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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	Docket No. 01-035-01
In the Matter of the Application	)	PRE-FILED DIRECT REVENUE
Of PacifiCorp for an Increase in	)	REQUIREMENT TESTIMONY OF
Its Rates and Charges	)	JOSEPH A. HERZ, P.E.
	)	FOR THE UNITED STATES
	)	EXECUTIVE AGENCIES

May 30, 2001

Prepared Revenue Requirement Direct Testimony
of
Joseph A. Herz, P.E.

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DIRECT TESTIMONY OF JOSEPH A. HERZ, P.E.

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Joseph A. Herz. My business address is P.O. Box 1306, 100 East Main Cross Street, Findlay, Ohio 45839-1306.

Q. In what capacity are you employed?

A. I am president of an independent consulting engineering firm operating under the name of Sawvel and Associates, Inc.

Q. Please describe Sawvel and Associates, Inc.

A. Sawvel and Associates, Inc. is a consulting firm serving clients on utility matters throughout the United States, principally in the areas related to electric power supply and transmission arrangements, feasibility studies, rates and regulatory matters.

Q. What is your educational background?

A. I graduated from the University of Nebraska at Lincoln, Nebraska with a Bachelor of Science degree in Electrical Engineering.

Q. Please state your professional experience.

A. From 1970 to 1972, I worked for the Nebraska Public Power District (District). During this time, I was assigned to the General Engineering Offices in the Distribution

Department. My principal duties consisted of revising and updating the District's distribution specifications and standards and analyzing distribution work orders as prepared by the District's regional offices. During 1972, I transferred to the Lincoln Electric System (LES) where I was responsible for the design and supervision of various additions and modifications (both overhead and underground) to LES' electric distribution system. In 1973, I accepted a position with R.W. Beck and Associates, a national consulting engineering firm. My activities consisted primarily of planning and analytical studies related to electric power supply arrangements, feasibility studies and rate studies. On August 1, 1978, I became sole proprietor of an independent consulting and engineering firm, Sawvel and Associates, Inc. In this capacity, I continue to provide consulting services relative to utility systems, principally in the areas mentioned.

Q. Are you a member of any professional organizations?

A. Yes, I am a member of The Institute of Electrical and Electronics Engineers, Inc., the National Society of Professional Engineers, the local chapter of the Ohio Society of Professional Engineers, the American Water Works Association, the American Standardization Society for Testing and Materials, the American Gas Association and the American Public Power Association.

Q. Are you registered to practice as a professional engineer?

A. Yes. I am registered as a Professional Engineer in the states of Indiana and Ohio.

Q. Have you previously provided expert testimony regarding rate matters before any public utility service commission?

A. Yes. I have sponsored testimony before the Federal Energy Regulatory Commission (formerly the Federal Power Commission), Kansas Corporation Commission, Colorado Public Utilities Commission, Florida Public Service Commission, Public Utilities Commission of Hawaii, Public Service Commission of Indiana, Michigan Public Service Commission, Missouri Public Service Commission, New Mexico Public Service Commission, Public Utilities Commission of Ohio, Public Utilities Commission of Texas, Wisconsin Public Service Commission and the Public Service Commission of Wyoming.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Department of the Air Force representing the United States Executive Agencies (USEA).

Q. What is your role in the revenue requirement phase of this proceeding?

A. My role in this phase of the proceeding is to review and analyze PacifiCorp's Power Cost Model and to describe some of the corrections and adjustments that should be incorporated for purposes of establishing Test Year power costs to be included in revenue requirements.

Q. What did you do in preparation for filing your direct testimony?

A. I reviewed PacifiCorp's application, certain testimonies, exhibits and work papers pertaining to PacifiCorp's Power Cost Model. I reviewed certain responses to interrogatories and requests for production of documents submitted by USEA and various intervenors to this proceeding. I reviewed some of the testimonies filed by PacifiCorp and others in PacifiCorp rate applications before the Oregon Commission and in a prior UP&L retail rate application. In addition, I had several useful and helpful discussions with PacifiCorp representatives regarding PacifiCorp's Power Cost Model in an attempt to achieve a better understanding and familiarity with the Power Cost Model and some of its inputs. I prepared certain analyses of PacifiCorp's thermal unit availability factors and scheduled maintenance and the impact of the corrections and adjustments on PacifiCorp's Power Cost Model results described later in this testimony. PacifiCorp's Power Cost Model was used to evaluate the impact of the corrections and adjustments described in my testimony.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibits USEA-_____ (JAH-2) through ______(JAH-4). Exhibit USEA-_____(JAH-2) summarizes the impact the Power Cost Model corrections and adjustments have on Test Year revenue requirements. Exhibit USEA-_____(JAH-3) provides the analysis of PacifiCorp's thermal operating equivalent availability for use in adjusting the availability factor inputs to PacifiCorp's Power Cost Model. Exhibit USEA-_____(JAH-4) provides the analysis of PacifiCorp's historical scheduled maintenance outages and the unit maintenance schedule adjustment to PacifiCorp's

Power Cost Model. My workpapers USEA-WP-1 through USEA-WP-6 are also provided with this testimony.

Q. Were these exhibits prepared by you or under your direct supervision?

A. Yes, they were.

II. SUMMARY OF POWER COST MODEL CORRECTIONS AND ADJUSTMENTS

Q. Please summarize your findings.

A. Based on my review of the information obtained and the analyses described later in my testimony, my findings are that there are at least two corrections that need to be made to the Power Cost Model inputs, and there are adjustments required to PacifiCorp's thermal unit modeling of availability factors and scheduled maintenance. As will be described in my testimony, the corrections and adjustments to the Power Cost Model are:

1. Correct PacifiCorp's use of 1999 Utah Retail Sales in one portion of the Power Cost Model rather than the normalized Test Year sales ending September 30, 2000. Perhaps when PacifiCorp updated its Power Cost Model from the 1999 Test Year to the Test Year ending September 30, 2000, it overlooked updating a portion of its model that referenced and utilized 1999 Utah Retail Sales rather than the updated Test Year sales.

2. Correct the modeled capacity inputs of the Colstrip units from the prior rating of 70 MW to the current rating of 74 MW for each unit.

3. Adjust the availability factor inputs for PacifiCorp thermal units, except for the Gadsby units, based on six-year historical averages rather than the four-year averages utilized by PacifiCorp; and, adjust the Gadsby units availability factors to the thermal system weighted average availability factor.

4. Adjust thermal unit scheduled maintenance inputs to a six-year historical average rather than the four-year average used by Pacificorp, and adjust the timing of scheduled maintenance on certain units from June to February and April.

Q. Based on these conclusions, what are your recommendations to this Commission?

A. It is my recommendation that this Commission establish Test Year revenue requirements in this proceeding based on Test Year power costs that incorporate the corrections and adjustments to the Power Cost Model inputs summarized above. The following tabulation summarizes the impact of the Power Cost Model input changes on Test Year Power Cost Model results:

Description of Correction or Adjustment	Impact on Utah Test Year Revenue Requirements Increase/(Decrease)
1. Correct use of 1999 Utah Retail Sales to Test Year Sales in Power Cost Model	($ 7,510,000)
2. Correct modeled capacity of Colstrip Units from 70 MW to 74 MW	($ 2,429,000)
3. Adjust thermal availability factors in Power Cost Model to six-year average	($ 21,409,000)
4. Adjust scheduled maintenance in Power Cost Model to six-year average and timing of maintenance periods	($ 21,443,000)

Source – see Exhibit USEA-_____(JAH-2).

The combined impact of the corrections and adjustments summarized above decrease Utah Test Year revenue requirements by approximately $43,229,000.

III. PACIFICORP'S USE OF 1999 UTAH RETAIL SALES

Q. Please describe the correction of PacifiCorp's use of 1999 Retail Sales rather than the Test Year sales ending September 30, 2000.

A. The Power Cost Model calculates retail and wholesale (firm and non-firm) sales, energy purchases and energy generated for the PacifiCorp system and then allocates these sales, purchases and generation to the UP&L and PP&L Divisions. The Power Cost Model subtracts retail and wholesale sales from purchases and generation to calculate the excess or shortage of energy needed to meet the PacifiCorp systemwide energy requirement. The excess or shortage is referred to as Secondary energy. The Test Year Power Cost Model resulted in the PacifiCorp system purchasing Secondary energy. However, the amount of Secondary energy purchases calculated for the UP&L Division were less than it should have been because the Power Cost Model used 1999 retail sales instead of 2000 retail sales for the UP&L Division. The 2000 Utah retail sales are greater than the 1999 Utah retail sales. Secondary energy was calculated correctly for the PacifiCorp system. Thus, correcting UP&L retail sales to 2000 retail sales will increase UP&L Secondary energy purchases and decrease PP&L Secondary energy purchases. PP&L Secondary purchase energy prices in the Power Cost Model are greater than UP&L Secondary purchase energy prices. Thus, the net result of this change decreases PacifiCorp systemwide Secondary energy purchase costs and decreases net power costs to the Utah revenue requirements.

Q. What impact does the Utah retail sales correction have on Power Cost Model results?

A. Correcting the 1999 Utah retail sales reference in the Power Cost Model decreases PacifiCorp's results by approximately $20.4 million on a total company basis (see workpaper USEA-WP-2).

IV. CORRECT COLSTRIP CAPACITY

Q. Please describe the correction that should be made to the capacity input for the Colstrip units in the Power Cost Model.

A. The Power Cost Model provided by PacifiCorp uses a capacity rating of 70 MW for each of the two Colstrip units. Rebuttal testimony recently filed by PacifiCorp before the Public Utility Commission of Oregon indicates that the capacity input amount for the Colstrip units of 70 MW represents the prior capacity rating for the units and that the current capacity rating for each unit is now 74 MW. A copy of a portion of PacifiCorp's rebuttal testimony filed in Oregon describing the use of a prior rating as an input for the Colstrip units is provided with my workpapers (see workpaper USEA-WP-1).

Q. What impact does this correction of the capacity input for the Colstrip units have on Power Cost Model results?

A. Correcting the capacity inputs for the Colstrip units decreases PacifiCorp's Power Cost Model results by approximately $6.6 million on a total company basis (see workpaper USEA-WP-3).

V. THERMAL AVAILABILITY FACTORS

Q. Please explain how the thermal generating unit availability factors input in the Power Cost Model affect Test Year revenue requirements in this proceeding?

A. The power cost component of PacifiCorp's Test Year revenue requirements is determined from the results of the Power Cost Model. One of the steps in the determination of the Test Year power cost component is to determine the level of thermal generation for the Test Year. The Power Cost Model calculates the amount of energy available from each thermal unit based on the availability factor input for each unit for the Test Year, decreased by that unit's scheduled maintenance input (the scheduled maintenance inputs are described later in my testimony). In summary, the Power Cost Model calculates the amount of energy from each thermal unit by multiplying the capacity of the unit by the availability factor input for the unit, times the number of hours the unit is available for operation and not on maintenance. In other words, the higher the availability factor input for a thermal unit in the Power Cost Model, the more energy the Power Cost Model will calculate to be available from that unit. Increased energy from PacifiCorp's thermal generating units, because of an increase in the availability factor inputs, will decrease Test Year Secondary purchases and/or increase the amount of off-system (Secondary) sales. Accordingly, the availability factor inputs, and the scheduled maintenance inputs in the Power Cost Model described later in my testimony, have a direct, and significant, impact on Power Cost Model results and on the power cost used to establish PacifiCorp's Test Year Revenue Requirements in this proceeding.

Q. How did PacifiCorp determine the availability factors to be input in the Power Cost Model?

A. With the exception of the Gadsby units, PacifiCorp used the average of each unit's four-year historical (1994 through 1999) operating equivalent availability. PacifiCorp indicates that using four-year averages for the availability factor inputs levelizes annual fluctuations in unit operation and performance (see direct testimony of Mark T. Widmer, page 8, lines 8-16). The four-year period used by PacifiCorp is 1996 through 1999. In the case of the Gadsby units, PacifiCorp did not use the historical four-year average for each unit as the availability factor inputs in the Power Cost Model. Instead, PacifiCorp used availability factors that are lower than the four-year average for each unit.

Q. Have you analyzed the availability factor inputs to the Power Cost Model utilized by PacifiCorp and the historical operating equivalent availability of PacifiCorp's thermal units?

A. Yes I did. Exhibit USEA-_____ (JAH-3) provides the historical operating equivalent availability of PacifiCorp's thermal units for the six-year period 1994 through 1999. I have analyzed the six-year average operating equivalent availability for each of PacifiCorp's units as well as "rolling" four-year averages commencing with the 1994 through 1997 period. Exhibit USEA-_____(JAH-3) also illustrates the operating equivalent availability of each unit for the historical six-year period graphically and provides a comparison with each unit's historical six-year average and with the availability factor that Pacificorp used as the input for that unit in its filing.

Q. Please summarize the findings from the analyses provided in Exhibit USEA- _____ (JAH-3).

A. The analyses indicate that the operating equivalent availability of PacifiCorp's thermal units has historically fluctuated from year to year, and that such fluctuations can be significant. Accordingly, attempts to levelize each unit's operating equivalent availability, rather than utilizing that unit's actual operating equivalent availability in the Test Year, appears to be appropriate for purposes of establishing Test Year revenue requirements in this proceeding. However, the analyses indicate that the 1996 through 1999 four-year average used by PacifiCorp understates the historical operating equivalent availability of PacifiCorp's thermal units as compared to the six years of actual operating equivalent availability from 1994 through 1999. This occurs because of a declining trend in unit operating equivalent availability of the thermal units in the 1996 through 1999 four-year period.

Q. Please explain the declining operating equivalent availability trend of PacifiCorp's thermal units.

A. Although results will vary between thermal units, PacifiCorp's thermal unit operating equivalent availability, on a system-wide basis, is significantly lower in the last two years of the six-year historical period than in the first two years of that six-year period. The last two years, 1998 and 1999, are lower than the average of the six-year historical period. The following tabulation summarizes PacifiCorp's weighted average operating equivalent availability of its thermal units.

Year	Weighted Average Thermal Operating Equivalent Availability
1994	94.10%
1995	93.45%
1996	92.44%
1997	92.04%
1998	91.94%
1999	90.52%
Six-year average (1994-1999)	92.41%
Four-year average (1996-1999)	91.73%

As shown in the above tabulation, PacifiCorp's thermal operating equivalent availability has declined from greater than 94% at the beginning of the historical six-year period (1994) to less than 91% during the last year of the six-year historical period (1999). As a result, use of a four-year average understates the thermal operating equivalent availability of PacifiCorp's thermal units over the six-year historical period. Given the high market value of power in the geographic area that PacifiCorp operates and the low dispatch costs of PacifiCorp's thermal generating units (relative to the market value of power), a decrease or understatement of PacifiCorp's thermal operating equivalent availability has a dramatic impact on power costs. In the Test Year, the dispatch costs of all of PacifiCorp's thermal units are significantly less than the off-system Secondary purchase/sale prices against which the units are compared and dispatched. Accordingly, a decrease, or understatement of PacifiCorp's thermal operating equivalent availability input into the Test Year Power Cost Model results in an increase in Secondary purchase power costs and/or a decrease in off-system Secondary sales that have a dramatic impact on Power Cost Model results. PacifiCorp's availability factor inputs to the Power Cost Model need to be adjusted to reflect PacifiCorp's actual six-year historical average thermal operating equivalent availability, with the exception of the Gadsby units, rather than the four-year average utilized by PacifiCorp.

Q. Should the Commission feel compelled or otherwise decide to accept the use of a four-year historical average of thermal operating equivalent availability rather than the six-year average that you are recommending, do you have any other suggestions or comments that the Commission should consider?

A. Yes, I do. The analysis provided in Exhibit USEA-_____ (JAH-3) clearly indicates that a 1996 to 1999 four-year historical average understates PacifiCorp's operating equivalent availability when compared with the 1994 to 1999 time period. Therefore, should the Commission, for whatever reason, decide to use a historical four-year average, it is my recommendation that the Commission use the historical six-year availability factors for each unit, eliminate the high year and low year of operating equivalent availability for each unit in that six-year period, and average the remaining four years of operating equivalent availability for each unit. This would mitigate the impact of extreme high and low operating equivalent availability that may have occurred for any thermal unit in the six-year historical period and not cause the Test Year modeling results to be influenced by those high/low extremes. Such a calculation is provided on page 1 of Exhibit USEA -

_____ (JAH-3). As previously mentioned, a separate determination should be made for PacifiCorp's Gadsby units.

Q. How should the availability factor inputs for the Gadsby units be determined?

A. Although the historical availability factors of the Gadsby units have averaged in excess of 98%, PacifiCorp's inputs to the Test Year Power Cost Model indicate that the Gadsby units generate energy commensurate with a weighted average availability of approximately 66% (before adjusting for scheduled maintenance). For the Test Year, the Gadsby unit dispatch costs are lower than the prices of Secondary energy purchases and sales in the Power Cost Model. Therefore, the Gadsby units should be dispatched at a higher availability than the 66% used by PacifiCorp. Although the Gadsby units historically operated at a high availability factor, they were used sparingly and thus, the availability factor should be less than the historical average. Accordingly, I recommend that the Gadsby units be modeled at a higher availability factor than the 66% used by PacifiCorp, specifically the system six-year weighted average of 92.41%. I address Gadsby unit maintenance outage hours later in my testimony.

Q. What impact do these changes in thermal availability factors have on Power Cost Model results?

A. These changes decrease Power Cost Model results by approximately $58 million (see workpaper USEA-WP-4).

VI. SCHEDULED MAINTENANCE

Q. What did you review concerning PacifiCorp's generator maintenance in the Power Cost Model?

A. I reviewed PacifiCorp's historical generating unit scheduled maintenance outage times for the six-year period from 1994 through 1999. I also reviewed when each generating unit would be out of service for scheduled maintenance during the Test Year.

Q. How did PacifiCorp incorporate scheduled maintenance in the Power Cost Model?

A. The PacifiCorp Power Cost Model decreases the energy generated from each generating unit to reflect the amount of hours that each unit is unavailable because of scheduled maintenance.

Q. How did PacifiCorp determine the maintenance outage hours for each unit included in the Power Cost Model.

A. PacifiCorp calculated a four-year average of maintenance outage hours for each of its generating units.

Q. What was the resulting four year average of total generator maintenance outage hours calculated by PacifiCorp for the power supply system?

A. The four-year average is 16,181 hours.

Q. Do you agree with the outage hours calculated by PacifiCorp?

A. PacifiCorp calculated the four-year average correctly. However, it is unclear why a four-year average is appropriate.

Q. Do you have a suggested alternative method of estimating maintenance outage hours for the system?

A. Yes. I believe an alternative method that considers that the generating units and system are a long-term investment that should be maintained for the benefit of the ratepayers is more appropriate. Presumably, PacifiCorp and other major electric utilities in the United States strive to maximize availability and thus, energy generated from low cost coal-fired generating units such as the units owned by PacifiCorp. Therefore, a longer-term average should be used to more appropriately reflect maintenance over the maintenance life cycle.

Q. What do you recommend for an appropriate period over which to calculate maintenance outage hours?

A. Other than the Gadsby units, I recommend that an average over six years is a more appropriate period to use. The recommended maintenance outage hours for the Gadsby units is described later in my testimony.

Q. Why is six years more appropriate?

A. As I stated earlier, a longer period, such as six years, is more appropriate because it would be more likely to incorporate the long-term maintenance cycle that is commensurate with large coal-fired generating units. It will also decrease the impact of periods of high maintenance or low maintenance to significantly impact the results of an average calculated over a shorter time frame such as four years.

Q. In your opinion, would this situation occur in this rate case if the PacifiCorp four-year average calculation is accepted by the Commission?

A. Yes. I believe that it has a significant impact on the results of the Power Cost Model.

Q. How did you calculate the impact on the results of the Power Cost Model?

A. Adjustments were made to the PacifiCorp Power Cost Model to use scheduled maintenance inputs based on the six-year average of maintenance hours for each generating unit instead of PacifiCorp's use of a four-year average. Page 1 of Exhibit USEA-_____(JAH-4) summarizes historical maintenance hours for each unit from 1994 through 1999. Page 1 of Exhibit USEA-_____(JAH-4) also shows the six and four year averages calculated for each unit.

Q. What was the six-year average number of maintenance outage hours that you calculated?

A. I calculated a six-year average of 14,584 hours.

Q. What was the number of maintenance outage hours calculated by PacifiCorp?

A. PacifiCorp calculated 16,181 hours of maintenance for the Test Year. The amount of hours calculated by PacifiCorp is approximately 11 percent greater than the six-year average.

Q. How should the Test Year maintenance outage hours for the Gadsby units be determined?

A. Using the four-year (1996 – 1999) average for the three Gadsby units, PacifiCorp's Power Supply Cost model for the Test Year has a combined total of less than 3 days (53 hours) of maintenance outage time for the Gadsby units. As previously indicated, the Gadsby units have been used sparingly in the past. Therefore, the historical four-year average maintenance outgae may not be indicative of increased maintenance that may occur as a result of increasing the level of operation of the Gadsby units to that used in the Test Year. Accordingly, the maintenance outage time inputs for the Gadsby units was increased to be more representative of PacifiCorp's average. The maintenance outage time of the Gadsby units was increased to a combined total of approximately 24 days (583 hours) (see Page 2 of Exhibit USEA - ____ (JAH-4).

Q. Do you have any other generator maintenance issues that should be addressed?

A. Yes I do. I will address the timing of generator maintenance outages.

Q. Why is the timing of the outages important?

A. In the same manner that maximizing the amount of energy generated from PacifiCorp's low cost generating resources is important to minimizing rates to retail ratepayers, the times when maintenance occurs during the year, and even during the month, can impact the price of energy that PacifiCorp would need to purchase to replace the energy that is not generated by the unit when it is out of service for maintenance or may decrease the revenues that would not be achieved if generating units are not available to increase sales at high market prices.

Q. Please give an example.

A. Typically, in the summer months of June, July and August, market energy prices have been higher than energy prices in the spring and fall months. The Power Cost Model inputs show similar market price differences in different months of the year.

Q. For Test Year Power Cost Model purposes, what maintenance schedules should be modified?

A. The PacifiCorp Power Cost Model for the Test Year should be modified to include maintenance schedules that maximize generator maintenance during lower market price periods so that it can maximize the amount of energy generated from its units during higher market price periods. For instance, the Power Cost Model indicates an energy sales price of $170 per MWh in June as compared to $72.94 and $95.26 per MWh in February and April, respectively.

Q. Does the PacifiCorp Power Cost Model for the Test Year include significant thermal unit maintenance in June?

A. Yes. Eight generating units are modeled by PacifiCorp to be down for maintenance resulting in approximately 840,000 MWh of unavailable energy.

Q. What changes should be made to the Test Year maintenance schedules?

A. The scheduled maintenance period for four of the generating units (i.e. Jim Bridger 1, Dave Johnston 3, Wyodak, Hunter 3) should be moved from June to April or February to take advantage of selling energy during higher market prices in June and purchasing energy during lower market price periods in February and April.

Q. In your review of the Power Cost Model, does it adequately reflect these market price dynamics for maintenance scheduling purposes?

A. No. It does not adequately recognize price inputs for purposes of determining the timing of maintenance outages of PacifiCorp's thermal units.

Q. How then should the Power Cost Model accurately represent current market conditions?

A. Although my intent was not to evaluate the suitability of the Power Cost Model to appropriately model PacifiCorp's Test Year power supply costs, I noticed that it seems to be more of a "looking backward" model as opposed to a "looking forward" model. In other words, the Power Cost Model reflects historical prices and operating practices based on historical price and operating conditions. The Power Cost Model does not recognize the impact that Test Year energy Secondary purchase and sales prices should have on maintenance schedules. Most of the scheduled maintenance input to the Power Cost Model is a direct result of past operating statistics and decisions made based on market power availability and prices at that time, as opposed to how the units would be scheduled for maintenance based on Test Year inputs to the Power Cost Model.

Q. What impact do these adjustments to the maintenance outage time based on a six-year average and the timing of scheduled maintenance have on Power Cost Model results?

A. Adjusting the scheduled maintenance inputs as described above decreases PacifiCorp's Power Cost Model results by approximately $58.1 million on a total company basis (see workpaper USEA-WP-5).

Q. Does this conclude your testimony?

A. Yes it does.