BEFORE THE

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IDAHO PUBLIC
UTILITIES COMMISSION

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	CASE NO. PAC-E-10-07

DIRECT TESTIMONY OF JOE LECKIE

IDAHO PUBLIC UTILITIES COMMISSION

OCTOBER 14, 2010

ALLEGEDLY PROPRIETARY DATA HAS BEEN DELETED FROM THIS DOCUMENT

Q. Please state your name and business address for the record.

A. My name is Joe Leckie. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission (Commission) as a senior auditor in the Utilities Division.

Q. What is your educational and experience background?

A. I graduated from Brigham Young University with a Bachelors of Science degree in Accounting. I worked for the accounting firm Touche Ross in its Los Angeles office for approximately one year. I then attended law school and graduated from the J. Rueben Clark School of Law at Brigham Young University with a Juris Doctorate degree. I am licensed to practice law in the State of Montana and practiced there for approximately 25 years. I have been employed at the Commission as an auditor since March 2001. I have attended the annual regulatory studies program sponsored by the National Association of Regulatory Utility Commissioners (NARUC) at Michigan State University in August of 2001. I have attended several other training courses sponsored by NARUC on regulatory accounting and auditing.

Q. Would you please summarize your contribution to Staff's recommendations in those areas of the rate case that you personally reviewed?

A. I personally reviewed a broad cross section of the Company's investments and expenses, and I recommend the following adjustments effecting revenue requirement:

1) Removal of $33,976,054 (system) from Company adjusted rate base to account for the differences in the cost and in-service dates of the 2010 capital addition requested by the Company.

2) Removal of $15,970,759 (system) from rate base to reduce the value of the Company's coal fuel stockpile inventory.

3) Removal of $1,000,000 (system) from the Company's rate base for a portion of the cost of the Dunlap I Wind Project. It is the portion of the Dunlap Ranch land that is not currently used and useful.

4) Removal of $240,497 (system) from rate base to properly account for liquidated damages received by the Company associated with the 2009 Bridger Unit #2 overhaul.

5) Removal of $662,119 (system) of incremental O&M expenses claimed by the Company for future

operation of the High Plains, McFadden Ridge I, and Dunlap I wind facilities.

6) I additionally reviewed the Company's proposal to establish a regulatory asset or liability resulting from the Company's accounting change regarding the deductibility of capital repairs for tax purposes. The Company also wants to normalize income tax expenses. I support the Company proposal on both issues.

Q. Are your adjustments shown and included in Staff's proposed revenue requirement?

A. All of my adjustments are included in Staff's proposed revenue requirement as shown in Staff witness Vaughn's Staff Exhibit No. 108.

Q. Would you please explain your recommendation to remove $33,976,054 (system) from the Company's adjusted rate base?

A. In the initial filing by the Company, rate base included not only plant placed into service by the Company though December 31, 2009 (the end of the test year); but also plant that was expected to be placed into service by December 31, 2010. The total plant expected to be placed into service in 2010 was $1,852,283,166. See Company witness McDougal, Exhibit 2, page 8.6.2. Staff reviewed these projects and requested that the Company update the dollar amounts and the expected in-service dates for each project. The Company provided the information for Staff's Exhibit No. 101. The updated information indicated that some in-service dates changed and that the forecasted cost for some projects also changed. The difference between the updated cost and the original forecasted cost is in Column (h) "Change in Cost" of the Exhibit. The total of all the updated costs is $1,818,307,112 (Column (g)). The difference between the original cost and the updated cost is $33,976,054 (Column h). Staff has included this amount as an adjustment reducing the Company's rate base.

The $33,976,054 is a Company system total. Idaho's share of this amount is $2,031,303.

Q. Does this reduction in rate base have any effect on the depreciation expense?

A. Yes, depreciation expense on a total Company basis is reduced by $875,226 and Idaho's share of the depreciation expense reduction is $52,583. Also, accumulated depreciation is reduced by the same amounts.

Q. Please summarize the adjustment to the coal fuel stockpile the Company described in its Application as an adjustment to Miscellaneous Rate Base.

A. The Company increased coal fuel stockpile in Account 151, Fuel Stock, by $24,644,591 on a system basis with $1,581,176 allocated to Idaho. The Company stated that this increase was due to the cost of coal and the number of tons stored at each site (McDougal direct testimony at page 33, lines 4-5.)

Q. Did you examine the increase in coal fuel stockpile proposed by the Company?

A. Yes. In response to Confidential Audit Request dated April 27, 2010, the Company provided a schedule of fuel stockpile values and tons at each plant. I used this schedule to estimate the average cost per ton for each stockpile at each plant as of December 31, 2010. See Staff Confidential Exhibit No. 102, Column (f). The average cost per ton is the Dec-2010 projected coal stockpile cost, Column (e) divided by the pro forma tonnage, Column (d). The average cost per ton was compared to the cost per ton of contracted coal for each plant and found to be a reasonable cost per ton for valuing the total value of the stockpile.

Q. Since you agree with the Company on the average cost per ton of each stockpile, do you also agree with the Company on the increase in tonnage of the stockpiles as proposed by the Company for each location?

A. No. As shown in Staff Confidential Exhibit No. 102, Column (g), there were some noticeable changes in the stockpile tonnage at the different plant sites with a significant tonnage increase at several plants. The

Company provided no acceptable explanation or justification for these increases. Therefore, Staff believes the tonnage of the stockpiles should be no greater than the 2009 actual tons level, Staff Confidential Exhibit No. 102, Column (b).

In determining the value of each sites' stockpile, if the stockpile increased in tonnage between 2009 and 2010, the 2009 actual tonnage is used. (See Confidential Exhibit 102, Column (b)). The 2009 tonnage is then valued at the average cost per ton as of December 31, 2010. Column (b) is multiplied by Column (f) to determine the value of Staff's Stockpile Values in Column (i). If the stockpile decreased in tonnage between 2009 and 2010, the 2010 tonnage and dollars are used. (See Confidential Exhibit No. 102, Columns (d) and (e)). The Company's stockpile value of $188,279,981, Column (e) is $15,970,759, Column (j) more than Staff's stockpile value of $172,309,222, Column (i). Therefore, Staff is recommending a $15,970,759 reduction to the Company's rate base on a system basis, and an allocated reduction to the Idaho rate base of $1,015,344.

Q. Staff Exhibit No. 102, Column (h) shows reductions to six coal fuel stockpiles. Does your adjustment accept the Company's 2009 to 2010 tonnage reductions for these six stockpiles?

A. Yes. The reduction of stockpile size was a decision made by the Company. Staff's adjustment only questions the necessity of increasing the tonnage size of the stockpiles from 2009 actuals to 2010 pro formas. The customers should receive the benefit of the Company's ability to operate the six coal sites at the reduced tonnage levels; but should not bear the cost of the increase tonnage without just and reasonable cause for the increase.

Q. Why have you recommended that the rate base for the Dunlap I Wind Project be reduced by $1,000,000?

A. The Dunlap I Wind Project was constructed on real property purchased by the Company in 2008 and referred to as Dunlap Ranch. The original property included deeded property of approximately 15,000 acres or 23 sections of land and the right to lease one additional section plus two (2) smaller portions of property owned by the State of Wyoming. The Company also has leased two sections of property owned by the United States Bureau of Land Management (BLM). The Company used the deeded property for the placement of the Dunlap I Wind Project which consists of 74 wind tower sites. The State of Wyoming land was crossed by the transmission line serving the wind generators but no generators were sited on either the State of Wyoming or the BLM land. The 74 sites use property from only 10 of the 23 sections of land that was purchased. The transmission facilities are located on 5 of the 23 sections purchased. This leaves 8 sections of land without any generation or transmission facility within its 640 acres. Additionally, one section only has 2 generation sites located on it and these are located in the upper north east corner occupying less than 20 acres.

Staff recognizes that not all property will be equally suitable for the placement of wind generation, and that there may be other restrictions on the property that would curtail the number of wind generation sites. However, it appears to Staff that some of the land purchased is not currently used and useful in providing utility service. *Idaho Code* § 61-502A.

The Company included in rate base the entire purchase price for the Dunlap Ranch as used and useful, and as part of the cost for the Dunlap I wind facility (the purchase price for the Dunlap Ranch is in Company's Confidential Responses to IPUC Production Request 180). Page 1 of the Agreement to Sell and Purchase is shown as Confidential Exhibit No. 103, page 1. Staff is recommending that $1.0 million of that purchase price be excluded from rate base at this time and put into Account 105, Property Held for Future Use.

Q. You are recommending that the total Company's rate base be reduced by $240,497 to properly account for liquidated damages received by the Company as part of the 2009 Bridger Unit #2 overhaul. What are your reasons for this recommendation?

A. The Company contracted to overhaul Bridger Unit #2 in 2009. As part of that overhaul, the contractor doing the overhaul became liable to the Company for $625,000 in liquidated damages. After the overhaul was completed, the Company accounted for the repairs to Unit #2 by capitalizing the complete cost of the overhaul and adding the complete cost to rate base.

The Company accounted for the liquidated damages by reducing the cost of other jobs the contractor was doing. An amount of $264,254 was accounted for as a credit against the total cost of repairs to the Bridger Unit #1 Reheater. The balance of the liquidated damages was credited to other various smaller repairs and are not included in the accounting for any of the projects included by the Company in this case.

The appropriate accounting for the liquidated damages should have been to reduce the total cost of the Bridger Unit #2 overhaul by $625,000. Since the Bridger Unit #1 Reheater project is part of the 2010 capital projects included by the Company in rate base for this case, the credit of $264,254 applied to the total cost of this project undervalues its total cost.

The matching principles of accounting require the total liquidated damages of $625,000 be credited to the total cost of the Unit #2 overhaul, and a reduction to the amount included in rate base. With the total amount of the damages credited to the Unit #2 overhaul, the total cost of Unit #1 Reheader should not have received a credit of $264,254. Therefore, the total cost of Unit #1 included in rate base should be increased by $264,254. The difference between these two changes of $360,746 is a reduction in the Company's accounting for these two projects.

The Company owns two thirds (2/3) of the Jim Bridger facility, therefore the Company's rate base should be reduced by 2/3 of the reduction of $360,746. This equals a total reduction in the Company's rate base of $240,497 (system).

Q. Will this reduction in the Company's rate base request have any effect on the total Company's depreciation expense and accumulated depreciation?

A. Yes, the rate base reduction of $240,497 will reduce the depreciation expense by $5,690 (system). The composite depreciation rate for this capital expense is 2.366%. Accumulated depreciation is also reduced by this same amount.

Q. Why have you recommended that $662,119 be reduced from the Company's request for an increase in its operation and maintenance expenses (O&M expense)?

A. The Company has requested an increase in its O&M expenses in the amount of $7,333,392 (system) to cover its anticipated increase in O&M expenses for the following facilities: High Plains Wind, McFadden Ridge I Wind, Dunlap I Wind, Wind Administration, DJ Scrubber. The individual amounts requested for each facility are in Exhibit No. 2 of Company witness McDougal's testimony, page 4.6. These increases are intended to capture the increase in costs to operate these facilities that were recently placed in service. Some of the increases in costs are due to contractual obligations that become effective in 2010 and are not included in the case. These contractual obligations are for land lease payments, plant maintenance, weed control, pest control, and road and vehicle maintenance. The Company is legally obligated for each of these payments and the actual amount of the expenses is capable of being determined. I have determined that these contractual expenses are an acceptable known and measurable increase in the test year expenses.

The other increases in expenses claimed by the

Company are budgeted amounts for "labor, employee expense, and electrical parts, breakers, fuses, filters, gaskets, gear oils, propane etc." These expenses are not sufficiently known and measurable and should not be included in the Company's test year expenses. The Company has not shown that the 2009 test year expenses are insufficient to cover these costs.

Staff in Exhibit No. 103, page 2, shows the specific increases proposed by the Company with the removal of those expenses that are not known and measurable.

Staff Exhibit No. 103, page 2, details the difference between the Company's total O&M request and Staff's recommendation. That difference of $662,119 (system) is a reduction to the Company's total requested revenue requirement.

Q. What is your assessment of the Company's request to establish a regulatory asset or liability for interest paid to or received from the Internal Revenue Service (IRS) on adjustments made to the repairs deductions taken in the Company's 2008 and 2009 federal income tax returns?

A. The Company is asking to have a regulatory asset or liability account established for any changes in taxes and the interest it may receive or be liable to pay for changes in the repair deductions it is taking in its 2008 and 2009 income tax returns with the IRS. Because of the change it is implementing in the repair deduction, and as explained in Company witness Fuller's testimony (pages 2-6) there is the potential for either a refund with interest for overpayment of taxes or a cost with interest for underpayment of taxes. The final outcome is subject to a subsequent review and determination of the Company's repair deduction by the IRS. The establishment of the regulatory asset or liability accounts will allow the Company to track what the refund/cost will be and then include that refund/cost in the next rate case. Staff supports this accounting treatment. It allows the customers to receive the benefit of any refund, and protects the Company from any cost that may result from an IRS audit.

Staff recommends that no interest accrue on either the regulatory asset or liability account between the time any refund or cost is determined and the matter is considered in a rate case.

Q. The Company also requested Commission approval of its proposal to move to full normalization treatment of income taxes for purposes of setting rates. What is Staff's recommendation on this change?

A. Staff agrees that the Company's income taxes should be fully normalized. The Company's analysis of the reasons for such a change are in Company witness Fuller's testimony (pages 6-11). Witness Fuller, in his testimony, clearly provides reasonable justification for the Commission's approval. The primary justification from Staff's perspective is that the full normalization of income taxes matches the tax benefits and the tax burdens of the tax liability with the customers paying the associated costs. Normalization allows all ratepayers to receive benefits from an asset at the same effective tax rate.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

Pacificorp Rate Case
PAC-E-10-07

Updated In-service and Costs for 2010 Rate Base Additions

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	As Filed by Company				Updated Infomation		
Project Description	Acct.	Factor	In-Service Date	Costs	Updated In Service Date	Updated Forecast Amount	Change
Steam Production							
Dave Johnston: U3 SO2 & PM Emission Cntrl Upgrades	312	SG	May-10	$ 299,768,628	No Change	$ 299,083,211.00	$ (685,417.00)
Huntington U1 Clean Air - PM	312	SG	Nov-10	$ 88,104,324	No Change	$ 86,881,032.00	$ (1,223,291.91)
Hunter: 301 Turbine Upgrade HP/IP/LP	312	SG	Apr-10	$ 31,714,226	No Change	$ 30,384,402.00	$ (1,329,823.90)
Huntington: U1 Turbine Upgrade HP/IP/LP	312	SG	Nov-10	$ 31,260,581	No Change	$ 30,172,885.00	$ (1,087,695.84)
U1 Huntington Clean Air - SO2	312	SG	Nov-10	$ 24,325,082	various	$ 6,493,942.00	$ (17,831,139.59)
Jim Bridger: U1 SO2 & PM Em Cntrl Upgrades	312	SG	Jun-10	$ 17,148,123	No Change	$ 14,975,646.00	$ (2,172,476.63)
Dave Johnston: U3 Low Nox Burners	312	SG	Aug-10	$ 15,080,879	May-10	$ 17,586,539.00	$ 2,505,659.56
Hunter: 301 Main Controls Replacement	312	SG	Apr-10	$ 10,959,812	No Change	$ 9,559,675.00	$ (1,400,136.74)
Dave Johnston: U3 - Replace Boiler/Turbine Controls	312	SG	May-10	$ 10,767,578	No Change	$ 10,767,577.97	$ -
Jim Bridger: U1 Turbine Upgrade HP/IP	312	SG	Jun-10	$ 9,471,009	No Change	$ 9,140,208.00	$ (330,801.00)
Huntington: U1 Clean Air - NOx	312	SG	Nov-10	$ 9,344,387	No Change	$ 9,344,386.67	$ -
Jim Bridger: U1 Reheater Replacement 10	312	SG	Jun-10	$ 8,067,849	No Change	$ 8,067,848.64	$ -
Huntington: U1 Economizer Replacement	312	SG	Nov-10	$ 8,011,393	No Change	$ 8,011,392.55	$ -
Huntington Water Efficiency Mgt Project	312	SG	Jun-10	$ 7,614,560	No Change	$ 8,971,432.00	$ 1,356,872.24
Jim Bridger: U1 Clean Air - NOx	312	SG	Jun-10	$ 7,086,474	No Change	$ 6,042,280.00	$ (1,044,194.33)
Hunter: 301 Economizer Replacement	312	SG	Apr-10	$ 6,301,709	No Change	$ 6,301,708.64	$ -
Huntington: U1 Boiler Finish SH Pendants Replacement	312	SG	Nov-10	$ 6,147,658	No Change	$ 5,807,429.00	$ (340,229.16)
Jim Bridger: U1 Generator Rewind	312	SG	Jun-10	$ 6,145,656	No Change	$ 5,857,138.00	$ (288,517.67)
Hunter: 301 Low Temp. SH Replacement	312	SG	Apr-10	$ 5,470,067	No Change	$ 5,470,066.58	$ -
Dave Johnston: U3 - Horizontal SH Replace	312	SG	May-10	$ 5,088,802	No Change	$ 5,643,210.00	$ 554,408.45
Steam Production Total				**$ 607,878,794**		**$ 584,562,010.05**	**$ (23,316,783.52)**
							$ -
Hydro Production							$ -
INU 11.5 Lemolo 1 Forebay Expansion & We	332	SG-P	Aug-10	$ 5,897,387	No Change	$ 6,117,381.00	$ 219,993.92
Hydro Production Total				**$ 5,897,387**		**$ 6,117,381.00**	**$ 219,993.92**
							$ -
Other Production							$ -
Dunlap I Wind Project	343	SG	Nov-10	$ 261,183,699	Sep-10	$ 253,106,361.00	$ (8,077,338.00)
Other Production Total				**$ 261,183,699**		**$ 253,106,361.00**	**$ (8,077,338.00)**
							$ -
Transmission							$ -
Populus to Terminal (Populus to Ben Lomond)	355	SG	Nov-10	$ 405,230,248	No Change	$ 402,938,994.00	$ (2,291,253.87)
Populus to Terminal (Populus to Ben Lomond)	355	SG	Oct-10	$ 144,568,559	No Change	$ 145,199,007.00	$ 630,447.97
Populus to Terminal (Ben Lomond to Terminal)	355	SG	Mar-10	$ 190,877,118	No Change	$ 190,877,117.94	$ -
Populus to Terminal (Ben Lomond to Terminal)	355	SG	Apr-10	$ 7,340,277	No Change	$ 7,340,277.28	$ -
Populus to Terminal (Ben Lomond to Terminal residual closings)	355	SG		$ -	Dec-10	$ 6,727,289.00	$ 6,727,289.00
Three Peaks Sub: Install 345 kV Substation - Phase II	355	SG	Jun-10	$ 51,134,840	No Change	$ 51,134,840.12	$ -
Camp Williams - 90th South Double Circuit 345 kV line	355	SG	Dec-10	$ 45,600,000	No Change	$ 45,400,000.00	$ (200,000.29)
Red Butte -St George 138 kv dbl ckt, (345 kv Const)	355	SG	May-10	$ 21,038,986	No Change	$ 22,651,000.00	$ 1,612,014.20
Pinto 345 kV Series Capacitor	355	SG	Nov-10	$ 19,500,463	No Change	$ 15,028,000.00	$ (4,472,462.82)
Dunlap Ranch Wind Farm Phase 1 Interconnection	355	SG	Aug-10	$ 11,130,000	No Change	$ 10,500,000.00	$ (630,000.02)
Upper Green River Basin Superior Project - Transmission Part	355	SG	Dec-10	$ 10,025,204	No Change	$ 10,025,203.73	$ -
Oquirrh - New 345-138 kV Sub & 138 kV Switchyard	355	SG	Jun-10	$ 8,416,078	Dec-10	$ 8,416,077.87	$ -
Parrish Gap Const Nw 230-69kV Sub	355	SG	Jun-10	$ 8,340,559	Jul-10	$ 9,900,000.00	$ 1,559,440.71
Line 37 Conv to 115kV Bld Nickel Mt Sub - Trans	355	SG	Mar-10	$ 7,962,605	Jun-10	$ 9,570,202.87	$ 1,607,598.27
Chappel Creek 230 kV Cimarex Energy 20 MW Phase II	355	SG	Dec-10	$ 5,496,321	No Change	$ 5,496,321.29	$ -
Community Park Convert to 115-12.5 kV - Transmission Part	355	SG	Oct-10	$ 5,286,621	No Change	$ 3,686,621.00	$ (1,600,000.00)
Transmission Total				**$ 941,947,879**		**$ 944,890,952.10**	**$ 2,943,073.15**
							$ -
Intangible							$ -
TrIP II Energy Trading Systems Capital	303	SG	Dec-10	$ 11,470,408	Oct-10	$ 11,470,407.68	$ -
Intangible Total				**$ 11,470,408**		**$ 11,470,407.68**	**$ -**
							$ -
Mining							$ -
Deer Creek-Reconstruct Longwall System	399	SE	Dec-10	$ 23,905,000	No Change	$ 18,160,000.00	$ (5,745,000.00)
Mining Total				**$ 23,905,000**		**$ 18,160,000.00**	**$ (5,745,000.00)**
				$ 1,852,283,166		**$ 1,818,307,111.83**	**$ 33,976,054.45**
				Ref# 8.6			
Division of Rate Base by Allocation Factor		SG					$ (28,231,054)
		SE					$ (5,745,000)
							$ (33,976,054)

Exhibit No. 101
Case No. PAC-E-10-07
J. Leckie, Staff
10/14/10

Case No. PAC-E-10-07

Exhibit No. 102 prepared and sponsored by Joe Leckie is Confidential and only available to those persons who have signed Protective Agreements

Case No. PAC-E-10-07

Exhibit No. 103, page 1, prepared and sponsored by Joe Leckie is Confidential and only available to those persons who have signed Protective Agreements

Pacificorp
PAC-E-10-07

Schedule on Adjustment to the Incremental Generation O&M

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Facility		2009 Actuals	Accepted 2010 O&M	Increase Accepted	Company Request	Difference
High Plains		$ 401,303		$ 2,362,060	$ 2,621,060	$ (259,000)
	Contracts		$ 1,873,363			
	Land Lease; Utilities		$ 890,000			
			$ 2,763,363			
McFadden Ridge I		$ 203,806		$ 592,655	$ 648,655	$ (56,000)
	Contracts		$ 540,461			
	Land Lease; Utilities		$ 256,000			
			$ 796,461			
Dunlap I		$ -		$ 2,262,111	$ 2,435,111	$ (173,000)
	Contracts		$ 2,049,111			
	Land Lease; Utilities		$ 213,000			
			$ 2,262,111			
Wind Administration		$ 1,662,029	$ 1,662,029	$ -	$ 174,119	$ (174,119)
DJ Scrubber		$ -	$ 1,454,447	$ 1,454,447	$ 1,454,447	$ -
Total		$ 2,267,138	$ 8,938,411	$ 6,671,273		
Company's Request		$ 2,267,138	$ 9,600,530	$ 7,333,392		
Difference				$ (662,119)		$ (662,119)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14TH DAY OF OCTOBER 2010, SERVED THE FOREGOING **NON-CONFIDENTIAL DIRECT TESTIMONY OF JOE LECKIE**, IN CASE NO. PAC-E-10-07, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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