9.2 Description of Ratemaking Tables

Description of Ratemaking Tables

Sales_01 Forecast of Priority Firm Power (PF) Preference Gigawatthour (GWh) energy sales and peak kilowatt (kW)/mo. demand amounts for each month of the Rate Test Period FY 2007-09

Sales_02 Forecast of PF Exchange GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2007-09.

Sales_03 Forecast of IP (industrial rate) GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2007-09. (Note: No direct sale to the Direct Service Industry customers is forecast for this test period. In order to calculate a rate in the case where there is no actual load, the token load of 0.001 aMW was used.)

Sales_04 Forecast of NR (industrial rate) GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2007-09. (Note: No sale under the NR rate schedule is forecast for this test period. In order to calculate a rate in the case where there is no actual load, the token load of 0.001 aMW was used.)

COSA_06 Itemized Revenue Requirements. Power Business Line (PBL) revenue requirements for each FY during the rate test period

COSA_07 Functionalization of Residential Exchange Costs. REP costs are functionalized to generation to comport with other functionalized moving through COSA into the Rate Design Step of the RAM.

COSA_08 Classified Revenue Requirement. Generation costs are classified between energy, demand, and load variance. All costs move through COSA into the Rate Design Step of the RAM. Demand charge and load variance charge revenues are applied to the generation revenue requirement during the calculation of energy charges.

COSA_09 Functionalized Revenue Credits. Revenue credits are anticipated revenues during the rate test period. In tables that follow, these revenue credits are directly assigned to Federal Base System (FBS) power and have the effect of reducing the cost of FBS resources in the ratemaking process.

ALLOCATE 01 Energy Allocation Factors (EAF). Values are derived from the rate case load/resource balance and are average megawatt (aMW) at generation level (sales plus transmission losses). These EAFs are used in the resource pool to rate pool allocation determination.

Description of Ratemaking Tables

ALLOCATE 02 Initial Rate Pool Cost Allocation. Table shows the initial allocation of the revenue requirement costs from the COSA to rate pools using the EAFs from table ALLOCATE 01.

RDS_05 Calculates BPA's Average Cost of Nonfirm Energy.

RDS_06 Calculates BPA's Average System Cost (BASC).

RDS_11 Allocation of Secondary Revenues and Other Revenue Credits. Tables summarize revenue from secondary power sales and revenues from Other Revenue Credits from Table COSA 09. These revenues are then allocated to rate pools using the EAFs from table ALLOCATE 01. The allocation is based on the service provided by the FBS and NR resources to these rate pools.

RDS_17 Surplus Firm Power Revenues Surplus/(Deficiency). Table calculates the firm surplus sale revenue surplus/deficiency. Generation revenue requirement costs allocated to FPS sales in table ALLOCATE 02 are reduced by the excess revenue credit allocated to FPS sales in table RDS_11. The resulting costs are compared with the revenues recovered from FPS sales, resulting in a revenue deficit. This revenue deficit is allocated based on the service provided by the FBS and NR resources to these rate pools.

RDS_19 Summary of Initial Allocations. Table summarizes the allocations from Tables ALLOCATE 02, RDS 11, and RDS 17, as well as allocates Low Density Discount and Irrigation Rate Mitigation costs to the PF Preference rate pool.

RDS_21 7(C)(2) Delta Calculation and Allocation of 7(C)(2) Delta. Table solves a formula for calculating the 7(c)(2) delta appropriate for this point in the model. Table allocates the 7(c)(2) delta to PF and NR rate classes based on allocation factors developed in ALLOCATE 01.

RDS_23 IP Floor Rate Calculation. The IP-83 rates are applied to the current DSI test period billing determinants to determine an average rate. Adjustments are made for Transmission, Exchange Cost, and Deferral to yield the DSI floor rate.

RDS_24 IP Floor Rate Test. Table performs the DSI floor rate test and calculates the DSI floor rate adjustment if applicable. IP revenue under proposed rates is compared with revenue under the DSI floor rate. If DSI floor rate revenues are greater, a DSI floor rate adjustment is required. The amount of the DSI floor rate adjustment is then added to the IP allocated costs and subtracted from the other firm power rate pools allocated costs.

Description of Ratemaking Tables

RDS_30 Calculation of 7(b)(2) Protection Amount. Table calculates the 7(b)(2) PF preference protection amount, based on the "7(b)(2) trigger" calculated in the 7(b)(2) rate test. The protection amount is the 7(b)(2) trigger in mills/kWh times the PF preference billing determinants.

RDS_31 Allocation of 7(b)(2) Protection Amount. Table allocates the 7(b)(2) protection amount from RDS_30 to PF Exchange, IP and NR rate pools. Allocation is based on allocation factors developed in **ALLOCATE 01**.

RDS_33 7(b)(2) Industrial Adjustment_7(c)(2) Delta Calculation. Table calculates the 7(b)(2) Industrial Adjustment_7(c)(2) Delta. The 7(b)(2) Industrial Adjustment_7(c)(2) Delta is the difference between the DSI allocated revenue requirement at this point in the modeling and the expected DSI revenues. Expected DSI revenues are; IP revenues at the PF preference rate; plus revenues at the DSI net margin; plus 7(b)(2) protection amount allocated to the IP class.

SLICESEP_01 Slice PF Product Separation. The previous rate design steps have been accomplished using the total firm PF Preference load in the PF Preference load pool. This table recognizes the PF Slice product by removing the firm loads, allocated costs, and secondary revenue credit associated with the PF Slice product from the PF Preference load pool. Here after, the PF Preference rate will be for the non-Slice portion of the PF firm loads.

PF 2007-09 PF Rate Schedule Charge Calculation. Table calculates PF Preference rates. Marginal cost rates are scaled down to produce rates that recover costs allocated to PF energy.

PFx 2007-09 PF Rate Schedule Charge Calculation. Table calculates the PF Exchange rates.

REP_1 Calculation of Look Back Net REP Benefits. The utilities' ASCs and the PF Exchange rate are used to determine their REP benefits.

IP 2007-09 IP Rate Schedule Charge Calculation. Table calculates IP rates. Marginal cost rates are scaled down to produce rates that recover costs allocated to PF energy.

NR 2007-09 NR Rate Schedule Charge Calculation. Table calculates NR rates. Marginal cost rates are scaled down to produce rates that recover costs allocated to PF energy.

PF 2009 Flat Flat PF Rate Calculation. Table calculates the average annual flat PF Preference rate. The PF Preference energy and demand rates are applied to a flat load to determine an average annual flat PF Preference rate. Example shown is for FY 2009

Description of Ratemaking Tables

Slice Costing Table Slice Product Pricing. Table shows the costs and revenue credits associated with the PF Slice Product and calculates a cost per month per Slice Product percent.

RDS_60A Allocated Costs and Unit Costs, Priority Firm Power. Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Power. A percent contribution to the final Priority Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

RDS_60B Allocated Costs and Unit Costs, Priority Firm Preference Power and Priority Firm Exchange Power. Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Preference Power and Priority Firm Exchange Power. A percent contribution to the final Priority Firm Preference Power rate and Priority Firm Exchange Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

RDS_61 Allocated Costs and Unit Costs, Industrial Firm Power. Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Industrial Firm Power. A percent contribution to the final Industrial Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

RDS_62 Allocated Costs and Unit Costs, New Resource Firm Power. Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with New Resource Firm Power. A percent contribution to the final New Resource Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

RDS_63 Resource Cost Contribution. Table provides a summary of the percentages of each resource pool, FBS, Residential Exchange, and New Resources, used in ratemaking to serve each of the rate pools, FP, IP, NR, FPS.

Table 9.2.1

Sales 01

Total PF Load Forecast FY2007-09

GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	2,890	3,211	3,537	3,458	3,041	3,190	2,809	2,814	2,883	2,970	3,013	2,730	60,840	6,945
	LLH	1,925	2,141	2,408	2,281	2,069	2,117	1,892	1,872	1,878	1,974	1,919	1,818		
	Demand	8,167	8,932	9,322	9,285	9,159	8,507	7,655	6,959	7,262	7,540	7,361	7,083		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2008	HLH	2,998	3,289	3,633	3,540	3,159	3,222	2,896	2,870	2,985	3,067	3,045	2,816	61,330	6,982
	LLH	1,855	2,070	2,294	2,179	2,039	2,084	1,821	1,827	1,942	1,957	1,963	1,781		
	Demand	8,647	9,424	9,807	9,799	9,737	8,972	7,999	7,332	7,723	7,742	7,582	7,241		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	3,042	3,277	3,715	3,569	3,125	3,254	2,928	2,807	2,984	3,112	3,072	2,829	61,568	7,028
	LLH	1,850	2,124	2,260	2,199	2,022	2,099	1,839	1,833	1,875	1,990	1,977	1,786		
	Demand	8,757	9,567	9,905	9,932	9,835	9,087	8,120	7,298	7,629	7,898	7,678	7,302		

Non-Slice PF Load Forecast FY2007-09

GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	2,195	2,445	2,772	2,849	2,475	2,521	2,225	2,197	2,082	2,171	2,236	2,091	47,050	5,371
	LLH	1,462	1,631	1,887	1,879	1,684	1,673	1,498	1,462	1,356	1,443	1,425	1,392		
	Demand	6,203	6,802	7,307	7,650	7,452	6,723	6,062	5,434	5,244	5,512	5,463	5,423		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2008	HLH	2,281	2,504	2,843	2,913	2,558	2,544	2,293	2,176	2,101	2,245	2,262	2,161	47,206	5,374
	LLH	1,411	1,576	1,796	1,793	1,651	1,645	1,442	1,385	1,367	1,433	1,458	1,367		
	Demand	6,579	7,176	7,675	8,063	7,885	7,085	6,334	5,560	5,436	5,668	5,632	5,558		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	2,318	2,499	2,912	2,940	2,544	2,573	2,316	2,174	2,150	2,265	2,285	2,183	47,600	5,434
	LLH	1,410	1,620	1,771	1,811	1,646	1,660	1,454	1,420	1,351	1,449	1,470	1,378		
	Demand	6,673	7,297	7,763	8,182	8,006	7,186	6,423	5,653	5,497	5,749	5,710	5,633		

Table 9.2.2

Sales 02

Total PF Exchange Load Forecast FY2007-09
GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	1,469	1,671	2,152	2,377	2,230	2,084	1,882	1,248	1,038	1,009	1,344	1,651	32,027	3,656
	LLH	888	961	1,210	1,560	1,415	1,259	1,076	782	565	569	672	917		
	Demand	4,882	5,167	6,554	7,434	7,182	5,241	5,097	3,496	2,950	3,365	3,976	4,864		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2008	HLH	1,482	1,683	2,165	2,384	2,238	2,093	1,919	1,282	1,079	1,052	1,386	1,688	32,511	3,711
	LLH	898	969	1,218	1,566	1,421	1,265	1,098	805	589	596	696	939		
	Demand	4,922	5,204	6,592	7,456	7,208	5,263	5,194	3,588	3,062	3,498	4,097	4,970		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2009	HLH	1,513	1,714	2,194	2,425	2,235	2,142	1,995	1,261	1,100	1,076	1,404	1,701	33,018	3,769
	LLH	918	988	1,236	1,594	1,419	1,296	1,145	792	602	611	707	949		
	Demand	5,015	5,293	6,682	7,579	6,928	5,388	5,399	3,531	3,119	3,567	4,147	5,008		

Sales 03

Total IP Load Forecast FY2007-09
GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2008	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2009	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		

Sales 04

Total NR Load Forecast FY2007-09
GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2008	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2009	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		

Table 9.2.3.1

COSA 06 - FY2007

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2007

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	4,955,805	136,816	60,793	370,385	567,994
4. BPA FISH & WILDLIFE PROGRAM	140,228	3,871	1,720	171,903	177,494
5. TROJAN				14,005	14,005
6. WNP #1				148,141	148,141
7. WNP #2				459,359	459,359
8. WNP #3				151,724	151,724
9. SYSTEM AUGMENTATION				169,090	169,090
10. BALANCING POWER PURCHASES				54,017	54,017
11. TOTAL FEDERAL BASE SYSTEM	5,096,033	140,687	62,513	1,538,624	1,741,824
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,089	14,089
15. OTHER NEW RESOURCES PURCHASES				46,764	46,764
16. TOTAL NEW RESOURCES				60,853	60,853
17. RESIDENTIAL EXCHANGE				1,456,235	1,456,235
18. CONSERVATION		21,184	9,413	151,430	182,027
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	43,785	1,209	537	182,192	183,938
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	43,785	1,209	537	182,192	183,938
23. TOTAL GENERATION COSTS	5,139,818	163,080	72,463	3,389,333	3,624,876
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				124,614	124,614
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,300	1,300
27. GENERAL TRANSFER AGREEMENTS				47,000	47,000
28. TOTAL TRANSMISSION COSTS				172,914	172,914
29. TOTAL PBL REVENUE REQUIREMENT		163,080	72,463	3,562,247	3,797,790
30. BPA TRANSMISSION REVENUE REQUIREMENT (Net of Line 25)		171,925	0	357,323	529,248

Table 9.2.3.2

COSA 06 - FY2008

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2008

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	4,971,786	145,229	31,126	380,709	557,064
4. BPA FISH & WILDLIFE PROGRAM	156,170	4,562	978	173,574	179,114
5. TROJAN				12,588	12,588
6. WNP #1				166,116	166,116
7. WNP #2				406,544	406,544
8. WNP #3				160,092	160,092
9. SYSTEM AUGMENTATION				118,024	118,024
10. BALANCING POWER PURCHASES				64,693	64,693
11. TOTAL FEDERAL BASE SYSTEM	5,127,956	149,791	32,104	1,482,340	1,664,235
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,078	14,078
15. OTHER NEW RESOURCES PURCHASES				53,147	53,147
16. TOTAL NEW RESOURCES				67,225	67,225
17. RESIDENTIAL EXCHANGE				1,530,359	1,530,359
18. CONSERVATION		22,354	4,791	154,173	181,318
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	35,876	1,048	224	184,374	185,647
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	35,876	1,048	224	184,374	185,647
23. TOTAL GENERATION COSTS	5,163,832	173,193	37,119	3,418,472	3,628,784
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				126,877	126,877
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,300	1,300
27. GENERAL TRANSFER AGREEMENTS				47,000	47,000
28. TOTAL TRANSMISSION COSTS				175,177	175,177
29. TOTAL PBL REVENUE REQUIREMENT		173,193	37,119	3,593,649	3,803,961
30. BPA TRANSMISSION REVENUE REQUIREMENT (Net of Line 25)		171,925	0	355,060	526,985

Table 9.2.3.3

COSA 06 - FY2009

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2009

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,028,112	153,037	38,543	391,777	583,357
4. BPA FISH & WILDLIFE PROGRAM	170,827	5,199	1,309	174,856	181,364
5. TROJAN				3,100	3,100
6. WNP #1				163,482	163,482
7. WNP #2				461,669	461,669
8. WNP #3				153,030	153,030
9. SYSTEM AUGMENTATION				169,926	169,926
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,198,939	158,236	39,852	1,579,409	1,777,497
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,089	14,089
15. OTHER NEW RESOURCES PURCHASES				60,110	60,110
16. TOTAL NEW RESOURCES				74,199	74,199
17. RESIDENTIAL EXCHANGE				1,585,821	1,585,821
18. CONSERVATION		23,893	6,018	157,908	187,819
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	26,604	811	204	194,603	195,618
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	26,604	811	204	194,603	195,618
23. TOTAL GENERATION COSTS	5,225,543	182,940	46,074	3,591,940	3,820,953
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				131,515	131,515
26. 3RD PARTY TRANS/ANCILLARY SERVICES				3,000	3,000
27. GENERAL TRANSFER AGREEMENTS				48,000	48,000
28. TOTAL TRANSMISSION COSTS				182,515	182,515
29. TOTAL PBL REVENUE REQUIREMENT		182,940	46,074	3,774,455	4,003,468
30. BPA TRANSMISSION REVENUE REQUIREMENT (Net of Line 25)		171,925	0	350,422	522,347

Table 9.2.3.4

COSA 07

Functionalization of Residential Exchange Costs:

	($ Thousands)
Gross Residential Exchange Cost	$ 4,572,415
Residential Exchange Transmission	$ 380,469
Functionalized Residential Exchange Costs	$ 4,191,946

Table 2.3.5

COSA 08

COST OF SERVICE ANALYSIS
Classified Revenue Requirement
Test Period October 2006 - September 2009

($ 000)

	Total Revenue Requirement	Energy Percent	Energy Total	Demand Percent	Demand Total	Load Variance Percent	Load Variance Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 1,708,414	93.15%	$ 1,591,454	5.91%	$ 100,896	0.94%	$ 16,065
4. BPA FISH & WILDLIFE PROGRAM	$ 537,972	94.09%	$ 506,200	5.91%	$ 31,772		
5. TROJAN	$ 29,693	94.09%	$ 27,939	5.91%	$ 1,754		
6. WNP #1	$ 477,739	94.09%	$ 449,525	5.91%	$ 28,214		
7. WNP #2	$ 1,327,572	93.15%	$ 1,236,684	5.91%	$ 78,404	0.94%	$ 12,484
8. WNP #3	$ 464,846	94.09%	$ 437,393	5.91%	$ 27,453		
9. SYSTEM AUGMENTATION	$ 457,040	93.15%	$ 425,750	5.91%	$ 26,992	0.94%	$ 4,298
10. BALANCING POWER PURCHASES	$ 180,279	93.15%	$ 167,937	5.91%	$ 10,647	0.94%	$ 1,695
11. TOTAL FEDERAL BASE SYSTEM	$ 5,183,555		$ 4,842,882		$ 306,131		$ 34,542
12. NEW RESOURCES							
13. IDAHO FALLS	$ -				$ -		$ -
14. COWLITZ FALLS	$ 42,256	93.15%	$ 39,363	5.91%	$ 2,496	0.94%	$ 397
15. OTHER NEW RESOURCES PURCHASES	$ 160,021	93.15%	$ 149,066	5.91%	$ 9,451	0.94%	$ 1,505
16. TOTAL NEW RESOURCES	$ 202,277		$ 188,429		$ 11,946		$ 1,902
17. RESIDENTIAL EXCHANGE	$ 4,191,946	100.00%	$ 4,191,946				
18. CONSERVATION	$ 551,163	94.09%	$ 518,612	5.91%	$ 32,551		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 565,203	93.15%	$ 526,508	5.91%	$ 33,380	0.94%	$ 5,315
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	$ 565,203		$ 526,508		$ 33,380		$ 5,315
23. TOTAL GENERATION COSTS	$ 10,694,145		$ 10,268,378		$ 384,008		$ 41,759
24. TRANSMISSION COSTS:							
25. TBL TRANSMISSION/ANCILLARY SERV	383,006	100.00%	$ 383,006				
26. 3RD PARTY TRANS/ANCILLARY SERVI	5,600	100.00%	$ 5,600				
27. GENERAL TRANSFER AGREEMENTS	142,000	100.00%	$ 142,000				
28. TOTAL TRANSMISSION COSTS	530,606		530,606				
29. TOTAL PBL REVENUE REQUIREMENT	$ 11,224,751		$ 10,798,984		$ 425,767		

Table 9.2.3.6

COSA 09

COST OF SERVICE ANALYSIS
Revenue Credits
Test Period October 2006 - September 2009

	FY 2007	FY 2008	FY 2009	Total
	($ 000)			
Colville Credit	$ 4,600	$ 4,600	$ 4,600	$ 13,800
'4(h)(10)(c)	$ 84,707	$ 84,927	$ 84,676	$ 254,310
Ancillary and Reserve Service Revs.	$ 73,131	$ 61,970	$ 62,715	$ 197,817
Energy Efficiency & Misc. Revenues	$ 16,305	$ 16,328	$ 16,353	$ 48,986
Reserve Product Revenue	$ 3,000	$ 3,300	$ 3,630	$ 9,930
Downstream Benefits & Storage	$ 8,921	$ 8,921	$ 8,921	$ 26,763
Green Tags	$ 1,079	$ 1,082	$ 1,082	$ 3,243
Aluminum Hedging	$ 875	$ -	$ -	$ 875
Totals	$ 192,618	$ 181,129	$ 181,977	$ 555,724

Table 9.2.4.1

ALLOCATE 01

Energy Allocation Factors with Residential Exchange Included
Average Megawatts

	2007	2008	2009	Totals
Federal Base System				
Total Usage				
Priority Firm..............................	10,900	10,984	11,102	32,987
Industrial Firm...........................	0	0	0	0
New Resource Firm...................	0	0	0	0
Surplus Firm Other....................	1,367	1,358	1,329	4,055
Total...	12,268	12,343	12,431	37,041
Federal Base System	0	0	0	0
Priority Firm..............................	8,518	8,550	8,566	25,634
Industrial Firm...........................	0	0	0	0
New Resource Firm...................	0	0	0	0
Surplus Firm Other....................	0	0	0	0
Total...	8,518	8,550	8,566	25,634
Residential Exchange	0	0	0	0
Priority Firm..............................	2,382	2,435	2,536	7,353
Industrial Firm...........................	0	0	0	0
New Resource Firm...................	0	0	0	0
Surplus Firm Other....................	1,377	1,371	1,339	4,087
Total...	3,759	3,806	3,875	11,440
New Resource	0	0	0	0
Priority Firm..............................	0	0	0	0
Industrial Firm...........................	0	0	0	0
New Resource Firm...................	0	0	0	0
Surplus Firm Other....................	0	0	0	0
Total...	0	0	0	0
Conservation	0	0	0	0
Priority Firm..............................	10,900	10,984	11,102	32,987
Industrial Firm...........................	0	0	0	0
New Resource Firm...................	0	0	0	0
Surplus Firm Other....................	1,367	1,358	1,329	4,055
Total...	12,268	12,343	12,431	37,041

Table 9.2.4.2

ALLOCATE 02

Initial Rate Pool Cost Allocations

($ 000)

	FY 2007	FY 2008	FY 2009	Totals
CLASSES OF SERVICE:				
Priority Firm - Preference				
FBS	$ 1,741,824	$ 1,664,235	$ 1,777,497	$ 5,183,555
NR	$ -	$ -	$ -	$ -
Exchange	$ 843,546.1	$ 898,034.2	$ 953,563.7	$ 2,695,144.0
conservation	$ 161,736	$ 161,366	$ 167,740	$ 490,842
BPA programs	$ 317,074	$ 321,119	$ 337,708	$ 975,902
Total	$ 3,064,180	$ 3,044,754	$ 3,236,509	$ 9,345,443
Industrial Firm Power				
FBS	$ -	$ -	$ -	$ -
NR	$ 0.0	$ 0.1	$ 0.1	$ 0.2
Exchange	$ 0.4	$ 0.4	$ 0.4	$ 1.1
conservation	$ 0.0	$ 0.0	$ 0.0	$ 0.0
BPA programs	$ 0.0	$ 0.0	$ 0.0	$ 0.1
Total	$ 0.5	$ 0.5	$ 0.5	$ 1.4
New Resources Firm				
FBS	$ -	$ -	$ -	$ 0.2
NR	$ 0.0	$ 0.1	$ 0.1	$ 1.1
Exchange	$ 0.4	$ 0.4	$ 0.4	$ 0.0
conservation	$ 0.0	$ 0.0	$ 0.0	$ 0.1
BPA programs	$ 0.0	$ 0.0	$ 0.0	$ 1.4
Total	$ 0.5	$ 0.5	$ 0.5	$ 1.4
Surplus Firm Power				
FBS	$ -	$ -	$ -	$ -
NR	$ 60,853	$ 67,225	$ 74,199	$ 202,277
Exchange	$ 487,784	$ 505,530	$ 503,485	$ 1,496,800
conservation	$ 20,290	$ 19,952	$ 20,079	$ 60,321
BPA programs	$ 39,778	$ 39,705	$ 40,424	$ 119,907
Total	$ 608,706	$ 632,412	$ 638,187	$ 1,879,305
			Grand Total	**$ 11,224,751**

Table 9.2.5.1

RDS 05

RATE DESIGN STUDY
Average Cost of Nonfirm Energy
Test Period October 2006 - September 2009

Generation Costs:		**($ 000)**
Federal Base System	$	5,183,555
New Resources	$	202,277
Exchange	$	4,572,415
Conservation and ESB	$	551,163
BPA Programs	$	565,203
Total Generation Costs	$	11,074,613
Transmission Costs For Firm Power	$	1,244,646
Transmission Costs For Nonfirm Pwr	$	383,006
Total Costs	$	12,702,265
Firm Power Sales:		**(GWh)**
Priority Firm		281,294
Industrial Power/Variable Industrial		0
New Resources		0
Other Obligations		29,247
FPS Pre-Sub., Slice Block, Rate Mitigation Contract Sales		5,297
Total Firm		315,838
Projected Trading Flr Sales		58,658
Total Sales		374,495
Average Cost of Nonfirm (mills/kwh)		33.92

Table 9.2.5.2

RDS 06

RATE DESIGN STUDY
Bonneville Average System Cost (BASC)
Test Period October 2006 - September 2009

Revenue Requirement:		**($ Thousands)**
Cost of Service Analysis	$	13,183,799
Applicable Revenue Credits	$	(357,907)
Total	$	12,825,893
Sales:		**(GWh)**
Firm Power		315,838
Nonfirm Energy		58,658
Total		374,495
Bonneville Average System Cost (mills/kwh):		34.25

Table 9.2.5.3

RDS 11

Rate Design Study
Allocation of Secondary and other Revenues
Test Period October 2006 - September 2009

($ 000)

	FY 2007	FY 2008	FY 2009	Totals
Forecast of Secondary Revenues	**$ 600,634**	**$ 582,252**	**$ 566,351**	**$ 1,749,236**
Additional Secondary Revenues	$ -	$ -	$ -	$ -
Total Gross Secondary Revenues	**$ 600,634**	**$ 582,252**	**$ 566,351**	**$ 1,749,236**

Allocation of Secondary Revenues Credit				
Priority Firm	$ (600,634)	$ (582,252)	$ (566,351)	$ (1,749,236)
Industrial Firm	$ -	$ -	$ -	$ -
New Resource Firm	$ -	$ -	$ -	$ -
Surplus Firm Other	$ -	$ -	$ -	$ -
Total	**$ (600,634)**	**$ (582,252)**	**$ (566,351)**	**$ (1,749,236)**

	FY 2007	FY 2008	FY 2009	Totals
Total Other Revenue Credits	**$ 192,618**	**$ 181,129**	**$ 181,977**	**$ 555,724**

Allocation of Other Revenue Credits				
Priority Firm	$ (192,618)	$ (181,129)	$ (181,977)	$ (555,724)
Industrial Firm	$ -	$ -	$ -	$ -
New Resource Firm	$ -	$ -	$ -	$ -
Surplus Firm Other	$ -	$ -	$ -	$ -
Total	**$ (192,618)**	**$ (181,129)**	**$ (181,977)**	**$ (555,724)**

Table 9.2.5.4

RDS 17

Rate Design Study
Calculation of FPS (Surplus)/Shortfall
Test Period October 2006 - September 2009

($ 000)

FPS (Surplus)/Shortfall	**FY 2007**	**FY 2008**	**FY 2009**	**Totals**
Costs allocated to FPS contract sales	$ 608,706	$ 632,412	$ 638,187	$ 1,879,305
Expected Revenue from FPS contract sales	$ (69,044)	$ (69,187)	$ (69,044)	$ (207,274)
FPS Pre-Sub Contract Revenue	$ (46,561)	$ (47,781)	$ (41,101)	$ (135,443)
(Surplus)/Shortfall	**$ 493,101**	**$ 515,444**	**$ 528,042**	**$ 1,536,587**
Secondary Revenues allocated to FPS	$ -	$ -	$ -	$ -
Revenue Credits allocated to FPS	$ -	$ -	$ -	$ -
FPS (Surplus)/Shortfall	**$ 493,101**	**$ 515,444**	**$ 528,042**	**$ 1,536,587**

Rate Design Study
Allocation of FPS (Surplus)/Shortfall
Test Period October 2006 - September 2009

($ 000)

Allocation of FPS (Surplus)/Shortfall	**FY 2007**	**FY 2008**	**FY 2009**	**Totals**
Priority Firm...	$ 493,101	$ 515,444	$ 528,042	$ 1,536,587
Industrial Firm...	$ -	$ -	$ -	$ -
New Resource Firm...	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ (493,101)	$ (515,444)	$ (528,042)	$ (1,536,587)
Total..	**$ -**	**$ -**	**$ -**	$ -

Table 9.2.5.5

RDS 19

Rate Design Study
Summary of Initial Allocations
Test Period October 2006 - September 2009

($ 000)

	FY 2007	FY 2008	FY 2009	Totals
Allocation of Revenue Requirement				
Priority Firm..	$ 3,064,180	$ 3,044,754	$ 3,236,509	$ 9,345,443
Industrial Firm...	$ 0.46	$ 0.48	$ 0.49	$ 1.43
New Resource Firm....................................	$ 0.46	$ 0.48	$ 0.49	$ 1.43
Surplus Firm Other......................................	$ 608,706	$ 632,412	$ 638,187	$ 1,879,305
Total..	$ 3,672,887	$ 3,677,167	$ 3,874,697	$ 11,224,751
Allocation of Secondary Revenues Credit				
Priority Firm..	$ (600,634)	$ (582,252)	$ (566,351)	$ (1,749,236)
Industrial Firm...	$ -	$ -	$ -	$ -
New Resource Firm....................................	$ -	$ -	$ -	$ -
Surplus Firm Other......................................	$ -	$ -	$ -	$ -
Total..	$ (600,634)	$ (582,252)	$ (566,351)	$ (1,749,236)
Allocation of other Revenues Credits				
Priority Firm..	$ (192,618)	$ (181,129)	$ (181,977)	$ (555,724)
Industrial Firm...	$ -	$ -	$ -	$ -
New Resource Firm....................................	$ -	$ -	$ -	$ -
Surplus Firm Other......................................	$ -	$ -	$ -	$ -
Total..	$ (192,618)	$ (181,129)	$ (181,977)	$ (555,724)
Allocation of FPS (Surplus)/Shortfall				
Priority Firm..	$ 493,101	$ 515,444	$ 528,042	$ 1,536,587
Industrial Firm...	$ -	$ -	$ -	$ -
New Resource Firm....................................	$ -	$ -	$ -	$ -
Surplus Firm Other......................................	$ (493,101)	$ (515,444)	$ (528,042)	$ (1,536,587)
Total..	$ -	$ -	$ -	$ -
Low Density Discount Expenses.......				
Priority Firm..	$ 22,289	$ 22,612	$ 22,853	$ 67,754
Irrigation Rate Mitigation...................				
Priority Firm..	$ 10,000	$ 10,000	$ 10,000	$ 30,000
Initial Allocation to Rate Pools...........				
Priority Firm..	$ 2,796,318	$ 2,829,429	$ 3,049,076	$ 8,674,823
Industrial Firm...	$ 0.46	$ 0.48	$ 0.49	$ 1.43
New Resource Firm....................................	$ 0.46	$ 0.48	$ 0.49	$ 1.43
Surplus Firm Other......................................	$ 115,604	$ 116,968	$ 110,145	$ 342,718
Total..	$ 2,911,924	$ 2,946,398	$ 3,159,222	$ 9,017,544

Table 9.2.5.6

RDS 21

Rate Design Study
7(c)(2) Delta Calculation
Test Period October 2006 - September 2009

	FY 2007	FY 2008	FY 2009	Totals
IP Allocated Costs	$ 0.5	$ 0.5	$ 0.5	$ 1.4
IP Revenues @ Net Margin	$ 0.0	$ 0.0	$ 0.0	$ 0.0
adjustment	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)
IP Marginal Cost Rate Revenues	$ 0.5	$ 0.5	$ 0.5	$ 1.4
PF Marginal Cost Rate Revenues	$ 5,058,680	$ 5,119,269	$ 5,162,924	$ 15,340,873
PF Allocated Energy Costs	$ 2,796,318	$ 2,829,429	$ 3,049,076	$ 8,674,823
Numerator: 1-2-3-((4/5)*6)	0.2	0.2	0.2	0.6
PF Allocation Factor for Delta	10,900	10,984	11,102	32,987
NR Allocation Factor for Delta	0.001	0.001	0.001	0.003
Total Allocation Factors for Delta	10,900	10,984	11,102	32,987
Denominator: 1.0 + ((9/11)*(4/5))	1.0000	1.0000	1.0000	1.0000
DELTA: (Numerator / Denominator)	**0.20**	**0.22**	**0.22**	**0.64**

Rate Design Study
7(c)(2) Delta allocation
Test Period October 2006 - September 2009

	FY 2007	FY 2008	FY 2009	Totals
IP-PF Linc Allocations:.......................				
Priority Firm..	$ 0.2	$ 0.2	$ 0.2	$ 0.6
Industrial Firm.......................................	$ (0.2)	$ (0.2)	$ (0.2)	$ (0.6)
New Resource Firm................................	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Surplus Firm Other.................................	$ -	$ -	$ -	$ -
Total..	$ 0.00	$ 0.00	$ (0.00)	$ 0.00

	FY 2007	FY 2008	FY 2009	Totals
Allocation to Rate Pools after Linc.....................................				
Priority Firm Preference..........................	$ 1,831,963	$ 1,849,172	$ 1,984,700	$ 5,665,835
Priority Firm Exchange...........................	$ 964,356	$ 980,257	$ 1,064,376	$ 3,008,989
Industrial Firm..	$ 0.3	$ 0.3	$ 0.3	$ 0.8
New Resource Firm................................	$ 0.5	$ 0.5	$ 0.5	$ 1.4
Surplus Firm Other.................................	$ 115,604	$ 116,968	$ 110,145	$ 342,718
Total..	$ 2,911,924	$ 2,946,398	$ 3,159,222	$ 9,017,544

Table 9.2.5.7

RDS 23

RATE DESIGN STUDY
Industrial Firm Power Floor Rate Calculation
Test Period October 2006 - September 2009
($ Thousands)

	A	B	C	D	E	F
	DEMAND		**ENERGY**		**Customer**	**Total/**
	Winter	**Summer**	**Winter**	**Summer**	**Charge**	**Average**
	(Dec-Apr)	(May-Nov)	(Sep-Mar)	(Apr-Aug)		
1 IP Billing Determinants[1]	0.015	0.021	0.015	0.011	0.036	0.026
2 IP-83 Rates	4.62	2.21	14.70	12.20	7.34	
3 Revenue	0.069	0.046	0.225	0.134	0.264	0.739
4 Exchange Adj Clause for OY 1985						
5 New ASC Effective Jul 1, 1984						
6 Actual Total Exchange Cost (AEC)	938,442					
7 Actual Exchange Revenue (AER)	772,029					
8 Forecasted Exchange Cost (FEC)	1,088,690					
9 Forecasted Exchange Revenue (FER)	809,201					
10 Total Under/Over-recovery (TAR)						
11 (TAR=(AEC-AER)-(FEC-FER))	(113,076)					
12 Exchange Cost Percentage for IP (ECP)	0.521					
13 Rebate or Surcharge for IP (CCEA=TAR*ECP)	(58,913)					
14 OY 1985 IP Billing Determinants[2]	24,368					
15 OY 1985 DSI Transmission Costs[3]	92,960					
16 Adjustment for Transmission Costs[4]	(3.81)					
17 Adjustment for the Exchange (mills/kWh)[5]	(2.42)					
18 Adjustment for the Deferral (mills/kWh)[6]	(0.90)					
19 IP-83 Average Rate (mills/kWh)[7]	28.10					
20 Floor Rate (mills/kWh)[8]	20.97					

Note 1 - Demand billing determinants are the test period DSI load expressed in noncoincidental demand MWs.
Note 2 - Billing determinants as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 82).
Note 3 - Transmission Costs as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 80).
Note 4 - Line 15 / Line 14
Note 5 - Rebate or Surcharge for IP divided by OY 1985 IP Billing Determinants
Note 6 - 1985 Final Rate Proposal (WP-85-FS-BPA-08A, p. 15).
Note 7 - Total Revenue Col F, divided by IP Billing Determinants, Col F
Note 8 - IP-83 Avg Rate adjusted for the effects of the Exchange and Deferral, Lines 16 + 17 + 18 + 19

Table 9.2.5.8

RDS 24

RATE DESIGN STUDY
Industrial Firm Power Floor Rate Test
Test Period October 2006 - September 2009
($ Thousands)

	A	B	C	D	E	F
	Unbundled Requirements Products	**Total Transmission**	**Total Generation Demand**	**Total Energy**	**TOTALS**	**Average Rate**
1 IP Billing Determinants				0.026		
2 Floor Rate (mills/kWh)				20.97		
3 Value of Reserves Credit (mills/kWh)						
4 Revenue at Floor Rate Less VOR Credit				0.552	0.552	20.97
5 IP Revenue Under Proposed Rates	0	0	0.058	0.816	0.874	33.23
6 Difference[1]					0	

Note 1 - Difference is Line 4 - Line 5. If difference is negative, Floor Rate does not trigger and difference is set to zero.

Table 9.2.5.9

RDS 30

Rate Design Study
Calculation of 7(b)(2) Protection Amount
Test Period October 2006 - September 2009

Section 7(b)(2) Rate Test Trigger 3.50

	FY 2007	FY 2008	FY 2009	Totals
Total PF Preference Load (GWH)	60840	61330	61568	183738
PF Preference Protection Amount	$ 212,940	$ 214,655	$ 215,487	$ 643,082

Rate Design Study
Calculation of 7(b)(3) Protection Amount Allocation
Test Period October 2006 - September 2009

	FY 2007	FY 2008	FY 2009	Totals
7b2 Protection Allocation..................................				
Priority Firm Preference.......................................	$ (212,940)	$ (214,655)	$ (215,487)	$ (643,082)
Priority Firm Exchange..	$ 212,940	$ 214,655	$ 215,487	$ 643,082
Industrial Firm...	$ 0	$ 0	$ 0	$ 0
New Resource Firm...	$ 0	$ 0	$ 0	$ 0
Surplus Firm Other..	$ -	$ -	$ -	$ -
Total..	$ (0)	$ 0	$ 0	$ 0

Allocation to Rate Pools after 7b2....................				
Priority Firm Preference.......................................	$ 1,619,022	$ 1,634,518	$ 1,769,213	$ 5,022,753
Priority Firm Exchange..	$ 1,177,296	$ 1,194,912	$ 1,279,863	$ 3,652,071
Industrial Firm...	$ 0.3	$ 0.3	$ 0.3	$ 1.0
New Resource Firm...	$ 0.5	$ 0.5	$ 0.6	$ 1.6
Surplus Firm Other..	$ 115,604	$ 116,968	$ 110,145	$ 342,718
Total..	$ 2,911,924	$ 2,946,398	$ 3,159,222	$ 9,017,544

Table 9.2.5.10

RDS 33

Rate Design Study
7(b)(2) industrial Adjustment 7(c)(2) Delta Calculation
Test Period October 2006 - September 2009

	FY 2007	FY 2008	FY 2009	Totals
IP Allocated Costs after 7c2 adjustment	$ 0.26	$ 0.26	$ 0.27	$ 0.79
IP share of 7b2 adjustment	$ 0.06	$ 0.06	$ 0.06	$ 0.17
Total IP revenue requirement	$ 0.32	$ 0.32	$ 0.33	$ 0.96
IP revenues at PF preference rate	$ 0.22	$ 0.22	$ 0.24	$ 0.69
IP Revenues @ Net Margin	$ 0.00	$ 0.00	$ 0.00	$ 0.01
IP share of 7b2 adjustment	$ 0.06	$ 0.06	$ 0.06	$ 0.17
Total IP revenue requirement	$ 0.29	$ 0.29	$ 0.30	$ 0.87
DELTA: (3 - 8)	$ 0.03	$ 0.03	$ 0.03	$ 0.09

	FY 2007	FY 2008	FY 2009	Totals
IP-PF Linc 2 Allocation..				
Priority Firm Preference...	$ -	$ -	$ -	$ -
Priority Firm Exchange..	$ -	$ -	$ -	$ -
Industrial Firm..	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.09)
New Resource Firm...	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -
Total..	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.09)
Allocation to Rate Pools after IP-PF Linc 2.......................				
Priority Firm Preference...	$ 1,619,022	$ 1,634,518	$ 1,769,213	$ 5,022,753
Priority Firm Exchange..	$ 1,177,296	$ 1,194,912	$ 1,279,863	$ 3,652,071
Industrial Firm..	$ 0.29	$ 0.29	$ 0.30	$ 0.87
New Resource Firm...	$ 0.52	$ 0.54	$ 0.55	$ 1.60
Surplus Firm Other..	$ 115,604	$ 116,968	$ 110,145	$ 342,718
Total..	$ 2,911,924	$ 2,946,398	$ 3,159,222	$ 9,017,544

Table 9.2.6

SLICESEP 01

Rate Design Study
Slice PF Product Separation
Test Period October 2006 - September 2009

	FY 2007	FY 2008	FY 2009	Totals
Slice Revenue requirement...	$ 514,919	$ 512,819	$ 546,405	$ 1,574,143
Slice Revenue Credits...	$ (42,464)	$ (39,994)	$ (40,111)	$ (122,569)
Net Slice PF Product Revenue Requirement	$ 472,455	$ 472,825	$ 506,294	$ 1,451,574
Slice Implementation Expenses	$ 2,400	$ 2,400	$ 2,400	$ 7,200
Amount to Allocate	$ 472,455	$ 472,825	$ 506,294	$ 1,451,574

	FY 2007	FY 2008	FY 2009	Totals
Allocation of Slice Revenues...				
Priority Firm Preference...	$ (472,455)	$ (472,825)	$ (506,294)	$ (1,451,574)
Priority Firm Exchange..	$ -	$ -	$ -	$ -
Industrial Firm...	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ -	$ -	$ -	$ -
Total...	$ (472,455)	$ (472,825)	$ (506,294)	$ (1,451,574)

	FY 2007	FY 2008	FY 2009	Totals
Allocation to Rate Pools after Slice Separation Step............................				
Priority Firm Preference...	$ 1,146,567	$ 1,161,693	$ 1,262,919	$ 3,571,179
Priority Firm Exchange..	$ 1,177,296	$ 1,194,912	$ 1,279,863	$ 3,652,071
Industrial Firm...	$ 0.3	$ 0.3	$ 0.3	$ 0.9
New Resource Firm..	$ 0.5	$ 0.5	$ 0.6	$ 1.6
Surplus Firm Other...	$ 115,604	$ 116,968	$ 110,145	$ 342,717.54
Total...	$ 2,439,469	$ 2,473,573	$ 2,652,928	$ 7,565,970

Table 9.2.7

PF 2007-09

Rate Design Study
Calculation of PF Preference Rate Components
Test Period October 2006 - September 2009

COMPROMISE PF PREFERENCE RATE SHAPE

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	2.21	2.36	2.48	2.10	2.14	1.99	1.87	1.55	1.42	1.74	2.04	2.10

LV Rate 0.53

PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy		
HLH	6,793	7,448	8,527	8,701	7,576	7,638	6,834	6,548	6,333	6,682	6,782	6,435	141856	47285	5398
LLH	4,283	4,826	5,454	5,484	4,981	4,978	4,395	4,267	4,074	4,325	4,353	4,138			
Demand	19,455	21,274	22,745	23,895	23,343	20,994	18,819	16,647	16,177	16,929	16,806	16,614			
											LV Billing Determinant		97249273		

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 229,414	$ 268,294	$ 320,520	$ 277,654	$ 246,904	$ 230,899	$ 193,870	$ 155,178	$ 135,851	$ 176,529	$ 209,848	$ 205,518	$ 3,882,166	$ 3,145,412	81.02%
LLH	$ 105,965	$ 126,792	$ 150,426	$ 126,560	$ 116,109	$ 110,323	$ 89,618	$ 69,891	$ 46,403	$ 83,640	$ 99,910	$ 106,047			
Demand	$ 42,995	$ 50,208	$ 56,408	$ 50,179	$ 49,954	$ 41,778	$ 35,192	$ 25,803	$ 22,972	$ 29,456	$ 34,284	$ 34,889	$ 474,117	$ 384,008	81.02%
												LV Revenue	$ 51,542	$ 41,759	81.02%
													$ 4,407,825	$ 3,571,179	81.02%

PF rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**27.36**	**29.18**	**30.46**	**25.85**	**26.40**	**24.49**	**22.99**	**19.20**	**17.38**	**21.41**	**25.07**	**25.88**
LLH	**20.04**	**21.28**	**22.35**	**18.70**	**18.89**	**17.95**	**16.52**	**13.27**	**9.23**	**15.67**	**18.59**	**20.77**
Demand	**1.79**	**1.91**	**2.01**	**1.70**	**1.73**	**1.61**	**1.52**	**1.26**	**1.15**	**1.41**	**1.65**	**1.70**
											LV Rate	**0.430**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 185,868	$ 217,346	$ 259,724	$ 224,925	$ 200,008	$ 187,057	$ 157,105	$ 125,714	$ 110,074	$ 143,054	$ 170,035	$ 166,525	$ 3,145,348
LLH	$ 85,834	$ 102,708	$ 121,901	$ 102,542	$ 94,093	$ 89,364	$ 72,609	$ 56,621	$ 37,604	$ 67,768	$ 80,930	$ 85,939	
Demand	$ 34,824	$ 40,634	$ 45,717	$ 40,621	$ 40,384	$ 33,800	$ 28,605	$ 20,975	$ 18,604	$ 23,870	$ 27,730	$ 28,243	$ 384,008
												LV Revenue	$ 41,817
													$ 3,571,173

Non-Slice PF Average Rate

Energy Costs	**$ 3,145,412**	**22.17**
Demand Costs	**$ 384,008**	**2.71**
Unbundled Cost	**$ 41,759**	**0.29**
Total	**$ 3,571,179**	**25.17**
Billing Determinants	**141856**	

Table 9.2.8

PFx 2007-09

Rate Design Study
Calculation of PF Exchange Rate Components
Test Period October 2006 - September 2009

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	53.34	63.03	66.13	59.13	59.27	56.85	47.16	41.76	41.17	49.51	54.63	56.83
LLH	46.08	52.01	54.79	50.01	52.39	50.21	40.56	35.55	31.27	41.07	46.87	50.78
MONTHLY DEMAND	1.79	1.91	2.01	1.70	1.73	1.61	1.52	1.26	1.15	1.41	1.65	1.70

PFx billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	4,464	5,068	6,511	7,186	6,703	6,319	5,796	3,790	3,218	3,137	4,134	5,040	97,556
LLH	2,704	2,918	3,664	4,720	4,254	3,820	3,320	2,379	1,756	1,777	2,074	2,805	
Demand	14,819	15,664	19,828	22,468	21,318	15,892	15,690	10,614	9,131	10,430	12,221	14,842	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
Energy	$ 362,698	$ 471,164	$ 631,355	$ 660,965	$ 620,113	$ 551,034	$ 407,992	$ 242,852	$ 187,392	$ 228,283	$ 323,029	$ 428,831	$ 5,115,707	$ 3,347,286	65.43%
Demand	$ 26,526	$ 29,918	$ 39,854	$ 38,195	$ 36,879	$ 25,587	$ 23,849	$ 13,373	$ 10,501	$ 14,707	$ 20,165	$ 25,231	$ 304,785	$ 304,785	100.00%
Transmission Costs													$ 380,469	$ 380,469	100.00%
													$ 5,800,961	$ 4,032,539	

PF exchange rates	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
Energy	**33.11**	**38.61**	**40.60**	**36.32**	**37.03**	**35.56**	**29.29**	**25.76**	**24.65**	**30.40**	**34.05**	**35.77**
Demand	**1.79**	**1.91**	**2.01**	**1.70**	**1.73**	**1.61**	**1.52**	**1.26**	**1.15**	**1.41**	**1.65**	**1.70**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
Energy	$ 237,319	$ 308,290	$ 413,105	$ 432,479	$ 405,750	$ 360,550	$ 266,956	$ 158,902	$ 122,613	$ 149,369	$ 211,363	$ 280,590	$ 3,347,286
Demand	$ 26,526	$ 29,918	$ 39,854	$ 38,195	$ 36,879	$ 25,587	$ 23,849	$ 13,373	$ 10,501	$ 14,707	$ 20,165	$ 25,231	$ 304,785
Transmission Costs													$ 380,469
													$ 4,032,539

PF Exchange Average Rate

Energy Costs	$ 3,347,286	34.31
Demand Costs	$ 304,785	3.12
Unbundled Cost	$ -	0.00
Transmission Costs	$ 380,469	3.90
Total	$ 4,032,539	41.34
Billing Determinants	$ 97,556	

Table 9.2.9

Rate Design Study **REP_1**

Calculation of LookBack REP Benefits

		2007		2008
PUGET SOUND ENERGY				
Averge System Cost		53.66		52.69
PF Exchange Rate		41.33		41.33
Residential Load		11,746,838		11,894,349
Benefits	$	144,821	$	135,110
PORTLAND GENERAL				
Averge System Cost		49.04		47.49
PF Exchange Rate		41.33		41.33
Residential Load		8,286,384		8,377,545
Benefits	$	63,869	$	51,565
NORTHWESTERN				
Averge System Cost		51.03		51.98
PF Exchange Rate		41.33		41.33
Residential Load		951,068		961,972
Benefits	$	9,223	$	10,249
AVISTA				
Averge System Cost		48.28		49.80
PF Exchange Rate		41.33		41.33
Residential Load		3,824,029		3,897,357
Benefits	$	26,594	$	33,008
PACIFICORP WA				
Averge System Cost		41.27		42.17
PF Exchange Rate		41.33		41.33
Residential Load		1,855,179		1,878,047
Benefits	$	-	$	1,573
PACIFICORP OR				
Averge System Cost		40.76		41.74
PF Exchange Rate		41.33		41.33
Residential Load		5,977,338		6,051,019
Benefits	$	-	$	2,507
PACIFICORP ID				
Averge System Cost		37.26		38.13
PF Exchange Rate		41.33		41.33
Residential Load		1,336,202		1,352,673
Benefits	$	-	$	-
IDAHO POWER				
Averge System Cost		32.44		32.98
PF Exchange Rate		41.33		41.33
Residential Load		7,218,346		7,380,466
Benefits	$	-	$	-
Total FY2007-08 Lookback REP Benefits	**$**	**244,507**	**$**	**234,011**

Table 9.2.10

IP 2007-09

Rate Design Study
Calculation of IP Rate Components
Test Period October 2006 - September 2009

LEVELIZED MARGINAL COSTS OF POWER

Energy Mills/kwh	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	53.34	63.03	66.13	59.13	59.27	56.85	47.16	41.76	41.17	49.51	54.63	56.83
LLH	46.08	52.01	54.79	50.01	52.39	50.21	40.56	35.55	31.27	41.07	46.87	50.78
MONTHLY DEMAND	1.79	1.91	2.01	1.70	1.73	1.61	1.52	1.26	1.15	1.41	1.65	1.70

IP billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.026
LLH	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
Demand	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 0.068	$ 0.075	$ 0.080	$ 0.074	$ 0.069	$ 0.072	$ 0.058	$ 0.051	$ 0.051	$ 0.061	$ 0.069	$ 0.067	$ 1.328	$ 0.816	61.43%
LLH	$ 0.044	$ 0.051	$ 0.056	$ 0.049	$ 0.046	$ 0.048	$ 0.038	$ 0.036	$ 0.029	$ 0.041	$ 0.045	$ 0.050			
Demand	$ 0.005	$ 0.006	$ 0.006	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.004	$ 0.003	$ 0.004	$ 0.005	$ 0.005	$ 0.058	$ 0.058	100.00%
													$ 1.386	$ 0.874	

IP rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**32.77**	**38.72**	**40.63**	**36.33**	**36.41**	**34.92**	**28.97**	**25.66**	**25.30**	**30.41**	**33.56**	**34.91**
LLH	**28.31**	**31.95**	**33.66**	**30.72**	**32.18**	**30.85**	**24.92**	**21.84**	**19.21**	**25.23**	**28.80**	**31.19**
Demand	**1.79**	**1.91**	**2.01**	**1.70**	**1.73**	**1.61**	**1.52**	**1.26**	**1.15**	**1.41**	**1.65**	**1.70**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 0.042	$ 0.046	$ 0.049	$ 0.045	$ 0.043	$ 0.044	$ 0.036	$ 0.032	$ 0.031	$ 0.037	$ 0.042	$ 0.041	$ 0.816
LLH	$ 0.027	$ 0.031	$ 0.034	$ 0.030	$ 0.028	$ 0.030	$ 0.023	$ 0.022	$ 0.018	$ 0.025	$ 0.028	$ 0.030	
Demand	$ 0.005	$ 0.006	$ 0.006	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.004	$ 0.003	$ 0.004	$ 0.005	$ 0.005	$ 0.058
													$ 0.874

IP Average Rate

Energy Costs	$ 0.816	31.01
Demand Costs	$ 0.058	2.22
Unbundled Cost	$ -	0.00
Total	$ 0.874	33.23
Non-Slice Billing Determinants	$ 0.026	

Table 9.2.11

NR 2007-09

Rate Design Study
Calculation of NR Rate Components
Test Period October 2006 - September 2009

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	53.34	63.03	66.13	59.13	59.27	56.85	47.16	41.76	41.17	49.51	54.63	56.83
LLH	46.08	52.01	54.79	50.01	52.39	50.21	40.56	35.55	31.27	41.07	46.87	50.78
MONTHLY DEMAND	1.79	1.91	2.01	1.70	1.73	1.61	1.52	1.26	1.15	1.41	1.65	1.70

NR billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.026
LLH	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
Demand	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 0.068	$ 0.075	$ 0.080	$ 0.074	$ 0.069	$ 0.072	$ 0.058	$ 0.051	$ 0.051	$ 0.061	$ 0.069	$ 0.067	$ 1.328	$ 1.545	116.38%
LLH	$ 0.044	$ 0.051	$ 0.056	$ 0.049	$ 0.046	$ 0.048	$ 0.038	$ 0.036	$ 0.029	$ 0.041	$ 0.045	$ 0.050			
Demand	$ 0.005	$ 0.006	$ 0.006	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.004	$ 0.003	$ 0.004	$ 0.005	$ 0.005	$ 0.058	$ 0.058	100.00%
													$ 1.386	$ 1.604	

NR rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**62.08**	**73.35**	**76.96**	**68.82**	**68.97**	**66.16**	**54.89**	**48.61**	**47.92**	**57.62**	**63.58**	**66.14**
LLH	**53.63**	**60.53**	**63.77**	**58.20**	**60.97**	**58.44**	**47.21**	**41.38**	**36.39**	**47.79**	**54.55**	**59.10**
Demand	**1.79**	**1.91**	**2.01**	**1.70**	**1.73**	**1.61**	**1.52**	**1.26**	**1.15**	**1.41**	**1.65**	**1.70**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 0.079	$ 0.087	$ 0.094	$ 0.086	$ 0.081	$ 0.084	$ 0.068	$ 0.060	$ 0.059	$ 0.071	$ 0.080	$ 0.078	$ 1.545
LLH	$ 0.051	$ 0.059	$ 0.065	$ 0.057	$ 0.053	$ 0.056	$ 0.044	$ 0.041	$ 0.034	$ 0.048	$ 0.053	$ 0.058	
Demand	$ 0.005	$ 0.006	$ 0.006	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.004	$ 0.003	$ 0.004	$ 0.005	$ 0.005	$ 0.058
													$ 1.604

NR Average Rate

Energy Costs	$ 1.545	58.75
Demand Costs	$ 0.058	2.22
Unbundled Cost	$ -	0.00
Total	$ 1.604	60.97
Non-Slice Billing Determinants	$ 0.026	

Table 9.2.12

PF 2007-09 Flat

Rate Design Study
Calculation of Flat PF Preference Rate
Test Period October 2006 - September 2009

PF Preference Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**27.36**	**29.18**	**30.46**	**25.85**	**26.40**	**24.49**	**22.99**	**19.20**	**17.38**	**21.41**	**25.07**	**25.88**
LLH	**20.04**	**21.28**	**22.35**	**18.70**	**18.89**	**17.95**	**16.52**	**13.27**	**9.23**	**15.67**	**18.59**	**20.77**
Demand	**1.79**	**1.91**	**2.01**	**1.70**	**1.73**	**1.61**	**1.52**	**1.26**	**1.15**	**1.41**	**1.65**	**1.70**

Flat Load FY2007-09

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HLH	32.0	29.6	30.4	31.2	29.2	31.6	30.8	30.8	30.8	30.8	31.6	29.6	657.6
LLH	23.8	24.5	25.4	24.6	21.8	24.1	23.2	25.0	23.2	25.0	24.2	24.4	
Demand	75	75	75	75	75	75	75	75	75	75	75	75	

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HLH	$ 876	$ 864	$ 926	$ 807	$ 771	$ 774	$ 708	$ 591	$ 535	$ 659	$ 792	$ 766	$ 14,217
LLH	$ 477	$ 520	$ 568	$ 460	$ 412	$ 433	$ 383	$ 332	$ 214	$ 392	$ 450	$ 507	
Demand	$ 134	$ 143	$ 151	$ 128	$ 130	$ 121	$ 114	$ 95	$ 86	$ 106	$ 124	$ 128	$ 1,458
													$ 15,675

Flat PF Preference Rate FY2007-09 $ 23.84

Table 9.2.13

Slice Costing Table

		FY 2007 forecast	FY 2008 forecast	FY 2009 forecast
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	263,669	188,688	242,902
5	BUREAU OF RECLAMATION	71,654	74,760	77,766
6	CORPS OF ENGINEERS	161,519	165,742	170,407
7	LONG-TERM CONTRACT GENERATING PROJECTS	24,932	25,314	25,751
8	**Sub-Total**	**521,774**	**454,504**	**516,826**
9	**Operating Generation Settlement Payment**			
10	COLVILLE GENERATION SETTLEMENT	16,968	17,354	17,749
11	SPOKANE GENERATION SETTLEMENT	0	0	0
12	**Sub-Total**	**16,968**	**17,354**	**17,749**
13	**Non-Operating Generation**			
14	TROJAN DECOMISSIONING	5,400	4,700	3,100
15	WNP-1&3 DECOMISSIONING	200	200	200
16	**Sub-Total**	**5,600**	**4,900**	**3,300**
17	**Contracted Power Purchases**			
18	PNCA HEADWATER BENEFIT	1,714	1,714	1,714
19	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)			
20	DSI MONETIZED POWER SALE	59,000	59,000	59,000
21	OTHER POWER PURCHASES (short term - omit)			
22	**Sub-Total**	**60,714**	**60,714**	**60,714**
23	**Augmentation Power Purchases**			
24	AUGMENTATION POWER PURCHASES (omit - calculated below)			
25	CONSERVATION AUGMENTATION (omit)			
26	**Residential Exchange/IOU Settlement Benefits**			
27	PUBLIC RESIDENTIAL EXCHANGE	**0**	**0**	**0**
28	IOU RESIDENTIAL EXCHANGE	**154,769**	**199,369**	**226,906**
29	**Renewable Generation (expenses related to reinvestment removed)**	30,289	34,719	40,835
30	**Generation Conservation**			
31	LOW INCOME WEATHERIZATION & TRIBAL	5,000	5,000	5,000
32	ENERGY EFFICIENCY DEVELOPMENT	12,885	12,908	12,933
33	ENERGY WEB	1,000	1,000	1,000
34	**LEGACY (Until 11/1/03 this was included with line 72)**	3,728	2,638	2,114
35	MARKET TRANSFORMATION	10,000	10,000	10,000
36	TECHNOLOGY LEADERSHIP	1,300	1,300	1,300
37	INFRASTRUCTURE SUPPORT AND EVALUATION	1,000	1,000	1,000
38	BI-LATERAL CONTRACT ACTIVITY	1,000	1,000	1,000
39	**Sub-Total**	**35,913**	**34,846**	**34,347**
40	CONSERVATION RATE CREDIT	36,000	36,000	36,000
41	**Power System Generation Sub-Total**	**862,026**	**842,406**	**936,677**
42				
43	**PBL Transmission Acquisition and Ancillary Services**			
44	**PBL Transmission Acquisition and Ancillary Services**			
45	PBL - TRANSMISSION & ANCILLARY SERVICES			
45a	Canadian Entitlement Agreement Transmission Expenses	24,806	25,550	26,991
45b	PNCA & NTS Transmission and System Obligaton Expenses	1,775	1,825	1,875
46	3RD PARTY GTA WHEELING	47,000	47,000	48,000
47	PBL - 3RD PARTY TRANS & ANCILLARY SVCS	0	0	0
48	RESERVE & OTHER SERVICES	8,462	8,462	8,462
49	TELEMETERING/EQUIP REPLACEMT	200	200	200
50	**PBL Trans Acquisition and Ancillary Services Sub-Total**	**82,243**	**83,037**	**85,528**
51				
52	**Power Non-Generation Operations**			
53	**PBL System Operations**			
54	EFFICIENCIES PROGRAM (omit TMS expenses)	0	0	0
55	INFORMATION TECHNOLOGY	0	0	0
56	GENERATION PROJECT COORDINATION	5,637	5,738	5,844
57	SLICE IMPLEMENTATION (omit - calculated separately)			
58	**Sub-Total**	**5,637**	**5,738**	**5,844**
59	**PBL Scheduling**			
60	OPERATIONS SCHEDULING	8,758	9,051	9,353
61	OPERATIONS PLANNING	5,202	5,358	5,521
62	**Sub-Total**	**13,960**	**14,409**	**14,874**
63	**PBL Marketing and Business Support**			
64	SALES & SUPPORT	15,884	16,278	16,745
64a	Contractual exclusion	(5,360)	(5,360)	(5,360)
65	PUBLIC COMMUNICATION & TRIBAL LIAISON	0	0	0
66	STRATEGY, FINANCE & RISK MGMT	10,965	11,359	11,771
67	EXECUTIVE AND ADMINISTRATIVE SERVICES	845	840	834
68	CONSERVATION SUPPORT (EE staff costs)	6,441	6,692	6,953
69	**Sub-Total**	**28,776**	**29,808**	**30,943**
70	**Power Non-Generation Operations Sub-Total**	**48,372**	**49,955**	**51,662**

Table 9.2.13

Slice Costing Table

		FY 2007 forecast	FY 2008 forecast	FY 2009 forecast
71				
72	**Fish and Wildlife/USF&W/Planning Council**			
73	**BPA Fish and Wildlife (includes F&W Shared Services)**			
74	FISH & WILDLIFE	143,000	143,000	143,000
75	F&W HIGH PRIORITY ACTION PROJECTS			
76	**Sub-Total**	**143,000**	**143,000**	**143,000**
77	**PBL-USF&W Lower Snake Hatcheries**			
78	USF&W LOWER SNAKE HATCHERIES	18,600	19,500	20,400
79	**PBL - Planning Council**			
80	PLANNING COUNCIL	9,085	9,276	9,467
81	**PBL - ENVIRONMENTAL REQUIREMENTS**			
82	ENVIRONMENTAL REQUIREMENTS	500	500	500
83	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**171,185**	**172,276**	**173,367**
84				
85	**BPA Internal Support**			
86	**CSRS/FERS**			
87	ADDITIONAL POST-RETIREMENT CONTRIBUTION	10,550	9,000	15,375
88	**Corporate Support - G&A (excludes direct project support)**			
89	CORPORATE G&A	50,247	51,753	51,764
90	**TBL Supply Chain - Shared Services**	368	374	380
91	**General and Administrative/Shared Services Sub-Total**	**61,165**	**61,127**	**67,519**
92				
93	**Bad Debt Expense**			
94	**Other Income, Expenses, Adjustments**	1,800	1,800	3,600
95	**Non-Federal Debt Service**			
96	**Energy Northwest Debt Service**			
97	COLUMBIA GENERATING STATION DEBT SVC	195,690	217,856	218,767
98	WNP-1 DEBT SVC	147,941	165,916	163,282
99	WNP-3 DEBT SVC	151,724	160,092	153,030
100	EN RETIRED DEBT	0	0	0
101	EN LIBOR INTEREST RATE SWAP	0	0	0
102	**Sub-Total**	**495,355**	**543,864**	**535,079**
103	**Non-Energy Northwest Debt Service**			
104	TROJAN DEBT SVC	8,605	7,888	0
105	CONSERVATION DEBT SVC	5,203	5,198	5,188
106	COWLITZ FALLS DEBT SVC	11,619	11,583	11,571
107	WASCO DEBT SVC	-	1,664	2,168
108	**Sub-Total**	**25,427**	**26,333**	**18,927**
109	**Non-Federal Debt Service Sub-Total**	**520,782**	**570,197**	**554,006**
110				
111				
112	**Total Operating Expenses**	**1,747,573**	**1,780,798**	**1,872,358**
113				
114	**Other Expenses**			
115	Depreciation (excl. TMS)	118,058	121,829	124,594
116	Amortization (excludes ConAug amortization)	55,567	60,241	65,172
117	Net Interest Expense	163,080	173,193	182,940
118	LDD	22,289	22,612	22,853
119	Irrigation Rate Mitigation Costs	10,000	10,000	10,000
120	**Sub-Total**	368,994	387,875	405,559
121	**Total Expenses**	**2,116,567**	**2,168,673**	**2,277,917**
122				
123	**Revenue Credits**			
124	Ancillary and Reserve Service Revs. Total	73,131	61,970	62,715
125	Downstream Benefits and Pumping Power	8,921	8,921	8,921
126	4(h)(10)(c)	84,707	84,927	84,676
127	Colville and Spokane Settlements	4,600	4,600	4,600
128	FCCF	0	0	0
129	Energy Efficiency Revenues	12,885	12,908	12,933
130	Miscellaneous	3,420	3,420	3,420
131	**Total Revenue Credits**	**187,664**	**176,746**	**177,265**
132				
133	**Augmentation Costs**			
134	**IOU Reduction of Risk Discount (includes interest)**	23,024	23,024	23,024
135	**Costs in this box are not subject to True-Up**			
136	**Forecasted Gross Augmentation Costs**	49,005	0	0
137	Residual augmentation cost	97,062	95,001	146,903
138	Other augmentation cost			
139	Minus revenues	67,993	42,972	64,641
140	**Net Cost of Augmentation**	**101,098**	**75,053**	**105,286**
141				
142				

Table 9.2.13

Slice Costing Table

		FY 2007 forecast	FY 2008 forecast	FY 2009 forecast	3-Year Total Slice Rev. Reqt.
143	**Minimum Required Net Revenue calculation**				
144	Principal Payment of Fed Debt for Power	202,331	172,483	185,065	
145	Irrigation assistance	0	2,950	6,590	
146	Depreciation	118,058	121,829	124,594	
147	Amortization	71,658	76,332	81,263	
148	Capitalization Adjustment	(45,937)	(45,937)	(45,937)	
149	Bond Premium Amortization	613	613	185	
150	Principal Payment of Fed Debt exceeds non cash expenses	57,939	22,596	31,550	
151	Minimum Required Net Revenues	**57,939**	**22,596**	**31,550**	
152					
153	SLICE TRUE-UP ADJUSTMENT CALCULATION				
154	Annual Slice Revenue Requirement (Amounts for each FY)	**2,087,941**	**2,089,576**	**2,237,488**	**$ 6,415,004**
155	TRUE UP AMOUNT (Diff. between actuals and forecast)				
156	AMOUNT BILLED (22.6278 percent)				
157	Slice Implementation Expenses (not incl. in base rate)	2,400	2,400	2,400	
158	TRUE UP ADJUSTMENT				
159					
160					
161	**SLICE RATE CALCULATION ($)**				
162	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**				**$ 178,194,564**
163	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Revenue Requirement divided by 100)**				**$ 1,781,946**
164					
165	**ANNUAL BASE SLICE REVENUES**				**$ 483,858,116**
166	**Annual Slice Implementation Expenses**				**$ 2,400,000**
167	**TOTAL ANNUAL SLICE REVENUES**				**$ 486,258,116**

Table 9.2.14.1

RDS 60A

RATE DESIGN STUDY
Allocated Costs and Unit Costs
Priority Firm Power (PF)
($ Thousands)
Test Period October 2006 - September 2009

GENERATION ENERGY	A ALLOCATED COSTS ($ Thousands)	B UNIT COSTS (Mills/KwH)	C PERCENT CONTRIBUTION (Percent)
Federal Base System			
Hydro	1,708,414	6.073	19.69%
Fish & Wildlife	537,972	1.912	6.20%
Trojan	29,693	0.106	0.34%
WNP #1	477,739	1.698	5.51%
WNP #2	1,327,572	4.720	15.30%
WNP #3	464,846	1.653	5.36%
System Augmentation	457,040	1.625	5.27%
Balancing Power Purchases	180,279	0.641	2.08%
Total Federal Base System	5,183,555	18.428	59.75%
New Resources			
Gross Residential Exchange	2,695,144	9.581	31.07%
Conservation	490,842	1.745	5.66%
BPA Programs	975,902	3.469	11.25%
TOTAL COSA ALLOCATIONS	9,345,443	33.223	107.73%
WNP #3 Excess Revenue Credit			
Nonfirm Excess Revenue Credit	(1,749,236)	-6.219	-20.16%
Low Density Discount Expense	67,754	0.241	0.78%
Other Revenue Credits	(555,724)	-1.976	-6.41%
Irrigation Rate Mitigation Expense	30,000	0.107	0.35%
SP Revenue Surplus/Dfct Adj.	1,536,587	5.463	17.71%
7(c)(2) Delta Adjustment	1	0.000	0.00%
7(c)(2) Floor Rate Adjustment			
TOTAL RATE DESIGN ADJUSTMENTS	(670,619)	-2.384	-7.73%
Total Generation	8,674,824	**30.839**	100.00%
Billing Determinants With LDD Discount	281,294		

Table 9.2.14.2

RDS 60B

RATE DESIGN STUDY
Allocated Costs and Unit Costs
Priority Firm Power (PF) Bifurcated
($ Thousands)
Test Period October 2006 - September 2009

	A ALLOCATED COSTS	B UNIT COSTS	C PERCENT CONTRIBUTION
Rate Design Step PF Rate	($ Thousands)	(Mills/KwH)	(Percent)
PRIORITY FIRM PREFERENCE			
Revenue Reqmt @ PF Combined Rate	5,666,290	30.839	112.80%
7(b)(2) Credit	(643,082)	-3.500	-12.80%
Subtotal	5,023,208	27.339	100.00%
Floor Rate Adjustment			
TOTAL	5,023,208	27.339	100.00%
Billing Determinants:			
Total PF Preference Forecasted Sales	183,738	27.339	100.00%
Adjusted for LDD	183,738		
Subscription Step PF Rate			
Revenue Reqmt @ Rate Design PF Pref.	5,023,208	27.339	100.00%
IOU REP Settlement Expenses			
Less IOU REP Benefits in Rates			
Total	5,023,208	27.339	100.00%
Total PF Preference Forecasted Sales	183,738	**27.339**	100.00%
Slice Separation Step			
Revenue Reqmt @ Subscription Step PF Pref	5,023,208		
Slice PF Product Revenues	(1,451,574)		
Revenue Reqmt @ Non-Slice PF Pref.	3,571,634		
Non-Slice PF Preference Forecasted Sales	141,856	**25.178**	
PRIORITY FIRM EXCHANGE			
Revenue Reqmt @ PF Combined Rate	3,008,534	30.839	74.61%
7(b)(2) Adjustment	643,082	6.592	15.95%
7(b)(2) Industrial Adjustment			
7(b)(2) Exchange Cost Adjustment			
Subtotal	3,651,616	37.431	90.56%
Floor Rate Adjustment			
Total Energy	3,651,616	37.431	90.56%
Total Transmission	380,469	3.900	9.44%
TOTAL	4,032,085	**41.331**	100.00%
Billing Determinants:			
Forecasted Exchange Loads	97,556	41.331	100.00%

Table 9.2.14.3

RDS 61

RATE DESIGN STUDY
Allocated Costs and Unit Costs
Industrial Firm Power Rate (IP)
($ Thousands/Unit Costs in Mills/KwH, or as Indicated)
Test Period October 2006 - September 2009

GENERATION ENERGY	A ALLOCATED COSTS ($ Thousands)	B UNIT COSTS (Mills/KwH)	C PERCENT CONTRIBUTION (Percent)
Federal Base System			
Hydro			
Fish & Wildlife			
Trojan			
WNP #1			
WNP #2			
WNP #3			
System Augmentation			
Balancing Power Purchases			
Total Federal Base System			
New Resources	0.154	5.857	17.63%
Gross Residential Exchange	1.139	43.302	130.32%
Conservation	0.046	1.745	5.25%
Energy Services Business			
BPA Programs	0.091	3.469	10.44%
TOTAL COSA ALLOCATIONS	1.430	54.373	163.63%
Nonfirm Excess Revenue Credit			
Other Revenue Credits			
SP Revenue Surplus/Dfct Adj.			
7(c)(2) Delta Adjustment	(0.642)	-24.424	-73.50%
7(c)(2) Floor Rate Adjustment			
TOTAL RATE DESIGN ADJSTMTS	(0.642)	-24.424	-73.50%
Total Generation	0.788	29.949	90.13%
Total Allocated & Adjusted Costs	0.788	29.949	90.13%
7(b)(2) Adjustments			
7(b)(2) Amount	0.173	6.593	19.84%
7(b)(2) Industrial Adj.	(0.087)	-3.313	-9.97%
Total With 7(b)(2) Adjustments	0.874	**33.228**	100.00%
Billing Determinants:			
Energy (GwH)	0.026		

Table 9.2.14.4

RDS 62

RATE DESIGN STUDY
Allocated Costs and Unit Costs
New Resources Firm Power (NR)
($ Thousands/Unit Costs in Mills/KwH, or as Indicated)
Test Period October 2006 - September 2009

GENERATION ENERGY	A ALLOCATED COSTS ($ Thousands)	B UNIT COSTS (Mills/KwH)	C PERCENT CONTRIBUTION (Percent)
Federal Base System			
Hydro			
Fish & Wildlife			
Trojan			
WNP #1			
WNP #2			
WNP #3			
System Augmentation			
Balancing Power Purchases			
Total Federal Base System			
New Resources	0.154	5.857	9.61%
Gross Residential Exchange	1.139	43.302	71.03%
Conservation	0.046	1.745	2.86%
BPA Programs	0.091	3.469	5.69%
TOTAL COSA ALLOCATIONS	1.430	54.373	89.19%
Nonfirm Excess Revenue Credit			
SP Revenue Surplus/Dfct Adj.			
7(c)(2) Delta Adjustment	0.000	0.000	0.00%
7(c)(2) Floor Rate Adjustment			
TOTAL RATE DESIGN ADJSTMTS	0.000	0.000	0.00%
Total Generation Energy	1.430	54.373	89.19%
Total Allocated & Adjusted Costs	1.430	54.373	89.19%
7(b)(2) Adjustments			
7(b)(2) Amount	0.173	6.593	10.81%
7(b)(2) Industrial Adj.			
7(b(2)Exchange Cost Adjustment			
Total With 7(b)(2) Adjustments	1.604	**60.965**	100.00%
Billing Determinant / Energy (GWh)	0.026		

Table 9.2.14.5

RDS63

RATE DESIGN STUDY
Rate Design Step Resource Cost Contribution
($ Thousands)
Test Period October 2006 - September 2009

	A	B	C	D	E	F	G	H
	ALLOCATED GENERATION COSTS				PERCENTAGES			
	FBS Resources	Exchange Resources	New Resources	Total	FBS Resources	Exchange Resources	New Resources	Total
CLASSES OF SERVICE:								
Power Rates								
Priority Firm - Preference	3,385,836	1,760,435		5,146,271	65.79%	34.21%		100.00%
Priority Firm - Exchange	1,797,720	934,709		2,732,429	65.79%	34.21%		100.00%
Priority Firm Power - Total	5,183,555	2,695,144		7,878,699	65.79%	34.21%		100.00%
Industrial Firm Power		1	0	1		88.09%	11.91%	100.00%
New Resources Firm		1	0	1		88.09%	11.91%	100.00%
Surplus Firm Power		1,496,800	202,277	1,699,077		88.09%	11.91%	100.00%
Supplemental Capacity								
Entitlement Capacity								
TOTALS	5,183,555	4,191,946	202,277	9,577,779	54.12%	43.77%	2.11%	100.00%