KARL T. KLEIN
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0320
IDAHO BAR NO. 5156

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5918

Attorney for the Commission Staff

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2015 THROUGH MAY 31, 2016.	)	**CASE NO. IPC-E-15-14** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's proposed rate adjustments. The comments are divided into four main sections: (1) Summary of Application; (2) Staff Audit and Analysis; (3) Customer Relations; and (4) Staff Recommendations.

I. SUMMARY OF APPLICATION

On April 15, 2015, Idaho Power Company (the "Company") filed its annual Power Cost Adjustment ("PCA") Application. The Company claims the 2015-2016 PCA will decrease its overall revenue by about $10.1 million (or 0.91%) over current billed revenue. Table 1 summarizes of the Company's proposal:

Table 1: Idaho Power Proposed Revenue Changes for Idaho Customers

Description	Current ($)	Proposed ($)	Difference ($)
PCA without Revenue Sharing	101,549,890	75,133,003	(26,416,887)
Associated DSM Rider Change	(4,073,117)	(3,970,036)	103,081
Allocated Revenue Sharing	(7,780,513)	(7,999,145)	(218,632)
Mitigation - DSM Rider Revenue	(16,408,596)	0	16,408,596
Difference	$73,287,673	$63,163,823	(10,123,850)
Total Billed Revenue	1,107,494,402	1,097,370,552	(10,123,850)
Decrease in Billed Revenue			(0.91%)

As shown above, the Company's proposal significantly decreases the PCA without revenue sharing, but expiration of the DSM Rider Mitigation Revenue largely offsets the decrease. The proposed PCA decrease (including the Company's revenue sharing proposal) is further described below. The Company proposes that the rate changes take effect June 1, 2015.

A. Proposed PCA Decrease

This year the Schedule 55 PCA rate for each class combines the three PCA's traditional components (forecast, "true-up," and reconciliation) with two additional components (the DSM rider credit and revenue sharing). These five components are described below.

1. Traditional PCA Components

The traditional annual PCA mechanism has three components: a) a "forecast" or projection that estimates the difference between power supply costs embedded in base rates and the coming year's power supply costs; b) a "true-up" that captures the difference between actual and base power supply costs and credits the revenue from the previous year's forecast rate; and c) a reconciliation of the prior year's true-up that captures any under-recovered or under-refunded true-up amount. This is also called the true-up of the true-up. Each component is described in more detail below.

A. Forecast

The Company uses its March 26, 2015 Operating Plan to forecast power-supply costs for the coming year. According to the Company, the Idaho ratepayer's share of the difference between forecasted and base power supply cost is about $39.14 million. The Company converts the power-supply cost difference to a cents-per-kilowatt hour (¢/kWh) rate by dividing the power costs by projected energy sales. The Company calculates this rate to be 0.2815 ¢/kWh.

B. True-Up.

The true-up amount is the difference between: (1) forecast and base power-supply costs, and (2) revenues from the forecast rate that accrued during the prior year. The prior year's PCA amount is not precisely recovered, because the expected-cost forecast is never 100% accurate. The Company converts the true-up amount to a ¢/kWh rate by dividing that amount by projected energy sales. The Company calculates the Idaho ratepayer's share of the true-up amount to be $34.5 million, and expects to recover that amount through a true-up rate of 0.2483 ¢/kWh.

C. Reconciliation of the True-Up.

The reconciliation of the true-up tracks the recovery of the prior year's true-up amounts. It nets the actual revenue collected from the true-up rates and revenue-sharing rates against the amounts set for recovery. Any difference is carried into the next year's true-up reconciliation along with the true-up difference. The Company calculates the Idaho ratepayer's share of the reconciliation of the true-up amount to be $1.5 million, and the rate to be 0.0107¢/kWh.

The Company combines the three traditional PCA rate components to propose a 2015/2016 PCA rate surcharge of 0.5405 ¢/kWh (0.2815 + 0.2483 + 0.0107). The Company expects this rate will allow it to recover traditional PCA costs in one year. The proposed rate is 0.19 ¢/kWh less than current PCA rates.

2. <u>Additional PCA Components</u>

Besides the three traditional components discussed above, this year's PCA includes the DSM rider adjustment and revenue-sharing components discussed below.

A. DSM Rider Adjustment

The Company continues to apply a $4.0 million DSM Rider credit to the PCA. This revenue credit assures that the change to base level Net Power Supply Expense ("NPSE") approved in March 2014 by Order No. 33000 remains revenue neutral. The credit is applied on a uniform basis to each customer class and will continue to be included in annual PCAs until NPSE included in base rates is re-established as part of a general rate case.

B. Revenue Sharing

The Company proposes to share $24.7 million of revenue with customers. This revenue sharing amount would decrease the PCA by $8.0 million, and the Company's pension balancing account by $16.7 million. The Company proposes to spread the revenue-sharing amount to the Company's rate schedules on a uniform percent of base revenue basis, and to assign it to the energy rates in each schedule. This class-specific energy credit results in a different combined PCA/ DSM Rider Adjustment/Revenue Sharing energy rate for each rate schedule.

B. Company's Rate Calculation

Company Exhibit No. 2 shows how the Company developed its proposed Schedule 55 rates. Schedule 55 rates include all the rate changes proposed in this filing. Column I shows the Schedule 55 energy rates proposed by the Company.

II. STAFF AUDIT AND ANALYSIS

A. Staff's Analysis of PCA Rates

Staff analyzed the traditional PCA components (forecast, true-up, and reconciliation) and additional components applied in this case (revenue sharing and DSM Rider Adjustment). In summary, Staff agrees with all of the Company's proposed PCA components except the true-up. Staff recommends that the Commission modify the Company's proposed true-up to reflect the proposed Settlement in Case No. IPC-E-15-15. Although not yet approved by the Commission, Staff believes the Commission should include the proposed Settlement's Load Change Adjustment Rate (LCAR)/Sales Based Adjustment Rate (SBAR) modification in PCA rates here because the parties have agreed to an adjustment in this case as a provision of the Settlement, and it would benefit customers by reducing the true-up deferral balance for which they would otherwise have to pay. Staff's analysis of the PCA components is as follows.

1. <u>Traditional PCA Components</u>

A. The Forecast

The first traditional PCA component is the forecast component. The Company uses its March 26, 2015 Operating Plan to forecast the difference between the power-supply costs embedded in rates and the power-supply costs the Company expects to recover in the coming year. The Operating Plan reflects the most current information available to the Company when it prepared its filing. The forecast considers many factors, including but not limited to: load, water conditions, gas hedges, market purchases, transmission availability and the cost of contracts under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Throughout the year, the Risk Management Committee ("RMC"), consisting of key Company employees, reviews and updates the Company's risk management strategy. Company Exhibit No 1 to Mr. Wright's testimony shows the Company's power-supply expense forecast by account. The table shows expenses included in Base Rates, Forecasted Expenses, and the Difference. Account 555 – PURPA Purchase Expense, is shown separately from other Account 555 Non-PURPA Expenses because the Company does not share differences in PURPA Contract Expenses with its customers. The Company passes the entire difference in PURPA Qualifying Facility ("QF") contracts to customers.[1]

Attachment A shows Staff's calculation of the PCA rate components. Lines 1 through 18 show the calculation of the forecast rate component. The forecast rate component is the sum of three rate elements: (1) PCA amounts subject to 95/5 sharing; (2) PCA amounts besides demand expense incentives, that flow to customers without sharing; and (3) the difference between base and actual demand response incentives. These three rate elements are described below.

The first element is composed of all PCA amounts subject to 95/5 sharing. Lines 2 through 8 show this calculation. Line 8 shows the first component of the forecast rate to be 0.2079 ¢/kWh. This rate element captures the effects of expected water conditions, thermal plant fuel costs and expected market prices that affect power purchases and sales, etc. The primary drivers of this year's forecast are lower anticipated surplus sales due to lower market prices, and slightly higher runoff and hydro generation than last year. While runoff volume is expected to be greater than last year, it is still anticipated to be significantly below average. The net of surplus

[1] A QF is a generating facility that qualifies for QF status under PURPA and 18 CFR Part 292 and has obtained certification of its QF status.

sales revenue and generation expense results in an increase of almost $5 million over last year's forecast.

The second element of the forecast rate component is shown in lines 10 through 12. The second element includes all amounts, except demand response incentives, which are passed through to customers without sharing. These amounts are almost entirely PURPA QF contract costs and total 0.0976 ¢/kWh as shown on line 12. PURPA costs are forecast to be almost $14 million higher than last year due to increased generation and higher contract prices.

The third element of the forecast rate component allows the Company to capture the difference between base and actual demand response incentive payments in the PCA. *See* Order No. 32426. The calculation of demand response incentive rates is shown on lines 14 through 16. The difference between these demand response payments and base amounts is shown on line 16 to be minus 0.0240 ¢/kWh. The amount is negative because the forecasted amount is less than the amount included in base rates.

The Company's forecast for demand response incentive payments is slightly lower in 2015-2016 than in 2014-2015, resulting in a slightly higher customer credit. While Irrigation Peak Rewards and AC Cool Credit program expenditures should remain relatively stable, expenditures for the Commercial Flex Peak program could change depending upon the outcome of Case No. IPC-E-15-03.[2] Any variation between forecasted and actual demand response expenditures will be captured in next year's PCA.

The above three elements combine to produce the PCA forecast rate component of 0.2815 ¢/kWh shown on line 18. The forecast rate component is significantly larger this year than it was last year due to a lower expectation of net surplus sales revenue and higher PURPA expenses. Staff believes the Company's forecast reflects reasonable future conditions. Staff again points out that any over or under-collected amounts due to forecast error are trued-up in the following year's PCA.

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[2] In IPC-E-15-03, the Company applied to self-manage a commercial demand response program that is similar to the Company's prior program, which was managed by EnerNoc, Inc. The Commission granted the Application in Order No. 33292, issued May 7, 2015.

B. The True-Up.

The second traditional PCA component is the "true-up" component. The Company's filing nets the PCA true-up difference against the amount collected from the application of the previous year's forecast rate. This difference, with interest, is the PCA true-up deferral balance. This deferral balance is divided by expected jurisdictional energy sales to produce the true-up rate component of the PCA.

Page 1, lines 4 through 90 of Company Exhibit No. 1 calculates a true-up deferral amount of $34.5 million. To verify revenues and costs associated with the Company's true-up deferrals, Staff audited the actual revenues and expenses that occurred during the PCA year (April 1, 2014 through March 30, 2015). These revenues and costs included water lease expenses, fuel expenses for coal, fuel expenses for natural gas, power sales and purchases, third-party transmission expenses, Renewable Energy Credits ("RECs") sales, Emission Allowance sales, and QF expenses. The Risk Management Operating Plans and Risk Management Committee minutes were also reviewed.

In addition, Staff verified that the monthly calculated and actual amounts for the revenue included in the PCA Forecast, as shown on page 1, line 7 of Company Exhibit No. 1 are correct, and that the megawatt hours used for the Actual Firm Load, as shown on page 1, line 10 of Company Exhibit No. 1 are correct.

The $34.5 million true-up balance, while lower than the prior year's true-up balance, still indicates that the prior year's forecast was inaccurate. While actual hydro generation was slightly lower during the PCA year than what the Company had forecast that generation to be, the difference between the current and prior true-up balances primarily is due to lower than expected net surplus sales, higher than expected PURPA expenses, and a load change adjustment rate (LCAR) reflecting lower than anticipated energy sales. The PCA true-up component includes the following items:

i. Load Change Adjustment. This year's true-up calculation includes a positive load change adjustment of $11,817,280. Actual loads during the true-up year were below normal loads in 4 months and above normal in 8 months. Overall, the actual load for the PCA year was below normal by 467,145 MWh. This represents a 3% overall decrease in normalized load. During the PCA year, the monthly increase in loads was less than the monthly decrease in loads, producing a positive load change adjustment amount.

The load change adjustment is the product of the positive or negative load growth and the LCAR of $17.64/MWh for the months of April and May 2014. Beginning June 1, 2014, the LCAR increased to $24.34 per Order No. 33000. The LCAR consists of the energy-classified fixed costs of production embedded in base rates. When load grows, the adjustment reduces power-supply costs to avoid double counting production costs. When load declines, the adjustment reimburses the Company for part of its lost fixed production costs.

The result is that $11,817,280 (before jurisdictional allocation and PCA sharing) has been added to the deferral balance for recovery from customers in this year's PCA. This LCAR-related increase is a cost to customers and is subject to jurisdictional allocation and sharing.

The Settlement proposed in Case No. IPC-E-15-15 recommends that the Commission replace the Company's LCAR methodology with a sales-based load adjustment methodology. Applying a sales-based load adjustment in this case will reduce the true-up deferral balance. This adjustment will be discussed in more detail later in these comments.

ii. Water Leases. The Company sometimes leases water from several entities to produce hydro power. The increase or decrease in the water lease expense from base rates is included in the PCA for recovery from or credit to customers. This year's PCA deferral balance includes actual water lease expenses of $1,527,000, which is less than the $2,297,091 of lease expenses included in base rates. The deferral balance includes the difference of $770,091. This decrease in water lease expenses from base expenses benefits customers and is subject to jurisdictional allocation and sharing.

iii. Fuel Expense - Coal. Some of the Company's electricity comes from coal plants. The Company owns an interest in three coal plants: Bridger, Valmy and Boardman. The increase or decrease in the coal expense from base rates is included in the PCA for recovery from or credit to customers. From April 2014 through March 2015, the total coal expense for the three plants was $139,308,896. The total coal expense included in base rates is $115,971,408. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $23,337,488. This increase in coal costs from base costs is a cost to customers and is subject to jurisdictional allocation and sharing.

iv. Fuel Expense - Gas. The Company owns and operates gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (3 Danskin units) and Bennett Mountain located at Mountain Home, Idaho; and Langley Gulch, located near New Plymouth, Idaho. Staff reviewed the natural gas purchases in conjunction with the Company's Operation Plan. The transactions appear reasonable and to follow the Risk Management Committee's recommendations.

From April 2014 through March 2015 PCA, the total variable gas and gas transportation expense for all the gas plants was $37,702,547. The total gas and gas transportation expense included in base rates is $35,733,899. The PCA includes this increase in gas expense from base rates. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $1,968,648. This increase in natural gas expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.

v. Power Sales and Purchases. Staff reviewed the Company's power purchases and sales in conjunction with the Company's Operating Plan. The transactions appear reasonable and to follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners on a timely basis, and there were no transactions conducted with a Company affiliate.

a. Power Sales. During the PCA year ending March 31, 2014, the Company sold off-system surplus power totaling $59,257,485. The total surplus sales included in base rates is $61,373,402. The PCA includes this decrease in the power sales from base rates. Actual surplus sales were less than base amounts by $2,115,917. This revenue decrease is a cost to customers and is subject to jurisdictional allocation and sharing.

b. Power Purchases. Excluding PURPA purchases during the PCA year ending March 31, 2015, the Company bought $81,170,256 of power on the market. The amount of non-PURPA power purchases included in base rates is $60,063,512. Actual non-PURPA power purchases exceeded base amounts by $21,106,744. This increase in purchases is a cost to customers and is subject to jurisdictional allocation and sharing.

vi. Third-Party Transmission. In Order No. 30715, the Commission directed the Company to track third-party transmission costs associated with market purchases and off-system sales through the PCA like other variable power supply costs. Including transmission expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales. For the April 2014 through March 2015 PCA period, the actual third-party transmission expense is $6,046,383. The third-party transmission expense included in base rates is $5,911,977. This year's PCA deferral balance includes the difference between actual costs and base costs of $234,406. Because the actual costs are more than the amount included in base rates, this amount represents a cost to customers. This cost to customers is subject to jurisdictional allocation and sharing.

vii. Hoku First Block Energy. In Order No. 32426 (Case No. IPC-E-11-08), the Commission determined that the Company should include first block energy revenue from Hoku in base rates like secondary sales revenue. The PCA tracks the variation between the amount of Hoku revenues built into base rates and the actual Hoku revenues. The amount of Hoku revenues included in base rates is $3,216,534. The actual amount of Hoku revenues during the current PCA period is $0. New base rates, beginning in June 2014, set in Order No. 33000, Case No. IPC-E-13-20, no longer include Hoku revenues. For the months of April and May 2014, the actual Hoku revenues are less than the amount included in base rates by $3,216,534. This revenue decrease is a cost to customers and is subject to jurisdictional allocations and sharing.

viii. Emission Allowance Sales. In Order No. 32424, the Commission ordered that revenues from the sale of emission allowances, plus any applicable interest, be reflected in the PCA and benefit customers by reducing the Company's PCA deferral balance, subject to jurisdictional allocations and sharing. In the current PCA period, the deferral balance includes emission allowance sales of $16,250. This revenue increase benefits customers and is subject to jurisdictional allocation and sharing.

ix. Renewable Energy Credit Sales. In Order No. 30818, the Commission ordered that revenues from the sale of renewable energy credits ("RECs") should benefit customers and be subject to jurisdictional allocation and sharing. The deferral balance includes $2,400,487 in revenue from REC sales. This increase in revenues is a benefit to customer and is subject to jurisdictional allocation and sharing.

x. Actual PURPA Purchases Including Net Metering and Raft River Expenses. For the April 2014 through March 2015 PCA period, the actual PURPA expense is $147,105,350. The PURPA expense included in base rates is $123,784,522. The difference between actual PURPA expense and base PURPA expense is included in the PCA for recovery from or credit to customers. In this year's PCA deferral balance, the actual PURPA expense exceeded the PURPA expense included in base rates by $23,320,828. This amount is a cost to customers and increases the PCA deferral balance. PURPA contracts are not currently subject to sharing, but they are subject to jurisdictional allocation.

xi. Demand Response Incentive Payments. In Order No. 32426 (Case No. IPC-E-11-08), the Commission determined that the Company must include Demand Response Incentive Payment expenses in base rates and track differences between base expenses and actual expenses through the PCA. Idaho Demand Response Incentive Payments are directly assigned to Idaho and are not subject to sharing. For the PCA period (April 2014 through March 2015), the actual Demand Response Incentive Payments are $7,946,728. The base amount of Incentive Payments included in base rates during the PCA period is $11,208,367. The difference between the actual amount and the base amount is $3,261,639, and is a benefit to customers. The Demand Response Incentive Payments are not currently subject to sharing and are allocated 100% to the Idaho jurisdiction.

Table 2 summarizes the PCA's true-up deferral balance:

Table 2: True-Up Deferral

Description	**Deferral Amount**
Load Change Adjustment	$11,817,280
Water Leases	(770,091)
Fuel Expense - Coal	23,337,488
Fuel Expense - Gas	1,968,648
Surplus Sales	2,115,917
Non-Firm Purchases	21,106,744
Third Party Transmission Expense	234,406
Hoku First Block Revenue	3,216,534
Subtotal	63,026,925

Emission Allowance Sales Credits	(16,250)
Renewable Energy Credit (REC) Sales	(2,400,487)
Subtotal	60,610,189
Amount After Jurisdictional Allocation and Sharing	54,700,695
Qualifying Facilities - After Jurisdictional Allocation	22,154,787
Demand Response Incentive Payments	(3,261,639)
Total Expense Items	73,593,843
Revenue from PCA Forecast	39,275,784
Deferral Balance	34,318,059
Interest on the Deferral Balance	197,922
Total Deferral	$34,515,981

The Company proposes a 0.2483 ¢/kWh true-up rate. Staff agrees that the Company's calculations are correct but recommends that the true-up deferral balance be reduced by $1.471 million to reflect Settlement Agreement terms submitted to the Commission in Case No. IPC-E-15-15.

The Company accepts Staff's proposed $1.471 million true-up adjustment in this case, and that adjustment has been incorporated in the Settlement Agreement filed with the Commission on May 2, 2015, in Case No. IPC-E-15-15. The main change proposed in the Settlement Agreement is to modify the PCA to track the difference between Idaho actual sales at meter and Idaho base sales at meter (sales based adjustment- SBA), rather than the difference between base system load at generation and actual system load at sales (load change adjustment- LCA). This solution addresses the "line loss" inaccuracy identified by Staff in last year's PCA.

Although the Commission has not yet approved the Settlement Agreement proposed in the other case, that Settlement Agreement specifies that the new methodology should apply to the PCA true-up calculation beginning on January 1, 2015 and incorporated in the 2015-2016 PCA (this case). Moreover, in Order No. 33049 and again in Order No. 33089, the Commission directed the parties to hold workshops and conduct informal discussions regarding modifications to the PCA to improve its accuracy. The Settlement Agreement and the recommended true-up adjustment in this case are the result of those discussions.

The adjustment results in a true-up rate of 0.2376 ¢/kWh. The Company's rate calculation with the Staff adjustment is shown on Staff Attachment A, Lines 23 through 26.

C. The Reconciliation of the True-up

The third traditional PCA rate component is the "reconciliation" component. The reconciliation of the true-up amount is the difference between what was approved to be collected or refunded when the PCA rate for last year's true-up was set, and what was actually collected or refunded. The reconciliation of the true-up assures the Company and its customers that the amount approved for recovery is the amount actually recovered.

Staff audited the amounts booked to the Reconciliation of the True-up, including the revenue sharing and the transfer of the deferral balance from the previous PCA year, and verified that the actual monthly collections and interest calculations are correct.

Table 3 summarizes the PCA's true-up reconciliation:

Table 3: True-Up Reconciliation

2012-13 Forecast True-Up	$58,088,876
2011-12 True-Up of the True-Up Balance	19,140,917
Revenue Sharing (Order No. 32821 + interest)	(7,624,233)
DSM Rider Funds (Order No. 33049)	(20,000,000)
Net Amount Set for Recovery/(Refund)	49,605,560
Collections from True-Up Rates	(48,414,394)
Interest	293,349
Sub-Total	(28,172,621)
True-Up Reconciliation	$1,484,515

Staff and the Company both recommend that customers recover this amount. Dividing this amount by expected sales produces the true-up reconciliation rate of 0.0107 ¢/kWh. This calculation is shown on Attachment A, line 28.

With the SBAR credit, Staff calculates the sum of all three PCA rate components to be 0.5298 ¢/kWh rather than 0.5405 ¢/kWh as proposed by the Company. Staff's recommended rate is shown on Attachment A, line 31.

2. Additional PCA Components

A. DSM Rider Adjustment

Staff has reviewed the Companies allocation of the ongoing $4.0 million DSM Rider credit to the PCA. This revenue credit assures revenue neutrality associated with base rate changes approved by Order No. 33000. Staff confirms that the credit is applied on a uniform basis to each customer class to reduce billed revenue by 0.0286 ¢/kWh or 0.39% of billed revenues.

B. Revenue Sharing

In 2010, Commission Order No. 30978 established a mechanism that in part required the Company to share revenue if the Company's actual Idaho jurisdictional year-end Return on Equity (ROE) exceeded 10.5% in the years 2009 through 2011. If revenue sharing was triggered, the Company was to share 50% of any earnings above 10.5% ROE with customers.

For the years ending December 31, 2009 and 2010, revenue sharing was not triggered, as the Idaho jurisdictional year-end ROE was between 9.5% and 10.5%. Revenue sharing was triggered for the years ending December 31, 2011 and 2012.

Order No. 32424 modified the revenue-sharing mechanism and extended it through 2014. Order No. 32424 reduced the sharing trigger to 10%, with equal sharing between customers and the Company when the ROE is greater than 10% up to and including 10.5%. This customer portion of the "revenue sharing" benefit serves as a customer credit that is netted with the traditional PCA components to yield a combined rate that is set forth in Schedule 55. In addition, when the ROE exceeds 10.5%, the earnings above 10.5% continue to be shared with customers receiving 75% of the earnings above 10.5%. The customer share of earnings above 10.5% will be applied to the Company's pension balancing accounts. This revenue-sharing contribution reduces the amount the Company would otherwise be allowed to collect from customers.

In Case No. IPC-E-14-14, the Commission approved extending, with modification, the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by Commission order or the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized. The provisions of the new settlement stipulation will be applied for calendar year 2015 and reflected in the next PCA.

In this year's filing, the Company proposes to share $24.7 million of revenue with customers. The offset to the PCA is $8 million, and the remaining $16.7 million is to be applied to the Company's pension balancing account. The Company proposes to spread the PCA revenue-sharing credit to customer classes based on each class's proportional share of the forecasted base revenue for the year beginning June 1, 2015. The Company has used this methodology to allocate revenue sharing in prior years. Staff has reviewed the workpapers, source documents and supporting documentation for the revenue sharing calculations and agrees with the Company filing.

The Company proposes that each special contract customer receive a different, flat-monthly credit during the PCA year. The proposed credits for the special contract customers are: Micron - $14,629.27; Simplot - $5,656.11; and Department Of Energy - $6,528.59 (Company Attachment 1). These rates are included in Tariff Schedule No. 55, which is proposed to be effective June 1, 2015, and remain in effect for one year.

B. Staff's Rate Calculations

The derivation of traditional PCA rates is shown on Attachment A to these comments. The uniform 0.5298 ¢/kWh PCA rate surcharge is the sum of the three traditional PCA components (0.2815 + 0.2376 + 0.0107) designed to collect an NPSE amount of $73.67 million. The new PCA surcharge rate also includes the true-up adjustment proposed in Case No. IPC-E-15-15, and reflects the agreed-upon use of an SBAR rather than an LCAR. The overall rate is significantly less than the current rate of 0.7304 ¢/kWh.

The revenue-sharing rate decrease of approximately $8.0 million is spread to the individual rate schedules on an equal percentage of base revenue basis. The rate spread reduces current base revenue to all schedules by 0.78 %. The reduction is credited through the energy rates of each schedule. This process creates a different rate for each schedule. Finally, the $4.0 million in DSM rider funds that accrue to the rider account each year is a direct result of the base rate increase approved in Order No. 33000. The credit is allocated to each customer rate schedule on an equal ¢/kWh basis for an overall rate decrease of 0.0286 ¢/kWh and an overall decrease in current base revenue of approximately 0.39%.

Attachment B shows the revenue-sharing allocation and the DSM credit by customer rate schedule, and Attachment C shows Schedule 55 rate components by customer class. The rate components are the same as those proposed by the Company, except for the traditional PCA that includes the SBAR true-up adjustment. The reduction in billed revenue by customer rate schedule is shown on Attachment D, as is the overall reduction of $11.6 million or 1.05%.

III. CUSTOMER RELATIONS

A. Customer Notice And Press Release

The Company filed copies of its press release and customer notice with its Application. Staff reviewed both documents and determined that they comply with the Commission's Procedural Rule 125, IDAPA 31.01.01.125.

The customer notice was mailed with cyclical billings beginning April 23 and ending May 21. This means that many customers will not receive notice of the case until after the comment filing deadline of May 15, 2015. Other customers who receive notice on or shortly before the comment deadline will not have a reasonable opportunity to prepare and file timely comments. Staff is concerned that many customers will not receive timely notice of the Company's Application. Staff does not believe customers will object to a decrease in the PCA, but recommends that the Commission accept late-filed comments, recognizing the probability that the Commission will be unable to take into consideration comments filed by customers whose bills are issued at the end of the billing cycle.

B. Customer Comments

As of May 14, 2015, the Commission has received no comments from customers.

IV. STAFF RECOMMENDATIONS

Staff recommends that the Commission approve the Company's proposed PCA rates as modified to include the SBAR true-up adjustment. Staff further recommends that the Commission approve the Company's proposed revenue-sharing amounts; specifically, PCA revenue sharing of $7,999,145 and a pension balancing account contribution of $16,693,134. Staff also recommends that the $4 million in energy efficiency tariff rider funds be credited to customers as a reduction in the 2015-2016 PCA.

Staff recommends that the Commission approve Schedule 55 rates as shown in Staff Attachment D. Staff further recommends that new base rates and updated Schedule 55 rates be effective June 1, 2014.

Respectfully submitted this 15th day of May 2014.

Karl T. Klein
Deputy Attorney General

Technical Staff: Randy Lobb
Kathleen Stockton
Daniel Klein

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2015-2016 PCA - Twenty Third Annual
IPC-E-15-14
Staff Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Forecast 2014-2015**					
2	PCA Expense (95%)	($)	160,578,735	192408459		
3	Hoku First Block Revenue	($)		0		
4	Difference	($)		192,408,459	31,829,724	
5	Sharing Percentage	(%)			0.95	
6	Shared Difference	($)			30,238,238	
7	Normalized System Firm Sales	(MWh)			14,545,294	
8	Rate for 95% Items	(¢/kWh)			0.2079	0.2079
9						
10	PCA Expense (PURPA at 100%)	($)	133,853,869	148,054,626	14,200,757	
11	Normalized System Fiirm Sales	(MWh)			14,545,294	
12	Rate For PURPA	(¢/kWh)			0.0976	0.0976
13						
14	Demand Response Incentives (100%)	($)	11,252,265	7,921,041	(3,331,224)	
15	Idaho Jurisdictional Sales	(MWh)			13,901,424	
16	Rate for Demand Response	(¢/kWh)			(0.0240)	(0.0240)
17						
18	Total Forecast Rate	(¢/kWh)				**0.2815**
19						
20						
21			($)	(MWh)	($/MWh)	(¢/kWh)
22						
23	**True-Up of 2014-2015:**					
24	Company Proposal		34,515,981	13,901,424	0.2483	0.2483
25	SBAR Adjustment (Case No. IPC-E-15-15)		(1,470,798)	13,901,424	(0.0106)	
26	Staff Proposal		33,045,183	13,901,424	0.2377	**0.2377**
27						
28	**True-Up of the True-Up:**		1,484,515	13,901,424	0.0107	**0.0107**
29						
30	**PCA Rates:**					
31	PCA Rate Adjustment From Base	(¢/kWh)				**0.5298**
32	PCA Rate Currently in Effect	(¢/kWh)				0.7305
33	Difference - Last Year to This Year	(¢/kWh)				(0.2007)
34						
35	Note: Negative rates and amounts indicate benefit to ratepayers					
36						
37						
38	**Expected PCA Revenues**		Rate	Energy	Revenue	
39			($/MWh)	(MWh)	($)	
40						
41	Forecast Revenues		2.815	13,901,424	39,132,509	
42	True-Up Revenue		2.377	13,901,424	33,045,183	
43	True-Up of the True Up Revenue		0.107	13,901,424	1,484,515	
44	Total		0.5298		73,662,207	
45						
46		13,901424 Company Forecast of 2015/2016 Idaho Jurisdictional sales				
47		14,545,294 Company Forecast of 2015/2015 Normalized System Firm Sales				

Notes: Rates for one year recovery period
Rates exclude Revenue Sharing and DSM Rider credit

Attachment A
Case No. IPC-E-15-14
Staff Comments
05/15/15

Idaho Power Company
PCA Revenue Sharing and DSM Rider Credits
Case No IPC-E-15-14

Line No	Tariff Description	Rate Sch. No.	(A) Average Number of Customers	(B) Normalized Energy (kWh)	(C) Current Base Revenue	(D) Allocated Revenue Sharing Benefit	(E) Percent Revenue Change	(F) Allocated DSM Rider (Ongoing) Transfer	Percent Revenue Change
	Uniform Tariff Rates:								
1	Residential Service	1	419,714	4,975,976,021	$451,890,740	($3,546,973)	(0.78)%	($1,421,063)	(0.31)%
2	Master Metered Mobile Home Park	3	22	5,051,507	$437,265	($3,432)	(0.78)%	($1,443)	(0.33)%
3	Residential Service Energy Watch	4	0	0	$0	$0	0.00%	$0	0.00%
4	Residential Service Time-of-Day	5	1,403	25,733,211	$2,241,125	($17,591)	(0.78)%	($7,349)	(0.33)%
5	Small General Service	7	27,849	139,242,087	$15,907,921	($124,864)	(0.78)%	($39,765)	(0.25)%
6	Large General Service - Secondary	9S	33,699	3,281,782,926	$223,120,061	($1,751,310)	(0.78)%	($937,227)	(0.42)%
7	Large General Service - Primary	9P	202	475,252,577	$28,047,944	($220,153)	(0.78)%	($135,725)	(0.48)%
8	Large General Service - Transmission	9T	3	3,688,446	$227,211	($1,783)	(0.78)%	($1,053)	(0.46)%
9	Dusk to Dawn Lighting	15	0	6,364,061	$1,264,908	($9,928)	(0.78)%	($1,817)	(0.14)%
10	Large Power Service - Secondary	19S	1	6,278,646	$370,254	($2,906)	(0.78)%	($1,793)	(0.48)%
11	Large Power Service - Primary	19P	103	2,194,372,131	$114,628,493	($899,740)	(0.78)%	($626,679)	(0.55)%
12	Large Power Service - Transmission	19T	2	32,291,814	$1,619,800	($12,714)	(0.78)%	($9,222)	(0.57)%
13	Agricultural Irrigation Service	24	17,641	1,815,896,060	$133,669,616	($1,049,197)	(0.78)%	($518,592)	(0.39)%
14	Unmetered General Service	40	1,317	11,638,626	$947,979	($7,441)	(0.78)%	($3,324)	(0.35)%
15	Street Lighting	41	1,516	27,445,918	$3,575,124	($28,062)	(0.78)%	($7,838)	(0.22)%
16	Traffic Control Lighting	42	498	2,834,897	$163,375	($1,282)	(0.78)%	($810)	(0.50)%
17	Total Uniform Tariffs		503,970	13,003,848,928	$978,111,817	($7,677,377)	(0.78)%	($3,713,702)	(0.38)%
18	Special Contracts								
19	Micron	26	1	474,108,872	$22,365,544	($175,551)	(0.78)%	($135,398)	(0.61)%
20	J R Simplot	29	1	198,846,061	$8,647,177	($67,873)	(0.78)%	($56,787)	(0.66)%
21	DOE	30	1	224,619,666	$9,981,048	($78,343)	(0.78)%	($64,148)	(0.64)%
22	Total Special Contracts		3	897,574,599	$40,993,769	($321,768)	(0.78)%	($256,334)	(0.63)%
23	Total Idaho Retail Sales		503,973	13,901,423,527	$1,019,105,586	($7,999,145)	(0.78)%	($3,970,036)	(0.39)%

Note:
(1) June 1, 2015 - May 31, 2016 Forecasted Test Year

Staff Recommendation
Schedule 55 Rates
Case No IPC-E-15-14

Line No	Tariff Description	Rate Sch. No.	(A) Average Number of Customers	(B) Normalized Energy (kWh)	(C) Current Base Revenue	(D) Traditional PCA per kWh Rate	(E) Revenue Sharing $ per kWh	(F) DSM Rider $ per kWh	(G) Schedule 55 Rate $ per kWh
	Uniform Tariff Rates:								
1	Residential Service	1	419,714	4,975,976,021	$451,890,740	$0.005298	($0.000713)	($0.000286)	$0.004300
2	Master Metered Mobile Home Park	3	22	5,051,507	$437,265	$0.005298	($0.000679)	($0.000286)	$0.004333
3	Residential Service Energy Watch	4	0	0	$0	$0.005298	$0.000000	($0.000286)	$0.005012
4	Residential Service Time-of-Day	5	1,403	25,733,211	$2,241,125	$0.005298	($0.000684)	($0.000286)	$0.004329
5	Small General Service	7	27,849	139,242,087	$15,907,921	$0.005298	($0.000897)	($0.000286)	$0.004116
6	Large General Service - Secondary	9S	33,699	3,281,782,926	$223,120,061	$0.005298	($0.000534)	($0.000286)	$0.004479
7	Large General Service - Primary	9P	202	475,252,577	$28,047,944	$0.005298	($0.000463)	($0.000286)	$0.004549
8	Large General Service - Transmission	9T	3	3,688,446	$227,211	$0.005298	($0.000484)	($0.000286)	$0.004529
9	Dusk to Dawn Lighting	15	0	6,364,061	$1,264,908	$0.005298	($0.001560)	($0.000286)	$0.003452
10	Large Power Service - Secondary	19S	1	6,278,646	$370,254	$0.005298	($0.000463)	($0.000286)	$0.004550
11	Large Power Service - Primary	19P	103	2,194,372,131	$114,628,493	$0.005298	($0.000410)	($0.000286)	$0.004602
12	Large Power Service - Transmission	19T	2	32,291,814	$1,619,800	$0.005298	($0.000394)	($0.000286)	$0.004619
13	Agricultural Irrigation Service	24	17,641	1,815,896,060	$133,669,616	$0.005298	($0.000578)	($0.000286)	$0.004435
14	Unmetered General Service	40	1,317	11,638,626	$947,979	$0.005298	($0.000639)	($0.000286)	$0.004373
15	Street Lighting	41	1,516	27,445,918	$3,575,124	$0.005298	($0.001022)	($0.000286)	$0.003990
16	Traffic Control Lighting	42	498	2,834,897	$163,375	$0.005298	($0.000452)	($0.000286)	$0.004560
17	Total Uniform Tariffs		503,970	13,003,848,928	$978,111,817				
18	Special Contracts								
19	Micron	26	1	474,108,872	$22,365,544	$0.005298	NA	($0.000286)	$0.005012
20	J R Simplot	29	1	198,846,061	$8,647,177	$0.005298	NA	($0.000286)	$0.005012
21	DOE	30	1	224,619,666	$9,981,048	$0.005298	NA	($0.000286)	$0.005012
22	Total Special Contracts		3	897,574,599	$40,993,769				
23	Total Idaho Retail Sales		503,973	13,901,423,527	$1,019,105,586				

Attachment C
Case No. IPC-E-15-14
Staff Comments
05/15/15

Staff Recommendation
Summary of Revenue Impact 2015 - 2016
PCA - With SBAR Adjustment
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	Current Billed Revenue	Mills Per kWh	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:									
1	Residential Service	1	419,714	4,975,976,021	$490,529,194	98.58	($2,744,289)	$487,784,905	98.03	(0.56)%
2	Master Metered Mobile Home Park	3	22	5,051,507	$477,051	94.44	($3,178)	$473,873	93.81	(0.67)%
3	Residential Service Energy Watch	4	0	0	$0	0.00	$0	$0	0.00	N/A
4	Residential Service Time-of-Day	5	1,403	25,733,211	$2,443,466	94.95	($15,962)	$2,427,504	94.33	(0.65)%
5	Small General Service	7	27,849	139,242,087	$17,024,504	122.27	($26,934)	$16,997,570	122.07	(0.16)%
6	Large General Service	9	33,904	3,760,723,949	$271,810,097	72.28	($3,534,446)	$268,275,651	71.34	(1.30)%
7	Dusk to Dawn Lighting	15	0	6,364,061	$1,279,520	201.05	$7,365	$1,286,885	202.21	0.58%
8	Large Power Service	19	106	2,232,942,591	$129,505,363	58.00	($2,607,740)	$126,897,624	56.83	(2.01)%
9	Agricultural Irrigation Service	24	17,641	1,815,896,060	$143,226,677	78.87	($1,502,605)	$141,724,072	78.05	(1.05)%
10	Unmetered General Service	40	1,317	11,638,626	$1,007,150	86.54	($8,264)	$998,886	85.83	(0.82)%
11	Street Lighting	41	1,516	27,445,918	$3,684,716	134.25	($58)	$3,684,658	134.25	(0.00)%
12	Traffic Control Lighting	42	498	2,834,897	$179,387	63.28	($3,082)	$176,305	62.19	(1.72)%
13	Total Uniform Tariffs		503,970	13,003,848,928	$1,061,167,124	81.60	($10,439,192)	$1,050,727,932	80.80	(0.98)%
14	Special Contracts:									
15	Micron	26	1	474,108,872	$25,174,938	53.10	($608,090)	$24,566,849	51.82	(2.42)%
16	J R Simplot	29	1	198,846,061	$9,838,510	49.48	($262,330)	$9,576,181	48.16	(2.67)%
17	DOE	30	1	224,619,666	$11,313,830	50.37	($285,036)	$11,028,793	49.10	(2.52)%
18	Total Special Contracts		3	897,574,599	$46,327,278	51.61	($1,155,455)	$45,171,823	50.33	(2.49)%
19	**Total Idaho Retail Sales**		**503,973**	**13,901,423,527**	**$1,107,494,402**	**79.67**	**($11,594,647)**	**$1,095,899,755**	**78.83**	**(1.05)%**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 15th DAY OF MAY 2015, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-15-14, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

LISA D NORDSTROM
REGULATORY DOCKETS
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-mail: lnordstrom@idahopower.com
dockets@idahopower.com

TIMOTHY E TATUM
GREGORY W SAID
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-mail: ttatum@idahopower.com
gsaid@idahopower.com

Ryna Quintero

SECRETARY