MCDOWELL RACKNER GIBSON PC

WENDY MCINDOO
503-595-3920
wendy@mrg-law.com

March 3, 2017

VIA ELECTRONIC FILING
Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Docket No. UE 314
2017 Annual Power Cost Update ("APCU") – Reply Testimony of Nicole A. Blackwell

Dear Filing Center:

Attached for filing in the above-referenced docket is an electronic copy of Idaho Power Company's Reply Testimony of Nicole A. Blackwell. Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 314

IN THE MATTER OF IDAHO POWER COMPANY'S 2017 ANNUAL POWER COST UPDATE	)))
	)
OCTOBER UPDATE	)
	))

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

NICOLE A. BLACKWELL

March 3, 2017

Q. Are you the same Nicole A. Blackwell who previously submitted Direct Testimony in this proceeding?

A. Yes.

Q. What is the purpose of your reply testimony?

A. The purpose of my Reply Testimony is to respond to the issues raised by the Public Utility Commission of Oregon ("Commission") Staff ("Staff") Witnesses Mr. Scott Gibbens and Mr. Lance Kaufman, in Staff's January 31, 2017, Opening Testimony.

Q. Please summarize the issues raised by Staff that you will respond to in your Reply Testimony.

A. My Reply Testimony responds to the following six issues raised by Staff in Opening Testimony:

1. The forecast used to estimate total oil, handling, administrative, and general ("OHAG") expenditures at each of Idaho Power Company's ("Idaho Power" or "Company") coal-fired facilities.
2. The allocation of net power supply expense ("NPSE").
3. Idaho Power's review of the Jim Bridger Plant's ("Bridger Plant" or "Plant") fuel supply.
4. Bridger Coal Company ("BCC") coal costs.
5. Idaho Power's review of the depreciation policy for BCC.
6. Supporting workpapers for Idaho Power's initial power cost filing.

Q. Please explain Staff's issue regarding the OHAG forecast.

A. The first issue, raised by Mr. Gibbens, involves the Company's forecast of total OHAG expense at each of its coal-fired facilities. In his testimony, Mr. Gibbens states, "the forecast is not updated on an annual basis"[1] and "there is no particular

[1] Staff/100, Gibbens/7, line 6.

number of years used as a basis in determining a cost trend or average baseline for the forecast."[2] Mr. Gibbens asserts that "the forecast needs to be formulaic, transparent, and follow a systematic approach, incorporating historical data and any prevalent trends."[3]

Q. What is Mr. Gibbens' recommendation for this issue?

A. Mr. Gibbens recommends that the OHAG forecast be updated annually. He also recommends that the forecast be based on a three-year historical average of actual OAHG costs, with a growth (reduction) rate equal to the five-year historical average growth (reduction) rate. Lastly, Mr. Gibbens recommends the update to the forecast methodology be reflected in the Company's upcoming 2017 March Forecast of NPSE so as to include the most recent annual data.

Q. Is Idaho Power willing to accept Mr. Gibbens' recommendation?

A. Yes. Idaho Power is willing to accept Mr. Gibbens' recommendation for the purpose of modeling OHAG within its Annual Power Cost Update ("APCU") filings, and intends to adopt his proposed methodology for the 2017 March Forecast and all future APCU filings if the Commission ultimately approves the proposed adjustment.

Q. Please explain Staff's issue regarding the allocation of NPSE.

A. The second issue, raised by Mr. Kaufman in his Opening Testimony, is related to Idaho Power's method of allocating power costs. Mr. Kaufman states that, "Idaho Power does not allocate total power costs. Instead, Idaho Power uses a rate update mechanism to allocate expenses incremental to the previous year." [4]

---

[2] Staff/100, Gibbens/7 lines 22-23.

[3] Staff/100, Gibbens/7 lines 24-25.

[4] Staff/200, Kaufman/2 lines 8-9.

Q. Do you agree with Mr. Kaufman's characterization of the rate calculation methodology utilized for the APCU?

A. Yes. The Company agrees with Mr. Kaufman that Idaho Power uses a rate update mechanism to allocate expenses incremental to the previous year. Specifically, power costs are allocated to the Oregon jurisdiction by multiplying the system incremental per-unit cost by the forecasted Oregon jurisdictional loss-adjusted normalized sales for the test period. This allocation method has been used and accepted in every APCU filing since its inception in Docket No. UE 195.

Q. What is Mr. Kaufman's recommendation for this issue?

A. Mr. Kaufman recommends using a "total cost method."[5] It is the Company's understanding that under Mr. Kaufman's recommended total cost method, the Oregon jurisdictional revenue requirement would be calculated using the system per-unit cost for the test period, not the incremental per-unit cost. Furthermore, base rates for each service schedule would be reset each year rather than applying an incremental adjustment to base rates each year.

Q. Can you provide an example to illustrate Mr. Kaufman's recommendation?

A. Yes. For the 2017 October Update, the system per-unit cost was $26.06 per megawatt-hour ("MWh") ($382.1 million/14.661 million MWh). The 2016 October Update system per-unit cost was $23.93 per MWh ($349.8 million/14.617 million MWh). To determine the Oregon jurisdictional revenue requirement for the 2017 October Update, the Company multiplied the system incremental per-unit cost of $2.13 per MWh ($26.06 - $23.93 = $2.13) by the Oregon jurisdictional loss-adjusted sales for the test period of 686,534.333 MWh. It is Idaho Power's understanding that because the system per-unit costs for the 2017 October Update and 2016 October

[5] Staff/200, Kaufman/4 line 19.

Update were not calculated using the same loss-adjusted normalized sales figure in the denominator, Mr. Kaufman believes that power costs are not accurately recovered.[6] As such, Mr. Kaufman recommends that the Company multiply the system per-unit cost of $26.06/MWh by the Oregon jurisdictional sales of 686,534.333 MWh to determine the total Oregon jurisdictional revenue requirement, not the incremental revenue requirement.

Q. Have the parties to this case discussed how to address Mr. Kaufman's recommendation?

A. Yes. It is Idaho Power's understanding that parties will discuss Staff's rate calculation recommendation at an upcoming workshop scheduled for March 6, 2017. Should the parties reach an agreement to modify the current rate calculation, such changes would be reflected in the 2017 March Forecast.

Q. Please explain the Company's understanding of the issue presented by Staff regarding the Bridger Plant fuel supply.

A. The third issue, raised by Mr. Kaufman in his Opening Testimony, is related to Idaho Power's oversight of the Bridger Plant's fuel supply. Mr. Kaufman states, "between 2013 and 2015, Idaho Power did not analyze the appropriateness of purchasing coal from BCC."[7]

Q. Please briefly describe the BCC fuel supply for the Bridger Plant.

A. The Bridger Plant was designed and constructed as a "mine-mouth" plant, which means it is physically located next to the coal mine that supplies the majority of its coal. The adjacent mine is owned by BCC, which is jointly owned by PacifiCorp and

[6] Staff/200, Kaufman/2 lines 4-6.

[7] Staff/200, Kaufman/6 lines 14-15.

Idaho Power, on the same two-thirds/one-third basis as the Bridger Plant.[8] This mine-mouth arrangement ensures that the Bridger Plant has access to a continuous and reliable supply of coal.

Coal is delivered to the Bridger Plant from the BCC mine by use of a large conveyor belt system that transports and delivers coal directly from the mining operation to the Plant. This type of mine-mouth plant operation has several advantages over an operation where the coal is delivered from another location. Most notably, it eliminates the need to ship coal over long distances in order to supply the Plant. BCC has supplied the Bridger Plant with coal since 1974.

Q. Do you agree with Mr. Kaufman's statement that "between 2013 and 2015, Idaho Power did not analyze the appropriateness of purchasing coal from BCC?"[9]

A. No. As an engaged partner in the Bridger Plant and BCC, Idaho Power continuously provides input, oversight, and review of all operations, including the fueling strategy for the Bridger Plant. At least annually, Idaho Power and PacifiCorp work together to develop a BCC mine plan using a 10-year planning horizon to develop a strategy for least-cost, least-risk fueling of the Bridger Plant. The BCC mine plan was last updated in late 2016. The Company also participates in the development of more comprehensive fueling plans based on the life-of-plant approximately every two years.

Idaho Power also participates in the development of Bridger Plant long-term fuel plans, which are filed by PacifiCorp, the Plant operator, in compliance with Order

[8] BCC is one-third owned by Idaho Energy Resources Company ("IERCo"), a subsidiary of Idaho Power, and two-thirds owned by Pacific Minerals Inc., a subsidiary of PacifiCorp. The coal supply agreement between Idaho Power and IERCo was approved by the Commission in Order No. 91-567 in Docket No. UI 107.

[9] Staff/200, Kaufman/6 lines 14-15.

No. 13-387.[10] In Order No. 13-387, the Commission approved a process under which PacifiCorp files a long-term fuel plan with its Transition Adjustment Mechanism ("TAM") filing to permit a multi-year examination of the prudence of the Bridger Plant fuel supply costs. As an engaged partner, Idaho Power is involved in the development of these plans. PacifiCorp filed the first Long-Term Fuel Supply Plan on December 30, 2015.

Q. Has Idaho Power performed any recent analysis of long-term fuel costs for the Bridger Plant?

A. Yes. In 2016, Idaho Power independently performed analyses to evaluate the Present Value Revenue Requirement impact of four life-of-mine scenarios presented by PacifiCorp, the owner-operator. These analyses incorporated the cost of the BCC coal supply provided by the owner-operator, and third-party fuel supply needed for Idaho Power's required output of the Bridger Plant. Idaho Power provided this analysis to Staff in response to Staff's Data Request ("DR") No. 20 on January 27, 2017.

Q. Do you agree with Mr. Kaufman's comments regarding Idaho Power's "oversight" of the Bridger Plant's fuel supply?[11]

A. No. Mr. Kaufman suggests that Idaho Power does not review the actions proposed or taken by the Bridger Plant's majority owner. Idaho Power works closely with its ownership partner and does not consider its minority ownership interest an exemption to this obligation.

As detailed above, Idaho Power recently performed an independent analysis with respect to the appropriate fueling strategy for the Bridger Plant. Another recent

[10] *In the matter of PacifiCorp's 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 7 (October, 28, 2013).

[11] Staff/200, Kaufman/6-7

example of Idaho Power's direct involvement in the decision-making of Bridger Plant operations is the Company's attendance at the January 20, 2017, and March 1, 2017, workshops regarding the long-term fueling strategy for the Bridger Plant. As part of Order No. 16-482 in PacifiCorp's 2017 TAM filing, Docket No. UE 307, the Commission directed PacifiCorp, Staff, and parties to informally meet and discuss the long-term fuel supply plan for the Bridger Plant. Although the workshop was part of PacifiCorp's TAM filing and Idaho Power was not a party to the case, the Company attended the workshops in order to provide input and stay informed on discussions pertaining to fueling strategies for the Bridger Plant.

Q. What is Mr. Kaufman's recommendation for this issue?

A. Mr. Kaufman recommends "the Commission affirm or clarify that minority owners of coal plants have a duty to review all major actions proposed or taken by the facility's majority owners . . . ."[12]

Q. Is Idaho Power opposed to the language proposed by Mr. Kaufman?

A. No. Idaho Power has no objection to the Commission affirming or clarifying this point, but does not feel it is necessary. As discussed above, Idaho Power is a fully engaged and active partner regarding the fueling source decisions for the Bridger Plant.

Q. Please explain Staff's concern regarding BCC coal costs.

A. The fourth issue, raised by Mr. Kaufman, relates to the inclusion of depreciation expense in BCC coal costs. In his testimony, Mr. Kaufman states, "Idaho Power

[12] Staff/200, Kaufman/7 lines 12-14.

appears to be recovering depreciation costs for [BCC] assets that are not included in rate base."[13]

Q. What is Mr. Kaufman's recommendation for this issue?

A. Mr. Kaufman recommends that depreciation costs associated with plant that is not currently in rate base be excluded from coal costs.[14] Mr. Kaufman asserts that he did not have sufficient data at the time his testimony was submitted to propose a specific dollar adjustment. However, he intends to adjust 2017 BCC coal costs by the amount of depreciation expense included in the BCC coal cost that is associated with plant added after Idaho Power's most recent general rate case.[15]

Q. Do you agree with Mr. Kaufman's conclusion and subsequent recommendation?

A. No. For reasons I will detail in my testimony, BCC costs included in the Company's NPSE appropriately reflect the current cost of procuring coal for use at the Bridger Plant. The treatment of the BCC coal sales agreement has already been approved by the Commission, and the inclusion of these costs in Company rates appropriately aligns with Commission precedent.

Q. Please describe the relationship between Idaho Power and BCC.

A. Idaho Power owns 100 percent of IERCo, which has a one-third joint venture interest in BCC. Idaho Power accounts for IERCo as an equity method investment. Separate records and accounts for IERCO are maintained and the operations of

[13] Staff/200, Kaufman/7 lines 17-18. Mr. Kaufman's testimony states, "Idaho Power appears to be recovering depreciation costs for assets that are not included in base rates." Idaho Power assumes Mr. Kaufman intended to state, Idaho Power appears to be recovering depreciation costs for BCC assets that are not included in rate base, not base rates.

[14] Staff/200, Kaufman/8 lines 6-7.

[15] Staff/200, Kaufman/8 lines14-19.

IERCO as a joint venturer in BCC are subject to regulatory review and scrutiny together with those of Idaho Power during general rate cases.

For general rate case revenue requirement determinations, Idaho Power includes its investment in IERCo as a component of utility rate base, and includes as an offset to the utility revenue requirement the test-year IERCo earnings in the form of electric operating income. Coal delivered from BCC to the Bridger Plant is priced at the mine's cost plus an operating margin equal to the revenue requirement on IERCo rate base from the most recent general rate case. This pricing approach ensures that the Company does not earn more than its allowed return on its investment in IERCo between rate cases.

Q. Are depreciation costs for BCC assets included in the cost of coal?

A. Yes. In 1974, PacifiCorp and Idaho Power entered into a long-term coal sales agreement with BCC. Pursuant to that agreement, and its restatements and amendments, the coal sales price is computed based on BCC's total projected costs, including depreciation, as well as a calculated operating margin as provided for in Idaho Power's rate base. In other words, under the terms of the coal sales agreement, the coal sales price ultimately reflects current costs associated with procuring coal for use at the Bridger Plant, including the cost of depreciable assets required to extract coal at the mine. The sales price is adjusted periodically as updated cost data becomes available. Each time the sales price is adjusted the parties execute an amendment to the agreement.

Q. Has the Commission approved the Company's current coal sales agreement?

A. Yes. The most recent coal sales agreement was approved by the Commission in Order No. 91-567 in Docket No. UI 107. In Order No. 91-567, the Commission stated:

> The application should be granted. The coal sales agreements in question will not harm [Idaho Power's] customers because the agreements provide to [Idaho Power] a reliable source of low-cost coal for operation of the Jim Bridger plant.
>
> The transfer price for the coal which is provided by Bridger to [Idaho Power] shall be billed at actual cost. . . . The Commission concludes that the agreement is fair and reasonable and not contrary to the public interest.
>
> [Idaho Power's] contract with Bridger has and shall continue to be recognized for rate-making purposes. Expenditures made should be charged to accounts in the manner directed by the Federal Energy Regulatory Commission regulations and by the Commission's rules.[16]

Q. Are assets associated with BCC treated in the same manner as the Company's standard utility assets from a ratemaking perspective?

A. No. BCC is a non-utility entity, and therefore its assets are treated differently for ratemaking purposes than the Company's standard utility assets. Under traditional ratemaking for standard utility assets, the Company invests in rate base on behalf of customers, then requests approval to collect through rates the cost of its investment and a fair rate of return through a ratemaking proceeding at the Commission. Alternatively, BCC is a non-utility entity, and its assets have been subject to treatment that differs from that of standard utility assets. Because BCC costs (including depreciation expense associated with assets in service at the mine) reflect the cost of procuring fuel for the Bridger Plant, they have been recognized by the Company and the Commission as a fuel expense. Therefore, when the Company prepares its APCU filings and updates fuel costs associated with its generation facilities, costs at BCC are updated to reflect assets currently in service at the mine,

[16] *In the Matter of the Application of Idaho Power Company for approval of an agreement for coal sales with Bridger Coal Company, a joint venture consisting of Idaho Energy Resources Company, a Wyoming Corporation, and Pacific Minerals, Inc., A Wyoming Corporation,* Docket No. UI 107, Order No. 91-567 at 4 (April 25, 1991).

whether assets have been added, retired, or sold. This ensures that customer rates are reflective of the current cost of procuring fuel for the Bridger Plant.

Q. Has the Commission approved this ratemaking treatment in prior proceedings?

A. Yes. The Commission has recognized and approved BCC costs as fuel expense in Docket Nos. UE 92, UE 167, UE 203, UE 213, UE 214, UE 222, UE 233, UE 242, UE 257, UE 279, UE 293, and UE 301.

Q. What customer benefits result from the existing treatment of BCC expense within the context of the APCU?

A. As previously discussed, the existing treatment of BCC expense within the context of the APCU ensures that costs included in customer rates remain current with regard to the expected cost of procuring fuel for the Bridger Plant. The Company views the update to BCC expense in the same manner as updating expected gas prices, heat rates, and other variables included in the annual APCU filing that are intended to maintain alignment between NPSE included in rates and actual NPSE incurred by the Company. Depreciation expense associated with BCC assets is only included in fuel costs if an asset is currently used and useful, meaning customers only pay for equipment that is a current operating cost at the mine.

Additionally, updating BCC costs to reflect depreciable assets currently in service can serve as an immediate benefit to customers in the event that mine assets are sold. A recent example of this occurred in Docket No. UP 334, in which the disposition of BCC assets resulted in lower overall fuel costs to customers. In Docket No. UP 334, the Company requested an order authorizing the sale by BCC of a Page 732E Dragline (“Dragline”) and associated parts. In the Application, Idaho Power explained that the Dragline, which is a large, earth moving machine, was put into service in 1974 for surface mining operations. The Dragline was taken out of service in 1998 because it was too small to continue to operate economically at the BCC surface mine. BCC attempted to negotiate the sale of the Dragline to various parties over time, and eventually sold the asset in 2016 at approximately $190,000 above net book value. As pointed out in Staff's Report:

> The proceeds will flow through BCC's income statement and be reflected in the cost of coal burned at the Jim Bridger generating plant, reducing net power costs. Fuel costs are updated annually through the Company's fuel cost adjustment mechanism; *therefore, lower fuel costs for the Company result in lower costs to customers, regardless of the timing of general rate cases*.[17]

It is also important to note that customer rates did not reflect expenses associated with the Dragline between 1998, when the Dragline was taken out of service, and 2016, when the Dragline was sold. In its Application, Idaho Power explained:

> Although the Dragline has not been in service, under the Commission-approved ratemaking treatment of IERCo, customer rates have not been adversely impacted. Depreciation expense is part of the overall expenses of BCC's coal operations, initially appearing in fuel inventory costs at Idaho Power as coal sales from BCC to Idaho Power, and is ultimately reflected in Federal Energy Regulatory Commission ("FERC") Account 501 – Fuel Expense Coal when the coal is burned at the plant. When the Dragline was taken out of service, depreciation ceased and therefore was not reflected in fuel inventory costs, resulting in lower overall costs to Idaho Power and its customers.[18]

Q. Does Idaho Power believe an adjustment is warranted with respect to depreciation expense embedded in BCC costs?

---

[17] *In the Matter of the Application of Idaho Power Company for an Order Authorizing the Sale of a Dragline and Associated Parts*, Docket No. UP 334, Revised Staff Report for January 12, 2016, Public Meeting (Item No. CA8) at 3-4 (January 4, 2016) (emphasis added).

[18] *In the Matter of the Application of Idaho Power Company for an Order Authorizing the Sale of a Dragline and Associated Parts*, Docket No. UP 334, Idaho Power's Application at 3 (December 4, 2015).

A. No. Idaho Power and PacifiCorp have a significant investment in the BCC mining operation which has benefited customers with a long-term, reliable, and fairly priced source of fuel. The fixed investment costs of BCC should continue to be recovered in rates, as the existing ratemaking treatment complies with the Commission-approved coal sales agreement and ensures that customer rates reflect the current costs of procuring coal for the Bridger Plant. Depreciation expense associated with assets currently in service and required in the operations of the Bridger mine is appropriately reflected in the Company's APCU filing and should not be adjusted.

Q. Please explain Staff's issue regarding the depreciation policy for BCC.

A. The fifth issue, raised by Mr. Kaufman in his Opening Testimony, relates to Idaho Power's review of the depreciation policy for BCC. In his testimony, Mr. Kaufman states that, "Idaho Power does not appear to monitor the depreciation policy for BCC."[19]

Q. Do you agree with Mr. Kaufman's conclusion?

A. No. As discussed previously, Idaho Power is an engaged partner in BCC. As part of the BCC Management Committee, Idaho Power oversees all operational decisions at BCC, including short and long-term strategy issues, mine plans, approval of all capital and operations and maintenance expenditures and depreciation practices.

Mr. Kaufman mischaracterizes Idaho Power's engagement in BCC decisions based on the Company's response to Staff's DR No. 23, in which Idaho Power requested additional time to obtain BCC deprecation analyses from its operating partner.[20] The request for additional time was the result of the need to gather information from the owner-operator, PacifiCorp; this is not an indication that Idaho

---

[19] Staff/200, Kaufman/8 lines 3-4.

[20] Staff/200, Kaufman/8 FN 11.

Power does not monitor the depreciation policy at the mine, but simply an indication that Idaho Power does not serve as the keeper of the BCC joint venture records requested by Staff. The Company has since responded to Staff with supplemental information to DR No. 23. While Idaho Power does not maintain the depreciation analyses of BCC assets, the Company is fully engaged in BCC operational decisions, including its deprecation practices. This assertion is further supported by the Company's response to Staff's DR No. 21, in which the Company provided the list of depreciable assets in use at the Bridger mine and their corresponding depreciable lives. The information provided in response to DR No. 21 is maintained and monitored by Idaho Power as an active partner at BCC.

Q. What is Mr. Kaufman's recommendation on this issue?

A. Mr. Kaufman recommends that the Commission direct Idaho Power to review the depreciation practices of its operating partner on an ongoing basis.

Q. Do you agree with Mr. Kaufman's recommendation?

A. Idaho Power has no objection to the Commission citing the importance of reviewing the depreciation practices of its operating partner on an ongoing basis. However, Idaho Power does not require a reminder by the Commission as this is a current practice of the Company. As discussed above, Idaho Power is fully engaged in BCC operational decisions.

Q. Please explain Staff's issue regarding workpapers.

A. The sixth issue, raised by Mr. Kaufman in his Opening Testimony, relates to workpapers filed in support of the Company's October Update filing. In his testimony, Mr. Kaufman states, "Idaho Power did not provide workpapers with its initial power cost filing."[21]

[21] Staff/200, Kaufman/9 line 5

Q. What is Mr. Kaufman's recommendation on this issue?

A. Mr. Kaufman recommends that Idaho Power, Staff, and other parties work together to collaboratively update Idaho Power's filing requirements for future power cost filings.

Q. Is Idaho Power open to modifying the workpapers provided with its APCU filings?

A. Yes. Idaho Power agrees that it would be in the best interest of the Company, Staff, and other parties to establish guidelines which would detail the workpapers to be filed in all future APCU filings. Parties discussed this issue at the February 16, 2017, Settlement Conference, and agreed to address this issue at the upcoming workshop scheduled for March 6, 2017.

Q. Have you responded to all of the issues addressed by Staff in Opening Testimony?

A. Yes. All of the issues or concerns identified in Staff's Opening Testimony have been addressed and reasonably explained.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.