aps

Valencia Fisker
Director
Federal Regulation

Mail Station 8995
P.O. Box 53999
Phoenix, AZ 85072-3999
Tel 602-250-4643
Lindy.Fisker@aps.com

UTAH PUBLIC SERVICE COMMISSION

2011 JUL -6 P 1:52

RECEIVED

290148

June 29, 2011

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Docket No. 11-999-01

Re: Modifications to the Long-Term Power Transactions Agreement between Arizona Public Service Company and PacifiCorp
Docket No. ER11-____

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. Part 35 (2011), Arizona Public Service Company ("APS" or "Company") hereby files proposed revisions to the Long-Term Power Transactions Agreement ("Agreement") between APS and PacifiCorp ("PAC") designated as FERC Electric Rate Schedule No. 182.

I. Background:

On March 19, 1991, the Commission accepted this Agreement, between APS and PAC, and designated it as APS FERC Rate Schedule No. 182. The Agreement provides for power sales between APS and PAC. This filing addresses the APS rates for sales of Supplemental Coal Energy ("SCE") and Other Supplemental Energy ("OSE") under the Agreement. Though APS offers PAC SCE and OSE on a daily basis, PAC is under no obligation to buy either product.

Pursuant to the Agreement, APS is permitted to recover its actual incremental costs (incremental fuel by the Company plus an Operation and Maintenance ("O&M") adder) to produce SCE or OSE, plus a percentage adder cost that would be treated as a contribution towards the fixed costs of the units producing SCE and OSE. The Agreement provides for changes to the O&M costs upon a timely filing with the Commission for approval. Thus, APS is seeking FERC's approval to increase the O&M adder from combined cycle and gas/oil fired steam resources and to decrease the O&M adder from coal fired steam and combustion turbine resources, as allowed in Sections 6.7 and 6.8 of the Agreement.

II. Communications:

Communications regarding this filing should be sent to the following individuals:

Valencia R. Fisker
Director, Federal Regulation
Arizona Public Service Company
400 North 5th Street
Mail Station 8995
Phoenix, AZ 85004
Phone: (602) 250-4643
Lindy.Fisker@aps.com

Thomas A. Loquvam
Senior Attorney
Pinnacle West Capital Corporation
400 North 5th Street
Mail Station 8695
Phoenix, AZ 85004
Phone: (602) 250-3616
Thomas.Loquvam@pinnaclewest.com

III. Proposed Change to Contract Rates:

Appendix E of the Agreement sets forth the methodology for establishing the incremental cost of supplemental energy provided by APS to PAC. Variable O&M expenses from the APS FERC Form No. 1, exclusive of fuel, were aggregated and divided by net generation to determine incremental O&M cost for the different types of generation resources anticipated to be utilized to provide such power, i.e., coal fired steam units, gas/oil fired steam units, combustion turbine units and combined cycle units. A cost justification is included as an attachment to this filing. The existing and proposed values are as follows:

Type of Generation Resource	Existing	O&M Factor (Mills/kWh) Proposed
Coal Fired Steam Units	5.07	4.68
Gas/Oil Fired Steam Units	13.95	21.94
Combustion Turbine Units	13.09	11.99
Combined Cycle Units	2.96	4.36

IV. Contents of Filing:

Included in this filing is (1) the APS Rate Schedule No. 182, (2) a red-lined copy of the affected sections, (3) a conformed copy of the agreement, (4) the applicable worksheets utilized in support of the proposed changes and (5) the rate impact calculation based on the most recently available historic twelve month sales period (April 2010 through March 2011).

V. Conclusion:

APS requests waiver of any additional reporting requirements in 18 C.F.R. §35.13(a), that may otherwise be required. APS respectfully requests an effective date of September 1, 2011 to implement these changes.

Sincerely,

Valencia R. Fisker

Valencia R. Fisker
Director, Federal Regulation
Arizona Public Service Company

Cc:

Steve Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

PacifiCorp
Commercial and Trading
Director, Marketing & Trading Contracts
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232

Public Utility Commission of Oregon
550 Capital Street NE, Suite 215
Salem, Oregon 97301-2551

Utah Public Service Commission
Heber M Wells Building, 4th Floor
160 East 300 South
Salt Lake City, Utah 84111

Washington Utilities and Transportation Commission
1300 South Evergreen Park Drive SW
Olympia, Washington 98504-7520

Montana Public Service Commission
P.O. Box 202601
Helena, Montana 59620-2601

Public Service Commission of Wyoming

Hansen Building
2515 Warren Avenue, Suite 300
Cheyenne, Wyoming 82002

Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0074

Wesley Franklin, Executive Director
California Public Utilities Commission
State Building
505 Van Ness Avenue, Room 5222
San Francisco, California 94102

Information Required In Accordance With

18 C.F.R. §35.13(a)(2)(ii)

FILING INFORMATION UNDER SECTION 35.13(a)(2)(ii)

I. General Information:

Arizona Public Service Company ("APS") requests regulatory approval to revise rate components inherent in charges to PacifiCorp for sales of Supplemental Coal Energy ("SCE") and Other Supplemental Energy ("OSE") as provided for in the Long-Term Power Transactions Agreement ("Agreement") between the parties previously accepted by the Commission in Docket Nos. ER03-347-000, ER08-1610-000, ER09-1567-000, and ER10-1386-000.

APS is requesting an effective date of September 1, 2011.

II. Estimates of the Transactions and Revenues:

The Attachments provided demonstrate the revenue impact for SCE and OSE transactions based on the most recent available 12 months of billing information.

III. Basis of the Proposed Rates, Explanation of How the Proposed Rates Were Derived and Rate Design Information:

The basic rate design is unchanged from that inherent in the Agreement. APS is seeking revisions to O&M factors as authorized in the Agreement upon a timely filing with the Commission.

Pursuant to the Agreement, APS may recover its actual incremental costs (incremental fuel incurred by the Company plus an O&M adder) to produce SCE or OSE, plus a percentage adder to be applied to incremental costs that would be treated as a contribution toward the fixed costs of the units producing this energy.

Proposed Change to O&M factors:

Appendix E of the Agreement sets forth the methodology for establishing the incremental cost of supplemental energy provided by APS to PacifiCorp. Variable O&M expenses from the APS FERC Form No. 1, exclusive of fuel, were aggregated and divided by net generation to determine incremental O&M cost for the different types of generation resources anticipated to be utilized to provide such power, i.e., coal fired steam units, gas/oil fired steam units, combustion turbine units and combined cycle units. Each type of generation resource has a specific O&M adder. Appendix E, Sections 1.1 and 1.2 provide for revisions in the O&M factors upon a timely filing demonstrating cost support for the proposed revisions. Cost justification demonstrates the support for changes to the O&M factors for the different types of generation resources that would be used to provide supplemental energy under the Agreement. The proposed values are as follows:

Type of Generation Resource	Proposed O&M Factor (Mills/kWh)
Coal Fired Steam Units	4.68
Gas/Oil Fired Steam Units	21.94
Combustion Turbine Units	11.99
Combined Cycle Units	4.36

IV. Comparison of the Proposed Rate with Other Rates for Similar Services:

The terms and conditions for service under this Agreement are unique, and APS has no other agreements providing similar service.

V. Any Specifically Assignable Facilities to be Installed or Modified in Order to Supply Service under the Proposed Rate Schedule:

No new facilities or modifications to existing facilities are required in order to implement the proposed rate changes.

Cost Justification

ARIZONA PUBLIC SERVICE COMPANY
DETERMINATION OF "DEEMED" NON-FUEL INCREMENTAL O&M FACTORS
APPLICABLE TO PAC AGREEMENT

	Type of Energy/Type of Resource	(1) Net Generation (kWh) /1/	(2) Variable O&M Expenses ($) /2/	(3) Cost Supportable O&M Factor $/MWh [(2) / (1)] * 1000	(4) Current O&M Factor $/MWh
	Supplemental Coal Energy (SCE):				
1	Cholla 1, 2, 3	4,499,920,301	19,739,985		
2	Four Corners 1, 2, 3	4,214,059,298	23,007,365		
3	Four Corners 4, 5	1,465,077,030	7,062,676		
4	Navajo 1, 2, 3	2,204,307,999	8,187,585		
5	**TOTAL**	**12,383,364,628**	**57,997,612**	**4.68**	**5.07**
	Other Supplemental Energy (OSE):				
	Gas/Oil Fired Steam:				
6	Ocotillo 1-2	51,643,000	1,045,293		
7	Saguaro 1-2	0	87,910		
8	**TOTAL**	**51,643,000**	**1,133,204**	**21.94**	**13.95**
	Combustion Turbines:				
9	Yucca	88,997,000	(151,523)		
10	Douglas	359,000	11,188		
11	Ocotillo	3,805,000	337,579		
12	West Phoenix	3,399,000	193,615		
13	Saguaro 1-2	1,058,000	54,450		
14	Saguaro 3	7,029,000	170,122		
15	Sundance	107,797,000	1,932,590		
16	**TOTAL**	**212,444,000**	**2,548,022**	**11.99**	**13.09**
	Combined Cycle:				
17	West Phoenix 1-3	285,038,702	726,443		
18	West Phoenix 4-5	1,431,253,000	5,124,925		
19	Redhawk 1-2	3,376,012,000	16,351,918		
20	**TOTAL**	**5,092,303,702**	**22,203,286**	**4.36**	**2.96**
21	***Coal Fired Steam: /3/***				

/1/ 2009 FERC Form 1, pp.402 - 403.3, line 12
/2/ 2009 FERC Form 1, pp.402 - 403.3, lines 29, 31, & 32
/3/ Use the same O&M factor as that for SCE line 5.

Revenue Impact

Supplemental Coal Energy
Supplemental Coal

	1	2	3	4	5	6
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	950	5.070	15.367	20.437	30%	25,239.28
May	0	5.070	0.000	5.070	30%	0.00
June	0	5.070	18.909	23.979	30%	0.00
July	300	5.070	18.107	23.177	30%	9,039.13
August	150	5.070	20.598	25.668	30%	5,005.33
September	0	5.070	19.103	24.173	30%	0.00
October	0	5.070	18.163	23.233	30%	0.00
November	0	5.070	17.695	22.765	30%	0.00
December	4,100	5.070	19.343	24.413	30%	130,122.75
January 2011	2,950	5.070	19.233	24.303	30%	93,200.67
February	270	5.070	20.035	25.105	30%	8,811.90
March	850	5.070	18.336	23.406	30%	25,863.82
SUBTOTAL	9,570					297,282.89

	7	8	9	10	11	12
		Proposed SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	950	4.680	15.367	20.047	30%	24,757.63
May	0	4.680	0.000	4.680	30%	0.00
June	0	4.680	18.909	23.589	30%	0.00
July	300	4.680	18.107	22.787	30%	8,887.03
August	150	4.680	20.598	25.278	30%	4,929.28
September	0	4.680	19.103	23.783	30%	0.00
October	0	4.680	18.163	22.843	30%	0.00
November	0	4.680	17.695	22.375	30%	0.00
December	4,100	4.680	19.343	24.023	30%	128,044.05
January 2011	2,950	4.680	19.233	23.913	30%	91,705.02
February	270	4.680	20.035	24.715	30%	8,675.01
March	850	4.680	18.336	23.016	30%	25,432.87
SUBTOTAL	9,570					292,430.90

Other Supplemental Energy
Supplemental Coal

	1	2	3	4	5	6
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	783	5.070	23.561	28.631	15%	25,780.43
May	81	5.070	25.996	31.066	15%	2,893.80
June	0	5.070	33.962	39.032	15%	0.00
July	0	5.070	36.012	41.082	15%	0.00
August	1,209	5.070	26.423	31.493	15%	43,786.94
September	2,713	5.070	23.203	28.273	15%	88,209.51
October	750	5.070	20.150	25.220	15%	21,751.88
November	6,735	5.070	18.723	23.793	15%	184,279.26
December	3,154	5.070	17.800	22.870	15%	82,953.25
January 2011	1,062	5.070	21.784	26.854	15%	32,797.20
February	920	5.070	16.993	22.063	15%	23,342.61
March	577	5.070	16.716	21.786	15%	14,455.84
SUBTOTAL	17,984					520,250.72

	7	8	9	10	11	12
		Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	783	4.680	23.561	28.241	15%	25,429.26
May	81	4.680	25.996	30.676	15%	2,857.47
June	0	4.680	33.962	38.642	15%	0.00
July	0	4.680	36.012	40.692	15%	0.00
August	1,209	4.680	26.423	31.103	15%	43,244.70
September	2,713	4.680	23.203	27.883	15%	86,992.73
October	750	4.680	20.150	24.830	15%	21,415.50
November	6,735	4.680	18.723	23.403	15%	181,258.61
December	3,154	4.680	17.800	22.480	15%	81,538.69
January 2011	1,062	4.680	21.784	26.464	15%	32,320.89
February	920	4.680	16.993	21.673	15%	22,929.99
March	577	4.680	16.716	21.396	15%	14,197.05
SUBTOTAL	17,984					512,184.90

Other Supplemental Energy
Combustion Turbine

	1	2	3	4	5	6
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	362	13.090	23.561	36.651	15%	15,257.65
May	770	13.090	25.996	39.086	15%	34,610.65
June	496	13.090	33.962	47.052	15%	26,838.73
July	397	13.090	36.012	49.102	15%	22,417.67
August	0	13.090	26.423	39.513	15%	0.00
September	0	13.090	23.203	36.293	15%	0.00
October	-81	13.090	20.150	33.240	15%	-3,096.27
November	-96	13.090	18.723	31.813	15%	-3,512.11
December	72	13.090	17.800	30.890	15%	2,557.73
January 2011	292	13.090	21.784	34.874	15%	11,710.80
February	0	13.090	16.993	30.083	15%	0.00
March	46	13.090	16.716	29.806	15%	1,576.72
SUBTOTAL	2,258					108,361.57

	7	8	9	10	11	12
		Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	362	11.990	23.561	35.551	15%	14,799.72
May	770	11.990	25.996	37.986	15%	33,636.60
June	496	11.990	33.962	45.952	15%	26,211.29
July	397	11.990	36.012	48.002	15%	21,915.46
August	0	11.990	26.423	38.413	15%	0.00
September	0	11.990	23.203	35.193	15%	0.00
October	-81	11.990	20.150	32.140	15%	-2,993.80
November	-96	11.990	18.723	30.713	15%	-3,390.67
December	72	11.990	17.800	29.790	15%	2,466.65
January 2011	292	11.990	21.784	33.774	15%	11,341.42
February	0	11.990	16.993	28.983	15%	0.00
March	46	11.990	16.716	28.706	15%	1,518.53
SUBTOTAL	2,258					105,505.20

Other Supplemental Energy
Combined Cycle

	1	2	3	4	5	6
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	3,217	2.960	23.561	26.521	15%	98,114.32
May	1,930	2.960	25.996	28.956	15%	64,267.84
June	4,745	2.960	33.962	36.922	15%	201,476.71
July	6,590	2.960	36.012	38.972	15%	295,351.74
August	760	2.960	26.423	29.383	15%	25,681.15
September	3,164	2.960	23.203	26.163	15%	95,195.71
October	2,516	2.960	20.150	23.110	15%	66,865.23
November	1,284	2.960	18.723	21.683	15%	32,016.46
December	558	2.960	17.800	20.760	15%	13,321.95
January 2011	781	2.960	21.784	24.744	15%	22,224.13
February	3,380	2.960	16.993	19.953	15%	77,557.17
March	698	2.960	16.716	19.676	15%	15,793.61
SUBTOTAL	29,623					1,007,866.01

	7	8	9	10	11	12
		Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	3,217	4.360	23.561	27.921	15%	103,293.69
May	1,930	4.360	25.996	30.356	15%	67,375.14
June	4,745	4.360	33.962	38.322	15%	209,116.16
July	6,590	4.360	36.012	40.372	15%	305,961.64
August	760	4.360	26.423	30.783	15%	26,904.75
September	3,164	4.360	23.203	27.563	15%	100,289.75
October	2,516	4.360	20.150	24.510	15%	70,915.99
November	1,284	4.360	18.723	23.083	15%	34,083.70
December	558	4.360	17.800	22.160	15%	14,220.33
January 2011	781	4.360	21.784	26.144	15%	23,481.54
February	3,380	4.360	16.993	21.353	15%	82,998.97
March	698	4.360	16.716	21.076	15%	16,917.39
SUBTOTAL	29,623					1,055,559.04

Other Supplemental Energy
Gas/Oil Fired Steam

	1	2	3	4	5	6		7	8	9	10	11	12
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue			Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]					(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)		MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	0	13.950	23.561	37.511	15%	0.00	**April 2010**	0	21.940	23.561	45.501	15%	0.00
May	0	13.950	25.996	39.946	15%	0.00	**May**	0	21.940	25.996	47.936	15%	0.00
June	0	13.950	33.962	47.912	15%	0.00	**June**	0	21.940	33.962	55.902	15%	0.00
July	0	13.950	36.012	49.962	15%	0.00	**July**	0	21.940	36.012	57.952	15%	0.00
August	0	13.950	26.423	40.373	15%	0.00	**August**	0	21.940	26.423	48.363	15%	0.00
September	0	13.950	23.203	37.153	15%	0.00	**September**	0	21.940	23.203	45.143	15%	0.00
October	0	13.950	20.150	34.100	15%	0.00	**October**	0	21.940	20.150	42.090	15%	0.00
November	0	13.950	18.723	32.673	15%	0.00	**November**	0	21.940	18.723	40.663	15%	0.00
December	0	13.950	17.800	31.750	15%	0.00	**December**	0	21.940	17.800	39.740	15%	0.00
January 2011	0	13.950	21.784	35.734	15%	0.00	**January 2011**	0	21.940	21.784	43.724	15%	0.00
February	0	13.950	16.993	30.943	15%	0.00	**February**	0	21.940	16.993	38.933	15%	0.00
March	0	13.950	16.716	30.666	15%	0.00	**March**	0	21.940	16.716	38.656	15%	0.00
SUBTOTAL	0					0.00	**SUBTOTAL**	0					0.00

Other Supplemental Energy
T&C

	1	2	3	4	5	6		7	8	9	10	11	12
		Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue			Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]					(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)		MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	71	0.000	23.561	23.561	15%	1,923.72	**April 2010**	71	0.000	23.561	23.561	15%	1,923.72
May	0	0.000	25.996	25.996	15%	0.00	**May**	0	0.000	25.996	25.996	15%	0.00
June	0	0.000	33.962	33.962	15%	0.00	**June**	0	0.000	33.962	33.962	15%	0.00
July	0	0.000	36.012	36.012	15%	0.00	**July**	0	0.000	36.012	36.012	15%	0.00
August	0	0.000	26.423	26.423	15%	0.00	**August**	0	0.000	26.423	26.423	15%	0.00
September	0	0.000	23.203	23.203	15%	0.00	**September**	0	0.000	23.203	23.203	15%	0.00
October	111	0.000	20.150	20.150	15%	2,572.09	**October**	111	0.000	20.150	20.150	15%	2,572.09
November	0	0.000	18.723	18.723	15%	0.00	**November**	0	0.000	18.723	18.723	15%	0.00
December	0	0.000	17.800	17.800	15%	0.00	**December**	0	0.000	17.800	17.800	15%	0.00
January 2011	0	0.000	21.784	21.784	15%	0.00	**January 2011**	0	0.000	21.784	21.784	15%	0.00
February	112	0.000	16.993	16.993	15%	2,188.69	**February**	112	0.000	16.993	16.993	15%	2,188.69
March	25	0.000	16.716	16.716	15%	480.57	**March**	25	0.000	16.716	16.716	15%	480.57
SUBTOTAL	248					5,241.36	**SUBTOTAL**	248					5,241.36

Annual Revenue Current	1,939,002.55
Annual Revenue Proposed	1,970,921.40
Revenue Impact	**31,918.85**

Marked Tariff Section

APPENDIX E: INCREMENTAL COST OF SUPPLEMENTAL ENERGY AND UNUSED CHOLLA CAPABILITY

This Appendix sets forth the method for establishing Incremental Cost ($/MWh) of Supplemental Energy to be made available by APS pursuant to Subsections 6.7 and 6.8 of this Agreement and the Incremental Cost ($/MWh) of energy associated with either Party's use of the other Party's unused generating capability at the Cholla Generating Station ("Unused Cholla Capability") pursuant to Subsection 13.06 of the Asset Agreement.

The Incremental Cost for each megawatt-hour of each transaction shall equal the sum of (1) the deemed incremental operating and maintenance expense ($/MWh) as determined in Section 1.0 below, and (2) the Incremental Fuel Cost ($/MWh) as determined in Section 2.0 below.

1.0 Incremental Operating and Maintenance Expense. The incremental operating and maintenance expense associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows: .

1.1 Supplemental Coal Energy. For all Supplemental Coal Energy, the incremental operating and maintenance expense shall be deemed to be $~~5.07~~4.68 per megawatt-hour. Any revision to the deemed $~~5.07~~4.68 per megawatt hour incremental operating and maintenance expense for Supplemental Coal Energy shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates that the proposed revisions are reasonable given APS' costs.

1.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental operating and maintenance expense shall be deemed to be $~~13.95~~21.94 per megawatt-hour for gas and oil fired steam units, $~~13.09~~11.99 for all single cycle combustion turbines and $~~2.96~~4.36 for all combined cycle units. Any revision to the deemed incremental operating and maintenance expense for gas and oil fired steam units, for combustion turbines, and for combined cycle units shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates that the proposed revisions are reasonable given APS' costs. Within three years of the Effective Date of this Agreement, the parties shall review the appropriateness of the foregoing deemed values and make adjustments that are equitable.

1.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental operating and maintenance expense shall be deemed to be $3.56 per megawatt-hour. Any revision to the deemed incremental operating and maintenance expense shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates the proposed revisions are reasonable.

2.0 Incremental Fuel Cost. The incremental fuel cost associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows:

2.1 Supplemental Coal Energy. For all Supplemental Coal Energy the incremental fuel cost ($/MWh) shall be determined by the APS dispatcher or scheduler based on his best-efforts forecast of the incremental coal cost and the incremental heat rate associated with the lowest cost generating unit(s) expected to be producing such energy.

2.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental fuel cost ($/MWh) shall be determined by the APS dispatcher or scheduler based upon his best-efforts forecast of the incremental fuel cost, either Natural Gas, Oil or Coal, utilizing the incremental heat rate associated with the lowest cost generating unit(s) that is expected to be producing such energy.

2.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental fuel cost ($/MWh) shall be determined by the Party's dispatcher or scheduler having such Unused Cholla Capability based on his best-efforts forecast of the incremental coal cost utilizing the incremental heat rate of the generating unit(s) that would produce such energy.

Conformed Tariff

APS CONTRACT N0. 48017

LONG-TERM POWER TRANSACTIONS AGREEMENT

BETWEEN

ARIZONA PUBLIC SERVICE COMPANY

AND

PACIFICORP

FERC Rate Schedule No. 182

LONG-TERM POWER TRANSACTIONS AGREEMENT

BETWEEN

PACIFICORP

AND

ARIZONA PUBLIC SERVICE COMPANY

EXECUTION COPY

LONG-TERM POWER TRANSACTIONS AGREEMENT

BETWEEN

PACIFICORP

AND

ARIZONA PUBLIC SERVICE COMPANY

Index to Sections

Section

LONG-TERM POWER TRANSACTIONS AGREEMENT
BETWEEN
PACIFICORP
AND
ARIZONA PUBLIC SERVICE COMPANY

THIS LONG-TERM POWER TRANSACTIONS AGREEMENT ("Agreement"), dated this 21st day of September, 1990, is between PacifiCorp Electric Operations, an assumed business name of PacifiCorp, an Oregon corporation (PacifiCorp) and Arizona Public Service Company, an Arizona corporation (APS). APS and PacifiCorp are sometimes referred to collectively as "Parties" and individually as "Party."

WHEREAS, PacifiCorp and APS are engaged in the generation, transmission and distribution of electric power and energy; and

WHEREAS, the Parties have resolved to enhance the efficient operation of their respective systems by taking advantage of the diversity of their respective loads and generation facilities; and

WHEREAS, the electric power needs of PacifiCorp's customers are highest in the winter months and the electric power needs of APS' customers are highest in the summer months; and

WHEREAS, the power supplies available to the Parties to meet their respective customer needs are diverse; and

WHEREAS, the Parties believe that various power transactions between interconnected electric utilities whose peak power needs and power supplies are different would be beneficial to the Parties' respective customers; and

WHEREAS, the Parties have entered into a series of contracts on this date to achieve such efficiencies; and

WHEREAS, the Parties intend to continue to study and discuss additional arrangements which will enhance efficiency and inure to the benefit of their respective customers,

NOW, THEREFORE, PacifiCorp and APS agree as follows:

Section 1: Definitions

As used herein, the following terms have the following meanings when used with initial capitalization, whether singular or plural:

1.1 "Agreement" means this agreement between PacifiCorp and APS.

1.2 "Annual Fixed Cost" for the calendar years 1996 through the Term of this Agreement, means the fully distributed weighted fixed cost, as determined and set forth in Appendix A, of the resources contained in the Resource Pool in such calendar year, with the costs of new resources, if any, added to the Resource Pool pursuant to Appendix C, being determined by a methodology substantially identical to that set forth in Appendix A.

1.3 "Annual Variable Cost" means, in the calendar years 1996 through the Term of this Agreement, the weighted variable cost, as determined and set forth in Appendix B, of the resources contained in the Resource Pool in such calendar year, with such costs of new resources, if any, added to the Resource Pool pursuant to Appendix C, being determined by a methodology substantially identical to that set forth in Appendix B.

1.4 "Asset Agreement" means the Asset Purchase and Power Exchange Agreement between the Parties dated September 21, 1990.

1.5 "Estimated Annual Fixed Cost" means PacifiCorp's estimate of the Annual Fixed Cost, based on the best information available to PacifiCorp at the time such estimates are made pursuant to Subsection 5.3, to be used for billing purposes as set forth in Section 8.

1.6 "Estimated Annual Variable Cost" means PacifiCorp's estimate of the Annual Variable Cost, based on the best information available to PacifiCorp at the time such estimates are made pursuant to Subsection 5.3, to be used for billing purposes as set forth in Section 8.

1.7 "Exchange Capacity" means capacity with Exchange Energy to be made available on a seasonal basis during the Term of this Agreement by each Party to the other and at no charge pursuant to the terms of Subsections 3.2 and 3.3.

1.8 "Exchange Energy" means energy associated with Exchange Capacity as set forth in Subsections 3.2 and 3.3.

1.9 "Firm Capacity" means capacity that is made available to APS by PacifiCorp to facilitate associated deliveries of Firm Energy as set forth in Section 3.

1.10 "Firm Energy" means the energy associated with Firm Capacity as set forth in Section 4.

1.11 "Point of Delivery" for all transactions hereunder means (1) Four Corners; (2) the Glen Canyon Substation or, in the event the Navajo Loop-In Project is constructed, Navajo; (3) the Pinnacle Peak Substation of the Western Area Power

Administration; (4) such other location(s) as may be established by mutual agreement of the Parties' dispatchers, schedulers, or authorized representatives; and (5) the Cholla Generating Station 500 Kv switchyard under the circumstances described in Subsection 15.03 of the Asset Agreement and Subsection 7.5 of this Agreement.

1.12 "Resource Pool" means a combination of resources available to PacifiCorp as defined in Appendix C.

1.13 "Seasonal Capacity Exchange" means the exchange of seasonal capacity as described in Subsections 3.2 and 3.3.

1.14 "Summer Season" means the May 1 through October 31 period of each of the calendar years of this Agreement.

1.15 "Supplemental Energy" means energy to be made available by APS to PacifiCorp as described in Section 6.

1.16 "Week" means a consecutive seven day period commencing on Sunday.

Section 2: Effective Date and Termination

2.1 Term of this Agreement. This Agreement shall be effective upon the Closing Date of the Asset Agreement and, except as provided in Subsections 2.2 and 3.2.4 and the final billing adjustment as provided in Subsection 8.2, shall terminate at 2400 hours MST, October 31, 2020.

2.2 Regulatory Approval and Termination.

2.2.1 Federal Energy Regulatory Commission Filing. PacifiCorp shall file this Agreement with the Federal Energy Regulatory Commission (FERC). APS shall file a letter of concurrence supporting PacifiCorp's filing of this Agreement with the FERC.

If the FERC issues an order not accepting this Agreement for filing in its entirety and without material change, the Parties shall exercise best efforts to amend the Agreement to comply with the FERC order or negotiate a replacement agreement providing similar benefits to both Parties. In the event such amendment or replacement agreement is not executed by the Parties within sixty days following the FERC's issuance of such order, or the Asset Agreement is terminated, this Agreement shall terminate.

Section 3: Capacity

3.1 Firm Capacity. For calendar years 1991 through 1995, PacifiCorp shall make available at the Point(s) of Delivery, and APS shall purchase 175 MW of Firm Capacity for the Summer Season of each calendar year. Except as provided in Subsection 3.2, commencing in calendar year 1996 and continuing through calendar year 1999, APS may increase the Firm Capacity amount up to a maximum amount equal to the rated capacity of Cholla Unit 4 for any year in increments of not less than 50 MW per calendar year upon providing PacifiCorp three years prior written notice. If APS increases its purchase of Firm Capacity under this Agreement above the 175 MW, such Firm Capacity amount will establish the then-effective Firm capacity purchase requirement which may not be thereafter reduced. Except as provided in Subsection 3.2, the amount of Firm Capacity made available for calendar year 1999 will establish the Firm Capacity amount for the remaining Term of this Agreement. In the event of an Uncontrollable Force, deliveries of Firm Capacity hereunder shall have priority over PacifiCorp's other firm wholesale contracts with terms of 10 years or less and equal priority with PacifiCorp's other firm wholesale contracts with terms greater than 10 years.

3.2 Exchange Option. Upon providing PacifiCorp three years advance written notice, APS may convert all or portions thereof of the Firm Capacity, to Exchange Capacity in increments of not less than 50 MW per calendar year, and the parties shall engage in a one-for-one Seasonal Capacity Exchange for the remaining Term of this Agreement. Any such conversion shall not be effective prior to calendar year 1996 and shall be effective for a full Summer or Winter Period as set forth in Subsections 3.2.1 and 3.2.2, respectively. Any amounts of Firm Capacity which are converted to Exchange Capacity may not be converted back to Firm Capacity. Exchange Capacity shall be made available at no charge to either Party in accordance with the provisions set forth below.

3.2.1 Summer Deliveries. PacifiCorp shall make Exchange Capacity available to APS during the period of May 15 through September 15 ("Summer Period"). Associated deliveries of Exchange Energy shall not exceed a load factor of 50 percent for each Week or any partial Week at the beginning or end of the Summer Period, and shall not exceed a load factor of 40 percent for any month or partial month thereof. By mutual agreement, a Party may pay for a portion of the Exchange Energy in lieu of returning it.

3.2.2 Winter Deliveries. APS shall make Exchange Capacity available to PacifiCorp from October 15 through the following February 15 ("Winter Period"). Associated deliveries of Exchange Energy shall not exceed a load factor of 50 percent for each Week or any partial Week at the beginning or end of the Winter Period, and shall not exceed a load factor of 40 percent for any month or partial month thereof. By mutual agreement, a Party may pay for Exchange Energy in lieu of returning it.

3.2.3 Delayed Return of Exchange Energy. The return of Exchange Energy delivered in the Winter or Summer Periods under Subsections 3.2.2 and 3.2.1 shall be delayed to the next following Summer or Winter Periods, respectively. The delivery of such Exchange Energy shall be coincident with and a part of any Exchange Capacity made available by the other Party under Subsections 3.2.1 and 3.2.2. Either Party's failure to schedule the return of such Exchange Energy owed to it from the preceding season shall operate as a waiver of the right to receive the return of such Exchange Energy, except that if such schedules cannot be made because of an Uncontrollable Force, it shall not constitute a wavier.

3.2.4 Final Settlement. At the end of the Term of this Agreement, if any Exchange Energy is owed to PacifiCorp from the immediate preceding period, the term of the Exchange Capacity obligations shall be extended until all Exchange Energy is returned, subject to the delivery rates set forth in Subsection 3.2.2.

3.3 Increased Capacity Exchange. Upon the later of (i) the completion of the Mead/Phoenix Line or (ii) May 15, 1997, and for the balance of the term of this Agreement, 100 megawatts of Exchange Capacity shall be made available in addition to any Exchange Capacity available as a result of the exchange option provided for in Subsection 3.2, subject to the same terms and conditions set forth in Subsections 3.2.1, 3.2.2, 3.2.3 and 3.2.4.

Section 4: Firm Energy

Delivery Provisions. Commencing May 1, 1991, and continuing through the Term of this Agreement, except as provided in Subsection 3.2, PacifiCorp shall make available Firm Energy associated with Firm Capacity as scheduled by APS at load factors not to exceed 100 percent per hour, 80 percent per month, and 70 percent per Summer Period and APS shall purchase such Firm Energy at load factors of not less than 40 percent per month, and 50 percent per Summer Period. Subsequent to 1996, the maximum monthly and Summer Period load factors of Firm Energy to be made available by PacifiCorp shall be increased to 100 percent and 85 percent respectively.

Section 5: Prices

APS shall be obligated to pay PacifiCorp for the Firm Capacity and Firm Energy as follows:

5.1 May 1, 1991 through October 31, 1995. During the Summer Season for each year of the calendar years 1991 through 1995, APS shall pay for all Firm Capacity the fixed prices expressed in \$/KW/mo as set forth below:

Year	\$/KW/mo
1991	10.87
1992	10.55
1993	10.19
1994	9.84
1995	9.51

The Firm Energy price for each of the calendar years 1991 through 1995 shall be the actual production expense for such year of Cholla Unit 4 as determined pursuant to the methodology set forth in Appendix B of this Agreement; provided, that in the event the capacity factor of Cholla Unit 4 in any calendar year is less than 40 percent, the Firm Energy price shall be the actual production expense of the resource having the highest actual production expense with a capacity factor equal to or greater than 40 percent for such year as determined pursuant to the methodology set forth in Appendix B among the other resources contained in the identified Resource Pool for 1996.

5.2 May 1, 1996 through October 31, 2020. During the Summer Season for each year of the calendar years 1996 through 2020, the payment prices for Firm Capacity as set forth in Subsection 3.1 and Firm Energy as set forth in Section 4 shall be the Annual Fixed Cost ($/KW/mo) and the Annual Variable cost ($/MWh) respectively.

5.3 Estimated Capacity Price and Energy Price. Unless all Firm Capacity has been converted to Exchange Capacity pursuant to Subsection 3.2, PacifiCorp shall provide APS with the following capacity and energy price estimates to be used for billing purposes prior to the time that actual costs are available:

5.3.1 May 1, 1991 through October 31, 1995. PacifiCorp shall provide to APS no later than March 1, 1991 and by each March 1 thereafter through calendar year 1995, estimates of the Cholla Unit 4 production expense to be used for billing purposes for the following Summer Season.

5.3.2 May 1, 1996 through October 31, 2020. PacifiCorp shall provide to APS no later than April 15, 1993 and by each April 15 thereafter an estimate of the capacity price ("Estimated Annual Fixed Cost") and an estimate of the energy price ("Estimated Annual Variable Cost") for the third subsequent Summer Season. Such estimate shall be determined using the best information available to PacifiCorp at the time the estimate is made. If during any Summer Season PacifiCorp determines that the Estimated Annual Fixed Cost and the Estimated Annual variable Cost used for billing purposes should be adjusted to reflect more accurate estimates, PacifiCorp shall notify APS as soon as possible. By mutual agreement of the Parties, PacifiCorp shall revise the Estimated Annual Fixed Cost and the Estimated Annual Variable Cost used for billing purposes in subsequent billing periods to reflect the more accurate estimates. Upon request, PacifiCorp shall provide to APS appropriate work papers and documentation supporting the revised estimates.

Section 6: Supplemental Energy

6.1 Option to Purchase. During the Term of this Agreement, APS shall make available at the Point of Delivery and PacifiCorp shall have the option to purchase Supplemental Energy on the basis provided for in this Section 6.

6.2 Quantities. There shall be two categories of Supplemental Energy, "Supplemental Coal Energy" and "Other Supplemental Energy." APS shall offer Supplemental Coal Energy and Other Supplemental Energy to PacifiCorp in the following Annual quantities during the Term of this Agreement:

Period	Supplemental Coal Energy (GWh per Year)	Other Supplemental Energy (GWh per Year)
Each year until 10/31/96	876	219
11/1/96 until 10/31/01	657	438
11/1/01 until 10/31/06	438	657
11/1/06 until 10/31/20	219	876

The required quantities for the period commencing on the Closing Date of the Asset Agreement until October 31, 1991 shall be proportionate shares of the required Annual quantities for that period. For purposes of this Section 6, "Year" or "Annual" shall mean the period commencing November 1 and ending October 31. In each of the following years, APS may defer offering a portion of that year's annual obligation to make Supplemental Coal Energy available to PacifiCorp to the first 90 days of the next year, but in no event shall the amount deferred exceed the specified maximum percentage:

Period	Maximum Deferral
11/01/00-10/31/01	20 percent
11/01/01-10/31/02	15 percent
11/01/02-10/31/06	10 percent
11/01/06-10/31/20	No deferral permitted

On or before September 15 of each Year in which it chooses to defer Supplemental Coal Energy, APS shall notify PacifiCorp in writing of the amount it intends to defer. APS shall have the right to defer as much as 20% more or 20% less than the amount stated in the notice, but in no event shall the deferral exceed the maximum permitted for that Year. Any deferred Supplemental Coal Energy shall be offered together with the next year's Supplemental Coal Energy, at rates of delivery not exceeding those set forth in Subsection 6.3.

6.3 <u>Rate of Delivery of Supplemental Coal Energy</u>. APS may offer up to 250 MWh per hour of Supplemental Coal Energy to PacifiCorp. APS' annual obligation for each Year to offer Supplemental Coal Energy to PacifiCorp shall be reduced by the amount of Supplemental Coal Energy offered pursuant to Subsection 6.6, regardless of whether such energy is purchased by PacifiCorp. Offered Supplemental Coal Energy which has been accepted and prescheduled by PacifiCorp but which APS is not able to deliver because of significant changes in its system conditions as set forth in Subsection 6.6, shall not reduce APS' annual obligation.

6.4 Rate of Delivery of Other Supplemental Energy. APS may offer up to 150 MWh per hour of Other Supplemental Energy to PacifiCorp. APS' Annual obligation for each Year to offer Other Supplemental Energy to PacifiCorp shall be reduced by the amount of Supplemental Coal Energy offered pursuant to Subsection 6.6 if it represents the lowest cost energy that is surplus to APS' system during that hour, regardless of whether such energy is purchased by PacifiCorp. Offered Other Supplemental Energy which has been accepted and prescheduled by PacifiCorp but which APS is not able to deliver because of significant changes in its system conditions as set forth in Subsection 6.6 shall not reduce APS' annual obligation.

6.5 Simultaneous Delivery. APS shall not offer Supplemental Coal Energy and Other Supplemental Energy for delivery during the same hour.

6.6 Supplemental Energy Offer. APS shall offer Supplemental Energy to PacifiCorp before 1000 hours MST on the last work day observed by both Parties immediately preceding the day(s) such Supplemental Energy is proposed to be made available. Such offer shall identify the type(s) and amount(s) of such Supplemental Energy as well as the Supplemental Energy Price. PacifiCorp shall preschedule any desired amounts of Supplemental Energy pursuant to Subsection 7.3. Prescheduled amounts of Supplemental Energy may be changed by the Parties' dispatchers or schedulers only in the event of significant changes in the affected Party's load, generation or transmission capability. The Supplemental Energy price as established at the time of prescheduling shall not change.

6.7 Pricing of Supplemental Coal Energy. The price of Supplemental Coal Energy for each transaction shall be as quoted by APS' dispatcher or scheduler prior to delivery and recorded in APS' system log and shall be derived from the best efforts forecast of the coal cost utilizing the incremental heat rate, together with incremental operating and maintenance expense associated with the generating unit producing such energy ("Incremental Cost"). Incremental Cost for purposes of establishing the price of Supplemental Coal Energy shall be computed in accordance with the methodology established in Appendix E, but in no event, except as provided below, shall such Incremental cost exceed the Incremental Cost of Cholla Unit 3, or Cholla Unit 2, if Cholla Unit 3 has been retired from service. Until November 1, 1996, the price of Supplemental Coal Energy shall equal 115% of Incremental Cost. From November 1, 1996 through February 28, 2003, the price of Supplemental Coal Energy shall equal 120% of Incremental Cost. From March 1, 2003 through October 31, 2006, the price of Supplemental Coal Energy shall equal 125% of Incremental Cost. From November 1, 2006 through October 31, 2020, APS shall be allowed to increase the price of Supplemental Energy to 130% of Incremental Cost upon the Commission's acceptance of a timely filing under Part 35 of the Code of Federal Regulations including the required cost data in support of this increase. Subsequent to October 31, 2010, if APS has constructed a base-load coal plant that is being used to provide utility service to APS' customers whose Incremental Cost is greater than that of Cholla Unit 3, the Parties shall negotiate in good faith to equitably adjust the Incremental Cost cap and multipliers provided for herein.

6.8 Pricing of Other Supplemental Energy. The price of Other Supplemental Energy for each transaction shall be as quoted by APS' dispatcher or scheduler prior to delivery and as recorded in APS' system log and shall be the higher of (1) the average price of Supplemental Coal Energy for the month prior to the month in question or (2) 115% of the Incremental Cost of generating unit producing the Other Supplemental Energy.

Any increase in the 15% adder used in the pricing of Other Supplemental Energy shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost data supporting that the revised percentage adder generates a reasonable contribution to the fixed costs of the facilities used to provide this service.

6.9 Price Caps Applicable to Supplemental Coal Energy and Other Supplemental Energy Transaction

In order to ensure that in addition to APS recovering its estimated incremental cost to produce supplemental energy, application of the adders do not result in APS recovering more than 100% of the fixed costs of the generating units producing the Supplemental Coal Energy or Other Supplemental Energy, the following price caps shall be applicable:

6.9.1 Price Cap for Supplemental Coal Energy. Notwithstanding the currently applicable adder of 30% to APS' Incremental Cost for Supplemental Coal Energy as set forth in Section 6.7, charges for energy from coal units shall not exceed 85.54 mills/kWh.

6.9.2 Price Caps for Other Supplemental Energy. Pursuant to Section 6.8 of this Agreement, the applicable adder of 15% for sales of Other Supplemental Energy shall further be subject to the following caps:

6.9.2.1 Energy from Combustion Turbines shall not exceed 9,125.66 mills/kWh.

6.9.2.2 Energy from Combined Cycle Units shall not exceed 826.39 mills/kWh.

6.9.2.3 Energy from Gas/Oil fired Steam Units shall not exceed 1,540.01 mills/kWh.

6.9.2.4 Energy from Coal fired Steam Units shall not exceed 342.18 mills/kWh.

Section 7: Scheduling

7.1 Projected Monthly Schedules. By December 1, 1990 and each December 1 thereafter, APS shall submit to PacifiCorp in writing the projected monthly amounts of Firm Energy associated with Firm Capacity to be delivered for the following Summer Season. Such projections shall represent a good faith estimate by APS of its anticipated deliveries hereunder; provided, that such estimates shall not be binding and shall be used by PacifiCorp for planning and information purposes only.

7.2 Daily Schedules by APS. APS shall preschedule all deliveries of Firm Energy associated with Firm Capacity and all deliveries of Exchange Energy associated with Exchange Capacity no later than 1000 hours MST on each work day observed by both Parties immediately preceding the day or day(s) of delivery, or as otherwise mutually agreed by the Parties' dispatchers or schedulers. PacifiCorp shall deliver in accordance with APS' preschedules which comply with the delivery provisions specified in Sections 3 and 4.

7.3 Daily Schedules by PacifiCorp. In the event the Parties commence a Seasonal Capacity Exchange(s) pursuant to Subsections 3.2 and/or 3.3, PacifiCorp shall preschedule deliveries of Exchange Energy associated with Exchange Capacity together with any deliveries of Supplemental Energy, no later than 1000 hours MST on each work day observed by both Parties immediately preceding the day or days on which such energy is to be delivered, or as mutually agreed by the Parties' dispatchers or schedulers. APS shall accept and deliver in accordance with those preschedules which comply with the delivery obligations specified in Subsection 3.2.2 and Section 6.

7.4 System Logs. All deliveries shall be deemed to be made during the hours and in the amounts as accounted for in the APS and PacifiCorp system logs; provided, that if scheduled deliveries are interrupted due to an Uncontrollable Force as defined in Section 14, such schedules shall be adjusted to reflect such interruption and any scheduled delivery so interrupted shall be rescheduled at a later date. Such rescheduling of interrupted deliveries shall be in amounts and at times as mutually agreed by the

Parties' dispatchers or schedulers and shall not increase either Party's obligation pursuant to Sections 3 and 4.

7.5 Point of Delivery at Cholla. Prior to 1996 and prior to the completion of the Navajo/Glen Canyon Loop-in Project, if APS, despite its best efforts, is unable to deliver the full amount of Firm Capacity into its system from Four Corners, PacifiCorp shall deliver such amounts of Firm Capacity that APS is unable to deliver from Four Corners to APS at the Cholla Generating Station 500 kV switchyard to the extent it is able to do so from available generating capacity from Cholla Unit 4 in excess of 200 MW. Commencing in 1996, to the extent APS is purchasing more than 200 MW of Firm Capacity, PacifiCorp shall deliver amounts of Firm Capacity in excess of 200 MW to APS at the Cholla Generating Station 500 kV switchyard to the extent it is able to do so from available generating capacity at Cholla Unit 4 in excess of 200 MW. For purposes of this Subsection, APS' best efforts shall not include a requirement that APS adjust generating resources on its system such that higher-cost generating resources are operated and lower-cost resources are curtailed in order to accommodate deliveries.

Section 8: Billing

8.1 Payments. Commencing May 1, 1991 through the term of this Agreement that Firm Capacity is being made available, APS shall pay PacifiCorp in the appropriate month of each year for Firm Capacity and Firm Energy the amounts determined in Subsections 8.1 through 8.4.

8.1.1 Summer Season 1991-1995. For the Summer Season of calendar years 1991 through 1995, the payment for each month shall equal the sum of (a) the Firm

Capacity as set forth in Subsection 3.1 as stated in kilowatts multiplied by the fixed price ($/KW/mo) for such year as set forth in Subsection 5.1 and, except as provided in Subsection 8.1.1.1, (b) the amount of Firm Energy stated in megawatt hours scheduled by APS pursuant to Section 4 during such month multiplied by the estimated Cholla Unit 4 production expense determined pursuant to Subsection 5.3.1.

8.1.1.1 Minimum Purchase Obligation. In the event the amount of Firm Energy scheduled by APS in any Summer Season is less than a 50 percent load factor, an amount of Firm Energy will be deemed to have been scheduled and delivered during the month of October that would increase APS' energy amount received for the Summer Season to equal a 50 percent load factor. APS shall pay for all such energy deemed to have been scheduled and delivered as determined above.

8.1.2 Summer Season - 1996-2020. Except as provided for in Subsections 3.2 and 8.1.3, for the Summer Season of calendar years 1996 through 2020, the payment for each month shall equal the sum of (a) the Firm Capacity as set forth in Subsection 3.1 stated in kilowatts multiplied by the Estimated Annual Fixed Cost as determined pursuant to Subsection 5.3.2 and, except as provided for in Subsection 8.1.2.1, (b) the amount of Firm Energy stated in megawatt-hours scheduled during such month multiplied by the Estimated Annual Variable Cost as determined pursuant to Subsection 5.3.2.

8.1.2.1 Minimum Purchase Obligation. In the event the amount of Firm Energy scheduled by APS in any Summer Season is less than 50 percent load factor, an amount of Firm Energy will be deemed to have been scheduled and delivered during the month of October that would increase APS' energy amount received for the Summer

Season to equal a 50 percent load factor. APS shall pay for all such energy deemed to have been scheduled and delivered as determined above.

8.1.3 Firm Capacity Payment Reduction. APS shall be entitled to a reduction in the payment provided for in Subsection 8.1.2 when all of the following occur:

(a) Firm Capacity is greater than 200 MW;

(b) Cholla Unit 4 is not operating for any reason;

(c) APS has no reasonable ability to adjust its system to accommodate delivery of more than 200 MW of Firm Capacity into its system through Navajo/Four Corners;

(d) PacifiCorp has combustion turbine capacity available to it in Arizona which it has elected not to utilize to provide APS with Firm Capacity in excess of 200 MW; and

(e) PacifiCorp has the ability to acquire power in Arizona from another entity which could be used to provide APS Firm Capacity in excess of 200 MW, but has elected not to acquire such power on APS' behalf.

For purposes of paragraph (c) above, APS shall not be required to adjust generating resources on its system such that higher-cost generating resources are operated and lower-cost resources are curtailed in order to accommodate deliveries.

The reduction in the required payment shall be computed for each hour of any month in which all of the aforementioned conditions occurred based upon the results of the following equation and the sum of the hourly reduction(s) shall equal the monthly reduction:

$$\frac{(C - 200{,}000)\ x}{730}$$

Where: C = Firm Capacity, stated in kilowatts
X = Estimated Capacity Price, stated in dollars per kilowatt month

8.2 Annual Adjustments. By June 1 of each of the calendar years 1992 through 2021, PacifiCorp shall determine APS' payment obligation for the preceding calendar year's Summer Season based on prices determined in accordance with Section 5, applied except for calendar years 1991 through 1995 to Firm Capacity, pursuant to Subsection 3.1, and applied to the Firm Energy as set forth in Section 4. Such determination shall also reflect any payment reductions owing pursuant to Subsection 8.1.3. In the event the amount so determined is greater than the amount actually paid by APS pursuant to Subsection 8.1, then PacifiCorp shall add the amount of such difference, as adjusted for interest pursuant to Appendix D, to the May invoice. In the event the amount so determined is less than the amount actually paid by APS pursuant to Subsections 8.1.1 or 8.1.2, then PacifiCorp shall subtract the amount of such difference, as adjusted for interest pursuant to Appendix D, from the May invoice. By June 1, 2021 PacifiCorp shall determine APS' payment obligation for the preceding Summer Season based on prices determined in accordance with Section 5, applied to Firm Capacity pursuant to Section 3, and the Firm Energy purchase obligations as set forth in Section 4. In the event the amount so described is different than the amount actually paid by APS pursuant to Subsection 8.1, then PacifiCorp shall refund or send APS an invoice for such difference, whichever is appropriate, as adjusted for interest pursuant to Appendix D. Such refund or invoice shall be submitted to APS by June 15, 2021.

8.3 Billing and Payment for Firm Capacity and Firm Energy. PacifiCorp shall bill APS by the fifteenth day of each month by regular mail for services provided during the preceding month. APS shall pay such amounts, by electronic wire transfer, within fifteen days of receipt of such bill. Payments for all services provided hereunder are to be electronically wire transferred to United States National Bank of Oregon, Metropolitan Branch, 900 S.W. Sixth Avenue, Portland, Oregon 97204 (for credit to Pacific Power & Light Company, Account #070-000-169), Attention: Treasurer or such other financial institution or account number as specified by PacifiCorp in writing. Simple interest shall accrue on any unpaid amounts at a rate equal to 1.25 multiplied times the prime rate as established by The Morgan Guaranty Trust Company of New York during the period of delinquency, if any.

8.4 Billing and Payment for Supplemental Energy. For months during which PacifiCorp acquires Supplemental Energy, PacifiCorp shall pay APS the amounts determined in Subsections 8.4.1 and/or 8.4.2.

8.4.1 Supplemental Coal Energy. The payment for each month shall equal the sum of the individual hourly amounts of Supplemental Coal Energy stated in megawatt-hours scheduled by PacifiCorp during such month multiplied by the corresponding hourly Supplemental Coal Energy price as established by the Parties' dispatchers or schedulers prior to the hour of delivery pursuant to Subsection 6.7.

8.4.2 Other Supplemental Energy. The payment for each month shall equal the sum of the individual hourly amounts of Other Supplemental Energy stated in megawatt-hours scheduled by PacifiCorp during such month multiplied by the corresponding hourly Other Supplemental Energy price as established by the Parties' dispatchers or schedulers prior to the hour of delivery pursuant to Subsection 6.8.

8.5 Billing and Payment Schedules for Supplemental Energy. APS shall bill PacifiCorp by the fifteenth day of each month by regular mail for Supplemental Energy delivered during the preceding month. PacifiCorp shall pay such amounts, by electronic wire transfer, within fifteen days of receipt of such bill. Payments for all Supplemental Energy delivered hereunder are to be electronically wire transferred to Account No. 1-2079 at Valley National Bank, 241 North Central Avenue, Phoenix, Arizona 85004, or such other financial institution or account number as specified by APS in writing. Simple interest shall accrue on any unpaid amounts at a rate equal to 1.25 multiplied times the prime rate as established by The Morgan Guaranty Trust Company of New York during the period of delinquency, if any.

Section 9: Audit Rights

During the period of this Agreement that Firm Capacity is being made available, APS may review PacifiCorp's accounting records and supporting documents associated with any billing for Firm Capacity and Firm Energy made during the prior 18 months. During the Term of this Agreement, PacifiCorp may review appropriate portions of APS' system logs, and APS' accounting records or supporting documents associated with any billing for Supplemental Energy made during the prior 18 months. If either Party believes there are any errors in the determination of a bill including prices, it shall pay the full amount of such bill and the Parties shall meet to review the accounting records and supporting documents and agree on any adjustments that may be appropriate. If the Parties agree that the billing is incorrect, a corrected bill shall be prepared and the difference between the incorrect bill and corrected bill, including simple interest on the difference as provided herein, shall be paid promptly after such determination. The simple interest rate shall be equal to the time-weighted average prime rate as established by Morgan Guaranty Trust Company of New York and calculated using the method described in Appendix D. The principal upon which interest rates are to be applied shall be limited to twenty-four months following the submittal of the incorrect bill. The Parties shall take all steps reasonably available to secure the confidentiality of each other's accounting records and supporting documents. Disclosure of accounting records and supporting documents to a Party is not intended to, and shall not be interpreted to, waive the other Party's right to maintain that such records and supporting document are privileged, confidential, proprietary, or otherwise protected from disclosure to the public. In the event such information is required in a legal or regulatory proceeding related to this Agreement, a Party shall advise the other Party of the requirement to disclose such information prior to disclosing it and at such other Party's request shall ask for confidentiality of any such information.

Section 10: Cost Determination Changes

The cost methodologies utilized for pricing purposes in this Agreement and the pricing formulae specified herein shall remain in effect through the term of this

Agreement, and neither Party shall petition the FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act to amend such methodologies or formulae absent the agreement in writing of the other Party or support such a petition filed by any third party.

Section 11: Future Studies and Arrangements

No later than 60 days subsequent to the Closing Date of the Asset Agreement, the Parties shall meet to begin discussions of further transactions and arrangements that could benefit the Parties' respective customers. In addition to the types of transactions and arrangements already agreed to by the Parties, the discussions shall include other potential arrangements associated with generation and transmission planning and other potential operating efficiencies.

Section 12: Governing Law

This Agreement shall be subject to and be construed under the laws of the State of Arizona.

Section 13: Notices

All written notices hereunder, shall be directed as follows, and shall be considered delivered when deposited in the U.S. Mail, or other certified mail, return receipt requested:

To APS: Arizona Public Service Company
Corporate Secretary
P.O. Box 53999
Phoenix, AZ 85072-3999

To PacifiCorp: PacifiCorp Commercial and Trading
Director, Marketing & Trading Contracts

825 NE Multnomah, Suite 600
Portland, OR 97232

The Parties may change the persons to whom notices are addressed, or their addresses, by providing notice thereof as specified in this Section.

Section 14: Uncontrollable Forces

Neither Party to this Agreement shall be considered to be in default in performance of any obligation hereunder if failure of performance shall be due to an Uncontrollable Force. The term "Uncontrollable Force" means any cause beyond the control of the Party affected, including, but not limited to, failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, and restraint by court order or public authority, which by exercise of due foresight such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to overcome. A Party shall not, however, be relieved of liability for failure of performance if such failure be due to causes arising out of its own negligence or to removable or remediable causes which it fails to remove or remedy with reasonable dispatch. Any Party rendered unable to fulfill any obligation by reason of an Uncontrollable Force shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein, however, shall be construed to require a Party to prevent or settle a strike against its will.

Section 15: Waiver

Any waiver by a Party of its rights with respect to default hereunder, or with respect to any other matter arising in connection herewith, shall not be deemed to be a waiver with respect to any subsequent default or matter. Except as provided for in Subsection 3.2.3, no delay in asserting or enforcing any right hereunder shall be deemed a waiver of such right.

Section 16: Arbitration

16.1 The Parties shall make best efforts to settle all disputes arising under this Agreement as a matter of normal business and without recourse to either arbitration or litigation. If any dispute arises under this Agreement, the Parties shall arbitrate the matter before an arbitrator who is an attorney or engineer familiar with contracts governing the operation of electrical systems. Any arbitration shall be commenced within a year of when a dispute arises and shall be commenced by either Party submitting to the other a Notice of Arbitration. The Parties shall have 30 days following the submittal of a Notice of Arbitration by either Party to attempt to mutually agree upon an arbitrator. If the Parties are unable to agree on an arbitrator within that time, either Party may request that a judge of the United States Circuit Court for the Ninth Circuit designate an arbitrator.

16.2 The arbitrator shall have discretion to establish a schedule and procedure for the arbitration and may conduct the arbitration based upon written submittals. The arbitrator may afford the Parties any or all of the discovery rights provided for in the Federal Rules of Civil Procedure.

16.3 At the commencement of the arbitration hearing, each Party shall submit a proposed Arbitration Award and the arbitrator shall be required to adopt in full the proposed Arbitration Award of one of the Parties and the Arbitration Award selected shall be final and binding on the Parties.

16.4 The Party whose proposed Arbitration Award is not selected shall pay all the costs of the arbitration, including the costs and the attorneys' fees of the prevailing Party.

Section 17: Indemnification

Neither Party ("First Party") shall be liable, whether in warranty, tort, or strict liability, to the other Party ("Second Party") for any injury or death to any person, or for any loss or damage to any property, caused by or arising out of any electric disturbance of the First Party's electric system, whether or not such electric disturbance resulted from the First Party's negligent act or omission. Each Second Party releases the First Party from, and shall indemnify and hold harmless the First Party from, any such liability. As used in this Section, (1) the term "Party" means, in addition to such Party itself, its agents, directors, officers, and employees; (2) the term "damage" means all damage, including consequential damage; and (3) the term "persons" means any person, including those not connected with either Party to this Agreement.

Section 18: Entire Agreement

This Agreement constitutes the entire agreement of the Parties hereto with respect to the transaction addressed herein and supersedes all prior agreements, whether oral or written. This Agreement may be amended only by a written document signed by both Parties hereto.

Section 19: Assignment

Neither Party shall assign this Agreement without the prior written consent of the other Party, except:

(a) to any corporation into which or with which the Party making the assignment is merged or consolidated or to which the Party transfers substantially all of its assets;

(b) to any person or entity wholly owning, wholly owned by or wholly owned in common with the Party making the assignment.

Nothing contained in this Section shall be construed to prevent the Parties from making a collateral assignment of the revenues due under the terms of this Agreement. No assignment, merger or consolidation shall relieve any Party of any obligation under this Agreement. Subject to the foregoing restrictions in this Section, this Agreement shall be binding upon, inure to the benefit of and be enforceable by the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names by their respective officers thereunder duly authorized.

PacifiCorp Electric Operations

By /s/
Title: President

Arizona Public Service Company

By /s/
Title: Chairman

APPENDIX A: ANNUAL FIXED COST

Introduction

This Appendix sets forth the elements and techniques to calculate Annual Fixed Cost.

The Annual Fixed Cost shall be the per-MW total of the following: (1) 70 MW multiplied by the Colstrip Project Annual Fixed Cost pursuant to Section A2 plus 350 MW multiplied by the Cholla Project Annual Fixed Cost pursuant to Section A4, plus 180 MW multiplied by the Hunter #2 Project Annual Fixed Cost pursuant to Section A6, plus 400 MW multiplied by the Hunter #3 Project Annual Fixed Cost pursuant to Section A8 and (2) dividing the above sum by 1000 MW.

The Annual Fixed Cost for PacifiCorp's share of the Colstrip Project, PacifiCorp's share of the Cholla Project, PacifiCorp's share of the Hunter #2 Project and PacifiCorp's share of the Hunter #3 Project is the per-MW sum of each Project's: (a) initial levelized annual fixed cost, (b) levelized annual fixed costs of subsequent capital additions, replacements and betterments (if any), and (c) other fixed annual charges directly related to the resources in the pool, including but not limited to property taxes, insurance, and taxes other than income tax.

Section A1: Discussion of Methodology

Levelized fixed charges are the basis of annual fixed costs hereunder. While actual capital-related charges associated with an investment may vary considerably from year to year, the levelized fixed charge translates these charges into a level annual amount which remains constant over time. The present values of the two streams (actual versus levelized) are equal.

The levelized fixed charge includes three basic components: (a) return on investment, given a specific capital structure and cost of capital; (b) recovery of investment, given the appropriate depreciation period related to the investment; and (c) income tax requirements, given tax law considerations. These components are commonly expressed as: (a) interest expense on debt and return required by shareholders, (b) book depreciation, and (c) income taxes incorporating the effects of investment tax credits and tax depreciation.

As of December 31, 1989, an initial levelized annual charge rate will be applied to the total investment of each Project. The rate will be recalculated effective each January 1 only in the event of a change during the preceding calendar year in any of the following: (a) the percentage of pollution control revenue bonds outstanding; (b) the interest rate on pollution control revenue bonds; (c) PacifiCorp's rate of return on common equity (ROE), as allowed by the Federal Energy Regulatory Commission (FERC), or (d) income tax law, but not to be applied retroactively.

Subsequent levelized annual fixed charge rates will be calculated each year to reflect the most current information and will be applied each year to the amount of capital additions, replacements (less credit for net salvage and insurance proceeds, if any) and betterments of each Project completed through the end of the preceding calendar year.

Section A2: Determination of Colstrip
Project Annual Fixed Cost

Colstrip Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A2.1 through A2.5, and (b) dividing the total by 140 MW ("Net Colstrip Capacity"), provided that, in the event the capacity of the Colstrip Project increases or decreases as a result of additions, replacements or betterments the Net Colstrip Capacity will be adjusted to reflect such change.

A2.1 PacifiCorp's initial levelized annual fixed charge rate for the Colstrip Project determined annually in accordance with Section A3 of this Appendix, multiplied by the total investment in the Colstrip Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Colstrip Project is $195,862,376. Such total investment shall remain constant through the term of the Agreement.

A2.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A3, below, by (b) the

dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Colstrip Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

A2.3 All ad valorem taxes imposed upon the Colstrip Project.

A2.4 Any tax, assessment, payment, in lieu of taxes, or other, charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Colstrip Project, excluding ad valorem taxes, state and federal income taxes.

A2.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Colstrip Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A3: Elements of Colstrip Project's
Levelized Annual Fixed Charge Rates

A3.1 Capital Structure:

A3.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Colstrip Project is:

Long Term Debt and Pollution Control Revenue Bonds	52%
Preferred Stock	12%
Common Stock Equity	36%
Total Capital	100%

The proportion of Pollution Control Revenue Bonds A to Total Capital will be the quotient of (a) $45,000,000 (the principal amount of Pollution Control Revenue Bonds relating to the Colstrip Project issued in January 1988) divided by (b) $195,862,376, i.e., the sum of PacifiCorp's total investment cost of the Colstrip Project as of December 31, 1989.

The proportion of Pollution Control Revenue Bonds B to Total Capital will be the quotient of (a) $8,500,000 (the principal amount of Pollution Control Revenue Bonds relating to the Colstrip Project issued in December 1986) divided by (b) $195,862,376, i.e., the sum of PacifiCorp's total investment cost of the Colstrip Project as of December 31, 1989. The proportion of Long Term debt to Total Capital will be the difference between (a) fifty-two percent (52%), (b) the proportion of Pollution Control Revenue Bonds A as calculated above, and (c) the proportion of Pollution Control Revenue Bonds B as calculated above. If PacifiCorp's City of Forsyth, Rosebud County, Montana, Floating Rate Monthly Demand Pollution Control Revenue Bonds, Series 1988 or Series 1986 (Pacific Power & Light Company Colstrip Project), as referenced above, are prepaid, redeemed or exchanged for bonds, in their entirety, the interest of which is taxable under federal income tax laws, the capital structure will be adjusted to determine the initial levelized annual charge rates in the calendar years immediately succeeding the year of prepayment or redemption, such that the Pollution Control Revenue Bonds (A or B) proportion will be zero (0) and the Long-Term Debt proportion will be the difference between (a) Fifty-two percent (52%) and (b) the remaining proportion of Pollution Control Revenue Bonds A or B as calculated above. In the event that the above-referenced pollution control revenue bonds are exchanged for another issue of bonds, the interest of which is exempt under federal income tax laws, the capital structure consequent to the subsequent issue will be employed prospectively for calculations under this section.

A3.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%

Total Capital	100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A3.2 Cost of Capital:

A3.2.1 Interest Rate for Debt: The interest rate for debt shall be equal to 1) the product of the proportion of Long Term Debt to Total Capital multiplied by the total Colstrip Project Investment multiplied by the bond interest rate (12.8%) as specified in Subsection A3.2.1.1, plus 2) the product of the amount of tax exempt Pollution Control Revenue Bonds A multiplied by the variable interest rate (which in 1989 was 6.48%) as specified in Subsection A3.2.1.2, plus 3) the product of the amount of tax exempt Pollution Control Revenue Bonds B multiplied by the variable interest rate (which in 1989 was 6.89%) as specified in Subsection A3.2.1.3 the sum of the products of 1) and 2) and 3) divided by the sum of 4) the product of the proportion of Long Term Debt to Total Capital as specified in Subsection A3.1.1 times the Total Colstrip Project investment, plus 5) the amount of tax exempt Pollution Control Revenue Bonds A, plus 6) the amount of tax exempt Pollution Control Revenue Bonds B.

A3.2.1.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be twelve and eight-tenths percent (12.8%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Colstrip Project, in the twelve (12) -month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) -month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A3.2.1.2 Pollution Control Revenue Bonds A: Bond interest applicable in the calculation of the 1989 initial levelized annual fixed charge rate shall be six and forty-eight hundredths percent (6.48%). Bond interest applicable in the calculation of the initial levelized annual fixed charge rate in each year from 1991 through 2010 shall be the average of that effective interest rate paid by PacifiCorp during the previous calendar year relating to its $45,000,000 City of Forsyth, Rosebud County, Montana, Floating Rate Monthly Demand Pollution Control Revenue Bonds, Series 1988 (Pacific Power & Light Company Colstrip Project). If such series of bonds is prepaid, redeemed, or exchanged for bonds, in their entirety, the interest of which is subject to federal income taxes, there will be no interest relating to Pollution Control Revenue Bonds A in the initial levelized annual fixed charge rates computed in the calendar year immediately following such prepayment or redemption. In the event that the above-referenced Pollution Control Revenue Bonds A are exchanged for another issue, the interest of which is exempt from federal income taxes, the interest rate consequent to the subsequent issue shall be employed prospectively for calculations under this section.

A3.2.1.3 Pollution Control Revenue Bonds B: Bond interest applicable in the calculation of the 1989 initial levelized annual fixed charge rate shall be six and eighty-nine hundredths percent (6.89%). Bond interest applicable in the calculation of the initial levelized annual fixed charge rate in each year from 1991 through 2010 shall be the average of that effective interest rate paid by PacifiCorp during the previous calendar year relating to its $8,500,000 City of Forsyth, Rosebud County, Montana, Floating Rate Monthly demand Pollution Control Revenue Bonds, Series 1986 (Pacific Power & Light Company Colstrip Project). If such series of bonds is prepaid, redeemed, or exchanged for bonds, the interest of which is subject to federal income taxes, there will be no interest relating to Pollution Control Revenue Bonds B in the initial levelized annual fixed charge rates computed in the calendar year immediately following such prepayment or redemption. In the event that the above-referenced pollution control bonds B are exchanged for another issue, the interest of which is exempt from federal income taxes, the interest rate consequent to the subsequent issue shall be employed prospectively for calculations under this section.

A3.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be thirteen and three-tenths percent (13.3%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A3.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC.

From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using Pacificorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A3.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35) -year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A3.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A3.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A3.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A3.4.3 Accelerated Cost Recovery System (ACRS) method of tax depreciation in accordance with the Tax Equity and Fiscal Responsibility Act of 1982 shall be used in calculating each initial levelized annual fixed charge rate and the modified Accelerated Cost Recovery System (modified ACRS method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

A3.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A3.4.5 Tax basis will be seventy-five percent (75%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Section A4: Determination of Cholla

Project Annual Fixed Cost

Cholla Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Section A4.1 through A4.5, and (b) dividing the total by 350 MW ("Net Cholla Capacity"), provided that, in the event the capacity of the Cholla Project increases or decreases as a result of additions, replacements or betterments the Net Cholla Capacity will be adjusted to reflect such change.

A4.1 PacifiCorp's initial levelized annual fixed charge rate for Cholla Project will be determined annually in accordance with Section A5 of this Appendix multiplied by the Initial Net Book investment in the Cholla Project as of December 31, 1995. For purposes of this section, PacifiCorp's Initial Net Book investment in Cholla Project is the sum of PacifiCorp's initial investment of $221,000,000, less book depreciation, plus PacifiCorp's investments in capital additions, and replacement (less credit for net salvage and insurance proceeds, if any) less associated depreciation. Such total Initial Net Book investment shall remain constant through the term of the Agreement.

A4.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A5, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Cholla Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1996.

A4.3 All ad valorem taxes imposed upon the Cholla Project.

A4.4 Any tax, assessment, payment in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Cholla Project, excluding ad valorem taxes, state and federal income taxes.

A4.5 Administrative and General Expense shall be the greater of the amount of Administrative and General Expense charged by APS to PacifiCorp associated with PacifiCorp's investment in the Cholla Project, or an amount equal to the product of 1) the quotient of total PacifiCorp Administrative and General Expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Cholla Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A5: Elements of Cholla Project Levelized Annual Fixed Charge Rates

A5.1 Capital Structure

A5.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Cholla Project is:

Long-Term Debt and Pollution Control Revenue Bonds	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

A5.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

provided, that if any par: of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A5.2 Cost of Capital

A5.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be ten percent (10.00%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Cholla Project, in the most recent twelve (12) -month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) -month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A5.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be nine and five-tenths percent (9.5%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A5.2.3 Common Stock Equity: For pricing purposes only, the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's the then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A5.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a twenty-five (25) -year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A5.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, that subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A5.4.1 The federal corporate income tax rate (46%) up through 1986, 40% in 1987, and 34% in 1988 and thereafter.

A5.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three (3) -factor formula for unitary allocation of state taxable income taxed upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A5.4.3 Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation shall be used in calculating each initial levelized annual fixed charge rate and the modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax Reform Act of 1986 shall be used in calculating subsequent levelized annual fixed charge rate.

A5.4.4 Investment Tax Credits shall be zero (0) in calculating each initial levelized annual fixed charge rate and Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits shall be used when calculating subsequent levelized annual fixed charge rates.

A5.4.5 Tax basis shall be one hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate.

Section A6: Determination of Hunter #2
Project Annual Fixed Cost

Hunter #2 Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A6.1 through A6.5, and (b) dividing the total by 235 MW ("Net Hunter #2 Capacity"), provided that, in the event the capacity of the Hunter #2 Project increases or decreases as a result of additions, replacements or betterments the Net Hunter #2 Capacity will be adjusted to reflect such change. The costs referred to above are:

A6.1 PacifiCorp's initial levelized annual fixed charge rate for the Hunter #2 Project determined annually in accordance with Section A7 of this Appendix, multiplied by the total investment in the Hunter #2 Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Hunter #2 Project is $174,355,375. Such total investment shall remain constant through the term of the Agreement.

A6.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A7, below, by (b) the

dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #2 Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from PacifiCorp's general accounting records, the required portions of which shall be provided by PacifiCorp each year, shall not include any amounts incurred by PacifiCorp prior to January 1, 1990.

A6.3 All ad valorem taxes imposed upon the Hunter #2 Project.

A6.4 Any tax, assessment, payment, in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Hunter #2 Project, excluding ad valorem taxes, state and federal income taxes.

A6.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Hunter #2 Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A7: Elements of Hunter #2 Project's Levelized Annual Fixed Charge Rates

A7.1 Capital Structure:

A7.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #2 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total Capital	100%

A7.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%

Common Stock Equity	<u>46%</u>
Total Capital	100%

<u>provided</u>, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

<u>A7.2</u> <u>Cost of Capital:</u>

<u>A7.2.1</u> <u>Long-Term Debt:</u> Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be eleven and ninety-seven hundredths percent (11.97%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #2 Project, in the twelve (12) -month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) -month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

<u>A7.2.2</u> <u>Preferred Stock:</u> Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be ten and ninety-six hundredths percent (10.96%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A7.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A7.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35) -year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A7.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A7.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A7.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A7.4.3 Sum of the Years Digits method of tax depreciation shall be used in calculating each initial levelized annual fixed charge rate and the Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

7.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A7.4.5 Tax basis will be one-hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Section A8: Determination of Hunter #3 Project Annual Fixed Cost

Hunter #3 Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A8.1 through A8.5, and (b) dividing the total by 400 MW ("Net Hunter #3 Capacity"), provided that, in the event the capacity of the Hunter #3 Project increases or decreases as a result of additions, replacements or betterments the Net Hunter #3 Capacity will be adjusted to reflect such change. The costs referred to above are:

A8.1 PacifiCorp's initial levelized annual fixed charge rate for the Hunter #3 Project determined annually in accordance with Section A9 of this Appendix, multiplied by the total investment in the Hunter #3 Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Hunter #3 Project is $453,116,692. Such total investment shall remain constant through the term of the Agreement.

A8.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A9, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #3 Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from PacifiCorp's general accounting records, the required portions of which shall be provided by PacifiCorp each year, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

A8.3 All ad valorem taxes imposed upon the Hunter #3 Project.

A8.4 Any tax, assessment, payment, in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Hunter #3 Project, excluding ad valorem taxes, state and federal income taxes.

A8.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Hunter #3 Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A9: Elements of Hunter #3 Project's Levelized Annual Fixed Charge Rates

A9.1 Capital Structure:

A9.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #3 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total Capital	100%

A9.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A9.2 Cost of Capital:

A9.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be fourteen and fifty-two hundredths percent (14.52%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #3 Project, in the twelve (12) -month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) -month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A9.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be eleven and six-tenths percent (11.6%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A9.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A9.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35) -year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A9.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change.

A9.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A9.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A9.4.3 Accelerated Cost Recovery System (ACRS) method of tax depreciation in accordance with the Tax Equity and Fiscal Responsibility Act of 1982 shall be used in calculating each initial levelized annual fixed charge rate and the Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

A9.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A9.4.5 Tax basis will be ninety-five percent (95%) of the book basis in calculating each initial levelized annual fixed charge rate and one-hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Colstrip Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(Estimated 1996 Price)

Initial Levelized Fixed Charge

Colstrip Project

Colstrip Initial Project Investment		$195,862,376
Initial Levelized Annual Fixed Rate		13.02%
Initial Levelized Annual Fixed Charge		$25,499,323
Subsequent Investment - (1990 thru 1995)		$5,949,810
Subsequent Levelized Annual Fixed Rate		13.02%
Subsequent Levelized Annual Fixed Charge		$774,665
Ad Valorem Tax		$1,086,608
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Colstrip A & G Expense		$3,773,328
Total Fixed Cost		**$31,133,924**
Net Colstrip Capacity		140
Annual Fixed Cost per MW		$222,385
Monthly Fixed Cost per kW		$18.53

PACIFICORP ELECTRIC OPERATIONS
COLSTRIP PROJECT

AUGUST 27, 1990

52%	DEBT FINANCING @ 9.886%	$814	LEVELIZED DEFERRED TAXES	15	YEAR TAX LIFE – ACRS
12%	PREFERRED EQUITY @ 13.3%	$3,217	LEVELIZED INTEREST EXPENSE	48.36%	TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
36%	COMMON EQUITY @ 12.36%	$999	LEVELIZED PREFERRED RETURN	42.62%	TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
11.19%	WEIGHTED COST OF CAPITAL	$2,784	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.11467	CAPITAL RECOVERY FACTOR	10%	INVESTMENT TAX CREDIT (ITC)
$13,019	LEVELIZED ANNUAL COST	1985	IN SERVICE DATE	95%	ITC BASIS ADJUSTMENT
$13,019	LEVELIZED FIXED CAPITAL COSTS	35	YEAR ESTIMATED LIFE	75%	TAX BASIS (% OF ORIGINAL COST)
$2,348	LEVELIZED INCOME TAXES	35	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RAIL BASE
1985	0	0	0	2,857	4,861	1,509	4,208	738	5,384	19,557	17,589	3,563	94,559
1986	0	0	0	2,857	4,450	1,382	3,852	2,461	3,209	18,210	14,730	7,125	86,567
1987	0	0	0	2,857	4,204	1,305	3,639	1,835	2,394	16,234	11,810	6,413	81,776
1988	0	0	0	2,857	3,987	1,238	3,451	1,321	1,850	14,704	9,621	5,700	77,556
1989	0	0	0	2,857	3,790	1,177	3,280	1,058	1,978	14,140	8,321	4,988	73,723
1990	0	0	0	2,857	3,600	1,118	3,116	1,058	1,847	13,595	7,196	4,988	70,022
1991	0	0	0	2,857	3,416	1,064	2,957	795	1,984	13,070	6,222	4,275	66,451
1992	0	0	0	2,857	3,239	1,006	2,804	795	1,862	12,564	5,379	4,275	63,015
1993	0	0	0	2,857	3,063	951	2,651	795	1,741	12,058	4,643	4,275	59,577
1994	0	0	0	2,857	2,886	896	2,498	795	1,619	11,551	4,001	4,275	56,139
1995	0	0	0	2,857	2,709	841	2,345	795	1,498	11,045	3,440	4,275	52,701
1996	0	0	0	2,857	2,532	786	2,192	795	1,376	10,539	2,953	4,275	49,263
1997	0	0	0	2,857	2,356	734	2,039	795	1,255	10,033	2,528	4,275	45,824
1998	0	0	0	2,857	2,179	676	1,886	795	1,133	9,527	2,159	4,275	42,386
1999	0	0	0	2,857	2,002	622	1,733	795	1,012	9,021	1,839	4,275	38,948
2000	0	0	0	2,857	1,866	579	1,615	(781)	2,495	8,631	1,582	0	36,299
2001	0	0	0	2,857	1,770	550	1,532	(781)	2,429	8,357	1,378	0	34,437
2002	0	0	0	2,857	1,675	520	1,449	(781)	2,364	8,083	1,199	0	32,576
2003	0	0	0	2,857	1,579	490	1,367	(781)	2,298	7,809	1,041	0	30,714
2004	0	0	0	2,857	1,483	460	1,284	(781)	2,232	7,535	904	0	28,853
2005	0	0	0	2,857	1,388	431	1,201	(781)	2,166	7,261	783	0	26,991
2006	0	0	0	2,857	1,292	401	1,118	(781)	2,101	6,987	678	0	25,130
2007	0	0	0	2,857	1,196	371	1,035	(781)	2,035	6,713	586	0	23,268
2008	0	0	0	2,857	1,100	342	953	(781)	1,969	6,439	505	0	21,407
2009	0	0	0	2,857	1,005	312	870	(781)	1,903	6,165	435	0	19,545
2010	0	0	0	2,857	909	282	787	(781)	1,838	5,891	374	0	17,684
2011	0	0	0	2,857	813	253	704	(781)	1,772	5,617	321	0	15,822
2012	0	0	0	2,857	718	223	621	(781)	1,706	5,343	274	0	13,961
2013	0	0	0	2,857	622	193	538	(781)	1,640	5,069	234	0	12,100
2014	0	0	0	2,857	526	163	456	(781)	1,574	4,795	199	0	10,238
2015	0	0	0	2,857	431	134	373	(781)	1,509	4,522	169	0	8,377
2016	0	0	0	2,857	335	104	290	(781)	1,443	4,248	143	0	6,515
2017	0	0	0	2,857	239	74	207	(781)	1,377	3,974	120	0	4,654
2018	0	0	0	2,857	144	45	124	(781)	1,311	3,700	101	0	2,792
2019	0	0	0	2,857	48	15	41	(781)	1,246	3,426	84	0	931
TOTAL	0	0	0	100,000	68,413	21,240	59,215	0	67,549	316,416	113,541	71,250	
1985 NET PRESENT VALUE @ 11.19%													
	0	0	0	24,917	28,054	8,710	24,282	7,097	20,481	113,541	64,475	35,376	

PACIFICORP ELECTRIC OPERATIONS
COLSTRIP PROJECT

AUGUST 27, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	INVESTMENT TAX CREDIT RESTORED	INVESTMENT TAX CREDIT RECAPTURE	DEFERRED TAXES CURRENT	DEFERRED TAXES RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1985	100,000	(2,857)	(7,500)	214	0	(738)	0	89,119	(175)	48.36%	5.000%	2.86%
1986	89,119	(2,857)	0	214	0	(2,461)	0	84,015	(584)	48.36%	10.000%	2.86%
1987	84,015	(2,857)	0	214	0	(1,865)	31	79,537	(251)	42.62%	9.000%	2.86%
1988	79,537	(2,857)	0	214	0	(1,351)	31	75,574	0	36.88%	8.000%	2.86%
1989	75,574	(2,857)	0	214	0	(1,089)	31	71,873	0	36.88%	7.000%	2.86%
1990	71,873	(2,857)	0	214	0	(1,089)	31	68,172	0	36.88%	7.000%	2.86%
1991	68,172	(2,857)	0	214	0	(826)	31	64,734	0	36.88%	6.000%	2.86%
1992	64,734	(2,857)	0	214	0	(826)	31	61,296	0	36.88%	6.000%	2.86%
1993	61,296	(2,857)	0	214	0	(826)	31	57,858	0	36.88%	6.000%	2.86%
1994	57,858	(2,857)	0	214	0	(826)	31	54,420	0	36.88%	6.000%	2.86%
1995	54,420	(2,857)	0	214	0	(826)	31	50,982	0	36.88%	6.000%	2.86%
1996	50,982	(2,857)	0	214	0	(826)	31	47,544	0	36.88%	6.000%	2.86%
1997	47,544	(2,857)	0	214	0	(826)	31	44,105	0	36.88%	6.000%	2.86%
1998	44,105	(2,857)	0	214	0	(826)	31	40,667	0	36.88%	6.000%	2.86%
1999	40,667	(2,857)	0	214	0	(826)	31	37,229	0	36.88%	6.000%	2.86%
2000	37,229	(2,857)	0	214	0	751	31	35,368	0	36.88%	0.000%	2.86%
2001	35,368	(2,857)	0	214	0	751	31	33,506	0	36.88%	0.000%	2.86%
2002	33,506	(2,857)	0	214	0	751	31	31,645	0	36.88%	0.000%	2.86%
2003	31,645	(2,857)	0	214	0	751	31	29,783	0	36.88%	0.000%	2.86%
2004	29,783	(2,857)	0	214	0	751	31	27,922	0	36.88%	0.000%	2.86%
2005	27,922	(2,857)	0	214	0	751	31	26,060	0	36.88%	0.000%	2.86%
2006	26,060	(2,857)	0	214	0	751	31	24,199	0	36.88%	0.000%	2.86%
2007	34,199	(2,857)	0	214	0	751	31	22,338	0	36.88%	0.000%	2.86%
2008	22,338	(2,857)	0	214	0	751	31	20,476	0	36.88%	0.000%	2.86%
2009	20,475	(2,857)	0	214	0	751	31	18,615	0	36.88%	0.000%	2.86%
2010	18,615	(2,857)	0	214	0	751	31	16,753	0	36.88%	0.000%	2.86%
2011	16,753	(2,857)	0	214	0	751	31	14,892	0	36.88%	0.000%	2.86%
2012	14,892	(2,857)	0	214	0	751	31	13,030	0	36.88%	0.000%	2.86%
2013	13,030	(2,857)	0	214	0	751	31	11,169	0	36.88%	0.000%	2.86%
2014	11,169	(2,857)	0	214	0	751	31	9,307	0	36.88%	0.000%	2.86%
2015	9,307	(2,857)	0	214	0	751	31	7,446	0	36.88%	0.000%	2.86%
2016	7,446	(2,857)	0	214	0	751	31	5,584	0	36.88%	0.000%	2.86%
2017	5,584	(2,857)	0	214	0	751	31	3,723	0	36.88%	0.000%	2.86%
2018	3,723	(2,857)	0	214	0	751	31	1,861	0	36.88%	0.000%	2.86%
2019	1,861	(2,857)	0	214	0	751	31	0	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(7,500)	7,500	0	(1,010)	1,010		(1,010)		100.000%	100.00%

COLSTRIP PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n - 1$
Where i = weighted cost of capital and n = ave. life of plant.

$$CRF = 0.1119\,(1 + 0.1119)^{35}/((1 + 0.1119)^{35} - 1) = 0.114701$$

(*2) BOOK DEPRECIATION = \$100,000/35 Years = \$2,857

(*3) TOTAL RETURN, (TR) = $A \times W_s$

Where	A	=	Average Rate Base; and
	W_s	=	Weighted Cost of Preferred and Common Stock
Let	A	=	$(R_0 + R_1)\ /2$
Where	R_0	=	Rate Base (Year 0)
	R_1	=	Rate base (End of Year 1)
Let	R_1	=	$I_b + I_c/L_g - D - T$
	I_0	=	Cumulative ITC (*9)
	L_g	=	Book Life (35 years)
	D	=	Cumulative Book Depreciation (*2)
	T	=	Cumulative Deferred Tax (*5)
	I_b	=	$E \times (1 - I_r \times I_8$ ITC Basis)
Where	E	=	Capital Expenditure (\$100,000)
	I_r	=	ITC Rate (0.10)
Therefore,	I_b	=	\$100,000 (1 – 0.1 x 0.75) = \$92,500
	R_1	=	\$92,500 + \$7,500/35 - \$2,857 - \$738 = \$89,199
	A	=	(\$100,000 + \$89,119) /2 = \$94,560
	TR	=	\$94,560 x (.12 x .133 + .36 x .1236) = \$5,717

(*4) INTEREST, (I) = $A \times W_d$

Where	W_d	=	Weighted Cost of Debt
Therefore	I	=	\$94,562 x (.52 x .09886) = \$4,861

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R + B_a\ /L_g \times T_r$

Where	T_D	=	Tax Depreciation (*8)
	T_R	=	Tax Rate (48.36%)
	B_a	=	Basis Adjustment
Let	B_a	=	\$100,000 $T_b \times I_a \times$ \$100,000

COLSTRIP PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where I_a = ITC Adjustment = $1 - I_r/2 = 1 - 0.1/2 = 0.95$
T_b = Tax Basis (75%)
Therefore, B_a = \$100,000 - 0.75 x 0.95 x \$100,000 = \$28,750
T = (\$3,563 - \$2,857) x .4836 + \$28,750/35 x .4836
T = \$738

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1 – Tax rate))
INCOME TAX = (\$5,717 + \$2,857 + \$738 - \$3,563) x (.4836/(1 - .4836)) = \$5,384

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax
ANNUAL COST = \$2,857 + \$5,717 + \$4,861 + \$738 + \$5,384 = \$19,557

(*8) TAX DEPRECIATION = (ACRS Percentages 15 Year Public Utility) x Original Tax Basis
TAX DEPRECIATION = 5% x 0.95 x 0.75 x \$100,000 = \$3,563

(*9) ITC = IT Credit x ITC Basis x Cumulative Book
ITC = 10% x 75% x \$100,000 = \$7,500

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1 + i)^n$
PRESENT WORTH ANNUAL COST = \$19,551 x $1/(1 + .1119)^1$ = \$17,589
where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.114701 x \$113,541) /\$100,000 = 0.1302 = <u>13.02%</u>

Cholla Project Annual Fixed Cost

(Estimated 1996 Price)

Initial Levelized Fixed Charge

Cholla Project

Cholla Initial Project Investment – Without Betterments		$184,166,667	/1
Initial Levelized Annual Fixed Rate		13.76%	
Initial Levelized Annual Fixed Charge		$25,346,858	
Subsequent Investment – Includes Betterments 1991 – 1995		$5,619,840	/2
Subsequent Levelized Annual Fixed Rate		13.76%	
Subsequent Levelized Annual Fixed Charge		$773,459	
Ad Valorem Tax		$1,897,865	
Taxes, assessments and in lieu of taxes		$0	
Administrative & General Expenses:			
1989 Total PacifiCorp A&G Expense	$139,130,109		
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075		
A&G Expense as a percent of Investment	1.87%		
Cholla A & G Expense		$3,548,481	
Total Fixed Cost		**$31,566,664**	
Net Cholla Capacity		350	
Annual Fixed Cost per MW		$90,190	
Monthly Fixed Cost per kW		$7.52	

/1 - $221,000,000 x (25/30) = $184,166,667
/2 - $6,743,810 x (25/30) = $5,619,840

PACIFICORP ELECTRIC OPERATIONS
CHOLLA PROJECT
1996 LFC – 25 YEAR REMAINING LIFE
SEPTEMBER 4, 1990

48%	DEBT FINANCING @ 10%	$345	LEVELIZED DEFERRED TAXES	20	YEAR TAX LIFE – ACRS
6%	PREFERRED EQUITY @ 9.5%	$3,186	LEVELIZED INTEREST EXPENSE	N/A	TAX RATE PRIOR TO 1987
46%	COMMON EQUITY @ 12.36%	$378	LEVELIZED PREFERRED RETURN	N/A	TAX RATE IN 1987
11.06%	WEIGHTED COST OF CAPITAL	$3,773	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.11922	CAPITAL RECOVERY FACTOR	0%	INVESTMENT TAX CREDIT (ITC)
$13,763	LEVELIZED ANNUAL COST	1996	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13,763	LEVELIZED FIXED CAPITAL COSTS	25	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$2,081	LEVELIZED INCOME TAXES	25	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RAIL BASE
1996	0	0	0	4,000	4,706	559	5,575	(92)	3,676	18,423	16,589	3,750	98,046
1997	0	0	0	4,000	4,488	533	5,316	1,187	2,230	17,754	14,395	7,219	93,499
1998	0	0	0	4,000	4,244	504	5,027	987	2,244	17,006	12,416	6,677	88,411
1999	0	0	0	4,000	4,009	476	4,748	803	2,250	16,286	10,707	6,177	83,516
2000	0	0	0	4,000	3,782	449	4,480	632	2,248	15,592	9,230	5,713	78,799
2001	0	0	0	4,000	3,564	423	4,221	474	2,240	14,922	7,954	5,285	74,246
2002	0	0	0	4,000	3,353	398	3,971	327	2,225	14,275	6,851	4,888	69,845
2003	0	0	0	4,000	3,148	374	3,729	193	2,205	13,648	5,899	4,522	65,585
2004	0	0	0	4,000	2,947	350	3,491	170	2,074	13,033	5,072	4,462	61,404
2005	0	0	0	4,000	2,747	326	3,254	170	1,922	12,419	4,352	4,461	57,214
2006	0	0	0	4,000	2,547	302	3,017	170	1,769	11,806	3,725	4,462	53,064
2007	0	0	0	4,000	2,347	279	2,780	170	1,617	11,193	3,180	4,461	48,893
2008	0	0	0	4,000	2,147	255	2,543	170	1,464	10,579	2,707	4,462	44,723
2009	0	0	0	4,000	1,947	231	2,306	170	1,312	9,966	2,296	4,461	40,553
2010	0	0	0	4,000	1,746	207	2,069	170	1,159	9,352	1,940	4,462	36,383
2011	0	0	0	4,000	1,546	184	1,831	170	1,007	8,739	1,632	4,461	32,213
2012	0	0	0	4,000	1,346	160	1,594	170	855	8,125	1,367	4,462	28,042
2013	0	0	0	4,000	1,146	136	1,357	170	703	7,512	1,138	4,461	23,872
2014	0	0	0	4,000	946	112	1,120	170	550	6,898	941	4,462	19,702
2015	0	0	0	4,000	746	89	883	170	398	6,285	772	4,461	15,532
2016	0	0	0	4,000	565	67	669	(652)	1,083	5,732	634	2,231	11,773
2017	0	0	0	4,000	424	50	502	(1,475)	1,798	5,300	528	0	8,837
2018	0	0	0	4,000	303	36	359	(1,475)	1,706	4,929	442	0	6,312
2019	0	0	0	4,000	182	22	215	(1,475)	1,614	4,557	368	0	3,787
2020	0	0	0	4,000	61	7	72	(1,475)	1,521	4,186	304	0	1,262
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	100,000	54,986	6,530	65,130	0	41,870	268,516	115,437	100,000	
1996 NET PRESENT VALUE @ 11.06%													
	0	0	0	33,551	26,719	3,173	31,649	2,894	17,452	115,437	66,600	41,397	

PACIFICORP ELECTRIC OPERATIONS
CHOLLA PROJECT
1996 LFC – 25 YEAR REMAINING LIFE
SEPTEMBER 4, 1990

			INVESTMENT TAX CREDIT			DEFERRED TAXES						
YEAR	BEGINNING RATE BASE	BOOK DEPREC	CREDIT	RESTORED	RECAPTURE	CURRENT	RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1996	100,000	(4,000)	0	0	0	92	0	96,092	0	36.88%	3.750%	4.00%
1997	96,092	(4,000)	0	0	0	(1,187)	0	90,905	0	36.88%	7.219%	4.00%
1998	90,905	(4,000)	0	0	0	(987)	0	85,918	0	36.88%	6.677%	4.00%
1999	85,918	(4,000)	0	0	0	(803)	0	81,115	0	36.88%	6.177%	4.00%
2000	81,115	(4,000)	0	0	0	(632)	0	76,483	0	36.88%	5.713%	4.00%
2001	76,483	(4,000)	0	0	0	(474)	0	72,009	0	36.88%	5.285%	4.00%
2002	72,009	(4,000)	0	0	0	(327)	0	67,682	0	36.88%	4.888%	4.00%
2003	67,682	(4,000)	0	0	0	(193)	0	63,489	0	36.88%	4.522%	4.00%
2004	63,489	(4,000)	0	0	0	(170)	0	59,319	0	36.88%	4.462%	4.00%
2005	59,319	(4,000)	0	0	0	(170)	0	55,149	0	36.88%	4.461%	4.00%
2006	55,149	(4,000)	0	0	0	(170)	0	50,978	0	36.88%	4.462%	4.00%
2007	50,978	(4,000)	0	0	0	(170)	0	46,808	0	36.88%	4.461%	4.00%
2008	46,808	(4,000)	0	0	0	(170)	0	42,638	0	36.88%	4.462%	4.00%
2009	42,638	(4,000)	0	0	0	(170)	0	38,468	0	36.88%	4.461%	4.00%
2010	38,468	(4,000)	0	0	0	(170)	0	34,298	0	36.88%	4.462%	4.00%
2011	34,298	(4,000)	0	0	0	(170)	0	30,128	0	36.88%	4.461%	4.00%
2012	30,128	(4,000)	0	0	0	(170)	0	25,957	0	36.88%	4.462%	4.00%
2013	25,957	(4,000)	0	0	0	(170)	0	21,787	0	36.88%	4.461%	4.00%
2014	21,787	(4,000)	0	0	0	(170)	0	17,617	0	36.88%	4.462%	4.00%
2015	17,617	(4,000)	0	0	0	(170)	0	13,447	0	36.88%	4.461%	4.00%
2016	13,447	(4,000)	0	0	0	652	0	10,099	0	36.88%	2.231%	4.00%
2017	10,099	(4,000)	0	0	0	1,475	0	7,574	0	36.88%	0.000%	4.00%
2018	7,574	(4,000)	0	0	0	1,475	0	5,050	0	36.88%	0.000%	4.00%
2019	5,050	(4,000)	0	0	0	1,475	0	2,525	0	36.88%	0.000%	4.00%
2020	2,525	(4,000)	0	0	0	1,475	0	0	0	36.88%	0.000%	4.00%
2021	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2022	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2023	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2024	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2025	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2026	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2027	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2028	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2029	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2030	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
TOTAL		(100,000)	0	0	0	0	0		0		100.000%	100.00%

CHOLLA PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) $= i(1+i)^n/(1+i)^n - 1$
Where $i =$ weighted cost of capital and $n =$ ave. life of plant.

$$CRF = 0.1106\,(1 + 0.1106)^{25}/((1 + 0.1106)^{25} - 1) = 0.119261$$

(*2) BOOK DEPRECIATION = \$100,000/25 Years = \$4,000

(*3) TOTAL RETURN, (TR) $= A \times W_s$

Where	A	=	Average Rate Base; and
	W_s	=	Weighted Cost of Preferred and Common Stock
Let	A	=	$(R_0 + R_1)\ /2$
Where	R_0	=	Rate Base (Year 0)
	R_1	=	Rate base (End of Year 1)
Let	R_1	=	$I_b + I_c/L_g - D - T$
	I_0	=	Cumulative ITC (*9)
	L_g	=	Book Life (25 years)
	D	=	Cumulative Book Depreciation (*2)
	T	=	Cumulative Deferred Tax (*5)
	I_b	=	$E \times (1 - I_r \times I_8$ ITC Basis)
Where	E	=	Capital Expenditure (\$100,000)
	I_r	=	ITC Rate (0.10)

Therefore,	I_b	=	\$100,000 (1 – 0.1 x 0) = \$100,000
	R_1	=	\$100,000 + 0/25 - \$4,000 - (\$92) = \$96,092
	A	=	(\$100,000 + \$96,092) /2 = \$98,046
	TR	=	\$98,046 x (.06 x .095 + .46 x .1236) = \$6,133

(*4) INTEREST, (I) $= A \times W_d$

Where	W_d	=	Weighted Cost of Debt
Therefore	I	=	\$98,046 x (.48 x .10) = \$4,706

(*5) DEFERRED TAX, (T) $= (T_d - D) \times T_R + B_a / L_g \times T_r$

Where	T_D	=	Tax Depreciation (*8)
	T_R	=	Tax Rate (36.88%)
	B_a	=	Basis Adjustment
Let	B_a	=	\$100,000 $T_b \times I_a \times$ \$100,000

CHOLLA PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where	I_a	=	ITC Adjustment = 1 - I_r/2 = 1 - 0.0/2 = 0
	T_b	=	Tax Basis (100%)
Therefore,	B_a	=	\$100,000 - 1 x 1.00 x \$100,000 = 0
	T	=	(\$3,750 - \$4,000) x 36.88 + 0/25 x 36.88
	T	=	\$92

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1 – Tax rate))

INCOME TAX = (\$6,133 + \$4,000 + (\$92) - \$3,750) x (.3688/(1 - .3688)) = \$3,675

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax

ANNUAL COST = \$4,000 + \$6,133 + \$4,706 + (\$92) + \$3,675 = \$18,423

(*8) TAX DEPRECIATION = (150% Declining Balance converting to Straight Line) x (1/2 yr. Amort. in 1st year)

TAX DEPRECIATION = 1.50 x (\$100,000/20) /2 = \$3,750

(*9) ITC = Not Applicable

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1 + i)^n$

PRESENT WORTH ANNUAL COST = \$18,423 x $1/(1 + .1106)^1$ = \$16,589

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost

INITIAL LEVELIZED FIXED CHARGE RATE = (0.119261 x \$115,437) /\$100,000 = 0.1376 = <u>13.76%</u>

Hunter #2 Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(Estimated 1996 Price)

Initial Levelized Fixed Charge

Hunter #2 Project

Hunter #2 Initial Project Investment		$174,355,375
Initial Levelized Annual Fixed Rate		13.67%
Initial Levelized Annual Fixed Charge		$23,827,406
Subsequent Investment - (1990 thru 1995)		$5,296,480
Subsequent Levelized Annual Fixed Rate		13.67%
Subsequent Levelized Annual Fixed Charge		$724,029
Ad Valorem Tax		$2,160,314
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #2 A & G Expense		$3,358,992
Total Fixed Cost		**$30,070,740**
Net Hunter #2 Capacity		235
Annual Fixed Cost per MW		$127,961
Monthly Fixed Cost per kW		$\boxed{\$10.66}$

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 PROJECT

AUGUST 28, 1990

50%	DEBT FINANCING @ 11.97%	$1,187	LEVELIZED DEFERRED TAXES	22.5	YEAR TAX LIFE – SUM OF THE YEAR DIGITS
10%	PREFERRED EQUITY @ 10.96%	$3,966	LEVELIZED INTEREST EXPENSE	48.36%	TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
40%	COMMON EQUITY @ 12.36%	$726	LEVELIZED PREFERRED RETURN	42.62%	TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
12.03%	WEIGHTED COST OF CAPITAL	$3,276	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.12255	CAPITAL RECOVERY FACTOR	10.00%	INVESTMENT TAX CREDIT (ITC)
$13,666	LEVELIZED ANNUAL COST	1980	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13,666	LEVELIZED FIXED CAPITAL COSTS	35	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$1,939	LEVELIZED INCOME TAXES	35	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RAIL BASE
1980	0	0	0	2,857	5,879	1,077	4,857	676	4,612	19,672	17,560	4,255	98,233
1981	0	0	0	2,857	5,609	1,027	4,633	2,646	2,387	18,873	15,039	8,329	93,715
1982	0	0	0	2,857	5,285	968	4,366	2,461	2,266	17,917	12,744	7,946	88,305
1983	0	0	0	2,857	4,972	911	4,107	2,277	2,155	16,993	10,790	7,565	83,079
1984	0	0	0	2,857	4,670	855	3,858	2,095	2,051	16,101	9,126	7,190	78,036
1985	0	0	0	2,857	4,379	802	3,618	1,913	1,958	15,242	7,712	6,814	73,174
1986	0	0	0	2,857	4,100	751	3,386	1,729	1,878	14,414	6,510	6,432	68,496
1987	0	0	0	2,857	3,836	702	3,169	1,362	1,301	12,942	5,218	6,052	64,094
1988	0	0	0	2,857	3,593	658	2,968	1,040	912	11,743	4,226	5,676	60,036
1989	0	0	0	2,857	3,364	616	2,779	900	917	11,147	3,581	5,297	56,209
1990	0	0	0	2,857	3,143	576	2,597	761	925	10,574	3,032	4,921	52,522
1991	0	0	0	2,857	2,931	537	2,421	621	941	10,022	2,565	4,540	48,974
1992	0	0	0	2,857	2,727	499	2,253	482	959	9,492	2,169	4,164	45,565
1993	0	0	0	2,857	2,531	464	2,091	342	984	8,983	1,832	3,784	42,296
1994	0	0	0	2,857	2,344	429	1,936	202	1,013	8,497	1,547	3,406	39,167
1995	0	0	0	2,857	2,165	397	1,789	63	1,047	8,032	1,305	3,027	36,177
1996	0	0	0	2,857	1,995	365	1,648	(93)	1,077	7,563	1,097	2,649	33,335
1997	0	0	0	2,857	1,835	336	1,516	(263)	1,104	7,099	919	2,270	30,656
1998	0	0	0	2,857	1,685	308	1,392	(432)	1,138	6,661	770	1,892	28,147
1999	0	0	0	2,857	1,545	283	1,276	(602)	1,177	6,250	645	1,514	25,807
2000	0	0	0	2,857	1,415	259	1,169	(771)	1,223	5,865	540	1,135	23,636
2001	0	0	0	2,857	1,295	237	1,070	(941)	1,274	5,506	453	757	21,635
2002	0	0	0	2,857	1,185	217	979	(1,111)	1,332	5,174	380	378	19,804
2003	0	0	0	2,857	1,086	199	897	(1,280)	1,395	4,868	319	0	18,142
2004	0	0	0	2,857	991	182	819	(1,280)	1,339	4,623	270	0	16,564
2005	0	0	0	2,857	897	164	741	(1,280)	1,284	4,377	229	0	14,987
2006	0	0	0	2,857	803	147	663	(1,280)	1,228	4,132	193	0	13,410
2007	0	0	0	2,857	708	130	585	(1,280)	1,172	3,887	162	0	11,832
2008	0	0	0	2,857	614	112	507	(1,280)	1,117	3,641	135	0	10,255
2009	0	0	0	2,857	519	95	429	(1,280)	1,061	3,396	113	0	8,678
2010	0	0	0	2,857	425	78	351	(1,280)	1,005	3,151	93	0	7,100
2011	0	0	0	2,857	331	61	273	(1,280)	950	2,905	77	0	5,523
2012	0	0	0	2,857	236	43	195	(1,280)	894	2,660	63	0	3,946
2013	0	0	0	2,857	142	26	117	(1,280)	838	2,415	51	0	2,369
2014	0	0	0	2,857	47	9	39	(1,280)	783	2,169	41	0	791
TOTAL	0	0	0	100,000	79,283	14,519	65,493	0	47,694	296,986	111,507	99,993	
1980 NET PRESENT VALUE @ 12.03%	0	0	0	23,314	32,358	5,925	26,730	9,689	15,823	111,507	111,507	44,160	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 PROJECT

AUGUST 28, 1990

	BEGINNING	BOOK	INVESTMENT TAX CREDIT			DEFERRED TAXES		ENDING	EXCESS	INCOME	TAX	BOOK
YEAR	RATE BASE	DEPREC	CREDIT	RESTORED	RECAPTURE	CURRENT	RESTORED	RATE BASE	DEFERRED	TAX RATE	DEPREC	DEPREC
1980	100,000	(2,857)	(286)	286	0	(676)	0	96,467	(160)	48.36%	4.255%	2.86%
1981	96,467	(2,857)	(286)	286	0	(2,646)	0	90,964	(628)	48.36%	8.329%	2.86%
1982	90,964	(2,857)	(286)	286	0	(2,461)	0	85,646	(584)	48.36%	7.946%	2.86%
1983	85,646	(2,857)	(286)	286	0	(2,277)	0	80,512	(540)	48.36%	7.565%	2.86%
1984	80,512	(2,857)	(286)	286	0	(2,095)	0	75,560	(497)	48.36%	7.190%	2.86%
1985	75,560	(2,857)	(286)	286	0	(1,913)	0	70,789	(454)	48.36%	6.814%	2.86%
1986	70,789	(2,857)	(286)	286	0	(1,729)	0	66,203	(410)	48.36%	6.432%	2.86%
1987	66,203	(2,857)	(286)	286	0	(1,362)	0	61,985	(183)	42.62%	6.052%	2.86%
1988	61,985	(2,857)	(286)	286	0	(1,040)	0	58,088	0	36.88%	5.676%	2.86%
1989	58,088	(2,857)	(286)	286	0	(900)	0	54,331	0	36.88%	5.297%	2.86%
1990	54,331	(2,857)	(286)	286	0	(761)	0	50,713	0	36.88%	4.921%	2.86%
1991	50,713	(2,857)	(286)	286	0	(621)	0	47,235	0	36.88%	4.540%	2.86%
1992	47,235	(2,857)	(286)	286	0	(482)	0	43,896	0	36.88%	4.164%	2.86%
1993	43,896	(2,857)	(286)	286	0	(342)	0	40,697	0	36.88%	3.784%	2.86%
1994	40,697	(2,857)	(286)	286	0	(202)	0	37,637	0	36.88%	3.406%	2.86%
1995	37,637	(2,857)	(286)	286	0	(63)	0	34,717	0	36.88%	3.027%	2.86%
1996	34,717	(2,857)	(286)	286	0	77	16	31,954	0	36.88%	2.649%	2.86%
1997	31,954	(2,857)	(286)	286	0	217	46	29,359	0	36.88%	2.270%	2.86%
1998	29,359	(2,857)	(286)	286	0	356	76	26,935	0	36.88%	1.892%	2.86%
1999	26,935	(2,857)	(286)	286	0	495	106	24,679	0	36.88%	1.514%	2.86%
2000	24,679	(2,857)	(286)	286	0	635	136	22,593	0	36.88%	1.135%	2.86%
2001	22,593	(2,857)	(286)	286	0	775	166	20,677	0	36.88%	0.757%	2.86%
2002	20,677	(2,857)	(286)	286	0	914	196	18,930	0	36.88%	0.378%	2.86%
2003	18,930	(2,857)	(286)	286	0	1,054	226	17,353	0	36.88%	0.000%	2.86%
2004	17,353	(2,857)	(286)	286	0	1,054	226	15,776	0	36.88%	0.000%	2.86%
2005	15,776	(2,857)	(286)	286	0	1,054	226	14,198	0	36.88%	0.000%	2.86%
2006	14,198	(2,857)	(286)	286	0	1,054	226	12,621	0	36.88%	0.000%	2.86%
2007	12,621	(2,857)	(286)	286	0	1,054	226	11,044	0	36.88%	0.000%	2.86%
2008	11,044	(2,857)	(286)	286	0	1,054	226	9,466	0	36.88%	0.000%	2.86%
2009	9,466	(2,857)	(286)	286	0	1,054	226	7,889	0	36.88%	0.000%	2.86%
2010	7,889	(2,857)	(286)	286	0	1,054	226	6,312	0	36.88%	0.000%	2.86%
2011	6,312	(2,857)	(286)	286	0	1,054	226	4,735	0	36.88%	0.000%	2.86%
2012	4,735	(2,857)	(286)	286	0	1,054	226	3,157	0	36.88%	0.000%	2.86%
2013	3,157	(2,857)	(286)	286	0	1,054	226	1,580	0	36.88%	0.000%	2.86%
2014	1,580	(2,857)	(286)	286	0	1,054	226	3	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(10,000)	10,000	0	(3,455)	3,458		(3,458)		99.990%	100.00%

HUNTER #2 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n - 1$
Where i = weighted cost of capital and n = ave. life of plant.

$$CRF = 0.1203\ (1 + 0.1203)^{35}/((1 + 0.1203)^{35} - 1) = 0.12260$$

(*2) BOOK DEPRECIATION = \$100,000/35 Years = \$2,857

(*3) TOTAL RETURN, (TR) = A x W_s

Where	A	=	Average Rate Base; and
	W_s	=	Weighted Cost of Preferred and Common Stock
Let	A	=	Beginning Investment - (D + T) /2

Where Beginning Investment = Previous year's beginning investment - previous year's D and T.

D	=	Book Depreciation (*2)
T	=	Deferred Tax (*5)

Therefore, beginning investment = \$100,000

A	=	\$100,000 - (2857 + 676) /2 = \$98,234
TR	=	\$98,234 x (.10 x .1096 + .40 x .1236) = \$5,933

(*4) INTEREST, (I) = A x W_d

Where	W_d	=	Weighted Cost of Debt
Therefore	I	=	\$98,234 x (.50 x .1197) = \$5,879

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R$

Where	T_D	=	Tax Depreciation (*8)
	T_R	=	Tax Rate (48.36%)
Let	T	=	(4,255 - 2,857) x .4836 = \$676

HUNTER #2 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation + ITC) x Tax rate/(1 – Tax rate)

INCOME TAX = ($5,933 + $2,857 + $676 - $4,255 - $285) x (.4836/(1 - .4836)) = $4,612

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax + ITC

ANNUAL COST = $2,857 + $5,933 + $5,879 + $676 + $4,612 - 285 = $19,672

(*8) TAX DEPRECIATION = (Sum of the Year's Digits) = Year's remaining /sum of Digits) x (Beginning Investment - Cumulative Tax Depreciation)

Where Sum of Digits in yr. 1 = 264.5 (For 22.5 year tax life)

TAX DEPRECIATION = (22.5/264.5) x (100,000 - 0) = $8,510
Adjusted for 1/2 year = $8,510/2 = $4,255

(*9) ITC = Beginning Investment x ITC Rate/Book Life
ITC = $100,000 x 0.10/^{35} = $285

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1 + i)^n$
PRESENT WORTH ANNUAL COST = $19,672 x $1/(1 + .1203)^1$ = $17,560

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.1226 x $111,507) /$100,000 = 0.1367 = 13.67%

Hunter #3 Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(1996 Estimated Price)

Initial Levelized Fixed Charge

Hunter #3 Project

Hunter #3 Initial Project Investment		$453,116,692
Initial Levelized Annual Fixed Rate		14.76%
Initial Levelized Annual Fixed Charge		$66,870,961
Subsequent Investment - (1990 thru 1995)		$13,764,557
Subsequent Levelized Annual Fixed Rate		14.76%
Subsequent Levelized Annual Fixed Charge		$2,031,649
Ad Valorem Tax		$5,210,051
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #2 A & G Expense		$8,729,385
Total Fixed Cost		**$82,842,046**
Net Hunter #2 Capacity		400
Annual Fixed Cost per MW		$207,105
Monthly Fixed Cost per kW		$17.26

PACIFICORP ELECTRIC OPERATIONS
HUNTER #3 PROJECT

AUGUST 28, 1990

50%	DEBT FINANCING @ 14.52%	$1,329	LEVELIZED DEFERRED TAXES	15	YEAR TAX LIFE – ACRS
10%	PREFERRED EQUITY @ 11.6%	$4,925	LEVELIZED INTEREST EXPENSE	48.36%	TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
40%	COMMON EQUITY @ 12.36%	$787	LEVELIZED PREFERRED RETURN	42.62%	TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
13.36%	WEIGHTED COST OF CAPITAL	$3,354	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.13532	CAPITAL RECOVERY FACTOR	10.00%	INVESTMENT TAX CREDIT (ITC)
$14,758	LEVELIZED ANNUAL COST	1980	IN SERVICE DATE	95%	ITC BASIS ADJUSTMENT
$14,758	LEVELIZED FIXED CAPITAL COSTS	35	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$1,792	LEVELIZED INCOME TAXES	35	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RAIL BASE
1983	0	0	0	2,857	7,121	1,138	4,849	984	4,488	21,151	18,657	4,750	98,079
1984	0	0	0	2,857	6,758	1,080	4,602	3,281	1,905	20,199	15,717	9,500	93,089
1985	0	0	0	2,857	6,329	1,011	4,310	2,822	2,027	19,071	13,090	8,550	87,180
1986	0	0	0	2,857	5,934	948	4,041	2,363	2,175	18,032	10,918	7,600	81,731
1987	0	0	0	2,857	5,580	892	3,800	1,677	1,701	16,220	8,663	6,650	76,854
1988	0	0	0	2,857	5,259	840	3,581	1,452	1,048	14,751	6,950	6,650	72,432
1989	0	0	0	2,857	4,959	792	3,377	1,101	1,251	14,051	5,840	5,700	68,299
1990	0	0	0	2,857	4,671	746	3,181	1,101	1,110	13,381	4,906	5,700	64,341
1991	0	0	0	2,857	4,384	700	2,985	1,101	969	12,711	4,111	5,700	60,382
1992	0	0	0	2,857	4,096	655	2,790	1,101	828	12,041	3,435	5,700	56,424
1993	0	0	0	2,857	3,809	609	2,594	1,101	687	11,371	2,861	5,700	52,466
1994	0	0	0	2,857	3,522	563	2,398	1,101	545	10,701	2,375	5,700	48,508
1995	0	0	0	2,857	3,234	517	2,203	1,101	404	10,030	1,964	5,700	44,549
1996	0	0	0	2,857	2,947	471	2,007	1,101	263	9,360	1,617	5,700	40,591
1997	0	0	0	2,857	2,660	425	1,811	1,101	122	8,690	1,324	5,700	36,633
1998	0	0	0	2,857	2,453	392	1,670	(1,124)	2,050	8,013	1,077	0	33,787
1999	0	0	0	2,857	2,327	372	1,585	(1,124)	1,989	7,719	915	0	32,055
2000	0	0	0	2,857	2,201	352	1,499	(1,124)	1,927	7,426	77	0	30,322
2001	0	0	0	2,857	2,076	332	1,413	(1,124)	1,865	7,133	658	0	28,589
2002	0	0	0	2,857	1,950	312	1,328	(1,124)	1,803	6,839	557	0	26,856
2003	0	0	0	2,857	1,824	291	1,242	(1,124)	1,741	6,546	470	0	25,124
2004	0	0	0	2,857	1,698	271	1,156	(1,124)	1,680	6,253	396	0	23,391
2005	0	0	0	2,857	1,572	251	1,071	(1,124)	1,618	5,959	333	0	21,658
2006	0	0	0	2,857	1,447	231	985	(1,124)	1,556	5,666	279	0	19,926
2007	0	0	0	2,857	1,321	211	899	(1,124)	1,494	5,373	234	0	18,193
2008	0	0	0	2,857	1,195	191	814	(1,124)	1,433	5,079	195	0	16,460
2009	0	0	0	2,857	1,069	171	728	(1,124)	1,371	4,786	162	0	14,728
2010	0	0	0	2,857	943	151	642	(1,124)	1,309	4,493	134	0	12,995
2011	0	0	0	2,857	818	131	557	(1,124)	1,247	4,199	111	0	11,262
2012	0	0	0	2,857	692	111	471	(1,124)	1,185	3,906	91	0	9,530
2013	0	0	0	2,857	566	90	385	(1,124)	1,124	3,612	74	0	7,797
2014	0	0	0	2,857	440	70	300	(1,124)	1,062	3,319	60	0	6,064
2015	0	0	0	2,857	314	50	214	(1,124)	1,000	3,026	48	0	4,332
2016	0	0	0	2,857	189	30	128	(1,124)	938	2,732	38	0	2,599
2017	0	0	0	2,857	63	10	43	(1,124)	876	2,439	30	0	866
TOTAL	0	0	0	100,000	96,420	15,406	65,661	0	48,792	316,278	109,065	95,000	
1983 NET PRESENT VALUE @ 13.36%													
	0	0	0	21,114	36,398	5,816	24,787	9,818	13,243	109,065	109,065	42,334	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #3 PROJECT

AUGUST 28, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	INVESTMENT TAX CREDIT RESTORED	INVESTMENT TAX CREDIT RECAPTURE	DEFERRED TAXES CURRENT	DEFERRED TAXES RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1983	100,000	(2,857)	(286)	286	0	(984)	0	96,158	(234)	48.36%	5.000%	2.86%
1984	96,158	(2,857)	(286)	286	0	(3,281)	0	90,020	(779)	48.36%	10.000%	2.86%
1985	90,020	(2,857)	(286)	286	0	(2,822)	0	84,341	(670)	48.36%	9.000%	2.86%
1986	84,341	(2,857)	(286)	286	0	(2,363)	0	79,121	(561)	48.36%	8.000%	2.86%
1987	79,121	(2,857)	(286)	286	0	(1,677)	0	74,587	(226)	42.62%	7.000%	2.86%
1988	74,587	(2,857)	(286)	286	0	(1,452)	0	70,278	0	36.88%	7.000%	2.86%
1989	70,278	(2,857)	(286)	286	0	(1,101)	0	66,320	0	36.88%	6.000%	2.86%
1990	66,320	(2,857)	(286)	286	0	(1,101)	0	62,361	0	36.88%	6.000%	2.86%
1991	62,361	(2,857)	(286)	286	0	(1,101)	0	58,403	0	36.88%	6.000%	2.86%
1992	58,403	(2,857)	(286)	286	0	(1,101)	0	54,445	0	36.88%	6.000%	2.86%
1993	54,445	(2,857)	(286)	286	0	(1,101)	0	50,487	0	36.88%	6.000%	2.86%
1994	50,487	(2,857)	(286)	286	0	(1,101)	0	46,528	0	36.88%	6.000%	2.86%
1995	46,528	(2,857)	(286)	286	0	(1,101)	0	42,570	0	36.88%	6.000%	2.86%
1996	42,570	(2,857)	(286)	286	0	(1,101)	0	38,612	0	36.88%	6.000%	2.86%
1997	38,612	(2,857)	(286)	286	0	(1,101)	0	34,654	0	36.88%	6.000%	2.86%
1998	34,654	(2,857)	(286)	286	0	1,001	123	32,921	0	36.88%	0.000%	2.86%
1999	32,921	(2,857)	(286)	286	0	1,001	123	31,188	0	36.88%	0.000%	2.86%
2000	31,188	(2,857)	(286)	286	0	1,001	123	29,455	0	36.88%	0.000%	2.86%
2001	29,455	(2,857)	(286)	286	0	1,001	123	27,723	0	36.88%	0.000%	2.86%
2002	27,723	(2,857)	(286)	286	0	1,001	123	25,990	0	36.88%	0.000%	2.86%
2003	25,990	(2,857)	(286)	286	0	1,001	123	24,257	0	36.88%	0.000%	2.86%
2004	24,257	(2,857)	(286)	286	0	1,001	123	22,525	0	36.88%	0.000%	2.86%
2005	22,525	(2,857)	(286)	286	0	1,001	123	20,792	0	36.88%	0.000%	2.86%
2006	20,792	(2,857)	(286)	286	0	1,001	123	19,059	0	36.88%	0.000%	2.86%
2007	19,059	(2,857)	(286)	286	0	1,001	123	17,327	0	36.88%	0.000%	2.86%
2008	17,327	(2,857)	(286)	286	0	1,001	123	15,594	0	36.88%	0.000%	2.86%
2009	15,594	(2,857)	(286)	286	0	1,001	123	13,861	0	36.88%	0.000%	2.86%
2010	13,861	(2,857)	(286)	286	0	1,001	123	12,129	0	36.88%	0.000%	2.86%
2011	12,129	(2,857)	(286)	286	0	1,001	123	10,396	0	36.88%	0.000%	2.86%
2012	10,396	(2,857)	(286)	286	0	1,001	123	8,663	0	36.88%	0.000%	2.86%
2013	8,663	(2,857)	(286)	286	0	1,001	123	6,931	0	36.88%	0.000%	2.86%
2014	6,931	(2,857)	(286)	286	0	1,001	123	5,198	0	36.88%	0.000%	2.86%
2015	5,198	(2,857)	(286)	286	0	1,001	123	3,465	0	36.88%	0.000%	2.86%
2016	3,465	(2,857)	(286)	286	0	1,001	123	1,733	0	36.88%	0.000%	2.86%
2017	1,733	(2,857)	(286)	286	0	1,001	123	0	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(10,000)	10,000	0	(2,469)	2,469		(2,469)		100.000%	100.00%

HUNTER #3 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n - 1$
Where i = weighted cost of capital and n = ave. life of plant.

$$CRF = 0.1336\ (1 + 0.1336)^{35}/((1 + 0.1336)^{35} - 1) = 0.13528$$

(*2) BOOK DEPRECIATION = \$100,000/30 Years = \$2,857

(*3) TOTAL RETURN, (TR) = A x W_s
Where A = Average Rate Base; and
W_s = Weighted Cost of Preferred and Common Stock
Let A = Beginning Investment - (D + T) /2
Where Beginning Investment = Previous year's beginning investment - previous year's D and T.

D = Book Depreciation (*2)
T = Deferred Tax (*5)
Therefore, beginning investment = \$100,000
A = \$100,000 - (2857 + 984) /2 = \$98,080
TR = \$98,080 x (.10 x .1160 + .40 x .1236) = \$5,987

(*4) INTEREST, (I) = A x W_d
Where W_d = Weighted Cost of Debt
Therefore I = \$98,080 x (.50 x .1452) = \$7,121

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R$
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (48.36%)
B^2 = \$100,000 - T^b x I_a x \$100,000
L_g = Book Life (35 years)

HUNTER #3 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where I_a = ITC Adjustment = $1 - I_r/2 = 1 - 0.1/2$
I_r = ITC Rate (0.10)
T_b = Tax Basis (100%)
Therefore, B_a = \$100,000 - 1.00 x 0.95 x \$100,000 = \$5,000
T = (\$4,750 - \$2,857) x .4836 + 5000/35 x .4836 = \$984

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation + ITC) x Tax rate/(1 – Tax rate)
INCOME TAX = (\$5,987 + \$2,857 + \$984 - \$4,750 - \$285) x (.4836/(1 - .4836)) = \$4,488

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax + ITC
ANNUAL COST = \$2,857 + \$5,987 + \$7,121 + \$984 + \$4,488 - 285 = \$21,151

(*8) TAX DEPRECIATION = (ACRS Percentages 15 Year Public Utility) x Original Tax Basis
TAX DEPRECIATION = 5% x 0.95 x 1.00 x \$100,000 = \$4,750

(*9) ITC = Beginning Investment x ITC Rate/Book Life
ITC = \$100,000 x $0.10/^{35}$ = \$285

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1 + i)^n$
PRESENT WORTH ANNUAL COST = \$21,151 x $1/(1 + .1336)^1$ = \$18,657

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.13528 x \$109,065) /\$100,000 = 0.1476 = <u>14.76%</u>

Annual Fixed Cost

Annual Fixed Cost

	Pool Size (mw)	Monthly Fixed Cost ($/kW/Mo.)	Weighted Average
Colstrip	70	18.53	$1,297
Cholla	350	7.52	$2,632
Hunter #2	180	10.66	$1,919
Hunter #3	400	17.26	$6,904
Total	1000	NA	$12,752

Annual Fixed Cost ,$/kW/mo.	$12.75
System Transmission Component =	**$0.00**
W/ System Transmission, $/kW/Mo. =	**$12.75**
Transmission Loss Factor =	1
Annual Fixed Cost Adjusted for Losses =	$12.75

APPENDIX B: ANNUAL VARIABLE COST

This Appendix sets forth the elements and techniques to calculate the Annual Variable Cost.

Section BI: Determination of Annual Variable Cost

The Annual Variable Cost shall be the $/Mwh result of the following: (1) the product of 70 MW multiplied by the Colstrip annual load factor multiplied by the Colstrip Project Annual Variable Cost plus the product of 350 MW multiplied by the Cholla annual load factor multiplied by the Cholla Project Annual Variable Cost plus the product of 180 MW multiplied by the Hunter #2 annual load factor multiplied by the Hunter #2 Project Annual Variable Cost plus the product of 400 MW multiplied by the Hunter #3 annual load factor multiplied by the Hunter #3 Project Annual Variable Cost, (2) dividing the above sum by the total of 70 MW multiplied by the Colstrip annual load factor plus 350 MW multiplied by the Cholla annual load factor plus 180 MW multiplied by the Hunter #2 annual load factor plus 400 MW multiplied by the Hunter #3 annual load factor.

Section B2: Determination of Colstrip Project Annual Variable Cost, Cholla Project Annual Variable Cost, Hunter #2 Project Annual Variable Cost and, Hunter #3 Project Annual Variable Cost

The Colstrip Project Annual Variable Cost, the Cholla Project Annual Variable Cost, the Hunter #2 Project Annual Variable Cost and the Hunter #3 Project Annual Variable Cost shall be determined, for each Project, by (a) adding the amounts as set forth in Sections B2.1 through B2.2 (plus B2.3 for Hunter #2 and plus B2.4 for Hunter #3) and (b) dividing each Project total by PacifiCorp's share of the associated Project's annual energy production as filed with the Federal Energy Regulatory Commission (FERC) in PacifiCorp's FERC Form No. 1, or its successor thereto.

B2.1 Production Expenses shall be equal to the production expenses of resources in the Resource Pool as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

B2.2 In lieu of payments shall consist of any assessment, payment in lieu of taxes or other charge which is imposed against PacifiCorp by governmental authority and related to the operation and maintenance of each Project.

B2.3 Hunter #2 Project allocated mining expenses, to be determined by adding the amounts calculated under Sections B2.3.1 through B2.3.4 below:

B2.3.1 PacifiCorp's adjusted initial levelized annual fixed charge rate for the Hunter #2 project mining investment multiplied by the Hunter #2 project mining initial investment, determined pursuant to Section B3, as of December 31, 1989. For purposes of this section, PacifiCorp's total investment in Hunter #2 project mining is $22,748,496. Such total investment shall remain constant through the book life (14 years) and shall be $0 afterwards. Such adjusted initial levelized annual fixed charge rate shall be determined by subtracting book depreciation (1/book life) from PacifiCorp's initial levelized annual fixed charge rate for the Hunter #2 project mining investment determined annually in accordance with Section B4, below. Such book depreciation is reflected in Hunter #2 fuel cost.

B2.3.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, for the Hunter #2 Project mining investment, as calculated in accordance with Section B4, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #2 Project allocated mining investment, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

B2.3.3 All ad valorem taxes imposed upon the Hunter #2 Project mining investment.

B2.3.4 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total Hunter #2 Project mining investment.

B2.4 Hunter #3 Project allocated mining expenses, to be determined by adding the amounts calculated under Section B2.4.1 through B2.4.4 below:

B2.4.1 PacifiCorp's adjusted initial levelized annual fixed charge rate for the Hunter #3 Project mining investment multiplied by the Hunter #3 Project mining initial investment, determined pursuant to Section B3, as of December 31, 1989. For purposes of this section, PacifiCorp's total investment in Hunter #3 project mining is $38,720,844. Such total investment shall remain constant through the book life (14 years) and shall be $0 afterwards. Such adjusted initial levelized annual fixed charge rate shall be determined by subtracting book depreciation (1/book life) from PacifiCorp's initial levelized annual fixed charge rate for the Hunter #3 project mining investment determined annually in accordance with Section B4, below. Such book depreciation is reflected in Hunter #3 fuel cost.

B2.4.2 Each subsequent annual levelized fixed charge shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for the Hunter #3 Project mining investment, as calculated in accordance with Section B4, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #3 Project allocated mining investment, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

B2.4.3 All ad valorem taxes imposed upon the Hunter #3 Project mining investment.

B2.4.4 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total Hunter #3 Project mining investment.

Section B3: Allocation of Mining Investment to Hunter #2 and Hunter #3 Projects

Hunter #2 mining initial investment and Hunter #3 mining initial investment shall be determined by (a) multiplying the dollar amount as set forth in Section B3.1 by (b) the ratio of

PacifiCorp's share of the associated Project's capability (235 MW for Hunter #2 Project and 400 MW for Hunter #3 Project) divided by the total capability of all Projects served by the mines (presently 1995 MW). Hunter #2 mining subsequent investment and Hunter #3 mining subsequent investment shall be determined by (a) multiplying the dollar amounts as set forth in Section B3.2 by (b) the ratio of PacifiCorp's share of the associated Projects capability (235 MW for Hunter #2 Project and 400 MW for Hunter #3 Project) divided by the total capability of all Projects served by the mines (presently 1995 MW).

B3.1 Gross coal plant, as reported in FERC account 399 as "Total Other Tangible Property" in PacifiCorp's FERC Form 1 as of December 31, 1989.

B3.2 Each subsequent coal mine investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments, as determined pursuant to data contained in PacifiCorp's FERC Form 1 or its successor thereto.

Section B4: Elements of Hunter #2 and Hunter #3 Project Mining Investment

Levelized Annual Fixed Charge Rates

B4.1 Capital Structure:

B4.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #2 and Hunter #3 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total	100%

B4.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total	100$

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization-

B4.2 Cost of Capital:

B4.2.1.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be eight and forty-seven hundredths percent (8.47%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #2 and Hunter #3 Project Mining Investment, in the twelve (12)-month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12)-month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

B4.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be eight and twenty-four hundredths (8.24%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

B4.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date

PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

B4.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a fourteen (14) year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment. Because book depreciation is reflected in the Hunter #2 and #3 fuel cost, an adjustment is made to the initial levelized annual fixed charge rate for the Hunter #2 and #3 project mining investment, pursuant to Subsections B2.3.1 and B2.4.1.

B4.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

B4.4.1 The federal corporate income tax rate, of 34%.

B4.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's (3) three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

B4.4.3 The Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating both the initial and subsequent levelized annual fixed charge rates.

B4.4.4 Regular Investment Tax Credits allowed in) accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits shall be used when calculating subsequent levelized annual fixed charge rates.

B4.4.5 Tax basis shall be one-hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate.

Colstrip Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Colstrip Project	
Annual Energy Production (MWh)	1,052,975
Production Expenses	
Operation, Supervision and Engineering	$180,275
Fuel	$7,394,559
Steam Expenses	$722,304
Electric Expenses	$330,429
Misc. Steam Power Expenses	$875,183
Rents	($74,887)
Maintenance, Supervision and Engineering	$225,070
Maintenance of Structures	$207,729
Maintenance of Boiler Plant	$1,315,261
Maintenance of Electric Plant	$261,013
Maintenance of Misc. Steam Plant	$244,057
Subtotal	$11,680,993
In Lieu of Payments *	$219,107
Total Variable Costs Colstrip Project	$11,900,100
Colstrip Project Annual Variable Cost	$11.30 per MWh

* Montana Electrical Energy License Tax

Cholla Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Cholla Project	
Annual Energy Production (MWh)	4,913,599
Production Expenses	
Operation, Supervision and Engineering	$391,540
Fuel	$84,460,268
Steam Expenses	$3,263,082
Electric Expenses	$834,325
Misc. Steam Power Expenses	$1,553,024
Rents	$139,392
Maintenance, Supervision and Engineering	$2,829,620
Maintenance of Structures	$504,564
Maintenance of Boiler Plant	$9,343,026
Maintenance of Electric Plant	$1,975,652
Maintenance of Misc. Steam Plant	$1,479,085
Subtotal	$106,773,578
In Lieu of Payments	-
Total Variable Costs Cholla Project	$106,773,578
Cholla Annual Variable Cost	$21.73 per MWh

Note: Example Purposes Only - Reflects Total Cholla Plant

Hunter #2 Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Hunter #2 Project	
Annual Energy Production (MWh)	1,653,390
Production Expenses	
Operation, Supervision and Engineering	$139,904
Fuel	$14,927,530
Steam Expenses	$1,457,346
Electric Expenses	$577,512
Misc. Steam Power Expenses	$623,071
Rents	$27
Maintenance, Supervision and Engineering	$373,099
Maintenance of Structures	$242,519
Maintenance of Boiler Plant	$1,974,717
Maintenance of Electric Plant	$336,814
Maintenance of Misc. Steam Plant	$468.726
Subtotal	$21,121,265
Allocated Mining Expenses	$2,189,452 *
In Lieu of Payments	-
Total Variable Costs Hunter #2 Project	$23,310,717
Hunter #2 Project Annual Variable Cost	**$14.10 per MWh**

* See Attached sheets for details

Hunter #3 Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Hunter #3 Project	
Annual Energy Production (MWh)	2,743,379
Production Expenses	
Operation, Supervision and Engineering	$231,997
Fuel	$24,859,535
Steam Expenses	$2,517,785
Electric Expenses	$1,179,383
Misc. Steam Power Expenses	$897,027
Rents	$2,437
Maintenance, Supervision and Engineering	$715,529
Maintenance of Structures	$431,445
Maintenance of Boiler Plant	$4,837,672
Maintenance of Electric Plant	$686,521
Maintenance of Misc. Steam Plant	$958,473
Subtotal	$37,317,804
Allocated Mining Expenses	$3,726,731 *
In Lieu of Payments	-
Total Variable Costs Hunter #3 Project	$41,044,535
Hunter #3 Project Annual Variable Cost	**$14.96 per MWh**

* See attached sheets for details

Annual Variable Cost

Project Annual Load Factors

	1989 Generation (Mwh)	Capacity MW	Load Factor
Colstrip	1,052,975	140	86%
Cholla	6,910,089	940	84%
Hunter #2	1,653,390	235	80%
Hunter #3	2,743,379	400	78%

Weighted Variable Cost

	Capacity MW	Load Factor	Variable Cost $/MWh	Numerator	Denominator
Colstrip	70	86%	11.30	679	60
Cholla	350	84%	21.73	6,382	294
Hunter #2	180	80%	14.10	2,038	145
Hunter #3	400	78%	14.96	4,685	313
Total				13,785	812

Numerator = Capacity x Load Factor x Variable Cost

Denominator = Capacity x Load Factor

Weighted Variable Cast =	13,785	÷	812	=	$16.99
Adjusted for Losses =	$16.99	÷	1		
Annual Variable Cost =			$\boxed{\$16.99}$		

Hunter #2 Project Allocated Mining Expenses

(Based on 1989 Actual Costs)

Initial Levelized Fixed Charge

Hunter #2 Project

Hunter #2 Mining Investment		$22,748,496
Adjusted Initial Levelized Annual Fixed Rate		6.75%
Initial Levelized Annual Fixed Charge		$1,535,751
Subsequent Investment		$0
Subsequent Levelized Annual Fixed Rate		0.00%
Subsequent Levelized Annual Fixed Charge		$0
Ad Valorem Tax		$228,367
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #2 A & G Expense		$425,334
Total Fixed Cost		$2,189,452

Hunter #3 Project Allocated Mining Expense

(Based on 1989 Actual Costs)

Initial Levelized Fixed Charge

Hunter #3 Project

Hunter #3 Mining Investment		$38,720,844
Adjusted Initial Levelized Annual Fixed Rate		6.75%
Initial Levelized Annual Fixed Charge		$2,614,044
Subsequent Investment		$0
Subsequent Levelized Annual Fixed Rate		0.00%
Subsequent Levelized Annual Fixed Charge		$0
Ad Valorem Tax		$388,714
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #3 A & G Expense		$723,972

Total Fixed Cost **$3,726,731**

Hunter #2 and #3 Mining Investment

Allocation Calculation

Gross Coal Plant $193,120,211

Power Plants Served By Mines:

	MW
Huntington #1	400
Huntington #2	415
Hunter #1 UPL	366
Hunter #1 Provo	24
Hunter #2 UPL	235
Hunter #2 DG&T	155
Hunter #3 UPL	400
Total	1,995

Hunter #2 Mining Investment = 235 ÷ 1995 x $193,120,211 = $22,748,496

Hunter #3 Mining Investment = 400 ÷ 1995 x $193,120,211 = $38,720,844

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 & #3 PROJECT

AUGUST 27, 1990

50%	DEBT FINANCING @ 8.47%	$9789	LEVELIZED DEFERRED TAXES	7	YEAR TAX LIFE – MODIFIED ACRS
10%	PREFERRED EQUITY @ 8.24%	$2,138	LEVELIZED INTEREST EXPENSE	N/A	TAX RATE PRIOR TO 1987
40%	COMMON EQUITY @ 12.36%	$416	LEVELIZED PREFERRED RETURN	N/A	TAX RATE IN 1987
10.00%	WEIGHTED COST OF CAPITAL	$2,496	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100.000	CAPITAL INVESTMENT	0.13577	CAPITAL RECOVERY FACTOR	0%	INVESTMENT TAX CREDIT (ITC)
$13.894	LEVELIZED ANNUAL COST	1989	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13.894	LEVELIZED FIXED CAPITAL COSTS	14	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$724	LEVELIZED INCOME TAXES	14	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RATE BASE
1989	0	0	0	7,143	4,028	784	4,702	2,636	570	19,862	18,056	14,290	95,111
1990	0	0	0	7,143	3,534	688	4,126	6,398	(3,585)	18,303	15,126	24,490	83,451
1991	0	0	0	7,143	3,015	587	3,520	3,816	(1,416)	16,665	12,519	17,490	71,201
1992	0	0	0	7,143	2,590	504	3,024	1,972	89	15,322	10,464	12,490	61,164
1993	0	0	0	7,143	2,232	434	2,606	659	1,117	14,191	8,810	8,930	52,706
1994	0	0	0	7,143	1,902	370	2,220	655	858	13,148	7,421	8,920	44,906
1995	0	0	0	7,143	1,571	306	1,835	659	591	12,105	6,211	8,930	37,106
1996	0	0	0	7,143	1,276	248	1,490	(989)	2,005	11,172	5,211	4,460	30,128
1997	0	0	0	7,143	1,050	204	1,226	(2,634)	3,470	10,459	4,435	0	24,797
1998	0	0	0	7,143	859	167	1,003	(2,634)	3,318	9,856	3,799	0	20,288
1999	0	0	0	7,143	668	130	780	(2,634)	3,166	9,253	3,242	0	15,780
2000	0	0	0	7,143	477	93	557	(2,634)	3,014	8,650	2,755	0	11,271
2001	0	0	0	7,143	286	56	334	(2,634)	2,862	8,047	2,330	0	6,763
2002	0	0	0	7,143	95	19	111	(2,634)	2,710	7,444	1,960	0	2,254
2003	0	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	100,000	23,586	4,589	27,534	0	18,769	174,479	102,338	100,000	
1983 NET PRESENT VALUE @ 10%													
	0	0	0	52,611	15,748	3,064	18,384	7,202	5,330	102,338	67,289	72,139	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 & #3 MINING INVESTMENT

AUGUST 27, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	INVESTMENT TAX CREDIT RESTORED	INVESTMENT TAX CREDIT RECAPTURE	DEFERRED TAXES CURRENT	DEFERRED TAXES RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1989	100,000	(7,143)	0	0	0	(2,636)	0	90,221	0	36.88%	14.290%	7.14%
1990	90,221	(7,143)	0	0	0	(6,398)	0	76,681	0	36.88%	24.490%	7.14%
1991	76,681	(7,143)	0	0	0	(3,816)	0	65,722	0	36.88%	17.490%	7.14%
1992	65,722	(7,143)	0	0	0	(1,972)	0	56,607	0	36.88%	12.490%	7.14%
1993	56,607	(7,143)	0	0	0	(659)	0	48,805	0	36.88%	8.930%	7.14%
1994	48,805	(7,143)	0	0	0	(655)	0	41,007	0	36.88%	8.920%	7.14%
1995	41,007	(7,143)	0	0	0	(659)	0	33,205	0	36.88%	8.930%	7.14%
1996	33,205	(7,143)	0	0	0	989	0	27,051	0	36.88%	4.460%	7.14%
1997	27,051	(7,143)	0	0	0	2,634	0	22,543	0	36.88%	0.000%	7.14%
1998	22,543	(7,143)	0	0	0	2,634	0	18,034	0	36.88%	0.000%	7.14%
1999	18,034	(7,143)	0	0	0	2,634	0	13,526	0	36.88%	0.000%	7.14%
2000	13,526	(7,143)	0	0	0	2,634	0	9,017	0	36.88%	0.000%	7.14%
2001	9,017	(7,143)	0	0	0	2,634	0	4,509	0	36.88%	0.000%	7.14%
2002	4,509	(7,143)	0	0	0	2,634	0	0	0	36.88%	0.000%	7.14%
2003	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2004	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2005	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2006	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2007	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2008	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2009	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2010	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2011	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2012	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2013	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2014	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2015	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2016	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2017	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2018	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2019	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2020	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2021	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2022	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2023	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
TOTAL		(100,000)	0	0	0	0	0		0		100.000%	100.00%

HUNTER #2 & #3 MINE INVESTMENT

FORMULAS FOR CALCULATING

INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i\,(1+i)^{n} / (1+i)^{n} - 1$
Where i = weighted cost of capital and n = ave.. life of plant.

CRF = $0.1000\ (1 + 0.1000)^{14} / ((1 + 0.1000)^{14} - 1)$ =
0.13575

(*2) BOOK DEPRECIATION = $100,000 / 14 Years = $7,143

(*3) TOTAL RETURN, (TR) = $A \times W_s$
Where A = Average Net Investment; and
W_s = Weighted Cost of Preferred and Common Stock
Let A = Beginning Investment - (D+T) /2
Where Beginning Investment = Previous year's beginning investment -

previous year's D and T.

D = Book Depreciation (*2)
T = Deferred Tax (*5)
Therefore, beginning investment = $100,000
A = $100,000 - (7,143 + 2636) /2 = $95,111
TR = $95,111 x (.10 x .0824 + .40 x .1236) = $5,486

(*4) INTEREST, (I) = $A \times W_d$
Where W_d = Weighted Cost of Debt
Therefore, I = $95,111 x (.50 x .0847) = $4,028

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R$
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (36.88%)
Let T = (14,290 - 7,143) x .3688 = $2,636

HUNTER #2 AND #3 MINE INVESTMENT

FORMULAS FOR CALCULATING

INITIAL LEVELIZED FIXED CHARGE RATE

(Con't.)

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1-Tax rate)

INCOME TAX = ($5,486 + $7,143 + $2,636 - $14,290) x (.3688/(1-.3688 = $570

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax

ANNUAL COST = $7,143 + $5,486 + $4,028 + $2,636 + $570 = $19,862

(*8) TAX DEPRECIATION = (Modified ACRS) x Original Investment

TAX DEPRECIATION = 14.29% x 1.00 x $100,000 = $14,290

Adjusted for 1/2 year = $8,510/2 = $4,255

(*9) ITC = Not Applicable

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1+i)^n$

PRESENT WORTH ANNUAL COST = $19,862 x $1/(1 + .1000)^1$ = $18,056

where I = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost

INITIAL LEVELIZED FIXED CHARGE RATE = (0.13575 x $102,338)/$100,000 = 0.1389 = 13.89%

HUNTER #2 AND #3 MINE INVESTMENT
CALCULATION OF ADJUSTED INITIAL
FIXED CHARGE RATE
(Based on $100,000 of Capital Expenditure)

CAPITAL STRUCTURE:

Component	Structure	Rate
Debt	50%	8.47%
Preferred	10%	8.24%
Common	40%	12.36%
Weighted Cost of capital		10.00%

INPUT DATA:

INVESTMENT TAX CREDIT	Not Applicable
SALVAGE VALUE	0
BOOK LIFE (Straight Line)	14 years
TAX LIFE (MACRS)	7 years
TAX RATE	36.88% (includes state Corp. tax)
TAX BASIS	100.00% of Book
PW RATE	10.00%

CALCULATED DATA:

CAPITAL RECOVERY FACTOR = 0.13575 (1*)

INITIAL LEVELIZED FIXED CHARGE RATE = 0.1394 = 13.94% (*11)

ADJUSTED INITIAL LEVELIZED FIXED CHARGE RATE* = 13.94% less book depreciation, where book depreciation = 1/14 years = 0.0714 = 7.14% = 13.89% = 6.75%

*Book depreciation is reflected in fuel cost.

Appendix C: "Resource Pool"

This Appendix sets forth the amount of capacity (MW) and the combination of resources which may be included in the Resource Pool which shall be the basis for determining the prices for Firm Capacity and associated Firm Energy under Section 5 of this Agreement commencing with calendar year 1996.

The Resource Pool shall contain 1000 megawatts of capacity, which, until October 31, 2010, shall always contain an amount of capacity equal to the current rated capacity of Cholla Unit 4 and PacifiCorp's associated Cholla Unit 4 capital costs as derived pursuant to Appendix A. On May 1, 1996, the Resource Pool shall contain 650 megawatts of the following
other resources:

Resource		Capacity (MW)
Colstrip Project		70
Hunter No. 2 Project		180
Hunter No. 3 Project		400
	Total	650 MW

Provided, that commencing May 1, 1997 and on each May 1 there-after through the term of this Agreement, PacifiCorp may replace up to a maximum of 200 megawatts of such other resources with other cost resources it owns or may acquire, including, but not limited to, thermal generation it owns or leases and firm power purchases under contracts with a term of three years or more. Subsequent to October 31', 2010, through the term of this Agreement, PacifiCorp may replace both the other resources and Cholla Unit 4 with other cost resources. Such other cost resources contained in the Resource Pool shall only be resources (1) that PacifiCorp acquires through prudent utility management practices, (2) that are being used to provide utility service to PacifiCorp's customers, and (3) that have been declared to be in commercial operation prior to May 1 of the calendar year in which such resources are included in the Resource Pool.

APPENDIX D: EXAMPLE CALCULATION
ESTABLISHING ADJUSTMENTS FOR INTEREST

Simple interest "Midyear Convention" shall be utilized in calculating the amount of the adjustments for interest.

Assumptions for Example Calculations:

(1) Total Annual Payment Difference for calendar year 1995 $12,000

(2) Prime Rate 9%

(3) Time of Adjustment June 1, 1996

Adjustments for Interest

Year	Prime Rate [1]	Factor [2]		Interest Rate
1995	9.0% multiplied by	1/2	=	4.50%
1996	9.0% multiplied by	5/12	=	3.75%
				8.25%

8.25% x $12,000 = $990 Adjustment For Interest

[1] The prime rate shall be the time weighted average prime rate for the period. For the example above it would be for the period January 1995 through May 1996. The prime rate shall be as established by Morgan Guaranty Trust Company of New York.

[2] 1995 mid-year convention 1/2 year
1996 5 months (January through May)

APPENDIX E: INCREMENTAL COST OF SUPPLEMENTAL ENERGY AND UNUSED CHOLLA CAPABILITY

This Appendix sets forth the method for establishing Incremental Cost ($/MWh) of Supplemental Energy to be made available by APS pursuant to Subsections 6.7 and 6.8 of this Agreement and the Incremental Cost ($/MWh) of energy associated with either Party's use of the other Party's unused generating capability at the Cholla Generating Station ("Unused Cholla Capability") pursuant to Subsection 13.06 of the Asset Agreement.

The Incremental Cost for each megawatt-hour of each transaction shall equal the sum of (1) the deemed incremental operating and maintenance expense ($/MWh) as determined in Section 1.0 below, and (2) the Incremental Fuel Cost ($/MWh) as determined in Section 2.0 below.

1.0 Incremental Operating and Maintenance Expense. The incremental operating and maintenance expense associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows: .

1.1 Supplemental Coal Energy. For all Supplemental Coal Energy, the incremental operating and maintenance expense shall be deemed to be $4.68 per megawatt-hour. Any revision to the deemed $4.68 per megawatt hour incremental operating and maintenance expense for Supplemental Coal Energy shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates that the proposed revisions are reasonable given APS' costs.

1.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental operating and maintenance expense shall be deemed to be $21.94 per megawatt-hour for gas and oil fired steam units, $11.99 for all single cycle combustion turbines and $4.36 for all combined cycle units. Any revision to the deemed incremental operating and maintenance expense for gas and oil fired steam units, for combustion turbines, and for combined cycle units shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates that the proposed revisions are reasonable given APS' costs. Within three years of the Effective Date of this Agreement, the parties shall review the appropriateness of the foregoing deemed values and make adjustments that are equitable.

1.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental operating and maintenance expense shall be deemed to be $3.56 per megawatt-hour. Any revision to the deemed incremental operating and maintenance expense shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates the proposed revisions are reasonable.

2.0 Incremental Fuel Cost. The incremental fuel cost associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows:

2.1 Supplemental Coal Energy. For all Supplemental Coal Energy the incremental fuel cost ($/MWh) shall be determined by the APS dispatcher or scheduler based on his best-efforts forecast of the incremental coal cost and the incremental heat rate associated with the lowest cost generating unit(s) expected to be producing such energy.

2.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental fuel cost ($/MWh) shall be determined by the APS dispatcher or scheduler based upon his best-efforts forecast of the incremental fuel cost, either Natural Gas, Oil or Coal, utilizing the incremental heat rate associated with the lowest cost generating unit(s) that is expected to be producing such energy.

2.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental fuel cost ($/MWh) shall be determined by the Party's dispatcher or scheduler having such Unused Cholla Capability based on his best-efforts forecast of the incremental coal cost utilizing the incremental heat rate of the generating unit(s) that would produce such energy.

APS Government Grant Charge Number Structure
Version 1.0

PURPOSE

To document the established charge number structure that appropriately tracks grant-funded activities and complies with 10CFR600.311, 10CFR600.313, 10CFR600.317, and the American Recovery and Reinvestment Act of 2009 Subtitle D Sec. 1551 (where applicable).

GENERAL STRUCTURE

1. The first two characters of a charge number beginning with the letters "GV" distinguishes the charge as a government-funded project.

2. The next two characters designate the government award.
   - GV01 - Integrated Energy Systems (IES)
   - GV02 - High Penetration Solar (HPS) ARRA Phase I
   - GV03 - Distributed Energy Leadership Program (DELP)
   - GV05 - High Penetration Solar (HPS) non-ARRA Phase I

   A full list of charge numbers are kept on record with the GPMO.

3. The next two characters in a charge number typically align with the associated task number(s). Currently for IES, only one character identifies the task.

4. The following two characters typically align with the associated subtask number(s).

5. An additional character may be added at the end of the charge number to identify subrecipient costs and cost share. This currently applies to HPS:
   - "G" - General Electric (GE)
   - "N" - National Renewable Energy Laboratory (NREL)
   - "S" - Arizona State University (ASU)
   - "V"- ViaSol

6. Charge number example: GV020101

   GV – Distinguishes as a government project (grant)
   02 – Number associated with a specific grant
   01 – Name of the task
   01 – Name of the sub-task

SPECIAL CHARGE NUMBERS

In addition to the charge numbers which designate the task and subtask, there are special charge numbers specific to each project. These charge numbers are designated to track charges directly associated with the project but are considered excluded. These may either be unallowable or unbudgeted costs (such as G&A). In addition to excluded costs, there are charge numbers to designate APS cost share for each grant. Special charge numbers to note are as follows:

- GV01999 – Unbillable Costs (IES)
- GV01500 – APS Cost Share (IES)
- GV020001 – Excluded Costs (HPS)
- GV020002 – APS Cost Share (HPS)
- GV039999 – Excluded Costs (DELP)

CLOSEOUT TRACKING

When an award enters the project closeout phase, additional charge numbers following the same convention above will be established in order to designate closeout charges. Currently, GV013% is used for IES Closeout.

HISTORICAL STRUCTURE PRIOR TO GPMO

Government-funded projects that were awarded prior to October 2009 did not follow the standard charge number structure implemented after that date. The two awards with exceptions to this structure are the Coal to SNG (SNG) project and the Membrane Technology Research (MTR) project.

Valencia Fisker
Director
Federal Regulation

Mail Station 8995
P.O. Box 53999
Phoenix, AZ 85072-3999
Tel 602-250-4643
Lindy.Fisker@aps.com

June 29, 2011

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Modifications to the Long-Term Power Transactions Agreement between Arizona Public Service Company and PacifiCorp
Docket No. ER11-____

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. Part 35 (2011), Arizona Public Service Company ("APS" or "Company") hereby files proposed revisions to the Long-Term Power Transactions Agreement ("Agreement") between APS and PacifiCorp ("PAC") designated as FERC Electric Rate Schedule No. 182.

I. Background:

On March 19, 1991, the Commission accepted this Agreement, between APS and PAC, and designated it as APS FERC Rate Schedule No. 182. The Agreement provides for power sales between APS and PAC. This filing addresses the APS rates for sales of Supplemental Coal Energy ("SCE") and Other Supplemental Energy ("OSE") under the Agreement. Though APS offers PAC SCE and OSE on a daily basis, PAC is under no obligation to buy either product.

Pursuant to the Agreement, APS is permitted to recover its actual incremental costs (incremental fuel by the Company plus an Operation and Maintenance ("O&M") adder) to produce SCE or OSE, plus a percentage adder cost that would be treated as a contribution towards the fixed costs of the units producing SCE and OSE. The Agreement provides for changes to the O&M costs upon a timely filing with the Commission for approval. Thus, APS is seeking FERC's approval to increase the O&M adder from combined cycle and gas/oil fired steam resources and to decrease the O&M adder from coal fired steam and combustion turbine resources, as allowed in Sections 6.7 and 6.8 of the Agreement.

II. Communications:

Communications regarding this filing should be sent to the following individuals:

Valencia R. Fisker
Director, Federal Regulation
Arizona Public Service Company
400 North 5th Street
Mail Station 8995
Phoenix, AZ 85004
Phone: (602) 250-4643
Lindy.Fisker@aps.com

Thomas A. Loquvam
Senior Attorney
Pinnacle West Capital Corporation
400 North 5th Street
Mail Station 8695
Phoenix, AZ 85004
Phone: (602) 250-3616
Thomas.Loquvam@pinnaclewest.com

III. Proposed Change to Contract Rates:

Appendix E of the Agreement sets forth the methodology for establishing the incremental cost of supplemental energy provided by APS to PAC. Variable O&M expenses from the APS FERC Form No. 1, exclusive of fuel, were aggregated and divided by net generation to determine incremental O&M cost for the different types of generation resources anticipated to be utilized to provide such power, i.e., coal fired steam units, gas/oil fired steam units, combustion turbine units and combined cycle units. A cost justification is included as an attachment to this filing. The existing and proposed values are as follows:

	O&M Factor (Mills/kWh)	
Type of Generation Resource	Existing	Proposed
Coal Fired Steam Units	5.07	4.68
Gas/Oil Fired Steam Units	13.95	21.94
Combustion Turbine Units	13.09	11.99
Combined Cycle Units	2.96	4.36

IV. Contents of Filing:

Included in this filing is (1) the APS Rate Schedule No. 182, (2) a red-lined copy of the affected sections, (3) a conformed copy of the agreement, (4) the applicable worksheets utilized in support of the proposed changes and (5) the rate impact calculation based on the most recently available historic twelve month sales period (April 2010 through March 2011).

V. Conclusion:

APS requests waiver of any additional reporting requirements in 18 C.F.R. §35.13(a), that may otherwise be required. APS respectfully requests an effective date of September 1, 2011 to implement these changes.

Sincerely,

Valencia R. Fisker

Valencia R. Fisker
Director, Federal Regulation
Arizona Public Service Company

Cc:

Steve Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

PacifiCorp
Commercial and Trading
Director, Marketing & Trading Contracts
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232

Public Utility Commission of Oregon
550 Capital Street NE, Suite 215
Salem, Oregon 97301-2551

Utah Public Service Commission
Heber M Wells Building, 4th Floor
160 East 300 South
Salt Lake City, Utah 84111

Washington Utilities and Transportation Commission
1300 South Evergreen Park Drive SW
Olympia, Washington 98504-7520

Montana Public Service Commission
P.O. Box 202601
Helena, Montana 59620-2601

Public Service Commission of Wyoming

Hansen Building
2515 Warren Avenue, Suite 300
Cheyenne, Wyoming 82002

Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0074

Wesley Franklin, Executive Director
California Public Utilities Commission
State Building
505 Van Ness Avenue, Room 5222
San Francisco, California 94102

Information Required In Accordance With

18 C.F.R. §35.13(a)(2)(ii)

FILING INFORMATION UNDER SECTION 35.13(a)(2)(ii)

I. General Information:

Arizona Public Service Company ("APS") requests regulatory approval to revise rate components inherent in charges to PacifiCorp for sales of Supplemental Coal Energy ("SCE") and Other Supplemental Energy ("OSE") as provided for in the Long-Term Power Transactions Agreement ("Agreement") between the parties previously accepted by the Commission in Docket Nos. ER03-347-000, ER08-1610-000, ER09-1567-000, and ER10-1386-000.

APS is requesting an effective date of September 1, 2011.

II. Estimates of the Transactions and Revenues:

The Attachments provided demonstrate the revenue impact for SCE and OSE transactions based on the most recent available 12 months of billing information.

III. Basis of the Proposed Rates, Explanation of How the Proposed Rates Were Derived and Rate Design Information:

The basic rate design is unchanged from that inherent in the Agreement. APS is seeking revisions to O&M factors as authorized in the Agreement upon a timely filing with the Commission.

Pursuant to the Agreement, APS may recover its actual incremental costs (incremental fuel incurred by the Company plus an O&M adder) to produce SCE or OSE, plus a percentage adder to be applied to incremental costs that would be treated as a contribution toward the fixed costs of the units producing this energy.

Proposed Change to O&M factors:

Appendix E of the Agreement sets forth the methodology for establishing the incremental cost of supplemental energy provided by APS to PacifiCorp. Variable O&M expenses from the APS FERC Form No. 1, exclusive of fuel, were aggregated and divided by net generation to determine incremental O&M cost for the different types of generation resources anticipated to be utilized to provide such power, i.e., coal fired steam units, gas/oil fired steam units, combustion turbine units and combined cycle units. Each type of generation resource has a specific O&M adder. Appendix E, Sections 1.1 and 1.2 provide for revisions in the O&M factors upon a timely filing demonstrating cost support for the proposed revisions. Cost justification demonstrates the support for changes to the O&M factors for the different types of generation resources that would be used to provide supplemental energy under the Agreement. The proposed values are as follows:

Type of Generation Resource	Proposed O&M Factor (Mills/kWh)
Coal Fired Steam Units	4.68
Gas/Oil Fired Steam Units	21.94
Combustion Turbine Units	11.99
Combined Cycle Units	4.36

IV. Comparison of the Proposed Rate with Other Rates for Similar Services:

The terms and conditions for service under this Agreement are unique, and APS has no other agreements providing similar service.

V. Any Specifically Assignable Facilities to be Installed or Modified in Order to Supply Service under the Proposed Rate Schedule:

No new facilities or modifications to existing facilities are required in order to implement the proposed rate changes.

Cost Justification

ARIZONA PUBLIC SERVICE COMPANY
DETERMINATION OF "DEEMED" NON-FUEL INCREMENTAL O&M FACTORS
APPLICABLE TO PAC AGREEMENT

	Type of Energy/Type of Resource	(1) Net Generation (kWh) /1/	(2) Variable O&M Expenses ($) /2/	(3) Cost Supportable O&M Factor $/MWh [(2) / (1)] * 1000	(4) Current O&M Factor $/MWh
	Supplemental Coal Energy (SCE):				
1	Cholla 1, 2, 3	4,499,920,301	19,739,985		
2	Four Corners 1, 2, 3	4,214,059,298	23,007,365		
3	Four Corners 4, 5	1,465,077,030	7,062,676		
4	Navajo 1, 2, 3	2,204,307,999	8,187,585		
5	**TOTAL**	**12,383,364,628**	**57,997,612**	**4.68**	**5.07**
	Other Supplemental Energy (OSE):				
	Gas/Oil Fired Steam:				
6	Ocotillo 1-2	51,643,000	1,045,293		
7	Saguaro 1-2	0	87,910		
8	**TOTAL**	**51,643,000**	**1,133,204**	**21.94**	**13.95**
	Combustion Turbines:				
9	Yucca	88,997,000	(151,523)		
10	Douglas	359,000	11,188		
11	Ocotillo	3,805,000	337,579		
12	West Phoenix	3,399,000	193,615		
13	Saguaro 1-2	1,058,000	54,450		
14	Saguaro 3	7,029,000	170,122		
15	Sundance	107,797,000	1,932,590		
16	**TOTAL**	**212,444,000**	**2,548,022**	**11.99**	**13.09**
	Combined Cycle:				
17	West Phoenix 1-3	285,038,702	726,443		
18	West Phoenix 4-5	1,431,253,000	5,124,925		
19	Redhawk 1-2	3,376,012,000	16,351,918		
20	**TOTAL**	**5,092,303,702**	**22,203,286**	**4.36**	**2.96**
21	***Coal Fired Steam: /3/***				

/1/ 2009 FERC Form 1, pp.402 - 403.3, line 12
/2/ 2009 FERC Form 1, pp.402 - 403.3, lines 29, 31, & 32
/3/ Use the same O&M factor as that for SCE line 5.

Revenue Impact

Supplemental Coal Energy
Supplemental Coal

	1	2	3	4	5	6		7	8	9	10	11	12
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue			Proposed SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]					(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)		MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	950	5.070	15.367	20.437	30%	25,239.28	April 2010	950	4.680	15.367	20.047	30%	24,757.63
May	0	5.070	0.000	5.070	30%	0.00	May	0	4.680	0.000	4.680	30%	0.00
June	0	5.070	18.909	23.979	30%	0.00	June	0	4.680	18.909	23.589	30%	0.00
July	300	5.070	18.107	23.177	30%	9,039.13	July	300	4.680	18.107	22.787	30%	8,887.03
August	150	5.070	20.598	25.668	30%	5,005.33	August	150	4.680	20.598	25.278	30%	4,929.28
September	0	5.070	19.103	24.173	30%	0.00	September	0	4.680	19.103	23.783	30%	0.00
October	0	5.070	18.163	23.233	30%	0.00	October	0	4.680	18.163	22.843	30%	0.00
November	0	5.070	17.695	22.765	30%	0.00	November	0	4.680	17.695	22.375	30%	0.00
December	4,100	5.070	19.343	24.413	30%	130,122.75	December	4,100	4.680	19.343	24.023	30%	128,044.05
January 2011	2,950	5.070	19.233	24.303	30%	93,200.67	January 2011	2,950	4.680	19.233	23.913	30%	91,705.02
February	270	5.070	20.035	25.105	30%	8,811.90	February	270	4.680	20.035	24.715	30%	8,675.01
March	850	5.070	18.336	23.406	30%	25,863.82	March	850	4.680	18.336	23.016	30%	25,432.87
SUBTOTAL	9,570					297,282.89	**SUBTOTAL**	9,570					292,430.90

Other Supplemental Energy
Supplemental Coal

	1	2	3	4	5	6		7	8	9	10	11	12
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue			Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]					(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)		MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	783	5.070	23.561	28.631	15%	25,780.43	April 2010	783	4.680	23.561	28.241	15%	25,429.26
May	81	5.070	25.996	31.066	15%	2,893.80	May	81	4.680	25.996	30.676	15%	2,857.47
June	0	5.070	33.962	39.032	15%	0.00	June	0	4.680	33.962	38.642	15%	0.00
July	0	5.070	36.012	41.082	15%	0.00	July	0	4.680	36.012	40.692	15%	0.00
August	1,209	5.070	26.423	31.493	15%	43,786.94	August	1,209	4.680	26.423	31.103	15%	43,244.70
September	2,713	5.070	23.203	28.273	15%	88,209.51	September	2,713	4.680	23.203	27.883	15%	86,992.73
October	750	5.070	20.150	25.220	15%	21,751.88	October	750	4.680	20.150	24.830	15%	21,415.50
November	6,735	5.070	18.723	23.793	15%	184,279.26	November	6,735	4.680	18.723	23.403	15%	181,258.61
December	3,154	5.070	17.800	22.870	15%	82,953.25	December	3,154	4.680	17.800	22.480	15%	81,538.69
January 2011	1,062	5.070	21.784	26.854	15%	32,797.20	January 2011	1,062	4.680	21.784	26.464	15%	32,320.89
February	920	5.070	16.993	22.063	15%	23,342.61	February	920	4.680	16.993	21.673	15%	22,929.99
March	577	5.070	16.716	21.786	15%	14,455.84	March	577	4.680	16.716	21.396	15%	14,197.05
SUBTOTAL	17,984					520,250.72	**SUBTOTAL**	17,984					512,184.90

Other Supplemental Energy
Combustion Turbine

	1	2	3	4	5	6
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	362	13.090	23.561	36.651	15%	15,257.65
May	770	13.090	25.996	39.086	15%	34,610.65
June	496	13.090	33.962	47.052	15%	26,838.73
July	397	13.090	36.012	49.102	15%	22,417.67
August	0	13.090	26.423	39.513	15%	0.00
September	0	13.090	23.203	36.293	15%	0.00
October	-81	13.090	20.150	33.240	15%	-3,096.27
November	-96	13.090	18.723	31.813	15%	-3,512.11
December	72	13.090	17.800	30.890	15%	2,557.73
January 2011	292	13.090	21.784	34.874	15%	11,710.80
February	0	13.090	16.993	30.083	15%	0.00
March	46	13.090	16.716	29.806	15%	1,576.72
SUBTOTAL	2,258					108,361.57

	7	8	9	10	11	12
		Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	362	11.990	23.561	35.551	15%	14,799.72
May	770	11.990	25.996	37.986	15%	33,636.60
June	496	11.990	33.962	45.952	15%	26,211.29
July	397	11.990	36.012	48.002	15%	21,915.46
August	0	11.990	26.423	38.413	15%	0.00
September	0	11.990	23.203	35.193	15%	0.00
October	-81	11.990	20.150	32.140	15%	-2,993.80
November	-96	11.990	18.723	30.713	15%	-3,390.67
December	72	11.990	17.800	29.790	15%	2,466.65
January 2011	292	11.990	21.784	33.774	15%	11,341.42
February	0	11.990	16.993	28.983	15%	0.00
March	46	11.990	16.716	28.706	15%	1,518.53
SUBTOTAL	2,258					105,505.20

Other Supplemental Energy
Combined Cycle

	1	2	3	4	5	6
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	3,217	2.960	23.561	26.521	15%	98,114.32
May	1,930	2.960	25.996	28.956	15%	64,267.84
June	4,745	2.960	33.962	36.922	15%	201,476.71
July	6,590	2.960	36.012	38.972	15%	295,351.74
August	760	2.960	26.423	29.383	15%	25,681.15
September	3,164	2.960	23.203	26.163	15%	95,195.71
October	2,516	2.960	20.150	23.110	15%	66,865.23
November	1,284	2.960	18.723	21.683	15%	32,016.46
December	558	2.960	17.800	20.760	15%	13,321.95
January 2011	781	2.960	21.784	24.744	15%	22,224.13
February	3,380	2.960	16.993	19.953	15%	77,557.17
March	698	2.960	16.716	19.676	15%	15,793.61
SUBTOTAL	29,623					1,007,866.01

	7	8	9	10	11	12
		Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	3,217	4.360	23.561	27.921	15%	103,293.69
May	1,930	4.360	25.996	30.356	15%	67,375.14
June	4,745	4.360	33.962	38.322	15%	209,116.16
July	6,590	4.360	36.012	40.372	15%	305,961.64
August	760	4.360	26.423	30.783	15%	26,904.75
September	3,164	4.360	23.203	27.563	15%	100,289.75
October	2,516	4.360	20.150	24.510	15%	70,915.99
November	1,284	4.360	18.723	23.083	15%	34,083.70
December	558	4.360	17.800	22.160	15%	14,220.33
January 2011	781	4.360	21.784	26.144	15%	23,481.54
February	3,380	4.360	16.993	21.353	15%	82,998.97
March	698	4.360	16.716	21.076	15%	16,917.39
SUBTOTAL	29,623					1,055,559.04

Other Supplemental Energy
Gas/Oil Fired Steam

	1	2	3	4	5	6		7	8	9	10	11	12
		Current SCE O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue			Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]					(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)		MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	0	13.950	23.561	37.511	15%	0.00	**April 2010**	0	21.940	23.561	45.501	15%	0.00
May	0	13.950	25.996	39.946	15%	0.00	**May**	0	21.940	25.996	47.936	15%	0.00
June	0	13.950	33.962	47.912	15%	0.00	**June**	0	21.940	33.962	55.902	15%	0.00
July	0	13.950	36.012	49.962	15%	0.00	**July**	0	21.940	36.012	57.952	15%	0.00
August	0	13.950	26.423	40.373	15%	0.00	**August**	0	21.940	26.423	48.363	15%	0.00
September	0	13.950	23.203	37.153	15%	0.00	**September**	0	21.940	23.203	45.143	15%	0.00
October	0	13.950	20.150	34.100	15%	0.00	**October**	0	21.940	20.150	42.090	15%	0.00
November	0	13.950	18.723	32.673	15%	0.00	**November**	0	21.940	18.723	40.663	15%	0.00
December	0	13.950	17.800	31.750	15%	0.00	**December**	0	21.940	17.800	39.740	15%	0.00
January 2011	0	13.950	21.784	35.734	15%	0.00	**January 2011**	0	21.940	21.784	43.724	15%	0.00
February	0	13.950	16.993	30.943	15%	0.00	**February**	0	21.940	16.993	38.933	15%	0.00
March	0	13.950	16.716	30.666	15%	0.00	**March**	0	21.940	16.716	38.656	15%	0.00
SUBTOTAL	0					0.00	**SUBTOTAL**	0					0.00

Other Supplemental Energy
T&C

	1	2	3	4	5	6		7	8	9	10	11	12
		Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Current Revenue			Proposed O&M Factor	Incremental Fuel Cost	Avg Cost	Current "Adder"	Proposed Revenue
				(2) + (3)		(1)*[(4)*(1.00 +(5))]					(8) + (9)		(7)*[(10)*(1.00+(11))]
	MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)		MWh	($/MWh)	($/MWh)	($/MWh)	(%)	($)
April 2010	71	0.000	23.561	23.561	15%	1,923.72	**April 2010**	71	0.000	23.561	23.561	15%	1,923.72
May	0	0.000	25.996	25.996	15%	0.00	**May**	0	0.000	25.996	25.996	15%	0.00
June	0	0.000	33.962	33.962	15%	0.00	**June**	0	0.000	33.962	33.962	15%	0.00
July	0	0.000	36.012	36.012	15%	0.00	**July**	0	0.000	36.012	36.012	15%	0.00
August	0	0.000	26.423	26.423	15%	0.00	**August**	0	0.000	26.423	26.423	15%	0.00
September	0	0.000	23.203	23.203	15%	0.00	**September**	0	0.000	23.203	23.203	15%	0.00
October	111	0.000	20.150	20.150	15%	2,572.09	**October**	111	0.000	20.150	20.150	15%	2,572.09
November	0	0.000	18.723	18.723	15%	0.00	**November**	0	0.000	18.723	18.723	15%	0.00
December	0	0.000	17.800	17.800	15%	0.00	**December**	0	0.000	17.800	17.800	15%	0.00
January 2011	0	0.000	21.784	21.784	15%	0.00	**January 2011**	0	0.000	21.784	21.784	15%	0.00
February	112	0.000	16.993	16.993	15%	2,188.69	**February**	112	0.000	16.993	16.993	15%	2,188.69
March	25	0.000	16.716	16.716	15%	480.57	**March**	25	0.000	16.716	16.716	15%	480.57
SUBTOTAL	248					5,241.36	**SUBTOTAL**	248					5,241.36

Annual Revenue Current	1,939,002.55
Annual Revenue Proposed	1,970,921.40
Revenue Impact	**31,918.85**

Marked Tariff Section

APPENDIX E: INCREMENTAL COST OF SUPPLEMENTAL ENERGY AND UNUSED CHOLLA CAPABILITY

This Appendix sets forth the method for establishing Incremental Cost ($/MWh) of Supplemental Energy to be made available by APS pursuant to Subsections 6.7 and 6.8 of this Agreement and the Incremental Cost ($/MWh) of energy associated with either Party's use of the other Party's unused generating capability at the Cholla Generating Station ("Unused Cholla Capability") pursuant to Subsection 13.06 of the Asset Agreement.

The Incremental Cost for each megawatt-hour of each transaction shall equal the sum of (1) the deemed incremental operating and maintenance expense ($/MWh) as determined in Section 1.0 below, and (2) the Incremental Fuel Cost ($/MWh) as determined in Section 2.0 below.

1.0 Incremental Operating and Maintenance Expense. The incremental operating and maintenance expense associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows: .

1.1 Supplemental Coal Energy. For all Supplemental Coal Energy, the incremental operating and maintenance expense shall be deemed to be $~~5.07~~4.68 per megawatt-hour. Any revision to the deemed $~~5.07~~4.68 per megawatt hour incremental operating and maintenance expense for Supplemental Coal Energy shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates that the proposed revisions are reasonable given APS' costs.

1.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental operating and maintenance expense shall be deemed to be $~~13.95~~21.94 per megawatt-hour for gas and oil fired steam units, $~~13.09~~11.99 for all single cycle combustion turbines and $~~2.96~~4.36 for all combined cycle units. Any revision to the deemed incremental operating and maintenance expense for gas and oil fired steam units, for combustion turbines, and for combined cycle units shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates that the proposed revisions are reasonable given APS' costs. Within three years of the Effective Date of this Agreement, the parties shall review the appropriateness of the foregoing deemed values and make adjustments that are equitable.

1.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental operating and maintenance expense shall be deemed to be $3.56 per megawatt-hour. Any revision to the deemed incremental operating and maintenance expense shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates the proposed revisions are reasonable.

2.0 Incremental Fuel Cost. The incremental fuel cost associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows:

2.1 Supplemental Coal Energy. For all Supplemental Coal Energy the incremental fuel cost ($/MWh) shall be determined by the APS dispatcher or scheduler based on his best-efforts forecast of the incremental coal cost and the incremental heat rate associated with the lowest cost generating unit(s) expected to be producing such energy.

2.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental fuel cost ($/MWh) shall be determined by the APS dispatcher or scheduler based upon his best-efforts forecast of the incremental fuel cost, either Natural Gas, Oil or Coal, utilizing the incremental heat rate associated with the lowest cost generating unit(s) that is expected to be producing such energy.

2.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental fuel cost ($/MWh) shall be determined by the Party's dispatcher or scheduler having such Unused Cholla Capability based on his best-efforts forecast of the incremental coal cost utilizing the incremental heat rate of the generating unit(s) that would produce such energy.

Conformed Tariff

APS CONTRACT N0. 48017

LONG-TERM POWER TRANSACTIONS AGREEMENT

BETWEEN

ARIZONA PUBLIC SERVICE COMPANY

AND

PACIFICORP

FERC Rate Schedule No. 182

LONG-TERM POWER TRANSACTIONS AGREEMENT

BETWEEN

PACIFICORP

AND

ARIZONA PUBLIC SERVICE COMPANY

EXECUTION COPY

LONG-TERM POWER TRANSACTIONS AGREEMENT

BETWEEN

PACIFICORP

AND

ARIZONA PUBLIC SERVICE COMPANY

Index to Sections

LONG-TERM POWER TRANSACTIONS AGREEMENT
BETWEEN
PACIFICORP
AND
ARIZONA PUBLIC SERVICE COMPANY

THIS LONG-TERM POWER TRANSACTIONS AGREEMENT ("Agreement"), dated this 21st day of September, 1990, is between PacifiCorp Electric Operations, an assumed business name of PacifiCorp, an Oregon corporation (PacifiCorp) and Arizona Public Service Company, an Arizona corporation (APS). APS and PacifiCorp are sometimes referred to collectively as "Parties" and individually as "Party."

WHEREAS, PacifiCorp and APS are engaged in the generation, transmission and distribution of electric power and energy; and

WHEREAS, the Parties have resolved to enhance the efficient operation of their respective systems by taking advantage of the diversity of their respective loads and generation facilities; and

WHEREAS, the electric power needs of PacifiCorp's customers are highest in the winter months and the electric power needs of APS' customers are highest in the summer months; and

WHEREAS, the power supplies available to the Parties to meet their respective customer needs are diverse; and

WHEREAS, the Parties believe that various power transactions between interconnected electric utilities whose peak power needs and power supplies are different would be beneficial to the Parties' respective customers; and

WHEREAS, the Parties have entered into a series of contracts on this date to achieve such efficiencies; and

WHEREAS, the Parties intend to continue to study and discuss additional arrangements which will enhance efficiency and inure to the benefit of their respective customers,

NOW, THEREFORE, PacifiCorp and APS agree as follows:

Section 1: Definitions

As used herein, the following terms have the following meanings when used with initial capitalization, whether singular or plural:

1.1 "Agreement" means this agreement between PacifiCorp and APS.

1.2 "Annual Fixed Cost" for the calendar years 1996 through the Term of this Agreement, means the fully distributed weighted fixed cost, as determined and set forth in Appendix A, of the resources contained in the Resource Pool in such calendar year, with the costs of new resources, if any, added to the Resource Pool pursuant to Appendix C, being determined by a methodology substantially identical to that set forth in Appendix A.

1.3 "Annual Variable Cost" means, in the calendar years 1996 through the Term of this Agreement, the weighted variable cost, as determined and set forth in Appendix B, of the resources contained in the Resource Pool in such calendar year, with such costs of new resources, if any, added to the Resource Pool pursuant to Appendix C, being determined by a methodology substantially identical to that set forth in Appendix B.

1.4 "Asset Agreement" means the Asset Purchase and Power Exchange Agreement between the Parties dated September 21, 1990.

1.5 "Estimated Annual Fixed Cost" means PacifiCorp's estimate of the Annual Fixed Cost, based on the best information available to PacifiCorp at the time such estimates are made pursuant to Subsection 5.3, to be used for billing purposes as set forth in Section 8.

1.6 "Estimated Annual Variable Cost" means PacifiCorp's estimate of the Annual Variable Cost, based on the best information available to PacifiCorp at the time such estimates are made pursuant to Subsection 5.3, to be used for billing purposes as set forth in Section 8.

1.7 "Exchange Capacity" means capacity with Exchange Energy to be made available on a seasonal basis during the Term of this Agreement by each Party to the other and at no charge pursuant to the terms of Subsections 3.2 and 3.3.

1.8 "Exchange Energy" means energy associated with Exchange Capacity as set forth in Subsections 3.2 and 3.3.

1.9 "Firm Capacity" means capacity that is made available to APS by PacifiCorp to facilitate associated deliveries of Firm Energy as set forth in Section 3.

1.10 "Firm Energy" means the energy associated with Firm Capacity as set forth in Section 4.

1.11 "Point of Delivery" for all transactions hereunder means (1) Four Corners; (2) the Glen Canyon Substation or, in the event the Navajo Loop-In Project is constructed, Navajo; (3) the Pinnacle Peak Substation of the Western Area Power

Administration; (4) such other location(s) as may be established by mutual agreement of the Parties' dispatchers, schedulers, or authorized representatives; and (5) the Cholla Generating Station 500 Kv switchyard under the circumstances described in Subsection 15.03 of the Asset Agreement and Subsection 7.5 of this Agreement.

1.12 "Resource Pool" means a combination of resources available to PacifiCorp as defined in Appendix C.

1.13 "Seasonal Capacity Exchange" means the exchange of seasonal capacity as described in Subsections 3.2 and 3.3.

1.14 "Summer Season" means the May 1 through October 31 period of each of the calendar years of this Agreement.

1.15 "Supplemental Energy" means energy to be made available by APS to PacifiCorp as described in Section 6.

1.16 "Week" means a consecutive seven day period commencing on Sunday.

Section 2: Effective Date and Termination

2.1 Term of this Agreement. This Agreement shall be effective upon the Closing Date of the Asset Agreement and, except as provided in Subsections 2.2 and 3.2.4 and the final billing adjustment as provided in Subsection 8.2, shall terminate at 2400 hours MST, October 31, 2020.

2.2 Regulatory Approval and Termination.

2.2.1. Federal Energy Regulatory Commission Filing. PacifiCorp shall file this Agreement with the Federal Energy Regulatory Commission (FERC). APS shall file a letter of concurrence supporting PacifiCorp's filing of this Agreement with the FERC.

If the FERC issues an order not accepting this Agreement for filing in its entirety and without material change, the Parties shall exercise best efforts to amend the Agreement to comply with the FERC order or negotiate a replacement agreement providing similar benefits to both Parties. In the event such amendment or replacement agreement is not executed by the Parties within sixty days following the FERC's issuance of such order, or the Asset Agreement is terminated, this Agreement shall terminate.

Section 3: Capacity

3.1 Firm Capacity. For calendar years 1991 through 1995, PacifiCorp shall make available at the Point(s) of Delivery, and APS shall purchase 175 MW of Firm Capacity for the Summer Season of each calendar year. Except as provided in Subsection 3.2, commencing in calendar year 1996 and continuing through calendar year 1999, APS may increase the Firm Capacity amount up to a maximum amount equal to the rated capacity of Cholla Unit 4 for any year in increments of not less than 50 MW per calendar year upon providing PacifiCorp three years prior written notice. If APS increases its purchase of Firm Capacity under this Agreement above the 175 MW, such Firm Capacity amount will establish the then-effective Firm capacity purchase requirement which may not be thereafter reduced. Except as provided in Subsection 3.2, the amount of Firm Capacity made available for calendar year 1999 will establish the Firm Capacity amount for the remaining Term of this Agreement. In the event of an Uncontrollable Force, deliveries of Firm Capacity hereunder shall have priority over PacifiCorp's other firm wholesale contracts with terms of 10 years or less and equal priority with PacifiCorp's other firm wholesale contracts with terms greater than 10 years.

3.2 Exchange Option. Upon providing PacifiCorp three years advance written notice, APS may convert all or portions thereof of the Firm Capacity, to Exchange Capacity in increments of not less than 50 MW per calendar year, and the parties shall engage in a one-for-one Seasonal Capacity Exchange for the remaining Term of this Agreement. Any such conversion shall not be effective prior to calendar year 1996 and shall be effective for a full Summer or Winter Period as set forth in Subsections 3.2.1 and 3.2.2, respectively. Any amounts of Firm Capacity which are converted to Exchange Capacity may not be converted back to Firm Capacity. Exchange Capacity shall be made available at no charge to either Party in accordance with the provisions set forth below.

3.2.1 Summer Deliveries. PacifiCorp shall make Exchange Capacity available to APS during the period of May 15 through September 15 ("Summer Period"). Associated deliveries of Exchange Energy shall not exceed a load factor of 50 percent for each Week or any partial Week at the beginning or end of the Summer Period, and shall not exceed a load factor of 40 percent for any month or partial month thereof. By mutual agreement, a Party may pay for a portion of the Exchange Energy in lieu of returning it.

3.2.2 Winter Deliveries. APS shall make Exchange Capacity available to PacifiCorp from October 15 through the following February 15 ("Winter Period"). Associated deliveries of Exchange Energy shall not exceed a load factor of 50 percent for each Week or any partial Week at the beginning or end of the Winter Period, and shall not exceed a load factor of 40 percent for any month or partial month thereof. By mutual agreement, a Party may pay for Exchange Energy in lieu of returning it.

3.2.3 Delayed Return of Exchange Energy. The return of Exchange Energy delivered in the Winter or Summer Periods under Subsections 3.2.2 and 3.2.1 shall be delayed to the next following Summer or Winter Periods, respectively. The delivery of such Exchange Energy shall be coincident with and a part of any Exchange Capacity made available by the other Party under Subsections 3.2.1 and 3.2.2. Either Party's failure to schedule the return of such Exchange Energy owed to it from the preceding season shall operate as a waiver of the right to receive the return of such Exchange Energy, except that if such schedules cannot be made because of an Uncontrollable Force, it shall not constitute a wavier.

3.2.4 Final Settlement. At the end of the Term of this Agreement, if any Exchange Energy is owed to PacifiCorp from the immediate preceding period, the term of the Exchange Capacity obligations shall be extended until all Exchange Energy is returned, subject to the delivery rates set forth in Subsection 3.2.2.

3.3 Increased Capacity Exchange. Upon the later of (i) the completion of the Mead/Phoenix Line or (ii) May 15, 1997, and for the balance of the term of this Agreement, 100 megawatts of Exchange Capacity shall be made available in addition to any Exchange Capacity available as a result of the exchange option provided for in Subsection 3.2, subject to the same terms and conditions set forth in Subsections 3.2.1, 3.2.2, 3.2.3 and 3.2.4.

Section 4: Firm Energy

Delivery Provisions. Commencing May 1, 1991, and continuing through the Term of this Agreement, except as provided in Subsection 3.2, PacifiCorp shall make available Firm Energy associated with Firm Capacity as scheduled by APS at load factors not to exceed 100 percent per hour, 80 percent per month, and 70 percent per Summer Period and APS shall purchase such Firm Energy at load factors of not less than 40 percent per month, and 50 percent per Summer Period. Subsequent to 1996, the maximum monthly and Summer Period load factors of Firm Energy to be made available by PacifiCorp shall be increased to 100 percent and 85 percent respectively.

Section 5: Prices

APS shall be obligated to pay PacifiCorp for the Firm Capacity and Firm Energy as follows:

5.1 May 1, 1991 through October 31, 1995. During the Summer Season for each year of the calendar years 1991 through 1995, APS shall pay for all Firm Capacity the fixed prices expressed in $/KW/mo as set forth below:

Year	$/KW/mo
1991	10.87
1992	10.55
1993	10.19
1994	9.84
1995	9.51

The Firm Energy price for each of the calendar years 1991 through 1995 shall be the actual production expense for such year of Cholla Unit 4 as determined pursuant to the methodology set forth in Appendix B of this Agreement; provided, that in the event the capacity factor of Cholla Unit 4 in any calendar year is less than 40 percent, the Firm Energy price shall be the actual production expense of the resource having the highest actual production expense with a capacity factor equal to or greater than 40 percent for such year as determined pursuant to the methodology set forth in Appendix B among the other resources contained in the identified Resource Pool for 1996.

5.2 May 1, 1996 through October 31, 2020. During the Summer Season for each year of the calendar years 1996 through 2020, the payment prices for Firm Capacity as set forth in Subsection 3.1 and Firm Energy as set forth in Section 4 shall be the Annual Fixed Cost ($/KW/mo) and the Annual Variable cost ($/MWh) respectively.

5.3 Estimated Capacity Price and Energy Price. Unless all Firm Capacity has been converted to Exchange Capacity pursuant to Subsection 3.2, PacifiCorp shall provide APS with the following capacity and energy price estimates to be used for billing purposes prior to the time that actual costs are available:

5.3.1 May 1, 1991 through October 31, 1995. PacifiCorp shall provide to APS no later than March 1, 1991 and by each March 1 thereafter through calendar year 1995, estimates of the Cholla Unit 4 production expense to be used for billing purposes for the following Summer Season.

5.3.2 May 1, 1996 through October 31, 2020. PacifiCorp shall provide to APS no later than April 15, 1993 and by each April 15 thereafter an estimate of the capacity price ("Estimated Annual Fixed Cost") and an estimate of the energy price ("Estimated Annual Variable Cost") for the third subsequent Summer Season. Such estimate shall be determined using the best information available to PacifiCorp at the time the estimate is made. If during any Summer Season PacifiCorp determines that the Estimated Annual Fixed Cost and the Estimated Annual variable Cost used for billing purposes should be adjusted to reflect more accurate estimates, PacifiCorp shall notify APS as soon as possible. By mutual agreement of the Parties, PacifiCorp shall revise the Estimated Annual Fixed Cost and the Estimated Annual Variable Cost used for billing purposes in subsequent billing periods to reflect the more accurate estimates. Upon request, PacifiCorp shall provide to APS appropriate work papers and documentation supporting the revised estimates.

Section 6: Supplemental Energy

6.1 Option to Purchase. During the Term of this Agreement, APS shall make available at the Point of Delivery and PacifiCorp shall have the option to purchase Supplemental Energy on the basis provided for in this Section 6.

6.2 Quantities. There shall be two categories of Supplemental Energy, "Supplemental Coal Energy" and "Other Supplemental Energy." APS shall offer Supplemental Coal Energy and Other Supplemental Energy to PacifiCorp in the following Annual quantities during the Term of this Agreement:

Period	Supplemental Coal Energy (GWh per Year)	Other Supplemental Energy (GWh per Year)
Each year until 10/31/96	876	219
11/1/96 until 10/31/01	657	438
11/1/01 until 10/31/06	438	657
11/1/06 until 10/31/20	219	876

The required quantities for the period commencing on the Closing Date of the Asset Agreement until October 31, 1991 shall be proportionate shares of the required Annual quantities for that period. For purposes of this Section 6, "Year" or "Annual" shall mean the period commencing November 1 and ending October 31. In each of the following years, APS may defer offering a portion of that year's annual obligation to make Supplemental Coal Energy available to PacifiCorp to the first 90 days of the next year, but in no event shall the amount deferred exceed the specified maximum percentage:

Period	Maximum Deferral
11/01/00-10/31/01	20 percent
11/01/01-10/31/02	15 percent
11/01/02-10/31/06	10 percent
11/01/06-10/31/20	No deferral permitted

On or before September 15 of each Year in which it chooses to defer Supplemental Coal Energy, APS shall notify PacifiCorp in writing of the amount it intends to defer. APS shall have the right to defer as much as 20% more or 20% less than the amount stated in the notice, but in no event shall the deferral exceed the maximum permitted for that Year. Any deferred Supplemental Coal Energy shall be offered together with the next year's Supplemental Coal Energy, at rates of delivery not exceeding those set forth in Subsection 6.3.

6.3 Rate of Delivery of Supplemental Coal Energy. APS may offer up to 250 MWh per hour of Supplemental Coal Energy to PacifiCorp. APS' annual obligation for each Year to offer Supplemental Coal Energy to PacifiCorp shall be reduced by the amount of Supplemental Coal Energy offered pursuant to Subsection 6.6, regardless of whether such energy is purchased by PacifiCorp. Offered Supplemental Coal Energy which has been accepted and prescheduled by PacifiCorp but which APS is not able to deliver because of significant changes in its system conditions as set forth in Subsection 6.6, shall not reduce APS' annual obligation.

6.4 Rate of Delivery of Other Supplemental Energy. APS may offer up to 150 MWh per hour of Other Supplemental Energy to PacifiCorp. APS' Annual obligation for each Year to offer Other Supplemental Energy to PacifiCorp shall be reduced by the amount of Supplemental Coal Energy offered pursuant to Subsection 6.6 if it represents the lowest cost energy that is surplus to APS' system during that hour, regardless of whether such energy is purchased by PacifiCorp. Offered Other Supplemental Energy which has been accepted and prescheduled by PacifiCorp but which APS is not able to deliver because of significant changes in its system conditions as set forth in Subsection 6.6 shall not reduce APS' annual obligation.

6.5 Simultaneous Delivery. APS shall not offer Supplemental Coal Energy and Other Supplemental Energy for delivery during the same hour.

6.6 Supplemental Energy Offer. APS shall offer Supplemental Energy to PacifiCorp before 1000 hours MST on the last work day observed by both Parties immediately preceding the day(s) such Supplemental Energy is proposed to be made available. Such offer shall identify the type(s) and amount(s) of such Supplemental Energy as well as the Supplemental Energy Price. PacifiCorp shall preschedule any desired amounts of Supplemental Energy pursuant to Subsection 7.3. Prescheduled amounts of Supplemental Energy may be changed by the Parties' dispatchers or schedulers only in the event of significant changes in the affected Party's load, generation or transmission capability. The Supplemental Energy price as established at the time of prescheduling shall not change.

6.7 Pricing of Supplemental Coal Energy. The price of Supplemental Coal Energy for each transaction shall be as quoted by APS' dispatcher or scheduler prior to delivery and recorded in APS' system log and shall be derived from the best efforts forecast of the coal cost utilizing the incremental heat rate, together with incremental operating and maintenance expense associated with the generating unit producing such energy ("Incremental Cost"). Incremental Cost for purposes of establishing the price of Supplemental Coal Energy shall be computed in accordance with the methodology established in Appendix E, but in no event, except as provided below, shall such Incremental cost exceed the Incremental Cost of Cholla Unit 3, or Cholla Unit 2, if Cholla Unit 3 has been retired from service. Until November 1, 1996, the price of Supplemental Coal Energy shall equal 115% of Incremental Cost. From November 1, 1996 through February 28, 2003, the price of Supplemental Coal Energy shall equal 120% of Incremental Cost. From March 1, 2003 through October 31, 2006, the price of Supplemental Coal Energy shall equal 125% of Incremental Cost. From November 1, 2006 through October 31, 2020, APS shall be allowed to increase the price of Supplemental Energy to 130% of Incremental Cost upon the Commission's acceptance of a timely filing under Part 35 of the Code of Federal Regulations including the required cost data in support of this increase. Subsequent to October 31, 2010, if APS has constructed a base-load coal plant that is being used to provide utility service to APS' customers whose Incremental Cost is greater than that of Cholla Unit 3, the Parties shall negotiate in good faith to equitably adjust the Incremental Cost cap and multipliers provided for herein.

6.8 Pricing of Other Supplemental Energy. The price of Other Supplemental Energy for each transaction shall be as quoted by APS' dispatcher or scheduler prior to delivery and as recorded in APS' system log and shall be the higher of (1) the average price of Supplemental Coal Energy for the month prior to the month in question or (2) 115% of the Incremental Cost of generating unit producing the Other Supplemental Energy.

Any increase in the 15% adder used in the pricing of Other Supplemental Energy shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost data supporting that the revised percentage adder generates a reasonable contribution to the fixed costs of the facilities used to provide this service.

6.9 Price Caps Applicable to Supplemental Coal Energy and Other Supplemental Energy Transaction

In order to ensure that in addition to APS recovering its estimated incremental cost to produce supplemental energy, application of the adders do not result in APS recovering more than 100% of the fixed costs of the generating units producing the Supplemental Coal Energy or Other Supplemental Energy, the following price caps shall be applicable:

6.9.1 Price Cap for Supplemental Coal Energy. Notwithstanding the currently applicable adder of 30% to APS' Incremental Cost for Supplemental Coal Energy as set forth in Section 6.7, charges for energy from coal units shall not exceed 85.54 mills/kWh.

6.9.2 Price Caps for Other Supplemental Energy. Pursuant to Section 6.8 of this Agreement, the applicable adder of 15% for sales of Other Supplemental Energy shall further be subject to the following caps:

6.9.2.1 Energy from Combustion Turbines shall not exceed 9,125.66 mills/kWh.

6.9.2.2 Energy from Combined Cycle Units shall not exceed 826.39 mills/kWh.

6.9.2.3 Energy from Gas/Oil fired Steam Units shall not exceed 1,540.01 mills/kWh.

6.9.2.4 Energy from Coal fired Steam Units shall not exceed 342.18 mills/kWh.

Section 7: Scheduling

7.1 Projected Monthly Schedules. By December 1, 1990 and each December 1 thereafter, APS shall submit to PacifiCorp in writing the projected monthly amounts of Firm Energy associated with Firm Capacity to be delivered for the following Summer Season. Such projections shall represent a good faith estimate by APS of its anticipated deliveries hereunder; provided, that such estimates shall not be binding and shall be used by PacifiCorp for planning and information purposes only.

7.2 Daily Schedules by APS. APS shall preschedule all deliveries of Firm Energy associated with Firm Capacity and all deliveries of Exchange Energy associated with Exchange Capacity no later than 1000 hours MST on each work day observed by both Parties immediately preceding the day or day(s) of delivery, or as otherwise mutually agreed by the Parties' dispatchers or schedulers. PacifiCorp shall deliver in accordance with APS' preschedules which comply with the delivery provisions specified in Sections 3 and 4.

7.3 Daily Schedules by PacifiCorp. In the event the Parties commence a Seasonal Capacity Exchange(s) pursuant to Subsections 3.2 and/or 3.3, PacifiCorp shall preschedule deliveries of Exchange Energy associated with Exchange Capacity together with any deliveries of Supplemental Energy, no later than 1000 hours MST on each work day observed by both Parties immediately preceding the day or days on which such energy is to be delivered, or as mutually agreed by the Parties' dispatchers or schedulers. APS shall accept and deliver in accordance with those preschedules which comply with the delivery obligations specified in Subsection 3.2.2 and Section 6.

7.4 System Logs. All deliveries shall be deemed to be made during the hours and in the amounts as accounted for in the APS and PacifiCorp system logs; provided, that if scheduled deliveries are interrupted due to an Uncontrollable Force as defined in Section 14, such schedules shall be adjusted to reflect such interruption and any scheduled delivery so interrupted shall be rescheduled at a later date. Such rescheduling of interrupted deliveries shall be in amounts and at times as mutually agreed by the

Parties' dispatchers or schedulers and shall not increase either Party's obligation pursuant to Sections 3 and 4.

7.5 Point of Delivery at Cholla. Prior to 1996 and prior to the completion of the Navajo/Glen Canyon Loop-in Project, if APS, despite its best efforts, is unable to deliver the full amount of Firm Capacity into its system from Four Corners, PacifiCorp shall deliver such amounts of Firm Capacity that APS is unable to deliver from Four Corners to APS at the Cholla Generating Station 500 kV switchyard to the extent it is able to do so from available generating capacity from Cholla Unit 4 in excess of 200 MW. Commencing in 1996, to the extent APS is purchasing more than 200 MW of Firm Capacity, PacifiCorp shall deliver amounts of Firm Capacity in excess of 200 MW to APS at the Cholla Generating Station 500 kV switchyard to the extent it is able to do so from available generating capacity at Cholla Unit 4 in excess of 200 MW. For purposes of this Subsection, APS' best efforts shall not include a requirement that APS adjust generating resources on its system such that higher-cost generating resources are operated and lower-cost resources are curtailed in order to accommodate deliveries.

Section 8: Billing

8.1 Payments. Commencing May 1, 1991 through the term of this Agreement that Firm Capacity is being made available, APS shall pay PacifiCorp in the appropriate month of each year for Firm Capacity and Firm Energy the amounts determined in Subsections 8.1 through 8.4.

8.1.1 Summer Season 1991-1995. For the Summer Season of calendar years 1991 through 1995, the payment for each month shall equal the sum of (a) the Firm

Capacity as set forth in Subsection 3.1 as stated in kilowatts multiplied by the fixed price ($/KW/mo) for such year as set forth in Subsection 5.1 and, except as provided in Subsection 8.1.1.1, (b) the amount of Firm Energy stated in megawatt hours scheduled by APS pursuant to Section 4 during such month multiplied by the estimated Cholla Unit 4 production expense determined pursuant to Subsection 5.3.1.

8.1.1.1 Minimum Purchase Obligation. In the event the amount of Firm Energy scheduled by APS in any Summer Season is less than a 50 percent load factor, an amount of Firm Energy will be deemed to have been scheduled and delivered during the month of October that would increase APS' energy amount received for the Summer Season to equal a 50 percent load factor. APS shall pay for all such energy deemed to have been scheduled and delivered as determined above.

8.1.2 Summer Season - 1996-2020. Except as provided for in Subsections 3.2 and 8.1.3, for the Summer Season of calendar years 1996 through 2020, the payment for each month shall equal the sum of (a) the Firm Capacity as set forth in Subsection 3.1 stated in kilowatts multiplied by the Estimated Annual Fixed Cost as determined pursuant to Subsection 5.3.2 and, except as provided for in Subsection 8.1.2.1, (b) the amount of Firm Energy stated in megawatt-hours scheduled during such month multiplied by the Estimated Annual Variable Cost as determined pursuant to Subsection 5.3.2.

8.1.2.1 Minimum Purchase Obligation. In the event the amount of Firm Energy scheduled by APS in any Summer Season is less than 50 percent load factor, an amount of Firm Energy will be deemed to have been scheduled and delivered during the month of October that would increase APS' energy amount received for the Summer

Season to equal a 50 percent load factor. APS shall pay for all such energy deemed to have been scheduled and delivered as determined above.

8.1.3 Firm Capacity Payment Reduction. APS shall be entitled to a reduction in the payment provided for in Subsection 8.1.2 when all of the following occur:

(a) Firm Capacity is greater than 200 MW;

(b) Cholla Unit 4 is not operating for any reason;

(c) APS has no reasonable ability to adjust its system to accommodate delivery of more than 200 MW of Firm Capacity into its system through Navajo/Four Corners;

(d) PacifiCorp has combustion turbine capacity available to it in Arizona which it has elected not to utilize to provide APS with Firm Capacity in excess of 200 MW; and

(e) PacifiCorp has the ability to acquire power in Arizona from another entity which could be used to provide APS Firm Capacity in excess of 200 MW, but has elected not to acquire such power on APS' behalf.

For purposes of paragraph (c) above, APS shall not be required to adjust generating resources on its system such that higher-cost generating resources are operated and lower-cost resources are curtailed in order to accommodate deliveries.

The reduction in the required payment shall be computed for each hour of any month in which all of the aforementioned conditions occurred based upon the results of the following equation and the sum of the hourly reduction(s) shall equal the monthly reduction:

$$\frac{(C - 200{,}000) \text{ x}}{730}$$

Where: C = Firm Capacity, stated in kilowatts
X = Estimated Capacity Price, stated in dollars per kilowatt month

8.2 Annual Adjustments. By June 1 of each of the calendar years 1992 through 2021, PacifiCorp shall determine APS' payment obligation for the preceding calendar year's Summer Season based on prices determined in accordance with Section 5, applied except for calendar years 1991 through 1995 to Firm Capacity, pursuant to Subsection 3.1, and applied to the Firm Energy as set forth in Section 4. Such determination shall also reflect any payment reductions owing pursuant to Subsection 8.1.3. In the event the amount so determined is greater than the amount actually paid by APS pursuant to Subsection 8.1, then PacifiCorp shall add the amount of such difference, as adjusted for interest pursuant to Appendix D, to the May invoice. In the event the amount so determined is less than the amount actually paid by APS pursuant to Subsections 8.1.1 or 8.1.2, then PacifiCorp shall subtract the amount of such difference, as adjusted for interest pursuant to Appendix D, from the May invoice. By June 1, 2021 PacifiCorp shall determine APS' payment obligation for the preceding Summer Season based on prices determined in accordance with Section 5, applied to Firm Capacity pursuant to Section 3, and the Firm Energy purchase obligations as set forth in Section 4. In the event the amount so described is different than the amount actually paid by APS pursuant to Subsection 8.1, then PacifiCorp shall refund or send APS an invoice for such difference, whichever is appropriate, as adjusted for interest pursuant to Appendix D. Such refund or invoice shall be submitted to APS by June 15, 2021.

8.3 Billing and Payment for Firm Capacity and Firm Energy. PacifiCorp shall bill APS by the fifteenth day of each month by regular mail for services provided during the preceding month. APS shall pay such amounts, by electronic wire transfer, within fifteen days of receipt of such bill. Payments for all services provided hereunder are to be electronically wire transferred to United States National Bank of Oregon, Metropolitan Branch, 900 S.W. Sixth Avenue, Portland, Oregon 97204 (for credit to Pacific Power & Light Company, Account #070-000-169), Attention: Treasurer or such other financial institution or account number as specified by PacifiCorp in writing. Simple interest shall accrue on any unpaid amounts at a rate equal to 1.25 multiplied times the prime rate as established by The Morgan Guaranty Trust Company of New York during the period of delinquency, if any.

8.4 Billing and Payment for Supplemental Energy. For months during which PacifiCorp acquires Supplemental Energy, PacifiCorp shall pay APS the amounts determined in Subsections 8.4.1 and/or 8.4.2.

8.4.1 Supplemental Coal Energy. The payment for each month shall equal the sum of the individual hourly amounts of Supplemental Coal Energy stated in megawatt-hours scheduled by PacifiCorp during such month multiplied by the corresponding hourly Supplemental Coal Energy price as established by the Parties' dispatchers or schedulers prior to the hour of delivery pursuant to Subsection 6.7.

8.4.2 Other Supplemental Energy. The payment for each month shall equal the sum of the individual hourly amounts of Other Supplemental Energy stated in megawatt-hours scheduled by PacifiCorp during such month multiplied by the corresponding hourly Other Supplemental Energy price as established by the Parties' dispatchers or schedulers prior to the hour of delivery pursuant to Subsection 6.8.

8.5 Billing and Payment Schedules for Supplemental Energy. APS shall bill PacifiCorp by the fifteenth day of each month by regular mail for Supplemental Energy delivered during the preceding month. PacifiCorp shall pay such amounts, by electronic wire transfer, within fifteen days of receipt of such bill. Payments for all Supplemental Energy delivered hereunder are to be electronically wire transferred to Account No. 1-2079 at Valley National Bank, 241 North Central Avenue, Phoenix, Arizona 85004, or such other financial institution or account number as specified by APS in writing. Simple interest shall accrue on any unpaid amounts at a rate equal to 1.25 multiplied times the prime rate as established by The Morgan Guaranty Trust Company of New York during the period of delinquency, if any.

Section 9: Audit Rights

During the period of this Agreement that Firm Capacity is being made available, APS may review PacifiCorp's accounting records and supporting documents associated with any billing for Firm Capacity and Firm Energy made during the prior 18 months. During the Term of this Agreement, PacifiCorp may review appropriate portions of APS' system logs, and APS' accounting records or supporting documents associated with any billing for Supplemental Energy made during the prior 18 months. If either Party believes there are any errors in the determination of a bill including prices, it shall pay the full amount of such bill and the Parties shall meet to review the accounting records and supporting documents and agree on any adjustments that may be appropriate. If the Parties agree that the billing is incorrect, a corrected bill shall be prepared and the difference between the incorrect bill and corrected bill, including simple interest on the difference as provided herein, shall be paid promptly after such determination. The simple interest rate shall be equal to the time-weighted average prime rate as established by Morgan Guaranty Trust Company of New York and calculated using the method described in Appendix D. The principal upon which interest rates are to be applied shall be limited to twenty-four months following the submittal of the incorrect bill. The Parties shall take all steps reasonably available to secure the confidentiality of each other's accounting records and supporting documents. Disclosure of accounting records and supporting documents to a Party is not intended to, and shall not be interpreted to, waive the other Party's right to maintain that such records and supporting document are privileged, confidential, proprietary, or otherwise protected from disclosure to the public. In the event such information is required in a legal or regulatory proceeding related to this Agreement, a Party shall advise the other Party of the requirement to disclose such information prior to disclosing it and at such other Party's request shall ask for confidentiality of any such information.

Section 10: Cost Determination Changes

The cost methodologies utilized for pricing purposes in this Agreement and the pricing formulae specified herein shall remain in effect through the term of this

Agreement, and neither Party shall petition the FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act to amend such methodologies or formulae absent the agreement in writing of the other Party or support such a petition filed by any third party.

Section 11: Future Studies and Arrangements

No later than 60 days subsequent to the Closing Date of the Asset Agreement, the Parties shall meet to begin discussions of further transactions and arrangements that could benefit the Parties' respective customers. In addition to the types of transactions and arrangements already agreed to by the Parties, the discussions shall include other potential arrangements associated with generation and transmission planning and other potential operating efficiencies.

Section 12: Governing Law

This Agreement shall be subject to and be construed under the laws of the State of Arizona.

Section 13: Notices

All written notices hereunder, shall be directed as follows, and shall be considered delivered when deposited in the U.S. Mail, or other certified mail, return receipt requested:

To APS:	Arizona Public Service Company Corporate Secretary P.O. Box 53999 Phoenix, AZ 85072-3999
To PacifiCorp:	PacifiCorp Commercial and Trading Director, Marketing & Trading Contracts

825 NE Multnomah, Suite 600
Portland, OR 97232

The Parties may change the persons to whom notices are addressed, or their addresses, by providing notice thereof as specified in this Section.

Section 14: Uncontrollable Forces

Neither Party to this Agreement shall be considered to be in default in performance of any obligation hereunder if failure of performance shall be due to an Uncontrollable Force. The term "Uncontrollable Force" means any cause beyond the control of the Party affected, including, but not limited to, failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, and restraint by court order or public authority, which by exercise of due foresight such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to overcome. A Party shall not, however, be relieved of liability for failure of performance if such failure be due to causes arising out of its own negligence or to removable or remediable causes which it fails to remove or remedy with reasonable dispatch. Any Party rendered unable to fulfill any obligation by reason of an Uncontrollable Force shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein, however, shall be construed to require a Party to prevent or settle a strike against its will.

Section 15: Waiver

Any waiver by a Party of its rights with respect to default hereunder, or with respect to any other matter arising in connection herewith, shall not be deemed to be a waiver with respect to any subsequent default or matter. Except as provided for in Subsection 3.2.3, no delay in asserting or enforcing any right hereunder shall be deemed a waiver of such right.

Section 16: Arbitration

16.1 The Parties shall make best efforts to settle all disputes arising under this Agreement as a matter of normal business and without recourse to either arbitration or litigation. If any dispute arises under this Agreement, the Parties shall arbitrate the matter before an arbitrator who is an attorney or engineer familiar with contracts governing the operation of electrical systems. Any arbitration shall be commenced within a year of when a dispute arises and shall be commenced by either Party submitting to the other a Notice of Arbitration. The Parties shall have 30 days following the submittal of a Notice of Arbitration by either Party to attempt to mutually agree upon an arbitrator. If the Parties are unable to agree on an arbitrator within that time, either Party may request that a judge of the United States Circuit Court for the Ninth Circuit designate an arbitrator.

16.2 The arbitrator shall have discretion to establish a schedule and procedure for the arbitration and may conduct the arbitration based upon written submittals. The arbitrator may afford the Parties any or all of the discovery rights provided for in the Federal Rules of Civil Procedure.

16.3 At the commencement of the arbitration hearing, each Party shall submit a proposed Arbitration Award and the arbitrator shall be required to adopt in full the proposed Arbitration Award of one of the Parties and the Arbitration Award selected shall be final and binding on the Parties.

16.4 The Party whose proposed Arbitration Award is not selected shall pay all the costs of the arbitration, including the costs and the attorneys' fees of the prevailing Party.

Section 17: Indemnification

Neither Party ("First Party") shall be liable, whether in warranty, tort, or strict liability, to the other Party ("Second Party") for any injury or death to any person, or for any loss or damage to any property, caused by or arising out of any electric disturbance of the First Party's electric system, whether or not such electric disturbance resulted from the First Party's negligent act or omission. Each Second Party releases the First Party from, and shall indemnify and hold harmless the First Party from, any such liability. As used in this Section, (1) the term "Party" means, in addition to such Party itself, its agents, directors, officers, and employees; (2) the term "damage" means all damage, including consequential damage; and (3) the term "persons" means any person, including those not connected with either Party to this Agreement.

Section 18: Entire Agreement

This Agreement constitutes the entire agreement of the Parties hereto with respect to the transaction addressed herein and supersedes all prior agreements, whether oral or written. This Agreement may be amended only by a written document signed by both Parties hereto.

Section 19: Assignment

Neither Party shall assign this Agreement without the prior written consent of the other Party, except:

(a) to any corporation into which or with which the Party making the assignment is merged or consolidated or to which the Party transfers substantially all of its assets;

(b) to any person or entity wholly owning, wholly owned by or wholly owned in common with the Party making the assignment.

Nothing contained in this Section shall be construed to prevent the Parties from making a collateral assignment of the revenues due under the terms of this Agreement. No assignment, merger or consolidation shall relieve any Party of any obligation under this Agreement. Subject to the foregoing restrictions in this Section, this Agreement shall be binding upon, inure to the benefit of and be enforceable by the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names by their respective officers thereunder duly authorized.

PacifiCorp Electric Operations

By /s/
Title: President

Arizona Public Service Company

By /s/
Title: Chairman

APPENDIX A: ANNUAL FIXED COST

Introduction

This Appendix sets forth the elements and techniques to calculate Annual Fixed Cost.

The Annual Fixed Cost shall be the per-MW total of the following: (1) 70 MW multiplied by the Colstrip Project Annual Fixed Cost pursuant to Section A2 plus 350 MW multiplied by the Cholla Project Annual Fixed Cost pursuant to Section A4, plus 180 MW multiplied by the Hunter #2 Project Annual Fixed Cost pursuant to Section A6, plus 400 MW multiplied by the Hunter #3 Project Annual Fixed Cost pursuant to Section A8 and (2) dividing the above sum by 1000 MW.

The Annual Fixed Cost for PacifiCorp's share of the Colstrip Project, PacifiCorp's share of the Cholla Project, PacifiCorp's share of the Hunter #2 Project and PacifiCorp's share of the Hunter #3 Project is the per-MW sum of each Project's: (a) initial levelized annual fixed cost, (b) levelized annual fixed costs of subsequent capital additions, replacements and betterments (if any), and (c) other fixed annual charges directly related to the resources in the pool, including but not limited to property taxes, insurance, and taxes other than income tax.

Section A1: Discussion of Methodology

Levelized fixed charges are the basis of annual fixed costs hereunder. While actual capital-related charges associated with an investment may vary considerably from year to year, the levelized fixed charge translates these charges into a level annual amount which remains constant over time. The present values of the two streams (actual versus levelized) are equal.

The levelized fixed charge includes three basic components: (a) return on investment, given a specific capital structure and cost of capital; (b) recovery of investment, given the appropriate depreciation period related to the investment; and (c) income tax requirements, given tax law considerations. These components are commonly expressed as: (a) interest expense on debt and return required by shareholders, (b) book depreciation, and (c) income taxes incorporating the effects of investment tax credits and tax depreciation.

As of December 31, 1989, an initial levelized annual charge rate will be applied to the total investment of each Project. The rate will be recalculated effective each January 1 only in the event of a change during the preceding calendar year in any of the following: (a) the percentage of pollution control revenue bonds outstanding; (b) the interest rate on pollution control revenue bonds; (c) PacifiCorp's rate of return on common equity (ROE), as allowed by the Federal Energy Regulatory Commission (FERC), or (d) income tax law, but not to be applied retroactively.

Subsequent levelized annual fixed charge rates will be calculated each year to reflect the most current information and will be applied each year to the amount of capital additions, replacements (less credit for net salvage and insurance proceeds, if any) and betterments of each Project completed through the end of the preceding calendar year.

Section A2: Determination of Colstrip Project Annual Fixed Cost

Colstrip Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A2.1 through A2.5, and (b) dividing the total by 140 MW ("Net Colstrip Capacity"), provided that, in the event the capacity of the Colstrip Project increases or decreases as a result of additions, replacements or betterments the Net Colstrip Capacity will be adjusted to reflect such change.

A2.1 PacifiCorp's initial levelized annual fixed charge rate for the Colstrip Project determined annually in accordance with Section A3 of this Appendix, multiplied by the total investment in the Colstrip Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Colstrip Project is $195,862,376. Such total investment shall remain constant through the term of the Agreement.

A2.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A3, below, by (b) the

dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Colstrip Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

A2.3 All ad valorem taxes imposed upon the Colstrip Project.

A2.4 Any tax, assessment, payment, in lieu of taxes, or other, charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Colstrip Project, excluding ad valorem taxes, state and federal income taxes.

A2.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Colstrip Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A3: Elements of Colstrip Project's Levelized Annual Fixed Charge Rates

A3.1 Capital Structure:

A3.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Colstrip Project is:

Long Term Debt and Pollution Control Revenue Bonds	52%
Preferred Stock	12%
Common Stock Equity	36%
Total Capital	100%

The proportion of Pollution Control Revenue Bonds A to Total Capital will be the quotient of (a) $45,000,000 (the principal amount of Pollution Control Revenue Bonds relating to the Colstrip Project issued in January 1988) divided by (b) $195,862,376, i.e., the sum of PacifiCorp's total investment cost of the Colstrip Project as of December 31, 1989.

The proportion of Pollution Control Revenue Bonds B to Total Capital will be the quotient of (a) $8,500,000 (the principal amount of Pollution Control Revenue Bonds relating to the Colstrip Project issued in December 1986) divided by (b) $195,862,376, i.e., the sum of PacifiCorp's total investment cost of the Colstrip Project as of December 31, 1989. The proportion of Long Term debt to Total Capital will be the difference between (a) fifty-two percent (52%), (b) the proportion of Pollution Control Revenue Bonds A as calculated above, and (c) the proportion of Pollution Control Revenue Bonds B as calculated above. If PacifiCorp's City of Forsyth, Rosebud County, Montana, Floating Rate Monthly Demand Pollution Control Revenue Bonds, Series 1988 or Series 1986 (Pacific Power & Light Company Colstrip Project), as referenced above, are prepaid, redeemed or exchanged for bonds, in their entirety, the interest of which is taxable under federal income tax laws, the capital structure will be adjusted to determine the initial levelized annual charge rates in the calendar years immediately succeeding the year of prepayment or redemption, such that the Pollution Control Revenue Bonds (A or B) proportion will be zero (0) and the Long-Term Debt proportion will be the difference between (a) Fifty-two percent (52%) and (b) the remaining proportion of Pollution Control Revenue Bonds A or B as calculated above. In the event that the above-referenced pollution control revenue bonds are exchanged for another issue of bonds, the interest of which is exempt under federal income tax laws, the capital structure consequent to the subsequent issue will be employed prospectively for calculations under this section.

A3.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%

Total Capital 100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A3.2 Cost of Capital:

A3.2.1 Interest Rate for Debt: The interest rate for debt shall be equal to 1) the product of the proportion of Long Term Debt to Total Capital multiplied by the total Colstrip Project Investment multiplied by the bond interest rate (12.8%) as specified in Subsection A3.2.1.1, plus 2) the product of the amount of tax exempt Pollution Control Revenue Bonds A multiplied by the variable interest rate (which in 1989 was 6.48%) as specified in Subsection A3.2.1.2, plus 3) the product of the amount of tax exempt Pollution Control Revenue Bonds B multiplied by the variable interest rate (which in 1989 was 6.89%) as specified in Subsection A3.2.1.3 the sum of the products of 1) and 2) and 3) divided by the sum of 4) the product of the proportion of Long Term Debt to Total Capital as specified in Subsection A3.1.1 times the Total Colstrip Project investment, plus 5) the amount of tax exempt Pollution Control Revenue Bonds A, plus 6) the amount of tax exempt Pollution Control Revenue Bonds B.

A3.2.1.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be twelve and eight-tenths percent (12.8%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Colstrip Project, in the twelve (12) -month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) -month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A3.2.1.2 Pollution Control Revenue Bonds A: Bond interest applicable in the calculation of the 1989 initial levelized annual fixed charge rate shall be six and forty-eight hundredths percent (6.48%). Bond interest applicable in the calculation of the initial levelized annual fixed charge rate in each year from 1991 through 2010 shall be the average of that effective interest rate paid by PacifiCorp during the previous calendar year relating to its $45,000,000 City of Forsyth, Rosebud County, Montana, Floating Rate Monthly Demand Pollution Control Revenue Bonds, Series 1988 (Pacific Power & Light Company Colstrip Project). If such series of bonds is prepaid, redeemed, or exchanged for bonds, in their entirety, the interest of which is subject to federal income taxes, there will be no interest relating to Pollution Control Revenue Bonds A in the initial levelized annual fixed charge rates computed in the calendar year immediately following such prepayment or redemption. In the event that the above-referenced Pollution Control Revenue Bonds A are exchanged for another issue, the interest of which is exempt from federal income taxes, the interest rate consequent to the subsequent issue shall be employed prospectively for calculations under this section.

A3.2.1.3 Pollution Control Revenue Bonds B: Bond interest applicable in the calculation of the 1989 initial levelized annual fixed charge rate shall be six and eighty-nine hundredths percent (6.89%). Bond interest applicable in the calculation of the initial levelized annual fixed charge rate in each year from 1991 through 2010 shall be the average of that effective interest rate paid by PacifiCorp during the previous calendar year relating to its $8,500,000 City of Forsyth, Rosebud County, Montana, Floating Rate Monthly demand Pollution Control Revenue Bonds, Series 1986 (Pacific Power & Light Company Colstrip Project). If such series of bonds is prepaid, redeemed, or exchanged for bonds, the interest of which is subject to federal income taxes, there will be no interest relating to Pollution Control Revenue Bonds B in the initial levelized annual fixed charge rates computed in the calendar year immediately following such prepayment or redemption. In the event that the above-referenced pollution control bonds B are exchanged for another issue, the interest of which is exempt from federal income taxes, the interest rate consequent to the subsequent issue shall be employed prospectively for calculations under this section.

A3.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be thirteen and three-tenths percent (13.3%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A3.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC.

From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using Pacificorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A3.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35) -year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A3.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A3.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A3.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A3.4.3 Accelerated Cost Recovery System (ACRS) method of tax depreciation in accordance with the Tax Equity and Fiscal Responsibility Act of 1982 shall be used in calculating each initial levelized annual fixed charge rate and the modified Accelerated Cost Recovery System (modified ACRS method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

A3.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A3.4.5 Tax basis will be seventy-five percent (75%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Section A4: Determination of Cholla Project Annual Fixed Cost

Cholla Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Section A4.1 through A4.5, and (b) dividing the total by 350 MW ("Net Cholla Capacity"), provided that, in the event the capacity of the Cholla Project increases or decreases as a result of additions, replacements or betterments the Net Cholla Capacity will be adjusted to reflect such change.

A4.1 PacifiCorp's initial levelized annual fixed charge rate for Cholla Project will be determined annually in accordance with Section A5 of this Appendix multiplied by the Initial Net Book investment in the Cholla Project as of December 31, 1995. For purposes of this section, PacifiCorp's Initial Net Book investment in Cholla Project is the sum of PacifiCorp's initial investment of $221,000,000, less book depreciation, plus PacifiCorp's investments in capital additions, and replacement (less credit for net salvage and insurance proceeds, if any) less associated depreciation. Such total Initial Net Book investment shall remain constant through the term of the Agreement.

A4.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A5, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Cholla Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1996.

A4.3 All ad valorem taxes imposed upon the Cholla Project.

A4.4 Any tax, assessment, payment in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Cholla Project, excluding ad valorem taxes, state and federal income taxes.

A4.5 Administrative and General Expense shall be the greater of the amount of Administrative and General Expense charged by APS to PacifiCorp associated with PacifiCorp's investment in the Cholla Project, or an amount equal to the product of 1) the quotient of total PacifiCorp Administrative and General Expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Cholla Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A5: Elements of Cholla Project Levelized Annual Fixed Charge Rates

A5.1 Capital Structure

A5.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Cholla Project is:

Long-Term Debt and Pollution Control Revenue Bonds	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

A5.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

provided, that if any par: of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A5.2 Cost of Capital

A5.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be ten percent (10.00%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Cholla Project, in the most recent twelve (12) -month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) -month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A5.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be nine and five-tenths percent (9.5%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A5.2.3 Common Stock Equity: For pricing purposes only, the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's the then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A5.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a twenty-five (25) -year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A5.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, that subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A5.4.1 The federal corporate income tax rate (46%) up through 1986, 40% in 1987, and 34% in 1988 and thereafter.

A5.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three (3) -factor formula for unitary allocation of state taxable income taxed upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A5.4.3 Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation shall be used in calculating each initial levelized annual fixed charge rate and the modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax Reform Act of 1986 shall be used in calculating subsequent levelized annual fixed charge rate.

A5.4.4 Investment Tax Credits shall be zero (0) in calculating each initial levelized annual fixed charge rate and Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits shall be used when calculating subsequent levelized annual fixed charge rates.

A5.4.5 Tax basis shall be one hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate.

Section A6: Determination of Hunter #2 Project Annual Fixed Cost

Hunter #2 Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A6.1 through A6.5, and (b) dividing the total by 235 MW ("Net Hunter #2 Capacity"), provided that, in the event the capacity of the Hunter #2 Project increases or decreases as a result of additions, replacements or betterments the Net Hunter #2 Capacity will be adjusted to reflect such change. The costs referred to above are:

A6.1 PacifiCorp's initial levelized annual fixed charge rate for the Hunter #2 Project determined annually in accordance with Section A7 of this Appendix, multiplied by the total investment in the Hunter #2 Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Hunter #2 Project is $174,355,375. Such total investment shall remain constant through the term of the Agreement.

A6.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A7, below, by (b) the

dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #2 Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from PacifiCorp's general accounting records, the required portions of which shall be provided by PacifiCorp each year, shall not include any amounts incurred by PacifiCorp prior to January 1, 1990.

A6.3 All ad valorem taxes imposed upon the Hunter #2 Project.

A6.4 Any tax, assessment, payment, in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Hunter #2 Project, excluding ad valorem taxes, state and federal income taxes.

A6.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Hunter #2 Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A7: Elements of Hunter #2 Project's Levelized Annual Fixed Charge Rates

A7.1 Capital Structure:

A7.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #2 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total Capital	100%

A7.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%

Common Stock Equity	46%
Total Capital	100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A7.2 Cost of Capital:

A7.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be eleven and ninety-seven hundredths percent (11.97%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #2 Project, in the twelve (12) -month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) -month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A7.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be ten and ninety-six hundredths percent (10.96%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A7.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A7.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35) -year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A7.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A7.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A7.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A7.4.3 Sum of the Years Digits method of tax depreciation shall be used in calculating each initial levelized annual fixed charge rate and the Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

7.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A7.4.5 Tax basis will be one-hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Section A8: Determination of Hunter #3 Project Annual Fixed Cost

Hunter #3 Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A8.1 through A8.5, and (b) dividing the total by 400 MW ("Net Hunter #3 Capacity"), provided that, in the event the capacity of the Hunter #3 Project increases or decreases as a result of additions, replacements or betterments the Net Hunter #3 Capacity will be adjusted to reflect such change. The costs referred to above are:

A8.1 PacifiCorp's initial levelized annual fixed charge rate for the Hunter #3 Project determined annually in accordance with Section A9 of this Appendix, multiplied by the total investment in the Hunter #3 Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Hunter #3 Project is $453,116,692. Such total investment shall remain constant through the term of the Agreement.

A8.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A9, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #3 Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from PacifiCorp's general accounting records, the required portions of which shall be provided by PacifiCorp each year, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

A8.3 All ad valorem taxes imposed upon the Hunter #3 Project.

A8.4 Any tax, assessment, payment, in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Hunter #3 Project, excluding ad valorem taxes, state and federal income taxes.

A8.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Hunter #3 Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A9: Elements of Hunter #3 Project's Levelized Annual Fixed Charge Rates

A9.1 Capital Structure:

A9.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #3 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total Capital	100%

A9.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A9.2 Cost of Capital:

A9.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be fourteen and fifty-two hundredths percent (14.52%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #3 Project, in the twelve (12) -month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) -month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A9.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be eleven and six-tenths percent (11.6%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A9.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A9.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35) -year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A9.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change.

A9.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A9.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A9.4.3 Accelerated Cost Recovery System (ACRS) method of tax depreciation in accordance with the Tax Equity and Fiscal Responsibility Act of 1982 shall be used in calculating each initial levelized annual fixed charge rate and the Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

A9.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A9.4.5 Tax basis will be ninety-five percent (95%) of the book basis in calculating each initial levelized annual fixed charge rate and one-hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Colstrip Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(Estimated 1996 Price)

Initial Levelized Fixed Charge

Colstrip Project

Colstrip Initial Project Investment		$195,862,376
Initial Levelized Annual Fixed Rate		13.02%
Initial Levelized Annual Fixed Charge		$25,499,323
Subsequent Investment - (1990 thru 1995)		$5,949,810
Subsequent Levelized Annual Fixed Rate		13.02%
Subsequent Levelized Annual Fixed Charge		$774,665
Ad Valorem Tax		$1,086,608
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Colstrip A & G Expense		$3,773,328
Total Fixed Cost		**$31,133,924**
Net Colstrip Capacity		140
Annual Fixed Cost per MW		$222,385
Monthly Fixed Cost per kW		$\boxed{\$18.53}$

PACIFICORP ELECTRIC OPERATIONS
COLSTRIP PROJECT

AUGUST 27, 1990

52%	DEBT FINANCING @ 9.886%	$814	LEVELIZED DEFERRED TAXES	15	YEAR TAX LIFE – ACRS
12%	PREFERRED EQUITY @ 13.3%	$3,217	LEVELIZED INTEREST EXPENSE	48.36%	TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
36%	COMMON EQUITY @ 12.36%	$999	LEVELIZED PREFERRED RETURN	42.62%	TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
11.19%	WEIGHTED COST OF CAPITAL	$2,784	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.11467	CAPITAL RECOVERY FACTOR	10%	INVESTMENT TAX CREDIT (ITC)
$13,019	LEVELIZED ANNUAL COST	1985	IN SERVICE DATE	95%	ITC BASIS ADJUSTMENT
$13,019	LEVELIZED FIXED CAPITAL COSTS	35	YEAR ESTIMATED LIFE	75%	TAX BASIS (% OF ORIGINAL COST)
$2,348	LEVELIZED INCOME TAXES	35	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RAIL BASE
1985	0	0	0	2,857	4,861	1,509	4,208	738	5,384	19,557	17,589	3,563	94,559
1986	0	0	0	2,857	4,450	1,382	3,852	2,461	3,209	18,210	14,730	7,125	86,567
1987	0	0	0	2,857	4,204	1,305	3,639	1,835	2,394	16,234	11,810	6,413	81,776
1988	0	0	0	2,857	3,987	1,238	3,451	1,321	1,850	14,704	9,621	5,700	77,556
1989	0	0	0	2,857	3,790	1,177	3,280	1,058	1,978	14,140	8,321	4,988	73,723
1990	0	0	0	2,857	3,600	1,118	3,116	1,058	1,847	13,595	7,196	4,988	70,022
1991	0	0	0	2,857	3,416	1,064	2,957	795	1,984	13,070	6,222	4,275	66,451
1992	0	0	0	2,857	3,239	1,006	2,804	795	1,862	12,564	5,379	4,275	63,015
1993	0	0	0	2,857	3,063	951	2,651	795	1,741	12,058	4,643	4,275	59,577
1994	0	0	0	2,857	2,886	896	2,498	795	1,619	11,551	4,001	4,275	56,139
1995	0	0	0	2,857	2,709	841	2,345	795	1,498	11,045	3,440	4,275	52,701
1996	0	0	0	2,857	2,532	786	2,192	795	1,376	10,539	2,953	4,275	49,263
1997	0	0	0	2,857	2,356	734	2,039	795	1,255	10,033	2,528	4,275	45,824
1998	0	0	0	2,857	2,179	676	1,886	795	1,133	9,527	2,159	4,275	42,386
1999	0	0	0	2,857	2,002	622	1,733	795	1,012	9,021	1,839	4,275	38,948
2000	0	0	0	2,857	1,866	579	1,615	(781)	2,495	8,631	1,582	0	36,299
2001	0	0	0	2,857	1,770	550	1,532	(781)	2,429	8,357	1,378	0	34,437
2002	0	0	0	2,857	1,675	520	1,449	(781)	2,364	8,083	1,199	0	32,576
2003	0	0	0	2,857	1,579	490	1,367	(781)	2,298	7,809	1,041	0	30,714
2004	0	0	0	2,857	1,483	460	1,284	(781)	2,232	7,535	904	0	28,853
2005	0	0	0	2,857	1,388	431	1,201	(781)	2,166	7,261	783	0	26,991
2006	0	0	0	2,857	1,292	401	1,118	(781)	2,101	6,987	678	0	25,130
2007	0	0	0	2,857	1,196	371	1,035	(781)	2,035	6,713	586	0	23,268
2008	0	0	0	2,857	1,100	342	953	(781)	1,969	6,439	505	0	21,407
2009	0	0	0	2,857	1,005	312	870	(781)	1,903	6,165	435	0	19,545
2010	0	0	0	2,857	909	282	787	(781)	1,838	5,891	374	0	17,684
2011	0	0	0	2,857	813	253	704	(781)	1,772	5,617	321	0	15,822
2012	0	0	0	2,857	718	223	621	(781)	1,706	5,343	274	0	13,961
2013	0	0	0	2,857	622	193	538	(781)	1,640	5,069	234	0	12,100
2014	0	0	0	2,857	526	163	456	(781)	1,574	4,795	199	0	10,238
2015	0	0	0	2,857	431	134	373	(781)	1,509	4,522	169	0	8,377
2016	0	0	0	2,857	335	104	290	(781)	1,443	4,248	143	0	6,515
2017	0	0	0	2,857	239	74	207	(781)	1,377	3,974	120	0	4,654
2018	0	0	0	2,857	144	45	124	(781)	1,311	3,700	101	0	2,792
2019	0	0	0	2,857	48	15	41	(781)	1,246	3,426	84	0	931
TOTAL	0	0	0	100,000	68,413	21,240	59,215	0	67,549	316,416	113,541	71,250	
1985 NET PRESENT VALUE @ 11.19%													
	0	0	0	24,917	28,054	8,710	24,282	7,097	20,481	113,541	64,475	35,376	

PACIFICORP ELECTRIC OPERATIONS
COLSTRIP PROJECT

AUGUST 27, 1990

			INVESTMENT TAX CREDIT			DEFERRED TAXES						
YEAR	BEGINNING RATE BASE	BOOK DEPREC	CREDIT	RESTORED	RECAPTURE	CURRENT	RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1985	100,000	(2,857)	(7,500)	214	0	(738)	0	89,119	(175)	48.36%	5.000%	2.86%
1986	89,119	(2,857)	0	214	0	(2,461)	0	84,015	(584)	48.36%	10.000%	2.86%
1987	84,015	(2,857)	0	214	0	(1,865)	31	79,537	(251)	42.62%	9.000%	2.86%
1988	79,537	(2,857)	0	214	0	(1,351)	31	75,574	0	36.88%	8.000%	2.86%
1989	75,574	(2,857)	0	214	0	(1,089)	31	71,873	0	36.88%	7.000%	2.86%
1990	71,873	(2,857)	0	214	0	(1,089)	31	68,172	0	36.88%	7.000%	2.86%
1991	68,172	(2,857)	0	214	0	(826)	31	64,734	0	36.88%	6.000%	2.86%
1992	64,734	(2,857)	0	214	0	(826)	31	61,296	0	36.88%	6.000%	2.86%
1993	61,296	(2,857)	0	214	0	(826)	31	57,858	0	36.88%	6.000%	2.86%
1994	57,858	(2,857)	0	214	0	(826)	31	54,420	0	36.88%	6.000%	2.86%
1995	54,420	(2,857)	0	214	0	(826)	31	50,982	0	36.88%	6.000%	2.86%
1996	50,982	(2,857)	0	214	0	(826)	31	47,544	0	36.88%	6.000%	2.86%
1997	47,544	(2,857)	0	214	0	(826)	31	44,105	0	36.88%	6.000%	2.86%
1998	44,105	(2,857)	0	214	0	(826)	31	40,667	0	36.88%	6.000%	2.86%
1999	40,667	(2,857)	0	214	0	(826)	31	37,229	0	36.88%	6.000%	2.86%
2000	37,229	(2,857)	0	214	0	751	31	35,368	0	36.88%	0.000%	2.86%
2001	35,368	(2,857)	0	214	0	751	31	33,506	0	36.88%	0.000%	2.86%
2002	33,506	(2,857)	0	214	0	751	31	31,645	0	36.88%	0.000%	2.86%
2003	31,645	(2,857)	0	214	0	751	31	29,783	0	36.88%	0.000%	2.86%
2004	29,783	(2,857)	0	214	0	751	31	27,922	0	36.88%	0.000%	2.86%
2005	27,922	(2,857)	0	214	0	751	31	26,060	0	36.88%	0.000%	2.86%
2006	26,060	(2,857)	0	214	0	751	31	24,199	0	36.88%	0.000%	2.86%
2007	34,199	(2,857)	0	214	0	751	31	22,338	0	36.88%	0.000%	2.86%
2008	22,338	(2,857)	0	214	0	751	31	20,476	0	36.88%	0.000%	2.86%
2009	20,475	(2,857)	0	214	0	751	31	18,615	0	36.88%	0.000%	2.86%
2010	18,615	(2,857)	0	214	0	751	31	16,753	0	36.88%	0.000%	2.86%
2011	16,753	(2,857)	0	214	0	751	31	14,892	0	36.88%	0.000%	2.86%
2012	14,892	(2,857)	0	214	0	751	31	13,030	0	36.88%	0.000%	2.86%
2013	13,030	(2,857)	0	214	0	751	31	11,169	0	36.88%	0.000%	2.86%
2014	11,169	(2,857)	0	214	0	751	31	9,307	0	36.88%	0.000%	2.86%
2015	9,307	(2,857)	0	214	0	751	31	7,446	0	36.88%	0.000%	2.86%
2016	7,446	(2,857)	0	214	0	751	31	5,584	0	36.88%	0.000%	2.86%
2017	5,584	(2,857)	0	214	0	751	31	3,723	0	36.88%	0.000%	2.86%
2018	3,723	(2,857)	0	214	0	751	31	1,861	0	36.88%	0.000%	2.86%
2019	1,861	(2,857)	0	214	0	751	31	0	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(7,500)	7,500	0	(1,010)	1,010		(1,010)		100.000%	100.00%

COLSTRIP PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n - 1$
Where i = weighted cost of capital and n = ave. life of plant.

$$CRF = 0.1119\,(1 + 0.1119)^{35}/((1 + 0.1119)^{35} - 1) = 0.114701$$

(*2) BOOK DEPRECIATION = \$100,000/35 Years = \$2,857

(*3) TOTAL RETURN, (TR) = $A \times W_s$

Where	A	=	Average Rate Base; and
	W_s	=	Weighted Cost of Preferred and Common Stock
Let	A	=	$(R_0 + R_1)\ /2$
Where	R_0	=	Rate Base (Year 0)
	R_1	=	Rate base (End of Year 1)
Let	R_1	=	$I_b + I_c/L_g - D - T$
	I_0	=	Cumulative ITC (*9)
	L_g	=	Book Life (35 years)
	D	=	Cumulative Book Depreciation (*2)
	T	=	Cumulative Deferred Tax (*5)
	I_b	=	$E \times (1 - I_r \times I_8$ ITC Basis)
Where	E	=	Capital Expenditure (\$100,000)
	I_r	=	ITC Rate (0.10)
Therefore,	I_b	=	\$100,000 $(1 - 0.1 \times 0.75)$ = \$92,500
	R_1	=	\$92,500 + \$7,500/35 - \$2,857 - \$738 = \$89,199
	A	=	(\$100,000 + \$89,119) /2 = \$94,560
	TR	=	\$94,560 x (.12 x .133 + .36 x .1236) = \$5,717

(*4) INTEREST, (I) = $A \times W_d$

Where	W_d	=	Weighted Cost of Debt
Therefore	I	=	\$94,562 x (.52 x .09886) = \$4,861

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R + B_a / L_g \times T_r$

Where	T_D	=	Tax Depreciation (*8)
	T_R	=	Tax Rate (48.36%)
	B_a	=	Basis Adjustment
Let	B_a	=	\$100,000 $T_b \times I_a \times$ \$100,000

COLSTRIP PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where I_a = ITC Adjustment = $1 - I_r/2 = 1 - 0.1/2 = 0.95$
T_b = Tax Basis (75%)
Therefore, B_a = \$100,000 - 0.75 x 0.95 x \$100,000 = \$28,750
T = (\$3,563 - \$2,857) x .4836 + \$28,750/35 x .4836
T = \$738

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1 – Tax rate))
INCOME TAX = (\$5,717 + \$2,857 + \$738 - \$3,563) x (.4836/(1 - .4836)) = \$5,384

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax
ANNUAL COST = \$2,857 + \$5,717 + \$4,861 + \$738 + \$5,384 = \$19,557

(*8) TAX DEPRECIATION = (ACRS Percentages 15 Year Public Utility) x Original Tax Basis
TAX DEPRECIATION = 5% x 0.95 x 0.75 x \$100,000 = \$3,563

(*9) ITC = IT Credit x ITC Basis x Cumulative Book
ITC = 10% x 75% x \$100,000 = \$7,500

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1 + i)^n$
PRESENT WORTH ANNUAL COST = \$19,551 x $1/(1 + .1119)^1$ = \$17,589
where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.114701 x \$113,541) /\$100,000 = 0.1302 = 13.02%

Cholla Project Annual Fixed Cost

(Estimated 1996 Price)

Initial Levelized Fixed Charge

Cholla Project

Cholla Initial Project Investment – Without Betterments		$184,166,667	/1
Initial Levelized Annual Fixed Rate		13.76%	
Initial Levelized Annual Fixed Charge		$25,346,858	
Subsequent Investment – Includes Betterments 1991 – 1995		$5,619,840	/2
Subsequent Levelized Annual Fixed Rate		13.76%	
Subsequent Levelized Annual Fixed Charge		$773,459	
Ad Valorem Tax		$1,897,865	
Taxes, assessments and in lieu of taxes		$0	
Administrative & General Expenses:			
1989 Total PacifiCorp A&G Expense	$139,130,109		
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075		
A&G Expense as a percent of Investment	1.87%		
Cholla A & G Expense		$3,548,481	
Total Fixed Cost		**$31,566,664**	
Net Cholla Capacity		350	
Annual Fixed Cost per MW		$90,190	
Monthly Fixed Cost per kW		$\boxed{\$7.52}$	

/1 - $221,000,000 x (25/30) = $184,166,667
/2 - $6,743,810 x (25/30) = $5,619,840

PACIFICORP ELECTRIC OPERATIONS
CHOLLA PROJECT
1996 LFC – 25 YEAR REMAINING LIFE
SEPTEMBER 4, 1990

48%	DEBT FINANCING @ 10%	$345	LEVELIZED DEFERRED TAXES	20	YEAR TAX LIFE – ACRS
6%	PREFERRED EQUITY @ 9.5%	$3,186	LEVELIZED INTEREST EXPENSE	N/A	TAX RATE PRIOR TO 1987
46%	COMMON EQUITY @ 12.36%	$378	LEVELIZED PREFERRED RETURN	N/A	TAX RATE IN 1987
11.06%	WEIGHTED COST OF CAPITAL	$3,773	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.11922	CAPITAL RECOVERY FACTOR	0%	INVESTMENT TAX CREDIT (ITC)
$13,763	LEVELIZED ANNUAL COST	1996	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13,763	LEVELIZED FIXED CAPITAL COSTS	25	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$2,081	LEVELIZED INCOME TAXES	25	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RAIL BASE
1996	0	0	0	4,000	4,706	559	5,575	(92)	3,676	18,423	16,589	3,750	98,046
1997	0	0	0	4,000	4,488	533	5,316	1,187	2,230	17,754	14,395	7,219	93,499
1998	0	0	0	4,000	4,244	504	5,027	987	2,244	17,006	12,416	6,677	88,411
1999	0	0	0	4,000	4,009	476	4,748	803	2,250	16,286	10,707	6,177	83,516
2000	0	0	0	4,000	3,782	449	4,480	632	2,248	15,592	9,230	5,713	78,799
2001	0	0	0	4,000	3,564	423	4,221	474	2,240	14,922	7,954	5,285	74,246
2002	0	0	0	4,000	3,353	398	3,971	327	2,225	14,275	6,851	4,888	69,845
2003	0	0	0	4,000	3,148	374	3,729	193	2,205	13,648	5,899	4,522	65,585
2004	0	0	0	4,000	2,947	350	3,491	170	2,074	13,033	5,072	4,462	61,404
2005	0	0	0	4,000	2,747	326	3,254	170	1,922	12,419	4,352	4,461	57,214
2006	0	0	0	4,000	2,547	302	3,017	170	1,769	11,806	3,725	4,462	53,064
2007	0	0	0	4,000	2,347	279	2,780	170	1,617	11,193	3,180	4,461	48,893
2008	0	0	0	4,000	2,147	255	2,543	170	1,464	10,579	2,707	4,462	44,723
2009	0	0	0	4,000	1,947	231	2,306	170	1,312	9,966	2,296	4,461	40,553
2010	0	0	0	4,000	1,746	207	2,069	170	1,159	9,352	1,940	4,462	36,383
2011	0	0	0	4,000	1,546	184	1,831	170	1,007	8,739	1,632	4,461	32,213
2012	0	0	0	4,000	1,346	160	1,594	170	855	8,125	1,367	4,462	28,042
2013	0	0	0	4,000	1,146	136	1,357	170	703	7,512	1,138	4,461	23,872
2014	0	0	0	4,000	946	112	1,120	170	550	6,898	941	4,462	19,702
2015	0	0	0	4,000	746	89	883	170	398	6,285	772	4,461	15,532
2016	0	0	0	4,000	565	67	669	(652)	1,083	5,732	634	2,231	11,773
2017	0	0	0	4,000	424	50	502	(1,475)	1,798	5,300	528	0	8,837
2018	0	0	0	4,000	303	36	359	(1,475)	1,706	4,929	442	0	6,312
2019	0	0	0	4,000	182	22	215	(1,475)	1,614	4,557	368	0	3,787
2020	0	0	0	4,000	61	7	72	(1,475)	1,521	4,186	304	0	1,262
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	100,000	54,986	6,530	65,130	0	41,870	268,516	115,437	100,000	
1996 NET PRESENT VALUE @ 11.06%	0	0	0	33,551	26,719	3,173	31,649	2,894	17,452	115,437	66,600	41,397	

PACIFICORP ELECTRIC OPERATIONS
CHOLLA PROJECT
1996 LFC – 25 YEAR REMAINING LIFE
SEPTEMBER 4, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	INVESTMENT TAX CREDIT RESTORED	INVESTMENT TAX CREDIT RECAPTURE	DEFERRED TAXES CURRENT	DEFERRED TAXES RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1996	100,000	(4,000)	0	0	0	92	0	96,092	0	36.88%	3.750%	4.00%
1997	96,092	(4,000)	0	0	0	(1,187)	0	90,905	0	36.88%	7.219%	4.00%
1998	90,905	(4,000)	0	0	0	(987)	0	85,918	0	36.88%	6.677%	4.00%
1999	85,918	(4,000)	0	0	0	(803)	0	81,115	0	36.88%	6.177%	4.00%
2000	81,115	(4,000)	0	0	0	(632)	0	76,483	0	36.88%	5.713%	4.00%
2001	76,483	(4,000)	0	0	0	(474)	0	72,009	0	36.88%	5.285%	4.00%
2002	72,009	(4,000)	0	0	0	(327)	0	67,682	0	36.88%	4.888%	4.00%
2003	67,682	(4,000)	0	0	0	(193)	0	63,489	0	36.88%	4.522%	4.00%
2004	63,489	(4,000)	0	0	0	(170)	0	59,319	0	36.88%	4.462%	4.00%
2005	59,319	(4,000)	0	0	0	(170)	0	55,149	0	36.88%	4.461%	4.00%
2006	55,149	(4,000)	0	0	0	(170)	0	50,978	0	36.88%	4.462%	4.00%
2007	50,978	(4,000)	0	0	0	(170)	0	46,808	0	36.88%	4.461%	4.00%
2008	46,808	(4,000)	0	0	0	(170)	0	42,638	0	36.88%	4.462%	4.00%
2009	42,638	(4,000)	0	0	0	(170)	0	38,468	0	36.88%	4.461%	4.00%
2010	38,468	(4,000)	0	0	0	(170)	0	34,298	0	36.88%	4.462%	4.00%
2011	34,298	(4,000)	0	0	0	(170)	0	30,128	0	36.88%	4.461%	4.00%
2012	30,128	(4,000)	0	0	0	(170)	0	25,957	0	36.88%	4.462%	4.00%
2013	25,957	(4,000)	0	0	0	(170)	0	21,787	0	36.88%	4.461%	4.00%
2014	21,787	(4,000)	0	0	0	(170)	0	17,617	0	36.88%	4.462%	4.00%
2015	17,617	(4,000)	0	0	0	(170)	0	13,447	0	36.88%	4.461%	4.00%
2016	13,447	(4,000)	0	0	0	652	0	10,099	0	36.88%	2.231%	4.00%
2017	10,099	(4,000)	0	0	0	1,475	0	7,574	0	36.88%	0.000%	4.00%
2018	7,574	(4,000)	0	0	0	1,475	0	5,050	0	36.88%	0.000%	4.00%
2019	5,050	(4,000)	0	0	0	1,475	0	2,525	0	36.88%	0.000%	4.00%
2020	2,525	(4,000)	0	0	0	1,475	0	0	0	36.88%	0.000%	4.00%
2021	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2022	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2023	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2024	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2025	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2026	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2027	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2028	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2029	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2030	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
TOTAL		(100,000)	0	0	0	0	0		0		100.000%	100.00%

CHOLLA PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(l+i)^n/(l+i)^n - 1$
Where i = weighted cost of capital and n = ave. life of plant.

$$CRF = 0.1106\,(1 + 0.1106)^{25}/((1 + 0.1106)^{25} - 1) = 0.119261$$

(*2) BOOK DEPRECIATION = \$100,000/25 Years = \$4,000

(*3) TOTAL RETURN, (TR) = $A \times W_s$

Where	A	=	Average Rate Base; and
	W_s	=	Weighted Cost of Preferred and Common Stock
Let	A	=	$(R_0 + R_1)\ /2$
Where	R_0	=	Rate Base (Year 0)
	R_1	=	Rate base (End of Year 1)
Let	R_1	=	$I_b + I_c/L_g - D - T$
	I_0	=	Cumulative ITC (*9)
	L_g	=	Book Life (25 years)
	D	=	Cumulative Book Depreciation (*2)
	T	=	Cumulative Deferred Tax (*5)
	I_b	=	$E \times (1 - I_r \times I_8$ ITC Basis)
Where	E	=	Capital Expenditure (\$100,000)
	I_r	=	ITC Rate (0.10)
Therefore,	I_b	=	\$100,000 (1 – 0.1 x 0) = \$100,000
	R_1	=	\$100,000 + 0/25 - \$4,000 - (\$92) = \$96,092
	A	=	(\$100,000 + \$96,092) /2 = \$98,046
	TR	=	\$98,046 x (.06 x .095 + .46 x .1236) = \$6,133

(*4) INTEREST, (I) = $A \times W_d$

Where	W_d	=	Weighted Cost of Debt
Therefore	I	=	\$98,046 x (.48 x .10) = \$4,706

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R + B_a\ /L_g \times T_r$

Where	T_D	=	Tax Depreciation (*8)
	T_R	=	Tax Rate (36.88%)
	B_a	=	Basis Adjustment
Let	B_a	=	\$100,000 $T_b \times I_a \times$ \$100,000

CHOLLA PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where I_a = ITC Adjustment = $1 - I_r/2 = 1 - 0.0/2 = 0$
T_b = Tax Basis (100%)
Therefore, B_a = \$100,000 - 1 x 1.00 x \$100,000 = 0
T = (\$3,750 - \$4,000) x 36.88 + 0/25 x 36.88
T = \$92

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1 – Tax rate))
INCOME TAX = (\$6,133 + \$4,000 + (\$92) - \$3,750) x (.3688/(1 - .3688)) = \$3,675

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax
ANNUAL COST = \$4,000 + \$6,133 + \$4,706 + (\$92) + \$3,675 = \$18,423

(*8) TAX DEPRECIATION = (150% Declining Balance converting to Straight Line) x (1/2 yr. Amort. in 1^{st} year)
TAX DEPRECIATION = 1.50 x (\$100,000/20) /2 = \$3,750

(*9) ITC = Not Applicable

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1 + i)^n$
PRESENT WORTH ANNUAL COST = \$18,423 x $1/(1 + .1106)^1$ = \$16,589
where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.119261 x \$115,437) /\$100,000 = 0.1376 = <u>13.76%</u>

Hunter #2 Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(Estimated 1996 Price)

Initial Levelized Fixed Charge

Hunter #2 Project

Hunter #2 Initial Project Investment		$174,355,375
Initial Levelized Annual Fixed Rate		13.67%
Initial Levelized Annual Fixed Charge		$23,827,406
Subsequent Investment - (1990 thru 1995)		$5,296,480
Subsequent Levelized Annual Fixed Rate		13.67%
Subsequent Levelized Annual Fixed Charge		$724,029
Ad Valorem Tax		$2,160,314
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #2 A & G Expense		$3,358,992
Total Fixed Cost		**$30,070,740**
Net Hunter #2 Capacity		235
Annual Fixed Cost per MW		$127,961
Monthly Fixed Cost per kW		$\boxed{\$10.66}$

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 PROJECT

AUGUST 28, 1990

50%	DEBT FINANCING @ 11.97%	$1,187	LEVELIZED DEFERRED TAXES	22.5	YEAR TAX LIFE – SUM OF THE YEAR DIGITS
10%	PREFERRED EQUITY @ 10.96%	$3,966	LEVELIZED INTEREST EXPENSE	48.36%	TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
40%	COMMON EQUITY @ 12.36%	$726	LEVELIZED PREFERRED RETURN	42.62%	TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
12.03%	WEIGHTED COST OF CAPITAL	$3,276	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.12255	CAPITAL RECOVERY FACTOR	10.00%	INVESTMENT TAX CREDIT (ITC)
$13,666	LEVELIZED ANNUAL COST	1980	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13,666	LEVELIZED FIXED CAPITAL COSTS	35	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$1,939	LEVELIZED INCOME TAXES	35	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RAIL BASE
1980	0	0	0	2,857	5,879	1,077	4,857	676	4,612	19,672	17,560	4,255	98,233
1981	0	0	0	2,857	5,609	1,027	4,633	2,646	2,387	18,873	15,039	8,329	93,715
1982	0	0	0	2,857	5,285	968	4,366	2,461	2,266	17,917	12,744	7,946	88,305
1983	0	0	0	2,857	4,972	911	4,107	2,277	2,155	16,993	10,790	7,565	83,079
1984	0	0	0	2,857	4,670	855	3,858	2,095	2,051	16,101	9,126	7,190	78,036
1985	0	0	0	2,857	4,379	802	3,618	1,913	1,958	15,242	7,712	6,814	73,174
1986	0	0	0	2,857	4,100	751	3,386	1,729	1,878	14,414	6,510	6,432	68,496
1987	0	0	0	2,857	3,836	702	3,169	1,362	1,301	12,942	5,218	6,052	64,094
1988	0	0	0	2,857	3,593	658	2,968	1,040	912	11,743	4,226	5,676	60,036
1989	0	0	0	2,857	3,364	616	2,779	900	917	11,147	3,581	5,297	56,209
1990	0	0	0	2,857	3,143	576	2,597	761	925	10,574	3,032	4,921	52,522
1991	0	0	0	2,857	2,931	537	2,421	621	941	10,022	2,565	4,540	48,974
1992	0	0	0	2,857	2,727	499	2,253	482	959	9,492	2,169	4,164	45,565
1993	0	0	0	2,857	2,531	464	2,091	342	984	8,983	1,832	3,784	42,296
1994	0	0	0	2,857	2,344	429	1,936	202	1,013	8,497	1,547	3,406	39,167
1995	0	0	0	2,857	2,165	397	1,789	63	1,047	8,032	1,305	3,027	36,177
1996	0	0	0	2,857	1,995	365	1,648	(93)	1,077	7,563	1,097	2,649	33,335
1997	0	0	0	2,857	1,835	336	1,516	(263)	1,104	7,099	919	2,270	30,656
1998	0	0	0	2,857	1,685	308	1,392	(432)	1,138	6,661	770	1,892	28,147
1999	0	0	0	2,857	1,545	283	1,276	(602)	1,177	6,250	645	1,514	25,807
2000	0	0	0	2,857	1,415	259	1,169	(771)	1,223	5,865	540	1,135	23,636
2001	0	0	0	2,857	1,295	237	1,070	(941)	1,274	5,506	453	757	21,635
2002	0	0	0	2,857	1,185	217	979	(1,111)	1,332	5,174	380	378	19,804
2003	0	0	0	2,857	1,086	199	897	(1,280)	1,395	4,868	319	0	18,142
2004	0	0	0	2,857	991	182	819	(1,280)	1,339	4,623	270	0	16,564
2005	0	0	0	2,857	897	164	741	(1,280)	1,284	4,377	229	0	14,987
2006	0	0	0	2,857	803	147	663	(1,280)	1,228	4,132	193	0	13,410
2007	0	0	0	2,857	708	130	585	(1,280)	1,172	3,887	162	0	11,832
2008	0	0	0	2,857	614	112	507	(1,280)	1,117	3,641	135	0	10,255
2009	0	0	0	2,857	519	95	429	(1,280)	1,061	3,396	113	0	8,678
2010	0	0	0	2,857	425	78	351	(1,280)	1,005	3,151	93	0	7,100
2011	0	0	0	2,857	331	61	273	(1,280)	950	2,905	77	0	5,523
2012	0	0	0	2,857	236	43	195	(1,280)	894	2,660	63	0	3,946
2013	0	0	0	2,857	142	26	117	(1,280)	838	2,415	51	0	2,369
2014	0	0	0	2,857	47	9	39	(1,280)	783	2,169	41	0	791
TOTAL	0	0	0	100,000	79,283	14,519	65,493	0	47,694	296,986	111,507	99,993	
1980 NET PRESENT VALUE @ 12.03%													
	0	0	0	23,314	32,358	5,925	26,730	9,689	15,823	111,507	111,507	44,160	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 PROJECT

AUGUST 28, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	RESTORED	RECAPTURE	DEFERRED TAXES CURRENT	RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1980	100,000	(2,857)	(286)	286	0	(676)	0	96,467	(160)	48.36%	4.255%	2.86%
1981	96,467	(2,857)	(286)	286	0	(2,646)	0	90,964	(628)	48.36%	8.329%	2.86%
1982	90,964	(2,857)	(286)	286	0	(2,461)	0	85,646	(584)	48.36%	7.946%	2.86%
1983	85,646	(2,857)	(286)	286	0	(2,277)	0	80,512	(540)	48.36%	7.565%	2.86%
1984	80,512	(2,857)	(286)	286	0	(2,095)	0	75,560	(497)	48.36%	7.190%	2.86%
1985	75,560	(2,857)	(286)	286	0	(1,913)	0	70,789	(454)	48.36%	6.814%	2.86%
1986	70,789	(2,857)	(286)	286	0	(1,729)	0	66,203	(410)	48.36%	6.432%	2.86%
1987	66,203	(2,857)	(286)	286	0	(1,362)	0	61,985	(183)	42.62%	6.052%	2.86%
1988	61,985	(2,857)	(286)	286	0	(1,040)	0	58,088	0	36.88%	5.676%	2.86%
1989	58,088	(2,857)	(286)	286	0	(900)	0	54,331	0	36.88%	5.297%	2.86%
1990	54,331	(2,857)	(286)	286	0	(761)	0	50,713	0	36.88%	4.921%	2.86%
1991	50,713	(2,857)	(286)	286	0	(621)	0	47,235	0	36.88%	4.540%	2.86%
1992	47,235	(2,857)	(286)	286	0	(482)	0	43,896	0	36.88%	4.164%	2.86%
1993	43,896	(2,857)	(286)	286	0	(342)	0	40,697	0	36.88%	3.784%	2.86%
1994	40,697	(2,857)	(286)	286	0	(202)	0	37,637	0	36.88%	3.406%	2.86%
1995	37,637	(2,857)	(286)	286	0	(63)	0	34,717	0	36.88%	3.027%	2.86%
1996	34,717	(2,857)	(286)	286	0	77	16	31,954	0	36.88%	2.649%	2.86%
1997	31,954	(2,857)	(286)	286	0	217	46	29,359	0	36.88%	2.270%	2.86%
1998	29,359	(2,857)	(286)	286	0	356	76	26,935	0	36.88%	1.892%	2.86%
1999	26,935	(2,857)	(286)	286	0	495	106	24,679	0	36.88%	1.514%	2.86%
2000	24,679	(2,857)	(286)	286	0	635	136	22,593	0	36.88%	1.135%	2.86%
2001	22,593	(2,857)	(286)	286	0	775	166	20,677	0	36.88%	0.757%	2.86%
2002	20,677	(2,857)	(286)	286	0	914	196	18,930	0	36.88%	0.378%	2.86%
2003	18,930	(2,857)	(286)	286	0	1,054	226	17,353	0	36.88%	0.000%	2.86%
2004	17,353	(2,857)	(286)	286	0	1,054	226	15,776	0	36.88%	0.000%	2.86%
2005	15,776	(2,857)	(286)	286	0	1,054	226	14,198	0	36.88%	0.000%	2.86%
2006	14,198	(2,857)	(286)	286	0	1,054	226	12,621	0	36.88%	0.000%	2.86%
2007	12,621	(2,857)	(286)	286	0	1,054	226	11,044	0	36.88%	0.000%	2.86%
2008	11,044	(2,857)	(286)	286	0	1,054	226	9,466	0	36.88%	0.000%	2.86%
2009	9,466	(2,857)	(286)	286	0	1,054	226	7,889	0	36.88%	0.000%	2.86%
2010	7,889	(2,857)	(286)	286	0	1,054	226	6,312	0	36.88%	0.000%	2.86%
2011	6,312	(2,857)	(286)	286	0	1,054	226	4,735	0	36.88%	0.000%	2.86%
2012	4,735	(2,857)	(286)	286	0	1,054	226	3,157	0	36.88%	0.000%	2.86%
2013	3,157	(2,857)	(286)	286	0	1,054	226	1,580	0	36.88%	0.000%	2.86%
2014	1,580	(2,857)	(286)	286	0	1,054	226	3	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(10,000)	10,000	0	(3,455)	3,458		(3,458)		99.990%	100.00%

HUNTER #2 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n - 1$
Where i = weighted cost of capital and n = ave. life of plant.

$$CRF = 0.1203\ (1 + 0.1203)^{35}/((1 + 0.1203)^{35} - 1) = 0.12260$$

(*2) BOOK DEPRECIATION = \$100,000/35 Years = \$2,857

(*3) TOTAL RETURN, (TR) = A x W_s
Where A = Average Rate Base; and
W_s = Weighted Cost of Preferred and Common Stock
Let A = Beginning Investment - (D + T) /2
Where Beginning Investment = Previous year's beginning investment - previous year's D and T.

D = Book Depreciation (*2)
T = Deferred Tax (*5)
Therefore, beginning investment = \$100,000
A = \$100,000 - (2857 + 676) /2 = \$98,234
TR = \$98,234 x (.10 x .1096 + .40 x .1236) = \$5,933

(*4) INTEREST, (I) = A x W_d
Where W_d = Weighted Cost of Debt
Therefore I = \$98,234 x (.50 x .1197) = \$5,879

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R$
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (48.36%)
Let T = (4,255 - 2,857) x .4836 = \$676

HUNTER #2 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation + ITC) x Tax rate/(1 – Tax rate)

INCOME TAX = ($5,933 + $2,857 + $676 - $4,255 - $285) x (.4836/(1 - .4836)) = $4,612

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax + ITC

ANNUAL COST = $2,857 + $5,933 + $5,879 + $676 + $4,612 - 285 = $19,672

(*8) TAX DEPRECIATION = (Sum of the Year's Digits) = Year's remaining /sum of Digits) x (Beginning Investment - Cumulative Tax Depreciation)

Where Sum of Digits in yr. 1 = 264.5 (For 22.5 year tax life)

TAX DEPRECIATION = (22.5/264.5) x (100,000 - 0) = $8,510
Adjusted for 1/2 year = $8,510/2 = $4,255

(*9) ITC = Beginning Investment x ITC Rate/Book Life
ITC = $100,000 x 0.10/35 = $285

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1 + i)^n$
PRESENT WORTH ANNUAL COST = $19,672 x $1/(1 + .1203)^1$ = $17,560

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.1226 x $111,507) /$100,000 = 0.1367 = 13.67%

Hunter #3 Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(1996 Estimated Price)

Initial Levelized Fixed Charge

Hunter #3 Project

Hunter #3 Initial Project Investment		$453,116,692
Initial Levelized Annual Fixed Rate		14.76%
Initial Levelized Annual Fixed Charge		$66,870,961
Subsequent Investment - (1990 thru 1995)		$13,764,557
Subsequent Levelized Annual Fixed Rate		14.76%
Subsequent Levelized Annual Fixed Charge		$2,031,649
Ad Valorem Tax		$5,210,051
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #2 A & G Expense		$8,729,385
Total Fixed Cost		**$82,842,046**
Net Hunter #2 Capacity		400
Annual Fixed Cost per MW		$207,105
Monthly Fixed Cost per kW		$\boxed{\$17.26}$

PACIFICORP ELECTRIC OPERATIONS
HUNTER #3 PROJECT

AUGUST 28, 1990

50%	DEBT FINANCING @ 14.52%	$1,329	LEVELIZED DEFERRED TAXES	15	YEAR TAX LIFE – ACRS
10%	PREFERRED EQUITY @ 11.6%	$4,925	LEVELIZED INTEREST EXPENSE	48.36%	TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
40%	COMMON EQUITY @ 12.36%	$787	LEVELIZED PREFERRED RETURN	42.62%	TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
13.36%	WEIGHTED COST OF CAPITAL	$3,354	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.13532	CAPITAL RECOVERY FACTOR	10.00%	INVESTMENT TAX CREDIT (ITC)
$14,758	LEVELIZED ANNUAL COST	1980	IN SERVICE DATE	95%	ITC BASIS ADJUSTMENT
$14,758	LEVELIZED FIXED CAPITAL COSTS	35	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$1,792	LEVELIZED INCOME TAXES	35	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RAIL BASE
1983	0	0	0	2,857	7,121	1,138	4,849	984	4,488	21,151	18,657	4,750	98,079
1984	0	0	0	2,857	6,758	1,080	4,602	3,281	1,905	20,199	15,717	9,500	93,089
1985	0	0	0	2,857	6,329	1,011	4,310	2,822	2,027	19,071	13,090	8,550	87,180
1986	0	0	0	2,857	5,934	948	4,041	2,363	2,175	18,032	10,918	7,600	81,731
1987	0	0	0	2,857	5,580	892	3,800	1,677	1,701	16,220	8,663	6,650	76,854
1988	0	0	0	2,857	5,259	840	3,581	1,452	1,048	14,751	6,950	6,650	72,432
1989	0	0	0	2,857	4,959	792	3,377	1,101	1,251	14,051	5,840	5,700	68,299
1990	0	0	0	2,857	4,671	746	3,181	1,101	1,110	13,381	4,906	5,700	64,341
1991	0	0	0	2,857	4,384	700	2,985	1,101	969	12,711	4,111	5,700	60,382
1992	0	0	0	2,857	4,096	655	2,790	1,101	828	12,041	3,435	5,700	56,424
1993	0	0	0	2,857	3,809	609	2,594	1,101	687	11,371	2,861	5,700	52,466
1994	0	0	0	2,857	3,522	563	2,398	1,101	545	10,701	2,375	5,700	48,508
1995	0	0	0	2,857	3,234	517	2,203	1,101	404	10,030	1,964	5,700	44,549
1996	0	0	0	2,857	2,947	471	2,007	1,101	263	9,360	1,617	5,700	40,591
1997	0	0	0	2,857	2,660	425	1,811	1,101	122	8,690	1,324	5,700	36,633
1998	0	0	0	2,857	2,453	392	1,670	(1,124)	2,050	8,013	1,077	0	33,787
1999	0	0	0	2,857	2,327	372	1,585	(1,124)	1,989	7,719	915	0	32,055
2000	0	0	0	2,857	2,201	352	1,499	(1,124)	1,927	7,426	77	0	30,322
2001	0	0	0	2,857	2,076	332	1,413	(1,124)	1,865	7,133	658	0	28,589
2002	0	0	0	2,857	1,950	312	1,328	(1,124)	1,803	6,839	557	0	26,856
2003	0	0	0	2,857	1,824	291	1,242	(1,124)	1,741	6,546	470	0	25,124
2004	0	0	0	2,857	1,698	271	1,156	(1,124)	1,680	6,253	396	0	23,391
2005	0	0	0	2,857	1,572	251	1,071	(1,124)	1,618	5,959	333	0	21,658
2006	0	0	0	2,857	1,447	231	985	(1,124)	1,556	5,666	279	0	19,926
2007	0	0	0	2,857	1,321	211	899	(1,124)	1,494	5,373	234	0	18,193
2008	0	0	0	2,857	1,195	191	814	(1,124)	1,433	5,079	195	0	16,460
2009	0	0	0	2,857	1,069	171	728	(1,124)	1,371	4,786	162	0	14,728
2010	0	0	0	2,857	943	151	642	(1,124)	1,309	4,493	134	0	12,995
2011	0	0	0	2,857	818	131	557	(1,124)	1,247	4,199	111	0	11,262
2012	0	0	0	2,857	692	111	471	(1,124)	1,185	3,906	91	0	9,530
2013	0	0	0	2,857	566	90	385	(1,124)	1,124	3,612	74	0	7,797
2014	0	0	0	2,857	440	70	300	(1,124)	1,062	3,319	60	0	6,064
2015	0	0	0	2,857	314	50	214	(1,124)	1,000	3,026	48	0	4,332
2016	0	0	0	2,857	189	30	128	(1,124)	938	2,732	38	0	2,599
2017	0	0	0	2,857	63	10	43	(1,124)	876	2,439	30	0	866
TOTAL	0	0	0	100,000	96,420	15,406	65,661	0	48,792	316,278	109,065	95,000	
1983 NET PRESENT VALUE @ 13.36%	0	0	0	21,114	36,398	5,816	24,787	9,818	13,243	109,065	109,065	42,334	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #3 PROJECT

AUGUST 28, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	RESTORED	RECAPTURE	DEFERRED TAXES CURRENT	RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1983	100,000	(2,857)	(286)	286	0	(984)	0	96,158	(234)	48.36%	5.000%	2.86%
1984	96,158	(2,857)	(286)	286	0	(3,281)	0	90,020	(779)	48.36%	10.000%	2.86%
1985	90,020	(2,857)	(286)	286	0	(2,822)	0	84,341	(670)	48.36%	9.000%	2.86%
1986	84,341	(2,857)	(286)	286	0	(2,363)	0	79,121	(561)	48.36%	8.000%	2.86%
1987	79,121	(2,857)	(286)	286	0	(1,677)	0	74,587	(226)	42.62%	7.000%	2.86%
1988	74,587	(2,857)	(286)	286	0	(1,452)	0	70,278	0	36.88%	7.000%	2.86%
1989	70,278	(2,857)	(286)	286	0	(1,101)	0	66,320	0	36.88%	6.000%	2.86%
1990	66,320	(2,857)	(286)	286	0	(1,101)	0	62,361	0	36.88%	6.000%	2.86%
1991	62,361	(2,857)	(286)	286	0	(1,101)	0	58,403	0	36.88%	6.000%	2.86%
1992	58,403	(2,857)	(286)	286	0	(1,101)	0	54,445	0	36.88%	6.000%	2.86%
1993	54,445	(2,857)	(286)	286	0	(1,101)	0	50,487	0	36.88%	6.000%	2.86%
1994	50,487	(2,857)	(286)	286	0	(1,101)	0	46,528	0	36.88%	6.000%	2.86%
1995	46,528	(2,857)	(286)	286	0	(1,101)	0	42,570	0	36.88%	6.000%	2.86%
1996	42,570	(2,857)	(286)	286	0	(1,101)	0	38,612	0	36.88%	6.000%	2.86%
1997	38,612	(2,857)	(286)	286	0	(1,101)	0	34,654	0	36.88%	6.000%	2.86%
1998	34,654	(2,857)	(286)	286	0	1,001	123	32,921	0	36.88%	0.000%	2.86%
1999	32,921	(2,857)	(286)	286	0	1,001	123	31,188	0	36.88%	0.000%	2.86%
2000	31,188	(2,857)	(286)	286	0	1,001	123	29,455	0	36.88%	0.000%	2.86%
2001	29,455	(2,857)	(286)	286	0	1,001	123	27,723	0	36.88%	0.000%	2.86%
2002	27,723	(2,857)	(286)	286	0	1,001	123	25,990	0	36.88%	0.000%	2.86%
2003	25,990	(2,857)	(286)	286	0	1,001	123	24,257	0	36.88%	0.000%	2.86%
2004	24,257	(2,857)	(286)	286	0	1,001	123	22,525	0	36.88%	0.000%	2.86%
2005	22,525	(2,857)	(286)	286	0	1,001	123	20,792	0	36.88%	0.000%	2.86%
2006	20,792	(2,857)	(286)	286	0	1,001	123	19,059	0	36.88%	0.000%	2.86%
2007	19,059	(2,857)	(286)	286	0	1,001	123	17,327	0	36.88%	0.000%	2.86%
2008	17,327	(2,857)	(286)	286	0	1,001	123	15,594	0	36.88%	0.000%	2.86%
2009	15,594	(2,857)	(286)	286	0	1,001	123	13,861	0	36.88%	0.000%	2.86%
2010	13,861	(2,857)	(286)	286	0	1,001	123	12,129	0	36.88%	0.000%	2.86%
2011	12,129	(2,857)	(286)	286	0	1,001	123	10,396	0	36.88%	0.000%	2.86%
2012	10,396	(2,857)	(286)	286	0	1,001	123	8,663	0	36.88%	0.000%	2.86%
2013	8,663	(2,857)	(286)	286	0	1,001	123	6,931	0	36.88%	0.000%	2.86%
2014	6,931	(2,857)	(286)	286	0	1,001	123	5,198	0	36.88%	0.000%	2.86%
2015	5,198	(2,857)	(286)	286	0	1,001	123	3,465	0	36.88%	0.000%	2.86%
2016	3,465	(2,857)	(286)	286	0	1,001	123	1,733	0	36.88%	0.000%	2.86%
2017	1,733	(2,857)	(286)	286	0	1,001	123	0	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(10,000)	10,000	0	(2,469)	2,469		(2,469)		100.000%	100.00%

HUNTER #3 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(l+i)^n/(l+i)^n - 1$
Where i = weighted cost of capital and n = ave. life of plant.

$$CRF = 0.1336\ (1 + 0.1336)^{35}/((1 + 0.1336)^{35} - 1) = 0.13528$$

(*2) BOOK DEPRECIATION = \$100,000/30 Years = \$2,857

(*3) TOTAL RETURN, (TR) = $A \times W_s$

Where A = Average Rate Base; and
W_s = Weighted Cost of Preferred and Common Stock
Let A = Beginning Investment - (D + T) /2
Where Beginning Investment = Previous year's beginning investment - previous year's D and T.

D = Book Depreciation (*2)
T = Deferred Tax (*5)

Therefore, beginning investment = \$100,000
A = \$100,000 - (2857 + 984) /2 = \$98,080
TR = \$98,080 x (.10 x .1160 + .40 x .1236) = \$5,987

(*4) INTEREST, (I) = $A \times W_d$
Where W_d = Weighted Cost of Debt
Therefore I = \$98,080 x (.50 x .1452) = \$7,121

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R$
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (48.36%)
B^2 = \$100,000 - $T^b \times I_a \times$ \$100,000
L_g = Book Life (35 years)

HUNTER #3 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where I_a = ITC Adjustment = 1 - I_r/2 = 1 - 0.1/2
I_r = ITC Rate (0.10)
T_b = Tax Basis (100%)
Therefore, B_a = \$100,000 - 1.00 x 0.95 x \$100,000 = \$5,000
T = (\$4,750 - \$2,857) x .4836 + 5000/35 x .4836 = \$984

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation + ITC) x Tax rate/(1 – Tax rate)
INCOME TAX = (\$5,987 + \$2,857 + \$984 - \$4,750 - \$285) x (.4836/(1 - .4836)) = \$4,488

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax + ITC
ANNUAL COST = \$2,857 + \$5,987 + \$7,121 + \$984 + \$4,488 - 285 = \$21,151

(*8) TAX DEPRECIATION = (ACRS Percentages 15 Year Public Utility) x Original Tax Basis
TAX DEPRECIATION = 5% x 0.95 x 1.00 x \$100,000 = \$4,750

(*9) ITC = Beginning Investment x ITC Rate/Book Life
ITC = \$100,000 x 0.10/^{35} = \$285

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1 + i)^n$
PRESENT WORTH ANNUAL COST = \$21,151 x $1/(1 + .1336)^1$ = \$18,657

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.13528 x \$109,065) /\$100,000 = 0.1476 = <u>14.76%</u>

Annual Fixed Cost

Annual Fixed Cost

	Pool Size (mw)	Monthly Fixed Cost ($/kW/Mo.)	Weighted Average
Colstrip	70	18.53	$1,297
Cholla	350	7.52	$2,632
Hunter #2	180	10.66	$1,919
Hunter #3	400	17.26	$6,904
Total	1000	NA	$12,752

Annual Fixed Cost ,$/kW/mo.	$12.75
System Transmission Component =	**$0.00**
W/ System Transmission, $/kW/Mo. =	**$12.75**
Transmission Loss Factor =	1
Annual Fixed Cost Adjusted for Losses =	$12.75

APPENDIX B: ANNUAL VARIABLE COST

This Appendix sets forth the elements and techniques to calculate the Annual Variable Cost.

Section BI: Determination of Annual Variable Cost

The Annual Variable Cost shall be the \$/Mwh result of the following: (1) the product of 70 MW multiplied by the Colstrip annual load factor multiplied by the Colstrip Project Annual Variable Cost plus the product of 350 MW multiplied by the Cholla annual load factor multiplied by the Cholla Project Annual Variable Cost plus the product of 180 MW multiplied by the Hunter #2 annual load factor multiplied by the Hunter #2 Project Annual Variable Cost plus the product of 400 MW multiplied by the Hunter #3 annual load factor multiplied by the Hunter #3 Project Annual Variable Cost, (2) dividing the above sum by the total of 70 MW multiplied by the Colstrip annual load factor plus 350 MW multiplied by the Cholla annual load factor plus 180 MW multiplied by the Hunter #2 annual load factor plus 400 MW multiplied by the Hunter #3 annual load factor.

Section B2: Determination of Colstrip Project Annual Variable Cost, Cholla Project Annual Variable Cost, Hunter #2 Project Annual Variable Cost and, Hunter #3 Project Annual Variable Cost

The Colstrip Project Annual Variable Cost, the Cholla Project Annual Variable Cost, the Hunter #2 Project Annual Variable Cost and the Hunter #3 Project Annual Variable Cost shall be determined, for each Project, by (a) adding the amounts as set forth in Sections B2.1 through B2.2 (plus B2.3 for Hunter #2 and plus B2.4 for Hunter #3) and (b) dividing each Project total by PacifiCorp's share of the associated Project's annual energy production as filed with the Federal Energy Regulatory Commission (FERC) in PacifiCorp's FERC Form No. 1, or its successor thereto.

B2.1 Production Expenses shall be equal to the production expenses of resources in the Resource Pool as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

B2.2 In lieu of payments shall consist of any assessment, payment in lieu of taxes or other charge which is imposed against PacifiCorp by governmental authority and related to the operation and maintenance of each Project.

B2.3 Hunter #2 Project allocated mining expenses, to be determined by adding the amounts calculated under Sections B2.3.1 through B2.3.4 below:

B2.3.1 PacifiCorp's adjusted initial levelized annual fixed charge rate for the Hunter #2 project mining investment multiplied by the Hunter #2 project mining initial investment, determined pursuant to Section B3, as of December 31, 1989. For purposes of this section, PacifiCorp's total investment in Hunter #2 project mining is $22,748,496. Such total investment shall remain constant through the book life (14 years) and shall be $0 afterwards. Such adjusted initial levelized annual fixed charge rate shall be determined by subtracting book depreciation (1/book life) from PacifiCorp's initial levelized annual fixed charge rate for the Hunter #2 project mining investment determined annually in accordance with Section B4, below. Such book depreciation is reflected in Hunter #2 fuel cost.

B2.3.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, for the Hunter #2 Project mining investment, as calculated in accordance with Section B4, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #2 Project allocated mining investment, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

B2.3.3 All ad valorem taxes imposed upon the Hunter #2 Project mining investment.

B2.3.4 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total Hunter #2 Project mining investment.

B2.4 Hunter #3 Project allocated mining expenses, to be determined by adding the amounts calculated under Section B2.4.1 through B2.4.4 below:

B2.4.1 PacifiCorp's adjusted initial levelized annual fixed charge rate for the Hunter #3 Project mining investment multiplied by the Hunter #3 Project mining initial investment, determined pursuant to Section B3, as of December 31, 1989. For purposes of this section, PacifiCorp's total investment in Hunter #3 project mining is $38,720,844. Such total investment shall remain constant through the book life (14 years) and shall be $0 afterwards. Such adjusted initial levelized annual fixed charge rate shall be determined by subtracting book depreciation (1/book life) from PacifiCorp's initial levelized annual fixed charge rate for the Hunter #3 project mining investment determined annually in accordance with Section B4, below. Such book depreciation is reflected in Hunter #3 fuel cost.

B2.4.2 Each subsequent annual levelized fixed charge shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for the Hunter #3 Project mining investment, as calculated in accordance with Section B4, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #3 Project allocated mining investment, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

B2.4.3 All ad valorem taxes imposed upon the Hunter #3 Project mining investment.

B2.4.4 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total Hunter #3 Project mining investment.

Section B3: Allocation of Mining Investment to Hunter #2 and Hunter #3 Projects

Hunter #2 mining initial investment and Hunter #3 mining initial investment shall be determined by (a) multiplying the dollar amount as set forth in Section B3.1 by (b) the ratio of

PacifiCorp's share of the associated Project's capability (235 MW for Hunter #2 Project and 400 MW for Hunter #3 Project) divided by the total capability of all Projects served by the mines (presently 1995 MW). Hunter #2 mining subsequent investment and Hunter #3 mining subsequent investment shall be determined by (a) multiplying the dollar amounts as set forth in Section B3.2 by (b) the ratio of PacifiCorp's share of the associated Projects capability (235 MW for Hunter #2 Project and 400 MW for Hunter #3 Project) divided by the total capability of all Projects served by the mines (presently 1995 MW).

B3.1 Gross coal plant, as reported in FERC account 399 as "Total Other Tangible Property" in PacifiCorp's FERC Form 1 as of December 31, 1989.

B3.2 Each subsequent coal mine investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments, as determined pursuant to data contained in PacifiCorp's FERC Form 1 or its successor thereto.

Section B4: Elements of Hunter #2 and Hunter #3 Project Mining Investment

Levelized Annual Fixed Charge Rates

B4.1 Capital Structure:

B4.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #2 and Hunter #3 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total	100%

B4.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total	100$

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization-

B4.2 Cost of Capital:

B4.2.1.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be eight and forty-seven hundredths percent (8.47%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #2 and Hunter #3 Project Mining Investment, in the twelve (12)-month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12)-month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

B4.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be eight and twenty-four hundredths (8.24%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

B4.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date

PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

B4.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a fourteen (14) year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment. Because book depreciation is reflected in the Hunter #2 and #3 fuel cost, an adjustment is made to the initial levelized annual fixed charge rate for the Hunter #2 and #3 project mining investment, pursuant to Subsections B2.3.1 and B2.4.1.

B4.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

B4.4.1 The federal corporate income tax rate, of 34%.

B4.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's (3) three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

B4.4.3 The Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating both the initial and subsequent levelized annual fixed charge rates.

B4.4.4 Regular Investment Tax Credits allowed in) accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits shall be used when calculating subsequent levelized annual fixed charge rates.

B4.4.5 Tax basis shall be one-hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate.

Colstrip Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Colstrip Project		
	Annual Energy Production (MWh)	1,052,975
Production Expenses		
	Operation, Supervision and Engineering	$180,275
	Fuel	$7,394,559
	Steam Expenses	$722,304
	Electric Expenses	$330,429
	Misc. Steam Power Expenses	$875,183
	Rents	($74,887)
	Maintenance, Supervision and Engineering	$225,070
	Maintenance of Structures	$207,729
	Maintenance of Boiler Plant	$1,315,261
	Maintenance of Electric Plant	$261,013
	Maintenance of Misc. Steam Plant	$244.057
	Subtotal	$11,680,993
In Lieu of Payments *		$219.107
Total Variable Costs Colstrip Project		$11,900,100
Colstrip Project Annual Variable Cost		$\boxed{\$11.30 \text{ per MWh}}$

* Montana Electrical Energy License Tax

Cholla Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Cholla Project		
	Annual Energy Production (MWh)	4,913,599
Production Expenses		
	Operation, Supervision and Engineering	$391,540
	Fuel	$84,460,268
	Steam Expenses	$3,263,082
	Electric Expenses	$834,325
	Misc. Steam Power Expenses	$1,553,024
	Rents	$139,392
	Maintenance, Supervision and Engineering	$2,829,620
	Maintenance of Structures	$504,564
	Maintenance of Boiler Plant	$9,343,026
	Maintenance of Electric Plant	$1,975,652
	Maintenance of Misc. Steam Plant	$1,479,085
	Subtotal	$106,773,578
In Lieu of Payments		-
Total Variable Costs Cholla Project		$106,773,578
Cholla Annual Variable Cost		$21.73 per MWh

Note: Example Purposes Only - Reflects Total Cholla Plant

Hunter #2 Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Hunter #2 Project	
Annual Energy Production (MWh)	1,653,390
Production Expenses	
Operation, Supervision and Engineering	$139,904
Fuel	$14,927,530
Steam Expenses	$1,457,346
Electric Expenses	$577,512
Misc. Steam Power Expenses	$623,071
Rents	$27
Maintenance, Supervision and Engineering	$373,099
Maintenance of Structures	$242,519
Maintenance of Boiler Plant	$1,974,717
Maintenance of Electric Plant	$336,814
Maintenance of Misc. Steam Plant	$468.726
Subtotal	$21,121,265
Allocated Mining Expenses	$2,189,452 *
In Lieu of Payments	-
Total Variable Costs Hunter #2 Project	$23,310,717
Hunter #2 Project Annual Variable Cost	$14.10 per MWh

* See Attached sheets for details

Hunter #3 Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Hunter #3 Project	
Annual Energy Production (MWh)	2,743,379
Production Expenses	
Operation, Supervision and Engineering	$231,997
Fuel	$24,859,535
Steam Expenses	$2,517,785
Electric Expenses	$1,179,383
Misc. Steam Power Expenses	$897,027
Rents	$2,437
Maintenance, Supervision and Engineering	$715,529
Maintenance of Structures	$431,445
Maintenance of Boiler Plant	$4,837,672
Maintenance of Electric Plant	$686,521
Maintenance of Misc. Steam Plant	$958,473
Subtotal	$37,317,804
Allocated Mining Expenses	$3,726,731 *
In Lieu of Payments	-
Total Variable Costs Hunter #3 Project	$41,044,535
Hunter #3 Project Annual Variable Cost	$14.96 per MWh

* See attached sheets for details

Annual Variable Cost

Project Annual Load Factors

	1989 Generation (Mwh)	Capacity MW	Load Factor
Colstrip	1,052,975	140	86%
Cholla	6,910,089	940	84%
Hunter #2	1,653,390	235	80%
Hunter #3	2,743,379	400	78%

Weighted Variable Cost

	Capacity MW	Load Factor	Variable Cost $/MWh	Numerator	Denominator
Colstrip	70	86%	11.30	679	60
Cholla	350	84%	21.73	6,382	294
Hunter #2	180	80%	14.10	2,038	145
Hunter #3	400	78%	14.96	4,685	313
Total				13,785	812

Numerator = Capacity x Load Factor x Variable Cost

Denominator = Capacity x Load Factor

Weighted Variable Cast =	13,785	÷	812	=	$16.99
Adjusted for Losses =	$16.99	÷	1		
Annual Variable Cost =			$\boxed{\$16.99}$		

Hunter #2 Project Allocated Mining Expenses

(Based on 1989 Actual Costs)

Initial Levelized Fixed Charge

Hunter #2 Project

Hunter #2 Mining Investment		$22,748,496
Adjusted Initial Levelized Annual Fixed Rate		6.75%
Initial Levelized Annual Fixed Charge		$1,535,751
Subsequent Investment		$0
Subsequent Levelized Annual Fixed Rate		0.00%
Subsequent Levelized Annual Fixed Charge		$0
Ad Valorem Tax		$228,367
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #2 A & G Expense		$425,334
Total Fixed Cost		$\boxed{\$2,189,452}$

Hunter #3 Project Allocated Mining Expense

(Based on 1989 Actual Costs)

Initial Levelized Fixed Charge

Hunter #3 Project

Hunter #3 Mining Investment		$38,720,844
Adjusted Initial Levelized Annual Fixed Rate		6.75%
Initial Levelized Annual Fixed Charge		$2,614,044
Subsequent Investment		$0
Subsequent Levelized Annual Fixed Rate		0.00%
Subsequent Levelized Annual Fixed Charge		$0
Ad Valorem Tax		$388,714
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #3 A & G Expense		$723,972

Total Fixed Cost **$3,726,731**

Hunter #2 and #3 Mining Investment

Allocation Calculation

Gross Coal Plant $193,120,211

Power Plants Served By Mines:

	MW
Huntington #1	400
Huntington #2	415
Hunter #1 UPL	366
Hunter #1 Provo	24
Hunter #2 UPL	235
Hunter #2 DG&T	155
Hunter #3 UPL	400
Total	1,995

Hunter #2 Mining Investment = 235 ÷ 1995 x $193,120,211 = $22,748,496

Hunter #3 Mining Investment = 400 ÷ 1995 x $193,120,211 = $38,720,844

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 & #3 PROJECT

AUGUST 27, 1990

50%	DEBT FINANCING @ 8.47%	$9789	LEVELIZED DEFERRED TAXES	7	YEAR TAX LIFE – MODIFIED ACRS
10%	PREFERRED EQUITY @ 8.24%	$2,138	LEVELIZED INTEREST EXPENSE	N/A	TAX RATE PRIOR TO 1987
40%	COMMON EQUITY @ 12.36%	$416	LEVELIZED PREFERRED RETURN	N/A	TAX RATE IN 1987
10.00%	WEIGHTED COST OF CAPITAL	$2,496	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.13577	CAPITAL RECOVERY FACTOR	0%	INVESTMENT TAX CREDIT (ITC)
$13,894	LEVELIZED ANNUAL COST	1989	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13,894	LEVELIZED FIXED CAPITAL COSTS	14	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$724	LEVELIZED INCOME TAXES	14	YEAR BOOK LIFE – STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RATE BASE
1989	0	0	0	7,143	4,028	784	4,702	2,636	570	19,862	18,056	14,290	95,111
1990	0	0	0	7,143	3,534	688	4,126	6,398	(3,585)	18,303	15,126	24,490	83,451
1991	0	0	0	7,143	3,015	587	3,520	3,816	(1,416)	16,665	12,519	17,490	71,201
1992	0	0	0	7,143	2,590	504	3,024	1,972	89	15,322	10,464	12,490	61,164
1993	0	0	0	7,143	2,232	434	2,606	659	1,117	14,191	8,810	8,930	52,706
1994	0	0	0	7,143	1,902	370	2,220	655	858	13,148	7,421	8,920	44,906
1995	0	0	0	7,143	1,571	306	1,835	659	591	12,105	6,211	8,930	37,106
1996	0	0	0	7,143	1,276	248	1,490	(989)	2,005	11,172	5,211	4,460	30,128
1997	0	0	0	7,143	1,050	204	1,226	(2,634)	3,470	10,459	4,435	0	24,797
1998	0	0	0	7,143	859	167	1,003	(2,634)	3,318	9,856	3,799	0	20,288
1999	0	0	0	7,143	668	130	780	(2,634)	3,166	9,253	3,242	0	15,780
2000	0	0	0	7,143	477	93	557	(2,634)	3,014	8,650	2,755	0	11,271
2001	0	0	0	7,143	286	56	334	(2,634)	2,862	8,047	2,330	0	6,763
2002	0	0	0	7,143	95	19	111	(2,634)	2,710	7,444	1,960	0	2,254
2003	0	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	100,000	23,586	4,589	27,534	0	18,769	174,479	102,338	100,000	
1983 NET PRESENT VALUE @ 10%	0	0	0	52,611	15,748	3,064	18,384	7,202	5,330	102,338	67,289	72,139	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 & #3 MINING INVESTMENT

AUGUST 27, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	INVESTMENT TAX CREDIT RESTORED	INVESTMENT TAX CREDIT RECAPTURE	DEFERRED TAXES CURRENT	DEFERRED TAXES RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1989	100,000	(7,143)	0	0	0	(2,636)	0	90,221	0	36.88%	14.290%	7.14%
1990	90,221	(7,143)	0	0	0	(6,398)	0	76,681	0	36.88%	24.490%	7.14%
1991	76,681	(7,143)	0	0	0	(3,816)	0	65,722	0	36.88%	17.490%	7.14%
1992	65,722	(7,143)	0	0	0	(1,972)	0	56,607	0	36.88%	12.490%	7.14%
1993	56,607	(7,143)	0	0	0	(659)	0	48,805	0	36.88%	8.930%	7.14%
1994	48,805	(7,143)	0	0	0	(655)	0	41,007	0	36.88%	8.920%	7.14%
1995	41,007	(7,143)	0	0	0	(659)	0	33,205	0	36.88%	8.930%	7.14%
1996	33,205	(7,143)	0	0	0	989	0	27,051	0	36.88%	4.460%	7.14%
1997	27,051	(7,143)	0	0	0	2,634	0	22,543	0	36.88%	0.000%	7.14%
1998	22,543	(7,143)	0	0	0	2,634	0	18,034	0	36.88%	0.000%	7.14%
1999	18,034	(7,143)	0	0	0	2,634	0	13,526	0	36.88%	0.000%	7.14%
2000	13,526	(7,143)	0	0	0	2,634	0	9,017	0	36.88%	0.000%	7.14%
2001	9,017	(7,143)	0	0	0	2,634	0	4,509	0	36.88%	0.000%	7.14%
2002	4,509	(7,143)	0	0	0	2,634	0	0	0	36.88%	0.000%	7.14%
2003	0	0	0	0	0	0	0	0	0	36.88%	0.000%	7.14%
2004	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2005	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2006	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2007	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2008	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2009	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2010	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2011	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2012	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2013	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2014	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2015	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2016	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2017	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2018	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2019	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2020	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2021	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2022	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2023	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
TOTAL		(100,000)	0	0	0	0	0		0		100.000%	100.00%

HUNTER #2 & #3 MINE INVESTMENT

FORMULAS FOR CALCULATING

INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i\,(1+i)^n / (1+i)^n - 1$
Where i = weighted cost of capital and n = ave.. life of plant.

CRF = $0.1000\ (1 + 0.1000)^{14} / ((1 + 0.1000)^{14} - 1)$ =
0.13575

(*2) BOOK DEPRECIATION = $100,000 / 14 Years = $7,143

(*3) TOTAL RETURN, (TR) = A x W_s
Where A = Average Net Investment; and
W_s = Weighted Cost of Preferred and Common Stock
Let A = Beginning Investment - (D+T) /2
Where Beginning Investment = Previous year's beginning investment - previous year's D and T.

D = Book Depreciation (*2)
T = Deferred Tax (*5)
Therefore, beginning investment = $100,000
A = $100,000 - (7,143 + 2636) /2 = $95,111
TR = $95,111 x (.10 x .0824 + .40 x .1236) = $5,486

(*4) INTEREST, (I) = A x W_d
Where W_d = Weighted Cost of Debt
Therefore, I = $95,111 x (.50 x .0847) = $4,028

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R$
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (36.88%)
Let T = (14,290 - 7,143) x .3688 = $2,636

HUNTER #2 AND #3 MINE INVESTMENT

FORMULAS FOR CALCULATING

INITIAL LEVELIZED FIXED CHARGE RATE

(Con't.)

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1-Tax rate)

INCOME TAX = ($5,486 + $7,143 + $2,636 - $14,290) x (.3688/(1-.3688 = $570

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax

ANNUAL COST = $7,143 + $5,486 + $4,028 + $2,636 + $570 = $19,862

(*8) TAX DEPRECIATION = (Modified ACRS) x Original Investment

TAX DEPRECIATION = 14.29% x 1.00 x $100,000 = $14,290

Adjusted for 1/2 year = $8,510/2 = $4,255

(*9) ITC = Not Applicable

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1+i)^n$

PRESENT WORTH ANNUAL COST = $19,862 x $1/(1 + .1000)^1$ = $18,056

where I = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost

INITIAL LEVELIZED FIXED CHARGE RATE = (0.13575 x $102,338)/$100,000 = 0.1389 = <u>13.89%</u>

HUNTER #2 AND #3 MINE INVESTMENT
CALCULATION OF ADJUSTED INITIAL
FIXED CHARGE RATE
(Based on $100,000 of Capital Expenditure)

CAPITAL STRUCTURE:

Component	Structure	Rate
Debt	50%	8.47%
Preferred	10%	8.24%
Common	40%	12.36%
Weighted Cost of capital		10.00%

INPUT DATA:

INVESTMENT TAX CREDIT	Not Applicable
SALVAGE VALUE	0
BOOK LIFE (Straight Line)	14 years
TAX LIFE (MACRS)	7 years
TAX RATE	36.88% (includes state Corp. tax)
TAX BASIS	100.00% of Book
PW RATE	10.00%

CALCULATED DATA:

CAPITAL RECOVERY FACTOR = 0.13575 (1*)

INITIAL LEVELIZED FIXED CHARGE RATE = 0.1394 = 13.94% (*11)

ADJUSTED INITIAL LEVELIZED FIXED CHARGE RATE* = 13.94% less book depreciation, where book depreciation = 1/14 years = 0.0714 = 7.14% = 13.89% = 6.75%

*Book depreciation is reflected in fuel cost.

Appendix C: "Resource Pool"

This Appendix sets forth the amount of capacity (MW) and the combination of resources which may be included in the Resource Pool which shall be the basis for determining the prices for Firm Capacity and associated Firm Energy under Section 5 of this Agreement commencing with calendar year 1996.

The Resource Pool shall contain 1000 megawatts of capacity, which, until October 31, 2010, shall always contain an amount of capacity equal to the current rated capacity of Cholla Unit 4 and PacifiCorp's associated Cholla Unit 4 capital costs as derived pursuant to Appendix A. On May 1, 1996, the Resource Pool shall contain 650 megawatts of the following
other resources:

Resource		Capacity (MW)
Colstrip Project		70
Hunter No. 2 Project		180
Hunter No. 3 Project		400
	Total	650 MW

Provided, that commencing May 1, 1997 and on each May 1 there-after through the term of this Agreement, PacifiCorp may replace up to a maximum of 200 megawatts of such other resources with other cost resources it owns or may acquire, including, but not limited to, thermal generation it owns or leases and firm power purchases under contracts with a term of three years or more. Subsequent to October 31', 2010, through the term of this Agreement, PacifiCorp may replace both the other resources and Cholla Unit 4 with other cost resources. Such other cost resources contained in the Resource Pool shall only be resources (1) that PacifiCorp acquires through prudent utility management practices, (2) that are being used to provide utility service to PacifiCorp's customers, and (3) that have been declared to be in commercial operation prior to May 1 of the calendar year in which such resources are included in the Resource Pool.

APPENDIX D: EXAMPLE CALCULATION
ESTABLISHING ADJUSTMENTS FOR INTEREST

Simple interest "Midyear Convention" shall be utilized in calculating the amount of the adjustments for interest.

Assumptions for Example Calculations:

(1) Total Annual Payment Difference for calendar year 1995 $12,000

(2) Prime Rate 9%

(3) Time of Adjustment June 1, 1996

Adjustments for Interest

Year	Prime Rate[1]	Factor[2]		Interest Rate
1995	9.0% multiplied by	1/2	=	4.50%
1996	9.0% multiplied by	5/12	=	3.75%
				8.25%

8.25% x $12,000 = $990 Adjustment For Interest

[1] The prime rate shall be the time weighted average prime rate for the period. For the example above it would be for the period January 1995 through May 1996. The prime rate shall be as established by Morgan Guaranty Trust Company of New York.

[2] 1995 mid-year convention 1/2 year
1996 5 months (January through May)

APPENDIX E: INCREMENTAL COST OF SUPPLEMENTAL ENERGY AND UNUSED CHOLLA CAPABILITY

This Appendix sets forth the method for establishing Incremental Cost ($/MWh) of Supplemental Energy to be made available by APS pursuant to Subsections 6.7 and 6.8 of this Agreement and the Incremental Cost ($/MWh) of energy associated with either Party's use of the other Party's unused generating capability at the Cholla Generating Station ("Unused Cholla Capability") pursuant to Subsection 13.06 of the Asset Agreement.

The Incremental Cost for each megawatt-hour of each transaction shall equal the sum of (1) the deemed incremental operating and maintenance expense ($/MWh) as determined in Section 1.0 below, and (2) the Incremental Fuel Cost ($/MWh) as determined in Section 2.0 below.

1.0 Incremental Operating and Maintenance Expense. The incremental operating and maintenance expense associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows: .

1.1 Supplemental Coal Energy. For all Supplemental Coal Energy, the incremental operating and maintenance expense shall be deemed to be $4.68 per megawatt-hour. Any revision to the deemed $4.68 per megawatt hour incremental operating and maintenance expense for Supplemental Coal Energy shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates that the proposed revisions are reasonable given APS' costs.

1.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental operating and maintenance expense shall be deemed to be $21.94 per megawatt-hour for gas and oil fired steam units, $11.99 for all single cycle combustion turbines and $4.36 for all combined cycle units. Any revision to the deemed incremental operating and maintenance expense for gas and oil fired steam units, for combustion turbines, and for combined cycle units shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates that the proposed revisions are reasonable given APS' costs. Within three years of the Effective Date of this Agreement, the parties shall review the appropriateness of the foregoing deemed values and make adjustments that are equitable.

1.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental operating and maintenance expense shall be deemed to be \$3.56 per megawatt-hour. Any revision to the deemed incremental operating and maintenance expense shall require a timely filing under Part 35 of the Code of Federal Regulations, together with cost support which demonstrates the proposed revisions are reasonable.

2.0 Incremental Fuel Cost. The incremental fuel cost associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows:

2.1 Supplemental Coal Energy. For all Supplemental Coal Energy the incremental fuel cost (\$/MWh) shall be determined by the APS dispatcher or scheduler based on his best-efforts forecast of the incremental coal cost and the incremental heat rate associated with the lowest cost generating unit(s) expected to be producing such energy.

2.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental fuel cost (\$/MWh) shall be determined by the APS dispatcher or scheduler based upon his best-efforts forecast of the incremental fuel cost, either Natural Gas, Oil or Coal, utilizing the incremental heat rate associated with the lowest cost generating unit(s) that is expected to be producing such energy.

2.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental fuel cost (\$/MWh) shall be determined by the Party's dispatcher or scheduler having such Unused Cholla Capability based on his best-efforts forecast of the incremental coal cost utilizing the incremental heat rate of the generating unit(s) that would produce such energy.