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, 2021, THROUGH MAY 31, 2022.	)))))))	CASE NO. IPC-E-21-10

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

NICOLE A. BLACKWELL

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

A. My name is Nicole A. Blackwell. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as a Regulatory Consultant in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2010, I received Bachelor of Science degrees in Finance and Economics 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 Advanced Course."

Q. Please describe your work experience with Idaho Power.

A. In January 2016, I was hired as a Regulatory Analyst in Idaho Power's Regulatory Affairs Department, and in 2021 I was promoted to my current position of Regulatory Consultant. As a Regulatory Consultant, I provide support for the Company's regulatory activities, including compliance reporting, financial analysis, and the development of revenue forecasts for regulatory filings.

Q. What is the Company requesting in this case?

A. The Company is requesting approval of its 2021-2022 Power Cost Adjustment ("PCA") rates to become effective June 1, 2021. If approved, the 2021-2022 PCA will result in an increase in total billed revenue of approximately $39.1 million, or 3.36 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 2021-2022 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 2021-2022 PCA rates to become effective June 1, 2021. In the third section, I will discuss the additional PCA component related to revenue sharing. In the final section, I detail the net customer impact of the 2021-2022 PCA rates if approved as filed.

I. PCA OVERVIEW

Q. What is the purpose of the PCA and how does the mechanism function?

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 True-up component ("True-up"). 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 True-up component includes a backward-looking tracking of differences between the prior PCA year's forecast and actual NPSE incurred by the Company. The True-up contains a second component that tracks the collection of the prior year's True-up amount, referred to as the "True-up of the True-up."

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 Idaho Public Utilities Commission ("Commission") in Order No. 34071.

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

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 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. 2021-2022 PCA

Q. What is the total PCA collection that would result under the 2021-2022 PCA rates proposed by the Company in this case?

A. The 2021-2022 PCA rates would result in total PCA collection of $109.3 million. This represents an increase in total billed revenue of $39.1 million for the upcoming year, an increase of 3.36 percent.

Q. Have you prepared a table that details the $39.1 million revenue impact by component?

A. Yes. Table 1 presents a separation of the $39.1 million increase into each component included in the Company's proposed rates.

Table 1	Revenue Impact by Component			
Line No.	Rate Component	2020-2021 PCA[1]	2021-2022 PCA[2]	Difference
1	PCA Forecast	$ 113,084,635	$ 126,944,108	$ 13,859,473
2	PCA True-up	$(42,892,181)	$ (17,641,954)	$ 25,250,227
3	**PCA Total**	**$ 70,192,455**	**$ 109,302,154**	**$ 39,109,700**

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

A. The increase in this year's PCA is primarily attributed to a smaller credit to customers through the true-up component. This year's PCA true-up reflects a credit to customers of approximately $17.6 million, which is $25.3 million, or 59 percent, less than last year's PCA true-up credit of $42.9 million. This year's lower true-up credit balance demonstrates that actual power supply costs for the 2020-2021 PCA Year were more in line with forecast power supply costs included in last year's PCA forecast than the forecast-to-actuals variance from the 2019-2020 PCA Year. As a result, the true-up credit is smaller than last year and is driving an increase in the PCA.

[1] Because Table 1 contains the expected billed revenue impact to customers, the "2020-2021 PCA" column reflects approved 2020-2021 PCA rates applied to the June 2021 through May 2022 sales forecast, and will not tie to the specific dollar amounts approved in the 2020 PCA filing.

[2] The "2021-2022 PCA" column reflects the Company's proposed rates applied to the June 2021 through May 2022 forecast, and may not tie exactly to the figures listed in the Company's testimony due to the rounding of rates to six digits.

The increase in this year's PCA forecast component is attributed to lower expected hydro generation and higher market energy prices, which are resulting in increased reliance on thermal generation and decreased market power purchases. Additionally, this year's PCA forecast reflects higher PURPA expense. These drivers will be discussed in detail later in testimony.

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 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[3] and the forecast of NPSE for the 2021-2022 PCA Year?

A. The system-level forecast of NPSE for the 2021-2022 PCA Year is $442,357,407, which is $136,672,538 higher than the currently approved base level NPSE of $305,684,869. Table 2 presents the system-level differences between currently approved base level NPSE and the forecast of NPSE for the 2021-2022 PCA Year by FERC

[3] *In the Matter of the Application of Idaho Power Company for Authority to Establish a New Base Level of Net Power Supply Expense*, Case No. IPC-E-13-20, Order No. 33000 (March 21, 2014).

account.

Table 2	2021-2022 PCA FORECAST (Total System)			
Line No.	FERC Account	Base NPSE	Forecast	Difference
	95% Sharing Accounts			
1	Account 501, Coal	$ 108,503,180	$ 118,562,796	$ 10,059,616
2	Account 536, Water for Power	$ 2,380,597	$ 0	$ (2,380,597)
3	Account 547, Other Fuel	$ 33,367,563	$ 57,235,044	$ 23,867,481
4	Account 555, Purchased Power Non-PURPA	$ 62,606,593	$ 74,800,530	$ 12,193,937
5	Account 565, 3rd Party Transmission	$ 5,455,955	$ 4,853,909	$ (602,046)
6	Account 447, Surplus Sales	$ (51,735,153)	$ (25,842,225)	$ 25,892,928
		$ 160,578,735	$ 229,610,054	$ 69,031,319
	100% Sharing Accounts			
7	Account 555, PURPA	$ 133,853,869	$ 205,133,741	$ 71,279,872
8	Account 555, Demand Response Incentives	$ 11,252,265	$ 7,613,612	$ (3,638,653)
9	Total	$ 305,684,869	$ 442,357,407	$ 136,672,538

Q. What is the basis for the forecast of NPSE for the 2021-2022 PCA Year?

A. The forecast of NPSE for the 2021-2022 PCA Year is based on the Company's March 25, 2021, 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 the Langley Gulch power plant ("Langley Gulch"), based on economics and available generating capacity at Langley Gulch. Economically dispatched generation above the system load forecast represents surplus energy sales. The forecast of monthly NPSE and generation for the 2021-2022 PCA Year, as determined in the Company's March 25, 2021, Operating Plan, is provided in Exhibit No. 1.

Q. How does the Company's forecast of system-level NPSE for the 2021-2022 PCA compare to the system-level forecast included in last year's PCA?

A. Table 3 compares this year's 2021-2022 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 2021-2022 PCA Year is $442,357,407, which is $15,452,686 higher than last year's forecast amount of $426,904,721.

Table 3	PCA Forecast Comparison Expenses (Total System)			
Line No.	FERC Account	2020-2021 Forecast	2021-2022 Forecast	Difference
	95% Sharing Accounts			
1	Account 501, Coal	$ 102,534,012	$ 118,562,796	$ 16,028,783
2	Account 536, Water for Power	$ 1,500,000	$ 0	$ (1,500,000)
3	Account 547, Other Fuel	$ 42,599,268	$ 57,235,044	$ 14,635,776
4	Account 555, Purchased Power Non-PURPA	$ 89,849,920	$ 74,800,530	$ (15,049,389)
5	Account 565, 3rd Party Transmission	$ 5,058,450	$ 4,853,909	$ (204,541)
6	Account 447, Surplus Sales	$ (16,076,860)	$ (25,842,225)	$ (9,765,365)
		$ 225,464,790	$ 229,610,054	$ 4,145,264
	100% Sharing Accounts			
7	Account 555, PURPA	$ 193,826,319	$ 205,133,741	$ 11,307,422
8	Account 555, Demand Response Incentives	$ 7,613,612	$ 7,613,612	$ -
		$ 201,439,931	$ 212,747,353	$ 11,307,422
9	Total PCA Forecast	$ 426,904,721	$ 442,357,407	$ 15,452,686

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 $4.1 million from last year's forecast, while the 100 percent sharing accounts have increased approximately $11.3 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 increase by 2 percent as compared to last year, from $225,464,790 to $229,610,054. Due to a reduction in forecast hydro generation and higher forecast market energy prices, the Company expects to rely more on thermal generation to serve load and is expected to decrease market power purchases.

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

A. In addition to lower forecast hydro generation, which will be discussed in detail later, higher forecast market energy prices are contributing to increased generation at the Company's thermal plants. For the 2021-2022 PCA Year, forward market prices range from a low of 10.35 per MWh to a high of $78.80 per MWh compared to a low of $4.85 per MWh and a high of $45.85 per MWh for last year's PCA. As a result of higher market energy prices, thermal generation becomes more economic, wherein the average per-unit costs of natural gas and coal-fired generation are $24.45 per MWh and $32.94 per MWh, respectively. Accordingly, natural gas expense is expected to increase 34 percent as compared to last year's forecast, from $42,599,268 to $57,235,044, and coal fuel expense is expected to increase 16 percent, from $102,534,012 to $118,562,796.

The increase in forecast market energy prices is also causing a $15,049,389 decrease in non-PURPA purchased power, a 17 percent decrease from last year's forecast. Non-PURPA purchased power expense includes market power purchases, as well as power purchase agreements ("PPAs"). The decrease in forecast non-PURPA purchased power is primarily related to market power purchases, which are expected to decrease from $41,404,266 in last year's PCA forecast to $24,654,472 in this year's PCA forecast, a 40 percent decrease.

The reduction in forecast hydro generation is also resulting in lower surplus sales volumes. However, as a result of higher market energy prices, surplus sales revenue is expected to increase 61 percent compared to last year, from $16,076,860 to $25,842,225. For the 2021-2022 PCA Year, the average forecast market sales price is $34.25 per MWh compared with $15.14 last year, a 126 percent increase.

Finally, this year's PCA forecast does not include water lease expense whereas last year's PCA forecast included $1.5 million in water lease expense. The Company does not anticipate procuring a water lease for this PCA Year due to weaker snowpack conditions in the Upper Snake basin and the decreased availability of water.

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

A. Forecast expenses included in the 100 percent sharing accounts are expected to increase by 6 percent as compared to last year, from $201,439,931 to $212,747,353.

With regard to the 100 percent sharing accounts, forecast PURPA costs increased by $11.3 million as compared to last year's forecast, while forecast demand response incentive payments did not change.

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, PURPA generation is anticipated to increase by 51,350 MWh, or less than 2 percent. The 6 percent increase in PURPA expense is largely the result of price escalation in PURPA contracts, whereby the average cost is $67.75 per MWh.

Table 4	PCA Forecast Comparison Generation (Total System-MWh)			
Line No.	FERC Account	2020-2021 Forecast	2021-2022 Forecast	Difference
1	Hydro	7,341,717	6,690,890	(650,827)
	<u>95% Sharing Accounts</u>			
2	Account 501, Coal	2,972,154	3,599,219	627,064
3	Account 547, Other Fuel	1,973,546	2,340,994	367,448
4	Account 555, Purchased Power Non-PURPA	2,095,454	1,478,696	(616,758)
	95% Sharing Accounts	14,382,871	14,109,799	(273,072)
	<u>100% Sharing Accounts</u>			
5	Account 555, PURPA	2,976,554	3,027,905	51,350
	100% Accounts	2,976,554	3,027,905	51,350
6	Total Generation	17,359,425	17,137,704	(221,721)
	<u>95% Sharing Accounts</u>			
7	Account 447, Surplus Sales	1,062,077	754,975	(307,102)
8	Total Load	16,297,348	16,382,729	85,381

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 decrease 650,827 MWh, or 9 percent. The decrease in hydro generation is driving a decrease in surplus sales volumes of 307,102 MWh, or 29 percent. As discussed previously, the decrease in forecast hydro generation is also resulting in an increase in thermal generation. Coal-fired generation is projected to increase 627,064 MWh compared to last year, or 21 percent, while natural gas generation is expected to increase 367,448 MWh, or 19 percent, compared to last year. Additionally, non-PURPA purchased power is expected to decrease by 616,758 MWh, or 29 percent. As discussed earlier, higher forward market prices are contributing to increased economic dispatch of the Company's thermal plants for load service and reducing market power purchases.

Q. What is causing the decrease in expected hydro generation of 650,827 MWh?

A. The decrease in expected hydro generation is mainly due to lower projected inflows into Brownlee reservoir. The March Operating Plan used in this year's PCA forecast projects April through July inflows into Brownlee of 4.2 million acre-feet ("MAF") as compared to 4.6 MAF used to determine last year's PCA forecast, a decrease of 9 percent. Expected inflows into Brownlee were higher for last year's PCA forecast as a result of better snowpack conditions, which provide for sustained runoff and increased hydro generation during the spring and summer months.

Additionally, this year's PCA forecast reflects weaker reservoir storage conditions, as compared to last year's forecast. The March Operating Plan used in this year's PCA demonstrates that available storage in the 11 reservoirs above Brownlee is 113 percent of normal and at 75 percent of capacity, compared to last year's 2020 March Operating Plan, in which storage was 125 percent of normal and at 82 percent of capacity. Together weaker snowpack conditions and carryover as compared to the prior year are resulting in the 9 percent reduction in forecast hydro generation for the 2021-2022 PCA Year.

Q. How are the forecasted NPSE differences presented in Table 2 used to determine the 2021-2022 PCA forecast component to be collected from Idaho customers?

A. The 2021-2022 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. What is the Company's forecast of system-level firm sales and Idaho jurisdictional firm sales for the 2021-2022 PCA Year?

A. For the 2021-2022 PCA Year, Idaho Power has forecast system-level firm sales to be 15,131,418 MWh and Idaho jurisdictional firm sales to be 14,436,951 MWh, or 95.41 percent of the system level.

Q. What is the Company's determination of the 2021-2022 PCA forecast component to be collected from Idaho customers?

A. The 2021-2022 PCA forecast component to be collected from Idaho customers is $126,939,705. Table 5 presents the determination of the 2021-2022 PCA forecast component by individual PCA expense and revenue category.

Table 5	2021-2022 PCA FORECAST			
Line No.	FERC Account	Difference from Base	Difference After Sharing	Idaho Allocation
	95% Sharing Accounts	(From Table 1)		
1	Account 501, Coal	$ 10,059,616	$ 9,556,635	$ 9,118,026
2	Account 536, Water for Power	$ (2,380,597)	$ (2,261,567)	$ (2,157,771)
3	Account 547, Other Fuel	$ 23,867,481	$ 22,674,107	$ 21,633,463
4	Account 555, Purchased Power Non-PURPA	$ 12,193,937	$ 11,584,240	$ 11,052,574
5	Account 565, 3rd Party Transmission	$ (602,046)	$ (571,944)	$ (545,694)
6	Account 447, Surplus Sales	$ 25,892,928	$ 24,598,282	$ 23,469,327
		$ 69,031,319	$ 65,579,753	$ 62,569,925
	100% Sharing Accounts			
7	Account 555, PURPA	$ 71,279,872	$ 71,279,872	$ 68,008,433
8	Account 555, Demand Response Incentives	$ (3,638,653)	$ (3,638,653)	$ (3,638,653)
9	Total	$ 136,672,538	$ 133,220,972	$ 126,939,705

B. True-up and True-up of the True-up.

Q. What is this year's quantification of the True-up?

A. The True-up portion of the PCA is detailed in the deferral expense 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 2021, with interest applied, was negative $22,156,786, as shown on row 104 of Exhibit No. 2. The approximate negative $22.1 million represents a refund due to customers in this year's PCA True-up.

Q. To what factors do you attribute the accumulation of the approximate negative $22.1 million deferral balance?

A. The approximate negative $22.1 million deferral balance was largely driven by unpredictable changes in market energy prices and the resulting variation between forecast prices and actual prices. Because actual market energy prices were higher than expected, it resulted in higher than forecast surplus sales revenue and coal fuel expense. The increase in market energy prices also resulted in higher than forecast market power purchase expense. Actual natural gas prices were also higher than forecast driving an increase in natural gas fuel expense. Although actual market energy prices and natural gas prices were higher than forecast, the Company's reliance on market power purchases and natural gas generation did not decrease as they were needed to serve load due to lower than expected hydro generation.

Q. Please elaborate on the changes in actual versus forecast generation and expense for the 2020-2021 PCA Year.

A. Last year's PCA forecast included an average market sales price of $15.14 per MWh. The actual average market sales price was $34.45 per MWh, a 128 percent increase. As a result of the difference in forecast and actual market sales prices, actual surplus sales volumes were 77 percent higher than forecast and surplus sales revenue totaled $64,583,553, which was 302 percent higher than forecast surplus sales revenue of $16,076,860.

Coal-fired generation totaled 3,794,008 MWh, which was 28 percent higher than forecast, and actual coal fuel expense was $18.3 million, or 18 percent, higher than forecast. Coal-fired generation was higher than forecast due to the increase in market energy prices, making it more economic for load service and surplus sales.

The increase in market energy prices contributed to higher than forecast purchased power expense. The actual average market purchase price for the 2020-2021 PCA year was $30.45 per MWh, a 12 percent increase from the average forecast price of $27.14 per MWh. Market power purchases totaled 1,583,605 MWh, which was 4 percent higher than forecast. As a result, market purchased power expense was $48,225,168 compared to $41,404,266 included in the forecast, reflecting a 16 percent increase.

Natural gas generation totaled 2,112,933 MWh for the 2020-2021 PCA Year, which was 139,387 MWh, or 7 percent, higher than forecast. Due to natural gas prices being higher than expected, actual natural gas expense totaled $54,873,821, which was 29 percent higher than forecast.

Although actual market energy prices and natural gas prices were higher than forecast, the Company's reliance on these resources increased, 4 percent and 7 percent, respectively, as they were needed to meet load due to the reduction in hydro generation. Actual hydro generation for the 2020-2021 PCA year was 6,786,206 MWh, which was 555,511 MWh, or 8 percent, less than forecast.

Finally, actual water for power expense was $480,000 compared to forecast expense of $1.5 million. Due to weaker-than-expected hydrologic conditions in the Upper Snake Basin last year and the resulting decrease in water availability, the Company was not able to procure as much leased water as expected.

Q. Please explain the water lease the Company entered into in 2020.

A. In 2020, Idaho Power entered into an agreement to purchase water from the Water District 1 supplemental rental pool. The agreement totaled 20,000 acre-feet at a price of $24 per acre foot for a total cost of $480,000, as shown on line 26 of Exhibit No. 2. The water was delivered above American Falls and flowed through Idaho Power's system, passing Milner Dam between September 15, 2020, and September 25, 2020.

Q. How did the water lease impact hydro generation?

A. Based on the actual daily water flow, the Company estimated that hydro generation from the water lease totaled 20,756 MWh, resulting in a price of approximately $23.13 per MWh.

Q. Did the water lease expense and associated increase in hydro generation benefit customers?

A. Yes. Idaho Power was able to reduce market purchases during this time by using the leased water and running additional water through the Hells Canyon Complex. The purchase of leased water at $23.13 per MWh compared favorably with the average price paid for market purchases during the month, which was approximately $61.55 per MWh.

This additional hydro generation also contributed to Idaho Power's ability to sell into high-priced hours to the benefit of customers. The average price for market sales during the month was $55.98 per MWh, compared to the cost of the leased water at $23.13 per MWh, resulting in net revenue from surplus sales.

Q. Were there any items included in this year's True-up in addition to actual NPSE incurred during the April 2020 through March 2021 period?

A. Yes. Per Commission Order No. 34100, Idaho Power included its actual costs of Western Energy Imbalance Market ("EIM") participation for April 2020 through March 2021 in the True-up. Benefits associated with EIM participation are embedded in actual NPSE experienced over that same period.

Q. Please summarize the conditions of Order No. 34100 as they pertain to EIM cost recovery through the 2021 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 2020 through March 2021 PCA deferral under the soft cap of annual CAISO-reported benefits for that same period?

A. Yes. For the April 2020 through March 2021 period, the EIM-related revenue requirement totaled $3.2 million, while CAISO reported EIM benefits for Idaho Power of approximately $21 million from April through December (CAISO's first quarter 2021 report has not yet been published). 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 2020 and December 2020 are approximately $14 million (benefits for the first quarter of 2021 are not yet available). This level of EIM benefits compared to the Idaho-jurisdictional EIM costs of $3.2 million, demonstrates a net benefit to the Company and, ultimately, its customers.

Q. What is this year's True-up of the True-up?

A. This year's True-up of the True-up balance is $4,519,614, as shown on row 124 of Exhibit No. 2.

Q. What is the combined effect of the True-up and the True-up of the True-up in this year's PCA?

A. The sum of the negative $22.1 million associated with the True-up and the $4.5 million associated with the True-up of the True-up represents an approximate $17.6 million credit to customers.

Q. How does this year's combined True-up and the True-up of the True-up compare to last year's amount?

A. The combined True-up and the True-up of the True-up for the last PCA Year was negative $42,648,447, as compared with this year's amount of negative $17,637,172. While this year's true-up reflects a credit to customers, it is approximately 59 percent less than the credit customers are currently receiving through last year's true-up, and ultimately reflects an increase in billed revenue of $25,011,275.

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

Q. How is the rate for the forecast portion of the PCA for April 2021 through March 2022 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, 2021, through May 31, 2022 ("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, 2021, through May 31, 2022.

Q. What is the rate for the forecast portion of the PCA for April 2021 through March 2022?

A. The rate for non-PURPA expenses is 0.4334 cents per kilowatt-hour ("kWh"), which is calculated by multiplying $69,031,319 from Table 2 by 95 percent and then dividing it by the System-level Sales Forecast of 15,131,418 MWh (($69,031,319 * 0.95) / 15,131,418) = $4.334/MWh = 0.4334 cents/kWh). The rate for PURPA expenses is 0.4711 cents per kWh, which is calculated by dividing $71,279,872 from Table 2 by the 15,131,418 MWh ($71,279,872 / 15,131,418 MWh = $4.711/MWh = 0.4711 cents/kWh). The rate for demand response incentive payments is a negative 0.0252 cents per kWh, which is calculated by dividing the negative $3,638,653 from Table 2 by the forecast of Idaho jurisdictional firm sales of 14,436,951 MWh (-$3,638,653 / 14,436,951 MWh = -$0.252/MWh = -0.0252 cents/kWh). The forecast portion of the PCA rate is 0.8793 cents per kWh, which is calculated by adding the non-PURPA expense of 0.4334 cents per kWh to the PURPA expense of 0.4711 cents per kWh to the demand response incentive payment of negative 0.0252 cents per kWh (0.4334 + 0.4711 + -0.0252 = 0.8793 cents/kWh).

Q. How did you compute this year's True-up rate?

A. As shown in Exhibit No. 2, this year's True-up component of the PCA is approximately negative $22.1 million, which, when divided by the Company's forecast of Idaho jurisdictional sales of 14,436,951 MWh, results in a rate of negative 0.1535 cents per kWh (-$22,156,786 / 14,436,951 = -$1.535/MWh = -0.1535 cents/kWh).

The True-up of the True-up rate is calculated by dividing $4,519,614 (also from Exhibit No. 2) by the forecast of Idaho jurisdictional sales of 14,436,951 MWh, which results in a rate of 0.0313 cents per kWh ($4,519,614 / 14,436,951 = $0.313/MWh = 0.0313 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 0.8793 cents per kWh for the 2021-2022 projected power cost of serving firm loads under the current PCA methodology and 95 percent sharing, (2) the negative 0.1535 cents per kWh for the 2020-2021 True-up portion of the PCA, and (3) the 0.0313 cents per kWh for the True-up of the True-up. The sum of these three components is a 0.7571 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 three times.[4] Most recently, the revenue sharing mechanism was extended indefinitely, with modifications, in Order No. 34071 in Case No. GNR-U-18-01.

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

[4] Order Nos. 32424, 33149 and 34071.

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. Did the revenue sharing mechanism result in any action following the 2009-2019 fiscal years?

A. Yes. The Company's earnings in each year from 2011 through 2015, as well as 2018, resulted in revenue sharing with customers totaling $126.2 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 and 2019 were below the revenue sharing threshold. These amounts are detailed in Table 6.

Table 6	2009-2018 Revenue Sharing				
Line No.	Revenue Sharing Component	2009-2011	2012-2014	2015-2019	
1	Available ADITC For Use	$45 Million	$45 Million	$45 Million	
2	ROE Threshold	9.5%	9.5%	10.0%	
3	50-50 Sharing Threshold	10.5%	10.0%	N/A	
4	75-25 Sharing Threshold	N/A	10.5%	10.0%	
5	Customer Benefits ($ Millions):				
6	Reduction to Rates	$27.1	$22.8	$8.2	Total
7	Offset to Pension Balancing Account	$20.3	$47.8	$0.0	2009-2019
8	Total	$47.4	$70.6	$8.2	$126.2

Q. Did the Company's year-end 2020 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 2020 financial results yielded an actual Idaho jurisdictional ROE of 9.98 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 2020 year-end ROE that was used in prior PCA filings?

A. Yes. The methodology used to determine the Company's Idaho jurisdictional 2020 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 2020 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 2021 through May 2022 test year results in a PCA increase of $39.1 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. Should the Commission approve the Company's computation of the PCA rates?

A. Yes. The Commission should approve the Company's computation of the PCA rates. The calculation of the PCA rates follows the methodology that was approved in Order Nos. 30715, 33307, and 34071. If approved, the 2021-2022 PCA will result in an increase in total billed revenue of approximately $39.1 million, or 3.36 percent.

Q. Does this conclude your testimony?

A. Yes, it does.

DECLARATION OF NICOLE A. BLACKWELL

I, Nicole A. Blackwell, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Nicole A. Blackwell. I am employed by Idaho Power Company as a Regulatory Consultant in the Regulatory Affairs Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 1-3 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 2021, at Boise, Idaho.

Signed: ______________________
Nicole A. Blackwell

BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION
CASE NO. IPC-E-21-10

IDAHO POWER COMPANY

BLACKWELL, DI
TESTIMONY

EXHIBIT NO. 1
(*EXCEL SPREADSHEET ALSO ATTACHED TO EMAIL)*

IDAHO POWER PCA FORECAST
APRIL 1, 2021 - MARCH 31, 2022

Line No.	FERC Account	April	May	June	July	August	September	October	November	December	January	February	March	Annual
	95% Sharing Accounts													
1	**Hydroelectric Generation (MWh)**	713,505	816,681	761,701	581,160	494,818	456,491	406,256	380,752	448,361	528,076	437,377	665,713	6,690,890
	Account 536, Water for Power													
2	Total Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Account 501, Coal													
	Jim Bridger													
3	Energy (MWh)	50,400	71,424	69,120	312,011	501,901	389,439	173,380	269,101	501,901	414,504	299,654	142,380	3,195,213
4	Total Expense	$ 1,342,676	$ 2,022,214	$ 1,950,286	$ 10,043,202	$ 16,605,286	$ 12,805,704	$ 5,356,606	$ 8,806,825	$ 17,107,157	$ 13,354,008	$ 9,021,163	$ 3,829,986	$ 102,245,112
	North Valmy													
5	Energy (MWh)	-	-	49,680	66,397	66,397	64,051	-	-	92,350	65,131	-	-	404,006
6	Total Expense	$ 247,687	$ 247,687	$ 1,935,508	$ 2,460,711	$ 2,421,424	$ 2,344,592	$ 247,687	$ 247,687	$ 3,271,111	$ 2,385,834	$ 253,879	$ 253,879	$ 16,317,684
	Account 547, Other Fuel													
	Langley Gulch													
7	Energy (MWh)	197,824	109,600	112,320	198,800	199,216	196,720	203,896	203,969	214,992	215,136	191,328	207,625	2,251,426
8	Total Expense	$ 3,843,748	$ 2,187,790	$ 2,223,314	$ 3,715,165	$ 3,832,792	$ 4,223,812	$ 4,266,962	$ 4,831,294	$ 6,368,244	$ 6,006,588	$ 5,025,690	$ 4,625,230	$ 51,150,628
	Danskin													
9	Energy (MWh)	-	-	-	22,048	67,520	-	-	-	-	-	-	-	89,568
10	Total Expense	$ 181,913	$ 188,260	$ 181,598	$ 851,905	$ 2,276,515	$ 181,598	$ 188,260	$ 181,598	$ 188,260	$ 188,260	$ 188,260	$ 188,260	$ 4,984,686
	Bennett Mountain													
11	Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Total Expense	$ 89,599	$ 92,725	$ 89,444	$ 92,725	$ 92,725	$ 89,444	$ 92,725	$ 89,444	$ 92,725	$ 92,725	$ 92,725	$ 92,725	$ 1,099,730
	Account 555, Purchased Power Non-PURPA													
13	Energy (MWh)	39,183	58,989	243,180	342,868	121,071	80,434	132,981	130,267	60,173	120,557	80,245	68,750	1,478,696
14	Total Expense	$ 2,881,106	$ 2,798,934	$ 6,266,136	$ 12,005,590	$ 7,082,616	$ 5,213,146	$ 7,370,599	$ 8,315,727	$ 6,056,859	$ 7,309,450	$ 5,655,829	$ 3,844,538	$ 74,800,530
	Account 565, 3rd Party Transmission													
15	Total Expense	$ 318,846	$ 265,579	$ 572,834	$ 757,524	$ 663,053	$ 450,639	$ 510,729	$ 280,784	$ 219,027	$ 266,890	$ 260,593	$ 287,409	$ 4,853,909
	Account 447, Surplus Sales													
16	Energy (MWh)	187,850	72,261	-	5,904	-	131,187	-	-	79,578	114,729	19,760	143,707	754,975
17	Total Expense	$ (4,140,532)	$ (1,215,666)	$ -	$ (219,924)	$ -	$ (7,600,957)	$ -	$ -	$ (3,261,147)	$ (4,808,352)	$ (692,262)	$ (3,903,385)	$ (25,842,225)
	100% Sharing Accounts													
	Account 555, PURPA													
18	Energy (MWh)	299,462	298,064	319,938	304,494	280,945	242,682	237,294	196,412	182,465	204,945	219,000	242,204	3,027,905
19	Total Expense	$ 14,681,769	$ 14,224,541	$ 20,883,906	$ 23,809,251	$ 22,268,433	$ 16,706,904	$ 16,398,806	$ 16,588,219	$ 15,708,826	$ 15,034,883	$ 15,855,610	$ 12,972,593	$ 205,133,741
	Account 555, Demand Response Incentives													
20	Total Expense	$ -	$ -	$ 280,500	$ 2,937,960	$ 3,068,678	$ 1,292,814	$ 33,660	$ -	$ -	$ -	$ -	$ -	$ 7,613,612
21	**Total Net Power Supply Expense**	$ 19,446,813	$ 20,812,063	$ 34,383,525	$ 56,454,108	$ 58,311,523	$ 35,707,695	$ 34,466,034	$ 39,341,578	$ 45,751,062	$ 39,830,285	$ 35,661,486	$ 22,191,236	$ 442,357,407
22	Total Generation (MWh)	1,300,374	1,354,758	1,555,939	1,827,778	1,731,867	1,429,817	1,153,806	1,180,501	1,500,241	1,548,348	1,227,603	1,326,672	17,137,704
23	Total Load (MWh)	1,112,524	1,282,497	1,555,939	1,821,874	1,731,867	1,298,630	1,153,806	1,180,501	1,420,663	1,433,619	1,207,843	1,182,966	16,382,729

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION
CASE NO. IPC-E-21-10

IDAHO POWER COMPANY

BLACKWELL, DI
TESTIMONY

EXHIBIT NO. 2
(*EXCEL SPREADSHEET ALSO ATTACHED TO EMAIL)*

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**Power Cost Adjustment**																
2	**April 2020 thru March 2021**																
3					April	May	June	July	August	September	October	November	December	January	February	March	Totals
4	**PCA Forecasted Revenues**	*Prior*	*New (Effective 6/1/20)*														
5	Actual Idaho Jurisdictional Billing Month Sales			Mwh	956,229	1,015,632	1,183,343	1,397,419	1,592,904	1,450,229	1,084,006	1,004,606	1,136,599	1,192,902	1,141,582	1,058,378	14,213,829
6	% of Prior Period Billings at Old Rate				100.000%	100.000%	66.050%	13.990%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
7	% of Current Period Billings at New Rate				0.000%	0.000%	33.950%	86.010%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
8	**Forecasted Billing Month Revenues**	$5.836	$ 7.833	$	(5,580,554.66)	(5,927,228.32)	(7,561,693.07)	(10,915,477.70)	(12,477,217.46)	(11,359,644.18)	(8,491,020.09)	(7,869,081.39)	(8,902,981.87)	(9,344,006.92)	(8,942,014.48)	(8,290,278.48)	(105,761,196.62)
9																	
10	**Sales Based Adjustment**	*Prior*	*New (Effective 6/1/15)*														
11	Actual Idaho Jurisdictional Billing Month Sales			Mwh	956,229	1,015,632	1,183,343	1,397,419	1,592,904	1,450,229	1,084,006	1,004,606	1,136,599	1,192,902	1,141,582	1,058,378	14,213,829
12	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	1,177,663	1,101,149	1,004,027	13,498,892
13	Sales Change			Mwh	9,037	62,346	51,657	27,277	164,138	149,621	38,511	46,742	55,585	15,239	40,433	54,351	714,937
14	% of Prior Period Billings at Old Rate				0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
15	% of Current Period Billings at New Rate				100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
16	Sales Adjustment Prior To Sharing		$ 26.72	$	(241,468.64)	(1,665,885.12)	(1,380,275.04)	(728,841.44)	(4,385,767.36)	(3,997,873.12)	(1,029,013.92)	(1,248,946.24)	(1,485,231.20)	(407,186.08)	(1,080,369.76)	(1,452,258.72)	(19,103,116.64)
17	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%	
18	**Sales Based Adjustment**			$	(229,395.21)	(1,582,590.86)	(1,311,261.29)	(692,399.37)	(4,166,478.99)	(3,797,979.46)	(977,563.22)	(1,186,498.93)	(1,410,969.64)	(386,826.78)	(1,026,351.27)	(1,379,645.78)	(18,147,960.80)
19																	
20	**Actual Non-QF**																
21	Fuel Expense-Coal			$	9,231,919.98	8,832,711.71	9,349,045.94	14,410,110.21	16,437,508.21	12,278,139.79	11,408,960.26	9,186,386.01	12,768,914.74	8,304,889.65	6,419,987.40	2,210,080.06	120,838,653.96
22	Fuel Expense-Gas			$	1,102,377.76	819,162.75	2,000,382.37	5,002,753.10	6,816,440.31	4,720,581.42	3,570,968.95	5,892,504.47	8,656,031.38	6,175,069.10	4,122,018.63	5,995,530.89	54,873,821.13
23	Non-Firm Purchases			$	3,279,550.15	3,319,552.04	5,452,125.40	8,611,445.19	12,506,143.97	13,421,964.81	6,058,071.37	7,323,208.29	8,899,296.01	8,810,322.88	8,848,393.66	5,231,761.36	91,761,835.13
24	Third Party Transmission			$	128,088.00	340,331.30	580,401.14	295,781.68	892,115.85	514,807.26	435,831.86	151,565.65	127,561.87	130,297.67	117,456.56	116,080.00	3,830,318.84
25	Surplus Sales			$	(4,273,770.58)	(1,209,001.50)	(3,546,397.87)	(3,677,930.89)	(8,858,570.73)	(15,644,744.27)	(4,828,776.96)	(3,224,618.65)	(5,124,023.86)	(2,083,873.45)	(6,701,063.29)	(5,410,780.89)	(64,583,552.94)
26	Water for Power (Leases)			$	-	-	-	-	-	480,000.00	-	-	-	-	-	-	480,000.00
27	Total Actual Non-QF			$	9,468,165.31	12,102,756.30	13,835,556.98	24,642,159.29	27,793,637.61	15,770,749.01	16,646,055.48	19,329,045.77	25,327,780.14	21,336,705.85	12,806,792.96	8,142,671.42	207,201,076.12
28	Idaho Allocation				95.2%	95.2%	95.7%	95.8%	95.7%	95.7%	95.6%	95.1%	95.1%	95.1%	95.7%	95.3%	
29	Net Idaho Jurisdictional Actual Non-QF			$	9,013,693.38	11,521,824.00	13,240,628.03	23,607,188.60	26,598,511.19	15,092,606.80	15,912,673.04	18,381,922.53	24,086,718.91	20,291,207.26	12,256,100.86	7,759,965.86	197,763,040.46
30																	
31	**Base Non-QF**																
32	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	9,553,773.00	8,912,994.00	8,098,078.00	108,503,180.00
33	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	2,938,035.00	2,740,979.00	2,490,369.00	33,367,563.00
34	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	5,512,549.00	5,142,819.00	4,672,610.00	62,606,593.00
35	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	480,400.00	448,179.00	407,203.00	5,455,955.00
36	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)	(4,555,312.00)	(4,249,784.00)	(3,861,227.00)	(51,736,153.00)
37	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	209,613.00	195,555.00	177,676.00	2,380,597.00
38	Net 95% Items			$	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	14,139,058.00	13,190,742.00	11,984,709.00	160,578,735.00
39	Idaho Allocation				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
40	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	13,432,105.10	12,531,204.90	11,385,473.55	152,549,798.25
41																	
42	Idaho Jurisdiction Change From Base			$	(1,566,404.37)	994,589.95	560,171.48	7,600,116.10	9,466,459.14	(87,192.40)	4,972,372.34	8,115,235.48	12,199,404.06	6,859,102.16	(275,104.04)	(3,625,507.69)	45,213,242.21
43	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%	
44	**Net Power Supply Costs Deferral**			$	(1,488,084.15)	944,860.45	532,162.91	7,220,110.30	8,993,136.18	(82,832.78)	4,723,753.72	7,709,473.71	11,589,433.86	6,516,147.05	(261,348.84)	(3,444,232.31)	42,952,580.10
45																	
46	**Emission Allowance and REC Sales**																
47	Emission Allowance Sales Credit			$	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
48	Renewable Energy Credit Sales			$	(72,324.46)	(349,165.81)	385.24	(556,713.46)	466.62	(1,351.09)	(383,416.22)	559.50	(992,878.14)	287.73	(3,146.64)	(2,872,593.54)	(5,229,890.27)
49	Total Emission Allowances and REC Sales			$	(72,324.46)	(349,165.81)	385.24	(556,713.46)	466.62	(1,351.09)	(383,416.22)	559.50	(992,878.14)	287.73	(3,146.64)	(2,872,593.54)	(5,229,890.27)
50	Idaho Allocation				95.2%	95.2%	95.7%	95.8%	95.7%	95.7%	95.6%	95.1%	95.1%	95.1%	95.7%	95.3%	
51	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%	
52	**Net Emission Allowances and REC Sales**			$	(65,410.24)	(315,785.56)	350.24	(506,664.92)	424.23	(1,228.34)	(348,218.61)	505.48	(897,015.76)	259.95	(2,860.77)	(2,600,702.56)	(4,736,346.86)
53																	
54	**Idaho Allocated EIM Participation Costs**																
55	Return on EIM Capital Investment			$	51,974.63	50,918.16	49,861.68	48,805.21	47,748.74	46,692.27	45,635.80	44,579.33	43,574.15	42,517.49	41,460.83	40,404.18	554,172.46
56	Operating Expenses			$	209,482.94	227,928.59	227,248.71	213,226.63	219,649.20	243,047.35	227,600.14	199,218.43	204,161.58	199,647.80	208,398.43	251,944.06	2,631,553.84
57	Total			$	261,457.56	278,846.75	277,110.40	262,031.85	267,397.94	289,739.62	273,235.94	243,797.76	247,735.72	242,165.29	249,859.26	292,348.23	3,185,726.31
58	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%	
59	**EIM Participation Costs**			$	248,384.69	264,904.41	263,254.88	248,930.25	254,028.04	275,252.64	259,574.14	231,607.87	235,348.94	230,057.02	237,366.30	277,730.82	3,026,440.00
60																	
61	**Demand Response Incentive Payments**																
62	Actual			$	0.00	0.00	151,499.84	2,333,340.98	3,066,206.90	1,030,886.24	(55,727.77)	166.45	7,361.11	0.00	18,612.57	2,304.30	6,554,650.62
63	Base			$	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	990,769.00	924,317.00	839,807.00	11,252,265.00
64	Change From Base			$	(780,401.00)	(776,502.00)	(783,827.16)	1,152,638.98	1,802,524.90	(88,794.76)	(862,697.77)	(757,117.55)	(869,461.89)	(990,769.00)	(905,704.43)	(837,502.70)	(4,697,614.38)
65	Idaho Allocation				100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
66	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%	
67	**Demand Response Incentive Payment Deferral**			$	(780,401.00)	(776,502.00)	(783,827.16)	1,152,638.98	1,802,524.90	(88,794.76)	(862,697.77)	(757,117.55)	(869,461.89)	(990,769.00)	(905,704.43)	(837,502.70)	(4,697,614.38)
68																	
69	**Actual QF**																
70	Actual QF (Includes Net Metering, Raft River 100% & Liquidated Damages)			$	14,041,211.36	15,232,386.02	19,248,614.42	24,205,952.70	21,553,290.83	15,201,424.15	17,106,901.83	15,489,843.77	14,785,243.49	14,050,373.70	17,607,218.41	13,054,900.86	201,577,361.54
71	Idaho Allocation				95.2%	95.2%	95.7%	95.8%	95.7%	95.7%	95.6%	95.1%	95.1%	95.1%	95.7%	95.3%	
72	Idaho Jurisdictional Actual QF			$	13,367,233.21	14,501,231.49	18,420,924.00	23,189,302.69	20,626,499.32	14,547,762.91	16,354,198.15	14,730,841.43	14,060,766.56	13,361,905.39	16,850,108.02	12,441,320.52	192,452,093.69
73																	
74	**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	11,785,917.00	10,995,427.00	9,990,113.00	133,853,870.00
75	Idaho Allocation				95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
76	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	11,196,621.15	10,445,655.65	9,490,607.35	127,161,176.50
77																	
78	Idaho Jurisdiction Change From Base			$	4,547,965.21	5,726,027.34	7,850,855.40	9,846,261.04	6,345,706.97	1,894,313.91	7,234,675.05	6,172,823.43	4,151,839.06	2,165,284.24	6,404,452.37	2,950,713.17	65,290,917.19
79	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%	
80	**QF Deferral**			$	4,547,965.21	5,726,027.34	7,850,855.40	9,846,261.04	6,345,706.97	1,894,313.91	7,234,675.05	6,172,823.43	4,151,839.06	2,165,284.24	6,404,452.37	2,950,713.17	65,290,917.19
81																	
82																	
83	**Total Deferral**			$	(3,347,495.36)	(1,666,314.54)	(1,110,158.09)	6,353,398.58	752,123.87	(13,160,912.97)	1,538,503.22	4,301,712.62	3,896,192.70	(1,809,854.44)	(4,496,461.12)	(13,323,917.84)	(22,073,183.37)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**Power Cost Adjustment**																
2	**April 2020 thru March 2021**																
3					April	May	June	July	August	September	October	November	December	January	February	March	Totals
84																	
85	**True-Up Summary:**																
86	Principal Balances																
87																	
88	Beginning True-Up Balance			$	0.00	(3,347,495.36)	(5,013,809.90)	(6,123,967.99)	229,430.59	981,554.46	(12,179,358.51)	(10,640,855.29)	(6,339,142.67)	(2,442,949.97)	(4,252,804.41)	(8,749,265.53)	0.00
89																	
90	Amount Deferred			$	(3,347,495.36)	(1,666,314.54)	(1,110,158.09)	6,363,398.58	752,123.87	(13,160,912.97)	1,538,503.22	4,301,712.62	3,896,192.70	(1,809,854.44)	(4,496,461.12)	(13,323,917.84)	(22,073,183.37)
91																	
92	Ending Balance			$	(3,347,495.36)	(5,013,809.90)	(6,123,967.99)	229,430.59	981,554.46	(12,179,358.51)	(10,640,855.29)	(6,339,142.67)	(2,442,949.97)	(4,252,804.41)	(8,749,265.53)	(22,073,183.37)	(22,073,183.37)
93																	
94	Interest Balances																
95																	
96	Accrual thru Prior Month			$	0.00	0.00	(5,580.27)	(13,938.29)	(24,146.94)	(23,764.48)	(22,128.23)	(42,431.22)	(60,169.53)	(70,736.88)	(72,771.86)	(76,314.45)	
97																	
98	Monthly Interest Rate (Annual 2% for 2020, 1% for 2021)				0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.0833%	0.0833%	0.0833%	
99																	
100	Monthly Interest Inc/(Exp)			$	0.00	(5,580.27)	(8,358.02)	(10,208.65)	382.46	1,636.25	(20,302.99)	(17,738.31)	(10,567.35)	(2,034.98)	(3,542.59)	(7,288.14)	(83,602.59)
101																	
102	Interest Accrued to date			$	0.00	(5,580.27)	(13,938.29)	(24,146.94)	(23,764.48)	(22,128.23)	(42,431.22)	(60,169.53)	(70,736.88)	(72,771.86)	(76,314.45)	(83,602.59)	(83,602.59)
103																	
104	**Ending True-Up Balance**			$	(3,347,495.36)	(5,019,390.17)	(6,137,906.28)	205,283.65	957,789.98	(12,201,486.74)	(10,683,286.51)	(6,399,312.20)	(2,513,886.85)	(4,325,576.27)	(8,825,579.98)	(22,156,785.96)	(22,156,785.96)
105																	
106																	
107	**True-Up of the True-Up Summary:**																
108	Beginning Balance True-Up of True-Up			$	(10,778,801.08)	(38,062,465.11)	(33,152,932.77)	(28,197,367.98)	(24,047,452.90)	(19,355,456.86)	(15,077,939.51)	(11,882,378.27)	(8,917,670.27)	(5,555,703.56)	(2,016,204.37)	1,373,885.89	(10,778,801.08)
109	Adjustments:																
110	Revenue Sharing			$													-
111	DSM Rider Forecasted Surplus Funds Order No.			$													-
112	2019-20 PCA trnsfr per IPUC Order No. 34682			$	(31,869,645.60)												(31,869,645.60)
113																	-
114	True-Up of True-Up Balance			$	(42,648,446.68)	(38,062,465.11)	(33,152,932.77)	(28,197,367.98)	(24,047,452.90)	(19,355,456.86)	(15,077,939.51)	(11,882,378.27)	(8,917,670.27)	(5,555,703.56)	(2,016,204.37)	1,373,885.89	(42,648,446.68)
115																	
116	Monthly Interest Rate (Annual 2% for 2020, 1% for 2021)				0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.1667%	0.0833%	0.0833%	0.0833%	
117																	
118	Monthly Interest			$	(71,094.96)	(63,450.13)	(55,265.94)	(47,005.01)	(40,087.10)	(32,265.55)	(25,134.93)	(19,807.92)	(14,865.76)	(4,627.90)	(1,679.50)	1,144.45	(374,140.25)
119																	
120	True-Up of True-Up Including Interest			$	(42,719,541.64)	(38,125,915.24)	(33,208,198.71)	(28,244,372.99)	(24,087,540.00)	(19,387,722.41)	(15,103,074.44)	(11,902,186.19)	(8,932,536.03)	(5,560,331.46)	(2,017,883.87)	1,375,030.34	(43,022,586.93)
121																	
122	Monthly Collection Applied To Balance			$	4,657,076.53	4,972,982.47	5,010,830.73	4,196,920.09	4,732,083.14	4,309,782.90	3,220,696.17	2,984,515.92	3,376,832.47	3,544,127.09	3,391,769.76	3,144,583.97	47,542,201.24
123																	
124	**Ending True-Up of the True-Up Balance**			$	(38,062,465.11)	(33,152,932.77)	(28,197,367.98)	(24,047,452.90)	(19,355,456.86)	(15,077,939.51)	(11,882,378.27)	(8,917,670.27)	(5,555,703.56)	(2,016,204.37)	1,373,885.89	4,519,614.31	4,519,614.31
125																	
126	Negative amounts indicate benefit to the customer.																
127																	
128																	
129																	
130	Idaho Billed Sales			Mwh	956,229	1,015,632	1,183,343	1,397,419	1,592,904	1,450,229	1,084,006	1,004,606	1,136,599	1,192,902	1,141,582	1,058,378	14,213,829
131	Oregon Billed Sales			Mwh	48,443	50,745	53,459	60,630	71,797	64,779	50,378	52,136	58,352	60,953	51,389	52,161	675,222
132	Total			Mwh	1,004,672	1,066,377	1,236,802	1,458,049	1,664,701	1,515,008	1,134,384	1,056,742	1,194,951	1,253,855	1,192,971	1,110,539	14,889,051
133	Idaho % Billed Sales				95.2%	95.2%	95.7%	95.8%	95.7%	95.7%	95.6%	95.1%	95.1%	95.1%	95.7%	95.3%	
134	Oregon % Billed Sales				4.8%	4.8%	4.3%	4.2%	4.3%	4.3%	4.4%	4.9%	4.9%	4.9%	4.3%	4.7%	
135																	
136																	
137																	

BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION
CASE NO. IPC-E-21-10

IDAHO POWER COMPANY

BLACKWELL, DI
TESTIMONY

EXHIBIT NO. 3
(*EXCEL SPREADSHEET ALSO ATTACHED TO EMAIL)*

Line		Actual September 30, 2020 TOTAL SYSTEM	Actual September 30, 2020 IDAHO	Actual September 30, 2020 IDAHO %	Actual December 31, 2020 TOTAL SYSTEM	Actual December 31, 2020 IDAHO	Actual December 31, 2020 IDAHO %
1	**IDAHO POWER COMPANY**						
2							
3	**ADDITIONAL INVESTMENT TAX CREDIT ANALYSIS**						
4	**For the Twelve Months Ended December 31, 2020**						
5							
6		**Actual September 30, 2020**			**Actual December 31, 2020**		
7		TOTAL			**TOTAL**		
8		SYSTEM	IDAHO	IDAHO %	**SYSTEM**	IDAHO	IDAHO %
9	**** * * SUMMARY OF RESULTS * * ****						
10	TOTAL COMBINED RATE BASE	3,539,638,329	3,392,241,258	95.8%	September Allocations/Ratios		
11							
12	DEVELOPMENT OF NET INCOME						
13	OPERATING REVENUES						
14	RETAIL SALES REVENUES (Incl 449.1 Rev)	896,037,053	857,137,508	Direct Assign	1,168,968,043	1,116,558,967	Direct Assign
15	OTHER OPERATING REVENUES	132,873,864	127,000,415	95.6%	175,200,998	167,456,555	95.6%
16	TOTAL OPERATING REVENUES	1,028,910,917	984,137,923		1,344,169,041	1,284,015,522	
17							
18	OPERATING EXPENSES						
19	OPERATION & MAINTENANCE EXPENSES	620,658,601	589,999,584	95.1%	830,692,777	789,658,586	95.1%
20	DEPRECIATION EXPENSE	121,742,624	116,646,466	95.8%	162,318,740	155,524,063	95.8%
21	AMORTIZATION OF LIMITED TERM PLANT	5,775,540	5,535,969	95.9%	7,727,513	7,406,973	95.9%
22	TAXES OTHER THAN INCOME	25,946,411	24,196,176	93.3%	33,047,693	30,818,436	93.3%
23	REGULATORY DEBITS/CREDITS	970,427	806,515	83.1%	1,332,529	1,107,455	83.1%
24	PROVISION FOR DEFERRED INCOME TAXES	5,327,100	5,245,567	98.5%	(6,233,127)	(6,137,727)	98.5%
25	INVESTMENT TAX CREDIT ADJUSTMENT	1,762,322	1,689,046	95.8%	2,820,899	2,703,608	95.8%
26	FEDERAL INCOME TAXES	15,717,056	15,520,476	98.7%	26,204,174	25,876,427	98.7%
27	STATE INCOME TAXES	3,359,422	3,315,556	98.7%	6,286,258	6,204,174	98.7%
28	TOTAL OPERATING EXPENSES	801,259,502	762,955,355		1,064,197,455	1,013,161,996	
29							
30	OPERATING INCOME	227,651,415	221,182,568		279,971,586	270,853,526	
31	ADD: IERCO OPERATING INCOME	6,245,994	5,962,892	95.5%	8,402,214	8,021,381	95.5%
32							
33	OPERATING INCOME BEFORE OTHER INCOME AND DEDUCTIONS	233,897,409	227,145,460		288,373,800	278,874,907	96.7%
34	ADD: AFUDC EQUITY				29,550,610	28,320,068	95.8% (L 10)
35	ADD: OTHER INCOME AND DEDUCTIONS				2,698,867	2,609,967	96.7% (L 33)
36							
37	INCOME BEFORE INTEREST CHARGES				320,623,277	309,804,942	
38	LESS: INTEREST CHARGES				87,388,734	83,749,706	95.8% (L 10)
39							
40	NET INCOME				233,234,543	226,055,237	
41							
42	ACTUAL YEAR-END RESULTS - BEFORE ITC ADJUSTMENT						
43	EARNINGS ON COMMON STOCK				233,234,543	226,055,237	
44	COMMON EQUITY AT YEAR END				2,363,834,455	2,265,400,027	95.8% (L10)
45							
46	RETURN ON YEAR-END COMMON EQUITY				9.87%	9.98%	
47							
48	EARNINGS ON COMMON STOCK @ 9.50 ROE				224,564,273	**212,947,603**	(L44 * 9.4%)
49	EARNINGS ON COMMON STOCK @ 10 ROE				236,383,446	**226,540,003**	(L44 * 10%)
50	EARNINGS ON COMMON STOCK @ 10.50 ROE				248,202,618	**237,867,003**	(L44 * 10.5%)
51							
52							
53	ACTUAL YEAR-END RESULTS - AFTER ITC ADJUSTMENT:						
54	INVESTMENT TAX CREDIT ADJUSTMENT					(14,467,587)	(L48-L43) / (1-9.4%)
55	ADJUSTED EARNINGS ON COMMON STOCK					211,587,649	
56	ADJUSTED COMMON EQUITY AT YEAR-END					2,250,932,440	
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-21-10
N. Blackwell, IPC