RICHARDSON & O'LEARY
ATTORNEYS AT LAW
Tel: 208-938-7900 Fax: 208-938-7904
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

February 16, 2010

Public Utility Commission
Attn: Filing Center
550 Capitol Street NE #215
PO Box 2148
Salem, OR 97308

Re: **In the Matter of Idaho Power Company 2010 Annual Power Cost Update, Docket No. UE 214**

Dear Filing Center:

Enclosed please find the Joint Rate Spread Testimony in Support of Partial Stipulation of the Public Utility Commission of Oregon Staff, the Oregon Industrial Customers of Idaho Power, and the Citizens' Utility Board of Oregon. Pursuant to O.A.R. 860-013-0060, I am providing the Commission with an original and five copies of the testimony and exhibits, which will be electronically filed today.

The joint parties will soon file the partial stipulation to which this testimony refers.

Thank you for your assistance.

Sincerely,

Greg Adams
Attorney for Oregon Industrial
Customers of Idaho Power

Enclosure

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON
UE 214

IN THE MATTER OF IDAHO POWER COMPANY 2010 ANNUAL POWER COST UPDATE	)

PUBLIC UTILITY COMMISSION OF OREGON STAFF

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

CITIZENS' UTILITY BOARD OF OREGON

JOINT RATE SPREAD TESTIMONY IN SUPPORT OF PARTIAL STIPULATION

DON READING

GEORGE R. COMPTON

GORDON FEIGHNER

February 16, 2010

Q. Would you please state your names, addresses, and occupations?

A. My name is Don Reading. I am a regulatory and utilities economist employed with Ben Johnson Associates, in Boise, Idaho. The Oregon Industrial Customers of Idaho Power ("OICIP") have retained my consulting service for Idaho Power's 2010 Annual Power Cost Update ("APCU").

My name is George R. Compton. I am a Senior Economist, employed by the Economic Research and Financial Analysis Division as a member of the staff of the Public Utility Commission of Oregon ("Commission"). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

My name is Gordon Feighner. I am a utility analyst employed by the Citizens' Utility Board of Oregon ("CUB"). My business address is 610 SW Broadway, Suite 308, Portland, OR 97205.

Q. Have you prepared an exhibit that describes your qualifications in regulatory and utility economics?

A. Yes. Exhibit Staff/OICIP/CUB/101, contains each of our witness qualification statements.

Q. Have other exhibits been prepared in support of this testimony?

A. Yes. Exhibit Staff/OICIP/CUB/102, is Exhibit Staff/102 to Docket No. UE 213, augmented to convey the APCU spread methodology to which the Joint Parties (i.e., Staff, OICIP, and CUB) have stipulated in this Docket (i.e., No. UE 214). Docket No. UE 213 is Idaho Power's (or "Company's") ongoing general rate case for Idaho Power's Oregon service area. The upper portion of Exhibit Staff/OICIP/CUB 102 shows the stipulated cost-of-service and rate spread for Idaho Power's base rates in that docket. The lower portion of Exhibit Staff/OICIP/CUB 102 shows the Joint Parties' proposed APCU spread methodology.

Q. What is your purpose in this hearing?

A. Our testimony will set forth a joint proposal of the Commission Staff ("Staff"), the OICIP, and the CUB. Specifically, our testimony will address the rate spread among customer classes for the $2.59 million revenue increase Idaho Power is requesting in its 2010 APCU, as set forth in Idaho Power's Exhibit 106 in this docket. We will outline a joint proposal to alter Idaho Power's current rate spread methodology for its APCU mechanism. The values used in the following joint testimony will be based on that requested $2.59 million APCU revenue requirement in the filing. If the APCU revenue amount is adjusted to a different value, the joint proposal is to allocate that in line with the method recommended below. Additionally, our testimony relies heavily on the stipulated rate spread cost-of-service calculations in Idaho Power's 2009 general rate case in Docket No. UE 213, under the assumption that the Commission will approve the parties' stipulation in that docket.

Q. By what method did Idaho Power propose to spread their requested revenue increase for their 2010 APCU?

A. Idaho Power, in its filing, proposed to follow the procedure that was used in Docket No. UE 195 that established the Company's power cost adjustment mechanism. This method simply divides the proposed revenue change, in this case $2.59 million, by the normalized jurisdictional forecasted kWh usage. This "equal cents per kWh charge" is applied to each customer's energy usage. The impact of this approach varies significantly among customer classes, with a percentage increase that varies from 1.7 percent for area lighting (Schedule 15) to

10.6 percent for large power service (Schedule 19), as set forth in Idaho Power's Exhibit 106.

Q. Why do you propose a different rate spread methodology?

A. What is being proposed departs from the Company's initial proposal in two important respects. First, the basic or preliminary APCU revenue allocation to each schedule is in direct proportion to that schedule's share of total generation costs (i.e., combining both energy- and demand-related costs as narrowly defined). Substituting generation costs for kWh usage has the effect of converting the allocation from a uniform cents per kWh basis to a uniform percentage of generation costs. This substitution is consistent with how net-variable-power costs were treated in PacifiCorp's most recent docket on this subject.

Second, for purposes of this docket, we support a different rate spread methodology than a pure marginal cost allocation because certain customer classes will be paying overall electricity bills in Idaho Power's Oregon service area that are far less than those classes' costs of service would otherwise require. Consequently, other customer classes will be paying more than their cost-of-service in order to subsidize the underpaying classes.

Cost-of-service-based rates foster inter-class equity and send price signals that encourage energy efficiency.

Q. Which customer classes will be potentially paying energy bills lower than their cost-of-service?

A. Exhibit Staff/OICIP/CUB/102 shows, for the general rate case, that the irrigation class (Schedule 24) and the traffic control class (Schedule 42) will both pay far less than their stipulated cost-of-service. The exhibit shows, at Column I, Line 27, that under the stipulated cost-of-service model in UE 213, the irrigation class would have seen a 70.61 percent increase in base rates, and Column L, Line 27, likewise shows that that the traffic control class would have seen a 93.60 percent increase. But, as set forth in Line 30, the stipulated revenue spread limits the irrigation class's increase to 27.96 percent, and limits the traffic control class's increase to 45.20 percent.

Q. How were those limitations to the increases determined?

A. In addition to cost-of-service rates, another principle of good rate-making is to prevent "rate shock" that would occur if a particular class incurred an unacceptably large increase in its rates. As shown on Line 31 of the same exhibit, the parties to the stipulation in the UE 213 docket have agreed to give the irrigation and traffic control classes increases that would have them paying 75 percent of their cost-of-service index to avoid the rate shock of bringing those classes up to 100 percent of their cost-of-service index all at once. This limitation is described in the Testimony of George R. Compton, Exhibit Staff/100 in Docket No. UE 213, on page five.

Q. Did this leave other customer classes with a rate increase above that required by a strict cost-of-service model?

A. Yes. This is described in the Testimony of George R. Compton, Exhibit Staff/100 in Docket No. UE 213, on page 6. In order to recover the entire revenue requirement increase of $5 million, several customer classes faced rate increases higher than they would have incurred if each class paid 100 percent of its cost-of-service index. From Line 31 of Exhibit Staff/OICIP/CUB/102, it is seen that most Schedules will face an increase that takes them to a level that is 2.87 percentage points above that required by a pure cost-of-service model. Comparing the figures in Lines 27 and 30 of Column G of that same exhibit shows that due to the added increase the large power primary service class, (Schedule 19-P) will face an increase that is approximately 50 percent higher than that class would have seen if each party paid the cost-of-service rates.

Additionally, because the parties agreed that no party should see a rate decrease, the large power transmission class (Schedule 19-T) is prevented from seeing the 10.62 percent decrease in its base rates that would have been justified under the stipulated cost-of-service model.

To conclude, as set forth in Line 31 in Exhibit Staff/OICIP/CUB/102, the residential and large power primary service classes will pay 102.87 percent of their stipulated cost-of-service, and the large power transmission class will pay 111.88 percent of its stipulated cost-of-service. These parties are providing a substantial subsidy to the irrigation and traffic control classes. Although the dollar amount of that subsidy is minimal for the very small traffic control class, the subsidy is substantial to the large irrigation class.

Q. Can the Commission bring the heavily subsidized classes up to a level closer to their cost-of-service in Idaho Power's general rate cases over time?

A. Yes, however, the aforementioned rate shock is a problem if general rate cases are infrequent. This problem is described in Gordon Feighner's Testimony, CUB Exhibit 200 in Docket No. UE 213, at pages 19-20. As that testimony states, over the course of the last several years or so, Idaho Power has not filed rate cases in Oregon very often. Prior to the 2009 general rate case, Idaho Power's last general rate case was in 2005 in Docket No. UE 167. So, in a general rate case like the UE 213 docket where the overall rate increase is high (a stipulated system average of 15.42 percent), the Commission policy that protects customers against rate shock also prevents the kind of rate hike that is necessary to bring irrigators up to par in relation to other class schedules and their respective costs-of-service. As Mr. Feighner explained, throughout most of the 1990s, residential customers regularly received an increase of two or three times greater than the system average in order to bring them closer to their actual cost-of-service. But ultimately for Idaho Power's Oregon customers, the combined effect of the existing subsidy to the irrigators, the infrequency of Idaho Power's general rate cases and the Commission's policy against rate shock prevents the price changes pursuant to Idaho Power's general rate cases that would be sufficient to take the Irrigation Schedule up to its cost-of-service.

Q. How can the APCU be used to address this problem?

A. The APCU filings present an opportunity to reduce the subsidy gradually because Idaho Power files for its APCU each year. Mr. Feighner's testimony proposed that when the APCU energy cost update results in a rate decrease, the decrease should only go to customers who are paying more than 90 percent of their class cost-of-service. When there is a rate increase in the APCU, if the increase is less than 10 percent, customers whose rates are paying less than 90 percent of their class cost-of-service would get two times the overall increase that class would otherwise experience. The excess amount created by increasing the rate hike or avoiding the refund would be spread to other classes in proportion to the subsidy that they pay to the subsidized classes. This proposal would use the APCU each year to gradually bring the subsidized class's overall rates up to their cost-of-service, without the rate shock that would occur if only the infrequent general rate cases were used to bring each customer class's overall rates up to 100 percent of their cost-of-service index.

Q. Do Staff, OICIP, and CUB support Mr. Feighner's proposal?

A. Yes, for the most part. Representatives from Staff, OICIP, CUB, and Idaho Power met in December 2009 and January 2010 to discuss the rate spread issue. An outcome of those meetings was the agreement among Staff, OICIP, and CUB to propose a rate increase to the subsidized parties more limited than the 200 percent of the overall APCU percentage increase suggested in Mr. Feighner's testimony --- at least for this year. (Idaho Power neither opposes nor supports this rate spread approach.) We are limiting our proposal in order to prevent the rate shock that might occur if the subsidized parties paid double the average increase in this APCU on their bills in June 2010, on top of the increase they will see in the general rate case's stipulated increase to base rates.

Nevertheless, an upward adjustment to the subsidized parties of 150 percent of the average APCU increase is clearly warranted, given that several other parties will still see substantial rate increases associated with the combined effect of the APCU increase and the increase to base rates from the general rate case. For example, the residential class will incur a 26.30 percent increase in base rates under the stipulated increase in the UE 213 general rate case, and would at the same time begin paying the APCU increase, which under Idaho Power's filing would average 6.92 percent.

While there is no commitment at this time on treatment of future APCU rate changes, assuming a policy consistent with the direction of this rate spread proposal, over time the gradual, overall rate increase to the irrigation class effected through these annual energy cost updates will bring the irrigation class closer to its cost-of-service. On the other hand, taking no steps to correct the subsidy in the APCU proceedings could lead to the subsidy growing over time and becoming even more difficult to correct in future general rate cases without imposing unacceptable rate shock.

Q. Could you describe in more detail the how the joint proposal for rate spread in the APCU works?

A. Yes. As described earlier in this testimony, Exhibit Staff/OICIP/CUB/102 displays the results of our joint proposal for the APCU rate spread in conjunction with the relevant figures from the stipulated cost-of-service calculations in the UE 213 general rate case. The following steps refer to that exhibit in describing the Joint Parties' stipulated methodology for developing the APCU incremental rates. The first seven steps below (i.e., up through Line 48 of the exhibit) operate as if the 2010 October APCU costs were part of the 2009 general rate case and test period. The final step and subsequent lines in the exhibit incorporate and adjust for the 2010 sales.

In step one (Line 34), the APCU revenue, including both the October Update and March Forecast, is allocated according to each class's share of the total generation marginal cost as determined in the last general rate case. Because the approach stipulated by all parties in the general rate case combines embedded capacity-related and energy-related costs prior to their final allocation to the rate schedules, this step-one treatment of the APCU energy costs is identical to the way they would have been allocated had they been part of the 2009 general rate case test period.

In step two (Line 35), the total dollar amount of a "subsidy correction" is determined by first applying, for any schedule that paid less than 90 percent of their cost-of-service index in the last general rate case, a factor that is the lesser of: a) the prior general rate case subsidy (Line 25 minus Line 29) less any APCU subsidy adjustments made since that case; and b) 50 percent of the APCU dollar amount increase calculated in step one. The factor outcomes for each of those schedules are added together and constitute the amount of the APCU revenue requirement that is to be transferred away from the schedules found in the general rate case to be bearing the subsidy burdens.

In step three (Line 36), are determined the interclass subsidy burdens borne by the various schedules as initially established in the current/last general rate case, and as subsequently reduced in accordance with the subsidy correction that is here being proposed.

In step four (Lines 37- 39), the subsidy correction preliminary dollar amount (calculated in step two) is allocated according to each schedule's share of the general rate case cost-of-service-determined subsidy (calculated in step three), and that amount is shown to be subtracted from the initial APCU allocation of step one.

In step five (Line 40), any negative amount that is produced in step four is eliminated by allocating that amount to the other subsidizing schedules of step four, with the allocation to those other schedules being performed in the same manner as in step four. This step produces the proposed APCU revenue spread.

In step six (Line 47), each schedule's ratable (i.e., loss-adjusted) sales are shown. It is against these sales figures that APCU incremental prices would be multiplied to satisfy the APCU revenue requirement if it were to be collected as part of the 2009 test period.

In step seven (Line 48), each schedule's 2009-oriented APCU incremental rate is determined by dividing its assigned APCU revenue (Line 40) by the loss-adjusted 2009 test-year-projected sales (Line 47).

In step eight (Line 49), the APCU incremental rate for 2010 is determined by adjusting the prices of the previous line by the ratio of total loss-adjusted 2009 test-year sales (Line 47, Column A) to the 2010 October projection (Line 50, Column A). This adjustment is necessary to recover the APCU revenue requirement with the reduced sales projected for 2010 as compared to 2009.

In addition to those eight steps, Lines 42-46 were included to provide an indication of the revenues, percentage rate increases, and final cost-of-service index levels that are the outcome of combining the stipulated general rate case and APCU revenue spreads. Line 51 confirms that the incremental APCU rates will recover the APCU revenue requirement given the 2010 October sales forecasts (Line 50).

Q. Does the joint proposal for the APCU rate spread create additional rate shock to the subsidized classes in the 2010 APCU?

A. The Company's original application in the general rate case docket called for irrigators to receive an in-season average increase in the neighborhood of 47 percent. (*See* Exhibit Idaho Power/1107, Sparks/1.) The APCU docket would add approximately another seven percent, taking the combined total increase for irrigators to around 54 percent—assuming Idaho Power was granted its full general rate case and APCU requests, along with its original rate spread proposals. Exhibit Staff/OICIP/CUB/102 (Column I, Line 43) shows that the irrigation class would incur a combined APCU and 2009 general rate case increase of 42.66 percent—assuming the stipulated revenue requirement and spread were adopted by the Commission, along with the amount of the APCU filed for by Idaho Power. Although that overall increase is high, so is the overall increase for the residential class, which would incur a stipulated combined rate increase of 32.7 percent. (The combined overall average across all schedules is 23.4 percent.) It should also be pointed out from this exhibit (Column I, Line 46) that irrigators' rates would still be approximately 20 percent below the stipulated cost-of-service level. The joint proposal represents a compromise between the Commission's conflicting goals of imposing cost-of-service rates and preventing rate shock.

Q. Do you have any other topics to discuss?

A. Yes. One final topic is how the APCU rate change should be reflected in the tariff sheets, as to whether it is a separate rate schedule or folded into base rates.

Q. How does Idaho Power currently implement the APCU rate?

A. Currently, the APCU rate is implemented as an equal-cent-per-kilowatt-hour allocation represented as a single rate listed on Schedule 55 and is applied equally to all classes of customers. The APCU rate shown on Schedule 55 is a combined rate with two components: 1) the October Update component which reflects the incremental change in normalized net power supply expense (NPSE) as compared to the level included in base rates and 2) the March Forecast component which reflects the level of deviation forecasted to exist between normal NPSE and actual NPSE during the APCU test period.

Q. Do the Joint Parties have a joint proposal to address how the class-specific APCU rates should be implemented?

A. Yes. We recommend that the class-specific rates determined for the October Update component of the APCU be implemented as an adjustment to each class's base energy rates. Further, we recommend that the class-specific rates determined for the March Forecast component of the APCU be listed separately for each customer class on Schedule 55.

Q. Why do the Joint Parties recommend an annual adjustment to base rates to

reflect changes in the October Update component of the APCU?

A. The October Update component of the APCU is based upon a quantification of NPSE under "normal" conditions. This is the same approach used when setting the level of NPSE expense recovery included in base rates during a general rate case proceeding. The October Update component of the APCU is simply an update to the base level NPSE set during a general rate case and is appropriately reflected as a base rate adjustment. Furthermore, the proposed allocation methodology is consistent with the approach applied in a general rate case. As a result, the class-specific rate determination for the October Update is virtually identical to that which would occur during a general rate case. We understand that the Company supports this recommendation.

Q. **Does this conclude your testimony?**

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 214

IN THE MATTER OF IDAHO POWER COMPANY 2010 ANNUAL POWER COST UPDATE	))))))))))

PUBLIC UTILITY COMMISSION OF OREGON STAFF

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

CITIZENS' UTILITY BOARD OF OREGON

JOINT EXHIBIT 101

WITNESS QUALIFICATION STATEMENTS OF DON READING,

GEORGE R. COMPTON, AND GORDON FEIGHNER

February 16, 2010

WITNESS QUALIFICATION STATEMENT

NAME: Don C. Reading

EMPLOYER: Ben Johnson Associates, Inc.

TITLE: Vice President and Consulting Economist

ADDRESS: 6070 Hill Road, Boise, Idaho 83703

EDUCATION: Doctor of Philosophy, Economics C
Utah State University

Master of Science, Economics C
University of Oregon

Bachelor of Science, Economics C
Utah State University

EXPERIENCE: I have provided expert testimony concerning economic and regulatory issues on more than 35 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, Texas, Utah, Wyoming, and Washington.

I have more than 30 years experience in the field of economics. From 1981 to 1986, I held positions at the Idaho Public Utilities Commission as an economist and as director of policy and administration. Prior to that, from 1968 to 1980, I taught economics at Middle Tennessee University, University of Hawaii at Hilo, and Idaho State University.

Relevant to the testimony in this proceeding, I have provided expert testimony on the issues of marginal cost, price elasticity, and measured service. My areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among my recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power. Also among my recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). I have also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho.

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Oregon Public Utility Commission

TITLE: Senior Economist (3/4), Economic Research & Financial Analysis Division (ERFA)

ADDRESS: 550 Capital Street NE, Suite 215
Salem, OR 97301-2551

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah I also taught economics part-time for about ten years at BYU. Prior to my utility regulatory career I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California. I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement have included the IRP/CO_2 Risk Guideline (UM 1302), the AVISTA General Rate Case (UG 181), the 2008 PGE General Rate Case (UE 197), and the 2009 PacifiCorp General Rate Case (UE210).

WITNESS QUALIFICATION STATEMENT

NAME: Gordon Feighner

EMPLOYER: Citizens' Utility Board of Oregon (CUB)

TITLE: Utility Analyst

ADDRESS: 610 SW Broadway, Suite 308
Portland, OR 97205

EDUCATION: Master of Environmental Management
Duke University, Durham, NC

Bachelor of Arts, Economics
Reed College, Portland, OR

EXPERIENCE: I have previously provided testimony in OPUC Dockets UM 1355, UM 1431, UE 196, UE 204, UE 208, and UE 213. Between 2004 and 2008, I worked for the US Environmental Protection Agency and the City of Portland Bureau of Environmental Services, conducting economic and environmental analyses on a number of projects. In January 2009 I joined the Citizens' Utility Board of Oregon as a Utility Analyst and began conducting research and analysis on behalf of CUB.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 214

IN THE MATTER OF IDAHO POWER COMPANY 2010 ANNUAL POWER COST UPDATE	))))))))))

PUBLIC UTILITY COMMISSION OF OREGON STAFF

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

CITIZENS' UTILITY BOARD OF OREGON

<u>JOINT EXHIBIT 102</u>

STIPULATED 2009 GENERAL RATE CASE RATE SPREAD

AND JOINT PROPOSED 2010 APCU RATE SPREAD

February 16, 2010

IDAHO POWER COMPANY, Oregon Jurisdiction: UE 213 & UE 214
Joint Parties Stipulations

General Rate Case (UE 213): Marginal Cost-of-Service Study and Revenue Spread
2009 Test Period

Line	Description	(A) TOTAL SYSTEM/AVERAGE	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) LG POWER TRANS (19-T)	(I) IRRIGATION SECONDARY (24-S)	(J) UNMETERED GEN SERVICE (40)	(K) MUNICIPAL ST LIGHT (41)	(L) TRAFFIC CONTROL (42)
1	*Loss-Inflated Normalized Sales (kWh)*	740,533,031	220,362,881	19,087,766	129,779,060	17,340,865	470,308	195,081,276	90,310,412	67,154,213	14,306	912,800	19,144
2	Current Revenue	$32,433,692	$11,262,377	$1,176,138	$6,331,332	$654,786	$98,625	$6,712,141	$3,243,600	$2,846,148	$772	$106,979	$794
3													
4	Generation Marginal Cost												
5	Generation Demand-Related	$5,368,907	$1,681,622	$160,628	$942,951	$119,727	$519	$1,078,999	$563,709	$819,581	$75	$995	$100
6	Generation Energy-Related	$46,251,305	$13,587,114	$1,187,823	$7,954,222	$1,055,870	$28,374	$11,838,944	$5,800,384	$4,741,513	$863	$55,044	$1,155
7	Generation Total	$51,620,212	$15,268,735	$1,348,451	$8,897,174	$1,175,597	$28,893	$12,917,943	$6,364,093	$5,561,094	$938	$56,039	$1,255
8	Transmission Marginal Cost												
9	Transmission Demand-Related (75%)	$14,714,881	$4,912,854	$433,698	$2,725,422	$348,347	$2,358	$3,117,028	$1,404,982	$1,765,148	$216	$4,540	$289
10	Transmission Energy-Related (25%)	$4,904,960	$1,459,585	$126,429	$859,599	$114,858	$3,115	$1,292,131	$598,176	$444,800	$95	$6,046	$127
11	Transmission Total	$19,619,842	$6,372,439	$560,127	$3,585,021	$463,205	$5,473	$4,409,159	$2,003,158	$2,209,948	$311	$10,586	$416
12	Distribution Marginal Cost												
13	Demand-Related	$9,658,948	$4,441,166	$280,793	$1,812,158	$171,415	$5,820	$1,102,323	$0	$1,833,817	$156	$11,191	$110
14	Customer-Related	$2,877,137	$1,831,719	$489,644	$230,216	$7,279	$0	$18,994	$6,595	$289,732	$261	$1,857	$838
15													
16	Total Functionized Revenue Requirement												
17	Generation	$20,407,194	$6,036,241	$533,088	$3,517,350	$464,753	$11,422	$5,106,895	$2,515,939	$2,198,486	$371	$22,154	$496
18	Transmission	$3,694,492	$1,199,955	$105,474	$675,073	$87,223	$1,031	$830,262	$377,202	$416,142	$58	$1,993	$78
19	Distribution												
20	Demand-Related	$10,306,242	$4,738,791	$299,610	$1,933,600	$182,902	$6,210	$1,176,195	$0	$1,956,711	$166	$11,941	$117
21	Customer-Related												
22	Allocated	$2,611,035	$1,662,306	$444,358	$208,924	$6,606	$0	$17,238	$5,985	$262,935	$237	$1,686	$760
23	Direct Assignment	$414,826	$190,712	$42,634	$18,964	$71	$58,699	$85	$30	$21,595	$43	$81,908	$85
24													
25	Total Cost of Service	$37,433,790	$13,828,005	$1,425,163	$6,353,911	$741,555	$77,361	$7,130,674	$2,899,156	$4,855,869	$876	$119,683	$1,537
26	Revenue Difficiency	$5,000,098	$2,565,628	$249,025	$22,579	$86,769	($21,264)	$418,533	($344,444)	$2,009,721	$104	$12,704	$743
27	% Increase Required	15.42%	22.78%	21.17%	0.36%	13.25%	-21.56%	6.24%	-10.62%	70.61%	13.41%	11.88%	93.60%
28													
29	Proposed Revenue Spread	$37,434,662	$14,224,869	$1,466,066	$6,536,268	$762,838	$98,625	$7,335,324	$3,243,600	$3,641,901	$901	$123,118	$1,153
30	% Increase Required	15.42%	26.30%	24.65%	3.24%	16.50%	0.00%	9.28%	0.00%	27.96%	16.67%	15.09%	45.20%
31	Cost of Service Index		102.87%	102.87%	102.87%	102.87%	127.49%	102.87%	111.88%	75.00%	102.87%	102.87%	75.00%
32	Average Mills Per kWh	50.55	64.55	76.81	50.36	43.99	209.70	37.60	35.92	54.23	62.96	134.88	60.22

2010 October APCU (UE 214): Initial Revenue Requirement Spread and Rates Development Employing the UE 213 Test Period Figures
Method Also to be Applied to the March Forecast

Line	Description	(A) TOTAL SYSTEM/AVERAGE	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) LG POWER TRANS (19-T)	(I) IRRIGATION SECONDARY (24-S)	(J) UNMETERED GEN SERVICE (40)	(K) MUNICIPAL ST LIGHT (41)	(L) TRAFFIC CONTROL (42)
34	2010 October APCU Cost of Service (Allocator -- Line 7)	$2,589,226	$765,867	$67,637	$446,275	$58,967	$1,449	$647,953	$319,217	$278,940	$47	$2,811	$63
35	Subsidy Correction Determination (+ 50%)	$139,501								$139,470			$31
36	General Rate Case Subsidy -- $ (Line 29 - Line 25)	$1,215,224	$396,864	$40,902	$182,357	$21,283	$21,264	$204,650	$344,444	$0	$25	$3,435	$0
37	General Rate Case Subsidy -- %	100.00%	32.66%	3.37%	15.01%	1.75%	1.75%	16.84%	28.34%	0.00%	0.002%	0.28%	0.00%
38	Allocated Subsidy Correction (Allocator -- Line 37)	-$139,501	-$45,558	-$4,695	-$20,934	-$2,443	-$2,441	-$23,493	-$39,540	$0	-$3	-$394	$0
39	Proposed APCU Spread -- Preliminary (Lines 34 + 35 + 38)	$2,589,226	$720,309	$62,942	$425,341	$56,524	-$992	$624,460	$279,677	$418,410	$44	$2,417	$94
40	Proposed APCU Spread (Eliminate the Line 39 negative)	$2,589,226	$719,980	$62,913	$425,147	$56,498	$0	$624,175	$279,549	$418,410	$44	$2,415	$94
42	% Increase Required Due to APCU (Proposed) (Line 40/Line 29)	6.92%	5.06%	4.29%	6.50%	7.41%	0.00%	8.51%	8.62%	11.49%	4.90%	1.96%	8.19%
43	General Rate Case and APCU Combined % Increase (Proposed) ({[Line 29 + Line 40]/Line 2} - 1)	23.40%	32.70%	30.00%	9.95%	25.13%	0.00%	18.58%	8.62%	42.66%	22.38%	17.34%	57.09%
44	Total Cost of Service: 2009 Test Period Plus Oct. 2010 APCU Costs (Line 25 + Line 34)	$40,023,016	$14,593,872	$1,492,801	$6,800,185	$800,522	$78,811	$7,778,627	$3,218,373	$5,134,808	$923	$122,494	$1,600
45	Proposed Combined Revenue Spread (Line 29 + Line 40)	$40,023,888	$14,944,849	$1,528,979	$6,961,415	$819,336	$98,625	$7,959,499	$3,523,149	$4,060,311	$945	$125,533	$1,247
46	Revised Cost of Service Index (Line 45/Line 44)		102.40%	102.42%	102.37%	102.35%	125.14%	102.33%	109.47%	79.07%	102.41%	102.48%	77.95%
47	Loss-Adjusted 2009 Normalized Sales (kWh) (Ex. Idaho Power/1212)	679,301,864	198,558,922	17,201,052	116,956,858	16,177,273	424,083	181,464,005	87,112,615	60,553,810	12,900	823,084	17,262
48	APCU Incremental Rate if for 2009 (Mills per kWh) (1000*{Line 40/Line 47})	3.812	3.626	3.658	3.635	3.492	0.000	3.440	3.209	6.910	3.421	2.935	5.470
49	**APCU Incremental Rate for 2010 (Mills per kWh) (Line 48*{Column A:[Line 47/Line 50]})**	**3.920**	**3.729**	**3.761**	**3.738**	**3.591**	**0.000**	**3.537**	**3.300**	**7.106**	**3.518**	**3.018**	**5.625**
50	*Loss-Adjusted 2010-2011 Normalized Sales (kWh)*	660,516,781	200,042,004	16,369,226	111,282,570	18,713,930	484,271	172,394,542	79,099,343	61,322,820	12,900	777,913	17,262
51	Projected APCU 2010-2011 Revenues (Line 49 * Line 50)	$2,599,735	$745,957	$61,565	$415,974	$67,202	$0	$609,759	$261,028	$435,760	$45	$2,348	$97

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 16th day of February 2010, a true and correct copy of the within and foregoing **JOINT RATE SPREAD TESTIMONY AND EXHIBITS IN SUPPORT OF PARTIAL STIPULATION** was served in the manner shown to:

G. Catriona McCracken CITIZEN'S UTILITY BOARD OF OREGON catriona@oregoncub.org (waived paper service)	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Gordon Feighner Robert Jenks CITIZEN'S UTILITY BOARD OF OREGON Gordon@oregoncub.org bob@oregoncub.org (waived paper service)	__ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Barton L Kline Christa Bearry Gregory W. Said Donovan E. Walker Tim Tatum Scott Wright IDAHO POWER COMPANY bkline@idahopower.com gsaid@idahopower.com dwalker@idahopower.com ttatum@idahopower.com swright@idahopower.com (waived paper service)	__ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile X_ Electronic Mail
Lisa Rackner Wendy McIndoo McDOWELL & RACKNER, P.C. 520 SW Sixth Ave Ste 830 Portland OR 97204 lisa@mcd-law.com wendy@mcd-law.com (waived paper service)	___ Hand Delivery ___U.S. Mail, postage pre-paid ___Facsimile _X_ Electronic Mail
Michael T. Weirich, Assistant AG Department of Justice 1162 Court Street, NE Salem OR 97301-4096 Michael.weirich@state.or.us	__ Hand Delivery _X_U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail

Ed Durrenberger
OREGON PUBLIC UTILITIES COMM.
PO Box 2148
Salem OR 97308-2148
ed.durrenberger@state.or.us

__ Hand Delivery
_X U.S. Mail, postage pre-paid
__ Facsimile
_X_ Electronic Mail

Greg Adams