BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO CHANGE ITS DEPRECIATION RATES EFFECTIVE JANUARY 1, 2014	)))))))	**DOCKET NO. 13-035-02** **DPU Exhibit 2.0 DIR**

DEPRECIATION

DIRECT TESTIMONY AND EXHIBITS

OF WILLIAM DUNKEL

ON BEHALF OF

THE UTAH DIVISION OF PUBLIC UTILITIES

June 21, 2013

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I. Introduction

Q. Please state your name and business address.

A. My name is William Dunkel. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. What is your present occupation?

A. I am a consultant providing services in utility regulatory proceedings. I am the principal of William Dunkel and Associates, which was established in 1980. Since that time, I have regularly provided expert consulting services in utility regulatory proceedings throughout the country. I have participated in over 250 state regulatory proceedings before over one-half of the state commissions in the United States. I have participated in utility regulatory proceedings for over 30 years.

I provide, or in the past have provided, services in utility regulatory proceedings to the following clients:

The Public Utility Regulatory Commission or the Staffs in the States of:

Arkansas	Maryland
Arizona	Mississippi
Delaware	Missouri
D.C.	New Mexico
Georgia	Virginia
Guam	Washington
Illinois	U.S. Virgin Islands
Kansas	

The Office of the Public Advocate, or its equivalent, in the States of:

Alaska	Maryland
California	Michigan
Colorado	Missouri
District of Columbia	New Jersey
Georgia	New Mexico

Hawaii	Ohio
Illinois	Pennsylvania
Indiana	Utah
Iowa	Washington
Maine	

The Department of Administration in the States of:

Illinois	South Dakota
Minnesota	Wisconsin

Q. Have you previously participated in proceedings in Utah?

A. Yes. I have participated in several prior proceedings in Utah. The prior Utah cases in which I have participated are:

U.S. West Communications (Mountain Bell Telephone Company)

General rate case	Docket No. 84-049-01
General rate case	Docket No. 88-049-07
800 Services case	Docket No. 90-049-05
General rate case/ incentive regulation	Docket No. 90-049-06/90-049-03
General rate case	Docket No. 92-049-07
General rate case	Docket No. 95-049-05
General rate case	Docket No. 97-049-08
Qwest Price Flexibility-Residence	Docket No. 01-2383-01
Qwest Price Flexibility-Business	Docket No. 02-049-82
Qwest Price Flexibility-Residence	Docket No. 03-049-49
Qwest Price Flexibility-Business	Docket No. 03-049-50

Carbon/Emery

General rate case/USF eligibility	Docket No. 05-2302-01

Q. Please briefly describe your experience pertaining to the electric utility industry.

A. I have worked in the electric engineering section of the Illinois Commerce Commission ("ICC"). The ICC regulates utilities in Illinois. I have also been a design engineer for a company that manufactured equipment for the electric utility industry. I was granted Patent No. 3822440 entitled a Solid State Pulse Initiator. This Initiator was used by electric utility companies for certain electric energy metering purposes. I have been addressing electric utility depreciation for over 30 years.

Q. Are you a member of any depreciation professional organization?

A. Yes. I am a senior member in good standing of the Society of Depreciation Professionals. I made a presentation pertaining to Current Depreciation Issues in State Rate Case Proceedings at the Society of Depreciation Professionals 25th Annual Meeting held September 2011 in Atlanta, GA.

Q. Did you prepare an Appendix that describes your qualifications?

A. Yes. My qualifications are shown on Appendix A.

Q. What type of client does your firm most frequently serve?

A. Nationwide my firm participates on behalf of the Commission Staffs or State Utility Regulatory Commissions in the majority of our cases. In the past five years 65% of my firm's cases have been on behalf of the Commission Staffs or State Utility Regulatory Commissions. In the past five years 51% of my personal cases have been on behalf of the Commission Staffs or State Utility Regulatory Commissions. As a frequent Staff witness, I understand that proper depreciation rates are fair to all parties, including investors, current ratepayers and future ratepayers. I have incorporated this proper concept into my recommendations in this proceeding.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Utah Division of Public Utilities ("Division" or "DPU").

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to determine the appropriate utility regulatory depreciation rates pertaining to PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or "RMP" or "Company").[1]

I recommend the Division depreciation rates shown on DPU Exhibit 2.19 DIR and as summarized on DPU Exhibit 2.1 DIR.[2]

II. Summary

Q. What change in depreciation rates in Utah does PacifiCorp propose?

A. The PacifiCorp Depreciation Study (Exhibit RMP___(JJS-2)), presented by Mr. Spanos, includes one set of depreciation rates calculated using the known data as of 12/31/2011 and a second set of projected depreciation rates calculated using projected 12/31/2013 data.

[1] I followed the depreciation requirements as contained in the FERC Uniform Systems of Accounts (USOA). In addition the "Public Utility Depreciation Practices" published by NARUC in 1996 contains detailed practices for calculating utility regulatory depreciation rates under USOA.

[2] The PacifiCorp 2013 Depreciation Study includes all Production, Transmission and General Plant expenses on a Total Company basis. Allocators (approximately 42% for Utah according to Mr. Lay) must be applied. The General Plant expenses are shown by State, but that cost does not apply to just that State (Utah is allocated approximately 42% of all General Plant costs). Distribution is the only category in which the expense shown for a State, applies to just that State. At this time parties other than PacifiCorp have not filed testimony this case. I reserve the right to review the testimony of other parties when filed, and consider any evidence provided. If I have not addressed an issue in this testimony that does not imply that I necessarily support the PacifiCorp position. At this time I have not seen the other parties' positions or evidence.

PacifiCorp proposes an increase in the annual depreciation expense over current depreciation rates of $70,463,058 in the Utah jurisdiction ($160,813,194 on a total company basis) based on projected 12/31/2013 data.[3]

Unfortunately PacifiCorp did not specifically state the amount of its proposed increase over current depreciation rates in the Utah jurisdiction based on the actual 12/31/2011 data.

Q. Please compare the DPU proposed depreciation rates to the PacifiCorp proposed depreciation rates.

A. Below is a table which summarize the DPU recommended depreciation rates and annual accrual amounts compared to the set of depreciation rates that RMP proposed based on 12/31/2011 data:

[3] Page 3, Exhibit RMP___(HEL-1).

Table 1

COMPARISON OF RMP AND DPU PROPOSED DEPRECIATION RATES AND ACCRUALS
RESERVE VARIANCE AMORTIZATION CALCULATED
USING 5-YEAR FOR STEAM PRODUCTION, 7-YEAR FOR HYDRAULIC PRODUCTION, AND 15-YEAR FOR ALL OTHER ACCOUNTS

		RMP Proposed- Total Company		DPU Proposed- Total Company			Allocated to Utah; DPU
Description	Plant Balance at 12/31/11	Accrual Rate	Annual Accrual	Accrual Rate	Annual Accrual	Difference from RMP Proposed	Difference from RMP Proposed
Production Plant							
Steam Production	6,310,917,128	3.68%	231,957,419	3.01%	189,658,725	(42,298,694)	(17,766,613)
Hydraulic Production	697,877,989	3.59%	25,085,845	3.37%	23,512,424	(1,573,421)	(660,880)
Other Production	3,303,331,092	3.28%	108,260,074	3.27%	108,117,844	(142,230)	(59,794)
Total Production Plant	**10,312,126,209**	**3.54%**	**365,303,338**	**3.12%**	**321,288,993**	**(44,014,345)**	**(18,487,286)**
Transmission Plant	**4,450,047,957**	**1.81%**	**80,443,837**	**1.31%**	**58,378,871**	**(22,064,966)**	**(9,267,892)**
Distribution Plant							
Oregon-Distribution	1,746,776,176	2.52%	44,018,809	2.52%	44,018,809	0	0
Washington-Distribution	404,227,933	2.80%	11,317,350	2.80%	11,317,350	0	0
Wyoming-Distribution	593,075,081	2.75%	16,281,391	2.75%	16,281,391	0	0
California-Distribution	225,035,481	2.66%	5,984,235	2.66%	5,984,235	0	0
Utah-Distribution	2,388,444,688	2.44%	58,339,442	1.53%	36,560,744	(21,778,698)	(21,778,698)
Idaho-Distribution	282,034,463	2.25%	6,352,051	2.25%	6,352,051	0	0
Total Distribution Plant	**5,639,593,821**	**2.52%**	**142,293,278**	**2.14%**	**120,514,580**	**(21,778,698)**	**(21,778,698)**
General Plant							
Oregon-General	134,886,355	3.83%	5,163,783	3.83%	5,163,783	0	0
Washington-General	27,282,077	4.21%	1,148,837	4.21%	1,148,837	0	0
Wyoming-General	56,396,614	5.19%	2,927,994	5.19%	2,927,994	0	0
California-General	10,157,894	3.92%	398,576	3.92%	398,576	0	0
Utah-General	194,647,202	4.14%	8,055,344	4.17%	8,107,331	51,987	42,045
Idaho-General	27,706,981	4.01%	1,109,909	4.01%	1,109,909	0	0
AZ, CO, MT, ETC.-General	3,715,888	2.28%	84,616	2.28%	84,616	0	0
Total General Plant	**454,793,011**	**4.15%**	**18,889,059**	**4.16%**	**18,941,046**	**51,987**	**42,045**
Utah Mining	**235,124,849**	**6.24%**	**14,665,519**	**5.87%**	**13,791,160**	**(874,359)**	**(367,874)**
Total Electric Plant	**21,091,685,847**	**2.95%**	**621,595,031**	**2.53%**	**532,914,650**	**(88,680,381)**	**(49,859,704)**

Q. Please provide the approximate impacts of each of issues that are different between the depreciation rates that RPM proposes and the depreciation rates that the DPU proposes.

A. The approximate impacts of each of the issues that are different between the depreciation rates that RPM proposes and the depreciation rates that the DPU proposes are shown on the following table and on DPU Exhibit 2.20 DIR.[4]

Table 2:

Impact of DPU Recommended Adjustments to RMP Filed Depreciation Expense
Amounts in Millions

Line	Description of Adjustment	Annual Depreciation Expense on a "Total Company" Basis	Difference from Prior Line on a "Total Company" Basis	Utah Allocated Annual Depreciation Expense	Utah Allocated Difference from Prior Line
<u>Spanos "Appendix" (Projected Depreciation Rates Calculated on Projected 12/31/13 Data)</u>					
1.	RMP Filed Projected Depreciation Rates based on Projected 12/31/13 Investment and Projected 12/31/13 Reserve Amounts	$743.3		$311.1	
2.	Depreciation Expense based on RMP Projected 12/31/13 Investment and using RMP Proposed 2011-Based Depreciation Rates	$667.7	($75.6)	$279.2	($31.9)
<u>Actual 12/31/11 Data</u>					
3.	Depreciation Expense based on RMP 12/31/11 Investment and using RMP Proposed 2011-Based Depreciation Rates	$621.6	($46.1) [(1)]	$259.5	($19.7) [(1)]

[4] Two comments need to be made: (1) These numbers should only be used to understand the magnitude of the various issues. For example, various adjustments interact, so if some adjustments were removed, the values shown for the remaining adjustments might be affected by those removals. (2) Below line 2 on table 2, the dollar amounts are based on the known plant investments as of 12/31/2011. Of course, in the future the depreciation rates as calculated are applied to the then-current Plant in Service amounts to calculate the then-current depreciation expense. As the Plant in Service amounts increase over time, the depreciation expense also increases. For example if at some time after 12/31/2011 the plant investment in an account is 10% higher than the investment in that account had been at 12/31/2011, then at that time the depreciation expense for that account (calculated using the same depreciation rate) would be also be 10% higher than the depreciation expense had been at the 12/31/2011 plant level.

4.	Gadsby Steam Production Plant Final Retirement Year of 2033	$621.1	($0.5)	$259.3	($0.2)
5.	Craig Production Plant Final Retirement Year of 2033	$620.3	($0.8)	$259.0	($0.3)
6.	James River Co-Gen Plant Final Retirement Year of 2026	$619.2	($1.1)	$258.5	($0.5)
7.	Use $40/kW for Carbon Production Plant Terminal Net Salvage	$604.0	($15.2)	$252.1	($6.4)
8.	Change Final Retirement Year of Some Hydro Production Plants	$602.8	($1.2)	$251.6	($0.5)
9.	Do Not Use Life Span on Some Mining Equipment Accounts	$600.5	($2.3)	$250.7	($0.9)
10.	Change Average Service Life of Some Transmission Accounts	$599.5	($1.0)	$250.2	($0.5)
11.	Change Average Service Life of Some Utah Distribution Accounts	$597.4	($2.1)	$248.1	($2.1)
12.	Present-Value Inflated Future Cost of Removal for Transmission and Utah Distribution Plant	$579.7	($17.7)	$235.5	($12.6)
13.	Reserve Variance Amortized over 5-Years for Steam Production Plant, 7-Years for Hydraulic Production Plant, and 15-Years for All Other Accounts based on pages 15, 17-18 of 9/19/12 Order Adopting Stipulation in Docket No. 11-035-200 (2)	$532.9	($46.8)	$209.7	($25.8)
14.	Total Difference from Company Filed Using Actual 12/31/2011 Data and 2011-Based Depreciation Rates. (Sum of the Differences from lines 4-13)		($88.7)		($49.8)

Notes:

(1) Much of this difference is caused by a different investment period which will not be a difference in a future rate case, since the depreciation rates would be applied to the current investment in the that future rate case. After line 2, the dollar amounts are based on the known plant investments as of 12/31/2011.

(2) For comparison, if a 10-year amortization was used for all reserve variances the total company annual accrual would be $524.7 million, a difference of ($55.0) million from line 12.

III. Amortizing Reserve Deficiencies and Reserve Surpluses

Q. What is a reserve deficiency and what is a reserve surplus?

A. A depreciation reserve deficiency indicates that the amount accumulated in the depreciation reserve[5] is less than it should be, knowing what we know now. This indicates past depreciation expense charged to ratepayers was less than it should have been. A reserve deficiency indicates additional funds need to be recovered from ratepayers.

A depreciation reserve surplus indicates that the amount accumulated in the depreciation reserve is more than it should be, knowing what we know now.[6] This indicates past depreciation expense charged to ratepayers was more than it should have been, knowing what we know now. A reserve surplus indicates a credit should be provided to ratepayers.

Together reserve deficiencies and reserve surpluses are referred to as "reserve variance."

Q. Over what time period should reserve surpluses be credited to, or reserve deficiencies be collected from, ratepayers?

A. There is no theoretically correct time period for amortizing reserve variances. This is similar to a person still owing a doctor after all the insurance is settled (or, on the other hand, a person having overpaid a doctor). The time period over which this variance has to be recovered can be a matter of negotiations between the patient and the doctor.

[5] Account 108, Accumulated Provision for Depreciation ("depreciation reserve").
[6] The amount that should be in the depreciation reserve is called the "Theoretical Reserve."

For a specific Utah example, in the Questar Gas Company depreciation rates currently in effect in Utah, the reserve variances were amortized over a 10 year period.[7]

In addition, the Questar Gas depreciation rates that were in effect in Utah prior to Docket No. 09-057-16 had also amortized the reserve variances over a 10 year period.[8]

Q. Do reserve surpluses and reserve deficiencies generally partially offset each other?

A. Yes. Often there will be reserve surpluses in some accounts or plants, but reserve deficiencies in other accounts or plants. The reserve surpluses and reserve deficiencies generally at least partially offset each other, provided that the reserve surpluses are treated the same as the reserve deficiencies.

Q. Are there reserve surpluses at some PacifiCorp Steam Production plants but reserve deficiencies at other PacifiCorp Steam Production plants?

A. Yes. In his Depreciation Study,[9] PacifiCorp witness Mr. John J. Spanos calculated the Reserve amount that should be at each of the various plants, including the Carbon Plant.[10]

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[7] "Report and Order", Issued June 3, 2010 in Docket No. 09-057-16, page 17, paragraph i of the approved Settlement Stipulation.

[8] "Order Approving Rate Reduction Stipulation", Issued May 26, 2006 in Docket No. 05-057-T01, pages 7-8.

[9] Unless otherwise stated, all references to the "Depreciation Study" or "Study" refer to the portions of Exhibit RMP___(JJS_2) which used data as of 12/31/2011. This includes all portions of Exhibit RMP___(JJS_2) except for the "Appendix"(the "Appendix" uses projected 12/31/2013 amounts) . Unless otherwise stated, such references are not referring to the depreciation calculations using projected 12/31/2013 data in the "Appendix" to that Depreciation Study.

[10] The amount that should be in the depreciation reserve is called the "Theoretical Reserve." Mr. Spanos labeled it as the "Calculated Accrual". For example see page III-873 of Mr. Spanos' Depreciation Study, Exhibit RMP___(JJS-2). The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

Mr. Spanos's Depreciation Study shows there was a $61 million deficiency in the Carbon steam production plant Depreciation Reserve.[11]

However, Mr. Spanos's own calculations show there is a total of a $109 million Reserve surplus at the steam plants other than Carbon.[12] PacifiCorp has collected from ratepayers, and has, a total of a $109 million reserve surplus for the steam plants other than Carbon.[13]

PacifiCorp's own Depreciation Study also shows there is no overall Steam Production Reserve deficiency. There is an overall Steam Production Reserve surplus of over $48 million according to PacifiCorp's own Depreciation Study.[14]

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[11] As of 12/31/2011, the Reserve assigned to Carbon on the books is $61 million less than the theoretical reserve. Page III-860 of the Company Study shows that the total Allocated Book Reserve for Account 312-Boiler Equipment for the Carbon Steam Production Plant is $36,904,687, but the amount that theoretically should be in the Reserve ("Calculated Accrued") is $71,906,057, a deficiency in the Reserve of $34,971,380 for this one account. When all steam production accounts are included, the Carbon deficiency is $61,016,423, according to the Company Study, based on the Company allocation of the Steam Reserve and using the Company estimate of the Terminal Retirement Costs. The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

[12] The only other steam plant with a significant reserve deficiency is Dave Johnston which had a $24.8 million deficiency in the Company study. Dave Johnston had a remaining life of 15 years in the Company Study. Had we shown it separately then the Steam Plants other than Carbon and Dave Johnston have a reserve surplus of $133 million. The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

[13] The Reserve assigned on the books to the steam plants other than Carbon is $109 million more than the theoretical reserve for those plants. Page III-869 shows that the "Allocated Book Reserve" for Account 312-Boiler Equipment for Jim Bridger is $293,188,983, but the amount that theoretically should be in the Reserve ("Calculated Accrued") is $267,188,983, a surplus in the Reserve of $25,749,970 for this one account for this one plant. When all steam production accounts at all steam production plants, other than Carbon, are included, the surplus is $109,332,803. The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

[14] Page III-873 of the Company Study (Exhibit RMP___(JJS-2)) shows that the total Book Reserve for Account 312-Boiler Equipment for all steam production plants is $1,349,358,618, but the amount that theoretically should be in the Reserve is $1,328,796,731, a surplus in the Reserve of $20,561,887 for this one account. When all steam production accounts are included, the surplus is $48,316,380. The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

Q. Can you show how the Steam Production reserve surpluses at other plants more than offset the Carbon Steam Production reserve deficiency, assuming uniform treatment of the surpluses and deficiencies?

A. Yes. Assuming a uniform treatment of both reserve surpluses and deficiencies, the larger $109 million reserve surplus at the other plants more than offset the Carbon $61 million reserve deficiency. This is shown in the following table using a uniform 10 year amortization of both reserve surpluses and reserve deficiencies:

Table 3-TOTAL COMPANY

Steam Production[15]	Applying a Uniform Amortization Period to the Reserve Variances from the Company Study (RMP___(JJS-2)):		
Reserve Variance	Reserve Surplus or (Deficiency)	Amortization Period in Years	Annual Credit or (Expense)
(a)	(b)	(c)	(d)
Steam Plants Other than Carbon	$ 109,332,803	10	$ 10,933,280
Carbon Steam Plant	$ (61,016,423)	10	$ (6,101,642)
Total Steam Production	$ 48,316,380		$ 4,831,638

The result is an overall net credit to the ratepayers. Since there is an overall Steam Production reserve surplus, a net credit to the ratepayers is the proper result.

Q. Are the Steam Production reserve surpluses and reserve deficiencies amortized over similar time periods in the PacifiCorp Depreciation Study?

A. No. The following table summarizes how the Steam Production reserve variances are amortized in the PacifiCorp Depreciation Study:

[15] Total Company amounts. According to PacifiCorp, Utah is allocated approximately 42% of the total company steam production amount.

Table 4 - TOTAL COMPANY

Steam Production [16]	In the Company Depreciation Study (RMP___(JJS-2)):		
Reserve Variance Using 12-31-2011 data	Reserve Surplus or (Deficiency)	Amortization Period in Years	Annual Credit or (Expense)
(a)	(b)	(c)	(d)
Steam Plants Other than Carbon	$ 109,332,803	22.44	$ 4,872,228
Carbon Steam Plant	$ (61,016,423)	3.3	$ (18,489,825)
Total Steam Production	$ 48,316,380		$ (13,617,597)

As can be seen in the above Table 4, although there is an overall steam reserve surplus, PacifiCorp calculates a net additional expense to the ratepayers of over $13 million per year for the steam reserve variances. Charging ratepayers a net expense for the steam reserve variance, when the steam reserve variance is a net surplus, is improper.

The reason that the $109 million reserve surplus for the other plants does not more than offset the $61 million Carbon reserve deficiency, is that the amortization of the Carbon reserve deficiency is over a much shorter time period than is the amortization of the reserve surplus. The PacifiCorp Depreciation Study proposes to recover the Carbon reserve deficiency over the 3.3 year remaining life.[17] Recovering this reserve deficiency over 3.3 years creates a large annual expense, in excess of $18 million per year just because of the Carbon reserve deficiency.[18] However, in the Company Study the reserve surplus for the other plants is being credited back to the ratepayers over an average of

[16] Total Company amounts. According to PacifiCorp, Utah is allocated approximately 42% of the total company steam production amount.
[17] The 3.3 year Carbon Remaining Life can be seen on page III-4 of the Company Study (Exhibit RMP___(JJS-2)).
[18] The proposed Carbon depreciation accrual also includes items in addition the reserve deficiency amortization.

22.44 years, which results in a relatively low annual credit, of less than $5 million per year.[19]

Using the average remaining life as the amortization period is a common treatment, in part because it does not require the parties to specifically select a specific amortization period. However, in this case it is worth the effort to select the amortization period, because in this case using the remaining life as the amortization period creates an inappropriate result. PacifiCorp applies a much shorter amortization period to the steam reserve deficiency than to the steam reserve surplus. Charging ratepayers a net <u>expense</u> for the steam reserve variance, when the steam reserve variance is a net <u>surplus</u>, is improper, but that is incorporated into the PacifiCorp Depreciation Study.

Q. Is the proper treatment of the reserve variance a major issue?

A. Yes. When all major relevant categories are included, the net total company reserve surplus exceeds $300 million in the Depreciation Study as filed by PacifiCorp.[20]

First of all, as discussed above, major distortions are being created in the PacifiCorp proposed Steam Production depreciation rates by applying a much shorter amortization period to the Carbon reserve deficiency compared to the amortization period applied to the Steam reserve surpluses. Correcting these distortions requires an examination of the reserve variances in the Company Study.

[19] See pages III-4 to 6 of the Company Study. The largest reserve surplus is at the Jim Bridger Plant, which is being credited back to ratepayers over 22.8 years for Account 312. The second largest reserve surplus is in the Hunter Plant, and that is being credited back over 26.3 years in account 312 (III-6, Company Study). The weighted average remaining life for all the steam plants other than Carbon is 22.44 years, using data from the Company study. The referenced pages from the Company Study are included in DPU Exhibit 2.18 DIR.
[20] In reserve variance in the major categories relevant to Utah. These are Total Company reserve variances: Production +$42 million; Transmission +$149 million; Utah Distribution +$150 million; Mining +$17 million.

Other major categories also have a net reserve surplus.

In the Utah Distribution category, the net of all the surpluses and deficiencies is a net reserve surplus of over $150 million in the PacifiCorp Depreciation study as filed by the Company. 100% of the Utah Distribution category is allocated to Utah.

In the Transmission Category there is over a $145 million total company net reserve surplus in the Depreciation Study as filed by the Company. Approximately 42% of the Transmission category is allocated to Utah.

Q. What do you recommend on this issue?

A. The treatment of the Steam Production reserve variances in the Company Depreciation Study should not be accepted. Data from the Company's own Depreciation Study show there is an overall reserve surplus in Steam Production. For an overall Steam Production reserve surplus, a net credit to the ratepayers is the proper result. Creating a net expense to the ratepayers as the result of an overall steam reserve surplus is improper, but that is what is proposed in the Company Study. To correct this improper result, I recommend that a uniform amortization period be applied to all reserve variances within a functional plant category.[21] The same amortization period that applies to reserve deficiencies should also apply to reserve surpluses within that same functional plant category.

[21] These are referred to as the "functional classifications" in the Uniform System of Accounts, 18CFR101.

Q. Are you strongly recommending a specific number of years as the amortization period?

A. No. There is no theoretically correct specific number of years for the amortization period for reserve variances. However to be fair to all parties, the amortization period for the reserve surpluses should be the same as the amortization period for the reserve deficiencies within that same functional plant category.

Q. Is there existing wording that may impact the selection of amortization periods?

A. Yes. On page 15 in an Order Issued September 19, 2012 in Docket No. 11-035-200 the Commission states that under the Commission-approved settlement Stipulation:

> "Thus, Remaining Carbon Balances will be amortized from the date net plant balances are transferred to the regulatory asset through 2020."

On page 17 of that same Order the Commission states that under the settlement Stipulation:

> "In Paragraph 58, the Parties agree the Company should be permitted to depreciate the Klamath Dam Facilities on an accelerated basis from June 1, 2012, through December 31, 2022, at rates to fully depreciate the asset by the end of calendar year 2022."

On page 15 of that same Order the Commission states that under the settlement Stipulation:

> "In Paragraph 45, the Parties agree the Company should be allowed to recover or refund the deferred depreciation expense beginning on the effective date of the 2014 GRC, and to amortize the deferred depreciation expense over a period not to extend beyond June 30, 2031, with no carrying charge. Parties specify that depreciation relating to the Carbon Plant Decommissioning and the Klamath Dam facilities, as described in the Stipulation, should not be included in the deferred depreciation expense

Q. What reserve variance amortization periods have you used in the DPU calculations in this proceeding?

A. I followed the recovery periods indicated in the above referenced Commission-approved settlement Stipulation. Based on that settlement Stipulation I used a five year amortization period for the Steam Production reserve variances. I used a seven year amortization period for the Hydraulic Production reserve variances. I used a fifteen year amortization period for all other reserve variances.

As previously discussed, if the Carbon reserve deficiency will effectively be amortized over approximately a five year period then, to be fair to all parties, that same amortization period should also be used for the other steam reserve variances, specifically including the steam reserve surpluses.

It is reasonable to use the recovery periods indicated in the above referenced Commission-approved settlement Stipulation. However in this proceeding if the parties and/or the Commission decide to alter the recovery periods, I can quickly recalculate the depreciation rates using any amortization periods agreed to by the parties or ordered.

Q. What does the fact that there is a significant overall reserve surplus indicate?

A. The fact that there is an overall reserve surplus indicates that past depreciation rates were higher than they should have been based what we know now. By itself this is not conclusive, but the fact that past depreciation rates created a reserve surplus means that we should be open to the possibility that properly determined new depreciation rates may be lower than past depreciation rates.

Q. In the above Tables 3 and 4 you addressed the Steam Production plant reserve variances as contained in the Depreciation Study as filed by PacifiCorp. Will you make other adjustments in this testimony which result in reserve variances that are different than shown in the Company Study?

A. Yes. Tables 3 and 4 are addressing this issue using the Steam Production plant reserve variance amounts contained in the PacifiCorp Depreciation Study as filed. Later in this testimony I will make other adjustments that impact the reserve variances amounts. For example I will address the lives of certain plants, and make adjustments to the Company proposed decommissioning cost for the Carbon Plant.

There is an overall reserve surplus in my calculations, but that surplus amount may be different than the surplus amount in the Company filing.

IV. Calculating Projected Depreciation Rates Using Projected 12/31/2013 Reserve and Plant Amounts

Q. What unusual calculation is contained in Mr. Spanos's Depreciation Study in this proceeding?

A. In addition to calculating depreciation rates on the actual data as of 12/31/2011, Mr. Spanos added an Appendix to his Depreciation Study[22] in which he calculated a second set of depreciation rates ("projected depreciation rates") using projected Reserve and projected Plant in Service amounts as of 12/31/2013.

Calculating projected depreciation rates using projected Reserve and projected Plant in Service amounts is very unusual.

[22] Exhibit RMP__(JJS-2).

Q. Can you demonstrate that calculating projected depreciation rates using projected Reserve and projected Plant amounts is very unusual?

A. Yes. Other than for PacifiCorp, Mr. Spanos has not calculated projected depreciation rates using projected Reserve and projected Plant amounts in any of the 13 electric utility depreciation studies Mr. Spanos filed in the last 16 months, as shown in the Company response to DPU Data Request 7.8.[23]

In none of these other cases has Mr. Spanos filed ”projected” depreciation rates, which is what is presented in the “Appendix” he included in this Depreciation Study for PacifiCorp in this proceeding.

Q. What is DPU Exhibit 2.2 DIR?

A. DPU Exhibit 2.2 DIR is a copy of the referenced PacifiCorp’s response to DPU Data Request 7.8.[24]

Q. What is one difference that results from PacifiCorp calculating projected depreciation rates using the projected figures?

A. In calculating the projected depreciation rates PacifiCorp amortized the Carbon plant reserve deficiency over only 1.3 years. This creates an even greater problem in the

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[23] PacifiCorp response to DPU Data Request 7.8.

[24] It should be noted the added statement in the response that “However, some of the cases included depreciation rates or expense beyond the historic test year outside the study” is not similar to the “Appendix” Mr. Spanos filed in this proceeding. The depreciation rate is normally calculated using recent actual Reserve and Plant amounts. That same depreciation rate may be used for years. As time passes the depreciation rate stays the same (until the next depreciation study is adopted) but that depreciation rate is applied to changing plant amounts. That is not what is occurring in the “Appendix” in this filing. The depreciation rate itself changes in the “Appendix” as compared to the rates using 12/31/2011 data. For example, for Carbon Account 312 the depreciation rate is 28.65% based on 12/31/2011 date (page III-4) of the Study, but the Carbon Account 312 depreciation rate is 67.38% in the Appendix (calculated using projected Plant in Service and projected Reserve figures).

projected depreciation rates in the PacifiCorp Depreciation Study (shown in the "Appendix").

It was previously demonstrated that in the portion of the Company Depreciation Study that used 12/31/2011 data, PacifiCorp was amortizing the reserve deficiency of the Carbon plant over only 3.3 years, while amortizing the steam reserve surpluses over more than 20 years.

In the projected depreciation rates PacifiCorp takes this one step further by amortizing the Carbon plant reserve deficiency over only 1.3 years. This even shorter amortization period creates an even larger claimed annual depreciation expense for Carbon in the Company projected depreciation rates.

Q. Since the investment generally increases over time, is it reasonable to expect a higher depreciation expense in 2013 than in 2011?

A. Yes, and the increase in depreciation expense caused by higher investments over time will occur under the DPU proposed depreciation rates.[25] However, the depreciation expense increase PacifiCorp is proposing for 2013 over 2011 is much more than is supported by the projected increase in investments.

[25] In the future the depreciation rates (including DPU proposed depreciation rates) are applied to the then-current Plant in Service amounts to calculate the then-current depreciation expense. As the Plant in Service amounts increase over time, the depreciation expense also increases. For example if at some time after 12/31/2011 the plant investment in an account is 10% higher than the investment in that account had been at 12/31/2011, then at that time the depreciation expense for that account (calculated using the same depreciation rate) would be also be 10% higher than the depreciation expense had been at the 12/31/2011 plant level.

Q. When the total proposed depreciation expense is examined, how large a difference is there between the PacifiCorp proposed depreciation expense using the 12/31/2011 actual data compared to using the projected 12/31/2013 numbers?

A. The difference is huge, as shown by the following Table 5:

Table 5-TOTAL COMPANY

Data As Of:	Total Company-Plant ($ Millions)	Current Depreciation Rates[26]		Company Proposed Depreciation Rates		Company Proposed Annual Increase Over Current Depreciation Rates	
		%	($ Millions)	%	($ Millions)	%	($ Millions)
12/31/2011	$ 21,091	2.57%	$ 542	2.92%	$ 622	0.35%	$ 80
Projected 12/31/2013	$ 22,923	2.54%	$ 582	3.24%	$ 743	0.70%	$ 161

The Company proposed overall percent depreciation rate is much higher in the projected depreciation rates (3.24%) than the depreciation rates calculated on the 12/31/2011 data (2.92%). The Company proposed Total Company dollar increase over current rates is twice as much on the projected 12/31/13 data ($161 million) than on the 12/31/2011 data ($80 million). However, there is only a relatively small difference in Plant Investment between these two time periods.

Q. How much of the PacifiCorp claimed increase in depreciation expense in 2013 over 2011 can be explained by the projected increase in investment?

A. Less than 40% of the PacifiCorp proposed depreciation expense increase that results from going from 2011 data to projected 2013 data can be explained by the projected increase

[26] The current amounts for 12/31/2011 are approximate since PacifiCorp did not provide the depreciation expense at current rates at 12/31/2011 investment levels.

in investment.[27] The depreciation expense increases the Company is proposing based on projected 2013 data are much higher than can be explained by just the projected increase in the investment amounts.

As can be seen in the prior Table 2 item 2, the result of the projected 12/31/2013 investments being higher than the 12/31/2011 investments is an expense impact of $46.1 million. This $46.1 million increase caused by the higher projected investments is less than 40% of the total $121.7 million[28] increase in depreciation expense that PacifiCorp is claiming as a result of using projected 2013 data as opposed to 2011 data.

However, item 1 on Table 2 shows that use of the projected depreciation rates (calculated using projected Reserve and projected Plant in Service amounts) adds $75.6 million to the PacifiCorp proposed annual depreciation expense based on projected 2013 data.

In other words, what the Company proposes based on the projection 2013 information goes far beyond adjusting just for the higher investment expected at the end of 2013 as compared to the investments at the end of 2011.

Q. What do you recommend on this issue?

A. The depreciation expense should not be calculated using the projected depreciation rates.

Calculating projected depreciation rates (using projected Reserve and projected Plant amounts) is seldom done. Other than for PacifiCorp, in none of the last 13 electric utility

[27] From Table 2, $46.1/($75.6+$46.1) = 0.3788.
[28] $75.6 million + $46.1 million = $121.7 million.

depreciation studies Mr. Spanos filed did Mr. Spanos calculate projected depreciation rates that used projected Reserve and projected Plant amounts.[29]

As previously discussed, using a shorter amortization period for the reserve deficiency creates improperly inflated depreciation rates. This problem increases in the projected depreciation rates, since the amortization period for the Carbon reserve deficiency is only 1.3 years in the projected 12/31/2013 depreciation rate calculations.

In addition, the Appendix is actually an inconsistent mix of some 12/31/2011 data and some projected 12/31/2013 figures. In the Company Study, the detailed net salvage and life analysis were all done using the actual 12/31/2011 data and that did not change in the Appendix. But in the Appendix some other numbers were projected 12/31/2013 amounts.

Of course the projected 12/31/2013 figures are estimates made by a party to this case. Projected 12/31/2013 figures are less accurate than are the actual known 12/31/2011 data.

As previously discussed, the projected increases in investments between the end of 2011 and the end of 2013 explains less than 40% of the PacifiCorp proposed depreciation expense increase from the end of 2011 to the end of 2013.

Projected depreciation rates should not be used. Depreciation rates should be calculated using known amounts (12/31/2011 actual data). Of course, in the future the depreciation rates so calculated can be applied to the then-current Plant in Service amounts to calculate the then-current depreciation expense. As the Plant in Service amounts increase

[29] PacifiCorp response to DPU Data Request 7.8, attached as DPU Exhibit 2.2 DIR.

over time, the depreciation expense also increases. This statement is true for virtually all depreciation rates, including the DPU proposed depreciation rates.

Unless otherwise stated, the calculations used in this testimony are based on the 12/31/2011 actual data. Items 3-14 of the above Table 2 are using both the Company proposed and DPU proposed depreciation rates based on the 12/31/2011 data.

V. Retirement Year for the Gadsby Steam Production Plant

Q. Since the Company Depreciation Study was prepared, has there been a change in the expected final retirement date of the Gadsby Steam Production Plant?

A. Yes. The Company Depreciation Study assumes that the Gadsby Steam Production Plant will retire in 2022.[30] However, the more recent 2013 PacifiCorp Integrated Resource Plan (IRP) shows the Gadsby Steam Production Plant is now expected to be in service at least through the end of 2032.

DPU Data Request 7.1 in this proceeding asked:

> "in the PacifiCorp 2013 IRP are the Gadsby Steam production units still in service at least through 2032?"

The PacifiCorp response was:

> "Yes, the Gadsby steam units are assumed to be available through end of the IRP study period."

Q. What is DPU Exhibit 2.3 DIR?

A. DPU Exhibit 2.3 DIR is the PacifiCorp response to the DPU Data Request 7.1 discussed above.

[30] Page II-30 of Company Study (Exhibit RMP___(JJS-2)). The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

Q. What is DPU Exhibit 2.9 DIR?

A. DPU Exhibit 2.9 DIR contains relevant pages from the 2013 PacifiCorp Integrated Resource Plan (IRP).

Q. What do you recommend on this issue?

A. I recommend that the final retirement date of 2033 be used for the Gadsby Steam Production Plant in the depreciation study.

VI. Retirement Year for the Craig Steam Production Plant.

Q. The Company Depreciation Study assumes that the Craig Steam Production Plant will retire in 2034.[31] **Has there been a change in the expected final retirement date of the Craig Steam Production Plant?**

A. Yes. In response to DPU Request 6.13, PacifiCorp stated:

> "The 2034 date was the retirement date selected by the majority owners in the previous depreciation study….. The Company has recently become aware (subsequent to submittal of the 2012 Depreciation proceedings) that the majority joint owner extended their proposed lives."

Q. What is DPU Exhibit 2.4 DIR?

A. DPU Exhibit 2.4 DIR is the PacifiCorp response to the DPU Data Request 6.13 discussed above.

Q. What do you recommend on this issue?

A. The expected final retirement date of the Craig Steam Production Plant has changed. I recommend this fact be recognized in the depreciation rate calculations. However, I have

[31] Page II-30 of Company Study, (Exhibit RMP___(JJS-2)). The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

not gone as far as the majority owner did. The majority owner is now using a life span of over 70 years.[32] I recommend a final retirement year of 2040. This is a life span of 60 years for one unit and 61 years for the other unit. 60 and 61 years are more consistent with the life spans used for other steam production plants in this case.[33]

VII. James River Steam Production Final Retirement Year

Q. What is the James River Steam Production unit?

A. The James River Steam Production unit is a co-generator that receives steam from Georgia Pacific's Camas paper mill under a current 20-year lease between PacifiCorp and the paper mill. When this lease expires three basic things can occur:

> "1) Georgia Pacific and PacifiCorp may negotiate a new lease or an extension of the existing lease, 2) if a new lease is not negotiated, then Georgia Pacific may exercise an option to purchase the steam turbine from PacifiCorp, or 3) if a new lease is not negotiate and Georgia Pacific does not exercise its purchase option, then PacifiCorp must dismantle and remove the steam turbine and associated structures at its own expense."[34]

Q. In its Depreciation Study calculations what has PacifiCorp assumed is 100% certain to happen to James River?

A. Although the text of the PacifiCorp Depreciation Study refers to it as a "Probable Retirement Date"[35] the actual depreciation rate calculations use the year 2016 as the final retirement date for James River with no adjustment for any other possibility.

PacifiCorp's proposed depreciation rates effectively assume it is 100% certain that what

[32] RMP response to DPU Data Request 8.1. Craig Unit 1 went in service in 1979. The Majority owner is using a 2051 final retirement date. Craig 2 went in service in 1980. The Majority owner is using a 2052 final retirement date.
[33] See page III-30 of the Company Depreciation Study.
[34] PacifiCorp response to DPU 2.36, attached as DPU Exhibit 2.5 DIR.
[35] See page III-30 of the Company Depreciation Study.

will occur is option (3) listed above (no lease renewal, no new lease, no sale, and therefore PacifiCorp must retire and remove the equipment).

This option (3) results in a higher depreciation rate than either option (1) or option (2). Under option (1), a new or renewed lease, the life would be longer, which decreases the depreciation rate. Under option (2), which is a sale, PacifiCorp would receive "salvage" which lowers the depreciation rate.

Q. According to PacifiCorp has Georgia Pacific made offers?

A. Yes. In response to DPU Data Request 6.1 (l) PacifiCorp stated:

> "The current lease expires December 31, 2015. There are no known mechanical or electrical issues that would require retirement in 2016. The lease makes provision for renewal lease; the paper mill has proposed a number of options in anticipation of the lease termination; however, none of the proposed options is a renewal of the current lease arrangement. It is expected the mill would seek a financial arrangement favorable to the mill. The future disposition of the Camas co-gen plant is unknown at this time."[36] (Emphasis added)

Q. What is DPU Exhibit 2.5 DIR?

A. DPU Exhibit 2.5 DIR contains the responses to DPU Data Request 2.36 and DPU Data Request 6.1(l), referenced above.

Q. What do you recommend on this issue?

A. No one can predict the future. However the statement that "the paper mill has proposed a number of options in anticipation of the lease termination" indicates that PacifiCorp does have options available other than retiring and removing the turbine in 2016.

[36] PacifiCorp response to DPU 6.1, attached as DPU Exhibit 2.5 DIR

We do not know if a new 20 year lease (or other period) will be signed, or if the turbine will be purchased, or removed. But a more balanced approach is to give some weighting to the other possibilities, as opposed to a 100% weighting to the costliest option. Conceptually this is essentially a weighted average of the different possibilities. This is more reasonable than PacifiCorp's effective assumption of a 100% certainty of the most costly possibility.

To give some weighting to the other possibilities, I have added an additional 10 years to the life of the James River investment for purpose of calculating the depreciation rates.[37]

VIII. Terminal Net Salvage for the Carbon Plant

Q. What Terminal Retirement cost does PacifiCorp include in its Depreciation Study for the Steam Production plants?

A. For most Steam production plants, the PacifiCorp Depreciation Study uses a Terminal Retirement Cost of $40 per Kilowatt capacity. However, for the Carbon Steam Production Plant PacifiCorp uses a Terminal Retirement Cost of $330 per Kilowatt. This is an assumed Terminal Retirement Cost for Carbon of $56,800,000.[38]

[37] This is the middle of the range of a 0-year additional life and a 20-year additional life.
[38] Page III-582 of the Company Study. The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

Q. Why is there such a large difference between the $40 per Kilowatt cost the Company uses for most steam plants and the $330 per Kilowatt cost the Company proposed for the Carbon plant?

A. The main difference is that the Company used an entirely different type of cost study for the Terminal Retirement Cost of Carbon than the type of cost study that was used for the other steam plants.

The $40 per Kilowatt cost was based on what it actually cost in the real world for the past actual decommissioning of previously retired steam production plants. I will call this an "actual cost" based study.

The $330 per Kilowatt cost was not based on what it has actually cost in the real world for the past actual decommissioning of previously retired steam production plants. Instead this study makes detailed assumptions about each step of the decommissioning process, and then prices out each of those assumptions. I will call the type of study used to arrive at $330 per Kilowatt cost a "hypothetical" cost study.

Q. Can you demonstrate that the study used to arrive at the $40 per Kilowatt cost was based on what it actually cost to decommission a previously retired steam production plant?

A. Yes. This fact is stated in the Direct Testimony of Company witness Mr. Andrews, as follows:[39]

> "The Company proposes to continue to use current decommissioning costs of $40 per kilowatt, with the exception of the Carbon plant. This rate is

[39] Starting on page 12 of Direct testimony of Company Witness Andrews.

> based on the cost of decommissioning the Company's Hale Plant in the 1993 to 1995 time period. Based on recent studies, the current estimate of the complete decommissioning cost for the Carbon plant is $56.8 million, or $330 per kilowatt."(Emphasis added).

The $40 per Kilowatt cost is based on what it actually cost to decommission a previously retired steam production plant.[40] The $330 per Kilowatt cost was not.

Q. Can you provide a simple analogy to understand the differences between these two types of cost studies?

A. Yes. As an analogy, assume that in the near future you will purchase a large ham and mushroom pizza. You want to estimate what you will be charged in the future for that pizza.

If you are performing an "actual cost" based study you will first determine what such pizzas are costing in the real world. You go to a restaurant and the records show that yesterday that restaurant sold a large ham and mushroom pizza for $13.99. Based on this and similar actual data from other restaurants, you make an estimate of what the future pizza will cost.[41] This would be an "actual cost" based study.

However in a "hypothetical" cost study you would not examine what pizzas actually cost in the real world. Instead you would make detailed assumptions about each step of the creation of the pizza, and then price out each of those assumptions. For example, for the mushrooms, a "hypothetical" cost study might assume that it would take a worker walking through the woods an average of one hour per mushroom to find a usable

[40] In the prior case that established the $40 per KW cost (Docket No. 07-035-13) Hale was not the only prior plant mentioned. See pages 23-27 of the Direct Testimony of Jacob Pous in Docket No. 07-035-13.
[41] If appropriate, you might include adjustments to the data you collected.

mushroom. It is difficult and time consuming to find a specific type of mushroom in the woods.[42] The "hypothetical" cost study might also assume that the owner of the woods would have to be compensated for access to the woods. It might also add in the attorneys' costs for negotiating access to the woods. With labor rates and the other charges, the cost could easily be over $100 per mushroom in the hypothetical cost study. If it is assumed that seven mushrooms are required for one a large ham and mushroom pizza, the cost for the mushrooms could be $700 in the "hypothetical" cost study for one pizza. When a similar "hypothetical" analysis is applied to the ham, sauce, dough, assembly and cooking, the total cost of one large ham and mushroom pizza could be thousands of dollars, using the "hypothetical" cost study.

Since the hypothetical cost study is based on assumptions, and is not based on what experience shows the actually costs are in the real world, a hypothetical cost study can create claimed costs that are far removed from reality, as this analogy demonstrates.

Q. In the "pizza" analogy the "hypothetical" cost study assumed a labor intensive method of acquiring mushrooms. Does the PacifiCorp study that arrived at the $330 per Kilowatt cost also assume labor intensive methods?

A. Yes. For example the PacifiCorp study assumes a very labor intensive method for demolishing the stack, boiler and main structure.

[42] Of course in an "actual cost" study you might find that in the real world the mushrooms are acquired in a less labor-intensive manner, such as being raised. But the hypothetical study is based on assumptions, not necessarily what actually happens in the real world.

In the actual demolition of a power plant the demolition contactor will use the most efficient methods possible. When the actual demolition is to occur, the financial incentives are for a demolition contractor to bid the demolition at the lowest possible price, while meeting all requirements. The lower the demolition contractor's bid, the more likely that demolition contractor's bid will be accepted, everything else equal. As a result, in the actual demolition of a power plant it is common for the contractor to bring down the stack and other large structures with explosives or by pulling them over.[43] Heavy equipment then finishes much of the clean up.[44]

However, the PacifiCorp decommissioning study that arrives at the $330 per Kilowatt cost assumes a very labor intensive top down piece-by-piece method for demolishing the stack, boiler and main structure**.** For removing the stacks the PacifiCorp study assumed: "From the top down, the stacks would be cut into manageable pieces and lowered to the ground by crane."[45] This is a labor-intensive assumed method. The assumed boiler removal was also a top down piece-by-piece method: "Portions of the boiler would be cut out and removed by crane and lowered to grade."[46] This is a labor-intensive assumed method. The main building was also assumed to be removed top down piece-by-piece: "Following removal of the boiler, the boiler structure (building) would be removed. The

[43] This would be after appropriate preparations, including removing asbestos.
[44] See DPU Exhibit 2.6 DIR.
[45] From part (f) of PacifiCorp response to DPU Data Request 4.2, attached as DPU Exhibit 2.7 DIR.
[46] From part (d) of PacifiCorp response to DPU Data Request 4.2, attached as DPU Exhibit 2.7 DIR.

boiler is top supported from the boiler structure. The boiler structure would be removed from the top down."[47] This is a labor-intensive assumed method.[48]

Q. What is DPU Exhibit 2.7 DIR?

A. DPU Exhibit 2.7 DIR is the PacifiCorp response to DPU Data Request 4.2, which is the source of the above quotations showing the removal methods assumed in the PacifiCorp study.

Q. What is DPU Exhibit 2.6 DIR?

A. DPU Exhibit 2.6 DIR is a document that is in the public record in Indiana which discusses the methods used when a production plant was <u>actually</u> being demolished. In this actual demolition the stack was brought down by explosives. Also,

> "The low bidder proposes to cut the boiler building steel, pull the structure over and slice the structure into scrap with hydraulic sheers. This proposed dismantlement technique would be less costly than the top down method represented in the Sargent and Lundy estimate."[49]

A "hydraulic shear" is a mobile piece of heavy equipment that has a long mechanical arm, and at the end of that arm can cut through a steel beam using a hydraulic powered motion similar to a bite.

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[47] From part (e) of PacifiCorp response to DPU Data Request 4.2, attached as DPU Exhibit 2.7 DIR.

[48] In addition, accepting a "hypothetical" type of study could require the Commission to make judgments about the numerous assumptions, since assumptions are the foundation of the "hypothetical" type of study. This is much less of a factor in a "real cost" study, because actual recorded decommissioning costs are the foundation of a "real cost" study.

[49] Schedule WDA-3 of Mr. Dunkel's March 30, 2006 Direct Testimony in Indiana Cause No. 42959.

Q. Was the actual cost to decommission previously retired steam production plants shown anywhere in the study that arrives as the $330 per Kilowatt cost?

A. No. The documents PacifiCorp provided in support of their proposed $330 per Kilowatt cost included no data showing what it had actually cost to actually decommission any prior steam production plants.[50]

Such past actual data was discussed in arriving at the $40 per Kilowatt terminal net salvage cost, but such past actual data was not discussed in arriving at the $330 per Kilowatt cost terminal net salvage cost.

Q. Is the decommissioning estimate that a utility prepares sometimes much higher than the later actual decommissioning cost?

A. Yes. This is so common that when speaking to investors, an executive from a demolition contractor that performs the actual demolition of power plants stated:

> "There is one project that we're familiar with that had an $80 million estimate at the very conceptual stages and their cost of doing that project is going to be less than 1/3 of that." [51]

To be clear, I have no reason to believe that PacifiCorp is the specific utility being discussed, but this statement makes it clear that vastly overstated utility decommissioning cost estimates do exist.

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[50] Company responses that included documents that support the $330 per kilowatt cost Include, but are not necessarily limited to, PacifiCorp responses to DPU Data Request 2.23, DPU Data Request 7.9 and DPU Data Request 7.10.

[51] Ed Malley, Vice President at TRC Solutions. Speaking July 30, 2012. Page 9 of transcript "Fossil-Fired Plant Decommissioning Call; Transcript and Thoughts." Downloaded 5/22/2013 from http://www.trcsolutions.com/ResourceCenter/REPower/Documents/Forms/AllItems.aspx

Q. Please provide some of the instances that you are aware of in which the utility decommissioning estimate was much higher than the later actual decommissioning cost.

A. There are several:

(1) I previously discussed the case where "their cost of doing that project is going to be less than 1/3 of" the utility's earlier decommissioning cost estimates.

(2) For the previously discussed Breed Plant in Indiana, the Utility's dismantling cost estimate had been $28,663,000.[52] When I&M completed the demolition of the Breed Plant the actual net cost to demolish the Breed plant was of $10,766,584.[53] The actual decommissioning cost was less than 40% of the prior estimate that I&M had provided to the Indiana Utility Regulatory Commission. Breed was a coal-fired steam production plant.

(3) The OCS cited to the testimony of Paul R Maguire, P.E. who is part of the Nevada Staff.[54] Mr. Maguire discusses differences between the original Nevada Power dismantlement estimates for certain production units, compared to later figures which were based on the actual dismantlement costs of those same production units. Mr. Maguire states: "Thus, the original B&V decommissioning cost study had been adjusted

[52] Page 6 of Mr. Bertheau's Direct testimony on behalf of I&M was filed on December 1, 2005 in Cause No. 42959. I&M also presented the similar $28.6 million demolition cost estimate for the Breed plant in a later proceeding, Cause No. 43231on page 14, line 20-22 of the Direct Testimony of I&M witness Henderson filed February 27, 2007.

[53] Removal Cost was $12,090,704 - Gross Salvage of $1,324,120 = $10,766,584 net demolition cost. Source is I&M response to OUCC DR 16-31, which is Attachment WWD-7 of Mr. Dunkel's April 27, 2012 Direct Testimony in Indiana Cause No. 44075.

[54] DPU Data Request 1.1 to the OCS

downward by approximately 72%." He states the later dismantlement cost figures were only 28 cents for every dollar of dismantlement costs in the original estimates.[55]

Q. Does the Public Utilities Depreciation Practices published by the National Association of Regulatory Utility Commissioners (NARUC) state that the past actual data should be collected and considered?

A. Yes. Public Utilities Depreciation Practices states:

> "Knowing what happened yesterday may help one better understand what is happening today and what may happen tomorrow."[56]

Specifically referring to determining future net salvage, the Public Utilities Depreciation Practices states:

> "Normally, the process should start by analyzing past salvage and cost of removal data and by using the results of this analysis to project future gross salvage and cost of removal."[57]

Q. What do you recommend on this issue?

A. I recommend that the decommissioning cost estimates to be used in this proceeding not be based on "hypothetical" cost studies. Instead the decommissioning cost estimates should be based on "actual cost" studies. The decommissioning cost estimates for steam production used in the current RMP depreciation rates in Utah are $40 per KW based on past actual decommissioning costs. In fact, the decommissioning cost estimates used for Carbon in the current PacifiCorp depreciation rates in Utah are $40 per KW based on past

[55]Page 20, Prepared Direct Testimony of Paul R Maguire, P.E on behalf of the Staff of the Public Utilities Commission of Nevada, Docket No. 11-06007.
[56] Page 111, Public Utilities Depreciation Practices published by the National Association of Regulatory Utility Commissioners (NARUC), August 1996.
[57] Pages 157-158, Public Utilities Depreciation Practices published by the National Association of Regulatory Utility Commissioners (NARUC), August 1996.

actual costs. I am not aware of any valid reason to convert from relying on "actual cost" studies to relying on a "hypothetical" cost study for the Carbon decommissioning cost estimate. In fact in its filing in this case, PacifiCorp is using $40 per KW based on past actual decommissioning costs for most steam production plants, with Carbon being the exception.

I recommend we base the Carbon decommissioning cost estimate on actual costs to decommission steam production plants. The actual data is the starting point. Appropriate adjustments could be made. For example, if an actual decommissioning was several years ago, an adjustment for the lower value of current dollars might be appropriate.

Q. As previously discussed, Company witness Mr. Andrews stated:

> **"The Company proposes to continue to use current decommissioning costs of $40 per kilowatt, with the exception of the Carbon plant. This rate is based on the cost of decommissioning the Company's Hale Plant in the 1993 to 1995 time period."** [58]

What was the decommissioning cost of the Hale plant?

A. The actual decommissioning cost of the prior PacifiCorp Hale Plant was $27 per KW.[59] This was in 1993 to 1995. If we adjust $27 per KW by the CPI-U, that is $42 per KW in today's dollars.[60]

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[58] Starting on page 12 of Direct testimony of Company Witness Andrews.

[59] Calculated from PacifiCorp response to DPU Data Request 7.6, attached as DPU Exhibit 2.8 DIR.

[60] The annual average 1994 CPI-U is 148.2 and the average annual 2012 CPI-U is 229.594 as published by the Bureau of Labor Statistics (www.bls.gov/cpi/). $27 in 1994 dollars * 1+((229.594-148.2)/148.2) = $42 in 2012 dollars.

However this $27 per KW (or $42 per KW in today's dollars) does not include the amount PacifiCorp received as the result of the sale of the land. If the sale of the land is included that would lower the net decommissioning cost.

Like Carbon, the Hale plant was a coal fired plant, that contained asbestos, had a coal yard and an ash landfill.[61]

Q. What is DPU Exhibit 2.8 DIR?

A. DPU Exhibit 2.8 DIR is the PacifiCorp response to DPU Data Request 7.6 regarding the actual decommissioning costs of the Hale Plant.

Q. What decommissioning cost do you recommend be used for the Steam Production Plants?

A. I recommend that the current $40 per Kilowatt decommissioning cost continued to be used for the Steam Production Plants, including Carbon. This is supported by the actual decommissioning cost experience.

[61] PacifiCorp response to DPU Data Request 7.6(f), attached as DPU Exhibit 2.8 DIR. In addition, (1) the previously discussed Breed plant in Indiana was a 400 MW coal powered steam production plant. The $10,766,584 actual dismantling cost equals $27 per Kilowatt. This was demolished in the 2006 to 2008 time frame. (Source is I&M response to OUCC DR 16-31, which is Attachment WWD-7 of Mr. Dunkel's April 27, 2012 Direct Testimony in Indiana Cause No. 44075). Also (2) it is public information that in 2011 the City Counsel of Austin, Texas awarded the contract to demolish the 570 megawatt Austin Energy Holly Street oil-fired steam plant for $11.5 million. The Holly Street plant did contain asbestos. This is an actual demolition cost of $20 per KW which includes Asbestos removal. There may be other decommissioning costs for the Holly Street Plant.

IX. Terminal Retirement Year for Certain Hydroelectric Production Plants

Q. What is the issue addressed in this section?

A. The Company Depreciation Study uses certain retirement dates for various Hydroelectric Production Plants.[62] For example the Company Study uses a 2016 retirement date for Wallowa Falls.

However, the more recent 2013 PacifiCorp IRP assumes a longer life for some Hydroelectric Production Plants than was used in the Company Depreciation Study. For example page 47 of the IRP says Wallowa Falls is currently undergoing FERC relicensing. In addition page 86 of the IRP states:

> "PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned pursuant to the Klamath Hydroelectric Settlement Agreement in the year 2020 and <u>that the Wallowa Falls project and other projects to be relicensed in future years will receive new operating licenses</u>..." (Emphasis Added)

In addition, the PacifiCorp response to DPU Data Request 7.4(c) confirms that the 2013 PacifiCorp IRP assumes that all of the Hydraulic Production Plants listed on page II-30 of the PacifiCorp Depreciation Study (Exhibit RMP___(JJS-2)) would be in service at least through 2032, other than Conduit, Fountain Green and Klamath River-Accelerated, and Olmstead.

Q. What is DPU Exhibit 2.9 DIR?

A. DPU Exhibit 2.9 DIR contains key pages from the recent 2013 PacifiCorp IRP, including the pages referenced above.

[62] Page II-30 of the Company Study (Exhibit RMP___(JJS-2)). The relevant pages from the Company Study are included in DPU Exhibit 2.18 DIR.

Q. What is DPU Exhibit 2.10 DIR?

A. DPU Exhibit 2.10 DIR contains the RMP response to the DPU Data Request 7.4 which was discussed above.

Q. What is your position on this issue?

A. For certain hydroelectric facilities, the recent IRP indicates that PacifiCorp's expected final retirement dates have changed from the retirement dates assumed in the Company Depreciation Study. The 2013 IRP indicates that PacifiCorp now expects more units to be relicensed than had been assumed in the Company Depreciation Study. I have incorporated these changes into my Study. [63]

X. The Depreciation Rates for the Utah Mining Equipment

Q. What is the primary reason that PacifiCorp provides for assuming that the mine equipment would have a final retirement in 2019?

A. PacifiCorp states that the primary reason that they expect the Deer Creek mine to close in 2019 is because the economically recoverable coal reserves are expected to be exhausted by then.[64] However, PacifiCorp has additional coal rights, namely the Cottonwood Lease. In response to DPU Data Request 3.1, PacifiCorp stated "Coal reserves in the Cottonwood lease tract are not included in Deer Creek's 2019 life-of-mine plan."[65] Therefore, even if the Deer Creek mine closes in 2019, it is reasonable to expect that PacifiCorp will continue to use coal mining equipment after 2019.

[63] As a result, other than Klamath River-Accelerate, Conduit, Olmstead and Fountain Green, I have added 30 years to each Hydroelectric Production Plant that shows a retirement year prior to 2021 on page II-30 of the Company Depreciation Study.
[64] Lay Direct Testimony page 13, and PacifiCorp response to DPU Data Request 2.32.
[65] PacifiCorp response to DPU Data Request 3.1, attached as DPU Exhibit 2.11 DIR.

Q. What is the major difference between the way the current Mine depreciation rates were calculated and the way PacifiCorp proposing to calculate them in this proceeding?

A. Both the current rates and the PacifiCorp proposed rates assumed the Deer Creek Mine will close in 2019. However in the proposed rates PacifiCorp changes what is assumed will occur in 2019. The current depreciation rates assumed that in 2019 any equipment that could be driven, or that could reasonably be disassembled and be moved, would continue to be used after 2019, presumably at PacifiCorp's new mining location. However in this case PacifiCorp has changed that to assuming that any equipment that could be driven, or could be disassembled and moved, ceases service in 2019, even if it has several years left in its normal life.

For example, for Mine "Heavy Construction Equipment" PacifiCorp assumes a normal average life span of 20 years (which I am not disputing). However if a piece of Heavy Construction Equipment is 5 years old in 2019 when the Deer Creek mine closes, in the depreciation rates proposed in this proceeding, PacifiCorp assumes that equipment would be retired in 2019, even though it was only 5 years old and not at the end of its normal expected 20 year life.

However in the calculation of the currently approved depreciation rates, that piece of equipment would continue in service wherever PacifiCorp is mining coal after 2019, for the remainder of its normal life.

Q. What is DPU Exhibit 2.11 DIR?

A. DPU Exhibit 2.11 DIR is the PacifiCorp response to DPU Data Request 3.1 discussed above.

Q. What do you recommend on this issue?

A. I recommend continuing to use the same treatment that was used in the currently approved depreciation rates. This reasonably assumes that when the Deer Creek Mine closes in 2019, any equipment that can be driven, or that can reasonably be disassembled and be moved, will continue to be used after 2019, for the remainder of its normal life.

XI. Transmission Plant Average Service Lives

Q. What is one Transmission account in which you recommend a different average Service Life than PacifiCorp proposes?

A. For Account 353-Station Equipment Mr. Spanos recommends a 57 year average Service Life. I recommend a 59 year average Service Life.

The major problem is Mr. Spanos's Depreciation Study treated the sale of the Midpoint substation inconsistently. Mr. Spanos excluded data from his sale from the data used in the Net Salvage analysis, treating the sale as an abnormal event.[66] However Mr. Spanos included data from this same sale in the data used in the Service Life analysis,[67] effectively treating the sale as a normal event.

[66] PacifiCorp response to DPU Data Request 7.12(c), attached as DPU Exhibit 2.12 DIR.
[67] PacifiCorp response to DPU Data Request 7.11(d), attached as DPU Exhibit 2.12 DIR. Also, PacifiCorp response to OCS 1.71.

The data related to this sale was excluded from the analysis in which exclusion results in a higher depreciation rate (the Net Salvage analysis)[68] and the data related to this sale was included in the analysis in which inclusion results in a higher depreciation rate (the Service Life analysis).[69]

Q. What is DPU Exhibit 2.12 DIR?

A. DPU Exhibit 2.12 DIR is the PacifiCorp responses to DPU Data Request 7.11 and DPU Data Request 7.12 discussing the treatment of the Midpoint substation in Mr. Spanos's Depreciation Study.

Q. How did you treat this sale?

A. I treated this sale as an abnormal event in both analyses. I excluded data from his sale from the data used in the Net Salvage analysis and I excluded data from this sale from the data used in the Service Life analysis. Because of the resulting difference in the Service Life data, I recommend a 59 year Service Life.[70]

Q. For what other Transmission accounts do you recommend a different average Service Life than PacifiCorp proposes?

A. I recommend an average Service Life of 25 years R2 for Account 353.7-Supervisory Equipment and an average Service Life of 65 years R2 for Account 357-Underground Conduit. These lives are a better fit to the actual PacifiCorp data, and I found no compelling reason to be as far away from the actual data as PacifiCorp is recommending.

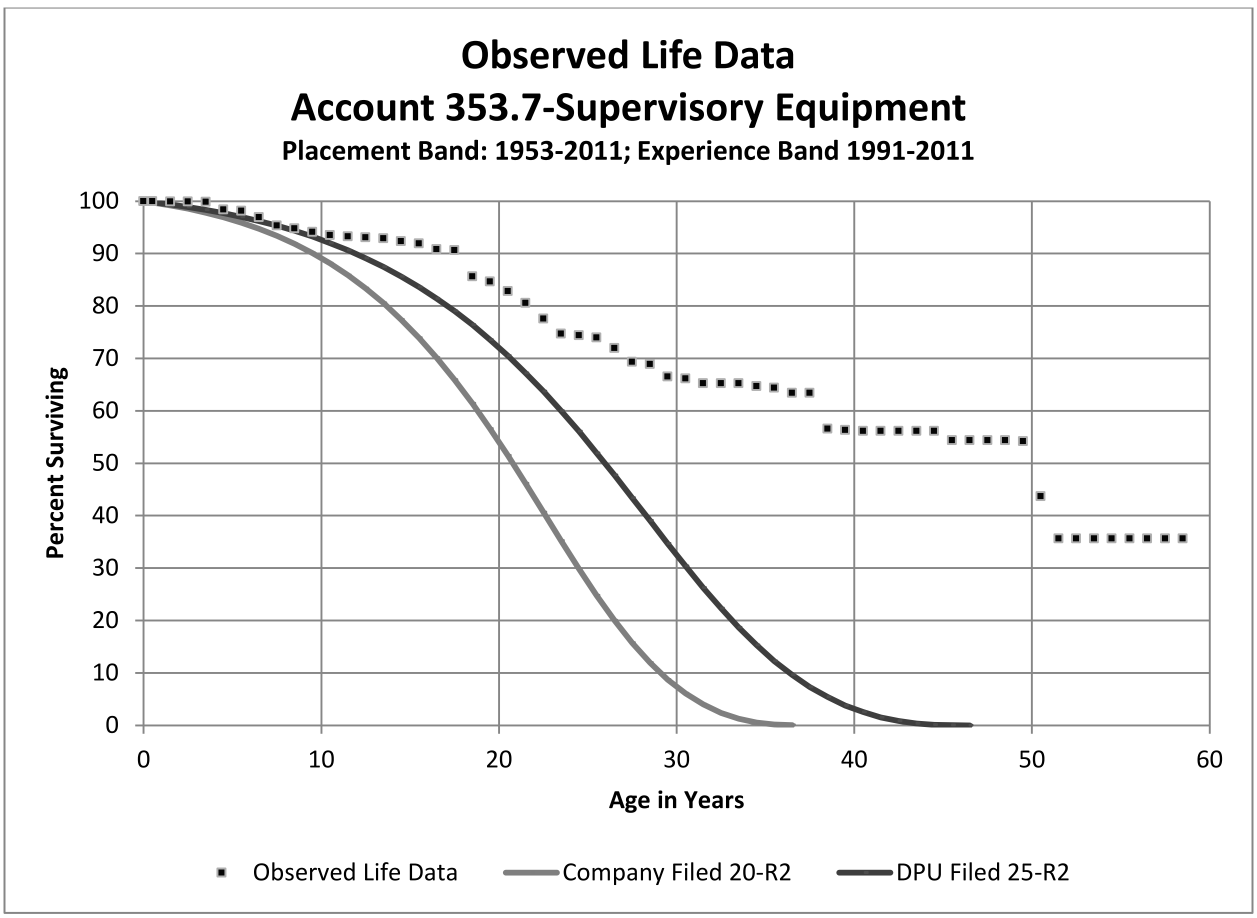
[68] Excluding the sale proceeds from salvage results in a lower depreciation rate than if they were included.
[69] Including the retirements produced a shorter average life for the account.
[70] I recommend a 59-S0 and Mr. Spanos recommends a 57-S0.

In addition, for each of these accounts, the life I recommend is in the range of lives used for that account by other electric utilities.

Q. What is DPU Exhibit 2.13 DIR?

A. DPU Exhibit 2.13 DIR contains graphs which compare Mr. Spanos's recommend lives and my recommended lives to the actual data for each of these accounts.

For example, below is the graph for Account 353.7-Supervisory Equipment comparing the actual data to the lives recommended by Mr. Spanos and me.



XII. Utah Distribution-Lives

Q. What is a problem in evaluating the Service Lives for the Utah Distribution accounts?

A. For most of the Utah Distribution accounts, PacifiCorp did not have the detailed data needed to perform the more accurate Actuarial life analysis. Therefore the analysis available is the less accurate Simulated Balance life analysis.

Because of these data limitations I focused on the two largest Utah Distribution accounts.

Q. Please discuss the life analysis for the largest Utah Distribution account.

A. The largest Utah Distribution account is Account 367-Underground Conductors and Devices. Mr. Spanos proposes a 50 year-R2. However, Mr. Spanos' own workpapers show that 50 years is not the best R2 fit. His own workpapers show the best R2 fit is 76 years.[71] To be conservative, I will not go to 76 years.[72] I recommend a 55 year R-2. In addition, 55 years is in the range in of lives used by other utilities for this account.

Q. Please discuss the life analysis for the second largest Utah Distribution account.

A. The second largest Utah Distribution account is Account 368-Line Transformers. Mr. Spanos proposes a 45 year average Service Life with R0.5 dispersion (R0.5 Iowa Curve). However, Mr. Spanos' own workpapers show that 45 years is not the best R0.5 fit. His

[71] The higher the "conformance Index", the better the fit (PacifiCorp response to DPU 2.15). The 50 R2 has a "conformance Index" of 36.6 (page III-510, Company Depreciation Study (Exhibit RMP___(JJS-2)). The 76 year R2 has a "conformance Index" of 462.2 (PacifiCorp response to DPU 2.2 Attachment 16, Account 367 Underground Conductors and Devices comparison years 1992-2011).

[72] A 76 year life would have produced a lower depreciation rate than the 55 year life which I recommend.

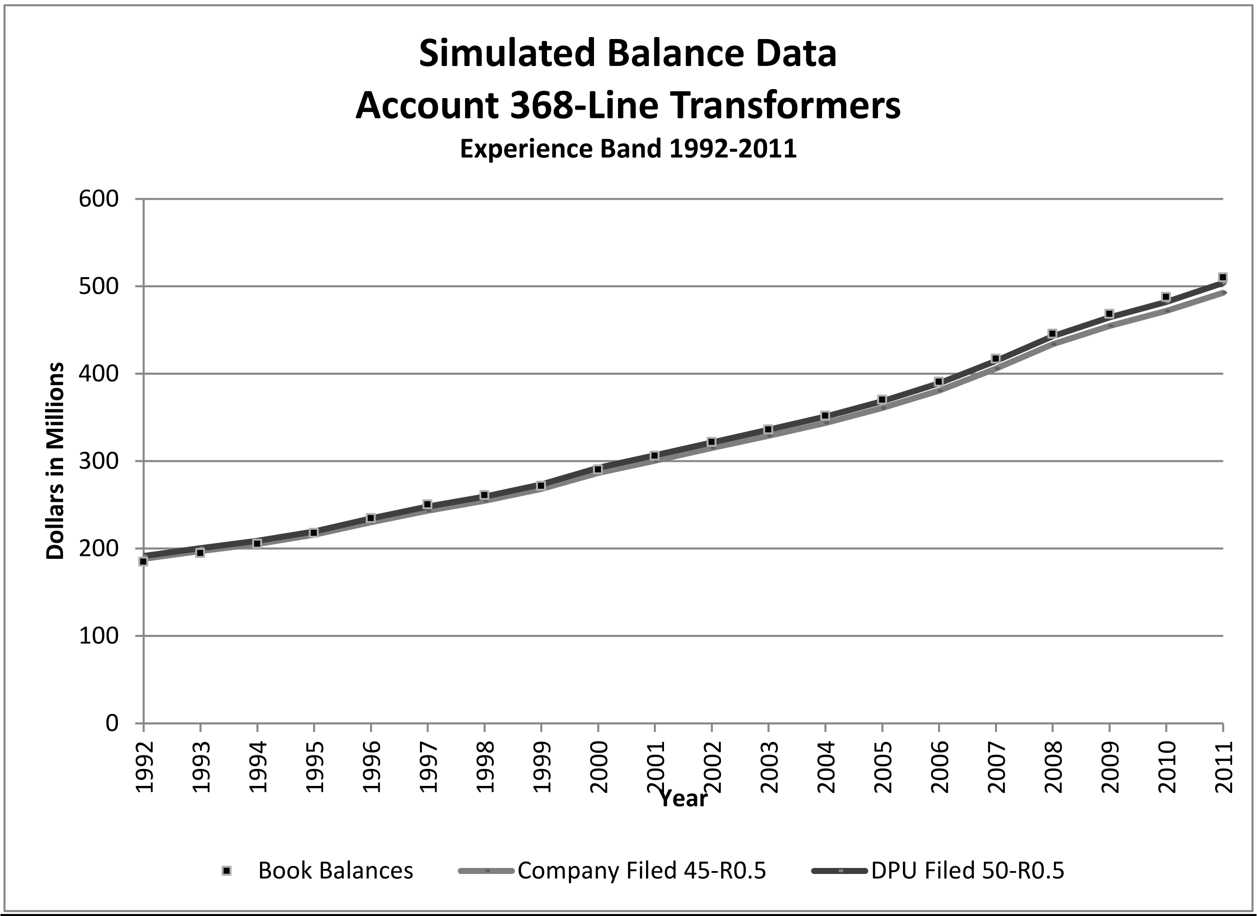
own workpapers show the best R0.5 fit is 51 years.[73] I recommend a 50 year R-0.5. In addition 50 years is in the range in use by other utilities for this account.

Q. What is DPU Exhibit 2.14 DIR?

A. DPU Exhibit 2.14 DIR contains graphs which compare Mr. Spanos recommend lives and my recommended lives to the actual data for each of these accounts.

For example, below is the graph for Account 368-Line Transformers comparing the actual data to the lives recommended by Mr. Spanos and me.

[73] The higher the "conformance Index", the better the fit (PacifiCorp response to DPU 2.15). The 45 R0.5 has a "conformance Index" of 36.2 (page III- 512, Company Depreciation Study (Exhibit RMP___(JJS-2)). The 51 year R0.5 has a "conformance Index" of 110.6 (PacifiCorp response to DPU 2.2 Attachment 16, Account 368 Line Transformers, comparison years 1992-2011).



XIII. PacifiCorp Inflates the Future Net Removal Costs for Future Inflation, But Fails to Apply a "Present-Value" to the Inflated Future Removal Costs.

Q. What issue will be addressed in this section?

A. For those retirement activities that are virtually certain to actually occur in the future, [74] the FERC Uniform System of Accounts (USOA) requires the future retirement costs to be increased for future inflation, and also requires that the present-value of those inflated future retirement costs be used.

[74] These are the future retirement activities that are "legally" required to occur in the future, as will be discussed.

In the Transmission and Distribution accounts the PacifiCorp Depreciation Study uses future retirement costs that include future inflation, but PacifiCorp did not apply a present-value to those inflated future retirement costs.

Q. Please demonstrate the treatment that the USOA requires for those retirement activities that are virtually certain to actually occur in the future.

A. For those retirement activities that are virtually certain to actually occur in the future,[75] the USOA requires that the inflated future cost be adjusted to a present-value.

As FERC stated pertaining to these Asset Retirement Obligations:

> "In summary, the new accounting standard requires the present value of the liability to be recorded for all assets."[76]

Q. What is DPU Exhibit 2.15 DIR?

A. DPU Exhibit 2.15 DIR contains the pages from SFAS-143 which shows the calculations adopted by the USOA for those retirement activities that are virtually certain to actually occur in the future.

The major steps in the table on page 48 of DPU Exhibit 2.15 DIR can be summarized as follows:

Table 6:

1.	Retirement Cost in Current Dollars:	$ 283,500
2.	Inflated for 10 years of Future inflation at 4% per year:	$ 419,637
3.	After Minor Adjustment:	$ 440,619
4.	Present Value of Line 3:	$ 194,879

[75] These are the future retirement activities that are "legally" required to occur in the future, as will be discussed.
[76] Paragraph 8 of FERC Notice of Proposed Rulemaking (NOPR) issued on October 30, 2002.

As can be seen, the retirement cost is inflated for future inflation (goes up from $283,500 to $419,637) but it is also adjusted for present-value (goes down from $440,619 to $194,879).

In the PacifiCorp Depreciation Study in this proceeding, PacifiCorp has inflated the future Retirement costs for future inflation (the amount over $400,000 in this illustration), but PacifiCorp has <u>not</u> adjusted for present-value (applied to this illustration, it would use the over $400,000 amount, which is not present-valued).

PacifiCorp is using the step that increases the cost (PacifiCorp includes future inflation), but is <u>excluding</u> the step that would reduce the cost (the present-value adjustment).

Q. Please cite to the FERC Order that incorporated the present-value requirement into the USOA.

A. On April 9, 2003, FERC issued Order No. 631 which altered the USOA.[77] As had occurred in SFAS 143, FERC Order No. 631 divides future retirement activities into two major categories:

(1) The future retirement activities which are virtually certain to occur in the future because these future retirement activities are "legally" required to occur (asset retirement obligation (legal-ARO)); and

[77] FERC Order No. 631 was based upon Statement of Financial Accounting Standards (SFAS) No. 143 in which the Financial Accounting Standards Board (FASB) had adopted the "present value" treatment for "legal" asset retirement obligations for financial reporting purposes. Since the USOA is the standard that applies to this proceeding, the financial reporting requirements are only being discussed as a background for the FERC Order No. 631. In June 2001 FASB issued *Accounting for Asset Retirement Obligations,* SFAS143. Later also addressed in FIN 47, *Accounting for Conditional Asset Retirement Obligations*.

(2) Future retirement activities which are not certain to occur, because there is no "legal" requirement that they occur ("non-AROs" or "non-legal" AROs). FERC Order No. 631 changed the treatment of a legal ARO which is "a liability resulting from a legal obligation to retire or decommission a plant asset."[78]

The USOA requires that both future inflation be included and required the present valuing of that inflated future cost for those retirement activities that are virtually certain to occur in the future. These future retirement activities are virtually certain to occur in the future because they are "legally" required to occur.[79]

Q. You stated above the USOA present-value requirement applies only to those retirement activities that are virtually certain to occur in the future, because those future retirement activities are "legally" required to occur. For future retirement costs that are not "legally" required to occur, should PacifiCorp be allowed to increase the future retirement costs for future inflation, but <u>not</u> adjust those inflated costs to a present-value?

A. No. As shown in the prior Table 6 from SFAS No. 143, the present-value adjustment reduces the cost from $440,619 to $194,879. If we use the present-value cost ($194,879 in this table) for the "legally" required future retirement costs, but use the <u>not</u> present-value inflated cost (over $400,000) for the non-legally required future retirement costs,

[78] Paragraph 2, FERC Order No. 631.

[79] See FERC Order No. 631 and the FERC Notice of Proposed Rulemaking (NOPR) issued on October 30, 2002, Docket No. RM02-7-000 which led to FERC Order No. 631. The "Present Value" treatment as adopted in SFAS 143 and FERC Order No. 631 for "legal" AROs also includes "accretion", which is effectively the change in the present value which occurs during the year. Adding accretion results in a higher accrual than would result from the basic present value calculation alone.

that would charge current ratepayers more for a future cost of retirement that might not even actually occur in the future (current ratepayers' share of over $400,000), than the current ratepayers should be charged for a similar cost of retirement that is virtually certain to actually occur in the future (current ratepayers' share of $194,879).

It makes no sense charge current ratepayers more for a future cost of retirement that might not even actually occur in the future, than the current ratepayers should be charged for a similar cost of retirement that is virtually certain to actually occur in the future.

In fact in FERC Order No. 631 a major issue pertaining to the not "legally" required future retirement cost was the concept that there should be no charge to current ratepayers for a future retirement cost that might not actually occur in the future. However in Order No. 631 FERC chose not to address the not "legally" required future retirement costs, saying they were outside the scope of the Order. In paragraph 37 of FERC Order No. 631, FERC stated:

> "The accounting for removal costs that do not qualify as legal retirement obligations falls outside the scope of this rule. The Commission is aware that there is an ongoing discussion in the accounting community as to whether the cost of removal should be considered as a component of depreciation. However, this issue is beyond the scope of this rule and we are not convinced that there is a need to fundamentally change accounting concepts at this time."

FERC Order No. 631 did not prohibit utilities from charging current ratepayers for future retirement costs that might not actually occur. However, I am not aware of any valid argument that can reasonably support charging current ratepayers more for a future cost of retirement that might not even actually occur in the future (not "legally" required), than the current ratepayers should be charged for a similar cost of retirement that is virtually certain to actually occur in the future (“legally “required); however this is what PacifiCorp is proposing.

Q. Is the PacifiCorp proposed treatment of net salvage cost-based?

A. No. PacifiCorp is calculating the future net retirement cost in lower-value future dollars, but is collecting that inflated amount in higher-value current dollars. This is an overcharge and is not cost-based.

To demonstrate this, assume:

(1) A new investment goes into service at the start of 2013 that will last 30 years.

(2) Because the investment will last 30 years, the ratepayers each year are responsible for 1/30th of the net retirement cost.

(3) The net retirement cost in today’s dollars is $30,000.

(4) Because the dollars 30 years from now will only be worth $0.33 compared to today’s dollars, the same retirement that would cost $30,000 in today’s dollars will cost $90,000 in the year-2043 dollars.[80]

Since the net retirement cost in year-2013 dollars is $30,000, and the ratepayers in the year 2013 will pay using year-2013 dollars, if ratepayers in the year 2013 pay $1,000 in year-2013 dollars they will have paid their fair 1/30th of the net retirement cost.[81]

[80] This is a 3.7% annual inflation. $30,000 *1.037^30 years = $89,225.
[81] $30,000 retirement cost in year-2013 dollars/ 30 = $1,000 in year-2013 dollars. Or if the inflated $90,000 retirement cost is used, current ratepayers should be charged based on the present-value of that inflated future cost.

However this is not what the PacifiCorp treatment does. Applied to this example, the PacifiCorp treatment would state the retirement cost in year-2043 dollars, which is $90,000. The PacifiCorp treatment would then charge the year-2013 ratepayers 1/30th of $90,000, which is $3,000 in year-2043 dollars. However, the $3,000 would be collected from the year-2013 ratepayers in year-2013 dollars.

This is an overcharge. The $90,000 and the $3,000 1/30th share of it were stated in year-2043 dollars, but the $3,000 is collected from the year-2013 ratepayers in the much more valuable year-2013 dollars.

To be cost-based, the cost must be determined in the same value of currency that will be collected from the ratepayer.[82] To calculate the cost in dollars that are worth $0.33, but to collect the number of dollars so calculated in dollars that are worth $1.00, is not cost based and is an overcharge.

Q. Does the net salvage treatment used in the PacifiCorp Depreciation Study determine the future retirement costs in inflated future dollars?

A. Yes. The treatment PacifiCorp uses builds decades of inflation into the Net Salvage factor. When that factor is applied to newer investments, it produces a Cost of Removal estimate that has decades of future inflation built into it.

Discussing the treatment PacifiCorp used, a standard depreciation textbook states:

> "One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is <u>measured in</u>

[82] Or else a conversion must be made or a present-value applied.

> dollars at the time of retirement, while the denominator is measured in dollars at the time of installation." (Emphasis added) [83]

When PacifiCorp uses this treatment to estimate the net salvage for a future retirement, the "time of retirement" is in the future, and that net salvage is "measured in dollars at the time of retirement," which is measured in future dollars.

The treatment PacifiCorp uses estimates future salvage by effectively assuming that future inflation will be equal to past inflation. The historic percents are calculated in a way that inflates the historic percents for past inflation. When a similar percent is applied in the current study to estimate future net salvage, the historic inflation that is built into the historic percent is projected into the future. This calculates the future net salvage in inflated future dollars.

I discuss how the PacifiCorp proposed treatment includes future inflation in more detail on DPU Exhibit 2.16 DIR.

Q. What do you recommend pertaining to the issue?[84]

A. I recommend that the amount that PacifiCorp can charge current ratepayers for expected future net retirement costs cannot exceed the amount PacifiCorp is allowed to charge current ratepayers under the treatment the USOA requires for the future retirement activities that are "legally" required to occur in the future.

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[83] Page 53 of *Depreciation Systems* by Frank K. Wolf and W. Chester Fitch, 1994, Iowa State University Press.

[84] This recommendation is addressing Transmission and Utah Distribution accounts. No adjustment was calculated for Distribution plant in states other than Utah.

This does not imply that all of the future expected net retirement costs of PacifiCorp are "legal" AROs. Instead one reason for this proposal is that I am not aware of any valid argument that can reasonably support charging current ratepayers <u>more</u> for a future cost of retirement that <u>might not even actually occur</u> in the future (is not "legally" required), than the current ratepayers would be charged for a similar cost of retirement that is virtually certain to actually occur in the future ("legally" required ARO). The second reason is that calculating the future retirement cost in lower-value future dollars, but collecting that un-present-valued inflated amount in higher-value current dollars is an overcharge and is not cost-based, as previously discussed.

Q. What is DPU Exhibit 2.17 DIR?

A. DPU Exhibit 2.17 DIR is the net salvage calculation for Account 356-Overhead Conductors and Devices using the calculation required by the USOA for those retirement activities that are virtually certain to actually occur in the future.[85]

I started with inflated future net salvage estimates proposed in the PacifiCorp Depreciation Study. After a review, I accepted these inflated future net salvage estimates as an appropriate input to the Present-Value calculation. I then applied the calculations as shown on DPU Exhibit 2.15 DIR, which are the calculations included in the USOA for the Asset Retirement Obligations. As required by this calculation, I establish a present-

[85] These are the future retirement activities that are "legally" required to occur in the future, as has been discussed.

value for the inflated future cost. The expense was calculated as shown on that DPU Exhibit 2.15 DIR document.[86]

For Account 356-Overhead Conductors and Devices, the resulting effective present-value Future Net Salvage of -13%[87] is lower than the PacifiCorp proposed -30% Future Net Salvage which is inflated and not adjusted by applying the present-value. I have applied this result, and results determined in a similar manner for other accounts, in my recommended depreciation rates shown on DPU Exhibit 2.1 DIR.

XIV. Conclusion

Q. What are DPU Exhibit 2.1 DIR and DPU Exhibit 2.19 DIR?

A DPU Exhibit 2.1 DIR is a summary of the DPU recommended depreciation rates and annual accrual amounts compared to the RMP proposal. The Utah allocated amounts are also shown.

DPU Exhibit 2.19 DIR contains the more detailed calculations that result in the rates and amounts shown on DPU Exhibit 2.1 DIR.

Q. What do you recommend?

A. I recommend that the DPU depreciation rates shown on DPU Exhibit 2.19 DIR and summarized on DPU Exhibit 2.1 DIR be adopted for the reason stated in this testimony.

[86] This includes both the "Depreciation Expense" and the "Accretion Expense." The impact of dispersion is included in the present value calculation shown on DPU Exhibit 2.17 DIR.
[87] DPU Exhibit 2.19 page 64, Parameter Report, Account 356, Column (Q) Effective Future Net Salvage After Present-Value.

Q. Does this conclude your testimony?

A. Yes.