2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal

Final Study

Chapter 6 – Risk Analysis

SN-03-FS-BPA-01

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BONNEVILLE
POWER ADMINISTRATION

CHAPTER 6: RISK ANALYSIS

6.1 Introduction

6.1.1 Background. The FCRPS, operated on behalf of the ratepayers of the PNW by BPA and other Federal agencies, faces many uncertainties during the remainder of the FY 2002-2006 rate period. Among these uncertainties are variable hydro conditions and volatile market prices. In order to provide a high probability of making its Treasury payments on time and in full during the rate period, BPA performs the Risk Analysis.

In this Risk Analysis, BPA identifies key risks, models their relationships, and then analyzes their impacts on net revenues (revenues less expenses). BPA subsequently evaluates in the ToolKit Model the impact that certain risk mitigation measures have on reducing its net revenue risk so that BPA can develop rates that cover all its costs and provide a high probability of making its Treasury payments on time and in full during the rate period.

6.1.2 Overview. The Risk Analysis focuses upon operating risks - variations in economic conditions, load, and generation resource capability - and their impacts on BPA's revenues and expenses. These operating risks are modeled in RiskMod. RiskMod is a computer simulation model that calculates firm and surplus energy revenues, balancing power purchase expenses, Fish Cost Contingency Fund (FCCF) credits, and 4(h)(10)(C) credits under various load, resource, and market price conditions to estimate BPA's operational net revenue risk.

The output from RiskMod yields a distribution of net revenue deviations that are input into the ToolKit Model. The ToolKit Model uses the net revenue data to test the effectiveness of implementing various risk mitigation measures in order to provide a high probability of BPA making its Treasury payments on time and in full during the rate period.

RiskMod uses the simulation methodology in the @RISK computer software package to assess the impacts of a distribution of risk factors on net revenues. RiskMod quantifies the operating risks associated with load and resource performance for California, the PNW, and the Federal system, in addition to those risks associated with natural gas prices.

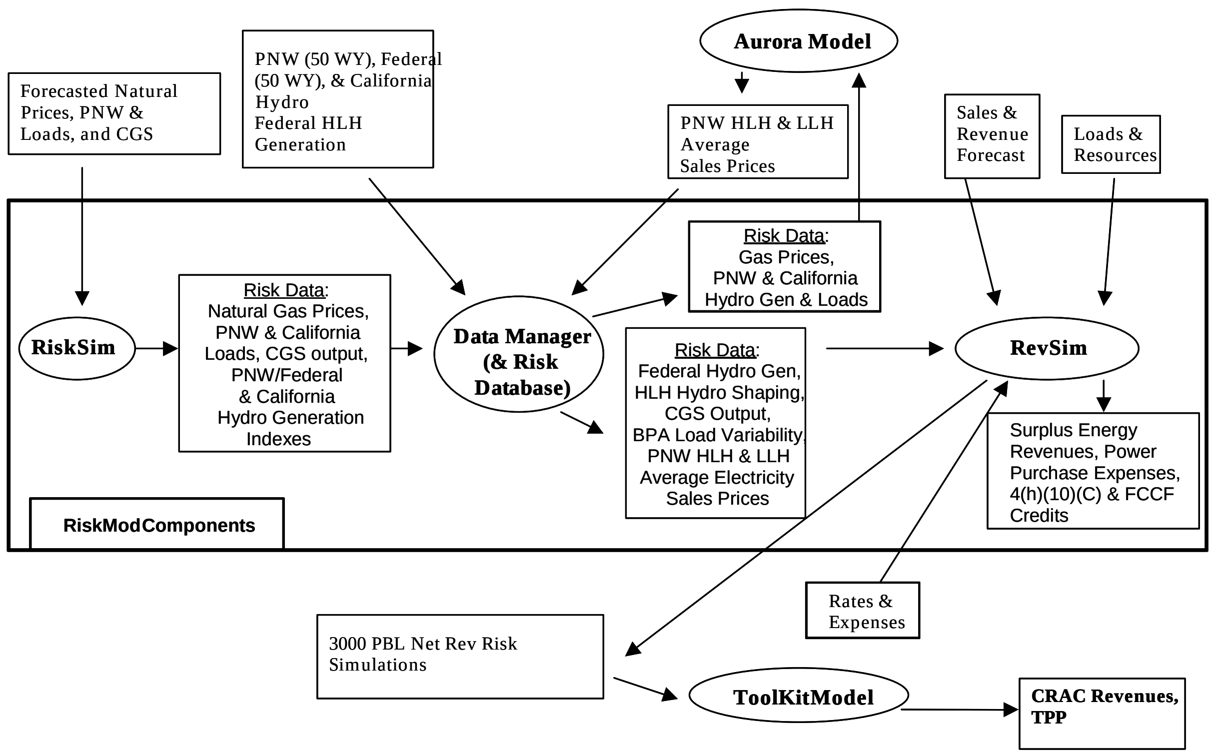
This chapter describes the operation of RiskMod and its quantification of net revenue risks. Chapter 7 of this study describes how the net revenue results of the Risk Analysis are used to assess risk mitigation (*i.e.*, develop the level of the CRACs) in the ToolKit Model. *See* McCoy, *et al.*, SN-03-E-BPA-10.

6.2 Analysis of PBL Operating Risk

6.2.1 RiskMod. RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manage data referred to as Data Manager; and RevSim, a model that calculates net revenues. Variations in monthly loads, resources, and natural gas prices are simulated in RiskSim. Monthly electricity prices for the simulated loads, resources, and natural gas prices are estimated by the AURORA Model. *See* chapter 4 of this study. The Data Manager facilitates the format and movement of data that flow to and from RiskSim, RevSim, and AURORA. RevSim uses risk data from RiskSim, electricity prices from AURORA, load and resource data from the Loads and Resources chapter (*see* chapter 2 of this study), various revenues and rates from the Revenue Forecast (*see* chapter 5 of this study), and expenses from the Revenue Recovery (*see* chapter 3 of this study) to estimate net revenues.

Annual average surplus energy revenues, purchase power expenses, section 4(h)(10)(C) credits, and FCCF credits calculated by RevSim are used in the Revenue Forecast. Net revenues estimated for each simulation by RevSim are input into the ToolKit Model. The processes and interactions between RiskMod and other models and studies are depicted in Graph 6-1.

Graph 6-1: RiskMod Risk Analysis Information Flow



6.2.2 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 and AURORA Model. *See* chapters 4 and 5 of this study.

The monthly output from these risk models was accumulated into a computer file to form a risk data base which contains values lower than, higher than, or equal to the base case values used in the Revenue Forecast and 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) electricity prices. The AURORA prices were then downloaded into the risk database and a consistent set of loads, resources, and electricity prices are used to calculate net revenues in RevSim.

6.2.3 @RISK Computer Software. The risk simulation models developed to quantify operational risks were developed in the @RISK computer software package. This software is an add-in computer package to Microsoft Excel and 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 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.

6.2.4 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 traditional operational risks that increase BPA's risk exposure, including the following: load variability due to changes in load growth and weather; nuclear plant (CGS) performance; and variability in electricity prices due to load, resource, and natural gas price variability.

The following is a discussion of the major risk factors included in RiskMod. For discussion purposes, the various risk factors are grouped under the categories of PNW and Federal Resource Performance, PNW and BPA Loads, California Resource Performance, California Loads, and Natural Gas Prices. Each of these risk factors is used in the AURORA Model, RevSim, or both.

6.2.4.1 PNW and Federal Hydro Generation Risk Factors. The PNW and Federal hydro generation risk factors reflect the uncertainty that the timing and volume of streamflows have on monthly PNW and Federal hydro generation under specified hydro operation requirements. This uncertainty is accounted for in this rate filing in two ways.

For FY 2004-2006, hydro generation risk was accounted for by inputting monthly hydro generation data estimated by the HydroSim Model for monthly streamflow patterns experienced from August 1929 through July 1978 (also referred to as the 50 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 600 months of the 50 water years. This analysis by HydroSim is referred to as a continuous study. *See* Hydro-Regulation component of the Loads and Resources chapter (chapter 2 of this study) regarding HydroSim, continuous study, and 50 water years. For FY 2004, additional hydro generation adjustments were made to each of the 50 water year data from the continuous study for FY 2004 to reflect the outlook that reservoirs on the FCRPS may not refill in FY 2003. *See* Hydro-Regulation component of the Loads and Resources chapter (chapter 2 of this study), regarding FY 2004 hydro generation adjustments.

For FY 2003, hydro generation risk was accounted for by probability-weighting hydro generation estimates by the HydroSim Model that reflected updated reservoir levels. Performing hydro-regulation studies where reservoir levels are updated to known levels is referred to as a refill study. *See* Hydro-Regulation component of the Loads and Resources chapter (chapter 2 of this study) regarding HydroSim, refill study, and 50 water years. The hydro generation data for each of the 50 water years from the refill study were probability-weighted in RiskMod to yield results consistent with the 2003 April-September runoff volume forecast (May Final Forecast) by the Northwest River Forecast Center. *See* Hydro-Regulation component of the Loads and Resources chapter (chapter 2 of this study).

The PNW and Federal hydro generation data are used to estimate prices and revenues for 3,000 four-year simulations (FY 2003-2006). The monthly Federal hydro generation data are input into the RevSim Model to quantify the impact that Federal hydro generation variability has on BPA's net revenues. The associated monthly PNW hydro generation data are input into the AURORA Model to quantify the impact that PNW hydro generation has on PNW electricity prices. Each simulation uses hydro generation from a streamflow pattern from the refill study for FY 2003 and a sequential set of three water years from the continuous study for FY 2004-2006.

The initial water year (FY 2004) of the sequential set of three water years is randomly sampled from 1929 through 1978. When the end of the 50 water years was reached (at the end of water year 1978), monthly hydro production data for water year 1929 was subsequently used. For example, if a simulation for FY 2004-2006 started with water year 1977, the simulation would use water years 1977 through 1978, as well as water year 1929, for a total of three water years. This approach was used so that each of the 50 water years was sampled an equal number of times.

For FY 2004-2006, prices and net revenues are estimated based on each of the 50 water years being sampled 60 times to produce 3,000 three-year simulations. Using the hydro-regulation data for FY 2004-2006 in this continuous manner captures the dry, normal, and wet weather patterns inherent in the 50 water years and the impact these patterns have on electricity prices and BPA's net revenues over time. Using the hydro-regulation data from the refill study for FY 2003 provides more accurate data on current FY hydro generation risk by relying on updated information about reservoir levels and streamflow forecasts.

Higher streamflows usually increase surplus energy revenues and decrease purchased power expenses. Surplus energy revenues usually increase because the revenue from the larger quantities of surplus energy available for sale more than compensates for the lower market prices. Conversely, lower streamflows usually decrease surplus energy revenues and increase purchased power expenses. Surplus energy revenues usually decrease because the revenues from the smaller quantities of surplus energy available for sale are not comparably offset by higher market prices.

6.2.4.2 Columbia Generating Station (CGS) Nuclear Plant Performance Risk Factor. The nuclear plant performance risk factor reflects the uncertainty in the amount of energy generated by the CGS nuclear plant. Nuclear plant performance risk is modeled such that the average of the simulated outcomes is equal to the expected monthly CGS output specified in the Loads and Resources chapter (*see* chapter 2 of this study). The potential values of the results simulated can vary from the output capacity of the plant to zero output.

Higher than expected nuclear plant performance either increases BPA's surplus energy revenues or reduces its power purchase expenses, because more energy is available for either making surplus energy sales or displacing power purchases. Lower than expected nuclear plant performance either decreases BPA's surplus energy revenues or increases its power purchase expenses, because less energy is available for either making surplus energy sales or displacing power purchases.

6.2.4.3 PNW and BPA Loads Risk Factor. This factor reflects the impact that variations in economic and weather conditions have on HLH and LLH spot market prices and Priority Firm Power (PF) loads. The level of economic activity impacts the overall annual amount of load placed on BPA by its PF customers while fluctuations in load due to weather conditions cause monthly variation in loads, especially during the winter when heating loads are highest. Load growth variability for the PNW (and indirectly for BPA) is simulated using annual variability parameters that were derived from historical Western Electricity Coordinating Council (WECC, formerly called the WSCC) load data. *See* chapter 6 of the documentation for SN-03 Study, SN-03-FS-BPA-02. Monthly load variability for the PNW (and indirectly for BPA) was derived from daily load variability parameters used as input data in PMDAM in the 1996 rate case. *See* Marginal Cost Analysis Study, WP-96-FS-BPA-04 and documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 6.

Higher than expected firm loads due to economic and weather conditions increase PF loads and revenues, increase power purchase expenses, and reduce surplus energy revenues. Lower than expected firm loads reduce PF loads and revenues, decrease power purchase expenses, and increase surplus energy revenues. Higher spot market electricity prices increase both BPA's surplus revenues and power purchase expenses. Conversely, lower spot market electricity prices decrease both BPA's surplus revenues and power purchase expenses.

6.2.4.4 California Hydro Generation Risk Factor. This factor reflects the uncertainty that the timing and volume of streamflows have on monthly hydro production in a given year in California. This uncertainty was derived from monthly hydro production data reported by the Energy Information Administration for 1980-1997. *See* chapter 6 of the documentation for SN-03 Study, SN-03-FS-BPA-02.

Higher California streamflows reduce the need to run thermal plants in California, which results in lower prices paid by California utilities for PNW surplus energy and lower prices paid by PNW utilities for purchased power from California. Conversely, lower streamflows increase the need to run thermal plants in California, which results in higher prices paid by California utilities for PNW surplus energy and higher prices paid by PNW utilities for purchased power from California.

6.2.4.5 California Loads Risk Factor. This factor reflects the uncertainty in California loads due to fluctuations in weather and economic conditions. This risk factor reflects the impact that the strength of the economy and fluctuations in temperature have on California loads and HLH and LLH spot market electricity prices. The level of economic activity impacts the overall annual amount of loads in California while fluctuations in load due to weather conditions cause monthly variation in loads, especially during the summer when cooling loads are highest. Load growth variability for California was simulated using annual variability parameters that were derived from historical WECC load data. *See* documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 6. Monthly load variability for California was derived from daily load variability parameters used as input data in PMDAM in the 1996 rate case. *See* Marginal Cost Analysis Study, WP-96-FS-BPA-04 and documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 6.

Higher California loads increase the need to run thermal plants in California, which results in higher prices paid by California utilities for PNW surplus energy and higher prices paid by PNW utilities for purchased power from California. Conversely, lower California loads decrease the need to run thermal plants in California, which results in lower prices paid by California utilities for PNW surplus energy and lower prices paid by PNW utilities for purchased power from California.

6.2.4.6 Natural Gas Price Risk Factor. This factor reflects the uncertainty in the costs of producing electricity from gas-fired resources throughout the WECC region. Higher than expected gas prices increase the cost of producing electricity from gas-fired resources, which increases the price of electricity on the spot market. Conversely, lower than expected gas prices decrease the cost of producing electricity from gas-fired resources, which decreases the price of electricity on the spot market.

Higher gas prices result in BPA earning higher surplus sale revenues and paying higher power purchase expenses. Lower gas prices result in BPA earning lower surplus sale revenues and paying lower power purchase expenses.

6.2.5 Results from RiskMod. Risk data were simulated by RiskSim to accommodate the calculation of 3,000 estimated net revenues in RevSim for each fiscal year from FY 2003-2006. This process yields a total of 12,000 annual net revenues. The 12,000 annual net revenues simulated by RiskMod were used to perform analyses with the ToolKit Model to assess BPA's probability of meeting its annual U.S. Treasury payments during FY 2003-2006. *See* chapter 7 of this study, regarding the ToolKit Model. A statistical summary of the annual net revenues for FY 2003-2006 from RiskMod is reported in Table 6-1. These net revenues include the impact of the LB CRAC rate and FB CRAC rate (the FB CRAC is assumed to trigger by the full amount in all fiscal years), but without the SN CRAC rate.

Table 6-1: Net Revenue Statistics

	FY 2003	FY 2004	FY 2005	FY 2006	4 Yr Average
Average	23,331	8,914	-116,475	-124,656	-52,222
Median	19,206	-3,198	-118,810	-128,083	
StDev	97,643	221,040	187,481	189,158	
1% <=	-160,692	-412,243	-468,657	-472,278	
2.5% <=	-145,663	-371,574	-436,365	-447,925	
5% <=	-131,185	-332,772	-409,848	-424,350	
10% <=	-105,074	-274,731	-368,075	-382,768	
15% <=	-85,870	-229,273	-324,127	-340,720	
20% <=	-67,003	-186,195	-287,819	-296,870	
25% <=	-48,813	-151,235	-256,153	-260,150	
30% <=	-35,314	-120,460	-226,049	-229,039	
35% <=	-21,157	-90,529	-195,100	-202,001	
40% <=	-7,854	-58,956	-168,814	-178,594	
45% <=	4,004	-30,459	-144,114	-154,379	
50% <=	19,156	-3,270	-118,971	-128,170	
55% <=	32,533	27,024	-98,239	-104,107	
60% <=	46,847	57,886	-71,917	-79,748	
65% <=	61,176	85,213	-49,464	-53,393	
70% <=	76,698	117,805	-21,720	-27,746	
75% <=	94,636	153,424	8,289	2,039	
80% <=	113,643	193,726	40,851	30,615	
85% <=	131,392	238,952	81,045	72,850	
90% <=	155,329	295,254	130,163	119,075	
95% <=	190,954	388,563	211,092	192,771	
97.5% <=	216,412	473,753	269,851	266,021	
99% <=	246,747	596,289	345,264	364,362	

6.3 Analysis of PBL Non-Operating Risk

In BPA's May Proposal (May 2000) and Supplemental Proposal (June 2001), the Non-Operating Risk Model (NORM) was used to reflect and calculate PBL non-operating risks, chiefly uncertainty in PBL expense categories. In this rate case, NORM was not used. It was unnecessary to use NORM in this proceeding because the risks associated with PBL expense categories present in the prior proceedings are not present in this proceeding. BPA has undertaken a rigorous cost review and is committed to managing its costs to specified levels.

Because of the importance of this commitment, BPA has determined it is not necessary to model uncertainties in these non-operating costs. *See* Keep, *et al.*, SN-03-E-BPA-04.

6.4 Analysis of TBL Risk

In this rate case, BPA applied a TPP standard that was calculated for BPA as a whole, not just for PBL. *See* Keep, *et al.*, SN-03-E-BPA-04. In order to model the agency as a whole, risk data from TBL were needed. The data used in this rate case for TBL come from the 2003 TBL Rate Case. No changes were made to the TBL risk model or risk data.

The TBL risk model was run for 3,000 games to match the number of games used in modeling PBL risks. The output used for each FY 2003-2006 was the net change in financial reserves. These data were then used in the ToolKit (*see* chapter 7 of this study).