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

2010 BPA Rate Case
Wholesale Power Rate Final Proposal

SECTION 7(b)(2) RATE TEST STUDY DOCUMENTATION

July 2009

WP-10-FS-BPA-06A

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SECTION 7(B)(2) RATE TEST

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COMMONLY USED ACRONYMS

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
ATC	Accrual to Cash
BAA	Balancing Authority Area
BASC	BPA Average System Cost
Bcf	billion cubic feet
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	combined-cycle combustion turbine
cfs	cubic feet per second
CGS	Columbia Generating Station
CHJ	Chief Joseph
C/M	consumers per mile of line ratio for LDD
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power 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
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DC	direct current
DDC	Dividend Distribution Clause
dec	decremental (pertains to generation movement)
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EAF	energy allocation factor
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc. (formerly Washington Public Power Supply System)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
F&O	financial and operating reports
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	firm energy load carrying capability
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GAAP	Generally Accepted Accounting Principles
GARD	Generation and Reserves Dispatch (computer model)
GCL	Grand Coulee
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	generator step-up transformers
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	heavy load hour
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
IDC	interest during construction
inc	incremental (pertains to generation movement)
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
ISD	incremental standard deviation
ISO	Independent System Operator
JDA	John Day
kaf	thousand (kilo) acre-feet

kcfs	thousand (kilo) cubic feet per second
K/I	kilowatthour per investment ratio for LDD
ksfd	thousand (kilo) second foot day
kV	kilovolt (1000 volts)
kVA	kilo volt-ampere (1000 volt-amperes)
kVAr	kilo-volt ampere reactive
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LGIP	Large Generator Interconnection Procedures
LLH	light load hour
LME	London Metal Exchange
LOLP	loss of load probability
LRA	Load Reduction Agreement
m/kWh	mills per kilowatthour
MAE	mean absolute error
Maf	million acre-feet
MCA	Marginal Cost Analysis
MCN	McNary
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
MOU	Memorandum of Understanding
MRNR	Minimum Required Net Revenue
MVA	mega-volt ampere
MVAr	mega-volt ampere reactive
MW	megawatt (1 million watts)
MWh	megawatthour
NCD	non-coincidental demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries (officially National Marine Fisheries Service)
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council

NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	BPA Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition

SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert
TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

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1. PROGRAM CASE RATES ANALYSIS MODEL

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

Table 1.1.1 (Sales_01)
Total PF Load Forecast, FY2010-15
Gigawatthour (GWh) energy sales and peak megawatt (MW)/mo. demand amounts for each month of the Rate Test Period Fiscal Year (FY) 2010-2015.

Table 1.1.2 (Sales_02)
Total PF Exchange Load Forecast, FY2010-15
GWh energy sales and peak MW/mo. demand amounts for each month of the Rate Test Period FY 2010-2015.

Table 1.1.3 (Sales_03)
Total IP Load Forecast, FY2010-15
GWh energy sales and peak MW/mo. demand amounts for each month of the Rate Test Period FY 2010-2015.

Table 1.1.4 (Sales_04)
Total NR Load Forecast, FY2010-15
GWh energy sales and peak MW/mo. demand amounts for each month of the Rate Test Period FY 2010-2015. (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, FY2010-15.
Forecast of potential exchanging utilities' average system cost (ASC) and exchangeable load.

Table 1.3.1 to Table 1.3.6 (COSA_06)
Itemized Revenue Requirements, FY2010-15.
Power Business Line (PBL) revenue requirements for each FY during the rate test period

Table 1.3.7 (COSA_07)
Functionalization of Residential Exchange Costs, FY2010.
REP costs are functionalized to power to comport with other functionalized costs moving through COSA into the Rate Design Step of the RAM.

Table 1.3.8 (COSA_08)
Classified Revenue Requirement, FY2010.
Generation costs are classified between energy, demand, and load variance for display purposes. All generation 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 1.3.9 (COSA_09)
Functionalized Revenue Credits, FY2010-15.
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 1.3.10 (COSA_09A)
Allocation of EE Revenue Credits to Conservation Costs, FY2010-15.
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 1.4.1 (ALLOCATE 01)
Energy Allocation Factors (EAF), FY2010-15.
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, FY2010-15.
Table shows the initial allocation of the revenue requirement costs from the COSA to rate pools using the EAFs from table ALLOCATE 01.

Table 1.5.1 (RDS_11)
Allocation of Secondary Revenues and Other Revenue Credits, FY2010-15.
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, FY2010-15.
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, FY2010-15.
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 rate pool.

Table 1.5.4 (RDS_21)
7(C)(2) Delta Calculation and Allocation of 7(C)(2) Delta, FY2010-15.
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, FY2010-15.
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 FY2010.
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, FY2010.
Table calculates unbifurcated PF rates. The FY 2009 PF Preference rates are scaled to produce rates that recover costs allocated to PF energy. Example shown is for FY 2010.

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
3								**Table 1.1.1**									Sales 01
4																	
5								**Total PF Load Forecast FY2010-15**									
6																	
7																Total	
8			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
9	**2010**	HLH	2852	3105	3489	3466	3089	3114	2693	2918	2849	2910	3026	2721		61370	7006
10		LLH	1844	2306	2503	2555	2091	2050	1799	2146	1852	2109	1978	1906			
11		Demand	8204	9117	9680	9970	9492	8646	7495	7677	7252	8010	7686	7359			
12			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
13	**2011**	HLH	2837	3190	3517	3496	3114	3143	2648	2847	2777	2934	3100	2745		61447	7014
14		LLH	1910	2274	2522	2574	2106	2068	1768	2091	1803	2120	1941	1921			
15		Demand	8336	9246	9821	10106	9631	8774	7414	7536	7114	8084	7800	7470			
16			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
17	**2012**	HLH	2999	3365	3595	3611	3360	3301	2830	3190	3036	3107	3267	2856		64044	7291
18		LLH	1900	2277	2577	2648	2179	2044	1850	2132	1862	2145	1931	1983			
19		Demand	8492	9331	9937	10384	9742	8880	7727	7791	7346	8175	7907	7464			
20			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
21	**2013**	HLH	3093	3413	3670	3790	3350	3286	2910	3159	2920	3180	3309	2888		64382	7350
22		LLH	1877	2305	2590	2542	2128	2114	1826	2109	1861	2107	1955	2001			
23		Demand	8634	9473	10071	10462	9883	8991	7833	7707	7192	8255	8004	7565			
24			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
25	**2014**	HLH	3127	3451	3718	3854	3409	3341	2956	3271	3069	3241	3310	2986		65611	7490
26		LLH	1894	2327	2620	2583	2164	2147	1853	2180	1953	2144	2032	1981			
27		Demand	8740	9587	10213	10643	10063	9145	7965	8023	7569	8425	8155	7704			
28			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
29	**2015**	HLH	3178	3451	3862	3889	3441	3366	2968	3201	3048	3247	3343	3017		66026	7537
30		LLH	1924	2415	2619	2603	2181	2158	1858	2208	1860	2145	2048	1998			
31		Demand	8891	9746	10450	10751	10171	9242	8012	7999	7418	8462	8258	7803			

Sales 02

Table 1.1.2

Total PF Exchange Load Forecast FY2010-15

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
															Total	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
2010	HLH	1785	2030	2615	2889	2710	2533	2288	1516	1262	1227	1633	2006		38924	4443
	LLH	1080	1167	1470	1896	1719	1530	1308	950	686	692	816	1115			
	Demand	5934	6279	7966	9035	8729	6370	6195	4249	3585	4090	4833	5912			
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
2011	HLH	1795	2038	2622	2887	2710	2534	2323	1552	1307	1274	1678	2044		39366	4494
	LLH	1087	1173	1475	1896	1720	1531	1330	974	713	722	842	1138			
	Demand	5959	6301	7982	9027	8728	6373	6289	4344	3708	4235	4961	6017			
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
2012	HLH	1821	2062	2641	2919	2689	2578	2401	1518	1324	1295	1690	2048		39738	4524
	LLH	1105	1189	1488	1918	1708	1560	1378	953	725	736	851	1142			
	Demand	6035	6371	8041	9121	8338	6484	6498	4249	3754	4293	4991	6027			
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
2013	HLH	1865	2111	2698	2953	2773	2611	2434	1539	1345	1322	1730	2078		40507	4624
	LLH	1133	1219	1522	1941	1762	1581	1398	968	737	753	873	1160			
	Demand	6177	6518	8206	9227	8926	6567	6587	4309	3814	4381	5106	6116			
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
2014	HLH	1852	2146	2736	2986	2802	2626	2406	1665	1428	1398	1820	2165		41437	4730
	LLH	1126	1241	1545	1965	1782	1591	1383	1050	787	800	924	1212			
	Demand	6131	6620	8314	9325	9035	6604	6511	4648	4039	4611	5363	6364			
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
2015	HLH	1958	2194	2760	2970	2772	2630	2398	1781	1594	1568	1910	2146		42554	4858
	LLH	1199	1277	1567	1958	1767	1599	1385	1131	892	910	982	1208			
	Demand	6369	6687	8298	9187	8850	6576	6442	4904	4440	5041	5538	6242			

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
3								**Table 1.1.3**									Sales 03
4																	
5								**Total IP Load Forecast FY2010-15**									
6																	
7																Total	
8			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
9	**2010**	HLH	174	154	167	161	154	174	167	161	167	167	167	161		3522	402
10		LLH	125	135	132	138	116	125	122	138	122	132	132	129			
11		Demand	402	402	402	402	402	402	402	402	402	402	402	402			
12			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
13	**2011**	HLH	167	161	167	161	154	174	167	161	167	161	174	161		3522	402
14		LLH	132	129	132	138	116	125	122	138	122	138	125	129			
15		Demand	402	402	402	402	402	402	402	402	402	402	402	402			
16			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
17	**2012**	HLH	167	161	167	161	161	174	161	167	167	161	174	154		3531	403
18		LLH	132	129	132	138	119	125	129	132	122	138	125	135			
19		Demand	402	402	402	402	402	402	402	402	402	402	402	402			
20			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
21	**2013**	HLH	174	161	161	167	154	167	167	167	161	167	174	154		3522	402
22		LLH	125	129	138	132	116	131	122	132	129	132	125	135			
23		Demand	402	402	402	402	402	402	402	402	402	402	402	402			
24			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
25	**2014**	HLH	174	161	161	167	154	167	167	167	161	167	167	161		3522	402
26		LLH	125	129	138	132	116	131	122	132	129	132	132	129			
27		Demand	402	402	402	402	402	402	402	402	402	402	402	402			
28			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
29	**2015**	HLH	174	154	167	167	154	167	167	161	167	167	167	161		3522	402
30		LLH	125	135	132	132	116	131	122	138	122	132	132	129			
31		Demand	402	402	402	402	402	402	402	402	402	402	402	402			

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
3								**Table 1.1.4**									Sales 04
4																	
5								**Total NR Load Forecast FY2010-15**									
6																	
7																Total	
8			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
9	**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
10		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			
11		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			
12			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
13	**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
14		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			
15		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			
16			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
17	**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
18		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			
19		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			
20			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
21	**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
22		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			
23		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			
24			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
25	**2014**	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
26		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			
27		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			
28			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			
29	**2015**	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
30		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			
31		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 Residential Exchange Program

Potential Exchanger ASC	**2010** ($/MWh)	**2011** ($/MWh)	**2012** ($/MWh)	**2013** ($/MWh)	**2014** ($/MWh)	**2015** ($/MWh)
Avista	$ 46.98	$ 47.80	$ 48.64	$ 48.73	$ 49.06	$ 49.39
Idaho Power	$ 35.65	$ 35.65	$ 36.68	$ 37.27	$ 38.00	$ 38.58
Northwestern Energy PNWR	$ 57.57	$ 57.57	$ 59.20	$ 60.35	$ 61.46	$ 62.52
Pacificorp	$ 56.48	$ 56.60	$ 55.87	$ 55.44	$ 55.22	$ 55.16
Portland General	$ 55.57	$ 58.21	$ 59.08	$ 59.50	$ 59.93	$ 60.34
Puget Sound Energy	$ 56.98	$ 61.63	$ 62.57	$ 63.12	$ 63.64	$ 64.09
Franklin	$ 49.28	$ 49.28	$ 51.27	$ 51.14	$ 51.62	$ 51.65
Snohomish	$ 46.33	$ 45.91	$ 48.02	$ 48.24	$ 49.04	$ 49.35

Potential Exchanger Load	**2010** (aMW)	**2011** (aMW)	**2012** (aMW)	**2013** (aMW)	**2014** (aMW)	**2015** (aMW)
Avista	455	461	443	460	468	480
Idaho Power	743	762	723	731	740	749
Northwestern Energy PNWR	71	72	72	74	74	75
Pacificorp	1,089	1,100	1,108	1,122	1,144	1,167
Portland General	999	1,009	1,022	1,044	1,065	1,087
Puget Sound Energy	1,361	1,376	1,395	1,432	1,478	1,541
Franklin	40	41	42	43	43	44
Snohomish	429	436	442	450	457	463

Table 1.3.1 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	0	134,911	43,682	432,374	610,967
4. BPA FISH & WILDLIFE PROGRAM	204,098	17,339	5,614	248,887	271,840
5. TROJAN				2,200	2,200
6. WNP #1				166,431	166,431
7. WNP #2				493,547	493,547
8. WNP #3				144,892	144,892
9. SYSTEM AUGMENTATION				180,762	180,762
10. BALANCING POWER PURCHASES				87,631	87,631
11. TOTAL FEDERAL BASE SYSTEM	**204,098**	**152,250**	**49,296**	**1,756,724**	**1,958,270**
12. NEW RESOURCES					
13. IDAHO FALLS				4,789	4,789
14. COWLITZ FALLS				14,857	14,857
15. OTHER NEW RESOURCES PURCHASES				62,781	62,781
16. TOTAL NEW RESOURCES				**82,427**	**82,427**
17. RESIDENTIAL EXCHANGE				2,120,999	2,120,999
18. CONSERVATION		13,318	4,312	169,147	186,777
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	18,254	1,551	502	138,219	140,272
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**18,254**	**1,551**	**502**	**138,219**	**140,272**
23. TOTAL GENERATION COSTS	**222,352**	**167,119**	**54,110**	**4,267,516**	**4,488,745**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				125,940	125,940
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				50,690	50,690
28. TOTAL TRANSMISSION COSTS				**177,630**	**177,630**
29. TOTAL PBL REVENUE REQUIREMENT		**167,119**	**54,110**	**4,445,147**	**4,666,376**
30. BPA TRANSMISSION REVENUE REQUIREMENT		130,625	77,936	602,570	811,131
(Net of Line 25)					

Table 1.3.2

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	0	138,674	37,213	447,358	623,245
4. BPA FISH & WILDLIFE PROGRAM	243,903	21,174	5,682	272,719	299,575
5. TROJAN				2,300	2,300
6. WNP #1				167,977	167,977
7. WNP #2				551,051	551,051
8. WNP #3				169,093	169,093
9. SYSTEM AUGMENTATION				273,041	273,041
10. BALANCING POWER PURCHASES				72,108	72,108
11. TOTAL FEDERAL BASE SYSTEM	**243,903**	**159,848**	**42,895**	**1,955,647**	**2,158,390**
12. NEW RESOURCES					
13. IDAHO FALLS				4,789	4,789
14. COWLITZ FALLS				14,802	14,802
15. OTHER NEW RESOURCES PURCHASES				62,105	62,105
16. TOTAL NEW RESOURCES				**81,696**	**81,696**
17. RESIDENTIAL EXCHANGE				2,225,993	2,225,993
18. CONSERVATION		12,274	3,294	176,696	192,264
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	13,577	1,179	316	138,617	140,112
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**13,577**	**1,179**	**316**	**138,617**	**140,112**
23. TOTAL GENERATION COSTS	**257,480**	**173,301**	**46,505**	**4,578,649**	**4,798,455**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				124,189	124,189
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				51,340	51,340
28. TOTAL TRANSMISSION COSTS				**176,529**	**176,529**
29. TOTAL PBL REVENUE REQUIREMENT		**173,301**	**46,505**	**4,755,178**	**4,974,984**
30. BPA TRANSMISSION REVENUE REQUIREMENT		145,757	73,507	644,203	863,467
(Net of Line 25)					

Table 1.3.3 COSA 06 FY2012

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement

FY 2012

FY 2012	**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	0	153,205	0	469,861	623,066
4. BPA FISH & WILDLIFE PROGRAM	271,798	22,569	0	294,600	317,169
5. TROJAN				2,300	2,300
6. WNP #1				192,951	192,951
7. WNP #2				628,707	628,707
8. WNP #3				162,208	162,208
9. SYSTEM AUGMENTATION				211,656	211,656
10. BALANCING POWER PURCHASES				85,220	85,220
11. TOTAL FEDERAL BASE SYSTEM	**271,798**	**175,774**	**0**	**2,047,502**	**2,223,276**
12. NEW RESOURCES					
13. IDAHO FALLS				4,967	4,967
14. COWLITZ FALLS				14,967	14,967
15. OTHER NEW RESOURCES PURCHASES				92,988	92,988
16. TOTAL NEW RESOURCES				**112,922**	**112,922**
17. RESIDENTIAL EXCHANGE				2,275,415	2,275,415
18. CONSERVATION		11,184	0	174,113	185,297
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	11,525	957	0	150,254	151,211
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**11,525**	**957**	**0**	**150,254**	**151,211**
23. TOTAL GENERATION COSTS	**283,323**	**187,915**	**0**	**4,760,206**	**4,948,121**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				121,347	121,347
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,428	52,428
28. TOTAL TRANSMISSION COSTS				**174,776**	**174,776**
29. TOTAL PBL REVENUE REQUIREMENT		**187,915**	**0**	**4,934,982**	**5,122,897**

Table 1.3.4 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	0	169,109	22,096	484,659	675,865
4. BPA FISH & WILDLIFE PROGRAM	293,187	25,297	3,305	302,591	331,193
5. TROJAN				2,400	2,400
6. WNP #1				292,968	292,968
7. WNP #2				549,085	549,085
8. WNP #3				178,719	178,719
9. SYSTEM AUGMENTATION				310,848	310,848
10. BALANCING POWER PURCHASES				77,314	77,314
11. TOTAL FEDERAL BASE SYSTEM	**293,187**	**194,406**	**25,401**	**2,198,585**	**2,418,392**
12. NEW RESOURCES					
13. IDAHO FALLS				5,427	5,427
14. COWLITZ FALLS				15,071	15,071
15. OTHER NEW RESOURCES PURCHASES				94,480	94,480
16. TOTAL NEW RESOURCES				**114,978**	**114,978**
17. RESIDENTIAL EXCHANGE				2,326,848	2,326,848
18. CONSERVATION		11,523	1,506	179,914	192,943
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	11,525	994	130	151,035	152,159
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**11,525**	**994**	**130**	**151,035**	**152,159**
23. TOTAL GENERATION COSTS	**304,712**	**206,923**	**27,037**	**4,971,359**	**5,205,320**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				120,794	120,794
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,437	52,437
28. TOTAL TRANSMISSION COSTS				**174,231**	**174,231**
29. TOTAL PBL REVENUE REQUIREMENT		**206,923**	**27,037**	**5,145,591**	**5,379,551**

Table 1.3.5 COSA 06 FY2014

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement

FY 2014

FY 2014

	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	0	186,820	0	499,708	686,528
4. BPA FISH & WILDLIFE PROGRAM	312,758	29,168	0	295,673	324,841
5. TROJAN				2,500	2,500
6. WNP #1				292,140	292,140
7. WNP #2				515,143	515,143
8. WNP #3				175,460	175,460
9. SYSTEM AUGMENTATION				308,232	308,232
10. BALANCING POWER PURCHASES				80,171	80,171
11. TOTAL FEDERAL BASE SYSTEM	**312,758**	**215,988**	**0**	**2,169,027**	**2,385,015**
12. NEW RESOURCES					
13. IDAHO FALLS				5,580	5,580
14. COWLITZ FALLS				15,155	15,155
15. OTHER NEW RESOURCES PURCHASES				95,489	95,489
16. TOTAL NEW RESOURCES				**116,224**	**116,224**
17. RESIDENTIAL EXCHANGE				2,396,484	2,396,484
18. CONSERVATION		12,492	0	183,426	195,918
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	10,189	992	0	156,853	157,845
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**10,189**	**992**	**0**	**156,853**	**157,845**
23. TOTAL GENERATION COSTS	**322,947**	**229,472**	**0**	**5,022,014**	**5,251,485**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,447	123,447
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,446	52,446
28. TOTAL TRANSMISSION COSTS				**176,893**	**176,893**
29. TOTAL PBL REVENUE REQUIREMENT		**229,472**	**0**	**5,198,906**	**5,428,378**

Table 1.3.6 COSA 06 FY2015

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2015

FY 2015	**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	0	199,050	0	513,971	713,021
4. BPA FISH & WILDLIFE PROGRAM	330,116	32,786	0	304,864	337,650
5. TROJAN				2,600	2,600
6. WNP #1				220,020	220,020
7. WNP #2				612,178	612,178
8. WNP #3				193,459	193,459
9. SYSTEM AUGMENTATION				415,263	415,263
10. BALANCING POWER PURCHASES				44,485	44,485
11. TOTAL FEDERAL BASE SYSTEM	**330,116**	**231,836**	**0**	**2,306,838**	**2,538,675**
12. NEW RESOURCES					
13. IDAHO FALLS				5,887	5,887
14. COWLITZ FALLS				15,270	15,270
15. OTHER NEW RESOURCES PURCHASES				95,767	95,767
16. TOTAL NEW RESOURCES				**116,924**	**116,924**
17. RESIDENTIAL EXCHANGE				2,474,491	2,474,491
18. CONSERVATION		12,897	0	180,030	192,927
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	7,498	795	0	162,582	163,377
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**7,498**	**795**	**0**	**162,582**	**163,377**
23. TOTAL GENERATION COSTS	**337,614**	**245,528**	**0**	**5,240,866**	**5,486,394**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				122,102	122,102
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,446	52,446
28. TOTAL TRANSMISSION COSTS				**175,548**	**175,548**
29. TOTAL PBL REVENUE REQUIREMENT		**245,528**	**0**	**5,416,414**	**5,661,942**

Table 1.3.7 **COSA 07**

COST OF SERVICE ANALYSIS

Functionalization of Residential Exchange Costs
Fiscal Year 2010

Gross Residential Exchange Cost	$ 2,120,999
Residential Exchange Transmission	$ 165,818
Functionalized Residential Exchange Costs	$ 1,955,181

Table 1.3.8 **COSA 08**

COST OF SERVICE ANALYSIS

Classified Revenue Requirement
Fiscal Year 2010

	Total Rev Req	Energy %	Energy Total	Demand %	Demand Total	Load Variance %	Load Variance Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 610,967	85.11%	$ 519,993	13.90%	$ 84,900	0.99%	$ 6,074
4. BPA FISH & WILDLIFE PROGRAM	$ 271,840	86.10%	$ 234,065	13.90%	$ 37,775		
5. TROJAN	$ 2,200	86.10%	$ 1,894	13.90%	$ 306		
6. WNP #1	$ 166,431	86.10%	$ 143,304	13.90%	$ 23,127		
7. WNP #2	$ 493,547	85.11%	$ 420,057	13.90%	$ 68,583	0.99%	$ 4,906
8. WNP #3	$ 144,892	86.10%	$ 124,758	13.90%	$ 20,134		
9. SYSTEM AUGMENTATION	$ 180,762	85.11%	$ 153,846	13.90%	$ 25,119	0.99%	$ 1,797
10. BALANCING POWER PURCHASES	$ 87,631	85.11%	$ 74,583	13.90%	$ 12,177	0.99%	$ 871
11. TOTAL FEDERAL BASE SYSTEM	**$ 1,958,270**		**$ 1,672,500**		**$ 272,122**		**$ 13,648**
12. NEW RESOURCES							
13. IDAHO FALLS	$ 4,789	85.11%	$ 4,076	13.90%	$ 665	0.99%	$ 48
14. COWLITZ FALLS	$ 14,857	85.11%	$ 12,645	13.90%	$ 2,065	0.99%	$ 148
15. OTHER NEW RESOURCES PURCHASES	$ 62,781	85.11%	$ 53,433	13.90%	$ 8,724	0.99%	$ 624
16. TOTAL NEW RESOURCES	**$ 82,427**		**$ 70,154**		**$ 11,454**		**$ 819**
17. RESIDENTIAL EXCHANGE	$ 1,955,181	100.00%	$ 1,955,181				
18. CONSERVATION	$ 186,777	86.10%	$ 160,823	13.90%	$ 25,955		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 140,272	85.11%	$ 119,386	13.90%	$ 19,492	0.99%	$ 1,394
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	**$ 140,272**		**$ 119,386**		**$ 19,492**		**$ 1,394**
23. TOTAL GENERATION COSTS	**$ 4,322,928**		**$ 3,978,042**		**$ 329,023**		**$ 15,862**
			$ -		$ -		$ -
24. TRANSMISSION COSTS							
25. TBL TRANSMISSION/ANCILLARY SERVICES	$ 125,940	100.00%	$ 125,940				
26. 3RD PARTY TRANS/ANCILLARY SERVICES	$ 1,000	100.00%	$ 1,000				
27. GENERAL TRANSFER AGREEMENTS	$ 50,690	100.00%	$ 50,690				
28. TOTAL TRANSMISSION COSTS	**177,630**		**177,630**				
29. TOTAL PBL REVENUE REQUIREMENT	**$ 4,500,558**		**$ 4,155,673**		**$ 344,885**		

Table 1.3.9 **COSA 09**

COST OF SERVICE ANALYSIS

Functionalized Revenue Credits
Test Period October 2009 - September 2015

	FY 2010	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
Downstream Benefits & Storage	$ 8,921	$ 8,921	$ 8,921	$ 8,571	$ 8,568	$ 8,568
4(h)(10)(c) Credit	$ 96,689	$ 101,969	$ 102,792	$ 105,969	$ 108,917	$ 111,680
Colville & Spokane Settlements	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600
Network Wind Integration&Shaping	$ 1,953	$ 1,953	$ -	$ -	$ -	$ -
Misc. Revenues	$ 3,420	$ 3,420	$ 3,420	$ 3,420	$ 3,420	$ 3,420
Green Tags	$ 5,040	$ 5,040	$ -	$ 404	$ -	$ -
Network Wind Integration&Shaping	$ 90,176	$ 102,730	$ 102,730	$ 102,730	$ 102,730	$ 102,730
Total	**$ 210,800**	**$ 228,633**	**$ 222,462**	**$ 225,693**	**$ 228,235**	**$ 230,998**

Table 1.3.10 COSA 09A

COST OF SERVICE ANALYSIS

Allocation of EE Revenue Credits to Conservation Costs
Test Period October 2009 - September 2015

	FY 2010	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
Conservation Expense Before EE Revenues	$ 186,777	$ 192,264	$ 185,297	$ 192,943	$ 195,918	$ 192,927
Energy Efficiency Revenues	$ (20,500)	$ (20,500)	$ (20,500)	$ (20,500)	$ (20,500)	$ (20,500)
Net Conservation Expense	**$ 166,277**	**$ 171,764**	**$ 164,797**	**$ 172,443**	**$ 175,418**	**$ 172,427**

	B	C	D	E	F	G	H	I	J	K
6						**Table 1.4.1**				ALLOCATE 01
7										
8						**Energy Allocation Factors w/ Res Exch**				
9						Average Megawatts				
10										
11					**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
12										
13	**Total Usage**									
14	Priority Firm........................				11772	11833	12148	12311	12565	12745
15	Industrial Firm.....................				413	413	413	413	413	413
16	New Resource Firm.............				0	0	0	0	0	0
17	Surplus Firm Other..............				696	666	262	261	256	256
18	**Total.......................................**				**12881**	**12912**	**12823**	**12986**	**13234**	**13413**
19	**Federal Base System**									
20	Priority Firm........................				8205	8181	8057	8124	8262	8311
21	Industrial Firm.....................				0	0	0	0	0	0
22	New Resource Firm.............				0	0	0	0	0	0
23	Surplus Firm Other..............				0	0	0	0	0	0
24	**Total.......................................**				**8205**	**8181**	**8057**	**8124**	**8262**	**8311**
25	**Residential Exchange**									
26	Priority Firm........................				3567	3652	4091	4188	4303	4434
27	Industrial Firm.....................				373	371	343	347	347	347
28	New Resource Firm.............				0	0	0	0	0	0
29	Surplus Firm Other..............				629	598	217	220	214	214
30	**Total.......................................**				**4569**	**4621**	**4651**	**4754**	**4864**	**4995**
31	**New Resource**									
32	Priority Firm........................				0	0	0	0	0	0
33	Industrial Firm.....................				40	41	75	71	72	72
34	New Resource Firm.............				0	0	0	0	0	0
35	Surplus Firm Other..............				68	67	48	45	44	44
36	**Total.......................................**				**108**	**108**	**123**	**116**	**116**	**116**
37	**Conservation**									
38	Priority Firm........................				11772	11833	12148	12311	12565	12745
39	Industrial Firm.....................				413	413	413	413	413	413
40	New Resource Firm.............				0	0	0	0	0	0
41	Surplus Firm Other..............				696	666	262	261	256	256
42	**Total.......................................**				**12881**	**12912**	**12823**	**12986**	**13234**	**13413**

	B	C	D	E	F	G	H	I	J
1						**Table 1.4.2**			ALLOCATE 02
2									
3						**Initial Rate Pool Cost Allocation**			
4									
5									
6				**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
7	**CLASSES OF SERVICE**								
8	**Power Rates**								
9	**Priority Firm - Preference**								
10	FBS			$ 1,958,270	$ 2,158,390	$ 2,223,276	$ 2,418,392	$ 2,385,015	$ 2,538,675
11	NR			$ -	$ -	$ -	$ -	$ -	$ -
12	Exchange			$ 1,526,348	$ 1,626,646	$ 1,852,459	$ 1,897,520	$ 1,963,957	$ 2,035,686
13	conservation			$ 151,956	$ 157,410	$ 156,118	$ 163,483	$ 166,551	$ 163,829
14	BPA programs			$ 290,523	$ 290,181	$ 308,819	$ 309,431	$ 317,818	$ 322,024
15	**Total**			**$ 3,927,096**	**$ 4,232,627**	**$ 4,540,672**	**$ 4,788,826**	**$ 4,833,342**	**$ 5,060,215**
16	**Industrial Firm Power**								
17	FBS			$ -	$ -	$ -	$ -	$ -	$ -
18	NR			$ 30,709	$ 31,296	$ 69,114	$ 70,431	$ 71,818	$ 72,255
19	Exchange			$ 159,768	$ 165,355	$ 155,261	$ 157,287	$ 158,194	$ 159,140
20	conservation			$ 5,335	$ 5,499	$ 5,312	$ 5,489	$ 5,479	$ 5,313
21	BPA programs			$ 10,201	$ 10,136	$ 10,508	$ 10,389	$ 10,455	$ 10,444
22	**Total**			**$ 206,013**	**$ 212,286**	**$ 240,195**	**$ 243,596**	**$ 245,946**	**$ 247,153**
23	**New Resources Firm**								
24	FBS			$ -	$ -	$ -	$ -	$ -	$ -
25	NR			$ 0.0076	$ 0.0078	$ 0.0172	$ 0.0175	$ 0.0179	$ 0.0180
26	Exchange			$ 0.0397	$ 0.0411	$ 0.0386	$ 0.0391	$ 0.0394	$ 0.0396
27	conservation			$ 0.0013	$ 0.0014	$ 0.0013	$ 0.0014	$ 0.0014	$ 0.0013
28	BPA programs			$ 0.0025	$ 0.0025	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026
29	**Total**			**$ 0.0512**	**$ 0.0528**	**$ 0.0597**	**$ 0.0606**	**$ 0.0612**	**$ 0.0615**
30	**Surplus Firm Power**								
31	FBS			$ -	$ -	$ -	$ -	$ -	$ -
32	NR			$ 51,718	$ 50,400	$ 43,808	$ 44,547	$ 44,406	$ 44,669
33	Exchange			$ 269,066	$ 266,294	$ 98,413	$ 99,482	$ 97,812	$ 98,383
34	conservation			$ 8,985	$ 8,855	$ 3,367	$ 3,472	$ 3,388	$ 3,285
35	BPA programs			$ 17,179	$ 16,324	$ 6,660	$ 6,571	$ 6,464	$ 6,457
36	**Total**			**$ 346,948**	**$ 341,874**	**$ 152,248**	**$ 154,071**	**$ 152,070**	**$ 152,794**
37									
38	**Total Revenue Requirement**			**$ 4,480,058**	**$ 4,786,787**	**$ 4,933,115**	**$ 5,186,492**	**$ 5,231,357**	**$ 5,460,161**
39									
40	1/ Note: Conservation expense from COSA 06 Tables reduced by EE Revenues in Table COSA 09A.								

Table 1.5.1 RDS 11

Rate Design Study

Allocation of Secondary and Other Revenue Credits
Test Period October 2009 - September 2015

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Forecast of Gross Secondary Revenues	**$ 703,912**	**$ 767,646**	**$ 821,998**	**$ 863,652**	**$ 901,284**	**$ 902,092**
7b3 Costs Allocated to Secondary Revenues	**$ (186,366)**	**$ (187,178)**	**$ (178,471)**	**$ (177,384)**	**$ (178,776)**	**$ (174,412)**
Secondary Revenues After 7b3 Allocation	**$ 517,547**	**$ 580,468**	**$ 643,527**	**$ 686,267**	**$ 722,507**	**$ 727,680**

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Allocation of Secondary Revenues Credit						
Priority Firm...	$ (517,547)	$ (580,468)	$ (643,527)	$ (686,267)	$ (722,507)	$ (727,680)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -	$ -	$ -
Total..	**$ (517,547)**	**$ (580,468)**	**$ (643,527)**	**$ (686,267)**	**$ (722,507)**	**$ (727,680)**

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Total Other Revenue Credits	**$ 210,800**	**$ 228,633**	**$ 222,462**	**$ 225,693**	**$ 228,235**	**$ 230,998**

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Allocation of Other Revenue Credits						
Priority Firm...	$ (210,800)	$ (228,633)	$ (222,462)	$ (225,693)	$ (228,235)	$ (230,998)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -	$ -	$ -
Total..	**$ (210,800)**	**$ (228,633)**	**$ (222,462)**	**$ (225,693)**	**$ (228,235)**	**$ (230,998)**

Table 1.5.2 RDS 17

Rate Design Study

Surplus Firm Power Revenues (Surplus)/Shortfall
Test Period October 2009 - September 2015

FPS (Surplus)/Shortfall	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Costs allocated to FPS contract sales	$ 346,948	$ 341,874	$ 152,248	$ 154,071	$ 152,070	$ 152,794
Expected Revenue from FPS contract sales	$ (96,778)	$ (88,437)	$ (32,136)	$ (31,663)	$ (31,663)	$ (31,600)
FPS Pre-Sub Contract Revenue	$ (37,228)	$ (34,456)	$ (510)	$ (557)	$ (569)	$ (581)
(Surplus)/Shortfall	**$ 212,942**	**$ 218,981**	**$ 119,602**	**$ 121,851**	**$ 119,838**	**$ 120,612**
Secondary Revenues allocated to FPS	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Credits allocated to FPS	$ -	$ -	$ -	$ -	$ -	$ -
FPS (Surplus)/Shortfall	**$ 212,942**	**$ 218,981**	**$ 119,602**	**$ 121,851**	**$ 119,838**	**$ 120,612**

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

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Allocation of FPS (Surplus)/Shortfall						
Priority Firm...	$ 211,902	$ 217,878	$ 118,493	$ 120,792	$ 118,805	$ 119,578
Industrial Firm..	$ 1,040	$ 1,103	$ 1,109	$ 1,059	$ 1,033	$ 1,034
New Resource Firm....................................	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Surplus Firm Other.....................................	$ (212,942)	$ (218,981)	$ (119,602)	$ (121,851)	$ (119,838)	$ (120,612)
Total...	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Table 1.5.3 RDS 19

Rate Design Study

Summary of Initial Allocations

Test Period October 2009 - September 2015

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Allocation of Revenue Requirement						
Priority Firm...	$ 3,927,096	$ 4,232,627	$ 4,540,672	$ 4,788,826	$ 4,833,342	$ 5,060,215
Industrial Firm..	$ 206,013	$ 212,286	$ 240,195	$ 243,596	$ 245,946	$ 247,153
New Resource Firm...	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Surplus Firm Other..	$ 346,948	$ 341,874	$ 152,248	$ 154,071	$ 152,070	$ 152,794
Total...	**$ 4,480,058**	**$ 4,786,787**	**$ 4,933,115**	**$ 5,186,492**	**$ 5,231,357**	**$ 5,460,161**
Allocation of Secondary Revenues Credit						
Priority Firm...	$ (517,547)	$ (580,468)	$ (643,527)	$ (686,267)	$ (722,507)	$ (727,680)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm...	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -	$ -	$ -
Total...	**$ (517,547)**	**$ (580,468)**	**$ (643,527)**	**$ (686,267)**	**$ (722,507)**	**$ (727,680)**
Allocation of other Revenues Credits						
Priority Firm...	$ (210,800)	$ (228,633)	$ (222,462)	$ (225,693)	$ (228,235)	$ (230,998)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm...	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -	$ -	$ -	$ -
Total...	**$ (210,800)**	**$ (228,633)**	**$ (222,462)**	**$ (225,693)**	**$ (228,235)**	**$ (230,998)**
Allocation of FPS (Surplus)/Shortfall						
Priority Firm...	$ 211,902	$ 217,878	$ 118,493	$ 120,792	$ 118,805	$ 119,578
Industrial Firm..	$ 1,040	$ 1,103	$ 1,109	$ 1,059	$ 1,033	$ 1,034
New Resource Firm...	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Surplus Firm Other..	$ (212,942)	$ (218,981)	$ (119,602)	$ (121,851)	$ (119,838)	$ (120,612)
Total...	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Low Density Discount						
Priority Firm...	$ 26,419	$ 26,465	$ 26,465	$ 26,465	$ 26,465	$ 26,465
Irrigation Rate Mitigation..............................						
Priority Firm...	$ 12,036	$ 12,036	$ 12,036	$ 12,036	$ 12,036	$ 12,036

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Initial Allocation						
Priority Firm...	$ 3,449,107	$ 3,679,905	$ 3,831,676	$ 4,036,158	$ 4,039,905	$ 4,259,616
Industrial Firm..	$ 207,053	$ 213,389	$ 241,304	$ 244,655	$ 246,979	$ 248,186
New Resource Firm...	$ 0.0515	$ 0.0531	$ 0.0600	$ 0.0609	$ 0.0614	$ 0.0617
Surplus Firm Other..	$ 134,007	$ 122,893	$ 32,646	$ 32,220	$ 32,232	$ 32,182
Total...	**$ 3,790,167**	**$ 4,016,187**	**$ 4,105,626**	**$ 4,313,033**	**$ 4,319,116**	**$ 4,539,984**

Table 1.5.4 RDS 21

Rate Design Study

7(c)(2) Delta Calculation

Test Period October 2009 - September 2015

		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
1	IP Allocated Costs	$ 207,053	$ 213,389	$ 241,304	$ 244,655	$ 246,979	$ 248,186
2	IP Revenues @ Net Margin	$ (578)	$ (578)	$ (579)	$ (578)	$ (578)	$ (578)
3	adjustment	$ (1,047)	$ (945)	$ (899)	$ (825)	$ (858)	$ (780)
4	IP Marginal Cost Rate Revenues	$ 151,581	$ 151,581	$ 152,016	$ 151,607	$ 151,593	$ 151,584
5	PF Marginal Cost Rate Revenues	$ 4,458,119	$ 4,484,242	$ 4,612,290	$ 4,666,188	$ 4,759,610	$ 4,824,124
6	PF Allocated Energy Costs	$ 3,449,107	$ 3,679,905	$ 3,831,676	$ 4,036,158	$ 4,039,905	$ 4,259,616
7	Numerator: 1-2-3-((4/5)*6)	91,404	90,519	116,494	114,921	119,744	115,698
8							
9	PF Allocation Factor for Delta	11,772	11,833	12,148	12,311	12,565	12,745
10	NR Allocation Factor for Delta	0	0	0	0	0	0
11	Total Allocation Factors for Delta	11,772	11,833	12,148	12,311	12,565	12,745
12	Denominator: 1.0 + ((9/11)*(4/5))	1.034	1.034	1.033	1.032	1.032	1.031
13							
14	DELTA: (7/12)	**88,399**	**87,560**	**112,777**	**111,304**	**116,048**	**112,173**

Rate Design Study
7(c)(2) Delta allocation
Test Period October 2009 - September 2015

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
IP-PF Linc Allocation.............................						
Priority Firm..	$ 88,399	$ 87,560	$ 112,777	$ 111,304	$ 116,048	$ 112,173
Industrial Firm.......................................	$ (88,399)	$ (87,560)	$ (112,777)	$ (111,304)	$ (116,048)	$ (112,173)
New Resource Firm...............................	$ 0.0008	$ 0.0008	$ 0.0010	$ 0.0009	$ 0.0009	$ 0.0009
Surplus Firm Other................................	$ -	$ -	$ -	$ -	$ -	$ -
Total...	**$ (0)**	**$ (0)**	**$ (0)**	**$ 0**	**$ (0)**	**$ (0)**

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Allocation after Linc..............................						
Priority Firm Preference..........................	$ 2,164,595	$ 2,296,327	$ 2,434,138	$ 2,545,767	$ 2,547,239	$ 2,658,424
Priority Firm Exchange...........................	$ 1,372,911	$ 1,471,138	$ 1,510,315	$ 1,601,696	$ 1,608,714	$ 1,713,365
Industrial Firm.......................................	$ 118,655	$ 125,830	$ 128,527	$ 133,350	$ 130,931	$ 136,013
New Resource Firm...............................	$ 0.0523	$ 0.0538	$ 0.0610	$ 0.0618	$ 0.0624	$ 0.0626
Surplus Firm Other................................	$ 134,007	$ 122,893	$ 32,646	$ 32,220	$ 32,232	$ 32,182
Total...	**$ 3,790,167**	**$ 4,016,187**	**$ 4,105,626**	**$ 4,313,033**	**$ 4,319,116**	**$ 4,539,984**

Table 1.5.5

RATE DESIGN STUDY

Industrial Firm Power Floor Rate Calculation
Test Period October 2009 - September 2015
Example Fiscal Year 2010
($ 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	2,010	2,814	2,045	1,476	4,824	3,522
2	IP-83 Rates	4.62	2.21	14.70	12.20	7.34	
3	Revenue	9,286	6,219	30,067	18,009	35,408	98,989
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

RATE DESIGN STUDY

Industrial Firm Power Floor Rate Test
Test Period October 2009 - September 2015
($ Thousands)

		A	B	C	D	E	F
		Unbundled Requirements Products	Transmission Total	Generation Demand Total	Energy Total	Total	Average Rate
1	IP Billing Determinants				3,521.520		
2	Floor Rate (mills/kWh)				20.98		
3	Value of Reserves Credit (mills/kWh)						
4	Revenue at Floor Rate Less VOR Credit				73,889.223	73,889.223	20.98
5	IP Revenue Under Proposed Rates	0	0	8,964.600	119,447.891	128,412.491	36.47
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 2010

LEVELIZED SHAPE OF POWER

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
Energy Mills/kwh												
HLH	29.21	31.15	32.51	27.60	28.19	26.15	24.54	20.50	18.55	22.85	26.76	27.62
LLH	21.40	22.72	23.85	19.96	20.16	19.17	17.64	14.17	9.85	16.73	19.85	22.17
MONTHLY DEMAND	2.05	2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96

PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy		
HLH	4,637	5,136	6,104	6,355	5,799	5,647	4,981	4,434	4,111	4,137	4,659	4,727	100294	100294	11449
LLH	2,924	3,474	3,973	4,451	3,810	3,580	3,107	3,096	2,538	2,801	2,794	3,021			
Demand	14,138	15,396	17,645	19,005	18,221	15,016	13,690	11,926	10,837	12,100	12,519	13,271			

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 135,438	$ 159,984	$ 198,455	$ 175,388	$ 163,467	$ 147,675	$ 122,226	$ 90,905	$ 76,263	$ 94,531	$ 124,667	$ 130,572	$ 2,383,046	$ 3,192,620	133.97%
LLH	$ 62,566	$ 78,922	$ 94,754	$ 88,835	$ 76,813	$ 68,621	$ 54,804	$ 43,874	$ 24,999	$ 46,855	$ 55,463	$ 66,970			
Demand	$ 28,983	$ 33,718	$ 40,585	$ 37,249	$ 36,260	$ 27,780	$ 23,820	$ 17,173	$ 14,305	$ 19,481	$ 23,660	$ 26,011	$ 329,023	$ 329,023	100.00%
												LV Revenue	$ 15,862	$ 15,862	100.00%
													$ 2,727,931	$ 3,537,506	

PF rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**39.13**	**41.73**	**43.55**	**36.98**	**37.77**	**35.03**	**32.88**	**27.46**	**24.85**	**30.61**	**35.85**	**37.00**
LLH	**28.67**	**30.44**	**31.95**	**26.74**	**27.01**	**25.68**	**23.63**	**18.98**	**13.20**	**22.41**	**26.59**	**29.70**
Demand	**2.05**	**2.19**	**2.30**	**1.96**	**1.99**	**1.85**	**1.74**	**1.44**	**1.32**	**1.61**	**1.89**	**1.96**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 181,434	$ 214,322	$ 265,847	$ 234,994	$ 219,020	$ 197,823	$ 163,765	$ 121,769	$ 102,164	$ 126,634	$ 167,015	$ 174,915	$ 3,192,497
LLH	$ 83,821	$ 105,738	$ 126,934	$ 119,010	$ 102,912	$ 91,925	$ 73,414	$ 58,767	$ 33,501	$ 62,762	$ 74,295	$ 89,716	
Demand	$ 28,983	$ 33,718	$ 40,585	$ 37,249	$ 36,260	$ 27,780	$ 23,820	$ 17,173	$ 14,305	$ 19,481	$ 23,660	$ 26,011	$ 329,023
												LV Revenue	$ 15,862
													$ 3,537,383

Unbifurcated PF Average Rate

Energy Costs	**$ 3,192,620**	**31.83**
Demand Costs	**$ 329,023**	**3.28**
Unbundled Cost	**$ 15,862**	**0.16**
Total	**$ 3,537,506**	**35.27**
Billing Determinants	**100294**	

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

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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, FY2010-15.
GWh energy sales and peak MW/mo. demand amounts for each month of the 7(b)(2) Rate Test Period FY 2010-2015. 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, FY2010-15.
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 resources for FY2001-2015 are also included.

Table 2.2.3 (7B2 Resource_03)
7(b)(2) Resources Sorted by Least Cost.
Table lists 7(b)(2) resources available to serve load in the 7(b)(2) Case. Individual resource output and cumulative output are listed. First year cost for each resource is listed along with the cumulative first year costs. For conservation resources, the first year cost is the programmatic costs expensed in the first year along with the first year's portion of the capitalized expense. For non-conservation resources, the first year cost is that year's portion of the capitalized cost. Also listed are the annual second year costs and the levelized cost that is used in the sorting process.

Table 2.2.4 (7B2 Resource_04)
Conservation Resources aMW Selected.
Table lists the conservation resources selected in each year and the total amount selected in each year. The amount of conservation selected in each year will affect the 7(b)(2) Customer load in that year. The original 7(b)(2) Customer load is increased for conservation saving that is assumed not to have occurred. If a conservation resource is selected from the 7(b)(2) resource stack, its costs go into the revenue requirement and the 7(b)(2) Customer loads are then reduced by the amount of the resource selected.

Table 2.2.5 (7B2 Resource_05)
Real Dollar Cost of Resources Selected.
Table lists costs of resources selected from the 7(b)(2) resource stack in real 2010 dollars. The costs are listed for each year in which the resource is used to serve load. The costs shown are before accounting for the amortization of the first year expensed portion of the conservation resources selected.

Table 2.2.6 (7B2 Resource_06)
Nominal Amortized Cost of Expensed Portion of Conservation Resources Selected.
Table lists the annual payments associated with amortizing the first year expensed portion of conservation resource costs over a five-year period. A mortgage payment calculation was used.

Table 2.2.7 (7B2 Resource_07)
Nominal Annual Cost of Capital Portion of Conservation Resources Selected.
Table lists the annual payments associated with the capitalized portion of conservation resource costs over the fifteen-year life of each resource. A mortgage payment calculation was used.

Table 2.2.8 (7B2 Resource_08)
Nominal Total Annual Cost of All Resources Selected.
Table lists the total nominal cost of resources selected for each year in which they serve 7(b)(2) Customer load. The annual totals are also shown.

Table 2.2.9 (7B2 Resource_09)
Calculation of Annual Credit for the Sale of Excess 7(b)(2) Resource Capability.
Table calculates the portion of the last resource selected in each year that is in excess of need. The excess capability is assumed to be sold at the levelized cost of the last resource selected in that year. The recovered cost of the last annual resource is then credited to the total cost of resources selected in each year and the net resource costs are input to the revenue requirement for each year.

Table 2.3.1 to Table 2.3.6 (COSA_06)
Itemized Revenue Requirements, FY2010-15.
Power Business Line (PBL) revenue requirements for each FY during the rate test period

Table 2.3.7 (COSA_08)
Classified Revenue Requirement, FY2010.
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 2.3.8 (COSA_09)
Functionalized Revenue Credits, FY2010-15.
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) , FY2010-15.
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, FY2010-15.*
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 7(b)(2) Case

Table 2.5.1 (RDS_11)
Allocation of Secondary Revenues and Other Revenue Credits, FY2010-15.
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, FY2010-15.
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 2.5.3 (RDS_19)
Summary of Initial Cost Allocations, FY2010-15.
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 rate pool.

Table 2.6 (RDS_50)
Calculation of 7(b)(2) Case PF Preference Rate Components, FY2010.
Table calculates 7(b)(2) Case PF rates. The FY 2009 PF Preference rates are scaled to produce rates that recover costs allocated to PF energy. Example shown is for FY 2010.

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.)

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	3042	3276	3673	3644	3259	3306	2877	3096	3034	3094	3211	2898	38409	7449
	LLH	1983	2455	2649	2706	2219	2188	1934	2298	1987	2255	2123	2049	26844	
	Demand	8647	9560	10123	10413	9936	9089	7938	8120	7695	8453	8129	7802	105906	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	3020	3366	3699	3672	3283	3332	2831	3023	2959	3110	3289	2920	38504	7453
	LLH	2054	2415	2666	2724	2233	2205	1902	2241	1937	2270	2079	2061	26786	
	Demand	8775	9685	10259	10544	10070	9212	7853	7975	7552	8523	8239	7908	106596	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	3182	3540	3778	3787	3534	3490	3006	3371	3219	3283	3456	3025	40671	7751
	LLH	2043	2418	2721	2798	2308	2181	1990	2277	1995	2295	2069	2130	27225	
	Demand	8931	9769	10376	10823	10181	9318	8165	8230	7784	8613	8345	7903	108439	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	3283	3588	3846	3972	3519	3469	3093	3341	3096	3362	3498	3057	41123	7788
	LLH	2013	2446	2740	2686	2254	2257	1959	2253	2001	2251	2092	2147	27101	
	Demand	9073	9912	10510	10901	10321	9430	8272	8145	7630	8694	8443	8004	109335	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2014	HLH	3316	3627	3894	4036	3577	3524	3138	3453	3245	3423	3493	3162	41888	7928
	LLH	2031	2468	2770	2727	2290	2290	1987	2324	2093	2289	2175	2121	27566	
	Demand	9179	10026	10652	11081	10501	9584	8404	8462	8008	8864	8593	8142	111497	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2015	HLH	3369	3621	4046	4074	3612	3551	3153	3379	3231	3431	3528	3194	42188	7981
	LLH	2062	2564	2765	2748	2309	2303	1993	2360	1996	2290	2193	2140	27722	
	Demand	9335	10189	10893	11195	10615	9685	8456	8442	7862	8905	8702	8246	112525	

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 (aMW)

	2010	2011	2012	2013	2014	2015
FBS Serving Posted Rates Load in Program Case	7,509	7,516	7,795	7,862	8,006	8,055
Long-Term Contracts Not in Force at time of Act w/losses	80	69	66	64	60	76
FBS Available to Serve Load in 7(b)(2) Case	7,589	7,584	7,861	7,926	8,067	8,131
7(b)(2) PF Load w/losses	7,897	7,942	8,267	8,368	8,553	8,642
Resources Needed From Resource Stack w/losses	**308**	**358**	**406**	**441**	**486**	**511**

Table 2.2.2 7b2 Resource_02

All Costs are in 2010 dollars

Example of 7(b)(2) Resource Stack

	A		B	C	D	E	F	G	H	I	J	K	L	M	N
	Project		Nameplate (MW)	Interest Rate (%)	Capital Investment ($ooo)	Annual O & M ($ooo)	Annual Fuel ($ooo)	Cons First Yr Amort ($ooo)	Capacity Factor	Life	Annual Capital Cost ($ooo)	Total Discounted Capital Cost ($ooo)	Total Discounted O & M and Fuel ($ooo)	Total Cost Dollars per AMW ($)	Total Cost Mills per KWH
11	BPA & Public resources														
12	*** The following resources are listed least cost first														
13															
14	BPA PROG CONS	2001	19.2	4.68	72	29,060	0	$6,471	100	15	7	66	$27,302	95,030	10.85
15	IDAHO FALLS ND	1982	14.0	0.00	0	4,978	0	$0	100	60	0	0	$81,183	96,646	11.03
16	BPA PROG CONS	2006	31.0	4.68	16,436	39,428	0	$8,780	100	15	1,549	15,107	37,043	112,152	12.80
17	BPA PROG CONS	2003	27.6	4.68	27,501	30,621	0	$6,819	100	15	2,593	25,278	$28,769	130,549	14.90
18	BPA PROG CONS	2002	26.6	4.68	34,588	26,137	0	$5,820	100	15	3,261	31,792	$24,556	141,224	16.12
19	BPA PROG CONS	2005	20.6	4.68	16,721	31,616	0	$7,040	100	15	1,576	15,369	$29,704	145,869	16.65
20	BOARDMAN PUBLIC ND	1980	49.7	0.00	0	16,104	0	$0	100	30	0	0	$223,094	149,597	17.08
21	BPA PROG CONS	2008	30.3	4.68	9,139	65,410	0	$14,565	100	15	862	8,400	$61,454	153,695	17.55
22	BPA PROG CONS	2004	20.1	4.68	22,725	27,251	0	$6,068	100	15	2,142	20,888	$25,603	154,199	17.60
23	BPA PROG CONS	2007	27.9	4.68	11454	59178	0	$13,177	100	15	1,080	10,528	55,599	158,009	18.04
24	COWLITZ FALLS	1994	26.0	4.25	0	4,137	0	0	100	60	11,620	189,488	67,467	164,715	18.80
25	BPA PROG CONS	2009	28.4	4.68	20,412	69,493	0	$15,474	100	15	1,924	18,762	$65,290	197,304	22.52
26	BPA PROG CONS	2015	39.5	4.68	42,697	87,986	0	$19,592	100	15	4,025	39,246	$82,665	205,756	23.49
27	BPA PROG CONS	2014	39.5	4.68	43,552	88,570	0	$19,722	100	15	4,106	40,032	$83,214	208,009	23.75
28	BPA PROG CONS	2013	39.5	4.68	44,431	89,602	0	$19,952	100	15	4,189	40,840	$84,183	211,009	24.09
29	BPA PROG CONS	2012	39.5	4.68	45,319	90,648	0	$20,185	100	15	4,272	41,656	$85,165	214,044	24.43
30	BPA PROG CONS	2011	34.9	4.68	38,807	86,162	0	$19,186	100	15	3,658	35,670	$80,951	222,771	25.43
31	BPA PROG CONS	2010	31.1	4.68	32,819	85,312	0	$18,997	100	15	3,094	30,166	$80,152	236,481	27.00
32	WAUNA-Steam-Cogen.	1996	21.7	0.00	0	11,176	0	0	100	30	0	0	154,827	237,830	27.15
33	BILLING CREDITS	1996	10.14	0.00	0	5268	0	0	100	30	0	0	72,978	239,902	27.39

	B	C	D	E	F	G	H	I	J
2				**Table 2.2.3**					7b2 Resource_03
3									
4					**Resources Sorted by Least Cost**				
5									
6									
7						Annual	Cum.	Annual	Levelized
8				AMW	Cum.	Costs	Costs	Costs	Costs
9				output	output	2010 $s	2010 $s	2nd Yr.	2010 $/MWh
10									
11	Resource 01	BPA PROG CONS		20	20	$ 29,067	$ 29,067	$ 7	$ 10.85
12	Resource 02	IDAHO FALLS ND		14	34	$ 4,978	$ 34,045	$ 4,978	$ 11.03
13	Resource 03	BPA PROG CONS		32	66	$ 40,977	$ 75,023	$ 1,549	$ 12.80
14	Resource 04	BPA PROG CONS		28	94	$ 33,214	$ 108,236	$ 2,593	$ 14.90
15	Resource 05	BPA PROG CONS		27	121	$ 29,398	$ 137,634	$ 3,261	$ 16.12
16	Resource 06	BPA PROG CONS		21	143	$ 33,192	$ 170,826	$ 1,576	$ 16.65
17	Resource 07	BOARDMAN PUBLIC ND		50	192	$ 16,104	$ 186,930	$ 16,104	$ 17.08
18	Resource 08	BPA PROG CONS		31	223	$ 66,272	$ 253,202	$ 862	$ 17.55
19	Resource 09	BPA PROG CONS		21	244	$ 29,393	$ 282,595	$ 2,142	$ 17.60
20	Resource 10	BPA PROG CONS		29	273	$ 60,258	$ 342,853	$ 1,080	$ 18.04
21	Resource 11	COWLITZ FALLS		26	299	$ 15,757	$ 358,610	$ 15,757	$ 18.80
22	Resource 12	BPA PROG CONS		29	328	$ 71,417	$ 430,027	$ 1,924	$ 22.52
23	Resource 13	BPA PROG CONS		41	369	$ 92,011	$ 522,038	$ 4,025	$ 23.49
24	Resource 14	BPA PROG CONS		41	409	$ 92,676	$ 614,714	$ 4,106	$ 23.75
25	Resource 15	BPA PROG CONS		41	450	$ 93,791	$ 708,505	$ 4,189	$ 24.09
26	Resource 16	BPA PROG CONS		41	490	$ 94,920	$ 803,425	$ 4,272	$ 24.43
27	Resource 17	BPA PROG CONS		36	526	$ 89,820	$ 893,245	$ 3,658	$ 25.43
28	Resource 18	BPA PROG CONS		32	558	$ 88,406	$ 981,651	$ 3,094	$ 27.00
29	Resource 19	WAUNA-Steam-Cogen.		22	580	$ 11,176	$ 992,826	$ 11,176	$ 27.15
30	Resource 20	BILLING CREDITS		10	590	$ 5,268	$ 998,094	$ 5,268	$ 27.39

	B	C	D	E	F	G	H	I
2		**Table 2.2.4**						7b2 Resource_04
3								
4		**Conservation aMW Selected**						
5								
6								
7			**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
8								
9	Resource 01	BPA PROG CONS	19.7	19.7	19.7	19.7	19.7	19.7
10	Resource 02	IDAHO FALLS ND	0.0	0.0	0.0	0.0	0.0	0.0
11	Resource 03	BPA PROG CONS	31.9	31.9	31.9	31.9	31.9	31.9
12	Resource 04	BPA PROG CONS	28.4	28.4	28.4	28.4	28.4	28.4
13	Resource 05	BPA PROG CONS	27.4	27.4	27.4	27.4	27.4	27.4
14	Resource 06	BPA PROG CONS	21.2	21.2	21.2	21.2	21.2	21.2
15	Resource 07	BOARDMAN PUBLIC ND	0.0	0.0	0.0	0.0	0.0	0.0
16	Resource 08	BPA PROG CONS	31.2	31.2	31.2	31.2	31.2	31.2
17	Resource 09	BPA PROG CONS	20.7	20.7	20.7	20.7	20.7	20.7
18	Resource 10	BPA PROG CONS	28.7	28.7	28.7	28.7	28.7	28.7
19	Resource 11	COWLITZ FALLS	0.0	0.0	0.0	0.0	0.0	0.0
20	Resource 12	BPA PROG CONS	29.2	29.2	29.2	29.2	29.2	29.2
21	Resource 13	BPA PROG CONS	0.0	40.6	40.6	40.6	40.6	40.6
22	Resource 14	BPA PROG CONS	0.0	0.0	40.6	40.6	40.6	40.6
23	Resource 15	BPA PROG CONS	0.0	0.0	0.0	40.6	40.6	40.6
24	Resource 16	BPA PROG CONS	0.0	0.0	0.0	0.0	40.6	40.6
25	Resource 17	BPA PROG CONS	0.0	0.0	0.0	0.0	0.0	35.9
26	Resource 18	BPA PROG CONS	0.0	0.0	0.0	0.0	0.0	0.0
27	Resource 19	WAUNA-Steam-Cogen.	0.0	0.0	0.0	0.0	0.0	0.0
28	Resource 20	BILLING CREDITS	0.0	0.0	0.0	0.0	0.0	0.0
32								
33		**Total Conservation Selected**	**238.2**	**278.8**	**319.5**	**360.1**	**400.7**	**436.6**

	B	C	D	E	F	G	H	I
2				**Table 2.2.5**				7b2 Resource_05
3								
4			**Real Dollar Cost of Resources Selected**					
5			(Before Amortization of Expensed Conservation)					
6								
7								
8			**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
9								
10	Resource 01	BPA PROG CONS	$ 29,067	$ 7	$ 7	$ 7	$ 7	$ 7
11	Resource 02	IDAHO FALLS ND	$ 4,978	$ 4,978	$ 4,978	$ 4,978	$ 4,978	$ 4,978
12	Resource 03	BPA PROG CONS	$ 40,977	$ 1,549	$ 1,549	$ 1,549	$ 1,549	$ 1,549
13	Resource 04	BPA PROG CONS	$ 33,214	$ 2,593	$ 2,593	$ 2,593	$ 2,593	$ 2,593
14	Resource 05	BPA PROG CONS	$ 29,398	$ 3,261	$ 3,261	$ 3,261	$ 3,261	$ 3,261
15	Resource 06	BPA PROG CONS	$ 33,192	$ 1,576	$ 1,576	$ 1,576	$ 1,576	$ 1,576
16	Resource 07	BOARDMAN PUBLIC ND	$ 16,104	$ 16,104	$ 16,104	$ 16,104	$ 16,104	$ 16,104
17	Resource 08	BPA PROG CONS	$ 66,272	$ 862	$ 862	$ 862	$ 862	$ 862
18	Resource 09	BPA PROG CONS	$ 29,393	$ 2,142	$ 2,142	$ 2,142	$ 2,142	$ 2,142
19	Resource 10	BPA PROG CONS	$ 60,258	$ 1,080	$ 1,080	$ 1,080	$ 1,080	$ 1,080
20	Resource 11	COWLITZ FALLS	$ 15,757	$ 15,757	$ 15,757	$ 15,757	$ 15,757	$ 15,757
21	Resource 12	BPA PROG CONS	$ 71,417	$ 1,924	$ 1,924	$ 1,924	$ 1,924	$ 1,924
22	Resource 13	BPA PROG CONS	$ -	$ 92,011	$ 4,025	$ 4,025	$ 4,025	$ 4,025
23	Resource 14	BPA PROG CONS	$ -	$ -	$ 92,676	$ 4,106	$ 4,106	$ 4,106
24	Resource 15	BPA PROG CONS	$ -	$ -	$ -	$ 93,791	$ 4,189	$ 4,189
25	Resource 16	BPA PROG CONS	$ -	$ -	$ -	$ -	$ 94,920	$ 4,272
26	Resource 17	BPA PROG CONS	$ -	$ -	$ -	$ -	$ -	$ 89,820
27	Resource 18	BPA PROG CONS	$ -	$ -	$ -	$ -	$ -	$ -
28	Resource 19	WAUNA-Steam-Cogen.	$ -	$ -	$ -	$ -	$ -	$ -
29	Resource 20	BILLING CREDITS	$ -	$ -	$ -	$ -	$ -	$ -

	B	C	D	E	F	G	H	I
2				Table 2.2.6				7b2 Resource_06
3								
4		**Nominal Amortized Cost of Expensed Portion of Conservation Resources Selected**						
5								
6								
7			**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
8								
9	Resource 01	BPA PROG CONS	$ 6,471	$ 6,471	$ 6,471	$ 6,471	$ 6,471	$ -
10	Resource 02	IDAHO FALLS ND	$ -	$ -	$ -	$ -	$ -	$ -
11	Resource 03	BPA PROG CONS	$ 8,780	$ 8,780	$ 8,780	$ 8,780	$ 8,780	$ -
12	Resource 04	BPA PROG CONS	$ 6,819	$ 6,819	$ 6,819	$ 6,819	$ 6,819	$ -
13	Resource 05	BPA PROG CONS	$ 5,820	$ 5,820	$ 5,820	$ 5,820	$ 5,820	$ -
14	Resource 06	BPA PROG CONS	$ 7,040	$ 7,040	$ 7,040	$ 7,040	$ 7,040	$ -
15	Resource 07	BOARDMAN PUBLIC ND	$ -	$ -	$ -	$ -	$ -	$ -
16	Resource 08	BPA PROG CONS	$ 14,565	$ 14,565	$ 14,565	$ 14,565	$ 14,565	$ -
17	Resource 09	BPA PROG CONS	$ 6,068	$ 6,068	$ 6,068	$ 6,068	$ 6,068	$ -
18	Resource 10	BPA PROG CONS	$ 13,177	$ 13,177	$ 13,177	$ 13,177	$ 13,177	$ -
19	Resource 11	COWLITZ FALLS	$ -	$ -	$ -	$ -	$ -	$ -
20	Resource 12	BPA PROG CONS	$ 15,474	$ 15,474	$ 15,474	$ 15,474	$ 15,474	$ -
21	Resource 13	BPA PROG CONS	$ -	$ 19,989	$ 19,989	$ 19,989	$ 19,989	$ 19,989
22	Resource 14	BPA PROG CONS	$ -	$ -	$ 20,542	$ 20,542	$ 20,542	$ 20,542
23	Resource 15	BPA PROG CONS	$ -	$ -	$ -	$ 21,205	$ 21,205	$ 21,205
24	Resource 16	BPA PROG CONS	$ -	$ -	$ -	$ -	$ 21,887	$ 21,887
25	Resource 17	BPA PROG CONS	$ -	$ -	$ -	$ -	$ -	$ 21,222
26	Resource 18	BPA PROG CONS	$ -	$ -	$ -	$ -	$ -	$ -
27	Resource 19	WAUNA-Steam-Cogen.	$ -	$ -	$ -	$ -	$ -	$ -
28	Resource 20	BILLING CREDITS	$ -	$ -	$ -	$ -	$ -	$ -

	B	C	D	E	F	G	H	I
2				**Table 2.2.7**				7b2 Resource_07
3								
4	**Nominal Annual Cost of Capital Portion of Conservation Resources Selected**							
5								
6								
7			**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
8								
9	Resource 01	BPA PROG CONS	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7
10	Resource 02	IDAHO FALLS ND	$ -	$ -	$ -	$ -	$ -	$ -
11	Resource 03	BPA PROG CONS	$ 1,549	$ 1,549	$ 1,549	$ 1,549	$ 1,549	$ 1,549
12	Resource 04	BPA PROG CONS	$ 2,593	$ 2,593	$ 2,593	$ 2,593	$ 2,593	$ 2,593
13	Resource 05	BPA PROG CONS	$ 3,261	$ 3,261	$ 3,261	$ 3,261	$ 3,261	$ 3,261
14	Resource 06	BPA PROG CONS	$ 1,576	$ 1,576	$ 1,576	$ 1,576	$ 1,576	$ 1,576
15	Resource 07	BOARDMAN PUBLIC ND	$ -	$ -	$ -	$ -	$ -	$ -
16	Resource 08	BPA PROG CONS	$ 862	$ 862	$ 862	$ 862	$ 862	$ 862
17	Resource 09	BPA PROG CONS	$ 2,142	$ 2,142	$ 2,142	$ 2,142	$ 2,142	$ 2,142
18	Resource 10	BPA PROG CONS	$ 1,080	$ 1,080	$ 1,080	$ 1,080	$ 1,080	$ 1,080
19	Resource 11	COWLITZ FALLS	$ -	$ -	$ -	$ -	$ -	$ -
20	Resource 12	BPA PROG CONS	$ 1,924	$ 1,924	$ 1,924	$ 1,924	$ 1,924	$ 1,924
21	Resource 13	BPA PROG CONS	$ -	$ 4,106	$ 4,106	$ 4,106	$ 4,106	$ 4,106
22	Resource 14	BPA PROG CONS	$ -	$ -	$ 4,276	$ 4,276	$ 4,276	$ 4,276
23	Resource 15	BPA PROG CONS	$ -	$ -	$ -	$ 4,452	$ 4,452	$ 4,452
24	Resource 16	BPA PROG CONS	$ -	$ -	$ -	$ -	$ 4,632	$ 4,632
25	Resource 17	BPA PROG CONS	$ -	$ -	$ -	$ -	$ -	$ 4,046
26	Resource 18	BPA PROG CONS	$ -	$ -	$ -	$ -	$ -	$ -
27	Resource 19	WAUNA-Steam-Cogen.	$ -	$ -	$ -	$ -	$ -	$ -
28	Resource 20	BILLING CREDITS	$ -	$ -	$ -	$ -	$ -	$ -

Table 2.2.8 7b2 Resource_08

Nominal Total Annual Cost of All Resources Selected

	B	C	D	E	F	G	H	I
2				Table 2.2.8				7b2 Resource_08
3								
4				Nominal Total Annual Cost of All Resources Selected				
5								
6								
7			**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
8								
9	Resource 01	BPA PROG CONS	$ 6,478	$ 6,478	$ 6,478	$ 6,478	$ 6,478	$ 7
10	Resource 02	IDAHO FALLS ND	$ 4,978	$ 5,079	$ 5,185	$ 5,291	$ 5,398	$ 5,507
11	Resource 03	BPA PROG CONS	$ 10,329	$ 10,329	$ 10,329	$ 10,329	$ 10,329	$ 1,549
12	Resource 04	BPA PROG CONS	$ 9,411	$ 9,411	$ 9,411	$ 9,411	$ 9,411	$ 2,593
13	Resource 05	BPA PROG CONS	$ 9,081	$ 9,081	$ 9,081	$ 9,081	$ 9,081	$ 3,261
14	Resource 06	BPA PROG CONS	$ 8,616	$ 8,616	$ 8,616	$ 8,616	$ 8,616	$ 1,576
15	Resource 07	BOARDMAN PUBLIC ND	$ 16,104	$ 16,429	$ 16,773	$ 17,115	$ 17,461	$ 17,812
16	Resource 08	BPA PROG CONS	$ 15,427	$ 15,427	$ 15,427	$ 15,427	$ 15,427	$ 862
17	Resource 09	BPA PROG CONS	$ 8,210	$ 8,210	$ 8,210	$ 8,210	$ 8,210	$ 2,142
18	Resource 10	BPA PROG CONS	$ 14,257	$ 14,257	$ 14,257	$ 14,257	$ 14,257	$ 1,080
19	Resource 11	COWLITZ FALLS	$ 15,757	$ 15,841	$ 15,929	$ 16,017	$ 16,106	$ 16,196
20	Resource 12	BPA PROG CONS	$ 17,398	$ 17,398	$ 17,398	$ 17,398	$ 17,398	$ 1,924
21	Resource 13	BPA PROG CONS	$ -	$ 24,095	$ 24,095	$ 24,095	$ 24,095	$ 24,095
22	Resource 14	BPA PROG CONS	$ -	$ -	$ 24,819	$ 24,819	$ 24,819	$ 24,819
23	Resource 15	BPA PROG CONS	$ -	$ -	$ -	$ 25,656	$ 25,656	$ 25,656
24	Resource 16	BPA PROG CONS	$ -	$ -	$ -	$ -	$ 26,519	$ 26,519
25	Resource 17	BPA PROG CONS	$ -	$ -	$ -	$ -	$ -	$ 25,268
26	Resource 18	BPA PROG CONS	$ -	$ -	$ -	$ -	$ -	$ -
27	Resource 19	WAUNA-Steam-Cogen.	$ -	$ -	$ -	$ -	$ -	$ -
28	Resource 20	BILLING CREDITS	$ -	$ -	$ -	$ -	$ -	$ -
32								
33		**Total Annual Cost of Selected Resources**	**$ 136,047**	**$ 160,652**	**$ 186,009**	**$ 212,201**	**$ 239,263**	**$ 180,866**

Table 2.2.9 7b2 Resource_09

Calculation of Annual Credit for the Sale of 7b2 Resource Capability in Excess of Need

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Last Resource Selected	Resource 12	Resource 13	Resource 14	Resource 15	Resource 16	Resource 17
Resources Selected From Resource Stack aMW	327.9	368.6	409.2	449.8	490.4	526.3
Resources Needed From Resource Stack aMW	307.8	358.0	405.7	441.4	486.1	511.1
Remainder	20.1	10.6	3.5	8.4	4.3	15.2
Last Resource Selected Levelized Cost Per MWh 2010$	$ 22.52	$ 23.49	$ 23.75	$ 24.09	$ 24.43	$ 25.43
Annual GDP Multiplier	1.000	1.020	1.042	1.063	1.084	1.106
Cost of Remander Recovered by Sales (Nominal $000)	**$ (3,973)**	**$ (2,224)**	**$ (757)**	**$ (1,875)**	**$ (1,008)**	**$ (3,742)**
Total Annual Cost of Selected Resources	**$ 136,047**	**$ 160,652**	**$ 186,009**	**$ 212,201**	**$ 239,263**	**$ 180,866**
Total Net Annual Cost of Selected Resources	**$ 132,074**	**$ 158,428**	**$ 185,252**	**$ 210,325**	**$ 238,255**	**$ 177,124**

Table 2.3.1 7B2 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	0	139,887	88,195	432,374	660,455
4. BPA FISH & WILDLIFE PROGRAM	204,098	14,142	8,916	248,887	271,945
5. TROJAN				2,200	2,200
6. WNP #1				166,431	166,431
7. WNP #2				493,547	493,547
8. WNP #3				144,892	144,892
9. SYSTEM AUGMENTATION				180,762	180,762
10. BALANCING POWER PURCHASES				87,631	87,631
11. TOTAL FEDERAL BASE SYSTEM	**204,098**	**154,029**	**97,111**	**1,756,724**	**2,007,863**
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. NEW RESOURCES FROM 7B2 STACK				132,074	132,074
16. TOTAL NEW RESOURCES				**132,074**	**132,074**
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	18,254	1,265	797	138,219	140,281
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**18,254**	**1,265**	**797**	**138,219**	**140,281**
23. TOTAL GENERATION COSTS	**222,352**	**155,294**	**97,908**	**2,027,017**	**2,280,219**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				125,940	125,940
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				50,690	50,690
28. TOTAL TRANSMISSION COSTS				**177,630**	**177,630**
29. TOTAL PBL REVENUE REQUIREMENT		**155,294**	**97,908**	**2,204,648**	**2,457,849**

Table 2.3.2 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	0	144,691	86,712	447,358	678,761
4. BPA FISH & WILDLIFE PROGRAM	243,903	15,464	9,268	272,719	297,451
5. TROJAN				2,300	2,300
6. WNP #1				167,977	167,977
7. WNP #2				551,051	551,051
8. WNP #3				169,093	169,093
9. SYSTEM AUGMENTATION				273,041	273,041
10. BALANCING POWER PURCHASES				72,108	72,108
11. TOTAL FEDERAL BASE SYSTEM	**243,903**	**160,155**	**95,980**	**1,955,647**	**2,211,782**
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. NEW RESOURCES FROM 7B2 STACK				158,422	158,422
16. TOTAL NEW RESOURCES				**158,422**	**158,422**
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	13,577	861	516	138,617	139,994
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**13,577**	**861**	**516**	**138,617**	**139,994**
23. TOTAL GENERATION COSTS	**257,480**	**161,016**	**96,496**	**2,252,686**	**2,510,198**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				124,189	124,189
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				51,340	51,340
28. TOTAL TRANSMISSION COSTS				**176,529**	**176,529**
29. TOTAL PBL REVENUE REQUIREMENT		**161,016**	**96,496**	**2,429,215**	**2,686,727**

Table 2.3.3 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	0	156,662	0	469,861	626,524
4. BPA FISH & WILDLIFE PROGRAM	271,798	17,263	0	294,600	311,863
5. TROJAN				2,300	2,300
6. WNP #1				192,951	192,951
7. WNP #2				628,707	628,707
8. WNP #3				162,208	162,208
9. SYSTEM AUGMENTATION				211,656	211,656
10. BALANCING POWER PURCHASES				85,220	85,220
11. TOTAL FEDERAL BASE SYSTEM	**271,798**	**173,925**	**0**	**2,047,502**	**2,221,427**
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. NEW RESOURCES FROM 7B2 STACK				185,254	185,254
16. TOTAL NEW RESOURCES				**185,254**	**185,254**
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	11,525	732	0	150,254	150,986
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**11,525**	**732**	**0**	**150,254**	**150,986**
23. TOTAL GENERATION COSTS	**283,323**	**174,657**	**0**	**2,383,010**	**2,557,667**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				121,347	121,347
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,428	52,428
28. TOTAL TRANSMISSION COSTS				**174,776**	**174,776**
29. TOTAL PBL REVENUE REQUIREMENT		**174,657**	**0**	**2,557,786**	**2,732,443**

Table 2.3.4 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	0	172,530	38,749	484,659	695,938
4. BPA FISH & WILDLIFE PROGRAM	293,187	18,828	4,229	302,591	325,648
5. TROJAN				2,400	2,400
6. WNP #1				292,968	292,968
7. WNP #2				549,085	549,085
8. WNP #3				178,719	178,719
9. SYSTEM AUGMENTATION				310,848	310,848
10. BALANCING POWER PURCHASES				77,314	77,314
11. TOTAL FEDERAL BASE SYSTEM	**293,187**	**191,358**	**42,978**	**2,198,585**	**2,432,920**
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. NEW RESOURCES FROM 7B2 STACK				210,325	210,325
16. TOTAL NEW RESOURCES				**210,325**	**210,325**
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	11,049	710	159	151,035	151,904
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**11,049**	**710**	**159**	**151,035**	**151,904**
23. TOTAL GENERATION COSTS	**304,236**	**192,068**	**43,137**	**2,559,945**	**2,795,150**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				120,794	120,794
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,437	52,437
28. TOTAL TRANSMISSION COSTS				**174,231**	**174,231**
29. TOTAL PBL REVENUE REQUIREMENT		**192,068**	**43,137**	**2,734,176**	**2,969,381**

Table 2.3.5 7B2 COSA 06 FY2014

COST OF SERVICE ANALYSIS

Itemized Revenue Requirement
FY 2014

FY 2014

	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	0	191,620	0	499,708	691,328
4. BPA FISH & WILDLIFE PROGRAM	312,758	22,214	0	295,673	317,887
5. TROJAN				2,500	2,500
6. WNP #1				292,140	292,140
7. WNP #2				515,143	515,143
8. WNP #3				175,460	175,460
9. SYSTEM AUGMENTATION				308,232	308,232
10. BALANCING POWER PURCHASES				80,171	80,171
11. TOTAL FEDERAL BASE SYSTEM	**312,758**	**213,834**	**0**	**2,169,027**	**2,382,861**
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. NEW RESOURCES FROM 7B2 STACK				238,255	238,255
16. TOTAL NEW RESOURCES				**238,255**	**238,255**
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	10,189	724	0	156,853	157,577
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	**10,189**	**724**	**0**	**156,853**	**157,577**
23. TOTAL GENERATION COSTS	**322,947**	**214,558**	**0**	**2,564,135**	**2,778,693**
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,447	123,447
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				52,446	52,446
28. TOTAL TRANSMISSION COSTS				**176,893**	**176,893**
29. TOTAL PBL REVENUE REQUIREMENT		**214,558**	**0**	**2,741,028**	**2,955,586**

	A	B	C	D	E	F	G
2		**Table 2.3.6**				7B2 COSA 06 FY2015	
3							
4		**COST OF SERVICE ANALYSIS**					
5							
6		**Itemized Revenue Requirement**					
7		FY 2015					
8							
9							
10							
11							
12	**FY 2015**						
13		**A**	**B**	**C**	**D**	**E**	
14		**INVEST**	**NET**	**NET**	**OPER**	**TOTAL**	
15		**BASE**	**INT**	**REVS**	**EXP**	**(B+C+D)**	
16	1. GENERATION COSTS						
17							
18	2. FEDERAL BASE SYSTEM						
19	3. HYDRO	0	204,560	2,784	513,971	721,314	
20	4. BPA FISH & WILDLIFE PROGRAM	330,116	25,657	349	304,864	330,870	
21	5. TROJAN				2,600	2,600	
22	6. WNP #1				220,020	220,020	
23	7. WNP #2				612,178	612,178	
24	8. WNP #3				193,459	193,459	
25	9. SYSTEM AUGMENTATION				415,263	415,263	
26	10. BALANCING POWER PURCHASES				44,485	44,485	
27	**11. TOTAL FEDERAL BASE SYSTEM**	**330,116**	**230,217**	**3,133**	**2,306,838**	**2,540,188**	
28							
29	12. NEW RESOURCES						
30	13. IDAHO FALLS				0	0	
31	14. COWLITZ FALLS				0	0	
32	15. NEW RESOURCES FROM 7B2 STACK				177,114	177,114	
33	**16. TOTAL NEW RESOURCES**				**177,114**	**177,114**	
34							
35	17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0	
36							
37	18. CONSERVATION		0	0	0	0	
38							
39	19. OTHER GENERATION COSTS						
40	20. BPA PROGRAMS	7,498	583	8	162,582	163,173	
41	21. WNP #3 PLANT				0	0	
42	**22. TOTAL OTHER GENERATION COSTS**	**7,498**	**583**	**8**	**162,582**	**163,173**	
43							
44	**23. TOTAL GENERATION COSTS**	**337,614**	**230,800**	**3,141**	**2,646,534**	**2,880,474**	
45							
46	24. TRANSMISSION COSTS						
47	25. TBL TRANSMISSION/ANCILLARY SERVICES				122,102	122,102	
48	26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000	
49	27. GENERAL TRANSFER AGREEMENTS				52,446	52,446	
50	**28. TOTAL TRANSMISSION COSTS**				**175,548**	**175,548**	
51							
52	**29. TOTAL PBL REVENUE REQUIREMENT**		**230,800**	**3,141**	**2,822,082**	**3,056,022**	

Table 2.3.7

COST OF SERVICE ANALYSIS

Classified Revenue Requirement

Fiscal Year 2010

	Total Rev Req	Energy %	Energy Total	Demand %	Demand Total	Load Variance %	Load Variance Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 660,455	90.26%	$ 596,109	8.72%	$ 57,602	1.02%	$ 6,744
4. BPA FISH & WILDLIFE PROGRAM	$ 271,945	91.28%	$ 248,227	8.72%	$ 23,718		
5. TROJAN	$ 2,200	91.28%	$ 2,008	8.72%	$ 192		
6. WNP #1	$ 166,431	91.28%	$ 151,916	8.72%	$ 14,515		
7. WNP #2	$ 493,547	90.26%	$ 445,462	8.72%	$ 43,045	1.02%	$ 5,040
8. WNP #3	$ 144,892	91.28%	$ 132,255	8.72%	$ 12,637		
9. SYSTEM AUGMENTATION	$ 180,762	90.26%	$ 163,151	8.72%	$ 15,765	1.02%	$ 1,846
10. BALANCING POWER PURCHASES	$ 87,631	90.26%	$ 79,093	8.72%	$ 7,643	1.02%	$ 895
11. TOTAL FEDERAL BASE SYSTEM	**$ 2,007,863**		**$ 1,818,221**		**$ 175,117**		**$ 14,525**
12. NEW RESOURCES							
13. IDAHO FALLS	$ -				$ -		$ -
14. COWLITZ FALLS	$ -		$ -		$ -		$ -
15. NEW RESOURCES FROM 7B2 STACK	$ 132,074	90.26%	$ 119,206	8.72%	$ 11,519	1.02%	$ 1,349
16. TOTAL NEW RESOURCES	**$ 132,074**		**$ 119,206**		**$ 11,519**		**$ 1,349**
17. RESIDENTIAL EXCHANGE	$ -		$ -				
18. CONSERVATION	$ -		$ -		$ -		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 140,281	90.26%	$ 126,614	8.72%	$ 12,235	1.02%	$ 1,432
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	**$ 140,281**		**$ 126,614**		**$ 12,235**		**$ 1,432**
23. TOTAL GENERATION COSTS	**$ 2,280,219**		**$ 2,064,042**		**$ 198,871**		**$ 17,306**
24. TRANSMISSION COSTS							
25. TBL TRANSMISSION/ANCILLARY SERVICES	$ 125,940	100.00%	$ 125,940				
26. 3RD PARTY TRANS/ANCILLARY SERVICES	$ 1,000	100.00%	$ 1,000				
27. GENERAL TRANSFER AGREEMENTS	$ 50,690	100.00%	$ 50,690				
28. TOTAL TRANSMISSION COSTS	**177,630**		**177,630**				
29. TOTAL PBL REVENUE REQUIREMENT	**$ 2,457,849**		**$ 2,241,672**		**$ 216,177**		

	B	C	D	E	F	G	H	I	J
2						**Table 2.3.8**			COSA 09
3									
4						**COST OF SERVICE ANALYSIS**			
5									
6						**Revenue Credits**			
7						Test Period October 2009 - September 2015			
8									
9									
10				**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
11									
12	Downstream Benefits & Storage			$ 8,921	$ 8,921	$ 8,921	$ 8,571	$ 8,568	$ 8,568
13	4(h)(10)(c) Credits			$ 96,689	$ 101,969	$ 102,792	$ 105,969	$ 108,917	$ 111,680
14	Colville & Spokane SettlementsCredit			$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600
15	Network Wind Integration&Shaping			$ 1,953	$ 1,953	$ -	$ -	$ -	$ -
16	Misc. Revenues			$ 3,420	$ 3,420	$ 3,420	$ 3,420	$ 3,420	$ 3,420
17	Green Tags			$ -	$ -	$ -	$ -	$ -	$ -
18	Ancillary Product Revenues			$ 90,176	$ 102,730	$ 102,730	$ 102,730	$ 102,730	$ 102,730
19	**Total**			**$ 205,759**	**$ 223,593**	**$ 222,462**	**$ 225,290**	**$ 228,235**	**$ 230,998**

	B	C	D	E	F	G	H	I	J	K
2						**Table 2.4.1**			7B2 ALLOCATE 01	
3										
4						**Energy Allocation Factors**				
5						Average Megawatts				
6										
7					**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
8										
9	**Total Usage**									
10	Priority Firm....................				7,897	7,942	8,267	8,368	8,553	8,642
11	Industrial Firm.................				0	0	0	0	0	0
12	New Resource Firm........				0	0	0	0	0	0
13	Surplus Firm Other..........				616	597	196	197	195	180
14	**Total................................**				**8,513**	**8,539**	**8,463**	**8,565**	**8,748**	**8,822**
15	**Federal Base System**									
16	Priority Firm....................				7,897	7,942	8,057	8,124	8,262	8,311
17	Industrial Firm.................				0	0	0	0	0	0
18	New Resource Firm........				0	0	0	0	0	0
19	Surplus Firm Other..........				308	239	0	0	0	0
20	**Total................................**				**8,205**	**8,181**	**8,057**	**8,124**	**8,262**	**8,311**
21	**Residential Exchange**									
22	Priority Firm....................				0	0	0	0	0	0
23	Industrial Firm.................				0	0	0	0	0	0
24	New Resource Firm........				0	0	0	0	0	0
25	Surplus Firm Other..........				0	0	0	0	0	0
26	**Total................................**				**0**	**0**	**0**	**0**	**0**	**0**
27	**New Resource**									
28	Priority Firm....................				0	0	0	0	0	0
29	Industrial Firm.................				0	0	0	0	0	0
30	New Resource Firm........				0	0	0	0	0	0
31	Surplus Firm Other..........				308	358	406	441	486	511
32	**Total................................**				**308**	**358**	**406**	**441**	**486**	**511**
33	**Conservation**				0	0	0	0	0	0
34	Priority Firm....................				0	0	0	0	0	0
35	Industrial Firm.................				0	0	0	0	0	0
36	New Resource Firm........				0	0	0	0	0	0
37	Surplus Firm Other..........				0	0	0	0	0	0
38	**Total................................**				**8,513**	**8,539**	**8,463**	**8,565**	**8,748**	**8,822**

	B	C	D	E	F	G	H	I	J
2					**Table 2.4.2**				7B2 ALLOCATE 02
3									
4						**Initial Rate Pool Cost Allocation**			
5									
6				**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
7	**CLASSES OF SERVICE**								
8	**Power Rates**								
9	**Priority Firm - Preference**								
10	FBS			$ 1,932,472	$ 2,147,164	$ 2,221,427	$ 2,432,920	$ 2,382,861	$ 2,540,188
11	NR			$ -	$ -	$ -	$ -	$ -	$ -
12	Exchange			$ -	$ -	$ -	$ -	$ -	$ -
13	conservation			$ -	$ -	$ -	$ -	$ -	$ -
14	BPA programs			$ 294,912	$ 294,395	$ 318,234	$ 318,633	$ 327,005	$ 331,826
15	**Total**			**$ 2,227,384**	**$ 2,441,559**	**$ 2,539,661**	**$ 2,751,553**	**$ 2,709,867**	**$ 2,872,014**
16	**Industrial Firm Power**								
17	FBS			$ -	$ -	$ -	$ -	$ -	$ -
18	NR			$ -	$ -	$ -	$ -	$ -	$ -
19	Exchange			$ -	$ -	$ -	$ -	$ -	$ -
20	conservation			$ -	$ -	$ -	$ -	$ -	$ -
21	BPA programs			$ -	$ -	$ -	$ -	$ -	$ -
22	**Total**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
23	**New Resources Firm**								
24	FBS			$ -	$ -	$ -	$ -	$ -	$ -
25	NR			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
26	Exchange			$ -	$ -	$ -	$ -	$ -	$ -
27	conservation			$ -	$ -	$ -	$ -	$ -	$ -
28	BPA programs			$ -	$ -	$ -	$ -	$ -	$ -
29	**Total**			**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**
30	**Surplus Firm Power**								
31	FBS			$ 75,391	$ 64,618	$ -	$ -	$ -	$ -
32	NR			$ 132,074	$ 158,422	$ 185,254	$ 210,325	$ 238,255	$ 177,114
33	Exchange			$ -	$ -	$ -	$ -	$ -	$ -
34	conservation			$ -	$ -	$ -	$ -	$ -	$ -
35	BPA programs			$ 23,000	$ 22,128	$ 7,528	$ 7,502	$ 7,464	$ 6,895
36	**Total**			**$ 230,465**	**$ 245,168**	**$ 192,782**	**$ 217,828**	**$ 245,719**	**$ 184,008**
37									
38	**'otal Revenue Requirement**			**$ 2,457,849**	**$ 2,686,727**	**$ 2,732,443**	**$ 2,969,381**	**$ 2,955,586**	**$ 3,056,022**

	B	C	D	E	F	G	H	I	J	K
2					Table 2.5.1				7B2 RDS 11	
3										
4				Rate Design Study						
5										
6				Allocation of Secondary and Other Revenue Credits						
7				Test Period October 2009 - September 2015						
8										
9										
10				**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	
11										
12	**Forecast of Secondary Revenues**			**$ 703,912**	**$ 767,646**	**$ 821,998**	**$ 863,652**	**$ 901,284**	**$ 902,092**	
13	Additional Secondary Revenues			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
14	**Total Gross Secondary Revenues**			**$ 703,912**	**$ 767,646**	**$ 821,998**	**$ 863,652**	**$ 901,284**	**$ 902,092**	
15										
16										
17				**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	
18	**Allocation of Secondary Revenues Credit**									
19	Priority Firm..			$ (677,482)	$ (745,219)	$ (821,998)	$ (863,652)	$ (901,284)	$ (902,092)	
20	Industrial Firm..			$ -	$ -	$ -	$ -	$ -	$ -	
21	New Resource Firm......................................			$ -	$ -	$ -	$ -	$ -	$ -	
22	Surplus Firm Other.......................................			$ (26,430)	$ (22,427)	$ -	$ -	$ -	$ -	
23	**Total..**			**$ (703,912)**	**$ (767,646)**	**$ (821,998)**	**$ (863,652)**	**$ (901,284)**	**$ (902,092)**	
24										
25										
26										
27				**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	
28										
29	**Total Other Revenue Credits**			**$ 205,759**	**$ 223,593**	**$ 222,462**	**$ 225,290**	**$ 228,235**	**$ 230,998**	
30										
31										
32				**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	
33	**Allocation of Other Revenue Credits**									
34	Priority Firm..			$ (198,033)	$ (217,060)	$ (222,462)	$ (225,290)	$ (228,235)	$ (230,998)	
35	Industrial Firm..			$ -	$ -	$ -	$ -	$ -	$ -	
36	New Resource Firm......................................			$ -	$ -	$ -	$ -	$ -	$ -	
37	Surplus Firm Other.......................................			$ (7,726)	$ (6,532)	$ -	$ -	$ -	$ -	
38	**Total..**			**$ (205,759)**	**$ (223,593)**	**$ (222,462)**	**$ (225,290)**	**$ (228,235)**	**$ (230,998)**	
39										

	B	C	D	E	F	G	H	I	J	K
2					**Table 2.5.2**					7B2 RDS 17
3										
4					**Rate Design Study**					
5										
6					**Calculation of FPS (Surplus)/Shortfall**					
7					Test Period October 2009 - September 2015					
8										
9										
10										
11	**FPS (Surplus)/Shortfall**			**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	
12										
13	Costs allocated to FPS contract sales			$ 230,465	$ 245,168	$ 192,782	$ 217,828	$ 245,719	$ 184,008	
14	Expected Revenue from FPS contract sales			$ -	$ -	$ -	$ -	$ -	$ -	
15	FBS Contract Obligation Revenue			$ 37,228	$ 34,456	$ 510	$ 557	$ 569	$ 581	
16	(Surplus)/Shortfall			**$ 193,237**	**$ 210,713**	**$ 192,272**	**$ 217,270**	**$ 245,150**	**$ 183,427**	
17										
18	Secondary Revenues allocated to FPS			$ (26,430)	$ (22,427)	$ -	$ -	$ -	$ -	
19	Revenue Credits allocated to FPS			$ (7,726)	$ (6,532)	$ -	$ -	$ -	$ -	
20										
21	**FPS (Surplus)/Shortfall**			**$ 159,081**	**$ 181,753**	**$ 192,272**	**$ 217,270**	**$ 245,150**	**$ 183,427**	
22										
23										
24										
25					**Rate Design Study**					
26					**Allocation of FPS (Surplus)/Shortfall**					
27					**Test Period October 2009 - September 2015**					
28										
29										
30				**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	
31	**Allocation of FPS (Surplus)/Shortfall**									
32	Priority Firm..			$ 159,081	$ 181,753	$ 192,272	$ 217,270	$ 245,150	$ 183,427	
33	Industrial Firm..			$ -	$ -	$ -	$ -	$ -	$ -	
34	New Resource Firm....................................			$ -	$ -	$ -	$ -	$ -	$ -	
35	Surplus Firm Other.....................................			$ (159,081)	$ (181,753)	$ (192,272)	$ (217,270)	$ (245,150)	$ (183,427)	
36	**Total..**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
37										

Table 2.5.3 7B2 RDS 19

Rate Design Study

Summary of Initial Cost Allocations

Test Period October 2009 - September 2015

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Allocation of Revenue Requirement						
Priority Firm..	$ 2,227,384	$ 2,441,559	$ 2,539,661	$ 2,751,553	$ 2,709,867	$ 2,872,014
Industrial Firm...	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm.....................................	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Surplus Firm Other......................................	$ 230,465	$ 245,168	$ 192,782	$ 217,828	$ 245,719	$ 184,008
Total..	**$ 2,457,849**	**$ 2,686,727**	**$ 2,732,443**	**$ 2,969,381**	**$ 2,955,586**	**$ 3,056,022**
Allocation of Secondary Revenues Credit						
Priority Firm..	$ (677,482)	$ (745,219)	$ (821,998)	$ (863,652)	$ (901,284)	$ (902,092)
Industrial Firm...	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm.....................................	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other......................................	$ (26,430)	$ (22,427)	$ -	$ -	$ -	$ -
Total..	**$ (703,912)**	**$ (767,646)**	**$ (821,998)**	**$ (863,652)**	**$ (901,284)**	**$ (902,092)**
Allocation of other Revenues Credits						
Priority Firm..	$ (198,033)	$ (217,060)	$ (222,462)	$ (225,290)	$ (228,235)	$ (230,998)
Industrial Firm...	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm.....................................	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other......................................	$ (7,726)	$ (6,532)	$ -	$ -	$ -	$ -
Total..	**$ (205,759)**	**$ (223,593)**	**$ (222,462)**	**$ (225,290)**	**$ (228,235)**	**$ (230,998)**
Allocation of FPS (Surplus)/Shortfall						
Priority Firm..	$ 159,081	$ 181,753	$ 192,272	$ 217,270	$ 245,150	$ 183,427
Industrial Firm...	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm.....................................	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other......................................	$ (159,081)	$ (181,753)	$ (192,272)	$ (217,270)	$ (245,150)	$ (183,427)
Total..	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	FY 2010	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
Low Density Discount						
Priority Firm..	$ 26,419	$ 26,465	$ 26,465	$ 26,465	$ 26,465	$ 26,465
Expenses Due to No DSI Reserves ...						
Priority Firm..	$ 2,817	$ 2,817	$ 2,817	$ 2,817	$ 2,817	$ 2,817
Irrigation Rate Mitigation....................						
Priority Firm..	$ 12,036	$ 12,036	$ 12,036	$ 12,036	$ 12,036	$ 12,036
	FY 2010	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
Initial Allocation						
Priority Firm..	$ 1,552,222	$ 1,702,352	$ 1,728,791	$ 1,921,201	$ 1,866,817	$ 1,963,670
Industrial Firm...	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm.....................................	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Surplus Firm Other......................................	$ 37,228	$ 34,456	$ 510	$ 557	$ 569	$ 581
Total..	**$ 1,589,450**	**$ 1,736,807**	**$ 1,729,301**	**$ 1,921,758**	**$ 1,867,386**	**$ 1,964,251**

Table 2.6

Rate Design Study

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

Fiscal Year 2010

LEVELIZED MARGINAL COSTS OF POWER

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
Energy Mills/kwh												
HLH	40.32	42.10	44.52	48.58	47.65	45.40	40.71	40.03	39.39	42.11	47.13	46.09
LLH	34.12	37.37	39.33	40.73	40.08	37.99	34.05	28.16	29.42	36.21	39.66	40.76
MONTHLY DEMAND	2.05	2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96

PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	3,042	3,276	3,673	3,644	3,259	3,306	2,877	3,096	3,034	3,094	3,211	2,898	65253
LLH	1,983	2,455	2,649	2,706	2,219	2,188	1,934	2,298	1,987	2,255	2,123	2,049	
Demand	8,647	9,560	10,123	10,413	9,936	9,089	7,938	8,120	7,695	8,453	8,129	7,802	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs
HLH	$ 122,666	$ 137,940	$ 163,529	$ 177,015	$ 155,277	$ 150,095	$ 117,112	$ 123,946	$ 119,501	$ 130,294	$ 151,328	$ 133,560	$ 2,666,439	$ 1,336,045
LLH	$ 67,655	$ 91,740	$ 104,181	$ 110,220	$ 88,923	$ 83,123	$ 65,868	$ 64,701	$ 58,447	$ 81,638	$ 84,185	$ 83,494		
Demand	$ 17,727	$ 20,937	$ 23,283	$ 20,410	$ 19,772	$ 16,815	$ 13,812	$ 11,693	$ 10,157	$ 13,610	$ 15,363	$ 15,293	$ 198,871	$ 198,871
												LV Revenue	$ 17,306	$ 17,306
													$ 2,882,616	$ 1,552,222

PF rates	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
HLH	**20.20**	**21.10**	**22.31**	**24.34**	**23.87**	**22.75**	**20.40**	**20.06**	**19.74**	**21.10**	**23.62**	**23.10**
LLH	**17.10**	**18.72**	**19.71**	**20.41**	**20.08**	**19.04**	**17.06**	**14.11**	**14.74**	**18.14**	**19.87**	**20.42**
Demand	**2.05**	**2.19**	**2.30**	**1.96**	**1.99**	**1.85**	**1.74**	**1.44**	**1.32**	**1.61**	**1.89**	**1.96**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 61,458	$ 69,130	$ 81,941	$ 88,689	$ 77,788	$ 75,206	$ 58,686	$ 62,108	$ 59,882	$ 65,285	$ 75,837	$ 66,935	$ 1,336,072
LLH	$ 33,907	$ 45,956	$ 52,207	$ 55,237	$ 44,551	$ 41,656	$ 33,001	$ 32,420	$ 29,282	$ 40,898	$ 42,177	$ 41,833	
Demand	$ 17,727	$ 20,937	$ 23,283	$ 20,410	$ 19,772	$ 16,815	$ 13,812	$ 11,693	$ 10,157	$ 13,610	$ 15,363	$ 15,293	$ 198,871
												LV Revenue	$ 17,306
													$ 1,552,248

Unbifurcated PF Average Rate

Energy Costs	**$ 1,336,045**	**20.47**
Demand Costs	**$ 198,871**	**3.05**
Unbundled Cost	**$ 17,306**	**0.27**
Total	**$ 1,552,222**	**23.79**
Billing Determinants	**65253**	

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

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	B	C	D	E	F
2			**Table 3**		
3					
4			**7(b)(2) Rate Test**		
5					
6			**Nominal mills/kWh**		
7					
8				**Adjusted**	
9		**Program Case**	**Program Case**	**Program Case**	**7(b)(2) Case**
10		**PF Rate**	**7(g) costs**	**PF Rate**	**PF Rate**
11					
12	**2010**	35.27	1.52	33.75	23.79
13	**2011**	37.37	1.56	35.81	26.07
14	**2012**	38.01	1.50	36.51	25.46
15	**2013**	39.54	1.56	37.98	28.16
16	**2014**	38.82	1.56	37.26	26.88
17	**2015**	40.26	1.51	38.75	28.09
18					
19					
20			**Discounted mills/kWh**		
21					
22		**Adjusted**			
23		**Program Case**		**7(b)(2) Case**	
24		**PF Rate**		**PF Rate**	
25					
26	**2010**	31.77		22.39	
27	**2011**	31.49		22.93	
28	**2012**	29.91		20.85	
29	**2013**	28.99		21.50	
30	**2014**	26.57		19.17	
31	**2015**	25.85		18.74	
32					
33	Average Discounted Program Case Rate			29.10	
34	Average Discounted 7(b)(2) Case Rate			20.93	
35	Rate Test Result (Triggers if Positive)			8.17	

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APPENDIX B

Section 7(b)(2)
Section 7(b)(2) Rate Test Study and Documentation

Rates Analysis Model - Resource Stack

GDP Inflator / Deflator Tables

Accounting / Financing Treatment of Expensed Conservation
Analysis and Documentation

WP-10 Final Study

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WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Accounting / Financing Treatment of Expensed Conservation

Introduction - Summary Information - Table of Contents

The detailed amounts and costs for non-conservation resources are contained in Appendix C to the 7 (b)(2) Study Documentation. The summary resource cost values that are contained in the resource stack are presented in 2010 dollars.

The detailed amounts and costs for conservation resources are contained in Appendix D to the 7 (b)(2) Study Documentation. The summary conservation resource cost values that are contained in the resource stack are presented in 2010 dollars.

BPA's 2010 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Rates Analysis Model - Resource Sort Spread Sheet Example

All Costs are in 2010 dollars

Example of 7(b)(2) Resource Stack

	A		B	C	D	E	F	G	H	I	J	K	L	M	N
	Project		Nameplate	Interest Rate	Capital Investment	Annual O & M	Annual Fuel	Cons First Yr Amort	Capacity Factor	Life	Annual Capital Cost	Total Discounted Capital Cost	Total Discounted O & M and Fuel	Total Cost Dollars per AMW	Total Cost Mills per KWH
			(MW)	(%)	($ooo)	($ooo)	($ooo)	($ooo)			($ooo)	($ooo)	($ooo)	($)	
	BPA & Public resources														
	*** The following resources are listed least cost first														
1.	BPA PROG CONS	2001	19.2	4.68	72	29,060	0	$6,471	100	15	7	66	$27,302	95,030	10.85
2.	IDAHO FALLS ND	1982	14.0	0.00	0	4,978	0	$0	100	60	0	0	$81,183	96,646	11.03
3.	BPA PROG CONS	2006	31.0	4.68	16,436	39,428	0	$8,780	100	15	1,549	15,107	37,043	112,152	12.80
4.	BPA PROG CONS	2003	27.6	4.68	27,501	30,621	0	$6,819	100	15	2,593	25,278	$28,769	130,549	14.90
5.	BPA PROG CONS	2002	26.6	4.68	34,588	26,137	0	$5,820	100	15	3,261	31,792	$24,556	141,224	16.12
6.	BPA PROG CONS	2005	20.6	4.68	16,721	31,616	0	$7,040	100	15	1,576	15,369	$29,704	145,869	16.65
7.	BOARDMAN PUBLIC ND	1980	49.7	0.00	0	16,104	0	$0	100	30	0	0	$223,094	149,597	17.08
8.	BPA PROG CONS	2008	30.3	4.68	9,139	65,410	0	$14,565	100	15	862	8,400	$61,454	153,695	17.55
9.	BPA PROG CONS	2004	20.1	4.68	22,725	27,251	0	$6,068	100	15	2,142	20,888	$25,603	154,199	17.60
10.	BPA PROG CONS	2007	27.9	4.68	11,454	59,178	0	$13,177	100	15	1,080	10,528	55,599	158,009	18.04
11.	COWLITZ FALLS	1994	26.0	4.25	0	4,137	0	0	100	60	11,620	189,488	67,467	164,715	18.80
12.	BPA PROG CONS	2009	28.4	4.68	20,412	69,493	0	$15,474	100	15	1,924	18,762	$65,290	197,304	22.52
13.	BPA PROG CONS	2015	39.5	4.68	42,697	87,986	0	$19,592	100	15	4,025	39,246	$82,665	205,756	23.49
14.	BPA PROG CONS	2014	39.5	4.68	43,552	88,570	0	$19,722	100	15	4,106	40,032	$83,214	208,009	23.75
15.	BPA PROG CONS	2013	39.5	4.68	44,431	89,602	0	$19,952	100	15	4,189	40,840	$84,183	211,009	24.09
16.	BPA PROG CONS	2012	39.5	4.68	45,319	90,648	0	$20,185	100	15	4,272	41,656	$85,165	214,044	24.43
17.	BPA PROG CONS	2011	34.9	4.68	38,807	86,162	0	$19,186	100	15	3,658	35,670	$80,951	222,771	25.43
	BPA PROG CONS	2010	31.1	4.68	32,819	85,312	0	$18,997	100	15	3,094	30,166	$80,152	236,481	27.00
	WAUNA-Steam-Cogen.	1996	21.7	0.00	0	11,176	0	0	100	30	0	0	154,827	237,830	27.15
	BILLING CREDITS	1996	10.14	0.00	0	5,268	0	0	100	30	0	0	72,978	239,902	27.39

Note 1 - Numbered resources are resources that were selected to serve 7(b)(2) Case loads.

BPA's 2010 Wholesale Power Rate Case

BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures

BPA 2010 Rate Case - 7(b)(2) Resource Stack

Nominal Dollars Corresponding to the Historical Year of Acquisition

($ 000)

Vintage Conservation Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Capitalized Amortization Period Years[2]
2001 Conservation	19.2	23,272.0	58.0	23,330.0	15
2002 Conservation	26.6	21,331.0	28,228.0	49,559.0	15
2003 Conservation	27.6	25,499.0	22,901.0	48,400.0	15
2004 Conservation	20.1	23,302.0	19,432.0	42,734.0	15
2005 Conservation	20.6	27,892.0	14,751.0	42,643.0	15
2006 Conservation	31.0	35,907.0	14,968.0	50,875.0	15
2007 Conservation	27.9	55,414.0	10,725.0	66,139.0	15
2008 Conservation	30.3	62,718.0	8,763.0	71,481.0	15
2009 Conservation	28.4	68,092.0	20,000.0	88,092.0	15
Subtotal[1]	231.7				
2010 Conservation	31.1	85,312.0	32,819.0	118,131.0	15
2011 Conservation	34.9	87,905.0	39,592.0	127,497.0	15
2012 Conservation	39.5	94,417.0	47,203.0	141,620.0	15
2013 Conservation	39.5	95,228.0	47,221.0	142,449.0	15
2014 Conservation	39.5	96,038.0	47,224.0	143,262.0	15
2015 Conservation	39.5	97,321.0	47,227.0	144,548.0	15
Cumulative Savings	**455.7**	**$899,648.0**	**$401,112.0**	**$1,300,760.0**	
Percentages		**69.16%**	**30.84%**	**100.00%**	
Average Cost of conservation Savings - $/aMW				**$2,854.4**	

Notes:

Note 1 - The amount of conservation in the resource stack for FY2001-2009 (231.7aMW) together with billing credit resources contained in the resource stack of 10.1 aMW establish the amount of the load resource balance difference between the Program Case and the 7(b)(2) Case at the start of the Rate Test Period (October 1, 2009) amounting to 241.8 aMW.

Note 2 - Historical conservation investments that occurred prior to FY 2001 that will have been fully amortized before the end of the rate test period in FY 2015, based on a composite useful life of 15 years, are viewed as obsolete conservation investments that are not includable in the 7(b)(2) resource stack.

Note 3 - Conservation saving amounts for FY2001-2008 were based on the information contained in Tables A and B of the Conservation Resource Energy Data for FY 2009 (The RED Book which covered FY1982-2008). Those savings amounts were then adjusted to arrive at the actual savings that would reduce the Administrator's load obligation in the 7(b)(2) Case. The projected FY 2009 savings and cost amounts were based on the 2nd Quarter review financial summary. Conservation costs and related savings amounts for FY 2010-2015 were revised for the final conservation spending levels that were adopted in the IPR - 2 process that concluded in May 2009. The conservation costs for FY 2001-2015 contain an allocation of general and administrative costs following full absorption costing principles.

Note 4 - Conservation costs for FY2001-FY2008 were based on the conservation costs contained in Table D of the Conservation Resource Energy Data for FY 2009. The costs contained in the RED Book do not contain general and administrative overhead costs. The costs displayed in Table D were increased for general and administrative costs. The allocation of general and administrative costs was based on the relationship of total direct staffing costs of BPA's Energy Efficiency organization and the Power Services Business Line. The amount of G & A administrative costs allocated to conservation resources was a portion of the total G & A costs assigned to Power Services and Energy Efficiency.

BPA's 2010 Wholesale Power Rate Case

BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures

BPA 2010 Rate Case - 7(b)(2) Resource Stack - Annual Investments and Savings

INVESTMENTS IN 2010 DOLLARS

($ 000)

Inflator / Deflator Adjustment Factor[1] To Change To 2010 $$$	Vintage Conservation Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Capitalized Amortization Period Years
0.800837	2001	19.2	29,059.6	72.4	29,132.0	15
0.816124	2002	26.6	26,137.0	34,587.9	60,724.9	15
0.832725	2003	27.6	30,621.2	27,501.3	58,122.5	15
0.855097	2004	20.1	27,250.7	22,724.9	49,975.6	15
0.882206	2005	20.6	31,616.2	16,720.6	48,336.8	15
0.910697	2006	31.0	39,428.0	16,435.8	55,863.8	15
0.936392	2007	27.9	59,178.2	11,453.5	70,631.7	15
0.958847	2008	30.3	65,409.8	9,139.1	74,548.9	15
0.979842	2009	28.4	69,492.8	20,411.5	89,904.3	15
	Subtotals	231.7				
1.000000	2010	31.1	85,312.0	32,819.0	118,131.0	15
1.020232	2011	34.9	86,161.8	38,806.9	124,968.7	15
1.041582	2012	39.5	90,647.7	45,318.6	135,966.3	15
1.062788	2013	39.5	89,602.1	44,431.3	134,033.4	15
1.084313	2014	39.5	88,570.4	43,552.0	132,122.4	15
1.106094	2015	39.5	87,986.2	42,697.1	130,683.3	15
	Cumulative Savings	**455.7**	**906,473.7**	**406,671.9**	**1,313,145.6**	
	Percentages		**69.03%**	**30.97%**	**100.00%**	

Notes:

Note 1 - The Inflator / Deflator Indices are based on Global Insight data, The U.S. Economy: The 30-Year Focus, August 2008, Base Case Scenario, adjusted to make FY2010 the base year with a inflator /deflator value of 1.000.

BPA's 2010 Wholesale Power Rate Case
BPA 2010 Rate Case - 7(b)(2) Resource Stack

Inflation Adjustment Factors

	Current 2008 GDP Deflator Fcst (Update)				Fiscal Year Cumulative	
YEAR	Global Insight **CY 2008 FORECAST CalendarYear Index**	**CY 2008 FORECAST CalendarYear % Change 2/**	BPA FY2008 FORECAST **Fiscal Year Index**	BPA FY2008 FORECAST **Fiscal Year % Change 2/**		**FY 2008 3/** **CUMULATIVE PRICE DEFLATOR INDEX** Base Year 2010 -FY
1997	0.746867					
1998	0.755169		0.753			
1999	0.766071	1.44%	0.763	1.36%	1999	0.767153
2000	0.782759	2.18%	0.779	2.00%	2000	0.782471
2001	0.801563	2.40%	0.797	2.35%	2001	0.800837
2002	0.815576	1.75%	0.812	1.91%	2002	0.816124
2003	0.832930	2.13%	0.829	2.03%	2003	0.832725
2004	0.856826	2.87%	0.851	2.69%	2004	0.855097
2005	0.884827	3.27%	0.878	3.17%	2005	0.882206
2006	0.913292	3.22%	0.906	3.23%	2006	0.910697
2007	0.937894	2.69%	0.932	2.82%	2007	0.936392
2008	0.959484	2.30%	0.954	2.40%	2008	0.958847
2009	0.980143	2.15%	0.975	2.19%	2009	0.979842
2010	1.000000	2.03%	0.995	2.06%	2010	1.000000
2011	1.020223	2.02%	1.015	2.02%	2011	1.020232
2012	1.041807	2.12%	1.036	2.09%	2012	1.041582
2013	1.062748	2.01%	1.058	2.04%	2013	1.062788
2014	1.084324	2.03%	1.079	2.03%	2014	1.084313
2015	1.106029	2.00%	1.101	2.01%	2015	1.106094
2016	1.127873	1.97%	1.122	1.98%	2016	1.128012
2017	1.150075	1.97%	1.145	1.97%	2017	1.150234
2018	1.172966	1.99%	1.167	1.99%	2018	1.173067
2019	1.196553	2.01%	1.191	2.01%	2019	1.196596
2020	1.221914	2.12%	1.216	2.09%	2020	1.221639
2021	1.246561	2.02%	1.240	2.04%	2021	1.246588
2022	1.270551	1.92%	1.265	1.95%	2022	1.270863
2023	1.294815	1.91%	1.289	1.91%	2023	1.295179
2024	1.319091	1.87%	1.313	1.88%	2024	1.319573
2025	1.343193	1.83%	1.337	1.84%	2025	1.343839
2026	1.367669	1.82%	1.362	1.82%	2026	1.368342
2027	1.393163	1.86%	1.387	1.85%	2027	1.393708
2028	1.418933	1.85%	1.412	1.85%	2028	1.419537
2029	1.444726	1.82%	1.438	1.83%	2029	1.445453
2030	1.470819	1.81%	1.464	1.81%	2030	1.471601
2031	1.497477	1.81%	1.491	1.81%	2031	1.498250
2032	1.523714	1.75%	1.517	1.77%	2032	1.524724
2033	1.549549	1.70%	1.543	1.71%	2033	1.550789
2034	1.575750	1.69%	1.569	1.69%	2034	1.577028
2035	1.602471	1.70%	1.596	1.69%	2035	1.603752
2036	1.629626	1.69%	1.623	1.69%	2036	1.630934
2037	1.657605	1.72%	1.651	1.71%	2037	1.658846
2038	1.686215	1.73%	1.679	1.72%	2038	1.687440

1/ Global Insight, The U.S. Economy: The 30-Year Focus, August 2008, Base Case Scenario.

2/ Fiscal Year Cumulative Price Deflator escalates to midyear dollars. The first year, 2009, is determined as follows: 1.011 = [(2.159/100)*.5] + 1. An example of subsequent year cumulative growth such as in 2010 is found as: 1.032 = [1+ (2.057/100)]*1.011 (Official Agency Forecast Footnote - Will Revise Later)

'3/ Index restated to arrive at FY 2010 value = 1.00000.

Section 7(b)(2) Rate Test Study and Documentation
Alternative Conservation Expense Deferral / Financing Periods Analysis
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SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 1 - Resource Stack Selected Resources - Resource Composition

a) - Conservation Resources - Composition and Timing of Investment Costs - Costs That are Constant Across All Alternatives[1]

Total FY 2010-FY 2015	FY 2010-2011	FY 2012-2015	FY 2016-2029
Total Expense Costs	Expense Costs	Expense Costs	Expense Costs
$849,034,700	$467,959,800	$381,074,900	None
Total Capitalized Costs	Capitalized Costs	Capitalized Costs	Capitalized Costs
$387,255,600	$202,607,900	$184,647,700	None
Total Investment Costs Excluding Interest			
$1,236,290,300	$670,567,700	$565,722,600	$0

Total FY 2010-FY 2029	FY 2010-2011	FY 2012-2015	FY 2016-2029
Total Interest Expense Capitalized Costs /1	Interest on Capitalized Costs	Interest on Capitalized Costs	Interest on Capitalized Costs
$160,341,346	$16,572,112	$52,302,404	$91,466,830

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	Totals FY 2010-2015
b) - Conservation Resources Selected from the Resource Stack:							
Number of years of conservation investments:	(9)	(1)	(1)	(1)	(1)	(1)	(14)
Conservation MWs-	231.7	39.5	39.5	39.5	39.5	34.9	424.6
Selected from the Resource Stack:	72.1%						82.6%
c) - Non-Conservation Resources Selected from the Resource Stack:							
Idaho Falls Hydro Resource	14.0						14.0
Boardman Coal Plant	49.7						49.7
Cowlitz Falls Hydro Resource	26.0						26.0
	89.7						89.7
	27.9%						17.4%
Selected Resource MW Amounts	321.4	39.5	39.5	39.5	39.5	34.9	514.3

Note 1 - Resource costs reflect the cost of the resource for the year the resource is selected from the resource stack. Conservation resource costs in this table have been adjusted for inflation to reflect the purchasing power costs of the year the resource is selected from the resource stack. This financing analysis assumes that financing origination of capitalized investments and conservation investments that have been deferred occurs on the first day of the fiscal year.

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SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 2 - Financing Costs Associated with Deferring Conservation Expensed Costs - Debt Service in Nominal Dollars

A	B	C	D	E	F	G	H
(3)		(4)	(5)	(6)	(7)	(8)	(9)
				(4) + (5)		(6) + (7)	(8) / (3)
Total Conservation Expense Costs Excluding Interest **849,034,700**	Interest Rate	Years 1-2 Rate Period Interest Paid - FY 2010-2011	Years 3-6 of Rate Test Period Interest Paid FY 2012-2015	Total Rate Test Period Interest Paid FY 2010-2015	Years Outside of Rate Test Period Interest Paid FY 2016-2029	Total Interest Paid FY 2010-2029	Percent of Total Interest to Deferred Expenses FY 2010-2029
Alternative 1 - Expense in the year incurred, no deferral	N/A	0	0	0	0	0	0.00%
Alternative 2 - Deferral -	3.57%	$27,007,767	$41,209,466	$68,217,233	$8,887,676	$77,104,909	9.08%
financing over 4-years		35.03%	53.45%	88.47%	11.53%	100.00%	
Alternative 3 - Deferral -	3.69%	$28,630,509	$52,807,295	$81,437,804	$14,819,515	$96,257,319	11.34%
financing over 5-years		29.74%	54.86%	84.60%	15.40%	100.00%	
Alternative 4 - Deferral -	3.81%	$30,055,689	$64,216,063	$94,271,752	$22,471,896	$116,743,648	13.75%
financing over 6-years		24.53%	55.16%	79.69%	20.31%	100.00%	
Alternative 5 - Deferral -	3.93%	$31,368,023	$73,414,290	$104,782,313	$33,824,439	$138,606,752	16.33%
financing over 7-years		22.63%	52.97%	75.60%	24.40%	100.00%	
Alternative 6 - Deferral -	4.68%	$38,759,787	$115,103,712	$153,863,499	$197,675,304	$351,538,803	41.40%
financing over 15-years		11.03%	32.74%	43.77%	56.23%	100.00%	

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SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 2 - Financing Costs Associated with Deferring Conservation Expensed Costs - Inflation Adjusted Debt Service Amounts[1]

(3)		(4)	(5)	(6)	(7)	(8)	(9)
				(4) + (5)		(6) + (7)	(8) / (3)
Total Conservation Expense Costs Excluding Interest Nominal Dollars **849,034,700**	Interest Rate	Years 1-2 Rate Period Interest Paid - FY 2010-2011	Years 3-6 of Rate Test Period Interest Paid FY 2012-2015	Total Rate Test Period Interest Paid FY 2010-2015	Years Outside of Rate Test Period Interest Paid FY 2016-2029	Total Interest Paid FY 2010-2029	Percent of Total Interest to Deferred Expenses FY 2010-2029
Alternative 1 - Expense in the year incurred, no deferral	N/A	0	0	0	0	0	0.00%
Alternative 2 - Deferral -	3.57%	$26,803,478	$40,213,105	$67,016,583	$8,543,456	$75,560,039	8.90%
financing over 4-years		35.47%	53.22%	88.69%	11.31%	100.00%	
Alternative 3 - Deferral -	3.69%	$28,405,176	$51,181,710	$79,586,886	$14,105,122	$93,692,008	11.04%
financing over 5-years		30.32%	54.63%	84.95%	15.05%	100.00%	
Alternative 4 - Deferral -	3.81%	$27,061,653	$59,385,313	$86,446,966	$21,176,852	$107,623,818	12.68%
financing over 6-years		25.14%	55.18%	80.32%	19.68%	100.00%	
Alternative 5 - Deferral -	3.93%	$31,110,675	$70,505,954	$101,616,629	$31,473,566	$133,090,195	15.68%
financing over 7-years		23.38%	52.98%	76.35%	23.65%	100.00%	
Alternative 6 - Deferral -	4.68%	$38,425,455	$109,742,013	$148,167,468	$171,209,421	$319,376,889	37.62%
financing over 15-years		10.53%	32.50%	43.02%	56.98%	100.00%	

Note 1 - Debt service cash flows are inflation adjusted to the year that the conservation resource is selected from the resource stack. The cash flows associated with the 9 conservation resources chosen in FY2010 are stated in FY 2010 purchasing power dollar values. The cash flows associated with the single conservation resource chosen in each of the remaining years of the rate test period are restated in the purchasing power dollar values associated with that year, the year the resource investment is made. Thus the debt service cash flows are a mixture of purchasing power dollars associated with the year that each conservation investment is made.

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SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 3 - Cost Recovery Metrics

	Weighted Average Cost Recovery Period				
	Conservation Investment Cost	Recovery Period Years	Weighted Average Recovery Period - Years	Percent of Total Costs Recovered During the Rate Test Period Nominal Dollars	Percent of Total Costs Recovered During the Rate Test Period Inflation Adjusted Dollars
Alternative 1 - Expense					
in the year incurred, no deferral					
Capital Expenditures	387,255,600	15	4.70		
Expensed Expenditures	849,034,700	1	0.69		
Total Cost	1,236,290,300		**5.39**	**75.58%**	**78.78%**
Alternative 2 - Deferral -					
financing over 4-years					
Capital Expenditures	387,255,600	15	4.70		
Expensed Expenditures	849,034,700	4	2.75		
Total Cost	1,236,290,300		**7.45**	**63.57%**	**66.02%**
Alternative 3 - Deferral -					
financing over 5-years					
Capital Expenditures	387,255,600	15	4.70		
Expensed Expenditures	849,034,700	5	3.43		
Total Cost	1,236,290,300		**8.13**	**59.51%**	**61.82%**
Alternative 4 - Deferral -					
financing over 6-years					
Capital Expenditures	387,255,600	15	4.70		
Expensed Expenditures	849,034,700	6	4.12		
Total Cost	1,236,290,300		**8.82**	**55.47%**	**56.53%**
Alternative 5 - Deferral -					
financing over 7-years					
Capital Expenditures	387,255,600	15	4.70		
Expensed Expenditures	849,034,700	7	4.81		
Total Cost	1,236,290,300		**9.51**	**47.69%**	**48.15%**
Alternative 6 - Deferral -					
financing over 15-years					
Capital Expenditures	387,255,600	15	4.70		
Expensed Expenditures	849,034,700	15	10.30		
Total Cost	1,236,290,300		**15.00**	**22.40%**	**24.98%**

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SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 4 - Cost Comparability Between the Program Case and the 7(b)(2) Case

($ 000)

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Program Case Conservation Costs:						
Staffing, Indirect, General & Administrative	23,812.1	24,904.6	26,417.5	27,228.3	28,037.6	29,321.0
Market Transformation Funding	14,500.0	14,500.0	15,000.0	15,000.0	15,000.0	15,000.0
Expense Agreements & Grants	5,000.0	5,000.0	6,000.0	6,000.0	6,000.0	6,000.0
Conservation Rate Credit	28,000.0	29,500.0	32,000.0	32,000.0	32,000.0	32,000.0
Program Support & Evaluation Costs	14,000.0	14,000.0	15,000.0	15,000.0	15,000.0	15,000.0
Sub Total Expense Costs - 7(b)(2) Amounts[1]	85,312.1	87,904.6	94,417.5	95,228.3	96,037.6	97,321.0
Federal Reimbursable Program (EE Development)	20,500.0	20,500.0	22,000.0	22,000.0	22,000.0	22,000.0
Legacy Conservation - Prior Year Efforts	1,987.7	1,622.1	998.9	1,310.8	716.5	716.5
Other Expenses / (Offsetting Credits)	0.0	0.0	0.0	0.0	0.0	0.0
Total Direct Conservation Expenses - Program Case - (A)	107,799.8	110,026.7	117,416.4	118,539.1	118,754.1	120,037.5
Program Case Offsetting Revenue Credits	(20,500.0)	(20,500.0)	(22,000.0)	(22,000.0)	(22,000.0)	(22,000.0)
Similar Program Case Expense Level Comparison - (B)	87,299.8	89,526.7	95,416.4	96,539.1	96,754.1	98,037.5
Program Case Capital Costs, Interest Expense:						
Current Year's Capitalized Conservation Amortization	3,280.0	3,960.0	4,720.0	4,720.0	4,720.0	4,720.0
Prior Year's BPA Capitalized Conservation Amortization	45,605.4	50,315.4	41,181.0	46,054.0	49,290.0	49,169.0
Prior Year's Other Entities Debt Service Requirements	5,079.0	4,924.0	4,923.0	4,916.6	4,910.7	305.1
Net Interest Expense - Allocated to Conservation	13,318.0	12,274.0	11,184.0	11,536.0	12,506.0	12,911.0
Total Program Case Capital Costs, Interest Expense - (C)	67,282.4	71,473.4	62,008.0	67,226.6	71,426.7	67,105.1
Program Case MRNR, PNRR, and Billing Credits						
MRNR - Allocated to Conservation	4,312.0	3,294.0	0.0	1,507.0	0.0	0.0
PNRR - Allocatied to Conservation	0.0	0.0	0.0	0.0	0.0	0.0
Billing Credits	7,383.2	7,468.9	5,872.6	5,684.7	5,750.0	5,798.0
Total Program Case MRNR, PNRR, and Billing Credits - (D)	11,695.2	10,762.9	5,872.6	7,191.7	5,750.0	5,798.0
Conservation Total - Line 18 COSA (E) = (A) + (C) + (D)	186,777.4	192,263.0	185,297.0	192,957.4	195,930.8	192,940.6
Similar Program Case Comparison Amounts (F) = (B) + (C)	**154,582.2**	**161,000.1**	**157,424.4**	**163,765.7**	**168,180.8**	**165,142.6**
Average "Similar" Program Case Revenue Requirement FY2010-2015 =	161,682.6					
7(b)(2) Case Debt Service Requirements - Principal and Interest ($ 000) -						
Expense Deferral and Financing Over 5-Years (Alternative 3)						
Capital Costs - Debt Service Requirements	14,993.2	19,099.7	23,376.1	27,827.6	32,460.0	36,506.4
Expense Costs - Debt Service Requirements	84,214.0	104,202.7	124,745.2	145,950.1	167,836.9	104,844.5
7(b)(2) CASE DEBT SERVICE REQUIREMENTS - (G)	**99,207.2**	**123,302.4**	**148,121.3**	**173,777.7**	**200,296.9**	**141,350.9**
Average 7(b)(2)Case Revenue Requirement FY2010-2015 =	147,676.1					
Increase - (Decrease) In Program Case Over 7(b)(2) Case (F- G)	**55,375.0**	**37,697.7**	**9,303.1**	**(10,012.0)**	**(32,116.1)**	**23,791.7**

Note 1 - See Page D -10 of Appendix D for a detailed description of conservation costs for FY 2010-FY 2015.

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SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 5 - 7(b)(2) Case - Rate Impacts:

	FY 2010-2011 Average Rates		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Alternative 1 - Expense in	**27.07**	7B2 Rate	28.29	25.85	24.98	27.42	25.88	27.95
the year incurred,		7B2 Load	65253	65290	67896	68225	69454	69910
no deferral		Revenues	$ 1,845,999	$ 1,687,744	$ 1,696,047	$ 1,870,724	$ 1,797,459	$ 1,953,990
Alternative 2 - Deferral -	**25.26**	7B2 Rate	24.08	26.43	25.88	28.64	25.94	28.07
financing over 4-years		7B2 Load	65253	65290	67896	68225	69454	69910
		Revenues	$ 1,571,285	$ 1,725,612	$ 1,757,153	$ 1,953,958	$ 1,801,627	$ 1,962,379
Alternative 3 - Deferral -	**24.93**	7B2 Rate	23.79	26.07	25.46	28.16	26.88	28.09
financing over 5-years		7B2 Load	65253	65290	67896	68225	69454	69910
		Revenues	$ 1,552,362	$ 1,702,107	$ 1,728,637	$ 1,921,210	$ 1,866,913	$ 1,963,777
Alternative 4 - Deferral -	**24.72**	7B2 Rate	23.60	25.84	25.19	27.84	26.52	28.89
financing over 6-years		7B2 Load	65253	65290	67896	68225	69454	69910
		Revenues	$ 1,539,964	$ 1,687,091	$ 1,710,305	$ 1,899,378	$ 1,841,910	$ 2,019,705
Alternative 5 - Deferral -	**24.57**	7B2 Rate	23.46	25.67	25.00	27.62	26.27	28.61
financing over 7-years		7B2 Load	65253	65290	67896	68225	69454	69910
		Revenues	$ 1,530,829	$ 1,675,992	$ 1,697,405	$ 1,884,369	$ 1,824,546	$ 2,000,130
Alternative 6 - Deferral -	**24.10**	7B2 Rate	23.04	25.15	24.40	26.93	25.49	27.73
financing over 15-years		7B2 Load	65253	65290	67896	68225	69454	69910
		Revenues	$ 1,503,423	$ 1,642,041	$ 1,656,667	$ 1,837,293	$ 1,770,372	$ 1,938,609

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	Inflation Adjustment	Capitalized Conservation: Deferral/ Maturity # of Years	Capitalized Conservation: Interest Rate 15 - Year Maturity	Expensed Conservation: Deferral/ Maturity # of Years	Expensed Conservation: Interest Rate
FY 2010	1.000000	15	0.0468	4	0.0357
FY 2011	1.020232			5	0.0369
FY 2012	1.041582			6	0.0381
FY 2013	1.062788			7	0.0393
FY 2014	1.084313			15	0.0468
FY 2015	1.106094				

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2010 Conservation Resources Selected						
1	2001 Conservation - 2010$$	19.2	29,059.6	72.4	29,132.0	
	Capitalized Costs - Debt Service Requirements					$6,825.13
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2010 only)	$29,059,600.00
3	2006 Conservation - 2010$$	31.0	39,428.0	16,435.8	55,863.8	
	Capitalized Costs - Debt Service Requirements					$1,549,397.68
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2010 only)	$39,428,000.00
4	2003 Conservation - 2010$$	27.6	30,621.2	27,501.3	58,122.5	
	Capitalized Costs - Debt Service Requirements					$2,592,538.87
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2010 only)	$30,621,200.00
5	2002 Conservation - 2010$$	26.6	26,137.0	34,587.9	60,724.9	
	Capitalized Costs - Debt Service Requirements					$3,260,590.41
	Expensed Costs /Deferral Debt Service Requirements					$26,137,000.00
6	2005 Conservation - 2010$$	20.6	31,616.2	16,720.6	48,336.8	
	Capitalized Costs - Debt Service Requirements					$1,576,245.68
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2010 only)	$31,616,200.00
8	2008 Conservation - 2010$$	30.3	65,409.8	9,139.1	74,548.9	
	Capitalized Costs - Debt Service Requirements					$861,540.07
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2010 only)	$65,409,800.00
9	2004 Conservation - 2010$$	20.1	27,250.7	22,724.9	49,975.6	
	Capitalized Costs - Debt Service Requirements					$2,142,269.15
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2010 only)	$27,250,700.00
10	2007 Conservation - 2010$$	27.9	59,178.2	11,453.5	70,631.7	
	Capitalized Costs - Debt Service Requirements					$1,079,717.83
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2010 only)	$59,178,200.00
12	2009 Conservation - 2010$$	28.4	69,492.8	20,411.5	89,904.3	
	Capitalized Costs - Debt Service Requirements					$1,924,185.66
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2010 only)	$69,492,800.00
	Totals - FY 2010	231.7	378,193.5	159,047.0	537,240.5	

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2010 Conservation Resources Selected											
1	**2001 Conservation - 2010$$**										
		6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
		29,059.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4
		39,428.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5
		30,621.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6
		26,137.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2
		31,616.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
		861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5
		65,409.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3
		27,250.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7
		59,178.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2
		69,492.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
		11	12	13	14	15	16	17	18	19	20
FY 2010	**Conservation Resources Selected**										
1	**2001 Conservation - 2010$$**										
		6.8	6.8	6.8	6.8	6.8	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
		861.5	861.5	861.5	861.5	861.5	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$		87,986.2	42,697.1	130,683.3	
13	**2015 Conservation - 2011$$**	39.5	89,766.3	43,560.9	133,327.2	
	Capitalized Costs - Debt Service Requirements					$4,106,472.29
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2011 only)	$89,766,300.00
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$		88,570.4	43,552.0	132,122.4	
14	**2014 Conservation - 2012$$**	39.5	92,253.3	45,363.0	137,616.3	
	Capitalized Costs - Debt Service Requirements					$4,276,355.69
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2012 only)	$92,253,300.00
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$		89,602.1	44,431.3	134,033.4	
15	**2013 Conservation - 2013$$**	39.5	95,228.0	47,221.1	142,449.1	
	Capitalized Costs - Debt Service Requirements					$4,451,518.19
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2013 only)	$95,228,000.00
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$		90,647.7	45,318.6	135,966.3	
16	**2012 Conservation - 2014$$**	39.5	98,290.5	49,139.5	147,430.0	
	Capitalized Costs - Debt Service Requirements					$4,632,365.15
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2014 only)	$98,290,500.00
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$		86,161.8	38,806.9	124,968.7	
17	**2011 Conservation - 2015$$**	34.9	95,303.1	42,924.1	138,227.2	
	Capitalized Costs - Debt Service Requirements					$4,046,441.35
	Expensed Costs /Deferral Debt Service Requirements				(first year, FY2015 only)	$95,303,100.00

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		387,255.6	160,340.4	547,596.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	849,034.7		0.0	849,034.7
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	849,034.7	387,255.6	160,340.4	1,396,630.7
Principal Expense Costs				849,034.7
Interest Paid Expensed Costs				0.0
Principal Capital Costs				387,255.6
Interest Paid Capital Costs				160,340.4
Totals				1,396,630.7

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
		0.0	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5
		0.0	89,766.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
		0.0	0.0	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4
		0.0	0.0	92,253.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
		0.0	0.0	0.0	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5
		0.0	0.0	0.0	95,228.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
		0.0	0.0	0.0	0.0	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4
		0.0	0.0	0.0	0.0	98,290.5	0.0	0.0	0.0	0.0	0.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
		0.0	0.0	0.0	0.0	0.0	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
		0.0	0.0	0.0	0.0	0.0	95,303.1	0.0	0.0	0.0	0.0
TCC		14,993.2	19,099.7	23,376.1	27,827.6	32,460.0	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4
TEC		378,193.5	89,766.3	92,253.3	95,228.0	98,290.5	95,303.1	0.0	0.0	0.0	0.0
TDSR		393,186.7	108,866.0	115,629.4	123,055.6	130,750.5	131,809.5	36,506.4	36,506.4	36,506.4	36,506.4

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
		11	12	13	14	15	16	17	18	19	20
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
		4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
		4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
		4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
		4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
		4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC		36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4
TEC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR		36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4

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= Expensed costs are expensed in the year incurred (1st year)

Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010	**Conservation Resources Selected**									
FY 2010	Conservation (9) Res. Selected - Total MW =	231.7								
1	**2001 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	72,400	3,437	3,598	3,766	3,942	4,127	4,320	4,522	4,734
	b Capital Expenditures - Interest Expense	29,975	3,388	3,227	3,059	2,883	2,698	2,505	2,303	2,091
	c Expense Expenditures - Amort. of Principal	29,059,600	29,059,600	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
3	**2006 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,435,800	780,203	816,716	854,938	894,949	936,833	980,677	1,026,573	1,074,616
	b Capital Expenditures - Interest Expense	6,805,165	769,195	732,682	694,460	654,449	612,565	568,721	522,825	474,782
	c Expense Expenditures - Amort. of Principal	39,428,000	39,428,000	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
4	**2003 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	27,501,300	1,305,478	1,366,575	1,430,530	1,497,479	1,567,561	1,640,923	1,717,718	1,798,107
	b Capital Expenditures - Interest Expense	11,386,782	1,287,061	1,225,964	1,162,009	1,095,060	1,024,978	951,616	874,821	794,432
	c Expense Expenditures - Amort. of Principal	30,621,200	30,621,200	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
5	**2002 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	34,587,900	1,641,876	1,718,716	1,799,152	1,883,352	1,971,493	2,063,759	2,160,343	2,261,448
	b Capital Expenditures - Interest Expense	14,320,958	1,618,714	1,541,874	1,461,438	1,377,238	1,289,097	1,196,831	1,100,247	999,143
	c Expense Expenditures - Amort. of Principal	26,137,000	26,137,000	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
6	**2005 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,720,600	793,722	830,868	869,753	910,457	953,067	997,670	1,044,361	1,093,237
	b Capital Expenditures - Interest Expense	6,923,083	782,524	745,378	706,493	665,789	623,179	578,576	531,885	483,009
	c Expense Expenditures - Amort. of Principal	31,616,200	31,616,200	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
8	**2008 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	9,139,100	433,830	454,133	475,387	497,635	520,924	545,303	570,824	597,538
	b Capital Expenditures - Interest Expense	3,784,002	427,710	407,407	386,153	363,905	340,616	316,237	290,716	264,002
	c Expense Expenditures - Amort. of Principal	65,409,800	65,409,800	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010	**Conservation Resources Selected**												
FY 2010	Conservation (9) Res. Selected - Total MW =												
1	**2001 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	4,955	5,187	5,430	5,684	5,950	6,228	6,520	0	0	0	0	0
	b Capital Expenditures - Interest Expense	1,870	1,638	1,395	1,141	875	597	305	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
3	**2006 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,124,908	1,177,554	1,232,662	1,290,351	1,350,739	1,413,954	1,480,127	0	0	0	0	0
	b Capital Expenditures - Interest Expense	424,490	371,844	316,735	259,046	198,658	135,443	69,270	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
4	**2003 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,882,259	1,970,348	2,062,560	2,159,088	2,260,133	2,365,908	2,476,633	0	0	0	0	0
	b Capital Expenditures - Interest Expense	710,280	622,191	529,978	433,450	332,405	226,631	115,906	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
5	**2002 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	2,367,284	2,478,073	2,594,046	2,715,448	2,842,531	2,975,561	3,114,818	0	0	0	0	0
	b Capital Expenditures - Interest Expense	893,307	782,518	666,545	545,143	418,060	285,030	145,773	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
6	**2005 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,144,400	1,197,958	1,254,022	1,312,710	1,374,145	1,438,455	1,505,775	0	0	0	0	0
	b Capital Expenditures - Interest Expense	431,845	378,287	322,223	263,535	202,100	137,790	70,470	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
8	**2008 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	625,503	654,777	685,420	717,498	751,077	786,227	823,024	0	0	0	0	0
	b Capital Expenditures - Interest Expense	236,037	206,763	176,120	144,042	110,463	75,313	38,518	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
46	FY 2010	Conservation Resources Selected - continued									
47	9	2004 Conservation - 2010$$									
48		a Capital Expenditures - Amort. of Principal	22,724,900	1,078,744	1,129,229	1,182,077	1,237,398	1,295,308	1,355,929	1,419,386	1,485,813
49		b Capital Expenditures - Interest Expense	9,409,137	1,063,525	1,013,040	960,192	904,871	846,961	786,340	722,883	656,456
50		c Expense Expenditures - Amort. of Principal	27,250,700	27,250,700	0	0	0	0	0	0	0
51		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
52	10	2007 Conservation - 2010$$									
53		a Capital Expenditures - Amort. of Principal	11,453,500	543,694	569,139	595,775	623,657	652,844	683,397	715,380	748,860
54		b Capital Expenditures - Interest Expense	4,742,268	536,024	510,579	483,943	456,061	426,874	396,321	364,338	330,858
55		c Expense Expenditures - Amort. of Principal	59,178,200	59,178,200	0	0	0	0	0	0	0
56		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
57	12	2009 Conservation - 2010$$									
58		a Capital Expenditures - Amort. of Principal	20,411,500	968,928	1,014,274	1,061,742	1,111,431	1,163,446	1,217,895	1,274,893	1,334,558
59		b Capital Expenditures - Interest Expense	8,451,283	955,258	909,912	862,444	812,755	760,740	706,291	649,293	589,628
60		c Expense Expenditures - Amort. of Principal	69,492,800	69,492,800	0	0	0	0	0	0	0
61		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
62	FY 2011	Conservation Resources Selected									
63	13	2015 Conservation - 2011$$									
64		a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
65		b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
66		c Expense Expenditures - Amort. of Principal	89,766,300	0	89,766,300	0	0	0	0	0	0
67		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
68	FY 2012	Conservation Resources Selected									
69	14	2014 Conservation - 2012$$									
70		a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
71		b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
72		c Expense Expenditures - Amort. of Principal	92,253,300	0	0	92,253,300	0	0	0	0	0
73		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
74	FY 2013	Conservation Resources Selected									
75	15	2013 Conservation - 2013$$									
76		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
77		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
78		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	95,228,000	0	0	0	0
79		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
80	FY 2014	Conservation Resources Selected									
81	16	2012 Conservation - 2014$$									
82		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
83		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
84		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	98,290,500	0	0	0
85		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
46	FY 2010	Conservation Resources Selected - continued												
47	9	2004 Conservation - 2010$$												
48		a Capital Expenditures - Amort. of Principal	1,555,349	1,628,140	1,704,337	1,784,100	1,867,596	1,955,000	2,046,494	0	0	0	0	0
49		b Capital Expenditures - Interest Expense	586,920	514,129	437,932	358,169	274,673	187,270	95,776	0	0	0	0	0
50		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
51		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
52	10	2007 Conservation - 2010$$												
53		a Capital Expenditures - Amort. of Principal	783,907	820,594	858,997	899,198	941,281	985,332	1,031,445	0	0	0	0	0
54		b Capital Expenditures - Interest Expense	295,811	259,124	220,721	180,520	138,437	94,385	48,272	0	0	0	0	0
55		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
56		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
57	12	2009 Conservation - 2010$$												
58		a Capital Expenditures - Amort. of Principal	1,397,014	1,462,394	1,530,835	1,602,478	1,677,474	1,755,979	1,838,159	0	0	0	0	0
59		b Capital Expenditures - Interest Expense	527,171	461,791	393,350	321,707	246,711	168,206	86,026	0	0	0	0	0
60		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
61		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
62	FY 2011	Conservation Resources Selected												
63	13	2015 Conservation - 2011$$												
64		a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
65		b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
66		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
67		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
68	FY 2012	Conservation Resources Selected												
69	14	2014 Conservation - 2012$$												
70		a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
71		b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
72		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
73		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
74	FY 2013	Conservation Resources Selected												
75	15	2013 Conservation - 2013$$												
76		a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
77		b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
78		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
79		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
80	FY 2014	Conservation Resources Selected												
81	16	2012 Conservation - 2014$$												
82		a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
83		b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
84		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
85		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
89											
90	FY 2015	Conservation Resources Selected									
91	17	2011 Conservation - 2015$$									
92		a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
93		b Capital Expenditures - Interest Expense	17,772,523	0	0	0	0	0	2,008,848	1,913,489	1,813,666
94		c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	95,303,100	0	0
95		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

Row	DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
100										
101	TOTALS - CAPITAL EXPENDITURES -	387,255,600								
102	a AMORTIZATION OF PRINCIPAL	387,255,600	7,549,912	9,971,070	12,591,084	15,421,915	18,476,297	21,378,581	22,379,100	23,426,442
103	TOTALS - CAPITAL EXPENDITURES -	160,341,346								
104	b INTEREST EXPENSE	160,341,346	7,443,399	9,128,713	10,785,055	12,405,742	13,983,725	15,127,882	14,127,363	13,080,022
105	TOTALS - EXPENSE EXPENDITURES -	849,034,700								
106	c AMORTIZATION OF PRINCIPAL	849,034,700	378,193,500	89,766,300	92,253,300	95,228,000	98,290,500	95,303,100	0	0
107	TOTALS - EXPENSE EXPENDITURES -									
108	d INTEREST EXPENSE	0	0	0	0	0	0	0	0	0
109	TOTAL CONSERVATION PRINCIPAL									
110	AND EXPENSE COSTS	1,236,290,300	385,743,412	99,737,370	104,844,384	110,649,915	116,766,797	116,681,681	22,379,100	23,426,442
111										
112	TOTALS - INTEREST EXPENSE	160,341,346	7,443,399	9,128,713	10,785,055	12,405,742	13,983,725	15,127,882	14,127,363	13,080,022
113										
114	PERCENTAGE OF TOTAL PRINCIPAL PAID	100.00%	31.20%	8.07%	8.48%	8.95%	9.44%	9.44%	1.81%	1.89%
115										
116	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		31.20%	39.27%	47.75%	56.70%	66.14%	$\boxed{75.58\%}$	77.39%	79.28%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 75.58%
TOTAL INTEREST PAID ON EXPENSED PORTION = $0

Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
16,572,112	52,302,404	68,874,516	91,466,830	160,341,346

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2015	Conservation Resources Selected												
17	2011 Conservation - 2015$$												
	a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,490	2,937,834	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,536
	b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,608	971,117	827,192	676,531	518,819	353,726	180,907
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
TOTALS - CAPITAL EXPENDITURES - a AMORTIZATION OF PRINCIPAL	24,522,798	25,670,466	26,871,840	28,129,444	29,445,902	30,823,970	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,536
TOTALS - CAPITAL EXPENDITURES - b INTEREST EXPENSE	11,983,664	10,835,996	9,634,620	8,377,016	7,060,558	5,682,492	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
TOTALS - EXPENSE EXPENDITURES - c AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS - EXPENSE EXPENDITURES - d INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CONSERVATION PRINCIPAL AND EXPENSE COSTS	24,522,798	25,670,466	26,871,840	28,129,444	29,445,902	30,823,970	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,536
TOTALS - INTEREST EXPENSE	11,983,664	10,835,996	9,634,620	8,377,016	7,060,558	5,682,492	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
PERCENTAGE OF TOTAL PRINCIPAL PAID	1.98%	2.08%	2.17%	2.28%	2.38%	2.49%	2.61%	1.52%	1.26%	0.97%	0.66%	0.31%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID	81.26%	83.34%	85.51%	87.79%	90.17%	92.66%	95.27%	96.79%	98.05%	99.02%	99.68%	99.99%

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Debt Service Components - (whole dollars)

INFLATION ADJUSTED ANALYSIS

Row	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
131										
132	**FY 2010 Conservation Resources Selected -**									
133	**Debt Service in Nominal Year Dollars**									
134	TOTALS - CAPITAL EXPENDITURES -	159,047,000								
135	a AMORTIZATION OF PRINCIPAL	159,047,000	7,549,912	7,903,248	8,273,120	8,660,300	9,065,603	9,489,873	9,934,000	10,398,911
136	TOTALS - CAPITAL EXPENDITURES -	65,852,653								
137	b INTEREST EXPENSE	65,852,653	7,443,399	7,090,063	6,720,191	6,333,011	5,927,708	5,503,438	5,059,311	4,594,401
138	TOTALS - EXPENSE EXPENDITURES -	378,193,500								
139	c AMORTIZATION OF PRINCIPAL	378,193,500	378,193,500	0	0	0	0	0	0	0
140	TOTALS - EXPENSE EXPENDITURES -									
141	d INTEREST EXPENSE	0	0	0	0	0	0	0	0	0
142	TOTAL CONSERVATION PRINCIPAL									
143	AND EXPENSE COSTS	537,240,500	385,743,412	7,903,248	8,273,120	8,660,300	9,065,603	9,489,873	9,934,000	10,398,911
144										
145	TOTALS - INTEREST EXPENSE	65,852,653	7,443,399	7,090,063	6,720,191	6,333,011	5,927,708	5,503,438	5,059,311	4,594,401
146										
147	FY 2010 Deflator values		1.000000	1.020232	1.041582	1.062788	1.084313	1.106094	1.128012	1.150234
149	**FY 2010 Conservation Resources Selected -**									
150	**Debt Service in FY2010 Purchasing Power Dollars**									
151	TOTALS - CAPITAL EXPENDITURES -									
152	a AMORTIZATION OF PRINCIPAL	136,462,442	7,549,912	7,746,520	7,942,841	8,148,662	8,360,688	8,579,626	8,806,644	9,040,692
153	TOTALS - CAPITAL EXPENDITURES -									
154	b INTEREST EXPENSE	59,786,671	7,443,399	6,949,461	6,451,908	5,958,866	5,466,787	4,975,561	4,485,157	3,994,319
155	TOTALS - EXPENSE EXPENDITURES -									
156	c AMORTIZATION OF PRINCIPAL	378,193,500	378,193,500	0	0	0	0	0	0	0
157	TOTALS - EXPENSE EXPENDITURES -									
158	d INTEREST EXPENSE	0	0	0	0	0	0	0	0	0
159	TOTAL CONSERVATION PRINCIPAL									
160	AND EXPENSE COSTS	514,655,942	385,743,412	7,746,520	7,942,841	8,148,662	8,360,688	8,579,626	8,806,644	9,040,692
161										
162	TOTALS - INTEREST EXPENSE	59,786,671	7,443,399	6,949,461	6,451,908	5,958,866	5,466,787	4,975,561	4,485,157	3,994,319
164	**FY 2011 Conservation Resources Selected -**									
165	**Debt Service in Nominal Year Dollars**									
166	**13** **2015 Conservation - 2011$$**									
167	a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
168	b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
169	c Expense Expenditures - Amort. of Principal	89,766,300	0	89,766,300	0	0	0	0	0	0
170	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
172	FY 2011 Deflator values			1.000000	1.020927	1.041712	1.062810	1.084159	1.105643	1.127424
173	**FY 2011 Conservation Resources Selected -**									
174	**FY2011 Purchasing Power Dollars**									
175	**13** **2015 Conservation - 2011$$**									
176	a Capital Expenditures - Amort. of Principal	37,389,568	0	2,067,822	2,120,226	2,175,168	2,231,766	2,290,208	2,350,806	2,413,282
177	b Capital Expenditures - Interest Expense	16,376,020	0	2,038,650	1,902,071	1,766,873	1,632,022	1,497,494	1,363,297	1,229,067
178	c Expense Expenditures - Amort. of Principal	89,766,300	0	89,766,300	0	0	0	0	0	0
179	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
180										

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Alternative Conservation Expense Accounting and Financing Treatments
WP-10 Initial Rate Proposal

Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are expensed in the year incurred (1st year)

Debt Service Components - (whole dollars)

INFLATION ADJUSTED ANALYSIS

	A	B	C	M	N	O	P	Q	R	S	T	U	V	W	X
130			Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
131															
132	FY 2010 Conservation Resources Selected -			FY 2010 Conservation Resources Selected - Nominal Year Dollars											
133			Debt Service in Nominal Year Dollars												
134	TOTALS - CAPITAL EXPENDITURES -														
135		a	AMORTIZATION OF PRINCIPAL	10,885,579	11,395,025	11,928,309	12,486,555	13,070,926	13,682,644	14,322,995	0	0	0	0	0
136	TOTALS - CAPITAL EXPENDITURES -														
137		b	INTEREST EXPENSE	4,107,731	3,598,285	3,064,999	2,506,753	1,922,382	1,310,665	670,316	0	0	0	0	0
138	TOTALS - EXPENSE EXPENDITURES -														
139		c	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
140	TOTALS - EXPENSE EXPENDITURES -														
141		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
142	TOTAL CONSERVATION PRINCIPAL														
143			AND EXPENSE COSTS	10,885,579	11,395,025	11,928,309	12,486,555	13,070,926	13,682,644	14,322,995	0	0	0	0	0
144															
145	TOTALS - INTEREST EXPENSE			4,107,731	3,598,285	3,064,999	2,506,753	1,922,382	1,310,665	670,316	0	0	0	0	0
146															
147	FY 2010 Deflator values			1.173067	1.196596	1.221639	1.246588	1.270863	1.295179	1.319573	1.343839	1.368342	1.393708	1.419537	1.445453
149	FY 2010 Conservation Resources Selected -														
150			Debt Service in FY2010 Purchasing Power Dollars												
151	TOTALS - CAPITAL EXPENDITURES -														
152		a	AMORTIZATION OF PRINCIPAL	9,279,588	9,522,867	9,764,185	10,016,585	10,285,079	10,564,288	10,854,265	0	0	0	0	0
153	TOTALS - CAPITAL EXPENDITURES -														
154		b	INTEREST EXPENSE	3,501,702	3,007,101	2,508,924	2,010,891	1,512,659	1,011,957	507,979	0	0	0	0	0
155	TOTALS - EXPENSE EXPENDITURES -														
156		c	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
157	TOTALS - EXPENSE EXPENDITURES -														
158		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
159	TOTAL CONSERVATION PRINCIPAL														
160			AND EXPENSE COSTS	9,279,588	9,522,867	9,764,185	10,016,585	10,285,079	10,564,288	10,854,265	0	0	0	0	0
161															
162	TOTALS - INTEREST EXPENSE			3,501,702	3,007,101	2,508,924	2,010,891	1,512,659	1,011,957	507,979	0	0	0	0	0
164	FY 2011 Conservation Resources Selected -														
165			Debt Service in Nominal Year Dollars												
166	13		2015 Conservation - 2011$$												
167			a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
168			b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
169			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
170			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
172	FY 2011 Deflator values			1.149804	1.172867	1.197413	1.221867	1.245661	1.269495	1.293405	1.317190	1.341207	1.366070	1.391386	1.416789
173	FY 2011 Conservation Resources Selected -														
174			FY2011 Purchasing Power Dollars												
175	13		2015 Conservation - 2011$$												
176			a Capital Expenditures - Amort. of Principal	2,477,053	2,541,992	2,606,410	2,673,785	2,745,455	2,819,985	2,897,390	2,978,220	0	0	0	0
177			b Capital Expenditures - Interest Expense	1,094,401	959,234	823,044	687,033	551,167	414,744	277,542	139,381	0	0	0	0
178			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
179			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
180															

Section 7(b)(2) Rate Test Study and Documentation
Alternative Conservation Expense Accounting and Financing Treatments
WP-10 Final Rate Proposal

Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are expensed in the year incurred (1st year)

Debt Service Components - (whole dollars)

Row	A	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
184		INFLATION ADJUSTED ANALYSIS									
186		**FY 2012 Conservation Resources Selected -**									
187		**Debt Service in Nominal Year Dollars**									
188	**14**	**2014 Conservation - 2012$$**									
189		a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
190		b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
191		c Expense Expenditures - Amort. of Principal	92,253,300	0	0	92,253,300	0	0	0	0	0
192		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
193											
194		FY 2012 Deflator values				1.000000	1.020359	1.041025	1.061937	1.082980	1.104314
195		**FY 2012 Conservation Resources Selected -**									
196		**Debt Service in FY2012 Purchasing Power Dollars**									
197	**14**	**2014 Conservation - 2012$$**									
198		a Capital Expenditures - Amort. of Principal	38,983,476	0	0	2,153,368	2,209,169	2,266,650	2,326,004	2,387,551	2,451,005
199		b Capital Expenditures - Interest Expense	17,067,371	0	0	2,122,988	1,981,862	1,841,182	1,700,935	1,561,142	1,421,405
200		c Expense Expenditures - Amort. of Principal	92,253,300	0	0	92,253,300	0	0	0	0	0
201		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
203		**FY 2013 Conservation Resources Selected - Debt Service in Nominal Year Dollars**									
204	**15**	**2013 Conservation - 2013$$**									
205		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
206		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
207		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	95,228,000	0	0	0	0
208		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
210		FY 2013 Deflator values					1.000000	1.020253	1.040748	1.061371	1.082280
211		**FY 2013 Conservation Resources Selected -**									
212		**Debt Service in FY2013 Purchasing Power Dollars**									
213	**15**	**2013 Conservation - 2013$$**									
214		a Capital Expenditures - Amort. of Principal	40,613,111	0	0	0	2,241,571	2,299,896	2,360,121	2,422,570	2,486,953
215		b Capital Expenditures - Interest Expense	17,773,934	0	0	0	2,209,947	2,063,255	1,917,109	1,771,550	1,626,139
216		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	95,228,000	0	0	0	0
217		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
218											
219		**FY 2014 Conservation Resources Selected -**									
220		**Debt Service in Nominal Year Dollars**									
221	**16**	**2012 Conservation - 2014$$**									
222		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
223		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
224		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	98,290,500	0	0	0
225		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
227		FY 2014 Deflator values						1.000000	1.020087	1.040301	1.060795
228		**FY 2014 Conservation Resources Selected -**									
229		**Debt Service in FY2014 Purchasing Power Dollars**									
230	**16**	**2012 Conservation - 2014$$**									
231		a Capital Expenditures - Amort. of Principal	42,298,028	0	0	0	0	2,332,636	2,393,721	2,457,058	2,522,358
232		b Capital Expenditures - Interest Expense	18,503,867	0	0	0	0	2,299,729	2,147,426	1,995,850	1,844,522
233		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	98,290,500	0	0	0
234		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0

Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are expensed in the year incurred (1st year)

Debt Service Components - (whole dollars)

Row	A	C	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
182		**Vintage - Year Selected**												
184							**INFLATION ADJUSTED ANALYSIS**							
186	**FY 2012 Conservation Resources Selected -**													
187		**Debt Service in Nominal Year Dollars**												
188	**14**	**2014 Conservation - 2012$$**												
189		a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
190		b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
191		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
192		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
193														
194	FY 2012 Deflator values		1.126236	1.148826	1.172869	1.196822	1.220128	1.243473	1.266893	1.290190	1.313715	1.338068	1.362866	1.387748
195	**FY 2012 Conservation Resources Selected -**													
196		**Debt Service in FY2012 Purchasing Power Dollars**												
197	**14**	**2014 Conservation - 2012$$**												
198		a Capital Expenditures - Amort. of Principal	2,515,771	2,581,724	2,647,148	2,715,576	2,788,366	2,864,063	2,942,678	3,024,772	3,109,631	0	0	0
199		b Capital Expenditures - Interest Expense	1,281,263	1,140,646	998,915	857,516	716,476	574,978	432,789	289,743	145,531	0	0	0
200		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
201		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
203	**FY 2013 Conservation Resources Selected - Debt Service i**													
204	**15**	**2013 Conservation - 2013$$**												
205		a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
206		b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
207		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
208		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
210	FY 2013 Deflator values		1.103764	1.125903	1.149466	1.172941	1.195782	1.218662	1.241615	1.264447	1.287502	1.311370	1.335673	1.360058
211	**FY 2013 Conservation Resources Selected -**													
212		**Debt Service in FY2013 Purchasing Power Dollars**												
213	**15**	**2013 Conservation - 2013$$**												
214		a Capital Expenditures - Amort. of Principal	2,552,671	2,619,592	2,685,977	2,755,408	2,829,267	2,906,072	2,985,839	3,069,138	3,155,243	3,242,793	0	0
215		b Capital Expenditures - Interest Expense	1,480,364	1,334,139	1,186,707	1,039,768	893,417	746,720	599,426	451,388	302,242	151,763	0	0
216		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
217		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
218														
219	**FY 2014 Conservation Resources Selected -**													
220		**Debt Service in Nominal Year Dollars**												
221	**16**	**2012 Conservation - 2014$$**												
222		a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
223		b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
224		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
225		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
227	FY 2014 Deflator values		1.081853	1.103552	1.126648	1.149657	1.172044	1.194470	1.216967	1.239346	1.261944	1.285337	1.309158	1.333059
228	**FY 2014 Conservation Resources Selected -**													
229		**Debt Service in FY2014 Purchasing Power Dollars**												
230	**16**	**2012 Conservation - 2014$$**												
231		a Capital Expenditures - Amort. of Principal	2,589,010	2,656,885	2,724,213	2,794,633	2,869,543	2,947,442	3,028,345	3,112,830	3,200,159	3,288,958	3,380,237	0
232		b Capital Expenditures - Interest Expense	1,692,870	1,540,801	1,387,422	1,234,713	1,082,838	930,734	778,139	624,920	470,658	315,050	158,195	0
233		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
234		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
235														

	A	B	C	D	E	F	G	H	I	J	K	L
1			**Section 7(b)(2) Rate Test Study and Documentation**									
2			**Alternative Conservation Expense Accounting and Financing Treatments**									
3			**WP-10 Final Rate Proposal**									
5			**Scenario = Capitalized costs amortized / financed over 15 years,**									
6			**= Expensed costs are expensed in the year incurred (1st year)**									
8			**Debt Service Components - (whole dollars)**									
237			**INFLATION ADJUSTED ANALYSIS**									
238												
239			**Vintage - Year Selected**	**TOTALS**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**
240												
241	**FY 2015 Conservation Resources Selected -**											
242			**Debt Service in Nominal Year Dollars**									
243	**17**		**2011 Conservation - 2015$$**									
244			a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
245			b Capital Expenditures - Interest Expense	17,772,523	0	0	0	0	0	2,008,848	1,913,489	1,813,666
246			c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	95,303,100	0	0
247			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
249	FY 2015 Deflator values											
250	**FY 2015 Conservation Resources Selected -**											
251			**Debt Service in FY2015 Purchasing Power Dollars**									
252	**17**		**2011 Conservation - 2015$$**							1.000000	1.019816	1.039906
253			a Capital Expenditures - Amort. of Principal	36,977,517	0	0	0	0	0	2,037,593	2,091,507	2,147,093
254			b Capital Expenditures - Interest Expense	16,169,438	0	0	0	0	0	2,008,848	1,876,308	1,744,067
255			c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	95,303,100	0	0
256			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0
257												
258					**SUMMARY TOTALS - INFLATION ADJUSTED VALUES ANALYSIS**							
259												
260			**DEBT SERVICE COMPONENT PARTS**	**TOTALS**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**
261												
262	TOTALS - CAPITAL EXPENDITURES -			332,724,142								
263		a	AMORTIZATION OF PRINCIPAL	332,724,142	7,549,912	9,814,342	12,216,435	14,774,570	17,491,636	19,987,273	20,516,136	21,061,383
264	TOTALS - CAPITAL EXPENDITURES -			145,677,301								
265		b	INTEREST EXPENSE	145,677,301	7,443,399	8,988,111	10,476,967	11,917,548	13,302,975	14,247,373	13,053,304	11,859,519
266	TOTALS - EXPENSE EXPENDITURES -			849,034,700								
267		c	AMORTIZATION OF PRINCIPAL	849,034,700	378,193,500	89,766,300	92,253,300	95,228,000	98,290,500	95,303,100	0	0
268	TOTALS - EXPENSE EXPENDITURES -											
269		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0
270				1,181,758,842								
271	TOTALS - CONSERVATION PRINCIPAL COSTS			1,181,758,842	385,743,412	99,580,642	104,469,735	110,002,570	115,782,136	115,290,373	20,516,136	21,061,383
272				145,677,301								
273	TOTALS - INTEREST EXPENSE			145,677,301	7,443,399	8,988,111	10,476,967	11,917,548	13,302,975	14,247,373	13,053,304	11,859,519
274												
275	PERCENTAGE OF TOTAL PRINCIPAL PAID			100.00%	32.64%	8.43%	8.84%	9.31%	9.80%	9.76%	1.74%	1.78%
276			(Capital and Expense Expenditures)									
277												
278	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID				32.64%	41.07%	49.91%	59.22%	69.02%	78.78%	80.52%	82.30%
279			(Capital and Expense Expenditures)									
280				PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD =					78.78%			
281				TOTAL INTEREST PAID ON EXPENSED PORTION =					$0			
282												
283									Total			
284					Interest Paid	Interest Paid	Interest Paid	Interest Paid	Interest Paid			
285					FY2010-2011	FY2012-2015	FY2010-2015	FY2016-2029	FY2010-2029			
286					16,431,510	49,944,863	66,376,373	79,300,928	145,677,301			
287												
288					Page 17 of 18							

Section 7(b)(2) Rate Test Study and Documentation

Alternative Conservation Expense Accounting and Financing Treatments

WP-10 Initial Rate Proposal

Scenario = Capitalized costs amortized / financed over 15 years,

= Expensed costs are expensed in the year incurred (1st year)

Debt Service Components - (whole dollars)

INFLATION ADJUSTED ANALYSIS

Row	A	C	M	N	O	P	Q	R	S	T	U	V	W	X
239		**Vintage - Year Selected**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
241	**FY 2015 Conservation Resources Selected -**													
242		**Debt Service in Nominal Year Dollars**												
243	**17**	**2011 Conservation - 2015$$**												
244		a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,490	2,937,834	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,536
245		b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,608	971,117	827,192	676,531	518,819	353,726	180,907
246		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
247		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
249	FY 2015 Deflator values													
250	**FY 2015 Conservation Resources Selected -**													
251		**Debt Service in FY2015 Purchasing Power Dollars**												
252	**17**	**2011 Conservation - 2015$$**	1.060549	1.081821	1.104462	1.127018	1.148965	1.170948	1.193003	1.214941	1.237094	1.260027	1.283378	1.306808
253		a Capital Expenditures - Amort. of Principal	2,203,828	2,261,606	2,318,917	2,378,860	2,442,624	2,508,936	2,577,802	2,649,717	2,724,054	2,799,641	2,877,341	2,957,998
254		b Capital Expenditures - Interest Expense	1,611,593	1,478,792	1,344,804	1,211,536	1,079,190	946,761	814,011	680,850	546,871	411,752	275,621	138,434
255		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
256		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
258							**SUMMARY TOTALS - INFLATION ADJUSTED VALUES ANALYSIS**							
260		**DEBT SERVICE COMPONENT PARTS**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
262	TOTALS - CAPITAL EXPENDITURES -													
263		a AMORTIZATION OF PRINCIPAL	21,617,921	22,184,666	22,746,850	23,334,847	23,960,334	24,610,786	25,286,319	14,834,677	12,189,087	9,331,392	6,257,578	2,957,998
264	TOTALS - CAPITAL EXPENDITURES -													
265		b INTEREST EXPENSE	10,662,193	9,460,713	8,249,816	7,041,457	5,835,747	4,625,894	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
266	TOTALS - EXPENSE EXPENDITURES -													
267		c AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
268	TOTALS - EXPENSE EXPENDITURES -													
269		d INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
271	TOTALS - CONSERVATION PRINCIPAL COSTS		21,617,921	22,184,666	22,746,850	23,334,847	23,960,334	24,610,786	25,286,319	14,834,677	12,189,087	9,331,392	6,257,578	2,957,998
273	TOTALS - INTEREST EXPENSE		10,662,193	9,460,713	8,249,816	7,041,457	5,835,747	4,625,894	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
275	PERCENTAGE OF TOTAL PRINCIPAL PAID		1.83%	1.88%	1.92%	1.97%	2.03%	2.08%	2.14%	1.26%	1.03%	0.79%	0.53%	0.25%
276		(Capital and Expense Expenditures)												
278	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		84.13%	86.01%	87.93%	89.90%	91.93%	94.01%	96.15%	97.41%	98.44%	99.23%	99.76%	100.01%
279		(Capital and Expense Expenditures)												
280		PE												

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Scenario = Capitalized costs are amortized and financed over 15 years,
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	Inflation Adjustment	Capitalized Conservation: Deferral/ Maturity # of Years	Capitalized Conservation: Interest Rate 15 - Year Maturity	Expensed Conservation: Deferral/ Maturity # of Years	Expensed Conservation: Interest Rate
FY 2010	1.000000	15	0.0468	4	0.0357
FY 2011	1.020232			5	0.0369
FY 2012	1.041582			6	0.0381
FY 2013	1.062788			7	0.0393
FY 2014	1.084313			15	0.0468
FY 2015	1.106094				

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2010 Conservation Resources Selected						
1	**2001 Conservation - 2010$$**	19.2	29,059.6	72.4	29,132.0	
	Capitalized Costs - Debt Service Requirements					$6,825.13
	Expensed Costs /Deferral Debt Service Requirements					$7,924,660.36
3	**2006 Conservation - 2010$$**	31.0	39,428.0	16,435.8	55,863.8	
	Capitalized Costs - Debt Service Requirements					$1,549,397.68
	Expensed Costs /Deferral Debt Service Requirements					$10,752,161.38
4	**2003 Conservation - 2010$$**	27.6	30,621.2	27,501.3	58,122.5	
	Capitalized Costs - Debt Service Requirements					2,592,538.87
	Expensed Costs /Deferral Debt Service Requirements					$8,350,514.46
5	**2002 Conservation - 2010$$**	26.6	26,137.0	34,587.9	60,724.9	
	Capitalized Costs - Debt Service Requirements					3,260,590.41
	Expensed Costs /Deferral Debt Service Requirements					$7,127,656.54
6	**2005 Conservation - 2010$$**	20.6	31,616.2	16,720.6	48,336.8	
	Capitalized Costs - Debt Service Requirements					1,576,245.68
	Expensed Costs /Deferral Debt Service Requirements					$8,621,854.63
8	**2008 Conservation - 2010$$**	30.3	65,409.8	9,139.1	74,548.9	
	Capitalized Costs - Debt Service Requirements					861,540.07
	Expensed Costs /Deferral Debt Service Requirements					$17,837,494.30
9	**2004 Conservation - 2010$$**	20.1	27,250.7	22,724.9	49,975.6	
	Capitalized Costs - Debt Service Requirements					2,142,269.15
	Expensed Costs /Deferral Debt Service Requirements					$7,431,366.64
10	**2007 Conservation - 2010$$**	27.9	59,178.2	11,453.5	70,631.7	
	Capitalized Costs - Debt Service Requirements					1,079,717.83
	Expensed Costs /Deferral Debt Service Requirements					$16,138,113.94
12	**2009 Conservation - 2010$$**	28.4	69,492.8	20,411.5	89,904.3	
	Capitalized Costs - Debt Service Requirements					1,924,185.66
	Expensed Costs /Deferral Debt Service Requirements					$18,950,943.50
	Totals - FY 2010	231.7	378,193.5	159,047.0	537,240.5	

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2010 Conservation Resources Selected											
1	**2001 Conservation - 2010$$**										
Capital		6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Expense		7,924.7	7,924.7	7,924.7	7,924.7	0.0	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
Capital		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4
Expense		10,752.2	10,752.2	10,752.2	10,752.2	0.0	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
Capital		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5
Expense		8,350.5	8,350.5	8,350.5	8,350.5	0.0	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
Capital		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6
Expense		7,127.7	7,127.7	7,127.7	7,127.7	0.0	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
Capital		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2
Expense		8,621.9	8,621.9	8,621.9	8,621.9	0.0	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
Capital		861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5
Expense		17,837.5	17,837.5	17,837.5	17,837.5	0.0	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
Capital		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3
Expense		7,431.4	7,431.4	7,431.4	7,431.4	0.0	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
Capital		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7
Expense		16,138.1	16,138.1	16,138.1	16,138.1	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2
Expense		18,950.9	18,950.9	18,950.9	18,950.9	0.0	0.0	0.0	0.0	0.0	0.0

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Debt Service Requirements - Principal and Interest ($ 000)

X	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Res. Stack Order	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
	11	12	13	14	15					
FY 2010 Conservation Resources Selected										
1	**2001 Conservation - 2010$$**									
Capital	6.8	6.8	6.8	6.8	6.8	0.0	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**									
Capital	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	0.0	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**									
Capital	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	0.0	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**									
	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**									
Capital	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	0.0	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**									
Capital	861.5	861.5	861.5	861.5	861.5	0.0	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**									
Capital	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	0.0	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**									
Capital	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	0.0	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**									
Capital	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	0.0	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Expensed costs are deferred and financed over 4-years

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$		87,986.2	42,697.1	130,683.3	
13	**2015 Conservation - 2011$$**	39.5	89,766.3	43,560.9	133,327.2	
	Capitalized Costs - Debt Service Requirements					4,106,472.29
	Expensed Costs /Deferral Debt Service Requirements					$24,479,601.90
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$		88,570.4	43,552.0	132,122.4	
14	**2014 Conservation - 2012$$**	39.5	92,253.3	45,363.0	137,616.3	
	Capitalized Costs - Debt Service Requirements					4,276,355.69
	Expensed Costs /Deferral Debt Service Requirements					$25,157,816.00
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$		89,602.1	44,431.3	134,033.4	
15	**2013 Conservation - 2013$$**	39.5	95,228.0	47,221.1	142,449.1	
	Capitalized Costs - Debt Service Requirements					4,451,518.19
	Expensed Costs /Deferral Debt Service Requirements					$25,969,027.69
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$		90,647.7	45,318.6	135,966.3	
16	**2012 Conservation - 2014$$**	39.5	98,290.5	49,139.5	147,430.0	
	Capitalized Costs - Debt Service Requirements					4,632,365.15
	Expensed Costs /Deferral Debt Service Requirements					$26,804,182.76
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$		86,161.8	38,806.9	124,968.7	
17	**2011 Conservation - 2015$$**	34.9	95,303.1	42,924.1	138,227.2	
	Capitalized Costs - Debt Service Requirements					4,046,441.35
	Expensed Costs /Deferral Debt Service Requirements					$25,989,507.73

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		387,255.6	160,340.4	547,596.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	849,034.7		77,105.3	926,140.0
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	849,034.7	387,255.6	237,445.7	1,473,736.0

Principal Expense Costs	849,034.7
Interest Paid Expensed Costs	77,105.3
Principal Capital Costs	387,255.6
Interest Paid Capital Costs	160,340.4
Totals	1,473,736.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5
Expense		0.0	24,479.6	24,479.6	24,479.6	24,479.6	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4
Expense		0.0	0.0	25,157.8	25,157.8	25,157.8	25,157.8	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5
Expense		0.0	0.0	0.0	25,969.0	25,969.0	25,969.0	25,969.0	0.0	0.0	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4
Expense		0.0	0.0	0.0	0.0	26,804.2	26,804.2	26,804.2	26,804.2	0.0	0.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense		0.0	0.0	0.0	0.0	0.0	25,989.5	25,989.5	25,989.5	25,989.5	0.0
TCC		14,993.2	19,099.7	23,376.1	27,827.6	32,460.0	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4
TEC		103,134.9	127,614.5	152,772.3	178,741.3	102,410.6	103,920.5	78,762.7	52,793.7	25,989.5	0.0
TDSR		118,128.1	146,714.2	176,148.4	206,568.9	134,870.6	140,426.9	115,269.1	89,300.1	62,495.9	36,506.4

X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
		11	12	13	14	15					
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC		36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4
TEC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR		36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010	**Conservation Resources Selected**									
FY 2010	Conservation (9) Res. Selected - Total MW =	231.7								
1	**2001 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	72,400	3,437	3,598	3,766	3,942	4,127	4,320	4,522	4,734
	b Capital Expenditures - Interest Expense	29,975	3,388	3,227	3,059	2,883	2,698	2,505	2,303	2,091
	c Expense Expenditures - Amort. of Principal	29,059,600	6,887,232	7,133,107	7,387,759	7,651,502	0	0	0	0
	d Expense Expenditures - Interest Expense	2,639,043	1,037,428	791,554	536,902	273,159	0	0	0	0
3	**2006 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,435,800	780,203	816,716	854,938	894,949	936,833	980,677	1,026,573	1,074,616
	b Capital Expenditures - Interest Expense	6,805,165	769,195	732,682	694,460	654,449	612,565	568,721	522,825	474,782
	c Expense Expenditures - Amort. of Principal	39,428,000	9,344,581	9,678,183	10,023,695	10,381,541	0	0	0	0
	d Expense Expenditures - Interest Expense	3,580,646	1,407,580	1,073,978	728,467	370,621	0	0	0	0
4	**2003 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	27,501,300	1,305,478	1,366,575	1,430,530	1,497,479	1,567,561	1,640,923	1,717,718	1,798,107
	b Capital Expenditures - Interest Expense	11,386,782	1,287,061	1,225,964	1,162,009	1,095,060	1,024,978	951,616	874,821	794,432
	c Expense Expenditures - Amort. of Principal	30,621,200	7,257,337	7,516,424	7,784,760	8,062,679	0	0	0	0
	d Expense Expenditures - Interest Expense	2,780,859	1,093,177	834,090	565,754	287,838	0	0	0	0
5	**2002 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	34,587,900	1,641,876	1,718,716	1,799,152	1,883,352	1,971,493	2,063,759	2,160,343	2,261,448
	b Capital Expenditures - Interest Expense	14,320,958	1,618,714	1,541,874	1,461,438	1,377,238	1,289,097	1,196,831	1,100,247	999,143
	c Expense Expenditures - Amort. of Principal	26,137,000	6,194,566	6,415,712	6,644,753	6,881,969	0	0	0	0
	d Expense Expenditures - Interest Expense	2,373,626	933,091	711,945	482,904	245,686	0	0	0	0
6	**2005 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,720,600	793,722	830,868	869,753	910,457	953,067	997,670	1,044,361	1,093,237
	b Capital Expenditures - Interest Expense	6,923,083	782,524	745,378	706,493	665,789	623,179	578,576	531,885	483,009
	c Expense Expenditures - Amort. of Principal	31,616,200	7,493,157	7,760,662	8,037,718	8,324,663	0	0	0	0
	d Expense Expenditures - Interest Expense	2,871,218	1,128,698	861,193	584,137	297,190	0	0	0	0
8	**2008 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	9,139,100	433,830	454,133	475,387	497,635	520,924	545,303	570,824	597,538
	b Capital Expenditures - Interest Expense	3,784,002	427,710	407,407	386,153	363,905	340,616	316,237	290,716	264,002
	c Expense Expenditures - Amort. of Principal	65,409,800	15,502,364	16,055,799	16,628,991	17,222,646	0	0	0	0
	d Expense Expenditures - Interest Expense	5,940,176	2,335,130	1,781,695	1,208,503	614,848	0	0	0	0

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected													
FY 2010	Conservation (9) Res. Selected - Total MW =												
1	**2001 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	4,955	5,187	5,430	5,684	5,950	6,228	6,520	0	0	0	0	0
	b Capital Expenditures - Interest Expense	1,870	1,638	1,395	1,141	875	597	305	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
3	**2006 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,124,908	1,177,554	1,232,662	1,290,351	1,350,739	1,413,954	1,480,127	0	0	0	0	0
	b Capital Expenditures - Interest Expense	424,490	371,844	316,735	259,046	198,658	135,443	69,270	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
4	**2003 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,882,259	1,970,348	2,062,561	2,159,089	2,260,134	2,365,908	2,476,630	0	0	0	0	0
	b Capital Expenditures - Interest Expense	710,280	622,191	529,978	433,450	332,405	226,631	115,906	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
5	**2002 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	2,367,284	2,478,073	2,594,046	2,715,448	2,842,531	2,975,561	3,114,818	0	0	0	0	0
	b Capital Expenditures - Interest Expense	893,307	782,518	666,545	545,143	418,060	285,030	145,773	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
6	**2005 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,144,400	1,197,958	1,254,022	1,312,710	1,374,145	1,438,455	1,505,775	0	0	0	0	0
	b Capital Expenditures - Interest Expense	431,845	378,287	322,223	263,535	202,100	137,790	70,470	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
8	**2008 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	625,503	654,777	685,420	717,498	751,077	786,227	823,024	0	0	0	0	0
	b Capital Expenditures - Interest Expense	236,037	206,763	176,120	144,042	110,463	75,313	38,518	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
47	**FY 2010**	**Conservation Resources Selected -Continued**									
48	**9**	**2004 Conservation - 2010$$**									
49		a Capital Expenditures - Amort. of Principal	22,724,900	1,078,744	1,129,229	1,182,077	1,237,398	1,295,308	1,355,929	1,419,386	1,485,813
50		b Capital Expenditures - Interest Expense	9,409,137	1,063,525	1,013,040	960,192	904,871	846,961	786,340	722,883	656,456
51		c Expense Expenditures - Amort. of Principal	27,250,700	6,458,517	6,689,086	6,927,886	7,175,211	0	0	0	0
52		d Expense Expenditures - Interest Expense	2,474,767	972,850	742,281	503,481	256,155	0	0	0	0
53	**10**	**2007 Conservation - 2010$$**									
54		a Capital Expenditures - Amort. of Principal	11,453,500	543,694	569,139	595,775	623,657	652,844	683,397	715,380	748,860
55		b Capital Expenditures - Interest Expense	4,742,268	536,024	510,579	483,943	456,061	426,874	396,321	364,338	330,858
56		c Expense Expenditures - Amort. of Principal	59,178,200	14,025,452	14,526,161	15,044,745	15,581,842	0	0	0	0
57		d Expense Expenditures - Interest Expense	5,374,256	2,112,662	1,611,953	1,093,369	556,272	0	0	0	0
58	**12**	**2009 Conservation - 2010$$**									
59		a Capital Expenditures - Amort. of Principal	20,411,500	968,928	1,014,274	1,061,742	1,111,431	1,163,446	1,217,895	1,274,893	1,334,557
60		b Capital Expenditures - Interest Expense	8,451,286	955,258	909,912	862,444	812,755	760,740	706,291	649,293	589,628
61		c Expense Expenditures - Amort. of Principal	69,492,800	16,470,051	17,058,031	17,667,003	18,297,715	0	0	0	0
62		d Expense Expenditures - Interest Expense	6,310,973	2,480,893	1,892,912	1,283,940	653,228	0	0	0	0
63	**FY 2011**	**Conservation Resources Selected**									
64	**13**	**2015 Conservation - 2011$$**									
65		a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
66		b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
67		c Expense Expenditures - Amort. of Principal	89,766,300	0	21,274,945	22,034,461	22,821,091	23,635,803	0	0	0
68		d Expense Expenditures - Interest Expense	8,152,107	0	3,204,657	2,445,141	1,658,511	843,798	0	0	0
69	**FY 2012**	**Conservation Resources Selected**									
70	**14**	**2014 Conservation - 2012$$**									
71		a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
72		b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
73		c Expense Expenditures - Amort. of Principal	92,253,300	0	0	21,864,373	22,644,931	23,453,355	24,290,641	0	0
74		d Expense Expenditures - Interest Expense	8,377,965	0	0	3,293,443	2,512,885	1,704,461	867,176	0	0
75	**FY 2013**	**Conservation Resources Selected**									
76	**15**	**2013 Conservation - 2013$$**									
77		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
78		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
79		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	22,569,388	23,375,116	24,209,607	25,073,889	0
80		d Expense Expenditures - Interest Expense	8,648,111	0	0	0	3,399,640	2,593,912	1,759,421	895,138	0
81	**FY 2014**	**Conservation Resources Selected**									
82	**16**	**2012 Conservation - 2014$$**									
83		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
84		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
85		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	23,295,212	24,126,851	24,988,180	25,880,257
86		d Expense Expenditures - Interest Expense	8,926,231	0	0	0	0	3,508,971	2,677,332	1,816,003	923,925

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	A	B	C	M	N	O	P	Q	R	S	T	U	V	W	X
46	Res. Stack Order		Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
47	FY 2010		Conservation Resources Selected -Continued												
48	9		2004 Conservation - 2010$$												
49		a	Capital Expenditures - Amort. of Principal	1,555,349	1,628,140	1,704,337	1,784,100	1,867,596	1,954,999	2,046,495	0	0	0	0	0
50		b	Capital Expenditures - Interest Expense	586,920	514,129	437,932	358,169	274,673	187,270	95,776	0	0	0	0	0
51		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
52		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
53	10		2007 Conservation - 2010$$												
54		a	Capital Expenditures - Amort. of Principal	783,907	820,594	858,997	899,198	941,281	985,333	1,031,444	0	0	0	0	0
55		b	Capital Expenditures - Interest Expense	295,811	259,124	220,721	180,520	138,437	94,385	48,272	0	0	0	0	0
56		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
57		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
58	12		2009 Conservation - 2010$$												
59		a	Capital Expenditures - Amort. of Principal	1,397,014	1,462,394	1,530,834	1,602,478	1,677,474	1,755,980	1,838,160	0	0	0	0	0
60		b	Capital Expenditures - Interest Expense	527,171	461,791	393,351	321,708	246,712	168,206	86,026	0	0	0	0	0
61		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
62		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
63	FY 2011		Conservation Resources Selected												
64	13		2015 Conservation - 2011$$												
65		a	Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
66		b	Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
67		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
68		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
69	FY 2012		Conservation Resources Selected												
70	14		2014 Conservation - 2012$$												
71		a	Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
72		b	Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
73		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
74		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
75	FY 2013		Conservation Resources Selected												
76	15		2013 Conservation - 2013$$												
77		a	Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
78		b	Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
79		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
80		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
81	FY 2014		Conservation Resources Selected												
82	16		2012 Conservation - 2014$$												
83		a	Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
84		b	Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
85		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
86		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

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Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2015 Conservation Resources Selected										
17	**2011 Conservation - 2015$$**									
	a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
	b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
	c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	22,587,187	23,393,550	24,228,700
	d Expense Expenditures - Interest Expense	8,654,931	0	0	0	0	0	3,402,321	2,595,958	1,760,808

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
TOTALS - CAPITAL EXPENDITURES - AMORTIZATION OF PRINCIPAL	387,255,600	7,549,912	9,971,070	12,591,084	15,421,915	18,476,297	21,378,581	22,379,100	23,426,441
TOTALS - CAPITAL EXPENDITURES - INTEREST EXPENSE	160,341,348	7,443,399	9,128,713	10,785,055	12,405,742	13,983,725	15,127,882	14,127,363	13,080,022
TOTALS - EXPENSE EXPENDITURES - AMORTIZATION OF PRINCIPAL	849,034,700	89,633,257	114,108,110	140,046,144	167,615,178	93,759,486	95,214,286	73,455,619	50,108,957
TOTALS - EXPENSE EXPENDITURES - INTEREST EXPENSE	77,104,909	13,501,509	13,506,258	12,726,041	11,126,033	8,651,142	8,706,250	5,307,099	2,684,733
TOTALS - CONSERVATION PRINCIPAL COSTS	1,236,290,300	97,183,169	124,079,180	152,637,228	183,037,093	112,235,783	116,592,867	95,834,719	73,535,398
TOTALS - INTEREST EXPENSE	237,446,257	20,944,908	22,634,971	23,511,096	23,531,775	22,634,867	23,834,132	19,434,462	15,764,755
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	100.00%	7.86%	10.04%	12.35%	14.81%	9.08%	9.43%	7.75%	5.95%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)		7.86%	17.90%	30.25%	45.06%	54.14%	$\boxed{63.57\%}$	71.32%	77.27%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 63.57%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (NOMINAL DOLLARS) = 77,104,909
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES-YEAR OF INVESTMENT) = 849,034,700
INTEREST AS A PECENTAGE OF ORIGINAL INVESTMENT COSTS = 9.08%

INTEREST (NOMINAL DOLLARS) EXPENDITURES BY PERIOD

	Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
Interest on Capital and Expense Expenditures	43,579,879	93,511,870	137,091,749	100,354,508	237,446,257

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Debt Service Components - (whole dollars)

	A	C	M	N	O	P	Q	R	S	T	U	V	W	X
89	**Res. Stack Order**	**Vintage - Year Selected**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
90														
91	**FY 2015 Conservation Resources Selected**													
92	**17**	**2011 Conservation - 2015$$**												
93		a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
94		b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
95		c Expense Expenditures - Amort. of Principal	25,093,663	0	0	0	0	0	0	0	0	0	0	0
96		d Expense Expenditures - Interest Expense	895,844	0	0	0	0	0	0	0	0	0	0	0
97														
98							**SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS**							
100		**DEBT SERVICE COMPONENT PARTS**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
102	TOTALS - CAPITAL EXPENDITURES -													
103		AMORTIZATION OF PRINCIPAL	24,522,798	25,670,466	26,871,840	28,129,445	29,445,904	30,823,972	32,266,533	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
104	TOTALS - CAPITAL EXPENDITURES -													
105		INTEREST EXPENSE	11,983,664	10,835,996	9,634,621	8,377,017	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
106	TOTALS - EXPENSE EXPENDITURES -													
107		AMORTIZATION OF PRINCIPAL	25,093,663	0	0	0	0	0	0	0	0	0	0	0
108	TOTALS - EXPENSE EXPENDITURES -													
109		INTEREST EXPENSE	895,844	0	0	0	0	0	0	0	0	0	0	0
110														
111	TOTALS - CONSERVATION PRINCIPAL COSTS		49,616,461	25,670,466	26,871,840	28,129,445	29,445,904	30,823,972	32,266,533	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
112														
113	TOTALS - INTEREST EXPENSE		12,879,508	10,835,996	9,634,621	8,377,017	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
114														
115	PERCENTAGE OF TOTAL PRINCIPAL PAID		4.01%	2.08%	2.17%	2.28%	2.38%	2.49%	2.61%	1.52%	1.26%	0.97%	0.66%	0.31%
116		(Capital and Expense Expenditures)												
117														
118	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		81.28%	83.36%	85.53%	87.81%	90.19%	92.68%	95.29%	96.81%	98.07%	99.04%	99.70%	100.01%
119		(Capital and Expense Expenditures)												

	A	B	C	D	E	F	G	H	I	J	K	L
1				Section 7(b)(2) Rate Test Study and Documentation								
2				Alternative Conservation Expense Accounting and Financing Treatments								
3				WP-10 Final Rate Proposal								
5				Scenario = Capitalized costs amortized / financed over 15 years,								
6				= Expensed costs are deferred and amortized / financed over 4 - years								
8					Debt Service Components - (whole dollars)							
135			Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
137					INFLATION ADJUSTED ANALYSIS							
139	FY 2010 Conservation Resources Selected -											
140			Debt Service in Nominal Year Dollars									
141	TOTALS - CAPITAL EXPENDITURES -			159,047,000								
142		a	AMORTIZATION OF PRINCIPAL	159,047,000	7,549,912	7,903,248	8,273,120	8,660,300	9,065,603	9,489,873	9,934,000	10,398,910
143	TOTALS - CAPITAL EXPENDITURES -			65,852,656								
144		b	INTEREST EXPENSE	65,852,656	7,443,399	7,090,063	6,720,191	6,333,011	5,927,708	5,503,438	5,059,311	4,594,401
145	TOTALS - EXPENSE EXPENDITURES -			378,193,500								
146		c	AMORTIZATION OF PRINCIPAL	378,193,500	89,633,257	92,833,165	96,147,310	99,579,768	0	0	0	0
147	TOTALS - EXPENSE EXPENDITURES -			34,345,564								
148		d	INTEREST EXPENSE	34,345,564	13,501,509	10,301,601	6,987,457	3,554,997	0	0	0	0
150	FY 2010 Deflator values				1.000000	1.020232	1.041582	1.062788	1.084313	1.106094	1.128012	1.150234
151	FY 2010 Conservation Resources Selected -											
152			Debt service in FY2010 Purchasing Power Dollars									
153	TOTALS - CAPITAL EXPENDITURES -											
154		a	AMORTIZATION OF PRINCIPAL	136,462,442	7,549,912	7,746,520	7,942,841	8,148,662	8,360,688	8,579,626	8,806,644	9,040,691
155	TOTALS - CAPITAL EXPENDITURES -											
156		b	INTEREST EXPENSE	59,786,673	7,443,399	6,949,461	6,451,908	5,958,866	5,466,787	4,975,561	4,485,157	3,994,319
157	TOTALS - EXPENSE EXPENDITURES -											
158		c	AMORTIZATION OF PRINCIPAL	366,631,125	89,633,257	90,992,211	92,308,920	93,696,737	0	0	0	0
159	TOTALS - EXPENSE EXPENDITURES -											
160		d	INTEREST EXPENSE	33,652,298	13,501,509	10,097,312	6,708,504	3,344,973	0	0	0	0
162	FY 2011 Conservation Resources Selected											
163	13		2015 Conservation - 2011$$ -									
164			Debt Service in Nominal Year Dollars									
165			a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
166			b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
167			c Expense Expenditures - Amort. of Principal	89,766,300	0	21,274,945	22,034,461	22,821,091	23,635,803	0	0	0
168			d Expense Expenditures - Interest Expense	8,152,107	0	3,204,657	2,445,141	1,658,511	843,798	0	0	0
170	FY 2011 Deflator values					1.000000	1.020927	1.041712	1.062810	1.084159	1.105643	1.127424
171	13		2015 Conservation - 2011$$ -									
172			Debt service in FY2011 Purchasing Power Dollars									
173			a Capital Expenditures - Amort. of Principal	37,389,568	0	2,067,822	2,120,226	2,175,168	2,231,766	2,290,208	2,350,806	2,413,282
174			b Capital Expenditures - Interest Expense	16,376,020	0	2,038,650	1,902,071	1,766,873	1,632,022	1,497,494	1,363,297	1,229,067
175			c Expense Expenditures - Amort. of Principal	87,004,010	0	21,274,945	21,582,798	21,907,294	22,238,973	0	0	0
176			d Expense Expenditures - Interest Expense	7,985,709	0	3,204,657	2,395,020	1,592,101	793,931	0	0	0
178	FY 2012 Conservation Resources Selected											
179	14		2014 Conservation - 2012$$ -									
180			Debt Service in Nominal Year Dollars									
181			a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
182			b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
183			c Expense Expenditures - Amort. of Principal	92,253,300	0	0	21,864,373	22,644,931	23,453,355	24,290,641	0	0
184			d Expense Expenditures - Interest Expense	8,377,965	0	0	3,293,443	2,512,885	1,704,461	867,176	0	0
186	FY 2012 Deflator values						1.000000	1.020359	1.041025	1.061937	1.082980	1.104314
187	14		2014 Conservation - 2012$$ -									
188			Debt service in FY2012 Purchasing Power Dollars									
189			a Capital Expenditures - Amort. of Principal	38,983,476	0	0	2,153,368	2,209,169	2,266,650	2,326,004	2,387,551	2,451,005
190			b Capital Expenditures - Interest Expense	17,067,371	0	0	2,122,988	1,981,862	1,841,182	1,700,935	1,561,142	1,421,405
191			c Expense Expenditures - Amort. of Principal	89,460,474	0	0	21,864,373	22,193,102	22,529,099	22,873,900	0	0
192			d Expense Expenditures - Interest Expense	8,210,078	0	0	3,293,443	2,462,746	1,637,291	816,598	0	0
194						Page 13 of 18						

Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are deferred and amortized / financed over 4 - years

Debt Service Components - (whole dollars)

	A	B / C	M	N	O	P	Q	R	S	T	U	V	W	X
135		**Vintage - Year Selected**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
137														
139	**FY 2010**	**Conservation Resources Selected -**												
140		**Debt Service in Nominal Year Dollars**												
141	TOTALS - CAPITAL EXPENDITURES -													
142		a AMORTIZATION OF PRINCIPAL	10,885,579	11,395,025	11,928,309	12,486,556	13,070,927	13,682,645	14,322,993	0	0	0	0	0
143	TOTALS - CAPITAL EXPENDITURES -													
144		b INTEREST EXPENSE	4,107,731	3,598,285	3,065,000	2,506,754	1,922,383	1,310,665	670,316	0	0	0	0	0
145	TOTALS - EXPENSE EXPENDITURES -													
146		c AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
147	TOTALS - EXPENSE EXPENDITURES -													
148		d INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
150	FY 2010 Deflator values		1.173067	1.196596	1.221639	1.246588	1.270863	1.295179	1.319573	1.343839	1.368342	1.393708	1.419537	1.445453
151	**FY 2010**	**Conservation Resources Selected -**												
152		**Debt service in FY2010 Purchasing Power Dollars**												
153	TOTALS - CAPITAL EXPENDITURES -													
154		a AMORTIZATION OF PRINCIPAL	9,279,588	9,522,867	9,764,185	10,016,586	10,285,080	10,564,289	10,854,263	0	0	0	0	0
155	TOTALS - CAPITAL EXPENDITURES -													
156		b INTEREST EXPENSE	3,501,702	3,007,101	2,508,924	2,010,892	1,512,660	1,011,957	507,979	0	0	0	0	0
157	TOTALS - EXPENSE EXPENDITURES -													
158		c AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
159	TOTALS - EXPENSE EXPENDITURES -													
160		d INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
162	**FY 2011**	**Conservation Resources Selected**												
163	**13**	**2015 Conservation - 2011$$ -**												
164		**Debt Service in Nominal Year Dollars**												
165		a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
166		b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
167		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
168		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
170	FY 2011 Deflator values		1.149804	1.172867	1.197413	1.221867	1.245661	1.269495	1.293405	1.317190	1.341207	1.366070	1.391386	1.416789
171	**13**	**2015 Conservation - 2011$$ -**												
172		**Debt service in FY2011 Purchasing Power Dollars**												
173		a Capital Expenditures - Amort. of Principal	2,477,053	2,541,992	2,606,410	2,673,785	2,745,455	2,819,985	2,897,390	2,978,220	0	0	0	0
174		b Capital Expenditures - Interest Expense	1,094,401	959,234	823,044	687,033	551,167	414,744	277,542	139,381	0	0	0	0
175		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
176		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
178	**FY 2012**	**Conservation Resources Selected**												
179	**14**	**2014 Conservation - 2012$$ -**												
180		**Debt Service in Nominal Year Dollars**												
181		a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
182		b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
183		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
184		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
186	FY 2012 Deflator values		1.126236	1.148826	1.172869	1.196822	1.220128	1.243473	1.266893	1.290190	1.313715	1.338068	1.362866	1.387748
187	**14**	**2014 Conservation - 2012$$ -**												
188		**Debt service in FY2012 Purchasing Power Dollars**												
189		a Capital Expenditures - Amort. of Principal	2,515,771	2,581,724	2,647,148	2,715,576	2,788,366	2,864,063	2,942,678	3,024,772	3,109,631	0	0	0
190		b Capital Expenditures - Interest Expense	1,281,263	1,140,646	998,915	857,516	716,476	574,978	432,789	289,743	145,531	0	0	0
191		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
192		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

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= Expensed costs are deferred and amortized / financed over 4 - years

Debt Service Components - (whole dollars)

Row	A	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
197					INFLATION ADJUSTED ANALYSIS						
199	FY 2013 Conservation Resources Selected										
200	15	2013 Conservation - 2013$$ -									
201		Debt Service in Nominal Year Dollars									
202		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
203		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
204		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	22,569,388	23,375,116	24,209,607	25,073,889	0
205		d Expense Expenditures - Interest Expense	8,648,111	0	0	0	3,399,640	2,593,912	1,759,421	895,138	0
207	FY 2013 Deflator values						1.000000	1.020253	1.040748	1.061371	1.082280
208	15	2013 Conservation - 2013$$ -									
209		Debt service in FY2013 Purchasing Power Dollars									
210		a Capital Expenditures - Amort. of Principal	40,613,111	0	0	0	2,241,571	2,299,896	2,360,121	2,422,570	2,486,953
211		b Capital Expenditures - Interest Expense	17,773,934	0	0	0	2,209,947	2,063,255	1,917,109	1,771,550	1,626,139
212		c Expense Expenditures - Amort. of Principal	92,366,281	0	0	0	22,569,388	22,911,098	23,261,738	23,624,057	0
213		d Expense Expenditures - Interest Expense	8,475,974	0	0	0	3,399,640	2,542,420	1,690,535	843,379	0
215	FY 2014 Conservation Resources Selected										
216	16	2012 Conservation - 2014$$ -									
217		Debt Service in Nominal Year Dollars									
218		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
219		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
220		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	23,295,212	24,126,851	24,988,180	25,880,257
221		d Expense Expenditures - Interest Expense	8,926,231	0	0	0	0	3,508,971	2,677,332	1,816,003	923,925
223	FY 2014 Deflator values							1.000000	1.020087	1.040301	1.060795
224	16	2012 Conservation - 2014$$ -									
225		Debt service in FY2014 Purchasing Power Dollars									
226		a Capital Expenditures - Amort. of Principal	42,298,028	0	0	0	0	2,332,636	2,393,721	2,457,058	2,522,358
227		b Capital Expenditures - Interest Expense	18,503,867	0	0	0	0	2,299,729	2,147,426	1,995,850	1,844,522
228		c Expense Expenditures - Amort. of Principal	95,364,153	0	0	0	0	23,295,212	23,651,758	24,020,144	24,397,039
229		d Expense Expenditures - Interest Expense	8,750,207	0	0	0	0	3,508,971	2,624,611	1,745,651	870,974
231	FY 2015 Conservation Resources Selected										
232	17	2011 Conservation - 2015$$ -									
233		Debt Service in Nominal Year Dollars									
234		a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
235		b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
236		c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	22,587,187	23,393,550	24,228,700
237		d Expense Expenditures - Interest Expense	8,654,931	0	0	0	0	0	3,402,321	2,595,958	1,760,808
239	FY 2015 Deflator values								1.000000	1.019816	1.039906
240	17	2011 Conservation - 2015$$ -									
241		Debt service in FY2015 Purchasing Power Dollars									
242		a Capital Expenditures - Amort. of Principal	36,977,518	0	0	0	0	0	2,037,593	2,091,507	2,147,093
243		b Capital Expenditures - Interest Expense	16,169,437	0	0	0	0	0	2,008,848	1,876,308	1,744,067
244		c Expense Expenditures - Amort. of Principal	92,486,123	0	0	0	0	0	22,587,187	22,938,991	23,298,933
245		d Expense Expenditures - Interest Expense	8,485,773	0	0	0	0	0	3,402,321	2,545,516	1,693,238

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Debt Service Components - (whole dollars)

Row	A	C	M	N	O	P	Q	R	S	T	U	V	W	X
195		**Vintage - Year Selected**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
197														
199	**FY 2013 Conservation Resources Selected**													
200	**15**	**2013 Conservation - 2013$$ -**												
201		**Debt Service in Nominal Year Dollars**												
202		a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
203		b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
204		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
205		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
207	FY 2013 Deflator values		1.103764	1.125903	1.149466	1.172941	1.195782	1.218662	1.241615	1.264447	1.287502	1.311370	1.335673	1.360058
208	**15**	**2013 Conservation - 2013$$ -**												
209		**Debt service in FY2013 Purchasing Power Dollars**												
210		a Capital Expenditures - Amort. of Principal	2,552,671	2,619,592	2,685,977	2,755,408	2,829,267	2,906,072	2,985,839	3,069,138	3,155,243	3,242,793	0	0
211		b Capital Expenditures - Interest Expense	1,480,364	1,334,139	1,186,707	1,039,768	893,417	746,720	599,426	451,388	302,242	151,763	0	0
212		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
213		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
215	**FY 2014 Conservation Resources Selected**													
216	**16**	**2012 Conservation - 2014$$ -**												
217		**Debt Service in Nominal Year Dollars**												
218		a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
219		b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
220		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
221		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
223	FY 2014 Deflator values		1.081853	1.103552	1.126648	1.149657	1.172044	1.194470	1.216967	1.239346	1.261944	1.285337	1.309158	1.333059
224	**16**	**2012 Conservation - 2014$$ -**												
225		**Debt service in FY2014 Purchasing Power Dollars**												
226		a Capital Expenditures - Amort. of Principal	2,589,010	2,656,885	2,724,213	2,794,633	2,869,543	2,947,442	3,028,345	3,112,830	3,200,159	3,288,958	3,380,237	0
227		b Capital Expenditures - Interest Expense	1,692,870	1,540,801	1,387,422	1,234,713	1,082,838	930,734	778,139	624,920	470,658	315,050	158,195	0
228		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
229		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
231	**FY 2015 Conservation Resources Selected**													
232	**17**	**2011 Conservation - 2015$$ -**												
233		**Debt Service in Nominal Year Dollars**												
234		a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
235		b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
236		c Expense Expenditures - Amort. of Principal	25,093,663	0	0	0	0	0	0	0	0	0	0	0
237		d Expense Expenditures - Interest Expense	895,844	0	0	0	0	0	0	0	0	0	0	0
239	FY 2015 Deflator values		1.060549	1.081821	1.104462	1.127018	1.148965	1.170948	1.193003	1.214941	1.237094	1.260027	1.283378	1.306808
240	**17**	**2011 Conservation - 2015$$ -**												
241		**Debt service in FY2015 Purchasing Power Dollars**												
242		a Capital Expenditures - Amort. of Principal	2,203,828	2,261,606	2,318,917	2,378,860	2,442,625	2,508,937	2,577,802	2,649,717	2,724,054	2,799,641	2,877,341	2,957,997
243		b Capital Expenditures - Interest Expense	1,611,593	1,478,792	1,344,804	1,211,536	1,079,190	946,760	814,011	680,850	546,871	411,752	275,621	138,434
244		c Expense Expenditures - Amort. of Principal	23,661,012	0	0	0	0	0	0	0	0	0	0	0
245		d Expense Expenditures - Interest Expense	844,698	0	0	0	0	0	0	0	0	0	0	0
246														
247														

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Debt Service Components - (whole dollars)

SUMMARY TOTALS - INFLATION ADJUSTED VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
TOTALS - CAPITAL EXPENDITURES -									
a AMORTIZATION OF PRINCIPAL	332,724,143	7,549,912	9,814,342	12,216,435	14,774,570	17,491,636	19,987,273	20,516,136	21,061,382
TOTALS - CAPITAL EXPENDITURES -									
b INTEREST EXPENSE	145,677,302	7,443,399	8,988,111	10,476,967	11,917,548	13,302,975	14,247,373	13,053,304	11,859,519
TOTALS - EXPENSE EXPENDITURES -									
c AMORTIZATION OF PRINCIPAL	823,312,166	89,633,257	112,267,156	135,756,091	160,366,521	90,974,382	92,374,583	70,583,192	47,695,972
TOTALS - EXPENSE EXPENDITURES -									
d INTEREST EXPENSE	75,560,039	13,501,509	13,301,969	12,396,967	10,799,460	8,482,613	8,534,065	5,134,546	2,564,212
TOTALS - CONSERVATION PRINCIPAL COSTS	1,156,036,309	97,183,169	122,081,498	147,972,526	175,141,091	108,466,018	112,361,856	91,099,328	68,757,354
TOTALS - INTEREST EXPENSE	221,237,341	20,944,908	22,290,080	22,873,934	22,717,008	21,785,588	22,781,438	18,187,850	14,423,731
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	100.00%	8.41%	10.56%	12.80%	15.15%	9.38%	9.72%	7.88%	5.95%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)		8.41%	18.97%	31.77%	46.92%	56.30%	$\boxed{66.02\%}$	73.90%	79.85%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 66.02%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (INFLATION ADJUSTED DOLLARS) = 75,560,039
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES-YEAR OF INVESTMENT) = 849,034,700
INFLATION ADJUSTED INTEREST AS A PERCENTAGE OF ORIGINAL INVESTMENT COSTS = 8.90%

INTEREST (INFLATION ADJUSTED) EXPENDITURES BY PERIOD

Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
43,234,988	90,157,968	133,392,956	87,844,385	221,237,341

Note 1 - Debt service cash flows are inflation adjusted to the year that the conservation resource is selected from the resource stack. The cash flows associated with the 9 conservation resources chosen in FY2010 are stated in FY 2010 purchasing power dollar values. The cash flows associated with the single conservation resource chosen in each of the remaining years of the rate test period are restated in the purchasing power dollar values associated with that year, the year the resource investment is made. Thus the debt service cash flows are a mixture of purchasing power dollars associated with the year that each conservation investment is made.

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Debt Service Components - (whole dollars)

Row	DEBT SERVICE COMPONENT PARTS		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
253	TOTALS - CAPITAL EXPENDITURES -													
254	a	AMORTIZATION OF PRINCIPAL	21,617,921	22,184,666	22,746,850	23,334,848	23,960,336	24,610,788	25,286,317	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
255	TOTALS - CAPITAL EXPENDITURES -													
256	b	INTEREST EXPENSE	10,662,193	9,460,713	8,249,816	7,041,458	5,835,748	4,625,893	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
257	TOTALS - EXPENSE EXPENDITURES -													
258	c	AMORTIZATION OF PRINCIPAL	23,661,012	0	0	0	0	0	0	0	0	0	0	0
259	TOTALS - EXPENSE EXPENDITURES -													
260	d	INTEREST EXPENSE	844,698	0	0	0	0	0	0	0	0	0	0	0
262	TOTALS - CONSERVATION PRINCIPAL COSTS		45,278,933	22,184,666	22,746,850	23,334,848	23,960,336	24,610,788	25,286,317	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
264	TOTALS - INTEREST EXPENSE		11,506,891	9,460,713	8,249,816	7,041,458	5,835,748	4,625,893	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
266	PERCENTAGE OF TOTAL PRINCIPAL PAID		3.92%	1.92%	1.97%	2.02%	2.07%	2.13%	2.19%	1.28%	1.05%	0.81%	0.54%	0.26%
267	(Capital and Expense Expenditures)													
269	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		83.77%	85.69%	87.66%	89.68%	91.75%	93.88%	96.07%	97.35%	98.40%	99.21%	99.75%	100.01%
270	(Capital and Expense Expenditures)													

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	Inflation Adjustment	Capitalized Conservation Deferral/ Maturity # of Years	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	15	0.0468	4	0.0357
FY 2011	1.020232			5	0.0369
FY 2012	1.041582			6	0.0381
FY 2013	1.062788			7	0.0393
FY 2014	1.084313			15	0.0468
FY 2015	1.106094				

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2010 Conservation Resources Selected						
1	**2001 Conservation - 2010$$**	19.2	29,059.6	72.4	29,132.0	
	Capitalized Costs - Debt Service Requirements					$6,825.13
	Expensed Costs /Deferral Debt Service Requirements					$6,470,832.82
3	**2006 Conservation - 2010$$**	31.0	39,428.0	16,435.8	55,863.8	
	Capitalized Costs - Debt Service Requirements					$1,549,397.68
	Expensed Costs /Deferral Debt Service Requirements					$8,779,611.44
4	**2003 Conservation - 2010$$**	27.6	30,621.2	27,501.3	58,122.5	
	Capitalized Costs - Debt Service Requirements					2,592,538.87
	Expensed Costs /Deferral Debt Service Requirements					$6,818,561.37
5	**2002 Conservation - 2010$$**	26.6	26,137.0	34,587.9	60,724.9	
	Capitalized Costs - Debt Service Requirements					3,260,590.41
	Expensed Costs /Deferral Debt Service Requirements					$5,820,044.24
6	**2005 Conservation - 2010$$**	20.6	31,616.2	16,720.6	48,336.8	
	Capitalized Costs - Debt Service Requirements					1,576,245.68
	Expensed Costs /Deferral Debt Service Requirements					$7,040,122.53
8	**2008 Conservation - 2010$$**	30.3	65,409.8	9,139.1	74,548.9	
	Capitalized Costs - Debt Service Requirements					861,540.07
	Expensed Costs /Deferral Debt Service Requirements					$14,565,096.59
9	**2004 Conservation - 2010$$**	20.1	27,250.7	22,724.9	49,975.6	
	Capitalized Costs - Debt Service Requirements					2,142,269.15
	Expensed Costs /Deferral Debt Service Requirements					$6,068,036.86
10	**2007 Conservation - 2010$$**	27.9	59,178.2	11,453.5	70,631.7	
	Capitalized Costs - Debt Service Requirements					1,079,717.83
	Expensed Costs /Deferral Debt Service Requirements					$13,177,477.98
12	**2009 Conservation - 2010$$**	28.4	69,492.8	20,411.5	89,904.3	
	Capitalized Costs - Debt Service Requirements					1,924,185.66
	Expensed Costs /Deferral Debt Service Requirements					$15,474,276.70
	Totals - FY 2010	231.7	378,193.5	159,047.0	537,240.5	

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2010 Conservation Resources Selected											
1	**2001 Conservation - 2010$$**										
Capital		6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Expense		6,470.8	6,470.8	6,470.8	6,470.8	6,470.8	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
Capital		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4
Expense		8,779.6	8,779.6	8,779.6	8,779.6	8,779.6	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
Capital		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5
Expense		6,818.6	6,818.6	6,818.6	6,818.6	6,818.6	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
Capital		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6
Expense		5,820.0	5,820.0	5,820.0	5,820.0	5,820.0	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
Capital		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2
Expense		7,040.1	7,040.1	7,040.1	7,040.1	7,040.1	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
Capital		861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5
Expense		14,565.1	14,565.1	14,565.1	14,565.1	14,565.1	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
Capital		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3
Expense		6,068.0	6,068.0	6,068.0	6,068.0	6,068.0	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
Capital		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7
Expense		13,177.5	13,177.5	13,177.5	13,177.5	13,177.5	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2
Expense		15,474.3	15,474.3	15,474.3	15,474.3	15,474.3	0.0	0.0	0.0	0.0	0.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
		11	12	13	14	15					
FY 2010 Conservation Resources Selected											
1	**2001 Conservation - 2010$$**										
Capital		6.8	6.8	6.8	6.8	6.8	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
Capital		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
Capital		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
Capital		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
Capital		861.5	861.5	861.5	861.5	861.5	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
Capital		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
Capital		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$		87,986.2	42,697.1	130,683.3	
13	**2015 Conservation - 2011$$**	39.5	89,766.3	43,560.9	133,327.2	
	Capitalized Costs - Debt Service Requirements					4,106,472.29
	Expensed Costs /Deferral Debt Service Requirements					$19,988,668.82
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$		88,570.4	43,552.0	132,122.4	
14	**2014 Conservation - 2012$$**	39.5	92,253.3	45,363.0	137,616.3	
	Capitalized Costs - Debt Service Requirements					4,276,355.69
	Expensed Costs /Deferral Debt Service Requirements					$20,542,460.38
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$		89,602.1	44,431.3	134,033.4	
15	**2013 Conservation - 2013$$**	39.5	95,228.0	47,221.1	142,449.1	
	Capitalized Costs - Debt Service Requirements					4,451,518.19
	Expensed Costs /Deferral Debt Service Requirements					$21,204,850.31
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$		90,647.7	45,318.6	135,966.3	
16	**2012 Conservation - 2014$$**	39.5	98,290.5	49,139.5	147,430.0	
	Capitalized Costs - Debt Service Requirements					4,632,365.15
	Expensed Costs /Deferral Debt Service Requirements					$21,886,791.07
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$		86,161.8	38,806.9	124,968.7	
17	**2011 Conservation - 2015$$**	34.9	95,303.1	42,924.1	138,227.2	
	Capitalized Costs - Debt Service Requirements					4,046,441.35
	Expensed Costs /Deferral Debt Service Requirements					$21,221,573.17

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		387,255.6	160,340.4	547,596.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	849,034.7		96,257.8	945,292.5
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	849,034.7	387,255.6	256,598.2	1,492,888.5

Principal Expense Costs	849,034.7
Interest Paid Expensed Costs	96,257.8
Principal Capital Costs	387,255.6
Interest Paid Capital Costs	160,340.4
Totals	1,492,888.5

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5
Expense		0.0	19,988.7	19,988.7	19,988.7	19,988.7	19,988.7	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4
Expense		0.0	0.0	20,542.5	20,542.5	20,542.5	20,542.5	20,542.5	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5
Expense		0.0	0.0	0.0	21,204.9	21,204.9	21,204.9	21,204.9	21,204.9	0.0	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4
Expense		0.0	0.0	0.0	0.0	21,886.8	21,886.8	21,886.8	21,886.8	21,886.8	0.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense		0.0	0.0	0.0	0.0	0.0	21,221.6	21,221.6	21,221.6	21,221.6	21,221.6
TCC		14,993.2	19,099.7	23,376.1	27,827.6	32,460.0	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4
TEC		84,214.0	104,202.7	124,745.2	145,950.1	167,836.9	104,844.5	84,855.8	64,313.3	43,108.4	21,221.6
TDSR		99,207.2	123,302.4	148,121.3	173,777.7	200,296.9	141,350.9	121,362.2	100,819.7	79,614.8	57,728.0

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Scenario = Capitalized costs are amortized and financed over 15 years,
Expensed costs are deferred and financed over 5-years

Debt Service Requirements - Principal and Interest ($ 000)

X	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Res. Stack Order	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
	11	12	13	14	15					
FY 2011 Conservation Resources Selected										
13	**2015 Conservation - 2011$$**									
Capital	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected										
14	**2014 Conservation - 2012$$**									
Capital	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected										
15	**2013 Conservation - 2013$$**									
Capital	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2014 Conservation Resources Selected										
16	**2012 Conservation - 2014$$**									
Capital	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2015 Conservation Resources Selected										
17	**2011 Conservation - 2015$$**									
Capital	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4
TEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4

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Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are deferred and amortized / financed over 5 - years

Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010	**Conservation Resources Selected**									
FY 2010	Conservation (9) Res. Selected - Total MW =	231.7								
1	**2001 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	72,400	3,437	3,598	3,766	3,942	4,127	4,320	4,522	4,734
	b Capital Expenditures - Interest Expense	29,975	3,388	3,227	3,059	2,883	2,698	2,505	2,303	2,091
	c Expense Expenditures - Amort. of Principal	29,059,600	5,398,534	5,597,740	5,804,296	6,018,474	6,240,556	0	0	0
	d Expense Expenditures - Interest Expense	3,294,564	1,072,299	873,093	666,537	452,358	230,277	0	0	0
3	**2006 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,435,800	780,203	816,716	854,938	894,949	936,833	980,677	1,026,573	1,074,616
	b Capital Expenditures - Interest Expense	6,805,165	769,195	732,682	694,460	654,449	612,565	568,721	522,825	474,782
	c Expense Expenditures - Amort. of Principal	39,428,000	7,324,718	7,595,000	7,875,256	8,165,853	8,467,173	0	0	0
	d Expense Expenditures - Interest Expense	4,470,058	1,454,893	1,184,611	904,356	613,759	312,439	0	0	0
4	**2003 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	27,501,300	1,305,478	1,366,575	1,430,530	1,497,479	1,567,561	1,640,923	1,717,718	1,798,107
	b Capital Expenditures - Interest Expense	11,386,782	1,287,061	1,225,964	1,162,009	1,095,060	1,024,978	951,616	874,821	794,432
	c Expense Expenditures - Amort. of Principal	30,621,200	5,688,639	5,898,549	6,116,206	6,341,895	6,575,911	0	0	0
	d Expense Expenditures - Interest Expense	3,471,607	1,129,922	920,012	702,355	476,667	242,651	0	0	0
5	**2002 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	34,587,900	1,641,876	1,718,716	1,799,152	1,883,352	1,971,493	2,063,759	2,160,343	2,261,448
	b Capital Expenditures - Interest Expense	14,320,958	1,618,714	1,541,874	1,461,438	1,377,238	1,289,097	1,196,831	1,100,247	999,143
	c Expense Expenditures - Amort. of Principal	26,137,000	4,855,589	5,034,760	5,220,543	5,413,181	5,612,927	0	0	0
	d Expense Expenditures - Interest Expense	2,963,220	964,455	785,284	599,501	406,863	207,117	0	0	0
6	**2005 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,720,600	793,722	830,868	869,753	910,457	953,067	997,670	1,044,361	1,093,237
	b Capital Expenditures - Interest Expense	6,923,083	782,524	745,378	706,493	665,789	623,179	578,576	531,885	483,009
	c Expense Expenditures - Amort. of Principal	31,616,200	5,873,485	6,090,217	6,314,946	6,547,966	6,789,586	0	0	0
	d Expense Expenditures - Interest Expense	3,584,413	1,166,638	949,906	725,177	492,156	250,536	0	0	0
8	**2008 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	9,139,100	433,830	454,133	475,387	497,635	520,924	545,303	570,824	597,538
	b Capital Expenditures - Interest Expense	3,784,002	427,710	407,407	386,153	363,905	340,616	316,237	290,716	264,002
	c Expense Expenditures - Amort. of Principal	65,409,800	12,151,475	12,599,865	13,064,800	13,546,890	14,046,770	0	0	0
	d Expense Expenditures - Interest Expense	7,415,683	2,413,622	1,965,232	1,500,297	1,018,206	518,326	0	0	0

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= Expensed costs are deferred and amortized / financed over 5 - years

Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010	**Conservation Resources Selected**												
FY 2010	Conservation (9) Res. Selected - Total MW =												
1	**2001 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	4,955	5,187	5,430	5,684	5,950	6,228	6,520	0	0	0	0	0
	b Capital Expenditures - Interest Expense	1,870	1,638	1,395	1,141	875	597	305	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
3	**2006 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,124,908	1,177,554	1,232,662	1,290,351	1,350,739	1,413,954	1,480,127	0	0	0	0	0
	b Capital Expenditures - Interest Expense	424,490	371,844	316,735	259,046	198,658	135,443	69,270	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
4	**2003 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,882,259	1,970,348	2,062,561	2,159,089	2,260,133	2,365,907	2,476,632	0	0	0	0	0
	b Capital Expenditures - Interest Expense	710,280	622,191	529,978	433,450	332,405	226,631	115,906	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
5	**2002 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	2,367,284	2,478,073	2,594,046	2,715,448	2,842,531	2,975,561	3,114,818	0	0	0	0	0
	b Capital Expenditures - Interest Expense	893,307	782,518	666,545	545,143	418,060	285,030	145,773	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
6	**2005 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,144,400	1,197,958	1,254,022	1,312,710	1,374,145	1,438,455	1,505,775	0	0	0	0	0
	b Capital Expenditures - Interest Expense	431,845	378,287	322,223	263,535	202,100	137,790	70,470	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
8	**2008 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	625,503	654,777	685,420	717,498	751,077	786,227	823,024	0	0	0	0	0
	b Capital Expenditures - Interest Expense	236,037	206,763	176,120	144,042	110,463	75,313	38,518	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

	A	C	D	E	F	G	H	I	J	K	L
1				Section 7(b)(2) Rate Test Study and Documentation							
2				Alternative Conservation Expense Accounting and Financing Treatments							
3				WP-10 Final Rate Proposal							
5			Scenario = Capitalized costs amortized / financed over 15 years,								
6			= Expensed costs are deferred and amortized / financed over 5 - years								
8				Debt Service Components - (whole dollars)							
45	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
46											
47	9	2004 Conservation - 2010$$									
48		a Capital Expenditures - Amort. of Principal	22,724,900	1,078,744	1,129,229	1,182,077	1,237,398	1,295,308	1,355,929	1,419,386	1,485,813
49		b Capital Expenditures - Interest Expense	9,409,137	1,063,525	1,013,040	960,192	904,871	846,961	786,340	722,883	656,456
50		c Expense Expenditures - Amort. of Principal	27,250,700	5,062,486	5,249,292	5,442,991	5,643,837	5,852,094	0	0	0
51		d Expense Expenditures - Interest Expense	3,089,484	1,005,551	818,745	625,046	424,200	215,942	0	0	0
52	10	2007 Conservation - 2010$$									
53		a Capital Expenditures - Amort. of Principal	11,453,500	543,694	569,139	595,775	623,657	652,844	683,397	715,380	748,860
54		b Capital Expenditures - Interest Expense	4,742,268	536,024	510,579	483,943	456,061	426,874	396,321	364,338	330,858
55		c Expense Expenditures - Amort. of Principal	59,178,200	10,993,802	11,399,474	11,820,114	12,256,277	12,708,533	0	0	0
56		d Expense Expenditures - Interest Expense	6,709,190	2,183,676	1,778,004	1,357,364	921,201	468,945	0	0	0
57	12	2009 Conservation - 2010$$									
58		a Capital Expenditures - Amort. of Principal	20,411,500	968,928	1,014,274	1,061,742	1,111,431	1,163,446	1,217,895	1,274,893	1,334,557
59		b Capital Expenditures - Interest Expense	8,451,286	955,258	909,912	862,444	812,755	760,740	706,291	649,293	589,628
60		c Expense Expenditures - Amort. of Principal	69,492,800	12,909,993	13,386,371	13,880,329	14,392,512	14,923,595	0	0	0
61		d Expense Expenditures - Interest Expense	7,878,583	2,564,284	2,087,906	1,593,948	1,081,764	550,681	0	0	0
62	13	2015 Conservation - 2011$$									
63		a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
64		b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
65		c Expense Expenditures - Amort. of Principal	89,766,300	0	16,676,293	17,291,648	17,929,710	18,591,315	19,277,334	0	0
66		d Expense Expenditures - Interest Expense	10,177,043	0	3,312,376	2,697,021	2,058,959	1,397,353	711,334	0	0
67	FY 2012	Conservation Resources Selected									
68	14	2014 Conservation - 2012$$									
69		a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
70		b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
71		c Expense Expenditures - Amort. of Principal	92,253,300	0	0	17,138,313	17,770,717	18,426,456	19,106,394	19,811,420	0
72		d Expense Expenditures - Interest Expense	10,459,002	0	0	3,404,147	2,771,743	2,116,004	1,436,067	731,041	0
73	FY 2013	Conservation Resources Selected									
74	15	2013 Conservation - 2013$$									
75		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
76		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
77		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	17,690,937	18,343,732	19,020,616	19,722,478	20,450,237
78		d Expense Expenditures - Interest Expense	10,796,252	0	0	0	3,513,913	2,861,118	2,184,234	1,482,373	754,614
79	FY 2014	Conservation Resources Selected									
80	16	2012 Conservation - 2014$$									
81		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
82		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
83		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	18,259,872	18,933,661	19,632,313	20,356,745
84		d Expense Expenditures - Interest Expense	11,143,455	0	0	0	0	3,626,919	2,953,130	2,254,478	1,530,046
85											
86					Page 9 of 18						

	A	B	C	M	N	O	P	Q	R	S	T	U	V	W	X
1								Section 7(b)(2) Rate Test Study and Documentation							
2								Alternative Conservation Expense Accounting and Financing Treatments							
3								WP-10 Final Rate Proposal							
5								Scenario = Capitalized costs amortized / financed over 15 years,							
6								= Expensed costs are deferred and amortized / financed over 5 - years							
8								Debt Service Components - (whole dollars)							
45	Res. Stack Order		Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
46															
47	9		2004 Conservation - 2010$$												
48			a Capital Expenditures - Amort. of Principal	1,555,349	1,628,140	1,704,337	1,784,100	1,867,596	1,954,999	2,046,495	0	0	0	0	0
49			b Capital Expenditures - Interest Expense	586,920	514,129	437,932	358,169	274,673	187,270	95,776	0	0	0	0	0
50			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
51			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
52	10		2007 Conservation - 2010$$												
53			a Capital Expenditures - Amort. of Principal	783,907	820,594	858,997	899,198	941,281	985,333	1,031,444	0	0	0	0	0
54			b Capital Expenditures - Interest Expense	295,811	259,124	220,721	180,520	138,437	94,385	48,272	0	0	0	0	0
55			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
56			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
57	12		2009 Conservation - 2010$$												
58			a Capital Expenditures - Amort. of Principal	1,397,014	1,462,394	1,530,834	1,602,478	1,677,474	1,755,980	1,838,160	0	0	0	0	0
59			b Capital Expenditures - Interest Expense	527,171	461,791	393,351	321,708	246,712	168,206	86,026	0	0	0	0	0
60			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
61			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
62	13		2015 Conservation - 2011$$												
63			a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
64			b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
65			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
66			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
67	FY 2012		Conservation Resources Selected												
68	14		2014 Conservation - 2012$$												
69			a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
70			b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
71			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
72			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
73	FY 2013		Conservation Resources Selected												
74	15		2013 Conservation - 2013$$												
75			a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
76			b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
77			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
78			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
79	FY 2014		Conservation Resources Selected												
80	16		2012 Conservation - 2014$$												
81			a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
82			b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
83			c Expense Expenditures - Amort. of Principal	21,107,909	0	0	0	0	0	0	0	0	0	0	0
84			d Expense Expenditures - Interest Expense	778,882	0	0	0	0	0	0	0	0	0	0	0
85															
86									Page 10 of 18						

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
89	**FY 2015**	**Conservation Resources Selected**									
90	**17**	**2011 Conservation - 2015$$**									
91		a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
92		b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
93		c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	17,704,889	18,358,199	19,035,617
94		d Expense Expenditures - Interest Expense	10,804,765	0	0	0	0	0	3,516,684	2,863,374	2,185,956

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

Row	DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
100	TOTALS - CAPITAL EXPENDITURES -	387,255,600								
101	AMORTIZATION OF PRINCIPAL	387,255,600	7,549,912	9,971,070	12,591,084	15,421,915	18,476,297	21,378,581	22,379,100	23,426,441
102	TOTALS - CAPITAL EXPENDITURES -	160,341,348								
103	INTEREST EXPENSE	160,341,348	7,443,399	9,128,713	10,785,055	12,405,742	13,983,725	15,127,882	14,127,363	13,080,022
104	TOTALS - EXPENSE EXPENDITURES -	849,034,700								
105	AMORTIZATION OF PRINCIPAL	849,034,700	70,258,721	89,527,561	109,969,442	131,718,249	154,838,520	94,042,894	77,524,410	59,842,599
106	TOTALS - EXPENSE EXPENDITURES -	96,257,319								
107	INTEREST EXPENSE	96,257,319	13,955,340	14,675,169	14,775,749	14,231,789	12,998,308	10,801,449	7,331,266	4,470,616
108		1,236,290,300								
109	TOTALS - CONSERVATION PRINCIPAL COSTS	1,236,290,300	77,808,633	99,498,631	122,560,526	147,140,164	173,314,817	115,421,475	99,903,510	83,269,040
110		256,598,667								
111	TOTALS - INTEREST EXPENSE	256,598,667	21,398,739	23,803,882	25,560,804	26,637,531	26,982,033	25,929,331	21,458,629	17,550,638
113	PERCENTAGE OF TOTAL PRINCIPAL PAID	100.00%	6.29%	8.05%	9.91%	11.90%	14.02%	9.34%	8.08%	6.74%
114	(Capital and Expense Expenditures)									
116	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		6.29%	14.34%	24.25%	36.15%	50.17%	59.51%	67.59%	74.33%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 59.51%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (NOMINAL DOLLARS) = 96,257,319
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES - YEAR OF INVESTMENT) = 849,034,700
INTEREST AS A PECENTAGE OF ORIGINAL INVESTMENT COSTS = 11.34%

INTEREST (NOMINAL DOLLARS) EXPENDITURES BY PERIOD

	Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
Interest on Capital and Expense Expenditures	45,202,621	105,109,699	150,312,320	106,286,347	256,598,667

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
89	FY 2015	Conservation Resources Selected												
90	17	2011 Conservation - 2015$$												
91		a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
92		b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
93		c Expense Expenditures - Amort. of Principal	19,738,031	20,466,364	0	0	0	0	0	0	0	0	0	0
94		d Expense Expenditures - Interest Expense	1,483,542	755,209	0	0	0	0	0	0	0	0	0	0
95														

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

Row	DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
100	TOTALS - CAPITAL EXPENDITURES -												
101	AMORTIZATION OF PRINCIPAL	24,522,798	25,670,466	26,871,840	28,129,445	29,445,903	30,823,971	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
102	TOTALS - CAPITAL EXPENDITURES -												
103	INTEREST EXPENSE	11,983,664	10,835,996	9,634,621	8,377,017	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
104	TOTALS - EXPENSE EXPENDITURES -												
105	AMORTIZATION OF PRINCIPAL	40,845,940	20,466,364	0	0	0	0	0	0	0	0	0	0
106	TOTALS - EXPENSE EXPENDITURES -												
107	INTEREST EXPENSE	2,262,424	755,209	0	0	0	0	0	0	0	0	0	0
109	TOTALS - CONSERVATION PRINCIPAL COSTS	65,368,738	46,136,830	26,871,840	28,129,445	29,445,903	30,823,971	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
111	TOTALS - INTEREST EXPENSE	14,246,088	11,591,205	9,634,621	8,377,017	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
113	PERCENTAGE OF TOTAL PRINCIPAL PAID	5.29%	3.73%	2.17%	2.28%	2.38%	2.49%	2.61%	1.52%	1.26%	0.97%	0.66%	0.31%
114	(Capital and Expense Expenditures)												
116	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID	79.62%	83.35%	85.52%	87.80%	90.18%	92.67%	95.28%	96.80%	98.06%	99.03%	99.69%	100.00%

Row	A	B / C	D	E	F	G	H	I	J	K	L
1			Section 7(b)(2) Rate Test Study and Documentation								
2			Alternative Conservation Expense Accounting and Financing Treatments								
3			WP-10 Final Rate Proposal								
5			Scenario = Capitalized costs amortized / financed over 15 years,								
6			= Expensed costs are deferred and amortized / financed over 5 - years								
8				Debt Service Components - (whole dollars)							
133		Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
135				INFLATION ADJUSTED ANALYSIS							
137	FY 2010 Conservation Resources Selected -										
138		Debt Service in Nominal Year Dollars									
139	TOTALS - CAPITAL EXPENDITURES -		159,047,000								
140		a AMORTIZATION OF PRINCIPAL	159,047,000	7,549,912	7,903,248	8,273,120	8,660,300	9,065,603	9,489,873	9,934,000	10,398,910
141	TOTALS - CAPITAL EXPENDITURES -		65,852,656								
142		b INTEREST EXPENSE	65,852,656	7,443,399	7,090,063	6,720,191	6,333,011	5,927,708	5,503,438	5,059,311	4,594,401
143	TOTALS - EXPENSE EXPENDITURES -		378,193,500								
144		c AMORTIZATION OF PRINCIPAL	378,193,500	70,258,721	72,851,268	75,539,481	78,326,885	81,217,145	0	0	0
145	TOTALS - EXPENSE EXPENDITURES -		42,876,802								
146		d INTEREST EXPENSE	42,876,802	13,955,340	11,362,793	8,674,581	5,887,174	2,996,914	0	0	0
148	FY 2010 Deflator values			1.000000	1.020232	1.041582	1.062788	1.084313	1.106094	1.128012	1.150234
149	FY 2010 Conservation Resources Selected -										
150		Debt service in FY2010 Purchasing Power Dollars									
151	TOTALS - CAPITAL EXPENDITURES -										
152		a AMORTIZATION OF PRINCIPAL	136,462,442	7,549,912	7,746,520	7,942,841	8,148,662	8,360,688	8,579,626	8,806,644	9,040,691
153	TOTALS - CAPITAL EXPENDITURES -										
154		b INTEREST EXPENSE	59,786,673	7,443,399	6,949,461	6,451,908	5,958,866	5,466,787	4,975,561	4,485,157	3,994,319
155	TOTALS - EXPENSE EXPENDITURES -										
156		c AMORTIZATION OF PRINCIPAL	362,790,469	70,258,721	71,406,570	72,523,796	73,699,444	74,901,938	0	0	0
157	TOTALS - EXPENSE EXPENDITURES -										
158		d INTEREST EXPENSE	41,724,326	13,955,340	11,137,460	8,328,275	5,539,368	2,763,883	0	0	0
160	FY 2011 Conservation Resources Selected										
161	13	2015 Conservation - 2011$$ -									
162		Debt Service in Nominal Year Dollars									
163		a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
164		b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
165		c Expense Expenditures - Amort. of Principal	89,766,300	0	16,676,293	17,291,648	17,929,710	18,591,315	19,277,334	0	0
166		d Expense Expenditures - Interest Expense	10,177,043	0	3,312,376	2,697,021	2,058,959	1,397,353	711,334	0	0
168	FY 2011 Deflator values				1.000000	1.020927	1.041712	1.062810	1.084159	1.105643	1.127424
169	13	2015 Conservation - 2011$$ -									
170		Debt service in FY2011 Purchasing Power Dollars									
171		a Capital Expenditures - Amort. of Principal	37,389,568	0	2,067,822	2,120,226	2,175,168	2,231,766	2,290,208	2,350,806	2,413,282
172		b Capital Expenditures - Interest Expense	16,376,020	0	2,038,650	1,902,071	1,766,873	1,632,022	1,497,494	1,363,297	1,229,067
173		c Expense Expenditures - Amort. of Principal	86,098,784	0	16,676,293	16,937,203	17,211,773	17,492,605	17,780,910	0	0
174		d Expense Expenditures - Interest Expense	9,901,516	0	3,312,376	2,641,737	1,976,515	1,314,772	656,116	0	0
176	FY 2012 Conservation Resources Selected										
177	14	2014 Conservation - 2012$$ -									
178		Debt Service in Nominal Year Dollars									
179		a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
180		b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
181		c Expense Expenditures - Amort. of Principal	92,253,300	0	0	17,138,313	17,770,717	18,426,456	19,106,394	19,811,420	0
182		d Expense Expenditures - Interest Expense	10,459,002	0	0	3,404,147	2,771,743	2,116,004	1,436,067	731,041	0
184	FY 2012 Deflator values					1.000000	1.020359	1.041025	1.061937	1.082980	1.104314
185	14	2014 Conservation - 2012$$ -									
186		Debt service in FY2012 Purchasing Power Dollars									
187		a Capital Expenditures - Amort. of Principal	38,983,476	0	0	2,153,368	2,209,169	2,266,650	2,326,004	2,387,551	2,451,005
188		b Capital Expenditures - Interest Expense	17,067,371	0	0	2,122,988	1,981,862	1,841,182	1,700,935	1,561,142	1,421,405
189		c Expense Expenditures - Amort. of Principal	88,540,209	0	0	17,138,313	17,416,142	17,700,301	17,992,022	18,293,431	0
190		d Expense Expenditures - Interest Expense	10,180,538	0	0	3,404,147	2,716,439	2,032,616	1,352,309	675,027	0
191											
192					Page 13 of 18						

	A	B	C	M	N	O	P	Q	R	S	T	U	V	W	X
1				Section 7(b)(2) Rate Test Study and Documentation											
2				Alternative Conservation Expense Accounting and Financing Treatments											
3				WP-10 Final Rate Proposal											
5				Scenario = Capitalized costs amortized / financed over 15 years,											
6				= Expensed costs are deferred and amortized / financed over 5 - years											
8				Debt Service Components - (whole dollars)											
133			**Vintage - Year Selected**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
135				**INFLATION ADJUSTED ANALYSIS**											
137	**FY 2010 Conservation Resources Selected -**														
138			**Debt Service in Nominal Year Dollars**												
139	TOTALS - CAPITAL EXPENDITURES -														
140		a	AMORTIZATION OF PRINCIPAL	10,885,579	11,395,025	11,928,309	12,486,556	13,070,926	13,682,644	14,322,995	0	0	0	0	0
141	TOTALS - CAPITAL EXPENDITURES -														
142		b	INTEREST EXPENSE	4,107,731	3,598,285	3,065,000	2,506,754	1,922,383	1,310,665	670,316	0	0	0	0	0
143	TOTALS - EXPENSE EXPENDITURES -														
144		c	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
145	TOTALS - EXPENSE EXPENDITURES -														
146		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
148	FY 2010 Deflator values			1.173067	1.196596	1.221639	1.246588	1.270863	1.295179	1.319573	1.343839	1.368342	1.393708	1.419537	1.445453
149	**FY 2010 Conservation Resources Selected -**														
150			**Debt service in FY2010 Purchasing Power Dollars**												
151	TOTALS - CAPITAL EXPENDITURES -														
152		a	AMORTIZATION OF PRINCIPAL	9,279,588	9,522,867	9,764,185	10,016,586	10,285,079	10,564,288	10,854,265	0	0	0	0	0
153	TOTALS - CAPITAL EXPENDITURES -														
154		b	INTEREST EXPENSE	3,501,702	3,007,101	2,508,924	2,010,892	1,512,660	1,011,957	507,979	0	0	0	0	0
155	TOTALS - EXPENSE EXPENDITURES -														
156		c	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
157	TOTALS - EXPENSE EXPENDITURES -														
158		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
160	**FY 2011 Conservation Resources Selected**														
161	**13**		**2015 Conservation - 2011$$ -**												
162			**Debt Service in Nominal Year Dollars**												
163		a	Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
164		b	Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
165		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
166		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
168	FY 2011 Deflator values			1.149804	1.172867	1.197413	1.221867	1.245661	1.269495	1.293405	1.317190	1.341207	1.366070	1.391386	1.416789
169	**13**		**2015 Conservation - 2011$$ -**												
170			**Debt service in FY2011 Purchasing Power Dollars**												
171		a	Capital Expenditures - Amort. of Principal	2,477,053	2,541,992	2,606,410	2,673,785	2,745,455	2,819,985	2,897,390	2,978,220	0	0	0	0
172		b	Capital Expenditures - Interest Expense	1,094,401	959,234	823,044	687,033	551,167	414,744	277,542	139,381	0	0	0	0
173		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
174		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
176	**FY 2012 Conservation Resources Selected**														
177	**14**		**2014 Conservation - 2012$$ -**												
178			**Debt Service in Nominal Year Dollars**												
179		a	Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
180		b	Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
181		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
182		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
184	FY 2012 Deflator values			1.126236	1.148826	1.172869	1.196822	1.220128	1.243473	1.266893	1.290190	1.313715	1.338068	1.362866	1.387748
185	**14**		**2014 Conservation - 2012$$ -**												
186			**Debt service in FY2012 Purchasing Power Dollars**												
187		a	Capital Expenditures - Amort. of Principal	2,515,771	2,581,724	2,647,148	2,715,576	2,788,366	2,864,063	2,942,678	3,024,772	3,109,631	0	0	0
188		b	Capital Expenditures - Interest Expense	1,281,263	1,140,646	998,915	857,516	716,476	574,978	432,789	289,743	145,531	0	0	0
189		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
190		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
191															
192															

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= Expensed costs are deferred and amortized / financed over 5 - years

Debt Service Components - (whole dollars)

Row	A	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
195					INFLATION ADJUSTED ANALYSIS						
196	FY 2013 Conservation Resources Selected										
197	15	2013 Conservation - 2013$$ -									
198		Debt Service in Nominal Year Dollars									
199		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
200		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
201		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	17,690,937	18,343,732	19,020,616	19,722,478	20,450,237
202		d Expense Expenditures - Interest Expense	10,796,252	0	0	0	3,513,913	2,861,118	2,184,234	1,482,373	754,614
204	FY 2013 Deflator values						1.000000	1.020253	1.040748	1.061371	1.082280
205	15	2013 Conservation - 2013$$ -									
206		Debt service in FY2013 Purchasing Power Dollars									
207		a Capital Expenditures - Amort. of Principal	40,613,111	0	0	0	2,241,571	2,299,896	2,360,121	2,422,570	2,486,953
208		b Capital Expenditures - Interest Expense	17,773,934	0	0	0	2,209,947	2,063,255	1,917,109	1,771,550	1,626,139
209		c Expense Expenditures - Amort. of Principal	91,424,028	0	0	0	17,690,937	17,979,591	18,275,909	18,582,077	18,895,514
210		d Expense Expenditures - Interest Expense	10,510,855	0	0	0	3,513,913	2,804,322	2,098,716	1,396,659	697,245
212	FY 2014 Conservation Resources Selected										
213	16	2012 Conservation - 2014$$ -									
214		Debt Service in Nominal Year Dollars									
215		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
216		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
217		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	18,259,872	18,933,661	19,632,313	20,356,745
218		d Expense Expenditures - Interest Expense	11,143,455	0	0	0	0	3,626,919	2,953,130	2,254,478	1,530,046
220	FY 2014 Deflator values							1.000000	1.020087	1.040301	1.060795
221	16	2012 Conservation - 2014$$ -									
222		Debt service in FY2014 Purchasing Power Dollars									
223		a Capital Expenditures - Amort. of Principal	42,298,028	0	0	0	0	2,332,636	2,393,721	2,457,058	2,522,358
224		b Capital Expenditures - Interest Expense	18,503,867	0	0	0	0	2,299,729	2,147,426	1,995,850	1,844,522
225		c Expense Expenditures - Amort. of Principal	94,393,433	0	0	0	0	18,259,872	18,560,830	18,871,762	19,190,084
226		d Expense Expenditures - Interest Expense	10,851,348	0	0	0	0	3,626,919	2,894,979	2,167,140	1,442,358
228	FY 2015 Conservation Resources Selected										
229	17	2011 Conservation - 2015$$ -									
230		Debt Service in Nominal Year Dollars									
231		a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
232		b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
233		c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	17,704,889	18,358,199	19,035,617
234		d Expense Expenditures - Interest Expense	10,804,765	0	0	0	0	0	3,516,684	2,863,374	2,185,956
236	FY 2015 Deflator values								1.000000	1.019816	1.039906
237	17	2011 Conservation - 2015$$ -									
238		Debt service in FY2015 Purchasing Power Dollars									
239		a Capital Expenditures - Amort. of Principal	36,977,518	0	0	0	0	0	2,037,593	2,091,507	2,147,093
240		b Capital Expenditures - Interest Expense	16,169,437	0	0	0	0	0	2,008,848	1,876,308	1,744,067
241		c Expense Expenditures - Amort. of Principal	91,541,086	0	0	0	0	0	17,704,889	18,001,482	18,305,132
242		d Expense Expenditures - Interest Expense	10,523,425	0	0	0	0	0	3,516,684	2,807,736	2,102,071

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Debt Service Components - (whole dollars)

Row	A	C	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
193		Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
195														
196	FY 2013	Conservation Resources Selected												
197	15	2013 Conservation - 2013$$ -												
198		Debt Service in Nominal Year Dollars												
199		a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
200		b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
201		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
202		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
204	FY 2013 Deflator values		1.103764	1.125903	1.149466	1.172941	1.195782	1.218662	1.241615	1.264447	1.287502	1.311370	1.335673	1.360058
205	15	2013 Conservation - 2013$$ -												
206		Debt service in FY2013 Purchasing Power Dollars												
207		a Capital Expenditures - Amort. of Principal	2,552,671	2,619,592	2,685,977	2,755,408	2,829,267	2,906,072	2,985,839	3,069,138	3,155,243	3,242,793	0	0
208		b Capital Expenditures - Interest Expense	1,480,364	1,334,139	1,186,707	1,039,768	893,417	746,720	599,426	451,388	302,242	151,763	0	0
209		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
210		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
212	FY 2014	Conservation Resources Selected												
213	16	2012 Conservation - 2014$$ -												
214		Debt Service in Nominal Year Dollars												
215		a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
216		b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
217		c Expense Expenditures - Amort. of Principal	21,107,909	0	0	0	0	0	0	0	0	0	0	0
218		d Expense Expenditures - Interest Expense	778,882	0	0	0	0	0	0	0	0	0	0	0
220	FY 2014 Deflator values		1.081853	1.103552	1.126648	1.149657	1.172044	1.194470	1.216967	1.239346	1.261944	1.285337	1.309158	1.333059
221	16	2012 Conservation - 2014$$ -												
222		Debt service in FY2014 Purchasing Power Dollars												
223		a Capital Expenditures - Amort. of Principal	2,589,010	2,656,885	2,724,213	2,794,633	2,869,543	2,947,442	3,028,345	3,112,830	3,200,159	3,288,958	3,380,237	0
224		b Capital Expenditures - Interest Expense	1,692,870	1,540,801	1,387,422	1,234,713	1,082,838	930,734	778,139	624,920	470,658	315,050	158,195	0
225		c Expense Expenditures - Amort. of Principal	19,510,885	0	0	0	0	0	0	0	0	0	0	0
226		d Expense Expenditures - Interest Expense	719,952	0	0	0	0	0	0	0	0	0	0	0
228	FY 2015	Conservation Resources Selected												
229	17	2011 Conservation - 2015$$ -												
230		Debt Service in Nominal Year Dollars												
231		a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
232		b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
233		c Expense Expenditures - Amort. of Principal	19,738,031	20,466,364	0	0	0	0	0	0	0	0	0	0
234		d Expense Expenditures - Interest Expense	1,483,542	755,209	0	0	0	0	0	0	0	0	0	0
236	FY 2015 Deflator values		1.060549	1.081821	1.104462	1.127018	1.148965	1.170948	1.193003	1.214941	1.237094	1.260027	1.283378	1.306808
237	17	2011 Conservation - 2015$$ -												
238		Debt service in FY2015 Purchasing Power Dollars												
239		a Capital Expenditures - Amort. of Principal	2,203,828	2,261,606	2,318,917	2,378,860	2,442,625	2,508,937	2,577,802	2,649,717	2,724,054	2,799,641	2,877,341	2,957,997
240		b Capital Expenditures - Interest Expense	1,611,593	1,478,792	1,344,804	1,211,536	1,079,190	946,760	814,011	680,850	546,871	411,752	275,621	138,434
241		c Expense Expenditures - Amort. of Principal	18,611,145	18,918,438	0	0	0	0	0	0	0	0	0	0
242		d Expense Expenditures - Interest Expense	1,398,843	698,091	0	0	0	0	0	0	0	0	0	0
243														

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Debt Service Components - (whole dollars)

SUMMARY TOTALS - INFLATION ADJUSTED VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
TOTALS - CAPITAL EXPENDITURES -									
a AMORTIZATION OF PRINCIPAL	332,724,143	7,549,912	9,814,342	12,216,435	14,774,570	17,491,636	19,987,273	20,516,136	21,061,382
TOTALS - CAPITAL EXPENDITURES -									
b INTEREST EXPENSE	145,677,302	7,443,399	8,988,111	10,476,967	11,917,548	13,302,975	14,247,373	13,053,304	11,859,519
TOTALS - EXPENSE EXPENDITURES -									
c AMORTIZATION OF PRINCIPAL	814,788,009	70,258,721	88,082,863	106,599,312	126,018,296	146,334,307	90,314,560	73,748,752	56,390,730
TOTALS - EXPENSE EXPENDITURES -									
d INTEREST EXPENSE	93,692,008	13,955,340	14,449,836	14,374,159	13,746,235	12,542,512	10,518,804	7,046,562	4,241,674
TOTALS - CONSERVATION PRINCIPAL COSTS	1,147,512,152	77,808,633	97,897,205	118,815,747	140,792,866	163,825,943	110,301,833	94,264,888	77,452,112
TOTALS - INTEREST EXPENSE	239,369,310	21,398,739	23,437,947	24,851,126	25,663,783	25,845,487	24,766,177	20,099,866	16,101,193
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	100.00%	6.78%	8.53%	10.35%	12.27%	14.28%	9.61%	8.21%	6.75%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)		6.78%	15.31%	25.66%	37.93%	52.21%	$\boxed{61.82\%}$	70.03%	76.78%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 61.82%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (INFLATION ADJUSTED DOLLARS) = 93,692,008
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES-YEAR OF INVESTMENT) = 849,034,700
INFLATION ADJUSTED INTEREST AS A PERCENTAGE OF ORIGINAL INVESTMENT COSTS = 11.04%

INTEREST (INFLATION ADJUSTED) EXPENDITURES BY PERIOD

Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
44,836,686	101,126,573	145,963,259	93,406,051	239,369,310

Note 1 - Debt service cash flows are inflation adjusted to the year that the conservation resource is selected from the resource stack. The cash flows associated with the 9 conservation resources chosen in FY2010 are stated in FY 2010 purchasing power dollar values. The cash flows associated with the single conservation resource chosen in each of the remaining years of the rate test period are restated in the purchasing power dollar values associated with that year, the year the resource investment is made. Thus the debt service cash flows are a mixture of purchasing power dollars associated with the year that each conservation investment is made.

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Debt Service Components - (whole dollars)

DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
TOTALS - CAPITAL EXPENDITURES -												
a AMORTIZATION OF PRINCIPAL	21,617,921	22,184,666	22,746,850	23,334,848	23,960,335	24,610,787	25,286,319	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
TOTALS - CAPITAL EXPENDITURES -												
b INTEREST EXPENSE	10,662,193	9,460,713	8,249,816	7,041,458	5,835,748	4,625,893	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
TOTALS - EXPENSE EXPENDITURES -												
c AMORTIZATION OF PRINCIPAL	38,122,030	18,918,438	0	0	0	0	0	0	0	0	0	0
TOTALS - EXPENSE EXPENDITURES -												
d INTEREST EXPENSE	2,118,795	698,091	0	0	0	0	0	0	0	0	0	0
TOTALS - CONSERVATION PRINCIPAL COSTS	59,739,951	41,103,104	22,746,850	23,334,848	23,960,335	24,610,787	25,286,319	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
TOTALS - INTEREST EXPENSE	12,780,988	10,158,804	8,249,816	7,041,458	5,835,748	4,625,893	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	5.21%	3.58%	1.98%	2.03%	2.09%	2.14%	2.20%	1.29%	1.06%	0.81%	0.55%	0.26%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	81.99%	85.57%	87.55%	89.58%	91.67%	93.81%	96.01%	97.30%	98.36%	99.17%	99.72%	99.98%

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	Inflation Adjustment	Capitalized Conservation Deferral/ Maturity # of Years	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	15	0.0468	4	0.0357
FY 2011	1.020232			5	0.0369
FY 2012	1.041582			6	0.0381
FY 2013	1.062788			7	0.0393
FY 2014	1.084313			15	0.0468
FY 2015	1.106094				

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2010 Conservation Resources Selected:						
1	2001 Conservation - 2010$$	19.2	29,059.6	72.4	29,132.0	
	Capitalized Costs - Debt Service Requirements					$6,825.13
	Expensed Costs /Deferral Debt Service Requirements					$5,509,223.68
3	2006 Conservation - 2010$$	31.0	39,428.0	16,435.8	55,863.8	
	Capitalized Costs - Debt Service Requirements					$1,549,397.68
	Expensed Costs /Deferral Debt Service Requirements					$7,474,902.32
4	2003 Conservation - 2010$$	27.6	30,621.2	27,501.3	58,122.5	
	Capitalized Costs - Debt Service Requirements					2,592,538.87
	Expensed Costs /Deferral Debt Service Requirements					$5,805,277.44
5	2002 Conservation - 2010$$	26.6	26,137.0	34,587.9	60,724.9	
	Capitalized Costs - Debt Service Requirements					3,260,590.41
	Expensed Costs /Deferral Debt Service Requirements					$4,955,146.64
6	2005 Conservation - 2010$$	20.6	31,616.2	16,720.6	48,336.8	
	Capitalized Costs - Debt Service Requirements					1,576,245.68
	Expensed Costs /Deferral Debt Service Requirements					$5,993,913.12
8	2008 Conservation - 2010$$	30.3	65,409.8	9,139.1	74,548.9	
	Capitalized Costs - Debt Service Requirements					861,540.07
	Expensed Costs /Deferral Debt Service Requirements					$12,400,625.59
9	2004 Conservation - 2010$$	20.1	27,250.7	22,724.9	49,975.6	
	Capitalized Costs - Debt Service Requirements					2,142,269.15
	Expensed Costs /Deferral Debt Service Requirements					$5,166,285.90
10	2007 Conservation - 2010$$	27.9	59,178.2	11,453.5	70,631.7	
	Capitalized Costs - Debt Service Requirements					1,079,717.83
	Expensed Costs /Deferral Debt Service Requirements					$11,219,216.40
12	2009 Conservation - 2010$$	28.4	69,492.8	20,411.5	89,904.3	
	Capitalized Costs - Debt Service Requirements					1,924,185.66
	Expensed Costs /Deferral Debt Service Requirements					$13,174,695.44
	Totals - FY 2010	231.7	378,193.5	159,047.0	537,240.5	

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2010 Conservation Resources Selected:											
1	**2001 Conservation - 2010$$**										
Capital		6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Expense		5,509.2	5,509.2	5,509.2	5,509.2	5,509.2	5,509.2	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
Capital		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4
Expense		7,474.9	7,474.9	7,474.9	7,474.9	7,474.9	7,474.9	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
Capital		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5
Expense		5,805.3	5,805.3	5,805.3	5,805.3	5,805.3	5,805.3	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
Capital		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6
Expense		4,955.1	4,955.1	4,955.1	4,955.1	4,955.1	4,955.1	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
Capital		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2
Expense		5,993.9	5,993.9	5,993.9	5,993.9	5,993.9	5,993.9	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
Capital		861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5
Expense		12,400.6	12,400.6	12,400.6	12,400.6	12,400.6	12,400.6	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
Capital		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3
Expense		5,166.3	5,166.3	5,166.3	5,166.3	5,166.3	5,166.3	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
Capital		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7
Expense		11,219.2	11,219.2	11,219.2	11,219.2	11,219.2	11,219.2	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2
Expense		13,174.7	13,174.7	13,174.7	13,174.7	13,174.7	13,174.7	0.0	0.0	0.0	0.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
		11	12	13	14	15					
FY 2010 Conservation Resources Selected:											
1	**2001 Conservation - 2010$$**										
Capital		6.8	6.8	6.8	6.8	6.8	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
Capital		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
Capital		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
Capital		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
Capital		861.5	861.5	861.5	861.5	861.5	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
Capital		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
Capital		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$		87,986.2	42,697.1	130,683.3	
13	**2015 Conservation - 2011$$**	39.5	89,766.3	43,560.9	133,327.2	
	Capitalized Costs - Debt Service Requirements					4,106,472.29
	Expensed Costs /Deferral Debt Service Requirements					$17,018,218.63
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$		88,570.4	43,552.0	132,122.4	
14	**2014 Conservation - 2012$$**	39.5	92,253.3	45,363.0	137,616.3	
	Capitalized Costs - Debt Service Requirements					4,276,355.69
	Expensed Costs /Deferral Debt Service Requirements					$17,489,713.05
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$		89,602.1	44,431.3	134,033.4	
15	**2013 Conservation - 2013$$**	39.5	95,228.0	47,221.1	142,449.1	
	Capitalized Costs - Debt Service Requirements					4,451,518.19
	Expensed Costs /Deferral Debt Service Requirements					$18,053,667.39
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$		90,647.7	45,318.6	135,966.3	
16	**2012 Conservation - 2014$$**	39.5	98,290.5	49,139.5	147,430.0	
	Capitalized Costs - Debt Service Requirements					4,632,365.15
	Expensed Costs /Deferral Debt Service Requirements					$18,634,267.18
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$		86,161.8	38,806.9	124,968.7	
17	**2011 Conservation - 2015$$**	34.9	95,303.1	42,924.1	138,227.2	
	Capitalized Costs - Debt Service Requirements					4,046,441.35
	Expensed Costs /Deferral Debt Service Requirements					$18,067,905.12

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		387,255.6	160,340.4	547,596.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	849,034.7		116,743.3	965,778.0
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	849,034.7	387,255.6	277,083.7	1,513,374.0

Principal Expense Costs	849,034.7
Interest Paid Expensed Costs	116,743.3
Principal Capital Costs	387,255.6
Interest Paid Capital Costs	160,340.4
Totals	1,513,374.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5
Expense		0.0	17,018.2	17,018.2	17,018.2	17,018.2	17,018.2	17,018.2	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4
Expense		0.0	0.0	17,489.7	17,489.7	17,489.7	17,489.7	17,489.7	17,489.7	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5
Expense		0.0	0.0	0.0	18,053.7	18,053.7	18,053.7	18,053.7	18,053.7	18,053.7	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4
Expense		0.0	0.0	0.0	0.0	18,634.3	18,634.3	18,634.3	18,634.3	18,634.3	18,634.3
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense		0.0	0.0	0.0	0.0	0.0	18,067.9	18,067.9	18,067.9	18,067.9	18,067.9
TCC		14,993.2	19,099.7	23,376.1	27,827.6	32,460.0	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4
TEC		71,699.2	88,717.4	106,207.1	124,260.8	142,895.1	160,963.0	89,263.8	72,245.6	54,755.9	36,702.2
TDSR		86,692.4	107,817.1	129,583.2	152,088.4	175,355.1	197,469.4	125,770.2	108,752.0	91,262.3	73,208.6

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
		11	12	13	14	15					
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense		18,067.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC		36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4
TEC		18,067.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR		54,574.3	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010	**Conservation Resources Selected**									
FY 2010	Conservation (9) Res. Selected - Total MW =	231.7								
1	**2001 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	72,400	3,437	3,598	3,766	3,942	4,127	4,320	4,522	4,734
	b Capital Expenditures - Interest Expense	29,975	3,388	3,227	3,059	2,883	2,698	2,505	2,303	2,091
	c Expense Expenditures - Amort. of Principal	29,059,600	4,402,053	4,569,771	4,743,880	4,924,622	5,112,249	5,307,025	0	0
	d Expense Expenditures - Interest Expense	3,995,742	1,107,171	939,453	765,344	584,602	396,974	202,198	0	0
3	**2006 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,435,800	780,203	816,716	854,938	894,949	936,833	980,677	1,026,573	1,074,616
	b Capital Expenditures - Interest Expense	6,805,165	769,195	732,682	694,460	654,449	612,565	568,721	522,825	474,782
	c Expense Expenditures - Amort. of Principal	39,428,000	5,972,695	6,200,255	6,436,485	6,681,715	6,936,288	7,200,562	0	0
	d Expense Expenditures - Interest Expense	5,421,413	1,502,207	1,274,647	1,038,417	793,187	538,614	274,341	0	0
4	**2003 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	27,501,300	1,305,478	1,366,575	1,430,530	1,497,479	1,567,561	1,640,923	1,717,718	1,798,107
	b Capital Expenditures - Interest Expense	11,386,782	1,287,061	1,225,964	1,162,009	1,095,060	1,024,978	951,616	874,821	794,432
	c Expense Expenditures - Amort. of Principal	30,621,200	4,638,609	4,815,340	4,998,805	5,189,260	5,386,971	5,592,215	0	0
	d Expense Expenditures - Interest Expense	4,210,465	1,166,668	989,937	806,472	616,018	418,307	213,063	0	0
5	**2002 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	34,587,900	1,641,876	1,718,716	1,799,152	1,883,352	1,971,493	2,063,759	2,160,343	2,261,448
	b Capital Expenditures - Interest Expense	14,320,958	1,618,714	1,541,874	1,461,438	1,377,238	1,289,097	1,196,831	1,100,247	999,143
	c Expense Expenditures - Amort. of Principal	26,137,000	3,959,327	4,110,178	4,266,775	4,429,340	4,598,096	4,773,284	0	0
	d Expense Expenditures - Interest Expense	3,593,880	995,820	844,969	688,372	525,807	357,050	181,862	0	0
6	**2005 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,720,600	793,722	830,868	869,753	910,457	953,067	997,670	1,044,361	1,093,237
	b Capital Expenditures - Interest Expense	6,923,083	782,524	745,378	706,493	665,789	623,179	578,576	531,885	483,009
	c Expense Expenditures - Amort. of Principal	31,616,200	4,789,336	4,971,809	5,161,235	5,357,878	5,562,015	5,773,927	0	0
	d Expense Expenditures - Interest Expense	4,347,280	1,204,577	1,022,104	832,678	636,035	431,899	219,987	0	0
8	**2008 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	9,139,100	433,830	454,133	475,387	497,635	520,924	545,303	570,824	597,538
	b Capital Expenditures - Interest Expense	3,784,002	427,710	407,407	386,153	363,905	340,616	316,237	290,716	264,002
	c Expense Expenditures - Amort. of Principal	65,409,800	9,908,513	10,286,027	10,677,924	11,084,752	11,507,082	11,945,502	0	0
	d Expense Expenditures - Interest Expense	8,993,953	2,492,113	2,114,599	1,722,701	1,315,873	893,543	455,124	0	0

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010	**Conservation Resources Selected**												
FY 2010	Conservation (9) Res. Selected - Total MW =												
1	**2001 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	4,955	5,187	5,430	5,684	5,950	6,228	6,520	0	0	0	0	0
	b Capital Expenditures - Interest Expense	1,870	1,638	1,395	1,141	875	597	305	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
3	**2006 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,124,908	1,177,554	1,232,662	1,290,351	1,350,739	1,413,954	1,480,127	0	0	0	0	0
	b Capital Expenditures - Interest Expense	424,490	371,844	316,735	259,046	198,658	135,443	69,270	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
4	**2003 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,882,259	1,970,348	2,062,561	2,159,089	2,260,133	2,365,907	2,476,632	0	0	0	0	0
	b Capital Expenditures - Interest Expense	710,280	622,191	529,978	433,450	332,405	226,631	115,906	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
5	**2002 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	2,367,284	2,478,073	2,594,046	2,715,448	2,842,531	2,975,561	3,114,818	0	0	0	0	0
	b Capital Expenditures - Interest Expense	893,307	782,518	666,545	545,143	418,060	285,030	145,773	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
6	**2005 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	1,144,400	1,197,958	1,254,022	1,312,710	1,374,145	1,438,455	1,505,775	0	0	0	0	0
	b Capital Expenditures - Interest Expense	431,845	378,287	322,223	263,535	202,100	137,790	70,470	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
8	**2008 Conservation - 2010$$**												
	a Capital Expenditures - Amort. of Principal	625,503	654,777	685,420	717,498	751,077	786,227	823,024	0	0	0	0	0
	b Capital Expenditures - Interest Expense	236,037	206,763	176,120	144,042	110,463	75,313	38,518	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
47	9	2004 Conservation - 2010$$									
48		a Capital Expenditures - Amort. of Principal	22,724,900	1,078,744	1,129,229	1,182,077	1,237,398	1,295,308	1,355,929	1,419,386	1,485,813
49		b Capital Expenditures - Interest Expense	9,409,137	1,063,525	1,013,040	960,192	904,871	846,961	786,340	722,883	656,456
50		c Expense Expenditures - Amort. of Principal	27,250,700	4,128,034	4,285,312	4,448,583	4,618,074	4,794,022	4,976,675	0	0
51		d Expense Expenditures - Interest Expense	3,747,016	1,038,252	880,974	717,703	548,212	372,264	189,611	0	0
52	10	2007 Conservation - 2010$$									
53		a Capital Expenditures - Amort. of Principal	11,453,500	543,694	569,139	595,775	623,657	652,844	683,397	715,380	748,860
54		b Capital Expenditures - Interest Expense	4,742,268	536,024	510,579	483,943	456,061	426,874	396,321	364,338	330,858
55		c Expense Expenditures - Amort. of Principal	59,178,200	8,964,527	9,306,075	9,660,637	10,028,707	10,410,801	10,807,453	0	0
56		d Expense Expenditures - Interest Expense	8,137,097	2,254,689	1,913,141	1,558,579	1,190,509	808,415	411,764	0	0
57	12	2009 Conservation - 2010$$									
58		a Capital Expenditures - Amort. of Principal	20,411,500	968,928	1,014,274	1,061,742	1,111,431	1,163,446	1,217,895	1,274,893	1,334,557
59		b Capital Expenditures - Interest Expense	8,451,286	955,258	909,912	862,444	812,755	760,740	706,291	649,293	589,628
60		c Expense Expenditures - Amort. of Principal	69,492,800	10,527,019	10,928,099	11,344,459	11,776,684	12,225,376	12,691,163	0	0
61		d Expense Expenditures - Interest Expense	9,555,373	2,647,676	2,246,596	1,830,236	1,398,012	949,320	483,533	0	0
62	FY 2011	Conservation Resources Selected									
63	13	2015 Conservation - 2011$$									
64		a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
65		b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
66		c Expense Expenditures - Amort. of Principal	89,766,300	0	13,598,123	14,116,211	14,654,039	15,212,358	15,791,948	16,393,621	0
67		d Expense Expenditures - Interest Expense	12,343,012	0	3,420,096	2,902,008	2,364,180	1,805,861	1,226,270	624,597	0
68	FY 2012	Conservation Resources Selected									
69	14	2014 Conservation - 2012$$									
70		a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
71		b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
72		c Expense Expenditures - Amort. of Principal	92,253,300	0	0	13,974,862	14,507,305	15,060,033	15,633,820	16,229,469	16,847,811
73		d Expense Expenditures - Interest Expense	12,684,978	0	0	3,514,851	2,982,408	2,429,680	1,855,893	1,260,244	641,902
74	FY 2013	Conservation Resources Selected									
75	15	2013 Conservation - 2013$$									
76		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
77		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
78		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	14,425,480	14,975,091	15,545,642	16,137,932	16,752,787
79		d Expense Expenditures - Interest Expense	13,094,005	0	0	0	3,628,187	3,078,576	2,508,025	1,915,736	1,300,881
80	FY 2014	Conservation Resources Selected									
81	16	2012 Conservation - 2014$$									
82		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
83		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
84		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	14,889,399	15,456,685	16,045,585	16,656,922
85		d Expense Expenditures - Interest Expense	13,515,103	0	0	0	0	3,744,868	3,177,582	2,588,682	1,977,345

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= Expensed costs are deferred and amortized / financed over 6 - years

Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
47	9	2004 Conservation - 2010$$												
48		a Capital Expenditures - Amort. of Principal	1,555,349	1,628,140	1,704,337	1,784,100	1,867,596	1,954,999	2,046,495	0	0	0	0	0
49		b Capital Expenditures - Interest Expense	586,920	514,129	437,932	358,169	274,673	187,270	95,776	0	0	0	0	0
50		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
51		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
52	10	2007 Conservation - 2010$$												
53		a Capital Expenditures - Amort. of Principal	783,907	820,594	858,997	899,198	941,281	985,333	1,031,444	0	0	0	0	0
54		b Capital Expenditures - Interest Expense	295,811	259,124	220,721	180,520	138,437	94,385	48,272	0	0	0	0	0
55		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
56		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
57	12	2009 Conservation - 2010$$												
58		a Capital Expenditures - Amort. of Principal	1,397,014	1,462,394	1,530,834	1,602,478	1,677,474	1,755,980	1,838,160	0	0	0	0	0
59		b Capital Expenditures - Interest Expense	527,171	461,791	393,351	321,708	246,712	168,206	86,026	0	0	0	0	0
60		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
61		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
62	FY 2011	Conservation Resources Selected												
63	13	2015 Conservation - 2011$$												
64		a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
65		b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
66		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
67		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
68	FY 2012	Conservation Resources Selected												
69	14	2014 Conservation - 2012$$												
70		a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
71		b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
72		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
73		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
74	FY 2013	Conservation Resources Selected												
75	15	2013 Conservation - 2013$$												
76		a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
77		b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
78		c Expense Expenditures - Amort. of Principal	17,391,068	0	0	0	0	0	0	0	0	0	0	0
79		d Expense Expenditures - Interest Expense	662,600	0	0	0	0	0	0	0	0	0	0	0
80	FY 2014	Conservation Resources Selected												
81	16	2012 Conservation - 2014$$												
82		a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
83		b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
84		c Expense Expenditures - Amort. of Principal	17,291,550	17,950,359	0	0	0	0	0	0	0	0	0	0
85		d Expense Expenditures - Interest Expense	1,342,717	683,909	0	0	0	0	0	0	0	0	0	0

	A	B	C	D	E	F	G	H	I	J	K	L

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
90	FY 2015	Conservation Resources Selected									
91	17	2011 Conservation - 2015$$									
92		a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
93		b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
94		c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	14,436,857	14,986,901	15,557,902
95		d Expense Expenditures - Interest Expense	13,104,331	0	0	0	0	0	3,631,048	3,081,004	2,510,003
96											

97 **SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS**

Row	DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
100										
101	TOTALS - CAPITAL EXPENDITURES -	387,255,600								
102	AMORTIZATION OF PRINCIPAL	387,255,600	7,549,912	9,971,070	12,591,084	15,421,915	18,476,297	21,378,581	22,379,100	23,426,441
103	TOTALS - CAPITAL EXPENDITURES -	160,341,348								
104	INTEREST EXPENSE	160,341,348	7,443,399	9,128,713	10,785,055	12,405,742	13,983,725	15,127,882	14,127,363	13,080,022
105	TOTALS - EXPENSE EXPENDITURES -	849,034,700								
106	AMORTIZATION OF PRINCIPAL	849,034,700	57,290,113	73,070,989	89,829,856	107,677,856	126,669,781	145,932,758	79,793,508	65,815,422
107	TOTALS - EXPENSE EXPENDITURES -	116,743,648								
108	INTEREST EXPENSE	116,743,648	14,409,173	15,646,516	16,377,361	16,583,030	16,225,371	15,030,301	9,470,263	6,430,131
109		1,236,290,300								
110	TOTALS - CONSERVATION PRINCIPAL COSTS	1,236,290,300	64,840,025	83,042,059	102,420,940	123,099,771	145,146,078	167,311,339	102,172,608	89,241,863
111		277,084,996								
112	TOTALS - INTEREST EXPENSE	277,084,996	21,852,572	24,775,229	27,162,416	28,988,772	30,209,096	30,158,183	23,597,626	19,510,153
113										
114	PERCENTAGE OF TOTAL PRINCIPAL PAID	100.00%	5.24%	6.72%	8.28%	9.96%	11.74%	13.53%	8.26%	7.22%
115	(Capital and Expense Expenditures)									
117	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		5.24%	11.96%	20.24%	30.20%	41.94%	55.47%	63.73%	70.95%

119 PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 55.47%

122 TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (NOMINAL DOLLARS) = 116,743,648
123 CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES - YEAR OF INVESTMENT) = 849,034,700
124 INTEREST AS A PECENTAGE OF ORIGINAL INVESTMENT COSTS = 13.75%

127 INTEREST (NOMINAL DOLLARS) EXPENDITURES BY PERIOD

	Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
Interest on Capital and Expense Expenditures	46,627,801	116,518,467	163,146,268	113,938,728	277,084,996

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
90	FY 2015	Conservation Resources Selected												
91	17	2011 Conservation - 2015$$												
92		a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
93		b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
94		c Expense Expenditures - Amort. of Principal	16,150,658	16,765,998	17,404,784	0	0	0	0	0	0	0	0	0
95		d Expense Expenditures - Interest Expense	1,917,247	1,301,907	663,122	0	0	0	0	0	0	0	0	0

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

Row	DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
101–102	TOTALS - CAPITAL EXPENDITURES - AMORTIZATION OF PRINCIPAL	24,522,798	25,670,466	26,871,840	28,129,445	29,445,903	30,823,971	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
103–104	TOTALS - CAPITAL EXPENDITURES - INTEREST EXPENSE	11,983,664	10,835,996	9,634,621	8,377,017	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
105–106	TOTALS - EXPENSE EXPENDITURES - AMORTIZATION OF PRINCIPAL	50,833,276	34,716,357	17,404,784	0	0	0	0	0	0	0	0	0
107–108	TOTALS - EXPENSE EXPENDITURES - INTEREST EXPENSE	3,922,564	1,985,816	663,122	0	0	0	0	0	0	0	0	0
110	TOTALS - CONSERVATION PRINCIPAL COSTS	75,356,074	60,386,823	44,276,624	28,129,445	29,445,903	30,823,971	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
112	TOTALS - INTEREST EXPENSE	15,906,228	12,821,812	10,297,743	8,377,017	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
114–115	PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	6.10%	4.88%	3.58%	2.28%	2.38%	2.49%	2.61%	1.52%	1.26%	0.97%	0.66%	0.31%
117	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID	77.05%	81.93%	85.51%	87.79%	90.17%	92.66%	95.27%	96.79%	98.05%	99.02%	99.68%	99.99%

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Debt Service Components - (whole dollars)

Row	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
136			INFLATION ADJUSTED ANALYSIS							
137	FY 2010 Conservation Resources Selected -									
138	Debt Service in Nominal Year Dollars									
139	TOTALS - CAPITAL EXPENDITURES -	142,611,200								
140	a AMORTIZATION OF PRINCIPAL	142,611,200	6,769,709	7,086,532	7,418,182	7,765,351	8,128,770	8,509,196	8,907,427	9,324,294
141	TOTALS - CAPITAL EXPENDITURES -	59,047,491								
142	b INTEREST EXPENSE	59,047,491	6,674,204	6,357,381	6,025,731	5,678,562	5,315,143	4,934,717	4,536,486	4,119,619
143	TOTALS - EXPENSE EXPENDITURES -	338,765,500								
144	c AMORTIZATION OF PRINCIPAL	338,765,500	51,317,418	53,272,611	55,302,298	57,409,317	59,596,612	61,867,244	0	0
145	TOTALS - EXPENSE EXPENDITURES -	46,580,806								
146	d INTEREST EXPENSE	46,580,806	12,906,966	10,951,773	8,922,085	6,815,068	4,627,772	2,357,142	0	0
148	FY 2010 Deflator values		1.000000	1.020232	1.041582	1.062788	1.084313	1.106094	1.128012	1.150234
149	FY 2010 Conservation Resources Selected -									
150	Debt service in FY2010 Purchasing Power Dollars									
151	TOTALS - CAPITAL EXPENDITURES -									
152	a AMORTIZATION OF PRINCIPAL	122,360,515	6,769,709	6,946,001	7,122,034	7,306,585	7,496,701	7,693,013	7,896,571	8,106,432
153	TOTALS - CAPITAL EXPENDITURES -									
154	b INTEREST EXPENSE	53,608,362	6,674,204	6,231,309	5,785,172	5,343,081	4,901,853	4,461,390	4,021,665	3,581,549
155	TOTALS - EXPENSE EXPENDITURES -									
156	c AMORTIZATION OF PRINCIPAL	321,541,403	51,317,418	52,216,173	53,094,522	54,017,656	54,962,554	55,933,080	0	0
157	TOTALS - EXPENSE EXPENDITURES -									
158	d INTEREST EXPENSE	45,018,878	12,906,966	10,734,591	8,565,898	6,412,443	4,267,930	2,131,050	0	0
160	FY 2011 Conservation Resources Selected									
161	13 2015 Conservation - 2011$$ -									
162	Debt Service in Nominal Year Dollars									
163	a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
164	b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
165	c Expense Expenditures - Amort. of Principal	89,766,300	0	13,598,123	14,116,211	14,654,039	15,212,358	15,791,948	16,393,621	0
166	d Expense Expenditures - Interest Expense	12,343,012	0	3,420,096	2,902,008	2,364,180	1,805,861	1,226,270	624,597	0
168	FY 2011 Deflator values			1.000000	1.020927	1.041712	1.062810	1.084159	1.105643	1.127424
169	13 2015 Conservation - 2011$$ -									
170	Debt service in FY2011 Purchasing Power Dollars									
171	a Capital Expenditures - Amort. of Principal	37,389,568	0	2,067,822	2,120,226	2,175,168	2,231,766	2,290,208	2,350,806	2,413,282
172	b Capital Expenditures - Interest Expense	16,376,020	0	2,038,650	1,902,071	1,766,873	1,632,022	1,497,494	1,363,297	1,229,067
173	c Expense Expenditures - Amort. of Principal	85,198,890	0	13,598,123	13,826,856	14,067,265	14,313,337	14,566,081	14,827,228	0
174	d Expense Expenditures - Interest Expense	11,927,267	0	3,420,096	2,842,523	2,269,514	1,699,138	1,131,079	564,917	0
176	FY 2012 Conservation Resources Selected									
177	14 2014 Conservation - 2012$$ -									
178	Debt Service in Nominal Year Dollars									
179	a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
180	b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
181	c Expense Expenditures - Amort. of Principal	92,253,300	0	0	13,974,862	14,507,305	15,060,033	15,633,820	16,229,469	16,847,811
182	d Expense Expenditures - Interest Expense	12,684,978	0	0	3,514,851	2,982,408	2,429,680	1,855,893	1,260,244	641,902
184	FY 2012 Deflator values				1.000000	1.020359	1.041025	1.061937	1.082980	1.104314
185	14 2014 Conservation - 2012$$ -									
186	Debt service in FY2012 Purchasing Power Dollars									
187	a Capital Expenditures - Amort. of Principal	38,983,476	0	0	2,153,368	2,209,169	2,266,650	2,326,004	2,387,551	2,451,005
188	b Capital Expenditures - Interest Expense	17,067,371	0	0	2,122,988	1,981,862	1,841,182	1,700,935	1,561,142	1,421,405
189	c Expense Expenditures - Amort. of Principal	87,623,528	0	0	13,974,862	14,217,844	14,466,543	14,721,984	14,985,936	15,256,359
190	d Expense Expenditures - Interest Expense	12,264,282	0	0	3,514,851	2,922,901	2,333,931	1,747,649	1,163,682	581,268

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Debt Service Components - (whole dollars)

Row	A	B	C	M	N	O	P	Q	R	S	T	U	V	W	X
134			**Vintage - Year Selected**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
136									**INFLATION ADJUSTED ANALYSIS**						
137	**FY 2010 Conservation Resources Selected -**														
138			**Debt Service in Nominal Year Dollars**												
139	TOTALS - CAPITAL EXPENDITURES -														
140		a	AMORTIZATION OF PRINCIPAL	9,760,671	10,217,471	10,695,647	11,196,205	11,720,187	12,268,690	12,842,868	0	0	0	0	0
141	TOTALS - CAPITAL EXPENDITURES -														
142		b	INTEREST EXPENSE	3,683,241	3,226,441	2,748,265	2,247,708	1,723,725	1,175,222	601,046	0	0	0	0	0
143	TOTALS - EXPENSE EXPENDITURES -														
144		c	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
145	TOTALS - EXPENSE EXPENDITURES -														
146		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
148	FY 2010 Deflator values			1.173067	1.196596	1.221639	1.246588	1.270863	1.295179	1.319573	1.343839	1.368342	1.393708	1.419537	1.445453
149	**FY 2010 Conservation Resources Selected -**														
150			**Debt service in FY2010 Purchasing Power Dollars**												
151	TOTALS - CAPITAL EXPENDITURES -														
152		a	AMORTIZATION OF PRINCIPAL	8,320,642	8,538,781	8,755,162	8,981,480	9,222,227	9,472,583	9,732,594	0	0	0	0	0
153	TOTALS - CAPITAL EXPENDITURES -														
154		b	INTEREST EXPENSE	3,139,839	2,696,349	2,249,654	1,803,088	1,356,342	907,382	455,485	0	0	0	0	0
155	TOTALS - EXPENSE EXPENDITURES -														
156		c	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
157	TOTALS - EXPENSE EXPENDITURES -														
158		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
160	**FY 2011 Conservation Resources Selected**														
161	**13**		**2015 Conservation - 2011$$ -**												
162			**Debt Service in Nominal Year Dollars**												
163			a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
164			b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
165			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
166			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
168	FY 2011 Deflator values			1.149804	1.172867	1.197413	1.221867	1.245661	1.269495	1.293405	1.317190	1.341207	1.366070	1.391386	1.416789
169	**13**		**2015 Conservation - 2011$$ -**												
170			**Debt service in FY2011 Purchasing Power Dollars**												
171			a Capital Expenditures - Amort. of Principal	2,477,053	2,541,992	2,606,410	2,673,785	2,745,455	2,819,985	2,897,390	2,978,220	0	0	0	0
172			b Capital Expenditures - Interest Expense	1,094,401	959,234	823,044	687,033	551,167	414,744	277,542	139,381	0	0	0	0
173			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
174			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
176	**FY 2012 Conservation Resources Selected**														
177	**14**		**2014 Conservation - 2012$$ -**												
178			**Debt Service in Nominal Year Dollars**												
179			a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
180			b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
181			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
182			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
184	FY 2012 Deflator values			1.126236	1.148826	1.172869	1.196822	1.220128	1.243473	1.266893	1.290190	1.313715	1.338068	1.362866	1.387748
185	**14**		**2014 Conservation - 2012$$ -**												
186			**Debt service in FY2012 Purchasing Power Dollars**												
187			a Capital Expenditures - Amort. of Principal	2,515,771	2,581,724	2,647,148	2,715,576	2,788,366	2,864,063	2,942,678	3,024,772	3,109,631	0	0	0
188			b Capital Expenditures - Interest Expense	1,281,263	1,140,646	998,915	857,516	716,476	574,978	432,789	289,743	145,531	0	0	0
189			c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
190			d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	A	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
195					INFLATION ADJUSTED ANALYSIS						
196	FY 2013 Conservation Resources Selected										
197	15	2013 Conservation - 2013$$ -									
198		Debt Service in Nominal Year Dollars									
199		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
200		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
201		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	14,425,480	14,975,091	15,545,642	16,137,932	16,752,787
202		d Expense Expenditures - Interest Expense	13,094,005	0	0	0	3,628,187	3,078,576	2,508,025	1,915,736	1,300,881
204	FY 2013 Deflator values						1.000000	1.020253	1.040748	1.061371	1.082280
205	15	2013 Conservation - 2013$$ -									
206		Debt service in FY2013 Purchasing Power Dollars									
207		a Capital Expenditures - Amort. of Principal	40,613,111	0	0	0	2,241,571	2,299,896	2,360,121	2,422,570	2,486,953
208		b Capital Expenditures - Interest Expense	17,773,934	0	0	0	2,209,947	2,063,255	1,917,109	1,771,550	1,626,139
209		c Expense Expenditures - Amort. of Principal	90,480,398	0	0	0	14,425,480	14,677,821	14,936,990	15,204,798	15,479,162
210		d Expense Expenditures - Interest Expense	12,662,734	0	0	0	3,628,187	3,017,463	2,409,829	1,804,964	1,201,982
212	FY 2014 Conservation Resources Selected										
213	16	2012 Conservation - 2014$$ -									
214		Debt Service in Nominal Year Dollars									
215		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
216		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
217		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	14,889,399	15,456,685	16,045,585	16,656,922
218		d Expense Expenditures - Interest Expense	13,515,103	0	0	0	0	3,744,868	3,177,582	2,588,682	1,977,345
220	FY 2014 Deflator values							1.000000	1.020087	1.040301	1.060795
221	16	2012 Conservation - 2014$$ -									
222		Debt service in FY2014 Purchasing Power Dollars									
223		a Capital Expenditures - Amort. of Principal	42,298,028	0	0	0	0	2,332,636	2,393,721	2,457,058	2,522,358
224		b Capital Expenditures - Interest Expense	18,503,867	0	0	0	0	2,299,729	2,147,426	1,995,850	1,844,522
225		c Expense Expenditures - Amort. of Principal	93,417,258	0	0	0	0	14,889,399	15,152,320	15,423,983	15,702,301
226		d Expense Expenditures - Interest Expense	13,073,159	0	0	0	0	3,744,868	3,115,011	2,488,397	1,864,022
228	FY 2015 Conservation Resources Selected										
229	17	2011 Conservation - 2015$$ -									
230		Debt Service in Nominal Year Dollars									
231		a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
232		b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
233		c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	14,436,857	14,986,901	15,557,902
234		d Expense Expenditures - Interest Expense	13,104,331	0	0	0	0	0	3,631,048	3,081,004	2,510,003
236	FY 2015 Deflator values								1.000000	1.019816	1.039906
237	17	2011 Conservation - 2015$$ -									
238		Debt service in FY2015 Purchasing Power Dollars									
239		a Capital Expenditures - Amort. of Principal	36,977,518	0	0	0	0	0	2,037,593	2,091,507	2,147,093
240		b Capital Expenditures - Interest Expense	16,169,437	0	0	0	0	0	2,008,848	1,876,308	1,744,067
241		c Expense Expenditures - Amort. of Principal	90,578,553	0	0	0	0	0	14,436,857	14,695,691	14,960,873
242		d Expense Expenditures - Interest Expense	12,677,498	0	0	0	0	0	3,631,048	3,021,137	2,413,683

	A	B / C	M	N	O	P	Q	R	S	T	U	V	W	X
1							**Section 7(b)(2) Rate Test Study and Documentation**							
2							**Alternative Conservation Expense Accounting and Financing Treatments**							
3							**WP-10 Final Rate Proposal**							
5							**Scenario = Capitalized costs amortized / financed over 15 years,**							
6							**= Expensed costs are deferred and amortized / financed over 6 - years**							
8							**Debt Service Components - (whole dollars)**							
193		**Vintage - Year Selected**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
195														
196	**FY 2013 Conservation Resources Selected**													
197	**15**	**2013 Conservation - 2013$$ -**												
198		**Debt Service in Nominal Year Dollars**												
199		a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
200		b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
201		c Expense Expenditures - Amort. of Principal	17,391,068	0	0	0	0	0	0	0	0	0	0	0
202		d Expense Expenditures - Interest Expense	662,600	0	0	0	0	0	0	0	0	0	0	0
204	FY 2013 Deflator values		1.103764	1.125903	1.149466	1.172941	1.195782	1.218662	1.241615	1.264447	1.287502	1.311370	1.335673	1.360058
205	**15**	**2013 Conservation - 2013$$ -**												
206		**Debt service in FY2013 Purchasing Power Dollars**												
207		a Capital Expenditures - Amort. of Principal	2,552,671	2,619,592	2,685,977	2,755,408	2,829,267	2,906,072	2,985,839	3,069,138	3,155,243	3,242,793	0	0
208		b Capital Expenditures - Interest Expense	1,480,364	1,334,139	1,186,707	1,039,768	893,417	746,720	599,426	451,388	302,242	151,763	0	0
209		c Expense Expenditures - Amort. of Principal	15,756,147	0	0	0	0	0	0	0	0	0	0	0
210		d Expense Expenditures - Interest Expense	600,309	0	0	0	0	0	0	0	0	0	0	0
212	**FY 2014 Conservation Resources Selected**													
213	**16**	**2012 Conservation - 2014$$ -**												
214		**Debt Service in Nominal Year Dollars**												
215		a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
216		b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
217		c Expense Expenditures - Amort. of Principal	17,291,550	17,950,359	0	0	0	0	0	0	0	0	0	0
218		d Expense Expenditures - Interest Expense	1,342,717	683,909	0	0	0	0	0	0	0	0	0	0
220	FY 2014 Deflator values		1.081853	1.103552	1.126648	1.149657	1.172044	1.194470	1.216967	1.239346	1.261944	1.285337	1.309158	1.333059
221	**16**	**2012 Conservation - 2014$$ -**												
222		**Debt service in FY2014 Purchasing Power Dollars**												
223		a Capital Expenditures - Amort. of Principal	2,589,010	2,656,885	2,724,213	2,794,633	2,869,543	2,947,442	3,028,345	3,112,830	3,200,159	3,288,958	3,380,237	0
224		b Capital Expenditures - Interest Expense	1,692,870	1,540,801	1,387,422	1,234,713	1,082,838	930,734	778,139	624,920	470,658	315,050	158,195	0
225		c Expense Expenditures - Amort. of Principal	15,983,271	16,265,984	0	0	0	0	0	0	0	0	0	0
226		d Expense Expenditures - Interest Expense	1,241,127	619,734	0	0	0	0	0	0	0	0	0	0
228	**FY 2015 Conservation Resources Selected**													
229	**17**	**2011 Conservation - 2015$$ -**												
230		**Debt Service in Nominal Year Dollars**												
231		a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
232		b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
233		c Expense Expenditures - Amort. of Principal	16,150,658	16,765,998	17,404,784	0	0	0	0	0	0	0	0	0
234		d Expense Expenditures - Interest Expense	1,917,247	1,301,907	663,122	0	0	0	0	0	0	0	0	0
236	FY 2015 Deflator values		1.060549	1.081821	1.104462	1.127018	1.148965	1.170948	1.193003	1.214941	1.237094	1.260027	1.283378	1.306808
237	**17**	**2011 Conservation - 2015$$ -**												
238		**Debt service in FY2015 Purchasing Power Dollars**												
239		a Capital Expenditures - Amort. of Principal	2,203,828	2,261,606	2,318,917	2,378,860	2,442,625	2,508,937	2,577,802	2,649,717	2,724,054	2,799,641	2,877,341	2,957,997
240		b Capital Expenditures - Interest Expense	1,611,593	1,478,792	1,344,804	1,211,536	1,079,190	946,760	814,011	680,850	546,871	411,752	275,621	138,434
241		c Expense Expenditures - Amort. of Principal	15,228,583	15,497,941	15,758,608	0	0	0	0	0	0	0	0	0
242		d Expense Expenditures - Interest Expense	1,807,787	1,203,440	600,403	0	0	0	0	0	0	0	0	0
243														
244								Page 16 of 18						

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Debt Service Components - (whole dollars)

SUMMARY TOTALS - INFLATION ADJUSTED VALUES ANALYSIS

Row	DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
250	TOTALS - CAPITAL EXPENDITURES -	318,622,216								
251	a AMORTIZATION OF PRINCIPAL	318,622,216	6,769,709	9,013,823	11,395,628	13,932,493	16,627,649	19,100,660	19,606,063	20,127,123
252	TOTALS - CAPITAL EXPENDITURES -	139,498,991								
253	b INTEREST EXPENSE	139,498,991	6,674,204	8,269,959	9,810,231	11,301,763	12,738,041	13,733,202	12,589,812	11,446,749
254	TOTALS - EXPENSE EXPENDITURES -	768,840,030								
255	c AMORTIZATION OF PRINCIPAL	768,840,030	51,317,418	65,814,296	80,896,240	96,728,245	113,309,654	129,747,312	75,137,636	61,398,695
256	TOTALS - EXPENSE EXPENDITURES -	107,623,818								
257	d INTEREST EXPENSE	107,623,818	12,906,966	14,154,687	14,923,272	15,233,045	15,063,330	14,165,666	9,043,097	6,060,955
258		1,087,462,246								
259	TOTALS - CONSERVATION PRINCIPAL COSTS	1,087,462,246	58,087,127	74,828,119	92,291,868	110,660,738	129,937,303	148,847,972	94,743,699	81,525,818
260		247,122,809								
261	TOTALS - INTEREST EXPENSE	247,122,809	19,581,170	22,424,646	24,733,503	26,534,808	27,801,371	27,898,868	21,632,909	17,507,704
263	PERCENTAGE OF TOTAL PRINCIPAL PAID									
264	(Capital and Expense Expenditures)	100.00%	5.34%	6.88%	8.49%	10.18%	11.95%	13.69%	8.71%	7.50%
266	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		5.34%	12.22%	20.71%	30.89%	42.84%	56.53%	65.24%	72.74%
267	(Capital and Expense Expenditures)									

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 56.53%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (INFLATION ADJUSTED DOLLARS) = 107,623,818
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES-YEAR OF INVESTMENT) = 849,034,700
INFLATION ADJUSTED INTEREST AS A PERCENTAGE OF ORIGINAL INVESTMENT COSTS = 12.68%

INTEREST (INFLATION ADJUSTED) EXPENDITURES BY PERIOD

Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
42,005,816	106,968,550	148,974,366	98,148,443	247,122,809

Note 1 - Debt service cash flows are inflation adjusted to the year that the conservation resource is selected from the resource stack. The cash flows associated with the 9 conservation resources chosen in FY2010 are stated in FY 2010 purchasing power dollar values. The cash flows associated with the single conservation resource chosen in each of the remaining years of the rate test period are restated in the purchasing power dollar values associated with that year, the year the resource investment is made. Thus the debt service cash flows are a mixture of purchasing power dollars associated with the year that each conservation investment is made.

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Debt Service Components - (whole dollars)

Row	DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
250	TOTALS - CAPITAL EXPENDITURES -												
251	a AMORTIZATION OF PRINCIPAL	20,658,975	21,200,580	21,737,827	22,299,742	22,897,483	23,519,082	24,164,648	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
252	TOTALS - CAPITAL EXPENDITURES -												
253	b INTEREST EXPENSE	10,300,330	9,149,961	7,990,546	6,833,654	5,679,430	4,521,318	3,357,392	2,186,282	1,465,302	878,565	433,816	138,434
254	TOTALS - EXPENSE EXPENDITURES -												
255	c AMORTIZATION OF PRINCIPAL	46,968,001	31,763,925	15,758,608	0	0	0	0	0	0	0	0	0
256	TOTALS - EXPENSE EXPENDITURES -												
257	d INTEREST EXPENSE	3,649,223	1,823,174	600,403	0	0	0	0	0	0	0	0	0
259	TOTALS - CONSERVATION PRINCIPAL COSTS	67,626,976	52,964,505	37,496,435	22,299,742	22,897,483	23,519,082	24,164,648	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
261	TOTALS - INTEREST EXPENSE	13,949,553	10,973,135	8,590,949	6,833,654	5,679,430	4,521,318	3,357,392	2,186,282	1,465,302	878,565	433,816	138,434
263	PERCENTAGE OF TOTAL PRINCIPAL PAID												
264	(Capital and Expense Expenditures)	6.22%	4.87%	3.45%	2.05%	2.11%	2.16%	2.22%	1.36%	1.12%	0.86%	0.58%	0.27%
266	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID	78.96%	83.83%	87.28%	89.33%	91.44%	93.60%	95.82%	97.18%	98.30%	99.16%	99.74%	100.01%
267	(Capital and Expense Expenditures)												

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Scenario = Capitalized costs are amortized and financed over 15 years,
Expensed costs are deferred and financed over 7-years

	Inflation Adjustment	Capitalized Conservation Deferral/ Maturity # of Years	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	15	0.0468	4	0.0357
FY 2011	1.020232			5	0.0369
FY 2012	1.041582			6	0.0381
FY 2013	1.062788			7	0.0393
FY 2014	1.084313			15	0.0468
FY 2015	1.106094				

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2010 Conservation Resources Selected:						
1	2001 Conservation - 2010$$	19.2	29,059.6	72.4	29,132.0	
	Capitalized Costs - Debt Service Requirements					$6,825.13
	Expensed Costs /Deferral Debt Service Requirements					$4,829,091.79
3	2006 Conservation - 2010$$	31.0	39,428.0	16,435.8	55,863.8	
	Capitalized Costs - Debt Service Requirements					$1,549,397.68
	Expensed Costs /Deferral Debt Service Requirements					$6,552,100.89
4	2003 Conservation - 2010$$	27.6	30,621.2	27,501.3	58,122.5	
	Capitalized Costs - Debt Service Requirements					2,592,538.87
	Expensed Costs /Deferral Debt Service Requirements					$5,088,596.73
5	2002 Conservation - 2010$$	26.6	26,137.0	34,587.9	60,724.9	
	Capitalized Costs - Debt Service Requirements					3,260,590.41
	Expensed Costs /Deferral Debt Service Requirements					$4,343,417.40
6	2005 Conservation - 2010$$	20.6	31,616.2	16,720.6	48,336.8	
	Capitalized Costs - Debt Service Requirements					1,576,245.68
	Expensed Costs /Deferral Debt Service Requirements					$5,253,944.72
8	2008 Conservation - 2010$$	30.3	65,409.8	9,139.1	74,548.9	
	Capitalized Costs - Debt Service Requirements					861,540.07
	Expensed Costs /Deferral Debt Service Requirements					$10,869,727.33
9	2004 Conservation - 2010$$	20.1	27,250.7	22,724.9	49,975.6	
	Capitalized Costs - Debt Service Requirements					2,142,269.15
	Expensed Costs /Deferral Debt Service Requirements					$4,528,490.81
10	2007 Conservation - 2010$$	27.9	59,178.2	11,453.5	70,631.7	
	Capitalized Costs - Debt Service Requirements					1,079,717.83
	Expensed Costs /Deferral Debt Service Requirements					$9,834,167.02
12	2009 Conservation - 2010$$	28.4	69,492.8	20,411.5	89,904.3	
	Capitalized Costs - Debt Service Requirements					1,924,185.66
	Expensed Costs /Deferral Debt Service Requirements					$11,548,235.70
	Totals - FY 2010	231.7	378,193.5	159,047.0	537,240.5	

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Scenario = Capitalized costs are amortized and financed over 15 years, Expensed costs are deferred and financed over 7-years

Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2010 Conservation Resources Selected:											
1	**2001 Conservation - 2010$$**										
Capital		6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Expense		4,829.1	4,829.1	4,829.1	4,829.1	4,829.1	4,829.1	4,829.1	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
Capital		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4
Expense		6,552.1	6,552.1	6,552.1	6,552.1	6,552.1	6,552.1	6,552.1	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
Capital		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5
Expense		5,088.6	5,088.6	5,088.6	5,088.6	5,088.6	5,088.6	5,088.6	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
Capital		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6
Expense		4,343.4	4,343.4	4,343.4	4,343.4	4,343.4	4,343.4	4,343.4	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
Capital		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2
Expense		5,253.9	5,253.9	5,253.9	5,253.9	5,253.9	5,253.9	5,253.9	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
Capital		861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5
Expense		10,869.7	10,869.7	10,869.7	10,869.7	10,869.7	10,869.7	10,869.7	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
Capital		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3
Expense		4,528.5	4,528.5	4,528.5	4,528.5	4,528.5	4,528.5	4,528.5	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
Capital		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7
Expense		9,834.2	9,834.2	9,834.2	9,834.2	9,834.2	9,834.2	9,834.2	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2
Expense		11,548.2	11,548.2	11,548.2	11,548.2	11,548.2	11,548.2	11,548.2	0.0	0.0	0.0

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Expensed costs are deferred and financed over 7-years

Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
		11	12	13	14	15					
FY 2010 Conservation Resources Selected:											
1	**2001 Conservation - 2010$$**										
Capital		6.8	6.8	6.8	6.8	6.8	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**										
Capital		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**										
Capital		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**										
		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**										
Capital		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**										
Capital		861.5	861.5	861.5	861.5	861.5	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**										
Capital		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**										
Capital		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	0.0	0.0	0.0	0.0	0.0
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$		87,986.2	42,697.1	130,683.3	
13	**2015 Conservation - 2011$$**	39.5	89,766.3	43,560.9	133,327.2	
	Capitalized Costs - Debt Service Requirements					4,106,472.29
	Expensed Costs /Deferral Debt Service Requirements					$14,917,263.23
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$		88,570.4	43,552.0	132,122.4	
14	**2014 Conservation - 2012$$**	39.5	92,253.3	45,363.0	137,616.3	
	Capitalized Costs - Debt Service Requirements					4,276,355.69
	Expensed Costs /Deferral Debt Service Requirements					$15,330,550.10
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$		89,602.1	44,431.3	134,033.4	
15	**2013 Conservation - 2013$$**	39.5	95,228.0	47,221.1	142,449.1	
	Capitalized Costs - Debt Service Requirements					4,451,518.19
	Expensed Costs /Deferral Debt Service Requirements					$15,824,882.42
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$		90,647.7	45,318.6	135,966.3	
16	**2012 Conservation - 2014$$**	39.5	98,290.5	49,139.5	147,430.0	
	Capitalized Costs - Debt Service Requirements					4,632,365.15
	Expensed Costs /Deferral Debt Service Requirements					$16,333,805.24
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$		86,161.8	38,806.9	124,968.7	
17	**2011 Conservation - 2015$$**	34.9	95,303.1	42,924.1	138,227.2	
	Capitalized Costs - Debt Service Requirements					4,046,441.35
	Expensed Costs /Deferral Debt Service Requirements					$15,837,362.45

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		387,255.6	160,340.4	547,596.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	849,034.7		138,607.2	987,641.9
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	849,034.7	387,255.6	298,947.6	1,535,237.9

Principal Expense Costs	849,034.7
Interest Paid Expensed Costs	138,607.2
Principal Capital Costs	387,255.6
Interest Paid Capital Costs	160,340.4
Totals	1,535,237.9

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5
Expense		0.0	14,917.3	14,917.3	14,917.3	14,917.3	14,917.3	14,917.3	14,917.3	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4
Expense		0.0	0.0	15,330.6	15,330.6	15,330.6	15,330.6	15,330.6	15,330.6	15,330.6	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5
Expense		0.0	0.0	0.0	15,824.9	15,824.9	15,824.9	15,824.9	15,824.9	15,824.9	15,824.9
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4
Expense		0.0	0.0	0.0	0.0	16,333.8	16,333.8	16,333.8	16,333.8	16,333.8	16,333.8
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense		0.0	0.0	0.0	0.0	0.0	15,837.4	15,837.4	15,837.4	15,837.4	15,837.4
TCC		14,993.2	19,099.7	23,376.1	27,827.6	32,460.0	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4
TEC		62,847.7	77,765.0	93,095.6	108,920.5	125,254.3	141,091.7	141,091.7	78,244.0	63,326.7	47,996.1
TDSR		77,840.9	96,864.7	116,471.7	136,748.1	157,714.3	177,598.1	177,598.1	114,750.4	99,833.1	84,502.5

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Debt Service Requirements - Principal and Interest ($ 000)

X	Y / Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Res. Stack Order	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
	11	12	13	14	15					
FY 2011 Conservation Resources Selected										
13	**2015 Conservation - 2011$$**									
Capital	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	0.0	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected										
14	**2014 Conservation - 2012$$**									
Capital	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	0.0	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected										
15	**2013 Conservation - 2013$$**									
Capital	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	0.0	0.0
Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2014 Conservation Resources Selected										
16	**2012 Conservation - 2014$$**									
Capital	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	0.0
Expense	16,333.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2015 Conservation Resources Selected										
17	**2011 Conservation - 2015$$**									
Capital	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense	15,837.4	15,837.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4
TEC	32,171.2	15,837.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR	68,677.6	52,343.8	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010 Conservation Resources Selected										
FY2010	Conservation (9) Res. Selected - Total MW =	231.7								
1	**2001 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	72,400	3,437	3,598	3,766	3,942	4,127	4,320	4,522	4,734
	b Capital Expenditures - Interest Expense	29,975	3,388	3,227	3,059	2,883	2,698	2,505	2,303	2,091
	c Expense Expenditures - Amort. of Principal	29,059,600	3,687,050	3,831,951	3,982,546	4,139,061	4,301,726	4,470,782	4,646,484	0
	d Expense Expenditures - Interest Expense	4,744,042	1,142,042	997,141	846,546	690,031	527,366	358,309	182,607	0
3	**2006 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,435,800	780,203	816,716	854,938	894,949	936,833	980,677	1,026,573	1,074,616
	b Capital Expenditures - Interest Expense	6,805,165	769,195	732,682	694,460	654,449	612,565	568,721	522,825	474,782
	c Expense Expenditures - Amort. of Principal	39,428,000	5,002,581	5,199,182	5,403,510	5,615,868	5,836,571	6,065,949	6,304,339	0
	d Expense Expenditures - Interest Expense	6,436,706	1,549,520	1,352,919	1,148,591	936,233	715,530	486,152	247,761	0
4	**2003 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	27,501,300	1,305,478	1,366,575	1,430,530	1,497,479	1,567,561	1,640,923	1,717,718	1,798,107
	b Capital Expenditures - Interest Expense	11,386,782	1,287,061	1,225,964	1,162,009	1,095,060	1,024,978	951,616	874,821	794,432
	c Expense Expenditures - Amort. of Principal	30,621,200	3,885,184	4,037,872	4,196,560	4,361,485	4,532,890	4,711,033	4,896,176	0
	d Expense Expenditures - Interest Expense	4,998,976	1,203,413	1,050,725	892,037	727,112	555,706	377,563	192,420	0
5	**2002 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	34,587,900	1,641,876	1,718,716	1,799,152	1,883,352	1,971,493	2,063,759	2,160,343	2,261,448
	b Capital Expenditures - Interest Expense	14,320,958	1,618,714	1,541,874	1,461,438	1,377,238	1,289,097	1,196,831	1,100,247	999,143
	c Expense Expenditures - Amort. of Principal	26,137,000	3,316,233	3,446,561	3,582,011	3,722,784	3,869,090	4,021,145	4,179,176	0
	d Expense Expenditures - Interest Expense	4,266,922	1,027,184	896,856	761,406	620,633	474,328	322,273	164,242	0
6	**2005 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,720,600	793,722	830,868	869,753	910,457	953,067	997,670	1,044,361	1,093,237
	b Capital Expenditures - Interest Expense	6,923,083	782,524	745,378	706,493	665,789	623,179	578,576	531,885	483,009
	c Expense Expenditures - Amort. of Principal	31,616,200	4,011,428	4,169,077	4,332,922	4,503,206	4,680,182	4,864,113	5,055,272	0
	d Expense Expenditures - Interest Expense	5,161,414	1,242,517	1,084,868	921,023	750,739	573,763	389,832	198,672	0
8	**2008 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	9,139,100	433,830	454,133	475,387	497,635	520,924	545,303	570,824	597,538
	b Capital Expenditures - Interest Expense	3,784,002	427,710	407,407	386,153	363,905	340,616	316,237	290,716	264,002
	c Expense Expenditures - Amort. of Principal	65,409,800	8,299,122	8,625,277	8,964,251	9,316,546	9,682,686	10,063,217	10,458,701	0
	d Expense Expenditures - Interest Expense	10,678,291	2,570,605	2,244,450	1,905,476	1,553,181	1,187,041	806,511	411,027	0

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Debt Service Components - (whole dollars)

Res. Stack Order		Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected														
FY2010 Conservation (9) Res. Selected - Total MW =														
1		**2001 Conservation - 2010$$**												
	a	Capital Expenditures - Amort. of Principal	4,955	5,187	5,430	5,684	5,950	6,228	6,520	0	0	0	0	0
	b	Capital Expenditures - Interest Expense	1,870	1,638	1,395	1,141	875	597	305	0	0	0	0	0
	c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
3		**2006 Conservation - 2010$$**												
	a	Capital Expenditures - Amort. of Principal	1,124,908	1,177,554	1,232,662	1,290,351	1,350,739	1,413,954	1,480,127	0	0	0	0	0
	b	Capital Expenditures - Interest Expense	424,490	371,844	316,735	259,046	198,658	135,443	69,270	0	0	0	0	0
	c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
4		**2003 Conservation - 2010$$**												
	a	Capital Expenditures - Amort. of Principal	1,882,259	1,970,348	2,062,561	2,159,089	2,260,133	2,365,907	2,476,632	0	0	0	0	0
	b	Capital Expenditures - Interest Expense	710,280	622,191	529,978	433,450	332,405	226,631	115,906	0	0	0	0	0
	c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
5		**2002 Conservation - 2010$$**												
	a	Capital Expenditures - Amort. of Principal	2,367,284	2,478,073	2,594,046	2,715,448	2,842,531	2,975,561	3,114,818	0	0	0	0	0
	b	Capital Expenditures - Interest Expense	893,307	782,518	666,545	545,143	418,060	285,030	145,773	0	0	0	0	0
	c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
6		**2005 Conservation - 2010$$**												
	a	Capital Expenditures - Amort. of Principal	1,144,400	1,197,958	1,254,022	1,312,710	1,374,145	1,438,455	1,505,775	0	0	0	0	0
	b	Capital Expenditures - Interest Expense	431,845	378,287	322,223	263,535	202,100	137,790	70,470	0	0	0	0	0
	c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
8		**2008 Conservation - 2010$$**												
	a	Capital Expenditures - Amort. of Principal	625,503	654,777	685,420	717,498	751,077	786,227	823,024	0	0	0	0	0
	b	Capital Expenditures - Interest Expense	236,037	206,763	176,120	144,042	110,463	75,313	38,518	0	0	0	0	0
	c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
	d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	A	B	C	D	E	F	G	H	I	J	K	L
45	Res. Stack Order		Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
47	9		2004 Conservation - 2010$$									
48		a	Capital Expenditures - Amort. of Principal	22,724,900	1,078,744	1,129,229	1,182,077	1,237,398	1,295,308	1,355,929	1,419,386	1,485,813
49		b	Capital Expenditures - Interest Expense	9,409,137	1,063,525	1,013,040	960,192	904,871	846,961	786,340	722,883	656,456
50		c	Expense Expenditures - Amort. of Principal	27,250,700	3,457,538	3,593,420	3,734,641	3,881,413	4,033,952	4,192,486	4,357,250	0
51		d	Expense Expenditures - Interest Expense	4,448,736	1,070,953	935,071	793,850	647,078	494,539	336,005	171,240	0
52	10		2007 Conservation - 2010$$									
53		a	Capital Expenditures - Amort. of Principal	11,453,500	543,694	569,139	595,775	623,657	652,844	683,397	715,380	748,860
54		b	Capital Expenditures - Interest Expense	4,742,268	536,024	510,579	483,943	456,061	426,874	396,321	364,338	330,858
55		c	Expense Expenditures - Amort. of Principal	59,178,200	7,508,464	7,803,546	8,110,226	8,428,958	8,760,216	9,104,492	9,462,298	0
56		d	Expense Expenditures - Interest Expense	9,660,968	2,325,703	2,030,621	1,723,941	1,405,209	1,073,951	729,675	371,868	0
57	12		2009 Conservation - 2010$$									
58		a	Capital Expenditures - Amort. of Principal	20,411,500	968,928	1,014,274	1,061,742	1,111,431	1,163,446	1,217,895	1,274,893	1,334,557
59		b	Capital Expenditures - Interest Expense	8,451,286	955,258	909,912	862,444	812,755	760,740	706,291	649,293	589,628
60		c	Expense Expenditures - Amort. of Principal	69,492,800	8,817,169	9,163,684	9,523,816	9,898,102	10,287,098	10,691,380	11,111,551	0
61		d	Expense Expenditures - Interest Expense	11,344,850	2,731,067	2,384,552	2,024,420	1,650,134	1,261,138	856,855	436,684	0
62	FY 2011		Conservation Resources Selected									
63	13		2015 Conservation - 2011$$									
64		a	Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
65		b	Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
66		c	Expense Expenditures - Amort. of Principal	89,766,300	0	11,389,447	11,837,053	12,302,249	12,785,727	13,288,206	13,810,434	14,353,184
67		d	Expense Expenditures - Interest Expense	14,654,543	0	3,527,816	3,080,210	2,615,014	2,131,536	1,629,057	1,106,830	564,080
68	FY 2012		Conservation Resources Selected									
69	14		2014 Conservation - 2012$$									
70		a	Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
71		b	Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
72		c	Expense Expenditures - Amort. of Principal	92,253,300	0	0	11,704,995	12,165,002	12,643,086	13,139,959	13,656,360	14,193,055
73		d	Expense Expenditures - Interest Expense	15,060,551	0	0	3,625,555	3,165,548	2,687,464	2,190,591	1,674,190	1,137,495
74	FY 2013		Conservation Resources Selected									
75	15		2013 Conservation - 2013$$									
76		a	Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
77		b	Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
78		c	Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	12,082,422	12,557,261	13,050,761	13,563,656	14,096,709
79		d	Expense Expenditures - Interest Expense	15,546,177	0	0	0	3,742,460	3,267,621	2,774,121	2,261,226	1,728,174
80	FY 2014		Conservation Resources Selected									
81	16		2012 Conservation - 2014$$									
82		a	Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
83		b	Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
84		c	Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	12,470,988	12,961,098	13,470,469	13,999,859
85		d	Expense Expenditures - Interest Expense	16,046,138	0	0	0	0	3,862,817	3,372,707	2,863,336	2,333,946

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
47	9	2004 Conservation - 2010$$												
48		a Capital Expenditures - Amort. of Principal	1,555,349	1,628,140	1,704,337	1,784,100	1,867,596	1,954,999	2,046,495	0	0	0	0	0
49		b Capital Expenditures - Interest Expense	586,920	514,129	437,932	358,169	274,673	187,270	95,776	0	0	0	0	0
50		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
51		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
52	10	2007 Conservation - 2010$$												
53		a Capital Expenditures - Amort. of Principal	783,907	820,594	858,997	899,198	941,281	985,333	1,031,444	0	0	0	0	0
54		b Capital Expenditures - Interest Expense	295,811	259,124	220,721	180,520	138,437	94,385	48,272	0	0	0	0	0
55		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
56		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
57	12	2009 Conservation - 2010$$												
58		a Capital Expenditures - Amort. of Principal	1,397,014	1,462,394	1,530,834	1,602,478	1,677,474	1,755,980	1,838,160	0	0	0	0	0
59		b Capital Expenditures - Interest Expense	527,171	461,791	393,351	321,708	246,712	168,206	86,026	0	0	0	0	0
60		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
61		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
62	FY 2011	Conservation Resources Selected												
63	13	2015 Conservation - 2011$$												
64		a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
65		b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
66		c Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
67		d Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
68	FY 2012	Conservation Resources Selected												
69	14	2014 Conservation - 2012$$												
70		a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
71		b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
72		c Expense Expenditures - Amort. of Principal	14,750,843	0	0	0	0	0	0	0	0	0	0	0
73		d Expense Expenditures - Interest Expense	579,708	0	0	0	0	0	0	0	0	0	0	0
74	FY 2013	Conservation Resources Selected												
75	15	2013 Conservation - 2013$$												
76		a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
77		b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
78		c Expense Expenditures - Amort. of Principal	14,650,709	15,226,482	0	0	0	0	0	0	0	0	0	0
79		d Expense Expenditures - Interest Expense	1,174,174	598,401	0	0	0	0	0	0	0	0	0	0
80	FY 2014	Conservation Resources Selected												
81	16	2012 Conservation - 2014$$												
82		a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
83		b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
84		c Expense Expenditures - Amort. of Principal	14,550,054	15,121,871	15,716,161	0	0	0	0	0	0	0	0	0
85		d Expense Expenditures - Interest Expense	1,783,752	1,211,935	617,645	0	0	0	0	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
90	FY 2015	Conservation Resources Selected									
91	17	2011 Conservation - 2015$$									
92		a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
93		b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
94		c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	12,091,950	12,567,164	13,061,053
95		d Expense Expenditures - Interest Expense	15,558,438	0	0	0	0	0	3,745,412	3,270,198	2,776,309

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

Row	DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
101	TOTALS - CAPITAL EXPENDITURES -	387,255,600								
102	AMORTIZATION OF PRINCIPAL	387,255,600	7,549,912	9,971,070	12,591,084	15,421,915	18,476,297	21,378,581	22,379,100	23,426,441
103	TOTALS - CAPITAL EXPENDITURES -	160,341,348								
104	INTEREST EXPENSE	160,341,348	7,443,399	9,128,713	10,785,055	12,405,742	13,983,725	15,127,882	14,127,363	13,080,022
105	TOTALS - EXPENSE EXPENDITURES -	849,034,700								
106	AMORTIZATION OF PRINCIPAL	849,034,700	47,984,769	61,260,017	75,372,531	90,417,096	106,441,473	122,716,571	127,539,330	69,703,860
107	TOTALS - EXPENSE EXPENDITURES -	138,606,752								
108	INTEREST EXPENSE	138,606,752	14,863,004	16,505,019	17,723,055	18,503,372	18,812,800	18,375,063	13,552,301	8,540,004
109		1,236,290,300								
110	TOTALS - CONSERVATION PRINCIPAL COSTS	1,236,290,300	55,534,681	71,231,087	87,963,615	105,839,011	124,917,770	144,095,152	149,918,430	93,130,301
111		298,948,100								
112	TOTALS - INTEREST EXPENSE	298,948,100	22,306,403	25,633,732	28,508,110	30,909,114	32,796,525	33,502,945	27,679,664	21,620,026
114	PERCENTAGE OF TOTAL PRINCIPAL PAID	100.00%	4.49%	5.76%	7.12%	8.56%	10.10%	11.66%	12.13%	7.53%
115	(Capital and Expense Expenditures)									
117	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		4.49%	10.25%	17.37%	25.93%	36.03%	47.69%	59.82%	67.35%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 47.69%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (NOMINAL DOLLARS) =	138,606,752
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES - YEAR OF INVESTMENT) =	$849,034,700
INTEREST AS A PECENTAGE OF ORIGINAL INVESTMENT COSTS =	16.33%

INTEREST (NOMINAL DOLLARS) EXPENDITURES BY PERIOD

	Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
Interest on Capital and Expense Expenditures	47,940,135	125,716,694	173,656,829	125,291,271	298,948,100

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2015	Conservation Resources Selected												
17	2011 Conservation - 2015$$												
	a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
	b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
	c Expense Expenditures - Amort. of Principal	13,574,354	14,107,826	14,662,263	15,238,490	0	0	0	0	0	0	0	0
	d Expense Expenditures - Interest Expense	2,263,009	1,729,537	1,175,100	598,873	0	0	0	0	0	0	0	0

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
TOTALS - CAPITAL EXPENDITURES - AMORTIZATION OF PRINCIPAL	24,522,798	25,670,466	26,871,840	28,129,445	29,445,903	30,823,971	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
TOTALS - CAPITAL EXPENDITURES - INTEREST EXPENSE	11,983,664	10,835,996	9,634,621	8,377,017	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
TOTALS - EXPENSE EXPENDITURES - AMORTIZATION OF PRINCIPAL	57,525,960	44,456,179	30,378,424	15,238,490	0	0	0	0	0	0	0	0
TOTALS - EXPENSE EXPENDITURES - INTEREST EXPENSE	5,800,643	3,539,873	1,792,745	598,873	0	0	0	0	0	0	0	0
TOTALS - CONSERVATION PRINCIPAL COSTS	82,048,758	70,126,645	57,250,264	43,367,935	29,445,903	30,823,971	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
TOTALS - INTEREST EXPENSE	17,784,307	14,375,869	11,427,366	8,975,890	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	6.64%	5.67%	4.63%	3.51%	2.38%	2.49%	2.61%	1.52%	1.26%	0.97%	0.66%	0.31%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID	73.99%	79.66%	84.29%	87.80%	90.18%	92.67%	95.28%	96.80%	98.06%	99.03%	99.69%	100.00%

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Debt Service Components - (whole dollars)

Row	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
138	INFLATION ADJUSTED ANALYSIS									
139	FY 2010 Conservation Resources Selected -									
140	Debt Service in Nominal Year Dollars									
141	TOTALS - CAPITAL EXPENDITURES -	159,047,000								
142	a AMORTIZATION OF PRINCIPAL	159,047,000	7,549,912	7,903,248	8,273,120	8,660,300	9,065,603	9,489,873	9,934,000	10,398,910
143	TOTALS - CAPITAL EXPENDITURES -	65,852,656								
144	b INTEREST EXPENSE	65,852,656	7,443,399	7,090,063	6,720,191	6,333,011	5,927,708	5,503,438	5,059,311	4,594,401
145	TOTALS - EXPENSE EXPENDITURES -	319,015,300								
146	c AMORTIZATION OF PRINCIPAL	319,015,300	40,476,305	42,067,024	43,720,257	45,438,465	47,224,195	49,080,105	51,008,949	0
147	TOTALS - EXPENSE EXPENDITURES -	61,740,905								
148	d INTEREST EXPENSE	61,740,905	14,863,004	12,977,203	11,017,290	8,980,350	6,863,362	4,663,175	2,376,521	0
150	FY 2010 Deflator values		1.000000	1.020232	1.041582	1.062788	1.084313	1.106094	1.128012	1.150234
151	FY 2010 Conservation Resources Selected -									
152	Debt service in FY2010 Purchasing Power Dollars									
153	TOTALS - CAPITAL EXPENDITURES -									
154	a AMORTIZATION OF PRINCIPAL	136,462,442	7,549,912	7,746,520	7,942,841	8,148,662	8,360,688	8,579,626	8,806,644	9,040,691
155	TOTALS - CAPITAL EXPENDITURES -									
156	b INTEREST EXPENSE	59,786,673	7,443,399	6,949,461	6,451,908	5,958,866	5,466,787	4,975,561	4,485,157	3,994,319
157	TOTALS - EXPENSE EXPENDITURES -									
158	c AMORTIZATION OF PRINCIPAL	299,582,842	40,476,305	41,232,802	41,974,858	42,754,025	43,552,180	44,372,454	45,220,218	0
159	TOTALS - EXPENSE EXPENDITURES -									
160	d INTEREST EXPENSE	59,262,524	14,863,004	12,719,855	10,577,458	8,449,804	6,329,687	4,215,894	2,106,822	0
162	FY 2011 Conservation Resources Selected									
163	13 2015 Conservation - 2011$$ -									
164	Debt Service in Nominal Year Dollars									
165	a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
166	b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
167	c Expense Expenditures - Amort. of Principal	89,766,300	0	11,389,447	11,837,053	12,302,249	12,785,727	13,288,206	13,810,434	14,353,184
168	d Expense Expenditures - Interest Expense	14,654,543	0	3,527,816	3,080,210	2,615,014	2,131,536	1,629,057	1,106,830	564,080
170	FY 2011 Deflator values			1.000000	1.020927	1.041712	1.062810	1.084159	1.105643	1.127424
171	13 2015 Conservation - 2011$$ -									
172	Debt service in FY2011 Purchasing Power Dollars									
173	a Capital Expenditures - Amort. of Principal	37,389,568	0	2,067,822	2,120,226	2,175,168	2,231,766	2,290,208	2,350,806	2,413,282
174	b Capital Expenditures - Interest Expense	16,376,020	0	2,038,650	1,902,071	1,766,873	1,632,022	1,497,494	1,363,297	1,229,067
175	c Expense Expenditures - Amort. of Principal	84,302,136	0	11,389,447	11,594,417	11,809,645	12,030,115	12,256,695	12,490,862	12,730,955
176	d Expense Expenditures - Interest Expense	14,064,758	0	3,527,816	3,017,072	2,510,304	2,005,566	1,502,600	1,001,074	500,326
178	FY 2012 Conservation Resources Selected									
179	14 2014 Conservation - 2012$$ -									
180	Debt Service in Nominal Year Dollars									
181	a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
182	b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
183	c Expense Expenditures - Amort. of Principal	92,253,300	0	0	11,704,995	12,165,002	12,643,086	13,139,959	13,656,360	14,193,055
184	d Expense Expenditures - Interest Expense	15,060,551	0	0	3,625,555	3,165,548	2,687,464	2,190,591	1,674,190	1,137,495
186	FY 2012 Deflator values				1.000000	1.020359	1.041025	1.061937	1.082980	1.104314
187	14 2014 Conservation - 2012$$ -									
188	Debt service in FY2012 Purchasing Power Dollars									
189	a Capital Expenditures - Amort. of Principal	38,983,476	0	0	2,153,368	2,209,169	2,266,650	2,326,004	2,387,551	2,451,005
190	b Capital Expenditures - Interest Expense	17,067,371	0	0	2,122,988	1,981,862	1,841,182	1,700,935	1,561,142	1,421,405
191	c Expense Expenditures - Amort. of Principal	86,705,520	0	0	11,704,995	11,922,276	12,144,844	12,373,577	12,609,984	12,852,373
192	d Expense Expenditures - Interest Expense	14,463,011	0	0	3,625,555	3,102,387	2,581,556	2,062,826	1,545,910	1,030,047

Row	A	B	C	M	N	O	P	Q	R	S	T	U	V	W	X
1							Section 7(b)(2) Rate Test Study and Documentation								
2							Alternative Conservation Expense Accounting and Financing Treatments								
3							WP-10 Final Rate Proposal								
5							Scenario = Capitalized costs amortized / financed over 15 years,								
6							= Expensed costs are deferred and amortized / financed over 7 - years								
8							Debt Service Components - (whole dollars)								
136			Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
138									INFLATION ADJUSTED ANALYSIS						
139	FY 2010 Conservation Resources Selected -														
140			Debt Service in Nominal Year Dollars												
141	TOTALS - CAPITAL EXPENDITURES -														
142		a	AMORTIZATION OF PRINCIPAL	10,885,579	11,395,025	11,928,309	12,486,556	13,070,926	13,682,644	14,322,995	0	0	0	0	0
143	TOTALS - CAPITAL EXPENDITURES -														
144		b	INTEREST EXPENSE	4,107,731	3,598,285	3,065,000	2,506,754	1,922,383	1,310,665	670,316	0	0	0	0	0
145	TOTALS - EXPENSE EXPENDITURES -														
146		c	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
147	TOTALS - EXPENSE EXPENDITURES -														
148		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
150	FY 2010 Deflator values			1.173067	1.196596	1.221639	1.246588	1.270863	1.295179	1.319573	1.343839	1.368342	1.393708	1.419537	1.445453
151	FY 2010 Conservation Resources Selected -														
152			Debt service in FY2010 Purchasing Power Dollars												
153	TOTALS - CAPITAL EXPENDITURES -														
154		a	AMORTIZATION OF PRINCIPAL	9,279,588	9,522,867	9,764,185	10,016,586	10,285,079	10,564,288	10,854,265	0	0	0	0	0
155	TOTALS - CAPITAL EXPENDITURES -														
156		b	INTEREST EXPENSE	3,501,702	3,007,101	2,508,924	2,010,892	1,512,660	1,011,957	507,979	0	0	0	0	0
157	TOTALS - EXPENSE EXPENDITURES -														
158		c	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
159	TOTALS - EXPENSE EXPENDITURES -														
160		d	INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0
162	FY 2011 Conservation Resources Selected														
163	13		2015 Conservation - 2011$$ -												
164			Debt Service in Nominal Year Dollars												
165		a	Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
166		b	Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
167		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
168		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
170	FY 2011 Deflator values			1.149804	1.172867	1.197413	1.221867	1.245661	1.269495	1.293405	1.317190	1.341207	1.366070	1.391386	1.416789
171	13		2015 Conservation - 2011$$ -												
172			Debt service in FY2011 Purchasing Power Dollars												
173		a	Capital Expenditures - Amort. of Principal	2,477,053	2,541,992	2,606,410	2,673,785	2,745,455	2,819,985	2,897,390	2,978,220	0	0	0	0
174		b	Capital Expenditures - Interest Expense	1,094,401	959,234	823,044	687,033	551,167	414,744	277,542	139,381	0	0	0	0
175		c	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
176		d	Expense Expenditures - Interest Expense	0	0	0	0	0	0	0	0	0	0	0	0
178	FY 2012 Conservation Resources Selected														
179	14		2014 Conservation - 2012$$ -												
180			Debt Service in Nominal Year Dollars												
181		a	Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
182		b	Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
183		c	Expense Expenditures - Amort. of Principal	14,750,843	0	0	0	0	0	0	0	0	0	0	0
184		d	Expense Expenditures - Interest Expense	579,708	0	0	0	0	0	0	0	0	0	0	0
186	FY 2012 Deflator values			1.126236	1.148826	1.172869	1.196822	1.220128	1.243473	1.266893	1.290190	1.313715	1.338068	1.362866	1.387748
187	14		2014 Conservation - 2012$$ -												
188			Debt service in FY2012 Purchasing Power Dollars												
189		a	Capital Expenditures - Amort. of Principal	2,515,771	2,581,724	2,647,148	2,715,576	2,788,366	2,864,063	2,942,678	3,024,772	3,109,631	0	0	0
190		b	Capital Expenditures - Interest Expense	1,281,263	1,140,646	998,915	857,516	716,476	574,978	432,789	289,743	145,531	0	0	0
191		c	Expense Expenditures - Amort. of Principal	13,097,471	0	0	0	0	0	0	0	0	0	0	0
192		d	Expense Expenditures - Interest Expense	514,730	0	0	0	0	0	0	0	0	0	0	0
193									Page 14 of 18						

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Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are deferred and amortized / financed over 7 - years

Debt Service Components - (whole dollars)

Row	A	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
196					INFLATION ADJUSTED ANALYSIS						
197	FY 2013	Conservation Resources Selected									
198	15	2013 Conservation - 2013$$ -									
199		Debt Service in Nominal Year Dollars									
200		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
201		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
202		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	12,082,422	12,557,261	13,050,761	13,563,656	14,096,709
203		d Expense Expenditures - Interest Expense	15,546,177	0	0	0	3,742,460	3,267,621	2,774,121	2,261,226	1,728,174
205	FY 2013 Deflator values										
206	15	2013 Conservation - 2013$$ -					1.000000	1.020253	1.040748	1.061371	1.082280
207		Debt service in FY2013 Purchasing Power Dollars									
208		a Capital Expenditures - Amort. of Principal	40,613,111	0	0	0	2,241,571	2,299,896	2,360,121	2,422,570	2,486,953
209		b Capital Expenditures - Interest Expense	17,773,934	0	0	0	2,209,947	2,063,255	1,917,109	1,771,550	1,626,139
210		c Expense Expenditures - Amort. of Principal	89,531,786	0	0	0	12,082,422	12,307,987	12,539,790	12,779,373	13,025,011
211		d Expense Expenditures - Interest Expense	14,933,266	0	0	0	3,742,460	3,202,756	2,665,507	2,130,477	1,596,790
213	FY 2014	Conservation Resources Selected									
214	16	2012 Conservation - 2014$$ -									
215		Debt Service in Nominal Year Dollars									
216		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
217		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
218		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	12,470,988	12,961,098	13,470,469	13,999,859
219		d Expense Expenditures - Interest Expense	16,046,138	0	0	0	0	3,862,817	3,372,707	2,863,336	2,333,946
221	FY 2014 Deflator values										
222	16	2012 Conservation - 2014$$ -						1.000000	1.020087	1.040301	1.060795
223		Debt service in FY2014 Purchasing Power Dollars									
224		a Capital Expenditures - Amort. of Principal	42,298,028	0	0	0	0	2,332,636	2,393,721	2,457,058	2,522,358
225		b Capital Expenditures - Interest Expense	18,503,867	0	0	0	0	2,299,729	2,147,426	1,995,850	1,844,522
226		c Expense Expenditures - Amort. of Principal	92,424,596	0	0	0	0	12,470,988	12,705,875	12,948,626	13,197,516
227		d Expense Expenditures - Interest Expense	15,416,928	0	0	0	0	3,862,817	3,306,293	2,752,411	2,200,186
229	FY 2015	Conservation Resources Selected									
230	17	2011 Conservation - 2015$$ -									
231		Debt Service in Nominal Year Dollars									
232		a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
233		b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
234		c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	12,091,950	12,567,164	13,061,053
235		d Expense Expenditures - Interest Expense	15,558,438	0	0	0	0	0	3,745,412	3,270,198	2,776,309
237	FY 2015 Deflator values								1.000000	1.019816	1.039906
238	17	2011 Conservation - 2015$$ -									
239		Debt service in FY2015 Purchasing Power Dollars									
240		a Capital Expenditures - Amort. of Principal	36,977,518	0	0	0	0	0	2,037,593	2,091,507	2,147,093
241		b Capital Expenditures - Interest Expense	16,169,437	0	0	0	0	0	2,008,848	1,876,308	1,744,067
242		c Expense Expenditures - Amort. of Principal	89,611,492	0	0	0	0	0	12,091,950	12,322,972	12,559,840
243		d Expense Expenditures - Interest Expense	14,949,708	0	0	0	0	0	3,745,412	3,206,655	2,669,769

	A	B	C	M	N	O	P	Q	R	S	T	U	V	W	X

Scenario = Capitalized costs amortized / financed over 15 years,
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Debt Service Components - (whole dollars)

Row		Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
196														
197	**FY 2013 Conservation Resources Selected**													
198	**15**	**2013 Conservation - 2013$$ -**												
199		**Debt Service in Nominal Year Dollars**												
200		a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
201		b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
202		c Expense Expenditures - Amort. of Principal	14,650,709	15,226,482	0	0	0	0	0	0	0	0	0	0
203		d Expense Expenditures - Interest Expense	1,174,174	598,401	0	0	0	0	0	0	0	0	0	0
205	FY 2013 Deflator values													
206	**15**	**2013 Conservation - 2013$$ -**	1.103764	1.125903	1.149466	1.172941	1.195782	1.218662	1.241615	1.264447	1.287502	1.311370	1.335673	1.360058
207		**Debt service in FY2013 Purchasing Power Dollars**												
208		a Capital Expenditures - Amort. of Principal	2,552,671	2,619,592	2,685,977	2,755,408	2,829,267	2,906,072	2,985,839	3,069,138	3,155,243	3,242,793	0	0
209		b Capital Expenditures - Interest Expense	1,480,364	1,334,139	1,186,707	1,039,768	893,417	746,720	599,426	451,388	302,242	151,763	0	0
210		c Expense Expenditures - Amort. of Principal	13,273,407	13,523,796	0	0	0	0	0	0	0	0	0	0
211		d Expense Expenditures - Interest Expense	1,063,791	531,485	0	0	0	0	0	0	0	0	0	0
213	**FY 2014 Conservation Resources Selected**													
214	**16**	**2012 Conservation - 2014$$ -**												
215		**Debt Service in Nominal Year Dollars**												
216		a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
217		b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
218		c Expense Expenditures - Amort. of Principal	14,550,054	15,121,871	15,716,161	0	0	0	0	0	0	0	0	0
219		d Expense Expenditures - Interest Expense	1,783,752	1,211,935	617,645	0	0	0	0	0	0	0	0	0
221	FY 2014 Deflator values		1.081853	1.103552	1.126648	1.149657	1.172044	1.194470	1.216967	1.239346	1.261944	1.285337	1.309158	1.333059
222	**16**	**2012 Conservation - 2014$$ -**												
223		**Debt service in FY2014 Purchasing Power Dollars**												
224		a Capital Expenditures - Amort. of Principal	2,589,010	2,656,885	2,724,213	2,794,633	2,869,543	2,947,442	3,028,345	3,112,830	3,200,159	3,288,958	3,380,237	0
225		b Capital Expenditures - Interest Expense	1,692,870	1,540,801	1,387,422	1,234,713	1,082,838	930,734	778,139	624,920	470,658	315,050	158,195	0
226		c Expense Expenditures - Amort. of Principal	13,449,197	13,702,908	13,949,486	0	0	0	0	0	0	0	0	0
227		d Expense Expenditures - Interest Expense	1,648,793	1,098,213	548,215	0	0	0	0	0	0	0	0	0
229	**FY 2015 Conservation Resources Selected**													
230	**17**	**2011 Conservation - 2015$$ -**												
231		**Debt Service in Nominal Year Dollars**												
232		a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
233		b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
234		c Expense Expenditures - Amort. of Principal	13,574,354	14,107,826	14,662,263	15,238,490	0	0	0	0	0	0	0	0
235		d Expense Expenditures - Interest Expense	2,263,009	1,729,537	1,175,100	598,873	0	0	0	0	0	0	0	0
237	FY 2015 Deflator values		1.060549	1.081821	1.104462	1.127018	1.148965	1.170948	1.193003	1.214941	1.237094	1.260027	1.283378	1.306808
238	**17**	**2011 Conservation - 2015$$ -**												
239		**Debt service in FY2015 Purchasing Power Dollars**												
240		a Capital Expenditures - Amort. of Principal	2,203,828	2,261,606	2,318,917	2,378,860	2,442,625	2,508,937	2,577,802	2,649,717	2,724,054	2,799,641	2,877,341	2,957,997
241		b Capital Expenditures - Interest Expense	1,611,593	1,478,792	1,344,804	1,211,536	1,079,190	946,760	814,011	680,850	546,871	411,752	275,621	138,434
242		c Expense Expenditures - Amort. of Principal	12,799,365	13,040,814	13,275,480	13,521,071	0	0	0	0	0	0	0	0
243		d Expense Expenditures - Interest Expense	2,133,809	1,598,728	1,063,957	531,378	0	0	0	0	0	0	0	0
244														

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Debt Service Components - (whole dollars)

SUMMARY TOTALS - INFLATION ADJUSTED VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
TOTALS - CAPITAL EXPENDITURES -	332,724,143								
a AMORTIZATION OF PRINCIPAL	332,724,143	7,549,912	9,814,342	12,216,435	14,774,570	17,491,636	19,987,273	20,516,136	21,061,382
TOTALS - CAPITAL EXPENDITURES -	145,677,302								
b INTEREST EXPENSE	145,677,302	7,443,399	8,988,111	10,476,967	11,917,548	13,302,975	14,247,373	13,053,304	11,859,519
TOTALS - EXPENSE EXPENDITURES -	742,158,372								
c AMORTIZATION OF PRINCIPAL	742,158,372	40,476,305	52,622,249	65,274,270	78,568,368	92,506,114	106,340,341	108,372,035	64,365,695
TOTALS - EXPENSE EXPENDITURES -	133,090,195								
d INTEREST EXPENSE	133,090,195	14,863,004	16,247,671	17,220,085	17,804,955	17,982,382	17,498,532	12,743,349	7,997,118
TOTALS - CONSERVATION PRINCIPAL COSTS	1,074,882,515	48,026,217	62,436,591	77,490,705	93,342,938	109,997,750	126,327,614	128,888,171	85,427,077
TOTALS - INTEREST EXPENSE	278,767,497	22,306,403	25,235,782	27,697,052	29,722,503	31,285,357	31,745,905	25,796,653	19,856,637
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	100.00%	4.47%	5.81%	7.21%	8.68%	10.23%	11.75%	11.99%	7.95%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)		4.47%	10.28%	17.49%	26.17%	36.40%	48.15%	60.14%	68.09%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 48.15%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (INFLATION ADJUSTED DOLLARS) = 133,090,195
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES-YEAR OF INVESTMENT) = 849,034,700
INFLATION ADJUSTED INTEREST AS A PERCENTAGE OF ORIGINAL INVESTMENT COSTS = 15.68%

INTEREST (INFLATION ADJUSTED) EXPENDITURES BY PERIOD

Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
47,542,185	120,450,817	167,993,002	110,774,495	278,767,497

Note 1 - Debt service cash flows are inflation adjusted to the year that the conservation resource is selected from the resource stack. The cash flows associated with the 9 conservation resources chosen in FY2010 are stated in FY 2010 purchasing power dollar values. The cash flows associated with the single conservation resource chosen in each of the remaining years of the rate test period are restated in the purchasing power dollar values associated with that year, the year the resource investment is made. Thus the debt service cash flows are a mixture of purchasing power dollars associated with the year that each conservation investment is made.

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Debt Service Components - (whole dollars)

DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
TOTALS - CAPITAL EXPENDITURES -												
a AMORTIZATION OF PRINCIPAL	21,617,921	22,184,666	22,746,850	23,334,848	23,960,335	24,610,787	25,286,319	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
TOTALS - CAPITAL EXPENDITURES -												
b INTEREST EXPENSE	10,662,193	9,460,713	8,249,816	7,041,458	5,835,748	4,625,893	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
TOTALS - EXPENSE EXPENDITURES -												
c AMORTIZATION OF PRINCIPAL	52,619,440	40,267,518	27,224,966	13,521,071	0	0	0	0	0	0	0	0
TOTALS - EXPENSE EXPENDITURES -												
d INTEREST EXPENSE	5,361,123	3,228,426	1,612,172	531,378	0	0	0	0	0	0	0	0
TOTALS - CONSERVATION PRINCIPAL COSTS	74,237,361	62,452,184	49,971,816	36,855,919	23,960,335	24,610,787	25,286,319	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
TOTALS - INTEREST EXPENSE	16,023,316	12,689,139	9,861,988	7,572,836	5,835,748	4,625,893	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	6.91%	5.81%	4.65%	3.43%	2.23%	2.29%	2.35%	1.38%	1.13%	0.87%	0.58%	0.28%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	75.00%	80.81%	85.46%	88.89%	91.12%	93.41%	95.76%	97.14%	98.27%	99.14%	99.72%	100.00%

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	Inflation Adjustment	Capitalized Conservation: Deferral/ Maturity # of Years	Capitalized Conservation: Interest Rate 15 - Year Maturity	Expensed Conservation: Deferral/ Maturity # of Years	Expensed Conservation: Interest Rate
FY 2010	**1.000000**	**15**	**0.0468**	**4**	**0.0357**
FY 2011	**1.020232**			**5**	**0.0369**
FY 2012	**1.041582**			**6**	**0.0381**
FY 2013	**1.062788**			**7**	**0.0393**
FY 2014	**1.084313**			**15**	**0.0468**
FY 2015	**1.106094**				

FY 2010 Conservation Resources Selected

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
1	**2001 Conservation - 2010$$**	19.2	29,059.6	72.4	29,132.0	
	Capitalized Costs - Debt Service Requirements					$6,825.13
	Expensed Costs /Deferral Debt Service Requirements					$2,739,439.32
3	**2006 Conservation - 2010$$**	31.0	39,428.0	16,435.8	55,863.8	
	Capitalized Costs - Debt Service Requirements					$1,549,397.68
	Expensed Costs /Deferral Debt Service Requirements					$3,716,865.11
4	**2003 Conservation - 2010$$**	27.6	30,621.2	27,501.3	58,122.5	
	Capitalized Costs - Debt Service Requirements					2,592,538.87
	Expensed Costs /Deferral Debt Service Requirements					$2,886,650.86
5	**2002 Conservation - 2010$$**	26.6	26,137.0	34,587.9	60,724.9	
	Capitalized Costs - Debt Service Requirements					3,260,590.41
	Expensed Costs /Deferral Debt Service Requirements					$2,463,926.74
6	**2005 Conservation - 2010$$**	20.6	31,616.2	16,720.6	48,336.8	
	Capitalized Costs - Debt Service Requirements					1,576,245.68
	Expensed Costs /Deferral Debt Service Requirements					$2,980,449.19
8	**2008 Conservation - 2010$$**	30.3	65,409.8	9,139.1	74,548.9	
	Capitalized Costs - Debt Service Requirements					861,540.07
	Expensed Costs /Deferral Debt Service Requirements					$6,166,161.19
9	**2004 Conservation - 2010$$**	20.1	27,250.7	22,724.9	49,975.6	
	Capitalized Costs - Debt Service Requirements					2,142,269.15
	Expensed Costs /Deferral Debt Service Requirements					$2,568,914.88
10	**2007 Conservation - 2010$$**	27.9	59,178.2	11,453.5	70,631.7	
	Capitalized Costs - Debt Service Requirements					1,079,717.83
	Expensed Costs /Deferral Debt Service Requirements					$5,578,710.23
12	**2009 Conservation - 2010$$**	28.4	69,492.8	20,411.5	89,904.3	
	Capitalized Costs - Debt Service Requirements					1,924,185.66
	Expensed Costs /Deferral Debt Service Requirements					$6,551,064.31
	Totals - FY 2010	231.7	378,193.5	159,047.0	537,240.5	

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2010 Conservation Resources Selected											
1	**2001 Conservation - 2010$$**										
Capital		6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Expense		2,739.4	2,739.4	2,739.4	2,739.4	2,739.4	2,739.4	2,739.4	2,739.4	2,739.4	2,739.4
3	**2006 Conservation - 2010$$**										
Capital		1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4
Expense		3,716.9	3,716.9	3,716.9	3,716.9	3,716.9	3,716.9	3,716.9	3,716.9	3,716.9	3,716.9
4	**2003 Conservation - 2010$$**										
Capital		2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5
Expense		2,886.7	2,886.7	2,886.7	2,886.7	2,886.7	2,886.7	2,886.7	2,886.7	2,886.7	2,886.7
5	**2002 Conservation - 2010$$**										
Capital		3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6
Expense		2,463.9	2,463.9	2,463.9	2,463.9	2,463.9	2,463.9	2,463.9	2,463.9	2,463.9	2,463.9
6	**2005 Conservation - 2010$$**										
Capital		1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2
Expense		2,980.4	2,980.4	2,980.4	2,980.4	2,980.4	2,980.4	2,980.4	2,980.4	2,980.4	2,980.4
8	**2008 Conservation - 2010$$**										
Capital		861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5	861.5
Expense		6,166.2	6,166.2	6,166.2	6,166.2	6,166.2	6,166.2	6,166.2	6,166.2	6,166.2	6,166.2
9	**2004 Conservation - 2010$$**										
Capital		2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3
Expense		2,568.9	2,568.9	2,568.9	2,568.9	2,568.9	2,568.9	2,568.9	2,568.9	2,568.9	2,568.9
10	**2007 Conservation - 2010$$**										
Capital		1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7
Expense		5,578.7	5,578.7	5,578.7	5,578.7	5,578.7	5,578.7	5,578.7	5,578.7	5,578.7	5,578.7
12	**2009 Conservation - 2010$$**										
Capital		1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2
Expense		6,551.1	6,551.1	6,551.1	6,551.1	6,551.1	6,551.1	6,551.1	6,551.1	6,551.1	6,551.1

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
	11	12	13	14	15					
FY 2010 Conservation Resources Selected										
1	**2001 Conservation - 2010$$**									
Capital	6.8	6.8	6.8	6.8	6.8	0.0	0.0	0.0	0.0	0.0
Expense	2,739.4	2,739.4	2,739.4	2,739.4	2,739.4	0.0	0.0	0.0	0.0	0.0
3	**2006 Conservation - 2010$$**									
Capital	1,549.4	1,549.4	1,549.4	1,549.4	1,549.4	0.0	0.0	0.0	0.0	0.0
Expense	3,716.9	3,716.9	3,716.9	3,716.9	3,716.9	0.0	0.0	0.0	0.0	0.0
4	**2003 Conservation - 2010$$**									
Capital	2,592.5	2,592.5	2,592.5	2,592.5	2,592.5	0.0	0.0	0.0	0.0	0.0
Expense	2,886.7	2,886.7	2,886.7	2,886.7	2,886.7	0.0	0.0	0.0	0.0	0.0
5	**2002 Conservation - 2010$$**									
	3,260.6	3,260.6	3,260.6	3,260.6	3,260.6	0.0	0.0	0.0	0.0	0.0
	2,463.9	2,463.9	2,463.9	2,463.9	2,463.9	0.0	0.0	0.0	0.0	0.0
6	**2005 Conservation - 2010$$**									
Capital	1,576.2	1,576.2	1,576.2	1,576.2	1,576.2	0.0	0.0	0.0	0.0	0.0
Expense	2,980.4	2,980.4	2,980.4	2,980.4	2,980.4	0.0	0.0	0.0	0.0	0.0
8	**2008 Conservation - 2010$$**									
Capital	861.5	861.5	861.5	861.5	861.5	0.0	0.0	0.0	0.0	0.0
Expense	6,166.2	6,166.2	6,166.2	6,166.2	6,166.2	0.0	0.0	0.0	0.0	0.0
9	**2004 Conservation - 2010$$**									
Capital	2,142.3	2,142.3	2,142.3	2,142.3	2,142.3	0.0	0.0	0.0	0.0	0.0
Expense	2,568.9	2,568.9	2,568.9	2,568.9	2,568.9	0.0	0.0	0.0	0.0	0.0
10	**2007 Conservation - 2010$$**									
Capital	1,079.7	1,079.7	1,079.7	1,079.7	1,079.7	0.0	0.0	0.0	0.0	0.0
Expense	5,578.7	5,578.7	5,578.7	5,578.7	5,578.7	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**									
Capital	1,924.2	1,924.2	1,924.2	1,924.2	1,924.2	0.0	0.0	0.0	0.0	0.0
Expense	6,551.1	6,551.1	6,551.1	6,551.1	6,551.1	0.0	0.0	0.0	0.0	0.0

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Expensed costs are deferred and financed over 15 years**

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$		87,986.2	42,697.1	130,683.3	
13	**2015 Conservation - 2011$$**	39.5	89,766.3	43,560.9	133,327.2	
	Capitalized Costs - Debt Service Requirements					4,106,472.29
	Expensed Costs /Deferral Debt Service Requirements					$8,462,240.76
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$		88,570.4	43,552.0	132,122.4	
14	**2014 Conservation - 2012$$**	39.5	92,253.3	45,363.0	137,616.3	
	Capitalized Costs - Debt Service Requirements					4,276,355.69
	Expensed Costs /Deferral Debt Service Requirements					$8,696,689.46
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$		89,602.1	44,431.3	134,033.4	
15	**2013 Conservation - 2013$$**	39.5	95,228.0	47,221.1	142,449.1	
	Capitalized Costs - Debt Service Requirements					4,451,518.19
	Expensed Costs /Deferral Debt Service Requirements					$8,977,113.49
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$		90,647.7	45,318.6	135,966.3	
16	**2012 Conservation - 2014$$**	39.5	98,290.5	49,139.5	147,430.0	
	Capitalized Costs - Debt Service Requirements					4,632,365.15
	Expensed Costs /Deferral Debt Service Requirements					$9,265,814.40
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$		86,161.8	38,806.9	124,968.7	
17	**2011 Conservation - 2015$$**	34.9	95,303.1	42,924.1	138,227.2	
	Capitalized Costs - Debt Service Requirements					4,046,441.35
	Expensed Costs /Deferral Debt Service Requirements					$8,984,193.14

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		387,255.6	160,340.4	547,596.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	849,034.7		351,538.3	1,200,573.0
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	849,034.7	387,255.6	511,878.7	1,748,169.0

Principal Expense Costs	849,034.7
Interest Paid Expensed Costs	351,538.3
Principal Capital Costs	387,255.6
Interest Paid Capital Costs	160,340.4
Totals	1,748,169.0

**Scenario = Capitalized costs are amortized and financed over 15 years,
Expensed costs are deferred and financed over 15 years**

Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5
Expense		0.0	8,462.2	8,462.2	8,462.2	8,462.2	8,462.2	8,462.2	8,462.2	8,462.2	8,462.2
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4
Expense		0.0	0.0	8,696.7	8,696.7	8,696.7	8,696.7	8,696.7	8,696.7	8,696.7	8,696.7
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5
Expense		0.0	0.0	0.0	8,977.1	8,977.1	8,977.1	8,977.1	8,977.1	8,977.1	8,977.1
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4
Expense		0.0	0.0	0.0	0.0	9,265.8	9,265.8	9,265.8	9,265.8	9,265.8	9,265.8
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense		0.0	0.0	0.0	0.0	0.0	8,984.2	8,984.2	8,984.2	8,984.2	8,984.2
TCC		14,993.2	19,099.7	23,376.1	27,827.6	32,460.0	36,506.4	36,506.4	36,506.4	36,506.4	36,506.4
TEC		35,652.2	44,114.4	52,811.1	61,788.2	71,054.0	80,038.2	80,038.2	80,038.2	80,038.2	80,038.2
TDSR		50,645.4	63,214.1	76,187.2	89,615.8	103,514.0	116,544.6	116,544.6	116,544.6	116,544.6	116,544.6

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Debt Service Requirements - Principal and Interest ($ 000)

X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Res. Stack Order		**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
		11	12	13	14	15					
FY 2011 Conservation Resources Selected											
13		**2015 Conservation - 2011$$**									
Capital		4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	4,106.5	0.0	0.0	0.0	0.0
Expense		8,462.2	8,462.2	8,462.2	8,462.2	8,462.2	8,462.2	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14		**2014 Conservation - 2012$$**									
Capital		4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	4,276.4	0.0	0.0	0.0
Expense		8,696.7	8,696.7	8,696.7	8,696.7	8,696.7	8,696.7	8,696.7	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15		**2013 Conservation - 2013$$**									
Capital		4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	4,451.5	0.0	0.0
Expense		8,977.1	8,977.1	8,977.1	8,977.1	8,977.1	8,977.1	8,977.1	8,977.1	0.0	0.0
FY 2014 Conservation Resources Selected											
16		**2012 Conservation - 2014$$**									
Capital		4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	4,632.4	0.0
Expense		9,265.8	9,265.8	9,265.8	9,265.8	9,265.8	9,265.8	9,265.8	9,265.8	9,265.8	0.0
FY 2015 Conservation Resources Selected											
17		**2011 Conservation - 2015$$**									
Capital		4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4	4,046.4
Expense		8,984.2	8,984.2	8,984.2	8,984.2	8,984.2	8,984.2	8,984.2	8,984.2	8,984.2	8,984.2
TCC		36,506.4	36,506.4	36,506.4	36,506.4	36,506.4	21,513.2	17,406.7	13,130.3	8,678.8	4,046.4
TEC		80,038.2	80,038.2	80,038.2	80,038.2	80,038.2	44,386.0	35,923.8	27,227.1	18,250.0	8,984.2
TDSR		116,544.6	116,544.6	116,544.6	116,544.6	116,544.6	65,899.2	53,330.5	40,357.4	26,928.8	13,030.6

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= Expensed costs are deferred and amortized / financed over 15 - years

Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY2010	Conservation (9) Res. Selected - Total MW =	231.7								
1	**2001 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	72,400	3,437	3,598	3,766	3,942	4,127	4,320	4,522	4,734
	b Capital Expenditures - Interest Expense	29,975	3,388	3,227	3,059	2,883	2,698	2,505	2,303	2,091
	c Expense Expenditures - Amort. of Principal	29,059,600	1,379,450	1,444,008	1,511,588	1,582,330	1,656,383	1,733,902	1,815,048	1,899,993
	d Expense Expenditures - Interest Expense	12,031,989	1,359,989	1,295,431	1,227,851	1,157,109	1,083,056	1,005,537	924,391	839,446
3	**2006 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,435,800	780,203	816,716	854,938	894,949	936,833	980,677	1,026,573	1,074,616
	b Capital Expenditures - Interest Expense	6,805,165	769,195	732,682	694,460	654,449	612,565	568,721	522,825	474,782
	c Expense Expenditures - Amort. of Principal	39,428,000	1,871,635	1,959,227	2,050,919	2,146,902	2,247,377	2,352,554	2,462,654	2,577,906
	d Expense Expenditures - Interest Expense	16,324,976	1,845,230	1,757,638	1,665,946	1,569,963	1,469,488	1,364,311	1,254,211	1,138,959
4	**2003 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	27,501,300	1,305,478	1,366,575	1,430,530	1,497,479	1,567,561	1,640,923	1,717,718	1,798,107
	b Capital Expenditures - Interest Expense	11,386,782	1,287,061	1,225,964	1,162,009	1,095,060	1,024,978	951,616	874,821	794,432
	c Expense Expenditures - Amort. of Principal	30,621,200	1,453,579	1,521,606	1,592,817	1,667,361	1,745,394	1,827,078	1,912,586	2,002,095
	d Expense Expenditures - Interest Expense	12,678,561	1,433,072	1,365,045	1,293,834	1,219,290	1,141,257	1,059,573	974,065	884,556
5	**2002 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	34,587,900	1,641,876	1,718,716	1,799,152	1,883,352	1,971,493	2,063,759	2,160,343	2,261,448
	b Capital Expenditures - Interest Expense	14,320,958	1,618,714	1,541,874	1,461,438	1,377,238	1,289,097	1,196,831	1,100,247	999,143
	c Expense Expenditures - Amort. of Principal	26,137,000	1,240,715	1,298,781	1,359,564	1,423,191	1,489,797	1,559,519	1,632,505	1,708,906
	d Expense Expenditures - Interest Expense	10,821,901	1,223,212	1,165,146	1,104,363	1,040,736	974,130	904,408	831,422	755,021
6	**2005 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	16,720,600	793,722	830,868	869,753	910,457	953,067	997,670	1,044,361	1,093,237
	b Capital Expenditures - Interest Expense	6,923,083	782,524	745,378	706,493	665,789	623,179	578,576	531,885	483,009
	c Expense Expenditures - Amort. of Principal	31,616,200	1,500,811	1,571,049	1,644,574	1,721,540	1,802,108	1,886,447	1,974,732	2,067,150
	d Expense Expenditures - Interest Expense	13,090,539	1,479,638	1,409,400	1,335,875	1,258,909	1,178,341	1,094,002	1,005,717	913,299
8	**2008 Conservation - 2010$$**									
	a Capital Expenditures - Amort. of Principal	9,139,100	433,830	454,133	475,387	497,635	520,924	545,303	570,824	597,538
	b Capital Expenditures - Interest Expense	3,784,002	427,710	407,407	386,153	363,905	340,616	316,237	290,716	264,002
	c Expense Expenditures - Amort. of Principal	65,409,800	3,104,982	3,250,296	3,402,409	3,561,642	3,728,327	3,902,813	4,085,464	4,276,664
	d Expense Expenditures - Interest Expense	27,082,619	3,061,179	2,915,865	2,763,752	2,604,519	2,437,834	2,263,348	2,080,697	1,889,497

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY2010 Conservation (9) Res. Selected - Total MW =													
1	2001 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	4,955	5,187	5,430	5,684	5,950	6,228	6,520	0	0	0	0	0
	b Capital Expenditures - Interest Expense	1,870	1,638	1,395	1,141	875	597	305	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	1,988,912	2,081,993	2,179,431	2,281,428	2,388,200	2,499,967	2,616,967	0	0	0	0	0
	d Expense Expenditures - Interest Expense	750,527	657,446	560,008	458,011	351,240	239,473	122,474	0	0	0	0	0
3	2006 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	1,124,908	1,177,554	1,232,662	1,290,351	1,350,739	1,413,954	1,480,127	0	0	0	0	0
	b Capital Expenditures - Interest Expense	424,490	371,844	316,735	259,046	198,658	135,443	69,270	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	2,698,552	2,824,844	2,957,047	3,095,437	3,240,303	3,391,949	3,550,694	0	0	0	0	0
	d Expense Expenditures - Interest Expense	1,018,313	892,021	759,818	621,428	476,562	324,916	166,172	0	0	0	0	0
4	2003 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	1,882,259	1,970,348	2,062,561	2,159,089	2,260,133	2,365,907	2,476,632	0	0	0	0	0
	b Capital Expenditures - Interest Expense	710,280	622,191	529,978	433,450	332,405	226,631	115,906	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	2,095,793	2,193,876	2,296,549	2,404,027	2,516,535	2,634,309	2,757,595	0	0	0	0	0
	d Expense Expenditures - Interest Expense	790,858	692,775	590,102	482,623	370,115	252,341	129,055	0	0	0	0	0
5	2002 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	2,367,284	2,478,073	2,594,046	2,715,448	2,842,531	2,975,561	3,114,818	0	0	0	0	0
	b Capital Expenditures - Interest Expense	893,307	782,518	666,545	545,143	418,060	285,030	145,773	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	1,788,883	1,872,602	1,960,239	2,051,978	2,148,011	2,248,538	2,353,771	0	0	0	0	0
	d Expense Expenditures - Interest Expense	675,044	591,325	503,687	411,948	315,915	215,388	110,156	0	0	0	0	0
6	2005 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	1,144,400	1,197,958	1,254,022	1,312,710	1,374,145	1,438,455	1,505,775	0	0	0	0	0
	b Capital Expenditures - Interest Expense	431,845	378,287	322,223	263,535	202,100	137,790	70,470	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	2,163,892	2,265,163	2,371,172	2,482,144	2,598,308	2,719,909	2,847,201	0	0	0	0	0
	d Expense Expenditures - Interest Expense	816,557	715,286	609,277	498,306	382,142	260,541	133,249	0	0	0	0	0
8	2008 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	625,503	654,777	685,420	717,498	751,077	786,227	823,024	0	0	0	0	0
	b Capital Expenditures - Interest Expense	236,037	206,763	176,120	144,042	110,463	75,313	38,518	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	4,476,812	4,686,327	4,905,647	5,135,232	5,375,561	5,627,137	5,890,487	0	0	0	0	0
	d Expense Expenditures - Interest Expense	1,689,349	1,479,834	1,260,514	1,030,930	790,601	539,025	275,675	0	0	0	0	0

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Debt Service Components - (whole dollars)

Row	Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
47	9	**2004 Conservation - 2010$$**									
48		a Capital Expenditures - Amort. of Principal	22,724,900	1,078,744	1,129,229	1,182,077	1,237,398	1,295,308	1,355,929	1,419,386	1,485,813
49		b Capital Expenditures - Interest Expense	9,409,137	1,063,525	1,013,040	960,192	904,871	846,961	786,340	722,883	656,456
50		c Expense Expenditures - Amort. of Principal	27,250,700	1,293,582	1,354,122	1,417,495	1,483,834	1,553,277	1,625,970	1,702,066	1,781,722
51		d Expense Expenditures - Interest Expense	11,283,023	1,275,333	1,214,793	1,151,420	1,085,081	1,015,638	942,945	866,849	787,193
52	10	**2007 Conservation - 2010$$**									
53		a Capital Expenditures - Amort. of Principal	11,453,500	543,694	569,139	595,775	623,657	652,844	683,397	715,380	748,860
54		b Capital Expenditures - Interest Expense	4,742,268	536,024	510,579	483,943	456,061	426,874	396,321	364,338	330,858
55		c Expense Expenditures - Amort. of Principal	59,178,200	2,809,170	2,940,639	3,078,261	3,222,324	3,373,129	3,530,991	3,696,241	3,869,226
56		d Expense Expenditures - Interest Expense	24,502,455	2,769,540	2,638,071	2,500,449	2,356,386	2,205,581	2,047,719	1,882,469	1,709,484
57	12	**2009 Conservation - 2010$$**									
58		a Capital Expenditures - Amort. of Principal	20,411,500	968,928	1,014,274	1,061,742	1,111,431	1,163,446	1,217,895	1,274,893	1,334,557
59		b Capital Expenditures - Interest Expense	8,451,286	955,258	909,912	862,444	812,755	760,740	706,291	649,293	589,628
60		c Expense Expenditures - Amort. of Principal	69,492,800	3,298,801	3,453,185	3,614,794	3,783,966	3,961,056	4,146,433	4,340,486	4,543,621
61		d Expense Expenditures - Interest Expense	28,773,166	3,252,263	3,097,879	2,936,270	2,767,098	2,590,008	2,404,631	2,210,578	2,007,443
62	**FY 2011**	**Conservation Resources Selected**									
63	13	**2015 Conservation - 2011$$**									
64		a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
65		b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
66		c Expense Expenditures - Amort. of Principal	89,766,300	0	4,261,178	4,460,601	4,669,357	4,887,883	5,116,636	5,356,095	5,606,760
67		d Expense Expenditures - Interest Expense	37,167,313	0	4,201,063	4,001,640	3,792,884	3,574,358	3,345,605	3,106,146	2,855,481
68	**FY 2012**	**Conservation Resources Selected**									
69	14	**2014 Conservation - 2012$$**									
70		a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
71		b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
72		c Expense Expenditures - Amort. of Principal	92,253,300	0	0	4,379,235	4,584,183	4,798,723	5,023,303	5,258,393	5,504,486
73		d Expense Expenditures - Interest Expense	38,197,042	0	0	4,317,454	4,112,506	3,897,966	3,673,386	3,438,296	3,192,203
74	**FY 2013**	**Conservation Resources Selected**									
75	15	**2013 Conservation - 2013$$**									
76		a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
77		b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
78		c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	4,520,443	4,731,999	4,953,457	5,185,279	5,427,950
79		d Expense Expenditures - Interest Expense	39,428,703	0	0	0	4,456,670	4,245,114	4,023,656	3,791,834	3,549,163
80	**FY 2014**	**Conservation Resources Selected**									
81	16	**2012 Conservation - 2014$$**									
82		a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
83		b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
84		c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	4,665,819	4,884,179	5,112,759	5,352,036
85		d Expense Expenditures - Interest Expense	40,696,716	0	0	0	0	4,599,995	4,381,635	4,153,055	3,913,778

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
9	2004 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	1,555,349	1,628,140	1,704,337	1,784,100	1,867,596	1,955,000	2,046,494	0	0	0	0	0
	b Capital Expenditures - Interest Expense	586,920	514,129	437,932	358,169	274,673	187,270	95,776	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	1,865,107	1,952,394	2,043,766	2,139,414	2,239,539	2,344,348	2,454,064	0	0	0	0	0
	d Expense Expenditures - Interest Expense	703,808	616,521	525,149	429,501	329,376	224,566	114,850	0	0	0	0	0
10	2007 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	783,907	820,594	858,997	899,198	941,281	985,332	1,031,445	0	0	0	0	0
	b Capital Expenditures - Interest Expense	295,811	259,124	220,721	180,520	138,437	94,385	48,272	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	4,050,305	4,239,860	4,438,286	4,645,998	4,863,431	5,091,039	5,329,300	0	0	0	0	0
	d Expense Expenditures - Interest Expense	1,528,405	1,338,850	1,140,425	932,713	715,280	487,672	249,411	0	0	0	0	0
12	2009 Conservation - 2010$$												
	a Capital Expenditures - Amort. of Principal	1,397,014	1,462,394	1,530,834	1,602,478	1,677,474	1,755,980	1,838,160	0	0	0	0	0
	b Capital Expenditures - Interest Expense	527,171	461,791	393,351	321,708	246,712	168,206	86,026	0	0	0	0	0
	c Expense Expenditures - Amort. of Principal	4,756,264	4,978,857	5,211,867	5,455,783	5,711,113	5,978,393	6,258,181	0	0	0	0	0
	d Expense Expenditures - Interest Expense	1,794,801	1,572,208	1,339,198	1,095,282	839,952	572,672	292,883	0	0	0	0	0
FY 2011	Conservation Resources Selected												
13	2015 Conservation - 2011$$												
	a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
	b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
	c Expense Expenditures - Amort. of Principal	5,869,156	6,143,833	6,431,364	6,732,352	7,047,426	7,377,246	7,722,500	8,083,913	0	0	0	0
	d Expense Expenditures - Interest Expense	2,593,085	2,318,408	2,030,877	1,729,889	1,414,815	1,084,995	739,740	378,327	0	0	0	0
FY 2012	Conservation Resources Selected												
14	2014 Conservation - 2012$$												
	a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
	b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
	c Expense Expenditures - Amort. of Principal	5,762,096	6,031,763	6,314,050	6,609,547	6,918,874	7,242,677	7,581,635	7,936,455	8,307,880	0	0	0
	d Expense Expenditures - Interest Expense	2,934,593	2,664,927	2,382,640	2,087,143	1,777,816	1,454,013	1,115,055	760,235	388,809	0	0	0
FY 2013	Conservation Resources Selected												
15	2013 Conservation - 2013$$												
	a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
	b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
	c Expense Expenditures - Amort. of Principal	5,681,978	5,947,894	6,226,257	6,517,646	6,822,671	7,141,972	7,476,217	7,826,104	8,192,365	8,575,768	0	0
	d Expense Expenditures - Interest Expense	3,295,135	3,029,219	2,750,857	2,459,468	2,154,443	1,835,142	1,500,897	1,151,010	784,749	401,346	0	0
FY 2014	Conservation Resources Selected												
16	2012 Conservation - 2014$$												
	a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
	b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
	c Expense Expenditures - Amort. of Principal	5,602,511	5,864,708	6,139,177	6,426,490	6,727,250	7,042,086	7,371,656	7,716,649	8,077,789	8,455,829	8,851,562	0
	d Expense Expenditures - Interest Expense	3,663,303	3,401,106	3,126,637	2,839,324	2,538,564	2,223,729	1,894,159	1,549,166	1,188,026	809,986	414,253	0

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2015	Conservation Resources Selected									
17	2011 Conservation - 2015$$									
	a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
	b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
	c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	4,524,008	4,735,731	4,957,364
	d Expense Expenditures - Interest Expense	39,459,800	0	0	0	0	0	4,460,185	4,248,462	4,026,829

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
TOTALS - CAPITAL EXPENDITURES -	387,255,600								
AMORTIZATION OF PRINCIPAL	387,255,600	7,549,912	9,971,070	12,591,084	15,421,915	18,476,297	21,378,581	22,379,100	23,426,441
TOTALS - CAPITAL EXPENDITURES -	160,341,348								
INTEREST EXPENSE	160,341,348	7,443,399	9,128,713	10,785,055	12,405,742	13,983,725	15,127,882	14,127,363	13,080,022
TOTALS - EXPENSE EXPENDITURES -	849,034,700								
AMORTIZATION OF PRINCIPAL	849,034,700	17,952,725	23,054,091	28,512,257	34,367,073	40,641,272	47,067,290	49,270,039	51,575,879
TOTALS - EXPENSE EXPENDITURES -	351,538,803								
INTEREST EXPENSE	351,538,803	17,699,456	21,060,331	24,298,854	27,421,151	30,412,766	32,970,941	30,768,192	28,462,352
	1,236,290,300								
TOTALS - CONSERVATION PRINCIPAL COSTS	1,236,290,300	25,502,637	33,025,161	41,103,341	49,788,988	59,117,569	68,445,871	71,649,139	75,002,320
	511,880,151								
TOTALS - INTEREST EXPENSE	511,880,151	25,142,855	30,189,044	35,083,909	39,826,893	44,396,491	48,098,823	44,895,555	41,542,374
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	100.00%	2.06%	2.67%	3.32%	4.03%	4.78%	5.54%	5.80%	6.07%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		2.06%	4.73%	8.05%	12.08%	16.86%	$\boxed{22.40\%}$	28.20%	34.27%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 22.40%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (NOMINAL DOLLARS) =	351,538,803
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES - YEAR OF INVESTMENT) =	849,034,700
INTEREST AS A PECENTAGE OF ORIGINAL INVESTMENT COSTS =	41.40%

INTEREST (NOMINAL DOLLARS) EXPENDITURES BY PERIOD

	Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
Interest on Capital and Expense Expenditures	55,331,899	167,406,116	222,738,015	289,142,136	511,880,151

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Debt Service Components - (whole dollars)

Res. Stack Order	Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2015	**Conservation Resources Selected**												
17	**2011 Conservation - 2015$$**												
	a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
	b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
	c Expense Expenditures - Amort. of Principal	5,189,368	5,432,231	5,686,459	5,952,585	6,231,166	6,522,785	6,828,051	7,147,605	7,482,113	7,832,276	8,198,826	8,582,532
	d Expense Expenditures - Interest Expense	3,794,825	3,551,962	3,297,734	3,031,608	2,753,027	2,461,408	2,156,142	1,836,589	1,502,081	1,151,918	785,368	401,662

SUMMARY TOTALS - NOMINAL DOLLAR VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
TOTALS - CAPITAL EXPENDITURES - AMORTIZATION OF PRINCIPAL	24,522,798	25,670,466	26,871,840	28,129,445	29,445,903	30,823,971	32,266,535	18,783,299	15,555,884	12,007,545	8,117,980	3,865,534
TOTALS - CAPITAL EXPENDITURES - INTEREST EXPENSE	11,983,664	10,835,996	9,634,621	8,377,017	7,060,559	5,682,491	4,239,929	2,729,855	1,850,798	1,122,782	560,828	180,907
TOTALS - EXPENSE EXPENDITURES - AMORTIZATION OF PRINCIPAL	53,989,629	56,516,345	59,161,311	61,930,061	64,828,388	67,862,355	71,038,319	38,710,726	32,060,147	24,863,873	17,050,388	8,582,532
TOTALS - EXPENSE EXPENDITURES - INTEREST EXPENSE	26,048,603	23,521,888	20,876,923	18,108,174	15,209,848	12,175,881	8,999,918	5,675,327	3,863,665	2,363,250	1,199,621	401,662
TOTALS - CONSERVATION PRINCIPAL COSTS	78,512,427	82,186,811	86,033,151	90,059,506	94,274,291	98,686,326	103,304,854	57,494,025	47,616,031	36,871,418	25,168,368	12,448,066
TOTALS - INTEREST EXPENSE	38,032,267	34,357,884	30,511,544	26,485,191	22,270,407	17,858,372	13,239,847	8,405,182	5,714,463	3,486,032	1,760,449	582,569
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	6.35%	6.65%	6.96%	7.28%	7.63%	7.98%	8.36%	4.65%	3.85%	2.98%	2.04%	1.01%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID	40.62%	47.27%	54.23%	61.51%	69.14%	77.12%	85.48%	90.13%	93.98%	96.96%	99.00%	100.01%

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Debt Service Components - (whole dollars)

Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
			INFLATION ADJUSTED ANALYSIS						
FY 2010 Conservation Resources Selected -									
Debt Service in Nominal Year Dollars									
TOTALS - CAPITAL EXPENDITURES -	159,047,000								
a AMORTIZATION OF PRINCIPAL	159,047,000	7,549,912	7,903,248	8,273,120	8,660,300	9,065,603	9,489,873	9,934,000	10,398,910
TOTALS - CAPITAL EXPENDITURES -	65,852,656								
b INTEREST EXPENSE	65,852,656	7,443,399	7,090,063	6,720,191	6,333,011	5,927,708	5,503,438	5,059,311	4,594,401
TOTALS - EXPENSE EXPENDITURES -	378,193,500								
c AMORTIZATION OF PRINCIPAL	378,193,500	17,952,725	18,792,913	19,672,421	20,593,090	21,556,848	22,565,707	23,621,782	24,727,283
TOTALS - EXPENSE EXPENDITURES -	156,589,229								
d INTEREST EXPENSE	156,589,229	17,699,456	16,859,268	15,979,760	15,059,091	14,095,333	13,086,474	12,030,399	10,924,898
FY 2010 Deflator values		1.000000	1.020232	1.041582	1.062788	1.084313	1.106094	1.128012	1.150234
FY 2010 Conservation Resources Selected -									
Debt service in FY2010 Purchasing Power Dollars									
TOTALS - CAPITAL EXPENDITURES -									
a AMORTIZATION OF PRINCIPAL	136,462,442	7,549,912	7,746,520	7,942,841	8,148,662	8,360,688	8,579,626	8,806,644	9,040,691
TOTALS - CAPITAL EXPENDITURES -									
b INTEREST EXPENSE	59,786,673	7,443,399	6,949,461	6,451,908	5,958,866	5,466,787	4,975,561	4,485,157	3,994,319
TOTALS - EXPENSE EXPENDITURES -									
c AMORTIZATION OF PRINCIPAL	324,490,298	17,952,725	18,420,235	18,887,059	19,376,480	19,880,651	20,401,256	20,941,073	21,497,611
TOTALS - EXPENSE EXPENDITURES -									
d INTEREST EXPENSE	142,165,094	17,699,456	16,524,936	15,341,817	14,169,421	12,999,321	11,831,249	10,665,134	9,497,979
FY 2011 Conservation Resources Selected									
13 2015 Conservation - 2011$$ -									
Debt Service in Nominal Year Dollars									
a Capital Expenditures - Amort. of Principal	43,560,900	0	2,067,822	2,164,596	2,265,899	2,371,943	2,482,950	2,599,152	2,720,792
b Capital Expenditures - Interest Expense	18,036,186	0	2,038,650	1,941,876	1,840,573	1,734,529	1,623,522	1,507,320	1,385,680
c Expense Expenditures - Amort. of Principal	89,766,300	0	4,261,178	4,460,601	4,669,357	4,887,883	5,116,636	5,356,095	5,606,760
d Expense Expenditures - Interest Expense	37,167,313	0	4,201,063	4,001,640	3,792,884	3,574,358	3,345,605	3,106,146	2,855,481
FY 2011 Deflator values			1.000000	1.020927	1.041712	1.062810	1.084159	1.105643	1.127424
13 2015 Conservation - 2011$$ -									
Debt service in FY2011 Purchasing Power Dollars									
a Capital Expenditures - Amort. of Principal	37,389,568	0	2,067,822	2,120,226	2,175,168	2,231,766	2,290,208	2,350,806	2,413,282
b Capital Expenditures - Interest Expense	16,376,020	0	2,038,650	1,902,071	1,766,873	1,632,022	1,497,494	1,363,297	1,229,067
c Expense Expenditures - Amort. of Principal	77,048,986	0	4,261,178	4,369,167	4,482,388	4,599,019	4,719,452	4,844,326	4,973,071
d Expense Expenditures - Interest Expense	33,746,200	0	4,201,063	3,919,614	3,641,010	3,363,120	3,085,899	2,809,357	2,532,748
FY 2012 Conservation Resources Selected									
14 2014 Conservation - 2012$$ -									
Debt Service in Nominal Year Dollars									
a Capital Expenditures - Amort. of Principal	45,363,000	0	0	2,153,368	2,254,145	2,359,639	2,470,070	2,585,670	2,706,679
b Capital Expenditures - Interest Expense	18,782,333	0	0	2,122,988	2,022,211	1,916,717	1,806,286	1,690,686	1,569,677
c Expense Expenditures - Amort. of Principal	92,253,300	0	0	4,379,235	4,584,183	4,798,723	5,023,303	5,258,393	5,504,486
d Expense Expenditures - Interest Expense	38,197,042	0	0	4,317,454	4,112,506	3,897,966	3,673,386	3,438,296	3,192,203
FY 2012 Deflator values									
14 2014 Conservation - 2012$$ -				1.000000	1.020359	1.041025	1.061937	1.082980	1.104314
Debt service in FY2012 Purchasing Power Dollars									
a Capital Expenditures - Amort. of Principal	38,983,476	0	0	2,153,368	2,209,169	2,266,650	2,326,004	2,387,551	2,451,005
b Capital Expenditures - Interest Expense	17,067,371	0	0	2,122,988	1,981,862	1,841,182	1,700,935	1,561,142	1,421,405
c Expense Expenditures - Amort. of Principal	79,279,462	0	0	4,379,235	4,492,716	4,609,614	4,730,321	4,855,485	4,984,530
d Expense Expenditures - Interest Expense	34,709,377	0	0	4,317,454	4,030,450	3,744,354	3,459,137	3,174,847	2,890,666

	A B C	M	N	O	P	Q	R	S	T	U	V	W	X
1						**Section 7(b)(2) Rate Test Study and Documentation**							
2						**Alternative Conservation Expense Accounting and Financing Treatments**							
3						**WP-10 Final Rate Proposal**							
5						**Scenario = Capitalized costs amortized / financed over 15 years,**							
6						**= Expensed costs are deferred and amortized / financed over 15 - years**							
8						**Debt Service Components - (whole dollars)**							
135	**Vintage - Year Selected**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
137							**INFLATION ADJUSTED ANALYSIS**						
138	**FY 2010 Conservation Resources Selected -**												
139	**Debt Service in Nominal Year Dollars**												
140	TOTALS - CAPITAL EXPENDITURES -												
141	a AMORTIZATION OF PRINCIPAL	10,885,579	11,395,025	11,928,309	12,486,556	13,070,926	13,682,644	14,322,995	0	0	0	0	0
142	TOTALS - CAPITAL EXPENDITURES -												
143	b INTEREST EXPENSE	4,107,731	3,598,285	3,065,000	2,506,754	1,922,383	1,310,665	670,316	0	0	0	0	0
144	TOTALS - EXPENSE EXPENDITURES -												
145	c AMORTIZATION OF PRINCIPAL	25,884,520	27,095,916	28,364,004	29,691,441	31,081,001	32,535,589	34,058,260	0	0	0	0	0
146	TOTALS - EXPENSE EXPENDITURES -												
147	d INTEREST EXPENSE	9,767,662	8,556,266	7,288,178	5,960,742	4,571,183	3,116,594	1,593,925	0	0	0	0	0
149	FY 2010 Deflator values	1.173067	1.196596	1.221639	1.246588	1.270863	1.295179	1.319573	1.343839	1.368342	1.393708	1.419537	1.445453
150	**FY 2010 Conservation Resources Selected -**												
151	**Debt service in FY2010 Purchasing Power Dollars**												
152	TOTALS - CAPITAL EXPENDITURES -												
153	a AMORTIZATION OF PRINCIPAL	9,279,588	9,522,867	9,764,185	10,016,586	10,285,079	10,564,288	10,854,265	0	0	0	0	0
154	TOTALS - CAPITAL EXPENDITURES -												
155	b INTEREST EXPENSE	3,501,702	3,007,101	2,508,924	2,010,892	1,512,660	1,011,957	507,979	0	0	0	0	0
156	TOTALS - EXPENSE EXPENDITURES -												
157	c AMORTIZATION OF PRINCIPAL	22,065,679	22,644,164	23,217,992	23,818,167	24,456,610	25,120,535	25,810,061	0	0	0	0	0
158	TOTALS - EXPENSE EXPENDITURES -												
159	d INTEREST EXPENSE	8,326,602	7,150,505	5,965,902	4,781,646	3,596,912	2,406,304	1,207,910	0	0	0	0	0
161	**FY 2011 Conservation Resources Selected**												
162	**13** **2015 Conservation - 2011$$ -**												
163	**Debt Service in Nominal Year Dollars**												
164	a Capital Expenditures - Amort. of Principal	2,848,125	2,981,418	3,120,949	3,267,010	3,419,906	3,579,957	3,747,499	3,922,882	0	0	0	0
165	b Capital Expenditures - Interest Expense	1,258,347	1,125,054	985,524	839,463	686,567	526,516	358,974	183,591	0	0	0	0
166	c Expense Expenditures - Amort. of Principal	5,869,156	6,143,833	6,431,364	6,732,352	7,047,426	7,377,246	7,722,500	8,083,913	0	0	0	0
167	d Expense Expenditures - Interest Expense	2,593,085	2,318,408	2,030,877	1,729,889	1,414,815	1,084,995	739,740	378,327	0	0	0	0
169	FY 2011 Deflator values	1.149804	1.172867	1.197413	1.221867	1.245661	1.269495	1.293405	1.317190	1.341207	1.366070	1.391386	1.416789
170	**13** **2015 Conservation - 2011$$ -**												
171	**Debt service in FY2011 Purchasing Power Dollars**												
172	a Capital Expenditures - Amort. of Principal	2,477,053	2,541,992	2,606,410	2,673,785	2,745,455	2,819,985	2,897,390	2,978,220	0	0	0	0
173	b Capital Expenditures - Interest Expense	1,094,401	959,234	823,044	687,033	551,167	414,744	277,542	139,381	0	0	0	0
174	c Expense Expenditures - Amort. of Principal	5,104,484	5,238,303	5,371,049	5,509,889	5,657,579	5,811,166	5,970,674	6,137,241	0	0	0	0
175	d Expense Expenditures - Interest Expense	2,255,241	1,976,702	1,696,054	1,415,775	1,135,795	854,667	571,932	287,223	0	0	0	0
177	**FY 2012 Conservation Resources Selected**												
178	**14** **2014 Conservation - 2012$$ -**												
179	**Debt Service in Nominal Year Dollars**												
180	a Capital Expenditures - Amort. of Principal	2,833,352	2,965,952	3,104,758	3,250,061	3,402,163	3,561,385	3,728,058	3,902,531	4,085,169	0	0	0
181	b Capital Expenditures - Interest Expense	1,443,004	1,310,404	1,171,597	1,026,294	874,192	714,970	548,297	373,824	191,186	0	0	0
182	c Expense Expenditures - Amort. of Principal	5,762,096	6,031,763	6,314,050	6,609,547	6,918,874	7,242,677	7,581,635	7,936,455	8,307,880	0	0	0
183	d Expense Expenditures - Interest Expense	2,934,593	2,664,927	2,382,640	2,087,143	1,777,816	1,454,013	1,115,055	760,235	388,809	0	0	0
185	FY 2012 Deflator values												
186	**14** **2014 Conservation - 2012$$ -**	1.126236	1.148826	1.172869	1.196822	1.220128	1.243473	1.266893	1.290190	1.313715	1.338068	1.362866	1.387748
187	**Debt service in FY2012 Purchasing Power Dollars**												
188	a Capital Expenditures - Amort. of Principal	2,515,771	2,581,724	2,647,148	2,715,576	2,788,366	2,864,063	2,942,678	3,024,772	3,109,631	0	0	0
189	b Capital Expenditures - Interest Expense	1,281,263	1,140,646	998,915	857,516	716,476	574,978	432,789	289,743	145,531	0	0	0
190	c Expense Expenditures - Amort. of Principal	5,116,242	5,250,371	5,383,423	5,522,581	5,670,613	5,824,555	5,984,432	6,151,385	6,323,959	0	0	0
191	d Expense Expenditures - Interest Expense	2,605,664	2,319,696	2,031,463	1,743,904	1,457,073	1,169,316	880,149	589,243	295,961	0	0	0
192													
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Debt Service Components - (whole dollars)

Row	Vintage - Year Selected	TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
196	**INFLATION ADJUSTED ANALYSIS**									
197	**FY 2013 Conservation Resources Selected**									
198	**15 2013 Conservation - 2013$$ -**									
199	**Debt Service in Nominal Year Dollars**									
200	a Capital Expenditures - Amort. of Principal	47,221,100	0	0	0	2,241,571	2,346,476	2,456,291	2,571,246	2,691,580
201	b Capital Expenditures - Interest Expense	19,551,672	0	0	0	2,209,947	2,105,042	1,995,227	1,880,272	1,759,938
202	c Expense Expenditures - Amort. of Principal	95,228,000	0	0	0	4,520,443	4,731,999	4,953,457	5,185,279	5,427,950
203	d Expense Expenditures - Interest Expense	39,428,703	0	0	0	4,456,670	4,245,114	4,023,656	3,791,834	3,549,163
205	FY 2013 Deflator values					1.000000	1.020253	1.040748	1.061371	1.082280
206	**15 2013 Conservation - 2013$$ -**									
207	**Debt service in FY2013 Purchasing Power Dollars**									
208	a Capital Expenditures - Amort. of Principal	40,613,111	0	0	0	2,241,571	2,299,896	2,360,121	2,422,570	2,486,953
209	b Capital Expenditures - Interest Expense	17,773,934	0	0	0	2,209,947	2,063,255	1,917,109	1,771,550	1,626,139
210	c Expense Expenditures - Amort. of Principal	81,902,060	0	0	0	4,520,443	4,638,064	4,759,516	4,885,454	5,015,292
211	d Expense Expenditures - Interest Expense	35,843,640	0	0	0	4,456,670	4,160,844	3,866,119	3,572,581	3,279,339
213	**FY 2014 Conservation Resources Selected**									
214	**16 2012 Conservation - 2014$$ -**									
215	**Debt Service in Nominal Year Dollars**									
216	a Capital Expenditures - Amort. of Principal	49,139,500	0	0	0	0	2,332,636	2,441,804	2,556,080	2,675,705
217	b Capital Expenditures - Interest Expense	20,345,979	0	0	0	0	2,299,729	2,190,561	2,076,285	1,956,660
218	c Expense Expenditures - Amort. of Principal	98,290,500	0	0	0	0	4,665,819	4,884,179	5,112,759	5,352,036
219	d Expense Expenditures - Interest Expense	40,696,716	0	0	0	0	4,599,995	4,381,635	4,153,055	3,913,778
221	FY 2014 Deflator values						1.000000	1.020087	1.040301	1.060795
222	**16 2012 Conservation - 2014$$ -**									
223	**Debt service in FY2014 Purchasing Power Dollars**									
224	a Capital Expenditures - Amort. of Principal	42,298,028	0	0	0	0	2,332,636	2,393,721	2,457,058	2,522,358
225	b Capital Expenditures - Interest Expense	18,503,867	0	0	0	0	2,299,729	2,147,426	1,995,850	1,844,522
226	c Expense Expenditures - Amort. of Principal	84,605,958	0	0	0	0	4,665,819	4,788,002	4,914,692	5,045,307
227	d Expense Expenditures - Interest Expense	37,012,062	0	0	0	0	4,599,995	4,295,354	3,992,167	3,689,476
229	**FY 2015 Conservation Resources Selected**									
230	**17 2011 Conservation - 2015$$ -**									
231	**Debt Service in Nominal Year Dollars**									
232	a Capital Expenditures - Amort. of Principal	42,924,100	0	0	0	0	0	2,037,593	2,132,952	2,232,775
233	b Capital Expenditures - Interest Expense	17,772,522	0	0	0	0	0	2,008,848	1,913,489	1,813,666
234	c Expense Expenditures - Amort. of Principal	95,303,100	0	0	0	0	0	4,524,008	4,735,731	4,957,364
235	d Expense Expenditures - Interest Expense	39,459,800	0	0	0	0	0	4,460,185	4,248,462	4,026,829
237	FY 2015 Deflator values							1.000000	1.019816	1.039906
238	**17 2011 Conservation - 2015$$ -**									
239	**Debt service in FY2015 Purchasing Power Dollars**									
240	a Capital Expenditures - Amort. of Principal	36,977,518	0	0	0	0	0	2,037,593	2,091,507	2,147,093
241	b Capital Expenditures - Interest Expense	16,169,437	0	0	0	0	0	2,008,848	1,876,308	1,744,067
242	c Expense Expenditures - Amort. of Principal	82,100,081	0	0	0	0	0	4,524,008	4,643,711	4,767,127
243	d Expense Expenditures - Interest Expense	35,900,516	0	0	0	0	0	4,460,185	4,165,910	3,872,301

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Debt Service Components - (whole dollars)

Vintage - Year Selected	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2013 Conservation Resources Selected												
15 2013 Conservation - 2013$$ -												
Debt Service in Nominal Year Dollars												
a Capital Expenditures - Amort. of Principal	2,817,546	2,949,407	3,087,439	3,231,931	3,383,186	3,541,519	3,707,262	3,880,762	4,062,382	4,252,502	0	0
b Capital Expenditures - Interest Expense	1,633,972	1,502,111	1,364,079	1,219,587	1,068,332	909,999	744,256	570,756	389,137	199,017	0	0
c Expense Expenditures - Amort. of Principal	5,681,978	5,947,894	6,226,257	6,517,646	6,822,671	7,141,972	7,476,217	7,826,104	8,192,365	8,575,768	0	0
d Expense Expenditures - Interest Expense	3,295,135	3,029,219	2,750,857	2,459,468	2,154,443	1,835,142	1,500,897	1,151,010	784,749	401,346	0	0
FY 2013 Deflator values	1.103764	1.125903	1.149466	1.172941	1.195782	1.218662	1.241615	1.264447	1.287502	1.311370	1.335673	1.360058
15 2013 Conservation - 2013$$ -												
Debt service in FY2013 Purchasing Power Dollars												
a Capital Expenditures - Amort. of Principal	2,552,671	2,619,592	2,685,977	2,755,408	2,829,267	2,906,072	2,985,839	3,069,138	3,155,243	3,242,793	0	0
b Capital Expenditures - Interest Expense	1,480,364	1,334,139	1,186,707	1,039,768	893,417	746,720	599,426	451,388	302,242	151,763	0	0
c Expense Expenditures - Amort. of Principal	5,147,820	5,282,777	5,416,652	5,556,670	5,705,614	5,860,503	6,021,365	6,189,349	6,362,992	6,539,549	0	0
d Expense Expenditures - Interest Expense	2,985,362	2,690,480	2,393,161	2,096,839	1,801,702	1,505,866	1,208,826	910,287	609,513	306,051	0	0
FY 2014 Conservation Resources Selected												
16 2012 Conservation - 2014$$ -												
Debt Service in Nominal Year Dollars												
a Capital Expenditures - Amort. of Principal	2,800,928	2,932,011	3,069,229	3,212,869	3,363,231	3,520,631	3,685,396	3,857,874	4,038,422	4,227,420	4,425,264	0
b Capital Expenditures - Interest Expense	1,831,437	1,700,354	1,563,136	1,419,496	1,269,134	1,111,734	946,969	774,492	593,944	404,946	207,102	0
c Expense Expenditures - Amort. of Principal	5,602,511	5,864,708	6,139,177	6,426,490	6,727,250	7,042,086	7,371,656	7,716,649	8,077,789	8,455,829	8,851,562	0
d Expense Expenditures - Interest Expense	3,663,303	3,401,106	3,126,637	2,839,324	2,538,564	2,223,729	1,894,159	1,549,166	1,188,026	809,986	414,253	0
FY 2014 Deflator values	1.081853	1.103552	1.126648	1.149657	1.172044	1.194470	1.216967	1.239346	1.261944	1.285337	1.309158	1.333059
16 2012 Conservation - 2014$$ -												
Debt service in FY2014 Purchasing Power Dollars												
a Capital Expenditures - Amort. of Principal	2,589,010	2,656,885	2,724,213	2,794,633	2,869,543	2,947,442	3,028,345	3,112,830	3,200,159	3,288,958	3,380,237	0
b Capital Expenditures - Interest Expense	1,692,870	1,540,801	1,387,422	1,234,713	1,082,838	930,734	778,139	624,920	470,658	315,050	158,195	0
c Expense Expenditures - Amort. of Principal	5,178,625	5,314,392	5,449,064	5,589,919	5,739,759	5,895,574	6,057,400	6,226,388	6,401,068	6,578,686	6,761,263	0
d Expense Expenditures - Interest Expense	3,386,137	3,081,963	2,775,168	2,469,714	2,165,929	1,861,687	1,556,459	1,249,987	941,425	630,174	316,427	0
FY 2015 Conservation Resources Selected												
17 2011 Conservation - 2015$$ -												
Debt Service in Nominal Year Dollars												
a Capital Expenditures - Amort. of Principal	2,337,268	2,446,653	2,561,156	2,681,018	2,806,491	2,937,835	3,075,325	3,219,250	3,369,911	3,527,623	3,692,716	3,865,534
b Capital Expenditures - Interest Expense	1,709,173	1,599,788	1,485,285	1,365,423	1,239,951	1,108,607	971,117	827,192	676,531	518,819	353,726	180,907
c Expense Expenditures - Amort. of Principal	5,189,368	5,432,231	5,686,459	5,952,585	6,231,166	6,522,785	6,828,051	7,147,605	7,482,113	7,832,276	8,198,826	8,582,532
d Expense Expenditures - Interest Expense	3,794,825	3,551,962	3,297,734	3,031,608	2,753,027	2,461,408	2,156,142	1,836,589	1,502,081	1,151,918	785,368	401,662
FY 2015 Deflator values	1.060549	1.081821	1.104462	1.127018	1.148965	1.170948	1.193003	1.214941	1.237094	1.260027	1.283378	1.306808
17 2011 Conservation - 2015$$ -												
Debt service in FY2015 Purchasing Power Dollars												
a Capital Expenditures - Amort. of Principal	2,203,828	2,261,606	2,318,917	2,378,860	2,442,625	2,508,937	2,577,802	2,649,717	2,724,054	2,799,641	2,877,341	2,957,997
b Capital Expenditures - Interest Expense	1,611,593	1,478,792	1,344,804	1,211,536	1,079,190	946,760	814,011	680,850	546,871	411,752	275,621	138,434
c Expense Expenditures - Amort. of Principal	4,893,096	5,021,377	5,148,623	5,281,712	5,423,286	5,570,516	5,723,415	5,883,088	6,048,136	6,215,959	6,388,473	6,567,554
d Expense Expenditures - Interest Expense	3,578,170	3,283,318	2,985,828	2,689,938	2,396,093	2,102,064	1,807,323	1,511,669	1,214,201	914,201	611,954	307,361

Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are deferred and amortized / financed over 15 - years

Debt Service Components - (whole dollars)

SUMMARY TOTALS - INFLATION ADJUSTED VALUES ANALYSIS

DEBT SERVICE COMPONENT PARTS		TOTALS	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
TOTALS - CAPITAL EXPENDITURES -		332,724,143								
a	AMORTIZATION OF PRINCIPAL	332,724,143	7,549,912	9,814,342	12,216,435	14,774,570	17,491,636	19,987,273	20,516,136	21,061,382
TOTALS - CAPITAL EXPENDITURES -		145,677,302								
b	INTEREST EXPENSE	145,677,302	7,443,399	8,988,111	10,476,967	11,917,548	13,302,975	14,247,373	13,053,304	11,859,519
TOTALS - EXPENSE EXPENDITURES -		729,426,845								
c	AMORTIZATION OF PRINCIPAL	729,426,845	17,952,725	22,681,413	27,635,461	32,872,027	38,393,167	43,922,555	45,084,741	46,282,938
TOTALS - EXPENSE EXPENDITURES -		319,376,889								
d	INTEREST EXPENSE	319,376,889	17,699,456	20,725,999	23,578,885	26,297,551	28,867,634	30,997,943	28,379,996	25,762,509
		1,062,150,988								
TOTALS - CONSERVATION PRINCIPAL COSTS		1,062,150,988	25,502,637	32,495,755	39,851,896	47,646,597	55,884,803	63,909,828	65,600,877	67,344,320
		465,054,191								
TOTALS - INTEREST EXPENSE		465,054,191	25,142,855	29,714,110	34,055,852	38,215,099	42,170,609	45,245,316	41,433,300	37,622,028
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)		100.00%	2.40%	3.06%	3.75%	4.49%	5.26%	6.02%	6.18%	6.34%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)			2.40%	5.46%	9.21%	13.70%	18.96%	$\boxed{24.98\%}$	31.16%	37.50%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD = 24.98%

TOTAL INTEREST PAID ON EXPENSED CONSERVATON COSTS (INFLATION ADJUSTED DOLLARS) = 319,376,889
CONSERVATION EXPENSE EXPENDITURES (NOMINAL DOLLAR VALUES-YEAR OF INVESTMENT) = 849,034,700
INFLATION ADJUSTED INTEREST AS A PERCENTAGE OF ORIGINAL INVESTMENT COSTS = 37.62%

INTEREST (INFLATION ADJUSTED) EXPENDITURES BY PERIOD

Interest Paid FY2010-2011	Interest Paid FY2012-2015	Interest Paid FY2010-2015	Interest Paid FY2016-2029	Total Interest Paid FY2010-2029
54,856,965	159,686,876	214,543,841	250,510,350	465,054,191

Note 1 - Debt service cash flows are inflation adjusted to the year that the conservation resource is selected from the resource stack. The cash flows associated with the 9 conservation resources chosen in FY2010 are stated in FY 2010 purchasing power dollar values. The cash flows associated with the single conservation resource chosen in each of the remaining years of the rate test period are restated in the purchasing power dollar values associated with that year, the year the resource investment is made. Thus the debt service cash flows are a mixture of purchasing power dollars associated with the year that each conservation investment is made.

Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are deferred and amortized / financed over 15 - years

Debt Service Components - (whole dollars)

DEBT SERVICE COMPONENT PARTS	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
TOTALS - CAPITAL EXPENDITURES -												
a AMORTIZATION OF PRINCIPAL	21,617,921	22,184,666	22,746,850	23,334,848	23,960,335	24,610,787	25,286,319	14,834,677	12,189,087	9,331,392	6,257,578	2,957,997
TOTALS - CAPITAL EXPENDITURES -												
b INTEREST EXPENSE	10,662,193	9,460,713	8,249,816	7,041,458	5,835,748	4,625,893	3,409,886	2,186,282	1,465,302	878,565	433,816	138,434
TOTALS - EXPENSE EXPENDITURES -												
c AMORTIZATION OF PRINCIPAL	47,505,946	48,751,384	49,986,803	51,278,938	52,653,461	54,082,849	55,567,347	30,587,451	25,136,155	19,334,194	13,149,736	6,567,554
TOTALS - EXPENSE EXPENDITURES -												
d INTEREST EXPENSE	23,137,176	20,502,664	17,847,576	15,197,816	12,553,504	9,899,904	7,232,599	4,548,409	3,061,100	1,850,426	928,381	307,361
TOTALS - CONSERVATION PRINCIPAL COSTS	69,123,867	70,936,050	72,733,653	74,613,786	76,613,796	78,693,636	80,853,666	45,422,128	37,325,242	28,665,586	19,407,314	9,525,551
TOTALS - INTEREST EXPENSE	33,799,369	29,963,377	26,097,392	22,239,274	18,389,252	14,525,797	10,642,485	6,734,691	4,526,402	2,728,991	1,362,197	445,795
PERCENTAGE OF TOTAL PRINCIPAL PAID (Capital and Expense Expenditures)	6.51%	6.68%	6.85%	7.02%	7.21%	7.41%	7.61%	4.28%	3.51%	2.70%	1.83%	0.90%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAI (Capital and Expense Expenditures)	44.01%	50.69%	57.54%	64.56%	71.77%	79.18%	86.79%	91.07%	94.58%	97.28%	99.11%	100.01%

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APPENDIX C

Non - Conservation Resources

Documentation of the Annual Amounts of Non - Conservation Resources Available

AND

Documentation of Projected Resource Costs

Section 7(b)(2) Rate Test Study and Documentation

WP-10 Final Rate Proposal
WP-10-FS-BPA-06A

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Section 7(b)(2) Rate Test Study and Documentation
Summary of Non - Conservation Resources
WP-10 Final Rate Proposal

Name of Resource	Amount MW	Projected Annual Generation MWh	Capital Investment 2010 $$ ($ 000)	Capital Investment 2015 $$ ($ 000)	Annual O & M ($ 000)	Remaining Useful Life	Annual Capital Cost ($ 000)	Cost Per MWh $ / MWh FY 2010
Resources Included in the 7(b)(2) Resource Stack:								
Billing Credits	10.14	88,833	------	------	$5,267.8	30	0.0	$59.30
Boardman Coal Plant	49.71	435,453	$65,850.9	$113,982.8	$16,103.6	30	0.0	$36.98
Cowlitz Falls Hydro Project	26.00	227,760	$194,980.2		$4,137.3	60	11,620.5	$69.19
Idaho Falls Hydro Project	14.00	122,640	------	------	$4,978.4	60	0.0	$40.59
Wauna Cogeneration	21.70	190,000	------	------	$11,175.9	30	0.0	$58.82
Other Resources NOT Included in the 7(b)(2) Resource Stack - Non-Dedicated Portions:								
Nine Canyon Wind Project	13.52	118,459	------	------	$8,751.0	20	0.0	$73.88
Priest Rapids Hydro	14.90	130,524	$10,644.7	$17,787.9	$2,931.8	70	0.0	$22.46
Wanapum Hydro	14.80	129,648	$19,084.7	$28,227.6	$3,712.9	70	0.0	$28.64

WP-10 Power Rate Case
Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts
Forecasted Cost of Resource During FY2010

Billing Credit Summary - 7(b)(2) Case

BPA Billing Credits - 7(b)(2) Case Costs - 2010$$

Summary:	Average aMW	Total MWh/Year	Cost Per MWh	Annual Cost
Project A - South Fork Tolt Hydro Project	6.5468	57,350	$59.4976	3,412,189
Project B - Wynochee Hydro Project	3.5939	31,483	$58.9409	$1,855,637
	10.1408	88,833	$59.30	$5,267,826
Annual Cost Data	10.1408	88,833	$59.30	$5,267,826

Estimated remaining useful life = 30 years

Notes:

Note 1 - The Program Case Revenue requirement includes the Smith Creek Hydro Project for the years of FY2010-2011 and the Short Mountain Landfill Project for the years FY 2010-2012. The Smith Creek Hydro Project contract terminates on September 30, 2011 and the Short Mountain landfill Project terminates on July 31, 2012. Because these resources are not available to serve 7(b)(2) Customer loads during all years of the rate test period (FY 2010-2015) they were omitted from the 7(b)(2) Case resource stack. The costs and the average hourly energy amounts are not comparable between the Program Case and the 7(b)(2) Case due to the expiration of these power purchase contracts.

Note 2 - Billing Credit Amounts for the Program Case:

	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Average Hourly Energy - aMW	17.5	17.5	11.8	10.1	10.1	10.1
Annual Revenue Requirement Costs	$7,383,000	$7,469,000	$5,873,000	$5,685,000	$5,749,967	$5,815,676

Note 3 - The cost of the two billing credit resources contained in the resource stack was based on the alternative cost value average for FY2010-2015 per the applicable contract schedule. Because this amount is an average of the entire six year rate test period, the cost of the resource would be overstated if this average cost amount was escalated by the rate models escalation cost factors. For this reason the annual cost amount is entered in the "Annual Capital Cost' column in the 2010 Rate Model's resource Sort tab, this annual cost amount does not escalate once it is chosen from the resource stack.

Note 4 - The cost paid for billing credits as determined by the applicable contract provisions is dependent on the level of BPA's power and transmission rates during the rate test period. This spread sheet used a projected percentage cost escalation amount of 7.5% for BPA's 2010-2011 Power Rates over the level of BPA's 2007-2009 power rates. Based on the TS-10 Partial Settlement Offer being worked out between BPA and the rate case parties, it was assumed that there would be a 0% percentage increase for BPA's 2010-2011 Transmission Rates over the level of BPA's 2008-2009 transmission rates.

WP-10 Power Rate Case
Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts
Forecasted Cost of Resource During FY2010

Project A - South Fork Tolt Hydro Project - Billing Credit Detail

Projected FY 2010-2015 Power Rate Increase over FY2007-2009 Power Rates = 1.0750
Projected FY 2010-2015 Transmission Rate Increase over FY2007-2009 Power Rates = 1.0000

NERC FY 2010 Hourly Amounts:

Month	Hours	HLH	LLH	Projected 2010-2011 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Load Variance $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Demand kW	Alternative Cost $/MWh /5	PF Power Only $	Projected PTP-10 plus Load Shaping 1.501	Alternative Cost Value $	Cost of PF Power plus Tx $	Billing Credit $
October	744	432	312	31.93	23.39	2.09	0.51	4085	0	11,200	97.75	155,845	22,515	399,309	178,360	220,948
November	721	384	337	34.06	24.83	2.24	0.51	3966	0	11,200	97.75	162,113	22,515	387,677	184,628	203,048
December	744	416	328	35.54	26.08	2.34	0.51	4136	0	11,200	97.75	175,328	22,515	404,294	197,843	206,451
January	744	400	344	30.18	21.82	1.99	0.51	4158	0	11,300	97.75	150,042	22,515	406,445	172,557	233,887
February	672	384	288	30.81	22.04	2.02	0.51	3783	0	11,300	97.75	141,301	22,515	369,788	163,816	205,972
March	743	432	311	28.58	20.95	1.88	0.51	4180	0	11,300	97.75	142,852	22,515	408,595	165,367	243,228
April	720	416	304	26.82	19.27	1.76	0.51	4060	0	11,300	97.75	130,867	22,515	396,865	153,382	243,483
May	744	400	344	22.40	15.49	1.46	0.51	4933	0	12,300	97.75	130,989	22,515	482,201	153,504	328,697
June	720	416	304	20.29	10.77	1.34	0.51	5710	0	13,600	97.75	136,989	22,515	558,153	159,504	398,649
July	744	416	328	24.98	18.29	1.64	0.51	6993	0	15,000	97.75	202,911	22,515	683,566	225,426	458,140
August	744	416	328	29.25	21.69	1.92	0.51	6702	0	14,700	97.75	227,711	22,515	655,121	250,226	404,894
September	720	400	320	30.20	24.23	1.99	0.51	4644	0	12,100	97.75	166,644	22,515	453,951	189,159	264,792
	8,760	4,912	3,848					57,350	0	146,500		1,923,593	270,180	5,605,963	2,193,773	3,412,189

Average aMW **6.5468** **Annual Cost per MWh** **59.4976**

Note 5 - Alternative cost value is the average of FY2010-2015 contract schedule, Exhibit C, Table 3.

Project A - South Fork Tolt Hydro Project

NERC FY 2010 Values:

Month	Hours	HLH	LLH	Final 2007-2009 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Load Variance $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Demand kW	Alternative Cost $/MWh /6	PF Power Only $	PTP-08 (1.298/kw/month) plus Ld shaping $0.203 1.501	Alternative Cost Value $	Cost of PF Power plus Tx $	Billing Credit $
October	744	432	312	29.70	21.76	1.94	0.47	4085	0	11200	96.7	143,053	22,515	395,020	165,568	229,452
November	721	384	337	31.68	23.10	2.08	0.47	3966	0	11200	96.7	148,939	22,515	383,512	171,454	212,058
December	744	416	328	33.06	24.26	2.18	0.47	4136	0	11200	96.7	161,152	22,515	399,951	183,667	216,284
January	744	400	344	28.07	20.30	1.85	0.47	4158	0	11300	96.7	137,620	22,515	402,079	160,135	241,944
February	672	384	288	28.66	20.50	1.88	0.47	3783	0	11300	96.7	129,665	22,515	365,816	152,180	213,636
March	743	432	311	26.59	19.49	1.75	0.47	4180	0	11300	96.7	130,921	22,515	404,206	153,436	250,770
April	720	416	304	24.95	17.93	1.64	0.47	4060	0	11300	96.7	119,829	22,515	392,602	142,344	250,258
May	744	400	344	20.84	14.41	1.36	0.47	4933	0	12300	96.7	119,532	22,515	477,021	142,047	334,974
June	720	416	304	18.87	10.02	1.25	0.47	5710	0	13600	96.7	124,748	22,515	552,157	147,263	404,894
July	744	416	328	23.24	17.01	1.53	0.47	6993	0	15000	96.7	185,467	22,515	676,223	207,982	468,241
August	744	416	328	27.21	20.18	1.79	0.47	6702	0	14700	96.7	208,674	22,515	648,083	231,189	416,894
September	720	400	320	28.09	22.54	1.85	0.47	4644	0	12100	96.7	152,835	22,515	449,075	175,350	273,725
	8,760	4,912	3,848					57,350	0	146,500		1,762,435	270,180	5,545,745	2,032,615	3,513,130

Average aMW **6.5468** **Annual Cost per MWh** **61.2577**

Note 6 - Alternative cost value is contract schedule amount for FY 2009, Exhibit C, Table 3.

WP-10 Power Rate Case
Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts
Forecasted Cost of Resource During FY2010

Project B - Wynochee Hydro Project - Billing Credit Detail

Projected FY 2010 Power Rate Increase over FY2007-2009 Power Rates = 1.0750

Projected FY 2010 Transmission Rate Increase over FY2007-2009 Power Rates = 1.0000

Row	NERC FY 2010 Values: Month	Hours	HLH	LLH	Projected 2010-2011 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Load Variance $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Assured Energy Capabilities	Demand kW	Alternative Cost $/MWh [7]	Alternative Cost Value $	Projected PTP-10 plus Load Shaping 1.501	PF Power Costs Only $	**PF Power Plus Tx** $	**Billing Credit** $
101	October	744	432	312	31.93	23.39	2.09	0.51	2,122	1,532	3,654	4,910	93.8	342,745	10,567	115,670	126,237	216,508
102	November	721	384	337	34.06	24.83	2.24	0.51	2,242	1,967	4,209	5,850	93.8	394,804	10,567	140,403	150,970	243,834
103	December	744	416	328	35.54	26.08	2.34	0.51	2,929	2,310	5,239	7,040	93.8	491,418	10,567	183,487	194,054	297,364
104	January	744	400	344	30.18	21.82	1.99	0.51	2,569	2,210	4,779	6,420	93.8	448,270	10,567	140,933	151,500	296,770
105	February	672	384	288	30.81	22.04	2.02	0.51	2,415	1,812	4,227	6,290	93.8	396,493	10,567	129,188	139,755	256,737
106	March	743	432	311	28.58	20.95	1.88	0.51	1,425	1,026	2,451	3,290	93.8	229,904	10,567	69,657	80,224	149,679
107	April	720	416	304	26.82	19.27	1.76	0.51	1,117	816	1,933	2,680	93.8	181,315	10,567	51,388	61,955	119,361
108	May	744	400	344	22.40	15.49	1.46	0.51	0	0	0	0	93.8	-	10,567	-	10,567	(10,567)
109	June	720	416	304	20.29	10.77	1.34	0.51	0	0	0	0	93.8	-	10,567	-	10,567	(10,567)
110	July	744	416	328	24.98	18.29	1.64	0.51	1,006	793	1,799	2,420	93.8	168,746	10,567	44,522	55,089	113,657
111	August	744	416	328	29.25	21.69	1.92	0.51	912	719	1,631	2,190	93.8	152,988	10,567	47,312	57,879	95,109
112	September	720	400	320	30.20	24.23	1.99	0.51	867	694	1,561	2,170	93.8	146,422	10,567	48,102	58,669	87,753
113		8,760	4,912	3,848					17,604	13,879	31,483	43,260		2,953,105	126,804	970,664	1,097,468	1,855,637

Average aMW **3.5939** **Annual Cost per MWh** **$58.9409**

Note 7 - Alternative cost value is the average of FY2010-2015 contract schedule, Exhibit C, page 10, Table 3.

Project B - Wynochee Hydro Project

Row	NERC FY 2010 Values: Month	Hours	HLH	LLH	Final 2007-2009 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Load Variance $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Assured Energy Capabilities	Demand kW	Alt Cost $/MWh [8]	**AC$** $	PTP-08 (1.298/kw/month) plus Ld shaping $0.203 1.501	PF Power Costs Only $	**PF Power Plus Tx** $	**Billing Credit** $
123	October	744	432	312	29.70	21.76	1.94	0.47	2,122	1,532	3,654	4,910	91.5	334,341	9,636	105,883	115,519	218,822
124	November	721	384	337	31.68	23.10	2.08	0.47	2,242	1,967	4,209	5,850	91.5	385,124	9,636	128,630	138,266	246,858
125	December	744	416	328	33.06	24.26	2.18	0.47	2,929	2,310	5,239	7,040	91.5	479,369	9,636	168,223	177,860	301,509
126	January	744	400	344	28.07	20.30	1.85	0.47	2,569	2,210	4,779	6,420	91.5	437,279	9,636	128,855	138,491	298,787
127	February	672	384	288	28.66	20.50	1.88	0.47	2,415	1,812	4,227	6,290	91.5	386,771	9,636	118,189	127,825	258,945
128	March	743	432	311	26.59	19.49	1.75	0.47	1,425	1,026	2,451	3,290	91.5	224,267	9,636	63,646	73,282	150,985
129	April	720	416	304	24.95	17.93	1.64	0.47	1,117	816	1,933	2,680	91.5	176,870	9,636	46,894	56,531	120,339
130	May	744	400	344	20.84	14.41	1.36	0.47	0	0	0	0	91.5	-	9,636	-	9,636	(9,636)
131	June	720	416	304	18.87	10.02	1.25	0.47	0	0	0	0	91.5	-	9,636	-	9,636	(9,636)
132	July	744	416	328	23.24	17.01	1.53	0.47	1,006	793	1,799	2,420	91.5	164,609	9,636	40,570	50,207	114,402
133	August	744	416	328	27.21	20.18	1.79	0.47	912	719	1,631	2,190	91.5	149,237	9,636	43,245	52,881	96,355
134	September	720	400	320	28.09	22.54	1.85	0.47	867	694	1,561	2,170	91.5	142,832	9,636	44,013	53,649	89,183
135		8,760	4,912	3,848					17,604	13,879	31,483	43,260		2,880,695	115,637	888,146	1,003,783	1,876,911

Average aMW **3.5939** **Annual Cost per MWh** **$59.6167**

Note 8 - Alternative cost value is the FY2009 contract schedule value, Exhibit C, page 10, Table 3.

Determination of Adjusted Alternative Cost

TABLE 3
(continued)

DERIVATION OF ADJUSTED ALTERNATIVE COST - SOUTH FORK TOLT HYDRO PROJECT

Adjusted Alternative Cost Stream 1/
(nominal mills/kWh)

2/ Year	Fixed	Variable	Total	2/ Year	Fixed	Variable	Total
1996	82.9	6.6	89.5	2021	82.9	22.4	105.3
1997	82.9	6.9	89.9	2022	82.9	23.5	106.4
1998	82.9	7.3	90.2	2023	82.9	24.7	107.6
1999	82.9	7.7	90.6	2024	82.9	25.9	108.8
2000	82.9	8.0	91.0	2025	82.9	27.2	110.1
2001	82.9	8.4	91.4	2026	82.9	28.6	111.5
2002	82.9	8.9	91.8	2027	82.9	30.0	112.9
2003	82.9	9.3	92.2	2028	82.9	31.5	114.4
2004	82.9	9.8	92.7	2029	0.0	0.0	0.0
2005	82.9	10.3	93.2	2030	0.0	0.0	0.0
2006	82.9	10.8	93.7	2031	0.0	0.0	0.0
2007	82.9	11.3	94.2	2032	0.0	0.0	0.0
2008	82.9	11.9	94.8	2033	0.0	0.0	0.0
2009	82.9	12.5	95.4	2034	0.0	0.0	0.0
2010	82.9	13.1	96.0	2035	0.0	0.0	0.0
2011	82.9	13.7	96.7	2036	0.0	0.0	0.0
2012	82.9	14.4	97.3	2037	0.0	0.0	0.0
2013	82.9	15.1	98.1	2038	0.0	0.0	0.0
2014	82.9	15.9	98.8	2039	0.0	0.0	0.0
2015	82.9	16.7	99.6	2040	0.0	0.0	0.0
2016	82.9	17.5	100.5	2041	0.0	0.0	0.0
2017	82.9	18.4	101.3	2042	0.0	0.0	0.0
2018	82.9	19.3	102.3	2043	0.0	0.0	0.0
2019	82.9	20.3	103.2	2044	0.0	0.0	0.0
2020	82.9	21.3	104.2	2045	0.0	0.0	0.0

Average of six years = 97.75

1/ This table derived from the levelized Adjusted Alternative Cost using the Variable/Total Cost Fraction and assumes 5 percent annual inflation and a 3 percent real discount rate.

2/ Year = Calendar Year.

(VS6-PMCE-4712c)

AC < NC

Revision No. 1
Exhibit C, Page 10 of 11
Contract No. DE-MS79-92BP93649
Procurement No. 76520
City of Tacoma
Effective at 0001 hours
on August 1, 1993

Determination of Adjusted Alternative Cost

TABLE 3
(continued)

DERIVATION OF ADJUSTED ALTERNATIVE COST - WYNOOCHEE HYDRO PROJECT

Adjusted Alternative Cost Stream 1/
(nominal mills/kWh)

2/ Year	Fixed	Variable	Total	2/ Year	Fixed	Variable	Total
1994	79.4	5.8	85.2	2015	79.4	16.2	95.6
1995	79.4	6.1	85.5	2016	79.4	17.1	96.4
1996	79.4	6.4	$\boxed{85.8}$	2017	79.4	17.9	97.3
1997	79.4	6.8	$\boxed{86.1}$	2018	79.4	18.8	98.2
1998	79.4	7.1	86.5	2019	79.4	19.7	99.1
1999	79.4	7.4	86.8	2020	79.4	20.7	100.1
2000	79.4	7.8	87.2	2021	79.4	21.8	101.2
2001	79.4	8.2	87.6	2022	79.4	22.9	102.2
2002	79.4	8.6	88.0	2023	79.4	24.0	103.4
2003	79.4	9.0	88.4	2024	79.4	25.2	104.6
2004	79.4	9.5	88.9	2025	79.4	26.5	105.8
2005	79.4	10.0	89.4	2026	79.4	27.8	107.2
2006	79.4	10.5	89.9	2027	79.4	29.2	108.6
2007	79.4	11.0	90.4	2028	79.4	30.6	110.0
2008	79.4	11.5	90.9	2029	79.4	32.2	111.6
2009	79.4	12.1	91.5	2030	79.4	33.8	113.2
2010	79.4	12.7	92.1	2031	79.4	35.5	114.8
2011	79.4	13.4	92.7	2032	79.4	37.2	116.6
2012	79.4	14.0	93.4	2033	79.4	39.1	118.5
2013	79.4	14.7	94.1	2034	79.4	41.1	120.4
2014	79.4	15.5	94.9	2035	79.4	43.1	122.5
2015	79.4	16.2	95.6				

Average of 6 years = 93.8

1/ This table derived from the levelized Adjusted Alternative Cost using the Variable/Total Cost ratio and assumes 5 percent annual inflation and a 3 percent real discount rate.
2/ Year = Calendar Year.

BPA-TS Transmission Rates Partial Settlement Offer
Summary for AE/CAT Meeting
As of January 9, 2009

The following is in the perspective of BPA-PS as a Transmission Customer (TC) of BPA-TS, so the BPA-TS perspective is not necessarily represented.

BPA has been holding Transmission and Power Rates Workshops for several months. BPA-TS has proposed a Transmission Rates Partial Settlement, and asked parties to returned signed copies by Jan. 16, 2009 so they may determine whether there is sufficient agreement prior to the Transmission Rates Initial Proposal (February 2009).

Partial Settlement summary:

- Rates stay at WT-08 levels for the base transmission rates, including Network Integration (NT), Point-to-Point (PTP) for the Network and Southern Intertie segments. Power Factor Penalty Charge, Utility Delivery Charge, Scheduling Control and Dispatch, and Generation Supplied Reactive also remained unchanged.
- The following were not included in the settlement: Regulation and Frequency Response, Energy Imbalance, Operating Reserves for Spinning and Supplemental, Generation Imbalance, and Control Area Services. The issues that are not included in the partial settlement will be litigated as part of the rate case.
    - Ancillary Services and Control Area Services will be part of the Transmission docket.
    - Generation Inputs are part of the Power Rates docket.
    - The Wind Integration Rate Case settlement put into place the BPA Wind Integration Team (WIT). The WIT is working on operational and reliability issues.
- To address customers' requests, the settlement includes BPA's plan to hold review and discussions on rate design for future rate periods, for rates such as Utility Delivery Charge (for low voltage service) and the Northern Intertie segment (as separate from the Network segment of PTP).
- The Failure to Comply (FTC) rate increased from $100 to $1,000/MW, and includes a new provision that states that those assessed the FTC will be assessed other costs to manage the situation and/or monetary penalties imposed on BPA that results from the customer's non-compliance, to the extent that the customer's non-compliance contributed to the problem.
- To address customer concerns about the increase in the FTC rate, BPA-TS will hold a public business practice process for implementing this new charge. BPA-TS included the provision that the new FTC rate will not be assessed until the business practice process is completed.
- Unauthorized Increase Charge (UIC) increased from twice the rate of the transmission purchase (which varies), to the lower of $100/MWh plus the FERC price cap for WECC spot market, or $1,000/MWh. If FERC eliminates this price cap, the charge will be $500/MWh.
- An updated "Procedures for Redispatch" (Attachment M, formerly referred to as Attachment K) is included. No substantive change.

On a separate note, BPA-PS submitted comments recommending that the Generation and Energy Imbalance rates schedules clarify that when (1) during the Spill Condition and Intentional Deviation situations, and (2) the BPA Incremental Cost is negative (due to negative Mid-C prices), BPA will not pay customers when imbalance energy is delivered to Customers. This is not part of the partial settlement, and is expected to be addressed in the Transmission Rate Case process.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Cost Projections -10% Interest in Boardman Coal Plant

SUMMARY

7(b)(2) Case - Resource Stack Values:		
		FY2010-$$
Total Annual Operating and Maintenance (O & M) / Production Expenses:		16,103,582
Debt Service - Included in O&M Amount Above		0
Total Operating and Financing Costs - (Production and Debt Service)		16,103,582
Cost per MWh		**$36.98**
	100.00%	**10.00%**
Projected Capital Investment - as of FY 2010	658,508,594	65,850,859
Projected Capital Investment - as of FY 2015	1,139,828,277	113,982,828
Depreciable Life at beginning placed in service date -1980	60 years	
Estimated remaining useful life at FY 2010	30 years	
Placed in service	1980	
	100.00%	**10.00%**
Plants Name Plate Rating (MW)	642	64.2
Net Continuous Plant Capability (MW)	585	58.50
Projected Net Annual Generation - MWh - Based on PGE's		
2007 FERC Form 1 Amounts	4,354,531	435,453
Projected Capacity Factor	77.43%	77.43%
Projected Average Hourly Generation - aMW	497.09	49.71

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Cost Projections -10% Interest in Boardman Coal Plant

SUMMARY

	BPA's Projected Boardman Operating 100% Budget FY 2010	BPA's Projected Boardman Operating 100% Budget FY 2011	BPA's Projected Boardman Operating 100% Budget FY 2012	BPA's Projected Boardman Operating 100% Budget FY 2013	BPA's Projected Boardman Operating 100% Budget FY 2014	BPA's Projected Boardman Operating 100% Budget FY 2015
1. Total Production Expenses - 100% See Production Analysis	105,276,294	107,490,627	109,081,119	110,674,143	131,867,068	133,895,077
2. 2010$$ Price Conversion Factor	1.000000	1.020232	1.041582	1.062788	1.084313	1.106094
PRC's Projected Operating Costs						
3. PRC's 10% Share of Production Expenses (line 1 times 10%)	10,527,629	10,749,063	10,908,112	11,067,414	13,186,707	13,389,508
PRC's 10% Debt Service Costs - See Debt Service Analysis	3,835,826	4,193,794	4,271,583	4,350,940	7,565,520	7,648,170
4. PRC's Projected Total Operating Costs - Nominal $$	14,363,455	14,942,857	15,179,695	15,418,354	20,752,227	21,037,678
Average Annual Operating Costs - Nominal $$	16,949,044					
5. Projected Annual Amounts Stated in 2010$$ (line 4 divided by line 2)	14,363,455	14,646,528	14,573,692	14,507,460	19,138,594	19,019,792
6. FY 2010 -2015 Average Total Operating Costs in 2010$$	16,041,587	16,041,587	16,041,587	16,041,587	16,041,587	16,041,587
7. Operating Cost Adjustment - See Note A below	61,995	61,995	61,995	61,995	61,995	61,995
8. Adjusted Annual Cost Amount in 2010 $$	16,103,582	16,103,582	16,103,582	16,103,582	16,103,582	16,103,582
Ram Model Annual Cost Amounts Using Average Cost Pricing 9. (line 8 times line 2)	16,103,582	16,429,390	16,773,201	17,114,694	17,461,323	17,812,075
Annual Variance Over / (Under) (line 9 less line 4)	1,740,127	1,486,533	1,593,506	1,696,339	(3,290,904)	(3,225,602)
Total of Annual Variances =	(1)					

Note A - It is necessary to make an operating adjustment so that the average total operating costs for all years of the rate test period (FY2010-2015) is equivalent to the total actual operating costs in nominal dollars (line 4) since the RAM model starts with a beginning cost of when the resource is selected from the resource stack and then escalates the cost using the fixed escalation factors at line 2 above. If a simple average of the nominal operating costs for the rate test period were used, the "starting operating cost" of the resource would have been higher at a rate of $16,878,712 in comparison to the adjusted operating cost amount of $16,036,758.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Production Cost Projections -10% Interest in Boardman Coal Plant

Boardman Operating Cost Historical Data OY2007 / PGE Operating Budgets 2008-2009 / FY 2010-2015 BPA Projections:

	PGE's FERC Form No. 1 Data Page 402 OY 2007 - 1/	Portland General Electric's Boardman 100% Budget OY 2008 - 2/	Portland General Electric's Boardman 100% Budget OY 2009 - 3/	BPA's Projected Boardman Operating 100% Budget OY 2010	BPA's Projected Boardman Operating 100% Budget OY 2011	BPA's Projected Boardman Operating 100% Budget OY 2012	BPA's Projected Boardman Operating 100% Budget OY 2013	BPA's Projected Boardman Operating 100% Budget OY 2014	BPA's Projected Boardman Operating 100% Budget OY 2015
Cumulative price deflator Index to convert 2009$$ to respective year $$:				1.020573	1.041221	1.063010	1.084652	1.106620	1.128849
Fuel Cost - FERC # 501 - See Note 5		1,864,722	1,837,111	1,892,224	1,948,991	2,007,461	2,067,685	2,129,715	2,193,607
Fuel Oil Costs			0	0	0	0	0	0	0
Fuel Inventory Oil Purchase - See Note 5		813,962	1,269,066	1,041,514	1,072,759	1,104,942	1,138,090	1,172,233	1,207,400
Payroll Taxes #408		1,016,802	1,016,802	1,037,720	1,058,716	1,080,871	1,102,877	1,125,214	1,147,816
Other Misc. Electric Revenues #456		(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)
Fuel Inventory - Coal fixed O&M #151 - See Note 4		1,930,798	1,601,966	1,617,505	1,633,195	1,649,037	1,665,033	1,681,183	1,697,491
Coal Fuel Costs #151- see Note 4	61,041,164	62,346,284	59,460,450	60,037,216	60,619,577	61,207,587	61,801,301	62,400,773	63,006,061
TOTAL FUEL COSTS	61,041,164	67,372,568	64,585,395	65,026,180	65,733,238	66,449,898	67,174,985	67,909,119	68,652,375
Operating Cost Data:									
Production Expenses - line 19	6,763,843	7,086,196	7,081,771	7,227,462	7,373,688	7,527,995	7,681,260	7,836,831	7,994,253
Incremental Production Expenses - new pollution controls-see Note 6			0	0	0	0	0	12,378,690	12,627,345
Misc. Steam / Power Expenses FERC #506 & #557- line 26	2,169,128	2,266,495	2,150,974	2,195,225	2,239,639	2,286,507	2,333,059	2,380,311	2,428,126
Rent Expense #507- line 27	0	0	0	0	0	0	0	0	0
Allowances - line 28	0	0	0	0	0	0	0	0	0
Administrative & General Expenses #921-#930		5,953,214	5,810,950	5,930,497	6,050,483	6,177,099	6,302,861	6,430,515	6,559,687
TOTAL OPERATION COSTS	8,932,971	15,305,905	15,043,695	15,353,184	15,663,810	15,991,601	16,317,180	29,026,347	29,609,410
Maintenance Expense -									
Base Amount line - 29	19,406,261	18,902,363	24,395,046	24,896,918	25,400,633	25,932,182	26,460,146	26,996,052	27,538,332
Incremental Costs Pollution Controls - See Note 6		0	0	0	692,944	707,445	721,849	7,935,562	8,094,967
TOTAL MAINTENANCE EXPENSES	19,406,261	18,902,363	24,395,046	24,896,918	26,093,577	26,639,627	27,181,994	34,931,614	35,633,299
Total Production Expenses	89,380,396	101,580,836	104,024,136	105,276,283	107,490,625	109,081,126	110,674,160	131,867,080	133,895,084

Notes:

Note 1 - PGE's 2007 FERC FORM No. 1 data for Boardman's 2007 operations can be found at Attachment A.

Note 2 - PGE's 2008 Boardman operating budget can be found at Attachment B.

Note 3 - PGE's 2009 Boardman operating budget can be found at Attachment C.

Note 4 - Extended outage planned for OY 2009, new fixed price coal contract signed June of 2008 accounts for decreased coal fuel costs for OY 2009. Coal expense for FY 2010-2015 was calculated using the average price increase information for FY 2010-2013 contained on the March 2008 # DOE/EIA-0383e web site. This annual average increase amount of 0.97% was used to inflate the cost of fuel used to in Boardman's operations.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Production Cost Projections -10% Interest in Boardman Coal Plant

Notes - Continued:

Note 5 - Fuel Oil inventory costs for FY2010 assumes the average of FY2008 and FY2009 amounts. Fuel oil costs for FY 2011-2015 are escalated at an annual rate of 3.0%.

Note 6 - Based on the information contained in PGE's Best Available Retrofit Technology (BART) Analysis Report (see PGE web site) there are four main areas of pollution controls that PGE has identified as meeting BART. These are presented below in chronological order of projected installation by the BPA analyst. The costs are based on information contained in Appendix D - Cost Analysis Summary to the BART report and are displayed below by total 1) Capital Investment Costs, 2) Direct Variable Annual Production expenses, and 3) Direct Variable Annual Maintenance costs. The Executive Summary and Exhibit D to the BART Report can be found at Attachment E. The projected debt service costs associated with PRC's 10% share of the capital investments are presented in the financing of capital additions analysis. The costs presented below are presented in 2007$$ based on the information contained in Appendix D to the Bart Report as referenced. The implementation of the measures was informed by PGE's letter to the Oregon Department of Environmental Quality regarding proposed regional haze rules dated December 17, 2008 (See Attachment D).

	OY 2011	OY 2012	OY 2013	OY 2014	OY 2015
Cumulative price deflator Index to convert 2007$$ to respective year $$:	1.089535	1.112335	1.134982	1.157969	1.181230
A. - Installation of New Low Nox Burners (NLNB) and Modified Over Fire Air (MOFA) System:					
1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-5)	32,651,000				
2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-5)	0				
3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-5)	636,000				
1b) Capital costs in 2011 $$	35,574,412	0	0	0	0
2b) Direct Variable Annual Production expenses in 2011-2015 $$	0	0	0	0	0
3b) Direct Variable Annual Maintenance costs in 2011-2015 $$	692,944	707,445	721,849	736,468	751,262
B. - Installation of Particulate Control Measure - Pulse Jet Fabric Filter (PJFF) System					
1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-12)	94,353,000				
2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-12)	2,121,000				
3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-12)	1,808,000				
1b) Capital costs in 2014 $$	0	0	0	109,257,858	
2b) Direct Variable Annual Production expenses in 2014-2015 $$	0	0	0	2,456,052	2,505,388
3b) Direct Variable Annual Maintenance costs in 2014-2015 $$	0	0	0	2,093,608	2,135,663
C. - Installation of SO_2 Pollution Controls - Semi-Dry Flue Gas Desulfurization (FGD) System					
1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-11)	247,293,000				
2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-11)	8,569,000				
3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-11)	4,409,000				
1b) Capital costs in 2014 $$	0	0	0	286,357,652	0
2b) Direct Variable Annual Production expenses in 2014-2015 $$	0	0	0	9,922,637	10,121,957
3b) Direct Variable Annual Maintenance costs in 2014-2015 $$	0	0	0	5,105,486	5,208,042
Either D. or E. would be installed by 2017 which is outside of the rate test period.					
D. - Selective Non-Catalytic Reduction (SNCR) System					
1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-6)	17,429,000				
2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-6)	3,398,000				
3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-6)	343,000				
E. - Selective Catalytic Reduction (SCR) System					
1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-6)	190,859,000				
2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-6)	2,927,000				
3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-6)	2,746,000				

	OY 2011	OY 2012	OY 2013	OY 2014	OY 2015
SUMMARY - CAPITAL COSTS BY YEAR	35,574,412	0	0	395,615,511	0
SUMMARY - DIRECT VARIABLE ANNUAL PRODUCTION COSTS BY YEAR	0	0	0	12,378,690	12,627,345
SUMMARY - DIRECT ANNUAL MAINTENANCE COSTS BY YEAR	692,944	707,445	721,849	7,935,562	8,094,967

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Cost Projections -10% Interest in Boardman Coal Plant
Analysis of Coal Fuel Cost

	2006	2007	2008
Oil Price Escalation			
Inflations Rate		2.00%	2.00%
Inflation Factor	100.0%	102.0%	104.0%
Coal ($2006) - Delivered Price - March 2008 # DOE/EIA-0383	33.85	34.52	35.23
Coal Nominal	$ 33.85	$ 35.21	$ 36.65
Percentage Change in Coal Price (Nominal)		4.02%	4.10%

		Historical - FERC Form No. 1				PGE Budget
		2004	2005	2006	2007	2008
Net Continuous Plant Capability (MW)	**FERC Form 1, Page 402**	568	585	585	585	585
Hours Connected to load	**FERC Form 1, Page 402**	6,449	6,235	4,357	6,686	
Capacity Factor		71.14%	69.49%	47.11%	84.98%	84.98%
Fuel	**FERC Form 1, Page 402**	$ 44,256,851	$ 47,834,482	$ 35,492,843	$ 61,041,164	$ 62,346,284
Fuel Burned						
Quantity Coal (tons)	**FERC Form 1, Page 402**	2,119,299	2,103,125	1,435,147	2,577,187	2,586,135
Average Heat Content - Coal	**FERC Form 1, Page 402**	8,517	8,517	8,517	8,517	8,517
Average Cost of Fuel - Coal - per unit burned	**FERC Form 1, Page 402**	$ 19.59	$ 20.80	$ 21.53	$ 22.86	$ 24.11
Average BTU / kWh (Heat Rate)	**FERC Form 1, Page 402**	10,198	10,060	10,125	10,081	10,116
Net Generation		3,539,923,433	3,561,096,546	2,414,448,790	4,354,707,207	4,354,707,207
Coal Cost (Total)		**41,517,067**	**43,745,000**	**30,898,715**	**58,914,495**	**62,346,284**
Quantity Oil	**FERC Form 1, Page 402**	11,960	7,418	8,006	6178	8390.5
Average cost of oil - per unit burned	**FERC Form 1, Page 402**	46.055	$ 57.53	$ 80.27	89.201	97.01
Oil cost Total		**$ 550,818**	**$ 426,758**	**$ 642,642**	**$ 551,084**	**$ 813,962**
Total Fuel Cost		**$ 42,067,885**	**$ 44,171,758**	**$ 31,541,357**	**$ 59,465,579**	**$ 63,160,246**

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Cost Projections -10% Interest in Boardman Coal Plant

Analysis of Coal Fuel Cost

	2009	2010	2011	2012	2013
Oil Price Escalation	3.00%	3.00%	3.00%	3.00%	3.00%
Inflations Rate	2.00%	2.00%	2.00%	2.00%	2.00%
Inflation Factor	106.1%	108.2%	110.4%	112.6%	114.9%
Coal ($2006) - Delivered Price -	36.19	36.63	36.06	35.24	34.73
March 2008 # DOE/EIA-0383					
Coal Nominal	$ 38.41	$ 39.65	$ 39.81	$ 39.69	$ 39.89
Percentage Change in Coal Price (Nominal)	4.78%	3.24%	0.41%	-0.32%	0.52%
			Forecast - Projection		
	2009	2010	2011	2012	2013
Net Continuous Plant Capability (MW)	585	585	585	585	585
Hours Connected to load					
Capacity Factor	84.98%	84.98%	84.98%	84.98%	84.98%
Fuel					
Fuel Burned					
Quantity Coal (tons)	2,586,135	2,586,135	2,586,135	2,586,135	2,586,135
Average Heat Content - Coal	8,517	8,517	8,517	8,517	8,517
Average Cost of Fuel - Coal - per unit burned	$ 25.26	$ 26.08	$ 26.19	$ 26.10	$ 26.24
Average BTU / kWh (Heat Rate)	10,116	10,116	10,116	10,116	10,116
Net Generation	4,354,707,207	4,354,707,207	4,354,707,207	4,354,707,207	4,354,707,207
Coal Cost (Total)	**65,326,093**	**67,442,738**	**67,721,126**	**67,504,779**	**67,858,393**
Average Annual Percentage Increase	4.78%	3.24%	0.41%	-0.32%	0.52%
Average Percentage Increase FY 2010-2013		**0.96%**			
Quantity Oil	8390.5	8390.5	8390.5	8390.5	8390.5
Average cost - Oil - per unit burned	99.92	102.92	106.01	109.19	112.46
Oil cost Total	**$ 838,381**	**$ 863,532**	**$ 889,438**	**$ 916,121**	**$ 943,605**
Total Fuel Cost	**$ 66,164,474**	**$ 68,306,270**	**$ 68,610,564**	**$ 68,420,900**	**$ 68,801,998**

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WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant
Summary of Annual Debt Service Amounts - 10% Interest

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Annual Debt Service Increments:						
Original Plant Investment	3,381,700	3,381,700	3,381,700	3,381,700	3,381,700	3,381,700
FY 2005 and Prior Additions	213,871	213,871	213,871	213,871	213,871	213,871
FY 2007 Additions	55,437	55,437	55,437	55,437	55,437	55,437
FY 2008 Additions	19,910	19,910	19,910	19,910	19,910	19,910
FY 2009 Additions	90,178	90,178	90,178	90,178	90,178	90,178
FY 2010 Additions	74,730	74,730	74,730	74,730	74,730	74,730
FY 2011 Additions	0	357,968	357,968	357,968	357,968	357,968
FY 2012 Additions	0	0	77,789	77,789	77,789	77,789
FY 2013 Additions	0	0	0	79,357	79,357	79,357
FY 2014 Additions	0	0	0	0	3,214,580	3,214,580
FY 2015 Additions	0	0	0	0	0	82,650
Total Annual Debt Service Amounts	3,835,826	4,193,795	4,271,583	4,350,940	7,565,520	7,648,171

Projected Annual Capital Additions

	Annual Additions	Cumulative Cost - 100%
1980 Additions	591,000,000	591,000,000
1981-2004 Additions	13,085,247	604,085,247
2005 Additions	18,145,870	622,231,117
2006 Retirements	(359,817)	621,871,300
2007 Additions - FERC Form No. 1 for 2007, page 402	7,037,182	628,908,482
Total Asset Cost -line 17, FERC Form No. 1 - FY 2007		628,908,482
PGE 2008 Final Budget - Capital Additions	8,803,660	
Projected Total Asset Cost - FY 2008		637,712,142
PGE 2009 Preliminary Capital Budget Projections	11,364,709	649,076,851
BPA Projected 2010 Capital Additions	9,431,743	658,508,594
PGE BART Pollution Control Additions - 2011	35,574,407	694,083,001
BPA Projected 2011 Other Capital Additions	9,622,566	703,705,567
PGE BART Pollution Control Additions - 2012	0	703,705,567
BPA Projected 2012 Other Capital Additions	9,823,934	713,529,501
PGE BART Pollution Control Additions - 2013	0	713,529,501
BPA Projected 2013 Other Capital Additions	10,023,943	723,553,444
PGE BART Pollution Control Additions - 2014	395,615,477	1,119,168,921
BPA Projected 2014 Other Capital Additions	10,226,962	1,129,395,883
PGE BART Pollution Control Additions - 2015	0	1,129,395,883
BPA Projected Capital Additions - 2015	10,432,394	1,139,828,277
Projected Total Asset Cost - 12/31/2015		1,139,828,277

Note: PGE's FERC Form 1 Indicates that the original plant is being depreciated over 60 years.
Note: PGE's BART Pollution control report indicates that the average useful life of pollution control equipment is 20 years.
Note: BPA assumes that the average useful life of other asset additions during 2008-2015 is 20 years.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

Initial Investment Amount

				Total AMT	PRC AMT	
Total Capitalized Cost - 1980				591,000,000	59,100,000	Payment
Debt/Capital Mix				80 /20	100 / 0	Amounts
Amount financed in 1980				472,800,000	59,100,000	
30 year Bond @10% in 1980			59,100,000	10.00%	10.00%	6,269,284
Refinance in 1990 - 30 yr. @ 8%			53,373,938	8.00%	8.00%	4,741,071
Refinance in 2000 - 30 yr. @ 6%			46,548,508	6.00%	6.00%	3,381,700

			Payment Amount	Interest	Principle	Balance
Beginning Balance						59,100,000
	1	1980	6,269,284	5,910,000	359,284	58,740,716
	2	1981	6,269,284	5,874,072	395,212	58,345,504
	3	1982	6,269,284	5,834,550	434,734	57,910,770
	4	1983	6,269,284	5,791,077	478,207	57,432,563
	5	1984	6,269,284	5,743,256	526,028	56,906,535
	6	1985	6,269,284	5,690,654	578,630	56,327,905
	7	1986	6,269,284	5,632,790	636,494	55,691,411
	8	1987	6,269,284	5,569,141	700,143	54,991,268
	9	1988	6,269,284	5,499,127	770,157	54,221,111
	10	1989	6,269,284	5,422,111	847,173	53,373,938
	11	1990	4,741,071	4,269,915	471,156	52,902,782
	12	1991	4,741,071	4,232,223	508,848	52,393,934
	13	1992	4,741,071	4,191,515	549,556	51,844,378
	14	1993	4,741,071	4,147,550	593,521	51,250,857
	15	1994	4,741,071	4,100,069	641,002	50,609,854
	16	1995	4,741,071	4,048,788	692,283	49,917,572
	17	1996	4,741,071	3,993,406	747,665	49,169,907
	18	1997	4,741,071	3,933,593	807,478	48,362,428
	19	1998	4,741,071	3,868,994	872,077	47,490,351
	20	1999	4,741,071	3,799,228	941,843	46,548,508
	21	2000	3,381,700	2,792,911	588,789	45,959,719
	22	2001	3,381,700	2,757,583	624,117	45,335,602
	23	2002	3,381,700	2,720,136	661,564	44,674,038
	24	2003	3,381,700	2,680,442	701,258	43,972,781
	25	2004	3,381,700	2,638,367	743,333	43,229,447
	26	2005	3,381,700	2,593,767	787,933	42,441,514
	27	2006	3,381,700	2,546,491	835,209	41,606,305
	28	2007	3,381,700	2,496,378	885,322	40,720,983
	29	2008	3,381,700	2,443,259	938,441	39,782,542
	30	2009	3,381,700	2,386,953	994,747	38,787,795
	31	2010	3,381,700	2,327,268	1,054,432	37,733,363
	32	2011	3,381,700	2,264,002	1,117,698	36,615,664
	33	2012	3,381,700	2,196,940	1,184,760	35,430,904
	34	2013	3,381,700	2,125,854	1,255,846	34,175,059
	35	2014	3,381,700	2,050,504	1,331,196	32,843,862
	36	2015	3,381,700	1,970,632	1,411,068	31,432,794

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2005 and Prior Capital Additions after Initial Investment

Debt Financing for 1982-2005 Capital Additions $31,231,117

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 1981-2006	31,231,117	3,123,112
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2005 (10/01/2004)	24,984,894	3,123,112
Financing Costs	493,960	12,888
Total Financing	25,478,854	3,136,000
30 year Bond @ 5.42% in 2005 - 1/	6.79%	5.42%
Payment amount - annual		$213,870.87

Note 1 - Interest rate from PFM financing study dated July 2006 Table I, page A-18

			Payment Amount	Interest	Principle	Balance
Beginning Balance						3,136,000
	1	2005	213,871	169,971	43,900	3,092,100
	2	2006	213,871	167,592	46,279	3,045,821
	3	2007	213,871	165,083	48,787	2,997,034
	4	2008	213,871	162,439	51,432	2,945,602
	5	2009	213,871	159,652	54,219	2,891,383
	6	2010	213,871	156,713	57,158	2,834,225
	7	2011	213,871	153,615	60,256	2,773,969
	8	2012	213,871	150,349	63,522	2,710,447
	9	2013	213,871	146,906	66,965	2,643,482
	10	2014	213,871	143,277	70,594	2,572,888
	11	2015	213,871	139,451	74,420	2,498,468
	12	2016	213,871	135,417	78,454	2,420,014
	13	2017	213,871	131,165	82,706	2,337,308
	14	2018	213,871	126,682	87,189	2,250,119
	15	2019	213,871	121,956	91,914	2,158,205
	16	2020	213,871	116,975	96,896	2,061,309
	17	2021	213,871	111,723	102,148	1,959,161
	18	2022	213,871	106,187	107,684	1,851,476
	19	2023	213,871	100,350	113,521	1,737,956
	20	2024	213,871	94,197	119,674	1,618,282
	21	2025	213,871	87,711	126,160	1,492,122
	22	2026	213,871	80,873	132,998	1,359,124
	23	2027	213,871	73,665	140,206	1,218,918
	24	2028	213,871	66,065	147,806	1,071,112
	25	2029	213,871	58,054	155,817	915,296
	26	2030	213,871	49,609	164,262	751,034
	27	2031	213,871	40,706	173,165	577,869
	28	2032	213,871	31,320	182,550	395,318

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2007 Capital Additions

2007 Capital Additions	$7,037,182	
	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2007	7,037,182	703,718
2007 Additions - Agrees to FERC Form No. 1 for 2007, page 402		
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in 2007 10-01-2006	5,629,746	703,718
Financing Costs	20,254	6,282
Total Financing	5,650,000	710,000
20 year Bond @ 4.68% in 2007 - 1/	4.73%	4.68%
Payment amount - annual		55,436.70

Note 1 - Interest rate from PFM financing study dated 08/21/08, Table D, page 15

			Payment Amount	Interest	Principle	Balance
Beginning Balance						710,000
	1	2007	55,437	33,228	22,209	687,792
	2	2008	55,437	32,189	23,248	664,543
	3	2009	55,437	31,101	24,336	640,207
	4	2010	55,437	29,962	25,475	614,732
	5	2011	55,437	28,769	26,667	588,065
	6	2012	55,437	27,521	27,915	560,150
	7	2013	55,437	26,215	29,222	530,928
	8	2014	55,437	24,847	30,589	500,339
	9	2015	55,437	23,416	32,021	468,318
	10	2016	55,437	21,917	33,519	434,799
	11	2017	55,437	20,349	35,088	399,711
	12	2018	55,437	18,706	36,730	362,980
	13	2019	55,437	16,987	38,449	324,531
	14	2020	55,437	15,188	40,249	284,283
	15	2021	55,437	13,304	42,132	242,150
	16	2022	55,437	11,333	44,104	198,046
	17	2023	55,437	9,269	46,168	151,878
	18	2024	55,437	7,108	48,329	103,549
	19	2025	55,437	4,846	50,591	52,959
	20	2026	55,426	2,478	52,947	11

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2008 Capital Additions

PGE 2008 Final Capital Budget $8,803,660

2008 Capital Additions $8,803,660

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2008	8,803,660	880,366
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in 2008 (10-01-2007)	7,042,928	880,366
Financing Costs	70,309	9,634
Total Financing	7,113,237	890,000
20 year Bond @ 4.68% in 2008 - 1/	4.73%	4.68%
Payment amount - annual		69,491

Note 1 - Interest rate from PFM financing study dated 08/21/08, Table D, page 15

		Year	Payment Amount	Interest	Principle	Balance
Beginning Balance - 10/01/2007						890,000
	1	2008	69,491	41,652	27,839	862,161
	2	2009	69,491	40,349	29,142	833,019
	3	2010	69,491	38,985	30,506	802,513
	4	2011	69,491	37,558	31,933	770,579
	5	2012	69,491	36,063	33,428	737,152
	6	2013	69,491	34,499	34,992	702,159
	7	2014	69,491	32,861	36,630	665,529
	8	2015	69,491	31,147	38,344	627,185
	9	2016	69,491	29,352	40,139	587,046
	10	2017	69,491	27,474	42,017	545,029
	11	2018	69,491	25,507	43,984	501,045
	12	2019	69,491	23,449	46,042	455,003
	13	2020	69,491	21,294	48,197	406,806
	14	2021	69,491	19,039	50,453	356,354
	15	2022	69,491	16,677	52,814	303,540
	16	2023	69,491	14,206	55,285	248,255
	17	2024	69,491	11,618	57,873	190,382
	18	2025	69,491	8,910	60,581	129,801
	19	2026	69,491	6,075	63,416	66,384
	20	2027	69,493	3,107	66,386	(2)

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2009 Capital Additions

PGE 2009 Preliminary Capital Budget $11,364,709

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2009	11,364,709	1,136,471
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2009 (10-01-2008)	9,091,767	1,136,471
Financing Costs	90,798	13,529
Total Financing	9,182,565	1,150,000
20 year Bond @ 4.73% in 2009 - 1/	N/A	4.73%
Payment amount - annual		90,178.24

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

		Year	Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2008						1,150,000
	1	2009	90,178	54,395	35,783	1,114,216
	2	2010	90,178	52,702	37,476	1,076,741
	3	2011	90,178	50,930	39,248	1,037,492
	4	2012	90,178	49,073	41,105	996,387
	5	2013	90,178	47,129	43,049	953,338
	6	2014	90,178	45,093	45,085	908,253
	7	2015	90,178	42,960	47,218	861,035
	8	2016	90,178	40,727	49,451	811,584
	9	2017	90,178	38,388	51,790	759,793
	10	2018	90,178	35,938	54,240	705,553
	11	2019	90,178	33,373	56,806	648,748
	12	2020	90,178	30,686	59,492	589,255
	13	2021	90,178	27,872	62,306	526,949
	14	2022	90,178	24,925	65,254	461,695
	15	2023	90,178	21,838	68,340	393,355
	16	2024	90,178	18,606	71,573	321,783
	17	2025	90,178	15,220	74,958	246,825
	18	2026	90,178	11,675	78,503	168,321
	19	2027	90,178	7,962	82,217	86,105
	20	2028	90,184	4,073	86,111	(7)

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

<u>FY 2010 Capital Additions</u>

BPA Projected 2010 Capital Additions - 2/ $9,431,743
(Average of 2007, 2008 and 2009 Capital additions)

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2010	9,431,743	943,174
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2009 (10-01-2009)	7,545,394	943,174
Financing Costs	75,334	9,826
Total Financing	7,620,728	953,000
20 year Bond @ 4.73% in 2009 - 1/	N/A	4.73%
Payment amount - annual		74,730

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2009						953,000
	1	2010	74,730	45,077	29,653	923,347
	2	2011	74,730	43,674	31,056	892,291
	3	2012	74,730	42,205	32,525	859,766
	4	2013	74,730	40,667	34,063	825,702
	5	2014	74,730	39,056	35,675	790,028
	6	2015	74,730	37,368	37,362	752,666
	7	2016	74,730	35,601	39,129	713,536
	8	2017	74,730	33,750	40,980	672,556
	9	2018	74,730	31,812	42,918	629,638
	10	2019	74,730	29,782	44,948	584,689
	11	2020	74,730	27,656	47,075	537,615
	12	2021	74,730	25,429	49,301	488,314
	13	2022	74,730	23,097	51,633	436,681
	14	2023	74,730	20,655	54,075	382,605
	15	2024	74,730	18,097	56,633	325,972
	16	2025	74,730	15,418	59,312	266,660
	17	2026	74,730	12,613	62,117	204,543
	18	2027	74,730	9,675	65,055	139,488
	19	2028	74,730	6,598	68,133	71,355
	20	2029	74,736	3,375	71,361	(6)

Note 2 - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2011 Capital Additions

BPA Projected Other 2011 Capital Additions - 2/	$9,622,566
PGE BART Pollution Control Additions - 2011	$35,574,407
Total Capital Additions	$45,196,973

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2011	45,196,973	4,519,697
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2011 (10-01-2010)	36,157,578	4,519,697
Financing Costs	361,455	45,303
Total Financing	36,519,033	4,565,000
20 year Bond @ 4.73% in 2011 - 1/	N/A	4.73%
Payment amount - annual		357,968

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2010						4,565,000
	1	2011	357,968	215,925	142,044	4,422,956
	2	2012	357,968	209,206	148,763	4,274,194
	3	2013	357,968	202,169	155,799	4,118,395
	4	2014	357,968	194,800	163,168	3,955,226
	5	2015	357,968	187,082	170,886	3,784,340
	6	2016	357,968	178,999	178,969	3,605,371
	7	2017	357,968	170,534	187,434	3,417,937
	8	2018	357,968	161,668	196,300	3,221,636
	9	2019	357,968	152,383	205,585	3,016,051
	10	2020	357,968	142,659	215,309	2,800,742
	11	2021	357,968	132,475	225,493	2,575,249
	12	2022	357,968	121,809	236,159	2,339,090
	13	2023	357,968	110,639	247,329	2,091,760
	14	2024	357,968	98,940	259,028	1,832,732
	15	2025	357,968	86,688	271,280	1,561,452
	16	2026	357,968	73,857	284,112	1,277,340
	17	2027	357,968	60,418	297,550	979,790
	18	2028	357,968	46,344	311,624	668,165
	19	2029	357,968	31,604	326,364	341,801
	20	2030	357,983	16,167	341,816	(15)

Note 2 - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.020232 for 2011$$ this amount is $9,622,566.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2012 Capital Additions

BPA Projected Other 2012 Capital Additions - 2/	$9,823,934
PGE BART Pollution Control Additions - 2012	0
Total Capital Additions	$9,823,934

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2012	9,823,934	982,393
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2012 (10-01-2011)	7,859,147	982,393
Financing Costs	78,259	9,607
Total Financing	7,937,407	992,000
20 year Bond @ 4.73% in 2012 - 1/	N/A	4.73%
Payment amount - annual		77,789

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2011						992,000
	1	2012	77,789	46,922	30,867	961,133
	2	2013	77,789	45,462	32,327	928,806
	3	2014	77,789	43,933	33,856	894,950
	4	2015	77,789	42,331	35,457	859,493
	5	2016	77,789	40,654	37,135	822,358
	6	2017	77,789	38,898	38,891	783,467
	7	2018	77,789	37,058	40,731	742,737
	8	2019	77,789	35,131	42,657	700,080
	9	2020	77,789	33,114	44,675	655,405
	10	2021	77,789	31,001	46,788	608,617
	11	2022	77,789	28,788	49,001	559,616
	12	2023	77,789	26,470	51,319	508,297
	13	2024	77,789	24,042	53,746	454,551
	14	2025	77,789	21,500	56,288	398,263
	15	2026	77,789	18,838	58,951	339,312
	16	2027	77,789	16,049	61,739	277,573
	17	2028	77,789	13,129	64,659	212,914
	18	2029	77,789	10,071	67,718	145,196
	19	2030	77,789	6,868	70,921	74,275
	20	2031	77,775	3,513	74,261	14

Note 2 - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.041582 for 2012$$ this amount is $9,823,934.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Debt Service Projections - 10% Interest in Boardman Coal Plant

<u>FY 2013 Capital Additions</u>

BPA Projected Other 2013 Capital Additions - 2/	$10,023,943
PGE BART Pollution Control Additions - 2013	0
Total Capital Additions	$10,023,943

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2013	10,023,943	1,002,394
Debt/Capital Mix	80 /20	100 / 0
Cap. Costs financed in FY 2013 (10-01-2012)	8,019,154	1,002,394
Financing Costs	80,324	9,606
Total Financing	8,099,478	1,012,000
20 year Bond @ 4.73% in 2013 - 1/	N/A	4.73%
Payment amount - annual		79,357

<u>Note 1</u> - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2012						1,012,000
	1	2013	79,357	47,868	31,489	980,511
	2	2014	79,357	46,378	32,979	947,532
	3	2015	79,357	44,818	34,539	912,994
	4	2016	79,357	43,185	36,172	876,821
	5	2017	79,357	41,474	37,883	838,938
	6	2018	79,357	39,682	39,675	799,263
	7	2019	79,357	37,805	41,552	757,711
	8	2020	79,357	35,840	43,517	714,194
	9	2021	79,357	33,781	45,575	668,619
	10	2022	79,357	31,626	47,731	620,888
	11	2023	79,357	29,368	49,989	570,899
	12	2024	79,357	27,004	52,353	518,545
	13	2025	79,357	24,527	54,830	463,716
	14	2026	79,357	21,934	57,423	406,292
	15	2027	79,357	19,218	60,139	346,153
	16	2028	79,357	16,373	62,984	283,169
	17	2029	79,357	13,394	65,963	217,206
	18	2030	79,357	10,274	69,083	148,123
	19	2031	79,357	7,006	72,351	75,773
	20	2032	79,355	3,584	75,771	2

<u>Note 2</u> - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.062788 for 2013$$ this amount is $10,023,943.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Debt Service Projections - 10% Interest in Boardman Coal Plant

<u>FY 2014 Capital Additions</u>

BPA Projected Other 2014 Capital Additions - 2/	$10,226,962
PGE BART Pollution Control Additions - 2014	395,615,477
Total Capital Additions	$405,842,439

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2014	405,842,439	40,584,244
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2014 (10-01-2013)	324,673,951	40,584,244
Financing Costs	3,246,488	405,540
Total Financing	327,920,439	40,994,000
20 year Bond @ 4.73% in 2014 - 1/	N/A	4.73%
Payment amount - annual		3,214,580

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2012						40,994,000
	1	2014	3,214,580	1,939,016	1,275,564	39,718,437
	2	2015	3,214,580	1,878,682	1,335,898	38,382,539
	3	2016	3,214,580	1,815,494	1,399,086	36,983,453
	4	2017	3,214,580	1,749,317	1,465,263	35,518,190
	5	2018	3,214,580	1,680,010	1,534,570	33,983,621
	6	2019	3,214,580	1,607,425	1,607,155	32,376,466
	7	2020	3,214,580	1,531,407	1,683,173	30,693,293
	8	2021	3,214,580	1,451,793	1,762,787	28,930,506
	9	2022	3,214,580	1,368,413	1,846,167	27,084,339
	10	2023	3,214,580	1,281,089	1,933,491	25,150,848
	11	2024	3,214,580	1,189,635	2,024,945	23,125,903
	12	2025	3,214,580	1,093,855	2,120,725	21,005,178
	13	2026	3,214,580	993,545	2,221,035	18,784,143
	14	2027	3,214,580	888,490	2,326,090	16,458,054
	15	2028	3,214,580	778,466	2,436,114	14,021,940
	16	2029	3,214,580	663,238	2,551,342	11,470,597
	17	2030	3,214,580	542,559	2,672,021	8,798,577
	18	2031	3,214,580	416,173	2,798,407	6,000,169
	19	2032	3,214,580	283,808	2,930,772	3,069,397
	20	2033	3,214,577	145,182	3,069,394	3

Note 2 - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.084313 for 2014$$ this amount is $10,226,962.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2015 Capital Additions

BPA Projected Other 2015 Capital Additions - 2/	$10,432,394
PGE BART Pollution Control Additions - 2015	0
Total Capital Additions	$10,432,394

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2015	10,432,394	1,043,239
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2014 (10-01-2013)	8,345,915	1,043,239
Financing Costs	83,459	10,761
Total Financing	8,429,374	1,054,001
20 year Bond @ 4.73% in 2014 - 1/	N/A	4.73%
Payment amount - annual		82,650

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2012						1,054,001
	1	2015	82,650	49,854	32,796	1,021,205
	2	2016	82,650	48,303	34,347	986,857
	3	2017	82,650	46,678	35,972	950,885
	4	2018	82,650	44,977	37,674	913,212
	5	2019	82,650	43,195	39,455	873,756
	6	2020	82,650	41,329	41,322	832,435
	7	2021	82,650	39,374	43,276	789,158
	8	2022	82,650	37,327	45,323	743,835
	9	2023	82,650	35,183	47,467	696,368
	10	2024	82,650	32,938	49,712	646,656
	11	2025	82,650	30,587	52,064	594,592
	12	2026	82,650	28,124	54,526	540,066
	13	2027	82,650	25,545	57,105	482,961
	14	2028	82,650	22,844	59,806	423,155
	15	2029	82,650	20,015	62,635	360,519
	16	2030	82,650	17,053	65,598	294,922
	17	2031	82,650	13,950	68,701	226,221
	18	2032	82,650	10,700	71,950	154,271
	19	2033	82,650	7,297	75,353	78,918
	20	2034	82,656	3,733	78,924	(6)

Note 2 - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.106094 for 2015$$ this amount is $10,432,394.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Boardman* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1980			1980
4	Year Last Unit was Installed			1980			1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			642.20			417.43
6	Net Peak Demand on Plant - MW (60 minutes)			595			0
7	Plant Hours Connected to Load			6686			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			585			0
10	When Limited by Condenser Water			585			0
11	Average Number of Employees			110			0
12	Net Generation, Exclusive of Plant Use - KWh			4354531000			2827461000
13	Cost of Plant: Land and Land Rights			1240068			798844
14	Structures and Improvements			151883454			99959737
15	Equipment Costs			474946319			304980403
16	Asset Retirement Costs			838641			622117
17	Total Cost			628908482			406361101
18	Cost per KW of Installed Capacity (line 17/5) Including			979.3031			973.4832
19	Production Expenses: Oper, Supv, & Engr			6763843			4420104
20	Fuel			61041164			39933425
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			2169128			1387631
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			19406261			12370455
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			163697			106530
34	Total Production Expenses			89544093			58218145
35	Expenses per Net KWh			0.0206			0.0206
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite			
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	2577187	6178	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8517	138600	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	23.264	93.920	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	22.858	89.201	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.342	15.324	1.353	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.014	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10081.400	8.300	10089.700	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see unt 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Clackamas River Hydro Relicensing Project	50,223,922
2	Pelton/R. Butte-Selective Water Withdrawal	28,140,038
3	Biglow Canyon Wind Farm Generation Project (Phases 2 & 3)	17,828,002
4	Carver Sub-Install VWR-4 Transformer	3,422,545
5	Energy Management System-Software	2,639,743
6	Sullivan Fish Passage	2,088,749
7	River District-Install Vaults	1,577,886
8	Pelton/Round Butte Hydro Facility - FERC License Requirements	1,552,732
9	Purchase Spare Bulk Transformers	1,419,662
10	Advanced Metering Infrastructure	1,183,873
11	Develop Automated Meter Exchange System - Software	1,175,189
12	Install Microsoft Exchange and Windows Technology-Software	1,076,112
13	Boardman Plant-Install Training Simulator	988,836
14	Carver Sub-Install 230-Kv Line Position	898,772
15	Identity Management Control System - Software	833,267
16	Boardman Plant-Rewind Generator Stator	792,607
17	Fiber Optic Cable Project-Portland's Eastside	773,188
18	McLoughlin Sub-Install 230-Kv Line Position	680,540
19	Web Infrastructure-Software	653,320
[illegible]	River Mill-Fish Passage Improvement	537,690
21	Boardman Plant-Purchase Spare Generator	467,226
22	Colstrip Plant-Capital Yearend Accrual	441,750
23	Beaver Plant-Install Remedial Action Scheme	339,673
24	Construct Carver-McLoughlin 230-Kv Line	330,768
25	Kelly Butte Sub-Install SCADA System	296,930
26	Sunset Sub-Install ZVC Switches	291,640
27	Beaver Plant-Rewind Generator Rotor Unit	258,902
28	River Mill Plant-Construct Boat Launch	256,788
29	Carver Sub-Install Carver-Hogan South 115-Kv Line	230,193
30	West Side Hydros-Install Safety (SHARPS) Upgrades	222,129
31	Carver Sub-Install Carver-Canemah 115-Kv Line	207,999
32	Progress Sub-Install SCADA System	203,522
33	Colstrip Plant-Install Mercury Controls for Units 3 & 4	194,677
34	Bald Peak Communication Station-Replace Alarm Monitoring on Communications Systems	192,831
35	Coffee Creek Sub-Build New Substation	188,668
36	Boardman Plant-Install Superheat Safety Valve	155,308
37	Purchase Helicopter	152,666
38	Coyote Springs Plant-Add Auto Bus Transfer to 115-Kv Line	139,057
39	McGill Sub-Replace WR-1 Transformer	131,131
40	R. Butte Switchyard-Replace 500-Kv Transformer Reactor Switches	128,360
41	Coyote Springs Plant-Automate Heat-Recovery-Steam-Generator (HRSG) Valves	122,696
[illegible]	Boardman Plant-Extend Dike and Piping at Carty Reservoir	112,260
43	TOTAL	125,676,924

Bonneville Power Administration
2007 Supplemental Wholesale Power Rate Case Initial Proposal

WP-07-E-BPA-88
(BPA-JP6-23)

PGE 2007 Supplemental Wholesale Power Rate Case Data Response

DATA REQUEST NUMBER: BPA-JP6-23

REQUEST DATE: May 15, 2008
REPSONSE DATE: May 22, 2008
DIRECTED TO: PGE

REQUESTOR'S NAME: Paul A. Brodie
AGENCY: BPA

EXHIBIT: WP-07-E-JP6-12

PAGE(S): 37-38

DATA REQUEST:

The above-cited rebuttal testimony addresses the projected costs used in the current rate proceeding. Please provide a copy of annual historical operating budgets for the operation of the Boardman coal plant for the years 2002-2008. Also, please provide the projected operating budgets for the Boardman coal plant to the extent available for CYs 2009-2013.

Paul A Brodie, CPA
Bonneville Power Rate Staff
503-230-3414

PGE RESPONSE:

See BPA-JP6-23 Attachments A and B for the requested information. Attachment A provides the PGE share of annual historical operating costs for the Boardman coal plant for the years 2002-2007. A copy of the 2008 Boardman Operations budget is provided as Attachment B; the PGE share would be 65% of these totals.

PGE does not have future year projected amounts to be charged to the other owners available. The Operation agreement requires only that a budget be prepared for the next year's activity. Funding of cost activities for the Boardman plant is done weekly with the other owners. Each company is responsible for having funds available as required, including those for capital construction, decommissioning, or any other activities necessary for continued operation.

BPA-JP-23 Attachment A

Portland General Electric
Response to Data Request: BPA-JP-23
5/21/2008

2002-2007 Operating Costs for PGE's Share of the Boardman Coal Plant *

Line	Operating Cost	2002	2003	2004	2005	2006	2007
1	Production Expenses: Oper. Supv. & Engr	3,123,338	3,197,010	4,457,560	3,818,762	3,742,813	4,420,104
2	Fuel	34,998,755	37,580,945	29,909,037	31,124,332	22,218,265	39,933,425
3	Misc Steam Power Expenses	1,734,302	1,733,390	789,729	1,432,334	1,341,837	1,387,631
4	Rents	2,662,404	2,726,569	2,688,319	640,712	-	-
5	Allowances	52,879	-	-	-	-	-
6	Maintenance Supervision and Engineering	9,645,388	9,541,455	15,116,268	12,396,430	11,752,427.00	12,370,455
7	Maintenance of Misc Steam Plant	86,914	144,319	119,863	89,610	67,827	106,530
8		52,303,980	54,923,688	53,080,776	49,502,180	39,123,169	58,218,145

* Note: PGE Share From page 402 of PGE FERC Form 1

BPA-JP-23 Attachment B

PORTLAND GENERAL ELECTRIC COMPANY
2008 BOARDMAN COAL PLANT OPERATIONS BUDGET - TOTAL
100% Corporate Loadings Included

	FERC	Final 2008 BUDGET
OPERATIONS		
STEAM POWER GENERATING EXPENSES:		
OPERATIONS SUPV & ENGR	500	7,086,196
FUEL COST	501	1,864,722
MISC STEAM POWER EXPENSES	506	2,093,620
RENTS	507	-
OTHER POWER SUPPLY EXPENSES:		
MISC OTHER POWER SUPPLY EXPENSE	557	172,875
ADMINISTRATIVE AND GENERAL EXPENSES:		
ADMINISTRATIVE & GENERAL	921	2,330,763
PROPERTY INSURANCE/LEGAL	924	580,550
INJURIES AND DAMAGES	925	154,695
EMPLOYEE BENEFITS	926	2,872,206
REGULATORY COMMISSION EXPENSES	928	-
MISC GENERAL EXPENSES	930	15,000
TOTAL OPERATIONS		17,170,627
STEAM POWER MAINTENANCE EXPENSES:		
MAINT SUPV & ENGR	510	18,812,003
MAINT OF MISC PLANT	514	44,738
MAINT OF LOAD DISPATCHING	561	-
MAINT OF STATION EQUIP (TRANSMIS.)	570	45,622
MAINT OVERHEAD LINES (TRANSMIS.)	571	-
MAINT OF MISC TRANSMISSION PLANT	573	-
TOTAL MAINTENANCE		18,902,363
FUEL, TAXES, INTEREST AND OTHER:		
FUEL INVENTORY-COAL PURCHASE	151	62,346,284
FUEL INVENTORY-COAL FIXED O&M	151	1,930,798
FUEL INVENTORY-OIL PURCHASE	151	813,962
PAYROLL TAXES	408	1,016,802
INTEREST EXPENSE	427	
OTHER MISC ELECTRIC REVENUES	456	(600,000)
TOTAL FUEL ,TAXES AND INTEREST		65,507,846

Brodie,Paul A - PFR-6

From:	Valerie Giles [Valerie.Giles@pgn.com]
Sent:	Monday, December 15, 2008 9:28 AM
To:	Brodie,Paul A - PFR-6
Cc:	Forman,Charles W - PSW-6; Bliven,Raymond D - PFR-6; Stefan Brown
Subject:	2009 Boardman Preliminary Budget
Attachments:	2009_PRE_budget.xls

Attached is the 2009 preliminary O&M and Capital budget for Boardman provided to the co-owners in September 2009.

Valerie Giles
Manager, Generation & Asset Accounting
Portland General Electric
(503) 464-7307
(503) 464-2507 Fax
Valerie.Giles@pgn.com

PORTLAND GENERAL ELECTRIC COMPANY
BOARDMAN COAL PLANT OPERATIONS BUDGET COMPARISON - PRELIMINARY
100% Corporate Loadings Included

	FERC	Preliminary 2009 BUDGET	Final 2008 BUDGET	VARIANCE Incr (Decr)
OPERATIONS				
STEAM POWER GENERATING EXPENSES:				
OPERATIONS SUPV & ENGR	500	7,081,771	7,086,196	(4,425)
FUEL COST	501	1,837,111	1,864,722	(27,611)
MISC STEAM POWER EXPENSES	506	1,990,633	2,093,620	(102,987)
RENTS	507		-	-
OTHER POWER SUPPLY EXPENSES:				-
MISC OTHER POWER SUPPLY EXPENSE	557	160,341	172,875	(12,534)
ADMINISTRATIVE AND GENERAL EXPENSES:				-
ADMINISTRATIVE & GENERAL	921	2,304,675	2,330,763	(26,088)
PROPERTY INSURANCE/LEGAL	924	488,183	580,550	(92,367)
INJURIES AND DAMAGES	925	154,896	154,695	201
EMPLOYEE BENEFITS	926	2,863,196	2,872,206	(9,010)
REGULATORY COMMISSION EXPENSES	928		-	-
MISC GENERAL EXPENSES	930		15,000	(15,000)
TOTAL OPERATIONS		16,880,806	17,170,627	(289,821)
STEAM POWER MAINTENANCE EXPENSES:				
MAINT SUPV & ENGR	510	24,297,083	18,812,003	5,485,080
MAINT OF MISC PLANT	514	42,239	44,738	(2,499)
MAINT OF LOAD DISPATCHING	561		-	-
MAINT OF STATION EQUIP (TRANSMIS.)	570	55,724	45,622	10,102
MAINT OVERHEAD LINES (TRANSMIS.)	571		-	-
MAINT OF MISC TRANSMISSION PLANT	573		-	-
TOTAL MAINTENANCE		24,395,046	18,902,363	5,492,683
FUEL, TAXES, INTEREST AND OTHER:				
FUEL INVENTORY-COAL PURCHASE	151	59,460,450	62,346,284	(2,885,834)
FUEL INVENTORY-COAL FIXED O&M	151	1,601,966	1,930,798	(328,832)
FUEL INVENTORY-OIL PURCHASE	151	1,269,066	813,962	455,104
PAYROLL TAXES	408	1,016,802	1,016,802	-
INTEREST EXPENSE	427			-
OTHER MISC ELECTRIC REVENUES	456	(600,000)	(600,000)	-
TOTAL FUEL ,TAXES AND INTEREST		62,748,284	65,507,846	(2,759,562)
SUBTOTAL		104,024,136	101,580,835	2,443,300
CHANGE IN WORKING CAPITAL:				
PLANT MATERIALS AND SUPPLIES	154			-
STORES EXPENSE UNDISTRIBUTED	163	630,217	718,976	(88,759)
PREPAYMENTS	165	24,000	23,086	914
PRELIMINARY SURVEY & INVESTIGATION	183	1,715,000	2,343,723	(628,723)
CLEARING ACCOUNT - MATERIAL O/H DIST	184	(265,848)	(265,848)	-
MISC. DEFERRED DEBITS	186			-
OTHER LONG TERM DEBT	224			-
DISCOUNT ON LONG TERM DEBT	226			-
INJURIES AND DAMAGES PROVISION	228	35,000	36,000	(1,000)
ACCOUNTS PAYABLE	232	(6,194,852)	(6,219,851)	24,999
TOTAL CHANGES IN WORKING CAPITAL		(4,056,483)	(3,363,914)	(692,569)
SUBTOTAL		99,967,653	98,216,921	1,750,731
CONSTRUCTION/RETIREMENTS	107/108	11,364,709	8,803,660	2,561,049
TOTAL FUNDING REQUESTED		111,332,362	107,020,581	4,311,781

note: used 2008 loadings so differences are direct items

1/2/2009

PORLTAND GENERAL ELECTRIC COMPANY
BOARDMAN COAL PLANT
2009 PRELIMINARY CAPITAL BUDGET

100% with Corporate Loadings Included

Job #	Title	100% Plant Preliminary Budget
C9300	Furniture	10,319
CN089	Portable Electrical Instruments	51,594
CN094	Minor Tools & Equipment	41,275
19888	Vintage Computers	10,319
21616	New Coal Dust Suppression System	61,913
22819	Install New Secondary Air Preheater Baskets	104,059
23260	Miscellaneous Pumps, Valves, Motors, etc.	454,912
24069	Install Platforms (2009)	30,956
24226	Generator Rotor	1,602,399
24554	Rewind Generator Stator	6,478,165
24555	Install New Cooling Water Supply Skid	119,530
24559	Generator DCS Connection	332,453
24561	Generator Start-up Testing & Tuning	256,876
25146	Desktop Vintage & Growth	80,497
25350	Install Type K Pneumatic Controllers - 2009	58,198
25421	Backup Communications Upgrade	9,906
25446	Upgrade Coal Car Dumper Drives	41,275
25452	Upgrade AWS Building HVAC Chillers	167,742
25519	Upgrade Coal Yard PLC Control System	1,055,459
25529	Replace Coal Conduit Bends	154,782
X0045	Misc Jobs to be identified	242,079
	TOTAL	11,364,709

Prepared by: Cathy Geiger
As of 8/29/07 - preliminary budget numbers

December 17, 2008
ES-266-2008
Gov Rel 9

Mr. Brian Finneran
Oregon Department of Environmental Quality
811 SW Sixth Ave
Portland, OR 97204

Re: Preliminary Comments on Proposed Regional Haze Rules

Dear Brian:

Portland General Electric Company (PGE) appreciates this opportunity to comment on the proposed Regional Haze rulemaking. As you know, the proposed rules are the result of the federal requirement that Oregon submit an initial implementation plan for regional haze (the Regional Haze SIP). This plan must include a determination of Best Available Retrofit Technology (BART) for each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I area. 40 CFR § 51.308(e)(1)(ii). The federal Clean Air Act contains specific criteria for establishing BART and these criteria are carried over into the regulations. In developing these regulations, EPA also promulgated guidelines to be used by the states in developing BART determinations. These guidelines, found in 40 CFR § 51 Appendix Y, contain the majority of the detail regarding how BART determinations are to be conducted.

1. Background

On November 2, 2007, PGE submitted a BART analysis for its coal-fired power plant located in Boardman, Oregon (the Boardman plant).[1] Sources in existence on August 7, 1977 and that both fall into one of the designated source categories and have the potential to emit more that 250 tons per year of a haze-causing pollutant are required to determine BART if they cause or contribute to visibility impairment in a mandatory Class I area. 40 CFR § 51.308(e). DEQ previously determined that the Boardman power plant was in existence, as that term is defined in the federal

[1] The Foster-Wheeler boiler is identified by the U.S. Environmental Protection Agency (EPA) as acid rain program ORISPL code 6106.

Regional Haze program, on August 7, 1977.[2] The Boardman plant emits more than 250 tons per year of NOx, SO_2 and PM, is in one of the designated source categories and was determined by the Oregon Department of Environmental Quality (DEQ or Department) to cause visibility impairment in at least one mandatory Class I area. Therefore, PGE engaged an extensive group of experts that assisted the company in preparing a BART determination for the Boardman plant. This report was submitted on November 2, 2007 and subsequently supplemented in response to dozens of questions posed by various state and federal agencies and interested third parties. The team of experts concluded that for the Boardman plant BART constituted the installation of new low-NOx burners with a modified overfire air system for NOx control and the installation of a semi-dry scrubbing system with fabric filters for SO_2 and PM control. PGE concluded that due to the long lead time and complex engineering challenges the company needed five years from the date that the Regional Haze SIP is approved in order to engineer, bid, procure, install and start up the semi-dry scrubbing system. Federal law authorizes DEQ to allow up to five years from the date EPA approves the Regional Haze SIP. 40 CFR § 51.308(e)(1)(iv).

On December 1, 2008, the Department issued the proposed Regional Haze proposal for public comment. The proposal includes new regulations that would require the installation of the controls identified below.

Limit (Assumed Control)	Installation Deadline	Authority
0.23 lb NOx/MMBtu (Low-NOx Burners/Overfire Air)*	7/1/2011	BART
0.12 lb SO_2/MMBtu 0.012 lb PM/MMBtu (Semi-Dry Scrubber)	7/1/2014	BART
0.070 lb NOx/MMBtu (SCR)	7/1/2017	Reasonable Progress

* If LNB/OFA doesn't meet limit, SNCR required by 7/1/2014

[2] 40 CFR § 51.301 defines "in existence on August 7, 1977" as "meaning that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time."

The Department's proposed BART determination is consistent with the controls determined to be BART by PGE's experts. However, the schedule proposed for installation of the semi-dry scrubber system is shorter than that proposed by PGE. DEQ anticipates presenting the final BART determination package to the Environmental Quality Commission (EQC) at its April 2009 meeting. Assuming the EQC adopts the package in April 2009, it must then be submitted to EPA for approval into the State Implementation Plan (SIP). This process is anticipated to take a minimum of six months and more likely a year or longer. Assuming that EPA does not approve the Regional Haze SIP until July 1, 2010, the proposed rule does not provide all of the time allowed for PGE to install the semi-dry scrubbers.

Although all that is required of DEQ at this time is to promulgate BART, DEQ chose to go further and also impose a requirement under the future "Reasonable Progress" program. The first stage of the Regional Haze program is to determine and require BART. However, each state must subsequently develop a plan to ensure that by 2064 visibility is restored to pre-human levels in mandatory Class I areas (BART and Reasonable Progress controls are evaluated based on benefits to mandatory Class I areas only). Consistent with this requirement, states must submit SIPs containing emissions limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the 2064 visibility goal. DEQ must also demonstrate to EPA every ten years that the state is making reasonable progress towards the ultimate visibility improvement goal. These "Reasonable Progress" demonstrations do not require any determination of controls on stationary sources at this time and we are aware of no western state making Reasonable Progress based control determinations at the same time that the state is making BART determinations. For example, California just released its draft Regional Haze SIP and it is proposing no stationary source Reasonable Progress control determinations. Nonetheless, the Department has proposed as part of this rulemaking that the Boardman plant be required to install additional NOx controls, specifically selective catalytic reduction (SCR), in 2017. These controls were demonstrated not to constitute BART due to their extreme cost and their limited effectiveness in addressing visibility impacts.

PGE has reviewed the Department's proposed BART and Reasonable Progress rules in light of this regulatory and statutory background. Based on our review, we have the following comments.

2. Comments on Proposed NOx BART Rule

NOx BART Limit Determination

PGE supports the Department's NOx BART determination. The proposed NOx BART determination will reduce NOx from the Boardman plant by approximately 46% from current levels by preventing the formation of NOx in the first place. While this comes at a significant capital expense, we believe that these controls constitute BART and note that the Department's determination is consistent with BART determinations throughout the western U.S. We believe that the determination of feasible control level is aggressive and concur with the Department that it is appropriate to determine compliance with the 0.23 lb/MMBtu heat input limit based on a rolling 12-month average.

NOx BART Compliance Schedule

PGE generally supports the NOx BART installation schedule, but notes that compliance with these deadlines is dependent on EPA approving the Regional Haze SIP and DEQ approving the necessary preconstruction permits in a timely manner. Because of the need to know with certainty that the SIP is approved and the need for preconstruction permits prior to commencing construction, PGE is faced with potentially critical delays beyond its control. In order to avoid PGE being placed in the untenable position of having to proceed with millions of dollars worth of controls in the absence of clear regulatory or permit authority, PGE requests that DEQ add language authorizing the Department to delay installation of the controls in the event of delays beyond PGE's reasonable control. We recognize that under federal law the Department cannot extend the compliance deadline by more than five years after EPA approves the portion of the SIP containing the NOx BART limits.

Neither PGE nor the Department can have absolute certainty that EPA will approve the Regional Haze SIP. Therefore, PGE believes that it is critical to add language to the proposed rules specifying that if the Regional Haze SIP provisions relating to the NOx BART determination is disapproved that PGE is not required to proceed with installation of the controls as a matter of state rule. If EPA disapproves the SIP provisions mandating controls, that agency will presumably require some other approach. Therefore, we suggest that the proposed rules provide a mechanism for staying the control requirements in the event that EPA disapproves the SIP provisions mandating controls.

3. Comments on Proposed SO_2 BART Rule

SO_2 BART Limit Determination

PGE supports the Department's SO_2 BART determination. The proposed SO_2 BART determination will reduce SO_2 from the Boardman plant by approximately 80% from current levels through the installation of a semi-dry scrubber system. While this technology comes at both a capital expense and generation efficiency penalty, we agree that these controls constitute BART and note that the Department's determination is consistent with or more aggressive than BART determinations throughout the western U.S. We concur with the Department that it is appropriate to determine compliance with the 0.12 lb/MMBtu heat input limit based on a rolling 30-day average basis.

SO_2 BART Compliance Schedule

PGE generally supports the SO_2 BART installation schedule, but notes that compliance with the deadline is also dependent on EPA approving the Regional Haze SIP and DEQ approving the necessary preconstruction permits in a timely manner. As noted above PGE needs to know with certainty that the SIP is approved and that it has all permits in hand prior to commencing construction of several hundred million dollars worth of control equipment. In addition, if EPA does not approve the portions of the Regional Haze SIP containing the SO_2 limits in a reasonable time frame then PGE will not have enough time to procure and install the controls. Therefore, we suggest that either DEQ change the installation deadline to be five years from the date of EPA approval of the relevant portions of the Regional Haze SIP or that DEQ add a provision to the rules extending the deadline to five years post-SIP approval in the event that EPA does not approve these portions of the SIP by the end of 2009.

Alternative SO_2 BART Determination

PGE also requests that DEQ add an alternative SO_2 BART determination to the proposed regulations. Section 169A(g) of the Clean Air Act specifies that BART determinations must take into account the remaining useful life of the BART eligible emission unit. See, also 40 CFR § 51.308(e)(1)(ii)(A). EPA stated that this factor should be accounted for in assessing the cost impacts of a particular control technology. 70 Fed. Reg. 39127 (July 6, 2005). In its November 2007 BART determination PGE noted that the possible premature cessation of operations of the coal-fired boiler may be appropriate for consideration in determining BART. Consistent with 40 CFR § 51, App Y Section IV(D)(4)(k) ("How do I take into account a project's 'remaining useful life' in calculating control costs"), PGE recognized the possibility that it might be necessary to include a regulatory scenario that anticipated the early closure of the Foster-Wheeler boiler. Based on the continued uncertainties about fuel cost/availability, replacement power, carbon regulation, control technologies and combustion technologies, PGE believes that including an alternative to the proposed BART determination is appropriate. EPA specifically anticipated sources needing flexibility and seeking alternatives, and addressed this possibility in Section IV(D)(4)(k)(3) of 40 CFR § 51, App Y. In evaluating the cost-effectiveness of the proposed SO_2 controls, PGE assumed that the controls would be in place and operational for twenty years. As a result, the annualized capital cost was amortized over the full twenty-year life of the control device. We believe that it is consistent with the Clean Air Act and EPA's regulations to include an alternate BART determination for SO_2 that reflects a shorter facility life than the twenty-year life assumed in the current evaluation.

Incorporating an alternative SO_2 BART determination into the Oregon BART rules provides PGE the flexibility needed to best protect its customers while protecting the environment. PGE is requesting the option to assume a federally enforceable permit limit requiring cessation of the Foster-Wheeler boiler operations by the end of 2020 in lieu of installing the semi-dry scrubbers. In order to ensure adequate time to incorporate the permit limit into its permit as well as to ensure that the permit limit was in place prior to the 2014 deadline for installing the SO_2 controls, PGE would need to apply for this federally enforceable limit no later than July 1, 2012. If PGE submitted an application requesting the condition by that date, and responded in a timely fashion to any Department requests, PGE would be required to terminate operation of the Foster-Wheeler boiler by 2020. Alternatively, if PGE did not submit an application by July 1, 2012 requesting the permit limit, PGE would be bound by the Department's proposed SO_2 BART compliance deadlines and would have to install the semi-dry scrubbers by July 1, 2014. Both options, including the requirement to submit the permit limit application by July 1, 2012, would be placed in the rules. PGE, with guidance from the Oregon Public Utilities Commission (OPUC) and stakeholders, would then need to decide no later than July 1, 2012 whether to install the SO_2 BART controls or cease operating the Foster-Wheeler boiler by the end of 2020.

Incorporating the recommended alternative SO_2 BART determination with the 2012 decision point into the Oregon BART rules is consistent with all federal requirements. As noted above, not only is there no prohibition on the Department incorporating alternative BART options, Appendix Y to the federal BART regulations states that alternatives are permissible so long as each option independently meets the BART criteria. 40 CFR § 51, App Y, Section IV(D)(4)(k). The 2020 alternative BART determination clearly meets the BART criteria. As noted above, the Clean Air Act requires consideration of the remaining useful life of the plant. EPA's rules recognize that if the remaining useful life is limited by permit condition then the cost-effectiveness needs to be determined based on amortizing the capital cost over the reduced equipment life. The cost-effectiveness of the semi-dry scrubbers based on a useful life of 6.5 years (i.e., the number of years after July 1, 2014 that the control would be operated if the Foster-

Wheeler boiler ceased operation in 2020) is approximately $5,200 per ton of SO_2 controlled (see attached spreadsheet for details of cost-effectiveness evaluation).[3] This cost-effectiveness far exceeds the range of SO_2 cost-effectiveness evaluated by EPA in establishing the presumptive BART limits. In EPA's assessment they looked at costs ranging from $400/ton to $2,000/ton. The cost-effectiveness of the semi-dry scrubbers if operated only 6.5 years would be almost triple the high end of the range of what EPA considered cost-effective. Therefore, with only a 6.5-year operational life it is appropriate to consider BART to require no additional SO_2 controls so long as the Foster-Wheeler boiler is required to cease operation by the end of 2020. This determination would not affect the requirement to operate the NOx BART controls and nor would it affect PGE's obligation to control mercury emitted from the boiler.

It is also appropriate to consider the alternative SO_2 BART determination in light of the long term benefits to the environment provided by both options. If the plant installed the proposed BART controls (i.e., low-NOx burners, modified overfire air and semi-dry scrubbers) and operated through 2040, the aggregate visibility pollutant (i.e., NOx, SO_2 and PM) emissions calculated on a potential to emit basis would total 336,358 tons.[4] If the proposed NOx/SO_2 BART controls and SCR were installed, the aggregate visibility pollutant emissions through 2040 would total 237,149 tons. If NOx BART but no other controls were installed on the boiler and the boiler ceased operation at the end of 2020, 232,453 tons of visibility pollutants would be emitted. A comparison of the aggregate emissions is presented below.

Controls Installed	Boiler Operated Through	Total Visibility Pollutant Emissions (tons)			
		NOx	SO_2	PM	Aggregate
LNB/OFA	12/31/2020	63,588	158,311	10,554	232,453
LNB/OFA and SD scrubbers	12/31/2040	184,960	139,313	12,084	336,358
LNB/OFA, SD Scrubbers & SCR	12/31/2040	85,752	139,313	12,084	237,149

Notes: All computations start 1/1/2011; emissions calculations based on plant potential to emit.

[3] Section 4(k)(2) of Appendix Y specifies that the remaining useful life of a control is the difference between the date the controls would go into place and the date the controlled unit permanently stops operation.

[4] 2040 is the current projected life of the Foster-Wheeler boiler that was identified in PGE's BART analysis. However, there is no legal requirement to cease operation of the boiler at that time and the actual life of the boiler could be longer.

These suggested revisions are consistent with the BART requirements, are environmentally beneficial and also provide additional benefits. As the Department knows, the electrical generation business is in a time of tremendous transition. Over the next decade we anticipate tremendous advances in both electricity generation and control technology (e.g., carbon capture and sequestration). In addition, we anticipate that carbon will become subject to regulation. The full costs and benefits of these changes cannot be fully assessed at this time. However, by the time that PGE must decide whether to apply for its federally enforceable condition requiring cessation of operation of the Foster-Wheeler boiler or install the SO_2 BART controls, both PGE and the OPUC likely will have a better idea of the best future for the Boardman plant. As the Department knows, PGE is also regulated by the OPUC, and resource decisions such as the installation of BART controls must be fully vetted in the OPUC's Integrated Resource Planning (IRP) process. That process includes extensive public and stakeholder input and detailed modeling of resource decisions to yield the best combination of expected costs and risks. By building this decision point into the BART rules, it will help ensure that the decisions regarding Boardman are made with the most complete information. By enabling a more comprehensive and reasoned decision making process on the future of Boardman we also anticipate that DEQ will reduce the fiscal impacts to businesses in Oregon as compared to the Department's proposed BART rules.

Startup, Shutdown and Malfunction Exemption

We appreciate the recognition in the proposed rules that the technology based limits do not apply during startups and shutdowns. EPA was clear in the BART regulations that startups and shutdowns were not normal operating conditions and that the BART visibility impact assessment was intended to assess normal operating conditions. Therefore, we believe that it is appropriate to not include periods of startup and shutdown in determining compliance. However, it is equally true that the controls cannot be anticipated to perform as designed during a malfunction (defined under federal law, see, e.g. 40 CFR 63.2, as an upset that is not reasonably foreseeable or preventable and not resulting from inadequate design or maintenance). Therefore, we suggest that the regulations similarly note that malfunction periods should similarly not be included when evaluating whether the controls are operating properly and compliance is being achieved.

PM Limit Error

The proposed BART rule identifies the PM limit as 0.12 lb/MMBtu heat input, but PGE's BART determination and the Department's documentation indicate that it should read "0.012 lb/mmBtu heat input." We believe this was just a typographical error.

Recommended BART Rule Edits

For the reasons stated above, we request that section 1 of the proposed OAR 340-223-0030 (the Boardman BART rule) be revised as follows:

340-223-0030
BART Requirements for the Foster-Wheeler boiler at the Boardman Coal-Fired Power Plant (Federal Acid rain program facility ORISPL code 6106)
(1) Emissions limits:
(a) On and after July 1, 2011, nitrogen oxides emissions must not exceed 0.28 lb/mmBtu heat input as a 30-day rolling average and 0.23 lb/mmBtu heat input as a 12-month rolling average.
(A)If it is demonstrated by July 1, 2012 that the emission limits in (a) cannot be achieved with combustion controls, the Department may grant an extension of compliance to July 1, 2014.
(B)If an extension is granted, the nitrogen oxides emissions must not exceed 0.23 lb/mm Btu heat input as a 30-day rolling average on and after July 1, 2014.
(b) On and after July 1, 2014, sulfur dioxide emissions must not exceed 0.12 lb/mmBtu heat input as a 30-day rolling average.
(c) On and after July 1, 2014, particulate matter emissions must not exceed 0.012 lb/mmBtu heat input as determined by compliance source testing.
(d) The emission limits in (a) through (c) above do not apply during periods of startup, ~~or~~ shutdown or malfunction.
(e) The emission limits in (b) and (c) above do not apply if the operator has assumed a federally enforceable permit condition prior to July 1, 2014 requiring that the Foster-Wheeler boiler cease emissions by December 31, 2020. In order to ensure adequate time for the Department to process the permit modification by this deadline, the request for the federally enforceable permit condition must be submitted to the Department no later than July 1, 2012. If the permittee submits a permit application requesting the permit limit on or before July 1, 2012 and submits to all Department information requests associated with the application in a timely manner, the permittee shall be deemed to have the permit condition in place.
(f) The emission limits in (a), (b) and (c) above do not apply if EPA disapproves the portion of the Regional Haze SIP containing these limits or that portion of the Regional Haze SIP is otherwise invalidated.

(g) If EPA fails to approve the portion of the Regional Haze SIP containing the emission limits and compliance deadlines in (b) and (c) above by December 31, 2009, then those deadlines shall automatically change to five years after approval of the portion of the Regional Haze SIP containing these limits and deadlines.
(h) The Department may extend the deadlines in (a), (b) and (c) above to account for delays beyond the reasonable control of the permittee, including delays in the issuance of permits authorizing construction of the controls. The Department may not extend the compliance deadline more than five years after the date that EPA approves the portion of the Regional Haze SIP containing these limits and deadlines.

4. Comments on Proposed Reasonable Progress Rule

SCR Is Not Justified by Reasonable Progress Requirements

PGE has significant concerns regarding DEQ's proposal that SCR is required under the Reasonable Progress program. In the November 2007 BART determination report, PGE demonstrated that SCR is not BART for the Boardman boiler. The technology is not cost-effective, does not provide material benefits to visibility in the mandatory Class 1 areas and has material non-air quality environmental impacts. For all these reasons DEQ reasonably concluded that SCR is not BART. Section 169A(g)(1) of the federal Clean Air Act mandates that the same considerations must be applied in determining what constitutes Reasonable Progress controls. Therefore, for the same reasons that DEQ determined that SCR did not constitute BART, it should not consider SCR to be required by Reasonable Progress.

DEQ Has No Basis For Imposing Reasonable Progress Requirements on Boardman At This Time

PGE is similarly concerned about DEQ's choice to proceed at this time with a Reasonable Progress determination for the Boardman Plant while not considering Reasonable Progress for any other emission sources in Oregon. We are not aware of any other state in the western U.S. addressing additional controls under Reasonable Progress at this time. The Reasonable Progress assessment in the Department's proposed Regional Haze SIP states that "it is not reasonable to require controls" for any of the stationary source categories reviewed and notes that the Department will be developing guidance for conducting Reasonable Progress control determinations over the next five years. Proposed Regional Haze Plan at 171. Putting aside the fact that for the reasons stated in the previous paragraph SCR does not meet the Reasonable Progress guidelines established by statute and EPA guidance, it is arbitrary for DEQ to single out one source for a program that is otherwise in its nascent stages and where no other source in the state is under consideration. For these reasons we propose that DEQ not include the Reasonable Progress component in the BART rules. DEQ can address Reasonable Progress for the Boardman plant when it develops its Reasonable Progress SIP for the state as a whole.

Alternative Reasonable Progress Determination

Even if DEQ were to proceed with Reasonable Progress at this time for the Boardman Plant and SCR was determined to constitute a Reasonable Progress control, we believe that DEQ should include an alternative determination similar to what is proposed above for BART. EPA's June 2007 EPA Reasonable Progress guidance states:

> "The fourth statutory factor is 'the remaining useful life of any existing source subject to [reasonable progress] requirements.' This factor is generally best treated as one element of the overall cost analysis. The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's *Air Pollution Control Cost Manual* require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life of the source will clearly exceed this time period, the remaining useful life factor has essentially no effect on control costs and on the reasonable progress determination process. Where the remaining useful life of the source is less than the time period for amortizing the costs of the retrofit control, you may wish to use this shorter time period in your cost calculations."

This statement supports a similar approach to that required under BART where a shorter facility life is taken into account when determining cost-effectiveness. In evaluating the cost-effectiveness of SCR, PGE assumed that the controls would be in place and operational for twenty years. As a result, the annualized capital cost was amortized over the full twenty-year life of the control device. We believe that it is consistent with the Clean Air Act and EPA's regulations to include an alternate Reasonable Progress determination for NOx that reflects a shorter facility life.

If DEQ proceeds with requiring SCR as Reasonable Progress, PGE recommends incorporating an option under which PGE may assume a federally enforceable permit limit requiring cessation of the Foster-Wheeler boiler operations by 2029. In order to ensure adequate time to incorporate the permit limit into its permit as well as to ensure that the permit limit is in place prior to the 2017 deadline currently proposed for installing SCR, PGE would need to apply for this federally enforceable limit no later than July 1, 2015. If PGE submitted an application requesting the condition by that date, and responded in a timely fashion to any Department requests, it would be required to terminate operation of the Foster-Wheeler boiler by 2029. Alternatively, if PGE did not submit an application by July 1, 2015 requesting the permit limit, PGE would be bound by the Department's proposed Reasonable Progress NOx control compliance deadline and would have to install SCR by July 1, 2017. Both options, including the requirement to submit the permit limit application by July 1, 2015, would be placed in the rules. PGE, with guidance from the OPUC and stakeholders, would then need to decide no later than July 1, 2015 whether to install SCR or cease operating the Foster-Wheeler boiler by the end of 2029.

Incorporating the recommended option into the Oregon Reasonable Progress rules is consistent with all federal requirements. As with BART, there is no prohibition on the Department incorporating alternative Reasonable Progress options so long as each option independently meets the Reasonable Progress criteria. The alternative Reasonable Progress option clearly meets all the statutory and regulatory criteria. As noted above, the Section 169A of the federal Clean Air Act requires consideration of the remaining useful life of the plant for both BART and Reasonable Progress determinations. EPA's rules recognize that if the remaining useful life is limited by permit condition then the cost-effectiveness needs to be determined based on amortizing the capital cost over the reduced equipment life. 40 CFR 51, App. Y Section IV(D)(4)(k). The cost-effectiveness of the SCR based on a useful life of 12.5 years (i.e., the number of years after July 1, 2017 that the control would be operated if the plant had to close by the end of 2029) is over $7,300 per ton of NO_x controlled. This cost-effectiveness far exceeds the range of NO_x cost-effectiveness evaluated by EPA in establishing the presumptive BART limits. In EPA's assessment they looked at costs ranging from $100/ton to $1,000/ton. The cost-effectiveness of the SCR if operated only 12.5 years would be over seven times greater than the high end range of what EPA considered cost-effective. Therefore, with only a 12.5-year operational life it is appropriate to consider the cessation of operation of the Foster-Wheeler boiler by the end of 2029 to constitute Reasonable Progress. This determination would not affect the requirement to operate the NOx and SO_2 BART controls and nor would it affect PGE's obligation to control mercury from the boiler.

It is also appropriate to consider the alternative of cessation of the Foster-Wheeler boiler operations at the end of 2029 to be Reasonable Progress in light of the long term benefits to the environment provided by both options. If the plant installed the proposed BART controls (i.e., low-NOx burners, modified overfire air and semi-dry scrubbers) and operated through 2040, the aggregate visibility pollutant emissions calculated on a potential to emit basis would total 336,358 tons. If the BART controls and SCR were installed, the aggregate visibility pollutant emissions through 2040 would total 237,149 tons. If the BART controls were installed on the boiler, no SCR was installed, and the boiler ceased operation at the end of 2029, then 231,292 tons of visibility pollutants would be emitted. By not installing the SCR, a material quantity of ammonia emissions would be avoided. A comparison of the aggregate emissions is presented below.

Controls Installed	Boiler Operated Through	Total Emissions (tons)			
		NOx	SO_2	PM	Aggregate
LNB/OFA and SD scrubbers	12/31/2029	118,208	104,485	8,602	231,292
LNB/OFA and SD scrubbers	12/31/2040	184,960	139,313	12,084	336,358
LNB/OFA, SD Scrubbers & SCR	12/31/2040	85,752	139,313	12,084	237,149

Notes: All computations start 1/1/2011; emissions calculations based on plant potential to emit.

These suggested revisions are consistent with the Reasonable Progress requirements, are environmentally beneficial and also provide additional benefits. As we discussed above, the electrical generation business is in a time of tremendous transition. Over the next decade we anticipate tremendous advances in both electricity generation and control technology (e.g., carbon capture and sequestration). In addition, we anticipate that carbon will become subject to regulation. The full costs and benefits of these changes cannot be fully assessed at this time. However, by the time that PGE must decide whether to apply for its federally enforceable condition requiring cessation of operation of the Foster-Wheeler boiler or install SCR, both PGE and the Oregon Public Utilities Commission will have a much better idea of the best future for the Boardman plant. By building this decision point into the Reasonable Progress rules, it is possible to ensure that the decisions regarding Boardman are made with the most complete information. By enabling a more comprehensive and reasoned decision making process on the future of Boardman we also anticipate that DEQ will reduce the fiscal impacts to businesses in Oregon as compared to the Department's proposed rulemaking.

Startup, Shutdown and Malfunction Exemption

As noted above in relation to the BART controls we appreciate the recognition in the proposed rules that the technology based Reasonable Progress limit does not apply during startups and shutdowns. EPA was clear in the BART regulations that startups and shutdowns were not normal operating conditions and that the BART visibility impact assessment was intended to assess normal operating conditions. Therefore, we believe that it is appropriate to not include periods of startup and shutdown in determining compliance. However, it is equally true that the controls cannot be anticipated to perform as designed during a malfunction (defined under federal law as an upset that is not reasonably foreseeable or preventable and not resulting from inadequate design or maintenance). Therefore, we suggest that the regulations similarly note that malfunction periods should similarly not be included when evaluating whether the controls are operating properly and compliance is being achieved.

For the reasons stated above, we request that the proposed OAR 340-223-0040 (the Boardman Reasonable Progress rule) be revised as follows:

340-223-0040
Additional NO_x Requirements for the Foster-Wheeler boiler at the Boardman Coal-Fired Power Plant (Federal Acid rain program facility ORISPL code 6106)

(1) On and after July 1, 2017, nitrogen oxides emissions must not exceed 0.070 lb/mmBtu heat input, excluding periods of startup, ~~or~~ shutdown or malfunction.

(a) Compliance with the NOx emissions limit must be determined with a continuous emissions monitoring system in accordance with OAR 340-223-0030(2) and (3).

(b) The Department must be notified in writing within 7 days after any control equipment used to comply with the emission limit begins operation.

(c) A compliance status report, including CEMS data, must be submitted by January 1, 2018.

(d) The emission limit in (1) above does not apply if the operator has assumed a federally enforceable permit condition prior to July 1, 2017 requiring that the Foster-Wheeler boiler cease emissions by December 31, 2029. In order to ensure adequate time for the Department to process the permit modification by this deadline, the request for the federally enforceable permit condition must be submitted to the Department no later than July 1, 2015. If the permittee submits a permit application

requesting the permit limit on or before July 1, 2015 and submits to all Department information requests associated with the application in a timely manner, the permittee shall be deemed to have the permit condition in place.
(e) The emission limit in (1) above does not apply if EPA disapproves the portion of the Regional Haze SIP containing that limit or that portion of the Regional Haze SIP is otherwise invalidated.
(f) If EPA fails to approve the portion of the Regional Haze SIP containing the emission limit and compliance deadline in (1) above by December 31, 2009, then those deadlines shall automatically change to eight years after approval of the portion of the Regional Haze SIP containing these limits and deadlines.

5. Conclusion

Attached please find spreadsheets documenting the cost-effectiveness values stated in our comments above as well as the comparative emissions between the different BART and Reasonable Progress alternatives. Please consider these spreadsheets to be an addendum to our November 2007 report. You will also find a flow diagram that visually presents the proposed alternative BART and Reasonable Progress determinations.

Thank you for your consideration of these comments. As you know, the OPUC and PGE must engage in a public IRP process that includes considering alternatives to the emission controls. By incorporating the BART and Reasonable Progress alternatives discussed above DEQ will better align the DEQ and OPUC processes. This protects the best interests of PGE, its customers and the Oregon economy while also satisfying all state and federal requirements, including protection of Oregon air quality. Therefore, we believe that it provides an important improvement to the proposed rules. We hope that DEQ will recognize these benefits, incorporate our suggested edits into the proposed rule and re-notice the package so as to enable the greatest degree of public participation.

Mr. Brian Finneran
December 17, 2008
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Please contact me if you have any questions or would like to discuss these comments further.

Sincerely,

Arya Behbehani-Divers

cc: Stephen Quennoz
Loren Mayer

Attachments: Tables 1-4
Flow Diagram

Table 1 - Cost Effectiveness Calculations for Alternative Evaluation Periods

SCR Cost Effectiveness Calculations for Reasonable Progress (NO_x)	
End of Evaluation Period, end of year	2,029
Years of Operation post-July 2017	12.5
Capital Recovery Factor (%)	12.27
Annualized Cost of SCR (1000$) after LNB/OFA in 2011	28,446
Reduced NO_x Emissions for SCR after LNB/OFA (tons/yr)	3,890
Cost Effectiveness of SCR ($/ton) after LNB/OFA in 2011	**7,312**

Semi-Dry FGD Cost Effectiveness Calculations for BART (SO_2)	
End of Evaluation Period, end of year	2,020
Years of Operation post-July 2014	6.5
Capital Recovery Factor (%)	19.68
Annualized Cost of Semi-Dry FGD (1000$)	61,935
Reduced SO_2 Emissions (tons/yr)	11,988
Cost Effectiveness of Semi-Dry FGD ($/ton)	**5,167**

Table 2 - LNB/OFA Installed in 2011 (No SDA//FF or SCR)

Year	NOx		SO2		PM		Total Annual	Total Cumulative
	lb/MMBTU [a]	Tons [d]	lb/MMBTU [b]	Tons [d]	lb/MMBTU [c]	Tons [d]	Aggregate	
1st half of 2011	0.45	5,937	0.60	7,916	0.04	528	14,380	14,380
LNB/OFA Installed								
2nd half of 2011	0.23	3,034	0.60	7,916	0.04	528	11,478	25,857
2012	0.23	6,069	0.60	15,831	0.04	1,055	22,955	48,812
2013	0.23	6,069	0.60	15,831	0.04	1,055	22,955	71,768
2014	0.23	6,069	0.60	15,831	0.04	1,055	22,955	94,723
2015	0.23	6,069	0.60	15,831	0.04	1,055	22,955	117,678
2016	0.23	6,069	0.60	15,831	0.04	1,055	22,955	140,633
2017	0.23	6,069	0.60	15,831	0.04	1,055	22,955	163,588
2018	0.23	6,069	0.60	15,831	0.04	1,055	22,955	186,543
2019	0.23	6,069	0.60	15,831	0.04	1,055	22,955	209,498
2020	0.23	6,069	0.60	15,831	0.04	1,055	22,955	232,453
Proposed Shutdown								
2021	0.23	6,069	0.60	15,831	0.04	1,055	22,955	255,408
2022	0.23	6,069	0.60	15,831	0.04	1,055	22,955	278,363
2023	0.23	6,069	0.60	15,831	0.04	1,055	22,955	301,318
2024	0.23	6,069	0.60	15,831	0.04	1,055	22,955	324,273
2025	0.23	6,069	0.60	15,831	0.04	1,055	22,955	347,228
2026	0.23	6,069	0.60	15,831	0.04	1,055	22,955	370,183
2027	0.23	6,069	0.60	15,831	0.04	1,055	22,955	393,138
2028	0.23	6,069	0.60	15,831	0.04	1,055	22,955	416,093
2029	0.23	6,069	0.60	15,831	0.04	1,055	22,955	439,048
2030	0.23	6,069	0.60	15,831	0.04	1,055	22,955	462,003
2031	0.23	6,069	0.60	15,831	0.04	1,055	22,955	484,959
2032	0.23	6,069	0.60	15,831	0.04	1,055	22,955	507,914
2033	0.23	6,069	0.60	15,831	0.04	1,055	22,955	530,869
2034	0.23	6,069	0.60	15,831	0.04	1,055	22,955	553,824
2035	0.23	6,069	0.60	15,831	0.04	1,055	22,955	576,779
2036	0.23	6,069	0.60	15,831	0.04	1,055	22,955	599,734
2037	0.23	6,069	0.60	15,831	0.04	1,055	22,955	622,689
2038	0.23	6,069	0.60	15,831	0.04	1,055	22,955	645,644
2039	0.23	6,069	0.60	15,831	0.04	1,055	22,955	668,599
2040	0.23	6,069	0.60	15,831	0.04	1,055	22,955	691,554

Calculations:

(a) NOx emission rate (lb/MMBTU) = [2007 NOx emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 NOx emissions (tons) = 10,656 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(b) SO2 emission rate (lb/MMBTU) = [2007 SO2 emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 SO2 emissions (tons) = 14,037 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(c) PM emission rate (lb/MMBTU) = [2007 PM emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 PM emissions (tons) = 853 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(d) Annual emissions (tons/yr) = [emission rate (lb/MMBTU)] * [2007 hourly heat input (MMBTU/hr)] * [future operating hours (hours)] /2000

2007 Heat Input (MMBtu/hr) = 6,024 (3)
Future Operating Hours 8,760

Notes:

(1) Portland General Electric's 2007 Annual Title V Report
(2) US EPA Clean Air Markets
(3) Based on US EPA Clean Air Markets reported annual heat input / 2007 annual operating hours (7,787)

Table 3 - LNB/OFA Installed in 2011, SDA/FF Installed in 2014 (No SCR)

Year	NOx		SO2		PM		Total Annual Aggregate	Total Cumulative
	lb/MMBTU [a]	Tons [d]	lb/MMBTU [b]	Tons [d]	lb/MMBTU [c]	Tons [d]		
1st half of 2011	0.45	5,937	0.60	7,916	0.04	528	14,380	14,380
LNB/OFA Installed								
2nd half of 2011	0.23	3,034	0.60	7,916	0.04	528	11,478	25,857
2012	0.23	6,069	0.60	15,831	0.04	1,055	22,955	48,812
2013	0.23	6,069	0.60	15,831	0.04	1,055	22,955	71,768
1st half of 2014	0.23	3,034	0.60	7,916	0.04	528	11,478	83,245
SDA/FF Installed								
Second half of 2014	0.23	3,034	0.12	1,583	0.012	158	4,776	88,021
2015	0.23	6,069	0.12	3,166	0.012	317	9,551	97,572
2016	0.23	6,069	0.12	3,166	0.012	317	9,551	107,124
2017	0.23	6,069	0.12	3,166	0.012	317	9,551	116,675
2018	0.23	6,069	0.12	3,166	0.012	317	9,551	126,226
2019	0.23	6,069	0.12	3,166	0.012	317	9,551	135,778
2020	0.23	6,069	0.12	3,166	0.012	317	9,551	145,329
2021	0.23	6,069	0.12	3,166	0.012	317	9,551	154,881
2022	0.23	6,069	0.12	3,166	0.012	317	9,551	164,432
2023	0.23	6,069	0.12	3,166	0.012	317	9,551	173,983
2024	0.23	6,069	0.12	3,166	0.012	317	9,551	183,535
2025	0.23	6,069	0.12	3,166	0.012	317	9,551	193,086
2026	0.23	6,069	0.12	3,166	0.012	317	9,551	202,638
2027	0.23	6,069	0.12	3,166	0.012	317	9,551	212,189
2028	0.23	6,069	0.12	3,166	0.012	317	9,551	221,741
2029	0.23	6,069	0.12	3,166	0.012	317	9,551	231,292
Proposed Shutdown								
2030	0.23	6,069	0.12	3,166	0.012	317	9,551	240,843
2031	0.23	6,069	0.12	3,166	0.012	317	9,551	250,395
2032	0.23	6,069	0.12	3,166	0.012	317	9,551	259,946
2033	0.23	6,069	0.12	3,166	0.012	317	9,551	269,498
2034	0.23	6,069	0.12	3,166	0.012	317	9,551	279,049
2035	0.23	6,069	0.12	3,166	0.012	317	9,551	288,600
2036	0.23	6,069	0.12	3,166	0.012	317	9,551	298,152
2037	0.23	6,069	0.12	3,166	0.012	317	9,551	307,703
2038	0.23	6,069	0.12	3,166	0.012	317	9,551	317,255
2039	0.23	6,069	0.12	3,166	0.012	317	9,551	326,806
2040	0.23	6,069	0.12	3,166	0.012	317	9,551	336,358

Calculations:

(a) NOx emission rate (lb/MMBTU) = [2007 NOx emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 NOx emissions (tons) = 10,656 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(b) SO2 emission rate (lb/MMBTU) = [2007 SO2 emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 SO2 emissions (tons) = 14,037 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(c) PM emission rate (lb/MMBTU) = [2007 PM emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 PM emissions (tons) = 853 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(d) Annual emissions (tons/yr) = [emission rate (lb/MMBTU)] * [2007 hourly heat input (MMBTU/hr)] * [future operating hours (hours)] / 2000

2007 Heat Input (MMBtu/hr) = 6,024 (3)
Future Operating Hours 8,760

Notes:

(1) Portland General Electric's 2007 Annual Title V Report
(2) US EPA Clean Air Markets
(3) Based on US EPA Clean Air Markets reported annual heat input / 2007 annual operating hours (7,787)

Table 4 - LNB/OFA Installed in 2011, SDA/FF Installed in 2014, and SCR Installed in 2017

Year	NOx		SO2		PM		Total Annual Aggregate	Total Cumulative
	lb/MMBTU [a]	Tons [d]	lb/MMBTU [b]	Tons [d]	lb/MMBTU [c]	Tons [d]		
1st half of 2011	0.45	5,937	0.60	7,916	0.04	528	14,380	14,380
LNB/OFA Installed								
2nd half of 2011	0.23	3,034	0.60	7,916	0.04	528	11,478	25,857
2012	0.23	6,069	0.60	15,831	0.04	1,055	22,955	48,812
2013	0.23	6,069	0.60	15,831	0.04	1,055	22,955	71,768
1st half of 2014	0.23	3,034	0.60	7,916	0.04	528	11,478	83,245
SDA/FF Installed								
Second half of 2014	0.23	3,034	0.12	1,583	0.012	158	4,776	88,021
2015	0.23	6,069	0.12	3,166	0.012	317	9,551	97,572
2016	0.23	6,069	0.12	3,166	0.012	317	9,551	107,124
1st half of 2017	0.23	3,034	0.12	1,583	0.012	158	4,776	111,899
SCR Installed								
2nd half of 2017	0.07	923	0.12	1,583	0.012	158	2,665	114,564
2018	0.07	1,847	0.12	3,166	0.012	317	5,330	119,894
2019	0.07	1,847	0.12	3,166	0.012	317	5,330	125,224
2020	0.07	1,847	0.12	3,166	0.012	317	5,330	130,554
2021	0.07	1,847	0.12	3,166	0.012	317	5,330	135,883
2022	0.07	1,847	0.12	3,166	0.012	317	5,330	141,213
2023	0.07	1,847	0.12	3,166	0.012	317	5,330	146,543
2024	0.07	1,847	0.12	3,166	0.012	317	5,330	151,873
2025	0.07	1,847	0.12	3,166	0.012	317	5,330	157,203
2026	0.07	1,847	0.12	3,166	0.012	317	5,330	162,532
2027	0.07	1,847	0.12	3,166	0.012	317	5,330	167,862
2028	0.07	1,847	0.12	3,166	0.012	317	5,330	173,192
2029	0.07	1,847	0.12	3,166	0.012	317	5,330	178,522
2030	0.07	1,847	0.12	3,166	0.012	317	5,330	183,852
2031	0.07	1,847	0.12	3,166	0.012	317	5,330	189,181
2032	0.07	1,847	0.12	3,166	0.012	317	5,330	194,511
2033	0.07	1,847	0.12	3,166	0.012	317	5,330	199,841
2034	0.07	1,847	0.12	3,166	0.012	317	5,330	205,171
2035	0.07	1,847	0.12	3,166	0.012	317	5,330	210,500
2036	0.07	1,847	0.12	3,166	0.012	317	5,330	215,830
2037	0.07	1,847	0.12	3,166	0.012	317	5,330	221,160
2038	0.07	1,847	0.12	3,166	0.012	317	5,330	226,490
2039	0.07	1,847	0.12	3,166	0.012	317	5,330	231,820
2040	0.07	1,847	0.12	3,166	0.012	317	5,330	237,149

Calculations:

(a) NOx emission rate (lb/MMBTU) = [2007 NOx emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000
2007 NOx emissions (tons) = 10,656 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(b) SO2 emission rate (lb/MMBTU) = [2007 SO2 emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000
2007 SO2 emissions (tons) = 14,037 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

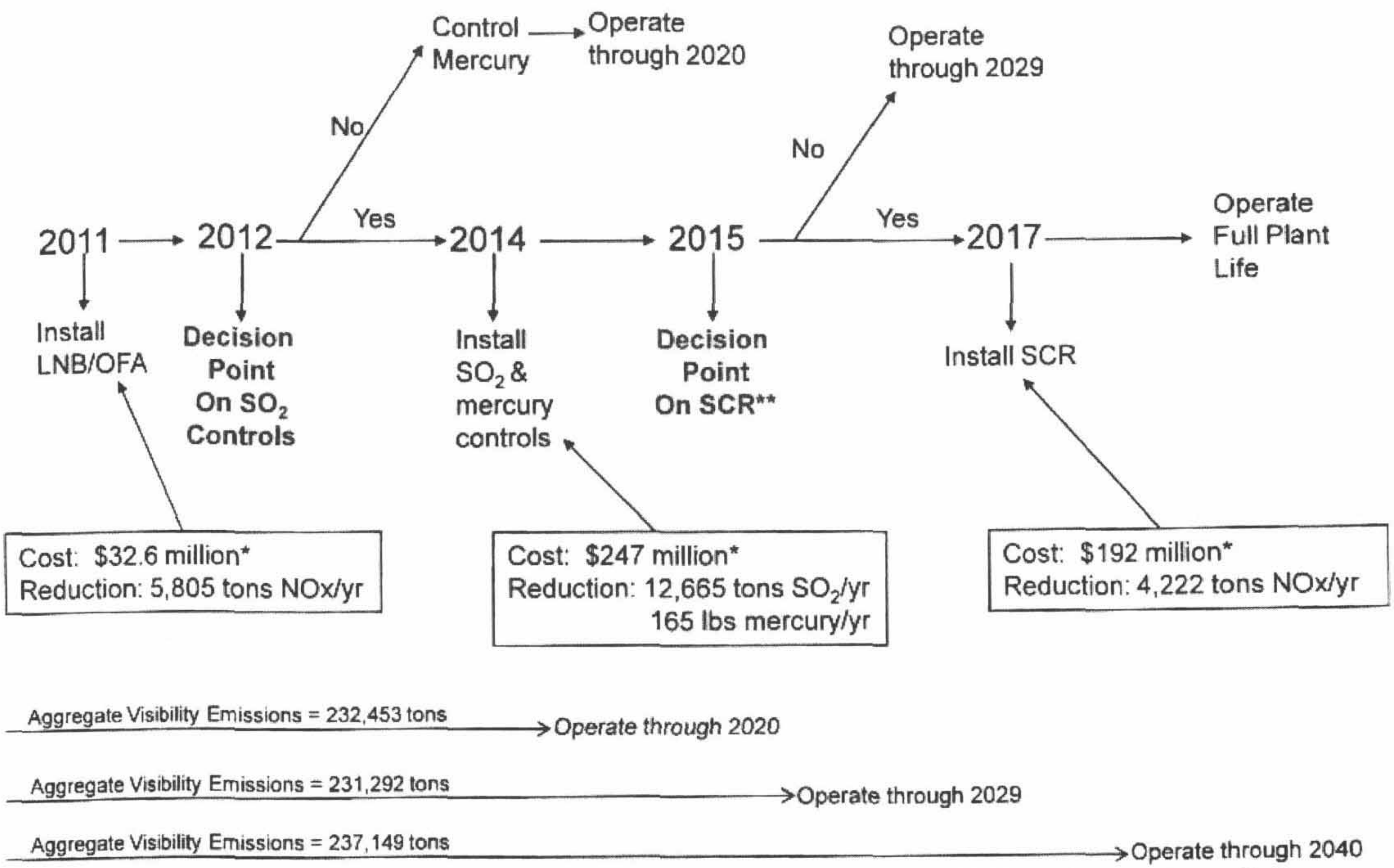
(c) PM emission rate (lb/MMBTU) = [2007 PM emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000
2007 PM emissions (tons) = 853 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(d) Annual emissions (tons/yr) = [emission rate (lb/MMBTU)] * [2007 hourly heat input (MMBTU/hr)] * [future operating hours (hours)] / 2000
2007 Heat Input (MMBtu/hr) = 6,024 (3)
Future Operating Hours 8,760

Notes:

(1) Portland General Electric's 2007 Annual Title V Report
(2) US EPA Clean Air Markets
(3) Based on US EPA Clean Air Markets reported annual heat input / 2007 annual operating hours (7,787)

PGE Alternative Boardman BART/Reasonable Progress Proposal



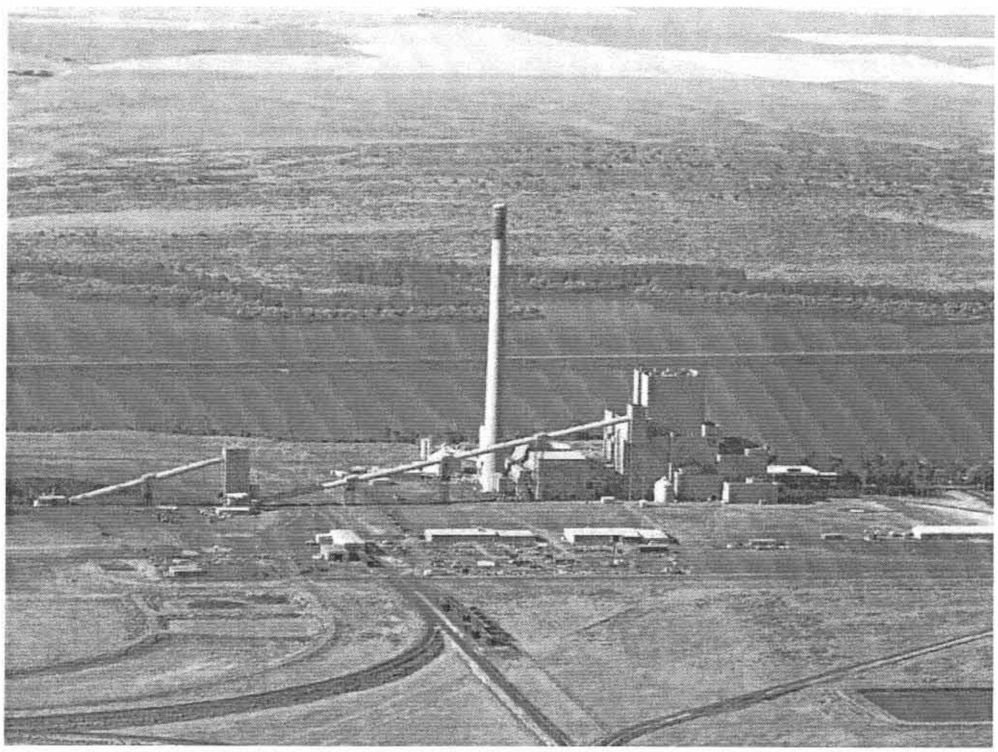
*Estimates are of full control cost in 2007 dollars

**Assumes that SCR is required under Reasonable Progress

Portland General Electric

Boardman Plant

Best Available Retrofit Technology (BART) Analysis



Black & Veatch Project: 144449
Black & Veatch File No.: 40.0000

November 2, 2007

BLACK & VEATCH
Building a world of difference.

CH2MHILL

Executive Summary

The Boardman Plant is a 584 megawatt (MW) net pulverized coal fired steam electric plant of more than 250 million British thermal unit (MMBTU) per hour heat input located near Boardman, Oregon, about 150 miles east of Portland. The plant was issued its construction authorization on February 27, 1975 by the Oregon Nuclear and Thermal Energy Council.

On July 6, 2005, the Environmental Protection Agency (EPA) issued its final *Regional Haze Regulations and Guidelines for Performing Best Available Retrofit Technology (BART) Determinations*. These rules/guidelines established a procedure for identifying those sources that must retrofit their existing facilities with BART and for determining what constitutes BART. The purpose of the BART program was to require controls, where appropriate, for facilities that were "grandfathered" from the new source review requirements of the 1977 Clean Air Act Amendments. Specifically, the BART rules apply exclusively to sources within one of the enumerated source categories that were in existence prior to August 7, 1977.

Because the Boardman Plant is a steam electric plant of more than 250 MMBTU per hour heat input that was in existence (as that term is defined by EPA) before August 7, 1977, it was identified by the Oregon Department of Environmental Quality (DEQ) as a BART source. Portland General Electric (PGE) volunteered to serve as the pilot source for DEQ's BART determination process. This analysis has been prepared in accordance with the five-step process identified in the EPA's *Regional Haze Regulations and Guidelines for Performing BART Determinations* (40 CFR Part 51, Appendix Y) to evaluate the best available retrofit control technologies for the reduction of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM) emissions from the Boardman Plant.

The five-step BART analysis was used to generate the information needed to identify the best control technology package that constitutes BART for the Boardman Plant. In Step 1, available NO_x, SO_2, and PM retrofit control technologies were identified for the Boardman Plant. In Step 2, this list was shortened by eliminating those technologies that are not considered technically feasible. In Step 3, the control effectiveness of each technically feasible control technology was evaluated and, based on this evaluation, the technologies were ranked in order of effectiveness. In Step 4, the cost, energy, and environmental impacts were evaluated for each technically feasible control technology. In the final step, the visibility improvements associated with the top-ranked options were evaluated consistent with the modeling protocol approved by DEQ on January 18, 2007 and amended on August 28, 2007.

NO_x Control Selection

After all of the statutory factors were considered, the NO_x controls combination of new low NO_x burners with modified overfire air and selective noncatalytic reduction (NLNB/MOFA/SNCR) was identified as the Best Available Retrofit Technology for NO_x control. This NO_x control combination results in significant modeled visibility improvement at the Class 1 areas for Boardman Plant impacts.

An alternative NO_x control package that utilizes selective catalytic reduction (SCR) in lieu of SNCR was considered, but ultimately determined to have excessive impacts and so eliminated from consideration as BART. The controls combination of new LNBs with modified OFA and SCR (NLNB/MOFA/SCR) would result in greater NO_x reductions and slightly better modeled visibility improvements than NLNB/MOFA/SNCR. However, as EPA recognized in the 2005 preamble, the modeling system required for evaluating visibility impacts magnifies and overstates those impacts. Therefore, the small incremental improvement between the NO_x controls incorporating SNCR and the NO_x controls incorporating SCR is not, by itself, determinative. In addition, the use of the NO_x controls incorporating SCR has other impacts that are more severe than new LNBs with modified OFA system and SNCR. Specifically, the non-air quality environmental impacts (i.e., hazardous material disposal during catalyst replacement) and the energy impacts (i.e., significant fan auxiliary power to overcome additional system resistance) associated with NLNB/MOFA/SCR are higher than for NLNB/MOFA/SNCR.

The economic impacts also support selecting NLNB/MOFA/SNCR as BART. The economic impacts associated with the NLNB/MOFA/SCR alternative are considerably higher than the economic impacts associated with the NLNB/MOFA/SNCR alternative. The total capital cost of the NO_x controls incorporating SNCR is approximately \$50 million while the total capital cost associated with the NO_x controls including SCR is approximately \$223 million. Operating costs are similarly much higher with the SCR alternative than the SNCR alternative (\$5.7 million per year as opposed to \$2.4 million per year). However, the visibility improvements associated with the NO_x controls incorporating SCR are not commensurate with the additional \$173 million in capital cost (as compared to the NO_x controls incorporating SNCR). Even if the plant were assumed to operate at its highest daily emission rate for every day of the year (something that never occurs), the use of the NO_x control package with SCR as opposed to that with SNCR, would result in only 7 fewer days per year where Mt Hood Wilderness Area visibility impacts exceeded 0.5 deciviews. The additional \$173 million capital cost and \$3.3 million per year of operating cost associated with the SCR control package is not justified by the minimal benefit. This limited benefit carries across all of the Class I areas. The average 98th percentile impact level across all the Class I areas is only 0.27 deciviews better with the control option incorporating SCR than the control option incorporating SNCR. This equates to an incremental annualized control cost associated with moving from the NO_x controls with SNCR to the NO_x controls with SCR of approximately \$72 million per deciview (based on an annualized cost of \$27 million/year for package with SCR v. \$7 million per year for package with SNCR). Again, the minimal improvement in visibility associated with the NO_x control option incorporating SCR does not justify the extreme incremental cost. This conclusion is confirmed through reference to the EPA cost-effectiveness recommendations. The cost effectiveness of the NO_x control package incorporating SCR (\$3,096/ton) is significantly higher than the range (\$100 to \$1000/ton) considered reasonable in EPA's BART guidelines.

Consideration of the impact of requiring SCR on plant viability also supports the conclusion that BART for NO_x constitutes the control package with SNCR. The EPA Guidelines state that it is appropriate to take into account the affordability of particular controls as part of the BART analysis where the cost of installing and operating the controls is judged to have a severe impact on plant operations. That would be the case were BART considered to include SCR. The Boardman Plant is a key resource for providing baseload power to the region throughout the year. The imposition of SCR as BART, on top of the \$300 million in air pollution control capital investments being proposed, could possibly require an investment in excess of what the plant can support. Under such circumstances the EPA Guidelines state that it is appropriate to consider the non-affordability of SCR and to therefore conclude that SCR is not BART. Based on the discussion within this report there is no need to rely on this factor to conclude that BART does not include SCR. However, this additional consideration lends further support to the conclusion that BART for NO_x constitutes the control package with SNCR.

From a design standpoint, since the Boardman boiler was not designed with space in the ductwork or with an appropriate temperature profile for utilization of SCR, very challenging and complex modifications to the boiler would be required at significant cost to lower the gas path temperature to the desired range while maintaining combustion efficiency. Therefore, a balancing of the statutory factors strongly supports NLNB/MOFA/SNCR as the best alternative.

SO_2 Control Selection

After all of the statutory factors were considered, the semi-dry flue gas desulfurization (semi-dry FGD) technology was determined to be the best BART alternative for SO_2 control. The two top SO_2 control technologies (wet FGD and semi-dry FGD) were modeled as having essentially the same level of visibility improvement at the Class I areas. However, the non-air quality environmental impacts and negative energy impacts are significantly greater for the wet FGD control technology, since it generates a visible plume, consumes more water, generates a wastewater stream requiring treatment and disposal, generates slightly more solid byproducts for landfill, and because the wet FGD requires significantly more auxiliary power consumption during operation. The economic impacts associated with the wet FGD are also much higher than the economic impacts associated with the semi-dry FGD. The costs associated with installing semi-dry FGD are very high, with a total capital cost of approximately $247 million and operating costs of approximately $13 million per year. While these costs are extremely high, the costs of the wet FGD system would be considerably higher with a total capital cost of approximately $382 million and operating costs of approximately $16 million per year. As a result, the cost effectiveness of the wet FGD control option is significantly higher than the range ($400 to $2000/ton) considered to be reasonable in EPA's BART guidelines. Given that wet FGD does not perform materially better than semi-dry FGD, there is no basis for spending the additional $135 million in capital and $3 million per year in operating expenses to implement the wet FGD technology. Therefore, consistent with the statutory factors, semi-dry FGD was chosen as the best alternative for SO_2 control.

Particulate (PM) Control Selection

After all of the statutory factors were considered, the pulse jet fabric filter (PJFF), in combination with the existing ESP, was determined to be the best BART control alternative for PM. Multiple technologies had equal control effectiveness, but the utilization of PJFF enables the highest level of mercury control. This improvement to water quality from reduction of mercury bioaccumulation is a significant positive environmental benefit and, therefore, supports the choice of PJFF as BART.

Best Control Combination Selection

The package of the selected controls (NLNB/MOFA/SNCR for NO_x and semi-dry FGD including PJFF for SO_2 and PM) constitutes BART for the Boardman Plant. This also constitutes the most effective package for integration with the controls being designed for the Boardman Plant to meet the Oregon mercury standards for coal fired power plants.

While the Columbia River Gorge National Scenic Area (CRGNSA) is not a Class I area and so not a part of the BART analysis, there was interest in the benefits to that area as a result of the proposed BART controls. The modeling of the benefits predicted from the proposed BART control package show significant improvement in visibility in the CRGNSA. While slightly greater improvements are shown by the model from the use of a control package that includes SCR, these improvements are not considered significant. This conclusion was independently verified in the draft *Columbia River Gorge Air Quality Study Science Summary Report* (September 27, 2007) prepared by DEQ in conjunction with other state and federal governmental authorities. The report authors compared CRGNSA visibility as a result of the proposed BART controls (i.e., NLNB/MOFA/SNCR, semi-dry FGD and PJFF) to CRGNSA visibility if Boardman emissions were reduced to "0" (i.e., complete shutdown of the plant). As the report notes, "practically zero" additional visibility benefit is achieved by reducing plant emissions from those achieved by the proposed BART control package all the way to zero plant emissions.

That assessment serves as independent verification of the conclusion that no material visibility benefit would be gained by controlling NO_x through the use of new LNB with modified OFA and SCR rather than new LNB with modified OFA and SNCR. If eliminating the Boardman Plant generates "practically zero" additional benefit as compared to the proposed BART control package, the much smaller incremental benefit achieved by requiring SCR rather than SNCR would be immaterial. Given the extreme incremental cost associated with the use of new LNB with modified OFA and SCR for NO_x control, there is no technically sound basis for requiring SCR as part of the BART control package.

PGE's implementation of the suite of BART controls identified through this report will cost more than $297 million dollars to install and approximately $15 million per year to operate. While this poses a significant economic impact to the Boardman Plant and to Northwest electric utility customers, the controls are predicted to improve the plant's modeled worst-case visibility impacts in the Class I areas by an average 64 percent, improve the plant's modeled worst-case visibility impacts at the most severely impacted Class I area by 56 percent, and enable the enhanced control of mercury emissions. Therefore, the utilization of the NLNB/MOFA/SNCR and semi-dry FGD (including PJFF) is the best alternative and constitutes BART.

The following appendices contain supporting data for the BART analysis described in this report:

- Appendix A Design Basis.
- Appendix B Stack Outlet Conditions.
- Appendix C Design Concept Definitions.
- Appendix D Cost Analysis Summary.
- Appendix E Visibility Modeling Results.
- Appendix F Visibility Modeling Protocol.
- Appendix G Emissions Performance Analysis Memo.

Appendix D
Cost Analysis Summary

Technology: Overfire Air System Operation **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
Neural network system for NOx optimization	$345,000	B&V cost estimate		
NOx monitoring equipment	$182,000	B&V cost estimate		
Water cannon system	$1,452,000	B&V cost estimate		
Subtotal capital cost (CC)	$1,979,000			
Freight	$99,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$2,078,000			
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$416,000	(PEC) X	20.0%	
Electrical	$312,000	(PEC) X	15.0%	
Piping	$42,000	(PEC) X	2.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$52,000	(PEC) X	2.5%	
Relocation	$0	(PEC) X	0.0%	
Total direct installation costs (DIC)	$822,000			
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$2,900,000			
Indirect Costs				
Engineering	$348,000	(DC) X	12.0%	
Owner's cost	$58,000	(DC) X	2.0%	
Construction management	$145,000	(DC) X	5.0%	
Start-up and spare parts	$58,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$290,000	(DC) X	10.0%	
Total indirect costs (IC)	$949,000			
Allowance for Funds Used During Construction (AFDC)	$173,000	[(DC)+(IC)]	8.99%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$4,022,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor and materials	$87,000	(DC) X	3.0%	
Total fixed annual costs	$87,000			
Variable annual costs				
Replacement power due to efficiency hit	$540,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh		
Total variable annual costs	$540,000			
Total direct annual costs (DAC)	$627,000			
Indirect Annual Costs				
Cost for capital recovery	$380,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$380,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,007,000**			

Technology: Overfire Air System Operation **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
Neural network system for NOx optimization	$345,000	B&V cost estimate		
NOx monitoring equipment	$182,000	B&V cost estimate		
Water cannon system	$1,452,000	B&V cost estimate		
Subtotal capital cost (CC)	$1,979,000			
Freight	$99,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$2,078,000	(A1)		
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$416,000	(PEC) X	20.0%	
Electrical	$312,000	(PEC) X	15.0%	
Piping	$42,000	(PEC) X	2.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$52,000	(PEC) X	2.5%	
Relocation	$0	(PEC) X	0.0%	
Total direct installation costs (DIC)	$822,000	(B1)		
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$2,900,000	(C1)		
Indirect Costs				
Engineering	$348,000	(DC) X	12.0%	
Owner's cost	$58,000	(DC) X	2.0%	
Construction management	$145,000	(DC) X	5.0%	
Start-up and spare parts	$58,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$290,000	(DC) X	10.0%	
Total indirect costs (IC)	$949,000			
Allowance for Funds Used During Construction (AFDC)	$173,000	[(DC)+(IC)]	8.99%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$4,022,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor and materials	$87,000	(DC) X	3.0%	
Total fixed annual costs	$87,000			
Variable annual costs				
Replacement power due to efficiency hit	$540,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh		
Total variable annual costs	$540,000			
Total direct annual costs (DAC)	$627,000			
Indirect Annual Costs				
Cost for capital recovery	$380,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$380,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,007,000**			

Technology: Upgraded Low NOx Burners | **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
New coal elbow, nozzle with air vane, fuel injector barrel, air zone swirler and coal piping	$2,753,000	from vendor quote, 06/30/06		
Dynamic classifier for coal pulverizers	$1,760,000	B&V cost estimate		
Coal/air flow instrument for burners	$935,000	B&V cost estimate		
Subtotal capital cost (CC)	$5,448,000			
Freight	$272,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$5,720,000	(A2)		
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$1,144,000	(PEC) X	20.0%	
Electrical	$572,000	(PEC) X	10.0%	
Piping	$0	(PEC) X	0.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$143,000	(PEC) X	2.5%	
Relocation	$0	(PEC) X	0.0%	
Total direct installation costs (DIC)	$1,859,000	(B2)		
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$7,579,000	(C2)		
Indirect Costs				
Engineering	$909,000	(DC) X	12.0%	
Owner's cost	$152,000	(DC) X	2.0%	
Construction management	$379,000	(DC) X	5.0%	
Start-up and spare parts	$152,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$758,000	(DC) X	10.0%	
Total indirect costs (IC)	$2,400,000			
Allowance for Funds Used During Construction (AFDC)	$449,000	[(DC)+(IC)]	8.99%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$10,428,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor and materials	$227,000	(DC) X	3.0%	
Total fixed annual costs	$227,000			
Variable annual costs				
N/A	$0	Similar annual costs as current LNB		
Total variable annual costs	$0			
Total direct annual costs (DAC)	$227,000			
Indirect Annual Costs				
Cost for capital recovery	$984,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$984,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,211,000**			

Technology: Upgraded LNB with existing OFA System operation **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
New coal elbow, nozzle with air vane, fuel injector barrel, air zone swirler and coal piping	$2,753,000	from vendor quote, 06/30/06		
Dynamic classifier for coal pulverizers	$1,760,000	B&V cost estimate		
Coal/air flow instrument for burners	$935,000	B&V cost estimate		
Neural network system for NOx optimization	$345,000	B&V cost estimate		
NOx monitoring equipment	$182,000	B&V cost estimate		
Water cannon system	$1,452,000	B&V cost estimate		
Subtotal capital cost (CC)	$7,427,000			
Freight	$371,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$7,798,000	A1 + A2		
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$1,560,000	(PEC) X	20.0%	
Electrical	$780,000	(PEC) X	10.0%	
Piping	$0	(PEC) X	0.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$195,000	(PEC) X	2.5%	
Relocation	$0	(PEC) X	0.0%	
Total direct installation costs (DIC)	$2,535,000	B1 + B2		
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$10,333,000			
Indirect Costs				
Engineering	$1,240,000	(DC) X	12.0%	
Owner's cost	$207,000	(DC) X	2.0%	
Construction management	$517,000	(DC) X	5.0%	
Start-up and spare parts	$207,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$1,033,000	(DC) X	10.0%	
Total indirect costs (IC)	$3,254,000			
Allowance for Funds Used During Construction (AFDC)	$611,000	[(DC)+(IC)]	8.99%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$14,198,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor and materials	$310,000	(DC) X	3.0%	
Total fixed annual costs	$310,000			
Variable annual costs				
Replacement power due to efficiency hit	$540,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh		
Total variable annual costs	$540,000			
Total direct annual costs (DAC)	$850,000			
Indirect Annual Costs				
Cost for capital recovery	$1,340,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$1,340,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$2,190,000**			

Technology: New Low NOx Burners & Modified OFA System **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
New Low NOx Burners with new secondary air registers	$4,593,000	from vendor quote, 06/30/06		
(8) OFA ports and (4) wing ports with tube throat openings	$1,994,000	from vendor quote, 06/30/06		
Neural network system for NOx optimization	$346,000	B&V cost estimate		
NOx monitoring equipment	$182,000	B&V cost estimate		
Water cannon system	$1,452,000	B&V cost estimate		
Dynamic classifier for coal pulverizers	$1,760,000	B&V cost estimate		
Coal/air flow instrument for burners	$935,000	B&V cost estimate		
Modulating orifice for burners	$282,000	B&V cost estimate		
Subtotal capital cost (CC)	$11,544,000			
Freight	$577,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$12,121,000			
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$6,061,000	(PEC) X	50.0%	
Electrical	$1,212,000	(PEC) X	10.0%	
Piping	$606,000	(PEC) X	5.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$606,000	(PEC) X	5.0%	
Relocation	$606,000	(PEC) X	5.0%	
Total direct installation costs (DIC)	$9,091,000			
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$21,212,000			
Indirect Costs				
Engineering	$2,545,000	(DC) X	12.0%	
Owner's cost	$424,000	(DC) X	2.0%	
Construction management	$1,061,000	(DC) X	5.0%	
Start-up and spare parts	$424,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$4,242,000	(DC) X	20.0%	
Total indirect costs (IC)	$8,746,000			
Allowance for Funds Used During Construction (AFDC)	$2,693,000	[(DC)+(IC)]	8.99%	2 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$32,651,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor and materials	$636,000	(DC) X	3.0%	
Total fixed annual costs	$636,000			
Variable annual costs				
N/A	$0	No associated annual cost		
Total variable annual costs	$0			
Total direct annual costs (DAC)	$636,000			
Indirect Annual Costs				
Cost for capital recovery	$3,082,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$3,082,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$3,718,000**			

Technology: Selective Non-Catalytic Reduction **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Reagent storage, handling, injection & controls	$5,083,000	CUECost estimate				
Initial urea inventory	$255,000	150,000 gal. urea initial inventory				
Air preheater modifications	$2,835,000	CUECost estimate				
Subtotal capital cost (CC)	$8,173,000					
Freight	$490,380	(CC) X	6.0%			
Total purchased equipment cost (PEC)	$8,663,000					
Direct installation costs						
Foundation & supports	$433,000	(PEC) X	5.0%			
Handling & erection	$866,000	(PEC) X	10.0%			
Electrical	$866,000	(PEC) X	10.0%			
Piping	$260,000	(PEC) X	3.0%			
Insulation	$0	(PEC) X	0.0%			
Painting	$0	(PEC) X	0.0%			
Demolition	$173,000	(PEC) X	2.0%			
Relocation	$173,000	(PEC) X	2.0%			
Total direct installation costs (DIC)	$2,771,000					
Site preparation	$0	N/A				
Buildings	$0	N/A				
Total direct costs (DC) = (PEC) + (DIC)	$11,434,000					
Indirect Costs						
Engineering	$1,372,000	(DC) X	12.0%			
Owner's cost	$572,000	(DC) X	5.0%			
Construction management	$1,143,000	(DC) X	10.0%			
Start-up and spare parts	$343,000	(DC) X	3.0%			
Performance test	$100,000	Engineering estimate				
Contingencies	$1,715,000	(DC) X	15.0%			
Total indirect costs (IC)	$5,245,000					
Allowance for Funds Used During Construction (AFDC)	$750,000	[(DC)+(IC)]	8.99%		1	years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$17,429,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$100,000	1	FTE and	100,000	$/year	Estimated manpower
Maintenance labor and materials	$343,000	(DC) X	3.0%			
Total fixed annual costs	$443,000					
Variable annual costs						
Reagent	$3,093,000	2,637	lb/hr and	315	$/ton	Engineering estimate
Auxiliary and ID fan power	$26,000	70	kW and	0.05	$/kWh	Engineering estimate
Water	$179,000	200	gpm and	2	$/1,000 gal	Engineering estimate
Total variable annual costs	$3,298,000					
Total direct annual costs (DAC)	$3,741,000					
Indirect Annual Costs						
Cost for capital recovery	$1,645,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life		
Total indirect annual costs (IDAC)	$1,645,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$5,386,000**					

Technology: New Low NOx Burners & Modified OFA System & SNCR **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Total Capital Investment (TCI) cost for:						
New Low NOx Burners & Modified OFA System	$32,651,000	Cost estimate for independent system				
Selective Non-Catalytic Reduction System	$17,429,000	Cost estimate for independent system				
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$50,080,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$100,000		1 FTE and	100,000 $/year		Estimated manpower
Maintenance labor and materials	$979,000	(DC) X	3.0%			
Total fixed annual costs	$1,079,000					
Variable annual costs						
Reagent	$1,105,000		942 lb/hr and	315 $/ton		Engineering estimate
Auxiliary and ID fan power	$26,000		70 kW and	0.05 $/kWh		Engineering estimate
Water	$179,000		200 gpm and	2 $/1,000 gal		Engineering estimate
Total variable annual costs	$1,310,000					
Total direct annual costs (DAC)	$2,389,000					
Indirect Annual Costs						
Cost for capital recovery	$4,728,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life		
Total indirect annual costs (IDAC)	$4,728,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$7,117,000**					

Technology: Upgraded Low NOx Burners with existing OFA and SNCR **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Total Capital Investment (TCI) cost for:					
Upgraded Low NOx Burners with existing OFA System	$14,198,000	Cost estimate for independent system			
Selective Non-Catalytic Reduction System	$17,429,000	Cost estimate for independent system			
Total Capital Investment (TCI) =	**$31,627,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$100,000		1 FTE and	100,000 $/year	Estimated manpower
Maintenance materials and labor	$653,000	(DC) X	3.0%		
Total fixed annual costs	$753,000				
Variable annual costs					
Replacement power due to efficiency hit	$540,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh			
Reagent	$2,430,000		2,072 lb/hr and	315 $/ton	Engineering estimate
Auxiliary power	$26,000		70 kW and	0.05 $/kWh	Engineering estimate
Water	$179,000		200 gpm and	2 $/1,000 gal	Engineering estimate
Total variable annual costs	$3,175,000				
Total direct annual costs (DAC)	$3,928,000				
Indirect Annual Costs					
Cost for capital recovery	$2,986,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$2,986,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$6,914,000**				

Technology: New Low NOx Burners & Modified OFA System & SCR **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Reactor housing	$5,580,000	CUECost estimate			
Ammonia handling and injection	$2,589,000	CUECost estimate			
Initial catalyst and ammonia	$4,750,000	CUECost estimate			
Electrical system modification	$2,261,000	from ref. cost			
ID fans	$3,658,000	from ref. cost			
Flue gas handling system	$6,500,000	from ref. cost			
Air preheater modifications	$2,835,000	CUECost estimate			
Ash handling system	$3,110,000	CUECost estimate			
Subtotal capital cost (CC)	$31,283,000				
Instruments and controls	$3,128,000	(CC) X	10.0%		
Freight	$1,564,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$35,975,000				
Direct installation costs					
Foundation & supports	$13,671,000	(PEC) X	38.0%		
Handling & erection	$13,311,000	(PEC) X	37.0%		
Electrical	$8,994,000	(PEC) X	25.0%		
Piping	$2,698,000	(PEC) X	7.5%		
Insulation	$3,598,000	(PEC) X	10.0%		
Painting	$360,000	(PEC) X	1.0%		
Demolition	$6,116,000	(PEC) X	17.0%		
Relocation	$4,317,000	(PEC) X	12.0%		
Total direct installation costs (DIC)	$53,065,000				
Site preparation	$2,000,000	Engineering estimate			
Buildings	$500,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$91,540,000				
Indirect Costs					
Engineering	$10,985,000	(DC) X	12.0%		
Owner's cost	$4,577,000	(DC) X	5.0%		
Construction management	$9,154,000	(DC) X	10.0%		
Start-up and spare parts	$2,746,000	(DC) X	3.0%		
Performance test	$200,000	Engineering estimate			
Contingencies	$13,731,000	(DC) X	15.0%		
Total indirect costs (IC)	$41,393,000				
Allowance for Funds Used During Construction (AFDC)	$17,926,000	[(DC)+(IC)]	8.99%	3 years (project time length X 1/2)	
Boiler Heat Transfer Surface Area Replacement	$40,000,000	B&V estimate to reduce SCR inlet FG temperature			
Total SCR Capital Investment (TCI)	**$190,859,000**				
Total Capital Investment (TCI) cost for:					
New Low NOx Burners & Modified OFA System	$32,651,000	Cost estimate for independent system			
Total Capital Investment (TCI) for LNB/OFA and SCR	**$223,510,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$100,000		1 FTE and	100,000 $/year	Estimated manpower
Maintenance labor & materials	$2,746,000	(DC) X	3.0%		
Yearly emissions testing	$25,000	Engineering estimate			
Catalyst activity testing	$5,000	Engineering estimate			
Fly ash sampling and analysis	$20,000	Engineering estimate			
Total fixed annual costs	$2,896,000				
Variable annual costs					
Reagent	$797,000		475 lb/hr and	450 $/ton	Engineering estimate
Auxiliary and ID fan power	$944,000		2,537 kW and	0.05 $/kWh	Engineering estimate
Catalyst replacement	$1,035,000		173 m3 and	6,000 $/m3	3 yr replacement rate
Catalyst disposal	$1,000		292,483 lb and	10 $/ton	3 yr replacement rate
Total variable annual costs	$2,777,000				
Total direct annual costs (DAC)	$5,673,000				
Indirect Annual Costs					
Cost for capital recovery	$21,099,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$21,099,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$26,772,000**				

Technology: *Wet Flue Gas Desulfurization (FGD)* **Date:** *10/11/2007*

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Reagent feed system: receiving, storage	$1,417,000	CUECost estimate				
Ball mill & classifier	$2,154,000	CUECost estimate				
SO2 removal system: tanks, pumps	$3,855,000	CUECost estimate				
Absorber tower	$30,207,000	CUECost estimate				
Spray pumps	$4,517,000	CUECost estimate				
Byproduct handling system	$1,737,000	CUECost estimate				
Vacuum filter system	$1,650,000	from ref. cost				
Fabric filter with ash handling system	$16,526,000	from ref. cost				
Booster fans	$4,840,000	Engineering estimate				
Electrical system upgrades	$4,245,491	from ref. cost				
Flue gas handling system	$8,800,000	Engineering estimate				
Subtotal capital cost (CC)	$79,948,491					
Instrumentation and controls	$3,997,000	(CC) X	5.0%			
Freight	$3,997,000	(CC) X	5.0%			
Total purchased equipment cost (PEC)	$87,942,000					
Direct installation costs						
Foundation & supports	$24,184,000	(PEC) X	27.5%			
Handling & erection	$35,177,000	(PEC) X	40.0%			
Electrical	$17,588,000	(PEC) X	20.0%			
Piping	$4,397,000	(PEC) X	5.0%			
Insulation	$4,397,000	(PEC) X	5.0%			
Painting	$879,000	(PEC) X	1.0%			
Demolition	$3,518,000	(PEC) X	4.00%			
Relocation	$3,518,000	(PEC) X	4.00%			
Total direct installation costs (DIC)	$93,658,000					
Site preparation	$200,000	Engineering estimate				
Buildings	*$7,500,000*	*Engineering estimate*				
New wet stack	$23,000,000	Recent quotes estimate of $23 mil				
Waste water treatment system	$15,000,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$227,300,000					
Indirect Costs						
Engineering	$27,276,000	(DC) X	12.0%			
Owner's cost	$9,092,000	(DC) X	4.0%			
Construction management	$22,730,000	(DC) X	10.0%			
Start-up and spare parts	*$3,410,000*	*(DC) X*	*1.5%*			
Performance test	$200,000	Engineering estimate				
Contingencies	$34,095,000	(DC) X	15.0%			
Total indirect costs (IC)	$96,803,000					
Allowance for Funds Used During Construction (AFDC)	$58,274,000	[(DC)+(IC)]	8.99%		4 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$382,377,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$400,000	4	FTE and	100,000	$/year	Estimated manpower
Maintenance labor and materials	$6,819,000	(DC) X	3.0%			
Total fixed annual costs	$7,219,000					
Variable annual costs						
Reagent	$2,015,000	5.9	tph and	46	$/ton	Mass bal. calcs.
Byproduct disposal	$806,000	10.8	tph and	10	$/ton	Mass bal. calcs.
Auxiliary and ID fan power	$5,679,000	15,254	kW and	0.05	$/kWh	CueCost calculations
Water	$532,000	595	gpm and	2	$/1,000 gal	Mass bal. calcs.
Bag replacement cost	$632,000	6,322	bags and	100	$/bag	18,966 total bags
Cage replacement cost	$158,000	3,161	cages and	50	$/cage	18,966 total cages
Total variable annual costs	$8,500,000					
Total direct annual costs (DAC)	$15,719,000					
Indirect Annual Costs						
Cost for capital recovery	$36,096,000	(TCI) X	9.44%		CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$36,096,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$51,815,000**					

Technology: Semi-Dry Flue Gas Desulfurization (FGD) **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Reagent feed: receiving, storage, grinding	$3,337,000	CUECost estimate			
SO2 removal system: tanks, pumps	$3,164,000	CUECost estimate			
Spray dryers and fabric filter	$41,189,000	CUECost estimate			
Ash handling system	$2,000,000	from ref. cost			
Booster fans	$4,840,000	Engineering estimate			
Electrical system upgrades	$2,860,000	from ref. cost			
Flue gas handling system	$8,800,000	CUECost estimate			
Subtotal capital cost (CC)	$66,190,000				
Instrumentation and controls	$1,324,000	(CC) X	2.0%		
Freight	$3,310,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$70,824,000				
Direct installation costs					
Foundation & supports	$19,477,000	(PEC) X	27.5%		
Handling & erection	$28,330,000	(PEC) X	40.0%		
Electrical	$14,165,000	(PEC) X	20.0%		
Piping	$3,541,000	(PEC) X	5.0%		
Insulation	$3,541,000	(PEC) X	5.0%		
Painting	$708,000	(PEC) X	1.0%		
Demolition	$2,833,000	(PEC) X	4.0%		
Relocation	$2,833,000	(PEC) X	4.0%		
Total direct installation costs (DIC)	$75,428,000				
Site preparation	$200,000	Engineering estimate			
Buildings	$500,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$146,952,000				
Indirect Costs					
Engineering	$17,634,000	(DC) X	12.0%		
Owner's cost	$5,878,000	(DC) X	4.0%		
Construction management	$14,695,000	(DC) X	10.0%		
Start-up and spare parts	$2,204,000	(DC) X	1.5%		
Performance test	$200,000	Engineering estimate			
Contingencies	$22,043,000	(DC) X	15.0%		
Total indirect costs (IC)	$62,654,000				
Allowance for Funds Used During Construction (AFDC)	$37,687,000	[(DC)+(IC)] X	8.99%	4 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$247,293,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$300,000		3 FTE and	100,000 $/year	Estimated manpower
Maintenance labor and materials	$4,409,000	(DC) X	3.0%		
Total fixed annual costs	$4,709,000				
Variable annual costs					
Reagent	$4,915,000		5.0 tph and	132 $/ton	Mass bal. calcs.
Byproduct disposal	$742,000		10.0 tph and	10 $/ton	Mass bal. calcs.
Bag replacement cost	$632,000		6,322 bags and	100 $/bag	18,966 total bags
Cage replacement cost	$158,000		3,161 cages and	50 $/cage	18,966 total bags
Auxiliary and ID fan power	$1,522,000		4,088 kW and	0.05 $/kWh	CueCost calculations
Water	$300,000		336 gpm and	2 $/1,000 gal	Mass bal. calcs.
Total variable annual costs	$8,269,000				
Total direct annual costs (DAC)	$12,978,000				
Indirect Annual Costs					
Cost for capital recovery	$23,344,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$23,344,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$36,322,000**				

Technology: Pulse Jet Fabric Filter (PJFF) **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Fabric filter system	$16,968,000	CUECost estimate			
Initial FF bags inventory	included				
Ash handling system	$1,210,000	Engineering estimate			
Booster fans	$5,434,000	Engineering estimate			
Electrical system upgrades	$2,057,000	from ref. cost			
Flue gas handling system	$3,630,000	Engineering estimate			
Subtotal capital cost (CC)	$29,299,000				
Instrumentation and controls	$1,465,000	(CC) X	5.0%		
Freight	$1,465,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$32,229,000				
Direct installation costs					
Foundation & supports	$9,669,000	(PEC) X	30.0%		
Handling & erection	$9,669,000	(PEC) X	30.0%		
Electrical	$4,834,000	(PEC) X	15.0%		
Piping	$806,000	(PEC) X	2.5%		
Insulation	$645,000	(PEC) X	2.0%		
Painting	$322,000	(PEC) X	1.0%		
Demolition	$1,611,000	(PEC) X	5.00%		
Relocation	$322,000	(PEC) X	1.00%		
Total direct installation costs (DIC)	$27,878,000				
Site preparation	$150,000	Engineering estimate			
Buildings	$0	N/A			
Total direct costs (DC) = (PEC) + (DIC)	$60,257,000				
Indirect Costs					
Engineering	$7,231,000	(DC) X	12.0%		
Owner's cost	$3,013,000	(DC) X	5.0%		
Construction management	$6,026,000	(DC) X	10.0%		
Start-up and spare parts	$904,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$9,039,000	(DC) X	15.0%		
Total indirect costs (IC)	$26,313,000				
Allowance for Funds Used During Construction (AFDC)	$7,783,000	[(DC)+(IC)]	8.99%	2 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$94,353,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$1,808,000	(DC) X	3.0%		
Total fixed annual costs	$1,808,000				
Variable annual costs					
Bag replacement cost	$632,000	6,322 bags and		100 $/bag	18,966 total bags
Cage replacement cost	$158,000	3,161 cages and		50 $/cage	18,966 total cages
ID fan power	$1,121,000	3,011 kW and		0.05 $/kWh	8" water d.p.
Auxiliary power	$210,000	563 kW and		0.05 $/kWh	Engineering estimate
Total variable annual costs	$2,121,000				
Total direct annual costs (DAC)	$3,929,000				
Indirect Annual Costs					
Cost for capital recovery	$8,907,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$8,907,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$12,836,000**				

Technology: Compact Hybrid Particulate Collector (COHPAC) **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Fabric filter system	$12,183,000	from ref. cost			
Initial FF bags inventory	included				
Ash handling system	$2,200,000	from ref. cost			
Booster fans	$5,016,000	Engineering estimate			
Electrical system upgrades	$2,057,000	from ref. cost			
Flue gas handling system	$6,600,000	Engineering estimate			
Subtotal capital cost (CC)	$28,056,000				
Instrumentation and controls	$1,403,000	(CC) X	5.0%		
Freight	$1,403,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$30,862,000				
Direct installation costs					
Foundation & supports	$7,716,000	(PEC) X	25.0%		
Handling & erection	$7,716,000	(PEC) X	25.0%		
Electrical	$3,858,000	(PEC) X	12.5%		
Piping	$772,000	(PEC) X	2.5%		
Insulation	$617,000	(PEC) X	2.0%		
Painting	$309,000	(PEC) X	1.0%		
Demolition	$309,000	(PEC) X	1.00%		
Relocation	$309,000	(PEC) X	1.00%		
Total direct installation costs (DIC)	$21,606,000				
Site preparation	$500,000	Engineering estimate			
Buildings	$0	N/A			
Total direct costs (DC) = (PEC) + (DIC)	$52,968,000				
Indirect Costs					
Engineering	$6,356,000	(DC) X	12.0%		
Owner's cost	$2,648,000	(DC) X	5.0%		
Construction management	$5,297,000	(DC) X	10.0%		
Start-up and spare parts	$795,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$7,945,000	(DC) X	15.0%		
Total indirect costs (IC)	$23,141,000				
Allowance for Funds Used During Construction (AFDC)	$6,842,000	[(DC)+(IC)]	8.99%	2 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$82,951,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$1,589,000	(DC) X	3.0%		
Total fixed annual costs	$1,589,000				
Variable annual costs					
Filter bag replacement	$381,000	3,805 bags and		100 $/bag	11,415 total bags
Cage replacement	$95,000	1,903 cages and		50 $/cage	11,415 total cages
ID fan power	$807,000	2,167 kW and		0.05 $/kWh	6" water d.p.
Auxiliary power	$204,000	549 kW and		0.05 $/kWh	Engineering estimate
Total variable annual costs	$1,487,000				
Total direct annual costs (DAC)	$3,076,000				
Indirect Annual Costs					
Cost for capital recovery	$7,831,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$7,831,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$10,907,000**				

Technology: Wet ESP | **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
WESP system includes casing, electrical sys., penthouse blower & heater, access provisions	$31,242,000	from ref. cost				
Ash handling system	$2,420,000	from ref. cost				
Booster fans	$4,598,000	Engineering estimate				
Electrical system upgrades	$1,331,000	from ref. cost				
Flue gas handling system	$3,630,000	Engineering estimate				
Subtotal capital cost (CC)	$43,221,000					
Instrumentation and controls	$2,161,000	(CC) X	5.0%			
Freight	$2,161,000	(CC) X	5.0%			
Total purchased equipment cost (PEC)	$47,543,000					
Direct installation costs						
Foundation & supports	$14,263,000	(PEC) X	30.0%			
Handling & erection	$14,263,000	(PEC) X	30.0%			
Electrical	$7,131,000	(PEC) X	15.0%			
Piping	$1,189,000	(PEC) X	2.5%			
Insulation	$951,000	(PEC) X	2.0%			
Painting	$475,000	(PEC) X	1.0%			
Demolition	$475,000	(PEC) X	1.00%			
Relocation	$475,000	(PEC) X	1.00%			
Total direct installation costs (DIC)	$39,222,000					
Site preparation	$500,000	Engineering estimate				
Buildings	$0	N/A				
New wet stack	$23,000,000	Recent quotes estimate of $23 mil				
Total direct costs (DC) = (PEC) + (DIC)	$110,265,000					
Indirect Costs						
Engineering	$13,232,000	(DC) X	12.0%			
Owner's cost	$5,513,000	(DC) X	5.0%			
Construction management	$11,027,000	(DC) X	10.0%			
Start-up and spare parts	$1,309,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$16,540,000	(DC) X	15.0%			
Total indirect costs (IC)	$47,721,000					
Allowance for Funds Used During Construction (AFDC)	$21,304,000	[(DC)+(IC)]	8.99%	3 years (project time length X 1/2)		
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$179,290,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance materials and labor	$2,618,000	(DC) X	3.0%			
Operating labor	$100,000		1 FTE and	100000 $/year		Estimated manpower
Total fixed annual costs	$2,718,000					
Variable annual costs						
Reagent	$179,000		20 lb/hr and	1.20 $/ton		Engineering estimate
Auxiliary power	$130,000		350 kW and	0.05 $/kWh		Engineering estimate
ID fan power	$522,000		1,402 kW and	0.05 $/kWh		4" water d.p.
Service water	$583,000		652 gpm and	2 $/1,000 gal		Engineering estimate
Total variable annual costs	$1,414,000					
Total direct annual costs (DAC)	$4,132,000					
Indirect Annual Costs						
Cost for capital recovery	$16,925,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life		
Total indirect annual costs (IDAC)	$16,925,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$21,057,000**					

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Cowlitz Falls Hydro Resource - Projected Costs FY 2010-2015

Cost Projections for Final Rate Proposal

Purchase Power Contract

Cowlitz Falls Hydro Project Resource - Cost Projections for FY 2010

7(b)(2) Case - Resource Stack Values:	**FY 2010-$$**	**FY 2015-$$**
Total O&M - 6-year average FY 2010 - FY 2015 as Adjusted	$4,137,294	4,576,236
Debt Service - 6-year average FY 2010 - FY 2015	11,620,481	11,620,481
Total Combined Costs - O&M and Debt Service	15,757,774	16,196,716
Cost per MWh	$69.19	$71.11
Capital Investment	194,980,245	194,980,245
Life	30 years	30 years
Placed in service	1994	1994
Average Annual Energy Output/@ 26.0MWh[3]	227,760	227,760

Projected Budget Amounts - IPR-2 - Program Case Revenue Requirement Amounts:

	FY2010	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**
Program Case Revenue Requirement:						
Operation and Maintenance Charges	3,288,954	3,236,807	3,405,122	3,522,965	3,610,969	3,738,898
Transmission Charges	870,555	870,555	890,555	890,555	890,555	910,555
Debt Service Payments 4.20% Actual	11,566,000	11,563,000	11,559,000	11,546,000	11,542,000	11,530,806
Total Amounts Paid - Program Case Rates	15,725,509	15,670,362	15,854,677	15,959,520	16,043,524	16,180,259
7(b)(2) Case Revenue Requirement Amounts:						
Annual Operation and Maintenance Charges	3,288,954	3,236,807	3,405,122	3,522,965	3,610,969	3,738,898
Annual Transmission Charges	870,555	870,555	890,555	890,555	890,555	910,555
Total Annual O&M	4,159,509	4,107,362	4,295,677	4,413,520	4,501,524	4,649,453
O&M Adjustment - Note 1	(22,215)	113,637	13,654	(16,454)	(15,403)	(73,217)
Adjusted Annual O&M	4,137,294	4,220,999	4,309,331	4,397,066	4,486,121	4,576,236
Debt Service Payments @ 4.25% - Note 2	11,620,481	11,620,481	11,620,481	11,620,481	11,620,481	11,620,481
Total Amounts Paid - 7(b)(2) Case Rates, assuming resource selection FY 2010.	15,757,774	15,841,480	15,929,811	16,017,547	16,106,602	16,196,716
Average Annual Energy Output/@ 26.0MWh[3]	227,760	227,760	227,760	227,760	227,760	227,760
Cost per MWh	$69.19	$69.55	$69.94	$70.33	$70.72	$71.11

Notes:

Note 1 - Due to model escalation of O&M, the average projected annual cost for O&M and Transmission costs of $4,136,228 for FY2010-2015 stated in real 2010 dollars in the Program Case amount was increased by $ 1,066, so that the average annual escalated costs during the rate test period were equal to the average Program Case costs. This adjustment is necessary to ensure that these costs are similar between the Program Case and the 7(b)(2) Case. This adjustment results in the sum of O&M and Transmission Costs for FY 2010 being decreased by ($ 22,215). The FY 2010 adjusted amount of $4,137,294 is then escalated in the rates model using the Cumulative GDP Inflator /Deflator values that are reflected in the table below.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Cowlitz Falls Hydro Resource - Projected Costs FY 2010-2015

Cost Projections for Final Rate Proposal

Purchase Power Contract

Note 1 - continued

	Total Annual O&M Before Adjustment	GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Program Case Nominal $$	7(b)(2) Case Escalated Cost Projections	7(b)(2) Case Over /(Under) Program Case
FY2010	4,159,509	1.000000	4,159,509	4,159,509	4,137,294	(22,215)
FY2011	4,107,362	1.020232	4,025,910	4,107,362	4,220,999	113,637
FY2012	4,295,677	1.041582	4,124,185	4,295,677	4,309,331	13,654
FY2013	4,413,520	1.062788	4,152,776	4,413,520	4,397,066	(16,454)
FY2014	4,501,524	1.084313	4,151,499	4,501,524	4,486,121	(15,403)
FY2015	4,649,453	1.106094	4,203,488	4,649,453	4,576,236	(73,217)
Averages	4,354,508		4,136,228		Total Differences	2
	Program Case Price Adjustment		1,066			
	7(b)(2) Case Pricing - 2010 $$		4,137,294			

Note 2 - Calculation of 7(b)(2) Debt Service - Average annual program case debt service FY2010-2015 = 11,551,134 Program Case Debt Service. Assuming 30 yr term financing at interest rate of 4.20% in the program case, the PV of the payment stream of 30 annual payments at an interest rate of 4.20% = Principle Amount Financed FY 2010 = 194,980,245 . In the 7(b)(2) Case, the debt service payments associated with retiring a principle amount of annual debt service payments for a principle amount of $194,980,245 @ 4.25% = 11,620,481 This amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model to minimize the models escalation of fixed amounts of debt service.

Note 3 - Firm average energy value (aMW) was obtained from Table 5 of the March 2007 BPA, 2007 Pacific Northwest Loads and Resources Study on page 23.

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Idaho Falls Hydro Project Resource for FY 2010-2015
Cost Projections for Final Rate Proposal
Purchase Power Contract

Idaho Falls Hydro Project Resource - Purchase Power Cost Projections:

	MWh	$/MWh	FY2010-$$	FY2015-$$
Annual Power Purchase Cost	122,640	$40.59	$4,978,418	5,506,599
Placed in service			1982	1982
Projected Average Annual Energy Output[3]			122,640	122,640
Average Hourly Energy aMW			14.0	14.0
Cost per MWh[/1,2]			$40.59	$44.90
Estimated remaining useful life = 60 years				

Projected Purchase Power Contract Pricing with Idaho Falls Power

	Projected Contract Price[1, 2]	GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Projected Program Case Revenue Requirement Purchase Amounts Nominal $$	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2010	$39.05	1.000000	39.05	4,789,092	4,978,418	189,326
FY 2011	$39.05	1.020232	38.28	4,789,092	5,079,142	290,050
FY 2012	$40.50	1.041582	38.88	4,966,920	5,185,431	218,511
FY 2013	$44.25	1.062788	41.64	5,426,820	5,291,003	(135,817)
FY 2014	$45.50	1.084313	41.96	5,580,120	5,398,164	(181,956)
FY 2015	$48.00	1.106094	43.40	5,886,720	5,506,599	(380,121)
Averages	$42.73		40.53	5,239,794	Total Difference	(7)
Program Case Price Adjustment - Note 3			0.0600	(261,376)		
7(b)(2) Case Pricing - 2010$$			40.59	4,978,418		
Projected Average Annual Energy Output[3]				122,640		
Cost per MWh				40.593757		

Notes:

Note 1 - Projected Contract Pricing MWH - $39.05 at contract cap rate, cost of power is expected to be at the current contract cap during the remaining years of the current contract that expires on September 30, 2011. Only one month in FY 2007 and one month in FY 2008 were billed at a rate below the contract cap.

Note 2 - Projected new contract's floor and cap amounts are projected to be $35.50/MWh and $55.50/MWh respectively, with a midpoint price of $45.50/MWh. This represents a 42% increase over the current contract pricing when comparing the contract cap limits. It is anticipated that the new power purchase contract would cover the ten-year period 10/01/11 through 09/30/21. Projected average prices for the last 4-years of the rate test period under the projected new contract terms:

FY 2012 - $40.50 - Average price between the floor of $35.50 and the midpoint of $45.50.

FY 2013 - $44.25 - 25% of the time the pricing would be between the floor price of $35.50 and the midpoint price of $45.50, and 75% of the time it would be at the midpoint of $45.50.

FY 2014 - $45.50 - Average pricing for the year would approximate the contract midpoint value of $45.50

FY 2015 - $48.00 - 75% of the time the price would be at the midpoint prioce of $45.50, and 25% of the time it would be between the midpoint price of $45.50 and the contract cap amount of $55.50.

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Idaho Falls Hydro Project Resource for FY 2010-2015
Cost Projections for Final Rate Proposal
Purchase Power Contract

Notes - continued:

Note 3 - The average annual energy output/purchase amount from the Idaho Falls Project was 121,747 MWhs for FY2002-2008. This results in an Average Hourly Energy amount of 13.9aMW. The White Book average energy amount was recently revised to 14.0aMW under 1937 Water conditions (70 year revised study). The projected forcasted output of the project is based on the 14.0 aMW value per the final WP-10 Loads and Resources Study.

Historical Generation / Purchases from IFP

W/P Reference	Annual Energy - MWh	Capacity Factor @27.5 aMW	Average Hourly Energy
2002	111,255	46.18%	
2003	113,442	47.09%	
2004	110,924	46.05%	
2005	119,434	49.58%	
2006	140,771	58.44%	
2007	140,898	58.49%	
2008	115,508	47.95%	
7-Year Average	121,747	50.54%	13.90

Table A-4: Regional Independent Hydro Projects, PNW Loads and Resource Study, 2009 -
2010 Fiscal Years, [51] 2007 Final Supplemental Rate Case (Final), 1937 Water Year, 2009

Projected annual hydro production for Idaho Falls Resource = 14.0 aMW 8,760 =	122,640
Capacity Amount at 27.5aMW	240,900

Note 4 - The current rate case model's section 7(b)(2) resource stack does not have the ability to model different annual price or quantity amounts. Due to rate case model escalation of O&M (escalation of the first year price amount by annual inflation), the average annual power purchase cost was decreased from $5,239,418 to $4,978,418, a difference of ($261,376). This resulted in a increase in the projected average annual cost per MWh to $40.59 from $40.53 (stated in 2010 $) that is applicable to the 7(b)(2) Case amount. This adjustment was necessary so that the average escalated rate during the rate test period was equal to the average Program Case rate, so that the average cost for this resource was similar between the Program Case and the 7(b)(2) Case.

Page 2 of 2

AUTHENTICATED Contract No. 06PB-11734

POWER PURCHASE AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

IDAHO FALLS POWER

Table of Contents

This POWER PURCHASE AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and the CITY OF IDAHO FALLS, doing business as IDAHO FALLS POWER (Idaho Falls) a municipal corporation organized under the laws of the State of Idaho. BPA and Idaho Falls are sometimes referred to individually as "Party" and collectively as "Parties."

RECITALS

BPA is authorized by Federal law, including the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501, the "Northwest Power Act") and other applicable laws, to dispose of electric power generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources.

Idaho Falls owns and operates hydro generation units in and around the City of Idaho Falls collectively known as the Bulb Turbine Project (Project). BPA currently purchases all of the Project power output under Power Purchase Agreement No. 00PB-10710 as amended, which terminates at 2400 hours on September 30, 2006.

The Parties agree:

1. TERM

This Agreement shall take effect on the date signed by BPA and Idaho Falls. Power deliveries shall commence on the hour beginning 0000 on October 1, 2006, and continue through the hour ending 2400 on September 30, 2011.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in the body of this Agreement.

(a) "Contracted Power" means the metered, monthly Project Power Output minus the monthly Station Service, both in MWh, delivered to BPA at the Point of Receipt.

(b) "Federal System" means the facilities of the Federal Columbia River Power System, including the Federal generating facilities for which BPA is designated as marketing agent; the federal facilities under the jurisdiction of BPA; and any other facilities:

(1) from which BPA receives all or a portion of the generating capability (other than Station Service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability.

(2) which BPA may use under contract or license; or

(3) to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

(c) "Operating Year" means the period that begins each August 1 and which ends the following July 31. For instance, Operating Year 2007 begins August 1, 2006, and continues through July 31, 2007.

(d) "Point of Receipt" means the point in Idaho Falls' Sugarmill Substation where the 46 kV facilities of Idaho Falls and Rocky Mountain Power (formally PacifiCorp and Utah Power & Light), or its successor, are connected, where Contracted Power will be made available to BPA.

(e) "Alternate Points of Receipt" (APOR) means the point in Idaho Falls' (1) Westside Substation where the 46 kV facilities of Idaho Falls and the Rocky Mountain Power are connected or the (2) Project's individual units' high-side transformer buses at 46kV.

(f) "Power Business Line" or "PBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA's Federal power.

(g) "Project" means the four hydro generation units owned and operated by Idaho Falls Power in and around the City of Idaho Falls collectively known as the Bulb Turbine Project ***pursuant*** to FERC Project No. 2842. The Project has a combined capacity of 24,600 kW. Specifically the units are: (1) Upper Plant, located at river mile 805, with a 7,200 kW nameplate capacity; (2) City Plant, located at river mile 800, with a 7,200 kW nameplate capacity; (3) Lower Plant, located at river mile 798, with a 7,200 kW nameplate capacity; and (4) Old Lower Plant, located at river mile 798, 2 units with a combined 3,000 kW installed capacity.

(h) "Project Power Output" means the amount of energy generated by the Project during any specified period of time as metered at the Points of Measurement.

(i) "Points of Measurement" means the four meters described in Exhibit A.

(j) "Prudent Utility Practice" means the practices, methods, and equipment, as changed from time to time, that are commonly and lawfully used in prudent engineering and operation of equipment, taking into consideration: (1) the fact that Idaho Falls is a municipal corporation under the laws of the State of Idaho with the statutory duties and responsibilities thereof; and (2) the objectives to integrate the Project with the generating resources of the Federal System, to achieve optimum utilization of such resources, and to achieve efficient and economical operation of such system.

(k) "Station Service" means the power used to serve load at the Project's facilities, including but not limited to light, space conditioning and the operation of auxiliary equipment.

(l) "Workday" means, for the purpose of scheduling, a day that the Parties both observe as a regular workday.

3. SALE AND PURCHASE OF PROJECT POWER OUTPUT

(a) **Power Amount**
Idaho Falls shall make available and BPA shall purchase all of the Contracted Power at the Point of Receipt for the period specified in Section 1 of this Agreement. BPA shall pay Idaho Falls the Contract Price for Contracted Power pursuant to Section 3(b).

(b) **Contract Price**
Subject to the Cap and Floor provision of Section 3(c), the Contract Price for any calendar month shall be calculated in accordance with the following methodology:

(1) Daily Dow Jones Mid-C (DJ Mid-C) heavy load and light load hour (heavy and light load hours as specified by the then current National Electric Reliability Council (NERC) or its successor's standards) prices will be weighted to develop a daily average DJ Mid-C price. The prices will be weighted by summing (a) the product of the number of heavy load hours and the daily DJ Mid-C heavy load hour price minus $1.00 and (b) the product of the number of light load hours and the daily DJ Mid-C light load hour price minus $1.00; and dividing the resulting sum by the number of hours in the day to create a daily average DJ Mid-C price.

(2) The daily average DJ Mid-C price shall be multiplied by that day's Project Power Output to derive a daily weighting factor.

(3) The daily weighting factors shall be summed for all days in the calendar month.

(4) The Contract Price is derived by dividing the sum of the weighting factors by the monthly Project Power Output.

(5) Exhibit B illustrates this process.

(c) **Cap and Floor of Contract Price**
For any calendar month, the Contract Price shall not exceed $39.05 per MWh (cap) or be less than $29.05 per MWh (floor).

(d) **Loss of the Dow Jones Mid-C Index**
In the event that the Dow Jones Mid-C Index ceases to be available to establish the price for the power pursuant to this Agreement, the Parties shall use the ICE (Intercontinental Exchange) Daily Indices for power delivered at Mid-C. In the event that the ICE Daily Indices cease to be available to establish the price for the power pursuant to this Agreement, the Parties shall have 90 days in which to agree on a new index. The last price calculated from the Dow Jones Mid-C Index or the ICE Daily Indices pursuant to this section 3(d) shall apply during that 90-day period.

Exhibit B

Contract Price Methodology

The Contract Price for any calendar month shall be based on the day-ahead Dow Jones Mid-C Index (DJ Mid-C) prices for firm power, and shall be weighted to each day's Project Power Output, in accordance with the following methodology:

- Daily DJ Mid-C heavy load and light load hour (heavy and light load hours as specified by the then current NERC Standards) prices will be weighted to develop a daily average DJ Mid-C Price. The prices will be weighted by summing (a) the product of the number of heavy load hours and the daily Mid-C heavy load hour price minus $1.00 and (b) the product of the number of light load hours and the daily Mid-C light load hour price minus $1.00; and dividing the resulting sum by the number of hours in the day to create a daily average DJ Mid-C price.
- The daily average DJ Mid-C Price shall be multiplied by that day's Project Power Output to derive a daily weighting factor.
- The daily weighting factors shall be summed for all days in the calendar month.
- The Contract Price is derived by dividing the sum of the weighting factors by the monthly Project Power Output.

$$\frac{\sum_{1}^{d}\{[HLHd*(HLHPd-\$1.00)+LLHd*(LLHPd-\$1.00)]/HOURSd\}*GENERATIONd}{\sum_{1}^{d}GENERATIONd}$$

Where:

d = the days in the month

HLHd = number of heavy load hours in the day

HLHPd = daily heavy load hour Mid-C firm energy price

LLHd = number of light load hours in the day

LLHPd = daily light load hour Mid-C firm energy price

HOURSd = HLHn + LLHn

GENERATIONd = the day's Project Power Output

BPA's 2010 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Wauna CoGen Resource for FY 2010-2015

Cost Projections for Final Rate Proposal

Purchase Power Contract

<u>Wauna Cogeneration Resource - Purchase Power Cost Projections:</u>

	MWh	FY2010-$$	FY2015-$$
Annual Power Purchase Cost - See Note 1	190,000	$11,175,851	$12,361,608
Placed in service		1996	1996
Projected Average Annual Energy Output - See Note 3		190,000	190,000
Average Hourly Energy aMW		21.7	21.7
Cost per MWh		$58.82	$65.06

<u>Note 1</u> - After a resource is chosen by the rates model, its annual costs (stated in 2010 "real dollars") are inflated by the GDP deflator values contained in the model to the nominal dollars of the year the resource is selected. These costs are escalated for each of the remaining years of the rate test period. The contract price for the 7(b)(2) resource stack was adjusted very slightly to ensure that the cost for this resource in the 7(b)(2) Case does not exceed the costs that were included for the Program Case revenue requirement. See the adjustment computation below:

	Contract Price - Nominal Pricing [2]	Cumulative GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Program Case Revenue Requirement Amounts @ 190,000 MWh Nominal Pricing	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2010	$58.94	1.000000	58.94	11,198,600	11,175,851	(22,749)
FY 2011	$60.05	1.020200	58.86	11,409,500	11,401,603	(7,897)
FY 2012	$61.22	1.041600	58.77	11,631,800	11,640,766	8,966
FY 2013	$62.44	1.062800	58.75	11,863,600	11,877,694	14,094
FY 2014	$63.73	1.084300	58.78	12,108,700	12,117,975	9,275
FY 2015	$65.07	1.106100	58.83	12,363,300	12,361,608	(1,692)
		Average	58.821667			(3)
Program Case Price Adjustment			-0.001400			
7(B)(2) Case Pricing - 2010$$			58.820267			

<u>Note 2</u> - See Attachment A, page 2 of 2 which contains the contract pricing schedule for the Wauna Cogeneration resource. The schedule at Attachment A reflects calendar year pricing, the prices in this column have been converted to fiscal year pricing.

<u>Note 3</u> - Firm average annual energy purchase amount (MWh) was based on recent historical purchases from this resource as outlined below:

Historical Generation / Purchases from Wauna Project:

	Average Annual Energy - MWh
FY 2003	181,603
FY 2004	204,417
FY 2005	189,046
FY 2006	data not used - abnormal year
FY 2007	181,603
FY 2008	data not used - abnormal year
4-Year Average	189,167
Adjustment	833
	190,000

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AUTHENTICATED

Exhibit D, Page 1 of 1
Contract No. DE-MS79-93BP94292
Procurement No. 56791
Western Generation Agency
Effective at 2400 hours on the
Effective Date

**MONTHLY AMOUNTS OF BASE FIRM ENERGY,
FLEXIBLE FIRM ENERGY, AND TOTAL FIRM ENERGY**

(1) Month	(2) Total Hours	(3) Base Firm Energy Delivery Rate	(4) Base Firm Energy	(5) Flexible Firm Energy	(6) Total Firm Energy
		(MWh/hr)	(MWh)	(MWh)	(MWh)
JAN	744	29.710	22,104	1,488	23,592
FEB	672	28.890	19,414	1,344	20,758
MAR	744	28.590	21,271	1,488	22,759
APR	720	26.600	19,152	2,376	21,528
MAY	744	23.730	17,655	2,425	20,080
JUN	720	23.710	17,071	2,376	19,447
JUL	744	23.792	17,701	2,424	20,125
AUG	744	25.180	18,734	1,488	20,222
SEP	720	25.031	18,022	1,440	19,462
OCT	744	26.280	19,552	1,488	21,040
NOV	720	26.840	19,325	1,440	20,765
DEC	744	29.081	21,636	1,488	23,124
		TOTALS:	**231,637**	**21,265**	**236,000** 1/

1/ The total of the monthly amounts in Column 6 is 252,902 MWh. However, Total Firm Energy cannot exceed 236,000 MWh, as described in section 2(y).

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AUTHENTICATED

Exhibit E, Page 1 of 1
Contract No. DE-MS79-93BP94292
Procurement No. 56791
Western Generation Agency
Effective at 2400 hours on the
Effective Date

TOTAL FIRM ENERGY PURCHASE PRICE

Calendar Year	Total Firm Energy Purchase Price (mills/kWh)
1995	47.56
1996	48.10
1997	48.67
1998	49.26
1999	49.89
2000	50.55
2001	51.23
2002	51.96
2003	52.72
2004	53.52
2005	54.35
2006	55.23
2007	56.16
2008	57.13
2009	58.14
2010	59.21
2011	60.33
2012	61.51
2013	62.75
2014	64.05
2015	65.41
2016	66.80
2017	68.22

(MyGuyer MPSI X5816 - M:\94292e.DOC)

WP-10 Wholesale Power Rate Case

Cost Projections for Nine Canyon Wind Project

Operating Results / Projected Operating Budgets

Portions available to Resource Stack - See Note 4:	**100% Amounts FY 2010$$**	**Non-Dedicated Portion 48.00% of Projected FY2010 Budget**	**7(b)(2) Resource Stack Amounts 0 MW**
Total Project Revenue Requirement	$18,232,540	$8,751	$ 0
Revenue Requirement Allocation to Non-Dedicated Portions			
Cost of Power ($/aMW)	$73.88	$73.88	$/aMW
Share of total projected annual generation (MWh)	246,800	118,459	0 MWh
Average energy per hour (aMW) = Projected net generation / 8760	28.17	13.52	0 aMW
Share of name plate rating (MW)	95.9MW	46.03 MW	0 MW
Capacity Factor	29.38%	29.38%	
Estimated remaining useful life = 20 years			

($ 000)

	OY_06 Actual	**OY_07 Actual**	**OY_08 Actual**	**100% of Project OY_09 Budget 2009- $$$**	**Projected FY 2010 Budget 2010- $$$**	**Non-Dedicated Portion 48.00% of Projected FY2010 Budget**
Projected Costs of Operations[1]:						
Labor & Overheads	$677	$813	$1,330	$1,715	$1,760	$844.6
Equipment / materials / Services	488	2,064	1,644	1,954	$2,005	$962.3
Insurance	118	130	117	341	$350	$167.9
Lease Payments	250	269	476	624	624	$299.5
Control Area Reserves - Within Hour Balancing Charges [2]				783	3,107	$1,491.4
Contingency / Fees	173	175		50	50	$24.0
Other Costs	336	176	148	568	$583	$279.7
Generation Taxes	34	34	51	52	$53	$25.6
Subtotal Operating Costs	$2,076	$3,661	$3,766	$6,087	$8,532	$4,095.0
Depreciation	3,798	3,697	3,993	7,222	7,222	$3,466.4
Interest Financing - Costs	5,694	5,493	6,606	6,514	6,514	$3,126.6
Gross Generation Costs	$11,568	$12,851	$14,365	$19,823	$22,268	$10,688
Renewable Energy Production Incentive Credits (REPI)	(2,299)	(1,198)	(791)	(295)	(295)	(141.6)
Net Generation Costs	$9,269	$11,653	$13,574	$19,528	$21,973	$10,546
Net Generation Costs per above	$9,269	$11,653	$13,574	$19,528	$21,973	$10,546
Less Depreciation Expense	(3,798)	(3,697)	(3,993)	(7,222)	(7,222)	(3,466)
Capital requirements	(32)	221	203	150	150	72.0
Bond Retirement / Trustee Fees	3,285	3,423	4,361	3,774	3,774	1,811.4
Interest Income	(537)	(619)	(449)	(442)	(442)	(212.2)
Projected Revenue Requirement Power Purchasers	$8,187	$10,981	$13,696	$15,788	$18,233	$8,751
Cost of Power ($/MWh)	$51.69	$70.08	$57.71	$63.97	$73.88	$73.88
Projected Annual Generation (MWh)	158,400	156,700	237,330	246,800	246,800	118,459
Average Generation per Hour (aMW)					28.17	13.52
Capacity Amount / Name plate	63.7MW	63.7MW	85.2	95.9MW	95.9MW	46.03 MW
Capacity Factor	28.39%	28.08%	31.81%	29.38%	29.38%	29.38%

Page 1 of 2

Notes:

Note 1 - The actual operating results for operating years (OY) 2006, 2007, and 2008 along with the projected operating budget numbers for the resource for OY 2009 were provided by Energy Northwest, the managing entity and operator of the wind project. Phase 3 of Nine Canyon became operational in May 2007. The budget comparisons between years have not been "normalized" for the increased generation, thus they are not comparable. Variable budget costs were increased by 2.06% over FY 2009 amounts based on the projected rate of inflation continued in Global Insight's forecast, costs were increased by 2.06% over FY 2009 amounts based on the projected rate of inflation, based on Global Insight's "The U.S. Economy: The 30-Year Focus, August 2008, Base Case Scenario."

Note 2 - Starting in FY 2009, parties interconnected through BPA transmission have to self provide or purchase wind integration service and within-hour balancing reserves for wind resources through their BPA transmission interconnection agreement . This cost was added to the operating cost budget by BPA to arrive at a reasonable operating cost for this resource in the resource stack. The charges are based on BPA's 2009 Wind Integration Rate Case Revised Proposal, Attachment 1 to Settlement Agreement ACS-09, page 1, where the rate is $0.68 per kilowatt per month with the rate based on the installed capacity of the wind plant. Mathematically this is expressed:

Installed capacity = 95.9MW * 1,000 = 95,900KW/Mo. * $0.68 = $65,212 per month, times 12 months = $782,544 for OY 2009.

For the FY 2010 Initial Rate Proposal, the assumption was made that the billing determinant for these charges would be:

Wind Integration Rate on Installed Wind Capacity ($2.70/kW/month) = 95,900KW/Mo. * $2.70 * 12 months = $3,107,160

Note 3 - Analysis of the dedicated and non-dedicated portions of the Nine Canyon resource is presented below:

Energy Northwest 95.9 MW Nine Canyon Wind Power Project Allocations - Phases 1, 2, and 3

Nine Purchasers	Phase 1 MW Share	Phase 2 MW Share	Phase 3 MW Share	Total MW Share	% total	Resource Dedicated to native Load?
Benton County PUD No. 1	3.00	0.00	6.00	9.00	9.38%	Yes /A
Chelan County PUD No. 1	6.01	1.95	0.00	7.96	8.30%	Yes
Cowlitz Co PUD	2.00	0.00	0.00	2.00	2.09%	Yes
Douglas County PUD No. 1	3.01	6.80	0.00	9.81	10.23%	Quasi /B
Franklin PUD No. 1	**2.01**	**0.00**	**8.05**	**10.06**	**10.49%**	**No /C**
Grays Harbor PUD No. 1	**6.01**	**1.95**	**12.08**	**20.04**	**20.90%**	**No /C**
Lewis County PUD No. 1	1.00	0.00	5.06	6.06	6.32%	Yes
Okanogan County PUD No. 1	**12.03**	**3.90**	**0.00**	**15.93**	**16.61%**	**No /C**
Grant County PUD No. 2	12.03	0.00	0.00	12.03	12.54%	Quasi /B
Mason County PUD No. 3	1.00	1.00	1.01	3.01	3.14%	Yes
Totals	48.10	15.60	32.20	95.90	100.00%	
Non-Dedicated Portion					**48.00%**	

Note 3 - Sub-Notes:

Note A - Gloria Bender from Benton PUD informed BPA that all of its wind purchases will be used to meet their Tier 2 loads during FY2012-2029.

Note B - Resource is part of the utilities resource mix, it is not treated as a firm resource, they have not entered into specific sales contracts for the sale of specific wind energy from this resource at this time. Utility is not sure how this resource will be used during the rate test period.

Note C - Confirmed that the resource was not formally dedicated to this utility's native load through their BPA Account Executive.

Note 4 - BPA has not included in the resource stack for the WP-10 Power Rate Case any of the portions of this resource that have been purchased by BPA's 7(b)(2) Customers. BPA assumes that 7(b)(2) Customers purchasing this project are using the project as an "unspecified" resource that has been declared as serving a utility's native load pursuant to section 5(b) of the Northwest Power Act, which decreases BPA's load obligations. BPA and Consumer Owned Utilities must comply with the Bonneville Project Act, Public Law 75-329; the Pacific Northwest Consumer Power Preference Act, Public Law 88-552; and the Northwest Power Act, Public Law 96-501; before selling power outside the region. None of the customers who own shares of the Nine Canyon Wind resource have had a portion of their BPA power purchases "decremented" based upon sales of power from this resource outside the region as provided in the foregoing statutory provisions and BPA's Section 5(b)/9(c) Policy.

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	FY2010-$$	**FY2010-$$**		**7(b)(2)**
	100.00%	**4.09%**		**Resource Stack**
		"undesignated" /		**Amounts**
		"non- dedicated"		**0 MW**
7(b)(2) Case - Resource Stack Values - See Note A Below				
Total O&M - Average FY2010-2015 Non-dedicated COU & Marketer Projection =				
14.9aMW *$22.46/MWh*8,760 hour /year	$71,937,787	$2,931,819		$ 0
Cost per MWh	$22.46	$22.46		$ 0 /MW
Capital Investment - Projected Net Utility Plant FY 2010	$261,540,547			
Capital Investment - Projected Net Utility Plant FY 2015	$437,048,564			
Life	70-100 years			
Placed in service	1970			
Non-dedicated COU & Marketer average hourly energy (aMW) six-year average FY2010-2015	365.6	14.9	MW	0 MW
Average Annual Energy Output associated with Non-dedicated portion / @ 14.9aMW	3,202,656	130,524	MWh	0 MWh

			2010	**2011**	**2012**	**2013**	**2014**	**2015**
1. 2010$$ Price Conversion Factor			1.000000	1.020232	1.041582	1.062788	1.084313	1.106094
2. **Net Costs Chargeable to Power Purchasers - per analysis below**			71,107,000	68,821,000	77,230,000	77,827,508	79,082,044	80,220,222
Average Annual Operating Costs - Nominal $$ =		75,714,629						
3. Projected Annual Amounts Stated in 2010$$ (line 2 divided by line 1)			71,107,000	67,456,226	74,146,826	73,229,570	72,932,856	72,525,682
4. FY 2010 -2015 Average Total Operating Costs in 2010$$			71,899,693	71,899,693	71,899,693	71,899,693	71,899,693	71,899,693
Operating Cost Adjustment - See Note B below			38,094	38,094	38,094	38,094	38,094	38,094
5. Adjusted Annual Cost Amount in 2010 $$			71,937,787	71,937,787	71,937,787	71,937,787	71,937,787	71,937,787
6. Ram Model Annual Cost Amounts Using Average Cost Pricing stated in 2010 $$ (line 5 times line 1)	Total Variance 2010-2015		71,937,787	73,393,233	74,929,104	76,454,617	78,003,078	79,569,955
7. Annual Variance Over / (Under) (line 6 less line 2)		1	830,787	4,572,232	(2,300,895)	(1,372,891)	(1,078,966)	(650,267)
8. Average Firm Energy Output 365.6aMW) times the number of hours in a year (8760)			3,202,656					
9. Projected Project Cost per MWh (line 5 divided by line 8)			$22.46					

Note B - It is necessary to make an operating adjustment so that the average total operating costs for all years of the rate test period (FY2010-2015) is equivalent to the total actual operating costs in nominal dollars (line 2) since the RAM model starts with a beginning cost of when the resource is selected from the resource stack and then escalates the cost using the fixed escalation factors at line 1 above. If a simple average of the nominal operating costs for the rate test period were used, the "starting operating cost" of the resource would have been higher at a rate of $75,714,629 in comparison to the adjusted operating cost amount of $71,937,787.

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

<u>Note A</u> - BPA has not included in the resource stack for the WP-10 Power Rate Case any of the portions of Grant Co. PUD's Wanapum and Priest Rapids hydro resources that have been purchased by BPA's 7(b)(2) Customers nor the annual portions that Grant sells in its' annual auction to establish a market price for these. During BPA's process of making its' Section 5(b)/9(c) Policy Determination, concerning the portion of Grant's resources that were sold at auction and for those portions of its resources sold to regional customers that were exchanged back to Grant to be sold at market prices, Grant Co. PUD was charged with ensuring that these resources were not sold, resold, distributed for use or used outside the Pacific Northwest region except in conformance with the Bonneville Project Act, Public Law 75-329; the Pacific Northwest Consumer Power Preference Act, Public Law 88-552; and the Northwest Power Act, Public Law 96-501; before selling power from these resources outside the region. A compliance protocol was established making Grant Co. PUD responsible for the in-region use of the power when the sale at auction is made to an entity that does not have a Northwest Power Act section 5(b) contract with BPA or that does not directly serve regional consumer loads (see the copy of BPA's 5(b)/9(c) compliance protocol letter to Grant Co. PUD and Grant Co. PUD's prototype market auction contract provisions). Grant is required to monitor the sales of it's' purchaser and if requested by BPA, Grant will provide this information to BPA within 15 days of the end of the month requested. In the event that the information does not corroborate that the power was used in the region, BPA may impose a decrement upon Grant during the remaining period of time of its Subscription contract ending September 30, 2011. Similar provisions to Grant's sale at auction have also been incorporated in the contracts with the Snake River Power Association 7(b)(2) Customers.

Neither Grant Co. PUD nor BPA's other 7(b)(2) Customers who own shares of the Priest Rapids or Wanapum Hydro resources have had a portion of their BPA power purchases "decremented" based upon sales of power from these resources outside the region as provided in the foregoing statutory provisions and BPA's Section 5(b)/9(c) Policy. To ensure consistency with BPA's Section 5(b)/9(c) Policy Determinations, BPA has decided to change its 7(b)(2) resource stack policy to one of presuming that power from these resources and other 7(b)(2) customer resources that have been designated as "unspecified resources" serving a utility's native load pursuant to section 5(b) of the Northwest Power Act, (which decreases BPA's load obligations) are presumed used to meet regional loads unless there is documentation that the power is being exported out of the region only after it was offered within the region in conformance with section 9(c). Based on this 7(b)(2) resource stack policy decision, it was decided to not include any portions of the Grant Co. PUD's hydro resources in the 7(b)(2) rate stack in performing the 7(b)(2) Rate Test.

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
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Section 7(b)(2) Resource Stack - Operating Cost Projections

	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Operating Revenues	52,000,000	57,500,000	62,000,000	62,500,000	63,000,000	63,500,000	64,000,000	66,000,000
Operating Expenses - See Notes 1, 2, and 4 below:								
Generation -	17,670,917	21,505,506	23,711,971	22,633,076	20,516,883	21,132,390	21,766,362	22,419,352
Transmission -	1,165,843	1,418,831	1,564,403	1,493,223	1,353,606	1,394,214	1,436,041	1,479,122
Administrative and General -	10,985,632	13,369,514	14,741,226	14,070,501	12,754,909	13,137,556	13,531,683	13,937,633
Administrative and General - Yakima Nation Payments	3,200,000	3,200,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000
Administrative and General - Habitat Funding Commitments	1,227,000	1,264,000	1,302,000	1,341,000	1,381,000	1,381,000	1,381,000	1,381,000
Maintenance Expenses	0	0	0	0	0	0	0	0
Depreciation Expenses	4,661,590	4,967,674	5,299,959	5,736,883	6,289,908	7,084,942	8,178,479	9,064,772
Taxes -	1,000,000	1,040,000	1,071,000	1,103,000	1,136,000	1,170,080	1,205,182	1,241,338
Other Operating Costs	0	3,578	15,250	4,801	6,601	0	0	0
Total Operating Expenses	39,910,982	46,769,103	50,105,809	48,782,484	45,838,907	47,700,182	49,898,747	51,923,217
Net Operating Income	12,089,018	10,730,897	11,894,191	13,717,516	17,161,093	15,799,818	14,101,253	14,076,783
Expense Changes From Prior Year - Excluding Yakima & Habitat Settlements	5,553,450	6,821,121	4,098,706	(1,362,326)	(2,983,576)	1,861,275	2,198,565	2,024,471
Operating Expense Percentage Change - From Prior Year	17.84%	18.58%	9.41%	-2.86%	-6.43%	4.28%	4.85%	4.26%
Average Percentage Change 2008-2012 =	7.31%							
Non Operating Revenues and (Expenses)								
Interest Income (Expense)/Gains on Debt Retirements	2,792,633	932,000	1,447,000	1,241,000	5,597,000	2,798,500	2,798,500	2,798,500
Interest on Long-Term Debt - See Note 3	(11,730,667)	(11,099,030)	(12,863,723)	(11,974,755)	(18,198,857)	(15,172,206)	(15,539,314)	(16,767,394)
Amortization of Debt Expense and Discounts	(364,636)	(364,636)	(364,636)	(364,636)	(364,636)	(364,636)	(364,636)	(91,478)
Total Non Operating Expenses	(9,302,670)	(10,531,666)	(11,781,359)	(11,098,391)	(12,966,493)	(12,738,342)	(13,105,450)	(14,060,372)
Excess (Shortfall) of Revenues Over Cost of Services	2,786,348	199,232	112,832	2,619,126	4,194,599	3,061,476	995,804	16,411

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
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Section 7(b)(2) Resource Stack - Operating Cost Projections

	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Projected Power Costs Charged to Power Purchasers - See Notes 2-4:								
Operating Costs As Outlined Above:	39,910,982	46,769,103	50,105,809	48,782,484	45,838,907	47,700,182	49,898,747	51,923,217
Budget/Operating Cost Adjustments - See Note 4:								
Less Other noncash expenses	0	0	0	0	0	0	0	0
Less Extraordinary maintenance paid by Reserve Funds	0	0	0	0	0	0	0	0
Less Depreciation Expense	(4,661,590)	(4,967,674)	(5,299,959)	(5,736,883)	(6,289,908)	(7,084,942)	(8,178,479)	(9,064,772)
Plus Interest on Long-Term Debt	11,730,667	11,099,030	12,863,723	11,974,755	18,198,857	15,172,206	15,539,314	16,767,394
Plus capitalized interest on CWIP	1,107,193	1,201,971	1,580,479	2,000,446	2,875,863	3,955,636	3,205,972	1,602,986
Plus Principal and sinking fund payments on debt - See Note 4 below.	9,325,000	9,870,000	12,576,799	13,041,799	20,082,280	21,032,434	21,414,991	21,789,897
Plus 15% of interest and sinking fund installments	3,324,429	3,326,000	4,053,150	4,052,550	6,173,550	6,024,041	6,024,041	6,024,041
Less Interest and Other Income	(2,792,633)	(932,000)	(1,447,000)	(1,241,000)	(5,597,000)	(2,798,500)	(2,798,500)	(2,798,500)
Less 15% of prior year second series debt installments	(3,320,716)	(3,324,429)	(3,326,000)	(4,053,150)	(4,052,550)	(6,173,550)	(6,024,041)	(6,024,041)
Bond issuance costs charged (credited) to power purchasers	0	0	0	0	0			
Net Costs Chargeable to Power Purchasers	54,623,332	63,042,000	71,107,000	68,821,000	77,230,000	77,827,508	79,082,044	80,220,222
Projected Owners Operating Budgets Amounts	$54,623,332	$63,042,000	$71,107,000	$68,821,000	$77,230,000	$77,827,508	$79,082,044	$80,220,222
Average Firm Energy Output (PNW L&R Study #55) (365.6aMW) times the number of hours in a year (8760)	3,202,656	3,202,656	3,202,656	3,202,656	3,202,656	3,202,656	3,202,656	3,202,656
Projected Project Cost per MWh	**$17.0556**	**$19.6843**	**$22.2025**	**$21.4887**	**$24.1144**	**$24.3009**	**$24.6926**	**$25.0480**
FY 2010-2015 Average =	**$23.6412**							
Percentage Increase / (Decrease)		**15.41%**	**12.79%**	**-3.21%**	**12.22%**	**0.77%**	**1.61%**	**1.44%**

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
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Section 7(b)(2) Resource Stack - Operating Cost Projections

	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts
Projected Balance Sheet Items -				(in whole dollars)				
Priest Rapids Hydroelectric Project:								
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Electric Plant Gross (Dam placed in service 1970)	297,015,175	316,277,895	338,038,059	370,219,142	406,312,683	468,371,453	541,317,339	577,790,281
Land and land rights	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576
Construction work in progress - See Note 3	38,525,441	43,520,329	64,362,165	72,187,082	124,117,541	145,891,771	72,945,885	36,472,943
Accumulated Depreciation & Amortization (15-95 year lives)	(133,178,620)	(138,146,294)	(143,446,253)	(149,183,136)	(155,473,044)	(162,557,985)	(170,736,465)	(179,801,236)
Projected Net Electric Plant	204,948,571	224,238,506	261,540,547	295,809,664	377,543,756	454,291,815	446,113,335	437,048,564
Depreciation expense	4,661,590	4,967,674	5,299,959	5,736,883	6,289,908	7,084,942	8,178,479	9,064,772
Depreciation expense as a % of gross plant	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%
Relicensing costs	29,001,622	29,001,622	29,001,622	29,001,622	29,001,622	29,001,622	29,001,622	29,001,622
Unamortized debt expense	2,279,294	1,914,658	1,550,022	1,185,386	820,750	456,114	91,478	0
Long-term noncash special funds	0	0	0	0	0	0	0	0
Other Deferred Charges and other assets	10,588	9,411	8,235	7,058	5,882	4,706	3,529	2,353
Projected Total Non Current Assets	236,240,075	255,164,198	292,100,426	326,003,730	407,372,010	483,754,256	475,209,965	466,052,538
Restricted Assets Current	60,228,193	56,594,006	111,740,818	108,106,631	276,329,443	272,695,256	269,061,070	265,153,725
Current and Accrued Assets	41,000,000	45,000,000	49,000,000	53,000,000	57,000,000	61,000,000	65,000,000	69,000,000
Projected Total Current Assets	101,228,193	101,594,006	160,740,818	161,106,631	333,329,443	333,695,256	334,061,070	334,153,725
Projected Total Assets	$337,468,268	$356,758,203	$452,841,244	$487,110,361	$740,701,453	$817,449,513	$809,271,034	$800,206,264
Current & Accrued Liabilities	18,674,760	18,674,760	18,674,760	18,674,760	18,674,760	18,674,760	18,674,760	18,674,760
Current portion of long-term debt	9,870,000	12,576,799	13,041,799	20,082,280	21,032,434	21,414,991	21,789,897	22,157,304
Long-Term Debt-net of discounts	238,010,000	225,433,201	271,172,402	251,090,122	401,914,688	380,499,697	358,709,801	336,552,496
Other Noncurrent Liabilities	0	0	0	0	0	0	0	0
Projected Total Liabilities	266,554,760	256,684,760	302,888,961	289,847,162	441,621,882	420,589,448	399,174,457	377,384,561
Retained Earnings - Invested in capital assets, net of related debt	56,353,508	85,513,443	135,392,283	182,703,198	284,519,571	382,300,064	395,536,575	408,261,700
Retained Earnings/Net Assets - unrestricted other	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,001	6,000,002	6,000,003
Retained Earnings/Net assets - restricted	8,560,000	8,560,000	8,560,000	8,560,000	8,560,000	8,560,000	8,560,000	8,560,000
Liabilities & Retained Earnings / Net Assets	$337,468,268	$356,758,203	$452,841,244	$487,110,361	$740,701,453	$817,449,513	$809,271,034	$800,206,264

Notes:

3. Debt Service Information Continued

	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Actual/Projected Interest on Priest Rapids Bonds	12,837,860	12,286,609	11,860,124	11,426,472	10,932,869	9,222,276	9,037,831	8,857,074
Projected future levelized debt service - interest	0	0	2,577,201	2,577,201	10,107,720	9,905,566	9,707,454	9,513,305
Total Projected Interest Payments (a1)	12,837,860	12,286,609	14,437,325	14,003,673	21,040,589	19,127,842	18,745,285	18,370,379
Less Capitalized interest expenses	(1,107,193)	(1,201,971)	(1,580,479)	(2,000,446)	(2,875,863)	(3,955,636)	(3,205,972)	(1,602,986)
Capitalized interest expense/CWIP	2.93%	2.93%	2.93%	2.93%	2.93%	2.93%	2.93%	2.93%
Adjustment in interest expense (a2)	0	14,391	6,876	(28,472)	34,131	0	0	0
Total Interest Expense per operating statement - projections for 2008-2012	11,730,667	11,099,030	12,863,723	11,974,755	18,198,857	15,172,206	15,539,314	16,767,394
Actual/Projected Principal payments on Priest Rapids Bonds	9,325,000	9,870,000	10,335,000	10,800,000	11,290,000	12,038,000	12,222,445	12,403,202
Projected future levelized debt service - principal	0	0	2,241,799	2,241,799	8,792,280	8,994,434	9,192,546	9,386,695
Total Projected Principal Payments (b)	9,325,000	9,870,000	12,576,799	13,041,799	20,082,280	21,032,434	21,414,991	21,789,897
Total Debt Service (a1) + (a2) + (b)	22,162,860	22,171,000	27,021,000	27,017,000	41,157,000	40,160,276	40,160,276	40,160,276
15% of Debt Service Requirements	3,324,429	3,326,000	4,053,150	4,052,550	6,173,550	6,024,041	6,024,041	6,024,041

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
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Section 7(b)(2) Resource Stack - Operating Cost Projections

	(in whole dollars)			(in whole dollars)		
	Financial Statement Information			Financial Statement Information		
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Revenues	32,064,057	30,810,541	30,707,299	30,731,802	40,183,300	46,712,241
Operating Expenses - See Notes 1, 2, and 4 below:						
Generation -	11,636,471	10,122,746	10,402,512	12,076,133	13,150,038	14,484,358
Transmission -	889,319	850,426	838,216	829,195	911,621	955,609
Administrative and General -	6,897,861	6,570,905	6,106,684	6,335,021	7,641,076	9,004,617
Administrative and General - Yakima Nation Payments	0	0	0	0	0	2,079,046
Administrative and General - Habitat Funding Commitments	0	0	0	0	1,312,487	1,204,644
Maintenance Expenses	0	0	0	0	0	0
Depreciation Expenses	4,613,571	3,681,788	5,078,184	4,687,574	4,305,179	4,494,085
Taxes -	856,948	783,116	801,631	806,559	963,642	991,863
Other Operating Costs						
Total Operating Expenses	24,894,170	22,008,981	23,227,227	24,734,482	28,284,043	33,214,221
Net Operating Income	7,169,887	8,801,560	7,480,072	5,997,320	11,899,257	13,498,020
Expense Changes From Prior Year - Excluding Yakima & Habitat Settlements		(2,885,189)	1,218,246	1,507,255	2,237,074	2,958,976
Operating Expense Percentage Change - From Prior Year		-11.59%	5.54%	6.49%	9.04%	10.46%
Average Percentage Change 2003-2007 =	3.9881%					
Non Operating Revenues and (Expenses)						
Interest Income (Expense)/Gains on Debt Retirements	967,727	451,766	338,167	869,153	2,405,970	4,653,266
Interest on Long-Term Debt - See Note 3	(8,253,381)	(8,029,995)	(7,575,817)	(7,145,249)	(9,217,948)	(11,806,973)
Amortization of Debt Expense and Discounts	(614,378)	(695,559)	(694,445)	(605,700)	(1,320,974)	(1,070,590)
Total Non Operating Expenses	(7,900,032)	(8,273,788)	(7,932,095)	(6,881,796)	(8,132,952)	(8,224,297)
Excess (Shortfall) of Revenues Over Cost of Services	(730,145)	527,772	(452,023)	(884,476)	3,766,305	5,273,723

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Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

Row	B	D	E	F	G	H	I
92–96							
97			(in whole dollars)			(in whole dollars)	
98							
99	**Schedule of Power Costs to Power Purchasers**:		Financial Statement Information			Financial Statement Information	
100		**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
101							
102	**Operating Costs As Outlined Above:**	24,894,170	22,008,981	23,227,227	24,734,482	28,284,043	33,214,221
103							
104	**Budget/Operating Cost Adjustments - See Note 4:**						
105	Less Other noncash expenses				0	0	(48,037)
106	Less Extraordinary maintenance paid by Reserve Funds	(76,008)	(68,630)	0	(1,426,967)	(157,470)	(48,438)
107	Less Depreciation Expense	(4,613,571)	(3,681,788)	(5,078,184)	(4,687,574)	(4,305,179)	(4,494,085)
108	Plus Interest on Long-Term Debt	8,253,381	8,029,995	7,575,817	7,145,219	9,217,948	11,806,973
109	Plus capitalized interest on CWIP	45,928	0	268,747	340,254	984,637	844,040
110	Plus Principal and sinking fund payments on debt - See Note 4 below.	4,545,000	4,985,000	5,195,000	5,430,000	7,795,000	9,325,000
111	Plus 15% of interest and sinking fund installments	1,926,646	1,952,249	1,955,935	1,885,136	2,727,513	3,320,716
112	Less Interest and Other Income	(927,793)	(506,481)	(484,994)	(732,843)	(2,451,184)	(4,480,636)
113	Less 15% of prior year second series debt installments	(1,985,010)	(1,926,646)	(1,952,249)	(1,955,935)	(1,885,135)	(2,727,513)
114	Bond issuance costs charged (credited) to power purchasers	1,314	17,861	0	0	(26,873)	0
115	**Net Costs Chargeable to Power Purchasers**	32,064,057	30,810,541	30,707,299	30,731,772	40,183,300	46,712,241
116							
117	Projected Owners Operating Budget Amounts						
118	Average Firm Energy Output (PNW L&R Study #55) (365.6aMW) times the number of hours in a year (8760)						
119	Projected Project Cost per MWh						
120–126							

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	Financial Statement Information (in whole dollars)			Financial Statement Information (in whole dollars)		
Selected Balance Sheet Items -						
Priest Rapids Hydroelectric Project:						
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Electric Plant Gross (Dam placed in service 1970)	$248,319,424	$250,995,893	$257,882,972	$263,274,453	$272,610,802	$278,489,734
Land and land rights	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576
Construction work in progress - See Note 3	4,381,441	10,183,113	8,827,546	20,746,214	29,187,118	37,050,881
Accumulated Depreciation & Amortization (15-95 year lives)	(107,042,152)	(110,725,130)	(115,853,195)	(120,564,200)	(123,894,407)	(128,517,030)
Net Electric Plant (Note 3 of 2007 F.S.)	148,245,289	153,040,452	153,443,899	166,043,043	180,490,089	189,610,161
Depreciation expense	4,613,571	3,681,788	5,078,184	4,687,574	4,305,179	4,494,085
Depreciation expense as a % of gross plant	1.86%	1.47%	1.97%	1.78%	1.58%	1.61%
Relicensing costs	15,969,761	21,479,506	25,926,488	28,055,996	28,716,130	29,001,622
Unamortized debt expense	1,747,505	2,084,600	1,853,557	2,554,017	3,008,566	2,643,930
Long-term noncash special funds	0	0	0	0	35,739,593	0
Other Deferred Charges and other assets	9,306	0	0	0	0	11,764
Total Non Current Assets	165,971,861	176,604,558	181,223,944	196,653,056	247,954,378	221,267,477
Restricted Assets Current	30,208,013	42,056,984	32,527,571	43,323,454	43,370,906	66,055,340
Current and Accrued Assets	16,200,038	7,951,490	8,182,286	16,756,206	27,102,424	36,444,046
Total Current Assets	46,408,051	50,008,474	40,709,857	60,079,660	70,473,330	102,499,386
Total Assets	$212,379,912	$226,613,032	$221,933,801	$256,732,716	$318,427,708	$323,766,863
Current & Accrued Liabilities	22,860,256	9,570,671	9,865,060	14,437,291	14,993,582	22,355,938
Current portion of long-term debt	4,545,000	4,985,000	5,195,000	5,430,000	7,795,000	9,325,000
Long-Term Debt-net of discounts	145,591,449	172,146,382	167,414,785	198,290,945	257,700,000	247,880,000
Other Noncurrent Liabilities	0	0	0	0	(4,401,659)	(3,408,583)
Total Liabilities	172,996,705	186,702,053	182,474,845	218,158,236	276,086,923	276,152,355
Retained Earnings - Invested in capital assets, net of related debt	27,044,403	26,970,630	29,280,193	28,295,148	28,915,376	31,690,098
Retained Earnings/Net Assets - unrestricted other	6,000,000	6,000,000	3,000,000	4,849,332	5,630,409	6,599,410
Retained Earnings/Net assets - restricted	6,338,804	6,940,349	7,178,763	5,430,000	7,795,000	9,325,000
Total Liabilities & Retained Earnings / Net Assets	$212,379,912	$226,613,032	$221,933,801	$256,732,716	$318,427,708	$323,766,863

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Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

Notes:

1. The financial information for the years 2002 -2007 was from Grant County PUD No. 2's audited financial statements (FS), primarily the audited financial statements on the individual developments (enterprise funds), and the Schedules of Power Costs and Allocation to Power Purchasers.

2. The operating cost projections for the years 2009-2012 were based on the 2009 Priest Rapids Project Final Proforma budget information dated December 1, 2008. The projected Net Power Costs Chargeable to Power Purchasers for the Wanapum Development for FY2009-2012 agrees to page 20 of the Proforma report. Variable operating expenses were trended and adjusted to agree with the Proforma budget information. The debt service information was taken from page 83 of the 2007 FS notes in addition to the information presented on pages 20 and 21 of the Priest Rapids Project Final Proforma budget information dated December 1, 2008. The amounts paid under the Yakima Nation and Habitat settlements that are outlined in Note 7 - Commitments on pages 85-86 of the 2007 FS. Depreciation expense was based on a composite depreciation rate of 1.59% (average of 2006 and 2007 rates) per Note 1 - Organization and Accounting policies of the 2007 FS on page 115. Depreciation expense was calculated on the average of the beginning and ending projected balances of gross utility plant. Capitalized interest expense relating to the average of the beginning and ending year balances for projected construction work in progress (CWIP) was computed using an interest rate of 4.93% which is the 3-year (2005-2007) average of capitalized interest expense divided by the average of the beginning and ending projected CWIP balances for the year, see Note 3 below.

3. Debt Service Information
The actual interest (a) and principal (b) on the Priest Rapids Bonds for the years 2002-2007 was taken from the Operating Statement and the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2008-2015 on the Wanapum Revenue Bonds was obtained from Note 5 of the 2007 financial statements at page 128, Schedule of Debt Service Requirements. A portion of the information for 2009-2012 was from the 2009 Priest Rapids Project Final Proforma budget information dated December 1, 2008, page 20 the Net Power Costs Charged to Power Purchasers.

	2002	2003	2004	2005	2006	2007
Actual/Projected Interest on Priest Rapids Bonds	8,052,724	7,511,045	7,683,777	9,757,101	6,216,854	11,360,078
Projected future levelized debt service - interest	0	0	0	0	0	0
Total Projected Interest Payments (a)	8,052,724	7,511,045	7,683,777	9,757,101	6,216,854	11,360,078
Less Capitalized interest expenses	(45,928)	0	(268,747)	(340,255)	(984,636)	(844,040)
Capitalized interest expense/CWIP				2.30%	3.94%	2.55%
Adjustment in interest expense	246,585	518,950	160,787	(2,271,627)	3,985,730	1,290,935
Total Interest Expense per operating statement - projections for 2008-2012	8,253,381	8,029,995	7,575,817	7,145,219	9,217,948	11,806,973
Actual/Projected Principal payments on Priest Rapids Bonds	4,545,000	4,985,000	5,195,000	5,430,000	7,795,000	9,325,000
Projected future levelized debt service - principal	0	0	0	0	0	0
Total Projected Principal Payments (b)	4,545,000	4,985,000	5,195,000	5,430,000	7,795,000	9,325,000
Total Debt Service (a) + (b)	12,597,724	12,496,045	12,878,777	15,187,101	14,011,854	20,685,078
15% of Debt Service Requirements		1,874,407	1,931,817	2,278,065	2,101,778	3,102,762

4. The Priest Rapids Power Sales Contracts (covering the Priest Rapids and Wanapum Developments) provide that each power purchaser will be obligated to make payments equal to annual power costs, which include all operating expenses and debt service on the Parity Bonds and debt service coverage (currently 15% of annual debt service) less any interest earnings, for the life of the new contracts, multiplied by the percentage of output or revenue, as applicable, that the purchaser is entitled to that year. The above debt service provisions take the place of recovering depreciation expense from power purchasers and thus depreciation is subtracted from the schedule of power costs charged purchasers. Extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and the Construction Fund and are not recovered from power purchasers.

	A	B	C	D	E	F	G	H	I	J
1	**BPA's 2010 Wholesale Power Rate Case**									
2	**Grant's Priest Rapids Allocation for 2010-2015 - Received from Grant PUD 12/22/08**									
3										
4	**Priest Rapids Dam, Project Owner = Grant County PUD, FERC License Exp. 3/31/2052,**									
5	**New Purchaser Agreements became effective 11/01/2005.**									
6										
7	**Grant County PUD's Allocation Amounts prepared by Michiko Sell of Grant PUD**									
8	**Priest Rapids**									
9	**Name**		**12-15 %'s**	**10-11 %'s**	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**
10	Avista Corp (WWP Division)		0.0364	0.0376	13.7	13.7	13.3	13.3	13.3	13.3
11	Clearwater Power	**	0.0011	0.0011	0.4	0.4	0.4	0.4	0.4	0.4
12	Cowlitz County PUD #1		0.0103	0.0179	6.5	6.5	3.8	3.8	3.8	3.8
13	Eugene Water & Electric Board		0.0102	0.0105	3.8	3.8	3.7	3.7	3.7	3.7
14	Fall River Electric Coop	**	0.0014	0.0014	0.5	0.5	0.5	0.5	0.5	0.5
15	Forest Grove, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
16	Grant County PUD #2		0.6347	0.6168	225.3	225.5	232.1	232.1	232.1	232.1
17	Idaho County L & P	**	0.0004	0.0004	0.1	0.1	0.1	0.1	0.1	0.1
18	Kittitas County PUD #1		0.0014	0.0014	0.5	0.5	0.5	0.5	0.5	0.5
19	Kootenai Electric Coop	**	0.0019	0.0019	0.7	0.7	0.7	0.7	0.7	0.7
20	Lost River Electric Coop	**	0.0003	0.0003	0.1	0.1	0.1	0.1	0.1	0.1
21	Lower Valley Energy	**	0.0025	0.0025	0.9	0.9	0.9	0.9	0.9	0.9
22	McMinnville, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
23	Milton-Freewater, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
24	Northern Lights	**	0.0017	0.0017	0.6	0.6	0.6	0.6	0.6	0.6
25	Pacific Power		0.0827	0.0855	31.2	31.3	30.2	30.2	30.2	30.2
26	Portland General Electric		0.0827	0.0855	31.2	31.3	30.2	30.2	30.2	30.2
27	Puget Sound Energy		0.0477	0.0493	18.0	18.0	17.4	17.4	17.4	17.4
28	Raft River Electric Coop	**	0.0004	0.0004	0.1	0.1	0.1	0.1	0.1	0.1
29	Salmon River Electric Coop	**	0.0003	0.0003	0.1	0.1	0.1	0.1	0.1	0.1
30	Seattle City Light		0.0202	0.0209	7.6	7.6	7.4	7.4	7.4	7.4
31	Tacoma Public Utilities		0.0204	0.0211	7.7	7.7	7.5	7.5	7.5	7.5
32	United Electric Coop	**	0.0007	0.0007	0.3	0.3	0.3	0.3	0.3	0.3
33	Unknown Marketer	**	0.0300	0.0300	11.0	11.0	11.0	11.0	11.0	11.0
34	**Priest Rapids After Encroachment**		**1.00**	**0.9998**	**365.2**	**365.6**	**365.7**	**365.7**	**365.6**	**365.6**
35										
36	COUs not Dedicated to Regional Loads and Market Purchaser Allocations - **				14.9	14.9	14.9	14.9	14.9	14.9
37	Other Power Allocations				350.3	350.7	350.8	350.8	350.8	350.7
38	TOTAL			**365.6**	365.2	365.6	365.7	365.7	365.6	365.6
39	Non-dedicated COUs and Market Purchaser Energy - Six Year Average Allocation FY2010-2015 =			**14.9**						
40										
41	**Priest Rapids Allocation Percentage Shares:**									
42	COUs not Dedicated to Regional Loads and Market Purchaser Allocations - **				4.07%	4.07%	4.07%	4.07%	4.07%	4.07%
43	Other Power Allocations				95.93%	95.93%	95.93%	95.93%	95.93%	95.93%
44	TOTAL				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
45	Non-dedicated COUs and Market Purchaser Energy - Six Year Average Allocation Percentage FY2010-2015				**4.07%**					
46										
47				Page 1 of 1						
48										
49										
50										

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	FY2010-$$	FY2010-$$		7(b)(2)
	100.00%	**4.09%**		**Resource Stack**
		"undesignated" /		**Amounts**
		"non- dedicated"		**0 MW**
7(b)(2) Case - Resource Stack Values - See Note A Below				
Total O&M - Average FY2010-2015 Non-dedicated COU & Marketer Projection =				
14.8aMW *$28.64 * 8,760 hour /year	$91,441,702	$3,712,859		$ 0
Cost per MWh per line 9 below -	$28.64	$28.64	$/MW	$ 0 /MW
Capital Investment - Projected Net Utility Plant FY 2010	$468,912,222			
Capital Investment - Projected Net Utility Plant FY 2015	$693,553,067			
Life	70-100 years			
Placed in service	1963			
Non-dedicated COU & Marketer average hourly energy (aMW) six-year average FY2010-2015	364.5	14.8	MW	0 MW
Average Annual Energy Output associated with Non-dedicated portion / @ 14.8aMW	3,193,020	129,648	MWh	0 MWh

		2010	2011	2012	2013	2014	2015
1. 2010$$ Price Conversion Factor		1.000000	1.020232	1.041582	1.062788	1.084313	1.106094
2. **Net Costs Chargeable to Power Purchasers - per analysis below**		90,209,000	87,704,000	98,461,000	99,054,312	100,396,305	101,630,557
Average Annual Operating Costs - Nominal $$ =	96,242,529						
3. Projected Annual Amounts Stated in 2010$$ (line 2 divided by line 1)		90,209,000	85,964,761	94,530,243	93,202,325	92,589,782	91,882,387
4. FY 2010 -2015 Average Total Operating Costs in 2010$$		91,396,416	91,396,416	91,396,416	91,396,416	91,396,416	91,396,416
Operating Cost Adjustment - See Note B below		45,286	45,286	45,286	45,286	45,286	45,286
5. Adjusted Annual Cost Amount in 2010 $$		91,441,702	91,441,702	91,441,702	91,441,702	91,441,702	91,441,702
6. Ram Model Annual Cost Amounts Using Average Cost Pricing stated in 2010 $$ (line 5 times line 1)		91,441,702	93,291,751	95,244,031	97,183,144	99,151,427	101,143,118
7. Annual Variance Over / (Under) (line 6 less line 2)		1,232,703	5,587,751	(3,216,969)	(1,871,168)	(1,244,878)	(487,439)
Total of Annual Variances =	(0)						
8. Average Firm Energy Output - 364.5aMW times the number of hours in a year (8760)		3,193,020	MWh				
9. Projected Project Cost per MWh (line 5 divided by line 8)		$28.64					

Note B - It is necessary to make an operating adjustment so that the average total operating costs for all years of the rate test period (FY2010-2015) is equivalent to the total actual operating costs in nominal dollars (line 2) since the RAM model starts with a beginning cost of when the resource is selected from the resource stack and then escalates the cost using the fixed escalation factors at line 1 above. If a simple average of the nominal operating costs for the rate test period were used, the "starting operating cost" of the resource would have been higher at a rate of $96,242,259 in comparison to the adjusted operating cost amount of $91,441,702.

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

Note A - BPA has not included in the resource stack for the WP-10 Power Rate Case any of the portions of Grant Co. PUD's Wanapum and Priest Rapids hydro resources that have been purchased by BPA's 7(b)(2) Customers nor the annual portions that Grant sells in its' annual auction to establish a market price for these. During BPA's process of making its' Section 5(b)/9(c) Policy Determination, concerning the portion of Grant's resources that were sold at auction and for those portions of its resources sold to regional customers that were exchanged back to Grant to be sold at market prices, Grant Co. PUD was charged with ensuring that these resources were not sold, resold, distributed for use or used outside the Pacific Northwest region except in conformance with the Bonneville Project Act, Public Law 75-329; the Pacific Northwest Consumer Power Preference Act, Public Law 88-552; and the Northwest Power Act, Public Law 96-501; before selling power from these resources outside the region. A compliance protocol was established making Grant Co. PUD responsible for the in-region use of the power when the sale at auction is made to an entity that does not have a Northwest Power Act section 5(b) contract with BPA or that does not directly serve regional consumer loads (see the copy of BPA's 5(b)/9(c) compliance protocol letter to Grant Co. PUD and Grant Co. PUD's prototype market auction contract provisions). Grant is required to monitor the sales of it's' purchaser and if requested by BPA, Grant will provide this information to BPA within 15 days of the end of the month requested. In the event that the information does not corroborate that the power was used in the region, BPA may impose a decrement upon Grant during the remaining period of time of its Subscription contract ending September 30, 2011. Similar provisions to Grant's sale at auction have also been incorporated in the contracts with the Snake River Power Association 7(b)(2) Customers.

Neither Grant Co. PUD nor BPA's other 7(b)(2) Customers who own shares of the Priest Rapids or Wanapum Hydro resources have had a portion of their BPA power purchases "decremented" based upon sales of power from these resources outside the region as provided in the foregoing statutory provisions and BPA's Section 5(b)/9(c) Policy. To ensure consistency with BPA's Section 5(b)/9(c) Policy Determinations, BPA has decided to change its 7(b)(2) resource stack policy to one of presuming that power from these resources and other 7(b)(2) customer resources that have been designated as "unspecified resources" serving a utility's native load pursuant to section 5(b) of the Northwest Power Act, (which decreases BPA's load obligations) are presumed used to meet regional loads unless there is documentation that the power is being exported out of the region only after it was offered within the region in conformance with section 9(c). Based on this 7(b)(2) resource stack policy decision, it was decided to not include any portions of the Grant Co. PUD's hydro resources in the 7(b)(2) rate stack in performing the 7(b)(2) Rate Test.

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Operating Revenues	59,500,000	69,000,000	74,500,000	75,000,000	76,000,000	79,000,000	83,500,000	87,500,000
Operating Expenses - See Notes 1, 2, and 4 below:								
Generation - *	17,181,606	21,631,642	23,621,753	22,889,479	21,271,193	21,909,329	22,566,608	23,243,607
Transmission - *	1,325,012	1,668,190	1,821,663	1,765,192	1,640,393	1,689,605	1,740,293	1,792,502
Administrative and General - *	11,918,573	15,005,484	16,385,988	15,878,022	14,755,446	15,198,110	15,654,053	16,123,674
Administrative and General - Yakima Nation Payments	3,200,000	3,200,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000
Administrative and General - Habitat Funding Commitments	1,227,000	1,264,000	1,302,000	1,341,000	1,381,000	1,381,000	1,381,000	1,381,000
Maintenance Expenses	0	0	0	0	0	0	0	0
Depreciation Expenses	7,160,698	7,358,570	7,699,790	8,397,164	9,486,830	10,863,849	12,244,009	13,210,303
Taxes - *	1,014,175	1,019,000	1,050,000	1,081,000	1,113,000	1,146,390	1,180,782	1,216,205
Other Operating Costs	0	5,411	12,945	19,157	5,818	0	0	0
Total Operating Expenses	43,027,064	51,152,297	54,294,140	53,771,014	52,053,680	54,588,282	57,166,744	59,367,291
Net Operating Income	16,472,936	17,847,703	20,205,860	21,228,986	23,946,320	24,411,718	26,333,256	28,132,709
Expense Changes From Prior Year - Excluding Yakima & Habitat Settlements	6,733,535	8,088,233	3,903,843	(562,126)	(1,757,334)	2,534,602	2,578,463	2,200,547
Operating Expense Percentage Change - From Prior Year	21.13%	20.95%	8.14%	-1.08%	-3.42%	5.10%	4.94%	4.02%
Average Percentage Change 2008-2012	9.14%							
Non Operating Revenues and (Expenses)								
Interest Income (Expense)/Gains on Debt Retirements	4,842,619	1,745,000	3,130,000	2,531,000	5,347,000	2,673,500	2,673,500	2,673,500
Interest on Long-Term Debt - See Note 3	(20,804,791)	(19,036,005)	(24,408,913)	(21,467,202)	(28,494,218)	(26,209,363)	(28,080,485)	(30,395,151)
Amortization of Debt Expense and Discounts	(433,898)	(433,898)	(433,898)	(433,898)	(433,898)	(433,898)	(433,898)	(433,898)
Total Non Operating Expenses	(16,396,070)	(17,724,903)	(21,712,811)	(19,370,100)	(23,581,116)	(23,969,761)	(25,840,883)	(28,155,549)
Excess (Shortfall) of Revenues Over Cost of Services	76,866	122,800	(1,506,951)	1,858,887	365,205	441,957	492,373	(22,841)

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Projected Power Costs Charged to Power Purchasers - See Notes 2-4:	BPA Analyst's Projected Operating Budget 2008	BPA Analyst's Projected Operating Budget 2009	BPA Analyst's Projected Operating Budget 2010	BPA Analyst's Projected Operating Budget 2011	BPA Analyst's Projected Operating Budget 2012	BPA Analyst's Projected Operating Budget 2013	BPA Analyst's Projected Operating Budget 2014	BPA Analyst's Projected Operating Budget 2015
Operating Costs As Outlined Above:	43,027,064	51,152,297	54,294,140	53,771,014	52,053,680	54,588,282	57,166,744	59,367,291
Budget/Operating Cost Adjustments - See Note 4:								
Less Other noncash expenses	0	0	0	0	0	0	0	0
Less Extraordinary maintenance paid by Reserve Funds	0	0	0	0	0	0	0	0
Less Depreciation Expense	(7,160,698)	(7,358,570)	(7,699,790)	(8,397,164)	(9,486,830)	(10,863,849)	(12,244,009)	(13,210,303)
Plus Interest on Long-Term Debt	20,804,791	19,036,005	24,408,913	21,467,202	28,494,218	26,209,363	28,080,485	30,395,151
Plus capitalized interest on CWIP	1,227,056	2,115,995	4,324,591	6,757,302	8,539,252	8,558,726	5,992,242	2,996,121
Plus Principal and sinking fund payments on debt - See Note 4 below.	10,445,000	11,320,000	16,149,496	16,639,496	22,071,531	23,378,980	24,074,342	24,755,797
Plus 15% of interest and sinking fund installments	4,871,527	4,870,800	6,732,450	6,729,600	8,865,750	8,722,060	8,722,060	8,722,060
Less Interest and Other Income	(4,842,619)	(1,745,000)	(3,130,000)	(2,531,000)	(5,347,000)	(2,673,500)	(2,673,500)	(2,673,500)
Less 15% of prior year second series debt installments	(4,868,452)	(4,871,527)	(4,870,800)	(6,732,450)	(6,729,600)	(8,865,750)	(8,722,060)	(8,722,060)
Bond issuance costs charged (credited) to power purchasers	0	0	0	0	0	0	0	0
Net Power Costs Chargeable to Power Purchasers	63,503,669	74,520,000	90,209,000	87,704,000	98,461,000	99,054,312	100,396,305	101,630,557
Projected Owners Operating Budget Amounts	$63,503,669	$74,520,000	$90,209,000	$87,704,000	$98,461,000	$99,054,312	$100,396,305	$101,630,557
Average Firm Energy Output 364.5MW times the number of hours in a year (8760)	3,193,020	3,193,020	3,193,020	3,193,020	3,193,020	3,193,020	3,193,020	3,193,020
Projected Project Cost per MWh	**$19.8883**	**$23.3384**	**$28.2519**	**$27.4674**	**$30.8363**	**$31.0221**	**$31.4424**	**$31.8290**
FY 2010-2015 Average =	**$30.1415**							
Percentage Increase / (Decrease)		**17.35%**	**21.05%**	**-2.78%**	**12.27%**	**0.60%**	**1.35%**	**1.23%**
Average Increase FY2010-2015	**5.6214%**							

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	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget
Selected Balance Sheet Items - Wanapum Hydroelectric Project:				(in whole dollars)				
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Electric Plant Gross (Dam placed in service 1963)	456,988,220	468,618,079	499,909,009	556,337,973	636,973,956	729,547,947	810,578,942	851,094,440
Land and land rights	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576
Construction work in progress - See Note 3	23,259,718	62,581,859	112,857,930	161,271,965	185,147,982	162,061,991	81,030,996	40,515,498
Accumulated Depreciation & Amortization (15-95 year lives)	(131,382,932)	(138,741,502)	(146,441,292)	(154,838,456)	(164,325,286)	(175,189,135)	(187,433,144)	(200,643,447)
Net Electric Plant (Note 3 of 2007 F.S.)	351,451,582	395,045,012	468,912,222	565,358,058	660,383,228	719,007,379	706,763,370	693,553,067
Depreciation expense	7,160,698	7,358,570	7,699,790	8,397,164	9,486,830	10,863,849	12,244,009	13,210,303
Depreciation expense as a % of gross plant	1.59%	1.59%	1.59%	1.59%	1.59%	1.59%	1.59%	1.59%
Relicensing costs	29,058,303	29,058,303	29,058,303	29,058,303	29,058,303	29,058,303	29,058,303	29,058,303
Unamortized debt expense	4,077,330	3,643,432	3,209,534	2,775,636	2,341,738	1,907,840	1,473,942	1,040,044
Long-term noncash special funds	0	0	0	0	0	0	0	0
Other Deferred Charges and other assets	10,588	9,411	8,235	7,058	5,882	4,706	3,529	2,353
Total Non Current Assets	384,587,215	427,746,747	501,180,059	597,191,997	691,783,269	749,973,522	737,295,615	723,651,414
Restricted Assets Current	137,065,070	133,498,968	282,063,866	278,497,764	448,931,662	445,365,560	441,799,458	438,233,356
Current and Accrued Assets	27,000,000	31,000,000	35,000,000	39,000,000	43,000,000	47,000,000	51,000,000	55,000,000
Total Current Assets	164,065,070	164,498,968	317,063,866	317,497,764	491,931,662	492,365,560	492,799,458	493,233,356
Total Assets	$548,652,285	$592,245,715	$818,243,925	$914,689,761	$1,183,714,931	$1,242,339,082	$1,230,095,073	$1,216,884,770
Current & Accrued Liabilities	30,228,885	30,228,885	30,228,885	30,228,885	30,228,885	30,228,885	30,228,885	30,228,885
Current portion of long-term debt	11,320,000	16,149,496	16,639,496	22,071,531	23,378,980	24,074,342	24,755,797	25,423,622
Long-Term Debt	410,710,000	394,560,504	530,052,007	507,980,476	658,601,496	634,527,154	609,771,358	584,347,736
Other Noncurrent Liabilities	0	0	0	0	0	0	0	0
Total Liabilities	452,258,885	440,938,885	576,920,388	560,280,892	712,209,361	688,830,381	664,756,039	640,000,242
Retained Earnings - Invested in capital assets, net of related debt	80,708,304	135,621,734	225,638,440	338,723,773	455,820,474	537,823,605	549,653,938	561,199,431
Retained Earnings/Net Assets - unrestricted other	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Retained Earnings/Net assets - restricted	9,685,097	9,685,097	9,685,097	9,685,097	9,685,097	9,685,097	9,685,097	9,685,097
Total Liabilities & Retained Earnings / Net Assets	$548,652,285	$592,245,715	$818,243,925	$914,689,761	$1,183,714,931	$1,242,339,082	$1,230,095,073	$1,216,884,770

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Note 3. Debt Service Information - continued:

	BPA Analyst's Projected Operating Budget 2008	BPA Analyst's Projected Operating Budget 2009	BPA Analyst's Projected Operating Budget 2010	BPA Analyst's Projected Operating Budget 2011	BPA Analyst's Projected Operating Budget 2012	BPA Analyst's Projected Operating Budget 2013	BPA Analyst's Projected Operating Budget 2014	BPA Analyst's Projected Operating Budget 2015
Actual/Projected Interest on Wanapum Bonds	22,031,847	21,119,154	20,607,856	20,066,951	19,492,295	17,547,069	17,196,128	16,852,205
Projected future levelized debt service - interest	0	0	8,197,504	8,197,504	17,572,469	17,221,020	16,876,599	16,539,067
Total Projected Interest Payments (a1)	22,031,847	21,119,154	28,805,360	28,264,455	37,064,764	34,768,089	34,072,727	33,391,272
Less Capitalized interest expenses	(1,227,056)	(2,115,995)	(4,324,591)	(6,757,302)	(8,539,252)	(8,558,726)	(5,992,242)	(2,996,121)
Capitalized interest expense/CWIP - %	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%
Adjustment in interest expense (a2)	0	32,846	(71,856)	(39,951)	(31295)	0	0	0
Total Interest Exp. - operating statement - projections 2008-2015	20,804,791	19,036,005	24,408,913	21,467,202	28,494,218	26,209,363	28,080,485	30,395,151
Actual/Projected Principal payments on Wanapum Bonds	10,445,000	11,320,000	11,885,000	12,375,000	12,930,000	13,886,000	14,236,941	14,580,864
Projected future levelized debt service - principal	0	0	4,264,496	4,264,496	9,141,531	9,492,980	9,837,401	10,174,933
Total Projected Principal Payments (b)	10,445,000	11,320,000	16,149,496	16,639,496	22,071,531	23,378,980	24,074,342	24,755,797
Total Debt Service (a1) + (a2) + (b)	32,476,847	32,472,000	44,883,000	44,864,000	59,105,000	58,147,069	58,147,069	58,147,069
15% of Debt Service Requirements	4,871,527	4,870,800	6,732,450	6,729,600	8,865,750	8,722,060	8,722,060	8,722,060

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	(in whole dollars)			(in whole dollars)		
	Financial Statement Information			Financial Statement Information		
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Revenues	$39,654,100	$37,623,004	$30,184,495	35,301,208	42,691,219	54,637,861
Operating Expenses - See Notes 1, 2, and 4 below:						
Generation - *	12,623,551	11,099,675	10,388,384	11,701,974	11,775,574	13,856,134
Transmission - *	977,237	948,778	969,101	868,489	1,042,200	1,068,558
Administrative and General - *	6,759,515	6,451,674	5,423,216	5,453,955	6,726,024	9,611,753
Administrative and General - Yakima Nation Payments	0	0	0	0	0	2,079,046
Administrative and General - Habitat Funding Commitments	0	0	0	0	1,312,487	1,204,644
Maintenance Expenses	0	0	0	0	0	0
Depreciation Expenses	4,924,752	5,031,141	5,152,363	4,907,668	5,994,813	6,358,381
Taxes - *	852,347	764,649	803,820	874,633	936,775	971,704
Other Operating Costs						
Total Operating Expenses	26,137,402	24,295,917	22,736,884	23,806,719	27,787,873	35,150,219
Net Operating Income	13,516,698	13,327,087	7,447,611	11,494,489	14,903,346	19,487,642
Expense Changes From Prior Year - Excluding Yakima & Habitat Settlements		(1,841,485)	(1,559,033)	1,069,835	2,668,667	5,391,144
Operating Expense Percentage Change - From Prior Year		-7.05%	-6.42%	4.71%	11.21%	19.40%
Average Percentage Change 2003-2007	4.3708%					
Non Operating Revenues and (Expenses)						
Interest Income (Expense)/Gains on Debt Retirements	958,126	476,575	219,143	2,760,540	2,809,745	7,940,238
Interest on Long-Term Debt - See Note 3	(7,177,897)	(7,838,985)	(6,275,562)	(9,335,290)	(11,692,267)	(17,769,525)
Amortization of Debt Expense and Discounts	(713,449)	(806,562)	(749,297)	(744,633)	(688,862)	(664,679)
Total Non Operating Expenses	(6,933,220)	(8,168,972)	(6,805,716)	(7,319,383)	(9,571,384)	(10,493,966)
Excess (Shortfall) of Revenues Over Cost of Services	6,583,478	5,158,115	641,895	4,175,106	5,331,962	8,993,676

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Schedule of Power Costs to Power Purchasers:	Financial Statement Information - (in whole dollars)					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Costs As Outlined Above:	26,137,402	24,295,917	22,736,884	23,806,719	27,787,873	35,150,219
Budget/Operating Cost Adjustments - See Note 4:						
Less Other noncash expenses	0	0	0	0	0	(30,139)
Less Extraordinary maintenance paid by Reserve Funds	(255,008)	(90,831)	0	(774,662)	(116,462)	0
Less Depreciation Expense	(4,924,752)	(5,031,141)	(5,152,363)	(4,907,668)	(5,994,813)	(6,358,381)
Plus Interest on Long-Term Debt	7,177,897	7,838,985	6,275,562	7,177,897	11,692,267	17,769,525
Plus capitalized interest on CWIP	487,657	299,965	1,437,425	3,000,691	2,586,136	3,762,460
Plus Principal and sinking fund payments on debt - See Note 4 below.	10,955,000	9,924,804	5,180,000	6,900,000	8,870,000	10,445,000
Plus 15% of interest and sinking fund installments	2,793,083	2,614,184	1,933,948	2,882,732	3,400,356	4,868,452
Less Interest and Other Income	(1,014,294)	(584,986)	(334,189)	(3,065,939)	(2,651,406)	(7,568,919)
Less 15% of prior year second series debt installments	(1,711,094)	(1,675,494)	(1,892,772)	(1,927,257)	(2,882,732)	(3,400,356)
Bond issuance costs charged (credited) to power purchasers	8,209	31,606	0	51,303	0	0
Net Costs Chargeable to Power Purchasers	39,654,100	37,623,009	30,184,495	33,143,816	42,691,219	54,637,861
Projected Owners Operating Budget Amounts						
Average Firm Energy Output (PNW L&R Study #55) (364.5MW) times the number of hours in a year (8760)						
Projected Project Cost per MWh						

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Selected Balance Sheet Items - Wanapum Hydroelectric Project:	Financial Statement Information (in whole dollars)			Financial Statement Information (in whole dollars)		
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Electric Plant Gross (Dam placed in service 1963)	258,738,862	$263,178,360	$272,017,524	$274,022,058	$344,636,849	$443,728,502
Land and land rights	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695
Construction work in progress - See Note 3	9,865,278	21,230,005	53,279,575	79,184,196	80,519,296	26,519,436
Accumulated Depreciation & Amortization (15-95 year lives)	(100,896,839)	(105,929,169)	(111,130,577)	(114,286,278)	(119,510,815)	(124,222,234)
Net Electric Plant (Note 3 of 2007 F.S.)	184,148,996	194,920,891	230,608,217	255,361,671	322,087,025	362,467,399
Depreciation expense	4,924,752	5,031,141	5,152,363	4,907,668	5,994,813	6,358,381
Depreciation expense as a % of gross plant	1.90%	1.91%	1.93%	1.80%	1.94%	1.61%
Relicensing costs	15,969,794	21,492,288	25,954,022	28,112,676	28,772,811	29,058,303
Unamortized debt expense	1,308,608	2,115,744	1,886,648	3,214,705	4,945,126	4,511,228
Long-term noncash special funds	9,306	0	33,566	0	70,478,698	0
Other Deferred Charges and other assets	0	0	0	0	0	11,764
Total Non Current Assets	201,436,704	218,528,923	258,482,453	286,689,052	426,283,660	396,048,694
Restricted Assets Current	18,796,718	30,027,733	27,831,707	89,902,639	109,348,485	147,918,391
Current and Accrued Assets	18,027,531	17,559,743	8,415,820	12,591,936	19,571,040	23,816,265
Total Current Assets	36,824,249	47,587,476	36,247,527	102,494,575	128,919,525	171,734,656
Total Assets	$238,260,953	$266,116,399	$294,729,980	$389,183,627	$555,203,185	$567,783,350
Current & Accrued Liabilities	24,983,524	9,156,639	40,633,275	18,515,358	26,192,013	34,265,756
Current portion of long-term debt	11,025,000	4,905,000	5,180,000	6,900,000	8,870,000	10,445,000
Long-Term Debt	137,185,000	181,560,000	176,380,000	283,600,000	432,885,000	422,030,000
Other Noncurrent Liabilities	(6,198,995)	(6,325,429)	(5,805,229)	(3,898,842)	1,365,441	2,208,158
Total Liabilities	166,994,529	189,296,210	216,388,046	305,116,516	469,312,454	468,948,914
Retained Earnings - Invested in capital assets, net of related debt	62,243,317	46,924,797	69,734,677	72,784,379	72,288,236	81,279,121
Retained Earnings/Net Assets - unrestricted other	1,369,023	23,097,621	1,500,000	1,500,000	4,732,495	7,055,122
Retained Earnings/Net assets - restricted	7,654,084	6,797,771	7,107,257	9,782,732	8,870,000	10,500,193
Total Liabilities & Retained Earnings / Net Assets	$238,260,953	$266,116,399	$294,729,980	$389,183,627	$555,203,185	$567,783,350

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Notes:

1. The financial information for the years 2002 -2007 was from Grant County PUD No. 2's audited financial statements (FS), primarily the audited financial statements on the individual developments (enterprise funds), and the Schedules of Power Costs and Allocation to Power Purchasers.

2. The operating cost projections for the years 2009-2012 were based on the 2009 Priest Rapids Project Final Proforma budget information dated December 1, 2008. The projected Net Power Costs Chargeable to Power Purchasers for the Wanapum Development for FY2009-2012 agrees to page 22 of 31 of the Proforma report. Variable operating expenses were trended and adjusted to agree with the Proforma budget information. The debt service information was taken from page 128 of the 2007 FS notes in addition to the information presented on pages 22 and 23 of the Priest Rapids Project Final Proforma budget information dated December 1, 2008. The amounts paid under the Yakima Nation and Habitat settlements that are outlined in Note 7 - Commitments on pages 130-131 of the 2007 FS. Depreciation expense was based on a composite depreciation rate of 1.59% (average of 2006 and 2007 rates) per Note 1 - Organization and Accounting policies of the 2007 FS on page 115. Depreciation expense was calculated on the average of the beginning and ending projected balances of gross utility plant. Capitalized interest expense relating to the average of the beginning and ending year balances for projected construction work in progress (CWIP) was computed using an interest rate of 4.93% which is the 3-year (2005-2007) average of capitalized interest expense divided by the average of the beginning and ending projected CWIP balances for the year, see Note 3 below.

3. Debt Service Information
The actual interest (a) and principal (b) on the Priest Rapids Bonds for the years 2002-2007 was taken from the Operating Statement and the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2008-2015 on the Wanapum Revenue Bonds was obtained from Note 5 of the 2007 financial statements at page 128, Schedule of Debt Service Requirements. A portion of the information for 2009-2012 was from the 2009 Priest Rapids Project Final Proforma budget information dated December 1, 2008, page 22 the Net Power Costs Charged to Power Purchasers.

	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Actual/Projected Interest on Wanapum Bonds	7,546,528	7,166,547	7,815,774	9,789,356	12,169,030	17,402,537
Projected future levelized debt service - interest	0	0	0	0	0	0
Total Projected Interest Payments (a)	7,546,528	7,166,547	7,815,774	9,789,356	12,169,030	17,402,537
Less Capitalized interest expenses	(487,657)	(299,965)	(1,437,425)	(3,000,691)	(2,586,136)	(3,762,460)
Capitalized interest expense/CWIP - %		1.93%	3.86%	4.53%	3.24%	7.03%
Adjustment in interest expense	119,026	972,403	(102,787)	2,546,625	2,109,373	4,129,448
Total Interest Exp. - operating statement - projections 2002-2007	7,177,897	7,838,985	6,275,562	7,177,897	11,692,267	17,769,525
Actual/Projected Principal payments on Wanapum Bonds (b)	11,570,000	19,025,000	4,905,000	5,180,000	6,900,000	8,870,000
Projected future levelized debt service - principal	0	0	0	0	0	0
Total Projected Principal Payments (b)	11,570,000	19,025,000	4,905,000	5,180,000	6,900,000	8,870,000
Total Debt Service (a) + (b)	19,116,528	26,191,547	12,720,774	14,969,356	19,069,030	26,272,537
15% of Debt Service Requirements	2,867,479	3,928,732	1,908,116	2,245,403	2,860,355	3,940,881

4. The Priest Rapids Power Sales Contracts (covering the Priest Rapids and Wanapum Developments) provide that each power purchaser will be obligated to make payments equal to annual power costs, which include all operating expenses and debt service on the Parity Bonds and debt service coverage (currently 15% of annual debt service) less any interest earnings, for the life of the new contracts, multiplied by the percentage of output or revenue, as applicable, that the purchaser is entitled to that year. The above debt service provisions take the place of recovering depreciation expense from power purchasers and thus depreciation is subtracted from the schedule of power costs charged purchasers. Extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and the Construction Fund and are not recovered from power purchasers.

	A	B	C	D	E	F	G	H	I	J
1	**BPA's 2010 Wholesale Power Rate Case**									
2	**Grant's Wanapum Allocation for 2010-2015 - Received from Grant PUD 12/22/08**									
3										
4	**Wanapum Dam, Project Owner = Grant County PUD, FERC License Expires 03/31/2052,**									
5	**Existing Purchaser Agreements Expire 10/31/2009, New Contracts Provisions become effective 11/01/09.**									
6										
7	**Grant County PUD's Allocation Amounts prepared by Michiko Sell of Grant PUD**									
8	**Wanapum**									
9	Name		**12-15 %'s**	**10-11 %'s**	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**
10	Avista Corp (WWP Division)		0.0364	0.0376	13.7	13.7	13.3	13.3	13.3	13.3
11	Clearwater Power	**	0.0011	0.0011	0.4	0.4	0.4	0.4	0.4	0.4
12	Cowlitz County PUD #1		0.0103	0.0179	6.5	6.5	3.8	3.8	3.8	3.8
13	Eugene Water & Electric Board		0.0102	0.0105	3.8	3.8	3.7	3.7	3.7	3.7
14	Fall River Electric Coop	**	0.0014	0.0014	0.5	0.5	0.5	0.5	0.5	0.5
15	Forest Grove, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
16	Grant County PUD #2		0.6347	0.6168	224.8	224.8	231.3	231.3	231.4	231.4
17	Idaho County L & P	**	0.0004	0.0004	0.1	0.1	0.1	0.1	0.1	0.1
18	Kittitas County PUD #1		0.0014	0.0014	0.5	0.5	0.5	0.5	0.5	0.5
19	Kootenai Electric Coop	**	0.0019	0.0019	0.7	0.7	0.7	0.7	0.7	0.7
20	Lost River Electric Coop	**	0.0003	0.0003	0.1	0.1	0.1	0.1	0.1	0.1
21	Lower Valley Energy	**	0.0025	0.0025	0.9	0.9	0.9	0.9	0.9	0.9
22	McMinnville, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
23	Milton-Freewater, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
24	Northern Lights	**	0.0017	0.0017	0.6	0.6	0.6	0.6	0.6	0.6
25	Pacific Power		0.0827	0.0855	31.2	31.2	30.1	30.1	30.2	30.2
26	Portland General Electric		0.0827	0.0855	31.2	31.2	30.1	30.1	30.2	30.2
27	Puget Sound Energy		0.0477	0.0493	18.0	18.0	17.4	17.4	17.4	17.4
28	Raft River Electric Coop	**	0.0004	0.0004	0.1	0.1	0.1	0.1	0.1	0.1
29	Salmon River Electric Coop	**	0.0003	0.0003	0.1	0.1	0.1	0.1	0.1	0.1
30	Seattle City Light		0.0202	0.0209	7.6	7.6	7.4	7.4	7.4	7.4
31	Tacoma Public Utilities		0.0204	0.0211	7.7	7.7	7.4	7.4	7.4	7.4
32	United Electric Coop	**	0.0007	0.0007	0.3	0.3	0.3	0.3	0.3	0.3
33	Unknown Marketer	**	0.0300	0.0300	10.9	10.9	10.9	10.9	10.9	10.9
34	**Wanapum After Encroachment**		**1.00**	**0.9998**	**364.3**	**364.3**	**364.4**	**364.4**	**364.6**	**364.7**
35										
36	COUs not Dedicated to Regional Loads and Market Purchaser Allocations - **				14.8	14.8	14.8	14.8	14.8	14.8
37	Other Power Allocations				349.5	349.5	349.6	349.6	349.8	349.8
38	TOTAL			**364.5**	364.3	364.3	364.4	364.4	364.6	364.7
39	Non-dedicated COUs and Market Purchaser Energy - Six Year Average Allocation FY2010-2015			**14.8**						
40										
41	Wanapum Allocation Percentage Shares:									
42	COUs not Dedicated to Regional Loads and Market Purchaser Allocatic				4.07%	4.07%	4.07%	4.07%	4.07%	4.07%
43	Other Power Allocations				95.93%	95.93%	95.93%	95.93%	95.93%	95.93%
44	TOTAL				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
45	Non-dedicated COUs and Market Purchaser Energy - Six Year Average Allocation Percentage FY2010-2015				**4.07%**					
46										
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Grant County
PUBLIC UTILITY DISTRICT
Excellence in Service and Leadership

2009 Priest Rapids Project

FINAL PROFORMA (NOV - DEC)

December 1, 2008

"UNOFFICIAL" PRIEST RAPIDS POWER COST FORECAST
($000)

	2009*	2010	2011	2012
O & M EXPENSES	$ 40,757	$ 43,735	$ 41,942	$ 38,413
DEBT:				
ISSUED DEBT-INTEREST	11,836	11,402	10,908	10,377
ISSUED DEBT-PRINCIPAL	10,335	10,800	11,290	11,880
FUTURE LEVELIZED DEBT	-	4,819	4,819	18,900
15% OF DS TO SUPP R&R	3,326	4,053	4,053	6,174
EXCESS FROM SUPP R&R	(3,320)	(3,326)	(4,053)	(4,053)
TOTAL PROPOSED DEBT	22,177	27,748	27,017	43,278
TOTAL TAXES	1,040	1,071	1,103	1,136
INTEREST INCOME	932	1,447	1,241	5,597
NET POWER COSTS	**$ 63,042**	**$ 71,107**	**$ 68,821**	**$ 77,230**

** - Full Year*

PRIEST RAPIDS
CONSTRUCTION FUND
($000)

	2009*	2010	2011	2012
BEGINNING BALANCE	$ 48,085	$ 23,827	$ 40,006	$ -
RECEIPTS :				
FINANCING PROCEEDS	**-**	**58,781**		**171,857**
INTEREST INCOME	719	1,226	800	5,114
TOTAL RECEIPTS	719	60,007	800	176,971
EXPENDITURES :				
GENERATOR RESTORATION	1,105	638	1,063	29,243
TURBINES	1,786	4,736	5,713	22,141
POWER HOUSE	6,266	3,648	3,369	3,472
FISH & WILDLIFE	9,431	18,792	14,251	17,148
BUILDINGS/PROP	3,746	12,754	14,328	14,573
OTHER	1,924	2,034	1,282	1,447
TOTAL PER DETAIL	24,258	42,602	40,006	88,024
TRANSFER INT TO REV FUND	(719)	(1,226)	(800)	(5,114)
ENDING BALANCE	**$ 23,827**	**$ 40,006**	**$ -**	**$ 83,833**

** - Full Year*

"UNOFFICIAL" WANAPUM POWER COST FORECAST
($000)

	2009*	2010	2011	2012
O & M EXPENSES	$ 42,763	$ 45,545	$ 44,292	$ 41,453
DEBT:				
ISSUED DEBT-INTEREST	20,587	20,046	19,472	18,851
ISSUED DEBT-PRINCIPAL	11,885	12,375	12,930	13,540
FUTURE LEVELIZED DEBT	-	12,462	12,462	26,714
15% OF DS TO SUPP R&C	4,871	6,732	6,730	8,866
EXCESS FROM SUPP R&C	(4,860)	(4,871)	(6,732)	(6,729)
TOTAL PROPOSED DEBT	32,483	46,744	44,862	61,242
TOTAL TAXES	1,019	1,050	1,081	1,113
INTEREST INCOME	1,745	3,130	2,531	5,347
NET POWER COSTS	**$ 74,520**	**$ 90,209**	**$ 87,704**	**$ 98,461**

** - Full Year*

WANAPUM
CONSTRUCTION FUND
($000)

	2009*	2010	2011	2012
BEGINNING BALANCE	$ 85,231	$ 34,279	$ 104,843	$ -
RECEIPTS :				
FINANCING PROCEEDS	-	**152,131**	-	**174,000**
INTEREST INCOME	1,195	2,913	2,097	4,870
TOTAL RECEIPTS	1,195	155,044	2,097	178,870
EXPENDITURES :				
GENERATOR RESTORATION	6,753	30,451	43,992	28,516
TURBINES	22,229	21,212	20,206	27,481
POWERHOUSE/SWITCHYARD	12,268	11,546	16,715	16,345
FISH AND WILDLIFE	3,366	3,030	8,133	15,635
BUILDINGS/PROPERTIES	3,756	12,758	14,307	14,618
OTHER	2,580	2,570	1,490	1,917
TOTAL PER DETAIL	50,952	81,567	104,843	104,512
TRANSFER FROM R&C FUND	-	-	-	-
PAID FROM THE CONST FUND	50,952	81,567	104,843	104,512
TRANSFER INT TO REV FUND	(1,195)	(2,913)	(2,097)	(4,870)
ENDING BALANCE	**$ 34,279**	**$ 104,843**	**$ -**	**$ 69,488**

** - Full Year*

6/16/2008
CONTRACT
FOR
OPEN-MARKET SALE OF PRIEST RAPIDS PROJECT POWER

INDEX TO SECTIONS

<u>Section</u> **<u>Page</u>**

Exhibits

CONTRACT
FOR
OPEN-MARKET SALE OF PRIEST RAPIDS PROJECT POWER

Executed by
PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY, WASHINGTON
And

This contract is entered into as of ____________, 2008 between Public Utility District No. 2 of Grant County, Washington (the "District"), a municipal corporation of the State of Washington, and _____________(the "Purchaser"), a ____________ corporation organized and existing under the laws of ____________________________. The District and the Purchaser are referred to as a "Party" and collectively as "Parties."

SECTION 1. TERM OF CONTRACT

Except as otherwise provided herein, this Contract shall be in full force and effect from and after it has been executed by the District and the Purchaser. Unless sooner terminated pursuant to other provisions, this Contract shall remain in effect until the end of HE 2400 (midnight) Pacific Prevailing Time "PPT", December 31, 2009. Except as otherwise provided herein, all obligations accruing under this Contract are preserved until satisfied.

SECTION 2. DEFINITIONS

As used in this Contract, the following terms when initially capitalized shall have the following meanings:

"Agreement for the Hourly Coordination of Projects on the Mid-Columbia River" (MCHC) shall mean the 1997 Agreement, as amended from time to time, with the Mid-Columbia PUD project owners, purchasers, the U.S. Department of Energy via the Bonneville Power Administration, the U.S. Department of the Army via the Army Corps of Engineers, and the U.S. Department of Interior via the Bureau of Reclamation to coordinate real time operation of the seven projects from Grand Coulee through Priest Rapids on the Columbia River.

"Bond Resolution" shall mean each and all of the resolutions adopted by the District authorizing the issuance of outstanding Debt for the Priest Rapids Project.

"Business Days" shall mean any weekday, Monday through Friday, excluding District Recognized Holidays as designated on Exhibit B of this Contract.

"Contract" shall mean this **CONTRACT FOR OPEN-MARKET SALE OF PRIEST RAPIDS PROJECT POWER**, in its' entirety.

"Defaulting Party" shall mean the Party who is responsible for an "Event of Default" as defined in Section 15.

"Electric System" shall mean the separate electric utility system of the District, including all associated generation, transmission and distribution facilities and any betterments, renewals, replacements and additions of such system, but does not include the Priest Rapids Project or any other utility properties designated as a separate utility system of the District.

"FERC" shall mean the Federal Energy Regulatory Commission or its successor.

"FERC License" shall mean the license for the Priest Rapids Project PL 2114 issued by FERC on_April 17, 2008, effective April 1, 2008.

"Guarantor" means the entity providing a guarantee pursuant to a Guarantee Agreement.

"HE" shall mean hour ending.

"Operating Agreements" shall mean any agreements to which the District is or may become a party, which provide for operation of the Priest Rapids Project, including but not limited to, the Pacific Northwest Coordination Agreement, the Agreement for the Hourly Coordination of Projects on the Mid-Columbia River, the Western Systems Coordinating Council Agreement, and the Northwest Power Pool Agreement, as such agreements currently exist or hereafter may be amended.

"Original FERC License" shall mean the Federal Power Commission License for the Priest Rapids Project issued to the District on November 4, 1955, together with amendments thereto.

"Pacific Northwest" shall have the meaning ascribed thereto in Section 3(14) of the Regional Act.

"Pacific Northwest Coordination Agreement" or "PNCA" shall mean the Agreement amongst northwest parties executed in 1997 for the coordinated operation of the Columbia River System which became effective August 1, 2003, as such Agreement may be amended from time to time.

"Pre-Schedule Day" shall mean days identified by the District pursuant to the Western Electricity Coordinating Council Interchange Scheduling and Accounting Subcommittee daily scheduling calendar.

"Priest Rapids Development" shall mean the separate utility system of the District, including a dam at the Priest Rapids Development, all generation and transmission facilities associated therewith, and all betterments, renewals, replacements, and additions to such system, as further described in Section 2(f) of Exhibit 1 of District Resolution No. 390 which is attached as Exhibit A, but shall not include any additional generation, transmission and distribution facilities hereafter constructed or acquired by the District as a part of the Electric System or the Wanapum Development or any other utility properties of the District acquired or constructed as a separate utility system.

"Priest Rapids Project Output" or "PRPO" shall mean: i.) the amount of capacity, energy (both firm and non-firm), pondage, reactive power, ancillary services and any other product produced by the Priest Rapids Development between the start of HE 0100 P.P.T. January 1, 2009 and the end of HE 2400 (midnight) P.P.T. December 31, 2009, after correction for encroachment, Canadian entitlement, station and project use, and depletions required by the FERC License or other regulatory requirements, together with ii.) the amount of capacity, energy (both firm and non-firm), pondage, reactive power, ancillary services and any other product produced by the Wanapum Development between the start of HE 0100 P.P.T November 1, 2009 and the end of HE 2400 (midnight) P.P.T. December 31, 2009, after correction for encroachment, Canadian entitlement, station and project use, and depletions required by the FERC License or other regulatory requirements

"Priest Rapids Project" shall mean the hydroelectric project on the Columbia River in the State of Washington designated by the Federal Power Commission as Project No. 2114. The Priest Rapids Project consists of the Priest Rapids Development and the Wanapum Development.

"Prudent Utility Practice" means those practices, methods and acts which: (i) when engaged in are commonly used in prudent engineering and operations to operate electric equipment and associated mechanical and civil facilities lawfully and with safety, reliability, efficiency and expedition or (ii) in the exercise of reasonable judgment considering the facts known when engaged in, could have been reasonably expected to achieve the desired result consistent with applicable law, safety, reliability, efficiency and expedition. Prudent Utility Practice is not intended to be the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of commonly used practices, methods or acts.

"Regional Act" shall mean Public Law 96-501, the Pacific Northwest Electric Power Planning and Conservation Act.

"Uncontrollable Forces" shall mean any cause reasonably beyond the control of the Party and which the Party subject thereto has made reasonable efforts to avoid, remove or mitigate, including but not limited to acts of God, fire, flood, explosion, strike, sabotage, acts of terrorism, act of the public enemy, civil or military authority, including court orders, injunctions, and orders of government agencies (other than those of the District) with proper jurisdiction, insurrection or riot, an act of the elements, failure of equipment or contractors, or inability to obtain or ship materials or equipment because of the affect of similar causes on suppliers or carriers; provided, however, that in no event shall an Uncontrollable Force excuse the Purchaser from the obligation to pay any amount when due and owing under this contract.

"Wanapum Development" shall mean the second stage of the Priest Rapids Project as more fully described in Section 2.2 of District Resolution No. 474, which is attached as Exhibit A, but shall not include any generation, transmission and distribution facilities hereafter constructed or acquired by the District as a part of the Electric System or the Priest Rapids Development, or any other utility properties of the District acquired or constructed as a separate utility system.

The following terms are defined in the cited sections of this Contract:

"Event of Default" at Section 15(a)

"Party" and "Parties" at the Preamble
"Purchaser Allocation of Pondage" at Section 6(d)(4)
"Purchaser's PRPO" at Section 3(a)

SECTION 3. PURCHASE AND SALE OF PRIEST RAPIDS PROJECT OUTPUT/REGULATORY APPROVAL

(a) Purchaser's PRPO. The District shall make available to the Purchaser and the Purchaser shall purchase an amount of PRPO equal to the total applicable PRPO multiplied by the corresponding Purchaser's PRPO Percentage which amount is herein referred to as "Purchaser's PRPO."

(b) The Purchaser's PRPO Percentage shall be _____ % of Priest Rapids Development power for the period starting at (midnight) HE 2400, December 31, 2008 and ending at HE 2400, October 31, 2009 AND ____% of Priest Rapids Project power for the period starting at HE 2400, October 31, 2009 and ending at (midnight) HE 2400, December 31, 2009.

SECTION 4. PRPO AVAILABILITY

(a) Purchaser understands and acknowledges that PRPO availability will fluctuate and is subject to and contingent upon many factors including, but not limited to, the following: weather and precipitation levels, regulatory and environmental considerations and requirements, Operating Agreements and Uncontrollable Forces.

(b) The District may restrict deliveries of PRPO if it determines that such action is necessary to avoid exceeding the capability of the Priest Rapids Project or subjecting it or its operation to undue hazard or violating the FERC License, any applicable law, regulation, or Operating Agreement. Any such restrictions in delivery by the District shall be made pro-rata with all purchasers of PRPO and with the District's share of PRPO.

(c) The District may also restrict deliveries of PRPO in case of emergencies or in order to install equipment in, make repairs to, make betterments, renewals, replacements, and additions to, investigations and inspections of, or perform other maintenance work on the Priest Rapids Project. Any such restrictions in delivery shall be made pro-rata with all purchasers of PRPO and with the District's share of PRPO.

(d) The District will use commercially reasonable efforts to give advance notice to the Purchaser regarding any planned limit, restriction, interruption or reduction of PRPO, giving the reason therefore and stating the probable duration thereof, and shall provide timely updates concerning the same should conditions change.

(e) Notwithstanding any other provision of this Contract, the District shall at times have the right to operate the Priest Rapids Project in such manner as it deems to be in its best interests so long as the same is consistent with the FERC License, applicable laws and regulations, Prudent Utility Practice and this Contract.

(f) Notwithstanding any other provision of this Contract, the District shall have the unilateral right to restrict deliveries of PRPO as may be necessary to fulfill any non-power regulatory or other legal requirements and shall have the unilateral right to determine the amounts of spill required at the Priest Rapids Project. Any such restrictions in delivery shall be made pro-rata with all purchasers of PRPO and with the District's share of PRPO.

SECTION 5. PURCHASE PRICE AND PAYMENTS BY PURCHASER

(a) The purchase price for the Purchaser's PRPO shall be the total dollar amount submitted by Purchaser on its bid form. Purchaser shall make 12 equal monthly payments of 1/12th of the purchase price with the first such payment due January 10, 2009.

(b) The monthly payments set forth above shall be due and payable by electronic funds transfer to the District's account, designated in writing by the District, on the 10th (tenth) calendar day of each month. If the 10th calendar day of the month is a Saturday, Sunday or a District Recognized Holiday as listed in Exhibit B, the next following Business Day

(c) If payment in full of any monthly payment amount set forth on a statement or revised statement is not received by the District on or before the close of business on the 10th calendar day of the month, a delayed payment charge of 2% of the unpaid amount due will be made. Any bill which remains unpaid for more than 30 calendar days after the due date shall, in addition to the delayed payment charge, accrue interest at the lesser of 1.5% per month or the maximum rate allowed by law. If the 10th calendar day of the month is a Saturday, Sunday or a District Recognized Holiday as listed in Exhibit B, the next following Business Day shall be the last day on which payment may be received without the addition of the delayed-payment charge. Additionally, if payment due to the District under this Section 5 remains unpaid 3 Business Days after the due date, the District may thereafter suspend delivery of the Purchaser's PRPO until payment in full of all amounts due and owing (including any interest and delay charges) is received by the District.

(d) The payments required under this Section 5 shall be due and owing notwithstanding the fact that the actual amount of power from the PRPO Percentage made available to the Purchaser is less or more than that which was anticipated by either Party at the time of execution of this Contract. The District makes no warranties of any type as to the PRPO that will actually be produced and available, other than, that the percentage of PRPO made available to the Purchaser will at all times be in accordance with Section 3(c), and Purchaser assumes all risks associated therewith.

(e) The purchase price submitted by the Purchaser on its bid form is the total price for the Purchaser's PRPO and all rights associated with it. Except as otherwise provided in Sections 6(c) and 18 (c), the Purchaser shall not be obligated to pay any other amounts charged to or payable by the Purchaser as a result of this Contract, including any water fees, license fees, penalties, taxes, operating, administration, maintenance or capital costs, damages or any other costs whatsoever, relating to ownership or operation of the Priest Rapids Project.

SECTION 6. SCHEDULING OF DELIVERIES OF PRIEST RAPIDS PROJECT OUTPUT

(a) This Section 6 shall apply to the scheduling of the Purchaser's PRPO.

(b) Scheduling of Purchaser's PRPO shall be as requested by the Purchaser, or its designated scheduling agent, and shall be subject to the limitations set forth in this Contract.

(c) The Purchaser, or its designated scheduling agent, shall provide the District each Pre-Schedule Day, in conformance with then prevailing scheduling procedures for scheduling Pacific Northwest generating resources, hourly schedules of desired Purchaser's PRPO deliveries for the following day or days. The schedules will be completed in a time frame consistent with standard industry practices in the Pacific Northwest. Such schedule shall be based upon the probable water supply to the Priest Rapids Project (inflows) and the resulting probable output. Schedules shall be in compliance with all applicable reliability and reserves criteria as put forth by the North American Electric Reliability Council, Western Electricity Coordinating Council, and the Northwest Power Pool; as such criteria are revised from time to time. If failure to comply with reliability or reserve criteria results in costs or fees incurred by the District, Purchaser shall reimburse District for all such costs or fees. Revisions in a schedule may be made at any time upon the request of the Purchaser in accordance with Section 6(d)(9). The District will use reasonable efforts to minimize deviations from the schedule and make corrections promptly as practicable on an hourly basis under conditions as nearly equivalent as practicable to those occurring when the deviations occurred. Alternatively, the Purchaser may provide scheduling information via a dynamic electronic signal. If the Purchaser chooses this option, it shall be solely responsible for providing any and all necessary hardware or software modifications necessary for the District to incorporate this signal.

(d) Purchaser's schedules shall be in accordance with the following:

(1) Subject to the provisions of this Contract, the District shall make available to Purchaser, each hour, Purchaser's PRPO.

(2) The District shall make all determinations concerning the Priest Rapids Project maximum output and minimum discharge; and the District shall have the unilateral right to determine the maximum allowable amount of change in PRPO during any time period and the maximum number of unit starts and stops allowable during any time period. Purchaser's daily and hourly schedules shall be based on Purchaser's PRPO in accordance with the Priest Rapids Project operational parameters as established by the District from time to time.

(3) Purchaser's schedule shall not be less than Purchaser's PRPO Percentage of the minimum operating capability of the Priest Rapids Project, as determined by the District, nor shall it be greater than Purchaser's PRPO Percentage of the maximum operating capability of the Priest Rapids Project as determined by the District.

(4) Purchaser shall be entitled to utilize a share of the pondage available at the Priest Rapids Project (the "Purchaser Allocation of Pondage"), determined by multiplying the total of the pondage available by the applicable Purchaser's PRPO Percentage. The pondage available at the Priest Rapids Project shall be determined by the District from time to time on the basis of the volume of water that can be stored between the then current maximum forebay elevation and the then current minimum forebay elevation.

(5) The District will establish and maintain for Purchaser a pondage account that will reflect the use of pondage by the Purchaser. On the last hour of the term of this Contract, the Purchaser shall return the pond account balance to at least where it was on the first hour of the term of this Contract. The Purchaser may schedule more than its share of the Priest Rapids Project inflows determined in accordance with Section 6(c) if the Purchaser has sufficient amount of energy in its pond account. The amount of the energy scheduled from the pondage account shall not exceed the Purchaser Allocation of Pondage determined in accordance with Section 6(d)(4).

(6) During any hour that spill is occurring at non-federal Mid-C Projects in order to control forebay elevation, the spill is allocated in the following manner: i) if spill is due to unloaded turbines at the spilling project, that spill will be allocated to any Mid-C participant whose generation was less than their capacity during the spill hour, ii) Spill past loaded units are allocated to each Mid-C party who has a share in the spilling project.

(7) During any hour that spill is occurring at the Priest Rapids Project for fish or any other non-power purpose determined necessary or desirable by the District, the spill shall be allocated to reduce the inflow of Purchaser and other PRPO purchasers in proportion to their percentage shares of PRPO, including the District.

(8) If the Purchaser chooses not to provide scheduling information via a dynamic electronic signal, the District will provide the following maximum number of schedules or paths available to schedule Purchaser's PRPO on an hourly basis according to the following formula: the amount of daily capacity available to the Purchaser, divided by 15 (rounded up), plus 1.

(9) In the absence of dynamic scheduling pursuant to Section 6 (c) real-time schedules shall be called in at least 30 minutes prior to the start of each hour.

SECTION 7. POINT OF DELIVERY

(a) PRPO power supplied hereunder shall be approximately 230 kV, three-phase, alternating current, at approximately 60 hertz.

(b) The PRPO power to be delivered hereunder shall be made available to the Purchaser, at its option, exercisable from time to time, at any one or more of the following points:

(1) The 230 kV bus of the Bonneville Power Administration's Midway Substation;

(2) The 230 kV bus of the switchyard of the Wanapum Development;

(3) The 230 kV bus of the Vantage Substation; or

(4) At any other location mutually agreed to by the District and Purchaser.

SECTION 8. METERING AND TRANSMISSION LOSSES

(a) The District shall provide and maintain suitable meters in the generator leads of the Priest Rapids Project to indicate and record the PRPO. The actual PRPO shall be determined from totaled readings from the meters. The District or an agent of the District shall read meters and records thereof shall be made available to the Purchaser as may be reasonably requested.

(b) Purchaser shall be required to schedule an amount of energy equal to the actual losses resulting from transformation and transmission to the District.

SECTION 9. INFORMATION TO BE MADE AVAILABLE TO THE PURCHASER

(a) The Purchaser, upon at least 30 days advance written notice to the District, shall have the right at its sole cost and expense to audit or examine operating records relating to the Priest Rapids Project during the District's normal business hours. All costs incurred by the District associated with such audit, including, but not limited to, District labor, materials and reproduction services shall be promptly reimbursed to the District by the Purchaser.

(b) The Purchaser's representatives shall at all times be given reasonable access to the Priest Rapids Project, subject to the District's applicable safety rules and regulations.

(c) The District shall exercise commercially reasonable efforts to provide to the Purchaser estimates and information reasonably necessary for the Purchaser to exercise its rights under this Contract.

SECTION 10. LIABILITY OF PARTIES

(a) Except as otherwise provided in this Contract, each Party hereby releases the other Party and its commissioners, officers, directors, agents and employees from any claim for loss or damage arising out of the ownership, operation, and maintenance of the Priest Rapids Project including any loss of profits or revenues, loss of use of power system, cost of capital, cost of purchased or replacement power, other substantially similar liability or other direct or indirect consequential loss or damage.

(b) The Purchaser shall have no claim of any type or right of action against the District: (i) as a result of a FERC or court order or amendment; (ii) as a result of adjustment of PRPO, and the Purchaser hereby releases the District and its commissioners, officers, agents and employees from any claim for loss or damage arising out of the events described in this paragraph.

(c) The Purchaser is purchasing output from or attributable to the Priest Rapids Project as available and scheduled by the Purchaser. The Purchaser acquires no interest in or rights to any facilities forming part of the Priest Rapids Project.

SECTION 11. NOTICES AND COMPUTATION OF TIME

(a) Any notice, demand or request provided for in this Contract shall be, unless otherwise specified herein, in writing and may be delivered by hand delivery, United States mail, overnight courier or facsimile. Notice by courier, facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a regular Business Day of the District, and otherwise shall be effective on the close of business on the next regular Business Day of the District. All notices by United States mail shall be sent certified, return receipt requested and shall be effective on the date of actual receipt by the recipient.

All notice, demand or request made by mail shall be mailed postage prepaid and addressed to:

Manager
Public Utility District No. 2 of Grant County
P.O. Box 878
30 C St S.W.
Ephrata, Washington 98823;

any notice or demand by the District to the Purchaser under this Contract shall be deemed properly given if a written copy is delivered to the Purchaser's representative specified herein by courier and the Purchaser's signature evidencing receipt thereof is obtained or if mailed postage prepaid and addressed to:

.

(b) In computing any period of time from such notice, such period shall commence at HE 2400 (midnight) PPT on the date mailed. The designations of the name and address to which any such notice or demand is directed may be changed at any time by either Party giving notice as provided above.

SECTION 12. DISTRICT'S BOND RESOLUTIONS AND LICENSE

It is recognized by the Parties that the District, in its operation of the Priest Rapids Project, must comply with the requirements of the Bond Resolution and with the FERC License together with amendments thereof from time to time made, and the District is hereby authorized to take such actions as the District determines are necessary and appropriate to comply with such Bond Resolutions and FERC License**.**

SECTION 13. GOVERNING LAW.

The Parties agree that the laws of the State of Washington shall govern this Contract.

SECTION 14. ASSIGNMENT OF CONTRACT

Neither the Purchaser nor the District shall by contract, operation of law or otherwise, assign this Contract or any right or interest in this Contract without the prior written consent of the other Party, which shall not be unreasonably withheld; provided, however, a Party may, without the consent of the other Party (and without relieving itself from liability hereunder) (i) transfer or assign this Contract to an affiliate of the Party provided that the affiliate's creditworthiness is equal or higher than that of the Party or (ii) transfer or assign this Contract to any person or entity succeeding to all or substantially all of the distribution and generating facilities of the Party whose creditworthiness is equal or higher than that of the Party; provided however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions in this Contract and the transferring Party shall deliver such tax and enforceability assurance as the other Party may reasonably request.

SECTION 15. REMEDIES ON DEFAULT

(a) An "Event of Default" shall mean with respect to a Party ("Defaulting Party"):

(1) the failure by the Defaulting Party to make, when due, any payment required pursuant to this Contract if such failure is not remedied within three (3) Business Days after written notice of such failure is given to the Defaulting Party by the other Party ("the Non-Defaulting Party"). The Non-Defaulting Party shall provide the notice by facsimile to the designated contact person for the Defaulting Party and also shall send the notice by overnight delivery to such contact person; or

(2) the failure by the District to deliver PRPO to the Purchaser as required by this Contract and such failure is not cured within three (3) Business Days after written notice thereof from the Purchaser to the District; or

(3) the failure by the Defaulting Party to have made accurate representations and warranties as required this Contract and such failure is not cured within three (3) Business Days after written notice thereof to the Defaulting Party; or

(4) the institution, with respect to the Defaulting Party, by the Defaulting Party or by another person or entity of a bankruptcy, reorganization, moratorium, liquidation or similar insolvency proceeding or other relief under any bankruptcy or insolvency law affecting creditor's rights or a petition is presented or instituted for its winding-up or liquidation; or

(5) the failure by the Defaulting Party to provide adequate assurances of its ability to perform all of its outstanding material obligations to the Non-Defaulting Party under this Contract.

(6) With respect to its Guarantor, if any:

(i) if a material representation or warranty made by a Guarantor in connection with this Contract, or any transaction entered into hereunder, is false or misleading in any material respect when made or when deemed made or repeated; or

(ii) the failure of a Guarantor to make any payment required or to perform any other material covenant or obligation in any guarantee made in connection with this Contract, including any transaction entered into hereunder, and such failure shall not be remedied within three (3) Business Days after written notice; or

(iii) the institution, with respect to the Guarantor, by the Guarantor or by another person or entity of a bankruptcy, reorganization, moratorium, liquidation or similar insolvency proceeding or other relief under any bankruptcy or insolvency law affecting creditor's rights or a petition is presented or instituted for its winding-up or liquidation; or

(iv) the failure, without written consent of the other Party, of a Guarantor's guarantee to be in full force and effect for purposes of this Contract (other than in accordance with its terms) prior to the satisfaction of all obligations of such Party under each transaction to which such guarantee shall relate; or

(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of, any guarantee.

(b) If an Event of Default occurs, the Non-Defaulting Party shall possess the right to terminate the Contract or seek specific performance. In the event the Non-Defaulting Party elects to terminate the Contract, it may pursue any legal or equitable remedies available at law or otherwise.

SECTION 16. CREDITWORTHINESS

Should the Purchaser's creditworthiness, financial responsibility, or performance viability be unsatisfactory to the District in the District's reasonably exercised discretion with regard to this Contract, the District may require the Purchaser to provide, at the Purchaser's option (but subject to the District's acceptance based upon reasonably exercised discretion), either (1) the posting of a letter of credit, (2) a cash prepayment, (3) the posting of other acceptable collateral or security by the Purchaser, (4) a guaranty agreement executed by a creditworthy entity; or (5) some other mutually agreeable method of satisfying the District.

All collateral posted in the form of cash or cash prepayment will be held in an interest bearing escrow account. In the event the collateral is no longer required to satisfy Purchaser's obligations, it will be returned to the Purchaser, with interest earned, on a tiered basis near the end of the term of this Contract. For each fiscal year beginning April 1 and ending March 31, deposits will earn interest calculated at the rate for the one-year Treasury Constant Maturity calculated by the U.S. Treasury, as published in the Federal Reserves Statistical Release H.15 on March 15 of each year. If March 15 falls on a non-Business Day, the District will use the rate posted on the next Business Day. The one-year Treasury Constant Maturity rate on March 15 of each year will be applied to the next fiscal year beginning April 1 and ending March 31.

Events which may trigger the District requesting assurance due to reasonable concern about the Purchaser's creditworthiness, financial responsibility, or performance viability include, but are not limited to, the following:

(a) The Purchaser or its Guarantor has debt which is rated as investment grade and that debt falls below the investment grade rating by at least one rating agency or is below investment grade and the rating of that debt is downgraded further by at least one rating agency.

(b) Other material adverse changes in the Purchaser's financial condition occur.

(c) Substantial changes in market prices which materially and adversely impact the Purchaser's ability to perform under this Contract occur.

If the Purchaser fails to provide such reasonably satisfactory assurances of its ability to perform an obligation hereunder within three (3) Business Days of demand therefore, that will be considered an Event of Default under Section 15 of this Contract and the District shall have the right to exercise any of the remedies provided for under that Section 15. Nothing contained in this Section 16 shall affect any credit agreement or arrangement, if any, between the Parties.

SECTION 17. VENUE AND ATTORNEY FEES

Venue of any action filed to enforce or interpret the provisions of this Contract shall be exclusively in the United States District Court for the Eastern District of Washington or the Superior Court of the State of Washington for Grant County and the Parties irrevocably submit to the jurisdiction of any such court. In the event of litigation to enforce the provisions of this Contract, the prevailing Party shall be entitled to reasonable attorney's fees in addition to any other relief allowed.

SECTION 18. COMPLIANCE WITH LAW

(a) The Parties understand and acknowledge that operation of the Priest Rapids Project must conform to and comply with all applicable laws, rules, regulations, license conditions or restrictions promulgated by the FERC, the State of Washington or any other governmental agency or entity having jurisdiction over the Priest Rapids Project. The Purchaser shall cooperate and take whatever action is necessary to cooperate fully with the District in meeting such requirements. Obligations of the District contained in this Contract are hereby expressly made subordinate and subject to such compliance.

(b) RCW 54.16.040 contains provisions relating to the District's sale of electric energy. The Parties understand and acknowledge that the District must comply with RCW 54.16.040 to the extent applicable to this Contract and the District's obligations and performance of this Contract are hereby expressly made subordinate and subject to such compliance.

(c) The Purchaser shall ensure that PRPO available to Purchaser under this Contract is not sold, resold, distributed for use or used outside the Pacific Northwest in violation of the Bonneville Project Act, Public Law 75-329, the Pacific Northwest Consumer Power Preference Act, Public Law 88-552, the Regional Act or in contravention of any applicable state or federal law, order, regulation, or policy. If such sales occur in violation of the foregoing, the Purchaser shall reimburse the District for any penalties imposed on and costs incurred by the District as a consequence of such violation. Attached hereto as Exhibit C is a letter from the Bonneville Power Administration regarding this subject.

SECTION 19. HEADINGS

The headings of sections and paragraphs of this Contract are for convenience of reference only and are not intended to restrict, affect or be of any weight in the interpretation or construction of the provisions of such sections and paragraphs.

SECTION 20. ENTIRE AGREEMENT; MODIFICATION; CONFLICT IN PRECEDENCE

This Contract constitutes the entire agreement between the Parties with respect to the subject matter of this Contract, and supersedes all previous communications between the Parties, either verbal or written, with respect to such subject matter. No modifications of this Contract shall be binding upon the Parties unless such modifications are in writing signed by each Party.

SECTION 21. NO PARTNERSHIP OR THIRD PARTY RIGHTS

(a) This Contract shall not be interpreted or construed to create an association, joint venture or partnership between the Parties, or to impose any partnership obligations or liability upon any Party.

(b) This Contract shall not be construed to create rights in or grant remedies to any third party as a beneficiary of this Contract.

SECTION 22. REPRESENTATIONS AND WARRANTIES

Each Party represents and warrants to the other Party that:

(a) It is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation.

(b) The execution, delivery and performance of this Contract are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, or order applicable to it.

(c) This Contract constitutes a legally valid and binding obligation enforceable against it in accordance with its terms, subject to equitable defenses and applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally.

SECTION 23. OPTIONAL AGREEMENT AVAILABLE TO PURCHASER

(a) The Purchaser shall have the option of becoming a joinder to the "1997 Agreement for the Hourly Coordination of Projects on the Mid-Columbia River", pursuant to Section 9(a) of that Agreement.

PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY, WASHINGTON

By: ________________________________

(SEAL) President

ATTEST:

Secretary

By: ________________________________

(SEAL) Title:

ATTEST:

Secretary

EXHIBIT A

DEFINITION OF PRIEST RAPIDS PROJECT

RESOLUTION NO. 390 – DEFINITION OF PRIEST RAPIDS DEVELOPMENT

Section 2(f) of Exhibit 1. "Priest Rapids Development" shall mean those properties and facilities consisting of the Priest Rapids dam, site, reservoir, switchyard and power plant, including all generating facilities associated therewith up to and including the first ten (10) main turbine generator units each with a nameplate rating of approximately 78,850 kilowatts and any additional generating facilities which may be installed as provided for in Section 19 of the Original Power Sales Contract, together with the associated transmission facilities consisting of two 230 KV transmission lines and terminal facilities interconnecting the Priest Rapids switchyard and the Bonneville Power Administration's Midway Substation and an undivided one-half (1/2) interest in the interconnecting facilities between the Priest Rapids switchyard and the Wanapum switchyard.

RESOLUTION NO. 474 - DEFINITION OF WANAPUM DEVELOPMENT

Section 2.2. The District specifies and adopts the plan and system hereinafter set forth for the acquisition, by purchase or condemnation, and construction of the following generation and transmission facilities as a separate utility system of the District constituting the Wanapum Development of the District, to wit:

A. The District shall constrict an electric generating plant and associated facilities on the Columbia River at approximately river mile 415 from the mouth of said river at the Wanapum site on said river, in Grant and Kittitas Counties, Washington, as authorized by the Federal Power Commission License for Project No. 2114, originally issued November 4, 1955, and all amendments thereto; said generating plant to have an installed nameplate rating of approximately 831,250 kilowatts, and said generating plant and associated facilities to include, but not limited to, a concrete gravity dam, a fully enclosed reinforced concrete powerhouse containing ten (10) turbo-generating units with provisions in the intake structure for the installation of six (6) additional turbo-generating units, a reservoir, waterways, fish ladders and other fish protective devices; provisions for future installation of navigation locks; transforming facilities; a switchyard; transmission facilities necessary to connect the powerhouse to the existing transmission facilities of the Priest Rapids Development and to the transmission facilities of the Bonneville Power Administration in the vicinity of said Project; railroad siding, shops, warehouses,

EXHIBIT B

DISTRICT RECOGNIZED HOLIDAYS

HOLIDAY	ACTUAL DATE	DATE OBSERVED
New Year's Day	Thursday, January 1, 2009	Thursday, January 1, 2009
President's Day	Monday, February 16, 2009 (3rd Monday in February)	Monday, February 16, 2009 (3rd Monday in February)
Memorial Day	Monday, May 25, 2009 (Last Monday in May)	Monday, May 25, 2009 (Last Monday in May)
Independence Day	Saturday, July 4, 2009	Friday, July 3, 2009
Labor Day	Monday, September 7, 2009 (1st Monday in September)	Monday, September 7, 2009 (1st Monday in September)
Veterans Day	Wednesday, November 11, 2009	Wednesday, November 11, 2009
Thanksgiving Day	Thursday, November 26, 2009 (4th Thurs. in November)	Thursday, November 26, 2009 (4th Thurs. in November)
Christmas Day	Friday, December 25, 2009	Friday, December 25, 2009

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER BUSINESS LINE

August 9, 2006

In reply refer to: PS-6

Mr. Tim Culbertson, General Manager
Public Utility District No. 2 of Grant County
P.O. Box 878
Ephrata, WA 98823

Dear Mr. Culbertson:

The Bonneville Power Administration (BPA) and Grant County Public Utility District No. 1 (Grant) met on July 26, 2006 to discuss Grant's pending Priest Rapids Development Project market based auction. Grant is preparing for its 2006 Power Auction of the Priest Rapids Project output as a pricing mechanism for the 30 percent Reasonable Portion product sold to Pub. L. 544 parties. The open market auction process is a fairly new mechanism for a utility to make power sales in the region and is Grant's choice for implementing the Federal Energy Regulatory Commission (FERC) order regarding the reasonable portion requirement of Pub. L. 544 in Kootenai Electric Coop. Inc. et al v. Public Utility District No. 2, 82 FERC ¶ 61,112, affirmed in Kootenai Electric Cooperative Inc. v. Federal Energy Regulatory Commission, 192 F.3d 144 (D.C. Cir. 1999). Grant conducted a prior auction which resulted in a sale of Project power to Constellation Energy, Inc. As we discussed at our July 26th meeting, we both would like to ensure compliance of Grant's auction sales with the application of BPA statutes and policy regarding the sale of customer-owned hydroelectric resources under Section 3(d) of Pub. L. 88-552, the Pacific Northwest Consumer Power Preference Act, and section 9(c) of Pub. L. 96-501, the Pacific Northwest Electric Power Planning and Conservation Act. Therefore, BPA wishes to address its understanding reached after our discussion on July 26th as to treatment of these sales and Grant's 2005 auction sale to Constellation.

BPA's Policy on Determining Net Requirements of the Pacific Northwest Utility Customers under Sections 5(b)(1) and 9(c) of the Northwest Power Act (May 2000) addresses the extra-regional sale of regional resources, including output from hydroelectric resources such as the Priest Rapids Project. It is understood by BPA that, based on the above mentioned FERC order, Grant has no right to the power from the Project that is represented by the 30 percent Reasonable Portion and is required to offer this power to participating parties. We also understand that the power offered is part of the Reasonable Portion and is used to set a price for the entire Reasonable Portion sale. As seller, and in order to comply with both the FERC order and BPA's policy and statutes, you have included in your contracts for the sale of this power a provision which states: "The purchaser shall ensure that Priest Rapids Development Output available to Purchaser under this contract is not sold, resold, distributed for use or used outside the Pacific Northwest in violation of the Bonneville Project Act, Public Law 75-329, the Pacific Northwest

Consumer Power Preference Act, Public Law 88-552, the Regional Act or in contravention of any applicable state or Federal law, order regulation or policy." While that provision is a good first step, it does not address the practical consideration of reporting resale information by the purchaser and does not in all instances identify what actions BPA may be required to take under its statutes.

To clarify our mutual responsibilities regarding Grant's auction sales we discussed and agreed upon the following compliance protocol:

1. Grant will continue to include in its open market auction contracts a provision that requires compliance by the purchaser with BPA's policy and statutes governing the sale of non-Federal power, substantially in the form noted above. In the event of resale in violation of that provision, BPA would have recourse against Grant by reduction of BPA's firm power sale (decrement) consistent with BPA's statutes and policy.

2. As the seller, Grant remains responsible for the in-region use of the power when the sale at auction is made to a purchaser that is an entity that does not have a Northwest Power Act section 5(b) contract with BPA, or that does not directly serve retail consumer load in the Region. Grant is responsible for demonstrating the purchaser resold the power to a Northwest load serving investor-owned utility, public or cooperative utility, or direct service industry (DSI) customer with a section 5(b) or 5(d) contract that has a planned load in excess of its planned generation. Customers holding a 5(b) or 5(d) contract, other than those that receive all of their firm power supply from BPA, are assumed to have a planned load in excess of their planned generation.

3. As long as the purchaser's monthly sales of power to the BPA customers identified in 2 above meets or exceeds the amount of firm power bought at auction and delivered for the month, then BPA will consider the resale as used in the Region. Grant will monitor such sales by the purchaser by keeping monthly records of tags, commercial arrangement documents, or FERC website hourly data files, whichever is appropriate. If requested by BPA, Grant will provide this information to BPA 15 days after the end of a month. In the event that such resale by the purchaser does not equal the amount of power purchased at auction in the month, BPA may impose a decrement on its firm power sales in subsequent months to Grant equal to the difference. Grant may have a contractual recourse against the purchaser.

4. If the sale at auction is to the BPA customers identified in 2 above, then BPA will consider the power sold at auction used for load in the Region.

Constellation Sale

BPA's statutes and 9(c) policy require BPA to make certain determinations regarding the effect of potential sales of power outside the region of non-Federal power resources, or exports upon its firm power requirements obligations to provide service to its customers. BPA is only allowed to replace such power exported with Federal power that is otherwise surplus to BPA's firm power obligations. These determinations are factually based and can result in BPA reducing or decrementing its firm power obligations to the seller. In response to BPA's April 27, 2006, letter to Grant, Grant has supplied BPA data files that show certain sales made at the Mid-Columbia Hub by Constellation, the 2005 purchaser of power auctioned by Grant as the 6 percent Priest Rapids Project output. These files demonstrate Constellation has sold the 2005 auction power to several Northwest load serving utilities, or cooperatives that have 5(b) or 5(d) contracts. Further, for the period of this 2005 auction, BPA's regional planning document, the Whitebook, as updated, showed both BPA and the region in a surplus power condition having firm resources that exceed firm loads for that planning year (2005). Therefore, BPA finds that Grant's sale to Constellation and Constellation's resale of power from the 2005 auction complies with BPA's 9(c) policy. BPA finds no need to decrement or reduce Grant's block purchase from BPA and Grant will not be decremented.

Thank you for taking the time to meet with us and establishing the compliance protocol we have both agreed to, as described above. I wish you success on your upcoming auction and appreciate your patience in resolving this issue.

Sincerely,

/s/ Mark Gendron

Mark Gendron
Vice President
Requirements Marketing

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APPENDIX D

BPA Programmatic Conservation Resources

Documentation of Annual Savings Amounts
AND
Costs of Conservation Resources

Documentation of Acquisition Costs
Annual Amounts Expensed and Amounts Capitalized

Section 7(b)(2) Rate Test Study and Documentation

WP-10 Final Rate Proposal

WP-10-FS-BPA-06A

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BPA's 2010 Wholesale Power Rate Case

BPA Programmatic Conservation - Historical Savings and Expenditures FYs 1982-2007 - Total Gross Amounts

ConMod, C&RD, and Market Transformation aMW Savings and Expenditures Before Adjustments

($ 000)

	A	B	C	D	E	F	G	I	J	L	M
6											(C)
7							(A)	BPA Bonds Issued		(B)	(A) + (B)
8								($ 000,000)			Total
9–11		Conser. Savings aMW[2,]	Amount Revenue Expensed[3,]	Amount Debt Financed[4]	Annual Expenditures[3]	Amort. Period Years	BPA Annual Conservation Capitalized[4]	Bond Principal Amount[5]	Bond Term	Third-Party Financed Conser.[6]	Capitalized/ Debt Financed Conservation[7]
12											
13	1982 Conservation	32.4	$4,974	$61,940	$66,914	20	$61,940	$0		$0	$61,940
14	1983 Conservation	66.6	2,907	204,092	206,999	20	204,092	140.0	20	0	204,092
15	1984 Conservation	17.2	8,311	66,783	75,094	20	66,783	150.0	20	0	66,783
16	1985 Conservation	17.9	24,680	103,067	127,747	20	103,067	50.0	5	0	103,067
17	1986 Conservation	24.3	5,256	99,743	104,999	20	97,618	50.0	10	2,125	99,743
18								50.0	5		0
19	1987 Conservation	18.3	3,928	71,631	75,559	20	67,381	75.0	20	4,250	71,631
20								50.0	5		0
21	1988 Conservation	17.0	8,535	58,570	67,105	20	54,320	90.0	20	4,250	58,570
22	1989 Conservation	20.8	17,643	46,069	63,712	20	41,819	40.0	20	4,250	46,069
23	1990 Conservation	13.1	41,859	36,220	78,079	20	34,095			2,125	36,220
24	1991 Conservation	19.1	43,811	45,714	89,525	20	45,714			0	45,714
25	1992 Conservation	37.5	68,496	62,151	130,647	20	62,151	100.0	15	0	62,151
26	1993 Conservation	58.4	59,432	96,717	156,149	20	96,717	50.0	20	0	96,717
27								50.0	20		
28								40.0	20		
29	1994 Conservation	51.1	58,812	121,242	180,054	20	115,030	50.0	20	6,212	121,242
30								50.0	4		0
31	1995 Conservation	67.7	50,702	85,252	135,954	20	72,428	85.0	20	12,824	85,252
32	1996 Conservation	57.3	53,532	52,274	105,806	20	39,450	30.0	15	12,824	52,274
33	1997 Conservation	55.3	28,023	32,953	60,976	20	20,329	40.0	20	12,624	32,953
34	1998 Conservation	33.7	32,636	26,331	58,967	20	14,308			12,023	26,331
35	1999 Conservation	33.1	20,937	19,728	40,665	20	13,716			6,012	19,728
36	2000 Conservation	18.2	15,377	347	15,724	20	347	32.0	3	0	347
37	**TOTALS 1982-2000**	659.0	$549,851	$1,290,824	$1,840,675		$1,211,305	$1,222.0		$79,519	$1,290,824
39	2001 Conservation	28.7	$32,872	$58	$32,930	20	$58	$0		$0	$58
40	2002 Conservation	63.3	60,194	28,228	88,422	10	28,228	40.0	3	0	28,228
41	2003 Conservation	57.5	64,990	22,901	87,891	9	22,901			0	22,901
42	2004 Conservation	45.1	53,144	19,432	72,576	8	19,432	30.0	4	0	19,432
43	2005 Conservation	38.9	52,502	14,751	67,253	7	14,751			0	14,751
44	2006 Conservation	49.5	52,133	14,968	67,101	6	14,968	20.0	3	0	14,968
45	2007 Conservation	52.9	55,414	10,725	66,139	5	10,725	20.0	3	0	10,725
46	2008 Conservation	58.2	62,718	8,763	71,481	5	8,763	10.0	5	0	8,763
47	**TOTALS 2001-2008**	394.1	$433,967	$119,826	$553,793		$119,826	$120.0		$0	$119,826
49	**TOTALS 1982-2008**	1,053.1	$983,818	$1,410,650	$2,394,468		$1,331,131	$1,342		$79,519	$1,410,650

Page 1 of 2

BPA's 2010 Wholesale Power Rate Case
BPA Programmatic Conservation - Historical Savings and Expenditures
Gross Cost Amounts Before Adjustments

Notes to Worksheet:

1. Dollar costs are in nominal dollars associated with the year of the expenditure.

2. The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts for the years 1982-2008 were obtained from the 2009 Conservation Resource Energy Data, "The RED Book." The annual savings totals for years 1982-2008 were based on Tables A and B using the sub-sector line amounts. The gross savings amounts attributable to building codes, market transformation efforts, and C&RD are included in the savings totals. See the spread sheet titled "Total BPA Historical Programmatic Conservation - Gross Savings Amounts," pages D-13 through D17.

3. Total Annual Expenditures for the years 1982-2008 are based on Table D of the 2009 version of the "RED Book." Information from Table D as adjusted for federal reimbursable expenditures and receipts received along with an allocation of general and administrative overheads for the years FY2001-2008 are presented on pages D-3, D-4, and D-5. Expenditures for market transformation, Conservation and Renewable Discounts (C&RD), Conservation Rate Credits (CRC), along with other major expenditure categories are separately indentified.

4. The annual capitalized amounts are based on the additions to Annual Plant in Service based on the 2010 Requirement Study Documentation WP-10-FS-BPA-10, Volume 1, Chapter 4, Tables 4M, 4N, and 4o. This number is consistent with the information in BPA's annual reports after subtracting amortization of prior year investments.

5. The amount of conservation bonds issued and the term of the bonds is based on the Revenue Requirement Study Documentation WP-10-FS-BPA-10 Volume 1, Chapter 7, Table 7A.

6. BPA has agreed to pay the debt service for Conservation and Renewable Energy System (CARES) a joint operating agency (JOA) of the State of Washington, Emerald Public Utility District, City of Tacoma (Tacoma Power), and Eugene Water and Electric Board. The amounts in the column Third-Party Financed Conservation represent the original issue amount (principle) of bonds to finance conservation projects.

7. Total Capitalized/Debt Financed Conservation is comprised of BPA capitalized expenditures that were financed with U.S. Treasury Bonds and the conservation that is capitalized under Nonfederal Projects in BPA's financial statements which consists of third-party funded conservation as outlined in Note 6 above.

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TOTAL BPA CONSERVATION COSTS BY SECTOR

Accrued & Committed

($ 000)

	1982-2000	2001	2002	2003	2004	2005	2006	2007	2008	Totals
RESIDENTIAL:										
State Low Income Weatherization		$3,103	$2,429	$3,745	$2,474	$3,817	$4,030	$3,576	$4,135	$27,309
C&RD Low Income Weatherization		70	1,379	1,321	1,197	990	254			5,211
CRC Low Income Weatherization							465	1,226	2,138	3,829
Conservation Augmentation		42	8,693	3,046	2,876	2,422	2,067	43		19,189
Conservation & Renewables Discount		6,237	24,062	18,989	16,577	14,903	5,966	0	0	86,734
Conservation Acquisition		0	0	0	0	0	242	855	248	1,345
Conservation Rate Credit		0	0	0	0	0	1,408	8,308	10,954	20,670
Savings with a Twist		0	0	0	0	0	906	1,456	1,201	3,563
Residential Total	**$1,006,407**	**$9,452**	**$36,563**	**$27,101**	**$23,124**	**$22,132**	**$15,338**	**$15,464**	**$18,676**	**$1,174,257**
COMMERCIAL:										
Conservation Augmentation		$12	$14,652	$14,248	$13,596	$9,259	$7,253	$425		$59,445
Conservation & Renewables Discount		695	2,534	5,850	1,565	920	1,435	0		12,999
Conservation Acquisition		0	0	0	0	0	702	3,101	468	4,271
Conservation Rate Credit		0	0	0	0	0	261	3,284	4,138	7,683
New Initiatives		0	0	92	6	0	0	63	425	586
Federal Conservation Acquisition		$0	$0	$0	$0	$0	$0	$3,371	$6,354	$9,725
Commercial Total	**$338,550**	**$707**	**$17,186**	**$20,190**	**$15,167**	**$10,179**	**$9,651**	**$10,244**	**$11,385**	**$433,259**
INDUSTRIAL:										
Conservation Augmentation		$4	$4,864	$5,571	$2,904	$2,974	$3,196	$19		$19,532
Conservation & Renewables Discount		106	1,676	3,014	1,822	941	4,053	0		11,612
Conservation Acquisition		0	0	0	0	0	289	1,176	376	1,841
Conservation Rate Credit		0	0	0	0	0	0	2,786	2,396	5,182
Industrial Total	**$108,691**	**$110**	**$6,540**	**$8,585**	**$4,726**	**$3,915**	**$7,538**	**$3,981**	**$2,772**	**$146,858**
AGRICULTURAL:										
Conservation Augmentation		$0	$16	$36	$0	$0	$100	$115		$267
Conservation & Renewables Discount		1,452	953	697	518	119	85	0		3,824
Conservation Acquisition		0	0	0	0	0	213	164	116	493
Conservation Rate Credit		0	0	0	0	0	156	1,087	1,719	2,962
Agricultural Total	**$28,946**	**$1,452**	**$969**	**$733**	**$518**	**$119**	**$554**	**$1,366**	**$1,835**	**$36,492**
MULTI-SECTOR:										
Conservation Augmentation		$0	$3	$0	$56	$96	$0	$0		$155
Conservation & Renewables Discount		0	290	511	175	140	0	0		1,116
Conservation Acquisition		0	0	0	0	0	0	0		0
Conservation Rate Credit		0	0	0	0	0	0	4	45	49
Irrigation Rate Mitigation Product			121	166	92	547	267	116	391	1,700
Multi-Sector Total	**$155,565**	**$0**	**$414**	**$677**	**$323**	**$783**	**$267**	**$120**	**$436**	**$158,585**
SUBTOTAL	**$1,638,159**	**$11,721**	**$61,672**	**$57,286**	**$43,858**	**$37,128**	**$33,348**	**$31,175**	**$35,104**	**$1,949,451**

TOTAL BPA CONSERVATION COSTS BY SECTOR
Accrued & Committed
($ 000)

	1982-2000	2001	2002	2003	2004	2005	2006	2007	2008	Totals
MARKET TRANSFORMATION:		$9,603	$7,798	$9,321	$9,709	$7,956	$10,140	$9,925	$9,353	$73,805
C&RD Expense		1,040	7,969	9,109	7,988	6,597	4,433	0		37,136
(Includes Donations/Admin/IT Development)										
CRC Expense		0	0	0	0	0	1,205	4,443	4,936	10,584
(Includes Donations/Admin)										
Energy Web		1,229	1,445	4,287	831	602	969	1,817	3,749	14,929
SUBTOTAL	**$0**	**$11,872**	**$17,212**	**$22,717**	**$18,528**	**$15,155**	**$16,747**	**$16,185**	**$18,038**	**$136,454**
CONSERVATION SUPPORT COSTS:										
Power Services Conservation Sales/Support	**$0**	$4,517	$787	$360	$794	$831	$669	$243	$34	$8,235
Conservation Staff expense		4,873	5,570	5,742	5,921	6,456	6,841	6,380	6,814	48,597
Conservation Support Expense	**$178,113**	753	3,778	1,808	1,756	902	68	398	1,067	188,643
General & Administrative Overhead Expense[2]	$0	4,823	5,709	6,239	6,859	8,043	9,904	10,879	10,545	63,001
SUBTOTAL	**$178,113**	**$14,966**	**$15,844**	**$14,149**	**$15,330**	**$16,232**	**$17,482**	**$17,900**	**$18,460**	**$308,476**
OTHER COSTS:										
Third Party Financing Costs	**$79,519**	0	0	0	0	0	0	0	0	79,519
Debt Service Payment Adjustments	**($71,508)**	(5,574)	(4,081)	(4,236)	(5,275)	0	0	0	0	(90,674)
Various Costs Adjustments	**($31,748)**	0	0	(3,371)	0	0	0	0	0	(35,119)
Federal Reimbursable Program Costs[1]	**$0**	6,979	10,053	9,074	8,266	14,093	17,233	17,172	11,205	94,075
SUBTOTAL	**($23,737)**	**$1,405**	**$5,972**	**$1,467**	**$2,991**	**$14,093**	**$17,233**	**$17,172**	**$11,205**	**$47,801**
Total Annual Expenditures[3]		**$39,964**	**$100,700**	**$95,619**	**$80,707**	**$82,608**	**$84,810**	**$82,432**	**$82,807**	**$649,647**
Total Federal Reimbursable (Revenues)[1]		**($7,034)**	**($12,278)**	**($7,728)**	**($8,131)**	**($15,355)**	**($17,709)**	**($16,293)**	**($11,326)**	**($95,854)**
Net Annual Conservation Expenditures	**$1,792,535**	**$32,930**	**$88,422**	**$87,891**	**$72,576**	**$67,253**	**$67,101**	**$66,139**	**$71,481**	**$2,346,328**
Program Summary Totals:										
Total Conservation & Renewables Discount	**$0**	$9,600	$38,863	$39,491	$29,842	$24,610	$16,226	$0	$0	$158,632
Total Conservation Rate Credit	**$0**	$0	$0	$0	$0	$0	$3,495	$21,138	$26,326	$50,959
Total Direct Acquisition (Capitalized Costs)	**$0**	$0	$0	$0	$0	$0	$2,352	$10,123	$8,763	$21,238
Total Direct Augmentation (Capitalized Costs)	**$0**	$58	$28,228	$22,901	$19,432	$14,751	$12,616	$602	$0	$98,588

Notes:

1. Federal reimbursable expenditures undertaken on behalf of other federal agencies and reimbursements for these costs are not included in the presentation of costs for years occurring prior to FY 2001. These expenditures and reimbursements would have netted out close to zero for the FY1982-2000 time period so there would not have been a material difference in the Cumulative Net Expenditures for this period of time.
2. Conservation costs for the years prior to FY 2001 do not include an allocation of general and administrative overhead costs.
3. Annual conservation costs do not include the cost of financing the current year's conservation efforts or the interest expense associated with prior year expenditures that were capitalized and debt financed.
4. Conservation Modernization (ConMod) expenditures totaling $48,140,000 that were incurred during FY1988-1999 were omitted from the expenditure totals in this report. The conservation savings associated with ConMod have been removed from the 7(b)(2) resource stack amounts. The Net Annual Conservation expenditures above of $1,792,535,000 for FY1982-2000 plus the ConMod expense of $48,140,000 agree to the total FY1982-2000 conservation expenditure total of $1,840,675,000 on Page D-6.

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Annual Conservation Expenditures by Major Categories

Accrued & Committed

($ 000)

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Direct Program Costs:								
Market Transformation Expense	$9,603	$7,798	$9,321	$9,709	$7,956	$10,140	$9,925	$9,353
Grant Expense	3,103	2,429	3,745	2,474	3,817	4,030	3,576	4,135
Conservation & Renewables Discount Expense	9,600	38,863	39,491	29,842	24,610	16,226	0	0
Conservation Rate Credit Expense	0	0	0	0	0	3,495	21,138	26,326
Subtotals	9,600	38,863	39,491	29,842	24,610	19,721	21,138	26,326
Infrastructure Support, New Initiatives, & Evaluation Costs	1,229	1,445	4,379	837	602	969	1,880	4,174
Direct Acquisition/Capitalized Costs	58	28,228	22,901	19,432	14,751	14,968	10,725	8,763
Subtotal Direct Program Costs	**23,593**	**78,763**	**79,837**	**62,294**	**51,736**	**49,828**	**47,244**	**52,751**
Staffing and Indirect Costs:								
Staffing Costs	4,873	5,570	5,742	5,921	6,456	6,841	6,380	6,814
Indirect Costs and Sales Support Expense	5,270	4,686	2,334	2,642	2,280	1,004	757	1,492
General & Administrative Overhead Expense	4,823	5,709	6,239	6,859	8,043	9,904	10,879	10,545
Subtotal	**14,966**	**15,965**	**14,315**	**15,422**	**16,779**	**17,749**	**18,016**	**18,851**
Other and Reimbursable Costs:								
Other Costs / Adjustments	(5,574)	(4,081)	(7,607)	(5,275)	0	0	0	0
Federal Reimbursable Program Costs	6,979	10,053	9,074	8,266	14,093	17,233	17,172	11,205
Subtotal	1,405	5,972	1,467	2,991	14,093	17,233	17,172	11,205
Gross Annual Conservation Expenditures	**$39,964**	**$100,700**	**$95,619**	**$80,707**	**$82,608**	**$84,810**	**$82,432**	**$82,807**
Federal Cost Reimbursements	($7,034)	($12,278)	($7,728)	($8,131)	($15,355)	($17,709)	($16,293)	($11,326)
Net Annual Conservation Expenditures	**$32,930**	**$88,422**	**$87,891**	**$72,576**	**$67,253**	**$67,101**	**$66,139**	**$71,481**

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BPA's 2010 Wholesale Power Rate Case
Total Historical Conservation Expenditures - FY1982 - FY2008

($000) [1]

Row	Year	Total Incremental Yearly Costs	CAPITALIZED COSTS: Total Capitalized Costs	CAPITALIZED COSTS: Third Party Financing Costs/ Original Issue Amount	CAPITALIZED COSTS: BPA Capitalized Conser. Costs	EXPENSED CONSERVATION COSTS: Total Expense Costs	EXPENSED CONSERVATION COSTS: Staffing, Indirect & Support Costs[2]	EXPENSED CONSERVATION COSTS: General Admin. & Overhead Allocation Costs	EXPENSED CONSERVATION COSTS: Market Transform. Costs[5]	EXPENSED CONSERVATION COSTS: Expense Agreements Grants	EXPENSED CONSERVATION COSTS: Con/Mod Costs[2]	EXPENSED CONSERVATION COSTS: C&RD CRC Total Costs[3,4]	EXPENSED CONSERVATION COSTS: Infrastructure Support, New Initiatives & Evaluation	EXPENSED CONSERVATION COSTS: Other Conser. Expense Costs	Gross Conser. Savings per Red Book
14	1982	$66,914	$61,940	$0	$61,940	$4,974	$4,974	$0	$0	$0	$0	$0		$0	32.4
15	1983	206,999	204,092	0	204,092	2,907	2,907	0	0	0	0	0		0	66.6
16	1984	75,094	66,783	0	66,783	8,311	7,242	0	0	0	0	0		1,069	17.2
17	1985	127,747	103,067	0	103,067	24,680	20,232	0	0	0	0	0		4,448	17.9
18	1986	104,999	99,743	2,125	97,618	5,256	5,256	0	0	0	0	0		0	24.3
19	1987	75,559	71,631	4,250	67,381	3,928	3,928	0	0	0	0	0		0	18.3
20	1988	67,105	58,570	4,250	54,320	8,535	6,654	0	0	0	1,881	0		0	17.0
21	1989	63,712	46,069	4,250	41,819	17,643	5,479	0	0	0	4,726	0		7,438	20.8
22	1990	78,079	36,220	2,125	34,095	41,859	3,515	0	0	0	6,063	0		32,281	13.1
23	1991	89,525	45,714	0	45,714	43,811	3,495	0	0	0	6,254	0		34,062	19.1
24	1992	130,647	62,151	0	62,151	68,496	4,134	0	0	0	4,553	0		59,809	37.5
25	1993	156,149	96,717	0	96,717	59,432	8,119	0	0	0	4,179	0		47,134	58.4
26	1994	180,054	121,242	6,212	115,030	58,812	8,210	0	0	0	6,462	0		44,140	51.1
27	1995	135,954	85,252	12,824	72,428	50,702	7,915	0	0	0	4,045	0		38,742	67.7
28	1996	105,806	52,274	12,824	39,450	53,532	7,863	0	0	0	4,595	0		41,074	57.3
29	1997	60,976	32,953	12,624	20,329	28,023	13,700	0	3,900	0	2,744	0		7,679	55.3
30	1998	58,967	26,331	12,023	14,308	32,636	18,278	0	12,000	0	2,358	0		0	33.7
31	1999	40,665	19,728	6,012	13,716	20,937	13,500	0	5,600	1,400	280	0		157	33.1
32	2000	15,724	347	0	347	15,377	3,077	0	12,000	300	0	0		0	18.2
33	TOTALS														
34	1982-2000	$1,840,675	$1,290,824	$79,519	$1,211,305	$549,851	$148,478	$0	$33,500	$1,700	$48,140	$0	$0	$318,033	659.0
36	2001	$32,930	$58	$0	$58	$32,872	$4,514	$4,823	$9,603	$3,103	$0	$9,600	$1,229	$0	28.7
37	2002	88,422	28,228	0	28,228	60,194	3,950	5,709	7,798	2,429	0	38,863	1,445	0	63.3
38	2003	87,891	22,901	0	22,901	64,990	1,815	6,239	9,321	3,745	0	39,491	4,379	0	57.5
39	2004	72,576	19,432	0	19,432	53,144	3,423	6,859	9,709	2,474	0	29,842	837	0	45.1
40	2005	67,253	14,751	0	14,751	52,502	7,474	8,043	7,956	3,817	0	24,610	602	0	38.9
41	2006	67,101	14,968	0	14,968	52,133	7,369	9,904	10,140	4,030	0	19,721	969	0	49.5
42	2007	66,139	10,725	0	10,725	55,414	8,016	10,879	9,925	3,576	0	21,138	1,880	0	52.9
43	2008	71,481	8,763	0	8,763	62,718	8,185	10,545	9,353	4,135	0	26,326	4,174	0	58.2
44	TOTALS														
45	1982-2000	$553,793	$119,826	$0	$119,826	$433,967	$44,746	$63,001	$73,805	$27,309	$0	$209,591	$15,515	$0	394.1
47	TOTALS 1982-2008	$2,394,468	$1,410,650	$79,519	$1,331,131	$983,818	$193,224	$63,001	$107,305	$29,009	$48,140	$209,591	$15,515	$318,033	1,053.1

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BPA's 2010 Wholesale Power Rate Case

NET Historical Conservation Savings and Expenditures 1982-2008

Expenditure Adjustments for ConMod and C&RD

Savings Adjustments for C&RD, CRC, Market Transformation, and Building Codes

($000) [1]

Year	Total Incremental Costs / Subtotal Cost Allocations	(-) C&RD[3] Cost Adjustments	(-) ConMod[2] Cost Adjustments	(-) Market Trans.[5] Cost Adjustments	Adjusted Net Annual Costs	Total Expense Costs	Capitalized Conservation Costs	Net Conser. Savings as Adjusted
1982	$66,914	$0	$0	$0	$66,914	$4,974	$61,940	32.4
1983	206,999	0	0	0	206,999	2,907	204,092	66.6
1984	75,094	0	0	0	75,094	8,311	66,783	17.2
1985	127,747	0	0	0	127,747	24,680	103,067	17.9
1986	104,999	0	0	0	104,999	5,256	99,743	24.3
1987	75,559	0	0	0	75,559	3,928	71,631	18.3
1988	67,105	0	(1,881)	0	65,224	6,654	58,570	17.0
1989	63,712	0	(4,726)	0	58,986	12,917	46,069	20.8
1990	78,079	0	(6,063)	0	72,016	35,796	36,220	13.1
1991	89,525	0	(6,254)	0	83,271	37,557	45,714	19.1
1992	130,647	0	(4,553)	0	126,094	63,943	62,151	37.5
1993	156,149	0	(4,179)	0	151,970	55,253	96,717	58.4
1994	180,054	0	(6,462)	0	173,592	52,350	121,242	51.1
1995	135,954	0	(4,045)	0	131,909	46,657	85,252	67.7
1996	105,806	0	(4,595)	0	101,211	48,937	52,274	57.3
1997	60,976	0	(2,744)	0	58,232	25,279	32,953	55.3
1998	58,967	0	(2,358)	0	56,609	30,278	26,331	33.7
1999	40,665	0	(280)	0	40,385	20,657	19,728	30.5
2000	15,724	0	0	0	15,724	15,377	347	15.0
TOTALS 1982-2000	$1,840,675	$0	($48,140)	$0	$1,792,535	$501,711	$1,290,824	653.2
2001	$32,930	($9,600)	$0	$0	$23,330	$23,272	$58	19.2
2002	88,422	(38,863)	0	0	49,559	21,331	28,228	26.6
2003	87,891	(39,491)	0	0	48,400	25,499	22,901	27.6
2004	72,576	(29,842)	0	0	42,734	23,302	19,432	20.1
2005	67,253	(24,610)	0	0	42,643	27,892	14,751	20.6
2006	67,101	(16,226)	0	0	50,875	35,907	14,968	31.0
2007	66,139	0	0	0	66,139	55,414	10,725	27.9
2008	71,481	0	0	0	71,481	62,718	8,763	30.3
TOTALS 1982-2000	$553,793	($158,632)	$0	$0	$395,161	$275,335	$119,826	203.3
TOTALS 1982-2008	$2,394,468	($158,632)	($48,140)	$0	$2,187,696	$777,046	$1,410,650	856.5

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BPA's 2010 Wholesale Power Rate Case
NET Historical Conservation Savings and Expenditures 1982-2008
With Expenditure Adjustments for ConMod and C&RD
Savings Adjustments for C&RD, CRC, Market Transformation and Building Codes

Notes Concerning Expenditure Adjustments:

1. Dollar costs for FY1982-2008 are in nominal dollars associated with the year of expenditure. Costs for FY1982-2008 were obtained from Table D of the 2009 Conservation Resource Energy Data, "The RED Book." Information from Table D as adjusted for federal reimbursable expenditures and receipts received along with an allocation of general and administrative overheads for the years FY2001-2008 are presented on pages D-3, D-4, and D-5. Adjustments to the gross expenditure amounts are presented on pages D-6 and D-7.

2. The 2009 RED Book totals have excluded the savings form ConMod Conservation investments that were placed primarily with the aluminum reduction industry. Since most of these plants are no longer operating and since the amount of load that BPA might serve is not known with a high degree of certainty, the conservation savings from these past investments is not available to reduce loads in the 2010-2015 time period of the 7(b)(2) rate test. The expenditures for ConMod investments were subtracted from the cost of conservation resources in the presentation of net 7(b)(2) conservation costs.

3. The C&RD investments costs were not included in BPA's revenue requirement in determining "base" rate levels for FY2001-2006. They were added after the determination of base rates and were credited back to customers as credits on their power bills in return for agreeing to invest the money in conservation efforts or renewable resources. The controls and documentation surrounding the achievement of this conservation during the FY2001-2006 time period was less than past practices making the savings from these expenditures less assured. Utilities participating in this program who were not "load following" customers did not have their contract purchases decreased for these conservation savings. Consequently, the Administrator's load obligations to these customers was not reduced (no decrementing of contract obligations occurred). For these reasons the savings and expenditures associated with the C&RD program for FY2001-2006 were removed from the totals for these years.

4. No reduction in expenditures for the CRC program for FY 2007-2008 were made. Unlike the FY2001-2006 time period when the C&RD costs were not included in the revenue requirement, the WP-07 revenue requirement included CRC costs. The rates charged all BPA customers included CRC costs. It would be inequitable and not feasible to conduct a CRC program where only load-following customers were eligible to participate. In order to achieve the conservation savings in load following customer service areas, BPA also needed to undertake the CRC Program in non-load following service territories whose customers also paid for CRC program costs. The controls surrounding documentation and verification of CRC savings were also improved compared to the controls and verification procedures that pertained to the C&RD program prior to FY 2007. As outlined in Note 2 to the "BPA 1982-2008 NET Historical Programmatic Conservation - After Adjustments" worksheet (page D-23), approximately 48% of the saving attributable to FY2007-2008 CRC efforts were attributable to non-load following loads that were not decremented for the savings achieved. These non-load following savings were removed from the 7(b)(2) resource stack for FY2007-2008.

Notes Concerning Expenditure Adjustments - Continued:

5. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for the most part during this period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1997-2009 time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. BPA's RED Book claims market transformation savings equal to BPA's 50% NEEA funding level. Since BPA's customer's service territories only account for approximately 35% of regional loads, an adjustment was made to reduce savings amounts claimed that occur outside of BPA customer service territories. Market transformation savings were reduced by a second adjustment for BPA's non-load following loads that make up approximately 48% of BPA's loads. The amount of market transformation expenditures were not reduced. The amount that BPA paid NEEA was material to NEEA's region wide efforts and the scale of it's programs. BPA's funding was critical to sustaining market transformation efforts in the region. In order to achieve the 18% of regional savings that are reflected in the 7(b)(2) resource stack savings amounts for FY2007-2009, BPA would have needed to fund the program at approximately the same level of funding. See Note 3 to the "BPA 1982-2008 NET Historical Programmatic Conservation - After Adjustments" worksheet at page D-24 for the load data and calculation of percentages.

6. Adjustments were made to remove the savings attributable to building codes for the years after 2001. It was thought that the benefits from earlier BPA expenditures to achieve Model Energy Code standards had largely been achieved by this time. The savings for the 7(b)(2) resource stack should be conservatively stated with a high degree of assurance that the conservation savings would be able to reduce loads. No direct expenditures by BPA for building code efforts occurred during FY2002-2008, so no expenditure adjustments are necessary.

7. The historical expenditures reflected in the adjusted annual expenditure totals presented at pages D-3, D-4 and D-5 contain direct conservation program costs along with indirect and overhead costs that were necessary to acquire the conservation savings reported for the years FY2001-2008. The expenditure totals do not contain any financing costs associated with conservation efforts. The rates analysis model (RAM) finances that portion of a year's conservation expenditures that were capitalized using a 15-year amortization and financing period. The interest rates used to finance conservation investments in the 7(b)(2) Case are based on the Financing Study results on the interest rates that would apply to a Joint Operating Agency formed to undertake these investments on behalf of the 7(b)(2) Customers that was prepared by BPA's financial advisor for the final studies. The first year expensed costs associated with conservation investments are treated as deferred charges under SFAS No. 71 and are amortized and financed over a five-year period in the WP-10 rate case. The interest rates used to finance the first-year expensed costs were based on Public Financial Management's revised financing study dated June 3, 2009 for the WP-10 final studies.

BPA's 2010 Wholesale Power Rate Case

Total BPA Conservation Program - Projected Expenditures - Program Case Rates

GROSS EXPENDITURES - 2009-2015

($1,000)1

	Energy Efficiency Staffing Costs	Indirect & Overhead Costs	Corporate G&A Costs	Total Staffing, Indirect, & G&A Costs	Direct Program Costs: Market Trans-formation Costs	Expense Agreements & Grants	CRC Costs	Infrastructure Support & Evaluation Costs	Direct Acquisition Capital Expenditures	Total Direct Program Costs	Projected Period Expenditures Energy Efficiency	Capitalized/ Debt Financed	Expensed	Total Projected Conser. Savings aMW
2009	7,175	2,615	10,790	20,580	10,000	5,812	24,700	7,000	20,000	67,512	88,092	20,000	68,092	42.6
2010	7,874	3,482	12,456	23,812	14,500	5,000	28,000	14,000	32,819	94,319	118,131	32,819	85,312	44.9
2011	8,195	3,808	12,902	24,905	14,500	5,000	29,500	14,000	39,592	102,592	127,497	39,592	87,905	49.0
2012	8,615	4,159	13,643	26,417	15,000	6,000	32,000	15,000	47,203	115,203	141,620	47,203	94,417	54.6
2013	8,913	4,240	14,075	27,228	15,000	6,000	32,000	15,000	47,221	115,221	142,449	47,221	95,228	54.6
2014	9,222	4,327	14,489	28,038	15,000	6,000	32,000	15,000	47,224	115,224	143,262	47,224	96,038	54.6
2015	9,702	4,571	15,048	29,321	15,000	6,000	32,000	15,000	47,227	115,227	144,548	47,227	97,321	54.6
Totals	59,696	27,202	93,403	180,301	99,000	39,812	210,200	95,000	281,286	725,298	905,599	281,286	624,313	354.9

Net BPA Conservation Program - Section 7 (b)(2) - Projected Expenditures

NET EXPENDITURES - 2009-2015

($1,000)

	Energy Efficiency Staffing Costs	Indirect & Overhead Costs	Corporate G&A Costs	Total Staffing, Indirect, & G&A Costs	Market Trans-formation Costs	Expense Agreements & Grants	CRC Costs	Infrastructure Support & Evaluation Costs	Acquisition Capital Costs	Total Direct Program Costs	Projected Period Costs Energy Efficiency	Capitalized/ Debt Financed	Expensed	Total Projected Conser. Savings aMW
2009	7,175	2,615	10,790	20,580	10,000	5,812	24,700	7,000	20,000	67,512	88,092	20,000	68,092	28.4
2010	7,874	3,482	12,456	23,812	14,500	5,000	28,000	14,000	32,819	94,319	118,131	32,819	85,312	31.1
2011	8,195	3,808	12,902	24,905	14,500	5,000	29,500	14,000	39,592	102,592	127,497	39,592	87,905	34.9
2012	8,615	4,159	13,643	26,417	15,000	6,000	32,000	15,000	47,203	115,203	141,620	47,203	94,417	39.5
2013	8,913	4,240	14,075	27,228	15,000	6,000	32,000	15,000	47,221	115,221	142,449	47,221	95,228	39.5
2014	9,222	4,327	14,489	28,038	15,000	6,000	32,000	15,000	47,224	115,224	143,262	47,224	96,038	39.5
2015	9,702	4,571	15,048	29,321	15,000	6,000	32,000	15,000	47,227	115,227	144,548	47,227	97,321	39.5
Totals	59,696	27,202	93,403	180,301	99,000	39,812	210,200	95,000	281,286	725,298	905,599	281,286	624,313	252.4

Difference in Conservation Expenditures and Savings Contained in 7(b)(2) Resource Stack — $0 — 122.1

BPA's 2010 Wholesale Power Rate Case
Projected Conservation GROSS and NET EXPENDITURES - 2009-2015
Net BPA Conservation Program - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Expenditure Amounts to Arrive at Section 7 (b)(2) Amounts

1. Dollar costs are in the nominal dollars associated with the year of expenditure. The expenditure projections for the years 2009-2011 come from BPA's Conservation Program Proposals that were finalized in the Integrated Program Review (IPR-2) process. The expenditure projections for 2012-2015 were based on the assumption that the conservation program design for 2009-2011 continued during these later four years. BPA's Direct Acquisition capital expenditures established in the IPR-2 process were reduced by a "lapse factor" amount that reflects past historical performance in obligating these expenditures during the budget year and to meet agency wide borrowing targets. The Direct Acquisition Conservation Capital Expenditure amounts established in the IPR-2 process, the lapse factor reduction amounts, and the net amount of these capital expenditures that are contained in the Program Case Revenue Requirement Assumptions are outlined in the table below:

Conservation Direct Acquisition Capital Costs:

Year	IPR-2 Budget Amount	Lapse Factor Reduction	Program Case Amount
2009	20,000	0	20,000
2010	39,000	6,181	32,819
2011	47,000	7,408	39,592
2012	56,000	8,797	47,203
2013	56,000	8,779	47,221
2014	56,000	8,776	47,224
2015	56,000	8,773	47,227

The conservation Direct Acquisition Capital Cost amounts contained in the 7(b)(2) Rate Test resource stack are consistent with the amounts contained in the Program Case Revenue Requirement.

2. Debt service costs are not present in the 7(b)(2) Case Expenditure Table. Annual debt service costs are included in the annual revenue requirements for each year by the Rates Analysis Model for the 7(b)(2) Case using the interest rate projections provided by BPA's Financial Advisor (Appendix A to the 7(b)(2) Study) associated with the hypothetical Joint Operating Agency's financing of conservation resources in performing the Section 7(b)(2) rate test.

3. No reduction in expenditures for the CRC program were made. The rates charged all BPA customers for FYs 2009-2015 included CRC costs. It would be inequitable and not feasible to conduct a CRC program where only load-following customers were eligible to participate. In order to achieve the conservation savings that occur in the service territories of full-requirements customers, BPA also needs to undertake the CRC program for BPA's other customers who pay for CRC costs.

Notes - Adjustments Made to BPA's Conservation Program Expenditure Amounts to Arrive at Section 7 (b)(2) Amounts - continued

4. BPA's market transformation efforts are being achieved through the Northwest Energy Efficiency Alliance (NEEA) during the 2010-2015 period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA is projected to pay for approximately 35% of NEEA's operating budgets during the FY2010-2015 time period. Since BPA's projected funding level for NEEA for FY2010-2015 approximate BPA customer's load service territories' share of regional loads, no adjustment for savings occurring outside of BPA's service territory was necessary for the FY2010-2015 time period. Market transformation savings were reduced for BPA's non-load following loads that make-up approximately 48% of BPA's loads. The amount of market transformation expenditures were not reduced. The amount that BPA is projected to pay NEEA is material to NEEA's region wide efforts and the scale of it's programs. BPA funding is critical to sustaining market transformation efforts in the region. In order to achieve the 18% of regional savings that are reflected in the 7(b)(2) resource stack savings amounts for FY2010-2015, BPA would have needed to fund the program at approximately the same level of funding. See Note 3 to the table, "Net BPA Projected Conservation Program Savings - 2010-2015 - Section 7(b)(2) Amounts" at page D-27.

5. The Net Conservation Savings for FY2009-2015 are outlined in the table titled, "Net BPA Projected Conservation Program Savings - 2009-2015 - Section 7(b)(2) Amounts" at page D-26.

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	A	B	C	D	E	F	G	H
1	**BPA's 2010 Wholesale Power Rate Case**							
2	**Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]**							
3								
4		1982	1983	1984	1985	1986	1987	1988
6	Residential - C&RD	30.0	49.5	10.6	9.0	9.3	5.0	5.0
7	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Sub TOTAL	30.0	49.5	10.6	9.0	9.3	5.0	5.0
10	Commercial - C&RD	2.5	20.8	6.4	8.0	12.4	8.0	1.0
11	Adj.	(0.1)	(4.2)	(0.3)	(0.4)	(0.7)	(0.4)	(0.1)
12	Sub TOTAL	2.4	16.6	6.1	7.6	11.7	7.6	0.9
14	Industrial - C&RD	0.0	0.0	0.0	0.0	0.4	0.9	4.3
15	Adj.	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.2)
16	Sub TOTAL	0.0	0.0	0.0	0.0	0.3	0.7	4.1
18	Agriculture - C&RD	0.0	0.5	0.5	0.9	0.9	1.3	1.4
19	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Sub TOTAL	0.0	0.5	0.5	0.9	0.9	1.3	1.4
22	Multi-Sector - C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Building Codes	0.0	0.0	0.0	0.4	2.1	3.7	5.6
27	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Sub TOTAL	0.0	0.0	0.0	0.4	2.1	3.7	5.6
30	Con/Mod	0.0	0.0	0.0	0.0	0.0	2.5	37.6
31	Adj.	0.0	0.0	0.0	0.0	0.0	(2.5)	(37.6)
32	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	C&RD and CRC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41								
42	**Totals before Adj.**	32.5	70.8	17.5	18.3	25.1	21.4	54.9
43	**Adjustments**	(0.1)	(4.2)	(0.3)	(0.4)	(0.8)	(3.1)	(37.9)
44	**Net Annual Amt.**	32.4	66.6	17.2	17.9	24.3	18.3	17.0
45								
46	Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no							
47	adjustments for degradation of measures over time. The annual savings amounts were							
48	obtained from the 2004 and 2005 Conservation Resource Energy Data, "The RED Book".							
49								
51	Page 1 of 5							
53								

BPA's 2010 Wholesale Power Rate Case

Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]

	1989	1990	1991	1992	1993	1994	Subtotal 1982-1994
Residential - C&RD	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Commercial - C&RD	0.9	1.0	1.0	5.0	11.4	14.1	92.5
Adj.	0.0	(0.1)	(0.1)	(0.3)	(0.4)	(0.6)	(7.7)
Sub TOTAL	0.9	0.9	0.9	4.7	11.0	13.5	84.8
Industrial - C&RD	6.7	2.2	6.3	6.1	15.2	11.3	53.4
Adj.	(0.5)	(0.2)	(0.3)	(0.3)	(2.5)	(1.3)	(5.6)
Sub TOTAL	6.2	2.0	6.0	5.8	12.7	10.0	47.8
Agriculture - C&RD	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Multi-Sector - C&RD	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Building Codes	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Con/Mod	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Adj.	(30.9)	(24.9)	0.0	0.0	0.0	0.0	(95.9)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD and CRC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	52.2	38.3	19.5	38.1	61.3	53.0	502.9
Adjustments	(31.4)	(25.2)	(0.4)	(0.6)	(2.9)	(1.9)	(109.2)
Net Annual Amt.	20.8	13.1	19.1	37.5	58.4	51.1	393.7

__Note 1__ - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained obtained from the 2004 and 2005 Conservation Resource Energy Data, "The RED Book".

	R	S	T	U	V	W	X	Y
1	**BPA's 2010 Wholesale Power Rate Case**							
2	**Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]**							
3								FY 1982-
4		1995	1996	1997	1998	1999	2000	FY 2000
6	Residential - C&RD	3.4	1.4	0.6	0.7	0.6	0.3	179.6
7	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Sub TOTAL	3.4	1.4	0.6	0.7	0.6	0.3	179.6
10	Commercial - C&RD	9.3	5.3	4.8	6.8	0.5	0.0	119.2
11	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(7.7)
12	Sub TOTAL	9.3	5.3	4.8	6.8	0.5	0.0	111.5
14	Industrial - C&RD	18.2	11.8	6.7	0.2	0.2	0.0	90.5
15	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(5.6)
16	Sub TOTAL	18.2	11.8	6.7	0.2	0.2	0.0	84.9
18	Agriculture - C&RD	1.8	0.6	0.0	0.0	0.0	0.0	14.8
19	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Sub TOTAL	1.8	0.6	0.0	0.0	0.0	0.0	14.8
22	Multi-Sector - C&RD	20.1	23.6	27.9	12.9	13.4	0.0	104.2
23	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Sub TOTAL	20.1	23.6	27.9	12.9	13.4	0.0	104.2
26	Building Codes	14.9	14.6	15.3	13.1	14.4	12.9	155.0
27	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Sub TOTAL	14.9	14.6	15.3	13.1	14.4	12.9	155.0
30	Con/Mod	0.0	0.0	0.0	0.0	0.0	0.0	95.9
31	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(95.9)
32	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Market Trans.	0.0	0.0	0.0	0.0	4.0	5.0	9.0
35	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Sub TOTAL	0.0	0.0	0.0	0.0	4.0	5.0	9.0
38	C&RD and CRC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41								
42	**Totals before Adj.**	67.7	57.3	55.3	33.7	33.1	18.2	768.2
43	**Adjustments**	0.0	0.0	0.0	0.0	0.0	0.0	(109.2)
44	**Net Annual Amt.**	67.7	57.3	55.3	33.7	33.1	18.2	659.0
45								
46	Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts							
47	with no adjustments for degradation of measures over time. The annual savings amounts							
48	were obtained from the 2004 and 2005 Conservation Resource Energy Data, "The RED Book".							
49	The above 659.0 aMW of cumulative savings agrees with the 2009 RED Book Table A at page 3.							
51	Page 3 of 5							
53								

BPA's 2010 Wholesale Power Rate Case

Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]

	2001	2002	2003	2004	Other Adjust's	FY 1982- FY 2004
Residential - C&RD	6.0	19.0	11.9	11.0		227.5
C&RD/CRC reallocation	(3.7)	(12.9)	(9.0)	(8.9)	0.0	(34.5)
Sub TOTAL	2.3	6.1	2.9	2.1	0.0	193.0
Commercial - C&RD	2.0	13.6	16.7	10.9		162.4
C&RD/CRC reallocation	(0.3)	(1.1)	(3.3)	(0.6)	0.0	(13.0)
Sub TOTAL	1.7	12.5	13.4	10.3	0.0	149.4
Industrial - C&RD	0.5	4.0	6.7	3.8		105.5
C&RD/CRC reallocation	(0.4)	(0.8)	(1.7)	(1.6)	0.0	(10.1)
Sub TOTAL	0.1	3.2	5.0	2.2	0.0	95.4
Agriculture - C&RD	0.3	0.4	0.4	0.2		16.1
C&RD/CRC reallocation	(0.3)	(0.4)	(0.4)	(0.2)		(1.3)
Sub TOTAL	0.0	0.0	0.0	0.0		14.8
Multi-Sector - C&RD	0.0	0.4	0.4	0.2		105.2
C&RD/CRC reallocation	0.0	(0.2)	(0.2)	(0.1)	0.0	(0.5)
Sub TOTAL	0.0	0.2	0.2	0.1		104.7
Building Codes	12.4	13.0	4.2	3.9		188.5
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	12.4	13.0	4.2	3.9		188.5
Con/Mod	0.0	0.0	0.0	0.0		95.9
Adj.	0.0	0.0	0.0	0.0	0.0	(95.9)
Sub TOTAL	0.0	0.0	0.0	0.0		0.0
Market Trans.	7.5	12.9	17.2	15.1		61.7
C&RD/CRC reallocation	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	7.5	12.9	17.2	15.1		61.7
C&RD and CRC	4.7	15.4	14.6	11.4		46.1
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	4.7	15.4	14.6	11.4	0.0	46.1
Totals before Adj.	33.4	78.7	72.1	56.5		1,008.9
Reclass./Adjustments	(4.7)	(15.4)	(14.6)	(11.4)	0.0	(155.3)
Net Annual Amt.	28.7	63.3	57.5	45.1	0.0	853.6
Adjustments to the above amounts made by the 2009 RED Book (results through FY2008):						
Adjustment amounts:	0.1	0.1	0.0	0.0	0.0	0.2
2009 RED Book Table B amounts, page 8	28.8	63.4	57.5	45.1	0.0	853.8

Page 4 of 5

	A	B	C	D	E	F	G	H	I
1		**BPA's 2010 Wholesale Power Rate Case**							
2		**Total BPA Historical Programmatic Conservation - Gross Savings Amounts**							
3							Other		FY 2005-
4			2005	2006	2007	2008	Adjust's		FY 2008
5									
6		Residential	10.5	10.7	12.4	22.6			56.2
7		C&RD/CRC reallocation	(8.4)	(5.0)	(6.9)	(10.8)			(31.1)
8		Utility Self Funded HWM Adj.	0.0	0.0	(2.7)	(8.6)			(11.3)
9		Sub TOTAL	2.1	5.7	2.8	3.2			13.8
11		Commercial	9.5	14.6	9.5	13.3			46.9
12		C&RD/CRC reallocation	(0.4)	(0.8)	(3.3)	(4.5)			(9.0)
13		Adjustment	(0.1)	0.1					0.0
14		Utility Self Funded HWM Adj.	0.0	0.0	(1.3)	(3.8)			(5.1)
15		Sub TOTAL	9.0	13.9	4.9	5.0			32.8
17		Industrial	3.4	8.2	6.8	6.4			24.8
18		C&RD/CRC reallocation	(0.6)	(2.6)	(5.4)	(2.7)			(11.3)
19		Utility Self Funded HWM Adj.	0.0	0.0	(0.7)	(3.2)			(3.9)
20		Sub TOTAL	2.8	5.6	0.7	0.5			9.6
22		Agriculture	0.1	0.5	3.0	3.1			6.7
23		C&RD/CRC reallocation	(0.1)	(0.1)	(2.9)	(2.7)			(5.8)
24		Utility Self Funded HWM Adj.	0.0	0.0	0.0	(0.2)			(0.2)
25		Sub TOTAL	0.0	0.4	0.1	0.2			0.7
27		Multi-Sector	1.9	0.2	0.1	0.4			2.6
28		C&RD/CRC reallocation	0.0	0.0	0.0	(0.1)			(0.1)
29		Utility Self Funded HWM Adj.	0.0	0.0	0.0	0.0			0.0
30		Sub TOTAL	1.9	0.2	0.1	0.3			2.5
32		Building Codes	0.0	0.0	0.0	0.0			0.0
33		Adj.	0.0	0.0	0.0	0.0			0.0
34		Sub TOTAL	0.0	0.0	0.0	0.0			0.0
36		Market Trans.	13.6	15.2	26.2	30.0			85.0
37		C&RD/CRC reallocation	0.0	(0.6)	(3.6)	(1.5)			(5.7)
38		Utility Self Funded HWM Adj.	0.0	0.0	(0.4)	(1.8)			(2.2)
39		Sub TOTAL	13.6	14.6	22.2	26.7			77.1
41		C&RD and CRC	9.5	9.1	22.1	22.3			63.0
42		Utility Self Funded HWM Adj.	0.0	0.0					0.0
43		Sub TOTAL	9.5	9.1	22.1	22.3			63.0
45		**Totals before Adj.**	48.5	58.5	80.1	98.1			285.2
46		**Reallocations / Adjustments**	(9.6)	(9.0)	(27.2)	(39.9)			(85.7)
47		**Rounding**	0.0	0.0	0.0	0.0	(0.1)		(0.1)
48		**Net Annual Gross Amts.**	38.9	49.5	52.9	58.2	(0.1)		199.4
49		Utility Self Funded - HWM	0.0	0.0	5.1	17.6			22.7
50		2009 RED Book Table B, page 8	38.9	49.5	58.0	75.8			222.1
51		Gross Conservation Savings Amounts FY1982-2004, page D-6							853.8
52		2009 RED Book Table A, page 3, total conservation savings FY1982-2008							1075.9
54		Page 5 of 5							
56									

BPA's 2010 Wholesale Power Rate Case

BPA 1982-2008 NET Historical Programmatic Conservation Savings - After Adjustments

	1982	1983	1984	1985	1986	1987	1988
Residential - C&RD	30.0	49.5	10.6	9.0	9.3	5.0	5.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.0	49.5	10.6	9.0	9.3	5.0	5.0
Commercial - C&RD	2.4	16.6	6.1	7.6	11.7	7.6	0.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	2.4	16.6	6.1	7.6	11.7	7.6	0.9
Industrial - C&RD	0.0	0.0	0.0	0.0	0.3	0.7	4.1
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.3	0.7	4.1
Agriculture - C&RD	0.0	0.5	0.5	0.9	0.9	1.3	1.4
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.5	0.5	0.9	0.9	1.3	1.4
Multi-Sector - C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Building Codes[4]	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Market Transformation[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	32.4	66.6	17.2	17.9	24.3	18.3	17.0
Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Annual Amt.	32.4	66.6	17.2	17.9	24.3	18.3	17.0

__Note 1__ - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The RED Book."

BPA's 2010 Wholesale Power Rate Case

BPA 1982-2008 NET Historical Programmatic Conservation Savings - After Adjustments

	1989	1990	1991	1992	1993	1994	1982-1994 Totals
Residential - C&RD	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Commercial - C&RD	0.9	0.9	0.9	4.7	11.0	13.5	84.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.9	0.9	0.9	4.7	11.0	13.5	84.8
Industrial - C&RD	6.2	2.0	6.0	5.8	12.7	10.0	47.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	6.2	2.0	6.0	5.8	12.7	10.0	47.8
Agriculture - C&RD	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Multi-Sector - C&RD	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Building Codes[4]	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Market Transformation[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	20.8	13.1	19.1	37.5	58.4	51.1	393.7
Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Annual Amt.	20.8	13.1	19.1	37.5	58.4	51.1	393.7

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The RED Book."

	Q	R	S	T	U	V	W	X
1	**BPA's 2010 Wholesale Power Rate Case**							
2	**BPA 1982-2008 NET Historical Programmatic Conservation Savings - After Adjustments**							
3								
4								1982-2000
5		1995	1996	1997	1998	1999	2000	Totals
6								
7	Residential less C&RD	3.4	1.4	0.6	0.7	0.6	0.3	179.6
8	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Sub TOTAL	3.4	1.4	0.6	0.7	0.6	0.3	179.6
11	Commercial less C&RD	9.3	5.3	4.8	6.8	0.5	0.0	111.5
12	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Sub TOTAL	9.3	5.3	4.8	6.8	0.5	0.0	111.5
15	Industrial less C&RD	18.2	11.8	6.7	0.2	0.2	0.0	84.9
16	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Sub TOTAL	18.2	11.8	6.7	0.2	0.2	0.0	84.9
19	Agriculture less C&RD	1.8	0.6	0.0	0.0	0.0	0.0	14.8
20	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Sub TOTAL	1.8	0.6	0.0	0.0	0.0	0.0	14.8
23	Multi-Sector less C&RD	20.1	23.6	27.9	12.9	13.4	0.0	104.2
24	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Sub TOTAL	20.1	23.6	27.9	12.9	13.4	0.0	104.2
27	Building Codes[4]	14.9	14.6	15.3	13.1	14.4	12.9	155.0
28	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Sub TOTAL	14.9	14.6	15.3	13.1	14.4	12.9	155.0
31	Market Transformation[3]	0.0				4.0	5.0	9.0
32	Regional Load Adjustment					(1.2)	(1.5)	(2.7)
33	Non-Decremental Load Adj.	0.0	0.0	0.0	0.0	(1.4)	(1.7)	(3.1)
34	Sub TOTAL	0.0	0.0	0.0	0.0	1.4	1.8	3.2
36	C&RD[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37								
38	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	**Totals before Adj.**	67.7	57.3	55.3	33.7	33.1	18.2	659.0
42	**Adjustments**	0.0	0.0	0.0	0.0	(2.6)	(3.2)	(5.8)
43	**Net Annual Amt.**	67.7	57.3	55.3	33.7	30.5	15.0	653.2
45								
46								
47				Total Above				653.2
48				Adjustment Detail:				
49				Market Trans. Reductions				5.8
50								
51								
52				2009 RED Book Table A page 3				659.0
54			Page 3 of 8					

	Y	Z	AA	AB	AC	AD	AE	AF	A
1	**BPA's 2010 Wholesale Power Rate Case**								
2	**BPA 1982-2008 NET Historical Programmatic Conservation Savings - After Adjustments**								
3									
4						Other		TOTALS	
5		2001	2002	2003	2004	Adjust's		FY 1982-	
6								FY 2004	
7	Residential less C&RD	2.3	6.1	2.9	2.1			193.0	
8	Adj.	0.0	0.0	0.0	0.0	0.0		0.0	
9	Sub TOTAL	2.3	6.1	2.9	2.1	0.0		193.0	
11	Commercial less C&RD	1.7	12.5	13.4	10.3			149.4	
12	Adj.	0.0	0.0	0.0	0.0	0.0		0.0	
13	Sub TOTAL	1.7	12.5	13.4	10.3	0.0		149.4	
15	Industrial less C&RD	0.1	3.2	5.0	2.2			95.4	
16	Adj.	0.0	0.0	0.0	0.0	0.0		0.0	
17	Sub TOTAL	0.1	3.2	5.0	2.2	0.0		95.4	
19	Agriculture less C&RD	0.0	0.0	0.0	0.0			14.8	
20	Adj.	0.0	0.0	0.0	0.0	0.0		0.0	
21	Sub TOTAL	0.0	0.0	0.0	0.0	0.0		14.8	
23	Multi-Sector less C&RD	0.0	0.2	0.2	0.1			104.7	
24	Adj.	0.0	0.0	0.0	0.0	0.0		0.0	
25	Sub TOTAL	0.0	0.2	0.2	0.1	0.0		104.7	
27	Building Codes[4]	12.4	13.0	4.2	3.9			188.5	
28	Adj.	0.0	(13.0)	(4.2)	(3.9)	0.0		(21.1)	
29	Sub TOTAL	12.4	0.0	0.0	0.0			167.4	
31	Market Transformation[3]	7.5	12.9	17.2	15.1			61.7	
32	Regional Load Adjustment	(2.3)	(4.0)	(5.3)	(4.6)			(18.9)	
33	Non-Decremental Load Adj.	(2.5)	(4.3)	(5.8)	(5.1)			(20.8)	
34	Sub Total - Type 1	2.7	4.6	6.1	5.4	0.0		22.0	
36	C&RD[2]	4.7	15.4	14.6	11.4			46.1	
37	Oversight / Compliance Adj.	(4.7)	(15.4)	(14.6)	(11.4)			(46.1)	
38	Non-Decremental Load Adj.	0.0	0.0	0.0	0.0	0.0		0.0	
39	Sub TOTAL	0.0	0.0	0.0	0.0	0.0		0.0	
41	**Totals before Adj.**	28.7	63.3	57.5	45.1			853.6	
42	**Adjustments[7]**	(9.5)	(36.7)	(29.9)	(25.0)	0.0		(106.9)	
43	**Net 7(b)(2) - Type 1 Amount**	19.2	26.6	27.6	20.1	0.0		746.7	
45	Total Above							746.7	
46	Adjustment Detail:								
47	Plus C&RD Reductions	4.7	15.4	14.6	11.4	0.0		46.1	
48	Plus Bldg. Code Reductions	0.0	13.0	4.2	3.9	0.0		21.1	
49	Market Trans. Reductions	4.8	8.3	11.1	9.7	0.0		39.7	
50									
51	Misc Adjustments / Rounding	0.1	0.1	0	0.0	(0.1)		0.1	
52	2009 RED Book Table A	28.8	63.4	57.5	45.1	(0.1)		853.7	
54			Page 4 of 8						

	AH	AI	AJ	AK	AL	AM	AN	AO	AP
1	**BPA's 2010 Wholesale Power Rate Case**								
2	**BPA 1982-2008 NET Historical Programmatic Conservation Savings - After Adjustments**								
3									
4							FY 2005-		FY 1982-
5		2005	2006	2007	2008		FY 2008		FY 2008
6									
7	Residential less C&RD	2.1	5.7	2.8	3.2		13.8		206.8
8	Adj.	0.0	0.0	0.0	0.0		0.0		0.0
9	Sub TOTAL	2.1	5.7	2.8	3.2		13.8		206.8
11	Commercial less C&RD	9.0	13.9	4.9	5.0		32.8		182.2
12	Adj.	0.0	0.0	0.0	0.0		0.0		0.0
13	Sub TOTAL	9.0	13.9	4.9	5.0		32.8		182.2
15	Industrial less C&RD	2.8	5.6	0.7	0.5		9.6		105.0
16	Adj.	0.0	0.0	0.0	0.0		0.0		0.0
17	Sub TOTAL	2.8	5.6	0.7	0.5		9.6		105.0
19	Agriculture less C&RD	0.0	0.4	0.1	0.2		0.7		15.5
20	Adj.	0.0	0.0	0.0	0.0		0.0		0.0
21	Sub TOTAL	0.0	0.4	0.1	0.2		0.7		15.5
23	Multi-Sector less C&RD	1.9	0.2	0.1	0.3		2.5		107.2
24	Adj.	0.0	0.0	0.0	0.0		0.0		0.0
25	Sub TOTAL	1.9	0.2	0.1	0.3		2.5		107.2
27	Building Codes[4]	0.0	0.0	0.0	0.0		0.0		188.5
28	Adj.	0.0	0.0	0.0	0.0		0.0		(21.1)
29	Sub TOTAL	0.0	0.0	0.0	0.0		0.0		167.4
31	Market Transformation[3]	13.6	14.6	22.2	26.6		77.0		138.7
32	Regional Load Adjustment	(4.2)	(4.5)	(6.8)	(8.2)		(23.7)		(42.6)
33	Non-Decremental Load Adj.	(4.6)	(4.9)	(7.5)	(8.9)		(25.9)		(46.7)
34	Sub Total - Type 1	4.8	5.2	7.9	9.5		27.4		49.4
36	C&RD and CRC[2]	9.5	9.1	22.1	22.3		63.0		109.1
37	Oversight / Compliance Adj.	(9.5)	(9.1)	0.0	0.0		(18.6)		(64.7)
38	Non-Decremental Load Adj.	0.0	0.0	(10.7)	(10.8)		(21.5)		(21.5)
39	Sub TOTAL	0.0	0.0	11.4	11.5		22.9		22.9
41	**Totals before Adj.**	38.9	49.5	52.9	58.1		199.4		1,053.0
42	**Adjustments[8]**	(18.3)	(18.5)	(25.0)	(27.8)		(89.6)		(196.5)
43	**Net 7(b)(2) - Type 1 Amount**	20.6	31.0	27.9	30.3		109.8		856.5
45	Total Above						109.8		856.5
46	Adjustment Detail:								
47	C&RD / CRC Reductions	9.5	9.1	10.7	10.8		40.1		86.2
48	Bldg. Code Reductions	0.0	0.0	0.0	0.0		0.0		21.1
49	Market Trans. Reductions	8.8	9.4	14.3	17.1		49.6		89.3
50	Utility Self Funded for HWM purposes[6]			5.5	17.7		23.2		23.2
51	Rounding			(0.4)	(0.1)		(0.5)		(0.4)
52	2009 RED Book Table A	38.9	49.5	58.0	75.8		222.2		1,075.9
54	Page 5 of 8								

Notes Concerning Conservation Savings Adjustments:

1. The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts for the years 1982-2008 were obtained from the 2009 Conservation Resource Energy Data, "The RED Book." The annual savings totals for years 1982-2008 were based on Tables A and B using the sub-sector line amounts. The gross savings amounts attributable to building codes, market transformation efforts, and C&RD are included in the savings totals. See the spread sheets titled "Total BPA Historical Programmatic Conservation - Gross Savings Amounts," pages D-13 through D17. On pages D-16 and D-17 covering FY2001-2008, the savings attributable to C&RD and CRC are included in the sector totals (e.g., residential, commercial). The C&RD and CRC savings were reallocated / reclassified into a combined C&RD/CRC annual total for simplicity in making the savings adjustments that are outlined at Note 2.

2. Savings and expenditures attributable to C&RD were removed in total for the years prior to 2007 because there was not adequate compliance efforts in place during those years to have sufficient certainty that the savings were achieved. BPA's post -2006 Conservation Program has provided additional compliance requirements surrounding the CRC program to help ensure the achievement of conservation savings associated with the granting of CRC credits. Unlike the FY2001- 2006 time period when the C&RD costs were not included in the revenue requirement, the WP-07 revenue requirement included CRC costs. The rates charged all BPA customers include CRC costs. The Subscription contracts govern power purchases in both the Program Case and the 7(b)(2) Case. The contract power purchase provisions are "take or pay" with no reduction in loads for conservation savings. CRC savings that occur in non-load following areas do not have the capability to reduce the contracted loads in the Program Case or the 7(b)(2) Case. Because the contract provisions do not allow for the reduction of customer loads, the savings associated with non-load following loads were excluded from the 7(b)(2) resource stack. No reduction in expenditures for the CRC program for FY 2007-2008 were made, see the explanation at Note 4 at page D-8.

   CRC Non-load Following Conservation Savings Reductions:
   The reduction in conservation savings attributable to the CRC program available to the Section 7(b)(2) resource stack for FY 2007-2008 was based on the projected amount of non-load following loads. Approximately 48% of CRC conservation savings for FY2007-2008 were removed from the resource stack.

   BPA Customer's Forecasted FY 2010 Total Retail Loads:

Load Following Customers	3,724.0	aMW	51.55%
Non-Load Following Customers	3,500.0	aMW	48.45%
	7,224.0	aMW	100.00%

3. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for FY1999-2008. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1999-2008 time period. BPA's RED Book claims market transformation savings equal to BPA's 50% NEEA funding level. Since BPA's customer's service territories only account for approximately 35% of regional loads, an adjustment was made to reduce savings amounts claimed that occur outside of BPA customer service territories. Market transformation savings were reduced by a second adjustment for BPA's non-load following loads that make up approximately 48% of BPA's loads. The amount of market transformation expenditures were not reduced as explained at Note 5 at page D-9.

Notes Concerning Conservation Savings Adjustments Continued:

Note 3 - Continued

Market Transformation Conservation Savings Reductions:

The amount of the reduction to reduce the savings to just those that occur in BPA's customers load service territories was calculated by multiplying the savings (A) that were represented by BPA's 50% funding level by two to arrive at total regional savings (100% = B). This amount (B) was then multiplied by 34.61% to arrive at the savings associated with BPA's Customer's service territory (C). The market transformation adjustment for loads outside of BPA's customer's service territories was the difference between (A) and (C). This adjustment was made to the Gross market transformation savings amounts for FY1999-2009. Forecasted FY 2010 regional and BPA loads are outlined below:

Forecasted FY 2010 Regional Loads (No DSIs)	20,871.0	aMW	100.00%
BPA's Forecasted FY 2010 Loads (No DSIs)	7,224.0	aMW	34.61%

The adjustment to reduce the savings associated with BPA's non-load following loads was made by taking the net savings amounts associated with BPA's load service territory (C) above by the percentage of BPA's non-load following loads (48.45%). This adjustment was made for FY1999-2009.

BPA Customer's Forecasted FY 2010 Total Retail Loads:			
Load Following Customers	3,724.0	aMW	51.55%
Non-Load Following Customers	3,500.0	aMW	48.45%
	7,224.0	aMW	100.00%

Both of these adjustments are reflected by two separate line adjustments to the market transformation savings amounts on pages D-20, D-21, and D-22.

Rate Periods After FY2011:

Under the Regional Dialogue contracts that take effect October 1, 2011, the amount of power purchased by a COU from BPA is the lower of its High Water Mark amount or the utility's net requirements at the start of each rate case. Thus there will be no reduction to conservation savings for Non-load following loads in determining the 7(b)(2) Case load augmentation amounts or to the amount of savings contained in the resource stack.

4. Adjustments were made to remove savings attributable to building codes for the years after 2001. BPA's Conservation Program staff are of the opinion that the benefits from earlier BPA expenditures to achieve Model Energy Code standards had largely been achieved by this time. The savings for the 7(b)(2) resource stack should have a high degree of assurance that the conservation savings would be able to reduce 7(b)(2) Case loads.

5. As previously noted in the table of Gross Conservation Savings, the 2009 RED Book totals have excluded the savings from ConMod Conservation investments that were placed primarily with the aluminum reduction industry. Since most of these plants are no longer operating, and since the amount of load that BPA might serve is not known with a high degree of certainty, the conservation savings from these past investments is not available to reduce loads in the 2010-2015 time period associated with the rate test period. The expenditures for past ConMod investments were removed from the expenditure totals that were included in the 7(b)(2) resource stack.

6. Starting in FY 2007 the RED Book started reporting utility Self-Funded conservation savings in the conservation savings totals. These savings were undertaken by BPA's customers without BPA funding. No expenditures for these savings were reported in the RED Book. These savings for FY 2007-2008 totaled 23.2 aMW, they were removed from the totals to arrive at BPA's conservation efforts that should be included in the 7(b)(2) resource stack.

Notes Concerning Conservation Savings Adjustments Continued:

7. The following adjustments were made to the 2009 RED Book's conservation savings for the years 1982-2004:

Building Code Savings	21.1	aMW
Market Transformation Savings	39.7	
C&RD Savings	46.1	
Rounding	0.1	
	107.0	aMW

The total conservation savings per the Red Book for FY1982-2004 was 853.7 aMW after netting out 95.9aMW of ConMod savings. The total savings included in the 7(b)(2) resource stack for those years was 746.7aMW after subtracting the above adjustments totaling 107.0 aMW.

8. The following adjustments were made to the 2009 RED Book's conservation savings for the years 2005-2008:

Utility Self Funded Conservation	23.2	aMW
Market Transformation Savings	49.6	aMW
C&RD and CRC Savings	40.1	aMW
Rounding	(0.5)	
	112.4	aMW

The total conservation savings per the RED Book for FY2005-2008 was 222.2 aMW, the total savings included in the 7(b)(2) resource stack for those years was 109.8 aMW after subtracting the above adjustments totaling 112.4 aMW.

	A	C	D	E	F	G	H	I	J	L
1	**BPA's 2010 Wholesale Power Rate Case**									
2	**Final Proposal - Studies**									
3	**BPA Projected Conservation Program Savings - 2008-2015**									
4	**Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts**									
5	**aMW**[1]									
6		**Red Book**	**Projected Savings**							**Cumulative**
7		**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Totals**
8										
9	**Projected Conservation Program - Gross Saving Amounts:**									
10	CRC - Non-Decremental Loads[1]	10.8	7.5	6.8	7.1	7.8	7.8	7.8	7.8	63.4
11	CRC - Equivalent-Decrement Loads[1]	11.5	8.0	7.2	7.6	8.2	8.2	8.2	8.2	67.1
12										130.5
13	Conservation Acquisition - Bi-lateral Contracts									
14	Equivalent-Decrement Loads[2]	9.3	13.3	16.4	19.8	23.6	23.6	23.6	23.6	153.2
15										
16	Market Trans.- Non-Decremental Loads[3]	8.8	6.7	7.0	7.0	7.3	7.3	7.3	7.3	58.7
17	Market Trans.- Equivalent-Decrement[3]	9.5	7.1	7.5	7.5	7.7	7.7	7.7	7.7	62.4
18										121.1
19										
20	Total Projected Conservation Savings - Program Case	49.90	42.60	44.90	49.00	54.60	54.60	54.60	54.60	404.8
21										
22										
23	**Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts:**									
24	Less CRC Non-Decremental Loads[1]	10.8	7.5	6.8	7.1	7.8	7.8	7.8	7.8	63.4
25	Less Market Trans.- Non-decremental Loads[3]	8.8	6.7	7.0	7.0	7.3	7.3	7.3	7.3	58.7
26	**Total Non-Decremental Load Savings**	19.6	14.2	13.8	14.1	15.1	15.1	15.1	15.1	122.1
27										
28										
29	**Net Projected Conservation savings for Section 7(b)(2) Resource Stack**	30.3	28.4	31.1	34.9	39.5	39.5	39.5	39.5	282.7
30										
31	Page 1 of 3									

Notes - Adjustments Made to BPA's Projected Conservation Program Savings Amounts to Arrive at Savings Available to Reduce Loads per the Section 7 (b)(2) Rate Test

1. The conservation saving projections for FY 2009 were based on BPA's second quarter review expenditure levels and projected cost per aMW of savings developed at that time. Projections for the years 2010-2011 come from BPA's Conservation Program Proposals that were finalized in the Integrated Program Review-2 process and were adjusted for the "lapse factor" adjustment that was applied to the Direct Acquisition Capital program amounts as explained at Note-1 to the worksheet titled, "Projected Conservation GROSS and NET EXPENDITURES - 2008-2015," at page D-11. The savings projections for 2012-2015 were based on the assumption that the conservation program design for 2010-2011 continued during the FY2012-2015 time period.

2. Non-load following customer contracted power amounts (customers who purchase the slice and block power products) enjoy the benefit of CRC power bill credits and the resulting savings associated with the purchase of conservation measures in their service areas with the proceeds of these credits. The Administrator's load obligations to these utilities however, is not reduced for these savings (contract power purchase amounts have not been decremented for the conservation savings) thus BPA does not receive a direct benefit from CRC savings associated with non-load following customers. BPA does receive a direct benefit from load following customers associated with the conservation savings that occurs in those utility's service territories. Because BPA does not receive a load reduction benefit from savings associated with non-load following loads, the portion of the CRC savings attributable to non-load following utilities has been removed from the Section 7(b)(2) resource stack. The reduction in conservation savings attributable to non-load following customer service areas is 48.45% based on BPA's FY2010 forecasted load amounts:

BPA's forecasted load following loads - FY2010	3,724.0	aMW	51.55%
BPA's forecasted non-load following loads - FY2010	3,500.0	aMW	48.45%
BPA's total forecasted loads - FY2010	7,224.0	aMW	100.00%

3. BPA's market transformation efforts will be achieved through the Northwest Energy Efficiency Alliance (NEEA) during the 2010-2015 period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA is projected to pay for approximately 35% of NEEA's operating budgets during the FY2010-2015 time period. Since BPA's projected funding level for NEEA for FY2010-2015 approximate BPA customer's load service territories' share of regional loads, no adjustment for savings occurring outside of BPA's service territory was necessary for the FY2010-2015 time period. Market transformation savings for FY2010-2015 were reduced for BPA's non-load following loads that make-up approximately 48% of BPA's loads as described in Note 2 above. The savings for FY2009 were adjusted for savings claimed in the RED Book that occur outside of BPA's customer's load service territories. The adjustments for FY 2009 were described at Note 3 on page D-24. These adjustments are reflected in the market transformation savings amounts on page D-26.

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4. Rate Periods After FY2011:
Under the Regional Dialogue contracts that take effect October 1, 2011, the amount of power purchased by a COU from BPA is the lower of its High Water Mark amount or the utility's net requirements at the start of each rate case. Thus there will be no reduction to conservation savings for Non-load following loads in determining the 7(b)(2) Case load augmentation amounts or to the amount of savings contained in the resource stack.

5. In summary, the following adjustments were made to the conservation savings projected for the years 2009-2015:

CRC Savings	63.4	aMW
Market Transformation Savings	58.7	aMW
	122.1	aMW

The total projected conservation savings to be achieved by BPA's Conservation Program for FYs 2009-2015 is 404.8 aMW. The total savings included in the 7(b)(2) resource stack for those years is 282.7 aMW.

BPA's 2010 Wholesale Power Rate Case
BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures
BPA 2010 Rate Case - 7(b)(2) Resource Stack
Nominal Dollars Corresponding to the Historical Year of Acquisition

	Savings aMW	Amount Revenue Expensed ($ 000)	Amount Capitalized & Debt Financed ($ 000)	NET Annual Expenditures ($ 000)	Capitalized Amortization Period Years[2]
2001 Conservation	19.2	23,272.0	58.0	23,330.0	15
2002 Conservation	26.6	21,331.0	28,228.0	49,559.0	15
2003 Conservation	27.6	25,499.0	22,901.0	48,400.0	15
2004 Conservation	20.1	23,302.0	19,432.0	42,734.0	15
2005 Conservation	20.6	27,892.0	14,751.0	42,643.0	15
2006 Conservation	31.0	35,907.0	14,968.0	50,875.0	15
2007 Conservation	27.9	55,414.0	10,725.0	66,139.0	15
2008 Conservation	30.3	62,718.0	8,763.0	71,481.0	15
2009 Conservation	28.4	68,092.0	20,000.0	88,092.0	15
Subtotal[1]	231.7				
2010 Conservation	31.1	85,312.0	32,819.0	118,131.0	15
2011 Conservation	34.9	87,905.0	39,592.0	127,497.0	15
2012 Conservation	39.5	94,417.0	47,203.0	141,620.0	15
2013 Conservation	39.5	95,228.0	47,221.0	142,449.0	15
2014 Conservation	39.5	96,038.0	47,224.0	143,262.0	15
2015 Conservation	39.5	97,321.0	47,227.0	144,548.0	15
Cumulative Savings	**455.7**	**899,648.0**	**$401,112.0**	**$1,300,760.0**	
Percentages		**69.16%**	**30.84%**	**100.00%**	
Average Cost of conservation Savings - $/aMW				**$2,854.4**	

Note 1 - The amount of conservation in the resource stack for FY2001-2009 (231.7aMW) together with billing credit resources contained in the resource stack of 10.1 aMW establish the amount of the load resource balance difference between the Program Case and the 7(b)(2) Case at the start of the Rate Test Period (October 1, 2009) amounting to 241.8 aMW.

Note 2 - Historical conservation investments that occurred prior to FY 2001 that will have been fully amortized before the end of the rate test period in FY 2015, based on a composite useful life of 15 years, are viewed as obsolete conservation investments that are not includable in the 7(b)(2) resource stack.

Note 3 - Conservation saving amounts for FY2001-2008 were based on the information contained in Tables A and B of the Conservation Resource Energy Data for FY 2009 (The RED Book which covered FY1982-2008). Those savings amounts were then adjusted to arrive at the actual savings that would reduce the Administrator's load obligation in the 7(b)(2) Case. The projected FY 2009 savings and cost amounts were based on the 2nd Quarter review financial summary. Conservation costs and related savings amounts for FY 2010-2015 were revised for the final conservation spending levels that were adopted in the IPR - 2 process that concluded in May 2009. The conservation costs for FY 2001-2015 contain an allocation of general and administrative costs following full absorption costing principles.

Note 4 - Conservation costs for FY2001-FY2008 were based on the conservation costs contained in Table D of the Conservation Resource Energy Data for FY 2009. The costs contained in the RED Book do not contain general and administrative overhead costs. The costs displayed in Table D were increased for general and administrative costs. The allocation of general and administrative costs was based on the relationship of total direct staffing costs of BPA's Energy Efficiency organization and the Power Services Business Line. The amount of G & A administrative costs allocated to conservation resources was a portion of the total G & A costs assigned to Power Services and Energy Efficiency.

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APPENDIX E

Residential Exchange Program Average System Cost

Summary Tables

Section 7(b)(2) Rate Test Study Documentation

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Appendix E

Table 1: Utility Contract System Cost

	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
Avista	$ 471,414,717	$ 493,995,044	$ 504,209,356	$ 519,720,150	$ 537,869,969
Franklin PUD	$ 52,095,775	$ 55,490,350	$ 56,157,097	$ 57,507,603	$ 58,372,724
Idaho Power Company	$ 572,350,242	$ 605,177,194	$ 620,335,368	$ 639,592,217	$ 656,166,765
Pacificorp	$ 1,297,124,368	$ 1,299,554,264	$ 1,302,472,733	$ 1,323,139,596	$ 1,348,281,903
Portland General Electric	$ 1,148,418,727	$ 1,193,626,375	$ 1,223,918,630	$ 1,258,299,011	$ 1,292,122,875
Puget Sound Energy	$ 1,434,877,605	$ 1,471,072,108	$ 1,493,453,621	$ 1,516,566,905	$ 1,539,940,955
NorthWest Energy	$ 361,963,153	$ 379,366,915	$ 391,691,594	$ 404,034,961	$ 416,248,432
Snohomish PUD	$ 335,428,916	$ 358,054,988	$ 362,971,034	$ 372,109,245	$ 377,697,776

Table 2: Utility Contract System Load (MWh)

	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
Avista	9,861,636	10,156,361	10,346,207	10,593,951	10,890,199
Franklin PUD	1,057,226	1,082,349	1,098,050	1,113,979	1,130,139
Idaho Power Company	16,054,942	16,498,753	16,643,425	16,832,645	17,006,458
Pacificorp	22,915,726	23,261,468	23,493,469	23,963,339	24,442,606
Portland General Electric	19,698,019	20,173,077	20,538,686	20,964,841	21,384,009
Puget Sound Energy	23,283,955	23,510,354	23,661,019	23,830,233	24,026,674
NorthWest Energy	6,287,433	6,407,964	6,490,111	6,573,472	6,658,067
Snohomish PUD	7,306,411	7,456,345	7,524,041	7,587,638	7,653,435

Table 3: Utility ASC ($/MWh)

	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
Avista	47.80	48.64	48.73	49.06	49.39
Franklin PUD	49.28	51.27	51.14	51.62	51.65
Idaho Power Company	35.65	36.68	37.27	38.00	38.58
Pacificorp	56.60	55.87	55.44	55.22	55.16
Portland General Electric	58.21	59.08	59.50	59.93	60.34
Puget Sound Energy	61.63	62.57	63.12	63.64	64.09
NorthWest Energy	57.57	59.20	60.35	61.46	62.52
Snohomish PUD	45.91	48.02	48.24	49.04	49.35

Appendix E

Table 4: Utility Residential and Small Farm Exchange Loads (MWh)

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Avista	3,986,348	4,034,141	3,888,712	4,031,401	4,098,536	4,209,102
Franklin PUD	352,920	361,564	367,247	372,575	377,980	383,463
Idaho Power Company	6,512,256	6,675,268	6,353,700	6,403,692	6,483,111	6,558,073
Pacificorp	9,537,744	9,631,984	9,729,476	9,826,514	10,023,044	10,223,505
Portland General Electric	8,750,249	8,837,336	8,980,520	9,143,024	9,332,440	9,518,750
Puget Sound Energy	11,920,407	12,051,542	12,250,186	12,544,453	12,951,182	13,499,041
NorthWest Energy	619,909	627,784	635,816	643,967	652,239	660,632
Snohomish PUD	3,756,771	3,821,252	3,885,583	3,944,859	4,001,408	4,059,805

	A	B	C	D	E	F	G
1	**Appendix E**						
2	**Table 5: Escalation Factors**						
3		**DATE**	**10/1/2010**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
4			7	11	12	13	14
5	**New Resource (True/False)**	**NR**	**TRUE**	**FALSE**	**FALSE**	**FALSE**	**FALSE**
6	**New Resource Column (5-25)**	**NRCOL**	**5**	**5**	**5**	**5**	**5**
7	**New Resource Switch (1=Used, 0=Not Used)**	**NRSW**	**0**	**0**	**0**	**0**	**0**
8	**Rate Period**	**RP**	**No**	**No**	**No**	**No**	**No**
9	**No Escalation**	**CONSTANT**	0.000%	0.000%	0.000%	0.000%	0.000%
10	**Distribution Plant**	**CD**	7.782%	2.384%	2.000%	2.000%	1.950%
11	**Inflation**	**INF**	6.086%	3.073%	2.092%	2.015%	2.022%
12	**Wages**	**WAGES**	8.942%	4.432%	2.850%	3.025%	3.100%
13	**Steam Fuel - (Coal)**	**COAL**	6.026%	0.524%	0.474%	1.375%	1.550%
14	**Steam Operations**	**SOPS**	10.800%	2.838%	2.075%	2.000%	2.025%
15	**Steam Maintenance**	**SMN**	8.730%	2.636%	2.175%	2.050%	1.925%
16	**Nuclear Fuel**	**NFUEL**	0.000%	0.000%	0.000%	0.000%	0.000%
17	**Nuclear Operations**	**NOPS**	9.350%	2.914%	2.000%	2.000%	2.000%
18	**Nuclear Maintenance**	**NMN**	6.230%	1.780%	1.700%	1.950%	1.825%
19	**Hydro Operations**	**HOPS**	11.123%	2.208%	1.250%	1.150%	1.375%
20	**Hydro Maintenance**	**HMN**	8.516%	2.384%	1.975%	1.875%	1.825%
21	**Other Fuel - (Natural Gas)**	**NATGAS**	-24.417%	10.384%	2.687%	2.682%	2.677%
22	**Other Operations**	**OOPS**	13.015%	3.619%	1.675%	1.650%	1.850%
23	**Other Maintenance**	**OMN**	8.025%	2.183%	1.725%	1.800%	1.825%
24	**Transmission Operations**	**TOPS**	10.104%	3.166%	1.825%	1.925%	2.000%
25	**Transmission Maintenances**	**TMN**	8.317%	1.704%	1.825%	1.850%	1.725%
26	**Distribution Operations**	**DOPS**	8.722%	2.914%	2.025%	2.100%	2.100%
27	**Distributions Maintenances**	**DMN**	8.954%	1.905%	1.900%	1.875%	1.800%
28	**Customers Accounts**	**CACNT**	8.779%	2.964%	2.050%	2.200%	2.200%
29	**Customers Service**	**CSERV**	8.320%	1.956%	1.600%	1.900%	1.900%
30	**Customers Sales**	**CSALES**	9.200%	3.091%	2.175%	2.375%	2.300%
31	**Administrative and General**	**A&G**	10.239%	4.559%	3.025%	3.100%	3.075%
32	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
33	**Purchased Power PF (FY Esc)**	**PURCHPF**	3.034%	14.599%	0.000%	1.790%	0.000%
34	**Purchased Power Slice (FY Esc)**	**PURCHSL**	4.549%	14.599%	0.000%	1.790%	0.000%
35	**Purchased Power Generic #1 (FY Esc)**	**PURCHG1**	6.028%	2.880%	1.967%	1.933%	2.000%
36	**Purchased Power Generic #2 (FY Esc)**	**PURCHG2**	6.028%	2.880%	1.967%	1.933%	2.000%
37	**Purchased Power Generic #3 (FY Esc)**	**PURCHG3**	6.028%	2.880%	1.967%	1.933%	2.000%
38	**Steam O&M**	**SOM**	9.672%	2.712%	2.075%	1.975%	1.925%
39	**Hydro O&M**	**HOM**	9.922%	2.359%	1.625%	1.425%	1.575%
40	**Other O&M**	**OOM**	10.357%	2.889%	1.700%	1.725%	1.825%
41	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
42	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
43	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
44	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
45	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
46	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
47	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
48	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
49	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%

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APPENDIX F

Residential Exchange Program Average System Cost

Forecast Contract System Cost, Contract System Load, and ASC
FY 2010 - 2015

Table A: Avista
Table B: Franklin County PUD
Table C: Idaho Power
Table D: NorthWestern Energy
Table E: PacifiCorp
Table F: Portland General Electric
Table G: Puget Sound Energy
Table H: Snohomish County PUD

Section 7(b)(2) Rate Test Study Documentation

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TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	15,259,132	15,259,132	15,259,132	15,259,132	15,259,132
5		Intangible Plant - Miscellaneous	2,153,743	2,153,743	2,153,743	2,153,743	2,153,743
6	**Total Intangible Plant**		17,412,874	17,412,874	17,412,874	17,412,874	17,412,874
7							
8	**Production Plant:**						
9		Steam Production	378,707,227	378,707,227	378,707,227	378,707,227	378,707,227
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	363,035,892	363,035,892	363,035,892	363,035,892	363,035,892
12		Other Production	273,034,180	273,034,180	273,034,180	273,034,180	273,034,180
13	**Total Production Plant**		1,014,777,299	1,014,777,299	1,014,777,299	1,014,777,299	1,014,777,299
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	443,832,431	443,832,431	443,832,431	443,832,431	443,832,431
17	**Total Transmission Plant**		443,832,431	443,832,431	443,832,431	443,832,431	443,832,431
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	77,703	77,826	77,826	77,826	77,826
25		Structures and Improvements	1,340,733	1,342,867	1,342,867	1,342,867	1,342,867
26		Furniture and Equipment	282,873	285,579	287,170	289,288	291,871
27		Transportation Equipment	2,841,582	2,821,246	2,804,311	2,782,502	2,756,988
28		Stores Equipment	187,455	187,753	187,753	187,753	187,753
29		Tools and Garage Equipment	2,052,584	2,055,852	2,055,852	2,055,852	2,055,852
30		Laboratory Equipment	1,912,363	1,915,408	1,915,408	1,915,408	1,915,408
31		Power Operated Equipment	6,634,726	6,587,246	6,547,703	6,496,783	6,437,212
32		Communication Equipment	20,091,677	20,123,666	20,123,666	20,123,666	20,123,666
33		Miscellaneous Equipment	2,423	2,427	2,427	2,427	2,427
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		35,424,118	35,399,871	35,344,984	35,274,374	35,191,870
38							
39	**Total Electric Plant In-Service**		1,511,446,722	1,511,422,475	1,511,367,588	1,511,296,978	1,511,214,474
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	262,012,312	279,292,113	290,811,980	302,331,847	313,851,714
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	101,773,952	113,102,713	120,655,220	128,207,727	135,760,234
47		Other Production Plant	82,467,873	102,022,350	115,058,668	128,094,986	141,131,304
48		Transmission Plant (i)	171,315,440	186,067,958	195,902,970	205,737,982	215,572,994
49		Distribution Plant	0	0	0	0	0
50		General Plant	26,035,643	28,223,507	29,641,770	30,947,741	32,150,614
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	3,664,564	4,171,223	4,508,996	4,846,769	5,184,542
53		Amortization of Intangible Plant - Account 303	1,200,929	1,619,715	1,898,906	2,178,097	2,457,288
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	19,064,009	22,925,619	25,500,026	28,074,433	30,648,840
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		667,534,722	737,425,198	783,978,535	830,419,582	876,757,530
65							
66	**Total Net Plant**		843,912,000	773,997,277	727,389,052	680,877,396	634,456,945
67	*(Total Electric Plant In-Service) - (Total Depreciation & Amortization)*						

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
68							
69	Assets and Other Debits (Comparative Balance Sheet)						
70							
71	Cash Working Capital (f)		19,871,618	20,350,513	20,684,385	21,023,396	21,369,703
72							
73	Utility Plant		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	41,366,474	41,366,474	41,366,474	41,366,474	41,366,474
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		Total	41,366,474	41,366,474	41,366,474	41,366,474	41,366,474
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		Total	0	0	0	0	0
88							
89							
90		Fuel Stock	2,366,409	2,359,645	2,370,826	2,403,423	2,440,676
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	11,300,316	11,509,474	11,652,993	11,758,180	11,838,623
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	0	0	0	0	0
98		Prepayments	3,949,459	3,902,711	3,870,389	3,828,188	3,777,969
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		Total	17,616,184	17,771,830	17,894,209	17,989,792	18,057,267

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	7,088,690	7,004,982	6,947,150	6,871,641	6,781,786
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	0	0	0	0	0
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	0	0	0	0	0
115		Miscellaneous Deferred Debits	13,724,067	13,724,067	13,724,067	13,724,067	13,724,067
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	12,838,385	12,686,782	12,582,041	12,445,286	12,282,549
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	33,651,142	33,415,832	33,253,258	33,040,994	32,788,402
121							
122	**Total Assets and Other Debits**		112,505,419	112,904,648	113,198,326	113,420,656	113,581,846

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	8,026,247	8,026,247	8,026,247	8,026,247	8,026,247
136		Other Regulatory Liabilities	0	0	0	0	0
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	2,160,496	2,134,983	2,117,357	2,094,343	2,066,957
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	10,186,743	10,161,231	10,143,604	10,120,591	10,093,205
144							
145	**Total Liabilities and Other Credits**		10,186,743	10,161,231	10,143,604	10,120,591	10,093,205
146							
147							
148	**Total Rate Base**		946,230,676	876,740,695	830,443,774	784,177,461	737,945,586
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		10.96%	10.96%	10.96%	10.96%	10.96%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		103,727,704	96,110,073	91,034,912	85,963,106	80,895,075

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		*Schedule 3: Expenses*					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	28,559,759	28,478,117	28,613,068	29,006,474	29,456,063
164		Steam Power - Operations (Excluding 501 - Fuel)	5,587,580	5,748,634	5,867,918	5,985,276	6,106,478
165		Steam Power - Maintenance	9,228,409	9,474,951	9,681,030	9,879,488	10,069,667
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	16,589,955	16,973,125	17,185,283	17,382,907	17,621,908
172		Hydraulic - Maintenance	4,644,324	4,755,058	4,848,970	4,939,887	5,030,040
173		**Other Power Generation**					
174		Other Power - Fuel	139,025,672	150,656,126	154,703,708	158,852,480	163,104,971
175		Other Power - Operations (Excluding 547 - Fuel)	3,375,428	3,513,395	3,572,244	3,631,185	3,698,361
176		Other Power - Maintenance	25,574,670	26,134,035	26,584,845	27,063,372	27,557,276
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	129,776,846	152,917,856	166,552,405	184,530,915	204,164,918
179		System Control and Load Dispatching	480,570	480,570	480,570	480,570	480,570
180		Other Expenses	26,956,543	26,956,543	26,956,543	26,956,543	26,956,543
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	**Total Production Expense**		389,799,757	426,088,410	445,046,583	468,709,097	494,246,794
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	19,385,753	19,981,170	20,399,274	20,810,319	21,231,208
187		Total Operations less Wheeling	6,162,386	6,379,454	6,495,878	6,620,923	6,753,342
188		Total Maintenance	3,081,782	3,136,012	3,193,244	3,252,318	3,308,420
189	**Total Transmission Expense**		28,629,921	29,496,636	30,088,396	30,683,560	31,292,970
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	9,080,121	9,281,685	9,430,179	9,609,352	9,791,930
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		9,080,121	9,281,685	9,430,179	9,609,352	9,791,930
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	11,573,761	12,059,330	12,389,883	12,727,878	13,062,724
207		Office Supplies & Expenses	2,169,125	2,260,129	2,322,080	2,385,427	2,448,183
208		(Less) Administration Expenses Transferred - Credit	20,876	21,752	22,348	22,957	23,561
209		Outside Services Employed	6,977,138	7,269,859	7,469,130	7,672,887	7,874,746
210		Property Insurance	761,418	787,120	804,235	820,154	834,319
211		Injuries and Damages	1,963,848	2,046,240	2,102,329	2,159,680	2,216,497
212		Employee Pensions & Benefits	591,968	616,803	633,710	650,998	668,124
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	4,809,039	4,971,740	5,080,085	5,180,963	5,270,848
222	**Total Administration and General Expenses**		28,825,421	29,989,469	30,779,105	31,575,029	32,351,879
223							
224	**Total Operations and Maintenance**		456,335,219	494,856,200	515,344,263	540,577,039	567,683,573

	A	B	C	D	E	F	G
1	Avista	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	337,773	337,773	337,773	337,773	337,773
230		Amortization of Intangible Plant - Account 303	66,656	66,656	66,656	66,656	66,656
231		Steam Production Plant	11,519,867	11,519,867	11,519,867	11,519,867	11,519,867
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	7,552,507	7,552,507	7,552,507	7,552,507	7,552,507
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	13,036,318	13,036,318	13,036,318	13,036,318	13,036,318
236		Transmission Plant (i)	9,835,012	9,835,012	9,835,012	9,835,012	9,835,012
237		Distribution Plant	0	0	0	0	0
238		General Plant	1,726,252	1,712,219	1,709,767	1,706,615	1,702,936
239		Common Plant - Electric	2,574,407	2,574,407	2,574,407	2,574,407	2,574,407
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		46,648,791	46,634,759	46,632,307	46,629,155	46,625,476
245							
246							
247	**Total Operating Expenses**		502,984,011	541,490,960	561,976,570	587,206,194	614,309,049
248	*(Total O&M - Total Depreciation & Amortization)*						

	A	B	C	D	E	F	G
1	Avista	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
249							
250		Schedule 3A Items: Taxes (Including Income Taxes)					
251		Account Description					
252							
253							
254	FEDERAL						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	0	0	0	0	0
257		Other Federal Taxes	0	0	0	0	0
258	TOTAL FEDERAL		0	0	0	0	0
259							
260	STATE AND OTHER						
261		Property	11,612,854	11,475,723	11,380,980	11,257,280	11,110,077
262		Unemployment	0	0	0	0	0
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	TOTAL STATE AND OTHER TAXES		11,612,854	11,475,723	11,380,980	11,257,280	11,110,077
269							
270	TOTAL TAXES		11,612,854	11,475,723	11,380,980	11,257,280	11,110,077
271							
272							

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	238,789	238,789	238,789	238,789	238,789
279		(Less) Regulatory Debits	337,368	337,368	337,368	337,368	337,368
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		(98,579)	(98,579)	(98,579)	(98,579)	(98,579)
286							
287	**Sale for Resale:**						
288		Sales for Resale	123,135,845	131,326,312	136,440,384	140,980,033	144,736,934
289	**Total Sales for Resale**		123,135,845	131,326,312	136,440,384	140,980,033	144,736,934
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	309,017	309,017	309,017	309,017	309,017
295		Rent from Electric Property	909,186	890,577	877,899	861,574	842,475
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	12,183,659	12,183,659	12,183,659	12,183,659	12,183,659
298		Revenues from Transmission of Electricity of Others (i)	10,470,726	10,470,726	10,470,726	10,470,726	10,470,726
299							
300	**Total Other Revenues**		23,872,588	23,853,979	23,841,301	23,824,976	23,805,877
301							
302	**Total Other Included Items**		146,909,853	155,081,712	160,183,106	164,706,430	168,444,232
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	Avista	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
304							
305		*Schedule 4: Average System Cost*					
306							
307			Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
308							
309	Total Operating Expenses		502,984,011	541,490,960	561,976,570	587,206,194	614,309,049
310	*(From Schedule 3)*						
311							
312	Federal Income Tax Adjusted Return on Rate Base		103,727,704	96,110,073	91,034,912	85,963,106	80,895,075
313	*(From Schedule 2)*						
314							
315	State and Other Taxes		11,612,854	11,475,723	11,380,980	11,257,280	11,110,077
316	*(From Schedule 3a)*						
317							
318	Total Other Included Items		146,909,853	155,081,712	160,183,106	164,706,430	168,444,232
319	*(From Schedule 3b)*						
320							
321	Total Cost		471,414,717	493,995,044	504,209,356	519,720,150	537,869,969
322	*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*						
323							
324							
325							
326	**Contract System Cost**						
327	Production and Transmission		471,414,717	493,995,044	504,209,356	519,720,150	537,869,969
328	(Less) New Large Single Load Costs (d)		0	0	0	0	0
329	**Total Contract System Cost**		**471,414,717**	**493,995,044**	**504,209,356**	**519,720,150**	**537,869,969**
330							
331	**Contract System Load (MWh)**						
332	Total Retail Load		9,385,297	9,665,785	9,846,461	10,082,239	10,364,177
333	(Less) New Large Single Load		0	0	0	0	0
334	Total Retail Load (Net of NLSL) (d)		9,385,297	9,665,785	9,846,461	10,082,239	10,364,177
335	Distribution Loss (f)		476,340	490,576	499,746	511,712	526,022
336	**Total Contract System Load**		**9,861,636**	**10,156,361**	**10,346,207**	**10,593,951**	**10,890,199**
337							
338	**Average System Cost $/MWh**		**47.80**	**48.64**	**48.73**	**49.06**	**49.39**

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	0	0	0	0	0
5		Intangible Plant - Miscellaneous	0	0	0	0	0
6	**Total Intangible Plant**		0	0	0	0	0
7							
8	**Production Plant:**						
9		Steam Production	0	0	0	0	0
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	0	0	0	0	0
12		Other Production	18,232,751	18,232,751	18,232,751	18,232,751	18,232,751
13	**Total Production Plant**		18,232,751	18,232,751	18,232,751	18,232,751	18,232,751
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	4,077,516	4,077,516	4,077,516	4,077,516	4,077,516
17	**Total Transmission Plant**		4,077,516	4,077,516	4,077,516	4,077,516	4,077,516
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	24,214	24,214	24,214	24,214	24,214
25		Structures and Improvements	802,526	802,526	802,526	802,526	802,526
26		Furniture and Equipment	497,437	503,269	506,770	510,322	513,926
27		Transportation Equipment	134,081	133,568	133,273	132,983	132,698
28		Stores Equipment	3,888	3,888	3,888	3,888	3,888
29		Tools and Garage Equipment	141,409	141,409	141,409	141,409	141,409
30		Laboratory Equipment	4,819	4,819	4,819	4,819	4,819
31		Power Operated Equipment	260	259	259	258	257
32		Communication Equipment	96,492	96,492	96,492	96,492	96,492
33		Miscellaneous Equipment	49,147	49,147	49,147	49,147	49,147
34		Other Tangible Property	7,933	7,933	7,933	7,933	7,933
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		1,762,207	1,767,525	1,770,730	1,773,992	1,777,310
38							
39	**Total Electric Plant In-Service**		24,072,474	24,077,792	24,080,997	24,084,259	24,087,577
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	0	0	0	0	0
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	0	0	0	0	0
47		Other Production Plant	9,538,897	10,898,824	11,805,442	12,712,060	13,618,678
48		Transmission Plant (i)	1,782,020	1,930,988	2,030,300	2,129,612	2,228,924
49		Distribution Plant	0	0	0	0	0
50		General Plant	405,766	488,530	543,257	597,486	651,229
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	0	0	0	0	0
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61			0				
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		11,726,682	13,318,341	14,378,998	15,439,158	16,498,830
65							
66	**Total Net Plant**		12,345,792	10,759,451	9,702,000	8,645,101	7,588,747
67	*(Total Electric Plant In-Service) - (Total Depreciation & Amortization)*						

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
68							
69	Assets and Other Debits (Comparative Balance Sheet)						
70							
71	Cash Working Capital (f)		906,966	909,096	908,626	908,162	907,704
72							
73	Utility Plant		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		Total	0	0	0	0	0
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		Total	0	0	0	0	0
88							
89							
90		Fuel Stock	0	0	0	0	0
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	600,350	601,382	593,187	585,098	577,114
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	0	0	0	0	0
98		Prepayments	14,849	14,507	14,310	14,115	13,922
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		Total	615,199	615,889	607,496	599,212	591,036

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	314,232	307,068	302,924	298,833	294,796
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	0	0	0	0	0
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	0	0	0	0	0
115		Miscellaneous Deferred Debits	0	0	0	0	0
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	0	0	0	0	0
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	314,232	307,068	302,924	298,833	294,796
121							
122	**Total Assets and Other Debits**		1,836,397	1,832,054	1,819,046	1,806,208	1,793,536

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	0	0	0	0	0
136		Other Regulatory Liabilities	0	0	0	0	0
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	0	0	0	0	0
144							
145	**Total Liabilities and Other Credits**		0	0	0	0	0
146							
147							
148	**Total Rate Base**		14,182,188	12,591,505	11,521,046	10,451,309	9,382,282
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		4.00%	4.00%	4.00%	4.00%	4.00%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		567,569	503,910	461,070	418,260	375,477

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
155							
156							
157		*Schedule 3: Expenses*					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	0	0	0	0	0
164		Steam Power - Operations (Excluding 501 - Fuel)	0	0	0	0	0
165		Steam Power - Maintenance	0	0	0	0	0
166		**Nuclear Power Generation**	0				
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	0	0	0	0	0
172		Hydraulic - Maintenance	0	0	0	0	0
173		**Other Power Generation**	0				
174		Other Power - Fuel	717,990	761,637	761,637	761,637	761,637
175		Other Power - Operations (Excluding 547 - Fuel)	38,528	39,934	39,934	39,934	39,934
176		Other Power - Maintenance	102,844	104,686	104,686	104,686	104,686
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	56,257,244	60,958,639	62,461,082	64,536,424	65,964,540
179		System Control and Load Dispatching	556,503	556,503	556,503	556,503	556,503
180		Other Expenses	6,026,010	6,026,010	6,026,010	6,026,010	6,026,010
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	**Production Expense**		63,699,119	68,447,409	69,949,852	72,025,195	73,453,310
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	0	0	0	0	0
187		Total Operations less Wheeling	16,500	17,006	17,006	17,006	17,006
188		Total Maintenance	0	0	0	0	0
189	**Total Transmission Expense**		16,500	17,006	17,006	17,006	17,006
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

	A	B	C	D	E	F	G
1	FRANKLIN	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	0	0	0	0	0
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		0	0	0	0	0
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	159,779	163,998	162,888	161,793	160,712
207		Office Supplies & Expenses	31,776	32,615	32,395	32,177	31,962
208		(Less) Administration Expenses Transferred - Credit	0	0	0	0	0
209		Outside Services Employed	20,658	21,203	21,060	20,918	20,778
210		Property Insurance	27,069	27,467	27,097	26,731	26,370
211		Injuries and Damages	732	752	747	741	737
212		Employee Pensions & Benefits	275,328	282,597	280,685	278,798	276,935
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	0	0	0	0	0
222	**Total Administration and General Expenses**		515,342	528,632	524,871	521,158	517,494
223							
224	**Total Operations and Maintenance**		64,230,962	68,993,046	70,491,728	72,563,358	73,987,810

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	0	0	0	0	0
230		Amortization of Intangible Plant - Account 303	0	0	0	0	0
231		Steam Production Plant	0	0	0	0	0
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	0	0	0	0	0
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	906,618	906,618	906,618	906,618	906,618
236		Transmission Plant (i)	99,312	99,312	99,312	99,312	99,312
237		Distribution Plant	0	0	0	0	0
238		General Plant	61,744	61,235	61,376	61,519	61,664
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		1,067,674	1,067,165	1,067,306	1,067,449	1,067,594
245							
246							
247	**Total Operating Expenses**		65,298,636	70,060,211	71,559,035	73,630,808	75,055,404
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
249							
250		*Schedule 3A Items: Taxes (Including Income Taxes)*					
251		Account Description					
252							
253							
254	FEDERAL						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	47,600	48,770	48,441	48,115	47,793
257		Other Federal Taxes	0	0	0	0	0
258	TOTAL FEDERAL		47,600	48,770	48,441	48,115	47,793
259							
260	STATE AND OTHER						
261		Property	0	0	0	0	0
262		Unemployment	6,176	6,328	6,285	6,243	6,201
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	TOTAL STATE AND OTHER TAXES		6,176	6,328	6,285	6,243	6,201
269							
270	TOTAL TAXES		53,776	55,098	54,726	54,358	53,995
271							
272							

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
273		*Schedule 3B: Other Included Items*					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	0	0	0	0	0
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		0	0	0	0	0
286							
287	**Sale for Resale:**						
288		Sales for Resale	13,820,024	15,124,797	15,913,724	16,591,875	17,108,265
289	**Total Sales for Resale**		13,820,024	15,124,797	15,913,724	16,591,875	17,108,265
290							
291	**Other Revenues:**						
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	4,094	3,984	3,921	3,859	3,799
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	0	0	0	0	0
298		Revenues from Transmission of Electricity of Others (i)	88	88	88	88	88
299			0				
300	**Total Other Revenues**		4,182	4,072	4,009	3,947	3,887
301							
302	**Total Other Included Items**		13,824,205	15,128,869	15,917,733	16,595,822	17,112,152
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
304							
305		*Schedule 4: Average System Cost*					
306							
307			Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
308							
309	Total Operating Expenses		65,298,636	70,060,211	71,559,035	73,630,808	75,055,404
310	*(From Schedule 3)*						
311							
312	Federal Income Tax Adjusted Return on Rate Base		567,569	503,910	461,070	418,260	375,477
313	*(From Schedule 2)*						
314							
315	State and Other Taxes		53,776	55,098	54,726	54,358	53,995
316	*(From Schedule 3a)*						
317							
318	Total Other Included Items		13,824,205	15,128,869	15,917,733	16,595,822	17,112,152
319	*(From Schedule 3b)*						
320							
321	Total Cost		52,095,775	55,490,350	56,157,097	57,507,603	58,372,724
322	*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*						
323							
324							
325							
326	**Contract System Cost**						
327	Production and Transmission		52,095,775	55,490,350	56,157,097	57,507,603	58,372,724
328	(Less) New Large Single Load Costs (d)		0	0	0	0	0
329	**Total Contract System Cost**		**52,095,775**	**55,490,350**	**56,157,097**	**57,507,603**	**58,372,724**
330							
331	**Contract System Load (MWh)**						
332	Total Retail Load		1,010,000	1,034,000	1,049,000	1,064,218	1,079,656
333	(Less) New Large Single Load		0	0	0	0	0
334	Total Retail Load (Net of NLSL) (d)		1,010,000	1,034,000	1,049,000	1,064,218	1,079,656
335	Distribution Loss (f)		47,226	48,349	49,050	49,762	50,483
336	**Total Contract System Load**		**1,057,226**	**1,082,349**	**1,098,050**	**1,113,979**	**1,130,139**
337							
338	**Average System Cost $/MWh**		**49.28**	**51.27**	**51.14**	**51.62**	**51.65**

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	21,771,624	21,771,624	21,771,624	21,771,624	21,771,624
5		Intangible Plant - Miscellaneous	0	0	0	0	0
6	**Total Intangible Plant**		21,771,624	21,771,624	21,771,624	21,771,624	21,771,624
7							
8	**Production Plant:**						
9		Steam Production	865,431,711	865,431,711	865,431,711	865,431,711	865,431,711
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	667,750,066	667,750,066	667,750,066	667,750,066	667,750,066
12		Other Production	106,527,982	106,527,982	106,527,982	106,527,982	106,527,982
13	**Total Production Plant**		1,639,709,759	1,639,709,759	1,639,709,759	1,639,709,759	1,639,709,759
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	684,399,525	684,399,525	684,399,525	684,399,525	684,399,525
17	**Total Transmission Plant**		684,399,525	684,399,525	684,399,525	684,399,525	684,399,525
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	5,892,813	5,892,813	5,892,813	5,892,813	5,892,813
25		Structures and Improvements	45,685,853	45,685,853	45,685,853	45,685,853	45,685,853
26		Furniture and Equipment	21,161,654	21,313,856	21,355,273	21,410,526	21,462,271
27		Transportation Equipment	20,778,559	20,557,559	20,499,174	20,422,409	20,351,660
28		Stores Equipment	713,715	713,715	713,715	713,715	713,715
29		Tools and Garage Equipment	2,928,915	2,928,915	2,928,915	2,928,915	2,928,915
30		Laboratory Equipment	6,795,542	6,795,542	6,795,542	6,795,542	6,795,542
31		Power Operated Equipment	3,160,857	3,127,239	3,118,357	3,106,680	3,095,917
32		Communication Equipment	17,196,121	17,196,121	17,196,121	17,196,121	17,196,121
33		Miscellaneous Equipment	2,009,662	2,009,662	2,009,662	2,009,662	2,009,662
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		126,323,691	126,221,274	126,195,425	126,162,236	126,132,468
38							
39	**Total Electric Plant In-Service**		2,472,204,599	2,472,102,182	2,472,076,333	2,472,043,144	2,472,013,376
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	499,464,271	535,482,691	559,494,971	583,507,251	607,519,531
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	287,003,913	306,217,492	319,026,545	331,835,598	344,644,651
47		Other Production Plant	20,988,377	25,555,298	28,599,912	31,644,526	34,689,140
48		Transmission Plant (i)	258,765,350	279,349,523	293,072,305	306,795,087	320,517,869
49		Distribution Plant	0	0	0	0	0
50		General Plant	66,500,653	75,839,055	82,392,620	88,816,579	95,240,248
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	0	0	0	0	0
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	3,138,454	3,138,454	3,138,454	3,138,454	3,138,454
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		1,135,861,017	1,225,582,512	1,285,724,806	1,345,737,494	1,405,749,891
65							
66	**Total Net Plant**		1,336,343,583	1,246,519,670	1,186,351,527	1,126,305,650	1,066,263,485
67	*(Total Electric Plant In-Service) - (Total Depreciation & Amortization)*						

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		10,140,829	10,888,217	11,431,750	11,986,848	12,556,982
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	0	0	0	0	0
81							
82							
83		Investment in Associated Companies	55,937,107	55,937,107	55,937,107	55,937,107	55,937,107
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	55,937,107	55,937,107	55,937,107	55,937,107	55,937,107
88							
89							
90		Fuel Stock	18,456,956	18,404,194	18,491,407	18,745,649	19,036,199
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	28,684,299	29,193,702	29,703,023	30,164,422	30,644,634
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	1,316,633	1,340,015	1,363,394	1,384,572	1,406,614
98		Prepayments	5,960,319	5,885,432	5,865,379	5,838,837	5,814,198
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	54,418,208	54,823,343	55,423,202	56,133,480	56,901,646

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	8,582,803	8,476,569	8,448,120	8,410,467	8,375,511
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	0	0	0	0	0
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	0	0	0	0	0
115		Miscellaneous Deferred Debits	59,024,108	59,024,108	59,024,108	59,024,108	59,024,108
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	8,684,282	8,576,793	8,548,008	8,509,909	8,474,540
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	76,291,193	76,077,470	76,020,236	75,944,484	75,874,159
121							
122	**Total Assets and Other Debits**		196,787,337	197,726,137	198,812,295	200,001,918	201,269,894

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	15,405,539	15,405,539	15,405,539	15,405,539	15,405,539
136		Other Regulatory Liabilities	0	0	0	0	0
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	15,405,539	15,405,539	15,405,539	15,405,539	15,405,539
144							
145	**Total Liabilities and Other Credits**		15,405,539	15,405,539	15,405,539	15,405,539	15,405,539
146							
147							
148	**Total Rate Base**		1,517,725,381	1,428,840,269	1,369,758,283	1,310,902,029	1,252,127,840
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		10.95%	10.95%	10.95%	10.95%	10.95%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		166,169,214	156,437,566	149,968,934	143,525,016	137,090,083

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
155							
156							
157		*Schedule 3: Expenses*					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	122,746,777	122,395,891	122,975,894	124,666,711	126,598,999
164		Steam Power - Operations (Excluding 501 - Fuel)	21,019,596	21,625,459	22,074,185	22,515,669	22,971,609
165		Steam Power - Maintenance	32,042,281	32,898,309	33,613,844	34,302,916	34,963,244
166		**Nuclear Power Generation**	0				
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**	0				
171		Hydraulic - Operation	27,077,007	27,711,850	28,058,238	28,380,897	28,771,111
172		Hydraulic - Maintenance	9,280,161	9,501,425	9,689,077	9,870,746	10,050,887
173		**Other Power Generation**					
174		Other Power - Fuel	15,223,463	16,256,336	16,693,084	17,140,752	17,599,611
175		Other Power - Operations (Excluding 547 - Fuel)	1,337,075	1,391,726	1,415,038	1,438,385	1,464,995
176		Other Power - Maintenance	981,453	1,003,252	1,020,558	1,038,928	1,057,889
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	290,330,411	336,650,482	359,278,297	383,950,513	404,335,599
179		System Control and Load Dispatching	77,489	77,489	77,489	77,489	77,489
180		Other Expenses	(118,678,522)	(118,678,522)	(118,678,522)	(118,678,522)	(118,678,522)
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	**Total Production Expense**		401,437,191	450,833,697	476,217,183	504,704,484	529,212,909
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	11,107,188	11,448,280	11,687,834	11,923,343	12,164,493
187		Total Operations less Wheeling	11,029,613	11,418,127	11,626,507	11,850,316	12,087,323
188		Total Maintenance	6,644,271	6,761,190	6,884,581	7,011,943	7,132,899
189	**Total Transmission Expense**		28,781,073	29,627,597	30,198,922	30,785,603	31,384,714
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	23,673,383	24,198,895	24,586,041	25,053,176	25,529,187
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		23,673,383	24,198,895	24,586,041	25,053,176	25,529,187
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	29,907,589	31,115,655	32,009,753	32,937,720	33,888,991
207		Office Supplies & Expenses	10,687,668	11,119,378	11,438,889	11,770,504	12,110,447
208		(Less) Administration Expenses Transferred - Credit	16,645,838	17,318,218	17,815,851	18,332,335	18,861,789
209		Outside Services Employed	6,748,145	7,020,724	7,222,462	7,431,843	7,646,481
210		Property Insurance	2,231,324	2,305,313	2,367,077	2,429,580	2,493,881
211		Injuries and Damages	3,273,090	3,405,301	3,503,152	3,604,708	3,708,816
212		Employee Pensions & Benefits	16,744,109	17,420,459	17,921,030	18,440,563	18,973,143
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	2,589,547	2,679,640	2,752,614	2,826,913	2,903,284
222	**Total Administration and General Expenses**		55,535,634	57,748,252	59,399,126	61,109,495	62,863,253
223							
224	**Total Operations and Maintenance**		509,427,281	562,408,441	590,401,273	621,652,758	648,990,062

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	781,058	781,058	781,058	781,058	781,058
230		Amortization of Intangible Plant - Account 303	4,084	4,084	4,084	4,084	4,084
231		Steam Production Plant	24,012,280	24,012,280	24,012,280	24,012,280	24,012,280
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	12,809,053	12,809,053	12,809,053	12,809,053	12,809,053
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	3,044,614	3,044,614	3,044,614	3,044,614	3,044,614
236		Transmission Plant (i)	13,722,782	13,722,782	13,722,782	13,722,782	13,722,782
237		Distribution Plant	0	0	0	0	0
238		General Plant	6,900,705	6,852,198	6,851,159	6,849,840	6,848,672
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		61,274,577	61,226,069	61,225,031	61,223,711	61,222,543
245							
246							
247	**Total Operating Expenses**		570,701,858	623,634,510	651,626,304	682,876,469	710,212,606
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		*Schedule 3A Items: Taxes (Including Income Taxes)*					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	74,949	77,801	79,900	82,157	84,550
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		74,949	77,801	79,900	82,157	84,550
259							
260	**STATE AND OTHER**						
261		Property	8,924,552	8,814,089	8,784,507	8,745,354	8,709,006
262		Unemployment	147,350	152,958	157,085	161,522	166,227
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		9,071,902	8,967,046	8,941,592	8,906,876	8,875,233
269							
270	**TOTAL TAXES**		9,146,851	9,044,847	9,021,493	8,989,033	8,959,784
271							
272							

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	0	0	0	0	0
279		(Less) Regulatory Debits	11,665	11,665	11,665	11,665	11,665
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	2,754,122	2,754,122	2,754,122	2,754,122	2,754,122
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	5,624,737	5,624,737	5,624,737	5,624,737	5,624,737
285	**Total Other Included Items**		8,367,194	8,367,194	8,367,194	8,367,194	8,367,194
286							
287	**Sale for Resale:**						
288		Sales for Resale	116,894,237	127,279,978	133,590,310	139,041,787	143,249,743
289	**Total Sales for Resale**		116,894,237	127,279,978	133,590,310	139,041,787	143,249,743
290							
291	**Other Revenues:**						
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	6,798,015	6,641,208	6,599,782	6,545,315	6,495,115
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	273,764	273,764	273,764	273,764	273,764
298		Revenues from Transmission of Electricity of Others (i)	16,229,091	16,229,091	16,229,091	16,229,091	16,229,091
299							
300	**Total Other Revenues**		23,300,870	23,144,063	23,102,637	23,048,170	22,997,970
301							
302	**Total Other Included Items**		148,562,301	158,791,234	165,060,141	170,457,151	174,614,907
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		*Schedule 4: Average System Cost*					
306							
307			**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
308							
309	**Total Operating Expenses**		570,701,858	623,634,510	651,626,304	682,876,469	710,212,606
310	*(From Schedule 3)*						
311							
312	**Federal Income Tax Adjusted Return on Rate Base**		166,169,214	156,437,566	149,968,934	143,525,016	137,090,083
313	*(From Schedule 2)*						
314							
315	**State and Other Taxes**		9,146,851	9,044,847	9,021,493	8,989,033	8,959,784
316	*(From Schedule 3a)*						
317							
318	**Total Other Included Items**		148,562,301	158,791,234	165,060,141	170,457,151	174,614,907
319	*(From Schedule 3b)*						
320							
321	**Total Cost**		597,455,622	630,325,688	645,556,590	664,933,368	681,647,566
322	*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*						
323							
324							
325							
326	**Contract System Cost**						
327	Production and Transmission		597,455,622	630,325,688	645,556,590	664,933,368	681,647,566
328	(Less) New Large Single Load Costs (d)		25,105,381	25,148,494	25,221,222	25,341,151	25,480,801
329	**Total Contract System Cost**		**572,350,242**	**605,177,194**	**620,335,368**	**639,592,217**	**656,166,765**
330							
331	**Contract System Load (MWh)**						
332	Total Retail Load		15,379,179	15,794,344	15,929,677	16,106,684	16,269,278
333	(Less) New Large Single Load		385,400	385,400	385,400	385,400	385,400
334	Total Retail Load (Net of NLSL) (d)		14,993,779	15,408,944	15,544,277	15,721,284	15,883,878
335	Distribution Loss (f)		1,061,163	1,089,810	1,099,148	1,111,361	1,122,580
336	**Total Contract System Load**		**16,054,942**	**16,498,753**	**16,643,425**	**16,832,645**	**17,006,458**
337							
338	**Average System Cost $/MWh**		**35.65**	**36.68**	**37.27**	**38.00**	**38.58**

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	469	452	447	442	437
5		Intangible Plant - Miscellaneous	1,927,038	1,927,038	1,927,038	1,927,038	1,927,038
6	**Total Intangible Plant**		1,927,507	1,927,490	1,927,486	1,927,480	1,927,475
7							
8	**Production Plant:**		0				
9	110	Steam Production	0	0	0	0	0
10	250	Nuclear Production	0	0	0	0	0
11	380	Hydraulic Production	0	0	0	0	0
12	480	Other Production	2,646,622	2,646,622	2,646,622	2,646,622	2,646,622
13	**Total Production Plant**		2,646,622	2,646,622	2,646,622	2,646,622	2,646,622
14							
15	**Transmission Plant: (i)**						
16	840	Transmission Plant	298,279,309	298,279,309	298,279,309	298,279,309	298,279,309
17	**Total Transmission Plant**		298,279,309	298,279,309	298,279,309	298,279,309	298,279,309
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	94,844	94,844	94,844	94,844	94,844
25		Structures and Improvements	1,809,581	1,809,581	1,809,581	1,809,581	1,809,581
26		Furniture and Equipment	630,596	636,118	640,095	644,211	648,469
27		Transportation Equipment	6,388,045	6,387,845	6,387,705	6,387,563	6,387,419
28		Stores Equipment	99,654	99,654	99,654	99,654	99,654
29		Tools and Garage Equipment	949,746	949,746	949,746	949,746	949,746
30		Laboratory Equipment	738,144	738,144	738,144	738,144	738,144
31		Power Operated Equipment	563,748	563,731	563,718	563,706	563,693
32		Communication Equipment	4,463,935	4,463,935	4,463,935	4,463,935	4,463,935
33		Miscellaneous Equipment	42,780	42,780	42,780	42,780	42,780
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36			0				
37	**Total General Plant**		15,781,075	15,786,379	15,790,203	15,794,165	15,798,267
38							
39	**Total Electric Plant In-Service**		318,634,513	318,639,800	318,643,619	318,647,576	318,651,674
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	0	0	0	0	0
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	0	0	0	0	0
47		Other Production Plant	2,349,170	2,510,705	2,618,395	2,726,085	2,833,775
48		Transmission Plant (i)	149,303,729	161,885,566	170,273,458	178,661,350	187,049,241
49		Distribution Plant	0	0	0	0	0
50		General Plant	10,568,053	11,595,811	12,259,690	12,913,472	13,556,985
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	752,166	882,306	969,066	1,055,825	1,142,585
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	8,783,353	10,331,966	11,364,375	12,396,784	13,429,192
59		Amortization of Other Utility Plant (a)	8,670,842	9,361,498	9,821,935	10,282,373	10,742,810
60		Amortization of Acquisition Adjustments	3,177,472	3,319,843	3,414,757	3,509,672	3,604,586
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		183,604,785	199,887,695	210,721,676	221,545,560	232,359,175
65							
66	**Total Net Plant**		135,029,728	118,752,105	107,921,943	97,102,016	86,292,499
67	*(Total Electric Plant In-Service) - (Total Depreciation & Amortization)*						

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		5,185,333	5,327,511	5,423,152	5,523,115	5,625,108
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	13,346,968	13,346,968	13,346,968	13,346,968	13,346,968
79		Acquisition Adjustments (Electric)	3,106,285	3,106,285	3,106,285	3,106,285	3,106,285
80		**Total**	16,453,253	16,453,253	16,453,253	16,453,253	16,453,253
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	200,067	199,495	200,440	203,196	206,346
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	1,876,394	1,904,061	1,922,457	1,939,052	1,955,428
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	0	0	0	0	0
98		Prepayments	0	0	0	0	0
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	2,076,461	2,103,556	2,122,898	2,142,248	2,161,774

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	1,517,204	1,493,763	1,477,324	1,460,685	1,443,862
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	11,138,909	11,138,909	11,138,909	11,138,909	11,138,909
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	18	18	17	17	17
115		Miscellaneous Deferred Debits	0	0	0	0	0
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	630,749	621,004	614,169	607,252	600,258
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	13,286,880	13,253,693	13,230,420	13,206,864	13,183,046
121							
122	**Total Assets and Other Debits**		37,001,927	37,138,013	37,229,723	37,325,481	37,423,182

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Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	3,105,871	3,105,871	3,105,871	3,105,871	3,105,871
136		Other Regulatory Liabilities	94,871	94,871	94,871	94,871	94,871
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	3,200,742	3,200,742	3,200,742	3,200,742	3,200,742
144							
145	**Total Liabilities and Other Credits**		3,200,742	3,200,742	3,200,742	3,200,742	3,200,742
146							
147							
148	**Total Rate Base**		168,830,913	152,689,376	141,950,925	131,226,755	120,514,939
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		11.20%	11.20%	11.20%	11.20%	11.20%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		18,902,309	17,095,103	15,892,826	14,692,148	13,492,853

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Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	5,584,064	5,568,101	5,594,487	5,671,407	5,759,312
164		Steam Power - Operations (Excluding 501 - Fuel)	0	0	0	0	0
165		Steam Power - Maintenance	0	0	0	0	0
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	0	0	0	0	0
172		Hydraulic - Maintenance	0	0	0	0	0
173		**Other Power Generation**					
174		Other Power - Fuel	125,151	133,642	137,233	140,913	144,685
175		Other Power - Operations (Excluding 547 - Fuel)	25,704	26,755	27,203	27,652	28,164
176		Other Power - Maintenance	71,233	72,815	74,071	75,404	76,780
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	353,241,185	376,153,626	391,819,121	407,020,297	421,484,843
179		System Control and Load Dispatching	0	0	0	0	0
180		Other Expenses	9,879,017	9,879,017	9,879,017	9,879,017	9,879,017
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	**Total Production Expense**		368,926,355	391,833,956	407,531,132	422,814,691	437,372,801
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	5,195,113	5,354,650	5,466,696	5,576,850	5,689,641
187		Total Operations less Wheeling	7,000,790	7,247,390	7,379,655	7,521,712	7,672,147
188		Total Maintenance	3,548,913	3,611,363	3,677,270	3,745,298	3,809,904
189	**Total Transmission Expense**		15,744,816	16,213,404	16,523,620	16,843,860	17,171,692
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

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Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	0	0	0	0	0
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		0	0	0	0	0
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	4,338,362	4,507,222	4,621,044	4,740,797	4,862,086
207		Office Supplies & Expenses	961,123	998,532	1,023,748	1,050,278	1,077,149
208		(Less) Administration Expenses Transferred - Credit	775,455	805,637	825,982	847,387	869,067
209		Outside Services Employed	1,036,714	1,077,066	1,104,265	1,132,882	1,161,865
210		Property Insurance	120,184	123,783	126,124	128,569	130,996
211		Injuries and Damages	1,200,939	1,247,682	1,279,190	1,312,340	1,345,915
212		Employee Pensions & Benefits	(127,648)	(132,616)	(135,965)	(139,489)	(143,058)
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	8,297,201	8,679,764	8,942,326	9,219,538	9,503,038
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	710,473	732,301	746,557	761,460	776,287
222	**Total Administration and General Expenses**		15,761,893	16,428,096	16,881,307	17,358,988	17,845,211
223							
224	**Total Operations and Maintenance**		400,433,064	424,475,455	440,936,059	457,017,539	472,389,705

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Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	0	0	0	0	0
230		Amortization of Intangible Plant - Account 303	81,945	81,945	81,945	81,945	81,945
231		Steam Production Plant	0	0	0	0	0
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	0	0	0	0	0
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	107,690	107,690	107,690	107,690	107,690
236		Transmission Plant (i)	8,387,892	8,387,892	8,387,892	8,387,892	8,387,892
237		Distribution Plant	0	0	0	0	0
238		General Plant	803,545	797,639	797,970	798,309	798,658
239		Common Plant - Electric	605,221	605,221	605,221	605,221	605,221
240		Common Plant - Electric	456,267	456,267	456,267	456,267	456,267
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	479,950	479,950	479,950	479,950	479,950
243		Amortization of Plant Acquisition Adjustments (Electric)	94,914	94,914	94,914	94,914	94,914
244	**Total Depreciation and Amortization**		11,017,424	11,011,518	11,011,849	11,012,188	11,012,537
245							
246							
247	**Total Operating Expenses**		411,450,488	435,486,974	451,947,908	468,029,727	483,402,241
248	*(Total O&M - Total Depreciation & Amortization)*						

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	675,441	700,152	716,614	734,650	753,628
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		675,441	700,152	716,614	734,650	753,628
259							
260	**STATE AND OTHER**						
261	96000	Property	12,488,424	12,295,473	12,160,160	12,023,206	11,884,729
262		Unemployment	4,558	4,724	4,836	4,957	5,085
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		12,492,981	12,300,198	12,164,996	12,028,163	11,889,814
269							
270	**TOTAL TAXES**		13,168,422	13,000,350	12,881,610	12,762,813	12,643,442
271							
272							

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	455,426	455,426	455,426	455,426	455,426
279		(Less) Regulatory Debits	1,819,311	1,819,311	1,819,311	1,819,311	1,819,311
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		(1,363,885)	(1,363,885)	(1,363,885)	(1,363,885)	(1,363,885)
286							
287	**Sale for Resale:**						
288		Sales for Resale	49,426,672	54,093,133	56,914,694	59,340,068	61,186,915
289	**Total Sales for Resale**		49,426,672	54,093,133	56,914,694	59,340,068	61,186,915
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	580,911	571,896	565,574	559,176	552,707
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	(448,071)	(448,071)	(448,071)	(448,071)	(448,071)
298		Revenues from Transmission of Electricity of Others (i)	33,362,439	33,362,439	33,362,439	33,362,439	33,362,439
299							
300	**Total Other Revenues**		33,495,279	33,486,264	33,479,942	33,473,544	33,467,075
301							
302	**Total Other Included Items**		81,558,066	86,215,511	89,030,750	91,449,727	93,290,104
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		*Schedule 4: Average System Cost*					
306							
307			**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
308							
309		**Total Operating Expenses**	411,450,488	435,486,974	451,947,908	468,029,727	483,402,241
310		*(From Schedule 3)*					
311							
312		**Federal Income Tax Adjusted Return on Rate Base**	18,902,309	17,095,103	15,892,826	14,692,148	13,492,853
313		*(From Schedule 2)*					
314							
315		**State and Other Taxes**	13,168,422	13,000,350	12,881,610	12,762,813	12,643,442
316		*(From Schedule 3a)*					
317							
318		**Total Other Included Items**	81,558,066	86,215,511	89,030,750	91,449,727	93,290,104
319		*(From Schedule 3b)*					
320							
321		**Total Cost**	**361,963,153**	**379,366,915**	**391,691,594**	**404,034,961**	**416,248,432**
322		*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*					
323							
324							
325							
326		**Contract System Cost**					
327		Production and Transmission	361,963,153	379,366,915	391,691,594	404,034,961	416,248,432
328		(Less) New Large Single Load Costs (d)	0	0	0	0	0
329		**Total Contract System Cost**	**361,963,153**	**379,366,915**	**391,691,594**	**404,034,961**	**416,248,432**
330							
331		**Contract System Load (MWh)**					
332		Total Retail Load	6,022,446	6,137,896	6,216,581	6,296,430	6,377,459
333		(Less) New Large Single Load	0	0	0	0	0
334		Total Retail Load (Net of NLSL) (d)	6,022,446	6,137,896	6,216,581	6,296,430	6,377,459
335		Distribution Loss (f)	264,988	270,067	273,530	277,043	280,608
336		**Total Contract System Load**	**6,287,433**	**6,407,964**	**6,490,111**	**6,573,472**	**6,658,067**
337							
338		**Average System Cost $/MWh**	**57.57**	**59.20**	**60.35**	**61.46**	**62.52**

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	48,106,078	48,106,078	48,106,078	48,106,078	48,106,078
5		Intangible Plant - Miscellaneous	114,767,228	114,767,228	114,767,228	114,767,228	114,767,228
6	**Total Intangible Plant**		162,873,306	162,873,306	162,873,306	162,873,306	162,873,306
7							
8	**Production Plant:**						
9		Steam Production	2,040,634,760	2,040,634,760	2,040,634,760	2,040,634,760	2,040,634,760
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	222,423,378	222,423,378	222,423,378	222,423,378	222,423,378
12		Other Production	1,388,275,447	1,388,275,447	1,388,275,447	1,388,275,447	1,388,275,447
13	**Total Production Plant**		3,651,333,584	3,651,333,584	3,651,333,584	3,651,333,584	3,651,333,584
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	1,197,843,013	1,197,843,013	1,197,843,013	1,197,843,013	1,197,843,013
17	**Total Transmission Plant**		1,197,843,013	1,197,843,013	1,197,843,013	1,197,843,013	1,197,843,013
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	4,753,836	5,017,116	5,017,116	5,017,116	5,017,116
25		Structures and Improvements	78,108,382	82,434,233	82,434,233	82,434,233	82,434,233
26		Furniture and Equipment	23,924,428	25,359,670	25,438,118	25,600,176	25,768,698
27		Transportation Equipment	15,020,551	15,767,476	15,708,092	15,588,138	15,467,145
28		Stores Equipment	4,120,933	4,349,161	4,349,161	4,349,161	4,349,161
29		Tools and Garage Equipment	20,002,100	21,109,870	21,109,870	21,109,870	21,109,870
30		Laboratory Equipment	14,560,050	15,366,424	15,366,424	15,366,424	15,366,424
31		Power Operated Equipment	20,279,096	21,287,512	21,207,338	21,045,390	20,882,038
32		Communication Equipment	82,654,899	87,232,549	87,232,549	87,232,549	87,232,549
33		Miscellaneous Equipment	1,961,923	2,070,579	2,070,579	2,070,579	2,070,579
34		Other Tangible Property	199,330,966	211,442,084	212,204,658	213,779,979	215,418,138
35		Asset Retirement Costs for General Plant	12,365	13,050	13,050	13,050	13,050
36							
37	**Total General Plant**		464,729,529	491,449,725	492,151,189	493,606,666	495,129,003
38							
39	**Total Electric Plant In-Service**		5,476,779,433	5,503,499,628	5,504,201,093	5,505,656,569	5,507,178,907
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	1,199,972,860	1,292,032,113	1,353,404,949	1,414,777,785	1,476,150,620
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	111,154,464	119,256,200	124,657,357	130,058,514	135,459,671
47		Other Production Plant	109,302,620	173,541,419	216,367,285	259,193,151	302,019,017
48		Transmission Plant (i)	515,761,382	552,105,585	576,335,053	600,564,522	624,793,990
49		Distribution Plant	0	0	0	0	0
50		General Plant	107,022,992	207,667,547	221,114,903	234,026,183	246,904,088
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	9,032,792	10,545,807	11,554,483	12,563,159	13,571,836
53		Amortization of Intangible Plant - Account 303	97,380,694	109,783,570	118,052,153	126,320,737	134,589,321
54		Mining Plant Depreciation	10,398,961	10,398,961	10,398,961	10,398,961	10,398,961
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	45,435	45,435	45,435	45,435	45,435
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	41,850,878	45,275,669	47,558,863	49,842,057	52,125,250
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		2,201,923,080	2,520,652,306	2,679,489,443	2,837,790,505	2,996,058,190
65							
66	**Total Net Plant**		3,274,856,353	2,982,847,323	2,824,711,650	2,667,866,065	2,511,120,716
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		41,419,342	42,638,984	43,482,735	44,322,378	45,175,349
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	13,798,491	13,728,557	13,679,222	13,578,422	13,475,164
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	65,501,139	65,501,139	65,501,139	65,501,139	65,501,139
80		**Total**	79,299,630	79,229,696	79,180,361	79,079,561	78,976,303
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	43,374,549	43,250,558	43,455,512	44,052,989	44,735,794
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	48,044,120	49,268,535	50,118,718	50,751,849	51,384,554
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	0	0	0	0	0
98		Prepayments	22,727,960	22,612,770	22,531,509	22,365,477	22,195,398
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	114,146,629	115,131,863	116,105,739	117,170,315	118,315,745

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	7,448,510	7,695,161	7,669,461	7,616,939	7,563,120
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	20,428,713	20,428,713	20,428,713	20,428,713	20,428,713
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	31,613	32,660	32,551	32,328	32,100
115		Miscellaneous Deferred Debits	19,148,701	19,148,701	19,148,701	19,148,701	19,148,701
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	5,699,304	5,888,032	5,868,367	5,828,179	5,786,999
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	52,756,841	53,193,268	53,147,793	53,054,860	52,959,632
121							
122	**Total Assets and Other Debits**		287,622,442	290,193,811	291,916,629	293,627,114	295,427,030

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	11,393,801	11,393,801	11,393,801	11,393,801	11,393,801
136		Other Regulatory Liabilities	163,894	163,894	163,894	163,894	163,894
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	11,557,695	11,557,695	11,557,695	11,557,695	11,557,695
144							
145	**Total Liabilities and Other Credits**		11,557,695	11,557,695	11,557,695	11,557,695	11,557,695
146							
147							
148	**Total Rate Base**		3,550,921,101	3,261,483,439	3,105,070,584	2,949,935,484	2,794,990,052
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		10.87%	10.87%	10.87%	10.87%	10.87%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		385,888,364	354,434,377	337,436,562	320,577,604	303,739,258

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	256,449,549	255,716,457	256,928,234	260,460,783	264,497,829
164		Steam Power - Operations (Excluding 501 - Fuel)	49,346,088	50,768,425	51,821,865	52,858,302	53,928,678
165		Steam Power - Maintenance	75,727,470	77,750,575	79,441,642	81,070,167	82,630,760
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	12,665,274	12,962,222	13,124,245	13,275,169	13,457,691
172		Hydraulic - Maintenance	2,633,999	2,696,800	2,750,062	2,801,625	2,852,755
173		**Other Power Generation**					
174		Other Power - Fuel	135,594,098	144,793,804	148,683,887	152,671,222	156,758,240
175		Other Power - Operations (Excluding 547 - Fuel)	18,666,861	19,429,850	19,755,298	20,081,253	20,452,749
176		Other Power - Maintenance	15,256,738	15,593,188	15,862,169	16,147,688	16,442,382
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	849,729,899	931,310,925	983,611,992	1,044,819,526	1,101,020,408
179		System Control and Load Dispatching	1,056,343	1,056,343	1,056,343	1,056,343	1,056,343
180		Other Expenses	25,120,151	25,120,151	25,120,151	25,120,151	25,120,151
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	27,304,074	27,716,026	27,992,455	28,552,304	29,123,350
183	**Total Production Expense**		1,469,550,546	1,564,914,767	1,626,148,345	1,698,914,536	1,767,341,339
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	47,112,104	48,558,874	49,574,963	50,573,898	51,596,755
187		Total Operations less Wheeling	9,755,067	10,098,685	10,282,985	10,480,932	10,690,551
188		Total Maintenance	11,848,963	12,057,469	12,277,516	12,504,646	12,720,350
189	**Total Transmission Expense**		68,716,134	70,715,028	72,135,464	73,559,476	75,007,655
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	8,062,565	8,241,542	8,373,394	8,532,489	8,694,606
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		8,062,565	8,241,542	8,373,394	8,532,489	8,694,606
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	35,529,013	37,140,249	38,244,176	39,388,535	40,556,216
207		Office Supplies & Expenses	2,643,942	2,763,844	2,845,995	2,931,154	3,018,048
208		(Less) Administration Expenses Transferred - Credit	5,879,679	6,146,322	6,329,010	6,518,389	6,711,628
209		Outside Services Employed	4,631,289	4,841,318	4,985,217	5,134,387	5,286,597
210		Property Insurance	8,909,498	9,628,578	9,886,712	10,123,394	10,360,959
211		Injuries and Damages	2,527,742	2,642,374	2,720,914	2,802,331	2,885,406
212		Employee Pensions & Benefits	0	0	0	0	0
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	1,809,543	1,955,661	2,008,090	2,056,163	2,104,415
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	7,550,852	7,863,367	8,075,333	8,271,110	8,467,839
222	**Total Administration and General Expenses**		54,103,114	56,777,748	58,421,246	60,076,358	61,759,022
223							
224	**Total Operations and Maintenance**		1,600,432,359	1,700,649,085	1,765,078,449	1,841,082,858	1,912,802,622

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	1,037,367	1,037,367	1,037,367	1,037,367	1,037,367
230		Amortization of Intangible Plant - Account 303	8,268,584	8,268,584	8,268,584	8,268,584	8,268,584
231		Steam Production Plant	61,372,836	61,372,836	61,372,836	61,372,836	61,372,836
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	5,401,157	5,401,157	5,401,157	5,401,157	5,401,157
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	42,825,866	42,825,866	42,825,866	42,825,866	42,825,866
236		Transmission Plant (i)	24,229,468	24,229,468	24,229,468	24,229,468	24,229,468
237		Distribution Plant	0	0	0	0	0
238		General Plant	7,956,628	13,928,523	13,953,410	14,004,933	14,058,666
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	2,283,194	2,283,194	2,283,194	2,283,194	2,283,194
244	**Total Depreciation and Amortization**		153,375,100	159,346,996	159,371,882	159,423,405	159,477,139
245							
246							
247	**Total Operating Expenses**		1,753,807,459	1,859,996,081	1,924,450,331	2,000,506,264	2,072,279,760
248	*(Total O&M - Total Depreciation & Amortization)*						

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Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		*Schedule 3A Items: Taxes (Including Income Taxes)*					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	14,288,790	14,903,199	15,320,098	15,767,033	16,238,389
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		14,288,790	14,903,199	15,320,098	15,767,033	16,238,389
259							
260	**STATE AND OTHER**						
261		Property	24,261,806	25,065,217	24,981,504	24,810,425	24,635,122
262		Unemployment	685,345	714,815	734,811	756,247	778,855
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		24,947,151	25,780,031	25,716,315	25,566,672	25,413,977
269							
270	**TOTAL TAXES**		39,235,941	40,683,230	41,036,412	41,333,705	41,652,366
271							
272							

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	0	0	0	0	0
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	6,047,872	6,047,872	6,047,872	6,047,872	6,047,872
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		6,047,872	6,047,872	6,047,872	6,047,872	6,047,872
286							
287	**Sale for Resale:**						
288		Sales for Resale	849,104,067	922,889,664	967,804,280	1,006,679,085	1,036,838,401
289	**Total Sales for Resale**		849,104,067	922,889,664	967,804,280	1,006,679,085	1,036,838,401
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	44,786	44,786	44,786	44,786	44,786
295		Rent from Electric Property	3,227,889	3,194,319	3,170,852	3,123,451	3,075,639
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	21,136	21,136	21,136	21,136	21,136
298		Revenues from Transmission of Electricity of Others (i)	23,361,647	23,361,647	23,361,647	23,361,647	23,361,647
299							
300	**Total Other Revenues**		26,655,458	26,621,888	26,598,421	26,551,020	26,503,208
301							
302	**Total Other Included Items**		881,807,397	955,559,424	1,000,450,573	1,039,277,977	1,069,389,481
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		*Schedule 4: Average System Cost*					
306							
307			**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
308							
309		**Total Operating Expenses**	1,753,807,459	1,859,996,081	1,924,450,331	2,000,506,264	2,072,279,760
310		*(From Schedule 3)*					
311							
312		**Federal Income Tax Adjusted Return on Rate Base**	385,888,364	354,434,377	337,436,562	320,577,604	303,739,258
313		*(From Schedule 2)*					
314							
315		**State and Other Taxes**	39,235,941	40,683,230	41,036,412	41,333,705	41,652,366
316		*(From Schedule 3a)*					
317							
318		**Total Other Included Items**	881,807,397	955,559,424	1,000,450,573	1,039,277,977	1,069,389,481
319		*(From Schedule 3b)*					
320							
321		**Total Cost**	**1,297,124,368**	**1,299,554,264**	**1,302,472,733**	**1,323,139,596**	**1,348,281,903**
322		*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*					
323							
324							
325							
326		**Contract System Cost**					
327		Production and Transmission	1,297,124,368	1,299,554,264	1,302,472,733	1,323,139,596	1,348,281,903
328		(Less) New Large Single Load Costs (d)	0	0	0	0	0
329		**Total Contract System Cost**	**1,297,124,368**	**1,299,554,264**	**1,302,472,733**	**1,323,139,596**	**1,348,281,903**
330							
331		**Contract System Load (MWh)**					
332		Total Retail Load	22,317,614	22,654,332	22,880,278	23,337,884	23,804,641
333		(Less) New Large Single Load	0	0	0	0	0
334		Total Retail Load (Net of NLSL) (d)	22,317,614	22,654,332	22,880,278	23,337,884	23,804,641
335		Distribution Loss (f)	598,112	607,136	613,191	625,455	637,964
336		**Total Contract System Load**	**22,915,726**	**23,261,468**	**23,493,469**	**23,963,339**	**24,442,606**
337							
338		**Average System Cost $/MWh**	**56.60**	**55.87**	**55.44**	**55.22**	**55.16**

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	63,106,174	63,106,174	63,106,174	63,106,174	63,106,174
5		Intangible Plant - Miscellaneous	44,076,821	44,076,821	44,076,821	44,076,821	44,076,821
6	**Total Intangible Plant**		107,182,995	107,182,995	107,182,995	107,182,995	107,182,995
7							
8	**Production Plant:**						
9		Steam Production	830,266,857	830,266,857	830,266,857	830,266,857	830,266,857
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	352,114,043	352,114,043	352,114,043	352,114,043	352,114,043
12		Other Production	1,569,444,272	1,569,444,272	1,569,444,272	1,569,444,272	1,569,444,272
13	**Total Production Plant**		2,751,825,172	2,751,825,172	2,751,825,172	2,751,825,172	2,751,825,172
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	328,736,753	328,736,753	328,736,753	328,736,753	328,736,753
17	**Total Transmission Plant**		328,736,753	328,736,753	328,736,753	328,736,753	328,736,753
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	2,975,024	3,208,797	3,208,797	3,208,797	3,208,797
25		Structures and Improvements	37,139,827	40,058,220	40,058,220	40,058,220	40,058,220
26		Furniture and Equipment	19,083,275	20,718,360	20,826,101	20,954,197	21,082,649
27		Transportation Equipment	4,891,434	5,215,180	5,168,916	5,115,991	5,065,055
28		Stores Equipment	530,806	572,516	572,516	572,516	572,516
29		Tools and Garage Equipment	6,571,167	7,087,520	7,087,520	7,087,520	7,087,520
30		Laboratory Equipment	6,596,075	7,114,385	7,114,385	7,114,385	7,114,385
31		Power Operated Equipment	5,223,470	5,569,192	5,519,788	5,463,270	5,408,877
32		Communication Equipment	35,309,053	38,083,587	38,083,587	38,083,587	38,083,587
33		Miscellaneous Equipment	129,289	139,449	139,449	139,449	139,449
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	41,385	44,637	44,637	44,637	44,637
36							
37	**Total General Plant**		118,490,805	127,811,842	127,823,915	127,842,567	127,865,691
38							
39	**Total Electric Plant In-Service**		3,306,235,724	3,315,556,762	3,315,568,835	3,315,587,487	3,315,610,611
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	597,321,045	615,895,212	628,277,990	640,660,768	653,043,546
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	142,198,026	152,397,646	159,197,393	165,997,140	172,796,887
47		Other Production Plant	289,577,529	379,113,102	438,803,484	498,493,866	558,184,248
48		Transmission Plant (i)	167,224,784	177,423,764	184,223,084	191,022,404	197,821,724
49		Distribution Plant	0	0	0	0	0
50		General Plant	66,713,950	76,438,454	82,727,674	88,836,439	94,905,203
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	6,709,418	9,393,185	11,182,363	12,971,541	14,760,719
53		Amortization of Intangible Plant - Account 303	11,305,302	13,020,895	14,164,623	15,308,352	16,452,080
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		1,281,050,053	1,423,682,257	1,518,576,611	1,613,290,509	1,707,964,406
65							
66	**Total Net Plant**		2,025,185,671	1,891,874,505	1,796,992,225	1,702,296,978	1,607,646,205
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		27,110,635	27,941,825	28,503,843	29,066,831	29,644,894
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	0	0	0	0	0
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	30,535,642	30,448,353	30,592,640	31,013,263	31,493,957
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	19,449,872	19,822,476	20,058,566	20,250,160	20,446,708
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	360,000	360,000	360,000	360,000	360,000
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	1,862,945	1,898,633	1,921,246	1,939,598	1,958,423
98		Prepayments	15,353,068	15,180,994	15,046,947	14,890,626	14,737,096
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	67,561,527	67,710,456	67,979,400	68,453,646	68,996,184

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	8,733,642	8,630,472	8,556,696	8,470,619	8,386,035
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	8,331,220	8,331,220	8,331,220	8,331,220	8,331,220
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	124,118	122,652	121,604	120,380	119,178
115		Miscellaneous Deferred Debits	5,689,848	5,689,848	5,689,848	5,689,848	5,689,848
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	16,009,066	15,819,953	15,684,719	15,526,936	15,371,891
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	38,887,895	38,594,145	38,384,086	38,139,002	37,898,173
121							
122	**Total Assets and Other Debits**		133,560,057	134,246,426	134,867,329	135,659,479	136,539,251

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	144,866	144,866	144,866	144,866	144,866
136		Other Regulatory Liabilities	14,400,592	14,400,592	14,400,592	14,400,592	14,400,592
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	108,130	106,853	105,940	104,874	103,827
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	14,653,588	14,652,311	14,651,397	14,650,331	14,649,284
144							
145	**Total Liabilities and Other Credits**		14,653,588	14,652,311	14,651,397	14,650,331	14,649,284
146							
147							
148	**Total Rate Base**		2,144,092,140	2,011,468,620	1,917,208,156	1,823,306,126	1,729,536,171
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		11.01%	11.01%	11.01%	11.01%	11.01%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		236,048,052	221,447,222	211,069,870	200,731,979	190,408,628

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		*Schedule 3: Expenses*					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	67,662,247	67,468,827	67,788,545	68,720,581	69,785,724
164		Steam Power - Operations (Excluding 501 - Fuel)	11,269,981	11,594,824	11,835,415	12,072,123	12,316,583
165		Steam Power - Maintenance	22,122,727	22,713,749	23,207,771	23,683,521	24,139,427
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	7,230,879	7,400,413	7,492,915	7,579,081	7,683,287
172		Hydraulic - Maintenance	4,576,963	4,686,090	4,778,640	4,868,239	4,957,084
173		**Other Power Generation**					
174		Other Power - Fuel	184,100,071	196,590,781	201,872,460	207,286,181	212,835,245
175		Other Power - Operations (Excluding 547 - Fuel)	16,776,856	17,449,140	17,741,412	18,034,138	18,367,763
176		Other Power - Maintenance	10,465,399	10,697,851	10,882,388	11,078,271	11,280,448
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	833,532,006	923,480,954	983,563,906	1,042,583,595	1,094,464,254
179		System Control and Load Dispatching	2,555,351	2,555,351	2,555,351	2,555,351	2,555,351
180		Other Expenses	9,565,691	9,565,691	9,565,691	9,565,691	9,565,691
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	46,244,150	47,357,634	48,214,580	49,213,440	50,195,926
183	**Total Production Expense**		1,216,102,320	1,321,561,304	1,389,499,073	1,457,240,213	1,518,146,784
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	69,226,324	71,352,202	72,845,239	74,313,070	75,816,051
187		Total Operations less Wheeling	8,819,449	9,130,111	9,296,734	9,475,695	9,665,209
188		Total Maintenance	4,114,792	4,187,199	4,263,615	4,342,491	4,417,398
189	**Total Transmission Expense**		82,160,565	84,669,511	86,405,588	88,131,256	89,898,659
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	0	0	0	0	0
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		0	0	0	0	0
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	21,488,637	22,373,859	22,965,943	23,576,022	24,197,860
207		Office Supplies & Expenses	9,132,596	9,508,813	9,760,446	10,019,728	10,284,007
208		(Less) Administration Expenses Transferred - Credit	6,272,216	6,530,599	6,703,420	6,881,493	7,062,998
209		Outside Services Employed	2,248,278	2,340,896	2,402,843	2,466,674	2,531,734
210		Property Insurance	3,760,712	3,887,370	3,970,727	4,052,637	4,135,543
211		Injuries and Damages	2,295,922	2,390,502	2,453,762	2,518,945	2,585,385
212		Employee Pensions & Benefits	17,674,821	18,402,933	18,889,934	19,391,735	19,903,210
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	1,125,298	1,163,277	1,188,221	1,212,732	1,237,541
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	957,214	991,484	1,013,558	1,035,459	1,057,662
222	**Total Administration and General Expenses**		50,160,666	52,201,980	53,565,573	54,966,975	56,394,861
223							
224	**Total Operations and Maintenance**		1,348,423,551	1,458,432,796	1,529,470,234	1,600,338,444	1,664,440,304

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	1,789,178	1,789,178	1,789,178	1,789,178	1,789,178
230		Amortization of Intangible Plant - Account 303	1,143,728	1,143,728	1,143,728	1,143,728	1,143,728
231		Steam Production Plant	12,382,778	12,382,778	12,382,778	12,382,778	12,382,778
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	6,799,747	6,799,747	6,799,747	6,799,747	6,799,747
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	59,690,382	59,690,382	59,690,382	59,690,382	59,690,382
236		Transmission Plant (i)	6,799,320	6,799,320	6,799,320	6,799,320	6,799,320
237		Distribution Plant	0	0	0	0	0
238		General Plant	7,051,571	7,018,320	7,028,274	7,040,135	7,052,052
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	19,783	19,783	19,783	19,783	19,783
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		95,676,488	95,643,237	95,653,190	95,665,051	95,676,969
245							
246							
247	**Total Operating Expenses**		1,444,100,039	1,554,076,033	1,625,123,424	1,696,003,495	1,760,117,273
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	7,268,645	7,551,059	7,737,716	7,937,486	8,148,821
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		7,268,645	7,551,059	7,737,716	7,937,486	8,148,821
259							
260	**STATE AND OTHER**						
261		Property	26,994,975	26,676,086	26,448,050	26,181,992	25,920,551
262		Unemployment	595,554	618,694	633,988	650,356	667,671
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		27,590,530	27,294,780	27,082,037	26,832,347	26,588,222
269							
270	**TOTAL TAXES**		34,859,175	34,845,839	34,819,754	34,769,833	34,737,043
271							
272							

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	7,364,214	7,364,214	7,364,214	7,364,214	7,364,214
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	4,177,797	4,177,797	4,177,797	4,177,797	4,177,797
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		11,542,011	11,542,011	11,542,011	11,542,011	11,542,011
286							
287	**Sale for Resale:**						
288		Sales for Resale	537,852,718	588,023,040	618,387,059	644,513,030	664,460,367
289	**Total Sales for Resale**		537,852,718	588,023,040	618,387,059	644,513,030	664,460,367
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	(23,300)	(23,300)	(23,300)	(23,300)	(23,300)
295		Rent from Electric Property	715,235	699,093	686,773	672,679	659,115
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	9,720,520	9,720,520	9,720,520	9,720,520	9,720,520
298		Revenues from Transmission of Electricity of Others (i)	6,781,356	6,781,356	6,781,356	6,781,356	6,781,356
299							
300	**Total Other Revenues**		17,193,811	17,177,669	17,165,349	17,151,255	17,137,691
301							
302	**Total Other Included Items**		566,588,539	616,742,720	647,094,419	673,206,296	693,140,069
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		*Schedule 4: Average System Cost*					
306							
307			**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
308							
309		**Total Operating Expenses**	1,444,100,039	1,554,076,033	1,625,123,424	1,696,003,495	1,760,117,273
310		*(From Schedule 3)*					
311							
312		**Federal Income Tax Adjusted Return on Rate Base**	236,048,052	221,447,222	211,069,870	200,731,979	190,408,628
313		*(From Schedule 2)*					
314							
315		**State and Other Taxes**	34,859,175	34,845,839	34,819,754	34,769,833	34,737,043
316		*(From Schedule 3a)*					
317							
318		**Total Other Included Items**	566,588,539	616,742,720	647,094,419	673,206,296	693,140,069
319		*(From Schedule 3b)*					
320							
321		**Total Cost**	**1,148,418,727**	**1,193,626,375**	**1,223,918,630**	**1,258,299,011**	**1,292,122,875**
322		*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*					
323							
324							
325							
326		**Contract System Cost**					
327		Production and Transmission	1,148,418,727	1,193,626,375	1,223,918,630	1,258,299,011	1,292,122,875
328		(Less) New Large Single Load Costs (d)	1,744,766	1,759,079	1,762,922	1,767,990	1,774,114
329		**Total Contract System Cost**	**1,146,673,961**	**1,191,867,296**	**1,222,155,708**	**1,256,531,021**	**1,290,348,761**
330							
331		**Contract System Load (MWh)**					
332		Total Retail Load	18,718,899	19,169,620	19,516,498	19,920,821	20,318,515
333		(Less) New Large Single Load	31,637	31,637	31,637	31,637	31,637
334		Total Retail Load (Net of NLSL) (d)	18,687,262	19,137,983	19,484,861	19,889,184	20,286,878
335		Distribution Loss (f)	1,010,757	1,035,095	1,053,825	1,075,657	1,097,131
336		**Total Contract System Load**	**19,698,019**	**20,173,077**	**20,538,686**	**20,964,841**	**21,384,009**
337							
338		**Average System Cost $/MWh**	**58.21**	**59.08**	**59.51**	**59.94**	**60.34**

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	0	0	0	0	0
5		Intangible Plant - Miscellaneous	0	0	0	0	0
6	**Total Intangible Plant**		0	0	0	0	0
7							
8	**Production Plant:**						
9		Steam Production	1,003,372,944	1,003,372,944	1,003,372,944	1,003,372,944	1,003,372,944
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	171,404,775	171,404,775	171,404,775	171,404,775	171,404,775
12		Other Production	1,798,976,511	1,798,976,511	1,798,976,511	1,798,976,511	1,798,976,511
13	**Total Production Plant**		2,973,754,230	2,973,754,230	2,973,754,230	2,973,754,230	2,973,754,230
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	334,956,608	334,956,608	334,956,608	334,956,608	334,956,608
17	**Total Transmission Plant**		334,956,608	334,956,608	334,956,608	334,956,608	334,956,608
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	3,548,029	3,950,433	3,950,433	3,950,433	3,950,433
25		Structures and Improvements	27,423,488	30,533,755	30,533,755	30,533,755	30,533,755
26		Furniture and Equipment	8,839,039	9,874,483	9,894,912	9,918,316	9,946,015
27		Transportation Equipment	105,455	116,847	116,500	116,109	115,653
28		Stores Equipment	573,670	638,733	638,733	638,733	638,733
29		Tools and Garage Equipment	3,117,641	3,471,232	3,471,232	3,471,232	3,471,232
30		Laboratory Equipment	7,360,331	8,195,111	8,195,111	8,195,111	8,195,111
31		Power Operated Equipment	122,761	136,022	135,618	135,162	134,631
32		Communication Equipment	22,382,294	24,920,808	24,920,808	24,920,808	24,920,808
33		Miscellaneous Equipment	240,776	268,083	268,083	268,083	268,083
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	17,525	19,513	19,513	19,513	19,513
36							
37	**Total General Plant**		73,731,008	82,125,020	82,144,700	82,167,256	82,193,968
38							
39	**Total Electric Plant In-Service**		3,382,441,846	3,390,835,858	3,390,855,538	3,390,878,094	3,390,904,806
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	654,863,651	691,051,710	715,177,083	739,302,456	763,427,829
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	163,809,584	181,233,626	192,849,654	204,465,682	216,081,710
47		Other Production Plant	305,121,054	399,353,644	462,175,370	524,997,096	587,818,823
48		Transmission Plant (i)	148,758,961	160,594,244	168,484,433	176,374,622	184,264,811
49		Distribution Plant	0	0	0	0	0
50		General Plant	33,710,022	37,536,314	40,081,856	42,601,410	45,083,875
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	0	0	0	0	0
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	38,898,276	55,697,797	66,897,478	78,097,159	89,296,840
59		Amortization of Other Utility Plant (a)	8,669,556	8,707,853	8,733,384	8,758,914	8,784,445
60		Amortization of Acquisition Adjustments	63,631,682	77,646,076	86,989,005	96,331,934	105,674,862
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		1,417,462,786	1,611,821,264	1,741,388,263	1,870,929,274	2,000,433,196
65							
66	**Total Net Plant**		1,964,979,061	1,779,014,594	1,649,467,275	1,519,948,820	1,390,471,610
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
68							
69	Assets and Other Debits (Comparative Balance Sheet)						
70							
71	Cash Working Capital (f)		36,891,698	37,940,006	38,669,093	39,417,980	40,186,169
72							
73	Utility Plant		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	44,167,617	43,917,243	43,763,441	43,588,567	43,383,395
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	73,978,271	73,978,271	73,978,271	73,978,271	73,978,271
79		Acquisition Adjustments (Electric)	77,568,769	77,568,769	77,568,769	77,568,769	77,568,769
80		Total	195,714,657	195,464,284	195,310,482	195,135,607	194,930,435
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		Total	0	0	0	0	0
88							
89							
90		Fuel Stock	9,280,144	9,253,615	9,297,466	9,425,298	9,571,387
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	27,622,257	28,309,120	28,800,270	29,263,193	29,714,513
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	1,073,944	1,100,649	1,119,744	1,137,743	1,155,290
98		Prepayments	6,710,104	6,672,066	6,648,700	6,622,133	6,590,962
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		Total	44,686,448	45,335,450	45,866,180	46,448,366	47,032,151

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	8,365,832	8,317,610	8,288,658	8,255,739	8,217,114
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	41,854,135	41,854,135	41,854,135	41,854,135	41,854,135
109		Other Regulatory Assets	217,021,787	217,021,787	217,021,787	217,021,787	217,021,787
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	(80,142)	(79,680)	(79,403)	(79,087)	(78,717)
115		Miscellaneous Deferred Debits	0	0	0	0	0
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	7,309,990	7,267,853	7,242,556	7,213,791	7,180,042
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	274,471,602	274,381,705	274,327,733	274,266,364	274,194,360
121							
122	**Total Assets and Other Debits**		551,764,405	553,121,445	554,173,487	555,268,318	556,343,115

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	3,547,878	3,547,878	3,547,878	3,547,878	3,547,878
136		Other Regulatory Liabilities	1,898,741	1,898,741	1,898,741	1,898,741	1,898,741
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	123,911	123,197	122,768	122,280	121,708
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	5,570,530	5,569,815	5,569,387	5,568,899	5,568,327
144							
145	**Total Liabilities and Other Credits**		5,570,530	5,569,815	5,569,387	5,568,899	5,568,327
146							
147							
148	**Total Rate Base**		2,511,172,937	2,326,566,224	2,198,071,375	2,069,648,239	1,941,246,399
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		10.77%	10.77%	10.77%	10.77%	10.77%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		270,418,555	250,538,968	236,701,852	222,872,459	209,045,358

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		*Schedule 3: Expenses*					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	62,752,429	62,573,044	62,869,562	63,733,966	64,721,819
164		Steam Power - Operations (Excluding 501 - Fuel)	15,573,518	16,022,405	16,354,868	16,681,966	17,019,774
165		Steam Power - Maintenance	20,397,058	20,941,977	21,397,463	21,836,103	22,256,446
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	5,712,495	5,846,429	5,919,507	5,987,579	6,069,904
172		Hydraulic - Maintenance	6,033,685	6,177,544	6,299,550	6,417,666	6,534,788
173		**Other Power Generation**					
174		Other Power - Fuel	101,371,411	108,249,197	111,157,459	114,138,428	117,193,921
175		Other Power - Operations (Excluding 547 - Fuel)	22,010,878	22,910,550	23,294,299	23,678,646	24,116,693
176		Other Power - Maintenance	38,230,224	39,075,148	39,749,191	40,464,676	41,203,153
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	766,920,846	824,359,631	861,474,131	897,121,363	930,647,331
179		System Control and Load Dispatching	873,300	873,300	873,300	873,300	873,300
180		Other Expenses	10,722,472	10,722,472	10,722,472	10,722,472	10,722,472
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	oduction Expense		1,050,598,316	1,117,751,697	1,160,111,804	1,201,656,167	1,241,359,601
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	98,751,937	101,784,887	103,914,724	106,008,605	108,152,628
187		Total Operations less Wheeling	3,311,976	3,428,639	3,491,211	3,558,416	3,629,585
188		Total Maintenance	4,343,425	4,419,856	4,500,518	4,583,776	4,662,846
189	**Total Transmission Expense**		106,407,338	109,633,381	111,906,453	114,150,798	116,445,059
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	40,224,200	41,117,113	41,774,927	42,568,650	43,377,455
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		40,224,200	41,117,113	41,774,927	42,568,650	43,377,455
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	7,614,299	7,946,741	8,175,337	8,414,948	8,656,989
207		Office Supplies & Expenses	5,146,412	5,371,106	5,525,611	5,687,561	5,851,154
208		(Less) Administration Expenses Transferred - Credit	53,548	55,886	57,494	59,179	60,881
209		Outside Services Employed	3,505,144	3,658,179	3,763,410	3,873,712	3,985,132
210		Property Insurance	1,992,869	2,072,634	2,127,898	2,185,150	2,241,805
211		Injuries and Damages	1,985,647	2,072,341	2,131,954	2,194,439	2,257,559
212		Employee Pensions & Benefits	6,955,358	7,259,031	7,467,844	7,686,719	7,907,814
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	1,802,233	1,875,584	1,926,153	1,978,634	2,030,734
222	**Total Administration and General Expenses**		28,948,413	30,199,730	31,060,712	31,961,984	32,870,305
223							
224	**Total Operations and Maintenance**		1,226,178,267	1,298,701,922	1,344,853,895	1,390,337,599	1,434,052,419

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
225							
226							
227	Depreciation and Amortization:						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	0	0	0	0	0
230		Amortization of Intangible Plant - Account 303	17,238	17,238	17,238	17,238	17,238
231		Steam Production Plant	24,125,373	24,125,373	24,125,373	24,125,373	24,125,373
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	11,616,028	11,616,028	11,616,028	11,616,028	11,616,028
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	62,821,726	62,821,726	62,821,726	62,821,726	62,821,726
236		Transmission Plant (i)	7,890,189	7,890,189	7,890,189	7,890,189	7,890,189
237		Distribution Plant	0	0	0	0	0
238		General Plant	2,682,292	2,676,769	2,678,726	2,680,958	2,683,586
239		Common Plant - Electric	1,932,193	1,932,193	1,932,193	1,932,193	1,932,193
240		Common Plant - Electric	3,472,907	3,472,907	3,472,907	3,472,907	3,472,907
241		Depreciation Expense for Asset Retirement Costs	(50,562)	(50,562)	(50,562)	(50,562)	(50,562)
242		Amortization of Limited Term Electric Plant	424,390	424,390	424,390	424,390	424,390
243		Amortization of Plant Acquisition Adjustments (Electric)	5,861,545	5,861,545	5,861,545	5,861,545	5,861,545
244	Total Depreciation and Amortization		120,793,319	120,787,796	120,789,754	120,791,986	120,794,614
245							
246							
247	**Total Operating Expenses**		1,346,971,586	1,419,489,718	1,465,643,649	1,511,129,585	1,554,847,033
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		*Schedule 3A Items: Taxes (Including Income Taxes)*					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	2,583,047	2,689,762	2,762,434	2,841,330	2,923,765
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		2,583,047	2,689,762	2,762,434	2,841,330	2,923,765
259							
260	**STATE AND OTHER**						
261		Property	21,157,623	21,035,665	20,962,444	20,879,190	20,781,507
262		Unemployment	0	0	0	0	0
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		21,157,623	21,035,665	20,962,444	20,879,190	20,781,507
269							
270	**TOTAL TAXES**		23,740,670	23,725,426	23,724,879	23,720,520	23,705,272
271							
272							

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	10,843,497	10,843,497	10,843,497	10,843,497	10,843,497
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	1,125,593	1,125,593	1,125,593	1,125,593	1,125,593
281		(Less) Loss from Disposition of Utility Plant	272,877	272,877	272,877	272,877	272,877
282		Gain from Disposition of Allowances	422,124	422,124	422,124	422,124	422,124
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	7,377,701	7,377,701	7,377,701	7,377,701	7,377,701
285	**Total Other Included Items**		19,496,037	19,496,037	19,496,037	19,496,037	19,496,037
286							
287	**Sale for Resale:**						
288		Sales for Resale	174,403,889	190,844,422	200,786,329	209,333,310	215,843,772
289	**Total Sales for Resale**		174,403,889	190,844,422	200,786,329	209,333,310	215,843,772
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	1,119,345	1,107,610	1,100,457	1,092,376	1,082,964
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	2,154,048	2,154,048	2,154,048	2,154,048	2,154,048
298		Revenues from Transmission of Electricity of Others (i)	9,079,888	9,079,888	9,079,888	9,079,888	9,079,888
299							
300	**Total Other Revenues**		12,353,280	12,341,545	12,334,393	12,326,311	12,316,899
301							
302	**Total Other Included Items**		206,253,206	222,682,004	232,616,759	241,155,658	247,656,708
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		*Schedule 4: Average System Cost*					
306							
307			**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
308							
309		**Total Operating Expenses**	1,346,971,586	1,419,489,718	1,465,643,649	1,511,129,585	1,554,847,033
310		*(From Schedule 3)*					
311							
312		**Federal Income Tax Adjusted Return on Rate Base**	270,418,555	250,538,968	236,701,852	222,872,459	209,045,358
313		*(From Schedule 2)*					
314							
315		**State and Other Taxes**	23,740,670	23,725,426	23,724,879	23,720,520	23,705,272
316		*(From Schedule 3a)*					
317							
318		**Total Other Included Items**	206,253,206	222,682,004	232,616,759	241,155,658	247,656,708
319		*(From Schedule 3b)*					
320							
321		**Total Cost**	**1,434,877,605**	**1,471,072,108**	**1,493,453,621**	**1,516,566,905**	**1,539,940,955**
322		*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*					
323							
324							
325							
326		**Contract System Cost**					
327		Production and Transmission	1,434,877,605	1,471,072,108	1,493,453,621	1,516,566,905	1,539,940,955
328		(Less) New Large Single Load Costs (d)	0	0	0	0	0
329		**Total Contract System Cost**	**1,434,877,605**	**1,471,072,108**	**1,493,453,621**	**1,516,566,905**	**1,539,940,955**
330							
331		**Contract System Load (MWh)**					
332		Total Retail Load	22,164,641	22,380,156	22,523,578	22,684,658	22,871,655
333		(Less) New Large Single Load	0	0	0	0	0
334		Total Retail Load (Net of NLSL) (d)	22,164,641	22,380,156	22,523,578	22,684,658	22,871,655
335		Distribution Loss (f)	1,119,314	1,130,198	1,137,441	1,145,575	1,155,019
336		**Total Contract System Load**	**23,283,955**	**23,510,354**	**23,661,019**	**23,830,233**	**24,026,674**
337							
338		**Average System Cost $/MWh**	**61.63**	**62.57**	**63.12**	**63.64**	**64.09**

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	1,089	1,044	1,037	1,030	1,023
5		Intangible Plant - Miscellaneous	16,373,214	16,373,214	16,373,214	16,373,214	16,373,214
6	**Total Intangible Plant**		16,374,303	16,374,258	16,374,251	16,374,244	16,374,237
7							
8	**Production Plant:**						
9		Steam Production	133,715,155	133,715,155	133,715,155	133,715,155	133,715,155
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	208,006,477	208,006,477	208,006,477	208,006,477	208,006,477
12		Other Production	0	0	0	0	0
13	**Total Production Plant**		341,721,632	341,721,632	341,721,632	341,721,632	341,721,632
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	93,329,902	93,329,902	93,329,902	93,329,902	93,329,902
17	**Total Transmission Plant**		93,329,902	93,329,902	93,329,902	93,329,902	93,329,902
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	1,045,189	1,045,189	1,045,189	1,045,189	1,045,189
25		Structures and Improvements	21,906,356	21,906,356	21,906,356	21,906,356	21,906,356
26		Furniture and Equipment	1,522,284	1,528,498	1,531,286	1,533,957	1,536,775
27		Transportation Equipment	2,403,558	2,390,040	2,384,152	2,378,610	2,372,866
28		Stores Equipment	317,054	317,054	317,054	317,054	317,054
29		Tools and Garage Equipment	661,839	661,839	661,839	661,839	661,839
30		Laboratory Equipment	814,584	814,584	814,584	814,584	814,584
31		Power Operated Equipment	97,780	97,230	96,991	96,765	96,532
32		Communication Equipment	11,794,341	11,794,341	11,794,341	11,794,341	11,794,341
33		Miscellaneous Equipment	23,471	23,471	23,471	23,471	23,471
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		40,586,456	40,578,602	40,575,263	40,572,166	40,569,006
38							
39	**Total Electric Plant In-Service**		492,012,293	492,004,393	492,001,047	491,997,944	491,994,777
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	160,671,695	173,561,961	182,155,472	190,748,983	199,342,495
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	0	0	0	0	0
47		Other Production Plant	0	0	0	0	0
48		Transmission Plant (i)	32,992,764	36,615,866	39,031,267	41,446,668	43,862,069
49		Distribution Plant	0	0	0	0	0
50		General Plant	27,287,150	29,504,969	31,058,981	32,613,204	34,147,226
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	13,978,289	15,868,855	17,129,233	18,389,611	19,649,988
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		234,929,898	255,551,651	269,374,953	283,198,465	297,001,777
65							
66	**Total Net Plant**		257,082,395	236,452,742	222,626,094	208,799,479	194,993,000
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		3,778,141	3,957,962	4,086,124	4,214,014	4,344,677
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	0	0	0	0	0
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	0	0	0	0	0
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	4,244,885	4,310,490	4,371,664	4,431,746	4,491,626
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	(74,061)	(75,206)	(76,273)	(77,322)	(78,366)
98		Prepayments	253,387	249,637	247,991	246,434	244,812
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	4,424,211	4,484,922	4,543,382	4,600,858	4,658,071

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	2,266,012	2,233,895	2,219,782	2,206,425	2,192,510
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	0	0	0	0	0
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	0	0	0	0	0
115		Miscellaneous Deferred Debits	16,522,224	16,522,224	16,522,224	16,522,224	16,522,224
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	10,551,545	10,401,994	10,336,279	10,274,083	10,209,289
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	29,339,781	29,158,113	29,078,285	29,002,732	28,924,022
121							
122	**Total Assets and Other Debits**		37,542,133	37,600,997	37,707,791	37,817,603	37,926,771

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	6,752,685	6,752,685	6,752,685	6,752,685	6,752,685
136		Other Regulatory Liabilities	0	0	0	0	0
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	6,752,685	6,752,685	6,752,685	6,752,685	6,752,685
144							
145	**Total Liabilities and Other Credits**		6,752,685	6,752,685	6,752,685	6,752,685	6,752,685
146							
147							
148	**Total Rate Base**		287,871,843	267,301,054	253,581,201	239,864,397	226,167,086
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		5.27%	5.27%	5.27%	5.27%	5.27%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		15,170,846	14,086,766	13,363,729	12,640,854	11,919,005

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	1,333,519	1,329,707	1,336,008	1,354,377	1,375,370
164		Steam Power - Operations (Excluding 501 - Fuel)	0	0	0	0	0
165		Steam Power - Maintenance	0	0	0	0	0
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	865,643	885,938	897,012	907,328	919,803
172		Hydraulic - Maintenance	1,180,931	1,209,087	1,232,967	1,256,085	1,279,008
173		**Other Power Generation**					
174		Other Power - Fuel	0	0	0	0	0
175		Other Power - Operations (Excluding 547 - Fuel)	0	0	0	0	0
176		Other Power - Maintenance	0	0	0	0	0
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	324,836,669	351,877,365	359,396,260	370,708,527	377,820,323
179		System Control and Load Dispatching	0	0	0	0	0
180		Other Expenses	(16,366,773)	(16,366,773)	(16,366,773)	(16,366,773)	(16,366,773)
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	12,173,715	12,423,529	12,536,322	12,642,286	12,751,915
183	**Total Production Expense**		324,023,703	351,358,853	359,031,795	370,501,830	377,779,645
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	37,023,246	38,160,197	38,958,694	39,743,712	40,547,528
187		Total Operations less Wheeling	131,455	136,085	138,569	141,236	144,061
188		Total Maintenance	0	0	0	0	0
189	**Total Transmission Expense**		37,154,701	38,296,282	39,097,263	39,884,948	40,691,589
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	0	0	0	0	0
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		0	0	0	0	0
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	3,013,310	3,118,273	3,197,233	3,281,361	3,366,178
207		Office Supplies & Expenses	1,268,469	1,312,654	1,345,892	1,381,306	1,417,010
208		(Less) Administration Expenses Transferred - Credit	1,412,134	1,461,322	1,498,326	1,537,751	1,577,499
209		Outside Services Employed	1,373,408	1,421,248	1,457,236	1,495,580	1,534,238
210		Property Insurance	212,764	219,419	224,629	230,198	235,781
211		Injuries and Damages	404,672	418,768	429,372	440,670	452,061
212		Employee Pensions & Benefits	505,395	523,000	536,243	550,353	564,578
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	2,024,747	2,087,124	2,136,247	2,188,805	2,241,444
222	**Total Administration and General Expenses**		7,390,631	7,639,162	7,828,527	8,030,523	8,233,791
223							
224	**Total Operations and Maintenance**		368,569,035	397,294,297	405,957,585	418,417,301	426,705,025

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	0	0	0	0	0
230		Amortization of Intangible Plant - Account 303	1,460,374	1,460,374	1,460,374	1,460,374	1,460,374
231		Steam Production Plant	8,593,511	8,593,511	8,593,511	8,593,511	8,593,511
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	0	0	0	0	0
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	0	0	0	0	0
236		Transmission Plant (i)	2,415,401	2,415,401	2,415,401	2,415,401	2,415,401
237		Distribution Plant	0	0	0	0	0
238		General Plant	1,776,138	1,762,781	1,762,834	1,762,888	1,762,946
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		14,245,425	14,232,067	14,232,121	14,232,174	14,232,232
245							
246							
247	**Total Operating Expenses**		382,814,459	411,526,364	420,189,706	432,649,474	440,937,257
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	122,718	126,707	129,695	133,011	136,482
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		122,718	126,707	129,695	133,011	136,482
259							
260	**STATE AND OTHER**						
261		Property	48,599	47,910	47,608	47,321	47,023
262		Unemployment	10,011	10,337	10,580	10,851	11,134
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		58,610	58,247	58,188	58,172	58,157
269							
270	**TOTAL TAXES**		181,329	184,954	187,883	191,183	194,639
271							
272							

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	0	0	0	0	0
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		0	0	0	0	0
286							
287	**Sale for Resale:**						
288		Sales for Resale	53,060,459	58,069,992	61,098,991	63,702,676	65,685,300
289	**Total Sales for Resale**		53,060,459	58,069,992	61,098,991	63,702,676	65,685,300
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	204,282	200,126	198,317	196,613	194,848
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	444,034	444,034	444,034	444,034	444,034
298		Revenues from Transmission of Electricity of Others (i)	9,028,943	9,028,943	9,028,943	9,028,943	9,028,943
299							
300	**Total Other Revenues**		9,677,259	9,673,103	9,671,294	9,669,590	9,667,825
301							
302	**Total Other Included Items**		62,737,718	67,743,096	70,770,285	73,372,266	75,353,125
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		*Schedule 4: Average System Cost*					
306							
307			**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
308							
309	**Total Operating Expenses**		382,814,459	411,526,364	420,189,706	432,649,474	440,937,257
310	*(From Schedule 3)*						
311							
312	**Federal Income Tax Adjusted Return on Rate Base**		15,170,846	14,086,766	13,363,729	12,640,854	11,919,005
313	*(From Schedule 2)*						
314							
315	**State and Other Taxes**		181,329	184,954	187,883	191,183	194,639
316	*(From Schedule 3a)*						
317							
318	**Total Other Included Items**		62,737,718	67,743,096	70,770,285	73,372,266	75,353,125
319	*(From Schedule 3b)*						
320							
321	**Total Cost**		**335,428,916**	**358,054,988**	**362,971,034**	**372,109,245**	**377,697,776**
322	*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*						
323							
324							
325							
326	**Contract System Cost**						
327	Production and Transmission		335,428,916	358,054,988	362,971,034	372,109,245	377,697,776
328	(Less) New Large Single Load Costs (d)		0	0	0	0	0
329	**Total Contract System Cost**		**335,428,916**	**358,054,988**	**362,971,034**	**372,109,245**	**377,697,776**
330							
331	**Contract System Load (MWh)**						
332	Total Retail Load		7,049,119	7,193,772	7,259,084	7,320,442	7,383,922
333	(Less) New Large Single Load		0	0	0	0	0
334	Total Retail Load (Net of NLSL) (d)		7,049,119	7,193,772	7,259,084	7,320,442	7,383,922
335	Distribution Loss (f)		257,293	262,573	264,957	267,196	269,513
336	**Total Contract System Load**		**7,306,411**	**7,456,345**	**7,524,041**	**7,587,638**	**7,653,435**
337							
338	**Average System Cost $/MWh**		**45.91**	**48.02**	**48.24**	**49.04**	**49.35**

APPENDIX G

Residential Exchange Program Average System Cost

Purchase Power and
Sales for Resale

Table A: Avista
Table B: Franklin County PUD
Table C: Idaho Power
Table D: NorthWestern Energy
Table E: PacifiCorp
Table F: Portland General Electric
Table G: Puget Sound Energy
Table H: Snohomish County PUD

Section 7(b)(2) Rate Test Study Documentation

WP-10 Final Rate Proposal
WP-10-FS-BPA-06A

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	C	D	E	F	G	H
1	**Avista Utilities**					
2						
3						
4	**Fiscal Year**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
9						
10	**Total Purchased Power ($)**	**129,776,846**	**152,917,856**	**166,552,405**	**184,530,915**	**204,164,918**
11	**Total Sale for Resale Credit ($)**	**123,135,845**	**131,326,312**	**136,440,384**	**140,980,033**	**144,736,934**
12						
13						
15	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
16	Base Period LT & IT Purchased Power (MWh)	2,900,972	2,900,972	2,900,972	2,900,972	2,900,972
17	New Resource LT & IT Purchased Power (MWh)					
18	LT & IT Terminated Contracts (MWh)					
19						
20	**Total LT & IT Purchased Power (MWh)**	**2,900,972**	**2,900,972**	**2,900,972**	**2,900,972**	**2,900,972**
21						
22						
23	Base Period LT & IT Sales for Resale (MWh)	770,428	770,428	770,428	770,428	770,428
24	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
25	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
26						
27	**Total LT & IT Sales for Resale (MWh)**	**770,428**	**770,428**	**770,428**	**770,428**	**770,428**
28						
29						
30	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
31	Base Case LT & IT Purchased Power, Market ($)	92,565,475	96,181,754	97,536,221	99,892,151	101,255,640
32	New Resource LT Purchases, Market ($)	-	-	-	-	-
33	Contract Terminations, Market ($)	-	-	-	-	-
34						
35	**Total LT & IT Purchases, Market ($)**	**92,565,475**	**96,181,754**	**97,536,221**	**99,892,151**	**101,255,640**
36						
37						
38	Base Case LT & IT Sales for Resale ($)	$ 53,922,485	$ 55,578,395	$ 56,741,367	$ 57,884,705	$ 59,055,423
39	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
40	**Total LT & IT Sales for Resale $**	**$ 53,922,485**	**$ 55,578,395**	**$ 56,741,367**	**$ 57,884,705**	**$ 59,055,423**
41						

	C	D	E	F	G	H
1	**Avista Utilities**					
42						
43	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
44	Base Period ST Purchased Power (MWh)	1,860,562	1,860,562	1,860,562	1,860,562	1,860,562
45	Cumulative CSL Load Growth (MWh)	570,032	778,671	968,517	1,216,261	1,512,509
46	**Base Short Term Purchases Plus Load Growth (MWh)**	**2,430,594**	**2,639,233**	**2,829,079**	**3,076,823**	**3,373,071**
47						
48	New Resource Total Expected Annual Generation (MWh)	1,423,334	0	0	0	0
49	New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
50	New Resource Less Firm Sales for Resale (MWh)					
51	Cumulative Net New Resources (MWh)	**1,423,334**	**1,423,334**	**1,423,334**	**1,423,334**	**1,423,334**
52	**Total ST Purchases (MWh)**	**1,007,260**	**1,215,899**	**1,405,745**	**1,653,489**	**1,949,737**
53						
54						
55	New ST Sales for Resale (MWh)	-	-	-	-	-
56	Base ST Sales for Resale (MWh)	1,765,675	1,765,675	1,765,675	1,765,675	1,765,675
57	**Total ST Sales for Resale (MWh)**	**1,765,675**	**1,765,675**	**1,765,675**	**1,765,675**	**1,765,675**
58						
59						
60	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
61	Total ST Purchases (MWh)	1,007,260	1,215,899	1,405,745	1,653,489	1,949,737
62	ST Purchase Power Price ($/MWh)	36.94	46.66	49.10	51.19	52.78
63						
64	Total ST Purchases ($)	37,211,371	56,736,102	69,016,184	84,638,764	102,909,279
65						
66	Total ST Sales for Resale (MWh)	1,765,675	1,765,675	1,765,675	1,765,675	1,765,675
67	ST Sales Power Price ($/MWh)	$ 39.20	$ 42.90	$ 45.14	$ 47.06	$ 48.53
68						
69	Total ST Sales for Resale ($)	69,213,360	75,747,917	79,699,017	83,095,328	85,681,511
70						
71	**Price Spread (Plus/Minus, %)**	**4.20%**				
72						
73	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
74	**Purchase Prices ($/MWh)**		**46.66**	**49.10**	**51.19**	**52.78**
75	**Mid-Point Price ($/MWh)**		**44.78**	**47.12**	**49.12**	**50.65**
76	**Sales Prices ($/MWh)**		**42.90**	**45.14**	**47.06**	**48.53**

	C	D	E	F	G	H
1	**PUD No. 1 of Franklin County**					
2						
3						
4	**Fiscal Year**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
9						
10	**Total Purchased Power ($)**	**56,257,244**	**60,958,639**	**62,461,082**	**64,536,424**	**65,964,540**
11	**Total Sale for Resale Credit ($)**	**13,820,024**	**15,124,797**	**15,913,724**	**16,591,875**	**17,108,265**
12						
13						
15	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
16	Base Period LT & IT Purchased Power (MWh)	1,131,609	1,131,609	1,131,609	1,131,609	1,131,609
17	New Resource LT & IT Purchased Power (MWh)					
18	LT & IT Terminated Contracts (MWh)					
19						
20	**Total LT & IT Purchased Power (MWh)**	**1,131,609**	**1,131,609**	**1,131,609**	**1,131,609**	**1,131,609**
21						
22						
23	Base Period LT & IT Sales for Resale (MWh)	-	-	-	-	-
24	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
25	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
26						
27	**Total LT & IT Sales for Resale (MWh)**	**-**	**-**	**-**	**-**	**-**
28						
29						
30	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
31	Base Case LT & IT Purchased Power, Market ($)	46,177,011	48,635,250	48,635,250	49,212,140	49,212,140
32	New Resource LT Purchases, Market ($)	-	-	-	-	-
33	Contract Terminations, Market ($)	-	-	-	-	-
34						
35	**Total LT & IT Purchases, Market ($)**	**46,177,011**	**48,635,250**	**48,635,250**	**49,212,140**	**49,212,140**
36						
37						
38	Base Case LT & IT Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
39	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
40	**Total LT & IT Sales for Resale $**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
41						

	C	D	E	F	G	H
1	**PUD No. 1 of Franklin County**					
42						
43	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
44	Base Period ST Purchased Power (MWh)	82,227	82,227	82,227	82,227	82,227
45	Cumulative CSL Load Growth (MWh)	137,853	154,601	170,302	186,232	202,392
46	**Base Short Term Purchases Plus Load Growth (MWh)**	**220,080**	**236,828**	**252,529**	**268,459**	**284,619**
47						
48	New Resource Total Expected Annual Generation (MWh)	0	0	0	0	0
49	New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
50	New Resource Less Firm Sales for Resale (MWh)					
51	Cumulative Net New Resources (MWh)	**0**	**0**	**0**	**0**	**0**
52	**Total ST Purchases (MWh)**	**220,080**	**236,828**	**252,529**	**268,459**	**284,619**
53						
54						
55	New ST Sales for Resale (MWh)	-	-	-	-	-
56	Base ST Sales for Resale (MWh)	271,537	271,537	271,537	271,537	271,537
57	**Total ST Sales for Resale (MWh)**	**271,537**	**271,537**	**271,537**	**271,537**	**271,537**
58						
59						
60	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
61	Total ST Purchases (MWh)	220,080	236,828	252,529	268,459	284,619
62	ST Purchase Power Price ($/MWh)	45.80	52.04	54.75	57.08	58.86
63						
64	Total ST Purchases ($)	10,080,233	12,323,388	13,825,832	15,324,285	16,752,401
65						
66	Total ST Sales for Resale (MWh)	271,537	271,537	271,537	271,537	271,537
67	ST Sales Power Price ($/MWh)	$ 50.90	$ 55.70	$ 58.61	$ 61.10	$ 63.01
68						
69	Total ST Sales for Resale ($)	13,820,024	15,124,797	15,913,724	16,591,875	17,108,265
70						
71	**Price Spread (Plus/Minus, %)**	**-3.40%**				
72						
73	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
74	**Purchase Prices ($/MWh)**		**52.04**	**54.75**	**57.08**	**58.86**
75	**Mid-Point Price ($/MWh)**		**53.87**	**56.68**	**59.09**	**60.93**
76	**Sales Prices ($/MWh)**		**55.70**	**58.61**	**61.10**	**63.01**

	C	D	E	F	G	H
1	**Idaho Power Company**					
3						
4	**Fiscal Year**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
9						
10	**Total Purchased Power ($)**	**290,330,411**	**336,650,482**	**359,278,297**	**383,950,513**	**404,335,599**
11	**Total Sale for Resale Credit ($)**	**116,894,237**	**127,279,978**	**133,590,310**	**139,041,787**	**143,249,743**
12						
13						
15	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
16	Base Period LT & IT Purchased Power (MWh)	925,369	925,369	925,369	925,369	925,369
17	New Resource LT & IT Purchased Power (MWh)					
18	LT & IT Terminated Contracts (MWh)					
19						
20	**Total LT & IT Purchased Power (MWh)**	**925,369**	**925,369**	**925,369**	**925,369**	**925,369**
21						
22						
23	Base Period LT & IT Sales for Resale (MWh)	126,314	126,314	126,314	126,314	126,314
24	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
25	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
26						
27	**Total LT & IT Sales for Resale (MWh)**	**126,314**	**126,314**	**126,314**	**126,314**	**126,314**
28						
29						
30	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
31	Base Case LT & IT Purchased Power, Market ($)	55,916,569	58,407,393	58,971,435	60,550,286	61,118,085
32	New Resource LT Purchases, Market ($)	-	-	-	-	-
33	Contract Terminations, Market ($)	-	-	-	-	-
34						
35	**Total LT & IT Purchases, Market ($)**	**55,916,569**	**58,407,393**	**58,971,435**	**60,550,286**	**61,118,085**
37						
38	Base Case LT & IT Sales for Resale ($)	$ 10,210,758	$ 10,524,321	$ 10,744,542	$ 10,961,044	$ 11,182,731
39	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
40	**Total LT & IT Sales for Resale $**	**$ 10,210,758**	**$ 10,524,321**	**$ 10,744,542**	**$ 10,961,044**	**$ 11,182,731**
41						

	C	D	E	F	G	H
1	**Idaho Power Company**					
42						
43	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
44	Base Period ST Purchased Power (MWh)	4,270,595	4,270,595	4,270,595	4,270,595	4,270,595
45	Cumulative CSL Load Growth (MWh)	1,071,095	1,338,942	1,483,614	1,672,834	1,846,647
46	**Base Short Term Purchases Plus Load Growth (MWh)**	**5,341,690**	**5,609,537**	**5,754,209**	**5,943,429**	**6,117,242**
47						
48	New Resource Total Expected Annual Generation (MWh)	0	0	0	0	0
49	New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
50	New Resource Less Firm Sales for Resale (MWh)					
51	Cumulative Net New Resources (MWh)	**0**	**0**	**0**	**0**	**0**
52	**Total ST Purchases (MWh)**	**5,341,690**	**5,609,537**	**5,754,209**	**5,943,429**	**6,117,242**
53						
54						
55	New ST Sales for Resale (MWh)	-	-	-	-	-
56	Base ST Sales for Resale (MWh)	2,617,333	2,617,333	2,617,333	2,617,333	2,617,333
57	**Total ST Sales for Resale (MWh)**	**2,617,333**	**2,617,333**	**2,617,333**	**2,617,333**	**2,617,333**
58						
59						
60	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
61	Total ST Purchases (MWh)	5,341,690	5,609,537	5,754,209	5,943,429	6,117,242
62	ST Purchase Power Price ($/MWh)	43.88	49.60	52.19	54.41	56.11
63						
64	Total ST Purchases ($)	234,413,842	278,243,089	300,306,862	323,400,227	343,217,514
65						
66	Total ST Sales for Resale (MWh)	2,617,333	2,617,333	2,617,333	2,617,333	2,617,333
67	ST Sales Power Price ($/MWh)	$ 40.76	$ 44.61	$ 46.94	$ 48.94	$ 50.46
68						
69	Total ST Sales for Resale ($)	106,683,478	116,755,657	122,845,768	128,080,743	132,067,011
70						
71	**Price Spread (Plus/Minus, %)**	**5.30%**				
72						
73	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
74	**Purchase Prices ($/MWh)**		**49.60**	**52.19**	**54.41**	**56.11**
75	**Mid-Point Price ($/MWh)**		**47.11**	**49.56**	**51.67**	**53.28**
76	**Sales Prices ($/MWh)**		**44.61**	**46.94**	**48.94**	**50.46**

	C	D	E	F	G	H
1	**NorthWestern Energy**					
2						
3						
4	**Fiscal Year**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
9						
10	**Total Purchased Power ($)**	**353,241,185**	**376,153,626**	**391,819,121**	**407,020,297**	**421,484,843**
11	**Total Sale for Resale Credit ($)**	**49,426,672**	**54,093,133**	**56,914,694**	**59,340,068**	**61,186,915**
12						
13						
15	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
16	Base Period LT & IT Purchased Power (MWh)	5,614,843	5,614,843	5,614,843	5,614,843	5,614,843
17	New Resource LT & IT Purchased Power (MWh)					
18	LT & IT Terminated Contracts (MWh)					
19						
20	**Total LT & IT Purchased Power (MWh)**	**5,614,843**	**5,614,843**	**5,614,843**	**5,614,843**	**5,614,843**
21						
22						
23	Base Period LT & IT Sales for Resale (MWh)	-	-	-	-	-
24	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
25	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
26						
27	**Total LT & IT Sales for Resale (MWh)**	**-**	**-**	**-**	**-**	**-**
28						
29						
30	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
31	Base Case LT & IT Purchased Power, Market ($)	257,908,204	265,828,331	271,390,759	276,859,282	282,458,759
32	New Resource LT Purchases, Market ($)	-	-	-	-	-
33	Contract Terminations, Market ($)	-	-	-	-	-
34						
35	**Total LT & IT Purchases, Market ($)**	**257,908,204**	**265,828,331**	**271,390,759**	**276,859,282**	**282,458,759**
36						
37						
38	Base Case LT & IT Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
39	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
40	**Total LT & IT Sales for Resale $**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
41						

	C	D	E	F	G	H
1	**NorthWestern Energy**					
2						
42						
43	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
44	Base Period ST Purchased Power (MWh)	1,906,487	1,906,487	1,906,487	1,906,487	1,906,487
45	Cumulative CSL Load Growth (MWh)	205,486	286,437	368,584	451,946	536,541
46	**Base Short Term Purchases Plus Load Growth (MWh)**	**2,111,973**	**2,192,924**	**2,275,071**	**2,358,433**	**2,443,028**
47						
48	New Resource Total Expected Annual Generation (MWh)	0	0	0	0	0
49	New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
50	New Resource Less Firm Sales for Resale (MWh)					
51	Cumulative Net New Resources (MWh)	**0**	**0**	**0**	**0**	**0**
52	**Total ST Purchases (MWh)**	**2,111,973**	**2,192,924**	**2,275,071**	**2,358,433**	**2,443,028**
53						
54						
55	New ST Sales for Resale (MWh)	-	-	-	-	-
56	Base ST Sales for Resale (MWh)	1,444,555	1,444,555	1,444,555	1,444,555	1,444,555
57	**Total ST Sales for Resale (MWh)**	**1,444,555**	**1,444,555**	**1,444,555**	**1,444,555**	**1,444,555**
58						
59						
60	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
61	Total ST Purchases (MWh)	2,111,973	2,192,924	2,275,071	2,358,433	2,443,028
62	ST Purchase Power Price ($/MWh)	45.14	50.31	52.93	55.19	56.91
63						
64	Total ST Purchases ($)	95,332,981	110,325,295	120,428,362	130,161,015	139,026,085
65						
66	Total ST Sales for Resale (MWh)	1,444,555	1,444,555	1,444,555	1,444,555	1,444,555
67	ST Sales Power Price ($/MWh)	$ 34.22	$ 37.45	$ 39.40	$ 41.08	$ 42.36
68						
69	Total ST Sales for Resale ($)	49,426,672	54,093,133	56,914,694	59,340,068	61,186,915
70						
71	**Price Spread (Plus/Minus, %)**	**14.66%**				
72						
73	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
74	**Purchase Prices ($/MWh)**		**50.31**	**52.93**	**55.19**	**56.91**
75	**Mid-Point Price ($/MWh)**		**43.88**	**46.17**	**48.13**	**49.63**
76	**Sales Prices ($/MWh)**		**37.45**	**39.40**	**41.08**	**42.36**

	C	D	E	F	G	H
1	**PacifiCorp**					
2						
3						
4	**Fiscal Year**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
9						
10	**Total Purchased Power ($)**	**849,729,899**	**931,310,925**	**983,611,992**	**1,044,819,526**	**1,101,020,408**
11	**Total Sale for Resale Credit ($)**	**849,104,067**	**922,889,664**	**967,804,280**	**1,006,679,085**	**1,036,838,401**
12						
13						
15	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
16	Base Period LT & IT Purchased Power (MWh)	4,881,360	4,881,360	4,881,360	4,881,360	4,881,360
17	New Resource LT & IT Purchased Power (MWh)					
18	LT & IT Terminated Contracts (MWh)					
19						
20	**Total LT & IT Purchased Power (MWh)**	**4,881,360**	**4,881,360**	**4,881,360**	**4,881,360**	**4,881,360**
21						
22						
23	Base Period LT & IT Sales for Resale (MWh)	1,987,006	1,987,006	1,987,006	1,987,006	1,987,006
24	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
25	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
26						
27	**Total LT & IT Sales for Resale (MWh)**	**1,987,006**	**1,987,006**	**1,987,006**	**1,987,006**	**1,987,006**
28						
29						
30	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
31	Base Case LT & IT Purchased Power, Market ($)	257,764,764	265,680,485	271,239,820	276,705,301	282,301,664
32	New Resource LT Purchases, Market ($)	-	-	-	-	-
33	Contract Terminations, Market ($)	-	-	-	-	-
34						
35	**Total LT & IT Purchases, Market ($)**	**257,764,764**	**265,680,485**	**271,239,820**	**276,705,301**	**282,301,664**
36						
37						
38	Base Case LT & IT Sales for Resale ($)	$ 100,150,215	$ 103,225,737	$ 105,385,724	$ 107,509,246	$ 109,683,619
39	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
40	**Total LT & IT Sales for Resale $**	**$ 100,150,215**	**$ 103,225,737**	**$ 105,385,724**	**$ 107,509,246**	**$ 109,683,619**
41						

	C	D	E	F	G	H
1	**PacifiCorp**					
2						
42						
43	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
44	Base Period ST Purchased Power (MWh)	13,978,301	13,978,301	13,978,301	13,978,301	13,978,301
45	Cumulative CSL Load Growth (MWh)	975,916	1,209,002	1,441,003	1,910,872	2,390,139
46	**Base Short Term Purchases Plus Load Growth (MWh)**	**14,954,217**	**15,187,302**	**15,419,304**	**15,889,173**	**16,368,440**
47						
48	New Resource Total Expected Annual Generation (MWh)	533,048	0	0	0	0
49	New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
50	New Resource Less Firm Sales for Resale (MWh)					
51	Cumulative Net New Resources (MWh)	**1,671,521**	**1,671,521**	**1,671,521**	**1,671,521**	**1,671,521**
52	**Total ST Purchases (MWh)**	**13,282,696**	**13,515,781**	**13,747,783**	**14,217,652**	**14,696,919**
53						
54						
55	New ST Sales for Resale (MWh)	-	-	-	-	-
56	Base ST Sales for Resale (MWh)	17,017,100	17,017,100	17,017,100	17,017,100	17,017,100
57	**Total ST Sales for Resale (MWh)**	**17,017,100**	**17,017,100**	**17,017,100**	**17,017,100**	**17,017,100**
58						
59						
60	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
61	Total ST Purchases (MWh)	13,282,696	13,515,781	13,747,783	14,217,652	14,696,919
62	ST Purchase Power Price ($/MWh)	44.57	49.25	51.82	54.03	55.71
63						
64	Total ST Purchases ($)	591,965,136	665,630,440	712,372,172	768,114,225	818,718,745
65						
66	Total ST Sales for Resale (MWh)	17,017,100	17,017,100	17,017,100	17,017,100	17,017,100
67	ST Sales Power Price ($/MWh)	$ 44.01	$ 48.17	$ 50.68	$ 52.84	$ 54.48
68						
69	Total ST Sales for Resale ($)	748,953,853	819,663,928	862,418,556	899,169,839	927,154,782
70						
71	**Price Spread (Plus/Minus, %)**	**1.11%**				
72						
73	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
74	**Purchase Prices ($/MWh)**		**49.25**	**51.82**	**54.03**	**55.71**
75	**Mid-Point Price ($/MWh)**		**48.71**	**51.25**	**53.43**	**55.10**
76	**Sales Prices ($/MWh)**		**48.17**	**50.68**	**52.84**	**54.48**

	C	D	E	F	G	H
1	**Portland General Electric**					
3						
4	**Fiscal Year**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
9						
10	**Total Purchased Power ($)**	**833,532,006**	**923,480,954**	**983,563,906**	**1,042,583,595**	**1,094,464,254**
11	**Total Sale for Resale Credit ($)**	**537,852,718**	**588,023,040**	**618,387,059**	**644,513,030**	**664,460,367**
12						
13						
15	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
16	Base Period LT & IT Purchased Power (MWh)	5,421,414	5,421,414	5,421,414	5,421,414	5,421,414
17	New Resource LT & IT Purchased Power (MWh)					
18	LT & IT Terminated Contracts (MWh)					
19						
20	**Total LT & IT Purchased Power (MWh)**	**5,421,414**	**5,421,414**	**5,421,414**	**5,421,414**	**5,421,414**
21						
22						
23	Base Period LT & IT Sales for Resale (MWh)	83,050	83,050	83,050	83,050	83,050
24	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
25	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
26						
27	**Total LT & IT Sales for Resale (MWh)**	**83,050**	**83,050**	**83,050**	**83,050**	**83,050**
28						
29						
30	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
31	Base Case LT & IT Purchased Power, Market ($)	169,692,290	174,903,386	178,563,220	182,161,268	185,845,478
32	New Resource LT Purchases, Market ($)	-	-	-	-	-
33	Contract Terminations, Market ($)	-	-	-	-	-
34						
35	**Total LT & IT Purchases, Market ($)**	**169,692,290**	**174,903,386**	**178,563,220**	**182,161,268**	**185,845,478**
36						
37						
38	Base Case LT & IT Sales for Resale ($)	$ 9,565,002	$ 9,858,735	$ 10,065,028	$ 10,267,838	$ 10,475,505
39	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
40	**Total LT & IT Sales for Resale $**	**$ 9,565,002**	**$ 9,858,735**	**$ 10,065,028**	**$ 10,267,838**	**$ 10,475,505**
41						

	C	D	E	F	G	H
1	**Portland General Electric**					
2						
42						
43	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
44	Base Period ST Purchased Power (MWh)	15,769,455	15,769,455	15,769,455	15,769,455	15,769,455
45	Cumulative CSL Load Growth (MWh)	1,477,958	1,800,097	2,165,706	2,591,861	3,011,029
46	**Base Short Term Purchases Plus Load Growth (MWh)**	**17,247,413**	**17,569,552**	**17,935,161**	**18,361,316**	**18,780,484**
47						
48	New Resource Total Expected Annual Generation (MWh)	522,595	0	0	0	0
49	New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
50	New Resource Less Firm Sales for Resale (MWh)					
51	Cumulative Net New Resources (MWh)	**997,569**	**997,569**	**997,569**	**997,569**	**997,569**
52	**Total ST Purchases (MWh)**	**16,249,844**	**16,571,983**	**16,937,592**	**17,363,747**	**17,782,915**
53						
54						
55	New ST Sales for Resale (MWh)	-	-	-	-	-
56	Base ST Sales for Resale (MWh)	12,928,925	12,928,925	12,928,925	12,928,925	12,928,925
57	**Total ST Sales for Resale (MWh)**	**12,928,925**	**12,928,925**	**12,928,925**	**12,928,925**	**12,928,925**
58						
59						
60	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
61	Total ST Purchases (MWh)	16,249,844	16,571,983	16,937,592	17,363,747	17,782,915
62	ST Purchase Power Price ($/MWh)	40.85	45.17	47.53	49.55	51.10
63						
64	Total ST Purchases ($)	663,839,716	748,577,568	805,000,687	860,422,327	908,618,776
65						
66	Total ST Sales for Resale (MWh)	12,928,925	12,928,925	12,928,925	12,928,925	12,928,925
67	ST Sales Power Price ($/MWh)	$ 40.86	$ 44.72	$ 47.05	$ 49.06	$ 50.58
68						
69	Total ST Sales for Resale ($)	528,287,716	578,164,305	608,322,031	634,245,192	653,984,862
70						
71	**Price Spread (Plus/Minus, %)**	**0.50%**				
72						
73	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
74	**Purchase Prices ($/MWh)**		**45.17**	**47.53**	**49.55**	**51.10**
75	**Mid-Point Price ($/MWh)**		**44.94**	**47.29**	**49.30**	**50.84**
76	**Sales Prices ($/MWh)**		**44.72**	**47.05**	**49.06**	**50.58**

	C	D	E	F	G	H
1	**Puget Sound Energy, Inc.**					
2						
3						
4	**Fiscal Year**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
9						
10	**Total Purchased Power ($)**	**766,920,846**	**824,359,631**	**861,474,131**	**897,121,363**	**930,647,331**
11	**Total Sale for Resale Credit ($)**	**174,403,889**	**190,844,422**	**200,786,329**	**209,333,310**	**215,843,772**
12						
13						
15	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
16	Base Period LT & IT Purchased Power (MWh)	9,353,824	9,353,824	9,353,824	9,353,824	9,353,824
17	New Resource LT & IT Purchased Power (MWh)					
18	LT & IT Terminated Contracts (MWh)					
19						
20	**Total LT & IT Purchased Power (MWh)**	**9,353,824**	**9,353,824**	**9,353,824**	**9,353,824**	**9,353,824**
21						
22						
23	Base Period LT & IT Sales for Resale (MWh)	7,810	7,810	7,810	7,810	7,810
24	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
25	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
26						
27	**Total LT & IT Sales for Resale (MWh)**	**7,810**	**7,810**	**7,810**	**7,810**	**7,810**
28						
29						
30	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
31	Base Case LT & IT Purchased Power, Market ($)	414,421,162	427,147,660	436,085,677	444,872,802	453,870,351
32	New Resource LT Purchases, Market ($)	-	-	-	-	-
33	Contract Terminations, Market ($)	-	-	-	-	-
34						
35	**Total LT & IT Purchases, Market ($)**	**414,421,162**	**427,147,660**	**436,085,677**	**444,872,802**	**453,870,351**
36						
37						
38	Base Case LT & IT Sales for Resale ($)	$ 396,370	$ 408,543	$ 417,091	$ 425,496	$ 434,101
39	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
40	**Total LT & IT Sales for Resale $**	**$ 396,370**	**$ 408,543**	**$ 417,091**	**$ 425,496**	**$ 434,101**
41						

	C	D	E	F	G	H
1	**Puget Sound Energy, Inc.**					
42						
43	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
44	Base Period ST Purchased Power (MWh)	9,619,746	9,619,746	9,619,746	9,619,746	9,619,746
45	Cumulative CSL Load Growth (MWh)	669,262	791,677	942,342	1,111,556	1,307,996
46	**Base Short Term Purchases Plus Load Growth (MWh)**	**10,289,008**	**10,411,423**	**10,562,088**	**10,731,302**	**10,927,742**
47						
48	New Resource Total Expected Annual Generation (MWh)	562,915	0	0	0	0
49	New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
50	New Resource Less Firm Sales for Resale (MWh)					
51	Cumulative Net New Resources (MWh)	**1,967,844**	**1,967,844**	**1,967,844**	**1,967,844**	**1,967,844**
52	**Total ST Purchases (MWh)**	**8,321,164**	**8,443,579**	**8,594,243**	**8,763,458**	**8,959,898**
53						
54						
55	New ST Sales for Resale (MWh)	-	-	-	-	-
56	Base ST Sales for Resale (MWh)	4,422,562	4,422,562	4,422,562	4,422,562	4,422,562
57	**Total ST Sales for Resale (MWh)**	**4,422,562**	**4,422,562**	**4,422,562**	**4,422,562**	**4,422,562**
58						
59						
60	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
61	Total ST Purchases (MWh)	8,321,164	8,443,579	8,594,243	8,763,458	8,959,898
62	ST Purchase Power Price ($/MWh)	42.36	47.04	49.50	51.61	53.21
63						
64	Total ST Purchases ($)	352,499,683	397,211,971	425,388,454	452,248,561	476,776,980
65						
66	Total ST Sales for Resale (MWh)	4,422,562	4,422,562	4,422,562	4,422,562	4,422,562
67	ST Sales Power Price ($/MWh)	$ 39.35	$ 43.06	$ 45.31	$ 47.24	$ 48.71
68						
69	Total ST Sales for Resale ($)	174,007,518	190,435,880	200,369,238	208,907,814	215,409,670
70						
71	**Price Spread (Plus/Minus, %)**	**4.42%**				
72						
73	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
74	**Purchase Prices ($/MWh)**		**47.04**	**49.50**	**51.61**	**53.21**
75	**Mid-Point Price ($/MWh)**		**45.05**	**47.40**	**49.42**	**50.96**
76	**Sales Prices ($/MWh)**		**43.06**	**45.31**	**47.24**	**48.71**

	C	D	E	F	G	H
1	**Snohomish PUD**					
2						
3						
4	**Fiscal Year**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
9						
10	**Total Purchased Power ($)**	**324,836,669**	**351,877,365**	**359,396,260**	**370,708,527**	**377,820,323**
11	**Total Sale for Resale Credit ($)**	**53,060,459**	**58,069,992**	**61,098,991**	**63,702,676**	**65,685,300**
12						
13						
15	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
16	Base Period LT & IT Purchased Power (MWh)	7,693,114	7,693,114	7,693,114	7,693,114	7,693,114
17	New Resource LT & IT Purchased Power (MWh)					
18	LT & IT Terminated Contracts (MWh)					
19						
20	**Total LT & IT Purchased Power (MWh)**	**7,693,114**	**7,693,114**	**7,693,114**	**7,693,114**	**7,693,114**
21						
22						
23	Base Period LT & IT Sales for Resale (MWh)	-	-	-	-	-
24	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
25	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
26						
27	**Total LT & IT Sales for Resale (MWh)**	**-**	**-**	**-**	**-**	**-**
28						
29						
30	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
31	Base Case LT & IT Purchased Power, Market ($)	290,676,248	307,547,558	309,225,759	314,944,005	316,633,384
32	New Resource LT Purchases, Market ($)	54,966,311	56,655,436	57,840,945	59,006,439	60,199,844
33	Contract Terminations, Market ($)	-	-	-	-	-
34						
35	**Total LT & IT Purchases, Market ($)**	**345,642,559**	**364,202,994**	**367,066,704**	**373,950,444**	**376,833,228**
36						
37						
38	Base Case LT & IT Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
39	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
40	**Total LT & IT Sales for Resale $**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
41						

	C	D	E	F	G	H
1	**Snohomish PUD**					
42						
43	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
44	Base Period ST Purchased Power (MWh)	889,352	889,352	889,352	889,352	889,352
45	Cumulative CSL Load Growth (MWh)	334,238	434,429	502,125	565,722	631,519
46	**Base Short Term Purchases Plus Load Growth (MWh)**	**1,223,590**	**1,323,781**	**1,391,477**	**1,455,074**	**1,520,871**
47						
48	New Resource Total Expected Annual Generation (MWh)	(219,600)	0	0	0	0
49	New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
50	New Resource Less Firm Sales for Resale (MWh)					
51	Cumulative Net New Resources (MWh)	**428,905**	**428,905**	**428,905**	**428,905**	**428,905**
52	**Total ST Purchases (MWh)**	**794,684**	**894,876**	**962,572**	**1,026,169**	**1,091,966**
53						
54						
55	New ST Sales for Resale (MWh)	-	-	-	-	-
56	Base ST Sales for Resale (MWh)	1,480,494	1,480,494	1,480,494	1,480,494	1,480,494
57	**Total ST Sales for Resale (MWh)**	**1,480,494**	**1,480,494**	**1,480,494**	**1,480,494**	**1,480,494**
58						
59						
60	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
61	Total ST Purchases (MWh)	794,684	894,876	962,572	1,026,169	1,091,966
62	ST Purchase Power Price ($/MWh)	42.99	49.54	52.12	54.34	56.03
63						
64	Total ST Purchases ($)	34,160,420	44,329,807	50,170,500	55,764,523	61,186,939
65						
66	Total ST Sales for Resale (MWh)	1,480,494	1,480,494	1,480,494	1,480,494	1,480,494
67	ST Sales Power Price ($/MWh)	$ 35.84	$ 39.22	$ 41.27	$ 43.03	$ 44.37
68						
69	Total ST Sales for Resale ($)	53,060,459	58,069,992	61,098,991	63,702,676	65,685,300
70						
71	**Price Spread (Plus/Minus, %)**	**11.62%**				
72						
73	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
74	**Purchase Prices ($/MWh)**		**49.54**	**52.12**	**54.34**	**56.03**
75	**Mid-Point Price ($/MWh)**		**44.38**	**46.70**	**48.69**	**50.20**
76	**Sales Prices ($/MWh)**		**39.22**	**41.27**	**43.03**	**44.37**

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