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

BP-18 Rate Proceeding

Initial Proposal

Power Market Price Study and Documentation

BP-18-E-BPA-04

November 2016

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COMMONLY USED ACRONYMS AND SHORT FORMS

ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DD	Dividend Distribution
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System

FELCC	firm energy load carrying capability
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge
Maf	million acre-feet
Mid C	Mid Columbia
MMBtu	million British thermal units
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
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)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries

NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability (assessment/charge)
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
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
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people's utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
RDC	Reserves Distribution Clause
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark

ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
SCD	Scheduling, System Control, and Dispatch rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VERBS	Variable Energy Resources Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

1. INTRODUCTION

1.1 Purpose of the Power Market Price Study

The Power Market Price Study explains the development of the power market price forecast, which incorporates natural gas pricing uncertainty and varying hydrology and load expectations. The power market price is used to forecast the value of secondary sales, the cost of anticipated balancing purchase and system augmentation purchases, Load Shaping and Demand rates, and the distribution of net revenues used to evaluate risk, among other values used in BPA's ratemaking. This Study includes BPA's natural gas price forecast and electricity market price forecast. In previous rate proposals the Power Market Price Study and the Power Risk Study were included in the same document (*e.g.,* BP-16-FS-BPA-04). For BP-18 the Market Price Study is separate, and the Power and Transmission risk studies are included in the same document, BP-18-E-BPA-05.

1.2 How Market Price Results Are Used

Projections of market prices for electricity are used for many aspects of setting power rates, including the quantitative analysis of risk presented in the Power and Transmission Risk Study, BP-18-E-BPA-05. The Risk Study applies this distribution of future price expectations to BPA's net position to quantify risk surrounding rate levels to reflect the uncertainty in cost recovery inherent in the volatility of market price fundamentals.

Forecasts of electricity market prices are used in the Power Rates Study, BP-18-E-BPA-01, in the calculations of:

- Prices for secondary energy sales and balancing power purchases
- Prices for augmentation purchases
- Load Shaping rates
- Load Shaping True-Up rate
- Resource Shaping rates
- Resource Support Services (RSS) rates
- Priority Firm Power (PF), Industrial Firm Power (IP), and New Resource Firm Power (NR) demand rates
- PF Tier 2 Balancing Credit
- PF Unused Rate Period High Water Mark (RHWM) Credit
- PF Tier 1 Equivalent rates
- PF Melded rates
- Balancing Augmentation Credit
- IP energy rates
- NR energy rates
- Energy Shaping Service (ESS) for New Large Single Load (NLSL) True-Up rate

2. FORECASTING MARKET PRICES

2.1 AURORAxmp®

BPA uses the AURORAxmp® (version 12.1.1043) model to forecast electricity market prices. For all assumptions other than those stated in section 2.3 of this Study, the model uses data provided by the developer, EPIS Inc. AURORAxmp® uses a linear program to minimize the cost of meeting load in the Western Electricity Coordinating Council (WECC), subject to a number of operating constraints. Given the solution (an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. This cost approximates the price of electricity by assuming that all resources are centrally dispatched (the equivalent of cost-minimization in production theory) and that the marginal cost of producing electricity approximates the price.

2.1.1 Operating Risk Models

Uncertainty in each of the following variables is modeled as independent:

- WECC Loads
- Natural Gas Price
- Regional Hydroelectric Generation
- Pacific Northwest (PNW) Hourly Wind Generation
- Columbia Generating Station (CGS) Generation
- PNW Hourly Intertie Availability

Each statistical model calibrates to historical data and employs Monte Carlo simulation to generate a distribution of future outcomes. Each realization from the joint distribution of these models constitutes one game and serves as input to AURORAxmp®. Where applicable, that game also serves as input to BPA's Revenue Simulation model (RevSim). The prices from AURORAxmp®, combined with the generation and expenses from RevSim, constitute one net revenue game. Each risk model may not generate 3,200 games, and where necessary a bootstrap is used to produce a full distribution of 3,200 games. Each of the 3,200 draws from the joint distribution is identified uniquely such that each combination of load, hydrology, and other conditions is consistently applied between AURORAxmp® prices and RevSim inventory levels.

2.2 R Statistical Software

The risk models used in AURORAxmp® were developed in R (www.r-project.org), an open-source statistical software environment that compiles on several platforms. It is released under the GNU General Public License (GPL), an operating system that is free software. R supports the development of risk models through an object-oriented, functional scripting environment; that is, it provides an interface for managing proprietary risk models and has a native random number generator useful for sampling distributions from any kernel. For the various risk models, the historical data is processed in R, the risk models are calibrated, and the risk distributions for input into AURORAxmp® are generated in a unified environment.

2.3 AURORAxmp® Model Inputs

AURORAxmp® produces a single electricity price forecast as a function of its inputs. Thus, producing a given number of price forecasts requires that AURORAxmp® be run that same number of times using different inputs. Risk models provide inputs to AURORAxmp®, and the resulting distribution of market price forecasts represents a quantitative measure of market price risk. As described in the Risk Study, BP-18-E-BPA-05, 3,200 independent games from the joint distribution of the risk models serve as the basis for the 3,200 market price forecasts. The monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices constitute the market price forecast. Because AURORAxmp® is an hourly model, the monthly prices in AURORAxmp® are the simple average of the simulated hourly prices for that diurnal period. The following subsections describe the various inputs and risk models used in AURORAxmp®.

2.3.1 Natural Gas Prices Used in AURORAxmp®

The price of natural gas is the predominant factor in determining the dispatch cost of a natural gas generator. When natural gas-fired resources are the marginal unit (the least-cost available generator to supply an incremental unit of energy), the price of natural gas determines the price of electricity. Due to natural gas plants' frequent position as the marginal resource in the Pacific Northwest, rising natural gas prices will typically translate into an increase in the market price for electricity (and vice versa). This effect varies seasonally; for example, electricity prices are much less sensitive to the price of natural gas in spring months, when hydroelectric generation is typically on the margin, whereas in the winter gas-fired generation is typically on the margin and electricity prices are strongly correlated with the prevailing price of natural gas.

2.3.1.1 Methodology for Deriving AURORAxmp® Zone Natural Gas Prices

Each natural gas plant modeled in AURORAxmp® operates using fuel priced at a natural gas hub according to the zone in which it is located. Each zone is a geographic subset of the WECC.

The foundation of natural gas prices in AURORAxmp® is the price at Henry Hub, a trading hub near Erath, Louisiana. Cash prices at Henry Hub are the primary reference point for the North American natural gas market.

Though Henry Hub is the point of reference for natural gas markets, AURORAxmp® uses prices for 11 gas trading hubs in the WECC. The prices at hubs other than Henry are derived using their basis differentials (differences in prices between Henry Hub and the hub in question). Basis differentials reflect differences in the regional costs of supplying gas to meet demand after accounting for pipeline constraints and pipeline costs. The 11 western hubs represent three major supply basins that are the source for most of the natural gas delivered in the western United States.

Sumas, Washington, is the primary hub for delivery of gas from the Western Canada Sedimentary Basin (WCSB) to western Washington and western Oregon. The Opal, Wyoming, hub represents the collection of Rocky Mountain supply basins that supply gas to the Pacific Northwest and California. The San Juan Basin has its own hub, which primarily delivers gas to southern California. AECO, the primary trading hub in Alberta, Canada, is the primary benchmark for Canadian gas prices. Kingsgate is another gateway for WCSB gas and is the hub that is associated with the demand center in Spokane, Washington. Two eastern Oregon hub locations, Stanfield and Malin, are included because major pipelines intersect at those locations. Pacific Gas and Electric (PG&E) Citygate represents demand centers in northern California. Topock, Arizona, and Ehrenberg, Arizona, represent intermediary locations between the San Juan Basin and demand centers in Southern California. *See* Figure 1. For purposes of the basis differential forecast, the same price is used for both of these Arizona hubs, as they are relatively specific to southern California markets. Finally, Southern California Citygate represents demand centers in southern California. The forecast of basis differentials is derived from recent historical price differentials between Henry Hub and each of the other 11 trading hubs, along with projections of regional supply and demand.

The final step is to estimate the basis differential between each of the western trading hubs and its associated AURORAxmp® zone. Sumas, AECO, Kingsgate, Stanfield, Malin, and PG&E Citygate are associated with the Pacific Northwest, Northern California, and Canadian zones. Opal is associated with the Montana, Idaho South, Wyoming, and Utah zones. San Juan, Topock, Ehrenberg, and Southern California Citygate are associated with the Nevada, Southern California, Arizona, and New Mexico zones.

2.3.1.2 Recent Natural Gas Market Fundamentals

Gas prices have varied substantially over time and most recently have been at the low end of historical values. *See* Figure 2. U.S. natural gas production for 2016 is on track to be roughly equivalent to that in 2015 on an annual basis. Despite a lack of annual growth in production, there continues to be an oversupply of natural gas. While the transportation and extraction infrastructure and recoverable gas reserves could allow for higher production levels, producers have been forced by low prices and high storage to reduce output. *See* Figures 3–5. Throughout 2015 and 2016, the marginal cost of production has continued to drop as advances in technology improve the efficiency of production in all phases, including exploration, drilling, and well stimulation. Producers are focusing on the most easily attainable resources by drilling longer, better targeted, lateral wells to increase rig efficiencies and decrease costs. These advances, along with Drilled but Uncompleted Well (DUC) completions, have allowed producers mostly to maintain production even with decreased capital expenditures and low drilling rig counts. The oversupply issues have been further exacerbated by "associated gas" resulting from domestic oil production. A byproduct of oil production in certain oil plays (a play being a defined geographic location where natural gas can be recovered from the underlying geology), associated gas has virtually no cost and today accounts for approximately 20 percent of domestic natural gas supply.

The winter of 2013–2014 created record demand due to cold weather and lagging supply that led to a record pace of storage withdrawals and increased prices. The supply response was swift and strong. Production powered through a colder than normal winter in 2014–2015, and storage entered the 2015–2016 withdrawal season at the all-time record high level of 4,009 billion cubic feet (bcf) of natural gas. Storage proceeded to exit the withdrawal season at another all-time record high of 2,473 bcf, setting the stage for 2016's low prices and attempts at producer restraint. *See* Figure 4.

Through 2015 and 2016, the market has struggled to rebalance. In an attempt to rein in production, firms cut capital expenditure plans and rig counts plummeted. Substantial production drops failed to materialize. The response to low prices from demand has led to increased consumption, where possible. The primary sector that can ramp up natural gas consumption is the power generation sector. Power sector coal-to-gas switching (essentially turning off coal plants and replacing their generation with natural gas plants when they are a cheaper source of power) has helped by setting historically high power burn levels and absorbing some excess supply. However, the combination of only gradual organic growth (which includes categories such as growth due to technology switching to natural gas, population growth, and GDP growth) (*see* Figure 5) and incremental fuel-switching demand has not been enough to balance the market or substantially lift prices.

Other sources of demand, including industrial growth, LNG exports, and Mexican export capacity, take a long time to work through investment decisions, permitting, and construction. These sources of long-term demand responses to low prices should begin to materialize by the BP-18 rate period.

2.3.1.3 Henry Hub Forecast

The average of the monthly forecast of Henry Hub prices is $3.24 per million British thermal units (MMBtu) during FY 2018 and $3.25/MMBtu during FY 2019. *See* Table 1.

Depending on the makeup of supply – from associated gas to dry gas and wet shale – gas prices are expected to eventually settle out at the long-run marginal cost of production of natural gas. It is estimated that, assuming normal weather, supply will lag demand in FY 2017 and balance should be reached by, or in, FY 2018. Given marginal cost estimates in the industry today and assuming that the market can remain close to equilibrium long-run marginal cost, prices in the FY 2018–2019 rate period are expected to average in the mid to low $3.00/MMBtu range.

There are many supply-side pressures, however, keeping gas price expectations from rising above this level. Just as the market price of electricity is determined by the marginal resource, the price of natural gas is determined by the marginal unit of gas production. In the current natural gas market, a couple of low-cost and highly productive plays are expanding production to meet additional calls on natural gas supply.

Located in the Appalachian region of the United States, the Marcellus and Utica gas plays have become a dominant story in the natural gas landscape. They provide low breakeven costs; they have shown that they can ramp up production levels very quickly; and they have provided (due to their location) relatively inexpensive gas to premium Northeast U.S. (NE) markets. Given their historical performance, it is reasonable to expect that these plays will be able quickly and inexpensively to increase production in the future to meet incremental calls from demand. The major barrier for these NE plays is take-away pipeline capacity. While there is ample capacity scheduled to come online through 2019, there is always the potential for unforeseen delays and cancellations to hamper the ability of NE gas to expand production and seize market share.

On the other side of the continent, WCSB gas has also shown itself to be resilient to the low-price environment. With a large amount of natural gas produced almost as a byproduct from extracting natural gas liquids (condensate) for Canadian oil-sand processing and transport, this persistent and cheap supply has pushed down into the Pacific Northwest and east into the Rockies as well as down from Canada into the Midwestern United States.

Growth in gas produced in the Marcellus and Utica plays, the WCSB, and in association with oil extraction in the United States is expected to prove sufficient to maintain the low prices the markets have come to expect from the U.S. shale gas era. Production and supply are expected to remain strong and capable of meeting incremental demand without significant price increases through the BP-18 rate period.

Although these supply-side pressures are significant, when forecasting Henry Hub prices it is important to consider demand as well. In response to low prices, the FY 2017–2019 timeframe shows the potential for significant demand growth in liquefied natural gas (LNG) exports, Mexican exports, the industrial sector, and gas burn for power generation. If demand growth outpaces supply growth, storage levels will decrease and Henry Hub prices will have to increase to the point that more expensive gas production is brought online to supply enough gas to meet demand. Conversely, if demand growth lags production growth, storage levels will grow and Henry Hub prices will need to drop to the point that production that is unprofitable at the new, lower, price is eliminated and supply scales down to match demand.

Looking forward, exports are expected to make up an increasingly significant portion of overall natural gas demand. For LNG in the United States, 2016 was a big year. The Sabine Pass LNG terminal sent out its first cargo in February and provided up to 1.3 bcf/d of incremental demand (once Train 2 ramped up). Through 2019, incremental LNG exports could grow by up to 3 bcf/d.

The Mexican natural gas extraction industry is currently reforming to a more deregulated environment with the specified aim of opening up the industry to the private sector. Into the foreseeable future the United States is likely to provide significant amounts of gas into the Mexican marketplace. About 1 bcf/d or more of incremental exports are expected through FY 2019.

Another category of major demand growth is industrial sector demand. To date, industrial demand has been slow to recover from the recession. However, the recent low natural gas prices have inspired growth in industries using natural gas or its byproducts as feedstock. A lag between a price change and induced demand is generally expected in the industrial component of natural gas demand, because investment decisions require implementation time. Due to this lag, the industrial sector has not been able to provide any meaningful price support in the FY 2015 and FY 2016 period. It is expected that investment decisions will begin to induce industrial demand growth during the BP-18 rate period, with projections ranging between 1 and 2 bcf/d of growth through FY 2019.

Gas demand for power burn has shown record strength in 2016, helping to absorb excess supply. Where possible, to maximize efficiencies and take advantage of low natural gas fuel costs, coal generating units have been shut down and gas generating units fired up in their place. As natural gas prices rise and the costs of operating natural gas plants also rise, some coal units will work their way back into the generating stack, reducing natural gas demand for power burn. However, coal and nuclear retirements through the duration of the rate period will continue to provide the opportunity to maintain or increase natural gas baseload demand. Because gas demand for power burn has been at such elevated levels and rising gas prices (which lower gas demand) can oppose the effect of retirements of competing fuel generating resources (coal and nuclear power plants), industry opinion is split on whether gas demand for power burn will increase or decrease through the rate period. Demand at its existing levels can be assumed to support Henry Hub prices.

Demand growth from these categories, combined with other organic growth, should prove sufficient to balance the market through the rate period. However, balance depends on both sides of the supply and demand equation. Risks to the forecast balance are risks to expected prices. Unexpected activities or shocks to either side could send prices higher or lower than the forecast. General sources of risk are weather, legislative action to restrict (or promote) the gas industry, and lack of producer restraint.

A risk specific to forecast supply strength comes from uncertainty around how the market will respond to the expected depletion of the DUC inventory in 2017 and interaction of that market response with effects of an extended duration of low natural gas drilling rig activity. Once all of the DUCs are gone and prices must reflect the full cost of natural gas extraction, the market will see how much technological advancements and cost reductions have actually changed the price landscape.

Risks to forecasted demand vary by the demand category. Risks to industrial demand center on continued recovery from the recession. Risks to LNG exports depend on a combination of global gas markets and local pricing. Risks to the expectation of continued strong natural gas demand for power burn center on any carbon legislation, the future of the coal industry in the United States, and the penetration of renewable resources.

The upward risks to the Henry Hub price forecast are tempered by the abundant supply of gas available at low prices, and the downward risks are tempered by the real (albeit declining) cost of extraction. Additional price risk moderation and balancing is provided by the flexibility and price sensitivity of LNG exports and gas burn for power demand.

2.3.1.4 The Basis Differential Forecast

Table 1 shows the basis differential forecast for the 11 trading hubs in the western U.S. used by AURORAxmp®. The location of natural gas supply source growth can dramatically change basis relationships as traditional pipeline flows are altered and even reversed. Production levels in the Rocky Mountains and Western Canada directly impact the relationships among western hubs. Additionally, pipeline transportation availability and cost can impact basis relationships.

In general, no significant shifts in recent historical regional dynamics are expected over the rate period.

The AECO and Kingsgate bases are expected to maintain their recent historical relationship to Henry Hub over the rate period. While NE production may displace the ability for WCSB production to supply Eastern Canada and the Northeast U.S. at some point in the future, current NE pipeline delays and improving WCSB economics should maintain the status quo through the rate period. Sumas and Stanfield will follow suit by staying level to recent historical basis values, taking their cues from upstream WCSB supply.

The Opal basis is expected to maintain its current, lowered, level over the rate period as NE production continues to increase and reduce the amount of Rocky Mountain gas that can economically be delivered eastward. Pipelines such as the Rockies Express Pipeline (REX) have given shippers the ability to reverse flow to send Marcellus natural gas east to west, contrary to the pipeline's original west-to-east design and contracts. Additional pressure is being placed on the Opal basis by WCSB gas displacing traditional flows west into Stanfield.

The PG&E Citygate basis will likely remain at a premium compared to other gas hubs in the country as strong Northern California natural gas demand continues. The continued strength of the PG&E Citygate basis will pull the Malin basis up slightly compared to recent historical basis values.

The Southern California hubs of Topock, Ehrenberg, and Southern California Citygate are expected to remain steady. Renewables growth will continue to erode natural gas market share, negating demand growth, and the Aliso Canyon storage field debacle (this field, which has been closed due to a leak and is anticipated to reopen in the winter of 2016, provides the primary balancing function for natural gas demand and supply within the Los Angeles basin) should resolve itself by the beginning of the rate period.

The producing San Juan Basin basis is expected to remain level to historical values.

2.3.1.5 Natural Gas Price Risk

Uncertainty regarding the price of natural gas is fundamental in evaluating electricity market price risk. As noted, when natural gas-fired generators deliver the marginal unit of electricity, as they frequently do in the Pacific Northwest, the price of natural gas largely determines the market price of electricity. Furthermore, as natural gas is an energy commodity, the price of natural gas is expected to fluctuate, and that volatility is an important source of market uncertainty.

The natural gas risk model simulates daily natural gas prices, generates a distribution of 875 natural gas price forecasts, and presumes that the gas price forecast represents the median of the resultant distribution. Model parameters are estimated using historical Henry Hub natural gas prices. Once estimated, the parameters serve as the basis for simulated possible future Henry

Hub price streams. This distribution of 875 simulated forecasts is randomly sampled to provide the Henry Hub natural gas price forecast input for each game in AURORAxmp®.

The model also constrains the minimum gas price to $1/MMBtu. Furthermore, because RAM2018 and the TPP calculations use only monthly electricity prices from AURORAxmp® and the addition of daily natural gas prices does not appreciably affect either the volatility or expected value of monthly electricity prices, the distribution of simulated natural gas prices is aggregated by month prior to being input into AURORAxmp®. The median, 5^{th}, and 95th percentiles of the forecast distribution are reported in Figure 6.

2.3.2 Load Forecasts Used in AURORAxmp®

This Study uses the West Interconnect topology, which comprises 46 zones. It is one of the default zone topologies supplied with the AURORAxmp® model and requires a load forecast for each zone.

2.3.2.1 Load Forecast

AURORAxmp® uses a WECC-wide, long-term load forecast as the base load forecast. Default AURORAxmp® forecasts are used for areas outside the United States. BPA produced a monthly load forecast for each balancing authority in the WECC within the United States for the rate period. Default AURORAxmp® forecasts are used for Canada and Mexico. As AURORAxmp® uses a cut-plane topology (*see* Figure 7) that does not directly correspond to the WECC balancing authorities, it is necessary to map the balancing authority load forecast onto the AURORAxmp® zones. The forecast by balancing authority is in Table 2.

2.3.2.2 Load Risk Model

The load risk model uses a combination of three statistical methods to generate annual, monthly, and hourly load risk distributions that, when combined, constitute an hourly load forecast for use in AURORAxmp®. When referring to the load model, this Study is referring to the combination of these models.

2.3.2.3 Yearly Load Model

The annual load model addresses variability in loads created by long-term economic patterns; that is, it incorporates variability at the yearly level and captures business cycles and other departures from forecast that do not have impacts measurable at the sub-yearly level. The model is calibrated using historical annual loads for each control area in the WECC aggregated into the AURORAxmp® zones defined in the West Interconnect topology. Furthermore, it assumes that load growth at the annual level is correlated across regions: the Pacific Northwest; California including Baja; Canada; and the Desert Southwest (which comprises all AURORAxmp® areas not listed in the other three). It also assumes that load growth is correlated perfectly within them, guaranteeing that zones within each of these regions will follow similar annual variability patterns.

The model takes as given the history of annual loads at the balancing authority level, as provided in FERC Form 714 filings from 1993 to 2014 and aggregated into the regions described above.

The model estimates the load in each region using a time series econometric model. Once the model is estimated, the parameters of the model are used to generate simulated load growth patterns for each AURORAxmp® zone.

2.3.2.4 Monthly Load Risk

Monthly load variability accounts for seasonal uncertainty in load patterns. This seasonal load variation can potentially pose substantial risk to BPA revenue. Unseasonably hot summers in California, the Pacific Northwest, and the inland Southwest have the potential to exert substantial pressure on prices at Mid-C and thus are an important component of price risk.

In addition to an annual load forecast produced in average megawatts, AURORAxmp® requires factors for each month of a forecast year that, when multiplied by the annual load forecast, yield the monthly loads, also in average megawatts. As such, the monthly load risk is represented by a distribution of vectors of 12 factors with a mean of one. The monthly load risk model generates a distribution of series of these factors for the duration of the forecast period. The monthly load model takes as given the historical monthly load for each AURORAxmp® zone, normalized by their annual averages and centered on zero. These historical load factors, which average to zero for any given year, constitute the observations used to calibrate a statistical model that generates a distribution of monthly load factors.

2.3.2.5 Hourly Load Risk

Hourly load risk embodies short-term price risk, as would be expected during cold snaps, warm spells, and other short-term phenomena. While this form of risk may not exert substantial pressure on monthly average prices, it generates variability within months and represents a form of risk that would not be captured in long-term business cycles or seasonal trends as reflected in the monthly and annual load risk models.

The hourly load model takes as inputs hourly loads for each AURORAxmp® zone from 2002 to 2014. The model groups these hourly load observations by week and month, and each group of week-long hourly load observations constitutes a sample for its respective month. The model then normalizes the historical hourly loads by their monthly averages, so the sample space is composed of hourly factors with an average of 1, and then uses a simple bootstrap with replacement to draw sets of week-long, hourly observations from each month. Each draw thus comprises 9,072 hours (54 weeks), with an average of 1. The model repeats this process 50 times, which generates 50 year-long hourly load factor time series. These 50 draws are assigned randomly to the 3,200 AURORAxmp® runs.

2.3.3 Hydroelectric Generation

Hydroelectric generation represents a substantial portion of the average generation in the region and thus is a primary driver of Mid-C electricity prices in AURORAxmp®. Thus, fluctuations in its output can have a substantial effect on the marginal generator.

2.3.3.1 PNW Hydro Generation Risk

The PNW hydroelectric generation risk factor reflects uncertainty regarding the timing and volume of streamflows. Given streamflows, BPA's Hydrosystem Simulator (HYDSIM) computes PNW hydroelectric generation amounts in average monthly values. *See* Power Loads and Resources Study, BP-18-E-BPA-03, § 3.1.2.1, for a description of HYDSIM. HYDSIM produces 80 records of PNW monthly hydroelectric generation, each one year long, based on actual water conditions in the region from 1929 through 2008 as applied to the current hydro development and operational constraints. For each of the 3,200 games, the model samples one of the 80 water years for the first year of the rate period (FY 2018) from a discrete uniform probability distribution using R, the software described in section 2.2.1 above. The model then selects the next historical water year for the following year of the rate period, FY 2019 *(e.g.,* if the model uses 1929 for FY 2018, then it selects 1930 for FY 2019). Should the model sample 2008 for FY 2018, it uses 1929 for FY 2019. The model repeats this process for each of the 3,200 games and guarantees a uniform distribution over the 80 water years. The resulting 3,200 water year combinations become AURORAxmp® inputs.

2.3.3.2 British Columbia (BC) Hydro Generation Risk

BC hydroelectric generation risk reflects uncertainty in the timing and volume of streamflows and the impacts on monthly hydroelectric generation in British Columbia. The risk model uses historical generation data from 1977 through 2008. The source of this information is Statistics Canada, a publication produced by the Canadian government. Because hydrological patterns, including runoff and hydroelectric generation, in BC are statistically independent of those in the

PNW, BPA samples historical water years from BC independently from the PNW water year. As with the PNW, water years are drawn in sequence.

2.3.3.3 California Hydro Generation Risk

California hydroelectric generation risk reflects uncertainty with respect to the timing and volume of streamflows and the impacts on monthly hydroelectric generation in California. Historical generation data from 1970 through 2008 was sourced from the California Energy Commission, the Federal Power Commission, and the Energy Information Agency. As with the BC hydro risk model, and for the same reasons, CA water years are drawn independently of PNW water years.

2.3.3.4 Hydro Generation Dispatch Cost

With the introduction of negative variable costs for renewable resources, discussed in section 2.3.7 below, reflecting the amounts of hydro energy available for curtailment (spillable hydro generation) in AURORAxmp® becomes crucial to the frequency such renewable resources would provide the marginal megawatt of energy and set prices for the zone. To model the amount of spillable hydro generation available in the PNW, a separate HYDSIM study is employed to determine the incremental amount of water and energy that may be spilled before reaching total dissolved gas limits. *See* Power Loads and Resources Study, BP-18-E-BPA-03, § 3.1.2.1.1. A relationship between average monthly hydro generation and these calculated levels of spillable hydro generation is estimated using an econometric model; the model is incorporated into AURORAxmp® to set the level of spillable hydro generation on a monthly, game-by-game basis for hydro resources in the PNW.

The dispatch cost of spillable hydro generation retains the AURORAxmp ® default of $1.74/MWh, while the remaining hydro generation (non-spillable hydro generation in the PNW and all other hydro generation across the Western Interconnection) dispatch cost is set to -$24/MWh, one dollar below the dispatch cost of wind. These assumptions ensure that, where available, approximated amounts of low-cost hydro generation are curtailed first. As the system moves down the resource supply stack, renewable resources are curtailed and zonal prices become negative, and finally, the remaining hydro generation and any must-run resources would be curtailed.

2.3.3.5 Hydro Shaping

AURORAxmp® uses an algorithm to determine hydro generation availability. This algorithm produces an hourly hydroelectric generation value that depends on average daily and hourly load, the average monthly hydro generation (provided by HYDSIM), and the output of any resource defined as "must run." Several constraints give the user control over minimum and maximum generation levels, the hydro shaping factor (*i.e.,* the extent to which it follows load), and so on. AURORAxmp® uses the default hydro shaping logic with two exceptions: minimum generation levels and the hydro shaping factor.

2.3.3.5.1 Hydro Minimum Generation Levels

Output from AURORAxmp® suggests that its hydro shaping algorithm generates a diurnal generation pattern that is inappropriate during high water; that is, the ratio of HLH generation to LLH generation is too high. It is recognized that high water compromises the ability of the hydro system to shape hydro between on-peak and off-peak hours. By default, AURORAxmp® limits minimum generation to 44 percent of nameplate capacity during May and June, but operations data suggest that this system minimum generation can be as high as 75 percent of nameplate capacity during high water months. To address this difference, a separate model is used to implement the minimum generation constraints. These constraints generally restrict the minimum generation to a higher percentage of nameplate capacity than default AURORAxmp® settings and reflect observed constraints to the degree to which the system can more realistically shape hydroelectric generation.

To implement this ratio in AURORAxmp®, the model limits the minimum hydro generation in each month to the expected ratio of minimum generation to nameplate capacity based on an econometric model.

2.3.3.5.2 Shaping Factor for PNW Hydro Resources

In AURORAxmp®, spillable hydro generation (described in section 2.3.3.4 above) is locked into a flat shape throughout the day, which in turn substantially reduces the amount of hydro generation shaped into on-peak hours in the PNW. While the adjustment to minimum generation levels described above prevents the model from over-shaping hydro generation during high streamflow conditions, additional modifications to the logic are required to increase shaping during normal and lower streamflow conditions. First, an econometric model estimates the historical relationship between monthly average hydro generation and the ratio of HLH to LLH hydro generation using Federal hydro system operations data from 2006 to 2016. Second, the model is implemented in AURORAxmp® to set a target HLH-to-LLH hydro generation ratio (Target Ratio) based on the relevant expected monthly hydro generation. Finally, a hydro shaping factor value necessary to achieve the Target Ratio is calculated and applied to PNW hydro resources.

2.3.4 Hourly Shape of Wind Generation

AURORAxmp® models wind generation as a must-run resource with a minimum capacity of 40 percent. This assumption implies that, for any given hour, AURORAxmp® dispatches 40 percent of the available capacity independent of economic fundamentals and dispatches the remaining 60 percent as needed. During the BP-18 rate period, BPA expects about 8,000 MW (nameplate) of wind capacity to operate in the PNW. The large amount of wind in the PNW (and throughout the rest of the WECC) affects the market price forecast at Mid-C by changing the generating resource used to determine the marginal price. Modeling wind generation on an hourly basis better captures the operational impacts that changes in wind generation can have on the marginal resource compared to using average monthly wind generation values. The hourly granularity for wind generation allows the price forecast more accurately to reflect the economic decision faced by thermal generators. Each hour, generators must decide whether to operate in a volatile market in which the marginal price can be below the cost of running the thermal generator but start-up and shut-off constraints could prevent the generator from shutting down.

2.3.4.1 PNW Hourly Wind Generation Risk

The PNW Hourly Wind Generation Risk Model simulates the uncertainty in wind generation output. The uncertainty is derived by averaging the observed output of wind plants within the BPA balancing authority area every five minutes for each hour and converting the data into hourly capacity factors. The source of these data is BPA's external website, www.bpa.gov. These data cover the period from 2006 through 2015. The model implements a Markov Chain Monte Carlo (MCMC) rejection sampling algorithm to generate synthetic series of wind generation data. This technique allows the production of statistically valid artificial wind series that preserve the higher-order moments of observed wind time series. Through this process, the model creates 30 time series, each of which includes 8,784 hours, to create a complete wind year. The model randomly samples these synthetic records and applies them as a forced outage rate against the wind fleet in select AURORAxmp® zones. This approach captures potential variations in annual, monthly, and hourly wind generation.

2.3.5 Thermal Plant Generation

The thermal generation units in AURORAxmp® often drive the marginal unit price, whether the units are natural gas, coal, or nuclear. With the exception of CGS generation, operation of thermal resources in AURORAxmp® is based on the EPIS-supplied database labeled North American DB 2015-02.

2.3.5.1 Columbia Generating Station Generation Risk

The CGS Generation Risk Model simulates monthly variability in the output of CGS such that the average of the simulated outcomes is equal to the expected monthly CGS output specified in the Power Loads and Resources Study, BP-18-E-BPA-03, § 3.1.3. The simulated results vary from the maximum output of the plant to zero output. The frequency distribution of the simulated CGS output is negatively skewed: the median is higher than the mean. This reflects the reality that thermal plants such as CGS typically operate at output levels higher than average output levels, but occasional forced outages result in lower monthly average output levels.

The output of the CGS Generation Risk Model feeds both RevSim (*see* the Power and Transmission Risk Study, BP-18-E-BPA-05, § 4.1.1) and AURORAxmp®, where the results of the model are converted into equivalent forced outage rates and applied to the nameplate capacity of CGS for each of 3,200 games.

2.3.6 Generation Additions and Retirements

As a result of state Renewable Portfolio Standards (RPS) and Federal tax credit policies, renewable resource additions have been substantial during recent years. Additionally, installation of behind-the-meter resources, namely rooftop solar photovoltaic panels, continues to grow significantly. Favorable net energy metering policies in California and declining installation costs throughout the WECC region are likely to reinforce this trend for the near future. Two main sets of data are used to quantify this growth.

First, data from the U.S. Energy Information Administration's database of planned and sited additions and retirements over the horizon of the rate period is referenced against additional data from sources such as BPA's Transmission Interconnection Queue, WECC's Transmission Expansion Planning Policy Committee, the California Energy Commission, the California Public Utilities Commission, and third-party consultant reports to create a set of planned additions and retirements in AURORAxmp®. BPA then adds sufficient generic resources to this stack to meet state renewable portfolio standards.

Second, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California were included from the California Energy Commission forecast. The corresponding zonal load forecasts are adjusted to keep projected net load (load minus behind-the-meter generation) aligned with BPA's load forecasts. Resources from both sets of data were included in the resource table of AURORAxmp®.

Finally, AURORAxmp® has logic capable of adding and retiring resources based upon economics. In a Long Term Study, AURORAxmp® generates a catalogue of resource additions and retirements consistent with long-term equilibrium: it (1) identifies any plants whose operating revenue is insufficient to cover their fixed and variable costs of operation and retires them; and (2) selects plants from a candidate list of additions whose operating revenue would cover their fixed and variable costs and adds them to the resource base. AURORAxmp® thus ensures that resources are added when economic circumstances justify. AURORAxmp® adds no new thermal resources to the PNW during the BP-18 rate period.

2.3.7 WECC Renewable Resource Dispatch Cost

The substantial growth of renewables across the Western Interconnection increases the likelihood that such resources will provide the marginal megawatt of energy and, when in market-based regions, set prices. Power purchase agreements, renewable energy credits, production tax credits, and other compensation mechanisms allow renewable resources to offer energy at negative prices and still earn revenue from production. Additionally, load-serving entities may operate renewable resources to satisfy RPS requirements and would be expected to offer such resources' generation at the replacement cost of renewable energy (if the operator had to curtail some amount of renewable output, the operator would be legally responsible to procure additional renewable energy sufficient to meet its RPS requirement). To approximate such behavior in AURORAxmp®, all wind resource dispatch costs are set to -$23/MWh, a reflection of an appropriate offer price if the resource receives the Federal production tax credit. Lacking a widely available and transparent supplemental income figure for solar resources analogous to the Federal production tax credit for wind resources, BPA relies on the AURORAxmp® default spread between wind and solar resource dispatch costs. The AURORAxmp® default dispatch cost of solar resources is 36 cents higher than wind; this default spread is applied to all solar resources, resulting in a dispatch cost of -$22.64 /MWh.

2.3.8 Transmission Capacity Availability

In AURORAxmp®, transmission capacity limits the amount of electricity that can be transferred between zones. Figure 2 shows the AURORAxmp® representation of the major transmission interconnections for the West Interconnect topology. The transmission path ratings for the

Alternating-Current or California-Oregon Intertie (AC Intertie or COI), the Direct-Current Intertie (DC Intertie), and the BC Intertie are based on historical intertie reports posted on the BPA OASIS Web site from 2003 through 2015. The ratings for the rest of the interconnections are based on the EPIS-supplied database labeled North American DB 2015-02.

2.3.8.1 PNW Hourly Intertie Availability Risk

PNW hourly intertie risk represents uncertainty in the availability of transmission capacity on each of three interties that connect the PNW with other regions in the WECC: AC Intertie, DC Intertie, and BC Intertie. The PNW hourly intertie risk model implements a Markov Chain duration model based on observed data from 2003 through 2015. The data comprise observed transmission path ratings and the duration of those ratings for both directions on each line.

The model begins with an observed path rating and duration from the historical record. It samples the proximate path rating using a Markov Chain that has been estimated with observed data. Then it samples a duration to associate with that rating based on the set of observed, historical durations associated with that specific rating. This process repeats until an 8,784-hour record has been constructed. The model generates 200 artificial records. Path ratings are rounded to avoid a Markov Chain that is too sparse to effectively generate synthetic profiles.

For each of 3,200 games, each intertie has a single record that is independently selected from the associated set of 200 records. The outage rate is applied to the Link Capacity Shape, a factor that determines the amount of power that can be moved between zones in AURORAxmp® for the associated intertie. By using this method, quantification of this risk results in the average of the simulated outcomes being equal to the expected path ratings in the historical record.

2.3.9 California Carbon Pricing

The California Air Resources Board established a carbon market by placing limits on CO_2 emissions and requiring entities in a number of sectors, including electricity, to purchase sufficient allowances (shares of the total CO_2 limit) in quarterly auctions to cover their emissions. These auctions are subject to a floor price beginning at \$10 per metric ton of CO_2 emissions in 2012 and escalating at five percent annually plus the rate of inflation. In the California electricity market, resources are allowed to incorporate the costs of purchasing CO_2 allowances in their offer, so prices should reflect a carbon adder roughly equal to the marginal resource's emission rate multiplied by the CO_2 allowance price. Out-of-state electricity producers wishing to export energy to California are subject to a default emission rate of 0.428 metric tons per megawatthour unless the producer qualifies for a lower rate more specific to its resources (specified sources).

The California carbon market mechanisms are reflected in AURORAxmp® by applying the auction floor prices to California resources using AURORAxmp® default CO_2 emission rates for each resource to establish an incremental carbon emission cost addition, which is incorporated into dispatch and commitment logic. Consequently, if a California resource provides the marginal MW of energy and sets a zonal price, the price will include the additional cost of CO_2 emissions tied to producing that MW of energy (the specific resource CO_2 emission rate multiplied by the cost of CO_2 emissions). Using BPA's inflation forecast, the auction floor prices are calculated to be \$13.60, \$14.53, and \$15.50 per metric ton of CO_2 emissions for calendar years 2017, 2018, and 2019, respectively.

Additionally, wheeling costs on all transmission lines going into California are subject to an adder of the default emission rate of 0.428 metric tons per megawatthour at the auction floor prices. While the carbon adders for California resources substantially increase prices in California zones, the wheeling adders increase the cost of sending energy to California, thereby preventing major shifts in energy flows. Ultimately, prices at Mid-C do not change significantly, but the spreads between prices at Mid-C and California trading hubs better reflect the real-world price impacts of California's carbon market, enabling more accurate estimates of BPA revenue generated from sales of secondary energy to California.

2.4 Market Price Forecasts Produced By AURORAxmp®

Two electricity price forecasts are created using AURORAxmp®. The market price forecast uses hydro generation data for all 80 water years, and the critical water forecast uses hydro generation for only the critical water year, 1937. Figure 8 shows the FY 2018 through FY 2019 monthly average HLH and LLH prices from the market price forecast. Figure 9 shows the FY 2018 and FY 2019 monthly average HLH and LLH prices from the critical water forecast.

As stated previously, these projections of market prices for electricity are used for many aspects of setting power rates, including the quantitative analysis of risk presented in the Power and

Transmission Risk Study, BP-18-E-BPA-05, and numerous components of the Power Rates Study, BP-18-E-BPA-01.

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DOCUMENTATION

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Table 1: Cash Prices at Henry Hub and Basis Differentials (nominal $/MMBtu)

	FY 2018	FY 2019
Henry	3.24	3.25
AECO	-0.61	-0.64
Kingsgate	-0.20	-0.21
Malin	-0.07	-0.07
Opal	-0.13	-0.13
PG&E	0.34	0.36
SoCal City	0.22	0.22
Ehrenberg	0.04	0.04
Topock	0.04	0.04
San Juan	-0.13	-0.13
Stanfield	-0.14	-0.14

Table 2: Control Area Load Forecast

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 2: Control Area Load Forecast (MWh)**														
2	**Date**	**APS**	**AVA**	**BPA**	**CHPD**	**CISO**	**DOPD**	**EPE**	**GCPD**	**IID**	**IPC**	**LDWP**	**NEVP**	**NWE**	**PAC**
3	**Oct-17**	2644652	1019788	4273875	331646	19897190	110952	731056	346993	320715	1286938	2290404	1953666	911493	4981571
4	**Nov-17**	2257672	1145977	5031565	371200	18662390	144564	672997	350447	266754	1372580	2127832	1833184	963502	5228522
5	**Dec-17**	2535223	1304837	5616643	413198	19782950	182143	719423	400429	278063	1607524	2295818	2002293	1063587	5731447
6	**Jan-18**	2547329	1268178	5509330	413132	19673580	182726	722815	400248	276727	1575494	2287132	2010102	1082855	5760271
7	**Feb-18**	2237022	1095779	4764958	351013	17706160	139858	649263	355540	255799	1362853	2059915	1776138	960536	5069422
8	**Mar-18**	2367991	1088409	4674363	345809	19217310	116540	696305	345707	273225	1325826	2244303	1879421	978378	5155706
9	**Apr-18**	2394621	1004157	4464067	322059	18533860	107642	700488	359545	275833	1291558	2145528	1806896	872452	4808056
10	**May-18**	2796268	1013411	4495691	319281	19957980	112347	764327	387729	356478	1600655	2311133	2148753	879145	4904336
11	**Jun-18**	3108837	1000239	4478601	311832	21391580	110971	837025	401945	414659	1728651	2486062	2587159	892865	5079799
12	**Jul-18**	3698334	1087481	4733653	332835	24504760	133829	917952	442680	479651	2111893	2776476	3091860	1017204	5821246
13	**Aug-18**	3660216	1088668	4626906	332837	24866650	134343	926317	437287	476025	1978101	2829526	2973417	980638	5704123
14	**Sep-18**	3127773	979195	4200372	313927	22379480	109210	809271	370083	411271	1564346	2603146	2401922	872062	4882518
15	**Oct-18**	2683104	1026278	4313267	334171	20028750	112690	745186	355038	327156	1301847	2307899	1989032	920779	5025627
16	**Nov-18**	2296124	1152452	5073237	373723	18793950	146302	687127	358469	273193	1387489	2145302	1868550	972776	5272446
17	**Dec-18**	2573676	1311296	5660076	415718	19914510	183881	733553	408428	284500	1622433	2313263	2037660	1072849	5775239
18	**Jan-19**	2584957	1274537	5548660	415014	19777380	184285	736699	408224	281926	1590267	2300414	2041271	1091157	5804372
19	**Feb-19**	2274650	1102123	4802060	352892	17809960	141417	663148	363494	260996	1377626	2073172	1807307	968826	5113392
20	**Mar-19**	2405618	1094738	4711200	347685	19321120	118099	710190	353638	278420	1340599	2257535	1910590	986655	5199547
21	**Apr-19**	2432249	1010471	4500279	323932	18637670	109200	714373	367454	281026	1306331	2158735	1838065	880718	4851767
22	**May-19**	2820161	1019710	4532003	321152	20075720	113906	778211	395616	361669	1620538	2324316	2174968	887398	4947919
23	**Jun-19**	3132730	1006523	4514868	313700	21509320	112529	850910	409810	419849	1748534	2499221	2613373	901106	5123255
24	**Jul-19**	3722226	1093751	4770691	334701	24622500	135387	931837	450524	484839	2131776	2789610	3118075	1025433	5864575
25	**Aug-19**	3684109	1094923	4663628	334701	24984400	135902	940202	445109	481211	1997984	2842637	2999632	988856	5747326
26	**Sep-19**	3151666	985436	4235821	315788	22497220	110769	823155	377883	416454	1584229	2616232	2428137	880267	4925595

Table 2: Control Area Load Forecast (cont.)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
27	**Table 2 (cont): Control Area Load Forecast (MWh)**														
28	**Date**	**PGE**	**PNM**	**PSC**	**PSE**	**SCL**	**SMUD**	**SPR**	**SRP**	**TEP**	**TID**	**TPWR**	**WACM**	**WALC**	**WAUW**
29	**Oct-17**	1750627	922638	3360494	2021410	831848	865759	1023744	2393725	1220192	229481	411853	2047973	711318	73259
30	**Nov-17**	1891428	926363	3413712	2320179	926508	845763	1036938	2061322	1161106	204348	483802	2104949	640812	82881
31	**Dec-17**	2105839	1037426	3834616	2554436	977229	967528	1149340	2324772	1262362	215562	532808	2329945	723449	89947
32	**Jan-18**	2075783	1028017	3780109	2557507	1014415	956448	1139311	2374520	1255713	214909	527437	2284884	713971	92815
33	**Feb-18**	1815906	907175	3351507	2246581	888281	820892	1025677	2061039	1130926	193358	471391	2079258	630009	81970
34	**Mar-18**	1841707	945246	3475712	2217676	893080	871221	1073227	2174552	1184423	207992	468493	2157080	664579	81606
35	**Apr-18**	1727435	891895	3240324	2011890	833948	812967	1011871	2183305	1129358	204306	426394	2011806	669506	71343
36	**May-18**	1727804	901207	3287250	1883875	801448	876164	1045579	2608252	1299586	248143	398448	2072818	763734	73572
37	**Jun-18**	1665574	975552	3470409	1824138	773946	1017553	1070677	2990811	1485573	269760	379503	2173503	861748	76447
38	**Jul-18**	1845543	1103810	4050719	1905827	800257	1201003	1177534	3452462	1685206	304898	388370	2434073	925811	94245
39	**Aug-18**	1867984	1092860	3910470	1945576	796985	1186030	1176794	3413155	1664959	301730	396711	2396204	877566	86438
40	**Sep-18**	1703449	951219	3301813	1855491	768488	1009293	1046584	2915920	1468605	267562	382892	2067461	790170	75973
41	**Oct-18**	1763938	933606	3376105	2026953	833743	870998	1044479	2437916	1235465	232705	415694	2061552	719598	73259
42	**Nov-18**	1904738	937341	3429323	2325721	928403	851003	1057673	2105405	1176234	207567	488183	2118407	649069	82881
43	**Dec-18**	2119150	1048680	3850227	2559979	979124	972768	1170075	2368749	1277743	218777	537558	2343284	731683	89947
44	**Jan-19**	2086931	1037318	3792546	2562154	1016004	961018	1155930	2418268	1271477	217835	532015	2298105	722181	92815
45	**Feb-19**	1827054	916179	3363944	2251228	889870	825462	1042297	2104680	1146384	196279	475549	2092364	638196	81970
46	**Mar-19**	1852855	954345	3488150	2222323	894669	875791	1089846	2218089	1200016	210908	472629	2170073	672743	81606
47	**Apr-19**	1738583	900863	3252762	2016538	835537	817537	1028491	2226737	1144817	207217	430216	2024688	677647	71343
48	**May-19**	1738952	910199	3299687	1888523	803037	880734	1062198	2644378	1315466	252141	402060	2085591	771852	73572
49	**Jun-19**	1676722	984729	3482846	1828785	775535	1022123	1087296	3026855	1501913	273750	382974	2186168	869844	76447
50	**Jul-19**	1856691	1113303	4063157	1910475	801846	1205573	1194153	3488422	1702039	308881	391908	2446632	933884	94245
51	**Aug-19**	1879132	1102327	3922908	1950223	798574	1190600	1193413	3449033	1681744	305705	400312	2408660	885617	86438
52	**Sep-19**	1714597	960338	3314250	1860138	770077	1013863	1063203	2951717	1484908	271530	386390	2079814	798198	75973

Figure 1: Basis Locations

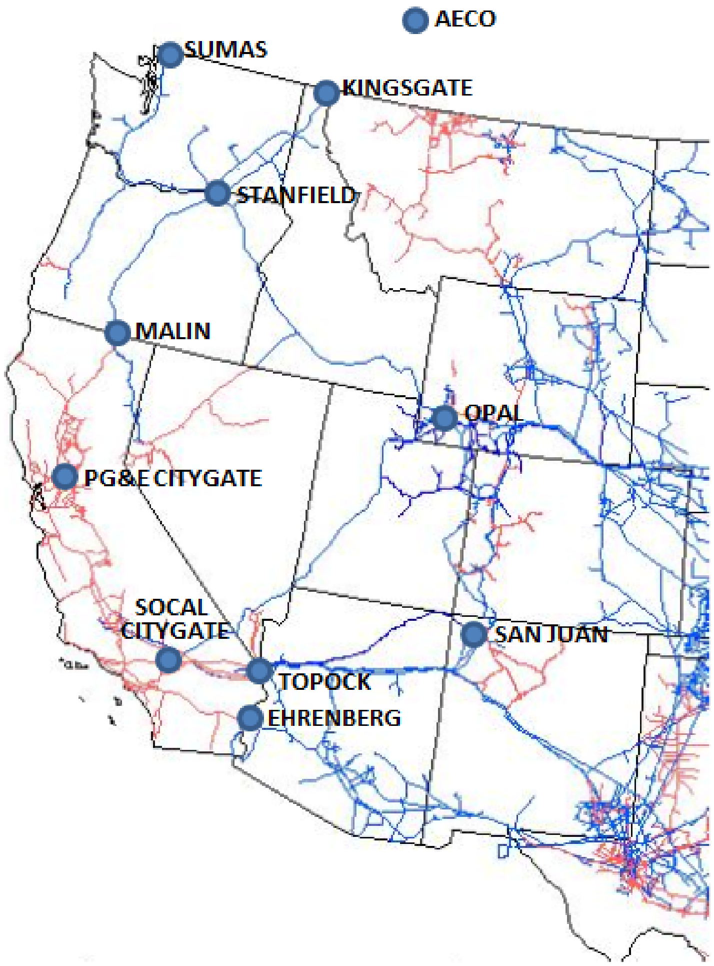
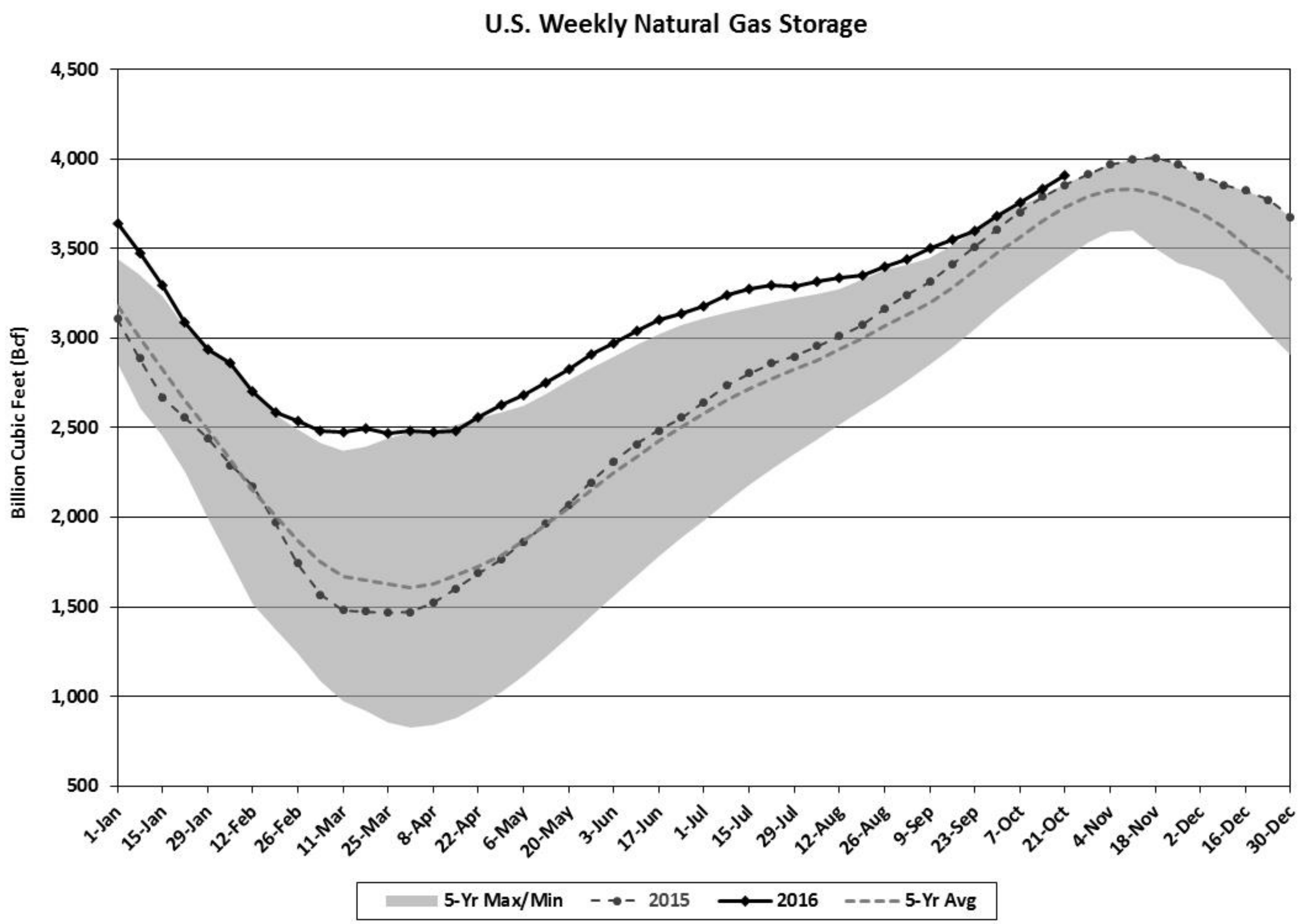


Figure 2: January 2011 Through July 2016 Monthly Henry Hub Gas Prices

Figure 3: U.S. Dry Natural Gas Production

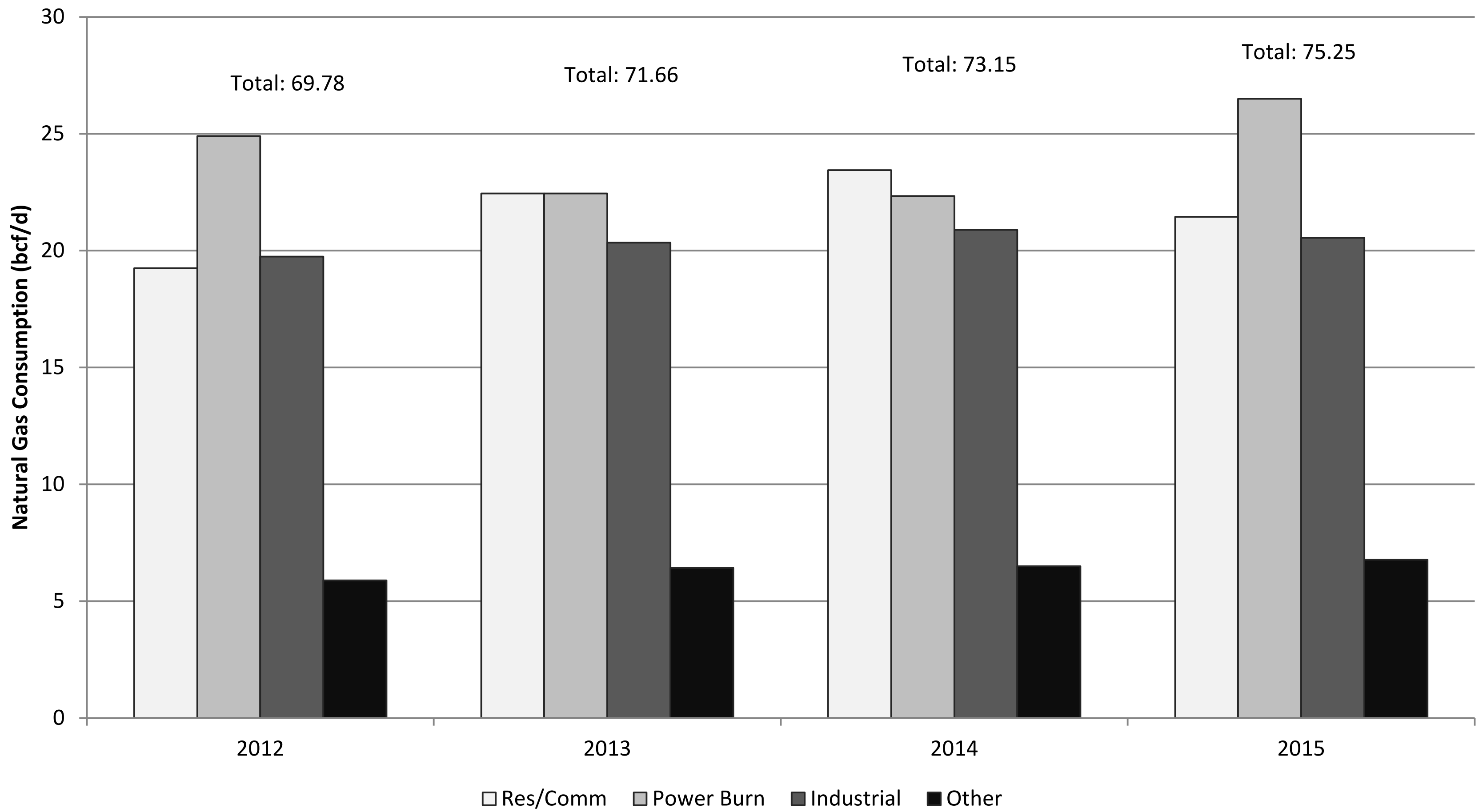
Source: U.S. Energy Information Administration

Figure 4: Natural Gas Storage



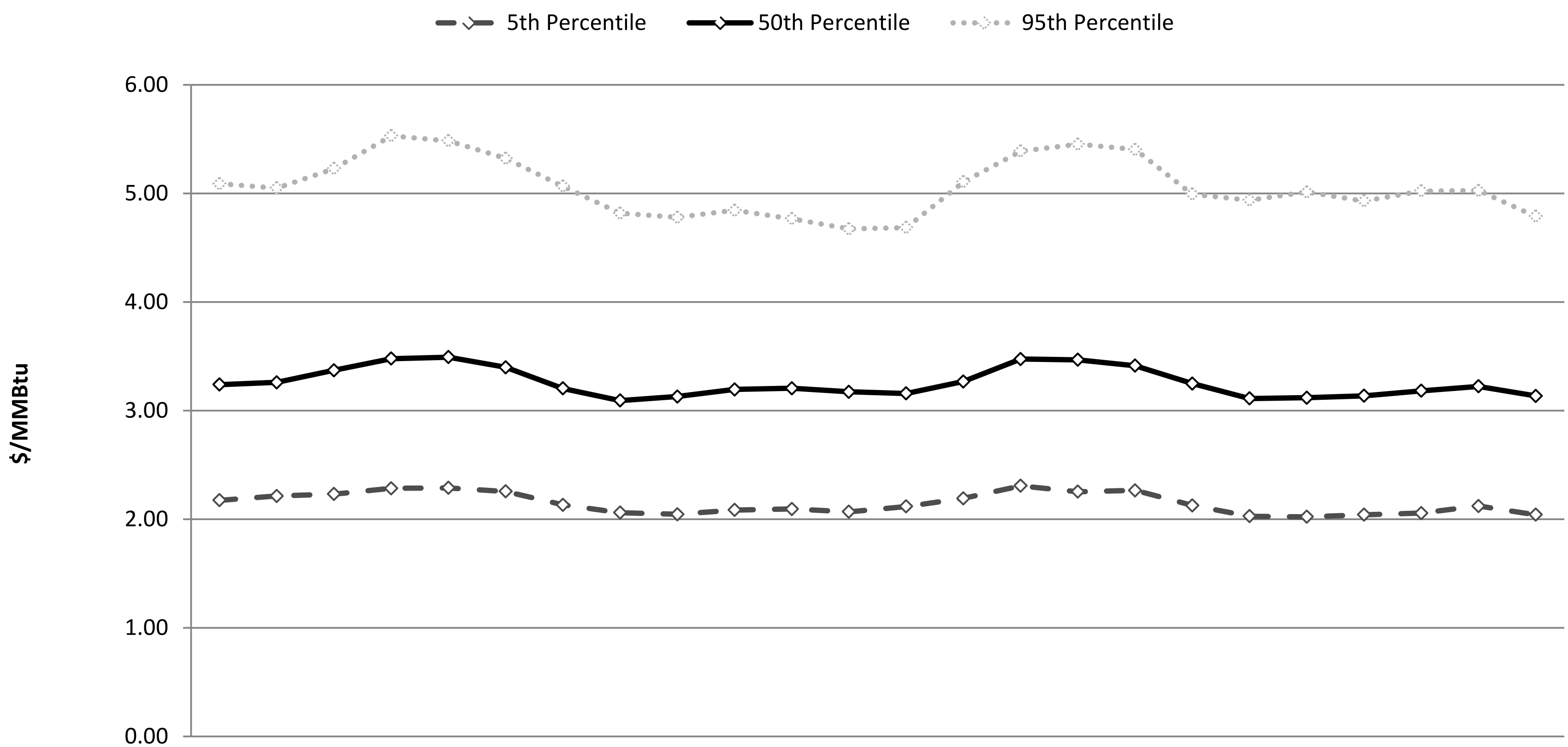
Source: U.S. Energy Information Administration

Figure 5: Natural Gas Domestic Consumption (Demand)



Source: U.S. Energy Information Administration

Figure 6: Natural Gas Price Risk Model Percentiles



	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
5th Percentile	2.17	2.21	2.23	2.29	2.29	2.26	2.13	2.06	2.05	2.09	2.10	2.07	2.12	2.19	2.31	2.25	2.27	2.13	2.03	2.02	2.04	2.06	2.12	2.04
50th Percentile	3.24	3.26	3.37	3.48	3.49	3.40	3.20	3.09	3.13	3.19	3.21	3.17	3.16	3.27	3.48	3.47	3.41	3.25	3.11	3.12	3.14	3.18	3.22	3.14
95th Percentile	5.09	5.05	5.23	5.53	5.48	5.32	5.07	4.82	4.78	4.84	4.77	4.67	4.69	5.11	5.39	5.45	5.40	4.99	4.94	5.01	4.93	5.02	5.03	4.79

Figure 7: AURORAxmp® Zonal Topology

AURORAxmp System Diagram: West_Interconnect 10/19/2016 10:02:01 AM

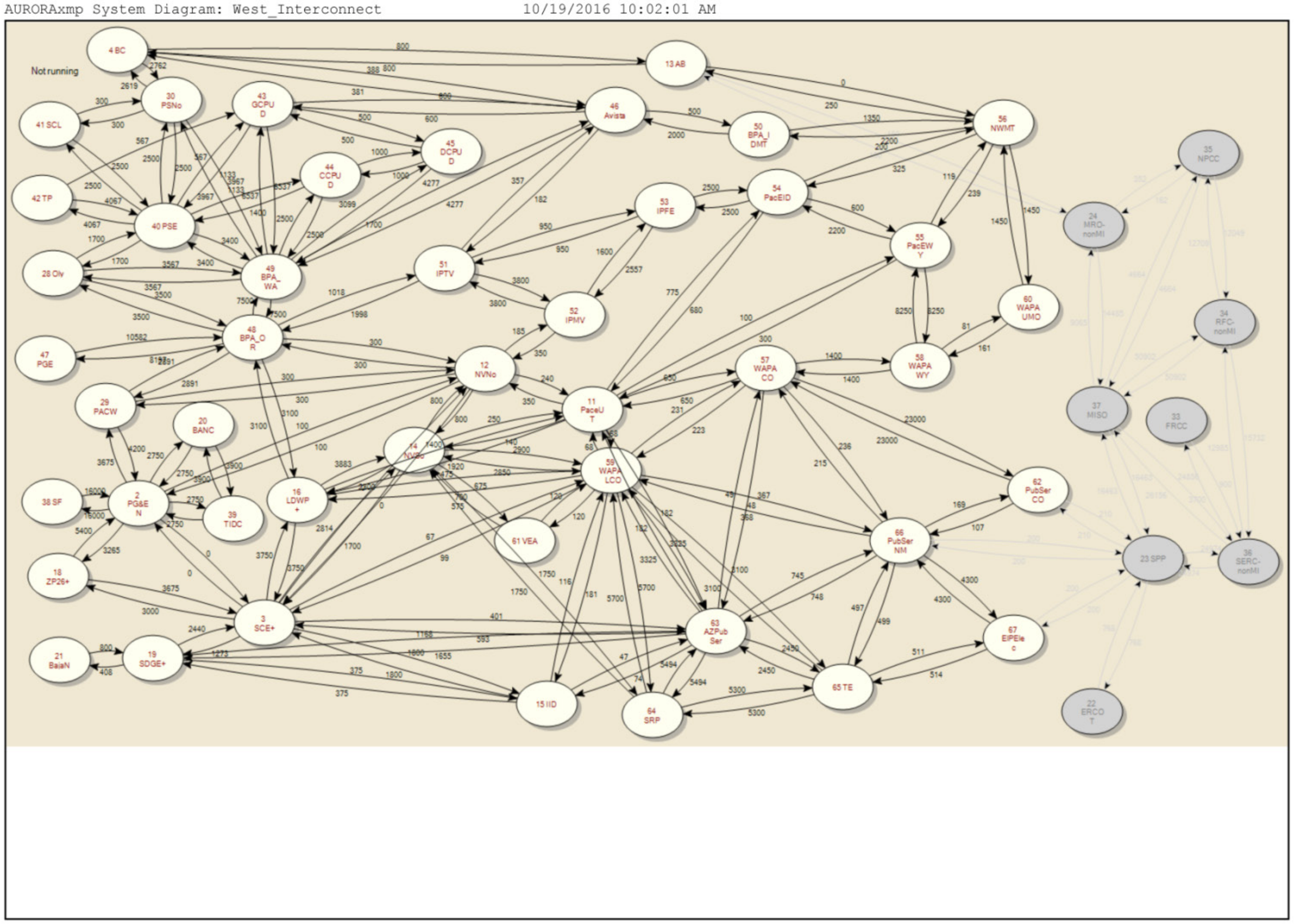
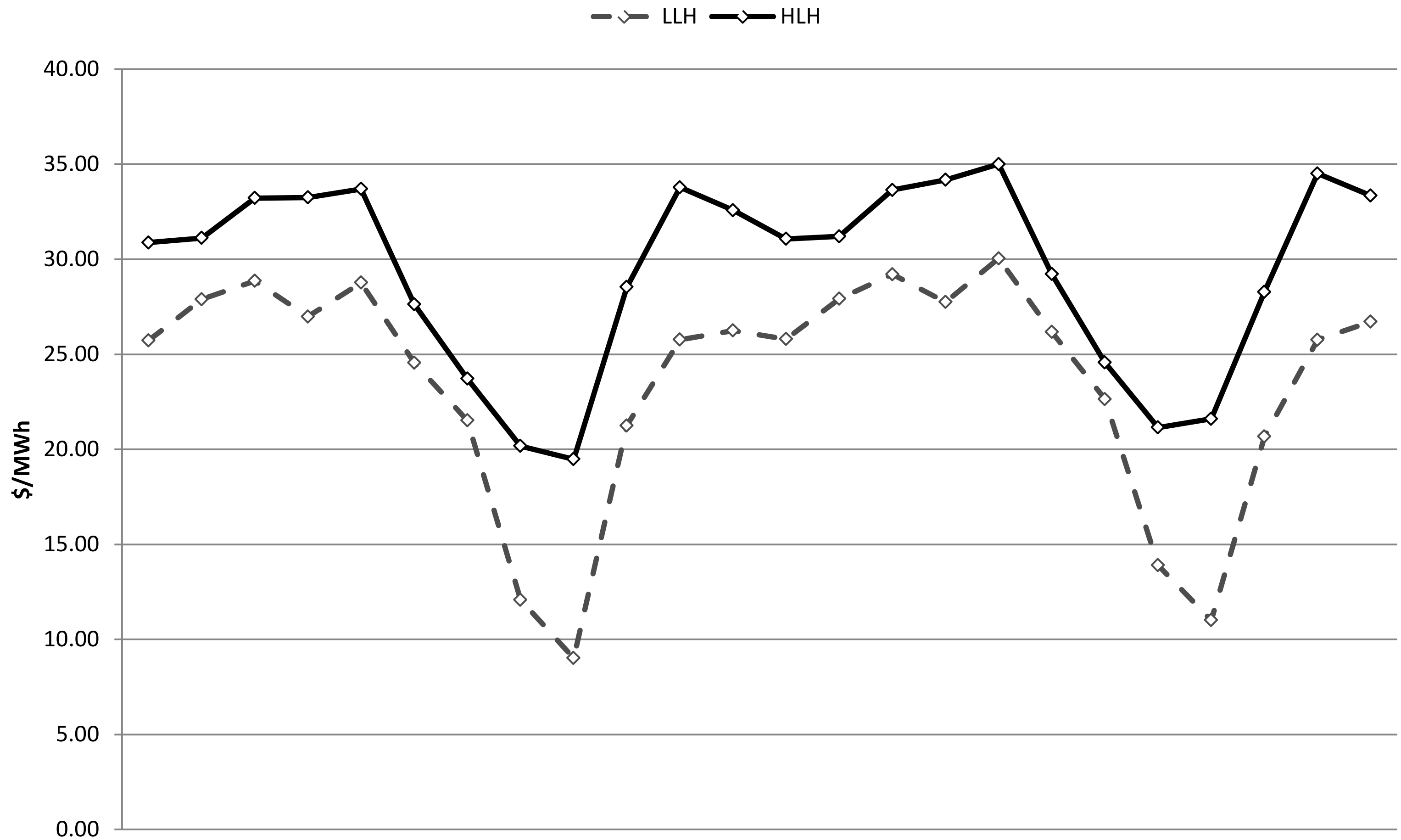
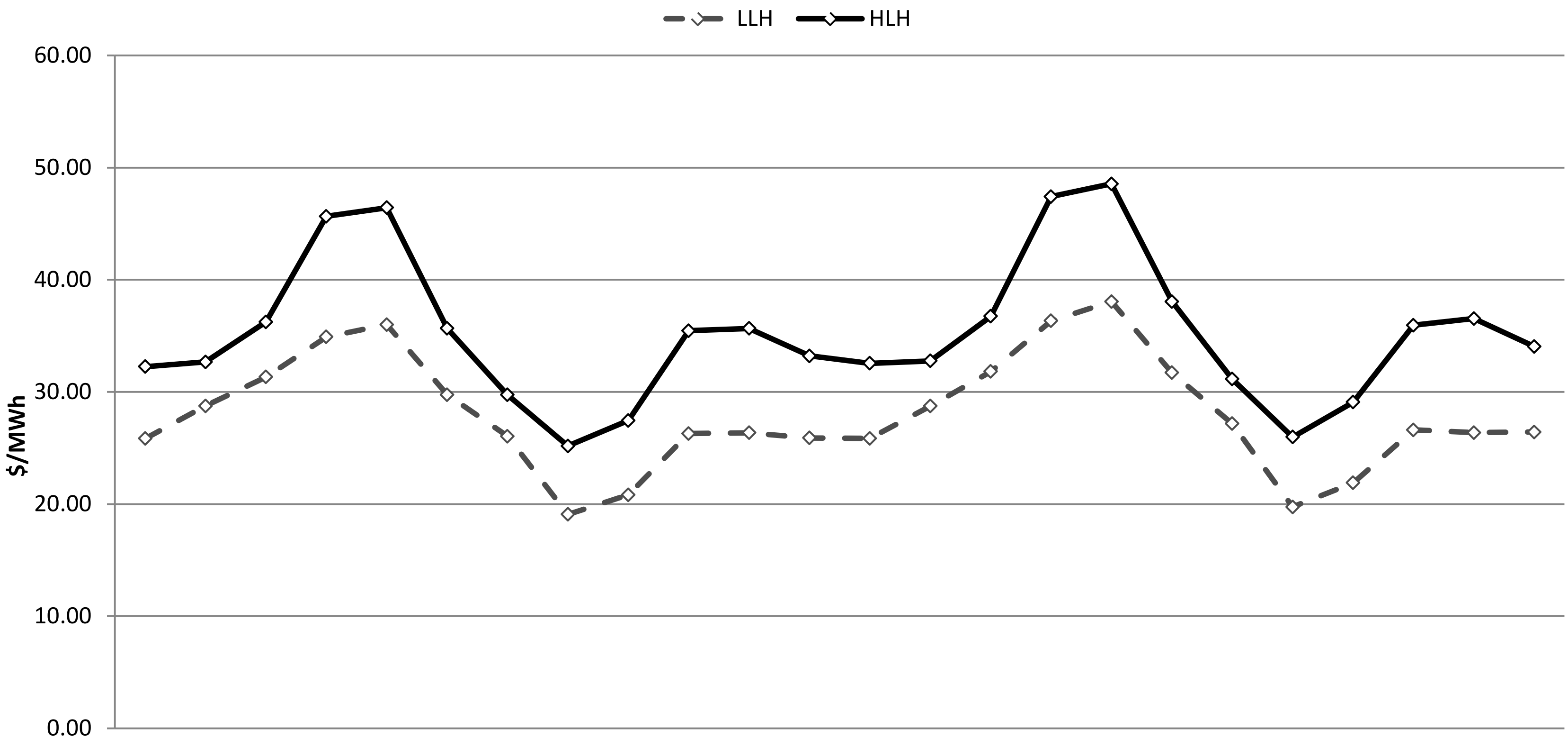


Figure 8: Monthly Average Mid-C Market Price for FY18/FY19



	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
LLH	25.7	27.9	28.8	26.9	28.7	24.5	21.5	12.0	9.02	21.2	25.7	26.2	25.8	27.9	29.2	27.7	30.0	26.1	22.6	13.9	11.0	20.6	25.7	26.7
HLH	30.8	31.1	33.2	33.2	33.7	27.6	23.7	20.1	19.4	28.5	33.7	32.5	31.0	31.2	33.6	34.1	35.0	29.2	24.5	21.1	21.6	28.2	34.5	33.3

Figure 9: Monthly Average Mid-C Market Price for FY18/FY19 Critical Water



	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
LLH	25.85	28.75	31.33	34.90	36.00	29.75	26.04	19.07	20.82	26.28	26.36	25.89	25.86	28.73	31.83	36.33	38.06	31.71	27.16	19.74	21.88	26.61	26.36	26.42
HLH	32.25	32.67	36.25	45.66	46.43	35.67	29.74	25.17	27.45	35.46	35.66	33.21	32.56	32.76	36.74	47.42	48.55	38.06	31.14	25.98	29.08	35.94	36.55	34.05

BONNEVILLE POWER ADMINISTRATION
November 2016