2007 Wholesale Power Rate Case Final Proposal

WHOLESALE POWER RATE DEVELOPMENT STUDY DOCUMENTATION

Volume 2 of 2

July 2006

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BONNEVILLE POWER ADMINISTRATION

WHOLESALE POWER RATE DEVELOPMENT STUDY DOCUMENTATION

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DOCUMENTATION

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COMMONLY USED ACRONYMS

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

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

JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company
JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities

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

JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	Million British thermal units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)

MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-Coincidental Demand
NWEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative

PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems

UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

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DOCUMENTATION FOR THE
WHOLESALE POWER RATE DEVELOPMENT STUDY

INTRODUCTION

The Documentation for Wholesale Power Rate Development Study shows the details of the calculation of the proposed rates. It contains the source data, the calculation, and the results. There are 2 Volumes, the first containing Sections 1, 2, and 3; the second containing Section 4 and 3 appendices.

Section 1 contains an overview of the information used and developed in the various models used in the rate development process.

Section 2 contains the documentation of the Rate Analysis Model (RAM2007). The RAM2007 is a group of computer applications that performs most of the computations that determine BPA's proposed rates. The output tables of RAM2007 show the source data, calculations (in sequence), and the results (rate charges) of the rate development process.

Section 3 provides documentation of revenue forecasts for the three-year rate test period FY 2007 through FY 2009 at both current and proposed rates and at current rates for the period immediately preceding the rate test period.

Section 4 includes supporting data for rate calculations not performed in RAM2007 or revenue analyses.

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4. ADDITIONAL RATE DESIGN TABLES

Table 4.1
Settlement Rates

Calculation of PF Preference Rate Components
Test Period October 2006 - September 2009
Attachment A

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Averages
Initial Proposal Demand Charges	$ 1.17	$ 1.25	$ 1.31	$ 1.11	$ 1.13	$ 1.05	$ 0.99	$ 0.82	$ 0.75	$ 0.92	$ 1.08	$ 1.11	1.06
Demand at $2 average													
Shaped per Initial Proposal	$ 2.21	$ 2.36	$ 2.48	$ 2.10	$ 2.14	$ 1.99	$ 1.87	$ 1.55	$ 1.42	$ 1.74	$ 2.04	$ 2.10	2.00
Incr. Demand Revenues ('000)	$ 19,443	$ 22,664	$ 25,639	$ 22,691	$ 22,456	$ 18,839	$ 15,923	$ 11,969	$ 10,557	$ 13,528	$ 15,814	$ 16,164	
Total Demand Revenues	$ 41,258	$ 48,093	$ 54,406	$ 48,151	$ 47,652	$ 39,976	$ 33,788	$ 25,398	$ 22,403	$ 28,708	$ 33,558	$ 34,300	

PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	6,625	7,074	8,129	8,322	7,428	7,469	6,647	5,966	5,497	5,663	5,939	6,149
LLH	4,327	5,088	5,851	5,841	5,081	5,093	4,399	4,257	3,695	3,907	3,919	4,274
Demand	18,646	20,343	21,960	22,937	22,297	20,131	18,046	16,377	15,794	16,499	16,430	16,339

Proposed PF rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	$ 33.77	$ 36.02	$ 37.59	$ 31.91	$ 32.59	$ 30.23	$ 28.37	$ 23.70	$ 21.45	$ 26.42	$ 30.94	$ 31.94
LLH	$ 29.23	$ 30.72	$ 31.96	$ 26.97	$ 27.73	$ 25.86	$ 24.01	$ 19.19	$ 14.25	$ 22.80	$ 26.99	$ 29.41
Demand	$ 1.17	$ 1.25	$ 1.31	$ 1.11	$ 1.13	$ 1.05	$ 0.99	$ 0.82	$ 0.75	$ 0.92	$ 1.08	$ 1.11
Load Variance	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 223,720	$ 254,794	$ 305,573	$ 265,558	$ 242,086	$ 225,781	$ 188,573	$ 141,404	$ 117,905	$ 149,626	$ 183,742	$ 196,410	$ 2,495,172
LLH	$ 126,464	$ 156,310	$ 187,009	$ 157,519	$ 140,900	$ 131,708	$ 105,623	$ 81,685	$ 52,648	$ 89,079	$ 105,770	$ 125,709	$ 1,460,422
Demand	$ 21,815	$ 25,429	$ 28,767	$ 25,460	$ 25,196	$ 21,137	$ 17,866	$ 13,429	$ 11,846	$ 15,179	$ 17,744	$ 18,136	$ 242,004
												LV Revenue	$ 52,592
													$ 4,250,191

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Revised LLH Revenues	$ 107,021	$ 133,646	$ 161,370	$ 134,828	$ 118,444	$ 112,869	$ 89,700	$ 69,716	$ 42,091	$ 75,550	$ 89,955	$ 109,545
Revised LLH Charges	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63

Compromise Charges	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
HLH	**33.77**	**36.02**	**37.59**	**31.91**	**32.59**	**30.23**	**28.37**	**23.70**	**21.45**	**26.42**	**30.94**	**31.94**
LLH	**24.74**	**26.27**	**27.58**	**23.08**	**23.31**	**22.16**	**20.39**	**16.38**	**11.39**	**19.34**	**22.95**	**25.63**
Demand	**2.21**	**2.36**	**2.48**	**2.10**	**2.14**	**1.99**	**1.87**	**1.55**	**1.42**	**1.74**	**2.04**	**2.10**
Load Variance	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**

Revenue Check

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 223,720	$ 254,794	$ 305,573	$ 265,558	$ 242,086	$ 225,781	$ 188,573	$ 141,404	$ 117,905	$ 149,626	$ 183,742	$ 196,410	$ 2,495,172
LLH	$ 107,021	$ 133,646	$ 161,370	$ 134,828	$ 118,444	$ 112,869	$ 89,700	$ 69,716	$ 42,091	$ 75,550	$ 89,955	$ 109,545	$ 1,244,736
Demand	$ 41,258	$ 48,093	$ 54,406	$ 48,151	$ 47,652	$ 39,976	$ 33,788	$ 25,398	$ 22,403	$ 28,708	$ 33,558	$ 34,300	$ 457,691
												LV Revenue	$ 52,592
													$ 4,250,191

TABLE 4.2 DEMAND RATE DOCUMENTATION

	Sum of HLH Deviations above Qtly HLH price				FPS HLH	Demand
	FY07	FY08	FY09		$/MWh	$/kW-mo
Oct	$454.33	$160.07	$105.01		$59.73	$1.17
Nov	$778.74	$817.64	$820.48		$63.71	$1.25
Dec	$1,389.19	$1,994.68	$1,324.40		$66.48	$1.31
Jan	$1,382.99	$1,001.14	$1,007.20		$56.43	$1.11
Feb	$1,300.82	$1,077.10	$1,157.39		$57.63	$1.13
Mar	$305.04	$360.62	$460.13		$53.47	$1.05
Apr	$4,892.66	$1,808.27	$2,035.93		$50.18	$0.99
May	$1,052.02	$385.78	$212.78		$41.91	$0.82
Jun	$297.30	$1,298.90	$563.93		$37.94	$0.75
Jul	$502.96	$250.75	$172.59		$46.73	$0.92
Aug	$1,290.48	$1,104.02	$1,240.27		$54.71	$1.08
Sep	$1,617.32	$1,621.58	$1,821.73		$56.48	$1.11
Average	$1,271.99	$990.05	$910.15		$645.40	$12.69
3-Yr Total	$38,066.24		Annual Demand	$12.69		
			Monthly average	$1.06		

Table 4.3 Load Variance Documentation

		Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02
Forecast	**HLH**	1,253,844	1,373,433	1,583,675	1,632,359	1,399,762	1,390,500	1,281,042	1,258,743	1,216,327	1,296,912	1,296,488	1,210,766	1,297,365
	LLH	782,653	887,435	1,030,294	1,055,044	921,747	928,549	830,777	814,347	791,970	801,684	808,463	750,819	817,509
Forecast Error	**HLH**	26,080	28,567	32,940	33,953	29,115	28,922	26,646	26,182	25,300	26,976	26,967	25,184	26,985
2.08%	**LLH**	16,279	18,459	21,430	21,945	19,172	19,314	17,280	16,938	16,473	16,675	16,816	15,617	17,004
(Cost)/Benefit of Error	**HLH**	($677,049)	($809,444)	($975,165)	($881,332)	($754,469)	($643,515)	($787,231)	($591,754)	($354,952)	($666,317)	($727,841)	($745,703)	($575,253)
	LLH	($431,726)	($424,127)	($523,107)	($534,409)	($484,124)	($480,295)	($439,772)	($243,225)	($132,748)	($337,011)	($397,215)	($365,076)	($393,969)
From J.Hirsh														
SalesFcstBDs30Updated(2).xls		**Oct-06**	**Nov-06**	**Dec-06**	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**
07 Forecast	**HLH**	1,546,494	1,617,952	1,803,317	1,872,207	1,628,310	1,647,798	1,522,276	1,531,407	1,519,304	1,626,014	1,606,788	1,439,891	1,579,576
07 Forecast	**LLH**	999,101	1,138,794	1,286,376	1,274,592	1,134,900	1,128,951	1,019,260	1,061,358	1,040,973	1,088,970	1,053,789	985,769	1,009,673
Load Growth	**HLH**	0	0	0	0	0	0	0	0	0	0	0	0	33,081
	LLH	0	0	0	0	0	0	0	0	0	0	0	0	10,572
(Cost)/Benefit of Load Gro	**HLH**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($705,209)
	LLH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($244,940)
Total Retail Load Forecast	**MWh**	2,545,596	2,756,746	3,089,693	3,146,799	2,763,211	2,776,749	2,541,536	2,592,764	2,560,277	2,714,984	2,660,576	2,425,660	2,589,249

Table 4.3 Load Variance Documentation

		Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03
Forecast	**HLH**	1,405,364	1,613,580	1,646,314	1,407,647	1,404,957	1,304,052	1,269,984	1,222,252	1,307,495	1,316,568	1,218,224	1,279,186	1,362,818
	LLH	913,949	1,054,108	1,066,095	926,510	940,914	843,791	819,294	794,939	807,304	827,713	746,928	808,112	900,284
Forecast Error	**HLH**	29,232	33,562	34,243	29,279	29,223	27,124	26,416	25,423	27,196	27,385	25,339	26,607	28,347
2.08%	**LLH**	19,010	21,925	22,175	19,271	19,571	17,551	17,041	16,535	16,792	17,216	15,536	16,809	18,726
(Cost)/Benefit of Error	**HLH**	($746,364)	($944,687)	($656,320)	($561,742)	($501,391)	($388,574)	($375,816)	($417,431)	($443,537)	($483,115)	($527,265)	($359,695)	($525,536)
	LLH	($416,011)	($510,486)	($414,185)	($355,295)	($364,204)	($254,629)	($216,403)	($189,229)	($231,421)	($327,538)	($259,447)	($286,968)	($306,983)
From J.Hirsh														
SalesFcstBDs30Updated(2).xls		**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Oct-08**	**Nov-08**
07 Forecast	**HLH**	1,646,941	1,836,315	1,905,499	1,669,534	1,669,669	1,554,425	1,557,246	1,540,954	1,659,846	1,631,049	1,470,239	1,597,544	1,657,549
07 Forecast	**LLH**	1,157,045	1,307,318	1,295,052	1,160,099	1,151,155	1,029,418	1,076,065	1,057,572	1,100,345	1,071,062	995,079	1,021,350	1,177,274
Load Growth	**HLH**	28,989	32,997	33,292	41,224	21,871	32,150	25,839	21,650	33,832	24,261	30,349	51,050	39,596
	LLH	18,251	20,943	20,460	25,199	22,204	10,157	14,708	16,599	11,375	17,274	9,310	22,248	38,480
(Cost)/Benefit of Load Gro	**HLH**	($740,162)	($928,784)	($638,088)	($790,910)	($375,243)	($460,564)	($367,613)	($355,480)	($551,768)	($428,016)	($631,503)	($690,132)	($734,100)
	LLH	($399,402)	($487,605)	($382,151)	($464,579)	($413,194)	($147,365)	($186,767)	($189,966)	($156,762)	($328,628)	($155,477)	($379,835)	($630,819)
Total Retail Load Forecast	**MWh**	2,803,986	3,143,633	3,200,551	2,829,633	2,820,824	2,583,843	2,633,311	2,598,526	2,760,191	2,702,112	2,465,319	2,618,894	2,834,822

Table 4.3 Load Variance Documentation

		Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04
Forecast	**HLH**	1,596,159	1,641,654	1,412,924	1,432,170	1,294,547	1,278,766	1,242,685	1,351,551	1,346,982	1,232,818	1,304,583
	LLH	1,040,176	1,062,974	946,580	955,434	854,508	840,390	800,821	835,724	841,493	767,889	833,762
Forecast Error	**HLH**	33,200	34,146	29,389	29,789	26,927	26,598	25,848	28,112	28,017	25,643	27,135
2.08%	**LLH**	21,636	22,110	19,689	19,873	17,774	17,480	16,657	17,383	17,503	15,972	17,342
(Cost)/Benefit of Error	**HLH**	($610,037)	($531,643)	($478,334)	($432,725)	($272,701)	($270,767)	($259,878)	($343,105)	($397,069)	($450,857)	($165,134)
	LLH	($346,302)	($327,721)	($312,898)	($320,738)	($199,309)	($189,609)	($173,390)	($191,500)	($270,992)	($211,110)	($170,300)
From J.Hirsh												
SalesFcstBDs30Updated(2).xls		**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	
07 Forecast	**HLH**	1,866,922	1,930,316	1,679,588	1,690,815	1,573,197	1,569,710	1,565,199	1,680,791	1,652,106	1,489,185	
07 Forecast	**LLH**	1,315,595	1,312,723	1,167,913	1,165,944	1,042,095	1,093,764	1,067,389	1,114,525	1,084,497	1,008,303	
Load Growth	**HLH**	63,604	58,109	51,278	43,017	50,922	38,304	45,895	54,777	45,318	49,295	
	LLH	29,220	38,131	33,013	36,993	22,835	32,407	26,415	25,555	30,708	22,534	
(Cost)/Benefit of Load Gro	**HLH**	($1,168,700)	($904,726)	($834,604)	($624,871)	($515,712)	($389,928)	($461,435)	($668,539)	($642,269)	($866,718)	
	LLH	($467,690)	($565,195)	($524,638)	($597,050)	($256,064)	($351,521)	($274,969)	($281,523)	($475,439)	($297,842)	
Total Retail Load Forecast	**MWh**	3,182,517	3,243,039	2,847,501	2,856,759	2,615,293	2,663,475	2,632,588	2,795,316	2,736,603	2,497,489	

Table 4.3 Load Variance Documentation

		Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Totals	
Forecast	**HLH**	1,398,924	1,580,524	1,623,935	1,394,767	1,414,558	1,287,434	1,302,361	1,264,623	1,380,772	-	-	63032393	MWh
	LLH	918,118	1,045,375	1,053,546	953,733	955,361	844,959	848,775	830,974	865,558	-	-	40767379	MWh
Forecast Error	**HLH**	29,098	32,875	33,778	29,011	29,423	26,779	27,089	26,304	28,720	-	-	1311074	MWh
2.08%	**LLH**	19,097	21,744	21,914	19,838	19,872	17,575	17,655	17,284	18,004	-	-	847961	MWh
(Cost)/Benefit of Error	**HLH**	($241,311)	($282,280)	($459,186)	($286,045)	($472,532)	($569,196)	($276,547)	($834,265)	($1,204,791)	$ -	$ -	($17,818,676)	Fcst Error
	LLH	($201,373)	($225,239)	($294,068)	($281,773)	($412,619)	($364,861)	($77,627)	($379,461)	($511,860)	$ -	$ -	($10,751,809)	($0.29)
From J.Hirsh														
SalesFcstBDs30Updated(2).xls														
07 Forecast	**HLH**													
07 Forecast	**LLH**													
Load Growth	**HLH**													
	LLH													
														Per unit cost
(Cost)/Benefit of Load Gro	**HLH**												($15,475,076)	Load Growth
	LLH												($8,659,423)	($0.24)
Total Retail Load Forecast	**MWh**												99,230,066	MWh TRL

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4.4 GENERATION INPUTS FOR ANCILLARY SERVICES AND OTHER SERVICES

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4.4.1 Operating Reserves

Section 4.4.1 - Table 1
Summary of Costs Assigned to TBL for the Generation Input for Operating Reserves
(x1000)

		Average Over Rate Period	
	Operating Reserves Generation Input	**Subtotals (X000)**	**Totals (X000)**
1	**All Hydro Projects**		
2	O&M	$ 216,244	
3	Depreciation	$ 86,396	
4	Net Interest	$ 112,745	
5	Planned Net Revenues	$ 34,013	
6	Total Revenue Requirement		$ 449,398
7	**Fish & Wildlife**		
8	O&M **1/**	$ 208,872	
9	Amortization/Depreciation	$ 36,042	
10	Net Interest	$ 35,053	
11	Planned Net Revenues	$ 10,397	
12	Subtotal Fish & Wildlife		$ 290,365
13	**A&G Expense 1/**		$ 92,349
14	**Total Revenue Requirement**		
15	Revenue Credits		
16	4h10C (non-operations)	$ 39,917	
17	Colville payment Treas. Credit	$ 4,600	
18	Generation Supplied Reactive Generation Input Cost 2/	$16,394	
19	Subtotal Revenue Credits		$ 60,911
20	**Net Revenue Requirement**		**$ 771,201**

1/ Power Marketing, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council

2/ Average forecasted revenue for Generation Supplied Reactive over three-year rate period

Section 4.4.1 - Table 1B
Summary of Assumptions and Application of Methods to Develop Per Unit Generation Input and Annual Revenue Forecast for Operating Reserves (Average over Rate Period)

	Operating Reserve Assumptions	**Average MWs**
1	**Regulated + Independent Hydro**	**9,217**
2	Total BPA Control Area Reserve Obligation (Line 3 + 4)	690
3	Total Self-Supply and Third Party-Supply Reserve Obligation	310
4	**Total PBL Reserve Obligation**	**380**
5	**Control Area Regulation Requirement.**	**350**
	Forecast of Average Hydro Generation System Uses	**Average MWs**
6	Average Hydro Generation (Line 1)	9,217
7	Total PBL Reserve Obligation (Line 4)	380
8	Control Area Regulation Requirement (Line 5)	350
9	**Total Average Hydro Generation System Uses**	**9,947**
	Factor to Apply to Revenue Requirement	**Average MWs**
10	Total PBL Reserve Obligation (Line 4)	380
11	Total Average Control Area Generation (Line 9)	9,947
12	**Multiplication Factor for Revenue Requirement (Line 10 / Line 11)**	**0.03820**
	Adjusted Revenue Requirement	**Average $'s**
13	Power Revenue Requirement for ALL Hydro Projects	**$771,201,466**
14	Multiplication Factor (Line 12)	3.8202%
15	**Adjusted Revenue Requirement for Operating Reserves**	**$ 29,461,803**
	Per Unit Rate	**Average $'s**
16	Adjusted Revenue Requirement for Operating Reserves (Line 15)	$ 29,461,803
17	Total PBL Reserve Obligation (Line 4) * 12 *1000	4,560,000
18	**Per Unit Rate Express Kw-Mo (Line 16 / Line 17)**	**$ 6.46**
	Annual Revenue Forecast for Operating Reserves	**Average $'s**
19	Total PBL Reserve Obligation (Line 4)	380
20	Per Unit Generation Input Rate	$ 6.46
21	**Annual Revenue Forecast (Line 19 * Line 20 *12*1000)**	**$ 29,461,803**

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4.4.2 Regulating Reserves

Section 4.4.2 - Table 1
Summary of Costs Assigned to TBL for the Generation Input for Regulating Reserves
(x1000)

	Regulating Reserves Generation Input	Average Over Rate Period Subtotals (X000)	Totals (X000)
1	**Big 10 Dams**		
2	O&M	$ 166,675	
3	Depreciation	$ 66,928	
4	Net Interest	$ 88,949	
5	Planned Net Revenues	$ 26,225	
6	Total Revenue Requirement		$ 348,777
7	**Fish & Wildlife**		
8	O&M **1/**	$ 208,872	
9	Amortization/Depreciation	$ 36,042	
10	Net Interest	$ 35,053	
11	Planned Net Revenues	$ 10,397	
12	Subtotal Fish & Wildlife		$ 290,364
13	**A&G Expense 1/**		$ 92,349
14	**Total Revenue Requirement**		
15	Revenue Credits		
16	4h10C (non-operations)	$ 39,917	
17	Colville payment Treas. Credit	$ 4,600	
18	Generation Supplied Reactive Generation Input Cost **2/**	$16,394	
19	Subtotal Revenue Credits		$ 60,911
20	**Net Revenue Requirement**		**$ 670,579**

1/ Power Marketing, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council
2/ Average forecasted revenue for Generation Supplied Reactive over three-year rate period

Section 4.4.2 - Table 1B

Summary of Assumptions and Application of Methods to Develop Per Unit Generation Input and Annual Revenue Forecast for Regulating Reserves (Average over Rate Period)

		FY07-09
	Regulating Reserve Assumptions	**Average MWs**
1	**Regulated + Independent Hydro**	**9,217**
2	Total BPA Control Area Reserve Obligation (Line 3 + 4)	690
3	Total Self-Supply and Third Party-Supply Reserve Obligation	310
4	**Total PBL Reserve Obligation**	**380**
5	**Control Area Regulation Requirement.**	**350**
5b	**TBL Regulating Reserves Requirement**	**150**
	Forecast of Average Hydro Generation System Uses	**Average MWs**
6	Average Hydro Generation (Line 1)	9,217
7	Total PBL Reserve Obligation (Line 4)	380
8	Control Area Regulation Requirement (Line 5)	350
9	**89% Average Hydro Generation System Uses**	**8,933**
		.
	Factor to Apply to Revenue Requirement	**Average MWs**
10	Control Area Regulating Requirement (Line 5)	350
11	Total Average Control Area Generation (Line 9)	8,933
12	**Multiplication Factor for Revenue Requirement (Line 10 / Line 11)**	**0.03918**
	Adjusted Revenue Requirement	**Average $'s**
13	Power Revenue Requirement for Big 10 Hydro Projects	**$670,579,044**
14	Multiplication Factor (Line 12)	3.9180%
15	**Adjusted Revenue Requirement for Regulating Reserves**	**$ 26,273,284**
	Per Unit Rate	**Average $'s**
16	Adjusted Revenue Requirement for Regulating Reserves (Line 15)	$ 26,273,284
17	Total Regulating Reserve Obligation (Line 4) * 12 *1000	4,560,000
18	**Per Unit Rate in Kw-Mo (Line 16 / Line 17)**	$ 5.76
	Annual Revenue Forecast for Operating Reserves	**Average $'s**
19	Total TBL Regulating Reserve Obligation (Line 5b)	150
20	Per Unit Rate in Kw-Mo (Line 16 / Line 17)	$ 5.76
20a	AGC Adder	$ 1.55
20b	Total Per Unit Rate (Linw 20 + 20a)	**$ 7.31**
21	**Annual Revenue Forecast (Line 19 * Line 20b *12*1000)**	**$ 13,161,033**

Section 4.4.2 - Table 2
AGC Adder Assumptions

	Big 10 Capacity		Turbine Type	Peak Efficiency MWs
1	GCC	Grand Coulee	Francis	5,467
2	CHJ	Chief Joseph	Francis	2,168
3	JDA	John Day	Kaplan	1,984
4	TDA	The Dalles	Kaplan	1,665
5	BON	Bonneville	Kaplan	841
6	MCN	McNary	Kaplan	706
7	LGS	Little Goose	Kaplan	730
8	LMN	Lower Monumental	Kaplan	706
9	LWG	Lower Granite	Kaplan	730
10	IH	Ice Harbor	Kaplan	658
11	**Francis Total Capacity**			**7,635**
12	**Kaplan Total Capacity**			**8,020**

Section 4.4.2 - Table 3
AGC Adder Calculation
BPA Incremental Cost of Regulation (AGC)

	Efficiency-Lost Costs of Regulation 1/	Kaplan	Francis	Notes
1	Efficiency Loss	25%	29%	On all kWh on AGC
2	kWh with Efficiency Loss	8,760	8,760	kWh per kW-yr on AGC
3	kWh Lost	22	25	per kW-yr on AGC
4	Average Price	30	30	$/MWh
5	Revenue Loss	0.66	0.77	per kW-yr on AGC

	Incremental Increased O&M Costs of Regualtion 1/	Kaplan	Francis	
6	Base O&M Cost per kW of Francis & Kaplan Capacity	13.78	8.78	$/kW-yr
7	Percent O&M Increase due to AGC (inc. small capital)	15%	10%	
8	Incremental O&M Costs for Regulation	2.07	0.88	per kW-yr on AGC

	AGC Multiplier 2/	Kaplan	Francis	
9	AGC Multiplier	3.70	12.30	kW on AGC per kW of AGC Resp

	Total Cost of Regulation	Kaplan	Francis	
10	Efficiency Loss Cost	0.66	0.77	kW on AGC per kW of AGC Resp
11	Increased O&M Cost	2.07	0.88	
12	Subtotal	2.73	1.65	
13	Multiply Costs by AGC Multiplier	3.70	12.30	
14	Costs per kW-yr of AGC Effciency Lost Cost	$2.44	$9.47	
15	Increased O&M Cost	$7.66	$10.82	
16	Total AGC Incremental Cost	$10.10	$20.30	
17	MW * Hours of AGC	3,485,639	16,708,059	per kW-yr of AGC Capability
18	Weight	17%	83%	
19	Weighted Average	18.56		per kW-yr of AGC Capability
20	**Weighted Average**	**1.55**		**per kW-mo** of AGC Capability

1/ Applied to all MW on AGC, not just MW of AGC Capability
2/ Calculate MW on AGC required to yield 1 MW of AGC Response Capability

Section 4.4.2 - Table 4
AGC Adder & Multiplier Worksheet

Summary of Equipment (Francis Units)
Grand Coulee
6 Operated @ 73 MW
? Eff = 0.3%
Range = 14 MW
Multiplier = 73 MW/14 MW * 2 = 10.4
12 Operated @ 81 MW
? Eff = 0.3%
Range = 20 MW
Multiplier = 81 MW/20 MW * 2 = 8.1
3 Operated @ 600 MW
? Eff = 0.2%
Range = 95 MW
Multiplier = 600 MW/95 MW * 2 = 12.6
3 Operated @ 718 MW
? Eff = 0.25%
Range = 167 MW
Multiplier = 718 MW/167 MW * 2 = 8.6

Calculation for Francis Units Weighted Multiplier
6 (73) 10.4 + 12 (81) 8
+3 (600) 12.6 + 3 (718) 8.6
+11 (88) 19.6 + 6 (75) 8.8
+10 (75) 21.4/WGTS = 92,518/7,532
12.3 Francis
6 (73) (3) + 12 (81) (3)
+3 (600) 2 + 3 (718) 2.5
+11 (88) 3.3 + 6 (75) 3.3
+10 (75) 5/WGTS = 21,644/7,532
.29% Francis

Chief Joseph
11 Operated @ 88 MW
? Eff = 0.33%
Range = 9 MW
Multiplier = 88 MW9 MW * 2 = 19.6
6 Operated @75 MW
? Eff = 0.33%
Range = 17 MW
Multiplier = 75 MW/17 MW * 2 = 8.8
10 Operated @ 75 MW
? Eff = 0.5%
Range = 7 MW
Multiplier =75 MW/7 MW * 2 = 21.4

Calculation for Kaplan Units Weighted Multiplier
.25% Kaplan
Range = 23.7 MW
Operated @ 43.7 MW
Multiplier = 43.7/23.7*2 = 3.68 Kaplan

4.4.3 REACTIVE SUPPLY AND VOLTAGE CONTROL

Section 4.4.3 - Table 1
Summary of Costs Assigned to TBL for the Generation Input for Generation Supplied Reactive Power and Voltage Control
(x1000)

		FY07	
	Costs for Electric Plant	**Total for Electric Plant**	**Allocated to Reactive**
1	Federal Hydro Generating Projects		
2	O&M	$ 80,329	
3	A&G Expenses	$ 14,395	
4	Depreciation	$ 27,342	
5	Net Interest Expense	$ 35,052	
6	Minimum Required Net Revenues	$ 13,211	
7	Generation Integration (BPA Facilities)	$ 9,297	
8	Revenue Requirement for Electrical Equipment (Total)	$ 179,626	
9	Reactive Allocation of Electrical RR (10%)	179626 x 10%	$ 17,963
10	Non-Federal Projects (CGS)	$ 3,399	
11	Reactive Allocation of Electrical RR (5%)	3,399 x 5%	$ 170
12	**Other Costs (Assigned 100% to Reactive)**		
13	Synchronous Condenser Real Power Consumption		$ 3,726
14	Synchronous Condenser Modifications (Paid by PBL)		$ 365
15	Real Power losses due to reactive production		$ 1,958
16	**Total Average Annual Cost**		**$ 24,182**

4.4.3 Reactive Supply and Voltage Control Table 2

Table Deleted. The data either no longer exists, is no longer applicable, or has been merged with other data.

Section 4.4.3 - Table 3
Corps of Engineers Facilities Included in Reactive Allocation

Category	From COE Account	Items Included
Generator	7200 Turbine/Generator	Generator, stator, air coolers, rotor, compressor for condensing.
Exciter	7200 Turbine/Generator	Generator exciter.
Voltage Regulator	7300 Power Plant	Voltage regulation and excitation equipment.
Electrical Equipment	7300 Power Plant	Miscellaneous equipment, generator grounding, main bus or cable, generator switchgear, control cable, load control equipment.
Switchyard	7600 Switchyard	All switchyard equipment.
Accessory Equipment	7300 Power Plant	Station service main bus, annuniciator system, grounding system, station service, antenna towers, radio buildings, engine generator sets, control switchboards, battery switchboards, recording annunciators, data logging equipment, SCADA equipment, central
	7400 Miscellaneous Powerplant Equipment	Bridge/gentry cranes, lubrication, fire protection, air system, radio/MW buildings and equipment, oil purifiers, air compressors, plant communication equipment (Excluded are tailrace cranes and drainage equipment)

Section 4.4.3 - Table 4
USBR Gross Investment Data to Determine Percentage of Gross Plant to Allocate to Reactive Power Production

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	
USBR Plants	**Gross Plant 1/**	**Gross Power Plant-Hydro (includes Waterwheels, Turbines and Generators2/**	**% Electrical to allocate to Electric Plant (used to separate Turbine costs from Powerlants- Hydro)3/**	**Subtotal Gross Electrical**	**% Gross Electrical Divided by Gross Plant**	**Gross Generation Integration**	**Gross GI (% of Transmission) 4/**	**Gross Generation Integration allocated to Electric Plant**	**Total Net Electrical Allocated to Reactive Power**	**Gross Plant assigned to Electrical (%of Gross Plant)**
				[2] X [3]	**[4] / [1]**			**[6] X [7]**	**[4] + [8]**	**[9] / [1]**
Boise	$ 26,326,436	$ 25,438,829	50%	$ 12,719,415	48%	$ 953,782	100.0%	$ 953,782	$ 13,673,197	**51.9%**
Columbia Basin Grand Coulee	$ 1,029,337,473	$ 757,610,923	50%	$ 378,805,462	37%	$ 178,831,533	76.2%	$ 136,269,628	$ 515,075,090	**50.0%**
Hungry Horse	$ 134,408,930	$ 49,452,271	50%	$ 24,726,135	18%	$ 11,854,647	79.1%	$ 9,377,026	$ 34,103,161	**25.4%**
Minidoka/ Palisades	$ 121,835,132	$ 117,889,095	50%	$ 58,944,548	48%	$ 3,703,353	58.7%	$ 2,173,868	$ 61,118,416	**50.2%**
Yakima **5/**	$ 5,810,089	$ 5,098,190	50%	$ 3,492,110	60%	$ -	100.0%	$ -	$ 3,492,110	**60.1%**
Green Springs Project **5/**	$ 10,778,940	$ 3,598,237	50%	$ 1,799,119	17%	$ 176,398	100.0%	$ 176,398	$ 1,975,516	**18.3%**

1/ Data taken from Plant , Property and Equipment Accounts as of September 30, 2004, Includes Interest During Construction (IDC)

2/ Includes Generator/Exciter/Voltage Regulator/Accessory Electrical. USBR does not separate turbine investments from generator investment (turbine costs estimated based on historical cost data from FY2002-FY2006 rate period where available)

3/ For plants with no historical information to separate turbine and generator investment, half of the turbine/generator investment is assumed to be generator equipment.

4/ Percent (%) determined using Transmission Segmentation Study in 1996 rate case. Grand Coulee Netwok and delivery costs updated with more detailed cost data in Generation Integration (GI) Study.

5/ Portions of Electirc Plant and all Transmission allocated to Irrigation - Plant, Property and Equipment Accounting, September 30, 2004. Excludes Lower Snake and Columbia River bypass, which are fish related investments.

Section 4.4.3 - Table 5A
COE Gross Investment Data to Determine Percentage of Gross Plant to Allocate to Reactive Power Production

COE Plants 1/	Gross Plant	Powerhouse (7000/7100) [1]	Turbines and Generators 2/ (7200) [2]	Powerplant Accessory Equipment (7300) [3]	Misc Powerplant equip (7400) [4]	% to exclude turbine costs and allocate accessory electrical equipment (estimated based on historical and investment cost data) 3/ [5]	Turbines and Generators allocated to Reactive Power [6]	50% Powerhouse [7]
							[5] X [2]	
Albeni Falls	$ 43,125,908	$ 13,962,040	$ 8,739,715	$ 2,105,926	$ 569,628	50%	$ 4,369,858	$ 6,981,020
Bonneville	927,603,078	362,500,774	195,747,924	14,741,265	10,939,614	50%	97,873,962	181,250,387
Ch Jo	571,149,469	85,543,955	163,583,240	36,981,589	4,081,539	50%	81,791,620	42,771,978
Cougar	36,313,701	1,974,458	3,597,784	454,443	813,857	50%	1,798,892	987,229
Detroit	41,220,358	5,140,402	6,772,374	3,020,914	641,842	50%	3,386,187	2,570,201
Dworshak	316,781,862	15,799,443	13,251,369	8,569,384	3,529,274	50%	6,625,685	7,899,722
GrnPet/Foster	50,954,947	3,897,571	5,871,676	1,418,328	508,702	50%	2,935,838	1,948,786
HillsCr	18,463,456	1,119,110	3,470,135	810,841	309,015	50%	1,735,068	559,555
Ice Harbor	159,246,545	51,318,297	38,642,504	9,700,253	2,687,275	50%	19,321,252	25,659,149
John Day	494,244,110	111,669,313	112,346,998	18,169,669	4,587,172	50%	56,173,499	55,834,657
Libby	433,211,642	37,415,453	62,141,172	8,619,908	3,684,712	50%	31,070,586	18,707,727
Little Goose	212,067,726	58,672,560	50,077,438	11,882,402	1,747,744	50%	25,038,719	29,336,280
LookOut	50,191,766	5,204,083	10,832,943	7,963,445	832,164	50%	5,416,472	2,602,042
LostCr	26,971,889	3,860,301	5,431,228	786,500	1,387,004	50%	2,715,614	1,930,151
Lower Granite	332,598,745	68,956,661	50,825,691	11,391,791	3,045,193	50%	25,412,846	34,478,331
Lower Monumental	230,564,378	58,186,024	51,143,566	11,422,584	1,641,242	50%	25,571,783	29,093,012
McNary	300,735,946	75,025,036	65,509,917	21,433,623	3,374,034	50%	32,754,959	37,512,518
The Dalles	308,486,648	92,794,123	130,964,391	19,930,866	8,588,004	50%	65,482,196	46,397,062

1/ Accounting Data from Plant, Property and Equipment Accounts as of October 2004
2/ COE does not separate turbine investments from generator investment (turbine costs estimated based on historical cost data from FY2002-FY2006 rate period where available)
3/ For plants with no historical information to separate turbine and generator investment, half of the turbine/generator investment is assumed to be generator equipment.
4/ 50% of the Power Plant, Power Plant Accessory Electrical and Misc Power Plant Equipment is assigned to the Electric Plant.
5/ %'s determined using Transmission Segmentation Study in 1996 rate case. Grand Coulee Netwok and delivery costs updated with more detailed cost data in Generation Integration Study.

Section 4.4.3 - Table 5B
COE Gross Investment Data to Determine Percentage of Gross Plant to Allocate to Reactive Power Production

COE Plants 1/	50 % Powerplant Accessory Equipment Allocated to Reactive [8]	50% Misc Powerplant Equipment Allocated to Reactive [9]	Subtotal Net Electrical Allocated to Reactive Power [10]	Gross Generation Integration (7600) 5/ [11]	Gross Generation Integration (% of Transmission) [12]	Gross Generation Integration allocated to Electric Plant [13]	Total Net Electrical Allocated to Reactive Power [14]	% Gross Plant allocated to Electrical Plant [15]
			[6]+[7]+[8]+[9]				[10]+[13]	[14]/Gross Plant
Albeni Falls	$ 1,052,963	$ 284,814	$ 12,688,655	$ 695,252	100%	$ 695,252	$ 13,383,907	**31%**
Bonneville	7,370,633	5,469,807	291,964,789	39,009,024	88%	34,249,923	326,214,712	**35%**
Ch Jo	18,490,795	2,040,770	145,095,162	19,770,689	100%	19,770,689	164,865,851	**29%**
Cougar	227,222	406,929	3,420,271	143,103	100%	143,103	3,563,374	**10%**
Detroit	1,510,457	320,921	7,787,766	1,141,762	100%	1,141,762	8,929,528	**22%**
Dworshak	4,284,692	1,764,637	20,574,735	1,765,530	100%	1,765,530	22,340,265	**7%**
GrnPet/Foster	709,164	254,351	5,848,139	1,351,853	100%	1,351,853	7,199,992	**14%**
HillsCr	405,421	154,508	2,854,551	133,724	100%	133,724	2,988,275	**16%**
Ice Harbor	4,850,127	1,343,638	51,174,165	1,531,193	100%	1,531,193	52,705,358	**33%**
John Day	9,084,835	2,293,586	123,386,576	5,485,427	100%	5,485,427	128,872,003	**26%**
Libby	4,309,954	1,842,356	55,930,623	4,176,296	100%	4,176,296	60,106,919	**14%**
Little Goose	5,941,201	873,872	61,190,072	3,341,903	100%	3,341,903	64,531,975	**30%**
LookOut	3,981,723	416,082	12,416,318	619,036	100%	619,036	13,035,354	**26%**
LostCr	393,250	693,502	5,732,517	462,080	100%	462,080	6,194,597	**23%**
Lower Granite	5,695,896	1,522,597	67,109,668	4,770,350	100%	4,770,350	71,880,018	**22%**
Lower Monumental	5,711,292	820,621	61,196,708	2,796,164	100%	2,796,164	63,992,872	**28%**
McNary	10,716,812	1,687,017	82,671,305	4,997,519	100%	4,997,519	87,668,824	**29%**
The Dalles	9,965,433	4,294,002	126,138,692	1,952,308	100%	4,667,203	130,805,895	**42%**

1/ Accounting Data from Plant, Property and Equipment Accounts as of October 2004
2/ COE does not separate turbine investment from generator investment. (turbine costs estimated based on historical cost data from FY2002-FY2006 rate period where available)
3/ For plants with no historical information to separate turbine and generator investment, half of the turbine/generator investment is assumed to be generator equipment.
4/ 50% of the Power Plant, Power Plant Accessory Electrical and Misc Power Plant Equipment is assigned to the Electric Plant.
5/ Percent **(**%) determined using Transmission Segmentation Study in 1996 rate case. Grand Coulee Netwok and delivery costs updated with ore detailed cost data in Generation Integration Study.

Section 4.4.3 - Table 6
Percentage to apply COE and BOR Capital Replacements

	[A] Planned Replacements (Total)	[B] Electrical	[C] Accessory Electrical	[D] Mechanical	[E] Transmission	[F] GI portion of transmisison	Electrical Replacements (Percentage) 1/
							([B]+ 50%[C]) +([D])/[A])
2005	$ 121,169	$ 42,948	$ 8,500	$ 39,250	$ 30,470	$ 20,583	55.9%
2006	$ 112,685	$ 61,159	$ 12,142	$ 30,087	$ 9,297	$ 8,301	67.0%
2007	$ 58,818	$ 40,788	$ 7,310	$ 9,970	$ 750	$ 375	76.2%
2008	$ 32,516	$ 19,202	$ 11,425	$ 1,889	$ -	$ -	76.6%
2009	$ 163,269	$ 18,941	$ -	$ 127,452	$ 16,876	$ 8,438	16.8%
Average percentage to allocate capital additions/ replacements to electric plant:							**58.5%**

Notes:
1/ Based on **PROJECTED** electrical vs mechanical capital program
Allocate 50% Accessory equipment to electrical

4.4.3 Reactive Supply and Voltage Control Table 7

Table Deleted. The data either no longer exists, is no longer applicable, or has been merged with other data.

Section 4.4.3 - Table 8
Columbia Generating Station

DESCRIPTION	ACQUISITION COST	ACCUM DEPR 12/31/1997	NET PLANT 12/31/1997	LIFE/YEARS
Nuclear Production - Turbogenerator *				
Excitation & Voltage	$ 1,292,835	$ 420,720	$ 872,116	40
Main generator	18,966,373	6,150,485	12,815,889	40
Hydrogen - Generator cooling	1,865,010	696,136	1,168,874	35
Hydrogen - Generator seal oil	806,016	300,824	505,192	35
Storage & Supply - Generator Hydrogen	400,529	138,471	262,058	35
Stator - Generator Cooling	618,090	230,705	387,385	35
Isolated Phase - Bus Duct Cooling	89,150	46,604	42,546	25
Subtotal	**$ 24,038,003**	**$ 7,983,944**	**$ 16,054,058**	
Transmission - Station Equipment				
Transformers	$ 4,750,999	$ 2,057,206	$ 2,693,793	30
Circuit Breakers	124,182	64,553	59,629	25
Tie-ins	47,911	24,905	23,006	25
Subtotal	**$ 4,923,092**	**$ 2,146,664**	**$ 2,776,428**	
Total Electrical & Transmission	**$ 28,961,095**	**$ 10,130,608**	**$ 18,830,486**	
Total Net Plant (from "Combining Balance Sheets - Assets")			**$ 2,531,782,112**	
Transmission as percent of total net plant investment			0.11%	
Electrical as percent of total net plant investment			0.63%	
Electrical and Transmission as percent of total net plant investment			0.74%	

Determined in FY2002-FY2006 rate period
* **Excludes turbine and steam components**
Service Date: 12/84
Depreciation Method: Straight Line

Section 4.4.3 - Table 9
Reactive - Electric Portion of
Power Revenue Requirement for Federal Base System Generating Units

	($ in thousands)	2007	2008	2009	Average Over Rate Period
1	O&M	$ 80,335	$ 83,602	$ 87,078	$ 83,672
2	A&G Expense 1/	14,807	15,216	15,640	15,221
3	Depreciation	26,490	26,185	26,556	26,410
4	Non-Federal Projects (CGS)	3,780	3,287	3,684	3,584
5	Net Interest Expense	39,272	39,159	40,269	39,567
6	Minimum Required Net Revenues	7,461	8,908	5,648	7,339
7	**Total Revenue Requirement**	**$ 172,145**	**$ 176,357**	**$ 178,875**	**$ 175,792**

1/Power Scheduling and Generation Project Coordination

	Calculations:	2007	2008	2009	Average Over Rate Period
1	Total Electric Average Net Plant	$ 1,249,664	$ 1,200,345	$ 1,201,922	$ 1,217,310
2	Total Corps/Bureau Average Net Plant	$ 4,775,952	$ 4,831,698	$ 4,902,276	$ 4,836,642
3	**percent electric**	26.17%	24.84%	24.52%	$ 0
4	Corps/Bureau Net Interest	$ 150,089	$ 157,625	$ 164,244	$ 157,319
5	**Electric Net Interest**	$ 39,272	$ 39,159	$ 40,269	$ 39,567
6	Corps/Bureau MRNR	$ 28,513	$ 35,858	$ 23,037	$ 29,136
7	**Electric MRNR**	$ 7,461	$ 8,908	$ 5,648	$ 7,339
8	Total COE O&M 1/	$ 123,759	$ 128,781	$ 134,344	$ 128,961
9	**COE Electric O&M @ 42%**	$ 51,979	$ 54,088	$ 56,424	$ 54,164
10	Total BOR O&M 2/	$ 63,014	$ 65,586	$ 68,120	$ 65,573
11	**BOR Electric O&M @ 45%**	$ 28,356	$ 29,514	$ 30,654	$ 29,508
12	CGS costs 3/	$ 510,755	$ 444,158	$ 497,872	$ 484,262
13	**CGS Electric @ 0.74%**	$ 3,780	$ 3,287	$ 3,684	$ 3,584

1/excludes Lower Snake F&W and O&M attributable in the aggregate to F&W at projects.

2/excludes payment to Colville Tribes, shown elsewhere in Columbia Basin O&M and F&W.

3/debt service and O&M (excludes nuclear insurance, fuel and revenue-financed capital).

	Determination of Synchronous Condensor Annual Costs:	2007	2008	2009	Average Over Rate Period
14	Synchronous Condensers Avg Net Plt	$ 6,885	$ 6,782	$ 6,679	$ 6,782
15	Total Corps/Bureau Average Net Plant	$ 4,775,952	$ 4,831,698	$ 4,902,276	$ 4,836,642
16	Percent	0.14%	0.14%	0.14%	$ 0
17	Corps/Bureau Net Interest	$ 150,089	$ 157,625	$ 164,244	$ 157,319
18	**Sync Cond Net Interest**	$ 216	$ 221	$ 224	$ 220
19	Corps/Bureau MRNR	$ 28,513	$ 35,858	$ 23,037	$ 29,136
20	Sync Cond MRNR	$ 41	$ 50	$ 31	$ 41
21	**Sync Cond Depreciation**	$ 103	$ 103	$ 103	$ 103
22	**Total Sync Cond Costs**	$ 360	$ 374	$ 358	$ 364

Section 4.4.3 - Table 10A

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs		**9/30/05**			**9/30/06**	
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
Bureau of Reclamation						
BOISE	29,179	8,710	389			
historic reactive	15,144	4,520	202	15,144	4,722	202
projected				410	3	3
COLUMBIA BASIN	1,224,791	384,977	16,331			
historic reactive	612,396	192,489	8,166	612,396	200,655	8,166
projected				1,442	10	10
GREEN SPRINGS	11,162	8,521	149			
historic reactive	2,043	1,559	27	2,043	1,586	27
projected				-	-	-
HUNGRY HORSE	119,591	48,598	1,595			
historic reactive	30,376	12,344	405	30,376	12,749	405
projected				4,102	27	27
MINIDOKA-PALISADES	110,217	23,959	1,470			
historic reactive	55,329	12,027	738	55,329	12,765	738
projected				-	-	-
YAKIMA	6,115	3,132	82			
historic reactive	3,675	1,882	49	3,675	1,931	49
projected	-			614	4	4
Total Bureau	2,190,839	694,008	29,214	725,531	234,452	9,631

Section 4.4.3 - Table 10A

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	9/30/05			9/30/06		
	gross	acc dep	depr exp	gross	acc dep	depr exp
ALBENI FALLS	43,239	21,721	577			
historic	13,404	6,734	179	13,404	6,913	179
projected				1,952	13	13
BONNEVILLE	961,873	316,631	12,825			
historic	336,656	110,821	4,489	336,656	115,310	4,489
projected				4,001	27	27
CHIEF JOSEPH	574,919	230,980	7,666			
historic	172,476	69,294	2,300	172,476	71,594	2,300
projected				4,110	27	27
COUGAR	72,804	8,590	971			
historic	3,640	430	49	3,640	479	49
projected				5,342	36	36
DETROIT-BIG CLIFF	43,810	24,151	584			
historic	9,638	5,313	128	9,638	5,441	128
projected				5,779	39	39
DWORSHAK	292,417	98,974	3,899			
historic	20,469	6,928	273	20,469	7,201	273
projected				2,143	14	14
GREEN PETER-FOSTER	55,614	20,955	742			
historic	7,786	2,934	104	7,786	3,038	104
projected				-	-	-
HILLS CREEK	19,683	10,099	262			
historic	2,952	1,515	39	2,952	1,554	39
projected				310	2	2
ICE HARBOR	165,052	70,313	2,201			
historic	54,467	23,203	726	54,467	23,929	726
projected				1,369	9	9
JOHN DAY	506,555	187,352	6,754			
historic	131,704	48,712	1,756	131,704	50,468	1,756
projected				5,169	34	34
LIBBY	433,679	132,919	5,782			
historic	69,389	21,267	925	69,389	22,192	925
projected				4,183	28	28
LITTLE GOOSE	212,666	92,511	2,836			
historic	63,800	27,753	851	63,800	28,604	851
projected				1,358	9	9

Section 4.4.3 - Table 10A

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/05**			**9/30/06**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
LOOKOUT POINT	59,931	38,487	799			
historic	14,383	9,237	192	14,383	9,429	192
projected				-	-	-
LOST CREEK	27,138	9,947	362			
historic	5,428	1,989	72	5,428	2,061	72
projected				884	6	6
LOWER GRANITE	336,476	120,939	4,486			
historic	74,025	26,607	987	74,025	27,594	987
projected				3,406	23	23
LOWER MONUMENTAL	232,606	99,110	3,101			
historic	65,130	27,751	868	65,130	28,619	868
projected				3,763	25	25
MCNARY	312,291	176,552	4,164			
historic	90,564	51,200	1,208	90,564	52,408	1,208
projected				1,325	9	9
THE DALLES	357,152	175,010	4,762			
historic	150,004	73,504	2,000	150,004	75,504	2,000
projected	980	7	7	13,071	101	94
Total Corps	5,951,561	2,328,719	79,349	1,344,080	532,740	17,541
Total Corps and Bureau	8,142,400	3,022,727	108,563	2,069,611	767,192	27,172

Section 4.4.3 - Table 10B

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/07**			**9/30/08**			**9/30/09**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
Bureau of Reclamation									
BOISE									
historic reactive	15,144	4,924	202	15,144	5,126	202	15,144	5,328	202
projected	-	6	3	-	6	-	-	6	-
COLUMBIA BASIN									
historic reactive	612,396	208,821	8,166	612,396	216,987	8,166	612,396	225,153	8,166
projected	2,944	39	29	5,682	97	58	73,246	623	526
GREEN SPRINGS									
historic reactive	2,043	1,613	27	2,043	1,640	27	2,043	1,667	27
projected	-	-	-	-	-	-	-	-	-
HUNGRY HORSE									
historic reactive	30,376	13,154	405	30,376	13,559	405	30,376	13,964	405
projected	240	56	29	1,002	64	8	-	71	7
MINIDOKA-PALISADES									
historic reactive	55,329	13,503	738	55,329	14,241	738	55,329	14,979	738
projected	483	3	3	-	6	3	-	6	-
YAKIMA									
historic reactive	3,675	1,980	49	3,675	2,029	49	3,675	2,078	49
projected	1,354	17	13	-	26	9	-	26	-
Total Bureau	723,983	244,116	9,664	725,647	253,781	9,665	792,209	263,901	10,120

Section 4.4.3 - Table 10B

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/07**			**9/30/08**			**9/30/09**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
ALBENI FALLS									
historic	13,404	7,092	179	13,404	7,271	179	13,404	7,450	179
projected	-	26	13	-	26	-	-	26	-
BONNEVILLE									
historic	336,656	119,799	4,489	336,656	124,288	4,489	336,656	128,777	4,489
projected	2,615	71	44	3,967	115	44	-	141	26
CHIEF JOSEPH									
historic	172,476	73,894	2,300	172,476	76,194	2,300	172,476	78,494	2,300
projected	2,102	68	41	-	82	14	-	82	-
COUGAR									
historic	3,640	528	49	3,640	577	49	3,640	626	49
projected	249	73	37	-	75	2	-	75	-
DETROIT-BIG CLIFF									
historic	9,638	5,569	128	9,638	5,697	128	9,638	5,825	128
projected	2,483	94	55	-	111	17	-	111	-
DWORSHAK									
historic	20,469	7,474	273	20,469	7,747	273	20,469	8,020	273
projected	348	31	17	1,485	43	12	858	59	16
GREEN PETER-FOSTER									
historic	7,786	3,142	104	7,786	3,246	104	7,786	3,350	104
projected	858	6	6	-	12	6	-	12	-
HILLS CREEK									
historic	2,952	1,593	39	2,952	1,632	39	2,952	1,671	39
projected	248	6	4	-	8	2	187	9	1
ICE HARBOR									
historic	54,467	24,655	726	54,467	25,381	726	54,467	26,107	726
projected	-	18	9	-	18	-	1,525	28	10
JOHN DAY									
historic	131,704	52,224	1,756	131,704	53,980	1,756	131,704	55,736	1,756
projected	4,938	101	67	-	134	33	-	134	-
LIBBY									
historic	69,389	23,117	925	69,389	24,042	925	69,389	24,967	925
projected	-	56	28	-	56	-	-	56	-
LITTLE GOOSE									
historic	63,800	29,455	851	63,800	30,306	851	63,800	31,157	851
projected	-	18	9	1,987	31	13	496	48	17

Section 4.4.3 - Table 10B

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/07**			**9/30/08**			**9/30/09**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
LOOKOUT POINT									
historic	14,383	9,621	192	14,383	9,813	192	14,383	10,005	192
projected	1,952	13	13	114	27	14	260	29	2
LOST CREEK									
historic	5,428	2,133	72	5,428	2,205	72	5,428	2,277	72
projected	-	12	6	-	12	-	380	15	3
LOWER GRANITE									
historic	74,025	28,581	987	74,025	29,568	987	74,025	30,555	987
projected	6,601	90	67	2,889	153	63	-	172	19
LOWER MONUMENTAL									
historic	65,130	29,487	868	65,130	30,355	868	65,130	31,223	868
projected	-	50	25	1,895	63	13	495	79	16
MCNARY									
historic	90,564	53,616	1,208	90,564	54,824	1,208	90,564	56,032	1,208
projected	-	18	9	-	18	-	3,749	43	25
THE DALLES									
historic	150,004	77,504	2,000	150,004	79,504	2,000	150,004	81,504	2,000
projected	2,331	204	103	-	220	16	4,444	250	30
Total Corps	1,310,640	550,439	17,699	1,298,252	567,834	17,395	1,298,309	585,145	17,311
Total Corps and Bureau	2,034,623	794,555	27,363	2,023,899	821,615	27,060	2,090,518	849,046	27,431

4.4.3 Reactive Supply and Voltage Control Table 11

Table Deleted. The data either no longer exists, is no longer applicable, or has been merged with other data.

Section 4.4.3 - Table 12
Generation Supplied Reactive Power and Voltage Control
Synchronous Condenser Energy Costs
Value of Energy Consumed for
Synchronous Condenser (Motoring) Operation

Generating Project	Nameplate rating (MW/unit)	Motoring power consumption (MW/unit)	Number of Units used	Hourly Energy Consumption (MW)	Motoring hours/year	Total Cost of Energy
John Day units (4units) 1/	155	2	4	8.0	925	$202,242
The Dalles units 14-20 1/	99	1.2	6	7.2	925	$182,018
Libby units 1-5 3/	0	0.0	0	0.0	0	$0
Palisades units 1-4	44	0.6	1	0.6	100	$1,563
Hungry Horse units 1-4 3/	107	0.0	0	0.0	0	$0
Grand Coulee units 19-24 2/	825	10.0	3	30.0	4,074	$3,340,273
TOTAL ENERGY COST						**$3,726,096**
Value of energy (mills/kW-hr)	**27.33**					

1/ The hours shown for The Dalles are estimated to be the same as John Day. There is no historical basis for The Dalles since the condensing units at The Dalles were just reconfigured to have the same functionality as John Day.
2/ At Coulee, six units (19-24) are connected to the 500kV bus, and are kept spinning for both TBL and USBR operations. For this study, half the condensing hours are considered "used," by TBL for voltage control and the other half "used" by USBR operations.
3/ These projects have not been in condensing mode for the last couple of years.

Section 4.4.3 - Table 13
Generator Losses -
Allocated to Generation Input for Reactive Power and Voltage Control

A.	Generating Capacity (MW)		**21,353**
B.	Stator Load Loss Differential (MW) **1/**		8
C.	Rotor (Field) Load Loss Differential **1/**		12
D.	Exciter Load Loss Differential **1/**		1
E.	Total Load Loss Due to Reactive Loading		**20**
	No-Load Loss Component		
1.	No-Load Loss		
2.	Generator Allocation Factor (10%)		11
3.	No-Load Reactive Component		X 0.10
F.	No-Load Loss Component		1
G.	*Total Losses		**22**
	Note 1. Differential Loss = Losses at rated MW and rated power factor - losses and MW at unity power factor.		
H.	Average Generation (MW)		9,280
I.	MVAR usage (August 10th 1996) MVAR		1,647
J.	Generation (August 10, 1996) (MW)		5,040
K.	Total Max MVARS (available machine data)		**6,597**
L.	MAX Actual MVARs = (I /J) X A		5,773
M.	Average MVARS = (L/A) X H		2,509
N.	Average Losses (kW-hr) = (G/K X M) X 8760		71,638
O.	Value of Energy (mills/kW-hr)		**27.33**
P.	**Total Cost (N X O)/1000**	**$**	**1,958**

**Some values may not appear to total 100%. This is due to rounding.*

Section 4.4.3 - Table 14
Regional Stakeholder Impacts of Costs of Current and Proposed Generation Supplied Reactive Power Policy by Customer Groups

		A	B	C	D	E	F
				$ Millions			
		ALLOCATION FACTOR 2/	2005 ACTUAL	2006 EXPECTED	2008 EXPECTED WITH CURRENT NON-FEDERAL GENERATORS	2008 ESTIMATE WITH ADDITIONAL NON-FEDERAL GENERATORS	ESTIMATED IMPACT OF PROPOSAL
1	TBL compensation to PBL for reactive "within the band"		$ 23	$ 23	$ 20.4	$ 20.4	$ (20.4)
2	Payments to IPP Generators		$ -	$ 7.6	$ 11.1	$ 15.7	$ (15.7)
3	Payments to IOU Generators		$ -	$ -	$ -	$ 9.2	$ (9.2)
	Net Cost By Customer Group 1/						
4	Preference Customers net cost	55.2%	$ (10.3)	$ (6.1)	$ (3.0)	$ 4.6	$ (4.6)
5	IOU/DSI net cost	23.3%	$ 5.4	$ 7.1	$ 7.4	$ 1.3	$ (1.3)
6	Extra-regional customer net cost	11.0%	$ 2.5	$ 3.4	$ 3.5	$ 5.0	$ (5.0)
7	Marketers/non-federal generators net cost	10.5%	$ 2.4	$ (4.4)	$ (7.8)	$ (11.0)	$ 11.0
8	Total customer net cost	100.0%	$ -	$ -	$ -	$ -	$ -
							$ -
9	Total Cost w/non-federal payments		$ 23.0	$ 30.6	$ 31.5	$ 45.3	$ (45.3)
10	**Net Cost to Regional Ratepayers (Line 4 + Line 5)**		**$ (4.9)**	**$ 1.1**	**$ 4.4**	**$ 6.0**	**$ (6.0)**

1/ GSR compensation less incremental increase in cost of GSR transmission purchases
2/ See Attachment 2 "Custbreakout" for list of customers in each grouping.
3/ Allocation of reactive payment cost across customer groups based on actual FY 05 TBL billing determinants. (See Table 16)
4/ SeeTable 17 "ReactiveCostEst" for FY 06 and FY 08 estimated annual reactive payments to current non-Federal generators.
5/ See Table 18 "Add.Gens" for list of additional IPP and IOU generators filing for reactive and the estimated payment amount.

Lines 1 through 3 show TBL's compensation to PBL and IPP and IOU generators for within the band reactive; line 9 is the sum of lines 1 through 3 and represents TBL's total reactive payment. Lines 4 through 7 show the net cost of these reactive payments to regional ratepayers. Line 10 represents the total net cost to the Region, which consists of Preference Customers, IOUs and DSIs (Lines 4 and 5).

When TBL compensates PBL for inside the band reactive, PBL treats this payment as a revenue credit which reduces the overall revenue requirement. Preference customers benefit through a reduction in PBL's cost-based rates. The cost of this reactive payment is distributed to all customer groups through TBL's GSR rate. Using the allocation factors in column A, which are based on FY 05 actuals, Preference Customers must pay for 55.2 percent of the reactive payment to PBL through TBL's GSR rate but they receive 100 percent of the benefit, of PBL being compensated inside the band, due to a reduction in their power rates. In FY 05, TBL compensated only PBL for inside the band reactive, and the benefits to Preference Customers was $10.3M.

Compensating IPPs for inside the band reactive increases the net cost to the region. Regional ratepayers experience no benefit from making reactive payments to IPPs through reduction in power purchase costs and must incur the cost of these reactive payments through increases in TBL's GSR rate. IPPs however benefit from this arrangement since they receive reactive compensation from TBL and the majority of the cost of these reactive payments are absorbed by other customer groups.

Section 4.4.3 - Table 15

Regional Stakeholder Impacts of Costs of Current and Proposed Generation Supplied Reactive Power Policy - Customer Group Breakout

Preference Customers	IOU/DSI	Extra-Regional	Markets/Non-Federal Generators
Albany Research Center - DOE	Alcoa, Inc.	BC Powerex	Avista Energy, Inc.
Alder Mutual Light Company	Avista Corp - WWP	Calpine Energy Services	BP West Coast Products
Asotin County PUD	Columbia Falls Aluminum	Mirant Americas Energy	Calpine Energy Services
Benton County PUD No 1	Idaho Power Company	Sierra Pacific Power	Cargill Power Markets LLC
Benton PUD	Kaiser Aluminum	TransAlta Energy Mktg US	Chehalis Power Generating
Benton Rural Electric Association	Northwestern Energy LLC	TransCanada Energy Ltd.	Chelan County PUD-CHPM
Big Bend Electric Cooperative	PacifiCorp	Turlock Irrigation District	Columbia Energy Partners
Blachly-Lane County Cooperative	Port Townsend Paper Corp		Constellation Energy
Bonneville PBL	Portland Gen Marketing		Coral Power
Canby Utility Board	Portland General Electric		Frederickson Power LP
Central Electric Cooperative	Puget Sound Energy		Goldendale Energy Center
Central Lincoln PUD	Sierra Pacific Power		Hermiston Power Partnership
Central Montana Electric Power Coop			J Aron & Company
Chelan County PUD No 1			Morgan Stanley
City of Albion			North Point Energy Solutions
City of Ashland			Portland Gen Marketing
City of Bandon			PPM Energy, Inc.
City of Blaine			Sempra Energy Trading
City of Bonners Ferry			Suez Energy Marketing
City of Burley			
City of Cascade Locks			
City of Centralia			
City of Cheney			
City of Chewelah			
City of Coulee Dam			
City of Declo			
City of Drain			
City of Ellensburg			
City of Forest Grove			
City of Heyburn			
City of Klamath Falls			
City of McCleary			
City of McMinnville			
City of Milton-Freewater			
City of Minidoka			
City of Monmouth			
City of Plummer			
City of Port Angeles Light Dept.			
City of Richland			
City of Rupert			
City of Soda Springs			
City of Springfield Utility Board			
City of Sumas			
City of Troy			
Clallam County PUD No. 1			
Clark Public Utilities			
Clatskanie PUD			
Clearwater Power Company			
Columbia Basin Electric Cooperative			
Columbia Power Cooperative			
Columbia River PUD			
Columbia Rural Electric Association			
Consolidated Irrigation District No. 1			
Consumers Power Inc.			
Coos-Curry Electric Cooperative			
Cowlitz County PUD No. 1			
Douglas Electric Cooperative			
East End Mutual Electric Cooperative			
Elmhurst Mutual Power & Light Company			
Emerald PUD			
Energy Northwest Inc. (WPPSS)			
Eugene Water & Electric Board			
Fall River Rural Electric Cooperative			
Farmers Electric Cooperative			

Section 4.4.3 - Table 15

Regional Stakeholder Impacts of Costs of Current and Proposed Generation Supplied Reactive Power Policy - Customer Group Breakout

Preference Customers	IOU/DSI	Extra-Regional	Markets/Non-Federal Generators
Ferry County PUD No. 1			
Flathead Electric Cooperative			
Franklin County PUD No 1			
Glacier Electric Cooperative			
Grant County PUD No. 2			
Grays Harbor County PUD			
Harney Electric Cooperative			
Hermiston Energy Services			
Hood River Electric Cooperative			
Idaho County Light & Power Cooperative			
Inland Power & Light Company			
Kittitas County PUD No. 1			
Klickitat			
Kootenai Electric Cooperative			
Lakeview Light & Power Company			
Lane Electric Cooperative			
Lewis County PUD No. 1			
Lincoln Electric Cooperative			
Longview Aluminum LLC			
Lost River Electric Cooperative			
Lower Valley Power & Light Inc.			
Mason County PUD 1			
Mason County PUD 3			
Midstate Electric Cooperative Inc.			
Missoula Electric Cooperative			
Modern Electric Water Company			
Nespelem Valley Electric Cooperative			
Northern Lights Inc			
Northern Wasco County PUD			
Ohop Mutual Light Company			
Okanogan County Electric Cooperative			
Okanogan County PUD No 1			
Orcas Power & Light Cooperative			
Oregon Trail Cooperative			
Pacific County PUD No. 2			
Pacific Northwest Gen			
Parkland Light & Power Company			
Pend Oreille County PUD			
Peninsula Light Company, Inc.			
Port of Seattle/SeaTac Airport			
Raft River Rural Electric Cooperative			
Ravalli County Electric Cooperative			
Riverside Electric Company Ltd.			
Salem Electri Cooperative			
Salmon River Electric Cooperative			
Seattle City Light			
Skamania County PUD No 1			
Snohomish County PUD No 1			
Southern Montana Electric Coop			
Southside Electric Lines Inc.			
Surprise Valley Electric Cooperative			
Tacoma Power			
Tanner Electric Cooperative			
Tillamook County PUD			
Town of Eatonville			
Town of Milton			
Town of Steilacoom			
Umatilla Electric Cooperative			
Umpqua Indian Utility Coop			
United Electric Coop			
US Air Force (Fairchild)			
US Department of Navy (Bangor)			
US Department of Navy (Jim Creek)			
US Dept of Energy (Richland)			
US Navel Shipyard Bremerton			

Section 4.4.3 - Table 15

Regional Stakeholder Impacts of Costs of Current and Proposed Generation Supplied Reactive Power Policy - Customer Group Breakout

Preference Customers	IOU/DSI	Extra-Regional	Markets/Non-Federal Generators
USBIA - Mission Valley Power			
USBIA - Wapato			
Vera Irrigation District No 15			
Vigilante Electric Cooperative			
Wahkiakum County PUD No 1			
Wasco Electric Cooperative			
Wells Rural Electric Cooperative			
West Oregon Electric Cooperative			
Whatcom County PUD No 1			

Section 4.4.3 - Table 16
Generation Supplied Reactive (GSR) Effective Billing Determinants (MW-yrs)

	IM	IR	PTP_LT	IS_LT	NT	FPT	PTP_ST	IS_ST	TOTAL	% of Total
Preference Customers	-	-	8,896	2,416	5,286	92	867	23	**17,581**	**56%**
IOU/DSI	6	4,414	958	-	44	1,632	161	63	**7,278**	**23%**
Extra-Regional Customers	-	-	842	1,722	-	-	230	546	**3,339**	**11%**
Marketer/Non-Federal Generators	-	-	2,665	454	-	-	22	174	**3,314**	**11%**
TOTAL	**6**	**4,414**	**13,361**	**4,591**	**5,330**	**1,725**	**1,280**	**807**	**31,513**	**100%**

Section 4.4.3 - Table 17

Generation Supplied Reactive (GSR) Reactive Cost Estimates
Effective Billing Determinants (MW-yrs)

Generator	Starting Date	Original Request	FY 06 Expected Annual Payment 1/	FY 08 Expected Annual Payment 2/
Centralia	December, 2004	$1,115,003	$802,194	$891,327
Big Hanaford	October, 2005	$3,257,435	$759,240	$1,898,100
Chehalis	August, 2005	$3,677,151	$2,505,027	$3,677,151
Hermiston	August, 2005	$1,656,077	$1,242,058	$1,656,077
Goldendale	August, 2005	$1,246,501	$747,901	$1,246,502
KFalls	October, 2005	$2,375,767	$1,763,269	$1,749,786
Total		**$13,327,935**	**$7,819,689**	**$11,118,942**

1/ The rates for Centralia, K.Falls, Big Hanaford, and Hermiston are final. Goldendale in process of submitting to FERC.
2/ Derived by removing service factors from FY 06 IPP reactive payments.

Section 4.4.3 - Table 18

Additional Generators Generation Supplied Reactive Costs
Potential Generators that may file FERC GSR Rates

Note: Excludes hydro, wind, and small generators (cost too low to file)

Generator	MW Capacity	Owner 2/	Note
Lancaster	280	IPP	
Cherry Point	600	IPP	Planned for 2008
Fredrickson	270	IPP	Puget/Benton/Grays H/Franklin tolling agreement
Boardman	550	Reg Util	PGE/PNGC
Coyote Spr 1	250	Reg Util	PGE
Coyote Spr 2	250	Reg Util	Avista
Hermiston PAC	480	Reg Util	PAC
River Road	248	Reg Util	Clark
Beaver	531	Reg Util	PGE
SUM - MW	3,459		
Average Cost/MW 1/	4,000		
Total Charge to TBL	**$13,836,000**		

1/ Use average per unit rate calculated below

Current FERC filings			Without Service Factor	Per Unit
Goldendale	250	747,900	1,246,500	4,986
Hermiston	536	1,242,000	1,656,000	3,090
Klamath Cogen	484	1,662,000	1,787,097	3,692
Klamath Peaker	100	101,000	404,000	4,040
Sum	1370	3,752,900	5,093,597	3,718
Average $/MW		2,739	3,718	
			ROUND TO $4000/MW	

Cost Assumptions:
1. Based on rates filed with FERC for recent CTs. Not expected to change much when final.
2. No heating loss for these filings, but may be included after 10/07.
3. Did not use Chehalis or Big Hannaford as filed rate is high and expected to be reduced.
4. Service factor adjustment excluded as this is not expected to be used after 10/07.

2/ IPP ownership assumes no regional benefits from reactive charge.
Regional utility ownership assumes that these entities will past on reactive charge to their regional customers.

Section 4.4.3 - Table 19

Reactive Revenue Risk Analysis

The table below illustrates the planned net revenue for risk model output from an expected value of $12.5 milliion of revenues received over the last two years of the power rate period. These are estimates for the purpose of setting final power rates.

	FY07	FY08-09	Delta
Avg. Annual PNRR	$97 million	$108 million	$11 million
3-Year Avg. Rate	30.34 mills	30.52 mills	0.18 mills
Annual Avg Rates			
FY 2007	32.22 mills	32.45 mills	0.23 mills
FY 2008	30.52 mills	30.64 mills	0.12 mills
FY 2009	28.29 mills	28.48 mills	0.19 mills

1 BPA assumed TBL would compensate PBL for full embedded costs of $24 million for FY 2007.

2 BPA assumed that it was equally likely that annual reactive power revenues from TBL could be any value between $4 and $20 million per year, or expected value of $12.5 million, for FY 2008-2009. *See* BPA's Supplemental Power Proposal WP-07-E-BPA-28-29.

3 As the table shows, this increases the annual PNRR by an average of $11 million, with a corresponding average annual rate increase of 0.18 mills/kwh. The rate effect is largest in FY 2007.

4.4.4 Generation Dropping

Section 4.4.4 - Table 1
Generation Dropping
Incremental Equipment Deterioriation / Replacement or Overhead

	Equipment	% Life Reduction/Drop	Cost of Major Overhaul	Cost/ Drop
1	**500 kV Circuit Breaker** (50 % of Replacement)	0.04%	$660,000	$264
2	**Main Power Transformer** (Equal to Replacement)	0.015%	$7,532,000	$1,284
3	**Generator** (Rewinding)	0.27%	$16,764,000	$45,263
4	**Turbine** (Refurbished)	0.24%	$1,320,000	$3,170
5	**500 kV Cable** (Replacement)	0.055%	$3,762,000	$2,070
6	**Total Annual Cost**			**$52,051**

Note: Text in parens indicates work needed to correct assumed deterioration and/or failure of equipment.

Section 4.4.4 -Table 2
Generation Dropping
Incremental Routine O and M Costs

	Equipment	% Increase O&M/Drop	Annual O&M Cost	Cost/ Drop
1	**500 kV Circuit Breaker** (50 % of Replacement)	0.04%	$6,522	$3
2	**Main Power Transformer** (Equal to Replacement)	0.015%	$75,331	$12
3	**Generator** (Rewinding)	0.27%	$594,000	$1,604
4	**Turbine** (Refurbished)	0.24%	$594,000	$1,426
5	**500 kV Cable** (Replacement)	0.055%	$281,779	$154
6	**Total Annual Cost**			**$3,198**

Section 4.4.4 - Table 3
Generation Dropping
Incremental Value of Lost Revenue during Replacement or Overhaul

	Equipment	Probability	Months Downtime	Downtime Costs	Cost/ Drop
1	**500 kV Circuit Breaker** (50 % of Replacement)	0.04%	0	$0	$0
2	**Main Power Transformer** (Equal to Replacement)	0.015%	1	$2,380,000	$428
3	**Generator** (Rewinding)	0.27%	18	$42,840,000	$115,668
4	**Turbine** (Refurbished)	0.24%	16	$38,080,000	$91,392
5	**500 kV Cable** (Replacement)	0.055%	1	$2,380,000	$1,310
6	**Total Annual Cost**				**$208,798**

Section 4.4.4 - Table 4
Generation Dropping
Summary Costs for Rate Period

	Generation Dropping	Total
1	Incremental Maintenance Costs (Table 1)	$52,051
2	Deterioriation and Risk Replacement Costs (Table 2)	$3,198
3	Lost Revenues (Table 3)	$208,798
4	Subtotal	$264,047
5	**Average Generation Drops (1.5 * Line 4)**	**$396,071**

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4.4.5 Station Service

Section 4.4.5 - Table 1
Station Service Analysis

Substation	KVA Rating	Monthly Historic Usage	Notes
Big Eddy / Celilo		1597750	
Ross Complex		1749300	
Large			
Alvey	2267	96923	
Bell	2250	149000	
Snohomish	1250	78000	
Olympia	1100	132738	
Covington	946	108333	
Pearl	875	28067	
Longview	825	38317	
McNary	800	108717	
Chemawa	725	18140	
Anaconda	600	42910	
Columbia	600	18292	
John Day	500	65896	
Santiam	400	25740	
St. Johns	310	15858	
Port Angeles	300	49920	
Valhalla	300	17592	
Fairview	300	12560	
Subtotal	**14,348**	**1,007,003**	**9.6% Load Factor**
Medium			
Oregon City	225	13663	
Walla Walla	150	6919	
Raymond	150	5808	
LaGrande	150	5663	
Ellensburg	100	3897	
Grandview	75	5605	
Roundup	75	5708	
Boardman	75	1595	
Drain	65	1654	
Reedsport	55	3922	
Subtotal	**1,120**	**54,434**	**6.7% Load Factor**

Substation	KVA Rating	Monthly Historic Usage	Notes
Small			
Valley Way	50	1984	
Salem Alumina	45	2604	
Sappho	45	2363	
Lookout Point	40	3387	
The Dalles	38	2657	
Carborundum	35	3187	
Bandon	25	1746	
Gardiner	25	1402	
Creston	15	1122	
Clatskanie	10	1771	
Newport	10	1735	
Hauser	10	1525	
Duckabush	10	1192	
Benton City	10	1076	
Ione	5	1028	
Subtotal	**373**	**28,779**	**10.6% Load Factor**
TOTAL	**15,473**	**1,062,465**	**9.4% Load Factor**

	Installed kVa	Load Factor 9.40% kWh	
Big Eddy / Celilo		1,597,750	
Ross Complex		1,749,300	
Large	36,936	2,534,548	
Medium	5,148	353,256	
Small	1,946	133,535	
TOTAL		**6,368,389**	**kWh / month**

(6,368,389 / 1,000) *27.33 mills * 12 months = **$2,088,577 Total Annual Cost**

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4.5 Segmentation of COE/USBR Transmission Facilities

4.5.1 COE Facilities

4.5.2 Columbia Basin Facilities

4.5.3 Other USBR Facilities

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4.5.1 COE Facilities

Section 4.5.1 - Table 1
COE Transmission Segmentation

BONNEVILLE DAM

A major rehab was done to the Bonneville Dam switchyard in 1999.
The current plant in service costs provided by the COE are:

Prop ID	Plant Item	Book Cost
BONNE-13361	power transformers	27,997,022
BONNE-13358	switchyard circuit breaker	1,499,685
BONNE-13559	switchyard circuit breaker	1,499,960
BONNE-13360	switchyard circuit breaker	1,500,514
	Total	**32,497,181**

The power transformers are assigned to generation.
Circuit breakers are allocated to Network & Generation Integration based on use.
There are six 115 kV circuit breakers; two Generation Integration and four Network.

BONNE-13358	switchyard circuit breaker	1,499,685
BONNE-13559	switchyard circuit breaker	1,499,960
BONNE-13360	switchyard circuit breaker	1,500,514
	Total Circuit Breakers	4,500,159

Network Allocation (4/6) **3,000,106**

4.5.2 Columbia Basin Facilities

Section 4.5.2 - Assumptions

COLUMBIA BASIN TRANSMISSION COST

Purpose - to split USBR Columbia Basin project transmission costs into the appropriate segments, including Network, Delivery, and Generation Integration (GI).

GI is transmission facilities between the generator and the Network station, including step-up transformers, powerhouse lines or cables, and switching equipment at the Network station for the powerhouse line. The remainder is Network.

The USBR does not have investment data to the level of major piece of equipment. The data is available by major group, as 500 kV switchyard. These costs will be allocated to GI and Network segments based on BPA typical facility costs for the major equipme

The typical costs will be developed for major divisions, as the 500 kV switchyard. The ratio for Network will be developed based on the cost of the equipment that is Network as a ratio of the total cost.

Assumptions/Method

1. Interest during construction (IDC) and other general costs will be allocated based on investment.

2. Typical costs as noted on investment ratio sheet.

3. USBR transmission starts at the high side of the generator breaker (low side of step-up transformer) through the substation per Chris Christoferson/USBR Coulee. This includes the step-up transformers, but not the powerhouse switching.

4. Delivery: The 115/13.8 kV facilities at Coulee are used for station service and to deliver power at 13.8 kV to Grant, Coulee City, and Nespelem Valley at Lonepine. An allocation of costs between uses is necessary.

5. The 500 kV additions for the Coulee-Bell line are not included in the investment.

6. Investment does not include construction work in progress. Use added below:

IDC % adder for electric plant for FY04:	**0.117891472**
IDC =	**108,552,675**
Total electric plant =	**1,029,337,473**

Section 4.5.2 - Table 1
COLUMBIA BASIN COSTS (Grand Coulee) SUMMARY

Segment	Investment	
Network	$ 41,914,344	23.4%
Generation Integration	136,295,305	76.2%
Delivery	621,883	0.3%
Total	**$ 178,831,533**	

THIRD POWERHOUSE (500 kV Facilities):

Segment	Investment		From USBR sheet 13.034
Network	$ 16,491,112	15.7%	93,823,188
Generation Integration	88,393,024	84.3%	Plus IDC of 11.78%
Total	**$ 104,884,136**		104,875,560

FIRST & SECOND POWERHOUSE & OTHERS:

Segment	Investment	
Network	$ 25,423,232	34.4%
Generation Integration	47,902,281	64.8%
Delivery	621,883	0.8%
Total	**$ 73,947,397**	

NOTES:

Investment includes IDC.
O&M for transmisssion only; does not include step-ups.
No updated O&M costs.

Section 4.5.2 - Table 2
COLUMBIA BASIN COSTS (Grand Coulee)
BOR data for investments as of 9/30/2004

Power	Cost	Notes/Source		
Multi-purpose		From BOR assets accounts		
Electric Plant	$1,029,337,473	**1/** From BOR assets accounts		
Total	**$1,029,337,473**			
Electric Plant	$964,537,093	BOR Financial Structure/asset account		
Irrigation Assignment	-5,655,456	**2/** From BOR assets accounts		
Total	**$958,881,637**			
13.031 Pump Generator Switchyard	4,742,053	**3/** from BOR Financial Structure		$4,742,053
Percent Network	None	All GI		11.789%
			GI	$5,301,101
13.034 500kV & Other Switchyard	$93,823,183	**3/** from BOR Financial Structure		
500kV cables **6/**	-29,897,939	Not sub-assume 500kV GI		
Net sub	**63,925,244**			
Percent Network	23.1%	Base on typical costs		
Network Allocation	14,751,979		GI	$79,071,204
Percent for IDC **5/**	11.789%	from BOR Electric costs		11.789%
Total Network-500kV	**$16,491,112**			$88,393,024
13.035 Modified Left Switchyard	$60,850,641	**4/** from BOR Financial Structure		
Lines **7/**	-14,775,732	Not sub - assume 230kV GI		
Net sub	**$46,074,909**			
Percent Network	0	Base on typical costs		
Network Allocation	22,742,129		GI	$38,108,512
Percent for IDC **5/**	11.789%	from BOR Electric costs		11.789%
Total Network-Left	**$25,423,232**			$42,601,180
TOTAL NETWORK	**$41,914,344**		GI	$136,295,305
Percent Delivery	1.2%	Left Yard only 115/12 kV		
Percent for IDC **5/**	0	from BOR Electric costs		
Total Delivery	**$621,883**			

NOTES:
1/ Assume all transmission is in electric plant.
2/ Assume this is in pump gen switchyard and power plant.
3/ Assume this includes all 500 kV line and sub costs; IDC not included.
4/ Assume this includes all 230 kV and other transmission costs; IDC not included.
5/ IDC is allocated based on ratio of investment to total investment.
6/ Assumes cables are all in 500 kV yard and can be removed as a group.
7/ Assumes all lines are part of left yard and can be removed as a group.

Section 4.5.2 - Table 3
NETWORK INVESTMENT RATIO-ASSIGNMENT BASED ON TYPICAL SUB COSTS
BPA typical cost of facilities - 12/11/98

Items	Total	Network	Gen Int	Unit Cost ($000)	Total	Network	Gen Int	Delivery	Note
500 kV Switchyard									
500 kV terminal (1&1/2)	11	5	6	$ 4,500	$ 49,500	$ 22,500	$ 27,000		
Step-ups 7-800 MVA	6		6	8,000	48,000	-	48,000		3/
Total					**$ 97,500**	**$ 22,500**	**$ 75,000**	**-**	
500kV - Network % =	23.08%		% w/o step-ups		45.5%				
Left Switchyard (includes 230 & 115 yards)									
230 kV PCB 1/	22	17	5	$ 560	$ 12,320	$ 9,520	$ 2,800		
500/230 tx 1200MVA	1	1		9,800	9,800	9,800	-		
230/287kV tx	1	1		2,600	2,600	2,600	-		
230/115 tx 230MVA	1	1		2,600	2,600	2,600	-		
115kV PCB	7	7		375	2,625	2,625	-		
Delivery - 20 MVA tx	2			1,010	2,020		1,616	404	2/
Delivery- feeder terminals	11			130	1,430		1,170	260	2/
Step-ups 1-125MVA	18		18	1,200	21,600	-	21,600		4/
Total					**$ 54,995**	**$ 27,145**	**$ 27,186**	**$ 664**	
Left Yard- % Network	49.4%		Network % w/o step-ups		81.3%		% Delivery	1.2%	
							% Del w/o step-up	2.0%	

1/ Some breakers are for bus tie, etc.; these are Network.

2/ Delivery transformer split 20% to Delivery; based on estimate of 25 MVA with low and hi side PCB.
Delivery terminals based on 12.5kV feeder cost; split based on 2 for Delivery and rest for station service.

3/ Cost of 500 kV step-ups are similar to 500/230, so cost of 700MVA without breakers is used.

4/ Cost of 230 kV step-ups are similar to 230/69, so cost of 75MVA without breakers is used.

Note: Coulee-Bell additions not in plant for FY04 so not included in allocation.

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4.5.3 Other USBR Facilities

Section 4.5.3 - Table 1
USBR SEGMENTATION - OTHER PROJECTS
Based on data from USBR - Boise, ID office

PROJECT	TRANSMISSION INVESTMENT 2/	NETWORK	GENERATION INTEGRATION	DELIVERY
Hungry Horse	$ 11,854,647	$ 2,477,090	$ 9,377,557	
Boise 1/	953,782	-	953,782	
Yakima(Rosa)	3,209,543	-	3,209,543	
Green Springs	176,398	-	176,398	
Minidoka	1,602,312	846,291	756,020	
Palisades	2,101,041	391,336	1,333,442	376,262
Total	$ 19,897,721	$ 3,714,718	$ 15,806,741	$ 376,262

Segment investment is total investment times segment % determined below.
Segment percent is estimated using 1998 typical BPA facility costs as proxy.

1/ Includes Anderson Ranch and Black Canyon.
2/ Total from BOR Electric Plant In Service, sub account 13 with IDC allocation.

SEGMENT PERCENTAGES FOR MULTI-SEGMENT PLANTS

Hungry Horse:

Item	Cost	Network	Gen Int
2-230kV terminals	$ 1,120,000	$ 1,120,000	-
2-230kV terminals	1,120,000	-	1,120,000
2-180MVA step-ups	3,120,000	-	3,120,000
Total	$ 5,360,000	$ 1,120,000	$ 4,240,000
Percent of total		20.9%	79.1%

Step-up transformer cost based on 230/69kV 75 MVA w disconnects.

Minidoka-Palisades:

Minidoka sub	Cost	Network	Gen Int	Delivery
5-138kV terminal	$ 2,250,000	$ 1,500,000	$ 750,000	
1 Step-up to 138kV	590,000		590,000	
Total	$ 2,840,000	$ 1,500,000	$ 1,340,000	
Percent of total		52.8%	47.2%	0.0%

Palisades:	Cost	Network	Gen Int	Delivery
9-115kV terminals	$ 3,375,000	$ 1,265,625	$ 1,687,500	$ 421,875
4-35MVA step-ups	2,360,000		2,360,000	
10MVA 115/12.5kV	1,060,000		265,000	795,000
Total	$ 6,795,000	$ 1,265,625	$ 4,312,500	$ 1,216,875
Percent of total		18.6%	63.5%	17.9%

NOTES:
Minidoka terminals - use 115kV terminal cost of $375,000;
Minidoka terminals - 4 Network, 2 Generation Integration, 1 bus tie
Minidoka step-up - use 115/34.5kV 25 MVA transformer cost
Palisades - 9 PCB/8 terminals - 4 GI, 3 Net, 1 Del
Palisades step-ups - use 115/34.5kV 25 MVA transformer cost
Palisades - delivery is for Lower Valley and station service
Base delivery tx on cost of 115/12.5 sub 25MVA
Split station servcie facilities 25% to delivery & 75% to station service/GI

4.6 UAI AND EXCESS FACTORING CHARGES

Documentation Table 4.6.1
Sample Derivation of UAI Charges (w/minimum) for Demand by Month
Historical Period August 2--4 through July 2005

	A	B	C	D
Month	**ISO NW1 ($/kW/mo)**	**ISO NW3 ($/kW/mo)**	**Minimum UAI charge (3x Prop PF-07 demand chg 2/ ($/kW/mo)**	**Effective charge (max of Cols. A, B, or C) ($/kW/mo)**
	Index based Charges 1/			
Aug-04	$1.09	$3.19	$10.17	$10.17
Sep-04	$1.09	$1.09	$10.17	$10.17
Oct-04	$1.89	$1.89	$7.02	$7.02
Nov-04	$1.35	$1.35	$9.21	$9.21
Dec-04	$1.58	$1.58	$9.21	$9.21
Jan-05	$4.33	$4.33	$8.61	$8.61
Feb-05	$3.85	$3.85	$8.10	$8.10
Mar-05	$4.00	$4.00	$7.23	$7.23
Apr-05	$5.97	$5.97	$5.94	$5.97
May-05	$4.84	$4.84	$5.88	$5.88
Jun-05	$3.33	$3.33	$7.35	$7.35
Jul-05	$6.06	$6.06	$9.51	$9.51

1/ Sum of hourly ISO market clearing spinning reserve capacity prices for all HLH's
2/ Minimum UAI demand charge is in this colum are three (3) times the proposed PF demand charge

Documentation Table 4.6.2 Sample Derivation of UAI Charges (w/minimum) for Energy by month
Historical period August 2004 through July 2005

	A	B	C	D
	Indexed based charges			
Month	DJ mid-C Firm ($/MWh)	ISO Supplemental energy NP-15 ($/MWh)	Minimum UAI charge ($/MWh)	Effective Charge (max of Cols A, B, C)
Aug-04	$61.59	$159.57	$100.00	$159.57
Sep-04	$44.42	$100.25	$100.00	$100.25
Oct-04	$60.68	$156.30	$100.00	$156.30
Nov-04	$54.27	$147.07	$100.00	$147.07
Dec-04	$57.57	$148.37	$100.00	$148.37
Jan-05	$60.12	$170.50	$100.00	$170.50
Feb-05	$49.90	$103.64	$100.00	$103.64
Mar-05	$57.57	$135.38	$100.00	$135.38
Apr-05	$57.61	$141.10	$100.00	$141.10
May-05	$48.44	$142.08	$100.00	$142.08
Jun-05	$51.67	$124.60	$100.00	$124.60
Jul-05	$77.36	$162.33	$100.00	$162.33

DOCUMENTATION TABLE 4.6.3 SAMPLE Derivation of Within-Day Excess Factoring Charges, by Month
Historical Period August 2004 through July 2005

	A	B	C	D	E	F
	HLH Within-Day Excess Factoring Charges			LLH Within-Day Excess Factoring Charges		
Month	Within-Day Deltas ISO Supplemental Energy (NP-15) ($/MWh)	Minimum Within-Day Excess Factoring Charges ($/MWh)	Effective Charge (Max. of Cols. A and B)	Within-Day Deltas Supplemental Energy (NP-15) ($/MWh)	Minimum Within-Day Excess Factoring Charge ($/MWh)	Effective Charge (Max. of Cols. D and E) ($/MWh)
Aug-04	$56.30	$5.00	$56.30	$99.08	$5.00	$99.08
Sep-04	$79.46	$5.00	$79.46	$90.38	$5.00	$90.38
Oct-04	$79.33	$5.00	$79.33	$126.26	$5.00	$126.26
Nov-04	$101.21	$5.00	$101.21	$92.83	$5.00	$92.83
Dec-04	$139.89	$5.00	$139.89	$100.18	$5.00	$100.18
Jan-05	$153.24	$5.00	$153.24	$134.52	$5.00	$134.52
Feb-05	$80.75	$5.00	$80.75	$67.26	$5.00	$67.26
Mar-05	$134.71	$5.00	$134.71	$129.21	$5.00	$129.21
Apr-05	$109.90	$5.00	$109.90	$116.99	$5.00	$116.99
May-05	$145.09	$5.00	$145.09	$102.31	$5.00	$102.31
Jun-05	$123.51	$5.00	$123.51	$103.61	$5.00	$103.61
Jul-05	$149.02	$5.00	$149.02	$102.10	$5.00	$102.10

DOCUMENTATION TABLE 4.6.4 SAMPLE Derivation of Within-Month Excess Factoring Charges, by Month 1/
Historical Period August 2004 through July 23005

	A	B	C	D	D	F	G	H
	HLH "Within Month" Excess Factoring Charges				LLH "Within Month" Excess Factoring Charges			
	Indexed Based Charges				Indexed Based Charges			
Month	ISO Suplemental Energy Index (NP-15) ($/MWh)	DJ Mid-C Index (Onpeak firm) ($/MWh)	Minimum Within-Month Excess Factoring Charge ($/MWh)	Effective Charge (Max. of Cols. A, B, C) ($/MWh)	ISO Suplemental Energy Index (NP 15) ($/MWh)	DJ Mid-C Index (Onpeak firm) ($/MWh)	Minimum Within-Month Excess Factoring Charge ($/MWh)	Effective Charge (Max. of Cols. A, B, C) ($/MWh)
Aug-04	$36.41	$25.36	$5.00	$36.41	$123.96	$23.22	$5.00	$123.96
Sep-04	$54.10	$9.41	$5.00	$54.10	$73.37	$7.80	$5.00	$73.37
Oct-04	$68.34	$23.63	$5.00	$68.34	$113.27	$21.09	$5.00	$113.27
Nov-04	$109.55	$14.19	$5.00	$109.55	$74.17	$12.68	$5.00	$74.17
Dec-04	$95.79	$17.12	$5.00	$95.79	$75.06	$17.25	$5.00	$75.06
Jan-05	$119.31	$18.26	$5.00	$119.31	$122.29	$13.94	$5.00	$122.29
Feb-05	$66.39	$5.86	$5.00	$66.39	$33.93	$9.35	$5.00	$33.93
Mar-05	$94.51	$10.93	$5.00	$94.51	$99.34	$15.24	$5.00	$99.34
Apr-05	$92.15	$13.48	$5.00	$92.15	$69.20	$16.92	$5.00	$69.20
May-05	$102.91	$32.25	$5.00	$102.91	$78.06	$33.23	$5.00	$78.06
Jun-05	$91.04	$19.47	$5.00	$91.04	$66.15	$19.58	$5.00	$66.15
Jul-05	$122.24	$41.46	$5.00	$122.24	$49.55	$31.64	$5.00	$49.55

1/ The 'Within-Month' deltas for the HLH within-month Excess Factoring are computed by subtracting the LOWEST average daily ISO or Mid-C HLH price (average of 16 hours) for the month from the HIGHEST average daily HLH price for the month. A corresponding calculation is performed to derive the LLH within-month Excess Factoring charge (24 hours on Sunday, 6 NERC holidays, and hours ending 1-6 and 23 -24 for all other days).

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Table 4.8
Firm Capacity without Energy

	Energy Rates $/MWh			Capacity w/o Energy $/kW/Mo	
	HLH	LLH	HLH- LLH	$ 7.01	annual average
Oct	53.34	46.08	7.26	$ 6.92	
Nov	63.03	52.01	11.02	$ 8.17	
Dec	66.13	54.79	11.34	$ 8.57	
Jan	59.13	50.01	9.12	$ 7.67	
Feb	59.27	52.39	6.88	$ 7.68	
Mar	56.85	50.21	6.64	$ 7.37	
Apr	47.16	40.56	6.60	$ 6.11	
May	41.76	35.55	6.21	$ 5.41	
Jun	41.17	31.27	9.90	$ 5.34	
Jul	49.51	41.07	8.44	$ 6.42	
Aug	54.63	46.87	7.76	$ 7.08	
Sep	56.83	50.78	6.05	$ 7.37	
Average	54.07	45.97		$ 7.01	

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4.9 ASC FORECAST

CookBook		Utility Name					
"F9" for Calculate Now				TEST PERIOD:			
				BPA DOCKET NO.		current file	
JURISDICTION:	jurisdiction			LAST APPROVED FILE NUMBER		last file	
ANALYST NAME:	analyst			DATE REPORT DUE:			
					DOLLARS IN	units	
			Data Matrix				
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Account	Funct.				Distribution/	Math
Account Description	No.(s)	Method	Total	Production	Transmission	Other	Check
Schedule 1 (Report Page 1 of 2)							
Production Plant:							
Steam Production	310-316	DIR-P	0	0	0	0	0
Nuclear Production	320-325	DIR-P	0	0	0	0	0
Hydraulic Production	330-336	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Total Production Plant			0	0	0	0	0
Transmission Plant:							
Transmission Plant	350-359	DIR-T	0	0	0	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Total Transmission Plant	350-359		0	0	0	0	0
Total Distribution Plant	360-373	DIR-D	0	0	0	0	0
Intangible Plant	301	PTD	0	0	0	0	0
Intangible Plant	302	PTD	0	0	0	0	0
Intangible Plant	303	PTD	0	0	0	0	0

General Plant:		389-399						
	Land and Land Rights	389	PTD	0	0	0	0	0
	Land and Land Rights	389	10%PTD	0	0	0	0	0
	Structures and Improvements	390	PTD	0	0	0	0	0
	Structures and Improvements	390	10%PTD	0	0	0	0	0
	Furniture and Equipment	391	Labor	0	0	0	0	0
	Furniture and Equipment	391	10%LABOR	0	0	0	0	0
	Transportation Equipment	392	TD	0	0	0	0	0
	Transportation Equipment	392	10%TD	0	0	0	0	0
	Stores Equipment	393	PTD	0	0	0	0	0
	Tools and Garage Equipment	394	PTD	0	0	0	0	0
	Laboratory Equipment	395	PTD	0	0	0	0	0
	Power Operated Equipment	396	TD	0	0	0	0	0
	Communication Equipment	397	PTD	0	0	0	0	0
	Miscellaneous Equipment	398	DIR-D	0	0	0	0	0
	Other Tangible Property	399	PTD	0	0	0	0	0
Total General Plant		389-399		0	0	0	0	0
Total Electric Plant In-Service				0	0	0	0	0
Less - Depreciation and Amortization:								
	Steam Plant	108	DIR-P	0	0	0	0	0
	Nuclear Plant	108	DIR-P	0	0	0	0	0
	Hydraulic Plant	108	DIR-P	0	0	0	0	0
	Other Production Plant	108	DIR-P	0	0	0	0	0
	Other Production Plant	108	DIR-P	0	0	0	0	0
	Other Production Plant	108	DIR-P	0	0	0	0	0
	Other Production Plant	108	DIR-P	0	0	0	0	0
	Other Production Plant	108	DIR-P	0	0	0	0	0
	Intangible Plant	108	PTD	0	0	0	0	0
	Transmission Plant	108	DIR-T	0	0	0	0	0
	Other Transmission Plant	108	DIR-T	0	0	0	0	0
	Other Transmission Plant	108	DIR-T	0	0	0	0	0
	Other Transmission Plant	108	DIR-T	0	0	0	0	0
	Distribution Plant	108	DIR-D	0	0	0	0	0
	General Plant	108	GP	0	0	0	0	0
	Other Amortization	Acct. No.	Funct. Code	0	0	0	0	0

	Amort. Reserve	111	PTD	0	0	0	0	0
Total Depreciation and Amortization				0	0	0	0	0
Total Net Electric Plant In-Service				0	0	0	0	0
Schedule 1 (Report Page 2 of 2)								
Add - Debits:								
	Cash Working Capital		Direct	0	0	0	0	0
	Plant Held Future Use	105	PTDG	0	0	0	0	0
	Completed Construction	106	PTD	0	0	0	0	0
	CWIP	107-120.1	DIR-D	0	0	0	0	0
	Acquisitions Adjustments	114	LABOR	0	0	0	0	0
	Nuclear Fuel	120.2-120.4	DIR-P	0	0	0	0	0
	Investments	123	DIR-D	0	0	0	0	0
	Other Investment	124	DIR-D	0	0	0	0	0
	Weatherization Investment	0	DIR-P	0	0	0	0	0
	Fuel Stock	151-152	DIR-P	0	0	0	0	0
	Materials and Supplies	153-157,163	TDG	0	0	0	0	0
	Clearing Accounts	184	LABOR	0	0	0	0	0
	Misc. Deferred Debits	186	LABOR	0	0	0	0	0
	Other Debits	182	Funct. Code	0	0	0	0	0
	Prepayments	165	DIR-D	0	0	0	0	0
Total Debits				0	0	0	0	0
Less - Credits:		252-283						
	Cust. Advances for Const.	252	DIR-D	0	0	0	0	0
	Other Deferred Credits	253	DIR-D	0	0	0	0	0
	Accum Def. Inv. Tax Credit	255	DIR-D	0	0	0	0	0
	Deferred Gain - Disposition	256	PTDG	0	0	0	0	0
	Unamortized Gain - Reacq.	257	PTDG	0	0	0	0	0
	Accum. Def. Income Taxes	281-283	DIR-D	0	0	0	0	0
	Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
	Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
Total Credits				0	0	0	0	0
Total Rate Base				0	0	0	0	0

Rate of Return		0.00%						
Schedule 3 (Report Page 1 of 2)								
Production Expense:								
	Steam - Fuel Exp.	501	DIR-P	0	0	0	0	0
	Steam - Operations Exp.	500,502	DIR-P	0	0	0	0	0
	Steam - Maintenance	510-514	DIR-P	0	0	0	0	0
	Nuclear - Fuel Exp.	518	DIR-P	0	0	0	0	0
	Nuclear - Other Exp.	517	DIR-P	0	0	0	0	0
	Nuclear - Maintenance	528-532	DIR-P	0	0	0	0	0
	Nuclear Research - Misc.	524	DIR-P	0	0	0	0	0
	Hydro - Operation Exp.	535-540	DIR-P	0	0	0	0	0
	Hydro - Maintenance	541-545	DIR-P	0	0	0	0	0
	Other Power - Fuel Exp.	547	DIR-P	0	0	0	0	0
	Other Power - Other Exp.	546	DIR-P	0	0	0	0	0
	Other - Maintenance Exp.	548-554	DIR-P	0	0	0	0	0
	Purchased Power	555	DIR-P	0	0	0	0	0
	Other Power Supply Exp.	556-557	DIR-P	0	0	0	0	0
	Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
Total Production Expense				0	0	0	0	0
Transmission Expense:								
	Wheeling Expense	565	DIR-T	0	0	0	0	0
	Trans. Exp. Operations	560-564	DIR-T	0	0	0	0	0
	Trans. - Maintenance	568-574	DIR-T	0	0	0	0	0
	Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
Total Transmission Expense				0	0	0	0	0
Distribution Expense:								
	Distn. - Operations Exp.	580-589	DIR-D	0	0	0	0	0
	Distn. - Maintenance Exp.	590-598	DIR-D	0	0	0	0	0

	Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
Total Distribution Expense				0	0	0	0	0
Customer and Sales Expenses:								
	Customer Accounting Exp.	901-905	DIR-D	0	0	0	0	0
	Customer Service Exp.	907-910	DIR-D	0	0	0	0	0
	Sales Expense	911-916	DIR-D	0	0	0	0	0
Total Customer and Sales Expenses				0	0	0	0	0
Administration and General Expense:								
	Adm. and General Salaries	920	LABOR	0	0	0	0	0
	Adm. and General Salaries	920	10%LABOR	0	0	0	0	0
	Office supplies & expenses	921	LABOR	0	0	0	0	0
	Office supplies & expenses	921-10%	10%LABOR	0	0	0	0	0
	Adm. expenses transfer- Cr.	922	LABOR	0	0	0	0	0
	Adm. expenses transfer- Cr.	922-10%	10%LABOR	0	0	0	0	0
	Outside services employed	923	LABOR	0	0	0	0	0
	Property insurance	924	PTDG	0	0	0	0	0
	Injuries and damages	925	LABOR	0	0	0	0	0
	Emp. pensions & benefits	926	LABOR	0	0	0	0	0
	Franchise requirements	927	DIR-D	0	0	0	0	0
	Regulatory Comm. Exp.	928	DIR-D	0	0	0	0	0
	Duplicate charges-credit	929	LABOR	0	0	0	0	0
	General advertising Exp.	930.1	DIR-D	0	0	0	0	0
	Misc. general expenses	930.2	DIR-D	0	0	0	0	0
	Misc. general expenses	9.30.2-10%	10%LABOR	0	0	0	0	0
	Rents	931	DIR-D	0	0	0	0	0
	Maint. of general plant	932	GPM	0	0	0	0	0
	Maint. of general plant	932-10%	10%LABOR	0	0	0	0	0
	Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
	Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
Total Administration and General Expenses				0	0	0	0	0
Total Operations and Maintenance				0	0	0	0	0
Schedule 3 (Report Page 2 of 2)								

Section 4.9 - Table 4.9.1 Continued
ASC CookBook Model

Depreciation and Amortization:								
	Steam - Depreciation Exp.	403	DIR-P	0	0	0	0	0
	Nuclear - Depreciation Exp.	403	DIR-P	0	0	0	0	0
	Hydro. - Depreciation Exp.	403	DIR-P	0	0	0	0	0
	Other Prod. - Depreciation	403	DIR-P	0	0	0	0	0
	Trans. - Depreciation Exp.	403	DIR-T	0	0	0	0	0
	Distr. - Depreciation Exp.	403	DIR-D	0	0	0	0	0
	Gen. Plant - Depreciation	403	GP	0	0	0	0	0
	Other Depreciation Exp.	404	DIR-D	0	0	0	0	0
	Amort Limited Term Plant	405	PTD	0	0	0	0	0
	Amort. of Plant Acq.	406	PTD	0	0	0	0	0
	Amort. of Prop Losses	407	PTD	0	0	0	0	0
	Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Total Depreciation and Amortization				0	0	0	0	0
Schedule 3A Items								
	Fed Tax-Insurance Contrib.	403	LABOR	0	0	0	0	0
	Fed Tax-Unemployment		LABOR	0	0	0	0	0
	In-lieu Tax		Direct	0	0	0	0	0
	Other Taxes		DIR-D	0	0	0	0	0
	Federal Income Tax		DIR-D	0	0	0	0	0
	Total Deferred Taxes		DIR-D	0	0	0	0	0
	Miscellaneous Taxes		DIR-D	0	0	0	0	0
Total Non-State Taxes				0	0	0	0	0
State One (Put name here)								
	State Income Taxes		DIR-D	0	0	0	0	0
	State Property Tax		PTDG	0	0	0	0	0
	State Unemp. Tax		LABOR	0	0	0	0	0
	State Reg. Commis. Tax		DIR-D	0	0	0	0	0
	State Generating Tax		DIR-D	0	0	0	0	0
	State Pollution Control Tax		DIR-D	0	0	0	0	0
	State Revenue and Business Tax		DIR-D	0	0	0	0	0
	Local Occupation and Franchise Tax		DIR-D	0	0	0	0	0
	Other Tax Item		Funct. Code	0	0	0	0	0

	Other Tax Item		Funct. Code	0	0	0	0	0
	Other Tax Item		Funct. Code	0	0	0	0	0
State Two (Put Name Here)								
	State Income Taxes		DIR-D	0	0	0	0	0
	State Property Tax		PTDG	0	0	0	0	0
	State Unemp. Tax		LABOR	0	0	0	0	0
	State Reg. Commis. Tax		DIR-D	0	0	0	0	0
	State Generating Tax		DIR-D	0	0	0	0	0
	State Pollution Control Tax		DIR-D	0	0	0	0	0
	State Rev. & Business Tax		DIR-D	0	0	0	0	0
	Local Occupation & Franchise		DIR-D	0	0	0	0	0
	Other Tax Item		Funct. Code	0	0	0	0	0
	Other Tax Item		Funct. Code	0	0	0	0	0
	Other Tax Item		Funct. Code	0	0	0	0	0
Total State Taxes				0	0	0	0	0
Total Taxes				0	0	0	0	0
Schedule 3B Items								
Other Included Items:								
	Gain from Disp. of Plant	411.6	PTDG	0	0	0	0	0
	Loss from Disp. of Plant	411.7	PTDG	0	0	0	0	0
Total Disp. of Plant				0	0	0	0	0
Sale from Resale:								
	Nonfirm Sales for Resale	447	DIR-P	0	0	0	0	0
	Firm Sales For Resale	447	DIR-P	0	0	0	0	0
Total Sales from Resale				0	0	0	0	0
Other Revenues:								
	Forfeited Discounts	450	DIR-D	0	0	0	0	0
	Miscellaneous Service Revenues	451	DIR-P	0	0	0	0	0
	Sales of water/water power	453	DIR-P	0	0	0	0	0
	Rent from property	454	DIR-P	0	0	0	0	0
	Interdepartmental Rents	455	DIR-P	0	0	0	0	0
	Other electric revenues	456	DIR-T	0	0	0	0	0

Section 4.9 - Table 4.9.1 Continued
ASC CookBook Model

	Billing Credits		DIR-P	0	0	0	0	0
	Other Revenue	Acct. No.	Funct. Code	0	0	0	0	0
	Other Revenue	Acct. No.	Funct. Code	0	0	0	0	0
Total Other Revenues				0	0	0	0	0
Total Other Included Items				0	0	0	0	0
Total Operating Expenses				0	0	0	0	0
Return from Rate Base		Schedule 1		0	0	0	0	0
Total Cost				0	0	0	0	0
Schedule 4 Items								
	Energy Measure - typically (MWh) or (kWh)		(kWh)					
	Total Load	**(kWh)**	0					
	Non-firm Adjustments	**(kWh)**	0					
	Other Adjustments	**(kWh)**	0					
	Distribution Losses	**(kWh)**	0					
	Excluded Load	**(kWh)**	0					
	Excl. Load Dist. Losses	**(kWh)**	0					
	Excluded Load Costs		0					
	Revenue Requirement		0					
	ASC Multiplier		1					
	Schedule 4 ASC	(mills/kWh)	0.00					
Revenue Cap Calculation			Last Approved					
	Revenue Requirement		0					
	Contract System Costs		0					
	Distribution Costs		0					
	Amount Exceeds Allowable Costs		0					
End Schedule 4 and Data Matrix								

Section 4.9 - Table 4.9.1 Continued
ASC CookBook Model

Remainder are Necessary Calculations.								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
		Account	Funct.				Distribution/	
	Account Description	No.(s)	Method	Total	Production	Transmission	Other	
Labor Ratio Input:		(source - FERC From 1)						
	Production	500-507	DIR-P	0	0	0	0	0
	Transmission	560-573	DIR-T	0	0	0	0	0
	Distribution	580-598	DIR-D	0	0	0	0	0
	Customer Account	901-905	DIR-D	0	0	0	0	0
	Customer Service	907-910	DIR-D	0	0	0	0	0
	Sales Expense	911-916	DIR-D	0	0	0	0	0
	Admin. & General	920-932	DIR-D	0	0	0	0	0
	Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
	Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Total Labor				0	0	0	0	0
Functionalization Ratio Schedules								
			Total				Math	
GP	**Production**	Ratio Used	Funct.	Production	Transmission	Distribution	Check	
	Land and Land Rights	PTD/10% TD	0	0	0	0	0	
	Structures and Improvements	PTD/10% TD	0	0	0	0	0	
	Furniture and Equipment	LABOR/10% TD	0	0	0	0	0	
	Transportation Equipment	TD/10% TD	0	0	0	0	0	
	Stores Equipment	PTD	0	0	0	0	0	
	Tools and Garage Equipment	PTD	0	0	0	0	0	
	Laboratory Equipment	PTD	0	0	0	0	0	
	Power Operated Equipment	TD	0	0	0	0	0	
	Communication Equipment	PTD	0	0	0	0	0	
	Miscellaneous Equipment	DIR-D	0	0	0	0	0	
	Other Tangible Property	PTD	0	0	0	0	0	
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0	
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0	
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0	

Section 4.9 - Table 4.9.1 Continued
ASC CookBook Model

	TOTAL		0	0	0	0	0	
	RATIO (GP)		0.00%	0.00%	0.00%	0.00%	0	
PTD	**Production, Transmission, Distribution**							
	Steam Production	DIR-P	15	5	5	5	0	
	Nuclear Production	DIR-P	0	0	0	0	0	
	Hydraulic Production	DIR-P	0	0	0	0	0	
	Other Production	DIR-P	0	0	0	0	0	
	Other Production	DIR-P	0	0	0	0	0	
	Other Production	DIR-P	0	0	0	0	0	
	Other Items for PTD Ratio Calc.	DIR-P	0	0	0	0	0	
	Total Production Plant		15	5	5	5	0	
	Transmission Plant	DIR-T	0	0	0	0	0	
	Other Transmission	DIR-T	0	0	0	0	0	
	Other Items for PTD Ratio Calc.	DIR-T	0	0	0	0	0	
	Total Transmission Plant	DIR-T	0	0	0	0	0	
	Total Distribution Plant	DIR-D	0	0	0	0	0	
	TOTAL		15	5	5	5	0	
	RATIO (PTD = PLANT IN SERVICE)		100.00%	33.33%	33.33%	33.33%	0	
PTDG	**Production, Transmission, Distribution and General Plant**							
	PTD Total		15	5	5	5	0	
	Intangible Plant	Direct	0	0	0	0	0	
	Intangible Plant	PTD	0	0	0	0	0	
	Other Items for PTDG Ratio Calc.	Func. Code	0	0	0	0	0	
	Other Items for PTDG Ratio Calc.	Func. Code	0	0	0	0	0	
	GP Total		0	0	0	0	0	
	TOTAL		15	5	5	5	0	
	RATIO (PTDG = GROSS PLANT)		100.00%	33.33%	33.33%	33.33%	0	
TD	**Transmission, Distribution**							
	Total Transmission Plant	DIR-T	0	0	0	0	0	
	Total Distribution Plant	DIR-D	0	0	0	0	0	
	TOTAL		0	0	0	0	0	
	RATIO (TD)		0.00%	0.00%	0.00%	0.00%	0	

TDG	**Transmission, Distribution and General Plant**							
	Total Transmission Plant	DIR-T	0	0	0	0	0	
	Total Distribution Plant	DIR-D	0	0	0	0	0	
	Other T&D Only Items for TDG Calc.	Func. Code	0	0	0	0	0	
	Other T&D Only Items for TDG Calc.	Func. Code	0	0	0	0	0	
	Intangible Plant T and D Only	Direct	0	0	0	0	0	
	Intangible Plant T and D Only	PTD	0	0	0	0	0	
	General Plant Total 389-399(T&D Only)		0	0	0	0	0	
	TOTAL		0	0	0	0	0	
	RATIO (TDG)		0.00%	0.00%	0.00%	0.00%	0	
GPM	**Maintenance of General Plant**							
	Structures and Improvements	PTD/10% TD	0	0	0	0	0	
	Furniture and Equipment	LABOR/10% TD	0	0	0	0	0	
	Communication Equipment	PTD	0	0	0	0	0	
	Miscellaneous Equipment	DIR-D	0	0	0	0	0	
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0	
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0	
	TOTAL		0	0	0	0	0	
	RATIO (GPM)		0.00%	0.00%	0.00%	0.00%	0	
LABOR	**Labor Ratios**							
	Production	DIR-P	0	0	0	0	0	
	Transmission	DIR-T	0	0	0	0	0	
	Distribution	DIR-D	0	0	0	0	0	
	Customer Account	DIR-D	0	0	0	0	0	
	Customer Service	DIR-D	0	0	0	0	0	
	Sales Expense	DIR-D	0	0	0	0	0	
	Admin. & General	DIR-D	0	0	0	0	0	
	Other Labor	Funct. Code	0	0	0	0	0	
	Other Labor	Funct. Code	0	0	0	0	0	
	TOTAL		0	0	0	0	0	
	RATIO (LABOR)		0.00%	0.00%	0.00%	0.00%	0	
Functionalization Ratios / DataTable								

Section 4.9 - Table 4.9.1 Continued
ASC CookBook Model

				10%LABOR	10.00%	0.00%	90.00%		
				10%TD	10.00%	0.00%	90.00%		
				DIR-D	0.00%	0.00%	100.00%		
				DIR-P	100.00%	0.00%	0.00%		
				DIR-T	0.00%	100.00%	0.00%		
				DIREGT	0.00%	0.00%	0.00%		
				GP	0.00%	0.00%	0.00%		
				GPM	0.00%	0.00%	0.00%		
				LABOR	0.00%	0.00%	0.00%		
				PTD	0.00%	0.00%	0.00%		
				PTDG	0.00%	0.00%	0.00%		
				TD	0.00%	0.00%	0.00%		
				TDG	0.00%	0.00%	0.00%		

Table 4.9.2
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

AVISTA UTILITIES

			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh				43.01	44.19	45.73	48.17	49.30	50.28	51.43	52.70	53.98
Assumed Gas Price			6.50	7.00	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price				60.0	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption				80%	80%	80%	80%	80%	80%	80%	80%	80%
O&M / total multiplier				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Annual Cost Escalation Rate				2.00%	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage		41%		40.9%	40.9%	40.9%	40.9%	40.9%	40.9%	40.9%	40.9%	40.9%
TRL Differential				852,488	335,727	211,708	318,443	337,590	333,113	336,094	299,257	259,567
Cost on new load				51,149,300	20,143,620	12,376,439	16,197,641	17,109,153	17,304,334	17,895,671	16,332,609	14,520,605
Fuel	Share	Coal Esc.	39,678,923	41,332,057	39,952,453	40,144,420	39,681,663	39,178,575	37,998,838	37,284,905	38,184,042	39,302,457
Coal	49%	0.5%	19,452,596	19,549,859	19,647,608	19,745,846	19,844,576	19,943,798	20,043,517	20,143,735	20,244,454	20,345,676
NG	51%		20,226,327	21,782,198	20,304,845	20,398,574	19,837,087	19,234,777	17,955,321	17,141,170	17,939,588	18,956,781
Off-system Sales				255	255	255	255	255	255	255	255	255
Sale for Resale credit			71,994,600	107,167,344	107,167,344	104,416,716	90,851,451	90,521,243	92,784,274	95,103,881	97,481,478	99,918,515

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load Growth %			109.69%	103.48%	102.12%	103.12%	103.21%	103.07%	103.00%	102.60%	102.20%
LARIS Ave MW Load Forecast		984	1,048.92	1,085.42	1,108.43	1,143.05	1,179.76	1,215.97	1,252.51	1,285.05	1,313.27
TRL		8,795,447	9,647,935	9,983,662	10,195,370	10,513,813	10,851,402	11,184,515	11,520,610	11,819,867	12,079,434
Residential load	39.9%	3,510,227	3,850,451	3,984,439	4,068,930	4,196,019	4,330,750	4,463,694	4,597,828	4,717,260	4,820,852
BASE											
			9.69%	6.32%	5.67%	8.63%	5.64%	5.11%	5.36%	5.13%	4.69%
Exchangeble Costs		378,305,096	414,971,872	441,209,347	466,232,706	506,453,225	535,022,734	562,358,821	592,516,553	622,888,697	652,097,102
ASC $ /Mwh		43.01	43.01	44.19	45.73	48.17	49.30	50.28	51.43	52.70	53.98

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

IDAHO POWER

			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh				38.60	39.42	40.88	42.77	43.82	44.83	45.92	47.00	48.12
Assumed Gas Price			**6.50**	**7.00**	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price				**60.0**	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption				80%	80%	80%	80%	80%	80%	80%	80%	80%
O&M / total multiplier				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Annual Cost Escalation Rate				**2.00%**	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage		41%		40.9%	0.0%	40.9%	0.0%	40.9%	0.0%	40.9%	0.0%	40.9%
TRL Differential				1,782,554	157,133	436,138	325,763	325,762	324,996	273,641	220,752	293,569
Cost on new load				106,953,251	9,427,972	25,496,635	16,570,009	16,509,727	16,882,691	14,570,263	12,048,016	16,422,722
Fuel	Share	Coal Escl	103,261,439	104,128,304	104,266,693	104,786,148	105,150,196	105,506,903	105,702,943	106,013,633	106,715,448	107,472,529
Coal	95%	**0.5%**	98,387,370	98,879,307	99,373,703	99,870,572	100,369,925	100,871,774	101,376,133	101,883,014	102,392,429	102,904,391
NG	5%		4,874,069	5,248,997	4,892,990	4,915,576	4,780,271	4,635,129	4,326,810	4,130,619	4,323,019	4,568,138
Off-system Sales			264	264	264	264	264	264	264	264	264	264
Sale for Resale credit			96,918,117	110,797,440	110,797,440	107,953,639	93,928,876	93,587,483	95,927,171	98,325,350	100,783,484	103,303,071

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load Growth %			112.82%	101.00%	102.75%	102.00%	101.96%	101.92%	101.59%	101.26%	101.65%
LARIS Ave MW Load Forecast		1,587	1705.166626	1722.25	1769.666626	1805.083374	1840.5	1875.833374	1905.583374	1929.583374	1961.5
TRL		13,901,568	15,684,123	15,841,256	16,277,394	16,603,157	16,928,919	17,253,915	17,527,556	17,748,308	18,041,877
Residential load	**44.1%**	6,135,452	6,922,182	6,991,533	7,184,022	7,327,798	7,471,573	7,615,010	7,735,781	7,833,210	7,962,776
			12.82%	3.15%	6.55%	6.72%	4.48%	4.25%	4.06%	3.64%	4.09%
Exchangeble Costs		536,607,351	605,414,816	624,495,146	665,399,467	710,120,642	741,909,037	773,423,048	804,832,425	834,145,195	868,238,128
ASC $ /Mwh		38.60	38.60	39.42	40.88	42.77	43.82	44.83	45.92	47.00	48.12

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

IDAHO POWER

			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh				38.60	39.42	40.88	42.77	43.82	44.83	45.92	47.00	48.12
Assumed Gas Price			**6.50**	**7.00**	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price				**60.0**	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption				80%	80%	80%	80%	80%	80%	80%	80%	80%
O&M / total multiplier				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Annual Cost Escalation Rate				**2.00%**	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage		41%		40.9%	0.0%	40.9%	0.0%	40.9%	0.0%	40.9%	0.0%	40.9%
TRL Differential				1,782,554	157,133	436,138	325,763	325,762	324,996	273,641	220,752	293,569
Cost on new load				106,953,251	9,427,972	25,496,635	16,570,009	16,509,727	16,882,691	14,570,263	12,048,016	16,422,722
Fuel	Share	Coal Escl	103,261,439	104,128,304	104,266,693	104,786,148	105,150,196	105,506,903	105,702,943	106,013,633	106,715,448	107,472,529
Coal	95%	**0.5%**	98,387,370	98,879,307	99,373,703	99,870,572	100,369,925	100,871,774	101,376,133	101,883,014	102,392,429	102,904,391
NG	5%		4,874,069	5,248,997	4,892,990	4,915,576	4,780,271	4,635,129	4,326,810	4,130,619	4,323,019	4,568,138
Off-system Sales			264	264	264	264	264	264	264	264	264	264
Sale for Resale credit			96,918,117	110,797,440	110,797,440	107,953,639	93,928,876	93,587,483	95,927,171	98,325,350	100,783,484	103,303,071

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load Growth %			112.82%	101.00%	102.75%	102.00%	101.96%	101.92%	101.59%	101.26%	101.65%
LARIS Ave MW Load Forecast		1,587	1705.166626	1722.25	1769.666626	1805.083374	1840.5	1875.833374	1905.583374	1929.583374	1961.5
TRL		13,901,568	15,684,123	15,841,256	16,277,394	16,603,157	16,928,919	17,253,915	17,527,556	17,748,308	18,041,877
Residential load	**44.1%**	6,135,452	6,922,182	6,991,533	7,184,022	7,327,798	7,471,573	7,615,010	7,735,781	7,833,210	7,962,776
			12.82%	3.15%	6.55%	6.72%	4.48%	4.25%	4.06%	3.64%	4.09%
Exchangeble Costs		536,607,351	605,414,816	624,495,146	665,399,467	710,120,642	741,909,037	773,423,048	804,832,425	834,145,195	868,238,128
ASC $ /Mwh		38.60	38.60	39.42	40.88	42.77	43.82	44.83	45.92	47.00	48.12

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

PacifiCorp

	Share	Coal Esc.	2004	2005	2006	2007	2008	2,009	2010	2011	2012	2013
ASC $ /MWh					41.67	43.55	48.05	49.41	50.29	51.34	52.46	53.60
Assumed Gas Price			**6.50**	**7.00**	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price			**50**	**60**	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption			**80%**	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**
O&M / total multiplier				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Annual Cost Escalation Rate				**2.00%**	0.0155	0.0191	0.0206	0.0209	0.0230	0.0248	0.0239	0.0235
Residential percentage					44.6%	44.6%	44.6%	44.6%	44.6%	44.6%	44.6%	44.6%
TRL Differential				360,697	862,313	91,980	295,104	197,757	263,675	283,606	398,579	392,449
Cost on new load				21,641,841.1	51,738,750.0	5,377,150.8	15,010,520.1	10,022,386.8	13,697,184.2	15,100,912.8	21,753,321.4	21,954,204.4
					0	0	0	0	0	0	0	0
Fuel	Share	Coal Esc.	201,913,299	205,081,455	203,753,113	204,760,311	204,799,620	204,782,717	203,765,427	203,442,978	205,517,738	207,921,573
Coal	**85%**	**0.5%**	171,900,831	172,760,335	173,624,137	174,492,258	175,364,719	176,241,543	177,122,750	178,008,364	178,898,406	179,792,898
NG	**15%**		30,012,468	32,321,119	30,128,976	30,268,053	29,434,901	28,541,175	26,642,677	25,434,614	26,619,332	28,128,675
Off-system Sales			1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450
Sale for Resale credit			452,031,612	609,846,366	609,846,366	594,193,643	516,999,162	515,120,085	527,998,087	541,198,039	554,727,990	568,596,190

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load Growth %	0.00%	101.60%	103.76%	100.39%	101.24%	100.82%	101.08%	101.15%	101.60%	101.55%
MW Load Forecast	0.00	2,492	2,586	2,596	2,628	2,649	2,678	2,709	2,752	2,795
TRL	22,561,484	22,922,182	23,784,494	23,876,474	24,171,578	24,369,335	24,633,010	24,916,616	25,315,196	25,707,644
Residential load	10,058,325	10,219,130	10,603,565	10,644,572	10,776,134	10,864,298	10,981,849	11,108,286	11,285,980	11,460,941
Exchangeable Costs	905,699,068	920,178,756	991,183,515	1,039,890,496	1,161,557,234	1,204,187,586	1,238,792,858	1,279,110,149	1,327,989,144	1,377,831,822
ASC $ /MWh	40.14	40.14	41.67	43.55	48.05	49.41	50.29	51.34	52.46	53.60

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

<u>Portland General</u>

			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh				47.32	48.21	49.64	52.47	53.56	54.34	55.35	56.66	58.00
Assumed Gas Price			6.50	7.00	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price			50	60.0	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption			80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
O&M / total multiplier				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Annual Cost Escalation Rate				2.00%	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage		41%		40.9%	40.9%	40.9%	40.9%	40.9%	40.9%	40.9%	40.9%	40.9%
TRL Differential				2,686,249	611,667	-76,651	434,606	417,743	401,647	497,458	469,864	521,987
Cost on new load			0	161,174,961	36,700,020	-4,481,047	22,106,290	21,171,359	20,864,473	26,487,638	25,643,827	29,200,751
Fuel	Share	Coal Escl.	137,101,439	144,425,279	137,908,894	138,562,864	136,228,060	133,708,105	128,099,309	124,614,965	128,490,318	133,365,157
Coal	33%	0.5%	44,803,760	45,027,779	45,252,918	45,479,182	45,706,578	45,935,111	46,164,787	46,395,611	46,627,589	46,860,727
NG	67%		92,297,679	99,397,500	92,655,976	93,083,682	90,521,482	87,772,994	81,934,522	78,219,354	81,862,729	86,504,430
Off-system Sales			738.30	738	738	738	738	738	738	738	738	738
Sale for Resale credit			323,373,254	310,438,323	310,438,323	302,470,406	263,175,058	262,218,526	268,773,990	275,493,339	282,380,673	289,440,190

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load Growth %			114.40%	102.87%	99.65%	101.99%	101.87%	101.77%	102.15%	101.99%	102.17%
LARIS Ave MW Load Forecast		2,028	2,320	2,386	2,378	2,425	2,471	2,514	2,569	2,620	2,676
TRL		18,652,345	21,338,594	21,950,261	21,873,610	22,308,215	22,725,959	23,127,605	23,625,063	24,094,927	24,616,913
Residential load	40.9%	7,633,624	8,732,993	8,983,323	8,951,953	9,129,819	9,300,783	9,465,161	9,668,749	9,861,045	10,074,672
Exchangeble Costs		882,556,218	1,009,659,061	1,058,116,835	1,085,747,098	1,170,537,894	1,217,214,204	1,256,838,811	1,307,759,404	1,365,196,568	1,427,855,620
ASC $ /Mwh		47.32	47.32	48.21	49.64	52.47	53.56	54.34	55.35	56.66	58.00

Table 4.9.2 continued
ASC Forecast Model

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates			**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast			**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast			**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

PUGET SOUND ENERGY

			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh				48.41	49.18	50.39	52.18	53.25	54.27	55.45	56.76	58.04
Assumed Gas Price			**6.50**	**7.00**	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price				**60.0**	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption				80%	80%	80%	80%	80%	80%	80%	80%	80%
O&M / total multiplier				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Annual Cost Escalation Rate				**2.00%**	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage				50.3%	50.3%	50.3%	50.3%	50.3%	50.3%	50.3%	50.3%	50.3%
TRL Differential				1,002,980	179,361	170,163	52,123	183,960	239,148	295,102	3,833	581,008
Cost on new load				60,178,815	10,761,660	9,947,729	2,651,233	9,323,150	12,423,098	15,712,989	209,208	32,502,493
Fuel	Share	Coal Escl.	80,772,003	83,725,465	81,363,978	81,757,135	81,003,095	80,178,658	78,168,598	76,975,202	78,609,189	80,627,780
Coal	56%	0.5%	45,322,991	45,549,606	45,777,354	46,006,241	46,236,272	46,467,453	46,699,791	46,933,290	47,167,956	47,403,796
NG	44%		35,449,012	38,175,859	35,586,624	35,750,894	34,766,823	33,711,204	31,468,807	30,041,913	31,441,233	33,223,984
Off-system Sales				311	311	311	311	311	311	311	311	311
Sale for Resale credit			92,284,877.6	130,645,488	130,645,488	127,292,254	110,755,121	110,352,572	113,111,386	115,939,171	118,837,650	121,808,591
			2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Load Growth %				104.81%	100.82%	100.77%	100.23%	100.83%	101.06%	101.30%	100.02%	102.53%
LARIS Ave MW Load Forecast			2,269	2,378	2,398	2,416	2,422	2,442	2,468	2,500	2,500	2,563
					2,397.58	2,416.08	2,421.75	2,441.75	2,467.75	2,499.83	2,500.25	2,563.42
TRL			20,870,630	21,873,610	22,052,971	22,223,134	22,275,257	22,459,217	22,698,365	22,993,466	22,997,300	23,578,307
Residential load		50.3%	10,508,203	11,013,195	11,103,502	11,189,178	11,215,422	11,308,044	11,428,453	11,577,035	11,578,965	11,871,498
Exchangeble Costs			1,010,361,351	1,058,916,307	1,084,505,121	1,119,839,898	1,162,263,303	1,196,032,613	1,231,864,736	1,274,953,715	1,305,250,506	1,368,370,190
ASC $ /Mwh			48.41	48.41	49.18	50.39	52.18	53.25	54.27	55.45	56.76	58.04

Table 4.9.2 continued
ASC Forecast Model

			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates					**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast					**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast					**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**
<u>Northwestern Energy PNW</u>												
ASC $ /Mwh				58.08	59.25	60.76	63.26	64.59	65.87	67.31	68.71	70.12
Exchange Benefits												
Assumed Gas Price			**7**	**7.00**	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Assumed Market Price			**50**	**60.0**	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**
2006 Sale for Resale assumption				**80%**	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**
O&M / total multiplier				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Annual Cost Escalation Rate				2.00%	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage				37.6%	37.6%	37.6%	37.6%	37.6%	37.6%	37.6%	37.6%	37.6%
TRL Differential				792,142	1,441,415	37,796	79,862	80,678	80,900	83,506	83,468	85,933
				47,528,530	86,484,891	2,209,574	4,062,175	4,088,780	4,202,548	4,446,372	4,555,448	4,807,205
Cost on new load												
Fuel	Share	Coal Escl.	32,641,612	32,832,820	32,966,453	33,131,135	33,284,020	33,436,938	33,577,645	33,728,135	33,910,494	34,097,898
Coal	99%	**0.50%**	32252303	32,413,565	32,575,632	32,738,510	32,902,203	33,066,714	33,232,048	33,398,208	33,565,199	33,733,025
NG	1%		389309	419,256	390,820	392,624	381,817	370,224	345,597	329,927	345,295	364,873
Off-system Sales			209	209	209	209	209	209	209	209	209	209
Sale for Resale credit			91,686,499	88,019,039	88,019,039	85,759,884	74,618,415	74,347,209	76,205,889	78,111,036	80,063,812	82,065,407

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load Growth %			102.88%	102.88%	102.88%	102.88%	102.88%	102.88%	102.88%	102.88%	102.88%
LARIS Ave MW Load Forecast		783.3735959	832	989	993	1,002	1,010	1,019	1,028	1,037	1,047
TRL		6,862,353	7,654,495	9,095,910	9,133,706	9,213,568	9,294,246	9,375,146	9,458,652	9,542,120	9,628,053
Residential load	0.38	2,580,941	2,878,867	3,420,985	3,435,200	3,465,236	3,495,579	3,526,006	3,557,413	3,588,805	3,621,125
PF Exchange Rate		44.26	44.26	44.26	44.26	44.26	44.26	44.26	44.26	44.26	44.26
BASE			832	989	993	1,002	1,010	1,019	1,028	1,037	1,047
Exchangeble Costs		398,577,445	444,586,447	538,973,221	554,944,840	582,808,185	600,342,069	617,562,452	636,616,651	655,651,368	675,111,121
ASC $ /Mwh		58.08	58.08	59.25	60.76	63.26	64.59	65.87	67.31	68.71	70.12

Table 4.9.2 continued
ASC Forecast Model

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates				**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast				**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast				**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

Clark County Pud

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /MWh				50.57	48.92	50.31	46.02	45.60	45.67	46.97	48.64
Gas Price				**8.10**	**8.10**	**8.10**	6.18	5.77	5.51	5.77	6.09
Assumed Market Price				60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
Sale for Resale % o **80%**				80%	80%	80%	80%	80%	80%	80%	80%
Annual Cost Escalation Rate				1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential Load % of Total	49.8%	49.8%	49.8%	49.8%	49.8%	49.8%	49.8%	49.8%	49.8%	49.8%	49.8%
TRL Growth				177,368	-25,557	174,197	157,917	145,327	150,137	134,371	180,146
PF Flat Block rate				**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**
BPA Step up purchases aMW				**23**	**68**						
BPA additional cost				5,420,250	16,260,750	0	0	0	0	0	0
Fuel cost			83,849,075	104,488,848	104,488,848	104,488,848	79,738,564	74,434,525	71,059,431	74,369,304	78,586,120
Off-system Sales			**20**	22	93	73	55	38	21	6	(15)
Sale for Resale credit			0	9,356,735	37,965,732	25,944,966	19,448,034	13,894,749	7,846,751	2,176,056	-7,289,571

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
		103.53%	103.35%	103.73%	99.48%	103.55%	103.11%	102.77%	102.79%	102.43%	103.18%
MWa Load Forecast	**508**	**500**	**517**	**536**	**534**	**553**	**570**	**586**	**602**	**617**	**636**
TRL	4,445,950	4,602,832	4,756,820	4,934,188	4,908,631	5,082,829	5,240,746	5,386,073	5,536,210	5,670,581	5,850,727
Residential load	2,214,450	2,292,590	2,369,289	2,457,633	2,444,904	2,531,668	2,610,324	2,682,709	2,757,490	2,824,417	2,914,145
Exchangeble Costs	215,487,203	223,091,017	230,554,520	249,538,134	240,137,044	255,731,628	241,174,800	245,580,719	252,839,766	266,345,125	284,583,036
ASC $ /Mwh	48.47	48.47	48.47	50.57	48.92	50.31	46.02	45.60	45.67	46.97	48.64

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

Utility #1

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh		46.68	48.51	48.80	44.17	44.57	43.01	40.79	38.22	36.53	34.80
Assumed Gas Price	**6.00**	**6.50**	**7.00**	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price		60	60	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption		1	0.8	80%	80%	80%	80%	80%	80%	80%	80%
Annual Cost Escalation Rate		0	2.20%	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage		36.4%	36.4%	36.4%	36.4%	36.4%	36.4%	36.4%	36.4%	36.4%	36.4%
TRL Differential		423,351	-126,265	-90,296	-136,805	-134,738	-132,622	-130,423	-128,177	-126,149	-123,810
PF Flat Block rate		**26.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**
BPA Step up purchases		**0**	**-1**	**5**	**40**	**10**	**0**	**0**	**6**	**-6**	**-6**
BPA additional cost		0	-240,900	1,204,500	9,636,000	2,409,000	0	0	1,445,400	-1,445,400	-1,445,400
Fuel cost	2678635	2901854.58	3,125,074	2,913,120	2,926,567	2,846,011	2,759,598	2,576,035	2,459,230	2,573,778	2,719,714
Off-system Sales	60.39	12	25	41	96	122	137	152	172	181	189
Sale for Resale credit	26,452,783	6,342,254	10,714,066	17,150,691	39,496,105	43,412,387	48,631,641	55,267,519	64,348,009	69,169,744	74,087,660
	50										

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load Growth %		125.51%	93.94%	95.39%	97.51%	100.11%	100.12%	100.12%	100.12%	100.11%	100.13%
LARIS aMW Load Forecast		**226**	**213**	**203**	**198**	**198**	**198**	**199**	**199**	**199**	**199**
TRL	1,659,789	2,083,140	1,956,875	1,866,578	1,820,069	1,822,137	1,824,253	1,826,452	1,828,698	1,830,725	1,833,064
Residential load	604,618	758,834	712,839	679,946	663,004	663,757	664,528	665,329	666,147	666,886	667,738
Exchangeble Costs	75,317,525	97,249,330	94,935,481	91,084,998	80,399,330	81,219,280	78,454,327	74,491,874	69,892,152	66,884,059	63,798,577
ASC $ /Mwh	45.38	46.68	48.51	48.80	44.17	44.57	43.01	40.79	38.22	36.53	34.80

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

Utility #2

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh			44.08	45.13	46.37	50.50	51.80	52.69	53.78	54.95	56.13
Assumed Gas Price		**6.00**	**7.00**	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price			**60.0**	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption			80%	80%	80%	80%	80%	80%	80%	80%	80%
Annual Cost Escalation Rate			2.20%	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%	30.8%
TRL Differential			-24,030	38,068	-1,483	10,724	10,746	10,787	10,479	10,234	10,429
PF Flat Block rate			**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**
BPA Purchases			**18**	**0**	**3**	**0**	**0**	**0**	**0**	**0**	**0**
BPA additional cost			4,336,200	0	722,700	0	0	0	0	0	0
Fuel Costs		1,317,111	1,536,630	1,432,409	1,439,021	1,399,411	1,356,921	1,266,662	1,209,227	1,265,552	1,337,310
Off-system Sales sensitivity		**30**	51	46	50	48	47	46	45	44	42
Sale for Resale credit	9558494	9558494	21,336,467	19,509,193	20,306,881	17,232,341	16,734,009	16,704,055	16,675,280	16,645,309	16,594,719

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Ave MW Load Forecast		97.41	94.80	98.94	98.78	99.94	101.11	102.28	103.42	104.54	105.67
TRL	788,063	896,000	871,970	910,039	908,556	919,279	930,026	940,813	951,292	961,527	971,956
Residential load	242,882	276,148	268,742	280,475	280,018	283,323	286,635	289,960	293,190	296,344	299,558
Exchangeble Costs	39,140,668	44,501,587	38,439,677	41,067,980	42,128,504	46,419,036	48,173,590	49,573,662	51,156,269	52,832,274	54,555,110
ASC $ /Mwh	49.67	49.67	44.08	45.13	46.37	50.50	51.80	52.69	53.78	54.95	56.13

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

Utility #3

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh					57.00	59.34	64.34	65.59	65.98	66.78	68.37	70.06
Assumed Gas Price					6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price				60.0	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption				80%	80%	80%	80%	80%	80%	80%	80%	80%
Annual Cost Escalation Rate					1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage		44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%
TRL Differential					-86,584	-5,853	9,313	9,337	9,378	9,397	9,322	9,415
PF Flat Block rate					27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5
BPA Purchases					12	0	0	0	0	0	0	0
BPA additional cost					2,861,100	0	0	0	0	0	0	0
Fuel Costs				13,588,190	13,640,939	13,703,907	13,326,696	12,922,060	12,062,512	11,515,560	12,051,943	12,735,300
Off-system Sales	sensitivity			70	92	93	91	90	89	88	87	86
Sale for Resale credit		24,945,852	24,945,852	29,433,600	38,635,390	37,917,489	32,612,481	32,115,377	32,528,512	32,941,453	33,357,966	33,770,577

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Ave MW Load Forecast		165	149	140	139	140	141	142	143	144	145
TRL	1,031,807	1,518,322	1,369,736	1,283,152	1,277,298	1,286,612	1,295,949	1,305,327	1,314,724	1,324,046	1,333,461
Residential load	457,090.35	672,616	606,793	568,436	565,843	569,969	574,105	578,260	582,423	586,552	590,723
Exchangeble Costs	58,731,297	86,424,129	77,966,492	73,136,723	75,790,627	82,776,997	84,998,717	86,120,340	87,802,134	90,528,351	93,423,115
ASC $ /Mwh	56.92	56.92	56.92	57.00	59.34	64.34	65.59	65.98	66.78	68.37	70.06

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

Utility #4

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh				42.66	45.23	46.00	47.02	47.72	48.37	49.02	49.68
Assumed Gas Price				6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price				60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption				80%	80%	80%	80%	80%	80%	80%	80%
Annual Cost Escalation Rate				1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%	44.0%
Sale for Resale assumption 2003				80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
TRL Differential				112,195	3,587	3,108	3,106	3,137	3,147	3,105	3,157
PF Flat Block rate				**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**	**27.5**
BPA Flat Block Mw				**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Market purchase for TRL diff.				3,478,046	111,195	96,335	96,291	97,235	97,562	96,254	97,873
Off-system Sales sensitivity				5	5	5	5	5	5	5	5
Sale for Resale credit				1,934,208	1,884,563	1,639,731	1,633,771	1,674,615	1,716,481	1,759,393	1,803,378

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Ave MW Load Forecast	69.93	80.42	77.79	78.73	79.12	79.45	79.79	80.13	80.47	80.81	81.16
TRL	611,922	739,688	715,474	724,117	727,704	730,812	733,918	737,054	740,202	743,307	746,464
Residential load	269,179	325,382	314,731	318,533	320,110	321,477	322,844	324,224	325,608	326,974	328,363
Exchangeble Costs	26,014,294	31,445,923	30,416,539	30,889,320	32,913,288	33,615,782	34,508,751	35,172,878	35,801,376	36,439,582	37,086,006
ASC $ /Mwh	42.51	42.51	42.51	42.66	45.23	46.00	47.02	47.72	48.37	49.02	49.68

Table 4.9.2 continued
ASC Forecast Model

	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Rates	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**	**1.02**
Gas forecast	**6.53**	**6.56**	**6.37**	**6.18**	**5.77**	**5.51**	**5.77**	**6.09**
Market forecast	**60.00**	**58.46**	**50.87**	**50.68**	**51.95**	**53.25**	**54.58**	**55.94**

Utility #5

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASC $ /Mwh			49.27	48.90	48.65	49.91	50.88	51.94	53.11	54.30	55.58
Assumed Gas Price			7.00	6.53	6.56	6.37	6.18	5.77	5.51	5.77	6.09
Assumed Market Price			60.0	60.0	58.5	50.9	50.7	51.9	53.2	54.6	55.9
2006 Sale for Resale assumption			80%	80%	80%	80%	80%	80%	80%	80%	80%
Annual Cost Escalation Rate			2.20%	1.55%	1.91%	2.06%	2.09%	2.30%	2.48%	2.39%	2.35%
Residential percentage	50.9%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%	48.5%
Sale for Resale assumption 2003			80%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
TRL Differential			995,346	-504,301	66,561	75,651	76,744	78,218	79,469	80,092	81,887
PF Flat Block rate			27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5
PF Flat Block rate				0	0	0	0	0			
BPA Purchases			0	0	0	0	0	0	0	0	0
Off-system Sales sensitivity		180	41	74	41	32	24	15	6	(3)	(13)
Sale for Resale credit	60,979,200	60,979,200	17,307,110	31,001,542	16,850,725	11,583,186	8,429,553	5,389,727	2,139,338	-1,630,184	-6,251,835
Purchase contracts aMW			25	25	25						
Purchase contracts $/MWh	6064884		90	90	90						
	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
				101.42%	101.30%	98.32%	100.98%	100.90%	100.58%	104.96%	102.99%
LARIS aMW Load Forecast	737.4	737.36	810.5	755.6	762.9	771.1	779.4	787.9	796.6	805.3	814.2
		100%	115%	93%	101%	101%	101%	101%	101%	101%	101%
TRL	6,459,297	6,459,297	7,454,642	6,950,341	7,016,902	7,092,553	7,169,297	7,247,515	7,326,984	7,407,076	7,488,963
Residential load	3,129,705	3,286,190	3,611,977	3,367,630	3,399,880	3,436,535	3,473,720	3,511,618	3,550,123	3,588,930	3,628,607
Exchangeble Costs	335,917,814	335,917,814	367,270,096	339,843,365	341,362,522	354,003,829	364,784,408	376,400,591	389,113,456	402,218,866	416,239,697
ASC $ /Mwh	52.01	52.01	49.27	48.90	48.65	49.91	50.88	51.94	53.11	54.30	55.58

APPENDIX A
Letter From Mike Weedall

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Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

ENERGY EFFICIENCY

June 28, 2005

In reply refer to: PN-1

Dear Interested Party:

You will find attached the Bonneville Power Administration's (BPA) Final Post-2006 Conservation Program Structure.

BPA initiated a collaborative conservation planning process last September to solicit recommendations for our post-2006 conservation program structure (i.e., the FYs 2007-09 rate period). Based on the recommendations from the Conservation Workgroup, BPA issued its proposal for a 30-day public review and comment period on March 28, 2005. BPA received over 50 comment letters on the proposal, and we appreciate the many very thoughtful and constructive suggestions for improving the proposed program.

We have reviewed and considered these comments in preparing the attached Final Post-2006 Conservation Program Structure. The first document is a summary of the key issues raised in the comment letters and BPA's final decision on those key issues. The second document is a more detailed description of the final program structure.

This is a major step in designing our future conservation programs. However, the work is not finished. There is a Conservation Workgroup Phase 2 Committee with nine very experienced utility representatives acting as a sounding board for BPA in establishing the incentive levels BPA will pay for cost-effective measures under this final program structure. This is a simplified approach for structuring the list of cost-effective measures that will be easier to implement, and will include the appropriate level of oversight, utility verification and measurement of savings. BPA's desire is to be clear about how customers can receive their reimbursements under BPA's new programs. It is not our intent to dictate to customers how they should design and run their conservation programs. Again, BPA appreciates the dedication and hard work of the Phase 2 Committee.

BPA representatives will be happy to meet with power sales customers, utility groups or stakeholder organizations to discuss the decisions related to our Final Post-2006 Conservation Program.
Please contact Becky Clark at 503-230-3158 to make the necessary arrangements.

Sincerely,

Mike Weedall
Energy Efficiency Vice President

Enclosures 2:
Summary of Key Issues Raised in Public Comment Process
Final Post-2006 Conservation Program Structure

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APPENDIX B
Post-2006 Key Issues

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Energy Efficiency
Bonneville Power Administration

Final Post-2006 Conservation Program Structure

Summary of Key Issues Raised in Public Comment Process

At the suggestion of Bonneville Power Administration (BPA), a Post-2006 Conservation Workgroup composed of over 65 utility representatives and conservation stakeholders was formed in the fall of 2004. This group met frequently to discuss new and existing approaches to BPA's conservation program for the post-2006 period. In January 2005, this group provided BPA recommendations and comments to help design the proposal that BPA distributed for public comment.

BPA issued its Post-2006 Conservation Program Structure Proposal for a 30-day public review and comment period on March 28, 2005. The close of comment period ended April 28, 2005. BPA received 56 comment letters and e-mails. Comments received are important to BPA and help provide guidance to improve upon BPA's and the region's efforts to develop conservation and energy efficiency.

After the brief program overview presented below, this document provides a statement of what was proposed for each key issue raised during the public comment period, a summary of the comments received on that topic, and BPA's response and evaluation for each issue. Again BPA appreciates the efforts of those parties taking the time to review the proposal. BPA has taken care to provide clarification of its program elements in response to any and all concerns raised in comments BPA received.

Program Overview

The portfolio of energy efficiency programs BPA will be offering for the post-2006 period is very similar to what is currently available. The key features of the final program are as follows:

1. a **conservation rate credit (CRC)** program (patterned after the current C&RD);
2. a **bilateral contracts program** for utility and federal agency customers (similar to the current ConAug program);
3. a **third-party contracts program** for cost-efficient, region-wide approaches (similar to the VendingMi$er program and includes support market transformation via the Northwest Energy Efficiency Alliance ((NEEA)));
4. support for critical **infrastructure** elements, including program evaluations to assure programs are achieving their intended targets;
5. a separately funded renewable resource option; and
6. a spending amount of **$80 million/year** intended to achieve BPA's 52 aMW/year share of the Northwest Power and Conservation Council's (Council) regional cost-effective conservation target at a weighted average cost of **$1.5 million/aMW**.

Key Issues: What was Proposed, Comment Summary, Evaluation and Final Decision

aMW Target Gap Proposal: Based upon the Northwest Power and Conservation Council's (Council) Fifth Power Plan, there is a regional conservation target over the 2007-11 period of about 700 aMW. BPA's responsibility to achieve its share of this regional target is based on the amount of regional firm load that BPA supplies with federal power. BPA estimates that it is responsible for about 40 percent of the 700 aMW or 280 aMW. While this amount equates to an annual target of 56 aMW, BPA proposed that it is reasonable to adjust the amount of its target to take into account the amount of "naturally occurring" conservation (about 7 percent or 4 aMW/year). As a result, BPA proposed to pursue a 52 aMW/year conservation target for the total of 260 aMW over the 2007-11 period.

BPA's existing and proposed conservation program structure is not focused on a centralized conservation acquisition program. To the contrary, most BPA programs are structured to provide funding support to BPA's customers and others to pursue and achieve regional conservation. Consequently, BPA proposed to include any and all of the conservation that is achieved and attributed to BPA's funding mechanisms toward the 52 aMW annual target, including the conservation achieved by investor owned utilities (IOUs) under the rate credit program and the conservation accomplished by BPA funding support for NEEA.

Summary of Comments Received: Some comments suggested that BPA should not reduce its share of the regional conservation target for "naturally occurring" conservation *(NEEC; NWEC; SCL)*; others agreed with this reduction *(Benton REA; PPC)*. Some comments stated that the target was too low and that BPA should consider the IOU exchange load as part of the calculation for determining BPA's share of the regional conservation target *(Council; NEEC; NWEC; PSE; WCTED)*. Others agreed that BPA should count the IOU conservation accomplished with BPA funds, even though BPA is not responsible for the IOU conservation *(Benton REA; PPC)*. Another comment suggested that BPA should be responsible for only 38 percent of the regional conservation (rather than rounding to 40 percent) *(Inland)*. Another concern that was raised related to the "gap" between the Council's five-year Action Plan (2005-09) and BPA's planned conservation horizon from 2007-11 *(Council; NWEC)*. They felt that there was a "gap" in 2005 and 2006 between BPA's current targets and the new ones and that it would be very difficult for BPA to "close the gap" with the proposed funding levels for 2007-09. One commenter indicated that the aMW target was too high and that more residential measures were needed *(Benton PUD)*.

Evaluation and Final Decision: With conservation being the least-cost resource for the region, BPA is aware that achieving the targets set by the Council are important to the region as a whole. Determining a reasonable percentage of the region's conservation target requires BPA to consider several factors, such as load and conservation that is naturally occurring. A factor that BPA believes is reasonable to reconsider, as expressed in comments above, is the duration of the planning horizon. As proposed, BPA is committed to achieving the 52 aMW/year conservation target. BPA will work toward this amount for the 2005-09 period, rather than the proposed 2007-11 period. This change reflects an adjustment and commitment by BPA to align the new conservation targets with the same five-year planning horizon in the Council's Fifth Power Plan. BPA expects to meet its 2002-06 target (220 aMW averaging 44 aMW/year) by the end of FY

2006. BPA will seek to acquire an additional 16 aMW on top of the 220 aMW target by the end of 2006 in order to be on track to meet the new target of 52 aMW/year (see table below).

	Average Annual Target
New target for 2005 and 2006	52 aMW/year
Old target for 2005 and 2006	44 aMW/year
Additional aMW BPA will acquire to close gap between the old and new targets for 2005 and 2006	8 aMW/year X 2 years = **16 aMW**

As indicated in the March 28 proposal, BPA will count all conservation savings achieved with its funds toward the new target.

Budget Proposal: BPA's proposed annual budget (capital and expense) for achieving the target of 52 aMW/year was $75 million. For the 2007-2009 rate period, the conservation rate credit (CRC) would be $0.0005/kWh (1/2 mill) on utility-purchased firm power from BPA and the equivalent treatment for IOU residential benefit payments. This equates to roughly $42 million. It is anticipated that $6 million per year out of the $42 million will be spent on renewable resource-related initiatives. BPA proposed paying an average of approximately $1.4M/aMW (which includes some administration allowance and infrastructure support costs) across the entire portfolio of programs.

Summary of Comments Received: Many commenters suggested that the budget was too low *(Council; EPUD; EWEB; Faste; Franklin PUD; Interfaith GWC; ODOE; NEEC; NWEC; SCL; WCTED)* with some proposing a budget increase of $25 to $35 M/year to achieve the higher targets *(Council; EPUD; NEEC; NWEC).* They indicated that it will cost closer to $1.8 to $1.9 M/aMW and not the $1.4 M/aMW that BPA proposed. Several comments recommended that BPA establish a "backstop" funding mechanism or contingency plan in case the proposed budget was insufficient to capture the new targets *(Benton PUD; Council; EWEB; NWEC; WCTED).* Some comments recommended that more funds are needed for infrastructure support and to address inflation *(SCL; NWEC).* One comment suggested that the budget was sufficient as proposed *(SUB).*

Evaluation and Final Decision: The fundamental question for BPA is what is the minimum spending level that will produce the targeted conservation savings level. Based on the comments received and further assessment, the spending level should be increased by $5M/year. This will provide $80M/year to capture the 52 aMW/year target. A majority of the comments received on this issue expressed support for this amount of funding. This increased amount of funding will provide customers and the region greater program flexibility at an average cost of $1.54M/aMW across the entire portfolio of programs, including the administrative cost allowances and infrastructure support (see Table 1). BPA believes these additional funds will facilitate achieving the Council's new targets by providing utilities a reasonable level of administrative allowance for the rate credit and the bilateral contract programs and more funds for incentives across the program portfolio BPA will be offering.

Table 1: Final Conservation Program Annual aMW Targets and Budgets

Program	aMW	Budget	Cost/aMW
Rate Credit (at 0.5 mills = $42M*/year)+	20	$36M	$1.8M
Utility & Fed. Agency Bilateral Contracts+	17	$26M	$1.5M
Third-Party Contracts	5	$7M	$1.4M
Market Transformation (via NEEA)	10	$10M	$1.0M
Infrastructure Support and Evaluation	---	$1M	---
Total	52	$80M	$1.5M

+ - includes a 15 percent administrative cost allowance.
* - assumes $6M/year of the $42M/year from a separate renewables budget will be spent on renewables.

Administrative Allowance Proposal: BPA proposed to include up to 10 percent administrative costs in the rate credit and bilateral contracts programs. Small utilities (7.5 aMW and under) would be allowed up 20 percent for administrative costs, provided they pursue cost-effective measures (or renewables) with the remaining 80 percent.

Summary of Comments Received: Many of the comments stated that allowing 10 percent for administrative costs under the rate credit was too low *(Benton PUD; Cowlitz; EPUD; Franklin; Grays Harbor; Hermiston; Idaho Falls; Lincoln Electric; Okanogan; PPC; PNGC; Richland; SCL; SUB; Umatilla; Whatcom).* It was suggested that 20 percent was more realistic given the new oversight and reporting requirements under the proposed rate credit program *(Canby; Cowlitz; EPUD; Idaho Falls; Okanogan; Pacific; PPC; PNGC; SCL; SUB).* One commenter thought 10 percent was too low and 20 percent was too high *(Inland).* A few commenters appreciated BPA including the up to 10 percent administrative costs under the bilateral contracts program *(Cowlitz; Lincoln Electric; PPC).*

Evaluation and Final Decision: BPA understands the concerns expressed in many comments regarding the administrative costs associated with implementing the new programs. BPA recognizes that many customers view a successful conservation program to include allowance for administration. BPA agrees with comments recommending an increase in the amount allowed under the program for administrative costs. BPA believes it is reasonable to increase the administrative allowance by 5 percent to allow up to 15 percent administrative costs in the rate credit and utility/federal agency bilateral contract programs. For the bilateral contracts, the 15 percent administrative allowance will be added to BPA's incentive amount that is invoiced. Small utilities will be allowed up to 30 percent for administrative costs. BPA also wants to continue to discuss with the region whether or not going forward into the next rate period with the 15 percent administrative expense is the right level or if a further adjustment is appropriate.

Willingness To Pay (BPA incentives) Proposal: BPA proposed a $75M/year budget to achieve 52 aMW/year. This equates to an average cost of $1.44M/aMW across the portfolio of energy efficiency programs, including the 10 percent administrative allowance and $1M/year for infrastructure support.

BPA would attempt to minimize willingness to pay adjustments. BPA may adjust payments with six months notice, if necessary, to compensate for such things as changes in codes, market prices, technology penetration or to stay on pace with targets. Adjustments would apply to measures installed after the date the adjustment notice is effective. No retroactive adjustments would be applied.

Summary of Comments Received: Some commenters suggested that BPA should allow payment up to the cost-effective level or threshold *(EPUD; Idaho Falls; Lincoln Electric; Okanogan; PPC; Richland).* Other comments recommended that BPA should not change our energy conservation measure (ECM) incentives more than once a year and only if there is a +/-10 percent change *(Hermiston; PNGC).* One comment stated that the levels BPA proposed are too low *(Pacific).* A few comments suggested that BPA should allow funding for code enforcement and count those aMW saving toward the target *(PPC; SCL; SUB)*, allowing utilities to bring in conservation at an average rate and providing an incentive to get the most savings at the least cost *(SUB).* One comment suggested that BPA pay based on value to the system (the same as C&RD does now) *(PNGC).* Another comment suggested that there was not a rationale for paying less per aMW in the bilateral contract program than in the rate credit program *(EWEB).*

Evaluation and Final Decision: As discussed earlier, BPA will increase its budget by $5M/year which results in a new weighted average cost of $1.54M/aMW across the entire program portfolio. The proposed cost was $1.44M/aMW. The increase to the new 15 percent administrative allowance and the $1M/year infrastructure support budget are covered in this revised cost target. BPA will continue to refine the details on BPA's incentives for cost-effective measures. BPA is receiving input from a Conservation Workgroup Phase 2 Committee composed of nine experienced utility representatives.

Since this is only a three-year rate period, BPA plans to make incentive payment adjustments on a six-month basis, but only if absolutely necessary. BPA is sensitive to comments that continual program changes can compromise program effectiveness. Hence, BPA will strive to implement changes as we do today on an annual basis.

Cost-Effective Measures Proposal: BPA proposed to pay only for cost-effective measures as defined by the Council in its Fifth Power Plan.

Summary of Comments Received: Many comments suggested that BPA should not use the Council's total resource cost (TRC) approach, but rather the utility-specific utility test cost (UTC) parameter and that non-energy benefits need to be included in the analysis *(Benton PUD; Benton REA; EWEB; Franklin; Grays Harbor; Lincoln Electric; Port Angeles)*. Some commenters felt that the cost-effectiveness criteria BPA is relying on was arbitrary and that they did not agree with the TRC approach *(Benton REA; EWEB; Franklin; Hermiston; Umatilla).* Some comments noted that the TRC ignores values to consumers or utilities that are very real economic values *(Cowlitz; EWEB; Grays Harbor).* Several did not support limiting the list of approved ECMs to only cost-effective measures *(Benton PUD; Cowlitz; EPUD; Franklin; Grays Harbor; Hermiston; Idaho Falls; Lincoln Electric; Okanogan; Pacific; Richland; SnoPUD; Umatilla; Wells REC).* Other comments recommended that more residential measures be included in the approved ECM list *(Benton PUD; Port Angeles)*. Some comments suggested that BPA consider packaging like measures *(SCL; WCTED)*. One comment supported BPA's position and stated that there are other cost-effective measures not included in the Council's plan *(Council).*

Evaluation and Final Decision: In general, conservation is considered the least-cost resource to meet increases in load demand in the Pacific Northwest. The Northwest Power Act provides that BPA support the development of cost-effective conservation. The Act includes a definition of the term "cost-effective" which applies to any conservation measure or resource BPA funds. BPA is not persuaded by comments that suggest use of an alternative standard or definition of cost-effective measures. If the region is to pursue non-cost-effective measures, then the region cannot achieve the least-cost approach mapped by the Council. BPA payment for measures that are not cost-effective has the potential to drive up BPA's overall budget and rates since non-cost-effective measures would not count against the annual 52 aMW target, since that target is for cost-effective conservation. Paying only for cost-effective conservation measure also ensures resources are being acquired at the lowest cost to the region. Both BPA's Strategic Direction (July 2004) and regional Dialogue Policy (February 2005) reinforced the achievement of "cost-effective" conservation by BPA. Thus, BPA concludes that conservation programs should follow the TRC mandate of the Council.

However, within this cost-effective constraint, BPA will make its programs as accommodating as possible toward customers' conservation strategies and priorities. For example, BPA proposed that "only cost-effective measures on the Regional Technical Forum (RTF) list would be allowed." BPA does not consider the RTF list to be exhaustive and has repeatedly said there may be cost-effective measures that can be implemented that are not on the list. For example, most industrial and almost all non-lighting commercial measures cannot be on a deemed list, yet many are cost-effective in most applications. The following provides additional clarification regarding this issue:

- Measures must be cost effective, but do not need to be on an approved measure list.
- Measures may be added through the rate period.

<u>**Incremental Conservation Proposal**</u>**:** BPA proposed that its conservation funding be used by our customers for energy efficiency savings and related activities beyond what they are required by law and/or regulatory requirements to accomplish.

Summary of Comments Received: A few comments opposed the incremental requirement stating that it was "unreasonable discrimination," that it punishes utilities that have been investing in conservation, especially in the state of Oregon, and that it sends the wrong signal *(CUB; EPUD; EWEB; OPUC; SnoPUD).* They felt that utilities that spend 3 percent of their retail revenues on conservation should be exempt from the incremental requirement. Other commenters agreed that the IOUs should be required to provide incremental savings *(NWEC; PPC).* Several comments suggested that NEEA contributions be allowed under the rate credit *(Council; Cowlitz; EWEB; NEEA; NEEC; PPC; SCL; WCTED),* although one comment agreed with BPA's proposal to not allow NEEA contributions to qualify for the rate credit *(Inland).*

Evaluation and Final Decision: BPA agrees that customers cannot be expected to face an ill-defined threat that their conservation activities my be defined as non-incremental. For this reason, BPA will add a "state" qualifier to the statement such that it will read "required by state law or regulation." This will be used to determine incrementality. A public utility board of directors decision to pursue a particular conservation program, for example, would not, in itself, make that conservation non-incremental.

As background, incremental spending is currently required under the existing C&RD program. BPA appreciates the fact that Oregon enacted legislation that requires the state's IOUs to charge a 3 percent public purpose charge. BPA understands that this program has been successful in facilitating development of conservation and renewable resources associated with service to consumers served by the IOUs. However, BPA does not agree that it is unreasonable discrimination to require incremental spending in this case. It is not in the best interest of the region to offer a conservation credit through power rates to customers to simply subsidize programs or costs otherwise required by state law or regulation.

As explained above, BPA thus believes it is reasonable to retain the requirement that use of the CRC be incremental to spending required by state law and/or regulatory requirements.

Eligibility Proposal: With respect to eligibility to participate in the rate credit program, preference and federal agency customers are eligible to participate in the CRC and can submit proposals under the bilateral contract program, and the IOUs are eligible to participate in the CRC. BPA did not propose to make the direct service industrial customers (DSIs) eligible for the CRC or bilateral contracts programs because of the extreme financial risk associated with installing conservation measures on such unstable loads.

Summary of Comments Received: Two comments strongly suggested that DSIs should not be excluded from participation in the rate credit *(Port Townsend Paper; Alcoa).* One stated that BPA should develop non-discriminatory eligibility requirements for its programs, but if DSIs are ineligible, then they should be offered the discounted rate *(Alcoa).* On the other hand, there were some comments supporting BPA's proposal that the DSIs not be eligible for the rate credit *(SUB).* Another commenter suggested that IOUs should only be able to invest in conservation in residential and farm loads and that any IOU rate credit benefits should be carefully monitored *(Inland).* One comment stated that BPA should clarify rate credit eligibility for customers with pre-subscription contracts *(PPC).*

Evaluation and Final Decision: BPA's proposal to exclude the DSIs from participating in the CRC because as a power customer class the aluminum-related DSIs have only operated at a minimal level during the current rate period and are highly dependent on market conditions (both world alumina prices and electricity). As a result it is not clear what the measure life would be for any installed ECMs in aluminum-related facilities. The aluminum-related DSI load has been severely curtailed over recent years, particularly when power demand is reduced due to economic business conditions that are totally unrelated to energy efficiency at DSI facilities.

Therefore, BPA clarifies that only aluminum-related DSI loads will not be eligible for the CRC and bilateral contract programs.

Decrement Proposal: BPA proposed to continue its current practice of not decrementing the slice/block customers under the rate credit program, but requiring load decrements under the bilateral contracts program. The decrement would not apply to the NEEA contract. Whether or not the decrement applies to other third-party contracts involving slice/block customers would be determined on a case-by-case basis. Customers would be kept informed of any potential conservation activities in their service areas and if a decrement would be applied should they decide to participate in any proposed third-party conservation initiative.

Summary of Comments Received: Several commenters opposed any decrement and stated that the decrement is a barrier to achieving the higher conservation targets *(Benton PUD; Council; EWEB; Grays Harbor; NEEC; NWEC; PNGC; Port Angeles; SnoPUD; Umatilla)*. A couple of comments claimed the approach in BPA's proposal was inconsistent (i.e., not decrementing the rate credit, but decrementing the bilateral contracts) *(NEEC; NWEC)*. One comment suggested that decrementing the slice/block customers was appropriate *(Inland)*. Some comments suggested that BPA consider "sharing the benefits and losses" of the decrement between BPA and the decremented customers *(EWEB; NWEC;SUB)*. Another comment letter agreed with decrementing the bilateral contracts *(Lincoln Electric)*.

Evaluation and Final Decision: The issue of decrement was one of the most challenging for BPA and the Conservation Workgroup. The preponderance of views from the Workgroup were consistent with the approach proposed by BPA, which is basically to continue the decrementing policy being used in the 2002-06 rate period. Based upon input BPA received, BPA believes that the "no decrement" decision is warranted under the rate credit program and under the NEEA contract. In these instances BPA is providing funding through the CRC or via a funding mechanism to a regionally supported conservation organization. BPA is not directly expending dollars to acquire conservation savings from these parties to meet and serve BPA's firm power load obligations. Thus, while BPA will take into account any actual conservation savings achieved through these programs, BPA will not correspondingly reduce or decrement the amount of federal power customers are eligible to buy from BPA. On the other hand, customer participation in bilateral conservation acquisition contracts with BPA could result in reduction in the amount of federal power being purchased to the extent such contracts obligate the customer to deliver actual energy savings. BPA believes, as stated in the original proposal, that decrementing is important to minimize cross-utility subsidies and to ensure that the benefits from conservation flow to BPA and its customers. BPA considers this strategy, along with the change to pay only for cost-effective measures, a positive step toward BPA's goal of achieving conservation at the lowest possible cost.

Donations Proposal: Third-party subcontracts with energy organizations would be allowed provided cost-effective aMW savings result. Utilities could not take administrative payments on pass-through contracts. Administrative costs must be tied to actual program delivery. Because BPA contracts directly with NEEA to conduct market transformation activities on behalf of all the loads paying into the conservation budget, utilities would not be allowed rate credit reimbursement for contributions to NEEA.

Summary of Comments Received: Many commenters suggested that BPA allow rate credit reimbursement for NEEA donations and BPA should count the associated aMW savings toward the target *(Council; Cowlitz; EWEB; NEEA; NEEC; PPC; SCL; WCTED)*. One comment expressed support for not allowing NEEA donations under the rate credit *(Inland)*. Several commenters indicated that we should not limit donations to low income weatherization since BPA is requiring the funds only be spent on cost-effective measures *(EPUD; EWEB; PSE; SUB)*.

Evaluation and Final Decision: In part because of the almost unanimous support for a change to BPA's proposal, BPA has decided to allow the rate credit to be used for contributions to NEEA. BPA will include these funds in determining its share of the NEEA aMW achieved and will count those aMW toward its new target. Third-party subcontracts with energy organizations will be allowed provided cost-effective aMW savings result. For example, if a utility chooses to subcontract with a local low-income (CAP) agency, the utility might specify that its funds go towards CFL installations in low income homes. There will be no cap on these types of activities since they will produce cost-effective conservation savings.

<u>Small Utility Option Proposal</u>: BPA proposed that small utilities (defined under the C&RD as those with a total load of 7.5 aMW or less) would be required to pursue cost-effective conservation measures that are achievable in their service area if they chose to participate in BPA's conservation programs. A variety of options and tools will be available for small utilities. These options and tools would provide several avenues to make it practical for even very small utilities to participate without incurring overly burdensome overhead (e.g., standard offers, off-the-shelf programs and templates, pooling, third-party options, etc.). A small utility could choose to use anywhere between 0 percent to 20 percent of its rate credit for administrative costs. Some small utilities could choose to simplify their spending of their rate credit by purchasing renewables. Small utilities would report savings through the RTF database in the same manner that all other utilities report.

Summary of Comments Received: Some commenters recommended that BPA retain the existing C&RD small utility policy *(Columbia Power; NRU; PPC)*, with one commenter recommending that the threshold should be increased from the current 7.5 aMW to 15 aMW *(Irecoop)*. One commenter requested further clarification of what small utilities could do to qualify for their rate credit *(NRU)*. Some commenters did not want the *pro rata* approach for renewables to apply to small customers *(Fairchild AFB; USDOE-Richland)*.

Evaluation and Final Decision: BPA wants to make participation in the rate credit feasible for small utilities, while ensuring that dollars actually go to cost-effective conservation and renewables. BPA will make several changes in response to comments to help make small utility participation feasible. BPA will include up to 30 percent for administrative costs, ensure that small utilities who wish to spend their rate credit dollars on renewables can do so without being affected by a *pro rata* adjustment if renewables are over subscribed by customers (exceed the $6M/year cap), provide a checklist of simple programs and initiatives suitable for a small utility to implement, and modify the performance reporting requirements to align more with their capabilities. More detail on these changes is included in Attachment 1. These changes, and others BPA will seek through ongoing work with these utilities, should facilitate small utilities' achievement of conservation and renewables with rate credit dollars within their limited staff resources. BPA will keep the 7.5 aMW size limit definition and maintain the proposed requirement that small utilities acquire cost-effective conservation (or renewables) in order to participate in the rate credit program.

<u>Third-Party Involvement Proposal</u>: BPA proposed that this third-party contract component of the program portfolio would allow BPA to contract to third parties when these contracts would lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. In general, regional programs would be designed to operate in coordination with local utility programs. For example, regional bulk purchases of a technology might be delivered locally. These third-party contracts may include activities such as the market transformation efforts of NEEA, bulk purchases and vendor programs.

Pre-committed funding for NEEA ($10 million per year for the next three years) is included in this mechanism, and no decrement is proposed for the NEEA bilateral contract.

Key Features

- Reasonable administration costs for third-party contracts would be negotiated.
- Region-wide programs and efforts would be coordinated with local utilities.
- A determination of whether or not a decrement applies for other third-party programs would be determined on a case-by-case basis.
- Customers would be kept informed of conservation activities in their service territories and whether or not a decrement would be applied.

Summary of Comments Received: Many comments indicated that third-party bilateral contracts were OK, but only with local utility approval for the vendors to work in their service areas *(Benton PUD; Franklin; Hermiston; Lincoln Electric; Okanogan; PPC; PNGC; Richland; Umatilla)*. One commenter endorsed the approach if cost-effective savings result *(Inland)*.

Evaluation and Final Decision: BPA will contract with third parties when these contracts would lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. BPA will only pay third parties to work in utility service territories that have agreed to participate in the third-party program. This policy of requiring pre-approval of utility partners is a continuation of BPA's current policy and is consistent with the recommendations of the majority of the comments BPA received on this issue. The use of the phrase "customers would be kept informed" in the proposal about third-party contractors was not intended to imply any change from the current policy of getting utility agreement for third-party activity before sending any third parties to do BPA funded conservation in the service territories of our customers. BPA believes having access to third-party vendors as part of it overall conservation portfolio would help lower the cost of acquiring conservation, especially when it needs to affect markets that cannot be changed at a local level. Utilities will not face a decrement for conservation done by third parties without their prior agreement to that result.

Rate Credit Performance Requirements Proposal: BPA proposed that utilities would report at least semi-annually to BPA. Use of the RTF reporting software would be required. If, at the first semi-annual report, the utility was not meeting its targets (50 percent or less of its expected rate credit spending), the utility would have to prepare and have BPA approve an action plan that provides sufficient proof of achievable intent by the end of the first year after the program starts. If by the third semi-annual report the utility was not performing (i.e., is 75 percent or less than its expected rate credit spending progress), BPA would have the option of cutting off the rate credit at the beginning of the third year. At the end of the third year of the rate credit program, there would be a true-up required for all participating utilities.

Summary of Comments Received: Several commenters supported the six-month reporting requirement *(Cowlitz; Pacific; PNGC)*. One commenter recommended that the initial check-in occur after one year rather than at six months *(Canby)*. Another commenter recommended reporting on a quarterly basis *(Council)*. A few commenters recommended that BPA re-evaluate the rate credit program if the goals are not being met *(Lincoln Electric; Okanogan; PPC)*. Another commenter suggested that peers rather than BPA should judge performance and be able to suggest remedies for the BPA program design *(SUB)*.

Evaluation and Final Decision: BPA's goal is to achieve the targeted rate credit aMW by the end of the rate period. A shorter rate period (three years instead of five) coupled with the need for utilities to develop and field programs to target cost-effective technologies that many utilities are not currently targeting, means utilities will need to develop and implement a plan early in the new rate period for achieving the conservation. BPA realizes it may need to provide tools and resources to assist utilities in this effort. The semi-annual reporting will enable BPA to identify and provide assistance to those utilities who need additional help soon enough that the targets for the rate period can be met.

BPA's intent is to provide assistance to utilities as needed to ensure the rate credit aMW is achieved. The reporting requirement provides the "flag" that allows BPA to identify and assist those utilities that need help. BPA will retain the requirement for semi-annual progress reports via the RTF reporting system. To address commenters' concerns, utilities will need to submit an Action Plan only if sufficient progress has not been made (i.e., 50 percent or less of its expected rate credit has been spent) at the end of the first full program year. BPA staff will be available to assist utilities in developing an Action Plan that will indicate how the utility will spend its rate credit funds by the end of the rate period (9/30/09). BPA's goal is for every participating utility to spend the full amount of its rate credit on qualified conservation and/or renewables activities by the end of the rate period. If at the 18-month period (third progress report) participants still have not made sufficient progress on their rate credit spending (i.e., 75 percent or less of their expected rate credit has been spent), then BPA may send a notification letter that the rate credit will be withdrawn for the third year of the program (i.e., customers will be required to pay the full PF or other appropriate power rate) so the funds can be reallocated. At the end of the third year of the rate credit program (9/30/09), there will be a final true-up required for participating utilities to make sure BPA's rate credit funds were spend on qualified measures. BPA is making these changes because it understands the concern about having a hard spending requirement too early in the new program's start-up period.

With regard to the bilateral contracts, since these are pay-for-performance type contracts, BPA will have a pretty good idea of how the delivered savings are proceeding. However, BPA will retain the right to withdraw budget commitments if participants are not making sufficient progress on delivering the agreed upon savings. This will be done on a case-by-case basis and in conjunction with the affected customer.

Oversight Proposal: Purpose: The expenditure of funds included in the published BPA rates for purposes of achieving conservation (and renewables, if applicable) is an activity for which BPA has fiduciary responsibility. In addition, by providing constructive oversight, BPA may be able to provide assistance to utilities to improve the programs and reporting.

(a) BPA proposed that BPA or BPA's agent shall have the right to conduct inspections of units or completed units and monitor or review utility's procedures, records, verified energy savings method and results, or otherwise oversee the utility's implementation of conservation programs funded through dollars included in BPA's rates. The number, timing, and extent of such audits shall be at the discretion of BPA. Such site reviews are expected to be conducted annually. Such audits shall occur at BPA's expense. Financial audits shall be in compliance with the audit standards established by the Comptroller General of the United States. BPA may contact appropriate federal, state, or local jurisdictions regarding environmental, health, or safety matters related to units or completed units.

(b) Prior to any oversight visit physical inspection, BPA shall give the utility written notice. If physical inspections are required by BPA, the utility shall have 30 days to arrange for the inspection of units or completed units. The oversight visit would include (but is not limited to): a review of energy audit or measure installation procedures, technical documents, records, and/or verified savings methods and results.

Summary of Comments Received: Regarding the rate credit, several commenters were concerned about the oversight being overly burdensome (i.e., don't use the past receipt and acceptance approach) *(Benton REA; Cowlitz; Lincoln Electric; Okanogan; PPC; Umatilla)*. Some of the commenters suggested that only one audit should be necessary over the third-year rate period if participants are in substantial compliance *(EPUD; Hermiston; PPC; PNGC; Umatilla)*. A few commenters indicated that our current ConAug oversight approach should be used for the rate credit *(Hermiston; Port Angeles; SCL)*. One commenter recommended that BPA consider relying on participants' CPA or state auditors to meet BPA financial audit requirements *(Umatilla)*. Another commenter objected to creating third-party transactions whereby BPA interfaces with end-users *(SUB)*. One commenter recommended that reporting not be broken down to member level of pooling customers *(PNGC)*.

Evaluation and Final Decision: To carry out its fiduciary responsibility, BPA believes that it must preserve the oversight rights described in its proposal. Although the detailed contract language on "oversight" has extensive language about the rights BPA has, the actual implementation of the oversight has not been onerous. Utilities experienced with ConAug oversight reiterated that it has not been a burden in reality. The Conservation Workgroup recommendations endorsed this approach to oversight for the new rate credit program. BPA does want to clarify that it will require only one oversight visit per year under the rate credit program and that it will try to coordinate that visit with any bilateral contract oversight requirements, if reasonable. Accordingly, BPA will aim to have one oversight visit for all of its conservation programs for each participating utility, unless major issues surface.

Another clarification relates to confusion about another utility performing oversight on a customer's contracts. This was never intended. Third-party evaluation contractors could be used for evaluations, but they will perform confidential work for research purposes not contract oversight. No utilities will be tasked with looking at the books of other utilities.

Renewables Proposal: BPA proposed a renewables option under the rate credit program that requires customers to commit up-front as to the portion of their rate credit they will apply to renewables for the full three years of the rate period and to do so by 7/1/06. This up front commitment would provide certainty of the amount of rate credit money that was available for conservation. Further, BPA proposed capping the level of renewables funding under the rate credit to \$6 M/year. If customers subscribe for more than \$6M/year, then BPA proposes to pro rate their shares down to the \$6M/year cap.

Summary of Comments Received: Some commenters recommended that BPA allow annual sign-ups for renewables, rather than a three-year commitment up-front as proposed *(Benton*

REA; PPC). A few commenters indicated that they would like to continue to have an option of purchasing green power under the new rate credit *(Benton PUD; PPC; USDOE-Richland)*. In addition, some commenters recommended that the federal customers should not be subject to pro-rating *(Fairchild AFB; USDOE-Richland)*. Another commenter wanted BPA to reconsider the pro-rating approach for over subscription on renewables *(SnoPUD)*. One commenter was opposed to the $6M/year renewables cap *(Interfaith GWC; Whatcom)*. Some commenters wanted customer-side renewables and related R&D funded under the rate credit *(EPUD; EWEB; Ferry County; SCL)*.

Evaluation and Final Decision: Consistent with commenters' recommendations, BPA will require a three-month advance notice prior to each year of the rate period (2007-09) with a $6M/year cap that will be pro rated if customers over subscribe. Small utilities (7.5 aMW and under) and BPA's federal agency power customers will be exempt from this *pro rata* requirement. This will provide sufficient advance notice to BPA regarding the amount of rate credit and thus aMW that will be achieved with the rate credit funds but provides additional flexibility for customers that manage their rate credit on an annual basis. Exempting small utilities and federal agency customers from the *pro rata* requirement will not compromise the plans these customers may put in place satisfy their rate credit obligations. BPA will issue for public review and comment a menu of renewable resource-related activities that will qualify for the rate credit prior to the program start date.

<u>Starting Programs Early Proposal</u>: BPA proposed to begin the CRC program when the new rate period started (i.e., October 1, 2006). Also, BPA planned to have the new bilateral contracts ready for signature in the fall of 2005, but not provide any funding until the new rate period started (i.e., again, October 1, 2006).

Summary of Comments Received: A few commenters recommended that BPA allow customers that have met their C&RD spending requirements to start funding projects/programs for the new rate credit early (e.g., similar to what BPA did with the C&RD during the 2001-02 energy crisis) *(Benton PUD; Idaho Falls; Wells REC;)*. One commenter recommended that BPA allow for a smooth transition to future programs and that BPA should provide an option for customers to discontinue their participation in the rate credit *(Idaho Falls)*.

Evaluation and Final Decision: BPA has worked hard over the last several years to provide stable level funding for its conservation programs. Allowing customers to implement the new programs early will provide continuity in the delivery of cost-effective conservation and helps avoid a potential "slow-down" in the achievement of aMW savings as customers transition from the old programs to the new ones. Accordingly, BPA, in response to the comments received on this issue, will allow customers that have used all their C&RD credits and have filed a final close-out report to spend their funds under the new rate credit starting in CY 2006 (targeted for January 1, 2006) and claim spending on approved, cost-effective ECMs when the new rate credit kicks in (October 1, 2006). This approach will require customers to indicate their willingness to participate in the new rate credit program (should it be approved in the rate process) and follow the implementation rules as defined by BPA. *(<u>Note</u>: There is a risk to utilities if they begin before the new rates are finalized. This is similar to the risk some utilities assumed when they started their rate credit conservation activities early in 2001 before the current rate period.)*

In response to a commenter's request, BPA will include a mechanism or procedure for customers to discontinue participation in the rate credit should they choose to do so. However, the customer has to continue to pay the full PF or appropriate power rate, including the 0.5 mill adder, for the remaining portion of the rate period.

Also, in response to commenters' recommendations and because BPA recognizes some customers may slow down their bilateral program efforts until the new bilateral contracts are available for execution, BPA will offer new bilateral contracts for execution this fall (targeting October 1, 2005). This will allow customers to begin implementing projects under the new contracts (with the new rules and incentive levels) during the current rate period. BPA believes this approach will allow BPA to maximize the use of existing rate period conservation budgets to facilitate achieving the higher targets presented in the Council's Fifth Power Plan.

Attachment 1

Post-2006 Conservation Program:
Small Utility Option under the Conservation Rate Credit

Keep the 7.5 aMW size limit and maintain the requirement that small utilities must acquire cost-effective conservation (or renewables) in order to receive the conservation rate credit (CRC). The following CRC Program elements would be available to small utilities with an annual CRC that is less than $32,851:

- Allow up to 30 percent of their CRC amount to be used for administrative costs, to include any information, education and outreach (marketing) efforts regarding energy efficiency.

- Require only one BPA oversight visit during the three-year CRC rate period (unless the utility requests a more frequent review).

- Allow use of a third party (or utility pooling) to run utility conservation programs (using some or all of the 30 percent administrative allowance to pay the third party).

- Small utility customers can satisfy their remaining 70 percent CRC spending by implementing appropriate (to their service areas) cost-effective measures, such as:
    - CFL programs
    - Appliance Rebate programs
    - SGC Manufactured Homes program
    - Energy Star New Construction program
    - Other qualifying cost-effective measures and standard offers

However, if small utility customers don't have sufficient opportunities to implement cost-effective measure programs with their end-use consumers, then the following options are available to help ensure that they will be successful in meeting their full CRC obligation:

- Allow donations for cost-effective measures to low-income weatherization organizations with no cap (e.g., CFLs).

- Allow purchase of the renewables (with no *pro rata* adjustment if renewables are over subscribed ((i.e., exceed $6M/year cap)) by CRC participants).

- Allow donations to NEEA (or other organizations that will use BPA's funds to install cost-effective measures) with no cap.

BPA's AEs and EERs are available to work with small utilities to develop a reasonable game plan for achieving CRC success under the new program requirements. BPA will continue to explore new program options for small utility customers.

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APPENDIX C
Post-2006 Program Structure

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Energy Efficiency
Bonneville Power Administration

Final Post-2006 Conservation Program Structure

This document describes BPA's final Post-2006 Conservation Program structure. A companion document, "Response to Key Issues Raised in Public Comment Process," summarizes the key issues raised in the 56 public comment letters and e-mails BPA received regarding BPA's Post-2006 Conservation Program Proposal. The companion document also summarizes BPA's final decisions on these key issues that are incorporated into this final program structure. This document is organized as follows.

Section I: Introduction. The program purpose and BPA's strategic direction are described in this section. The five-year (FYs 05 – 09) aMW targets are identified. The five program principles that were included in BPA's Final Record of Decision on the short-term Regional Dialogue Policy are described along with seven key policy directives that help frame the post-2006 conservation programs. Finally, the timeframe anticipated for implementation of these final programs is explained.

Section II: Program Portfolio and Structure. This section includes a description of the portfolio of programs followed by a more detailed description of program design features for each of the four portfolio components: a rate credit; utility and federal agency customer bilateral contracts; third-party contracts; and regional infrastructure support. Features that are consistent across all programs are identified up front. Oversight requirements and tracking and reporting activities are described in Appendix 1 and the small utility option for the rate credit program is described in Appendix 2.

Appendices:
1. Sample of BPA Reporting, Oversight, and Evaluation Requirements.
2. Small Utility Option under the Conservation Rate Credit

I. Introduction

Purpose
The purpose of this document is to describe the portfolio of programs that BPA will offer during the 2007 through 2009 timeframe and through 2011 (pending the outcome of post-2009 rate case decisions and/or future long-term power sales contract requirements). BPA anticipates that this portfolio will: (1) facilitate BPA's ability to achieve its share of the regional conservation targets as defined by the Northwest Power and Conservation Council's (Council) Fifth Power Plan; (2) enable BPA to achieve its strategic objective described below; and (3) provide consistency with BPA's Regional Dialogue policy decisions. In addition, the seven BPA policy directives described below provided supplemental guidance to the portfolio design.

Strategic Direction
Strategic Objective 3: BPA ensures development of all cost-effective energy efficiency in the loads BPA serves, facilitates development of regional renewable resources, and adopts cost-effective non-construction alternatives to transmission expansion.

Explanation of S3: BPA will continue to treat energy efficiency as a resource and define our goals in terms of megawatts of energy efficiency acquired. Even if we adopt tiered rates, we are very likely to continue to need limited amounts of new resources. We expect conservation to continue to be a cost-effective resource to meet this limited need, with first priority by law. Accordingly, our goal is to continue to ensure that the cost-effective conservation in the load we serve gets developed, since this amount is very unlikely to exceed our total need. We will ensure this amount is developed with the smallest possible BPA outlay. We will do this through a combination of acquisition of conservation, adoption of policies and rates that support others' development or acquisition of cost-effective conservation, and support of market transformation that results in more efficient electric energy use.

Program Principles
The following five conservation principles were included in BPA's Final Record of Decision on the short-term Regional Dialogue Policy (dated February 2005). They provide the framework for future conservation program design purposes.

- **Conservation Targets from Council's Plan:** BPA will use the Council's plan to identify the regional cost-effective conservation targets upon which the agency's share (approximately 40 percent[1]) of cost-effective conservation is based.
- **Conservation Achieved at the Local Level:** The bulk of the conservation to be achieved is best pursued and achieved at the local level. There are some initiatives that are best served by regional approaches (for example, market transformation through the Northwest Energy Efficiency Alliance). However, the knowledge local utilities have of their consumers and their needs reinforces many of the successful energy efficiency programs being delivered today.
- **Achieve Conservation at Lowest Cost Possible to BPA:** BPA will seek to meet its conservation goals at the lowest possible cost to BPA. While only cost-effective measures and programs are a given, the region can benefit by working together to jointly drive down the cost of acquiring those resources.
- **Administrative Support:** BPA will continue to provide an appropriate level of funding for local administrative support to plan and implement conservation programs.
- **Funding for Education, Outreach and Low-Income Weatherization:** BPA will continue to provide an appropriate level of funding for education, outreach, and low-income weatherization such that these important initiatives complement a complete and effective conservation portfolio.

[1] Based on the FY03 White Book information.

In addition to the five approved principles listed above, BPA's Post-2006 Conservation Program Structure is guided by the following key policy directives:

- **Benefits Must Flow to BPA:** BPA must realize directly the benefit of the savings achieved from the conservation acquisition programs it funds. (Note: the decrement will only be required in conjunction with slice/block customers' bilateral acquisition agreements and in some third-party contractor programs, as appropriate and with utility agreement.)

- **Cost-Effective Measures:** BPA will only pay for cost-effective measures as defined in the Council's Power Plan.

- **Accountability:** BPA needs to be sure it is getting what it pays for -- incremental, reliable and verifiable conservation savings. Measurement and verification will be included in all program mechanisms. This will include managing performance risks upfront such that BPA will avoid any need to "backstop" underachievement.

- **Tracking Progress:** BPA will monitor and report, on a regular basis, how our utilities and other parties are spending the conservation funds it provides across all components of the conservation portfolio.

- **Flexibility:** BPA will retain flexibility to shift budgets and targets across all program elements of the conservation portfolio and across program years to ensure the Council's target is met at the lowest cost possible.

- **Leveraging and Coordination:** BPA will coordinate and synchronize its efforts with those of others as part of an effective and efficient regional effort to achieve cost-effective conservation.

- **Local Control:** BPA will foster local utility initiative and control of conservation efforts to the maximum extent it can, consistent with meeting cost and verification goals.

Timeframe

It is anticipated that this program structure will be implemented for BPA's FYs 2007 to 2011 period. However, new power sales contracts and/or post-2009 rate case decisions may require that elements of this program structure be adjusted. This program approach will be ready for implementation on or before October 1, 2006. BPA will allow customers that have used all their C&RD credits and have filed a final closeout report to spend their funds under the new rate credit starting in calendar year 2006 (targeted for January 1, 2006) and to claim spending on approved, cost-effective measures when the new rate credit kicks in (October 1, 2006). This approach will require customers to indicate their willingness to participate in the new rate credit program (should it be approved in the rate process) and follow the implementation rules as defined by BPA. Only qualified ECMs implemented after the customers have satisfied their C&RD obligations and indicated to BPA that they want to begin the new program will be allowed. *(Note: There is a risk to utilities if they begin before the new rates are finalized. This is similar to the risk some utilities assumed when they started their rate credit conservation activities early in 2001 before the start of the current rate period.)* BPA will include a mechanism or procedure for customers to discontinue participation in the rate credit. However, should they choose to discontinue participation, they will have to pay the full PF or appropriate power rate, including the 0.5 mill adder, for the remaining portion of the rate period.

BPA will offer new bilateral contracts for execution by customers in the fall of 2005 (targeting October 1, 2005). Customers may choose to close out current ConAug contracts and transition to new bilateral conservation acquisition agreements. Customers can begin implementing projects and receiving reimbursement from BPA under the new contracts (with modified terms and incentive levels) once the new contracts have been executed. However, commercial and industrial projects already purchased or approved under ConAug will be subject to the current ConAug incentive levels and contract terms. Payment for projects under the new bilateral contracts can only occur after the execution date for the new agreement. BPA believes this approach will allow BPA to maximize the use of existing rate period conservation budgets to facilitate achieving the higher targets presented in the Council's Fifth Power Plan.

Commitment to Achieving the Target: BPA believes it is important to maintain a steady level of support for conservation over time and will continue to provide a strong energy efficiency program with a firm commitment to achieving its share of the Council's conservation target. This commitment has been demonstrated in the current rate period. BPA more than quadrupled its budget for installing energy conservation measures and capturing conservation savings from about $15M in 2001 to over $70M in 2002. Since that substantial increase in funding for conservation, BPA has maintained a high level of support for delivering conservation savings each year. In the 2007-09 rate period, BPA proposes to continue this support and increase the funding level from about $70M/year, on average, to $80M/year, on average.

II. Program Portfolio and Structure

Program Design Features

BPA's Post-2006 Conservation Program is a portfolio of programs and supporting activities designed to achieve BPA's share of the regional cost-effective conservation target (as identified by the Council's Fifth Power Plan). The portfolio includes: (1) a rate credit program; (2) utility and federal agency customer acquisition program; (3) third-party acquisition initiatives; and (4) support for regional infrastructure necessary to effectively carry out the other portfolio elements. Options are provided under the rate credit program for small utilities. In addition, under the rate credit program, a renewables alternative is provided.

The program portfolio is shown in the following chart and explained in further detail in the remainder of this document.

Post 2006 Conservation Program aMW Targets

Based upon the Council's Fifth Power Plan, there is a regional conservation target over the 2005-2009 period of about 700 aMW. BPA's responsibility to achieve its share of this regional target is based on the amount of regional firm load that BPA supplies with federal power. BPA estimates that it is responsible for about 40 percent of the 700 aMW or 280 aMW. While this amount equates to an annual target of 56 aMW, BPA will adjust the amount of its target to take

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Rate Credit Program (no decrement)

- Standard offers, deemed, protocol & custom measures
- Reporting through enhanced RTF database system
- Administrative costs included
- Financing/revolving loan option
- Continue pooling option
- Optional contracting w/ service providers
- Measurement & Verification
- Proposal reviews, optional pre-approval, BPA technical assistance
- Monitoring, reporting & tracking
- Cost-effective LIWx & direct application renewables
- Renewables alternative

Utility & Federal Agency Customers Bilateral Contracts (decrement applies)

- Standard offers, deemed, protocol & custom measures
- Reporting through enhanced RTF database system
- Administrative costs included
- Proposal reviews, optional pre-approval, BPA technical assistance
- Measurement & verification
- Option for pooling & contracting with third-party service providers
- Monitoring, reporting & tracking

Third-Party Contracts (decrement TBD)

- Market transformation incl. codes & standards (no decrement)
- Bulk purchases
- Vendor programs
- Monitoring, reporting & tracking
- Measurement & verification

Regional Infrastructure Support

- BPA & collaborative region-wide RD&D
- BPA & collaborative evaluation
- Peer sharing & training
- BPA's share of support for RTF
- Coordinated regional marketing education & outreach

into account the estimated amount of "naturally occurring" conservation (about 7 percent or 4 aMW/year). This results in an average annual conservation target of 52 aMW/year for a total of 260 aMW over the 2005-2009 period. BPA will increase its near-term conservation targets for the 2005-09 period, rather than the originally proposed 2007-11 period. This change reflects an adjustment and commitment by BPA to align the new conservation targets with the same five-year planning horizon in the Council's Fifth Power Plan. BPA expects to meet its 2002-06 target (220 aMW averaging 44 aMW/year) by the end of FY 2006. To meet the 52 aMW/year target in 2005 and 2006 (i.e., an additional 8 aMW/year from the Council's new target), BPA will seek to acquire an additional 16 aMW in 2006.

BPA will conduct an evaluation to estimate the accuracy of this assumption about naturally occurring conservation and whether the assumption should be modified going forward. BPA's commitment is to ensure development of the five-year target, recognizing that there will be variations in the pace of the delivered savings on an annual basis.

As indicated in the March 28 proposal, BPA will count all conservation savings achieved with its funds toward the new target. For example, BPA will count 50 percent of NEEA's conservation acquisition towards BPA's targets since BPA provides 50 percent of NEEA's funding. BPA will also count the conservation savings that result from IOU rate credit expenditures.

Eligibility
All BPA customers (including the IOUs), with the exception of the aluminum-related DSIs, will be eligible to participate in the rate credit program. All BPA preference and federal agency customers will be eligible to participate under the bilateral contract program.

Incremental Requirements
BPA's conservation funding must be used by our customers for energy efficiency savings and related activities beyond what they are required by state law and/or regulatory requirements to accomplish. A public utility board of directors decision to pursue a particular conservation program, for example, would not, in itself, make that funding non-incremental.

Decrement
BPA believes, as stated in the original proposal, that decrementing is necessary to minimize cross-utility subsidies and to ensure that the benefits from conservation flow to BPA and its customers. BPA will continue its current practice of not decrementing the slice/block or participating IOU customers under the rate credit program, but will continue requiring a load decrement for these customer groups in conjunction with the bilateral contracts program. The decrement will not apply to the NEEA contract. Whether or not the decrement applies to other third-party contracts involving slice/block customers will be determined on a case-by-case basis. Customers will be asked if they want to participate in any third-party program in their service area. Customers will be informed if a decrement applies to the program at the time they are asked.

This approach continues the policy we currently apply and ensures that BPA realizes a load reduction from the conservation BPA pays for and that BPA and its customers see the full benefit from the conservation acquisitions. For the rate credit program, this approach, while not resulting in a BPA load reduction, reduces a barrier to utility participation in BPA's conservation programs and is consistent with the Conservation Workgroup's recommendations. However, BPA does not believe this approach is consistent with how conservation should be acquired, so the decision to not decrement the rate credit program for the 2007-09 rate period is not meant to set any precedent for future conservation program activities post 2009.

BPA considers this strategy, along with the change to pay only for cost-effective measures, a positive step toward BPA's goal of achieving cost-effective conservation at the lowest possible cost.

Renewables Alternative
Under the rate credit program, eligible customers can choose to use their credits for qualified renewable resource related activities. BPA will require a three-month advance notice prior to each year of the rate period (2007-09) with a $6M/year cap that will be pro rated if customers over subscribe. Small utilities (7.5 aMW and under) and BPA's federal agency power customers will be exempt from this *pro rata* requirement. This is intended to provide sufficient advance notice to BPA regarding the amount of rate credit and thus aMW that will be achieved with the rate credit funds, and provides additional flexibility for customers that manage their rate credit on an annual basis. A list of eligible renewable measures will be distributed for public review and comment prior to the start of the new rate credit program.

Budget
BPA's annual budget (capital and expense) for acquiring the target of 52 aMW/year is $80 million (see Table 1). BPA has an additional $6 million per year from BPA's Generating Renewable Program Fund for renewables. For the 2007 – 2009 rate period, the rate credit will be $0.0005/kWh (1/2 mill) on utility-purchased power from BPA and the equivalent treatment for IOU residential benefit payments. This equates to roughly $42 million (including

Table 1: Program Annual aMW Targets and Budgets

Program	aMW	Budget	Cost/aMW
Rate Credit (at 0.5 mills = $42M*/year with IOUs and Pre-Subers included)**	20	$36M	$1.8M
Utility & Fed. Agency Bilateral Contracts**	17	$26M	$1.5M
Third- Party Contracts	5	$7M	$1.4M
Market Transformation (via NEEA)	10	$10M	$1.0M
Infrastructure Support and Evaluation	---	$ 1M	---
Total	52	$80M	$1.5M

* Assumes $6M/year of the $42 M/year from a separate renewable budget will be spent on renewables.
** Includes a 15 percent administration allowance.

participation by pre-subscription contract holders and IOUs). BPA anticipates that $6 million per year will be spent on renewable resource related initiatives. As shown in Table1, BPA will pay a weighted average of $1.5 M/aMW (which includes a 15 percent administration allowance for the rate credit and bilateral contracts programs) across the entire portfolio of programs.

Features Consistent For All Programs
There are several features that will be consistent across all of the conservation programs:

- BPA will pay only for qualified cost-effective measures from the RTF list as defined by the Council's Fifth Power Plan, as well as for approved calculated and custom program designs, and for additional deemed measures that are approved throughout the rate period.
- The list of qualified, cost-effective measures, deemed kWh savings and payment rate per measure will generally be consistent across programs. However, BPA retains the flexibility to negotiate custom agreements.
- BPA's willingness to pay may vary by sector and measure, and will reflect the actual cost to acquire resources in each sector. It may also reflect program implementation realities.
- BPA's will consider measure life in our determination of willingness to pay levels for specific measures.
- BPA will strive to simplify implementation by using averages that take advantage of measure similarity.
- Packaging of measures will be allowed, but BPA will only pay an amount equivalent to payment for the cost-effective measures in the package.
- BPA will attempt to minimize the frequency of adjustments to willingness to pay adjustments. For example, BPA may adjust payments with six months notice, if necessary, to compensate, for changes in codes, market prices, technology penetration or, if needed, to stay on pace with targets. Adjustments will apply to measures installed after the date the adjustment notice is effective. No retroactive adjustments will be applied.
- Utilities may request the RTF review the eligibility of new measures or measures previously deemed to not be regionally cost effective. If the RTF recommends the requested measures as cost-effective, BPA will review the RTF's recommendations to determine whether or not BPA will pay an incentive for the measure.
- Semi-annual reporting will be required.
- BPA retains the flexibility to shift funds between programs and program elements, and across fiscal years as needed to ensure the conservation targets are achieved at the lowest cost possible.
- Oversight and verification will be similar to the current requirements under the ConAug program. Participating utilities will be required to support evaluations (see Appendix 1).
- Information on individual utility expenditures and achievements resulting from BPA funding will be made available to the public, as appropriate.

Rate Credit Program

Overview
A rate credit will be established to facilitate local development of conservation. The aMW purchased with rate credit money will be counted towards BPA's aMW target. Load forecasts will not be reduced and no decrement off block or slice will be required. If IOU's participate,

they will participate under the same rules and conditions that apply to all utilities. Utilities will make a commitment to BPA if they plan to participate in the rate credit program no later than three months prior to the start of the rate period (program start October 1, 2006; notification to participate required by July 1, 2006). The utility will make the commitment by submitting a letter to BPA that states that the utility will participate and that the utility agrees to abide by the program rules as documented in the appropriate GRSPs and the Implementation Manual. If a utility chooses to discontinue participation, the utility must provide BPA notice no later than July 1 for the following October 1 to September 30 fiscal year period. A Rate Credit Implementation Manual, similar to the existing C&RD Implementation Manual, will be prepared and distributed approximately six months prior to program implementation and three months before utility commitments to the rate credit are required. An overview of this program is shown on the chart. Key features of this proposed program include:

Key Features

- Customers may choose to be reimbursed from the rate credit for administration costs at a rate of up to 15 percent of the customer's eligible annual rate credit.
- Monthly credit amount is equal to the forecasted eligible annual credit/12.
- Each utility may choose the incentive level to pay the end user but is credited only the amount BPA offers for each cost-effective measure.
- Rate credits will be provided for qualified deemed, deemed calculated, custom/protocol projects and standard offers.
- BPA engineers will provide custom proposal reviews to the extent engineering resources are available
- Utilities will report at least semi-annually to BPA via the RTF reporting system. If, at the second semi-annual report (end of the first full year of the program), the utility is not meeting its targets (50 percent or less of its expected rate credit spending), the utility will have to prepare and have BPA approve an Action Plan that provides sufficient proof of achievable intent by the end of the first year after the program starts (10/1/07). BPA staff will be available to assist utilities in developing an Action Plan that will indicate how the utility will spend its rate credit funds by the end of the rate period (9/30/09). BPA's goal is for every participating utility to spend the full amount of its rate credit on qualified conservation and/or renewables activities by the end of the rate period. If at the 18-month period (third progress report – 4/1/08) participants still have not made sufficient progress on their rate credit spending (i.e., 75 percent or less of their expected rate credit has been spent), then BPA may send a notification letter that the rate credit will be withdrawn for the third year of the program (i.e., customers will be required to pay the full PF or other appropriate power rate) so the funds can be reallocated. After the end of the third year of the rate credit program (9/30/09), there will be a final true-up required for participating utilities.
- The existing RTF web-based information and reporting system will be used. The RTF database will include all measures in the current C&RD database and the cost-effective measures for which BPA is willing to pay an incentive during the new rate period (FYs 2007-09). The reporting system will be enhanced to include means for utilities (at their option) to enter savings acquired from non-cost-effective measures, measures the utility pays for with its own money, and for identifying savings from lost opportunity measures.
- Measurement and verification for non-deemed measures at a level similar to that done under the current ConAug program will be required (see Appendix 1).

- Utility records related to spending of BPA funds will be subject to federal financial review.
- BPA will conduct an annual oversight visit (see Appendix 1 for further detail).
- Pooling of utility funding is allowed (optional), but there will be a 15 percent cap on total administration costs for the pool.
- Utilities may contract independently with third-party service providers to operate their programs (optional).
- An annual commitment to renewables will be allowed (see earlier Renewables Alternative section).

Rate Credit Eligibility

- Only qualified, cost-effective conservation and direct application (customer side) renewable measures will be eligible for a rate credit and renewables option.
- There will be a no cap on the total dollars in the rate credit program that a utility may either contract to low income weatherization organizations or spend on utility low income programs. No double counting of savings will be allowed, and utilities may not claim administration costs on the amount of money contracted or passed through.
- Third party subcontracts with energy organizations will be allowed provided cost-effective aMW savings result. Utilities may not take administration payments on pass-through contracts. BPA will include these funds in determining its share of the NEEA aMW achieved and will count these aMWs toward BPA's target.

Small Utility Option

Overview

Small utilities are defined as those with a 7.5 aMW or smaller total load. BPA wants to make participation in the rate credit feasible for small utilities, while ensuring that dollars actually go to cost-effective conservation and renewables. Small utilities will be required to acquire cost-effective measures (or renewables) in order to participate in the rate credit program. BPA will allow up to 30 percent of their rate credit for administrative costs, ensure that small utilities who wish to spend their rate credit dollars on renewables can do so without being affected by a *pro rata* adjustment if renewables are over subscribed by customers (exceed the $6M/year cap), provide a checklist of simple programs and initiatives suitable for a small utility to implement, and modify the performance reporting requirements to align more with their capabilities. More detail on these changes is included in Attachment 2.

Utility and Federal Agency Bilateral Contracts Program

Overview

BPA anticipates this bilateral program component of the program portfolio to be a five-year program and is committing funding for a three-year period (2007 though 2009). This program is needed because the conservation resources are not evenly distributed across the region. BPA may shift money between the bilateral contract and other programs in the portfolio, as appropriate.

Streamlined, standardized umbrella agreements will be written with interested utilities (participation is optional). Similar to the current ConAug program, each agreement will have exhibits that provide specific program details. Utilities can select from available program exhibits to customize the selection of programs best suited to their service territory. BPA will fund both standard offer and custom designed programs. BPA (or its designated contractor) will conduct oversight. BPA will make a budget commitment to the utility for the duration of the contract subject to utility performance. Similar to the current ConAug program, BPA (or its designated contractor) will provide limited engineering assistance for project scoping and, if requested, pre-approval of projects. The proposed Utility and Federal Agency Bilateral Program is an acquisition program and, as such, the decrement will apply to all slice/block customers. Key features of this proposed program include:

Key Features

- Reimbursement of administration costs at a rate up to 15 percent of the allowable costs may be included with the project budget and reimbursed by BPA.
- Each utility may choose the incentive level to pay the end user but is credited only the amount BPA offers for each cost-effective measure.
- BPA engineers will provide custom proposal reviews to the extent engineering resources are available.
- Measurement, verification and oversight will be similar to that done under the current ConAug program.
- Incentives will be provided for qualified deemed, standard offers and custom/protocol projects.
- BPA will explore augmenting the existing RTF database to allow bilateral contract reporting -- so that tracking for both programs will be through the same database. Invoicing for BPA payment will be separate.
- Stranded cost repayment provisions will be put in place between each participating utility and BPA.
- BPA will strive to provide simplified contracts.
- BPA will strive to provide a streamlined approval process

Measure Eligibility

Only qualified cost-effective conservation and direct application (customer-side) renewable measures will be eligible.

Third-Party Contracts

Overview

This third-party contract component of the program portfolio will allow BPA to contract to third parties when these contracts will lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. BPA will only pay third parties to work in utility service territories that have agreed to participate in the third-party program. This policy of requiring pre-approval of utility partners is a continuation of BPA's current policy. In general, regional programs will be designed to operate in coordination with local utility programs. For example, regional bulk purchases of a technology might be delivered locally. BPA anticipates transferring funds between third-party contracts and utility and federal agency bilateral contracts, as needed, to balance the level of effort needed at both the regional and local levels and to achieve the targets at the lowest possible cost.

Pre-committed funding for NEEA ($10 million per year for the 2007-09 period) is included in this mechanism and no decrement will be applied for the NEEA contract.

Key Features
- BPA will negotiate reasonable administration costs for third-party contracts.
- Region-wide programs and efforts will be coordinated with local utilities.
- The decrement will not apply to NEEA.
- A determination of whether or not a decrement applies for other third-party programs will be determined on a case-by-case basis.
- Customers will be notified as to whether or not a decrement will apply to any third-party program of interest to the utility before the utility agrees to participate.

Infrastructure Support

Overview
A number of proposed support activities will be undertaken to optimize expenditures through BPA's energy efficiency programs, to leverage other available resources and to reduce the overall cost of accomplishing the conservation. These activities may include:
- Setting up a mechanism for peer sharing (e.g., so utilities can share successful program ideas and marketing materials).
- Conducting limited BPA and collaboratively funded RD&D to ensure we are developing the next wave of energy efficiency technologies.
- Performing evaluations (process and impact) and market assessments to ensure BPA's programs are achieving the intended result and to gather the information necessary to make mid-stream program adjustments. Co-funding from other affected organizations may be solicited for these evaluations/assessments. BPA may also contribute to a regional evaluation designed to assess how much naturally occurring conservation has been achieved.
- Enhancing and supporting the RTF database to include expanding the reporting elements and website to allow bilateral contract acquisition reporting and tracking and to track lost opportunity acquisition.
- Developing, with utility guidance, tool kit components such as utility program marketing and implementation materials that utilities need and may choose to use to launch new programs.
- Developing templates and other program design "off the shelf" materials that small utilities can easily use.

Tracking and Reporting

BPA is upgrading the RTF/C&RD database to allow utilities to report both bilateral and rate credit program accomplishments in an on-line database. BPA will continue to rely on invoicing for reimbursement under bilateral agreements. BPA is also expanding the database to allow utilities to report conservation savings from other funding sources as well.

Appendix 1
Sample of Reporting, Oversight, and Evaluation Requirements

Reporting:

Purpose: Tracking progress to meeting the regional goals in real time will be important if the region is going to be able to respond and adapt to shortfalls. In addition, the use of public funds requires a minimum level of accounting.

All utilities will report at least semi-annually, using the RTF database, on their accomplishments and expenditures of funds, whether from the rate credit or bilateral contracts. BPA will strive to have this single source of reporting meet as many needs as possible to avoid duplicative or inconsistent reporting needs. All data received will be in the public domain except where consumer business confidentiality is needed.

Oversight and Verification:

Purpose: The expenditure of funds included in the published BPA rates for purposes of achieving conservation (and renewables, if applicable) is an activity for which BPA has fiduciary responsibility. In addition, by providing constructive oversight, BPA may be able to provide assistance to utilities to improve the programs and reporting. BPA will aim to have one oversight visit per year for all of its conservation programs for each participating utility, unless major issues surface.

(a) Bonneville Power Administration (BPA) or BPA's agent shall have the right to conduct inspections of units or completed units and monitor or review a utility's procedures, records, verified energy savings method and results, or otherwise oversee the utility's implementation of conservation programs funded through dollars included in BPA's rates. The number, timing, and extent of such audits shall be at the discretion of BPA. Such site reviews are expected to be conducted annually. Such audits shall occur at BPA's expense. Financial audits shall be in compliance with the audit standards established by the Comptroller General of the United States. BPA may contact appropriate federal, state, or local jurisdictions regarding environmental, health, or safety matters related to units or completed units.

(b) Prior to any oversight visit physical inspection, BPA shall give the utility written notice. If physical inspections are required by BPA, the utility shall have 30 days to arrange for the inspection of units or completed units. The oversight visit will include: review of energy audit or measure installation procedures, technical documents, records, and/or verified savings methods and results.

Evaluations:

Purpose: Evaluations are needed to determine barriers to program success, identify ways to improve programs, help track program accomplishments, and to assess the market conditions, the accuracy of the savings estimates, and to answer the ultimate question of whether programs are meeting their expected goals.

(a) BPA may conduct, and the utility shall cooperate with, evaluations of conservation impacts and project implementation processes to assess the amount, cost effectiveness, and reliability of conservation in the utilities' service areas or region. After consultation with the participating utilities, BPA shall determine the timing, frequency, and type of such evaluations.

(b) BPA anticipates that many of the evaluations will be done collaboratively with other organizations to share costs and improve the usefulness of the evaluations. In some cases, this will result in the evaluation being managed by another party on behalf of BPA and others. Such evaluation contract management responsibilities might be shared with other parties, including among others, the NEEA, the RTF, the Power Council, the Energy Trust of Oregon, or another utility.

(c) BPA will determine the specific requirements for evaluations with consideration for the schedules and reasonable needs of the utility and the utility's customers.

(d) Unless requested by the program managers to improve program operation, any evaluation of the project initiated by BPA shall be conducted at BPA's expense or shared regional expense and such costs shall be excluded from the implementation budget. Utility or other entities who cooperate with the evaluation are implicitly recognized as providing some resource/cost, but will not be considered for direct reimbursement by BPA, except under unusual circumstances. Cooperation with the evaluation is a cost of the partnership in delivering the programs.

Appendix 2
Post-2006 Conservation Program:
Small Utility Option under the Conservation Rate Credit

BPA will continue to define small utility as those utilities with loads of 7.5 aMW or under. BPA intention is that small utilities acquire cost-effective conservation (or renewables) in order to receive the conservation rate credit (CRC). The following CRC Program elements will be available to small utilities:

- Up to 30 percent of a small utility's CRC amount may be used for administrative costs, (which include information, education and outreach (marketing) efforts regarding energy efficiency).

- Only one BPA oversight visit will be required during the three-year CRC rate period (unless the utility requests a more frequent review).

- Third-party (or utility pooling) to run utility conservation programs (using some or all of the 30 percent administrative allowance to pay the third-party) is allowed.

- Small utility customers can satisfy their remaining 70 percent CRC spending by implementing appropriate (to their service areas) cost-effective measures, such as:
  - CFL programs
  - Appliance Rebate programs
  - SGC Manufactured Homes program
  - Energy Star New Construction program
  - Other qualifying cost-effective measures and standard offers

However, if small utility customers don't have sufficient opportunities to implement cost-effective measure programs with their end-use consumers, then the following options are available to help ensure that they will be successful in meeting their full CRC obligation:

- Donations for cost-effective measures to low income weatherization organizations with no cap (e.g., CFLs).

- Purchase of the renewables (with no *pro rata* adjustment if renewables are over subscribed ((i.e., exceed $6M/year cap)) by CRC participants).

- Donations to NEEA (or other organizations that will use BPA's funds to install cost-effective measures) with no cap.

BPA's AEs and EERs are available to work with small utilities to develop a reasonable game plan for achieving CRC success under the new program requirements. BPA will continue to explore new program options for small utility customers.

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