrand
STOEL RIVES LLP
600 University Street, Suite 3600
Seattle, Washington 98101
Telephone: (206) 624-0900
Fax: (206) 386-7500

Attorneys for PacifiCorp

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application	:	
of PacifiCorp for an Increase	:	Docket No. 01-035-01
in its Rates and Charges	:	
	:	PACIFICORP'S POST-HEARING BRIEF
	:	
	:	

TABLE OF CONTENTS

Edward A. Hunter (Utah Bar No. 1592)
John M. Eriksson (Utah Bar No. 4827)
STOEL RIVES LLP
201 South Main Street, Suite 1100
Salt Lake City, Utah 84111
Telephone: (801) 328-3131
Fax: (801) 578-6999

James M. Van Nostrand
STOEL RIVES LLP
600 University Street, Suite 3600
Seattle, Washington 98101
Telephone: (206) 624-0900
Fax: (206) 386-7500

Attorneys for PacifiCorp

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp for an Increase in its Rates and Charges	:	Docket No. 01-035-01
	:	PACIFICORP'S POST-HEARING BRIEF

PacifiCorp, doing business as Utah Power & Light Company ("PacifiCorp" or "Company") respectfully submits the following post-hearing brief:

I. INTRODUCTION

PacifiCorp seeks a rate increase in this case of approximately $118 million. This increase is largely driven by increased power costs, which are being experienced not only by the Company, but by utilities throughout the western United States. PacifiCorp has demonstrated that, at a time when it is critical that it have access to affordable capital to make infrastructure investments, it is essential that it receive a fair and reasonable result in this case which would provide significant rate relief. Notwithstanding the unprecedented price increases in the Western power market, other parties recommend adjustments that would significantly reduce, or even eliminate, any rate relief for PacifiCorp. For all the reasons stated in PacifiCorp's evidence, at the hearings and in this Brief, the Commission should reject the recommendations of the other parties and grant the rate relief requested by PacifiCorp.

II. PROCEDURAL HISTORY

PacifiCorp initiated this case with the filing of its Application and supporting testimony on January 12, 2001, wherein it requested a rate increase of approximately $142 million based on a test year ending December 31, 1999. With its Application, PacifiCorp also filed an Emergency Motion for Interim Rate Relief. Following hearings on that Motion, an Order Granting an Interim Rate Increase in the amount of $70 million was issued February 2, 2001.

Following discussions with the Division of Public Utilities ("Division") and the Committee of Consumer Services ("Committee"), PacifiCorp supplemented its filing on February 12, 2001, with testimony and exhibits supporting a rate increase of approximately $169 million, based on a test year ending September 30, 2000. However, the Company held its requested rate increase at the level contained in its original filing, $142.2 million.

A scheduling conference was held February 13, 2001, and pursuant to the schedule set by the Commission, as subsequently amended, the Division, the Committee and intervenors filed direct testimony on revenue requirement on or before June 4, 2001. Except with respect to testimony filed by the Utah Energy Office related to funding of demand-side management ("DSM") measures, the Division and the Committee were the only parties to offer testimony regarding revenue requirement issues other than power costs.[1]

The Company, the Division and the Committee entered into a Stipulation on Certain Revenue Requirement Issues (the "Stipulation"), resolving all non-power cost revenue requirement issues except an issue related to Dave Johnston Mine coal costs and an issue related to the proceeds of an environmental settlement, as well as the DSM funding issue. (Resolutions to the Dave Johnston Mine coal cost and the environmental settlement issues were presented to the Commission during hearing on August 3, 2001. Ex. 7.1R, 7.2R; Tr. 1311-13.) A hearing on the Stipulation was held on July 26, 2001, at which time the Commission approved the Stipulation. As a result of the Stipulation, the remaining increase sought by PacifiCorp and at issue in this case is approximately $118 million.

III. ARGUMENT

A. The Commission Must Provide a Fair and Reasonable Overall Result in This Case.

In determining the legality of a rate-making order, the focus is on the reasonableness of the overall result, not on the reasonableness of the individual adjustments. The seminal case for determining the reasonableness of a rate-making decision is *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603, 64 S.Ct. 281, (1944). The constitutional standard that should guide Commission ratemaking decisions was articulated in *Hope* as follows:

---

[1] Direct testimony of Michael Gorman on behalf of UIEC, regarding certain tax issues, was filed, but was withdrawn. Tr. 707.

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Rates that do not satisfy this constitutional standard as an *end result* are "unjust, unreasonable and confiscatory" and violate the Fourteenth Amendment. *See Hope,* 320 U.S. at 603; U.S. Const. Amend. XIV. The "end results" test was affirmed by the United States Supreme Court in *Duquesne Light Co. v. Barasch,* 488 U.S. 299, 312, 109 S.Ct. 609 (1989). *See generally* Charles F. Phillips, Jr., *The Regulation of Public Utilities: Theory and Practice* 327-30 (1993); Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions* 40 (1993).

Thus, reasonableness must be determined based on whether the end result of the adjustments meets the constitutional standard. If the overall result is not just and reasonable, then the individual adjustments by definition cannot be fair and reasonable.

B. A Fair and Reasonable Result in This Case, Providing Significant Rate Relief, is Necessary for PacifiCorp's Financial Stability.

There is no question that the events in the wholesale market have impaired the financial performance of PacifiCorp. As the Commission concluded in its February 2, 2001 Order Granting an Interim Rate Increase in this case, "wholesale market difficulties are impairing the Company's financial performance. For the first time in the Company's history, a monthly operating loss has been reported." It is indisputable that PacifiCorp's increased power costs have created concern in the financial community about PacifiCorp's financial stability. On January

22, 2001, Moody's changed the rating outlook on PacifiCorp's debt from neutral to negative, and on February 13, 2001, Standard and Poor's placed the Company on Credit Watch with negative implications. Further, on May 18, 2001, Moody's placed the Company's debt ratings under review for possible downgrade, followed by a June 15, 2001 downgrade of ScottishPower UK plc, at which time Moody's stated:

> While PaciCorp's existing ratings benefit from its affiliation with Scottish Power, [Moody's] review for possible downgrade [of PacifiCorp] focuses on the company's ability to manage its exposure to the wholesale electric power market in the western United States. An important factor that will influence the outcome of the rating review will be the extent of state regulatory support received by PacifiCorp for recovery of wholesale electric power, especially from the regulators in Oregon and Utah.

Ex. UP&L 2R at 5-6.

As established by the testimony of PacifiCorp's Chief Financial Officer, Karen Clark, what is now a concern of the rating agencies will likely be transformed into real and harmful effects if PacifiCorp does not obtain reasonable rate relief in this case. First, if rates are not set at a level sufficient to enable the Company to pay its actual costs, the Company's cash flow and liquidity will be impaired, which would likely lead to a downgrade in the Company's ratings. In turn, PacifiCorp would have greater difficulty in accessing capital markets and would incur higher costs for financing. Second, the Company's current cash flow is insufficient to sustain appropriate recurring capital spending, let alone provide funds for additional generation or transmission enhancements. Thus, the Company anticipates having to go to the debt market in the near future. However, because of insufficient cash flow, it is increasingly difficult and expensive to access capital markets. Tr. 684-85.

While the Division professes to be concerned about PacifiCorp's financial integrity in its recommendations in this case, it does not put forth a consistent position. On the one hand, the Division agrees that the Commission should take into account the ability of the Company to access the capital markets and build infrastructure in the state, and earn its allowed rate of return on equity. Tr. 763-64. On the other hand, the Division suggests that the Commission should send a signal to the Company, by disallowing its normalized power costs, that management should be held accountable for its decision to buy power in the market rather than build generation. Tr.701-03. (The Division's proposal to impute revenues related to wholesale market activity, supposedly done on grounds other than imprudence, is addressed below.) In particular, the Division seeks to impute revenues in connection with certain wholesale sales contracts, the effect of which would be to cause underrecovery of power costs. In other words, the Division asks the Commission to significantly reduce the Company's requested rate increase in order to send a message to the Company that it better look at building generation (which of course would require accessing the capital markets), while at the same time purporting to be concerned about the Company's financial integrity and access to capital at reasonable costs.

The Division, as does UIEC witness Gorman, critiques Ms. Clark's calculation of various financial ratios used by rating agencies, but significantly, neither party rebuts PacifiCorp's testimony that the Company's financial position is deteriorating in the face of extremely high purchased power costs. Further, neither party seriously rebuts the Ms. Clark's testimony that meaningful rate relief is necessary in this proceeding to stave off a rating downgrade. The closest Mr. Gorman gets is to put forth ratios which he states will be reasonably consistent with Standard and Poor's "A" benchmark ratios for PacifiCorp's <u>Utah</u> operations <u>if</u> the Commission designs rates to provide PacifiCorp an opportunity to earn an 11% return on equity, and if the Company earns that same return in all its other states, and if the Company's unregulated operations also earn that return. Ex. UIEC 1SR at 8-9. Mr. Gorman's caveat regarding the level of rates is that he expects "the Commission to set rates based on a reasonable amount of normalized purchase power costs that reflect what PacifiCorp's actual future purchase power cost will be." Yet, that "caveat" is completely inconsistent with proposals to impute revenues associated with wholesale contracts and make other adjustments reducing the net power costs in rates, the effect of which is to provide for recovery at a level lower than actual costs. Further, any suggestion that the Company is protected, by the FERC-imposed cap on wholesale energy prices, from actually incurring the level of power costs included in its filing, flies in the face of the reality that the Company previously executed forward purchases that are now higher priced than the current forward price curve. Such prudent action was similarly taken by other utilities. *See, e.g.* Tr. at 802.

In response to Mr. Gorman's suggestion that the Company would be able to earn an 11% return on equity because that is what was stipulated to, Company witness Doug Larson presented the results of an analysis reflecting the outcomes of the Committee's proposed $10 million rate decrease and the Division's proposed $28 million rate increase. The Company's evidence showed that applying those positions to the Company's actual power costs for the twelve-month period ending May 2001 (adjusted as though Hunter 1 was running that entire time), the return on equity under the Committee's proposal would be only 4.6%, and 6.6% under the Division's proposal. Tr. 1348-49.

The Commission must recognize that PacifiCorp is not alone in being severely impacted by the energy crisis in the Western United States. The impact to the financial strength of the Company threatens its ability to access capital at reasonable costs and make the investments in infrastructure necessary for reliable service. That is a concern not only of the Company, but also the State's chief economic officer, as well as representatives from communities served by PacifiCorp, whether at the retail level or with transmission service. Tr. 787-92; 800-03; 830-34.

The Commission should approve PacifiCorp's requested rate increase, which will provide a fair result and will send the appropriate signal to the financial community necessary to maintain the Company's financial health.

C. The Commission Should Reject Proposed Revenue Imputations to Long-Term Firm Wholesale Sales Contracts.

In its power supply strategy, PacifiCorp has historically used wholesale activities to optimize its resource system, minimize the need for rate increases, stabilize costs to retail customers, and achieve a reasonable rate of return for its shareholders. Part of that strategy consisted of entering into long-term wholesale transactions, both purchases and sales. In particular, during the 1990s, the Company prudently acquired over 1,300 MW of resources. However, given that such resources come in large "blocks," the acquisitions temporarily provided the Company with more resources than needed to meet its retail load. Rather than selling the excess into the market as short-term firm power, the Company chose to enter into long-term firm[2] sales contracts at prices higher than what could have been obtained in the short-

[2] For purposes of this Brief, PacifiCorp uses the term "long-term firm" as including intermediate term firm contracts, which have terms ranging from one to five years.

term firm market. Ex. UP&L 3R at 8-9. The long-term firm contracts at issue in this case, entered into during the 1996-1998 time period, were timed to terminate about the time the Company's resources were expected to become fully necessary to serve its retail load.[3] Ex. UP&L 3R at 11. Further, a comparison to the avoided costs upon which the contracts were evaluated at the time shows that the contracts were reasonably expected to provide benefits to the Company's retail customers. Ex. UP&L 3R at 23-24, 3.6R. Under the revenue credit method, whereby the costs and revenues of such sales are allocated system-wide, customers received the benefit of the Company's strategy. Compared to the revenues that would have been received had the sales been made in the short-term firm market, the Company's customers have received approximately $1.3 billion in benefits over the last decade.[4] Ex. UP&L 3.2R.

In the Company's last Utah rate case, Docket 99-035-10, the Division and the Committee took issue with a number of the long-term firm contracts and proposed to impute additional revenues, claiming that the sales prices were too low. The Commission adopted the Division's proposal to impute revenues based on a comparison to the "filed in Utah" avoided costs. The

[3] Division witness Compton is critical of the Company's analysis regarding energy needs, as opposed to peaking capacity needs. Ex. DPU 13SR. However, as noted by Mr. Watters, with the market prices that existed at the time, and were projected to exist, the Company would probably have been laughed out of the hearing room if it had suggested that it should cover its summer peak with simple cycle combustion turbines. Mr. Watters quoted a Commission Staff member as stating, during the course of RAMPP discussions, "Why would you even build [a simple cycle combustion turbine] for capacity since you can buy capacity on the market for 40 mills?" Tr. 1284. The point is, the market was perceived to be the lowest cost resource for the period in question.

[4] UAE/Nucor is likely to argue that the Company's comparison to a strategy of selling all the surplus in the short-term firm market is a comparison to an imprudent strategy, and that the comparison should have been to some other alternative. However, there was no other specific alternative identified as the basis for calculating a different level of benefits.

imputation in that case, based on six contracts, resulted in a $1.5 million reduction to the Company's Utah revenue requirement. Ex. UP&L 3R at 4-5.

In this case, the Company included in its filing an adjustment of $1.3 million consistent with the approach adopted by the Commission in Docket No. 99-035-10. Ex. UP&L 3R at 8. However, that was not enough of an imputation for the Division, the Committee and UAE/Nucor. Instead, they seek to impute revenues (or, alternatively stated, disallow revenue requirement) in amounts ranging from $64 million for UAE/Nucor, to $63 million for the Division, and $157 million for the Committee (exclusive of the proposed imputation regarding the Deseret contract). Ex. UAE/Nucor 1.15; Ex. DPU 8SR at 1; Ex. DPU 9.9 at 2 (showing Committee's proposed imputations). The Commission should reject the revenue imputations proposed by the Division, the Committee and UAE/Nucor.

1. The Commission has established standards that parties must meet to support their adjustments.

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

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

Id. at 49-50.

2. <u>The Division, Committee and UAE/Nucor have not met their burden to establish that the Company has acted imprudently.</u>

The Division, Committee and UAE/Nucor have proposed adjustments to impute additional revenue to varying numbers of the Company's long-term wholesale sales agreements. However, none of the parties have made any attempt to establish a reasonable basis upon which to conclude that the Company has acted imprudently in entering into any of those agreements. Indeed, none of those parties made any attempt to analyze the prudence of any of those agreements. Instead, the parties take no position on the prudence of the wholesale contracts at issue, with the Committee and UAE/Nucor very specifically taking the position that their proposed imputation is not based on a prudence review. Tr. 857; 1029.

In light of the requirement that a prudence review of the wholesale contracts would entail an analysis of what was known or reasonably should have been known at the time decisions were made to enter those contracts, it is apparent the Division, Committee and UAE/Nucor have turned to another means that would allow review with perfect hindsight. As Mr. Anderson, on behalf of UAE/Nucor, put it, "My question does not address the question of prudency. Instead, I question the allocation of risk resulting from these contracts." Tr. 1029. Similarly, Ms. Wilson for the Division states that the Company "must be held accountable for its choices in maintaining a resource portfolio adequate to manage the risks associated with serving its obligations at least cost or, at a minimum, at reasonable cost."[5] Tr. 1227.

The Commission must reject the hindsight "risk allocation" approach applied by the parties in their imputation proposals. Such an approach is contrary to the prudence review standard previously adopted by the Commission and can be used to render prudence and public interest determinations meaningless. On behalf of the Company, Mr. Larson expressed considerable concern regarding what rate recovery treatment might be obtained in Utah if it were to construct a new coal fired generation unit. The approach taken by the parties in their imputation proposals highlights the basis for that concern. Specifically, the Company could obtain a certificate from this Commission that the public convenience and necessity requires the construction of the unit, only to have parties such as the Division and the Committee later take the position that the "risk" created by the Company's decision to build, rather than buy in the wholesale market, requires a disallowance of the generation unit costs.

[5] The Division's and UAE/Nucor's reliance on testimony of Mr. Topham and Mr. Duvall in Docket No. 90-035-06, regarding the elimination of the EBA, in support of their argument that the Company accepted all the risk related to long-term wholesale sales is unsupported by the facts. Neither Mr. Topham nor Mr. Duvall testified to that effect, and in any event, the costs of short-term and long-term firm wholesale contracts were not even dealt with in the EBA. Tr. 1314. Thus, elimination of the EBA would not have affected ratemaking treatment with respect to those types of contracts. Finally, the risk of fluctuation *in between* rate cases of power costs which had been treated in the EBA, which was accepted by the Company, has indeed been borne by the Company, to the benefit of customers. Tr. 1317-22; Ex. UP&L 7.4R.

The inappropriateness of the “risk allocation” rather than prudence approach can particularly be seen in this case with reference to the impacts of the sale of the Company’s interest in the Centralia plant. A significant contributing factor to the Company’s need to buy short-term firm energy during the test year was the sale of the Centralia plant. Ex. UP&L 3R at 14. In the case before this Commission in which the Company sought approval of the sale of its interest in the Centralia plant, Division witness Wilson proposed that the Company’s ratepayers receive the gain from the sale of the plant in order to be “compensated for the risk that replacement cost will be higher than the cost of keeping Centralia.” Ex. UP&L 3R at 15 (quoting Ex. DPU1.0, p. 14, Docket No. 99-2035-03). The Commission agreed with the proposal to compensate ratepayers for that risk, stating that “the important remaining risk occasioned by the sale is the going-forward risk of high-cost replacement power,” and allocated 95% of the gain to ratepayers. (Docket No. 99-2035-03 Order at 17.)[6] As she must, Ms. Wilson agrees that the Commission drew the conclusion that customers were going to bear the risk of replacement power for Centralia, and arrived at its decision on gain allocation based on that risk. Tr. 1233. Yet, Ms. Wilson then decides that the Commission’s determination that the ratepayers have the going-forward risk of high-cost replacement power, and its allocation of gain to the ratepayers to compensate them for that risk, does not mean that the ratepayers now should bear those costs. Thus, she cavalierly claims, “Risk is different than allocation of cost.” Tr. 1253.

Under that theory now apparently adopted by the Division, the Commission could issue an order granting a certificate of convenience and necessity for the construction of a generating unit, explicitly stating that ratepayers will bear the risk of the generating unit, prudently constructed and operated, being more costly than purchased power, then later, if market prices

[6] Significantly, the Commission *did not* adopt a proposal by Ms. Wilson that the Commission adopt a revenue imputation approach as a means of mitigating the risk of high replacement power costs. Tr. 1229-30.

actually are lower than the costs of that generating unit, the Commission could disallow recovery of the investment in the unit by simply declaring “Risk is different than allocation of cost.”

Aside from being contrary to precedent, the hindsight analysis proposed by the Division, Committee and UAE/Nucor is unsound from a regulatory policy perspective, and should be rejected.

3. The 1990 Order Regarding Revenue Credit Treatment Does Not Provide a Basis for the Proposed Imputations.

The Division, Committee and UAE/Nucor rely upon the Commission’s December 7, 1990 Order issued in Docket No. 90-035-06(the “1990 Order”), and testimony in that case, in making their imputation proposals. Ex. DPU 8 at 9; Ex. CCS 7 at 12; Ex. UAE/Nucor 1, Tr. 1039-42. However, rather than purportedly applying the criteria adopted in the 1990 Order, the parties have selectively applied only some of the criteria as a basis for their proposed imputations.

The 1990 Order adopted by reference the following criteria regarding the use of the revenue credit method:

> 1. All existing firm Utah FERC wholesale and wheeling business taking service prior to the merger be excluded from the Utah jurisdiction and included in a FERC jurisdiction for reports and filings in Utah. New firm sales and wheeling at tariffed, fully-embedded rates would also be included in the FERC jurisdiction.
>
> 2. Nonfirm sales for resale and wheeling, and long term contracts not covering fully embedded costs where service is begun on or after the merger (Sierra and Puget included), would be treated as revenue credits, after approval of the contracts by the Utah Public Service Commission.
>
> 3. In the event that costs are imposed on UP&L by the FERC Order No. 318 that are not fully recovered from those imposing the costs, then those contracts would also be included in the proposed FERC jurisdiction.

> 4. Any long term contract proposed to be treated as a revenue credit be filed with the Utah Public Service commission for subsequent approval of that revenue credit status. That filing would have to include the necessary information to verify that:
>
> A. The sales couldn't have been made at rates based on full embedded costs.
> B. The contract covers marginal cost.
> C. The contract make a contribution to fixed costs.
> D. After a short time, the contract either terminates, or covers full embedded costs.

Ex. DPU 8 at 9.

The Division and the Committee explicitly rely on the criteria from the 1990 Order as the basis for their proposed imputations. Ex. DPU 8 at 17; CCS 7 at 24-27. The Division bases its proposed imputation on the subject contracts not covering full embedded costs (Ex. DPU 8 at 17), while the Committee and UAE/Nucor use the short-term firm purchase price in the Company's filing as the basis for their proposed imputations. Ex. CCS 7 at 27; Ex. UAE/Nucor 1 at 25. However, despite the supposed adherence to the 1990 Order, none of the parties actually propose that the 1990 Order be fully applied in this case. Rather, the Division and the Committee seek to selectively apply just those portions of the criteria that support their positions. Specifically, the 1990 Order provides that certain criteria must be met for long-term firm wholesale sales contracts to be given revenue credit treatment. The Division focuses on contracts failing to meet the fully embedded cost criterion, while the Committee focuses on its view of the marginal cost criterion, and both parties point to the lack of prior Commission approval of the contracts. Yet, the 1990 Order provides that revenue credit treatment is applicable <u>if</u> the various criteria are met, and if they are not met, the alternative treatment is to assign the contracts to a FERC jurisdiction for purposes of Utah ratemaking. Neither party presented an analysis of what the ratemaking impact would be if the subject contracts were assigned to a FERC jurisdiction. Tr. 1246, 1264-65; 856-57. Ms. Wilson for the Division acknowledged that she did not follow the terms of the 1990 Order regarding assigning contracts to a FERC jurisdiction, and Mr. Yankel similarly acknowledged that he is not proposing that the subject contracts be assigned to a FERC jurisdiction.[7] Tr. 1246, 856. The Committee even went so far as to say that revenue credit treatment for the contracts is not appropriate (Ex. CCS 7 at 16), while at the same time, it uses the revenue credit treatment in conjunction with its proposed revenue imputation.

The Committee also uses the 1990 Order to apply a perverted view of what are the "marginal costs" that must be covered in order to receive revenue credit treatment. Specifically, Mr. Yankel defines marginal cost, as used in the 1990 Order, as incremental cost, which he in turn defines as the "*actual* additional cost to supply the contract." Tr. 860. What Mr. Yankel views as the "actual" cost of supplying the contracts (short-term firm purchase prices, discussed below) could not have been known in 1996 and 1997, but he applies it anyway, notwithstanding that the marginal cost standard in the 1990 Order could have only been based on the information that existed at that time. Again, the Committee finds a way to advocate a hindsight analysis.

Application of the 1990 Order would require the contracts to be assigned to a FERC jurisdiction rather than be given revenue credit treatment. An analysis of the revenue requirement impact of assigning those contracts to a FERC jurisdiction has not been presented. Thus, there is no basis in the record for the Commission to adopt imputations regarding the subject contracts based on the criteria in the 1990 Order. If the Commission were to adopt revenue imputations related to those contracts, the only approach to doing so which would be consistent with

---

[7] Ms. Wilson "sort of did a screening analysis" to see what Utah's share of net power costs would be with a FERC jurisdiction, but she did not conduct an analysis of what the revenue impact would be if the 14 contract at issue were assigned to a FERC jurisdiction. Tr. 1246-47, 1264-65. Mr. Larsen, on behalf of the Company, presented testimony that, contrary to Ms. Wilson's "screening analysis," establishment of a FERC jurisdiction would increase the Utah revenue requirement compared to what the Company is proposing in this case. Tr. 1330-31.

precedent (Docket No. 99-035-10) and have support in the record, is an imputation based on the "filed in Utah" avoided cost standard. Ex. UP&L 3R at 7-8, 26-27; UP&L 3R.1, 3R.7.

4. The Committee's and UAE/Nucor's proposed imputation based on short-term firm purchases is based on a false premise and must be rejected.

The Committee and UAE/Nucor base their proposed imputations on the premise that the long-term wholesale sales were served entirely by energy acquired through short-term firm purchases. Based on that premise, the Committee and UAE/Nucor propose imputations based on pricing *all* of MWhs sold under the subject long-term firm contracts during the test period at the purchase price filed by the Company for short-term firm purchases.[8] Ex. CCS 7.4 at 1, Tr. 864-65; Ex. UAE/Nucor 1 at 25, 1R.2. The premise necessary for the Committee's and UAE/Nucor's proposed imputations is false, and their imputations must be rejected.

Considerable reliance is placed upon a statement in the Company's RAMPP 5 Report, filed in December 1997 (after most of the contracts at issue had been executed), that an adjustment in the base case "increases the amount of short-term wholesale purchases made in each of the first five years of the planning horizon to achieve a balance between wholesale sales and wholesale purchases by the fifth year." *See, e.g.* Ex. DPU 8 at 14. However, the parties' reliance on that resource planning assumption is misplaced. The Company's RAMPP process and report is a high level, long-term load and resource balancing model. The RAMPP Report is specifically not an operating plan which guides the Company's day-by-day operations. Ex. UP&L 4R at 2-3; Tr. 399. The referenced assumption in RAMPP 5 is for planning purposes,

---

[8] The Division similarly asserts that the Company relied upon short-term firm purchases to meet its long-term firm wholesale sales obligations. Ex. DPU 8 at 13-15. While the Division's imputation is based on embedded cost instead of the price of short-term firm purchases, its conclusion that the Company "accepted a risk for a strategy that has backfired" is not supported by the false premise.

effectively removing the issue of wholesale transactions from the RAMPP process, to assure that the integrated resource planning process is for the retail operations and does not result in resources being selected to serve wholesale load. Tr. 398-99. Moreover, even when that planning assumption, and an assumption of a 10% retail load loss, were removed, the analysis showed that the need for new resources was only brought forward to 2002, beyond the test period in this case, reflecting that until 2002, the Company would have adequate resources to meet its retail and wholesale obligations. Even then, the analysis only indicated a need for approximately 85 MW of new resources. Tr. 400-01. The statement in RAMPP 5 simply does not provide a basis for concluding that the Company actually operated so as to balance its long-term wholesale sales with wholesale purchases.

The Committee's and UAE/Nucor's assumption that all of the obligations under the long-term firm contracts at issue were served out of energy obtained through short-term firm purchases is contrary to the Company's strategy with respect to the long-term firm contracts. Specifically, "the intermediate- to long-term contracts signed during the 1996-98 period were timed to expire at about the time that the Company's resources were expected to become fully necessary to serve retail load." Ex. UP&L 3R at 11. And in practice, the Company actually matched very closely its long-term wholesale sales decisions with its available long-term resources. Ex. UP&L 3R at 13-14. More importantly, the Committee's and UAE/Nucor's assumption is proved wrong by the Company's actual volumes of short-term purchases and sales. Company witness Watters presented evidence regarding the level of net short-term purchases during the test period. Ex. UP&L 3.9R. Mr. Watters showed that the Company's net short-term firm purchases during the test-period, adjusted to reflect the effects of the sale of Centralia, amounted to only 1.9 million MWhs.[9] *Id.*; Tr. 1279. Yet, the premise behind the Committee's and UAE/Nucor's proposed imputations is that all long-term firm sales are supplied by the Company's short-term firm purchases. Obviously, 6.2 million MWhs of long-term sales (Ex. DPU 8.13SR) cannot be fully supplied out of 1.9 million MWhs of purchases. Nor could the 4.5 million MWhs on which the Committee seeks to impute revenues (Tr. 864-65) be supplied out of 1.9 million MWhs of short-term firm purchases.

The fallacy of the premise upon which the Committee and UAE/Nucor rely is also shown by Mr. Yankel's graph presented in his surrebuttal testimony, depicting all the hours during the first three days of January 2000 in which PacifiCorp was a *net seller* of short-term firm. Ex. CCS 7SR at 5. Mr. Yankel inexplicably takes the position that even during those hours when PacifiCorp was a net seller of short-term firm, it was somehow meeting its long-term firm obligations with short-term firm purchases.[10] Tr. 862-73.

As shown, the premise and assumption of the Committee and UAE/Nucor that the Company serves all its long-term sales obligations out of short-term firm purchases, is false. That false premise is at the very foundation of their proposed imputations, since their imputations are calculated based on the price of the Company's short-term firm purchases. Accordingly, their proposed imputations must be rejected.

---

[9] The adjustment regarding Centralia is necessary to eliminate the MWhs purchased for the purpose of replacing the generation that the Company would have obtained from Centralia if it still owned its interest in the plant.

[10] Mr. Yankel did not net out long-term firm MWhs in arriving at the net seller positions. Tr. 872. Thus, he cannot claim that his graph reflects hours when PacifiCorp was a net seller of short-term firm *after* using short-term firm to meet long-term firm sales obligations.

D. The Commission Should Reject the Proposed Adjustments for Short Term Firm "Losses".

1. DPU/CCS Witness Falkenberg's Adjustment is Based on a Simplistic Comparison of Monthly Purchase and Sales Prices, and Incorrectly Concludes that "Losses" Occur.

DPU/CCS witness Falkenberg proposes an adjustment to remove the "losses" from short-term firm transactions. Mr. Falkenberg calculated his adjustment in the same manner as the Committee's adjustment in Docket No. 99-035-10. In that case, a $6.7 million adjustment was calculated by setting the monthly purchase price equal to the monthly sales price (*i.e.*, disallowing the purchase price to the extent it exceeds the sales price). Mr. Falkenberg calculated the adjustment in the same manner in this proceeding, which results in a disallowance of $46.9 million on a Total Company basis, or $17.3 million for Utah. In calculating his adjustment, Mr. Falkenberg performed no analysis of the underlying transactions, but simply performed the straightforward mathematical exercise of subtracting the sales price from the purchase price and disallowing the difference. Tr. 1139.

This methodology is fundamentally flawed, and results in charging the Company with "losses" when no losses in fact occur. Mr. Falkenberg's approach assumes that there is a "loss" whenever the monthly purchase price exceeds the monthly sales price. This simplistic method to determine the profitability of short-term firm transactions does not adequately measure the profitability of transactions undertaken to handle the complex process of balancing and optimizing the Company's system. Mr. Falkenberg's proposed adjustment uses a simple average method that does not take into account time and product related differences.

Two examples illustrate the point. Cross-Exam Ex. 23 is the Company's response to CCS Data Request No. 8.7. It shows that under the simplistic type of analysis performed by Mr. Falkenberg, it appears that the Company incurred a "loss" on transactions at "COB N-S" during

January 2000: the average purchase price was $28.30 per MWh, while the average sales price was $27.55. (Mr. Falkenberg's "analysis" would simply subtract the $27.55 from the $28.30 and disallow the difference.) In fact, as demonstrated in the Company's response, *no "loss" was incurred at all when the transactions are properly analyzed and separated between on-peak and off-peak transactions*. The on-peak price for sales ($29.57/MWh) exceeded the on-peak price for purchases ($29.22/MWh), and the off-peak price for sales ($24.42/MWh) exceeded the off-peak price for purchases ($24.00/MWh). Only by combining all the transactions and disregarding the difference between on-peak and off-peak can a "loss" be generated, and that is precisely the mathematical exercise performed by Mr. Falkenberg. Mr. Falkenberg did not disagree with the analysis presented in Cross-Exam Ex. 23; his adjustment simply did not consider individual transactions "because that's not the methodology that was used in the last case." Tr. 1144.

A second example is discussed in Mr. Widmer's rebuttal testimony. Given the Company's load profile, it is difficult to match loads and resources perfectly with single transactions. As a result, it generally takes multiple transactions to balance the Company's system for a given period. For example, during a typical summer day on the east side, the Company is generally short during the peak or super-peak periods and long during the off-peak and shoulder-peak periods. Ex. UP&L 5.6R at 1. When the Company purchases energy to cover its short position, there are generally two impacts. First, the shortage is covered by the most valuable component of the block purchase, the super peak period. Second, the Company is put in a long position, during the lower cost shoulder hours of the peak period, because demand is lower during the shoulder hours. Ex. UP&L 5.6R at 2. In order to balance the system, the Company must then sell the lower value long position. In this example, a monthly comparison of these transactions – such as performed by Mr. Falkenberg – would generally show a loss because the Company bought a higher value product to cover its short position and sold the leftover lower value product to balance the long created by the purchase that covered the short. Once again, in reality a "loss" was not incurred; rather, the Company merely balanced its system. This situation occurs very often in the Company's east side system during the summer season and demonstrates why it is critical to do a more detailed analysis.

When confronted with such situations, Mr. Falkenberg replies that it is "not possible to develop a 'clean' analysis on hourly basis since transactions may be up to 1 year long." Ex. DPU 9SR at 3. In other words, he admits that the analysis is deficient. Yet the Company is being charged with "losses" in the magnitude of $46.9 million, without a supporting "analysis" that withstands even a minimum amount of scrutiny. The proper response is that this adjustment is a complete and utter fabrication that should be rejected as lacking foundation.

Mr. Falkenberg's other defense is that the adjustment must be proper because the "percentage of on-peak purchases [is] virtually [the] same as percentage of on-peak sales (65.1% vs. 63.5%)." Ex. DPU 9SR at 3. Yet in the months where he proposes the largest adjustments – June and July – this comparison does not hold at all. In June, the percentage of on-peak purchases exceeds on-peak sales by 13.8% (85.3% purchases versus 71.5% sales), and in July the percentage difference is 11.4% (77.0% purchases versus 65.6% sales). (Source: Ex. UP&L 5.8R and 5.9R) When the Company makes more purchases than sales on-peak, "losses" are suggested under the simplistic Falkenberg "analysis." This is precisely what occurs in June and July – the months which produce the majority of the disallowance proposed by Mr. Falkenberg – and it is thus completely disingenuous for Mr. Falkenberg to claim that the "percentage of on-peak purchases [is] virtually [the] same as percentage of on-peak sales."[11] This statement is as false as the premise underlying this entire adjustment, which should be rejected by the Commission.

---

[11] CCS submitted a late-filed exhibit which provided back-up data for the 65.1% purchases and 63.5% sales percentages used by Mr. Falkenberg. Yet this exhibit demonstrates the same point: During the months of June and July, the level of purchases far exceed s the level of sales (71% versus 54% for June and 62% versus 52% for July), and the relatively equivalent figure on an annual basis is meaningless.

2. <u>UIEC Witness Chalfant's Adjustment is Based upon Out-of-Period Data, and Fails to Take Account of Differences in Product, Timing and Delivery Location.</u>

UIEC witness Chalfant proposes to reduce the Company's net power costs for "losses" on short-term firm and non-firm sales and purchase transactions he calculated, based on an hourly model he developed. The adjustment would reduce the Company's net power costs by $44.7 million on a Total Company basis, or $16.6 million for Utah. Revised Ex. UIEC 2.2, Schedule 2.

Mr. Chalfant's adjustment is flawed in its calculation in two respects. First, his adjustment uses data from October and November 2000, which are beyond the test period in this proceeding (which ends on September 30, 2000). This data is not consistent with the rest of the Company's case, and therefore is not valid for use in this case. Removing the October and November 2000 data reduces the size of the adjustment to $32.4 million on a Total Company basis, or $12.1 million for Utah. Rev. Ex. UIEC 2.2, Schedule 2.2. Second, actual non-firm transactions should be excluded since retail rates are set on the basis of normalized non-firm sales and purchase transactions calculated by the Company's net power cost model.

Notwithstanding these two errors in calculation, Mr. Chalfant recognized that it is imperative to compare relevant sales and purchase transactions on a comparable basis, not on a monthly or annual aggregated basis, to achieve a valid comparison. Specifically, he stated the following:

> It is critical to avoid time-related differences in comparisons of costs and revenues to be assigned to the power marketing function. For example, it would not be reasonable to compare a purchase made on a summer afternoon with a price of $10 per MWh to a sale that was made on a winter night with a price of $3 per MWh and conclude that the Company lost $7 on that pair of transactions. In fact, the Company may have been selling for $12 per MWh at the same time the $10 per MWh purchase was made, and purchasing for $2.75 per MWh at the same time the $3 sale was made.

> Using aggregate annual or monthly data on short-term sales and purchases implicitly involve such comparisons. Specifically, if purchases tend to occur more heavily during hours when market prices are high and sales tend to be made at hours when market prices are low, then comparing average sales and purchase prices may not give an accurate picture of whether the Company's marketing activities are profitable.

Ex. UIEC 2 at 10.

Despite Mr. Chalfant's effort to consider timing differences between transactions, however, his analysis does not adequately calculate the profitability of short-term transactions. At least three additional major changes to Mr. Chalfant's proposed adjustment are necessary to correct the inadequacies of his analysis: (1) the transactions should be reviewed based on the time they were executed in addition to an hourly comparison, (2) the transactions should be compared on a like-kind product basis, and (3) the transactions should be compared on a similar location basis because of transmission constraints that exist in the Company's system.
Ex. UP&L 5R at 16.

With respect to the *time of execution*, the process of balancing the Company's system is a complex, ongoing process that starts well in advance of the actual delivery time. During the time leading up to delivery, the Company's load and resource balance can change frequently (higher or lower) due to a number of factors. Those factors include higher than expected retail load growth, unit outages, weather and hydro conditions. The Company generally makes both sales and purchases in advance of real time in an effort to keep loads and resources in balance at the lowest possible cost. Because of this, it is imperative that transactions executed months ago for delivery today not be compared with transactions executed very recently. Unless the timing of the prudent transactions are taken into consideration, it may appear that the Company sold energy at a loss when, in reality, the transactions were prudent because they were executed at market based upon expectations at the time of the transactions. Accordingly, it is essential that execution dates are taken into consideration as well as delivery time differences. Ex. UP&L 5R at 17-18.

With respect to *like-kind product basis*, it must be kept in mind that it generally takes multiple transactions to balance the Company's system for a specific period, given the Company's load profile and the difficulty of matching loads and resources perfectly with single transactions. For example, as noted above, the Company is generally short during the peak or super-peak periods during a typical summer day on the east-side. At the same time, the Company is long during the off-peak and shoulder-peak periods. Accordingly, there are two related impacts when the Company purchases energy to cover its short position: (1) the shortage is covered by the most valuable component of the block purchase, the super peak period, and (2) the Company is put in a long position, during the lower cost shoulder hours of the peak period, because demand is lower during the shoulder hours. In order to balance the system, the Company then sells the lower value long position. These transactions can be evaluated fairly only if the products are compared on a like-kind basis. A comparison such as performed by Mr. Chalfant would generally show a loss because the Company bought a higher value product to cover its short position and sold the leftover lower value product to balance the long created by the purchase that covered the short. Ex. UP&L 5R at 19-20.

With respect to *delivery location points*, it must be recognized that transactions may not be comparable because of transmission constraints on the Company's system. For example, the Company could be long on the west-side during the summer and deficit on the east-side. Transmission constraints prevent the Company from moving the entire surplus from the west-side to cover the deficit in the east. In order to balance the system, the Company must sell some energy in the lower priced west-side and buy some energy in the higher priced east-side at the same time. Once again, a comparison of those transactions would show a loss when in reality a loss was not incurred. Mr. Chalfant's model aggregates these types of transactions to determine profitability without regard for delivery points, when in fact these transactions cannot be aggregated in this manner as they are not comparable. UP&L 5R at 20-21.

Mr. Widmer performed an analysis of the June and July data to take these factors into account. These months were chosen because they encompass the bulk of Mr. Chalfant's and Mr. Falkenberg's proposed adjustments and are sufficient to demonstrate that the purported "losses" are not real. Page 1 of Ex. UP&L 5.8R summarizes the purported June "losses" from Ex. UP&L 5.7R between peak and off-peak transactions. This comparison reduces the purported "losses" for June from $24 million to $22.5 million or $22 million on-peak and $.5 million off-peak on a Total Company basis. Page 2 of Ex. UP&L 5.8R summarizes the data from page 1 by delivery day and breaks the information down between gains and losses. Page 3 of Ex. UP&L 5.8R recalculates the information from page 2 based on comparable delivery and execution dates. This shows that the purported level of "losses" drops to $5.9 million for on-peak transactions and $.4 million for off-peak transactions on a Total Company basis. Page 4 of Ex. UP&L 5.8R analyzes the losses of the four purported highest loss days shown on page 3 by comparable delivery points. This analysis shows that when comparable delivery points are taken into consideration all of the purported "losses" occurred at the Four Corners delivery point. Page 5 of Ex. UP&L 5.8R analyzes the Fours Corners transactions from page 4 that generated the losses. This data shows that the purported losses are reduced from over $5 million to zero when the transactions are reviewed on an hourly basis.[12]

[12] Page 1 of Ex. UP&L 5.9R summarizes the purported July losses from Ex. UP&L 5.7R between peak and off-peak transactions. This comparison reduces the purported "losses" for July to a $4.5 million net monthly gain from a $6 million monthly "loss" when the transactions are broken down between peak and off-peak transactions, or to a $7.3 million on-peak gain and $2.8 million off-peak loss on a Total Company basis. Page 2 of Ex. UP&L 5.9R summarizes the data from page 1 by execution day for the off-peak transactions. This data reduces the purported off-peak "losses" from $2.7 million to $.8 million. Page 3 of Ex. UP&L 5.9R recalculates the information from page 2 based on comparable delivery and execution dates and delivery points. This data shows that almost all of the purported off-peak "losses"

Ex. UP&L 5.9R shows similar information for July. The analyses from these exhibits demonstrate that when the short-term firm transactions for June and July 2000 are analyzed on a fully comparable basis, there are no material losses. Accordingly, Mr. Chalfant's proposed adjustment to reflect "losses" is unfounded, and should be rejected.

E. The Commission Should Accept the Company's Proposed Annualization of Market Power Prices.

1. The Company's Annualization Adjustment Captures the Increase in Purchased Power Costs that the Company Experienced in 2000 and Will Continue to Experience.

At issue is the extent to which the dramatic increase in wholesale prices which occurred in the latter half of the test period will be captured in rates on a going-forward basis. In contrast to the adopted net power cost in the Company's last Utah rate case of approximately $426 million on a Total Company basis, the Company's actual net power costs for 2000 were approximately $833 million on a Total Company basis. Most of this increase is attributable to the extraordinary increase in purchased power costs which began during May 2000 as a result of the western energy crisis. The test period in this proceeding – the twelve months ended September 30, 2000 – thus reflects only about four months of these higher power costs – the months of June, July, August and September. Actual net power costs during this twelve month period were $602 million, far short of the $833 million actually incurred by the Company during calendar year 2000. To set power costs at a level which reflects the increased wholesale market

were related to Four Corners transactions, as was the case in June. Page 4 of Ex. UP&L 5.9R analyzes the Fours Corners transactions from page 3 on an hourly basis. This information shows that the purported "losses" are reduced from $.8 million to .05 million when the off-peak transactions from page 3 that generated the purported losses are reviewed on an hourly basis.

prices , the Company "annualized" the data from June, July, August and September 2000 to spread the impact of higher wholesale market prices throughout the twelve month test period.[13]

In the Company's view, the type of annualizing adjustment it proposes is consistent with historical ratemaking treatment the Company has received in the state of Utah. Ex. UP&L 5R at 6. For example, if a wholesale contract has a price change at some time during the test year, the change is typically annualized to the beginning of the test year in the net power cost study. Similarly, if a contract terminates during the test year, the termination is annualized to the beginning of the test year. Following that same logic, the Company annualized the significant wholesale market price increases that affected the Company and the rest of the WSCC since spring 2000.

2. The Company's Annualization Adjustment Complies with Commission Rule 746-407.

In 1990, the Commission adopted a rule governing the annualization of data when changes occur *within* a test period. According to the rule, "annualization" is defined as "adjustments made to test-year data to reflect the partial period effects of events that occurred or

---

[13] The Company's market price annualization included several steps:

- First, the Company calculated the monthly average for each month from the year of inception to year-end 1999 for each index (Mavg);
- Second, the Company calculated the 12-month average of the above monthly averages (Aavg) and the average of June through September (JSAvg), and the ratio of the June-September average over the annual average (Ratio = JSAvg / Aavg);
- Third, the Company calculated the average actual prices for the period June 2000 through September 2000 (JSavg2000). The annualized average price (Aavg2000) for 2000 is determined by dividing the ratio developed above into the actual average price for June-September 2000: (Aavg2000= JSAvg2000/Ratio).
- Fourth, the annualized monthly prices (MP) for the period October 1999 through May 2000 are determined from the annual average price (Aavg2000) for 2000 multiplied by the monthly average index price (Mavg), divided by the annual average (Aavg). (MP = Aavg2000 * Mavg / Aavg)

The Company used the entire history of the indexes since their inception, except year 2000, to develop the monthly shape of the prices. The annualized market prices for the test year were determined based on that shape and the prices in the months (June-September) that showed significant price increases during the test period.

were ongoing during only a portion of the test year and are either recurring or have terminated." (R746-407-2(A)) Annualization under the rule will be allowed if:

- the change is "known to occur at a specific moment or moments in time" (R746-407(3)(D));
- "the effects of the change [are] measurable" (R746-407(3)(E));
- the change occurs on or before the effective date of a final Commission order (R746-407(3)(F)); and
- the change is "expected to be ongoing after final rates become effective." (R746-407(3)(G))

The high market prices incurred during the test year are certainly known to the entire WSCC. Mr. Widmer's direct testimony, Ex. UP&L 5, and supplemental direct testimony, Ex. UP&L 5S, describe the actual market prices experienced by the Company during the test period, and the specific times in which these higher prices began to appear. The impact of the high market prices is certainly measurable also. As described in Mr. Widmer's direct testimony, 2000 market prices were drastically higher than 1999 market prices, and they did not decline after the end of the test period. As a matter of fact, market prices were substantially higher after September 30, 2000 than those included in the Company's case.

Moreover, these increased market prices are expected to continue after the effective date of higher rates in this proceeding. Ex. UP&L 5S.3 shows the average short-term purchase prices paid by the Company over various time periods. Under the annualization adjustment proposed by the Company, the price for short-term purchases during the test period is $108.30/MWh, which is nearly double the actual price paid during the test period of $51.42/MWh. Actual prices paid by the Company for the period beginning May 2000 through March 2001 were $108.41/MWh, which is nearly the same as the annualized price. This confirms the correctness of the Company's methodology and the reasonableness of the resulting figure. After March 2001, the prices paid by the Company are actually higher than this annualized figure. For the 12 months ending May 2001, the figure is $125.92/MWh, and for the 12 months ending September 2001, the figure is $142.93/MWh. For the 12 months ending March 2002, the short-term purchase price is $112.30/MWh. Thus, the Company has demonstrated that the change in wholesale prices is "expected to be ongoing after final rates become effective," as required by Rule 746-407(3)(G). In fact, the Company's annualized figure of $108.30/MWh appears conservative when compared to the prices that are expected to prevail after the rate-effective date.

The impact of the FERC-imposed cap on wholesale energy prices is expected to produce lower market prices today and through the remainder of the year. Unfortunately, the Company's previously executed forward purchases are now higher priced than the current forward price curve. This has effectively eliminated the prior expected benefits of the Company's forward purchases, which had the effect of driving the lower expected net power costs for the second half of 2001, referred to by Mr. Falkenberg. Ex. DPU 9 at 10. As a result, the Company now expects net power costs for 2001 to be substantially higher than the $760 million previously forecasted. Ex. UP&L 5R at 5. Mr. Chalfant, for his part, claimed that the effect of the FERC price cap would "reduce PacifiCorp's revenue requirement." Ex. UIEC 2R at 6. But his conclusion was "strictly based on arithmetic" with "no actual logic involved," and failed to take into consideration the Company's forward purchases prior to FERC's imposition of the price cap. Tr. 1019-20.

3. <u>The Annualization Adjustment Can Be Adopted Even if it does not Technically Comply with Commission Rule 746-407.</u>

Whether or not the Company's annualization adjustment meets the technical requirements of Commission rule 746-407, the Commission can adopt the annualization adjustment. The concept of annualization is a general ratemaking principle, and can be applied by the Commission in the absence of Rule 746-407. Re Utah Gas Co., 11 P.U.R.4th 314, Case No. 7117 (Utah Pub. Serv. Comm'n, September 23, 1990); Re Utah Power and Light Co.,. 30 P.U.R.4th 197, Case Nos. 7167, 76-035-06, 78-035-14 (Utah Pub. Serv. Comm'n, May 2, 1979) (additional revenues collected in an annualized amount were "lawfully and properly collected in all respects"); Re Utah Gas Service Co., 28 P.U.R.4th 487, Case Nos. 78-059-07, 78-059-08 (Utah Pub. Serv. Comm'n, March 29, 1979) (using annualized data to approve increased rates in light of higher gas prices resulting from Natural Gas Policy Act). The annualization of test year data is a matter of general ratemaking, not merely a creature of regulation. Indeed, annualization was a process routinely applied in rate proceedings before the rule was even contemplated. For example, in Re Utah Gas Co., 11 P.U.R.4th 314, Case No. 7117 (Utah Pub. Serv. Comm'n, September 23, 1990), the Commission adopted a gas company's figures that were annualized for known changes during the test period but also were adjusted to account for the effect of an upcoming change in the company's billing system. There, the Commission authorized the company's new schedule of rates and charges based on the annualized data. The annualization rule is not the exclusive means to annualize test year data. On the contrary, it is entirely reasonable and consistent with prior commission precedent to adopt annualized figures, even if those figures to not comply with the rule.

Moreover, the annualization rule is more appropriately termed as a guideline or policy, not a conservatively interpreted hard and fast rule. Indeed, the Commission itself has referred to the rule in those very terms. Re Mountain Fuel Supply Co., 1990 WL 509865, Docket No. 89-057-15 (Utah Pub. Serv. Comm'n, November 21, 1990) (describing rule as prescribing annualization test year guidelines); Re Mountain State Telephone and Telegraph Co., 71 P.U.R.4th 598, Case No. 85-049-02 (Utah Pub. Serv. Comm'n, December 31, 1985) (division's proposed annualization method was consistent with the division's "proposed annualization policy.") The rule is a non-exclusive means to annualize test-year data. To otherwise limit annualization to the guidelines outlined in the rule would create the potential to reach an unjust or unreasonable result in cases that do not fully comply with the rule's approach. Accordingly, strict compliance with the rule is not necessary before data can be annualized. Thus, the Company's annualization adjustment can be adopted even if the Commission determines that it technically does not comply with Rule 746-407.

4. <u>Neither DPU/CCS Witness Falkenberg and UIEC Witness Chalfant Provide a Basis for Rejecting the Annualization Adjustment.</u>

Both CCS/DPU witness Falkenberg and UIEC witness Chalfant recommend rejection of the Company's market price annualization adjustment. Mr. Falkenberg claims that the Company has failed to comply with the annualization rule, R746-407.2D, G. As described above, however, the Company submits that its proposal meets the requirements of the rule and, in any event, that the Commission can accept the adjustment irrespective of technical compliance with the rule. Moreover, Mr. Falkenberg's testimony on its face is internally inconsistent on this point, as he suggests that the lower market prices that occurred at the beginning of the test period are more appropriate. At the same time, however, he states that "it is quite questionable as to whether 'normal' conditions actually exist anymore. . . . It may be some time before the market returns to a state of surplus and attendant lower prices." Ex. DPU –9 at 18.

Mr. Chalfant, for his part, makes the incredulous statement that it is not "obvious whether these subsequent price changes had a negative or positive impact on PacifiCorp's costs and revenues, for example, because, they may have had a greater impact on sales than purchases and, as a result, increased revenue more than costs." Ex. UIEC 2 at 6. In fact, high market prices have driven the Company's net power costs up substantially, as described above. Net power costs have risen from the $426 million figure on a Total Company basis adopted in the

Company's 1998 Utah rate case to $833 million on an actual basis for 2000. Of these costs, approximately $68 million are for replacement power purchases for the Hunter outage. Ex. UP&L 5R at 12. It is obvious that high market prices have had a negative impact on the Company, even though prices weren't high for the entire year. That it is not obvious to this witness provides a strong suggestion regarding the weight to be given Mr. Chalfant's testimony.

Mr. Chalfant makes the further curious statement that the Company should file a rate case "after it has data that fully reflects what it argues are long-term changes in market prices, rather than to make incorrect adjustments to historical data." Ex. UIEC 2 at 6. As described in Ms. Clark's rebuttal testimony, the significant cost increases experienced by the Company from high market prices have caused the Company to suffer credit and liquidity problems. Ex. UP&L 2R. Therefore, Mr. Chalfant's suggestion that the Company should wait for a test year that fully reflects higher market prices is a solution that is belied by the realities of the financial marketplace.

F. The Commission Should Continue to Use a 4-Year Average in Determining the Thermal Availability of the Company's Generating Units, and Reject the Various Adjustments to Thermal Availability Factors Proposed by the Parties.

1. <u>Neither CCS/DPU Witness Falkenberg Nor USEA Witness Herz Have Provided Any Basis for Departing from the Historical Practice of Using a 4-Year Average for Determining Thermal Availability.</u>

CCS/DPU witness Falkenberg proposes an adjustment based on what he claims is an increase in the Company's average scheduled and unscheduled outage rates. Ex. DPU 9 at 31. Following an historical practice in effect since the Utah/PacifiCorp merger more than ten years ago, the Company uses a four-year rolling average of scheduled and unscheduled outages for the Company's thermal generators as an input in its net power cost model. For this proceeding, the Company proposed to use the four-year period 1996-99. Mr. Falkenberg proposes to use a six-year average, which produces an adjustment of $45.6 million on a Total Company basis, or $16.9 million for Utah, to the Company's net power costs. Ex. DPU 9SR at 4. Mr. Herz, for his part, proposes a similar adjustment. Ex. USEA 1 at 14.

Mr. Falkenberg's analysis is based upon selective years' data that result in a misleading impression of the Company's actual performance. In fact, the Company runs its thermal units exceptionally well (as compared to industry standards), and its performance has changed very little from prior years. Ex. UP&L 5R at 27. Mr. Falkenberg's adjustment is based on the selective use of data from particular years to create an unrepresentative statistic.

Ex. UP&L 5.10R is a summary of the Company's actual forced outage rates compared to the industry average for the last 10 years. That information shows that the Company runs its thermal units exceptionally well, as compared to industry averages. From 1991 through 1999, the Company exceeded the industry average in all years except one. From 1991-99 the Company exceeded the industry average by approximately 23.7 percent on average and expects that it exceeded the industry again in 2000 based on the Company's performance. Ex. UP&L 510R. Thus Mr. Falkenberg's suggestion that the Company's thermal unit performance is "unsatisfactory" is unfair under any objective standard.

The basis for Mr. Falkenberg's adjustment seems to be that the four-year period used by the Company is "unrepresentative" and should be replaced with a six-year average which he claims is "more representative of future conditions." Ex. DPU 9 at 32. The data do not support this claim, however. Table 1 below, which is excerpted from Ex. UP&L 5.10R, shows that the four-year average proposed to be used by the Company is representative and should not be discarded.

Table 1
PacifiCorp Forced Outage Rates

Year	Outage Rate
1991	4.99
1992	3.65
1993	5.50
1994	3.73
1995	4.08
1996	4.10
1997	4.58
1998	4.15
1999	5.63
2000	4.41
Average 1991-2000	4.48
Average 1996-99	4.62
Average 1994-99	4.38

As shown in Table 1, the Company's forced-outage rates are a slight 0.14 percent higher for the 1996-99 average than the 10-year average from 1991 to 2000. This is certainly within a reasonable range of variation and does not provide justification for throwing out the four-year average as "unrepresentative." Moreover, as shown in Table 2 below, when equivalent availability statistics are considered, it is the six year period proposed by Mr. Falkenberg that appears to be out of line with the 10-year average (89.41% versus 89.12%), while the four-year average proposed to be used by the Company (89.16%) is virtually the same as the 10-year average. (Source: Ex. UP&L 5.11R.

Table 2
PacifiCorp Equivalent Availability

Year	Equivalent Availability
Average 1991-2000	89.12%
Average 1996-99	89.16%
Average 1994-99	89.41%

Moreover, it is Mr. Falkenberg's selective use of data and high market prices that gives rise to his adjustment. The starting point of his analysis was the year the Company reported its second lowest forced-outage rate over the last 10 years (3.73 in 1994), while the ending point was the year with the highest forced outage rate over the last ten years (5.63 in 1999). Comparing the two produces Mr. Falkenberg's referenced "50% increase." Ex. DPU 9 at 31. Over the representative period proposed by the Company, however, the Company's performance has been very much in line with its historical performance. In addition, Mr. Falkenberg indicates that the changes result from changes in market prices. Ex. DPU 9 at 33.

Mr. Falkenberg's "analysis" and the claim of "unsatisfactory performance in today's industry" have more to do with the starting point and the level of market prices than the Company's actual performance. Ex. UP&L 5.12R shows the current case net power cost results if 1997 and 1998 market prices are used with availability factors for each of the years 1994 through 1999, compared with the runs that Mr. Falkenberg made for the comparable years. The data clearly shows that when a lower price level is used the changes in generation levels have a limited impact on overall net power costs. For example, using the market prices from the Company's 1997 Utah stipulation shows that the difference between a four-year average and a six-year average only produces a Total Company difference of $8.1 million. Using the adopted market prices from Docket No. 99-035-10 produces a difference of $12.8 million. In comparison, Mr. Falkenberg's Ex. DPU 9.8, which uses the much higher market prices included in the Company's filing, produces an $82.3 million difference between four and six-year averages. Thus, the main driver of the increase in net power costs is market prices, not thermal availability.

Mr. Falkenberg's and Mr. Herz's proposed adjustments for thermal availability should be rejected.

2. USEA Witness Herz's Adjustment to Increase the Maintenance Cycles from 4 Years to 6 Years is Unsupported, and Should be Rejected.

USEA witness Herz proposes to calculate maintenance outage hours over a 6-year period rather than the 4 years currently used by the Company. Ex. USEA 1 at 21. Although stated as a separate adjustment, this proposal is, for all practical purposes, the same as the Thermal Availability adjustment discussed above, where Mr. Herz proposes to use a 6-year rather than a 4-year average for purposes of calculating thermal availability. (Maintenance outages obviously affect the availability of thermal generating units.)

In an effort to offer an independent rationale for use of a 6-year maintenance cycle, Mr. Herz suggests that a longer period "would *be more likely to* incorporate the long-term maintenance cycle that is commensurate with large coal-fired generating units." Ex. USEA 1 at 21-22. Yet Mr. Herz included no analysis or technical information regarding maintenance cycles that would support his "theory" that six years is more representative than four. Tr. 1067. In fact, given that PacifiCorp has thirty thermal generating units on its system (Ex. USEA 1.3), it is not necessary to move to a six-year average in order to produce a representative level of maintenance outage hours: the sample is large enough to reflect whatever maintenance interval is used. Mr. Herz is proposing to use six years rather than four for the same reason as his thermal availability adjustment: it produces a lower number of outage hours, and therefore results in lower net power costs. This adjustment is unsupported in the record, and should be rejected.

3. USEA Witness Herz's Proposal to Adjust Monthly Maintenance Schedules is Based Upon an Incomplete Analysis, and Should be Rejected.

Mr. Herz's proposal to move some of the Company's thermal maintenance from June to either April or February is designed to capture the lower prices for those months. In fact, Mr. Herz based his analysis solely on the lower power costs which occur in those months, without considering the other factors that the Company must take into account in developing its maintenance schedule. Other factors that also need to be considered are the availability of Company and contract workforces to perform the maintenance, contractual issues, and weather. Ex. UP&L 5R at 55. Mr. Herz's proposal results in two of the Company's Wyoming coal plants (Jim Bridger 1 and Wyodak) being scheduled for maintenance in February, for example, which involves weather impacts not taken into account by Mr. Herz. Tr. 1071-72. On this point, Mr. Herz claimed incorrectly that Cross-Exam Ex. 21, an actual maintenance schedule of the Company, supported his rescheduling of Wyoming coal units to February. In fact, that document shows none of the Company's Wyoming generating units being scheduled for maintenance in February. Tr. 1072. Apart from weather circumstances, it is necessary to plan major outages in advance, at which time the expected market conditions may be different from actuals. An example of this is the spring of 2000, which had higher prices than the preceding winter. Ex. UP&L 5R at 55. The Company's modeling of thermal maintenance is appropriate, and Mr. Herz's proposal to shift some maintenance should be rejected by the Commission.

4. CCS/DPU Witness Falkenberg's Proposed Adjustment to Thermal Availability Factors to Reflect Extended Cholla Outage Is Not Warranted, and Should be Rejected.

Mr. Falkenberg proposes to remove a 1996 outage at the Company's Cholla 4 generating plant in computing the average availability factor for the plant as a consequence of the Commission allowing the Company to defer replacement power costs associated with the Company's Hunter 1 failure. Ex. DPU 9 at 43-44. This adjustment is not warranted, and should be rejected. First, the adjustment presumes that the Commission will grant rate recovery of the Hunter deferrals, a determination that has not yet been made. Second, there are several important differences in the circumstances surrounding the two outages. For example, the Company did not file to recover replacement power costs associated with the Cholla 4 overhaul outage. (Of course, had the Company recovered replacement power costs for the overhaul outage, it would have been appropriate to exclude it from the Company's normalized thermal availability calculation.) Moreover, the Hunter 1 outage was a catastrophic failure of a generating unit during a peak season, while the Cholla outage was a planned major overhaul outage which occurred at a time when replacement power costs were relatively inconsequential. Ex. UP&L 5R at 47. Therefore, Mr. Falkenberg's suggestion that the two events are similar is false, and there is no basis for his proposed adjustment.

G. The Commission Should Continue to Use the $37/MWh Price from the Renegotiated SCE Contract as the Surrogate Price for the SMUD Agreement.

In the Company's previous general rate proceeding (Docket No. 99-035-10), the Commission adopted a revenue imputation in connection with the Company's contract with the Sacramento Municipal Utility District, or SMUD. This contract, entered into in 1987, allows SMUD to acquire electricity from the Company at rates that have been determined by the Commission to be "below market," and thus requiring a revenue imputation. As the Commission stated in its Order in Docket No. 99-035-10:

> 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. (Order, p. [46])

In Docket No. 99-035-10, the Commission adopted a figure of $37 per MWh, based on a renegotiated contract between Southern California Edison ("SCE") and the Company. (This SCE contract had been previously used for revenue imputation purposes as a contemporaneous contract reflecting a market rate.) The SCE contract was renegotiated in 1995, and the $37 per MWh rate represented the expected sale price under the SCE contract for the first year the renegotiated contract was in effect. Ex. UP&L 5R at 43. The Company in this proceeding proposes to continue using the $37 per MWh figure as the basis for the revenue imputation, consistent with the Commission's decision in Docket No. 99-035-10. (This rate would provide an adjustment level that is consistent with the adjustment included in Docket UE 116 in a Stipulation with the Commission Staff on the SMUD issue.)

CCS/DPU witness Falkenberg proposes to adjust the SMUD contract price to $47.7 per MWh, which represents the price under the SCE contract during the test period. Ex. DPU 9 at 36. This adjustment would reduce the Company's net power costs by $11.5 million on a Total Company basis, or $4.3 million in Utah. Ex. DPU 9SR at 6.

As described above, the order from Docket No. 99-035-10 does not suggest that the Commission's intent was to impute SMUD revenues based on the actual SCE contract price during the test year. If that were the case, the price used in the revenue imputation from Docket No. 99-035-10 would have been $49.42 per MWh, the actual SCE price in 1999.[14] The price adopted by the Commission for revenue imputation, however, was $37 per MWh, or the sale price for the first year the renegotiated SCE contract was in effect. The methodology adopted by the Commission in the last case therefore does not suggest that the Commission intended to have the price imputation change yearly based on the actual SCE contract price for each successive test year, as proposed by Mr. Falkenberg.

The current terms and price of the SCE contract are not comparable to the SMUD contract and should not be used for the purpose of imputing revenues for the SMUD contract. Based on the terms of the renegotiated SCE contract, the price is expected to be almost $80 per MWh in 2001 because the energy price component is escalated based on the annual change in the Southern California border price of gas. Ex. UP&L 5R at 45. The annual effect of this adjustment would be approximately $22 million, which represents 25% of the $94 million up-

[14] In Docket No. 99-035-10, the Commission had available to it the information necessary to base the imputation on the actual SCE contract price during the 1999 test period, had the Commission intended to reach such a determination. Prices under the SCE contract were included as part of the Company's power cost data in that case, and thus the $49.42 figure was in the record. Mr. Falkenberg's claim on cross-examination that the Commission lacked the information to make such a finding is without merit. (Tr. at 1154-55).

front payment received by the Company from SMUD in 1987. Id. (The revenue imputation is justified, in part, as a means of flowing through to customers over time the benefits of this one-time payment from SMUD.) Considering that the SMUD contract does not expire until 2014 (*i.e.*, that 13 years remain on the contract), a proposal that suggests payment of 25% of the benefits in one year clearly over-compensates customers. Mr. Falkenberg's methodology, which ties the level of imputation to actual SCE contract prices each year, produces such an illogical result.

The continued use of the $37 per MWh imputation price adopted in Docket No. 99-035-10 continues to provide a reasonable outcome. The Commission should reject Mr. Falkenberg's proposed adjustment.

H. The Commission Should Reject Mr. Hayet's Proposed Calculation of Transmission Benefits from the Integrated System, and Accept the Company's Calculation of those Benefits, Which Reflect the Correct Transfer Capabilities and Transmission Constraints on Access to Wholesale Markets.

The Company's net power cost model as filed balances the Company's system on an east-side and west-side basis independently from the other. CCS/DPU witness Hayet proposes to adjust the model in a manner that purportedly reflects the ability to dispatch the system on an integrated basis. Ex. DPU 10 at 11-16. His adjustment, as originally proposed, would reduce the Company's net power costs by $32.5 million on a Total Company basis, assuming the Company's proposed market prices are adopted. If Mr. Falkenberg's proposed short-term firm and non-firm market price adjustment is adopted, Mr. Hayet's proposed adjustment would reduce the Company's proposed net power costs by $1.2 million on a Utah allocated basis.

The Company agrees that it is appropriate to model the Company's system on an integrated basis. In doing so, however, it is important to make sure that transfer capabilities and market sizes are stated correctly in order to achieve reasonable results. Mr. Hayet's original proposal included transmission modeling errors, including incorrect transfer capabilities from the eastern system to the western system. Mr. Widmer's Ex. UP&L 5.15R contains the correct transfer capabilities. Mr. Hayet, in his surrebuttal testimony, accepts these corrected transfer capabilities in his analysis. Ex. DPU 10SR at 5-6. A remaining difference, however, concerns Mr. Hayet's assumption that non-firm market sizes are unlimited. This assumption is not reflective of the Company's ability to buy and sell power. The Company's PD Mac power cost model recognized constraints on the Company's ability to move power into other markets, and Mr. Hayet did not take issue with those constraints in his analysis of the PD Mac model in previous cases. Tr. 1098. Mr. Hayet's modeling of the Company's system on an integrated basis in this case is wrong because it does not recognize such constraints and therefore is not representative of the Company's system. A calculation of market sizes that takes into consideration firm transmission rights to wholesale markets, existing transactions and various restrictions is provided in Mr. Widmer's Ex. UP&L 5.16R.

Mr. Hayet's concerns that the integrated system provides substantially more benefits than the Company's proposed adjustment is unfounded. As explained by Mr. Widmer, the bulk of the benefits of system integration are captured in the Company's STF transactions. Tr. 1188-89. The corrections reduce Mr. Hayet's proposed adjustment to $.8 million on a Total Company basis, which should be accepted as the correct calculation of the Company's system capabilities.

I. The Commission Should Reject the Proposed Adjustment to Capacity Ratings Proposed by CCS/DPU Witness Falkenberg and USEA Witness Herz.

CCS/DPU witness Falkenberg proposed a number of adjustments to the Company's capacity factors. In his direct testimony, Mr. Falkenberg claimed that (1) the Company understated the capacity of the Company's Wyodak and Gadsby plants and (2) the Company does not lose as much generation to spinning reserves as the Company has modeled. Based on these assumptions, he proposed to increase the generation levels for Wyodak and Gadsby and reduce the amount of spinning reserves the Company has modeled, thereby reducing the Company's net power costs by $16.5 million on a Total Company basis. In his surrebuttal testimony, Mr. Falkenberg (1) indicates that he "agree[s] with the Company's new spinning reserve modeling with some reservations," (2) agreed to adjust the Wyodak availability factor, (3) agreed that "Gadsby may run too much" under his proposal, and (4) claims that the Company's Gadsby adjustment "double-counts" the spinning reserve impact. (Ex. DPU 9SR at 5) These remaining capacity issues would reduce net power costs on a Total Company basis by $7.6 million, or $2.8 million for Utah. USEA witness Herz, for his part, proposes an adjustment to the Gadsby capacity factor. (Ex. USEA 1 at 19).

1. <u>Mr. Falkenberg's Modeling of Spinning Reserves Understates the Company's Cost of Carrying Spinning Reserves on its East-Side Thermal Units.</u>

Although Mr. Falkenberg states that he agrees with the Company's spinning reserve modeling with some reservations (Ex. DPU 9SR at 5), his modeling does not reflect this. As shown below in Table 3, Mr. Falkenberg's spinning reserve modeling is significantly lower than the Company's.

Table 3
Comparison of Spinning Reserves

	Company Rebuttal	**Falkenberg Rebuttal**	**Average Actual[15]**
January	79 MW	45 MW	81 MW
February	79 MW	45MW	65 MW
March	79 MW	45 MW	53 MW
April	79 MW	45 MW	41 MW
May	79 MW	15 MW	41 MW
June	79 MW	15 MW	84 MW
July	79 MW	100 MW	84 MW

[15] February 2000 through January 2001.

August	79 MW	45 MW	74 MW
September	79 MW	25 MW	72 MW
October	79 MW	40 MW	78 MW
November	79 MW	40 MW	84 MW
December	79 MW	40 MW	85 MW
Annual Avg.	79 MW	42 MW	70 MW

As shown in Table 3, the monthly amount proposed by Mr. Falkenberg varies from 15 MW to 100, a level of variability which in and of itself should cast doubt upon the methodology underlying his proposed adjustment. Mr. Falkenberg's modeling is based on his assumption that Company generally accounts for spinning reserves by bringing additional units on-line.
Ex. DPU 9 at 38. In general, the Company does not disagree with this assumption. However, it is not valid in this case because market price levels are substantially higher than fuel costs.
Ex. UP&L 5R at 38. As a result, the Company's production dispatch model, with the exception of Gadsby, dispatches thermal units at their availability factor levels. Therefore, it is not possible to bring additional units on-line. Mr. Hayet even recognized this point on page 23 of his testimony:

> In PacifiCorp's normalized net power cost case, the annual average cost for its plants ranges from $5.21/MWh for the Dave Johnston plant to about $42/MWh, for the Gadsby plant, while the cost of purchasing from the market is over $100/MWh. This is quite a disparity, and effectively results in the PacifiCorp units operating at the maximum capacity all of the time.

Ex. DPU 10 at 10. This is further substantiated by the fact that normalized thermal generation on the East-side, in Mr. Falkenberg's proposed net power costs, is over 1.0 million MWh higher than actual test period generation. Ex. UP&L 5R at 42. Therefore, either Mr. Falkenberg's proposed thermal generation level is too low or he has not modeled enough spinning reserves. In either case, his proposed net power cost do not reflect the true cost of spinning reserves. The Commission should reject his proposed spinning reserve modeling.

2. The Proposed Capacity Adjustments to Gadsby Would Result in that Unit "Running" Far in Excess of Its Actual Experience.

The Company's treatment of the Gadsby units reflects the actual operation of these units. For example, under the Company's modeling approach, the Gadsby units ran at an overall capacity factor of 49% compared to the 48% capacity factor the units actually ran during the period May 2000 through March 2001, a period with market prices higher than those included in the Company's case. Ex. UP&L 5R at 35. The adjustments proposed by Mr. Herz and Mr. Falkenberg do not reflect the absence of any market for Gadsby generation during off-peak hours. Unless the model inputs controlling Gadsby's generation are constrained, the model will run Gadsby too much. For example, using the Company's proposed market prices, Mr. Falkenberg's modeling would result in Gadsby running at a completely unrealistic 83% capacity factor. Tr. 444. The adjustments to Gadsby generation proposed by Mr. Herz and Mr. Falkenberg should be rejected.

3. The Company's Treatment of Spinning Reserves is Correct, and Does Not Double-Count the Spinning Reserve Impact at Gadsby.

The Company agrees with Mr. Falkenberg that the Gadsby modeling should be adjusted to reflect more reserves being carried on the Gadsby units as a result of higher market prices. However, this change does not increase the overall generation levels of the Company's units, which remain consistent with the actual operation of Gadsby during a period of high market prices. Ex. UP&L 5R at 42. Mr. Falkenberg's modeling does not reflect this circumstance. The Company's treatment does not double-count the spinning reserve at Gadsby. If anything, the Company's modeling of spinning reserves understates the actual costs incurred, because the Company's modeling assigned a significant level of reserves to Gadsby and did not make an adjustment to carry reserves on other units when Gadsby is not running (Gadsby's capacity factor is 49%). Ex. UP&L 5R at 36. The Company's proposed modeling is conservative and should be adopted.

J. The Commission Should Adopt the Company's Proposed Adjustment Regarding the Pricing of the Deseret Contract.

Committee witness Yankel proposed a revenue imputation of approximately $37 million (total Company) related to the Company's revenues under its long-term wholesale sales contract with Deseret Generation & Transmission. Ex. CCS 7 at 30-31. In rebuttal, the Company responded with a correction that would reduce the Company's filed net power costs by $25.5 million on a total Company basis, rather than the $37 million initially proposed by Mr. Yankel. In surrebuttal, Mr. Yankel accepted the Company's correction. Ex. CCS 7SR at 7. However, if the Commission were to adopt Mr. Falkenberg's proposed market priced adjustments, the $25.5 million decrease would need to be reversed to be consistent with Mr. Falkenberg's proposal. Ex. UP&L 5R at 56.

K. The Commission Should Reject the Committee's Proposed Revenue Imputations Regarding the WAPA I and WAPA II Contracts.

Committee witness Yankel proposed revenue imputations amounting to $15.2 million, on a Utah jurisdictional basis, related to two long-term sales contracts with the Western Area Power Administration (WAPA). Ex. CCS 7 at 31-33. As with Mr. Yankel's proposed imputations regarding other long-term sales, this imputation was based on the false premise that the Company's obligation was met entirely with short-term firm purchases. Moreover, Mr. Yankel's proposal was also based on his view that the Company normalized short-term firm and non-firm prices on "going forward prices." *Id.* For the reasons discussed above with respect to other proposed imputations on long-term sales and adjustments based on challenges to the Company's use of annualized prices, Mr. Yankel's proposed imputation should be rejected. Finally, the proposal should be rejected because it is based on post-test year events, a point which Mr. Yankel did not rebut. Ex. UP&L 5R at 56-57.

L. The Commission Should Not Adopt a Power Cost Credit Mechanism With Respect to DSM Expenditures.

Although the Utah Energy Office does not propose that the Commission adjust the Company's revenue requirement in this case to provide funding for DSM measures, it appears to nevertheless still put forth a proposal to establish a power cost credit mechanism, whereby customers would receive a "credit" based on the price of wholesale market purchases avoided through acquisition of DSM. Ex. UEO 1 at 6, UEO 2 at 22-24. The Commission must reject that proposal, because it would necessarily result in requiring the Company's shareholders to fund the DSM measures.

The UEO proposal would impose a cost on the Company (i.e. its shareholders) which would not be recoverable in rates. The proposal would have the Company paying a credit to customers out of "savings," but such "savings" is not revenue. Tr. 541, 548-49. As acknowledged by UEO witness Dr. Nichols, UEO's proposed mechanism would require that the Company contribute to the cost of DSM. Tr. 543. Such a requirement would be confiscatory, and cannot be approved.

IV. CONCLUSION

For all the reasons stated in PacifiCorp's prefiled testimony, testimony at hearings, and this Brief, the Commission should grant PacifiCorp's requested rate increase.

Dated: August 21, 2001

Stoel Rives LLP

By ______________________________

Edward A. Hunter
John M. Eriksson
James M. Van Nostrand
Attorneys for PacifiCorp

CERTIFICATE OF SERVICE

I hereby certify that on this 21st day of August, 2001, I caused to be served, via United States mail, postage prepaid, a true and correct copy of the foregoing PacifiCorp's Post-Hearing Brief to the following:

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

Lee Brown
Tony J. Rudman
Counsel for MagCorp
Magnesium Corporation of America
238 North 2200 West
Salt Lake City, Utah 84116

Reed Warnick
Assistant Attorney General
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, Utah 84111
366-0352

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

Gary Dodge
Hatch James & Dodge
10 West Broadway, Suite 400
Salt Lake City, Utah 84101

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

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

Captain Robert C. Cottrell, Jr.
Utility Litigation and Negotiation
Attorney
AFLS/ULT
139 Barnes Drive, Suite 1
Tyndall AFB, Florida 32403-5319

Glen E. Davies
Parsons Davies Kinghorn & Peters
185 South State Street, Suite 700
Salt Lake City, Utah 84111

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

Dr. Charles E. Johnson
1338 Foothill Boulevard, PMB 134
Salt Lake City, Utah 84108

Bill Thomas Peters
Parsons Davies Kinghorn & Peters
185 South State Street, Suite 700
Salt Lake City, Utah 84111

Cheryl Murray
Committee of Consumer Services
Heber M. Wells Building, Room 410
160 East 300 South
Salt Lake City, Utah 84111

Scott Gutting
Rick Anderson
Energy Strategies, Inc.
39 Market Street, Suite 200
Salt Lake City, Utah 84101

Eric C. Guidry
LAW Fund Energy Project
2260 Baseline Road, Suite 200
Boulder, CO 8032-7740

Donald E. Gruenemeyer, P.E.
Sawvel & Associates
100 East Main Cross Street
Suite 300
Findlay, OH 45840

David Nichols
Tellus Institute
11 Arlington Street
Boston, MA 02116