ORDER NO. 13 166

ENTERED MAY 06 2013

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 257

In the Matter of IDAHO POWER COMPANY, 2013 Annual Power Cost Update.	ORDER

DISPOSITION: STIPULATIONS ADOPTED

I. INTRODUCTION

On October 24, 2012, Idaho Power Company filed its 2013 Annual Power Cost Update (APCU) application. The APCU is composed of two elements—an "October Update" and a "March Forecast." The October Update contains the company's forecasted net power supply expense reflected on a normalized unit basis for an April through March test period. The March Forecast contains the company's net power supply expense based on updated actual forecasted conditions.

Under the terms of Order No. 10-091, Idaho Power allocates the APCU revenue requirement to customer class based on the total generation-related revenue requirement approved in the company's last general rate case. The company adjusts its base rates to reflect changes in revenue requirements related to the October Update, while the rates resulting from the March Forecast are listed on Schedule 55. The rates associated with the October Update and the March Forecast become effective on June 1 of each year.

A prehearing conference was held on November 16, 2012. Parties appearing were Idaho Power, the Staff of the Public Utility Commission of Oregon and the Citizens' Utility Board of Oregon (CUB).

On October 24, 2012, Idaho Power filed testimony regarding its October Update proposed rates. The overall revenue impact of the 2012 October Update compared to the 2011 October Update is a 5.17 percent increase.

On January 25, 2013, the parties filed a partial stipulation relating to the October Update. In their stipulation the parties settled all issues relating to the October Update (October Settlement). The stipulation is attached to this order as Appendix A.

On March 22, 2013, Idaho Power filed testimony regarding its March Forecast proposed rates. The overall revenue impact of the combined October Settlement and March Forecast is an increase of about $2.9 million, or 6.03 percent.[1]

On April 18, 2013, the parties filed a second partial stipulation resolving all issues relating to the March Forecast and an explanatory brief in support of both stipulations. Also on April 18, 2013, Idaho Power filed a motion for the admission into evidence of its pre-filed testimony and exhibits. The second partial stipulation is attached to this order as Appendix B.

II. THE STIPULATIONS

A. October Update

In its October Update, Idaho Power updates the following variables: loads, fuel prices, transportation costs, maintenance rates, heat rates, and forced outage rates for thermal plants. The test period for the 2013 October Update was April 2013 through March 2014 and included plant capacities for all company owned resources and updates sales and load forecast. The 2013 October Update specifically accounts for changes in natural gas and coal prices, generation, and expenses related to contracts entered into pursuant to the Public Utility Regulatory Policy Act of 1978 (PURPA) and the addition of the costs and benefits associated with the Langley Gulch power plant and Neal Hot Springs geothermal purchased power agreement (PPA).

Staff and CUB served discovery on Idaho Power and thoroughly investigated the company's filing. When responding to discovery, Idaho Power revised its exhibits to include an additional year of hydro-generation that had been inadvertently omitted from the original filing. As a result of that correction, the cost per unit dropped from $23.41 per MWh to $23.34 per MWh.

The parties agreed to adjust Idaho Power's filing to include only six months (October 2013 – March 2014) of the Dynamis PURPA contract. That adjustment reduced the estimated Total Net Power Supply Expenses by $3 million on a total system basis.

The parties agreed that Idaho Power's allocation methodology conforms to that adopted in Order No. 10-091. The result of the agreed upon adjustment reduces the Oregon share of APCU revenues from $2.5 million to $2.4 million.

The parties also agreed that Idaho Power's method of repricing PURPA contracts executed in Idaho to reflect Oregon's non-levelized methodology is reasonable.

[1] The $2.9 million increase reflects the $3.7 associated with the 2013 APCU, less the $0.8 million currently included in Oregon customers' rates related to the 2012 APCU.

B. March Forecast

In its March Forecast, Idaho Power estimated the expected net power supply expense for the upcoming water year—April 2013 through March 2014. This estimate included updates for the following variables: fuel prices, transportation costs, wheeling expenses, planned and forced outages, heat rates, forecast of normalized sales and loads updated for significant changes since the October update, forecast hydro generation, wholesale power purchase and sale contracts, forward price curve, PURPA expenses, and the Oregon state allocation factor. In this year's filing, the only variables that had changed since the October Update were (1) fuel prices; (2) the forecast of hydro conditions from the Northwest River Forecast Center; (3) known power purchases and surplus sales resulting from the company's Risk Management Policy; (4) the forward price curve; and (5) PURPA contract expenses.

Idaho Power calculated a cost per unit for the March Forecast of $25.49 per MWh, which is $4.66 per MWh more than last year's unit cost of $20.83 per MWh. Combining the price per unit from the October Settlement and the March Forecast resulted in a cost per unit of $25.37 per MWh. The overall proposed revenue impact of the combined rate is an increase of about 6.03 percent, or $2.9 million.

The parties agreed that the calculation of the agreed upon cost per unit rate is correct and conforms to the methodology adopted in Order No. 08-238.

The parties agree that Idaho Power's allocation methodology conforms to that adopted by the Commission in Order No. 10-191.

The parties agree that the existing and past practice of repricing Idaho Power's levelized PURPA contracts to reflect Oregon's non-levelized requirements is reasonable.

The parties agree that the rates agreed to by the terms of their stipulation should be made effective on June 1, 2013.

III. JOINT EXPLANATORY BRIEF

In their brief the parties describe the process and explain the two stipulations.

Regarding the October Update, they note that the primary drivers of the increased net power supply expenses were the removal of the Hoku special contract, the inclusion of the Neal Hot Springs PPA, lower electricity market prices (resulting in less revenue from off-system sales), reduced hydro generation due to lower stream flows, and a reduction in the Company's system load.

Regarding the March Forecast, they note that fuel prices were updated to reflect changes in forecasted natural gas and coal costs, the hydro update reflected forecasts that are significantly lower than last year's. The decreased hydro forecast resulted in higher variable power supply expenses. The March Forecast also included reduced PURPA expenses that are the result of Idaho Power removing five PURPA contracts from its model.

The parties note that it is this Commission's practice to approve a stipulation if it is an appropriate resolution of the issues in a case and results in just and reasonable rates. Here, the parties agree that the agreed upon cost per unit rate was correctly calculated using the methodology approved in Order No. 08-238. The parties also agree that the company's proposed rate spread conforms to the methodology approved in Order No. 10-191.

IV. DISCUSSION

As described in their joint brief, the parties conducted extensive discovery and review of Idaho Power's filings. The rate calculations and proposed rate spread conforms to the methodologies approved in prior orders. Following our review, we find that the resulting rates are just and reasonable, and that the parties' stipulations should be adopted. Idaho Power's motion for the admission of the pre-filed testimony and exhibits is granted.

V. ORDER

IT IS ORDERED that the stipulations by and between Idaho Power Company, the Staff of the Public Utility Commission of Oregon, and the Citizens' Utility Board of Oregon attached as Appendices A and B are adopted.

Made, entered, and effective MAY 06 2013.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 257

In the Matter of: Idaho Power Company's 2013 Annual Power Cost Update	**PARTIAL STIPULATION**

This Partial Stipulation resolves all issues among the parties to this Partial Stipulation related to Idaho Power Company's ("Idaho Power" or "Company") October Update component of the 2013 Annual Power Cost Update ("APCU") filed pursuant to Order No. 08-238.[1] The APCU updates the Company's net power supply expense and results in new rates, to be effective June 1, 2013.

PARTIES

1. The parties to this Partial Stipulation are Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB") and Idaho Power (together, the "Stipulating Parties").

BACKGROUND

2. Pursuant to Order No. 08-238, Idaho Power annually updates its net power supply expense included in rates through an automatic adjustment clause, the APCU. The APCU is comprised of two components—an "October Update" and a "March Forecast." The October Update contains the Company's forecasted net power supply expense reflected on a normalized unit basis for an April through March test period. The March Forecast contains the Company's net power supply expense based upon updated actual forecasted conditions. Pursuant to Order No. 10-191[2] the Company allocates the APCU revenue requirement to

[1] *Re Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket UE 195, Order No. 08-238 (Apr. 28, 2008).

[2] *Re Idaho Power Company's 2010 Annual Power Cost Update*, Docket UE 214, Order No. 10-191 (May 24, 2010).

individual customer classes on the basis of the total generation-related revenue requirement approved in the Company's last general rate case, instead of the previous equal cents per kWh approved in Order No. 08-238. Order No. 10-191 also directs the Company to adjust its base rates to reflect changes in revenue requirement related to the October Update, while the rates resulting from the March Forecast are listed on Schedule 55. The rates associated with the October Update and the March Forecast become effective on June 1 of each year.

3. On October 24, 2012, Idaho Power filed testimony and exhibits for the 2013 APCU ("2013 October Update").[3] Pursuant to Order No. 08-238 the 2013 October Update updated the following variables: loads, fuel prices, transportation costs, maintenance rates, heat rates, and forced outage rates for thermal plants.[4] The test period for the 2013 October Update was April 2013 through March 2014 and included updated plant capacities for all Company owned resources and updated sales and load forecast.[5] The 2013 October Update specifically accounted for changes in natural gas and coal prices, generation and expenses related to contracts entered into pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and the addition of the costs and benefits associated with the Langley Gulch power plant and Neal Hot Springs geothermal PPA.[6]

4. The 2013 October Update resulted in a cost per unit of $23.41 per megawatt-hour ("MWh").[7] This represents an increase of $3.94 per MWh over last year's October Update.[8]

---

[3] *See* Idaho Power/100 – 107.
[4] Idaho Power/100, Wright/2.
[5] Idaho Power/100, Wright/2.
[6] Idaho Power/100, Wright/2-3.
[7] Idaho Power/100, Wright/8.
[8] Idaho Power/100, Wright/8.

5. The 2013 October Update also included the Company's proposed method of allocation, which was consistent with the revenue spread methodology approved by the Commission in Order No. 10-191.[9]

6. On October 31, 2012, CUB filed its Notice of Intervention. On November 16, 2012, Administrative Law Judge ("ALJ") Lisa Hardie held a prehearing conference at which the parties to Docket UE 257 agreed upon a procedural schedule that would allow the Public Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2013 APCU prior to June 1, 2013.[10]

7. Staff and CUB served discovery on Idaho Power and conducted a thorough investigation of the 2013 October Update. When responding to discovery, the Company revised Exhibits 101, 105 and 106 to include an additional year of hydro generation that was inadvertently omitted from the original filed computations. The original filing made on October 24, 2012, included 83 years of hydro generation and should have included the 84 years of hydro data. As a result of this correction, the cost per unit on Exhibit 105 dropped from $23.41 per MWh to $23.34 per MWh.

8. On January 11 and 16, 2013, the Stipulating Parties conducted two settlement conferences. As a result of these discussions, the parties agreed to the settlement reflected below.

9. This Partial Stipulation, presented on behalf of all parties to the docket, resolves all issues in the docket related to the 2013 October Update filed on October 24, 2012.

---

[9] Idaho Power/100, Wright/12; Idaho Power/106.

[10] *Re Idaho Power Company's 2012 Annual Power Cost Update*, Docket UE 242, Prehearing Conference Memorandum at 1 (Nov. 16, 2012).

AGREEMENT

10. Subject to the adjustments discussed below, the Stipulating Parties agree that the Company's 2013 October Update was calculated in conformance with the methodology adopted by the Commission in Order No. 08-238.

11. The Stipulating Parties agree to adjust the Company's filed 2013 October Update to include only 6 months (October 2013 – March 2014) of the Dynamis PURPA contract. Attachment 1 to this Partial Stipulation contains the re-dispatch of the AURORA simulation model that includes all 84 years of hydro generation as well as only the inclusion of 6 months of the Dynamis PURPA contract. This adjustment reduces the filed Total Net Power Supply Expenses ("NPSE"), including PURPA, to $325.2 million, a decrease of $3 million on a total system basis. Attachment 1 and Attachment 2 to this Partial Stipulation present the results of these calculations.

12. The Company will file its March Forecast consistent with the schedule adopted by ALJ Hardie on November 16, 2012. Staff and CUB reserve the right to challenge all elements of the March Forecast and will do so in accordance with the schedule adopted by ALJ Hardie on November 16, 2012.

13. The Stipulating Parties agree that the Company's allocation methodology conforms to that adopted by the Commission in Order No. 10-191. The results of this allocation are set forth in Attachment 3 to this Partial Stipulation. The result of the agreed upon adjustment changes the Oregon share of APCU revenues from $2.5 million to $2.4 million, a reduction of nearly $100,000.

14. For purposes of this Partial Stipulation, the Stipulating Parties agree that Idaho Power's method of repricing PURPA contracts executed in Idaho to reflect Oregon's non-levelized methodology is reasonable.

15. The Stipulating Parties agree to submit this Partial Stipulation to the Commission and request that the Commission approve the Partial Stipulation as presented. The

Stipulating Parties agree that the adjustments and the rates resulting from the Partial Stipulation are fair, just, and reasonable.

16. This Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Partial Stipulation throughout this proceeding and any appeal, (if necessary) provide witnesses to sponsor this Partial Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

17. If this Partial Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Partial Stipulation. The Stipulating Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Partial Stipulation.

18. The Stipulating Parties have negotiated this Partial Stipulation as an integrated document. If the Commission rejects all or any material part of this Partial Stipulation, or adds any material condition to any final order that is not consistent with this Partial Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Partial Stipulation or to withdraw from the Partial Stipulation. Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Partial Stipulation.

19. By entering into this Partial Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Partial Stipulation, other than those specifically identified in the body of this Partial Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Partial Stipulation is appropriate for

resolving issues in any other proceeding, except as specifically identified in this Partial Stipulation.

20. This Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Partial Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: Mike [illegible] (attorney)

Date: 1/24/13

IDAHO POWER

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: ______________________

resolving issues in any other proceeding, except as specifically identified in this Partial Stipulation.

20. This Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Partial Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: ____________________________

Date: ____________________________

IDAHO POWER	CITIZENS' UTILITY BOARD OF OREGON
By:	By: ____________________
Date: 1-25-13	Date: ____________________

resolving issues in any other proceeding, except as specifically identified in this Partial Stipulation.

20. This Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Partial Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: ______________________

Date: ______________________

IDAHO POWER

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD OF OREGON

By: [signature]

Date: 1-24-13

Docket UE 257

Attachment 1

to

Partial Stipulation

January 25, 2013

IPCO POWER SUPPLY COSTS FOR APRIL 2013 - MARCH 2014 NORMALIZED LOADS OVER 84 WATER YEAR CONDITIONS

AVERAGE

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	856,155.7	954,893.9	899,010.8	674,604.0	507,197.1	539,308.3	551,515.6	465,796.1	673,443.5	756,766.5	827,276.0	839,201.9	8,545,169.3
Bridger													
Energy (MWh)	152,970.8	230,366.0	257,493.2	405,810.8	432,422.7	389,455.7	395,001.2	394,476.2	403,120.6	355,608.3	278,975.6	284,580.0	3,980,261.0
Cost ($ x 1000)	$ 3,662.4	$ 5,491.0	$ 6,041.3	$ 9,091.5	$ 9,631.9	$ 8,732.0	$ 8,872.1	$ 8,833.9	$ 9,036.9	$ 8,377.2	$ 6,676.9	$ 6,802.1	$ 91,249.2
Boardman													
Energy (MWh)	13,112.7	9,864.4	28,221.6	40,360.7	41,578.5	40,182.0	41,088.4	40,094.5	40,560.5	17,325.8	13,264.0	14,382.5	340,035.5
Cost ($ x 1000)	$ 302.6	$ 220.4	$ 616.2	$ 845.5	$ 868.0	$ 839.0	$ 858.9	$ 837.4	$ 849.2	$ 561.4	$ 446.9	$ 486.1	$ 7,731.7
Valmy													
Energy (MWh)	20,913.3	39,380.5	50,461.4	95,917.5	103,473.8	76,021.8	69,960.2	70,515.7	79,662.4	65,482.7	52,308.5	48,605.4	772,903.2
Cost ($ x 1000)	$ 797.9	$ 1,498.8	$ 1,917.7	$ 3,441.2	$ 3,674.7	$ 2,806.4	$ 2,638.5	$ 2,641.9	$ 2,940.1	$ 2,622.1	$ 2,107.5	$ 1,967.6	$ 29,054.6
Langley Gulch													
Energy (MWh)	93,700.9	88,476.7	88,377.1	135,311.7	140,534.0	114,508.7	117,078.0	114,684.3	122,921.4	107,663.8	78,257.1	80,881.7	1,282,395.4
Cost ($ x 1000)	$ 3,096.0	$ 2,887.1	$ 2,909.6	$ 4,480.6	$ 4,662.2	$ 3,894.2	$ 3,994.0	$ 4,613.0	$ 5,145.1	$ 4,628.9	$ 3,408.8	$ 3,498.5	$ 47,217.9
Danskin													
Energy (MWh)	-	-	-	1,755.0	1,097.9	8.3	-	-	1.7	-	-	-	2,862.8
Cost ($ x 1000)	$ -	$ -	$ -	$ 91.3	$ 56.8	$ 0.4	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ 148.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 466.9	$ 478.2	$ 476.2	$ 498.4	$ 499.8	$ 484.4	$ 481.3	$ 738.2	$ 759.6	$ 760.8	$ 714.1	$ 760.8	$ 7,118.5
Total Cost	$ 466.9	$ 478.2	$ 476.2	$ 589.6	$ 556.6	$ 484.8	$ 481.3	$ 738.2	$ 759.7	$ 760.8	$ 714.1	$ 760.8	$ 7,267.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	566.4	2,760.9	34,222.9	146,478.8	145,406.8	37,285.1	6.8	44.5	14,887.7	14,181.0	72.9	155.5	396,069.4
Contract Energy (MWh)	46,687.5	46,823.3	43,472.0	46,370.2	44,592.7	40,051.4	45,541.0	51,536.6	53,680.7	39,954.2	44,964.2	46,915.5	550,589.3
Total Energy Excl. CSPP (MWh)	47,253.9	49,584.2	77,694.8	192,849.1	189,999.5	77,336.6	45,547.8	51,581.1	68,568.5	54,135.2	45,037.2	47,071.0	946,658.7
Market Cost ($ x 1000)	$ 23.6	$ 126.6	$ 1,877.7	$ 12,459.8	$ 11,669.9	$ 2,921.0	$ 0.3	$ 2.0	$ 791.9	$ 650.5	$ 3.1	$ 6.7	$ 30,533.1
Contract Cost ($ x 1000)	$ 2,457.1	$ 2,479.5	$ 3,162.3	$ 4,021.0	$ 3,899.7	$ 2,966.7	$ 3,304.8	$ 4,352.3	$ 4,526.8	$ 2,710.6	$ 3,310.0	$ 2,565.9	$ 39,756.4
Total Cost Excl. CSPP ($ x 1000)	$ 2,480.7	$ 2,606.1	$ 5,040.0	$ 16,480.8	$ 15,569.6	$ 5,887.7	$ 3,305.1	$ 4,354.2	$ 5,318.7	$ 3,361.1	$ 3,313.1	$ 2,572.6	$ 70,289.6
Surplus Sales													
Energy (MWh)	345,257.1	383,240.9	201,788.8	21,421.2	14,650.2	183,419.0	366,384.4	219,301.3	141,818.8	158,045.2	339,940.8	380,047.4	2,755,315.0
Revenue Including Transmission Costs ($ x 1000)	$ 11,088.0	$ 11,906.3	$ 6,498.5	$ 981.7	$ 741.5	$ 7,477.7	$ 17,754.0	$ 10,547.1	$ 8,498.7	$ 7,170.9	$ 14,527.2	$ 15,444.0	$ 112,535.5
Transmission Costs ($ x 1000)	$ 345.3	$ 383.2	$ 201.8	$ 21.4	$ 14.7	$ 183.4	$ 366.4	$ 219.3	$ 141.8	$ 158.0	$ 339.9	$ 380.0	$ 2,755.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 10,742.7	$ 11,523.1	$ 6,296.7	$ 960.3	$ 726.8	$ 7,294.3	$ 17,387.6	$ 10,327.8	$ 8,356.8	$ 7,012.9	$ 14,187.2	$ 15,063.9	$ 109,880.2
Net Power Supply Costs ($ x 1000)	$ 63.7	$ 1,658.6	$ 10,704.3	$ 33,968.9	$ 34,236.2	$ 15,349.8	$ 2,762.2	$ 11,691.0	$ 15,692.9	$ 13,298.5	$ 2,480.1	$ 1,023.8	$ 142,929.9

ORDER NO. 13 166

Docket UE 257

Attachment 2

to

Partial Stipulation

January 25, 2013

IPCO POWER SUPPLY COSTS FOR APRIL 1, 2013 -- MARCH 31, 2014 (Multiple Gas Prices/84 Years of Hydro)
Repriced Using UE195 Settlement Methodology - October Update
AVERAGE
REVISED

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	856,155.7	954,893.9	899,010.8	674,604.0	507,197.1	539,308.3	551,515.6	465,798.1	673,443.5	756,766.5	827,276.0	839,201.9	8,545,169.3
Bridger													
Energy (MWh)	152,970.8	230,366.0	257,493.2	405,810.8	432,422.7	389,455.7	395,001.2	394,476.2	403,120.6	355,608.3	278,975.5	284,560.0	3,980,281.0
Cost ($ x 1000)	$ 3,662.4	$ 5,491.0	$ 6,041.3	$ 9,091.5	$ 9,631.9	$ 8,732.0	$ 8,872.1	$ 8,833.9	$ 9,036.9	$ 8,377.2	$ 6,676.9	$ 6,802.1	$ 91,249.2
Boardman													
Energy (MWh)	13,112.7	9,864.4	28,221.6	40,360.7	41,578.5	40,182.0	41,088.4	40,094.5	40,560.5	17,325.8	13,264.0	14,352.5	340,085.5
Cost ($ x 1000)	$ 302.6	$ 220.4	$ 616.2	$ 845.5	$ 868.0	$ 839.0	$ 858.9	$ 837.4	$ 849.2	$ 561.4	$ 446.9	$ 486.1	$ 7,731.7
Valmy													
Energy (MWh)	20,913.3	39,380.5	50,461.4	95,917.5	103,473.8	76,021.6	69,960.2	70,516.7	79,662.4	65,482.7	52,308.5	48,805.4	772,903.2
Cost ($ x 1000)	$ 797.9	$ 1,498.8	$ 1,917.7	$ 3,441.2	$ 3,674.7	$ 2,806.4	$ 2,638.5	$ 2,641.9	$ 2,940.1	$ 2,622.1	$ 2,107.5	$ 1,967.6	$ 29,054.6
Langley Gulch													
Energy (MWh)	93,700.9	88,476.7	88,377.1	135,311.7	140,534.0	114,508.7	117,078.0	114,684.3	122,021.4	107,663.8	78,257.1	80,881.7	1,282,395.4
Cost ($ x 1000)	$ 3,096.0	$ 2,887.1	$ 2,909.6	$ 4,480.6	$ 4,662.2	$ 3,894.2	$ 3,994.0	$ 4,613.0	$ 5,145.1	$ 4,628.9	$ 3,408.8	$ 3,498.5	$ 47,217.9
Danskin													
Energy (MWh)	-	-	-	1,755.0	1,097.9	8.3	-	-	1.7	-	-	-	2,862.8
Cost ($ x 1000)	$ -	$ -	$ -	$ 91.3	$ 56.8	$ 0.4	$ -	$ -	$ 0.1	$ -	$ -	$ -	$ 148.6
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 466.9	$ 478.2	$ 476.2	$ 498.4	$ 499.8	$ 484.4	$ 481.3	$ 738.2	$ 759.6	$ 760.8	$ 714.1	$ 760.8	$ 7,118.5
Total Cost	$ 466.9	$ 478.2	$ 476.2	$ 589.6	$ 556.6	$ 484.8	$ 481.3	$ 738.2	$ 759.7	$ 760.8	$ 714.1	$ 760.8	$ 7,267.2
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	566.4	2,760.9	34,222.9	146,478.8	145,406.8	37,285.1	6.8	44.5	14,887.7	14,181.0	72.9	155.5	396,069.4
Contract Energy (MWh)	46,687.5	46,823.3	43,472.0	46,370.2	44,592.7	40,051.4	45,541.0	51,536.6	53,680.7	39,954.2	44,964.2	46,915.5	550,589.3
Total Energy Excl. CSPP (MWh)	47,253.9	49,584.2	77,694.8	192,849.1	189,999.5	77,336.5	45,547.8	51,581.1	68,568.5	54,135.2	45,037.2	47,071.0	946,658.7
Market Cost ($ x 1000)	$ 17.1	$ 70.6	$ 673.3	$ 5,307.0	$ 5,935.4	$ 1,484.1	$ 0.3	$ 1.8	$ 671.4	$ 610.4	$ 3.0	$ 5.4	$ 14,779.7
Contract Cost ($ x 1000)	$ 2,457.1	$ 2,479.5	$ 3,162.3	$ 4,021.0	$ 3,899.7	$ 2,966.7	$ 3,304.8	$ 4,352.3	$ 4,526.8	$ 2,710.6	$ 3,310.0	$ 2,565.9	$ 39,756.4
Total Cost Excl. CSPP ($ x 1000)	$ 2,474.1	$ 2,550.0	$ 3,835.6	$ 9,328.0	$ 9,835.1	$ 4,450.7	$ 3,305.1	$ 4,354.1	$ 5,198.2	$ 3,321.0	$ 3,312.9	$ 2,571.3	$ 54,536.1
Surplus Sales													
Energy (MWh)	345,257.1	383,240.9	201,788.8	21,421.2	14,650.2	183,419.0	366,384.4	219,301.3	141,816.8	158,045.2	339,940.8	380,047.4	2,755,315.0
Revenue Including Transmission Costs ($ x 1000)	$ 9,438.3	$ 8,879.8	$ 3,597.0	$ 703.5	$ 542.2	$ 6,620.3	$ 13,099.6	$ 8,148.9	$ 5,800.4	$ 6,169.5	$ 12,597.4	$ 11,948.1	$ 87,545.2
Transmission Costs ($ x 1000)	$ 345.3	$ 383.2	$ 201.8	$ 21.4	$ 14.7	$ 183.4	$ 366.4	$ 219.3	$ 141.8	$ 158.0	$ 339.9	$ 380.0	$ 2,755.3
Revenue Excluding Transmission Costs ($ x 1000)	$ 9,093.1	$ 8,496.6	$ 3,395.2	$ 682.1	$ 527.6	$ 6,436.9	$ 12,733.2	$ 7,929.6	$ 5,658.6	$ 6,011.5	$ 12,257.5	$ 11,568.0	$ 84,789.9
Hoku First Block Revenues													
Net Hedges													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost($ X 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Power Supply Costs ($ x 1000)	$ 1,706.9	$ 4,629.0	$ 12,401.5	$ 27,094.2	$ 28,701.0	$ 14,770.2	$ 7,416.6	$ 14,089.0	$ 18,270.6	$ 14,259.8	$ 4,409.7	$ 4,518.4	$ 152,266.8
PURPA ($ x 1000)	$ 12,290.9	$ 15,785.5	$ 18,006.7	$ 18,745.5	$ 16,462.4	$ 14,706.8	$ 14,549.6	$ 15,353.0	$ 12,310.6	$ 12,486.1	$ 11,409.8	$ 10,804.5	$ 172,911.4
Total Net Power Supply Expense ($ x 1000)	$ 13,997.8	$ 20,414.5	$ 30,408.1	$ 45,839.7	$ 45,163.3	$ 29,477.0	$ 21,966.2	$ 29,442.0	$ 30,581.2	$ 26,745.9	$ 15,819.6	$ 15,322.9	$ 325,178.3
Sales at Customer Level (In 000s MWH)	1,000.535	1,001.776	1,167.710	1,395.693	1,474.793	1,342.353	1,077.825	1,005.193	1,135.660	1,249.058	1,152.265	1,058.826	14,061.686
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	$13.99	$20.38	$26.04	$32.84	$30.62	$21.96	$20.38	$29.29	$26.93	$21.41	$13.73	$14.47	$23.13
Prices Used in Purchased Power & Surplus Sales Above:													
Heavy Load													
Portion of Purchased Power considered HL F	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	64.25%	
Purchased Power HL Price	33.36	30.34	26.29	42.54	45.46	42.70	41.07	42.98	47.32	44.93	42.85	37.02	
Portion of Surplus Sales considered HL Surpl	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	62.70%	
Surplus Sales HL Price	30.95	28.15	24.40	39.47	42.18	39.62	38.11	39.68	43.90	41.69	39.76	34.35	
Light Load													
Portion of Purchased Power considered LL P	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	35.75%	
Purchased Power LL Price	24.38	16.98	7.78	24.89	32.48	34.60	36.46	37.36	41.12	39.65	37.29	30.44	
Portion of Surplus Sales considered LL Surpl	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	37.30%	
Surplus Sales LL Price	21.28	14.81	6.78	21.70	28.32	30.17	31.79	32.58	35.86	34.58	32.52	26.55	

ORDER NO. 13 166

Docket UE 257

Attachment 3

to

Partial Stipulation

January 25, 2013

Idaho Power Company
Rate Spread Exhibit for October Update APCU

General Rate Case (UE 233): Marginal Cost-of-Service Study and Stipulated Revenue Spread
2011 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) GEN SRV TRANS (9-T)	(G) AREA LIGHTING (15)	(H) LG POWER PRIMARY (19-P)	(I) LG POWER TRANS (19-T)	(J) IRRIGATION SECONDARY (24-S)	(K) UNMETERED GEN SERVICE (40)	(L) MUNICIPAL ST LIGHT (41)	(M) TRAFFIC CONTROL (42)
1	Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	Current Revenue	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	Demand Related Marginal Cost													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,173	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	Energy Related Marginal Cost													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	Simple-Summed Energy-Related and Demand-Related Marginal Costs													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	Customer Related Marginal Cost	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	Total Functionalized Revenue Requirement													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$890
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$33,209	$83
29														
30	Total: Staff-Adjusted Allocation	$41,684,482	$16,134,429	$1,449,425	$6,902,669	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	Revenue Deficiency - Staff Adj. Allocation	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	% Increase Required by Staff Adj. Alloc. Approach	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	$ Increase Recommended per Stipulation	$1,810,890	$862,348	$44,153	$197,517	$22,598	$0	$0	$232,545	$212,777	$235,318	$44	$3,507	$84
34	% Increase Recommended per Stipulation	4.54%	5.62%	2.83%	2.83%	2.83%	0.00%	0.00%	2.83%	6.81%	6.81%	4.56%	2.83%	6.81%
35	Average Rate Given Stipulation ($/kWh)	0.0641	0.0816	0.0899	0.0628	0.0544	0.0547	0.2324	0.0471	0.0450	0.0791	0.0788	0.1637	0.0805
36	Final Revenue Allocation	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	**Spread Floors and Ceilings:**													
39	No increase for those warranting a decrease greater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													
	2012 October Update APCU (UE 242): Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
42	2012 October Update APCU Cost of Service (UE 242)	$1,298,993	$427,230	$35,118	$223,454	$28,138	$5,025	$722	$310,094	$150,288	$117,706	$24	$1,163	$30
	2013 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures													
43	2013 October Update APCU Cost of Service (Allocator -- Line 14)	$2,409,527	$792,478	$65,142	$414,488	$52,194	$9,321	$1,339	$575,200	$278,772	$218,335	$44	$2,157	$56
44	% Increase Required Due to APCU (Proposed) (Line 43/(Line 36)	5.78%	4.89%	4.06%	5.78%	6.36%	6.01%	1.19%	6.81%	8.36%	5.92%	4.36%	1.69%	4.27%
45	Proposed Combined Revenue Spread (Line 36 + Line 42 + Line 43)	$45,393,000	$17,437,988	$1,703,813	$7,811,374	$901,032	$159,342	$114,523	$9,330,904	$3,765,230	$4,025,630	$1,084	$130,678	$1,401
46	Loss-Adjusted 2011 Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
47	2013 October Update APCU Incremental Rate given 2011 Test Period Sales (Mills per kWh) (1000*(Line 43/Line 46))	3.706	3.985	3.651	3.628	3.457	3.291	2.767	3.210	3.759	4.680	3.432	2.772	3.436
48	APCU Incremental Rate for 2013 October Update (Mills per kWh) (Line 47*(Column A:(Line 46/Line 49)))	**3.660**	**4.197**	**3.513**	**3.581**	**3.468**	**3.336**	**2.786**	**3.226**	**3.448**	**3.835**	**3.432**	**2.765**	**3.433**
49	*Loss-Adjusted 2013-2014 Normalized Sales (kWh)*	658,340,684	188,841,889	18,540,455	115,757,333	15,048,876	2,793,636	480,698	178,282,611	80,849,225	56,936,611	12,900	780,105	16,345
50	Projected October Update APCU 2013-2014 Revenues (Line 48 * Line 49)	$2,409,527	$792,478	$65,142	$414,488	$52,194	$9,321	$1,339	$575,200	$278,772	$218,335	$44	$2,157	$56

Notes:

1 2013 October Update APCU Revenues = $3.66/MWh x 658,340.684 MW's = $ 2,409,527 (Line 42, Column A)

2 $3.66 = $23.13 (2013 October APCU Rate) - $19.47 (2012 October APCU Rate)

ORDER NO. 13 169

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 257

In the Matter of: Idaho Power Company's 2013 Annual Power Cost Update	**PARTIAL STIPULATION**

This Partial Stipulation resolves all issues among the parties to this Partial Stipulation related to Idaho Power Company's ("Idaho Power" or "Company") March Forecast component of the 2013 Annual Power Cost Update ("APCU") filed pursuant to Order No. 08-238.[1] The APCU updates the Company's net power supply expense and results in new rates, to be effective June 1, 2013.

PARTIES

1. The parties to this Partial Stipulation are Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB") and Idaho Power (together, the "Stipulating Parties").

BACKGROUND

2. Pursuant to Order No. 08-238, Idaho Power annually updates its net power supply expense included in rates through an automatic adjustment clause, the APCU. The APCU is comprised of two components—an "October Update" and a "March Forecast." The October Update contains the Company's forecasted net power supply expense reflected on a normalized unit basis for an April through March test period. The March Forecast contains the Company's net power supply expense based upon updated actual forecasted conditions. Pursuant to Order No. 10-191[2] the Company allocates the APCU revenue requirement to

---

[1] *Re Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket UE 195, Order No. 08-238 (Apr. 28, 2008).

[2] *Re Idaho Power Company's 2010 Annual Power Cost Update*, Docket UE 214, Order No. 10-191 (May 24, 2010).

individual customer classes on the basis of the total generation-related revenue requirement approved in the Company's last general rate case, instead of the previous equal cents per kWh approved in Order No. 08-238. Order No. 10-191 also directs the Company to adjust its base rates to reflect changes in revenue requirement related to the October Update, while the rates resulting from the March Forecast are listed on Schedule 55. The rates associated with the October Update and the March Forecast become effective on June 1 of each year.

3. On October 24, 2012, Idaho Power filed testimony and exhibits for the 2013 APCU ("2013 October Update").[3]

4. On October 31, 2012, CUB filed its Notice of Intervention. On November 16, 2012, Administrative Law Judge ("ALJ") Lisa Hardie held a prehearing conference at which the parties to Docket UE 257 agreed upon a procedural schedule that would allow the Public Utility Commission of Oregon ("Commission") to issue an order on Idaho Power's 2013 APCU prior to June 1, 2013.[4]

5. Staff and CUB served discovery on Idaho Power and conducted a thorough investigation of the 2013 October Update. Thereafter, the Stipulating Parties participated in two settlement conference and ultimately agreed to a settlement. On January 25, 2013, the Stipulating Parties filed a Partial Stipulation that resolved all issues related to the 2013 October Update (hereinafter, the "October Update Stipulation"). The October Update Stipulation included a cost per unit of $23.13 per MWh.

6. Pursuant to the procedural schedule adopted by ALJ Hardie on November 16, 2012, and the terms of the October Update Stipulation, on March 22, 2013, Idaho Power filed its March Forecast. The March Forecast consisted of direct testimony describing the Company's estimate of the expected net power supply expense for the upcoming water

[3] *See* Idaho Power/100-107.

[4] *Re Idaho Power Company's 2013 Annual Power Cost Update*, Docket UE 257, Prehearing Conference Memorandum at 1 (Nov. 16, 2012).

year—April 2013 through March 2014.[5] Order No. 08-238 calls for the March Forecast to update the following variables: fuel prices, transportation costs, wheeling expenses, planned and forced outages, heat rates, forecast of normalized sales and loads updated for significant changes since the October Update, forecast hydro generation, wholesale power purchase and sale contracts, forward price curve, Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses, and the Oregon state allocation factor.[6] In this year's filing, however, the only variables that had changed since the October Update were (1) fuel prices; (2) the forecast of hydro conditions from the Northwest River Forecast Center ("NRFC"); (3) known power purchases and surplus sales resulting from the Company's Risk Management Policy; (4) the forward price curve in accordance with Order No. 08-238; and (5) PURPA contract expenses.[7]

7. The fuel prices were updated to reflect changes in forecast natural gas and coal costs.[8] The hydro update, based upon updated streamflow forecasts and reservoir levels from the NFRC, reflected the fact that this year's forecasts are significantly lower than last year's.[9] The decreased hydro forecast resulted in higher variable power supply expenses because less hydro generation results in increased market purchases and decreased off-system sales.[10] The 2013 March Forecast also included reduced PURPA expenses, which were the result of the Company removing five PURPA contracts from the model. These five contracts are not expected to result in actual generation during the test period and have either been terminated by Idaho Power or by agreement of the contracting parties.[11]

---

[5] Idaho Power/200-205.

[6] Idaho Power/200, Wright/2.

[7] Idaho Power/200, Wright/2-3.

[8] Idaho Power/200, Wright/3-5.

[9] Idaho Power/200, Wright/5-6.

[10] Idaho Power/200, Wright/6.

[11] Idaho Power/200, Wright/7.

8. The Company calculated a cost per unit for the 2013 March Forecast of $25.49 per MWh, which is $4.66 per MWh more than last year's cost per unit of $20.83 per MWh.[12] This equates to a system-wide net power supply expense of $358,445,038.[13]

9. Combining the price per unit from the October Update Stipulation and 2013 March Forecast resulted in a cost per unit of $25.37 per MWh.[14] The overall proposed revenue impact of the combined rate is an increase of approximately 6.03 percent, or $2.9 million.[15]

10. The 2013 March Forecast also included the Company's proposed rate spread used to spread the revenue requirement to the various customer classes. The Company's proposed allocation conformed to the methodology approved by the Commission in Order No. 10-191.[16]

11. On March 22, 2013, the Company also filed Tariff Advice No. 13-07, which included the revised tariff sheets for the 2013 October Update and March Forecast. The rate effective date on the revised tariff sheets is June 1, 2013.

12. A settlement conference was held on April 1, 2013. During that settlement conference the Stipulating Parties agreed to resolve all the issues in this case, subject to Staff's and CUB's review of additional discovery responses from Idaho Power. Thereafter Staff moved to suspend the schedule and ALJ Patrick Power granted Staff's motion.[17]

13. This Partial Stipulation, presented on behalf of all parties to the docket, resolves all issues in the docket related to the 2013 March Forecast. Together with the October Update Stipulation this Partial Stipulation resolves all the issues in this docket.

---

[12] Idaho Power/200, Wright/8-9.

[13] Idaho Power/203.

[14] Idaho Power/203.

[15] Idaho Power/200, Wright/11.

[16] Idaho Power/200, Wright/9-10; Order No. 10-191.

[17] *Re Idaho Power Company's 2012 Annual Power Cost Update*, Docket UE 257, Ruling (April 2, 2013).

AGREEMENT

14. The Stipulating Parties agree that the calculation of the agreed upon cost per unit rate in the March Forecast and the combined rate is correct and in conformance with the methodology adopted by the Commission in Order No. 08-238 and the Stipulating Parties agree that the rates resulting from the agreed upon cost per unit are fair, just, and reasonable.

15. The Stipulating Parties agree that the Company's allocation methodology conforms to that adopted by the Commission in Order No. 10-191.

16. The Stipulating Parties agree that rates agreed to by the terms of this Stipulation should be made effective on June 1, 2013.

17. For purposes of this Partial Stipulation, the Stipulating Parties agree that the existing and past practice of repricing Idaho's levelized PURPA contracts to reflect Oregon's non-levelized requirements is reasonable.

18. The Stipulating Parties agree to submit this Partial Stipulation to the Commission and request that the Commission approve the Partial Stipulation as presented. The Stipulating Parties agree that the adjustments and the rates resulting from the Partial Stipulation are fair, just, and reasonable.

19. This Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Partial Stipulation throughout this proceeding and any appeal, (if necessary) provide witnesses to sponsor this Partial Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

20. If this Partial Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Partial Stipulation. The Stipulating Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Partial Stipulation.

21. The Stipulating Parties have negotiated this Partial Stipulation as an integrated document. If the Commission rejects all or any material part of this Partial Stipulation, or adds any material condition to any final order that is not consistent with this Partial Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Partial Stipulation or to withdraw from the Partial Stipulation. Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Partial Stipulation.

22. By entering into this Partial Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Partial Stipulation, other than those specifically identified in the body of this Partial Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Partial Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Partial Stipulation.

23. This Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Partial Stipulation is entered into by each Stipulating Party on the date entered below such Stipulating Party's signature.

STAFF

By: Mike [signature]

Date: 4/18/13

IDAHO POWER

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

IDAHO POWER

By: [signature]

Date: 4/18/13

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

IDAHO POWER

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD OF OREGON

By: ______________________

Date: 4-18-13