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August 22, 2016

VIA ELECTRONIC FILING
AND COURIER DELIVERY

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

Attn: Filing Center

Re: UE 307 – PacifiCorp Surrebuttal Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Surrebuttal Testimony and Exhibits of Brian S. Dickman, Kelcey A. Brown, Dana M. Ralston and R. Bryce Dalley. Included with this filing is a CD containing the electronic workpapers.

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
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Please direct informal correspondence and questions regarding this filing to Natasha Siores at (503) 813-6583.

Confidential material in support of this filing has been provided to parties under the protective order in this docket (Order No.16-128). Highly confidential material in support of this filing has been provided to parties under the modified protective order in this docket (Order No. 16-231).

Sincerely,

R.B.Dalley

R. Bryce Dalley
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

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

UE 307

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Dated this 22nd day of August 2016.

Jennifer Angell

Jennifer Angell
Supervisor, Regulatory Operations

REDACTED
Docket No. UE 307
Exhibit PAC/800
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Brian S. Dickman

August 2016

SURREBUTTAL TESTIMONY OF BRIAN S. DICKMAN

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ATTACHED EXHIBITS

Q. Are you the same Brian S. Dickman who previously submitted direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to various net power cost-related issues raised in the rebuttal testimony of Public Utility Commission of Oregon Staff (Staff) witnesses Mr. John Crider and Mr. Lance Kaufman, the Citizens' Utility Board of Oregon (CUB) witness Ms. Jamie McGovern, the Industrial Customers of Northwest Utilities (ICNU) witness Mr. Bradley G. Mullins, and Noble Americas Energy Solutions LLC (Noble Solutions) witness Mr. Kevin Higgins.

Q. Please identify the other witnesses providing surrebuttal testimony supporting the 2017 transition adjustment mechanism (TAM).

A. There are three other witnesses providing surrebuttal testimony in support of the Company's 2017 TAM filing: Ms. Kelcey A. Brown, Mr. Dana M. Ralston, and Mr. R. Bryce Dalley.

Q. Has the Company changed its net power cost (NPC) recommendation in its surrebuttal testimony?

A. No. The Company's Reply Update filed August 1, 2016, reflects the most current determination of 2017 NPC and sets a reasonable and realistic NPC baseline for 2017. Consistent with the TAM Guidelines, the Company will provide a Final Update in November 2016.

Q. Please summarize the issues raised in the parties' rebuttal testimony to which you respond.

A. My surrebuttal testimony supports the Company's modeling of benefits resulting from the Company's participation in the Energy Imbalance Market (EIM) with the California Independent System Operator (CAISO), system balancing transactions, coal plant dispatch, and qualifying facilities (QF) contracts. I also address Noble Solution's testimony related to transition adjustments and the calculation of the consumer opt-out charge for customers electing the Company's five-year direct access program. References to NPC throughout my surrebuttal testimony reflect Oregon-allocated amounts unless otherwise noted and with the exception of EIM benefits which are generally referred to in total-company dollars.

Several of the modeling refinements that are in dispute in this case were just approved by the Commission in the 2016 TAM, docket UE 296, based on the Commission's conclusion that the refinements resulted in a more accurate NPC forecast.[1] Despite having additional time to study and review the refinements approved last year, and despite having the opportunity to submit two rounds of testimony in this case, the parties have not presented any new or compelling evidence or argument justifying a reversal or modification of the Commission's decision in docket UE 296.

In my testimony, I respond to five major issues. First, Staff and CUB continue to incorrectly argue that the Company's forecast of EIM benefits is too low:

[1] *See e.g.*, Order No. 15-394 at 4.

- Relying on benefit calculations performed by CAISO, both argue that the Company is receiving substantial intra-regional benefits that are not reflected in the NPC forecast. But their position is based on a fundamental misunderstanding of how CAISO calculates EIM benefits and ignores the undisputed fact that the Company's 2015 NPC forecast was substantially less than actuals, refuting the claim of missing EIM benefits. In fact, the intra-regional benefits are built into the NPC forecast through the Generation and Regulation Initiative Decision Tools model's (GRID) perfectly optimized dispatch.

- Staff also increased the amount of its adjustment by including an increase to the inter-regional benefits based on what Staff believes to be the production costs of units supporting transfers to CAISO. But Staff has acknowledged that its calculation has numerous errors. Correcting just those errors reduces Staff's proposed inter-regional benefits by more than 50 percent and produces a benefits forecast that is actually *less* than the Company's.

- CUB continues to claim that the Company has discounted the projected EIM benefits by a transmission utilization discount and an opportunity cost offset. CUB's own testimony, however, demonstrates that the Company reasonably and correctly accounts for transmission constraints when forecasting EIM benefits. And CUB has still failed to produce evidence verifying its claim that the Company improperly discounts EIM benefits based on opportunity cost.

Second, Staff, CUB, and ICNU ask the Commission to reverse its decision in the 2016 TAM and eliminate the system balancing transactions adjustment. But none of the parties present any compelling new evidence or argument justifying a reversal:

- Staff and CUB each recommend that the Commission reject the Company's system balancing transactions adjustment on the basis that it should be replaced by a more refined modeling approach, although neither proposed such an approach, and neither demonstrated that the Company's NPC forecast is more accurate without the system balancing transactions adjustment.

- ICNU reiterates its belief that the system balancing transaction costs overlap the inter-hour integration costs included in the NPC forecast. In fact, there is no overlap and the presence of inter-

> hour integration costs in the NPC forecast is no basis to reject or modify the system balancing transactions adjustment.

Third, Staff argues that the NPC forecast should ignore the costs resulting from minimum take coal supply agreements, even though Staff does not claim the contracts are imprudent. Staff does not refute that the Company's modeling of coal plant dispatch has not changed, but now simply argues that it was unaware of how this modeling occurred until this case. But that is no basis to disallow real costs that have not been found imprudent or unreasonable. CUB's rebuttal arguments in support of a disallowance of the minimum take impacts of post-2015 contracts completely ignore the counter-arguments raised in the Company's reply testimony.

Fourth, CUB still asserts that not all QF contracts should be included in the TAM forecast, despite the Company's obligation to purchase the output from these facilities. CUB's proposal changed from excluding all QFs not online by the time of the final TAM update in November, to reducing the forecasted QF energy by a discount factor to account for the failure of QFs to reach commercial operation. Staff agrees that the current modeling works, but nonetheless recommends that the Company reduce the QF capacity included in the TAM forecast by a discount factor. Neither Staff nor CUB calculate their proposed discount factors or present any evidence showing that the application of their discount factors will result in more accurate QF modeling. Given Staff's agreement that the existing modeling works, there is no basis to adopt an unproven change.

Fifth, Noble Solutions claims that the Company should recognize some value for freed-up renewable energy certificates (REC) related to direct access customers, and that the consumer opt-out charge be reduced. The Commission has previously rejected both arguments and there is no basis for a different result here. Adoption of either proposal would cause unwarranted cost-shifting, in contradiction of well-established Commission policy and Oregon law.

Q. Do you have a general response to the parties' recommended adjustments to the Company's NPC forecast?

A. Yes. In some cases, parties have failed to quantify or model their adjustments, contrary to the TAM Guidelines.[2] All parties fail to consider the collective impact of their adjustments, which is to understate the NPC forecast for the test period. If all of the adjustments proposed by parties are adopted by the Commission, the Company's Reply NPC could be reduced by approximately $42 million, as demonstrated in Exhibit PAC/801. This would produce an NPC forecast of approximately $333 million for 2017, reducing NPC to a level of actual NPC not seen since 2011. Given the significant reduction in wholesale sales revenues that has occurred since 2011 and taking into account other NPC-related cost increases over the last five years, this result is unreasonable on its face.

The parties also largely ignore the Company's persistent under-recovery of NPC, up to and including 2015. CUB goes so far as to claim that the TAM process is biased in favor of the Company,[3] but never disputes that the Company's

[2] *In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism*, Docket UE 199, Order No. 09-274, Appendix A at 18 (July 16, 2009) (requiring parties to produce modeling results and workpapers that show, on an individual adjustment basis, the impact of the adjustment on NPC).
[3] CUB/200, McGovern/2.

NPC forecast has been substantially less than its actual costs since at least 2008. The Commission has directed the Company to continue to refine its NPC forecasting to produce a more accurate forecast.[4] Staff has also urged PacifiCorp to "work on developing improved" NPC forecasting to address the risk of NPC under-collection.[5] In response, the Company has proposed improvements to the NPC forecast in an effort to eliminate the inherent tendency of the perfectly optimized GRID model to under-forecast actual costs.

Q. Staff claims the Company has not provided a direct link between the forecast improvements, such as the adjustment for system balancing transactions, and the past under-recovery of NPC.[6] How do you respond?

A. The Company's NPC are the result of a complex interaction of many moving pieces required to balance load and resources across a widely dispersed customer base. Utilizing a production cost model such as GRID is essential to accurately reflect the operation of the Company's system, and to value the energy freed up by customers electing to participate in direct access programs. While the GRID model is configured to reflect the operating characteristics and constraints of the Company's system, because it is a computerized model with deterministic inputs it is able to perfectly optimize the system in a way that has not been achieved in actual operations. To the extent there are inefficiencies or costs incurred in the

[4] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012).
[5] *Re Portland General Electric Company and PacifiCorp Request for Generic Power Cost Adjustment Mechanism Investigation*, Docket No. UM 1662, Staff's Prehearing Brief at 8 (Sept. 16, 2015); *see also* Docket No. UM 1662, Staff/100, Crider/5 ("A persistent under-collection, if it exists, could be caused by a persistent difference between forecasted energy generation and actual energy generation. Instead of correcting for this difference by utilizing and external recovery process as proposed by Joint Utilities, Staff recommends further refinement of the forecast such that the forecast error—and the associated costs of the error—is reduced.").
[6] Staff/400, Kaufman/33-34.

real world that are not naturally represented in the GRID model, adjustments must be made to the forecast in order to achieve a reasonable overall result for the test period. The costs related to system balancing transactions are just one example of this type of adjustment.

In the 2016 TAM, the Commission adopted the Company's modeling improvements, while encouraging parties to continue to understand and refine the NPC modeling. But parties to this case ask the Commission to roll-back various improvements made last year without providing any evidence that the NPC forecast is more accurate without the refinements. Importantly, the forecast improvements approved in the 2016 TAM have helped close the under-recovery gap. For the period January through June 2016 total-company actual NPC is $24.84/megawatt-hour (MWh), while the 2016 TAM predicted $25.05/MWh for the same period, a difference of only 0.8 percent. Adopting the parties' recommendations in this case will remove known costs from the NPC forecast and revert the Company's modeling to a less accurate forecast and continue the one-sided under-recovery of actual NPC.

Q. CUB argues the Company has not been forthcoming with information or support in this TAM filing, and even accuses the Company of intentionally misrepresenting facts.[7] How do you respond?

A. CUB's accusations are unfounded. As I described in my reply testimony, throughout this process the Company has worked diligently with the parties to provide a transparent process and ensure that the Commission's decision ultimately rests on a well-developed and accurate record.

[7] CUB/200, McGovern/3.

CUB claims that the Company held workshops with Staff to facilitate Staff's use of GRID, without inviting CUB.[8] In fact, Staff requested Company support to ensure their GRID access was functional and to provide training on how to use the model. CUB has had credentials to access GRID for many years. The Company separately worked with CUB to ensure that its witness had functional GRID access, in part because CUB had not attempted to use the model in this case. On June 8, 2016, the Company reached out to CUB via e-mail to confirm that CUB had been provided with GRID access, including the 2017 TAM filing, and offering to assist in ensuring the functionality of the access. After the June 20, 2016, tour of the PacifiCorp trade floor, the Company met individually with CUB to discuss GRID access, training, and potential model scenarios that CUB wanted produced. During that discussion, CUB requested that the Company work with CUB and produce several modeling scenarios related to the exploration of the system balancing transactions adjustments. The Company agreed to perform these GRID runs, which were provided on June 29, 2016.[9] The Company also held several phone calls with CUB to discuss the results of these scenarios and to assist with CUB's understanding of the Company's testimony. CUB's testimony omits a full description of the Company's efforts to support CUB's review of its filing.

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[8] CUB/200, McGovern/8.
[9] Three GRID studies were provided in the Company's 1st Supplemental Response to CUB Data Request 30.

Q. CUB is also critical of the Company for not scheduling a Commissioner workshop during the pendency of this case, instead recommending a workshop after the final order is issued.[10] Is this a reasonable criticism?

A. No. In Order No. 15-394, Commissioner Bloom requested a Commissioner workshop after the parties had time to work together to understand the modeling changes approved in last year's TAM.[11] The Company has acted reasonably in assuming that this workshop would be convened after the Commission had reviewed the parties' positions on the modeling changes in this case. The Company would have supported an earlier workshop if CUB or any other party had made such a request, and is still open to this option.

SURREBUTTAL TESTIMONY

EIM Benefits – General

Q. Did Staff update its recommendation regarding EIM benefits in its rebuttal testimony?

A. Yes. In its opening testimony, Staff recommended two adjustments to increase the EIM benefits forecast for 2017. First, Staff proposed an adjustment to impute intra-regional dispatch benefits equal to the total benefits reported by CAISO less the inter-regional dispatch benefits calculated by the Company.[12]

Second, Staff proposed an adjustment to recalculate the inter-regional dispatch benefits, purportedly to calculate the benefits using the average annual

[10] CUB/200, McGovern/8.
[11] Order No. 15-394 at 14.
[12] Staff/100, Crider/22.

production costs for each resource in the TAM, rather than the EIM bids.[13] In its opening testimony, Staff calculated intra-regional dispatch benefits of $12.3 million (total-company), but did not quantify the impact of its proposal on inter-regional benefits.[14]

Q. How did Staff's recommendations change in rebuttal testimony?

A. Staff continues to recommend the same adjustment for intra-regional and inter-regional dispatch benefits. But Staff has now quantified its inter-regional dispatch benefit adjustment as a decrease to total-company NPC of [redacted].[15] In total, Staff's proposed EIM adjustments are now [redacted], or more than 350 percent of the amount Staff originally quantified.[16]

Q. Did Staff's rationale for the two EIM adjustments change?

A. Not exactly. Staff continues to claim that intra-regional dispatch benefits are not included in the Company's NPC modeling because it believes the CAISO counterfactual used to compute total EIM benefits is a complete security constrained economic dispatch (SCED) solution equivalent to the GRID dispatch. Thus, Staff argues that CAISO's benefits calculation includes an intra-regional benefit that the Company omits from its forecast.[17]

Staff also continues to claim that the default energy bids used for resources participating in the EIM do not reflect actual production costs of the Company's generating units. But in its rebuttal testimony Staff changed how it

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13 Staff/100, Crider/21.
14 Staff/100, Crider/21-22.
15 Staff/300, Crider/15.
16 Staff/300, Crider/15.
17 Staff/300, Crider/6-7.

claimed the Company determines its bid price.[18]

Q. Does Staff provide any other new arguments?

A. Yes. Staff argues generally that the Company's "bottom-up" approach to calculating EIM benefits involves large amounts of data that make it non-transparent, difficult to audit, and fundamentally flawed and that a simplified approach to calculating the forecasted benefits would be preferred.[19] By "bottom-up" approach, Staff means that the Company's calculation of the inter-regional benefits begins with an analysis of each five-minute interval to determine which resources were dispatched in that interval and what corresponding EIM benefits were received. Because of the granularity of this approach, it necessarily relies on voluminous data.

Q. Do you agree with Staff's criticism that the Company's modeling is too complex?

A. No. The Company recognizes that evaluating EIM operation and computing the resulting benefits involves large amounts of data, which can make it cumbersome to review. However, the complexity of market operations only increases the need for a detailed and thoughtful approach to calculating the benefits for the TAM.

Q. Is it possible for the Company to determine exactly which resource is being dispatched to support EIM transfers?

A. No. Because the EIM functions as an economic dispatch of all resources within its footprint, it is impossible to know exactly which resource actually supplied the energy transmitted across BAAs. It is for precisely this reason that the Company

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[18] Staff/300, Crider/8.
[19] Staff/300, Crider/11.

utilizes the stack of PacifiCorp resources bid into EIM on a daily basis to determine, based on production costs, which resources were on the margin at the time of a transfer.

Q. Has the Commission previously approved modeling methodologies over objections that the modeling was too complex?

A. Yes. Just last year the Commission approved the Company's system balancing transactions adjustment over Staff's objection that the methodology was too complex and relied on voluminous data and complex formulas.[20] And in the 2014 TAM, Staff and CUB also urged the Commission to reject a proposal for hourly wind shaping.[21] The Commission correctly found that the benefits of the improved model outweighed concerns about complexity and refused to delay approval. The complexity of the Company's modeling is no basis for its rejection.

Q. In lieu of the Company's "bottom-up" approach, has Staff recommended an alternative to modeling EIM benefits?

A. Yes. Staff proposes to calculate the test period benefits based on the actual benefits achieved in the prior year, including savings from inter-regional exports and imports, intra-regional dispatch benefits, and flexible reserve savings.[22] Using this methodology Staff calculates 2017 EIM benefits of [redacted], which consists of [redacted] in intra-regional benefits, [redacted] in inter-regional benefits, and [redacted] in flexibility savings.[23]

[20] Docket No. UE 296, Staff's Response Brief at 4-5.
[21] Order No. 13-387 at 3-4.
[22] Staff/300, Crider/12-13.
[23] Staff/300, Crider/15.

Q. Does Staff's preferred approach resolve concerns over transparency and auditability?

A. No. Staff's proposal relies on the benefit calculations performed by CAISO. But CAISO's calculations are every bit as complex as the Company's and rely on data that is equally voluminous. In addition, the CAISO calculations are not available to the parties. If they were, reviewing and auditing the CAISO's calculations would require the same level of analysis that Staff complains is too difficult to perform in this case. Simply relying on the CAISO to set rates, which is effectively Staff's recommendation, creates less transparency and would result in the parties forgoing substantive review and auditing of the EIM.

Q. Do you have any other concerns with Staff's proposed EIM benefits?

A. Yes. Staff's overall calculation cannot be reconciled with its stated desire to rely on actual benefits achieved during a historical period. Based on its calculation of inter-regional benefits, which is the only benefit category not taken directly from CAISO, Staff's overall EIM benefit for 2017 is [redacted] percent higher than the actual 2015 benefits reported by the CAISO.[24] Indeed, Staff's inter-regional benefits *alone* are [redacted], greater than CAISO's *total* benefits. Given Staff's stated desire to rely on CAISO's calculation, these discrepancies demonstrate that Staff's calculations are seriously flawed.

Moreover, Staff's results are illogical. Staff calculates the intra-regional benefits as the difference between CAISO's total benefits ($26.2 million) and the inter-regional benefits calculated by PacifiCorp ($13.9 million).[25] But if Staff

[24] Staff/300, Crider/6 (CAISO benefits reported as $26.2 million).
[25] Staff/300, Crider/6-7.

believes that the inter-regional benefits are actually [redacted], then the difference between CAISO's total benefits and the inter-regional benefits is [redacted]. The fact that Staff's "top-down" approach results in negative intra-regional benefits indicates that it is unreliable.

Q. Did CUB's EIM adjustments change in rebuttal testimony?

A. Yes. In CUB's opening testimony it also argued that the Company should include intra-regional dispatch benefits as a reduction to the NPC calculated by GRID, and raised concerns related to a perceived discount for transmission utilization and a purported offset for opportunity costs in the EIM benefits calculation. CUB did not quantify the impact of its EIM benefits proposals in opening testimony.

In its rebuttal testimony, CUB continues to argue the Company's EIM benefits calculation is inadequate for the same reasons, but now proposes that EIM benefits included in the TAM should be equal to the actual benefits as reported by the CAISO for the most recent four quarters.[26] Although CUB does not explicitly quantify this adjustment, based on its testimony it appears to support total EIM benefits of $36.05 million (subject to the Final Update).[27]

Q. Is CUB's alternative proposal for calculating EIM benefits reasonable?

A. No. As I described in my reply testimony, CAISO's estimated benefits include intra-regional benefits, which are already built into the Company's NPC modeling (as I discuss again below). Simply relying on CAISO's benefit calculation will result in double counting this benefit.

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[26] CUB/200, McGovern/33.
[27] CUB/200, McGovern/19.

EIM Benefits – Intra-Regional Benefits

Q. Did you address Staff's proposals related to intra-regional benefits in your reply testimony?

A. Yes. In my reply testimony, I provided evidence that the CAISO counterfactual is not equivalent to a perfectly optimized GRID dispatch, but is really an exercise intended to determine how the Company would have met load imbalance using a manual process with limited flexible resources prior to the EIM's existence.[28] Because of the limited nature of the counterfactual, it would be double counting to include intra-regional benefits as a reduction to the GRID NPC.

Q. Did Staff accept the Company's explanations?

A. No. Staff still claims that the CAISO counterfactual is a fully optimized SCED model result.[29] I will respond to several points, but the remainder of the Company's surrebuttal testimony on this issue will be provided by Ms. Brown, the Company's manager of market policy and analytics.

Q. Staff claims that the Company agreed with its assertion that the CAISO counterfactual is equivalent to GRID.[30] Is this true?

A. No. The Company's position has not changed—CAISO's counterfactual is not a perfectly optimized solution because it is designed to mimic the Company's manual pre-EIM dispatch operation and only quantifies changes in resources to meet variations in load relative to the scheduled load. On the contrary, GRID is designed to model optimized dispatch with perfect foresight.

[28] PAC/400, Dickman/60-61.
[29] Staff/300, Crider/6.
[30] Staff/300, Crider/5-6.

Q. What is the basis for Staff's claim that the Company agrees that the counterfactual is equivalent to GRID?

A. Staff relies on the Company's response to CUB Data Request 72.[31] Contrary to Staff's claim, however, in that response the Company described the operation of the EIM market model (*i.e.*, the world *with* the EIM), not the counterfactual modeling (*i.e.*, the world *without* EIM). Clearly, the EIM dispatch achieves the most economic resource dispatch for PacifiCorp and other EIM participants, as described in the response to the data request.

The CAISO's counterfactual computation, on the other hand, is intended to reflect how PacifiCorp would have operated prior to the EIM, which I described in my reply testimony as a manual process performed by human operators rather than a computerized dispatch. It would not make sense for the counterfactual to be a fully optimized SCED model because the Company could not dispatch in that manner before the EIM.

Q. Similar to Staff, CUB also continues to claim that the Company is not modeling all of the intra-regional benefits resulting from the EIM.[32] Has CUB presented any additional arguments in its rebuttal testimony?

A. No. CUB now claims that the EIM's sub-hourly transactions will achieve efficiencies over-and-above GRID's optimization because GRID is an hourly

[31] As set forth on page 6 of Staff's testimony, the response states: "The CAISO security constrained economic dispatch model (SCED) is used to optimize PacifiCorp's participating generation resources relative to the combined balancing authority area (BAA) – CAISO + Nevada + PacifiCorp East (PACE) + PacifiCorp West (PACW) – load and variable energy resources for each operating hour…The CAISO real-time market optimization serves load by the most economic resource, drawn from the larger pool of resources, to most efficiently match load with supply while ensuring reliability." The full response is also attached as Staff/301.
[32] CUB/200, McGovern/22.

model.[33] The Company already rebutted this argument, which was presented by Staff in its opening testimony.[34] In sum, GRID balances the system within the hour with perfect foresight and at a single average load level. In real operations, the Company does not have perfect foresight, but with the EIM it is able to achieve efficiencies that it could not before the EIM. Thus, the EIM has allowed real operations to more accurately match GRID's perfectly optimized modeling. CUB's rebuttal testimony does not acknowledge the Company's explanation or provide any response.

Q. If the Company calculated NPC in GRID on a five-minute basis, what would be the effect?

A. The projected NPC would increase. The inter-regional benefits associated with transfers to other EIM participants have already been reflected in NPC, and any other changes across the hour would necessarily have to be met by the Company's resources. This would result in dispatch over a wider range of incremental costs, both higher and lower. When demand is higher, more expensive resources than GRID has identified will be dispatched up. When demand is lower, low-cost resources GRID was already using to generate will be backed down. The net effect of more dispatch by expensive resources and less dispatch by low-cost resources is an increase in NPC. EIM merely reduces the effect, but cannot eliminate it. GRID is thus understating costs by using a less granular representation of the Company's operations, even under EIM.

[33] CUB/200, McGovern/22.
[34] PAC/400, Dickman/62-63.

Q. Are there any other general observations regarding Staff's and CUB's intra-regional benefit adjustment?

A. Yes. Both Staff and CUB argue that there are substantial EIM benefits that the Company is receiving but that are not included in its NPC forecast. But neither party disputes that in 2015, the first full year of EIM operation, the Company's NPC forecast was over $18 million *less* than actual. While there are many reasons why NPC actuals will differ from forecasts, the substantial under-recovery in 2015 belies the notion that there are substantial EIM benefits that are being excluded from the forecast. The results for January through June 2016 discussed above provide additional support for the Company's position that the benefits of intra-regional dispatch are already included in the GRID forecast.

EIM Benefits – Inter-Regional Benefits

Q. Did you address Staff's proposals related to inter-regional benefits in your reply testimony?

A. Yes. I provided evidence that the Company's calculation of inter-regional EIM export benefits is made by subtracting the Company's production cost from the revenue received for EIM transactions. I demonstrated that using resource bids as the production costs resulted in average costs that are approximately equal to the annual production costs from the 2017 TAM.[35] I also rebutted Staff's claim that instead of using production costs to calculate benefits, the Company was actually using the Load Aggregation Point (LAP) prices.

[35] PAC/400, Dickman/72.

Q. Did Staff dispute your analysis demonstrating that the average cost of energy used to calculate the inter-regional EIM benefits was nearly the same as the production costs Staff had calculated in its opening testimony?[36]

A. No.

Q. Has Staff presented any new arguments in support of its inter-regional benefits adjustment?

A. Yes. In its opening testimony, Staff claimed that the Company relied on the LAP as the production cost used to calculate the EIM benefits. Staff agrees that the LAP is not the price the Company uses to determine the inter-regional export benefits.[37] But, Staff claims that the Company uses the Locational Marginal Price (LMP). While Staff states that their "issue remains the same regardless of the term used to describe it," the LAP is very different from the LMP, as described by Staff in its testimony.[38]

Q. Is Staff correct that the Company uses the LMP to determine the cost of resources that may have supported inter-regional transfers?

A. No. I described in my reply testimony how the Company calculates the inter-regional benefits and that description, unlike Staff's, has not changed.[39] Moreover, as I noted above, Staff did not dispute my testimony showing that the Company's calculation of production costs closely matched the values Staff calculated. Ms. Brown's testimony provides additional details regarding the resource bids used to calculate the EIM benefits.

[36] PAC/400, Dickman/72.
[37] Staff/300, Crider/8.
[38] Staff/300, Crider/8.
[39] PAC/400, Dickman/66.

Q. Is Staff's calculation of inter-regional EIM benefits reasonable?

A. No. First, as noted above, Staff calculates more inter-regional benefits ($31.2 million) than the total benefits calculated by CAISO ($26.2 million). Given Staff's insistency on the accuracy of the CAISO calculation, this alone indicates that Staff's method is flawed.

Second, Staff's simplified calculation is based on erroneous calculations and assumptions that produce an inaccurate forecast. It is also notable that despite being called a "top-down" approach, Staff's proposed method for calculating the inter-regional EIM benefits is very similar to the Company's in that it still requires calculation of the revenue received for EIM transfers and a determination of the specific units assumed to supply the transfers and the cost of such generation, as revealed in Staff's workpapers.

Q. Please describe the errors in Staff's calculation of inter-regional EIM benefits.

A. Staff's calculation of inter-regional benefits is set forth in Confidential Staff/305. In that exhibit, Staff purports to contain results from 2015 for export revenue and volume, import revenue and volume, production costs, and the resulting margin. Although Staff's testimony does not describe how the calculations in Staff/305 were performed, Staff's workpapers reveal several material errors:

- First, the dollars and volume for exports and imports are the sum total of 13 months (January 2015 through January 2016) rather than a 12-month calendar year.[40] Removing the additional month decreases Staff's calculation by [redacted].
- Second, the production costs used in Staff's calculation use volumes that are reported by CAISO as having been deemed to be transferred

[40] PAC/802 (Staff Response to PacifiCorp Data Request 47).

for greenhouse gas compliance purposes, not the actual energy transfers.[41]

- Third, the production costs are the sum total of 15 months (November 2014 through January 2016), not 12.[42]

- Fourth, the volumes underlying the export revenue and related production costs do not match. Staff's analysis includes [redacted] MWh of exports, but only [redacted] MWh of generation supplying those exports, understating the cost of production while overstating the revenue from transfers.[43] Correcting this error by applying Staff's average production cost to the additional export volumes it used to calculate EIM benefits reduces the inter-regional benefits by another [redacted].[44]

- Fifth, Staff's calculation of import benefits captures the avoided generation costs but fails to account for the cost of the imported energy. The benefits from imports are equal to the costs paid for import volumes minus the avoided cost that PacifiCorp would have incurred without the import energy.[45] Including the cost to purchase imported energy reduces Staff's benefit calculation by over [redacted].

Without changing Staff's methodology, and correcting only for the errors, reduces its calculated inter-regional benefits from [redacted] to [redacted], which is *less* than the Company's calculated inter-regional benefits of $19.2 million.

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[41] PAC/803 (Staff Response to PacifiCorp Data Request 50).
[42] Id.
[43] PAC/804 (Staff Response to PacifiCorp Data Request 48). Staff incorrectly blames the Company for its error, claiming that the error is due to "incomplete reporting by the company." But Staff's Response to PacifiCorp Data Request 50 confirmed that the error was due to Staff's use of 15 months of production data that was reported for greenhouse gas compliance purposes, not EIM energy transfers.
[44] Staff's average production cost is [redacted]. Multiplying [redacted] by the additional [redacted], produces additional production costs of [redacted]. Because production costs are subtracted from export revenue, correcting Staff's error reduces its EIM benefits calculation by [redacted]
[45] Staff/300, Crider/7.

EIM Benefits – Transmission Utilization Factor

Q. CUB continues to claim that the Company improperly reduces the inter-regional export benefits by applying a transmission utilization factor.[46] Please explain your understanding of the issue raised by CUB.

A. Exports to the CAISO from PACW are limited by the amount of transmission capacity available for use by the Company over the California-Oregon Intertie (COI). The Company's COI transmission rights may be used to make sales in the wholesale market at the California-Oregon Border (COB) or to facilitate transfers in the EIM. It cannot be used for both. Because the GRID model makes economic system balancing sales at the COB market, the available transmission in the test period for EIM depends on the projected volume of sales at COB. To calculate the test period EIM benefits of exporting over the COI, the Company first calculates the historical margin earned, expressed in dollars per megawatt-hour ($/MWh) of transmission available during the historical period, then applies this margin to the transmission available for use in the EIM in the test period. In its opening testimony, CUB argued that the Company discounted the actual benefits by the historical transmission usage factor, *i.e.*, the megawatt-hours that were exported over the line compared to the amount of transmission available for use.

Q. Did CUB clarify its disagreement with the Company in rebuttal testimony?

A. Yes. In its rebuttal testimony, CUB clarifies that it does not believe the Company discounted the historical benefits by transmission utilization, but that it applies the

[46] CUB/200, McGovern/15-16.

discount to the forecasted benefits.[47]

Q. Has CUB disputed your testimony that the EIM benefits are limited by the available transmission available on the COI, as described above and in your reply testimony?[48]

A. No.

Q. Has CUB provided any additional evidence to support this claim?

A. No. In fact, CUB provides a simplified example of how the Company accounts for transmission in its calculation of EIM benefits that actually demonstrates that the Company's methodology is sound, and CUB's concern that the Company is improperly discounting the benefits is unwarranted.

Q. Please describe CUB's example and identify its errors.

A. CUB's simplified example assumes that in the historical period the Company received $3,000 in export revenues, based on the availability of 300 MWh of transmission between PacifiCorp and CAISO and export of 150 MWh of energy transferred.[49] Thus, in this example, to support 150 MWh of exports, the Company had to make twice that amount of transmission available. In this historical period, the Company received $20 per MWh for exported energy ($3,000/150 MWh) and $10 per MWh of transmission ($3,000/150 MWh) made available for EIM transfers.

Next, CUB attempts to calculate the benefits that would be forecast in the test period using the Company's methodology, assuming 100 MWh of energy transferred between PacifiCorp and CAISO. As described in my rebuttal

[47] CUB/200, McGovern/15-16.
[48] PAC/400, Dickman/77.
[49] CUB/200, McGovern/15-16.

testimony, the first step in calculating the forecast benefits is to divide the historical export benefits by the total transmission made available for the EIM, to determine a dollar per MWh of available transmission. In this example, this calculation results in $10 per MWh of available transmission, as noted above.

In the Company's methodology, this $10 per MWh figure would then be multiplied by the transmission that will be made available to support EIM transfers during the test period. CUB's example, however, does not apply the margin to the forecast of available transmission. Instead, CUB's calculation multiplies the $10 per MWh of transmission by 100 MWh of exports, which CUB claims erroneously produces revenues of only $1,000 (rather than the $2,000 in revenues that would be expected because the forecast exports are two-thirds of the historical exports). CUB acknowledges that this final step in its calculation has "obvious problems," and I agree. The proper calculation multiplies the $10 per MWh of transmission by the forecast available transmission, not a forecast of energy exported. Indeed, the Company does not forecast the energy exported, but applies the $10 per MWh to the transmission available for EIM in the test period.

Q. Is it possible to correct CUB's example?

A. Yes. In the historical period in CUB's example, the Company achieved 1 MWh of export energy for every 2 MWh of available transmission. Assuming this relationship holds true during the test period, CUB's example would include 200 MWh of available transmission in the test period, which is double the export of 100 MWh. Multiplying $10 per MWh of available transmission by 200 MWh of available transmission results in revenue of $2,000. Thus, using the Company's methodology, the forecast revenue is exactly the amount CUB claims it should be.[50]

Q. CUB's testimony includes several screenshots of the Company's workpapers, which CUB claims prove that the Company is improperly discounting EIM benefits based on the application of a transmission utilization factor.[51] Is this correct?

A. No. In the screenshot found on page 14 of CUB's testimony, it shows that the Company calculates the export margin on a dollar-per-megawatt-hour basis by dividing the export margin (expressed in dollars) by the "Mid C to COB Transmission left open (MWh)." The transmission "left open" is calculated as the total COI transmission capacity minus hourly sales already modeled in GRID to be made at the COB market. CUB correctly explains that if the Company first calculated the dollars per MWh margin in terms of total available transmission, but then applied that margin to the MWh expected to be transferred in the future, the benefit would be understated. However, as described above, because the Company applies the dollar per MWh margin to the transmission available in the test period, no discount occurs.

Q. Does CUB provide any other support for its claim that the Company should disregard transmission limits when modeling EIM transactions?

A. Yes. CUB testifies that the Company's modeling implies it is exporting

[50] This calculation is also verified by the screen shot of the Company's calculation included on page 15 of CUB's rebuttal testimony. Cell D18 in the spreadsheet is the "EIM Export Benefit." As the highlighted equation indicates, that value is calculated by multiplying the "Total Transmission Left Available" (cell D14) by the "EIM Export Margin (per MWh Transmission)" (cell D16). CUB claims this is "clear" that the Company is multiplying cell D16 by the forecasted EIM exports. But what is "clear" is that the spreadsheet is calculating the benefits in the same way that the Company described in its testimony.
[51] CUB/200, McGovern/14-15.

transmission, not energy to the EIM.[52] This is wrong.[53] The Company does not export transmission, but we do forecast the transmission that will be available to support EIM energy transfers. Because the forecast transmission will not necessarily match the historical transmission, we calculate the benefits using a dollar-per-MWh of available transmission factor.

Q. CUB also contends that the Company treats EIM exports to CAISO differently from EIM exports to NV Energy, claiming that the Company does not model any transmission constraints for exports to NV Energy.[54] Is CUB correct?

A. Yes. The EIM transfers between PACW and CAISO across the COI are the only EIM transfers that are limited due to transmission constraints. There are no comparable restraints between PacifiCorp and NV Energy and therefore the forecast benefits do not depend on transmission availability during the test period.

Q. Has Staff taken a position on CUB's adjustment?

A. Yes. Staff supports CUB's proposal, claiming that forecasting available transmission for EIM transfers is "unnecessarily limiting and subject to error" because the Company cannot know with certainty what transmission will actually be made available during the test period.[55] This position makes little sense. If it is "unnecessarily limiting and subject to error" to forecast transmission available to support EIM transfers, it is equally "unnecessarily limiting and subject to error"

[52] CUB/200, McGovern/16.
[53] CUB testifies that "CAISO requires the Company to provide a base schedule that specifies generation *and transmission*. CUB/200, McGovern/16 (emphasis added). Base schedules specify the generation that is needed to balance load, and transmission to deliver that generation to cover any firm sales at COB that are transacted outside the EIM. Any remaining generation and transmission is then available to optimize with the EIM.
[54] CUB/200, McGovern/18.
[55] Staff/300, Crider/14.

to forecast transmission to support transactions at COB, or any other market, or transfers between PACW and PACE. All of the Company's forecasting is subject to error and forecasting available transmission to support transactions at COB and the EIM is a fundamental part of the Company's NPC modeling.

EIM Benefits – Opportunity Costs

Q. CUB continues to argue that the Company is improperly discounting EIM benefits based on an opportunity cost, claiming that the Company's statements to the contrary are misrepresentations.[56] How do you respond?

A. The Company has not misrepresented anything. As I described in my reply testimony, the Company does not discount EIM benefits to account for opportunity cost. CUB's concerns are unfounded because they are based on a misinterpretation of data and labeling in a Company workpaper. I described CUB's apparent misunderstanding of the Company's workpapers and explained the meaning of the labeling. In addition to the explanation, in an attempt to resolve the misunderstanding, I provided citations to Company responses to data requests where example calculations were provided and I provided a monthly summary of the actual generation production costs[57] used in the EIM benefit calculation to show that the costs were reasonable.

I also testified that CUB was unable to provide any verification of their claim to the contrary. In its rebuttal testimony, CUB again provides no actual evidence demonstrating that the Company accounts for opportunity cost as CUB claims.

[56] CUB/200, McGovern/17.
[57] PAC/400, Confidential Table 3.

Day-Ahead and Real-Time System Balancing Transactions

Q. CUB reiterates its claim that it is improper to use pre-EIM data to calculate the system balancing transactions adjustment because the EIM will reduce the Company's system balancing costs.[58] Is this correct?

A. No. The system balancing transactions adjustment relates to monthly, weekly, and hourly transactions. The EIM relates to sub-hourly transactions. The fact that the Company can more efficiently balance its system within the hour, does not mean that we can avoid transactions to balance the system before the hour.[59] As described by E3, the EIM "does not replace the day-ahead or hourly markets and scheduling procedures that exist today."[60] Therefore, the premise of CUB's argument is incorrect.

Q. CUB also interprets the Company's testimony to mean that the EIM has resulted in "market manipulation" because potential counterparties know that PacifiCorp is now required to submit balanced base schedules 55 minutes prior to the hour.[61] Is this a fair characterization?

A. No. There is no market manipulation, or "gaming the system," because of the EIM. First, much of the Company's purchases are done on a day-ahead basis, and the timing is no different than in the past. Second, potential counterparties for the Company's hour-ahead purchases are now required to commit earlier, and it is not market manipulation that these parties are only willing to accept the increased risk associated with doing so at a higher cost. While there may be some incremental

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[58] CUB/200, McGovern/25-26.
[59] PAC/400, Dickman/65.
[60] Staff/106, Crider/6.
[61] CUB/200, McGovern/25.

costs associated with system balancing caused by the EIM's 55-minute requirement, they are far outweighed by the overall benefits of the EIM.

Q. CUB also expresses a concern that the Company used four-years of historical data, instead of three, because the "Company has a lot of data and gets to apply it differently in each TAM as a way to maximize the adjustment."[62] Is this a fair characterization?

A. No. CUB fails to acknowledge that the use of four-years of historical data *decreases* the system balancing transactions adjustment. There was no manipulation by the Company to "maximize the adjustment." Further, contrary to CUB's implication that only the Company has access to the data, the parties have also had access to the additional historical data referenced by CUB. Indeed, the Company provided the data from 2009 through 2014 through discovery in docket UE 296 to all the parties to that case, including CUB.

Q. CUB also recommends that the Company should rely on its own production capacity and capacity factors to determine when market prices will be above or below the monthly average, instead of historical data of actual variations in market prices.[63] How do you respond?

A. As indicated in my reply testimony, the Company is willing to explore modifications and refinements to the system balancing transactions adjustment going forward. But for purposes of this TAM, CUB does not provide any evidence that the NPC forecast is more accurate without the system balancing

[62] CUB/200, McGovern/27.
[63] CUB/200, McGovern/27.

transactions adjustment, nor does CUB provide any evidence that its alternative methodology would be more accurate.

Q. ICNU claims that the historical transactions used in the system balancing transactions adjustment include transactions made to integrate load and wind on a day-ahead basis.[64] Is this correct?

A. Yes; however, the market prices used in the inter-hour integration analysis are scaled hourly prices with uniform values on each weekday of the month. As such they do not reflect the incremental price impact that is measured in the historical transaction data and that is used to adjust the cost of system balancing transactions in the TAM.

Q. Are the inter-hour integration costs for wind and load directly related to the Company's system balancing modeling, and thus a double-count as ICNU claims?

A. No. As I described in my reply testimony, the inter-hour integration costs calculated in the Company's 2014 Wind Integration Study are related to the commitment of gas plants.[65] As such, the gas plant operating costs are the most important element. When a gas plant is committed online to meet the day-ahead load and that load does not materialize in actual operations, the Company cannot turn the plant off and instead may need to back down lower cost generation such as coal. The cost differential between the gas plant and lower cost generation is part of the inter-hour integration expense and has nothing to do with market prices, as ICNU implies. To the extent the cost differential between the gas plant

[64] ICNU/200, Mullins/2-3.
[65] PacifiCorp/400, Dickman/39-40.

and market is driving the inter-hour integration costs in the analysis, as indicated above, the market prices used in the analysis did not include the incremental impacts measured in the historical system balancing data.

Q. Does the Company's measurement of variances in historical short term firm transaction costs capture all system balancing costs, *i.e.*, all costs associated with matching supply and demand for each interval?

A. No. As described above, gas plant commitment constraints impact gas and coal costs. Such costs are not captured by analyzing historical short term firm transactions. The Company also curtails wind generation when oversupply conditions occur, which results in lost production tax credits.

Q. Are inter-hour integration costs at all related to any of the Company's historical short term firm transactions?

A. Day-ahead commitment of gas plants is analogous to day-ahead purchases or sales for the heavy load hour (HLH) or light load hour (LLH) block. The Company's combined cycle combustion turbine (CCCT) gas plants typically have minimum up times of around 12 hours, including startup and shutdown. This is slightly less than the 16 hours of the HLH block. The Company's CCCTs typically have minimum down times of around 8 hours, comparable to the 8 hours of the nightly LLH block. Committing a gas plant up for a day is thus comparable to a quantity of HLH block purchases. Committing to keep a gas plant up overnight is thus comparable to a quantity of LLH block purchases. For both gas plants and block transactions, the commitment is for multiple hours and can only be reversed indirectly, piecemeal, and at uncertain cost. For both gas plants and block transactions, the optimal decision using information available on a day-ahead basis may not be the optimal decision for the conditions that prevail in reality. Any decision that deviates from the optimum for actual conditions will result in higher costs.

Q. Staff is concerned that the system balancing adjustment is arbitrary and does not make sense under extreme scenarios.[66] How do you respond?

A. Far from being arbitrary, the Company's adjustment is based on actual costs incurred over a historical period of system operations. Staff describes a hypothetical situation with the extreme assumption that the Company makes no market transactions, and ran the GRID model with market sales restricted to zero. Staff anticipated zero system balancing costs in this hypothetical, but the scenario resulted in a system balancing adjustment of [redacted]. Staff reasons that this result demonstrates that the system balancing adjustment is unreasonable.

On the contrary, the Company's proposed adjustment to include system balancing transaction costs, and use of the GRID model, results in a reasonable forecast of NPC only to the extent it is consistent with reality. The system balancing transactions adjustment was not designed to work in such an extreme scenario, but it does work in the situations the Company expects to experience during 2017. Zero market sales is significantly different from any historical results the Company has experienced; it is not unreasonable that the Company's adjustment creates unexpected results in unrealistic scenarios.

[66] Staff/400, Kaufman/32-33.

Q. Should the system balancing adjustment be proportionate to the market transactions identified in GRID?

A. No. The Company has not claimed that all day-ahead and real-time transactions must be acquired at additional cost. Indeed, the Company has identified several months in the historical period in which the Company was able to transact at prices better than the market.

Q. Are there any errors in Staff's analysis of system balancing transactions?

A. Yes. In Confidential Figure 6, Staff claims that the market transaction volume forecasted by GRID increased by 611% from the Company's Direct Filing to its Reply Update. Staff has mistakenly reported the cost of system balancing purchases in the Reply Update, rather than the volume. In addition, the labels for sales and purchases are switched. Staff filed errata testimony in which it attempted to correct its Confidential Figure 6, by replacing the erroneous system balancing costs with volumes. However, the labeling of sales and purchases remains switched, and Staff introduced a new error by reporting the system balancing purchase volume for both purchases and sales. If the table is correctly prepared, the total market transaction volume increases by just 5%, undermining Staff's argument.

Q. Staff also argues that the system balancing transactions adjustment double counts costs because GRID limits market purchases and instead meets load by generating with expensive peaking plants.[67] Is this correct?

A. No. On the contrary, market purchases in GRID are constrained only by transmission limits providing access to wholesale markets—the same

[67] Staff/400, Kaufman/34.

transmission limits the Company faces in actual operations. Staff may be confusing this issue with the market caps that limit wholesale sales in the GRID model based on the actual sales made over a historical 48-month period. The same type of cap does not apply to purchases.

Q. Are the 1,273 monthly balancing buckets identified by Staff consistent with the transactions used in the Company's historical system balancing analysis?

A. No. Staff's analysis included transactions with delivery points outside of major market hubs. While transactions at these points also have a differential between purchase prices and sales prices, the associated cost is not included in the historical results used to develop the adjustment incorporated in the TAM forecast. The fact that PacifiCorp rarely transacts for monthly products at illiquid points should not be a surprise.

Q. ICNU, Staff, and CUB all agree that more realistic hourly prices would better address the system balancing issue than the Company's proposal. Do you agree?

A. While more realistic hourly prices could improve the representation of market prices in GRID, it cannot capture the impact of uncertainty in the Company's position and market prices between a day-ahead and hour-ahead time frame. In addition, an hourly price curve cannot capture the necessity of transacting for block products on a day-ahead basis, rather than for products that perfectly align with the Company's position. CUB recognizes that modeling sequential transactions with multiple price curves leading up to the hour of delivery would be a better representation, but concludes that the Company's modeling should be disregarded in favor of more realistic hourly price curve alone.[68]

Even with a more realistic hourly price curve, the GRID model has fixed inputs such as load, wind generation, and thermal outages, and does not realistically evaluate the impact of changes in these components from day-ahead to hour-ahead. In addition, while the GRID model now contains two market prices, they are both fixed and applicable only for specified volume ranges. Given that the Company's position (load, wind, thermal) is perfectly known within the model, the market prices relevant to dispatch are also perfectly known in GRID. In reality, the Company cannot know its prices or market positions in advance and, as a result, systematically incurs additional costs as its day-ahead commitments do not perfectly align with reality.

Q. Do the Company's current hourly buy and sell prices represent a more realistic hourly price curve than the single hourly price used previously?

A. Yes. Under the current methodology, only one market price is effective for transactions at a given market (*i.e.*, if the model needs to purchase energy the buy price is effective, and if the model needs to sell energy the sell price is effective). That hourly effective price is more strongly correlated with the Company's load than when a single hourly price is used, as was done in the past. Thus the Company's current methodology is a step in the direction all of the parties support.

[68] CUB/200, McGovern/24-25.

Q. If the Company applied more realistic single stream of hourly prices in GRID, what would be the effect?

A. NPC would increase. The current system balancing transactions adjustment does not exhibit the full range of prices experienced in actual operations. More realistic pricing would have a wider range of prices, both higher and lower. During periods when prices are higher, more expensive resources will become economic and will thus be dispatched up more frequently. During periods when prices are lower, low-cost resources will become uneconomic and will thus be dispatched down more frequently. The net effect of more dispatch by expensive resources and less dispatch by low-cost resources is an increase in NPC. This is demonstrated by the fact that the total NPC impact of the system balancing adjustment in the forecast period is greater than the historical impact on market transactions, even though the market transaction impact in that forecast matches the historical level.

Coal Plant Dispatch

Q. CUB continues to recommend a coal cost disallowance, claiming that the Company's coal contracts executed since the 2013 IRP are imprudent.[69] Has CUB provided any evidence to support this claim of imprudence?

A. No. In its opening testimony, CUB simply asserted in a conclusory statement that all binding commitments to coal after the 2015 are imprudent.[70] The Company rebutted this argument in Mr. Ralston's reply testimony, pointing out the reasonableness of the Company's three post-2015 coal contracts and pointing out

[69] CUB/200, McGovern/32.
[70] CUB/100, McGovern/7.

that CUB had previously supported the prudence of one of the contracts. CUB's rebuttal testimony does not acknowledge or respond to any of this testimony.

Q. Staff continues to assert that the Company's modeling of coal plant dispatching is new in this case because the methodology for determining incremental fuel costs was never explicitly described in prior TAMs.[71] Are the use of incremental fuel costs in GRID a change from past practice?

A. No. Incremental fuel costs for use in the GRID dispatch optimization have been required inputs since GRID version 5.3 was released more than ten years ago. The application of incremental fuel costs within the GRID logic has been identified in GRID user manuals since that time. I disagree with Staff's implication that any aspect of GRID that is not specifically addressed in a prior TAM represents a "new modeling method."

Q. Have the plant-specific incremental fuel costs changed over time?

A. Yes. The Company has updated incremental fuel costs in each TAM filing to reflect the coal supply cost and volume for each plant during the forecast period. Recently, the incremental costs for certain units have been zero under certain conditions, due to "take or pay" clauses in coal contracts. As further discussed in the testimony of Mr. Ralston, under such clauses the Company agrees to pay the contract price for the required volume, whether or not it takes required volume of coal. Because the Company pays for the coal either way, the incremental cost of coal up to the required volume is effectively zero.

[71] Staff/400, Kaufman/41.

Q. Staff claims that the Company's modeling is "prone to error," citing an alleged user error when selecting the Hunter dispatch tier in the Initial Filing that Staff claims increased NPC.[72] Is this accurate?

A. No. To support this testimony, Staff mischaracterizes a Company response to a data request. The actual response,[73] states that the coal volume modeled at Hunter was on the cusp between two coal price tiers. Through the Company's iterative process, which I described in my reply testimony,[74] we determined that the best overall coal fleet dispatch occurred when Hunter used the price that corresponded to a slightly lower volume than was actually modeled for the plant. Had the Company used the price corresponding to the higher volumes at Hunter, it negatively impacted the coal supply parameters of the rest of the Company's other coal resources. To the extent burning slightly cheaper Hunter coal, as Staff recommends, results in other coal plants failing to take zero cost coal up to their minimum requirements, would increase NPC, not decrease it as Staff claims.

Q. Does Staff continue to acknowledge that minimum take contracts impose real costs?

A. Yes. Staff does not dispute my previous testimony that their recommendation to simply ignore contract minimums will create an unrealistic and less accurate NPC forecast.

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[72] Staff/400, Kaufman/41.
[73] Staff/407, Kaufman/1.
[74] PAC/400, Dickman/41-44.

Avian Compliance Curtailment

Q. Staff's testimony implies that the Company is seeking to recover the fines resulting from the court order that resulted in the curtailment at the Glenrock and Seven Mile Hill wind sites.[75] Is this true?

A. No. The fines were booked below the line and will not be recovered from customers.

Q. Staff continues to argue that it has presented new evidence in this case of the risk and consequences associated with complying with the Migratory Bird Treaty Act (MBTA).[76] Did the Company discuss the potential avian risk when it sought state permitting for the projects?

A. Yes. The Company's permit applications to the Wyoming Industrial Siting Council prepared in November 2007 identified the potential avian issues at each project. The Company provided the permit applications to Staff in discovery in this case.

Q. When the Company sought to include these projects in rates in Oregon, did the parties and the Commission have access to the permit applications which referenced the avian risk?

A. Yes. The permit applications were referenced in the parties' testimony and briefs in docket UE 200, and were even mentioned by the Commission in its final order.[77] The risk associated with avian issues, however, was not sufficient for the Commission to find that the projects were imprudent at the time.

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[75] Staff/400, Kaufman/46.
[76] Staff/400, Kaufman/44.
[77] *In the Matter of PacifiCorp's 2009 Renewable Adjustment Clause*, Docket No. UE 200, Order No. 08-548 at 3 (Nov. 14, 2008) (referencing Staff's arguments based on the applications); Docket No. UE 200, Staff's Opening Brief at 2 (discussing the applications).

Modeling QF Contracts

Q. Has CUB's recommended treatment of QF contracts changed in its rebuttal testimony?

A. Yes. In its opening testimony, CUB proposed an adjustment that removes from rates any QF that is not commercially operating on the date of the final TAM update, regardless of whether the QF is reasonably expected to operate during the test period.[78] In its rebuttal testimony, CUB recommends that the Company include in rates all QFs that are operational or have a signed contract, but that the Company apply a discount factor to new QF contracts, based on the historical difference between forecasted and actual energy generation from new QFs.[79]

Q. Is CUB's new recommendation reasonable?

A. No. It is unclear exactly how CUB's discount factor would be calculated and how it would be applied. Without a better explanation for the adjustment, there is no basis for determining that it would produce a more accurate NPC forecast, as compared to the current methodology. Indeed, CUB did not even perform the calculation, or provide any evidence regarding the difference between forecast and actual energy production.

Q. In its opening testimony, CUB failed to acknowledge the historical treatment of QF contracts in the TAM or explain why that historical treatment is now inadequate. Has CUB addressed this omission from its opening testimony?

A. Partially. In its rebuttal testimony CUB now acknowledges that in 2010 it supported the Company's current modeling of QF contracts, but still has not

[78] CUB/100, McGovern/24.
[79] CUB/200, McGovern/31.

acknowledged the more specific stipulation it supported in the 2015 TAM that resolved this very issue related specifically to new QF contracts.[80]

Q. Has Staff taken a position on CUB's proposal?

A. Yes. Staff acknowledges that the current methodology works "for the most part," recognizing that any forecast has a certain amount of uncertainty built in.[81] Despite this acknowledgement, Staff recommends that the Company change its current methodology and instead apply a "historical success factor" to new QFs with executed contracts that are not operational by January 1 of the test period.[82]

Q. How would Staff calculate the historical success factor?

A. Staff recommends that the Company divide the number of QFs that become operational in the year by the number of QFs with contracts at the beginning of the year. Staff proposes that this ratio would be based on four years of historical data.

Q. Is Staff's historical success factor a reasonable approach to forecasting QF capacity during the test period?

A. No. Staff's testimony does not actually calculate its proposed factor, or even provide the data that would be necessary to calculate the factor. Without performing any analysis, there is no basis to conclude that Staff's approach would create a more accurate NPC forecast. The lack of evidence supporting Staff's recommendation is particularly glaring because Staff agrees that the current method largely works. It makes little sense to abandon a methodology that works, in favor of an untested methodology without any meaningful evidentiary support.

[80] CUB/200, McGovern/28.
[81] Staff/300, Crider/17.
[82] Staff/300, Crider/19.

Q. Have you provided information comparing the number of QFs and the related generation volume included in past TAM forecasts to actual results?

A. Yes. CUB data request 79 asked for a comparison of the number of QFs and the volume of energy from QFs forecasted in each TAM and actual results. The summary table from the Company's 1st Revised Response is provided as Exhibit PAC/805. Table 1 below uses data taken from that response and shows the total number of QFs and the corresponding generation by year from 2008 to 2015.

Table 1

	2015	2014	2013	2012	2011	2010	2009	2008
# of QFs forecasted to sell power in TAM	116	99	101	89	79	71	66	58
# of QFs that actually sold power	120	101	95	98	91	84	83	66
Difference (Actual - Forecast)	4	2	(6)	9	12	13	17	8
Percentage Difference	3%	2%	-6%	10%	15%	18%	26%	14%
QF MWh Forecasted	2,476,266	2,435,389	2,438,691	1,912,866	2,724,235	2,861,965	3,221,069	2,395,995
QF MWh Actual	2,306,533	2,564,988	2,341,269	2,227,854	2,683,387	2,678,393	2,979,815	2,959,861
Difference (Actual - Forecast)	(169,733)	129,598	(97,422)	314,988	(40,848)	(183,572)	(241,255)	563,866
Percentage Difference	-7%	5%	-4%	16%	-1%	-6%	-7%	24%

As shown in the table, on average the Company's final TAM forecasts have understated both the total count and total volume of QFs generating energy on the Company's system.

Direct Access – REC Obligation

Q. Noble Solutions continues to recommend that the Schedule 294, 295, and 296 transition adjustments be adjusted to reflect the value of RECs freed-up by departing direct access customers.[83] Does the Company continue to object to this recommendation?

A. Yes. As I described in my reply testimony, Noble Solutions' proposal is problematic for various reasons. First, PacifiCorp is currently acquiring additional RECs to meet its RPS compliance obligation, and does not intend to

[83] Noble Solutions/200, Higgins/3-5.

sell RECs in the near term. Because the Company would bank any RECs freed-up by a departing direct access customer, monetizing RECs and adjusting the transition adjustment to reflect the value of RECs freed up by departing direct access customers is a purely hypothetical exercise requiring speculative assumptions. The REC market is volatile and illiquid, and there is no reliable way to determine the monetary value of freed-up RECs.

Second, implementing Noble Solutions' proposal would create an unreasonable administrative burden for the Company. To prevent cost-shifting, it would be necessary to track the hypothetically sold RECs in the event that the departing direct access returns to cost-of-service rates, necessitating the creation of multiple REC banks to track the RECs that are "sold" to departing direct access customers.[84]

Q. Is the Company categorically opposed to accounting for RPS compliance costs in its implementation of direct access?

A. No. The Company is open to accounting for RPS compliance costs when there is a readily identifiable cost associated with RPS compliance that can be accounted for in a reasonable and verifiable way. For example, the Company intends to seek cost recovery associated with the RECs that will be purchased following the recently completed Request for Proposal (RFP) process through Schedule 203. But the Company does not intend for direct access customers participating in the five-year program to pay Schedule 203. Because the Company is no longer planning to serve those customers and the costs are easily identifiable, it is reasonable that those customers not pay for the cost of RECs purchased to meet

[84] PAC/400, Dickman/91.

the Company's current and future RPS obligation. And excluding five-year program participants from Schedule 203 does not result in cost-shifting.

On the other hand, Noble Solutions' proposal here does not account for readily identifiable costs that can be reasonably calculated and included in the transition charge calculation without compromising non-participating customers.

Q. In your reply testimony, you stated that if the Company were to sell Oregon-eligible RECs in future years, those revenues would be passed back to all customers.[85] Noble Solutions claims that spreading the value of REC sales among all customers is unreasonable.[86] How do you respond?

A. The Company's approach equitably distributes the value of any REC sales among all customers that have contributed to the acquisition of the REC—the proceeds are distributed to both cost-of-service and direct access customers. To prevent cost-shifting, as required by Oregon's direct access laws, cost-of-service customers should be no worse off because of direct access. Thus, if a REC is sold, cost-of-service customers should receive the same value regardless of whether other customers have elected direct access. But under Noble Solutions' proposal, cost-of-service customers would not receive fair value for a REC that is sold; instead, the value would effectively transfer to the departing direct access customer.

Moreover, because the Company is not planning to make any REC sales in the near term, it is too speculative to assume the timing and price for a future sale. Thus, existing cost-of-service customers would bear the cost of adding the value

[85] PAC/400, Dickman/90.
[86] Noble Solutions/200, Higgins 7.

of RECs (at a hypothetical market price) to the transition adjustment, creating a significant risk of over- or under-valuing RECs, potentially exacerbating cost-shifting associated with Noble Solutions' proposal.

Q. Noble Solutions suggests that an alternative approach for valuing freed-up RECs is to use the value of RECs from PacifiCorp's recent RFP process.[87] Is this approach reasonable?

A. No. The REC values from the recent RFP may not be representative of future REC values if and when the Company decides to seek approval to sell RECs. Noble Solutions has presented no evidence regarding the REC market to support a conclusion that the Company could market and sell RECs for the values obtained from most recent RFP at some indeterminate point in the future.

Q. In your reply testimony, you state that it would be administratively burdensome to value RECs because the remaining customers would need to be surcharged, and RECs that are hypothetically sold would need to be tracked to ensure that if a direct access customer returns to cost-of-service rates, that customer does not receive the benefit from those RECs.[88] Does Noble Solutions respond to this evidence?

A. Yes. Noble Solutions first claims that there would be no administrative burden associated with a surcharge because either the REC values that would be provided to direct access customers would be *de minimis*, so the Company would simply absorb the cost, or the cost could be easily recovered through Schedule 203.[89]

[87] Noble Solutions/200, Higgins/8.
[88] PAC/400, Dickman/91.
[89] Noble Solutions/200, Higgins/9.

Q. Do you agree with Noble Solutions' reasoning?

A. No, because Noble Solutions' reasoning is internally inconsistent. Either the value of freed-up RECs is *de minimis*, and there is no reason to include the value in the transition adjustment, or the value is not *de minimis* and the Company will need to implement a surcharge to recover the value of the freed-up REC from cost-of-service customers. Regardless of how recovery were accomplished—through Schedule 203 or some other means—implementing a surcharge would create an unnecessary administrative burden associated with tracking the RECs hypothetically "sold" by direct access customers to cost-of-service customers.

Q. What is Noble Solutions' second reason for concluding that its recommendation would not be administratively burdensome?

A. Noble Solutions claims that crediting direct access customers with the value of freed-up RECs would not require the creation of multiple REC banks because departed direct access customers returning to PacifiCorp's system could be treated as new customers.[90]

Q. Is it reasonable to simply treat returning direct access customers as if they were new customers?

A. No. When implementing direct access, the Commission has consistently refused to treat direct access customers as if they are simply new customers when they want to return to cost-of-service rates. This differential treatment is grounded in the Commission's commitment to prevent cost-shifting due to direct access. The fundamental purpose of tracking RECs that are "sold" to direct access customers is to prevent the direct access customers from subsequently receiving credit for

[90] Noble Solutions/200, Higgins 9-11.

the same REC twice if the customers choose to return to cost-of-service rates. New customers are not subject to the same prohibition on cost-shifting.

Q. Noble Solutions proposes that as an alternative, PacifiCorp could transfer to the ESS the RECs for which the direct access customers are paying, and the ESS could retire the RECs for the compliance year and pass the value to the customer.[91] Would this approach work for the Company?

A. No. Transferring the freed-up REC still creates the same cost-shifting as transferring the value of the freed-up REC. Although this proposal removes concerns over valuing the REC, remaining customers would still be deprived of the value of the REC that is transferred, despite having paid for it.

Direct Access – Schedule 200 Escalation

Q. Does Noble Solutions continue to support its recommended adjustment to the consumer opt-out charge to account for accumulated depreciation in years six through 10?

A. Yes, based on the same rationale.

Q. By way of background, how does the Consumer Opt-Out Charge operate together with Schedule 200?

A. In the first five years after the direct access customer elects to leave, the customer pays the actual Schedule 200 costs, as those costs change during that five-year period. If the Company adds incremental generation during those five years and those costs flow into Schedule 200, the direct access customer pays those costs. Noble does not object to this treatment.

[91] Noble Solutions/200, Higgins 11.

The Consumer Opt-Out Charge accounts for forecast Schedule 200 costs for years six through 10. To calculate the Consumer Opt-Out Charge, the Company first takes the Schedule 200 costs in effect at the time the customer departs and escalates those costs for five years, using an inflation escalator. The departing customer does not pay these escalated Schedule 200 costs (because the customer is paying the *actual* Schedule 200 costs for the first five years). Noble Solutions does not object to this escalation.

The Company then takes the escalated Schedule 200 cost for year five, and escalates that cost through year 10, again, using an inflation escalator, to develop a forecast of Schedule 200 costs for years six through 10. The Consumer Opt-Out Charge is then calculated by taking the forecast Schedule 200 costs and reducing them back to calculate a levelized payment made in years one through five. By using inflation to forecast the Schedule 200 costs, the Schedule 200 costs in effect when the customer leaves are held constant in real terms for purposes of calculating the Consumer Opt-Out Charge. Together, through the payment of Schedule 200 and the Consumer Opt-Out Charge, departing customers pay the Company's fixed generation costs for 10 years (offset by the value of freed-up energy).

The Company's proposed Consumer Opt-Out Charge is consistent with the methodology approved by Commission Order No. 15-060 and affirmed in Order Nos. 15-195 and 15-394. The Commission did so after concluding that PacifiCorp had presented unrebutted evidence that there were transition costs in years six through 10.[92] It was within the Commission's discretion to require departing customers to pay actual Schedule 200 costs for the full 10 years, but, instead, the Commission adopted the Company's conservative forecast of Schedule 200 costs for years six through 10, as reflected in the Consumer Opt-Out Charge.

Q. What is the basis for Noble Solutions' contention that the Consumer Opt-Out Charge should decrease for years six through 10?[93]

A. Noble Solutions argues that departing customers should be responsible for only those incremental generation investments made in years one through five. After year five, the Company's portfolio of generating assets should be "frozen," and no new costs should go into the frozen assets and accumulated depreciation should reduce their balance.

Q. Is there any basis for Noble Solutions' claim that the fixed generation costs should be frozen in year five?

A. No. When the Commission approved the Consumer Opt-Out Charge in docket UE 267, it did so after concluding that PacifiCorp had presented unrebutted evidence of transition costs in years six through 10.[94] The Consumer Opt-Out Charge recovers those transition costs, and, together with Schedule 200 in the first five years, results in departing customers paying fixed generation costs for 10 years. Thus, to use Noble Solutions' terminology, under the Consumer Opt-Out Charge the generation assets are frozen in year 10, not five. If the portfolio of

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[92] Order No. 15-060 at 7.
[93] Noble Solutions/200, Higgins/12-13.
[94] Order No. 15-060 at 7.

assets is not frozen in year five, there is no basis for Noble Solutions' recommendations.

Q. Noble Solutions does not object to direct access customers paying incremental generation costs for the first five years.[95] What is the basis for the five-year cut-off?

A. Noble Solutions testifies that the five-year period is reasonable because it reflects the time period for which PacifiCorp has already planned for the departing customer prior to the customer's departure and that PacifiCorp "cannot unwind prior commitments for five full years after the date of the opt-out election."[96] This testimony is at odds with the Commission's finding in dockets UE 267 and UE 296, however, where the Commission adopted a 10-year period over which it required departing customers to pay transition costs, including fixed generation costs. Thus, to the extent that the Commission found a reasonable time period for the payment of incremental generation costs, that time period is 10 years, not five. Noble Solutions offers no support for its five-year limitation on paying fixed generation costs, other than its own opinion.

Q. The Company has testified that the Consumer Opt-Out Charge does not include incremental investments in years six through 10.[97] What is the basis for Noble Solutions' rejection of this argument?

A. Noble Solutions claims that the Schedule 200 costs are escalated at virtually the same inflation rate for years one through five and years six through 10.[98] Given

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[95] Noble Solutions/200, Higgins/12.
[96] Noble Solutions/200, Higgins/12.
[97] PAC/400, Dickman/93.
[98] Noble Solutions/200, Higgins 16.

that the Company concedes that years one through five include incremental generation investment, Noble Solutions reasons that years six through 10 must also include incremental generation investment.

Q. Is Noble Solutions' reasoning sound?

A. No. It appears that Noble Solutions misunderstands the Company's testimony. In years one through five, the direct access customer pays for incremental generation because the customer pays the actual Schedule 200 costs during those years. For years six through 10, the direct access customer does not pay incremental generation, because Schedule 200 is held constant in real terms. The use of an inflation escalator in the Consumer Opt-Out Charge in years one through five is not intended to account for new generation, just as the inflation adjustment in years six through 10 is not intended to account for new generation.

Q. Noble Solutions argues that application of an inflation adjustment is inappropriate because the value of the rate base assets is expected to decline due to accumulated depreciation.[99] How do you respond?

A. This argument relies on the rejected assumption that the fixed generation costs are frozen in year five. The Commission has never concluded that assets should be frozen after year five, and, as explained above, this premise is unreasonable given the Commission's explicit adoption of a 10-year period for transition cost recovery. It is reasonable to consider the assets frozen after year 10, which is effectively what happens with the Consumer Opt-Out Charge.

Noble Solutions also argues that the costs that cause Schedule 200 to increase are all forward-looking costs, like maintenance and generation overhauls,

[99] Noble Solutions/200, Higgins 14.

that should not be recovered from departing customers.[100] Again, however, Noble Solutions' position is based exclusively on the assumption that year five marks a cut-off after which departing customers pay only for costs that have already been incurred. But there is no basis for this assumption. Noble Solutions does not object to paying for maintenance and service related costs in years one through five, both under Schedule 200 and the Consumer Opt-Out Charge.

Q. Noble Solutions suggests that an inflation adjustment is not necessary because the rate base assets are not actually subject to inflation.[101] Do you agree?

A. No. If escalation is not applied to Schedule 200, the Consumer Opt-Out Charge would actually decline in real terms. Moreover, Noble Solutions' agrees that the Schedule 200 costs should be escalated at the rate of inflation for years one through five and Noble Solutions has not presented any compelling basis to stop that escalation after year five.

Q. In your reply testimony, you suggest that the Company's inflation methodology is similar to the methodology used by PGE in its five-year opt out program.[102] Noble Solutions disputes the comparison to PGE's five-year direct access program because PGE does not include a consumer opt-out charge.[103] Does PGE's lack of a consumer opt-out charge differentiate the application of the inflation methodology?

A. No. While Noble Solutions is correct that PGE does not have a consumer opt-out

[100] Noble Solutions/200, Higgins 17.
[101] Noble Solutions/200, Higgins/14.
[102] PAC/400, Dickman/93-94.
[103] Noble Solutions/200, Higgins/17.

charge, Noble Solutions misses the point of the comparison. Under PGE's program, departing customers pay all costs for five years, because at the time of adoption of PGE's program, the Commission concluded that five years was an appropriate time period for recovery of transition costs *for PGE*. In PacifiCorp's five-year opt-out program, the Commission explicitly found that it was necessary for the Company to recover transition costs beyond year five. In essence, PacifiCorp adapted the same basic methodology as PGE, including escalation, and applied it over the term determined by the Commission to be necessary to prevent cost-shifting.

Q. Has Noble Solutions demonstrated that transition costs do not exist in years six through 10?

A. No. Noble Solutions has not challenged the Commission's fundamental conclusion in Order No. 15-060 that transition costs exist through year 10 and that the Consumer Opt-Out Charge is necessary to recover those costs.

Q. Have any other parties taken a position on Noble Solutions' direct access proposals?

A. Yes. Staff recommends that the Commission reject both of Noble Solutions' proposals, concluding that Noble Solutions has not presented any new evidence or arguments that merit overturning the Commission's rejection of the same proposals in docket UE 296.[104]

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[104] Staff/500, Gibbens/3-4.

Docket No. UE 307
Exhibit PAC/801
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman

List of Staff and Intervenor Adjustments

August 2016

Oregon 2017 TAM List of Staff and Intervenor Adjustments
($ millions) - Oregon Allocated (24.69%)

vs Reply TAM Filing

	Staff (Crider/Kaufman)	CUB (McGovern)	ICNU (Mullins)	Noble (Higgins)
Day-ahead/Real-time System Balancing Adjustment	($9.226)	($9.226)	($1.944)	
Bridger Coal Company costs	($23.498)		($5.964)	
Eliminate Coal Contract Minimum Take	[a]	[b]		
Jim Bridger 3 & 4 SCR Removal		adopted		
EIM Benefits	($5.527)	($3.046)		
Forced Outages	[c]			
Avian Compliance Curtailment	($0.064)			
New QF Forecast [d]	($4.016)	[d]		
Total Adjustments	**($42.331)**	**($12.271)**	**($7.908)**	

Generic Investigation Into Ratemaking of EIM Benefits (incl. PGE)	√			
EIM Audit of Accounting, Costs, and Benefits		√		
Transition Adjustment - REC Obligation				√
Transition Adjustment - Schedule 200 Escalation				√
Modeling Moratorium			√	

[a] Of Staff's proposed minimum take adjustments based on Direct, only Cholla's price was adjusted for min take in Reply. Impact not quantified.

[b] The Company's Reply defending the prudence of the coal contracts contested by CUB was unrebutted. No impact in Reply filing.

[c] The four year average forced outage modeling resulted in an increase to NPC and the Company's Reply was unrebutted.

[d] Impact of QF proposal removes all QFs with online dates after the Final Update. Alternative proposals not quantified.

Docket No. UE 307
Exhibit PAC/802
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman

Staff Response to PacifiCorp Data Request 47

August 2016

PacifiCorp Data Request 47

Refer to Staff/305, Crider/1. Please confirm that the total export and import revenue includes a total of 13 months from January 2015 through January 2016, rather than the 12 calendar months of 2015.

a. Please also confirm that the total export and import volume includes a total of 13 months from January 2015 through January 2016, rather than the 12 calendar months of 2015.

Response to PacifiCorp Data Request 47

Staff confirms that the revenue reported in Staff/305, Crider/1 includes 13 months of revenue.

a. Staff confirms that the volumes total for exports and imports include 13 months.

REDACTED
Docket No. UE 307
Exhibit PAC/803
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman

Staff Response to PacifiCorp Data Request 50

August 2016

PacifiCorp Data Request 50

Refer to Staff/305, Crider/1.

a. Please confirm that total production cost of [redacted] is computed based on a total generation volume of [redacted] MWh.

b. Please also confirm that the [redacted] MWh is equal to the total transfers reported for greenhouse gas compliance purposes for the months of November 2014 through January 2016 (i.e., 15 months), as contained in the Company's workpaper ORTAM17w_EIM Benefits OR TAM17 (Jan15-Jan16) CONF, on the tab entitled REX Data.

Response to PacifiCorp Data Request 50

a. Staff confirms the two confidential numbers for total production cost and total generation volume.

b. Staff confirms the source of the confidential number as the sum of transfers contained on the REX data tab of the Company's workpaper ORTAM17w_EIM Benefits OR TAM17 (Jan15-Jan16) CONF.

REDACTED
Docket No. UE 307
Exhibit PAC/804
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman

Staff Response to PacifiCorp Data Request 48

August 2016

PacifiCorp Data Request 48

Refer to Staff/305, Crider/1 and the workpapers supporting the exhibit.

a. Please confirm that the workpapers include total export volume of [redacted] MWhs.

b. Please confirm that the workpapers use a total volume of [redacted] MWh to compute the generation costs related to exports.

c. Please reconcile the difference in volumes and explain why it is appropriate to include revenue from [redacted] MWh but generation cost for only [redacted] MWh.

d. If Staff cannot confirm (a) or (b), please explain the basis for Staff's position.

Response to PacifiCorp Data Request 48

a. Staff confirms the confidential number for export MWhs as included in the workpapers.

b. Staff confirms the confidential number related to generation plant output MWhs.

c. The generation output for individual plants was supplied by the company. Any difference in volumes is due to incomplete reporting by the company.

d. Please see Staff's responses to (a) and (b) above.

REDACTED
Docket No. UE 307
Exhibit PAC/805
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman

PacifiCorp Response to CUB Data Request 79

August 2016

CUB Data Request 79

Please provide monthly forecast and online dates for all QF facilities for the last 10 years, separated by solar and wind.

A communication was sent to the Citizens' Utility Board of Oregon (CUB) on July 22, 2016 to seek clarification of this request. Clarification and the rephrasing of CUB Data Request 79 was received on July 26, 2016, as follows:

For each year that there has been a TAM, please provide the following information:

(a) Number of QF projects that were forecast to sell power to PacifiCorp during the year.

(b) Number of QF projects that actually sold power to PacifiCorp during the year.

(c) Volume (in MWh) of energy from QFs that was forecast for that year.

(d) Volume of energy from QF's that were actually purchased in that year.

(e) Number of new projects by type (solar, wind, hydro) that were forecast each year.

(f) Number of new projects by type that produced power each year.

(g) Number of new projects by type that produced and sold power to PacifiCorp more than 1 month before their forecasted date of beginning service.

(h) Number of new projects by type that began producing and selling power to PacifiCorp more than 1 month after the date that was forecast in the TAM.

(i) Number of new projects by type that began producing and selling power to PacifiCorp more than 6 months after the date that was forecast in the TAM.

NOTE: "forecast" refers to the forecast year in each TAM.

1st Revised Response to CUB Data Request 79

Further to the Company's response to CUB Data Request 79 dated August 5, 2016, the Company provides this revised response which replaces the Company's original response in its entirety.

(a) to (i) Please refer to Confidential Attachment CUB 79 1st Revised.

The purpose of this revised response is explained below:

The Company has identified an error in the original Confidential Attachment CUB 79 related to the response to subpart (d) of the clarified / rephrased request shown above. Confidential Attachment CUB 79 1st Revised provides the corrected actual volume of energy purchased from qualifying facilities (QF) by year. For additional details on the actual volume of energy purchased from QFs by year, please refer to the Company's original and supplemental responses to ICNU Data Request 002.

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

		Through June 30, 2016 2016	2015	2014	2013	2012	2011	2010	2009	2008
Subpart (a)	# of QFs forecasted to sell power in TAM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subpart (b)	# of QFs that actually sold power	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subpart (c)	QF MWh Forecasted		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subpart (d)	QF MWh Actual		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subpart (e)	# of new wind projects forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new solar projects forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new other projects forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subpart (f)	# of new wind projects actual	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new solar projects actual	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new other projects actual	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subpart (g)	# of new wind projects online 1 month before forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new solar projects online 1 month before forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new other projects online 1 month before forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subpart (h)	# of new wind projects online 1 month after forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new solar projects online 1 month after forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new other projects online 1 month after forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subpart (i)	# of new wind projects online 6 months after forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new solar projects online 6 months after forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	# of new other projects online 6 months after forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL
Exhibit PAC/805
Dickman/3

Docket No. UE 307
Exhibit PAC/900
Witness: Kelcey A. Brown

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Kelcey A. Brown

August 2016

SURREBUTTAL TESTIMONY OF KELCEY A. BROWN

TABLE OF CONTENTS

Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

A. My name is Kelcey A. Brown. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present title is Manager, Market Policy and Analytics.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have been employed by PacifiCorp since May 2011. I have been the Manager of Market Policy and Analytics since July 2015. Before that time, I worked as the Manager of Load Forecasting and as a Senior Consultant in the Regulatory Net Power Costs Department. Before joining PacifiCorp, I worked at the Public Utility Commission of Oregon from November 2007 through May 2011. During my time at the Commission, I sponsored testimony in several dockets involving net power costs, integrated resource planning, and various revenue and policy issues. From 2003 through 2007, I was an Economic Analyst with Blackfoot Telecommunications Group, where I was responsible for revenue forecasts, resource acquisition analysis, pricing, and regulatory support. I have a Bachelor of Science degree in Business Economics from the University of Wyoming, and I have completed all course work towards a Master's degree in Economics from the University of Wyoming.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide additional detail on the California Independent System Operator (CAISO) estimates of the Energy Imbalance Market (EIM) benefits, PacifiCorp's estimation of EIM benefits and how PacifiCorp determines the bid price for its participating resources in the EIM.

Q. As Manager of Market Policy and Analytics, what are your primary responsibilities for PacifiCorp?

A. My responsibilities at PacifiCorp are primarily related to the EIM. My group is responsible for submitting bids and resource schedules to the CAISO on a daily basis, scheduling resource outages, reviewing actual EIM operations on a daily basis, and the calculation of EIM benefits. As stated by several parties in this proceeding, the EIM is a complex operation that produces large amounts of data that PacifiCorp must monitor and utilize to ensure that its resource schedules are correct, bid prices accurately reflect the cost of operation, and resources are dispatched accordingly.

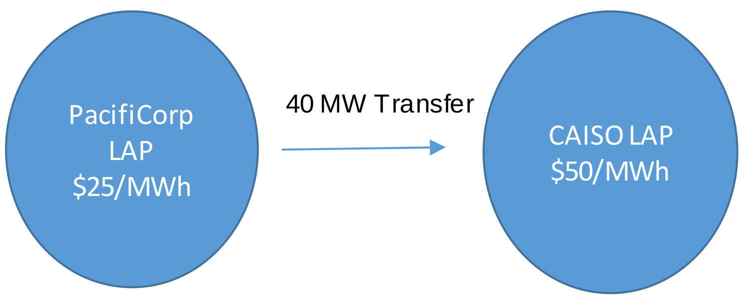
EIM BENEFITS

Q. Do you agree with Company witness Mr. Brian S. Dickman's explanation of PacifiCorp's calculation of EIM benefits in his reply testimony in this proceeding?

A. Yes. As explained by Mr. Dickman, PacifiCorp's estimated EIM benefits are derived from selling power in the EIM and realizing a margin on the sale and buying power in the EIM that allows PacifiCorp to avoid generating higher cost energy. More simply put, EIM benefits equal export revenue minus production cost minus import cost plus the avoided cost of production for imports.[1]

Q. How do you calculate the EIM export revenue?

A. EIM export revenues are calculated utilizing the fifteen minute and five minute load aggregation point (LAP) prices for each respective balancing authority area (BAA) and the fifteen minute and five minute transfer volumes. Utilizing the respective interval prices, PacifiCorp calculates a "transfer price" by taking the average of the two BAA prices. Please see the below example:



Transfer Price = ($25+$50)/2 = $37.5/Megawatt-hour (MWh)

Export Revenue = $37.5 * 40 = $1,500

Q. Why do you utilize the "average of the two BAA prices" in calculating the transfer price?

A. In the initial construct of the EIM, the CAISO determined that any congestion amounts, which are what causes the LAPs to be different between the BAAs, would be split between the adjacent BAAs.

[1] PAC/400, Dickman/52.

Q. Do you calculate the cost of EIM imports in the same way as you illustrated for the export revenue?

A. Yes.

Q. How often is this calculation performed?

A. The calculation is repeated 12 times an hour for the five minute intervals and four times an hour for the fifteen minute intervals, which means that for every hour there are 16 calculations for export and import revenue alone. Over the course of a month there are 11,520 calculations and over the course of a year there are 138,240 calculations. Accounting for the fact that there are currently three transfer points in the EIM means that there are 48 calculations of export revenue or import cost per hour, 34,560 per month, and 414,720 per year. In addition, once additional EIM entities join, this will only continue to grow.

Q. Do you need to review all 414,720 calculations of intervals to determine that it is accurate?

A. No. Rather, it is important to understand this is the methodology that PacifiCorp utilizes to calculate the export revenue and import cost. One can verify that the logic used in the calculation is correct by testing different intervals.

Q. Does the CAISO utilize the same methodology as PacifiCorp in calculating the export revenue and import cost in its EIM benefit calculation?

A. Yes. I have spent several days with personnel from the CAISO and verified that the CAISO's calculation of export revenue and import cost is equal to PacifiCorp's calculation of export revenue and import cost.

Q. Once you have determined the export revenue and import cost what is the next step in determining the EIM benefits?

A. Once the export revenues and import costs are calculated the next step is to identify the production cost to support the export volumes and the avoided production cost when PacifiCorp was importing energy.

Q. What are production costs?

A. Production costs, as they relate to EIM benefits, are the marginal cost to produce an additional MWh at a given resource. For example, in the case of a gas generation facility, the marginal cost to produce an additional MWh is the incremental cost of natural gas fuel multiplied by the heat rate of the unit to produce electricity plus the related variable operation and maintenance costs.

DETERMINATION OF BID PRICES

Q. Mr. Dickman states in his reply testimony that PacifiCorp utilizes bid prices as production costs to calculate the EIM benefits. Are bid prices equal to production costs?

A. Yes. As described later in my testimony, the Company is required to submit bids equal to the cost of dispatching its units. PacifiCorp submits bid prices to the EIM on a daily basis for its participating generation facilities to reflect their respective production costs.

Q. How does PacifiCorp determine its bid prices on a daily basis?

A. For its thermal generation facilities bids are equal to the fuel costs plus variable operation and maintenance costs of the unit. Using gas generation as an example, the bid for a resource is equal to its daily gas purchase price times the heat rate for each operating segment, plus variable operation and maintenance costs of the unit. For hydro facilities, due to the limited water available for generation bids are equal to the replacement cost of the energy. PacifiCorp's participating wind resources are bid in as a resource that would be paid to reduce production (negative price) with a price that is calculated based on the lost production tax credit plus the value of the renewable energy credit.

Q. Staff stated that PacifiCorp utilizes the Default Energy Bid (DEB) in the EIM.[2] Is Staff correct?

A. No. The DEB is calculated by the Department of Market Monitoring and published each night at approximately 10:00 PM (Pacific Time) and functions as a cap on PacifiCorp's resource-specific bids. As of December 1, 2015, with the joining of NV Energy into the EIM, PacifiCorp is required by the Federal Energy Regulatory Commission to bid in its resources **at or below** the DEB for each resource.

In its DEB formula for each of PacifiCorp's participating units, the Department of Market Monitoring includes a ten percent adder that is intended to cover costs that may not be accurately reflected in the DEB calculation due to the use of average index gas, coal or market prices. As explained in the Company's 1st Supplemental Response to Staff Data Request 46, the ten percent adder was adopted in 2006 by the Department of Market Monitoring in its DEB calculations because it recognized that its calculation of costs could not capture the day-to-day changes in costs of variable operation and maintenance, actual fuel costs versus

[2] Staff/300, Crider/9-10.

an index price, pipeline fees, and, more importantly, the fact that the Department of Market Monitoring utilizes market index prices that are one to two days old in its DEB calculation.

Q. Does PacifiCorp include a 10 percent adder, similar to the DEB formula, when calculating its resource bids for EIM?

A. No. For gas plants, the Company includes a percentage adjustment to the bid to account for the possible change in gas prices or other costs typically incurred over time such as pipeline charges. However, this adder is typically less than 10 percent of the bid price. For all other resources there is no such adder included in the bid.

Q. Why wouldn't PacifiCorp simply utilize the DEB for its submittal of bid prices versus utilizing its own purchased fuel costs to determine the bid price?

A. The bid price of the PacifiCorp unit may actually be lower than the DEB due to the fact that the Department of Market Monitoring utilizes an average of four regional gas indices in its calculation of the DEB which may reflect a higher price of gas than what PacifiCorp was able to procure for its gas generation facilities.

Q. Wouldn't PacifiCorp want to use the DEB price for its hydro facilities?

A. Not necessarily. The DEB for hydro facilities is based on the Mid-Columbia market price, but during times of high run-off, PacifiCorp may submit a bid price that is potentially lower than the DEB to provide the correct price signal to the market to appropriately place the unit in the resource stack and be dispatched accordingly. Similarly, when PacifiCorp has limited in-flows into its hydro storage facilities, such as during the summer period, the hydro resources are bid in at the replacement cost of energy or market price, which may be equal to the DEB.

Q. Is there any incentive for PacifiCorp to submit bid prices that are higher than its marginal cost of operation?

A. No. If PacifiCorp submitted bid prices into the EIM that were higher than the marginal cost of operation there is the very likely possibility that the CAISO's economic least cost dispatch model would displace the PacifiCorp resource with a cheaper resource, not necessarily in the PacifiCorp BAA. In other words, PacifiCorp would potentially end up importing energy from other BAAs and paying for power that it actually could have generated at a cheaper price. Similarly, PacifiCorp would not want to submit a bid that was lower than its variable production cost due to the fact that it may be dispatched to support an export at less than its production cost. The fundamental premise of the EIM is to optimize the diverse pool of participating resources to generate the least cost dispatch. Attempting to extract additional market value from resources participating in the EIM could have the opposite effect.

Q. Does PacifiCorp get paid only its bid price for exports in the EIM?

A. No. As shown in the example above, PacifiCorp can be paid a higher price than its bid price for exports, and similarly, pay a lower price for imports than its avoided generation cost, based on the EIM avoided marginal resource cost and transmission constraints. It is only in the bilateral market where PacifiCorp is paid only the price that is offered in the transaction.

Q. Why is it important for PacifiCorp to submit a bid price that accurately reflects its marginal cost of production?

A. The bid price is a signal to the CAISO's economic least cost dispatch model to make sure that the unit is correctly placed in the stack to achieve an optimized, least cost dispatch for PacifiCorp's customers.

Q. Can you summarize your explanation of EIM bids and DEBs?

A. Yes. In summary, PacifiCorp submits a bid on a daily basis that is equal to its marginal cost of production for each of its participating resources in EIM. The resource bid must be at or below the DEB, but, to clarify, PacifiCorp is not submitting the DEB as its bid price.

Q. Now that you have clarified that the bid price is equal to the production cost for the EIM resource, please explain how you determine the production cost in your EIM benefit calculation.

A. As explained by Mr. Dickman in his reply testimony, PacifiCorp utilizes the LAP to identify which resource in each interval was the marginal unit. Table 1, below, is an illustrative example of a LAP price and how it is used to determine which resource was the marginal unit in PacifiCorp's EIM resource stack.

Table 1

Market	PacifiCorp EIM Resource Stack					
LAP	Day	Hour	5-Minute Interval	Price	Segment (MW)	Resource
	1-Jul-15	16	6	$25.0	25	Lake Side 2
	1-Jul-15	16	6	$24.8	40	Lake Side 1
	1-Jul-15	16	6	$24.0	25	Currrant Creek
$23.75	1-Jul-15	16	6	$23.3	8	Currant Creek
	1-Jul-15	16	6	$22.4	20	Lake Side 2
	1-Jul-15	16	6	$15.0	50	Chehalis
	1-Jul-15	16	6	$14.0	49	Hunter 3
	1-Jul-15	16	6	$13.0	10	Dave Johnston
	1-Jul-15	16	6	($10.0)	99	Leaning Juniper
	1-Jul-15	16	6	($15.0)	30	Goodnoe

The shaded line shows that a segment of Currant Creek is the marginal resource relative to the LAP price.

Q. Why are there multiple segments for Currant Creek in your example above?

A. In the EIM, PacifiCorp's units are modeled in a way that reflects the different operating configurations for each unit, such as one turbine operating versus two turbines operating, as well as the heat rate of the unit. Essentially, PacifiCorp's bid prices and segments reflect the additional operating cost to produce each incremental MWh of energy in different operating stages.

Q. Once you identify the unit that supported the transfer, how do you determine the cost of production?

A. Using the same resource stack illustrated in Table 1 above, the EIM benefit calculation multiplies the segment volume by the segment price, working down the stack until it reaches the total transfer volume. Table 2 below illustrates this calculation for a 50 MW transfer.

Table 2

Market	PacifiCorp EIM Resource Stack						Production Cost	
LAP	Day	Hour	5-Minute Interval	Price	Segment (MW)	Resource	Export (MW)	Cost
	1-Jul-15	16	6	$25.0	25	Lake Side 2		
	1-Jul-15	16	6	$24.8	40	Lake Side 1		
	1-Jul-15	16	6	$24.0	25	Currrant Creek		
$23.75	1-Jul-15	16	6	$23.3	8	Currant Creek	8	$186.3
	1-Jul-15	16	6	$22.4	20	Lake Side 2	20	$448.0
	1-Jul-15	16	6	$15.0	50	Chehalis	22	$330.0
	1-Jul-15	16	6	$14.0	49	Hunter 3		
	1-Jul-15	16	6	$13.0	10	Dave Johnston		
	1-Jul-15	16	6	($10.0)	99	Leaning Juniper		
	1-Jul-15	16	6	($15.0)	30	Goodnoe		
						Total	50	$964.3
						$/MWh		$19.3

Q. How would it work to determine the avoided cost of an import?

A. Instead of moving down the stack in the case of an export, the calculation moves up the stack to reflect the units that were backed down to accommodate the import.

Q. Is anything else considered in determining the cost to supply transfers in the EIM?

A. No, that is it. PacifiCorp does not utilize any additional information to determine the cost to produce the export or the avoided cost of the import.

Q. Staff recommended that it might be simpler to use an average cost of production, versus using the marginal cost of energy.[3] Do you support Staff's recommendation?

A. No. Staff's proposal would effectively be a mismatch of the revenue and costs in the EIM benefit calculation. EIM revenues are based on the marginal cost of energy in each interval. Similarly, PacifiCorp calculates the cost based on the

[3] Staff/300, Crider/12-14.

marginal cost of energy in each interval. Subtracting annual average costs of production from the actual EIM revenue would produce a margin that would reflect a mismatch in gas prices, coal prices, electricity prices and even unit availability.

The illustrations in Tables 1 and 2 above are a depiction of how PacifiCorp calculates the production costs for each interval. Due to the amount of data and the logic required to reference resource bids and bid segments for the same day, hour, interval, and then working through a "stack" for every single transaction, the Company must perform the calculation in a database rather than a spreadsheet that could be provided for review.

Q. Why does PacifiCorp's calculation of EIM benefits need to be so complex and done at the five-minute level? Why can't the Company simply do the calculation on a monthly or annual basis?

A. The Company's benefits are based on the differential between the market price and its marginal resource(s). The marginal resource cannot be identified by looking at monthly or annual results. Even if a particular resource is identified, it is not possible to know what operating range it was in based on monthly or annual results. Likewise there is no guarantee that a particular resource will ever be on the margin, and the frequency it is on the margin is key to determining the Company's benefits.

Q. Why is the CAISO's estimate of EIM benefits larger than the EIM benefits included in the transition adjustment mechanism (TAM) as a reduction to the net power costs modeled in the Generation and Regulation Initiative Decision Tools model (GRID)?

A. The CAISO's estimate of EIM benefits includes an estimate of the margin earned on EIM transfers, plus the benefits realized by having the EIM optimize the dispatch of PacifiCorp's own resources within its BAA (i.e. the 'intra-regional benefits'). Mr. Dickman's testimony describes how the GRID model already optimizes dispatch of the Company's generating units, obviating the need for an adjustment to recognize the intra-regional dispatch benefits.

Q. Staff argues that the CAISO utilizes a least cost economic dispatch model, like GRID, to calculate the EIM benefits.[4] Do you agree?

A. No. On the contrary, the CAISO uses a database that includes bid segments, bid prices, transfer volumes, and LAP prices as well as hourly base schedules and EIM dispatch information for each five and fifteen-minute interval. The CAISO then utilizes a program called SAS to perform logic calculations (formulas) to determine the EIM benefits, similar to the method used by the Company to calculate the benefit of EIM transfers.

[4] Staff/100, Crider/10-11.

Q. If the CAISO does not use a least cost economic dispatch model for its EIM benefit calculation, then how does it calculate a "counterfactual" of what would have occurred if there was no EIM?

A. The CAISO counterfactual is a simplified calculation of the cost that would have been incurred to meet changes in load by increasing or decreasing output from PacifiCorp's generating units relative to a base schedule. To do the counterfactual the CAISO begins with the base schedule of resources for each hour, puts them into a stack and assumes that the change in load that occurred would have been served by one or more of the resources, in merit order. If there was a decrease in load, the CAISO logic assumes that, starting at the top of the stack, PacifiCorp's resources would have decremented through the hour.

For example, if Lake Side 1 had a base schedule to generate 100 MW across the operating hour and it was at the top of the PacifiCorp resource stack, but load decreased 50 MW relative to the forecast, the CAISO calculation simply assumes that Lake Side 1 would have been decremented 50 MW to accommodate the change in load.

Q. Does the CAISO also use a "limited" set of resources in the PacifiCorp counterfactual resource stack?

A. Yes. Prior to EIM PacifiCorp was unable to "move" all of its resources to respond to changes in load across the hour. The CAISO attempts to reflect this pre-EIM operation in its counterfactual calculation.

Q. What is a base schedule for the next operating hour?

A. PacifiCorp is required to submit a base schedule for the next operating hour to identify how PacifiCorp is going to serve demand and meet its regulation requirements. Each PacifiCorp resource, non-participating and participating, is scheduled at a certain output level, flat across the operating hour.

Q. How is the base schedule developed by PacifiCorp for each operating hour?

A. The base schedule is currently a manual input by the operator based on a forecast of load, variable energy resources and an expectation of regulation requirements. While the operator optimizes the base schedule to the best of their ability, it is not an automated process, and it is inherently sub-optimal due to the fact that demand and variable resource outputs will always be different during the operating hour than what was originally forecast.

Q. What does it mean to have an "optimized" base schedule?

A. An optimized base schedule means that the schedule of resources that were submitted to the CAISO was optimized based on each unit's marginal cost, including efficient scheduling of flexible reserves. It does not mean that the schedule matches expected wind or load, which is referred to as a "balanced" base schedule. As stated previously, PacifiCorp is required to submit a resource schedule on an hourly basis that matches forecast load and wind, and it must also accommodate non-participating resource schedules and any purchases or sales. All of these things must be managed and scheduled to balance by the operator within one percent of the CAISO load forecast in a very short time frame.

Q. Why is it a short-time frame that the operator is working in to submit a resource schedule?

A. The CAISO does not provide a load forecast for balancing purposes until 70 minutes prior to the operating hour and the operator must submit a resource schedule by 57 minutes prior to the hour, which means that the operator has 13 minutes to manually schedule approximately 20 resources in the most efficient manner.

Q. Mr. Dickman made the point in Reply Testimony that the CAISO specifically stated that NV Energy was submitting an optimized schedule to the CAISO.[5] Doesn't NV Energy also have a limited time frame to schedule resources in an efficient manner?

A. Yes. NV Energy also has a limited time frame to schedule its resources; however, NV Energy utilizes an automated system to submit its base schedules that takes into consideration the marginal cost of each unit. It is unrealistic to expect an operator to manually determine a perfectly optimized base schedule, given the small time frame and large number of resources in the PacifiCorp system.

Q. Does the EIM optimize the Company's resources after base schedules are submitted?

A. Yes. The EIM market model dispatches the Company's resources during the operating hour, optimizing each resource relative to its base schedule and responding to changes in load and other variable resources on the Company's system. However, this is the end result of the EIM, not the counterfactual without

[5] PAC/400, Dickman/62.

EIM. The reduced costs resulting from the optimization of the Company's resources relative to the base schedules are the intra-regional benefits included in the EIM benefits as reported by the CAISO. Because the Company's GRID model also optimizes the Company's resources, and the net power cost forecast in the TAM is not based on the manually prepared base schedules, reducing the TAM net power costs for the intra-regional EIM dispatch would double count these benefits.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

REDACTED
Docket No. UE 307
Exhibit PAC/1000
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Dana M. Ralston

August 2016

SURREBUTTAL TESTIMONY OF DANA M. RALSTON

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ATTACHED EXHIBITS

Q. Are you the same Dana M. Ralston who previously submitted direct and reply testimony in this Transition Adjustment Mechanism (TAM) proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony addresses two issues. First, I respond to the rebuttal testimony filed by Public Utility Commission of Oregon (Commission) Staff witness Mr. Lance Kaufman and Industrial Customers of Northwest Utilities' (ICNU) witness Bradley G. Mullins on August 12, 2016, proposing adjustments to the cost of coal from the Bridger Coal Company (BCC). Company witness Mr. R. Bryce Dalley also responds to the policy and modeling issues raised by these adjustments.

Second, I address adjustments proposed by Staff witness Mr. Kaufman and by Citizens' Utility Board of Oregon (CUB) witness Ms. Jaime McGovern related to minimum take requirements in the Company's coal contracts. Company witness Mr. Brian Dickman also provides testimony on this issue.

Q. Please summarize your surrebuttal testimony.

A. BCC coal unit costs increased in this case because of lower production at the mine caused by decreased dispatch of the Jim Bridger plant. This fact is undisputed, as is the fact that as wholesale electricity market prices and Jim Bridger plant dispatch increase, BCC unit costs will trend downward. This point was demonstrated by the overall reduction in BCC unit costs in the Reply Update caused by a higher wholesale electricity costs and the associated increased dispatch of the Jim Bridger plant. Despite the recent market-based and potentially episodic nature of the increase in Jim Bridger unit fuel costs, Staff and ICNU have seized upon it to propose major cost disallowances in this proceeding.

It is also undisputed that the Company would have had to decide in 2013, at the latest, to switch to Powder River Basin (PRB) coal at Jim Bridger plant for this change to have been in effect by 2017. Staff appears to concede this issue by purporting to convert its initial 2015 analysis to 2013.

My testimony demonstrates that in 2013, the Company made a prudent decision to continue to supply the Jim Bridger plant with a combination of coal from BCC and the Black Butte mine. Through the course of several litigated TAM proceedings beginning in 2010, this fuel strategy was thoroughly vetted and in October 2013, the Commission found that the Company's BCC/Black Butte fuel strategy was reasonable and prudent.

The Company's decision during this timeframe to continue its BCC/Black Butte fuel strategy was reasonable. The Commission had just reviewed and approved the fuel strategy and, at the time, coal from the PRB was not an economic or viable alternative to replace the long-term fuel supply for the Jim Bridger plant. In 2013, Black and Veatch produced a study advising that the cost of retrofitting the Jim Bridger plant to allow it to bring in PRB coal would be $[redacted] (100 percent share), or $[redacted] in 2017 after adjusting for inflation. Due to this prohibitively large capital investment and uncertainty about how the Jim Bridger plant would operate using PRB coal, the Company adhered to its historical fueling strategy. The Company did, however, continue to explore

PRB coal as a future market alternative as a part of its long-term fuel supply planning for the Jim Bridger plant.

In June 2014, the Company issued a Request for Proposals (RFP) to all potential market suppliers to the Jim Bridger plant, including three mines in Southwest Wyoming and four mines in the PRB. The Company issued the RFP to determine the best fueling replacement option for the terminating Black Butte coal contract and confirmed that renewing the Black Butte contract was the least-cost, least-risk option. The RFP process also led to the Company acquiring a transportation contract to carry both the Black Butte coal and the volume of PRB coal the Jim Bridger plant could use without retrofits or potential operational concerns.

In July 2014, the Company completed a new long-term fuel plan for its 2015 Integrated Resource Plan (IRP) that reflected the closure of the Bridger underground mine in 2024 and the use of PRB coal as a long-term fuel supply source for the Jim Bridger plant. This plan evolved into the Long-Term Fuel Plan filed with the Commission in 2015, which includes the major capital investments necessary at the Jim Bridger plant to switch to PRB coal by 2023, based on an updated and more refined cost estimate at significantly reduced costs. The Company is updating the Long-Term Fuel Plan to respond to rapidly changing market conditions and proposes to file an updated Plan by the end of 2016 reviewing all viable fueling options, including those involving PRB coal supply.

The evidence shows that, contrary to Staff's claims, the Company has carefully reviewed and developed the option of supplying the Jim Bridger plant from the PRB for many years. The quantitative analysis and price comparisons I present in my reply testimony and surrebuttal testimony demonstrate that the Company was reasonable in deciding not to make an immediate and irrevocable switch to PRB coal in 2013.

Staff argues that the Company was imprudent in 2013 for not disregarding the Commission's concurrent order approving its historical fuel supply strategy, not beginning the retrofit of the Jim Bridger plant to take full supply from PRB coal as soon as possible, not avoiding contractual commitments to Black Butte coal, and not beginning the process of closing the BCC mine. But the evidence here shows that the Company's more deliberate approach to integrating PRB coal supply at the Jim Bridger plant was reasonable and far less risky for customers. This is demonstrated by the fact that, at this point, the Company retains a full range of options to address long-term fuel supply needs at the Jim Bridger plant. As stated in the testimony of Mr. Dalley, the Company requests that the Commission open a new planning docket in Oregon to review these options, as reflected in the Company's update to its Long-Term Fuel Plan.

While ICNU generally supports the Company's analysis demonstrating the reasonableness of its historical fuel supply strategy in 2017, ICNU unreasonably changes the amortization period from four years to 13 years and the return on the Company's undepreciated investment in the mine to argue that PRB coal is lower cost. ICNU incorrectly argues that the Commission should impute a lower fuel supply price by disregarding the fact that PRB coal is not an available, viable fuel supply for the Jim Bridger plant in 2017. ICNU also compares PRB unit costs to

BCC unit costs, instead of looking at total Jim Bridger plant coal supply unit costs. The Company disagrees with this comparison because the most accurate and complete way to analyze Jim Bridger plant costs is to look at total fueling costs not just one element of the fueling plan. In the interest of showing that BCC is the least-cost least-risk option, the Company examined ICNU's hypothetical view and corrected it. Once ICNU's incorrect assumptions are amended, the PRB unit cost becomes $[redacted] per ton, which is still $[redacted] per ton higher than the BCC-only unit cost of $[redacted] per ton which includes a BCC return on rate base amount of $[redacted] per ton.

Staff's challenge to minimum-take provisions in the Company's coal contracts ignores the commercial reality that the Company must either accept these provisions or purchase coal on the spot market and assume the attendant price volatility and reliability risks. Staff's proposal for how to manage the Company's coal inventory in conjunction with minimum take provisions likewise ignores the facts that the Company already uses inventory levels to manage supply volatility, based on periodic coal inventory studies.

STAFF'S COAL PRICE ADJUSTMENT

Q. Has Staff changed its proposed adjustment to Jim Bridger plant fueling costs in its rebuttal testimony?

A. Yes. Staff initially proposed an adjustment to re-price coal supplied by BCC at Staff's calculated price for PRB coal. Staff's original adjustment decreased net power cost (NPC) by $40.9 million (total system), or $10.4 million on an Oregon-allocated basis.

In rebuttal testimony, Staff significantly broadened the scope of its adjustment by adopting three changes to its methodology for determining Jim Bridger plant coal costs.[1] First, Staff recommends that *all* Jim Bridger plant coal be re-priced using PRB prices, *i.e.*, in addition to re-pricing BCC coal, Staff also re-priced Black Butte coal. Staff witness Mr. Kaufman devoted only one sentence of his testimony to this new disallowance. He failed to explain that the Black Butte coal contract is the result of an RFP (which included bids from PRB mines) that the contract has been in rates since the 2016 TAM, and that no party has ever challenged its prudence.

Second, Staff changed its testimony on rail transportation costs, decreasing its cost estimate by approximately 25 percent from the average PRB transportation price Staff identified in its opening testimony, and ignoring the Company's actual PRB transportation contract.

Third, Staff purported to calculate NPC dispatch benefits resulting from the use of PRB coal at the plant. In total, Staff's Bridger coal supply adjustment in rebuttal increased by more than 230 percent to $95.2 million (total system), or $23.5 million on an Oregon-allocated basis.[2]

Q. Is Staff's new adjustment more unreasonable than its original adjustment?

A. Yes. While Staff purports to correct several of the deficiencies the Company identified in its reply testimony, Staff's rebuttal position is even more problematic:

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[1] Staff/400, Kaufman/30-31.
[2] Staff/400, Kaufman/31.

- Staff's testimony flatly mischaracterizes the Company's coal supply strategy and planning processes, despite Staff's possession of numerous planning documents provided by the Company through discovery.
- Staff's analysis of coal costs is incomplete and inaccurate and ignores actual data and engineering studies the Company provided.
- Staff relies on impermissible hindsight review to second-guess prudent decisions that were made years ago and not contemporaneously challenged by Staff or any other party.

I demonstrate that when Staff's analysis is corrected and viewed in the correct and complete historical context, it shows that the Company's fueling strategy for the Jim Bridger plant for 2017 is reasonable.

Q. Does Staff's adjustment consider the consequences of a decision in 2013 to transition to 100 percent fuel supply from PRB by 2017, including closure of the Bridger mine and discontinuation of coal supply from the Black Butte mine?

A. No. An expedited transition to PRB (100 percent) coal supplies at the Jim Bridger plant beginning in 2013 would have resulted in: (1) significant underfunding of final reclamation obligations, impairment of mine assets (property plant and equipment, construction work in progress, coal inventories, material/supply inventories, pension obligations, etc.); (2) operational challenges associated with retention of skilled workers; (3) financial risk associated with large capital expenditures in the mine; (4) foreclosing alternative fueling strategies with potentially lower capital expenditures; (5) increased operational risk associated with burning large quantities of coal containing significantly different quality characteristics than existing fuel supply; (6) loss of historical fuel sources because BCC would close, and most likely the Black Butte mine; and (7) less flexibility to respond to the major changes occurring in the wholesale electricity markets and coal markets.

Response to Staff's Criticism of the Company's Long-Term Fueling Strategy

Q. What are Staff's criticisms of the Company's long-term fueling strategy for the Jim Bridger plant?

A. Staff incorrectly testifies that "PacifiCorp performed no multi-year cost analysis of market alternatives until ordered to do so by the Commission" in the 2014 TAM.[3] At least once a year, the Company develops a BCC mine plan that utilizes a 10-year planning horizon to develop a strategy for least-cost, least-risk fueling of the Jim Bridger plant. The Company provided BCC's mine plans from 2012, 2013, 2014 and 2015 to Staff in discovery, along with a detailed description of how these plans are developed.

In addition to annual 10-year plans, approximately every two years, the Company develops a life-of-plant fueling plan used in the Company's IRP. These more comprehensive plans assess the fueling options available for the Jim Bridger plant and determine the least-cost, least-risk option. The Company prepared a long-term fuel plan in May 2010 for the 2011 IRP (docket LC 52), January 2013 for the 2013 IRP (docket LC 57), and July 2014 for the 2015 IRP (docket LC 62).

The Long-Term Fuel Plan filed with the Commission in December 2015 was a new tool that added to the Company's well-established planning practices

[3] Staff/400, Kaufman/2. Staff misleadingly relies on the Company's response to OPUC 221 for this statement. In that data request response, the Company indicated that it had not prepared "comprehensive delivered coal costs evaluations" for large volumes of PRB coal given the cost-prohibitive capital investment projections. The Company's companion response to OPUC 244, however, makes clear that it did analyze PRB coal in 2013-2015 timeframe for potential supply to the Jim Bridger plant in the 2017-2019 timeframe.

for the Bridger mine and for fuel supply to the Jim Bridger plant. That Plan was not, as Staff incorrectly claims, the Company's first multi-year cost analysis of market alternatives. Staff also wrongly implies that the Commission had to order the Company to conduct multi-year planning of market alternatives; in fact, I understand that the Company, Staff, and CUB all endorsed the proposal to make such filings in docket UE 264, to follow-up on extended, informal discussions between the Company and Staff on the issue.[4]

Q. Staff also testifies that prior to developing its Long-Term Fuel Plan in December 2015, "PacifiCorp had not analyzed the long run costs or benefits of PRB coal in place of BCC coal."[5] Is this true?

A. No. The Company's long-term fuel plans discussed above included consideration of PRB coal as a potential fuel source to the Jim Bridger plant in the future, taking into account the viability and economics of PRB coal at the time.

Q. Staff specifically claims that the Company did not assess PRB coal as an alternative prior to investing in BCC's underground mine in 2005.[6] Is this true?

A. No. In 2003, the Company analyzed fueling options for the Jim Bridger plant, including developing an underground mine at BCC, and several market alternatives, including PRB, Uintah Basin (Utah and Colorado), and Hannah

[4] *In the Matter of PacifiCorp d/b/a/ Pacific Power's 2014 Transition Adjustment Mechanism*, Docket UE 264, Opening Brief of PacifiCorp at 13 ("PacifiCorp supports development of periodic Bridger plant fuel plans to permit parties to review the reasonableness of BCC coal supply on a longer-term, multi-year basis rather than on a year-by-year basis as costs fluctuate in annual NPC updates, Given renewed interest from all parties in this approach, the Commission should reject ICNU's adjustment and direct parties to work together to develop a long-term fuel plan review process for generation plants supplied by the Company's affiliate mines.")
[5] Staff/400, Kaufman/2-3, 7.
[6] Staff/400, Kaufman/2-3.

Basin (Wyoming) coal. The Company's analysis demonstrated that pursuing the underground mine was the least-cost, least-risk option. When the Company sought recovery of its mine development investments in the underground mine in 2005, the Commission approved a settlement allowing a three-year amortization of these costs.

Q. During that time period, were there general concerns about fueling the Jim Bridger plant with coal from the PRB?

A. Yes. First, the Company completed an unsuccessful test burn of PRB coal in 2000 at the Jim Bridger plant. As a result of the unsuccessful test burn, the Company did not view PRB as a viable replacement coal source during that time period. Second, coal supply from the PRB in 2005 was severely disrupted for an extended period of time because of a train derailment. Purchasers were forced to uneconomically curtail plants and fully deplete inventories. PRB prices doubled in the wake of failure of the rail lines. This incident highlighted both the transportation risk associated with PRB coal and the risk of a single-source fuel supply plan.

Q. Staff also claims that the Company did not assess PRB coal as an alternative in 2013 "after BCC costs escalated substantially."[7] Is this true?

A. No. First, I disagree with Staff's claim that BCC costs escalated substantially relative to other fuel sources in Southwest Wyoming. The historical evidence from past TAM filings, summarized in Mr. Dalley's reply testimony, demonstrates that this is incorrect. Beginning with the 2014 TAM, filed in 2013,

[7] Staff/400, Kaufman/3.

per unit costs in the three Southwest Wyoming mines increased at a similar, moderate pace.

- The record in the 2014 TAM, docket UE 264, shows forecast BCC per unit costs of $[redacted] per ton, while Black Butte was $[redacted] per ton. The forecast for the Kemmerer mine in Southwest Wyoming was $[redacted] per ton, not counting transportation costs.[8]
- The record in the 2015 TAM, docket UE 287, shows forecast BCC per unit costs of $[redacted] per ton, while Black Butte was $[redacted] per ton. The forecast for the Kemmerer mine was $[redacted] per ton.[9]
- The record in the 2016 TAM, docket UE 296, shows forecast BCC per unit costs of $[redacted] per ton, while Black Butte was $[redacted] per ton. The forecast for the Kemmerer mine was $[redacted] per ton.[10]

Second, Staff's claim that the Company never assessed PRB coal supply is simply wrong. As Staff acknowledges, in January 2013, the Company retained the engineering firm Black and Veatch to "estimate the maximum achievable load (of PRB coal) while incorporating the minimum capital modifications necessary to safely fire PRB coal and coal blends in the Jim Bridger units."[11] The fact that the Company commissioned this study is clear evidence that it assessed PRB coal as an alternative to BCC.

[8] *In the Matter of PacifiCorp d/b/a Pacific Power 2014 Transition Adjustment Mechanism*, Docket UE 264, Confidential Exhibit PAC/601, Crane/1.
[9] *In the Matter of PacifiCorp d/b/a Pacific Power 2015 Transition Adjustment Mechanism*, Docket UE 287, PAC/200, Crane/20.
[10] *In the Matter of PacifiCorp d/b/a Pacific Power 2016 Transition Adjustment Mechanism*, Docket UE 296, PAC/300, Larsen/17.
[11] Exhibit PAC/1002, Ralston/1 (Black and Veatch 2013 Study).

In addition, as noted above, the Company issued an RFP in 2014 for coal to serve the Jim Bridger plant and sent it to PRB suppliers. The responses to this RFP informed the Company's analysis and decision-making on the Jim Bridger plant's long-term coal supply, and led to the execution of a new Black Butte contract beginning in 2015.

Q. Staff claims that because of the capital investment required to receive PRB coal, the Company did not analyze the long-term cost of PRB coal. Is this a fair characterization?

A. No. Staff implies that because of the large capital investment, the Company simply refused to even consider PRB coal. In fact, the Company analyzed PRB coal, but the capital investment consistently made PRB a more expensive option. It is not that the Company never analyzed PRB coal because of the capital investment, it is that the capital investment rendered PRB coal uneconomic compared to available alternatives.

Q. Staff claims that the Company had to convert to PRB coal after it decided to close the underground mine, so the question was "when" not "whether" to make the capital investment. Is this correct?

A. No. The Company has various options to replace the coal from the underground mine. Contrary to what Staff contends, it has never been a foregone conclusion that the Company would make the capital investment necessary to retrofit the Jim Bridger plant to burn PRB coal by 2024, irrespective of the economics of doing so.

Q. Does Staff correctly characterize the historical BCC pricing?

A. No. To support its position, Staff re-writes history to claim the Company steadfastly refused to explore alternatives to BCC coal even though BCC costs have been unreasonably high for years. The actual historical evidence, however, is contrary to Staff's claims.

For example, Staff argues that BCC coal costs have escalated rapidly since 2005.[12] But Staff fails to acknowledge that Black Butte coal escalated at roughly the same rate. From the 2010 TAM through the 2016 TAM, BCC coal and Black Butte coal have been comparably priced, as described in Mr. Dalley's reply testimony. Staff's characterization of historical BCC costs also ignores its own prior testimony on the subject. As Mr. Dalley testifies, since 2009 Staff has never challenged the reasonableness of BCC coal prices. Even in 2009, Staff's own pre-TAM analysis found that BCC provided customer benefits and was expected to continue doing so for some time. Staff's current version of history cannot be reconciled with its prior, contemporaneous positions.

Finally, Staff's position here ignores entirely the fact that the Commission has never found that its cost-based pricing approach to BCC coal results in unreasonable coal costs for the Jim Bridger plant. On the contrary, as described by Mr. Dalley, the Commission has consistently found that BCC coal has provided customer benefits over the long-term.

[12] Staff/400, Kaufman/2.

Q. Staff also compares Jim Bridger plant to the Dave Johnston plant and implies that this comparison indicates that BCC has historically been a high-cost source of coal for the Jim Bridger plant.[13] Is this a reasonable comparison?

A. No. The fact that Dave Johnson is located near PRB coal and therefore incurs substantially less transportation costs does not in any way suggest that BCC coal is unreasonably priced for the Jim Bridger plant. In addition, like Figure 3 in Staff's opening testimony, Figure 1 in Staff's rebuttal testimony relies on data reported to the U.S. Energy Information Administration (EIA), not data provided directly from PacifiCorp. Changes in EIA reporting requirements in 2010 (*i.e.*, from reporting production costs to reporting contract prices) distort the accuracy of the trend that Staff purports to show, especially with respect to price spikes in the 2010 period. PacifiCorp's testimony in this and past cases demonstrates that BCC's per unit costs were not high-priced relative to other suppliers to the Southwest Wyoming market.

Q. Why is the historical coal pricing relevant?

A. Historical coal pricing is relevant because, as Staff now acknowledges, its prudence analysis must be based on what the Company knew or should have known in 2013. Contrary to Staff's claims, since at least the 2010 TAM, BCC has been comparably priced to available alternatives, including Black Butte and PRB coal. Based on the Company's extensive analysis, as of 2013 there was nothing

[13] Staff/400, Kaufman/6-7, Figure 1.

that would suggest that by 2017, PRB coal would be a more economical alternative to either BCC or Black Butte.

While Staff repeatedly mischaracterizes BCC coal prices, *e.g.*, claiming they have been rapidly escalating for over a decade, the reality is that changing market dynamics in the last year, not the last decade, have caused a major shift in the relative economics of BCC, Black Butte, and PRB coal. Staff acknowledges as much in its opening testimony when it correctly points out that BCC's pricing for the 2017 TAM is driven largely by the unprecedented market dynamics that have caused substantially lower burns at the Jim Bridger plant.[14]

Q. Staff also faults the Company for only analyzing PRB costs in 2017 in its reply testimony.[15] Why did the Company focus on 2017 costs in its reply testimony?

A. The Company was simply responding to the analysis performed by Staff and ICNU claiming that in 2017, PRB coal was lower cost than BCC. My testimony demonstrates that this is untrue. The Company agrees with Staff that the prudence of the Company's fueling strategy must be assessed using a long-term view. As I describe below, based on what was known in 2013, the long-term view did not support a switch to PRB coal.

Q. Given your support for a long-term analysis of Jim Bridger plant fueling costs, is the Company updating its Long-Term Fueling Plan?

A. Yes. In my reply testimony, I indicated that the Company was planning on updating its long-term plan to coincide with the Company's 2017 IRP. As

[14] Staff/200, Kaufman/27-28, 30, 35-36.
[15] Staff/400, Kaufman/8.

discussed in more detail in Mr. Dalley's surrebuttal testimony, the Company proposes to expedite this update to respond to Staff's position advocating for immediate and exclusive PRB coal supply to the Jim Bridger plant and a more robust Long-Term Fuel Plan. Staff's adjustment requires the Commission to agree that the Company must make major capital investments at the Jim Bridger plant now to switch fuel supply, even if it means permanently shuttering the BCC mine and losing Black Butte as an alternative source of coal. As explained by Mr. Dalley, the Company proposes that the Commission open an expedited planning docket as soon as practicable to review these important issues outside the context of a litigated TAM filing. The Company is prepared to file an update to the Long-Term Fuel Plan by the end of 2016.

Response to Staff's Comparison of PRB to BCC and Black Butte Coal

Q. Staff's original analysis relied on coal pricing data from 2015 to support its proposed adjustment. Has Staff modified its position in its rebuttal testimony?

A. Yes. In rebuttal, Staff acknowledges that in order for PRB coal to replace BCC coal in 2017, the Company would have had to decide to make the switch no later than 2013. Therefore, Staff's rebuttal testimony properly focuses on what the Company knew or should have known in 2013.[16]

[16] *Id.*

Q. Staff's analysis also claims to compare PRB to BCC and Black Butte coal over a 20-year planning horizon.[17] Is that a reasonable approach?

A. No. For purposes of this case, which proposes an adjustment to NPC in Oregon, relying on what the Company knew or should have known in 2013, the Commission should review the analysis based on the depreciable life of the Jim Bridger plant in Oregon, which ends in 2025.

Q. Staff testifies that the most significant difference between the Company's and Staff's pricing relates to the transportation costs for PRB coal.[18] How did the Company determine the transportation costs it used in its 2013 analysis?

A. The Company calculated a transportation price for 2017 of $[redacted] per ton, based on what was known in 2013.[19] $[redacted] per ton is the calculated average price resulting from numbers derived from the U.S. Department of Transportation Surface Transportation Board's (STB) Uniform Rail Costing System model adjusted for 180 percent and 250 percent of long term variable costs. 180 percent of long term variable cost represents a cost level that shippers may look to seek relief from railroads with the STB. 250 percent of long term variable cost represents a level that provided the Company with an upper book-ended sensitivity to the estimated transportation price calculation.

Estimating transportation costs is a key aspect of managing the Company's fuel supply. The Company has considerable experience estimating

[17] *Id.*
[18] Staff/400, Kaufman/9. Staff's testimony states that the Company's transportation price is $[redacted] per ton. Staff/400, Kaufman/9. For purposes of its 2013 analysis, however, the Company forecast a transportation price for 2017 of $[redacted] per ton.
[19] PAC/500, Ralston/20 (Confidential Figure 2).

and forecasting rail transportation costs, which it applied in developing the cost estimate in this case.

Q. Was the $[redacted] per ton forecast transportation price a reasonable estimate in 2013 for the actual contract price provided for PRB coal deliveries in 2017?

A. Yes. The actual rail contract price provided by the Union Pacific Railroad Company (UPRR) as of June 2016 is $[redacted] per ton prior to fuel surcharge, dust and anti-freeze application and handling costs. The price adjusted for inflation in the 2017 TAM is $[redacted] per ton. This actual 2017 contract rate is [redacted] percent higher than what the Company estimated in 2013. A comparison of the actual 2017 rail contract rate to the Company's 2013 estimate demonstrates that the methodology used by the Company in 2013 provided a more accurate estimate of rail costs than Staff's methodology that resulted in a calculation of $[redacted] per ton.

Q. How did Staff calculate the transportation costs for PRB coal?

A. Staff calculates a transportation rate of $[redacted] per ton for 2016, 25 percent less than the $[redacted] per ton Staff identified as the average PRB transportation price for 2015 last month in its opening testimony.[20] To arrive at this figure, Staff analyzed PacifiCorp's other rail contracts and determined the relationship between the cost per ton and the rail miles from the mine to the plant. Based on only the distance from the PRB to the Jim Bridger plant, Staff claims that the transportation costs should be only $[redacted] per ton based on 2016 data, or $[redacted] based on 2013 data.[21]

[20] Staff/400, Kaufman/10.
[21] Staff/402, Kaufman/1.

Q. Is Staff's analysis reasonable?

A. Not at all. Staff's analysis is far too simplistic by assuming that the rail prices are directly proportional to distance and that no other factors impact transportation costs. In fact, Staff's methodology fails to account for a number of important considerations that influence and weigh into the development of transportation rates. Some of these key considerations are described as follows:

1) market alternatives available,
2) unit train cycle times,
3) competition with truck transportation and other railroads,
4) rail line traffic and congestion,
5) required number of rail sidings and switches,
6) topography of the rail route terrain,
7) size of the unit trains,
8) number of locomotives required,
9) location of the railroad crews,
10) power plant track configuration,
11) unloading facilities,
12) required unloading hours,
13) rail car size and type, and
14) location of railcar maintenance facilities.

All of the aforementioned items factor into the development of transportation rates. Staff's methodology is an academic calculation with insufficient data and fails to account for real world differences to accurately calculate costs.

Q. What is Staff's basis for rejecting PacifiCorp's estimated transportation costs for its 2017 analysis?

A. Staff acknowledges that the Company's estimate is based on an actual contract, negotiated at arm's length between the Company and UPRR for PRB coal transported to the Jim Bridger plant.[22] Staff claims because the contract was not negotiated as a high volume contract, the Commission should disregard its pricing terms. Staff disregards the fact that this contract also included volumes for shipping from the Black Butte mine and, in total, had a significant minimum volume requirement. The transportation costs under this contract were reflected in rates in the 2016 TAM without objection from any party. A copy of the UPRR contract is attached as Highly Confidential Exhibit PAC/1001.

The Company's actual transportation costs are the most accurate available information for this analysis, and they correlate closely to the Company's rail transportation cost estimate for its 2013 analysis based on industry indices. As stated previously, the estimate done in 2013 was actually [redacted] percent lower than the actual contract rate.

Staff also claims that the Company had no incentive to negotiate a lower rate because doing so would make PRB more cost effective and make ongoing investments in BCC more questionable.[23] There is no basis for this claim. PacifiCorp always has an incentive to obtain the least cost pricing terms for its customers and co-owner Idaho Power because failure to do so exposes the

[22] Staff/400, Kaufman/12-13.
[23] Staff/400, Kaufman/13.

Company to a potential prudence disallowance or a contractual complaint from Idaho Power Company. Staff's accusation that the Company would manipulate its contract negotiations and harm customers simply to keep BCC open has no factual basis. Without any actual evidence that the contract terms are unreasonable, Staff's claim is insufficient to undermine the market-based transportation pricing used in the Company's 2017 analysis.

Q. Staff bolsters its calculated transportation price by noting that generic information from the EIA shows that the cost of transportation from PRB to bordering states averaged $11.77 in 2014.[24] Is this metric relevant?

A. Not at all. The average coal rail transportation costs from PRB to neighboring states is not specific to any particular mine or any particular route of rail transportation. Therefore that data does not represent the actual costs from a specific mine to a specific plant nor does it provide information relating to rail distances, tonnage requirements, contract term length or vintage, service commitment, ownership of rail cars, or even the name of railroad shipping the coal. All of these factors, along with several others, influence rail rates.

In addition, the information demonstrates the high variability of data within the averages. For example, transportation from the PRB to Nebraska increased from $8.62 to $14.35 per ton in 2012 dollars or 66.4 percent from 2008 to 2012, while transportation to Colorado increased from $12.01 to $13.23 per ton, only 10 percent, during the same period. Significant variability will occur based on the terms and conditions of specific contracts and the logistics of the

[24] Staff/400, Kaufman/10.

transportation path. The data sources used also shows that data from states west and north of Wyoming were "withheld to avoid disclosure of individual company data." In other words, the market is so small that providing the data would publish the rate for that customer. Since the market to the west is small, and the Jim Bridger plant market would be a western market, using a mathematical analysis using data from states with a larger market would result in an inaccurate result. Using actual contract data that the Company provided is the most accurate source.

Q. Staff also faults the Company's long-term forecast of PRB transportation costs.[25] Is Staff's criticism legitimate?

A. No. Staff's criticism is unfounded. Staff has attempted to refute PacifiCorp's estimated rail costs by using results from a regression analysis model which has limited inputs. Seventy percent of the data points used in Staff's regression analysis come from only two contracts which utilized rail rates provided from a different Class I railroad. As previously noted, estimating a potential range for a specific rail rate, for a given power plant, for a definite period of time, for certain tonnage volumes involves many more factors. Staff's attempt to estimate a specific rail rate utilizing a limited regression analysis, along with estimated EIA data, is overly simplified and flawed. Doing so ignores the results and outcomes of real "arm's length" negotiations transacted between a shipper and the railroad. Given that the forecast rail rate used by the company in the 2017 TAM is the actual contract rail rate negotiated for 2015 PRB coal deliveries to the Jim Bridger

[25] Staff/400, Kaufman/13.

plant, adjusted for inflation, the rate used by the Company is a better representation than the overly simplified regression analysis used by Staff.

Q. Staff's rebuttal analysis purports to include the costs of BCC closure in its comparative analysis.[26] Nonetheless, Staff still claims that the Company could sell BCC coal on the market once it is replaced by PRB coal.[27] Is this reasonable?

A. No. Staff claims there is "no evidence" that BCC would close if it could no longer sell coal to the Jim Bridger plant.[28] Staff ignores the fact that BCC is a captive mine that has never sold coal to an entity other than the Jim Bridger plant. My reply testimony explained that BCC has no rail load-out facilities for coal sales and provided substantial evidence that there is no market for BCC coal. This is a logical conclusion supported by simply looking at the location of the BCC mine. The Jim Bridger plant was designed to receive BCC coal directly by means of conveyor belt without incurring transportation costs—costs that Staff acknowledges are significant.[29] If BCC is no longer the least cost source of coal for the Jim Bridger plant, which has no transportation costs, it will not be the least cost source of coal for some other buyer who will have to pay for transportation.

Q. Do you have any corrections to the BCC mine closure costs Staff includes in its analysis?

A. Yes. First, Staff uses an unreasonably long amortization period of 20 years,

[26] Staff/400, Kaufman/15.
[27] Staff/400, Kaufman/14.
[28] Staff/400, Kaufman/15.
[29] Staff/400, Kaufman/9 (transportation costs single largest component of PRB price).

which Staff incorrectly claims is the remaining life of the plant.[30] This one change accounts for 80 percent of Staff's reduction in the closure costs.[31] The depreciable life of the Jim Bridger plant in Oregon extends to 2025, not 2037. Thus, even if Staff's rationale is sound and the amortization period should match the life of the plant, Staff overstates the amortization period by 12 years.

Q. What amortization period did the Company use in its analysis?

A. The Company used a four-year amortization period. Based on what was known in 2013, this is a reasonable assumption. In 2002, when the Company closed the Trail Mountain mine, the undepreciated investment was amortized over five years.[32] In 2005, the Commission allowed the Company to amortize the capital investment incurred to develop the Bridger underground mine over three years.[33] The four-year amortization period was reasonably consistent with the Commission's amortization of previous non-recurring BCC costs and closure of other affiliate mines.

Q. Does Staff have any other criticisms of the Company's calculation of the amortization costs associated with closure of BCC?

A. Yes. Staff also claims that by using only a four-year amortization period, the Company front-loaded the closure costs in 2017, without analyzing the long-term impact of switching to PRB coal.[34] The Company's four-year amortization period is consistent with the Commission's recent treatment of the Deer Creek mine.[35]

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[30] Staff/400, Kaufman/16.
[31] Staff/400, Kaufman/18.
[32] Order No. 02-343 at 4.
[33] Order No. 05-1050 at 6.
[34] Staff/400, Kaufman/16.
[35] Order No. 15-161 at 8.

In that case, ICNU specifically recommended a longer amortization period of nine years, making a similar argument to Staff here.[36] Yet, the Commission chose a shorter, four-year period.

Q. What other concerns do you have over Staff's calculation of the impact of BCC closure costs on the decision to switch to PRB coal?

A. Staff also recommends that that the regulatory asset created by the closure of BCC accrue interest at the rate of 3.43 percent in its present value revenue requirement (PVRR) analysis and 1.88 percent interest in its 2017 analysis.[37] Mr. Dalley explains why the Company's use of its weighted average cost of capital of 7.69 percent is reasonable.

Q. Staff also reduces the size of the unrecovered investment by 46 percent.[38] Do you agree with Staff's recalculated amount?

A. No. The Company calculated the unrecovered investment based on the 2013 plant in service. Staff reasons, however, that the mine would remain open until 2017 and therefore the 2013 plant balances would depreciate. Staff claims that this three-year depreciation (between the end of 2013 and beginning of 2017) would reduce the unrecovered investment by 46 percent from $[redacted] to $[redacted] (total PacifiCorp and Idaho Power's share). The Company agrees that in this hypothetical example, the mine would need to operate until 2016 and the Company supplied the corrected calculation to Staff on August 8, 2016. The corrected number is $[redacted]. This amount is still significantly more than

[36] Order No. 15-161 at 7.
[37] Staff/400, Kaufman/17.
[38] Staff/400, Kaufman/18.

Staff's calculation. The amounts in this paragraph refer to total BCC costs not PacifiCorp's share.

Utilizing information from the depreciation file in PacifiCorp's Confidential 2015 Long-term Fuel Supply Plan for the Jim Bridger plant, Staff incorrectly eliminated all capital expenditures from underground and surface mining operations even though the mine continues to operate through 2016 in the hypothetical scenario. Staff's action of removing all capital expenses between 2013 and 2016 accounts for the majority of the claimed reduction from the Company's calculation of $[redacted] to Staff's calculation of $[redacted]. Aside from using a recent depreciation schedule that contains information not known by the Company in the fall of 2013, this simplistic approach would effectively shutter the underground mine prior to year-end 2016 and result in fewer tons produced in both the surface and underground operations.

To illustrate, as the underground mine advances deeper into the coal reserve, longwall panels and underground mine support systems must be developed and installed. These costs are capitalized and include expenditures for section/mainline extension, de-watering, ventilation, tailgate bleeders, mine monitoring and conveying systems to remove coal from advancing locations. As underground mine development expands, significant amounts of water are liberated from overlying aquifers and must be handled to maintain safe, efficient operations in compliance with strict Mine Safety and Health Administration (MSHA) standards.

Additionally, significant expenditures are required to install seals to minimize oxygen levels from previously mined areas and maintain adequate levels of oxygen in active working areas compliant with MSHA requirements. Elimination of these expenditures would shutter underground mining operations. The wholesale removal of equipment replacement costs would either dramatically increase operating costs or result in fewer tons produced. Operating costs would be higher because expenditures for equipment repairs would increase and production would decrease because of reduced equipment availability. In some instances, it might not be possible to obtain replacement parts due to the equipment age. This would result in less coal produced due to operating less equipment.

Q. Staff also ignored the costs of removal that the Company included in its closure costs, claiming that these costs were already included in the depreciation and net salvage.[39] Is this correct?

A. No. These $[redacted] of labor costs were not included in mine operating costs or final reclamation costs and are therefore, appropriate to include in the costs of removal.

Q. Overall, Staff's adjustments to the closure costs reduce the regulatory asset from $[redacted] to only $[redacted] per ton in 2017.[40] Do you still maintain that the $[redacted] per ton calculation is correct?

A. Yes, with the exception of the change to the unrecovered investment noted above,

[39] *Id.*
[40] *Id.*

the number was revised to$[redacted]per ton according to the errata filed on August 8, 2016 as shown in Confidential Figure 1.

Q. Staff also disputes the Company's calculation of the capital investment that would have been required to receive and burn PRB coal in 2017.[41] What value did PacifiCorp use when determining the capital investments required for PRB coal?

A. Based on what the Company knew in 2013, its analysis included $[redacted] (PacifiCorp plus Idaho Power share) in capital investments required to receive and burn PRB coal in 2017. This estimate was based on a comprehensive and detailed analysis performed by Black and Veatch, a highly reputable engineering firm that was retained specifically to analyze this issue. The summary of the Black and Veatch study is attached to my testimony as Exhibit PAC/1002.

Q. Does Staff use the estimate provided by Black and Veatch in 2013?

A. No. Staff claims that the costs included in the Black and Veatch study are excessive as compared to the costs for similar facilities at the Company's other plants.[42] Staff's analysis is again an academic calculation and completely ignores an in-depth engineering analysis that uses the specifics from the plant site, volumes required, and the use of current engineering standards compared to Staff's calculation of original costs of the systems escalated for inflation.

Q. What value does Staff use for the capital investments required to receive and burn PRB coal?

A. Staff uses the Company's estimated investment developed in 2015, claiming that

[41] Staff/400, Kaufman/19.
[42] Staff/400, Kaufman/19-20.

if the Company had "seriously evaluated PRB coal in 2013" it would have revised the Black and Veatch estimate downward.[43] Staff's recommendation is impermissible hindsight review. Based on what the Company knew in 2013, the capital investment costs were in excess of $[redacted] (total plant share).

Q. Why did the Company ultimately conclude by 2015 that the investment costs were likely to be lower?

A. In 2014-2015, the Company continued to review the PRB fuel supply option and explore whether PRB coal presented operational limitations at the Jim Bridger plant. As a part of this effort, the Company performed an internal review of the Black and Veatch study to determine whether the capital investment costs could be reduced. This resulted in the Company developing a revised minimum capital investment in 2015 dollars of $[redacted] (total plant share).

Q. Staff also uses a 20-year depreciable life for the capital investments.[44] Is this a reasonable assumption based on what the Company knew in 2013?

A. No. Staff claims that the depreciable life is based on the expected useful life of the assets. But the Jim Bridger plant's depreciable life in Oregon extends through 2025, so there is no basis to adopt a depreciable life for these investments that is longer than the plant life. In 2013, the reasonable depreciable life would have been through 2025, to correspond to the depreciable life of the plant. In my direct testimony, the Company assumed a more conservative depreciable life of 2029, corresponding to the removal of coal assets from Oregon rates under Senate Bill 1547 (SB 1547). Adjusting the depreciable life to 2025 results in an increase of

[43] Staff/400, Kaufman/20.
[44] *Id.*

$[redacted] per ton from $[redacted] per ton to $[redacted] per ton as shown in Confidential Figure 1.

Confidential Figure 1
Bridger Plant Market Comparison
Hypothetical 2017 Test Year using information available to the Company in 2013
Fuel Costs

	PRB	Bridger Coal Company	Black Butte	**Bridger Plant**
Tons	[redacted]	[redacted]	[redacted]	[redacted]
MMBtus	[redacted]	[redacted]	[redacted]	[redacted]
BTU/lb	[redacted]	[redacted]	[redacted]	[redacted]
Coal Cost $/ton (a)	[redacted]	[redacted]	[redacted]	[redacted]
Rail Cost (b)	[redacted]		[redacted]	[redacted]
Fuel Surcharge	[redacted]		[redacted]	[redacted]
Anti-Freeze/Dust Supression	[redacted]		[redacted]	[redacted]
Handling	[redacted]		$ -	$ -
Market Price before BTU Adjustment	[redacted]	[redacted]	[redacted]	[redacted]
BTU Adjustment to BCC 9262 BTU/lb	[redacted]		[redacted]	[redacted]
Bridger Coal Return on Rate Base		[redacted]		[redacted]
Cost Before Conversion Impact	[redacted]	[redacted]	[redacted]	[redacted]
Capital Investment Amortization (c)	[redacted]			
Regulatory Asset Amortization (d)	[redacted]			
Total Comparative Price Per Ton	[redacted]	[redacted]	[redacted]	[redacted]
Tons Consumed				[redacted]
Total dollars	[redacted]	[redacted]	[redacted]	[redacted]
Oregon SE Factor	[redacted]	[redacted]	[redacted]	[redacted]
Oregon-allocated dollars	[redacted]	[redacted]	[redacted]	[redacted]

(a) PRB price per Fall 2013 EVA Coalcast
(b) PRB rail price per the Company's internal calculations
(c) Capital investment cost based on levelized revenue requirement through 2025 consistent with Jim Bridger plant depreciable life for Oregon (excludes AFUDC and capital surcharge)
(d) PacifiCorp regulatory asset amortization assumes four years based on levelized revenue requirement of mine closure, reclamation obligation and unrecovered investment in BCC mine

Q. Overall, Staff's adjustments to the capital investment reduce it from $[redacted] per ton to $[redacted] per ton.[45] Do you still support the $[redacted] per ton figure included in your reply testimony?

A. As described above, the Company now calculates a capital investment cost of $[redacted] per ton after adjusting the amortization period to align with the 2025 depreciable life.

Q. Staff also relies on a different 2013 forecast of PRB prices in its analysis.[46] How do you respond to Staff's alternative forecast?

A. Staff relies on a publicly available forecast provided by SNL, while the Company relied on a forecast developed by EVA. Staff does not challenge the reasonableness of the EVA forecast, but simply states that SNL is "more appropriate" because it is "widely available."[47] Notably, Staff does not dispute the reasonableness of the EVA forecast nor suggest that the Company was imprudent for having relied on the EVA forecast in 2013.

Q. Is it reasonable for the Company to use EVA's coal price forecasts for long-term fuel planning?

A. Yes. The Company has relied upon EVA forecasts for many years, without challenge. EVA is a well-known and respected expert in coal and energy forecasting and has provided expert witness testimony on coal prices in many jurisdictions.

[45] Staff/400, Kaufman/21.
[46] *Id.*
[47] *Id.*

Q. Are there any errors in Staff's analysis relating to its choice of forecasts?

A. Yes. Staff originally, and correctly, compared the SNL and EVA forecasts for PRB coal with a heat content of 8,800 Btu/lb. When Staff then calculated its PRB coal price in its analysis, however, Staff incorrectly used the 8,400 Btu/lb. price, which decreased the overall PRB costs because 8,400 Btu/lb. coal is cheaper. The 8,400 Btu/lb. market and the 8,800 Btu/lb. market are different markets and must be evaluated on a constant market basis. In addition 8,800 Btu/lb. coal would minimize the amount of coal purchased, the transportation costs, and the capital expenditures.

Q. Staff also prepared a 20-year model purportedly based on what was known in 2013 and claims that the PVRR derived from the model supports a decision to switch to PRB coal by 2017.[48] How do you respond to this argument?

A. As stated above, I disagree with several of Staff's assumptions and calculations. Using the model that Staff utilized, and based on what was known to the Company in 2013, the least-cost, least-risk Jim Bridger fueling plan relies on BCC and Black Butte coal deliveries. Confidential Exhibit PAC/1003 compares a Base Case and a Market Case similar to Staff Exhibit 403 but corrects Staff's assumptions and calculations to correspond to the information available to the Company in 2013. The Base Case continues the Company's historical fuel plan using BCC and Black Butte coal. The Market Case shutters the BCC operation at the end of 2016 and utilizes PRB coal exclusively beginning in 2017. The

[48] Staff/400, Kaufman/24-29.

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

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

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

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

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

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

adjustment at that time.[50] Staff's delay in proposing this adjustment deprived the Company of the time necessary to adequately respond to it.

ICNU'S LOWER OF COST OR MARKET ADJUSTMENT

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

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

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

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

I also testified that, in order for PRB coal to replace BCC coal in 2017, the Company would have had to decide to make the switch at the latest in 2013. Again, ICNU does not challenge this evidence nor does ICNU present any evidence indicating that as of late 2013, a reasonable utility would have invested PacifiCorp's share of over [redacted] million to make the switch to PRB coal in 2017.

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

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

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

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

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

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

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

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

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

A. Yes, ICNU originally modified the volumes of coal in the comparison but did not correct the capital investment amortization for the reduced volumes. In an errata

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

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

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

A. No.

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

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

[53] ICNU/200, Mullins/12.

MINIMUM TAKE PROVISIONS IN COAL CONTRACTS

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

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

In terms of determining the appropriate level of a coal supply contract subject to a take-or-pay provision, the Company analyzes that in the context of each individual plant and the expected volumes of coal that will be required during the term of the contract.

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

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

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

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

A. No, Staff misrepresents the Company's testimony. In fact, my reply testimony explicitly states that the Company does *not* rely on its inventory piles to manage

[57] Staff/400, Kaufman/38.
[58] Staff/406, Kaufman/1.
[59] Staff/400, Kaufman/42.

minimum take requirements and that doing so would be imprudent.[60] Indeed, in the very same data response Staff apparently relies on to support this statement it is clear that the Company's inventory levels are governed by policies established pursuant to biennial studies, as Staff acknowledged by including the 2010 study in the record in this proceeding.[61] Those studies are clear that the inventory is not designed to manage minimum take requirements, but rather to account for factors such as potential supply or transportation disruptions, coal quality, coal market conditions, potential labor disruptions, and uncertainties in weather.[62]

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

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

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

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

[60] PAC/400, Ralston/36.
[61] Staff/212.
[62] Staff/212, Kaufman/6.
[63] Staff/400, Kaufman/42.
[64] CUB/200, McGovern/32.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

HIGHLY CONFIDENTIAL
Docket No. UE 307
Exhibit PAC/1001
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

HIGHLY CONFIDENTIAL
Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston

Union Pacific Railroad Contract

August 2016

THIS EXHIBIT CONTAINS HIGHLY PROTECTED INFORMATION SUBJECT TO MODIFIED PROTECTIVE ORDER NO.16-231.

THE EXHIBIT IN ITS ENTIRETY WILL BE PROVIDED UNDER SEPARATE COVER AND MAY ONLY BE DISCLOSED TO QUALIFIED PERSONS AS DEFINED IN ORDER NO. 16-231.

CONFIDENTIAL
Docket No. UE 307
Exhibit PAC/1002
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston

Black and Veatch 2013 Study

August 2016

THIS EXHIBIT CONTAINS PROTECTED INFORMATION
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CONFIDENTIAL
Docket No. UE 307
Exhibit PAC/1003
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston

Comparison of Base Case and a Market Case

August 2016

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REDACTED
Docket No. UE 307
Exhibit PAC/1100
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of R. Bryce Dalley

August 2016

SURREBUTTAL TESTIMONY OF R. BRYCE DALLEY

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Q. Are you the same R. Bryce Dalley who previously submitted reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. My testimony responds to the adjustments to fuel supply costs at the Jim Bridger plant proposed in the rebuttal testimony filed by Public Utility Commission of Oregon Staff (Staff) witness Mr. Lance Kaufman and the Industrial Customers of Northwest Utilities' (ICNU) witness Mr. Bradley G. Mullins. I address the regulatory issues raised by these proposed adjustments and, along with Company witnesses Mr. Dana M. Ralston and Mr. Brian S. Dickman, support the overall reasonableness of fuel supply costs at the Jim Bridger plant in the 2017 Transition Adjustment Mechanism (TAM).

Q. Please summarize your surrebuttal testimony.

A. In response to the parties' adjustments related to fuel supply for the Jim Bridger plant, the Company proposes that the Commission reject the adjustments and open an expedited planning docket to consider the least-cost, least-risk fuel supply plan for the Jim Bridger plant. This proposal to review fueling options for the Jim Bridger plant in a planning docket instead of litigating them on a hindsight, one-off basis in the TAM is consistent with Commission Order No. 13-387 in the 2014 TAM approving the Long-Term Fuel Plan filing. The Company's proposal also provides a forum to address ICNU's new arguments related to the long-term economics of Bridger Coal Company (BCC).

The adjustments in this case require the Commission to approve and impute alternative fueling strategies for the Jim Bridger plant in an adversarial proceeding with a truncated schedule, a forum ill-suited to the complex and far-reaching issue presented. The adjustments also rely on a hindsight review by bringing in new costs and considerations that no party recognized in 2013.

The Company's recommended approach will allow the Commission to consider the fueling strategy for the Jim Bridger plant on a prospective basis with a more developed record. As a part of this new docket, the Company will file an update to the December 2015 Long-Term Fuel Plan by the end of 2016, and respond to Staff's concerns regarding the December 2015 Long-Term Fuel Plan. The Company will seek a schedule in the docket that permits the results to be integrated into the 2018 TAM.

With respect to Staff's adjustment on how to include production tax credits (PTCs) in the TAM, the Company appreciates Staff's rebuttal testimony which resolves the contested issues.

STAFF'S COAL PRICE ADJUSTMENT

Q. Please describe Staff's proposed adjustment related to Jim Bridger plant coal costs.

A. Staff's rebuttal testimony includes a new coal cost adjustment, which uses different data and expands the scope of its initial adjustment. While Staff originally challenged the reasonableness of only BCC costs based on data from

2015, Staff's new adjustment challenges the reasonableness of *all* Jim Bridger plant coal costs based on data from 2013. Staff also explicitly supports its adjustment using a long-term coal cost study that it presented for the first time in its rebuttal testimony—providing the Company only 10 days to respond.[1] In total, the new coal adjustment increases Staff's proposed disallowance by 230 percent, from $40.9 million to $95.2 million on a total system basis.[2]

The crux of Staff's new adjustment is its claim that the Company was imprudent in 2013 for failing to decide to spend millions of dollars in 2013 to retrofit the Jim Bridger plant to enable it to rely exclusively on Powder River Basin (PRB) coal by 2017. Staff claims the required investment was $[redacted] million, disregarding the evidence that, in 2013, the Company's expert consultants quantified the investment at $[redacted] million. Staff also attempts to downplay the clear consequences of a decision to transition to 100 percent fuel supply from PRB by 2017, which include closure of the Bridger mine and discontinuation of coal supply from the Black Butte mine.[3] Mr. Ralston outlines the specific consequences and risks in his surrebuttal testimony.

Q. Does Staff's adjustment have potential implications beyond setting net power costs (NPC) for 2017?

A. Yes. Staff's adjustment is based on the premise that the Company should have already made a major long-term capital investment at the Jim Bridger plant to permanently switch to PRB fuel supply, even if this shuttered the BCC mine and

[1] While Staff claims that its original adjustment was also based on a long-term study, that study was included only in Staff's workpapers and not referenced in Staff's opening testimony. The original study was based on 2015 data, which Staff now agrees makes it irrelevant to the issues in this case.
[2] Staff/400, Kaufman/31.
[3] Staff/400, Kaufman/8, 20.

caused the Company to lose the Black Butte mine as an alternative source of coal. The Commission cannot logically accept Staff's adjustment without finding that the Company should have adopted the underlying long-term fueling strategy Staff advocates. Such a decision and disallowance could push the Company to conform to this fueling strategy, short-circuiting the prospective long-term planning process that the Company sought to initiate by filing its Long-Term Fuel Plan in Oregon in December 2015.

Q. Is the 2017 TAM an appropriate forum for review of Staff's proposal to fuel the Jim Bridger plant immediately, exclusively and permanently with coal from the PRB?

A. No. The TAM is designed to forecast baseline NPC for the upcoming calendar year to facilitate calculation of the transition adjustments. Consistent with this, the Company's testimony and analysis in this case focused on 2017 costs to demonstrate that they are reasonable, taking into account the multi-year nature of the Company's plant fueling strategies.

Staff's proposal has far-reaching resource planning implications. Staff seeks review of whether the Company's long-term fueling strategy is prudent, arguing that the Company should have invested millions in the Jim Bridger plant in 2013, even if this meant closing BCC and terminating its coal supply arrangements with the Black Butte mine. Such an investigation is beyond the scope of the issues normally litigated in a TAM. This is a concern because parties already criticize the annual TAM for being too complex.

Staff presents its position on the long-term fueling of the Jim Bridger plant as a very large, backward-looking rate adjustment, not as collaborative input and direction to the Company as it reviews prospective, long-term fueling options. Staff also sought and obtained an expedited, five-round testimony schedule in this case that resulted in Staff having 10 days to develop its new position and the Company having 10 days to respond. These timeframes are inadequate to develop and respond to the myriad issues raised by converting the fuel supply at the Jim Bridger plant. All of these variables make this docket an unsuitable forum to review Staff's proposal to immediately and irrevocably move to PRB coal supply at the Jim Bridger plant.

Q. How do you propose that the Commission review the Company's long-term fuel strategy for the Jim Bridger plant?

A. The Company proposes that the Commission open an expedited planning docket as soon as practicable to review these important issues outside the context of a litigated TAM filing. The Company is preparing a comprehensive update to the Long-Term Fuel Plan to file before the end of the year to facilitate this review. In this filing, the Company intends to respond to Staff's concerns about the December 2015 Long-Term Fuel Plan by adding a broader range of scenarios and analysis.

Q. Is the Company's proposal for a planning docket for the Jim Bridger plant fuel supply consistent with the treatment of major TAM adjustments in the past?

A. Yes. In docket UE 227, the Commission faced a similar issue when addressing ICNU's prudence challenge to the Company's hedging costs resulting from a decrease in market prices.[4] The Commission reviewed the hedging costs for the TAM test period and rejected the argument that the Company was imprudent when it executed the hedging transactions. In the same order, the Commission approved a stipulation among the other parties that called for a collaborative review of the Company's prospective hedging policies.[5] As a part of this process, the Company revised its long-term hedging policy and instituted ongoing regulatory reporting.

Q. Is the Company's proposal for a separate planning docket consistent with the parties' expectations when they recommended that the Company file long-term fuel plans in docket UE 264?

A. Yes. PacifiCorp, Staff, and the Citizens' Utility Board of Oregon (CUB) all supported the use of periodic fuel-supply plans as a means to review the long-term prudence of the Company's planning process outside of annual TAM

[4] *In the Matter of PacifiCorp, dba Pacific Power*, *2012 Transition Adjustment Mechanism*, Docket UE 227, Order No. 11-435 (Nov. 4, 2011).

[5] *Id.* at 12. ("We encourage Pacific Power to work with Staff and stakeholders in workshops, as the company has committed to do, to address any stakeholder concerns about the company's present and future hedging strategies." The stipulation in that case provided as follows: "PacifiCorp agrees to enter into a series of workshops with interested parties to review PacifiCorp's going-forward hedging policy in detail and seek input from the interested parties on how the policy is implemented and whether the policy should be revised to better reflect customer risk tolerances and preferences. While all Parties agree that this is not, and will not be, stated to be a pre-approval process in any future prudence review, the Company agrees to implement appropriate policy changes on a going-forward basis that result from agreement in the collaborative process.")

filings.[6] Indeed, in docket UE 264, CUB's briefing specifically stated that "CUB is amenable to further discussion of PacifiCorp's coal supply *but would like such discussions to be part of an investigatory docket*."[7]

When the Company filed its proposal for long-term fuel plans in docket UE 287, it proposed that the plan would be filed in a "separate docket subject to the Commission's Open Meetings decision-making process (similar to other utility planning dockets)."[8] No party objected to this approach, and the Company continues to believe that a separate planning docket is the most appropriate forum for examining this issue.

Q. What is your understanding of the prudence standard applicable to Staff's adjustment?

A. My understanding is that a decision is prudent if it is reasonable based on what a utility knew or should have known at the time the decision was made.[9] Under this standard, the analysis cannot rely on the benefit of hindsight.[10]

Q. Has Staff applied the prudence standard properly in this case?

A. No. In its rebuttal testimony, Staff now agrees that the prudence of the Company's 2017 coal costs must be assessed based on what was known or should have been known in 2013, which is the correct timeframe for the analysis. Staff still relies on hindsight review, however, by failing to take into account contemporaneous events that undermine Staff's claim that in 2013, it was

[6] PAC/601, Dalley/1.
[7] *See e.g.*, Docket No. UE 296, CUB's Post-Hearing Response Brief (emphasis added).
[8] PAC/501, Ralston/2.
[9] *See e.g.*, *Re Portland General Electric Co.*, Docket UE 196, Order No. 10-051 at 6 (Feb. 11, 2010) ("In a prudence review, the Commission examines the objective reasonableness of a utility's actions at the time the utility acted: 'Prudence is determined by the reasonableness of the actions 'based on information that was available (or could reasonably have been available) at the time.'").
[10] Order No. 07-200.

unreasonable for the Company to continue to rely on BCC and Black Butte coal past 2016.

Q. How does Staff's analysis rely on hindsight review?

A. Staff disregards its own prior testimony and positions regarding the prudence of the Company's fueling strategy for the Jim Bridger plant. As I described in my reply testimony:

- In 2009, Staff wrote that BCC may result in increasing benefit to PacifiCorp's customers due to potential rate spikes in PRB coal.
- In 2010, Staff's TAM testimony specifically analyzed BCC costs and determined they were lower cost than available market alternatives. In that case, the Company testified that it is "committed to a regular review of its fueling strategies in its efforts to reduce fuel costs and optimize customer benefits."[11]
- In 2011, Staff's TAM testimony specifically analyzed BCC costs and determined they were lower cost than available market alternatives.
- In 2012, no party challenged the Company's coal costs.
- In 2013, Jim Bridger fueling costs were a litigated issue in the Company's TAM. In that case, Staff did not challenge the Company's strategy to rely on BCC and Black Butte coal, and the Commission agreed that the Company's fueling plan was reasonable.[12]
- In 2014 and 2015, no party challenged the prudence of the Company's Jim Bridger coal costs, fueling strategy, or approach to the Long-Term Fueling Plan.[13]

It was not until this case—when BCC costs increased due to the significant changes in the market *over the last year*—that Staff now claims the Company has been imprudent since 2013. But the contemporaneous evidence in the record in

[11] Docket No. UE 216, PPL/300, Crane/13-14.
[12] Order No. 13-387.
[13] I understand that the Commission has been explicit that if neither the parties nor the Commission challenge a particular item, "then the item is adopted when the Commission issues its final order, even if not specifically addressed in the order." *Re PacifiCorp*, Docket Nos. UM 995, UE 121, & UC 578, Order No. 02-469 at 7 (July 18, 2002). Thus, even in years where coal costs for the Jim Bridger coal plant were not specifically challenged, the Commission implicitly approved inclusion of these costs in rates.

the past three TAMs does not support Staff's position. Staff's position that the Company's actions were clearly imprudent based on the evidence known at the time is inconsistent with Staff's failure to make such a claim contemporaneously with the actual imprudent action.

Q. Does Staff's recommendation take into account the potential risks associated with a decision in 2013 to invest millions in the Jim Bridger plant, shuttering BCC and losing Black Butte as an alternative supplier?

A. No. Staff's recommendation is based exclusively on a quantitative adjustment that has no qualitative analysis demonstrating the reasonableness of a non-diversified fuel supply strategy. In 2013, the Commission found that the Company's fuel supply at Jim Bridger was prudent and reasonable. Without a clearly identified need to dramatically and permanently change fuel supply in 2013, the Company's decision to adhere to its historical fueling strategy was reasonable and risk-reducing. This is especially true given the uncertainties in the coal and energy markets which Staff acknowledges in its testimony.[14] Mr. Ralston addresses the risks of Staff's proposal in his surrebuttal testimony.

Q Staff criticizes the Company's quantitative analysis on various grounds, including that the Company overstated the impact of BCC closure costs on the decision to switch to PRB coal. Please respond.

A. Staff criticizes several aspects of the Company's calculation of BCC closure costs, including the four-year amortization period and the return on the undepreciated investment. Mr. Ralston also addresses these issues in his surrebuttal testimony. I respond only to Staff's position that it was unreasonable

[14] Staff/200, Kaufman/40-41.

for the Company to assume a return on the undepreciated investment in the Bridger mine, and Staff's related removal of a tax allowance.[15] Staff contends that mine balances should accrue interest at the rate of 3.43 percent over his proposed 20-year amortization period.

First, Staff wrongly contends that the Company applied a pre-tax 9.8 percent return on equity, grossed up for taxes. In fact, the Company used its weighted average cost of capital, 7.69 percent, grossed up for taxes.

Second, Staff disallows the return based on the rationale that the mine will not be providing service to customers. The Company's proposed amortization period, however, generally matches the estimated time period for the retrofits at the Jim Bridger plant. For simplification, the Company's hypothetical analysis presented in Figure 2 and Figure 4 of Mr. Ralston's reply testimony showed the amortization period beginning at the closure of the mine. In reality, the Company would propose to match the period for amortization of the undepreciated investment with the period of time left before closure of the mine. Accelerating depreciation would permit the Company to earn its allowed return on the undepreciated plant balances. In 2012, the Commission approved accelerated depreciation in conjunction with closure of the Company' Carbon plant, supporting the reasonableness of the Company's underlying assumption.[16] Third, Staff removes the tax allowance because it removed the return component.[17] For the reasons just stated, Staff's position is unreasonable.

[15] Staff/400, Kaufman/17.
[16] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket UE 246, Order No. 12-493 (Dec. 20, 2012).
[17] Staff/400, Kaufman/17-18.

ICNU'S COAL PRICE ADJUSTMENT

Q. Did ICNU modify its proposed adjustment in its rebuttal testimony?

A. Yes. For purposes of my testimony, the relevant change is ICNU's support of Staff's proposed prudence disallowance as an alternative remedy to its proposed application of the lower of cost or market standard.

Q. In support of its adjustment, ICNU claims that BCC is not competitive with the market and implies that it has not been competitive since at least the 2010 TAM.[18] Is this a fair characterization?

A. No. ICNU mischaracterizes previous TAM litigation related to BCC coal, which I described in detail in my reply testimony. Contrary to ICNU's suggestion, since the 2010 TAM, only one party has ever challenged the reasonableness of BCC costs—ICNU in the 2014 TAM. In that case, the Commission rejected ICNU's adjustment, concluding that continued reliance on BCC and Black Butte was reasonable. As noted above, the 2014 TAM is particularly significant in this case because while ICNU challenged BCC costs, neither CUB nor Staff claimed that the Company was imprudent for not starting the transition from BCC and Black Butte coal in favor of PRB coal. The fact that both Staff and ICNU now make just such an argument reveals their impermissible use of hindsight review.

In addition, while Staff challenged the reasonableness of BCC coal in the 2010 TAM, that case was ultimately settled, so there is no basis to claim that the record in that case established the unreasonableness of BCC costs. This is particularly true relative to PRB costs, which were undisputed in that case to be higher priced than BCC.

[18] ICNU/200, Mullins/8.

ICNU's reliance on the 2010 TAM is further undermined by the fact that in the 2014 TAM, Staff repudiated the approach that it had used in the 2010 TAM to claim that BCC was not competitively priced. Commissioner Savage also rejected Staff's approach in the 2010 TAM in his concurring opinion in the 2014 TAM.

ICNU's attempt to re-write history and argue that BCC coal has been excessively priced for the last six years is unsupported by the historical evidence.

Q. Similar to Staff, does ICNU reduce the return on the undepreciated investment in the Bridger mine in response to the analysis in Figure 4 in Mr. Ralston's reply testimony?

A. Yes. ICNU proposes a carrying charge of 3.31 percent, based on the recent order on the closure of the Deer Creek Mine.[19] As I noted above, the Company's analysis assumes accelerated depreciation before the mine is closed. This is distinguishable from the Deer Creek case, where the mine was closed before the Company recovered its undepreciated investment.

Q. ICNU also recommends that the Commission begin treating BCC as a stranded investment and remove it from rate base.[20] How do you respond?

A. ICNU's recommendation is beyond the scope of the issues in this case. As long as BCC is used and useful, it should remain in PacifiCorp's rate base. ICNU's position does, however, support the Company's recommendation for initiation of a new planning docket to review the Jim Bridger plant's long-term fuel supply and the future of the BCC mine.

[19] ICNU/200, Mullins/8-10.
[20] ICNU/200, Mullins/12.

STAFF'S PRODUCTION TAX CREDIT ADJUSTMENT

Q. Did Staff file rebuttal testimony clarifying its position on the treatment of Production Tax Credits in the 2017 TAM?

A. Yes. Staff's rebuttal testimony clarifies that removing current PTCs from base rates is required to avoid double-counting. Staff therefore supports the Company's approach to the PTC adjustment, which removes PTCs from base rates in this filing. This approach is set forth in my reply testimony and in the reply testimony of Ms. Judith Ridenour.

Q. Does this agreement resolve the contested issues on the PTC adjustment in this case?

A. Yes. The Company appreciates Staff's efforts to resolve the PTC adjustment in this manner.

Q. Does this conclude your surrebuttal testimony?

A. Yes.