Exhibit No. JBT-19HCT
Docket UE-152253
Witness: Jeremy B. Twitchell
REDACTED VERSION

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-152253

SUPPLEMENTAL TESTIMONY OF

Jeremy B. Twitchell

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Selective Catalytic Reduction at Jim Bridger

May 6, 2016

CONFIDENTIAL PER PROTECTIVE ORDER

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeremy Twitchell and my business address is the Richard Hemstad Building, 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington, 98504. My email address is jtwitche@utc.wa.gov.

Q. Are you the same Jeremy Twitchell who previously filed testimony in this case on behalf of Washington Utilities and Transportation Commission Staff?

A. Yes.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. Please summarize your supplemental testimony.

A. My supplemental testimony provides additional analysis of increased coal costs and decreased natural gas costs affecting the decision by Pacific Power & Light Company (Pacific Power or Company) to install selective catalytic reduction (SCR) systems at the Jim Bridger plant (Bridger). Pacific Power identified the changes to Bridger's coal costs in October 2013, one month after it revised its natural gas cost forecasts downward. Both the increased coal costs and the decreased natural gas cost forecast served to erode the cost-effectiveness of installing SCR at Bridger. Pacific Power, however, never analyzed the effect of these two significant cost changes in its System Optimizer Model. Instead, the Company issued the full notice to proceed with the installation of SCR systems at Bridger on December 1, 2013, based on an outdated analysis that was no longer accurate or valid.

Furthermore, on December 11, 2013, just 10 days after issuing the full notice to proceed, the Company again identified an even sharper decline in its natural gas cost forecasts. Had the Company accounted for these changing circumstances, its analysis of compliance options at Bridger would have identified about $[redacted] million in net benefits associated with natural gas conversion, even when the higher costs associated with cancelling its contract for SCR installation after one month are taken into account.

Pacific Power's refusal to re-evaluate its SCR decision in light of this new information, which on its face called that decision into question, prevented the Company from recognizing that natural gas conversion had become the lower-cost option. On at least two occasions, the Company had new information that justified cancelling its contract for SCR installation at a time when the Company could have done so while saving customers money. Not only did Pacific Power fail to act on these opportunities; there is no evidence that it even evaluated them. Accordingly, the Company's decision to proceed with SCR installation was imprudent.

Q. Please summarize your analysis relating to increased coal costs.

A. My analysis of the Bridger Coal Company (BCC) October 2013 Mine Plan and a third-party coal arrangement in place at that time shows that the cost increases for Bridger's fuel supply that the Company identified in October 2013 likely offset the benefits of SCR installation that the Company identified in its modeling. This reinforces Staff's argument that installing SCR was an imprudent decision at the time the Company issued the full notice to proceed on December 1, 2013, and that converting Bridger units 3 and 4 to run on natural gas would have been the more cost-effective solution.

Importantly, my supplemental testimony shows that the October 2013 coal price increases *alone* likely rendered the SCR uneconomic.

My testimony reiterates why it is necessary that the prudence of the SCR investment be evaluated in light of the October 2013 Mine Plan, rather than the January 2013 long-term fuel plan that the Company used in its analysis. I then explain how the October 2013 Mine Plan increased both the cost and risk of Bridger's long-term fuel supply, and quantify the impact of the cost increases on the Company's analysis to the extent possible. To conform to the Company's methodology and facilitate the Commission's review, I incorporate the new information that the Company provided on rebuttal regarding how it analyzes the costs identified in a mine plan.[1]

Q. Please summarize your analysis relating to decreasing natural gas price forecasts.

A. Leading up to Pacific Power's decision to issue the full notice to proceed with SCR installation, natural gas price forecasts were dramatically declining. The Company's official natural gas price forecast in September 2013 revealed that the benefits of

[1] Ralston, Exh. No. DR-1CT 5:1-13.

SCR installation had decreased by approximately 30 percent over the previous year.[2] Between that time and when the Company issued the full notice to proceed with SCR installation, the Company received two more forecasts from consultants that identified natural gas price forecasts were continuing to decline. Importantly, 10 days after issuing the full notice to proceed, Pacific Power received new information regarding future natural gas prices from a third consultant that had a major impact on the Company's official natural gas price projection.

My testimony demonstrates that based on the three consultant projections, Pacific Power reduced its official natural gas price forecast so significantly that SCR installation was clearly no longer economic. In fact, that reduction was so significant that had it been used within the context of the decision to proceed with SCR installation, it would have increased the benefits of gas conversion by $[redacted] million.

While I recognize that this information came into the Company's possession after it issued the full notice to proceed, my testimony demonstrates that the Company could have acted on this information, terminated the SCR contract, and still captured most of those $[redacted] million in net benefits by changing course and pursuing gas conversion. My testimony further shows that despite the fact that this information came after issuance of the full notice to proceed, the structure of the Company's contract for SCR installation and the magnitude of the information's impact on the Company's analysis justify the Commission's inclusion of this information in its prudence determination.

---

[2] The Company's SCR analysis, based on a September 2012 natural gas price projection, identified $[redacted] million in net benefits for SCR. Inputting the September 2013 natural gas price projection indicates that the benefits would fall to about $[redacted] million.

Q. Your response testimony identified an issue related to how Pacific Power's model treated replacement power costs. Does Staff remain concerned with that issue?

A. Yes. My supplemental testimony is limited to the new information related to coal costs and updated natural gas prices that the Company presented on rebuttal. The issue of replacement power costs can be addressed with reference to my response testimony; the fact that I do not discuss it in this testimony should not be interpreted as Staff's acceptance of the Company's rebuttal testimony on that issue. If I were to incorporate this issue into my analysis, it would only further increase the $[redacted] million net benefit associated with natural gas conversion.

III. BACKGROUND

Q. Please explain how mine plans are used in the Company's planning.

A. In his rebuttal testimony, Mr. Ralston explains that a mine plan is a forward-looking budget for BCC that is used in the preparation of the Company's 10-year business plan, which is updated each year.[3] Mine plans are also used in rate cases to support fuel costs.[4] Additionally, mine plans, along with third-party coal contracts, are used as inputs when the Company updates its long-term fuel plans every two years as part of the integrated resource plan (IRP) process.[5]

---

[3] *Id.* at 3:8-11.
[4] *Id.* at 3:11-15.
[5] *Id.* at 2:18 – 3:1.

Q. Why does Staff consider the October 2013 Mine Plan to be important to the Commission's prudence review of the SCR installation at Bridger units 3 and 4?

A. The Commission has stated that a Company asking for a prudence determination must not only show that it analyzed different options, but that its analysis was based on the *most recent information*.[6] In his rebuttal testimony, Mr. Ralston explains that the Company's SCR analysis is based on a long-term fuel forecast from January 2013, which combined costs from the then-current mine plan and third-party agreements to "provide a comprehensive life-of-plant fueling forecast."[7] Mr. Ralston later explains that long-term fuel plans are prepared on two-year cycles as part of the IRP process,[8] and that the 2013 long-term fuel forecast was based on the January 2013 Mine Plan.[9]

The October 2013 Mine Plan rendered the January 2013 long-term fuel forecast obsolete. In the October 2013 Mine Plan, BCC's share of Bridger's coal supply increased from 68 percent to 85 percent,[10] and as I demonstrate, the costs of BCC coal significantly increased in the October 2013 Mine Plan. If a fuel plan is a combination of the current BCC mine plan and current third-party supply contracts, then in disregarding the October 2013 Mine Plan and sticking to the January 2013 fuel plan, Pacific Power chose to rely on an outdated and inaccurate price forecast for the source of 85 percent of its fuel needs at Bridger.

---

[6] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket UE-921262, Nineteenth Supplemental Order, 2 (Sept. 27, 1994).
[7] Ralston, Exh. No. DR-1CT 2:19-21.
[8] *See id. at* 2:22 – 3:1.
[9] *Id.* at 4:11-13.
[10] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.,* Docket UE-140762, Exh. No. GND-1CT 19:5-7.

Q. Does Pacific Power consider the October 2013 Mine Plan to be important to the Commission's prudence review of the SCR installation at Bridger units 3 and 4?

A. No. The Company asserts that the October 2013 Mine Plan should not be viewed as a long-term forecast of fuel costs for Bridger.[11] This however, is essentially an argument for a new prudence standard – one that would allow the Company to rely on outdated information when critical new information becomes available outside of its normal planning routine.

As I explained in my response testimony, the Company used the October 2013 Mine Plan to support a rate increase in its 2014 general rate case.[12] If that mine plan created cost increases that were sufficiently known and measurable to support a rate increase, then those cost increases were sufficiently known and measurable to be included in the Company's planning.

Staff cannot determine whether the Company met the Commission's prudence standard, which requires the use of the most current information available, without evaluating the impact of the October 2013 Mine Plan – the most current information regarding future coal costs that was available when the Company committed itself to the SCR installation on December 1, 2013.

---

[11] Ralston, Exh. No. DR-1CT 3:16-19.
[12] Twitchell, Exh. No. JBT-1CT at 35:14-16.

Q. You mentioned that the Company used the October 2013 Mine Plan in the 2014 general rate case to increase the cost of Bridger fuel in Washington rates. What was the size of that increase?

A. In response to a data request in the instant proceeding, Pacific Power indicated that the fuel costs for Bridger were set at $[redacted] per million British thermal units (mmBtu) in the 2013 general rate case. This response is provided as Exhibit No. JBT-20C. In the 2014 rate case, the Company presented the October 2013 Mine Plan in its initial filing to support a fuel cost of $[redacted] per mmBtu,[13] an increase of 6 percent.

Q. Did the Company support any other increases in rates associated with Bridger's fuel supply in the 2014 rate case?

A. Yes. On rebuttal in that case, the Company presented a July 2014 Mine Plan that it used to support an additional increase to $[redacted] per mmBtu – making for a total increase in Bridger's fuel costs of 18 percent in the 2014 rate case.

Q. Have you reviewed the July 2014 Mine Plan?

A. No. As it was prepared several months after Pacific Power issued the full notice to proceed with SCR installation at Bridger, it is not relevant in evaluating the prudence of the Company's decision. I note that in response to the Sierra Club, the Company conducts extensive analysis based on the July 2014 Mine Plan and January 2015 long-term fuel plan, which was based on the July 2014 Mine Plan, to assert that SCR remained cost effective. I do not understand why the Company chose to conduct

[13] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140762, Exh. No. CAC-1CT at 3, Table 1 and 7:5-7.

these analyses based on the July 2014 Mine Plan, which was not available when it issued the full notice to proceed, rather than the October 2013 Mine Plan, which was available at the time. The Commission should not grant any weight to Company analyses based on the July 2014 Mine Plan and January 2015 fuel plan.

IV. THE OCTOBER 2013 MINE PLAN

Q. Please summarize your conclusions regarding the October 2013 Mine Plan.

A. As I explained in my response testimony, Pacific Power's SCR analysis had three sensitivity analyses related to future natural gas prices: low, base, and high.[14] The costs of Bridger's coal supply were fixed across all three scenarios according to the January 2013 fuel plan, which relied on the January 2013 Mine Plan for BCC costs and third-party supply contracts.

When the October 2013 Mine Plan increases are applied to the Bridger fuel costs that the Company modeled in the base case, the net present value of Bridger's fuel costs from 2016–2030 increases by $[redacted] million. Costs increase by $[redacted] million and $[redacted] million in the high and low gas cases, respectively.

Using the same regression analysis presented by the Company in Exhibit No. RTL-9C and explained in my response testimony,[15] my analysis estimates that had the October 2013 Mine Plan prices been included in the Company's SCR modeling, with no further changes to the Company's inputs, the model would have identified approximately $[redacted] million in net benefits associated with gas conversion. I present

[14] Twitchell, Exh. No. JBT-1CT at 18:21-19:1.
[15] *Id.* at 23:9 – 24:8.

this information in Exhibit No. JBT-21C, which is an updated version of Exhibit No. JBT-4C.

Q. How did you calculate the coal cost increase for each scenario?

A. First, I compared the January 2013 and October 2013 mine plans to determine, on a percentage basis, the degree to which costs increased in the October 2013 plan. Next, I took that increase and the increase associated with the Company's third-party coal supplier, as identified by Mr. Duvall in the 2014 rate case, and weighted each based on its share of Bridger's fuel consumption. Exhibit No. JBT-22C shows this process.

I then used the Company's model data, provided in Mr. Link's initial workpapers in this proceeding, to identify the total fuel expenditures for Bridger that the Company modeled in the low, base and high gas cases. I then calculated a net present value for the modeled fuel costs in each case, and multiplied each figure by the overall weighted increase described above. Exhibit No. JBT-23C shows this process.

Q. What were the drivers of the increased costs in the October 2013 Mine Plan relative to the January 2013 Mine Plan?

A. In the Company's initial filing in the 2014 rate case, Mr. Duvall testified that the Company was rapidly accelerating surface mine production in the October 2013 Mine Plan, but that the cost increases were mostly driven by changes in the underground mine plan resulting from unfavorable conditions for machine-based longwall mining, which forced the Company to increase its reliance on more expensive miner-based production. Duvall stated:

> The amount of coal produced by the continuous miners has increased from 17.6 percent of the underground mine production in the 2013 Rate Case to 23.7 percent in this filing. This increase reflects the impact of bypassing the 12th right longwall panel due to high ash content, the shortening of the longwall panels, and three longwall moves instead of two in the pro forma period. Bypassing and shortening longwall panels require additional continuous miner production, *which increases production costs*. The variable cost of production for a longwall ton is within a range of $[redacted] per ton to $[redacted] per ton, compared to $[redacted] per ton to $[redacted] per ton for continuous miner production.[16]

Q. Have you conducted any additional analysis of the October 2013 Mine Plan?

A. Yes. Mr. Duvall's testimony focused on the rate year changes identified in the plan to support the Company's proposed pro-forma adjustment in the 2014 rate case, but there were other significant changes in the plan in later years. Exhibit No. JBT-24C provides a side-by-side comparison of the summary tabs from the January and October mine plans for the 2016–2030 period, which provides additional insights.

Q. Are any of those other changes relevant to this discussion?

A. Yes, a key change is that the October 2013 Mine Plan projected that the [redacted]

[16] Docket UE-140762, Exh. No. GND-1CT 21:5-13 (emphasis added).

[redacted]. As I show, this change in strategy has significant impacts on the long-term overall cost of BCC coal.

Q. What conclusions do you draw from the October 2013 Mine Plan?

A. As Mr. Duvall explained, the cost increases in the October 2013 Mine Plan were largely driven by increased variable production costs associated with substituting miner-based production for machine-based production. These variable cost increases represent costs that could have been avoided to some degree by converting Bridger units 3 and 4 to run on natural gas, thereby reducing the plant's coal consumption.

Additionally, the decision [redacted][17] [redacted]. Staff has not quantified this increased risk, but it should be considered when determining whether the Company acted prudently when it committed to the long-term operation of Bridger as a coal-fired resource after this increased risk had been identified.

---

17 [redacted]

Q. Have you quantified the increased costs associated with the October 2013 Mine Plan?

A. Yes. I present this analysis in Exhibit No. JBT-22C, which finds that for the period of 2016–2030, coal costs identified by the October 2013 Mine Plan are [redacted] percent higher than in the January 2013 Mine Plan.

Q. Please describe your analysis of the coal cost increase contained in Exhibit No. JBT-22C.

A. The purpose of this exhibit is to provide a comparison between the January and October mine plans in common terms. The mine plans express coal costs in terms of dollars per tons, but the Company's SCR model used coal costs in terms of dollars per mmBtu. Exhibit No. JBT-22C makes this conversion while accounting for the differences in both the amount and distribution of production between the surface and underground mines in the two plans and also accounting for differences in assumed heat content of BCC coal between the two plans.

The exhibit has two tabs – one for January 2013, and one for October 2013. The first section on each tab is Production, which identifies total projected production amounts and how that production breaks down between the surface and underground sections of the mine. Beneath each of those totals is a row labeled "PAC Share," which multiples production amounts by two-thirds to represent the share of output for which Pacific Power, as a two-thirds owner of both Bridger and BCC, would be responsible. The remaining rows of this section identify the variable production (cash) costs for each year's production forecast and the projected mine capital expenditures for each year.[18]

The next section on each tab is the Heat Content section, which identifies the different assumed heat content of coal from each section of the mine, in Btu per pound. Using the breakdown of production between the surface mine (which generally produces coal with a lower heat content) and the underground mine (which generally produces coal with a higher heat content), this section concludes by calculating the total heat content of the coal delivered from BCC to the Bridger plant, in mmBtu.

The next two sections of each tab express the total costs on a dollars per mmBtu basis, then levelize those costs for the purposes of comparing the costs of the two plans. One section does this for cash costs; the other section does this for cash plus capital costs. The "October 2013 Mine Plan" tab also has a final section that calculates the increases relative to the January 2013 Mine Plan in various terms.

Q. Does Staff's revised analysis, based on the actual October 2013 mine plan, take into account any of the issues with Staff's treatment of mine plan costs that Pacific Power identified in its rebuttal filing?

A. Yes, it does. In order to be as accurate as possible, my analysis and calculations reflect the clarifications that the Company provided on rebuttal regarding how it models coal costs.

[18] Mine capital expenditures have been multiplied by two-thirds so that they are expressed on a Pacific Power share basis.

Q. What are the issues that Pacific Power raised and that you have resolved in your analysis and calculations associated with the October 2013 mine plan?

A. Aside from pointing out that Staff's initial analysis relied on the same January 2013 Mine Plan used by the Company, Mr. Ralston identified three issues:

- Staff did not account for capital cost differences;
- Staff did not account for the cost of coal provided by third parties; and
- Staff used operating costs in its analysis, rather than the cash costs used by the Company in its SCR analysis.[19]

Q. Were you aware of these issues when you filed your testimony?

A. I was only aware of the third-party coal issue, and explained in my testimony why I chose to omit third-party coal costs.[20] The cost differential for Black Butte coal – the Company's third-party supplier – is more impactful when compared to BCC's cash costs, so I have included the cost of Black Butte coal in this analysis, though its impact is minimal.

I was not aware of the difference between mine plan operating costs and cash costs until the Company filed its rebuttal testimony. Although Mr. Link references cash costs in Exhibit No. RTL-3C, there was no explanation of how these were determined in his testimony, and the Company did not explain the matter when it directed Staff to the January 2013 Mine Plan in its initial response to Staff Data Request No. 99. It did not become clear to me how cash costs are extracted from the

[19] Ralston, Exh. No. DR-1CT at 5:1-13.
[20] Twitchell, Exh. No. JBT-1CT at 35:11 – 36:2.

mine plan's operating costs until after I received the Company's supplemental response to Staff Data Request No. 99 on April 18, 2016, and had a subsequent discussion with the Company.

Similarly, I was not aware that the mine plan to which the Company referred me in its initial response to Staff Data Request No. 99 did not include capital costs in its summary costs until the Company filed its rebuttal testimony.

Q. How does the Company calculate cash costs?

A. In its supplemental response to Staff Data Request No. 99 provided via email on April 16, 2016, the Company indicated that it had provided the October 2013 Mine Plan in response to Sierra Club Data Request No. 1.6(a). The Company also indicated that the October 2013 Mine Plan was filed in the workpapers of Sierra Club witness Dr. Jeremy Fisher, and provided the relevant workpaper as an attachment to the email.

In the referenced attachment, Dr. Fisher's workpaper identified four line items that are removed when the Company calculates cash costs: depreciation and amortization, depletion, coal inventory adjustment, and deferred longwall amortization. In a subsequent discussion, the Company informed me that the deferred longwall amortization expense is, in fact, included in the Company's cash cost calculation. The Company did not identify this issue when it directed me to the workpapers of Dr. Fisher, which clearly identified the deferred longwall amortization expense as being excluded from cash costs, and did not clarify the matter until more than two weeks after it had provided the supplemental response.

Q. How does your analysis account for cash costs?

A. Based on the information provided by the Company in its supplemental response to Staff Data Request No. 99 and in further conversation, my calculation of cash costs removes three line items from BCC's cost summary: depreciation and amortization, depletion, and coal inventory adjustments. My calculation of BCC cash costs can be seen in Exhibit No. JBT-24C, on row 61 of each tab. The three costs that are removed in the cash cost calculation are in the highlighted rows on each tab. These cash cost calculations are used as inputs in my analysis of increased coal costs contained in Exhibit No. JBT-22C.

Q. What are your findings relating to cash costs?

A. As seen in cell B31 on the "October 2013 Mine Plan" tab of Exhibit No. JBT-22C, the October 2013 Mine Plan increased the cost of BCC coal by [redacted] percent on a cash cost basis.

Q. How does your analysis account for capital expenditures?

A. Each mine plan had an accompanying capital expenditure forecast.[21] I took the forecast from each plan and multiplied each year's forecasted expenditure by two-

[21] The forecasts are in different places in each plan. In the January 2013 Mine Plan, which I have provided as a workpaper under that title, the capital expenditure forecast was provided on the "OPEX" summary tab on row 222. In the October 2013 Mine Plan, capital expenditures for the first 10 years were identified in a separate document, which the Company provided in response to Sierra Club Data Request 1.6 and which I have provided as a workpaper under the title "October 2013 Mine CAPEX Plan." Capital expenditures are identified in that document on the "SUM" tab in column S; the adjustment to express those costs on a Pacific Power basis can be seen in column U, rows 63-70. The remaining October 2013 Mine Plan capital expenditures (2024-2030) can be found in the "October 2013 Mine Plan" workpaper, on the "OPEX" summary tab, row 222.

thirds to reflect Pacific Power's ownership share of BCC. The resulting figures are in Exhibit No. JBT-22C, on row 9 of each tab.

Q. How do capital expenditure forecasts vary between the two plans?

A. As I explained above, October 2013 Mine Plan reflected the Company's decision to [redacted], which results in a major reduction in long-term capital expenditures. On a net present value basis, Pacific Power's share of capital expenditures from 2016–2030 decreases by about 44 percent in the October 2013 Mine Plan.

Q. What is the impact of including capital costs in your analysis?

A. The decrease in capital costs significantly offsets the cash cost increase between the two plans. As shown in cell B32 of the "October 2013 Mine Plan" tab of Exhibit No. JBT-22C, when the analysis accounts for capital costs, the increase falls from [redacted] percent to [redacted] percent.

Q. How does the analysis account for third-party coal costs?

A. In the 2014 rate case, Mr. Duvall testified in his direct testimony that in the 2013 Mine Plan, BCC accounted for 85 percent of Bridger's fuel and the Black Butte Mine provided the remaining 15 percent.[22] Mr. Duvall further testified that the cost of Black Butte coal rose in that case from $[redacted] per ton to $[redacted] per ton, an increase of [redacted] percent.[23]

---

[22] Docket UE-140762, Exh. No. GND-1CT at 19:3-7.
[23] *Id.* at 20:7-10.

I relied on these figures to determine the impact of the Black Butte coal agreement on the overall cost of Bridger's fuel. Once I determined the overall increase for BCC coal identified in the October 2013 Mine Plan, including capital costs, I weighted that increase by 85 percent and the [redacted] percent increase for Black Butte by 15 percent. This calculation yielded an overall increase of [redacted] percent in the cost of Bridger fuel resulting from the October 2013 Mine Plan, the calculation of which can be seen in cell B33 of the "October 2013 Mine Plan" tab of Exhibit No. JBT-22C.

Q. How did you apply this increase to the Company's analysis?

A. Please refer to Exhibit No. JBT-23C. Since the Company represents that the January 2013 fuel plan used in its analysis combined a BCC mine plan and a third-party coal supply agreement, and my analysis used the most recent versions of those same two components based on their shares of Bridger fuel supply as of October 2013, I applied the increase that I calculated to the fuel costs that the Company modeled using the January 2013 fuel plan.

I obtained the modeled fuel costs for the Bridger plant in each of the three natural gas price scenarios that the Company modeled, determined the net present value of fuel costs in each scenario, and multiplied that figure by [redacted] percent. This results in an adjustment of $[redacted] million in the low gas case, $[redacted] million in the base gas case, and $[redacted] million in the high gas case.

Q. What is the overall impact of these coal cost adjustments?

A. Please refer to exhibit No. JBT-21C. Page 1 of the exhibit shows the impact of the adjustment on the Company's regression analysis, including the new break-even price point for natural gas conversion to become cost effective. Page 2 shows the coal cost adjustments being applied to the model, and page 3 shows that using the Company's September 2013 OFPC, the model would have identified about $[redacted] million in net benefits for gas conversion.

Q. Did you analyze the impact of the October 2013 Mine Plan on the gas conversion case, in which Bridger units 1 and 2 would have continued to operate as coal-fired units?

A. No. There was not enough information in this case for Staff to determine how the coal cost increases identified in the October 2013 Mine Plan would affect the gas conversion case. Ultimately, only Pacific Power could conduct such an analysis.

The Company's SCR analysis relied on the January 2013 Mine Plan, which was developed to evaluate two different scenarios: one reflecting four units of Bridger operating on coal (the SCR scenario), and one reflecting two units of Bridger operating on coal (the gas conversion scenario). The October 2013 Mine Plan, in contrast, was only prepared based solely on the four-unit SCR scenario – suggesting that the Company had no intention of re-evaluating the relationship between SCR and natural gas conversion based on the October 2013 Mine Plan. Staff could not replicate the January 2013 Mine Plan's two-unit scenario for the October 2013 Mine Plan.

Staff identified no clear relationship between the four-unit and two-unit mine plans used in the Company's SCR analysis, and the conclusions of the two-unit plan appear counterintuitive. For example, overall production by BCC from 2016–2030 decreases by [redacted] percent in the two-unit plan relative to the four-unit plan, but Exhibit No. RTL-3C shows that on a levelized basis, cash costs only decrease by about [redacted] percent in the two-unit plan. By the Company's own implication, cash costs are the costs that vary according to production,[24] so their failure to track with reduced production is puzzling.

Additionally, the differences between the January 2013 Mine Plan and the October 2013 Mine Plan further complicate any attempt at estimating what a two-unit plan would look like relative to the October 2013 Mine Plan. [redacted]

Preparing a two-unit mine plan based on the October 2013 Mine Plan would require not only an understanding of how mine operations would generally change in a two-unit scenario, but also an understanding of how they would change in light of the significant changes presented in the October 2013 Mine Plan. Pacific Power is the only party to this case with sufficient information to prepare such a plan, and there is no evidence that the Company did so.

[24] Link, Exh. No. RTL-11CT 6:5-12.

Q. If the October 2013 Mine Plan increased fuel costs for the four-unit SCR scenario, would it also necessarily increase fuel costs for the two-unit gas conversion scenario?

A. I do not believe that would be the case. The nature of the two-unit mine plan prepared in January 2013 suggests that when it is conformed to the long-term strategy changes adopted in the October 2013 Mine Plan, costs for the two-unit scenario would likely decrease.

As I explained above, Exhibit No. RTL-3C shows that on a levelized basis, coal cash costs between the four-unit and two-unit scenarios used in the Company's SCR analysis are similar. Looking closer at this exhibit, it becomes clear that the reason levelized costs are so similar between the two cases is because the two-unit scenario has three high-cost years at the front end (2016–2018), which inflates the levelized cost of the scenario.

Q. Why does the two-unit scenario have three high-cost years in the early years of the plan?

A. The reason for these early, high-cost years is explained in the January 2013 two-unit mine plan.[25] The higher costs are driven by the surface mine, which in the two-unit plan [redacted]

[25] This document is filed as a workpaper under the title "January 2013 – 2 Unit."
[26] "January 2013 Mine Plan" workpaper, "OPEX" tab, row 115.

[redacted].[27] This decision results in significantly higher cash costs for surface coal, ranging from $[redacted] per mmBtu in 2016 to $[redacted] per mmBtu in 2018. [redacted]

Q. Why would fuel costs for the two-unit gas conversion scenario likely decrease?

A. The reason that costs for a two-unit scenario would likely decrease from January 2013 to October 2013 is because the October 2013 Mine Plan [redacted]

Furthermore, surface production is subject to economies of scale; the more surface coal that BCC produces, the lower its per-unit cash costs get. For example, in the January 2013 Mine Plan, the surface mine averages [redacted] million tons per year from 2016 to 2030, at an average cash cost of $[redacted] per mmBtu. In the October

[27] "January 2013 – 2 Unit" workpaper, "OPEX" tab, row 115.

2013 Mine Plan, average surface mine production increases to [redacted] million tons per year and the average cash cost falls to $[redacted] per mmBtu.

These figures establish a clear, inverse relationship for the surface mine's cash costs: as production goes up, per-unit cash costs go down. The October 2013 Mine Plan's decision to [redacted] strongly suggests that the early years of a two-unit scenario based on the October 2013 Mine Plan would have a lower cash cost than the same years in the two-unit scenario developed from the January 2013 Mine Plan. The availability of [redacted] in the October 2013 Mine Plan would also serve to push cost increases further out. These two factors – lower costs in early years and increase costs shifted out to later years –indicates that on a levelized basis, coal costs for a two-unit scenario in October 2013 would likely have been lower than coal costs for the two-unit January 2013 plan that the Company used in its SCR analysis.

Q. How would the lower cash costs for a two-unit scenario in October 2013 impact Staff's analysis of the net benefit in favor of gas conversion?

A. Adjusting the SCR scenario's costs to reflect the October 2013 Mine Plan identifies $[redacted] million net benefits in favor of gas conversion. As I have explained, costs for the natural gas scenario based on a two-unit mine plan from October 2013 would likely be lower than the costs that the Company modeled based on the two-unit mine plan from January 2013, which would reduce the cost of the gas conversion scenario and thereby increase the net benefits of gas conversion. Staff's estimate of $[redacted] million in net benefits in favor of gas conversion based on the October 2013 Mine Plan should therefore be taken as a conservative estimate.

V. THE DECEMBER 2013 OFFICIAL FORWARD PRICE CURVE

Q. Please describe the role of natural gas prices in the Company's SCR analysis.

A. When Pacific Power prepared its SCR analysis, it also prepared the regression model presented in RTL-9C that determined that for gas conversion to become cost effective, the levelized forward price of natural gas would have to be $[redacted] per million British thermal units (mmBtu) or lower. Pacific Power monitors natural gas markets through its Official Forward Price Curve (OFPC), which is an internally generated natural gas price forecast that is informed by projections obtained from three consultants and updated on a quarterly basis.

The SCR analysis was based on the September 2012 OFPC, which identified a levelized forward price of $[redacted] per mmBtu. A year later, the September 2013 OFPC identified a forward levelized price of $[redacted] per mmBtu; this is the price that Pacific Power compared to the $[redacted] per mmBtu breakeven price point identified in its regression model when it decided to issue the full notice to proceed with SCR installation in December 2013.

As I explained in my initial testimony, natural gas price assumptions have a major impact on the outcome of the Company's SCR model. Changing the levelized forward price of natural gas by just one penny swings the outcome of the model by $[redacted] million – an increase of a penny increases the benefits of SCR installation by

$[redacted] million, and a decrease of a penny increases the benefits of gas conversion by $[redacted] million.

Q. You previously testified that in evaluating whether Pacific Power acted prudently when it installed SCR, the Company should only be held accountable for "the information that was in its possession" when it issued the full notice to proceed. Is this still Staff's position?

A. No. Based on new information provided by the Company in its rebuttal case and subsequent discovery, it became apparent to Staff that the Company came into new information regarding natural gas price forecasts between October and December 2013 that significantly improved the cost effectiveness of gas conversion. Had Pacific Power considered that information alongside the coal cost increases it identified in the October 2013 Mine Plan, the Company would have identified natural gas conversion as the clearly most cost-effective compliance alternative for Bridger units 3 and 4.

Importantly, the Company could have still availed itself of flexibility built into its engineer, procure and construct (EPC) contract for SCR installation and cancelled the SCR project in January 2014, while still capturing the majority of the increased benefits of gas conversion that were identified in December 2013. Staff therefore concludes that it is reasonable to consider the Company's decision to install SCR based on what it knew as of January 1, 2014.

Q. Please describe the new information regarding natural gas price forecasts that the Company received between October and December 2013.

A. Subsequent to the development of the September 2013 OFPC, Mr. Link testifies on rebuttal that the Company received updated forecasts from its three consultants.[28] Two of these consultants provided updates in October and November, which reflected moderate reductions in their natural gas price projections. On December 11, 2013, ten days after issuing the full notice to proceed with SCR installation, the Company received the last of these updates.[29] This last update was from the consultant that had provided the highest projection of natural gas prices for the September 2013 OFPC, and its update reflected a significant decrease that would, in turn, have a significant impact on the Company's own projections. When the OFPC was updated on December 31, 2013, Pacific Power's official levelized forward price fell from $[redacted] per mmBtu to $[redacted] per mmBtu.[30]

Q. Had the Company applied the December 2013 OFPC to its SCR analysis, what would have been the impact?

A. Setting aside Staff's coal cost adjustment and applying <u>*only*</u> the December 2013 OFPC to the Company's regression model, it predicts that the analysis would have only identified about $[redacted] million in net benefits associated with SCR installation. This figure is almost 90 percent lower than the $[redacted] million in net benefits that the Company identified in its initial analysis, which was based on the December 2011

---

[28] Link, Exh. No. RTL-11CT 18:5-12.
[29] *Id.*
[30] Twitchell, Exh. No. JBT-25C.

OFPC. Relative to the September 2013 OFPC, the December 2013 OFPC created a $[redacted] million swing in favor of gas conversion, reducing the net benefits of SCR conversion from $[redacted] million to $[redacted] million.

Therefore, in just the two years from December 2011 to December 2013, the Company had seen nearly all of the benefits it identified for SCR installation swallowed up by declining natural gas prices. Not only was this trend sustained; it was accelerating. In the year between the September 2012 and September 2013 OFPCs, the Company's levelized forward price for natural gas fell by 6.5 percent. Then, in just the three months between the September 2013 and December 2013 OFPCs, it fell by another 6.5 percent.

A reasonable board of directors would have recognized this powerful trend and responded by extricating the Company from the SCR project, which was growing riskier by the day.

Q. But the Company issued the full notice to proceed to the EPC contractor on December 1, 2013 – 30 days before generating the December 2013 OFPC. How could it have backed out of the project at that point?

A. The EPC contract was designed with significant flexibility around the full notice to proceed; [redacted][31] This flexibility is central to Staff's argument in this case – that the low exit fees on December 1, 2013, coupled with the new cost information that became available during the limited notice to proceed phase,

[31] Twitchell, Exh. No. JBT-12C.

justified the Company exiting the EPC contract at that time and pursuing gas conversion.

The Company, however, had continued flexibility—albeit at a higher cost—after the issuance of the full notice to proceed, for at least the first month of the EPC contract. Although the cost to exit the contract in January 2014 was higher than it was in December 2013, that cost was only a small fraction of the increased benefits that the December 2013 OFPC identified for gas conversion.

The same logic that Staff used in supporting a December 1, 2013 date for determining prudence also supports a January 1, 2014 date, given the additional information provided in rebuttal and subsequent discovery. That is, if the benefits of natural gas conversion out-weighed the costs of getting out of the EPC contract, then the prudent course of action would be to cancel the SCR project and pursue natural gas conversion.

//

//

//

//

//

//

//

//

//

//

Q. [redacted]

A. [redacted]

Q. You have presented how the increased coal costs and decreased gas costs affect the model independently. What happens when they are combined?

A. Please refer to Exhibit No. JBT-27HC. This exhibit is an updated version of Exhibit No. JBT-21C. The first exhibit presented only the impact of coal costs on the analysis; the latter exhibit presents the impact of the coal and natural gas costs together. The first page of Exhibit No. JBT-27HC shows the impact of these adjustments on the regression analysis and the new breakeven price. The second page shows the adjustments that Staff applied to the model; it has been marked highly confidential because it contains the costs associated with terminating the EPC contract on January 1, 2014. The third page of the exhibit shows that with these adjustments applied, the breakeven price at which natural gas conversion becomes cost effective rises to $[redacted] per mmBtu, and that at the December 2013 OFPC levelized forward price of $[redacted] per mmBtu, the model identifies $[redacted] million in net benefits associated with natural gas conversion.

VI. SUMMARY

Q. Please summarize your testimony.

A. My testimony has demonstrated that, when taken independently, increased coal costs from the October 2013 Mine Plan and decreased natural gas costs from the December 2013 OFPC each demonstrate that the decision to install SCR was uneconomic, or at a minimum, was moving in that direction at an accelerating pace. Accounting for either one of these trends would have led a reasonable board of directors to scuttle the SCR project and pursue natural gas conversion; when both are taken into consideration, there is no question that SCR had become uneconomic.

That Pacific Power recommitted itself to SCR at every opportunity reflects a willingness to ignore not only obvious trends in the industry, but the Company's own data. It should not be forgotten that the October 2013 Mine Plan and the December 2013 OFPC are both products of Pacific Power. While there has been some dispute over how these documents are evaluated, the fundamental point of disagreement between Staff and the Company is whether they are relevant in the context of the

Company's SCR analysis. The Commission has clearly articulated that an analysis presented in support of a resource acquisition must be based on the most up-to-date information.[32] Pacific Power's decision to install SCR, and then recommit itself to that decision at every opportunity for re-evaluation, fails this most basic component of a prudence review.

When Pacific Power issued the full notice to proceed with SCR installation on December 1, 2013, the October 2013 Mine Plan represented the most accurate, up-to-date information regarding the Company's future coal costs for the Bridger plant. Staff's objective analysis of this mine plan, on the terms spelled out by the Company, demonstrates that there were significant increases in Bridger's coal costs between January 2013 and October 2013.

In relying on the January 2013 long-term fuel forecast when it decided to move forward with the SCR installation, the Company disregarded crucial, updated information that would have changed the outcome of its analysis and identified gas conversion as the more cost-effective compliance option. The fact that Pacific Power failed to incorporate these costs and act accordingly locked the Company and its ratepayers into a more costly, more risky compliance path.

When Pacific Power determined on January 1, 2014, that SCR remained the best alternative, it failed to consider the December 2013 OFPC, which had nearly wiped out the benefits associated with SCR and demonstrated that what few benefits remained were being rapidly eroded. The September 2013 OFPC upon which the Company hangs its final decision had been shown to be obsolete and inaccurate at a

[32] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket UE-921262, Nineteenth Supplemental Order at 2.

time in which the Company still had enough flexibility to alter course. Pacific Power chose not to.

Taken together, these crucial developments identify about $[redacted] million in net benefits associated with gas conversion. These benefits have only increased as the very trends the Company ignored in its decision – rising coal costs and falling natural gas costs – have both continued to unfold.

Staff therefore stands by the recommendation presented in my response testimony – that the Commission disallow the incremental cost of the SCR installation relative to the gas conversion, as well as all costs associated with the other major maintenance projects that could have been avoided by gas conversion.

Q. Does this conclude your testimony?

A. Yes.