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

2010 Wholesale Power Rate Case
Initial Proposal

MARKET PRICE FORECAST STUDY

February 2009

WP-10-E-BPA-03

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MARKET PRICE FORECAST STUDY
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COMMONLY USED ACRONYMS

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

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

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

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

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

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1. INTRODUCTION

1.1 Definitions and Purpose

This study presents the Market Price Forecast for the WP-10 Initial Proposal. The Market Price Forecast is the common title for three electric energy price forecasts, which result from the forecasts of electric energy market fundamentals. These fundamentals include, but are not limited to, hydroelectric conditions, load conditions, and natural gas prices. To produce the three electric energy price forecasts, electric energy market fundamentals are used as inputs to a forecasting model, AURORA$^{xmp®}$. AURORA$^{xmp®}$ calculates the variable cost of the marginal resource in a competitively priced electric energy market. In competitive market pricing, the marginal cost of production is equivalent to the market-clearing price. Market-clearing prices are important factors for informing BPA's power rates.

AURORA$^{xmp®}$ is used as the primary tool in the Market Price Forecast. The electric energy prices that result from the Market Price Forecast are used as price inputs for the following: (a) the secondary revenue forecast, (b) augmentation purchase costs, (c) the risk analysis, (d) the variable cost component of generation input capacity, (e) utility average system costs, and (f) rate design.

For more information on how the Market Price Forecast is used for the secondary revenue forecast, augmentation purchase costs, and the risk analysis, *see* the Risk Analysis and Mitigation Study, WP-10-E-BPA-04. For more information on how the Market Price Forecast is used in establishing the variable cost component of generation input capacity, *see* the Generation Inputs Study WP-10-E-BPA-08. For more information on how the Market Price Forecast is used for calculating utility average system costs for FY 2010 and FY 2011, *see* the Wholesale Power

Rate Development Study (WPRDS), WP-10-E-BPA-05 Section 6. For more information on how the Market Price Forecast is used for calculating utility average system costs for FY 2012 through FY 2015, *see* the Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06. For more information on how the Market Price Forecast is used for rate design, *see* the Rate Design section of the WPRDS, WP-10-E-BPA-05, Section 2.

2. METHODOLOGY

2.1 Overview

The principal tool used in this analysis is an electric energy market model called AURORA$^{xmp®}$. AURORA$^{xmp®}$ is owned and licensed by EPIS, Incorporated (EPIS). Production costing is a major component of this model's functions. Production cost models are widely used in the electric power industry for forecasting electricity prices.

To describe AURORA$^{xmp®}$'s methodology, it is helpful to distinguish between two main aspects of modeling the electric energy market: the short-term determination of the hourly market-clearing price and the long-term optimization of the resource portfolio.

2.2 AURORA$^{xmp®}$ Model Framework

As noted, the AURORA$^{xmp®}$ model is used for forecasting electricity market prices in the rate case. AURORA$^{xmp®}$ assumes a competitive market pricing structure as the fundamental mechanism underlying how it estimates the wholesale electric energy market clearing prices during the term of this analysis. Two fundamental inferences for electric energy pricing in a competitive market follow from the economic theory of market pricing. First, the price in any hour approximates the variable cost of the marginal generating resource. Second, the long-term average price gravitates toward the full cost of a new resource, where the cost includes both the fixed and variable components.

As noted above, the determination of hourly prices follows directly from economic theory of market pricing, which concludes that a firm will continue to produce additional goods or services as long as the revenue from the sale of those units covers its marginal cost. A competitive market will produce a quantity of goods or services up to the amount consumers are willing to pay for marginal consumption, which equals the marginal cost of production. Therefore, the market-clearing price is equal to the cost to produce the marginal unit for consumption. For the electricity market, the hourly market-clearing price translates to the variable cost of the marginal electric generator.

In the long term, when the amount of capital is not fixed, the average price will move toward the full cost of a new resource. When prices are high enough to justify additional investment, the average investment cost will be lower than the average price before the investment. Therefore, new resources will bring down the price. When the long-term average price outlook is lower than the average cost of a new resource, new resources will not be built. In this case, demand growth will move prices up the supply curve until new resource investment is profitable.

Because long-term prices should gravitate toward the cost of new resources, the assumptions concerning the cost of a new resource will have an important impact on the long-term price forecast. Another important factor is the load forecast. The load forecast will affect how quickly prices move up the supply curve and reach the point where investment in new resources is profitable.

Economic theory of market pricing also concludes that until prices reach the level where new resource investment is profitable, excess generating capacity will decline. A decline in excess generating capacity tends to exacerbate price increases in those periods when relatively less surplus generating capacity is available; *i.e.*, the peak pricing months and heavy load hour periods.

2.3 Hourly Price Determination

The hourly market-clearing price is based upon a fixed set of resources dispatched in least-cost order to meet demand while maintaining operating constraints on the resources. The hourly market-clearing price is set equal to the variable cost of the marginal resource. AURORA$^{xmp®}$ sets the hourly market-clearing price using assumptions on demand levels (load) and supply costs. The supply side is defined by the cost and operating characteristics of individual electric generating plants, including resource capacity, heat rate, location, and fuel price.

AURORA$^{xmp®}$ recognizes the effect that transmission capacity, losses, and prices have on the ability to move generation output between zones. For this study, the implementation of AURORA$^{xmp®}$ recognizes 14 zones within the Western Electricity Coordinating Council (WECC) area.

2.4 Long-Term Resource Optimization

The long-term resource optimization feature within AURORA$^{xmp®}$ allows generating resources to be added to or retired from the resource inventory based on economic profitability. Economic profitability is measured as the net present value of revenue minus the fixed and variable costs. AURORA$^{xmp®}$ will add a new resource that is economically profitable to the resource inventory. Likewise, an existing resource that is no longer economically profitable will be retired from the resource inventory, by AURORA$^{xmp®}$.

In reality, the market-clearing price (hence the profitability of a resource) and the resource inventory are interdependent. The market-clearing price will affect the revenues any particular resource will receive, and consequently, which resources are added and retired. In parallel, changes in the resource inventory will change the supply cost structure and will therefore affect the market-clearing price. AURORA$^{xmp®}$ uses an iterative process to address this interdependency.

During the iterative process, AURORA$^{xmp®}$ uses a preliminary price forecast to evaluate existing resources and potential new resources in terms of economic profitability. If an existing resource is not profitable, it becomes a candidate for retirement. Alternatively, if a potential new resource is economically profitable, it is a candidate to be added to the resource inventory. In the first step of the iterative process, a small set of new resources is drawn from those with the greatest profitability and added to the resource inventory. Similarly, a small set of the most unprofitable existing resources is retired. This modified resource inventory is used in the next step in the iterative process to derive a revised market-clearing price forecast. The modified price then drives a new iteration of resource changes. AURORA$^{xmp®}$ will continue the iterative solution of the resources inventory and the market-clearing price until the difference in price between the last two iterations reaches a minimum and the iterative process converges to a stable solution.

2.5 Application of AURORA$^{xmp®}$ for Ratesetting

For the WP-10 Initial Proposal, AURORA$^{xmp®}$ is used to produce three different electric energy price forecasts. All of the electric energy price forecasts are run in a stochastic mode. The first electric energy price forecast, the 70 water year price forecast, is accomplished by running AURORA$^{xmp®}$ 70 times. Each of the 70 different runs uses a unique water year from the 70 water years (1929 through 1998). In the 70 water year price forecast, all other inputs and assumptions are constant. The second electric energy price forecast, the risk-adjusted price forecast, is accomplished by running AURORA$^{xmp®}$ 3,500 times. In the risk-adjusted price forecast, hydroelectric conditions, load conditions, and natural gas prices are altered. The third electric energy price forecast, used to estimate augmentation price risk, is run in the same manner as the second forecast, with one exception. In the third forecast, PNW hydroelectric conditions do not vary; 1937 hydroelectric conditions are used for all 3,500 games. All three forecasts produce monthly HLH and LLH prices for October 2009 through September 2011.

The Market Price Forecast Documentation, WP-10-E-BPA-03A, presents the forecasts' average HLH, LLH, and Flat prices by time period. The Flat prices are representative of the average of the prices over all hours and are derived by weighting the HLH prices by 57% and the LLH prices by 43%. The Risk Analysis and Mitigation Study, WP-10-E-BPA-04, includes additional information that describes the variance associated with the hydroelectric conditions, load conditions, and natural gas prices used for the electric energy price forecasts.

In accordance with past practice, *see* Petty, *et al*., WP-07-E-BPA-11, the loads in Oregon, Washington, and Northern Idaho, the zone for which AURORA is forecasting prices, are decremented by approximately 2,500 aMW each year to reflect the fact that BPA does not participate in a market that produces an hourly marginal clearing price, such as the former California Power Exchange. Instead, BPA markets power in a bilateral market in which parties are not assured of receiving the hourly marginal clearing price. All of the electricity price forecasts decrement the loads by 2,500 aMW.

3. MARKET PRICE FORECAST ASSUMPTIONS

3.1 Overview

Three primary drivers are relevant to the market price forecast: the load forecast, the natural gas price forecast, and assumptions about hydroelectric generation conditions. The load forecast determines where on the supply curve the marginal price will occur. Natural gas prices will generally determine the variable cost of the resource on the margin, which sets the marginal clearing price. Hydroelectric generation conditions determine the amount of hydroelectric generation that can be used to meet loads. In general, greater amounts of hydroelectric generation will reduce the marginal clearing price, because hydroelectric generation is a low variable cost resource. The assumptions for the load forecast, natural gas prices, hydroelectric generation conditions, and generating resources are described in detail in the following sections. The Market Price Forecast Documentation, WP-10-E-BPA-03A, lists additional data and assumptions used in AURORA$^{xmp®}$ for this study.

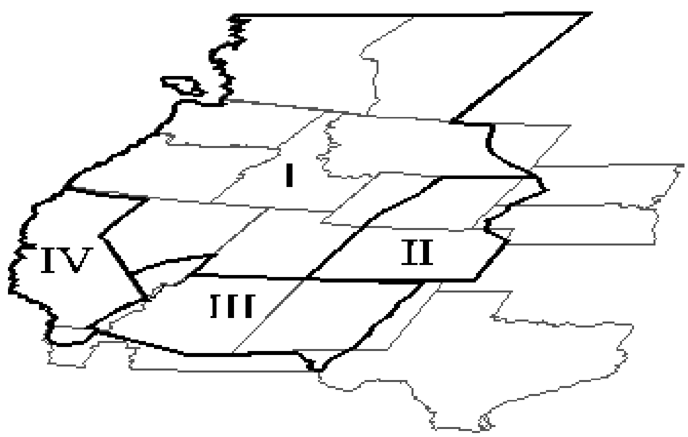
3.2 Load Forecast

The load forecast for AURORA$^{xmp®}$ consists of four parts: the base-year load forecast, the annual average growth rate, monthly load-shape factors, and hourly load-shape factors. The base-year load forecast determines the starting level for the loads. The annual average growth rate increases the loads from year to year. The monthly load-shape factors shape the annual loads into monthly loads. The hourly load-shape factors then shape the monthly loads into hourly loads.

3.2.1 Base-Year Load Forecast

For the base-year load forecast used in AURORA$^{xmp®}$, the WECC 10-Year Coordinated Plan Summary (2006-2015) is used. The base-year load forecast for the final Market Price Forecast Study will be updated to be consistent with the most recent WECC 10-Year Coordinated Plan Summary. For further discussion, refer to Petty *et al.*, WP-10-E-BPA-13. The WECC publishes load forecasts for four areas: the Northwest Power Pool Area; the California-Mexico Power Area; the Rocky Mountain Power Area; and the Arizona-New Mexico-Southern Nevada Power Area. Figure 3-1 represents these areas.

Figure 3-1: 2006 WECC Areas



Where:	I	=	Northwest Power Pool Area
	II	=	Rocky Mountain Power Area
	III	=	Arizona-New Mexico–Southern Nevada Power Area
	IV	=	California-Mexico Power Area

The four WECC areas are converted into 14 AURORA$^{xmp®}$ zones for the forecast. A description of the conversion process follows. Table 1 represents the 14 AURORA$^{xmp®}$ zones.

Table 1: AURORA$^{xmp®}$ Zones

A	B	C
Zone Number	**Zone Name (Geographic Area)**	**Short Name**
1	BPA (Oregon, Washington, and Northern Idaho)	BPA
2	NP15 (Northern California)	NP15
3	SP15 (Middle and Southern California)	SP15
4	British Columbia	BC
5	Southern Idaho (Southern and Eastern Idaho)	SI
6	Montana	MT
7	Wyoming	WY
8	Colorado	CO
9	New Mexico	NM
10	Arizona (Arizona and Southern NV)	AZ
11	Utah	UT
12	Northern Nevada	NV
13	Alberta	AB
14	Baja California	Baja

The following example illustrates the methodology used to convert the WECC regional loads to AURORA$^{xmp®}$ geographical load zones. For the Northwest Power Pool Area, the area loads in the EPIS database labeled North American DB 2008-02 that are equivalent to the modeled zones BPA, British Columbia, Southern Idaho, Montana, Utah, Northern Nevada, and Alberta are summed to produce an aggregate total load. The loads for BPA, British Columbia, Southern Idaho, Montana, Utah, Northern Nevada, and Alberta are each divided by the aggregate total load to develop individual percentages. The individual percentages are then applied to the aggregate WECC regional load forecast for the Northwest Power Pool Area 2008 load forecast to create zonal loads. This procedure was repeated for each of the other WECC regions to derive the 2008 base-load forecasts for each AURORA$^{xmp®}$ load zone. For this study, the Pacific Northwest (PNW) is synonymous with the BPA, SI, and MT zones.

3.2.2 Annual Average Growth Rate

The average annual growth rates for each WECC area from the WECC 10-Year Coordinated Plan Summary (2006-2015) are used for this study. For the final Market Price Forecast Study, the annual average growth rates will be updated to be consistent with the most recent WECC 10-Year Coordinated Plan Summary. For further discussion, refer to Petty *et al.*, WP-10-E-BPA-13. These WECC regional growth rates reflect the prediction that loads will grow at different rates in the different WECC regions. Table 2 shows the WECC annual growth rates used for the load forecast.

Table 2: Load Forecast Annual Average Growth Rate (Percent)

A	B	C	D	E
WECC Area:	I	II	III	IV
2009	2.2	2.3	3.1	2.1
2010	2.1	1.9	3.4	2.1
2011	1.9	2.1	2.7	2.1

The annual average growth rates are applied to the base load forecast to determine the load forecast over time.

3.2.3 Monthly and Hourly Load-Shaping Factors

The EPIS supplied AURORA$^{xmp®}$ database labeled North American DB2008-01 is used to derive the monthly load-shaping factors for converting the annual load forecast into a monthly load forecast. AURORA$^{xmp®}$ multiplies the monthly shaping factor by the annual load forecast to derive the monthly load forecast. The AURORA$^{xmp®}$ hourly load-shaping factors are used for converting the monthly load forecast into an hourly load forecast.

3.3 Natural Gas Prices

3.3.1 Methodology for Deriving AURORA$^{xmp®}$ Zone Natural Gas Prices

To forecast electricity market prices, the study forecast natural gas prices for gas delivered to electric generators in each AURORA$^{xmp®}$ zone. The study first forecast natural gas prices at Henry Hub, Louisiana. Henry Hub is frequently referenced as a touchstone for North American gas prices and is the most liquid natural gas futures market.

In the next step, the forecast basis, or price differential, between Henry Hub and three primary western trading hubs is applied. These three hubs represent production basins that are the source for most of the natural gas delivered in the western United States. The Western Canada Sedimentary Basin is represented by the Sumas, Washington, Hub. The collection of Rocky Mountain supply basins is represented by the Opal, Wyoming, Hub. The San Juan Basin is represented by the Ignacio, Colorado, Hub.

The final step is to estimate the price differentials between the primary western trading hubs and the associated AURORA$^{xmp®}$ zones. The hub associated with each zone is the hub that tends to be the source of marginal gas supply in that zone and therefore the hub that has the highest price correlation to prices in the local zone. The Sumas Hub is associated with the Pacific Northwest and Northern California and Canadian zones. The Opal Hub is associated with Montana, Idaho South, Wyoming, and Utah. The San Juan Hub is associated with Nevada, Southern California, Arizona, and New Mexico.

In summary, the forecast begins with a price forecast for Henry Hub. The forecast basis between Henry Hub and each primary western trading hub is then applied. The final step is to apply the forecast basis between the primary western trading hub and its associated AURORA$^{xmp®}$ zone. The forecasts of these price differentials are described in section 3.3.4 below.

3.3.2 Natural Gas Market Fundamentals

The natural gas price forecast is based on an expectation of recession in 2009 and an economic recovery beginning by 2010 and continuing through 2011. In general terms, natural gas prices are forecast to follow economic trends. The dynamics of natural gas demand and supply are expected to cause a decline in 2009 prices, with prices rising beginning in 2010 and continuing through 2011. The following sections detail the assumptions behind demand, then supply, and finally, overall price and risk.

The recession is expected to cause natural gas demand to decline, especially in the industrial and power generation sectors. Evidence of declining demand is already apparent. Output from the top six gas-intensive manufacturing sectors—chemicals, refining, primary metals (steel), food processing, pulp and paper, and nonmetallic mineral products—has declined by 8 percent since commodity prices peaked in July 2008.

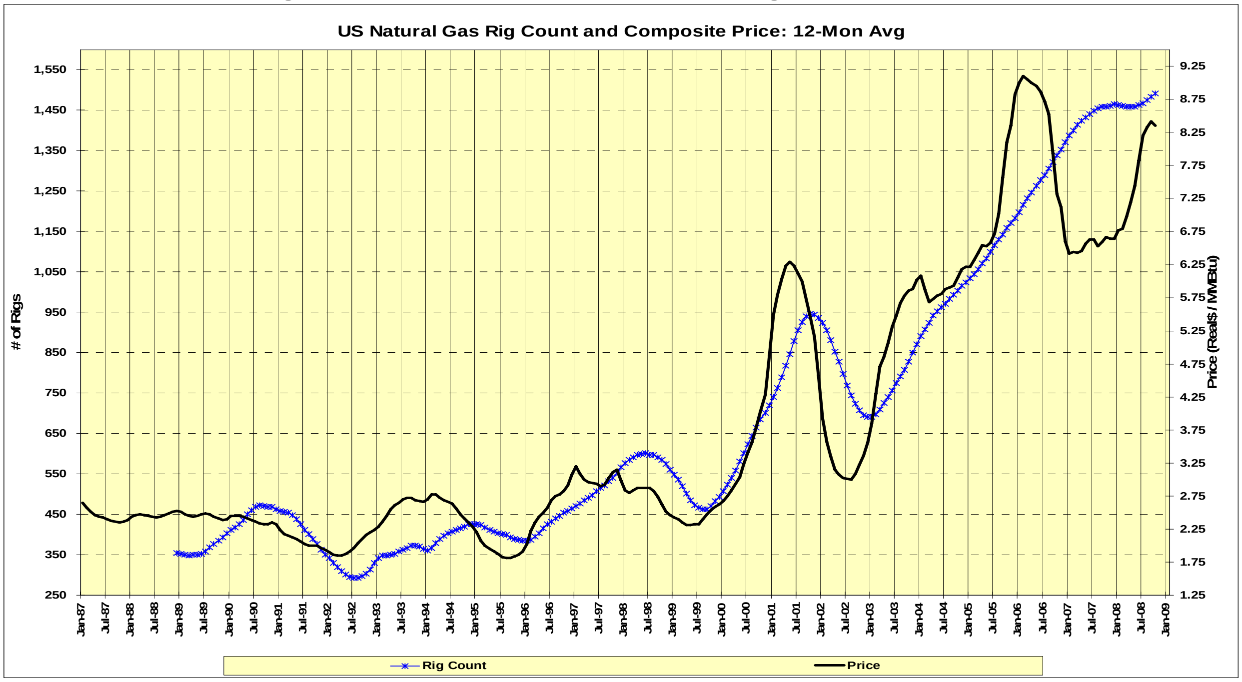
Natural gas demand for power generation is also expected to decline as the recession continues and weakening electricity demand cuts disproportionately into gas-fired generation. In addition, power generation demand for natural gas is expected to fall due to the sharp decline in crude oil prices. This will cause reduced residual fuel oil prices to fall below natural gas price equivalents, providing an incentive for switching from gas to oil in dual-fuel power generation facilities.

The residential and commercial sectors may also see some reduced demand following reduced income. However, these sectors generally have a lower income elasticity of demand. Therefore, the quantity of natural gas demanded by these sectors does not vary as much with income changes.

On the supply side, production is expected to see downward pressure in response to price reductions. This effect will limit the downward price path in the near term and provide some price support in the mid-term with an economic recovery.

Signs of production declines due to the recession are already evident. As the recession has taken hold, natural gas prices have fallen and the rig count for the lower 48 states has fallen from a high of 1,581 in August 2008 to 1,498 in November 2008. Natural gas production often follows price with a short time lag, as shown in Figure 2, which shows natural gas prices and rig counts calculated on a 12-month rolling average.

Figure 3-2: Natural Gas Price and Rig Count



Note: Prices are in real 2000$/MMBtu

As the demand and supply dynamic plays out during an economic recovery, prices can be expected to climb as a result of both increasing demand and the reduced supply, with a time lag.

These factors account for the forecast of declining prices in 2009, with a recovery beginning by 2010 and continuing through 2011.

In summary, as supply and demand act to balance the natural gas market in times of recession and possible recovery, the overall forecast is for declining prices in 2009, with a recovery beginning by 2010 and continuing through 2011. The prices for the forecast period (along with historical 2008 for reference) at Henry Hub in nominal $/MMBtu are shown in Table 3.

Table 3: Henry Hub Natural Gas Prices (Nominal $/MMBtu)

A	B	C	D
2008	2009	2010	2011
8.85	7.00	7.21	7.39

Note: 2008 are actual prices from Natural Gas Week

It is important to note that an economic recession has already begun, while a recovery in the 2010 to 2011 time period is speculative. The natural gas price forecast is subject to update as perceived risks may shift. The natural gas price forecast is especially sensitive to the perceived risk to the secondary revenue forecast. For more information on the perceived risk to the natural gas price forecast, *see* Bliven *et al.,* WP-10-E-BPA-10 and Petty *et al.,* WP-10-E-BPA-13.

3.3.3 The Basis Forecasts

The primary western trading hubs basis forecast is shown in Table 4. The values in Table 4 indicate the forecast difference between Henry Hub and the primary western trading hubs. These forecasts are based on historical data, transportation cost of natural gas, and the outlook for pipeline expansions.

Table 4: Basis between Henry and the Western Hubs

A	B	C	D
Year	Sumas	Rockies	San Juan
2008	0.66	2.27	1.61
2009	0.72	2.43	1.66
2010	0.54	2.36	0.92
2011	0.30	1.46	0.50

Note: 2008 are actual basis differentials from Natural Gas Week

The next step in the natural gas price forecast is to link the western hubs to the AURORA$^{xmp®}$ zones. Table 5 shows these pricing differentials. For AURORA$^{xmp®}$ analysis, all values are shown in real (inflation-adjusted) dollars for the year 2005. Table 5 lists the three western hubs and their associated AURORA$^{xmp®}$ zone below. The value for each AURORA$^{xmp®}$ zone is the basis differential between the western hub and the AURORA$^{xmp®}$ zone.

Table 5: Basis between Hubs and AURORA$^{xmp®}$ Zones

AURORA^{xmp} Zone to Western Hub Differential

Price Differential (real 2005$/MMBtu)

A		B		C	
Sumas		Opal		San Juan	
BPA	0.23	UT	0.35	CO	0.36
NP15	0.31	WY	0.40	SP15	0.47
BC	0.22	MT	0.33	AZ	0.41
AB	0.22	SI	0.35	NM	0.33
		NV	0.46		

The AURORA$^{xmp®}$ zone gas price forecast is derived by taking the western hub price and adding the differentials shown in the above table.

3.4 Hydroelectric Generation

For the market price forecast, the Loads and Resources Study, WP-10-E-BPA-01, supplied AURORA$^{xmp®}$ with hydroelectric generation values for the PNW. For the California zones, RiskMod supplied the hydroelectric generation values. For the PNW, 70 water years were used for the variation in hydroelectric conditions. For the California zones, 18 years of historical hydroelectric generation values were used for determining hydroelectric generation variability. For the remaining zones, EPIS-supplied values are used.

3.5 Generating Resources

Actual resources that are expected to be operating through the end of 2009 are used for the price forecast. For calendar years 2010 and 2011 the following are used:

(1) PNW wind capacity is modeled to equal to 4,330 MW to be consistent with Transmission Services' forecast of calendar year 2011 wind resources in BPA's Balancing Authority Area. If needed, for the final Market Price Forecast Study, the wind capacity will be revised. The BPA zone's wind capacity will be consistent with Transmission Services' forecast of wind resources in BPA's Balancing Authority Area. For further discussion, refer to Petty *et al.*, WP-10-E-BPA-13.

(2) Using a long-term study, AURORA$^{xmp®}$ can retire specific resources and determine which generic resources should be added within the AURORA$^{xmp®}$ database. As discussed in Section 2.3, AURORA$^{xmp®}$ adds or retires resources based on an economic profitability calculation. Generic natural gas-fired combined-cycle and simple-cycle power plants were available for selection in 2010 and 2011. AURORA$^{xmp®}$ did not retire or add resources in the PNW during FY 2010 and 2011.

(3) The extended outage scheduled for the Columbia Generating Station in 2011 is modeled as an 88-day outage from 4/8/2011 through 7/4/2011. Revisions to the extended outage schedule will be accounted for in the final Market Price Forecast Study.

A complete listing of all the generating resources can be found in the Market Price Forecast Study Documentation, WP-10-E-BPA-03A.

The generating resources' variable and fixed operation and maintenance expenses were updated based on the EPIS-supplied database labeled North American DB 2008-02. A tiered set of variable and fixed operation and maintenance expenses shown in Table 6 are assigned to the existing and updated actual natural gas-fueled resources.

Table 6: Variable and Fixed Operation and Maintenance Expense Assignment

A Existing Resource Heat Rate (Btu/kWh)	B Variable O&M (real 2005$/MWh)	C Fixed O&M (real 2005$/MW/week)
Less than 9,000	2.61	180.77
Between 9,000 and 11,000	4.49	152.46
Greater than 11,000	5.96	175.38

3.6 Other Assumptions

For the Market Price Forecast Study, AURORA$^{xmp®}$ version 9.2 is used. For the assumptions not mentioned above, EPIS data supplied with version 9.2 is used.

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