BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application	**:**	**Docket No. 01-035-01**
of PacifiCorp for Approval of its	**:**	**PREFILED DIRECT TESTIMONY OF**
Proposed Electric Rate Schedules	**:**	**ANTHONY J. YANKEL**
and Electric Service Regulations	**:**	**FOR THE COMMITTEE OF**
	:	**CONSUMER SERVICES**

June 4, 2001

Non-Confidential

INTRODUCTION

Q. **PLEASE STATE YOUR NAME, ADDRESS, AND EMPLOYMENT**.

A. I am Anthony J. Yankel. I am President of Yankel and Associates, Inc. My address is 29814 Lake Road, Bay Village, Ohio, 44140.

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I received a Bachelor of Science Degree in Electrical Engineering from Carnegie Institute of Technology in 1969 and a Master of Science Degree in Chemical Engineering from the University of Idaho in 1972. From 1969 through 1972, I was employed by the Air Correction Division of Universal Oil Products as a product design engineer. My chief responsibilities were in the areas of design, start-up, and repair of new and existing product lines for coal-fired power plants. From 1973 through 1977, I was employed by the Bureau of Air Quality for the Idaho Department of Health & Welfare, Division of Environment. As Chief Engineer of the Bureau, my responsibilities covered a wide range of investigative functions. From 1978 through June 1979, I was employed as the Director of the Idaho Electrical Consumers Office. In that capacity, I was responsible for all organizational and technical aspects of advocating a variety of positions before various governmental bodies that represented the interests of the electrical consumers in the State of Idaho. Since that time, I have been in business for myself. I am a registered Professional Engineer in the states of Ohio and Idaho. I have presented testimony before the Federal Energy Regulatory Commission (FERC), as well as the State Public Utility Commissions of Idaho, Montana, Ohio, Pennsylvania, Utah, and West Virginia.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Committee of Consumer Services (Committee or CCS).

Q. **DO YOU HAVE A SUMMARY OF THE KEY ISSUES AND CONCERNS ADDRESSED IN YOUR TESTIMONY?**

A. Yes I do. Over the last decade ~~there has been considerable effort and concern regarding~~the issue of PacifiCorp's activities in the wholesale market and the jurisdictional ratemaking treatment of the associated costs and revenues has been extensively studied. A task force was established as a result of Docket 90-35-06 to address issues pertaining to wholesale contracts. A similar task force was established as a result of Docket 97-035-01 to study the impact of wholesale contracts on jurisdictional revenue requirement. In comparing this rate case to previous cases, the ratemaking treatment afforded to long-term firm wholesale sales contracts and associated costs has enormous impacts on the level of jurisdictional revenue requirement.

Using a "Revenue Credit" method, the costs and the revenues of wholesale transactions are presently assigned to retail customers under the presumption that these transactions will foster a net benefit. A fundamental assumption in the Company's case is that each long-term firm wholesale sales provide benefits to retail customers. This assumed benefit may have been appropriate in the past for many of the Company's transactions, but PacifiCorp's more recent actions have exposed retail customers to risks stemming from skyrocketing wholesale market prices.

When the Wholesale Contracts Task Force Report from Docket 90-35-06 was issued (April 13, 1993), firm wholesale sales were about 20% of the retail load. During that timeframe, the Company acquired a number of generation resources:

1990	Cholla	380 MW
1992	Craig & Hayden	250 MW
1992	James River	50 MW
1993	Hermiston	474 MW

PacifiCorp's business strategy was to use revenues from wholesales sales to cover a portion of the costs of these additional resources before they were needed to meet retail load requirements. This strategy was discussed with, and generally endorsed by, regulators.

However, long after these resources were acquired there was a dramatic and unrelated increase in wholesale transactions (new sales as well as matching purchases to meet these load obligations). This increase in wholesale market activity occurred after 1995. Unlike its earlier wholesale sales contracts, PacifiCorp did not meet this increased wholesale activity with its own generation, but relied mainly on short-term firm purchases to supply these Post-1995 contracts. By 1997 wholesale sales exceeded retail sales and short-term firm purchases were increased accordingly. Many of the Post-1995 long-term firm wholesale sales contracts are still in existence during the test year. Although somewhat reduced, the level of wholesale sales is still on the same order of magnitude as retail sales. Retail sales in 1999 amounted to 46,605 GWH while wholesale transactions amounted to 36,315 GWH[1]. This relatively high level of wholesale sales is still primarily supported by short-term firm purchases.

Q. ISN'T IT TRUE THAT ELECTRONS ARE NOT COLOR-CODED AND ELECTRONS CANNOT BE SIMPLY MATCHED TO SPECIFIC LOADS?

A. Despite the fact that electrons are not color-coded, it is obvious that if firm wholesale sales were increased over 400%[2] between 1995 and 1997, but generation only increased 4%[3], then the supply for these new sales was procured from sources other than the Company's own generation. This other source was primarily short-term firm purchases.

Although the level of firm wholesale sales has declined since 1997, sales volumes are still significantly higher than historical levels. For example, firm wholesale sales in 1999 exceeded 1995 levels by 275%. And short-term firm purchases remain the primary source of supply for this increased load.

Q. **PLEASE CONTINUE WITH YOUR SUMMARY.**

A. In this changed environment it is necessary to ensure that Utah customers are not harmed under the Revenue Credit method because of the long-term firm wholesale

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[1] 1999 FERC Form 1 page 301.
[2] See Graph on page 21.
[3] 1995 FERC Form 1 page 401 lists Net Generation at 52,698 GWH and the 1997 FERC Form 1 page 401 lists Net Generation at 54,626 GWH.

sales contracts and matching purchases that were added after 1995. The revenue from most of these Post-1995 contracts <u>never covered the incremental cost of short-term firm purchases</u> that were used to supply them. The cost of short-term firm purchases in the present market, compared to the revenue received from specific long-term firm wholesale sales contracts, results in significant losses being borne by retail customers under the Revenue Credit method, unless certain adjustments are made. It is unfair and unreasonable to ask retail customers in Utah to continue to subsidize PacifiCorp's flawed business strategy of failing to hedge their wholesale power contracts. My recommended adjustments mitigate the size of the loss (subsidy) that would otherwise be incurred by retail customers in Utah.

Q. **WHAT SPECIFIC RECOMMENDATIONS DO YOU OFFER IN YOUR DIRECT TESTIMONY?**

A. I offer the following recommendations for consideration:

1. The use of the revenue credit method for addressing cost/revenue responsibility is generally appropriate for those specific contracts where (according to previously set Commission guidelines) the revenue from the sales contract has provided, or has been expected to provide, a net benefit to retail customers.
2. The Commission should remove from the Company's power cost model eight post-1995 long-term firm wholesale sales agreements (as well as the short-term firm wholesale purchases that support these sales) that do not meet the Commission's approved guidelines for revenue credit treatment. The removal of these eight long-term firm wholesale sales contracts that have always been priced below average system cost results in a net reduction in Utah jurisdictional revenue requirement of $108,963,784.
3. There are four additional contracts that should be removed for purposes of setting rates in this case. Although these contracts could fit under the heading of being under-priced wholesale sales contracts, there are unique features about them that warrant individual discussion. The contract with Citizens Power is for supply during only the super-peak hours and yet it is

only priced at $30.50 per MWH. There is nothing wrong with the fact that the terms of the Deseret contract sets Supplemental Sales at market price. However, the Company's power cost model has the price for these sales set well below market prices. Additionally, two contracts have been terminated per the contract terms because they were no longer economical for the wholesale customer. I recommend that the jurisdictional revenue requirement be further reduced by $32,619,914 associated with the removal of these four contracts and their related costs from the Company's power cost model.

4. There is a strong indication that the manner in which the Company defines the Utah Jurisdiction's load results in losses associated with wholesale transactions, wheeling, and system customers being assigned to Utah. It is possible that these losses could add 5% to the peak demand and energy responsibility assigned to the Utah jurisdiction. A reduction of 5% in these two parameters would reduce the Company's calculated Utah revenue requirement by $22.8 million. I recommend that a task force be convened to study and submit a report to the Commission detailing its findings and conclusions. Because of the potentially large impact on Utah rates, that report should be issued before the Company files another rate case.

TREATMENT OF FERC FIRM WHOLESALE COSTS AND REVENUES IN TODAY'S ELECTRIC UTILITY ENVIRONMENT

Q. WHAT IS YOUR UNDERSTANDING OF WHAT COSTS SHOULD GO INTO THE RATES THAT PACIFICORP CHARGES ITS CUSTOMERS?

A. My understanding is that PacifiCorp is charged with providing safe and reliable service at the lowest possible cost to its firm retail customers in Utah. The firm retail customers in Utah are the ultimate customers to be served by PacifiCorp. This means that retail customers should receive the benefit of the lowest cost resources while any additional sales should be priced at the Company's incremental cost of service. At a minimum, Utah customers should not be subsidizing customers in other jurisdictions. The safety, reliability, and cost considerations for the Utah firm retail customers are to be equivalent to those of other firm retail customers in other state jurisdictions, but superior to FERC jurisdictional customers. Essentially, firm retail (state jurisdictional) load is the Company's primary business, while FERC jurisdictional customers are secondary.

Q. DOES THE FERC CONSIDER SALES THAT COME UNDER ITS JURISDICTION (FROM A UTILITY SUCH AS PACIFICORP TO OTHER UTILITIES) SECONDARY TO THOSE SALES MADE TO RETAIL CUSTOMERS THAT FALL UNDER A STATE COMMISSION'S JURISDICTION?

A. Yes. The FERC recognizes the fact that the sales that fall under its jurisdiction are secondary to those of a utility's ultimate customers—firm retail customers. Even if FERC jurisdictional sales are "firm", they are still considered secondary to firm retail sales that would fall under the Utah Commission's jurisdiction. In general, there are four categories of sales that fall under the jurisdiction of the FERC. The most "firm" of these sales is known as Requirements Service (RQ) which the FERC defines as:

> Requirements service is service, which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of Requirements Service must be the same as, or second only to, the supplier's service to its own ultimate customers.[4] (Emphasis added)

[4] FERC Form 1 page 310.XX

A second category of FERC sales which is less “firm” than that of the Requirements Service (and thus, less “firm” than Utah jurisdictional firm Retail service) is that of Long-, Intermediate-, and Short-Term Firm Service. FERC’s definition of Long-Term Firm Service is:

> “Long-Term” means five years or Longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-Term firm service that meets the definition of RQ service.[1]

Intermediate-term and Short-Term firm contain the same definition except Intermediate-term is for contracts with lengths between one and five years, while Short-Term firm sales are one year or less.

A third category of FERC sales is known as Unit Sales. These sales are tied to the availability and reliability of a designated generation unit and are only firm to the extent that the specific unit is operating.

The fourth category of FERC sales, known as Other Service (OS), is generally not firm in nature and includes any kind of sale that cannot be placed in one of the categories of “firm” sales described above.

Q. IN THIS CASE HOW DOES PACIFICORP TREAT THE REVENUES IT RECEIVES FROM ITS FERC WHOLESALE TRANSACTIONS?

A. There are three ways that PacifiCorp has treated FERC revenues in this case. Some of the Requirements Service (RQ) revenues are assigned to the Utah jurisdiction, while some of the RQ revenues are assigned to a separate FERC jurisdiction. However, the vast majority of the FERC revenues are put into a pool and divided among the various jurisdictions on what is known as a Revenue Credit method.

Q. WHY IS THE TREATMENT OF FERC WHOLESALE REVENUES IMPORTANT IN SETTING RATES FOR UTAH RETAIL CUSTOMERS?

A. All costs incurred by the Company and revenues received for providing those services have an impact on the overall operation of the Company. Because costs and revenues must be allocated/assigned appropriately to all of the Company's operations in order to determine what costs should be paid by Utah ratepayers, the Company's wholesale activities should be reviewed as any other operational area. However, PacifiCorp's wholesale operation has grown enormously over the past few years. In 1997, wholesale Sales represented 56%[5] of PacifiCorp's total sales. In 1998, wholesale sales represented 49%[6] of total sales and in 1999 wholesale sales represented 44%[7] of total sales. With wholesale transactions now comprising a sizeable share of PacifiCorp's sales of electricity, and substantial support for those sales coming from short-term firm purchased power, it is imperative that costs/revenues be fully reviewed for appropriate rate making treatment.

Q. HOW DOES THE REVENUE CREDIT MECHANISM WORK?

A. The easiest way to explain how PacifiCorp's Revenue Credit mechanism works is to contrast it with the way the Company allocates and/or assigns all of the other costs to the various state jurisdictions in its IJA model. The Company attributes cost causation to various jurisdictions such as Utah, Oregon, Wyoming, etc. Cost allocations are based upon jurisdictional contribution to coincident peak demand, energy consumed, number of customers, etc. Revenues from these same jurisdictions are directly assigned to the jurisdiction in which the revenues are collected.

However, the vast majority of the costs and revenues associated with FERC jurisdictional sales are not treated in this manner. Instead, the Company simply combines the demand-related and energy -related costs to serve these FERC customers with the costs to serve the various state jurisdictions and then allocates all of these costs to only the state jurisdictions. For example, in this case 36.89% of system energy-related costs are allocated to the Utah jurisdiction[8] (with only 0.17%

[5] 1997 FERC Form 1 page 301
[6] 1998 FERC Form 1 page 301
[7] 1999 FERC Form 1 page 301
[8] PacifiCorp Results of Operations September 2000 Tab 10 Page 1

of the system energy costs going to the FERC jurisdiction), because Utah represents 36.89% of the system retail usage, which excludes the vast majority of wholesale transactions. Under this method, the Utah jurisdiction is then allocated 36.89% of the system energy and fuel costs associated with supplying the needs of the vast majority of the FERC load. As the name implies, each state jurisdiction is allocated a revenue credit associated with these FERC sales. In this case Utah is allocated 36.89% of the energy-related revenues associated with the FERC sales that are being treated in this manner.

Q. DOES THE REVENUE CREDIT METHOD OF TREATING THESE COSTS PRODUCE A FAIR AND REASONABLE OUTCOME FOR UTAH RETAIL CUSTOMERS?

A. The Revenue Credit allocation method, like any allocation method, is not inherently good or bad, but develops its appropriateness from the manner in which it is applied to specific circumstances. PacifiCorp has been using the revenue credit approach with respect to wholesale costs for about ten years and that method may have been appropriate in the past and may be appropriate in the future. However, PacifiCorp and the electric utility industry have been undergoing significant changes. PacifiCorp's approach to wholesale transactions has greatly changed over the last several years. In the case of certain Post-1995 long-term firm wholesale contracts that are priced below average system costs (and in most cases below the cost of purchase power used to support those sales), the Revenue Credit Method produces an unreasonable result.

Q. WHY ISN'T THE REVENUE CREDIT METHOD FOR CERTAIN POST-1995 WHOLESALE CONTRACTS FAIR, JUST, AND REASONABLE TO UTAH RETAIL CUSTOMERS?

A. Use of the Revenue Credit approach for certain Post-1995 wholesale contracts results in PacifiCorp falling short of its charge to provide safe and reliable service <u>at the lowest possible cost to its firm retail customers in Utah</u>. According to the Company's filing in this case, its firm Utah retail customers should pay 37.60 mills per kWh (at input level) in order to cover generation and transmission costs in the test year (See Exhibit CCS-7.1 page 1). By contrast, the Company's filing contains eight Post-1995 <u>long-term firm</u> wholesale customers that pay well below this amount during the test year in order to cover the generation and transmission costs they imposed on the system. The highest priced of these contracts (Clark) is only paying 59% of this average generation/transmission cost and the lowest priced (Okanogan) is only paying 38% of this average price. Not only do the prices associated with these eight contracts fail to recover the average cost of generation and transmission during the test year in this case, but they have failed to cover the average generation and transmission costs in the two previous Utah rate cases that have occurred since these contracts were executed (See Exhibit CCS-7.1 pages 2 and 3).

Q. HAS PACIFICORP ALWAYS RECEIVED SUCH LOW RATES FOR ITS FIRM FERC WHOLESALE SALES?

A. No. Generally speaking, the amount of revenue collected from long-term firm wholesale contacts that were written prior to 1996 have been providing revenues in excess of the average generation and transmission costs of the system. As illustrated in Exhibit CCS-7.2, there is a substantial difference between the rates being charged for Post-1995 contracts when compared to those executed earlier. The eight Post-1995 contracts I recommend removing here averaged $21.57 per MWH. By contrast, the contracts written previously brought in a weighted average price of $40 per MWH (including the SMUD contract for which the Company received a significant buy-down payment). The Revenue Credit method used by PacifiCorp may be appropriate for these earlier contracts, but this approach is not appropriate for these newer contracts that have been recovering significantly less than the system average cost of producing power.

Q. DO YOU HAVE ANY CONCERNS WITH THE USE OF THE REVENUE CREDIT METHOD FOR NON-FIRM FERC SALES?

A. Not at this time. PacifiCorp's non-firm FERC sales in this case are relatively small. Additionally, non-firm sales are just that—not firm—and thus, are distinct from firm wholesale and/or firm retail sales. I will confine my remarks in this testimony to only the firm wholesale transactions.

Q. **HAS THERE BEEN A LONG HISTORY OF CONCERN REGARDING THE COMPANY'S APPLICATION OF THE REVENUE CREDIT METHOD TO LONG-TERM FIRM WHOLESALE CONTRACTS?**

A. Yes. The Company first introduced the concept of using the Revenue Credit method for allocating the cost and revenues associated with long-term firm wholesale sales contracts (as opposed to direct assignment to the FERC Jurisdiction) during Docket No. 90-035-06. There were substantial concerns raised during that case that under such an approach retail customers would subsidize the Company's wholesale activities. In support of its position, the Company provided the following testimony:

> While the company continues to provide service to existing firm wholesale tariff customers under the embedded system cost approach, the Company no longer desires to offer such firm service to new wholesale customers. The Company's current approach to pricing of firm wholesale sales is to use a market based approach, which, under current FERC regulations, is limited to the average cost of a pool of resources made up of the Company's most expensive thermal generation. <u>Such an approach ultimately produces a price substantially greater than a price based on average embedded system cost and therefore provides greater benefit to Retail customers</u>.[9] (Emphasis added)

Q. DID THE COMMISSION ADOPT THE REVENUE CREDIT METHOD FOR THE TREATMENT OF LONG-TERM FIRM WHOLESALE CONTRACTS IN THAT DOCKET?

A. The Commission adopted use of the Revenue Credit method for long-term firm wholesale contracts in its December 7, 1990, Order with modifications recommended by the Division of Public Utilities (Division) and supported by other parties in the case. The policy adopted by the Commission provided for adequate information for regulatory oversight and to address concerns about wholesale

[9] May 1990 testimony of Company witness Gregory Duvall at page 32.

customers paying their fair and proper share of system costs. The Commission adopted the following policy:[10]

> 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. Non-firm 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, <u>after approval of the contracts by the Utah Public Service Commission</u>.
>
> 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. <u>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</u>. 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 makes a contribution to fixed costs.
> d. After a short time, the contract either terminates or covers full embedded <u>costs</u>. (Emphasis added)

Q. HAS THIS POLICY BEEN MODIFIED OR BETTER DEFINED SINCE THE COMMISSION'S DECEMBER 7, 1990 ORDER?

A. A Wholesale Contracts Task Force was convened as a result of Docket No. 90-35-06. On April 13, 1993, that Task Force issued a Final Report. Although the Commission never acted upon that Final Report, it does serve as an indication of what the various parties understood the treatment of a wholesale contract should have been with respect to the Revenue Credit method. With respect to what constitutes appropriate conditions for Revenue Credit treatment of wholesale contracts, there were two significant areas that were addressed in this Final Report. The first area addressed the fourth item (and four

[10] Based upon page 12 of the August 20, 1990 testimony of Division witness Kenneth B. Powell in Docket 90-035-06.

subparts) regarding the criteria for treatment of a wholesale contract under the Revenue Credit mechanism as adopted in the Commission's December 7, 1990, Order. The Final Report reaffirmed the Task Force's belief in the first three subparts that were adopted by the Commission. The Task Force modified its interpretation of the Commission's fourth subpart to be as follows:

> Pricing shall be structured such that over the life of the contract <u>retail revenue requirement will be protected from increases resulting from resource acquisitions needed to serve the wholesale contract</u>. (Emphasis added)

Although this is a departure from the fourth criteria adopted by the Commission, it still sets a requirement for Revenue Credit treatment that the retail customers are protected from subsidizing the Company's wholesale activities.

Q. WHAT IS THE SECOND SIGNIFICANT AREA THAT WAS ADDRESSED IN THE FINAL REPORT?

A. The second significant area in that Final Report is a description of how the parties understood the Company developed the pricing mechanism it used for wholesale contracts on a going forward basis. In a document dated February 1993 entitled "PacifiCorp and the Wholesale Market - An Overview" the Company sets out a detailed description of how it plans and operates its system for its Retail and Wholesale loads. That document begins:

> <u>Retail electric operations is the core of PacifiCorp's business</u>, however, its wholesale operations play an important role that allows PacifiCorp to maximize the efficiency of the Company's power system. The Company plans and acquires its resources based on need or growth in the retail sector, however, because of the complementary relationship between wholesale sales and retail sales, the Company may maximize the utilization of all its resources through its sales in the wholesale marketplace. <u>Wholesale sales decisions are based on the benefits they provide to the Company's retail business</u>.
>
> The following is an overview of PacifiCorp's current wholesale sales and the wholesale marketplace. This paper will include discussions of the types of wholesale transactions PacifiCorp makes and its wholesale customers, <u>the benefits of wholesale sales to the Company and its retail customers, and PacifiCorp's wholesale pricing mechanism</u>. The paper will also examine today's wholesale marketplace and recent changes that have transpired. (Emphasis added)

Q. HOW WERE WHOLESALE TRANSACTIONS AND THE REVENUE CREDIT METHOD USED DURING THAT TIME (EARLY 1990'S) TO BENEFIT UTAH RETAIL CUSTOMERS?

A. During the early 1990's, wholesale transactions were believed to provide benefit to the Company's retail customers. In the above mentioned 1993 document, PacifiCorp stated that one of the benefits of the wholesale transactions was that it resulted in lower rates for retail customers:

> For retail customers, the benefits of wholesale sales are significant in two main areas: 1) lower revenue requirements and net power costs, and 2) increased flexibility in acquisition of supply-side resources. (Emphasis added)

The benefits of these wholesale transactions were then to be spread to the retail customers in the most beneficial manner possible. In 1993, PacifiCorp considered the most beneficial treatment for the retail customers to be the application of the Revenue Credit method:

> The accepted regulatory treatment that PacifiCorp uses for most of its wholesale sales is the Revenue Credit approach. Through this method all utility capital costs and expenses are assigned to the retail jurisdictions. Included in these costs are those associated with serving Wholesale load requirements. Wholesale revenues are deducted from these total costs in determining the revenue requirement for the retail jurisdictions. Wholesale sale revenues thereby reduce retail revenue requirements. An alternative to this approach is to assign a separate jurisdiction for wholesale costs and revenues; a FERC jurisdiction. This approach results in less benefit for retail customers over the contract term of wholesale sales.
>
> The Revenue Credit approach provides lower revenue requirements to retail customers because over the life of a wholesale contract the prices charged for the sale exceed the costs to serve that sale. The reason for this is that the prices charged to wholesale customers reflect incremental costs rather than embedded. (Emphasis added)

Q. WHY WOULD THE REVENUE CREDIT METHOD HAVE BEEN APPROPRIATE FOR TREATMENT OF WHOLESALE COSTS AND REVENUES IN 1993, WHEREAS AN ADJUSTMENT OR A DIFFERENT APPROACH FOR CERTAIN WHOLESALE CONTRACTS IS REQUIRED TODAY?

A. The major reason that the revenue credit method was appropriate in 1993 is that PacifiCorp was pricing firm wholesale customers at incremental costs. Both the fixed costs as well as the variable costs of PacifiCorp's more expensive resources were used to price wholesale transactions under what is known as the Resource Pool Pricing mechanism. As stated in PacifiCorp's 1993 Overview of its treatment of Wholesale transactions:

> A key component of developing wholesale sales prices and the ability of these prices to absorb new resource costs is the Resource Pool Pricing mechanism employed in PacifiCorp's Special Sales transactions. This mechanism is the current FERC approved pricing methodology that PacifiCorp is using in developing many of its Special Sales transactions. A resource pool is made up of selected existing generating resources that are typically some of the Company's higher cost resources. The costs of these resources are weighted by the MW amounts of each resource contained in the pool, creating a melded pool price. Transmission costs and losses are then added to this melded price to arrive at the final pool price for the wholesale sale. The resource pool pricing method and calculation are demonstrated through Figures 5 and 6[11].
>
> A unique feature of this pricing mechanism is the "Roll-in/out" capability. When new, higher cost, resources are added to PacifiCorp's system, a portion, or all, of the resources may be "rolled-in" to the pool. An equal amount of the lower cost original pool resources may be "rolled-out" to maintain the original pool size. Figure 7 demonstrates the pool and the "Roll-in/out" feature[4].
>
> The resource pool pricing method is advantageous to retail customers because of the insulation it provides for retail prices from new higher cost resources. Wholesale customers absorb the bulk of costs of adding new resources, as a result of the roll-in feature, and the lower cost resources are reserved for retail customers. Retail customers are also insulated from resource cost uncertainties. Once resource acquisitions have been prejudged to be prudent, if the new resources are more expensive than originally forecast, the prudently incurred additional costs can be recovered through wholesale sales. If new resources cost less than the existing pool resources, the new resources would not be rolled into the wholesale sales pools and would be reserved for service to our retail customers. (Emphasis added)

Thus, under the Resource Pool Pricing mechanism that was used in 1993, the incremental fixed and variable costs of PacifiCorp's more expensive resources were

[11] See Exhibit CCS-7.3 for a depiction of Figures 5, 6 and 7 from PacifiCorp's 1993 overview of how it utilizes wholesale transactions.

channeled to wholesale customers while the lower cost resources were reserved for retail customers.

Today, the Resource Pool Pricing mechanism is only an artifact of some old contracts while new firm wholesales contracts (long-term, intermediate-term, and short-term) are priced at much lower, negotiated rates. These low-priced contracts were executed after 1995 – the period when PacifiCorp decided to drastically increase its level of firm wholesale transactions. With the move from using the incremental costs associated with the Resource Pool Pricing mechanism to using low priced negotiated rates, PacifiCorp effectively stopped dedicating its lowest cost resources to its firm retail load. Because of the way many of the Post-1995 long-term firm wholesale contracts were priced, the Revenue Credit treatment is not appropriate.

Q. IS THERE ANYTHING INHERENTLY CORRECT ABOUT USING A RESOURCE POOL PRICING MECHANISM OR INHERENTLY WRONG WITH USING A NEGOTIATED PRICE TO ESTABLISH RATES FOR FIRM WHOLESALE CONTRACTS?

No. The overall concern is: How does the overall cost recovery from each of these long-term firm wholesale contracts impact retail customers? Under the Resource Pooling Pricing mechanism, retail customers are supposed to benefit from wholesale transactions because rates charged to these customers should reflect incremental cost. It does not matter if incremental costs are developed through a resource pooling mechanism or are simply negotiated—what does matter is that they are above, not below, average system cost as well as the incremental cost of serving each of these loads. When firm wholesale sales contracts were being priced at the incremental fixed and variable costs, the use of the Revenue Credit method was appropriate for setting rates for retail customers. The Revenue Credit method may be appropriate in this case for those contracts that have historically been priced at or above incremental cost, but an adjustment must be made to reflect the fact that many of the wholesale contracts initiated after 1995 have not recovered average cost, let alone incremental cost.

Q. HAS THE COMPANY FILED ANY REQUESTS WITH THE COMMISSION FOR APPROVAL OF ANY LONG-TERM FIRM WHOLESALE CONTRACT FOR REVENUE CREDIT TREATMENT?

A. The last time the Company filed anything with the Commission requesting that Revenue Credit treatment be applied to any wholesale sales contracts was on April 30, 1991.[12] Thus, none of the Post-1995 contracts have been submitted to the Commission for its approval regarding possible Revenue Credit treatment.

Q. HAVE THERE BEEN CLEAR STATEMENTS BY PACIFICORP AFTER 1993 THAT WOULD SUGGEST A NEW FOCUS ON THE WHOLESALE MARKET?

A. Yes, there were many such statements that indicate that the Company has changed its focus on wholesale transactions after it issued its 1993 Overview of wholesale transactions and justification for using the Revenue Credit method. For example the following statements can be found in the Company's 1994 Annual Report to Stockholders:

> To better position the company for the challenging new marketplace, PacifiCorp's electric operations were restructured in 1994 into three internal business units—generation, wholesale transactions and transmission, and retail sales. <u>This structure lets us focus greater and more creative attention on specific groups of customers and opportunities to expand our markets</u>.[13]
>
> …
>
> These are a rapidly growing number of business opportunities in the Wholesale Transactions and Transmission area, but only for companies that are fast, flexible and innovative.[14]
>
> …
>
> Through 1995, PacifiCorp expects to emerge as a national presence in marketing, brokering and trading. <u>The company will sell both electricity commodities and services, and will aggressively pursue new markets</u>.
>
> While juggling all the challenges outlined above, the Wholesale Transactions and Transmission unit continues to look for acquisitions of properties or other companies that could add shareholder value. It also is responsible for the least-cost planning process—assuring there will be adequate future power resources

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[12] See Company response to CCS Request 10.17-d.

[13] PacifiCorp's 1994 Annual Report to Stockholders page 3.

[14] PacifiCorp's 1994 Annual Report to Stockholders page 11.

so that PacifiCorp has flexibility and can maximize use of its overall resources base.[14] (Emphasis added)

In PacifiCorp's RAMPP-4 Report dated November 1995, it is even clearer that the Company has changed its emphasis on the wholesale market from one of supporting its retail customers to being an independent market center of its own:

> In the past, wholesale sales were a minor part of PacifiCorp's total revenues. The company used the revenues to help offset retail prices. However, several changes are occurring: 1) wholesale is becoming a larger part of the company's total business, 2) wholesale prices are declining, and 3) that part of the business carries increasing risks and potential rewards.
>
> The wholesale part of the business is growing rapidly and the company is looking at wholesale sales as a major business activity. Wholesale marketing will increasingly evolve as a separate business with its own strategies, rewards and risks.
>
> …
>
> The greater the company's activity in the wholesale market, the greater the potential rewards and the greater the risks. Those who bear the risks should also benefit from the rewards. The company would prefer to not expose retail customers to the higher risk/reward situation. Equity capital is a better place for such activities. The company will experience upward pressure on retail rates if it cannot maintain the current level of wholesale contribution. Changing conditions in the wholesale markets mean the company must take on greater risk to achieve the same level of wholesale contributions. However, the company continues, for now, to use the retail credit approach for wholesale sales. These are transition times, and that approach may change in the future as other changes occur, some expected and some unforeseen. These changes could include alternative regulation, deregulation, and restructuring.[15] (Emphasis added)

It should be clear from these statements that PacifiCorp's approach to the wholesale market had greatly changed from that expressed in 1993 when retail electric operations were considered to be "the core of PacifiCorp's business" and when "wholesale sales decisions [were] based on the benefits they provide to the Company's retail business". As pointed out in RAMPP-4, even as early as 1995 PacifiCorp itself was questioning the appropriateness of the Revenue Credit method as applied to wholesale transactions on a going forward basis.

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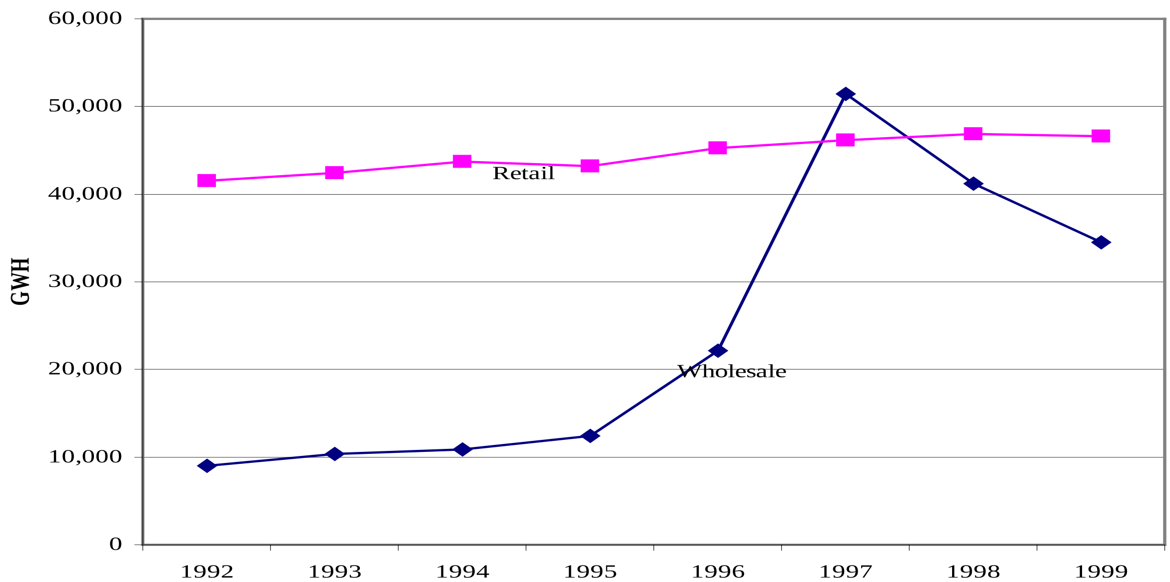
[15] PacifiCorp's RAMPP-4 Report pages 12 and 13.

Q. HOW HAS THE QUANTITY OF FIRM WHOLESALE TRANSACTIONS CHANGED COMPARED TO THE AMOUNT OF ENERGY SOLD TO RETAIL CUSTOMERS?

A. As indicated in the Company's RAMPP-4 Report, the amount of firm wholesale energy sold has greatly increased over pre-1996 levels. As the following graph depicts, firm wholesale energy increased from less than 1/4th of the retail energy sold during the 1992 – 1994 period to approximately the same level as retail sales in 1997 and 1998. Thus, as stated by the Company, wholesale transactions (and in



this case firm wholesale transactions) became a major part of the Company's electric operations.

Q. WHAT DID PACIFICORP'S WHOLESALE MARKETING PLAN INDICATE ABOUT THE COMPETITIVE TRENDS IN THE WHOLESALE MARKET DURING THE TIME WHEN THE COMPANY BEGAN TO INCREASE ITS LONG-TERM FIRM WHOLESALE SALES?

A. On page A-21 of the Company's 1996 Wholesale Marketing Plan, there is the recognition that there were strong competitive trends in this area. The Plan stated:

(Begin Confidential)
(End Confidential)

This is a strong suggestion on the part of the Company that the Revenue Credit method may no longer be relevant on a going forward basis.

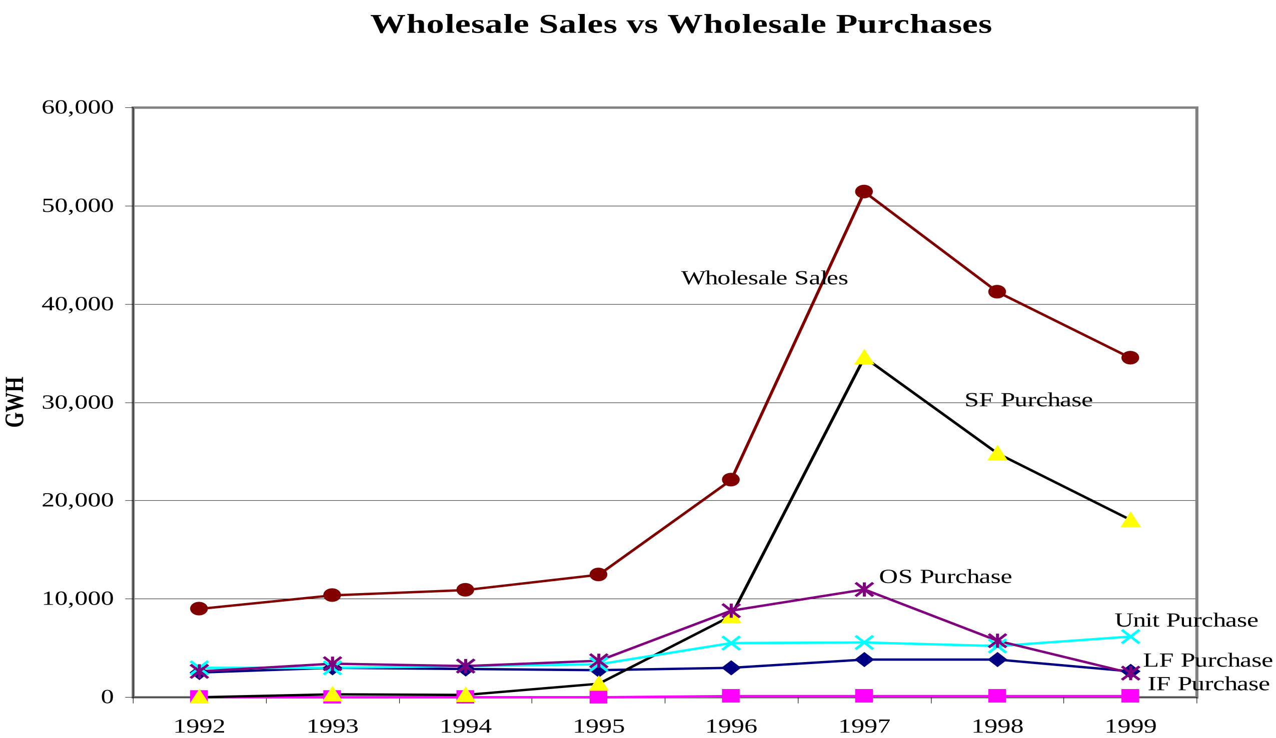
> Of even more significance to the present case, the Company's 1997 Wholesale Marketing Plan indicates that PacifiCorp anticipated *(BEGIN CONFIDENTIAL)*
>
> *(END CONFIDENTIAL)*

In spite of this prediction, PacifiCorp's overall strategy for meeting its overall wholesale marketing objectives included the objective to:

> *(BEGIN CONFIDENTIAL)*
>
> *(END CONFIDENTIAL)*

Q. WHAT RESOURCES DID PACIFICORP RELY ON TO SUPPLY THIS DRAMATIC INCREASE IN WHOLESALE LOADS?

A. To meet its increased wholesale obligations, PacifiCorp relied on all available resources. Although electrons are not color-coded, these firm wholesale sales were incremental to the sales (retail and wholesale) that existed at the time. Therefore, additional supply had to be procured. What is notable is that the Company relied on supplies in the wholesale market, rather than acquiring or building new generation plant, to service these new, firm wholesale obligations. Thus, there was a significant increase in purchase power (firm and non-firm) that coincides with this increase in firm wholesale sales. As seen from the table and chart below, the level of purchase power (primarily short-term firm and non-firm) closely resembles the level of firm wholesale transactions on the PacifiCorp system over this timeframe.



Q. **DID THE COMPANY HEDGE ITS NEW LONG-TERM FIRM WHOLESALE CONTRACTS AGAINST PRICE RISK?**

A. According to the Company, it did hedge (after a fashion) these Post-1995 contracts against price risk. The Company stated:[16]

> The Company determines the need for a hedge against the price risk of each contract at the time of contract execution. The nature of the contract determines if it will be hedged physically, financially, or with the Company's existing portfolio. This is done for each contract.

When asked to further clarify this statement regarding a number of specific long-term firm wholesale contracts, the Company admitted:[17]

> At the time the Company entered into these sales contracts, PacifiCorp anticipated being surplus power during the delivery time period. As such, the overall system of resources was viewed as the hedge, and there is no documentation of such determinations for the specified contracts.

[16] Company's February 14, 2001 response to Retail/Wholesale Revenue Requirement Forum Data Request 8.

Thus, the Company was using its generation resources as well as its long-term firm purchase contracts to hedge against any risk that the cost of short-term firm purchases would not exceed the price obtained by the Company for making these sales. However, any “spare” generation was minimal in comparison to the magnitude of the Wholesale sales involved. Consequently, all of the risk of these Post-1995 sales is placed upon the retail customers while PacifiCorp was trying “to better position the company for the challenging new marketplace” and “looking at wholesale sales as a major business activity...[that] will increasingly evolve as a separate business with its own strategies, rewards, and risks.”

Q. ARE THERE ANY OTHER STATEMENTS BY THE COMPANY THAT DISCUSSES ITS RISK MANAGEMENT OR HEDGING STRATEGY?

Yes. *(BEGIN CONFIDENTIAL)*

(END CONFIDENTIAL)

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[17] Company’s Response to CCS Request 10.13.

Q. DID THE FIRM WHOLESALE TRANSACTIONS THAT WERE INITIATED AFTER 1995 RESULT IN REVENUES THAT WERE IN EXCESS OF THE FIRM PURCHASE POWER COSTS THAT WERE INCURRED BY THE COMPANY?

A. No. The following purchase power costs and rates were experienced by PacifiCorp after this policy of increasing activity in the wholesale market was initiated:

Year	Firm Purchase GWH[18]	Firm Cost $ Millions	Firm Rate $/MWH	SF Purchase GWH	SF Cost $ Millions	SF Rate $/MWH
1996	16,853	461	27.35	8,245	127	15.40
1997	44,149	1,042	23.60	34,606	687	19.85
1998	34,052	955	28.04	24,824	598	24.11
1999	27,019	829	30.70	18,050	487	26.96
Test Year	24,987	2,122	84.92	15,611	1,700	118.76

Exhibit CCS-7.2 reveals that many of the long-term firm wholesale contracts negotiated after 1995 are producing revenues that have consistently been priced at approximately half of the cost of firm purchase power. For example, the PNGC sale is priced at $17 per MWH during the test year, yet, average firm purchase prices since this contract went into effect have been $27 to $31 per MWH.

The Clark-FW, Clark-WT, Cowlitz-BHP, and Hinson contracts are each for the supply of a single, large industrial customer that is not on PacifiCorp's system. The price for each of these contracts for firm service to these industrial customers is $16.62, $16.30, $17.61, and $23.00 per MWH, respectively. By way of contrast, the Company, in its filing, attempts to price Utah firm industrial contract customers taking service at transmission voltage at $27.81 per MWH.[19]

Of even more relevance to this case is the relationship of the price of these Post-1995, long-term firm wholesale contracts with the cost of purchase power in the test

[18] FERC Form 1 page 401.
[19] Exhibit CCS-7.4LT-3 Tab 4 page 2 Column "D" prices firm industrial contracts in Utah at $8,927,831 and Tab 5 page 12 lists firm industrial contract sales of 248,249 MWH at transmission level.

year. Exhibit CCS-7.2 shows that other than contracts that were only renegotiated after 1995, or had special terms, there are eight Post-1995 wholesale contracts where PacifiCorp sells long-term firm power at less than $23.30 per MWH. This is not only significantly less[20] than the price being proposed to be charged retail customers for generation and transmission, it is not even in the ballpark of the cost of the short-term firm purchases that PacifiCorp is making in order to meet these Post-1995wWholesale sales obligations. As a matter of fact, the Company's claimed cost of short-term firm purchases is on the order of 5 to 8 times higher than the revenue the Company claims it will make from these sales. If the Revenue Credit method is used for these sales, the Retail customers invariably pick up the shortfall.

Q. WITH RESPECT TO THESE EIGHT POST-1995 LONG-TERM FIRM WHOLESALE CONTRACTS THAT ARE PRICED 1/5TH TO 1/8TH OF THE COST OF OBTAINING THE ENERGY TO SERVE THESE CONTRACTS, HAS PACIFICORP FOLLOWED THE POLICIES AND PROCEDURES ADOPTED BY THE COMMISSION IN ITS DECEMBER 7, 1990 ORDER WITH RESPECT TO INSURING THAT THESE WHOLESALE CONTRACTS PAY THEIR FAIR SHARE OF THE COSTS THEY IMPOSE ON THE SYSTEM?

A. No. The fourth policy item adopted by the Commission with respect to the use of the revenue credit method for future contracts was that:

> Any long term contract proposed to be treated as a Revenue cCredit be filed with the Utah Public Service Commission for subsequent approval of that Revenue Credit status.

No such filings have been made and no approval given for any Post-1995 wholesale contract, let alone, the eight contracts that are most troublesome. Additionally, if such a filing had been made, it would not have been able to meet most of the criteria. For example, the contract must cover incremental cost, but if incremental cost is defined as the actual additional cost to supply the contract, then this would be the price of the additional short-term firm purchases being made. None of these

[20] See Exhibit CCS-7.1

eight contracts covered short-term firm purchase power costs in 1998 and none of them have covered short-term firm purchase power costs since. Given the fact that incremental costs have not been covered, it is impossible for these contracts to make a contribution to fixed costs. To reiterate, if revenue credit treatment is afforded these contracts, then the retail customers will be paying substantial subsidies in order to support these below cost sales.

Q. WITH RESPECT TO THESE EIGHT POST-1995 LONG-TERM FIRM WHOLESALE CONTRACTS, HAS PACIFICORP FOLLOWED THE POLICIES AND PROCEDURES ADOPTED IN THE APRIL 13, 1993 WHOLESALE CONTRACTS TASK FORCE REPORT WITH RESPECT TO INSURING THAT THESE WHOLESALE CONTRACTS PAY THEIR FAIR SHARE OF THE COSTS THEY IMPOSE ON THE SYSTEM?

A. No. The April 13, 1993, Wholesale Contracts Task Force Report was never addressed by the Commission, and thus, should not carry the same force and weight as the Commission's December 7, 1990, Order on this subject. However, the Report does reflect the general agreement and understanding of the Task Force, which would include the Company. The Task Force Report agreed to adopt as the fourth criteria for use of Revenue Credit treatment the following standard:

> Pricing shall be structured such that over the life of the contract retail revenue requirement will be protected from increases resulting from resource acquisitions needed to serve the wholesale contract.

In the case of these eight problem Post-1995 wholesale sales contracts, the resources that PacifiCorp management procured to serve these sales was predominantly short-term firm purchases. No new facilities were built and no available generation from existing resources was used to supply this substantial increase in firm obligation. The additional electricity came from the one area that increased in relationship to the increase in wholesale sales—short-term firm purchases. As pointed out above, most of these eight Post-1995 problem contracts were not covering their resource acquisition cost in 1998 and none of them have been covering them since. Given the differential between test year short-term firm purchase prices and revenue from these contracts, there is no way that over the life of these contracts that retail customers will be protected from losses that can be directly attributed to these eight contracts.

Thus, no matter whether one relies upon the criteria set forth in the Commission's December 7, 1990, Order or the criteria agreed upon in the April 13, 1993 Wholesale Contracts Task Force Report, if these eight contracts are afforded Revenue Credit treatment, retail rates will be significantly increased. It would be unfair and unreasonable to saddle retail customers with a large rate increase due to PacifiCorp's poor risk management strategy.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. The problem relating to these eight contracts are not a blanket condemnation of the Revenue Credit method to the treatment of Wholesale contracts. The Revenue Credit method is generally sound, but there are obvious situations and specific contracts for which this method should not apply. For each of these eight contracts, this is obviously one of those situations as suggested by the Commission's December 7, 1999 Order, and the April 13, 1993,Wholesale Contracts Task Force Report. The revenue from each of these contracts does not cover the incremental cost of the resources acquired (short-term firm purchases) to serve this load.

The simplest way to make an adjustment in this case to is to remove these contracts from the Company's power cost model and an equal amount of short-term firm purchases. Both the energy and revenue associated with these wholesale sales contracts should be removed as well as the energy and the average expense associated with the supporting short-term firm purchases. Although it would be more appropriate to remove the most expensive short-term firm purchases first, it is easier to simply remove the average price and recognize that <u>the adjustment is conservative</u>.

Q. HOW DID YOU MAKE THE SPECIFIC ADJUSTMENT TO REMOVE THE EXPENSE AND REVENUES ASSOCIATED WITH THESE EIGHT POST-1995 WHOLESALE CONTRACTS AND WHAT IS THE NET IMPACT?

A. The Company's power cost model breaks out the energy and revenue associated with each of these contracts during the test year on a monthly basis. It also breaks out short-term firm purchase power energy and expense by operating division (Utah Division, Pacific Division) and by month. In order to make an adjustment, I took the energy from the contracts in either the Pacific Division or the Utah Division and on a monthly basis removed a corresponding amount of short-term firm purchased energy. Page 1 of Exhibit CCS-7.4 lists the monthly energy and revenue associated with these eight wholesale sales contracts that are being removed as well as the corresponding short-term firm purchased energy and expense that are being removed. As shown on page 1 of Exhibit CCS-7.4 , included in the Company's power cost model is $62 million of revenue received from these eight Post-1995 wholesale sales contracts and a corresponding short-term firm purchase power expense of $356 million. By removing both the revenue and expense required to serve just these eight contracts, there is a net reduction in system power costs of $293 million. These wholesale sales and the associated short-term firm purchases are both allocated to Utah on the "SG" factor which the Company set at 37.144% in this case. Using this allocation factor, the net adjustment on a Utah basis is $108,963,784.

Q. HOW DOES THE 2.9 MILLION MWH OF SHORT-TERM FIRM PURCHASES YOU PROPOSE TO REMOVE BECAUSE OF THESE EIGHT POST-1995 WHOLESALE CONTRACTS COMPARE TO THE OVERALL AMOUNT OF SHORT-TERM FIRM PURCHASES THAT THE COMPANY HAS LISTED IN ITS POWER COST MODEL?

A. This 2.9 million MWH of short-term firm purchases only represents 18% of the short-term firm purchases that are found in the Company's power cost model. The remaining high cost short-term firm purchases are available to supply other long-term firm Wholesale sales contracts, which have not been addressed in the above adjustment. The short-term firm purchase price is being used as a conservative estimate of the necessary adjustment. The short-term firm sales price could also be used under the premise that had these long-term firm contracts not been executed, then the Company could have made these same sales (or similar sales) on a short-term firm basis at short-term firm sale prices. Such an approach would result in an even larger adjustment.

Q. HOW DOES YOUR ADJUSTMENT ON EXHIBIT CCS-7.4 PAGE 1 RELATE TO THE ADJUSTMENTS PROPOSED BY WITNESS FALKENBURG IN THIS CASE?

A. Mr. Falkenburg has proposed two alternative adjustments that, if adopted by the Commission, would impact the magnitude of the above adjustment.

If Mr. Falkenburg's proposal to use actual test year short-term firm purchase power costs is adopted, my adjustment would still be appropriate, but it would be significantly reduced as shown on page 2 of Exhibit CCS-7.4. Using the "SG" allocation factor of 37.144%, my adjustment for these eight problem contracts would be reduced to $16,858,355.

If Mr. Falkenburg's proposal to remove all long-term sales contracts that will have expired by the end of 2001 is adopted, my adjustment would still be appropriate, but it would be significantly reduced as shown on page 3 of Exhibit CCS-7.4. Using the "SG" allocation factor of 37.144%, my adjustment for these eight problem contracts would be reduced to $14,266,002.

Q. WOULD A SIMILAR ADJUSTMENT HAVE BEEN APPROPRIATE DURING THE LAST RATE CASE?

A. Yes. As pointed out above, the prices of these same eight contracts were below actual short-term firm purchase power costs in 1998 and 1999. A similar adjustment would have been warranted during the last case if a similar analysis had been performed. The chief difference in the adjustment would have been its magnitude, given that short-term firm purchases at that time were priced significantly lower during the last case. Exhibit CCS-7.5 performs the same analysis for the last case as is found on page 1 of Exhibit CCS-7.4 for this case. As can be seen from Exhibit CCS-7.5, the removal of all wholesale sales contracts in the 1998 test year with prices at or below $23 per MWH (and associated short-term firm purchases) would have resulted in a net reduction in net power costs of $7.8 million.

Q. DOES THE ADJUSTMENT THAT YOU HAVE PROPOSED IN THIS CASE ASSOCIATED WITH THESE EIGHT LONG-TERM FIRM SALES REPRESENT THE MAXIMUM ADJUSTMENT THAT COULD BE MADE TO THE COMPANY'S NET POWER COSTS?

A. No. A review of the data in Exhibit CCS-7.2 reflects the fact that there are several more Post-1995 long-term firm wholesale contracts in the $23-28 range that are also priced significantly below the cost of the short-term firm purchases required to support these sales. I have chosen to only address the lowest priced contracts in the above analysis. This should not be taken as an acceptance of these other contracts as being just and reasonable for inclusion in setting retail rates.

OTHER PROBLEM CONTRACTS IN THE COMPANY'S POWER COST MODEL

<u>Deseret Supplemental</u>

Q. ARE THERE OTHER ADJUSTMENTS THAT SHOULD BE MADE TO THE COMPANY'S NET POWER COSTS WITH RESPECT TO THE LONG-TERM FIRM WHOLESALE SALES CONTRACTS THAT ARE INCLUDED?

A. Yes, there are several. The first problem is associated with the Deseret contract. There are various provisions included in this contract, but the one provision of concern pertains to "Supplemental Energy". A copy of the relevant section of the contract can be found in Exhibit CCS-7.6. Although there has been a line in the Company's power cost model for a long-term firm wholesale sale under the heading of "Deseret Supplemental" for the 1997, 1998, and the current test years, the current case is the only one where actual sales have been listed.

Unlike the pricing provisions of many Post-1995 wholesale sales contracts, this particular contract provision requires that prices be set at the Heavy Load Hour (HLH) and Light Load Hour (LLH) market prices. Although the monthly prices listed in the Company's Power Cost Model are generally higher under the Deseret Supplemental contract ($18.77--$95.94 per MWH) than those listed for other Post-1995 wholesale contracts, they are substantially below the incremental cost (short-term firm) that the Company incurs to serve this load ($49.58--$135.95 per MWH). Therefore, the Company's power cost model (contrary to the contract) is pricing these sales below incremental cost and presumably below the HLH and LLH market prices that will actually be received for these sales.

Q. WHAT TYPE OF AN ADJUSTMENT SHOULD BE MADE TO THE COMPANY'S NET POWER COSTS TO CORRECT THE PRICE RECEIVED FROM THE "DESERET SUPPLEMENTAL" SALE TO BE MORE IN LINE WITH PROVISIONS IN THE CONTRACT?

A. The prices received for these sales should be set at no less than the short-term firm price for monthly purchases in the Utah portion of the system. This adjustment will not provide for any profit, but will insure that the prices charged in the power cost model are no less than the incremental cost that the Company incurs to supply this load. Exhibit CCS-7.7 lists the monthly energy and revenues for this contract that are included in the power cost model. The model shows a total of $21.6 million in revenue based upon 578,380 MWH of sales under this contract for an average price of $37.33 per MWH. By contrast, if this supplemental energy were sold at the average monthly short-term firm price into the Utah Division, then the total revenue collected would be $58.9 million at an average price of $101.75 per MWH. This results in a net increase revenues of $37,263,393 on a total Company basis. On a Utah jurisdictional basis this adjustment (using 37.144% as the allocation factor) is $13,841,115.

My proposed adjustment essentially balances the costs and revenues associated with the contract to produce a neutral impact on the retail customers. If Mr. Falkenburg's recommendation to use actual short-term firm purchase costs is adopted by the Commission, the revenue associated with this contract would have to be adjusted accordingly. The net result would be the same $13,841,115 reduction identified above.

<u>WAPA CONTRACTS</u>

Q. IS THERE ANOTHER POWER COST ADJUSTMENT THAT NEEDS TO BE MADE TO THE WHOLESALE FIRM SALES CONTRACTS?

A. Yes. The Company's net power costs include two long-term firm wholesale sales contracts with the Western Area Power Administration (WAPA) that are referred to as WAPA I and WAPA II. Both of these contracts have termination clauses that allow WAPA to terminate the contract early if the United States Congress does not make the necessary funding available to continue to make these purchases. In fact, six months ago the WAPA II contract was terminated and the Block "A" of the WAPA I contract was also terminated. The Block "A" of the WAPA I contract that was terminated had market based rates while the Blocks "D" of the WAPA I contract had a fixed energy price of $32.00 per MWH. The WAPA II contract was to be based upon market rates beginning in 2001.

Q. WHAT PRICES DID THE COMPANY INCLUDE IN ITS POWER COST MODEL FOR THE WAPA I AND THE WAPA II CONTRACTS?

A. The average price listed in the Company's power cost model for the WAPA I contract was $36.29 per MWH while the average price for the WAPA II contract was listed at $40.82 per MWH. In contrast, the market based prices for short-term firm purchases that support these contracts were listed at between $77.11 per MWH and $138.86 per MWH.

Q. REGARDING THE WAPA CONTRACTS, WHAT ADJUSTMENT DO YOU RECOMMEND?

A. WAPA did not terminate these contracts during the test year ending September 30, 2000, when the actual market prices were relatively low, but on the rise. However, the Company did not use actual test year market prices in its power cost model. Instead it used a form of normalized or going forward prices. It is inappropriate for the Company to adjust test year short-term firm and non-firm purchase prices and not adjust contracts that can (and do) react to those changing (higher) prices.

Because these contracts had provisions that allowed WAPA to terminate them if the prices got too high, and WAPA did in fact eventually terminate the market-based portions of the contracts when prices continued to increase, the market-based portion of the WAPA I contract and the entire WAPA II contract should be removed from net power costs. Page 1 of Exhibit CCS-7.8 outlines this adjustment. The Market Base Block "A" of the WAPA I contract that is removed produced revenues of $4.1 million while the WAPA II contract produced revenues of $24.4 million. The associated market-based purchase power cost found in the Company's power cost model to serve this market-based load is $69.5 million. The net adjustment on a total Company basis is $40,999,308. On a Utah jurisdictional basis, the removal of the market-based components of the WAPA contracts that have in fact been terminated results in a lowering of the Company's net power costs by $15,228,783 ($40,999,308 x 0.37144).

If Mr. Falkenburg's proposal to use actual test year short-term firm purchase power costs is adopted, my adjustment would still be appropriate, but it would be reduced as shown on page 2 of Exhibit CCS-7.8. Using the "SG" allocation factor of 37.144%, my adjustment for the WAPA contracts would be reduced to $3,956,589 ($10,652,143 x 0.37144).

If Mr. Falkenburg's proposal to remove all long-term sales contracts that will have expired by the end of 2000 is adopted, my adjustment would essentially be the same as his for these contracts. These contracts (or portions of contracts) should only be removed once.

Citizens Power Contract

Q. IS THERE ANOTHER POWER COST ADJUSTMENT THAT NEEDS TO BE MADE TO THE WHOLESALE FIRM SALES?

A. Yes. Unlike most of the other long-term firm wholesale sales contracts in the Company's filing, the Citizens Power contract is only for electricity that is to be delivered during the "Super-Peak". During the summer months of April through September, electricity is to be delivered Monday through Friday, excluding holidays, during the hours 11 a.m. through 6 p.m. During the winter months of October through March, electricity is to be delivered Monday through Friday, excluding holidays, during the hours 2 p.m. through 10 p.m. Electricity that is only delivered during these hours is far more expensive to provide than that which is supplied during light-load, orheavy-loadhours. The average price for electricity delivered under this contract is listed as $30.50 per MWH in the Company's power cost model. This price is significantly below the average generation and transmission price of $37.60 per MWH charged retail customers in this case[21]; however that price reflects the average cost of usage during all hours of the day and every day of the week. Electricity provided during only the super-peak hours should be priced significantly above the average cost of generation and transmission on the system. Because this contract is being essentially supplied out

[21] See Exhibit CCS-7.1 page 1 of 3.

of short-term firm purchases; it should also be priced significantly above the average short-term firm purchase price of $105.12 per MWH,[22] which reflects purchases during every hour of every day.

Q. REGARDING THE CITIZENS POWER CONTRACT, WHAT ADJUSTMENT DO YOU RECOMMEND?

A. The Company's power cost model does not break out costs or revenues by light-load, heavy-load, or super-peak load hours. Consequently, it would be difficult to impute the actual cost of this contract within this model. The easiest thing to do would be to remove the revenues and expenses associated with this contract from the Company's power cost model. This type of an adjustment does not fully address the problem because the Company's actual costs are higher because it is serving a wholesale load only during the super-peak period and, therefore, its costs are raised disproportionately. However, for purposes of this case, this adjustment will at least serve to remove a portion of the subsidy that is flowing from retail customers to this wholesale customer.

Page 1 of Exhibit CCS-7.9 lists by month the energy and revenues associated with the Citizens Power contract in the Company's power cost model. Removing these revenues and the corresponding short-term firm purchase power costs results in a net adjustment of $9,557,440 on a total Company basis. On a Utah jurisdictional basis, the adjustment reduces net power costs by $3,550,016 ($9,557,440 x 0.37144).

If Mr. Falkenburg's proposal to use actual test year short-term firm purchase power costs is adopted, my adjustment would still be appropriate, but it would be reduced as shown on page 2 of Exhibit CCS-7.9. Using the "SG" allocation factor of 37.144%, my adjustment for the Citizens Power contract would be reduced to $1,186,798 ($3,195,161 x 0.37144).

If Mr. Falkenburg's proposal to remove all long-term sales contracts that will have expired by the end of 2001 is adopted, my adjustment would not change from the original proposal, i.e., an adjustment on a Utah basis of $3,550,016 should be made.

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[22] Company's Normalized Power Cost for Utah area purchases of Short-Term Firm

LOSSES ASSIGNED TO UTAH

Q. ARE THERE CONCERNS WITH RESPECT TO THE ENERGY AND COINCIDENT DEMAND DATA USED TO DEVELOP THE UTAH JURISDICTIONAL REVENUE REQUIREMENT?

A. Yes. The costs that make up the Utah Jurisdictional revenue requirement are heavily dependent upon the amount of energy consumption and coincident peak demand responsibility that is assigned to the Utah jurisdiction. The greater these values, the greater the revenue requirement.

Measuring equipment left over from the utah Power & Light days is used to define what load is coming into or leaving the Utah Jurisdiction. Similar data gathering equipment has never been used in the Pacific Division. Thus, these same measurements are not made in the Pacific Division. The basic calculation used for the Utah Jurisdiction is that the Utah load equals anything that is generated inside of the jurisdiction, plus any energy that is imported into the jurisdiction, minus any energy that is exported from the jurisdiction. The problem with this calculation is that it assumes that everything that this equation defines as the Utah Jurisdictional load is in fact consumed by, or for, the benefit of Utah Jurisdictional customers. This assumption ignores the fact that there is wholesale load, wheeling load, and system customer load that results in electrical losses within the boundaries of the Utah Jurisdiction which should not be defined as being a part of the Utah Jurisdictional load.

Q. IS IT POSSIBLE TO PRECISELY SEPARATE OUT THE LOSSES THAT ARE DUE TO UTAH JURISDICTIONAL LOAD AND THOSE THAT ARE ASSOCIATED WITH SERVING WHOLESALE, WHEELING, AND SYSTEM CUSTOMERS?

A. This is exactly what should be expected from the loss study that has been requested by the Division in Docket 97-035-01 and for which the Commission wrote:[23]

[23] See page 80 of the Commission's March 2, 1999 Order in Docket 97-035-01.

> Given the serious questions about their appropriateness for use in this Docket, we will grant the request to study loss factors and assign this issue to the cost-of-service task force herein established.

This loss study has gained the reputation of being filed "soon", but "soon" has yet to arrive.

Q. IS THERE A WAY TO DEMONSTRATE THE MAGNITUDE OF THE PROBLEM?

A. Yes. As a part of the overall process of developing individual hourly demand data for the Company's class cost of service study, there is a correction or calibration made to the Company's load research data. The correction is made to the load research data such that the sum of the load research data plus the census data (customer groups that are 100% metered as opposed to sampled), equals the Utah Jurisdictional load as defined above. A positive correction or calibration means that the summation of the load research data and the census data is less than that defined as the Utah Jurisdictional load. A positive correction means that for all customer classes with hourly demand data based upon load research have had their demands increased in order to reflect whatever is defined as the Utah Jurisdictional load. A positive correction also means that the entire Utah Jurisdiction has had its usage increased over that, which can be directly attributed to customer usage. Increased usage is followed by increased revenue requirement for all customer classes—even those whose loads are not measured with load research meters.

Q. IS THERE ANY GENERAL PATTERN TO THE CALIBRATIONS THE COMPANY USES TO MATCH ITS LOAD RESEARCH AND CENSUS DATA TO THAT WHICH IT CALLS THE UTAH JURISDICTIONAL LOAD?

A. Yes. A listing of the average monthly calibration percentages used by the Company to force its load research data (plus its census data) to equate the defined Utah Jurisdictional load is contained in Exhibit CCS-7.10 page 1 of 3. This exhibit lists the average correction made to the load research data for each hour in any given month between January 1999 and September 2000. As can be seen from the data, there are many hours when the average correction for any given month is positive, while there are very few hours during which the corrections are negative. On average during the more than 15,000 hours during this period there was an overall positive correction or bias of 7%. This means that the energy that was assigned to the customer classes with load research data was increased by 7% because of a belief that all of the Utah Jurisdictional load (as defined above) must come from Utah customers. It also means that the Utah Jurisdictional load (as defined above) is much larger than the actual load that can be accounted for from customer usage data.

Q. ARE THERE OTHER PATTERNS THAT CAN BE FOUND IN THIS "LOAD CORRECTION" DATA USED TO MATCH "UTAH JURISDICTIONAL LOAD"?

A. Yes. Exhibit CCS-7.10 Page 2 of 3 and the chart below contain essentially the same average hourly correction data for each month, but it only lists data for the months and hours when the correction was +/- 3%.

Only Months With Average Calibrations Within + or - 3%

Month	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Jan-99											##	##	##	##	##	##	##							
Feb-99								##	##	##	##	##	##	##	##	##	##	##	##	##	##	##	##	##
Mar-99											##	##		##	##	##	##							
Apr-99															##	##	##							
May-99																								##
Jun-99	##																							##
Jul-99																								##
Aug-99																								##
Sep-99									##	##	##	##	##	##	##	##	##		##				##	##
Oct-99										##	##	##	##	##	##	##	##	##	##				##	##
Nov-99										##	##	##	##	##	##	##	##						##	##
Dec-99											##		##	##	##	##	##							
Jan-00									##	##	##	##	##	##	##	##	##							
Feb-00									##	##	##	##	##	##	##	##	##	##						
Mar-00									##	##	##	##	##	##	##	##	##	##						
Apr-00											##	##	##	##	##	##								
May-00											##	##	##	##	##	##							##	##
Jun-00																								##
Jul-00																								##
Aug-00																								##
Sep-00											##	##	##	##	##	##							##	

One would hope that all of the corrections would fall in this range and essentially average each other out. However, an average correction of –3% is as negative as these values get while on Page 1 of 3 it can be seen that the positive values go as high as 16%. What is found on the above chart is essentially the lowest 1/3rd of the corrections that are made.

Of most significance is the fact that those smaller corrections (which are the average of over 700 hours of data each month) are all bundled in essentially the 10 a.m. to 5 p.m. time frame during the fall, winter, and spring months as well as the 12 p.m. hour during summer and fall months. I do not have an explanation to offer for this pattern, but there is no question that a pattern exists. This is not simple random error, but an event(s) is taking place that dictates the time and magnitude of these corrections.

Q. DO ANY OTHER PATTERNS EXIST?

A. Yes. Exhibit CCS-7.10 Page 3 of 3 and the following chart list the hours of each

Only Months With Average Corrections at 10% or Greater

Month	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Jan-99	###	###	###	###	###	###	###																	
Feb-99																								
Mar-99	###	###	###	###	###	###	###																	
Apr-99	###	###	###	###	###	###	###	###													###	###		###
May-99		###	###	###	###	###	###	###	###												###	###		
Jun-99			###	###	###	###	###	###	###													###		
Jul-99		###	###	###	###	###	###	###	###	###							###	###	###	###	###	###		
Aug-99		###	###	###	###	###	###	###	###								###	###	###	###	###	###		
Sep-99			###	###	###	###	###																	
Oct-99		###	###	###	###	###	###	###																
Nov-99			###	###	###	###	###	###																
Dec-99		###	###	###	###																			
Jan-00		###	###	###	###																			
Feb-00		###	###	###	###																			
Mar-00		###	###	###			###																	
Apr-00		###	###	###	###	###	###																	
May-00			###	###	###	###	###	###																
Jun-00		###	###	###	###	###	###	###	###													###		
Jul-00		###	###	###	###	###	###									###	###	###	###	###	###	###		
Aug-00			###	###	###	###	###																	
Sep-00		###	###	###	###	###	###	###													###			

month when the average correction factor was equal to or greater than 10%. As can be seen from that page, the hours in which the largest 1/3rd of the corrections took place was consistently during the hours of 2 a.m. through 7 a.m. with many additional hours from 5 p.m. through 10 p.m. during the months of June and July. Once again, I do not have an explanation to offer for this pattern, but there is no question that a pattern exists. When there is obvious bias to the data such as this, there is usually a very logical explanation. That explanation needs to be found. Until the reason for assigning additional energy and demand to the Utah Jurisdiction is found, Utah will continue to be assigned additional revenue requirement responsibility that it should not be required to shoulder.

Q. WHAT IS A BALLPARK ESTIMATE OF THE IMPACT OF SUCH A PROBLEM ON THE UTAH JURISDICTION?

A. It is possible to place an order of magnitude on the impact of this problem. Without further study, it is impossible to quantify the exact amount of excess demand and energy that is being assigned/allocated to the Utah Jurisdiction. However, if 5% of the demand and energy that is attributed to the Utah jurisdiction in this case were to be removed, then the impact upon the IJA results would be to lower the revenue requirement by $22.8 million.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR THE COMMISSION WITH REGARD TO THE LEVEL OF UTAH JURISDICTIONAL ENERGY AND PEAK DEMAND RESPONSIBILITY THAT SHOULD BE ASSIGNED?

A. Yes. Generally, task forces have served this Commission well with respect to addressing the technical questions that surround issues such as this. Therefore, I recommend that a task force be formed as soon as possible to address this issue before the Company files another general rate case. Additionally, the Company should be ordered to provide the Loss Study it has been conducting --in whatever draft form presently exists-- to this task force. As the Company makes progress on its Loss Study, it can furnish updated information to the task force.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THE REVENUE REQUIREMENT PHASE OF THIS CASE?

A. Yes.