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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, 2019 THROUGH MAY 31, 2019.	)	**CASE NO. IPC-E-19-16** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's Application.

BACKGROUND

On April 15, 2019, Idaho Power Company filed its annual power cost adjustment (PCA) Application. The Company's PCA Application, if approved, would decrease the revenue collected by about $50.1 million or 4.34%. The Company requested the new rates take effect on June 1, 2019. The Commission first approved the annual PCA mechanism in 1993, and it has been modified several times since then. *See* Commission Order Nos. 24806, 30715, 30978, 32206, 32424, 33149, and 33307. The Company's actual cost to provide electricity (Net Power Supply Expense, or NPSE) varies from year to year depending on changes in stream flows, the amount of purchased power, fuel costs, the market price of power, and other factors. The PCA mechanism tracks annual differences between actual NPSE and NPSE recovered through base rates. The PCA is also used to provide revenue-sharing benefits resulting from the revenue-sharing mechanism approved in Order No. 33149. Earnings for this PCA year would provide customers with a revenue-sharing credit. This year's PCA also includes the Company's actual costs of Western Energy Imbalance Market (EIM) participation as approved in Order No. 34100 and tax reform benefits approved in Order No. 34071.

STAFF REVIEW

If approved by the Commission, this year's PCA filing would decrease Schedule 55 billed revenue by $50.1 million. The decrease includes three components from this year's PCA: A $50.1 million decrease from the traditional PCA mechanism; a $5.0 million decrease from revenue sharing under Order No. 33149; and a total increase of $5.1 million because of adjustments from the tax reform case (*See* Order No. 34071).[1]

These three rate components combine to change Schedule 55 rates by class as summarized in Table 1 below:

Table 1: Overall Rate Impact (Excerpted from Company's Application, Attachment 2)

Class Description	Rate Schedule No.	Change
Residential	1	-3.49%
Master Metered Mobile Home Park	3	-3.66%
Residential Service Time of Day	5	-3.63%
Residential Service On-Site Generation	6	-3.35%
Small General Service	7	-2.79%
Small General Service On-Site Generation	8	-2.84%
Large General Service	9	-4.80%
Large Power Service	19	-6.06%
Irrigation	24	-4.33%
Micron	26	-6.76%
JR Simplot	29	-7.03%
DOE	30	-6.99%
Unmetered General Service	40	-4.00%
Street Lighting	41	-2.63%
Traffic Control Lighting	42	-5.53%
System Average Decrease		**-4.34%**

[1] The $5.1 million tax reform increase consisted of: (1) A $4.2 million tax reform one-time benefit that was removed in this year's PCA; and (2) a $0.9 million reduction in OATT-related tax benefits, $3.6 million that was included in last year's PCA which was reduced to $2.7 million in this year's PCA.

Staff audited the Company's sales and costs for the 2018-2019 PCA year, and reviewed the Company's sales and cost forecasting methodologies for the upcoming 2019-2020 PCA year. Staff also reviewed the Company's filing and methodologies to ensure they complied with the Commission's prior orders, including orders on revenue sharing and tax reform benefits. Staff determined:

1. Actual loads, fuel consumption, fuel costs, purchased power costs, and kilowatt-hour sales for the current PCA year (2018 -2019) are accurate;
2. The Company reasonably forecast kilowatt-hour sales, loads, fuel consumption, fuel costs, and purchased power costs for the upcoming PCA year (2019-2020);
3. The Company calculated the incremental change in the upcoming year's PCA rates in compliance with Commission Order Nos. 24806, 30715, 30978, 32206, 32424, 33149, and 33307;
4. The Company incurred a reasonable and prudent amount of actual NPSE to serve its customer load;
5. The Company's Idaho jurisdictional year-end Return on Equity (ROE) exceeded the 10.0% ROE threshold for revenue sharing (Order No. 33149), so the 2019-2020 PCA includes a revenue-sharing component and was calculated correctly; and
6. The Company applied the tax reform benefits consistent with Commission Order No. 34071.

PCA Mechanism

The traditional PCA mechanism is designed to ensure that customers pay no more and no less than actual NPSE minus customer sharing. The mechanism compares actual NPSE during the deferral year (April 2018 through March 2019) to NPSE recovered through base rates. If actual NPSE is higher or lower than the amount recovered through base rates, customers are surcharged or credited the difference, respectively, minus customer sharing, through Schedule 55 rates.

The traditional PCA mechanism consists of: (1) a forecast of the difference between the NPSE embedded in base rates and the 2019-2020 projected NPSE; (2) a "true-up" that captures the difference between actual NPSE and base NPSE that was actually collected in that year and credits the revenue from the previous year's forecast rate; and (3) a reconciliation of the 2017-2018 true-up that captures any under-recovered or under-refunded amounts. This reconciliation is also called the "true-up of the true-up." These components combine for a uniform 0.1318 ¢/kWh rate applied across all rate classes.

Forecast Analysis

Staff believes the 2019-2020 PCA forecast is reasonable, and notes that any over or under-collected amounts due to forecast variance are trued-up in the following year. The PCA forecast component to be collected from Idaho customers is $82,706,715. Annis, DI at 15. Staff verified the forecast portion of the PCA rate and recommends the Commission accept the rate of 0.5836 ¢/kWh for the 2019-2020 PCA period. *Id.* at 24.

The Company uses its March 29, 2018 Operating Plan to forecast the difference between NPSE embedded in base rates and NPSE the Company expects to recover in the coming year. The Company uses dispatch simulation to analyze projected load, resource balance, and energy supply to create a monthly forecast for the PCA year. Additional considerations for the forecast include forward market energy prices, hydro generation, fuel prices, existing hedge transactions, and costs associated with Public Utility Regulatory Policies Act (PURPA) and non-PURPA contracts. This year, the Company participated in the EIM, which contributed to an increase in Forecast Sharing Account 447, Surplus Sales.

Forecasted NPSE expenses are $394,288,927 for the 2019-2020 PCA year, which is an $8,786,346 decrease from last year. *Id.* at 8. Table 1 on page 6 of Mark Annis' testimony shows the forecasted NPSE is $88,604,058 higher than the base level of NPSE already collected in rates. The Company took the Idaho jurisdictional share of NPSE differences and adjusted it for PCA sharing to determine that the PCA forecast component to be collected from Idaho customers is $82,706,715. *Id.* at 15.

Accounts Shared at 95% Customers and 5% Company ("95%/5%")

Accounts shared at 95%/5% contain Power Supply Costs and Surplus Sales. The Commission created a methodology that assigns purchased power costs or benefits to customers and shareholders as incentive to the Company to make careful resource acquisition decisions. In the PCA, annual deviations in normalized power supply costs are shared 95%/5% by customers and Company shareholders. Order No. 30715. If costs are below those anticipated, customers receive 95% of the difference. If costs are above those anticipated, customers pay 95% of the excess costs and the Company absorbs 5%.

The accounts shared at 95% are forecasted to decrease in total by 7.6%. As a result of the 61% forecasted increase in electric market purchase prices, from $16.77 MWh last year to $35.84 MWh, the Company plans to reduce market and non-PURPA purchases. Annis, DI at 9. The Company also anticipates increasing coal generation by 29% to serve load and contribute to surplus sales to capture the market opportunity of rising electric market prices. *Id.* at 13. This is forecasted to increase coal fuel expense by 17%, and increase revenue in sharing accounts above the prior year by 150%, which will benefit customers in the next PCA filing. *Id.* at 9-10. The Company also forecasts that natural gas fuel expense at its gas plants will increase due to an estimated 19% increase in natural gas prices. Last, the Company projects a decrease in hydro generation as result of reduced snowpack and reservoir storage that will impact inflow to most of the Company's hydro generation plants. *Id.* at 14.

Accounts Recovered 100% from Customers

Accounts recovered at 100% contain PURPA and Demand Response Incentive expense. The Company forecasts a 3.8% increase to the accounts recovered at 100%. *Id.* at 8. PURPA energy purchases are expected to increase by 4% due to a 2% increase in PURPA generation and contract price escalation. *Id.* at 10-11. Forecasted demand response expenses did not change. *Id.* at 10.

True-Up Analysis

Staff's review of the true-up includes: (1) an on-site audit of the components included in the true-up or deferral balance; (2) an analysis of the methods and basis used to calculate the cost deferrals and account balances; (3) a review of actual NPSE, including monthly Energy Risk Management Committee minutes, operating plans, and other reports presented to the Risk Management Committee; and (4) an analysis to determine if the Company prudently dispatched resources, purchased power, and sold power in the wholesale market. Based on its review, Staff believes the Company's proposed true-up amount is accurate, that the methods used conform to the Commission's past orders, and that actual costs incurred are reasonable and prudent.

The true-up deferral balance, which is shown in Table 2 below, primarily consists of the differences between actual NPSE and NPSE recovered through base rates, and forecast revenues. It also includes the participation costs in the EIM, Renewable Energy Credit (REC) sales, and the difference between actual demand response incentive payments and the amount recovered in base rates. The ending balance of the true-up also includes collections through the current forecast PCA rate and monthly accrued interest.

The Company converts the true-up amount to a ¢/kWh rate by dividing it by projected energy sales. The Company calculates Idaho ratepayers' share of the true-up amount for a refund of about $54 million, and expects to refund that amount through a true-up rate of -0.3806 ¢/kWh as compared to last year's rate of 0.1398 ¢/kWh. Table 2, below, summarizes the Company's proposed $53,933,956 true-up refund amount.

Table 2: PCA True-Up Summary

Net Power Supply Expense Differential	**Deferral Amount**
Fuel Expense – Coal	$ 20,666,921
Fuel Expense – Gas	(6,340,692)
Non-Firm Purchases	21,926,034
Off-System Sales	(45,386,121)
Third-Party Transmission Expense	(1,670,302)
Water for Power (Leases)	78,929
Subtotal - Net Power Supply Expense	$ (10,725,231)
Other PCA Items	
Emission Allowances & Renewable Energy Credit (REC) Sales	(3,166,495)
Sales-Based Adjustment	(13,212,397)
Qualifying Facilities	58,834,175
Demand Response Incentive Payments	(4,100,533)
EIM Participation Costs	2,951,196
Subtotal – Other PCA Items	$ 41,305,946
Total Expense Items	$ 30,580,715
Revenue from PCA Forecast	$ (84,316,932)
Deferral Balance (Expense Items less PCA Forecast Revenue)	$ (53,736,217)
Interest on the Deferral Balance	(197,739)
Total True-Up Deferral	$ (53,933,956)

Details of the different components in the PCA true-up, as shown in Table 2, are described below. Positive numbers represent a customer cost (recovery from customers), and negative numbers represent a customer benefit (credit to customers). All amounts are shown after jurisdictional allocation and sharing.

Net Power Supply Expense Differential

Staff believes the Company prudently incurred NPSE to meet customer load. The Company's NPSE primarily consists of costs related to coal and other fuels, non-PURPA purchased power, and surplus sales. During the 2018/2019 PCA year, due to higher market prices and the integration into the EIM markets, the Company has dispatched its thermal resources (coal and gas units) more than expected, which also increased surplus sales. Coal costs increased due the higher dispatch. Gas costs would have increased as well, except the Company's hedging practices benefited customers by about $25 million. All power purchases through the EIM are recorded as non-firm purchases and, therefore, those expenses have increased. The main NPSE components are described below.

1. *Fuel Expense - Coal*. The Company owns an interest in, and receives electricity from, three coal plants: Bridger, Valmy, and Boardman. Staff reviewed all months of the coal expenses and performed an in-depth audit for June and November 2018. The Company includes the increase or decrease in coal expense from base rates in the PCA for recovery from, or a credit to, customers. From April 2018 through March 2019, the total coal expense for the three plants was $124,832,676. The total coal expense included in base rates is $103,078,021. This year's PCA deferral balance, after jurisdictional allocation and sharing, includes a coal expense difference of $20,666,921 for recovery from customers.
2. *Fuel Expense - Gas*. The Company owns and operates gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (Danskin), Bennett Mountain, and Langley Gulch. Staff reviewed all months of the natural gas expenses and performed an in-depth audit for June and November 2018. The transactions appear reasonable and follow the Idaho Power Energy Risk Management Committee's policies and standards.

   The Company includes the increase or decrease in natural gas expense from base rates in the PCA for recovery from, or a credit to, customers. For the 2018-2019 deferral period, the total variable gas and gas transportation expense for all the gas plants was $25,024,772. The total gas and gas transportation expense included in base rates is $31,699,184. This year's PCA deferral balance, after jurisdictional allocation and sharing, includes a gas expense difference of $6,340,692 credit to customers.

3. *Non-firm Purchases.* To supplement its own generation, the Company buys wholesale power based on its Energy Risk Management Policy and Standards, operating reserve margins, unit availability, and economics. In addition the Company has entered the EIM, and all EIM purchases are included as non-firm purchases. Excluding PURPA purchases during the 2018-2019 PCA year, the Company bought $82,556,229 of power on the market. Base rates included $59,476,263 in non-PURPA power purchases. After jurisdictional allocation and sharing, actual non-PURPA power purchases exceeded base amounts by $21,926,034.

   Staff reviewed the purchases, and performed an in-depth audit of select transactions during the PCA deferral period. Staff compared the term purchase price to the forward market prices from the monthly operating plans, and compared the day-ahead and real-time market prices to the Intercontinental Exchange Mid-C daily price index. The transactions appear reasonable and follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners in a timely manner.

4. *Off-System Sales.* During the 2018-2019 PCA year, the Company's off-system sales of surplus power totaled $96,923,260. The total surplus sales included in base rates is $49,148,395. The increase in surplus sales compared to base amounts is driven primarily by higher market electricity prices, and entering the EIM. After jurisdictional allocation and sharing, actual surplus sales were greather than base amounts by $45,386,121; this decreases the deferral balance to be recovered from customers.

5. *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 2018-2019 PCA period, the actual third-party transmission expense is $3,424,944. The third-party transmission expense included in base rates is $5,183,157. After jurisdictional allocation and sharing, third-party transmission expense decreases the deferral balance by $1,670,302 and is a credit to customers.

6. *Water Leases.* The Company occasionally leases water to produce hydro power. There is $2,380,597 included in base NPSE for water leases. Any deviation from the amount included in base rates either increases or decreases the PCA deferral. This year the Company entered into one water lease for $2,450,000 ($2,344,650 Idaho Allocated). After jurisdictional allocation and sharing, $78,929 is an increase to the deferral balance.

Other PCA Items

7. *Emission Sales & REC Sales*. In Order No. 30818, the Commission required the Company to sell RECs and apply the benefits to customers. The deferral balance includes $3,166,495 in revenue from Emission and REC sales, after allocation and sharing. This increase in revenues decreases the deferral balance recovered from customers.

   Staff reviewed the Emission and REC transactions included in the PCA deferral period and verified that the amount included in the deferral period is accurate. Staff notes that the only Emissions Sales of $15.84 occurred in November 2018. Idaho Power has had no emission sales in recent years.

8. *Sales-Based Adjustment*. The Company calculates a $13,212,397 Sales-Based Adjustment (SBA) credit to customers from the Company's over-recovery of actual NPSE collected through base rates due to differences in base versus actual sales. The SBA uses the $26.72/MWh SBA rate established in Order No. 33307 (Case No. IPC-E-15-15). When multiplied by the difference in actual and base rate sales, it calculates the over or under recovery of actual NPSE due to sales that are higher or lower than sales used to determine base rates (subject to 95% customer sharing). During the 2018-2019 PCA deferral year, actual sales were 520,501 MWh higher than sales used to set base rates, resulting in a credit back to customers. Staff audited and analyzed the Company's SBA calculations by: (1) auditing actual sales; (2) confirming the SBA rate and sales used to set base rates; and (3) verifying the Company's method for calculating the SBA followed the Commission's prior orders. Staff believes the Company calculated the SBA adjustment consistently with past Commission orders, and that the adjustment is accurate.

9. *Qualifying Facility/PURPA Expense*. For the 2018-2019 PCA deferral period, the actual Idaho Jurisdictional PURPA expense is $185,995,351. The Idaho Jurisdictional PURPA expense included in base rates is $127,161,176. In this year's PCA deferral balance, the actual Idaho jurisdictional PURPA expense exceeded the PURPA expense included in base rates by $58,834,175. PURPA contracts are not subject to sharing, but they are subject to jurisdictional allocation. Staff audited the actual monthly PURPA expense during the deferral period and believes the amount reported is accurate.
10. *Demand Response Incentive Payments*. Staff reviewed the Company's actual Demand Response (DR) incentive payments included in the 2018-2019 PCA deferral balance. Staff confirms there were $7,151,732 in actual DR Incentive expenditures in the deferral, which is $4,100,533 less than the $11,252,265 included in Base NPSE. DR incentive payments are allocated 100% to Idaho and are not subject to sharing. The prudency of the DR incentive payments will be determined in Idaho Power's annual DSM prudency filing currently before the Commission (Case No. IPC-E-18-03). Any DSM prudency disallowance in that case will be reflected in next year's PCA deferral balance. This reduced level of DR incentive payments reduces the deferral balance to be recovered from customers.
11. *EIM Participation Costs*. The Company has included operation and maintenance expenses directly related to its participation in the EIM. The Idaho Power recovery method for actual costs associated with participating in the EIM, was approved in Order No. 34100, Case No. IPC-E-17-16. The benefits of the EIM market automatically flow through the PCA, matching costs with benefits until the next general rate case, at which point the costs and benefits will be built into rates. Staff has reviewed these costs and believes they are appropriately recorded and accurate. The Idaho share of the EIM expenses is $2,951,196.
12. *Revenue from the PCA Forecast*. The Company's forecast rates generated $84,316,932 in revenue during the deferral period. The forecast rate changes each June when the new PCA rates are established. Therefore, the deferral period reflects the rate set in the two previous PCA periods. This amount is credited to customers in the calculation of the overall deferral balance for the 2018-2019 deferral period. Staff verified the revenue collected during the PCA period.

13. *Interest on the Deferral Balance.* The deferral balance accrues interest at the customer deposit rate, which was at 1% for 2018 when it changed to 2% for 2019 per Order No. 34204. The interest accrued during the current deferral period is a credit to customers of $197,739. Staff verified the interest calculations and agrees with the Company.

NPSE Analysis

Staff finds that the actual NPSE the Company incurred during the PCA year (April 2018 through March 2019) was reasonable and prudent. To analyze the Company's NPSE, Staff compared the actual NPSE for the 2018-2019 PCA year and the base NPSE approved in Order No. 33000. In addition, Staff compared actual NPSE for the 2018-2019 PCA year and the actual NPSE for the 2017-2018 PCA year. A summary of the analysis is provided in the Tables 3 and 4 below on a total system basis. Expenses reflected in the prior sections are on an Idaho jurisdictional bases so are less.

Table 3: 2018-2019 Actual NPSE compared to Authorized base NPSE

Actual versus Authorized NPSE Differences (Total System)				
Expense Category	**Actual NPSE**	**Base NPSE**	**$ Difference**	**% Difference**
Acct 501 Coal	$ 130,865,930	$ 108,503,180	$ 22,362,750	21%
Acct 536 Water for Power (Leases)	$ 2,450,000	$ 2,380,597	$ 69,403	3%
Acct 547 Other Fuel (Natural Gas)	$ 26,123,248	$ 33,367,563	$ (7,244,315)	-22%
Acct 555 Purchased Power Non-PURPA	$ 86,561,811	$ 62,606,593	$ 23,955,218	38%
Acct 565 Third-Party Transmission	$ 3,584,536	$ 5,455,955	$ (1,871,419)	-34%
Acct 447 Surplus Sales	$ (101,576,987)	$ (51,735,153)	$ (49,841,834)	96%
Acct 555 PURPA	$ 194,969,848	$ 133,853,870	$ 61,115,978	46%
Acct 565 Demand Response Incentives	$ 7,151,732	$ 11,252,265	$ (4,100,533)	-36%

When comparing actual-to-base NPSE, the major drivers in the difference were PURPA related expenses and surplus sales. PURPA-related expenses were approximately $61 million higher than those reflected in base rates. These expenses are expected to be higher since the current base NPSE was approved five years ago. The cause of the increase is due to escalating avoided cost pricing built into current contracts and from the Company's obligation to take on additional Qualifying Facilities under PURPA. Actual surplus sales were 96% higher than base NPSE, which reduced the total actual NPSE by about $50 million when compared to the base. Actual surplus sales were significantly higher because higher average market sales price allowed the Company to take advantage of economic dispatch of coal-fired plants and a higher than expected hydro generation.

Table 4: 2018-2019 Actual NPSE compared to 2017-2018 Actual NPSE

2018-2019 versus 2017-2018 NPSE Differences (Total System)				
Expense Category	**2018-2019 NPSE**	**2017-2018 NPSE**	**$ Difference**	**% Difference**
Acct 501 Coal	$ 130,865,930	$ 103,318,634	$ 27,547,296	27%
Acct 536 Water for Power (Leases)	$ 2,450,000	$ -	$ 2,450,000	n/a
Acct 547 Other Fuel (Natural Gas)	$ 26,123,248	$ 33,654,349	$ (7,531,102)	-22%
Acct 555 Purchased Power Non-PURPA	$ 86,561,811	$ 64,633,258	$ 21,928,554	34%
Acct 565 Third-Party Transmission	$ 3,584,536	$ 4,077,351	$ (492,815)	-12%
Acct 447 Surplus Sales	$ (101,576,987)	$ (40,633,415)	$ (60,943,573)	150%
Acct 555 PURPA	$ 194,969,848	$ 186,067,647	$ 8,902,202	5%
Acct 565 Demand Response Incentives	$ 7,151,732	$ 6,983,307	$ 168,425	2%

When comparing 2018-2019 to 2017-2018 NPSE, the major drivers in the difference were caused by surplus sales, coal generation, and non-PURPA purchased power. The reason for a 150% increase in surplus sales is the same as previously discussed when comparing actual-to-base NPSE. Above average market prices allowed the Company to dispatch surplus capacity into the market. Part of the increase in surplus sales came from the Company utilizing additional hydro generation from water for power leases which the Company used to sell into the market during higher priced hours and to avoid high market purchases by using the cheaper water to meet native load. Higher market prices also allowed the Company to sell more coal generation into the market as illustrated by the 27% increase in coal expense. However, higher market prices caused purchased power expense (Non-PURPA) to be 34% higher than in last year's PCA.

Part of the increase in purchased power expense compared to last year's PCA was due to increased purchases through the EIM that wasn't implemented until the beginning of this year's deferral period.

<u>Reconciliation of the True-up (True-up of the True-up) Analysis</u>

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 any other line items collected in the PCA such as revenue sharing, 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 true-up was over-collected by about $10.1 million, resulting in a proposed reconciliation of the true-up rate of -0.0712 ¢/kWh as compared to a rate of 0.0063 ¢/kWh in last year's PCA.

Table 5, below, summarizes the reconciliation of the true-up for the 2017-2018 PCA period. The $(10,097,124) ending balance amount is the revenue requirement used to form the reconciliation of the true-up portion of the overall PCA rate. The reconciliation is shown on the line labeled "Ending True-Up of the True-Up Balance" in Company Exhibit 2.

Staff audited the amounts booked to the reconciliation of the true-up, verified the Company's calculations, and reviewed the method used to ensure it complies with past Commission orders. Because of its review, Staff believes the Company correctly reconciled the true-up. The specifics of Staff's review are discussed below.

Table 5: True-Up Reconciliation

2017-2018 True-Up Deferral (Order No. 34080)	$	(19,993,280)
2016-2017 True-Up of the True-Up Ending Balance		(898,592)
Tax Settlement (Order No. 34071)		(4,244,015)
Net Amount Set for Recovery/(Refund)	$	(25,135,887)
Collections from True-Up Rates	$	15,282,895
Interest		(244,132)
Subtotal	$	15,038,763
True-Up Reconciliation	$	(10,097,124)

1. 2017-2018 True-up Deferral Balance. The ending true-up deferral balance from the 2017-2018 PCA period was approved in Order No. 24080; Case No. IPC-E-18-06. The ending deferral balance in last year's PCA was $(19,993,280). This amount is added to the beginning balance of the reconciliation of the true-up. This amount has been properly recorded in April 2017 in the reconciliation of the true-up for recovery.
2. 2017-2018 Reconciliation of the True-Up Balance. The remaining balance in the reconciliation of the true-up that was over-recovered in the previous PCA period is the beginning balance of the reconciliation of the true-up for this PCA period. The amount of $898,598 was over-recovered in the previous period, and has been properly recorded in the reconciliation of the true-up as the beginning balance.
3. Tax Settlement. In Case No. GNR-U-18-01, Order No. 34071, the Commission approved a multi-party settlement where the Company included the tax savings deferral from January to May of 2018 in the PCA. The $4,244,015 was agreed upon in the settlement and this one-time reduction is correctly recorded in May 2018 in the reconciliation of the true-up.
4. Collections from True-Up Rates and Interest. Staff reviewed and verified the collections from customers and the interest calculations. Staff has also verified that the collections and interest are properly reflected in the reconciliation of the true-up.

Revenue Sharing

The Commission established a mechanism in 2010 that required the Company to share revenue with customers based on the Company's actual Idaho jurisdictional year-end ROE. *See* Order No. 30978. The Commission subsequently modified the revenue-sharing mechanism and extended it in Order Nos. 32424 and 33149. The terms are effective through 2019, or until otherwise modified or terminated by Commission Order, or the full $45 million of Accumulated Deferred Investment Tax Credits are amortized.

The Company's 2018 year-end Idaho jurisdictional ROE was 10.21%. The Company's earnings exceeding the ROE of 10% is $4,974,987. Per the stipulation, 75% is shared with customers as a reduction to PCA rates, effective June 1, 2019. The customer amount is $3,731,240, and after tax gross-up, the revenue-sharing amount to be flowed through to customers through the PCA is $5,024,562.

Staff has reviewed the work papers, source documents, and supporting documentation and agrees with the revenue-sharing calculations.

Tax Reform Benefits

As part of a settlement stipulation approved in Commission Order No. 34701 in Case No. GNR-U-18-01, Parties agreed to a $7.8 million PCA credit from June 1, 2018 through May 31, 2019. The total tax credit benefits reflect the $4.2 million one-time adjustment discussed above and an additional $3.6 million credit that will decrease to $2.7 million on June 1, 2019 and reach $0 on June 1, 2020. *See* Commission Order No. 34701 at 3. These PCA credits are associated with tax savings and reduced OATT third-party transmission revenues agreed to in the settlement stipulation.

Staff reviewed the work papers and supporting documentation, and agrees the tax reform benefits included in the PCA filing conform to the settlement stipulation.

Rate Calculations

Staff thoroughly reviewed the all the components that make up this year's Schedule 55 PCA rates, which include the traditional PCA mechanism, revenue sharing, and tax reform benefits, and have concluded that they are fair, just, and reasonable. Staff's review of all the rate components included verification that: (1) the rates were calculated accurately; (2) the methods used to spread the rates across the customer classes provided a fair allocation; and (3) the methods complied with past Commission orders.

For the PCA mechanism, the Company proposes a 2019-2020 PCA rate of 0.1318 ¢/kWh using a forecast of 0.5836 ¢/kWh, a true-up of -0.3806 ¢/kWh, and a -0.0712 ¢/kWh true-up of the true-up. The Company calculated the overall PCA rate of 0.1318 ¢/kWh by summing the rates of the three traditional components: the forecast, the true-up, and the reconciliation of the true-up. Staff confirmed that the method used to allocate the revenue requirement across the customer classes was done on an equal cents per kilowatt-hour basis. This ensures that customers share the PCA revenue requirement based on the energy consumed, which is how NPSE is allocated in customer base rates.

As noted previously, the revenue-sharing amount to be flowed through to customers through the PCA is $5,024,562. The Company proposed to allocate this amount based on the class's proportional share of forecasted base rate revenues, which is the same methodology used in past cases. This amount will be brought into rates on a cents per kilowatt-hour basis except for the special contracts, which will use a flat dollar-per-month credit in 12 equal portions. Staff confirmed the rates were calculated as proposed and believes the method is reasonable.

The tax reform benefits to be received by customer through the PCA for 2019-2020 is $2,680,957. The Company proposed to allocate this amount to customer classes and bring into rates using the same methodology as revenue sharing. Annis, DI at 33-34. During Staff's review of the rate calculation for tax reform benefits, Staff found the Company allocated the tax reform benefits to customer classes the same as revenue sharing, but that the Company did not bring the class-allocated tax reform benefits into rates in the same manner as revenue sharing for special contract customers. For special contracts, the Company included the class-allocated tax reform benefits on cents-per-kWh basis instead of a flat dollar-per-month credit in 12 equal portions as was done with revenue sharing. While this method differs from how it was described in testimony, Staff believes this method is reasonable since the benefits are still allocated based on the class's proportional share of forecasted base rate revenues.

CUSTOMER NOTICE AND PRESS RELEASE

The Company's press release and customer notice were included with its Application. Staff reviewed the documents and determined that both meet the requirements of Rule 125 of the Commission's Rules of Procedure. IDAPA 31.01.01.125. The notice was or will be included with bills mailed to customers beginning April 24 and ending May 23, 2019. Customers whose bills will be mailed on May 20, 21, 22, and 23 were sent a direct mail postcard, mailed by May 17th, outlining the Company's filing on April 15, 2019. Unfortunately, even with the Company's attempt to notify some customers earlier, many will not have a reasonable opportunity to file comments by the May 15th comment deadline.

Because the Company is proposing a rate decrease, customers probably will not object to the proposed rate changes. However, all customers should have an opportunity to comment and have their comments considered by the Commission. Staff thus recommends the Commission accept and consider late-filed customer comments. As of May 14, 2019 the Commission had received no comments from customers.

STAFF RECOMMENDATIONS

Staff recommends that the Commission:

1. Approve the Company's proposed PCA rates as filed, effective June 1, 2019.
2. Accept late-filed customer comments.

Respectfully submitted this 15th day of May 2019.

For: Matt Hunter
Deputy Attorney General

Technical Staff: Michael Eldred
Rachelle Farnsworth
Joe Terry
Johan Kalala-Kasanda
Curtis Thaden

i:umisc/comments/ipce19.16mhmerfjtjkct comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 15th DAY OF MAY 2019, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-19-16, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY