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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, 2024 THROUGH MAY 31, 2025	)	**CASE NO. IPC-E-24-17** **COMMENTS OF THE COMMISSION STAFF**

COMMISSION STAFF ("STAFF") OF the Idaho Public Utilities Commission ("Commission"), by and through its Attorney of record, Chris Burdin, Deputy Attorney General, submits the following comments.

BACKGROUND

On April 15, 2024, Idaho Power Company ("Company") filed an application ("Application") with the Idaho Public Utilities Commission ("Commission") requesting an order approving an update to Schedule No. 55 based on the Company's quantification of the 2024-2025 Power Cost Adjustment ("PCA"), to become effective June 1, 2024, for the period of June 1, 2024, through May 31, 2025.

The PCA mechanism permits the Company to increase or decrease its PCA rates to reflect the Company's annual "power supply costs." Due to its diverse generation portfolio, the Company's actual cost of providing electricity varies from year to year depending on changes in such things as the river streamflow, the amount of purchased power, fuel costs, the market price of power, and other factors. The annual PCA surcharge or credit is combined with the Company's "base rates" to produce a customer's overall energy rate.

The PCA quantifies and tracks annual differences between actual Net Power Supply Expenses ("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 uses a 12-month test period from April through March ("PCA Year") and includes a forecast component and a Balancing Adjustment. The forecast component represents the difference between the Company's NPSE forecast from the March Operating Plan and base level NPSE recovered in the Company's base rates. The Balancing Adjustment includes a backward-looking tracking of differences between the prior PCA Year's forecast and actual NPSE incurred by the Company, and also tracks the collection of the prior year's Balancing Adjustment.

Except for 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 with base level NPSE, whether positive or negative. With respect to PURPA expenses and demand response incentive payments the Company is allowed to pass 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 customer benefits resulting from the revenue sharing mechanism, approved by the Commission in Order No. 34071.

The Company represents that the update to Schedule No. 55, based on the Company's quantification of the 2024-2025 PCA, will result in an overall decrease to current billed revenue of approximately $35.7 million, to become effective June 1, 2024. Application at 15.

The Company represents that the system-level forecast of NPSE for the 2024-2025 PCA Year is $509,555,990, which is $24,648,746 higher than the currently approved base level NPSE of $484,907,244, and $31,943,394 lower than last year's forecast amount of $541,499,384. *Id.* at 7-8. The Company states that the 2024-2025 PCA forecast component to be collected from Idaho customers is $22,712,031. *Id.* at 8.

The Company represents that the PCA Balancing Adjustment deferral balance at the end of March 2024, with interest applied, was approximately $90 million, which represents a decrease to customers rates in this year's PCA Balancing Adjustment. *Id.*

The Company represents that the Company's Idaho jurisdictional year-end Return on Equity ("ROE") was below the 10.0 percent ROE threshold for revenue sharing; therefore, the 2024-2025 PCA does not include a revenue sharing component. *Id.* at 9.

The Company represents that for the 2024-2025 PCA Year, the Company's uniform PCA is comprised of: (1) the 0.1501 cents per kilowatt-hour ("kWh") for the 2024-2025 projected power cost of serving firm loads under the current PCA methodology and 95 percent sharing; and (2) the 0.5946 cents per kWh for the 2023-2024 Balancing Adjustment, with the sum of these two components resulting in a 0.7447 cents per kWh charge for all rate classes. *Id.* at 9-10.

STAFF ANALYSIS

The Company's proposed update to Schedule 55 reflects an approximate decrease of $35.7 million, or 2.31 percent, in billed revenue, effective June 1, 2024, through May 31, 2025. Based on its review of the Application, audit of sampled transactions, examination of the testimony and workpapers of Company witness Jessica G. Brady, and a review of the Company responses to Staff's audit and production requests, Staff recommends the Commission approve the Company's Application and Schedule 55, as filed, effective June 1, 2024.

Staff examined the Company's sales and expenses for the historical 2023-2024 PCA year and its forecasting methods, projected revenues, and expenses for the upcoming 2024-2025 PCA year. Staff also verified that the Company's filing and methods complied with prior, relevant Commission Orders. Staff believes that:

1. The Company's forecast for the upcoming PCA year (2024-2025) of electricity sales, loads, fuel consumption, fuel costs, and purchased power costs are reasonable;
2. The Company should apprise the Commission of how the forecast changes during the PCA Year; and, if an adjustment to the forecast rate is warranted, the Company should make an off-cycle filing;
3. The Company's balancing adjustment is accurate and the NPSE is prudent;
4. The NPSE from the previous PCA case is prudent; and
5. The Commission should consider late filed comments by customers.

Components of Proposed PCA Increase

The components of the $35.7 million decrease in the PCA are shown in Table No. 1 below.

Table No. 1: Revenue Impact by PCA Rate Component, Idaho Basis

	2023-2024 PCA[1]	2024-2025 PCA[2]	Difference
PCA Forecast	$ 52,202,870	$ 22,712,031	$ (29,490,839)
PCA Balancing Adjustment	$ 96,189,461	$ 89,970,511	$ (6,218,950)
PCA Total	$ 148,392,331	$ 112,682,542	$ (35,709,789)
Revenue Sharing	$ 0	$ 0	$ 0
Total Revenue Impact	**$ 148,392,331**	**$ 112,680,542**	**$ ($35,709,789)**

The Company's NPSE varies each year depending on factors, which may include changes in river streamflow, the amount of purchased power, fuel costs, market energy price of power, and a limited coal supply. The PCA trues up annually to differences between actual NPSE and the NPSE collected through base rates. With the PCA, the Company's customers are paying their actual NPSE.

The Company's power supply costs and surplus sales are subject to a 95 percent/5 percent sharing band, with the Company responsible for 5 percent of the excess NPSE compared to NPSE revenue the Company collected through base rates. The Commission created this sharing band to provide a financial incentive for the Company to make careful resource acquisition and operating decisions to reduce costs. If actual costs are less than revenue collected, the Company keeps 5 percent of that difference. If costs are more than revenue collected, customers pay 95 percent of the excess costs, and the Company absorbs 5 percent.

In Order No. 36042, the Company's base rates were changed, effective January 1, 2024. Because the PCA period runs from April through March, April through December's base rates are set at the previously authorized levels, while January through March base rates are set at the

[1] Because Table No. 1 contains the expected billed revenue impact to customer, the "2023-2024 PCA" column reflects approved PCA rates applied to the June 2023 through May 2024 sales forecast and will not tie to the specific dollar amounts approved in the 2023 PCA filing.
[2] The "2024-2025 PCA" column reflects the Company's proposed rates applied to the June 2024 through May 2025 forecast and may not tie exactly to the figures listed in the Company's Application due to the rounding of rates to six digits.

newly authorized levels. Staff verified that the Company used the correct base rates for each month's calculations.

Forecast Analysis

The Company used its March 2024 Operating Plan to forecast the difference between expenses embedded in base rates and the expenses the Company expects to incur in the coming year. The Company uses a dispatch simulation model to analyze projected load and to determine and analyze resource balance and energy supply for the upcoming PCA Year. The forecast also accounts for forward market energy prices, hydro generation, fuel prices, existing hedge transactions, and costs associated with PURPA and non-PURPA contracts.

In its forecast, the Company projects that hydro and gas generation will be higher than average. The former is due to a wet winter that has filled the reservoirs, and the latter is due to a coal-to-gas conversion of Unit Nos. 1 and 2 at Jim Bridger Power Plan ("Bridger"). The increased generation from these two resource types will offset the overall increase in system load, and it will enable the Company to make fewer expensive market purchases. Since the NPSE of hydro generation is zero, the increased hydro generation helps to reduce the overall NPSE.

Staff also notes that the Company forecasts an increase of approximately 500 gigawatt-hours ("GWh") of coal generation from what it was able to generate in the 2023-2024 PCA year. Since coal on average is the cheapest form of generation after hydro, the increased generation reduces the forecast NPSE. Staff encourages the Company to actively manage coal operations to meet or exceed the coal forecast, as long as coal remains cost-effective.

Based on the 2024-2025 PCA forecast, the Company expects to collect $22.7 million above the amount in base rates from Idaho customers. This results in a decrease of $29.5 million compared to last year's PCA forecast. Over or under-collected amounts due to forecast variance will be trued up in the following year. Staff believes the Company's forecast is reasonable and maximizes the use of the most cost-effective resources.

Balancing Adjustment

The Balancing Account incorporates additional components into the PCA as shown in Table No. 2 below. In Order No. 35804, the Commission directed the Company to collect the

2022-2023 deferral balance over two years. As a result, a majority of the $89.8 million deferral balance is the balance remaining from the 2022-2023 PCA period.

Table No. 2: Balancing Account Summary

	Amount
Beginning Balance	$ 190,205,569
2023-2024 Incremental Deferral	$ 153,247,264
2023-2024 Forecast Revenues Collections	$ (174,657,030)
2023-2024 Prior Balance Revenues Collected	$ (82,707,151)
Revenue Sharing	$ 0
Current Month Interest	$ 3,882,536
2023-2024 Ending Deferral Balance	$ 89,791,188

Staff comments below focus on the incremental deferral balance for the period of April 2023 through March 2024 first, followed by the remaining components.

Incremental Deferral Balance

To best explain the incremental deferral balance of $153 million, Staff divided it into two subordinate components: (1) the NPSE from April 1, 2023, to March 31, 2024; and (2) other PCA expenses. Table No. 3, below, summarizes the two sub-components, which are the amounts allocated to Idaho customers after the jurisdictional allocation and the 95 percent/5 percent sharing band are applied.

Table No. 3: PCA Incremental Deferral Balance Summary

	Amount
Net Power Supply Expenses	$ 144,289,803
Other PCA Expenses	$ 8,957,461
Total Incremental Deferral Balance	$ 153,247,264

Staff's review included: (1) an audit of the deferral components; (2) an analysis of the methods and the basis used to calculate the cost deferrals and account balances; (3) an examination of the actual NPSE, including the Company's energy risk management policies and actions; 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 has confidence that the Company's proposed deferral is accurate and that it conforms to past Commission orders.

Net Power Supply Expense

NPSE Analysis

The $144 million NPSE was the main contributor to the $153 million incremental deferral balance. Staff reviewed the major sub-components of the NPSE and believes they were prudent. A brief discussion of each resource type follows, with all the cost and megawatt-hour ("MWh") quantities obtained from Brady's testimony.

Because hydro generation incurs zero NPSE, it was the most cost-effective power generation option for the Company. Due to abundant snowpack, the Company was able to generate approximately 1,463 GWh more than the previous PCA year, which translated into a significant NPSE reduction.

The next most cost-effective resource was coal, with an average unit cost of approximately $41 per megawatt-hour ("MWh"). The Company generated approximately 695 GWh less than the previous year, which meant the Company had to make up for the under-production with a more expensive option. Staff has thoroughly researched the ongoing coal-supply challenges faced by the Company and believes that the Company did all that it could to maximize its coal supply. Staff is encouraged that the Company forecasts coal generation to increase next year by 496 GWh compared to the actual generation this year.

The third most cost-effective resource was gas, with an average unit cost of approximately $56 per MWh. Annual gas generation increased by approximately 369 GWh (14 percent) from the previous year. Staff believes this increased quantity of gas generation was reasonable because the only alternative to supply the system load was market purchases, which were slightly more expensive, on average, than gas.

The most-expensive power option for the Company (except for must-take Qualified Facility ("QF") purchases) was market purchases, with an average unit cost of approximately $58 per MWh. The Company purchased approximately 385 GWh less than the previous year, which helped reduce the NPSE from last year's record high. Staff believes this outcome is reasonable. However, given that market purchases have been the most expensive non-QF resource for the past two years, Staff is concerned with the Company's heavy dependence on them. Market purchases supplied 20 to 25 percent of the Company's annual load each of the past two years. Furthermore, the Company's focus on acquiring additional transmission resources to meet future load growth will only increase the Company's reliance on market purchases.

NPSE Observations

First, Staff requests that the Company consider adjusting its annual PCA testimony to focus more on the actual expenses incurred, and less on the PCA forecast. Because the PCA is fundamentally a true-up of actual expenses, Staff believes the testimony should emphasize analysis of the actual expenses and actual generation. Staff also requests that the Company provide a table that lists the actual expenses and actual MWh for each resource type. Currently some of this information is dispersed in the narrative and some is not available.

Second, Staff notes that gas and market purchases continued to be the primary contributors to the high NPSE, contributing 98 percent of the non-QF deficit. Table No. 4 compares the *actual* gas and market purchase expenses to the *base* expenses for the previous two years.

Table No. 4: Comparison of Actual and Base Expenses for Gas and Market Purchases

	2022-2023			2023-2024		
Expense	Base	Actual	Difference	Base[1]	Actual	Difference
Gas	$ 33,367,563	$ 178,317,314	$ (144,949,751)	$ 53,513,746	$ 171,893,815	$ (118,380,070)
Market Purchase	$ 62,606,593	$ 404,938,271	$ (342,331,678)	$ 70,816,616	$ 218,730,125	$ (147,913,509)

Note 1: The base amount increased for January - March 2024, in accordance with the 2023 rate case.

Upon examination of the expenses month-by-month, Staff observed that *actual* expenses exceeded *base* expenses every month of the year. However, the biggest differences occurred in the peak summer months (June, July, and August) and especially during the peak winter months (November, December, and January). These six months incurred 77 percent of the entire year's deficit. The data is similar for the previous year. Even after incorporating the new higher *base* amounts in January 2024, the Company's *actual* gas and market purchase expenses for that month exceeded the *base* by approximately $59 million.

Staff is concerned that underlying market conditions may be shifting, and the Company's reliance on gas and market purchases in the peak months may continue to be exorbitantly expensive. Staff encourages the Company to search for solutions to mitigate the cost risk in the peak months, and to discuss its efforts in the next PCA filing.

Lack of Coal Supply and NPSE Prudence for 2022-2023 PCA

Staff recommends that the Commission recognize the NPSE from the 2022-2023 PCA as prudent.

In last year's PCA case (IPC-E-23-12), Staff expressed concern about the Company's coal supply shortfall, which resulted in under-generation of inexpensive coal power, and required the Company to compensate with more expensive Gas generation and Market Purchases. The Commission withheld a determination of prudence for the NPSE and ordered Staff to investigate and issue a report. Order 35804 at 8. Staff filed its report, which the Company included in this case as Confidential Attachment 3. The Company provided its response to Staff's report via Attachments 4, 5, and 6.

Staff reviewed the Company's response and agrees that the Company made reasonable efforts to procure additional coal for Bridger in the first half of the PCA year. Furthermore, Staff accepts the Company's counterfactual analysis, which concludes that early hedging actions would not have avoided additional NPSE.

Accordingly, Staff believes that the Company's NPSE for 2022-2023 was prudent.

Hells Canyon Unit No. 3

As part of last year's PCA case, the Commission ordered the Company to inform it of the outcome of the damage claim to Hells Canyon Unit No. 3. Order 35804 at 9.

The Company complied by reporting the outcome of the damage claim in its current application. Application at 12. Staff confirmed that the liquidated damages were credited to the NPSE, reducing the total expense.

Other PCA Expenses

Other PCA expenses include the difference between forecast expenses from the prior PCA Year and what is embedded in base rates: (1) Idaho Jurisdictional QF, PURPA Expense Deferral, and Export Credit Rate ("ECR"); (2) the Idaho Revenue Adjustment from the Sales Based Adjustment ("SBA") Rate; (3) the difference between actual DR incentive payments and amounts recovered in base rates; (4) the Actual Renewable Energy Credit ("REC") revenues; and (5) Idaho Power Energy Imbalance Market ("EIM") Participation Costs.

1. *QF/PURPA/ECR*. PURPA and QF contracts are not subject to the 95 percent sharing band but are subject to jurisdictional allocation between the Company's Idaho and Oregon customers. Additionally, as established in Order No. 36048, the Commission approved the Company's proposal to implement an ECR subject to 100% recovery through the PCA as a NPSE, effective January 1, 2024. The effective date of the order creates an overlap with the PCA balancing adjustment between Jan 1, 2024, and March 31, 2024.

For the PCA deferral year, the Company calculated that QF, PURPA, and ECR expenses were $50.5 million above the amount recovered in base rates. Staff reviewed QF, PURPA, and ECR expenses and agrees with the Company's calculation of an increase of $50.5 million to the deferral balance.

2. *SBA Rate*. The SBA is used to determine 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 percent customer sharing). It is the difference in actual and base rate sales multiplied by the SBA rate. The SBA Rate is $26.72/MWh between April and December 31, 2023, of the PCA year, as established in Order No. 33307, and $30.90/MWh beginning January 1, 2024, through March, as established in Order No. 36042.

The Company calculated a decrease of $24.1 million due to the Company's over-recovery of actual NPSE. Staff determined that the correct SBA Rate was used for each month's calculation and agrees with the Company's calculation of a $24.1 million decrease to the deferral balance.

3. *DR Incentive Payments*. The Company's DR incentive payments are not subject to the sharing band and are wholly allocated to Idaho. The Company calculates a $2.5 million DR

incentive decrease due to the actual DR incentive payments being less than those recovered in the base. The prudence of DR incentive payments will be determined in the Company's annual Demand-Side Management prudency filing currently before the Commission (Case No. IPC-E-24-11). If there are any DR disallowances in that case they will be reflected in next year's PCA deferral balance. Staff reviewed the DR incentive expenses and agrees with the Company's calculation of a $2.5 million decrease to the deferral balance.

4. *REC Revenues*. In Order No. 30818, the Commission required the Company to sell all RECs it receives for renewable generation to benefit its customers. REC sales are not included in the base and all sales are returned to customers at the 95 percent sharing band. The Company calculates a $18.4 million decrease due to the sales of RECs. Staff reviewed the Company's REC transactions and agrees with the Company's calculation of a $18.4 million decrease to the deferral balance.

5. *EIM Participation Costs*. The Company's operation and maintenance expenses attributed to its participation in the EIM are included in the PCA deferral in compliance with Order No. 34100. The benefits of the EIM market, such as lower energy purchase prices and increased sales volume, flow through the PCA. Including participation costs appropriately matches costs with benefits of sales on the EIM. As established in Order No. 36042, EIM participation costs are no longer tracked through the PCA and now are included in customer base rates beginning January 1, 2024. However, EIM participation costs still occurred in this past PCA period from April through December 31, 2023. The Company calculated a $1.9 million increase based upon costs of EIM participation. Staff reviewed EIM participation expenses and agrees with the Company's calculation of an increase of $1.9 million to the deferral balance.

Forecasted Revenues Collected

The Company calculated $174.7 million in revenue collected from its 2023-2024 PCA forecast. Staff reviewed the components of the Company's calculation and agrees with the $174.7 million decrease to the deferral balance.

Collections of the 2022-2023 Deferral Balance

The Company calculated $82.7 million in revenue collected from its balancing adjustment in the 2023-2024 PCA year. Staff reviewed the components of the Company's calculation and agrees with the Company's calculation of a $82.7 million decrease to the deferral balance.

Interest

The deferral balance accrues interest monthly at the Commission-approved customer deposit rate of two percent in 2023 and five percent in 2024. The Company calculated an interest balance of $3.9 million. Staff agrees with the monthly balance amounts and determined that interest rates applied to each month's balance were accurate, resulting in the $3.9 million increase to the deferral balance, as calculated by the Company.

Revenue Sharing and Rate Calculation

The revenue sharing mechanism, established in 2010 and last modified in Order No. 34071 in 2018, requires the Company to share revenues with customers based on its actual Idaho jurisdictional year-end ROE, if it exceeds ten percent. In 2023, the Company calculated that ROE was below ten percent, resulting in no revenue sharing benefit to customers. Staff reviewed the revenue sharing inputs and calculations and agree with the Company's determination.

PCA Rate Calculations

Staff reviewed the components that make up this year's PCA rates. Based on its review, Staff believes that the methods used comply with Commission orders and are calculated accurately.

Staff's review of all the rate components included verification that rates were calculated accurately and that the Company's methods comply with Commission orders. Staff confirmed that the revenue requirement was allocated across customer classes on an equal cents per kWh basis, which ensures that customers share the PCA revenue requirement based on the amount of energy consumed.

Overall Impact of Filings Effective June 1, 2023

On March 15, 2024, the Company filed its annual Fixed Cost Adjustment ("FCA") in Case No. IPC-E-24-10. The Company's 2024 FCA filing proposes a $10.6 million increase in current billed revenue, or a 1.44 percent increase, for Idaho Residential and Small General Service customers, effective June 1, 2024, through May 31, 2025.

If the PCA and FCA applications are approved as filed, the combined impact is an overall decrease in current billed revenue of $25.1 million, or 1.63 percent. The Company has proposed to implement the PCA and FCA rates on June 1, 2024. The impact by revenue class is reflected in the following tables.

Proposed 2023-2024 Revenue Impact by Class:
Percentage Increase from Current Billed Rates by Proposed Change PCA

Residential	Small General Service	Large General Service	Large Power	Irrigation
-1.91%	-1.57%	-2.57%	-3.12%	-2.33%

FCA

Residential	Small General Service	Large General Service	Large Power	Irrigation
1.44%	1.39%	N/A	N/A	N/A

Total Combined Impact

Residential	Small General Service	Large General Service	Large Power	Irrigation
-0.47%	-0.17%	-2.57%	-3.12%	-2.33%

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 18 and ending May 25, 2024. Customers whose bills will be mailed on May 18, 21, 22, 23, 24, and 25 were sent a direct mail postcard, mailed no later than May 17, outlining the Company's filing.

Even with the Company's attempt to provide earlier notice to some customers, many will not have a reasonable opportunity to file timely comments with the Commission by the May 15 comment deadline. Customers should have the opportunity to file comments and have those comments considered by the Commission. Staff recommends that the Commission consider late filed comments by customers. As of May 14, 2024, no customer comments had been filed.

STAFF RECOMMENDATIONS

Staff recommends that the Commission approve the Company's Application and Schedule 55, as filed, effective June 1, 2024. Staff also believes that:

1. The Company's forecast for the upcoming PCA year (2024-2025) of electricity sales, loads, fuel consumption, fuel costs, and purchased power costs are reasonable;
2. The Company should apprise the Commission of how the forecast changes during the PCA Year; and, if an adjustment to the forecast rate is warranted, the Company should make an off-cycle filing;
3. The Company's balancing adjustment is accurate and the NPSE is prudent;
4. The NPSE from the previous PCA case is prudent; and
5. The Commission should consider late filed comments by customers.

Respectfully submitted this 15th day of May 2024.

Chris Burdin
Deputy Attorney General

Technical Staff: James Chandler
Matt Suess
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 15th DAY OF MAY 2024, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-24-17, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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