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March 14, 2008

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket No. UE 195

Enclosed for filing in the above-referenced docket are an original and five copies of the Stipulation by the Parties and the Joint Direct Testimony of Ed Durrenberger, Michael J. Youngblood, and Lowrey Brown in support of the Stipulation.

A copy of this filing has been served on all parties to this proceeding as indicated on the attached certificate of service.

Very truly yours,

Wendy McIndoo

Wendy L. McIndoo

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in UE 195 on the following named person(s) on the date indicated below by email and first-class mail addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: March 14, 2008.

Wendy McIndoo

Wendy L. McIndoo
Legal Assistant

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 195

In The Matter of the Application of IDAHO POWER COMPANY for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon

JOINT DIRECT TESTIMONY

OF

ED DURRENBERGER,

MICHAEL J. YOUNGBLOOD

AND

LOWREY BROWN

March 14, 2008

Introduction

Q. Please state your names, occupations, and business addresses.

A. My name is Ed Durrenberger. I am employed by the Public Utility Commission of Oregon ("Staff") as a Senior Utility Analyst. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551. My qualifications are shown in Staff/Idaho Power/CUB Exhibit 101.

My name is Michael J. Youngblood. I am employed by Idaho Power Company ("Idaho Power") as the Regulatory Affairs Representative. My business address is 1221 West Idaho Street, Boise, Idaho 83702. My qualifications are shown in Staff/Idaho Power/CUB Exhibit 102.

My name is Lowrey Brown. I am a Utility Analyst for the Citizens' Utility Board of Oregon ("CUB"). My business address is 610 SW Broadway, Suite 308, Portland, Oregon 97205. My qualifications are listed in Staff/Idaho Power/CUB Exhibit 103.

Q. Are Staff, Idaho Power and CUB (the "Parties") all of the Parties to this proceeding?

A. Yes.

Q. What is the purpose of your joint testimony?

A. The purpose of our joint testimony is to describe and support the Stipulation dated March 14, 2008 (the "Stipulation") of the Parties to settle all of the issues arising out of Idaho Power's August 17, 2007 Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon ("Application"). The Stipulation is being submitted to the Commission herewith.

Q. Could you summarize the major issues addressed in the Stipulation?

A. First, the Stipulation recommends that the Commission adopt for Idaho Power an Annual Power Cost Update ("APCU") and a Power Cost Adjustment Mechanism

("PCAM"). The APCU will be comprised of the following two components: an October Power Cost Update ("October Update") and a March Power Cost Forecast ("March Forecast"). Second, the Stipulation describes the process by which each of these components will be calculated and administered. And third, the Stipulation contains the Parties' agreement that the application of the APCU and PCAM will operate to allow Idaho Power to recover its power cost expenses in a fair and reasonable manner.

Q. Do the parties generally agree that the Commission should adopt an APCU and a PCAM for Idaho Power?

A. Yes. The Parties agree that it will be beneficial for Idaho Power to have these mechanisms by which it can recover its prudently-incurred power expenses on a timely basis.

Q. Are there any considerations unique to Idaho Power that you have attempted to address with the proposed PCAM?

A. Yes, there are two. First, as recognized by the Commission in its order in UE 167, Idaho Power is, among Oregon investor owned utilities, uniquely reliant on hydro generation. Nearly 50% of Idaho Power's total generating capacity is hydro, and the Company depends on its hydro generation to serve approximately 50 % of its total load. By way of comparison, the Commission has recognized that PGE is heavily reliant on hydro at 25% of total generating capacity.

Q. What is the significance to this docket of Idaho Power's unique reliance on hydro?

A. The Parties recognize that rainfall (and snowfall) is highly variable, and because Idaho Power relies on hydro generation to provide nearly one half of its load, the Company's power supply expenses are subject to very significant variations on a regular basis. Moreover, the financial impact of this variation is asymmetric. When regional hydro conditions are poor, it puts upward pressure on power costs overall, and results in greater magnitude power cost increases than the magnitude of power cost decreases when regional hydro conditions are good. These factors, combined with the recurring drought conditions over the past several years, have resulted in power supply expenses significantly in excess of those included in rates and have forced the Company to file for (and receive) multiple excess power supply expense deferrals. The Commission granted the Company's requests for deferred power costs expenses for 2005-06[1], and 2006-07[2]. The Company has also filed an application for 2007-2008, but the Commission has not acted on that application yet.[3]

Q. **You said that there are two considerations that make Idaho Power unique. What is the second?**

A. The second is the Company's limited ability to amortize deferred expenses for inclusion in its rates. Under Oregon's deferral statute, the Commission may not authorize amortizations of deferred amounts with an overall average rate impact of over six percent.[4] This prohibition has resulted in exceedingly long delays between the time the Company incurs excess power costs and their recovery. In 2001 the Commission granted Idaho Power's application to defer excess approximately 4 million dollars in excess power costs that were incurred during the Western Energy

[1] In UM 1198, the Company filed an application for authorization to defer excess power supply expenses for 2005-06. That application was granted (Order No. 05-870) and the Commission subsequently approved $2,889,117 in Oregon jurisdictionally-allocated excess power supply expenses for amortization (Order No. 07-119).

[2] In UM 1261, the Company filed an application for authorization to defer $3,254,778 in Oregon jurisdictionally-allocated excess power supply expenses for 2006-07. The Commission approved the parties Stipulation to approve Idaho Power's recovery of $2,000,000 of the amount requested. (Order No. 07-555)..

[3] In UM 1331, the Company filed an application for authorization to defer $5,705,230 in Oregon jurisdictionally-allocated excess power supply expenses for 2007-08. No action has been taken on that application.

[4] ORS 757.259(8).

Crisis of 2000-01. The Company began amortizing those amounts in May of 2001 and anticipates that they will not be fully recovered until sometime in 2010. Any amounts approved for inclusion in rates from subsequent drought-related deferrals will not begin to be amortized until after that date.

Q. Please describe the process by which the Parties were able to come to agreement on the proposed APCU and PCAM

A. In its Order issued in Idaho Power's last rate case, UE 167, the Commission specifically recognized the Company's unique reliance on hydro generation and its extended amortization of deferred costs, and therefore directed the parties to work together to "consider whether there is a more effective regulatory mechanism for Idaho Power to recover its allowable power costs."[5] Following that Order, the Company began a series of conversations with Commission Staff and the other Parties in which it discussed what form a PCAM for Idaho Power should take. After several months of informal conversations, over which the parties refined alternative proposals, the Company finally filed its Application in this case.

Q. Did the Parties have additional discussions after the Application was filed?

A. Yes. After the Application was filed, the Parties met for settlement discussions on November 5, 2007. At that end of that conference, the Parties agreed to continue settlement discussions at an additional settlement conference which was held on December 7, 2007, which was followed up by a teleconference on December 12, 2007. A final settlement conference was held on March 10, 2008. As a result of these discussions the Company agreed to significant changes to the mechanism proposed in its Application.

[5] Order No. 05-871, p. 7.

Q. Please describe the general framework for the APCU and PCAM to which the Parties have agreed.

A. As we stated above, the Parties have agreed that the Commission should adopt for Idaho Power both an APCU and a PCAM. The APCU is made up of two parts: an October Update and a March Forecast. The PCAM will be implemented by a filing we are calling the Annual Power Expense True-Up.

Q. Please describe the October Update.

A. In October of each year, the Company will file its October Update. This filing will provide calculations for the Company's net power supply expense ("NPSE") on a normalized basis ("Base Power Costs"), and on a unit basis ("the October Update Rate"). The filing will have an effective date of June 1 of the following year and will be based on a test period of the following April through March (the "April through March Test Period" or "Test Period

Q. How will the Base Power Cost be calculated?

A. The following method will be used to calculate the Base Power Cost:

a. The output of the Company's power supply model (AURORA or its successor) will be used to determine the net power supply average dispatch for normal loads and an average of streamflow conditions;

b. The wholesale electric prices for purchased power and surplus sales determined by the Company's power supply model will be replaced with an average forward electric price curve calculated from the previous 12 months (the previous October through the September prior to the October filing) of daily Mid-Columbia heavy load (Mid-C HL) and light load (Mid-C LL) forward price curves for the period starting in the April immediately following the April through March Test Period. Forward prices will be adjusted for inflation back one year using the most recent Global Insight Producer Price Index for

Electric Power. For example: The October 2007 filing of normal power supply expenses would use a Test Period of April 2008 through March of 2009 and would incorporate the average of the daily price curves collected from October 2006 through September 2007 for the period April 2009 through March 2010. This average forward price curve would then be adjusted for inflation back one year to April 2008 through March 2009 using the most recent Global Insight Producer Price Index for Electric Power.

c. The volume of purchased power and surplus sales determined from the output of the Company's "normalized" power supply model run will be re-priced in the following manner:

- Purchased Power
    - Heavy Load – 3.9% above average Mid-C HL prices
    - Light Load – 7.1% above average Mid-C LL prices
- Surplus Sales
    - Heavy Load – 3.6% below average Mid-C HL prices
    - Light Load – 6.6% below average Mid-C LL prices.

Q. What are the variables that will be updated in order to calculate Base Power Costs?

A. The Parties agree that the following power supply expense variables will be updated for the Base Power costs contained in the October Update.

a. Fuel prices and transportation costs;

b. Wheeling expenses;

c. Planned outages and forced outage rates;

d. Heat rates;

e. Forecast of Normalized Load and Normalized Sales

f. Contracts for wholesale power and power purchases and sales;

g. Forward price curve as defined in paragraph 3;

h. PURPA contract expenses; and

i. The Oregon state allocation factor.

Q. What is the October Update Rate and how will it be calculated?

A. As mentioned above, the October Update Rate is the unit expression of Base Power Costs. The October Update rate is calculated by taking the Base Power Costs calculated as described above, and dividing that number by Normalized Sales.

Q. What are Normalized Sales?

A. Normalized Sales are the amount of energy in megawatt-hours that is sold to the customer as measured at the customer's meter. Normalized Sales are used to calculate the rate, per megawatt-hour, required to recover normalized power supply expenses.

Q. How are Normalized Sales determined?

A. Normalized Sales are to be determined in accordance with the methodology employed in Idaho Power's most recently acknowledged Integrated Resource Plan ("IRP").

Q. What is Normalized Load?

A. Normalized Load is the amount of energy in megawatt hours required to be generated in order to meet customer demand on a normal basis, and is measured at the generation source. The difference between Normalized Load and Normalized Sales is the transmission and distribution losses between the generation source and the metered customer sales.

Q. How is Normalized Load to be determined?

A. Normalized Loads is to be determined in accordance with the methodology employed in Idaho Power's most recently acknowledged Integrated Resource Plan.

Q. Have the Parties agreed on the appropriate methodology for establishing the Base Power Cost in the event that the Commission adopts a different methodology for establishing NPSE for Idaho Power?

A. Yes, in the event that the Commission, in a future general rate case, adopts a different methodology for establishing Idaho Power's NPSE, the October Update methodology will be adjusted to conform with the methodology approved in the general rate proceeding.

Q. Please describe the March Forecast.

A. In March of each year the Company will file its March Forecast. The March Forecast will reflect the Company's estimate of expected power supply expenses for the upcoming April through March Test Period allowing for the most recent updates to specific variables: This cost will be termed the Forecast Power Costs. The March Update will also include a unit rate which will be termed the March Update Rate.

Q. What variables will be updated for the March Forecast?

A. The following variables will be updated for the March Forecast:

a. Fuel prices and transportation costs;

b. Wheeling expenses;

c. Planned outages and forced outage rates;

d. Heat rates;

e. Forecast of Normalized Sales and Normalized Loads, updated only for known significant changes since the October Annual Power Cost Update;

f. Forecast Hydro generation from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center in Portland Oregon, and current reservoir levels;

g. Contracts for wholesale power and power purchases and sales;

h. Forward price curve;

i. PURPA contract expenses;

j. The Oregon state allocation factor.

Q. How will the updated forward price curve be derived?

A. The updated forward price curve to be used for market purchased power and surplus sales will be based on the most recent monthly forward curve for the April through March Test Period, with heavy load and light load mid-Columbia prices modified in the following manner:

- Purchased Power
  - Heavy Load – 3.9% above average Mid-C HL prices
  - Light Load – 7.1% above average Mid-C LL prices
- Surplus Sales
  - Heavy Load – 3.6% below average Mid-C HL prices
  - Light Load – 6.6% below average Mid-C LL prices

Q. How will the Forecast Power Costs be calculated?

A. A single water condition run of the power supply model for the April through March Test Period with inputs updated as described above will be used to determine the Forecast Power Costs.

Q. What is the March Forecast Rate and how will it be calculated?

A. The unit cost for the Forecast Power Costs will be termed the March Forecast Rate, and will be calculated by dividing the Forecast Power Costs by Forecast Sales in megawatt-hours.

Q. How will the rate change effective June 1 be calculated?

A. The rate change will be based upon the numbers from both the October Update and the March Forecast as follows:

a. The Sales Adjusted Forecast Power Cost Change is the March Forecast Rate minus the October Update Rate, the result multiplied by the Forecast Sales.

b. The Forecast Change Allowed is 95% of the Sales Adjusted Forecast Power Cost Change.

c. The March Forecast Rate Adjustment is the Forecast Change Allowed divided by March Forecast Sales.

d. The Combined Rate is the sum of the October Update Rate and the March Forecast Rate Adjustment. The Combined Rate is part of the Effective Rate Change described below taking place on June 1 for the June through May power cost year.

Q. Please describe the Annual Power Supply Expense True-Up

A. The Annual Power Supply Expense True-Up is the filing that will be made by Idaho Power to implement the PCAM. In February of each year, beginning in February of 2009, the Company will file the Annual Power Supply Expense True-up. This filing will calculate the deviation between actual net power supply expenses incurred for the preceding January through December period and the net power supply expenses recovered through the Combined Rate for that same period. For the purposes of the true-up, power costs are first calculated on a total system basis and then allocated to Oregon based on the allocation factor.

Q. How will the Annual Power Supply Expense True-Up be calculated?

A. The Actual Power Supply True-Up will be calculated as follows:

a. The Actual Unit Cost for net power supply expenses incurred will be the total Actual (system-wide) Power Supply Expense incurred divided by the Actual Sales. Actual Sales is the actual consumption in megawatt-hours at the customer level ($/MWH) for the April through-March Test Period. Actual Power Supply Expenses include FERC Accounts 501 (Fuel-Coal), 547 (Fuel-Gas), 555 (Purchased Power), and 447 (Sales for Resale).

b. The annual deviation between the Combined Rate and the Annual Actual Unit Cost times the Annual Sales is multiplied by the current Oregon allocation factor in order to determine the Oregon Allocated Power Cost Deviation.

Q. Did the Parties agree on a deadband to be applied to the Oregon Allocated Power Cost Deviation?

A, Yes. A power supply expense deadband based on the Company's authorized ROE (from its last general rate case and using the rate base measured on an Oregon basis from the most recent Oregon Results of Operations report) will be applied to the Oregon Allocated Power Cost Deviation as follows:

a. A positive deviation (actual net power supply expenses greater than those recovered through the Combined Rate) constitutes an excess power supply expense. This expense is first reduced by a deadband that is the dollar equivalent of 250 basis points of ROE (measured on an Oregon basis). If, after applying the deadband, there is still excess power supply expense, 90% of that amount will be deferred for possible recovery by the Company through the mechanism described below.

b. A negative deviation (actual net power supply unit expense less than those recovered through the Combined Rate) is a power supply expense savings. This savings is reduced by the dollar equivalent of 125 basis points of ROE (Oregon basis). If, after applying the deadband, there is still remaining power supply expense, 90% of the savings amount will be deferred for later refunding by the Company to the customer.

Q. How will the Company account for the positive or negative deviation?

A. Subject to the Earnings Test described below, eligible power supply expense deviations calculated by the process described above (after applying the deadbands and sharing) will be added to the Annual Power Supply Expense True-Up Balancing

Account ("True-Up Balancing Account") at the end of each 12-month period ending December, along with 50 percent of the annual interest calculated at the Company's authorized cost of capital. Interest will accrue on the balancing account at the Commission-authorized rate for deferred accounts.

Q. What is the Annual Power Expense True-Up?

A. The Annual Power Expense True-Up is the unit cost of the excess power supply costs or savings in the True-Up Balancing Account. It is derived by dividing the costs or savings in the True-Up Balancing Account by the Forecast Sales for the upcoming Test Period, divided by the Oregon Allocation factor.

Q. Have the Parties agreed to an Earnings Test to be applied before deferred amounts are included in the Company's rates?

A. Yes. Before any amounts in the Annual Power Supply Expense True-Up Balancing Account are approved for inclusion in the Company's rates as a result of the Annual Power Supply True-up, the Commission will apply an earnings test. If Idaho Power is earning within +/- 100 basis points of its authorized ROE on the Company's overall rate base, as measured by the most recent calendar year's Oregon Results of Operations, there will be no true-up adjustment for that year. If the Company's current earnings are more than 100 basis points below its authorized ROE (Oregon basis), the Company will be allowed to recover excess power supply true-up costs, after application of the deadband and 90-10 sharing described above up to an earnings level that is 100 basis points less than its authorized ROE. If the Company's earnings are more than 100 basis points above its authorized ROE (Oregon basis), it will be required to refund to customers power supply expense savings, after application of the deadband and 90-10 sharing, down to the authorized ROE plus 100 basis points threshold.

Q. Please explain how the Effective Rate Change is calculated.

A. The Effective Rate Change equals the Combined Rate (the sum of the October Update Rate, filed in October, and the March Forecast Rate Adjustment, filed in March) plus or minus the Annual Power Supply Expense True-up Rate (subject to Oregon law regarding deferrals).

Q. How are PURPA expenses treated?

A. All PURPA related power supply expenses will be treated the same as all other non-PURPA power supply expenses.

Q. Do the Parties have an opinion as to the impact of the application of the proposed APCU and PCAM?

A, Yes. The parties believe that these mechanisms will operate to produce fair and reasonable rates.

Q. Does this conclude your testimony?

A. Yes.

WITNESS QUALIFICATION STATEMENT

NAME:	Ed Durrenberger
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst
ADDRESS:	550 Capitol St. NE, Ste. 215, Salem, Oregon 97301
EDUCATION:	B.S. Mechanical Engineering Oregon State University, Corvallis, Oregon
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since February of 2004. My current responsibilities include staff research, analysis and technical support on electric power cost issues.
OTHER EXPERIENCE:	I have over twenty years of experience managing boiler plant engineering, operations and maintenance in a heavy industrial manufacturing environment. I have also managed manufacturing and production in high tech equipment manufacturing.

WITNESS QUALIFICATION STATEMENT

NAME	Michael Youngblood
EMPLOYER	Idaho Power Company
TITLE	Senior Pricing Analyst
ADDRESS	1221 West Idaho Street Boise, Idaho 83702
EDUCATION	Bachelor of Science Degree, Mathematics, 1977 Bachelor of Science Degree, Computer Science, 1977 University of Idaho Graduate student in the MBA Program Colorado State University, 1994 - 1996
EXPERIENCE	Became employed by Idaho Power in 1977. Worked in several departments and subsidiaries of the Company, including Systems Development, Demand Planning, Strategic Planning and IDACORP Solutions.

From 1981 to 1988. worked as a Rate Analyst in the Rates and Planning Department. Responsible for the preparation of electric rate design studies and bill frequency analyses. Also responsible for the validation and analysis of the load research data used for cost of service allocations.

From 1988 through 1991, worked in Demand Planning and was responsible for the load research and load forecasting functions of the Company including sample design, implementation, data retrieval, analysis, and reporting. Responsible for the preparation of the five-year and twenty-year load forecasts used in revenue projections and resource plans as well as the presentation of these forecasts to the public and regulatory commissions.

In 2001, Worked in the Pricing and Regulatory Department on special projects related to deregulation, the Company's Integrated Resource Plan, and filings with the Oregon Public Utility Commission (the "Commission") regarding the Company's deferral applications for recovery of excess net power supply expenses.

Provided testimony to the Commission in UE 123/UE 131, UM 1198, and UM 1261.

WITNESS QUALIFICATION STATEMENT

NAME	Lowrey R. Brown
EMPLOYER	Citizens' Utility Board of Oregon
TITLE	Utility Analyst
ADDRESS	610 SW Broadway, Suite 308 Portland, OR 97205
EDUCATION	Master of Science, Engineering Bachelor of Science, Civil Engineering Stanford University, Stanford California
EXPERIENCE	Provided comments and participated in settlement discussions in OPUC dockets AR 495, UE 161, UE 173, UM 1014, UM 1147, UM 1158, UM 1169, UM 1206, and UM 1209. Presented testimony and engaged in settlement proceedings in UE 165, UE 167, UE 170, UE 179, UE 180, UM 1121, UM 1187, and UM 1271. Participated in technical subcommittees for the Governor's Advisory Group on Global Warming, and in the Regional Representatives Group for Grid West. Currently involved in the development of PacifiCorp's and PGE's integrated resource plan. Prior to this, worked as a consultant with KEMA-Xenergy in Portland from 2002 to 2003 on energy and energy efficiency issues. Between 1997 and 2001, freelanced in Colorado for The Valley Journal, Solar Energy International, Energy Systems Engineering, and Resource Engineering providing writing and technical assistance.