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

2007 Wholesale Power Rate Case Final Proposal

RISK ANALYSIS STUDY DOCUMENTATION

July 2006

WP-07-FS-BPA-04A

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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
MMBTUMMBtu	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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RISK ANALYSIS STUDY DOCUMENTATION

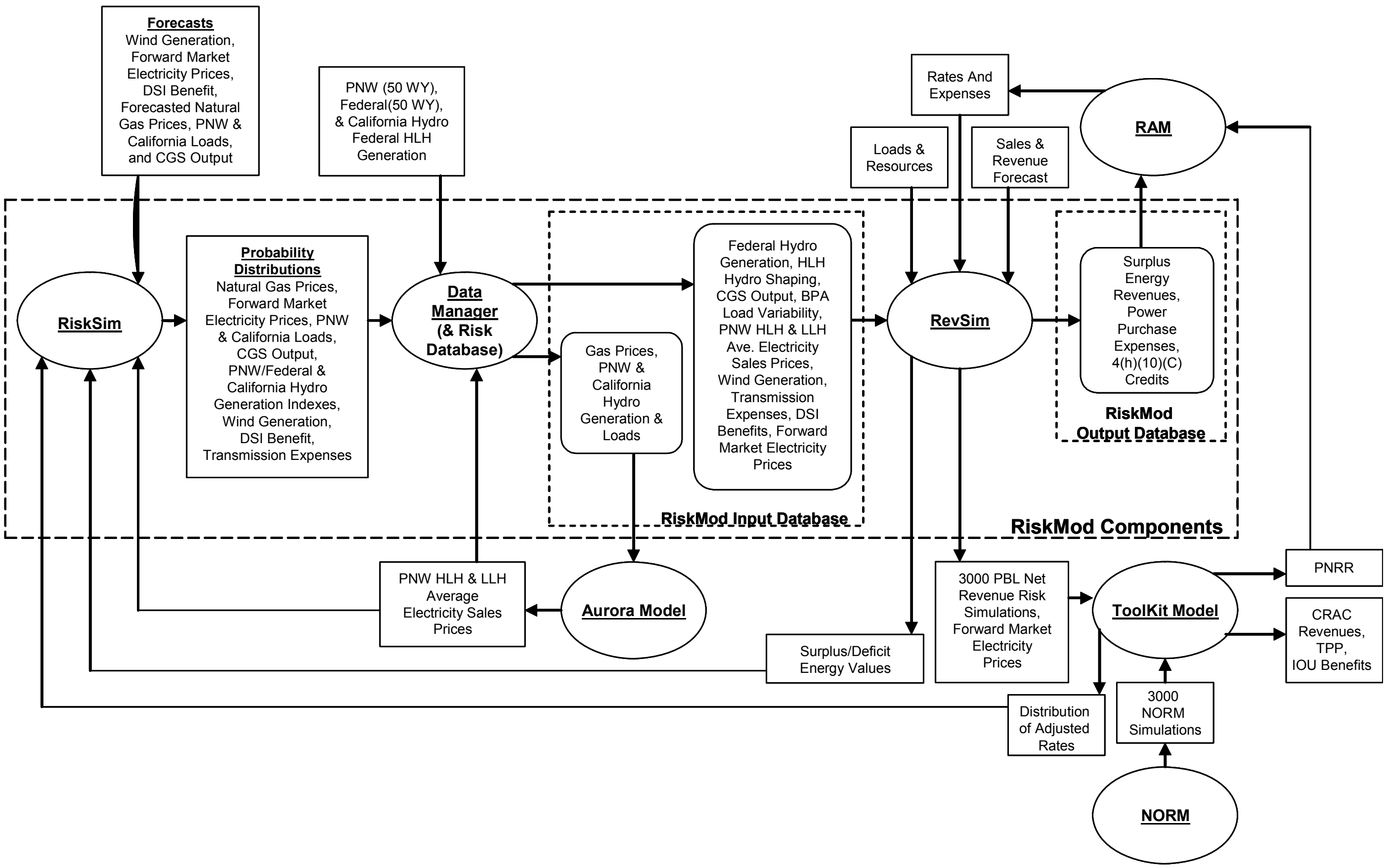
1. OPERATIONAL RISK ANALYSIS MODEL (RISKMOD)

1.1 RiskMod

The RiskMod Model is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manages data referred to as Data Management Procedures; and RevSim, a model that calculates net revenues. RiskMod interacts with the AURORA Model, the RAM2007, and the ToolKit Model during the process of performing the Risk Analysis Study. AURORA is the computer model being used to perform the Market Price Forecast Study (*see* Market Price Forecast Study, WP-07-FS-BPA-03); the RAM2007 is the computer model being used to calculate rates (*see* Wholesale Power Rate Development Study, WP-07-FS-BPA-05); and the ToolKit is the computer model being used to develop the risk mitigation package that achieves BPA's 92.6 percent TPP standard (*see* Section 3 in the Risk Analysis Study, WP-07-FS-BPA-04).

Variations in monthly loads, resources, natural gas prices, forward market electricity prices, transmission expenses, and aluminum smelter benefit payments are simulated in RiskSim. Monthly spot market electricity prices for the simulated loads, resources, and natural gas prices are estimated by the AURORA Model. Data Management Procedures facilitate the format and movement of data that flow to and/or from RiskSim, AURORA, and RevSim. RevSim estimates net revenues using risk data from RiskSim, spot market electricity prices from AURORA, loads and resources data from the Load Resource Study, WP-07-FS-BPA-01, various revenues from the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05, and rates and expenses from the RAM2007. Annual average surplus energy revenues, purchased power expenses, and section 4(h)(10)(C) credits calculated by RevSim are used in the Revenue Forecast and the RAM2007. Heavy Load Hour (HLH) and Light Load Hour (LLH) surplus and deficit energy values from RevSim are used in the Transmission Expense Risk Model. Net revenues estimated for each simulation by RevSim are input into the ToolKit Model to develop the risk mitigation package that achieves BPA's 92.6 percent TPP standard. The processes and interaction between each of the models and studies are depicted in Graph 1.

Graph 1: RiskMod Risk Analysis Information Flow



1.2 Risk Simulation Models (RiskSim)

To quantify the effects of operational risks, BPA developed risk models that combine the use of logic, econometrics, and probability distributions to quantify the ordinary operational risks that BPA faces. Econometric modeling techniques are used to capture the dependency of values through time. Parameters for the probability distributions were developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and are deviations from the base case values used in the Revenue Forecast, Revenue Requirement, and AURORA Model. *See* the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05; the Revenue Requirement Study, WP-07-FS-BPA-02; and discussion of the AURORA Model in the Market Price Forecast Study, WP-07-FS-BPA-03.

The monthly output from these risk simulation models are accumulated into a computer file to form a risk database which contains values lower than, higher than, or equal to the base case values used in the Revenue Forecast component of the Wholesale Power Rate Development Study, Revenue Requirement Study, and the AURORA Model. *Id*. Loads, resources, and natural gas price risk data for each simulation are input into the AURORA Model to estimate monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) spot market electricity prices. The prices estimated by AURORA are then downloaded into the risk database and a consistent set of loads, resources, and spot market electricity prices are used to calculate net revenues in RevSim. The risk models run 3000 games to produce monthly risk data for FY 2007-2009 for this rate filing. Thus, each of the risk models produces 3000 rows and 36 columns of simulated data.

1.3 @RISK Computer Software

Most of the risk simulation models developed to quantify operational risks were developed in Microsoft Excel workbooks using the add-in risk simulation computer package @RISK, which is available from Palisade Corporation. @RISK allows statisticians to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the type of probability distribution that best reflects the risk, providing the necessary parameters required for developing the probability distribution, and letting @RISK sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately capturing risk are not developed in @RISK, but are developed in analyses external to @RISK.

1.4 Operational Risk Factors

In the course of doing business, BPA manages risks that are unique to operating a hydro system as large as the FCRPS. The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. BPA also faces other operational risks that increase BPA's risk exposure, including the following: (1) load variability due to changes in load growth and weather; (2) nuclear plant (CGS) generation; (3) wind generation and value of output; (4) transmission expenses; (5) IOU payment benefits; (6) DSI payment benefits; and (7) variability in electricity prices due to load, resource, and natural gas price variability. All these risk factors are quantified in the Risk Analysis Study. One major operational risk that is not quantified in this Risk Analysis Study is the potential impact of a new Biological Opinion. There is currently no specific guidance on what the remanded 2004 Bi-Op will contain to incorporate this risk in the Final Studies. However, BPA has incorporated what it believes to be the most likely hydro operations for the rate period absent a new Bi-Op that includes 2006 court-ordered spill operations for FY 2007-2009. Detail of the power and non-power requirements for the hydro regulation study for FY 2007-2009 are presented in the WP-07 Final Study, Load Resource Study Documentation, WP-07-FS-BPA-01A, Section 2.9.2 through 2.9.3, at 110-130.

The following is a discussion of the major risk factors included in RiskMod. Each of these risk factors is used in the AURORA Model, RevSim, or both.

1.5 PNW and Federal Hydro Generation Risk Factors

Federal hydro generation risk is incorporated into RiskMod to account for the impact that various Federal hydro generation levels and HLH and LLH hydro generation shaping capability have on the quantity of energy that BPA has to buy and sell during HLH and LLH periods. PNW hydro generation risk is incorporated into the Risk Analysis Study to account for the impact that various PNW hydro generation levels have on monthly HLH and LLH spot market electricity prices estimated by the AURORA Model.

1.5.1 Modeling Hydro Risk

Variability in Federal and PNW hydro generation is incorporated into RiskMod by using monthly Federal and PNW hydro generation data for each of the historical 50 water years from the Hydroregulation component of the Load Resource Study. *See* Load Resource Study, WP-07-FS-BPA-01, regarding 50 water years. The monthly hydro generation data for each of the 50 water years are developed in the HydroSim Model using hydro operations specified in the Load and Resource Study and historical monthly water supply for the 50 water years (1929-1978). *See* Load Resource Study, WP-07-FS-BPA-01, regarding HydroSim.

A consistent set of monthly Federal and PNW hydro generation data for hydro operations in FY 2007 are randomly sampled, by water year, from tables containing hydro generation values for each of the 50 water years for 12 months of the year (50 X 12 tables). The 50 x 12 tables were derived from 50 x 14 tables by averaging hydro generation data for the first and second half of April and August. The ability of the FCRPS to shape average monthly hydro generation into HLH hydro generation, for each water year, is incorporated into RiskMod by selecting from a 50 x 12 table of HLH hydro generation ratios produced from a comparable run of the Hourly Operating and Scheduling Simulator (HOSS) Model. *See* Load Resource Study, WP-07-FS-BPA-01. The HLH ratios used are based on the water year sampled for hydro generation and these ratios reflect the portion of average energy that can be shaped into HLH. Given the HLH ratios from HOSS, LLH ratios are calculated in RevSim. Tables 1-3 and Tables 4-6 contain the 50 x 12 tables of PNW and Federal hydro generation data for each year in the rate period. Similarly, Tables 7-9 contain the 50 x 12 table of HLH ratios from HOSS for each year in the rate period.

Federal and PNW hydro generation data from the Hydroregulation component of the Loads and Resources Study are produced by performing a continuous study with the HydroSim Model. See

Load Resource Study, WP-07-FS-BPA-01, regarding a continuous study by HydroSim. The term "continuous study" refers to calculating hydro generation data sequentially over all 600 months of the 50 water year period. Developing hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water year period.

Table 1: PNW Hydro Generation (aMW) with Hydro Independents for FY 2007

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	11,106	13,310	11,990	13,242	10,521	11,249	10,753	11,499	17,017	13,990	11,725	10,543
1930	11,303	12,755	12,908	11,111	12,223	11,110	11,395	10,875	14,566	14,082	12,256	10,325
1931	11,335	12,860	11,139	11,192	10,870	10,832	10,891	10,206	14,488	13,741	11,720	10,583
1932	10,711	12,717	11,943	11,516	10,120	13,820	18,862	21,077	20,297	16,861	12,958	11,534
1933	11,455	13,481	14,171	20,251	15,576	12,682	14,296	17,721	20,735	18,462	15,715	12,283
1934	13,710	16,577	23,385	22,022	20,533	18,518	19,387	20,801	14,653	14,574	11,436	9,995
1935	11,242	13,501	12,913	19,082	19,375	11,218	13,940	16,617	18,577	16,801	12,962	10,878
1936	11,172	12,771	13,217	11,792	10,823	10,901	14,929	21,982	18,965	13,864	12,275	10,692
1937	11,232	12,726	13,214	10,516	9,984	10,740	11,030	11,730	15,917	13,276	11,746	10,621
1938	11,640	13,536	13,574	19,622	13,703	15,901	17,384	22,644	20,437	16,350	11,872	11,366
1939	11,543	12,961	12,774	15,783	11,019	12,553	14,576	18,247	14,893	14,694	12,511	10,485
1940	11,640	12,790	13,238	14,541	12,722	16,206	15,889	16,339	14,998	13,731	10,959	10,138
1941	11,189	12,396	12,971	14,449	11,279	10,515	10,582	12,994	14,716	12,990	11,091	11,205
1942	11,072	11,975	16,044	18,445	13,617	9,623	13,218	16,239	20,162	17,855	14,129	10,765
1943	11,279	13,344	13,468	18,725	17,942	17,600	20,483	22,356	20,761	18,876	14,287	11,124
1944	11,482	13,077	13,734	14,116	10,856	9,679	9,925	10,598	13,068	12,860	11,071	10,465
1945	10,666	12,482	11,822	11,369	11,140	10,511	10,578	16,615	19,999	14,524	12,072	10,465
1946	11,226	13,545	13,509	17,704	14,771	18,625	18,966	23,425	20,220	17,913	14,001	11,782
1947	11,256	13,614	18,786	20,537	19,592	19,118	16,617	21,097	19,832	17,530	12,547	11,498
1948	16,601	15,290	16,645	21,945	14,617	15,297	17,161	23,363	24,233	18,375	16,380	12,370
1949	12,191	13,465	13,160	15,086	13,935	19,306	18,396	22,722	20,103	13,315	11,757	10,136
1950	11,585	13,741	13,101	17,146	20,076	21,098	19,739	21,035	20,759	18,616	15,176	12,089
1951	14,090	16,587	21,159	22,504	21,771	18,660	20,257	23,156	20,139	18,365	15,066	12,033
1952	15,477	13,896	16,754	20,166	16,997	15,311	19,996	23,517	20,785	16,155	12,563	11,156
1953	11,282	12,975	12,029	16,168	18,035	12,701	13,841	20,217	20,980	18,667	14,418	11,650
1954	11,997	13,684	15,799	18,016	19,701	16,412	17,696	21,952	20,174	18,646	18,162	16,152
1955	12,442	14,296	15,460	14,592	11,678	10,233	13,214	15,791	20,219	18,547	16,287	11,118
1956	13,482	15,551	20,048	22,722	17,776	20,343	20,313	23,289	21,157	18,539	15,058	11,824
1957	12,848	13,488	15,113	17,540	13,496	15,964	18,443	23,544	20,683	15,694	11,874	11,101
1958	11,487	13,078	13,542	15,515	17,210	16,000	16,867	22,972	20,426	15,456	12,190	11,361
1959	11,535	14,431	17,828	21,872	19,755	16,107	17,312	19,922	20,170	18,334	14,593	16,558
1960	17,556	17,341	18,837	20,478	13,307	15,384	20,138	18,252	20,010	16,705	12,698	11,431
1961	11,590	13,660	13,788	18,451	18,806	16,831	16,452	20,319	19,855	16,306	12,802	10,689
1962	11,637	13,408	13,099	17,331	13,253	11,153	19,701	19,803	19,425	16,971	13,507	11,092
1963	12,670	14,640	18,030	19,807	15,522	11,811	13,585	19,266	20,327	16,830	13,955	11,721
1964	11,261	13,848	13,353	16,887	12,954	10,902	15,518	18,045	21,201	18,509	15,883	12,825
1965	13,482	13,682	19,727	22,664	21,736	19,024	18,853	22,574	20,761	16,916	15,171	11,942
1966	12,615	13,397	14,476	20,252	12,595	11,541	17,966	17,328	18,231	17,230	13,843	10,899
1967	11,447	13,433	13,933	21,921	20,900	13,982	14,029	18,758	20,964	18,436	14,363	11,757
1968	12,379	13,428	13,856	19,143	18,730	16,163	11,488	16,509	20,112	18,280	15,376	13,924
1969	14,129	15,475	16,995	22,275	19,814	14,864	20,239	23,530	20,252	17,437	12,793	11,449
1970	11,934	13,442	13,096	17,905	15,608	13,169	13,054	19,699	20,830	16,056	11,581	10,764
1971	11,569	14,016	13,727	21,115	21,557	18,253	19,401	23,243	21,041	18,945	17,176	12,347
1972	12,572	13,892	14,641	22,250	21,832	21,497	19,752	23,136	21,962	18,640	17,625	13,334
1973	12,372	13,366	15,700	19,712	11,116	10,877	10,722	13,331	14,908	13,889	11,468	9,470
1974	11,047	12,722	17,495	22,940	21,872	21,347	20,232	23,106	21,998	18,750	17,122	12,176
1975	10,741	13,375	13,727	19,622	15,598	16,945	14,574	20,446	20,986	19,051	13,512	12,226
1976	13,915	16,143	22,662	22,668	19,966	16,555	20,221	23,497	20,682	18,527	18,713	17,450
1977	11,933	12,970	13,094	14,528	10,707	9,541	8,924	11,150	12,173	11,980	11,259	9,832
1978	10,098	12,575	13,348	17,744	15,408	16,581	17,163	19,556	18,650	18,392	13,265	11,165

Table 2: PNW Hydro Generation (aMW) with Hydro Independents for FY 2008

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	11,117	13,312	11,992	13,262	10,533	11,265	10,767	11,517	17,038	14,090	11,800	10,546
1930	11,317	12,770	12,909	11,124	12,239	11,126	11,412	10,892	14,584	14,186	12,337	10,328
1931	11,346	12,862	11,141	11,205	10,882	10,847	10,906	10,224	14,504	13,838	11,801	10,586
1932	10,723	12,718	11,944	11,529	10,132	13,841	18,890	21,110	20,325	16,987	13,046	11,537
1933	11,464	13,481	14,174	20,276	15,598	12,697	14,315	17,746	20,771	18,490	15,824	12,287
1934	13,714	16,582	23,401	22,057	20,563	18,544	19,422	20,830	14,667	14,686	11,513	9,998
1935	11,244	13,501	12,914	19,106	19,400	11,231	13,961	16,642	18,601	16,927	13,054	10,881
1936	11,184	12,780	13,220	11,807	10,836	10,918	14,951	22,019	18,986	13,966	12,358	10,695
1937	11,246	12,740	13,215	10,530	9,997	10,756	11,045	11,748	15,934	13,373	11,827	10,624
1938	11,649	13,536	13,575	19,648	13,721	15,924	17,409	22,678	20,464	16,472	11,949	11,369
1939	11,556	12,962	12,776	15,804	11,033	12,571	14,597	18,277	14,911	14,801	12,597	10,488
1940	11,651	12,801	13,239	14,559	12,739	16,231	15,913	16,367	15,018	13,831	11,034	10,141
1941	11,200	12,396	12,975	14,469	11,292	10,531	10,596	13,014	14,738	13,089	11,170	11,208
1942	11,076	11,977	16,052	18,472	13,632	9,637	13,238	16,265	20,192	17,989	14,227	10,769
1943	11,292	13,344	13,471	18,751	17,967	17,627	20,517	22,390	20,792	18,902	14,384	11,127
1944	11,488	13,079	13,738	14,136	10,869	9,693	9,939	10,616	13,086	12,955	11,146	10,469
1945	10,678	12,490	11,828	11,383	11,155	10,527	10,592	16,643	20,028	14,629	12,151	10,468
1946	11,239	13,546	13,511	17,726	14,793	18,651	18,994	23,459	20,245	18,043	14,096	11,785
1947	11,257	13,615	18,799	20,565	19,619	19,144	16,639	21,131	19,858	17,661	12,632	11,501
1948	16,607	15,294	16,653	21,975	14,636	15,318	17,185	23,402	24,271	18,399	16,491	12,374
1949	12,194	13,465	13,163	15,108	13,954	19,337	18,424	22,758	20,127	13,410	11,830	10,139
1950	11,587	13,742	13,102	17,169	20,103	21,129	19,769	21,064	20,796	18,643	15,278	12,092
1951	14,094	16,593	21,173	22,536	21,805	18,688	20,287	23,190	20,163	18,389	15,168	12,037
1952	15,482	13,899	16,763	20,193	17,021	15,335	20,028	23,556	20,813	16,275	12,648	11,159
1953	11,297	12,990	12,036	16,189	18,062	12,718	13,858	20,246	21,015	18,693	14,514	11,653
1954	12,008	13,685	15,804	18,040	19,727	16,432	17,722	21,984	20,205	18,673	18,227	16,158
1955	12,446	14,299	15,465	14,611	11,692	10,246	13,232	15,813	20,256	18,577	16,397	11,122
1956	13,484	15,555	20,061	22,755	17,801	20,374	20,347	23,329	21,195	18,564	15,159	11,827
1957	12,851	13,490	15,120	17,564	13,513	15,985	18,472	23,582	20,720	15,811	11,952	11,105
1958	11,498	13,080	13,544	15,537	17,235	16,022	16,892	23,008	20,457	15,568	12,271	11,365
1959	11,543	14,434	17,838	21,904	19,782	16,129	17,335	19,949	20,204	18,359	14,692	16,564
1960	17,566	17,349	18,849	20,504	13,326	15,406	20,168	18,278	20,037	16,831	12,784	11,435
1961	11,598	13,661	13,790	18,474	18,831	16,855	16,476	20,347	19,889	16,425	12,887	10,693
1962	11,639	13,409	13,099	17,354	13,270	11,169	19,732	19,830	19,449	17,098	13,598	11,095
1963	12,674	14,643	18,039	19,831	15,545	11,830	13,603	19,298	20,356	16,957	14,049	11,725
1964	11,271	13,849	13,356	16,909	12,971	10,917	15,541	18,072	21,238	18,538	15,989	12,829
1965	13,494	13,683	19,742	22,701	21,770	19,053	18,882	22,610	20,794	17,048	15,275	11,945
1966	12,630	13,403	14,485	20,278	12,612	11,558	17,990	17,354	18,252	17,359	13,935	10,903
1967	11,455	13,433	13,936	21,947	20,929	13,999	14,049	18,783	21,001	18,463	14,461	11,761
1968	12,382	13,432	13,862	19,169	18,755	16,185	11,504	16,533	20,141	18,304	15,482	13,929
1969	14,131	15,476	17,000	22,308	19,843	14,890	20,272	23,568	20,279	17,566	12,878	11,452
1970	11,935	13,442	13,095	17,932	15,634	13,187	13,071	19,727	20,863	16,176	11,656	10,766
1971	11,572	14,015	13,727	21,147	21,594	18,281	19,430	23,282	21,078	18,973	17,291	12,351
1972	12,574	13,890	14,645	22,280	21,867	21,532	19,780	23,175	22,000	18,668	17,696	13,338
1973	12,381	13,367	15,706	19,741	11,131	10,892	10,735	13,351	14,927	13,989	11,543	9,473
1974	11,050	12,720	17,501	22,980	21,907	21,379	20,266	23,143	22,036	18,782	17,237	12,180
1975	10,751	13,380	13,731	19,648	15,620	16,971	14,596	20,476	21,019	19,083	13,601	12,230
1976	13,919	16,145	22,676	22,701	19,994	16,581	20,252	23,535	20,709	18,554	18,723	17,458
1977	11,943	12,979	13,106	14,549	10,720	9,554	8,936	11,167	12,187	12,065	11,337	9,835
1978	10,100	12,572	13,349	17,768	15,429	16,608	17,186	19,585	18,675	18,416	13,350	11,168

Table 3: PNW Hydro Generation (aMW) with Hydro Independents for FY 2009

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	11,121	13,308	11,989	13,259	10,529	11,260	10,828	11,580	17,218	14,334	12,000	10,545
1930	11,322	12,767	12,906	11,120	12,235	11,121	11,472	10,956	14,747	14,412	12,520	10,327
1931	11,351	12,859	11,139	11,201	10,878	10,842	10,967	10,290	14,635	13,975	11,878	10,586
1932	10,727	12,715	11,942	11,524	10,128	13,835	18,920	21,178	20,325	17,224	13,242	11,537
1933	11,468	13,477	14,173	20,276	15,598	12,692	14,377	17,814	20,773	18,492	16,017	12,288
1934	13,719	16,580	23,403	22,061	20,564	18,541	19,423	20,900	14,758	14,842	11,615	9,998
1935	11,248	13,497	12,912	19,107	19,400	11,226	14,023	16,710	18,774	17,141	13,200	10,881
1936	11,189	12,777	13,217	11,803	10,832	10,913	14,977	22,088	19,158	14,193	12,548	10,694
1937	11,250	12,738	13,212	10,526	9,993	10,751	11,106	11,813	16,096	13,600	11,948	10,623
1938	11,653	13,532	13,572	19,649	13,718	15,920	17,471	22,746	20,462	16,723	12,184	11,370
1939	11,560	12,958	12,772	15,802	11,029	12,566	14,657	18,345	15,067	15,023	12,709	10,488
1940	11,656	12,798	13,236	14,557	12,735	16,227	15,975	16,433	15,182	14,054	11,168	10,140
1941	11,204	12,393	12,973	14,467	11,288	10,526	10,657	13,080	14,909	13,328	11,397	11,208
1942	11,080	11,973	16,051	18,473	13,628	9,632	13,298	16,331	20,192	18,224	14,434	10,768
1943	11,296	13,340	13,467	18,750	17,964	17,623	20,517	22,459	20,791	18,901	14,622	11,127
1944	11,492	13,075	13,735	14,135	10,865	9,688	10,000	10,680	13,252	13,197	11,353	10,468
1945	10,682	12,487	11,826	11,378	11,151	10,522	10,653	16,707	20,027	14,879	12,370	10,467
1946	11,243	13,543	13,507	17,724	14,790	18,648	19,056	23,460	20,245	18,273	14,321	11,785
1947	11,261	13,612	18,797	20,565	19,617	19,141	16,702	21,143	20,042	17,891	12,868	11,501
1948	16,613	15,292	16,651	21,974	14,632	15,314	17,248	23,403	24,389	18,399	16,714	12,376
1949	12,198	13,462	13,160	15,106	13,950	19,334	18,451	22,758	20,126	13,656	12,055	10,137
1950	11,591	13,738	13,098	17,168	20,102	21,127	19,831	21,132	20,797	18,642	15,510	12,093
1951	14,099	16,590	21,173	22,537	21,805	18,684	20,286	23,191	20,161	18,389	15,394	12,038
1952	15,488	13,895	16,761	20,193	17,019	15,331	20,026	23,558	20,811	16,532	12,886	11,158
1953	11,301	12,987	12,033	16,186	18,060	12,713	13,919	20,314	21,016	18,693	14,745	11,653
1954	12,012	13,682	15,802	18,039	19,726	16,429	17,784	22,052	20,206	18,674	18,343	16,164
1955	12,451	14,296	15,464	14,608	11,688	10,242	13,293	15,879	20,259	18,580	16,601	11,122
1956	13,489	15,552	20,061	22,757	17,798	20,371	20,346	23,330	21,197	18,564	15,389	11,827
1957	12,855	13,486	15,118	17,564	13,509	15,980	18,535	23,583	20,722	16,052	12,190	11,104
1958	11,502	13,076	13,540	15,535	17,232	16,019	16,953	23,008	20,458	15,809	12,512	11,364
1959	11,547	14,431	17,836	21,906	19,781	16,125	17,398	20,017	20,205	18,360	14,917	16,569
1960	17,572	17,347	18,848	20,504	13,323	15,402	20,169	18,346	20,036	17,052	13,002	11,435
1961	11,602	13,658	13,788	18,474	18,829	16,852	16,540	20,416	19,891	16,639	13,029	10,692
1962	11,643	13,405	13,096	17,354	13,266	11,164	19,761	19,898	19,635	17,330	13,822	11,095
1963	12,679	14,640	18,038	19,831	15,541	11,826	13,665	19,365	20,451	17,196	14,276	11,725
1964	11,276	13,845	13,353	16,908	12,969	10,912	15,602	18,138	21,239	18,540	16,215	12,831
1965	13,499	13,680	19,741	22,702	21,769	19,050	18,910	22,629	20,792	17,323	15,512	11,945
1966	12,635	13,400	14,483	20,278	12,609	11,553	18,053	17,423	18,416	17,566	14,074	10,902
1967	11,459	13,430	13,933	21,948	20,930	13,995	14,113	18,848	21,002	18,464	14,678	11,761
1968	12,386	13,428	13,860	19,169	18,753	16,182	11,551	16,600	20,140	18,305	15,707	13,932
1969	14,136	15,473	16,999	22,309	19,842	14,886	20,272	23,570	20,279	17,796	13,104	11,452
1970	11,939	13,439	13,092	17,931	15,632	13,182	13,134	19,793	20,862	16,441	11,897	10,765
1971	11,576	14,012	13,723	21,147	21,594	18,277	19,492	23,284	21,079	18,973	17,512	12,351
1972	12,578	13,886	14,643	22,280	21,867	21,531	19,814	23,176	22,120	18,669	17,813	13,339
1973	12,386	13,364	15,704	19,740	11,126	10,887	10,796	13,416	15,091	14,217	11,707	9,471
1974	11,054	12,716	17,499	22,983	21,909	21,376	20,266	23,143	22,116	18,785	17,461	12,182
1975	10,755	13,376	13,728	19,648	15,618	16,968	14,658	20,543	21,019	19,084	13,855	12,230
1976	13,924	16,143	22,676	22,702	19,994	16,577	20,285	23,536	20,707	18,556	18,735	17,464
1977	11,948	12,976	13,103	14,547	10,715	9,549	8,956	11,208	12,313	12,200	11,422	9,834
1978	10,104	12,568	13,344	17,766	15,425	16,605	17,248	19,652	18,864	18,415	13,557	11,167

Table 4: Federal Hydro Generation (aMW) with Hydro Independents for FY 2007

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	6,000	7,325	6,723	7,507	5,535	6,453	5,336	5,874	10,138	8,224	7,087	6,217
1930	6,516	7,458	7,298	5,510	6,822	6,357	5,910	5,806	8,595	8,807	7,691	6,027
1931	6,532	7,424	6,597	5,588	5,524	6,103	5,702	5,759	8,519	8,452	7,585	6,397
1932	6,157	7,252	6,794	5,654	5,264	7,889	11,089	13,277	11,503	10,125	7,982	6,873
1933	6,494	6,843	7,849	12,147	9,569	7,197	8,218	10,811	10,551	9,537	9,649	7,192
1934	7,371	8,974	14,126	11,929	11,608	10,713	11,118	12,861	8,129	9,045	6,817	5,979
1935	6,211	6,775	6,956	11,110	11,681	6,199	8,111	9,831	10,647	10,027	7,998	6,346
1936	6,337	7,297	7,112	6,367	5,714	6,341	8,738	14,056	11,082	8,420	7,611	6,225
1937	6,441	7,345	7,161	5,524	5,803	6,108	5,686	6,487	8,765	7,719	7,295	6,233
1938	6,574	7,028	7,373	11,432	7,849	9,433	10,183	13,876	11,931	9,702	6,922	6,885
1939	6,602	7,278	7,148	8,705	5,772	7,095	8,125	10,970	8,177	8,973	7,895	6,165
1940	6,704	7,221	7,428	8,048	6,871	9,586	9,277	10,146	8,918	8,245	6,583	6,123
1941	6,587	7,095	7,534	8,509	5,701	6,042	5,736	7,841	8,741	7,874	6,909	6,848
1942	6,352	6,842	9,424	11,573	7,740	5,430	7,344	9,971	12,087	11,013	8,931	6,301
1943	6,428	7,024	7,276	10,894	10,522	10,620	11,315	13,620	11,847	10,609	8,687	6,415
1944	6,365	7,211	7,112	8,275	5,652	5,488	4,873	5,765	7,343	7,689	6,823	6,300
1945	6,240	7,282	6,451	5,708	6,211	5,940	5,253	9,962	12,002	8,582	7,167	6,158
1946	6,191	7,221	7,323	9,753	8,379	11,074	11,181	14,292	11,478	10,635	8,638	6,923
1947	6,144	7,163	11,025	12,130	11,468	11,350	9,172	13,241	11,773	10,796	7,622	6,694
1948	9,236	8,090	9,778	13,340	8,411	9,266	10,001	14,696	13,983	10,638	10,064	7,185
1949	6,689	7,116	7,418	8,625	7,764	11,685	10,745	13,927	11,546	7,389	6,499	5,881
1950	6,387	7,022	6,911	9,480	12,140	12,521	11,311	12,942	10,323	10,089	8,944	6,959
1951	7,576	8,639	11,966	12,796	11,805	10,794	11,547	14,193	11,567	10,720	9,337	6,862
1952	8,496	7,215	9,758	11,742	9,714	8,979	12,054	14,332	12,266	9,631	7,609	6,467
1953	6,379	7,339	6,857	8,352	10,437	7,046	7,683	12,161	11,489	10,559	8,768	6,777
1954	6,610	7,239	8,717	9,920	11,720	9,419	10,116	13,670	10,576	9,793	11,287	9,755
1955	6,836	7,426	8,831	8,369	5,999	5,728	7,412	9,572	10,457	9,438	10,160	6,352
1956	7,079	7,998	11,680	12,740	10,200	12,159	11,264	13,972	10,372	10,510	9,195	6,801
1957	6,875	7,055	8,211	10,015	7,074	9,046	10,981	14,564	11,142	9,538	7,134	6,431
1958	6,400	7,218	7,040	8,472	9,855	9,438	9,792	14,256	11,759	9,364	7,389	6,613
1959	6,352	7,482	10,283	12,690	11,858	9,516	9,707	12,220	10,965	10,352	9,046	9,839
1960	9,861	9,358	11,114	12,574	7,139	8,869	11,210	11,026	11,460	9,881	7,635	6,655
1961	6,478	7,089	7,913	10,346	10,967	9,941	9,632	12,812	10,645	9,901	7,969	6,215
1962	6,481	7,363	7,144	9,852	7,371	6,287	11,346	12,057	11,489	10,379	8,258	6,404
1963	7,091	7,696	10,380	11,844	8,426	6,651	7,356	11,977	12,205	10,277	8,776	6,910
1964	6,169	7,281	7,353	9,342	7,437	5,952	8,930	10,817	10,794	9,868	9,764	7,465
1965	7,601	7,264	11,633	12,821	12,795	11,446	10,885	13,923	11,927	9,942	9,306	6,886
1966	7,051	7,217	8,420	11,869	7,132	6,129	10,391	10,276	10,614	10,271	8,689	6,274
1967	6,354	7,212	7,480	12,848	12,719	8,039	7,450	11,057	10,648	10,459	9,038	6,917
1968	6,611	7,006	7,691	10,767	10,684	9,069	6,069	9,922	11,332	11,094	9,598	8,140
1969	7,735	8,162	9,858	13,018	11,897	8,544	11,415	14,169	11,235	10,632	7,983	6,579
1970	6,557	7,285	7,282	10,068	9,043	7,494	7,180	11,903	11,860	9,692	6,927	6,151
1971	6,396	7,737	7,145	12,245	11,882	10,583	11,499	14,239	10,787	10,337	10,744	7,214
1972	6,846	7,282	8,301	12,884	12,801	11,388	10,293	14,081	11,364	9,804	11,047	7,826
1973	6,903	7,138	8,684	11,365	5,991	5,921	5,176	7,688	8,536	8,336	6,934	5,537
1974	6,225	6,685	10,009	12,186	11,708	12,533	11,386	14,199	11,307	9,367	10,629	7,068
1975	5,881	7,223	7,356	11,012	9,168	10,286	8,274	12,221	11,412	10,119	7,902	7,025
1976	7,690	8,529	13,128	12,735	11,831	9,628	11,777	14,450	11,688	10,125	11,181	10,759
1977	6,691	7,146	7,106	8,577	5,503	5,019	4,419	6,222	6,994	7,273	7,148	5,946
1978	5,851	6,946	7,452	10,120	9,009	9,821	9,793	11,448	10,908	11,119	7,931	6,333

Table 5: Federal Hydro Generation (aMW) with Hydro Independents for FY 2008

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	6,014	7,340	6,739	7,527	5,547	6,469	5,350	5,892	10,161	8,325	7,162	6,220
1930	6,531	7,474	7,314	5,523	6,838	6,372	5,926	5,822	8,615	8,912	7,772	6,031
1931	6,548	7,440	6,613	5,602	5,536	6,118	5,717	5,777	8,537	8,551	7,667	6,401
1932	6,172	7,268	6,809	5,667	5,276	7,910	11,118	13,310	11,532	10,253	8,070	6,877
1933	6,509	6,858	7,868	12,172	9,591	7,212	8,236	10,835	10,589	9,566	9,758	7,196
1934	7,388	8,994	14,157	11,965	11,637	10,738	11,153	12,889	8,145	9,159	6,895	5,983
1935	6,225	6,790	6,973	11,134	11,705	6,212	8,131	9,856	10,673	10,155	8,090	6,350
1936	6,352	7,312	7,128	6,382	5,726	6,358	8,759	14,092	11,105	8,523	7,695	6,228
1937	6,456	7,360	7,177	5,537	5,815	6,123	5,700	6,505	8,784	7,817	7,376	6,237
1938	6,589	7,043	7,390	11,458	7,866	9,456	10,208	13,909	11,960	9,826	6,999	6,889
1939	6,617	7,293	7,165	8,725	5,785	7,114	8,146	11,000	8,196	9,082	7,981	6,168
1940	6,720	7,236	7,444	8,067	6,888	9,611	9,301	10,173	8,941	8,346	6,658	6,126
1941	6,603	7,110	7,552	8,529	5,714	6,059	5,750	7,861	8,764	7,975	6,988	6,851
1942	6,368	6,858	9,447	11,600	7,755	5,444	7,364	9,997	12,119	11,148	9,028	6,305
1943	6,443	7,039	7,293	10,920	10,546	10,647	11,349	13,654	11,879	10,636	8,784	6,419
1944	6,381	7,226	7,129	8,296	5,665	5,502	4,887	5,782	7,363	7,785	6,898	6,303
1945	6,254	7,298	6,467	5,722	6,226	5,955	5,267	9,989	12,032	8,690	7,246	6,161
1946	6,206	7,236	7,340	9,776	8,401	11,101	11,209	14,326	11,504	10,767	8,733	6,926
1947	6,160	7,179	11,053	12,158	11,495	11,376	9,195	13,275	11,800	10,928	7,708	6,698
1948	9,257	8,109	9,801	13,369	8,430	9,287	10,026	14,735	14,023	10,664	10,175	7,190
1949	6,705	7,131	7,437	8,646	7,782	11,716	10,773	13,962	11,572	7,486	6,572	5,884
1950	6,402	7,038	6,927	9,503	12,167	12,552	11,341	12,971	10,361	10,117	9,046	6,963
1951	7,594	8,660	11,995	12,828	11,838	10,821	11,577	14,227	11,592	10,745	9,439	6,867
1952	8,515	7,232	9,782	11,770	9,738	9,002	12,086	14,372	12,296	9,752	7,695	6,471
1953	6,394	7,355	6,873	8,374	10,464	7,063	7,700	12,190	11,526	10,586	8,865	6,781
1954	6,626	7,255	8,737	9,944	11,746	9,440	10,142	13,701	10,608	9,821	11,353	9,762
1955	6,853	7,444	8,851	8,387	6,013	5,741	7,429	9,595	10,496	9,469	10,271	6,356
1956	7,096	8,017	11,709	12,774	10,225	12,190	11,297	14,011	10,411	10,536	9,296	6,804
1957	6,892	7,070	8,232	10,038	7,090	9,067	11,010	14,602	11,180	9,657	7,213	6,434
1958	6,416	7,234	7,057	8,494	9,879	9,460	9,816	14,292	11,792	9,478	7,470	6,617
1959	6,367	7,500	10,308	12,722	11,885	9,538	9,730	12,247	11,000	10,379	9,145	9,845
1960	9,885	9,380	11,139	12,601	7,157	8,891	11,240	11,051	11,489	10,010	7,721	6,659
1961	6,493	7,106	7,931	10,369	10,991	9,965	9,655	12,839	10,680	10,021	8,054	6,218
1962	6,496	7,379	7,159	9,875	7,387	6,303	11,377	12,083	11,515	10,507	8,350	6,408
1963	7,108	7,714	10,404	11,868	8,449	6,670	7,374	12,008	12,236	10,405	8,871	6,914
1964	6,184	7,296	7,369	9,365	7,455	5,967	8,953	10,843	10,832	9,898	9,870	7,469
1965	7,619	7,281	11,663	12,858	12,829	11,475	10,914	13,958	11,961	10,076	9,410	6,890
1966	7,068	7,234	8,442	11,895	7,148	6,146	10,414	10,302	10,637	10,402	8,782	6,277
1967	6,369	7,227	7,497	12,875	12,747	8,056	7,470	11,081	10,685	10,487	9,136	6,921
1968	6,627	7,023	7,712	10,793	10,709	9,091	6,085	9,946	11,362	11,119	9,704	8,145
1969	7,753	8,182	9,881	13,052	11,925	8,569	11,448	14,206	11,263	10,762	8,068	6,583
1970	6,572	7,301	7,299	10,095	9,069	7,512	7,196	11,931	11,895	9,813	7,002	6,154
1971	6,412	7,753	7,164	12,278	11,918	10,611	11,528	14,278	10,825	10,366	10,859	7,218
1972	6,861	7,299	8,323	12,915	12,835	11,423	10,322	14,119	11,404	9,833	11,119	7,831
1973	6,918	7,154	8,706	11,393	6,005	5,936	5,189	7,707	8,556	8,438	7,008	5,540
1974	6,240	6,701	10,035	12,225	11,742	12,565	11,420	14,236	11,346	9,401	10,745	7,073
1975	5,895	7,239	7,375	11,038	9,189	10,311	8,296	12,251	11,447	10,152	7,992	7,029
1976	7,708	8,549	13,161	12,768	11,858	9,654	11,808	14,487	11,716	10,154	11,191	10,766
1977	6,708	7,162	7,124	8,597	5,515	5,032	4,431	6,239	7,010	7,360	7,226	5,949
1978	5,865	6,961	7,471	10,144	9,029	9,848	9,816	11,476	10,935	11,144	8,018	6,337

Table 6: Federal Hydro Generation (aMW) with Hydro Independents for FY 2009

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	6,018	7,345	6,744	7,533	5,551	6,472	5,419	5,964	10,349	8,578	7,371	6,229
1930	6,535	7,479	7,319	5,526	6,842	6,376	5,995	5,894	8,787	9,147	7,964	6,040
1931	6,552	7,445	6,618	5,605	5,540	6,121	5,786	5,850	8,676	8,696	7,752	6,410
1932	6,176	7,273	6,814	5,670	5,279	7,913	11,155	13,385	11,541	10,499	8,274	6,887
1933	6,513	6,863	7,874	12,180	9,598	7,215	8,306	10,911	10,599	9,577	9,959	7,207
1934	7,393	9,001	14,167	11,976	11,646	10,744	11,161	12,968	8,245	9,323	7,005	5,992
1935	6,229	6,794	6,978	11,142	11,713	6,215	8,201	9,932	10,854	10,377	8,245	6,359
1936	6,356	7,318	7,133	6,386	5,729	6,361	8,793	14,169	11,285	8,759	7,893	6,237
1937	6,460	7,366	7,182	5,541	5,819	6,127	5,769	6,578	8,954	8,053	7,506	6,246
1938	6,594	7,048	7,394	11,466	7,871	9,460	10,278	13,985	11,966	10,085	7,243	6,899
1939	6,622	7,298	7,169	8,731	5,789	7,117	8,214	11,076	8,361	9,313	8,101	6,177
1940	6,724	7,241	7,449	8,072	6,892	9,616	9,371	10,248	9,113	8,578	6,801	6,135
1941	6,607	7,115	7,557	8,535	5,718	6,062	5,819	7,936	8,944	8,222	7,224	6,861
1942	6,372	6,862	9,453	11,608	7,758	5,447	7,432	10,071	12,128	11,392	9,244	6,314
1943	6,447	7,043	7,298	10,927	10,551	10,651	11,356	13,730	11,886	10,643	9,030	6,428
1944	6,385	7,231	7,134	8,302	5,668	5,505	4,956	5,854	7,538	8,036	7,114	6,312
1945	6,258	7,303	6,472	5,725	6,229	5,959	5,336	10,062	12,039	8,948	7,473	6,170
1946	6,210	7,241	7,344	9,781	8,406	11,106	11,279	14,335	11,513	11,006	8,967	6,937
1947	6,164	7,184	11,060	12,166	11,500	11,382	9,265	13,295	11,993	11,167	7,952	6,707
1948	9,263	8,114	9,807	13,377	8,434	9,291	10,096	14,744	14,149	10,672	10,406	7,201
1949	6,709	7,136	7,442	8,653	7,786	11,721	10,809	13,970	11,580	7,740	6,806	5,892
1950	6,407	7,043	6,931	9,509	12,173	12,559	11,411	13,047	10,370	10,125	9,286	6,973
1951	7,599	8,665	12,003	12,837	11,846	10,826	11,583	14,236	11,599	10,754	9,674	6,877
1952	8,521	7,237	9,788	11,778	9,743	9,007	12,092	14,382	12,303	10,018	7,941	6,480
1953	6,399	7,360	6,878	8,378	10,470	7,066	7,769	12,266	11,536	10,595	9,104	6,791
1954	6,630	7,260	8,743	9,951	11,752	9,445	10,212	13,777	10,618	9,831	11,477	9,777
1955	6,858	7,449	8,858	8,393	6,017	5,745	7,498	9,668	10,507	9,481	10,483	6,365
1956	7,100	8,022	11,716	12,783	10,230	12,196	11,305	14,021	10,422	10,544	9,534	6,814
1957	6,896	7,075	8,238	10,046	7,094	9,071	11,081	14,611	11,191	9,906	7,459	6,443
1958	6,420	7,239	7,061	8,501	9,884	9,465	9,885	14,300	11,801	9,727	7,720	6,626
1959	6,371	7,505	10,314	12,731	11,892	9,542	9,801	12,324	11,009	10,388	9,379	9,860
1960	9,892	9,387	11,146	12,609	7,162	8,895	11,248	11,127	11,497	10,239	7,948	6,669
1961	6,497	7,111	7,937	10,377	10,997	9,970	9,727	12,916	10,691	10,242	8,205	6,227
1962	6,500	7,384	7,164	9,883	7,390	6,306	11,414	12,159	11,709	10,748	8,583	6,417
1963	7,113	7,719	10,411	11,876	8,453	6,675	7,444	12,084	12,338	10,653	9,107	6,925
1964	6,188	7,301	7,374	9,372	7,459	5,970	9,022	10,917	10,842	9,908	10,106	7,481
1965	7,624	7,286	11,670	12,868	12,836	11,480	10,950	13,986	11,968	10,359	9,656	6,899
1966	7,072	7,239	8,448	11,903	7,153	6,149	10,485	10,379	10,809	10,618	8,929	6,286
1967	6,373	7,232	7,503	12,883	12,755	8,061	7,541	11,154	10,695	10,496	9,362	6,932
1968	6,631	7,028	7,717	10,801	10,714	9,096	6,140	10,021	11,371	11,129	9,938	8,158
1969	7,759	8,187	9,887	13,060	11,932	8,574	11,456	14,217	11,272	11,001	8,303	6,592
1970	6,576	7,306	7,305	10,101	9,074	7,515	7,267	12,005	11,902	10,087	7,252	6,162
1971	6,416	7,758	7,168	12,285	11,927	10,616	11,598	14,288	10,835	10,375	11,089	7,228
1972	6,866	7,304	8,328	12,922	12,843	11,430	10,363	14,128	11,533	9,843	11,244	7,842
1973	6,923	7,159	8,712	11,401	6,008	5,940	5,258	7,781	8,729	8,673	7,181	5,548
1974	6,244	6,705	10,041	12,236	11,751	12,570	11,427	14,244	11,435	9,412	10,977	7,084
1975	5,899	7,244	7,379	11,045	9,195	10,317	8,366	12,326	11,455	10,162	8,254	7,039
1976	7,713	8,555	13,168	12,776	11,866	9,658	11,848	14,496	11,722	10,164	11,211	10,783
1977	6,713	7,167	7,129	8,603	5,518	5,035	4,459	6,288	7,144	7,503	7,320	5,958
1978	5,869	6,966	7,475	10,150	9,032	9,853	9,886	11,552	11,133	11,152	8,232	6,346

Table 7: Heavy-Load-Hour Hydro Generation Ratios for FY 2007

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	1.2139	1.1792	1.1633	1.1805	1.1138	1.1209	1.1072	1.1063	1.2246	1.2196	1.2434	1.2351
1930	1.2168	1.1850	1.1639	1.1521	1.1335	1.1295	1.1076	1.1018	1.2642	1.2337	1.2451	1.2363
1931	1.2177	1.1840	1.1666	1.1409	1.1143	1.1209	1.1133	1.1701	1.2622	1.2488	1.2503	1.2393
1932	1.2167	1.1802	1.1638	1.1405	1.1103	1.1195	1.1179	1.1504	1.1823	1.2102	1.2081	1.2421
1933	1.2166	1.1679	1.1839	1.1730	1.2149	1.1128	1.1533	1.1766	1.0865	1.1010	1.1964	1.2347
1934	1.2023	1.2107	1.1868	1.0760	1.1604	1.2083	1.1100	1.1282	1.2393	1.2237	1.2452	1.2420
1935	1.2143	1.1686	1.1731	1.1972	1.1834	1.1063	1.1761	1.2166	1.2213	1.2154	1.2188	1.2363
1936	1.2161	1.1808	1.1656	1.1655	1.1130	1.1248	1.0756	1.1206	1.2376	1.2352	1.2401	1.2333
1937	1.2170	1.1829	1.1646	1.1667	1.1246	1.1281	1.1088	1.1174	1.2228	1.2335	1.2446	1.2339
1938	1.2197	1.1741	1.1651	1.1644	1.1424	1.1874	1.1634	1.1120	1.1900	1.2239	1.2326	1.2437
1939	1.2200	1.1786	1.1639	1.1958	1.1230	1.1287	1.1105	1.1977	1.2638	1.2276	1.2372	1.2343
1940	1.2187	1.1799	1.1673	1.1766	1.1365	1.1910	1.1643	1.2141	1.2574	1.2350	1.2453	1.2339
1941	1.2186	1.1732	1.1786	1.2038	1.1180	1.1234	1.1083	1.2019	1.2602	1.2394	1.2431	1.2350
1942	1.2176	1.1682	1.2333	1.1662	1.1322	1.1131	1.1118	1.2079	1.1745	1.1992	1.1947	1.2321
1943	1.2161	1.1699	1.1674	1.2350	1.1817	1.1659	1.1237	1.1060	1.1717	1.1770	1.2021	1.2373
1944	1.2174	1.1785	1.1641	1.1944	1.1184	1.1117	1.1038	1.1441	1.2413	1.2356	1.2439	1.2354
1945	1.2126	1.1817	1.1629	1.1444	1.1236	1.1216	1.1072	1.1744	1.2172	1.2243	1.2303	1.2309
1946	1.2179	1.1771	1.1703	1.2194	1.1813	1.1851	1.1524	1.0804	1.1890	1.2015	1.2078	1.2400
1947	1.2164	1.1716	1.2275	1.1811	1.1983	1.2113	1.1675	1.1614	1.2069	1.2134	1.2115	1.2412
1948	1.1942	1.2022	1.2212	1.2042	1.1371	1.1680	1.1513	1.0969	1.0054	1.1830	1.1973	1.2328
1949	1.2215	1.1767	1.1788	1.2140	1.1453	1.1804	1.0865	1.1480	1.2166	1.2245	1.2413	1.2258
1950	1.2169	1.1727	1.1714	1.2297	1.2100	1.1829	1.1508	1.1171	1.0429	1.1693	1.2118	1.2396
1951	1.2221	1.2060	1.2364	1.1516	1.1578	1.1847	1.1198	1.0399	1.1977	1.1794	1.2081	1.2343
1952	1.2014	1.1815	1.2272	1.1895	1.1949	1.2000	1.1207	1.0709	1.2085	1.2213	1.2198	1.2391
1953	1.2136	1.1822	1.1643	1.1977	1.2094	1.1190	1.1268	1.1777	1.1253	1.1844	1.2042	1.2385
1954	1.2202	1.1773	1.2059	1.2346	1.2118	1.1944	1.1529	1.0985	1.0348	1.1411	1.1854	1.2384
1955	1.2153	1.1964	1.2053	1.1765	1.1319	1.1249	1.1089	1.1851	1.0387	1.0767	1.1887	1.2300
1956	1.2203	1.2008	1.2286	1.1528	1.1934	1.1926	1.0885	1.0332	1.0651	1.1720	1.2007	1.2386
1957	1.2231	1.1718	1.2119	1.2310	1.1323	1.1285	1.1644	1.1226	1.0846	1.2205	1.2365	1.2409
1958	1.2188	1.1779	1.1647	1.2260	1.1917	1.1959	1.1371	1.1469	1.1518	1.2222	1.2361	1.2424
1959	1.2163	1.1900	1.2313	1.1509	1.1967	1.1808	1.1955	1.1351	1.1044	1.1545	1.2013	1.2268
1960	1.1849	1.2091	1.2378	1.2222	1.1482	1.1776	1.1400	1.2009	1.1981	1.2086	1.2159	1.2434
1961	1.2192	1.1793	1.1787	1.2253	1.2090	1.1969	1.1704	1.1643	1.0254	1.2257	1.2402	1.2411
1962	1.2155	1.1746	1.1697	1.2330	1.1268	1.1196	1.1290	1.1855	1.2048	1.2066	1.2239	1.2417
1963	1.2222	1.1932	1.2348	1.2372	1.1457	1.1646	1.1629	1.2001	1.2183	1.2121	1.1946	1.2371
1964	1.2116	1.1742	1.1688	1.2370	1.1442	1.1206	1.1441	1.1941	1.0750	1.1030	1.2035	1.2337
1965	1.2202	1.1814	1.2189	1.1458	1.1815	1.1896	1.1444	1.1133	1.1606	1.2000	1.2016	1.2382
1966	1.2231	1.1846	1.2010	1.2004	1.1369	1.1271	1.2063	1.2174	1.2484	1.1966	1.2038	1.2362
1967	1.2138	1.1769	1.1719	1.1664	1.1678	1.1631	1.1889	1.2017	1.0736	1.1446	1.1996	1.2422
1968	1.2215	1.1807	1.1992	1.2155	1.2015	1.1904	1.1468	1.2281	1.1915	1.1642	1.1925	1.2310
1969	1.2214	1.2011	1.2232	1.1522	1.2103	1.1698	1.1134	1.0640	1.1826	1.2065	1.2196	1.2439
1970	1.2162	1.1814	1.1716	1.2381	1.1911	1.1254	1.1619	1.1970	1.1797	1.2217	1.2316	1.2305
1971	1.2152	1.1774	1.1630	1.1996	1.1430	1.1725	1.1361	1.0299	1.1129	1.1690	1.1878	1.2384
1972	1.2154	1.1740	1.1962	1.1996	1.1608	1.0926	1.1406	1.0539	1.0321	1.1375	1.1820	1.2343
1973	1.2164	1.1730	1.2069	1.2101	1.1215	1.1213	1.1036	1.1828	1.2635	1.2276	1.2476	1.2287
1974	1.2140	1.1590	1.2315	1.0958	1.1523	1.1797	1.0797	1.0317	1.0293	1.0678	1.1895	1.2411
1975	1.2136	1.1766	1.1711	1.2298	1.1866	1.1930	1.1609	1.1231	1.1319	1.1396	1.2306	1.2417
1976	1.2263	1.2051	1.2207	1.1492	1.1964	1.1577	1.1472	1.0833	1.1922	1.0702	1.1488	1.2390
1977	1.2197	1.1782	1.1649	1.2013	1.1160	1.0994	1.0968	1.1776	1.2366	1.2508	1.2488	1.2323
1978	1.2094	1.1699	1.1571	1.2387	1.1281	1.2104	1.1796	1.1372	1.2002	1.1962	1.2285	1.2426

Table 8: Heavy-Load-Hour Hydro Generation Ratios for FY 2008

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	1.21381	1.17878	1.16272	1.18002	1.11235	1.12017	1.10745	1.10595	1.22357	1.21954	1.24277	1.23539
1930	1.21675	1.18453	1.16340	1.15173	1.13125	1.12872	1.10786	1.10146	1.26303	1.23362	1.24443	1.23663
1931	1.21763	1.18357	1.16606	1.14052	1.11302	1.12015	1.11355	1.16954	1.26121	1.24865	1.24963	1.23960
1932	1.21662	1.17975	1.16333	1.14010	1.10903	1.11868	1.11808	1.15000	1.18121	1.21012	1.20737	1.24238
1933	1.21657	1.16751	1.18333	1.17258	1.21388	1.11214	1.15341	1.17612	1.08537	1.10122	1.19573	1.23503
1934	1.20228	1.21019	1.18628	1.07568	1.15951	1.20731	1.11039	1.12786	1.23838	1.22364	1.24458	1.24225
1935	1.21430	1.16814	1.17254	1.19677	1.18243	1.10570	1.17607	1.21603	1.22025	1.21537	1.21812	1.23661
1936	1.21607	1.18032	1.16514	1.16506	1.11177	1.12397	1.07589	1.12026	1.23659	1.23512	1.23949	1.23364
1937	1.21692	1.18248	1.16413	1.16620	1.12328	1.12727	1.10904	1.11702	1.22180	1.23338	1.24402	1.23415
1938	1.21960	1.17362	1.16458	1.16400	1.14127	1.18649	1.16350	1.11169	1.18906	1.22384	1.23199	1.24403
1939	1.21992	1.17811	1.16342	1.19529	1.12114	1.12786	1.11076	1.19706	1.26262	1.22750	1.23658	1.23462
1940	1.21866	1.17947	1.16679	1.17614	1.13462	1.19005	1.16448	1.21345	1.25621	1.23489	1.24458	1.23423
1941	1.21856	1.17273	1.17805	1.20323	1.11677	1.12257	1.10851	1.20135	1.25894	1.23929	1.24241	1.23527
1942	1.21752	1.16772	1.23257	1.16573	1.13107	1.11226	1.11203	1.20736	1.17345	1.19921	1.19407	1.23239
1943	1.21607	1.16946	1.16682	1.23433	1.18024	1.16495	1.12395	1.10572	1.17059	1.17695	1.20143	1.23764
1944	1.21733	1.17807	1.16355	1.19387	1.11673	1.11095	1.10411	1.14362	1.24005	1.23556	1.24334	1.23573
1945	1.21252	1.18123	1.16236	1.14398	1.12148	1.12079	1.10743	1.17391	1.21613	1.22420	1.22959	1.23117
1946	1.21788	1.17667	1.16973	1.21885	1.17956	1.18415	1.15253	1.08013	1.18804	1.20145	1.20712	1.24034
1947	1.21633	1.17110	1.22682	1.18060	1.19678	1.21033	1.16758	1.16094	1.20589	1.21332	1.21082	1.24154
1948	1.19421	1.20169	1.22052	1.20368	1.13544	1.16713	1.15143	1.09661	1.00468	1.18298	1.19664	1.23315
1949	1.22142	1.17624	1.17821	1.21338	1.14373	1.17944	1.08679	1.14754	1.21564	1.22442	1.24063	1.22614
1950	1.21688	1.17226	1.17083	1.22906	1.20850	1.18191	1.15097	1.11676	1.04192	1.16931	1.21103	1.23993
1951	1.22199	1.20540	1.23566	1.15120	1.15562	1.18373	1.12001	1.03976	1.19678	1.17936	1.20735	1.23466
1952	1.20139	1.18099	1.22645	1.18905	1.19289	1.19895	1.12089	1.07068	1.20750	1.22124	1.21905	1.23941
1953	1.21351	1.18177	1.16378	1.19718	1.20704	1.11819	1.12692	1.17720	1.12416	1.18442	1.20352	1.23880
1954	1.22013	1.17683	1.20529	1.23399	1.21009	1.19359	1.15301	1.09824	1.03401	1.14123	1.18482	1.23869
1955	1.21523	1.19587	1.20475	1.17602	1.13027	1.12414	1.10925	1.18460	1.03770	1.07704	1.18807	1.23036
1956	1.22024	1.20027	1.22794	1.15233	1.19181	1.19160	1.08875	1.03307	1.06400	1.17198	1.19996	1.23893
1957	1.22304	1.17139	1.21123	1.23039	1.13038	1.12773	1.16460	1.12226	1.08354	1.22045	1.23579	1.24124
1958	1.21871	1.17748	1.16418	1.22538	1.18938	1.19494	1.13718	1.14645	1.15078	1.22219	1.23545	1.24272
1959	1.21629	1.18946	1.23059	1.15049	1.19569	1.17993	1.19556	1.13475	1.10336	1.15456	1.20063	1.22716
1960	1.18498	1.20852	1.23711	1.22173	1.14637	1.17664	1.14036	1.20041	1.19702	1.20853	1.21523	1.24374
1961	1.21914	1.17883	1.17816	1.22475	1.20683	1.19594	1.17049	1.16387	1.02452	1.22566	1.23951	1.24141
1962	1.21543	1.17419	1.16925	1.23244	1.12562	1.11883	1.12918	1.18503	1.20388	1.20660	1.22316	1.24201
1963	1.22212	1.19270	1.23416	1.23665	1.14371	1.16359	1.16301	1.19956	1.21723	1.21209	1.19389	1.23746
1964	1.21154	1.17380	1.16827	1.23636	1.14270	1.11980	1.14432	1.19363	1.07394	1.10327	1.20290	1.23400
1965	1.22010	1.18093	1.21815	1.14537	1.18011	1.18865	1.14452	1.11294	1.15949	1.19998	1.20090	1.23858
1966	1.22300	1.18411	1.20029	1.19989	1.13546	1.12623	1.20631	1.21675	1.24741	1.19655	1.20312	1.23653
1967	1.21381	1.17644	1.17138	1.16597	1.16685	1.16232	1.18894	1.20118	1.07258	1.14465	1.19888	1.24246
1968	1.22141	1.18018	1.19849	1.21496	1.19952	1.18947	1.14690	1.22748	1.19040	1.16424	1.19188	1.23136
1969	1.22129	1.20060	1.22257	1.15174	1.20880	1.16871	1.11368	1.06377	1.18153	1.20642	1.21888	1.24419
1970	1.21613	1.18099	1.17109	1.23741	1.18933	1.12468	1.16199	1.19647	1.17856	1.22168	1.23092	1.23082
1971	1.21515	1.17701	1.16241	1.19904	1.14144	1.17152	1.13627	1.02974	1.11175	1.16901	1.18716	1.23874
1972	1.21538	1.17351	1.19550	1.19908	1.15872	1.09164	1.14098	1.05372	1.03116	1.13759	1.18137	1.23461
1973	1.21634	1.17254	1.20622	1.20953	1.11982	1.12045	1.10388	1.18233	1.26229	1.22750	1.24692	1.22905
1974	1.21395	1.15857	1.23079	1.09546	1.15081	1.17872	1.08002	1.03156	1.02838	1.06821	1.18888	1.24146
1975	1.21354	1.17615	1.17050	1.22920	1.18493	1.19204	1.16103	1.12275	1.13083	1.13967	1.22988	1.24202
1976	1.22628	1.20452	1.21996	1.14877	1.19499	1.15674	1.14740	1.08300	1.19117	1.07055	1.14813	1.23934
1977	1.21966	1.17772	1.16431	1.20080	1.11439	1.09863	1.09707	1.17703	1.23546	1.25072	1.24815	1.23261
1978	1.20941	1.16946	1.15656	1.23809	1.12714	1.20929	1.17962	1.13677	1.19913	1.19618	1.22771	1.24293

Table 9: Heavy-Load-Hour Hydro Generation Ratios for FY 2009

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	1.21368	1.17812	1.16312	1.17987	1.11352	1.12010	1.10737	1.10513	1.22409	1.21953	1.24244	1.23502
1930	1.21661	1.18385	1.16376	1.15161	1.13308	1.12863	1.10778	1.10068	1.26356	1.23357	1.24408	1.23623
1931	1.21749	1.18289	1.16643	1.14042	1.11399	1.12007	1.11346	1.16866	1.26162	1.24856	1.24915	1.23919
1932	1.21647	1.17909	1.16368	1.14001	1.11000	1.11862	1.11800	1.14933	1.18169	1.21003	1.20699	1.24199
1933	1.21643	1.16686	1.18369	1.17245	1.21430	1.11208	1.15335	1.17546	1.08615	1.10108	1.19541	1.23463
1934	1.20215	1.20948	1.18664	1.07559	1.15993	1.20718	1.11032	1.12724	1.23876	1.22352	1.24412	1.24183
1935	1.21416	1.16749	1.17291	1.19661	1.18286	1.10564	1.17600	1.21530	1.22075	1.21528	1.21772	1.23621
1936	1.21593	1.17965	1.16548	1.16495	1.11267	1.12389	1.07584	1.11954	1.23703	1.23505	1.23916	1.23326
1937	1.21678	1.18180	1.16448	1.16606	1.12421	1.12718	1.10899	1.11623	1.22230	1.23338	1.24362	1.23377
1938	1.21946	1.17297	1.16495	1.16386	1.14200	1.18639	1.16344	1.11106	1.18952	1.22377	1.23172	1.24364
1939	1.21979	1.17745	1.16381	1.19514	1.12259	1.12779	1.11069	1.19627	1.26314	1.22743	1.23615	1.23424
1940	1.21852	1.17880	1.16714	1.17601	1.13613	1.18994	1.16440	1.21271	1.25675	1.23486	1.24415	1.23384
1941	1.21843	1.17208	1.17843	1.20307	1.11768	1.12249	1.10842	1.20062	1.25953	1.23934	1.24208	1.23490
1942	1.21740	1.16705	1.23295	1.16559	1.13184	1.11219	1.11197	1.20665	1.17396	1.19912	1.19376	1.23200
1943	1.21594	1.16882	1.16723	1.23418	1.18123	1.16487	1.12389	1.10507	1.17113	1.17682	1.20114	1.23726
1944	1.21720	1.17741	1.16396	1.19371	1.11806	1.11087	1.10403	1.14283	1.24070	1.23563	1.24304	1.23535
1945	1.21238	1.18056	1.16276	1.14389	1.12327	1.12071	1.10731	1.17317	1.21661	1.22415	1.22927	1.23082
1946	1.21773	1.17601	1.17013	1.21872	1.18068	1.18406	1.15247	1.07951	1.18847	1.20135	1.20680	1.23995
1947	1.21621	1.17044	1.22722	1.18047	1.19770	1.21021	1.16749	1.16024	1.20635	1.21322	1.21053	1.24116
1948	1.19408	1.20097	1.22086	1.20355	1.13668	1.16704	1.15136	1.09592	1.00537	1.18282	1.19635	1.23272
1949	1.22129	1.17558	1.17860	1.21321	1.14490	1.17935	1.08671	1.14685	1.21603	1.22448	1.24036	1.22579
1950	1.21675	1.17161	1.17122	1.22888	1.20942	1.18180	1.15092	1.11616	1.04275	1.16916	1.21070	1.23953
1951	1.22186	1.20468	1.23604	1.15107	1.15725	1.18363	1.11994	1.03915	1.19719	1.17920	1.20704	1.23424
1952	1.20126	1.18030	1.22683	1.18891	1.19434	1.19883	1.12083	1.06996	1.20794	1.22119	1.21877	1.23903
1953	1.21338	1.18110	1.16417	1.19706	1.20875	1.11812	1.12684	1.17653	1.12483	1.18426	1.20322	1.23842
1954	1.21999	1.17617	1.20563	1.23382	1.21123	1.19347	1.15295	1.09763	1.03472	1.14107	1.18457	1.23827
1955	1.21508	1.19514	1.20508	1.17589	1.13153	1.12405	1.10918	1.18396	1.03855	1.07692	1.18777	1.22997
1956	1.22010	1.19957	1.22833	1.15220	1.19280	1.19150	1.08869	1.03236	1.06485	1.17182	1.19967	1.23855
1957	1.22291	1.17074	1.21164	1.23021	1.13195	1.12767	1.16455	1.12156	1.08429	1.22038	1.23551	1.24086
1958	1.21858	1.17681	1.16459	1.22520	1.19110	1.19483	1.13711	1.14576	1.15133	1.22215	1.23514	1.24234
1959	1.21616	1.18875	1.23095	1.15037	1.19612	1.17984	1.19548	1.13413	1.10403	1.15441	1.20033	1.22678
1960	1.18487	1.20779	1.23743	1.22157	1.14776	1.17654	1.14027	1.19973	1.19749	1.20844	1.21495	1.24334
1961	1.21900	1.17813	1.17851	1.22457	1.20841	1.19582	1.17039	1.16327	1.02531	1.22556	1.23909	1.24103
1962	1.21530	1.17355	1.16959	1.23226	1.12643	1.11875	1.12910	1.18439	1.20437	1.20651	1.22284	1.24162
1963	1.22199	1.19198	1.23450	1.23649	1.14525	1.16346	1.16290	1.19882	1.21774	1.21201	1.19359	1.23707
1964	1.21141	1.17315	1.16864	1.23617	1.14378	1.11972	1.14425	1.19297	1.07472	1.10314	1.20261	1.23360
1965	1.21996	1.18024	1.21858	1.14525	1.18095	1.18856	1.14444	1.11226	1.16006	1.19992	1.20061	1.23820
1966	1.22287	1.18341	1.20069	1.19974	1.13652	1.12614	1.20623	1.21597	1.24786	1.19644	1.20277	1.23614
1967	1.21367	1.17578	1.17176	1.16585	1.16731	1.16222	1.18884	1.20061	1.07336	1.14450	1.19858	1.24205
1968	1.22128	1.17947	1.19891	1.21480	1.20093	1.18936	1.14676	1.22678	1.19092	1.16409	1.19159	1.23095
1969	1.22116	1.19988	1.22292	1.15162	1.20971	1.16861	1.11361	1.06307	1.18200	1.20633	1.21855	1.24380
1970	1.21600	1.18030	1.17148	1.23724	1.19042	1.12461	1.16187	1.19583	1.17912	1.22164	1.23062	1.23046
1971	1.21502	1.17638	1.16288	1.19891	1.14247	1.17143	1.13622	1.02906	1.11249	1.16885	1.18689	1.23837
1972	1.21525	1.17284	1.19591	1.19895	1.16028	1.09157	1.14094	1.05304	1.03196	1.13743	1.18112	1.23424
1973	1.21621	1.17187	1.20663	1.20937	1.12118	1.12037	1.10379	1.18164	1.26282	1.22745	1.24653	1.22867
1974	1.21382	1.15790	1.23119	1.09535	1.15169	1.17863	1.07998	1.03093	1.02921	1.06811	1.18859	1.24102
1975	1.21340	1.17547	1.17092	1.22903	1.18606	1.19193	1.16095	1.12210	1.13147	1.13952	1.22959	1.24163
1976	1.22615	1.20378	1.22037	1.14865	1.19579	1.15666	1.14735	1.08233	1.19164	1.07045	1.14783	1.23893
1977	1.21952	1.17704	1.16474	1.20063	1.11563	1.09856	1.09699	1.17620	1.23595	1.25067	1.24770	1.23222
1978	1.20928	1.16880	1.15702	1.23794	1.12781	1.20916	1.17953	1.13609	1.19966	1.19603	1.22741	1.24254

1.5.2 Adjustments to Federal Hydro Generation Tables

The following two sections will discuss adjustments made to Federal hydro generation to account for refilling non-treaty storage in Canada and to reconcile differences between the HYDSIM study for FY 2006 and the HYDSIM study for FY 2007. These storage adjustments are added to the values presented in Tables 4-6 to get the final hydro generation for each of the 50 water years.

1.5.3 Non-Treaty Storage

Adjustments to hydro generation were made for each water year during FY 2007-2009 to reflect the return of non-treaty storage. Since the non-treaty storage agreement expired in FY 2004, BPA is under an obligation to ensure that the storage balance is full by June 30, 2011. Since the current storage balance is 96 ksfd (thousand second foot days) and a full balance is 1134 ksfd, there is a significant amount of water that needs to be stored in the next six years.

The method constructed to model the return of non-treaty storage attempts to minimize the total cost of this return. For purposes of this analysis, it is assumed that 355 ksfd is returned in FY 2006 and that the analysis will focus on the remainder to be returned in FY 2007-2011.

The basic model constructs 50 water year sequences that start in October 2006 and end in July 2011, with each water year incrementing after each October. For FY 2007-2009, hydro generation output from the HYDSIM rate case studies and electricity prices estimated by AURORA were used. For FY 2010-2011, the results from the FY 2009 HYDSIM study and electricity prices estimated by AURORA for FY 2009 were used.

The first step in each water year sequence is to identify opportunities for returning non-treaty storage flows under extremely high flows. The metric chosen for this step is to determine when spill exceeds 150 kcfs, which results in total dissolved gases violating the gas cap at Bonneville dam. Storage under these conditions would occur up to 200 ksfd per month, subject to operational limits in Canada. The median amount of this type of storage over the 50 sequences is 242 ksfd with 2 percent of the sequences able to return the full amount. This is the only storage that is allowed in the April-September period, since additional storage would inhibit Biological Opinion flow objectives.

For sequences in which high flows did not return the full amount, the objective of the next step is to find the lowest cost time to return the remaining amount by July 2011 between October and March. Looking at price variability results from AURORA over the fifty water years, the standard deviations as a percentage of monthly average price were determined for each month. These percentages were used to represent daily price variability and are listed in the following table.

	Oct	Nov	Dec	Jan	Feb	Mar
Avg	3.9%	2.9%	7.8%	11.1%	11.1%	11.2%

Given these daily price distributions, the amount of storage that needs to be returned, a maximal amount that can be stored each day (5 ksfd) and project/operational limitations (Chum, Vernita

Bar, Canadian constraints), a daily plan for returning non-treaty storage can be developed for each sequence. These daily storage amounts are then averaged for each day of the month to yield average monthly storage amounts. The median balance over all 50 sequences is 800 ksfd at the end of FY09 with a range of 192-1134 ksfd.

Given that BC Hydro also needs to return its storage, it is assumed that the amounts of these returns are doubled. Even if BC Hydro does not match BPA's storage return over the course of the month, there will be an energy delivery from BPA to BC hydro that is roughly equivalent to the amount of lost Federal generation that would have occurred had they matched.

These average monthly storage amounts are then multiplied by the Federal h/k (a measure of electrical energy produced per unit of streamflow) reported by HYDSIM to create a matrix of monthly adjustments to Federal hydro generation.

An additional effect of not having returned storage is that the storage elevation of Mica is lower than it would have been had all of the storage been returned. Since the h/k of a hydro project is proportional to the storage elevation, the energy production per unit of streamflow has been reduced at Mica. This energy reduction is called head loss and BPA must also deliver this additional energy to BC Hydro. The amounts for these energy deliveries are computed for each month of each sequence based upon the amount of non-treaty storage returned. Given these storage return computations, the hydro generation adjustments associated with refilling non-treaty storage during FY 2007-2009 are provided in Tables 10-12.

Table 10: Federal Hydro Generation Adjustment for Refill of Non-Treaty Storage, FY 2007

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	-111	0	0	-95	0	0	0	0	0	0	0	0
1930	-530	0	0	0	-43	0	0	0	0	0	0	0
1931	-98	0	0	0	0	0	0	0	0	0	0	0
1932	-236	0	0	0	0	0	0	0	0	0	0	0
1933	-353	0	0	-94	-82	-73	0	0	-288	0	0	0
1934	-508	0	-345	-125	-165	-273	0	0	0	0	0	0
1935	-569	0	0	-206	-435	0	0	0	0	0	0	0
1936	-589	0	0	0	0	0	0	0	0	0	0	0
1937	-589	0	0	0	0	0	0	0	0	0	0	0
1938	-549	0	0	-143	-62	-310	0	0	0	0	0	0
1939	-432	0	0	-57	0	0	0	0	0	0	0	0
1940	-529	0	0	-39	0	-367	0	0	0	0	0	0
1941	-588	0	0	-77	0	0	0	0	0	0	0	0
1942	-471	0	-20	-104	-62	0	0	0	0	0	0	0
1943	-334	0	0	-114	-248	-354	-217	0	0	0	0	0
1944	-354	0	0	-19	0	0	0	0	0	0	0	0
1945	-39	0	0	0	0	0	0	0	0	0	0	0
1946	0	0	0	0	0	-15	0	0	0	0	0	0
1947	0	0	0	0	0	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	-262	0	0	0	0
1949	0	0	0	0	0	-45	0	-445	0	0	0	0
1950	0	0	0	0	0	-320	0	0	-53	0	0	0
1951	0	0	0	-84	-119	-23	0	-49	0	0	0	0
1952	0	0	0	0	0	0	0	-271	0	0	0	0
1953	0	0	0	0	0	0	0	0	0	0	0	0
1954	0	0	0	0	0	0	0	0	-47	0	0	0
1955	0	0	0	0	0	0	0	0	-335	0	0	0
1956	0	0	0	0	0	0	-119	-68	-295	0	0	0
1957	0	0	0	0	0	-37	0	-404	-288	0	0	0
1958	-59	0	0	-19	-103	-128	0	0	0	0	0	0
1959	-39	0	0	-79	-118	-91	0	0	-81	0	0	0
1960	-489	0	-18	-47	-22	-116	0	0	0	0	0	0
1961	0	0	0	-19	-57	-148	0	0	-66	0	0	0
1962	-118	0	0	-38	-21	0	0	0	0	0	0	0
1963	-78	0	0	-31	-21	-19	0	0	0	0	0	0
1964	-20	0	0	-19	0	0	0	0	-288	0	0	0
1965	0	0	0	-112	-360	-90	0	0	0	0	0	0
1966	-98	0	0	-31	0	0	0	0	0	0	0	0
1967	0	0	0	-31	-33	0	0	0	-227	0	0	0
1968	0	0	0	0	0	0	0	0	0	0	0	0
1969	0	0	0	0	0	0	0	-270	0	0	0	0
1970	0	0	0	0	0	0	0	0	0	0	0	0
1971	0	0	0	0	0	0	0	-260	-232	0	0	0
1972	0	0	0	0	0	0	0	-197	0	0	0	0
1973	0	0	0	0	0	0	0	0	0	0	0	0
1974	0	0	0	-15	-31	-244	0	-50	0	0	0	0
1975	-58	0	0	-57	-41	-200	0	0	-394	0	0	0
1976	-547	0	-242	-362	-202	-331	0	-243	0	0	0	0
1977	-588	0	0	-152	0	0	0	0	0	0	0	0
1978	-122	0	0	-324	-331	-481	0	0	0	0	0	0

Table 11: Federal Hydro Generation Adjustment for Refill of Non-Treaty Storage, FY 2008

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	-451	0	0	0	-128	0	0	0	0	0	0	0
1930	-20	0	0	0	0	0	0	0	0	0	0	0
1931	0	0	0	0	0	0	0	0	0	0	0	0
1932	0	0	0	-78	-62	-55	0	0	-288	0	0	0
1933	-39	0	-431	-132	-103	-182	0	0	0	0	0	0
1934	0	0	0	-69	-117	0	0	0	0	0	0	0
1935	-59	0	0	0	0	0	0	0	0	0	0	0
1936	-137	0	0	0	0	0	0	0	0	0	0	0
1937	-98	0	-20	-239	-103	-274	0	0	0	0	0	0
1938	-39	0	0	-76	0	0	0	0	0	0	0	0
1939	0	0	0	-39	0	-174	0	0	0	0	0	0
1940	0	0	0	-38	0	0	0	0	0	0	0	0
1941	-59	0	-39	-173	-83	0	0	0	0	0	0	0
1942	0	0	0	-114	-152	-185	-217	0	0	0	0	0
1943	0	0	0	-19	0	0	0	0	0	0	0	0
1944	0	0	0	0	0	0	0	0	0	0	0	0
1945	0	0	0	-19	-21	-105	0	0	0	0	0	0
1946	0	0	0	0	0	0	0	0	0	0	0	0
1947	0	0	0	0	0	0	0	-262	0	0	0	0
1948	0	0	0	0	0	0	0	-445	0	0	0	0
1949	0	0	0	0	0	-238	0	0	-53	0	0	0
1950	0	0	0	0	0	0	0	-49	0	0	0	0
1951	0	0	0	0	0	0	0	-271	0	0	0	0
1952	0	0	0	0	0	0	0	0	0	0	0	0
1953	0	0	0	0	0	0	0	0	-47	0	0	0
1954	0	0	0	0	0	0	0	0	-335	0	0	0
1955	0	0	0	0	0	0	-119	-68	-295	0	0	0
1956	0	0	0	0	0	0	0	-404	-288	0	0	0
1957	0	0	0	0	-21	-18	0	0	0	0	0	0
1958	0	0	0	-79	-84	-73	0	0	-81	0	0	0
1959	-309	0	-18	-47	0	-39	0	0	0	0	0	0
1960	0	0	0	-38	-76	-92	0	0	-66	0	0	0
1961	0	0	0	-19	0	0	0	0	0	0	0	0
1962	0	0	0	-47	-42	-19	0	0	0	0	0	0
1963	0	0	0	-19	0	0	0	0	-288	0	0	0
1964	0	0	-16	-89	-165	-90	0	0	0	0	0	0
1965	0	0	0	-16	0	0	0	0	0	0	0	0
1966	0	0	0	-109	-100	-37	0	0	-227	0	0	0
1967	0	0	0	0	-19	-18	0	0	0	0	0	0
1968	0	0	0	0	0	0	0	-270	0	0	0	0
1969	0	0	0	0	0	0	0	0	0	0	0	0
1970	0	0	0	0	0	0	0	-260	-232	0	0	0
1971	0	0	0	0	0	0	0	-197	0	0	0	0
1972	0	0	0	0	0	0	0	0	0	0	0	0
1973	0	0	0	-29	-10	-244	0	-50	0	0	0	0
1974	0	0	0	0	0	0	0	0	-394	0	0	0
1975	0	0	-387	-251	-84	-74	0	-243	0	0	0	0
1976	0	0	0	-19	0	0	0	0	0	0	0	0
1977	-122	0	0	-305	-290	-382	0	0	0	0	0	0
1978	-111	0	0	-114	0	0	0	0	0	0	0	0

Table 12: Federal Hydro Generation Adjustment for Refill of Non-Treaty Storage, FY 2009

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	-490	0	0	0	0	0	0	0	0	0	0	0
1930	-20	0	0	0	0	0	0	0	0	0	0	0
1931	0	0	0	-78	-41	-37	0	0	-288	0	0	0
1932	-78	0	-431	-110	-114	-167	0	0	0	0	0	0
1933	0	0	0	-60	0	0	0	0	0	0	0	0
1934	0	0	0	0	0	0	0	0	0	0	0	0
1935	-98	0	0	0	0	0	0	0	0	0	0	0
1936	-255	0	-20	-239	-103	-329	0	0	0	0	0	0
1937	-157	0	0	-95	0	0	0	0	0	0	0	0
1938	-59	0	0	-39	0	-251	0	0	0	0	0	0
1939	0	0	0	-19	0	0	0	0	0	0	0	0
1940	-20	0	-20	-121	-41	0	0	0	0	0	0	0
1941	-137	0	-20	-228	-286	-292	-217	0	0	0	0	0
1942	-20	0	0	-19	0	0	0	0	0	0	0	0
1943	0	0	0	0	0	0	0	0	0	0	0	0
1944	0	0	0	-57	-62	-165	0	0	0	0	0	0
1945	0	0	-19	-79	-95	-105	0	0	0	0	0	0
1946	0	0	0	-16	0	0	0	-262	0	0	0	0
1947	0	0	0	0	0	0	0	-445	0	0	0	0
1948	0	0	0	0	0	0	0	0	-53	0	0	0
1949	0	0	0	-14	-8	0	0	-49	0	0	0	0
1950	0	0	0	0	0	0	0	-271	0	0	0	0
1951	0	0	0	0	0	0	0	0	0	0	0	0
1952	0	0	0	0	0	0	0	0	-47	0	0	0
1953	0	0	0	0	0	0	0	0	-335	0	0	0
1954	0	0	0	0	0	0	-119	-68	-295	0	0	0
1955	0	0	0	0	0	0	0	-404	-5	0	0	0
1956	0	0	0	0	0	0	0	0	0	0	0	0
1957	0	0	0	-20	-17	-18	0	0	-81	0	0	0
1958	-440	0	-18	-63	-22	-77	0	0	0	0	0	0
1959	0	0	0	-38	-76	-92	0	0	-66	0	0	0
1960	0	0	0	-38	-21	0	0	0	0	0	0	0
1961	0	0	0	-31	-21	0	0	0	0	0	0	0
1962	0	0	0	-19	-21	0	0	0	-288	0	0	0
1963	0	0	-16	-89	-120	-90	0	0	0	0	0	0
1964	0	0	0	-31	0	0	0	0	0	0	0	0
1965	0	0	0	-63	-33	-18	0	0	-227	0	0	0
1966	0	0	0	-38	-57	-74	0	0	0	0	0	0
1967	0	0	0	-28	-19	0	0	-270	0	0	0	0
1968	0	0	0	0	0	0	0	0	0	0	0	0
1969	0	0	0	0	0	0	0	-260	-232	0	0	0
1970	0	0	0	0	0	0	0	-197	0	0	0	0
1971	0	0	0	0	0	0	0	0	0	0	0	0
1972	0	0	0	0	0	0	0	-50	0	0	0	0
1973	0	0	0	0	0	0	0	0	-394	0	0	0
1974	0	0	0	0	0	0	0	-243	0	0	0	0
1975	0	0	0	0	0	0	0	0	0	0	0	0
1976	0	0	0	-57	-62	-9	0	0	0	0	0	0
1977	-111	0	0	-114	0	0	0	0	0	0	0	0
1978	-510	0	0	0	-149	0	0	0	0	0	0	0

1.5.4 FY 2007 Storage Adjustment

The HYDSIM study for FY 2006, which was completed after the rate case HYDSIM study for FY 2007, showed September 2006 ending reservoir storage contents for reservoirs in Canada that were different than the values assumed in the FY 2007 HYDSIM study. To reconcile these differences between the FY 2006 and 2007 HYDSIM studies, generation adjustments were applied to the FY 2007 hydro generation table. These generation adjustments to the FY 2007 HYDSIM study are shown in Table 13.

Table 13: Federal Hydro Generation Storage Adjustment for FY 2007

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	-46	-46	-46	-46	-46	-46	-46	-46	-46	-46	0	0
1930	90	90	90	90	90	90	90	90	90	90	0	0
1931	187	187	187	187	187	187	187	187	187	187	0	0
1932	758	758	758	758	758	758	758	758	758	758	0	0
1933	20	20	20	20	20	20	20	20	20	20	0	0
1934	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1935	118	118	118	118	118	118	118	118	118	118	0	0
1936	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	0	0
1937	28	28	28	28	28	28	28	28	28	28	0	0
1938	368	368	368	368	368	368	368	368	368	368	0	0
1939	13	13	13	13	13	13	13	13	13	13	0	0
1940	15	15	15	15	15	15	15	15	15	15	0	0
1941	192	192	192	192	192	192	192	192	192	192	0	0
1942	415	415	415	415	415	415	415	415	415	415	0	0
1943	-15	-15	-15	-15	-15	-15	-15	-15	-15	-15	0	0
1944	-34	-34	-34	-34	-34	-34	-34	-34	-34	-34	0	0
1945	565	565	565	565	565	565	565	565	565	565	0	0
1946	342	342	342	342	342	342	342	342	342	342	0	0
1947	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1948	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1949	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1950	115	115	115	115	115	115	115	115	115	115	0	0
1951	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1952	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1953	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	0	0
1954	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1955	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1956	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1957	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1958	0	0	0	0	0	0	0	0	0	0	0	0
1959	-21	-21	-21	-21	-21	-21	-21	-21	-21	-21	0	0
1960	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1961	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50	0	0
1962	-14	-14	-14	-14	-14	-14	-14	-14	-14	-14	0	0
1963	-37	-37	-37	-37	-37	-37	-37	-37	-37	-37	0	0
1964	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1965	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1966	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1967	-30	-30	-30	-30	-30	-30	-30	-30	-30	-30	0	0
1968	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1969	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1970	-29	-29	-29	-29	-29	-29	-29	-29	-29	-29	0	0
1971	2	2	2	2	2	2	2	2	2	2	0	0
1972	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1973	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1974	190	190	190	190	190	190	190	190	190	190	0	0
1975	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1976	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1977	-51	-51	-51	-51	-51	-51	-51	-51	-51	-51	0	0
1978	802	802	802	802	802	802	802	802	802	802	0	0

1.5.5 Variable 4(h)(10)(C) Fish Credits

The 4(h)(10)(C) credit is a provision in the 1980 Pacific Northwest Electric Power Planning and Conservation Act that allows BPA and its ratepayers to receive a credit for non-power fish and wildlife impacts attributable to the Federal projects. The amount of 4(h)(10)(C) credits that BPA can collect for each of the 50 water years for FY 2007-2009 is determined by summing the costs of the operational impacts, the expenses, and the capital costs associated with fish and wildlife mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent).

The costs of the operational impacts are calculated for each of the 50 water years in RiskMod for FY 2007-2009 by multiplying HLH and LLH spot market electricity prices from AURORA by the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits. The amounts of power purchases (aMW) that qualifies for 4(h)(10)(C) credits are derived external to RiskMod, but are used in RiskMod to calculate the dollar amount of the 4(h)(10)(C) credits. Documentation of the power purchases used for FY 2007-2009, along with a description of the methodology used to derive the amounts of power purchases (aMW) associated with the 4(h)(10)(C) credits, are contained in the Load Resource Study Documentation, WP-07-FS-BPA-01A. The capital costs for FY 2007-2009 are $36 million per year and the expenses are $143 million per year (*see* Revenue Requirement Study, WP-07-FS-BPA-02).

1.5.6 Sampling Hydro Generation

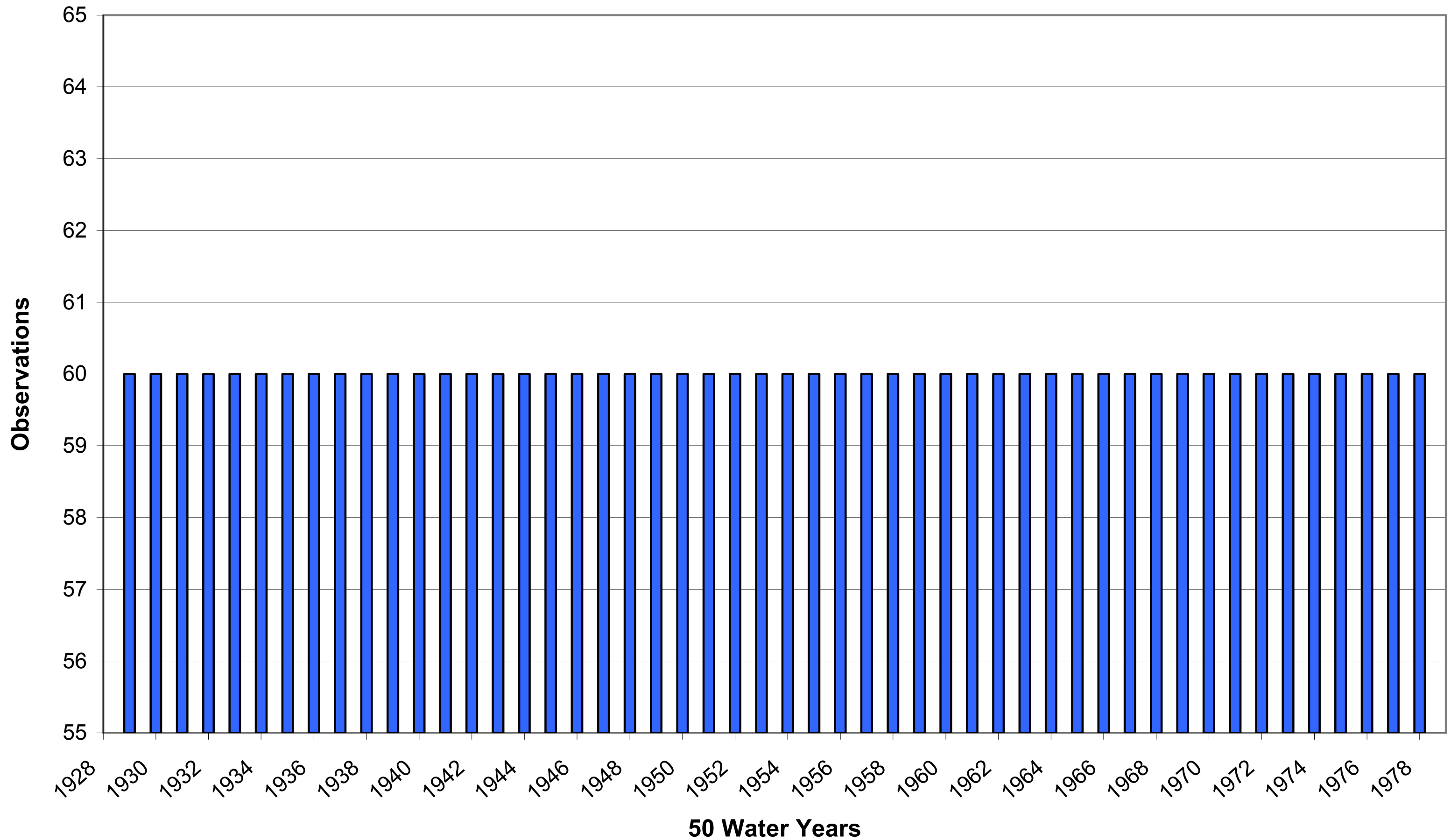
Federal and PNW hydro generation variability is modeled in RiskMod by randomly sampling, in the @RISK computer software, each of the 50 water years (1929-1978) and using the associated hydro generation data in the same continuous manner that the data are developed by HydroSim when performing a continuous study. The random selection of the initial water year (for FY 2007) is accomplished by sampling real values ranging from 1929-1978 from a uniform probability distribution in a risk simulation model and subsequently converting each number to the nearest integer values (whole numbers). Given the water year, the corresponding monthly Federal and PNW hydro generation data and the HOSS HLH hydro generation ratios for that water year are selected for the first year of the Rate Period (FY 2007). The uniform probability distribution was selected for modeling hydro generation risk because it appropriately assigns equal probability to each of the 50 water years being sampled. Graph 2 reports the number of times that each of the 50 water years were sampled from a uniform probability distribution for 3000 simulations. As shown in this graph, each of the 50 water years was sampled 60 times.

After an initial water year is selected for FY 2007 for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2007, are selected from water years 1929-1978. When the end of the 50 water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used. Thus, if a simulation starts with water year 1977, the simulation will use water years 1977 and 1978, as well as water year 1929, for a total of three sequential water years. Using Federal and PNW hydro generation data in this continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water years of hydro generation data.

Surplus energy revenues and power purchase expenses reported in the Revenue Forecast component of the Wholesale Power Rate Development Study and used in setting rates in the RAM2007 are derived by performing a 50 water year run of RiskMod. *See* the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05; and discussion of the RAM2007 components of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05.

For the 50 water year run of RiskMod, average surplus energy revenues, 4(h)(10)(C) credits and power purchase expenses are estimated using Federal HLH and LLH hydro generation for the 50 water years. No other risk factors, except for PNW hydro generation, are allowed to vary when performing the 50 water year run of RiskMod. HLH and LLH spot market electricity prices estimated by the AURORA Model using PNW hydro generation for the 50 water years are input into RevSim and used to calculate surplus energy revenues, 4(h)(10)(C) credits, and power purchase expenses. Results from the 50 water year run of RiskMod are reported in the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05. For the Risk Simulation run of RiskMod, Federal, and PNW hydro generation data for each of the 50 water years are combined with additional risk factors to quantify net revenue risk.

Graph 2: Number of Times PNW and Federal Hydro Generation for the 50 Water Years were Sampled Based on 3,000 Sampled Values



1.5.7 Use of PNW Hydro Generation Risk in AURORA

Variability in PNW hydro generation is incorporated into the AURORA Model by calculating (via the Data Manager), from monthly PNW hydro generation data for each of the 50 water years, PNW annual energy to capacity ratios (using the total capacity value for all of the PNW in the AURORA Model), calculating PNW monthly to annual hydro generation ratios, and inputting this data into the AURORA Model. These sets of ratios are used by AURORA to calculate first the annual and then the monthly hydro generation for each of the three regions (Oregon/Washington, Idaho, and Montana) for the PNW in AURORA. This process results in the sum of the hydro generation for the three regions in AURORA being equal to the PNW hydro generation.

1.6 PNW and BPA Load Risk Factor

PNW load risk is incorporated into the Risk Analysis Study to account for the impact that PNW load variability, which is simulated in the PNW Load Risk Model, has on monthly HLH and LLH spot market electricity prices, which impacts PBL's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model various PNW load values and having it estimate the associated HLH and LLH spot market electricity prices.

BPA load risk is incorporated into the Risk Analysis Study to account for the impact that monthly PF load variability has on Priority Firm Power (PF) revenues, surplus energy revenues, and power purchase expenses. This impact is accounted for by inputting into RevSim various monthly load variability values that modify the amount of PF loads served by BPA.

1.6.1 PNW and BPA Load Variability

Only monthly PNW load variability is modeled in the PNW Load Risk Model. BPA monthly load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability.

The PNW Load Risk Model is designed to incorporate forecasted monthly load data from the AURORA Model such that, when no risk is being simulated for CY 2006-2009, the forecasted monthly loads match the sum of the forecasted loads for the three regions (Oregon/Washington, Idaho, and Montana) that comprise the PNW in the AURORA Model. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads that AURORA uses to perform the Market Price Forecast Study. *See* Market Price Forecast Study, WP-07-FS-BPA-03.

Variability in monthly BPA loads is derived from simulated PNW loads by dividing simulated loads by forecasted PNW loads to obtain ratios that are values relative to 1.00 (when the simulated loads equal the forecasted loads). For instance, a value of 1.05 translates into a 5 percent increase in PNW loads and a 5 percent increase in BPA loads.

PNW (and indirectly BPA) load variability is modeled in the PNW Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one PNW load variability factor. This task is accomplished by first simulating annual load growth for years from CY 2006-2009 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

1.6.2 Annual PNW and BPA Load Growth Risk

Annual PNW (and indirectly BPA) load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique. The random-walk technique simulates various annual average load levels through time with the starting point for simulating annual average load in a given year being the annual average load level from the previous year. Under this method, simulated annual average loads randomly increase and decrease through time from the annual average load level of the prior year with the results including outcomes that represent periods of strong load growth, weak load growth, and vacillating positive and negative load growth. The mean-reverting technique causes simulated annual loads to tend to revert to the forecasted loads as loads move further from forecasted loads (either higher or lower).

Input data from the AURORA Model used in the PNW Load Risk Model are the following: (1) annual average CY 2004 PNW load; (2) forecasted annual load growth for CY 2005-2009; and (3) monthly load shaping factors (values relative to 1.00) that are derived for use in AURORA by dividing historical monthly loads by historical annual average loads. *See* Market Price Forecast Study, WP-07-FS-BPA-03. Inputting the data used by the AURORA Model allows the PNW Load Risk Model to replicate the forecasted monthly PNW loads in AURORA.

Load growth variability is incorporated into the PNW Load Risk Model by sampling values from standard normal distributions (normal distributions with a mean of zero and a standard deviation of one) in @RISK, multiplying the sampled values by an annual load growth standard deviation, and adding the simulated positive and negative values to the annual load level of the prior year. The values sampled from the standard normal distribution are in terms of the number of positive or negative standard deviations.

The annual load growth standard deviation used in the PNW Load Risk Model is 3.26 percent with cumulative annual load growth standard deviations over two, three, and four year durations being 4.23, 5.16, and 6.00 percent. These values were derived from historical annual Western Electricity Coordinating Council (WECC) load data for the Northwest Power Pool Area during 1982-2004. The source of this data was a publication by the WECC titled, 10-Year Coordinated Plan Summary, Planning and Operation for Electric System Reliability, Western Electricity Coordinating Council, June 2005, at 56. Variability in monthly loads due to load growth risk is derived by multiplying variable annual loads by deterministic monthly load shape factors. The historical WECC load data and the cumulative annual load growth standard deviation calculations by BPA for the PNW are reported in Table 14.

Table 14: PNW and California Load Growth Standard Deviation Calculations for One to Seven Years

Pacific Northwest (NWPP)

Year	NWPP	% Change Over 1 Yr	% Change Over 2 Yrs	% Change Over 3 Yrs	% Change Over 4 Yrs	% Change Over 5 Yrs	% Change Over 6 Yrs	% Change Over 7 Yrs
1982	26,804							
1983	26,861	0.21%						
1984	28,642	6.63%	6.86%					
1985	29,372	2.55%	9.35%	9.58%				
1986	28,927	-1.52%	1.00%	7.69%	7.92%			
1987	29,954	3.55%	1.98%	4.58%	11.52%	11.75%		
1988	31,986	6.78%	10.58%	8.90%	11.68%	19.08%	19.34%	
1989	33,265	4.00%	11.05%	15.00%	13.25%	16.14%	23.84%	24.11%
1990	34,372	3.33%	7.46%	14.75%	18.82%	17.02%	20.01%	27.96%
1991	34,840	1.36%	4.74%	8.92%	16.31%	20.44%	18.62%	21.64%
1992	35,114	0.79%	2.16%	5.56%	9.78%	17.23%	21.39%	19.55%
1993	35,708	1.69%	2.49%	3.89%	7.34%	11.63%	19.21%	23.44%
1994	36,107	1.12%	2.83%	3.64%	5.05%	8.54%	12.88%	20.54%
1995	36,336	0.63%	1.76%	3.48%	4.29%	5.71%	9.23%	13.60%
1996	38,151	5.00%	5.66%	6.84%	8.65%	9.50%	10.99%	14.69%
1997	37,911	-0.63%	4.34%	5.00%	6.17%	7.96%	8.81%	10.30%
1998	39,144	3.25%	2.60%	7.73%	8.41%	9.62%	11.48%	12.35%
1999	39,829	1.75%	5.06%	4.40%	9.61%	10.31%	11.54%	13.43%
2000	40,479	1.63%	3.41%	6.78%	6.10%	11.40%	12.11%	13.36%
2001	36,998	-8.60%	-7.11%	-5.48%	-2.41%	-3.02%	1.82%	2.47%
2002	39,121	5.74%	-3.36%	-1.78%	-0.06%	3.19%	2.54%	7.67%
2003	38,881	-0.61%	5.09%	-3.95%	-2.38%	-0.67%	2.56%	1.92%
2004	39,646	1.97%	1.34%	7.16%	-2.06%	-0.46%	1.28%	4.58%
	Avg	**0.018**	**0.038**	**0.056**	**0.073**	**0.097**	**0.122**	**0.145**
	StDev	**0.0326**	**0.0423**	**0.0516**	**0.0600**	**0.0687**	**0.0732**	**0.0792**
	Min	**-0.086**	**-0.071**	**-0.055**	**-0.024**	**-0.030**	**0.013**	**0.019**
	Max	**0.068**	**0.111**	**0.150**	**0.188**	**0.204**	**0.238**	**0.280**

NWPP & Cal/Mex Correlation (Post 1986)	**0.8943**

California (Cal/Mex)

Year	CAL/MEX	% Change Over 1 Yr	% Change Over 2 Yrs	% Change Over 3 Yrs	% Change Over 4 Yrs	% Change Over 5 Yrs	% Change Over 6 Yrs	% Change Over 7 Yrs
1987	24,498							
1988	25,491	4.05%						
1989	26,153	2.60%	6.76%					
1990	27,021	3.32%	6.00%	10.30%				
1991	26,324	-2.58%	0.65%	3.27%	7.46%			
1992	27,021	2.65%	0.00%	3.32%	6.00%	10.30%		
1993	26,895	-0.46%	2.17%	-0.46%	2.84%	5.51%	9.79%	
1994	27,820	3.44%	2.96%	5.68%	2.96%	6.37%	9.14%	13.56%
1995	27,454	-1.31%	2.08%	1.61%	4.29%	1.61%	4.98%	7.70%
1996	28,390	3.41%	2.05%	5.56%	5.07%	7.85%	5.07%	8.56%
1997	29,326	3.30%	6.82%	5.42%	9.04%	8.53%	11.41%	8.53%
1998	29,064	-0.90%	2.37%	5.86%	4.47%	8.06%	7.56%	10.41%
1999	29,943	3.02%	2.10%	5.47%	9.06%	7.63%	11.33%	10.82%
2000	31,461	5.07%	8.25%	7.28%	10.82%	14.59%	13.09%	16.98%
2001	30,708	-2.39%	2.55%	5.66%	4.71%	8.16%	11.85%	10.38%
2002	31,689	3.20%	0.73%	5.83%	9.03%	8.06%	11.62%	15.43%
2003	31,632	-0.18%	3.01%	0.54%	5.64%	8.84%	7.86%	11.42%
2004	32,945	4.15%	3.96%	7.29%	4.72%	10.03%	13.35%	12.34%
	Avg	**0.018**	**0.033**	**0.048**	**0.062**	**0.081**	**0.098**	**0.115**
	StDev	**0.0248**	**0.0243**	**0.0278**	**0.0251**	**0.0294**	**0.0287**	**0.0292**
	Min	**-0.026**	**0.000**	**-0.005**	**0.028**	**0.016**	**0.050**	**0.077**
	Max	**0.051**	**0.082**	**0.103**	**0.108**	**0.146**	**0.134**	**0.170**

Note: For the reason describe below, California load growth variability was calculated using data that starts in 1987.

Prior to 1997, the Southern Nevada reporting-area data were included in the California sub-area data.
The Arizona-New Mexico-Southern Nevada Power Area and California-Mexico Power Area data, prior to 1987,
have not been adjusted for the Southern Nevada reporting-area change

1.6.3 PNW and BPA Load Risk Due to Weather

Monthly PNW (and indirectly BPA) load variability due to weather conditions is quantified by first sampling values from standard normal distributions in @RISK, then multiplying the sampled values by monthly load standard deviations, and finally adding the resulting positive and negative values to the simulated loads after load growth.

The monthly PNW load standard deviations are derived from utility-specific, monthly historical daily load standard deviations and forecasted CY 2005 loads for PNW utilities, which were used as input data in PMDAM when performing the MCA in the 1996 rate case (*see* Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A, Part 2 of 2; pages 305 and 257). This derivation is accomplished by calculating composite, load-weighted, monthly load standard deviations from utility-specific, daily load standard deviations (for the 12 months of the year) and annual average load data.

1.6.4 Derivation of PNW/BPA Monthly Load Variability Due to Weather

BPA assumes, for rate setting purposes, that daily weather patterns over the course of a month are independent and that each day of a given month has the same daily load standard deviation. Accordingly, BPA used the following statistical equation to derive monthly load standard deviations from daily load standard deviations for each month. The statistical equation for calculating the standard deviation for the average of "n" number of independent random variables is the following:

$$\sigma_{\bar{x}} = \frac{\sigma_x}{\sqrt{n}}$$

Where:

$\underline{\sigma_x}$ is the standard deviation for all independent random variables

$\overline{n}$ is the number of independent random variables

In the case of BPA's analysis, the number of independent random variables is the number of days in a month and the standard deviation for all the independent random variables is the daily load standard deviations for each month. The PNW monthly load standard deviations for each month are derived by inserting values for the number of days in each month and the daily load standard deviations for each month into the equation above. Table 15 contains the calculations performed to derive PNW monthly load standard deviations from daily load standard deviations for each month. These monthly load standard deviations are input into the PNW Load Risk Model to quantify monthly load variability due to weather.

Table 15: Derivation of Load-Weighted, Monthly Load Standard Deviations for PNW

PNW

		Loads CY 2005	**Daily Load Standard Deviations Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
PGE	PGEFRM	2057	0.10	0.10	0.08	0.09	0.08	0.08	0.11	0.08	0.09	0.09	0.09	0.10
PP&L	PPLFRM	2462	0.12	0.13	0.10	0.13	0.12	0.10	0.16	0.11	0.12	0.12	0.12	0.13
OIOU	OIOFRM	2772	0.07	0.09	0.05	0.07	0.06	0.07	0.08	0.06	0.07	0.06	0.07	0.07
GPUB	GPUFRM	2827	0.08	0.08	0.07	0.08	0.09	0.07	0.08	0.07	0.08	0.09	0.08	0.09
BPA	BPAFRM	3740	0.09	0.09	0.06	0.07	0.06	0.05	0.06	0.06	0.07	0.08	0.09	0.10
OIOU	PSPL	2673	0.09	0.10	0.07	0.10	0.08	0.06	0.07	0.06	0.07	0.09	0.09	0.09
GPUB	COPOSN	1499	0.09	0.08	0.06	0.08	0.08	0.08	0.14	0.04	0.07	0.07	0.07	0.10
BPA	DSIFRM	1061	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
BPA	DSI2Q	2122	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
BPA	DSINFM	0	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
Total PNW		**21213**												

		Loads CY 2005	**Daily Load Variances Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
PGE	PGEFRM	2057	0.0100	0.0100	0.0064	0.0081	0.0064	0.0064	0.0121	0.0064	0.0081	0.0081	0.0081	0.0100
PP&L	PPLFRM	2462	0.0144	0.0169	0.0100	0.0169	0.0144	0.0100	0.0256	0.0121	0.0144	0.0144	0.0144	0.0169
OIOU	OIOFRM	2772	0.0049	0.0081	0.0025	0.0049	0.0036	0.0049	0.0064	0.0036	0.0049	0.0036	0.0049	0.0049
GPUB	GPUFRM	2827	0.0064	0.0064	0.0049	0.0064	0.0081	0.0049	0.0064	0.0049	0.0064	0.0081	0.0064	0.0081
BPA	BPAFRM	3740	0.0081	0.0081	0.0036	0.0049	0.0036	0.0025	0.0036	0.0036	0.0049	0.0064	0.0081	0.0100
OIOU	PSPL	2673	0.0081	0.0100	0.0049	0.0100	0.0064	0.0036	0.0049	0.0036	0.0049	0.0081	0.0081	0.0081
GPUB	COPOSN	1499	0.0081	0.0064	0.0036	0.0064	0.0064	0.0064	0.0196	0.0016	0.0049	0.0049	0.0049	0.0100
BPA	DSIFRM	1061	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
BPA	DSI2Q	2122	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
BPA	DSINFM	0	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
Total PNW		**21213**												
Number of Days Per Month			31	28	31	30	31	30	31	31	30	31	30	31
Weighted Daily Load Variances			**0.0072**	**0.0080**	**0.0043**	**0.0069**	**0.0058**	**0.0045**	**0.0085**	**0.0044**	**0.0062**	**0.0065**	**0.0068**	**0.0082**
Weighted Daily Load Standard Deviations			**0.0849**	**0.0894**	**0.0654**	**0.0829**	**0.0758**	**0.0669**	**0.0921**	**0.0661**	**0.0784**	**0.0807**	**0.0822**	**0.0903**
Monthly Load Standard Deviations			**0.0153**	**0.0169**	**0.0118**	**0.0151**	**0.0136**	**0.0122**	**0.0165**	**0.0119**	**0.0143**	**0.0145**	**0.0150**	**0.0162**

1.6.5 Modeling Methodology

In order for the PNW Load Risk Model to simulate the cumulative annual load growth standard deviations reflected in the historical data over various time durations, mean-reversion decay parameters were developed so that the simulated cumulative annual load growth standard deviations for years two through four (CY 2007-2009) would be calibrated to the values in the historical data. No mean-reversion decay parameter was developed for year 1, since the load growth standard deviation used in the probability distributions is the annual load growth standard deviation for a year.

<u>The mean-reversion methodology incorporated into the standard normal probability distributions is as follows:</u>

Sampled positive or negative standard deviation = RiskNormal (Annual mean-reversion decay parameters * (1 - Simulated mean-reversion ratios), 1)

Where:

RiskNormal = Normal probability distribution in @RISK with
Mean = Annual mean-reversion decay parameters * (1 - Simulated mean-reversion ratios)
Standard deviation = 1
Mean-reversion decay parameters = Calibrated annual load decay values
Simulated mean-reversion ratios = Simulated prior annual load / Forecasted annual load

<u>Annual load movements through time were modeled as follows:</u>

Annual load for time t = Annual load for time t-1 * (1 + (Forecasted load growth from time t-1 to time t + (Sampled positive or negative standard deviation * annual load growth standard deviation)))

1.6.6 Calibrating Annual Load Variability

The final step in the modeling process is the derivation of annual decay parameters to better calibrate the cumulative annual load variability simulated by the PNW Load Risk Model to the historical cumulative annual load variability reflected in the WECC annual load data. The calibration of the annual decay values is performed in the following manner: (1) run the model; (2) calculate the cumulative annual load standard deviations for the simulated data and compare these results to the cumulative annual load standard deviations derived by multiplying the forecasted annual loads times the historical cumulative annual load standard deviations; and (3) revise the annual decay values for CY 2007-2009 to test how well the values computed in step (2) compare.

BPA used the statistical approach of minimizing the sum of residuals squared to help objectively determine the relative merits of one set of annual decay values versus another. The sum of residuals squared is calculated by squaring the difference between the values computed in Step

(2) above and summing these squared differences. The lower the sum of residuals squared, the better the results.

1.6.7 Model and Results

Tables 16 and 17 contain copies of the results of the calibration process for PNW load variability and the PNW Load Risk Model. Graph 3 shows the simulated PNW loads at the 5th, 50th, and 95th percentiles.

Table 16: PNW and California Load Variability Calibration

Mean-Reversion Calibration Section		CY06	CY07	CY08	CY09
Mean Reversion Rate		1.000	4.830	0.960	0.600
Additional California Annual Load Volatility Adjustment Factors		1.000	0.140	0.437	0.001
Sum of Residuals ^2 for PNW (CY06-09)		47			
Sum of Residuals ^2 for California (CY06-09)		4,954			
Sum of Residuals ^2 for PNW & California (CY06-09)		5,001			

PNW Load Risk Result Section	Avg 06-09	CY 2006	CY 2007	CY 2008	CY 2009
Simulated Annual PNW Loads (aMW)	23,761	23,034	23,537	24,084	24,389
Forecasted Annual PNW Loads (aMW)	23,754	23,023	23,530	24,078	24,384
Sim Less Forecast	7	11	7	6	5
	Avg 06-09	CY 2006	CY 2007	CY 2008	CY 2009
Sim Load Stdev	1,111	744	996	1,243	1,463
Historical Load Stdev Applied to Current Load Forecast	1,113	751	996	1,243	1,463
Sim Less Hist Stdev	(2)	(7)	0	(0)	(0)

California Load Risk Result Section	Avg 06-09	CY 2006	CY 2007	CY 2008	CY 2009
Simulated Annual Calif Loads (aMW)	35,466	34,114	35,001	35,904	36,844
Forecasted Annual Calif Loads (aMW)	35,485	34,132	35,019	35,923	36,864
Sim Less Forecast	(19)	(18)	(19)	(19)	(20)
	Avg 06-09	CY 2006	CY 2007	CY 2008	CY 2009
Sim Load Stdev	905	839	856	950	973
Historical Load Stdev Applied to Current Load Forecast	905	848	850	999	924
Sim Less Hist Stdev	(1)	(8)	6	(49)	49

Table 17: PNW Load Risk Model for 2006 - 2009

PNW Load Variability

PNW Load Growth Uncertainty:

Forecasted Calendar Year (2004) Annual Average PNW Loads	**22,121**
Forecasted PNW Load Growth for 2005; Source: Aurora	**1.94%**
Forecasted PNW Load Growth for 2006; Source: Aurora	**2.10%**
Forecasted PNW Load Growth for 2007; Source: Aurora	**2.20%**
Forecasted PNW Load Growth for 2008; Source: Aurora	**2.33%**
Forecasted PNW Load Growth for 2009; Source: Aurora	**1.27%**
Annual Load Growth Std Dev; Source: WECC Load Data (1982-2004)	**3.26%**

Estimated Base Case Loads		***Std Normal Dist***	**Base MR**	**Additional MR Decay Factors**
CY 2005	**22,550**	***0.0***	Entered zero; i.e., no load variability	
CY 2006	**23,023**	***0.0***	**1.00**	**1.00**
CY 2007	**23,530**	***0.0***	**1.00**	**4.83**
CY 2008	**24,078**	***0.0***	**1.00**	**0.96**
CY 2009	**24,384**	***0.0***	**1.00**	**0.60**

Load Growth Dev from any specified forecasted load level	
CY 2005	***22550***
CY 2006	***23023***
CY 2007	***23530***
CY 2008	***24078***
CY 2009	***24384***

PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2006

	Jan '06	**Feb '06**	**Mar '06**	**Apr '06**	**May '06**	**Jun '06**	**Jul '06**	**Aug '06**	**Sep '06**	**Oct '06**	**Nov '06**	**Dec '06**	**Simple Avg**
Average Annual PNW Loads (Average Energy in aMW)	23023	23023	23023	23023	23023	23023	23023	23023	23023	23023	23023	23023	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	26205	25506	23258	21645	21213	21522	22069	21677	20980	21634	24484	26213	**23,034 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '06	**Feb '06**	**Mar '06**	**Apr '06**	**May '06**	**Jun '06**	**Jul '06**	**Aug '06**	**Sep '06**	**Oct '06**	**Nov '06**	**Dec '06**	**Simple Avg**
PNW Loads after Load Growth (Average Energy in aMW)	26205	25506	23258	21645	21213	21522	22069	21677	20980	21634	24484	26213	**23,034 aMW**
Monthly Load Standard Deviation	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***26,205***	***25,506***	***23,258***	***21,645***	***21,213***	***21,522***	***22,069***	***21,677***	***20,980***	***21,634***	***24,484***	***26,213***	**23,034 aMW**

Table 17: PNW Load Risk Model for 2007 (Continued)

PNW Load Variability

PNW Load Variability Due to Load Growth Uncertainty

	Calendar Year 2007												
	Jan '07	**Feb '07**	**Mar '07**	**Apr '07**	**May '07**	**Jun '07**	**Jul '07**	**Aug '07**	**Sep '07**	**Oct '07**	**Nov '07**	**Dec '07**	**Simple Avg**
Average Annual PNW Loads (Average Energy in aMW)	23530	23530	23530	23530	23530	23530	23530	23530	23530	23530	23530	23530	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	26782	26067	23770	22121	21680	21995	22554	22154	21442	22110	25022	26790	**23,541 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '07	**Feb '07**	**Mar '07**	**Apr '07**	**May '07**	**Jun '07**	**Jul '07**	**Aug '07**	**Sep '07**	**Oct '07**	**Nov '07**	**Dec '07**	**Simple Avg**
PNW Loads after Load Growth (Average Energy in aMW)	26782	26067	23770	22121	21680	21995	22554	22154	21442	22110	25022	26790	**23,541 aMW**
Monthly Load Standard Deviation	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***26,782***	***26,067***	***23,770***	***22,121***	***21,680***	***21,995***	***22,554***	***22,154***	***21,442***	***22,110***	***25,022***	***26,790***	**23,541 aMW**

Table 17: PNW Load Risk Model for 2008 (Continued)

PNW Load Variability

PNW Load Variability Due to Load Growth Uncertainty

	Calendar Year 2008												
	Jan '08	**Feb '08**	**Mar '08**	**Apr '08**	**May '08**	**Jun '08**	**Jul '08**	**Aug '08**	**Sep '08**	**Oct '08**	**Nov '08**	**Dec '08**	**Simple Avg**
Average Annual PNW Loads (Average Energy in aMW)	24078	24078	24078	24078	24078	24078	24078	24078	24078	24078	24078	24078	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	27406	26675	24324	22637	22185	22508	23080	22670	21941	22625	25605	27414	**24,089 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '08	**Feb '08**	**Mar '08**	**Apr '08**	**May '08**	**Jun '08**	**Jul '08**	**Aug '08**	**Sep '08**	**Oct '08**	**Nov '08**	**Dec '08**	**Simple Avg**
PNW Loads after Load Growth (Average Energy in aMW)	27406	26675	24324	22637	22185	22508	23080	22670	21941	22625	25605	27414	**24,089 aMW**
Monthly Load Standard Deviation	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***27,406***	***26,675***	***24,324***	***22,637***	***22,185***	***22,508***	***23,080***	***22,670***	***21,941***	***22,625***	***25,605***	***27,414***	**24,089 aMW**

Table 17: PNW Load Risk Model for 2009 (Continued)

PNW Load Variability

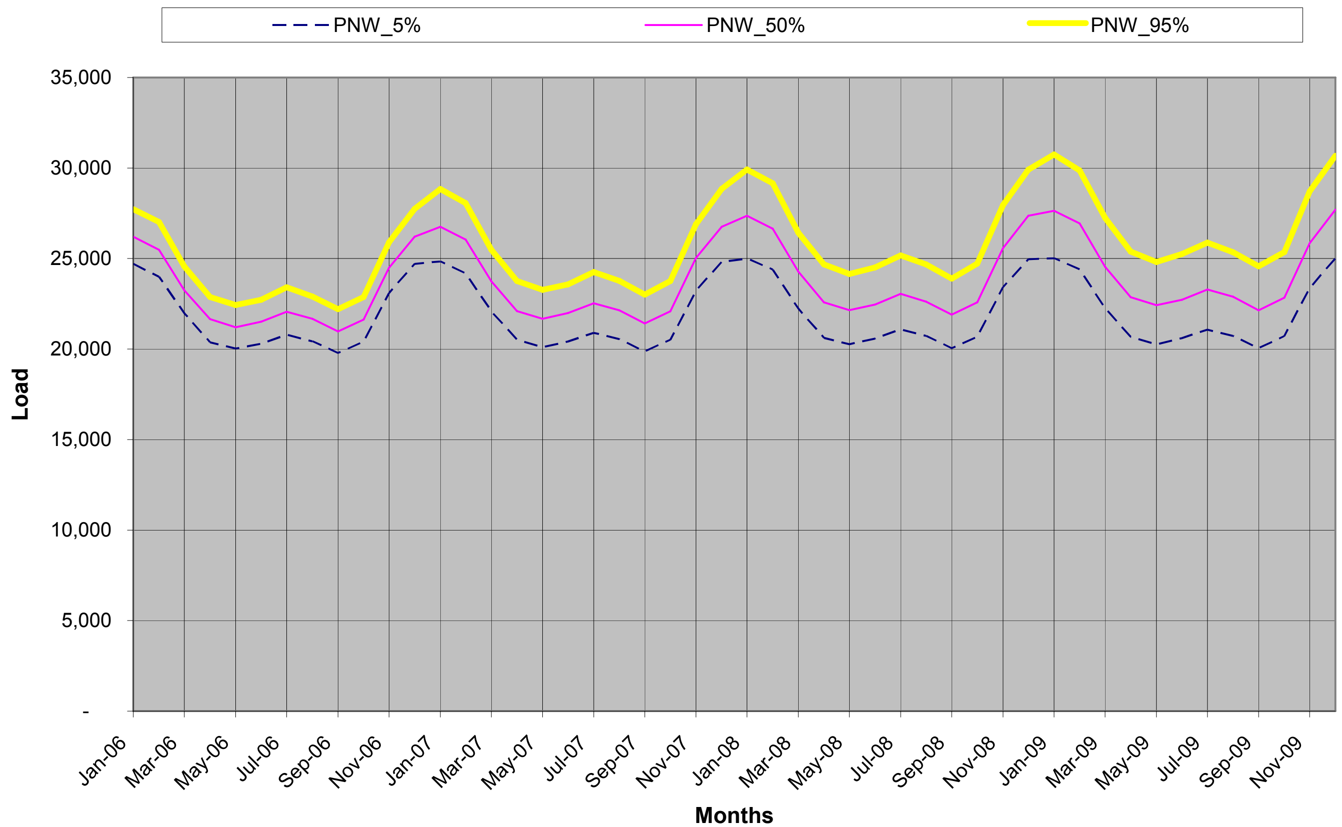
PNW Load Variability Due to Load Growth Uncertainty

	Calendar Year 2009												
	Jan '09	**Feb '09**	**Mar '09**	**Apr '09**	**May '09**	**Jun '09**	**Jul '09**	**Aug '09**	**Sep '09**	**Oct '09**	**Nov '09**	**Dec '09**	**Simple Avg**
Average Annual PNW Loads (Average Energy in aMW)	24384	24384	24384	24384	24384	24384	24384	24384	24384	24384	24384	24384	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	27754	27013	24633	22924	22467	22794	23373	22958	22220	22913	25931	27762	**24,395 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Oct '09	Nov '09	Dec '09	Simple Avg
PNW Loads after Load Growth (Average Energy in aMW)	27754	27013	24633	22924	22467	22794	23373	22958	22220	22913	25931	27762	**24,395 aMW**
Monthly Load Standard Deviation	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***27,754***	***27,013***	***24,633***	***22,924***	***22,467***	***22,794***	***23,373***	***22,958***	***22,220***	***22,913***	***25,931***	***27,762***	**24,395 aMW**

Graph 3: Simulated PNW Loads for CYs 2006 - 2009



1.6.8 Use of Simulated PNW Loads in AURORA

The HLH and LLH spot market electricity prices associated with changes in PNW monthly loads are estimated in the AURORA Model by inputting PNW load data simulated by the PNW Load Risk Model. This process involves calculating (via the Data Manager) monthly load ratios (monthly loads divided by the annual average loads) from monthly and annual load data simulated by the PNW Load Risk Model and then inputting the monthly ratios and annual average energy loads into the AURORA Model for each simulation. These data are input into AURORA to calculate annual and monthly loads for each of the three PNW regions (Oregon/ Washington, Idaho, and Montana) in AURORA. This process results in the sum of the loads for the three PNW regions in AURORA being equal to the simulated PNW loads from the PNW Load Risk Model.

1.7 California Hydro Generation Risk Factor

California hydro generation risk is incorporated into the Risk Analysis Study to account for the impact that variability in California hydro generation has on monthly HLH and LLH spot market electricity prices, which impacts BPA's surplus energy revenues and power purchase expenses.

1.7.1 Modeling Hydro Risk

California hydro generation risk is incorporated into the Risk Analysis Study by sampling 18 years of historical monthly California hydro generation data and estimating the associated monthly HLH and LLH spot market electricity prices in the AURORA Model. The historical monthly California hydro generation data used to incorporate risk was collected from reports published by the Energy Information Administration (EIA) for 1980-1997 and they are reported in Table 18.

Table 18: California Hydro Generation for 1980 - 1997

	FY	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
1	1980	2983	2486	3179	5011	5351	6007	5438	5128	4957	5087	4858	4418
2	1981	3210	3132	3142	2450	2701	2894	3471	3633	3931	4043	3667	3243
3	1982	2179	3167	5336	5649	5884	6243	6757	6800	6332	5809	5587	5146
4	1983	4036	4933	5649	5778	6903	7276	7075	7563	7547	6945	6302	5601
5	1984	4668	5338	6956	6786	5430	5250	5222	5110	5375	5517	5235	4501
6	1985	3261	3315	3950	3195	3594	3522	4176	4366	3943	4501	3962	3476
7	1986	3114	3276	3062	3215	4975	6784	5851	5423	5701	5621	4812	4721
8	1987	3750	3274	2710	2011	2342	2446	3118	3230	3322	3923	3548	3081
9	1988	2422	1951	2214	2327	2115	2392	2764	2792	3524	4238	3687	2779
10	1989	1677	1858	1887	1421	2060	3349	4318	4313	4557	5048	4415	3149
11	1990	2605	2665	2454	1995	1671	2656	3128	3164	3428	4081	3712	2692
12	1991	2522	1828	1626	1267	1146	1626	1978	2293	3711	3992	3398	2879
13	1992	2157	1664	1776	1478	1767	1991	2369	3071	2978	3106	2559	2078
14	1993	1687	1424	1704	2403	3463	5177	5785	6293	6650	5819	5071	3604
15	1994	2878	2515	2703	1767	1708	2409	2713	3226	3860	3989	3599	2403
16	1995	1875	1465	2203	3738	5443	6431	7339	7484	7507	6694	6121	4915
17	1996	3853	2910	2591	3013	5684	6597	6871	6954	6089	5442	4883	3688
18	1997	3003	2926	5204	5597	5923	5171	4896	5321	5489	5245	4796	3838

Source: Energy Information Administration (EIA) - Electric Power Monthly. Electric Utility Hydroelectric Net Generation by Census Division and State, 1980 - 1997

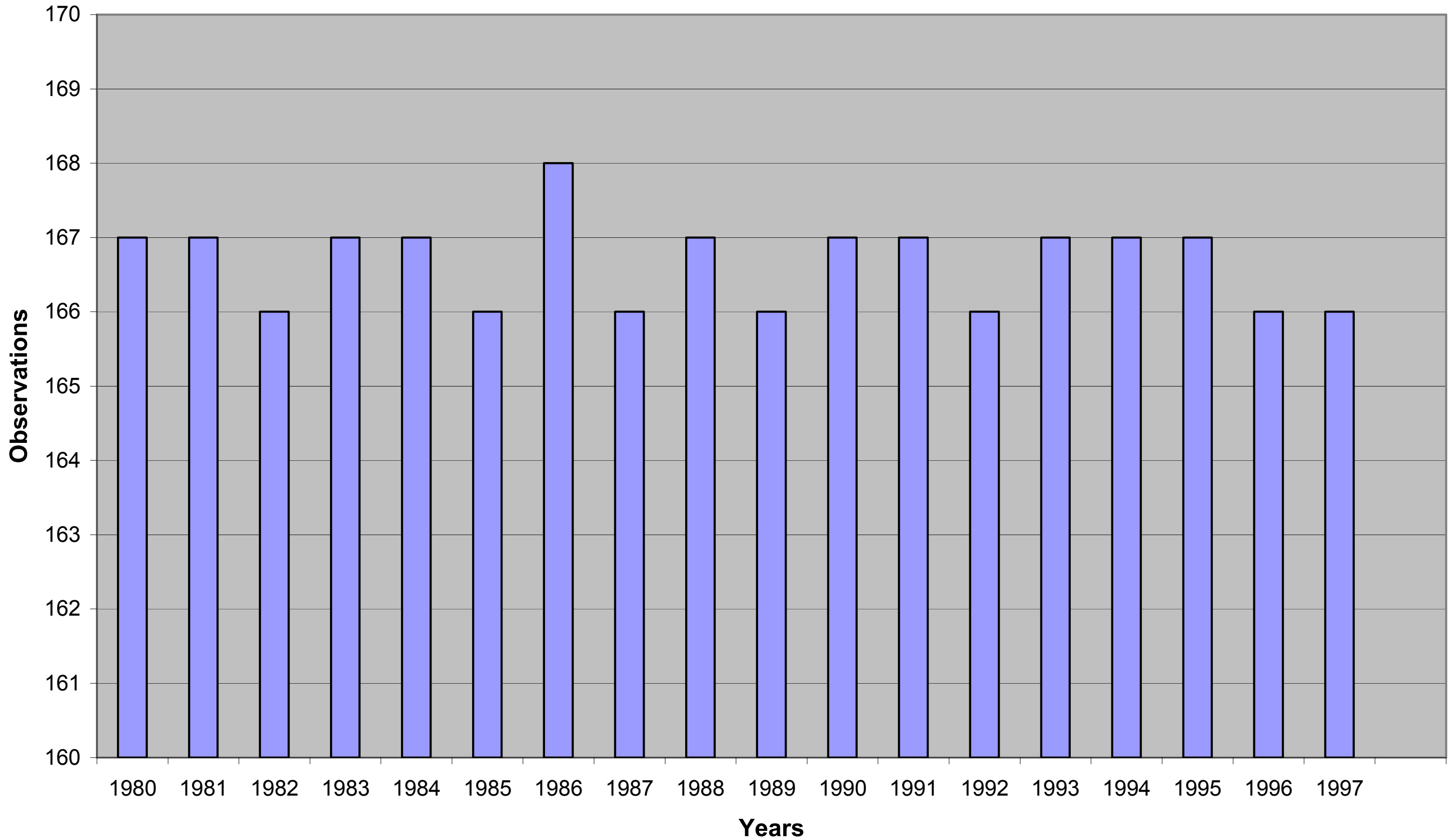
1.7.2 Sampling Hydro Generation

California hydro generation risk is modeled in RiskMod by randomly sampling, in the @RISK computer software, values from 1 to 18 (which represent each of the 18 hydro generation years) and using the associated hydro generation data in a continuous manner like that used for the 50 water year analysis. The random selection of the initial hydro generation year (for FY 2007) is accomplished by sampling real values ranging from 1 to 18 from a uniform probability distribution in a risk simulation model and subsequently converting each number to the nearest integer value (whole numbers). Given the sampled hydro generation year, the corresponding monthly California hydro generation data for that year are selected for the first year of the rate period (FY 2007).

Graph 4 reports the number of times that each of the 18 years of hydro generation data were sampled from a uniform probability distribution for 3000 simulations. The uniform probability distribution was selected for use in the risk simulation model because it appropriately assigns equal probability to each of the 18 years of data being sampled. The average number of times that each hydro generation year could have been sampled for 3000 simulations is 166.7 (3000/18). These results in Graph 4 indicate that all years, except for 1986, were sampled either 166 or 167 times. The hydro generation data for 1986 were sampled 168 times.

After the initial year is selected for FY 2007 for a given simulation, hydro generation data for a sequential set of three years of data, starting with the hydro generation year selected for FY 2007, are selected from 1 through 18. When the end of the data is reached (at the end of 18), monthly hydro generation data for hydro generation year one is subsequently used. Thus, if a simulation starts with hydro generation data for hydro generation year 17, the simulation will use hydro generation data for years 17 and 18, as well as year 1, for a total of three sequential years of hydro generation data. Using historical California hydro generation data in this continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 18 years of hydro generation data.

Graph 4: Number of Times California Hydro Generation for 18 Years were Sampled Based on 3,000 Sampled Values



1.7.3 Use of California Hydro Generation Risk in AURORA

Variability in California hydro generation is incorporated into the AURORA Model by calculating (via the Data Manager), from monthly California hydro generation data for 18 years, California annual energy to capacity ratios (using the total capacity value for all of California in the AURORA Model), and calculating California monthly to annual hydro generation ratios. These data are input into the AURORA Model. These sets of ratios are used by AURORA to calculate the annual and then the monthly hydro generation for each of the two California regions (northern and southern California) in AURORA. This process results in the sum of the hydro generation for the two California regions in AURORA being equal to the historical monthly California hydro generation.

1.8 California Load Risk Factor

California load risk is incorporated into the Risk Analysis Study to account for the impact that California load variability has on monthly HLH and LLH spot market electricity prices, which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model various California load values and having it estimate the associated HLH and LLH spot market electricity prices.

1.8.1 California Load Variability

The California Load Risk Model is designed to incorporate forecasted monthly load data from the AURORA Model such that, when no risk is being simulated for CY 2006-2009, the forecasted monthly loads match the sum of the forecasted loads for the two regions (southern and northern California) that comprise California in the AURORA Model. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads that AURORA uses to perform the Market Price Forecast Study. *See* Market Price Forecast Study, WP-07-FS-BPA-03.

California load variability is modeled in the California Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one California load variability factor. This task is accomplished by first simulating annual load growth for years from CY 2006-2009 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

1.8.2 Annual California Load Growth Risk

Annual California load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique. The random-walk technique simulates various annual average load levels through time with the starting point for simulating the annual average load in a given year being the annual average load level from the previous year. Under this method, simulated annual average loads randomly increase and decrease through time from the annual average load level of the prior year with the results including outcomes that represent periods of strong load growth, weak load growth, and vacillating positive and negative load growth. The mean-reverting technique causes simulated annual loads to tend to revert to the forecasted loads as loads move further from forecasted loads (either higher or lower).

Input data from the AURORA Model used in the California Load Risk Model are the following: (1) annual average CY 2004 California loads; (2) forecasted annual load growth for CY 2005-2009; and (3) monthly load shaping factors (values relative to 1.00) that are derived for use in AURORA by dividing historical monthly loads by historical annual average loads (*see* Market Price Forecast Study, WP-07-FS-BPA-03). Inputting the data used by the AURORA Model allows the California Load Risk Model to replicate the forecasted monthly California loads in AURORA.

Load growth variability is incorporated into the California Load Risk Model by multiplying an annual load growth standard deviation by values sampled from standard normal distributions (normal probability distributions with a mean of zero and a standard deviation of one) in @RISK and adding the simulated positive and negative values to the annual load level of the prior year. The values sampled from the standard normal distribution are in terms of the number of positive or negative standard deviations.

The annual load growth standard deviation used in the California Load Risk Model is 2.48 percent with cumulative annual load growth standard deviations over two, three, and four years being 2.43, 2.78, and 2.51 percent. These values were derived from historical annual Western Electricity Coordinating Council (WECC) load data for the California/Mexico Power Area during 1987-2004. The source of this data was a publication by the WECC titled, 10-Year Coordinated Plan Summary, Planning and Operation for Electric System Reliability, Western Electricity Coordinating Council, June 2005, at 56. Variability in monthly loads due to load growth variability is derived by multiplying variable annual loads by deterministic monthly load shape factors. The historical WECC load data and the cumulative annual load growth standard deviation calculations by BPA for California, along with the PNW, are reported in Table 14.

1.8.3 California Load Risk Due to Weather

Monthly California load variability due to weather conditions is quantified by first sampling values from standard normal distributions in @RISK, then multiplying the sampled values sampled by monthly load standard deviations, and finally adding the resulting positive and negative values to the simulated loads after load growth.

The monthly California load standard deviations are derived from utility-specific, monthly, historical daily load standard deviations and forecasted CY 2005 loads for California utilities, which were used as input data in PMDAM when performing the MCA in the 1996 rate case (*see* Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A, Part 2 of 2; pages 305 and 256). This derivation is accomplished by calculating composite, load-weighted, monthly load standard deviations from utility specific, daily load standard deviations (for the 12 months of the year) and annual average load data.

1.8.4 Derivation of California Monthly Load Variability Due to Weather

BPA assumes, for rate-setting purposes, that daily weather patterns over the course of a month are independent and that each day of a given month has the same daily load standard deviation. Accordingly, BPA used the following statistical equation to derive monthly load standard deviations from daily load standard deviations for each month. The statistical equation for calculating the standard deviation for the average of "n" number of independent random variables is the following:

$$\sigma_{\bar{x}} = \frac{\sigma_x}{\sqrt{n}}$$

Where:

σ_x is the standard deviation for all independent random variables

n is the number of independent random variables

In the case of BPA's analysis, the number of independent random variables is the number of days in a month and the standard deviation for all the independent random variables is the daily load standard deviations for each month. The California monthly load standard deviations for each month are derived by inserting values for the number of days in each month and the daily load standard deviations for each month into the equation above. Daily California load standard deviations for each month and the resulting California monthly load standard deviations are reported in Table 19. These monthly load standard deviations are input into the California Load Risk Model to quantify monthly load variability due to weather.

Table 19: Derivation of Load-Weighted, Monthly Load Standard Deviations for California

California

		Loads CY 2005	Daily Load Standard Deviations Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE	SCEFRM	11497	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	AAAFRM	423	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	BCRVFM	420	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	DWRFRM	910	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
LADWP	LADFRM	3366	0.09	0.09	0.10	0.10	0.10	0.11	0.12	0.11	0.12	0.11	0.10	0.09
SDG&E	SDEFRM	2319	0.07	0.08	0.07	0.07	0.08	0.09	0.09	0.09	0.10	0.08	0.07	0.07
OSC	BGPFRM	442	0.09	0.08	0.09	0.09	0.10	0.10	0.11	0.10	0.11	0.10	0.09	0.09
OSC	IIDOFM	474	0.09	0.08	0.09	0.09	0.10	0.10	0.11	0.10	0.11	0.10	0.09	0.09
PG&E	PG&FRM	10987	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	NCPFRM	393	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	REDFRM	130	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	SNCFRM	305	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	MIDFRM	275	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	TIDFRM	200	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	SMUFRM	1271	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
Total Cal		**33412**												

		Loads CY 2005	Daily Load Variances Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE	SCEFRM	11497	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	AAAFRM	423	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	BCRVFM	420	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	DWRFRM	910	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
LADWP	LADFRM	3366	0.0081	0.0081	0.0100	0.0100	0.0100	0.0121	0.0144	0.0121	0.0144	0.0121	0.0100	0.0081
SDG&E	SDEFRM	2319	0.0049	0.0064	0.0049	0.0049	0.0064	0.0081	0.0081	0.0081	0.0100	0.0064	0.0049	0.0049
OSC	BGPFRM	442	0.0081	0.0064	0.0081	0.0081	0.0100	0.0100	0.0121	0.0100	0.0121	0.0100	0.0081	0.0081
OSC	IIDOFM	474	0.0081	0.0064	0.0081	0.0081	0.0100	0.0100	0.0121	0.0100	0.0121	0.0100	0.0081	0.0081
PG&E	PG&FRM	10987	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	NCPFRM	393	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	REDFRM	130	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	SNCFRM	305	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	MIDFRM	275	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	TIDFRM	200	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	SMUFRM	1271	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
Total Cal		**33412**												
Number of Days Per Month			31	28	31	30	31	30	31	31	30	31	30	31
Weighted Daily Load Variances			**0.0066**	**0.0066**	**0.0068**	**0.0068**	**0.0090**	**0.0093**	**0.0096**	**0.0079**	**0.0106**	**0.0071**	**0.0068**	**0.0066**
Weighted Daily Load Standard Deviations			**0.0811**	**0.0815**	**0.0823**	**0.0823**	**0.0948**	**0.0965**	**0.0980**	**0.0887**	**0.1028**	**0.0845**	**0.0823**	**0.0811**
Monthly Load Standard Deviations			**0.0146**	**0.0154**	**0.0148**	**0.0150**	**0.0170**	**0.0176**	**0.0176**	**0.0159**	**0.0188**	**0.0152**	**0.0150**	**0.0146**

1.8.5 Modeling Methodology

Based on a correlation analysis of PNW and California loads from 1987-2004 that indicates they are highly correlated (the correlation coefficient between these loads is 0.8943 (*See* Table 14), the values sampled from the standard normal distributions for California are identical (including the mean-reversion impacts) to the values sampled from the standard normal distributions used to estimate annual load growth risk for the PNW. By using this approach, positive/negative load growth due to the economy in California is directly linked with positive/negative load growth in the PNW due to the economy. With the strong relationship between these loads modeled, additional annual load variability adjustment factors were developed for years one through four (CY 2006-2009) in the California Load Risk Model to more closely match the simulated load growth standard deviations for California to the load growth standard deviations in the historical data.

<u>Annual load movements through time were modeled as follows:</u>

Annual load for time t = Annual load for time t-1 * (1 + (Forecasted load growth from time t-1 to time t + (Sampled positive or negative standard deviation * annual load growth standard deviation)))

Where,

The sampled positive or negative standard deviation is the same as for the PNW, but is adjusted by additional annual load variability adjustment factors.

1.8.6 Calibrating Annual Load Variability

The final step in the modeling process is the derivation of annual load variability adjustment factors, which are used to better calibrate the cumulative annual load variability simulated by the California Load Risk Model to the historical annual variability reflected in the WECC annual load data. The calibration of the cumulative annual load variability adjustment factors is performed in the following manner: (1) run the model; (2) calculate the cumulative annual load standard deviations for the simulated data and compare these results to the annual load standard deviations derived by multiplying the forecasted annual loads times the historical cumulative annual load standard deviations; and (3) revise the annual load variability adjustment factors for CY 2006-2009 to test how well the values computed in step (2) compare.

BPA used the statistical approach of minimizing the sum of residuals squared to help objectively determine the relative merits of one set of annual decay values versus another. The sum of residuals squared is calculated by squaring the difference between the values computed in Step (2) above and summing these squared differences. The lower the sum of residuals squared, the better the results.

1.8.7 Model and Results

Table 16 and Table 20 contain copies of the results of the calibration process for California load variability and the California Load Risk Model. Graph 5 shows the simulated California loads at the 5th, 50th, and 95th percentiles.

Table 20: California Load Risk Model for 2006 - 2009

California Load Variability

California Load Growth Uncertainty:

Forecasted Calendar Year (2004) Annual Average California Loads	**31,836**		
Forecasted California Load Growth for 2005; Source: Aurora	**4.50%**		
Forecasted California Load Growth for 2006; Source: Aurora	**2.60%**		
Forecasted California Load Growth for 2007; Source: Aurora	**2.60%**		
Forecasted California Load Growth for 2008; Source: Aurora	**2.58%**		
Forecasted California Load Growth for 2009; Source: Aurora	**2.62%**		
Annual Load Growth Std Dev; Source: WECC Load Data (1987-2004)	**2.48%**		
		Std Normal Dist	**Additional Adj**
Estimated Base Case Loads		***(Same as PNW)***	**Factors**
CY 2005	**33,267**	***0.0***	**N/A**
CY 2006	**34,132**	***0.0***	**1.000**
CY 2007	**35,019**	***0.0***	**0.140**
CY 2008	**35,923**	***0.0***	**0.437**
CY 2009	**36,864**	***0.0***	**0.001**

Load Growth Dev from any specified forecasted load level

CY 2005	***33267***
CY 2006	***34132***
CY 2007	***35019***
CY 2008	***35923***
CY 2009	***36864***

California Load Variability Due to Load Growth Uncertainty

Calendar Year 2006

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Simple Avg
Average Annual California Loads (Average Energy in aMW)	34132	34132	34132	34132	34132	34132	34132	34132	34132	34132	34132	34132	
California Monthly Load Shapes (Source: AURORA)	**0.954**	**0.934**	**0.919**	**0.925**	**0.955**	**1.063**	**1.126**	**1.167**	**1.074**	**0.971**	**0.944**	**0.962**	
Simulated Monthly California Loads (Average Energy in aMW)	32545	31863	31381	31581	32604	36297	38426	39826	36674	33145	32204	32827	**34,114 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Simple Avg
California Loads after Load Growth (Average Energy in aMW)	32545	31863	31381	31581	32604	36297	38426	39826	36674	33145	32204	32827	**34,114 aMW**
Monthly Load Standard Deviation	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Loads (Average Energy in aMW)	***32,545***	***31,863***	***31,381***	***31,581***	***32,604***	***36,297***	***38,426***	***39,826***	***36,674***	***33,145***	***32,204***	***32,827***	**34,114 aMW**

Table 20: California Load Risk Model for 2007 (Continued)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

	Calendar Year 2007												
	Jan '07	**Feb '07**	**Mar '07**	**Apr '07**	**May '07**	**Jun '07**	**Jul '07**	**Aug '07**	**Sep '07**	**Oct '07**	**Nov '07**	**Dec '07**	**Simple Avg**
Average Annual California Loads (Average Energy in aMW)	35019	35019	35019	35019	35019	35019	35019	35019	35019	35019	35019	35019	
California Monthly Load Shapes (Source: AURORA)	**0.954**	**0.934**	**0.919**	**0.925**	**0.955**	**1.063**	**1.126**	**1.167**	**1.074**	**0.971**	**0.944**	**0.962**	
Simulated Monthly California Loads (Average Energy in aMW)	33391	32691	32197	32402	33452	37241	39425	40861	37628	34007	33041	33681	**35,001 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '07	**Feb '07**	**Mar '07**	**Apr '07**	**May '07**	**Jun '07**	**Jul '07**	**Aug '07**	**Sep '07**	**Oct '07**	**Nov '07**	**Dec '07**	**Simple Avg**
California Loads after Load Growth (Average Energy in aMW)	33391	32691	32197	32402	33452	37241	39425	40861	37628	34007	33041	33681	**35,001 aMW**
Monthly Load Standard Deviation	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Loads (Average Energy in aMW)	***33,391***	***32,691***	***32,197***	***32,402***	***33,452***	***37,241***	***39,425***	***40,861***	***37,628***	***34,007***	***33,041***	***33,681***	**35,001 aMW**

Table 20: California Load Risk Model for 2008 (Continued)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

	Calendar Year 2008												
	Jan '08	**Feb '08**	**Mar '08**	**Apr '08**	**May '08**	**Jun '08**	**Jul '08**	**Aug '08**	**Sep '08**	**Oct '08**	**Nov '08**	**Dec '08**	**Simple Avg**
Average Annual California Loads (Average Energy in aMW)	35923	35923	35923	35923	35923	35923	35923	35923	35923	35923	35923	35923	
California Monthly Load Shapes (Source: AURORA)	**0.954**	**0.934**	**0.919**	**0.925**	**0.955**	**1.063**	**1.126**	**1.167**	**1.074**	**0.971**	**0.944**	**0.962**	
Simulated Monthly California Loads (Average Energy in aMW)	34253	33535	33028	33238	34315	38202	40442	41916	38599	34885	33894	34550	**35,905 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '08	**Feb '08**	**Mar '08**	**Apr '08**	**May '08**	**Jun '08**	**Jul '08**	**Aug '08**	**Sep '08**	**Oct '08**	**Nov '08**	**Dec '08**	**Simple Avg**
California Loads after Load Growth (Average Energy in aMW)	34253	33535	33028	33238	34315	38202	40442	41916	38599	34885	33894	34550	**35,905 aMW**
Monthly Load Standard Deviation	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Loads (Average Energy in aMW)	***34,253***	***33,535***	***33,028***	***33,238***	***34,315***	***38,202***	***40,442***	***41,916***	***38,599***	***34,885***	***33,894***	***34,550***	**35,905 aMW**

Table 20: California Load Risk Model for 2009 (Continued)

California Load Variability

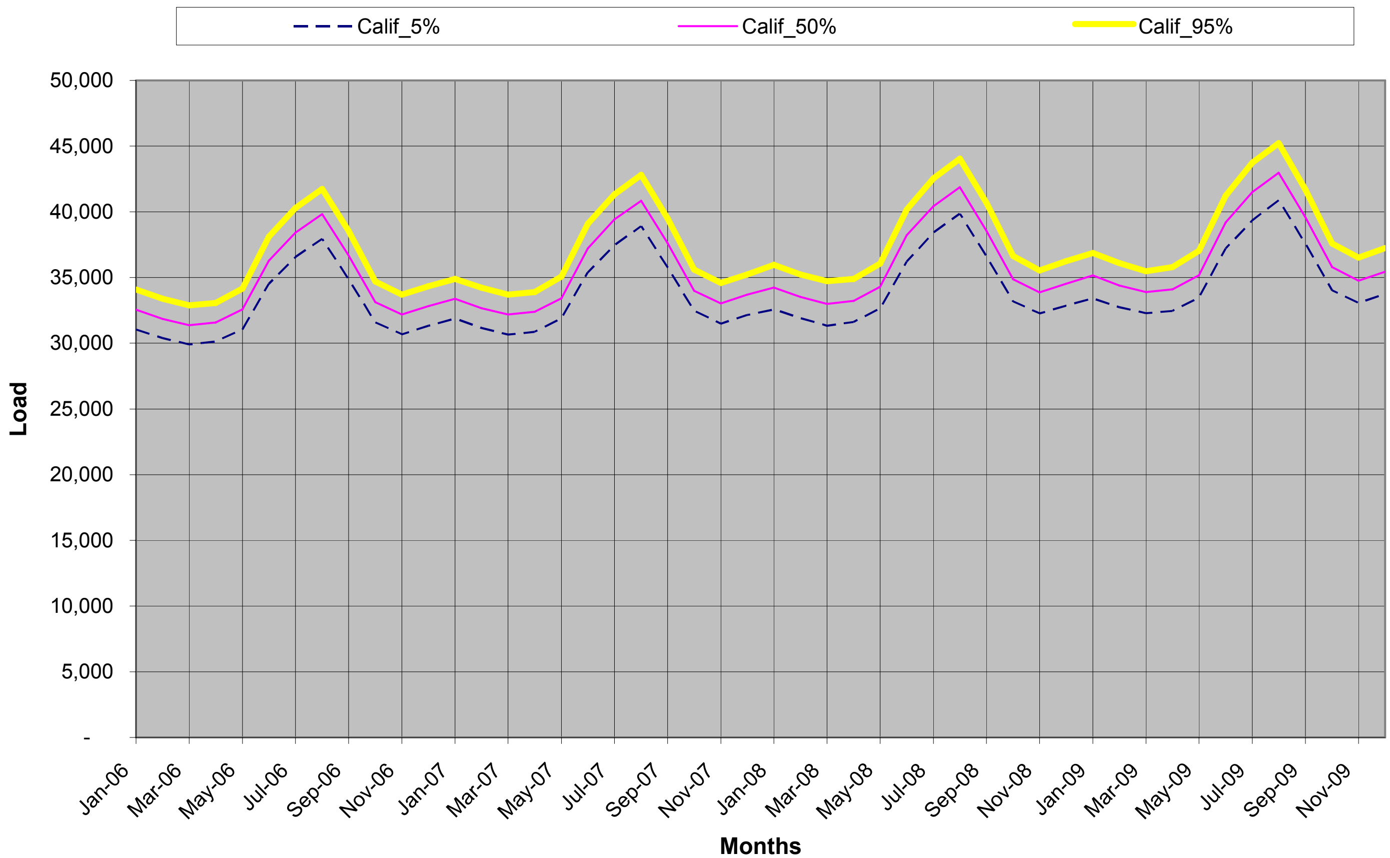
California Load Variability Due to Load Growth Uncertainty

	Calendar Year 2009												
	Jan '09	**Feb '09**	**Mar '09**	**Apr '09**	**May '09**	**Jun '09**	**Jul '09**	**Aug '09**	**Sep '09**	**Oct '09**	**Nov '09**	**Dec '09**	**Simple Avg**
Average Annual California Loads (Average Energy in aMW)	36864	36864	36864	36864	36864	36864	36864	36864	36864	36864	36864	36864	
California Monthly Load Shapes (Source: AURORA)	**0.954**	**0.934**	**0.919**	**0.925**	**0.955**	**1.063**	**1.126**	**1.167**	**1.074**	**0.971**	**0.944**	**0.962**	
Simulated Monthly California Loads (Average Energy in aMW)	35150	34413	33893	34109	35214	39202	41501	43014	39610	35798	34782	35455	**36,845 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '09	**Feb '09**	**Mar '09**	**Apr '09**	**May '09**	**Jun '09**	**Jul '09**	**Aug '09**	**Sep '09**	**Oct '09**	**Nov '09**	**Dec '09**	**Simple Avg**
California Loads after Load Growth (Average Energy in aMW)	35150	34413	33893	34109	35214	39202	41501	43014	39610	35798	34782	35455	**36,845 aMW**
Monthly Load Standard Deviation	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Loads (Average Energy in aMW)	***35,150***	***34,413***	***33,893***	***34,109***	***35,214***	***39,202***	***41,501***	***43,014***	***39,610***	***35,798***	***34,782***	***35,455***	**36,845 aMW**

Graph 5: Simulated California Loads for CYs 2006 - 2009



1.8.8 Use of Simulated California Loads in AURORA

The HLH and LLH spot market electricity prices associated with changes in California monthly loads are estimated in the AURORA Model by inputting California load data simulated by the California Load Risk Model. This process involves calculating (via the Data Manager) monthly load ratios (monthly loads divided by the annual average loads) from monthly and annual load data simulated by the California Load Risk Model and then inputting the monthly ratios and annual average energy loads into the AURORA Model for each simulation. These data are input into AURORA to calculate annual and monthly loads for each of the two California regions (southern and northern California) in AURORA. This process results in the sum of the loads for the two California regions in AURORA being equal to the simulated California loads from the California Load Risk Model.

1.9 Natural Gas Price Risk Factor

Natural gas price risk is incorporated into the Risk Analysis Study to account for the impact that natural gas price variability has on monthly HLH and LLH spot market electricity prices, which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into AURORA the simulated monthly natural gas prices (in real 2000 dollars) from the Natural Gas Price Risk Model and having AURORA estimate the associated nominal monthly HLH and LLH spot market electricity prices for each simulation.

The Natural Gas Price Risk Model is designed to simulate various gas price patterns through time. The modeling method used to simulate gas price patterns through time is a mean-reverting, random-walk technique. The random-walk technique simulates monthly natural gas prices through time with the starting point for simulating the natural gas price in a given month being the monthly natural gas price from the prior month. Under this method, simulated monthly natural gas prices randomly increase and decrease through time from the natural gas price of the prior month. The mean-reverting technique causes simulated natural gas prices to tend to revert to the forecasted prices as prices move further from forecasted prices (either higher or lower).

1.9.1 Inputs into the Natural Gas Price Risk Model

The Natural Gas Price Risk Model is designed to simulate variable natural gas prices based on natural gas prices used in AURORA to perform the Market Price Forecast Study (s*ee* Market Price Forecast Study, WP-07-FS-BPA-03). To accomplish this task, forecasted annual median delivered natural gas prices (in real 2000 dollars) to southern California for CY 2006-2009 and monthly gas price shape data (values relative to 1.00) from AURORA are input into the Natural Gas Price Risk Model. *Id.* With this data, the deterministic forecasted monthly prices in AURORA are calculated in the Natural Gas Price Risk Model by multiplying the annual median natural gas prices by the monthly gas price shapes. *Id.*

Additional information input into the Natural Gas Price Risk Model are minimum and maximum delivered natural gas price constraints (in real 2000 dollars) and monthly price volatilities for natural gas prices, which were derived from historical monthly spot market natural gas prices by computing the standard deviations of all the natural log (ln) price ratio changes from one month to the next month. These natural log price ratio changes (ln (price at time t/price at time t-1)) are commonly referred to as "returns" in the technical literature. Accordingly, they will be referred to as returns in this study.

Minimum and maximum delivered gas price constraints used in the Natural Gas Risk Model are $1.50/MMBTU (Million British Thermal Units) and $50.00/MMBTU. The minimum price constraint was set based on reviewing the historical real 2005 dollar prices at Ignacio, Colorado (*See* Table 21 in the Risk Analysis Study Documentation, WP-07-FS-BPA-04A) and adding an additional charge for delivery from Ignacio to southern California and the maximum price constraint was set such that no simulated prices would be constrained.

Historical monthly spot market gas prices in real 2005 dollars for Ignacio, Colorado, from December 1989 through December 2005 were used to calculate the monthly price volatilities for month-to-month price movements. Monthly price volatilities were estimated in terms of month-to-month price changes so that price movements through time could be modeled using the random-walk technique.

Table 21: Estimated Monthly Price Volatilities, Annual CY 2006 Price Volatility, and Annual CY 2006 Price Variability Based on the Gas Price Forecast

Input Calculations for Gas Price Risk Model

Dec-89 3.17

Ignacio Monthly Spot Gas Prices in real 2005$

Year	1 Jan	2 Feb	3 Mar	4 Apr	5 May	6 Jun	7 Jul	8 Aug	9 Sep	10 Oct	11 Nov	12 Dec	Annual Average
1990	3.64	2.53	2.00	2.01	1.98	2.03	1.98	1.95	1.93	2.37	2.69	2.56	2.30
1991	2.19	1.58	1.38	1.43	1.39	1.36	1.38	1.47	1.67	1.69	2.24	2.24	1.67
1992	1.64	1.48	1.57	1.79	1.89	1.96	2.06	2.36	2.79	2.74	2.69	2.75	2.14
1993	2.57	2.20	2.67	2.51	2.34	2.17	2.30	2.47	2.59	2.36	2.48	2.57	2.44
1994	2.31	2.66	2.39	2.19	2.06	1.89	1.97	1.96	1.65	1.62	1.85	1.97	2.04
1995	1.57	1.36	1.35	1.39	1.42	1.40	1.24	1.48	1.55	1.45	1.51	1.55	1.44
1996	1.45	1.47	1.41	1.38	1.35	1.57	2.08	2.24	1.86	2.19	3.15	4.16	2.03
1997	4.17	2.86	1.89	2.03	2.24	2.32	2.40	2.65	3.08	3.25	3.47	2.54	2.74
1998	2.34	2.26	2.43	2.54	2.27	1.98	2.21	2.08	1.99	1.99	2.24	2.06	2.20
1999	2.04	1.90	1.75	2.06	2.32	2.35	2.34	2.76	2.75	2.91	2.60	2.57	2.36
2000	2.54	2.73	2.92	3.11	3.44	4.89	4.19	3.87	4.67	5.10	5.78	8.66	4.33
2001	9.06	6.30	5.34	5.10	3.91	2.96	2.70	2.83	2.03	2.32	2.43	2.51	3.96
2002	2.27	2.30	2.92	2.85	2.71	2.51	2.77	2.64	2.61	3.01	3.67	4.19	2.87
2003	4.76	5.49	5.68	3.78	4.76	5.19	4.79	4.85	4.47	4.49	4.29	5.60	4.85
2004	5.67	5.03	4.93	5.30	5.49	5.44	5.41	5.19	4.45	5.11	5.65	6.22	5.32
2005	5.53	5.54	6.27	6.39	5.62	5.77	6.22	7.42	9.00	10.19	7.43	11.30	7.22
Annual Average	3.36	2.98	2.93	2.87	2.82	2.86	2.88	3.01	3.07	3.30	3.39	3.96	3.12
Median	2.44	2.41	2.41	2.35	2.29	2.25	2.32	2.56	2.60	2.55	2.69	2.57	2.40
Annual Standard Deviation													1.59

Ignacio Monthly Spot Gas Price Natural Log (Ln) Ratio Deltas (Returns) and Volatility Computations; Reflects Month-To-Month Price Changes

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1990	0.14	-0.37	-0.23	0.00	-0.02	0.02	-0.02	-0.02	-0.01	0.21	0.13	-0.05
1991	-0.16	-0.33	-0.13	0.04	-0.03	-0.02	0.02	0.06	0.12	0.01	0.28	0.00
1992	-0.31	-0.10	0.06	0.13	0.05	0.04	0.05	0.13	0.17	-0.02	-0.02	0.02
1993	-0.07	-0.15	0.19	-0.06	-0.07	-0.08	0.05	0.07	0.05	-0.09	0.05	0.03
1994	-0.10	0.14	-0.11	-0.09	-0.06	-0.08	0.04	-0.01	-0.17	-0.02	0.13	0.06
1995	-0.22	-0.14	-0.01	0.03	0.02	-0.01	-0.12	0.18	0.05	-0.07	0.04	0.02
1996	-0.07	0.01	-0.04	-0.02	-0.02	0.15	0.28	0.08	-0.19	0.16	0.36	0.28
1997	0.00	-0.38	-0.42	0.07	0.10	0.03	0.03	0.10	0.15	0.05	0.07	-0.31
1998	-0.08	-0.03	0.07	0.05	-0.11	-0.14	0.11	-0.06	-0.04	0.00	0.12	-0.09
1999	-0.01	-0.07	-0.08	0.16	0.12	0.01	-0.01	0.16	0.00	0.05	-0.11	-0.01
2000	-0.01	0.07	0.07	0.06	0.10	0.35	-0.15	-0.08	0.19	0.09	0.12	0.40
2001	0.05	-0.36	-0.17	-0.05	-0.26	-0.28	-0.09	0.05	-0.33	0.13	0.04	0.03
2002	-0.10	0.01	0.24	-0.02	-0.05	-0.08	0.10	-0.05	-0.01	0.14	0.20	0.13
2003	0.13	0.14	0.03	-0.41	0.23	0.09	-0.08	0.01	-0.08	0.00	-0.05	0.27
2004	0.01	-0.12	-0.02	0.07	0.04	-0.01	-0.01	-0.04	-0.15	0.14	0.10	0.10
2005	-0.12	0.00	0.12	0.02	-0.13	0.03	0.07	0.18	0.19	0.12	-0.32	0.42
Volatilities (Std Devs of Ln Ratio Deltas)	0.117	0.175	0.164	0.127	0.116	0.134	0.105	0.086	0.153	0.088	0.156	0.187
Average of Ln Ratio Deltas	-0.06	-0.10	-0.03	0.00	-0.01	0.00	0.02	0.05	0.00	0.06	0.07	0.08

Cumulative Monthly Price Standard Deviation Computations for Gas Price Forecast Made at the Beginning of the Current Calendar Year (Impacted by Both Price Level and Volatility)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
CY06 Price Forecast (Median)	6.89	6.05	5.12	5.10	4.90	4.72	4.34	3.98	4.10	4.11	5.25	5.67	5.02
CY06 Computed Average Prices	6.94	6.18	5.39	5.30	5.16	5.16	4.78	4.39	4.60	4.65	5.78	6.64	5.41

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1990	8.38	5.61	3.64	3.64	3.40	3.29	2.78	2.25	2.35	2.75	4.04	3.96	3.84
1991	6.24	4.14	2.81	2.89	2.62	2.37	1.99	1.67	2.02	1.94	3.54	3.67	2.99
1992	5.36	4.52	3.99	4.54	4.62	4.61	4.38	4.42	5.37	4.98	5.70	5.78	4.86
1993	6.81	5.65	6.10	5.73	5.17	4.60	4.40	4.16	4.50	3.88	4.93	5.12	5.09
1994	6.58	7.55	6.04	5.52	5.02	4.42	4.16	3.58	3.14	2.93	4.25	4.59	4.82
1995	5.83	4.76	3.90	4.03	3.92	3.68	2.83	2.86	3.13	2.78	3.83	4.02	3.80
1996	6.84	6.86	5.81	5.69	5.42	6.08	7.54	7.40	6.28	6.99	10.49	13.20	7.38
1997	7.32	4.73	2.28	2.43	2.50	2.39	2.06	1.81	2.24	2.23	3.36	2.68	3.00
1998	6.73	6.39	6.10	6.37	5.53	4.62	4.69	3.85	3.83	3.63	4.94	4.59	5.11
1999	7.26	6.65	5.35	6.29	6.93	6.83	6.29	6.71	6.85	6.84	6.84	6.63	6.62
2000	7.23	7.77	7.63	8.10	8.82	12.31	10.01	8.45	10.35	10.70	12.42	17.54	10.11
2001	7.65	5.06	3.47	3.30	2.35	1.59	1.05	0.69	0.61	0.68	1.80	2.13	2.53
2002	6.60	6.57	7.65	7.46	6.93	6.22	6.36	5.44	5.50	6.01	7.95	8.80	6.79
2003	8.30	9.77	9.45	6.28	7.75	8.25	7.10	6.50	6.14	5.84	6.32	8.03	7.48
2004	7.40	6.43	5.55	5.95	6.00	5.75	5.24	4.43	3.94	4.29	5.54	6.04	5.55
2005	6.50	6.38	6.48	6.60	5.63	5.59	5.54	5.95	7.37	7.88	6.48	9.51	6.66
CY06 Cumulative Price Std Dev	0.802	1.441	1.944	1.655	1.897	2.599	2.360	2.230	2.462	2.601	2.711	4.061	2.018

Cumulative Monthly Volatility Computations for Gas Price Forecast Made at the Beginning of the Current Calendar Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual (LN)
1990	0.19	-0.08	-0.34	-0.34	-0.37	-0.36	-0.45	-0.57	-0.55	-0.40	-0.26	-0.36	1.35
1991	-0.10	-0.38	-0.60	-0.57	-0.63	-0.69	-0.78	-0.87	-0.71	-0.75	-0.40	-0.44	1.10
1992	-0.25	-0.29	-0.25	-0.12	-0.06	-0.02	0.01	0.10	0.27	0.19	0.08	0.02	1.58
1993	-0.01	-0.07	0.18	0.12	0.05	-0.02	0.01	0.04	0.09	-0.06	-0.06	-0.10	1.63
1994	-0.05	0.22	0.17	0.08	0.02	-0.06	-0.04	-0.11	-0.27	-0.34	-0.21	-0.21	1.57
1995	-0.17	-0.24	-0.27	-0.24	-0.22	-0.25	-0.43	-0.33	-0.27	-0.39	-0.32	-0.34	1.33
1996	-0.01	0.13	0.13	0.11	0.10	0.25	0.55	0.62	0.43	0.53	0.69	0.85	2.00
1997	0.06	-0.25	-0.81	-0.74	-0.67	-0.68	-0.75	-0.79	-0.61	-0.61	-0.45	-0.75	1.10
1998	-0.02	0.06	0.18	0.22	0.12	-0.02	0.08	-0.03	-0.07	-0.13	-0.06	-0.21	1.63
1999	0.05	0.10	0.05	0.21	0.35	0.37	0.37	0.52	0.51	0.51	0.26	0.16	1.89
2000	0.05	0.25	0.40	0.46	0.59	0.96	0.84	0.75	0.93	0.96	0.86	1.13	2.31
2001	0.10	-0.18	-0.39	-0.44	-0.74	-1.09	-1.42	-1.75	-1.90	-1.81	-1.07	-0.98	0.93
2002	-0.04	0.08	0.40	0.38	0.35	0.28	0.38	0.31	0.29	0.38	0.41	0.44	1.92
2003	0.18	0.48	0.61	0.21	0.46	0.56	0.49	0.49	0.40	0.35	0.18	0.35	2.01
2004	0.07	0.06	0.08	0.15	0.20	0.20	0.19	0.11	-0.04	0.04	0.05	0.06	1.71
2005	-0.06	0.05	0.24	0.26	0.14	0.17	0.25	0.40	0.59	0.65	0.21	0.52	1.90
Cumulative Volatilities	0.117	0.227	0.390	0.352	0.405	0.509	0.587	0.662	0.676	0.672	0.467	0.557	0.384

1.9.2 Modeling Natural Gas Price Volatility and Variability

Statistical parameters needed to quantify risk in probability distributions in the Natural Gas Price Risk Model are developed from the Ignacio price data. This quantification allows the volatility in the historical natural gas price data for Ignacio to be incorporated into the Natural Gas Price Risk Model. This process is performed in the following manner: (1) all the returns from one month to the next month for all months from December 1989 through December 2005 are calculated; (2) all the returns are accumulated, by month, for each of the 12 months in a year; and (3) the standard deviation of all the returns from one month to the next month for each month are calculated. This process results in monthly price volatilities being calculated from a set of 16 price changes for all months of the year. Using a similar approach with annual price data, cumulative annual price volatilities over several years duration were computed to quantify how much annual prices could deviate in the future from the current natural gas price forecast.

Table 21 contains the historical Ignacio monthly spot market natural gas prices, the calculations of the month-to-month returns, and the derivation of the monthly price volatilities. Comparisons between the average and median prices for the monthly and annual historical price data indicate that average prices are greater than median prices. Additional comparisons indicate that the differences between the maximum prices and the median prices are greater than the differences between the minimum prices and the median prices. These asymmetrical differences were accounted for in this study by modeling natural gas price risk in lognormal probability distributions that differ in skewness depending on the size of the differences.

A comparison of the month-to-month volatilities in Table 21 reveals that, in general, month-to-month price movements, either upward or downward, are greatest during the wintertime. At the bottom of this table, the month-to-month returns are applied to the CY 2006 natural gas price forecast to compute monthly price variability, annual price variability, and the annual price volatility for CY 2006. As the values in this table indicate, price variability (as measured by standard deviation) is impacted by both the volatility and the price level with price variability increasing the higher the volatility and/or the price level.

The results reported in Table 21 indicate that monthly and annual price variability at forecasted CY 2006 prices are substantial with annual CY 2006 price variability being $2.02/MMBTU, which translates into an annual price volatility of 38.4 percent. These results reflect how much natural gas prices can vary from a gas price forecast made at the beginning of CY 2006. Natural gas price variability was turned off in the Natural Gas Price Risk Model for the months of January and February of 2006 to account for the fact that there is less natural gas price risk for the remainder of the year than for a full year.

Table 22 contains the calculations of the cumulative annual price returns for one to three years duration after the current calendar year (CY 2006) and the derivation of the associated cumulative annual price volatilities. The cumulative annual price returns for one to three years duration were derived by computing all the annual price returns over one-, two-, and three-year increments and calculating the associated standard deviations to get the cumulative annual price volatilities. These values were computed so that the simulated prices over various durations in time would have values to calibrate to, rather than move through time in an unconstrained manner. The cumulative annual price volatilities for one to three years duration after the current calendar year (CY 2006) were calculated to be 31.2 percent for one year, 38.9 percent for two years, and 33.2 percent for three years. These results reflect that cumulative annual price volatilities over various annual time durations are large and exhibit cyclical behavior.

At the bottom of Table 22, the cumulative annual price returns for one to three years duration after the current calendar year (CY 2006) were applied to the CY 2007-2009 natural gas price forecast to compute the cumulative annual price variability over these years. This price variability (as measured by standard deviation) is impacted by both the volatility and the price level with price variability increasing the higher the volatility and/or the price level.

Monthly gas price variability was incorporated into the Natural Gas Price Risk Model by sampling positive and negative standard deviation values from truncated standard normal probability distributions in @RISK, multiplying the sampled standard deviation values by monthly price volatility values, and multiplying the natural gas price of the prior month by the exponential of the simulated positive and negative values (which transforms values that are in terms of natural logs into unlogged values). A truncated standard normal distribution is a normal distribution having a mean of zero, a standard deviation of one, and a specified maximum and minimum value that sets an upper and lower bound on the standard deviation values that can be sampled. For this study, the specified maximum and minimum values were set at +5 and -5 standard deviations (which results in them having no impact), since controlling the maximum and minimum standard deviations was not needed.

In the @RISK computer software, this information is entered into a truncated standard normal probability distribution (RiskTNormal) as follows:

RiskTNormal (Mean = 0, Standard deviation = 1, Min value = -5, Max value = +5).

Under this methodology, the positive and negative values sampled from the truncated standard normal distributions are the number of standard deviations of a random price movement. The standard deviations sampled from the monthly truncated standard normal distributions in the Natural Gas Price Risk Model are multiplied by the monthly volatilities as part of the price movement computations reported in the equation below.

<u>Prices movements through time are modeled as follows:</u>

Price t = Price t-1 * EXP (Sampled positive or negative standard deviation * monthly volatility) + (FP t minus FP t-1)

Where:
Price t = Simulated price at time t
Price t-1 = Simulated price at time t-1
FP t = Forecasted price for time t
FP t-1 = Forecasted price for time t-1

EXP = Exponential Function (used to take the antilog of the returns; which are in logs)

The mean-reversion methodology was modeled using an algorithm and a set of monthly and annual mean reversion decay parameters (decay parameters) that adjust the value of the mean in each of the monthly truncated standard normal distributions from the typical constant of zero.

<u>The mean-reversion methodology incorporated into the monthly truncated standard normal probability distributions is as follows:</u>

Sampled positive or negative standard deviation = RiskTNormal (Mean-reversion decay parameters * (1 - Simulated mean-reversion ratios), 1, Maximum negative monthly standard deviation, Maximum positive monthly standard deviation)

Where:
RiskTNormal = Truncated normal probability distribution in @RISK with
Mean = Mean-reversion decay parameters * (1- Simulated mean-reversion ratios)
Standard deviation = 1
Minimum value = - 5 standard deviations
Maximum value = + 5 standard deviations
Mean-reversion decay parameters = Calibrated price decay values
Simulated mean-reversion ratios = LN(Simulated prior month price) / LN(Forecasted prior month price)
LN = Natural log function in Excel

Table 22: Estimated CYs 2007-2009 Price Statistics Based on Applying Historical Volatility to the Gas Price Forecast

Annual Gas Price Forecast		
CY07	CY08	CY09
4.93	4.72	4.52

Ignacio Annual Spot Gas Price Natural Log (Ln) Ratio Deltas (Returns) and Volatility Computations; Reflects Cumulative Annual Price Changes Over Time

Year	Annual Average Historical Real Prices	1 Yr LN Ratio Changes	2 Yr LN Ratio Changes	3 Yr LN Ratio Changes
1990	2.30			
1991	1.67	-0.32		
1992	2.14	0.25	-0.07	
1993	2.44	0.13	0.38	0.06
1994	2.04	-0.18	-0.05	0.20
1995	1.44	-0.35	-0.53	-0.40
1996	2.03	0.34	-0.01	-0.18
1997	2.74	0.30	0.64	0.29
1998	2.20	-0.22	0.08	0.42
1999	2.36	0.07	-0.15	0.15
2000	4.33	0.61	0.68	0.46
2001	3.96	-0.09	0.52	0.59
2002	2.87	-0.32	-0.41	0.20
2003	4.85	0.52	0.20	0.11
2004	5.32	0.09	0.62	0.30
2005	7.22	0.31	0.40	0.92
Volatilities (Std Devs of Ln Ratio Deltas)		0.312	0.389	0.332

	Gas Price Standard Deviations for Gas Price Forecast and Historical Volatility		
Year	CY07	CY08	CY09
1990			
1991	3.31		
1992	5.87	3.72	
1993	5.19	5.85	3.76
1994	3.83	3.82	4.36
1995	3.22	2.37	2.39
1996	6.42	3.97	2.96
1997	6.18	7.62	4.77
1998	3.66	4.35	5.43
1999	4.91	3.45	4.15
2000	8.37	7.88	5.61
2001	4.18	6.71	6.40
2002	3.31	2.66	4.32
2003	7.71	4.90	3.98
2004	5.02	7.43	4.78
2005	6.20	5.97	8.95
Standard Deviation	1.62	1.86	1.65

1.9.3 Calibrating Future Natural Gas Price Volatility

The final step in the modeling process is the derivation of monthly and annual decay parameters to better calibrate the natural gas price volatility simulated by the Natural Gas Price Risk Model to the historical volatility reflected in the Ignacio natural gas price data. The calibration of the decay values is performed in the following manner: (1) run the model; (2) calculate monthly and cumulative annual price volatilities from the simulated data and compare the results to monthly and cumulative annual price volatilities for the historical data; and (3) revise the decay values to test how well the monthly and cumulative annual price volatilities of the simulated prices approximate the monthly and cumulative annual price volatilities in the historical gas price data.

BPA used the statistical approach of minimizing the sum of residuals squared to help objectively determine the relative merits of one set of decay values versus another. The sum of residuals squared is calculated by squaring the differences between historical monthly and annual natural gas price volatilities and simulated monthly and annual natural gas price volatilities and summing these squared differences. The lower the sum of residuals squared, the better the simulated gas price volatilities approximate the historical gas price volatilities. Table 23 contains the final calibration results for natural gas price volatility along with additional summary statistical information.

The use of monthly and annual decay parameters, coupled with each month having different month-to-month gas price standard deviations, allows the Natural Gas Price Risk Model the flexibility to simulate natural gas prices that are more volatile in some months than others, as well as to simulate gas prices that rise and fall at different rates during the year and across years. Thus, the flexibility associated with the methodology utilized in the Natural Gas Price Risk Model allows the model to closely calibrate to the attributes of gas price movements in the historical data.

Table 23: Natural Gas Price Volatility Calibration

Mean-Reversion Calibration Section:

CY 2006	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Reversion Rate	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Max/Min Std Dev.	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000

CY 2007	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Reversion Rate	1.470	1.470	1.470	1.470	1.470	1.470	1.470	1.470	1.470	1.470	1.470	1.470
Max/Min Std Dev.	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000

CY 2008	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Reversion Rate	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315
Max/Min Std Dev.	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000

CY 2009	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Reversion Rate	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190
Max/Min Std Dev.	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000

Volatility Reporting & Calibration Section:

	Sum 06-09	CY 2006	CY 2007	CY 2008	CY 2009
Simulated Price Volatilities for FY06-09		0.348	0.312	0.389	0.332
Historical Price Volatilities Over 1, 2, and 3 Year Periods		0.384	0.312	0.389	0.332
Simulated Less Historical Volatilities		-0.036	0.000	0.000	0.000
Residual ^2	0.0013	0.001	0.000	0.000	0.000

Statistical Reporting Section:

	Sum 06-09	CY 2006	CY 2007	CY 2008	CY 2009
Simulated FY06-09 Price Standard Deviations		1.991	1.729	2.107	1.678
Estimated FY06-09 Price Standard Deviations; Derived By Applying Historical Price Volatilities to the Price Forecast		2.018	1.665	2.053	1.627
Simulated Less Estimated Standard Deviations		-0.027	0.064	0.053	0.051
Residual ^2	0.0103	0.001	0.004	0.003	0.003

	Avg 06-09	CY 2006	CY 2007	CY 2008	CY 2009
Simulated Average Price	5.17	5.39	5.28	5.17	4.86
Simulated Median Price	4.85	5.02	5.00	4.78	4.61
Simulated Average Minus Median Price	0.32	0.37	0.27	0.39	0.25
Average Minus Median Prices; Derived By Applying Historical Price Volatilities to the Price Forecast	0.32	0.39	0.25	0.37	0.26
Gas Price Forecast	4.80	5.02	4.93	4.72	4.52
Simulated Average Price Less Forecast Price	0.38	0.37	0.35	0.45	0.34
Simulated Median Price Less Forecast Price	0.06	0.00	0.07	0.06	0.09

CY 2006	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Simulated Cumulative Monthly Price Volatilities	0.117	0.240	0.346	0.368	0.399	0.438	0.483	0.518	0.523	0.528	0.425	0.427	0.348
Historical Cumulative Monthly Price Volatilities	0.117	0.227	0.390	0.352	0.405	0.509	0.587	0.662	0.676	0.672	0.467	0.557	0.384
Simulated Less Historical Monthly Price Volatiles	0.000	0.013	-0.044	0.016	-0.005	-0.071	-0.105	-0.144	-0.153	-0.144	-0.042	-0.130	-0.036
Residual ^2	0.0000	0.0002	0.0020	0.0002	0.0000	0.0051	0.0110	0.0207	0.0234	0.0208	0.0018	0.0169	0.0013
Sum of Squares	0.1020												0.0013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Simulated Cumulative Monthly Price Standard Deviations	0.816	1.503	1.880	2.017	2.128	2.286	2.340	2.366	2.564	2.640	2.756	3.037	1.991
Estimated Cumulative Price Std Devs; Derived From Historical LN Price Changes and tl	0.802	1.441	1.944	1.655	1.897	2.599	2.360	2.230	2.462	2.601	2.711	4.061	2.018
Simulated Less Estimated Price Standard Deviations	0.014	0.062	-0.064	0.361	0.231	-0.313	-0.020	0.136	0.102	0.039	0.045	-1.024	-0.027
Residual ^2	0.0002	0.0039	0.0041	0.1305	0.0535	0.0979	0.0004	0.0186	0.0104	0.0015	0.0020	1.0491	0.0008
Sum of Squares	1.3722												0.0008

1.9.4 Model and Results

Table 24 contains a copy of the Natural Gas Price Risk Model. Results from this risk model on a monthly basis over time are shown in Graph 6 for the 5th, 50th, and 95th percentiles. As can be noted in this graph, gas price variability started being simulated in March 2006. This was the first month that prices were forecasted in the Natural Gas Price Forecast. The monthly natural gas price variability patterns shown in this graph for CY 2006-2009 reflect the computations previously calculated in Table 21, which indicate that gas price volatility, in general, is highest during the winter.

The prices in Graph 6 include month-specific price level adjustments during FY 2007-CY 2009 that perfectly align the median monthly simulated gas prices to the monthly prices in the natural gas price forecast. These adjustments were made based on median prices rather than average simulated prices because BPA's natural gas price forecast represents its assessment that there is a 50 percent probability that natural gas prices could go higher or lower than its forecast. *See* Petty, *et al.*, WP-07-E-BPA-11. Because each of these monthly price level adjustments is applied to all simulated prices for that month, such adjustments do not alter the simulated price volatility values.

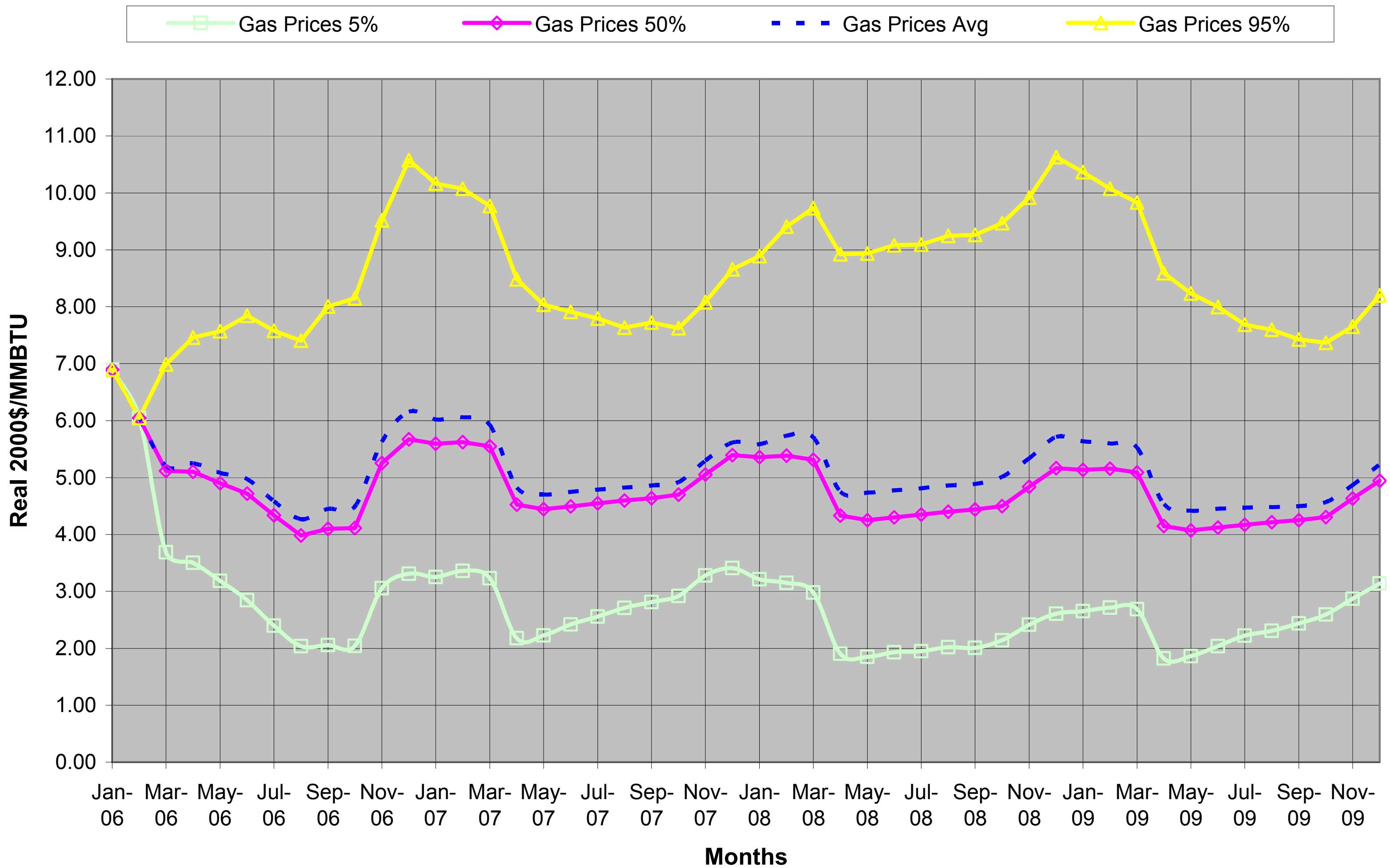
Table 24: Natural Gas Price Risk Model

Forecasted Real 2000$ Delivered Natural Gas Prices Per MMBTU to Southern California

CY 2006 Avg	$	5.02
CY 2007 Avg	$	4.93
CY 2008 Avg	$	4.72
CY 2009 Avg	$	4.52
CY07-09 Avg	$	4.72

	Price Forecast ($/MMBTU)	Standard Normal Truncated Distribution N(var mean, 1); Includes Max and Min Std Devs	Monthly Volatility	Price Risk ($/MMBTU)	Standard Normal Distribution Mean Adjustor (Causes Mean Reversion)	Actuals		Monthly Volatility	Mean Reversion Decay Parameters	Maximum and Minimum Standard Deviations	Monthly Gas Price Shapes	Price Forecast ($/MMBTU)	Minimum Price ($/MMBTU)	Maximum Price ($/MMBTU)	Unconstrained Simulated Prices ($/MMBTU)
Initial Value					1.00										
Jan-06	6.89	0.00	0.117	6.89	1.00	Y	Jan-06	0.117	0.00	5.00	1.37	6.89	1.50	50.00	6.89
Feb-06	6.05	0.00	0.175	6.05	1.00	Y	Feb-06	0.175	0.00	5.00	1.20	6.05	1.50	50.00	6.05
Mar-06	5.12	0.00	0.164	5.12	1.00	N	Mar-06	0.164	0.00	5.00	1.02	5.12	1.50	50.00	5.12
Apr-06	5.10	0.00	0.127	5.10	1.00	N	Apr-06	0.127	0.00	5.00	1.02	5.10	1.50	50.00	5.10
May-06	4.90	0.00	0.116	4.90	1.00	N	May-06	0.116	0.00	5.00	0.98	4.90	1.50	50.00	4.90
Jun-06	4.72	0.00	0.134	4.72	1.00	N	Jun-06	0.134	0.00	5.00	0.94	4.72	1.50	50.00	4.72
Jul-06	4.34	0.00	0.105	4.34	1.00	N	Jul-06	0.105	0.00	5.00	0.86	4.34	1.50	50.00	4.34
Aug-06	3.98	0.00	0.086	3.98	1.00	N	Aug-06	0.086	0.00	5.00	0.79	3.98	1.50	50.00	3.98
Sep-06	4.10	0.00	0.153	4.10	1.00	N	Sep-06	0.153	0.00	5.00	0.82	4.10	1.50	50.00	4.10
Oct-06	4.11	0.00	0.088	4.11	1.00	N	Oct-06	0.088	0.00	5.00	0.82	4.11	1.50	50.00	4.11
Nov-06	5.25	0.00	0.156	5.25	1.00	N	Nov-06	0.156	0.00	5.00	1.05	5.25	1.50	50.00	5.25
Dec-06	5.67	0.00	0.187	5.67	1.00	N	Dec-06	0.187	0.00	5.00	1.13	5.67	1.50	50.00	5.67
Jan-07	5.60	0.00	0.117	5.60	1.00		Jan-07	0.117	1.47	5.00	1.14	5.60	1.50	50.00	5.60
Feb-07	5.62	0.00	0.175	5.62	1.00		Feb-07	0.175	1.47	5.00	1.14	5.62	1.50	50.00	5.62
Mar-07	5.55	0.00	0.164	5.55	1.00		Mar-07	0.164	1.47	5.00	1.13	5.55	1.50	50.00	5.55
Apr-07	4.53	0.00	0.127	4.53	1.00		Apr-07	0.127	1.47	5.00	0.92	4.53	1.50	50.00	4.53
May-07	4.44	0.00	0.116	4.44	1.00		May-07	0.116	1.47	5.00	0.90	4.44	1.50	50.00	4.44
Jun-07	4.49	0.00	0.134	4.49	1.00		Jun-07	0.134	1.47	5.00	0.91	4.49	1.50	50.00	4.49
Jul-07	4.55	0.00	0.105	4.55	1.00		Jul-07	0.105	1.47	5.00	0.92	4.55	1.50	50.00	4.55
Aug-07	4.60	0.00	0.086	4.60	1.00		Aug-07	0.086	1.47	5.00	0.93	4.60	1.50	50.00	4.60
Sep-07	4.64	0.00	0.153	4.64	1.00		Sep-07	0.153	1.47	5.00	0.94	4.64	1.50	50.00	4.64
Oct-07	4.70	0.00	0.088	4.70	1.00		Oct-07	0.088	1.47	5.00	0.95	4.70	1.50	50.00	4.70
Nov-07	5.05	0.00	0.156	5.05	1.00		Nov-07	0.156	1.47	5.00	1.02	5.05	1.50	50.00	5.05
Dec-07	5.40	0.00	0.187	5.40	1.00		Dec-07	0.187	1.47	5.00	1.09	5.40	1.50	50.00	5.40
Jan-08	5.36	0.00	0.117	5.36	1.00		Jan-08	0.117	0.32	5.00	1.14	5.36	1.50	50.00	5.36
Feb-08	5.39	0.00	0.175	5.39	1.00		Feb-08	0.175	0.32	5.00	1.14	5.39	1.50	50.00	5.39
Mar-08	5.31	0.00	0.164	5.31	1.00		Mar-08	0.164	0.32	5.00	1.13	5.31	1.50	50.00	5.31
Apr-08	4.33	0.00	0.127	4.33	1.00		Apr-08	0.127	0.32	5.00	0.92	4.33	1.50	50.00	4.33
May-08	4.25	0.00	0.116	4.25	1.00		May-08	0.116	0.32	5.00	0.90	4.25	1.50	50.00	4.25
Jun-08	4.30	0.00	0.134	4.30	1.00		Jun-08	0.134	0.32	5.00	0.91	4.30	1.50	50.00	4.30
Jul-08	4.35	0.00	0.105	4.35	1.00		Jul-08	0.105	0.32	5.00	0.92	4.35	1.50	50.00	4.35
Aug-08	4.40	0.00	0.086	4.40	1.00		Aug-08	0.086	0.32	5.00	0.93	4.40	1.50	50.00	4.40
Sep-08	4.44	0.00	0.153	4.44	1.00		Sep-08	0.153	0.32	5.00	0.94	4.44	1.50	50.00	4.44
Oct-08	4.50	0.00	0.088	4.50	1.00		Oct-08	0.088	0.32	5.00	0.95	4.50	1.50	50.00	4.50
Nov-08	4.84	0.00	0.156	4.84	1.00		Nov-08	0.156	0.32	5.00	1.02	4.84	1.50	50.00	4.84
Dec-08	5.17	0.00	0.187	5.17	1.00		Dec-08	0.187	0.32	5.00	1.09	5.17	1.50	50.00	5.17
Jan-09	5.13	0.00	0.117	5.13	1.00		Jan-09	0.117	1.19	5.00	1.14	5.13	1.50	50.00	5.13
Feb-09	5.16	0.00	0.175	5.16	1.00		Feb-09	0.175	1.19	5.00	1.14	5.16	1.50	50.00	5.16
Mar-09	5.09	0.00	0.164	5.09	1.00		Mar-09	0.164	1.19	5.00	1.13	5.09	1.50	50.00	5.09
Apr-09	4.15	0.00	0.127	4.15	1.00		Apr-09	0.127	1.19	5.00	0.92	4.15	1.50	50.00	4.15
May-09	4.07	0.00	0.116	4.07	1.00		May-09	0.116	1.19	5.00	0.90	4.07	1.50	50.00	4.07
Jun-09	4.12	0.00	0.134	4.12	1.00		Jun-09	0.134	1.19	5.00	0.91	4.12	1.50	50.00	4.12
Jul-09	4.17	0.00	0.105	4.17	1.00		Jul-09	0.105	1.19	5.00	0.92	4.17	1.50	50.00	4.17
Aug-09	4.21	0.00	0.086	4.21	1.00		Aug-09	0.086	1.19	5.00	0.93	4.21	1.50	50.00	4.21
Sep-09	4.25	0.00	0.153	4.25	1.00		Sep-09	0.153	1.19	5.00	0.94	4.25	1.50	50.00	4.25
Oct-09	4.31	0.00	0.088	4.31	1.00		Oct-09	0.088	1.19	5.00	0.95	4.31	1.50	50.00	4.31
Nov-09	4.63	0.00	0.156	4.63	1.00		Nov-09	0.156	1.19	5.00	1.02	4.63	1.50	50.00	4.63
Dec-09	4.95	0.00	0.187	4.95	1.00		Dec-09	0.187	1.19	5.00	1.09	4.95	1.50	50.00	4.95

Graph 6: Simulated Natural Gas Prices for 2006 - 2009



1.9.5 Use of Simulated Natural Gas Prices in AURORA

The spot market electricity price impacts associated with changes in natural gas prices are estimated in the AURORA model by inputting real monthly gas price data simulated by the Natural Gas Price Risk Model. From each simulation of monthly southern California natural gas prices (in real 2000 dollars), annual average gas prices and monthly gas price ratios (monthly gas prices divided by annual average gas prices) are derived. From this data, simulated monthly and annual gas prices are derived for each of the 13 regions that represent the WECC region in the AURORA Model. This task is accomplished by adding deterministic positive/negative annual average price basis differences for each of the remaining 12 regions modeled in AURORA to the simulated annual average delivered natural gas prices for southern California to get simulated annual average natural gas prices for all 13 regions. Monthly natural gas prices for each of the remaining 12 regions are derived by using the simulated monthly gas price ratios for southern California to yield simulated monthly natural gas prices for all 13 regions (*see* Market Price Forecast Study, WP-07-FS-BPA-03, for further discussion of AURORA).

1.10 Nuclear Plant Generation Risk Factor

Nuclear plant generation risk is incorporated into the Risk Analysis Study to account for the impact that changes in CGS generation have on the amount of BPA's surplus energy revenues and power purchase expenses. CGS generation risk is modeled in the CGS Nuclear Plant Risk Model.

1.10.1 Data and Modeling Methodology

Inputs into the CGS Nuclear Plant Risk Model consist of the forecasted peak capability of CGS (1,162 MW) and expected monthly energy output reported in the Load Resource Study, WP-07-FS-BPA-01. Nuclear plant generation risk is modeled using the following equation:

CGS Output = (CGS capacity * H * RiskUniform(0,1))/(1+(H - 1)*RiskUniform(0,1)), where

> CGS capacity = the maximum amount of output that can be produced by CGS;
> H = calibration factor;
> RiskUniform(0,1) = a uniform probability distribution in @RISK that samples real values between 0 and 1.

The calibration factor (H) is derived by running risk simulations and modifying the factor until the expected monthly CGS output from the risk simulations are equal to the expected monthly values reported in the Load Resource Study, WP-07-FS-BPA-01.

Using this equation, monthly CGS output varies from zero to peak output capability as values sampled from uniform probability distributions vary from zero to one. Although the values ranging from zero to one sampled from the uniform probability distributions are symmetrical, the frequency distribution of CGS output produced from the equation is negatively skewed with the median value (the value at the 50th percentile) being higher than the average. The shape of the frequency distribution reflects that thermal plants (including CGS) typically operate at output levels higher than average output levels, but the average output is driven down by occasional forced outages in which monthly output can be substantially lower than the typical monthly output.

1.10.2 Model and Results

Table 25 contains a copy of the CGS Nuclear Plant Risk Model. The simulated frequency distribution for CGS output for October 2006 is shown in Graph 7.

Table 25: CGS Nuclear Plant Risk Model

	H Factor:	Capacity
CGS Input Parameters	14.40	1162

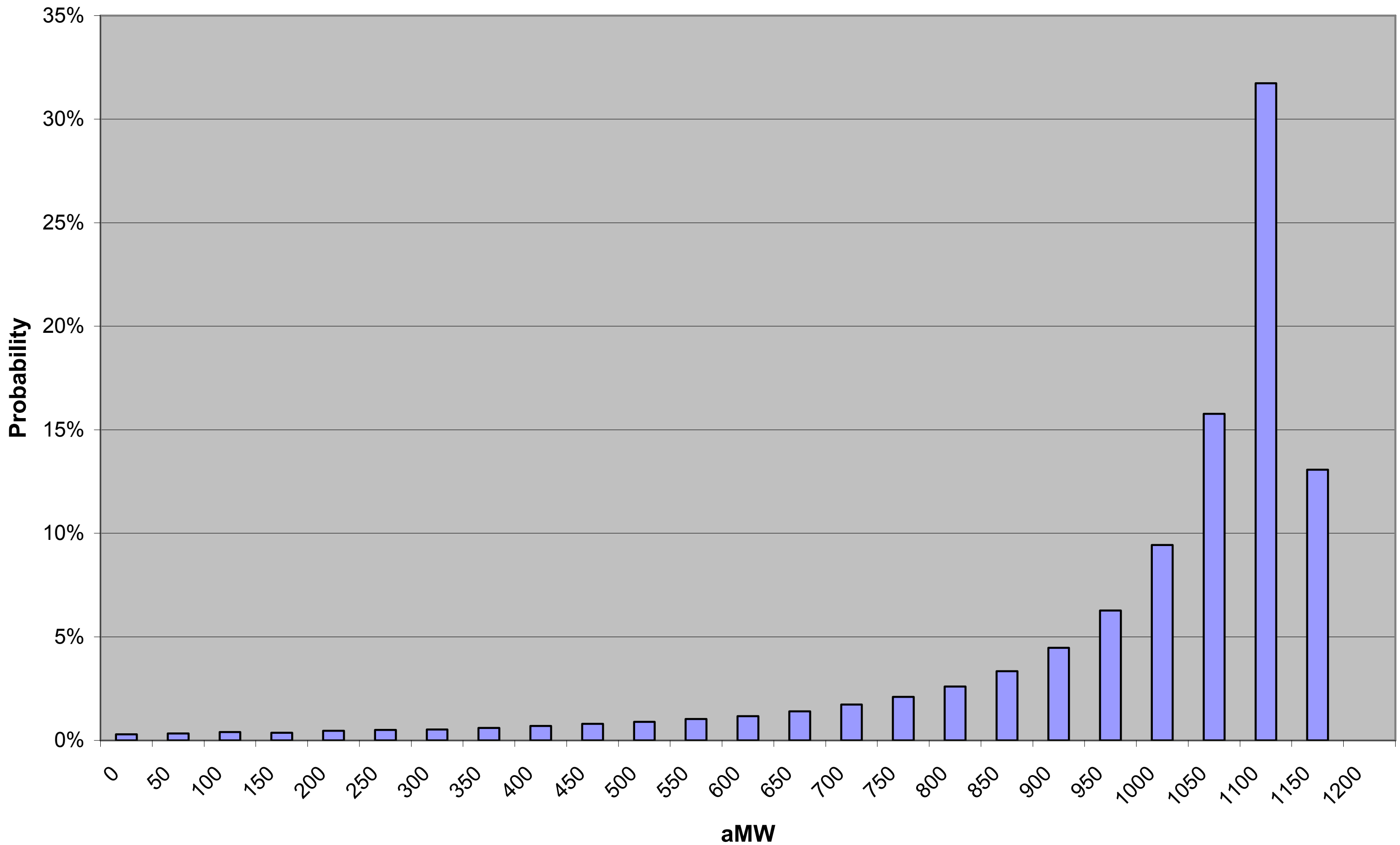
CY 2006	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06
Simulated CGS Output (aMW)	1087	1087	1087	1087	1087	1087	1087	1087	1087	1087	1087	1087
CGS L&R Study (Average Energy in aMW)	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Simulated Mean Values	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Risk Uniform Distribution	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

CY 2007	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Oct '07	Nov '07	Dec '07
Simulated CGS Output (aMW)	1087	1087	1087	1087	386	181	1087	1087	1087	1087	1087	1087
CGS L&R Study (Average Energy in aMW)	1000	1000	1000	1000	355	167	1000	1000	1000	1000	1000	1000
Simulated Mean Values	1000	1000	1000	1000	355	167	1000	1000	1000	1000	1000	1000
Risk Uniform Distribution	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

CY 2008	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08
Simulated CGS Output (aMW)	1087	1087	1087	1087	1087	1087	1087	1087	1087	1087	1087	1087
CGS L&R Study (Average Energy in aMW)	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Simulated Mean Values	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Risk Uniform Distribution	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

CY 2009	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Oct '09	Nov '09	Dec '09
Simulated CGS Output (aMW)	1087	1087	1087	1087	386	181	1087	1087	1087	1087	1087	1087
CGS L&R Study (Average Energy in aMW)	1000	1000	1000	1000	355	167	1000	1000	1000	1000	1000	1000
Simulated Mean Values	1000	1000	1000	1000	355	167	1000	1000	1000	1000	1000	1000
Risk Uniform Distribution	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Graph 7: Simulated CGS Output Distribution for October 2006



1.11 Investor Owned Utility (IOU) Benefits Risk Factor

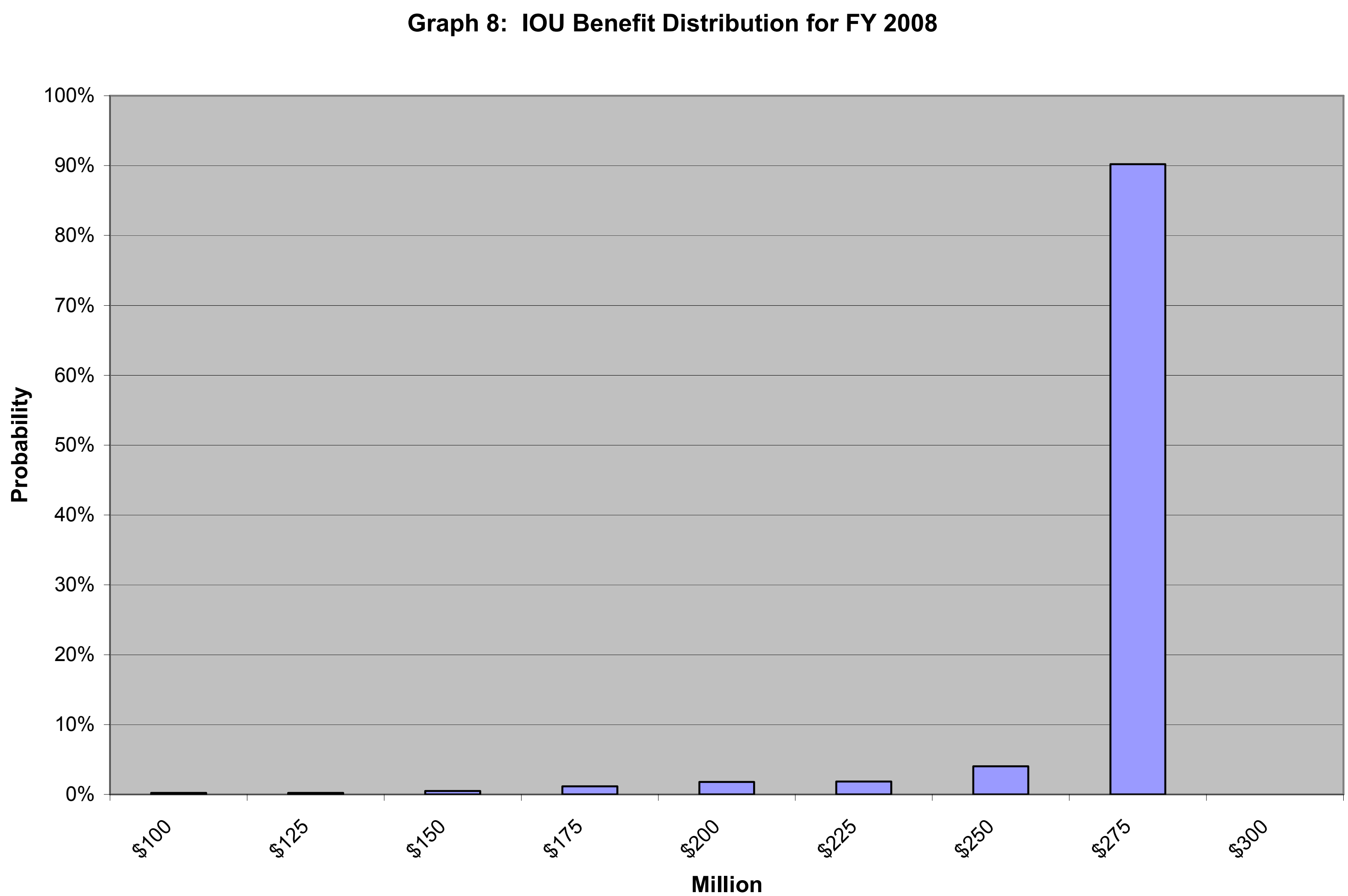
This risk factor reflects the uncertainty in the amount of IOU REP Settlement benefits paid to the IOUs in FY 2007-2009, relative to the $300 million/year benefits included in the Revenue Requirement when setting rates. *See* Revenue Requirement Study, WP-07-FS-BPA-02**.** The quantification of this risk reflects the contract terms set forth in the IOU REP Settlement Agreements entered into in May 25, 2004. This settlement provides 2200 aMW of financial benefits based on the difference between forward market electricity prices and the lowest cost flat PF rate with a maximum (capped) value of $300 million/year and a minimum (floor) value of $100 million/year. For more detail on the proposal, please refer to the Residential Exchange Program Settlement Agreements with Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision, signed October 4, 2000, as amended, Administrator's Record of Decision, signed May 25, 2004.

1.11.1 Data and Modeling Methodology

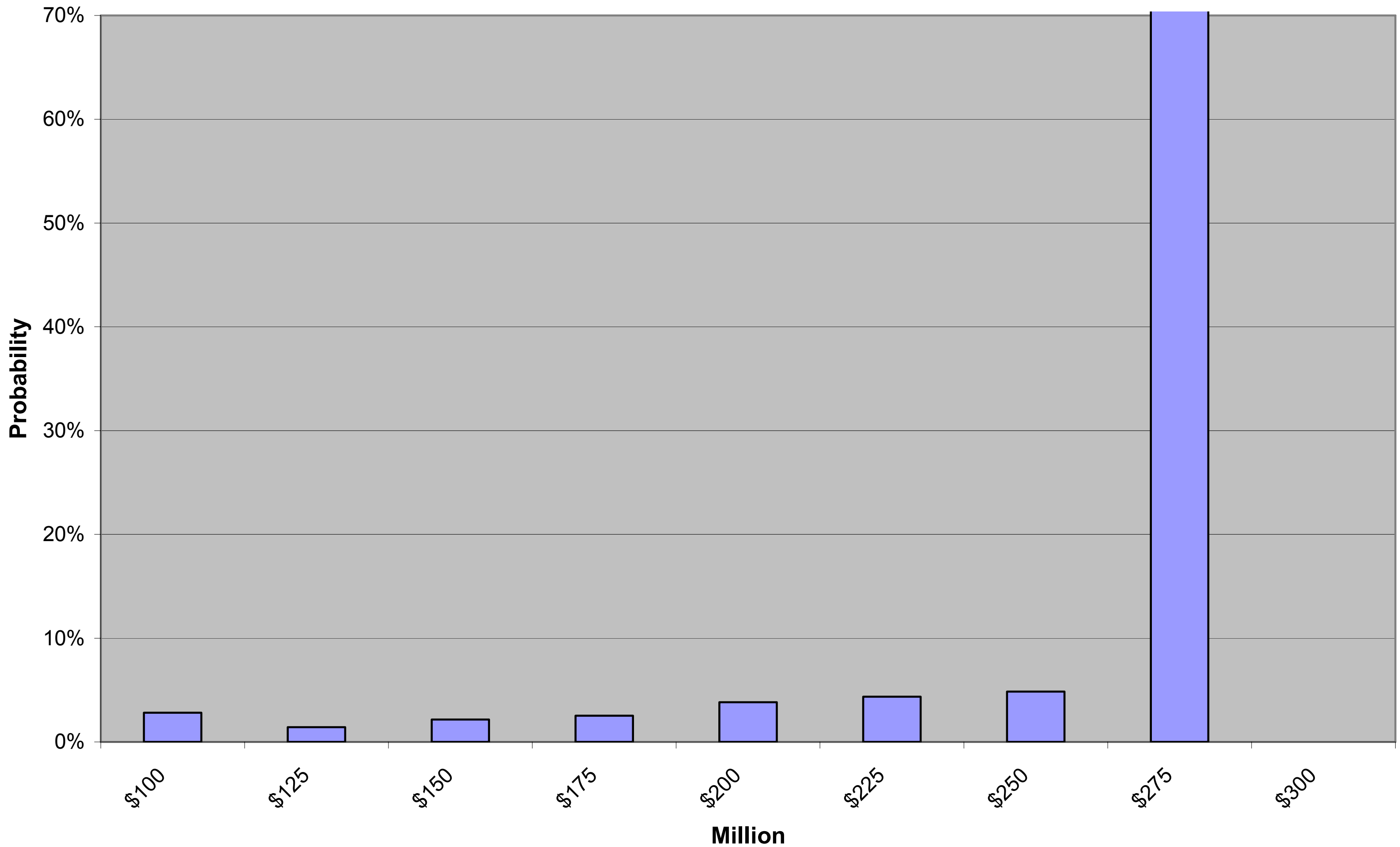
The forward market price risk for a 12-month strip of power was simulated 3000 times per FY for FY 2008-2009 by the Forward Market Price Risk Model. Annual forward market prices were not simulated for FY 2007, since the deterministic price forecast to be used for computing the FY 2007 IOU REP Settlement benefits was known prior to the Final Proposal. *See* Section 1.15 of this Study Documentation, regarding simulated forward market prices in the Forward Market Price Risk Model. The price outcomes for each FY were input into ToolKit, which calculated the IOU benefit risk for FY 2007-2009 on an iteration-by-iteration basis based on iteration-by-iteration flat PF rate computations. S*ee* Section 3.2 in the Risk Analysis Study, WP-07-FS-BPA-04, regarding the ToolKit Model.

1.11.2 Results

Graphs 8-9 show the probability distributions for the IOU REP Settlement Benefits for FY 2008-2009. No comparable graph was developed for FY 2007, since the IOU REP Settlement Benefits for each of the 3000 games were at the cap of $300 million/year.


Graph 8: IOU Benefit Distribution for FY 2008
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
$100
$125
$150
$175
$200
$225
$250
$275
$300
Million

Graph 9: IOU Benefit Distribution for FY 2009



1.12 Direct Service Industry (DSI) Benefits Risk Factor

This risk factor reflects the uncertainty in the amount of DSI benefit payments during FY 2007-2009, relative to the $58.9 million/year benefits included in the Revenue Requirement when setting rates. *See* Revenue Requirement Study, WP-07-FS-BPA-02**.** BPA is proposing to offer 560 aMW of service benefits to the aluminum smelters, capped at $58.9 million, and 17 aMW to Port Townsend Paper Corporation for the FY 2007-2011 period. BPA is structuring the offer to the aluminum smelters as a surplus power sale but with an option BPA may exercise if it is unable to meet the $58.9 million cap with a power sale. BPA will be partnering with the local preference utility to provide these service benefits to the DSI. For more detail on the proposal, please refer to the BPA Service to DSI Customers for Fiscal Years 2007-2011, Administrator's Record of Decision signed June 30, 2005 (DSI ROD), and the DSI Supplemental Administrator's Record of Decision signed June 1, 2006 (DSI Supplemental ROD).

1.12.1 Data and Modeling Methodology

The quantification of DSI benefit risk reflects providing the aluminum smelters with financial benefits equivalent to 560 aMW based on the difference between forward market electricity prices and the lowest cost flat PF rate up to a maximum of $12.00/MWh or $58.9 million/year and an FPS sale of 17 aMW to the Port Townsend Paper Company via its local PUD at a PF-equivalent flat rate. BPA modeled the risk associated with service to the aluminum smelters in the DSI Benefit Risk Model and service to Port Townsend in RiskMod, which are both components of the Risk Analysis Study.

The risk associated with making an FPS sale of 17 aMW to Port Townsend (PT) at the flat PF rate was quantified in RiskMod by BPA selling this power at a PF-equivalent flat rate rather than as a surplus energy sale at variable prices on the wholesale power market. The revenues and loads associated with this FPS sale were included under West Hub FPS Sales in the Revenue Forecast component of the WPRDS and under Interregional Transfers Out in the Load Resource Study, which are both inputs into RiskMod. *See* the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05 and Load Resource Study, WP-07-FS-BPA-01. The reduction in surplus energy sales and revenues were computed via the load and resource values in RiskMod.

For the Final Proposal, BPA assumes in the DSI Benefit Risk Model that the benefits to the aluminum smelters (560 aMW) will be monetized and the aluminum smelters will maximize their benefits and adjust their energy usage (to as low as 280 aMW) to minimize their per aMW effective (after BPA payments) electricity prices. Because any unused service benefits will be reallocated to the other DSIs, it is assumed that, to the extent that a less efficient smelter cannot operate economically, the more efficient smelters will acquire the freed up service benefits via this reallocation. For a complete description of the DSI service benefits, refer to the DSI ROD and DSI Supplemental ROD.

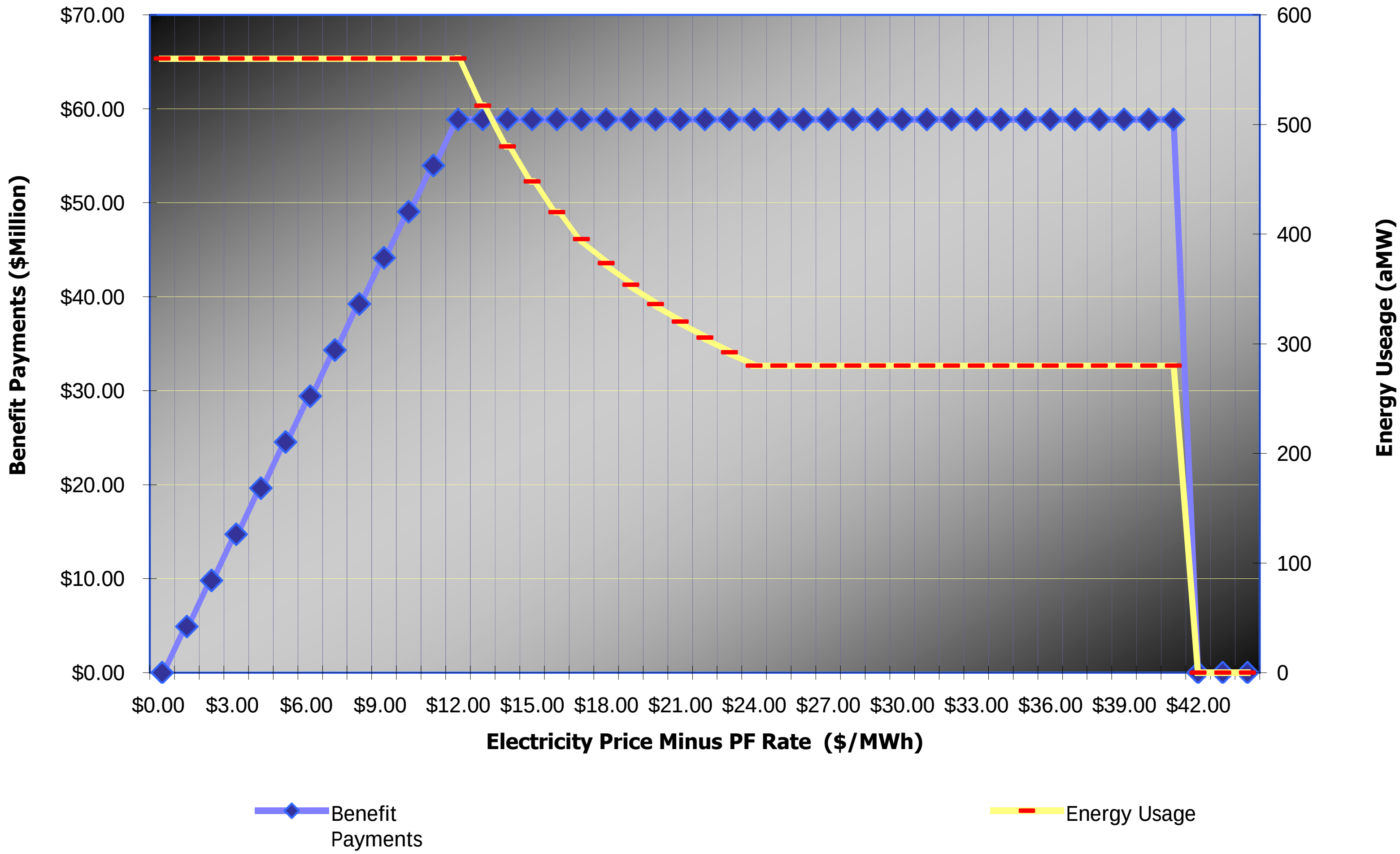
Benefit computations were based on comparisons between forward market electricity prices and the lowest cost flat PF rates, assuming a complete shutdown of all smelters at forward market electricity prices of $70.00/MWh or more (no benefit payments) and no benefit payments for prices below the lowest cost flat PF rates. The forward market price risk for a 12-month strip of power was simulated 3000 times per FY for FY 2008-2009 by the Forward Market Price Risk Model. It was assumed, for rate setting purposes, that the deterministic price forecast used for computing the FY 2007 DSI benefits will be the same as for the FY 2007 IOU REP Settlement benefits. Therefore, annual forward market prices were not simulated for FY 2007 since this price was known prior to the final studies. *See* Section 1.15 of this Study Documentation, regarding simulated forward market prices in the Forward Market Price Risk Model. The rates for 3000 outcomes per FY for FY 2007-2009 were calculated by the ToolKit Model. *See* Section 3.2 in the Risk Analysis Study, WP-07-FS-BPA-04), regarding the ToolKit Model. These prices and rates were copied into the DSI Benefit Risk Model to compute DSI benefits relative to the benefits included in the Revenue Requirement when setting rates, which are $59 million/year in the Final Proposal.

Table 26 contains an example of the algorithm used to compute the aluminum smelter benefits in the DSI Benefit Risk Model. This algorithm computes the aluminum smelter benefits, energy usage, and effective electricity prices (after BPA benefit payments) for forward market electricity prices ranging from the lowest cost flat PF rates to over $70.00/MWh. Under this algorithm, DSI benefits and energy usage can range from a minimum of $0M to $58.9M and from 560 aMW to 280 aMW depending on the differences between forward market electricity prices and the lowest cost flat PF rates. The interrelationships between these factors are shown in Graph 10.

Table 26: Aluminum Smelter Benefit Payments and Energy Usage Algorithm
Results Reflect an Assumed Effective Flat PF Rate of $28.00/MWh

Electricity Prices ($/MWh)	Electricity Prices Minus PF Rate ($/MWh)	Alum Smelter Energy Usage (aMW)	Alum Smelter Payments ($Million)	Smelter Effective Electricity Price ($/MWh)
$ 28.00	$ -	560	$ -	$ 28.00
$ 29.00	$ 1.00	560	$ 4.9	$ 28.00
$ 30.00	$ 2.00	560	$ 9.8	$ 28.00
$ 31.00	$ 3.00	560	$ 14.7	$ 28.00
$ 32.00	$ 4.00	560	$ 19.6	$ 28.00
$ 33.00	$ 5.00	560	$ 24.5	$ 28.00
$ 34.00	$ 6.00	560	$ 29.4	$ 28.00
$ 35.00	$ 7.00	560	$ 34.3	$ 28.00
$ 36.00	$ 8.00	560	$ 39.2	$ 28.00
$ 37.00	$ 9.00	560	$ 44.2	$ 28.00
$ 38.00	$ 10.00	560	$ 49.1	$ 28.00
$ 39.00	$ 11.00	560	$ 54.0	$ 28.00
$ 40.00	$ 12.00	560	$ 58.9	$ 28.00
$ 41.00	$ 13.00	517	$ 58.9	$ 28.00
$ 42.00	$ 14.00	480	$ 58.9	$ 28.00
$ 43.00	$ 15.00	448	$ 58.9	$ 28.00
$ 44.00	$ 16.00	420	$ 58.9	$ 28.00
$ 45.00	$ 17.00	395	$ 58.9	$ 28.00
$ 46.00	$ 18.00	373	$ 58.9	$ 28.00
$ 47.00	$ 19.00	354	$ 58.9	$ 28.00
$ 48.00	$ 20.00	336	$ 58.9	$ 28.00
$ 49.00	$ 21.00	320	$ 58.9	$ 28.00
$ 50.00	$ 22.00	305	$ 58.9	$ 28.00
$ 51.00	$ 23.00	292	$ 58.9	$ 28.00
$ 52.00	$ 24.00	280	$ 58.9	$ 28.00
$ 53.00	$ 25.00	280	$ 58.9	$ 29.00
$ 54.00	$ 26.00	280	$ 58.9	$ 30.00
$ 55.00	$ 27.00	280	$ 58.9	$ 31.00
$ 56.00	$ 28.00	280	$ 58.9	$ 32.00
$ 57.00	$ 29.00	280	$ 58.9	$ 33.00
$ 58.00	$ 30.00	280	$ 58.9	$ 34.00
$ 59.00	$ 31.00	280	$ 58.9	$ 35.00
$ 60.00	$ 32.00	280	$ 58.9	$ 36.00
$ 61.00	$ 33.00	280	$ 58.9	$ 37.00
$ 62.00	$ 34.00	280	$ 58.9	$ 38.00
$ 63.00	$ 35.00	280	$ 58.9	$ 39.00
$ 64.00	$ 36.00	280	$ 58.9	$ 40.00
$ 65.00	$ 37.00	280	$ 58.9	$ 41.00
$ 66.00	$ 38.00	280	$ 58.9	$ 42.00
$ 67.00	$ 39.00	280	$ 58.9	$ 43.00
$ 68.00	$ 40.00	280	$ 58.9	$ 44.00
$ 69.00	$ 41.00	280	$ 58.9	$ 45.00
$ 70.00	$ 42.00	0	$ -	N/A
$ 71.00	$ 43.00	0	$ -	N/A
$ 72.00	$ 44.00	0	$ -	N/A

Graph 10: Aluminum Smelter Benefit Payments And Energy Usage



1.12.2 Model and Results

Table 27 contains a copy of the top portion of the DSI Benefit Risk Model, which provides examples of how computations for 3000 outcomes per FY are performed throughout the entire Excel workbook. Results of the model, which are based on PF rates from a preliminary run of ToolKit, indicate that the average DSI Benefits during FY 2007-2009 are $58.9/M, $56.8/M, and $52.3/M. The PF rates used for the DSI Benefit computations were flat PF rates, which were derived by subtracting $1.45/MWh from the shaped PF rates output by the ToolKit. Graphs 11-12 show the probability distributions for the DSI benefits for FY 2008-2009. No comparable graph was developed for FY 2007, since the DSI Benefits for each of the 3000 games were identical ($58.9 million/year).

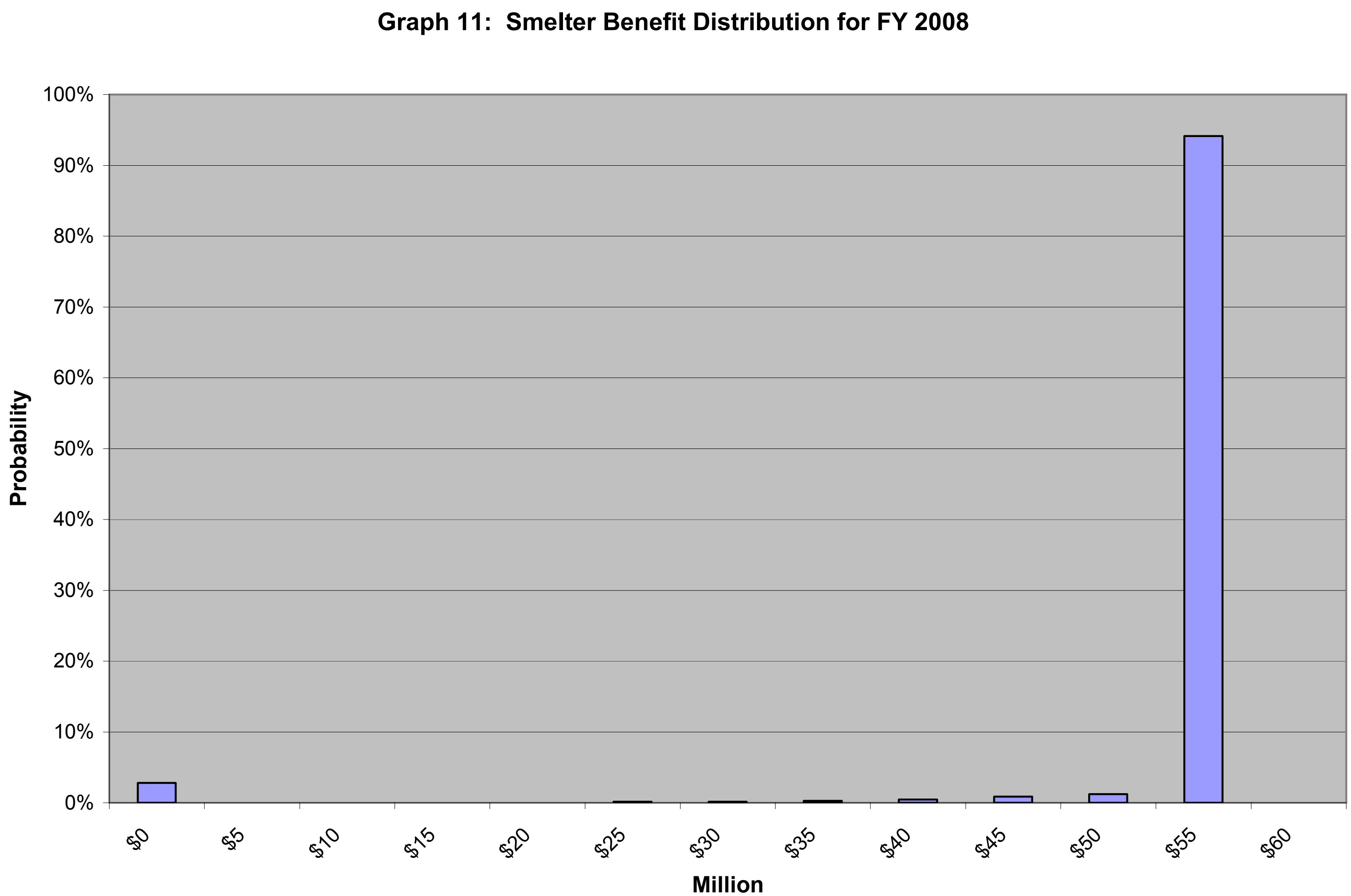
Table 27: DSI Benefit Risk Model

Firm	Initial Alloc
Alcoa	320
CFAC	140
GNA	100
Total (aMW)	560
Total (Max Payment)	$ 58,867

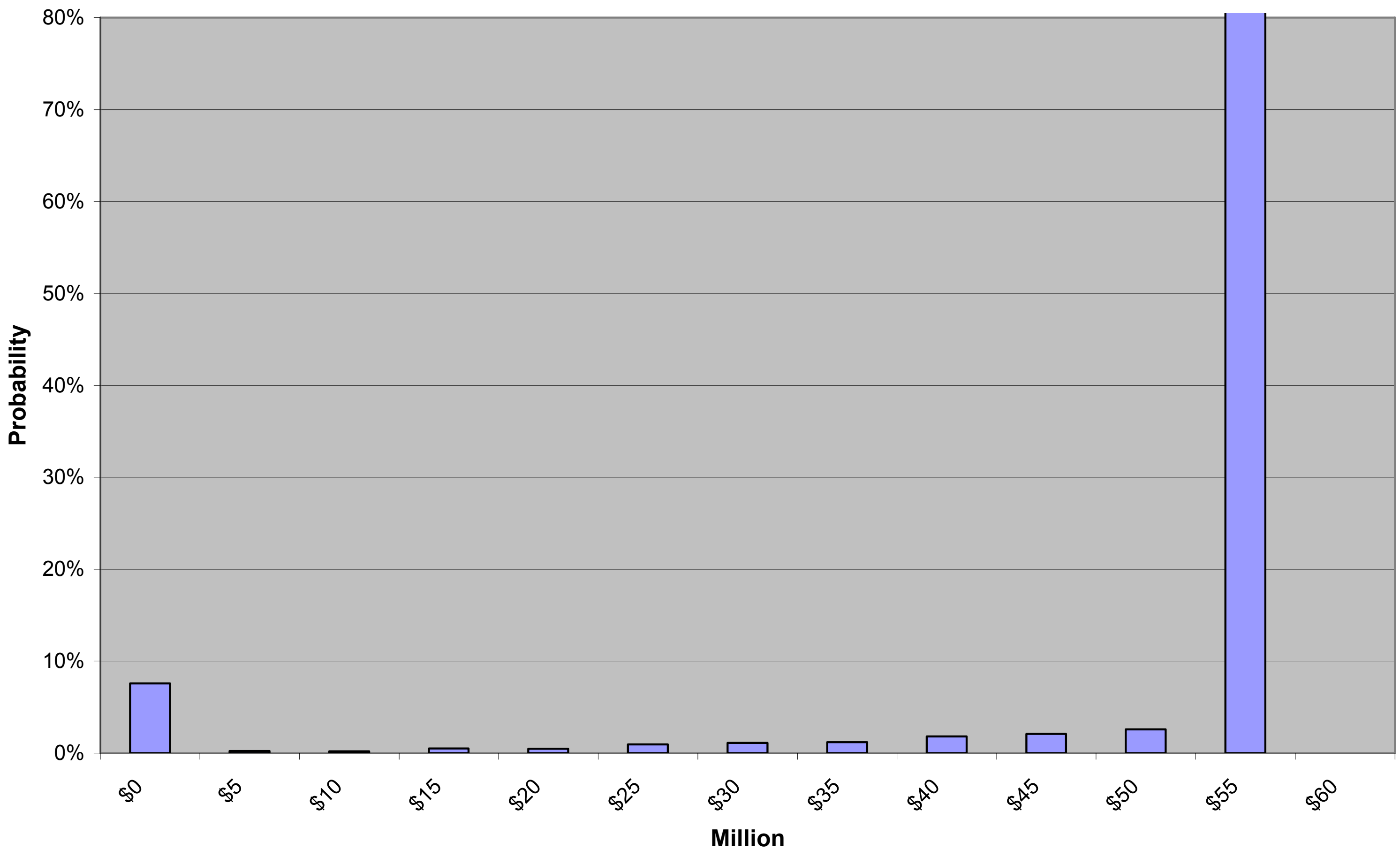
Max Electricity Price Benefit	**$ 12.00**
Shutdown Electricity Price	**$ 70.00**
Flat Vs. Shaped PF Rate Delta	**$ (1.45)**
Min Output (aMW) for Max $	**280**

3-Year Average			**$ 55,982**				**316**				**$ 53.79**				**$ 25.69**
Average (3000 iterations)	**$ 58,867**	**$ 56,820**	**$ 52,258**	Average	**280**	**326**	**343**	Average	**$ 58.46**	**$ 51.41**	**$ 51.49**	Average	**$ 25.76**	**$ 25.59**	**$ 25.73**
Max (3000 iterations)	**$ 58,867**	**$ 58,867**	**$ 58,867**	Stdev	**0**	**97**	**142**								
Min (3000 iterations)	**$ 58,867**	**$ -**	**$ -**												

	Smelter Payments				Smelter Energy Usage				Annual Flat Forward Mkt Prices ($/MWh)				Effective Flat PF Rate ($/MWh)		
Iteration	**2007**	**2008**	**2009**		**2007**	**2008**	**2009**		**2007**	**2008**	**2009**		**2007**	**2008**	**2009**
1	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 53.34	$ 54.82		$ 25.84	$ 25.84	$ 21.38
2	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 53.83	$ 66.67		$ 25.84	$ 24.13	$ 27.08
3	$ 58,867	$ 58,867	$ -		280	299	0		$ 58.46	$ 54.70	$ 80.24		$ 25.84	$ 32.21	$ 32.14
4	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 49.44	$ 51.64		$ 25.84	$ 25.26	$ 19.56
5	$ 58,867	$ 58,867	$ 58,867		280	316	280		$ 58.46	$ 51.02	$ 59.93		$ 25.49	$ 29.74	$ 32.14
6	$ 58,867	$ 58,867	$ 57,657		280	399	560		$ 58.46	$ 43.98	$ 41.85		$ 25.84	$ 27.16	$ 30.09
7	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 65.20	$ 61.01		$ 25.84	$ 21.02	$ 25.84
8	$ 58,867	$ 58,867	$ 58,867		280	395	470		$ 58.46	$ 49.21	$ 46.10		$ 25.85	$ 32.21	$ 31.79
9	$ 58,867	$ 58,867	$ 58,867		280	332	289		$ 58.46	$ 46.08	$ 54.68		$ 25.84	$ 25.84	$ 31.45
10	$ 58,867	$ 58,867	$ 58,867		280	530	508		$ 58.46	$ 42.34	$ 40.44		$ 25.84	$ 29.66	$ 27.22
11	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 52.17	$ 50.66		$ 25.84	$ 25.84	$ 13.60
12	$ 58,867	$ 58,867	$ 58,867		280	381	308		$ 58.46	$ 43.46	$ 51.59		$ 25.84	$ 25.84	$ 29.75
13	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 56.59	$ 50.51		$ 25.84	$ 25.99	$ 25.84
14	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 60.35	$ 45.86		$ 25.84	$ 19.14	$ 20.92
15	$ 58,867	$ 58,867	$ 58,867		280	381	505		$ 58.46	$ 49.83	$ 40.32		$ 25.84	$ 32.21	$ 27.02
16	$ 58,867	$ 58,867	$ 58,867		280	554	280		$ 58.46	$ 37.97	$ 63.98		$ 25.84	$ 25.84	$ 32.14
17	$ 58,867	$ 58,867	$ 47,337		280	475	560		$ 58.46	$ 45.96	$ 40.28		$ 25.84	$ 31.81	$ 30.63
18	$ 58,867	$ 58,867	$ 58,867		280	379	485		$ 58.46	$ 43.59	$ 41.47		$ 25.84	$ 25.84	$ 27.61
19	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 54.81	$ 58.90		$ 25.84	$ 25.84	$ 24.30
20	$ 58,867	$ 58,867	$ 58,867		280	467	280		$ 58.46	$ 40.23	$ 51.91		$ 25.84	$ 25.84	$ 25.84
21	$ 58,867	$ 58,867	$ 58,867		280	321	366		$ 58.46	$ 46.76	$ 44.19		$ 25.84	$ 25.84	$ 25.84
22	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 51.89	$ 60.37		$ 25.81	$ 21.69	$ 24.44
23	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 51.96	$ 53.00		$ 25.84	$ 25.84	$ 24.94
24	$ 58,867	$ 58,867	$ 58,867		280	298	280		$ 58.46	$ 48.38	$ 66.49		$ 25.95	$ 25.84	$ 26.94
25	$ 58,867	$ 58,867	$ 58,867		280	375	280		$ 58.46	$ 44.98	$ 50.73		$ 25.84	$ 27.06	$ 25.84
26	$ 58,867	$ 58,867	$ 58,867		280	385	296		$ 58.46	$ 47.29	$ 50.80		$ 25.84	$ 29.85	$ 28.10
27	$ 58,867	$ -	$ 58,867		280	0	340		$ 58.46	$ 72.70	$ 47.79		$ 25.84	$ 32.21	$ 28.02
28	$ 58,867	$ 58,867	$ 58,867		280	326	392		$ 58.46	$ 46.44	$ 43.25		$ 25.84	$ 25.84	$ 26.10
29	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 59.22	$ 51.99		$ 25.84	$ 25.42	$ 25.84
30	$ 58,867	$ 58,867	$ 58,867		280	463	481		$ 58.46	$ 40.78	$ 39.82		$ 25.84	$ 26.27	$ 25.84
31	$ 58,867	$ 58,867	$ 58,867		280	366	280		$ 58.46	$ 44.18	$ 54.67		$ 25.84	$ 25.84	$ 30.66
32	$ 58,867	$ 58,867	$ 58,867		280	280	302		$ 58.46	$ 50.62	$ 51.15		$ 25.84	$ 20.80	$ 28.93
33	$ 58,867	$ 58,867	$ 58,867		280	280	496		$ 58.46	$ 53.03	$ 39.40		$ 25.84	$ 25.84	$ 25.84
34	$ 58,867	$ 58,867	$ 58,867		280	376	301		$ 58.46	$ 43.73	$ 48.14		$ 25.84	$ 25.84	$ 25.84
35	$ 58,867	$ 58,867	$ 58,867		280	280	280		$ 58.46	$ 60.60	$ 58.58		$ 25.99	$ 25.84	$ 20.20
36	$ 58,867	$ 58,867	$ 58,867		280	311	280		$ 58.46	$ 47.46	$ 50.22		$ 25.84	$ 25.84	$ 21.06


Graph 11: Smelter Benefit Distribution for FY 2008
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
$0
$5
$10
$15
$20
$25
$30
$35
$40
$45
$50
$55
$60
Million

Graph 12: Smelter Benefit Distribution for FY 2009



1.13 Wind Resource Risk Factor

The wind resource risk factor reflects the uncertainty in the amount and value of the energy generated by BPA's portion of Condon, Klondike, Stateline, and Foote Creek I, II, and IV wind projects. Wind generation risk is modeled in four risk simulation models (Foote Creek I, II, and IV wind projects were combined) such that the average of the simulated monthly generation outcomes for each project is equal to the expected monthly generation included in the Load Resource Study, WP-07-FS-BPA-01. These four risk simulation models are collectively referred to as Wind Generation Risk Models.

The risk of the value of the wind generation is calculated in RevSim and is based on the differences between the purchase prices specified in output contracts that wind generators have with BPA and the wholesale electricity prices at which BPA can sell the amount of variable energy produced. Under its output contracts, BPA only pays for the amount of energy that is produced.

1.13.1 Historical Data

To model monthly wind generation risk, daily average energy output data from March 2002 thru April 2005 for Stateline, January 2002 thru April 2005 for Condon, January 2002 through April 2005 for Klondike, and October 2001 through September 2004 for Foote Creek I, II, and IV were sorted by month for each wind project, regardless of year. This process yielded a minimum of three years worth of daily output data for each month of the year from which cumulative probability distributions of daily output for each month were derived in the RiskCumul function in the @RISK computer package. The historical daily wind generation data used for this analysis were the data used to compute the monthly wind generation values included under Non-Utility Generation in the Load Resource Study. *See* Load Resource Study and Documentation, WP-07-FS-BPA-01 and WP-07-FS-BPA-01A, regarding this data.

1.13.2 Modeling Methodology for Wind Generation Risk

Monthly wind generation variability for each of the wind projects (the Foote Creek projects were combined) was derived in risk simulation models in the following manner: (1) Sample the daily wind generation values from the cumulative probability distributions for each day in a given month (*i.e.*, 31 days for January); (2) Sum the daily wind generation values for all days in a given month; (3) Divide the monthly sum by the number of days in that particular month.

The daily wind generation from one day to the next day was modeled independently based on the highly variable daily generation amounts from one day to the next day exhibited in the historical data. The output of all the wind projects were simulated independent of one another, with the exception that the generation from the three Foote Creek projects, which are all on the same ridgeline, contiguously located, and electrically connected at the same substation, were modeled together.

Tables 28-31 contain copies of the cumulative probability distributions of the daily output by month for each of the wind projects (with the Foote Creek projects combined) from which daily output risk was modeled. The values in these tables are specified in terms of daily capacity factors for which energy values can be computed by multiplying the capacity factors times the capacity value for a particular wind project. Tables 32-35 contain copies of the four risk simulation models.

Table 28: Condon Wind Project Daily Output Variability by Month

Condon

Nameplate Capacity: 49.8 MW

	Cumulative Probability Distribution of Daily Capacity Factors (Energy = Capacity * Capacity Factors)											
Percentile	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Min	0.000	0.001	0.000	0.008	0.000	0.000	0.027	0.004	0.001	0.000	0.000	0.000
0.01	0.000	0.003	0.003	0.013	0.000	0.000	0.027	0.005	0.001	0.000	0.000	0.000
0.05	0.000	0.010	0.011	0.031	0.000	0.000	0.031	0.015	0.014	0.003	0.003	0.000
0.10	0.000	0.025	0.037	0.038	0.014	0.026	0.037	0.025	0.025	0.014	0.008	0.001
0.15	0.003	0.035	0.051	0.046	0.024	0.044	0.044	0.034	0.036	0.035	0.020	0.008
0.20	0.005	0.046	0.077	0.064	0.035	0.057	0.047	0.040	0.044	0.046	0.024	0.019
0.25	0.009	0.055	0.088	0.072	0.049	0.068	0.058	0.053	0.058	0.058	0.035	0.044
0.30	0.018	0.065	0.100	0.084	0.064	0.075	0.067	0.067	0.064	0.073	0.051	0.071
0.35	0.028	0.075	0.125	0.106	0.078	0.080	0.085	0.081	0.073	0.083	0.083	0.083
0.40	0.044	0.092	0.168	0.113	0.095	0.101	0.100	0.088	0.082	0.097	0.107	0.100
0.45	0.076	0.105	0.224	0.125	0.106	0.118	0.119	0.092	0.093	0.130	0.154	0.125
0.50	0.101	0.131	0.265	0.147	0.124	0.136	0.131	0.098	0.105	0.147	0.176	0.188
0.55	0.158	0.139	0.300	0.170	0.137	0.155	0.138	0.111	0.124	0.182	0.197	0.233
0.60	0.200	0.155	0.356	0.187	0.157	0.169	0.152	0.123	0.137	0.212	0.255	0.248
0.65	0.292	0.187	0.389	0.206	0.196	0.192	0.177	0.134	0.176	0.252	0.315	0.278
0.70	0.335	0.200	0.422	0.242	0.230	0.204	0.205	0.161	0.205	0.272	0.358	0.327
0.75	0.369	0.215	0.452	0.268	0.265	0.234	0.222	0.199	0.245	0.298	0.406	0.402
0.80	0.419	0.268	0.518	0.291	0.274	0.269	0.251	0.223	0.268	0.351	0.467	0.474
0.85	0.488	0.311	0.574	0.325	0.308	0.318	0.267	0.258	0.327	0.426	0.527	0.541
0.90	0.522	0.429	0.683	0.396	0.443	0.374	0.312	0.306	0.437	0.483	0.630	0.628
0.95	0.596	0.513	0.752	0.499	0.525	0.444	0.343	0.406	0.483	0.635	0.739	0.662
0.99	0.825	0.823	0.831	0.651	0.681	0.554	0.586	0.593	0.594	0.794	0.876	0.776
Max	0.866	0.953	0.901	0.712	0.696	0.628	0.723	0.719	0.758	0.859	0.931	0.800
Average	0.207	0.175	0.301	0.189	0.175	0.169	0.158	0.142	0.166	0.213	0.254	0.243
Energy (aMW)	10.3	8.7	15.0	9.4	8.7	8.4	7.9	7.1	8.3	10.6	12.6	12.1

Table 29: Combined Foote Creek I, II, and IV Wind Project Daily Output Variability by Month

Foote Creek I, II, and IV												
Nameplate Capacity: 33.9 MW												
	Cumulative Probability Distribution of Daily Capacity Factors (Energy = Capacity * Capacity Factors)											
Percentile	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Min	0.270	0.331	0.168	0.189	0.151	0.135	0.118	0.075	0.092	0.144	0.189	0.162
0.01	0.274	0.342	0.168	0.213	0.160	0.141	0.119	0.082	0.103	0.153	0.198	0.177
0.05	0.322	0.353	0.176	0.245	0.176	0.155	0.129	0.088	0.114	0.158	0.224	0.213
0.10	0.382	0.364	0.202	0.269	0.186	0.177	0.134	0.097	0.122	0.167	0.254	0.278
0.15	0.435	0.382	0.246	0.282	0.190	0.186	0.140	0.103	0.134	0.182	0.290	0.317
0.20	0.469	0.405	0.265	0.298	0.201	0.193	0.144	0.116	0.140	0.203	0.341	0.354
0.25	0.490	0.439	0.272	0.310	0.206	0.225	0.149	0.127	0.151	0.216	0.349	0.374
0.30	0.500	0.462	0.319	0.332	0.210	0.233	0.152	0.130	0.169	0.236	0.363	0.409
0.35	0.519	0.506	0.354	0.353	0.233	0.246	0.156	0.140	0.188	0.245	0.375	0.430
0.40	0.539	0.524	0.361	0.373	0.246	0.253	0.165	0.151	0.200	0.264	0.392	0.465
0.45	0.561	0.542	0.400	0.386	0.265	0.264	0.168	0.157	0.207	0.303	0.399	0.495
0.50	0.576	0.569	0.409	0.399	0.280	0.274	0.175	0.171	0.229	0.334	0.435	0.520
0.55	0.582	0.587	0.428	0.418	0.292	0.283	0.190	0.181	0.235	0.355	0.459	0.540
0.60	0.590	0.592	0.444	0.443	0.303	0.295	0.193	0.192	0.244	0.369	0.475	0.556
0.65	0.602	0.619	0.453	0.459	0.321	0.318	0.195	0.204	0.250	0.388	0.502	0.561
0.70	0.612	0.630	0.475	0.479	0.329	0.336	0.204	0.225	0.273	0.413	0.524	0.571
0.75	0.624	0.638	0.492	0.490	0.342	0.353	0.222	0.242	0.282	0.418	0.529	0.590
0.80	0.630	0.654	0.510	0.506	0.366	0.376	0.229	0.258	0.298	0.426	0.540	0.598
0.85	0.643	0.676	0.559	0.519	0.390	0.398	0.240	0.270	0.315	0.446	0.566	0.610
0.90	0.661	0.691	0.587	0.540	0.426	0.444	0.265	0.278	0.344	0.473	0.595	0.628
0.95	0.673	0.696	0.604	0.580	0.452	0.485	0.296	0.321	0.386	0.495	0.643	0.636
0.99	0.706	0.721	0.639	0.627	0.484	0.566	0.334	0.350	0.485	0.526	0.680	0.648
Max	0.713	0.723	0.639	0.642	0.515	0.644	0.369	0.420	0.492	0.530	0.693	0.654
Average	0.545	0.543	0.398	0.405	0.287	0.293	0.189	0.184	0.230	0.321	0.435	0.478
Energy (aMW)	18.5	18.4	13.5	13.7	9.7	9.9	6.4	6.3	7.8	10.9	14.7	16.2

Table 30: Klondike Wind Project Daily Output Variability by Month

Klondike

Nameplate Capacity: 24.0 MW

	Cumulative Probability Distribution of Daily Capacity Factors (Energy = Capacity * Capacity Factors)											
Percentile	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Min	0.000	0.000	0.003	0.001	0.007	0.010	0.002	0.008	0.002	0.000	0.000	0.000
0.01	0.000	0.001	0.004	0.002	0.022	0.027	0.017	0.018	0.009	0.000	0.000	0.000
0.05	0.000	0.002	0.015	0.012	0.050	0.049	0.052	0.045	0.017	0.002	0.000	0.000
0.10	0.000	0.007	0.027	0.037	0.080	0.068	0.106	0.068	0.032	0.007	0.003	0.000
0.15	0.001	0.015	0.049	0.063	0.131	0.092	0.155	0.096	0.050	0.021	0.005	0.001
0.20	0.003	0.025	0.065	0.094	0.158	0.137	0.205	0.131	0.070	0.037	0.007	0.004
0.25	0.007	0.033	0.109	0.134	0.182	0.191	0.256	0.173	0.084	0.058	0.022	0.007
0.30	0.011	0.045	0.135	0.164	0.231	0.248	0.302	0.216	0.105	0.080	0.036	0.010
0.35	0.015	0.050	0.167	0.186	0.294	0.310	0.338	0.249	0.154	0.107	0.044	0.019
0.40	0.021	0.068	0.201	0.214	0.326	0.346	0.363	0.283	0.191	0.137	0.050	0.036
0.45	0.033	0.094	0.246	0.244	0.379	0.401	0.416	0.301	0.217	0.216	0.058	0.047
0.50	0.048	0.104	0.316	0.274	0.424	0.427	0.478	0.357	0.272	0.232	0.064	0.071
0.55	0.073	0.135	0.360	0.297	0.456	0.470	0.553	0.378	0.302	0.277	0.083	0.102
0.60	0.113	0.189	0.416	0.353	0.491	0.489	0.577	0.411	0.368	0.323	0.144	0.114
0.65	0.132	0.229	0.482	0.391	0.546	0.595	0.622	0.448	0.436	0.348	0.196	0.177
0.70	0.185	0.258	0.533	0.426	0.567	0.616	0.639	0.510	0.497	0.400	0.233	0.196
0.75	0.255	0.287	0.565	0.488	0.609	0.732	0.678	0.584	0.527	0.449	0.268	0.260
0.80	0.287	0.361	0.595	0.531	0.704	0.768	0.727	0.642	0.605	0.530	0.387	0.289
0.85	0.304	0.487	0.687	0.598	0.735	0.811	0.785	0.699	0.651	0.569	0.508	0.330
0.90	0.404	0.593	0.757	0.664	0.824	0.853	0.824	0.750	0.705	0.645	0.549	0.381
0.95	0.562	0.713	0.822	0.808	0.903	0.894	0.854	0.799	0.769	0.714	0.633	0.500
0.99	0.673	0.808	0.887	0.904	0.970	0.961	0.900	0.843	0.821	0.895	0.802	0.685
Max	0.817	0.835	0.915	0.918	0.978	0.976	0.915	0.852	0.873	0.896	0.827	0.847
Average	0.142	0.207	0.350	0.323	0.428	0.450	0.469	0.378	0.326	0.283	0.188	0.148
Energy (aMW)	3.4	5.0	8.4	7.8	10.3	10.8	11.3	9.1	7.8	6.8	4.5	3.6

Table 31: Stateline Wind Project Daily Output Variability by Month												
Stateline												
Nameplate Capacity: 90.4 MW												
	Cumulative Probability Distribution of Daily Capacity Factors (Energy = Capacity * Capacity Factors)											
Percentile	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Min	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000
0.01	0.000	0.000	0.000	0.000	0.003	0.001	0.002	0.001	0.000	0.000	0.000	0.000
0.05	0.000	0.000	0.003	0.007	0.005	0.003	0.005	0.003	0.000	0.000	0.000	0.000
0.10	0.000	0.000	0.018	0.017	0.013	0.006	0.020	0.010	0.000	0.000	0.000	0.000
0.15	0.000	0.000	0.036	0.028	0.019	0.009	0.025	0.015	0.008	0.001	0.001	0.000
0.20	0.000	0.001	0.063	0.049	0.041	0.021	0.044	0.033	0.014	0.007	0.002	0.000
0.25	0.000	0.002	0.086	0.078	0.068	0.029	0.070	0.049	0.022	0.020	0.005	0.001
0.30	0.001	0.005	0.125	0.105	0.091	0.037	0.094	0.080	0.039	0.027	0.011	0.003
0.35	0.002	0.009	0.240	0.132	0.114	0.071	0.130	0.114	0.061	0.063	0.027	0.014
0.40	0.005	0.012	0.299	0.170	0.140	0.101	0.167	0.152	0.074	0.095	0.034	0.024
0.45	0.009	0.017	0.343	0.194	0.168	0.143	0.201	0.180	0.090	0.126	0.047	0.031
0.50	0.015	0.025	0.387	0.212	0.195	0.179	0.221	0.196	0.125	0.143	0.067	0.053
0.55	0.045	0.043	0.425	0.244	0.208	0.213	0.259	0.223	0.179	0.215	0.113	0.133
0.60	0.089	0.087	0.508	0.285	0.232	0.260	0.310	0.251	0.200	0.241	0.176	0.158
0.65	0.176	0.108	0.546	0.305	0.307	0.337	0.329	0.280	0.277	0.290	0.241	0.254
0.70	0.222	0.141	0.585	0.357	0.409	0.412	0.391	0.314	0.316	0.329	0.346	0.316
0.75	0.269	0.191	0.623	0.399	0.482	0.505	0.415	0.342	0.372	0.392	0.446	0.356
0.80	0.325	0.234	0.647	0.503	0.507	0.563	0.453	0.384	0.482	0.457	0.528	0.471
0.85	0.376	0.306	0.699	0.537	0.578	0.628	0.491	0.480	0.526	0.483	0.585	0.505
0.90	0.671	0.393	0.750	0.658	0.645	0.691	0.554	0.551	0.614	0.545	0.760	0.587
0.95	0.787	0.569	0.847	0.719	0.728	0.769	0.604	0.686	0.721	0.622	0.822	0.692
0.99	0.878	0.951	0.875	0.821	0.858	0.880	0.815	0.760	0.804	0.788	0.857	0.779
Max	0.899	0.956	0.893	0.849	0.948	0.922	0.829	0.780	0.827	0.800	0.889	0.825
Average	0.174	0.134	0.385	0.271	0.272	0.274	0.261	0.238	0.228	0.227	0.233	0.203
Energy (aMW)	15.8	12.1	34.8	24.5	24.6	24.7	23.6	21.5	20.6	20.5	21.1	18.3

Table 32: Condon Wind Project Risk Model

Condon																							
Capacity (MW)	**49.8**																						
	Month aMW	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13	Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20	Day 21	Day 22
Jan-05	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-05	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-05	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-05	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-05	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-05	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-05	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-05	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-05	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-05	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-05	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-05	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-06	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-06	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-06	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-06	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-06	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-06	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-06	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-06	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-06	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-06	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-06	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-06	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-07	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-07	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-07	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-07	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-07	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-07	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-07	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-07	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-07	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-07	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-07	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-07	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-08	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-08	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-08	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-08	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-08	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-08	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-08	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-08	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-08	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-08	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-08	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-08	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-09	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-09	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-09	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-09	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-09	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-09	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-09	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-09	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-09	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-09	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-09	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-09	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Table 32: Condon Wind Project Risk Model (Continued)

Condon									
apacity (MW)									
	Day 23	Day 24	Day 25	Day 26	Day 27	Day 28	Day 29	Day 30	Day 31
Jan-05	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-05	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-05	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-05	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-05	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-05	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-05	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-05	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-05	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-05	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-05	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-05	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-06	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-06	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-06	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-06	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-06	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-06	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-06	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-06	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-06	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-06	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-06	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-06	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-07	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-07	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-07	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-07	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-07	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-07	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-07	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-07	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-07	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-07	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-07	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-07	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-08	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-08	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-08	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-08	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-08	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-08	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-08	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-08	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-08	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-08	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-08	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-08	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-09	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-09	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-09	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-09	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-09	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-09	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-09	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-09	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-09	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-09	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-09	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-09	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Table 33: Foote Creek I, II, and IV Wind Project Risk Model

Foote Creek I, II, IV

Capacity (MW) **33.9**

	Month aMW	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13	Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20	Day 21	Day 22
Jan-05	**18.5**	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-05	**18.4**	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-05	**13.5**	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-05	**13.7**	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-05	**9.7**	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-05	**9.9**	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-05	**6.4**	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-05	**6.2**	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-05	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-05	**10.9**	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-05	**14.7**	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-05	**16.2**	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-06	**18.5**	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-06	**18.4**	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-06	**13.5**	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-06	**13.7**	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-06	**9.7**	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-06	**9.9**	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-06	**6.4**	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-06	**6.2**	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-06	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-06	**10.9**	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-06	**14.7**	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-06	**16.2**	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-07	**18.5**	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-07	**18.4**	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-07	**13.5**	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-07	**13.7**	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-07	**9.7**	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-07	**9.9**	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-07	**6.4**	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-07	**6.2**	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-07	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-07	**10.9**	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-07	**14.7**	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-07	**16.2**	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-08	**18.5**	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-08	**18.4**	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-08	**13.5**	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-08	**13.7**	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-08	**9.7**	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-08	**9.9**	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-08	**6.4**	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-08	**6.2**	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-08	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-08	**10.9**	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-08	**14.7**	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-08	**16.2**	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-09	**18.5**	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-09	**18.4**	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-09	**13.5**	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-09	**13.7**	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-09	**9.7**	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-09	**9.9**	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-09	**6.4**	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-09	**6.2**	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-09	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-09	**10.9**	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-09	**14.7**	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-09	**16.2**	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Table 33: Foote Creek I, II, & IV Wind Risk Model (Continued)

Foote Creek I, II, IV

Capacity (MW)

	Day 23	Day 24	Day 25	Day 26	Day 27	Day 28	Day 29	Day 30	Day 31
Jan-05	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-05	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-05	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-05	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-05	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-05	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-05	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-05	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-05	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-05	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-05	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-05	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-06	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-06	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-06	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-06	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-06	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-06	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-06	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-06	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-06	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-06	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-06	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-06	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-07	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-07	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-07	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-07	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-07	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-07	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-07	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-07	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-07	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-07	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-07	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-07	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-08	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-08	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-08	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-08	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-08	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-08	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-08	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-08	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-08	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-08	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-08	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-08	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-09	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-09	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-09	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-09	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-09	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-09	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-09	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-09	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-09	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-09	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-09	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-09	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Table 34: Klondike Wind Project Risk Model

Klondike																						
Capacity (MW)	**24.0**																					
	Month aMW	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13	Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20	Day 21
Jan-05	**3.4**	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-05	**4.9**	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-05	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-05	**7.7**	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-05	**10.3**	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-05	**10.8**	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-05	**11.3**	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-05	**9.1**	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-05	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-05	**6.7**	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-05	**4.5**	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-05	**3.5**	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-06	**3.4**	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-06	**4.9**	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-06	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-06	**7.7**	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-06	**10.3**	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-06	**10.8**	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-06	**11.3**	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-06	**9.1**	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-06	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-06	**6.7**	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-06	**4.5**	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-06	**3.5**	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-07	**3.4**	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-07	**4.9**	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-07	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-07	**7.7**	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-07	**10.3**	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-07	**10.8**	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-07	**11.3**	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-07	**9.1**	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-07	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-07	**6.7**	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-07	**4.5**	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-07	**3.5**	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-08	**3.4**	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-08	**4.9**	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-08	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-08	**7.7**	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-08	**10.3**	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-08	**10.8**	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-08	**11.3**	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-08	**9.1**	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-08	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-08	**6.7**	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-08	**4.5**	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-08	**3.5**	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-09	**3.4**	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-09	**4.9**	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-09	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-09	**7.7**	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-09	**10.3**	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-09	**10.8**	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-09	**11.3**	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-09	**9.1**	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-09	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-09	**6.7**	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-09	**4.5**	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-09	**3.5**	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5

Table 34: Klondike Wind Project Risk Model (Continued)										
Klondike										
Capacity (MW)										
	Day 22	Day 23	Day 24	Day 25	Day 26	Day 27	Day 28	Day 29	Day 30	Day 31
Jan-05	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-05	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-05	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-05	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-05	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-05	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-05	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-05	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-05	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-05	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-05	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-05	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-06	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-06	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-06	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-06	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-06	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-06	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-06	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-06	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-06	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-06	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-06	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-06	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-07	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-07	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-07	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-07	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-07	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-07	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-07	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-07	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-07	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-07	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-07	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-07	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-08	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-08	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-08	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-08	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-08	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-08	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-08	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-08	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-08	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-08	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-08	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-08	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-09	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-09	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-09	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-09	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-09	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-09	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-09	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-09	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-09	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-09	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-09	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-09	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5

Table 35: Stateline Wind Project Risk Model

Stateline																						
Capacity (MW)	**90.4**																					
	Month aMW	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13	Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20	Day 21
Jan-05	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-05	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-05	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-05	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-05	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-05	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-05	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-05	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-05	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-05	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-05	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-05	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-06	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-06	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-06	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-06	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-06	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-06	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-06	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-06	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-06	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-06	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-06	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-06	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-07	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-07	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-07	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-07	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-07	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-07	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-07	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-07	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-07	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-07	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-07	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-07	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-08	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-08	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-08	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-08	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-08	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-08	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-08	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-08	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-08	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-08	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-08	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-08	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-09	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-09	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-09	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-09	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-09	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-09	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-09	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-09	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-09	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-09	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-09	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-09	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1

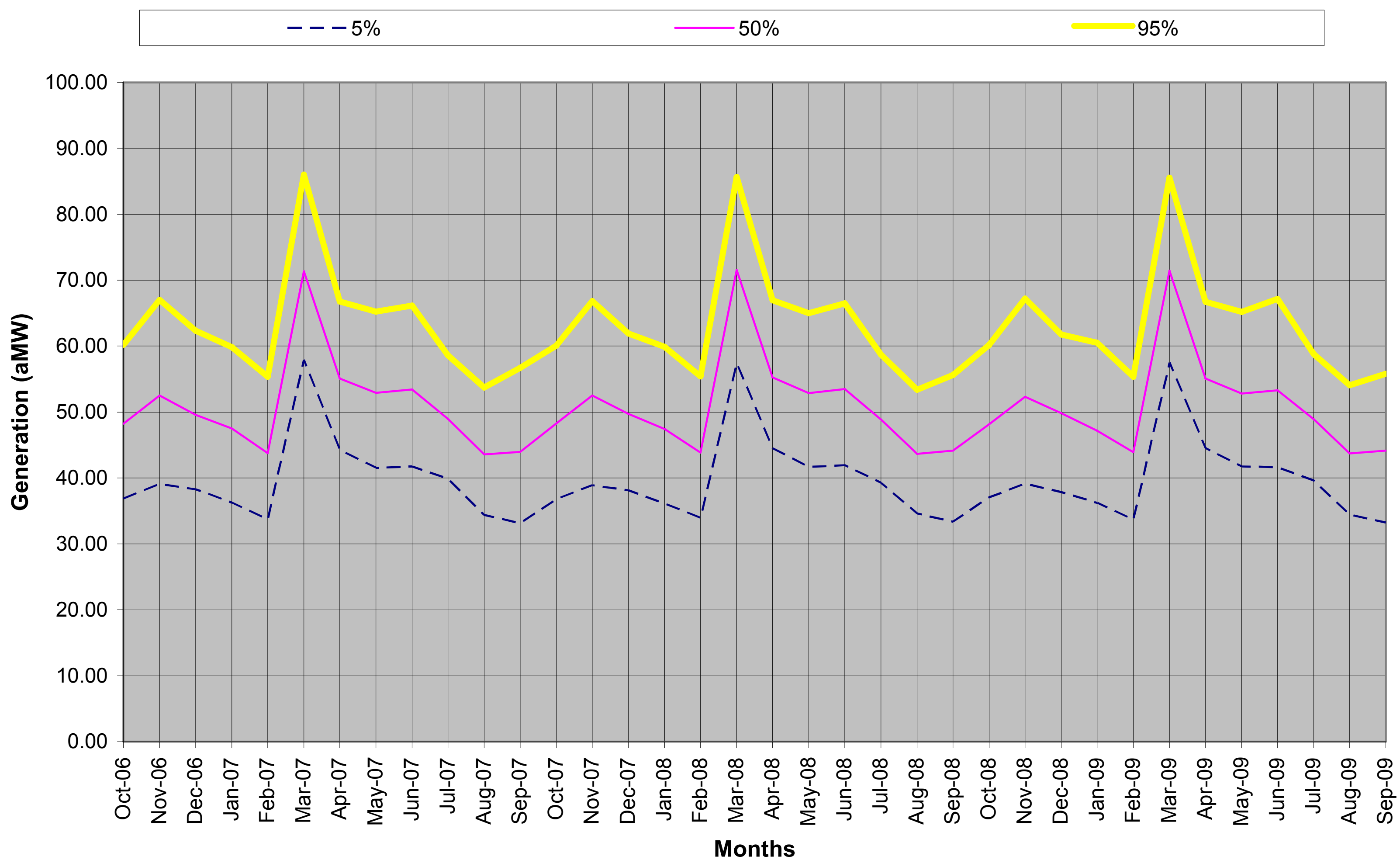
Table 35: Stateline Wind Project Risk Model (Continued)

Stateline										
Capacity (MW)										
	Day 22	Day 23	Day 24	Day 25	Day 26	Day 27	Day 28	Day 29	Day 30	Day 31
Jan-05	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-05	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-05	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-05	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-05	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-05	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-05	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-05	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-05	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-05	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-05	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-05	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-06	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-06	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-06	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-06	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-06	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-06	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-06	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-06	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-06	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-06	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-06	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-06	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-07	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-07	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-07	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-07	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-07	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-07	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-07	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-07	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-07	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-07	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-07	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-07	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-08	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-08	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-08	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-08	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-08	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-08	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-08	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-08	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-08	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-08	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-08	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-08	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-09	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-09	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-09	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-09	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-09	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-09	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-09	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-09	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-09	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-09	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-09	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-09	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1

1.13.3 Wind Generation Risk Results

The monthly generation results from the risk simulations models are in terms of flat energy. Graph 13 shows the combined monthly flat energy output for all the wind projects during FY 2007-2009 at the 5^{th}, 50^{th}, and 95^{th} percentiles. These monthly flat energy values are input into RevSim, where they are converted into monthly heavy and light load hour energy values by applying HLH and LLH shaping factors that are associated with each of these wind projects. The source of these HLH and LLH shaping factors is the data used to compute the monthly HLH and LLH wind generation values included under Non-Utility Generation in the Load Resource Study and Documentation. *See* Load Resource Study, WP-07-FS-BPA-01 and WP-07-FS-BPA-01A, regarding this data.

Graph 13: Simulated Total Wind Generation for FY 2007 - FY 2009



1.13.4 Risk Modeling Methodology for the Value of Wind Generation

The risk of the value of the wind generation is computed in RevSim in the following manner: (1) Subtract from expenses the expected monthly payments for the expected output of the various wind projects (a weighted contract price was used for the combined Foote Creek wind projects); (2) On a game-by-game basis, compute the monthly payments for the output of the various wind projects; and (3) On a game-by-game basis, compute the revenues associated with the wind generation.

1.13.5 Value of Wind Generation Risk Results

Tables 36-38 provide information from which the value of wind generation during FY 2007-2009 can be derived for expected monthly flat energy output levels. Total deterministic wind generation purchase costs and total revenues earned from the sale of all wind generation at average, median, 5th percentile, and 95th percentile spot market electricity prices estimated by AURORA are provided with the value of the wind generation being the difference between the revenues earned and purchase costs paid.

Table 36: Value of Wind Generation at Expected Wind Generation for FY 2007

Expected Generation (aMW)

Wind Project	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
Foote Creek I, II, & IV	12.8	19.0	23.2	24.2	22.1	16.5	13.2	10.5	9.4	7.5	7.5	8.7	
Stateline	20.5	21.1	18.3	15.4	12.3	34.8	24.5	24.6	24.7	23.6	21.3	20.6	
Condon	10.6	12.6	12.1	9.8	8.8	15.0	9.4	8.7	8.4	7.8	7.0	8.3	
Klondike Phase 1	6.8	4.5	3.6	3.3	5.0	8.4	7.8	10.3	10.8	11.3	9.0	7.8	
Total Wind Generation	50.6	57.2	57.1	52.7	48.2	74.7	54.9	54.1	53.3	50.1	44.8	45.4	**53.66**

Contract Prices ($/MWh)

Wind Project	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
Foote Creek I, II, & IV	49.52	49.55	49.51	49.05	49.08	49.06	49.05	49.14	49.08	49.04	49.10	49.01	
Stateline	32.15	32.15	32.15	33.05	33.05	33.05	33.05	33.05	33.05	33.05	33.05	33.05	
Condon	60.27	60.27	60.27	60.27	60.27	60.27	60.27	60.27	61.77	61.77	61.77	61.77	
Klondike Phase 1	31.78	31.78	31.78	32.57	32.57	32.57	32.57	32.57	32.57	32.57	32.57	32.57	
Wtd. Average Price	42.37	44.11	45.12	45.43	45.31	41.99	41.49	40.47	40.31	39.80	40.14	41.27	**42.34**

Power Purchase Costs for Expected Wind Generation ($1,000)

	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
Total Purchase Cost	1,596	1,817	1,918	1,782	1,466	2,334	1,641	1,629	1,548	1,484	1,339	1,349	**19,903**

Average, Median, 5th Percentile, and 95th Percentile Spot Market Electricity Prices Estimated by AURORA ($/MWh)

	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
5%	30.91	32.28	32.77	21.42	20.11	23.65	18.38	7.94	5.77	14.64	24.53	27.59	**26.27**
50%	58.35	59.72	61.56	50.44	49.37	48.52	44.13	23.61	20.76	36.65	52.40	56.81	**48.48**
Average	62.81	64.02	66.20	54.38	53.38	52.56	48.24	29.44	25.43	41.33	56.26	60.63	**51.20**
95%	109.34	109.88	116.69	98.84	101.32	94.08	92.50	68.94	59.16	82.47	100.58	106.75	**86.87**

Revenues from Expected Wind Generation at Various AURORA Price Percentiles ($1,000)

	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
5%	1,164	1,330	1,393	840	651	1,314	727	320	222	546	818	902	**10,227**
50%	2,198	2,460	2,617	1,978	1,597	2,697	1,745	951	797	1,366	1,748	1,858	**22,013**
Average	2,366	2,637	2,814	2,133	1,727	2,922	1,908	1,185	977	1,541	1,876	1,982	**24,069**
95%	4,119	4,526	4,961	3,877	3,279	5,229	3,659	2,776	2,272	3,075	3,354	3,490	**44,617**

Table 37: Value of Wind Generation at Expected Wind Generation for FY 2008

Expected Generation (aMW)

Wind Project	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
Foote Creek I, II, & IV	12.8	19.0	23.2	24.2	22.1	16.5	13.2	10.5	9.4	7.5	7.5	8.7	
Stateline	20.5	21.1	18.3	15.4	12.3	34.8	24.5	24.6	24.7	23.6	21.2	20.6	
Condon	10.6	12.6	12.1	9.8	8.8	15.0	9.4	8.7	8.4	7.8	7.0	8.3	
Klondike Phase 1	6.8	4.5	3.6	3.3	5.0	8.4	7.8	10.3	10.8	11.3	9.0	7.8	
Total Wind Generation	50.6	57.2	57.1	52.7	48.2	74.7	54.9	54.1	53.3	50.1	44.7	45.4	**53.64**

Contract Prices ($/MWh)

Wind Project	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
Foote Creek I, II, & IV	49.04	49.08	49.04	49.30	49.33	49.30	49.29	49.39	49.32	49.28	49.35	49.25	
Stateline	33.05	33.05	33.05	33.97	33.97	33.97	33.97	33.97	33.97	33.97	33.97	33.97	
Condon	61.77	61.77	61.77	61.77	61.77	61.77	61.77	61.77	63.32	63.32	63.32	63.32	
Klondike Phase 1	32.57	32.57	32.57	33.38	33.38	33.38	33.38	33.38	33.38	33.38	33.38	33.38	
Wtd. Average Price	43.04	44.68	45.58	46.14	46.02	42.87	42.35	41.33	41.19	40.70	41.05	42.15	**43.12**

Power Purchase Costs for Expected Wind Generation ($1,000)

	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
Total Purchase Cost	1,621	1,840	1,938	1,810	1,543	2,383	1,674	1,664	1,582	1,517	1,366	1,378	**20,316**

Average, Median, 5th Percentile, and 95th Percentile Spot Market Electricity Prices Estimated by AURORA ($/MWh)

	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
5%	26.35	29.55	31.22	17.87	21.92	21.10	16.59	6.71	5.32	13.43	25.63	29.68	**24.72**
50%	53.79	56.87	59.62	45.37	48.17	44.51	36.75	23.94	22.13	35.52	46.85	49.07	**44.81**
Average	57.29	60.30	63.22	48.37	51.31	46.30	38.46	26.97	25.35	35.99	48.20	50.19	**46.03**
95%	99.19	102.07	107.91	89.60	90.82	76.68	66.75	56.81	53.78	62.71	74.05	74.01	**71.30**

Revenues from Expected Wind Generation at Various AURORA Price Percentiles ($1,000)

	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
5%	992	1,217	1,327	701	735	1,173	656	270	204	501	853	970	**9,599**
50%	2,026	2,342	2,534	1,780	1,615	2,474	1,453	964	850	1,324	1,560	1,604	**20,526**
Average	2,158	2,484	2,688	1,897	1,720	2,574	1,520	1,086	973	1,342	1,604	1,641	**21,687**
95%	3,736	4,204	4,588	3,514	3,044	4,263	2,639	2,287	2,065	2,338	2,465	2,420	**37,562**

Table 38: Value of Wind Generation at Expected Wind Generation for FY 2009

Expected Generation (aMW)

Wind Project	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	**Annual**
Foote Creek I, II, & IV	12.8	19.0	23.2	24.2	22.1	16.5	13.2	10.5	9.4	7.5	7.5	8.7	
Stateline	20.5	21.1	18.3	15.4	12.3	34.8	24.5	24.6	24.7	23.6	21.2	20.6	
Condon	10.6	12.6	12.1	9.8	8.8	15.0	9.4	8.7	8.4	7.8	7.0	8.3	
Klondike Phase 1	6.8	4.5	3.6	3.3	5.0	8.4	7.8	10.3	10.8	11.3	9.0	7.8	
Total Wind Generation	50.6	57.2	57.1	52.7	48.2	74.7	54.9	54.1	53.3	50.1	44.7	45.4	**53.65**

Contract Prices ($/MWh)

Wind Project	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	**Annual**
Foote Creek I, II, & IV	49.29	49.33	49.29	59.11	59.11	59.12	59.17	59.24	59.14	59.18	59.13	59.08	
Stateline	33.97	33.97	33.97	34.92	34.92	34.92	34.92	34.92	34.92	34.92	34.92	34.92	
Condon	63.32	63.32	63.32	63.32	63.32	63.32	63.32	63.32	64.90	64.90	64.90	64.90	
Klondike Phase 1	33.38	33.38	33.38	34.22	34.22	34.22	34.22	34.22	34.22	34.22	34.22	34.22	
Wtd. Average Price	43.91	45.50	46.36	51.26	51.12	45.88	45.53	44.09	43.78	43.06	43.56	44.90	**45.73**

Power Purchase Costs for Expected Wind Generation ($1,000)

	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	**Annual**
Total Purchase Cost	1,654	1,874	1,971	2,010	1,654	2,550	1,800	1,775	1,681	1,605	1,450	1,468	**21,494**

Average, Median, 5th Percentile, and 95th Percentile Spot Market Electricity Prices Estimated by AURORA ($/MWh)

	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	**Annual**
5%	29.65	33.31	32.49	19.38	23.99	21.95	13.34	5.51	4.30	11.00	23.77	24.95	**25.01**
50%	46.91	51.21	51.78	43.81	47.17	42.89	33.94	22.85	19.63	31.67	46.53	46.21	**41.24**
Average	47.78	51.88	52.85	48.11	53.48	45.33	35.94	26.12	22.90	34.71	51.95	49.75	**43.24**
95%	68.84	73.09	75.74	87.71	103.44	77.17	67.05	56.94	53.03	67.21	98.66	83.57	**69.07**

Revenues from Expected Wind Generation at Various AURORA Price Percentiles ($1,000)

	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	**Annual**
5%	1,117	1,372	1,381	760	776	1,220	527	222	165	410	791	816	**9,558**
50%	1,767	2,109	2,201	1,718	1,526	2,384	1,342	920	754	1,181	1,549	1,511	**18,962**
Average	1,800	2,137	2,247	1,887	1,731	2,520	1,420	1,052	880	1,294	1,729	1,627	**20,322**
95%	2,593	3,010	3,220	3,440	3,347	4,290	2,650	2,293	2,037	2,506	3,284	2,732	**35,402**

1.14 Transmission Expense Risk Factor

This risk factor reflects the uncertainty in PBL transmission and ancillary services expenses, relative to the expected expenses, which average $119 million during FY 2007-2009, included in the Revenue Requirement when setting rates. *See* Revenue Requirement Study, WP-07-FS-BPA-02**.** This risk is modeled in the Transmission Expense Risk Model.

1.14.1 Data and Modeling Methodology

The modeling of this risk is based on comparisons between monthly firm transmission capacity that PBL has under contract, the amount of existing firm contract sales, and the variability in surplus energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that the PBL has under contract, which must be paid regardless of whether or not it is used. Because the PBL has more firm transmission capacity under contract than it has firm contract sales, the probability distributions for these expenses is asymmetrical since the PBL does not incur the costs of purchasing additional transmission capacity until the amounts of surplus energy sales exceed the amounts of residual firm transmission capacity after serving all firm sales.

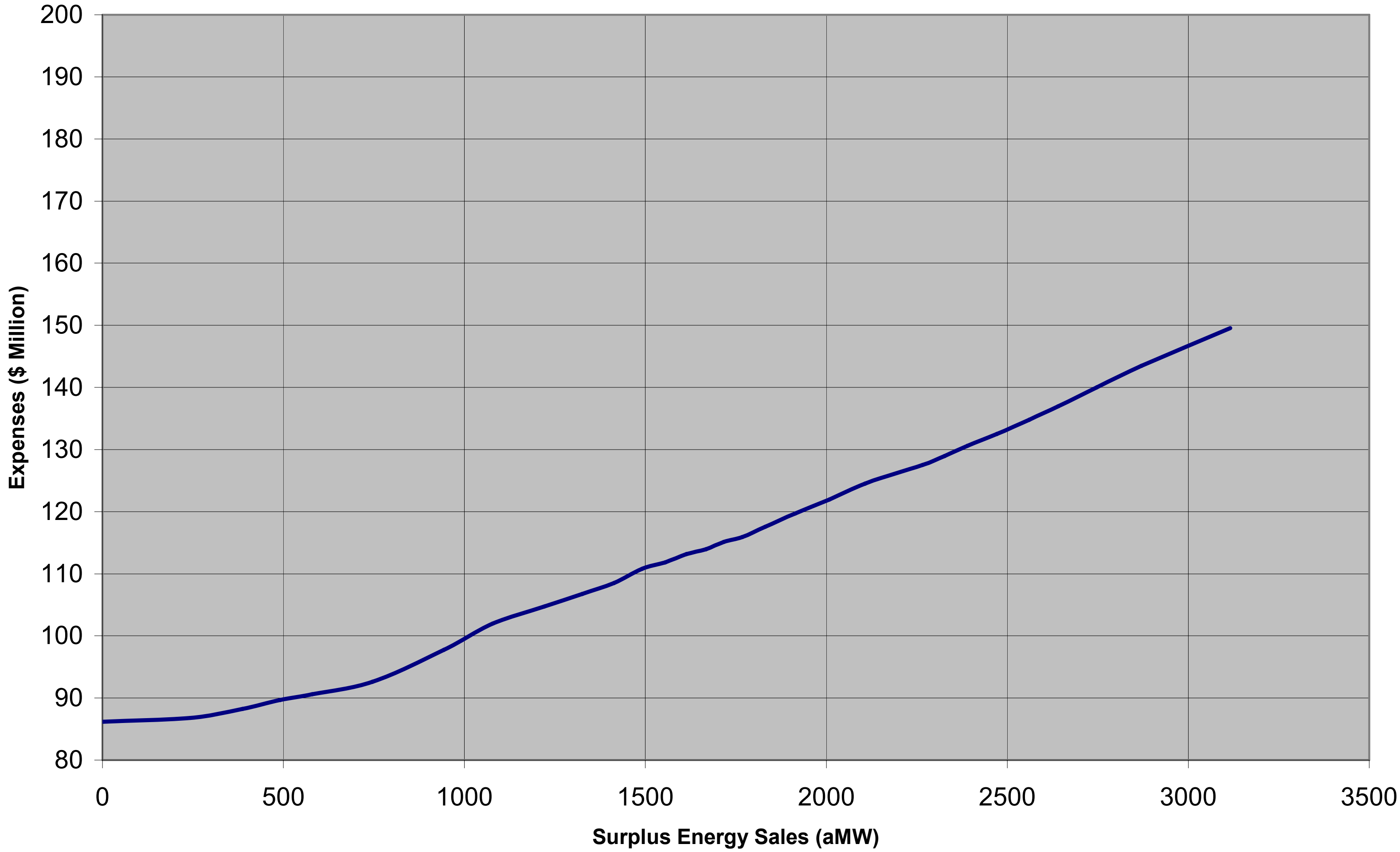
Under conditions where the PBL sells more energy than it has firm transmission rights, transmission and ancillary services expenses will increase. Alternatively, under conditions where the PBL sells less energy than it has firm transmission rights, transmission expenses will remain unchanged but ancillary services expenses will decline. The methodology used in the Transmission Expense Model is consistent with the methodology documented in BPA's Power Function Review February 1, 2005 Technical Workshop on the Transmission Acquisition Program.

1.14.2 Results

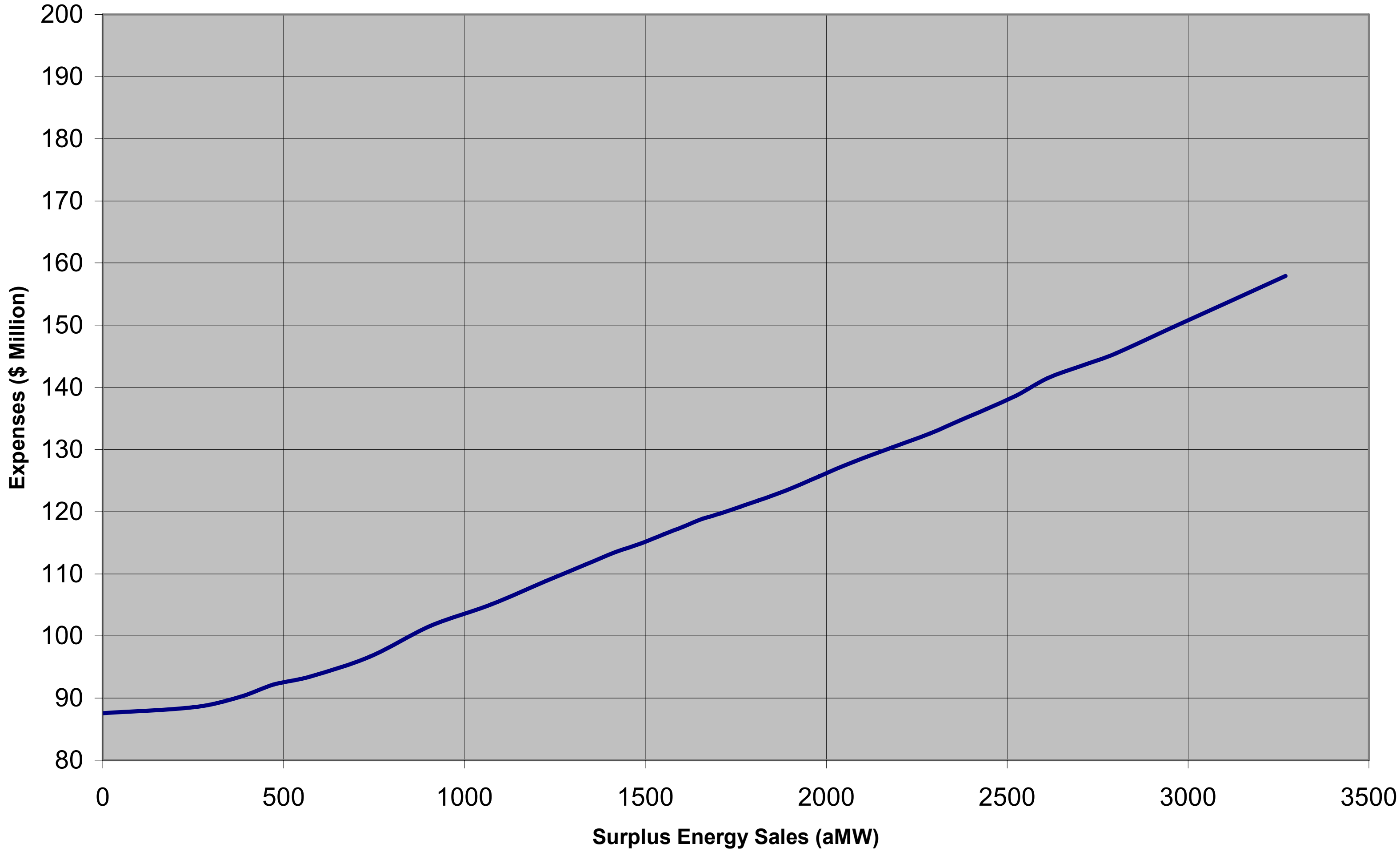
Results shown in Graphs 14-16 indicate how transmission and ancillary service expenses vary depending on the amount of surplus energy sales. In these graphs, the PBL transmission and ancillary services expenses do not fall below $85 million/year, regardless of the amount of surplus energy sales, because the PBL must pay for the take or pay firm transmission capacity it has under contract. This $85 million/year figure does not include the cost of ancillary services for any surplus energy sales, since these charges are assessed depending on the amount of transmission usage. PBL's firm transmission capacity can accommodate approximately 1000 MW of surplus energy sales. So, only ancillary service expenses vary on the first increment of secondary energy sales (up to about 1000 MW) while both transmission line capacity and ancillary service expenses vary on surplus energy sales above this amount.

Results shown in Graphs 17-19 reflect the probability distributions for transmission and ancillary service expenses during FY 2007-2009. These graphs indicate how often transmission and ancillary service expenses fall within various expense ranges.

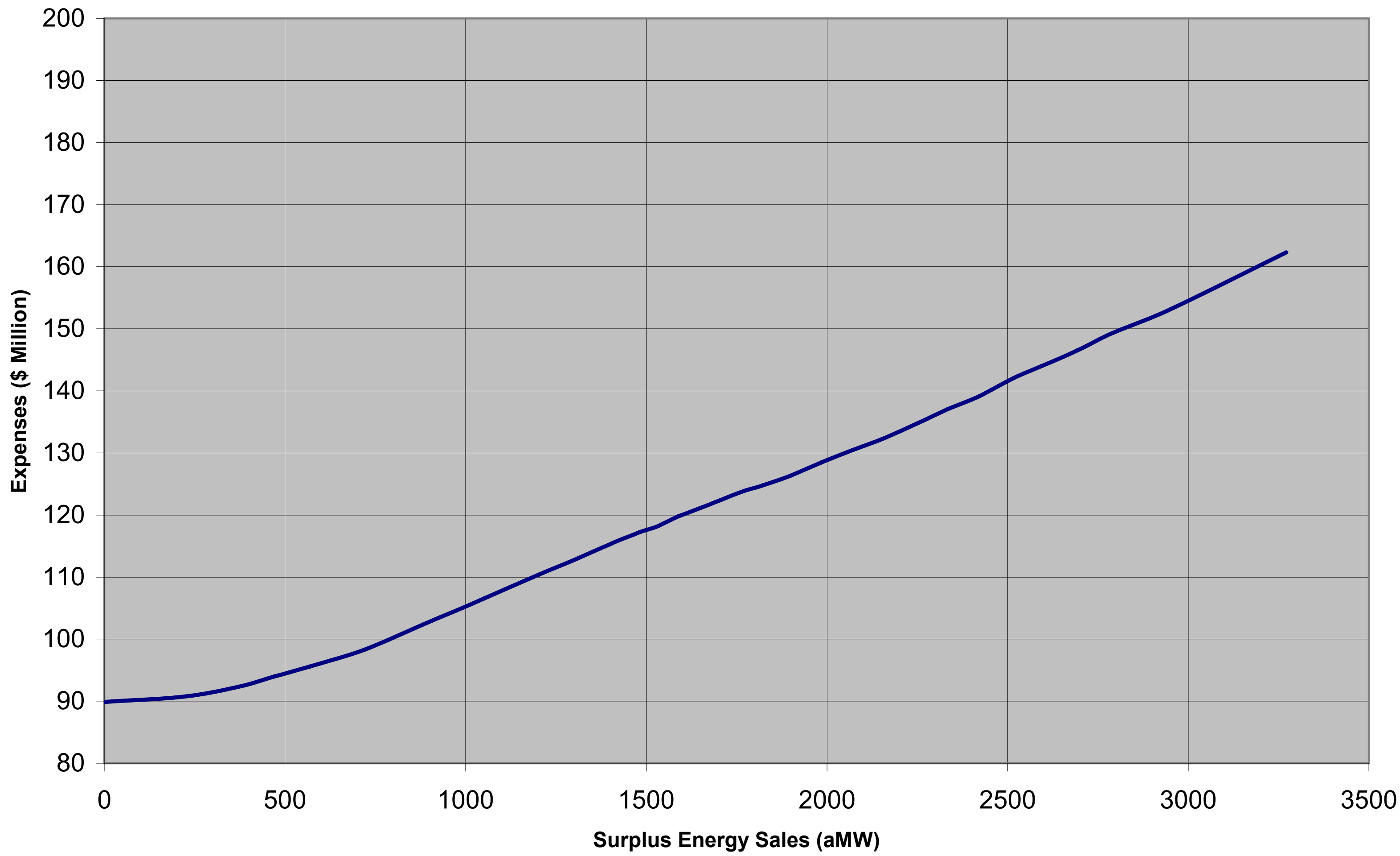
Graph 14: PBL Transmission & Ancillary Services Expenses vs. Surplus Energy Sales (FY07)



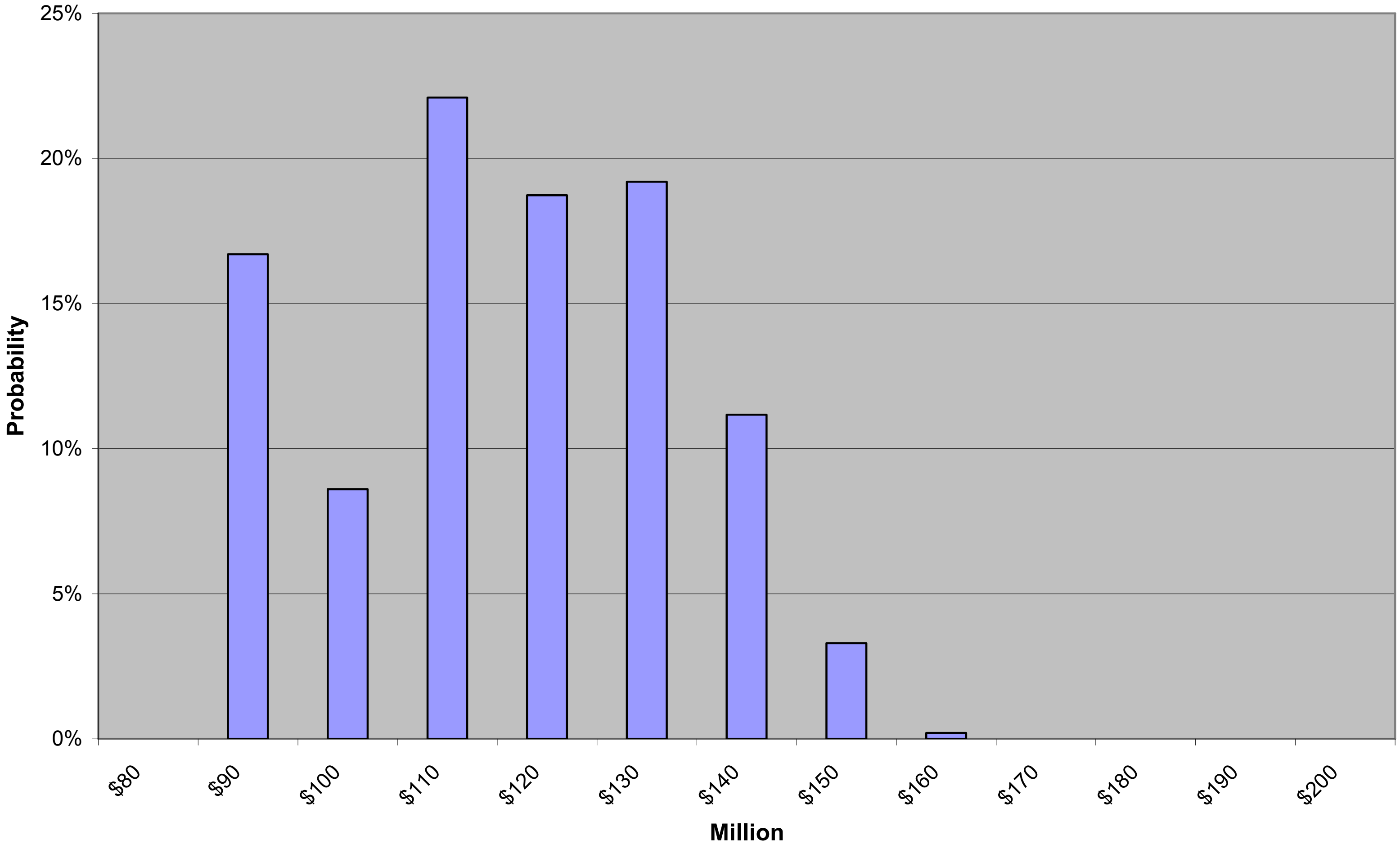
Graph 15: PBL Transmission & Ancillary Services Expenses vs. Surplus Energy Sales (FY08)



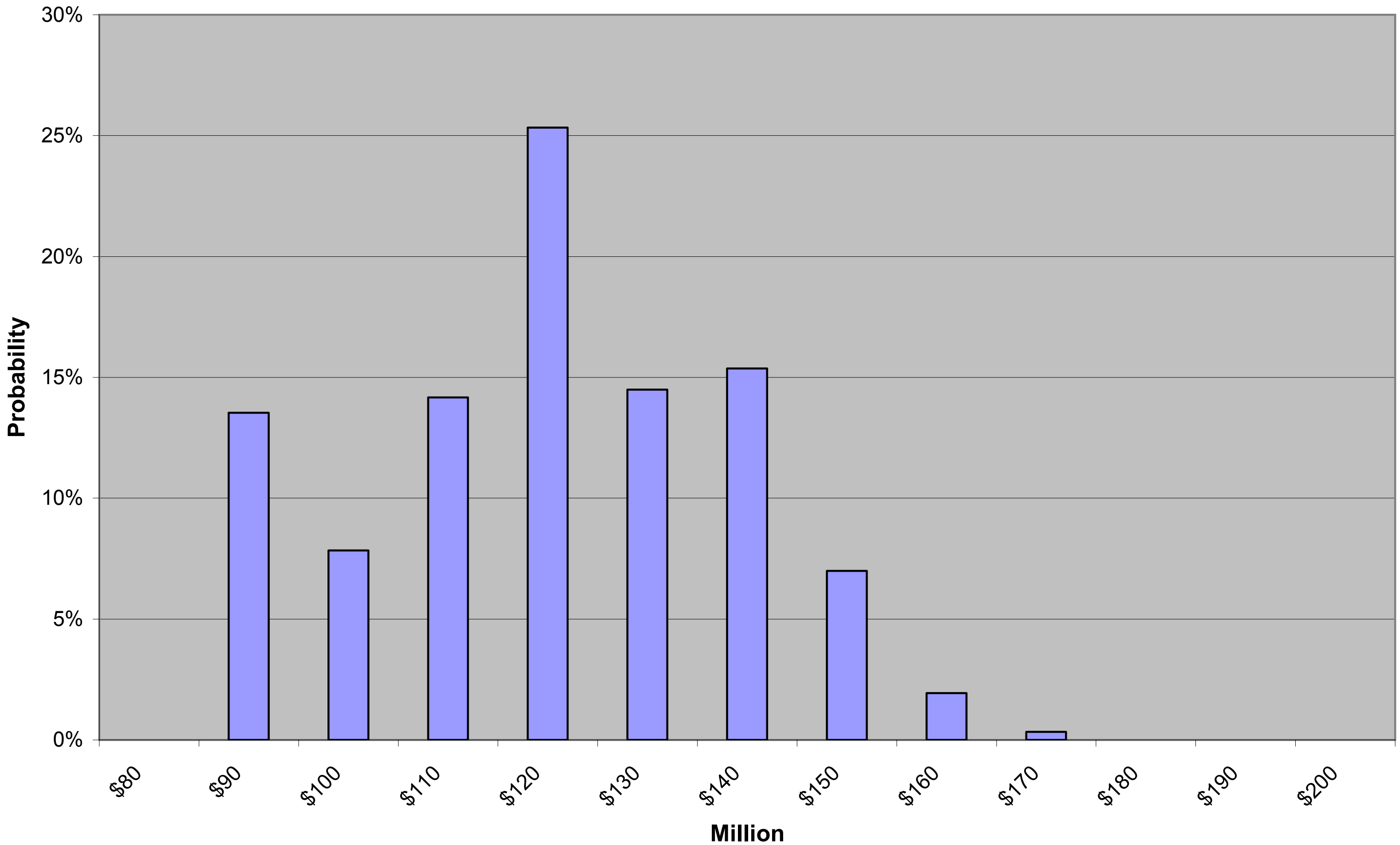
Graph 16: PBL Transmission & Ancillary Services Expenses vs. Surplus Energy Sales (FY09)



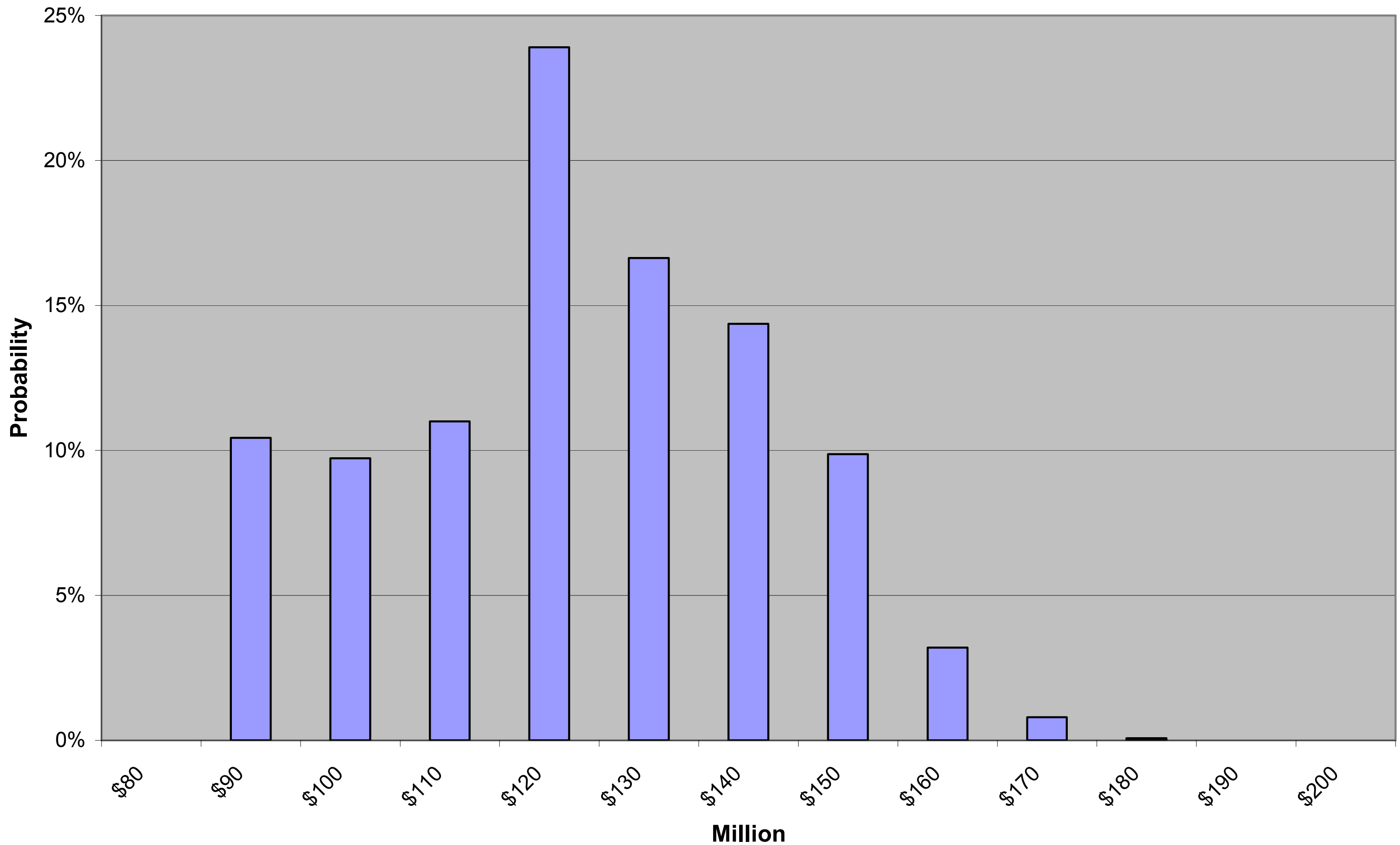
Graph 17: PBL Transmission and Ancillary Service Expense Distribution for FY 2007



Graph 18: PBL Transmission and Ancillary Service Expense Distribution for FY 2008



Graph 19: PBL Transmission and Ancillary Service Expense Distribution for FY 2009



1.15 Forward Market Price Risk Model

The Forward Market Price Risk Model was developed for the purpose of quantifying the risk associated with actual annual average forward market prices (*i.e.*, for a 12-month strip of power) differing from the forecasted annual average forward market prices used when setting rates. Forward market price results from this risk model are used in other models to compute IOU and DSI benefit risk relative to the expense values included in the Revenue Requirement. *See* Revenue Requirement Study, WP-07-FS-BPA-02 and Sections 1.11 and 1.12 of this Study Documentation, regarding IOU and DSI benefits and risk. The IOU REP Settlement benefits are explicitly tied to forward market electricity prices in the contract terms of the IOU REP Settlement Agreements and BPA assumed, for rate setting purposes, that the DSI benefits would also be tied to the same forward market electricity prices.

Forward market electricity price curves are estimates at a point in time of what electricity prices will be over a period of time in the future. These estimates will change as we move through time, often in response to whether actual spot market prices are higher or lower than the forward market price at the beginning of the spot month for that month. Based on this interrelationship, BPA designed the Forward Market Price Risk Model to estimate forward market electricity price curve movements through time that are consistent with the spot market electricity price movements estimated by the AURORA model. Thus, this approach accounts for the dependency between the spot market electricity prices used to calculate surplus energy revenues and power purchase expenses and the forward market electricity prices for a 12-month strip of power used to calculate IOU REP Settlement and DSI benefits, while also allowing for different price outlooks between spot and forward electricity markets.

1.15.1 Estimation of the Historical Relationships Between Forward and Spot Market Price Movements

Daily forward market electricity price data at Mid C from January 2004 to August 2005 were merged with daily spot market electricity price data at Mid C for the same dates. From this data, average price changes for the spot month and 35 subsequent forward months were computed for all 20 months of data (Jan 2004-Aug 2005). Regression equations for each of the 35 forward months were developed from this data to estimate monthly changes in forward market prices across time based on changes in spot market prices. These regression equations have the following form:

$\Delta Y = \alpha + \beta \Delta X + \varepsilon$

Where,

ΔY = Change in the monthly forward market price

ΔX = Change in the average monthly spot market price

α, β, and ε = The intercept, slope, and standard error of the regression, which are parameters estimated by regression analysis

Table 39 contains the average price changes for the spot month and 35 subsequent forward months for all 20 months of data, as well as, the regression equations for each of the 35 forward months. These regression equations were developed for use in the Forward Market Price Risk Model.

Table 39: Regression Equations that Estimate Changes in Forward Prices Across Time Based on Changes in Spot Market Prices

	Spot Vs Fwd 1	Spot Vs Fwd 2	Spot Vs Fwd 3	Spot Vs Fwd 4	Spot Vs Fwd 5	Spot Vs Fwd 6	Spot Vs Fwd 7	Spot Vs Fwd 8	Spot Vs Fwd 9	Spot Vs Fwd 10	Spot Vs Fwd 11	Spot Vs Fwd 12	Spot Vs Fwd 13	Spot Vs Fwd 14	Spot Vs Fwd 15	Spot Vs Fwd 16	Spot Vs Fwd 17
R^2	0.3062	0.2242	0.1581	0.1930	0.1695	0.1282	0.1712	0.1550	0.1719	0.1863	0.1713	0.1922	0.2780	0.2720	0.1406	0.1332	0.0896
Intercept	-0.1126	-0.0069	0.0188	0.0638	0.1018	0.0924	0.0925	0.0746	0.0660	0.0627	0.0491	0.0619	0.0687	0.0722	0.0536	0.0561	0.0612
Slope	0.3466	0.3075	0.2466	0.2509	0.2129	0.1601	0.1844	0.1319	0.1318	0.1371	0.1276	0.1365	0.1535	0.1442	0.0944	0.0927	0.0729
Std Err	0.2889	0.3168	0.3151	0.2841	0.2610	0.2311	0.2247	0.1705	0.1602	0.1587	0.1555	0.1550	0.1370	0.1306	0.1292	0.1310	0.1286

Historical Average Monthly HLH Spot and Forward Market Price Deltas for Mid-C from January 2004 - August 2005; Derived from Daily Data

Obs	Spot	Fwd 1	Fwd 2	Fwd 3	Fwd 4	Fwd 5	Fwd 6	Fwd 7	Fwd 8	Fwd 9	Fwd 10	Fwd 11	Fwd 12	Fwd 13	Fwd 14	Fwd 15	Fwd 16	Fwd 17
1	-0.342	-0.188	-0.090	-0.021	-0.021	-0.021	-0.042	-0.042	-0.042	-0.042	-0.042	-0.042	0.014	0.014	0.014	-0.005	-0.005	-0.005
2	-0.334	-0.042	0.049	0.167	0.167	0.319	0.319	0.319	0.208	0.208	0.208	0.111	0.111	0.111	0.120	0.120	0.120	0.120
3	-0.195	-0.159	0.199	0.091	0.040	0.040	0.040	0.074	0.074	0.074	0.080	0.080	0.080	0.064	0.064	0.064	0.064	0.064
4	0.588	0.625	0.675	0.363	0.363	0.363	0.238	0.238	0.238	0.288	0.288	0.288	0.175	0.175	0.175	0.044	0.044	0.044
5	-0.551	-0.368	-0.118	-0.053	-0.053	0.026	0.026	0.026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.532	-0.553	-0.474	-0.513	-0.211	-0.211	-0.211	-0.184	-0.184	-0.184	-0.105	-0.105	-0.105	-0.039	-0.039	-0.039	-0.039	-0.039
7	0.389	0.069	0.025	0.013	0.013	0.013	0.113	0.113	0.113	0.075	0.075	0.075	0.125	0.125	0.125	0.088	0.088	0.088
8	-1.091	-0.575	-0.350	-0.338	-0.338	-0.300	-0.300	-0.300	-0.163	-0.163	-0.163	-0.150	-0.150	-0.150	-0.138	-0.138	-0.138	-0.038
9	-0.172	-0.050	0.213	0.200	0.225	0.225	0.225	0.175	0.175	0.175	0.100	0.100	0.100	0.100	0.100	0.100	0.150	0.150
10	1.042	0.263	0.550	0.488	0.488	0.488	0.263	0.263	0.263	0.238	0.238	0.238	0.388	0.388	0.388	0.200	0.200	0.200
11	0.321	-0.711	-0.632	-0.434	-0.434	-0.158	-0.158	-0.158	-0.066	-0.066	-0.066	-0.197	-0.197	-0.197	-0.184	-0.184	-0.184	-0.184
12	-0.552	-0.325	-0.275	-0.275	0.100	0.100	0.100	-0.025	-0.025	-0.025	-0.075	-0.075	-0.075	-0.013	-0.013	-0.013	-0.013	-0.013
13	-0.208	-0.053	0.079	0.395	0.395	0.395	0.303	0.303	0.303	0.132	0.132	0.132	0.184	0.184	0.184	0.219	0.219	0.219
14	0.153	0.125	0.375	0.542	0.542	0.604	0.604	0.604	0.389	0.389	0.389	0.306	0.306	0.306	0.250	0.250	0.250	0.250
15	-0.031	0.119	0.060	0.167	0.262	0.262	0.262	0.274	0.274	0.274	0.357	0.357	0.357	0.198	0.198	0.198	0.198	0.198
16	-0.295	-0.275	-0.400	-0.431	-0.431	-0.431	-0.263	-0.263	-0.263	-0.225	-0.225	-0.225	-0.150	-0.150	-0.150	-0.188	-0.188	-0.188
17	-0.704	-0.463	-0.375	-0.363	-0.363	-0.163	-0.163	-0.163	-0.113	-0.113	-0.113	-0.088	-0.088	-0.088	-0.025	-0.025	-0.025	-0.025
18	0.465	-0.143	-0.089	-0.095	0.060	0.060	0.060	0.167	0.167	0.167	0.060	0.060	0.060	0.244	0.244	0.244	0.244	0.244
19	0.553	0.105	0.053	0.013	0.013	0.013	0.013	0.013	0.013	-0.013	-0.013	-0.013	-0.026	-0.026	-0.026	-0.026	-0.026	-0.026
20	0.535	0.382	0.421	0.487	0.487	0.434	0.434	0.434	0.145	0.145	0.145	0.145	0.145	0.145	0.171	0.171	0.171	0.171

Table 39: Regression Equations that Estimate Changes in Forward Prices Across Time Based on Changes in Spot Market Prices (Continued)

	Spot Vs Fwd 18	Spot Vs Fwd 19	Spot Vs Fwd 20	Spot Vs Fwd 21	Spot Vs Fwd 22	Spot Vs Fwd 23	Spot Vs Fwd 24	Spot Vs Fwd 25	Spot Vs Fwd 26	Spot Vs Fwd 27	Spot Vs Fwd 28	Spot Vs Fwd 29	Spot Vs Fwd 30	Spot Vs Fwd 31	Spot Vs Fwd 32	Spot Vs Fwd 33	Spot Vs Fwd 34	Spot Vs Fwd 35
R^2	0.1265	0.1020	0.1134	0.1045	0.1017	0.1048	0.1224	0.1190	0.1308	0.1243	0.1294	0.1219	0.1196	0.1152	0.1074	0.0995	0.1018	0.1051
Intercept	0.0683	0.0625	0.0598	0.0658	0.0668	0.0632	0.0594	0.0600	0.0613	0.0607	0.0595	0.0601	0.0595	0.0594	0.0596	0.0634	0.0628	0.0566
Slope	0.0859	0.0757	0.0810	0.0716	0.0717	0.0700	0.0730	0.0717	0.0732	0.0709	0.0717	0.0692	0.0683	0.0681	0.0664	0.0623	0.0623	0.0608
Std Err	0.1250	0.1244	0.1255	0.1160	0.1180	0.1132	0.1082	0.1080	0.1045	0.1041	0.1029	0.1028	0.1026	0.1044	0.1060	0.1039	0.1024	0.0982

Historical Average Monthly HLH Spot and Forward Market Price Deltas for Mid-C from January 2004 - August 2005; Derived from Daily Data

Obs	Spot	Fwd 18	Fwd 19	Fwd 20	Fwd 21	Fwd 22	Fwd 23	Fwd 24	Fwd 25	Fwd 26	Fwd 27	Fwd 28	Fwd 29	Fwd 30	Fwd 31	Fwd 32	Fwd 33	Fwd 34	Fwd 35
1	-0.342	-0.005	-0.005	-0.005	-0.005	-0.005	-0.005	-0.007	-0.007	-0.007	-0.007	-0.007	-0.007	-0.007	-0.007	-0.007	-0.007	-0.007	-0.007
2	-0.334	0.120	0.120	0.120	0.120	0.120	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.118	0.097
3	-0.195	0.064	0.064	0.064	0.064	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.063	0.063
4	0.588	0.044	0.044	0.044	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
5	-0.551	0.000	0.000	-0.053	-0.053	-0.053	-0.053	-0.053	-0.053	-0.053	-0.053	-0.053	-0.053	-0.053	-0.053	-0.092	-0.092	-0.092	-0.092
6	0.532	-0.039	-0.079	-0.079	-0.079	-0.079	-0.079	-0.079	-0.079	-0.079	-0.079	-0.079	-0.079	-0.079	-0.092	-0.092	-0.092	-0.092	-0.092
7	0.389	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.113	0.113	0.113	0.113	0.113	0.113
8	-1.091	-0.038	-0.038	-0.038	-0.038	-0.038	-0.038	-0.038	-0.038	-0.038	-0.038	-0.038	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025
9	-0.172	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125
10	1.042	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.188	0.188	0.188	0.188	0.188	0.188	0.188	0.188	0.188
11	0.321	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.158	-0.158	-0.158	-0.158	-0.158	-0.158	-0.158	-0.158	-0.158	-0.158
12	-0.552	-0.013	-0.013	-0.013	-0.013	-0.013	-0.013	-0.013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
13	-0.208	0.219	0.219	0.219	0.219	0.219	0.219	0.145	0.145	0.145	0.145	0.145	0.145	0.145	0.145	0.145	0.145	0.145	0.145
14	0.153	0.250	0.250	0.250	0.250	0.250	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.181	0.076
15	-0.031	0.198	0.198	0.198	0.198	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.226	0.208	0.208
16	-0.295	-0.188	-0.188	-0.188	-0.050	-0.050	-0.050	-0.050	-0.050	-0.050	-0.050	-0.050	-0.050	-0.050	-0.050	-0.050	0.025	0.025	0.025
17	-0.704	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	-0.025	0.019	0.019	0.019	0.019
18	0.465	0.244	0.167	0.167	0.167	0.167	0.167	0.167	0.167	0.167	0.167	0.167	0.167	0.167	0.179	0.179	0.179	0.179	0.179
19	0.553	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
20	0.535	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171	0.171

1.15.2 Future Price Data Sources

Additional deterministic inputs into the Forward Market Price Risk Model for FY 2007-2009 are forecasted annual forward market prices and expected flat monthly spot market prices estimated by the AURORA model. Monthly forward market prices were derived from these annual prices through the use of monthly price shaping factors calculated from the expected flat monthly spot market prices estimated by the AURORA model.

The forecasted annual forward market price used for FY 2007 is based on the average of the forward market price quotes from the Eligible Data Providers for the four quarters of FY 2007 that averaged $58.46/MWh, obtained pursuant to Exhibit C, "Determination of Forward Flat-Block Price Forecast for Contract Years 2007 through 2011," of the May 2004 subscription agreements with the region's IOUs. *See* Market Price Forecast Study Documentation, WP-07-FS-BPA-03A, regarding the forward market price quotes for FY 2007. No price risk was simulated for the forecasted FY 2007 annual forward market price to be used for computing FY 2007 IOU REP Settlement benefits and DSI benefits, since this forecasted price was known prior to the Final Proposal.

Forecasted annual forward market prices for FY 2008-2009 are based on annual average electricity prices estimated by AURORA, which are $50.87/MWh and $50.68/MWh. *See* Market Price Forecast Study Documentation, WP-07-FS-BPA-03A, regarding the forward market prices for FY 2008-2009. Monthly forward price curve movements through September 2009 are simulated beginning in October 2006 and continuing until October 2008. FY 2008-2009 results from the Forward Market Price Risk Model consist of annual average flat prices for a 12-month strip of power at the end of September 2007 for October 2007-September 2008 and at the end of September 2008 for October 2008-September 2009.

Variable inputs consist of 3000 sets of simulated flat monthly spot market prices estimated by AURORA for FY 2007-2009 and monthly standard deviations for each forward month derived by sampling 3000 times from standard normal probability distributions using the @RISK computer software. These variable inputs are read into the risk model from a database via VBA computer code, the forward price curve movements are calculated, and the results are reported in the model output to the database that RevSim uses.

Because the expected flat monthly spot market prices estimated by the AURORA model for the Risk Analysis Study were not identical to the average flat monthly forward market prices, all the monthly flat spot market prices estimated by the AURORA model were adjusted by the monthly differences between the expected flat monthly spot market prices and the average flat monthly forward market prices. These adjustments calibrate the level of the flat monthly spot market prices estimated by the AURORA model for the Risk Analysis Study to the forward market price so that the simulated forward market price movements, which are based on the spot market price movements, are not biased either upward or downward.

1.15.3 Modeling Methodology

The modeling methodology used in the Forward Market Price Risk Model assumes that the forward market price at the beginning of the spot month for the spot month is the same as the expected spot market price for the same month, since otherwise arbitrage opportunities exist that will likely be exploited which removes the differences. As spot market prices change each month through the rate period, monthly forward market prices for each of the forward months is computed in following manner:

$FPt = MAX(FPt\text{-}1 + ((\alpha + \beta * ((SPt\text{-}1,m\text{-}1 + (EFPt\text{-}1,m\text{-}1 – ESPt\text{-}1,m\text{-}1)) – FPt\text{-}1,m\text{-}1)) + \varepsilon * N(0,1)), Min\ Price)$

Where,
FPt = Updated forward market prices for each forward month for a given month (varying values)
FPt-1 = Prior forward market prices for each forward month (varying values)
SPt-1,m-1 = Actual average spot market price for the prior month (varying values)
FPt-1,m-1 = Forward price for the prior spot month at the start of the spot month(varying values)
EFPt-1,m-1 = Forecasted expected forward price for the prior spot month (constant values)
ESPt-1,m-1 = Forecasted expected spot market price for the prior spot month (constant values)
(EFPt-1,m-1 – ESPt-1,m-1) = Calibrates the overall price level of the flat monthly spot market prices estimated by AURORA to the level of the forecasted monthly forward market prices
α, β, and ε = The intercept, slope, and standard error of the regression, which differ across the forward months
N(0,1) = Sampled standard deviations from a standard normal distribution
Min Price = Minimum price for a monthly forward price, which was set at $5.00/MWh based on professional judgment.
MAX = Maximum function in Excel

Table 40 illustrates how deviations in actual average monthly spot market prices (*i.e.*, AURORA prices) from the forward market price at the beginning of the spot month (recorded in cells with boxed borders) over time impacted the forward market price curve from October 2006 through September 2008 for simulation iteration number 3000 (the last iteration). For instance, for October, 2006, the actual spot market price was $19.75/MWh higher than the September 2006, forward market price for October 2006. This difference resulted in the forward market prices for November and December of 2006 increasing by $10.05/MWh and $9.03/MWh with price changes generally increasing by lesser amounts from January, 2007 through September 2009.

Overall, these results reflect the commonly observed phenomenon that the forward market prices closest in time to the spot month react strongest to changes in monthly spot market prices and tamper off through time. This result reflects the fact that the impact of new information gained in the spot month is often short-lived and often has little, if any, impact on longer-term price expectations.

Table 40: Changes in Monthly Forward Price Curves Through Time Due to Actual Spot Market Prices Differing From Forward Market Prices at the Beginning of the Spot Months
The Amount of $/MWh that Actual Spot Market Prices Differed From Forward Market Prices at the Beginning of the Spot Months Are Indicated In Single Bordered Cells/Boxes
Results for Simulation Iteration Number 3000

Date	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	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08
Forward Month																								
Oct-06	19.75																							
Nov-06	10.05	-18.26																						
Dec-06	9.03	-2.65	-21.32																					
Jan-07	7.28	-2.29	-3.26	-5.89																				
Feb-07	7.44	-1.85	-2.78	1.81	-1.13																			
Mar-07	6.37	-1.81	-2.19	1.74	3.03	9.69																		
Apr-07	4.81	-1.50	-2.19	1.46	2.72	6.58	-10.80																	
May-07	5.52	-1.13	-1.81	1.51	2.14	5.90	-0.26	-4.13																
Jun-07	3.96	-1.30	-1.33	1.34	2.26	4.72	-0.03	0.87	-5.08															
Jul-07	3.95	-0.92	-1.56	1.05	1.94	4.87	0.10	0.92	0.50	-20.08														
Aug-07	4.10	-0.93	-1.11	1.16	1.44	4.17	0.09	0.82	0.62	-3.80	-15.36													
Sep-07	3.81	-0.97	-1.12	0.85	1.69	3.13	0.15	0.85	0.61	-3.21	-2.03	-23.51												
Oct-07	4.08	-0.91	-1.17	0.83	1.21	3.62	0.19	0.79	0.61	-2.49	-1.70	-4.82	-15.77											
Nov-07	4.57	-0.96	-1.10	0.85	1.21	2.59	0.14	0.64	0.60	-2.53	-1.34	-4.24	-5.39	-12.68										
Dec-07	4.30	-1.06	-1.17	0.79	1.26	2.59	0.12	0.68	0.51	-2.07	-1.32	-3.44	-4.75	-3.95	10.62									
Jan-08	2.83	-0.99	-1.32	0.85	1.15	2.69	0.10	0.51	0.52	-1.51	-1.07	-3.42	-3.85	-3.40	3.75	27.41								
Feb-08	2.79	-0.66	-1.23	0.93	1.26	2.49	0.08	0.49	0.39	-1.79	-0.79	-2.87	-3.84	-2.70	3.34	9.92	27.54							
Mar-08	2.22	-0.65	-0.79	0.88	1.45	2.68	0.08	0.49	0.37	-1.26	-0.92	-2.18	-3.23	-2.70	2.62	8.89	10.31	-25.47						
Apr-08	2.60	-0.51	-0.77	0.61	1.37	3.03	0.07	0.46	0.37	-1.28	-0.65	-2.48	-2.45	-2.24	2.76	7.16	9.31	-8.44	-10.95					
May-08	2.30	-0.59	-0.58	0.61	0.86	2.85	0.02	0.49	0.34	-1.35	-0.66	-1.78	-2.79	-1.67	2.36	7.33	7.56	-7.40	-3.57	-8.52				
Jun-08	2.45	-0.53	-0.70	0.51	0.84	1.85	0.03	0.51	0.36	-1.26	-0.69	-1.77	-2.00	-1.94	1.75	6.26	7.69	-5.91	-3.09	-2.36	-7.89			
Jul-08	2.18	-0.56	-0.61	0.58	0.65	1.82	0.10	0.49	0.35	-1.35	-0.65	-1.84	-1.99	-1.38	2.05	4.73	6.60	-5.97	-2.47	-1.92	-2.83	-4.74		
Aug-08	2.18	-0.49	-0.66	0.53	0.79	1.43	0.11	0.37	0.34	-1.55	-0.69	-1.73	-2.07	-1.39	1.46	5.43	5.02	-5.02	-2.46	-1.43	-2.48	-1.01	-3.00	
Sep-08	2.13	-0.49	-0.57	0.55	0.69	1.70	0.15	0.37	0.29	-1.45	-0.78	-1.83	-1.95	-1.45	1.47	3.89	5.72	-3.76	-2.04	-1.46	-2.03	-0.74	-0.41	-3.90
Oct-08	2.21	-0.48	-0.57	0.50	0.73	1.49	0.12	0.33	0.30	-0.90	-0.72	-2.03	-2.06	-1.36	1.53	3.88	4.11	-4.34	-1.53	-1.16	-1.98	-0.50	-0.22	-0.71
Nov-08	2.18	-0.50	-0.56	0.51	0.66	1.59	0.14	0.36	0.29	-0.87	-0.47	-1.90	-2.28	-1.44	1.41	4.03	4.09	-3.10	-1.77	-0.81	-1.65	-0.51	-0.11	-0.49
Dec-08	2.22	-0.49	-0.59	0.49	0.66	1.42	0.12	0.34	0.30	-0.64	-0.45	-1.28	-2.13	-1.63	1.53	3.74	4.24	-3.10	-1.26	-1.01	-1.26	-0.36	-0.09	-0.32
Jan-09	2.15	-0.50	-0.58	0.50	0.64	1.42	0.13	0.35	0.28	-0.79	-0.34	-1.26	-1.44	-1.52	1.77	4.01	3.94	-3.23	-1.26	-0.70	-1.43	-0.22	-0.01	-0.31
Feb-09	2.17	-0.48	-0.59	0.49	0.67	1.38	0.14	0.32	0.29	-0.68	-0.40	-0.99	-1.41	-0.98	1.67	4.51	4.21	-3.02	-1.32	-0.72	-1.02	-0.31	0.03	-0.20
Mar-09	2.10	-0.49	-0.57	0.50	0.66	1.44	0.13	0.33	0.27	-0.74	-0.35	-1.15	-1.12	-0.96	1.04	4.24	4.69	-3.22	-1.24	-0.77	-1.02	-0.20	-0.01	-0.11
Apr-09	2.08	-0.47	-0.58	0.49	0.68	1.42	0.11	0.31	0.28	-0.64	-0.38	-1.03	-1.30	-0.74	1.02	2.78	4.42	-3.62	-1.31	-0.71	-1.06	-0.22	0.01	-0.17
May-09	2.07	-0.47	-0.56	0.49	0.66	1.45	0.11	0.31	0.26	-0.63	-0.33	-1.10	-1.16	-0.88	0.78	2.74	2.95	-3.39	-1.46	-0.77	-1.00	-0.25	-0.01	-0.11
Jun-09	2.02	-0.46	-0.55	0.48	0.66	1.41	0.10	0.31	0.26	-0.62	-0.33	-0.96	-1.23	-0.77	0.96	2.17	2.91	-2.22	-1.37	-0.92	-1.05	-0.23	-0.02	-0.12
Jul-09	1.91	-0.45	-0.55	0.47	0.64	1.42	0.11	0.31	0.26	-0.67	-0.32	-0.96	-1.08	-0.83	0.83	2.56	2.33	-2.17	-0.90	-0.85	-1.15	-0.25	-0.02	-0.14
Aug-09	1.90	-0.42	-0.53	0.47	0.63	1.37	0.10	0.31	0.25	-0.65	-0.34	-0.94	-1.09	-0.72	0.89	2.25	2.71	-1.69	-0.88	-0.49	-1.07	-0.32	-0.02	-0.13
Sep-09	1.85	-0.42	-0.49	0.46	0.63	1.35	0.11	0.30	0.25	-0.67	-0.33	-0.98	-1.06	-0.72	0.79	2.41	2.41	-2.00	-0.68	-0.47	-0.74	-0.29	-0.06	-0.14

1.15.4 Model and Results

Table 41 contains a copy of the Forward Market Price Risk Model. The deterministic input data used by the model and a summary of the results for FY 2008-2009 are reported in the top left quadrant of the first page of this table. The results indicate that the variability, as measured by standard deviation, of annual forward market prices for a 12-month strip of power over FY 2008-2009 is $10.38/MWh, which is 58.0 percent of the $17.90/MWh standard deviation for annual average spot market prices estimated by the AURORA model. The correlation between the AURORA and forward market prices was found to be moderate, having a correlation coefficient of 0.636. The average simulated FY 2008-2009 annual forward market prices for a 12-month strip of power was $51.45/MWh, which is slightly (1 percent) higher than the average annual FY 2008-2009 forward market price of $50.78/MWh, which was input into the model. Graphs 20 and 21 show the probability distributions for the simulated average annual forward market prices for a 12-month strip of power during FY 2008-2009.

Table 41: Forward Market Price Risk Model

INPUT DATA:

	Forward Mkt	Aurora Spot	Differences
FY07 Annual Price	$ 58.46	$ 48.92	$ 9.54
FY08 Annual Price	$ 50.87	$ 49.51	$ 1.36
FY09 Annual Price	$ 50.68	$ 50.31	$ 0.37
Min Monthly Price	5.00		
Avg FY08-09 Price	$ 50.78	$ 49.91	$ 0.87

AVERAGE FY08-09 RESULTS AND COMPARISONS

	Simulated Forward Price	AURORA Spot Price	Forward Vs Spot Prices
Average (FY08-09)	$ 51.45	$ 49.87	$ 1.59
Std Dev (FY08-09)	$ 10.38	$ 17.90	58.0%
Correlation (FY08-09)	0.636		

	Spot Vs Fwd 1	Spot Vs Fwd 2	Spot Vs Fwd 3	Spot Vs Fwd 4	Spot Vs Fwd 5	Spot Vs Fwd 6	Spot Vs Fwd 7	Spot Vs Fwd 8	Spot Vs Fwd 9	Spot Vs Fwd 10	Spot Vs Fwd 11	Spot Vs Fwd 12
R^2	0.3062	0.2242	0.1581	0.1930	0.1695	0.1282	0.1712	0.1550	0.1719	0.1863	0.1713	0.1922
Intercept	-0.1126	-0.0069	0.0188	0.0638	0.1018	0.0924	0.0925	0.0746	0.0660	0.0627	0.0491	0.0619
Slope	0.3466	0.3075	0.2466	0.2509	0.2129	0.1601	0.1844	0.1319	0.1318	0.1371	0.1276	0.1365
Std Err	0.2889	0.3168	0.3151	0.2841	0.2610	0.2311	0.2247	0.1705	0.1602	0.1587	0.1555	0.1550

FY07 | FY08

Forecasted FY07 Forward Price Curve

Fiscal Year	2007	2007	2007	2007	2007	2007	2007	2007	2007	2007	2007	2007	2008
Month	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Monthly Hours	745	720	744	744	672	744	719	744	720	744	744	720	745
Forward Price Curve - Avg Aurora Spot	47.97	58.37	61.50	55.52	56.61	51.57	45.84	31.45	29.07	44.00	50.14	54.94	52.11
Forward Price Curve - Used	57.33	69.76	73.50	66.36	67.66	61.64	54.78	37.59	34.74	52.59	59.93	65.66	53.54
Aurora Spot Price 3000	77.08	61.55	58.55	62.20	71.14	78.46	55.86	45.33	40.15	43.35	51.14	45.91	37.99
No. of Stdevs 3000	0.26	-0.54	0.29	0.71	-1.03	-0.53	1.71	0.98	1.41	1.04	0.06	-0.96	-1.06
Selected Annual Avg FY Forward Prices												58.46	

Simulated FY07 Forward Price Curve

		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
Sep-06	Fwd PC (Oct-06 to Sep-09)	57.33	69.76	73.50	66.36	67.66	61.64	54.78	37.59	34.74	52.59	59.93	65.66	53.54
Oct-06		77.08	79.81	82.52	73.64	75.10	68.00	59.60	43.11	38.70	56.53	64.02	69.46	57.62
Nov-06			61.55	79.87	71.35	73.25	66.19	58.09	41.97	37.40	55.61	63.10	68.50	56.71
Dec-06				58.55	68.09	70.47	64.00	55.90	40.17	36.07	54.05	61.99	67.38	55.54
Jan-07					62.20	72.28	65.74	57.36	41.67	37.41	55.09	63.15	68.23	56.37
Feb-07						71.14	68.77	60.08	43.81	39.67	57.04	64.60	69.92	57.57
Mar-07							78.46	66.66	49.71	44.39	61.91	68.76	73.05	61.19
Apr-07								55.86	49.45	44.36	62.01	68.85	73.21	61.38
May-07									45.33	45.23	62.93	69.67	74.05	62.17
Jun-07										40.15	63.43	70.30	74.66	62.78
Jul-07											43.35	66.50	71.45	60.29
Aug-07												51.14	69.42	58.59
Sep-07	Fwd PC (Oct-07 to Sep-09)												45.91	53.77
Oct-07														37.99
Nov-07														
Dec-07														
Jan-08														
Feb-08														
Mar-08														
Apr-08														
May-08														
Jun-08														
Jul-08														
Aug-08														
Sep-08	Fwd PC (Oct-08 to Sep-09)													

Table 41: Forward Market Price Risk Model (Continued)

	Spot Vs Fwd 13	Spot Vs Fwd 14	Spot Vs Fwd 15	Spot Vs Fwd 16	Spot Vs Fwd 17	Spot Vs Fwd 18	Spot Vs Fwd 19	Spot Vs Fwd 20	Spot Vs Fwd 21	Spot Vs Fwd 22	Spot Vs Fwd 23	Spot Vs Fwd 24
R^2	0.2780	0.2720	0.1406	0.1332	0.0896	0.1265	0.1020	0.1134	0.1045	0.1017	0.1048	0.1224
Intercept	0.0687	0.0722	0.0536	0.0561	0.0612	0.0683	0.0625	0.0598	0.0658	0.0668	0.0632	0.0594
Slope	0.1535	0.1442	0.0944	0.0927	0.0729	0.0859	0.0757	0.0810	0.0716	0.0717	0.0700	0.0730
Std Err	0.1370	0.1306	0.1292	0.1310	0.1286	0.1250	0.1244	0.1255	0.1160	0.1180	0.1132	0.1082

Forecasted FY08 Forward Price Curve

												FY09
Fiscal Year	2008	2008	2008	2008	2008	2008	2008	2008	2008	2008	2008	2009
Month	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Monthly Hours	720	744	744	696	744	719	744	720	744	744	720	745
Forward Price Curve - Avg Aurora Spot	55.60	58.53	54.76	58.94	53.56	43.49	31.06	32.47	44.96	52.78	55.82	54.50
Forward Price Curve - Used	57.13	60.14	56.27	60.57	55.03	44.69	31.92	33.36	46.20	54.23	57.35	54.90
Aurora Spot Price **3000**	39.50	63.26	80.52	95.90	47.81	42.64	27.73	27.48	39.43	47.91	51.45	58.19
No. of Stdevs **3000**	0.10	-1.31	0.02	1.10	-0.04	-0.26	1.40	-1.02	1.09	0.82	0.76	2.26
Selected Annual Avg FY Forward Prices											50.87	

Simulated FY08 Forward Price Curve

		Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Oct '08
Sep-06	Fwd PC (Oct-06 to Sep-09	57.13	60.14	56.27	60.57	55.03	44.69	31.92	33.36	46.20	54.23	57.35	54.90
Oct-06		61.71	64.44	59.11	63.36	57.25	47.29	34.22	35.82	48.38	56.42	59.48	57.12
Nov-06		60.75	63.38	58.12	62.69	56.60	46.78	33.63	35.29	47.81	55.93	58.99	56.64
Dec-06		59.65	62.21	56.79	61.46	55.81	46.01	33.04	34.59	47.20	55.27	58.43	56.07
Jan-07		60.50	63.01	57.64	62.38	56.69	46.62	33.65	35.11	47.79	55.79	58.98	56.57
Feb-07		61.71	64.26	58.80	63.64	58.14	47.99	34.51	35.95	48.44	56.59	59.66	57.31
Mar-07		64.30	66.85	61.48	66.13	60.81	51.02	37.36	37.80	50.26	58.02	61.36	58.80
Apr-07		64.44	66.97	61.58	66.21	60.89	51.09	37.38	37.83	50.36	58.13	61.51	58.92
May-07		65.08	67.66	62.09	66.70	61.39	51.55	37.87	38.34	50.85	58.50	61.88	59.26
Jun-07		65.67	68.17	62.61	67.09	61.76	51.92	38.21	38.70	51.20	58.84	62.17	59.55
Jul-07		63.15	66.09	61.10	65.30	60.49	50.64	36.86	37.44	49.85	57.29	60.72	58.65
Aug-07		61.81	64.78	60.03	64.51	59.57	49.99	36.20	36.75	49.20	56.60	59.94	57.93
Sep-07	Fwd PC (Oct-07 to Sep-09	57.57	61.34	56.61	61.64	57.39	47.50	34.43	34.98	47.36	54.86	58.11	55.91
Oct-07		52.18	56.59	52.76	57.80	54.17	45.05	31.64	32.98	45.36	52.79	56.16	53.85
Nov-07		39.50	52.64	49.36	55.10	51.46	42.81	29.97	31.04	43.98	51.41	54.71	52.49
Dec-07			63.26	53.11	58.44	54.09	45.57	32.33	32.79	46.04	52.87	56.18	54.02
Jan-08				80.52	68.36	62.98	52.73	39.66	39.05	50.77	58.30	60.07	57.90
Feb-08					95.90	73.29	62.04	47.22	46.74	57.36	63.32	65.79	62.01
Mar-08						47.81	53.60	39.82	40.83	51.39	58.30	62.03	57.67
Apr-08							42.64	36.25	37.74	48.92	55.84	59.99	56.14
May-08								27.73	35.38	47.00	54.41	58.53	54.97
Jun-08									27.48	44.17	51.93	56.50	52.99
Jul-08										39.43	50.91	55.76	52.49
Aug-08											47.91	55.35	52.26
Sep-08	Fwd PC (Oct-08 to Sep-09)											51.45	51.55

Table 41: Forward Market Price Risk Model (Continued)

	Spot Vs Fwd 25	Spot Vs Fwd 26	Spot Vs Fwd 27	Spot Vs Fwd 28	Spot Vs Fwd 29	Spot Vs Fwd 30	Spot Vs Fwd 31	Spot Vs Fwd 32	Spot Vs Fwd 33	Spot Vs Fwd 34	Spot Vs Fwd 35
R^2	0.1190	0.1308	0.1243	0.1294	0.1219	0.1196	0.1152	0.1074	0.0995	0.1018	0.1051
Intercept	0.0600	0.0613	0.0607	0.0595	0.0601	0.0595	0.0594	0.0596	0.0634	0.0628	0.0566
Slope	0.0717	0.0732	0.0709	0.0717	0.0692	0.0683	0.0681	0.0664	0.0623	0.0623	0.0608
Std Err	0.1080	0.1045	0.1041	0.1029	0.1028	0.1026	0.1044	0.1060	0.1039	0.1024	0.0982

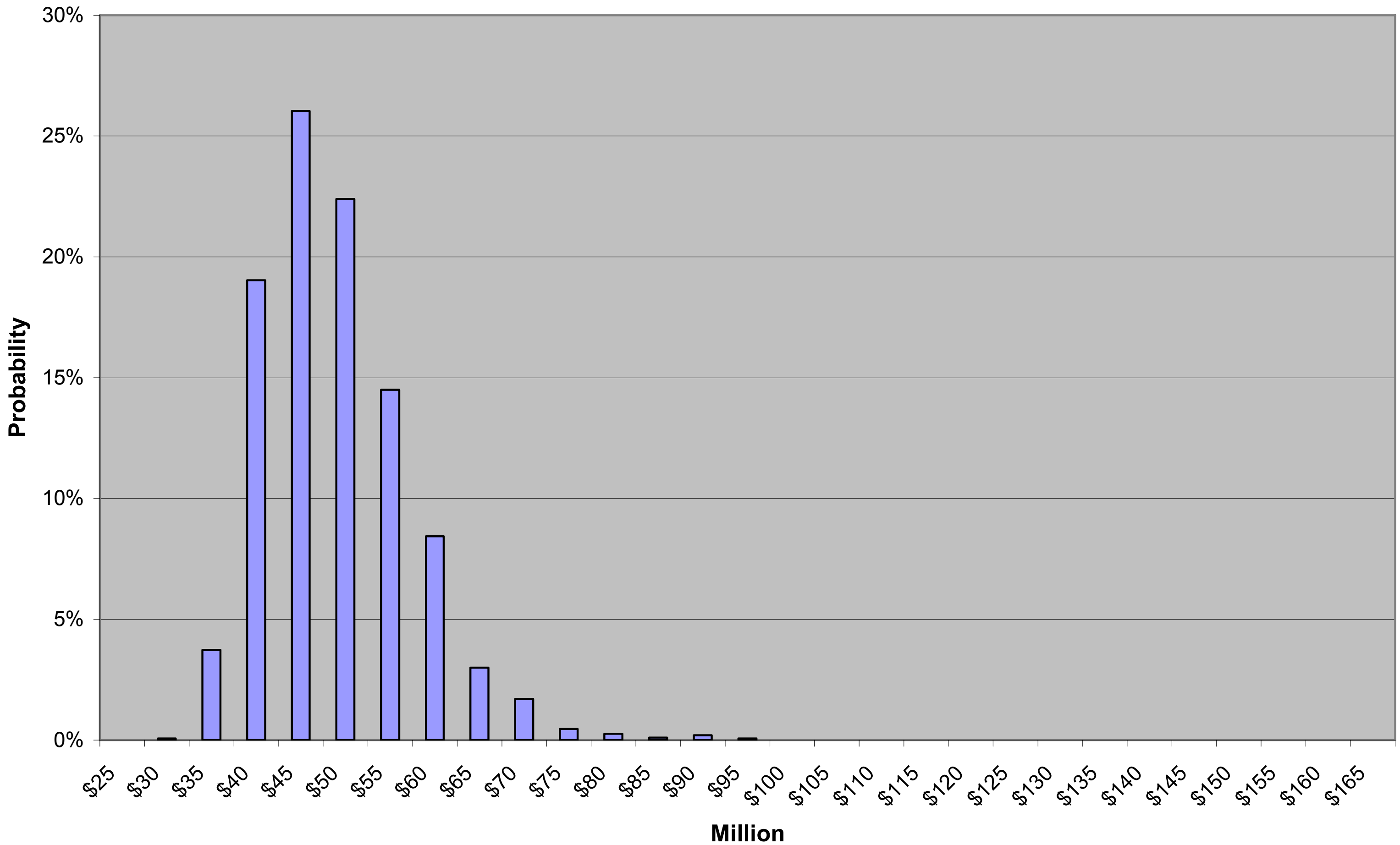
Forecasted FY09 Forward Price Curve

Fiscal Year		2009	2009	2009	2009	2009	2009	2009	2009	2009	2009	2009
Month		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Monthly Hours		720	744	744	672	744	719	744	720	744	744	720
Forward Price Curve - Avg Aurora Spot		59.73	62.98	59.97	63.79	55.44	41.17	29.35	29.70	41.95	52.27	52.85
Forward Price Curve - Used		60.17	63.45	60.41	64.26	55.84	41.48	29.57	29.92	42.26	52.65	53.24
Aurora Spot Price	**3000**	50.78	52.49	46.52	66.10	99.25	84.53	69.20	42.29	67.41	89.57	106.40
No. of Stdevs	**3000**	-0.48	0.36	-0.77	-1.45	0.20	1.15	1.31	-1.87	-0.45	0.01	0.53
Selected Annual Avg FY Forward Prices												50.68

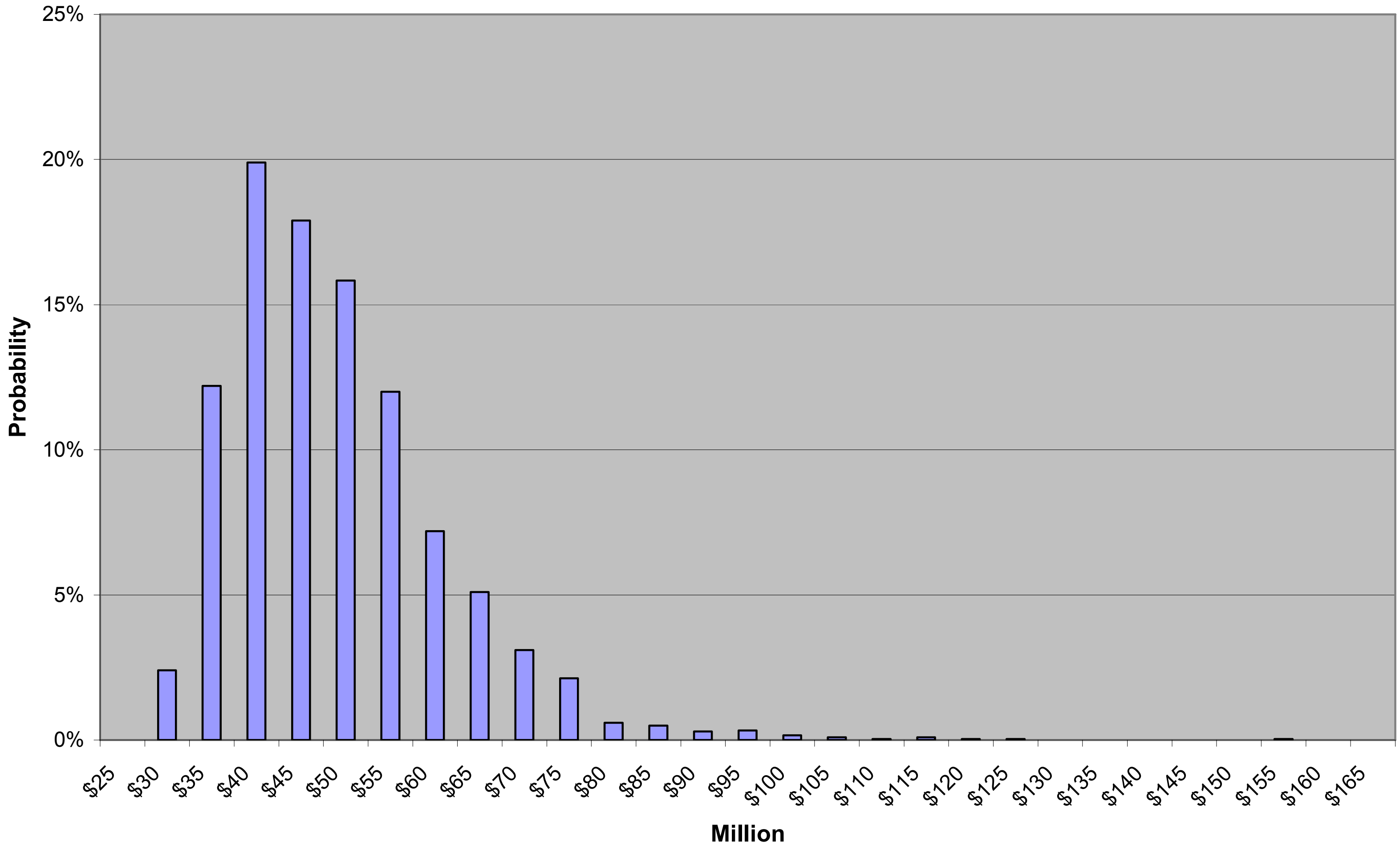
Simulated FY09 Forward Price Curve

		Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09
Sep-06	Fwd PC (Oct-06 to Sep-09	**60.17**	**63.45**	**60.41**	**64.26**	**55.84**	**41.48**	**29.57**	**29.92**	**42.26**	**52.65**	**53.24**
Oct-06		**62.35**	**65.67**	**62.57**	**66.43**	**57.95**	**43.55**	**31.64**	**31.94**	**44.17**	**54.56**	**55.09**
Nov-06		**61.85**	**65.18**	**62.07**	**65.95**	**57.46**	**43.08**	**31.17**	**31.47**	**43.71**	**54.14**	**54.67**
Dec-06		**61.29**	**64.59**	**61.49**	**65.36**	**56.89**	**42.50**	**30.62**	**30.93**	**43.17**	**53.61**	**54.18**
Jan-07		**61.80**	**65.08**	**61.99**	**65.85**	**57.38**	**42.99**	**31.10**	**31.40**	**43.64**	**54.08**	**54.64**
Feb-07		**62.45**	**65.73**	**62.63**	**66.52**	**58.04**	**43.67**	**31.76**	**32.07**	**44.28**	**54.71**	**55.27**
Mar-07		**64.05**	**67.15**	**64.05**	**67.91**	**59.49**	**45.09**	**33.21**	**33.47**	**45.70**	**56.08**	**56.63**
Apr-07		**64.18**	**67.27**	**64.18**	**68.04**	**59.62**	**45.20**	**33.32**	**33.58**	**45.81**	**56.18**	**56.73**
May-07		**64.55**	**67.61**	**64.52**	**68.37**	**59.94**	**45.51**	**33.64**	**33.89**	**46.12**	**56.49**	**57.04**
Jun-07		**64.83**	**67.91**	**64.81**	**68.65**	**60.21**	**45.79**	**33.90**	**34.14**	**46.37**	**56.74**	**57.29**
Jul-07		**63.96**	**67.26**	**64.02**	**67.97**	**59.47**	**45.15**	**33.27**	**33.52**	**45.70**	**56.09**	**56.62**
Aug-07		**63.49**	**66.81**	**63.68**	**67.57**	**59.12**	**44.77**	**32.94**	**33.19**	**45.38**	**55.75**	**56.28**
Sep-07	Fwd PC (Oct-07 to Sep-09	**61.60**	**65.53**	**62.42**	**66.57**	**57.97**	**43.74**	**31.84**	**32.23**	**44.42**	**54.81**	**55.31**
Oct-07		**59.32**	**63.40**	**60.99**	**65.16**	**56.85**	**42.45**	**30.69**	**31.00**	**43.34**	**53.72**	**54.25**
Nov-07		**57.88**	**61.77**	**59.47**	**64.18**	**55.89**	**41.71**	**29.81**	**30.23**	**42.51**	**53.00**	**53.53**
Dec-07		**59.28**	**63.30**	**61.23**	**65.84**	**56.92**	**42.73**	**30.60**	**31.18**	**43.33**	**53.89**	**54.31**
Jan-08		**63.31**	**67.04**	**65.25**	**70.35**	**61.17**	**45.51**	**33.34**	**33.35**	**45.89**	**56.14**	**56.72**
Feb-08		**67.40**	**71.28**	**69.19**	**74.56**	**65.86**	**49.93**	**36.28**	**36.26**	**48.22**	**58.85**	**59.13**
Mar-08		**64.30**	**68.18**	**65.95**	**71.54**	**62.64**	**46.31**	**32.89**	**34.04**	**46.04**	**57.16**	**57.13**
Apr-08		**62.54**	**66.92**	**64.69**	**70.23**	**61.41**	**45.00**	**31.43**	**32.67**	**45.14**	**56.28**	**56.45**
May-08		**61.73**	**65.91**	**64.00**	**69.51**	**60.64**	**44.29**	**30.66**	**31.76**	**44.29**	**55.79**	**55.97**
Jun-08		**60.07**	**64.65**	**62.57**	**68.49**	**59.62**	**43.23**	**29.66**	**30.71**	**43.15**	**54.72**	**55.24**
Jul-08		**59.56**	**64.29**	**62.35**	**68.18**	**59.42**	**43.01**	**29.41**	**30.48**	**42.90**	**54.40**	**54.94**
Aug-08		**59.46**	**64.20**	**62.33**	**68.21**	**59.41**	**43.02**	**29.40**	**30.46**	**42.88**	**54.38**	**54.89**
Sep-08	Fwd PC (Oct-08 to Sep-09	58.97	63.87	62.02	68.01	59.30	42.85	29.30	30.33	42.74	54.24	54.74

Graph 20: FY 2008 Forward Market Price Distribution For 12-Month Strip of Power



Graph 21: FY 2009 Forward Market Price Distribution For 12-Month Strip of Power



1.16 Revenue Simulation Model (RevSim)

The purpose of the RevSim module within RiskMod is to determine, via simulation, PBL's operational net revenue risk. Inputs to RevSim include risk data simulated by RiskSim and the AURORA model along with deterministic monthly load and resource data, monthly PF rates, and non-varying revenues and expenses from the Load Resource Study, WP-07-FS-BPA-01, the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05, and the RAM2007.

RevSim uses these inputs to calculate all revenues and expenses needed to determine PBL operational net revenues. These revenues and expenses include revenues from firm power sales (including the SLICE product), surplus energy sales revenue, 4(h)(10)(C) credits, power purchase expenses, and purchase expenses for wind generation. Additional net revenue adjustments include varying DSI benefits and transmission expenses, which are computed external to RevSim and are then input into the model. These variable revenues and expenses are then combined with deterministic revenues and expenses to calculate PBL operational net revenues.

RevSim calculates firm and surplus energy revenues and balancing power purchase expenses under various load, resource, and market price conditions to estimate PBL's operational net revenue risk. A key attribute of RevSim is that it is a HLH and LLH load and resource model. For each simulation, RevSim calculates PBL's HLH and LLH load and resource condition and determines HLH and LLH surplus energy sales and power purchases.

Transmission losses on BPA's transmission system are incorporated into RevSim by reducing Federal hydro generation and CGS output by 2.82 percent. This factor excludes losses on the Southern Intertie. This loss factor is identical to the loss factor used in the Load Resource Study, WP-07-FS-BPA-01.

Electricity prices estimated by AURORA are applied to the surplus sales and power purchase amounts to determine surplus energy revenues and power purchase expenses. These HLH and LLH revenues and expenses are then combined with deterministic revenues and expenses to calculate PBL operational net revenues.

RevSim calculates the 4(h)(10)(C) credit that BPA can collect for each of the 50 water years for FY 2007-2009. The 4(h)(10)(C) credit is a provision in the 1980 Pacific Northwest Power Planning and Conservation Act that allows BPA and its ratepayers to receive a credit for non-power fish and wildlife impacts attributable to Federal projects. The 4(h)(10)(C) credits that BPA can collect for each of the 50 water years for FY 2007-2009 is determined by summing the costs of the operational impacts, the expenses, and the capital costs associated with fish and wildlife mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent).

Power purchases (aMWs) that qualify for 4(h)(10)(C) credits vary depending on monthly hydro operations due to fish mitigation measures. The amounts of power purchases (aMWs) that qualifies for 4(h)(10)(C) credits is derived external to RevSim, but are used in RevSim to calculate the dollar amount of the 4(h)(10)(C) credits. A description of the methodology used to derive the amounts of the power purchases (aMWs) associated with the 4(h)(10)(C) credits is contained in the Load Resource Study, WP-07-FS-BPA-01, and Table 2.8.1 in the Load Resource Study Documentation, WP-07-FS-BPA-01A, contains the 4(h)(10)(C) power purchase amounts for FY 2007-2009.

The costs of the operational impacts for Fish & Wildlife measures are calculated for each of the 50 water years in RevSim for FY 2007-2009 by multiplying the amount of monthly power purchases (aMWs) that qualifies for 4(h)(10)(C) credits in a given water year by the flat monthly spot market electricity prices (computed from the AURORA HLH and LLH spot market electricity prices) for the same water year. The expenses and capital costs associated with the 4(h)(10)(C) credit are determined external to RevSim and are input into RevSim, *See* Revenue Requirement Study, WP-07-FS-BPA-02, regarding expenses and capital costs.

The calculation of rates requires two different analyses by RevSim, which are referred to as the "50 Water Year Run" and the "Risk Simulation Run." The 50 Water Year Run provides data to the RAM2007 model for calculating base rates. The Risk Simulation Run provides data to the ToolKit model for the purpose of determining if BPA has met its financial objectives for the rate period.

1.16.1 Fifty (50) Water Year Run

The purpose of the 50 Water Year Run is to calculate revenues from surplus energy sales, expenses associated with purchases needed to meet firm load, and 4(h)(10)(C) credits. Although there is no year-to-year dependency in the 50 Water Year Run, each iteration in the study uses successive water years for each FY. The affect of using successive water years for each FY is that tables of results for FY 2007 will be listed as water years 1929-1978, results for FY 2008 will be listed as water years 1930-1978 with water year 1929 appearing after water year 1978, and results for 2009 will be listed as water years 1931-1978 with water years 1929 and 1930 appearing after water year 1978.

The risk data simulated by RiskSim are not used in the 50 Water Year Run of RevSim. CGS output and PBL loads are provided to RevSim by repeating the respective forecasted values for each of the 50 simulations. HLH and LLH spot market electricity prices from the 50 Water Year Run of AURORA are used to calculate surplus energy revenues and power purchase expenses associated with the monthly HLH and LLH surplus and deficit amounts for each of the 50 water years. Surplus energy sales amounts, surplus energy sales revenues, power purchase amounts, and power purchases expenses are reported in the Revenue Forecast component of the Wholesale Power Rate Development Study Documentation, Volume 1, WP-07-FS-BPA-05A.

The 50 Water Year Run of RiskMod calculates the annual 4(h)(10)(C) credits for inclusion into the Revenue Forecast and RAM2007 calculation of rates. The dollar amounts of 4(h)(10)(C) credits for the 50 Water Year Run of RiskMod are reported in the Revenue Forecast component of the Wholesale Power Rate Development Study Documentation, WP-07-FS-BPA-05B.

1.16.2 Risk Simulation Run

The Risk Simulation Run of RevSim provides PBL annual net revenues for 3000 iterations per FY considering several risk variables in addition to the variable hydro generation and 4(h)(10)(C) credits used in the 50 Water Year Run. All the risk data, with the exception of PF load variability, are input into RevSim as values. PF load variability is quantified as ratios relative to 1.00. These load variability ratios are multiplied by the forecasted monthly PF loads subject to the load variance charge (*see* Load Resource Study, WP-07-FS-BPA-01). The differences between the simulated and forecasted values are added to the forecasted monthly PF loads reported in the Load Resource Study, WP-07-FS-BPA-01, to obtain variable PF loads**.**

These variable PF loads are multiplied by the PF rate to obtain variable PF energy revenues. In addition to adjusting PF loads (energy), the ratios (relative to 1.00) are multiplied by the forecasted monthly PF demand in the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05, to obtain variable PF demand. These variable demand values are multiplied by the PF demand charge to obtain variable PF demand revenues.

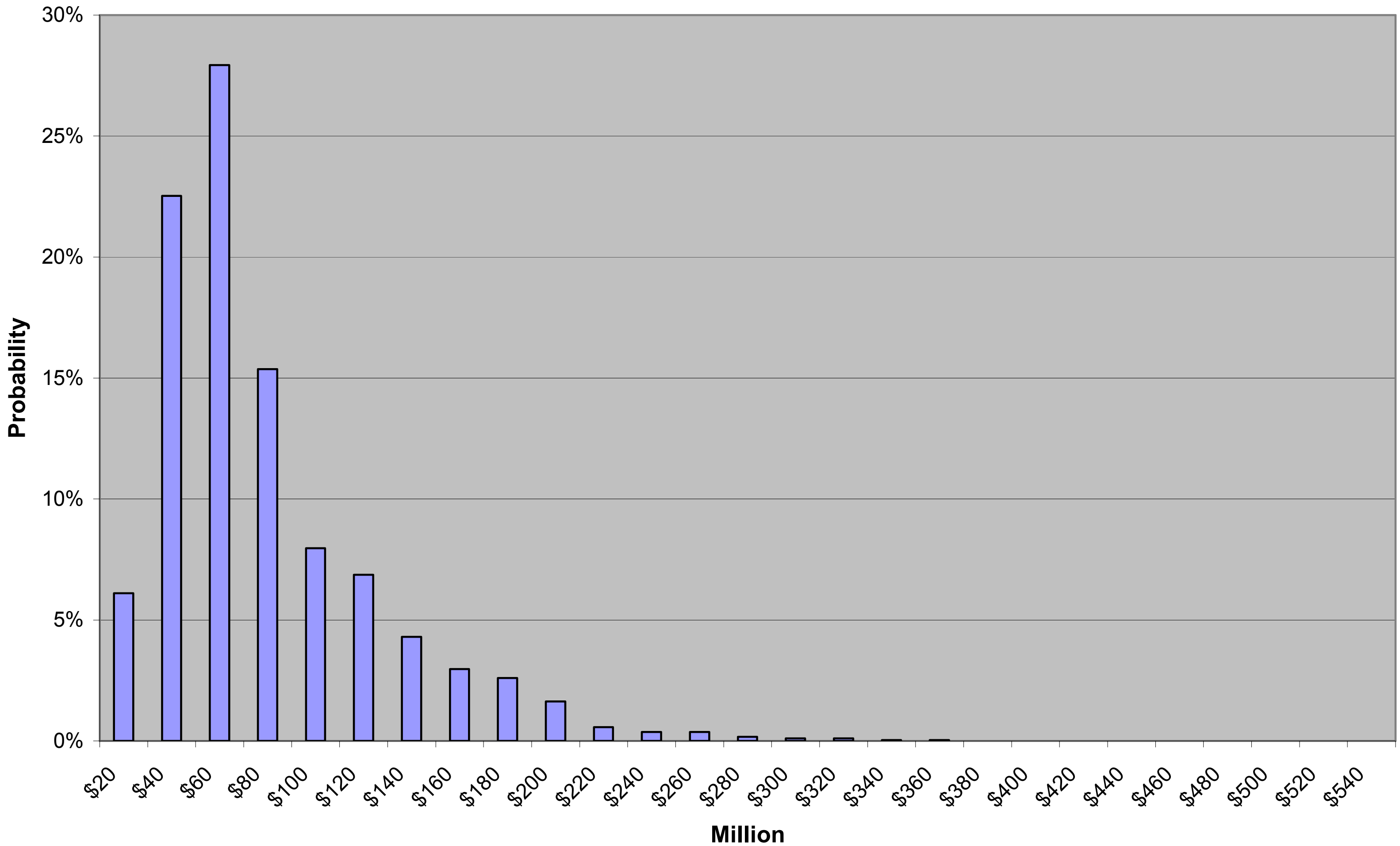
Surplus energy sales revenue and power purchase expenses are based on Federal hydro generation (50 water years), Federal HLH hydro generation ratios (50 water years), BPA load variability, CGS output variability, variable wind generation, transmission expenses, and AURORA prices. RevSim calculates monthly HLH and LLH surplus energy sales and power purchases and applies corresponding HLH and LLH prices estimated by the AURORA Model to determine surplus energy sales revenues and power purchase expenses.

For a given simulation, Federal hydro generation data and HLH hydro generation ratios are determined by the water year sampled for the "hydro index." The hydro index is the water year to use for the first fiscal year, *i.e.,* FY 2007. Successive water years are used for each subsequent FY. For example, if water year 1940 is selected as the hydro index for a given simulation, then hydro generation data for water year 1940 are used for FY 2007, hydro generation data for water year 1941 are used for FY 2008, etc. If water year 1978 is selected as the hydro index, then the data is "wrapped" to water year 1929, *i.e.,* hydro generation data for water year 1978 are used for FY 2007, hydro generation for water year 1929 are used for FY 2008, etc. Given the hydro index (water year) for a simulation, Federal hydro generation data are retrieved from the Risk Input Database.

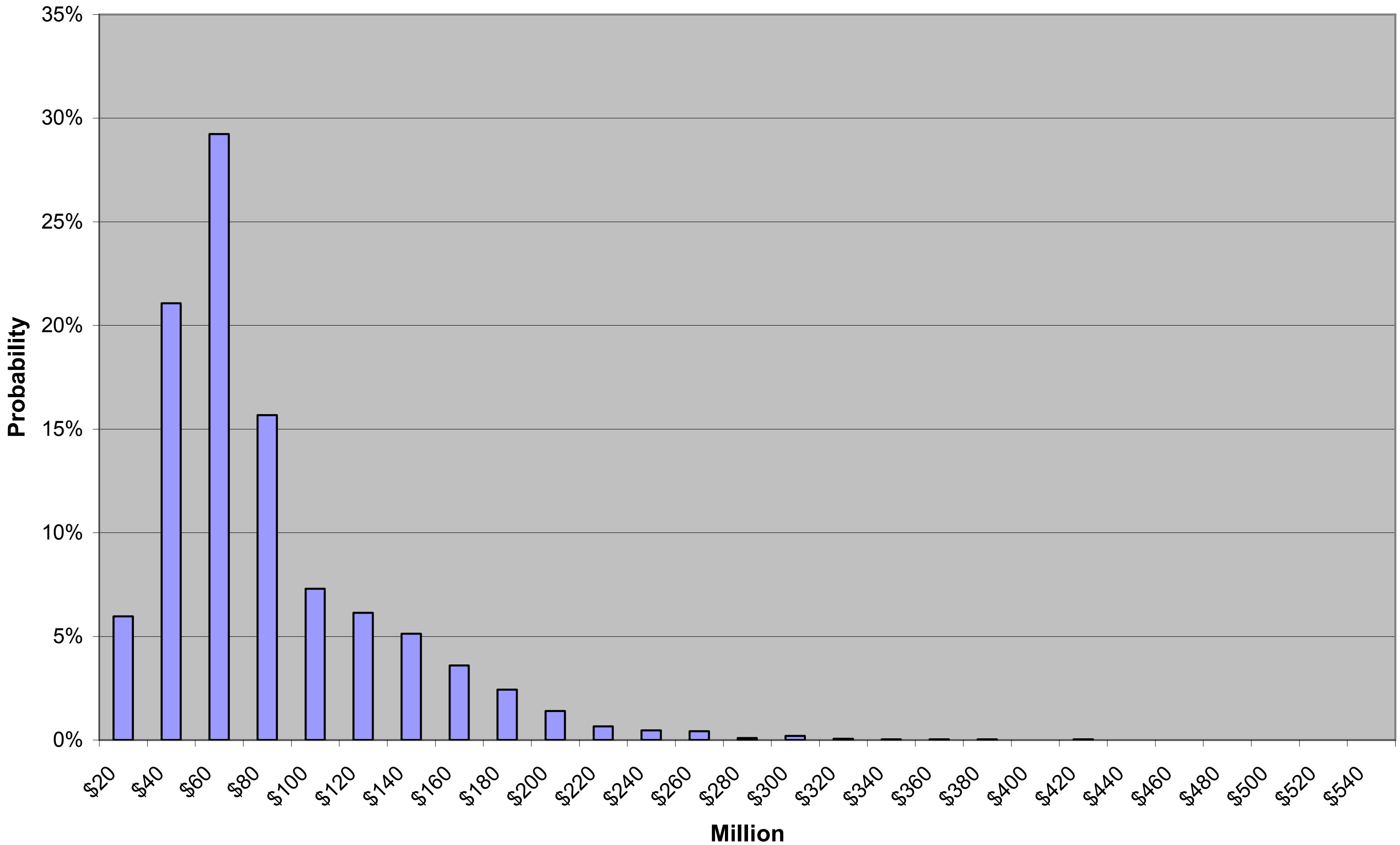
The operational portion of the 4(h)(10)(C) credit is computed from 4(h)(10)(C) power purchase amounts and AURORA prices that are read from the Risk Input Database. The variable operational portion of the credit is combined with the deterministic expense and capital portions to calculate the total 4(h)(10)(C) credit. The 4(h)(10)(C) credits for the three-year rate period calculated in the Risk Simulation Run are included in the PBL net revenues passed to the ToolKit Model. Graphs 22-24 show the probability distributions of the 4(h)(10)(C) credits calculated in the Risk Simulation Run.

The difference in the 4(h)(10)(C) credits between the 50 Water Year Run and the Risk Simulation Run is derived from in the differences in the spot market electricity prices AURORA estimated between the 50 Water Year Run and the Risk Simulation Run.

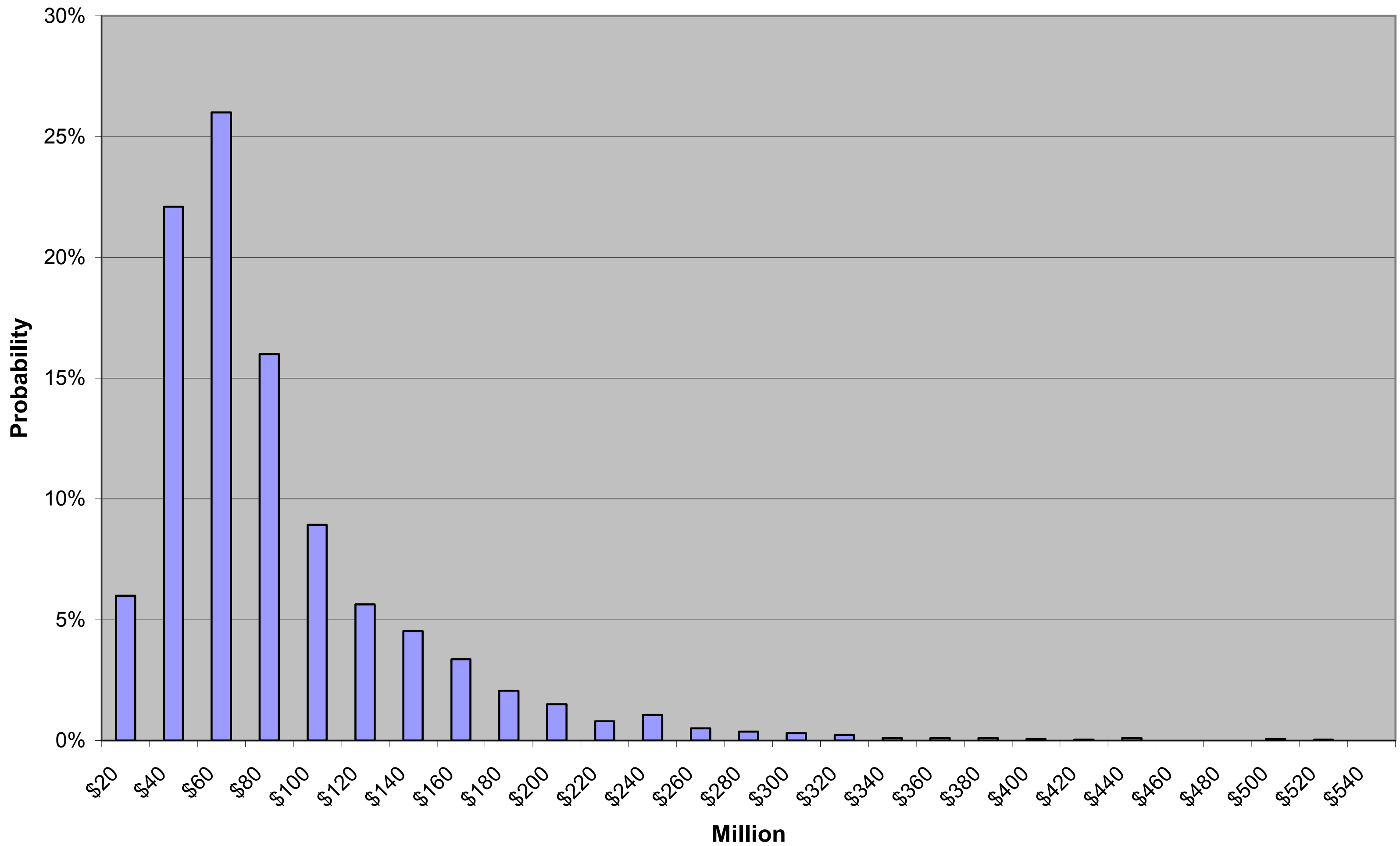
Graph 22: Simulated 4(h)(10)(C) Credits for FY 2007



Graph 23: Simulated 4(h)(10)(C) Credits for FY 2008



Graph 24: Simulated 4(h)(10)(C) Credits for FY 2009



1.17 Data Management Procedures (DMPs)

RiskMod receives data from a variety of sources and provides data to other computer models used in the rates process including AURORA, RAM2007, and ToolKit. Data are stored in two ACCESS databases, the Risk Input Database and the Risk Output Database. Figure 1 depicts a typical Risk Input Database and Figure 2 depicts a typical Risk Output Database. The computer applications used to move data between modules within RiskMod (*i.e.*, RiskSim, RevSim, and the Risk input and output databases) and also between RiskMod and other computer models are collectively referred to as Data Management Procedures (DMPs).

Figure 1: Typical Risk Input Database shown in Microsoft Access

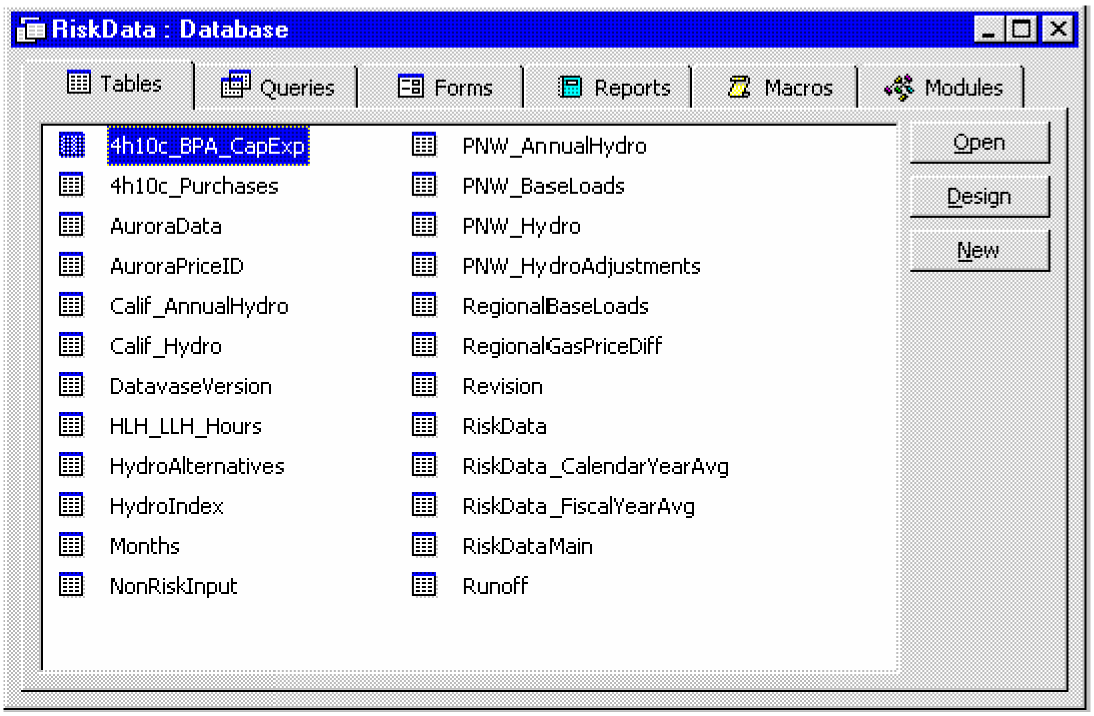
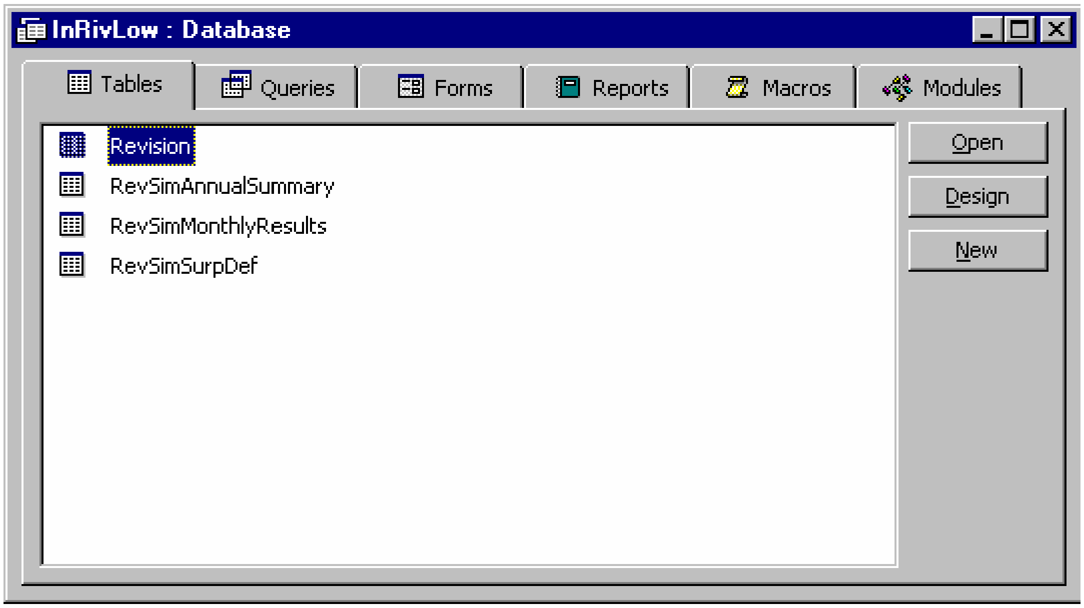


Figure 2: Typical Risk Output Database shown in Microsoft Access



1.17.1 DMPs For Deterministic Data

Deterministic data from the Load Resource Study, WP-07-FS-BPA-01, are stored in the Risk Input Database and then read from the database by automated procedures within RevSim. Non-varying revenues, expenses, monthly rates, and the factor for estimating transmission losses are manually input directly into RevSim.

1.17.2 DMPs For Hydro Generation Data

Federal hydro generation data from the Load Resource Study, WP-07-FS-BPA-01, are downloaded as flat energy and HLH energy generation for each of the 50 water years. These data are used to calculate Federal HLH hydro generation ratios for each of the 50 water years. The flat generation values and HLH ratios are loaded into the Risk Input Database using the Data Manager computer application, which is one of the Data Management Procedures previously discussed.

The adjustments to Federal hydro generation associated with refilling non-treaty storage in Canada and reconciling differences between the HydroSim study for FY 2006 and the HydroSim study for FY 2007 are not included in the Load Resource Study, WP-07-FS-BPA-01, and were received in Excel workbooks. These adjustments are added to Federal generation values as part of the process of loading hydro generation data into the Risk Input Database.

1.17.3 DMPs For Risk Data

Risk data simulated by RiskSim are loaded into the Risk Input Database using the Data Manager computer application.

1.17.4 DMPs For Interaction with AURORA

AURORA reads data from an input Access database and writes results to an output Access data base. This process is performed using scripting, which is a VB language built into AURORA that allows the user to run AURORA commands, run the commands of other applications (*i.e.,* Excel), and to build loops to repeat procedures.

AURORA uses calendar year (CY) data rather than FY data. The rate case period (FY 2007-2009) starts in October of CY 2006 and ends in September of CY 2009. In order to obtain prices that cover the rate case period, it is necessary to provide AURORA with four CY of data, *i.e.,* January 2006 through December 2009.

1.17.4.1 AURORA Fifty (50) Water Year Run

The only data varied in the 50 Water Year Run of AURORA is PNW hydro generation (*see* Hydroregulation component of the Load Resource Study, WP-07-FS-BPA-01), which is reported in Tables 1-3 of this Study Documentation. Data are supplied to AURORA as twelve monthly energy "ratios" along with a 13th value, which is the annual average hydro generation energy to capacity factor. The monthly hydro generation ratios supplied to AURORA are computed in an Excel workbook. These monthly hydro generation ratios are computed by dividing the monthly hydro generation by the annual average hydro generation (calendar year average) for each of the 50 water years. The annual energy to capacity factor is calculated by dividing the PNW annual average hydro generation for each of the 50 water years (*see* Load Resource Study, WP-07-FS-BPA-01) by the PNW hydro capacity used in AURORA (*see* Market Price Forecast Study, WP-07-FS-BPA-03).

A link between the Excel workbook and the Access input file used by AURORA allows AURORA to read the data that is in the workbook. A macro is used to alter values in the Excel workbook as each of the simulations (*i.e.*, water years) is processed. The whole process is combined in a script file that runs AURORA, writes the output from AURORA to an Excel workbook, revises the input data used by AURORA for the next simulation, and then runs AURORA again. The script file contains a loop that repeats this procedure 50 times (once for each water year). Upon completion of this process, AURORA produces an Excel workbook containing monthly HLH and LLH spot market electricity prices for each of the 50 water years for three years, which the Data Manager loads into the Risk Input Database.

1.17.4.2 AURORA Risk Simulation Run

For the Risk Simulation Run of AURORA, variation in PNW and California loads and natural gas prices are considered along with variability in PNW and California hydro generation. *See* Market Price Forecast Study, WP-07-FS-BPA-03. AURORA is used to estimate HLH and LLH spot market electricity prices for 3000 simulations. Considering the large number of simulated values produced in a Risk Simulation Run, the volume of data could not be reasonably loaded into a single workbook, as is done for the 50 Water Year Run. BPA created an Excel workbook which contains data for a single simulation that is refreshed with data from the Risk Input Database for each simulation. This workbook is called "RiskIn." The RiskIn workbook contains both VBA procedures and data for hydro generation, loads, and natural gas prices. The VBA procedures are designed so that they can be called by the VBA scripting within AURORA.

The modeling process for the Risk Simulation Run of AURORA is similar to that used for a 50 Water Year Run of AURORA. Scripting is used to call the VBA procedures in RiskIn, run AURORA, and write HLH and LLH spot market electricity prices to an Excel Workbook. The script file contains a loop that runs this procedure for 3000 simulations. Upon completion of the 3000 simulations, an Excel workbook receives HLH and LLH spot market electricity prices estimated by AURORA. These HLH and LLH spot market electricity prices are loaded into the Risk Input Database by the Data Manager.

1.17.5 DMPs For RevSim

The net revenue simulations in RevSim combine variable data from the Risk Input Database with deterministic data that are directly input. Code within RevSim reads the data from the Risk Input Database, activates the calculation within RevSim, and writes results to the Risk Output Database. The computer code contained in these procedures is comprised of a combination of Microsoft Visual Basic and Structured Query Language.

The procedures in RevSim perform the study one iteration at a time, *i.e.*, 50 iterations for the 50 Water Year Run and 3000 iterations for the Risk Simulation Run. For each iteration, data are read which reflect the variability in PF loads, the output of CGS, variable wind generation, transmission expenses, DSI benefits, Federal hydro generation, Federal hydro generation HLH ratios, 4(h)(10)(c) power purchase amounts, and the HLH and LLH spot market electricity prices from the AURORA Model. Using these data, surplus energy sales and purchase amounts (aMW), surplus energy revenues and power purchase expenses, 4(h)(10)(C) credits, and PBL net revenues are calculated and written to the Risk Output Database. The Risk Output Database contains both monthly and annual summary data for many of the quantities calculated.

1.17.6 DMPs Between RiskMod, RAM2007, and ToolKit

Data transfers between these models are generally accomplished through Excel files or as manual data entry. Surplus energy revenues, power purchase expenses, and 4(h)(10)(C) credits are provided to RAM2007 as an Excel workbook generated from the Risk Output Database. *See* Wholesale Power Rate Development Study, WP-07-FS-BPA-05, regarding RAM2007. Rates from RAM2007 are manually entered into RevSim from a RAM2007 summary file. Annual net revenues are provided from RiskMod to ToolKit as an Excel workbook generated from the Risk Output Database. There is no automated procedure for communicating the value of PNRR from ToolKit to RAM2007.

1.18 Interaction Between RiskMod, RAM2007, and ToolKit to Calculate Rates

RiskMod is used in an iterative process with the RAM2007 and ToolKit Model to calculate rates, PNRR, and to design other financial tools as needed (*i.e.*, surcharges or credits) to assure BPA will achieve its financial objectives for the rate period. The initial step in the process is to estimate the annual average surplus energy revenues, power purchase expenses, and 4(h)(10)(C) credits in the 50 Water Year Run of RiskMod and input these data into RAM2007. With this information, RAM2007 calculates an initial set of rates for the rate period which is fed back to

RevSim. RevSim is run and produces 3000 net revenues for each FY in the rate period. These results are input into ToolKit to calculate the amount of PNRR and other financial tools needed to achieve BPA's financial objectives.

1.19 Results

A statistical summary of the annual net revenues for FY 2007-2009 estimated by RiskMod using Proposed Rates with $11 million in PNRR is reported in Table 42. Net revenues over the rate period averaged $69.0 million/year. These values only represent the operational net revenues calculated in RiskMod and do not reflect additional net revenue adjustments in the ToolKit Model, such as IOU benefits, the NORM output, interest earned on cash reserves, Cost Recovery Adjustment Clause (CRAC), and Dividend Distribution Clause (DDC).

Table 42: RiskMod Net Revenue Statistics (With PNRR of $11 million)

	FY 2007	FY 2008	FY 2009
Average	117,001	115,556	-25,444
Median	110,492	102,176	-41,982
Standard Deviation	327,010	345,335	370,843
1%	-498,496	-531,371	-876,666
2.50%	-458,161	-458,634	-661,287
5%	-412,332	-407,581	-545,658
10%	-325,920	-328,067	-475,935
15%	-224,485	-248,626	-392,622
20%	-156,871	-177,070	-316,482
25%	-103,933	-117,380	-256,078
30%	-50,914	-69,375	-209,052
35%	-4,864	-22,673	-164,600
40%	33,708	22,958	-123,721
45%	69,986	58,094	-78,976
50%	110,492	102,176	-41,982
55%	145,655	140,136	-4,976
60%	181,910	179,793	36,472
65%	225,268	218,570	81,999
70%	270,580	262,515	132,067
75%	311,678	320,167	180,960
80%	370,002	381,205	240,813
85%	437,112	457,223	321,665
90%	536,058	565,548	429,283
95%	682,241	709,790	594,130
97.50%	817,900	862,209	789,089
99%	963,499	1,048,700	1,065,763

2. NON-OPERATING RISK MODEL (NORM)

2.1 Methodology

NORM is written in Excel 2003 with the @RISK add-in package. Each of the risks is modeled using probability functions available in @RISK. Some of these functions are *discrete* while others are *continuous*. Discrete functions take two arrays as inputs, one listing the possible values the uncertain variable can take, the other the respective probabilities of those values. In other words, for an uncertainty having to do with expense levels, the input consists of a series of dollar amounts by which the expense level in the revenue requirement could vary, and the probability, as a percentage, that each amount of variation could occur.

For example, when rolling dice, the operation of a single die would be described as follows (fractions rounded off):

<die> =RiskDiscrete(A1:F1,A2:F2)

with the values 1, 2, 3, 4, 5, and 6 in cells A1 to F1, and identical probabilities of 17 percent in each of the cells A2 to F2. When @RISK is run, each game will have a value for the function drawn randomly from the set of six possible values according to those probabilities. If 1,000 games are run, there should be about 167 games (1,000 / 6) where the value is 1, and about the same number with each of the other values. The actual number may vary slightly, but probably not by much. The larger the number of games, the more closely the actual count is likely to approach the expected number, which equals the probability times the number of games.

Since NORM is used to represent the possibilities that actual values for various factors will be different from the deterministic value used as starting points in the rate case calculations, this example will illustrate NORM better with one change. Assume that the expected value of the roll of the die, 3.5, has been used in the revenue requirement. Then the actual NORM distribution would comprise the six possible values shown above, while the output from NORM used in the ToolKit would comprise the six deviations from the expected value, or 2.5, 1.5, .5, -.5, -1.5, and -2.5.

Each risk modeled in NORM is described by a *model* and enough data to *specify* the model. A model could be as simple as the discrete risk example above of a single die, or it could be a complicated formula with many random factors in it, each of which uses a different probability distribution. A simple model's specification might require only a few numbers; a complex model might require specifying several distributions (identifying the distributions and giving the parameters) as well as the functional relationships among the various distributions.

Some distributions in NORM are continuous probability distributions, such as the Normal probability distribution. For these, the *parameters* of the distribution of possible deviations are entered (*e.g.*, mean and standard deviation for the Normal distribution). For example, the Consumer Price Index (CPI) is a factor in the calculation of payments under the Colville/ Spokane Settlement. The future values of the CPI cannot be known now, but are modeled in

NORM. For calculating the FY 2007 Colville/Spokane Settlement payments, the annual change in the CPI is modeled as a Normal distribution with a mean of 3.0 percent and a standard deviation of 0.1 percent. In each game, @Risk produces a number for the annual change in CPI in such a way that the set of results from all of the games approximates a Normal distribution, that is, @Risk "draws" a number from a Normal distribution with mean of 3.0 percent and standard deviation of 0.1 percent. This set of results will approximate a Normal distribution more and more closely as the number of games increases.

Deviations are expressed in annual average amounts. Negative amounts indicate a decrease in net revenues, *i.e.*, either a decrease in revenue or an increase in expense. Positive amounts indicate an increase in net revenues, *i.e.*, either an increase in revenue or a decrease in expense. BPA developed the distributions of the risks (possible values and associated probabilities). For instance, the probabilities that a line item will deviate from the costs included in the revenue requirement could be distributed as follows:

- 40 percent probability that costs will deviate $0 (in other words, a 40 percent probability that they will be the same as the level projected in the revenue requirement

- 20 percent probability that costs will be $10 M higher (shown as -$10 M in NORM output)

- 20 percent probability that costs will be $10 M lower (shown as $10 M in NORM output)

- 10 percent probability that costs will be $25 M higher

- 10 percent probability that costs will be $25 M lower

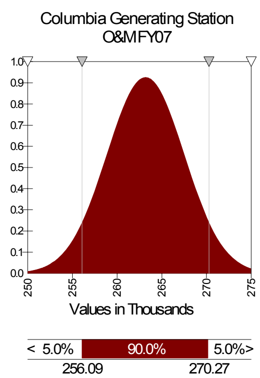
NORM models the risks of the generation function, as well as the risks of the Corporate costs which are the responsibility of the generation function. Transmission function risks are not included in the analysis. In general, NORM includes the generation function expense uncertainty due to the rates yet to be developed for transmission services. The impacts of transmission function revenue uncertainty on BPA's financial picture are excluded. NORM does model some changes in revenue, and some changes in cash. Many of the expense risks are included in the Slice true-up, so NORM models the change in the Slice true-up that would be implied by a change in these expense items, which could result in an increase in revenue if the Slice true-up is positive for BPA. A NORM deviation of -$10M subject to the Slice true-up is handled in this way. In year N, the increase of $10M in expense is noted. $2.26M of this will be covered by the Slice true-up booked in that same year, so NORM notes an increase in net revenue of $2.26M, partially offsetting that expense increase. In that same year N, cash is decreased by the full $10M, but the payment by the Slice customers (or a reduction in payment by BPA to the Slice customers) of $2.26M in the year following year N is also noted. (*See* Revenue Requirement Study, WP-02-FS-BPA-02).

The distributions for each expense and revenue item modeled in NORM are shown in Section 2.2. The values in the probability distribution graphs in Section 2.2 are in millions of dollars and the statistical data accompanying those graphs are in thousands of dollars. (The deviations are calculated by comparing the values in the distributions to the point values assumed elsewhere in the rate case (*e.g.*, the revenue requirement).)

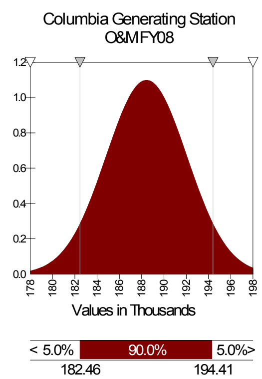
2.2 NORM Distributions

2.2.1 CGS O&M Distributions

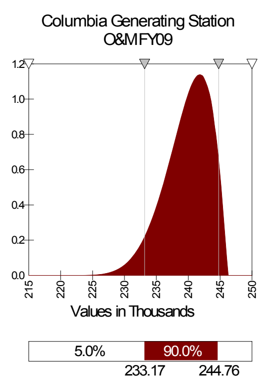
Table 1: CGS O&M Distributions



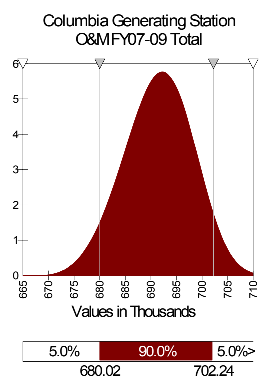
Minimum	$	252,369
5th Percentile	$	256,053
Median	$	263,233
95th Percentile	$	270,220
Maximum	$	274,169
Std. Dev	$	4,311
Final Proposal	$	263,669



Minimum	$	179,188
5th Percentile	$	182,526
Median	$	188,388
95th Percentile	$	194,413
Maximum	$	197,657
Std. Dev	$	3,632
Final Proposal	$	188,688



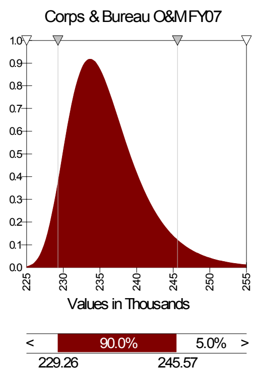
Minimum	$	225,333
5th Percentile	$	233,002
Median	$	240,511
95th Percentile	$	244,667
Maximum	$	246,233
Std. Dev	$	3,627
Final Proposal	$	242,902



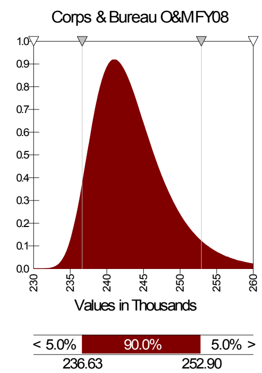
Minimum	$	666,967
5th Percentile	$	680,257
Median	$	691,551
95th Percentile	$	702,204
Maximum	$	710,449
Std. Dev	$	6,702
Final Proposal	$	695,259

2.2.2 COE and Bureau O&M Distributions

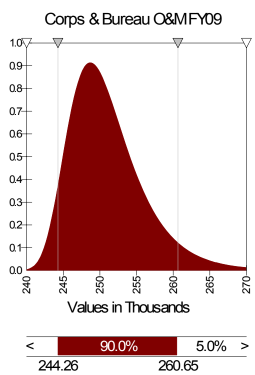
Table 2: COE and Bureau O&M Distributions



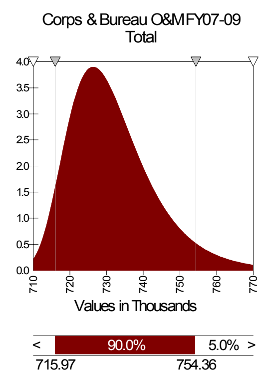
Minimum	$	231,187
5th Percentile	$	231,575
Median	$	232,629
95th Percentile	$	250,477
Maximum	$	308,900
Std. Dev	$	7,958
Final Proposal	$	233,173



Minimum	$	238,518
5th Percentile	$	238,906
Median	$	239,973
95th Percentile	$	257,626
Maximum	$	299,487
Std. Dev	$	7,645
Final Proposal	$	240,502



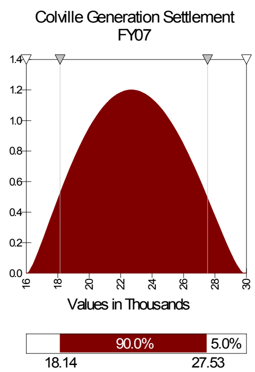
Minimum	$	246,188
5th Percentile	$	246,599
Median	$	247,628
95th Percentile	$	265,564
Maximum	$	307,036
Std. Dev	$	7,769
Final Proposal	$	248,173



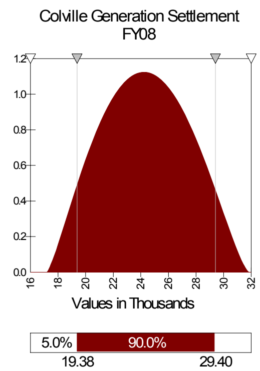
Minimum	$	716,741
5th Percentile	$	718,355
Median	$	731,713
95th Percentile	$	757,181
Maximum	$	828,733
Std. Dev	$	13,558
Final Proposal	$	721,848

2.2.3 Colville Settlement Payments Distributions

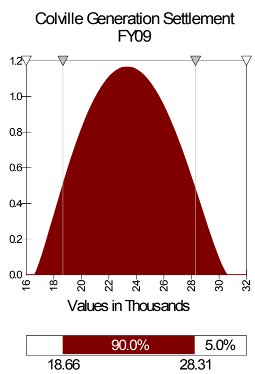
Table 3: Colville Settlement Payments Distributions



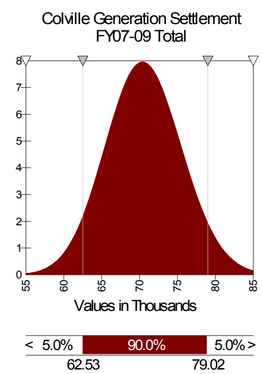
Minimum	$	16,500
5th Percentile	$	18,068
Median	$	22,778
95th Percentile	$	27,569
Maximum	$	29,336
Std. Dev	$	2,840
Final Proposal	$	16,968



Minimum	$	17,624
5th Percentile	$	19,299
Median	$	24,334
95th Percentile	$	29,454
Maximum	$	31,331
Std. Dev	$	3,034
Final Proposal	$	17,354



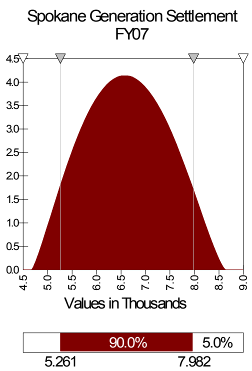
Minimum	$	16,979
5th Percentile	$	18,581
Median	$	23,428
95th Percentile	$	28,359
Maximum	$	30,182
Std. Dev	$	2,921
Final Proposal	$	17,749



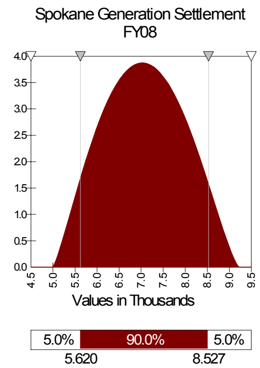
Minimum	$	53,528
5th Percentile	$	62,493
Median	$	70,615
95th Percentile	$	78,942
Maximum	$	88,158
Std. Dev	$	5,013
Final Proposal	$	52,071

2.2.4 Spokane Settlement Payment Distributions

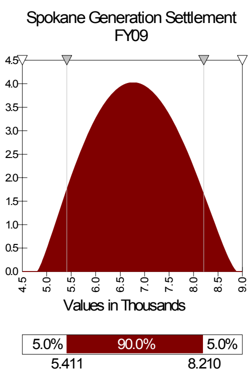
Table 4: Spokane Settlement Payment Distributions



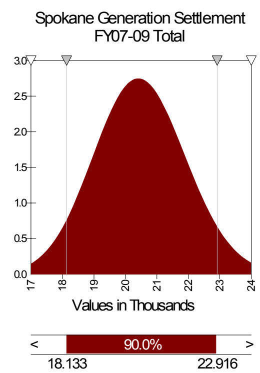
Minimum	$	4,785
5th Percentile	$	5,240
Median	$	6,606
95th Percentile	$	7,995
Maximum	$	8,507
Std. Dev	$	824
Final Proposal	$	-



Minimum	$	5,111
5th Percentile	$	5,597
Median	$	7,057
95th Percentile	$	8,542
Maximum	$	9,086
Std. Dev	$	880
Final Proposal	$	-



Minimum	$	4,924
5th Percentile	$	5,389
Median	$	6,794
95th Percentile	$	8,224
Maximum	$	8,753
Std. Dev	$	847
Final Proposal	$	-



Minimum	$	15,523
5th Percentile	$	18,123
Median	$	20,478
95th Percentile	$	22,893
Maximum	$	25,566
Std. Dev	$	1,454
Final Proposal	$	-

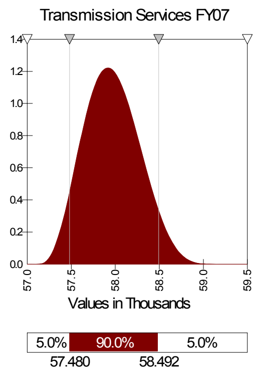
2.2.5 Public Residential Exchange Cost Distributions

Table 5: Public Res. Exch. Cost Distributions

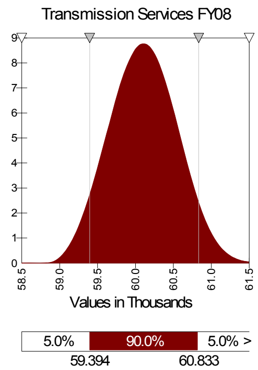
Probability	2007	2008	2009
	$000		
50%	$ 7,000	$ 7,000	$ 7,000
25%	$ 47,000	$ 47,000	$ 47,000
20%	$ 67,000	$ 67,000	$ 67,000
5%	$ 137,000	$ 137,000	$ 137,000

2.2.6 Transmission Services Expense Distributions

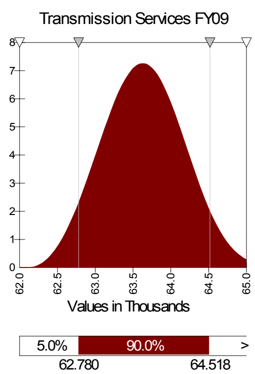
Table 6: Transmission Services Expense Distributions



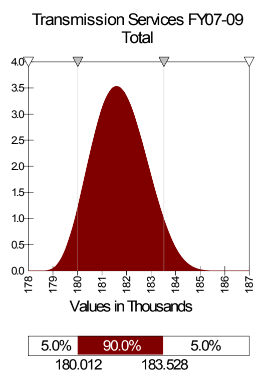
Minimum	$	57,200
5th Percentile	$	57,479
Median	$	57,954
95th Percentile	$	58,470
Maximum	$	59,001
Std. Dev	$	307
Final Proposal	$	56,962



Minimum	$	58,876
5th Percentile	$	59,419
Median	$	60,104
95th Percentile	$	60,854
Maximum	$	61,490
Std. Dev	$	433
Final Proposal	$	56,962



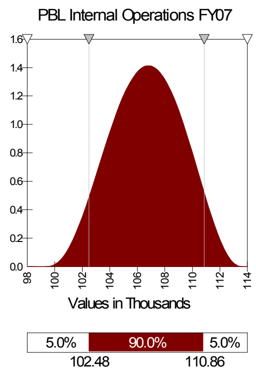
Minimum	$	62,124
5th Percentile	$	62,791
Median	$	63,614
95th Percentile	$	64,510
Maximum	$	65,472
Std. Dev	$	523
Final Proposal	$	59,662



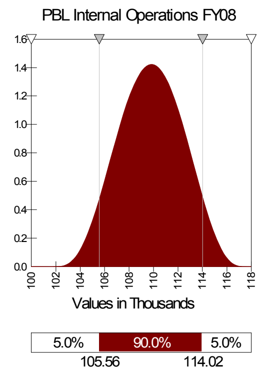
Minimum	$	178,951
5th Percentile	$	180,024
Median	$	181,692
95th Percentile	$	183,523
Maximum	$	185,130
Std. Dev	$	1,066
Final Proposal	$	173,586

2.2.7 Internal Operations Distributions

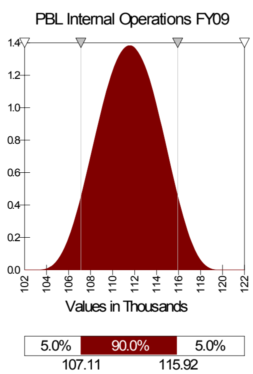
Table 7: Internal Operations Distributions



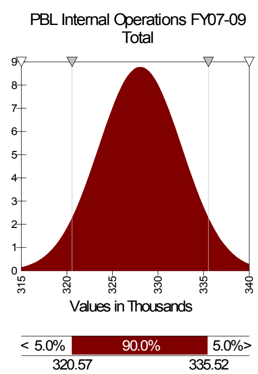
Minimum	$	99,895
5th Percentile	$	102,550
Median	$	106,712
95th Percentile	$	110,863
Maximum	$	113,140
Std. Dev	$	2,544
Final Proposal	$	106,747



Minimum	$	102,466
5th Percentile	$	105,524
Median	$	109,821
95th Percentile	$	114,005
Maximum	$	116,789
Std. Dev	$	2,571
Final Proposal	$	109,842



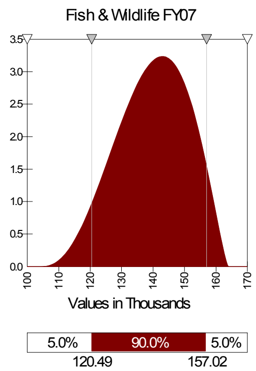
Minimum	$	104,143
5th Percentile	$	107,118
Median	$	111,569
95th Percentile	$	115,936
Maximum	$	119,402
Std. Dev	$	2,672
Final Proposal	$	111,566



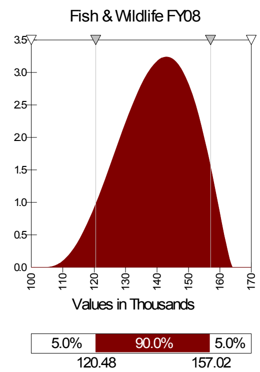
Minimum	$	313,682
5th Percentile	$	320,624
Median	$	328,049
95th Percentile	$	335,585
Maximum	$	343,137
Std. Dev	$	4,546
Final Proposal	$	328,155

2.2.8 Fish and Wildlife Direct Program Expense Distributions

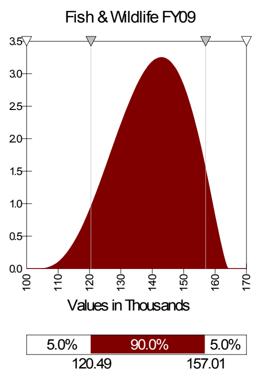
Table 8: F&W Direct Program Expense Distributions



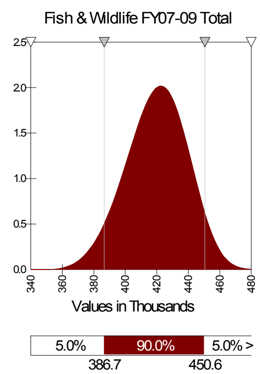
Minimum	$	107,056
5th Percentile	$	120,458
Median	$	140,672
95th Percentile	$	157,007
Maximum	$	163,722
Std. Dev	$	11,146
Final Proposal	$	143,000



Minimum	$	106,934
5th Percentile	$	120,467
Median	$	140,671
95th Percentile	$	156,995
Maximum	$	163,505
Std. Dev	$	11,146
Final Proposal	$	143,000



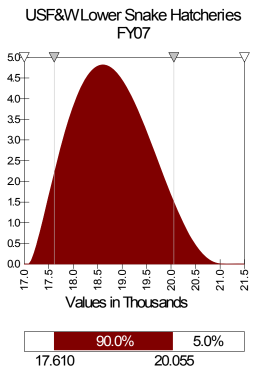
Minimum	$	107,054
5th Percentile	$	120,467
Median	$	140,675
95th Percentile	$	156,992
Maximum	$	163,243
Std. Dev	$	11,145
Final Proposal	$	143,000



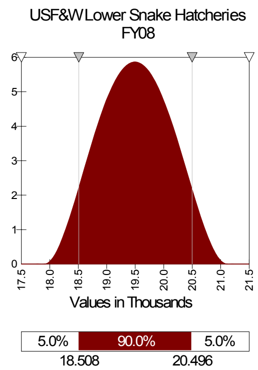
Minimum	$	358,521
5th Percentile	$	387,545
Median	$	420,459
95th Percentile	$	449,595
Maximum	$	475,742
Std. Dev	$	18,847
Final Proposal	$	429,000

2.2.9 Lower Snake River Hatcheries Expense Distributions

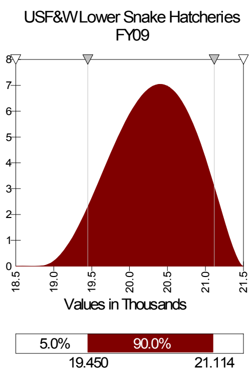
Table 9: Lower Snake River Hatcheries Expense Distributions



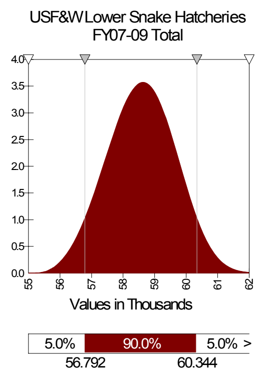
Minimum	$	17,119
5th Percentile	$	17,610
Median	$	18,727
95th Percentile	$	20,057
Maximum	$	20,907
Std. Dev	$	745
Final Proposal	$	18,600



Minimum	$	17,996
5th Percentile	$	18,505
Median	$	19,500
95th Percentile	$	20,494
Maximum	$	21,067
Std. Dev	$	605
Final Proposal	$	19,500



Minimum	$	18,878
5th Percentile	$	19,451
Median	$	20,336
95th Percentile	$	21,114
Maximum	$	21,453
Std. Dev	$	506
Final Proposal	$	20,400



Minimum	$	55,373
5th Percentile	$	56,840
Median	$	58,588
95th Percentile	$	60,355
Maximum	$	62,489
Std. Dev	$	1,075
Final Proposal	$	58,500

Table 10: Borrowing and Inflation Rates

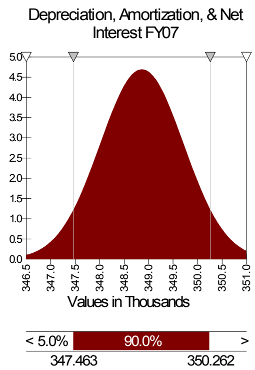
2007	2007	2007	2007	2007	2007
5-Year Treas	15-Year Muni Tax Exempt	30-Year Approp	30-Year Treas	CPI Inflate	15-Year Muni Taxable
4.82	4.34	4.90	5.83	0.53	5.84
4.91	4.37	4.93	5.86	0.80	5.88
4.99	4.40	4.97	5.90	1.07	5.92
5.04	4.42	5.00	5.92	1.26	5.94
5.09	4.44	5.01	5.94	1.40	5.97
5.13	4.45	5.03	5.96	1.53	5.98
5.16	4.47	5.05	5.98	1.64	6.00
5.19	4.48	5.06	5.99	1.74	6.02
5.22	4.49	5.07	6.00	1.84	6.03
5.25	4.50	5.09	6.02	1.94	6.05
5.28	4.51	5.10	6.03	2.03	6.06
5.29	4.53	5.12	6.05	2.17	6.09
5.30	4.56	5.14	6.07	2.32	6.13
5.31	4.58	5.17	6.10	2.47	6.16
5.32	4.61	5.19	6.12	2.63	6.20
5.33	4.64	5.22	6.15	2.80	6.24
5.34	4.67	5.25	6.18	2.99	6.28
5.35	4.71	5.28	6.21	3.22	6.33
5.37	4.75	5.33	6.26	3.50	6.39
5.40	4.82	5.39	6.32	3.91	6.49
5.42	4.89	5.45	6.38	4.33	6.58

2008	2008	2008	2008	2008	2008
5-Year Treas	14-Year Muni Tax Exempt	30-Year Approp	30-Year Treas	CPI Inflate	14-Year Muni Taxable
4.72	4.19	4.81	5.75	0.78	5.64
4.87	4.28	4.92	5.86	1.00	5.78
5.01	4.38	5.03	5.97	1.22	5.91
5.11	4.45	5.11	6.05	1.37	6.00
5.19	4.50	5.17	6.10	1.48	6.07
5.26	4.54	5.22	6.16	1.58	6.13
5.32	4.58	5.26	6.20	1.67	6.18
5.37	4.62	5.30	6.24	1.76	6.23
5.43	4.65	5.34	6.28	1.84	6.28
5.48	4.69	5.38	6.32	1.91	6.32
5.53	4.72	5.42	6.36	1.99	6.37
5.55	4.73	5.43	6.37	2.16	6.39
5.57	4.74	5.44	6.38	2.32	6.40
5.60	4.76	5.45	6.39	2.50	6.42
5.62	4.77	5.46	6.40	2.68	6.44
5.65	4.79	5.47	6.41	2.88	6.46
5.68	4.80	5.48	6.42	3.10	6.48
5.71	4.82	5.49	6.43	3.36	6.51
5.75	4.84	5.51	6.45	3.68	6.54
5.82	4.88	5.54	6.48	4.16	6.59
5.88	4.91	5.56	6.50	4.64	6.64

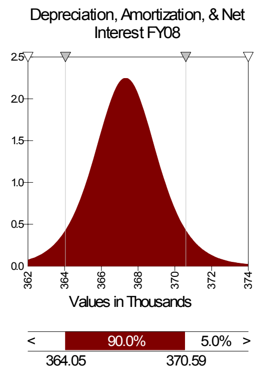
2009	2009	2009	2009	2009	2009
5-Year Treas	13-Year Muni Tax Exempt	30-Year Approp	30-Year Treas	CPI Inflate	13-Year Muni Taxable
4.68	4.04	4.78	5.73	0.78	5.46
4.88	4.21	4.95	5.91	1.00	5.68
5.08	4.37	5.12	6.08	1.23	5.91
5.22	4.48	5.24	6.20	1.38	6.06
5.33	4.56	5.33	6.29	1.50	6.17
5.42	4.64	5.41	6.37	1.60	6.28
5.51	4.71	5.48	6.44	1.70	6.37
5.58	4.77	5.55	6.51	1.78	6.45
5.66	4.83	5.61	6.57	1.86	6.53
5.73	4.88	5.67	6.63	1.94	6.61
5.80	4.94	5.73	6.69	2.02	6.69
5.85	4.95	5.74	6.70	2.21	6.71
5.91	4.97	5.76	6.72	2.40	6.73
5.96	4.98	5.77	6.73	2.59	6.74
6.02	4.99	5.79	6.75	2.80	6.76
6.08	5.01	5.80	6.76	3.03	6.78
6.15	5.03	5.82	6.78	3.27	6.81
6.24	5.05	5.84	6.81	3.57	6.84
6.34	5.07	5.87	6.83	3.93	6.87
6.49	5.11	5.91	6.87	4.47	6.92
6.64	5.15	5.95	6.91	5.01	6.97

2.2.11 Federal Depreciation, Amortization and Net Interest Distributions

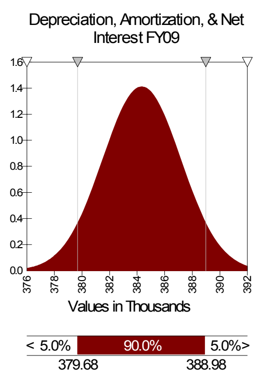
Table 11: Federal Depreciation, Amortization and Net Interest Distributions



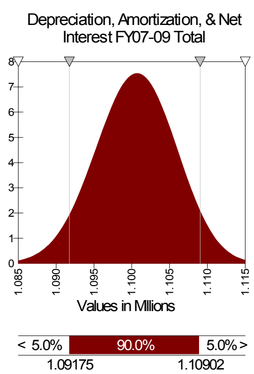
Minimum	$	346,099
5th Percentile	$	347,405
Median	$	348,878
95th Percentile	$	350,211
Maximum	$	351,270
Std. Dev	$	851
Final Proposal	$	348,916



Minimum	$	360,543
5th Percentile	$	363,979
Median	$	367,341
95th Percentile	$	370,381
Maximum	$	373,546
Std. Dev	$	1,937
Final Proposal	$	368,011



Minimum	$	373,965
5th Percentile	$	379,532
Median	$	384,373
95th Percentile	$	388,909
Maximum	$	393,167
Std. Dev	$	2,827
Final Proposal	$	385,991



Minimum	$	1,081,341
5th Percentile	$	1,091,702
Median	$	1,100,619
95th Percentile	$	1,108,939
Maximum	$	1,117,419
Std. Dev	$	5,248
Final Proposal	$	1,102,918

2.2.12 Annual Grand Coulee Generation

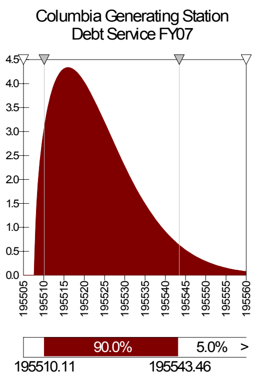
Table 12: Annual Grand Coulee Generation

Avg. MW	GWh
1,931	16,916
1,947	17,053
2,025	17,743
2,380	20,845
2,766	24,228
3,267	28,615
2,453	21,486
2,312	20,256
1,944	17,028
2,456	21,515
2,189	19,174
2,317	20,300
1,998	17,498
2,317	20,296
2,512	22,007
1,836	16,084
1,975	17,297
2,441	21,387
2,646	23,177
2,864	25,087
2,436	21,337
2,594	22,726
2,892	25,335
2,697	23,623
2,417	21,174
2,755	24,132
2,803	24,553
3,096	27,119
2,600	22,775
2,432	21,306
2,797	24,501
2,991	26,205
2,787	24,413
2,416	21,165
2,496	21,867
2,556	22,392
2,812	24,637
2,578	22,579
2,715	23,781
2,551	22,349
3,029	26,534
2,346	20,553
2,676	23,443
3,091	27,078
2,245	19,663
3,097	27,129
2,655	23,257
2,855	25,012
2,359	20,661
2,266	19,851

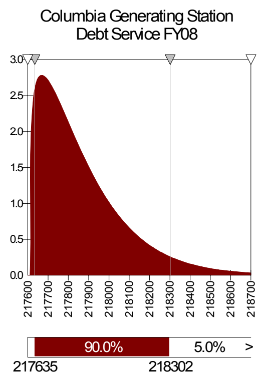
	GWh
Mean	22,183
Std. Dev.	3,003
Min	16,084
Max	28,615

2.2.13 CGS Debt Service Distributions

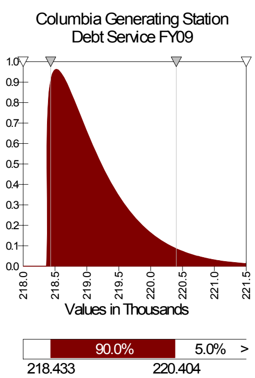
Table 13: CGS Debt Service Distributions



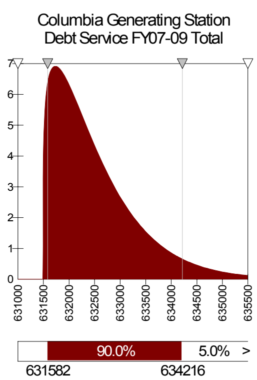
Minimum	$	195,508
5th Percentile	$	195,511
Median	$	195,520
95th Percentile	$	195,542
Maximum	$	195,547
Std. Dev	$	10
Final Proposal	$	195,520



Minimum	$	217,615
5th Percentile	$	217,628
Median	$	217,781
95th Percentile	$	218,123
Maximum	$	218,162
Std. Dev	$	189
Final Proposal	$	217,686



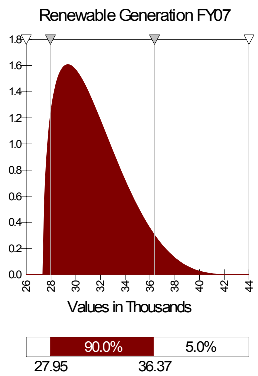
Minimum	$	218,377
5th Percentile	$	218,416
Median	$	218,760
95th Percentile	$	219,829
Maximum	$	219,905
Std. Dev	$	558
Final Proposal	$	218,597



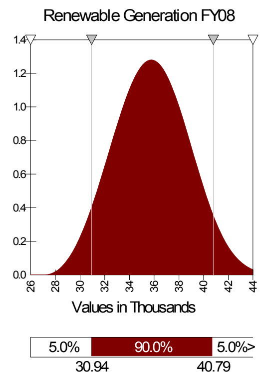
Minimum	$	631,500
5th Percentile	$	631,555
Median	$	632,088
95th Percentile	$	633,489
Maximum	$	633,614
Std. Dev	$	749
Final Proposal	$	631,803

2.2.14 Renewable Generation Distributions

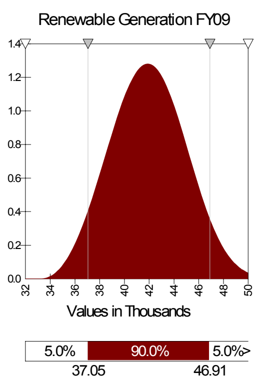
Table 14: Renewable Generation Distributions



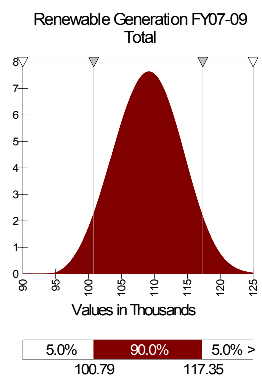
Minimum	$	27,376
5th Percentile	$	27,949
Median	$	30,905
95th Percentile	$	36,369
Maximum	$	41,244
Std. Dev	$	2,619
Final Proposal	$	31,368



Minimum	$	28,301
5th Percentile	$	30,827
Median	$	35,800
95th Percentile	$	40,765
Maximum	$	43,283
Std. Dev	$	3,024
Final Proposal	$	35,801



Minimum	$	34,326
5th Percentile	$	36,938
Median	$	41,915
95th Percentile	$	46,884
Maximum	$	49,475
Std. Dev	$	3,024
Final Proposal	$	41,917



Minimum	$	93,803
5th Percentile	$	101,033
Median	$	108,922
95th Percentile	$	117,477
Maximum	$	126,183
Std. Dev	$	4,977
Final Proposal	$	109,086

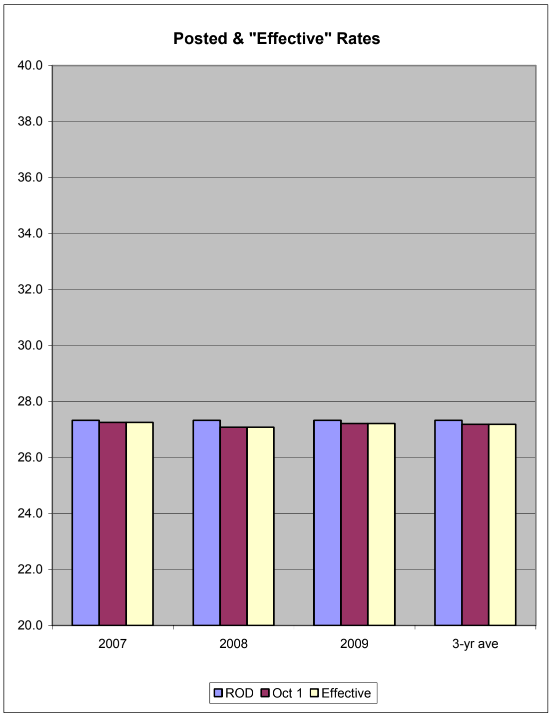
3. TOOLKIT OUTPUT

3.1 Table 1: ToolKit Main

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	ToolKit v. 2.38, (6-26-2006)					Study title:	11th iteration, Amortization Shift in ATC, $125M Cust. Liq., Final Studies | PBL reserves											
2	Time of run: 8:53:54 on 7-5-06				3	-yr TPP =	92.67%	Run Type	PBL-only run									
3	Inputs	PBL data:	RM_Final-Studies-6_06=26-Jun-06_07-9=1-July-06.xls															
4		NORM dat	NORM_Final-Proposal_No-Net_Bill_Penultimate-Data_30-Jun-06.xls															
5	Files =>	TBL data:																
6	Start in	Stop in	Run Type	CRAC	PBL	TBL	PBL Strt.	Add'l	Deferral	☐	Sec. Rev. Rebate Description							
7	TK Year	TK Year	PBL ◉	Lim/Total	LiqRes	LiqRes	ANR	LiqRes 7-9	Logic	n / a								
8	3	6	BPA ○	20,000	88.67403	20	-369.18	0	Hybrid									
9	Start TPP	"Small"	No. of	Starting	PBL Strt	TBL Strt	Debug	Reserves	AutoPrint	AutoPrint	Flat PNRR	Enable	CRAC	CRAC				
10	in TK Yr	Def. Size	Iterations	Iteration	Rsrv Bal	Rsrv Bal	Level	Graph	Res Grph	This Page	Rate Imp.?	PNRR?	Fixed?	Stats On?				
11	4	$200	3,000	1	374.8	180	0	☑	☐	☐	☑	☑	☐	☐				
12	ToolKit	Fiscal	Probabi-	Treasury	Amort	Interest	PBL Int.	TBL Int.	Other	TBL Rsrvs	Cash Lag	PBL Cash	TBL Cash					
13	Year	Year	listic?	Int. Rate	Sched	Sched	Cr. Sched	Cr. Sched	Cash Adj	Available	for PNRR	Tmg Adj	Tmg Adj					
15	2	2005	FALSE	4.88%	271.3	247.4	29.96	11.08		0.0		11.5	4.6					
16	3	2006	TRUE	4.88%	296.5	250.4	35.7	11.9		0.0		12.2	5.8					
17	4	2007	TRUE	4.88%	202.3	270.4	54.0			55.0	-1.2	11.9						
18	5	2008	TRUE	4.88%	175.4	280.5	53.9			-57.7	0.0	7.1						
19	6	2009	TRUE	4.88%	191.7	291.7	54.9			0.0	0.0	7.4						
20	ToolKit	Fiscal	Div. Dist.			CRAC			PNRR			TBL Fed.	PBL Fed.	Other NR	Delta			
21	Year	Year	Threshold	Lim/Year	Threshold	Lim/Year	Rev Basis	Shape	Risk Mod	Calc'd in TK	Sum	Int. Red.	Int. Red.	& Csh Adj	Int. Cred.			
23	2	2005	401	5,000	1	0		0.0						6.6				
24	3	2006	401	5,000	1	0		0.0										
25	4	2007	148.8	1,208	-151.2	300	1,332.6	1.00	11	0	11			-0.3				
26	5	2008	247.1	1,208	-52.9	300	1,351.6	1.00	11	0	11			-0.8				
27	6	2009	348.2	1,222	48.2	300	1,362.7	1.00	11	0	11			-1.3				
28	Outputs																	
29	ToolKit	Fiscal	No. of	"Small"	1-year	Cumul.	Cumul.	Ave. Def.	Ave. Def.	Ave 1st	Ave. End.	Ave. End.	PNRR	PBL		Approx PF rates		
30	Year	Year	Deferrals	Deferrals	Probab.	Deferrals	Probab.	per Year	per Def.	Def./Def.	Reserves	PBL ANR	Added	Strt Bal		(average rates, not block)		
31														374.8		Base	After	After
32																	PNRR	Var.Rates
33	3	2006	0	-	100.0%	n / a	n / a	0.0	n / a	n / a	895	-6	-	FCCF				
34	4	2007	3	3	99.9%	3	99.9%	0.0	48.3	48.3	935	77.17	-	Strt Bal		27.33	27.33	27.26
35	5	2008	93	73	96.9%	95	96.8%	4.0	128.8	130.1	854	148.05	-	n / a		27.33	27.33	27.08
36	6	2009	176	99	94.1%	220	92.7%	15.8	270.0	214.6	823	89	-			27.33	27.33	27.21
37	3	-yr Total	272	175	n / a	n / a	n / a	19.9	n / a	n / a	n / a	n / a	-	5-yr sum>		n / a	n / a	n / a
38	3	-yr Ave.	91	58	n / a	n / a	n / a	6.6	219.3	177.0	n / a	n / a	-	3-yr sum>		27.3	27.3	27.18
39	ToolKit	Fiscal	Ave. DDC	Ave DDC	PF share	IOU Share	No. of	Ave DDC	Ave. CRAC	Ave CRAC	PF share	IOU Share	No. of	Ave CRAC	Ann.Lim.	Total Lim.	CRAC	
40	Year	Year	per each	per Year	of DDC	of DDC	DDCs	Rate	per each	per Year	of CRAC	of CRAC	CRACs	Rate	Reached	Reached	Freqncy	
42				0			0							0%			0%	
43	3	2006		0			0	0%		0			0	0%	0	0	0%	
44	4	2007	69	5	5	0	216	0.4%	37	2	2	0	129	0.1%	0	0	4%	
45	5	2008	263	78	78	0	883	5.7%	187	69	66	4	1115	4.9%	344	0	37%	
46	6	2009	284	83	83	0	876	6.1%	204	85	77	8	1249	5.7%	499	0	42%	
47	3	-yr Total	n / a	165.5	165.4	0	1975	n / a	n / a	156	145	11	2493	n / a	843	0	n / a	
48	3	-yr Ave.	251	55	55	0	658	4.1%	188	52	48	4	831	3.6%	281	n / a	28%	
49	ToolKit	Fiscal	NORM	PBL	TBL	A-T-C	Ave. Reb.	Ave Reb.	PF share	IOU Share	No. of	Ave. Re-	PBL Int	TBL Int	IOU Benefits After each calculation			
50	Year	Year	Inputs	Inputs	Inputs	Totals	per each	per Year	of Rebate	of Rebate	Rebates	bate Rate	Credit	Credit	Base	PNRR	Mkt Upd	Var.Rates
52			0												0			
53	3	2006	0	358	0	157						0%	33	0.0	0			
54	4	2007	-31	117	0	-97			0	0		0.0%	43	0.0	323	323	323	323
55	5	2008	-34	116	0	-100			0	0		0.0%	38	0.0	323	323	320	316
56	6	2009	-31	-25	0	7			0	0		0.0%	36	0.0	323	323	311	301
57	3 -yr Total		-95	207	0	-190						n / a	117	0.0	969	969	954	940
58	3 -yr Ave.		-32	69	0	-63							39	0.0	323	323	318	313

3.2 Table 2: Graphs

11th iteration, Amortization Shift in ATC, $125M Cust. Liq., Final Studies | PBL reserves



Notes **3-year TPP:** **92.7%**

Not yet Final Prop. data, but oh so close
2007-9 data is last-ditch Final Prop. with a few issues outstanding
2006 data from 3rd Q Review with tweaks

Rates are approximations of an ave. PF rate (PF revs/PF load).
"ROD" rate is what is published in the Rod.
"Oct 1" rate is the rate going into effect on Oct 1 - this will take into account any CRAC or DDC on top of Rod rate.
"Effective" rate is a calculation that takes into account the rate calculated in the ROD, plus any CRAC or DDC amounts that into effect on Oct 1, plus any after-the-fact adjustments from a Rebate.

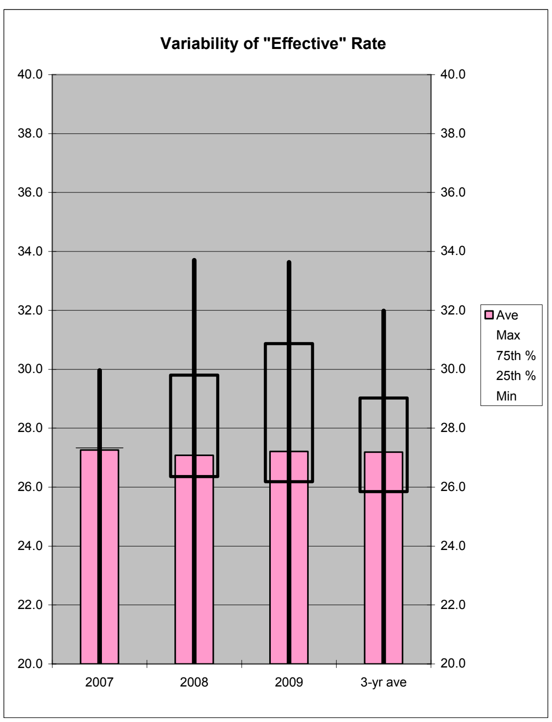
The hollow box on the variability charts below shows the 75th and 25th percentile values - 50% of the outcomes fall between these two values. The vertical line shows the maximum and minimum values over all 3000 games.

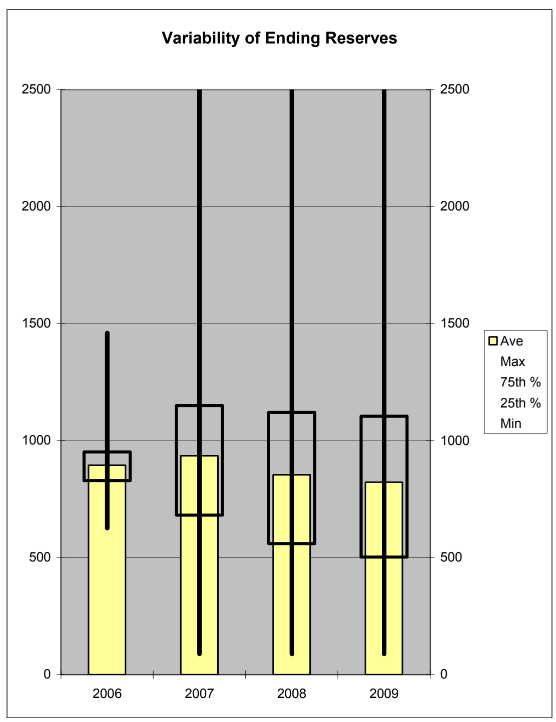
The DDC is calculated near the end of a year but isn't distributed till the next year, so it doesn't cap ending reserves immediately.

	2007	2008	2009
DDC threshold	1,050	1,050	1,050
DDC caps	0	1,208	1,222
CRAC threshold	750	750	750
CRAC caps	300	300	300
CRAC trigger freq.	4%	37%	42%
CRAC at max freq.	0%	11%	17%

Rebate
Calcns n / a

	2007	2008	2009	3-yr ave.
PNRR	11	11	11	11





11th iteration, Amortization Shift in ATC, $125M Cust. Liq., Final Studies | PBL reserves

	PF Rates - 3-year averages			
	Original Rate from RAM	After Change in PNRR	After adj. for CRAC or DDC	After Sec Rev Rebate
Max	27.33	27.33	31.98	31.98
75th pcntl	27.33	27.33	29.02	29.02
Average	27.33	27.33	27.18	27.18
median	27.33	27.33	27.33	27.33
25th pcntl	27.33	27.33	25.84	25.84
min	27.33	27.33	11.18	11.18
Range	0.00	0.00	20.80	20.80
Std dev	0.00	0.00	2.84	2.84

===>	IOU Broker Price		IOU Benefits						Average PF rates (not block rates)				CRAC Results				DDC Results			
2007	Price Used in RAM	Updated Price from RiskMod	Original Amount from RAM	After Change in PNRR	After Mrkt Quote Update	After adj. for CRAC or DDC	After Sec Rev Rebate	Net Sum IOU ben. Change	Original Rate from RAM	After Change in PNRR	After adj. for CRAC or DDC	After Sec Rev Rebate	Amount From Formula	Amount Collected From PF	Amt. BPA IOU Exp. Reduced	Amount IOU Ben. Reduced	Amount From Formula	Amount Distribut'd To PF	Amt. BPA IOU Exp. Increased	Amount IOU Ben. Increased
Max	58.46	0.00	323.0	323.0	323.0	323.0	323.0	0.0	Max	27.33	29.95	29.95	123.5	123.5	0.0	0.0	409.4	409.4	0.0	0.0
75th pcntl	58.46	0.00	323.0	323.0	323.0	323.0	323.0	0.0	75th pcntl	27.33	27.33	27.33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Average	58.46	0.00	323.0	323.0	323.0	323.0	323.0	0.0	Average	27.33	27.26	27.26	1.6	1.6	0.0	0.0	5.0	5.0	0.0	0.0
median	58.46	0.00	323.0	323.0	323.0	323.0	323.0	0.0	median	27.33	27.33	27.33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25th pcntl	58.46	0.00	323.0	323.0	323.0	323.0	323.0	0.0	25th pcntl	27.33	27.33	27.33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
min	58.46	0.00	323.0	323.0	323.0	323.0	323.0	0.0	min	27.33	18.63	18.63	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Range	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	Range	0.00	11.33	11.33	123.5	123.5	0.0	0.0	409.4	409.4	0.0	0.0
Std dev	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	Std dev	0.00	0.59	0.59	9.3	9.3	0.0	0.0	26.1	26.1	0.0	0.0

===>	IOU Broker Price		IOU Benefits						Average PF rates (not block rates)				CRAC Results				DDC Results			
2008	Price Used in RAM	Updated Price from RiskMod	Original Amount from RAM	After Change in PNRR	After Mrkt Quote Update	After adj. for CRAC or DDC	After Sec Rev Rebate	Net Sum IOU ben. Change	Original Rate from RAM	After Change in PNRR	After adj. for CRAC or DDC	After Sec Rev Rebate	Amount From Formula	Amount Collected From PF	Amt. BPA IOU Exp. Reduced	Amount IOU Ben. Reduced	Amount From Formula	Amount Distribut'd To PF	Amt. BPA IOU Exp. Increased	Amount IOU Ben. Increased
Max	50.87	99.62	323.0	323.0	323.0	323.0	323.0	0.0	Max	27.33	33.70	33.70	300.0	300.0	72.2	93.3	1208.3	1208.3	21.5	27.8
75th pcntl	50.87	55.95	323.0	323.0	323.0	323.0	323.0	0.0	75th pcntl	27.33	29.80	29.80	128.2	116.2	0.0	0.0	46.6	46.6	0.0	0.0
Average	50.87	51.41	323.0	323.0	320.5	315.7	315.7	-7.3	Average	27.33	27.08	27.08	69.5	65.8	3.7	4.8	77.5	77.5	0.0	0.0
median	50.87	50.23	323.0	323.0	323.0	323.0	323.0	0.0	median	27.33	27.33	27.33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25th pcntl	50.87	45.50	323.0	323.0	323.0	323.0	323.0	0.0	25th pcntl	27.33	26.35	26.35	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
min	50.87	34.07	323.0	323.0	181.0	129.3	129.3	-193.7	min	27.33	1.66	1.66	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Range	0.00	65.55	0.0	0.0	142.0	193.7	193.7	193.7	Range	0.00	32.04	32.04	300.0	300.0	72.2	93.3	1208.3	1208.3	21.5	27.8
Std dev	0.00	8.21	0.0	0.0	11.6	23.9	23.9	23.9	Std dev	0.00	4.85	4.85	110.5	105.4	12.7	16.4	175.3	175.3	0.7	0.9

===>	IOU Broker Price		IOU Benefits						Average PF rates (not block rates)				CRAC Results				DDC Results			
2009	Price Used in RAM	Updated Price from RiskMod	Original Amount from RAM	After Change in PNRR	After Mrkt Quote Update	After adj. for CRAC or DDC	After Sec Rev Rebate	Net Sum IOU ben. Change	Original Rate from RAM	After Change in PNRR	After adj. for CRAC or DDC	After Sec Rev Rebate	Amount From Formula	Amount Collected From PF	Amt. BPA IOU Exp. Reduced	Amount IOU Ben. Reduced	Amount From Formula	Amount Distribut'd To PF	Amt. BPA IOU Exp. Increased	Amount IOU Ben. Increased
Max	50.68	159.00	323.0	323.0	323.0	323.0	323.0	0.0	Max	27.33	33.63	33.63	300.0	300.0	71.6	92.5	1221.7	1221.7	51.5	66.5
75th pcntl	50.68	57.47	323.0	323.0	323.0	323.0	323.0	0.0	75th pcntl	27.33	30.87	30.87	190.9	168.5	0.0	0.0	55.8	55.8	0.0	0.0
Average	50.68	51.49	323.0	323.0	310.6	300.9	300.9	-22.1	Average	27.33	27.21	27.21	85.1	77.4	7.6	9.9	83.0	82.9	0.1	0.2
median	50.68	49.37	323.0	323.0	323.0	323.0	323.0	0.0	median	27.33	27.33	27.33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25th pcntl	50.68	42.73	323.0	323.0	323.0	311.9	311.9	-11.1	25th pcntl	27.33	26.17	26.17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
min	50.68	31.21	323.0	323.0	125.8	123.0	123.0	-200.0	min	27.33	1.66	1.66	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Range	0.00	127.79	0.0	0.0	197.2	200.0	200.0	200.0	Range	0.00	31.97	31.97	300.0	300.0	71.6	92.5	1221.7	1221.7	51.5	66.5
Std dev	0.00	12.16	0.0	0.0	31.9	47.2	47.2	47.2	Std dev	0.00	5.12	5.12	120.8	111.3	18.4	23.7	184.8	184.7	1.8	2.4

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