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March 5, 2015

Via E-Mail and Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Drive SE
Salem OR 97302

Re: PACIFICORP dba PACIFIC POWER
Application for Approval of Deer Creek Mine Transaction
Docket No. UM 1712

Dear Filing Center:

Attached for filing in the above-captioned proceeding, please find the Redacted Response Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities.

The confidential portions of Mr. Mullins' testimony and exhibits will follow to the Commission via Federal Express, and will be served via hand-delivery or U.S. Mail on the parties that have signed the Protective Order in this docket.

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

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the attached **Response Testimony and Exhibits of Bradley G. Mullins on behalf of ICNU** upon all parties in this proceeding, as shown below, by sending a copy via electronic mail, and by sending the confidential pages of same via First Class U.S. Mail, postage prepaid, or by hand-delivery.

Dated at Portland, Oregon, this 5th day of March, 2015.

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1712

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Application for Approval of Deer Creek Mine Transaction.	)
	)
	)
	)

REDACTED RESPONSE TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

MARCH 5, 2015

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

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

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. On December 12, 2014, the Company filed an Application for Approval (the "Application"). The Application contained an array of requests related to the disposition of the Deer Creek Mine, including agreements to sell certain mining assets to Bowie Energy Resource Partners, LLC ("Bowie"), a long-term coal supply agreement for the Huntington facility ("Huntington CSA"), costs related to the expected withdrawal from the United Mine Workers of America ("UMWA") 1974 Pension Trust, and a loss on the settlement of the UMWA Retiree Medical liability (collectively, the "Transaction"). My testimony addresses the Company's requests for accounting associated with the

Transaction, as well as the request for a 3.4% general rate increase through Schedule No. 198.

Q PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. My testimony is organized as follows:

- **Request for Accounting.** The Company's request for a 3.4% rate increase outside of a general rate case proceeding constitutes single-issue rate making and should not be permitted. The Commission should reject the Company's ratemaking proposal and defer a decision on the ratemaking issues associated with the Transaction until the next general rate case.

- **Amortization.** The ratepayer benefits of the Transaction will be recognized over the period June 2015 through December 2029. In order to properly match costs with benefits, the Commission should amortize any regulatory account approved in this proceeding over the same period.

- **Pension Withdrawal Deferral.** The Commission should place a cap on the amount that can be deferred and collected from customers related to the withdrawal from the 1974 Pension Trust. The cap should be based on the current perpetuity value to ratepayers of the annual withdrawal payments at the current authorized rate of return, or $39.4 million.

- **Deer Creek Mine Closure Tariff.** To the extent that Schedule No. 198 is approved, there are several errors that must be corrected and adjustments that should be made.

    a. **Embedded Cost Differential.** The Company neglected to account for the Embedded Cost Differential ("ECD"), a critical component of the 2010 inter-jurisdictional cost allocation methodology ("2010 Protocol"). Properly accounting for the ECD reduces the Company's request by $3.7 million on an Oregon allocated basis.

    b. **Return on Mine Assets.** The Company did not remove the return on the mining assets already reflected in rates from its calculation of Schedule No. 198. Removing these costs reduces the Company's request by $2.6 million on an Oregon allocated basis.

    c. **Bonus Depreciation.** Schedule No. 198 collections should be adjusted to reflect the financial windfall that the Company has received as a result of the extension of bonus depreciation. Based on my estimate, accounting for bonus depreciation would reduce the Company's request under Schedule No. 198 by approximately $2.4 million on an Oregon allocated basis.

d. **Retiree Medical Settlement.** The Company's proposal to include a book loss on the settlement of the UMWA retiree medical plan in undepreciated plant investment should be rejected. This loss was incurred before the Application was filed and is not intrinsically tied to the closure of the mine. Removing this settlement loss reduces the Company's request under Schedule No. 198 by [redacted] on an Oregon allocated basis.

- **Public Interest Test.** Given the high degree of uncertainty surrounding the future operation of the Huntington facility, it may not be in the public interest for the Company to execute a long-term coal supply agreement at this time. Damages under the coal supply agreement may eliminate the Company's option to retire Huntington if it becomes uneconomic in the near future.

Q. TO THE EXTENT THAT YOUR TESTIMONY DOES NOT ADDRESS AN ISSUE, SHOULD THAT BE INTERPRETED AS YOUR ACCEPTANCE OF THAT ISSUE?

A. No.

II. REQUEST FOR ACCOUNTING

Q. WHAT ARE YOUR CONCERNS WITH THE COMPANY'S ACCOUNTING REQUESTS?

A. The Company has formulated a complicated series of accounting requests, with the ultimate intent of collecting approximately $42.6 million in rates over a one-year period, while deferring a number of other costs associated with the Transaction.[1/] This additional collection represents a 4.4% rate increase to industrial customers, a magnitude that would be large even in the context of a general rate proceeding. I am concerned that this sort of accounting and rate treatment would set a dangerous precedent for ratepayers by providing utilities with a framework to conduct single-issue ratemaking outside of a general rate proceeding. Accordingly, I recommend that the Commission reject the

1/ Application, Attachment B at 2.

Company's ratemaking proposal in this proceeding and evaluate it, subsequently, in a general rate proceeding.

Q. IS IT FAIR, JUST, AND REASONABLE FOR THE COMPANY TO INCREASE ITS RATES BY 3.4% OUTSIDE OF A GENERAL RATE CASE?

A. No. It would not be fair, just, or reasonable for the Commission to approve a rate increase of this magnitude without conducting a comprehensive review of the Company's overall operating budgets and earnings within the context of a general rate revision. Focusing on only an isolated group of costs—in this case, the costs associated with the Transaction—outside of a general rate revision would constitute a form of single-issue ratemaking which is not permitted by the Commission.[2/]

Q. HOW HAS THE COMMISSION HISTORICALLY REVIEWED ACCOUNTING REQUESTS SUCH AS THIS?

A. Traditionally, the Commission has approved or rejected accounting requests such as this either in a general rate case or a docket devoted solely to evaluating whether a particular accounting method should be used. In the latter case, the ultimate ratemaking treatment associated with the accounting method has traditionally been postponed and evaluated subsequently in a general rate revision proceeding.

For example, in Docket No. DR 10, the initial request associated with the retirement of the Trojan Nuclear Power Plant ("Trojan"), the Commission did not approve any ratemaking treatment.[3/] Rather, it focused on evaluating a framework to

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2/ In re Portland Gen. Elec. Co. ("PGE"), Docket Nos. DR 10, UE 88 & UM 989, Order No. 04-597 at 6 (Oct 2004), *affirmed* Order No. 08-487 (Sept. 30, 2008), *affirmed* Gearhart v, Pub. Util. Comm'n of Oregon, 356 Or 216 (2014).

3/ See In re the Application of PGE for an Investigation into Least Cost Plan Plant Retirement, DR 10, Order No. 93-1117 at 1 (Aug. 9, 1993).

determine whether the plant retirement was in the public interest, making undepreciated plant investment eligible for rate treatment in a later general rate case.[4/] The ultimate ratemaking treatment associated with the unrecovered investment in Trojan was not evaluated until nearly two years later, when, in general rate case Docket No. UE 88, a comprehensive review of rates and earnings took place, including a detailed review of the prudence of the Trojan retirement costs and benefits.[5/]

In fact, in the very proceedings cited by the Company as precedent for its Application, the Commission did not approve any ratemaking treatment but, rather, deferred ratemaking issues for later review in a rate case. In the proceeding cited regarding the retirement of the Powerdale Hydro Generation Plant, for example, the Commission adopted the Staff recommendation, which stated:

> The Company is not seeking ratemaking treatment for the Powerdale costs. Ratemaking treatment of the costs will be reserved for a future ratemaking proceeding.[6/]

In the proceeding cited regarding the retirement of the Trail Mountain Mine, the Commission, again, adopted the Staff recommendation, which allowed the Company "to record unrecovered costs associated with closure of its Trail Mountain Mine, for accounting purposes only, leaving ratemaking treatment to be decided in Docket UE 134," a power cost rate case.[7/]

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4 Id.

5 See In re the Revised Tariffs Schedules for Electric Service in Oregon Filed by PGE, Docket No. UE 88, Order No. 95-322 (Mar. 29, 1995).

6 In re PacifiCorp Application for an accounting order regarding closure of the Powerdale Hydro Generation Plant, Docket No. UM 1298, Order No. 07-375, Appendix A at 3 (Aug. 23, 2007).

7/ In re PacifiCorp Application for an Accounting Order Regarding Deferral of Trail Mountain Mine Unrecovered Closure Costs, Docket No. UM 1047, Order No. 02-224, Appendix A at 1 (Mar. 29, 2002).

Finally, the proceeding cited regarding the retirement of the Dave Johnston Mine, was, itself, a general rate proceeding, in which a comprehensive review of the Company's budgets and earnings took place.[8/] Thus, the Company's proposal for ratemaking treatment in this proceeding, outside of a rate case, is not consistent with how the Commission has evaluated requests under ORS 757.140(2) in the past. ICNU's attorneys have not been able to locate a single case in which he Commission has handled a rate increase in the manner proposed by the Company.

Q. HAVE DEFERRED ACCOUNTING REQUESTS TRADITIONALLY BEEN HANDLED IN A SIMILAR MANNER?

A. Yes. Proceedings related to deferred accounting applications have also traditionally focused on evaluating whether an accounting method appropriately matches costs and benefits received by ratepayers, without evaluating any ratemaking issues. The Commission recognizes that "[t]he granting of [a deferred accounting] application will not authorize a change in rates, but will permit the Commission to consider allowing such deferred amounts in rates in a subsequent proceeding."[9/]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO REVIEW BOTH THE ACCOUNTING APPLICATION AND RATEMAKING TREATMENT IN THIS PROCEEDING?

A. No. The Company's request seeks approval of an accounting method that appears to be similar to that approved for Trojan in Docket No. DR 10. Yet, it is also seeking ratemaking treatment, on a single-issue basis, in the same proceeding. I disagree with this approach, especially given the magnitude of the Company's proposed rate increase.

8/ See In re Revised Tariff Schedules Applicable to Electric Service Filed by PacifiCorp, Docket No. UE 111, Order No. 00-580 (Sept. 25, 2000).

9/ OAR § 860-027-0300(6)(e).

My recommendation is that the Commission continue its practice of reviewing the ratemaking treatment for accounting requests, such as this, in an appropriate general rate revision proceeding.

Q. WOULD IT BE CONSISTENT WITH COMMISSION RULES TO APPROVE A 3.4% RATE INCREASE OUTSIDE OF A GENERAL RATE CASE?

A. No. My understanding is that, under the Commission rules, Schedule No. 198 would have to be approved in a general rate revision proceeding. "[A] general rate revision is a filing by a utility that affects all or most of the utility's rate schedules."[10/] Because the Company's proposed ratemaking will increase the rates charged to each of the 13 standard rate schedules,[11/] my understanding is that, if approved, it would constitute a general rate revision.[12/] A general rate revision must be accompanied by a showing of the utility's requested capital and equity returns, in order to ensure that the utility is not over-earning.[13/] However, the Company has not made the requisite showing related to its capital and equity returns in this proceeding in order to qualify for a general rate revision. Accordingly, the Company's proposal for ratemaking outside of a properly filed general rate case should be rejected.

10/ OAR § 860-022-0019(1).

11/ Application, Attachment B at 3.

12/ While I am aware that the Commission excludes certain changes from the definition of a "General rate revision," none of the exclusionary exceptions provided under Commission rule seem to apply to the Application. See OAR § 860-022-0017(1). Nor does the Application implicate any special rate mechanisms previously approved by the Commission or agreed to by parties under prior stipulation.

13/ OAR § 860-022-0019(1)(e).

Q. IS THE PROPOSED RATE INCREASE CONSISTENT WITH THE STIPULATION IN THE 2014 GENERAL RATE CASE?

A. No. In Docket No. UE 263—the Company's 2014 general rate case—parties agreed to a rate case stay-out period prohibiting a rate increase until January 1, 2016. Pursuant to paragraph 15 of the joint party Stipulation in that case, the parties' agreement was as follows:

> General Rate Case Stay-Out. The Company agrees to forego a general rate case filing in Oregon in 2014. Following the implementation of rates on January 1, 2014, in this case and the implementation of the Lake Side 2 tariff rider on approximately June 1, 2014, the earliest proposed rate effective date for the Company's next general rate case filing will be January 1, 2016. The Stipulating Parties may file for deferrals during the general rate case stay-out period, but such filings will be subject to the Commission's guidelines for deferrals set forth in Docket UM 1147, unless otherwise authorized by the Commission. The Stipulating Parties agree that their goal is to minimize rate changes during the general rate case stay-out period.[14/]

The Company's proposal for a 3.4% rate increase, on June 1, 2014, is clearly inconsistent with the intent of parities, "to minimize rate changes during the general rate case stay-out period." It is also in conflict with the agreement of the Company to forego filing a general rate case with a rate effective date prior to January 1, 2016. Accordingly, no rate increase should be approved during the pendency of the stay-out period. It appears that the Company filed this case in this manner in an attempt to "get around" the clear requirements of the 2014 general rate case stipulation.

[14/] In re PacifiCorp Request for a General Rate Revision, UE 263, Order No. 13-474, Appendix A at ¶15 (Dec. 18, 2013).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION?

A. I recommend that the Commission reject the Company's request for immediate ratemaking treatment for the Transaction through Schedule No. 198. Approving such a request would constitute single-issue ratemaking, may violate Commission rules, would not be consistent with how the Commission has historically handled accounting requests for plant retirements in the past, and is in violation of the 2014 general rate case stipulation. Instead, the Commission should limit this proceeding to an evaluation of whether the retirement of the Deer Creek Mine, and associated transactions with Bowie, is in the public interest, which, if approved, would qualify the retired plant as an unrecovered plant balance eligible for ratemaking in the Company's next general rate proceeding pursuant to ORS 757.140(2).

III. AMORTIZATION

Q. WHAT IS THE APPROPRIATE WAY TO AMORTIZE THE TRANSACTION?

A. Accounting under ORS 757.140(2) has historically been premised on a net benefit principle, the concept that unrecovered investment associated with the early retirement of utility plant should be eligible for recovery to the extent it will produce a net benefit to ratepayers.[15/] Based on the Company's analysis, the net benefits of the Transaction will accrue to ratepayers over the 14-year and 7-month period ending December 2029, with the largest proportion of those benefits being recognized in the latter part of that period. In order to properly match ratepayer costs with benefits, it is my recommendation that the Transaction be amortized ratably over the same period. In addition, any amounts

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[15/] See Docket No. DR 10, Order No. 93-1117 at 1-2.

amortized should be adjusted over time to reflect changes to inter-jurisdictional allocations of the Huntington facility.

Q. WHEN WILL RATEPAYERS RECEIVE THE BENEFITS ASSOCIATED WITH THE TRANSACTION?

A. The majority of the Transaction benefits will not begin to be recognized by ratepayers until well after [redacted]. Confidential Figure 1, below, details the timing of these benefits based on the net present value revenue requirement calculations that the Company presented to the Commission in the February 23, 2015 technical conference.

Confidential Figure 1
Timing of Ratepayer Benefits Associated with the Transaction
on a Total Company Basis ($m)

[redacted]

As can be seen from Confidential Figure 1, despite the fact that the Company is requesting for ratepayers to pay the entire amount of the Transaction costs upfront, the benefits of those costs will not begin to be recognized by ratepayers for approximately [redacted]. The figure includes the major benefit categories in the Company's financial analysis, with the exception of the UMWA retiree medical settlement, which I do not support in the analysis. If the UMWA retiree medical settlement benefits were included, it would further demonstrate that the benefits of the transaction will not be recognized fully by ratepayers until [redacted] time period. In addition, the benefit category related to the 1974 Pension Trust savings excludes the terminal value of the pension withdrawal annuity liability, which, if included, would result in an additional [redacted] ratepayer benefit in 2029.

Q. WHAT RATIONALE DID THE COMPANY PROVIDE FOR ITS ONE-YEAR AMORTIZATION PROPOSAL?

A. The Company proposed to amortize, and collect, the Transaction costs over the one-year period ending on May 31, 2016. The Company's application, however, provided no rationale for why such accelerated amortization is consistent with how the benefits of the Transaction will accrue to ratepayers. In fact, the Company's proposed amortization is so accelerated that much of the amortization will actually occur prior to when the Company incurs much of the closure costs requiring ratepayers to, in essence, prepay the regulatory account balance.

Q. DO YOU AGREE WITH A ONE-YEAR AMORTIZATION?

A. No. Notwithstanding my objection to single-issue ratemaking outside of a general rate proceeding, a one-year amortization would violate the matching principle. As demonstrated in Confidential Figure 1, above, such a short amortization would not appropriately match the costs borne, and benefits received by ratepayers. In addition, because the public interest test relies on the principle that the benefits of retirement must exceed the costs to ratepayers, the amortization period should be commensurate with the period over which the Company forecasts those benefit to be received. If the amortization is over a shorter period there will be no "net benefit" to ratepayers over that period.

Q. DOES THE FACT THAT ENERGY WEST MINING COMPANY IS AN AFFILIATE IMPACT THE AMORTIZATION?

A. Yes. The Commission has traditionally treated coal acquired from captive mines as an affiliate transaction, governed under the lower of cost or market ratemaking principles. Under a consistent view of this rate treatment, any above market costs incurred as a result of retiring a captive mine should be borne by the utility and not allowed in rates. To the extent that the Company is allowed to amortize the transaction costs over a one-year period, it would require ratepayers to pay a cost for coal that vastly exceeds market rates over the amortization period. This is detailed in Confidential Figure 2, below.

Confidential Figure 2
Huntington Coal Costs with One Year Amortization

[redacted]

To the extent that the Commission requires the Company to amortize costs over a longer period, commensurate with Transaction benefits, however, the smaller amortization amounts included in each year would result in a cost of coal to ratepayers that is closer to market rates. Such a scenario is detailed in Confidential Figure 3, below.

Confidential Figure 3
Huntington Coal Costs with Proposed Amortization

[redacted]

As can be seen by comparing Figure 2 and Figure 3, long-term amortization of the transaction will result in coal prices that are more consistent with market rates for coal over time. Accordingly, I believe that such an approach is more consistent with the regulatory treatment of captive mine costs, as well as a more reasonable approach for ratepayers.

Q. SHOULD PARTIES STILL BE ABLE TO CONTEST HUNTINGTON FUEL PRICES THAT EXCEED MARKET PRICES?

A. Yes. To the extent that the cost of fuel at the Huntington facility, including amortization of the Transaction amounts, exceeds the market price of coal, it would be consistent with the lower of cost or market principle to allow parties to contest the above market costs associated with Transaction amortization in a general rate case.

Q. WHAT OTHER FORMS OF INEQUITY WILL RESULT FROM A ONE-YEAR AMORTIZATION?

A. If a one-year amortization is approved, generational inequity will occur. The ratepayers responsible for paying the upfront amortization will not be the same ratepayers that ultimately receive the benefits associated with the Transaction. Further, increases in other jurisdictions' loads may create a situation where the benefits ultimately received by ratepayers through the inter-jurisdictional allocation methodology become diluted with time. It is possible, in fact, that the jurisdictional allocation methodology approved for use following the expiration of the 2010 Protocol will not allocate any benefits associated with the Transaction to Oregon. This jurisdictional inequity to Oregon customers, whose loads are expected to decline over time relative to other jurisdictions, must be resolved in any amortization approved by the Commission.

Q. HOW DO YOU PROPOSE TO RESOLVE THESE PROBLEMS?

A. First, the amortization must occur over the same period that benefits are received in order to ensure that the ratepayers responsible for the costs are the same ratepayers receiving the benefits. Second, any amount amortized must be dynamic, such that the amortization will be reduced in the circumstance where Oregon's jurisdictional allocation of the Transaction benefits, via the Huntington facility, declines.

Q. HOW WOULD A DYNAMIC AMORTIZATION WORK?

A. Table 1, below, provides a simplified illustration of an amortization methodology that would respond to changes in Oregon's jurisdictional allocation of potential Transaction benefits over time.

Table 1
Illustrative Dynamic Amortization Methodology

1		2015	2016	2017	2018	. . .	2025	2026	. . .
2	Illustrative Total Company Amortization ($m)	10.00	10.00	10.00	10.00		10.00	10.00	
3	Huntington Fuel Allocator	24.8%	23.8%	22.8%	21.8%		0.0%	0.0%	
4	Oregon Allocated Amortization before ECD ($m)	2.48	2.38	2.28	2.18		-	-	
5	ECD ($m) *	0.15	0.24	0.23	0.22		-	-	
6	Oregon Allcoated Amortization After ECD ($m)	2.34	2.14	2.05	1.96		-	-	
7	* ECD values for illustration only. Amortization would be included in the cost of other resources in the ECD calculation.								

As can be seen from Table 1, as the allocator assigned to Huntington declines, the amortization reflected in Oregon rates also declines. Similarly, when the allocator declines to zero—i.e., Huntington is no longer included in Oregon rates—the amortization also declines to zero.

Q. PLEASE SUMMARIZE YOUR PROPOSAL REGARDING AMORTIZATION.

A. The benefits of the Transaction will not substantially accrue to ratepayers for a number of years. In order to match costs with benefits, and to ensure that ratepayers are not required to pay above market rates for the cost of coal from a captive mine, any regulatory account approved by this Commission should be amortized over life of the Transaction. In addition, the amortization should be dynamic, responding to changes in the level of rate benefits that Oregon ratepayers will receive over time as a result of changing jurisdictional allocation factors and methods.

IV. 1974 PENSION TRUST WITHDRAWAL

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO WITHDRAW FROM THE 1974 PENSION TRUST?

A. The financial exposure to ratepayers of withdrawing from the 1974 Pension Trust is currently limited to a $3.0 million per year annuity payment.[16/] Thus, to the extent that the Company negotiates a lump-sum withdrawal payment, it should be prohibited from recovering any amount in excess of the perpetuity value of the $3.0 million annuity payment to ratepayers. Based on the 7.62% cost of capital stipulated in Docket No. UE 263,[17/] the exposure of ratepayers to the lump-sum payment should be limited to $39.4 million on a total Company basis,[18/] or approximately $9.7 million on an Oregon allocated basis.

Q. WHY IS THE RATEPAYER WITHDRAWAL EXPOSURE CURRENTLY LIMITED TO $39.4 MILLION?

A. The Company believes that it will have the option to settle the $3.0 million annual liability with an upfront, lump-sum settlement amount.[19/] My understanding is that the lump-sum settlement amount would be determined in a bilateral negotiation between the Company and the 1974 Pension Trust. The amount for which either party may be willing

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16/ PAC/200 at 10:5-7.

17/ Docket No. UE 263, Order No. 13-474, Appendix A at ¶15.

18/ $39.4 m = $3.0 m ÷ 7.621%.

19/ PAC/200 at 10:13-15.

to settle is largely driven by the perpetuity value of the $3 million annuity payment to each party. The perpetuity value represents the present value of a fixed stream of payments made for an indefinite period of time and is calculated, simply, by dividing the payment by the periodic interest rate:

Figure 4
Perpetuity Value

$$\textbf{Perpetuity Value} = \frac{\textbf{Payment}}{\textbf{Discout Rate}}$$

The perpetuity calculation is highly sensitive to the assumed discount rate. As an example, based on a 10.00% discount rate the perpetuity value of a $3.0 million annuity payment would be $30.0 million ($3.0 million ÷ 10.00%). Based a 5.00% discount rate, the perpetuity value of the $3.0 million would increase to $60.0 million ($3.0 million ÷ 5.00%). As a result, it is my understanding that the underlying discount rate often becomes a negotiating point in the lump-sum settlement of an annuity payment.

Q. WHAT IS THE COMPANY'S MOST RECENTLY APPROVED COST OF CAPITAL?

A. The overall cost of capital stipulated in UE 263 was 7.62%.[20/] Such a discount rate would result in a $39.4 million (3.0 million ÷ 7.62%) perpetuity value of the pension withdrawal annuity to ratepayers.

20/ Docket No. UE 263, Order No. 13-474, Appendix A at ¶15.

Q. WILL RATEPAYERS BE HARMED IF THE COMPANY WERE TO SETTLE FOR AN AMOUNT EXCEEDING $39.4 MILLION?

A. Yes. At a 7.62% cost of capital, any amounts paid in excess of the $39.4 million would serve to increase costs to ratepayers over time. From the ratepayer perspective, any amount of funds collected in excess of that amount would be more efficiently deployed by the Company as a permanent offset to rate base, rather than as a lump-sum payment. It follows that any amount collected in excess of that amount would only serve to eliminate any risk to shareholders corresponding to the return that the Company is currently earning on rate base, and would not be appropriately included in rates.

Q. DO YOU BELIEVE THAT THE 1974 PENSION TRUST WOULD BE WILLING TO ACCEPT A 7.62% INTEREST RATE TO DETERMINE THE LUMP-SUM WITHDRAWAL PAYMENT?

A. Yes. Based on its 2013 actuarial report, 1974 Pension Trust assumed a [redacted] expected market return for 2013.[21/] Based on this market return assumption, the perpetuity value of the $3.0 million annuity payment to the 1974 Pension Trust would be approximately [redacted]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE 1974 PENSION TRUST WITHDRAWAL LIABILITY.

A. I recommend that the Commission place a $39.4 million cap on the amount of funds related to a lump-sum payment option that are recoverable in rates based on the

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21/ Confidential ICNU/102.

Company's current cost of capital. Such a cap will ensure that ratepayer interests are represented in the negotiation of the pension withdrawal.

V. DEER CREEK MINE CLOSURE TARIFF

Q. PLEASE PROVIDE AN OVERVIEW OF THE TECHNICAL ISSUES YOU IDENTIFIED WITH THE DEER CREEK MINE CLOSURE TARIFF.

A. While I continue to disagree that the Company should be provided with ratemaking treatment in this proceeding, if ratemaking treatment is approved, there are a number of corrections and adjustments that must be made. These corrections and adjustments would also need to be accounted for in any amounts included in unrecovered investment, subject to later recovery in a general rate proceeding. Table 2, below, summarizes these corrections and adjustments

Table 2
Adjustments to Deer Creek Mine Closure Tariff
on an Oregon Allocated Basis

		$m
1	**Company Rate Request**	**42.6**
2	**Adjustments**	
3	Embedded Cost Differential	(3.7)
4	Return on Mining Assets	(2.6)
5	Bonus Depreciation	(2.8)
6	UMWA Retiree Medical	[redacted]
7	**Total**	[redacted]
8	**Adjusted Rate Request**	[redacted]

A. Embedded Cost Differential

Q. PLEASE PROVIDE AN OVERVIEW OF THE ISSUE SURROUNDING THE ECD IN THE COMPANY'S FILING.

A. The Company did not account for the ECD provision of the 2010 Protocol when it performed the inter-jurisdictional cost allocation for the expense and investment associated with the Transaction. As a result, the Company's application overstates the amount of Transaction costs that should be allocated to Oregon ratepayers under the 2010 Protocol. Properly accounting for the ECD in the inter-jurisdictional allocation would reduce the amount of costs initially allocable to Oregon retail customers through Schedule No. 198, or through a regulatory asset, by $3.7 million.

Q. WHAT IS THE ECD?

A. The ECD is a provision of the 2010 Protocol inter-jurisdictional cost allocation methodology. It is also commonly referred to as the hydro endowment, which refers more specifically to a prior iteration of the ECD. The purpose of the provision is to ensure that customers located in areas that were served by Pacific Power, prior to the 1989 merger with Utah Power & Light, continue to pay all of the costs, and receive all of the benefits of the Company's legacy hydro system located in the Northwest.

Q. HOW IS THE ECD CALCULATED?

A. The ECD calculation is designed to directly assign the costs and benefits of the Northwest hydro system to the states formerly served by Pacific Power. It functions by comparing the embedded production cost on a dollars-per-megawatt-hour basis of Northwest hydro resources to the embedded costs of all other resources on the Company's system. The cost differential between the two is multiplied by the generation of hydro resources historically allocable to Oregon to develop a credit, which ultimately reduces Oregon rates.

Q. HAVE YOU PREPARED AN ANALYSIS TO DEMONSTRATE HOW THE AMORTIZATION OF THE TRANSACTION OVER A ONE-YEAR PERIOD WILL IMPACT THE ECD?

A. Yes. Attached as Exhibit ICNU/103 is a calculation of how the Transaction costs included in the Schedule No. 198 tariff would have impacted the ECD calculation approved in the Company's last general rate case, Docket No. UE 263. As can be seen by the Exhibit, the Company's accelerated, one-year amortization request would increase the costs of all other resources in the ECD calculation, resulting in an increase to the overall ECD credit. Because the costs associated with the Deer Creek Mine would have otherwise flown through the cost of other resources in the ECD calculation, the amortization of amounts associated with the Transaction should be afforded the same allocation treatment.

Q. PLEASE SUMMARIZE YOUR CORRECTION SURROUNDING THE ECD.

A. Exhibit ICNU/103 demonstrates that, if the ECD approved in Docket No. UE 263 had reflected the one-year amortization that the Company proposed in this proceeding, the ECD credit amount would increase by approximately $3.7 million. Accordingly, I recommend that the Commission apply this additional credit to any amount collected, or included in a regulatory asset, associated with the Transaction in this proceeding.

<u>B.</u> <u>Return on Mining Assets</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE ISSUE RELATED TO RETURN ON DISPOSED MINING ASSETS.

A The Company has proposed to collect through Schedule No. 198 the unrecovered investment, including closure costs, associated with retired and sold mining assets. The Company, however, is currently recovering the capital costs associated with the disposed mining assets in rate base and did not propose any adjustment to remove the return on mining assets already included in rates.[22/] The Company's surcharge, therefore, overstates the amount of cost incremental to base rates that ought to be recovered through a Schedule No. 198 surcharge. While this is yet another reason why the ratemaking of these sorts of accounting requests should be evaluated in a comprehensive general rate proceeding, eliminating this double counting of the return component will result in a $2.6 million reduction to the Company's Schedule No. 198 request.[23/]

Q. HOW HAS THE DEER CREEK MINE HISTORICALLY BEEN INCLUDED IN REVENUE REQUIREMENT?

A. Two categories of costs have traditionally been included in rates associated with the Deer Creek Mine. First, mine operating costs—including depreciation—are included in the cost of fuel for the Huntington facility. This fuel cost is reflected in rates as a net power cost and is recalculated annually through the Transition Adjustment Mechanism filing. Second, the net plant investment in the mining assets is included in rate base, separate from the net power cost calculation. The rate base amounts and associate return on the

22/ <u>See</u> Application, Attachment B at 2. No return component is removed to arrive at the amount flowing into the tariff.

23/ <u>See</u> ICNU/104 at 1-3 (the Company's Response to ICNU Data Request ("DR") 3.64).

mining assets are periodically updated in rates through general rate case filings. The last update of the mine rate base amounts occurred in Docket No. UE 263.

Q. DID THE COMPANY'S PROPOSAL REMOVE THE RETURN ON MINING ASSETS CALCULATED IN DOCKET NO. UE 263?

A. No. The Company did not remove the return on mining assets that was already reflected in rates in Docket No. UE 263. This can be noted from the Application, particularly on page 2 of Attachment B where no return on mining assets was deducted from the ultimate amount that the Company has requested in rates. While the Company did remove the return of, or depreciation on, the mining assets in its proposed true up of net power costs, I have not identified any place in the Company's calculation where it has accounted for the return on component of the mining assets already reflected in rates.

Q. DID THE COMPANY'S FINANCIAL ANALYSIS ASSUME THAT THE 'RETURN ON' COMPONENT WOULD BE REMOVED FROM RATES?

A. Yes. The Company's financial analysis assumed that ratepayers would recognize benefits of [redacted], on a total company basis, [redacted].[24]

Q. IS THIS ANOTHER REASON WHY THE COMPANY RATEMAKING REQUEST SHOULD NOT BE EVALUATED OUTSIDE OF A GENERAL RATE PROCEEDING?

A. Yes. Absent a comprehensive review of the Company's overall earnings—including a detailed review of the many ancillary and offsetting revenue requirement impacts of the Company's various proposals—I do not think it is practical for the Commission to demonstrate that rates are fair, just, and reasonable, outside of a general rate proceeding.

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[24] Confidential ICNU/106 at 3 (Deer Creek Mine Transaction, Technical Conference with Public Utility Commission of Oregon (Feb. 23, 2015)).

Q. PLEASE SUMMARIZE YOUR PROPOSED CORRECTION RELATED TO THE RETURN ON MINING ASSETS ALREADY REFLECTED IN RATES?

A. The Company's single-issue ratemaking approach did not properly account for the fact that the rates approved in Docket No. UE 263 fairly compensate the Company for a return on the mining assets that will be disposed in the transaction. If any ratemaking is to be approved in this proceeding, the return on mining assets currently reflected in rates must be removed from any amounts that the Company collects or accrues to a regulatory asset. Doing so reduces the Company's Schedule No. 198 request by approximately $2.6 million on an Oregon allocated basis.

C. Bonus Depreciation

Q. PLEASE PROVIDE AN OVERVIEW OF THE ISSUE SURROUNDING BONUS DEPRECIATION.

A. Repeated one-sided requests for accounting from the Company are unfair and damaging to ratepayers. When an accounting event results in additional costs, the Company has the option to file for a deferral. Yet, when an accounting event results in windfall revenues, the Company has the option not to file for a deferral, leaving the deferral request to ratepayer advocacy groups. Because, however, ratepayer advocates do not possess the same level of financial information, it results in an unfair advantage to the Company with regard to accounting requests such as this.

As an example, on December 19, 2014, the President signed into law the Tax Increase Prevention Act of 2014, which, among other things, retroactively extended 50% bonus depreciation through calendar year 2014. This legislation resulted in a financial windfall to the Company relative to the rates approved in Docket No. UE 263.

Notwithstanding, the Company has not filed any sort of accounting application to return these windfall profits to customers. In order to consider the comprehensive impact of the Transaction in relation to the Company's overall earnings, I recommend that these windfall profits be returned to ratepayers through the regulatory asset sought in this proceeding, including amounts over-collected in 2014. While the Company has not calculated the precise amount of benefits that it received as a result of this legislation, my high-level calculations suggest that the Company will receive approximately $2.8 million in Oregon allocated benefits as a result of the extension of 50% bonus depreciation.

Q. PLEASE PROVIDE AN OVERVIEW OF BONUS DEPRECIATION.

A. Bonus depreciation is a tax accounting provision found in IRC § 168(k) that allows a taxpayer to deduct up to 50% of its tax basis in qualified property in the year that the property is placed into service. While this provision has traditionally been implemented as a means to encourage investment in fixed assets, it has fallen into a group of tax provisions, which expire on an annual basis, only to be reinstated retroactively by Congress in last-minute tax extenders legislation. Prior to the December 2014 tax extenders legislation, bonus depreciation would have expired on January 1, 2014, making taxpayers ineligible to claim the bonus deduction on their calendar year 2014 tax returns. The new legislation extended bonus depreciation through the end of 2014, allowing it to be claimed on 2014 tax returns.

Q. HOW DOES BONUS DEPRECIATION IMPACT REVENUE REQUIREMENT?

A While, under IRC § 168(f), the tax expense reflected in public utility rates must be calculated on an accrual basis excluding the current tax benefits of accelerated and bonus depreciation, a bonus depreciation election does result in an increase in the allowance for deferred income taxes ("ADIT") included in rate base. ADIT is a benefit to ratepayers because it represents a source of zero interest financing for the Company, typically applied as offset to rate base. Thus, as the election of bonus depreciation will cause ADIT to increase, overall revenue requirement will decline. While the overall impact can be small in years when little capital is placed into service, in years when a large amount of capital is placed into service, bonus depreciation can have a material impact on rate base and revenue requirement.

Q. WILL ANY 2014 CAPITAL EXPENDITURES QUALIFY FOR BONUS DEPRECIATION?

A. Yes. In 2014, the Company placed into service the 645 MW Lake Side II combined cycle combustion turbine. As a result of the extension of bonus depreciation, the Company will now be able to deduct 50% of the cost of Lake Side II on its 2014 tax return, which will be filed in September 2015. This will likely result in a material reduction to the tax liability calculated on the Company's 2014 tax return.

Q. HOW WAS LAKE SIDE II INCLUDED IN RATES IN DOCKET NO. UE 263?

A. Pursuant to the joint party Stipulation in Docket No. UE 263, the Company was provided with the opportunity to establish a separate tariff rider to recover the revenue requirement associated with Lake Side II.[25/] Parties agreed that the rider would collect $22.7 million in revenue requirement.[26/] My understanding is that this tariff rider, however, assumed that bonus depreciation expired on January 1, 2014, and did not reflect the substantial

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25/ Docket No. UE 263, Order No. 13-474, Appendix A at ¶13.
26/ Id. at 4.

benefits that the Company will now receive as a result of claiming 50% bonus depreciation on its 2014 tax return.

Q. HOW WOULD BONUS DEPRECIATION IMPACT THE REVENUE REQUIREMENT FOR LAKE SIDE II APPROVED IN DOCKET NO. UE 263?

A. Exhibit ICNU/105 includes a high-level calculation of the impact that bonus depreciation would have on the revenue requirement stipulated for Lake Side II. This calculation did not review any potentially offsetting tax impacts, such as the Domestic Production Activities Deduction. My calculation demonstrates that bonus depreciation would have reduced the Lake Side II revenue requirement by approximately $2.8 million annually.

Q. DID YOU ASK THE COMPANY TO CALCULATE THE IMPACT OF BONUS DEPRECIATION ON THE RATES APPROVED IN UE 263?

A. Yes. While the Company was requested to perform this calculation in discovery, it was not forthcoming in its response, calculating only the bonus depreciation benefits associated with the Deer Creek Mine assets.[27/] As a result, my estimate of the windfall benefits that the Company is currently receiving as a result of bonus depreciation was done at a high level, with the expectation that the Company would provide more clarity on the actual benefits that it has recognized.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that the Commission require the Company to recalculate the revenue requirement approved in Docket No. UE 263, assuming bonus depreciation was extended until the end of 2014. I propose that the revenue requirement benefit associated with bonus depreciation in 2014 be included in the regulatory asset sought in this proceeding.

27/ ICNU/104 at 4 (The Company's Response to ICNU DR 4.73).

Based on my estimation of the bonus depreciation benefit associated with only Lake Side II, this would result in a $2.8 million Oregon allocated reduction to the Company's proposed recovery under Schedule No. 198.

D. UMWA Retiree Medical Settlement

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE UMWA RETIREE MEDICAL SETTLEMENT.

A. The Company settled its UMWA retiree medical liability for a [redacted] book loss, yet it claims that the settlement will produce approximately [redacted] in ratepayer benefits over the plan's remaining life.[28] I disagree with including this loss as a component of the unrecovered plant investment in the Deer Creek Mine under ORS 757.140(2). The settlement loss appears to be unrelated to the Transaction and was incurred prior to when the Company submitted its application. Removing this cost component from the Company's Schedule No. 198 calculation would reduce recovery by approximately [redacted] on an Oregon allocated basis.

Q. WHY ARE YOU CONCERNED WITH THE BOOK LOSS THAT THE COMPANY HAS INCURRED RELATED TO THE UMWA RETIREE MEDICAL OBLIGATION?

A. The Company alleges that it settled the UMWA retiree medical obligation for a substantial gain, yet it is proposing to pass unrecognized losses onto ratepayers. This is concerning because the amounts that the Company is seeking recovery of in this proceeding represent a paper loss, rather than an actual expenditure that it has incurred in

[28] Confidential ICNU/106 at 2 (Deer Creek Mine Transaction, Technical Conference with Public Utility Commission of Oregon (Feb. 23, 2015)).

connection with retiring the Deer Creek Mine assets. It is also unclear whether ratepayers have historically received the benefit of unrecognized losses in rates.

Q. SHOULD THE SETTLEMENT LOSS BE INCLUDED IN THE UNRECOVERED INVESTMENT IN THE DEER CREEK MINE?

A. No. First, my understanding is that the Company could have entered into this settlement agreement regardless of whether it entered into the Transaction. For example, if the Company were to purchase coal on the market, rather than enter into the Transaction with Bowie, the benefits of this settlement would continue to exist. Second, my understanding is that this settlement agreement was executed prior to when the Company submitted its accounting application. The rules surrounding retroactive ratemaking typically prohibit deferred accounting treatment for costs incurred prior to an accounting application. Accordingly, I recommend that the UMWA retiree medical settlement be eliminated from the Transaction costs eligible for accounting under ORS 757.140(2).

VI. PUBLIC INTEREST TEST

Q. PLEASE SUMMARIZE YOUR CONCERNS REGARDING WHETHER THE RETIREMENT OF THE DEER CREEK MINE IS IN THE PUBLIC INTEREST.

A. Based on my review of the Company's filing, I cannot conclude that the Company's decision to close the Deer Creek Mine is, or is not, in the public interest. In order to qualify for ORS 757.140(2) accounting, the Company has the burden to demonstrate that its decision to retire the mine is in the public interest. Yet, while the Company claims that the long-term coal Huntington CSA will hold customers harmless to the extent that it becomes economic to retire the Huntington facility early, the language in the Huntington CSA is not sufficiently clear to arrive at that conclusion. Accordingly, I recommend that the Commission find that the Transaction is not in the public interest, unless the Company were to agree that it would exclude any long-term coal contract liabilities or costs related to the Huntington CSA in any future analysis evaluating the retirement of the Huntington facility. In addition, the Company should agree to exclude from rates any actual Huntington CSA contract liabilities actually incurred to the extent Huntington is retired prior to the end of its useful life.

VII. OTHER OBJECTIONS TO THE COMPANY'S FILING

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE COMPANY'S FILING?

A. Yes. I am concerned with the complicated nature of how the Company has estimated the benefits associated with the Transaction. The Company's workpapers are not well documented and are difficult to follow. As a practical matter, accounting workpapers, such as the ones relied on by the Company to demonstrate that the Transaction will produce benefits, need to be organized in such a manner that the purpose of individual calculations is explained, including cross references between the workpapers used in the calculation. As I have reviewed the Company's calculation, I have not been able to become comfortable with how the benefit calculation was performed and am concerned that there may be material inaccuracies in the level of benefits estimated by the Company. It should be a straightforward analysis for the Company to evaluate the discrete benefits that it is suggesting will be derived from the Transaction, yet in the approximately 50 megabytes of files provided by the Company, it is difficult to gain a clear understanding of how the benefits will be derived, let alone review the accuracy of the Company's calculation. As I continue my review, I may address the accuracy of the Company's benefit calculations at a later stage in the proceeding.

Q. ARE THERE ANY OTHER SPECIFIC COST ITEMS THAT YOU ARE CONCERNED ABOUT?

A. Yes. The Company has assumed that it will incur a large amount of abandonment and recovery-based royalty costs associated with the retirement of the Deer Creek mine. Virtually no documentation was provided in the Application regarding these costs, despite the fact that these royalties represent the largest component of the closure cost to retire the Deer Creek Mine. These royalty costs appear to be speculative, depending on the outcome of complicated negotiations with the Bureau of Land Management, as well as legal interpretations of the underlying royalty obligations. At this point I do not believe that the Company has demonstrated that such costs should be eligible to be included in the unrecovered plant balance associated with the Transaction. Accordingly, I propose that, absent a clear demonstration of the amount of royalty costs expected to be incurred by the Company, such costs should be excluded from the unrecovered plant balance associated with the Transaction. To the extent that additional information is discovered surrounding these royalty costs, I may address this issue further at a later stage in this proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1712

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Application for Approval of Deer Creek Mine Transaction.	)
	)
	)
	)

EXHIBIT ICNU/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

March 5, 2015

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am an independent consultant representing industrial customers throughout the western United States. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

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

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

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

- Bonneville Power Administration, BP-16: 2016 Joint Power and Transmission Rate Proceeding
- Wa.UTC, UE-141368: In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes
- Wa.UTC, UE-140762: In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million
- Wa.UTC, UE-141141: In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs
- Wy.PSC, 20000-446-ER-14: In re The Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent
- Wa.UTC, UE-140188: In re Avista Corporation, General Rate Increase For Electric Services, RE: Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015
- Or.PUC, UM 1689: In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market
- Or.PUC, UE 287: In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism.
- Or.PUC, UE 283: In re Portland General Electric Company, Request for a General Rate Revision

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1712

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Application for Approval of Deer Creek Mine	)
Transaction.	)
	)
	)

REDACTED EXHIBIT ICNU/102

EXCERPT FROM 1974 PENSION TRUST 2013 ACTUARIAL REPORT

March 5, 2015

Exhibit ICNU/102 is confidential pursuant to the general protective order in this proceeding and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1712

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Application for Approval of Deer Creek Mine Transaction.	)
	)
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	)

EXHIBIT ICNU/103

ECD CALCULATION WITH TRANSACTION COSTS

March 5, 2015

Exhibit No. ICNU/103
ECD Calculation with Transaction Costs, from UE 263

Oregon General Rate Case - December 2014
12 Months Ended December 31, 2014
ANNUAL EMBEDDED COSTS
Year End Balance

2010 Protocol ECD

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
535 - 545	Hydro Operation & Maintenance Expense	33,582,849				Page 2.7, West only
403HP	Hydro Depreciation Expense	25,755,587				Page 2.15, West only
404IP / 404HP	Hydro Relicensing Amortization	11,134,225				Page 2.16, West only
	Total West Hydro Operating Expense	**70,472,660**				
330 - 336	Hydro Electric Plant in Service	789,409,821				Page 2.23, West only
302 & 182M	Hydro Relicensing	170,183,089				Page 2.29, West only
108HP	Hydro Accumulated Depreciation Reserve	(232,984,150)				Page 2.36, West only
111IP / 111HP	Hydro Relicensing Accumulated Reserve	(44,162,729)				Page 2.39, West only
154	Materials and Supplies	1,563				Page 2.32, West only
	West Hydro Net Rate Base	**682,447,594**				
	Pre-tax Return	10.79%				
	Rate Base Revenue Requirement	**73,623,599**				
	Annual Embedded Cost					
	West Hydro-Electric Resources	**144,096,260**	3,599,635	40.03	(34,213,314)	MWh from GRID

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Annual Mid-C Contracts Costs	5,503,818	341,005	16.14	(11,387,995)	GRID
	Grant Reasonable Portion	(6,200,845)			(6,200,845)	GRID
		(697,026)			(17,588,840)	

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Utah Annual Qualified Facilities Costs					
555	Oregon Annual Qualified Facilities Costs					
555	Idaho Annual Qualified Facilities Costs					
555	WYU Annual Qualified Facilities Costs					
555	WYP Annual Qualified Facilities Costs					
555	California Annual Qualified Facilities Costs					
555	Washington Annual Qualified Facilities Costs					
	Total Qualified Facilities Costs	-	-		-	GRID

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh	Reference
500 - 514	Steam Operation & Maintenance Expense	1,176,885,490			Page 2.5
535 - 545	East Hydro Operation & Maintenance Expense	9,111,468			Page 2.7, East only
546 - 554	Other Generation Operation & Maintenance Expense	71,061,764			Page 2.8
555	Other Purchased Power Contracts	96,435,883			GRID less QF and Mid-C
40910	Production Tax Credits	0			Page 2.20
4118	SO2 Emission Allowances	(206,119)			Page 2.4
	James River	(4,302,805)			James River Adj (Tab 5)
	REC Revenues	0			REC Revenues (Tab 3)
403SP	Steam Depreciation Expense	272,550,907			Page 2.15
403HP	East Hydro Depreciation Expense	6,838,628			Page 2.15, East only
403OP	Other Generation Depreciation Expense	9,919,167			Page 2.15
403MP	Mining Depreciation Expense	0			Page 2.15
404IP / 404 HP	East Hydro Relicensing Amortization	362,261			Page 2.16, East only
406	Amortization of Plant Acquisition Costs	4,834,296			Page 2.17
	Add Transaction Amortization:				
	PP&E	91,539,976			
	Materials & Supplies	4,187,301			
	CWIP/Preliminary Survey & Inv.	5,109,229			
	Severance & Medical/Supp. Unempl. Welfare Plan	5,428,439			
	Closure/Idling Costs	19,069,858			
	Royalties on closure costs	16,487,368			
	Royalties on abandoned reserves	21,086,842			
	Misc. (ARO, pre-payments, income taxes)	7,947,510			
	Total All Other Operating Expenses	**1,814,347,462**			
310 - 316	Steam Electric Plant in Service	6,670,697,674			Page 2.21
330 - 336	East Hydro Electric Plant in Service	162,450,450			Page 2.23, East only
302 & 186M	East Hydro Relicensing	9,612,645			Page 2.29, East only
340 - 346	Other Electric Plant in Service	293,900,766			Page 2.24
399	Mining	482,121,148			Page 2.28
108SP	Steam Accumulated Depreciation Reserve	(2,796,163,830)			Page 2.36
108OP	Other Generation Accumulated Depreciation Reserve	(111,767,875)			Page 2.36
108MP	Other Accumulated Depreciation Reserve	(174,787,386)			Page 2.38, East only
108HP	East Hydro Accumulated Depreciation Reserve	(56,811,238)			Page 2.36, East only
111IP / 111HP	East Hydro Relicensing Accumulated Reserve	(5,080,719)			Page 2.39, East only
114	Electric Plant Acquisition Adjustment	159,175,508			Page 2.31
115	Accumulated Provision Acquisition Adjustment	(120,513,028)			Page 2.31
151	Fuel Stock	244,812,858			Page 2.32
253.16 - 253.19	Joint Owner WC Deposit	(6,681,672)			Page 2.32
253.98	SO2 Emission Allowances	(121,735)			Page 2.34
154	Materials & Supplies	93,226,734			Page 2.32
154	East Hydro Materials & Supplies	0			
	Less:				
	Deer Creek Rate Base	(91,539,976)			
	Total Net Rate Base	**4,752,530,324**			
	Pre-tax Return	10.79%			
	Rate Base Revenue Requirement	**512,711,000**			
	Annual Embedded Cost				
	All Other Generation Resources	**2,327,058,462**	46,977,633	49.54	MWh from GRID
	Total Annual Embedded Costs	**2,470,457,696**	**50,918,273**	**48.52**	

Exhibit No. ICNU/103
ECD Calculation with Transaction Costs, from UE 263

Oregon General Rate Case - December 2014
12 Months Ended December 31, 2014

Embedded Cost Differentials		TOTAL	CA	OR	WA	WY	UT	ID	FERC
Company Owned Hydro	DGP	**(34,213,314)**	(1,093,392)	(18,649,445)	(5,556,332)	(8,914,145)	-	-	-
Company Owned Hydro	SG	34,213,314	522,592	8,913,595	2,655,677	5,363,080	14,705,268	1,938,394	114,707
Mid-C Contract	MC	**(17,588,840)**	(199,237)	(7,331,491)	(1,624,371)	(2,044,659)	(5,606,343)	(739,007)	(43,732)
Mid-C Contract	SG	17,588,840	268,661	4,582,421	1,365,266	2,757,124	7,559,882	996,516	58,970
Total Non-Levelized ECD		-	(501,375)	(12,484,920)	(3,159,761)	(2,838,600)	16,658,808	2,195,903	129,946
ECD Approved in UE 263		-	(300,195)	(8,792,171)	(2,096,760)	(1,605,652)	11,227,263	1,479,936	87,577
Delta		**-**	(201,181)	**(3,692,749)**	(1,063,001)	(1,232,948)	5,431,544	715,966	42,368
Klamath Surcharge Adjustment Non-Levelized		0	1,113,278	11,342,884	(1,335,084)	(2,696,172)	(7,392,754)	(974,486)	(57,667)
	DGP	100.000%	3.196%	54.509%	16.240%	26.055%	0.000%	0.000%	0.000%
	SG	100.000%	1.527%	26.053%	7.762%	15.675%	42.981%	5.666%	0.335%
	MC	100.000%	1.133%	41.683%	9.235%	11.625%	31.874%	4.202%	0.249%

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1712

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Application for Approval of Deer Creek Mine Transaction.	)
	)
	)
	)

EXHIBIT ICNU/104

COMPANY RESPONSES TO ICNU DATA REQUESTS

March 5, 2015

UM-1712/PacifiCorp
February 20, 2015
ICNU Data Request 3.64

ICNU Data Request 3.64

Please state the amount of return on rate base that was included in the Company's most recent general rate proceeding associated with each and every asset that will be sold, disposed, or retired as a result of the Deer Creek Mine Closure and associated transaction with Bowie.

Response to ICNU Data Request 3.64

Please refer to Attachment ICNU 3.64.

OR UM 1712
ICNU 3.64

Attachment ICNU 3.64

ATTACHMENT ICNU 3.64
ASSETS SOLD, DISPOSED OR RETIRED AS A RESULT OF THE DEER CREEK MINE CLOSURE

	RATE BASE from UE 263 (1)		Pre-Tax Return	Oregon Rev. Req.
	Total Company	Oregon Portion		
Electric Plant in Service				
Coal Mine Assets				
Sold	42,245,429	10,429,016	10.75%	1,121,526
Retired/Disposed	254,533,715	62,836,058	10.75%	6,757,325
Intangible Assets				
Sold	11,706	2,890	10.75%	311
Retired/Disposed	3,431,094	847,025	10.75%	91,088
General Plant				
Sold	64,568	15,940	10.75%	1,714
Retired/Disposed				
Distribution Plant				
Sold	966,545	-	10.75%	-
Retired/Disposed	2,995,576	-	10.75%	-
Accumulated Depreciation				
Coal Mine Assets				
Sold	(22,024,192)	(5,437,053)	10.75%	(584,695)
Retired/Disposed	(150,653,791)	(37,191,499)	10.75%	(3,999,535)
Intangible Assets				
Sold	(7,659)	(1,891)	10.75%	(203)
Retired/Disposed	(2,244,725)	(554,149)	10.75%	(59,593)
General Plant				
Sold	(3,362)	(830)	10.75%	(89)
Retired/Disposed				
Distribution Plant				
Sold	(308,472)	-	10.75%	-
Retired/Disposed	(1,164,419)	-	10.75%	-
Accumulated Deferred Income Tax				
Sold	(21,739,947)	(5,366,883)	10.75%	(577,149)
Retired/Disposed	(6,607,107)	(1,631,079)	10.75%	(175,405)
			TOTAL OREGON "RETURN ON" IN RATES	**2,575,294**

SE Factor from UE-263 Stipulation 24.687%

Notes
(1) UE 263 reflected projected plant balances for the test year. ADIT for these assets from UE 263 is not readily available. Actual ADIT balances are reflected for purposes of this response.

OR UM 1712
ICNU 3.64

Attachment ICNU 3.64

ATTACHMENT ICNU 3.64

Pre-Tax Return from UE-263 Stipulation

Component	Structure	Cost	Weighted Cost	Pre -Tax Return
Long-Term	47.600%	5.250%	2.499%	2.499%
Preferred S	0.300%	5.427%	0.016%	0.026%
Common	52.100%	9.800%	5.106%	8.229%
	100.00%		7.621%	10.754%

UM-1712/PacifiCorp
February 24, 2015
ICNU Data Request 4.73

ICNU Data Request 4.73

Please recalculate the final revenue requirement approved in the Company's most recent general rate case (the workpapers for which are provided in the response to ICNU data request 0063), assuming that 50% bonus depreciation, as defined in the Tax Increase Prevention Act of 2014 (Public Law No. 113-295), was available for the entire test period.

Response to ICNU Data Request 4.73

The Company objects to this request as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:

The Tax Increase Prevention Act of 2014 extended 50 percent bonus depreciation for qualifying assets placed in service by December 31, 2014. The Utah mine transaction had $3,305.85 in qualifying assets placed in service during 2014, for which the 50 percent bonus depreciation amount is $1,652.93.

However, none of the assets divested as part of the Deer Creek transaction that qualified for bonus depreciation were included in the Oregon general rate case filed in 2013.

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT ICNU/105

HIGH-LEVEL CALCULATION OF 50% BONUS DEPRECIATION IMPACT

March 5, 2015

Exhibit ICNU 105

High-level Calculation of the Impact of Bonus Depreciation on Lake Side II Surcharge

			$000
(a)	Approximate Lake Side II Capital Cost	Note 1	645,000
(b)	50% Bonus Depreciation	(a) * 0.5	322,500
(c)	20 Yr MACRS Depreciation (5%)	(a) * 0.05	32,250
(d)	Tax Depreciation Difference	(b) - (c)	290,250
(e)	Tax Rate		35.00%
(f)	Additional ADIT Not in UE 263 Rates	(d) * (e)	101,588
(g)	Oregon SG Factor		26.05%
(h)	Oregon Allocated ADIT	(f) * (g)	26,467
(i)	Pretax Rate of Return		10.75%
(j)	Approx Oregon Lake Side II Rate Impact Of Bonus Depreciation	(h) * (i)	2,846

Note 1 - The total capital cost of Lake Side II was estimated at $1,000/kW

BEFORE THE PUBLIC UTILITY COMMISSION

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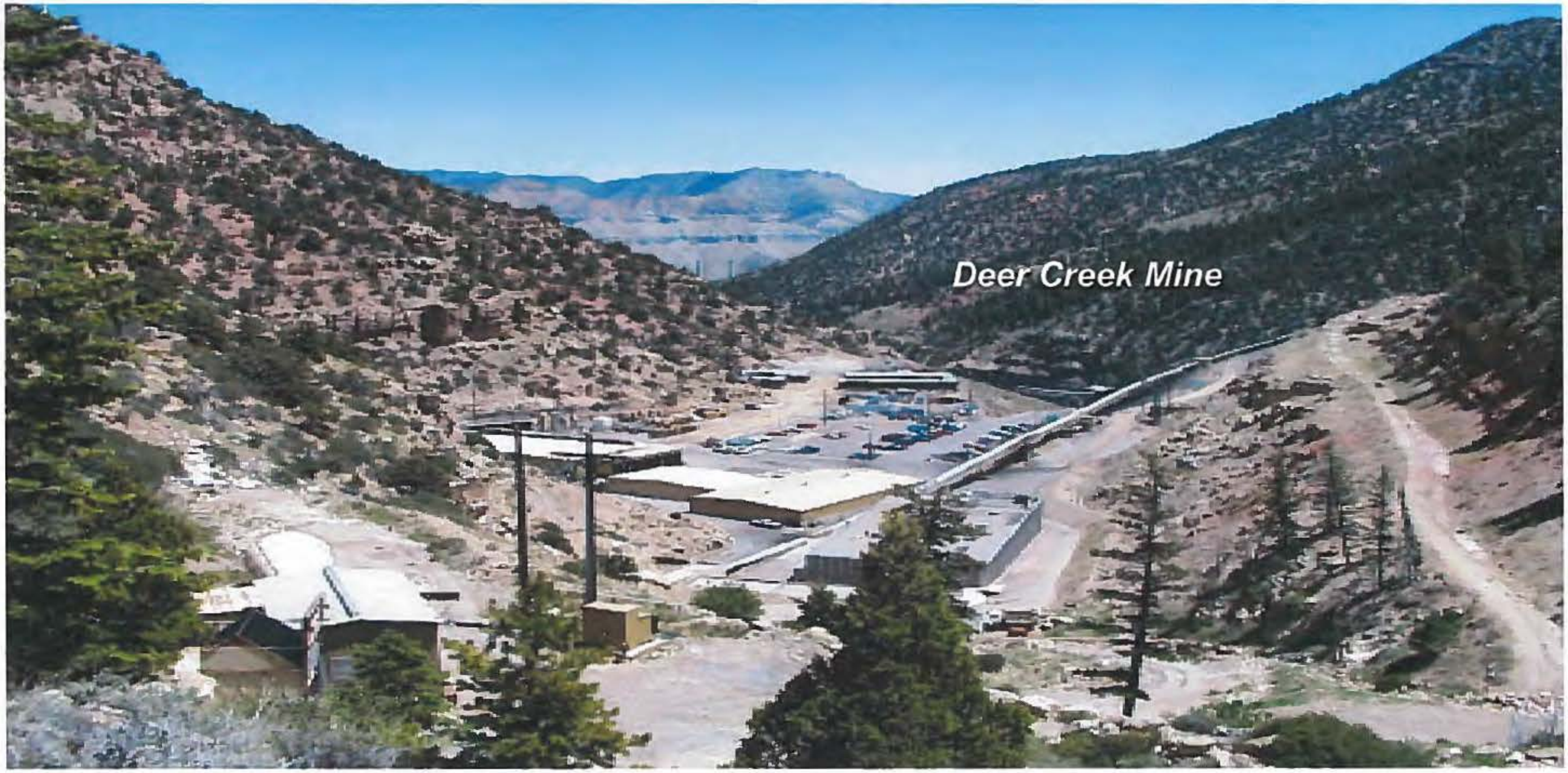
____	)

REDACTED EXHIBIT ICNU/106

EXCERPT OF DEER CREEK MINE TRANSACTION
TECHNICAL CONFERENCE WITH PUBLIC UTILITY COMMISSION OF OREGON
(FEB. 23, 2015)

March 5, 2015



Deer Creek Mine Transaction
Technical Conference with Public Utility Commission of Oregon

February 23, 2015

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Other Transaction Items

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- UMWA Retiree Medical Obligation (retired and active)
  - UMWA retirees receive ~ 100% health-care cost coverage
  - UMWA retiree health-care costs subject to an excise tax beginning in 2018
  - Energy West negotiated the following settlement with the UMWA

[redacted]

- Other Transaction Items
  - Bowie will lease 400 acre feet of water for use at the preparation plant and 200 acre feet for use at the Trail Mountain mine
  - Working capital adjustment limited to $744k
  - Bowie to reimburse company for appropriate expenditures associated with purchased "mining assets" before close

PVRR Differential—
Keep vs. Transaction

PACIFIC POWER
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[redacted]

CONFIDENTIAL
SUBJECT TO GENERAL PROTECTIVE ORDER