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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT ("PCA") RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2016, THROUGH MAY 31, 2017.	)	CASE NO. IPC-E-16-08

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MATTHEW T. LARKIN

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Matthew T. Larkin. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Revenue Requirement Manager in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration degree in Finance from the University of Oregon in 2007. In 2008, I earned a Master of Business Administration degree from the University of Oregon. I have also attended electric utility ratemaking courses, including the *Electric Rates Advanced Course*, offered by the Edison Electric Institute, and *Estimation of Electricity Marginal Costs and Application to Pricing*, presented by National Economic Research Associates, Inc.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power as a Regulatory Analyst I in January 2009. As a Regulatory Analyst I, I provided support for the Company's regulatory activities, including compliance reporting, financial analysis, and the development of revenue forecasts for regulatory filings.

In January 2012, I was promoted to Regulatory Analyst II, and, in January 2014, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, my responsibilities expanded to include the development of complex cost-related studies and the analysis of strategic regulatory issues.

In March of 2016, I was promoted to my current position of Revenue Requirement Manager. As Revenue Requirement Manager, I oversee the Company's regulatory activities related to revenue requirement, such as power supply expense modeling, jurisdictional separation studies, and Idaho Power's Open Access Transmission Tariff Formula Rate.

Q. What is the Company requesting in this case?

A. The Company is requesting approval of its quantification of the 2016-2017 Power Cost Adjustment ("PCA") rates to become effective June 1, 2016. If approved, the 2016-2017 PCA will result in a revenue increase of approximately $17.3 million, or 1.57 percent.

Q. How is your testimony organized?

A. My testimony is comprised of four sections. In the first section, I will provide an overview of the PCA. In the second section, I will detail the 2016-2017 PCA amount, identify and discuss the main factors contributing to this amount, and present the quantification of the 2016-

2017 PCA rates. In the third section, I will discuss additional rate adjustments resulting from revenue sharing and the Company's 2014 update to base net power supply expenses ("NPSE"). In the final section of my testimony, I will summarize the rates proposed to become effective June 1, 2016, and the net customer impact of these rates if approved.

I. PCA OVERVIEW

Q. What is the purpose of the PCA and how does the mechanism function?

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual NPSE and the normalized or "base level" of NPSE recovered in the Company's base rates, resulting in a credit or surcharge that is updated annually on June 1. The PCA mechanism utilizes a 12-month test period of April through March ("PCA Year") and is comprised of a forecast component and a true-up component ("True-Up"). The forecast component represents the difference between the NPSE forecast from the March Operating Plan and base level NPSE recovered in the Company's base rates. The True-Up includes a backward looking tracking of differences between the prior year's forecast and actual NPSE incurred by the Company in that PCA Year. The True-Up contains a second component that tracks the collection of the prior year's True-Up amount, referred to as the "True-Up of the True-Up."

With the exception of Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses and demand response incentive payments, the PCA allows the Company to pass through to customers 95 percent of the annual differences in actual NPSE as compared to base level NPSE, whether positive or negative. With respect to PURPA expenses and demand response incentive payments, as actual annual expenses deviate from base, the Company is allowed to pass through 100 percent of the difference for recovery or credit through the PCA. The PCA is also the rate mechanism used by the Company to provide direct benefits resulting from the revenue sharing mechanism approved by the Idaho Public Utilities Commission ("Commission") in Order No. 33149.

Q. What are the components of the PCA base level NPSE?

A. The PCA base level NPSE include the following Federal Energy Regulatory Commission ("FERC") accounts: FERC Account 501, fuel (coal); FERC Account 536, water for power; FERC Account 547, fuel (gas); FERC Account 555, purchased power; FERC Account 565, transmission of electricity by others; and FERC Account 447, sales for resale (typically referred to as surplus sales).

The PCA base level expense component for FERC Account 555 includes costs resulting from both PURPA and non-PURPA (market) purchases. Per Order No. 32426, the Company adjusts FERC Account 555 to include demand response incentive payments that the Company provides to customers for participating in any of its three demand response programs.

II. 2016-2017 PCA

Q. What is the total 2016-2017 PCA amount as measured from the currently approved base level NPSE?

A. The 2016-2017 total PCA amount as measured from the currently approved base level NPSE[1] is $79.2 million.[2] This represents an increase in total billed revenue of $17.3 million for the upcoming year, an increase of 1.57 percent.

PCA Forecast

Q. What is the Company's determination of the system-level difference between currently approved base level NPSE and the forecast of NPSE for the 2016-2017 PCA Year?

A. The system-level forecast of NPSE for the 2016-2017 PCA Year is $357,547,740, which is $51,862,871

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[1] Approved on March 21, 2014, Order No. 33000.

[2] Includes the impact of revenue sharing and the ongoing Demand-Side Management Rider ("DSM Rider") transfer detailed in Section III below.

higher than the currently approved base level NPSE of $305,684,869. Table 1 below presents the system-level differences between currently approved base level NPSE and the forecast of NPSE for the 2016-2017 PCA Year by FERC account.

Table 1	**2016-2017 PCA FORECAST (Total System)**			
Line No.	**FERC Account**	**Base NPSE**	**Forecast**	**Difference**
	95% Sharing Accounts			
1	Account 501, Coal	$ 108,503,180	$ 112,127,106	$ 3,623,926
2	Account 536, Water for Power	$ 2,380,597	$ -	$ (2,380,597)
3	Account 547, Other Fuel	$ 33,367,563	$ 39,202,822	$ 5,835,259
4	Account 555, Purchased Power Non-PURPA	$ 62,606,593	$ 54,988,467	$ (7,618,126)
5	Account 565, 3rd Party Transmission	$ 5,455,955	$ 5,999,412	$ 543,457
6	Account 447, Surplus Sales	$ (51,735,153)	$ (20,930,147)	$ 30,805,006
		$ 160,578,735	$ 191,387,660	$ 30,808,925
	100% Sharing Accounts			
7	Account 555, PURPA	$ 133,853,869	$ 158,758,382	$ 24,904,513
8	Account 555, Demand Response Incentives	$ 11,252,265	$ 7,401,698	$ (3,850,567)
9	Total	$ 305,684,869	$ 357,547,740	$ 51,862,871

Q. What is the basis for the forecast of NPSE for the 2016-2017 PCA Year?

A. The forecast of NPSE for the 2016-2017 PCA Year is based on the Company's March 31, 2016, Operating Plan.

Q. How is the NPSE forecast developed for the Company's Operating Plan?

A. The Operating Plan is prepared monthly and represents a forecast of the Company's monthly NPSE for the following 18-month period; however, for the PCA, the Company includes only the 12 months that correspond to the PCA Year. The Operating Plan is developed by simulating the economic dispatch of the Company's generation resources for each month, segmented by heavy load and light load hours. The dispatch considers a current forecast of forward market energy prices, available hydro generation, coal and natural gas prices, and any existing hedge transactions. The system load forecast is then analyzed against the resulting monthly heavy load and light load dispatch to determine a monthly load and resource balance. Any identified resource deficiency is assumed to be filled with market energy purchases. Economically dispatched generation above the system load forecast represents surplus energy sales.

Q. How does the Company's forecast of NPSE for the 2016-2017 PCA compare to the forecast from last year's PCA?

A. Table 2 compares this year's 2016-2017 PCA forecast to last year's PCA forecast for each NPSE category. As detailed in this table, the PCA forecast on a total system basis for the 2016-2017 PCA is expected to be

$357,547,740, which is $9,163,614 higher than last year's forecast amount of $348,384,126.

Table 2	PCA Forecast Comparison - Expenses (Total System)			
Line No.	**FERC Account**	**2015-2016 Forecast**	**2016-2017 Forecast**	**Difference**
	95% Sharing Accounts			
1	Account 501, Coal	$ 117,032,475	$ 112,127,106	$ (4,905,369)
2	Account 536, Water for Power	$ 2,425,230	$ -	$ (2,425,230)
3	Account 547, Other Fuel	$ 57,173,815	$ 39,202,822	$ (17,970,993)
4	Account 555, Purchased Power Non-PURPA	$ 48,372,214	$ 54,988,467	$ 6,616,253
5	Account 565, 3rd Party Transmission	$ 6,453,427	$ 5,999,412	$ (454,015)
6	Account 447, Surplus Sales	$ (39,048,702)	$ (20,930,147)	$ 18,118,555
		$ 192,408,459	$ 191,387,660	$ (1,020,799)
	100% Sharing Accounts			
7	Account 555, PURPA	$ 148,054,626	$ 158,758,382	$ 10,703,756
8	Account 555, Demand Response Incentives	$ 7,921,041	$ 7,401,698	$ (519,343)
		$ 155,975,667	$ 166,160,080	$ 10,184,413
9	Total PCA Forecast	$ 348,384,126	$ 357,547,740	$ 9,163,614

Q. What general conclusions can be drawn from the information contained in Table 2?

A. When viewed by category, the 95 percent sharing accounts represent a decrease of $1 million from last year's forecast, while the 100 percent sharing accounts represent an increase of $10.2 million over last year's forecast.

Q. Why is the Company forecasting $0 for inclusion in FERC Account 536, Water for Power, when last year's forecast was $2.4 million?

A. Account 536 was reduced to $0 in the current forecast from the previous forecast amount of $2.4 million due to the expiration of the Company's water lease with the Shoshone-Bannock Tribal Water Supply Bank. In the past, the Company leased 45,716 acre-feet of American Falls storage water. Under the terms of this agreement, the Company could schedule the release of the water to maximize the value of generation from the entire system of mainstem Snake River hydroelectric projects. The Company typically scheduled delivery of the water between July and October each year to offset the effect of drought and changing water-use patterns in southern Idaho, and to provide additional generation in summer months when customer demand is high. However, the five-year contract term expired in 2015, and the Company made an economic decision not to renew as the potential contract pricing was not competitive with current market energy prices.

Q. What other factors do you believe contributed to the notable differences presented in Table 2?

A. Expected market prices have declined due to low projected gas prices and improved hydrologic conditions in the region. When market prices are depressed, it is economic for the Company to serve load through increased market purchases and system generation, while the ability to sell surplus is reduced. Consequently, the Company's expectation of surplus sales revenue has declined by 46 percent compared to last year's forecast, while expected non-PURPA market purchases have increased by 14 percent. The reduction in surplus sales revenue and increase in non-PURPA market purchases are offset by reductions in expected coal and gas production costs, resulting in the $1 million net decrease in the 95 percent sharing accounts relative to last year's forecast.

With regard to the 100 percent sharing accounts, PURPA costs increased by $10.7 million as compared to last year's forecast, reflecting a 7 percent increase, while demand response incentive payments declined by $519,343, reflecting a 7 percent decrease. The net impact to the 100 percent sharing accounts is an increase of $10.2 million over last year's forecast.

Q. Is the increase in PURPA costs related to increased generation output from PURPA projects?

A. Yes. Table 3 below details changes between last year's PCA forecast and this year's PCA forecast with respect to forecasted generation in megawatt-hours ("MWh"). As shown in Table 3, PURPA generation is anticipated to increase by 257,857 MWh, or 12 percent, as compared to last year's PCA forecast. This increase is largely due to the addition of 320 megawatts ("MW") of PURPA solar projects and 50 MW of PURPA wind projects that are expected to come on-line in the 2016-2017 PCA year.

Table 3	PCA Forecast Comparison - Generation (Total System-MWh)			
Line No.	FERC Account	2015-2016 Forecast	2016-2017 Forecast	Difference
1	Hydro	8,132,991	7,633,253	(499,738)
	95% Sharing Accounts			
2	Account 501, Coal	3,953,060	3,895,094	(57,966)
3	Account 547, Other Fuel	2,297,609	1,847,736	(449,873)
4	Account 555, Purchased Power Non-PURPA	858,438	1,187,511	329,073
	95% Sharing Accounts	15,242,098	14,563,594	(678,504)
	100% Sharing Accounts			
5	Account 555, PURPA	2,199,216	2,457,073	257,857
	100% Accounts	2,199,216	2,457,073	257,857
6	Total Generation	17,441,314	17,020,667	(420,647)
	95% Sharing Accounts			
7	Account 447, Surplus Sales	1,651,264	1,135,459	(515,805)
8	Total Load	15,790,050	15,885,208	95,158

Q. Did the expiration of the Shoshone-Bannock Tribal Water Supply Bank lease impact modeled hydro generation in the 2016-2017 PCA forecast?

A. Yes. The expiration of the Shoshone-Bannock Tribal Water Supply Bank lease led to a reduction in modeled hydro generation of approximately 53,000 MWh.

Q. Is the remainder of the 499,738 MWh reduction in expected hydro generation the result of lower projected inflows into Brownlee?

A. No. The March Operating Plan used in this year's PCA forecast projects April through July inflows into Brownlee of 4.5 million acre-feet ("MAF"). This is approximately equivalent to the 4.5 MAF used to determine last year's PCA forecast.

Q. Why is projected hydro generation less than last year's forecast if expected inflows into Brownlee have not declined?

A. While this year's forecast of April through July inflows into Brownlee is comparable to last year's, projected hydro generation is lower due to decreased flows from the Upper Snake Basin. The reservoir levels in this region are lower than initially forecast in 2015, which has resulted in no projected flood control from the Upper Snake Basin. Consequently, while projected inflows into Brownlee and through the Company's Hells Canyon Complex are comparable to last year, the lack of flood control in the Upper Snake Basin results in less water projected to flow through all upstream generation facilities from American Falls to Swan Falls.

Q. What else can be concluded from the information in Table 3?

A. Another item of note in Table 3 is the additional non-PURPA market purchases of 329,073 MWh over last year's PCA forecast. The average market purchase price for this year's PCA forecast is $46.31 per MWh, compared to last year's forecast of $56.35 per MWh. As discussed above, these lower prices are driving an increase in non-PURPA market purchases for this year's PCA forecast as compared to last year's PCA forecast.

Alternatively, lower market prices also result in an expected reduction in surplus sales volumes of 31 percent, or 515,805 MWh, as compared to last year's forecast. The average market energy sale price for this year's PCA forecast is $18.43 per MWh, compared to last year's forecast of $23.65 per MWh.

The combination of additional non-PURPA market purchases of 329,073 MWh and reduced surplus sales volumes of 515,805 MWh is offset by the reduction in hydro generation of 6 percent, or 499,738 MWh, as well as a reduction in coal generation of 1.5 percent, or 57,966 MWh, and natural gas generation of 20 percent, or 449,873 MWh, from last year's PCA forecast.

Q. How are the forecasted NPSE differences presented in Table 1 used to determine the 2016-2017 PCA forecast component to be collected from Idaho customers?

A. The 2016-2017 PCA forecast component reflects the Idaho jurisdictional share of the forecasted NPSE differences presented in Table 1, adjusted for the PCA sharing provisions. The Idaho jurisdictional share of the forecast NPSE differences is determined by applying a ratio of forecast firm Idaho jurisdictional sales to forecast firm system-level sales to the system-level NPSE differences, adjusted for sharing.

Q. What is the Company's forecast of system-level firm sales and Idaho jurisdictional firm sales for the 2016-2017 PCA Year?

A. For the 2016-2017 PCA Year, Idaho Power has forecast system-level firm sales to be 14,647,388 MWh and Idaho jurisdictional firm sales to be 13,955,821 MWh, or 95.28 percent of the system level.

Q. What is the Company's determination of the 2016-2017 PCA forecast component to be collected from Idaho customers?

A. The 2016-2017 PCA forecast component that is expected to be collected from Idaho customers is $47,764,680. Table 4 presents the determination of the 2016-2017 PCA forecast component by individual PCA expense and revenue category.

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Table 4	2016-2017 PCA FORECAST			
Line No.	FERC Account	Difference From Base	Difference After Sharing	Idaho Allocation
	95% Sharing Accounts	(From Table 1)		
1	Account 501, Coal	$ 3,623,926	$ 3,442,730	$ 3,280,183
2	Account 536, Water for Power	$ (2,380,597)	$ (2,261,567)	$ (2,154,789)
3	Account 547, Other Fuel	$ 5,835,259	$ 5,543,496	$ 5,281,763
4	Account 555, Purchased Power Non-PURPA	$ (7,618,126)	$ (7,237,220)	$ (6,895,519)
5	Account 565, 3rd Party Transmission	$ 543,457	$ 516,284	$ 491,908
6	Account 447, Surplus Sales	$ 30,805,006	$ 29,264,756	$ 27,883,039
		$ 30,808,925	$ 29,268,479	$ 27,886,585
	100% Sharing Accounts			
7	Account 555, PURPA	$ 24,904,513	$ 24,904,513	$ 23,728,662
8	Account 555, Demand Response Incentives	$ (3,850,567)	$ (3,850,567)	$ (3,850,567)
9	Total	$ 51,862,871	$ 50,322,425	$ 47,764,680

True-Up and True-Up of the True-Up

Q. What is this year's quantification of the True-Up?

A. The True-Up portion of the PCA is detailed on the deferral expense report, attached as Exhibit No. 1. This report compares actual PCA account results to last year's PCA account projections on a monthly basis, with the differences accumulated as the deferral balance. The balance at the end of March 2016, with interest applied, was $43,661,193, as shown on row 97 of Exhibit No. 1. The approximate $43.7 million represents a charge to customers in this year's PCA.

Q. To what factors do you attribute the accumulation of the approximate $43.7 million deferral balance?

A. The $43.7 million deferral balance was largely driven by lower than forecast hydro generation coupled with lower than forecast market energy prices. Actual hydro generation for the 2015-2016 PCA year was 5,938,469 MWh, which was 2,194,522 MWh less than the forecast of 8,132,991 MWh, reflecting a 27 percent reduction between forecast generation and actual generation.

In addition to lower than forecast hydro generation, lower market energy prices led to a decrease in surplus sales and an increase in market purchases. Actual surplus sales volumes were approximately 26 percent lower than forecasted in last year's PCA, while actual non-PURPA purchase volumes were approximately 92 percent higher than forecasted in last year's PCA.

Q. Did the Company calculate the Sales Based Adjustment ("SBA") per the terms of the settlement stipulation approved in Order No. 33307 in Case No. IPC-E-15-15?

A. Yes. The Company's deferral report provided as Exhibit No. 1 contains a modified structure from previous years' PCA deferral reports to reflect the methodology approved in Case No. IPC-E-15-15. Beginning on line 10 of Exhibit No. 1, the Company calculates the SBA using actual Idaho jurisdictional billing month sales rather than system generation-level loads, as was the case under the prior Load Change Adjustment ("LCA") method.

Q. Did the Company quantify the impact of the methodology change on the 2015-2016 PCA deferral balance?

A. Yes. Had the Company continued to calculate the deferral balance utilizing the LCA method, the 2015-2016 True-Up balance as of March 31, 2016, would have been $47,798,396, or $4,137,203 greater than the deferral balance calculated under the new SBA method.

Q. What is this year's True-Up of the True-Up?

A. This year's True-Up of the True-Up balance is a benefit to customers of $5,073,137, as shown on row 119 of the deferral expense report.

Q. What is the combined effect of the True-Up and the True-Up of the True-Up in this year's PCA?

A. The sum of the $43,661,193 associated with the True-Up and the negative $5,073,137 associated with the True-Up of the True-Up represents $38,588,056 of required collection from customers. This additional cost in large part reflects that actual NPSE for the 2015-2016 PCA year were greater than the forecast.

Q. How does this year's combined True-Up and the True-Up of the True-Up compare to last year's amount?

A. The combined True-Up and the True-Up of the True-Up for the last PCA Year was $34,529,699,[3] as compared to this year's amount of $38,588,056, an increase of $4,058,357.

PCA Rate Determination

Q. How is the rate for the forecast portion of the PCA for April 2016 through March 2017 determined?

A. The rate for the forecast portion of the PCA is equal to the sum of (1) 95 percent of the difference between the non-PURPA expenses quantified in the Operating Plan and those quantified in the Company's last approved update of NPSE, divided by the Company's normalized system firm sales, and (2) 100 percent of the difference between PURPA-related expenses quantified in the Operating Plan and those quantified in the Company's last approved update of NPSE, divided by the Company's normalized system firm sales, and (3) 100 percent of the difference between the Idaho jurisdictional demand response incentive payments quantified in the Operating Plan and those quantified in the Company's last approved update of NPSE, divided by Idaho jurisdictional firm sales.

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[3] This amount reflects the level of recovery currently embedded in rates, which includes the $36,000,496 deferral approved in the 2015 PCA case (Case No. IPC-E-15-14, Order No. 33306), as well as the $1,470,797 deferral balance reduction due to the transition to the SBA approved by Order No. 33307 in Case No. IPC-E-15-15.

Q. What is the rate for the forecast portion of the PCA for April 2016 through March 2017?

A. The rate for non-PURPA expenses is 0.1998 cents per kilowatt-hour ("kWh"), which is calculated by multiplying $30,808,925 from Table 1 by 95 percent and then dividing it by the normalized system firm sales of 14,647,388 MWh (($30,808,925 * 0.95) / 14,647,388) = $1.998/MWh = 0.1998 cents/kWh). The rate for PURPA expenses is 0.1700 cents per kWh, which is calculated by dividing $24,904,513 from Table 1 by the 14,647,388 MWh ($24,904,513 / 14,647,388 MWh = $1.70/MWh = 0.1700 cents/kWh). The rate for demand response incentive payments is a negative 0.0276 cents per kWh, which is calculated by dividing the negative $3,850,567 from Table 1 by the Idaho jurisdictional firm sales of 13,955,821 MWh (-$3,850,567 / 13,955,821 MWh = -$0.276/MWh = -0.0276 cents/kWh). The forecast portion of the PCA rate is 0.3422 cents per kWh, which is calculated by adding the non-PURPA expense of 0.1998 cents per kWh to the PURPA expense of 0.1700 cents per kWh to the demand response incentive payment of negative 0.0276 cents per kWh (0.1998 + 0.1700 + -0.0276 = 0.3422 cents/kWh).

Q. How did you compute this year's True-Up rate?

A. As shown in Exhibit No. 1, this year's True-Up component of the PCA is $43.7 million, which when divided by the Company's forecast of Idaho jurisdictional sales of 13,955,821 MWh results in a rate of 0.3129 cents per kWh ($43,661,193 / 13,955,821 = $3.13/MWh = 0.3129 cents/kWh).

The True-Up of the True-Up rate is calculated by dividing a negative $5.1 million (also from Exhibit No. 1) by the forecast of Idaho jurisdictional sales of 13,955,821 MWh, which results in a rate of negative 0.0364 cents per kWh (-$5,073,137 / 13,955,821 = -$0.36/MWh = -0.0364 cents/kWh).

Q. Does the quantified True-Up rate include the sales of Renewable Energy Certificates ("REC" or "RECs") and Sulfur Dioxide ("SO_2") proceeds?

A. Yes. The RECs and SO_2 proceeds are included in the Company's deferral expense report, provided as Exhibit No. 1, on lines 47 and 48. Order No. 32002 issued on June 11, 2010, accepted for filing the Company's REC Management Plan, which passes the customers' share of REC benefits back to customers through the PCA. Order No. 32434 approved on January 12, 2012, directed the Company to pass SO_2 proceeds through the PCA to help offset the Company's PCA deferral balance.

Q. What is the resulting PCA rate when you combine all of the PCA components described previously?

A. The Company's PCA rate for the 2016-2017 PCA year is detailed in Exhibit No. 2, column E. The uniform

PCA rate is comprised of (1) the 0.3422 cents per kWh adjustment for the 2016-2017 projected power cost of serving firm loads under the current PCA methodology and 95 percent sharing, (2) the 0.3129 cents per kWh for the 2015-2016 True-Up portion of the PCA, and (3) the negative 0.0364 cents per kWh for the True-Up of the True-Up. The sum of these three components results in a 0.6187 cents per kWh charge for all rate classes.

III. ADDITIONAL RATE ADJUSTMENTS

Revenue Sharing

Q. When was the revenue sharing mechanism originally established?

A. The revenue sharing mechanism was originally established in Case No. IPC-E-09-30 and approved in Order No. 30978, effective for the years 2009-2011, then modified and extended for the years 2012-2014 in Order No. 32424 in Case No. IPC-E-11-22.

Q. Did the revenue sharing mechanism result in any action following the 2009-2014 fiscal years?

A. Yes. The Company's earnings in each year from 2011 through 2014 resulted in revenue sharing with customers totaling $118 million, either as a direct rate offset in the PCA or as an offset to amounts that would have otherwise been collected in rates. These amounts are detailed in Table 5 below.

Table 5	2009-2014 Revenue Sharing			
Line No.	**Revenue Sharing Component**	**2009-2011**	**2012-2014**	
1	Available ADITC For Use	$45 Million	$45 Million	
2	ROE Threshold	9.5%	9.5%	
3	50-50 Sharing Threshold	10.5%	10.0%	
4	75-25 Sharing Threshold	N/A	10.5%	
5	Customer Benefits ($ Millions):			
6	Reduction to Rates	$27.1	$22.8	**Total**
7	Offset to Pension Balancing Account	$20.3	$47.8	**2009-2014**
8	**Total**	$47.4	$70.6	**$118.0**

Q. Has the revenue sharing mechanism been extended beyond the 2012-2014 time frame?

A. Yes. In Case No. IPC-E-14-14, the Company filed a motion to approve a settlement stipulation ("2014 Stipulation") extending the sharing mechanism, with modifications, through the end of the 2019 fiscal year. The Commission approved the 2014 Stipulation in Order No. 33149.

Q. What are the provisions of the current revenue sharing mechanism as approved in the 2014 Stipulation?

A. Per the terms of the 2014 Stipulation, if the Company's actual, year-end Return on Equity ("ROE") for the Idaho jurisdiction exceeds 10 percent, all amounts up to and including a 10.5 percent ROE will be shared between customers and the Company on a 75 percent and 25 percent basis, respectively, to be provided as a rate reduction to become effective at the time of the subsequent year's PCA.

If the Company's Idaho jurisdictional ROE exceeds 10.5 percent, all amounts in excess of 10.5 percent will be shared 50 percent with Idaho customers as a rate reduction to become effective with the subsequent year's PCA, 25 percent will be shared with Idaho customers in the form of an offset to amounts in the Company's pension balancing account and 25 percent will be apportioned to the Company.

With regard to the amortization of Accumulated Deferred Investment Tax Credits ("ADITC"), the 2014 Stipulation allows the Company to accelerate the amortization of ADITC to achieve a maximum 9.5 percent Idaho jurisdictional ROE if the Company's year-end actual results fall below that amount in any single year between 2015 and 2019. The extension limits total cumulative accelerated amortization of ADITC to $45 million over the 2015-2019 time period, with no more than $25 million to be accelerated in a single year.

Q. Have you provided an exhibit that summarizes the terms of the current sharing mechanism?

A. Yes. Exhibit No. 3 contains a graphical depiction of the current sharing mechanism, detailing the various ROE thresholds and sharing provisions.

Q. Did the Company's year-end 2015 financial results warrant any action related to the existing sharing agreement per the terms of the 2014 Stipulation?

A. Yes. The Company's year-end 2015 financial results yielded an actual Idaho jurisdictional ROE of 10.13 percent, resulting in a revenue amount to be shared with customers after tax gross-up of $3,159,478.

Q. Did the Company utilize the same methodology to determine the Idaho jurisdictional 2015 year-end ROE that was used in prior PCA filings?

A. Yes. The methodology used to determine the Company's Idaho jurisdictional 2015 year-end ROE is consistent with the methodology used for the year-end ROE determinations since the inception of the mechanism.

Q. Do you have an exhibit demonstrating the application of this methodology?

A. Yes. Exhibit No. 4 provides a step-by-step calculation of the Idaho jurisdictional ROE and subsequent revenue sharing benefits based on year-end 2015 financial results utilizing the Commission-approved methodology from previous PCA filings.

Q. What is the revenue sharing amount to be included in the 2016-2017 PCA?

A. As detailed in Exhibit No. 4, the 2015 Idaho jurisdictional ROE was 10.13 percent. As quantified on line 63 of Exhibit No. 4, in 2015, the Company's earnings exceeded an Idaho jurisdictional ROE of 10 percent by $2,565,553. Per the terms of the 2014 Stipulation, 75 percent of the $2,565,553 should be shared with customers as a direct reduction to PCA rates effective June 1, 2016. Applying the 75 percent sharing provision to the $2,565,553 yields a customer-allocated sharing amount of $1,924,165. After tax gross-up, the revenue sharing amount to be applied to customer bills is $3,159,478.

Q. How does the Company propose to allocate the $3,159,478 revenue sharing to customer classes?

A. The Company proposes to allocate the revenue sharing benefit to customer classes utilizing the same methodology as in past cases; i.e., based on each class's proportional share of forecasted base rate revenues for the upcoming PCA rate effective year, which in this case is June 1, 2016, through May 31, 2017.

Q. Have you provided an exhibit detailing the class allocation utilizing this methodology?

A. Yes. Exhibit No. 5 details the class allocation of the $3,159,478 revenue sharing benefit. As displayed in column G of Exhibit No. 5, each customer class receives a decrease of approximately 0.31 percent relative to current base revenues.

Q. How does the Company propose to include the class-allocated revenue sharing benefits in rates?

A. With the exception of the special contracts for Micron Technology, Inc., the U.S. Department of Energy, and the J.R. Simplot Company - Pocatello, Idaho Power proposes to include the class-allocated revenue sharing benefits on a cents-per-kWh basis applied to the 2016 PCA rates effective June 1, 2016, through May 31, 2017. Column F of Exhibit No. 5 contains the rates proposed for inclusion in each class's PCA rate.

Q. What is the Company's proposal for providing revenue sharing benefits to its special contract customers?

A. Consistent with the methodology used to share 2011, 2012, 2013, and 2014 revenues, the Company proposes to provide the special contract customers a flat dollar-per-month credit in 12 equal portions to serve as a reduction to monthly invoices billed from June 2016 through May 2017. The total revenue sharing benefit allocated to each special contract customer is displayed in column E of Exhibit No. 5.

Q. Is the Company's rate design proposal for the 2015 revenue sharing benefits consistent with past-approved proposals?

A. Yes.

DSM Rider Transfer

Q. Is the Company proposing the continuation of the approximate $4.0 million DSM Rider transfer adjustment that was included in the 2015 PCA filing?

A. Yes. The Company is proposing the continuation of a PCA credit related to the DSM Rider in the amount of $3,970,036.

Q. Why is this credit necessary?

A. This credit is necessary to maintain the revenue neutrality associated with the 2014 update to the normalized level of NPSE included in base rates approved by Order No. 33000.

Q. Please explain.

A. Idaho Power's current level of DSM Rider collection is 4 percent of base rate revenues. The approval to increase the Company's level of base rate revenues by $99.3 million effective June 1, 2014, results in the Company collecting approximately $4.0 million per year of additional DSM Rider funds. To ensure the base rate increase associated with the new base level of NPSE approved in Case No. IPC-E-13-20 remains revenue neutral for all classes of customers, it is appropriate to offset the increase in DSM Rider revenue by moving $4.0 million out of the DSM Rider balancing account and providing that amount as a credit to customers in the 2016-2017 PCA. This adjustment should continue to be included in PCA rate determinations until the level of NPSE recovery in base rates is re-established as part of a general rate case or otherwise adjusted by Commission order.

Q. How is the Company proposing to apply the DSM Rider transfer to customer rates?

A. The Company is proposing to apply the previously approved method of a cents-per-kWh credit to each class's PCA rate effective June 1, 2016, through May 31, 2017. This approach allows each customer class to receive the credit in the same proportion as its respective increase in base rates.

IV. RATE SUMMARY AND NET CUSTOMER IMPACT

Q. Has the Company provided an exhibit detailing the final rates requested to become effective June 1, 2016, including the PCA components, revenue sharing, and DSM Rider transfer?

A. Yes. Column F of Exhibit No. 2 contains the final rates for each customer class proposed to become effective June 1, 2016, through May 31, 2017. These rates include the standard PCA rate of 0.6187 cents per kWh, the -0.0284 cents per kWh associated with the DSM Rider transfer, and each class's allocation of the revenue sharing component.

Q. What is the revenue impact of the requested PCA rate combined with revenue sharing and the adjustment related to the DSM Rider when compared to PCA rates currently in effect?

A. Attachment 2 to the Application provides a detailed description of the overall revenue impact of this filing on each customer class. As shown on Attachment 2, applying the requested PCA rates to expected customer sales for the June 2016 through May 2017 test year results in a PCA increase of $17.3 million.

Q. Have you prepared a table that details the $17.3 million revenue impact by component?

A. Yes. Table 6 below separates the $17.3 million increase into each component included in the Company's proposed rates.

Table 6	**Revenue Impact by Component**			
Line No.	**Rate Component**	**2015-2016 PCA[4]**	**2016-2017 PCA[5]**	**Difference**
1	PCA Forecast	$ 39,299,591	$ 47,770,774	$ 8,471,183
2	PCA True-Up	$ 34,652,303	$ 38,587,844	$ 3,935,541
3	Revenue Sharing	$ (8,048,717)	$ (3,159,478)	$ 4,889,239
4	DSM Rider Ongoing Transfer	$ (3,991,365)	$ (3,970,036)	$ 21,329
5	**PCA Total**	**$ 61,911,812**	**$ 79,229,104**	**$ 17,317,292**

Q. Have you prepared a revised Schedule 55 that includes the proposed PCA rates?

[4] Because Table 6 contains the expected billed revenue impact to customers, the "2015-2016 PCA" column reflects approved 2015-2016 PCA rates applied to the June 2016 through May 2017 sales forecast, and will not tie to the specific dollar amounts approved in the 2015 PCA filing.

[5] The "2016-2017 PCA" column reflects the Company's proposed rates applied to the June 2016 through May 2017 forecast, and may not tie exactly to the figures listed in the above testimony due to the rounding of rates to six digits.

A. Yes. Attachment 1 to the Application is a revised Schedule 55 and includes the proposed PCA rates in clean and legislative formats.

Q. Should the Commission approve the Company's computation of the PCA rates?

A. Yes. The Commission should approve the Company's computation of the PCA rates. The calculation of the PCA rates follows the methodology that was approved in Order Nos. 30715, 30978, 32424, 32578, and 33000.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada)

I, Matthew T. Larkin, having been duly sworn to testify truthfully, and based upon my personal knowledge, state the following:

I am employed by Idaho Power Company as the Revenue Requirement Manager in the Regulatory Affairs Department and am competent to be a witness in this proceeding.

I declare under penalty of perjury of the laws of the state of Idaho that the foregoing pre-filed testimony and exhibits are true and correct to the best of my information and belief.

DATED this 15th day of April 2016.

Matthew T. Larkin

SUBSCRIBED AND SWORN to before me this 15th day of April 2016.

CHRISTA S. BEARRY NOTARY PUBLIC STATE OF IDAHO

Christa S. Bearry
Notary Public for Idaho
Residing at: Boise, Idaho
My commission expires: 02/04/2021

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-16-08

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 1

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**Power Cost Adjustment**																
2	**April 2015 thru March 2016**																
3					April	May	June	July	August	September	October	November	December	January	February	March	Totals
4	**PCA Forecasted Revenues**	*Prior*	*New (Effective 6/1/15)*														
5	Actual Idaho Jurisdictional Billing Month Sales			Mwh	961,156	1,061,961	1,147,790	1,557,565	1,379,371	1,342,005	1,012,234	936,904	1,069,144	1,155,022	1,050,660	941,498	13,615,310
6	% of Prior Period Billings at Old Rate				100.000%	100.000%	58.009%	0.003%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	100.000%	0.000%	
7	% of Current Period Billings at New Rate				0.000%	0.000%	41.990%	99.997%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	0.000%	100.000%	
8	**Forecasted Billing Month Revenues**	$ 1.609	$ 2.815	$	(1,546,499.59)	(1,708,694.80)	(2,368,621.22)	(4,379,809.97)	(3,882,928.81)	(3,777,743.67)	(2,849,438.40)	(2,637,385.19)	(3,009,639.15)	(3,251,387.22)	(2,957,609.06)	(2,650,315.96)	(35,020,073.04)
9																	
10	**Sales Based Adjustment**	*Prior*	*New (Effective 6/1/14)*														
11	Actual Idaho Jurisdictional Billing Month Sales			Mwh	961,156	1,061,961	1,147,790	1,557,565	1,379,371	1,342,005	1,012,234	936,904	1,069,144	1,155,022	1,050,660	941,498	13,615,310
12	Normalized Idaho Jurisdictional Billing Month Sales			Mwh	947,192	953,286	1,131,686	1,370,142	1,428,766	1,300,608	1,045,495	957,864	1,081,014	1,177,663	1,101,149	1,004,027	13,498,892
13	Sales Change			Mwh	13,964	108,675	16,104	187,423	(49,395)	41,397	(33,261)	(20,960)	(11,870)	(22,641)	(50,489)	(62,529)	116,418
14	% of Prior Period Billings at Old Rate				0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
15	% of Current Period Billings at New Rate				100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
16	Sales Adjustment Prior To Sharing		$ 26.72	$	(373,118.08)	(2,903,796.00)	(430,298.88)	(5,007,942.56)	1,319,834.40	(1,106,127.84)	888,733.92	560,051.20	317,166.40	604,967.52	1,349,066.08	1,670,774.88	(3,110,688.96)
17	Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
18	**Sales Based Adjustment**			$	(354,462.18)	(2,758,606.20)	(408,783.94)	(4,757,545.43)	1,253,842.68	(1,050,821.45)	844,297.22	532,048.64	301,308.08	574,719.14	1,281,612.78	1,587,236.14	(2,955,154.52)
19																	
20	**Actual Non-QF**																
21	Fuel Expense-Coal			$	10,719,507.16	8,148,495.82	14,745,927.44	14,898,475.11	18,065,415.27	10,904,730.72	9,622,839.62	9,589,670.63	10,419,660.84	10,581,123.02	8,513,914.83	4,570,231.44	130,779,991.90
22	Fuel Expense-Gas			$	2,071,160.49	4,340,495.49	6,310,174.96	7,735,567.10	8,941,254.00	5,746,499.93	3,749,765.01	3,104,906.18	5,390,361.88	5,024,228.65	3,968,136.99	2,978,166.36	59,360,717.04
23	Non-Firm Purchases			$	4,046,263.01	2,863,240.66	10,099,422.39	9,356,606.10	7,883,392.52	4,467,697.61	5,570,061.34	8,105,597.99	8,034,132.40	4,314,882.64	3,797,971.69	3,644,998.50	72,184,266.85
24	Third Party Transmission			$	389,701.25	319,651.21	599,152.22	1,285,851.01	828,124.04	603,419.48	529,302.95	609,272.15	157,869.28	310,482.04	318,865.00	283,697.04	6,235,387.67
25	Surplus Sales			$	(1,059,360.10)	(1,505,677.05)	(1,039,300.58)	(3,087,225.97)	(974,119.53)	(2,079,282.99)	(3,510,785.98)	(1,454,310.05)	(2,319,464.24)	(3,827,618.00)	(2,424,594.16)	(2,778,012.63)	(26,059,751.28)
26	Water for Power (Leases)			$	34,000.00	-	343,499.00	1,474,843.20	606,309.00	-	-	-	-	-	-	-	2,458,651.20
27	Total Actual Non-QF			$	16,201,271.81	14,166,206.13	31,058,875.43	31,664,116.55	35,350,375.30	19,643,064.75	15,961,182.94	19,955,136.90	21,682,560.16	16,403,098.35	14,174,294.35	8,699,080.71	244,959,263.38
28	Idaho Allocation				95.2%	95.4%	95.6%	95.7%	95.6%	95.7%	95.5%	94.8%	95.2%	95.0%	95.6%	95.5%	
29	Net Idaho Jurisdictional Actual Non-QF			$	15,423,610.76	13,514,560.65	29,692,284.91	30,302,559.54	33,794,958.79	18,798,412.97	15,242,929.71	18,917,469.78	20,641,797.27	15,582,943.43	13,550,625.40	8,307,622.08	233,769,775.29
30																	
31	**Base Non-QF**																
32	Fuel Expense-Coal			$	7,525,242.00	7,487,643.00	9,019,153.00	11,385,255.00	12,185,412.00	10,796,845.00	7,781,442.00	7,302,324.00	8,455,019.00	9,553,773.00	8,912,994.00	8,098,078.00	108,503,180.00
33	Fuel Expense-Gas			$	2,314,209.00	2,302,646.00	2,773,625.00	3,501,263.00	3,747,333.00	3,320,312.00	2,392,997.00	2,245,656.00	2,600,139.00	2,938,035.00	2,740,979.00	2,490,369.00	33,367,563.00
34	Non-Firm Purchases			$	4,342,083.00	4,320,388.00	5,204,073.00	6,569,319.00	7,031,012.00	6,229,805.00	4,489,910.00	4,213,459.00	4,878,566.00	5,512,549.00	5,142,819.00	4,672,610.00	62,606,593.00
35	Third Party Transmission			$	378,398.00	376,507.00	453,517.00	572,494.00	612,729.00	542,907.00	391,281.00	367,189.00	425,151.00	480,400.00	448,179.00	407,203.00	5,455,955.00
36	Surplus Sales			$	(3,588,093.00)	(3,570,166.00)	(4,300,402.00)	(5,428,577.00)	(5,810,099.00)	(5,148,019.00)	(3,710,251.00)	(3,481,805.00)	(4,031,418.00)	(4,555,312.00)	(4,249,784.00)	(3,861,227.00)	(51,735,153.00)
37	Water for Power (Leases)			$	165,106.00	164,281.00	197,883.00	249,796.00	267,352.00	236,886.00	170,727.00	160,216.00	185,506.00	209,613.00	195,555.00	177,676.00	2,380,597.00
38	Net 95% Items			$	11,136,945.00	11,081,299.00	13,347,849.00	16,849,550.00	18,033,739.00	15,978,736.00	11,516,106.00	10,807,039.00	12,512,963.00	14,139,058.00	13,190,742.00	11,984,709.00	160,578,735.00
39	Idaho Allocation				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
40	Net Idaho Jurisdiction 95% Items			$	10,580,097.75	10,527,234.05	12,680,456.55	16,007,072.50	17,132,052.05	15,179,799.20	10,940,300.70	10,266,687.05	11,887,314.85	13,432,105.10	12,531,204.90	11,385,473.55	152,549,798.25
41																	
42	Idaho Jurisdiction Change From Base			$	4,843,513.01	2,987,326.60	17,011,828.36	14,295,487.04	16,662,906.74	3,618,613.77	4,302,629.01	8,650,782.73	8,754,482.42	2,150,838.33	1,019,420.50	(3,077,851.47)	81,219,977.04
43	Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
44	**Net Power Supply Costs Deferral**			$	4,601,337.36	2,837,960.27	16,161,236.94	13,580,712.69	15,829,761.40	3,437,683.08	4,087,497.56	8,218,243.59	8,316,758.30	2,043,296.41	968,449.48	(2,923,958.90)	77,158,978.18
45																	
46	**Emission Allowance and REC Sales**																
47	Emission Allowance Sales Credit			$	-	-	-	-	-	-	-	-	-	-	-	-	0.00
48	Renewable Energy Credit Sales			$	(729,608.57)	(20,816.50)	324.76	(308,073.06)	676.73	(10,396.78)	(85,310.17)	(1,738.78)	(58,413.88)	347.14	(400,227.23)	(17,444.40)	(1,630,680.74)
49	Total Emission Allowances and REC Sales			$	(729,608.57)	(20,816.50)	324.76	(308,073.06)	676.73	(10,396.78)	(85,310.17)	(1,738.78)	(58,413.88)	347.14	(400,227.23)	(17,444.40)	(1,630,680.74)
50	Idaho Allocation				95.2%	95.4%	95.6%	95.7%	95.6%	95.7%	95.5%	94.8%	95.2%	95.0%	95.6%	95.5%	
51	Sharing Percentage				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
52	**Net Emission Allowances and REC Sales**			$	(659,857.99)	(18,865.99)	294.95	(280,084.62)	614.61	(9,452.23)	(77,397.65)	(1,565.95)	(52,829.51)	313.29	(363,486.37)	(15,826.43)	(1,478,143.89)
53																	
54	**Demand Response Incentive Payments**																
55	Actual			$	135.69	623.98	261.81	2,683,791.39	3,107,377.87	1,049,704.59	(144,707.89)	3,925.47	-	-	-	-	6,701,112.91
56	Base			$	780,401.00	776,502.00	935,327.00	1,180,702.00	1,263,682.00	1,119,681.00	806,970.00	757,284.00	876,823.00	990,769.00	924,317.00	839,807.00	11,252,265.00
57	Change From Base			$	(780,265.31)	(775,878.02)	(935,065.19)	1,503,089.39	1,843,695.87	(69,976.41)	(951,677.89)	(753,358.53)	(876,823.00)	(990,769.00)	(924,317.00)	(839,807.00)	(4,551,152.09)
58	Idaho Allocation				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
59	Sharing Percentage				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
60	**Demand Response Incentive Payment Deferral**			$	(780,265.31)	(775,878.02)	(935,065.19)	1,503,089.39	1,843,695.87	(69,976.41)	(951,677.89)	(753,358.53)	(876,823.00)	(990,769.00)	(924,317.00)	(839,807.00)	(4,551,152.09)
61																	
62	**Actual QF**																
63	Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)			$	10,851,939.60	9,025,249.06	12,763,083.30	15,842,792.65	13,255,084.60	9,444,845.88	9,260,244.12	13,829,108.00	14,324,978.01	13,304,555.08	11,725,516.55	10,413,792.31	144,041,189.16
64	Idaho Allocation				95.2%	95.4%	95.6%	95.7%	95.6%	95.7%	95.5%	94.8%	95.2%	95.0%	95.6%	95.5%	
65	Idaho Jurisdictional Actual QF			$	10,331,046.50	8,610,087.60	12,201,507.63	15,161,552.57	12,671,860.88	9,038,717.51	8,843,533.13	13,109,994.38	13,637,379.07	12,639,327.33	11,209,593.82	9,945,171.66	137,399,772.08
66																	
67	**Base QF**			$	9,283,440.00	9,237,057.00	11,126,388.00	14,045,307.00	15,032,413.00	13,319,420.00	9,599,498.00	9,008,440.00	10,430,450.00	11,785,917.00	10,995,427.00	9,990,113.00	133,853,870.00
68	Idaho Allocation				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
69	Idaho Jurisdictional Base			$	8,819,268.00	8,775,204.15	10,570,068.60	13,343,041.65	14,280,792.35	12,653,449.00	9,119,523.10	8,558,018.00	9,908,927.50	11,196,621.15	10,445,655.65	9,490,607.35	127,161,176.50
70																	
71	Idaho Jurisdiction Change From Base			$	1,511,778.50	(165,116.55)	1,631,439.03	1,818,510.92	(1,608,931.47)	(3,614,731.49)	(275,989.97)	4,551,976.38	3,728,451.57	1,442,706.18	763,938.17	454,564.31	10,238,595.58
72	Sharing Percentage				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
73	**QF Deferral**			$	1,511,778.50	(165,116.55)	1,631,439.03	1,818,510.92	(1,608,931.47)	(3,614,731.49)	(275,989.97)	4,551,976.38	3,728,451.57	1,442,706.18	763,938.17	454,564.31	10,238,595.58
74																	
75																	
76	**Total Deferral**			$	2,772,030.79	(2,589,201.29)	14,080,500.57	7,484,872.98	13,436,054.28	(5,085,042.17)	777,290.87	9,909,958.94	8,407,226.29	(181,121.20)	(1,231,412.00)	(4,388,107.84)	43,393,050.22

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**Power Cost Adjustment**																
2	**April 2015 thru March 2016**																
3					April	May	June	July	August	September	October	November	December	January	February	March	Totals
77																	
78	**True-Up Summary:**																
79	Principal Balances																
80																	
81	Beginning True-Up Balance			$	0.00	2,772,030.79	182,829.50	14,263,330.07	21,748,203.05	35,184,257.33	30,099,215.16	30,876,506.03	40,786,464.97	49,193,691.26	49,012,570.06	47,781,158.06	-
82																	
83	Amount Deferred			$	2,772,030.79	(2,589,201.29)	14,080,500.57	7,484,872.98	13,436,054.28	(5,085,042.17)	777,290.87	9,909,958.94	8,407,226.29	(181,121.20)	(1,231,412.00)	(4,388,107.84)	43,393,050.22
84																	
85	Ending Balance			$	2,772,030.79	182,829.50	14,263,330.07	21,748,203.05	35,184,257.33	30,099,215.16	30,876,506.03	40,786,464.97	49,193,691.26	49,012,570.06	47,781,158.06	43,393,050.22	43,393,050.22
86																	
87	Interest Balances																
88																	
89	Accrual thru Prior Month			$	-	-	2,309.10	2,461.40	14,342.75	32,459.00	61,767.49	86,840.14	112,560.27	146,535.40	187,513.74	228,341.21	
90																	
91	Monthly Interest Rate (Annual 1%)				0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	
92																	
93	Monthly Interest Inc/(Exp)			$	0.00	2,309.10	152.30	11,881.35	18,116.25	29,308.49	25,072.65	25,720.13	33,975.13	40,978.34	40,827.47	39,801.70	268,142.91
94																	
95	Interest Accrued to date			$	-	2,309.10	2,461.40	14,342.75	32,459.00	61,767.49	86,840.14	112,560.27	146,535.40	187,513.74	228,341.21	268,142.91	268,142.91
96																	
97	**Ending True-Up Balance**			$	2,772,030.79	185,138.60	14,265,791.47	21,762,545.80	35,216,716.33	30,160,982.65	30,963,346.17	40,899,025.24	49,340,226.66	49,200,083.80	48,009,499.27	43,661,193.13	43,661,193.13
98																	
99																	
100	**True-Up of the True-Up Summary:**																
101	Beginning Balance True-Up of True-Up			$	1,484,514.90	32,494,113.20	15,121,597.51	11,816,306.88	9,294,636.96	7,067,692.43	4,898,060.59	3,250,688.39	1,724,781.66	2,749.11	(1,848,820.27)	(3,543,398.26)	1,484,514.90
102	Adjustments:																-
103	Revenue Sharing Order No. 33306					(8,029,176.53)											(8,029,176.53)
104	DSM Rider Forecasted Surplus Funds Order No. 33306					(3,970,036.00)											(3,970,036.00)
105	2014-15 PCA trnsfr per IPUC Ord No. 33306			$	34,515,981.39												34,515,981.39
106	LCA to SBA additional benefit Jan - Mar 2015 Order No. 33307					(1,470,797.50)											(1,470,797.50)
107	Salmon MWH Adjustment					(838.95)											(838.95)
108																	-
109	True-Up of True-Up Balance			$	36,000,496.29	19,023,264.22	15,121,597.51	11,816,306.88	9,294,636.96	7,067,692.43	4,898,060.59	3,250,688.39	1,724,781.66	2,749.11	(1,848,820.27)	(3,543,398.26)	22,529,647.31
110																	
111	Monthly Interest Rate (Annual 1%)				0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	0.0833%	
112																	
113	Monthly Interest			$	30,000.41	15,852.72	12,596.29	9,842.98	7,742.43	5,887.39	4,080.08	2,707.82	1,436.74	2.29	(1,540.07)	(2,951.65)	85,657.43
114																	
115	True-Up of True-Up Including Interest			$	36,030,496.70	19,039,116.94	15,134,193.80	11,826,149.86	9,302,379.39	7,073,579.82	4,902,140.67	3,253,396.21	1,726,218.40	2,751.40	(1,850,360.34)	(3,546,349.91)	22,615,304.74
116																	
117	Monthly Collection Applied To Balance			$	(3,536,383.50)	(3,917,519.43)	(3,317,886.92)	(2,531,512.90)	(2,234,686.96)	(2,175,519.23)	(1,651,452.28)	(1,528,614.55)	(1,723,469.29)	(1,851,571.67)	(1,693,037.92)	(1,526,787.39)	(27,688,442.04)
118																	
119	**Ending True-Up of the True-Up Balance**			$	32,494,113.20	15,121,597.51	11,816,306.88	9,294,636.96	7,067,692.43	4,898,060.59	3,250,688.39	1,724,781.66	2,749.11	(1,848,820.27)	(3,543,398.26)	(5,073,137.30)	(5,073,137.30)
120																	
121	Negative amounts indicate benefit to the customer.																
122																	
123																	
124																	
125	Idaho Billed Sales			MWh	961,156	1,061,961	1,147,790	1,557,565	1,379,371	1,342,005	1,012,234	936,904	1,069,144	1,155,022	1,050,660	941,498	13,615,310
126	Oregon Billed Sales			MWh	48,660	50,697	53,323	70,672	62,751	60,364	47,405	50,902	54,418	61,311	48,520	44,463	653,486
127	Total			MWh	1,009,816	1,112,658	1,201,113	1,628,237	1,442,122	1,402,369	1,059,639	987,806	1,123,562	1,216,333	1,099,180	985,961	14,268,796
128	Idaho % Billed Sales				95.2%	95.4%	95.6%	95.7%	95.6%	95.7%	95.5%	94.8%	95.2%	95.0%	95.6%	95.5%	
129	Oregon % Billed Sales				4.8%	4.6%	4.4%	4.3%	4.4%	4.3%	4.5%	5.2%	4.8%	5.0%	4.4%	4.5%	
130																	

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-16-08

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 2

Idaho Power Company
Total PCA Rate Calculation
Class Allocated Revenue Sharing and DSM Rider Transfer
State of Idaho

Line No	Tariff Description	Rate Sch. No.	(A) Allocated Revenue Sharing Benefit	(B) Allocated DSM Rider (Ongoing) Transfer	(C) Revenue Sharing Dollars per kWh Rate	(D) Allocated DSM Rider (Ongoing) Transfer Dollars per kWh Rate	(E) PCA per kWh Rate	(F) Revenue Sharing + Ongoing DSM Rider Transfer + PCA Rate
	Uniform Tariff Rates:							
1	Residential Service	1	($1,394,335)	($1,418,213)	(0.000280)	($0.000284)	$0.006187	$0.005623
2	Master Metered Mobile Home Park	3	($1,351)	($1,439)	(0.000267)	($0.000284)	$0.006187	$0.005636
3	Residential Service Energy Watch	4	$0	$0	0.000000	($0.000284)	$0.006187	$0.005903
4	Residential Service Time-of-Day	5	($6,446)	($6,811)	(0.000269)	($0.000284)	$0.006187	$0.005633
5	Small General Service	7	($46,382)	($37,167)	(0.000355)	($0.000284)	$0.006187	$0.005548
6	Large General Service - Secondary	9S	($699,887)	($948,627)	(0.000210)	($0.000284)	$0.006187	$0.005693
7	Large General Service - Primary	9P	($85,515)	($133,156)	(0.000183)	($0.000284)	$0.006187	$0.005720
8	Large General Service - Transmission	9T	($672)	($965)	(0.000198)	($0.000284)	$0.006187	$0.005704
9	Dusk to Dawn Lighting	15	($3,882)	($1,810)	(0.000610)	($0.000284)	$0.006187	$0.005292
10	Large Power Service - Secondary	19S	($1,163)	($1,823)	(0.000182)	($0.000284)	$0.006187	$0.005721
11	Large Power Service - Primary	19P	($351,677)	($621,521)	(0.000161)	($0.000284)	$0.006187	$0.005742
12	Large Power Service - Transmission	19T	($5,054)	($9,354)	(0.000154)	($0.000284)	$0.006187	$0.005749
13	Agricultural Irrigation Service	24	($426,901)	($530,569)	(0.000229)	($0.000284)	$0.006187	$0.005674
14	Unmetered General Service	40	($2,867)	($3,247)	(0.000251)	($0.000284)	$0.006187	$0.005651
15	Street Lighting	41	($10,663)	($7,798)	(0.000389)	($0.000284)	$0.006187	$0.005514
16	Traffic Control Lighting	42	($500)	($800)	(0.000178)	($0.000284)	$0.006187	$0.005725
17	Total Uniform Tariffs		($3,037,295)	($3,723,302)				
18	Special Contracts							
19	Micron	26	($68,753)	($134,649)	NA	($0.000284)	$0.006187	$0.005903
20	J R Simplot	29	($25,946)	($54,666)	NA	($0.000284)	$0.006187	$0.005903
21	DOE	30	($27,484)	($57,419)	NA	($0.000284)	$0.006187	$0.005903
23	Total Special Contracts		($122,183)	($246,734)				
24	Total Idaho Retail Sales		($3,159,478)	($3,970,036)				

Note:
(1) June 1, 2016 - May 31, 2017 Forecasted Test Year

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

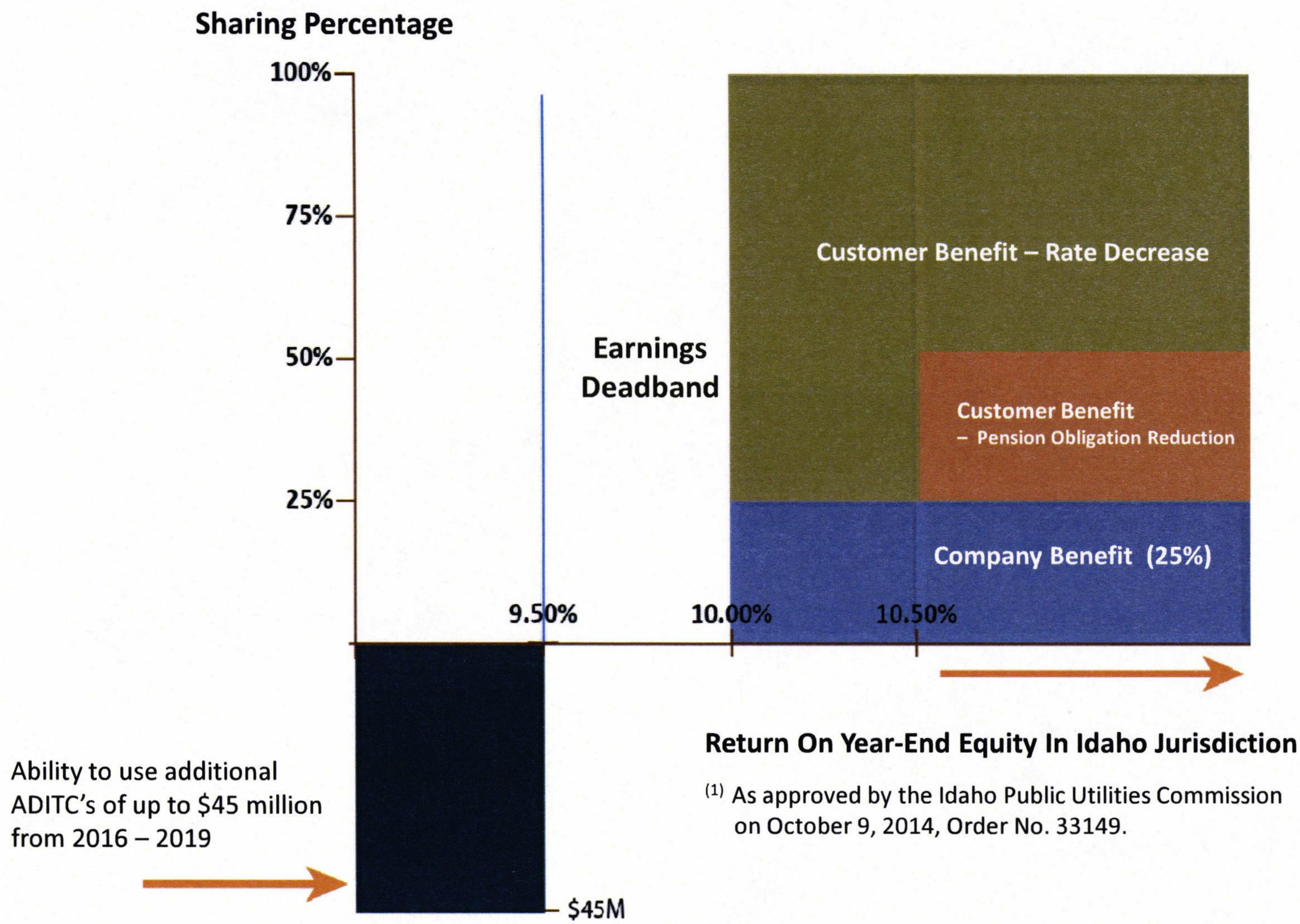
CASE NO. IPC-E-16-08

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 3

Revenue Sharing/ADITC Settlement 2015-2019[1]



[1] As approved by the Idaho Public Utilities Commission on October 9, 2014, Order No. 33149.

ADITC—Accumulated Deferred Investment Tax Credits

Exhibit No. 3
Case No. IPC-E-16-08
M. Larkin, IPC
Page 1 of 1

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-16-08

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 4

IDAHO POWER COMPANY

ADDITIONAL INVESTMENT TAX CREDIT ANALYSIS
For the Twelve Months Ended December 31, 2015

	Actual September 30, 2015			Actual December 31, 2015			
	TOTAL SYSTEM	IDAHO	IDAHO %	TOTAL SYSTEM	IDAHO	IDAHO %	
*** SUMMARY OF RESULTS ***							
TOTAL COMBINED RATE BASE	3,084,399,544	2,952,272,349	95.7%	September Allocations/Ratios			
DEVELOPMENT OF NET INCOME				Update figures in RED			
OPERATING REVENUES							
RETAIL SALES REVENUES (Incl 449.1 Rev)	897,942,786	857,942,940	Direct Assign	1,154,197,532	1,101,862,025	Direct Assign	
OTHER OPERATING REVENUES	84,077,301	80,032,272	95.2%	115,163,392	109,622,785	95.2%	
TOTAL OPERATING REVENUES	982,020,087	937,975,212		1,269,360,925	1,211,484,810		
OPERATING EXPENSES							
OPERATION & MAINTENANCE EXPENSES	611,253,343	582,013,224	95.2%	800,756,552	762,451,295	95.2%	
DEPRECIATION EXPENSE	97,613,066	93,396,616	95.7%	130,931,146	125,275,504	95.7%	
AMORTIZATION OF LIMITED TERM PLANT	5,231,314	5,008,289	95.7%	6,998,504	6,700,139	95.7%	
TAXES OTHER THAN INCOME	24,999,080	23,284,959	93.1%	32,808,301	30,558,723	93.1%	
REGULATORY DEBITS/CREDITS	61,959	0	0.0%	82,611	0	0.0%	
PROVISION FOR DEFERRED INCOME TAXES	(2,048,295)	(1,928,345)	94.1%	29,419,016	28,251,081	96.0%	(1)
INVESTMENT TAX CREDIT ADJUSTMENT	(444,742)	(425,774)	95.7%	492,099	471,112	95.7%	
FEDERAL INCOME TAXES	41,031,302	39,848,590	97.1%	12,593,365	12,230,366	97.1%	
STATE INCOME TAXES	4,309,721	4,205,337	97.6%	5,986,110	5,841,123	97.6%	
TOTAL OPERATING EXPENSES	782,006,747	745,402,896		1,020,067,703	971,779,341		
OPERATING INCOME	200,013,340	192,572,316		249,293,221	239,705,469		
ADD: IERCO OPERATING INCOME	4,693,753	4,485,489	95.6%	6,659,942	6,364,437	95.6%	
OPERATING INCOME BEFORE OTHER INCOME AND DEDUCTIONS	204,707,093	197,057,805		255,953,163	246,069,906	96.1%	
ADD: AFUDC EQUITY				21,785,246	20,852,026	95.7% (L 10)	
ADD: OTHER INCOME AND DEDUCTIONS				(3,105,928)	(2,985,997)	96.1% (L 33)	
INCOME BEFORE INTEREST CHARGES				274,632,481	263,935,935		
LESS: INTEREST CHARGES				81,724,718	78,223,856	95.7% (L 10)	
NET INCOME				192,907,762	185,712,079		
ACTUAL YEAR-END RESULTS - BEFORE ITC ADJUSTMENT							
EARNINGS ON COMMON STOCK				192,907,762	185,712,079		
COMMON EQUITY AT YEAR END				1,916,111,771	1,834,030,811	95.7% (L10)	
RETURN ON YEAR-END COMMON EQUITY				10.07%	10.13%		
EARNINGS ON COMMON STOCK @ 9.50 ROE				182,030,618	**174,232,927**	(L44 * 9.5%)	
EARNINGS ON COMMON STOCK @ 10 ROE				191,611,177	**183,403,081**	(L44 * 10%)	
EARNINGS ON COMMON STOCK @ 10.50 ROE				201,191,736	**192,573,235**	(L44 * 10.5%)	
ACTUAL YEAR-END RESULTS - AFTER ITC ADJUSTMENT:							
INVESTMENT TAX CREDIT ADJUSTMENT					(12,684,145)	(L48-L43) / (1-9.5%)	
ADJUSTED EARNINGS ON COMMON STOCK					173,027,933		
ADJUSTED COMMON EQUITY AT YEAR-END					1,821,346,666		
ADJUSTED RETURN ON YEAR-END COMMON EQUITY					9.50%		

IF IDAHO RETURN ON COMMON EQUITY (Line 46) <9.5%			
ADDITIONAL ITC ADJUSTMENT (Annualized) — If L 54 is negative, then 0; if positive, then smaller of L54 or $25,000,000	0		
IF IDAHO RETURN ON COMMON EQUITY (Line 46) >10%			
IDAHO EARNINGS GREATER THAN 10% ROE BUT LESS THAN 10.5%	2,565,553	(L43-L49)/(1-10%)	
IF IDAHO RETURN ON COMMON EQUITY (Line 46) >10.5%			
INCREMENTAL IDAHO EARNINGS GREATER THAN 10.50% ROE	0	(L43-L50)/(1-10.5%)	
Per Order #33149:	After Tax	Tax Gross Up	
ROE between 10%-10.5% --CUSTOMER SHARE - 75% (Reduction to rates)	1,924,165	3,159,478	
ROE between 10%-10.5% --COMPANY SHARE - 25%	641,388		
ROE greater than 10.5% (Incremental) -- CUSTOMER SHARE - 50% (Reduction to rates)	0	-	
ROE greater than 10.5% (Incremental) -- CUSTOMER SHARE - 25% (Offset to Pension balance)	0	-	
ROE greater than 10.5% (Incremental) --COMPANY SHARE - 25%	0		
	2,565,553		

Notes: **(1)** The line item "Provision for Deferred Tax" reflects the sum of two deferred tax categories that are allocated to the Idaho jurisdiction under different allocation bases. For the month-ending September 30,2015 the detailed tax categories included both positive and negative values resulting in a skewed allocation ratio. To remove the skewing effect the September 30, 2015 detailed tax deviations were converted to absolute values which resulted in a more reasonable allocation ratio of 96.0 percent.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-16-08

IDAHO POWER COMPANY

LARKIN, DI
TESTIMONY

EXHIBIT NO. 5

Idaho Power Company
Class Allocated Revenue Sharing Benefits
State of Idaho
Filed April 15, 2016

Line No	Tariff Description	Rate Sch. No.	(A) Average Number of Customers	(B) Normalized Energy (kWh)	(C) Current Base Revenue	(D) Percentage of Idaho Base Revenues	(E) Allocated Revenue Sharing Benefit	(F) Dollars per kWh Rate	(G) Percent Revenue Change
	Uniform Tariff Rates:								
1	Residential Service	1	429,310	4,985,427,763	452,062,249	44.13%	($1,394,335)	(0.000280)	(0.31)%
2	Master Metered Mobile Home Park	3	22	5,059,520	437,957	0.04%	($1,351)	(0.000267)	(0.31)%
3	Residential Service Energy Watch	4	0	0	0	0.00%	$0	0.000000	0.00%
4	Residential Service Time-of-Day	5	1,335	23,944,320	2,089,936	0.20%	($6,446)	(0.000269)	(0.31)%
5	Small General Service	7	27,894	130,654,397	15,037,532	1.47%	($46,382)	(0.000355)	(0.31)%
6	Large General Service - Secondary	9S	34,431	3,334,698,197	226,912,650	22.15%	($699,887)	(0.000210)	(0.31)%
7	Large General Service - Primary	9P	209	468,080,713	27,724,958	2.71%	($85,515)	(0.000183)	(0.31)%
8	Large General Service - Transmission	9T	3	3,393,264	217,934	0.02%	($672)	(0.000198)	(0.31)%
9	Dusk to Dawn Lighting	15	0	6,361,595	1,258,745	0.12%	($3,882)	(0.000610)	(0.31)%
10	Large Power Service - Secondary	19S	1	6,408,782	377,173	0.04%	($1,163)	(0.000182)	(0.31)%
11	Large Power Service - Primary	19P	107	2,184,826,475	114,018,294	11.13%	($351,677)	(0.000161)	(0.31)%
12	Large Power Service - Transmission	19T	2	32,881,779	1,638,687	0.16%	($5,054)	(0.000154)	(0.31)%
13	Agricultural Irrigation Service	24	18,225	1,865,104,107	138,407,032	13.51%	($426,901)	(0.000229)	(0.31)%
14	Unmetered General Service	40	1,346	11,414,394	929,621	0.09%	($2,867)	(0.000251)	(0.31)%
15	Street Lighting	41	1,674	27,412,831	3,456,978	0.34%	($10,663)	(0.000389)	(0.31)%
16	Traffic Control Lighting	42	547	2,811,020	161,999	0.02%	($500)	(0.000178)	(0.31)%
17	Total Uniform Tariffs		515,106	13,088,479,157	$984,731,745	96.13%	($3,037,295)		(0.31)%
18	Special Contracts								
19	Micron	26	1	473,329,675	22,290,745	2.18%	($68,753)	NA	(0.31)%
20	J R Simplot	29	1	192,166,897	8,411,920	0.82%	($25,946)	NA	(0.31)%
21	DOE	30	1	201,844,932	8,910,710	0.87%	($27,484)	NA	(0.31)%
23	Total Special Contracts		3	867,341,504	$39,613,375	3.87%	($122,183)		(0.31)%
24	Total Idaho Retail Sales		515,109	13,955,820,661	$1,024,345,120	100.00%	($3,159,478)		(0.31)%

Note:
(1) June 1, 2016 - May 31, 2017 Forecasted Test Year