MRG
McDOWELL RACKNER GIBSON PC

ADAM LOWNEY
Direct (503) 595-3926
adam@mrg-law.com

April 21, 2017

VIA ELECTRONIC FILING
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: **Docket No. UE 314 - 2017 Annual Power Cost Update ("APCU")**

Attention Filing Center:

Attached for filing is **CORRECTED** Idaho Power/300, Blackwell/2 and 17, **CORRECTED** Idaho Power/304, and **CORRECTED** Idaho Power/305 of Idaho Power Company's ("Idaho Power" or "Company") March Forecast Testimony of Nicole A. Blackwell. The Company has provided both clean and redlined versions of each corrected page.

During the April 10, 2017, settlement conference, Public Utility Commission of Oregon ("Commission") Staff ("Staff") identified a hardcoded number within Idaho Power/304, and asked the Company to follow up with the calculation used to produce this figure. Upon further investigation, Idaho Power discovered that its modeling of the agreed upon revenue requirement determination method did not correctly implement the intended methodology change.

Therefore, on April 19, 2017, Idaho Power contacted Staff to notify and discuss with them two needed updates to its filed exhibit Idaho Power/304, which flow into Idaho Power/305 and are discussed within the March Forecast Testimony of Nicole Blackwell.

The first change is in regards to the quantification of Net Power Supply Expense ("NPSE") currently included in base rates, reflected on line 50 of Idaho Power/ 304, Blackwell/1, of $16,473,704. The $16,473,704 was calculated by multiplying the system NPSE per-unit cost of $23.93 per megawatt-hour ("MWh"), the effective per-unit cost from the 2016 APCU, by the normalized sales of 688,412.209 MWh for the April 2016 – March 2017 test period. The figure is incorrect as the Company did not update normalized sales for the correct test period, which is April 2017 - March 2018. Using the correct test period sales of 683,817.790 MWh, results in $16,363,760 in NPSE currently included in base rates. Without correcting this figure, the Oregon Jurisdictional Incremental NPSE, as reflected on line 51 of Idaho Power/304, Blackwell/1, reflects $1,346,587. After correcting this figure, the Oregon Jurisdictional Incremental NPSE reflects $1,456,532, as shown on line 51 of **CORRECTED** Idaho Power/304, Blackwell/1.

Please note that the incremental NPSE shown on Idaho Power/304 was for informational purposes only. While the quantification of this figure has changed, it does not impact the quantification of total NPSE for the 2017 APCU October Update. The 2017 NPSE to be included in base rates remains as filed at $17,820,292, as reflected on lines 42 and 49 of both Idaho Power/304, Blackwell/1, and **CORRECTED** Idaho Power/304, Blackwell/1, and was not impacted by this correction.

The second change is in regards to the loss-adjusted 2017-2018 normalized sales of 683,817,790 kilowatt-hours ("kWh"), as reflected on line 47 of Idaho Power/304, Blackwell/1, and line 48 of Idaho Power/304, Blackwell/2. The normalized sales reflected on these lines are for the test period of April 2017 - March 2018. This is the correct test period sales figure to use for the quantification of total NPSE because it is consistent with the test period utilized in all forecasts used in the determination of system NPSE, including the gas price forecast, coal forecast, hydro forecast, PURPA forecast, etc. However, this is not the correct test period sales figure to use when establishing rates and revenue collection by class. If approved, the proposed APCU rates will go into effect on June 1, 2017, with the collection period running through May 31, 2018. As such, it is appropriate to use the loss-adjusted normalized sales of 685,937,209 kWh for the collection period of June 2017 – May 2018 to establish rates and revenue collection by class. Idaho Power has corrected the test period sales, as shown on line 47 of **CORRECTED** Idaho Power/304, Blackwell/1, and line 48 of **CORRECTED** Idaho Power/304, Blackwell/2, to align with the APCU collection period.

Please note that updating the test period sales to match the collection period, results in a slight rate decrease from that which was filed, as shown on line 46 of **CORRECTED** Idaho Power/304, Blackwell/1, and line 47 of **CORRECTED** Idaho Power/304, Blackwell/2. As a result of the changes in rates by class, the Company is providing **CORRECTED** Idaho Power/305. **CORRECTED** Idaho Power/305 also provides a greater level of detail than the initial exhibit filed by the Company, as requested by Staff.

The Company conferred with Staff and Staff recommended that the Company make this errata filing. The Company also conferred with the Oregon Citizens' Utility Board ("CUB"). Both Staff and CUB understand these corrections and do not object to this filing.

In order to reflect these changes, attached are electronic copies of the corrected testimony pages and exhibits to Ms. Blackwell's testimony. Redlined copies of Pages 2 and 17 of the testimony are also attached for reference and the Commission's convenience.

If you have any questions regarding the enclosed corrected information or this matter, please do not hesitate to contact me.

Very truly yours,

Adam Lowney

Enclosures

previously, the Company filed the first part of the APCU, the October Update, on October 28, 2016. The initial October Update filing proposed a revenue increase of approximately $1.5 million, or 2.64 percent. If the March Forecast is approved, the 2017 composite APCU (both the October Update and March Forecast components) will result in a revenue increase of approximately $0.7 million, or 1.27 percent, to become effective June 1, 2017.

Q. How is your testimony organized?

A. My testimony begins by describing the filing requirements associated with the March Forecast and the differences between the October Update and the March Forecast. Next, my testimony describes the required updates to the AURORAxmp Electric Market Model ("AURORA"). I then present and discuss the forecast of total net power supply expenses ("NPSE") for the 2017 March Forecast and how it compares to last year's 2016 March Forecast. My testimony concludes with the quantification of the projected revenue deficiency and the proposed rate implementation to eliminate that deficiency.

Q. Have you prepared exhibits for this proceeding?

A. Yes, I am sponsoring the following exhibits:

1. Exhibit 301, Forward Price Curves used for re-pricing purchased power and surplus sales.
2. Exhibit 302, determination of expected NPSE for the 2017 March Forecast.
3. Exhibit 303, October Update and March Forecast combined rate calculation.
4. Exhibit 304, Revenue Spread.
5. Exhibit 305, Calculation of Revenue Impact.

<u>March Forecast Overview</u>

Q. What is the March Forecast?

previously, the Company filed the first part of the APCU, the October Update, on October 28, 2016. The initial October Update filing proposed a revenue increase of approximately $1.5 million, or 2.64 percent. If the March Forecast is approved, the 2017 composite APCU (both the October Update and March Forecast components) will result in a revenue increase of approximately $0.7~~6~~ million, or 1.27~~08~~ percent, to become effective June 1, 2017.

Q. How is your testimony organized?

A. My testimony begins by describing the filing requirements associated with the March Forecast and the differences between the October Update and the March Forecast. Next, my testimony describes the required updates to the AURORAxmp Electric Market Model ("AURORA"). I then present and discuss the forecast of total net power supply expenses ("NPSE") for the 2017 March Forecast and how it compares to last year's 2016 March Forecast. My testimony concludes with the quantification of the projected revenue deficiency and the proposed rate implementation to eliminate that deficiency.

Q. Have you prepared exhibits for this proceeding?

A. Yes, I am sponsoring the following exhibits:

1. Exhibit 301, Forward Price Curves used for re-pricing purchased power and surplus sales.
2. Exhibit 302, determination of expected NPSE for the 2017 March Forecast.
3. Exhibit 303, October Update and March Forecast combined rate calculation.
4. Exhibit 304, Revenue Spread.
5. Exhibit 305, Calculation of Revenue Impact.

March Forecast Overview

Q. What is the March Forecast?

test period. However, Staff recommended that the Company calculate the Oregon jurisdictional revenue requirement using the system total per-unit cost for the test period, not the incremental per-unit cost.

After reviewing Staff's recommendation, the Company agreed to move forward with the proposed total per-unit cost method in place of the existing incremental approach. As such, the Company adjusted the rate calculation for the October Update. Rather than using the system incremental per-unit cost of $2.13 per MWh, the Company used the system total per-unit cost of $26.06 per MWh to determine the Oregon jurisdictional revenue requirement. Using the system total per-unit cost, as well as adjusting the loss adjusted sales to align with the March Forecast as discussed previously, results in a decrease in the Oregon jurisdictional revenue requirement of $5,786 relative to the October Update contained in the Company's initial filing, as shown on line 53 of **CORRECTED** Exhibit 304.

Q. What is the overall revenue impact of this year's combined October Update and March Forecast compared to last year's combined October Update and March Forecast using the rate spread methodology described above?

A. Exhibit 305 provides a summary of the revenue change resulting from this year's combined October Update and March Forecast as compared to current revenue. As can be seen in Column N of **CORRECTED** Exhibit 305, the overall revenue impact of this year's combined October Update and March Forecast is an increase of approximately $0.7 million or 1.27 percent overall. The $0.7 million increase reflects an increase of $1.46 million in base rate revenues associated with the October Update, and a $0.76 million decrease in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2016 APCU.

test period. However, Staff recommended that the Company calculate the Oregon jurisdictional revenue requirement using the system total per-unit cost for the test period, not the incremental per-unit cost.

After reviewing Staff's recommendation, the Company agreed to move forward with the proposed total per-unit cost method in place of the existing incremental approach. As such, the Company adjusted the rate calculation for the October Update. Rather than using the system incremental per-unit cost of $2.13 per MWh, the Company used the system total per-unit cost of $26.06 per MWh to determine the Oregon jurisdictional revenue requirement. Using the system total per-unit cost, as well as adjusting the loss adjusted sales to align with the March Forecast as discussed previously, results in a decrease in the Oregon jurisdictional revenue requirement of $5,786 ~~115,731~~ relative to the October Update contained in the Company's initial filing, as shown on line 53 of **CORRECTED** Exhibit 304.

Q. What is the overall revenue impact of this year's combined October Update and March Forecast compared to last year's combined October Update and March Forecast using the rate spread methodology described above?

A. Exhibit 305 provides a summary of the revenue change resulting from this year's combined October Update and March Forecast as compared to current revenue. As can be seen ~~on line 11~~in Column N of **CORRECTED** Exhibit 305, the overall revenue impact of this year's combined October Update and March Forecast is an increase of approximately $0.7~~6~~ million or 1.27~~08~~ percent overall. The $0.7~~6~~ million increase reflects an increase of $1.46~~3~~ million in base rate revenues associated with the October Update, and a $0.76~~7~~ million decrease in Schedule 55 revenues associated with the March Forecast, as compared to what is currently included in Oregon customers' rates related to the 2016 APCU.

CORRECTED
Idaho Power/304
Blackwell/1

Idaho Power Company
Revenue Spread Exhibit for October Update APCU

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

Line No.	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	$1,671,178	$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	$83,209	$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													

2017 October Update APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

Line No.	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)
42	2017 October Update APCU Cost of Service (Allocator -- Line 14)	$17,820,292	$5,860,979	$481,774	$3,065,459	$386,016	$68,933	$9,905	$4,254,042	$2,061,732	$1,614,757	$327	$15,954	$415
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	42.75%	36.14%	30.04%	42.73%	47.04%	44.47%	8.81%	50.37%	61.80%	43.77%	32.22%	12.53%	31.56%
44	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
45	2017 October Update APCU Rates given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 44))	27.409	29.475	27.001	26.830	25.566	24.336	20.467	23.741	27.803	34.615	25.381	20.503	25.413
46	**APCU Rates for 2017 October Update (Mills per kWh) (Line 45*(Column A:[Line 44/Line 47]))**	**25.979**	**31.101**	**25.408**	**25.878**	**23.452**	**26.369**	**22.645**	**24.906**	**19.884**	**24.793**	**60.766**	**17.563**	**18.916**
47	*Loss-Adjusted June 2017- May 2018 Normalized Sales (kWh)*	685,937,209	188,452,205	18,961,725	118,455,942	16,459,848	2,614,124	437,388	170,802,763	103,687,726	65,129,799	5,388	908,365	21,936
48	Projected October Update APCU 2017-2018 Revenues (Line 46 * Line 47)	$17,820,293	$5,860,979	$481,774	$3,065,459	$386,016	$68,933	$9,905	$4,254,042	$2,061,732	$1,614,757	$327	$15,954	$415

Notes:

49	**2017 October Update Base NPSE = $26.06/MWh x 683,817.790 Mwhs for April 2017 - March 2018 test period=**	**$17,820,292**	**(Line 48, Column A)**
50	**NPSE Currently Included in Base Rates = $23.93/MWh (2016 Settled October Update) x 683,817.790 MWhs for April 2017 through March 2018 test period=**	**$16,363,760**	
51	**Oregon Jurisdictional Incremental NPSE =**	**$1,456,532**	
52	**Initial October Update Filing Oregon Jurisdictional Incremental NPSE =**	**$1,462,318**	
53		**($5,786)**	

Idaho Power Company
Revenue Spread Exhibit for March Forecast 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	$1,671,178	$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	$83,209	$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													

2017 March Forecast APCU: Baseline Revenue Requirement Spread and Rates Development Employing the UE 233 Test Period Figures

42	2017 March Forecast APCU Cost of Service (Allocator -- Line 14)	$164,116	$53,977	$4,437	$28,231	$3,555	$635	$91	$39,178	$18,988	$14,871	$3	$147	$4
43	% Increase Required Due to APCU (Proposed) (Line 42/(Line 36)	0.39%	0.33%	0.28%	0.39%	0.43%	0.41%	0.08%	0.46%	0.57%	0.40%	0.30%	0.12%	0.29%
44	Proposed Combined Revenue Spread (Line 36 + Line 42)	$41,848,597	$16,272,257	$1,607,990	$7,201,663	$824,255	$155,632	$112,553	$8,484,788	$3,355,157	$3,704,460	$1,019	$127,505	$1,319
45	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
46	2016 March Forecast Update APCU Rates given 2011 Test Period Sales (Mills per kWh) (1000*(Line 42/Line 45))	0.252	0.271	0.249	0.247	0.235	0.224	0.188	0.219	0.256	0.319	0.234	0.189	0.234
47	**APCU Rates for 2017 March Forecast (Mills per kWh) (Line 46*{Column A:[Line 45/Line 48]})**	**0.239**	**0.286**	**0.234**	**0.238**	**0.216**	**0.243**	**0.209**	**0.229**	**0.183**	**0.228**	**0.560**	**0.162**	**0.174**
48	*Loss-Adjusted June 2017 - May 2018 Normalized Sales (kWh)*	685,937,209	188,452,205	18,961,725	118,455,942	16,459,848	2,614,124	437,388	170,802,763	103,687,726	65,129,799	5,388	908,365	21,936
49	Projected March Forecast APCU 2017-2018 Revenues (Line 47 * Line 48)	$164,116	$53,977	$4,437	$28,231	$3,555	$635	$91	$39,178	$18,988	$14,871	$3	$147	$4

Notes:

2017 March Forecast APCU Revenues = $0.24/MWh x 683,817.790 MWhs for April 2017 through May 2018 test per **$ 164,116** **(Line 49, Column A)**

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Revised October Update / March Forecast Filing
Effective June 1, 2017

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	(A) Tariff Description	Rate Sch. No.	(B) Average Number of Customers [1]	(C) Normalized Energy (kWh) [1]	(D) Current Billed Revenue w/o March Forecast NPSE	(E) Current Mills Per kWh w/o March Forecast NPSE	(F) Current Billed March Forecast NPSE	(G) Current March Forecast NPSE Mills Per kWh	(H) Current Total Billed Revenue w/March Forecast NPSE	(I) Current Total Mills Per kWh	(J) Proposed March Forecast NPSE	(K) Proposed March Forecast NPSE Mills Per kWh [2]	(L) Adjustments to Billed Revenue for March Forecast NPSE	(M) Adjustments to Base Revenue for October Update NPSE [3]	(N) Total Adjustments to Billed Revenue [3]	(O) Proposed Total Billed Revenue [3]	(P) Proposed Total Mills Per kWh [2]	(Q) Percent Change Billed to Billed Revenue [3]
	Uniform Tariff Rates:																	
1	Residential Service	1	13,701	188,452,205	$19,331,607	102.58	$300,016	1.592	$19,631,623	104.17	$53,977	0.286	($246,039)	$479,044	$233,005	$19,864,628	105.41	1.19%
2	Small General Service	7	2,565	18,961,725	$1,965,967	103.68	$25,409	1.340	$1,991,376	105.02	$4,437	0.234	($20,972)	$39,378	$18,406	$2,009,781	105.99	0.92%
3	Large General Service	9	915	137,529,914	$10,419,749	75.76	$177,644	1.292	$10,597,394	77.06	$32,421	0.236	($145,223)	$287,739	$142,515	$10,739,909	78.09	1.34%
4	Dusk to Dawn Lighting	15	0	437,388	$107,450	245.66	$506	1.157	$107,956	246.82	$91	0.209	($415)	$810	$395	$108,351	247.72	0.37%
5	Large Power Service	19	7	274,490,489	$15,911,970	57.97	$334,583	1.219	$16,246,553	59.19	$58,165	0.212	($276,417)	$516,216	$239,799	$16,486,352	60.06	1.48%
6	Agricultural Irrigation Service	24	1,932	65,129,799	$6,203,791	95.25	$81,477	1.251	$6,285,268	96.50	$14,871	0.228	($66,606)	$131,981	$65,375	$6,350,643	97.51	1.04%
7	Unmetered General Service	40	2	5,388	$682	126.66	$16	3.044	$699	129.70	$3	0.560	($13)	$27	$13	$712	132.19	1.91%
8	Street Lighting	41	25	908,365	$135,598	149.28	$813	0.895	$136,411	150.17	$147	0.162	($666)	$1,307	$641	$137,052	150.88	0.47%
9	Traffic Control Lighting	42	8	21,936	$1,916	87.35	$22	1.022	$1,938	88.37	$4	0.174	($19)	$34	$15	$1,954	89.07	0.79%
10	Total Uniform Tariffs		19,155	685,937,209	$54,078,731	78.84	$920,487	1.342	$54,999,218	80.18	$164,116	0.239	($756,371)	$1,456,535	$700,164	$55,699,382	81.20	1.27%
11	Total Oregon Retail Sales		19,155	685,937,209	$54,078,731	78.84	$920,487	1.340	$54,999,218	80.18	$164,116	0.239	($756,371)	$1,456,535	$700,164	$55,699,382	81.20	1.27%

(1) Updated June 2017-May 2018 Test Year
(2) This amended exhibit includes updates to the figures in Columns (K) and (P) as a result of using a June 2017 - May 2018 collection test period, rather than an April 2017 - March 2018 test period.
(3) This amended exhibit includes updates to the figures in Columns (M), (N), (O) and (Q) as a result of a correction to the incremental NPSE figure presented on line 51 of Amended Exhibit 304. This amended exhibit also provides more detail than the initial exhibit submitted by the Company, as per Commission Staff's directive.