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July 8, 2016

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
2017 Transition Adjustment Mechanism
Docket No. UE 307

Dear Filing Center:

Enclosed for filing in the above-captioned proceeding, please find the redacted version of the Opening Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

The confidential portions of ICNU's testimony and exhibits are being handled in accordance with the general protective order issued in this proceeding and will follow via Federal Express.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential pages of the **Opening Testimony and Exhibits of Bradley G. Mullins** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid, or via hand-delivery.

Dated at Portland, Oregon, this 8th day of July, 2016.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2017 Transition Adjustment Mechanism.	)
______________________________________	)

CONFIDENTIAL OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

(REDACTED VERSION)

July 8, 2016

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EXHIBIT LIST

Exhibit ICNU/101: Qualification Statement of Bradley G. Mullins

Confidential Exhibit ICNU/102: PacifiCorp Confidential Long-term Fuel Supply Plan for the Jim Bridger Power Plant

Confidential Exhibit ICNU/103: The Company's Responses to Data Requests

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing industrial customers throughout the western United States. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including customers of PacifiCorp, d.b.a. Pacific Power (the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the Company's Transition Adjustment Mechanism ("TAM") filing for 2017. Specifically, my testimony discusses the Company's request to increase the amount of net power cost ("NPC") included in rates by $45.0 million, on a total-Company basis.[1/] This increase to NPC, when combined with other aspects of the Company's filing, such as the true-up of production tax credits pursuant to Senate Bill 1547, represents an approximate 1.6% rate increase to Oregon customers.[2/] On a total-Company basis, the Company's proposed modeling would support NPC of $1,566.0 million,[3/] which is approximately $[redacted] million

[1/] PAC/101 at 1:33
[2/] PAC/100 at 3
[3/] PAC/101 at 1:33

greater than the $[redacted] million the Company actually incurred over the 12 months ending April 2016.[4]

Q. WHAT ARE YOUR KEY RECOMMENDATIONS AND CONCLUSIONS?

A. While I continue to be concerned with several of the modeling adjustments approved in the 2016 TAM, my testimony in this proceeding is limited to the following three recommendations:

1. *The day-ahead and real-time ("DART") system balancing adjustments should, at a minimum, consider the cost of day-ahead integration;*
2. *Coal from the Bridger Coal Company ("BCC") should be reflected in rates at the lower of cost or market;*
3. *The moratorium on new modeling changes should be extended until the Company files its next general rate case.*

Q WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS?

A. Table 1, below, details the NPC impacts of my recommendations.

TABLE 1
NPC Impact of Recommendations ($000)

	Total-Company	Oregon-Allocated
Filed NPC	**1,566,032**	**378,655**
Adjustments		
DART Modeling	(7,636)	(1,944)
BCC Disallowance	(45,716)	(11,641)
Total	**(53,351)**	**(13,585)**
Adjusted NPC	**1,512,680**	**365,070**

[4] Based on Actual NPC data provided by the Company in response to ICNU Data Requests 002 and 003.

II. DAY-AHEAD AND REAL-TIME SYSTEM BALANCING

Q. PLEASE SUMMARIZE THE COMPANY'S DAY-AHEAD AND REAL-TIME SYSTEM BALANCING ADJUSTMENT.

A. In the 2016 TAM, the Company proposed an adjustment to reflect what it alleged to be the cost of system balancing between the day-ahead and real-time markets. In effect, the Company argued that various operational factors forced it, on average, to purchase additional generation in high-priced periods and sell excess generation in low-priced periods, transactions which the Company argued were not reflected in GRID. In Order 15-394, the Commission approved the Company's modeling adjustment.[5/] It also, however, "encourage[d] parties to examine this modeling change in more detail in the next TAM cycle."[6/]

Q. DO YOU CONTINUE TO DISAGREE WITH THE COMPANY'S MODELING OF DAY-AHEAD AND REAL-TIME SYSTEM BALANCING?

A. Yes. In my opinion, forecasting system balancing costs based on the historical differences between actual system balancing costs and monthly market prices is not the best way to forecast normalized NPC. Notwithstanding, the Commission approved the use of the Company's DART modeling in Order 15-394,[7/] and accordingly, the Company's NPC forecast in this case includes this methodology, the impact of which is to increase NPC by approximately $37.8 million in the test period. I continue to recommend that the Commission reject the DART modeling methodology. If the Commission is going to accept the DART modeling methodology, however, there is at least one change that should be made.

5/ In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Docket UE 296, Order 15-394 at 4 (Dec. 11, 2015).

6/ Id.

7/ Id. at 2-4.

Specifically, the DART modeling should be adjusted to better account for day-ahead integration costs.

Q. HOW SHOULD THE DART MODELING BETTER ACCOUNT FOR DAY-AHEAD INTEGRATION COSTS?

A. The Company has historically included a charge in forecast NPC to reflect day-ahead integration costs. This charge, however, was not modified when the Company implemented its DART modeling methodology. The historical transaction data used by the Company in the DART methodology should include the cost of transactions made or forgone as a result of integrating load and wind on a day-ahead basis. Therefore, my opinion is that the DART modeling and the day-ahead integration charge should be consolidated to better reflect the costs of day-ahead integration. Specifically, my proposal is to eliminate the day-ahead integration charge included in the Company's initial filing to prevent double-counting this charge.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. Consolidating the day-ahead integration charge with the DART adjustment reduces NPC by $7.6 million on a total-Company basis.

Q. WHAT ARE DAY-AHEAD INTEGRATION COSTS?

A. Day-ahead integration costs, sometimes referred to as intra-hour integration costs, are described in Appendix H of the Company's 2015 Integrated Resource Plan. In that document the Company characterized those costs as "the cost associated with day-ahead forecast variances…which affects how dispatchable resources are committed to operate, and subsequently, <u>affect daily system balancing</u>."[8/] The Company calculates this charge separately

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[8/] <u>PacifiCorp 2015 Integrated Resource Plan,</u> Volume II, Appendix H, at 100 (emphasis added).

for both load and wind.[9/] As the Company describes, "[l]oad system balancing costs capture the difference between committing resources based on a day-ahead load forecast and committing resources based on actual load, while keeping inputs for wind generation unchanged. Similarly, wind system balancing costs capture the difference between committing resources based on day-ahead wind generation forecasts and committing resources based on actual wind generation, while keeping inputs for load unchanged."[10/]

Q. WHY DO YOU BELIEVE THAT THE HISTORICAL TRANSACTIONS USED IN THE DART ADJUSTMENT INCLUDE THE COST OF DAY-AHEAD INTEGRATION?

A. My understanding is that the Company includes all historical day-ahead and real-time transactions in its DART modeling adjustment. Thus, any day-ahead or real-time transaction made historically in connection with sub-optimal day-ahead unit commitment already would be reflected in the average system balancing costs used in the DART modeling.

Q. WHY DO YOU CONTINUE TO DISAGREE WITH THE DART MODELING?

A. In my view, there are many conceptual problems with the Company's DART modeling, and while I don't necessarily disagree with the Company's narrative on how it balances its system, I do have concerns with how the Company has implemented the modeling underlying this adjustment.

First, the DART modeling relies on historical data that may not be reflective of normalized operations. For example, in my testimony in Docket UE 296, I noted that the Company experienced extraordinary system balancing costs in February 2014 and I questioned the appropriateness of including the impact of those costs in a normalized NPC forecast.[11/]

9/ Id. at 122.
10/ Id.
11/ Docket UE 296, Opening Testimony of Bradley G. Mullins at 18:8-15.

Similarly, the historical transaction data relied upon by the DART modeling includes transactions that were made as a result of forced outages. Because the Company models normalized forced outages separately in GRID, however, the financial implications to the Company of these outages may be overstated.

I am also concerned that the mechanics of the DART modeling do not necessarily address the problem that the Company described in testimony. Modeling hourly spreads between purchases and sales in the GRID model, for instance, does not appear to address the problem related to the Company's claim that "[i]n reality, however, prices vary within each month and the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods."[12/] If the within-month price variability was truly the problem that the Company was attempting to address, it may have been more accurate to simply model market prices with greater within-month price variability, rather than using market spreads, which could have differing impacts on system dispatch costs.

Additionally, the Company's claims regarding the need to include additional volumes in NPC are, in my view, entirely misleading. These alleged additional volumes are not supported by the historical data—other than through the inclusion of book-out transactions, which have historically been excluded from NPC. The cost that the Company assigns to the additional volumes is also wholly unrelated to any incremental volumes that the Company might procure, as the cost is established as a plug to force the impact of its DART adjustment to tie to historical averages. The volumes themselves could be set at any level, and based on the way the Company's adjustment works, it would have no impact on NPC. In my view,

[12/] PAC/100 at 17:8-11

these additional volumes serve no purpose other than to confuse what the Company has actually done with this aspect of the DART adjustment.

Finally, actual net power costs have declined in recent years. As discussed above, actual NPC over the 12-months ending April 2016 was $[redacted] million. That is down from approximately $[redacted] million in calendar year 2014. Not only does this declining NPC mitigate the need for the extraordinary DART modeling, it calls into question whether it is appropriate to use average system dispatch costs in the DART methodology from 2014, which may not fairly represent the lower level of NPC that is being experienced today.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION ON THE DART MODELING ADJUSTMENTS.

A. As a general matter, I continue to believe that the Company's DART adjustments do not assist the Company in accurately projecting its NPC. However, if the Company continues to implement the DART adjustments, then, at a minimum, day-ahead integration costs should be consolidated with these adjustments. If day-ahead integration costs are not considered together with the DART adjustments, I am concerned that there is a potential for double-counting because day-ahead integration costs would be reflected both as a separate charge in the model, and as a Component of the DART modeling adjustments. My recommendation results in a $7.6 million total-Company, or $1.9 million Oregon-allocated, reduction to NPC.

III. BRIDGER COAL COMPANY COSTS

Q. WHAT IS YOUR CONCERN WITH THE COST OF COAL FROM THE BRIDGER COAL COMPANY?

A. Due to numerous factors, including environmental regulations and low natural gas prices, the market price for coal in Wyoming has been declining.[13/] Counter to this market trend, however, the Company is experiencing increasing costs at Bridger Coal Company ("BCC") and, as a result, is charging ratepayers coal prices that have been consistently higher than the market rate for coal. There also appears to be no expectation that the BCC costs will decrease in the foreseeable future such that the mine will once again be competitive with the market. Faced with rising costs for BCC coal and declining costs in the market, I believe it is appropriate for the Commission to reevaluate whether it is reasonable for customers to bear the full cost of the increasingly uncompetitive BCC mines.

Q. HAS ICNU RAISED CONCERNS ABOUT THE BCC MINES IN THE PAST?

A. Yes. In Docket UE 264, ICNU witness Michael Deen raised concerns regarding the competitiveness of BCC relative to market rates. For purposes of determining the cost of a market alternative, Mr. Deen used the cost from Black Butte mine, which is adjacent to the Bridger Coal Company mines.[14/] In that proceeding, the Commission found the use of "the 2014 contract cost of Black Butte coal as a substitute for BCC coal under the [lower of cost or market] rule to be unpersuasive."[15/]

[13/] See Godby et al., Center for Energy Economics and Public Policy, o/b/o Wyoming Infrastructure Authority, The Impact of the Coal Economy on Wyoming at 18-20 (Feb. 2015). Available at: http://www.uwyo.edu/cee/_files/docs/wia_coal_full-report.pdf.

[14/] In re PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism, Docket UE 264, Order 13-387 at 5-7.

[15/] Id. at 7.

Q. WHY DO YOU BELIEVE IT IS APPROPRIATE TO REEVALUATE THE ISSUE SURROUNDING BCC COSTS IN THIS PROCEEDING?

A. Given the recent decline in market prices for coal, as well as the existence of more robust information surrounding other market alternatives, I believe it is timely for the Commission to reevaluate this issue surrounding the competitiveness of BCC in this proceeding, particularly as the spreads between the market and BCC coal appear to have widened since the 2014 TAM, making BCC coal no longer a reasonably priced option for the Company.

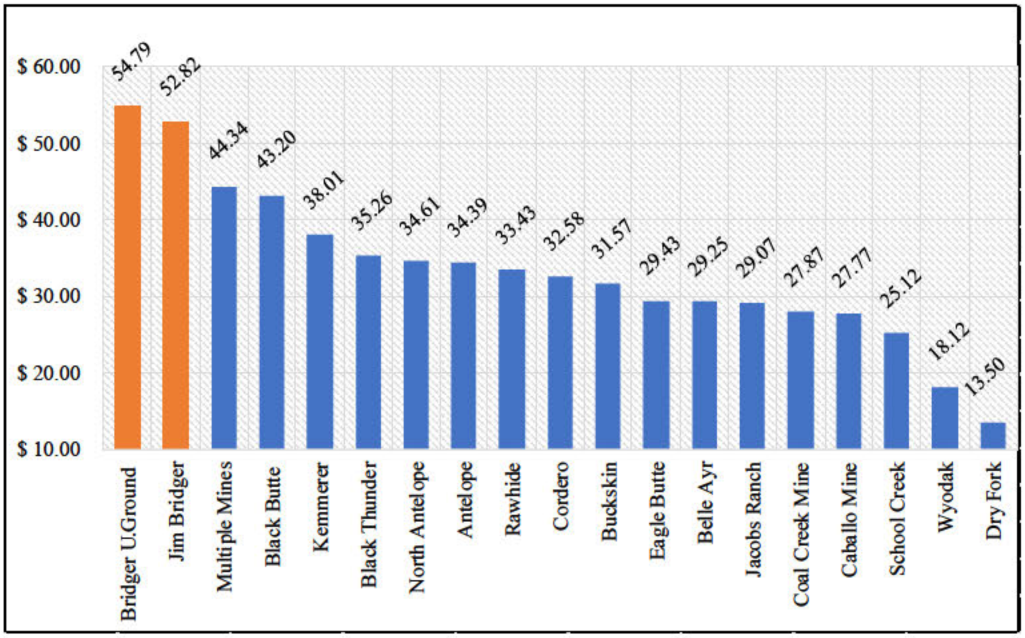
Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RATEMAKING TREATMENT OF BCC IN THIS PROCEEDING?

A. In order to provide the Company with the proper incentives for managing the ongoing operation of the BCC mines, I recommend that the Commission apply lower of cost or market pricing to the coal acquired from BCC. Based on the Company's forecast of the market price of coal delivered from the Powder River Basin, this ratemaking treatment supports a downward adjustment of $11.6 million on an Oregon-allocated basis.

Q. HOW HAVE YOU CONCLUDED THAT THE COST OF COAL FROM BCC EXCEEDS MARKET RATES?

A. The BCC surface and underground mines are unequivocally the two most expensive sources of coal in Wyoming. Figure 1, below, demonstrates the weighted average delivered cost of coal from each of the coal mines located in Wyoming:

FIGURE 1
Weighted Average Delivered Coal Cost ($/ton) by Wyoming Coal Mine
Calendar Year 2015[16/]



Q. PLEASE DESCRIBE THE DATA USED TO DEVELOP FIGURE 1.

A. Figure 1 is based on data from Energy Information Administration ("EIA") Form 923, a filing that large power producers must make to provide information on their fuel supply, including pricing terms and volumes for coal contracts. The EIA cost data used to develop the above figure includes all of the rail transportation costs necessary to deliver coal from the mine to the power plant where the coal is ultimately consumed.

Q. WHAT CONCLUSION DO YOU DRAW FROM FIGURE 1?

A. The coal prices included Figure 1 include rail transportation costs to areas as distant as Robert W Scherer Power Plant located in Juliette, Georgia. Rail transportation is typically one of the most, if not the most, significant inputs to coal prices. The cost of coal from BCC, on the other hand, includes no transportation costs to deliver coal to the Jim Bridger power plant because

16/ EIA Form 923 Data, Calendar Year 2014.

Jim Bridger receives all of its coal from BCC via conveyor belt. Thus, BCC coal appears to be the most expensive coal currently being produced in Wyoming because its cost exceeds the average cost of coal from every of the other coal mine located in Wyoming, including the cost of transportation.

Q. HOW HAVE BCC COAL COSTS BEEN TRENDING IN RECENT YEARS?

A. Counter to the trend in coal prices in the market, prices from BCC have been escalating rapidly in recent years. Confidential Figure 2, below, details the trajectory of coal costs from BCC over the period 2008 through 2017.

CONFIDENTIAL FIGURE 2

Historical Trend of Bridger Coal Company Costs to Ratepayers ($/ton)[17]

[redacted]

As can be noted from the figure, prices paid by ratepayers for BCC have nearly doubled over the past decade, increasing from approximately $[redacted]/ton in 2008 to $[redacted]/ton in 2017.

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[17] For simplicity purposes, the historical amounts include a return component based on the return amount that BCC assigns to the cost of coal—called the "fuels credit"—rather than the actual amount of return embedded in rates. My understanding is that the fuels credit amount is roughly equivalent to the amount of return reflected in rates. Also note that the historical amounts for 2015 reported in the Company's actual NPC report were slightly different than those reported in EIA Form 923, above. No data was available yet for 2016.

Q. IS THE TREND IN BCC COSTS EXPECTED TO REVERSE?

A. Upon my review of information presented in discovery, I have been unable to identify any data that would suggest that the cost of BCC coal will decline to be comparable to market rates in the future.

Q. WHAT IS THE MARKET PRICE FOR COAL DELIVERED TO THE JIM BRIDGER POWER PLANT?

A. Confidential Table 2, below, details my calculation of the market price of coal delivered from the Powder River Basin to the Jim Bridger power plant.

CONFIDENTIAL TABLE 2

Comparison of BCC Cost to the Market Price of Powder River Basin Coal

	BCC	Market (EVA)	Delta
BTU/LB	[redacted]	[redacted]	
Market ($/Ton)		[redacted]	
Transp. ($/Ton)		[redacted]	
BCC Cost ($/Ton)	[redacted]		
BCC Return ($/Ton)	[redacted]		
Total $/Ton	[redacted]	[redacted]	[redacted]
Tons	[redacted]	[redacted]	
Total Cost ($000)	[redacted]	[redacted]	[redacted]
SG Factor	25.46%	25.46%	
Oregon-Allocated ($000)	[redacted]	[redacted]	[redacted]
1st year Rev. Req. of Cap. Additions ($000)		[redacted]	
Total Oregon-Allocated ($000)	[redacted]	[redacted]	[redacted]

Q. PLEASE PROVIDE AN OVERVIEW OF CONFIDENTIAL TABLE 2.

A. Confidential Table 2 shows that the market cost of coal is materially lower than the cost ratepayers are currently paying for coal from BCC. Based on the data provided by the Company in discovery, a market equivalent cost of coal delivered from the Powder River Basin to the Jim Bridger power facility is approximately $[redacted]/ton. In contrast, ratepayers are currently paying approximately $[redacted]/ton for coal from BCC, an amount which is [redacted] higher than the prevailing market rates, including rail transportation.

Q. PLEASE DESCRIBE HOW YOU CALCULATED THE COST OF COAL FROM BCC IN CONFIDENTIAL TABLE 2.

A. Two categories of costs associated with BCC are included in rates, as reflected in Confidential Table 2, above. First, mine operating costs, including depreciation, are included in the cost of fuel for the Jim Bridger power plant. This fuel cost is reflected in rates as a component of NPC, established in the TAM and trued-up annually through the power cost adjustment mechanism. Second, the return on net plant investment in the mining assets is included as an adjustment to the Company's results, separate from NPC, and based on the Company's overall cost of capital. The amounts related to the return on the mining assets are only updated in general rate case proceedings and are recovered through base rate billing elements.

Q. DID YOU REVIEW THE COMPANY'S CONTRACTS WITH BCC?

A. No. The Company has classified these contracts as "highly confidential" pursuant to a modified protective order the Administrative Law Judge entered in this docket on June 30, 2016.[18/] Under the terms of that modified protective order, I am currently prohibited from viewing information designated as "highly confidential." Consequently, I have not been able to review the Company's contracts with BCC, which could impact my recommendation. If it becomes apparent that reviewing these contracts is necessary for me to evaluate the reasonableness of the Company's transactions with BCC, ICNU's attorneys have indicated that they may seek to qualify me under Paragraph 14 of the modified protective order as someone who may access highly confidential information.

[18/] Order No. 16-231.

Q. WHAT IS THE SOURCE OF THE MARKET DATA IN CONFIDENTIAL TABLE 2?

A. The Company provided the market data, as well as the rail transportation costs, detailed in Confidential Table 2 in response to Staff Data Request 32.[19] I adjusted the amounts provided in response to Staff Data Request 32 to reflect the slightly lower heat content associated with coal from the Powder River Basin. The market alternative includes a provision for rail transportation and a provision for capital upgrades necessary to accommodate larger volumes of market coal at the Jim Bridger power plant. It excludes any provision to account for unrecovered investment costs associated with a potential mine closure.

Q. WHY HAVE YOU INCLUDED CAPITAL UPGRADES IN CONFIDENTIAL TABLE 2?

A. The Company has historically argued that it must make capital upgrades at the Jim Bridger power plant in order to accommodate the rail transportation of greater volumes of coal from the Powder River Basin. According to the Confidential Long-term Fuel Supply Plan for the Jim Bridger Power Plant, however, [redacted].[20] [redacted] While it may not be necessary to incorporate those costs into the lower of cost or market analysis detailed above, I have included a provision for the first-year revenue requirement associated with those costs, assuming a 20-year depreciable life.

[19] Confidential Exhibit ICNU/103 at 1-2 (the Company’s Resp. to OPUC Staff Data Request 32)
[20] Confidential Exhibit ICNU/102 at 7-8.

Q. WHY HAVE YOU NOT CONSIDERED UNRECOVERED INVESTMENT COSTS?

A. To the extent the mine is closed early, there is a question of the extent that ratepayers should be responsible for unrecovered investment and closure costs. Although the Company has historically argued that those costs should be considered in a lower of cost or market analysis, it is not clear at this time whether ratepayers will be subject to those costs, and accordingly, I did not include them in my analysis.

The Company's shareholders have earned substantial returns in connection with their investment in Bridger Coal Company. The returns that shareholders have received have compensated for investment risk. This investment risk reflects, among other things, the possibility that the Company would ultimately have to dispose of the mining assets for a loss. In recognition of this investment risk, I do not necessarily believe it would be reasonable to assign the losses incurred as a result of the ultimate disposition of the mining assets to ratepayers, who have been subsidizing the shareholders' returns for an extended period. This is likely an issue for a future proceeding.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING BCC COSTS.

A. There is strong evidence to support a conclusion that BCC is uncompetitive relative to the market prices in the test period, and there is no indication that this relationship will change in the future. Accordingly, I recommend that the Commission apply lower of cost or market ratemaking to prevent ratepayers from paying unreasonable costs for coal supply to Jim Bridger. As discussed above, the impact of this adjustment is a $11.6 million reduction to NPC on an Oregon-allocated basis.

IV. MORATORIUM ON MODELING CHANGES

Q. WHAT IS YOUR RECOMMENDATION RELATED TO FUTURE MODELING ADJUSTMENTS?

A. In Order 15-353, the Commission imposed "a one-year moratorium on PacifiCorp changing the GRID model to allow parties adequate time to understand, review, and evaluate recent changes to the model."[21/] I recommend that the Commission extend this moratorium until the Company files its next general rate case.

Q. WHY DO YOU RECOMMEND THAT THE MORATORIUM ON MODELING CHANGES BE EXTENDED?

A. My understanding is that the annual update filings accompanying the Company's Transition Adjustment Mechanism were meant to be stream-lined proceedings where controversial modeling proposals were not at issue. In my view, major modeling changes, such as those approved in the 2016 TAM, would be better evaluated in the context of a holistic rate review, rather than in the accelerated TAM proceedings. The GRID model has been in use for around 15 years, and I am concerned with the large number of modeling work-arounds that have been built into the Company's modeling framework in order to accommodate perceived deficiencies in the GRID model algorithms. It can take over a day of intensive manual financial analysis just to complete a single run from the GRID model. At some point, the large amount of manual complexity outweighs the value of having a modeling tool to begin with. Thus, if more significant modeling adjustments are to be made, they ought to be considered against alternative models, and that consideration should occur in a general rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

21/ Docket UE 296, Order 15-353 at 2.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2017 Transition Adjustment Mechanism	)
	)

EXHIBIT ICNU/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

July 8, 2016

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked as a Tax Senior at Deloitte Tax, LLP, where I provided tax compliance and consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily surrounding power supply costs. I began performing independent consulting services in September 2013 and provide consulting services to large utility customers, and independent power producers on matters ranging from power costs and revenue requirement to power purchase agreement negotiations.

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

A. I have sponsored testimony in regulatory proceedings throughout the Western United States, including the following:

- Or.PUC, UE 308: In the Matter of Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125)
- Or.PUC, UM 1050: In the Matter of PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol
- Wa.UTC, UE-152253: In re Pacific Power & Light Co., General rate increase for electric services

- Wy.PSC, 20000-469-ER-15 In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming Of $32.4 Million Per Year or 4.5 Percent
- Wa.UTC, UE-150204: In re Avista Corporation, General rate increase for electric services
- Wy.PSC, 20000-472-EA-15: In re the Application of Rocky Mountain Power to Decrease Rates by $17.6 Million to Recover Deferred Net Power Costs Pursuant To Tariff Schedule 95 to Decrease Rates by $4.7 Million Pursuant to Tariff Schedule 93
- Wa.UTC, UE-143932: Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules
- Or.PUC, UE 296: In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism
- Or.PUC, UE 294: In re Portland General Electric Company, Request for a General Rate Revision
- Or.PUC, UM 1662: In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation
- Or.PUC, UM 1712: In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction
- Or.PUC, UM 1719: In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator’s Contribution to Capacity

- Or.PUC, UM 1623: In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions
- Bonneville Power Administration, BP-16: 2016 Joint Power and Transmission Rate Proceeding
- Wa.UTC, UE-141368: In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes
- Wa.UTC, UE-140762: In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million
- Wa.UTC, UE-141141: In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs
- Wy.PSC, 20000-446-ER-14: In re The Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent
- Wa.UTC, UE-140188: In re Avista Corporation, General Rate Increase For Electric Services, RE: Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015
- Or.PUC, UM 1689: In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market
- Or.PUC, UE 287: In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism.

- Or.PUC, UE 283: In re Portland General Electric Company, Request for a General Rate Revision
- Or.PUC, UE 286: In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU)
- Or.PUC, UE 281: In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment
- Or.PUC, UE 267: In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck).

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2017 Transition Adjustment Mechanism	)
	)

CONFIDENTIAL EXHIBIT ICNU/102

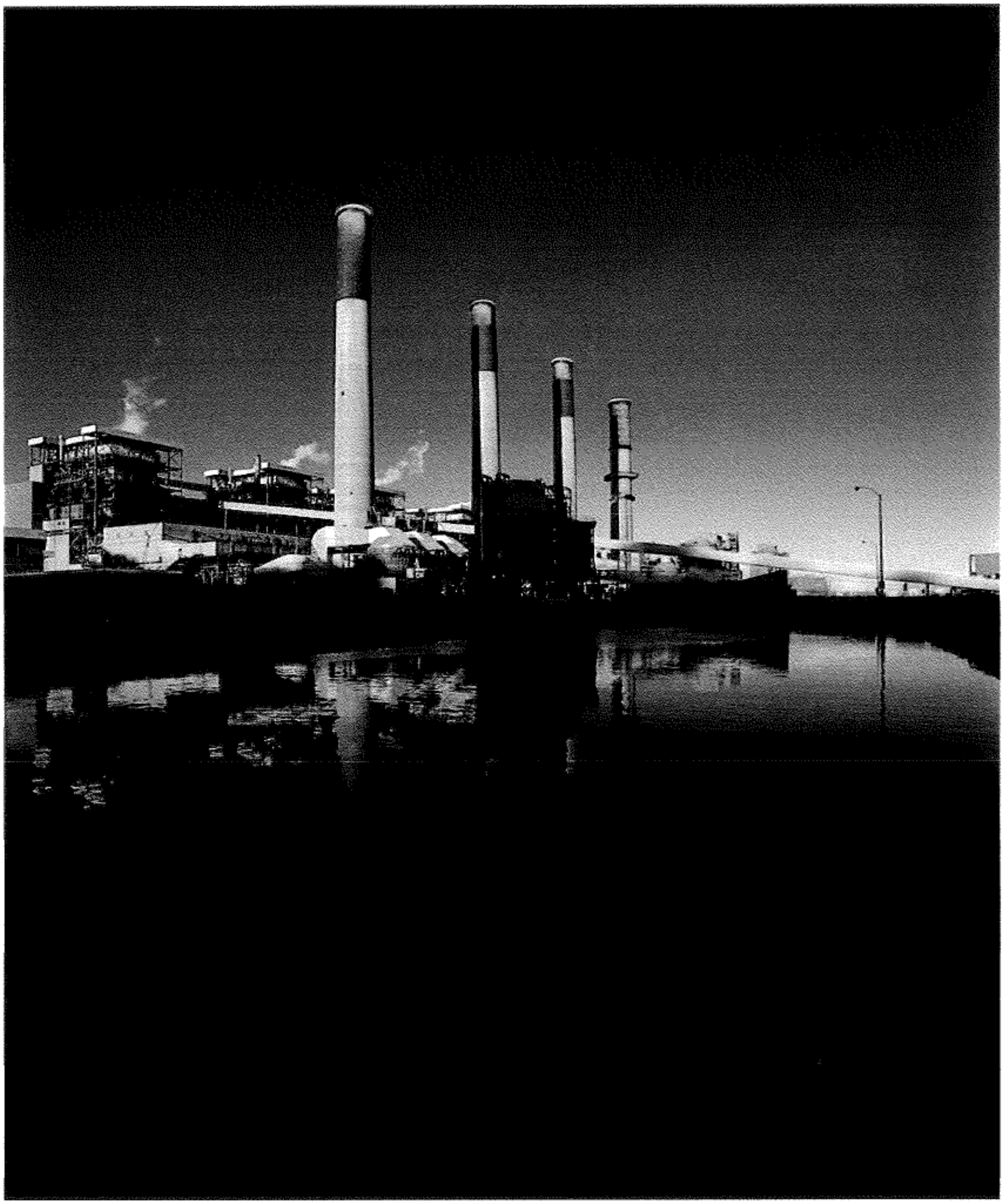
PACIFICORP CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER POWER PLANT

July 8, 2016

(REDACTED VERSION)

PACIFICORP

PACIFICORP's CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER PLANT



Contents

Introduction

In Public Utility Commission of Oregon (Oregon Commission) Order No. 13-387 in docket UE 264, the Oregon Commission adopted the proposal of PacifiCorp dba Pacific Power (PacifiCorp or Company) to prepare periodic fuel supply plans comparing affiliate mine supply to alternative fuel supply options, including market alternatives.[1] In docket UE 287, PacifiCorp filed a compliance proposal for future periodic fuel supply plan filings.[2] No party objected to the proposal, and the case was resolved through Commission approval of stipulation resolving all issues.[3]

As set forth in the Company's docket UE 287 compliance filing, the purpose of long-term fuel supply plans for plants fueled from captive mines is to determine the least-cost, least risk coal supply, viewed on a multi-year basis. The long-term fuel supply plan is designed to ensure that fuel supplies are fair, just and reasonable, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

To develop this long-term fuel supply plan for the Jim Bridger plant, the Company has reviewed the fueling options for the plant, reviewed Bridger Coal Company mine plans, reviewed data on market costs for alternative supplies, including transportation costs and costs for plant modifications required to support alternative supplies, and compared the different fuel supply options under different scenarios to determine the least-cost, least-risk approach.

Background

The Jim Bridger plant is a four unit coal-fired plant in Sweetwater County, Wyoming. The facility is located approximately eight miles north of Point of Rocks, Wyoming, and approximately 24 miles east of the city of Rock Springs, Wyoming. The Union Pacific railroad provides rail access to the plant.

The Jim Bridger plant is the largest plant on the PacifiCorp system (2,120 megawatts) and is jointly owned by PacifiCorp (66.7 percent) and Idaho Power Company (Idaho Power) (33.3 percent). The depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2025 in Oregon and through 2037 in all other states, based on PacifiCorp's 2012 depreciation study. The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. The Jim Bridger plant typically consumes 7.5 million to 8.5 million tons of coal per year, and is designed to burn local southwest Wyoming coal with heat content in the range of 9,000 Btu/lb to 10,000 Btu/lb.

Bridger Coal Company is located adjacent to the Jim Bridger plant. Bridger Coal Company includes both surface and underground mining operations and, similar to the Jim Bridger plant, is jointly owned by PacifiCorp (66.7 percent) and Idaho Power (33.3 percent). The surface operation consists of a combination dragline and truck/loader operation that produces approximately 2.0 to 2.5 million tons of coal per year. The underground operation uses continuous miner and longwall mining equipment to produce coal. The coal is transported from the underground operation to the surface

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1 *In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism*, Docket UE 264, Order No. 13-387 at 7 (Oct. 28, 2013).
2 *In the Matter of PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism*, Docket UE 287, Direct Testimony of Cindy Crane, Exhibit PAC/201 (April 2014).
3 *In the Matter of PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism*, Docket UE 287, Order No. 14-331 (Oct. 1, 2014).

stockpile or directly to the Jim Bridger plant via a nine mile overland conveyor belt. The underground mine produces approximately 3.5 to 4.0 million tons of coal per year.

In addition to the estimated 5.5 to 6.0 million tons of coal delivered annually from Bridger Coal Company to the Jim Bridger plant, the Jim Bridger plant has historically received the remaining portion of its coal supply requirements, approximately 2.0 to 2.5 million tons per year, from the nearby Black Butte mine, which is located approximately 20 miles from the Jim Bridger plant.

For regulatory purposes, Bridger Coal Company is consolidated with PacifiCorp's regulated operations, including the Jim Bridger plant.[4] PacifiCorp's share of Bridger Coal Company is included in the Company's rate base and its share of mining costs, including depreciation and depletion, is included in net power costs. This is a cost-based approach, limiting the price of Bridger Coal Company coal in rates to operating expenses, plus PacifiCorp's authorized rate of return on the investment in the mine.[5]

4 *In re Pacific Power & Light Co.*, Docket UE 21, Order No. 84-898 (Nov. 14, 1984).
5 *In re Pacific Power & Light Co.*, Docket UF 3779, Order No. 82-606 (Aug. 18, 1982).

Available Fuel Supply Alternatives

Based on the location of the Jim Bridger plant, economic fuel supply alternatives are limited to the mines located in southwest Wyoming and the Powder River Basin mines of Campbell County, Wyoming.

In addition to Bridger Coal Company, there are three other coal mines in southwest Wyoming: Kemmerer, Haystack and Black Butte. Two of these mines, the Kemmerer and Haystack mines, are not viable fuel sources for the Jim Bridger plant. The Kemmerer mine currently supplies PacifiCorp's Naughton plant and southwest Wyoming's trona (soda ash) industry. The Kemmerer mine is an older operation, PacifiCorp having first purchased coal from the Kemmerer mine under a Coal Purchase Agreement dated December 30, 1957. The Kemmerer mine coal is delivered to customers via overland conveyor, truck transportation and limited rail operations. Presently, the Kemmerer mine's rail loading infrastructure is incapable of loading a full unit train efficiently. In addition, the grade elevation surrounding the mine requires additional locomotives to power a full unit train. As a result, the mine rarely loads full unit trains. Given the Kemmerer mine's current rail loading infrastructure, any sizable volume of Kemmerer coal would require truck transportation to the Jim Bridger plant. The mine's production costs, required truck transportation for a distance of approximately 120 miles, and the lack of significant excess capacity, result in the Kemmerer mine not being a viable fuel source on a delivered costs basis for the Jim Bridger plant.

The Haystack mine, located 30 miles south of PacifiCorp's Naughton plant, is owned by Kiewit Mining. Designed to operate as a small surface truck/loader operation, Kiewit Mining began construction of the mine in 2012. Due to a lack of demand for coal, Kiewit Mining made a decision to idle this mine in April 2013. All coal sold from the Haystack mine will be delivered with truck transportation. Similar to the Kemmerer mine, the Haystack mine's location, lack of transportation infrastructure, and limited capacity negate its viability as a fuel source on a delivered cost basis for the Jim Bridger plant.

In addition to Bridger Coal Company, this leaves two possible coal supply alternatives for the Jim Bridger plant. These alternatives are the Black Butte mine and the Powder River Basin mines of Campbell County, Wyoming.

The Black Butte mine, located 20 miles southeast of the Jim Bridger plant, is jointly owned by Lighthouse Resources and Anadarko Petroleum. Operated by Lighthouse Resources, the mine is a multiple seam, multiple pit operation with the overburden removed by draglines and a truck and shovel fleet. Historically, Black Butte has mined approximately 3.5 million to 4.0 million tons per year, a significant portion of which has supplied the Jim Bridger plant. One of the Black Butte mine's significant contracts will expire December 31, 2015. Starting in 2016, the mine is expected to produce between [redacted]. Currently, the Jim Bridger plant receives approximately 25 percent of its fuel supplies from the Black Butte mine, under a contract that began earlier this year and terminates in 2017. Coal from the Black Butte mine is delivered to the plant under an agreement with the Union Pacific Railroad.

The Powder River Basin of Wyoming and Montana is the largest coal mining region in the United States. Coal from the Powder River Basin is classified as sub-bituminous coal. Wyoming Powder River Basin coal contains average heat content of approximately 8,500 Btu/lb. The majority of the coal mined in the Wyoming Powder River Basin is low sulfur and low ash coal, making coal from the Wyoming Powder River Basin very desirable. Due to its unique quality characteristics, in 2014

Wyoming Powder River Basin coal was consumed by energy markets in 30 states across the country. In 2014, there were seven different mining companies operating eleven active mines in the region, producing more than 345 million tons.

Powder River Basin mines are served by two railroads, the Union Pacific and Burlington Northern Santa Fe. Both of these railroads have joint access to all of the mines located in the Powder River Basin which are south of Gillette, Wyoming. Only the Burlington Northern Santa Fe Railway serves the mines located north of Gillette, Wyoming.

The Powder River Basin mines that would be considered to supply coal to the Jim Bridger plant are those located in the southern portion of the Powder River Basin. Mines located in this region contain the highest heat content ranging between 8,600 Btu/lb. and 9,000 Btu/lb. These mines are located approximately 550 to 600 miles from the Jim Bridger plant.

Alternative Fuel Supply Plans Evaluated

Considering the limited coal supply alternatives available to the Jim Bridger plant, the Company evaluated two fuel supply alternatives only, the Base Operating Plan and the Market Alternative Plan. Both plans assume decreasing reliance on fuel supply from the Bridger Coal Company and from the Black Butte mine and increasing reliance on fuel supply from the Powder River Basin; the plans differ in whether the Company continues to source fuel from the Bridger Coal Company surface mine or moves entirely to a market-based supply. Because this is a long-term planning document, the Company's evaluation of alternative fuel supply plans was conducted on a total company basis, utilizing the longest depreciable life now recognized in PacifiCorp's jurisdictions, 2037.

Base Operating Plan

Historically, the Jim Bridger plant has consumed about 7.5 million to 8.5 million tons of coal on an annual basis. Approximately two-thirds of the coal has been sourced from Bridger Coal Company while the remainder, approximately one-third, has been purchased from the Black Butte mine. [redacted]

As the largest plant in PacifiCorp's portfolio, on average the Jim Bridger plant consumes the equivalent of roughly 1 1/2 unit trains of coal daily. The Jim Bridger plant's existing unloading facilities consist of three ladder tracks and an unloading hopper designed to unload rapid discharge railcars with a payload of up to 118 tons per railcar. The existing design necessitates that trains longer than 72 railcars be broken into sections for unloading which significantly increases train unloading time. The current plant infrastructure does not include additional sidings to allow for the staging of large unit trains. This configuration essentially limits the plant's ability to place more than one Powder River Basin unit train in service at any one time. Given the Jim Bridger plant's existing rail unloading facility constraints, the Jim Bridger plant's capacity for unloading Powder River Basin coal trains is estimated at [redacted] tons per year at a rate of approximately one train every [redacted] days.

A major plant capital investment will be required to accommodate the [redacted]. The capital investment is required primarily to upgrade the Jim Bridger plant's rail unloading capabilities. The cost of this conversion is estimated at [redacted] (PacifiCorp share)[6] and would include a rail loop track and other major expenditures to accommodate the unloading of more than 300 trains per year. With the addition of the rail unloading infrastructure, [redacted] Key components of the Base Operating Plan are summarized below:

- Base Operating Plan
  [redacted]

Market Alternative Plan

Similar to the Base Operating Plan, the Market Alternative Plan assumes the same major capital expenditures to upgrade the Jim Bridger plant's rail unloading facility. As this expenditure is sufficient to accommodate unloading 100 percent of the Jim Bridger plant's requirements, the Market Alternative Plan contemplates [redacted]. Key components of the Market Alternative Plan are summarized below:

- Market Alternative Plan
  [redacted]

6 The capital investments and present value revenue requirement costs referenced in this plan are stated on a total company basis.

[redacted]

The Base Operating Plan assumptions were derived from PacifiCorp's 2015 Integrated Resource Plan (IRP), submitted March 31, 2015. For comparison purposes, the key assumptions used in preparation of the IRP, including coal consumption (MMBtus), were also used in the preparation of the Market Alternative Plan.

The volume assumptions used in the two plans are provided in Confidential Table 1 below:

Confidential Table 1

[redacted]

The key pricing assumptions used in the two plans are summarized in Confidential Table 2 below:

Confidential Table 2

[redacted]

[redacted]

Results

Confidential Table 3 below compares the Present Value Revenue Requirement (PVRR) for the two fueling options. The Company estimates that the Base Operating Plan is [redacted] less costly than the Market Alternative Plan.

Confidential Table 3

[redacted]

[redacted]

Conclusion

PacifiCorp has evaluated the Base Operating Plan and Market Alternative Plan for the Jim Bridger plant. The PVRR analysis of the Base Operating Plan for the Jim Bridger plant yields a PVRR of [redacted]. The PVRR analysis of the Market Alternative Plan yields a result of [redacted]. The evaluation demonstrates that the Base Operating Plan is [redacted] favorable to the Market Alternative Plan fuel plan. As a part of its regular planning process, PacifiCorp will continue to evaluate all available options for the long-term fueling of the Jim Bridger plant.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2017 Transition Adjustment Mechanism	)
	)

CONFIDENTIAL EXHIBIT ICNU/103

THE COMPANY'S RESPONSES TO DATA REQUESTS

July 8, 2016

(REDACTED VERSION)

UE 307 / PacifiCorp
June 8, 2016
OPUC Data Request 32

OPUC Data Request 32

GRID Model, Coal Costs - Please refer to page 5 of the confidential attachment provided in response to OPUC DR 20. Please respond to the following requests with respect to the Jim Bridger plant.

(a) This response indicates that a significant contract of the Black Butte mine recently expired. Please confirm that Black Butte mine has or recently had excess production capacity.

(b) How much coal did PacifiCorp purchase from Black Butte in each year beginning January 1, 2005 and ending December 31, 2015?

(c) What is the contracted minimum and maximum amount of coal PacifiCorp could have or did purchase from Black Butte beginning January 1 2005 and ending December 31, 2017?

(d) What was the average delivered price per ton for Black Butte coal beginning January 1, 2005 and ending December 31, 2016?

(e) What is the current cost per ton for Powder River Basin coal?

(f) What is the current cost per ton for delivery of Powder River Basin coal?

(g) Has PGE evaluated the cost of purchasing all Jim Bridger coal requirements from market sources for 2017? If yes please provide all related work papers. If not, why not?

Confidential Response to OPUC Data Request 32

(a) PacifiCorp does not own or operate the Black Butte mine and, therefore, cannot confirm or deny production capacity at the mine. PacifiCorp is aware that in 2015, Black Butte mine sold coal for delivery to the North Valmy Generating Station (jointly owned by NV Energy and Idaho Power) located in Nevada, and it is the Company’s understanding that Black Butte is no longer selling coal for delivery to the North Valmy Generating Station.

(b) Please refer to Confidential Attachment OPUC 32.

(c) Please refer to Confidential Attachment OPUC 32.

(d) Please refer to Confidential Attachment OPUC 32.

(e) According to Energy Ventures Analysis, Inc. (EVA) most recent May 2016 coal commodity price forecast, the 2017 FOB mine price for High-Btu (8800 Btu/lb.) coal is [redacted] per ton.

UE 307 / PacifiCorp
June 8, 2016
OPUC Data Request 32

(f) PacifiCorp does not have a current coal supply agreement for Powder River Basin coal for the Jim Bridger plant. PacifiCorp does however have a current rail agreement which allows for coal shipments from the Southern Powder River Basin mines. The current rail rate for Q2 2016 is [redacted] per ton plus fuel surcharge, which varies with the actual price of diesel fuel.

(g) No, PacifiCorp has not evaluated the cost of purchasing all the Jim Bridger coal requirements for 2017. The Jim Bridger plant does not have the ability to receive all of its coal requirements from outside market sources due to its existing rail unloading infrastructure facilities.

The confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.