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, 2025, THROUGH MAY 31, 2026.	)	CASE NO. IPC-E-25-20

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JESSICA G. BRADY

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

A. My name is Jessica G. Brady. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as a Senior Regulatory Analyst in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May 2016, I received a Bachelor of Science degree in Economics and a Bachelor of Arts degree in Spanish from the University of Idaho. I have also attended "The Basics: Practical Regulatory Training for the Electric Industry," an electric utility ratemaking course offered through New Mexico State University's Center for Public Utilities, "Electric Utility Fundamentals & Insights," an electric utility course offered through the Western Energy Institute, and Edison Electric Institute's "Electric Rates Course" offered at the University of Wisconsin-Madison.

Q. Please describe your work experience.

A. In September 2021, I accepted a position at Idaho Power as a Regulatory Analyst in the Regulatory Affairs Department. In October 2023, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, I am responsible for running the AURORA model ("AURORA") to calculate net power supply expenses ("NPSE") for ratemaking purposes, as well as the determination of the marginal cost of energy used in the Company’s marginal cost analyses. My duties also include providing analytical support for other regulatory activities within the Regulatory Affairs Department.

Q. What is the Company requesting in this case?

A. The Company is requesting approval of its 2025-2026 Power Cost Adjustment (“PCA”) rates to become effective June 1, 2025. If approved, the 2025-2026 PCA will result in a decrease in total billed revenue of approximately $94.8 million, or 5.89 percent.

Q. How is your testimony organized?

A. My testimony consists of four sections. In the first section, I provide an overview of the PCA. In the second section, I detail the 2025-2026 PCA amount in comparison to last year’s PCA amount, identify and discuss the main factors contributing to this change, and present the quantification of the 2025-2026 PCA rates to become effective June 1, 2025. In the third section, I discuss the additional PCA component related to revenue sharing. In the fourth section, I detail the net customer impact of the 2025-2026 PCA rates if approved as filed.

Q. Are you sponsoring any exhibits?

A. Yes. I am offering the following exhibits:

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Exhibit	Description
Exhibit No. 1	2025-2026 PCA Forecast
Exhibit No. 2	2024 Balancing Adjustment
Exhibit No. 3	2024 ROE Determination Revenue Sharing
Exhibit No. 4	Confidential – Clean Energy Your Way Generation and Expenses
Exhibit No. 5	Confidential – Liquidated Damages

I. PCA OVERVIEW

Q. What is the purpose of the PCA?

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual NPSE and the normalized or “base level” of NPSE recovered in the Company’s base rates, resulting in a credit or surcharge that is updated annually on June 1. The PCA mechanism uses a 12-month test period of 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. In addition, beginning with this year’s PCA filing, the Balancing Adjustment tracks the annual variance between actual wheeling revenues and base-level wheeling revenues. This is discussed in more detail later in my testimony.

Q. How does the PCA mechanism function?

A. 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 the exception of Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses and demand response incentive payments. With respect to PURPA expenses and demand response incentive payments, as actual annual expenses deviate from base level NPSE, the Company is allowed to pass 100 percent of the difference for recovery or credit through the PCA. In addition, beginning with this year's PCA filing, Idaho Power is requesting to include recovery of the capital lease payments associated with the Kuna Battery Energy Storage System ("BESS") at 100 percent. I will discuss this in more detail later in my testimony. 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.

Q. Does the revenue collected from customers through the annual PCA rate contribute toward the Company's earnings?

A. No. The PCA mechanism provides for the annual collection or refund of net power supply cost differences between actual costs incurred by the Company and the base level NPSE component of base rates. Aside from the 95 percent to 5 percent sharing component I just described, the PCA provides for a one-for-one collection or refund of actual net power supply expenses incurred, or to be incurred, to provide safe, reliable electric service to customers.

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

A. The PCA base level NPSE includes the following Federal Energy Regulatory Commission ("FERC") accounts: Account 501, Fuel (steam); Account 536, Water for Power; Account 547, Fuel (gas); Account 555, Purchased Power; Account 565, Transmission of Electricity by Others; and Account 447, Sales for Resale (typically referred to as surplus sales).

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

Q. Is Idaho Power proposing to include a new FERC account in the PCA NPSE beginning with this year's filing?

A. Yes. Beginning with this year's PCA filing, Idaho Power is proposing to include FERC Account 577.4, Energy Storage Rents, in the PCA base level NPSE in order to collect expenses associated with the Kuna BESS Energy Storage Agreement ("ESA").

Q. Please provide additional information regarding the Kuna BESS ESA.

A. On April 26, 2023, Idaho Power and Kuna BESS entered into an ESA, whereby a battery storage facility located in Kuna, Idaho, will supply 150 megawatts of capacity on Idaho Power's system for the period of 20 years from a commercial operation date of June 1, 2025. The ESA acts as a type of lease through which Kuna BESS will develop, design, construct, own, and operate the battery storage system and, in accordance with the terms of the agreement, Idaho Power will supply the charging energy for the system and has the exclusive right to dispatch and use the charging and discharging energy in exchange for a monthly payment.

On November 27, 2023, in Order No. 36011, the Commission approved the Company's Application for a Certificate of Public Convenience and Necessity for the Kuna BESS, acknowledged the expenses as prudently incurred for ratemaking purposes, and acknowledged the lease accounting necessary to facility the transaction.[1]

II. 2025-2026 PCA

Q. What is the total PCA collection that would result under the 2025-2026 PCA rates proposed by the Company in this case?

A. The 2025-2026 PCA rates would result in total PCA collection of $21.0 million. This represents a decrease in total billed revenue of $94.8 million for the upcoming year, a decrease of 5.89 percent.

Q. Have you prepared a table that details the $94.8 million revenue impact by component?

A. Yes. Table 1 presents a separation of the $94.8 million decrease into each component included in the Company's proposed rates.

Table 1 — Idaho Jurisdictional Revenue Impact by Component

Line No.	Rate Component	2024-2025 PCA	2025-2026 PCA	Difference
1	PCA Forecast	$ 23,342,867	$ 73,092,256	$ 49,749,389
2	PCA Balancing Adjustment	$ 92,469,480	$ (52,064,539)[2]	$ (144,534,019)
3	PCA Total	$ 115,812,347	$ 21,027,717	$ (94,784,630)
4	Revenue Sharing	$ 0	$ 0	$ 0
5	**Total Revenue Impact**	**$ 115,812,347**	**$ 21,027,717**	**$ (94,784,630)**

[1] *In the Matter of the Application for CPCN to acquire resources to be online in both 2024 and 2025 and for approval of an energy storage agreement with Kuna BESS LLC.,* Case No. IPC-E-23-20, Order No. 36011 (November 27, 2023).

[2] Will not tie to Balancing Adjustment in Exhibit No. 2 due to rounding of Balancing Adjustment rate.

Q. What are the main factors driving the revenue change requested in this case?

A. The decrease in this year’s PCA is driven by a decrease in the Balancing Adjustment, partially offset by an increase in the forecast component. The decrease in this year’s Balancing Adjustment is largely attributed to the completed recovery of the 2023 PCA balancing adjustment, which was recovered over two years per Order No. 35804.[3] Additional factors include the Sales Based Adjustment (“SBA”), which accounts for the variance in actual sales and the sales used to set base level NPSE, an increase in Renewable Energy Credit (“REC”) sales, a credit for liquidated damages associated with the delayed commissioning of certain BESS resources, and a credit related to the variance in actual wheeling revenues as compared to the levels recovered in base rates.

A. <u>PCA Forecast</u>.

Q. How is the PCA forecast amount determined?

A. As described previously, the PCA forecast component represents the difference between the Company’s

[3] *In the Matter of the Application For authority to implement Power Cost Adjustment (“PCA”) rates for electric service from June 1, 2023, through May 31, 2024.,* Case No. IPC-E-23-12, Order No. 35804 (May 31, 2023).

forecast of NPSE for the upcoming April – March test year and base level NPSE recovered in the Company’s base rates.[4]

Q. What is the Company’s determination of the system-level difference between currently approved base level NPSE and the forecast of NPSE for the 2025-2026 PCA Year?

A. The system-level forecast of NPSE for the 2025-2026 PCA Year is $563,563,648, which is $78,656,404 higher than the currently approved base level NPSE of $484,907,244. Table 2 presents the system-level differences between currently approved base level NPSE and the forecast of NPSE for the 2025-2026 PCA Year by FERC account.

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[4] *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Idaho and for Associated Regulatory Accounting Treatment,* Case No. IPC-E-23-11, Order No. 36042 (December 28, 2023).

Table 2	2025 - 2026 PCA FORECAST (Total System)			
Line No.	**FERC Account**	**Base NPSE**	**Forecast**	**Difference**
	95% Sharing Accounts			
1	Account 501, Steam	$ 65,523,000	$ 151,558,050	$ 86,035,050
2	Account 536, Water for Power	$ 0	$ 0	$ 0
3	Account 547, Other Fuel	$ 119,653,675	$ 129,974,528	$ 10,320,852
4	Account 555, Purchased Power Non-PURPA	$ 99,465,021	$ 103,402,787	$ 3,937,767
5	Account 565, 3rd Party Transmission	$ 10,263,139	$ 11,925,403	$ 1,662,264
6	Account 447, Surplus Sales	$ (34,686,350)	$ (88,732,720)	$ (54,046,370)
		$ 260,218,486	$ 308,128,048	$ 47,909,562
	100% Sharing Accounts			
7	Account 555, PURPA	$ 214,448,755	$ 227,069,067	$ 12,620,313
8	Account 555, Demand Response Incentives	$ 10,240,003	$ 10,411,533	$ 171,530
9	Account 577.4, Energy Storage Rents	$ 0	$ 17,955,000	$ 17,955,000
10	Total	$ 484,907,244	$ 563,563,648	$ 78,656,404

Q. What is the basis for the forecast of NPSE for the 2025-2026 PCA Year?

A. The forecast of NPSE for the 2025-2026 PCA Year is based on the Company’s March 2025 Operating Plan.

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

A. The Operating Plan is prepared monthly and represents a forecast of the Company’s monthly NPSE for the following 18-month period; however, for the PCA, the Company includes only the 12 months that correspond to the PCA Year. The Operating Plan is developed by simulating the dispatch of the Company’s generation resources for each month, segmented by heavy load and light load hours. The dispatch considers a current forecast of forward market energy prices, available hydro generation, coal and natural gas prices, and any existing hedge transactions. The system load forecast is then analyzed against the resulting monthly heavy load and light load dispatch to determine a monthly load and resource balance. Any identified resource deficiency is assumed to be filled with market energy purchases or natural gas to fuel either the Langley Gulch power plant ("Langley Gulch") or Jim Bridger Units 1 and 2, based on economics and available generating capacity at each plant. Economically dispatched generation above the system load forecast represents surplus energy sales. The forecast of monthly NPSE and generation for the 2025-2026 PCA Year, as determined in the Company's March 2025 Operating Plan, is provided in Exhibit No. 1.

Q. How does the Company's forecast of system-level NPSE for the 2025-2026 PCA compare to the system-level forecast included in last year's PCA?

A. Table 3 below compares this year's 2025-2026 PCA forecast of NPSE to last year's PCA forecast by FERC account. As detailed in this table, the PCA forecast on a total system basis for the 2025-2026 PCA year is $563,563,648, which is $54,007,658 higher than last year's forecast amount of $509,555,990.

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Table 3	PCA Forecast Comparison Expenses (Total System)			
Line No.	FERC Account	2024-2025 Forecast	2025-2026 Forecast	Difference
	95% Sharing Accounts			
1	Account 501, Steam	$ 154,419,821	$ 151,558,050	$ (2,861,771)
2	Account 536, Water for Power	$ 0	$ 0	$ 0
3	Account 547, Other Fuel	$ 109,958,254	$ 129,974,528	$ 20,016,274
4	Account 555, Purchased Power Non-PURPA	$ 90,809,149	$ 103,402,787	$ 12,593,638
5	Account 565, 3rd Party Transmission	$ 10,419,009	$ 11,925,403	$ 1,506,394
6	Account 447, Surplus Sales	$ (86,055,453)	$ (88,732,720)	$ (2,677,267)
		$ 279,550,780	$ 308,128,048	$ 28,577,268
	100% Sharing Accounts			
7	Account 555, PURPA	$ 219,593,677	$ 227,069,067	$ 7,475,390
8	Account 555, Demand Response Incentives	$ 10,411,533	$ 10,411,533	$ 0
9	Account 577.4, Energy Storage Rents	$ 0	$ 17,955,000	$ 17,955,000
		$ 230,005,210	$ 255,435,600	$ 25,430,390
10	Total PCA Forecast	$ 509,555,990	$ 563,563,648	$ 54,007,658

Q. What general conclusions can be drawn from the information contained in Table 3?

A. When viewed by category, the 95 percent sharing accounts have increased approximately $28.6 million from last year’s forecast, while the 100 percent sharing accounts have increased approximately $25.4 million over last year’s forecast.

Q. How does the Company’s generation forecast for the 2025-2026 PCA compare to the forecast included in last year’s PCA?

A. Table 4 below compares this year’s 2025-2026 PCA generation forecast to last year’s PCA forecast by FERC account. As detailed in this table, the 520,163 megawatt-hour (“MWh”) (3 percent) increase to load from the prior year is forecast to be met with a 147,810 MWh (2 percent) increase to hydro generation, a 6,981 MWh (0.2 percent) increase to steam power generation, a 153,494 MWh (5 percent) increase to natural gas-fired generation, and a 346,999 MWh (22 percent) increase to non-PURPA market purchases, which is largely due to the increase in forecast power purchase agreement (“PPA”) generation as a result of Pleasant Valley Solar, a 200 megawatt alternating current solar photovoltaic facility, coming online in March 2025. These increases in generation are partially offset by a 140,881 MWh (11 percent) increase to surplus sales.

Table 4	**PCA Forecast Comparison Generation (Total System-MWh)**			
Line No.	**FERC Account**	**2024-2025 Forecast**	**2025-2026 Forecast**	**Difference**
1	Hydro	7,293,179	7,440,989	147,810
	<u>95% Sharing Accounts</u>			
2	Account 501, Steam	3,787,742	3,794,723	6,981
3	Account 547, Other Fuel	2,913,524	3,067,019	153,494
4	Account 555, Purchased Power Non-PURPA	1,577,970	1,924,968	346,999
		15,572,415	16,227,698	655,283
	<u>100% Sharing Accounts</u>			
5	Account 555, PURPA	2,921,156	2,926,917	5,761
		2,921,156	2,926,917	5,761
6	Total Generation	18,493,571	19,154,615	661,044
	<u>95% Sharing Accounts</u>			
7	Less Account 447, Surplus Sales	1,306,125	1,447,006	140,881
8	Total Load	17,187,446	17,707,609	520,163

Q. Please provide additional information about Pleasant Valley Solar.

A. Pleasant Valley Solar is a PPA that was negotiated in conjunction with a new special contract with Brisbie, LLC (“Brisbie”), as a part of the Company’s Clean Energy Your Way (“CEYW”) program. Meta Platforms, Inc. is the parent company of Brisbie. Brisbie’s special contract states that Idaho Power will procure renewable resources to support 100 percent of Brisbie’s operations with renewable energy on an annual basis. While Pleasant Valley Solar is connected to the grid and therefore doesn’t serve Brisbie directly, Brisbie will pay for the full cost of the PPA, as well as Idaho Power retail electric service required to serve their load. In addition, Brisbie will receive a capacity credit for the value that Pleasant Valley Solar provides to Idaho Power’s system and will be credited for any PPA generation that exceeds their load in a given hour. Per the terms of the contract, the value of the excess generation is defined as the lower of 1) 85 percent of the non-firm Mid-Columbia hourly price forecast, or 2) the actual heavy or light load price in the hour of excess generation.

Q. How are the Company’s CEYW resources, like Pleasant Valley Solar, accounted for in the PCA forecast?

A. Resources procured through the CEYW – Construction Option are paid for by the participating customer. Accordingly, the cost of the PPA is not included in the forecast of NPSE for the PCA year. However, the participating customer will be credited for the value of the resource’s capacity contribution to the system and for any PPA generation that exceeds their load in a given hour. Both the forecast capacity credit and excess generation credit amounts are included as expenses in the PCA forecast.

Q. How are the Company’s marginal-cost priced customers accounted for in the PCA forecast?

A. All forecast marginal-cost priced energy sales are included in the PCA forecast as an offset to NPSE, included in Account 447, Surplus Sales.

Q. Were any changes made to the Idaho jurisdictional sales and system-level sales to account for modifications related to CEYW or marginal cost-priced customers?

A. Yes. All load forecast to be met with CEYW resources or priced at a marginal cost-based rate are excluded from total forecast sales and are not used in the derivation of the PCA rate.

Q. What is the Company’s forecast of system-level firm sales and Idaho jurisdictional firm sales for the 2025-2026 PCA Year?

A. For the 2025-2026 PCA Year, Idaho Power has forecast system-level firm sales to be 16,226,039 MWh and Idaho jurisdictional firm sales to be 15,551,544 MWh, or 95.84 percent of the system level.

Q. What is the Company’s determination of the 2025-2026 PCA forecast component to be collected from Idaho customers?

A. As shown in Table 1, the 2025-2026 PCA forecast component to be collected from Idaho customers is $73,092,256.

B. Balancing Adjustment.

Q. What is this year’s quantification of the Balancing Adjustment?

A. The Balancing Adjustment is detailed in the PCA deferral report, attached hereto as Exhibit No. 2. This report compares actual NPSE amounts to actual power cost collections monthly, with the differences accumulated as a deferral balance. The balance at the end of March 2025, with interest applied, is negative $52,045,994 as shown on row 104 of Exhibit No. 2. The approximate negative $52 million represents a decrease to customer rates in this year’s PCA Balancing Adjustment.

Q. To what factors do you attribute the accumulation of the approximate negative $52 million deferral balance?

A. Actual power supply expenses in the 2024-2025 PCA Year were just 2 percent lower than forecast expenses, with load coming in 0.4 percent higher than forecast. As a result, the variance between forecast and actual power supply expenses for the 2024-2025 PCA Year had a relatively small impact on this year's deferral balance. See Table 5 below for the variance in actual versus forecast NPSE for the 2024-2025 PCA Year.

However, this year's deferral balance does include increased benefits associated with the SBA, REC sales, and wheeling revenues. In addition, it includes liquidated damages associated with the delayed commissioning of certain BESS resources, for which the amount is included in Confidential Exhibit 5.[5]

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[5] Liquidated damages are included in the balancing adjustment in Non-Firm Purchases. See Exhibit No. 2, Line 9.

Table 5	2024-2025 Forecast to Actual Expenses			
Line No.	**FERC Account**	**2024-2025 Forecast**	**2024-2025 Actuals**	**Difference**
	<u>95% Sharing Accounts</u>			
1	Account 501, Steam	$ 154,419,821	$ 94,896,524	$ (59,523,297)
2	Account 536, Water for Power	$ 0	$ 0	$ 0
3	Account 547, Other Fuel	$ 109,958,254	$ 136,341,920	$ 26,383,666
4	Account 555, Purchased Power Non-PURPA	$ 90,809,149	$ 141,511,695	$ 50,702,545
5	Account 565, 3rd Party Transmission	$ 10,419,009	$ 13,357,650	$ 2,938,640
6	Account 447, Surplus Sales	$ (86,055,453)	$ (113,124,433)	$ (27,068,980)
		$ 279,550,780	$ 272,983,355	$ (6,567,425)
	<u>100% Sharing Accounts</u>			
7	Account 555, PURPA	$ 219,593,677	$ 219,689,249	$ 95,572
8	Account 555, Demand Response Incentives	$ 10,411,533	$ 8,953,587	$ (1,457,946)
		$ 230,005,210	$ 228,642,836	$ (1,362,374)
9	Total	$ 509,555,990	$ 501,626,191	$ (7,929,799)

Q. Please explain the changes in actual versus forecast generation and expense for the 2024-2025 PCA Year.

A. Table 6 below details the changes in actual versus forecast generation for the 2024-2025 PCA Year.

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Table 6	2024 - 2025 Forecast to Actual Generation			
Line No.	**FERC Account**	**2024-2025 Forecast**	**2024-2025 Actuals**	**Difference**
1	Hydro	7,293,179	7,577,592	284,413
	<u>95% Sharing Accounts</u>			
2	Account 501, Steam	3,787,742	2,633,381	(1,154,361)
3	Account 547, Other Fuel	2,913,524	3,567,777	654,253
4	Account 555, Purchased Power Non-PURPA	1,577,970	3,250,943	1,672,973
	95% Sharing Accounts	15,572,415	17,029,693	1,457,278
	<u>100% Sharing Accounts</u>			
5	Account 555, PURPA	2,921,156	2,937,191	16,035
	100% Accounts	2,921,156	2,937,191	16,035
6	Total Generation	18,493,571	19,966,883	1,473,312
	<u>95% Sharing Accounts</u>			
7	Account 447, Surplus Sales	1,306,125	2,706,363	1,400,238
8	Total Load	17,187,446	17,260,520	73,074

Actual steam power generation for the 2024-2025 PCA year totaled 2,633,381 MWh, which is 30 percent lower than forecast. Actual steam fuel expense totaled $94,896,524, which is 39 percent lower than forecast. The actual per-unit cost of steam power generation was $36.04, a 12 percent decrease from forecast.

Actual natural gas-fired generation for the 2024-2025 PCA year totaled 3,567,777 MWh, which is 22 percent higher than forecast. Actual natural gas fuel expense totaled $136,341,920, which is 24 percent higher than forecast. The actual per-unit cost of natural gas generation was $38.21, a 1 percent increase from forecast.

Actual non-PURPA purchased power totaled 3,250,943 MWh for the 2024-2025 PCA Year. This included 2,042,803 MWh in market purchases and 1,208,140 MWh in PPA generation. PPA generation was 1 percent higher than forecast, whereas market purchase volumes were 440 percent higher than forecast. Actual non-PURPA purchased power expense was $141,511,695, which is 56 percent higher than forecast. This includes $80,569,880 in market purchase expense (243 percent higher than forecast) and $60,033,683 in PPA expenses (10 percent lower than forecast).

Surplus sales totaled 2,706,363 MWh for the 2024-2025 PCA Year, which is 107 percent higher than forecast. Actual surplus sales revenue was $113,124,433, which is 31 percent higher than forecast.

Q. Can you elaborate on the differences between forecast and actual purchases and sales?

A. Yes. Purchase volumes included in the PCA forecast consist of the known power purchases executed in accordance with the Energy Risk Managements Standards (“ERMS”) prior to the development of the March Operating Plan. Sales volumes included in the forecast are, generally speaking, based on the economics of the Company’s resources compared to Mid-Columbia forward market prices in the March Operating Plan, and also include any known sale transactions executed in accordance with the ERMS.

On the other hand, *actual* power purchase and sales include additional activity, such as transactions made in the Energy Imbalance Market ("EIM") as well as bundled REC sales that may result in actual purchases and sales being different than the forecast.[6]

Q. Please explain how Idaho Power implemented the tracking of wheeling revenues into this year's Balancing Adjustment.

A. In accordance with Order No. 36502, the wheeling revenue deferral was calculated by taking the difference between actual Idaho-jurisdictional wheeling revenues and base-level sales-adjusted wheeling revenues, multiplied by the sharing percentage of 95 percent.[7] See Exhibit No. 2, Line 79.

Q. How much is this year's wheeling revenue deferral, as shown on line 79 of Exhibit No. 2?

A. The wheeling revenue deferral for the 2024-2025 PCA year is a credit to customers of approximately $3.9 million.

[6] Bundled REC sales refer to the sale of RECs together with the electricity generated from renewable sources. This means that the environmental attributes of the renewable energy are sold along with the energy (either generated from Idaho Power's resources or purchased on the market).

[7] *In the Matter of Idaho Power Company's Filing in Compliance with Order No. 36402 for Authority to Track Annual Wheeling Revenues in the Power Cost Adjustment,* Case No. IPC-E-24-38, Order No. 36502 (March 11, 2025).

Q. Did Idaho Power include its actual costs of EIM participation in this year’s Balancing Adjustment?

A. No. Because EIM costs were included in base rates resulting from the Company’s 2023 General Rate Case, which went into effect on January 1, 2024, EIM costs are no longer included in the PCA as of that date. Benefits associated with EIM participation are embedded in actual NPSE.

Q. Were there any other items included in this year’s Balancing Adjustment in addition to what was already discussed?

A. Yes. This year’s Balancing Adjustment includes two additional items: 1) a one-time adjustment to recover the conversion of accumulated kWh credits into a financial credit for large general and irrigation customers and 2) a one-time adjustment to credit the difference between February and January base rates, as a result of the Errata issued on January 21, 2025 in the Company’s 2024 filing to recover incremental capital investments and certain ongoing operations and maintenance expenses.[8] In total, these two items result in an additional credit to customers of $13,372.

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[8] kWh conversion per Order No. 36048 issued in Case No. IPC-E-23-14. Errata to Order No. 36438 issued in Case No. IPC-E-24-07.

Q. How were these amounts incorporated into this year’s Balancing Adjustment?

A. A cents per kwh rate for these two adjustments was calculated for each individual rate class and added to the overall Balancing Adjustment Rate, as detailed later in my testimony.

C. <u>PCA Rate Determination.</u>

Q. How is the rate for the forecast portion of the PCA for April 2025 through March 2026 determined?

A. The rate for the forecast portion of the PCA is equal to the sum of (1) 95 percent of the difference between the non-PURPA expenses quantified in the Operating Plan and those quantified in the Company’s last approved update of NPSE, divided by the Company’s forecast of system firm sales for June 1, 2025, through May 31, 2026 (“System-level Sales Forecast”); (2) 100 percent of the difference between PURPA-related expenses quantified in the Operating Plan and those quantified in the Company’s last approved update of NPSE, divided by the Company’s System-level Sales Forecast; (3) 100 percent of the difference between the Idaho jurisdictional demand response incentive payments quantified in the Operating Plan and those quantified in the Company’s last approved update of NPSE, divided by the forecast of Idaho-jurisdictional firm sales for June 1, 2025, through May 31, 2026 (“Idaho-jurisdictional Sales

Forecast”); and(4) 100 percent of the difference between the Energy Storage Rent expenses quantified in the Operating Plan and those quantified in the Company’s last approved update of NPSE, divided by the System-level Sales Forecast.

Q. What is the rate for the forecast portion of the PCA for April 2025 through March 2026?

A. The rate for non-PURPA expenses is 0.2805 cents per kilowatt-hour (“kWh”), which is calculated by multiplying $47,909,562 from Table 2 by 95 percent and then dividing it by the System-level Sales Forecast of 16,226,039 MWh (($47,909,562 * 0.95) / 16,226,039) = $2.805 /MWh = 0.2805 cents/kWh). The rate for PURPA expenses is 0.0778 cents per kWh, which is calculated by dividing $12,620,313 from Table 2 by the 16,226,039 MWh ($12,260,313 / 16,226,039 MWh = $0.778/MWh = 0.0778 cents/kWh). The rate for demand response incentive payments is 0.0011 cents per kWh, which is calculated by dividing the $171,530 from Table 2 by the forecast of Idaho jurisdictional firm sales of 15,551,544 MWh ($171,530 / 15,551,544 MWh = $0.0110/MWh = 0.0011 cents/kWh). The rate for Energy Storage Rents is 0.1107 cents per kWh, which is calculated by dividing $17,955,000 from Table 2 by the 16,226,039 MWh ($17,955,000 / 16,226,039 MWh = $1.107 /MWh = 0.1107 cents/kWh). The forecast portion of the PCA rate is 0.4700 cents per kWh, which is calculated by adding the non-PURPA expense of 0.2805 cents per kWh to the PURPA expense of 0.0778 cents per kWh to the demand response incentive payment of 0.0011 cents per kWh to the Energy Storage Rents expense of 0.1107 cents per kwh (0.2805 + 0.0778 + 0.0011 + 0.1107 = 0.4700 cents/kWh).

Q. How did you compute this year’s Balancing Adjustment rate?

A. As shown in Exhibit No. 2, this year’s Balancing Adjustment of the PCA is approximately negative $52 million, which, when divided by the Company’s forecast of Idaho jurisdictional sales of 15,551,544 MWh, results in a rate of negative 0.3347 cents per kWh (-$52,045,994 / 15,551,544 = -$3.347/MWh = -0.3347 cents/kWh).

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

A. The uniform PCA rate comprises (1) the 0.4700 cents per kWh for the 2025-2026 projected power cost of serving firm loads under the current PCA methodology and 95 percent sharing, and (2) the negative 0.3347 cents per kWh for the 2024-2025 Balancing Adjustment of the PCA. The sum of these two components is a 0.1354 cents per kWh charge.

Q. How were the one-time adjustments you discussed earlier in your testimony incorporated into this year’s Balancing Adjustment Rate?

A. The cents per kwh rates associated with the two one-time adjustments were added to the Balancing Adjustment Rate of negative 0.3347 cents per kwh to determine class-specific Balancing Adjustment Rates. For example, the total credit associated with the 2024 General Rate Case Errata for Schedule 09S is $3,818. The total expenses associated with kWh conversion for Schedule 09S is $8,625. Based on the Idaho-jurisdictional Sales Forecast for Schedule 09S of 3,409,784 MWh, the rate associated with the adjustments is 0.0001 cents per kwh ((-$3,818 + $8,625)/ 3,409,784 = $0.001/MWh = 0.0001 cents/kWh). When added to the initial Balancing Adjustment Rate of negative 0.3347 cents per kwh, the final Schedule 09S Balancing Adjustment Rate is negative 0.3346 cents per kwh.

III. ADDITIONAL PCA RATE ADJUSTMENTS

A. Revenue Sharing.

Q. When was the revenue sharing mechanism originally established?

A. The revenue sharing mechanism was originally established in Case No. IPC-E-09-30 and approved in Order No. 30978, effective for the years 2009-2011. Since then, the revenue sharing mechanism has been modified and extended four times.[9] Order No. 34071 in Case No. GNR-U-18-

[9] Order Nos. 32424, 33149, 34071, and 36042.

01 extended the revenue sharing mechanism indefinitely, with modifications.

The mechanism was most recently modified in the Company's 2023 General Rate Case, effective January 1, 2024 (Order No. 36402).

Q. What is the purpose of the Revenue Sharing Mechanism?

A. The Revenue Sharing Mechanism includes provisions for the accelerated amortization of Accumulated Deferred Investment Tax Credits ("ADITC") to help achieve a minimum specified percent Idaho-jurisdictional return on year-end equity ("Idaho ROE") and also provides for the potential sharing between Idaho Power and its Idaho customers of Idaho jurisdictional earnings in excess of a maximum specified Idaho ROE.

Q. Can you explain the modifications related to the Revenue Sharing Mechanism from the 2023 General Rate Case?

A. The Revenue Sharing Mechanism was modified to include an additional amount of Investment Tax Credits ("ITC") equal to the incremental ITC generated from the Company's investment in 2023 battery storage projects, including augmentation costs. In addition, the ADITC cap previously set at $25 million was removed.

Effective January 1, 2024, potential revenue sharing between Idaho Power and customers will occur if earnings are in excess of a 9.6 percent Idaho ROE. In addition, all revenue sharing will be implemented through the PCA, rather than a portion offsetting customer-funded pension obligations. Lastly, the minimum-specified Idaho ROE is 9.12 percent.[10]

Q. What have been the results of the revenue sharing mechanism since it was implemented through 2023?

A. The Company's earnings in each year from 2011 through 2015, as well as 2018 and 2021, resulted in revenue sharing with customers totaling $126.7 million, either as a direct rate offset in the PCA or as an offset to amounts that would have otherwise been collected in rates. The Company's earnings in 2016, 2017, 2019, 2020, 2022, and 2023 were below the revenue sharing threshold. These amounts are detailed in Table 7 below.

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[10] *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Idaho and for Associated Regulatory Accounting Treatment,* Case No. IPC-E-23-11, Order No. 36042 (December 28, 2023).

Table 7	2009-2024 Revenue Sharing and ADITC ($ Millions)						
Line No.	**Revenue Sharing/ADITC Component**	**2009-2011**	**2012-2014**	**2015-2019**	**2020 - 2023**	**2024**	
1	Available ADITC For Use	$45 Million	$45 Million	$45 Million	$45 Million	$107.03	
2	ADITC Used:	$0.00	$0.00	$0.00	$0.00	$29.83	**Total ADITC $29.83**
3	**Customer Benefits**						
4	Reduction to Rates:	$27.10	$22.80	$8.20	$0.60	$0.00	
5	Offset to Pension Balancing Account:	$20.30	$47.80	$0.00	$0.00	$0.00	**Total Sharing**
6	**Total Sharing**	$47.40	$70.60	$8.20	$0.60	$0.00	**$126.70**

Q. Did the Company's year-end 2024 financial results warrant any action related to the Revenue Sharing Mechanism per the terms of the 2023 Stipulation?

A. Yes. The Company's year-end 2024 financial results yielded an actual Idaho ROE of 8.19 percent, falling below the minimum specified Idaho ROE of 9.12 percent. As a result, $29,831,234 of ADITC was used to achieve the minimum specified ROE of 9.12 percent.

Q. Did the Company use the same methodology to determine the Idaho jurisdictional 2024 year-end ROE that was used in prior PCA filings?

A. Yes. The methodology used to determine the Company's Idaho jurisdictional 2024 year-end ROE is consistent with the methodology used for the year-end ROE determinations since the inception of the mechanism.

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

A. Yes. Exhibit No. 3 provides a step-by-step calculation of the Idaho jurisdictional ROE based on year-end 2024 financial results utilizing the Commission-approved methodology from previous PCA filings.

IV. NET CUSTOMER IMPACT

Q. What is the revenue impact of the requested PCA rate when compared with PCA rates currently in effect?

A. Attachment 2 to the Application filed contemporaneously with my testimony provides a detailed description of the overall revenue impact of this filing on each customer class. As shown in Attachment 2, applying the requested PCA rates to expected customer sales for the June 2025 through May 2026 test year results in a PCA decrease of $94.8 million, or 5.89 percent.

Q. What is the combined revenue impact of each of the Company’s filings to be effective June 1, 2025?

A. If the proposed PCA, Fixed Cost Adjustment (“FCA”), and Hells Canyon Complex Relicensing filings are approved as filed, the combined impact is an overall decrease in current billed revenue of $105.8 million, or 6.57 percent.

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

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

Q. Please summarize the Company’s request in this filing.

A. If approved, the 2025-2026 PCA will result in a decrease in total billed revenue of approximately $94.8 million, or 5.89 percent. The Commission should approve the Company’s computation of the PCA rates, the calculation of which follows the methodology that was approved in Order Nos. 30715.

Q. Does this conclude your testimony?

A. Yes, it does.

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DECLARATION OF JESSICA G. BRADY

I, Jessica G. Brady, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Jessica G. Brady. I am employed by Idaho Power Company as a Regulatory Analyst in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 1-5 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 15th day of April 2025, at Boise, Idaho.

Signed: Jessica Brady
Jessica G. Brady

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-20

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 1

IDAHO POWER PCA FORECAST
APRIL 1, 2025 - MARCH 31, 2026

Line No.	FERC Account	April	May	June	July	August	September	October	November	December	January	February	March	Annual
	95% Sharing Accounts													
1	**Hydroelectric Generation (MWh)**	962,069	1,111,750	909,370	620,080	503,020	488,126	418,443	364,935	445,869	556,009	465,999	595,318	7,440,989
	Account 536, Water for Power													
2	Total Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Account 501, Steam													
	Jim Bridger 3 & 4 (Coal)													
3	Energy (MWh)	136,981	23,808	84,846	243,149	243,149	235,306	243,149	235,633	243,149	243,149	219,619	243,149	2,395,088
4	Total Expense	$ 4,666,796	$ 769,031	$ 2,910,432	$ 8,459,144	$ 8,476,778	$ 8,210,107	$ 8,490,005	$ 8,228,678	$ 8,495,883	$ 8,340,108	$ 7,438,728	$ 8,141,714	$ 82,627,408
	North Valmy 2 (Coal)													
5	Energy (MWh)	-	-	18,000	48,240	43,560	50,000	48,360	59,122	-	-	-	-	267,282
6	Total Expense	$ 379,114	$ 379,114	$ 1,352,378	$ 2,993,949	$ 2,752,579	$ 3,065,322	$ 2,993,949	$ 3,571,785	$ 379,114	$ -	$ -	$ -	$ 17,867,306
	Jim Bridger 1 & 2 (Gas)													
7	Energy (MWh)	-	-	-	150,247	208,200	99,180	128,469	183,101	132,692	199,743	9,792	20,928	1,132,353
8	Total Expense	$ 113,036	$ 113,036	$ 113,036	$ 5,660,642	$ 11,324,804	$ 5,790,534	$ 205,695	$ 286,217	$ 10,375,563	$ 15,193,184	$ 802,517	$ 953,296	$ 50,931,559
	North Valmy 1 (Gas)													
9	Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (33,476)	$ (33,476)	$ 198,729	$ 131,777
	Account 547, Other Fuel													
	Langley Gulch													
11	Energy (MWh)	76,759	133,245	207,200	210,704	211,120	180,475	125,155	215,681	226,896	226,896	194,863	-	2,008,994
12	Total Expense	$ 3,116,235	$ 3,023,409	$ 4,895,065	$ 5,428,295	$ 5,393,985	$ 4,867,797	$ 2,855,593	$ 8,501,417	$ 11,783,226	$ 11,463,303	$ 8,080,557	$ 357,939	$ 69,766,821
	Danskin													
13	Energy (MWh)	-	-	-	121,096	121,096	54,720	-	73,894	137,288	137,288	71,232	-	716,614
14	Total Expense	$ 351,227	$ 351,227	$ 351,227	$ 5,056,186	$ 5,012,206	$ 2,402,680	$ 268,333	$ 4,580,430	$ 10,731,199	$ 10,437,756	$ 4,536,860	$ 362,437	$ 44,441,770
	Bennett Mountain													
15	Energy (MWh)	-	-	-	105,592	77,696	7,040	67,176	-	29,952	-	-	53,955	341,411
16	Total Expense	$ 172,992.60	$ 172,992.60	$ 172,992.60	$ 4,250,265.56	$ 3,145,834.84	$ 437,344.60	$ 2,256,530.49	$ 132,164.01	$ 2,437,806.57	$ 132,164.01	$ 132,164.01	$ 2,322,685.49	$ 15,765,937
	Account 555, Purchased Power Non-PURPA													
17	Energy (MWh)	151,013	204,794	206,226	211,234	189,124	128,954	105,910	117,658	132,154	103,768	166,359	207,776	1,924,968
18	Total Expense	$ 5,453,339	$ 6,886,585	$ 9,942,682	$ 12,574,112	$ 10,450,620	$ 5,717,860	$ 6,184,728	$ 9,269,018	$ 11,269,795	$ 7,105,009	$ 9,834,271	$ 8,714,766	$ 103,402,787
	Account 565, 3rd Party Transmission													
19	Total Expense	$ 674,709	$ 757,421	$ 1,368,386	$ 1,532,092	$ 1,368,713	$ 946,932	$ 1,389,807	$ 904,951	$ 783,381	$ 889,854	$ 595,030	$ 714,127	$ 11,925,403
	Account 447, Surplus Sales													
20	Energy (MWh)	(386,475)	(403,611)	(111,647)	(5)	(65,390)	(68,116)	(105,457)	(91,347)	(32,805)	(145,673)	(5,253)	(31,227)	(1,447,006)
21	Total Expense	$ (17,474,445)	$ (11,986,551)	$ (4,281,746)	$ (1,079,525)	$ (8,617,634)	$ (6,409,488)	$ (6,774,219)	$ (6,871,989)	$ (5,073,627)	$ (14,682,149)	$ (2,045,498)	$ (3,435,848)	$ (88,732,720)
	100% Sharing Accounts													
	Account 555, PURPA													
22	Energy (MWh)	294,023	315,287	298,997	281,166	272,853	228,596	215,290	172,832	184,782	194,865	226,513	241,713	2,926,917
23	Total Expense	$ 16,905,658	$ 18,278,073	$ 22,695,665	$ 25,393,912	$ 25,311,877	$ 17,979,445	$ 16,811,282	$ 16,273,377	$ 17,804,998	$ 16,119,863	$ 18,808,009	$ 14,686,908	$ 227,069,067
	Account 555, Demand Response Incentives													
24	Total Expense	$ -	$ -	$ 270,468	$ 3,047,657	$ 4,657,950	$ 1,277,208	$ 184,487	$ 973,763	$ -	$ -	$ -	$ -	$ 10,411,533
	Account 577.4, Energy Storage Rents													
25	Total Expense	$ -	$ -	$ 1,795,500	$ 1,795,500	$ 1,795,500	$ 1,795,500	$ 1,795,500	$ 1,795,500	$ 1,795,500	$ 1,795,500	$ 1,795,500	$ 1,795,500	$ 17,955,000
	95% Sharing Accounts	$ (2,546,996)	$ 466,265	$ 16,824,454	$ 44,875,161	$ 39,307,887	$ 25,029,088	$ 17,870,422	$ 28,602,673	$ 51,182,340	$ 38,845,755	$ 29,341,153	$ 18,329,846	$ 308,128,048
	100% Sharing Accounts	$ 16,905,658	$ 18,278,073	$ 24,761,633	$ 30,237,069	$ 31,765,327	$ 21,052,153	$ 18,791,269	$ 19,042,640	$ 19,600,498	$ 17,915,363	$ 20,603,509	$ 16,482,408	$ 255,435,600
26	**Total Net Power Supply Expense**	$ 14,358,662	$ 18,744,338	$ 41,586,088	$ 75,112,230	$ 71,073,214	$ 46,081,241	$ 36,661,691	$ 47,645,313	$ 70,782,838	$ 56,761,118	$ 49,944,662	$ 34,812,254	$ 563,563,649
27	Total Generation (MWh)	1,620,845	1,788,885	1,724,639	1,991,508	1,869,818	1,472,397	1,351,951	1,422,856	1,532,782	1,661,718	1,354,377	1,362,839	19,154,615
28	Total Load (MWh)	1,234,371	1,385,273	1,612,992	1,991,504	1,804,428	1,404,280	1,246,494	1,331,510	1,499,977	1,516,045	1,349,123	1,331,612	17,707,609

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-20

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 2

Power Cost Adjustment
April 2024 thru March 2025

		April	May	June	July	August	September	October	November	December	January	February	March	Totals
Idaho Jurisdiction Net Power Supply Expense (Non-QF)														
Actual Non-QF														
Fuel Expense-Coal	$	1,179,263.10	2,020,383.43	2,660,584.17	8,276,217.38	8,214,487.25	5,427,737.37	4,591,973.37	5,886,796.66	7,166,727.02	8,863,012.76	7,479,870.26	6,785,498.76	68,552,551.53
Fuel Expense-Gas	$	3,105,500.83	2,045,522.45	7,402,724.83	20,890,491.28	19,449,759.20	11,102,585.98	9,113,568.82	16,694,639.91	26,676,433.00	26,814,879.16	15,052,547.31	4,246,714.20	162,595,366.97
Non-Firm Purchases	$	6,656,403.76	6,010,904.13	14,375,782.67	17,532,267.74	11,224,012.78	7,279,802.76	15,352,454.19	15,298,338.72	15,781,881.54	14,256,189.94	14,167,759.71	(3,307,706.78)	134,628,091.16
Third Party Transmission	$	716,985.04	664,439.29	2,204,857.03	1,503,513.56	1,307,907.49	1,053,138.16	1,538,346.15	1,183,539.33	623,185.17	965,091.75	854,311.26	742,335.38	13,357,649.61
Surplus Sales & Transmission Losses	$	(15,013,723.41)	(11,093,728.13)	(4,977,163.03)	(3,642,120.11)	(3,859,600.11)	(3,098,189.78)	(8,674,380.21)	(8,765,004.92)	(8,492,038.53)	(13,033,218.13)	(16,750,820.05)	(15,724,694.50)	(113,124,680.91)
Water for Power (Leases)	$	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Actual NPSE	$	(3,355,570.68)	(352,478.83)	21,666,785.67	44,560,369.85	36,336,566.61	21,765,074.49	21,921,962.32	30,298,309.70	41,756,188.20	37,865,955.48	20,803,668.49	(7,257,852.94)	266,008,978.36
Idaho Allocation		95.6%	95.7%	95.9%	96.0%	96.0%	96.0%	95.7%	95.3%	95.6%	95.5%	95.5%	96.1%	
Net Idaho Jurisctional Actual Non-QF	$	(3,207,925.57)	(337,322.24)	20,778,447.46	42,777,955.06	34,883,103.95	20,894,471.51	20,979,317.94	28,874,289.14	39,918,915.92	36,161,987.48	19,867,503.41	(6,974,796.68)	254,615,947.38
Base Non-QF														
Fuel Expense-Coal	$	4,321,401.00	4,578,880.00	5,597,322.00	7,146,746.00	7,643,877.00	6,655,023.00	4,655,438.00	4,397,909.00	5,020,646.00	5,483,866.00	5,225,193.00	4,796,697.00	65,522,998.00
Fuel Expense-Gas	$	7,891,450.00	8,361,642.00	10,221,452.00	13,050,904.00	13,958,732.00	12,152,953.00	8,501,447.00	8,031,165.00	9,168,364.00	10,014,266.00	9,541,895.00	8,759,405.00	119,653,675.00
Non-Firm Purchases	$	6,559,959.00	6,950,818.00	8,496,830.00	10,848,881.00	11,603,535.00	10,102,437.00	7,067,034.00	6,676,100.00	7,621,425.00	8,324,601.00	7,931,932.00	7,281,468.00	99,465,020.00
Third Party Transmission	$	676,879.00	717,209.00	876,732.00	1,119,424.00	1,197,292.00	1,042,404.00	729,201.00	688,863.00	786,405.00	858,961.00	818,444.00	751,327.00	10,263,141.00
Surplus Sales	$	(2,287,649.00)	(2,423,953.00)	(2,963,092.00)	(3,783,321.00)	(4,046,491.00)	(3,523,014.00)	(2,464,481.00)	(2,328,151.00)	(2,657,813.00)	(2,903,031.00)	(2,766,096.00)	(2,539,260.00)	(34,686,352.00)
Water for Power (Leases)	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Idaho Base NPSE	$	17,162,040.00	18,184,596.00	22,229,244.00	28,382,634.00	30,356,945.00	26,429,803.00	18,488,639.00	17,465,886.00	19,939,027.00	21,778,663.00	20,751,368.00	19,049,637.00	260,218,482.00
Idaho Allocation		95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	
Net Idaho Jurisdiction 95% Items	$	16,401,761.63	17,379,018.40	21,244,488.49	27,125,283.31	29,012,132.34	25,258,962.73	17,669,592.29	16,692,147.25	19,055,728.10	20,813,868.23	19,832,082.40	18,205,738.08	248,690,803.25
Idaho Jurisdiction Change From Base	$	(19,609,687.20)	(17,716,340.64)	(466,041.03)	15,652,671.75	5,870,971.61	(4,364,491.22)	3,309,725.65	12,182,141.89	20,863,187.82	15,348,119.25	35,421.01	(25,180,534.76)	5,925,144.13
Sharing Percentage		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Net Power Supply Expense Deferral (1)	$	(18,629,202.84)	(16,830,523.61)	(442,738.98)	14,870,038.16	5,577,423.03	(4,146,266.66)	3,144,239.37	11,573,034.80	19,820,028.43	14,580,713.29	33,649.96	(23,921,508.02)	5,628,886.93
Idaho Jurisdictional Qualifying Facility NPSE														
Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)	$	18,465,796.01	21,121,427.39	23,883,265.91	25,495,769.78	23,624,763.79	16,900,807.35	15,467,343.46	20,278,316.74	16,413,427.77	14,034,010.11	16,509,338.73	13,940,441.73	226,134,708.77
Idaho Allocation		95.6%	95.7%	95.9%	96.0%	96.0%	96.0%	95.7%	95.3%	95.6%	95.5%	95.5%	96.1%	
Idaho Jurisctional Actual QF	$	17,653,300.99	20,213,206.01	22,904,052.01	24,475,938.99	22,679,773.24	16,224,775.06	14,802,247.69	19,325,235.85	15,691,236.95	13,402,479.66	15,766,418.49	13,396,764.50	216,535,429.44
Base QF	$	14,143,416.00	14,986,115.00	18,319,351.00	23,390,424.00	25,017,474.00	21,781,075.00	15,236,680.00	14,393,818.00	16,431,959.00	17,948,022.00	17,101,418.00	15,699,003.00	214,448,755.00
Idaho Allocation		95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	95.57%	
Idaho Jurisdictional Base	$	13,516,862.67	14,322,230.11	17,507,803.75	22,354,228.22	23,909,199.90	20,816,173.38	14,561,695.08	13,756,171.86	15,704,023.22	17,152,924.63	16,343,825.18	15,003,537.17	204,948,675.17
Idaho Jurisdiction Change From Base	$	4,136,438.32	5,890,975.90	5,396,248.26	2,121,710.77	(1,229,426.66)	(4,591,398.32)	240,552.61	5,569,063.99	(12,786.27)	(3,750,444.97)	(577,406.69)	(1,606,772.67)	11,586,754.27
Sharing Percentage		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
QF Deferral (2)	$	4,136,438.32	5,890,975.90	5,396,248.26	2,121,710.77	(1,229,426.66)	(4,591,398.32)	240,552.61	5,569,063.99	(12,786.27)	(3,750,444.97)	(577,406.69)	(1,606,772.67)	11,586,754.27
Idaho Revenue Adjustment (SBAR)														
Actual Idaho Jurisdictional Billing Month Sales	MWh	1,028,112	1,089,783	1,309,703	1,675,693	1,744,131	1,452,517	1,142,179	1,049,305	1,179,618	1,235,496	1,275,661	1,162,831	15,345,030
Normalized Idaho Jurisdictional Billing Month Sales	MWh	1,017,495	1,092,040	1,256,135	1,544,353	1,630,099	1,445,881	1,124,956	1,049,883	1,166,688	1,263,248	1,210,192	1,106,864	14,907,834
Sales Change	MWh	10,617	(2,257)	53,568	131,340	114,032	6,636	17,223	(578)	12,930	(27,752)	65,469	55,967	437,196
% of Prior Period Billings at Old Rate-effective thru 12/2023	$ 26.72	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
% of Current Period Billings at New Rate-effective 01/2024	$ 30.90	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
Sales Adjustment Prior To Sharing @	$	(328,071.69)	69,733.11	(1,655,240.60)	(4,058,421.30)	(3,523,579.41)	(205,062.97)	(532,199.98)	17,874.39	(399,542.80)	857,547.30	(2,023,002.64)	(1,729,379.40)	(13,509,345.99)
Sharing Percentage		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Idaho Revenue Adjustment (SBAR) (3)	$	(311,668.11)	66,246.45	(1,572,478.57)	(3,855,500.24)	(3,347,400.44)	(194,809.82)	(505,589.98)	16,980.67	(379,565.66)	814,669.94	(1,921,852.51)	(1,642,910.43)	(12,833,878.70)
Idaho Jurisdcitional Demand Response Incentive Payments														
Idaho Actual Demand Response	$	-	-	236,321.59	2,511,013.89	3,000,465.39	2,342,359.16	784,667.28	61,236.69	14,519.40	3,553.70	(550.20)	-	8,953,586.90
Idaho Base Demand Response	$	675,353.00	715,592.00	874,755.00	1,116,901.00	1,194,593.00	1,040,054.00	727,557.00	687,310.00	784,632.00	857,024.00	816,599.00	749,633.00	10,240,003.00
Change From Base	$	(675,353.00)	(715,592.00)	(638,433.41)	1,394,112.89	1,805,872.39	1,302,305.16	57,110.28	(626,073.31)	(770,112.60)	(853,470.30)	(817,149.20)	(749,633.00)	(1,286,416.10)
Sharing Percentage		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Change From Base (4)	$	(675,353.00)	(715,592.00)	(638,433.41)	1,394,112.89	1,805,872.39	1,302,305.16	57,110.28	(626,073.31)	(770,112.60)	(853,470.30)	(817,149.20)	(749,633.00)	(1,286,416.10)
Idaho Miscellaneous Revenue														
System Emission Allowance Sales Credit	$	-	-	-	-	-	-	-	-	-	-	-	-	-
System Renewable Energy Credit Sales	$	(4,120.00)	612.89	100.87	202.86	(37,249.32)	(15,795.54)	(1,442,033.63)	(562,115.94)	2,575.00	(20,660.63)	(21,207,968.38)	(339,315.91)	(23,625,767.73)
Revenue Subtotal	$	(4,120.00)	612.89	100.87	202.86	(37,249.32)	(15,795.54)	(1,442,033.63)	(562,115.94)	2,575.00	(20,660.63)	(21,207,968.38)	(339,315.91)	(23,625,767.73)
Idaho Allocation		95.6%	95.7%	95.9%	96.0%	96.0%	96.0%	95.7%	95.3%	95.6%	95.5%	95.5%	96.1%	
Sharing Percentage		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Miscellaneous Revenue Deferral (5)	$	(3,741.78)	557.21	91.90	185.01	(33,971.38)	(14,405.53)	(1,311,024.87)	(508,911.67)	2,338.62	(18,744.36)	(19,240,929.31)	(309,778.46)	(21,438,334.62)
Idaho PTP Wheeling Revenues														

Actual PTP Revenue Booked	$	(4,359,217.44)	(3,635,946.28)	(4,447,738.64)	(4,928,396.77)	(4,904,003.55)	(4,627,236.44)	(4,384,215.31)	(4,535,577.98)	(4,673,856.36)	(4,264,695.00)	(5,166,433.48)	(4,228,015.54)	(54,155,332.79)
Idaho Allocation		95.6%	95.7%	95.9%	96.0%	96.0%	96.0%	95.7%	95.3%	95.6%	95.5%	95.5%	96.1%	
ID PTP Revenue	$	(4,167,411.87)	(3,479,600.59)	(4,265,381.36)	(4,731,260.90)	(4,707,843.41)	(4,442,146.98)	(4,195,694.05)	(4,322,405.81)	(4,468,206.68)	(4,072,783.73)	(4,933,943.97)	(4,063,122.93)	(51,849,802.28)
% of Prior Period Billings at Old Rate-effective N/A		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
% of Current Period Billings at New Rate-effective 04/2024	$ 3.11	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
OATT Revenue Credited in Base Rates	$	(3,197,428.96)	(3,389,225.95)	(4,073,175.26)	(5,211,406.77)	(5,424,246.47)	(4,517,328.93)	(3,552,177.62)	(3,263,337.12)	(3,668,612.56)	(3,842,391.50)	(3,967,306.77)	(3,616,404.32)	(47,723,042.25)
OATT Revenue Difference		(969,982.91)	(90,374.64)	(192,206.10)	480,145.87	716,403.06	75,181.95	(643,516.43)	(1,059,068.69)	(799,594.12)	(230,392.23)	(966,637.20)	(446,718.61)	(4,126,760.03)
Sharing Percentage		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
OATT Revenue Deferral (6)	$	(921,483.76)	(85,855.90)	(182,595.79)	456,138.58	680,582.90	71,422.86	(611,340.61)	(1,006,115.25)	(759,614.41)	(218,872.62)	(918,305.34)	(424,382.68)	(3,920,422.02)
TOTAL DEFERRAL (Sum of 1-6)	**$**	**(16,405,011.17)**	**(11,674,191.95)**	**2,560,093.41**	**14,986,685.17**	**3,453,079.84**	**(7,573,152.31)**	**1,013,946.80**	**15,017,979.23**	**17,900,288.11**	**10,553,850.98**	**(23,441,993.09)**	**(28,654,985.26)**	**(22,263,410.24)**

PCA Forecasted Revenues														
Actual Idaho Jurisdictional Billing Month Sales	MWh	1,028,112	1,089,783	1,309,703	1,675,693	1,744,131	1,452,517	1,142,179	1,049,305	1,179,618	1,235,496	1,275,661	1,162,831	15,345,030
% of Prior Period Billings at Old Rate		0.000%	0.000%	56.299%	0.3101%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
% of Current Period Billings at New Rate		100.000%	100.000%	43.700%	99.700%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
Forecast Rate Revenues (7)		(3,546,987.19)	(3,759,752.71)	(3,044,896.98)	(2,523,391.49)	(2,617,940.25)	(2,180,228.64)	(1,714,411.11)	(1,575,006.14)	(1,770,606.89)	(1,854,479.01)	(1,914,767.67)	(1,745,383.27)	(28,247,851.35)

PCA Balancing Account Balance

Monthly Interest Rate 5% for 2024/2025	%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	0.4167%	5.0000%
Beginning Balance	$	89,971,187.52	63,860,297.09	41,765,119.97	32,919,115.95	35,522,952.82	25,921,257.69	7,839,425.61	379,441.39	7,585,144.45	16,732,381.45	18,157,352.76	(14,668,450.65)	89,971,187.52
2024-2025 Incremental Deferral (Sum of 1-6 above)		(16,405,011.17)	(11,674,191.95)	2,560,093.41	14,986,685.17	3,453,079.84	(7,573,152.31)	1,013,946.80	15,017,979.23	17,900,288.11	10,553,850.98	(23,441,993.09)	(28,654,985.26)	(22,263,410.24)
2024-2025 PCA Forecast Revenues (Collections) 7 above		(3,546,987.19)	(3,759,752.71)	(3,044,896.98)	(2,523,391.49)	(2,617,940.25)	(2,180,228.64)	(1,714,411.11)	(1,575,006.14)	(1,770,606.89)	(1,854,479.01)	(1,914,767.67)	(1,745,383.27)	(28,247,851.35)
2024-2025 PCA Prior Balance Revenues (Collections)		(6,533,772.02)	(6,927,317.03)	(8,535,221.78)	(9,996,619.79)	(10,584,847.02)	(8,436,456.37)	(6,792,184.18)	(6,238,851.04)	(7,014,048.99)	(7,344,118.92)	(7,544,698.29)	(6,916,056.02)	(92,864,191.45)
2024-2025 Ending Balance Without Current Month Interest		63,485,417.14	41,499,035.40	32,745,094.62	35,385,789.84	25,773,245.39	7,731,420.37	346,777.12	7,583,563.44	16,700,776.68	18,087,634.50	(14,744,106.29)	(51,984,875.20)	(53,404,265.52)
Current Month Interest		374,879.95	266,084.57	174,021.33	137,162.98	148,012.30	108,005.24	32,664.27	1,581.01	31,604.77	69,718.26	75,655.64	(61,118.54)	1,358,271.78
2024-2025 Ending Deferral Balance	**$**	**63,860,297.09**	**41,765,119.97**	**32,919,115.95**	**35,522,952.82**	**25,921,257.69**	**7,839,425.61**	**379,441.39**	**7,585,144.45**	**16,732,381.45**	**18,157,352.76**	**(14,668,450.65)**	**(52,045,993.74)**	**(52,045,993.74)**

Tab is 100% locked down, with no manual inputs.

Idaho Billed Sales	MWh	1,028,112	1,089,783	1,309,703	1,675,693	1,744,131	1,452,517	1,142,179	1,049,305	1,179,618	1,235,496	1,275,661	1,162,831	15,345,030
Oregon Billed Sales	MWh	47,563	49,345	56,090	69,291	72,841	59,784	51,811	51,890	54,890	57,683	60,097	47,432	678,716
Total	MWh	1,075,675	1,139,128	1,365,793	1,744,984	1,816,971	1,512,301	1,193,990	1,101,195	1,234,508	1,293,179	1,335,758	1,210,263	16,023,746
Idaho % Billed Sales		95.6%	95.7%	95.9%	96.0%	96.0%	96.0%	95.7%	95.3%	95.6%	95.5%	95.5%	96.1%	
Oregon % Billed Sales		4.4%	4.3%	4.1%	4.0%	4.0%	4.0%	4.3%	4.7%	4.4%	4.5%	4.5%	3.9%	

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-20

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 3

#		Actual September 30, 2024			Actual December 31, 2024		
1	**IDAHO POWER COMPANY**						
2							
3	**ADDITIONAL INVESTMENT TAX CREDIT ANALYSIS**						
4	**For the Twelve Months Ended December 31, 2024**						
5							
6		**Actual September 30, 2024**			**Actual December 31, 2024**		
7		TOTAL			TOTAL		
8		SYSTEM	IDAHO	IDAHO %	SYSTEM	IDAHO	IDAHO %
9	**** * * SUMMARY OF RESULTS * * ****						
10	TOTAL COMBINED RATE BASE	4,750,866,989	4,546,034,817	95.7%		Sept Allocations/Ratios	
11							
12	DEVELOPMENT OF NET INCOME						
13	OPERATING REVENUES						
14	RETAIL SALES REVENUES (Incl 449.1 Rev)	1,217,132,286	1,168,693,704	Direct Assign	1,552,780,508	1,487,976,576	Direct Assign
15	OTHER OPERATING REVENUES	205,023,767	196,465,546	95.8%	265,808,787	254,713,242	95.8%
16	TOTAL OPERATING REVENUES	1,422,156,052	1,365,159,250		1,818,589,295	1,742,689,818	
17							
18	OPERATING EXPENSES						
19	OPERATION & MAINTENANCE EXPENSES	955,477,260	916,556,286	95.9%	1,253,874,561	1,202,798,496	95.9%
20	DEPRECIATION EXPENSE	158,762,555	152,277,981	95.9%	214,706,954	205,937,360	95.9%
21	AMORTIZATION OF LIMITED TERM PLANT	4,883,630	4,684,267	95.9%	6,857,622	6,577,675	95.9%
22	TAXES OTHER THAN INCOME	21,837,808	20,002,572	91.6%	16,155,738	14,798,020	91.6%
23	REGULATORY DEBITS/CREDITS	4,250,230	4,004,715	94.2%	5,389,668	5,078,333	94.2%
24	PROVISION FOR DEFERRED INCOME TAXES	(62,769,404)	(60,511,358)	96.4%	(74,296,567)	(71,623,847)	96.4%
25	INVESTMENT TAX CREDIT ADJUSTMENT	12,434,372	11,912,994	95.8%	94,674,793	90,705,046	95.8%
26	FEDERAL INCOME TAXES	66,789,566	64,580,552	96.7%	5,421,813	5,242,491	96.7%
27	STATE INCOME TAXES	20,219,388	19,569,449	96.8%	8,877,729	8,592,360	96.8%
28	TOTAL OPERATING EXPENSES	1,181,885,405	1,133,077,459		1,531,662,311	1,468,105,935	
29							
30	OPERATING INCOME	240,270,647	232,081,790		286,926,984	274,583,884	
31	ADD: IERCO OPERATING INCOME	1,202,994	1,152,790	95.8%	1,651,182	1,582,273	95.8%
32							
33	OPERATING INCOME BEFORE OTHER INCOME AND DEDUCTIO	241,473,641	233,234,580		288,578,166	276,166,157	95.7%
34	ADD: AFUDC EQUITY				53,238,345	50,942,990	95.7% (L 10)
35	ADD: OTHER INCOME AND DEDUCTIONS				44,473,493	42,560,648	95.7% (L 33)
36							
37	INCOME BEFORE INTEREST CHARGES				386,290,005	369,669,795	
38	LESS: INTEREST CHARGES				135,516,528	129,673,775	95.7% (L 10)
39							
40	NET INCOME				250,773,476	239,996,020	
41							
42	ACTUAL YEAR-END RESULTS - BEFORE ITC ADJUSTMENT						
43	EARNINGS ON COMMON STOCK				250,773,476	239,996,020	
44	COMMON EQUITY AT YEAR END				3,060,764,881	2,928,800,942	95.7% (L10)
45							
46	RETURN ON YEAR-END COMMON EQUITY				8.19%	8.19%	
47							
48	EARNINGS ON COMMON STOCK @ 9.12 ROE				279,141,757	**267,106,646**	(L44 * 9.12%)
49	EARNINGS ON COMMON STOCK @ 9.6 ROE				293,833,429	**281,164,890**	(L44 * 9.6%)
51							
52							
53	ACTUAL YEAR-END RESULTS - AFTER ITC ADJUSTMENT:						
54	INVESTMENT TAX CREDIT ADJUSTMENT					29,831,234	(L48-L43) / (1-9.12%)
55	ADJUSTED EARNINGS ON COMMON STOCK					269,827,254	
56	ADJUSTED COMMON EQUITY AT YEAR-END					2,958,632,176	
57	ADJUSTED RETURN ON YEAR-END COMMON EQUITY					9.12%	
58							
59	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) <9.12%**						
60	ADDITIONAL ITC ADJUSTMENT (Annualized)	If L 54 is negative, then 0 (no cap on ADITC per Order 36042)				29,831,234	
61							
62	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) >9.6%**						
63	IDAHO EARNINGS GREATER THAN 9.6% ROE					0	(L43-L49)/(1-9.6%)
64							
67							
68	**Per Order #36042:**					After Tax	Tax Gross Up
69	ROE Greater than 9.6% --CUSTOMER SHARE - 80% (Reduction to rates)					0	-
70	ROE Greater than 9.6% --COMPANY SHARE - 20%					0	
73						0	
74							

Exhibit No. 3
Case No. IPC-E-25-20
J. Brady, IPC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-20

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

CONFIDENTIAL
EXHIBIT NO. 4

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-20

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

CONFIDENTIAL
EXHIBIT NO. 5