B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Supplemental Wholesale Power Rate Case
Final Proposal

FY 2009 7(b)(2) RATE TEST
STUDY DOCUMENTATION

September 2008

WP-07-FS-BPA-14A

FY 2009 7(b)(2) RATE TEST STUDY

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COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COU	Consumer Owned Utility
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy

DOP	Debt Optimization Program
DROD	Draft Record of Decision
DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatt-hour
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)

IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
JP	Joint Party
JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company
JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities
JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause

LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
LRA	Load Reduction Agreement
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)
MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWEC	Northwest Energy Coalition
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council

OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PS	Power Services (formerly Power Business Line)
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People’s Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator

SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
TS	Transmission Services (formerly Transmission Business Line)
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

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1. PROGRAM CASE RATES ANALYSIS MODEL

Description of Ratemaking Tables
7(b)(2) Rate Test Program Case

Table 1.1.1 (Sales_01)
Total PF Load Forecast, FY2009-13
Gigawatthour (GWh) energy sales and peak kilowatt (kW)/mo. demand amounts for each month of the Rate Test Period Fiscal Year (FY) 2009-2013.

Table 1.1.2 (Sales_02)
Total PF Exchange Load Forecast, FY2009-13
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2009-2013.

Table 1.1.3 (Sales_03)
Total IP Load Forecast, FY2009-13
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2009-2013. (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 0.0001 aMW was used.)

Table 1.1.4 (Sales_04)
Total NR Load Forecast, FY2009-13
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2009-2013. (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 0.0001 aMW was used.)

Table 1.2 (Exchange_01)
Forecast for Traditional Residential Exchange Program, FY2009.
Forecast of potential exchanging utilities' average system cost (ASC) and exchangeable load.

Table 1.3.1 to Table 1.3.5 (COSA_06)
Itemized Revenue Requirements, FY2009-13.
Power Business Line (PBL) revenue requirements for each FY during the rate test period

Table 1.3.6 (COSA_07)
Functionalization of Residential Exchange Costs, FY2009.
REP costs are functionalized to power to comport with other functionalized moving through COSA into the Rate Design Step of the RAM.

Table 1.3.7 (COSA_08)
Classified Revenue Requirement, FY2009.
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.

Table 1.3.8 (COSA_09)
Functionalized Revenue Credits, FY2009-13.
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.

Table 1.3.9 (COSA_09A)
Allocation of EE Revenue Credits to Conservation Costs, FY2009-13.
Energy Efficiency revenues are credited against conservation program costs rather than being directly assigned to Federal Base System (FBS) power as are the bulk of BPA's other revenue credits.

Table 1.3.10 (COSA_09B)
Allocation of Deemer Credit to BPA Program Costs, FY2009-13.
The deemer credit that is due to Avista's deemer balance is credited to BPA Programs and the credit is allocated to all load pools.

Table 1.4.1 (ALLOCATE 01)
Energy Allocation Factors (EAF), FY2009-13.
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.

Table 1.4.2 (ALLOCATE 02)
Initial Rate Pool Cost Allocation, FY2009-13.
Table shows the initial allocation of the revenue requirement costs from the COSA to rate pools using the EAFs from table ALLOCATE 01.

Description of Ratemaking Tables
7(b)(2) Rate Test Program Case

Table 1.5.1 (RDS_11)
Allocation of Secondary Revenues and Other Revenue Credits, FY2009-13.
Tables summarize revenue from secondary power sales and revenues from Other Revenue Credits from Table COSA 09. Gross secondary revenues are adjusted to account for a 7(b)(3) cost allocation to secondary sales. 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.

Table 1.5.2 (RDS_17)
Surplus Firm Power Revenues (Surplus)/Shortfall, FY2009-13.
Table calculates the firm surplus sale revenue (surplus)/shortfall. 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.

Table 1.5.3 (RDS_19)
Summary of Initial Cost Allocations, FY2009-13.
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.

Table 1.5.4 (RDS_21)
7(C)(2) Delta Calculation and Allocation of 7(C)(2) Delta, FY2009-13.
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.

Table 1.5.5 (RDS_23)
Industrial Firm Power Floor Rate Calculation, FY2009-13.
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.

Table 1.5.6 (RDS_24)
Industrial Firm Power Floor Rate Test FY2009.
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.

Table 1.6 (RDS_50)
Calculation of PF Preference Rate Components, FY2009.
Table calculates unbifurcated PF rates. Marginal cost rates are scaled down to produce rates that recover costs allocated to PF energy. Example shown is for FY 2009.

Table 1.1.1 Sales 01

Total PF Load Forecast FY2009-13

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	
2009	HLH	3052	3240	3708	3535	3186	3312	2948	2867	3091	3114	3114	2811	63123	7206
	LLH	1883	2300	2448	2371	2095	2175	1887	1999	1937	2116	2006	1928		
	Demand	8854	9827	10160	10111	10065	9305	8245	7671	7951	8117	7785	7517		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2010	HLH	3109	3284	3818	3513	3213	3380	2956	2959	3225	3263	3044	2746	63973	7303
	LLH	1915	2326	2516	2445	2102	2130	1896	2059	2018	2215	1958	1881		
	Demand	9058	9992	10494	10241	10169	9387	8310	7946	8326	8538	7632	7372		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2011	HLH	3096	3375	3852	3550	3246	3412	2911	2887	3151	3241	3106	2765	64039	7310
	LLH	1972	2284	2539	2464	2119	2146	1864	2003	1969	2262	1929	1896		
	Demand	9200	10099	10629	10378	10305	9510	8215	7778	8164	8625	7704	7457		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2012	HLH	3165	3455	3937	3643	3467	3479	3007	3099	3432	3366	3196	2795	66400	7580
	LLH	2008	2324	2582	2512	2229	2183	1986	2075	2171	2336	1978	1977		
	Demand	9578	10541	11043	10808	10752	9889	8776	8666	8742	9105	8132	7781		
		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2013	HLH	3220	3476	3904	3733	3366	3462	3074	3056	3327	3418	3224	2820	66393	7579
	LLH	1974	2330	2646	2478	2191	2245	1960	2043	2154	2309	1991	1989		
	Demand	9678	10648	11155	10945	10882	10010	8884	8572	8584	9180	8225	7873		

Table 1.1.2 Sales 02

Total PF Exchange Load Forecast FY2009-13

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	
2009	HLH	1625	1841	2358	2606	2401	2302	2144	1355	1182	1156	1509	1828	35477	4050
	LLH	986	1062	1328	1713	1525	1393	1230	851	647	657	759	1019		
	Demand	5388	5688	7179	8143	7444	5789	5801	3794	3352	3833	4456	5381		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	1648	1865	2384	2609	2450	2307	2151	1360	1189	1168	1528	1836	35792	4086
	LLH	1001	1077	1345	1715	1557	1397	1235	855	652	665	771	1025		
	Demand	5458	5759	7251	8153	7887	5803	5820	3808	3370	3871	4512	5404		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	1618	1874	2390	2609	2448	2294	2102	1454	1247	1221	1590	1892	36196	4132
	LLH	984	1084	1350	1716	1557	1390	1208	918	687	698	807	1059		
	Demand	5356	5782	7262	8146	7892	5769	5688	4060	3528	4028	4685	5559		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	1679	1882	2368	2548	2378	2257	2058	1528	1367	1346	1638	1841	36508	4168
	LLH	1029	1095	1344	1679	1516	1372	1188	970	765	781	842	1037		
	Demand	5464	5737	7119	7882	7593	5642	5527	4208	3809	4325	4751	5355		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	1693	1898	2386	2576	2377	2282	2082	1551	1391	1367	1659	1859	36885	4211
	LLH	1038	1105	1355	1698	1516	1388	1203	986	779	794	854	1048		
	Demand	5507	5784	7173	7965	7310	5705	5600	4271	3873	4392	4808	5406		

Table 1.1.3 Sales 03

Total IP Load Forecast FY2009-13

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	
2009	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		

Table 1.1.4

Sales 04

Total NR Load Forecast FY2009-13															
														Total	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		

Table 1.2 Exchange 01

Forecast for Traditional Residential Exchange Program

Potential Exchanger	2009 ASC ($/MWh)	2009 Exchange Load (aMW)
Avista	$ 50.28	474
Idaho Power	$ 33.86	880
Northwestern Energy PNWR	$ 54.84	106
Pacificorp	$ 51.27	1098
Portland General	$ 55.61	977
Puget Sound Energy	$ 59.71	1355
Centralia	$ 35.56	16
Franklin	$ 45.74	39
Snohomish	$ 38.08	420

Table 1.3.1 COSA 06 FY2009

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2009

FY 2009

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,345,120	138,413	0	411,799	550,212
4. BPA FISH & WILDLIFE PROGRAM	176,547	4,572	0	231,929	236,501
5. TROJAN				2,500	2,500
6. WNP #1				169,746	169,746
7. WNP #2				518,334	518,334
8. WNP #3				150,817	150,817
9. SYSTEM AUGMENTATION				161,123	161,123
10. BALANCING POWER PURCHASES				74,835	74,835
11. TOTAL FEDERAL BASE SYSTEM	5,521,667	142,985	0	1,721,083	1,864,068
12. NEW RESOURCES					
13. IDAHO FALLS				6,436	6,436
14. COWLITZ FALLS				14,089	14,089
15. OTHER NEW RESOURCES PURCHASES				61,483	61,483
16. TOTAL NEW RESOURCES				82,008	82,008
17. RESIDENTIAL EXCHANGE				1,955,586	1,955,586
18. CONSERVATION		17,166	0	157,322	174,488
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	26,824	694	0	189,006	189,700
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	26,824	694	0	189,006	189,700
23. TOTAL GENERATION COSTS	5,548,491	160,845	0	4,105,005	4,265,850
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,728	123,728
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				50,370	50,370
28. TOTAL TRANSMISSION COSTS				175,098	175,098
29. TOTAL PBL REVENUE REQUIREMENT		160,845	0	4,280,103	4,440,948
30. BPA TRANSMISSION REVENUE REQUIREMENT (Net of Line 25)		165,152	31,335	448,084	644,571

Table 1.3.2 COSA 06 FY2010

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2010

FY 2010

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,435,317	146,679	49,888	438,362	634,929
4. BPA FISH & WILDLIFE PROGRAM	213,196	5,753	1,957	264,462	272,172
5. TROJAN				2,200	2,200
6. WNP #1				163,422	163,422
7. WNP #2				502,112	502,112
8. WNP #3				139,538	139,538
9. SYSTEM AUGMENTATION				158,272	158,272
10. BALANCING POWER PURCHASES				83,902	83,902
11. TOTAL FEDERAL BASE SYSTEM	5,648,513	152,432	51,845	1,752,270	1,956,547
12. NEW RESOURCES					
13. IDAHO FALLS				6,436	6,436
14. COWLITZ FALLS				14,110	14,110
15. OTHER NEW RESOURCES PURCHASES				59,418	59,418
16. TOTAL NEW RESOURCES				79,964	79,964
17. RESIDENTIAL EXCHANGE				1,954,002	1,954,002
18. CONSERVATION		19,420	6,605	170,989	197,014
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	29,975	809	275	201,721	202,805
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	29,975	809	275	201,721	202,805
23. TOTAL GENERATION COSTS	5,678,488	172,661	58,725	4,158,945	4,390,332
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,728	123,728
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				50,690	50,690
28. TOTAL TRANSMISSION COSTS				175,418	175,418
29. TOTAL PBL REVENUE REQUIREMENT		172,661	58,725	4,334,363	4,565,750

Table 1.3.3 COSA 06 FY2011

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2011

FY 2011

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,474,513	155,477	32,711	457,965	646,153
4. BPA FISH & WILDLIFE PROGRAM	252,385	7,168	1,508	273,239	281,915
5. TROJAN				2,300	2,300
6. WNP #1				165,333	165,333
7. WNP #2				586,834	586,834
8. WNP #3				164,683	164,683
9. SYSTEM AUGMENTATION				276,217	276,217
10. BALANCING POWER PURCHASES				69,169	69,169
11. TOTAL FEDERAL BASE SYSTEM	5,726,898	162,645	34,219	1,995,740	2,192,604
12. NEW RESOURCES					
13. IDAHO FALLS				6,436	6,436
14. COWLITZ FALLS				14,163	14,163
15. OTHER NEW RESOURCES PURCHASES				61,588	61,588
16. TOTAL NEW RESOURCES				82,187	82,187
17. RESIDENTIAL EXCHANGE				1,986,597	1,986,597
18. CONSERVATION		22,482	4,730	179,107	206,319
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	35,155	998	210	207,132	208,341
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	35,155	998	210	207,132	208,341
23. TOTAL GENERATION COSTS	5,762,053	186,125	39,159	4,450,763	4,676,048
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,728	123,728
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				51,340	51,340
28. TOTAL TRANSMISSION COSTS				176,068	176,068
29. TOTAL PBL REVENUE REQUIREMENT		186,125	39,159	4,626,831	4,852,116

Table 1.3.4 COSA 06 FY2012

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2012

FY 2012

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,537,070	171,213	0	472,180	643,393
4. BPA FISH & WILDLIFE PROGRAM	279,664	8,648	0	280,676	289,324
5. TROJAN				2,300	2,300
6. WNP #1				190,379	190,379
7. WNP #2				609,051	609,051
8. WNP #3				157,810	157,810
9. SYSTEM AUGMENTATION				101,541	101,541
10. BALANCING POWER PURCHASES				94,626	94,626
11. TOTAL FEDERAL BASE SYSTEM	5,816,734	179,861	0	1,908,564	2,088,425
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,216	14,216
15. OTHER NEW RESOURCES PURCHASES				98,399	98,399
16. TOTAL NEW RESOURCES				112,616	112,616
17. RESIDENTIAL EXCHANGE				2,005,807	2,005,807
18. CONSERVATION		21,055	0	175,469	196,524
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	40,088	1,239	0	211,374	212,614
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	40,088	1,239	0	211,374	212,614
23. TOTAL GENERATION COSTS	5,856,822	202,155	0	4,413,829	4,615,984
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,928	123,928
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,428	52,428
28. TOTAL TRANSMISSION COSTS				177,356	177,356
29. TOTAL PBL REVENUE REQUIREMENT		202,155	0	4,591,185	4,793,341

Table 1.3.5 COSA 06 FY2013

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2013

FY 2013

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,606,593	181,408	27,160	484,958	693,526
4. BPA FISH & WILDLIFE PROGRAM	300,436	9,721	1,455	288,649	299,825
5. TROJAN				2,400	2,400
6. WNP #1				285,566	285,566
7. WNP #2				493,755	493,755
8. WNP #3				172,110	172,110
9. SYSTEM AUGMENTATION				195,624	195,624
10. BALANCING POWER PURCHASES				83,556	83,556
11. TOTAL FEDERAL BASE SYSTEM	5,907,029	191,129	28,615	2,006,619	2,226,363
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,262	14,262
15. OTHER NEW RESOURCES PURCHASES				99,613	99,613
16. TOTAL NEW RESOURCES				113,875	113,875
17. RESIDENTIAL EXCHANGE				2,031,888	2,031,888
18. CONSERVATION		22,680	3,396	181,018	207,094
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	43,723	1,415	212	213,729	215,356
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	43,723	1,415	212	213,729	215,356
23. TOTAL GENERATION COSTS	5,950,752	215,224	32,223	4,547,129	4,794,576
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,928	123,928
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,437	52,437
28. TOTAL TRANSMISSION COSTS				177,365	177,365
29. TOTAL PBL REVENUE REQUIREMENT		215,224	32,223	4,724,494	4,971,941

Table 1.3.6 COSA 07

COST OF SERVICE ANALYSIS

Functionalization of Residential Exchange Costs

Fiscal Year 2009

Gross Residential Exchange Cost	$ 1,953,586
Residential Exchange Transmission	$ 151,134
Functionalized Residential Exchange Costs	$ 1,802,452

Table 1.3.7 COSA 08

COST OF SERVICE ANALYSIS

Classified Revenue Requirement

Fiscal Year 2009

	Total Rev Req	Energy		Demand		Load Variance	
		%	Total	%	Total	%	Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 550,212	92.72%	$ 510,140	6.21%	$ 34,164	1.07%	$ 5,908
4. BPA FISH & WILDLIFE PROGRAM	$ 236,501	93.79%	$ 221,816	6.21%	$ 14,685		
5. TROJAN	$ 2,500	93.79%	$ 2,345	6.21%	$ 155		
6. WNP #1	$ 169,746	93.79%	$ 159,206	6.21%	$ 10,540		
7. WNP #2	$ 518,334	92.72%	$ 480,584	6.21%	$ 32,185	1.07%	$ 5,565
8. WNP #3	$ 150,817	93.79%	$ 141,452	6.21%	$ 9,365		
9. SYSTEM AUGMENTATION	$ 161,123	92.72%	$ 149,389	6.21%	$ 10,005	1.07%	$ 1,730
10. BALANCING POWER PURCHASES	$ 74,835	92.72%	$ 69,384	6.21%	$ 4,647	1.07%	$ 803
11. TOTAL FEDERAL BASE SYSTEM	$ 1,864,068		$ 1,734,317		$ 115,745		$ 14,006
12. NEW RESOURCES							
13. IDAHO FALLS	$ 6,436	92.72%	$ 5,967	6.21%	$ 400	1.07%	$ 69
14. COWLITZ FALLS	$ 14,089	92.72%	$ 13,063	6.21%	$ 875	1.07%	$ 151
15. OTHER NEW RESOURCES PURCHASES	$ 61,483	92.72%	$ 57,005	6.21%	$ 3,818	1.07%	$ 660
16. TOTAL NEW RESOURCES	$ 82,008		$ 76,035		$ 5,092		$ 881
17. RESIDENTIAL EXCHANGE	$ 1,802,452	100.00%	$ 1,802,452				
18. CONSERVATION	$ 174,488	93.79%	$ 163,654	6.21%	$ 10,834		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 189,700	92.72%	$ 175,884	6.21%	$ 11,779	1.07%	$ 2,037
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	$ 189,700		$ 175,884		$ 11,779		$ 2,037
23. TOTAL GENERATION COSTS	$ 4,112,716		$ 3,952,343		$ 143,450		$ 16,924
			$ -		$ -		$ -
24. TRANSMISSION COSTS							
25. TBL TRANSMISSION/ANCILLARY SERVICES	$ 123,728	100.00%	$ 123,728				
26. 3RD PARTY TRANS/ANCILLARY SERVICES	$ 1,000	100.00%	$ 1,000				
27. GENERAL TRANSFER AGREEMENTS	$ 50,370	100.00%	$ 50,370				
28. TOTAL TRANSMISSION COSTS	175,098		175,098				
29. TOTAL PBL REVENUE REQUIREMENT	$ 4,287,814		$ 4,127,441		$ 160,374		

Table 1.3.8 COSA 09

COST OF SERVICE ANALYSIS

Functionalized Revenue Credits
Test Period October 2008 - September 2013

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Colville Credit	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600
'4(h)(10)(c)	$ 88,480	$ 93,488	$ 93,723	$ 93,710	$ 95,577
Ancillary and Reserve Service Revs.	$ 79,306	$ 79,306	$ 79,306	$ 79,306	$ 79,306
Misc. Revenues	$ 3,420	$ 3,420	$ 3,420	$ 3,420	$ 3,420
Reserve Product Revenue	$ 3,630	$ 3,630	$ 3,630	$ 3,630	$ 3,630
Downstream Benefits & Storage	$ 8,921	$ 8,921	$ 8,921	$ 8,921	$ 8,571
Green Tags	$ 2,799	$ 1	$ 1	$ -	$ -
Network Wind Integration&Shaping	$ 1,933	$ 1,836	$ 1,836	$ -	$ -
Total	$ 193,087	$ 195,202	$ 195,437	$ 193,587	$ 195,103

Table 1.3.9 COSA 09A

COST OF SERVICE ANALYSIS

Allocation of EE Revenue Credits to Conservation Costs
Test Period October 2008 - September 2013

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Conservation Expense Before EE Revenues	$ 174,488	$ 174,488	$ 174,488	$ 174,488	$ 174,488
Energy Efficiency Revenues	$ (22,000)	$ (22,000)	$ (22,000)	$ (22,000)	$ (22,000)
Net Conservation Expense	$ 152,488	$ 152,488	$ 152,488	$ 152,488	$ 152,488

Table 1.3.10 COSA 09B

COST OF SERVICE ANALYSIS

Allocation of Deemer Credit to BPA Program Costs
Test Period October 2008 - September 2013

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
BPA Program Costs Before Deemer Credit	$ 364,798	$ 378,223	$ 384,409	$ 389,970	$ 392,721
Deemer Credit	$ (16,530)	$ -	$ -	$ -	$ -
Net BPA Program Costs	$ 348,268	$ 378,223	$ 384,409	$ 389,970	$ 392,721

Table 1.4.1 ALLOCATE 01

Energy Allocation Factors w/ Res Exch
Average Megawatts

	2009	2010	2011	2012	2013
Federal Base System					
Total Usage					
Priority Firm..............................	11582	11719	11774	12055	12132
Industrial Firm...........................	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0
Surplus Firm Other....................	640	624	602	195	195
Total...	12223	12344	12377	12250	12327
Federal Base System	0	0	0	0	0
Priority Firm..............................	7916	7950	7936	7810	7856
Industrial Firm...........................	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0
Surplus Firm Other....................	0	0	0	0	0
Total...	7916	7950	7936	7810	7856
Residential Exchange	0	0	0	0	0
Priority Firm..............................	3666	3769	3839	4246	4276
Industrial Firm...........................	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0
Surplus Firm Other....................	502	435	413	31	57
Total...	4167	4204	4252	4277	4333
New Resource	0	0	0	0	0
Priority Firm..............................	0	0	0	0	0
Industrial Firm...........................	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0
Surplus Firm Other....................	142	191	191	165	141
Total...	142	191	191	165	141
Conservation	0	0	0	0	0
Priority Firm..............................	11582	11719	11774	12055	12132
Industrial Firm...........................	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0
Surplus Firm Other....................	640	624	602	195	195
Total...	12223	12344	12377	12250	12327

Table 1.4.2 ALLOCATE 02

Initial Rate Pool Cost Allocation

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
CLASSES OF SERVICE					
Power Rates					
Priority Firm - Preference					
FBS	$ 1,864,068	$ 1,956,547	$ 2,192,604	$ 2,088,425	$ 2,226,363
NR	$ -	$ -	$ -	$ -	$ -
Exchange	$ 1,585,548.6	$ 1,613,247.5	$ 1,652,602.6	$ 1,834,880.2	$ 1,848,260.9
conservation	$ 144,499	$ 166,160	$ 175,350	$ 171,745	$ 182,166
BPA programs	$ 330,023	$ 359,090	$ 365,704	$ 383,763	$ 386,508
Total	$ 3,924,138	$ 4,095,044	$ 4,386,261	$ 4,478,813	$ 4,643,297
Industrial Firm Power					
FBS	$ -	$ -	$ -	$ -	$ -
NR	$ 0.0132	$ 0.0132	$ 0.0140	$ 0.0594	$ 0.0601
Exchange	$ 0.0349	$ 0.0307	$ 0.0304	$ 0.0071	$ 0.0129
conservation	$ 0.0013	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0015
BPA programs	$ 0.0029	$ 0.0032	$ 0.0032	$ 0.0033	$ 0.0033
Total	$ 0.0523	$ 0.0485	$ 0.0492	$ 0.0712	$ 0.0778
New Resources Firm					
FBS	$ -	$ -	$ -	$ -	$ -
NR	$ 0.0132	$ 0.0132	$ 0.0140	$ 0.0594	$ 0.0601
Exchange	$ 0.0349	$ 0.0307	$ 0.0304	$ 0.0071	$ 0.0129
conservation	$ 0.0013	$ 0.0015	$ 0.0015	$ 0.0015	$ 0.0015
BPA programs	$ 0.0029	$ 0.0032	$ 0.0032	$ 0.0033	$ 0.0033
Total	$ 0.0523	$ 0.0485	$ 0.0492	$ 0.0712	$ 0.0778
Surplus Firm Power					
FBS	$ -	$ -	$ -	$ -	$ -
NR	$ 82,008	$ 79,964	$ 82,187	$ 112,616	$ 113,875
Exchange	$ 216,904	$ 186,280	$ 177,799	$ 13,401	$ 24,496
conservation	$ 7,989	$ 8,854	$ 8,969	$ 2,778	$ 2,928
BPA programs	$ 18,245	$ 19,133	$ 18,704	$ 6,207	$ 6,213
Total	$ 325,146	$ 294,230	$ 287,659	$ 135,002	$ 147,513
Total Revenue Requirement	$ 4,249,284	$ 4,389,274	$ 4,673,920	$ 4,613,815	$ 4,790,810

Table 1.5.1

Rate Design Study

Allocation of Secondary and Other Revenue Credits
Test Period October 2008 - September 2013

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Forecast of Gross Secondary Revenues	**$ 774,239**	**$ 755,752**	**$ 822,323**	**$ 861,380**	**$ 906,255**
7b3 Costs Allocated to Secondary Revenues	**$ (205,293)**	**$ (202,779)**	**$ (204,249)**	**$ (193,336)**	**$ (193,693)**
Secondary Revenues After 7b3 Allocation	**$ 568,946**	**$ 552,974**	**$ 618,074**	**$ 668,044**	**$ 712,563**

Allocation of Secondary Revenues Credit	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Priority Firm..	$ (568,946)	$ (552,974)	$ (618,074)	$ (668,044)	$ (712,563)
Industrial Firm...	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -	$ -
Total..	**$ (568,946)**	**$ (552,974)**	**$ (618,074)**	**$ (668,044)**	**$ (712,563)**

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Total Other Revenue Credits	**$ 193,087**	**$ 195,202**	**$ 195,437**	**$ 193,587**	**$ 195,103**

Allocation of Other Revenue Credits	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Priority Firm..	$ (193,087)	$ (195,202)	$ (195,437)	$ (193,587)	$ (195,103)
Industrial Firm...	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -	$ -
Total..	**$ (193,087)**	**$ (195,202)**	**$ (195,437)**	**$ (193,587)**	**$ (195,103)**

Table 1.5.2

Rate Design Study

Surplus Firm Power Revenues (Surplus)/Shortfall
Test Period October 2008 - September 2013

FPS (Surplus)/Shortfall	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Costs allocated to FPS contract sales	$ 325,146	$ 294,230	$ 287,659	$ 135,002	$ 147,513
Expected Revenue from FPS contract sales	$ (83,106)	$ (85,588)	$ (76,974)	$ (25,432)	$ (25,289)
FPS Pre-Sub Contract Revenue	$ (41,165)	$ (47,821)	$ (45,472)	$ (1,272)	$ (1,272)
(Surplus)/Shortfall	**$ 200,874**	**$ 160,821**	**$ 165,214**	**$ 108,298**	**$ 120,952**
Secondary Revenues allocated to FPS	$ -	$ -	$ -	$ -	$ -
Revenue Credits allocated to FPS	$ -	$ -	$ -	$ -	$ -
FPS (Surplus)/Shortfall	**$ 200,874**	**$ 160,821**	**$ 165,214**	**$ 108,298**	**$ 120,952**

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

Allocation of FPS (Surplus)/Shortfall	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Priority Firm..	$ 200,874	$ 160,821	$ 165,214	$ 108,298	$ 120,952
Industrial Firm...	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ (200,874)	$ (160,821)	$ (165,214)	$ (108,298)	$ (120,952)
Total..	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Table 1.5.3

Rate Design Study

Summary of Initial Allocations
Test Period October 2008 - September 2013

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation of Revenue Requirement					
Priority Firm..	$ 3,924,138	$ 4,095,044	$ 4,386,261	$ 4,478,813	$ 4,643,297
Industrial Firm..	$ 0.05225	$ 0.04849	$ 0.04915	$ 0.07124	$ 0.07783
New Resource Firm...	$ 0.05225	$ 0.04849	$ 0.04915	$ 0.07124	$ 0.07783
Surplus Firm Other..	$ 325,146	$ 294,230	$ 287,659	$ 135,002	$ 147,513
Total...	$ 4,249,284	$ 4,389,274	$ 4,673,920	$ 4,613,815	$ 4,790,810
Allocation of Secondary Revenues Credit					
Priority Firm..	$ (568,946)	$ (552,974)	$ (618,074)	$ (668,044)	$ (712,563)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -
New Resource Firm...	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -	$ -
Total...	$ (568,946)	$ (552,974)	$ (618,074)	$ (668,044)	$ (712,563)
Allocation of other Revenues Credits					
Priority Firm..	$ (193,087)	$ (195,202)	$ (195,437)	$ (193,587)	$ (195,103)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -
New Resource Firm...	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -	$ -
Total...	$ (193,087)	$ (195,202)	$ (195,437)	$ (193,587)	$ (195,103)
Allocation of FPS (Surplus)/Shortfall					
Priority Firm..	$ 200,874	$ 160,821	$ 165,214	$ 108,298	$ 120,952
Industrial Firm..	$ -	$ -	$ -	$ -	$ -
New Resource Firm...	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ (200,874)	$ (160,821)	$ (165,214)	$ (108,298)	$ (120,952)
Total...	$ -	$ -	$ -	$ -	$ -

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Low Density Discount					
Priority Firm..	$ 24,860	$ 24,860	$ 24,860	$ 24,860	$ 24,860
Irrigation Rate Mitigation.....................................					
Priority Firm..	$ 12,036	$ 12,036	$ 12,036	$ 12,036	$ 12,036

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Initial Allocation					
Priority Firm..	$ 3,399,875	$ 3,544,586	$ 3,774,860	$ 3,762,376	$ 3,893,479
Industrial Firm..	$ 0.05225	$ 0.04849	$ 0.04915	$ 0.07124	$ 0.07783
New Resource Firm...	$ 0.05225	$ 0.04849	$ 0.04915	$ 0.07124	$ 0.07783
Surplus Firm Other..	$ 124,271	$ 133,409	$ 122,446	$ 26,705	$ 26,561
Total...	$ 3,524,147	$ 3,677,995	$ 3,897,305	$ 3,789,080	$ 3,920,040

Table 1.5.4

Rate Design Study

7(c)(2) Delta Calculation
Test Period October 2008 - September 2013

		FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
1	IP Allocated Costs	$ 0.05225	$ 0.04849	$ 0.04915	$ 0.07124	$ 0.07783
2	IP Revenues @ Net Margin	$ 0.00050	$ 0.00050	$ 0.00050	$ 0.00050	$ 0.00050
3	adjustment	$ (0.00035)	$ (0.00035)	$ (0.00033)	$ (0.00035)	$ (0.00034)
4	IP Marginal Cost Rate Revenues	$ 0.04630	$ 0.04629	$ 0.04630	$ 0.04643	$ 0.04630
5	PF Marginal Cost Rate Revenues	$ 5,395,366	$ 5,456,674	$ 5,486,214	$ 5,617,915	$ 5,641,272
6	PF Allocated Energy Costs	$ 3,399,875	$ 3,544,586	$ 3,774,860	$ 3,762,376	$ 3,893,479
7	Numerator: 1-2-3-((4/5)*6)	0.02293	0.01826	0.01712	0.04000	0.04572
8						
9	PF Allocation Factor for Delta	11,582	11,719	11,774	12,055	12,132
10	NR Allocation Factor for Delta	0.000	0.000	0.000	0.000	0.000
11	Total Allocation Factors for Delta	11,582	11,719	11,774	12,055	12,132
12	Denominator: 1.0 + ((9/11)*(4/5))	1.0000	1.0000	1.0000	1.0000	1.0000
13						
14	DELTA: (7/12)	**0.02293**	**0.01826**	**0.01712**	**0.04000**	**0.04572**

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

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
IP-PF Linc Allocation....................					
Priority Firm.....................................	$ 0.02293	$ 0.01826	$ 0.01712	$ 0.04000	$ 0.04572
Industrial Firm..................................	$ (0.02293)	$ (0.01826)	$ (0.01712)	$ (0.04000)	$ (0.04572)
New Resource Firm..........................	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Surplus Firm Other...........................	$ -	$ -	$ -	$ -	$ -
Total..	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation after Linc......................					
Priority Firm Preference....................	$ 2,176,569	$ 2,272,915	$ 2,411,719	$ 2,427,620	$ 2,502,946
Priority Firm Exchange.....................	$ 1,223,306	$ 1,271,671	$ 1,363,141	$ 1,334,755	$ 1,390,533
Industrial Firm..................................	$ 0.02932	$ 0.03023	$ 0.03203	$ 0.03125	$ 0.03212
New Resource Firm..........................	$ 0.05225	$ 0.04849	$ 0.04915	$ 0.07124	$ 0.07783
Surplus Firm Other...........................	$ 124,271	$ 133,409	$ 122,446	$ 26,705	$ 26,561
Total..	$ 3,524,147	$ 3,677,995	$ 3,897,305	$ 3,789,080	$ 3,920,040

Table 1.5.5

RDS 23

RATE DESIGN STUDY

Industrial Firm Power Floor Rate Calculation
Test Period October 2008 - September 2009
($ Thousands)

		A	B	C	D	E	F
		DEMAND		ENERGY		Customer	Total/
		Winter (Dec-Apr)	Summer (May-Nov)	Winter (Sep-Mar)	Summer (Apr-Aug)	Charge	Average
1	IP Billing Determinants	0.001	0.001	0.001	0.000	0.001	0.001
2	IP-83 Rates	4.62	2.21	14.70	12.20	7.34	
3	Revenue	0.002	0.002	0.007	0.004	0.009	0.025
4							
5	Exchange Adj Clause for OY 1985						
6	New ASC Effective Jul 1, 1984						
7	Actual Total Exchange Cost (AEC)	938,442					
8	Actual Exchange Revenue (AER)	772,029					
9	Forecasted Exchange Cost (FEC)	1,088,690					
10	Forecasted Exchange Revenue (FER)	809,201					
11	Total Under/Over-recovery (TAR)						
12	(TAR=(AEC-AER)-(FEC-FER))	(113,076)					
13	Exchange Cost Percentage for IP (ECP)	0.521					
14	Rebate or Surcharge for IP (CCEA=TAR*ECP)	(58,913)					
15	OY 1985 IP Billing Determinants	24,368					
16							
17	OY 1985 DSI Transmission Costs	92,960					
18							
19	Adjustment for Transmission Costs	(3.81)					
20	Adjustment for the Exchange (mills/kWh)	(2.42)					
21	Adjustment for the Deferral (mills/kWh)	(0.90)					
22	IP-83 Average Rate (mills/kWh)	28.11					
23	Floor Rate (mills/kWh)	20.98					

1 Demand billing determinants are the test period DSI load expressed in noncoincidental demand MWs.
15 Billing determinants as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 82).
17 Transmission Costs as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 80).
19 Line 17 / Line 15
20 Line 14 / Line 15
21 1985 Final Rate Proposal (WP-85-FS-BPA-08A, p. 15).
22 Line 3, Col F / Line 1, Col F
23 IP-83 Avg Rate adjusted for the effects of the Exchange and Deferral, Lines 19 + 20 + 21 + 22

Table 1.5.6

RDS 24

RATE DESIGN STUDY

Industrial Firm Power Floor Rate Test
Test Period October 2008 - September 2009
($ Thousands)

		A	B	C	D	E	F
		Unbundled Requirements Products	Transmission Total	Generation Demand Total	Energy Total	Total	Average Rate
1	IP Billing Determinants				0.001		
2	Floor Rate (mills/kWh)				20.98		
3	Value of Reserves Credit (mills/kWh)						
4	Revenue at Floor Rate Less VOR Credit				0.018	0.018	20.98
5	IP Revenue Under Proposed Rates	0	0	0.002	0.028	0.030	34.50
6	Difference					0	

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

Table 1.6 RDS 50

Rate Design Study

Calculation of PF Preference Rate Components
Fiscal Year 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	1.91	2.04	2.14	1.82	1.85	1.72	1.62	1.34	1.23	1.50	1.76	1.82

PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy		
HLH	4,677	5,081	6,066	6,141	5,587	5,613	5,092	4,222	4,273	4,270	4,623	4,639	98601	98601	11256
LLH	2,870	3,362	3,777	4,083	3,620	3,567	3,117	2,850	2,584	2,773	2,766	2,947			
Demand	14,242	15,515	17,339	18,254	17,509	15,094	14,046	11,465	11,303	11,950	12,241	12,898			

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 249,477	$ 320,265	$ 401,115	$ 363,111	$ 331,138	$ 319,120	$ 240,148	$ 176,328	$ 175,956	$ 211,396	$ 252,543	$ 263,591	$ 5,092,867	$ 3,080,453	60.49%
LLH	$ 132,230	$ 174,855	$ 206,943	$ 204,192	$ 189,632	$ 179,124	$ 126,435	$ 101,306	$ 80,810	$ 113,863	$ 129,639	$ 149,651			
Demand	$ 27,203	$ 31,651	$ 37,105	$ 33,223	$ 32,391	$ 25,962	$ 22,755	$ 15,363	$ 13,902	$ 17,925	$ 21,544	$ 23,474	$ 302,499	$ 302,499	100.00%
												LV Revenue	$ 13,805	$ 16,924	122.59%
													$ 5,409,171	$ 3,399,875	

PF rates	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
HLH	**32.26**	**38.12**	**40.00**	**35.77**	**35.85**	**34.39**	**28.52**	**25.26**	**24.90**	**29.94**	**33.04**	**34.37**
LLH	**27.87**	**31.46**	**33.14**	**30.25**	**31.69**	**30.37**	**24.53**	**21.50**	**18.91**	**24.84**	**28.35**	**30.71**
Demand	**1.91**	**2.04**	**2.14**	**1.82**	**1.85**	**1.72**	**1.62**	**1.34**	**1.23**	**1.50**	**1.76**	**1.82**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 150,892	$ 193,700	$ 242,630	$ 219,651	$ 200,307	$ 193,046	$ 145,232	$ 106,649	$ 106,409	$ 127,847	$ 152,742	$ 159,428	$ 3,080,402
LLH	$ 79,980	$ 105,772	$ 125,160	$ 123,521	$ 114,707	$ 108,341	$ 76,461	$ 61,266	$ 48,871	$ 68,873	$ 78,407	$ 90,510	
Demand	$ 27,203	$ 31,651	$ 37,105	$ 33,223	$ 32,391	$ 25,962	$ 22,755	$ 15,363	$ 13,902	$ 17,925	$ 21,544	$ 23,474	$ 302,499
												LV Revenue	$ 13,805
													$ 3,396,706

Unbifurcated PF Average Rate

Energy Costs	**$ 3,080,453**	**31.24**
Demand Costs	**$ 302,499**	**3.07**
Unbundled Cost	**$ 16,924**	**0.17**
Total	**$ 3,399,875**	**34.48**
Billing Determinants	**98601**	

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2. 7(b)(2) CASE RATES ANALYSIS MODEL

Description of Ratemaking Tables

7(b)(2) Rate Test 7(b)(2) Case

Table 2.1 (7b2 Sales_01)
7(b)(2) Case Load Forecast, FY2009-13.
GWh energy sales and peak kW/mo. demand amounts for each month of the 7(b)(2) Rate Test Period FY 2009-2013. These billing determinants are used to calculate PF Preference rates and revenues for the rate test period. For the 7(b)(2) Case, PF Preference sales assume no programmatic conservation has been achieved and DSI load within or adjacent to 7(b)(2) customer service areas will be served by those customers.

Table 2.2.1 (7B2 Resource_01)
Section 7(b)(2) Load Resource Balance Calculation, FY2009-13.
Table starts with the FBS resource from the Program Case used to serve posted rates load. Transmission losses are subtracted. The amount of Program Case FBS used to serve FPS load for contract not in force at the time of the Regional Power Act is added. The 7(b)(2) Case PF load is then subtracted to yield the amount of resource needed from the 7(b)(2) resource stack.

Table 2.2.2 (7B2 Resource_02)
Example of 7(b)(2) Resource Stack
Table lists and example of the 7(b)(2) resources in order of least cost first. Resources include those that are owned or purchased by 7(b)(2) customers and are not dedicated to serve regional loads under 5(b). Programmatic conservation for FY1999-2013 are also included.

Table 2.2.3 (7B2 Resource_03)
7(b)(2) New Resource Calculator.
Table lists the cumulative 7(b)(2) resources needed for each year of the test period and the last resource taken from the resource stack to satisfy that need. Total aMWs and costs of resources brought on per year are listed. A remainder amount of load from the acquisition of resources is listed along with the extra secondary revenue assumed to be recovered from the sale of the remainder power in the market. The net cost of the additional resources taken from the stack is calculated and is included in the revenue requirement for each year in the rate test period.

Table 2.3.1 to Table 2.3.5 (COSA_06)
Itemized Revenue Requirements, FY2009-13.
Power Business Line (PBL) revenue requirements for each FY during the rate test period

Table 2.3.6 (COSA_08)
Classified Revenue Requirement, FY2009.
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.

Table 2.3.7 (COSA_09)
Functionalized Revenue Credits, FY2009-13.
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.

Table 2.4.1 (ALLOCATE 01)
Energy Allocation Factors (EAF) , FY2009-13.
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.

Table 2.4.2 (ALLOCATE 02) *Initial Rate Pool Cost Allocation, FY2009-13.*
Table shows the initial allocation of the revenue requirement costs from the COSA to rate pools using the EAFs from table ALLOCATE 01.

Table 2.5.1 (RDS_11)
Allocation of Secondary Revenues and Other Revenue Credits, FY2009-13.
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.

Table 2.5.2 (RDS_17)
Calculation of FPS (Surplus)/Shortfall, FY2009-13.
Table calculates the firm surplus sale revenue (surplus)/shortfall. 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.

Description of Ratemaking Tables
7(b)(2) Rate Test 7(b)(2) Case

Table 2.5.3 (RDS_19)
Summary of Initial Cost Allocations, FY2009-13.
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.

Table 2.6 (RDS_50)
Calculation of 7(b)(2) Case PF Preference Rate Components, FY2009.
Table calculates 7(b)(2) Case PF rates. Marginal cost rates are scaled down to produce rates that recover costs allocated to PF energy. Example shown is for FY 2009.

Table 2.1 7b2 Sales 01

7(b)(2) Case Load Forecast

(The forecast has been adjusted for conservation resources brought on from resource stack.)

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
2009	HLH	3075	3260	3730	3556	3206	3333	2970	2888	3113	3136	3136	2831	38235	7258
	LLH	1900	2318	2465	2388	2110	2192	1902	2016	1953	2133	2023	1945	25345	
	Demand	8906	9880	10212	10164	10117	9358	8297	7723	8003	8169	7837	7569	106235	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	3117	3291	3826	3520	3220	3388	2963	2966	3232	3271	3052	2753	38598	7320
	LLH	1921	2332	2521	2451	2107	2136	1901	2065	2024	2220	1964	1886	25528	
	Demand	9076	10010	10511	10258	10186	9405	8327	7964	8344	8556	7650	7389	107675	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	3103	3382	3859	3557	3252	3420	2918	2894	3158	3248	3114	2772	38677	7328
	LLH	1977	2290	2545	2470	2124	2152	1869	2009	1975	2268	1935	1902	25516	
	Demand	9217	10116	10646	10395	10322	9528	8232	7796	8182	8643	7721	7474	108272	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	3172	3462	3944	3650	3474	3486	3014	3106	3439	3373	3203	2802	40125	7597
	LLH	2013	2330	2588	2518	2234	2189	1991	2081	2177	2342	1984	1982	26429	
	Demand	9595	10558	11060	10826	10769	9906	8793	8684	8759	9122	8149	7799	114022	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	3244	3498	3928	3757	3388	3486	3098	3079	3351	3442	3248	2843	40361	7636
	LLH	1992	2350	2664	2497	2208	2264	1977	2062	2171	2328	2010	2008	26531	
	Demand	9735	10705	11212	11002	10939	10067	8941	8629	8641	9237	8282	7930	115320	

Section 7(b)(2) PF Load includes any within/adjacent DSI Load and additional load due to unrealized conservation programs

Table 2.2.1 7b2 Resource_01

Section 7(b)(2) Load Resource Balance Calculation

	2009	2010	2011	2012	2013
FBS Serving Posted Rates Load in Program Case	7276.1	7325.6	7333.4	7614.6	7660.7
Long-Term Contracts Not in Force at time of Act w/losses	91.6	94.7	94.7	77.2	77.2
FBS Available to Serve Load in 7(b)(2) Case	7367.7	7420.2	7428.0	7691.8	7737.8
7(b)(2) PF Load w/losses	7734.5	7874.9	7923.4	8220.0	8281.1
Resources Needed From Resource Stack w/losses	**366.8**	**454.7**	**495.4**	**528.3**	**543.3**

Table 2.2.2 7b2 Resource_02

All Costs are in 1980 dollars **Example of 7(b)(2) Resource Stack**

A Project		B Nameplate (MW)	C Interest Rate (%)	D Capital Investment ($ooo)	E Annual O & M ($ooo)	F Annual Fuel ($ooo)	G Year Available	H Capacity Factor	I Life	J Annual Capital Cost ($ooo)	K Total Discounted Capital Cost ($ooo)	L Total Discounted O & M and Fuel ($ooo)	M Total Cost Dollars per AMW ($)	M Total Cost Mills per KWH
BPA & Public resources														
*** The following resources are listed least cost first														
WANAPAM 1963 ND	1963	10.00	0.00	0	581	0	2009	100	70	0	0	9,611	13,729	1.57
PRIEST RAPIDS 1959 ND	1959	17.70	0.00	0	1,075	0	2009	100	70	0	0	17,779	14,349	1.64
BOARDMAN PUBLIC ND	1980	49.71	0.00	0	4453	0	2009	100	60	1,551	25,286	72,614	32,823	3.75
BPA PROG CONS	2004	31.0	4.53	9,368	7,627	0	2009	100	15	874	8,523	7,627	34,731	3.96
BPA PROG CONS	2001	18.5	4.53	29	10,238	0	2009	100	15	3	27	10,238	36,991	4.22
BPA PROG CONS	2000	14.7	4.53	183	8,092	0	2009	100	15	17	166	8,092	37,452	4.28
IDAHO FALLS ND	1982	18.5	0.00	0	2,590	0	2009	100	60	0	0	42,229	38,044	4.34
BPA PROG CONS	2006	30.2	4.53	6,785	12,697	0	2009	100	15	633	6,173	12,697	41,655	4.76
BPA PROG CONS	1999	30.3	4.53	10,576	11,074	0	2009	100	15	987	9,621	11,074	45,534	5.20
BPA PROG CONS	2007	28.5	4.53	4,726	17,122	0	2009	100	15	441	4,299	17,122	50,109	5.72
BPA PROG CONS	2003	24.7	4.53	11,323	8,547	0	2009	100	15	1,056	10,301	8,547	50,871	5.81
BPA PROG CONS	2005	20.0	4.53	6,898	10,498	0	2009	100	15	644	6,276	10,498	55,912	6.38
BPA PROG CONS	2002	25.7	4.53	14,231	8,643	0	2009	100	15	1,328	12,947	8,643	56,006	6.39
COWLITZ FALLS	1994	26.0	4.25	0	0	0	2009	100	60	6,498	105,958	0	67,922	7.75
BPA PROG CONS	2008	34.7	4.53	6,463	30,904	0	2009	100	15	603	5,880	30,904	70,671	8.07
BPA PROG CONS	2009	34.7	4.53	13,517	31,228	0	2009	100	15	1,261	12,297	31,228	83,622	9.55
BPA PROG CONS	2013	39.5	4.53	21,864	34,863	0	2009	100	15	2,040	19,892	34,863	92,412	10.55
BPA PROG CONS	2011	39.5	4.53	22,764	34,758	0	2009	100	15	2,124	20,710	34,758	93,618	10.69
BPA PROG CONS	2012	39.5	4.53	22,308	35,273	0	2009	100	15	2,081	20,295	35,273	93,786	10.71
WAUNA-Steam-Cogen.	1996	23.0	0.00	0	4,711	0	2009	100	30	0	0	65,269	94,592	10.80
BPA PROG CONS	2010	39.5	4.53	23,206	35,142	0	2009	100	15	2,165	21,112	35,142	94,944	10.84
BILLING CREDITS	1996	11.8	0.00	0	2434	0	2009	100	30	0	0	33,716	95,242	10.87
NINE CANYON WIND PROJ.	2008	13.5	0.00	0	3,201	0	2009	100	35	0	0	46,737	98,769	11.27

Table 2.2.3

7(b)(2) Resource Calculator

Rate Year	AMW needed.	Last Res. Added.	Total New Res.	Cost of New Res. 1/	Remainder	Additional Secondary	Net Cost New Res.
2009	366.8	Resource 15	387.7	$ 104,635	20.9	$ 3,502	$ 101,133
2010	454.7	Resource 17	464.1	$ 139,526	9.4	$ 2,086	$ 137,441
2011	495.4	Resource 18	504.7	$ 159,380	9.4	$ 2,154	$ 157,226
2012	528.3	Resource 19	545.4	$ 179,772	17.1	$ 4,032	$ 175,740
2013	543.3	Resource 19	545.4	$ 180,214	2.1	$ 498	$ 179,716

1/ Costs reflect the effect of deferring the first-year expensed portion of conservation resource costs and amortizing/financing them over seven years.

			AMW output	Cum. output	Annual Costs 80$s	Cum. Costs 80$s	Annual Costs 2nd Yr.	Cum. Costs 2nd Yr.
Resource 01	WANAPAM 1963 ND	1963	10	10	$ 581	$ 581	581	$ 581
Resource 02	PRIEST RAPIDS 1959 ND	1959	18	28	$ 1,075	$ 1,656	1075	$ 1,656
Resource 03	BOARDMAN PUBLIC ND	1980	50	77	$ 6,004	$ 7,660	6004	$ 7,660
Resource 04	BPA PROG CONS	2004	32	109	$ 8,501	$ 16,161	874	$ 8,534
Resource 05	BPA PROG CONS	2001	19	128	$ 10,241	$ 26,402	3	$ 8,536
Resource 06	BPA PROG CONS	2000	15	143	$ 8,109	$ 34,511	17	$ 8,553
Resource 07	IDAHO FALLS ND	1982	19	162	$ 2,590	$ 37,101	2590	$ 11,143
Resource 08	BPA PROG CONS	2006	31	193	$ 13,330	$ 50,431	633	$ 11,776
Resource 09	BPA PROG CONS	1999	31	224	$ 12,060	$ 62,492	987	$ 12,763
Resource 10	BPA PROG CONS	2007	29	254	$ 17,563	$ 80,055	441	$ 13,204
Resource 11	BPA PROG CONS	2003	25	279	$ 9,603	$ 89,658	1056	$ 14,260
Resource 12	BPA PROG CONS	2005	21	300	$ 11,141	$ 100,799	644	$ 14,904
Resource 13	BPA PROG CONS	2002	26	326	$ 9,971	$ 110,770	1328	$ 16,232
Resource 14	COWLITZ FALLS	1994	26	352	$ 6,498	$ 117,268	6498	$ 22,730
Resource 15	BPA PROG CONS	2008	36	388	$ 31,507	$ 148,775	603	$ 23,333
Resource 16	BPA PROG CONS	2009	36	423	$ 32,489	$ 181,265	1261	$ 24,594
Resource 17	BPA PROG CONS	2013	41	464	$ 36,903	$ 218,168	2040	$ 26,634
Resource 18	BPA PROG CONS	2011	41	505	$ 36,882	$ 255,050	2124	$ 28,758
Resource 19	BPA PROG CONS	2012	41	545	$ 37,355	$ 292,404	2081	$ 30,839
Resource 20	WAUNA-Steam-Cogen.	1996	23	568	$ 4,711	$ 297,115	4711	$ 35,551
Resource 21	BPA PROG CONS	2010	41	609	$ 37,307	$ 334,423	2165	$ 37,716
Resource 22	BILLING CREDITS	1996	12	621	$ 2,434	$ 336,857	2434	$ 40,150
Resource 23	NINE CANYON WIND PROJ.	2008	14	634	$ 3,201	$ 340,058	3201	$ 43,351
Resource 24	TCL HOOD ST ND*	0	0	634	$ 163	$ 340,221	163	$ 43,514
Resource 25	TCL PEC 66 ND*	0	0	634	$ 163	$ 340,384	163	$ 43,677
Resource 26	TCL RD SMITH ND*	0	0	634	$ 300	$ 340,683	300	$ 43,976
Resource 27	TCL MAIN CANAL ND*	0	0	634	$ 818	$ 341,501	818	$ 44,794
Resource 28	BONNER'S FRY 1 & 2 ND	0	0	634	$ 210	$ 341,711	210	$ 45,004
Resource 29	TCL SUMMER FALLS ND*	0	0	634	$ 3,073	$ 344,784	3073	$ 48,077
Resource 30	DALLES DAM FISHWAY ND	1992	0	634	$ 228	$ 345,012	228	$ 48,305
Resource 31	BPA PROG CONS	1998	0	634	$ 17,728	$ 362,740	1334	$ 49,639
Resource 32	BPA PROG CONS	1997	0	634	$ 15,604	$ 378,344	1692	$ 51,331
Resource 33	BPA PROG CONS	1989	0	634	$ 11,606	$ 389,950	2898	$ 54,229
Resource 34	BPA PROG CONS	1988	0	634	$ 8,467	$ 398,417	3818	$ 58,047
Resource 35	BPA PROG CONS	1990	0	634	$ 25,434	$ 423,851	2194	$ 60,241
Resource 36	BPA PROG CONS	1991	0	634	$ 26,197	$ 450,048	2672	$ 62,913
Resource 37	BPA PROG CONS	1987	0	634	$ 7,645	$ 457,694	4815	$ 67,728

Table 2.3.1 7B2 COSA 06 FY2009

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2009

FY 2009

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,345,120	134,294	17,153	411,799	563,246
4. BPA FISH & WILDLIFE PROGRAM	176,547	4,436	567	231,929	236,932
5. TROJAN				2,500	2,500
6. WNP #1				169,746	169,746
7. WNP #2				518,334	518,334
8. WNP #3				150,817	150,817
9. SYSTEM AUGMENTATION				161,123	161,123
10. BALANCING POWER PURCHASES				74,835	74,835
11. TOTAL FEDERAL BASE SYSTEM	5,521,667	138,730	17,720	1,721,083	1,877,533
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	26,824	673	86	189,006	189,765
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	26,824	673	86	189,006	189,765
23. TOTAL GENERATION COSTS	5,548,491	139,403	17,806	1,910,089	2,067,298
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,728	123,728
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				50,370	50,370
28. TOTAL TRANSMISSION COSTS				175,098	175,098
29. TOTAL PBL REVENUE REQUIREMENT		139,403	17,806	2,085,187	2,242,396

Table 2.3.2

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2010

FY 2010

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,435,317	145,623	107,164	438,362	691,149
4. BPA FISH & WILDLIFE PROGRAM	213,196	5,712	4,203	264,462	274,377
5. TROJAN				2,200	2,200
6. WNP #1				163,422	163,422
7. WNP #2				502,112	502,112
8. WNP #3				139,538	139,538
9. SYSTEM AUGMENTATION				158,272	158,272
10. BALANCING POWER PURCHASES				83,902	83,902
11. TOTAL FEDERAL BASE SYSTEM	5,648,513	151,335	111,367	1,752,270	2,014,972
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	29,975	803	591	201,721	203,115
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	29,975	803	591	201,721	203,115
23. TOTAL GENERATION COSTS	5,678,488	152,138	111,958	1,953,990	2,218,086
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,728	123,728
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				50,690	50,690
28. TOTAL TRANSMISSION COSTS				175,418	175,418
29. TOTAL PBL REVENUE REQUIREMENT		152,138	111,958	2,129,408	2,393,504

Table 2.3.3 7B2 COSA 06 FY2011

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2011

FY 2011

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,474,513	154,459	90,041	457,965	702,465
4. BPA FISH & WILDLIFE PROGRAM	252,385	7,121	4,151	273,239	284,511
5. TROJAN				2,300	2,300
6. WNP #1				165,333	165,333
7. WNP #2				586,834	586,834
8. WNP #3				164,683	164,683
9. SYSTEM AUGMENTATION				276,217	276,217
10. BALANCING POWER PURCHASES				69,169	69,169
11. TOTAL FEDERAL BASE SYSTEM	5,726,898	161,580	94,192	1,995,740	2,251,512
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	35,155	991	579	207,132	208,702
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	35,155	991	579	207,132	208,702
23. TOTAL GENERATION COSTS	5,762,053	162,571	94,771	2,202,872	2,460,214
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,728	123,728
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				51,340	51,340
28. TOTAL TRANSMISSION COSTS				176,068	176,068
29. TOTAL PBL REVENUE REQUIREMENT		162,571	94,771	2,378,940	2,636,282

Table 2.3.4 7B2 COSA 06 FY2012

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2012

FY 2012

	A INVEST BASE	**B NET INT**	**C NET REVS**	**D OPER EXP**	**E TOTAL (B+C+D)**
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,537,070	167,667	0	472,180	639,847
4. BPA FISH & WILDLIFE PROGRAM	279,664	8,468	0	280,676	289,144
5. TROJAN				2,300	2,300
6. WNP #1				190,379	190,379
7. WNP #2				609,051	609,051
8. WNP #3				157,810	157,810
9. SYSTEM AUGMENTATION				101,541	101,541
10. BALANCING POWER PURCHASES				94,626	94,626
11. TOTAL FEDERAL BASE SYSTEM	5,816,734	176,135	0	1,908,564	2,084,699
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	40,088	1,215	0	211,374	212,589
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	40,088	1,215	0	211,374	212,589
23. TOTAL GENERATION COSTS	5,856,822	177,350	0	2,119,938	2,297,288
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,928	123,928
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,428	52,428
28. TOTAL TRANSMISSION COSTS				177,356	177,356
29. TOTAL PBL REVENUE REQUIREMENT		177,350	0	2,297,294	2,474,644

Table 2.3.5 7B2 COSA 06 FY2013

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2013

FY 2013

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,606,593	179,507	51,331	484,958	715,796
4. BPA FISH & WILDLIFE PROGRAM	300,436	9,619	2,751	288,649	301,019
5. TROJAN				2,400	2,400
6. WNP #1				285,566	285,566
7. WNP #2				493,755	493,755
8. WNP #3				172,110	172,110
9. SYSTEM AUGMENTATION				195,624	195,624
10. BALANCING POWER PURCHASES				83,556	83,556
11. TOTAL FEDERAL BASE SYSTEM	5,907,029	189,126	54,082	2,006,619	2,249,827
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	43,723	1,400	400	213,729	215,530
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	43,723	1,400	400	213,729	215,530
23. TOTAL GENERATION COSTS	5,950,752	190,526	54,482	2,220,348	2,465,357
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,928	123,928
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,437	52,437
28. TOTAL TRANSMISSION COSTS				177,365	177,365
29. TOTAL PBL REVENUE REQUIREMENT		190,526	54,482	2,397,713	2,642,721

Table 2.3.6 7B2 COSA 08

COST OF SERVICE ANALYSIS

Classified Revenue Requirement
Fiscal Year 2009

	Total Rev Req	Energy %	Energy Total	Demand %	Demand Total	Load Variance %	Load Variance Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 563,246	90.09%	$ 507,441	8.99%	$ 50,618	0.92%	$ 5,187
4. BPA FISH & WILDLIFE PROGRAM	$ 236,932	91.01%	$ 215,639	8.99%	$ 21,293		
5. TROJAN	$ 2,500	91.01%	$ 2,275	8.99%	$ 225		
6. WNP #1	$ 169,746	91.01%	$ 154,492	8.99%	$ 15,255		
7. WNP #2	$ 518,334	90.09%	$ 466,978	8.99%	$ 46,582	0.92%	$ 4,773
8. WNP #3	$ 150,817	91.01%	$ 137,263	8.99%	$ 13,554		
9. SYSTEM AUGMENTATION	$ 161,123	90.09%	$ 145,159	8.99%	$ 14,480	0.92%	$ 1,484
10. BALANCING POWER PURCHASES	$ 74,835	90.09%	$ 67,420	8.99%	$ 6,725	0.92%	$ 689
11. TOTAL FEDERAL BASE SYSTEM	$ 1,877,533		$ 1,696,668		$ 168,732		$ 12,133
12. NEW RESOURCES							
13. IDAHO FALLS	$ -				$ -		$ -
14. COWLITZ FALLS	$ -		$ -		$ -		$ -
15. OTHER NEW RESOURCES PURCHASES	$ -		$ -		$ -		$ -
16. TOTAL NEW RESOURCES	$ -		$ -		$ -		$ -
17. RESIDENTIAL EXCHANGE	$ -		$ -				
18. CONSERVATION	$ -		$ -		$ -		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 189,765	90.09%	$ 170,964	8.99%	$ 17,054	0.92%	$ 1,748
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	$ 189,765		$ 170,964		$ 17,054		$ 1,748
23. TOTAL GENERATION COSTS	$ 2,067,298		$ 1,867,632		$ 185,786		$ 13,881
24. TRANSMISSION COSTS							
25. TBL TRANSMISSION/ANCILLARY SERVICES	$ 123,728	100.00%	$ 123,728				
26. 3RD PARTY TRANS/ANCILLARY SERVICES	$ 1,000	100.00%	$ 1,000				
27. GENERAL TRANSFER AGREEMENTS	$ 50,370	100.00%	$ 50,370				
28. TOTAL TRANSMISSION COSTS	175,098		175,098				
29. TOTAL PBL REVENUE REQUIREMENT	$ 2,242,396		$ 2,042,730		$ 199,666		

Table 2.3.7

COST OF SERVICE ANALYSIS

Revenue Credits

Test Period October 2008 - September 2013

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Downstream Benefits & Storage	$ 8,921	$ 8,921	$ 8,921	$ 8,921	$ 8,571
4(h)(10)(c) Credits	$ 88,480	$ 93,488	$ 93,723	$ 93,710	$ 95,577
Colville & Spokane SettlementsCredit	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600
Network Wind Integration&Shaping	$ 1,933	$ 1,836	$ 1,836	$ -	$ -
Misc. Revenues	$ 3,420	$ 3,420	$ 3,420	$ 3,420	$ 3,420
Green Tags	$ 2,799	$ 1	$ 1	$ -	$ -
Ancillary Product Revenues	$ 79,306	$ 79,306	$ 79,306	$ 79,306	$ 79,306
Reserve Product Revenue	$ 3,630	$ 3,630	$ 3,630	$ 3,630	$ 3,630
Total	$ 193,087	$ 195,202	$ 195,437	$ 193,587	$ 195,103

Table 2.4.1 7B2 ALLOCATE 01

Energy Allocation Factors
Average Megawatts

	2009	2010	2011	2012	2013
Federal Base System					
Total Usage					
Priority Firm...........................	7734	7875	7923	8220	8281
Industrial Firm.......................	0	0	0	0	0
New Resource Firm...............	0	0	0	0	0
Surplus Firm Other................	549	530	508	118	118
Total.....................................	8283	8405	8431	8338	8399
Federal Base System	0	0	0	0	0
Priority Firm...........................	7734	7875	7923	8220	8281
Industrial Firm.......................	0	0	0	0	0
New Resource Firm...............	0	0	0	0	0
Surplus Firm Other................	549	530	508	118	118
Total.....................................	8283	8405	8431	8338	8399
Residential Exchange	0	0	0	0	0
Priority Firm...........................	0	0	0	0	0
Industrial Firm.......................	0	0	0	0	0
New Resource Firm...............	0	0	0	0	0
Surplus Firm Other................	0	0	0	0	0
Total.....................................	0	0	0	0	0
New Resource	0	0	0	0	0
Priority Firm...........................	0	0	0	0	0
Industrial Firm.......................	0	0	0	0	0
New Resource Firm...............	0	0	0	0	0
Surplus Firm Other................	0	0	0	0	0
Total.....................................	0	0	0	0	0
Conservation	0	0	0	0	0
Priority Firm...........................	0	0	0	0	0
Industrial Firm.......................	0	0	0	0	0
New Resource Firm...............	0	0	0	0	0
Surplus Firm Other................	0	0	0	0	0
Total.....................................	8283	8405	8431	8338	8399

Table 2.4.2 7B2 ALLOCATE 02

Initial Rate Pool Cost Allocation

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
CLASSES OF SERVICE					
Power Rates					
Priority Firm - Preference					
FBS	$ 1,847,579	$ 2,016,739	$ 2,263,726	$ 2,228,493	$ 2,395,451
NR	$ -	$ -	$ -	$ -	$ -
Exchange	$ -	$ -	$ -	$ -	$ -
conservation	$ -	$ -	$ -	$ -	$ -
BPA programs	$ 340,691	$ 354,673	$ 361,606	$ 384,435	$ 387,381
Total	$ 2,188,270	$ 2,371,412	$ 2,625,333	$ 2,612,928	$ 2,782,832
Industrial Firm Power					
FBS	$ -	$ -	$ -	$ -	$ -
NR	$ -	$ -	$ -	$ -	$ -
Exchange	$ -	$ -	$ -	$ -	$ -
conservation	$ -	$ -	$ -	$ -	$ -
BPA programs	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -
New Resources Firm					
FBS	$ -	$ -	$ -	$ -	$ -
NR	$ -	$ -	$ -	$ -	$ -
Exchange	$ -	$ -	$ -	$ -	$ -
conservation	$ -	$ -	$ -	$ -	$ -
BPA programs	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -
Surplus Firm Power					
FBS	$ 131,087	$ 135,673	$ 145,012	$ 31,945	$ 34,092
NR	$ -	$ -	$ -	$ -	$ -
Exchange	$ -	$ -	$ -	$ -	$ -
conservation	$ -	$ -	$ -	$ -	$ -
BPA programs	$ 24,172	$ 23,860	$ 23,164	$ 5,511	$ 5,513
Total	$ 155,260	$ 159,533	$ 168,176	$ 37,456	$ 39,605
Total Revenue Requirement	$ 2,343,529	$ 2,530,945	$ 2,793,508	$ 2,650,384	$ 2,822,437

Table 2.5.1 7B2 RDS 11

Rate Design Study

Allocation of Secondary and Other Revenue Credits
Test Period October 2008 - September 2013

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Forecast of Secondary Revenues	**$ 774,239**	**$ 755,752**	**$ 822,323**	**$ 861,380**	**$ 906,255**
Additional Secondary Revenues	$ -	$ -	$ -	$ -	$ -
Total Gross Secondary Revenues	**$ 774,239**	**$ 755,752**	**$ 822,323**	**$ 861,380**	**$ 906,255**

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation of Secondary Revenues Credit					
Priority Firm..	$ (722,945)	$ (708,115)	$ (772,817)	$ (849,206)	$ (893,539)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ (51,294)	$ (47,637)	$ (49,506)	$ (12,173)	$ (12,717)
Total..	**$ (774,239)**	**$ (755,752)**	**$ (822,323)**	**$ (861,380)**	**$ (906,255)**

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Total Other Revenue Credits	**$ 193,087**	**$ 195,202**	**$ 195,437**	**$ 193,587**	**$ 195,103**

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation of Other Revenue Credits					
Priority Firm..	$ (180,295)	$ (182,898)	$ (183,671)	$ (190,851)	$ (192,366)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ (12,792)	$ (12,304)	$ (11,766)	$ (2,736)	$ (2,738)
Total..	**$ (193,087)**	**$ (195,202)**	**$ (195,437)**	**$ (193,587)**	**$ (195,103)**

Table 2.5.2

Rate Design Study

Calculation of FPS (Surplus)/Shortfall
Test Period October 2008 - September 2013

FPS (Surplus)/Shortfall	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Costs allocated to FPS contract sales	$ 155,260	$ 159,533	$ 168,176	$ 37,456	$ 39,605
Expected Revenue from FPS contract sales	$ -	$ -	$ -	$ -	$ -
FPS Pre-Sub Contract Revenue	$ (41,165)	$ (47,821)	$ (45,472)	$ (1,272)	$ (1,272)
(Surplus)/Shortfall	**$ 114,094**	**$ 111,712**	**$ 122,704**	**$ 36,184**	**$ 38,333**
Secondary Revenues allocated to FPS	$ (51,294)	$ (47,637)	$ (49,506)	$ (12,173)	$ (12,717)
Revenue Credits allocated to FPS	$ (12,792)	$ (12,304)	$ (11,766)	$ (2,736)	$ (2,738)
FPS (Surplus)/Shortfall	**$ 50,009**	**$ 51,771**	**$ 61,432**	**$ 21,275**	**$ 22,878**

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

Allocation of FPS (Surplus)/Shortfall	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Priority Firm..	$ 50,009	$ 51,771	$ 61,432	$ 21,275	$ 22,878
Industrial Firm...	$ -	$ -	$ -	$ -	$ -
New Resource Firm......................................	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.......................................	$ (50,009)	$ (51,771)	$ (61,432)	$ (21,275)	$ (22,878)
Total..	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Table 2.5.3 7B2 RDS 19

Rate Design Study

Summary of Initial Cost Allocations
Test Period October 2008 - September 2013

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation of Revenue Requirement					
Priority Firm.......................................	$ 2,188,270	$ 2,371,412	$ 2,625,333	$ 2,612,928	$ 2,782,832
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ 155,260	$ 159,533	$ 168,176	$ 37,456	$ 39,605
Total...	$ 2,343,529	$ 2,530,945	$ 2,793,508	$ 2,650,384	$ 2,822,437
Allocation of Secondary Revenues Credit					
Priority Firm.......................................	$ (722,945)	$ (708,115)	$ (772,817)	$ (849,206)	$ (893,539)
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ (51,294)	$ (47,637)	$ (49,506)	$ (12,173)	$ (12,717)
Total...	$ (774,239)	$ (755,752)	$ (822,323)	$ (861,380)	$ (906,255)
Allocation of other Revenues Credits					
Priority Firm.......................................	$ (180,295)	$ (182,898)	$ (183,671)	$ (190,851)	$ (192,366)
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ (12,792)	$ (12,304)	$ (11,766)	$ (2,736)	$ (2,738)
Total...	$ (193,087)	$ (195,202)	$ (195,437)	$ (193,587)	$ (195,103)
Allocation of FPS (Surplus)/Shortfall					
Priority Firm.......................................	$ 50,009	$ 51,771	$ 61,432	$ 21,275	$ 22,878
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ (50,009)	$ (51,771)	$ (61,432)	$ (21,275)	$ (22,878)
Total...	$ -	$ -	$ -	$ -	$ -

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Low Density Discount					
Priority Firm.......................................	$ 24,860	$ 24,860	$ 24,860	$ 24,860	$ 24,860
Irrigation Rate Mitigation............					
Priority Firm.......................................	$ 12,036	$ 12,036	$ 12,036	$ 12,036	$ 12,036

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Initial Allocation					
Priority Firm.......................................	$ 1,371,934	$ 1,569,066	$ 1,767,173	$ 1,631,041	$ 1,756,702
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ 41,165	$ 47,821	$ 45,472	$ 1,272	$ 1,272
Total...	$ 1,413,099	$ 1,616,887	$ 1,812,644	$ 1,632,313	$ 1,757,975

Table 2.6

Rate Design Study

Calculation of 7(b)(2) Case PF Preference Rate Components
Fiscal Year 2009

VELIZED MARGINAL COSTS OF POWER

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
ergy 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
NTHLY DEMAND	1.91	2.04	2.14	1.82	1.85	1.72	1.62	1.34	1.23	1.50	1.76	1.82

F billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	3,075	3,260	3,730	3,556	3,206	3,333	2,970	2,888	3,113	3,136	3,136	2,831	63581
LLH	1,900	2,318	2,465	2,388	2,110	2,192	1,902	2,016	1,953	2,133	2,023	1,945	
Demand	8,906	9,880	10,212	10,164	10,117	9,358	8,297	7,723	8,003	8,169	7,837	7,569	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs
HLH	$ 163,988	$ 205,473	$ 246,650	$ 210,303	$ 190,028	$ 189,493	$ 140,068	$ 120,616	$ 128,173	$ 155,253	$ 171,312	$ 160,898	$ 3,256,526	$ 1,172,268
LLH	$ 87,529	$ 120,543	$ 135,095	$ 119,408	$ 110,542	$ 110,042	$ 77,166	$ 71,689	$ 61,070	$ 87,592	$ 94,846	$ 98,747		
Demand	$ 17,011	$ 20,154	$ 21,853	$ 18,498	$ 18,717	$ 16,095	$ 13,442	$ 10,349	$ 9,844	$ 12,254	$ 13,793	$ 13,776	$ 185,786	$ 185,786
												LV Revenue	$ 13,881	$ 13,881
													$ 3,456,192	$ 1,371,934

PF rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**19.20**	**22.69**	**23.80**	**21.29**	**21.33**	**20.46**	**16.98**	**15.03**	**14.82**	**17.82**	**19.66**	**20.46**
LLH	**16.59**	**18.72**	**19.72**	**18.00**	**18.86**	**18.07**	**14.60**	**12.80**	**11.26**	**14.78**	**16.87**	**18.28**
Demand	**1.91**	**2.04**	**2.14**	**1.82**	**1.85**	**1.72**	**1.62**	**1.34**	**1.23**	**1.50**	**1.76**	**1.82**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 59,031	$ 73,970	$ 88,772	$ 75,718	$ 68,392	$ 68,198	$ 50,432	$ 43,408	$ 46,134	$ 55,884	$ 61,653	$ 57,931	$ 1,172,213
LLH	$ 31,515	$ 43,389	$ 48,619	$ 42,982	$ 39,795	$ 39,602	$ 27,775	$ 25,811	$ 21,992	$ 31,525	$ 34,135	$ 35,550	
Demand	$ 17,011	$ 20,154	$ 21,853	$ 18,498	$ 18,717	$ 16,095	$ 13,442	$ 10,349	$ 9,844	$ 12,254	$ 13,793	$ 13,776	$ 185,786
												LV Revenue	$ 13,881
													$ 1,371,879

Unbifurcated PF Average Rate

Energy Costs	**$ 1,172,268**	**18.44**
Demand Costs	**$ 185,786**	**2.92**
Unbundled Cost	**$ 13,881**	**0.22**
Total	**$ 1,371,934**	**21.58**
Billing Determinants	**63581**	

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3. 7(b)(2) RATE TEST RESULTS

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Table 3

7(b)(2) Rate Test

Nominal mills/kWh

	Program Case PF Rate	Program Case 7(g) costs	Adjusted Program Case PF Rate	7(b)(2) Case PF Rate
2009	34.48	1.47	33.01	21.58
2010	35.53	1.67	33.86	24.47
2011	37.66	1.75	35.91	27.53
2012	36.56	1.67	34.89	24.51
2013	37.70	1.76	35.94	26.26

Discounted mills/kWh

	Adjusted Program Case PF Rate	7(b)(2) Case PF Rate
2009	30.98	20.25
2010	29.76	21.51
2011	29.54	22.65
2012	26.87	18.87
2013	25.93	18.94

Average Discounted Program Case Rate	28.6
Average Discounted 7(b)(2) Case Rate	20.4
Rate Test Result (Triggers if Positive)	8.20