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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT ("PCA") RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2024, THROUGH MAY 31, 2025.	)	CASE NO. IPC-E-24-17

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 2024-2025 Power Cost Adjustment ("PCA") rates to become effective June 1, 2024. If approved, the 2024-2025 PCA will result in a decrease in total billed revenue of approximately $35.7 million, or 2.31 percent.

Q. How is your testimony organized?

A. My testimony consists of five sections. In the first section, I provide an overview of the PCA. In the second section, I detail the 2024-2025 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 2024-2025 PCA rates to become effective June 1, 2024. 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 2024-2025 PCA rates if approved as filed. In the final section, I discuss additional topics related to Order Nos. 35804 and 36042 of the Company's 2023 PCA filing and General Rate Case, respectively.

Q. Are you sponsoring any exhibits?

A. Yes. I am offering the following exhibits:

Exhibit	Description
Exhibit No. 1	2024-2025 PCA Forecast
Exhibit No. 2	2023 Balancing Adjustment
Exhibit No. 3	2023 ROE Determination Revenue Sharing
Exhibit No. 4	Confidential - Black Mesa Solar Generation and Expenses
Exhibit No. 5	Confidential – Hells Canyon 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 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 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.

Q. How does the PCA mechanism function?

A. With the exception of Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses and demand response incentive payments, the PCA allows the Company to pass through to customers 95 percent of the annual differences in actual NPSE as compared with base level NPSE, whether positive or negative. 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. 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 (coal); 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.

II. 2024-2025 PCA

Q. What is the total PCA collection that would result under the 2024-2025 PCA rates proposed by the Company in this case?

A. The 2024-2025 PCA rates would result in total PCA collection of $112.7 million. This represents a decrease in total billed revenue of $35.7 million for the upcoming year, a decrease of 2.31 percent.

Q. Have you prepared a table that details the $35.7 million revenue impact by component?

A. Yes. Table 1 presents a separation of the $35.7 million decrease into each component included in the Company's proposed rates.

Table 1 — Idaho Jurisdictional Revenue Impact by Component

Line No.	Rate Component	2023-2024 PCA	2024-2025 PCA	Difference
1	PCA Forecast	$ 52,202,870	$ 22,712,031	$ (29,490,839)
2	PCA Balancing Adjustment	$ 96,189,461	$ 89,970,511	$ (6,218,951)
3	PCA Total	$ 148,392,331	$ 112,682,542	$ (35,709,789)
4	Revenue Sharing	$ 0	$ 0	$ 0
5	**Total Revenue Impact**	**$ 148,392,331**	**$ 112,682,542**	**$ (35,709,789)**

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 both the forecast component and the Balancing Adjustment. The decrease in this year's forecast component is attributed primarily to higher forecast hydro generation. The decrease in this year's Balancing Adjustment is primarily attributed to the Sales Based Adjustment ("SBA"), which accounts for the variance in actual sales and the sales used to set base level NPSE, and an increase in Renewable Energy Credit ("REC") sales.

A. PCA Forecast.

Q. How is the PCA forecast amount determined?

A. As described previously, the PCA forecast component represents the difference between the Company's forecast of NPSE for the upcoming April – March test year and base level NPSE recovered in the Company's base rates.

Q. What is the Company's determination of the system-level difference between currently approved base level NPSE[1] and the forecast of NPSE for the 2024-2025 PCA Year?

A. 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. Table 2 presents the system-level differences between currently approved base level NPSE and the forecast of NPSE for the 2024-2025 PCA Year by FERC account.

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[1] *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	2024 - 2025 PCA FORECAST (Total System)			
Line No.	FERC Account	Base NPSE	Forecast	Difference
	95% Sharing Accounts			
1	Account 501, Coal	$ 65,523,000	$ 117,075,844	$ 51,552,844
2	Account 536, Water for Power	$ 0	$ 0	$ 0
3	Account 547, Other Fuel	$ 119,653,675	$ 147,302,230	$ 27,648,555
4	Account 555, Purchased Power Non-PURPA	$ 99,465,021	$ 90,809,149	$ (8,655,871)
5	Account 565, 3rd Party Transmission	$ 10,263,139	$ 10,419,009	$ 155,870
6	Account 447, Surplus Sales	$ (34,686,350)	$ (86,055,453)	$ (51,369,103)
		$ 260,218,486	$ 279,550,780	$ 19,332,294
	100% Sharing Accounts			
7	Account 555, PURPA	$ 214,448,755	$ 219,593,677	$ 5,144,922
8	Account 555, Demand Response Incentives	$ 10,240,003	$ 10,411,533	$ 171,530
9	Total	$ 484,907,244	$ 509,555,990	$ 24,648,746

Q. What is the basis for the forecast of NPSE for the 2024-2025 PCA Year?

A. The forecast of NPSE for the 2024-2025 PCA Year is based on the Company’s March 2024 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 2024-2025 PCA Year, as determined in the Company's March 2024 Operating Plan, is provided in Exhibit No. 1.

Q. Did the Company make any adjustments to the March 2024 Operating Plan, for purposes of quantifying forecast NPSE for the 2024-2025 PCA Year?

A. Yes. The Company made two adjustments to the March 2024 Operating Plan for purposes of quantifying NPSE. The first is the modification related to the power purchase agreement ("PPA") with Black Mesa Solar, which was introduced in last year's PCA filing. The second is a modification related to a new special contract with Lamb Weston, Inc. ("Lamb Weston").[2]

Q. Please explain the modification related to Black Mesa Solar.

A. For purposes of quantifying forecast NPSE for the 2024-2025 PCA Year, the Company removed the forecasted expenses associated with Black Mesa Solar, because Micron Technology, Inc. ("Micron") will be paying for 100 percent of the generation according to the provisions of the special contract[3] between Idaho Power and Micron.

Q. Please provide more information on the Black Mesa Solar PPA and its treatment in the PCA forecast.

A. Black Mesa Solar is a 40 MW alternating current solar photovoltaic generation facility that came online in June 2023. The PPA was negotiated in conjunction with the Micron special contract, which states that Idaho Power will procure renewable resources to assist Micron in meeting a portion of its annual energy requirements with energy generated by those resources. While the renewable resource, Black Mesa Solar in this case, is connected to

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[2] *In the Matter of the Application for Approval of Special contract and Tariff Schedule 34 to Provide Electric Service to Lamb Weston, Inc.*, Case No. IPC-E-23-18, Order No. 35929 (September 21, 2023).

[3] *In the Matter of the Replacement Special contract with Micron Technology, Inc., and Purchase Agreement with Black Mesa Energy LLC,* Case No. IPC-E-22-06, Order No. 35482 (August 01, 2023).

the Company's system and does not serve Micron directly, Micron is paying for all of the output.

As a result, the cost of the PPA was removed from the Company's calculation of forecast NPSE. In compliance with Commission Order No. 35893,[4] the Company has provided Black Mesa Solar's forecast generation and expenses, as well as Micron's monthly load forecast, as Confidential Exhibit No. 4.

Q. How will the excess generation and renewable capacity credit payments, as detailed in Micron's special contract, be incorporated into this year's PCA filing?

A. In the event that Black Mesa Solar's generation exceeds Micron's load in a given hour, the Company will compensate Micron for the excess generation according to the methodology approved by the Commission in Order No. 35482. However, for the 2024-2025 PCA year, the Company does not expect Black Mesa Solar's generation to exceed Micron's load in any hour. As a result, no excess generation payments are included in this year's PCA forecast.

In addition, as stated in Order No. 35482, the Company will not begin renewable capacity credit payments

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[4] *In the Matter of Idaho Power's Application to Expand Optional Customer Clean Energy Offerings through The Clean Energy Your Way Program,* Case No. IPC-E-21-40, Order No. 35893 (August 15, 2023).

until July 1, 2026. As a result, no renewable capacity credit payments are included in this year's PCA forecast.

Q. Please explain the modification related to Lamb Weston.

A. Order No. 35929 approved a new special contract with Lamb Weston. It consists of a two-block pricing structure that includes an embedded cost pricing block ("Block 1") and a marginal cost pricing block ("Block 2"). Block 2 consists of electricity consumed beyond 20 megawatts. According to the Lamb Weston special contract, revenues from Block 2 energy sales should be treated as a surplus sale in NPSE calculations. As a result, revenues associated with Lamb Weston's forecast Block 2 energy sales have been included in Account 447, Sales for Resale, as an offset to NPSE.

Q. How does the Company's forecast of system-level NPSE for the 2024-2025 PCA compare to the system-level forecast included in last year's PCA?

A. Table 3 below compares this year's 2024-2025 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 2024-2025 PCA year is \$509,555,990, which is \$31,943,394 lower than last year's forecast amount of \$541,499,384.

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Table 3	PCA Forecast Comparison Expenses (Total System)			
Line No.	FERC Account	2023-2024 Forecast	2024-2025 Forecast	Difference
	95% Sharing Accounts			
1	Account 501, Coal	$ 130,090,026	$ 117,075,844	$ (13,014,182)
2	Account 536, Water for Power	$ 0	$ 0	$ 0
3	Account 547, Other Fuel	$ 134,623,640	$ 147,302,230	$ 12,678,591
4	Account 555, Purchased Power Non-PURPA	$ 123,492,688	$ 90,809,149	$ (32,683,539)
5	Account 565, 3rd Party Transmission	$ 7,964,649	$ 10,419,009	$ 2,454,360
6	Account 447, Surplus Sales	$ (84,191,539)	$ (86,055,453)	$ (1,863,914)
		$ 311,979,464	$ 279,550,780	$ (32,428,684)
	100% Sharing Accounts			
7	Account 555, PURPA	$ 218,535,412	$ 219,593,677	$ 1,058,265
8	Account 555, Demand Response Incentives	$ 10,984,508	$ 10,411,533	$ (572,975)
		$ 229,519,920	$ 230,005,210	$ 485,290
9	Total PCA Forecast	$ 541,499,384	$ 509,555,990	$ (31,943,394)

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 decreased approximately $32.4 million from last year’s forecast, while the 100 percent sharing accounts have increased approximately $0.49 million over last year’s forecast.

Q. What factors are contributing to the major differences presented in Table 3?

A. Forecast expenses included in the 95 percent sharing accounts are expected to decrease by 10 percent as compared to last year, from $311,979,464 to $279,550,780. Due to the 12 percent increase in forecast hydro generation and the conversion of Bridger Units 1 and 2 to natural gas, the Company expects to rely more on hydro and natural gas generation and less on purchased power and coal generation to serve load in the 2024-2025 PCA Year.

Q. Please elaborate on the changes in the 95 percent sharing accounts for this year’s forecast as compared with last year’s forecast as presented in Table 3.

A. For the 2024-2025 PCA year, the average forecast market purchase price is $62.07 per megawatt-hour (“MWh”), compared to $76.01 per MWh last year, a decrease of 18 percent. Accordingly, expenses from non-PURPA purchased power are expected to decrease 26 percent compared to last year.

The per-unit cost of natural gas-fired generation for the 2024-2025 PCA year is $40.52 per MWh, a decrease of 2 percent compared to last year. The per-unit cost of coal-fired generation for the 2024-2025 PCA year is $38.18 per MWh, an increase of 3 percent compared to last year. While the forecast prices for natural gas and coal remained relatively unchanged, due to the conversion of Bridger Units 1 and 2 to natural gas, natural gas generation is expected to increase 11 percent and coal-fired generation is expected to decrease 13 percent as compared to last year’s forecast.

Surplus sales revenue is expected to increase 2 percent compared to last year, from $84,191,539 to $86,055,453. For the 2024-2025 PCA Year, the average forecast market sales price is $62.64 per MWh compared with $82.96 last year, a 25 percent decrease.

Q. Does Account 447, Sales for Resale, include forecasted revenues from wheeling losses?

A. Yes. Consistent with Order No. 36042 in the Company's 2023 General Rate Case, Idaho Power has included both actual and forecasted revenues from wheeling losses in NPSE beginning January 2024.

Q. What factors are contributing to the change in the 100 percent sharing accounts?

A. As can be seen in Table 3, forecast expenses included in the 100 percent sharing accounts are expected to increase 0.2 percent compared to last year, from $229,519,920 to $230,005,210. Forecast PURPA costs increased by $1.06 million as compared to last year's forecast and forecast demand response incentive payments decreased by $0.57 million as compared to last year.

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

A. In part. Table 4 details changes between last year's PCA forecast and this year's PCA forecast with respect to forecasted generation in MWh. As shown in Table

4, total PURPA generation is anticipated to decrease by 136,646 MWh, or 4 percent. The increase in PURPA expense is largely the result of price escalation in PURPA contracts, for which the average cost is $75.17 per MWh, compared to $71.47 last year.

Table 4	PCA Forecast Comparison Generation (Total System-MWh)			
Line No.	FERC Account	2023-2024 Forecast	2024-2025 Forecast	Difference
1	Hydro	6,487,995	7,293,179	805,184
	95% Sharing Accounts			
2	Account 501, Coal	3,520,905	3,066,212	(454,693)
3	Account 547, Other Fuel	3,261,784	3,635,055	373,271
4	Account 555, Purchased Power Non-PURPA	1,695,683	1,577,970	(117,713)
	95% Sharing Accounts	14,966,367	15,572,415	606,048
	100% Sharing Accounts			
5	Account 555, PURPA	3,057,802	2,921,156	(136,646)
	100% Accounts	3,057,802	2,921,156	(136,646)
6	Total Generation	18,024,169	18,493,571	469,402
	95% Sharing Accounts			
7	Less Account 447, Surplus Sales	1,014,817	1,306,125	291,308
8	Total Load	17,009,352	17,187,446	178,094

Q. What other general conclusions can be drawn from the information in Table 4?

A. Compared to last year's forecast, hydro generation is expected to increase from 6,487,995 MWh to 7,293,179 MWh, or 12 percent. In addition, coal-fired generation is expected to decrease 13 percent and natural gas generation is expected to increase 11 percent compared to last year. Lastly, non-PURPA purchased power is expected to decrease 7 percent from last year, which is largely attributed to the reduction in forecast short-term market purchases.

Q. What is causing the 12 percent increase in expected hydro generation?

A. The increase in expected hydro generation is mainly due to higher projected inflows into Brownlee reservoir. The March Operating Plan used in this year's PCA forecast projects April through July inflows into Brownlee of 4.8 million acre-feet ("MAF") as compared to 4.3 MAF used to determine last year's PCA forecast, an increase of 12 percent. Expected inflows into Brownlee are higher than last year's PCA forecast as a result of better reservoir storage conditions, which provide for sustained runoff and increased hydro generation during the spring and summer months. Storage at major reservoirs above Brownlee are 85 percent full, which is 127 percent of normal.

Q. How are the forecasted NPSE differences presented in Table 2 used to determine the 2024-2025 PCA forecast component to be collected from Idaho customers?

A. The 2024-2025 PCA forecast component reflects the Idaho jurisdictional share of the forecasted NPSE differences presented in Table 2, adjusted for the PCA sharing provisions. The Idaho jurisdictional share of the forecast NPSE differences is determined by applying a ratio of forecast firm Idaho jurisdictional sales to forecast firm system-level sales to the system-level NPSE differences.

Q. Were any changes made to the Idaho jurisdictional sales and system-level sales to account for the discussed modifications related to Black Mesa Solar and Lamb Weston?

A. Yes. Both the portion of Micron's load forecast to be met by Black Mesa Solar and forecast Lamb Weston Block 2 energy sales were removed from the total forecast Idaho jurisdictional sales and system-level sales and were 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, net of the Black Mesa Solar and Lamb Weston modifications, for the 2024-2025 PCA Year?

A. For the 2024-2025 PCA Year, Idaho Power has forecast system-level firm sales to be 15,787,686 MWh and Idaho jurisdictional firm sales to be 15,131,267 MWh, or 95.84 percent of the system level.

Q. What is the Company's determination of the 2024-2025 PCA forecast component to be collected from Idaho customers?

A. The 2024-2025 PCA forecast component to be collected from Idaho customers is $22,704,611.[5] Table 5 presents the determination of the 2024-2025 PCA forecast component by individual PCA expense and revenue category.

Table 5	2024-2025 PCA FORECAST						
Line No.	FERC Account	Difference from Base		Difference After Sharing		Idaho Allocation	
	95% Sharing Accounts	(From Table 2)					
1	Account 501, Coal	$	51,552,844	$	48,975,202	$	46,938,915
2	Account 536, Water for Power	$	0	$	0	$	0
3	Account 547, Other Fuel	$	27,648,555	$	26,266,127	$	25,174,036
4	Account 555, Purchased Power Non-PURPA	$	(8,655,871)	$	(8,223,078)	$	(7,881,179)
5	Account 565, 3rd Party Transmission	$	155,870	$	148,077	$	141,920
6	Account 447, Surplus Sales	$	(51,369,103)	$	(48,800,648)	$	(46,771,618)
		$	19,332,295	$	18,365,680	$	17,602,074
	100% Sharing Accounts						
7	Account 555, PURPA	$	5,144,922	$	5,144,922	$	4,931,007
8	Account 555, Demand Response Incentives	$	171,530	$	171,530	$	171,530
9	Total	$	24,648,747	$	23,682,132	$	22,704,611

B. <u>Balancing Adjustment</u>.

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 2024, with interest applied, was $89,971,188 as shown on row 100

[5] This will not tie to the forecast component from Table 1 due to rounding of PCA rate.

of Exhibit No. 2. The approximate $90 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 $90 million deferral balance?

A. Order No. 35804 in last year's PCA filing directed Idaho Power to collect the 2022-2023 PCA deferral balance equally over a two-year period. As a result, this year's approximate $90 million balance is primarily attributed to the continued collection of last year's deferral balance. Actual power supply expenses in the 2023-2024 PCA Year were just 3 percent higher than forecast expenses. As a result, the variance between forecast and actual power supply expenses for the 2023-2024 PCA Year had a relatively small impact on this year's deferral balance. However, this year's deferral balance does include increased benefits associated with the SBA, as well as increased REC sales.

Q. Please explain the changes in actual versus forecast generation and expense for the 2023-2024 PCA Year.

A. Actual hydro generation for the 2023-2024 PCA year totaled 6,921,812 MWh, a 7 percent increase from last year's forecast of 6,487,995 MWh. Actual non-PURPA purchased power totaled 3,912,307 MWh, a 131 percent increase from last year’s forecast. Actual natural gas generation totaled 3,086,278 MWh, a 5 percent decrease from last year’s forecast. Lastly, actual surplus sales volumes totaled 2,637,210 MWh, an increase of 160 percent from last year’s forecast.

Q. Please elaborate on the changes in actual versus forecast generation and expense for the 2023-2024 PCA Year.

A. Actual coal-fired generation for the 2023-2024 PCA year was 27 percent lower than forecast. Actual coal fuel expense totaled $106,401,903, which was 18 percent lower than forecast.

Actual natural gas generation for the 2023-2024 PCA was 5 percent lower than forecast. Actual natural gas expense was $171,487,628, which was 27 percent higher than forecast. The per-unit cost of natural gas in the 2023-2024 PCA Year was $55.56/MWh, a 35 percent increase from forecast.

Actual non-PURPA purchased power totaled 3,912,307 MWh for the 2023-2024 PCA Year, which was 131 percent higher than forecast. Actual non-PURPA purchased power expense was $225,264,049, which was 82 percent higher than forecast.

Surplus sales totaled 2,637,210 MWh for the 2023-2024 PCA Year, which was 160 percent higher than forecast.

Actual surplus sales revenue was $160,755,918, which was 91 percent higher than forecast.

While both purchased power and surplus sales increased, surplus sale volumes were highest in off-peak spring and winter months, and purchased power was highest in either summer months, where hot temperatures caused higher than forecast peak loads, or in spring months, where prices were relatively low.

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

A. Yes. Per Commission Order No. 34100, Idaho Power included its actual costs of Western Energy Imbalance Market (“EIM”) participation for April 2023 through December 2023 in the Balancing Adjustment. 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. Please summarize the conditions of Order No. 34100 as they pertain to EIM cost recovery through the 2023 PCA.

A. Per the terms of the settlement stipulation (“EIM Stipulation”) approved by Order No. 34100, Idaho

Power agreed to include an EIM-related monthly revenue requirement in its monthly PCA deferral calculation based on actual EIM participation costs commencing April 1, 2018. The Company also agreed to apply a soft cap to EIM-related revenue requirement included in the PCA deferral equal to annual EIM benefits as reported by the California Independent System Operator ("CAISO") for the corresponding period.

Q. Is the EIM-related revenue requirement included in the April 2023 through March 2024 PCA deferral under the soft cap of annual CAISO-reported benefits for that same period?

A. Yes. For the April 2023 through December 2023 period, the EIM-related revenue requirement totaled $1.9 million, while CAISO reported EIM benefits for Idaho Power of approximately $49.6 million from April through December. Therefore, the Company's EIM-related revenue requirement is less than the soft cap agreed to in the EIM Stipulation.

Q. Does Idaho Power believe the EIM has provided net benefits to customers since joining in April 2018?

A. Yes. While Idaho Power believes the CAISO benefit calculation overstates estimated benefits to Idaho Power's system, the Company believes customers have realized significant net benefits since the Company's entry into the EIM in April 2018. As discussed in the Company's

May 24, 2019, Report of EIM Benefits and Costs of Participation, filed in Case No. IPC-E-16-19, Idaho Power has developed a more precise methodology for determining EIM benefits that uses inputs specific to the Company. Based on this methodology, the Company believes benefits achieved between April 2023 and December 2023 are approximately $39.5 million (benefits for the first quarter of 2024 are not yet available). This level of EIM benefits compared to the Idaho-jurisdictional EIM costs of $1.9 million, demonstrates a net benefit to the Company and, ultimately, its customers.

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

Q. How is the rate for the forecast portion of the PCA for April 2024 through March 2025 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, 2024, through May 31, 2025 ("System-level Sales Forecast"); and (2) 100 percent of the difference between PURPA-related expenses quantified in the Operating Plan and those quantified in the Company's last approved update of NPSE, divided by the Company's System-level Sales Forecast; and (3) 100 percent of the difference between the Idaho jurisdictional demand response incentive payments quantified in the Operating Plan and those quantified in the Company’s last approved update of NPSE, divided by the forecast of Idaho jurisdictional firm sales for June 1, 2024, through May 31, 2025.

Q. What is the rate for the forecast portion of the PCA for April 2024 through March 2025?

A. The rate for non-PURPA expenses is 0.1163 cents per kilowatt-hour (“kWh”), which is calculated by multiplying $19,332,295 from Table 2 by 95 percent and then dividing it by the System-level Sales Forecast (net of Black Mesa Solar generation and Lamb Weston Block 2 energy sales) of 15,787,686 MWh (($19,332,295 * 0.95) / 15,787,686) = $1.163 /MWh = 0.1163 cents/kWh). The rate for PURPA expenses is 0.0326 cents per kWh, which is calculated by dividing $5,144,922 from Table 2 by the 15,787,686 MWh ($5,144,922 / 15,787,686 MWh = $0.326/MWh = 0.0326 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 (net of Black Mesa Solar and Lamb Weston modifications) of 15,131,267 MWh (171,530 / 15,131,267 MWh = $0.0110/MWh = 0.0011 cents/kWh). The forecast portion of the PCA rate is 0.1501 cents per kWh, which is calculated by adding the non-PURPA expense of

0.1163 cents per kWh to the PURPA expense of 0.0326 cents per kWh to the demand response incentive payment of 0.0011 cents per kWh (0.1163 + 0.0326 + 0.0011 = 0.1501 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 $90 million, which, when divided by the Company's forecast of Idaho jurisdictional sales of 15,131,267 MWh, results in a rate of 0.5946 cents per kWh ($89,971,188 / 15,131,267 = $5.946/MWh = 0.5946 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 0.1501 cents per 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 of the PCA. The sum of these two components is a 0.7447 cents per kWh charge for all rate classes.

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.[6] Order No. 34071 in Case No. GNR-U-18-01 extended the revenue sharing mechanism indefinitely, with modifications.

The mechanism was most recently modified in the Company's 2023 General Rate Case. However, the stipulated modifications were effective January 1, 2024, and will not impact the PCA filing until 2025.

Q. What are the provisions of the current revenue sharing mechanism?

A. In Case No. GNR-U-18-01, the Company filed a motion to approve a settlement stipulation ("2018 Stipulation") extending the sharing mechanism indefinitely, with modifications. The Commission approved the 2018 Stipulation in Order No. 34071.

Per the terms of the 2018 Stipulation, if the Company's actual year-end Return on Equity ("ROE") for the Idaho jurisdiction exceeds 10 percent, all amounts up to and including a 10.5 percent ROE will be shared between customers and the Company on an 80 percent and 20 percent basis, respectively, to be provided as a rate reduction to

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

become effective at the time of the subsequent year's PCA. If the Company's Idaho jurisdictional ROE exceeds 10.5 percent, all amounts in excess of 10.5 percent will be shared 55 percent with Idaho customers as a rate reduction to become effective with the subsequent year's PCA, 25 percent will be shared with Idaho customers in the form of an offset to amounts in the Company's pension balancing account, and 20 percent will be apportioned to the Company.

With regard to the amortization of Accumulated Deferred Investment Tax Credits ("ADITC"), the 2018 Stipulation allows the Company to accelerate the amortization of ADITC, in an amount up to $45 million, to achieve a maximum 9.4 percent Idaho jurisdictional ROE if the Company's year-end actual results fall below that amount for any year beginning January 1, 2020. Idaho Power may use up to $25 million of additional amortization of ADITC per year, provided the total, cumulative amount of ADITC does not exceed $45 million. Per the 2018 Stipulation, once the Company has fully amortized the $45 million of ADITC, revenue sharing will cease; however, Idaho Power may at any time request to replenish the total amount of ADITC it is permitted to amortize, and if approved by the Commission, revenue sharing would continue.

Q. What have been the results of the revenue sharing mechanism since it was implemented through 2022?

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, and 2022 were below the revenue sharing threshold. These amounts are detailed in Table 6 below.

Table 6	**2009-2022 Revenue Sharing**					
Line No.	**Revenue Sharing Component**	**2009-2011**	**2012-2014**	**2015-2019**	**2020-2022**	
1	Available ADITC For Use	$45 Million	$45 Million	$45 Million	$45 Million	
2	Customer Benefits ($ Millions):					
3	Reduction to Rates	$27.1	$22.8	$8.2	$0.6	**Total**
4	Offset to Pension Balancing Account	$20.3	$47.8	$0.0	$0.0	**2009-2022**
5	**Total**	$47.4	$70.6	$8.2	$0.6	**$126.7**

Q. Did the Company's year-end 2023 financial results warrant any action related to the existing sharing agreement per the terms of the 2018 Stipulation?

A. No. The Company's year-end 2023 financial results yielded an actual Idaho jurisdictional ROE of 9.4 percent, falling below the 10 percent ROE threshold for revenue sharing, and thus resulting in no revenue sharing with customers.

Q. Did the Company use the same methodology to determine the Idaho jurisdictional 2023 year-end ROE that was used in prior PCA filings?

A. Yes. The methodology used to determine the Company's Idaho jurisdictional 2023 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 2023 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 2024 through May 2025 test year results in a PCA decrease of $35.7 million.

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 2024-2025 PCA will result in a decrease in total billed revenue of approximately $35.7 million, or 2.31 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, 33307, and 34071.

V. COMPLIANCE WITH PRIOR ORDERS

Q. Please describe the topics discussed in Idaho Power's 2023 PCA filing (Order No. 35804) that the Company is addressing in this filing.

A. Idaho Power is addressing two issues that were discussed in Order No. 35804. The first is the outcome of damage claims for Hells Canyon Unit No. 3. The second is regarding the Company's coal supply management in the 2022-2023 PCA Year.

Q. What was the Commission's order regarding Hells Canyon Unit No. 3?

A. Idaho Power was directed to notify the Commission of any outcome on the Hells Canyon Unit No. 3 damage claim.

Q. Please summarize the issues that led to Idaho Power seeking damage claims for Hells Canyon Unit No. 3.

A. Hells Canyon Unit No. 3 failed due to a phase-to-phase stator on June 23, 2020. The likely root cause was degraded coil insulation. At the time of the failure, Idaho Power had already planned for scheduled maintenance from August 2021 to December 2021 and was under contract with Alstom Renewable US ("General Electric"). Because General Electric did not meet the completion dates for the project, Idaho Power withheld delay liquidated.

Q. Were the delay liquidated damages that Idaho Power received included in this year's PCA filing as an offset to power supply costs?

A. Yes. The majority of delay liquidated damages were included as an offset to power supply costs in the 2023-2024 PCA Year. However, a portion was also recorded to offset labor costs that would not have otherwise occurred. The Company has provided additional detail on the delay liquidated damage amounts in Confidential Exhibit No. 5.

Q. What was the Commission's order regarding Idaho Power's coal supply management in the 2022-2023 PCA Year?

A. Order No. 35804 directed Commission Staff to investigate the prudency of the Company's power supply expenses related to coal supply issues and report its assessment to the Commission within six months of the Commission's final order.

Q. Did Commission Staff provide a report detailing its investigation?

A. Yes. On November 30, 2023, Commission Staff filed a confidential report that recommended an adjustment to NPSE be considered in the 2024 PCA filing. Staff also recommended that Idaho Power include Staff’s report and a response to Staff’s report as a part of the 2024 PCA filing.

Q. Has Idaho Power included a response to Staff’s report with this filing?

A. Yes. Idaho Power has included both Staff’s report and its response to Staff’s report as Confidential Attachments 3 and Attachment 4 to this filing, respectively.

Q. What can be concluded from the information contained in Attachment 4?

A. The information contained in Attachment 4 demonstrates that Idaho Power’s management of its available coal supply during the 2022-2023 PCA Year was reasonable and prudent based on the information available to the Company at the time. The Company does not agree that an adjustment to NPSE is reasonable under the circumstances presented. To the contrary, as more fully described in Attachment 4, the Company moved expeditiously and judiciously to mitigate the challenges that arose from sustained market volatility and limited coal inventories in the region.

Q. Are there any other issues stemming from the Company's 2023 General Rate Case that the Company is addressing in this filing?

A. Yes. In the 2023 General Rate Case settlement stipulation, parties agreed to discuss the annual tracking of third-party point-to-point wheeling revenues in a separate proceeding.

Q. Has Idaho Power discussed a proposed wheeling revenue tracking mechanism with Staff?

A. Yes. Idaho Power provided its proposed wheeling revenue tracking mechanism to Staff on March 28, 2024, and has been engaged in continuing discussions with Staff regarding the mechanism. Idaho Power will continue to work with Staff and make a filing detailing the proposal as soon as possible.

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 Senior 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 2024, at Boise, Idaho.

Signed: Jessica Brady ________________________

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 1

IDAHO POWER PCA FORECAST
APRIL 1, 2024 - MARCH 31, 2025

Line No.	FERC Account	April	May	June	July	August	September	October	November	December	January	February	March	Annual
	95% Sharing Accounts													
1	**Hydroelectric Generation (MWh)**	984,013	1,014,012	840,054	580,097	533,664	525,889	376,759	368,488	490,260	498,374	469,152	612,417	7,293,179
	Account 536, Water for Power													
2	Total Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Account 501, Coal													
	Jim Bridger													
3	Energy (MWh)	90,468	32,238	145,785	245,367	245,367	237,452	245,367	237,452	245,367	245,367	221,622	225,522	2,417,371
4	Total Expense	$ 2,871,016	$ 945,751	$ 4,603,392	$ 7,898,826	$ 7,943,000	$ 7,693,577	$ 7,951,834	$ 7,692,152	$ 7,947,417	$ 8,334,677	$ 7,660,886	$ 7,854,302	$ 79,396,827
	North Valmy													
5	Energy (MWh)	(0)	-	-	56,892	87,108	80,561	87,104	84,294	87,104	87,104	78,674	(0)	648,841
6	Total Expense	$ 332,698	$ 332,698	$ 332,698	$ 3,293,293	$ 4,877,353	$ 4,505,872	$ 4,860,741	$ 4,682,835	$ 4,825,208	$ 4,855,438	$ 4,447,480	$ 332,698	$ 37,679,017
	Account 547, Other Fuel													
	Langley Gulch													
7	Energy (MWh)	174,453	28,052	207,200	210,704	211,056	208,320	41,718	215,505	227,040	226,896	202,080	120,492	2,073,516
8	Total Expense	$ 2,613,583	$ 741,628	$ 3,069,456	$ 5,672,395	$ 5,410,032	$ 5,221,659	$ 1,061,272	$ 7,844,304	$ 10,443,023	$ 11,057,701	$ 9,613,294	$ 3,649,775	$ 66,398,122
	Bridger Gas													
9	Energy (MWh)	-	-	-	147,766	81,537	83,441	84,223	-	154,144	137,923	32,497	-	721,530
10	Total Expense	-$33,476	-$33,476	-$33,476	$4,595,181	$2,828,501	$2,549,886	$2,486,104	$291,204	$11,604,917	$10,467,898	$2,318,886	$301,830	$ 37,343,977
	Danskin													
11	Energy (MWh)	-	-	-	120,680	121,032	44,016	78,816	-	51,440	56,744	8,352	-	481,080
12	Total Expense	$ 188,260	$ 188,260	$ 181,598	$ 5,495,380	$ 5,257,425	$ 2,031,590	$ 3,096,800	$ 181,598	$ 3,803,819	$ 4,398,665	$ 867,110	$ 188,260	$ 25,878,765
	Bennett Mountain													
13	Energy (MWh)	-	-	-	118,488	125,496	-	41,496	41,112	32,336	-	-	-	358,928
14	Total Expense	$ 92,724.99	$ 92,724.99	$ 89,443.76	$ 5,277,150.27	$ 5,324,428.59	$ 89,443.76	$ 1,608,948.27	$ 2,442,656.48	$ 2,385,670.75	$ 92,724.99	$ 92,724.99	$ 92,724.99	$ 17,681,367
	Account 555, Purchased Power Non-PURPA													
15	Energy (MWh)	154,437	95,729	206,462	203,717	138,109	89,501	77,522	169,317	100,158	92,938	121,704	128,377	1,577,970
16	Total Expense	$ 7,247,733	$ 3,873,409	$ 8,205,246	$ 12,155,377	$ 7,780,932	$ 4,681,890	$ 5,038,880	$ 13,197,004	$ 8,771,299	$ 6,679,661	$ 8,160,739	$ 5,016,979	$ 90,809,149
	Account 565, 3rd Party Transmission													
17	Total Expense	$ 484,900	$ 642,929	$ 979,873	$ 1,588,903	$ 1,413,041	$ 763,336	$ 1,063,909	$ 675,368	$ 735,071	$ 773,786	$ 810,920	$ 486,974	$ 10,419,009
	Account 447, Surplus Sales													
18	Energy (MWh)	(504,188)	(114,532)	(114,102)	(48,368)	(49,256)	(135,907)	(57,956)	(17,855)	(68,817)	(78,661)	(56,303)	(60,179)	(1,306,125)
19	Total Expense	$ (20,401,610)	$ (4,333,683)	$ (5,979,539)	$ (4,029,466)	$ (4,873,012)	$ (12,237,123)	$ (3,550,765)	$ (2,821,347)	$ (8,233,743)	$ (7,219,658)	$ (6,810,908)	$ (5,564,599)	$ (86,055,453)
	100% Sharing Accounts													
	Account 555, PURPA													
20	Energy (MWh)	287,513	300,952	296,853	281,342	269,878	229,984	221,701	171,622	188,068	200,471	228,193	244,581	2,921,156
21	Total Expense	$ 15,984,371	$ 16,481,737	$ 21,588,102	$ 24,318,489	$ 24,037,578	$ 17,360,119	$ 16,703,289	$ 15,726,756	$ 17,639,259	$ 16,286,900	$ 18,511,882	$ 14,955,194	$ 219,593,677
	Account 555, Demand Response Incentives													
22	Total Expense	$ -	$ -	$ 270,468	$ 3,047,657	$ 4,657,950	$ 1,277,208	$ 184,487	$ 973,763	$ -	$ -	$ -	$ -	$ 10,411,533
	95% Sharing Accounts	$ (6,604,171)	$ 2,450,240	$ 11,448,693	$ 41,947,040	$ 35,961,700	$ 15,300,131	$ 23,617,722	$ 34,185,774	$ 42,282,682	$ 39,440,893	$ 27,161,132	$ 12,358,944	$ 279,550,780
	100% Sharing Accounts	$ 15,984,371	$ 16,481,737	$ 21,858,570	$ 27,366,146	$ 28,695,528	$ 18,637,327	$ 16,887,776	$ 16,700,519	$ 17,639,259	$ 16,286,900	$ 18,511,882	$ 14,955,194	$ 230,005,210
23	**Total Net Power Supply Expense**	$ 9,413,676	$ 18,965,452	$ 33,340,739	$ 64,718,005	$ 61,828,727	$ 31,387,572	$ 38,019,395	$ 50,595,089	$ 48,317,024	$ 45,259,895	$ 43,354,129	$ 27,012,309	$ 509,555,990
24	Total Generation (MWh)	1,690,885	1,470,982	1,696,354	1,965,052	1,813,247	1,499,162	1,254,705	1,287,790	1,575,915	1,545,816	1,362,273	1,331,390	18,493,571
25	Total Load (MWh)	1,186,696	1,356,450	1,582,253	1,916,684	1,763,991	1,363,255	1,196,749	1,269,935	1,507,098	1,467,155	1,305,970	1,271,211	17,187,446

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 2

Power Cost Adjustment
April 2023 thru March 2024

		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		2,221,982.74	3,006,071.09	3,437,223.59	12,886,895.53	11,461,334.14	7,444,181.67	15,680,984.56	8,559,225.36	13,738,240.92	10,268,546.59	6,808,703.71	4,172,539.41	99,685,929.31
Fuel Expense-Gas		7,084,049.35	5,632,516.53	9,664,980.87	16,368,505.15	15,390,577.21	8,095,915.38	4,831,072.03	14,413,078.28	26,189,452.80	38,423,877.14	15,831,447.36	9,968,343.12	171,893,815.22
Non-Firm Purchases		13,612,936.00	12,063,983.02	17,058,770.81	30,288,116.14	26,184,632.46	11,304,712.44	11,979,506.45	17,926,344.45	15,702,529.69	38,520,410.04	15,102,861.53	8,985,321.92	218,730,124.95
Third Party Transmission		716,175.77	602,066.71	535,012.88	1,176,942.34	1,008,219.06	768,675.58	1,746,235.99	849,206.95	904,819.59	751,248.84	787,301.02	777,689.06	10,623,593.79
Surplus Sales & Transmission Losses		(14,249,788.30)	(13,613,311.21)	(11,301,514.81)	(1,879,447.33)	(5,179,737.42)	(5,343,609.05)	(9,474,443.50)	(14,859,598.98)	(9,842,557.98)	(42,573,490.54)	(18,602,476.72)	(13,835,943.58)	(160,755,919.42)
Water for Power (Leases)		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Actual NPSE	$	9,385,355.56	7,691,326.14	19,394,473.34	58,841,011.83	48,865,025.45	22,269,876.02	24,763,355.53	26,888,256.06	46,692,485.02	45,390,592.07	19,927,836.90	10,067,949.93	340,177,543.85
Idaho Allocation		95.7%	95.8%	95.7%	96.4%	95.9%	96.2%	95.9%	95.4%	95.4%	95.5%	95.7%	95.9%	
Net Idaho Jurisctional Actual Non-QF	$	8,981,785.27	7,368,290.44	18,560,510.99	56,722,735.40	46,861,559.41	21,423,620.73	23,748,057.95	25,651,396.28	44,544,630.71	43,348,015.43	19,070,939.91	9,655,163.98	325,936,706.50
Base Non-QF														
Fuel Expense-Coal	$	7,525,242.00	7,487,643.00	9,019,153.00	11,385,255.00	12,185,412.00	10,796,845.00	7,781,442.00	7,302,324.00	8,455,019.00	5,483,866.09	5,225,193.36	4,796,697.48	97,444,091.93
Fuel Expense-Gas	$	2,314,209.00	2,302,646.00	2,773,625.00	3,501,263.00	3,747,333.00	3,320,312.00	2,392,997.00	2,245,656.00	2,600,139.00	10,014,265.74	9,541,895.08	8,759,404.84	53,513,745.65
Non-Firm Purchases	$	4,342,083.00	4,320,388.00	5,204,073.00	6,569,319.00	7,031,012.00	6,229,805.00	4,489,910.00	4,213,459.00	4,878,566.00	8,324,601.37	7,931,931.79	7,281,467.80	70,816,615.95
Third Party Transmission	$	378,398.00	376,507.00	453,517.00	572,494.00	612,729.00	542,907.00	391,281.00	367,189.00	425,151.00	858,960.68	818,443.70	751,326.61	6,548,904.00
Surplus Sales	$	(3,588,093.00)	(3,570,166.00)	(4,300,402.00)	(5,428,577.00)	(5,810,099.00)	(5,148,019.00)	(3,710,251.00)	(3,481,805.00)	(4,031,418.00)	(2,903,030.97)	(2,766,095.65)	(2,539,259.91)	(47,277,216.54)
Water for Power (Leases)	$	165,106.00	164,281.00	197,883.00	249,796.00	267,352.00	236,886.00	170,727.00	160,216.00	185,506.00	0.00	0.00	0.00	1,797,753.00
Idaho Base NPSE	$	11,136,945.00	11,081,299.00	13,347,849.00	16,849,550.00	18,033,739.00	15,978,736.00	11,516,106.00	10,807,039.00	12,512,963.00	21,778,662.91	20,751,368.28	19,049,636.81	182,843,894.00
Idaho Allocation		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.57%	95.57%	95.57%	
Net Idaho Jurisdiction 95% Items	$	10,580,097.75	10,527,234.05	12,680,456.55	16,007,072.50	17,132,052.05	15,179,799.20	10,940,300.70	10,266,687.05	11,887,314.85	20,813,868.14	19,832,082.66	18,205,737.90	174,052,703.40
Idaho Jurisdiction Change From Base	$	(1,598,312.48)	(3,158,943.61)	5,880,054.44	40,715,662.90	29,729,507.36	6,243,821.53	12,807,757.25	15,384,709.23	32,657,315.86	22,534,147.29	(761,142.75)	(8,550,573.92)	151,884,003.10
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	$	(1,518,396.86)	(3,000,996.43)	5,586,051.72	38,679,879.76	28,243,031.99	5,931,630.45	12,167,369.39	14,615,473.77	31,024,450.07	21,407,439.93	(723,085.61)	(8,123,045.22)	144,289,802.96
Idaho Jurisdictional Qualifying Facility NPSE														
Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)	$	16,401,337.57	13,300,989.58	17,636,195.14	23,467,171.34	22,980,416.01	17,241,806.00	16,357,011.20	13,643,091.85	15,759,446.92	17,281,218.32	16,967,890.11	12,465,314.51	203,501,888.55
Idaho Allocation		95.7%	95.8%	95.7%	96.4%	95.9%	96.2%	95.9%	95.4%	95.4%	95.5%	95.7%	95.9%	
Idaho Jurisctional Actual QF	$	15,696,080.05	12,742,348.02	16,877,838.75	22,622,353.17	22,038,218.95	16,586,617.37	15,686,373.74	13,015,509.62	15,034,512.36	16,503,563.50	16,238,270.84	11,954,236.62	194,995,922.99
Base QF	$	9,283,440.00	9,237,057.00	11,126,388.00	14,045,307.00	15,032,413.00	13,319,420.00	9,599,498.00	9,008,440.00	10,430,450.00	17,948,022.13	17,101,417.96	15,699,003.40	151,830,856.49
Idaho Allocation		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.57%	95.57%	95.57%	
Idaho Jurisdictional Base	$	8,819,268.00	8,775,204.15	10,570,068.60	13,343,041.65	14,280,792.35	12,653,449.00	9,119,523.10	8,558,018.00	9,908,927.50	17,152,924.75	16,343,825.15	15,003,537.55	144,528,579.80
Idaho Jurisdiction Change From Base	$	6,876,812.05	3,967,143.87	6,307,770.15	9,279,311.52	7,757,426.60	3,933,168.37	6,566,850.64	4,457,491.62	5,125,584.86	(649,361.25)	(105,554.31)	(3,049,300.93)	50,467,343.19
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	$	6,876,812.05	3,967,143.87	6,307,770.15	9,279,311.52	7,757,426.60	3,933,168.37	6,566,850.64	4,457,491.62	5,125,584.86	(649,361.25)	(105,554.31)	(3,049,300.93)	50,467,343.19
Idaho Revenue Adjustment (SBAR)														
Actual Idaho Jurisdictional Billing Month Sales	MWh	1,079,076	1,078,897	1,243,540	1,506,736	1,665,023	1,405,767	1,074,008	1,009,195	1,144,193	1,229,509	1,200,336	1,114,051	14,750,331
Normalized Idaho Jurisdictional Billing Month Sales	MWh	947,192	953,286	1,131,686	1,370,142	1,428,766	1,300,608	1,045,495	957,864	1,081,014	1,263,248	1,210,192	1,106,864	13,796,357
Sales Change	MWh	131,884	125,611	111,854	136,594	236,257	105,159	28,513	51,331	63,179	(33,739)	(9,856)	7,187	953,974
% of Prior Period Billings at Old Rate-effective thru 12/2023	$ 26.72	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	58.425%	0.786%	0.000%	
% of Current Period Billings at New Rate-effective 01/2024	$ 30.90	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	41.600%	99.200%	100.000%	
Sales Adjustment Prior To Sharing @	$	(3,523,950.16)	(3,356,314.10)	(2,988,746.58)	(3,649,793.13)	(6,312,780.62)	(2,809,857.48)	(761,859.82)	(1,371,567.66)	(1,688,151.06)	960,407.85	304,189.30	(222,064.65)	(25,420,488.11)
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	$	(3,347,752.65)	(3,188,498.40)	(2,839,309.25)	(3,467,303.47)	(5,997,141.59)	(2,669,364.61)	(723,766.83)	(1,302,989.28)	(1,603,743.51)	912,387.46	288,979.84	(210,961.42)	(24,149,463.71)
Idaho Jurisdcitional Demand Response Incentive Payments														
Idaho Actual Demand Response	$	90.32	103.84	190,860.22	2,459,729.26	2,713,656.90	1,850,742.44	1,212,407.52	27,315.09	-	-	-	-	8,454,905.59
Idaho Base Demand Response	$	780,401.00	776,502.00	935,327.00	1,180,702.00	1,263,682.00	1,119,681.00	806,970.00	757,284.00	876,823.00	857,024.33	816,598.69	749,632.90	10,920,627.92
Change From Base	$	(780,310.68)	(776,398.16)	(744,466.78)	1,279,027.26	1,449,974.90	731,061.44	405,437.52	(729,968.91)	(876,823.00)	(857,024.33)	(816,598.69)	(749,632.90)	(2,465,722.33)
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	$	(780,310.68)	(776,398.16)	(744,466.78)	1,279,027.26	1,449,974.90	731,061.44	405,437.52	(729,968.91)	(876,823.00)	(857,024.33)	(816,598.69)	(749,632.90)	(2,465,722.33)
Idaho Miscellaneous Revenue														
System Emission Allowance Sales Credit	$	-	-	-	-	-	-	-	-	-	-	-	-	-
System Renewable Energy Credit Sales	$	(630,210.04)	(259,069.46)	335.82	(364,192.90)	(1,649,463.00)	(84,934.41)	(163,816.01)	(28,547.22)	(3,835,483.45)	(6,144,859.78)	(5,124,642.59)	(159,687.15)	(18,444,570.19)
Revenue Subtotal	$	(630,210.04)	(259,069.46)	335.82	(364,192.90)	(1,649,463.00)	(84,934.41)	(163,816.01)	(28,547.22)	(3,835,483.45)	(6,144,859.78)	(5,124,642.59)	(159,687.15)	(18,444,570.19)
Idaho Allocation		95.7%	95.8%	95.7%	96.4%	95.9%	96.2%	95.9%	95.4%	95.4%	95.5%	95.7%	95.9%	
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	$	(572,955.46)	(235,779.12)	305.31	(333,527.86)	(1,502,743.27)	(77,621.56)	(149,244.58)	(25,872.35)	(3,476,098.65)	(5,574,924.04)	(4,659,068.81)	(145,482.98)	(16,753,013.37)

Idaho EIM Participation Costs														
Return on EIM Capital Investment	$	28,871.58	28,222.16	27,572.73	26,923.30	26,273.88	25,624.45	24,975.02	24,325.60	23,676.17	-	-	-	236,464.90
Operating Expenses	$	167,711.80	184,168.76	174,913.14	183,130.19	215,392.32	262,228.23	212,616.66	155,300.39	164,197.09	-	-	-	1,719,658.58
Revenue Subtotal	$	196,583.38	212,390.91	202,485.87	210,053.50	241,666.20	287,852.68	237,591.68	179,625.99	187,873.26	0.00	0.00	0.00	1,956,123.47
Sharing Percentage		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	0.0%	0.0%	0.0%	
EIM Revenue Requirement ⑥	$	186,754.21	201,771.37	192,361.58	199,550.82	229,582.89	273,460.05	225,712.10	170,644.69	178,479.60	0.00	0.00	0.00	1,858,317.31
TOTAL DEFERRAL (Sum of ①-⑥)	**$**	**844,150.61**	**(3,032,756.87)**	**8,502,712.73**	**45,636,938.03**	**30,180,131.52**	**8,122,334.14**	**18,492,358.24**	**17,184,779.54**	**30,371,849.37**	**15,238,517.77**	**(6,015,327.58)**	**(12,278,423.45)**	**153,247,264.05**
PCA Forecasted Revenues														
Actual Idaho Jurisdictional Billing Month Sales	MWh	1,079,076	1,078,897	1,243,540	1,506,736	1,665,023	1,405,767	1,074,008	1,009,195	1,144,193	1,229,509	1,200,336	1,114,051	14,750,331
% of Prior Period Billings at Old Rate		100.000%	100.000%	58.321%	1.563%	0.000%	0.000%	0.000%	0.000%	0.000%	58.425%	0.786%	0.000%	
% of Current Period Billings at New Rate		0.000%	0.000%	41.700%	98.400%	100.000%	100.000%	100.000%	100.000%	100.000%	41.600%	99.200%	100.000%	
Forecast Rate Revenues ⑦		(12,259,386.52)	(12,257,343.81)	(15,642,099.90)	(21,950,132.14)	(24,262,717.74)	(20,489,411.26)	(15,652,952.14)	(14,707,632.03)	(16,673,307.14)	(12,700,800.30)	(4,216,873.09)	(3,844,373.82)	(174,657,029.89)
PCA Balancing Account Balance														
Monthly Interest Rate 2% for 2023 and 5% for 2024	%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.4167%	0.4167%	0.4167%	2.7500%
Beginning Balance		$ 190,205,568.62	176,366,072.47	158,628,085.50	146,720,978.03	161,097,764.80	156,699,273.09	135,654,963.94	131,890,644.72	128,177,579.55	134,815,898.27	130,106,737.33	112,709,561.34	190,205,568.62
2023-2024 Incremental Deferral (Sum of ①-⑥ above		844,150.61	(3,032,756.87)	8,502,712.73	45,636,938.03	30,180,131.52	8,122,334.14	18,492,358.24	17,184,779.54	30,371,849.37	15,238,517.77	(6,015,327.58)	(12,278,423.45)	153,247,264.05
2023-2024 PCA Forecast Revenues (Collections) ⑦ above		(12,259,386.52)	(12,257,343.81)	(15,642,099.90)	(21,950,132.14)	(24,262,717.74)	(20,489,411.26)	(15,652,952.14)	(14,707,632.03)	(16,673,307.14)	(12,700,800.30)	(4,216,873.09)	(3,844,373.82)	(174,657,029.89)
2023-2024 PCA Prior Balance Revenues (Collections)		(2,741,269.52)	(2,741,829.74)	(5,032,100.44)	(9,554,554.08)	(10,584,401.76)	(8,938,397.49)	(6,829,816.93)	(6,410,030.42)	(7,273,852.81)	(7,808,611.32)	(7,707,086.73)	(7,085,199.72)	(82,707,150.96)
Revenue Sharing - Order No.		-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Rider Forecasted Surplus Funds - Order No.		-	-	-	-	-	-	-	-	-	-	-	-	-
2023-2024 Ending Balance Without Current Month Interest		176,049,063.19	158,334,142.05	146,456,597.89	160,853,229.84	156,430,776.82	135,393,798.48	131,664,553.11	127,957,761.81	134,602,268.97	129,545,004.42	112,167,449.93	89,501,564.35	86,088,651.82
Current Month Interest		317,009.28	293,943.45	264,380.14	244,534.96	268,496.27	261,165.46	226,091.61	219,817.74	213,629.30	561,732.91	542,111.41	469,623.17	3,882,535.70
2023-2024 Ending Deferral Balance		**$ 176,366,072.47**	**158,628,085.50**	**146,720,978.03**	**161,097,764.80**	**156,699,273.09**	**135,654,963.94**	**131,890,644.72**	**128,177,579.55**	**134,815,898.27**	**130,106,737.33**	**112,709,561.34**	**89,971,187.52**	**89,971,187.52**

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

Idaho Billed Sales	MWh	1,079,076	1,078,897	1,243,540	1,506,736	1,665,023	1,405,767	1,074,008	1,009,195	1,144,193	1,229,509	1,200,336	1,114,051	14,750,331
Oregon Billed Sales	MWh	48,403	47,674	55,881	56,914	70,809	56,024	46,374	48,778	55,179	58,434	53,656	47,133	645,259
Total	MWh	1,127,479	1,126,570	1,299,421	1,563,650	1,735,832	1,461,792	1,120,381	1,057,973	1,199,372	1,287,943	1,253,992	1,161,184	15,395,590
Idaho % Billed Sales		95.7%	95.8%	95.7%	96.4%	95.9%	96.2%	95.9%	95.4%	95.4%	95.5%	95.7%	95.9%	
Oregon % Billed Sales		4.3%	4.2%	4.3%	3.6%	4.1%	3.8%	4.1%	4.6%	4.6%	4.5%	4.3%	4.1%	

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

EXHIBIT NO. 3

1 **IDAHO POWER COMPANY**

3 **ADDITIONAL INVESTMENT TAX CREDIT ANALYSIS**

4 **For the Twelve Months Ended December 31, 2023**

Line		Actual September 30, 2023			Actual December 31, 2023		
7		TOTAL			TOTAL		
8		SYSTEM	IDAHO	IDAHO %	SYSTEM	IDAHO	IDAHO %
9	*** SUMMARY OF RESULTS ****						
10	TOTAL COMBINED RATE BASE	4,206,978,903	4,022,103,489	95.606%	September Allocations/Ratios		
11							
12	DEVELOPMENT OF NET INCOME						
13	OPERATING REVENUES						
14	RETAIL SALES REVENUES (Incl 449.1 Rev)	1,131,444,961	1,084,202,950	Direct Assign	1,472,666,391	1,409,982,947	Direct Assign
15	OTHER OPERATING REVENUES	216,499,424	207,160,642	95.7%	285,571,483	273,253,253	95.7%
16	TOTAL OPERATING REVENUES	1,347,944,384	1,291,363,592		1,758,237,874	1,683,236,200	
17							
18	OPERATING EXPENSES						
19	OPERATION & MAINTENANCE EXPENSES	904,132,356	863,119,398	95.5%	1,209,651,994	1,154,780,153	95.5%
20	DEPRECIATION EXPENSE	137,896,300	132,136,256	95.8%	187,945,683	180,095,035	95.8%
21	AMORTIZATION OF LIMITED TERM PLANT	3,994,103	3,827,696	95.8%	5,439,874	5,213,231	95.8%
22	TAXES OTHER THAN INCOME	21,599,657	19,903,828	92.1%	25,081,924	23,112,696	92.1%
23	REGULATORY DEBITS/CREDITS	1,384,615	1,146,334	82.8%	1,846,154	1,528,445	82.8%
24	PROVISION FOR DEFERRED INCOME TAXES	(16,780,812)	(16,131,902)	96.1%	(22,518,627)	(21,647,836)	96.1%
25	INVESTMENT TAX CREDIT ADJUSTMENT	10,660,148	10,204,953	95.7%	50,193,136	48,049,858	95.7%
26	FEDERAL INCOME TAXES	32,639,240	31,794,214	97.4%	(4,035,971)	(3,931,480)	97.4%
27	STATE INCOME TAXES	8,535,520	8,344,625	97.8%	319,336	312,194	97.8%
28	TOTAL OPERATING EXPENSES	1,104,061,128	1,054,345,402		1,453,923,503	1,387,512,294	
29							
30	OPERATING INCOME	243,883,256	237,018,190		304,314,371	295,723,906	
31	ADD: IERCO OPERATING INCOME	5,742,172	5,490,626	95.6%	8,033,987	7,682,044	95.6%
32							
33	OPERATING INCOME BEFORE OTHER INCOME AND DEDUCTIONS	249,625,428	242,508,817		312,348,358	303,405,950	97.1%
34	ADD: AFUDC EQUITY				43,221,277	41,321,921	95.6% (L 10)
35	ADD: OTHER INCOME AND DEDUCTIONS				17,357,747	16,860,801	97.1% (L 33)
36							
37	INCOME BEFORE INTEREST CHARGES				372,927,382	361,588,672	
38	LESS: INTEREST CHARGES				116,116,912	111,014,162	95.6% (L 10)
39							
40	NET INCOME				256,810,470	250,574,510	
41							
42	ACTUAL YEAR-END RESULTS - BEFORE ITC ADJUSTMENT						
43	EARNINGS ON COMMON STOCK				256,810,470	250,574,510	
44	COMMON EQUITY AT YEAR END				2,782,171,830	2,659,909,470	95.6% (L10)
45							
46	RETURN ON YEAR-END COMMON EQUITY				9.23%	9.42%	
47							
48	EARNINGS ON COMMON STOCK @ 9.40 ROE				261,524,152	**250,031,490**	(L44 * 9.4%)
49	EARNINGS ON COMMON STOCK @ 10 ROE				278,217,183	**265,990,947**	(L44 * 10%)
50	EARNINGS ON COMMON STOCK @ 10.50 ROE				292,128,042	**279,290,494**	(L44 * 10.5%)
51							
52							
53	ACTUAL YEAR-END RESULTS - AFTER ITC ADJUSTMENT:						
54	INVESTMENT TAX CREDIT ADJUSTMENT					(599,360)	(L48-L43) / (1-9.4%)
55	ADJUSTED EARNINGS ON COMMON STOCK					249,975,150	
56	ADJUSTED COMMON EQUITY AT YEAR-END					2,659,310,110	
57	ADJUSTED RETURN ON YEAR-END COMMON EQUITY					9.40%	
58							
59	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) <9.4%**						
60	ADDITIONAL ITC ADJUSTMENT (Annualized)	If L 54 is negative, then 0; if positive, then smaller of L54 or $25,000,000				0	
61							
62	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) >10%**						
63	IDAHO EARNINGS GREATER THAN 10% ROE BUT LESS THAN 10.5%					0	(L43-L49)/(1-10%)
64							
65	**IF IDAHO RETURN ON COMMON EQUITY (Line 46) >10.5%**						
66	INCREMENTAL IDAHO EARNINGS GREATER THAN 10.50% ROE					0	(L43-L50)/(1-10.5%)
67							
68	**Per Order #34071:**					After Tax	Tax Gross Up
69	ROE between 10%-10.5% --CUSTOMER SHARE - 80% (Reduction to rates)					0	-
70	ROE between 10%-10.5% --COMPANY SHARE - 20%					0	
71	ROE greater than 10.5% (Incremental) -- CUSTOMER SHARE - 55% (Reduction to rates)					0	-
	ROE greater than 10.5% (Incremental) -- CUSTOMER SHARE - 25% (Offset to Pension balance)					0	-
72	ROE greater than 10.5% (Incremental) --COMPANY SHARE - 20%					0	
73						0	
74							

Exhibit No. 3
Case No. IPC-E-24-17
J. Brady, IPC

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

CONFIDENTIAL
EXHIBIT NO. 4

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-24-17

IDAHO POWER COMPANY

BRADY, DI
TESTIMONY

CONFIDENTIAL
EXHIBIT NO. 5