PACIFIC POWER
A DIVISION OF PACIFICORP

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September 1, 2016

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: UE 307 – Errata Filing

Per the direction of the administrative law judge, PacifiCorp d/b/a Pacific Power hereby submits the attached Second Errata to the Reply Testimony (PAC/500), Errata to the Surrebuttal Testimony (PAC/1000), and Surrebuttal Testimony supporting Exhibit (PAC/1003) sponsored by Mr. Dana M. Ralston in the above-referenced docket. The revision to PAC/500 identified during the hearing removes a footnote, resulting in the renumbering of all subsequent footnotes. Accordingly, PacifiCorp is filing the revision to page 18 of PAC/500 and all subsequent pages. Similarly, the addition of an item to the bullet list on page 33 of the PAC/1000, also identified during the hearing, changes the pagination of Mr. Ralston's Surrebuttal Testimony. Thus, PacifiCorp is filing the revision to page 33 of PAC/1000 and all subsequent pages.

In addition, the revised cross-exhibit (PAC/1210) is enclosed as provided at the hearing held in this docket on August 29, 2016.

Please direct informal questions to Natasha Siores at (503) 813-6583.

Confidential material has been provided to parties under the protective order in this docket (Order No.16-128).

Sincerely,

R.B.Dalley

R. Bryce Dalley
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Errata Filing in Docket UE 307 on the parties listed below via e-mail and/or overnight delivery in compliance with OAR 860-001-0180.

UE 307

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Dated this 1st day of September 2016.

Lauren Haney
Coordinator, Regulatory Operations

ERRATA
REDACTED
Docket No. UE 307
PAC/500
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

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REDACTED
Reply Testimony of Dana M. Ralston

September 2016

account for-the capital investments necessary to deliver and burn significant volumes of PRB coal.[22] Additionally, Staff does not include costs associated with unrecovered mine investments, final reclamation obligation or mine closure. In the calculation of the most recent BCC monthly cost, Staff fails to account for the fact that production at the mine has been reduced during 2016 due to various factors including reduced generation demand at Jim Bridger plant. It is likewise inappropriate to use a short-term view–especially a one-month snapshot–of costs in 2016 and make comparisons or decisions related to long-term fuel plans.

Q. Does Staff's analysis take into consideration the time required to construct the facilities necessary to receive large volumes of PRB coal?

A. No. Staff's calculation of PRB costs for 2017 is based on information presented in the workpapers for my direct testimony, but omits the relevant costs discussed above. Thus, implicit in Staff's adjustment is the incorrect assumption that the Company could have constructed the necessary facilities to handle large volumes of PRB coal this year, to allow receipt of PRB coal in 2017.

Q. Based on what the Company knew or should have known in 2013, would it have been prudent to make the decision to replace BCC coal with PRB coal in 2017?

A. No. The Company's 2013 forecasts, both long- and short-term, did not indicate that PRB coal would be least-cost by 2017. Instead, the Company's market evidence from 2013 confirms that PRB coal was expected to be a higher-cost source of coal in 2017, due to the cost of rail transportation and the capital

[22] Staff/200, Kaufman/54-55.

expenditures required to receive and burn large quantities of PRB coal, which are discussed above.

In fact, based on data available to the Company in the fall of 2013, including the amortization of a regulatory asset and capital expenditures, the Company estimates that the total delivered costs for PRB coal would be [Begin Confidential] $[redacted] [End Confidential] per ton in 2017. At that same time, fuel costs to the Jim Bridger plant were forecast at [Begin Confidential] $[redacted] [End Confidential] per ton. See Confidential Figure 2 below.

[Begin Confidential]

[redacted]

[End Confidential]

Q. **After 2013, did forecast market data continue to confirm that a fuel plan using BCC coal remained least-cost for the Jim Bridger plant?**

A. Yes. In the Company's Wyoming general rate case filed in fall 2015, the Company conducted an additional analysis of PRB coal prices that demonstrated that reliance on BCC coal remained the least-cost fueling option in 2016. That analysis demonstrated that the total Jim Bridger plant delivered coal cost including the return on rate base at BCC was approximately [Begin Confidential] $[redacted] [End Confidential] per ton for 2016. In contrast, based on the 2015 EVA Long-Term Outlook Coalcast, the Company estimated that the total delivered costs for PRB coal would be [Begin Confidential] $[redacted] [End Confidential] in 2016.[23] In addition, relying on an April 2015 RFP for PRB coal to be delivered to the Company's Dave Johnston plant in 2016, the Company determined that the total delivered costs for PRB coal would be [Begin Confidential] $[redacted] [End Confidential] in 2016. Thus, based on what the Company prepared in fall 2015, a fuel plan using BCC coal remained the preferred option for 2016.

Q. Have PRB coal prices demonstrated significant volatility in recent years?

A. Yes. To illustrate the volatility in coal market price projections, EVA's 2014 Coalcast projected PRB coal pricing in calendar year 2017 to be [Begin Confidential] $[redacted] [End Confidential] per ton for coal containing 8,800 Btu/lb. EVA's 2015 Coalcast projected coal pricing in calendar year 2017 to be [Begin Confidential] $[redacted] [End Confidential] per ton for coal containing 8,800 Btu/lb. See Confidential Figure 3 below.

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[23] Because BCC and PRB coal have different heat contents, for a fair comparison these prices were adjusted so that the dollar-per-ton figure for each option includes the same heat content.

[Begin Confidential]

[redacted]

[End Confidential]

This is a projected reduction in 2017 PRB coal costs of 33 percent. This drastic change is predominantly driven by lower natural gas prices resulting in displacing coal-fueled generation with natural gas fueled generation, uncertainties associated with recent governmental environmental policies, and the increased availability of renewable energy sources displacing fossil fueled-generation. As shown in Confidential Figure 3 above, EVA has recently forecast the 2017 PRB 8,800 Btu/lb price to be [Begin Confidential] $[redacted] [End Confidential] per ton. Pursuant to the April 2016 RFP for PRB coal to be delivered to the Company's Dave Johnston plant, the Company recently obtained a bid for 8,800 Btu/lb adjusted coal as low as [Begin Confidential] $[redacted] [End Confidential] per ton in 2017. However, the risk exists that the actual pricing available for any coal in 2017 for deliveries to Jim Bridger could be higher depending upon the market conditions which have been volatile in the past few years.

Q. How does recent price volatility inform the Company's fuel strategy?

A. The volatility in prices demonstrates that fuel plans, by design, require a long-term perspective and cannot and should not be abandoned by short-term market anomalies or cyclical changes, such as those raised by Staff and ICNU in this case. The Company is actively modifying its coal procurement strategy to respond to current, unprecedented changes in the energy markets. As described above, however, the Company cannot simply switch reliance from BCC coal to PRB coal on a year-to-year basis. The market changes that have occurred in the last year were clearly not forecast in the 2013-2015 timeframe.

Q. Staff claims that the Company historically has not considered PRB coal as an alternative to BCC coal, citing the Company's testimony in the 2014 TAM, docket UE 264.[24] How do you respond?

A. In the 2014 TAM, docket UE 264, the Company's testimony focused on Black Butte coal because the Company was responding to claims by ICNU that Black Butte was lower cost than BCC. The Company never compared PRB coal to BCC coal in docket UE 264 because there was no dispute that BCC was more cost effective than PRB. As described in more detail in Mr. Dalley's testimony, the Company provided testimony in the 2010, 2011, and 2012 TAMs that PRB coal was not a viable alternative to BCC coal due to the cost of transportation and infrastructure upgrades required to receive large volumes of PRB coal. That

[24] Staff/200, Kaufman/59.

remained true in the 2013 and 2014 TAMs, even though the point was not at issue in those cases.

Q. Staff further claims that PRB coal will be less than BCC coal in every year until 2036.[25] Do you agree with Staff's analysis?

A. No. In Figure 4 below, the Company shows the incompleteness of Staff's analysis for 2017. The point is also irrelevant to the prudence issue in this case because Staff's PRB prices are based on a June 2016 forecast.[26] The Company could not have closed BCC and replaced the BCC coal volumes with PRB coal in 2017 in six months.

Q. If the Company were to entirely replace BCC coal with PRB coal, are there any other costs that Staff has not included in its analysis?

A. Yes. Staff's analysis assumes that if the BCC mine were closed, customers are not responsible for future closure costs, final reclamation, and undepreciated assets.[27] Mr. Dalley's testimony explains why this assumption is incorrect. An accurate comparison of BCC and PRB coal must include the full costs of BCC mine closure.

Q. What types of costs would be incurred if the BCC mine were closed?

A. Similar to the closure of the Deer Creek mine approved by the Commission in Order No. 15-161, early closure of BCC mining operations would create asset impairment issues, accelerate funding requirements for final reclamation obligations and trigger unplanned expenditures for mine closure, severance and

[25] Staff/200, Kaufman/57.
[26] Staff/244.
[27] Staff/200, Kaufman/56, 63-64.

royalty costs. These costs would result in the creation of a regulatory asset, which would be amortized over future periods. The closure of the Company's Trail Mountain mine and Dave Johnston mine resulted in the creation of similar regulatory assets.

Q. Have you developed a comparison of PRB coal costs and the current fuel plan for Jim Bridger that includes the actual costs involved in changing fuel supplies?

A. Yes. Assuming that it were possible to fuel the plant with significant amounts of PRB in 2017 (which the Company has demonstrated is unrealistic), a cost comparison factoring in the additional costs of amortization of the regulatory asset and capital investment demonstrates that the Company's fuel plan for the Jim Bridger plant in the 2017 TAM remains the most cost effective option for customers. This is shown below in Confidential Figure 4. Based on data available to the Company in 2016, including the amortization of a regulatory asset and capital expenditures, the Company estimates that the total delivered costs for PRB coal would be [Begin Confidential] $[redacted] [End Confidential] per ton in 2017. At that same time, fuel costs to the Jim Bridger plant are forecast at [Begin Confidential] $[redacted] [End Confidential] per ton in the Reply Update.

[Begin Confidential]

[redacted]

[End Confidential]

Q. Staff also contends that replacing BCC coal with PRB coal would not necessarily result in the closure of the BCC mine because it could sell into the general coal market.[28] Is this a reasonable assumption?

A. No, Staff's claim is entirely unsupported. There are two fundamental flaws in Staff's assumption that BCC could sell its coal on the open market. First, the mine has no loadout facilities to move BCC coal from the mine to another location. Thus, significant capital investments would be required for the construction of a loadout facility and attainment of any necessary permits.

[28] Staff/200, Kaufman/67.

Second, even if the mine had the necessary infrastructure to move its coal, there is no current market for BCC coal. Southwest Wyoming is a niche market with limited participants. The relatively low heat content in comparison to Colorado and Utah coals and the high ash content relative to PRB coal confines Southwest Wyoming coal largely to the local area. Thus, it is clear that the BCC mine will close if it no longer serves the Jim Bridger plant.

Q. How do you respond to Staff's claim that the Company "may not be operating [BCC] in customers' interests?"[29]

A. I strongly disagree with this claim. Staff argues that the Company does not perform due diligence analysis related to capital investments at the mine.[30] On the contrary, the Company conducts thorough and comprehensive due diligence analysis before making any capital investments in BCC and regularly evaluates least-cost, risk-adjusted fuel forecasts for the Jim Bridger plant. BCC is subject to the PacifiCorp asset capitalization policy and also maintains distinct capital policy and procedures. As described in the "Capital Policy and Procedures" for BCC provided in in response to Staff Data Request 93, a capital approval document is required for each project over a certain value. An accompanying financial analysis is performed for each project. Higher value projects require additional justification and scrutiny. Moreover, because the mine is consolidated with PacifiCorp for ratemaking purposes, any capital investment in the mine is subject to the same prudence review as all other Company investments.

[29] Staff/200, Kaufman/32.
[30] Staff/200, Kaufman/31-32.

Q. Have any of the Company's capital investments in BCC been found imprudent by the Commission?

A. No.

Q. Are all of the anticipated capital investments included in the Company's Long-Term Fuel Supply plan?

A. Yes. Thus, the full revenue requirement impact of continued operation of BCC is fairly compared to the revenue requirement impact of transitioning to market alternatives.

Q. Staff also testifies that the Company has dramatically increased its capital investments in BCC since the acquisition of PacifiCorp by Berkshire Hathaway Energy in 2005.[31] How do you respond?

A. The construction of the BCC underground mine began in 2004 with the construction of the mine portal and subsequent purchase of significant capital mining equipment over the course of several years. The construction of the underground mine included PacifiCorp's share of approximately [Begin Confidential] $[redacted] [End Confidential] in capital assets, reflected in Oregon rates in docket UE 170.[32] A significant amount of underground mine equipment was purchased and placed in service in 2007 as longwall mining production began in that year. These capital investments at the mine correspond to the development of the underground mine and are unrelated to the change in ownership of PacifiCorp.

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[31] Staff/200, Kaufman/32-34.
[32] See *Pacific Power & Light Co. Request for General Rate Increase*, Docket No. UE 170, Order No. 05-1050 at 6 (Sept. 28, 2005); Docket No. UE 207, PPL/202, Lasich/3-4.

Q. Staff testifies that the Company's forecasts of 2017 BCC production and prices have changed in recent years, with the price increasing and the production decreasing.[33] How do you respond?

A. As Staff's testimony confirms, BCC prices and production have been volatile in recent years, reflecting broader market volatility. This underlines the importance of examining fuel supply plans on a long-term basis. Staff's testimony also confirms that, at the critical time the Company would have needed to decide to close BCC and replace its output with PRB coal in 2017, BCC's costs were expected to be lower.

Q. Please respond to Staff's criticism of the Company's 2016 business plan.[34]

A. Energy market conditions changed drastically from when the plan was developed in the summer of 2015 to early 2016. The 2016 business plan and BCC mine plan developed in 2015 pre-dated many of these changes. The Company developed a BCC mine plan with lower production levels for the 2017 TAM based upon market conditions and the Company's experience in spring 2016 with reduced generation levels at the Jim Bridger plant. For business planning purposes, the Company continues to evaluate the BCC mine plan and operations and will make additional changes as needed in response to market conditions.

The BCC mine plan utilized for the 2017 TAM anticipated delivered volumes of [Begin Confidential] [redacted] [End Confidential] tons (PacifiCorp share). However, if market conditions dictate, the mine could produce an incremental amount of approximately [Begin Confidential] [redacted] [End

[33] Staff/200, Kaufman/31.
[34] Staff/200, Kaufman/37, 45.

Confidential] tons above the existing mine plan. Flexing the mine up to produce this incremental volume would require additional production shifts, with the cost for this limited quantity equal to the incremental price of production of [Begin Confidential] $[redacted] [End Confidential] per MMBtu. The Company has reflected the ability of BCC to deliver this incremental quantity of coal in its Reply Update. Further ramping the mine to deliver quantities above the total [Begin Confidential] [redacted] [End Confidential] tons would be a long-term commitment requiring additional staffing.

Q. Staff further contends that reliance on PRB coal would result in optimal dispatch of the Jim Bridger plant, which would create additional cost savings not accounted for in Staff's analysis.[35] Please comment.

A. Staff's analysis is focused on fuel supply for and dispatch of the Jim Bridger plant in 2017. As I have described in my testimony, the Company does not have the ability to receive and burn significant quantities of PRB coal at the Jim Bridger plant in 2017. In the Reply Update, however, the Company has recognized the potential to receive deliveries of up to [Begin Confidential] [redacted] [End Confidential] tons of PRB coal during 2017 for consumption at the Jim Bridger plant at an incremental cost of [Begin Confidential] $[redacted] [End Confidential] per MMBtu.

[35] Staff/200, Kaufman/56.

ICNU'S LOWER OF COST OR MARKET ADJUSTMENT

Q. What does the lower of cost or market rule require?

A. The lower of cost or market rule states that transactions between utilities and affiliates "shall be recorded in the energy utility's accounts at the affiliate's cost or the market rate, whichever is lower."[36] The rule defines "market rate" as "the lowest price that is available from nonaffiliated suppliers for comparable services or supplies."[37] As discussed in Mr. Dalley's testimony, the Commission has not historically applied this standard to BCC coal.

Q. What is the basis for ICNU's recommendation that the Commission apply the lower of cost or market pricing to coal acquired from BCC?

A. ICNU claims that BCC is no longer a reasonably priced option for the Company because the market price for coal in Wyoming has been declining, while BCC costs have been increasing.[38] ICNU's high-level analysis, which looks broadly at state-wide coal costs, fails to account for coal costs at the Jim Bridger plant. The evidence in recent TAM filings contradicts ICNU's assertion and demonstrates that coal costs for both BCC and Black Butte have been increasing at a comparable rate and that in the 2014, 2015, and 2016 TAMs, the costs of coal have been comparable.

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36 OAR 860-027-0048(4)(e).
37 OAR 860-027-0048(1)(i).
38 ICNU/100, Mullins/8-9.

Q. What market alternative does ICNU claim should replace BCC coal?

A. Like Staff, ICNU claims that PRB coal is least-cost and that the Company should use PRB coal instead of BCC coal in 2017.[39]

Q. Are there any problems with ICNU's analysis?

A. Yes. First, like Staff, ICNU ignores the infrastructure requirements necessary to receive and burn significant quantities of PRB coal. ICNU simply assumes the Company can replace BCC with PRB coal without any delay to construct the necessary facilities. Thus, like ICNU's lower of cost or market recommendation in docket UE 264, the market alternative here is also unrealistic and cannot actually replace BCC coal in 2017.

Second, ICNU's analysis does not include fuel surcharge, dust suppression, coal handling, unrecovered mine investments, final reclamation obligation and mine closure costs.

Third, ICNU's analysis amortizes the capital investment over a 20-year period which extends beyond the timelines in Senate Bill 1547 which phases out coal-fired generation in Oregon by 2030.

MINIMUM TAKE PROVISIONS IN COAL CONTRACTS

Q. Have Staff and CUB challenged costs in the 2017 TAM related to the minimum take provisions in certain of the Company's coal contracts?

A. Yes. Staff contests how the Company modeled minimum take provisions in the 2017 TAM and, in testimony, also claims that contracts containing these

[39] ICNU/100, Mullins/12, 15.

provisions "may" be imprudent.[40] Staff clarified during discovery, however, that it is not challenging the prudence of the post-2015 contracts and therefore Staff's adjustment is limited to the modeling of the minimum take provisions in GRID.[41]

CUB directly challenges the prudence of minimum take provisions in the Company's coal contracts executed since 2015 and recommends that all "costs and impacts" of these contracts be disallowed.[42] Company witness Mr. Dickman addresses the modeling of these contract provisions, while I address their prudence.

Q. Which coal supply contracts has the Company executed since 2015?

A. The coal supply contracts executed since 2015 relate to the Huntington, Jim Bridger, and Dave Johnston plants. Although Staff claims that the Company entered into four contracts since 2015,[43] the contract related to the Naughton plant that indicates a term beginning in 2017 was actually executed in 2010, but included two distinct terms.[44]

Q. Were any of the post-2015 coal supply contracts subject to a minimum take adjustment in this case?

A. No. As described by Mr. Dickman in the Company's Initial Filing, there were four plants adjusted to account for minimum take requirements: [Begin Confidential] [redacted]. [End Confidential] In the Reply Update, only [Begin Confidential] [redacted] [End Confidential] are subject to a minimum take adjustment. Therefore, none of the minimum take

[40] Staff/200, Kaufman/22, 24.
[41] PAC/502 (Staff Response to PacifiCorp Data Request 11).
[42] CUB/100, McGovern/9.
[43] Staff/200, Kaufman/24.
[44] Staff/209.

provisions in the contracts challenged by CUB are actually at issue at this point in the case.

Q. Are all three contracts executed since 2015 long term coal supply contracts?

A. No. The coal supply contract for the Huntington plant is the only long-term coal supply agreement executed since 2015. The Jim Bridger contract expires in 2017 and the Dave Johnston contract expires in 2018.

Q. Please explain how minimum take provisions operate in the Company's coal contracts.

A. A minimum take, or "take-or-pay," provision generally requires the Company to purchase a minimum specified amount of coal over a given time period.

Q. Are minimum take provisions a standard aspect of coal supply contracts?

A. Yes. Minimum take provisions are an essential component of virtually all long-term coal supply agreements and constitute the consideration required to obtain favorable pricing. Coal producers cannot continue to invest in extending the operations at the existing mines without coal sales contracts and some guarantee that they will be able to sell a minimum volume.

Q. Please explain why it was prudent for the Company to continue to execute coal supply contracts with minimum take provisions in 2015 and beyond.

A. Coal supply contracts, which necessarily include minimum take provisions, ensure that a reliable supply of coal will be committed and available to fuel the Company's plants at predictable and stable prices, terms, and conditions. Absent a coal supply agreement, the Company would be required to supply its plants exclusively with spot market purchases. Relying exclusively on the spot market, however, is an extremely risky strategy that would expose customers to substantial and unreasonable price and supply risk. The Company has never relied exclusively on the spot market and doing so in these uncertain times would be categorically imprudent.

Q. Has CUB provided any contract-specific evidence that the Company acted unreasonably in executing coal contracts with minimum take provisions since 2015?

A. No. CUB fails to present any actual evidence related to specific contracts. CUB simply argues that "an expensive and binding commitment to coal in the current environmental, federal, and regulatory atmosphere is imprudent."[45] But CUB provides no analysis or evidence indicating that any of the contracts it references were imprudent when they were executed or that a reasonable utility would rely exclusively on the spot market, rather than a coal supply contract. Moreover, CUB does not acknowledge that the minimum take provisions in the challenged contracts are not even an issue this case because the Company's modeling exceeded the minimum take under those contracts.

Q. Is CUB's argument in this case consistent with its past positions?

A. No. As noted above, the Company's only post-2015, long-term coal supply agreements is with Bowie Coal Sales LLC for delivery at the Huntington plant. This contract replaced the coal that was previously provided by the Company's affiliate-owned Deer Creek mine, which closed in 2014. In docket UM 1712, CUB entered into a stipulation with the Company that included a term specifically

[45] CUB/100, McGovern/7.

stating that this coal supply contract was prudent.[46] Moreover, this contract has significant provisions in the contract to account for changes in law or regulation.

Q. Staff also suggests that the Company should be relying on its ability to stockpile coal at its plants to mitigate the impact of minimum take provisions.[47] Is this a reasonable suggestion?

A. No. The majority of the Company's coal plant stockpiles have limited capacity levels. As such, surging stockpile levels up or down would not provide adequate flexibility on a repeated year-over-year basis to mitigate the impact of minimum take provisions. The Company uses the stockpiles to adjust for actual conditions when they differ from the forecast due to changes in market or coal quality conditions. Losing this operational flexibility would subject customers to added supply risk and create situations where the Company is forced to operate in a sub-optimal condition.

Q. CUB also claims that the Company can re-sell the coal it is required to purchase, to mitigate the impact on customers.[48] Is this feasible?

A. No. From a physical and practical position, the existing facilities at most plants do not have the infrastructure to load coal for sale. Environmental permitting and significant amounts of capital infrastructure would be required to allow loading out of coal. The sale price after purchasing this coal, adding the handling costs, and adding transportation costs would make the coal unmarketable. As stated above, the Company manages any differences between coal purchases and coal

[46] Docket UM 1712, Stipulation ¶ 9 (Mar. 25, 2015).
[47] Staff/200, Kaufman/24.
[48] CUB/100, McGovern/8.

consumption by maintaining inventory stockpiles as well as adjusting the annual nominations of coal that are required in the prior year.

Q. CUB is also concerned that the Company is operating its coal plants in a way that will cause long-term damage and greater forced outages.[49] Is this a valid concern?

A. No. CUB is using information from a study that does not represent how the Company forecasts that its plants will operate. The study references a plant that has cycled on and off as many as four times a day. The Company's forecast is that while capacity factors on the plants will drop, they will still be significantly high capacity factors and will be online and operating the majority of the time. While the Company will be monitoring the condition of the plants and the operating profile, it does not expect significant impacts to availability or costs for the remaining life of the units.

Q. Does this conclude your reply testimony?

A. Yes.

[49] CUB/100, McGovern/8.

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Docket No. UE 307
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BEFORE THE PUBLIC UTILITY COMMISSION

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Surrebuttal Testimony of Dana M. Ralston

September 2016

Company performs a similar analysis as Staff using the same models but utilizes different inputs for the following items:

- PRB coal cost and Btu/lb.
- Transportation cost for PRB coal
- Regulatory asset and capital investment amortization period
- Time value of money
- Tax assumptions
- Undepreciated investment amount
- Regulatory asset amount
- Jim Bridger plant dispatch fuel cost
- BCC and Black Butte fuel prices.

The Company's analysis results in a PVRR difference of [redacted] favorable for the Base Case compared to the Market Case.

Q. Staff's rebuttal testimony also includes a new adjustment related to the dispatch benefits Staff calculates based on the use of PRB coal in 2017.[49] How do you respond to this new adjustment?

A. As explained above and in my reply testimony, there is no basis for imputing PRB coal supply to the Jim Bridger plant as Staff proposes. For this reason, Staff's secondary adjustment to recalculate the Jim Bridger's plant's dispatch in NPC based on artificially low fuel costs is also incorrect. In addition, it is improper for Staff to propose a new and complex secondary adjustment in its rebuttal testimony, when the Company has only ten days to respond. Staff flagged the

[49] Staff/400, Kaufman/28-29.

issue in its opening testimony, and it could have proposed the secondary adjustment at that time.[50] Staff's delay in proposing this adjustment deprived the Company of the time necessary to adequately respond to it.

ICNU'S LOWER OF COST OR MARKET ADJUSTMENT

Q. Has ICNU modified its recommendation in its rebuttal testimony?

A. Yes. ICNU has recalculated its proposed adjustment and has recommended that, if the Commission rejects its lower of cost or market adjustment, it approve Staff's prudence-based adjustment to BCC coal costs.[51]

Q. How do you respond to ICNU's modified position?

A. I continue to disagree with ICNU's recommendation. While I will respond to several of the particular claims made by ICNU in its testimony, I first want to provide an overall assessment of ICNU's position. Nowhere does ICNU contend that the Company could actually replace BCC coal with PRB coal in 2017. I presented evidence in my reply testimony demonstrating that due to the infrastructure investments needed to handle PRB coal, it is impossible for the Company to rely on the volume of PRB coal that would be necessary to replace BCC coal in 2017. PRB is therefore not an "available" market alternative under the rule. ICNU never disputed this evidence.

I also testified that, in order for PRB coal to replace BCC coal in 2017, the Company would have had to decide to make the switch at the latest in 2013. Again, ICNU does not challenge this evidence nor does ICNU present any

[50] Staff/200, Kaufman/56.
[51] ICNU/200, Mullins/10-12.

evidence indicating that as of late 2013, a reasonable utility would have invested PacifiCorp's share of over [redacted] million to make the switch to PRB coal in 2017.

Q. While ICNU generally agrees with your comparison of PRB coal to BCC coal presented in Confidential Figure 4 of your reply testimony, it proposes "a few minor changes."[52] Do ICNU's changes have merit?

A. No. Confidential Figure 4 in my Reply Testimony compares the unit costs of PRB coal to the unit costs of fueling the Jim Bridger plant based on information that is known today. ICNU made two changes to the calculation.

First, ICNU adjusted the amortization period for the regulatory asset that would be created upon closure of the BCC mine. In my testimony, I had used a four-year amortization period. ICNU recommends a 13-year amortization period, which corresponds to the removal of coal assets from Oregon rates under Senate Bill 1547.

Q. Is ICNU's 13-year amortization period reasonable?

A. No. The Company used a four-year amortization period. As I explained above, based on what was known in 2013, four years is a reasonable assumption for amortization.

Q. ICNU also recommends a lower return on the undepreciated balances. Please comment.

A. Mr. Dalley responds to ICNU's position and supports use of the Company's weighted average cost of capital.

[52] ICNU/200, Mullins/8-9.

Q. Did ICNU make any other errors when modifying table 1R?

A. Yes, ICNU originally modified the volumes of coal in the comparison but did not correct the capital investment amortization for the reduced volumes. In an errata filed on August 19, 2016, ICNU corrected this error, increasing the capital investment amortization from $[redacted] per ton to $[redacted] per ton. In addition, ICNU did not adjust the [redacted] tons of PRB coal for heat content. The Company disagrees with ICNU's comparison because the most accurate and complete way to analyze Jim Bridger plant fuel costs is to look at the total fueling costs not just one element of the fueling plan. In the interest of showing that BCC fuel is the least-cost least-risk option, the Company looked at ICNU's hypothetical view and corrected it. Once ICNU's incorrect assumptions are amended, the PRB unit cost becomes higher than the BCC-only unit cost.

Q. Did ICNU present any evidence challenging your determination of PRB coal pricing based on what was known in 2013?

A. No.

Q. ICNU argues that the Company has an incentive to keep the mine open even when doing so is not in customers' interests.[53] Do you agree?

A. No. The Company's incentive is to fuel the Jim Bridger plant in the least cost, least risk manner. This serves the Company, its customers, and its plant co-owner Idaho Power Company. As demonstrated just two years ago with respect to another affiliate mine, Deer Creek, the Company will close a mine if the public interest is served by doing so. That example also illustrates, however, the

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[53] ICNU/200, Mullins/12.

importance of careful and deliberate planning, given the complexity and expense associated with mine closure.

MINIMUM TAKE PROVISIONS IN COAL CONTRACTS

Q. Staff claims that the Company has no performed no analysis to determine the appropriate quantity of coal to purchase under take-or-pay provisions.[54] Is this true?

A. No. As I described in my reply testimony, take-or-pay provision are standard and accepted terms in any coal contract, even short-term contracts. Therefore, if the Company is going to purchase coal on anything but the spot market, it will do so subject to a take-or-pay requirement. When Staff claims that "[a]pparently without any analysis or substantial policy, PacifiCorp has chosen to secure a substantial amount of coal under take-or-pay provisions,"[55] Staff is really claiming that the Company has not performed any analysis justifying the use of contracts, instead of the spot market. This is untrue. The spot market would subject customers to significant risk in both supply reliability and price variability. Staff even states that "Staff does not propose that PacifiCorp should rely on only spot market purchases of coal."[56] The use of the Company's current fueling strategy minimizes risk and costs for customers.

In terms of determining the appropriate level of a coal supply contract subject to a take-or-pay provision, the Company analyzes that in the context of

[54] Staff/400, Kaufman/38.
[55] Staff/400, Kaufman/39.
[56] *Id.*

each individual plant and the expected volumes of coal that will be required during the term of the contract.

Q. Staff also criticizes the Company's hedging policy for having a single sentence about coal.[57] Is Staff's characterization of the Company's hedging policy correct?

A. No. The basis for Staff's claim is a Staff data request asking for the Company's hedging policy related to coal. Because the Company's coal supply is not governed by its Energy Risk Management Policy (the hedging policy for electricity and gas), the Company's response indicated that it utilizes a combination of spot, medium and long-term physical delivery coal purchase contracts, along with the volume flexibility of plant coal inventory levels.[58] In addition to this "single sentence" referred to by Staff, the Company also directed Staff to the "PacifiCorp Coal Inventory Policies and Procedures, Effective 1/1/13," which was already provided to Staff in discovery. Contrary to Staff's claim, the Company's "hedging policy" for coal is much more than a single sentence.

[57] Staff/400, Kaufman/38.
[58] Staff/406, Kaufman/1.

Q. Staff testifies: "Given that PacifiCorp's own hedging policy is to use inventory capacity to manage minimum take requirements, it is reasonable to expect them to have a specific plan with regards to how to model this relationship."[59] Is Staff's characterization of the Company's policy correct?

A. No, Staff misrepresents the Company's testimony. In fact, my reply testimony explicitly states that the Company does *not* rely on its inventory piles to manage minimum take requirements and that doing so would be imprudent.[60] Indeed, in the very same data response Staff apparently relies on to support this statement it is clear that the Company's inventory levels are governed by policies established pursuant to biennial studies, as Staff acknowledged by including the 2010 study in the record in this case.[61] Those studies are clear that the inventory is not designed to manage minimum take requirements, but rather to account for factors such as potential supply or transportation disruptions, coal quality, coal market conditions, potential labor disruptions, and uncertainties in weather.[62]

Q. Staff proposes that the Company allow the 2017 year-end inventory levels to reach the maximum capacity prior to artificially modifying dispatch tier GRID prices.[63] Is this proposal reasonable?

A. No. If the Company were to max out the inventories, as Staff recommends, it would effectively eliminate the flexibility to respond to changing market dynamics and differences between the forecast and actual burns at the coal plants.

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[59] Staff/400, Kaufman/42.
[60] PAC/400, Ralston/36.
[61] Staff/212.
[62] Staff/212, Kaufman/6.
[63] Staff/400, Kaufman/42.

Q. CUB continues to claim that all post-2015 contracts are imprudent for including take-or-pay provisions.[64] Do you have any additional response to CUB?

A. No. CUB did not dispute or rebut any of the Company's evidence demonstrating the prudence of the contracts. Thus, CUB has not presented any evidence supporting its position nor has CUB disputed any of the evidence refuting its position.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[64] CUB/200, McGovern/32.

ERRATA
CONFIDENTIAL
Docket No. UE 307
Exhibit PAC/1003
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

ERRATA

CONFIDENTIAL
Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston

Comparison of Base Case and a Market Case

September 2016

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ERRATA
CONFIDENTIAL
Docket No. UE 307
Exhibit PAC/1210
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Revised Cross-Exhibit

Summary of Staff Exhibit 403 and PAC Exhibit 1003 Assumptions

September 2016

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