Witness CCS - 6
Exhibit CCS-6

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	Docket No. 99-035-10
In the Matter of the Application of	)	
PacifiCorp for Approval of its	)	PRE-FILED DIRECT TESTIMONY OF
Proposed Electric Rate Schedules	)	RANDALL J. FALKENBERG
and Electric Service Regulations	)	FOR THE COMMITTEE OF
	)	CONSUMER SERVICES

February 4, 2000

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DIRECT TESTIMONY OF RANDALL J. FALKENBERG

Q. Please state your name and business address.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Committee for Consumer Services ("CCS"), under contract with Hayet Power Systems Consulting.

Q. Please briefly describe the nature of the consulting services provided by RFI.

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design and fuel cost recovery issues.

I. QUALIFICATIONS

Q. Please describe your education and professional experience.

A. Exhibit No.____(RJF-1) describes my education and experience within the utility industry. I have more than twenty years of experience in the utility industry and have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal government agencies, and public service commissions. I have been directly involved in a number of cases related to the Beaver Valley, Grand Gulf, Limerick, Millstone, Palo Verde, Perry, River Bend, Susquehanna, and Vogtle nuclear generating facilities, and the Bath County, Brandon Shores, Rocky Mountain, Trimble County, and Wilson non-nuclear power plants concerning the topics of plant cancellation, phase-in, rate base treatment of construction work in progress, prudence, power system reliability, and economics.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for twenty utility companies and the Wisconsin Public Service Commission Staff. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). At EBASCO, I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD III and PROSCREEN II planning models. In particular, I assisted planners in the application of these models to analyze revenue requirements and the financial impact of alternative expansion plans. I also assisted in EMA's educational seminars and trained utility personnel in revenue requirements analysis, production cost modeling, reliability analysis, and other techniques of generation planning.

I was a founder of J. Kennedy and Associates, Inc. in 1984. With that firm I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation and the rate treatment of new capacity additions. I presented expert testimony on these and other matters in more than one hundred cases before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions and courts in Arkansas, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, and West Virginia. Included in Exhibit No. ____(RJF-1) is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc. At RFI, my practice is comparable to that which I directed at Kennedy, my previous firm.

Q. Have you previously appeared before the Public Service Commission of Utah (the "PSC")?

A. Yes. I testified in support of the power cost stipulation in PacifiCorp Docket No. 97-035-01. That stipulation included most of the modeling and data input adjustments that I recommended in the CCS "top sheet" filing.

Q. Have you appeared as an expert in other proceedings involving fuel cost or net power cost issues?

A. Yes. In Texas, I have been involved in a number of recent fuel related cases on behalf of the Office of Public Utility Counsel ("OPC"). I testified in the most recent Southwestern Public Service Company ("SPS") fuel reconciliation case (Docket No. 19512), the most recent Central Power and Light Company fuel reconciliation case (Docket No. 20290) and have filed testimony in a pending Entergy Gulf States fuel reconciliation case (Docket No. 21111). I also assisted OPC in the recent Houston Lighting and Power Company fuel reconciliation. I also have prepared testimony in Georgia (Docket No. 3741-U) and Kentucky (Docket No. 92-490) regarding fuel procurement issues. Finally, I have appeared in a number of other cases where fuel or purchased power costs were at issue. Exhibit No.____(RJF-1) summarizes other cases in which I have appeared.

II. INTRODUCTION AND SUMMARY

Q. What is the purpose of this testimony?

A. The Committee of Consumer Services ("CCS") retained me to review the data and modeling assumptions used in PacifiCorp's power cost normalization model (PD-Mac), as filed by PacifiCorp, in order to make recommendations regarding the proper level of PacifiCorp's net power costs for the 1998 Test Year. Specifically, I will address:

- The proper inputs and modeling assumptions for development of net power costs in PD-Mac; and

- The appropriate rate making treatment for certain other fuel related costs.

Q. What are the major conclusions of your testimony?

A. My principal conclusions are:

1. PD Mac continues to be a reasonable tool for purposes of determining normalized net power costs. In addition, PacifiCorp has reasonably implemented the various adjustments identified in the power cost stipulation in Docket No. 97-035-1, except for one minor item.

2 I disagree with some of PacifiCorp's modeling assumptions used in PD-Mac. I propose a series of adjustments in order to provide a more accurate modeling of PacifiCorp's net power costs. My proposed adjustments (all stated on a total Company basis) are as follows:

A. PacifiCorp has understated the capacity of several generating units. Increasing the capacity of these units to their full rating decreases net power costs by $9.454 million.

B. I disagree with PacifiCorp's use of "normalized" market prices for secondary purchases and sales as opposed to actual. I do not believe it is possible to characterize such an adjustment as a "known and measurable" change. This results in a reduction to net power costs of $1.79 million.

C. Likewise, I disagree with PacifiCorp's normalization adjustment for short- term firm purchases and sales. I propose to use actual sales and prices, but to eliminate losses which occurred in months when PacifiCorp purchased short-term power at a price higher than the company sold it for. This adjustment reduces net power costs by $6.742 million.

D. The dispatch of the Hermiston plant should be determined according to the model logic, not by "forcing" certain inputs. This results in a reduction to net power costs of $611 thousand.

E. I disagree with the modeling of the Cholla Unit # 4 capacity. PacifiCorp has reduced the capacity of this unit by 40 mW to account for spinning reserve. This reduction is inconsistent with the Stipulation in Case No. 97-035-1 and is unwarranted. My proposed adjustment reduces net power costs by $1.935 million.

F. PacifiCorp has eliminated the effect of a refund for coal transportation to Cholla from the PD-Mac run. CCS witness, Mr. Kevin Cardwell, proposes to amortize this refund over a 45-month period. This reduces net power costs by $2.51 million. Mr. Cardwell also recommends adjustments related to above market coal prices at Wyodak. Implementing his recommended Wyodak adjustments reduces net power costs by $6.533 million.

G. PacifiCorp has also eliminated the impact of a liquidated damage award related to the Hermiston plant. I recommend that this be reflected in the test year as well. This adjustment reduces net power costs by $100 thousand.

H. PacifiCorp witness, Mr. Jeff Larson, makes an adjustment to the cost of certain coal plants due to tonnage discounts. Because the tonnages for these plants changed in our final PD-Mac run, this adjustment is modified. The net effect is to reduce net power costs by $50 thousand.

Q. Based on the above adjustments, what total decrease do you recommend to PacifiCorp's net power costs?

A. I recommend that PacifiCorp's net power costs be reduced by $29.725 million on a total Company basis or $10.293 million on a Utah Jurisdictional basis.

III. NET POWER COST ISSUES

Q. Please discuss the PD-Mac model and the review of it that was performed in Docket No. 97-035-01.

A. PacifiCorp ("the Company") has used its PD-Mac model to estimate normalized net power costs for ratemaking purposes since before the Utah Power - PacifiCorp merger. PD-Mac is a production costing tool that was developed in-house at PacifiCorp in the late 1970's and has undergone numerous enhancements. A major update to PD-Mac occurred after the merger, when PacifiCorp modified the model to accommodate the inclusion of Utah Division loads and resources. Normalized power cost results based on PD-Mac have been used in various Utah proceedings over the past decade.

Typically regulators are reluctant to use the fuel and purchase power results developed by running a computer simulation model in place of using actual data. In many jurisdictions throughout the U.S., actual data are applied by using a balancing account. However, Utah regulators have concerns regarding the use of a balancing account and have seen advantages in the use of projected normalized results.

In the 1990 PacifiCorp rate case, a CCS witness identified a number of problems related to PacifiCorp's use of the PD-Mac software for projecting normalized results. Recognizing the concern about relying on a computer model for projecting normalized results in place of using actual data, and at the same time, considering the advantages of avoiding the use of a balancing account, the Division of Public Utilities ("DPU") and the CCS retained Hayet Power Systems Consulting and J. Kennedy and Associates, Inc., to conduct a further audit of the PD-Mac model. In that 1997 PacifiCorp rate case audit, we examined a number of issues related to the PD-Mac including:

1. Does PD-Mac have all of the features necessary to model the PacifiCorp system without ignoring or glossing over important considerations?

2. Does the model have the proper balance between chronological modeling and statistical analysis?

3. What methodology does the model use to monitor transmission interconnections and transmission losses?

4. Is the model documentation adequate to rely on for ratemaking purposes?

5. Is the input data used by PacifiCorp reasonable and realistic?

6. Are there any biases in the input data or model logic which would tend to impact net

power costs?

7. What are the implications of the model performing an energy balance simulation?

8. How does the wholesale energy market evaluation work?

These questions were preliminary to the ultimate question of the audit, e.g. "*Is PD-Mac an appropriate tool to use for ratemaking purposes as applied in the current PacifiCorp rate proceeding?*"

Q. What was the outcome of that effort?

A. We identified a number of modeling issues and recommended changes that should be implemented in PD-Mac. A settlement was reached among the DPU, the CCS and PacifiCorp implementing most, but not all of the recommended adjustments. The Stipulation reduced power costs by approximately $3.1 million on a Utah basis.

Q. How does your effort differ in this proceeding?

A. In the last case the primary focus was on technical or modeling issues. For example, one of the adjustments proposed was to model generators in PD-Mac on a unit rather than plant basis. In addition, the major focus of that effort was to test the reasonableness of PD-Mac in a modeling context. Thus, a substantial amount of effort was spent in verifying calculations within the model.

In this case, we have been asked to perform a broader review, including examining the reasonableness of PacifiCorp's treatment of wholesale transactions in the model.

Q. Please contrast your prior assignment, to the assignment undertaken in this case.

A. In this proceeding many issues surrounding the reasonableness of the model, and many of the inputs have already been resolved. Thus, we focused on three basic issues:

1. Did PacifiCorp reasonably implement the input changes identified in the power cost stipulation in the 1997 rate case?

2. Are there any changed circumstances that have arisen, suggesting a need to modify either the model or the input data?

3. Are there any other issues related to net power costs that should be addressed?

Q. Turning to the first question, are you satisfied that PacifiCorp has implemented the terms of the power cost stipulation in Docket No. 97-035-01?

A. My review indicates that with one minor exception, the Company has adopted the technical adjustments included in the agreement.

Q. Does this mean that all issues surrounding net power costs are resolved?

A. No. While a number of technical issues are resolved, net power costs are not static. In some cases, new input changes may be required because factors (such as fuel prices, unit capacities, etc.) change over time. In other cases, new information may become available that suggests further data modifications are warranted. Finally, PD-Mac does not determine net power costs in a vacuum. Many other factors, such as certain fuel accounting items and power purchases/sales, are not so much “simulated” as “accounted for” in the model. As a result, it is necessary to take a close look at these types of items.

A. <u>Capacity Upgrade Adjustment</u>

Q. Are there any instances where changed circumstances, or better information leads you to recommend further modeling adjustments in PD-Mac?

A. Yes. There are a number of items. <u>First</u>, I believe the Company has seriously understated the capacity of certain generators.

Q. Please explain the issue surrounding capacity ratings.

A. In its database, the Company showed changes in capacity ratings for several units taking place on January 1, 1999, which is outside of the 1998 Test Year. Based on its response to RFI CCS-23.1 [See Exhibit No.___(RJF-2)], these capacity upgrades were related to projects completed in 1997 and 1998. In addition, the Company included the costs of these upgrades in the Test Year.

Q. How does the Company justify not reflecting the increased ratings in the 1998 PD-Mac study?

A. According to the response to the data request, the Company alleges it does not immediately reflect capacity increases because the regulatory and governmental agencies(such as NERC, FERC and DOE) that track unit statistics do so on a calender year basis. It further states that capacity ratings must be verified after collection of enough data has taken place.

Q. Do you believe that these are valid reasons for not reflecting the increased capacities?

A. No. First of all, there should be a proper matching of expense and investment levels within the test year and the corresponding capacity levels. If the costs related to these upgrades have been reflected in the 1998 Test Year, then so should the increases in capacity.

As for the issue of information being reported on a calendar year basis, this is completely arbitrary. If NERC collected statistics only every other year, would the Company wait two years to recognize and upgrade for ratemaking or modeling purposes? Of course not. Net power costs in Utah should not be dictated by the timing of reporting to NERC, FERC and DOE.

As for PacifiCorp's second argument (related to requiring enough time and data to verify the change) this is also a specious argument. The Company was certain enough about the upgrades to include the associated costs in the Test Year. Further, in the data response the Company admitted that these capacity changes were "likely noticed" prior to January 1, 1999 [See Exhibit No.___(RJF-2)]. At the <u>very most</u> the Company could have had some question as to the precise <u>amount</u> of the capacity associated with these upgrades, but there was no doubt that the investments were made and that capacity changes had taken place. However, even questions concerning the amount of additional capacity should have been resolved long before January 1, 1999.

In some cases the capacity upgrades were made in 1997. In others they were completed in 1998. In the case of Huntington, for example, the work was completed in the Second Quarter of 1998, and testing conducted until the end of the year. In my experience, utilities generally only take about six months to complete the testing of an entire new generator. Six months to more than a year seems excessive for testing capacity upgrades.

Finally, it goes without saying that under the circumstances, there was no incentive to complete the testing or verification process. In fact, the incentive would be to delay this until after the 1998 Test Year. This fact alone should be sufficient justification for the Commission to normalize the adjustment for the entire year. If the Company can arbitrarily decide when to acknowledge a capacity increase, there is tremendous potential for abuse. Measurable changes that occurred within a test period should not be considered discretionary on the part of the Company.

Q. You acknowledge that the precise amount of the capacity changes may not have been known as of December 1998. To what extent where the rating changes known and measurable by that time?

A. Capacity ratings are not static. Thus, the exact capacity rating of a unit may never be known perfectly. However, PacifiCorp's generator logs clearly show that by December 1998, the capacity ratings of the units in question met or exceeded the levels shown in the PD-Mac data base for both 1998 and January 1, 1999. Exhibit No.___(RJF-3) summarizes data from the generator logs. It shows that all of the units in question were able to operate for periods of one to eight hours in excess of the levels shown in the PD-Mac database for January 1, 1999. In addition, the maximum daily outputs of each of these units were quite close to the January 1, 1999 ratings. In some cases the expected capacity ratings were exceeded for hundreds of hours in December 1998. Considering that generators may be derated on a daily basis for economic reasons, this information clearly establishes that by December 1998, PacifiCorp's generator upgrades were effective and met or exceeded the January 1, 1999, entries in the PD-Mac database. As a result, this is a known and measurable change that should be implemented for the entire 1998 Test Year.

Q. What is your recommendation regarding this issue?

A. I believe that the Company is trying to take advantage of this situation by manufacturing this "out of test year" argument. I recommend that the Commission reflect the capacity upgrades for the entire year of 1998. This is consistent with PacifiCorp's normalization procedure. In other words, when an event is considered to be known and measurable by the end of the Test Year, then PacifiCorp treats it as if it had occurred for the entire Test Year. This adjustment reduces net power costs by $9.454 million.

B. <u>Cholla Unit # 4 Capacity</u>

Q. Do you agree with the 40 mW derate of Cholla Unit #4 in the PD-Mac database?

A. No. First of all, the stipulation in Docket No. 97-035-01 included a 30 mW reduction in Cholla's capacity. In addition, new information suggests a further modification to this input is warranted.

Q. Please provide some background concerning this issue.

A. In its filing in Docket No. 97-035-01, PacifiCorp derated the capacities of three plants (Carbon, Cholla and Naughton) below the maximum dependable capacity ratings of the units in order to reflect spinning reserve considerations. These data changes were investigated to see if they were appropriate in light of the way that PD-Mac operates and given some of the other data changes that were made in the model audit.

While it was agreed that spinning reserve requirements do impact unit dispatch decisions, and generally lower the efficiency of system operation, it is not appropriate to reflect these considerations by a simple capacity deration to the degree that PacifiCorp had assumed. In fact, capacity deration is a poor way of representing spinning reserve. Spinning reserve requirements are manifested not through a reduction in capacity of any specific unit, but rather by the commitment and dispatch of more generating units at any point in time than is required to serve load. In emergency conditions, operators will “dip into” the spinning reserve to maintain stability of the system. Thus, spinning reserve is really manifested in system dispatch by an increase in the amount of capacity on line and a corresponding reduction in the loadings of units. This in turn increases average heat rates. In Docket No. 97-035-01, we recommended PacifiCorp model individual units in PD-Mac and use corresponding heat rate curves for each unit. Under this approach the model will reflect changes in unit efficiency with changes in unit loading. I also recommended modeling all coal units as “must run minimum” units which was done by lowering the displacement limit to the minimum capacity point at which each unit can operate. This effectively modeled a situation where all coal units are assumed to be on line during all hours. This would naturally provide more than enough spinning reserve because 100% of system capacity would be committed 100% of the time. By modeling individual unit heat rate curves, the cost of these impacts would be accounted for within PD-Mac.

Further, it is incorrect to assume that spinning reserve requirements would result in the complete elimination of capacity, as was the case in PacifiCorp’s modeling of the Carbon, Cholla, and Naughton units. PacifiCorp removed 115 MW of capacity from these plants in its PD-Mac data. Indeed, a review of PacifiCorp’s 1998 operating logs for the units in question demonstrated that these units frequently operated at the maximum dependable capacity and that there appeared to be no systematic deration of unit capacities for spinning reserve purposes.

In the 1997 rate case, the Company did acknowledge, eventually, that it may have overstated the impact of spinning reserve. PacifiCorp also indicated that in the Pacific Division, hydro resources sufficiently satisfied its spinning reserve requirement. While PacifiCorp's database originally showed 115 mW of capacity derations on the Cholla, Carbon and Naughton units, the power cost stipulation only incorporated a 30 mW deration on the highest cost unit in the group, Cholla Unit #4.

Regarding PacifiCorp's use of a 40 mW deration, instead of 30 mW, I believe this is simply a mistake. The power cost stipulation allows parties to modify inputs, but Mr. Widmer's testimony does not provide any explanation or evidence supporting this change. However, it is possible that the Company intends to propose this change and re-open this issue. In either case, the Cholla capacity should be changed from the amount filed by the Company.

Q. Do you think this 30 mW deration of Cholla is still justified?

A. No. I believe that all of the arguments stated above (which were made to PacifiCorp in the last case) remain valid. In addition, it's important to recognize that (at least in part due to this deration) PD-Mac continues to understate the actual generation of Cholla. In 1998, the unit produced 8% more generation than in the normalized PD-Mac run. In 1997 the plant produced 12% more than predicted in the PacifiCorp study. Thus, I believe the continued under-prediction of generation from this unit, as well as the Company's possible decision to re-open this issue, justifies elimination of the Cholla deration. Elimination of the 40 mW deration reduces net power costs by $1.935 million on a total Company basis.

C. <u>Normalization Adjustment to Secondary Sales and Purchases</u>

Q. Do you agree with PacifiCorp's "Type 2" normalization adjustment to secondary sales and purchases?

A. No. These inputs control how the model treats hour- by-hour opportunity sales. In the Type 1 run, actual data were used. In the Type 2 (or normalized) run, prices developed from the Company's market price model and forward price curves were used. The net impact was to decrease the prices for opportunity sales in the Nevada and Four Corners markets and increase prices in the Pacific Northwest and Pacific Southwest markets.

My main problem with this modeling change is that it elevates market price model results over actual data in situations where such price changes are highly speculative and demonstrably inconsistent with the modeling logic underlying PD-Mac.

Q. Please explain.

A. Certain types of normalization adjustments are warranted if they reflect known and measurable changes. For example, if PacifiCorp has a contract with another utility that requires a price change mid year, such changes should be reflected. A number of the Type 2 adjustments I examined are related to this type of situation. Because normalized power costs are intended to be forward looking, prices related to fuel and power contracts should reflect year-end levels.

However, a market price is by its very nature a volatile and dynamic variable. I have developed detailed market price forecasts used in numerous regulatory proceedings for purposes of computing stranded costs. I have also examined numerous market- price forecasts prepared by other experts. It is my opinion that forecasts of market prices are never preferable to actual prices, when the actual data are available. Indeed, in recent cases where I testified concerning market-price issues in Maine and Connecticut, the commissions specifically developed procedures to use actual market prices instead of forecasts for determination of stranded costs related to long-term power contracts. Certainly, there are many situations, particularly those involving stranded costs, where the use of forecasted data is the best alternative. However, that is often the case only because it would be impossible to obtain actual price data for a long forward-looking time horizon.

Part of the problem lies with market prices themselves. They can fluctuate by a substantial amount for both fundamental and psychological reasons. This makes market prices quite volatile and difficult to model. A fundamental problem is that in the short run, supply and demand factors greatly influence price levels. In the long run, the market entry price is a far more important determinant of price levels because most analysts believe that eventually equilibrium levels will be reached. Thus, normalizing historical prices is quite difficult because the actual supply and demand balance under “normalized” conditions remains quite problematical. For long-term forecasts this is not a major issue. Thus, use of forecasts for stranded cost determinations has been an acceptable regulatory solution in many cases. However, I am not aware of a single instance where a regulator expressed a preference for use of “normalized” market prices for a historical test year when actual data were available.

A second major problem is that different models and analysts make widely different assumptions in the modeling of market prices. Once again, I have been in many cases involving market price forecasts and have often found substantial differences in the forecasted market prices.

In the case at hand, PacifiCorp's adjustment is (or should be) intended to reflect what "normalized year-end" market price levels would have been during the Test Year. However, there is little reason to believe that a model's prediction of "normal prices" for a historical period constitutes a "known and measurable" change. To assume so gives far too much credit to market price models and the objectivity of those who use them. To justify the claim that the "normalized" market price is appropriate, it would be necessary for PacifiCorp to demonstrate all of the following are true:

1. When supplied with actual data for the Test Year, the model could replicate monthly prices for each market simulated.
2. All fuel prices for all suppliers modeled in the program represented "normalized" year-end price levels.
3. All generating capacity resources included in the model were included at year-end levels. If new capacity was added during the year, it should be included for a full year in the "normalized" run.
4. All loads modeled reflected weather normalized year-end levels.
5. All out of market power transactions were properly reflected at year-end levels.
6. All unusual plant outages were removed from the database.

This list could probably be expanded. It should be apparent that the creation of normalized market prices at appropriate year-end levels is something that would be quite disputable.

Another problem is that market prices will fluctuate with water levels in hydro dominant regions such as the Pacific Northwest. In the PacifiCorp modeling, it is assumed that average hydro conditions prevail in the development of the models' normalized market price. However, these prices will absolutely change as hydro conditions change. In PD-Mac, 50 different years of water conditions are simulated. Each should have its own market price, yet does not in the PacifiCorp normalization. Thus, PacifiCorp is likely simulating scenarios where "average" market prices were used in both surplus and shortage hydro conditions.

Finally, to justify departure from actual, PacifiCorp should demonstrate that such a departure is warranted. This would entail proving that 1998 was an abnormal year for market prices.

Q. What then, is your recommendation regarding market prices for secondary sales and purchases?

A. Absent any compelling reason to prefer model-generated prices over actual, I recommend that the Commission require the use of actual prices. This adjustment reduces net power costs by $1.79 million.

D. <u>Normalization Adjustment to Short-Term Firm Purchases and Sales</u>

Q. Would similar comments apply in the case of short-term firm purchases and sales?

A. Yes. PacifiCorp has developed another series of normalization adjustments for these transactions. Once again these adjustments are speculative. For example, PacifiCorp has developed the normalized 1998 transaction volumes based on an arbitrary weighting of 1997 and 1998 actual sales volumes. I don’t see how such an approach can be considered known and measurable.

As a result, I recommend that actual volumes and prices for transactions be used where reasonable. However, in many months, PacifiCorp made transactions in the Utah Division where purchase prices were higher than the comparable sales prices. I have eliminated these losses from the analysis. This is consistent with the assumptions made by the Company in its modeling of the normalized prices because in its normalization adjustment the Company assumed no losses occurred. The net impact of this adjustment is to reduce net power costs by $6.742 million.

E. <u>Hermiston Plant Modeling</u>

Q. Are there any modeling issues related to the Hermiston plant?

A. Yes. I recommend that the modeling of the Hermiston combined-cycle gas plant be revised slightly. In the PacifiCorp PD-Mac run, this plant is “forced” by inputs to go off-line in the “fish flush” months of May and June. I believe this modeling treatment is a “hold over” from the Company’s prior modeling technique for this plant. In the PacifiCorp filing in Docket No. 97-035-01, Hermiston was modeled with a high average gas price. Because it would not have been dispatched by the model in this case, its operation was “forced” in the model by adjusting other inputs. In the original modeling, Hermiston was modeled as running fully loaded all months except for the fish flush, when it was “turned off”. In the model audit it was determined that Hermiston’s incremental cost of gas was low enough to allow it to be dispatched correctly in the model. Gas costs were then split into a fixed and variable component, and the plant was dispatched on the basis of economics. Thus, it was proposed (and PacifiCorp accepted) an adjustment to the modeling of this plant. However, the modeling retained the feature that prevented the plant from running in May and June.

In our last review of PD-Mac, there was very little historical data available for Hermiston because it came on line in 1996. Thus, its actual operation throughout the year under “normal” circumstances was difficult to determine at the time. Now there is one additional year of data. In 1998 the unit actually ran at a level much different than suggested by PD-Mac. This suggests that the actual dispatch of the plant is more dynamic than allowed by the model. This led me to re-examine the issue of the Hermiston dispatch modeling.

The reasons for preventing the Hermiston plant from running during the fish flush months (presence of low-cost hydro power in the market) are already considered by PD-Mac. In scenarios with low water levels, PD-Mac could simulate a high level of operation for the plant, even during the fish flush, if it were allowed to do so. In favorable hydro scenarios, the model could simulate the displacement of the plant by low-cost hydro purchases. As a result, we determined it would be reasonable to allow the model to operate the plant during any month when it is available, but to also displace its generation by lower cost energy when available. In the PacifiCorp modeling, PD-Mac is prevented from adjusting the Hermiston displacement in response to the changing water conditions by setting the inputs to turn the plant off every May and June. I recommend these constraints be relaxed and allow the model to dynamically simulate the operation of the plant. This modeling adjustment results in a reduction to net power costs of $611 thousand.

Q. You are not disputing that PacifiCorp has modeled Hermiston in accordance with the settlement?

A. No. However, this is a logical extension of the modeling changes made in the last case and is supported by additional information and further review.

F. <u>Cholla Fuel Cost Issue</u>

Q. Please explain the issue surrounding the Cholla fuel costs.

A. PacifiCorp and Arizona Public Service Company obtained relief from the Surface Transportation Board because the rail carrier for the Cholla plant was determined to have exercised market power in its pricing of rail rates. This resulted in a refund to the plant owners that was booked in December 1998. PacifiCorp has “reversed” this entry on the basis that it pertained to prior periods.

Mr. Cardwell recommends that the Commission compute net power costs based on the assumption that the total refund amount be amortized back to ratepayers over a forty-five month period. This adjustment reduces net power costs by $2.51 million.

G. Hermiston Liquidated Damages Issue

Q. Please explain the issue related to the Hermiston liquidated damages award.

A. PacifiCorp received a $400,000 liquidated damages award related to Hermiston gas purchases in 1998. It appears that the Company reversed this award on the grounds that it applied to 1997 gas costs. As in the case of the Cholla fuel, I believe a longer term (4-year) amortization is appropriate. This adjustment amounts to $100,000. Unless the circumstances are markedly different from the Cholla issue, I recommend a comparable treatment. However, my discovery requests related to this item have not yet been answered by the Company, so this adjustment is offered contingent on later resolution.

H. Wyodak Coal Price Adjustment

Q. Are there any other adjustments to the net power costs?

A. Yes. Mr. Cardwell recommends an adjustment of $4/ton for Wyodak coal due to its above market price. I have input this into PD-Mac and it results in a reduction to net power costs of $6.533 million.

I. Coal Tonnage Synchronization

Q. Please discuss the issue related to the tonnage adjustment.

A. PacifiCorp receives a tonnage discount for some of its coal. However, PD-Mac is not well suited to modeling fuel prices that vary with production levels. Thus, Mr. Larson has computed (See Schedule 5.3) an adjustment to synchronize the coal tonnages used in PD-Mac with the appropriate volume discounts. I have adopted his method, but simply substituted the revised tonnages from my final PD-Mac run. This adjustment decreases net power costs by $50 thousand on a total company basis.

Q. Do you have an exhibit that summarizes these adjustments?

A. Yes. Exhibit No.___(RJF-4) summarizes the results of all adjustments.

Q. Does this conclude your testimony?

A. Yes.