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A DIVISION OF PACIFICORP

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March 19, 2015

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attn: Filing Center

Re: Docket UM 1712—PacifiCorp's Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power submits for filing its reply testimony and exhibits in this proceeding. Confidential information is being provided in accordance with Protective Order 14-431.

Please direct any informal inquiries to Natasha Siores, Director of Regulatory Affairs & Revenue Requirement, at (503) 813-6583.

Sincerely,

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: UM 1712 Service List

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's Reply Testimony with the Public Utility Commission of Oregon Filing Center, who will serve the parties listed below via electronic mail in compliance with OAR 860-001-0180. PacifiCorp will provide a Confidential CD to the following parties that can receive confidential information via Overnight Delivery.

UM 1712

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Dated this 19th of March, 2015.

Carrie Meyer

Carrie Meyer
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REDACTED
Docket No. UM 1712
Exhibit PAC/400
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of R. Bryce Dalley

March 2015

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ATTACHED EXHIBIT

Confidential Exhibit PAC/401—Updated Deer Creek Mine Closure Tariff

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

A. My name is R. Bryce Dalley, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Vice President, Regulation.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science degree in Business Management with an emphasis in finance from Brigham Young University in 2003. I completed the Utility Management Certificate Program at Willamette University in 2009, and I have also attended various educational, professional, and electric-industry-related seminars. I have been employed by PacifiCorp since 2002 in various positions in the regulation and finance organizations. I was appointed Manager of Revenue Requirement in 2008 and was promoted to Director, Regulatory Affairs and Revenue Requirement in 2012. I assumed my current position in January 2014. I am responsible for all regulatory activities in Oregon, California, and Washington.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony responds to the ratemaking policy issues and technical adjustments presented in response testimony filed by Public Utility Commission of Oregon (Commission) Staff, the Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and the Sierra Club. I also clarify, update, and make modifications to the Company's proposal for rate recovery related to the Transaction.[1]

Q. Please summarize your testimony.

A. My testimony demonstrates that the Company's recommended Deer Creek Mine Closure tariff and related proposals advance the interests of customers and the Company and represent good public policy. The Company's proposals are reasonable, especially given the parties' general agreement that the Transaction is prudent and that closure of the Deer Creek mine is in the public interest. Specifically, the Company's decision to make this filing outside of a general rate case is reasonable because regulatory approval is necessary to proceed and delay will impede full recovery of the Company's undepreciated investment in the Deer Creek mine. Likewise, the Company's recommended amortization period, coupled with a reasonable interest rate, will allow full cost recovery by the time that the mine is closed.

RATEMAKING POLICY

Q. Please provide your overall response to parties' positions in this case.

A. First, PacifiCorp appreciates the fact that, with only a few qualifications, the parties recognize that the Transaction is prudent and that the closure of the Deer Creek mine meets the public interest standard. To be clear, no party argues that the Company should not close the mine, sell the Mining Assets, withdraw from the 1974 Pension

[1] Consistent with the Company's previous filings, the "Transaction" consists of the four components of the Deer Creek mine closure and the settlement of the Company's retiree medical obligation related to Energy West union participants (Retiree Medical Obligation). The four components of the closure are: (1) the Company will permanently close the Deer Creek Mine and incur direct closure costs; (2) Energy West will withdraw from the United Mine Workers of America (UMWA) 1974 Pension Trust (1974 Pension Trust), incurring a withdrawal liability; (3) the Company will sell certain mining assets (Mining Assets); and (4) the Company will execute a replacement coal supply agreement (CSA) for the Huntington generating plant and an amended CSA for the Hunter generating plant.

Trust, or settle the Retiree Medical Obligation. And no party disputes that the Transaction as a whole provides substantial net benefits to customers.

Second, PacifiCorp is surprised and disappointed that the parties' proposals would allow customers to receive 100 percent of the substantial benefits from the Transaction without requiring customers to pay the necessary costs to achieve those benefits. The Commission has directed utilities to consider environmental risks associated with continued reliance on coal-fired generation and take steps now to mitigate these risks.[2] The Transaction effectuates this policy through early retirement of a coal mine and execution of a CSA for the Huntington generating plant that is terminable if environmental regulations render the plant uneconomic. The Transaction also allows the Company to save customers millions of dollars in pension and benefit costs. The parties' proposals shift incremental costs and risks to the Company and threaten to undermine or undo the Transaction. And these proposals strongly discourage similar future coal resource management decisions.

Third, while PacifiCorp is flexible regarding how the costs of the Transaction should be recovered in rates, as discussed in more detail below, this flexibility is limited by Oregon law and precedent associated with the Commission's decision

[2] *See, e.g.*, *In the Matter of PacifiCorp, d/b/a Pacific Power, 2013 Integrated Resource Plan*, Docket No. LC 57, Order No. 14-252 at 5 (July 8, 2014) (directing PacifiCorp to perform additional coal analysis prospectively through the IRP process), Order No. 14-296, App. A at 3 (Aug. 19, 2014) (directing the Company to perform specific modeling and analysis for coal-fired plants in the 2015 IRP); *In the Matter of Portland General Electric Company, 2009 Integrated Resource Plan*, Docket No. LC 48, Order No. 10-457 at 15 (Nov. 23, 2010) (acknowledging PGE's Boardman plant closure proposal as the best option, in part because it "mitigates the risk of future carbon regulation"); *In the Matter of PacifiCorp, d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 28 (Dec. 20, 2012) (acknowledging that PacifiCorp's "initial development of a coordinated and forward-looking response" regarding the Company's major emissions sources was reasonable, and "declin[ing] to find that a prudent utility faced with these state and federal regulations would have simply done nothing and waited to see what additional requirements emerged"); *In the Matter of the Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at 17-19 (Jan. 8, 2007) (utilities should include external environmental costs when considering long-term resource commitments).

regarding the early retirement of the Trojan nuclear power plant (the Trojan decision).[3] Recovery of the Company's investment in the Deer Creek mine must be accelerated, with a reasonable interest rate, to make the Company whole. ICNU's proposal to amortize the investment over fourteen years (when the remaining depreciable life of the mine is only four years) and Staff's proposal to begin amortizing the regulatory asset before recovery begins in rates are punitive and effectively penalize the Company for acting in the best interests of its customers. These positions are also contrary to the Trojan decision and ORS 757.140(2)(b), which allows expedited and full recovery of investment in plant retired in the public interest.

SINGLE-ISSUE RATEMAKING

Q. Please respond to the parties' claim that the Company's proposed tariff constitutes improper single-issue ratemaking[4] and ICNU's claim that there is no precedent for the Company's request outside of a general rate case.[5]

A. The Company's proposal does not constitute improper single-issue ratemaking, nor is it otherwise inconsistent with Commission policy. It is my understanding that the Commission has previously approved similar tariff filings to allow for accelerated depreciation of unamortized plant balances and decommissioning costs associated with the early retirement of a utility asset.

Q. Please provide examples of relevant Commission precedent.

A. In docket UE 239, the Commission approved a stand-alone tariff filing made by Idaho

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[3] *In re Portland General Electric Co*., Docket Nos. DR 10, UE 88 & UM 989, Order No. 08-487 (Sept. 30, 2008), *aff'd Gearhart v. Pub. Util. Comm'n of Oregon*, 356 Or 216 (2014).
[4] *See*, *e.g.*, Staff/100, Wittekind/14; ICNU/100, Mullins/3-4; CUB/100, Jenks-McGovern/14-16.
[5] ICNU/100, Mullins/6.

Power Company to recover the incremental costs and benefits associated with the early shutdown of the Boardman power plant.[6] Idaho Power's tariff implemented a balancing account to recover "three types of costs associated with the early closure of the Boardman plant: (1) a return on undepreciated capital investments; (2) the accelerated depreciation; and (3) the decommissioning costs."[7] The parties to UE 239, including Staff and CUB, entered into a stipulation with Idaho Power supporting the proposed balancing account, which would allow Idaho Power to recover its accelerated depreciation and decommissioning costs on a dollar-for-dollar basis. In Order No. 12-235, the Commission found the proposed balancing account to be reasonable and approved the stipulation.[8] The Commission also approved a rate increase to account for the impacts of the accelerated depreciation of the Boardman plant accounts and from increased decommissioning costs.[9]

Furthermore, the Commission has approved stand-alone tariff filings to allow a utility to include a new generating plant in rates,[10] to accelerate the depreciation of metering equipment to facilitate the implementation of advanced metering infrastructure,[11] and to allow a utility to begin recovering the costs of a gas reserves contract.[12]

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[6] PGE has also implemented a tariff to recover the costs associated with the early closure of the Boardman plant. While the Commission approved the use of a separate tariff to recover the accelerated depreciation and decommissioning costs in a general rate case, the Commission approved the actual rate change in a stand-alone filing. *See In re Portland General Electric Co.*, Docket No. UE 230, Order No. 11-242 (July 5, 2011).
[7] *In re Idaho Power Co.*, Docket No. UE 239, Order No. 12-235 at 2 (June 26, 2012).
[8] *Id*. at 3.
[9] *Id.*
[10] *In re Idaho Power Co.*, Docket No. UE 248, Order No. 12-358 (Sept. 20, 2012) (approving rate adjustment for Langley Gulch plant).
[11] *In re Portland General Electric Co.*, Docket No. UE 189, Order No. 08-245 (May 5, 2008) (approving accelerated depreciation of PGE's meters); *In re Idaho Power Co.*, Docket No. UE 202, Order No. 08-614 (Dec. 30, 2008); (approving accelerated depreciation of Idaho Power's meters).
[12] *In re Northwest Natural Gas Co.*, Docket Nos. UM 1520 & UG 204, Order No. 11-140 (Apr. 28, 2011), *aff'd* Order No. 11-176.

Based on these precedents, the Commission's general policy against single-issue ratemaking should not preclude the approval of the Company's proposed Deer Creek Mine Closure tariff.

Q. Given the parties' concerns over single-issue ratemaking, they generally recommend that Commission authorize deferred accounting for the Transaction costs and address ratemaking treatment in the Company's next general rate case. Does the Company support this approach?

A. No. This approach is inconsistent with the Trojan decision because it does not allow for accelerated amortization of the undepreciated investment in the Deer Creek mine. In addition, deferred accounting treatment is unnecessary in this case because, to the extent the Company requests authorization of a regulatory asset for later recovery in rates, the Company proposes to address this recovery in its next general rate case where all elements of revenue requirement are reviewed. Notably, deferred accounting does not address the parties' concerns about single-issue ratemaking since the Company could request amortization of the deferred amounts outside of a general rate case.

Q. Please respond to Staff's contention that the Company will be able to recover a return of its investment even after the mine closes, so there is "no compelling reason to violate general ratemaking principles and create special ratemaking treatment for the costs associated with this transaction."[13]

A. First, I disagree that the Company's request constitutes "special ratemaking treatment" since the Commission has approved similar tariff filings for other utilities in similar circumstances.

[13] Staff/100, Wittekind/14.

Second, because the Company cannot earn a return on the undepreciated investments, timely recovery is important. It is my understanding that the Commission has acknowledged that without a return on investment, a utility may recover less than the full value of its investment, even if it is allowed a reasonable interest rate on the undepreciated balance.[14] The Company therefore requests that the Commission not delay recovery of the undepreciated investment.

Q. Do you agree with ICNU's claim that the proposed tariff constitutes a "general rate revision" under the Commission's rules and can only be approved in a general rate case?[15]

A. No. ICNU's conclusion is based on misreading the Commission's rules. The Commission's rules define a "general rate revision" as a tariff filing that "affects all or most of the utility's rate schedules."[16] ICNU claims that the Company's proposed Deer Creek Mine Closure tariff, Schedule 198, will increase the rates charged to all customers and therefore constitutes a "general rate revision." ICNU's argument is incorrect because the approval of Schedule 198 would affect only one rate schedule—Schedule 198—and no others. Although Schedule 198 will affect all customers, the Company is not proposing a change to "all or most of" its rates schedules.[17]

Q. The parties also point to the Company's stipulation in its last general rate case, docket UE 263, and claim that the general rate case stay-out provision in that stipulation prohibits the Company's tariff filing.[18] Do you agree?

A. No. First, by its terms the stipulation prohibits "a general rate case filing."[19] This

[14] Order No. 08-487 at 72.
[15] ICNU/100, Mullins/7.
[16] OAR 860-022-0019(1).
[17] *See also* OAR 860-022-0017(1).
[18] Staff/100, Wittekind/11-12; ICNU/100, Mullins/8-9; CUB/100, Jenks-McGovern/16-17.

filing is not a general rate case as that term is defined in the Commission's rules.

Second, the goal of the general rate case stay-out provision, as described by the parties to the stipulation, was to "minimize rate changes."[20] The provision is not an absolute prohibition on any rate changes occurring during the general rate case stay-out period.

PRUDENCE DETERMINATION

Q. Please clarify the prudence determinations the Company is requesting in this case.

A. The Company requests that the Commission find that the decision to enter into the Transaction is prudent, including the decisions to (1) close the mine, (2) withdraw from the 1974 Pension Trust, and (3) settle the Retiree Medical Obligation. The Company also requests approval of the sale of the Mining Assets and the new Huntington CSA and amended Hunter CSA.

Q. Do you agree with Staff's claim that a prudence determination in this proceeding would be premature?[21]

A. No. Staff agrees that the Transaction provides net benefits to customers, so long as the long-term CSA risks can be substantially mitigated.[22] Given that Staff recommends that the Commission should find that the Transaction provides customers net benefits, there is no reason why it should urge the Commission to reserve its prudence determination for a later date. Moreover, Staff specifically

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[19] *In re PacifiCorp*, Docket No. 263, Order No. 13-474, Appendix A at 5-6 (paragraph 15) (Dec. 18, 2013).
[20] *See id. See also* Docket No. UE 263, Stipulating Parties/100 at 10.
[21] Staff/100, Wittekind/14.
[22] Staff/100, Wittekind/15.

concludes that the decision to withdraw from the 1974 Pension Trust was prudent[23] that the decision to settle the Retiree Medical Obligation was prudent,[24] and that the sale of the Mining Assets is in the public interest.[25] Therefore, it is unclear what aspects of the Transaction would be addressed in a later proceeding. The record is fully developed in this proceeding and there is no reason to defer a prudence determination to a later proceeding.

Q. Staff claims that a determination of prudence is "only necessary to remove regulatory risk to the Company and is not necessary to actually proceeding with the transaction."[26] Do you agree?

A. No. As described in Ms. Cindy A. Crane's initial and reply testimonies, the lack of a prudence determination may affect the Company's decision to move forward with the Transaction. Staff's claim to the contrary is merely speculation.

RATEMAKING TREATMENT OF TRANSACTION COSTS

Q. Please describe the Company's recommended rate treatment for the costs associated with the Transaction.

A. In its initial filing, the Company requested approval of the Deer Creek Mine Closure tariff to recover the following costs over one year beginning June 1, 2015:

- The undepreciated investment in the Deer Creek mine (approximately $86.0 million total company or $21.1 million Oregon allocated);
- The estimated closure costs (approximately $[redacted] total company or $[redacted] Oregon-allocated);
- The loss on the sale of the Mining Assets ($[redacted] total company or $[redacted] Oregon allocated);

[23] Staff/200, Bahr/16-17.
[24] Staff/200, Bahr/18-19.
[25] Staff/300, Crider/9.
[26] Staff/200, Bahr/9.

- The one-time loss associated with the settlement of the Retiree Medical Obligation (approximately $[redacted] total company or $[redacted] Oregon allocated);[27] and

- The difference between fuel costs included in rates through the 2015 Transition Adjustment Mechanism (TAM) for the Huntington and Hunter plants and fuel costs under the CSAs (a credit of approximately $1.0 million total company or $0.25 million Oregon allocated).[28]

The Company accounted for the return on the undepreciated investment in the Deer Creek mine currently in rates by not applying interest to any of the amounts in the tariff.

In addition, the Company proposed continued recovery of $3.0 million through the TAM for the ongoing annual payment for the 1974 Pension Trust withdrawal liability because this annual payment amount is the same as the amount currently included in rates through the TAM for UMWA pension contributions. This recovery would continue until the payments change, end, or the withdrawal obligation is otherwise satisfied. The Company also requested authorization to record this withdrawal liability as a regulatory asset, as discussed in more detail in Mr. Douglas K. Stuver's direct and reply testimonies.

Q. Is the Company modifying its ratemaking proposal at this time?

A. Yes. To address the parties' concerns, the Company modifies it proposal to limit the Deer Creek Mine Closure tariff to only:

- The undepreciated investment in the Deer Creek mine; and

[27] This loss was included in the tariff calculation shown in Attachment B to the application, but the application did not make it clear that recovery of this amount was included in the tariff.
[28] This amount covers the period from June 1, 2015, through December 31, 2015, assuming fuel costs are reset to reflect the CSAs in the 2016 TAM.

- The estimated closure costs.[29]

In addition, the Company proposes to change the amortization period for the tariff from one to two years beginning June 1, 2015, with interest accruing during amortization at the Company's authorized cost of debt, 5.25 percent.[30]

Q. What is the basis for the Company's recommended interest rate?

A. It is my understanding that the Commission can apply interest to the unamortized balance to account for the time value of money.[31] In the Trojan decision, the Commission observed that a utility's debt cost "represents the amount a utility must pay for borrowed funds, which we believe is a reasonable estimate of a utility's time value of money."[32] Although the circumstances of the Trojan case led the Commission to calculate interest using a treasury rate, rather than the utility's debt costs, it is my understanding that the Commission is not required to use a treasury rate in all circumstances. Given that treasury rates are at a historically low level, which was not the case in the Trojan case, a treasury rate does not reasonably represent the Company's time value of money.

Q. What is the Company's modified proposal for the ratemaking treatment of the other Transaction costs?

A. The Company requests approval of an accounting order authorizing the creation of a regulatory asset for the:

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[29] In addition to approval of the tariff, for accounting purposes, the Company requests an accounting order authorizing creation of a regulatory asset for these cost elements. This regulatory asset will be amortized as amounts are collected through the tariff.
[30] Order No. 13-474, Appendix A at 3-4 (paragraph 12).
[31] *Gearhart*, 365 Or at 250.
[32] Order No. 08-487 at 73.

- The one-time loss associated with the settlement of the Retiree Medical Obligation;[33]
- The difference between fuel costs included in rates through the 2015 TAM for the Huntington and Hunter plants and fuel costs under the CSAs;[34] and
- The difference between estimated closure costs included in the Deer Creek Mine Closure tariff and actual closure costs.[35]

The Company proposes offsetting this regulatory asset with a credit for the return on the undepreciated investment in the Deer Creek mine that is currently reflected in rates (approximately $0.22 million per month or $2.6 million annually). This credit would begin on June 1, 2015, the effective date of the Deer Creek Mine Closure tariff, and would continue until base rates are reset in the Company's next general rate case.[36] The net regulatory asset balance would accrue interest at the Company's authorized weighted cost of capital (7.621 percent[37]) beginning June 1, 2015.

Finally, the Company proposes including the loss on the sale of the Mining Assets in rates through the Company's existing property sales balancing account, Schedule 96, and proposes no changes from its initial proposal for the continued recovery of the annual payment for the withdrawal from the 1974 Pension Trust and creation of a regulatory asset for the withdrawal liability.

Q. Why is the Company's modified proposal reasonable?

A. The Company's modified proposal responds to the parties' concerns while still complying with the Commission's Trojan decision by allowing accelerated and full

[33] As discussed in the reply testimony of Mr. Stuver, the one-time retiree settlement loss was estimated at $[redacted] total company or $[redacted] Oregon-allocated at the time of the Company's initial filing, but the final amount will not be known until June 2015.
[34] Consistent with the Company's initial proposal, this amount covers the period from June 1, 2015, through December 31, 2015, assuming fuel costs are reset to reflect the CSAs in the 2016 TAM.
[35] Any difference associated with salvage values for undepreciated investments included in the tariff will also be trued up in the regulatory asset.
[36] If the credit for the return on is included in the tariff, the credit would end when the tariff expires.
[37] Order No. 13-474, Appendix A at 3-4 (paragraph 12).

recovery of the Company's undepreciated investment in the mine. In addition, allowing recovery of closure costs as those costs are being incurred encourages this type of beneficial transaction.

The Company's modified proposal also gives the Company the opportunity to recover other costs associated with this Transaction, but gives parties the opportunity to address the prudence and the appropriate ratemaking treatment of these costs in the context of a general rate case. Furthermore, the proposal ensures that customers pay only for actual closure costs by truing up any difference between the estimated amounts and the actual amounts through the regulatory asset.

Q. Has the Company updated its tariff schedule and supporting documentation to reflect these modifications?

A. Yes. The updated tariff and supporting documentation is included with my testimony as Confidential Exhibit PAC/401.

Q. If the Commission approves the Deer Creek Mine Closure tariff, Staff recommends that amortization of tariff amounts begin June 1, 2015, but no rate recovery would begin until January 1, 2016.[38] In other words, the Company would absorb the amounts amortized from June 1 through December 31, 2015 (seven months). Is this recommendation reasonable?

A. No. While a two-year amortization period is not unreasonable on its own, Staff's recommendation results in a disallowance of approximately 30 percent of the Transaction costs—a result that is entirely unreasonable given that Staff agrees that the Transaction as a whole benefits customers. Staff's only basis for this recommendation is its interpretation of the general rate case stay-out provision from

[38] Staff/100, Wittekind/13.

docket UE 263. As discussed above, the Company does not agree with Staff's interpretation of the general rate case stay-out provision, and even if Staff's understanding is deemed correct, it is no basis to disallow 30 percent of the costs of a beneficial transaction.

Q. Please respond to CUB's recommendation that the amortization period be no more than five years?[39]

A. The Company agrees with CUB that amortization beyond five years is unreasonable given the amount at issue and that fact that the mine investment is currently being amortized through 2019. That said, even a five-year amortization period is excessive for the reasons discussed above.

Q. Please respond to ICNU's recommendation to amortize the tariff through 2029 to match the benefits with the costs of the Transaction.[40]

A. ICNU's recommendation is entirely unreasonable. The Deer Creek mine's depreciable life currently runs through its expected reserve depletion in 2019. It makes no sense to *extend* the amortization period beyond the period over which the investment would have been recovered without the Transaction. ICNU's recommendation would *decelerate* depreciation on the mine, which is contrary to Commission precedent accelerating depreciation for early plant retirement.

Q. Do you have any other concerns with ICNU's recommended amortization period?

A. Yes. ICNU's recommendation is punitive. When determining the amortization period for the Trojan balance, the Commission observed:

[39] CUB/100, Jenks-McGovern/8.
[40] ICNU/100, Mullins/9-10.

> Requiring recovery over 17 years with interest at a rate lower than the utility's rate of return would likely increase PGE's risk profile, because PGE would have less than the full value of its Trojan investment returned to it and available to make new investments in rate base assets and earn a return on those investments.[41]

Similarly, if the Company is required to recover its costs over nearly 15 years, as ICNU recommends, it will preclude the Company from recovering the full value of its investment. This result is unreasonable given that the early closure provides substantial benefits to customers.

Q. ICNU also recommends "dynamic amortization" to reduce amortization if Oregon's share of the Transaction benefits decreases.[42] Do you agree with this proposal?

A. No. ICNU's recommendation is based on an amortization period that is unreasonably long. Because it is entirely inappropriate to extend the amortization period, as discussed above, there is no basis for ICNU's proposal.

Q. ICNU claims that the "Commission has traditionally treated coal acquired from captive mines as an affiliate transaction, governed under the lower of cost or market ratemaking principles."[43] Based on this conclusion, ICNU argues that the lower of cost or market standard prohibits the one-year amortization because it would result in coal costs in excess of market.[44] Does ICNU's argument have merit?

A. No. The Commission expressly rejected this same argument from ICNU in docket

[41] Order No. 08-487 at 72.
[42] ICNU/100, Mullins/14-15.
[43] ICNU/100, Mullins/12.
[44] *Id*.

UE 264.[45] As described in the Company's response to OPUC Bench Request 3, the Commission does not apply the lower of cost or market standard to transactions between PacifiCorp and its affiliate mines, including the Deer Creek mine. Therefore, the lower of cost or market standard is irrelevant to the amortization period at issue in this case.

INTEREST RATE FOR TARIFF AMORTIZATION

Q. ICNU claims that the Company included a return on the mine and related assets in Schedule 198.[46] Is ICNU correct?

A. No. As discussed above, although the Company's initial tariff did not expressly provide a credit for the return on the assets now in rates, it did not propose any interest rate on any amounts included in the Deer Creek Mine Closure tariff. The Company's modified proposal explicitly addresses the return on currently in rates.

Q. Staff recommends a blended modified treasury rate for a two-year amortization period.[47] CUB recommends an interest rate of between 2.85 percent and 3.31 percent, depending upon the amortization period, based on a blend of PacifiCorp's debt costs and treasury rates.[48] Please respond to these recommendations.

A. As the Commission recognized in its Trojan decision, the reasonableness of the interest rate depends largely on the amortization period. If the amortization period is relatively short, *i.e.*, one or two years, then a lower interest rate may be reasonable. Given historically low treasury rates, Staff's reliance exclusively on those rates is

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[45] *In re PacifiCorp*, Docket No. UE 264, Order No. 13-387 (Oct. 28, 2013).
[46] ICNU/100, Mullins/22.
[47] Staff/100, Wittekind/13.
[48] CUB/100, Jenks-McGovern/10.

unreasonable, even if the amortization period is two years. CUB's recommendation is more reasonable because it takes into account the historically low treasury rates and includes the Company's debt costs in the calculation.

OTHER ISSUES

Q. Please respond to Staff's and ICNU's claims that an adjustment to the Company's request should be made to reflect the effect of the Transaction on the calculation of the 2010 Protocol's embedded cost differential (ECD).[49]

A. Staff's and ICNU's assertion that the ECD should be updated in this docket is inappropriate and should be rejected. The ECD is updated as part of a general rate case and involves all generation rate base and operating costs, as well as purchased power, fuel, and projected generation output from owned and contracted resources. It would be highly unusual and illogical to update the ECD outside of a general rate case, particularly because the vast majority of the elements used in the ECD calculation would not be updated as part of Staff's and ICNU's proposed adjustment.

Q. Does this conclude your reply testimony?

A. Yes.

[49] Staff/100, Wittekind/9-10; ICNU/100, Mullins/20-21.

Docket No. UM 1712
Exhibit PAC/401
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Reply Testimony of R. Bryce Dalley

Updated Deer Creek Mine Closure Tariff

March 2015

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 198

DEER CREEK MINE CLOSURE ADJUSTMENT

Purpose

This schedule recovers costs associated with the closure of the Deer Creek Mine, as authorized by Order No. 15-xxx in Docket UM 1712.

Monthly Billing

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.36 will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Delivery Service Schedule	
Schedule 4, per kWh	0.165¢
Schedule 5, per kWh	0.165¢
Schedule 15, per kWh	0.112¢
Schedule 23, 723, per kWh	0.157¢
Schedule 28, 728, per kWh	0.162¢
Schedule 30, 730, per kWh	0.155¢
Schedule 41, 741, per kWh	0.160¢
Schedule 47, 747, per kWh	0.142¢
Schedule 48, 748, per kWh	0.142¢
Schedule 50, per kWh	0.112¢
Schedule 51, 751, per kWh	0.112¢
Schedule 52, 752, per kWh	0.112¢
Schedule 53, 753, per kWh	0.112¢
Schedule 54, 754, per kWh	0.112¢

This schedule will terminate when ordered amounts have been fully recovered.

DEER CREEK MINE CLOSURE - SUPPLY SERVICE ADJUSTMENT
Schedule 198 -- *Revised in Reply Testimony 3-19-15*

		Tariff Increases		*Net Tariff*
		Projected Balances at 12/31/2014	**Closure Costs**	
Existing Costs:				
Deer Creek assets [1]				
Gross electric plant in service		$ 217		
Accumulated depreciation		(130)		
CWIP		5		
Expected salvage		(6)		
Net book value		86		
Total net rate base				
New costs:				
Closure costs			[redacted]	
Total amounts flowing into tariff		$ 86	[redacted]	**$ 160**
Oregon SE factor (per 2015 TAM)	24.484%	$ 21.1	[redacted]	**$ 39.2**

(1) As discussed in Mr. R. Bryce Dalley's reply testimony, assets that will be sold are not reflected in Schedule 198.
The company proposes that the loss on assets sold be addressed through Schedule 96, Property Sales Balancing Account.

DEER CREEK MINE CLOSURE - SUPPLY SERVICE ADJUSTMENT
Schedule 198 Interest Calculation

Interest Rate **5.25%** Authorized cost of debt from docket UE 263
(Order No. 13-474, Appendix A, paragraph 12)

($ millions)

	Beginning Balance	Proposed Amort.	Interest	Ending Balance
June-15	**39.2**	(1.7)	0.17	37.6
July-15	37.6	(1.7)	0.16	36.1
August-15	36.1	(1.7)	0.15	34.5
September-15	34.5	(1.7)	0.15	32.9
October-15	32.9	(1.7)	0.14	31.3
November-15	31.3	(1.7)	0.13	29.8
December-15	29.8	(1.7)	0.13	28.2
January-16	28.2	(1.7)	0.12	26.6
February-16	26.6	(1.7)	0.11	25.0
March-16	25.0	(1.7)	0.11	23.3
April-16	23.3	(1.7)	0.10	21.7
May-16	21.7	(1.7)	0.09	20.1
June-16	20.1	(1.7)	0.08	18.5
July-16	18.5	(1.7)	0.08	16.8
August-16	16.8	(1.7)	0.07	15.2
September-16	15.2	(1.7)	0.06	13.5
October-16	13.5	(1.7)	0.06	11.9
November-16	11.9	(1.7)	0.05	10.2
December-16	10.2	(1.7)	0.04	8.5
January-17	8.5	(1.7)	0.03	6.8
February-17	6.8	(1.7)	0.03	5.1
March-17	5.1	(1.7)	0.02	3.4
April-17	3.4	(1.7)	0.01	1.7
May-17	1.7	(1.7)	0.00	(0.0)
		(41.3)	**2.1**	

Annual Amortization	**(20.6)**

Deer Creek Mine Closure

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDING DECEMBER 31, 2015

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
Line		Sch	No. of		Base		Net	Base		Net	Base Rates		Net Rates		Line
No.	Description	No.	Cust	MWh	Rates	Adders[1]	Rates	Rates	Adders[1]	Rates	($000)	%[2]	($000)	%[2]	No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	484,343	5,253,064	$596,641	$5,735	$602,376	$596,641	$14,422	$611,063	$0	0.0%	$8,686	1.4%	1
2	**Total Residential**		484,343	5,253,064	$596,641	$5,735	$602,376	$596,641	$14,422	$611,063	$0	0.0%	$8,686	1.4%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	76,950	1,121,146	$122,085	$5,208	$127,293	$122,085	$6,969	$129,054	$0	0.0%	$1,761	1.4%	3
4	Gen. Svc. 31 - 200 kW	28	10,093	2,014,017	$181,669	$3,141	$184,810	$181,669	$6,407	$188,076	$0	0.0%	$3,266	1.8%	4
5	Gen. Svc. 201 - 999 kW	30	857	1,343,078	$107,746	$1,055	$108,801	$107,746	$3,133	$110,879	$0	0.0%	$2,078	1.9%	5
6	Large General Service >= 1,000 kW	48	203	3,046,739	$212,223	($9,425)	$202,798	$212,223	($5,113)	$207,110	$0	0.0%	$4,312	2.1%	6
7	Partial Req. Svc. >= 1,000 kW	47	7	61,069	$6,441	($199)	$6,242	$6,441	($116)	$6,325	$0	0.0%	$83	2.1%	7
8	Agricultural Pumping Service	41	7,942	228,528	$26,253	($1,240)	$25,013	$26,253	($874)	$25,379	$0	0.0%	$366	1.5%	8
9	**Total Commercial & Industrial**		96,052	7,814,577	$656,417	($1,459)	$654,958	$656,417	$10,407	$666,824	$0	0.0%	$11,866	1.8%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,579	9,214	$1,177	$221	$1,398	$1,177	$231	$1,408	$0	0.0%	$10	0.7%	10
11	Street Lighting Service	50	246	8,768	$970	$195	$1,165	$970	$205	$1,175	$0	0.0%	$10	0.8%	11
12	Street Lighting Service HPS	51	736	19,319	$3,374	$712	$4,086	$3,374	$733	$4,107	$0	0.0%	$22	0.5%	12
13	Street Lighting Service	52	26	565	$73	$13	$86	$73	$14	$87	$0	0.0%	$1	0.7%	13
14	Street Lighting Service	53	249	9,518	$597	$120	$717	$597	$131	$728	$0	0.0%	$11	1.5%	14
15	Recreational Field Lighting	54	105	1,246	$104	$20	$124	$104	$21	$125	$0	0.0%	$1	1.1%	15
16	**Total Public Street Lighting**		7,941	48,630	$6,295	$1,281	$7,576	$6,295	$1,335	$7,630	$0	0.0%	$54	0.7%	16
17	**Total Sales before Emp. Disc. & AGA**		588,336	13,116,271	$1,259,353	$5,557	$1,264,910	$1,259,353	$26,164	$1,285,517	$0	0.0%	$20,607	1.6%	17
18	Employee Discount				($463)	($3)	($466)	($463)	($10)	($473)	$0		($7)		18
19	**Total Sales with Emp. Disc**		588,336	13,116,271	$1,258,890	$5,554	$1,264,444	$1,258,890	$26,154	$1,285,044	$0	0.0%	$20,600	1.6%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		588,336	13,116,271	$1,261,329	$5,554	$1,266,883	$1,261,329	$26,154	$1,287,483	$0	0.0%	$20,600	1.6%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

REDACTED
Docket No. UM 1712
Exhibit PAC/500
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Cindy A. Crane

March 2015

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Q. Are you the same Cindy A. Crane who previously provided direct testimony in this case 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 testimony?

A. My testimony responds to the testimony filed by Public Utility Commission of Oregon (Commission) Staff, the Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and the Sierra Club. I address the parties' overall recommendations, their concerns regarding the long-term replacement coal supply agreement for the Huntington generating plant, Sierra Club's criticism of the Company's net benefits analysis, and Staff's contention that timely regulatory approval of the Transaction[1] is not required.

Q. Please summarize your testimony.

A. First, I recognize the general agreement among the parties that the Company's decision to enter into the Transaction was prudent and results in significant customer benefits.

Second, I will explain how the Company mitigated the risks associated with a conventional long-term CSA by negotiating broad termination rights and flexibility

[1] Consistent with the Company's previous filings, the "Transaction" includes the four components of the Deer Creek mine closure and the settlement of the Company's retiree medical obligation related to Energy West union participants (Retiree Medical Obligation). The four components of the closure are: (1) the Company will permanently close the Deer Creek Mine and incur direct closure costs; (2) Energy West will withdraw from the United Mine Workers of America (UMWA) 1974 Pension Trust (1974 Pension Trust), incurring a withdrawal liability; (3) the Company will sell certain mining assets (Mining Assets); and (4) the Company will execute a replacement coal supply agreement (CSA) for the Huntington generating plant and an amended CSA for the Hunter generating plant.

under the Huntington CSA. Specifically, the Company successfully negotiated a provision in the CSA that allows the Company to terminate the agreement without penalty if an environmental requirement affects the Company's ability to burn coal at the plant. Contrary to parties' concerns, the intent of this provision is to allow the Company to terminate its purchase obligation when an environmental requirement makes it uneconomic to burn coal at Huntington, even if the requirement does not outright prohibit the burning of coal. Thus, the long-term nature of the CSA will not adversely affect the Company's resource planning or otherwise limit the Company's options as it responds to new and existing environmental requirements.

Third, my testimony responds to Sierra Club's criticisms of the Company's net benefits analysis and demonstrates that their specific adjustments are meritless. I also show that, even accepting all of the adjustments to the Company's net benefits analysis, the Transaction still provides significant customer benefits.

Fourth, I reiterate the Company's need for timely regulatory approval of each of the individual components of the Transaction to allow the Company to move forward and achieve substantial customer benefits.

GENERAL SUPPORT FOR THE TRANSACTION

Q. Do the parties generally agree that the Company's decision to enter into the Transaction is prudent and that it satisfies the net benefits standard?

A. Yes. The parties largely agree that the Transaction satisfies the net benefits standard and the Company's decision to enter into the Transaction is prudent. With a limited exception, the parties have not challenged the Company's present value revenue requirement differential (PVRR(d)) analysis demonstrating the substantial customer benefits resulting from the Transaction. No party has provided economic analysis contesting the fact that the Transaction provides greater customer benefits than any alternative.

Staff recommends that the Commission conclude that the Transaction provides net benefits to customers, provided the risks associated with the Huntington CSA can be substantially mitigated.[2] Staff also specifically concludes that the Company's decision to withdraw from the 1974 Pension Trust was prudent,[3] that the decision to settle the Retiree Medical Obligation was prudent,[4] and that the sale of the mining assets is in the public interest.[5] CUB, ICNU, and Sierra Club likewise agree that the Transaction is in the public interest, subject to similar concerns about the long-term replacement CSA.[6]

While all of the parties have reservations relating to the Huntington CSA, as I discuss below, the Company substantially mitigated the risk related to potential environmental requirements by a first-of-its-kind contract provision that allows the Company to terminate the CSA if an environmental requirement affects the Company's ability to burn coal at Huntington. The Company therefore anticipated these types of concerns and addressed them through its contract negotiations.

[2] Staff/100, Wittekind/15.
[3] Staff/200, Bahr/16-17.
[4] Staff/200, Bahr/18-19.
[5] Staff/300, Crider/9.
[6] CUB/100, Jenks-McGovern/3, 14, 19-21; ICNU/100, Mullins/29-30; Sierra Club/100, Fisher/6.

Q. You state that the parties generally did not challenge the Company's net benefits analysis. Did any party allege errors that change the overall results of the Company's analysis?

A. No. Sierra Club is the only party that challenged aspects of the Company's net benefits calculations. Company expert Seth Schwartz and I address each of Sierra Club's arguments. Importantly, even taking into account Sierra Club's arguments, the analysis still shows substantial customer benefits associated with the Transaction.[7]

HUNTINGTON CSA

Q. Please describe the Huntington CSA.

A. As part of the overall Transaction, the Company executed a long-term agreement with Bowie Resource Partners, LLC (Bowie), whereby Bowie agreed to supply the Company's coal requirements for Huntington from the close of the Transaction through December 31, 2029. The CSA includes a "take-or-pay" provision generally requiring the Company to purchase a minimum specified amount of coal. Such "take or pay" provisions are an essential component of virtually all long-term coal supply agreements and constitute the consideration required to obtain favorable pricing. In this case, however, the Company was able to mitigate the risk associated with the take-or-pay provision by negotiating a provision—Article 8—that provides the Company with the broad termination rights if new or existing environmental laws, regulations, or a settlement agreement affect the Company's ability to burn coal at Huntington.

[7] Sierra Club/100, Fisher/29-30.

Q. What are the parties' concerns about the CSA?

A. The parties argue that the Company's termination rights may not be as broad as the Company intended and that the provision may not allow the Company to terminate the CSA if it were to decide to stop burning coal for economic reasons.[8] For example, CUB and the Sierra Club claim that PacifiCorp's recent decisions to end coal burning at Company-owned plants were driven by economic reasons and were not the result of new or existing environmental requirements that explicitly prohibited burning coal.[9]

Q. Do you agree with the parties' concerns?

A. No. Article 8 was specifically negotiated by PacifiCorp to provide the Company with relief from the take-or-pay provision of the CSA if environmental laws or government policies or settlements affect the Company's ability to burn the minimum amount of coal specified in the contract.

Q. Please discuss the relevant portions of Article 8.

A. The first paragraph of Article 8 describes a "Coal Consumption Event" (CCE) and states that, if a CCE occurs, [redacted] The mitigation measures are also described in Article 8, which is set out in full on pages 20 and 21 of Exhibit PAC/104, attached to my direct testimony. [redacted]

[8] *See*, *e.g.*, Staff/300, Crider/6-7; CUB/100, Jenks-McGovern/10-11.
[9] CUB/100, Jenks-McGovern/11; Sierra Club/100, Fisher/15-17.

[redacted]

Q. Why did the Company negotiate Article 8?

A. The Company negotiated Article 8 in recognition of the uncertainty now inherent in the environmental regulation of coal generation. The Company's intent was to secure broad flexibility in responding to the impacts of changing environmental regulations or settlements on Huntington, including the ability to terminate the CSA without liquidated damages if future changes in applicable environmental requirements affect the Company's ability to operate Huntington as a coal-fired facility.

Article 8 allows the Company to terminate if a regulation [redacted]" per year. Under Article 3 of the CSA, the Company's minimum requirement is [redacted] tons and its maximum requirement is [redacted] tons. The use of the [redacted] threshold for Article 8, which is less than the plant's [redacted], was intended to provide the broadest protection possible.

Q. Would Article 8 allow the Company to terminate the CSA if an environmental requirement made continued operation of Huntington uneconomic?

A. Yes. The Company intended Article 8 to address a scenario where an environmental requirement made the continued operation of the plant as a coal-fired facility uneconomic, and the Company made this intent clear during its negotiations with Bowie. As Sierra Club correctly points out, none of the Company's decisions to close or re-power coal plants was the result of an outright prohibition on burning coal. Rather, the decisions were made based on the economic impact of the environmental requirement on the operation of the particular plant. From the Company's perspective, it would make no sense to agree to a narrow clause that would limit the Company's termination rights in the manner the parties' fear.

Q. Is it your understanding that Bowie recognizes that Article 8 is intended to allow the Company to terminate the CSA if an environmental requirement makes continued operation of Huntington uneconomic?

A. Yes. During the negotiations this intent was made clear to Bowie and, based on the communications between the Company and Bowie, Bowie recognizes that Article 8 was intended, at a minimum, to cover this type of scenario. Thus, the Company believes that the contract language substantially mitigates the potential risk to customers related to changing environmental requirements.

Q. Parties are also concerned that the long-term CSA creates an incentive for the Company to continue to burn coal at Huntington when it would otherwise be uneconomic to do so and therefore limits the Company's future options.[10] Please respond.

A. Because the Company can exercise its termination rights if it becomes uneconomic to burn coal at Huntington, there is no incentive to continue burning coal when it is uneconomic to do so and the Company's options are not limited. Furthermore, the Company will conduct its future planning based on its understanding of Article 8.

[10] *See*, *e.g.*, Sierra Club/100, Fisher/30.

Q. Sierra Club also argues that non-regulatory developments, such as low gas or market prices or reduced demand, could render Huntington uneconomic, and concludes that instead of entering into a long-term CSA, the Company should purchase coal on the market.[11] Are Sierra Club's concerns justified?

A. No. Sierra Club produced no evidence or analysis indicating that there is a material probability that such a scenario would occur. Moreover, as described in the direct and reply testimonies of Mr. Seth Schwartz, given current market conditions, it is reasonable and prudent to enter into the long-term Huntington CSA at below-market prices. Sierra Club is essentially asking customers to bear the burden of higher market coal prices for the foreseeable future based on speculation that other market forces may eventually render market coal a better option than a long-term CSA. While it is theoretically possible that the scenario described by Sierra Club may occur, mere speculation is no basis for long-term resource planning or decision-making.

Q. Staff and Sierra Club recommend that the Commission impose conditions that would essentially require the Company to hold customers harmless from any potential risk associated with the take-or-pay provisions.[12] Is this type of condition necessary or appropriate?

A. No. The parties are asking the Commission to prejudge ratemaking treatment of speculative damages under the contract. The Company is simply asking that the Commission not prejudge the appropriate ratemaking treatment of future damages incurred under the CSA based on unfounded fears and speculation. The parties'

[11] Sierra Club/100, Fisher/19.
[12] Staff/100, Wittekind/15; Staff/300, Crider/6-7; Sierra Club/100, Fisher/19-20.

conditions are no more reasonable than a condition preemptively requiring customers to bear all future costs, including potential damages, incurred under the CSA.

Q. Staff and the Sierra Club argue that the Company's analysis relating to the decision to enter into the long-term Huntington CSA should have considered shutting down the plant or re-powering with natural gas.[13] Please respond to these concerns.

A. First, I would point out that even though Staff and Sierra Club raised this concern, they do not dispute that the transaction provides customer benefits and is in the public interest. Second, as discussed above, the Company's decision to enter into the long-term CSA does not affect the Company's decision-making related to closing or re-powering Huntington because of the broad termination rights. Third, this type of analysis is conducted as part of the Company's integrated resource planning process, and the Company's assumptions in its economic analysis in this case are consistent with its most recent integrated resource plan.

Q. Do you have any other concerns related to the parties' criticisms of the Huntington CSA?

A. Yes. The parties' recommendations fail to acknowledge the integrated nature of the Transaction. The Huntington CSA was part of the overall deal with Bowie, which also included the sale of the Mining Assets and Bowie's assumption of Preparation Plant obligations. The Company could not have achieved the same deal with Bowie if it had not entered into a long-term CSA. Not only does the CSA provide below market coal prices, but it also enables the Company and customers to realize

[13] Staff/300, Crider/6; Sierra Club/100, Fisher/10.

numerous other benefits.

As described in my direct testimony, the Company's net benefits analysis compared the PVRR of mine closure without the Bowie deal (Market case) and mine closure with the Bowie deal (Transaction case). The result of this analysis demonstrated that the customer benefit of the Transaction case over Market case is $[redacted].

Q. Sierra Club faults the Company for modeling the Retiree Medical Obligation in only its Transaction case, but not its Market case, even though both cases assumed mine closure.[14] Does this criticism have merit?

A. No. Without support, Sierra Club assumes that the Company would have been able to successfully negotiate the Retiree Medical Obligation settlement regardless of whether it entered into the Transaction. In reality, the Company was able to negotiate this benefit with the union because the overall Transaction gave the Company leverage that it otherwise lacked.

Q. How did the Transaction provide the Company leverage?

A. The UMWA was unwilling to settle the Retiree Medical Obligation as long as it believed there was a chance that the mine would remain open. Once the Transaction was nearly finalized and the Company's intent to close the mine became clear to the UMWA, the Company was able to negotiate this settlement.

[14] Sierra Club/100, Fisher/21.

Q. Sierra Club claims that the Company did not appropriately account for coal blending costs at the Hunter plant in its net benefits analysis by excluding those costs from the Transaction case, while including them in the Market case.[15] Sierra Club asserts that the Company's Transaction case assumes that the coal blending, which was previously conducted by the Company at the Preparation Plant, will be provided for free once the Preparation Plant is sold to Bowie. Are Sierra Club's criticisms warranted?

A. No. Sierra Club misrepresents the Company's analysis. The Transaction case assumes Bowie will absorb Preparation Plant operating costs through 2020. Beyond 2020, the Company assumes that all coal purchases will comply with Hunter plant coal specifications, obviating the need for incremental coal handling costs. This assumption is warranted because (1) Bowie controls and produces the vast majority of coal in Utah, (2) Bowie will need to continue to operate the Preparation Plant to meet contract specifications, and (3) coal pricing assumptions are for coal that meets Hunter plant specifications.

The Market case assumes the Preparation Plant is shuttered in 2015 and coal deliveries to the Hunter plant are either put in the plant's hopper or on the plant's stockpile and pushed into reclaim feeders using bulldozers or scrapers. The Company's analysis reasonably reflects the additional coal handling costs it would incur in this scenario.

[15] Sierra Club/100, Fisher/28.

OTHER ISSUES

Q. Staff disputes the Company's claim that it needs regulatory approval by May 31, 2015, claiming that the Company can waive regulatory approval of the sale of the Mining Assets and CSAs if it so chooses.[16] Please respond.

A. If the Company does not receive the necessary regulatory approvals by May 31, 2015, it can waive the conditions precedent requiring the approvals, but only if Bowie also agrees. If the Company does not receive one or more state regulatory approvals by that deadline, it would need to weigh the risks of a decision to waive.

Regarding the asset sale agreements, it is my understanding that ORS 757.480 requires the Company to obtain Commission approval before selling the Mining Assets. So even if the contract allows PacifiCorp to waive this requirement, Oregon law does not.

Q. What are the Company's options if it does not receive the necessary regulatory approvals?

A. The benefits of the Transaction are contingent on timely regulatory approvals. If regulatory approvals are not obtained, the Company would be left with two options. First, the Company could close the mine and purchase coal from the market, assuming that this scenario met the Commission's public interest standard. The assumptions and results would be similar to the Market Case, including Preparation Plant closure and pension withdrawal. This option would result in higher replacement coal prices and loss of the proceeds from sale of the Preparation Plant.

Second, the Company could operate the mine through its depletion. In this

[16] Staff/100, Wittekind/3.

case, the costs would be higher than estimated in the Keep case due to restarting development work to initiate longwall mining operations.

Q. Are any of the Company's specific requests set forth in its application severable in a way that would allow the Company to move forward with only certain aspects of the Transaction?

A. No. The requests for regulatory approvals are not severable because they are all integral to the Transaction to close the Deer Creek mine. Where possible, however, the Company seeks approval of regulatory assets and proposes to address ratemaking treatment in future ratemaking proceedings, as addressed in more detail in Mr. R. Bryce Dalley's reply testimony.

The major components of the transaction are integrated through Article 10 of the Huntington CSA. On or before the May 31, 2015, deadline in the Huntington CSA, PacifiCorp must have resolved labor disputes and associated successorship obligations with the UMWA in a manner satisfactory to Bowie, closed the property sale agreements that are part of the Transaction, and received all necessary regulatory approvals. The Huntington CSA requires the Company to begin closing the Deer Creek mine within three months of its effective date. Because of the pre-closing and post-closing conditions of the Huntington CSA, the Company must obtain all the regulatory approvals requested in the application by May 31, 2015. The Huntington CSA is terminable by Bowie if PacifiCorp does not meet this deadline. The benefits of the Transaction to close the Deer Creek mine are derived, in part, from the Huntington CSA, and the proposed closure of the mine is contingent on its approval.

Q. Please respond to ICNU's claim that the Company has not substantiated its claim that it will incur substantial abandonment and recovery-based royalty costs.[17]

A. The royalty cost estimates arise from the federal requirements that an operator achieve "maximum economic recovery" (referred to as MER) of all profitable portions of a coal reserve within a federal coal lease. While the Company believes it has achieved MER at the Deer Creek mine as required under the federal coal leasing regulations, BLM will determine, in coordination with the Company, whether MER has been fully achieved and, if not, whether any additional royalties will be required. The Company estimated abandonment royalties by assessing risk levels for the different areas of the mine and applying an estimated market price per ton for tons classified as moderate to high risk.

The recovery-based royalties are dependent upon the amounts to be recovered as a result of the Transaction. Federal coal lease regulations require royalties to be based on the value of the gross proceeds accruing to the lessee. At the Deer Creek mine, the determination of gross proceeds for valuation is based on actual mining costs plus a return on the net investment of the mine assets. The Company paid royalties under this same methodology and agreement for production from the Trail Mountain mine. Consistent with royalties assessed on the Trail Mountain mine closure, the Company expects to pay royalties on costs associated with or triggered by the Deer Creek mine closure including the 1974 Pension Trust withdrawal and retiree medical settlement loss.

[17] ICNU/100, Mullins/31.

Q. Does this conclude your reply testimony?

A. Yes.

REDACTED
Docket No. UM 1712
Exhibit PAC/600
Witness: Douglas K. Stuver

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Douglas K. Stuver

March 2015

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Q. Are you the same Douglas K. Stuver who previously provided direct testimony in this case 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 testimony?

A. My testimony responds to the testimony filed by Public Utility Commission of Oregon (Commission) Staff and the Industrial Customers of Northwest Utilities (ICNU) related to the Company's withdrawal from the United Mine Workers of America (UMWA) 1974 Pension Trust (1974 Pension Trust) and the Company's settlement with the UMWA of its Retiree Medical Obligation. I also address ICNU's recommendation that the Commission approve a regulatory asset related to bonus depreciation.

Q. Please summarize your testimony.

A. My testimony clarifies the Company's proposed ratemaking treatment for the 1974 Pension Trust withdrawal and responds to Staff's erroneous concern that the Company's proposal may lead to "double dipping." I also respond to ICNU's unnecessary and inappropriate recommendation to cap the Company's potential cost recovery for a negotiated lump-sum payment. Regarding the Company's Retiree Medical Obligation, I demonstrate that the Company's filing was timely and preserved its ability to be granted approval to record the settlement loss as a regulatory asset and address ICNU's unsupported claim that the settlement loss is a "paper loss" without financial consequences to the Company. Finally, I demonstrate that ICNU grossly overstated the potential bonus depreciation benefit to customers and failed to show any nexus between the alleged benefit and this case.

PENSION WITHDRAWAL

Q. Please describe the pension withdrawal issue.

A. As part of the overall Transaction,[1] Energy West Mining Company (Energy West) will stop participating in the 1974 Pension Trust, thereby incurring a withdrawal liability. The withdrawal liability is based on Energy West's share of unfunded, vested benefits in the plan. When I filed my direct testimony, the Trust estimated the withdrawal liability (as of July 1, 2014) to be $125.6 million. The Trust recently updated this number and now estimates the withdrawal liability to be $96.7 million for the plan year ending June 30, 2015. The main drivers for the decrease in the lump-sum withdrawal obligation are increases in the discount rates used to compute the actuarial present value of vested benefits and favorable investment returns for the year ended June 30, 2014.

Energy West may choose to pay this liability through a single lump-sum payment of the stated withdrawal liability, the annual installment payment methodology, or a negotiated pre-payment of the annual installments in perpetuity. The annual installment payment is approximately $3 million on a total-company basis, which is comparable to the amount currently in rates through the Company's

[1] Consistent with the Company's previous filings, the "Transaction" includes the four components of the Deer Creek mine closure and the settlement of the Company's retiree medical obligation related to Energy West union participants (Retiree Medical Obligation). The four components of the closure are: (1) the Company will permanently close the Deer Creek Mine and incur direct closure costs; (2) Energy West will withdraw from the 1974 Pension Trust, incurring a withdrawal liability; (3) the Company will sell certain mining assets (Mining Assets); and (4) the Company will execute a replacement coal supply agreement (CSA) for the Huntington generating plant and an amended CSA for the Hunter generating plant.

annual transition adjustment mechanism (TAM) for contributions to the UMWA pension.

Q. What ratemaking treatment is the Company requesting for the pension withdrawal liability?

A. The Company requests that the Commission determine that the decision to withdraw from the 1974 Pension Trust was prudent and authorize the creation of a regulatory asset for the withdrawal liability. This treatment would allow the Company to reflect this change without any modification to customer rates. The Company also requests continued recovery of approximately $3 million for the annual withdrawal liability payment through the TAM until the payments end or change or the withdrawal liability is otherwise satisfied.

Q. Staff agrees that the decision to withdraw was prudent and supports the creation of a regulatory asset.[2] But Staff also expresses concerns that the creation of the regulatory asset and the approval of the continued collection of the $3 million annual installment payment may be "double dipping."[3] Is Staff's concern warranted?

A. No. As described in my direct testimony, the $3 million annual payment does not affect the recorded regulatory asset or withdrawal liability because the annual payment is not sufficient to pay down the principal.

Moreover, once the final withdrawal liability is known, the Company will adjust its withdrawal liability and associated regulatory asset to match the present value of remaining payments. When the Company seeks recovery of the adjusted

[2] Staff/100, Bahr/6, 16.
[3] Staff/100, Bahr/5.

regulatory asset in a future general rate case, the amortization of the regulatory asset will replace the $3 million annual installment payment then in rates, resulting in no double dipping.

Q. ICNU recommends that if the Company negotiates a lump sum withdrawal payment, the amount in rates should be capped at $39.4 million (total Company).[4] Please explain the difference between the Company's estimate of its withdrawal liability for accounting purposes and ICNU's estimate of $39.4 million.

A. The difference is entirely attributable to the discount rate used. As explained in my direct testimony, for accounting purposes, the Company is required to use a risk-free discount rate. ICNU used the Company's weighted average cost of capital in its calculations. The significant impact of these different discount rates on the total potential liability demonstrates that the discount rate will be a key issue in the negotiation of the Company's lump-sum withdrawal payment.

Q. How do you respond to ICNU's recommendation to cap the amount of withdrawal liability the Company may recover in rates?

A. ICNU's proposal is premature, unnecessary, and potentially harmful. First, it is premature for the Commission to adopt a cap since the Company is not seeking final ratemaking treatment of the liability in this case. After the Company negotiates the withdrawal payment and seeks recovery of that amount, the Commission can review the prudence of the Company's negotiations based on what the Company knew or should have known at that time and based on the overall outcome of the negotiations.

[4] ICNU/100, Mullins/16.

Second, adopting a cap at this time results in pre-judging the appropriate lump-sum withdrawal liability, which could adversely affect the Company's negotiating position with the 1974 Pension Trust.

RETIREE MEDICAL OBLIGATION

Q. Please describe the Retiree Medical Obligation.

A. The Company was able to successfully negotiate a settlement of its Retiree Medical Obligation with the UMWA by transferring assets to the UMWA in an amount less than the Company's existing obligation, thereby creating a benefit for customers. In addition, the settlement triggers a one-time expense (the Retiree Medical Settlement Loss) that otherwise would have been incurred over time.

Q. What ratemaking treatment has the Company requested for the Retiree Medical Settlement Loss?

A. The Company does not request any ratemaking treatment for the Retiree Medical Obligation at this time. In its initial filing, the Company requested an accounting order allowing it to record the Retiree Medical Settlement Loss as a regulatory asset. The Company also requested to include the loss in the Deer Creek Mine Closure tariff. As discussed in the testimony of Mr. R. Bryce Dalley, the Company is modifying its proposal and is no longer requesting recovery of the loss through the tariff. The Company also requests a determination that its decision to settle the Retiree Medical Obligation was prudent.

As indicated in my direct testimony, the Retiree Medical Settlement Loss was estimated to be $[redacted]. The final amount of the settlement loss will not be known until June 2015, when the loss is actually incurred. The final amount may be lower or higher than the Company's initial estimate due to changes in actuarial assumptions (*e.g.*, discount rates). The final amount will also be offset by benefits associated with a reduction in the Company's retiree medical expense. These benefits were not anticipated at the time of the Company's initial filing, but the Company proposes to net this benefit against the settlement loss to calculate the amount included in the regulatory asset.

Q. Does Staff support the Company's request to include the Retiree Medical Settlement Loss in the regulatory asset?

A. It is unclear. Staff recommends that the Commission reject the Company's request to create a regulatory asset, claiming that this obligation is severable from the overall Transaction and would normally be addressed in the Company's next general rate case.[5] But Staff also testifies that "given the context of the overall transaction," Staff alternatively recommends that the Commission determine that the Company's decision to settle the Retiree Medical Obligation was prudent because the settlement results in customer benefits.[6] Staff emphasizes that the ratemaking treatment of the regulatory asset should be addressed in a later proceeding.

Q. ICNU also argues that the Retiree Medical Obligation is severable from the overall Transaction and therefore recommends that the Commission deny the creation of the regulatory asset.[7] How do you respond to both Staff and ICNU?

A. As explained in Ms. Cindy A. Crane's reply testimony, the settlement of the Retiree Medical Obligation would not have occurred without the Company's decision to

[5] Staff/200, Bahr/8.
[6] Staff/200, Bahr/18.
[7] ICNU/100, Mullins/28.

close the mine. That said, even if the Retiree Medical Obligation were severable from the overall Transaction, there is no reason to deny the creation of a regulatory asset—particularly when the settlement creates significant customer benefits.

Q. ICNU also claims that the settlement agreement was executed before the submission of the Company's application and therefore the creation of a regulatory asset would be prohibited as retroactive ratemaking.[8] Is ICNU's understanding accurate?

A. No. The Memorandum of Understanding was executed in December 2014. But the actual settlement, *i.e.*, the transfer of funds from the Company's trust to the UMWA trust, will occur on June 1, 2015. Consistent with Generally Accepted Accounting Principles (GAAP), the Company will record the Retiree Medical Settlement Loss on its books in June 2015. Therefore, the Company's application precedes Company's incurrence of the loss, and retroactive ratemaking is not implicated.

Q. ICNU also claims that the settlement is merely a "paper loss" and does not represent any actual expenditure made by the Company that would need to be recovered in rates.[9] Is ICNU correct?

A. No. Given that the settlement triggers immediate loss recognition, without a regulatory asset, the Company would be required to record the loss as an expense (write-off) on its income statement and would deny the Company an opportunity for recovery. Therefore, the denial of a regulatory asset would have true financial consequences for the Company in 2015.

[8] ICNU/100, Mullins/28-29.
[9] ICNU/100, Mullins/28-29.

Moreover, because the Retiree Medical Settlement Loss simply represents accelerated recognition of a portion of the plan's unrecognized losses, the Company would have recovered this expense over time if it had not negotiated a settlement with the union. Therefore, the fact that the Company is recognizing this loss now as a result of the Transaction is no reason to deny the regulatory asset and eventual cost recovery.

Q. ICNU also states that it is "unclear whether ratepayers have historically received the benefit of unrecognized losses in rates."[10] Is ICNU correct?

A. No. The unrecognized losses represent the aggregate net actuarial losses resulting from historical changes in actuarial assumptions that have not yet been amortized to expense. Without the ability provided by GAAP to defer these unrecognized losses and amortize them to expense over time, they would be expensed immediately when incurred.

BONUS DEPRECIATION

Q. ICNU proposes offsetting amounts included in the Deer Creek Mine Closure tariff with $2.8 million in unrelated bonus depreciation, allegedly for Lake Side 2.[11] Is ICNU's proposal reasonable?

A. No. The extension of bonus depreciation—and the Lake Side 2 generating plant—are irrelevant to this case. Because the mining assets involved in the Transaction will be removed from rate base, the extension of bonus depreciation does not impact this case.

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[10] ICNU/100, Mullins/29.
[11] ICNU/100, Mullins/24-28.

Q. Did ICNU miscalculate and vastly overstate its proposed offset for bonus depreciation for Lake Side 2?

A. Yes. ICNU proposes updating bonus depreciation for Lake Side 2 only. But ICNU fails to recognize that the Company updated Lake Side 2 for bonus depreciation in the Company's separate tariff rider for the plant, filed in May 2014. The tariff reflected bonus depreciation on capital investments of $600.5 million through December 31, 2013. Thus, the vast majority of bonus depreciation for Lake Side 2 has already been reflected in rates. At the time of the tariff filing, approximately $70.1 million in capital investment in Lake Side 2 was not eligible for bonus depreciation. Including the additional $70.1 million would have increased total-company accumulated deferred income taxes (ADIT) effective December 31, 2014, the enactment date of the extension. On a 13-month average basis, total-company ADIT would have increased by $5.9 million (or $1.5 million on an Oregon-allocated basis), resulting in an Oregon revenue requirement impact of less than $0.2 million. Thus, ICNU's adjustment is overstated by $2.6 million.

Q. Does this conclude your reply testimony?

A. Yes.

REDACTED
Docket No. UM 1712
Exhibit PAC/700
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Seth Schwartz

March 2015

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ATTACHED EXHIBIT

INTRODUCTION

Q. Are you the same Seth Schwartz who previously provided direct testimony in this case 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 reply testimony discusses the reasons why it is reasonable for the Company to enter into a long-term coal supply agreement (CSA) for the Huntington generating plant in conjunction with its decision to close the Deer Creek mine, including discussing the risks of relying on short-term market purchases.

Q. Please summarize your reply testimony.

A. My testimony responds to the testimonies of Public Utility Commission of Oregon Staff, the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities, and the Sierra Club. The parties assert that the Company is taking a risk by entering into a long-term commitment with a minimum "take-or-pay" provision to purchase coal because there is a risk that the plant may become uneconomic during the term of the CSA, and the Company may have to pay damages for not taking the minimum quantity of coal.[1] These parties question whether the Company adequately protected against this risk. I also respond to Sierra Club's assertion that there may be more risk under the CSA than if the Company chose to rely on the market for its coal supply.

[1] Staff/300, Crider/6-7; ICNU/100, Mullins/29-30; Sierra Club/100, Fisher/19-20; CUB/100, Jenks-McGovern/12-13.

COAL SUPPLY OPTIONS FOR HUNTINGTON AND HUNTER

Q. Please describe the likely coal supply options for the Huntington and Hunter generating plants.

A. The Huntington and Hunter plants are located south of Price, Utah. Coal can only be delivered to the plants by truck or, in the case of Huntington, by conveyor belt. Because trucking can be expensive over longer distances, the coal supply for the Huntington and Hunter plants has always come from the local Utah coal mines operating in the Central Utah coal fields (Wasatch, Book Cliffs, and Emery coal fields), which have been mined for over 100 years. While coal could be imported from other coal areas by rail and then trucked to the plants, the transportation costs would make supply from outside of Central Utah much more expensive.

Q. Who are the producers in the Central Utah coal fields?

A. There are only four producers operating seven coal mines in Central Utah and one mine operating in Southern Utah. Historical Utah coal production from 2006 through 2014 by mine is shown in Exhibit PAC/701. The Utah coal producers are:

- Bowie Resources (Canyon Fuel): Bowie is the largest producer, with three mines (Sufco, Skyline and Dugout Canyon) that produced 11.4 million tons in 2014;
- Murray Energy: Murray operates two mines (West Ridge and Lila Canyon) that produced 2.8 million tons in 2014. West Ridge is expected to deplete its reserves by 2016, while Lila Canyon is under development;
- PacifiCorp: The Company operated the Deer Creek mine in 2014, producing 2.1 million tons;
- Rhino Energy: Rhino operates one mine, Castle Valley, producing 1.1 million tons in 2014; and,
- Alton Coal: Alton operates a surface mine in Southern Utah, over 200 miles south of the power plants, producing 0.6 million tons in 2014.

Q. How much coal will the Company require to operate the Huntington and Hunter plants?

A. The Huntington and Hunter plants are expected to consume about 7.3 million tons per year, with a range 7.0 to 7.5 million tons.

Q. How will the closure of the Deer Creek mine affect the Company's coal supply options?

A. With the Deer Creek mine closed, there will only be three logical coal suppliers for the Huntington and Hunter plants: Bowie Resources, Murray Energy, and Rhino Energy. These mines produced 15.3 million tons in 2014 and are likely to continue producing at about that level. The Company will need to purchase almost one-half of the total production from these mines.

Q. Does the Company already purchase coal from these Utah mines?

A. Yes. The Company had contracts to purchase coal from each of these companies, even before signing the Huntington CSA.

THE NEED FOR A LONG-TERM CSA

Q. Sierra Club claims that the Company could rely upon short-term contracts and spot purchases to replace the Deer Creek mine. Do you agree?

A. No. In my opinion, the Company would not be able to replace the coal supply from the Deer Creek mine exclusively with short-term contracts and spot purchases. The Utah coal market is a relatively illiquid market. There are few options to supply coal and few customers. The amount of coal available to purchase in the short-term or spot markets is small compared to the demand at the Huntington plant. The coal producers cannot continue to invest in extending the operations at the existing mines without coal sales contracts. Signing a new long-term contract to supply the Huntington plant ensures that the coal supply will be committed and available to meet the plant's needs.

Q. What would happen to the market price for Utah coal if the Company shut the Deer Creek mine without first entering into a new long-term contract?

A. The market price would be likely to increase significantly. The few remaining producers would see an immediate jump in demand for their limited production and would increase their prices because demand would exceed supply.

Q. Does the Huntington CSA avoid a price increase for replacing the Deer Creek coal supply?

A. Yes. By negotiating a new long-term CSA with fixed prices before closing the Deer Creek mine, the Company was able to contract for coal at current market prices and lock in these prices with modest escalation through 2029.

Q. The parties are concerned that the Company will be committed to purchase coal under the Huntington CSA that it does not need and will face "take-or-pay" damages. What terms in the CSA protect the Company from this situation?

A. The CSA contains a large volume option for the Company to vary the amount of coal that it must purchase in any calendar year. The contract is for the annual requirements for the Huntington plant, with the minimum annual quantity of [redacted] tons and the maximum of [redacted] tons per year. It is [redacted] that the Huntington plant will burn [redacted] The contract also contains a broad termination provision as discussed in the direct and reply testimonies of Ms. Cindy A. Crane.

IMPACT OF CARBON REGULATION

Q. Sierra Club claims that the Company's analysis of Transaction benefits did not account for the impact of carbon regulation and the Company did not explain why it relied on a "No Carbon" scenario in the Transaction case.[2] Is this correct?

A. No. As I noted in my direct testimony, the Company evaluated the impact of carbon regulation on the Utah coal market using an alternate forecast of coal prices developed by EVA. This forecast demonstrated that the planned retirement of several power plants before the implementation of carbon regulation largely mitigated the impact of these regulations on the Utah market. This is reflected in my Exhibit PPL/310.

Q. Sierra Club originally claimed that use of the "Carbon" case would have reduced the benefits of the Transaction case compared to the Market case by $[redacted]. In an errata filing on March 17, 2015, Sierra Club corrected this amount to $[redacted]. Please comment.

A. Under the "Carbon" case, market prices are slightly lower, which slightly reduces the benefits of the Transaction case as measured against the Market case (*i.e.*, it reduces the total $[redacted] differential by $[redacted]). Sierra Club's errata acknowledging that the impact of using the "Carbon" case is less than one-half of its original estimate supports the Company's position that carbon regulation is not a major driver in the net benefits analysis.

[2] Sierra Club/100, Fisher/25.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UM 1712
Exhibit PAC/701
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Seth Schwartz

Utah Coal Production by Mine

March 2015

Utah Coal Production by Mine (1000 tons)

Company	Mine	Type	2006	2007	2008	2009	2010	2011	2012	2013	2014
Alton Coal	Coal Hollow	S	-	-	-	-	-	403	570	741	563
America West	Horizon	U	256	233	229	194	272	370	210	-	-
Bowie/Canyon Fuel	Dugout Canyon	U	4,387	3,826	4,145	3,291	2,461	2,395	1,516	561	676
Bowie/Canyon Fuel	Skyline	U	1,647	2,533	3,120	2,718	2,805	2,948	1,894	2,729	4,170
Bowie/Canyon Fuel	Sufco	U	7,908	6,712	6,946	6,748	6,398	6,498	5,650	5,960	6,539
Consol Energy	Emery Mine	U	1,054	1,026	1,050	1,238	999	-	-	4	-
Hiawatha Coal	Bear Canyon #3	U	27	-	-	-	-	-	-	-	-
Murray Energy	Crandall Canyon	U	605	402	-	-	-	-	-	-	-
Murray Energy	So Crandall Canyon	U	759	-	-	-	-	-	-	-	-
Murray Energy	Lila Canyon	U	-	-	-	-	72	156	304	257	335
Murray Energy	Aberdeen	U	2,089	1,045	242	-	-	-	-	-	-
Murray Energy	Pinnacle	U	8	-	-	-	-	-	-	-	-
Murray Energy	West Ridge	U	3,022	4,255	3,809	3,063	3,326	3,566	2,409	2,629	2,514
Pacificorp	Deer Creek	U	3,748	3,685	3,878	3,833	2,954	3,143	3,295	2,810	2,089
Rhino Energy	Castle Valley #4	U	509	588	946	633	-	572	997	876	1,056
			26,018	**24,307**	**24,365**	**21,718**	**19,288**	**20,051**	**16,847**	**16,568**	**17,942**

Source: Mine Safety and Health Administration Form 7000-2 data, 2006 - 2014