Exhibit No. ___T (JBT-1CT)
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

CONFIDENTIAL TESTIMONY OF

Jeremy B. Twitchell

**STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION**

Selective Catalytic Reduction at Jim Bridger

March 17, 2016

CONFIDENTIAL PER PROTECTIVE ORDER

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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. Where are you employed and in what capacity?

A. I am employed at the Washington Utilities and Transportation Commission (Commission) as a Regulatory Analyst in the Conservation and Energy Planning Section of the Regulatory Services Division. My duties include representing Commission staff (Staff) in Pacific Power & Light Company's ("Pacific Power" or "Company") demand-side management and integrated resource planning advisory groups and reviewing all filings from the Company in those matters. I was also a member of the team that represented Staff in Pacific Power's most recent iteration of the Multi-State Allocation Process and have been the Staff lead on matters relating to the Energy Imbalance Market and Pacific Power's exploration of full membership in the California Independent System Operator. More broadly, I review the annual renewable portfolio standard filings from Washington's three investor-owned electric utilities, analyze various tariff filings in the electric and natural gas industries, and assist in the drafting of Commission rules. I am also the Staff lead for the Commission's investigation into energy storage technologies.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since June 2013.

Q. Please describe your educational and professional background.

A. I graduated from Brigham Young University in 2005 with a Bachelor of Arts degree in Communications (Print Journalism Emphasis), then worked as a newspaper reporter in Utah and Nevada for six years covering local government, energy, and other issues. I graduated from Texas A&M University with a Master of Public Service and Administration degree in 2013, with an emphasis on energy, natural resource, and technology policy. My studies included courses in energy markets, energy policy, natural resource economics, finance, and econometric analysis. Since being hired by the Commission, I have attended various conferences and regulatory training courses, including a course in cost of service and rate design provided by Electric Utility Consultants, Inc. in February 2014 and the National Association of Regulatory Utility Commissioners Regulatory Studies Program in August 2014. I have also presented on panels at the 2014 National Summit on RPS (incremental costs of renewable portfolio standard compliance) and the 2016 National Association of Regulatory Utility Commissioners Winter Meeting (energy storage).

Q. Have you previously testified before the Commission?

A. Yes. I was Staff's witness for cost of service and rate design matters in Pacific Power's 2014 General Rate Case (UE-140762), in which I provided written and oral testimony. I also prepared a written declaration relating to the Company's 2014 Schedule 37 avoided cost tariff filing (UE-144160).

II. SCOPE AND SUMMARY OF TESTIMONY

Q. Please summarize your testimony in this proceeding.

A. My testimony summarizes the Commission's standards for prudence reviews and then presents Staff's prudence review of the Company's decision to install selective catalytic reduction (SCR) technology on Jim Bridger (Bridger) units 3 and 4 and continue operating them as coal-fired resources.

Q. What is Staff's conclusion in its prudence review of the SCR installations at Bridger units 3 and 4?

A. Staff concludes that the Company acted imprudently when it decided to install the SCR, and recommends that the Commission disallow $42,400,594 (70 percent) of the Company's requested $60.8 million increase associated with the installation of SCR and related major maintenance projects at Bridger. This disallowance is based on the Company's representation of the difference in capital costs between converting the Bridger units to run on natural gas and installing the SCR technology. The recommended disallowance also includes the capital costs of other major maintenance projects that would have been avoided had the units been converted to natural gas.

Q. Please summarize why Pacific Power's decision to install SCR was imprudent.

A. In section III of my testimony I discuss the Commission's prudence standard and its application to Pacific Power's decision to install SCR. The Commission's prudence standard is rooted in the central question of whether a reasonable board of directors would have approved a resource decision based on what it knew – or should have known – at the time. Prior to making the final decision to install SCR at Bridger, Pacific Power became aware of critical new information that a reasonable board would have recognized as having significant, negative impacts on the economics of the SCR installation. Had Pacific Power updated its analysis of SCR at Bridger with this information, it would have identified natural gas conversion as the more cost-effective alternative for complying with federal Regional Haze obligations. But rather than re-evaluate its decision, Pacific Power chose to ignore the new information, dismiss a directive from the Commission to update its analysis, and instead forge ahead on its preferred course, relying on outdated and inaccurate information.

In section IV, I present the timeline of events that led to the Company's decision to install SCR on Bridger units 3 and 4. Exhibit No. JBT-2C summarizes these events. As the exhibit shows, the Company became aware of its Regional Haze compliance obligations at Bridger in November 2010. Those obligations required Pacific Power to achieve certain emissions reductions for Bridger Unit 3 by the end of 2015, and Bridger Unit 4 by the end of 2016. The Company identified three options for complying with these obligations: install SCR on the units, convert the units to run on natural gas, or decommission the units.

Pacific Power's initial analyses identified SCR as the more cost-effective alternative for meeting Regional Haze obligations at Bridger, although by a diminishing margin. In its initial review of the Company's analysis, the Commission concluded that the relatively small difference in cost between SCR and gas conversion warranted further analysis, and directed Pacific Power to take a closer look at the issue before committing itself to SCR. Pacific Power never conducted this additional analysis.

Some states, however, were satisfied with the Company's analyses. The public service commissions in Wyoming and Utah both granted ex ante approval of the Bridger SCR in May 2013. Based on those approvals, the Company signed a contract on May 31, 2013, for the design, construction and installation of the SCR systems. That contract was structured to give the Company flexibility to walk away at minimal cost until December 1, 2013, at which time it either had to cancel the project or give the contractor a final notice to proceed. In section V of my testimony I discuss this contract and the importance of the final notice to proceed date in greater detail.

From the time that Pacific Power first began analyzing this issue in December 2011 until the time that it had to make a final decision on December 1, 2013, every observable trend in the electric industry was working against the Company's initial conclusion that SCR was the more cost-effective means of compliance. Natural gas prices were plummeting, the Company's coal costs were rising, and the President of the United States directed the promulgation of a rule for regulating carbon dioxide (CO_2) emissions from power plants.

For a time, the Company analyzed the impact of these trends. It updated its initial analysis, based on December 2011 data, with data from September 2012. That update showed that, in less than a year, the benefits associated with SCR installation had nearly been halved.

Once Pacific Power won regulatory pre-approval from two states in May 2013, however, the updates ceased. Data received by the Company between August and October 2013 showed that gas prices continued to fall rapidly and that coal prices for the Bridger plant were rising, but Pacific Power did not update its analysis to reflect either development. In section VI of my testimony, I present Staff's corrections to the Company's model to demonstrate that had the Company reasonably accounted for that information, the model would have identified natural gas conversion as the most cost-effective option.

Figure 1 below – also provided as Exhibit No. JBT-3C – shows the trend of declining benefits for SCR installation that the Company's own analyses identified from 2011 to 2013. It also demonstrates the impact of Staff's corrections to the Company's 2012 analysis. These corrections account for increased coal costs and fix a modeling error in the gas conversion model that caused it to overestimate the replacement power costs that would have been incurred while the units were being retrofitted. My testimony will describe both of these corrections in detail.

[redacted]

As Figure 1 shows, the initial net benefits of [redacted] million that the Company identified for SCR in December 2011 had fallen by nearly 60 percent by September 2013, even with the unrealistically high projection of future natural gas prices that the Company was using at that time.[1]

The Figure goes on to show that when Staff's correction to account for Bridger's increased coal costs is applied, the net benefits fall to about [redacted] million, and when Staff's correction to equalize replacement power costs is applied, the net benefits fall to about [redacted] million. Finally, when a more realistic forward natural gas

[1] The "PAC 2013" entry does not refer to an actual analysis that the Company performed, since the Company's last analysis was performed using data from September 2012. Rather, it is what the Company's model predicts would have happened had the 2012 analysis been updated to use the Company's September 2013 Official Forward Price Curve for natural gas.

curve is used – such as an average of three consultant forecasts that the Company received in August and September of 2013 – then the model identifies [redacted] million in net benefits for gas conversion. In section VII of my testimony I demonstrate why the Company's September 2013 Official Forward Price Curve (OFPC) – the final check it used before committing itself to the SCR installation – was unreasonably high, given data it had received from consultants and the forward curves being used by multiple other entities, including the federal government and several regional utilities.

In making these corrections to the model, Staff has only used data provided by the Company – data that was readily available to Pacific Power before it made the final decision to proceed with SCR installation on December 1, 2013. Had the Company simply acted on this data by using it to update the 2012 analysis, Pacific Power would have identified natural gas conversion as the more cost-effective compliance option and could have utilized the flexibility in its contract to cancel the SCR installation and pursue natural gas conversion.

Because the Company failed to update its analysis of its own accord, then disregarded explicit direction from the Commission to do so, and ultimately proceeded in reliance on outdated information, Pacific Power's decision to install SCR on Bridger units 3 and 4 was imprudent, and the significantly increased costs that resulted from that imprudent decision should not be recovered from ratepayers. In section VIII of my testimony I describe how Staff calculated its recommended disallowance.

In addition to the issues identified in Staff's prudence review, model corrections, and recommended disallowance, there are other matters that the Commission should consider in relation to the Bridger SCR. I present these matters in section IX of my testimony. In section X, I provide a more in-depth review of the regulatory proceedings related to Bridger SCR in other states and explain Staff's rationale for why the Commission should not consider the decisions of other states when making a decision in this case. Finally, in section XI, I respond to the Company's West Control Area (WCA) analysis of Bridger SCR and explain why the Commission should not accept this study as a reasonable representation of the benefits of SCR installation to Washington customers.

III. THE COMMISSION'S PRUDENCE STANDARD AND THRESHOLD FOUR-PART REVIEW

Q. Do any Washington State statutes apply to utility resource acquisitions?

A. Yes. RCW 80.04.130(1) gives the Commission the authority to suspend any tariff filing that would create a rate increase and to conduct a hearing on the matter. At such a hearing, pursuant to RCW 80.04.130(4), the company requesting an increase in rates carries "the burden of proof to show that such increase is just and reasonable."

Q. Please describe the standard that the Commission has developed for evaluating whether a proposed rate increase is "just and reasonable."

A. In previous orders, the Commission has articulated a reasonableness standard for prudence reviews:

> The Commission has consistently applied a reasonableness standard when reviewing the prudence of decisions relating to power costs, including those arising from power generation asset acquisitions. The test the Commission applies to measure prudence is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. The company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.[2]

Q. Has the Commission provided any guidance specific to Pacific Power on the prudence standard?

A. Yes. In evaluating the prudence of resources previously constructed or acquired by the Company, the Commission has applied a four-part review:

> When examining the acquisition of new facilities, we consider whether: (1) the new resources are necessary; (2) the Company evaluated and considered alternatives; (3) the acquisition decision involved the Board of Directors; and (4) whether the Company's analysis and decision-making process is adequately documented.[3]

Ms. O'Connell discusses these four factors further in section III.C.1 of her direct testimony.

Q. Has Pacific Power demonstrated that new resources at the Bridger plant are necessary?

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[2] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12, ¶ 19 (Apr. 7, 2004) (footnotes and related citations omitted).

[3] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-090205, Order 09, ¶ 64 (Dec. 16, 2009) (footnotes and related citations omitted).

A. Yes. As described in the testimony of Chad A. Teply, the U.S. Environmental Protection Agency's Regional Haze Rule required Pacific Power to reduce certain emissions from Bridger Unit 3 by the end of 2015 and Unit 4 by the end of 2016.[4] Staff has independently reviewed and confirmed the standards that the agreement imposed on Bridger. While there were various options for complying with those standards, a business as usual case – in which the units continue to operate without additional resource investments – was not an option.

Q. Did Pacific Power evaluate and consider alternatives for achieving Regional Haze compliance for units 3 and 4?

A. Yes. As described in the testimony of Rick T. Link, Pacific Power evaluated several compliance options using System Optimizer (SO Model), which is the model that the Company uses for integrated resource planning.[5] Resource options considered in the model included installing SCR; converting the units to run on natural gas; and closing the units and replacing them with other resources, including energy efficiency, market purchases, and new wind and natural gas plants.[6]

The Commission, however, has indicated that simply presenting an analysis of different resource options is not enough to support a prudence finding; the analysis must be based on "up-to-date information."[7]

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[4] Teply, Exh. No. CAT-1CT 11:11-17.
[5] Link, Exh. No. RTL-1CT 3:3-13.
[6] *Id.* at 5:18–6:10.
[7] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket UE-921262, Nineteenth Supplemental Order, 2 (Sept. 27, 1994).

As I discuss in section VI, the Company failed to update its analysis for known increases in its coal costs at Bridger, the parameters of its contract for SCR installation, and a reasonable projection of future natural gas prices. Had the Company used up-to-date information that was in its possession at the time the decision was made, it would have determined that converting Bridger units 3 and 4 to run on natural gas would have been the least-cost option.

Q. Was the board of directors involved in Pacific Power's decision to install SCR at Bridger?

A. No. Pacific Power's corporate structure differs from those of other utilities in that there is not a formal board of directors, nor is there any other executive-level body that approves major resource decisions.[8] Absent that level of review, the Commission has previously asked Staff to affirm whether "a reasonable Board would have approved [the] acquisition"[9] in prudence reviews for Pacific Power.

Q. Does Staff affirm that a reasonable board would have approved the SCR installation?

A. No, a reasonable board would not have approved the SCR installation. A reasonable board would have recognized that market trends were increasingly undermining the economic basis of the decision to install SCR, and it would have ensured that its final decision was based on up-to-date information, which would have enabled it to

[8] Pacific Power response to Staff Data Request 90.

[9] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-090205, Order 09, ¶ 65 (Dec. 16, 2009) (footnotes and related citations omitted).

recognize that gas conversion had become the better option. The fact that Pacific Power failed to operate in this manner raises fundamental doubts about the process that the Company employs for reviewing and approving major capital projects.

Q. Have you reviewed any internal documents related to the Company's decision to install SCR at Bridger units 3 and 4?

A. Yes. In response to a data request, the Company provided the internal proposals that were presented to the final decision maker. While there were separate proposals for units 3 and 4, they were presented on the same date (May 20, 2013), relied on the same analysis, and were approved at the same time. For simplicity, my testimony will only refer to the Bridger Unit 3 proposal.

Q. You previously referred to different SCR analyses prepared by the Company over time. What version of the analysis was used in the Company's internal decision making process?

A. Both proposals communicated the results of the 2011 and 2012 analyses, but the results presented in their executive summaries relied on the 2011 analysis – the analysis most favorable to the installation of SCR.

Q. To whom were the proposals addressed?

A. The proposals identify Greg Abel, president and chief executive officer of Mid-American Energy Holdings Company, as the final approver.

Q. Why is Staff unable to affirm that a reasonable board of directors would have approved the SCR project?

A. Staff's review of the Company's internal decision-making process has raised major doubts regarding its efficacy and accuracy. Those doubts begin with the internal proposals, which portrayed an inaccurate and incomplete representation of the risks and benefits of SCR installation at Bridger. They extend to the post-decision process, which failed to reasonably respond to known changes that had a clear, negative impact on the economics of SCR.

Despite the fact that the Company's 2012 analysis demonstrated that the underlying factors supporting the decision were rapidly eroding and that the net benefits of SCR had been reduced by 42 percent in the course of just nine months – from [redacted] million to [redacted] million – the executive summary relied on the older analysis that was more favorable to SCR installation, and downplayed the findings of the 2012 analysis. Emphasizing the 2011 analysis in the proposal was an inaccurate representation that overstated the benefits of SCR and understated the risks.

Furthermore, the proposals de-emphasized the risk of future carbon emission regulations, asserting that "there has been limited activity in the CO_2 policy arena,"[10] despite the fact that in his 2013 State of the Union Address in January, President Barack Obama had signaled his intent to direct federal agencies to begin regulating carbon emissions.[11] President Obama formally directed the Environmental Protection Agency to develop a rule to regulate carbon emissions from existing

[10] Twitchell, Exh. No. JBT-10C at 19 (Pacific Power response to Staff Data Request 90, Attachment 1).
[11] "Remarks by the President in the State of the Union Address." Retrieved Feb. 22, 2016. Available at: https://www.whitehouse.gov/the-press-office/2013/02/12/remarks-president-state-union-address.

power plants under section 111(d) of the Clean Air Act on June 25, 2013 – more than five months before Pacific Power issued the final notice to proceed to its SCR contractor.[12] If the Company's analysis was based on an assumption that actions on CO_2 policy would be limited, then the promise of forthcoming CO_2 regulations should have, at a minimum, prompted the Company to revisit its analysis and underlying assumptions. There is no evidence that the Company did so.

Q. Did Pacific Power adequately document its analysis and decision-making process?

A. Yes. My prudence analysis is not based on a failure by the Company to document its decisions.

IV. SCR PROJECT TIMELINE

A. Company Analyses

Q. When did Pacific Power become aware of the requirement to reduce nitrogen oxide (NOx) emissions at Bridger?

A. Certainly by November 9, 2010. On that date, the Company reached a settlement with the Wyoming Department of Environmental Quality in relation to the state's Regional Haze plan. In the settlement, the Company agreed to reduce Bridger's

[12] "Presidential Memorandum – Power Sector Carbon Pollution Standards." Retrieved Feb. 22, 2016. Available at https://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

NOx emissions to 0.07 pounds per million British Thermal Units (mmBtu) by the end of 2015 for Unit 3, the end of 2016 for Unit 4, the end of 2021 for Unit 2 and the end of 2022 for Unit 1.[13]

Q. Did the agreement prescribe SCR installation to meet the target NOx emissions rate?

A. No. The target was calculated based on what could reasonably be achieved using SCR, but the agreement gave the Company complete discretion in determining how it would achieve compliance.

Q. When did the Company analyze its compliance options for Jim Bridger?

A. The first analysis of which I am aware was prepared in 2012, but was based on 2011 data. The analysis was subsequently updated twice in 2013 – a major update to use more recent cost projections (from September 2012) and a minor update to incorporate the analysis into the Company's 2013 IRP framework.

Q. Please summarize how those analyses differ in their key inputs and findings.

A. All three analyses take the same fundamental approach in that they analyze the same set of compliance options for Bridger units 3 and 4: installing SCR, converting the units to run on natural gas, or decommissioning the units and replacing them with new resources. Each of the analyses also uses low, base and high scenarios for

[13] "BART Appeal Settlement Agreement," Wyoming Department of Environmental Quality, Docket 10-2801 (Nov. 9, 2010).

natural gas and carbon prices.[14] Natural gas prices are based on the Company's long-term projection of prices at the Opal hub, which is the natural gas hub closest to Bridger.

Each natural gas case is paired with each carbon tax case, resulting in nine different scenarios considered by the analysis. Scenarios with low natural gas prices and/or high carbon prices generally favor gas conversion, while cases with base or high natural gas prices and base or no carbon prices generally favor SCR installation.

The analyses model the same period – from 2016, when Bridger unit 3's compliance obligation begins, to 2030, which was the extent of the Company's December 2011 OFPC that was used in the initial analysis. The base case of that initial analysis included the adoption of a carbon tax in 2021, starting at $16 per ton and increasing at 3 percent real per year. The base case analysis identified a net benefit of [redacted] million for the SCR installation.[15] My testimony refers to this version as the 2011 analysis.

The Company later updated the analysis based on its September 2012 OFPC, which in its base case predicted a 2016–2030 levelized forward price for natural gas of [redacted] per mmBtu and the adoption of a carbon tax in 2022, starting at $16 per ton and increasing to $23 per ton by 2030. The base case analysis identified a net benefit of [redacted] million for the SCR installation.[16] My testimony refers to this version as the 2012 analysis; this is the version that the Company presents in this case to support the decision to install SCR.

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[14] The low case for carbon assumes that no carbon price is in place.
[15] Twitchell, Exh. No. JBT-10C at 17 (Pacific Power response to Staff Data Request 90, Attachment 1).
[16] Link, Exh. No. RTL-1CT 2:8.

While preparing the 2013 IRP, the Company prepared a minor update of the 2012 analysis. This version continued to rely on the September 2012 OFPC, but updated the cost assumptions for future resources to align with those used in the 2013 IRP. As one would expect, the difference from the 2012 analysis is minor; it identified a net benefit of [redacted] million for the SCR. My testimony refers to this version as the IRP analysis.

B. Commission Response to the 2013 IRP

Q. Which version of the analysis was first presented to Staff and the Commission?

A. While previous versions of the analysis were filed in proceedings in other states, the first version filed with the Commission was the IRP analysis, when it was filed with the Company's 2013 IRP in April 2013.

Q. Please summarize your involvement in Pacific Power's IRP process.

A. I was assigned to review the Company's 2013 IRP after it had been filed with the Commission. I reviewed the plan in depth, discussed it with Company representatives, prepared briefing materials for the Commission, facilitated the recessed open meeting at which the Company presented the plan, and assisted in the drafting of the Commission's acknowledgment letter.

I also participated in the 2015 IRP process from the beginning, which allowed me to attend advisory group meetings and provide verbal and written feedback to the Company as the plan was prepared. After the plan was filed with the

Commission, I was responsible for conducting staff's review, preparing briefing materials for the Commission, facilitating the recessed open meeting at which the plan was presented, and assisting in the drafting of the acknowledgment letter.

Q. Please summarize the scope and conclusions of the Company's Bridger analysis in the 2013 IRP.

A. Pacific Power identified three compliance options for Bridger units 3 and 4: install the SCR as required, convert the units to run on natural gas, or decommission the units by the compliance deadlines.

The Company conducted its analysis in the SO Model, which is the primary model used in the IRP. The SO Model uses inputs such as load, fuel costs, market prices and transmission constraints to model how the Company would optimally dispatch its system on an hourly basis over a period of many years. In the IRP, the Company models the system over a 20-year period.

The 2013 IRP analysis concluded that the optimal compliance option for Bridger would be to install the SCR. The analysis found that SCR installation would result in a 20-year total portfolio net present value (NPV) of [redacted] billion, which would be [redacted] million (0.6 percent) less expensive than the gas conversion option, for which the model identified a 20-year portfolio NPV of [redacted] billion.

Q. What was the Commission's response to the 2013 IRP's SCR analysis?

A. Given the relatively narrow cost difference between the SCR and gas conversion scenarios (0.6 percent), the Commission requested that the Company revisit the issue in its 2013 IRP Update and provide additional information.

Specifically, the Commission requested two analyses of the Company in its 2013 IRP Update: a break-even analysis that would identify the levelized forward price for natural gas at which gas conversion would become cost effective,[17] and an updated analysis based on current data.[18]

Q. Did the Commission identify the risk associated with relying on the analysis presented in the 2013 IRP?

A. Yes. The Commission stated that the updated analysis it requested was "necessary to ensure that the Company does not commit itself to investments that later prove not to be cost-effective."[19]

C. The IRP Update

Q. When was the 2013 IRP Update filed with the Commission?

A. The 2013 IRP Update was filed in conjunction with the Company's 2015 IRP Work Plan on March 31, 2014.

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[17] *"PacifiCorp 2013 IRP Acknowledgment Letter – Attachment,"* Docket UE-120416, 3 (Nov. 25, 2013) ("However, a more detailed analysis that focuses on the gaps between the various projections that the Company used and identifies the price level at which it would become cost-effective to switch an existing coal plant to natural gas is required to better inform the company's decision-making process.").
[18] *Id.* at 4 ("Given these developments, the Commission concludes that PacifiCorp should update its coal analysis as part of its 2013 IRP Update").
[19] *Id.*

Q. On page 13, lines 1-5 of his testimony, Company witness Chad A. Teply states that the Company responded to the Commission's 2013 IRP acknowledgment letter in the IRP Update. Do you agree?

A. No. Pacific Power provided only the requested break-even analysis, which identified the levelized forward natural gas price at which converting Bridger units 3 and 4 to run on natural gas would be cost effective. Pacific Power never provided an updated analysis based on current data.

Q. How did Pacific Power prepare the break-even analysis?

A. As I previously explained, the Company used three natural gas scenarios in its analyses: low, base, and high. The Company ran each of those scenarios with the base scenario for carbon prices ($16 per ton beginning in 2022, increasing to $30 per ton by 2030) and identified the benefit or cost of gas conversion relative to SCR installation in each scenario. Pacific Power then used those data points in a regression analysis to predict the levelized forward price for natural gas at which the present values of gas conversion and SCR installation would be equal. The Company presents the results of this analysis in Exhibit No. RTL-9C.

Q. In your opinion, was this a reasonable way of conducting this analysis?

A. Yes. Although the analysis only has three data points, each of those data points implicitly contains a significant number of control variables, which ensures that the observed differences in the three scenarios are almost entirely driven by the changes in the variable of interest – natural gas prices. The r^2 value for this analysis, which measures the degree to which the regression analysis accounts for the observed changes between the cases, is .995, which means that 99.5 percent of the cost differences among the three cases can be explained by their differences in gas prices.

Q. What was the break-even levelized price for natural gas that the model predicted?

A. [redacted] per mmBtu.[20]

D. Staff's Response to Company's 2013 IRP Update

Q. What was Staff's response to the 2013 IRP Update?

A. Staff drafted a series of informal data requests regarding the 2013 IRP Update and submitted them to the Company on April 23, 2014. One of those requests repeated the Commission's request for Pacific Power to update its analysis of Bridger units 3 and 4 "using the most recent official forward price curve for the Opal natural gas hub."[21]

[20] Link, Exh. No. RTL-9C.
[21] Twitchell, Exh. No. JBT-11 (Pacific Power response to Staff Data Request 94).

Q. What was the Company's response to Staff's informal data request?

A. The Company objected to the request "as overly broad and unduly burdensome, and seek[ing] evaluation and analysis of information *that the Company has not performed*."[22]

The Company further stated that it would examine, within the 2015 IRP, "costs and risks associated with outstanding decisions related to pollution controls on its coal fleet."[23]

Q. In your opinion, was that an acceptable response?

A. No. As Mr. Link explained in his testimony, the Company committed itself to the SCR installation on Bridger units 3 and 4 on December 1, 2013.[24] Any analysis of Bridger's Regional Haze obligations in the 2015 IRP would have been irrelevant.

Q. If Pacific Power committed itself to the SCR installation on December 1, 2013, then why did Staff issue data requests after the IRP Update was filed in March 2014 that requested updated analyses?

A. Staff had not been advised that the Company had already executed the contract for SCR installation. Staff was unaware of the contract's timing until this case was filed.

[22] *Id.* (emphasis added).
[23] *Id.*
[24] Link, Exh. No. RTL-1CT 20:9-13.

Q. To your knowledge, has Pacific Power ever updated its 2013 IRP analysis of SCR installation at Bridger units 3 and 4 since the Commission requested an updated analysis in its 2013 IRP Acknowledgment Letter?

A. No. Based on the Company's response to Staff's informal data request in relation to the 2013 IRP Update and Mr. Link's representation that the Company's analysis in this rate filing is premised upon an analysis conducted in 2012,[25] the Company has not made a meaningful update to its Bridger analysis since the 2012 version – which was already more than a year out of date when the Company issued the final notice to proceed to its SCR contractor on December 1, 2013.

V. THE ENGINEER, PROCURE AND CONSTRUCT CONTRACT FOR SCR INSTALLATION

Q. Have you reviewed Pacific Power's engineer, procure and construct (EPC) contract for SCR installation at Jim Bridger?

A. Yes. Pursuant to the Company's designation of the EPC contract as highly confidential, I reviewed it in person at Pacific Power's offices. It has not been placed into the record for this proceeding, but the Company has provided certain details in response to data requests.

[25] Link, Exh. No. RTL-1CT 1:21.

Q. Please summarize the timeline for the EPC execution.

A. As stated in the testimony of Mr. Link, the Company signed the contract on May 31, 2013, with a limited notice to proceed, followed by a full notice to proceed on December 1, 2013.[26] During the limited notice to proceed phase, the contractor was limited to engineering and planning activities, and expressly forbidden from entering into any procurement agreements or conducting any on-site work.[27]

Q. What would Pacific Power's responsibilities to the EPC contractor have been if the Company had decided not to issue the final notice to proceed on December 1, 2013?

A. The Company built significant flexibility into the EPC contract. [redacted][28]

Q. Please explain the significance of the EPC contract details.

A. The details are important in determining when the Company officially made the final decision to acquire the SCR project, thereby establishing the point in time at which prudence should be evaluated. Based on the language of the EPC contract, Staff asserts that December 1, 2013, is the correct point in time for evaluating the prudence of the Bridger SCR, particularly in light of critical developments that had taken place since the contract was signed on May 31, 2013.

[26] Link, Exh. No. RTL-1CT 20:9-13.
[27] Company response to Staff Data Request 22.
[28] Twitchell, Exh. No. JBT-12C (Company response to Staff Data Request 161).

Since the Company's final decision was made on December 1, 2013, and the Commission's stated prudence standard requires that a decision be made "using the data and methods that a reasonable management would have used *at the time the decisions were made*,"[29] Pacific Power's final decision should have incorporated all of those developments that took place during the limited notice to proceed phase. My examination shows that it did not.

Q. What developments took place during the limited notice to proceed phase?

A. In August and September of 2013, Pacific Power received updated natural gas forecasts from three consulting firms that, on average, predicted a nearly 18 percent drop in price relative to the Company's 2012 OFPC. Forecasts prepared by other reliable sources and regional utilities around the same time were all predicting similar – and in some cases steeper – decreases as the natural gas market continued to undergo a fundamental transformation.

It is crucial to note that of the three consultant forecasts that Pacific Power received in August and September of 2013, two predicted forward levelized prices that were below the Company's identified break-even forward price of [redacted] per mmBtu, meaning that their data supported gas conversion at Bridger even with all of the Company's other assumptions in the 2012 analysis intact.

[29] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12, ¶ 19 (Apr. 7, 2004) (footnotes and related citations omitted). Emphasis added.

Additionally, in October 2013, the Bridger Coal Company finalized the 2013 Mine Plan.[30] This plan increased the forecast prices for the mine's output – which is the Bridger plant's primary fuel source – by [redacted] percent relative to the price inputs that the Company used in the 2012 analysis.

Taken together, these developments negated the benefits of SCR installation and made gas conversion the most cost-effective compliance option for Bridger. All of these developments had taken place by October 2013 – more than a month before the Company's final notice to proceed deadline, giving ample time for the Company to update its analysis. The timing of these developments, coupled with the flexibility in the EPC contract, lead Staff to conclude that Pacific Power could have, and should have, decided on December 1, 2013, to cancel the EPC contract and pursue gas conversion.

Pacific Power failed to correct its analysis to account for these critical developments. In the next section I explain how Staff has calculated and applied the necessary corrections to the Company's model.

VI. STAFF'S CORRECTIONS TO THE SCR ANALYSIS

A. Overview

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

B. Q. When Staff's corrections are applied to the Company's model, what is the impact?

A. Figure 2, also provided as Exhibit No. JBT-4C, illustrates the impact of Staff's corrections to the Company's model. This exhibit is based on the Company's break-even analysis, presented in Exhibit No. RTL-9C.

[redacted]

This graph shows the Company's initial analysis, represented by the modeled outputs for the low, base and high gas cases (the triangles on the graph), the regression curve that predicts the model's outcome for a given natural gas price (the solid line with the x's), and the predicted breakeven, levelized forward natural gas price (the circle) at [redacted] per mmBtu.

As the exhibit shows, when Staff's model corrections are applied, the Company's model outputs for the low, base and high gas cases increase from the points represented by the triangles to the points represented by the squares. This causes the regression curve that predicts the model's output to shift upward, which in turn shifts the break-even point at which gas conversion becomes cost effective outward, from the levelized forward price of [redacted] per mmBtu that the Company identified to a levelized forward price of [redacted] per mmBtu.

Q. Please summarize Staff's corrections to Pacific Power's SCR analysis.

A. Staff made the following corrections:

- Added the increased coal costs associated with the 2013 Bridger Mine Plan;
- Subtracted the replacement power costs that were modeled in the gas conversion scenario; and
- Added the expense the Company would have had to pay if it did not issue a final notice to proceed to the EPC contractor.

Each correction was independently calculated and applied to the low, base and high gas cases except for the EPC contract exit fee, which was constant across the cases.

Q. Were Staff's corrections made in the SO Model?

A. No. I was unable to directly work in the SO Model, as it is proprietary software housed on Company servers in Portland. Unlike other models generally used in a rate case proceeding, Pacific Power does not provide the model or make it available for remote access by intervening parties, which complicates any review of the model's conclusions. While Staff understands the SO Model's size and complexity, access to the model is critical to an informed analysis. Pacific Power has managed a similar challenge involving the comparably complicated GRID model, which it uses to calculate net power costs, by enabling virtual access to intervening parties as needed. If the Company is going to rely on the SO Model to support future prudence reviews, then it must find a way to make the model accessible to intervening parties as it has done with GRID and its other models.

Q. If Staff did not have direct access to the SO Model, how were Staff's corrections calculated?

A. Although Pacific Power did not provide the model directly, it did provide all the data files for the model's inputs and outputs in both the SCR and the gas conversion scenarios, which allowed Staff to partially replicate the model and calculate the impact of its corrections.

Staff's corrections to the model are necessarily limited; without access to the model, Staff could do nothing more than calculate minor adjustments. Therefore, Staff's corrections only take place at the margins of the SO Model, and do not affect any underlying assumptions or modeling conventions. Aside from the specific corrections explained below, Staff has not changed the Company's model in any other way.

Staff does not present its corrections as a perfect representation as how the SO Model would respond to these changes. Without access to the SO Model, it is impossible to predict exactly how it would respond. However, Staff is confident that its corrections are a reasonable and reliable estimate of how the SO Model would respond, and has endeavored to provide a transparent explanation in testimony and exhibits of how these corrections were calculated. I want to emphasize that Staff only undertook this effort because the Company has repeatedly refused requests to update its model.

C. Bridger Coal Cost Correction

Q. Did Staff ask the Company whether the SCR analysis it presented in this case reflected the 2013 Mine Plan?

A. Yes, and the Company responded that:

> The coal costs listed in Confidential Exhibit No. RTL-3C incorporated the cost increases reported in Bridger Coal Company's (BCC) 2013 Mine Plan. There were no significant increases between then and the time of the September 2013 official forward price curve (OFPC).[31]

[31] Twitchell, Exh. No. JBT-13 (Company response to Staff Data Request 11).

Q. What is your opinion of this response?

A. It is both inaccurate and misleading. The Company asserts that the 2013 Mine Plan was reflected in its analysis, but as I show below, that is clearly not the case. Also, the response suggests that the 2013 Mine Plan was developed before the September 2013 OFPC, but that is not possible, since the 2013 Mine Plan was finalized in October 2013.

Q. How do the coal prices in the 2013 Mine Plan compare to the prices used in the 2012 analysis?

A. I present this comparison in Exhibit No. JBT-5C. The prices used in the 2012 analysis were presented in Exhibit No. RTL-3C; the 2013 Mine Plan prices were provided by the Company in response to a data request.[32] The 2013 Mine Plan increased Bridger's coal costs for the 2016–2030 period by [redacted] percent, from a levelized forward cost of [redacted] per mmBtu to [redacted] per mmBtu.

Q. What was the dollar amount of Staff's coal cost correction?

A. On an NPV basis, the corrections were [redacted] million in the low gas case, [redacted] million in the base gas case, and [redacted] million in the high gas case.

Q. Please describe how you calculated these corrections.

[32] Twitchell, Exh. No. JBT-14C (Company response to Sierra Club Data Request 8) (The exhibit presents the section of the workbook that Staff used in its calculation; the complete workbook is available in Staff's workpapers).

A. Exhibit No. JBT-6C summarizes the calculations, which are a straightforward comparison between the fuel cost required to achieve the modeled coal-fired output of Bridger units 3 and 4 in each scenario using the Company's fuel inputs and the 2013 Mine Plan's fuel inputs.[33] In each case, Staff determined the increase in fuel costs for each year, then expressed the stream of increased costs on an NPV basis.

Q. Is the Bridger coal mine the sole source of fuel for the Bridger plant?

A. No. Pacific Power also obtains coal from the Black Butte Mine, which is owned by another party.

Q. Did you adjust your analysis to reflect the inclusion of Black Butte coal in the fuel mix for Bridger?

A. No. I evaluated the potential impact of such an adjustment on the analysis, but omitted it because it was negligible. In Pacific Power's initial filing in the 2014 rate case, when the Company proposed to include the increased costs associated with the 2013 Mine Plan in Washington rates, the Company also identified its fuel costs associated with Black Butte. And while Black Butte coal was approximately [redacted] than Bridger Coal at the time, it only made up about [redacted] of the fuel mix for Bridger, meaning that the Company's projected total average cost

[33] Staff's process for converting the 2013 Mine Plan costs from the dollars per ton figure used in the Mine Plan to the dollars per MWh input used by System Optimizer can be seen in Exhibit No. JBT-6C, pages 6 and 7 (the "2013 Mine Plan" and "Heat Content" tabs).

for fuel at the Bridger plant, on a dollars per mmBtu basis, was only [redacted] than the cost of coal from the Bridger mine.[34]

Although the Black Butte contract was set to expire at the end of 2014, replacement fuel was not identified until June 2014, well after the Company had issued the final notice to proceed with the SCR installation.[35] Staff's adjustment is necessarily limited to what the Company knew or could reasonably assume at the time it made its decision. Staff therefore assumed that the Company would either renew the Black Butte contract on similar pricing terms or allow it to expire and rely wholly on coal from the Bridger Mine. In either scenario, future fuel prices for the Bridger plant would be predominantly based on coal prices from the Bridger mine.

Q. If the costs of generation at Bridger increased because of the 2013 Mine Plan, as Staff has argued, then isn't it also logical to assume that the Company would reduce generation at Bridger accordingly?

A. Only if the increase was large enough to move Bridger toward the margin of the Company's generation fleet. Staff's review of the SO Model suggests that this is generally not the case. In the base gas and high gas cases, even with the 2013 Mine Plan increase, Bridger units 3 and 4 would remain among the lowest-cost resources in the Company's portfolio on an average variable cost basis, and are below the

[34] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140762, Exh. No. CAC-1CT at 3, Table 1 (Although this testimony was filed on rebuttal to reflect increased coal costs for the Bridger plant that were identified in 2014, Staff's position does not incorporate the higher costs that were identified in 2014. Staff cites to this exhibit only for the simplicity with which Table 1 summarized the Company's position on Direct Testimony, which reflected the 2013 Mine Plan.).

[35] *Id.* at 4:12-14.

model's projected prices at the six market hubs where the Company transacts at all times with the exception of the Mid-Columbia market during off-peak hours in the spring runoff months. It is therefore highly unlikely in the base gas and high gas cases that the Company would alter the dispatch of Bridger units 3 and 4 based solely on the fuel increases associated with the 2013 Mine Plan.

In the low gas case, the combination of low gas prices and carbon prices beginning in 2022 and increasing annually thereafter caused the model to reduce dispatch of coal units in the later years of the scenario, which is why the adjustment for the low case was slightly lower than the adjustment for the base gas and high gas cases, in which the model dispatches coal units to the imposed constraints. It is possible that the increased coal costs associated with the 2013 Mine Plan would have caused a further reduction in the modeled output of Bridger units 3 and 4 in those later years.

Q. If it is possible that the increased costs associated with the 2013 Mine Plan could result in reduced dispatch of Bridger units 3 and 4 in at least some scenarios, why did Staff's correction hold generation constant for those units?

A. In his testimony, Mr. Link states that the net benefits that the Company's analysis identified for SCR conversion are associated with lower fuel costs and higher revenue from selling into the market.[36] Higher fuel costs at Bridger would erode both of those benefit categories by increasing the Company's total expenditures on fuel and reducing its opportunities to make profitable sales into the market. In every

[36] Link, Exh. No. RTL-1CT 13:10–14:8.

hour, the Company would either be spending more money to serve its own loads with Bridger generation or making less revenue from selling power into the market, and over time, both of those factors would significantly reduce the value proposition associated with SCR installation.

In reality, higher coal prices would likely increase the Company's response to lower gas prices by further reducing the dispatch of Bridger units 3 and 4 to some degree, which would be manifested in some combination of reduced market sales and increased generation from other resources. Absent access to the SO Model, it isn't possible for Staff to model exactly how the Company's system would respond when higher fuel costs move a particular resource into the margin. But by calculating the dollar amount that it would cost the Company to maintain generation constant at Bridger units 3 and 4, Staff's adjustment is a reasonable proxy for the economic impacts of higher fuel costs and reduced market sales that higher coal costs would have on the model in the low gas case.

D. Replacement Power Cost Correction

Q. Please explain why Staff made an adjustment related to replacement power costs.

A. The SCR installation and gas conversion scenarios both required the same, two-month outage window. Logically, therefore, the outage window in each scenario should have had the same impact on system operations. However, by choosing to model the outage period for SCR installation during a low-demand, low-cost period and the outage period for gas conversion during a high-demand, high cost period, the Company created a severe inequity that inaccurately works in favor of the SCR case by assigning millions of dollars in replacement power costs to the gas conversion case that were not reflected in the SCR case. Staff's correction calculates and removes those replacement power costs to ensure that the two options are compared on equal footing.

Q. Why does Staff contend that Pacific Power did not account for replacement power costs in its SCR scenario?

A. Generally, the Company's planned outages for major maintenance at its plants are scheduled to take place in April and May of each year. April and May are among the lowest-demand months on the Company's system; it is generally warm enough for the west to not be using electric heat, but not warm enough to drive significant air conditioning loads in the east. Bringing one or two units down each April and May allows the Company to perform major maintenance at a time when it can easily absorb the reduction in generation, and when low prices driven by hydro runoff in the west have depressed market prices and limited the opportunity for the Company to sell into the market. In keeping with this practice, the Company's SCR analysis assumed that Bridger Unit 3 would be down in April and May of 2015, while Unit 4 would be down in April and May of 2016.

However, the internal proposal for the SCR installation targeted an outage period for units 3 and 4 lasting for two months from mid-September to mid-

November in 2015 and 2016, respectively.[37] This change made sense; installing the SCR during April and May, as originally scheduled, would have increased the cost of the units' generation just before the summer peak each year. Had there been a delay in construction, the units may have been rendered unavailable for meeting summer peaks. Given that the Company's compliance deadline was at the end of each year, and its peak months generally occur in July and August, it makes sense that Pacific Power moved the outages for SCR installation on Bridger units 3 and 4 to the September-November time frame.

The problem is that the Company never updated its analysis to reflect this schedule change. September, October, and November, while not peak months for the Company, are nevertheless higher demand months than April and May. It is unlikely that the Company could take a major unit offline during this window each year without having to replace its generation with higher-cost resources and market purchases. Market prices are generally higher in these months as well, meaning that the opportunity cost for lost sales is also higher than in April and May. By not updating the analysis to reflect the actual scheduled outage period, the Company underestimated the replacement power costs that it would face while the SCR units were installed.

Q. Why does Staff contend that Pacific Power's gas conversion analysis contained incorrect replacement power costs?

[37] Twitchell, Exh. No. JBT-10C at 43 (Company response to Staff Data Request 90, Attachment 1).

A. The Company's gas conversion scenario assumed that the outage period for Bridger units 3 and 4 to be converted to run on gas would be in January and February of 2016 and 2017, respectively. January, while not as high as July, is generally among the top two or three next highest-demand months on the Company's system due to the WCA's electric heating-driven winter peak. Pacific Power would simply be unable to absorb a major outage in January. Modeling a unit outage in January and February would require the model to replace the lost generation using higher-cost resources within the Company's portfolio and market purchases at a time when prices in the Northwest are at their highest.

Q. Has Pacific Power explained why it modeled the gas conversions to take place in January and February?

A. Yes. In response to a data request, the Company articulated that it had two considerations when deciding when to schedule the gas conversion: allowing the unit to operate on coal until the compliance deadline (December 31 of each year), and completing the conversion work before the following summer so that the unit would be ready to meet peak needs.[38] Based on those constraints, the Company selected the January-February time frame.

Q. Do you agree with that logic?

A. Not at all. There is nothing in the Company's analysis or the response to that data request that suggests that any effort was made to identify the least-cost window for

[38] Company response to Staff Data Request 14.

conversion to take place. As explained above, the default selection to schedule the conversion to take place in January and February would, as a simple question of logic, increase the overall cost of the project. If September-November was the optimal window for an outage to install SCR, it should have also been the optimal window for an outage to convert units 3 and 4 to run on natural gas.

Q. Did Staff ask the Company to quantify the difference in power costs that resulted from this difference in modeling assumptions?

A. Yes, but the Company responded that "the costs of the replacement power cannot be isolated as the system optimizer model (SO Model) rebalances the system when resource availability changes through dispatch and market transactions on an economic basis."[39]

Q. What is your opinion of that response?

A. I think it overstates the difficulty of the request. It is true that disentangling the system impact of a single change (such as moving an outage period from the winter peak to the fall) can be a complicated exercise, but it is one that is well within the Company's abilities to perform. Pacific Power does this exercise multiple times in every IRP in its sensitivity analyses, which make one change to the model and quantify the impacts. Running a model with an outage period in one part of the year and a model with the outage period moved to another part of the year may have taken a day or two for the models to actually run, but in my opinion, it was a request

[39] Twitchell, Exh. No. JBT-15 (Company response to Staff Data Request 15).

that the Company could have reasonably met within 10 business days. As I show below, Staff was able to calculate the difference in replacement power costs without having direct access to the SO Model.

The fact that the Company overlooked this inequity when it designed the models raises questions; but the fact that it declined to investigate the issue when it was raised is troubling, in Staff's opinion.

Q. Please describe how Staff calculated its replacement power cost corrections.

A. Fortunately, the Company's analyses did provide the opportunity for the type of one-off sensitivity study explained above. As I previously explained, Pacific Power provided the SO Model outputs for both the SCR and natural gas conversion cases. In the months of January and February 2016, the only difference between the models is that Bridger 3 is operating as a coal-fired unit with SCR in one scenario, and is offline for natural gas conversion in the other. No gas conversions had been completed yet, so no variables other than Bridger 3 could be driving the different outcomes between the models in these two months.

Exhibit No. JBT-7C summarizes Staff's process for calculating replacement power costs, which total [redacted] million in the low gas case, [redacted] million in the base gas case, and [redacted] million in the high gas case.

First, Staff reviewed the monthly resource dispatch in the model outputs for each scenario in January 2016 and February 2016, compared every resource in the Company's portfolio between the two cases in each month, and identified all the differences in the gas conversion case. Generally, the model replaced Bridger unit

3's lost generation in the gas conversion case by increasing generation at natural-gas fired facilities, purchasing more energy on the spot market, and, to a much lesser extent, increasing the dispatch of coal units that still had some headroom in their capacity.

Staff multiplied the increased generation for each Company resource in each month (in MWh) by that resource's average variable cost (in dollars per MWh) that was identified by the model, then summed the increased generation and costs for each unit for each month to determine the cost of replacement power generated by Company resources.

After examining the Company's resources, Staff compared the difference in the Company's net market position (total revenue from market sales minus total costs of market purchases) between the SCR and the gas conversion cases in each month. Generally, the gas conversion case had a lower net market position due to reduced sales and increased purchases to meet load. Staff treated the reduction in net market position as a replacement power cost (the "Market Position Adjustment" row in Exhibit No. JBT-7C).

Staff's final adjustment was to account for the difference in power costs for December 2015 and December 2016. If the gas conversion had been done from September to November of each year, then the model would have had to replace Bridger's low-cost coal-fired generation in December of each year with other, higher-cost resources. Staff's calculation is based on the models' December 2016 output, which like the rest of 2016, only differed in Bridger unit 3's fuel source. As before, Staff identified the difference in dispatch of Company resources and in the

Company's net market position between the two models in this month and applied the difference as an offset to the January 2016 replacement power costs. As Exhibit No. JBT-7C shows in the "December Adjustment" row for each case, this adjustment fully offsets the replacement power costs for January in the base gas and low gas cases, and mostly offsets January's replacement power costs in the high gas case.

Q. Did Staff follow the same process for calculating the 2017 replacement power costs for Bridger Unit 4?

A. No. In January and February 2017, the model was dealing with two changes. The gas scenario not only had taken Bridger Unit 4 down for conversion, but it was also modeling Bridger Unit 3 as a gas-fired resource. Determining the cost of replacement power in these months would require an additional adjustment to account for the impact of Bridger Unit 3 operating as a gas resource. Without access to the SO Model, there was simply no way for Staff to isolate the effects of the two changes.

Staff's correction therefore assumes that the model would respond to the loss of Bridger Unit 4 in January and February of 2017 in much the same way that it responded to the loss of Bridger Unit 3 during the same months of the previous year. Staff projected 2017's replacement power cost correction by using the 2016 replacement power costs that had been calculated for each case, reducing them by 0.7 percent to reflect Bridger 4's slightly lower modeled available capacity factor, and discounting them by one year.

Q. Why is Staff's replacement power cost adjustment reasonable?

A. Because it is rooted in a simple counterfactual analysis – the only difference between the models in January and February 2016 is the status of Bridger Unit 3. By comparing the differences in resource dispatch and market behavior in the two models, we have a directly observable and quantifiable demonstration of the increased replacement power costs that are attributable to the Company's decision to model gas conversion in the months of January and February. And by also using the model to identify the costs associated with foregoing coal-fired generation in December of each year, this adjustment provides a full and objective accounting of the net effect of modeling the two scenarios at different times – the costs that must be removed if the alternatives are to be compared on the same grounds.

It is true that this adjustment does not accurately reflect the actual replacement power costs associated with modeling gas conversion in September-November; there would have surely been some degree of replacement power costs in those months. However, as I previously stated, the Company's decision to model the SCR outage in the low-demand months of April and May effectively removed any replacement power costs from the analysis, so removing all replacement power costs from the natural gas conversion scenario is necessary to place the options on even footing. Neither scenario models the correct replacement power costs, but with Staff's adjustment, they at least offer the same replacement power costs, which given their similar outage windows, is appropriate from a comparative standpoint.

Finally, as a check on the adjustment, Staff compared the amount of replacement generation that the adjustment identified for each month in the gas conversion model and compared it to the SCR model's dispatch of Bridger Unit 3 for that month as a check to ensure that the adjustment was accounting for all of the lost generation in the gas conversion model. This check found that, on average across the six months studied (two months in each gas price scenario), Staff's correction accounts for 99.25 percent of Bridger Unit 3's lost dispatch.

E. Summary of Staff's Model Corrections

Q. Did Staff make any other changes to Pacific Power's analysis?

A. Yes. The final adjustment was to add [redacted] million to the cost of the gas conversion case in each gas price scenario – the amount that Pacific Power would have had to pay to its EPC contractor had it decided not to issue a final notice to proceed with the SCR installation.

Q. Once Staff had calculated these three corrections, how were they incorporated into the Company's analysis?

A. Staff used Exhibit No. RTL-7C, which identified the present value revenue requirement (PVRR) associated with the SCR and gas conversion cases under low, base and high gas scenarios. Staff added a line item for each of its three corrections and applied them in each case.

Exhibit No. JBT-8C summarizes the corrections and their impact on the PVRR of the SCR and gas conversion cases. Collectively, Staff's corrections reduce the net benefit of SCR conversion that was identified in the Company's 2012 analysis from [redacted] million to [redacted] million in the high gas case and from [redacted] million to [redacted] million in the base gas case. In the low gas case, Staff's corrections increase the net benefits of gas conversion from [redacted] million to [redacted] million.

Q. Please summarize the impact of Staff's corrections on the Company's analysis.

A. All of the complexity surrounding Pacific Power's analysis of compliance options for Bridger's Regional Haze obligations and its decision to install SCR can be summarized in two fundamental questions: how cheap would natural gas have to be to make gas conversion cost effective, and how much will natural gas cost?

According to the Company's analysis, the answer to the first question is that natural gas would have to reach a levelized forward price point of [redacted] per mmBtu. That analysis, however, was based on an outdated projection of the Company's future coal costs and a modeling flaw that skewed the analysis in favor of SCR installation.

In correcting the Company's analysis for these flaws, Staff has solely relied on the Company's data. The coal cost correction is based on the 2013 Mine Plan that the Company – as a two-thirds owner of the Bridger Coal Company – had a hand in finalizing in October 2013. The replacement power cost correction is a simple counterfactual comparison using the Company's own model data. Staff's model corrections do nothing more than hold the Company accountable for crucial information that it should have included in its analysis, but chose not to.

When these corrections are applied, the answer to the first question – how cheap natural gas would have to be to make gas conversion cost effective – increases from [redacted] per mmBtu to [redacted] per mmBtu. The next section of my testimony will address the second question – how much will natural gas cost?

VII. THE SEPTEMBER 2013 OFFICIAL FORWARD PRICE CURVE

Q. Please explain the importance of natural gas price inputs to the SCR analysis.

A. As Mr. Link indicates in his testimony, there is a strong relationship between gas price inputs and the costs and benefits of SCR installation.[40] Using the regression analysis discussed above, with Staff's corrections applied, Staff was able to quantify that a change in the levelized forward price of natural gas of just one cent will swing the model's predicted outcome by about [redacted] million.

Q. Please summarize Staff's natural gas correction.

A. Inasmuch as the Company did a final check on its SCR analysis, it was based on the September 2013 OFPC, an internally generated forecast of natural gas prices at various hubs, including the Opal hub near the Bridger plant. This is the information that the Company compared to its projected break-even price for natural gas in determining whether to issue the final notice to proceed.

The September 2013 OFPC, however, is an unreasonably high projection of forward natural gas prices that created an insurmountable obstacle for the gas conversion scenario. I will demonstrate that the September 2013 OFPC was significantly higher than any projection that the Company received from consultants

[40] Link, Exh. No. RTL-1CT 19:1-13.

or the projections in use by other regional utilities at the time. Had Pacific Power used an average of the reasonable projections in its possession, it would have identified natural gas conversion as the most cost-effective alternative, even without the model corrections discussed in the previous section.

Staff's natural gas correction replaces the September 2013 OFPC with a more reasonable projection that was calculated by averaging three diverse projections provided to the Company by consultants prior to the formulation of the September 2013 OFPC. When this correction is made in addition to Staff's other model corrections discussed above, the base natural gas model identifies [redacted] million in net benefits for natural gas conversion.

Q. What was the September 2013 OFPC's levelized forward price for natural gas at the Opal hub from 2016 to 2030?

A. [redacted] per mmBtu.

Q. How does the September 2013 OFPC compare with the projections used by other entities during the same period?

A. Staff has reviewed seven other forward natural gas curves prepared around the same time: three of these curves were provided to Pacific Power by consultants,[41] one curve was generated by the federal government, and the other three curves were in use by other utilities in the Pacific Northwest. To the best of Staff's knowledge, all of these curves were generated between the middle and end of 2013. Figure 3 below,

[41] Pacific Power's consultants were CERA, PIRA and Wood Mackenzie.

also provided in Exhibit No. JBT-9C, summarizes how the September 2013 OFPC compares to the other projections:

[redacted]

As the figure shows, the September 2013 OFPC (thick line) is at the top of the range. Although it starts out in the middle of the pack in 2016, the September 2013 OFPC forecasts a steep, sustained increase that moves it to the top of the range by 2021, where it remains for the rest of the period. Only two other curves end up in the same range by 2030, but it is important to note that those two curves forecast a gradual, stable increase from 2016 to 2030. The September 2013 OFPC, with its aggressive assumptions in the early years of the forecast, effectively maximizes the levelized price of natural gas, which makes the commodity appear significantly more expensive than in the other curves – even the ones that move in the same general direction. The levelized prices for the two curves that end up in the same range as the 2013 OFPC, for example, are [redacted] and [redacted] per mmBtu.

On a levelized basis, Pacific Power's September 2013 OFPC was well above any of the other projections. The average levelized forward price of the seven other projections is [redacted] per mmBtu, well below the Company's predicted break-even levelized price of [redacted] per mmBtu. The September 2013 OFPC's levelized price is 16 percent higher than this average.

The most relevant of these seven curves are the three consultant forecasts that Pacific Power received in August and September of 2013 and, thus, had in hand when it prepared the September 2013 OFPC. The Company indicated that it uses consultant forecast in preparing its own projections,[42] yet the September 2013 OFPC's levelized forward price from 2016 to 2030 is [redacted] per mmBtu, which is 14 percent higher than the average levelized forward price of [redacted] identified by the consultant forecasts. Furthermore, two of those consultants identified forward levelized prices that were [redacted] per mmBtu and [redacted] per mmBtu, both of which were well below the [redacted] per mmBtu point at which the Company's own analysis indicated it would be cost effective to convert Bridger units 3 and 4 to run on natural gas. A reasonable board of directors would have recognized this conspicuous red flag and reacted by revisiting the SCR analysis. Pacific Power did not.

[42] Company response to Staff Data Request 92.

Q. Why is Staff's natural gas correction based on the three consultant forecasts, rather than all seven forecasts?

A. Staff included the curves in use by the federal government and other regional utilities only to show that Pacific Power's peers were recognizing and responding to falling natural gas prices much more accurately than was Pacific Power. The Company should only be held accountable, however, for failing to act on the information that was in its possession – the information provided by the three consultants prior to the formulation of the September 2013 OFPC.

Q. Why does Staff's correction use an average of the consultant forecasts?

A. The three consultant forecasts, with levelized prices of [redacted], [redacted], and [redacted] per mmBtu, form a spread of future natural gas price projections. Using an average captures the fact that two of the forecasts are fairly closely aligned in their lower projections, while recognizing the risk component embodied in the higher projection.

As previously noted, the two lower forecasts were both below Pacific Power's stated break-even price, and the higher projection is well below the break-even price identified after Staff's model corrections are applied.

Q. What is the impact of applying the [redacted] per mmBtu average forward levelized price identified by Pacific Power's consultants to the Company's model?

A. Combined with Staff's other model corrections previously discussed, the natural gas price correction increases the net benefits of gas conversion by [redacted] million, swinging it from a net cost of [redacted] million to a net benefit of [redacted] million.

VIII. THE CALCULATION OF STAFF'S RECOMMENDED DISALLOWANCE

Q. You previously stated Staff's recommendation that $42.4 million of Pacific Power's requested adjustment for expenditures on SCR and major maintenance projects at Bridger be disallowed. How did Staff determine that figure?

A. Staff's recommended disallowance has two components: the incremental capital cost of the SCR systems and the capital cost of other maintenance projects that would have been avoided in the gas conversion scenario.[43]

Staff's recommended SCR disallowance is [redacted]. This amount was calculated by subtracting the gas conversion scenario's total-company capital costs of [redacted][44] from Pacific Power's requested total-company SCR adjustment of [redacted],[45] then multiplying by the WCA conversion factor in this case of 22.437%. The remaining [redacted] corresponds to the capital costs identified for the other, avoidable maintenance projects on a WCA basis.[46] Table 1 summarizes the calculation of Staff's recommended disallowance:

[43] Twitchell, Exh. No. JBT-16 (Company response to Staff Data Request 7).
[44] Twitchell, Exh. No. JBT-17C (Company response to Staff Data Request 162).
[45] McCoy, Exh. No. SEM-5C.
[46] *Id.*

Table 1: Staff's Disallowance Calculation

	Bridger 3 (Total Company)	Bridger 4 (Total Company)	WCA
Requested			
[redacted]	[redacted]	[redacted]	[redacted]
Total	$ 127,544,646	$ 143,656,688	$ 60,849,455
NG Capital Costs	[redacted]	[redacted]	[redacted]
Disallowance			
[redacted]	[redacted]	[redacted]	[redacted]
Total Disallowed	**$ 83,870,568**	**$ 105,105,651**	**$ 42,400,594**
Staff's Adjustment	**$ 43,674,078**	**$ 38,551,037**	**$ 18,448,849**

IX. OTHER MATTERS FOR CONSIDERATION

Q. Please summarize the other matters related to the Company's Bridger SCR analysis that you would like the Commission to consider.

A. The Company's analysis of Bridger SCR raises two broader questions: how the decision to install SCR interacts with the Company's request for accelerated depreciation, and whether the Company should have modeled the long-term impacts of converting all four units of the Bridger plant to run on natural gas.

Q. Do these matters factor into Staff's recommended disallowance?

A. No. Staff's case for a disallowance is based on known and measurable costs that the Company failed to consider in its SCR analysis. These issues do not rise to the level of requiring a model correction or supporting a disallowance, but Staff feels that they nevertheless require the Commission's consideration.

Q. Please explain how the installation of SCR at Bridger interacts with the Company's request for accelerated depreciation.

A. As Mr. Link explained in his testimony, the tradeoffs generally involved with SCR installation relative to natural gas conversion are significantly higher initial capital costs and lower ongoing fuel costs, which reduce annual power costs.[47] The implicit assumption supporting SCR installation, then, is that the retrofitted unit will continue to operate for an extended period – long enough for those annual power cost savings to offset the initial capital expenditure.

The Commission touched on this matter with the Company at the recessed open meeting at which Pacific Power presented its 2013 IRP. While the 2013 IRP identified SCR as the most cost effective option for meeting Regional Haze obligations at Bridger units 3 and 4, it identified natural gas conversion (rather than SCR) as the most cost-effective Regional Haze compliance option for Naughton Unit 3. In explaining this difference, Mr. Teply suggested that the decision for Naughton 3 was driven by the fact that:

> Naughton units … have a depreciable life – a currently established depreciable life – of 2029. EPA, in their 2013 action, came out and required SCR to be installed on those facilities here basically by 2018, obviously only leaving, then, 11 years to pay back an SCR on a relatively small unit.[48]

[47] Link, Exh. No. RTL-1CT 13:10–14:8.
[48] Recording of the Commission's October 3, 2013, Recessed Open Meeting at 45:55. This recording was filed as a work paper.

The Company has not conducted any analysis of how its request for accelerated depreciation would affect the economics of SCR at Bridger units 3 and 4.[49] Intuitively, and based on the explanations above, accelerating the depreciation of a unit with SCR weakens the economic factors that supported SCR installation – each year, the benefits of reduced power costs would be offset to some degree by the higher depreciation expense, and those diminished power cost benefits accrue for fewer years. Logically, if Naughton Unit 3 could not have broken even with SCR installation in 11 years, then Bridger Unit 3 would likely not break even in 10 years, and it is even more likely that Bridger Unit 4, with its higher SCR costs, would not break even in 9 years.

Staff recognizes that the Company's decision to seek accelerated depreciation of the Bridger plant was made some time after the decision to install SCR, and is therefore not advocating that the prudence of the SCR be evaluated through the lens of accelerated depreciation. But there is an inherent conflict in the Company's case in that it requests a prudence determination for SCR at Bridger on one hand, while on the other hand asking for a ratemaking treatment of the Bridger plant that, in Staff's opinion, would have certainly rendered the SCR uneconomic, even in the Company's model.

Q. Please explain what long-term impacts the Company likely would have identified had it modeled gas conversion for all four units of Bridger.

[49] Company response to Public Counsel Data Request 16.

A. Staff sees two likely benefits that could have been realized by converting all four units to natural gas. The first is that the cost of converting units 1 and 2 would have been lower because the infrastructure to deliver natural gas to the plant would have already been in place.

The second impact deals with future expenses at the Bridger mine. Exhibit No. RTL-5C identifies [redacted].

Pacific Power's modeling of future coal costs only considered two futures: one in which all four Bridger units are fueled by coal, and one in which two units remain fueled by coal. Logically, the Company's future coal expenses were lower under a two-unit scenario than a four-unit scenario; a scenario in which all four units are converted to natural gas would have likely identified additional avoided costs that would have further improved the overall cost effectiveness of natural gas conversion.

Staff understands the Company's decision to model the compliance obligations for units 3 and 4 separately from the compliance obligations for units 1 and 2, given the six-year span between them. But since the compliance obligations for all four units were known at the time, there is an argument to be made that the

Company should have studied the economic impacts of converting all four units to natural gas.

X. SCR PROCEEDINGS IN OTHER STATES

Q. Has Pacific Power presented its SCR analyses in proceedings in other states?

A. Yes. The Company used the 2011 analysis and the 2012 analysis in proceedings in Wyoming and Utah. In 2012, the Company used the earlier analysis in support of an application for a Certificate of Public Convenience and Necessity (CPCN) to install the SCR systems on Bridger units 3 and 4. Wyoming law requires utilities to acquire a CPCN from the Wyoming Public Utilities Commission (Wyoming PUC) prior to beginning "construction of a line, plant or system, or of any extension of a line, plant or system."[50]

Also in 2012, the Company used the earlier analysis in a voluntary application for pre-approval of the Bridger SCR project in Utah. Utah law allows utilities to voluntarily apply with the Utah Public Service Commission (Utah PSC) for pre-approval of a major resource acquisition prior to acquiring the resource.[51] If the Utah PSC grants an order to proceed, the resource is determined to be prudent and included in rates in the Company's next rate case up to the cost approved in the pre-approval order; any cost increases are subject to a prudence review in the rate

[50] WY Stat. § 37-2-205(a).
[51] Utah Code § 54-17-402.

case.[52] During the course of that proceeding, the Company updated its initial analysis with 2012 data at the request of other parties.

In 2015, the Company filed a general rate case in Wyoming that included a request for a prudence determination on the Bridger SCR and to include the project in rates.

Q. What were the outcomes of the Company's filings in Wyoming?

A. The Company submitted its CPCN application on August 7, 2012; the Wyoming PUC granted it on May 30, 2013.[53] In its order approving the CPCN, the Wyoming PUC explicitly stated that it was not making a prudence determination at that time, and that prudence would be determined at the time that the Company sought to include the Bridger SCR in rates.[54] However, a coalition of parties that included the Wyoming Office of Consumer Advocates and Wyoming Industrial Energy Consumers had previously agreed that in exchange for a more detailed review of the project than would normally be conducted in a CPCN proceeding, they would not contest its prudence in a subsequent rate case unless the project went over budget or was mismanaged.[55]

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[52] Utah Code § 54-17-403.
[53] *In the Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4 Located Near Point of Rocks, Wyoming*, Wyoming PUC Docket 20000-418-EA-12, Order Granting Application for a Certificate of Public Convenience (May 30, 2013).
[54] *Id.* at ¶ 31.
[55] *In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Retail Electric Service Rates in Wyoming, of $97.9 Million per Annum or an Average Overall Increase of 17.3 Percent*, Wyoming PSC Docket 20000-384-ER-10, Stipulation and Agreement, 11 (Sept. 22, 2011).

In the 2015 Wyoming Rate Case, there were only two parties, Wyoming PUC staff and the North Laramie Range Alliance, that were not party to the CPCN agreement. Based on Staff's review of that case, it appears that neither of those parties contested the prudence of the SCR investments, and the Wyoming PSC determined that the SCR projects for Bridger units 3 and 4 were both prudent and granted the Company's requested adjustment.[56]

Q. What was the outcome of the Company's filing in Utah?

A. The Company filed its application for pre-approval with the Utah PSC on August 24, 2012, and the Utah PSC issued an order to proceed on May 10, 2013. Three of the four parties that intervened in the docket and took a position opposed the request.[57] The Division of Public Utilities, which is the equivalent of Staff in Utah, initially opposed the request, but expressed conditional support after the Company updated the initial analysis with 2012 data. Ultimately, the Utah PSC granted the Company's request, but cautioned in its order that "the approval of resource decision projected costs in this Order is conditioned on the Company acting prudently when responding to potential new information and changed conditions."[58]

[56] *In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent*, Wyoming PSC Docket 20000-469-ER-15, Order, ¶ 73 (Dec. 30, 2015).
[57] *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4*, Docket 12-035-92, Report and Order, 16-21 (May 10, 2013) (The Office of Consumer Services, Sierra Club, and Western Resource Advocates all recommended that the Utah Public Service Commission not grant the Company's request.).
[58] *Id.* at 34.

Q. Have the Bridger SCR investments been reviewed within the context of a rate case in Utah?

A. Based on my review of the record in the Company's one subsequent rate case in Utah after the SCR pre-approval, it does not appear so.

Q. Should the fact that other states have found the SCR installation to be prudent factor into the Commission's decision in this case?

A. No. If anything, the decisions made by the Wyoming and Utah commissions should only serve to reinforce this Commission's practices of not granting pre-approval for resource acquisitions and not using future test years in rate proceedings. By granting the Company carte blanche authorization to build the SCR, despite the 2012 analysis showing that falling gas prices were rapidly eroding the benefits initially identified for the SCR project, those commissions created a perverse incentive for Pacific Power to ignore a rapidly changing market and unfairly shift all risk associated with Bridger's Regional Haze compliance onto ratepayers. Pacific Power has embraced that perverse incentive.

The Commission should not allow the questionable policies of other states and commissions to be used to justify an imprudent decision that, if authorized, would unfairly increase Pacific Power's revenue requirement for Washington ratepayers by millions of dollars.

XI. THE COMPANY'S WEST CONTROL AREA ANALYSIS

Q. What is the West Control Area?

A. The WCA refers to the methodology the Commission adopted in Docket UE-061546 to allocate costs of the Company's multi-state system to Washington ratepayers. Based on RCW 80.04.250, the WCA includes only the resources that are used and useful in providing service to Washington ratepayers. Due to transmission constraints that exist between the Company's east and west balancing areas, the WCA has generally been defined as the resources that are located with the Company's west balancing area: those resources located in Washington, Oregon, and California; as well as the Bridger plant and the Colstrip plant in Montana.[59] For a resource to be included in Washington rates, the Commission has clearly established "that the Company must demonstrate tangible and quantifiable benefits to Washington of resources in the system."[60]

Q. What is your opinion of the Company's analysis of Regional Haze compliance options for Bridger on a WCA basis, as presented on pages 14-18 of Mr. Link's testimony?

A. The analysis is fundamentally flawed and should not be considered by the Commission as a reasonable estimate of the impacts on Washington ratepayers.

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[59] Qualifying resources purchased pursuant to the Public Utilities Regulatory Policy Act are situs assigned under the WCA.

[60] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-050684, Order 04, ¶ 68 (Apr. 17, 2006).

Q. Please elaborate.

A. The Company's analysis essentially models the WCA as an electrical island – one that can only rely on resources within its own balancing area and cannot transact with other balancing areas, including the east control area.[61] Similarly, it can only transact with market hubs physically located in the WCA.

These are unreasonable assumptions based on a misconstrued perception of the WCA. The WCA does not prescribe that the Company operate its system in a different manner; it is a principled approach to cost allocation based on observed data of how the Company's system actually operates. It does not constrain the Company to serve western customers with a particular set of resources, but it does assign costs to Washington ratepayers only for resources that have been shown to serve them in a meaningful way. The Company's WCA analysis twists this principle into an unreasonable constraint that exaggerates the impacts of SCR installation on the WCA and should therefore not be accorded any weight.

Furthermore, the analysis assumes benefit flows from the east that have never been proved. For example, Mr. Link asserts that one reason the analysis shows increased benefits for the WCA relative to the rest of the system is that in the gas conversion case, the WCA would have less surplus generation from east-side resources to make wholesale sales.[62] The Company provides no evidence for its implicit claim that the WCA receives benefits from surplus generation on the east side. Based on the transmission constraint between the balancing areas and on the Commission's previous orders, there is no reason for the Commission to accept the

[61] Link, Exh. No. RTL-1CT 16:18-20.
[62] *Id.* at 16:21-22.

claim here that east-side resources are benefitting the WCA. Were that the case, Pacific Power surely would have attempted by now to use those benefits as justification for including east-side resources in Washington rates.

Finally, the work papers supporting Mr. Link's testimony demonstrate that the Company did not actually model how it would dispatch its system on a WCA basis – which would be a necessary component of a counterfactual analysis that attempts to identify the benefits of system integration. The work papers show that in the gas conversion case, the model dispatched the converted units only in June, July, and August of each year – when they would be needed to meet east-side peak demand. Had the model actually been done on a WCA basis, those units would have been dispatched very differently.

In conducting its WCA analysis, the Company simply took the system model and tried to draw a box around the WCA. By failing to model how the Bridger plant would be dispatched on a WCA basis, the Company's WCA analysis effectively dispatches resources to an east-side load profile and assigns the resulting costs to the WCA.

For those reasons, the Company's WCA analysis should not be viewed as a reasonable representation of the impacts of SCR installation on Washington ratepayers.

XII. SUMMARY

Q. Please summarize your testimony.

A. The Commission's prudence standard is rooted in a single key concept: would a reasonable board of directors have approved a particular project, given what they knew, or reasonably should have known, at the time?

In this case, the answer is a resounding no. A reasonable board of directors would have taken pause when presented with the rapidly eroding economics between the 2011 and 2012 analyses. Even if that reasonable board chose to enter into the EPC contract at that time, it would have done so cautiously, availing itself of the flexibility that had been built into the contract to evaluate whether those trends that were reducing the value of the SCR continued. That reasonable board would have stopped and re-evaluated the matter when it saw its coal prices for the Bridger plant dramatically increase weeks before the deadline for the final decision on the EPC contract and two consultants identified forward levelized natural gas prices that were well below the Company's stated break-even target for gas conversion. That reasonable board would have probed the internal analysis and likely identified the deficiencies associated with Pacific Power's unreasonably high September 2013 OFPC and the outage timing of the two scenarios that skewed the analysis in favor of SCR. And finally, even if this reasonable board somehow failed to do any of these things, it most certainly would not have ignored a direct request from the Commission to re-evaluate its course.

From the time that the Company first analyzed its compliance options for Bridger in August 2012 and selected the SCR scenario, until the time that it issued the final notice to proceed with the SCR installation in December 2013, every observable trend in the energy industry was working against that initial decision to install SCR. Gas prices were falling, coal prices were rising, and the promise of carbon regulation had become a certainty. Yet the Company chose to ignore all of these trends and forge ahead with its preferred decision, which had significantly higher capital costs that exposed ratepayers to undue risk while holding out the promise of a sizeable return on investment for the Company.

The internally generated September 2013 OFPC, which was the final check to which the Company's SCR project was subjected, was clearly designed to reinforce the Company's decision, despite mounting, contradictory information that was reliable and readily available.

Despite Pacific Power's insistence that certain costs were already included in its analysis or could not be quantified, Staff has been able to use the Company's own data to identify what the Company should have updated and what the impact of those updates would have been. This was accomplished in an accelerated time frame without access to the Company's internal models and with limited prior understanding of the models' inner workings.

Since being presented with the need for reducing NOx emissions at Bridger, Pacific Power has pursued SCR with single-minded intent. The Company willingly did updates of its analysis while the data supported its preferred outcome, but those updates ceased once the data began to place that outcome in doubt. Pacific Power willfully ignored fundamental changes in the natural gas and coal markets that Staff has clearly shown would have changed the outcome of the Company's analysis had they been appropriately addressed. These decisions resulted in key modeling inputs that skewed the outcome in favor of SCR.

That the Company failed to account for these changes in its model and exercise the flexibility built into the EPC contract to change course, in the face of increased coal costs at the Bridger mine, in the face of identified modeling errors, and in the face of credible information that its natural gas projections were way off, is indefensible.

Pacific Power's failure to prudently approach the matter of Regional Haze compliance at Bridger units 3 and 4 resulted in the Company spending millions more than it had to. It deprived ratepayers of the opportunity to make a cost-effective transition away from coal and its mounting risks at a time when carbon regulations were becoming a certainty.

Pacific Power's Washington customers must not be held accountable for the Company's imprudent actions. Their costs for keeping the Bridger plant operational should only be based on the actions that would have been taken had the Company acted prudently – the cost of converting Bridger units 3 and 4 to run on natural gas.

Granting the Company full recovery of its SCR investments at Bridger would be a dangerous precedent. The Commission should not allow a utility to make multi-million dollar decisions on the basis of faulty analysis, ignore Commission requests, and then profit from the results. This will not be the last time that a Washington utility is faced with major retrofit decisions at a coal plant. Fully granting the

Company's requested adjustment for Bridger SCR would send a tacit message to utilities that the bar for evaluating continued investment in coal facilities will be set low, at a time when climate change, forthcoming environmental regulations, and public sentiment dictate that the bar be higher than ever.

Staff therefore respectfully recommends that the Commission disallow $42.4 million of the Company's requested $60.8 million in adjustments for SCR and related equipment at the Bridger plant.

Q. Does this conclude your testimony?

A. Yes.