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May 21, 2020

VIA ELECTRONIC FILING

Diane M. Hanian, Secretary
Idaho Public Utilities Commission
11331 W. Chinden Boulevard
Building 8, Suite 201-A
Boise, Idaho 83714

Re: Case No. IPC-E-20-21
2020-2021 Power Cost Adjustment – Idaho Power Company's Reply Comments

Dear Ms. Hanian:

Attached for electronic filing in the above matter is Idaho Power Company's Reply Comments.

If you have any questions about the enclosed documents, please do not hesitate to contact me.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:sdh
Enclosures

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Attorney for Idaho Power Company

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, 2020 THROUGH MAY 31, 2021	)))))))	CASE NO. IPC-E-20-21 IDAHO POWER COMPANY'S REPLY COMMENTS

Idaho Power Company ("Idaho Power" or "Company") respectfully submits the following Reply Comments in response to comments filed by the Idaho Public Utilities Commission ("Commission") Staff ("Staff") on May 14, 2020. In these Reply Comments, Idaho Power concurs with Staff's conclusion that the proposed Power Cost Adjustment ("PCA") rates should be approved as filed, and addresses Staff's belief that the PCA could be simplified by removing the forecast component of the mechanism.

I. BACKGROUND

On April 15, 2020, Idaho Power applied to the Commission for an order approving an update to Schedule 55 based on the quantification of the 2020-2021 PCA to become effective June 1, 2020, for the period June 1, 2020, through May 31, 2021. If approved, the 2020-2021 PCA will result in an overall revenue increase of approximately $58.7 million, or a 5.21 percent increase over current billed revenue.

On May 14, 2020, Staff filed comments in this case detailing its audit of the Company's filing. As described in Staff's comments, "Staff reviewed the components that make up this year's Schedule 55 PCA rates and has concluded that they are fair, just, and reasonable."[1] Staff recommended that the Commission approve the Company's proposed Schedule 55 rates as filed in Attachment 1 to the Company's Application.

Staff also recommended that the Commission order the Company to meet with Staff to discuss simplification to the PCA methodology.[2] Specifically, Staff believes the Company's PCA could be simplified, while not diminishing its purpose, by removing the forecast component which has contributed to significant rate fluctuations for customers.[3]

II. <u>IDAHO POWER'S REPLY</u>

Idaho Power acknowledges Staff's review and agrees with Staff's conclusion that the filed PCA components appropriately calculate 2020-2021 PCA rates under the currently approved methodology. With respect to Staff's suggestion to simplify the PCA mechanism by removing the PCA forecast component, Idaho Power discourages this methodological change as it is contrary to the intent of the PCA, would send improper price signals to customers, would cause financial harm to the Company and ultimately customers, and would likely not achieve Staff's stated intent of increased rate stability.

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[1] Staff Comments, p. 13.
[2] Staff Comments, p. 14.
[3] Staff Comments, p. 13.

A. A Forecast-Based PCA More Closely Matches Revenue Collection to Actual Power Supply Expenses.

In 1981 Idaho Power proposed to change from its historic method of median stream flow normalization for rate setting purposes to normalization of average net power supply costs under multiple hydro conditions.[4] Under the proposed normalization method, Idaho Power's rates were set based on the averages and were not adjusted annually to account for the difference between actual stream flows and normalized conditions. At the time, both the Company and the Commission believed that the normalization system adopted would make the Company whole in the long run and it was approved.[5] No party to that proceeding anticipated the severe drought years that occurred in the following decade. Because Idaho Power's generating fleet is predominately hydro-based, the Company's power supply costs can vary significantly from year to year as stream flows change. When stream flows are high, the can generate more energy at its hydro facilities, which are essentially zero-variable cost resources, in place of other higher cost resources. Additionally, high stream flows increase Idaho Power's ability to take advantage of surplus sales; a benefit to customers in the form of lower net power supply expense ("NPSE"). Conversely, when steam flows are low, Idaho Power relies more heavily on purchased power and thermal resources to serve load and the ability to make surplus sales is reduced. As modeled in the Company's last general rate case, NPSE can vary in excess of $200 million from one year to the next based on changes in stream flow conditions. [6]

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[4] *In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service in the State of Idaho.* Case No. U-1006-185.

[5] *In the Matter of the Application of Idaho Power Company for Authority to Implement a Power Cost Adjustment Tariff for Electric Service to Customers in the State of Idaho and for Approval of New Rates for Service Under the FMC Special Contract.* Case No. IPC-E-92-25. Order No. 24806, p. 4 (March 29, 1993).

[6] *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service to its Customers in the State of Idaho.* Case No. IPC-E-11-08. Wright, DI, Exhibit No. 17, pp. 5, 58.

To address the variability in NPSE from year to year as stream flows change, Idaho Power filed an application to implement the PCA in Case No. IPC-E-92-25. The Commission-adopted PCA mechanism included a forecast component in which April through July inflows at Brownlee Reservoir are used as the basis for predicting annual NPSE, as well as a true-up component to account for the difference in forecast NPSE and actual NPSE. It was determined that a forecast-based PCA would meet the primary objective of implementing a mechanism, which is to more closely match revenue collection to the actual power supply expenses incurred by the Company. Specifically, the component of a customer's rate which reflects the variable expenses of generating energy to serve the customer's load would be variable and change as the cost of energy changes. As a result, proper and understandable price/cost signals would be sent to customers.

As part of its order adopting the implementation of the PCA, the Commission made the following statement:

> We find that a forecast-based PCA with a true-up is most appropriate for Idaho Power. A forecast most closely matches costs to the time period in which they are incurred. This sends the more appropriate price signals to ratepayers....
>
> Ratepayers in Idaho Power's service territory are aware of changing stream flow conditions and understand the impact they have on the cost of generating electricity. A PCA that adjusts rates to reflect projected stream flows for the coming year should be understandable to ratepayers and send short-term price signals to ratepayers more reflective of actual conditions....
>
> Finally, we find that a forecast-based PCA that trues-up to actual, as proposed by Idaho Power, eliminates the possibility of the Company over-recovering its power supply costs. [7]

[7] Order No. 24806, pp. 8-9.

Staff's suggestion to limit the PCA mechanism to a true-up component, or a strict deferred accounting approach, is contrary to the purpose of the PCA. Under this approach, the Company would defer current expenses or revenues for recovery or reimbursement through rates in a future time period. This would send inaccurate price signals to customers as they would pay for current energy use at rates that reflect expenses for energy consumed in a prior time. Additionally, this approach could result in the accumulation of expenses and an associated rate increase just before an abundant water year, or vice-versa an accumulation of revenues and an associated rate decrease coincident with a low water year. Ultimately, Idaho Power's customer would be receiving inappropriate price signals.

Alternatively, use of the PCA forecast component allows the Company to adjust rates to match forecast NPSE to be incurred by the Company. Customers receive a proper price signal that better reflects the costs of energy at the time the customer is consuming and paying for the energy. Idaho Power finds this increasingly important as a significant portion of the forecast NPSE included in the Company's PCA forecast is known. As noted in the direct testimony of Mr. Tatum, approximately 51 percent of this year's proposed PCA forecast is related to the recovery of Public Utility Regulatory Policies Act of 1978 costs – costs that are known today and are under contract.[8] Deferral of these costs to a future time period is a direct contradiction of matching revenue collection with the time expenses are incurred and sends an improper price signal to customers.

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[8] Tatum, DI, p. 28, lines 11-14.

B. A Forecast-Based PCA is Critical to Idaho Power's Financial Healthy and Cost-Effective Access to Capital.

In addition to diminishing the primary objective of the PCA, removal of the forecast component would cause financial harm to the Company and ultimately result in higher costs for customers. As Staff noted in its Comments:

> Due to its diverse generation portfolio, Idaho Power's actual power supply costs vary each year depending on changes in river streamflow, the amount of purchased power, fuel costs, the market price of power, and other factors. Because of **potentially large differences** [emphasis added] in actual cost as compared to the amount of Net Power Supply Expense (NPSE) collected through base rates, the PCA mechanism is designed to true-up these annual differences so that customers are paying no more and no less than actual NPSE (minus sharing).[9]

The Company agrees with Staff's assessment and notes that this is precisely why the forecast component of the PCA is critical to the financial health of Idaho Power and beneficial to customers.

Without the forecast component of the PCA, if actual NPSE were significantly higher than what is being collected through base rates, Idaho Power would likely have to borrow money to fund those higher NPSE. For example, this year's PCA forecast is $112 million. If the forecast component of the PCA were removed, the Company would have to fund this amount and collect it from customers the following year. Removal of the PCA forecast component could also result in a credit rating downgrade for Idaho Power. Both or either of these events would result in higher costs to fund Company operations, which are ultimately passed on to customers through rates. If the PCA was modified to an

[9] Staff Comments, p. 3.

annual deferred accounting approach, as suggested by Staff, the Company may not be able to cost-effectively access financial markets to offset lost cash in the near term.

As addressed in the direct testimony of Mr. Tatum, reduced cash from PCA-related sales would challenge the Company's ability to cost-effectively fund its near-term operations.[10] Reflecting on the decade before the forecast-based PCA was implemented, the Commission stated:

> It is now apparent that while normalization does make the Company whole over a period of years, during periods of extended drought the Company suffers significant earnings instability and cash-flow problems. The Company, for example, is forced to curtail its plans for maintenance and expansion of plant and services. Ratepayers do not benefit from a utility that is financially impaired in this manner.[11]

While the earnings instability that existed prior to the implementation of the PCA would not be a concern under the Staff's recommendation, the same cash-flow concerns previously acknowledged by the Commission would be reintroduced into the mechanism.

C. Removing the PCA Forecast is Unlikely to Result in More Rate Stability.

Finally, Staff states that since 2011, the Company's PCA rate has varied considerably from a credit of 0.0629 cents per kWh in 2011 to a surcharge of 1.2306 cents per kWh in 2013.[12] Idaho Power concurs with Staff that the PCA rate has varied since 2011. However, the intent of the PCA is to allow the Company to adjust rates on an annual basis to capture the variability in stream flow conditions. Because stream flow conditions vary from year to year, it is reasonable that NPSE, and thus the PCA rate, would vary from year to year. As stated in Staff's Comments:

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[10] Tatum, DI, p. 30, lines 10-12.
[11] Order No. 24806, p. 4.
[12] Staff Comments, p. 13.

> Due to its diverse generation portfolio, Idaho Power's actual power supply costs vary each year depending on changes in river streamflow.... Because of the potentially large differences in actual cost as compared to the amount of NPSE collected through base rates, the PCA mechanism is designed to true-up these annual differences so that customers are paying no more and no less than actual NPSE (minus sharing).[13]

Staff asserts that a PCA mechanism that does not rely on forecasts could create more rate stability than the current method.[14] Idaho Power does not agree with Staff's claim that eliminating the PCA forecast component could create more rate stability. A review of the variation in actual NPSE compared to the PCA forecast of NPSE over the prior 10 years reveals that a deferred accounting approach would have resulted in similar, if not larger, variations in annual rate adjustments.

Attachment 1 to these Reply Comments includes the system-level PCA forecast of NPSE, as approved by the Commission, in Idaho Power's last 10 PCA filings.[15] The attachment shows that year-over-year changes in the PCA forecast of NPSE varies from negative 5.4 percent to 12.0 percent. The attachment also includes actual system-level NPSE incurred by the Company during those same PCA years. The attachment demonstrates that year-over-year changes in actual NPSE varies from negative 10.6 percent to 57.6 percent. Furthermore, the year-over-year variation in actual NPSE is larger than the same year-over-year variation in the PCA forecast of NPSE for 7 out of the 9 instances. Therefore, removing the PCA forecast and limiting the mechanism to the

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[13] Staff Comments, p. 3.
[14] Staff Comments, p. 14.
[15] Note for comparative purposes, the analysis is limited to the Federal Energy Regulatory Commission (FERC) accounts that are included in the current PCA forecast methodology. Early PCA years in this analysis included forecast benefits/expenses associated with the Hoku special contract, Renewable Energy Credits sales, Sulfur Dioxide sales, etc. These components have been removed from the analysis to perform an apples-to-apples comparison.

true-up of actual expenses is unlikely to result in more rate stability for customers and could potentially result in less rate stability.

While Staff suggests that the PCA mechanism could be simplified by removing the forecast component, Staff ultimately states that it was unable to fully investigate the matter. Staff plans to conduct a study of the current PCA mechanism's stability prior to next year's filing and believes it would be beneficial for Staff to meet with the Company during this process.[16] As such, Staff recommends that the Commission order the Company to meet with Staff to discuss simplifications to the PCA mechanism. While Idaho Power believes it has described the reasons why removing the PCA forecast component is inappropriate, the Company is open to meeting with Staff to further discuss this issue.

III. CONCLUSION

Idaho Power acknowledges Staff's review and conclusion that the Company's proposed PCA rates in this case are fair, just, and reasonable and comply with the existing PCA methodology. Idaho Power disagrees with Staff's suggestion that removal of the forecast component of the PCA mechanism would result in more rate stability. As more fully described above, removing the forecast component would send improper price signals to customers and create undue risk for the Company and ultimately customers. Furthermore, the Company finds that removal of the PCA forecast would not result in more rate stability for customers. Idaho Power is open to meeting with Staff to discuss this topic further.

[16] Staff Comments, p. 14.

Idaho Power respectfully requests that the Commission approve the 2020-2021 PCA rates as filed in this proceeding.

DATED at Boise, Idaho, this 21st day of May 2020.

Lisa D. Nordstrom

LISA D. NORDSTROM
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 21st day of May 2020 I served a true and correct copy of IDAHO POWER COMPANY'S REPLY COMMENTS upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Matt Hunter Deputy Attorney General Idaho Public Utilities Commission 11331 W Chinden Blvd, Bldg. 8, Suite 201-A P.O. Box 83720 Boise, Idaho 83720-0074	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email matt.hunter@puc.idaho.gov

Sandra D. Holmes

Sandra Holmes, Legal Assistant

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-20-21

IDAHO POWER COMPANY

ATTACHMENT 1

PCA Forecast by PCA Year										
FERC Account	**2010-2011**	**2011-2012**	**2012-2013**	**2013-2014**	**2014-2015**	**2015-2016**	**2016-2017**	**2017-2018**	**2018-2019**	**2019-2020**
95% Sharing Accounts										
Account 501, Coal	$ 164,409,166	$ 153,268,673	$ 147,503,921	$ 165,951,392	$ 169,424,879	$ 117,032,475	$ 112,127,106	$ 126,769,503	$ 125,477,505	$ 146,631,692
Account 536, Water for Power	$ 2,003,640	$ 2,291,000	$ 2,521,000	$ 2,354,374	$ 1,751,000	$ 2,425,230	$ -	$ -	$ -	$ 0
Account 547, Other Fuel	$ 12,854,025	$ 8,971,778	$ 52,250,517	$ 66,536,064	$ 73,941,673	$ 57,173,815	$ 39,202,822	$ 37,305,583	$ 37,609,237	$ 44,723,759
Account 555, Purchased Power Non-PURPA	$ 81,877,623	$ 62,308,530	$ 41,169,588	$ 40,080,534	$ 61,996,853	$ 48,372,214	$ 54,988,467	$ 52,615,287	$ 67,654,802	$ 62,039,274
Account 565, 3rd Party Transmission	$ 7,664,171	$ 7,897,586	$ 7,554,520	$ 6,692,385	$ 6,645,775	$ 6,453,427	$ 5,999,412	$ 6,017,025	$ 5,435,404	$ 5,319,681
Account 447, Surplus Sales	$ (62,915,788)	$ (79,083,135)	$ (110,167,401)	$ (98,510,169)	$ (126,166,913)	$ (39,048,702)	$ (20,930,147)	$ (34,371,858)	$ (25,523,296)	$ (64,129,054)
100% Sharing Accounts										
Account 555, PURPA	$ 64,054,993	$ 99,801,054	$ 129,590,113	$ 131,731,526	$ 134,142,386	$ 148,054,626	$ 158,758,382	$ 181,714,395	$ 185,019,923	$ 192,301,878
Account 555, Demand Response Incentives			$ 14,723,210	$ 4,668,960	$ 8,290,603	$ 7,921,041	$ 7,401,698	$ 7,401,698	$ 7,401,698	$ 7,401,698
Total	**$ 269,947,830**	**$ 255,455,486**	**$ 285,145,468**	**$ 319,505,066**	**$ 330,026,256**	**$ 348,384,126**	**$ 357,547,740**	**$ 377,451,632**	**$ 403,075,274**	**$ 394,288,928**
Percent Change from Prior Year		**-5.4%**	**11.6%**	**12.0%**	**3.3%**	**5.6%**	**2.6%**	**5.6%**	**6.8%**	**-2.2%**

Actual NPSE by PCA Year										
FERC Account	**2010-2011**	**2011-2012**	**2012-2013**	**2013-2014**	**2014-2015**	**2015-2016**	**2016-2017**	**2017-2018**	**2018-2019**	**2019-2020**
95% Sharing Accounts										
Account 501, Coal	$ 138,868,030	$ 122,922,864	$ 143,733,017	$ 160,995,670	$ 139,308,896	$ 130,779,992	$ 141,879,874	$ 103,318,634	$ 130,865,930	$ 82,407,803
Account 536, Water for Power	$ 2,055,185	$ 2,577,915	$ 2,295,597	$ 706,411	$ 1,527,000	$ 2,458,651	$ -	$ -	$ 2,450,000	$ 2,100,000
Account 547, Other Fuel	$ 12,921,516	$ 10,877,122	$ 31,593,483	$ 59,228,806	$ 37,702,547	$ 59,360,717	$ 37,820,518	$ 33,654,349	$ 26,123,248	$ 52,280,833
Account 555, Purchased Power Non-PURPA	$ 77,085,070	$ 62,156,365	$ 56,000,484	$ 78,523,687	$ 81,170,256	$ 72,184,267	$ 79,009,662	$ 64,633,258	$ 86,561,811	$ 76,273,363
Account 565, 3rd Party Transmission	$ 5,812,011	$ 6,516,274	$ 6,245,230	$ 5,760,718	$ 6,046,383	$ 6,235,388	$ 5,522,758	$ 4,077,351	$ 3,584,536	$ 3,033,932
Account 447, Surplus Sales	$ (70,077,566)	$ (96,750,895)	$ (48,751,418)	$ (66,784,731)	$ (59,257,485)	$ (26,059,751)	$ (25,768,277)	$ (40,633,415)	$ (101,576,987)	$ (50,014,065)
100% Sharing Accounts										
Account 555, PURPA	$ 64,792,474	$ 103,846,995	$ 128,789,373	$ 133,003,093	$ 147,105,350	$ 144,041,189	$ 155,172,920	$ 186,067,647	$ 194,969,848	$ 195,231,742
Account 555, Demand Response Incentives	$ -	$ -	$ 14,479,509	$ 4,197,214	$ 7,946,728	$ 6,701,113	$ 7,059,424	$ 6,983,307	$ 7,151,732	$ 6,996,236
Total	**$ 231,456,720**	**$ 212,146,640**	**$ 334,385,275**	**$ 375,630,868**	**$ 361,549,675**	**$ 395,701,565**	**$ 400,696,879**	**$ 358,101,131**	**$ 350,130,118**	**$ 368,309,843**
Percent Change from Prior Year		**-8.3%**	**57.6%**	**12.3%**	**-3.7%**	**9.4%**	**1.3%**	**-10.6%**	**-2.2%**	**5.2%**

PCA Forecast by PCA Year

FERC Account	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
95% Sharing Accounts										
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Actual NPSE by PCA Year

FERC Account	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020
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Account 501, Coal	$ 138,868,030	$ 122,922,864	$ 143,733,017	$ 160,995,670	$ 139,308,896	$ 130,779,992	$ 141,879,874	$ 103,318,634	$ 130,865,930	$ 82,407,803
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