BP-24 Rate Proceeding

Final Proposal

Power Market Price Study

BP-24-FS-BPA-04

July 2023

POWER MARKET PRICE STUDY

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
AGC	automatic generation control
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission (see also "FERC")
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also "NPCC")
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
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
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
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
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GI	generation imbalance
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
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
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
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	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council (see also "Council")
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement

NUG	non-utility generation
OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	oversupply
OY	operating year (August through July)
P10	tenth percentile of a given dataset
PDCI	Pacific DC Intertie
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
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
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
RRHL	Regional Residual Hydro Load
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability

RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
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
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource 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
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool

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1. INTRODUCTION

1.1 Purpose of the Power Market Price Study

This Power Market Price Study (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 by the Bonneville Power Administration (BPA) in ratemaking. This Study includes BPA's natural gas price forecast and electricity market price forecast.

1.2 How Market Price Results Are Used

Projections of electricity market prices are used for many aspects of setting power rates, including the quantitative analysis of risk presented in the Power and Transmission Risk Study, BP-24-FS-BPA-05. The Risk Study applies this distribution of future market price expectations to forecasts of BPA's loads and resources to create another distribution that assigns possible values to BPA's energy surplus or deficits. This resulting distribution is leveraged to quantify risk surrounding rate levels by reflecting the uncertainty in cost recovery attributed to the volatility of market price fundamentals.

Forecasts of electricity market prices are used in the Power Rates Study, BP-24-FS-BPA-01, in the calculations of:

- Prices for secondary energy sales and balancing power purchases
- Prices for augmentation purchases (if there is augmentation in the rate period)
- 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 Aurora

BPA uses the Aurora[1] model (version 14.1.1049) 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, Energy Exemplar Proprietary Limited, in the database labeled North American DB 2020v9. Aurora uses a mixed integer 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. Recognizing that actual hub prices can systemically differ from a simplistic calculation of the marginal cost of electricity, BPA uses recent historical data to further calibrate the model. *See* Bid Modifiers, Section 2.3.6.1 of this Study.

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) and California hourly wind generation
- Columbia Generating Station (CGS) generation
- PNW hourly intertie availability

[1] Aurora is a registered trademark of Energy Exemplar Proprietary Limited (ACN 120 461 716), the software developer.

Each statistical model calibrates to historical data to generate a distribution of future outcomes. Each realization from the joint distribution of these models constitutes one game and serves as input to Aurora. Where applicable, that game also serves as input to BPA's Revenue Simulation model (RevSim). The prices from Aurora, combined with the generation and expenses from RevSim, constitute one net revenue game. Because each risk model may not generate a full distribution of 2,700 games, where necessary the risk model is resampled to produce a full distribution. Each of the 2,700 draws from the joint distribution is identified uniquely such that each combination of load, hydrology, and other conditions is consistently applied between Aurora prices and RevSim inventory levels.

2.2 R Statistical Software

The risk models used in Aurora 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), a licensing system that specifies fair use for 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 Aurora are generated in a unified environment.

2.3 Aurora Model Inputs

Aurora produces a single electricity price forecast as a function of its inputs. Thus, producing a given number of price forecasts requires that Aurora be run that same number of times using different inputs. Risk models provide inputs to Aurora, and the resulting distribution of market price forecasts represents a quantitative measure of market price risk. As described in the Power and Transmission Risk Study, BP-24-FS-BPA-05, 2,700 independent games from the joint distribution of the risk models serve as the basis for the 2,700 market price forecasts. The monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices constitute the market price forecast. Because Aurora is an hourly model, the monthly prices in Aurora 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 Aurora.

2.3.1 Natural Gas Prices Used in Aurora

The price of natural gas is the predominant factor in determining the dispatch cost of a natural gas-fired power generation plant. When natural gas-fired resources are the marginal unit (the least-cost generator available to supply an incremental unit of energy), the price of natural gas influences the price of electricity. Due to natural gas plants' frequent position as the marginal resource in the Pacific Northwest, falling natural gas prices will typically translate into a decrease 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 (*i.e.,* is the marginal unit), 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 Henry Hub Forecast

The foundation of natural gas prices in Aurora is the price at Henry Hub, a trading hub near Erath, Louisiana. Cash prices at Henry Hub are used as the primary reference point for the North American natural gas market. For BP-24, BPA produced forecasts of monthly average prices under three different scenarios: a baseline scenario based on trading in futures markets as well as the independent forecasts of various consultants; a "low price" scenario associated with deep decarbonization and rapid transition to electrification utilized in the "High Policy" scenario in BPA's 2022 Resource Program; and a "high price" scenario designed to simulate a continuation of tight domestic markets observed throughout much of FY 2022. See Section 2.3.1.4 for details on how these three separate forecasts are used in the gas risk model.

The average of the monthly forecast of Henry Hub prices is $4.27 per million British thermal units (MMBtu) for FY 2024 and $4.16 per MMBtu for FY 2025 under the baseline scenario; $2.77 MMBtu for FY 2024 and $2.85 per MMBtu for FY 2025 under the "low price" scenario; and $8.66 per MMBtu for FY 2024 and $8.86 per MMBtu for FY 2025 under the "high price" scenario. *See* Table 1. (All tables and figures referenced are at the back of this document.)

2.3.1.2 Methodology for Deriving Aurora Zone Natural Gas Prices

Although Henry Hub is the point of reference for natural gas markets, Aurora uses prices for nine gas trading hubs in the WECC. Each natural gas plant modeled in Aurora operates using fuel priced at a natural gas hub according to the zone in which the gas plant is located. Each zone is a geographic subset of the WECC. The prices at the other hubs 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 regional heterogeneity, including pipeline constraints, pipeline costs, regional production costs, and storage levels. The nine Western hubs represent regional demand areas as well as three major supply basins that are the source for most of the natural gas delivered in the western U.S.

Figure 1 shows the location of the nine Western hubs. The forecast of basis differentials is derived from recent historical price differentials between Henry Hub and each of the other nine trading hubs, along with projections of regional supply and demand. AECO, the primary trading hub in Alberta, Canada, is a main benchmark for Canadian gas prices. Sumas, Washington, is the primary hub for the delivery of gas from the Western Canada Sedimentary Basin (WCSB) into western Washington and western Oregon. Kingsgate is another gateway for WCSB gas and is the hub that is associated with the demand center in Spokane, Washington. Stanfield, an Oregon hub, is included because major pipelines intersect at that location. The Opal, Wyoming, hub represents the collection of Rocky Mountain supply basins that supply gas to the Pacific Northwest and California. Pacific Gas and Electric (PG&E) Citygate represents demand centers in northern California. The San Juan Basin has its own hub, which primarily delivers gas to southern California. Ehrenberg, Arizona, represents an intermediary location between the San Juan Basin and demand centers in Southern California. Ehrenberg is also a receipt point for Permian gas, a producing area primarily located in western Texas. Inflows from the Permian area are accounted for in the formulation of the nine basis forecasts, but there is no Permian basis forecast or Aurora zone. Finally, Southern California Citygate represents demand centers in southern California.

Once a forecast is prepared for the trading hubs' basis values, Aurora assigns a forecast to each zone. Sumas, AECO, Kingsgate, Stanfield, and PG&E Citygate hubs are associated with zones in the Pacific Northwest, Northern California, and Canada. The Opal hub is associated with zones in Montana, Idaho, Wyoming, and Utah. San Juan, Ehrenberg, and Southern California Citygate hubs are associated with zones in Nevada, Southern California, Arizona, and New Mexico.

2.3.1.3 The Basis Price Forecasts

Adding the Henry Hub price forecast to a regional basis forecast yields that regional trading hub's price forecast. Table 1 shows the price forecast for the nine trading hubs in the Western U.S. used by Aurora. Regional supply and demand fundamentals result in some forecast prices that are significantly below the Henry Hub benchmark, such as AECO and Kingsgate, while others like SoCal Citygate and PG&E Citygate, are above.

2.3.1.4 Natural Gas Price Risk

Addressing 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.

BPA's natural gas risk model simulates daily natural gas prices, generates a distribution of natural gas price forecasts, and presumes that the gas price forecast represents the median of the resulting 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. Three simulations are produced, one around each future scenario, which results in a total distribution of 1,440 simulated forecasts. This distribution is randomly sampled with weights to provide the Henry Hub natural gas price forecast input for each game in Aurora. The weights correspond with the estimated likelihood of each scenario occurring over the rate period.

The distribution of simulated natural gas prices is aggregated by month prior to being input into Aurora because the Treasury Payment Probability (TPP, *see* Power and Transmission Risk Study, BP-24-FS-BPA-05, § 3.1) calculations and the Rate Analysis Model (RAM2024) (*see* Power Rates Study, BP-24-FS-BPA-01, § 2.1) use only monthly electricity prices from Aurora. Also, the addition of daily natural gas prices does not appreciably affect either the volatility or expected value of monthly electricity prices. The 5th, 50th, and 95th percentiles of the forecast distribution are reported in Figure 2.

2.3.2 Load Forecasts Used in Aurora

This Study uses WECC topology, which comprises 34 zones. It is one of the default zone topologies supplied with the Aurora model and requires a load forecast for each zone.

2.3.2.1 Load Forecast

Aurora uses a WECC-wide, long-term load forecast as the base load forecast. Default Aurora forecasts are used for areas outside the U.S. BPA produces a monthly load forecast for each balancing authority (BA) in the WECC within the U.S. for the rate period. Default Aurora forecasts are used for British Columbia (BC) and Mexico, and the Alberta Electric System Operator (AESO) 2021 Long-Term Outlook load forecast is used for Alberta. As Aurora uses a cut-plane topology (Figure 3) that does not directly correspond to the WECC BAs, it is necessary to map the BA load forecast onto the Aurora zones. The forecast by BA 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 Aurora. When referring to the load model, this Study is referring to the combination of these models.

2.3.2.3 Yearly Load Model

The yearly load model addresses variability in loads created by long-term economic patterns; that is, it incorporates variability at the annual 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 Aurora 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, the Rocky Mountain West, and the Southwest. 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 BA level, as provided in FERC Form 714 filings from 2001 to 2020 and aggregated into the regions described above. The model de-trends and normalizes these annual aggregate load observations, so the sample space is composed of annual factors with an average of zero, and then uses a simple bootstrap with replacement to draw sets of random length observations from each year until enough draws are made to fill the forecast horizon. The model repeats this process 450 times, which generates 450 annual load factor time series used to generate simulated load growth patterns for each Aurora 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-Columbia (Mid-C) and thus are an important component of price risk.

In addition to an annual load forecast produced in average megawatts, Aurora requires factors for each month of a forecast year that, when multiplied by the annual load forecast, yield the monthly loads in average megawatts. As such, the monthly load risk is represented by a distribution of vectors of 12 factors with a mean of 1. The monthly load risk model generates a distribution of these factors for the duration of the forecast period. The monthly load model takes as given the historical monthly load for each Aurora zone, normalized by their annual averages, and uses deviations from the average normalized monthly factors as inputs.

A reduced-form Vector Autoregression (VAR) is then used to estimate each balancing authority's monthly deviation as a function of its own past deviations and the past deviations of all other modeled balancing authorities, as well as an error term. The model parameters and errors are then used to simulate 450 profiles of monthly deviations around the load forecast for the duration of the forecast horizon. The 450 profiles are randomly assigned to the 2,700 Aurora iterations.

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 Aurora zone from 2001 to 2020. The model groups these hourly load observations by week of the year, and then normalizes the historical hourly loads by a rolling five-week average. The model then uses a simple bootstrap with replacement to draw sets of weeklong, hourly observations from a rolling range of three candidate weeks. For example, if the model is sampling for week 25 of a particular synthetic year, it may select observations from week 24, 25, or 26 from any of the historical observations. Draws are repeated until a full set of 8,952 hours is produced (8,760 hours plus eight days to account for leap years and allow indexing to align with the correct starting day of the week for any year). 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 2,700 Aurora runs.

2.3.3 Hydroelectric Generation

Hydroelectric generation represents a substantial portion of the average generation in the PNW region, and fluctuations in its output can have a substantial effect on which generator is determined to be the marginal generator. Thus, PNW hydro generation is a primary driver of Mid-C electricity prices in Aurora.

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-24-FS-BPA-03, § 3.1.2.1, for a description of HYDSIM. HYDSIM produces 30 year-long records of PNW monthly hydroelectric generation, based on actual water conditions in the region from 1989 through 2018 as applied to the current hydro development and operational constraints. For each of the 2,700 games, the model samples one of the 30 water years for the first year of the rate period (FY 2024) from a discrete uniform probability distribution using R, the software described in Section 2.2 above. The model then selects the next historical water year for the following year of the rate period, FY 2025 *(i.e.,* if the model uses 1989 for FY 2024, then it selects 1990 for FY 2025). Should the model sample 2018 for FY 2024, it uses 1989 for FY 2025. The model repeats this process for each of the 2,700 games and guarantees a uniform distribution over the 30 water years. The resulting 2,700 water year combinations become Aurora inputs.

2.3.3.2 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 BC. The risk model uses historical generation data from 2001 through 2020. The source of this information is Statistics Canada, a publication produced by the Canadian government. Because hydrological patterns in BC, including runoff and hydroelectric generation, 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 2001 through 2020 was sourced from the California Energy Commission, the Federal Power Commission, and the U.S. Energy Information Administration (EIA). As with the BC hydro risk model, and for the same reasons, California 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 Aurora becomes crucial to the frequency with which such renewable resources would provide the marginal megawatts 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-24-FS-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 Aurora 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 Aurora default of $1.74/MWh (2020 real dollars), 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 (2020 real dollars), 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 are curtailed.

2.3.3.5 Hydro Shaping

Aurora 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. Aurora 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 Aurora 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, Aurora 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 Aurora settings and reflect observed constraints on the degree to which the system can more realistically shape hydroelectric generation.

To implement this ratio in Aurora, 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 Aurora, 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 July 2012 to June 2021. Second, the model is implemented in Aurora 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

By the end of the BP-24 rate period, BPA expects more than 11,000 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 and California Hourly Wind Generation Risk

The PNW and California Hourly Wind Generation Risk Models simulate the uncertainty in wind generation output. The uncertainty is derived by averaging the observed output of wind plants within the respective balancing authority area (BAA) for each hour and converting the data into hourly capacity factors. The source of these data is recent 10-year historical periods from BPA's external website, www.bpa.gov, and from the California Independent System Operator (CAISO) daily renewable energy reports. The models implement 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 for both the PNW and California, each of which includes 8,784 hours, to create a complete wind year for each geographic area. The model randomly samples these synthetic records and applies them as a forced outage rate against the wind fleet in select Aurora zones. This approach captures potential variations in annual, monthly, and hourly wind generation.

2.3.5 Solar Plant Generation

For photovoltaic solar resources built in or after 2016 (including future generic builds), BPA uses hourly generation profiles for three general technology types: fixed-axis rooftop, fixed-axis utility scale, and single-axis tracking. The profiles were produced using the National Renewable Energy Laboratory's (NREL's) PVWatts calculator for each Aurora zone. This enables modeling of single-axis tracking systems where the default database lacks generation profiles, distinguishing between utility scale and rooftop generation profiles, as well as capturing the latest trends in inverter-to-panel size ratios (a characteristic that strongly influences generation profiles), while keeping a consistent methodology across the WECC. All other solar generators rely on Aurora default generation profiles.

2.3.6 Thermal Plant Generation

The thermal generation units in Aurora often drive the marginal unit price, whether the units are natural gas, coal, or nuclear. With the exceptions of bid modifiers, minimum operating levels of natural gas and coal plants, and CGS generation, operation of thermal resources in Aurora is based on the Energy Exemplar-supplied database labeled North American DB 2020v92020v9.

2.3.6.1 Bid Modifiers

Bid modifiers are tools in Aurora that allow a resource's dispatch cost (used to calculate dispatch and prices) to differ from the resource's total variable costs. Bid modifiers can have the effect of changing prices from simplistic, marginal costs of producing and delivering energy to values that better account for causal factors that are not otherwise included in BPA's implementation of Aurora. Such factors can include, but are not limited to: impacts of providing ancillary services, resource and gas pipeline outages, differences between gas hub prices and actual plant fuel costs, differences in market design, and components of scarcity pricing.

BPA uses bid modifiers to address differences between observed, historical day-ahead hub prices and simplistic marginal cost calculations generated by Aurora. Using historical values from 2015 to 2020, bid modifier values are calibrated to achieve better alignment with observed, monthly average hub prices at Mid-C, SP-15, and NP-15. BPA also considers impacts on prices averaged by hour and by month in the calibration, but the primary effect of the bid modifiers is to reduce overall bias and mean absolute error of monthly averages of day-ahead HLH and LLH hub prices over the calibration period. In general, the calibrated bid modifiers tend to increase peak hour prices, especially during summer months, and put modest downward pressure on spring prices.

2.3.6.2 Minimum Operating Levels

The minimum operating level is the lowest amount of power a plant can generate while the plant is on, usually expressed in percentage of total plant capacity. The North American DB 2020v92020v9 database supplied by Energy Exemplar contained substantial amounts of natural gas and coal plant capacity with minimum operating levels of 0 percent, while such plants tend to have minimum operating levels ranging from 20 to 60 percent. Accordingly, for all coal and natural gas plants in the Western Interconnection that were built prior to 2018, BPA updated the minimum operating levels consistent with a recent California Energy Commission study that estimated average minimum operating levels for multiple fuel and technology types using actual generation levels from plants in the Western U.S.[2]

2.3.6.3 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-24-FS-BPA-03, § 3.1.4. The

[2] *Updating Thermal Power Plant Efficiency Measures and Operational Characteristics for Production Cost Modeling*, Paul Deaver, California Energy Commission (Jan. 2019), https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-001.pdf.

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 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* Power and Transmission Risk Study, BP-24-FS-BPA-05, § 4.1.1) and Aurora, where the results of the model are converted into equivalent forced outage rates and applied to the nameplate capacity of CGS for each of 2,700 games.

2.3.7 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 EIA 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 Aurora. BPA then employs a set of Aurora LT energy minimum constraints in a Long-Term Capacity Expansion study that ensures a sufficient number of generic renewable resources is added to this stack to meet state renewable portfolio standards. An energy minimum constraint forces the model to build additional resources from a list of candidate resources, based on whichever potential resource has the lowest overall expected cost, if the existing fleet fails to produce enough energy to meet the constraint. BPA used Aurora default overnight capital costs for new resources (wind, solar, and combined solar plus four-hour batteries) blended with our most recent consultant estimates to estimate fixed costs of new candidate resources.

Second, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California, Nevada, Arizona, and New Mexico were included from the California Energy Commission forecast, published January 2022, and various utility Integrated Resource Plans (IRPs) published between 2019 and 2022. The corresponding zonal load forecasts were 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 Aurora.

Finally, Aurora has logic capable of adding and retiring resources based upon economics. In a Long-Term Capacity Expansion Study, Aurora generates a catalogue of resource additions and retirements consistent with long-term equilibrium: it (1) identifies any resources whose operating revenue is insufficient to cover their fixed and variable costs of operation and retires a subset of the least economic resources, subject to annual retirement limits modified by BPA; 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. Aurora thus ensures that resources are added when economic circumstances justify. The retirement limits allow for retirement of one additional medium-size power plant per pool, per year, above any planned retirements BPA incorporates. Aurora adds no new thermal resources to the PNW during the BP-24 rate period.

2.3.8 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 (*i.e.,* 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 Aurora, all wind resource dispatch costs are set to -$23/MWh (2020 real dollars), 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 simplifying assumption that wind and solar resource dispatch costs are comparable. The Aurora default dispatch cost of solar resources is also set to -$23/MWh (2020 real dollars).

2.3.9 Transmission Capacity Availability

In Aurora, transmission capacity limits the amount of electricity that can be transferred between zones. Figure 3 shows the Aurora 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 British Columbia Intertie (BC Intertie) are based on historical intertie reports posted on the BPA OASIS website from 2012 through 2021. The ratings for the rest of the interconnections are based on North American DB 2020v9.

2.3.9.1 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 2012 through 2021. The data is composed of 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 and conditioned on the relevant season (a rolling three-month period). This process repeats until an 8,784-hour record has been constructed. The model generates 100 artificial records. Path ratings are rounded to avoid a Markov Chain that is too sparse to effectively generate synthetic profiles.

For each of 2,700 games, each intertie has a single record that is independently selected from the associated set of 100 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 Aurora 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, as well as preserving observed seasonal path rating variation.

2.3.10 California Carbon Pricing

The California Air Resources Board established a carbon market by placing limits on carbon dioxide (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. In the California electricity market, resources 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 MWh unless the producer qualifies for a lower rate more specific to its resources.

The California carbon market mechanisms are reflected in Aurora by applying BPA's forecast of allowance prices to California resources using Aurora 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 megawatt of energy and sets a zonal price, the price will include the additional cost of CO_2 emissions tied to producing that megawatt of energy (the specific resource CO_2 emission rate multiplied by the cost of CO_2 emissions). BPA forecasts the following allowance prices for the BP-24 rate period: $30.64, $33.76, and $37.09 per metric ton of CO_2 emissions (nominal) for calendar years 2023, 2024, and 2025, respectively.

Wheeling costs on transmission lines going into California are subject to an adder of the default emission rate of 0.428 metric tons per MWh at the forecast allowance prices.

However, recognizing that California has historically imported substantial amounts of low or zero-carbon emission energy from the PNW, and that this practice is likely to continue for the BP-24 rate period, all flows are exempted from the carbon emission adders on the AC and DC interties to California.

2.3.11 Washington Carbon Pricing

The Washington Climate Commitment Act (CCA) was signed into law in May 2021 and establishes carbon pricing mechanisms with many similarities to California's program. Washington's program is expected to take effect beginning January 1, 2023. A simplistic representation of Washington's program has been implemented in Aurora for BP-24 calculations because, at the time BPA produced the market price forecast, significant regulatory details of the program had not been finalized.

In Aurora, an incremental carbon emission cost addition for each resource in Washington is estimated using the default CO_2 emission rates multiplied by the forecast carbon allowance price. This incremental carbon emission cost is incorporated into dispatch and commitment logic and tends to put upward pressure on forecast Mid-C prices. While the two programs are not formally linked, BPA has assumed that the Washington carbon allowance price will be equal to the California allowance price for the BP-24 rate period.

2.4 Market Price Forecasts Produced By Aurora

Two electricity price forecasts are created using Aurora. The market price forecast uses hydro generation data for all 30 water years, and the firm water forecast uses monthly 10th percentile (P10) hydro generation. Figure 4 shows the FY 2024-2025 monthly average HLH and LLH prices from the market price forecast. Figure 5 shows the FY 2024-2025 monthly average HLH and LLH prices from the firm water forecast. The BP-24 rate case average Mid-C price from the market price forecast is $39.62/MWh (nominal).

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-24-FS-BPA-05, and numerous components of the Power Rates Study, BP-24-FS-BPA-01.

TABLES & FIGURES

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Table 1: Cash Prices at Henry Hub and Other Hubs (Nominal $/MMBtu)

	FY24			FY25		
Hub	**Low**	**Baseline**	**High**	**Low**	**Baseline**	**High**
Henry	$2.77	**$4.27**	$8.66	$2.85	**$4.16**	$8.86
AECO	$2.20	**$3.33**	$7.72	$2.30	**$3.21**	$7.91
Kingsgate	$5.12	**$3.84**	$8.23	$5.30	**$3.66**	$8.36
Malin	$2.40	**$4.15**	$8.55	$2.50	**$4.02**	$8.73
Opal	$5.39	**$4.13**	$8.52	$5.54	**$3.97**	$8.67
PG&E	$2.54	**$5.14**	$9.53	$2.64	**$5.02**	$9.73
SoCal City	$5.93	**$5.32**	$9.71	$6.04	**$4.93**	$9.64
Ehrenberg	$2.69	**$4.38**	$8.77	$2.80	**$4.13**	$8.84
Topock	$5.46	**$4.38**	$8.77	$5.65	**$4.13**	$8.84
San Juan	$2.58	**$3.88**	$8.28	$2.61	**$3.84**	$8.55
Stanfield	$5.14	**$4.07**	$8.46	$5.37	**$3.90**	$8.60
Sumas	$2.64	**$4.26**	$8.65	$2.68	**$4.07**	$8.77

Table 2: Balancing Area Load Forecast

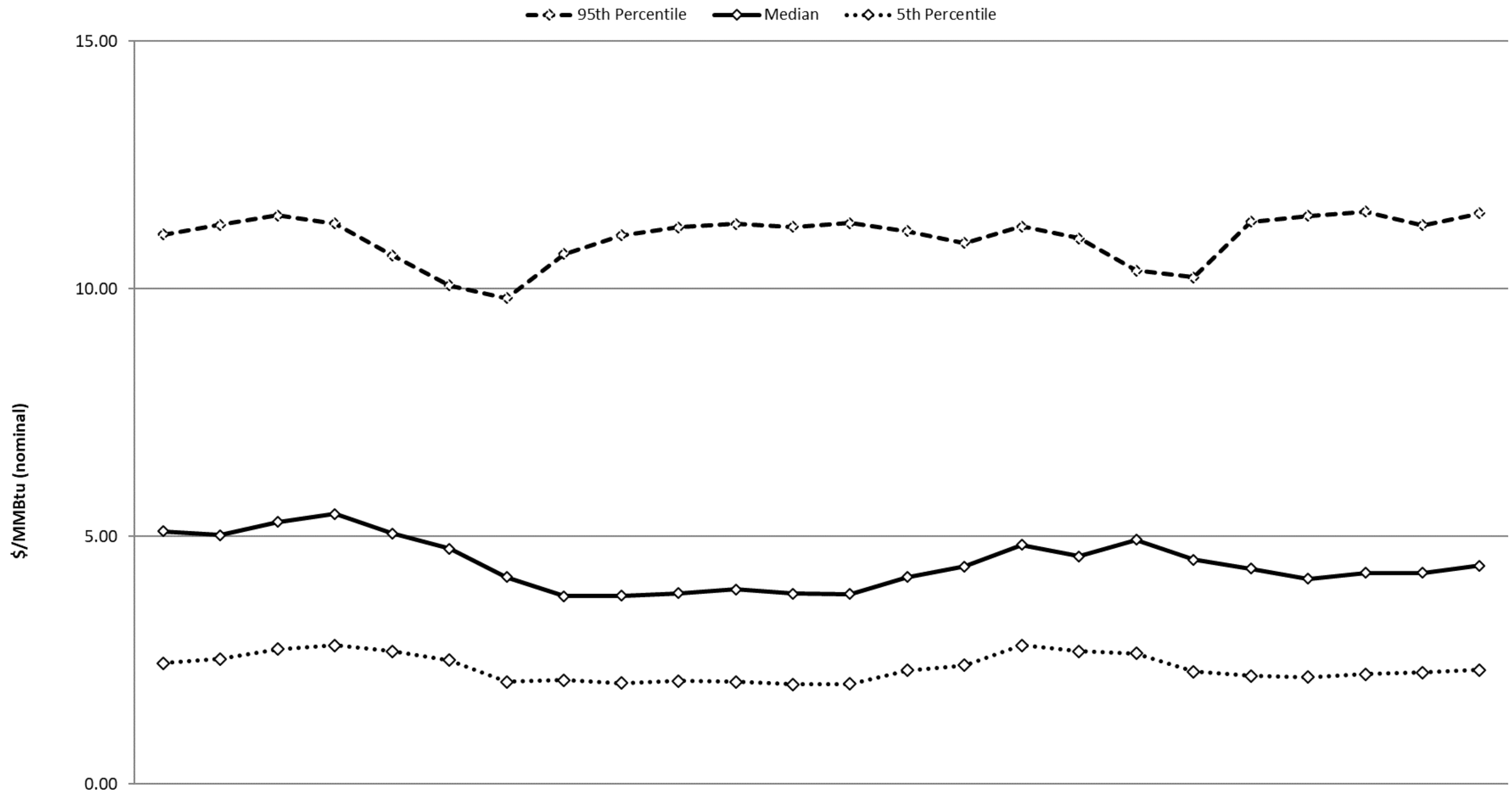
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 2: Balance Area Load Forecast (MWh)**														
2	**Date**	**APS**	**AVA**	**BPA**	**CISO**	**CHPD**	**DOPD**	**EPE**	**GCPD**	**IPC**	**IID**	**LDWP**	**NEVP**	**NWE**	**PAC**
3	**Oct-23**	2446080	1008124	4405965	18283288	126295	139997	694991	477622	1270827	308744	2046671	1844293	966810	5757202
4	**Nov-23**	2080697	1070327	4654904	16604345	163342	164227	639830	469723	1291393	244881	1893510	1687705	989593	5835343
5	**Dec-23**	2336300	1289132	5498676	17517372	225997	213161	711422	523894	1605668	228660	1998625	1879769	1128262	6558774
6	**Jan-24**	2325219	1277132	5575231	17510936	231953	216178	713217	534658	1576888	238188	2055414	1852971	1131399	6586998
7	**Feb-24**	2057553	1108128	4869800	16327778	172711	168618	626884	448054	1367638	220217	1935186	1662399	984402	5875768
8	**Mar-24**	2158226	1092193	4897386	16630166	152716	153532	645839	460341	1307009	241608	1970595	1710397	1013504	5957368
9	**Apr-24**	2191614	990115	4609134	16026260	119842	136287	646919	466680	1293455	280185	1842314	1676236	942212	5556693
10	**May-24**	2663687	955790	4633651	17129562	110267	139664	714746	497468	1488765	343067	2001524	2134553	937216	5606847
11	**Jun-24**	2945177	975812	4660101	18591676	115451	145215	798830	537811	1787736	437281	2146533	2658307	972311	6070363
12	**Jul-24**	3502583	1090147	5104873	21487692	134187	169902	906762	578406	2099916	531333	2781470	3102872	1087874	6936252
13	**Aug-24**	3475667	1061245	4994183	23048772	131858	162309	901272	559686	1915636	530254	2743503	3047554	1057187	6668122
14	**Sep-24**	2986435	924024	4500768	20307116	115981	141008	769469	477820	1416512	403607	2306664	2428633	932953	5730299
15	**Oct-24**	2466829	1008752	4506871	18407176	126686	142232	697735	476888	1279015	309708	2040481	1852311	975580	5785092
16	**Nov-24**	2101310	1070930	4759619	16716854	163736	166422	642640	468769	1299667	245646	1887782	1695702	998350	5863342
17	**Dec-24**	2356778	1289711	5608934	17636062	226393	215324	714192	522719	1614030	229374	1992580	1887746	1137009	6586880
18	**Jan-25**	2345562	1277685	5681816	17682436	232351	218301	715945	533288	1585337	239708	2060165	1860928	1140134	6615212
19	**Feb-25**	2048195	1075394	4875811	15919154	168834	169859	624913	459937	1346516	213980	1872774	1626620	1000319	5807009
20	**Mar-25**	2178298	1092696	5001896	16793042	153120	155576	648555	458506	1315632	243149	1975151	1718313	1022216	5985797
21	**Apr-25**	2211551	990592	4708942	16183226	120248	138291	649664	464625	1302165	281973	1846573	1684132	950914	5585230
22	**May-25**	2683488	956242	4733693	17297332	110675	141628	717519	495193	1497562	345255	2006151	2142429	945907	5635492
23	**Jun-25**	2964843	976239	4766330	18773764	115862	147148	801630	535315	1796620	440070	2151495	2666163	980989	6099114
24	**Jul-25**	3522020	1090563	5233113	21698142	134600	171810	909608	576106	2108816	534722	2787900	3110642	1096561	6964933
25	**Aug-25**	3494783	1061664	5120389	23274512	132271	164217	904185	557973	1924480	533637	2749845	3055174	1065901	6696552
26	**Sep-25**	3005227	924447	4621404	20506006	116395	142908	772446	476694	1425299	406182	2311997	2436102	941691	5758478

Table 2: Balancing Area Load Forecast (cont.)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
27	**Table 2 (cont): Balance Area Load Forecast (MWh)**														
28	**Date**	**PGE**	**PSC**	**PNM**	**PSE**	**SMUD**	**SRP**	**SCL**	**SPP**	**TPWR**	**TEP**	**TID**	**WACM**	**WALC**	**WAUW**
29	**Oct-23**	1686358	3599280	764973	1995408	1240311	2414228	737815	1073671	392574	1180825	236966	1871339	758823	67298
30	**Nov-23**	1750705	3679639	780427	2176114	1190664	2045793	827201	1084805	420944	1085347	212578	1917081	661118	71639
31	**Dec-23**	2085044	4130789	880925	2467831	1354511	2311694	949211	1197026	490412	1197597	219808	2124490	696309	91623
32	**Jan-24**	2064678	4121019	870997	2523076	1356976	2296382	952695	1175136	494525	1202559	215074	2252853	673886	93968
33	**Feb-24**	1757992	3729237	778649	2184460	1197178	2047244	862011	1069190	439528	1079996	201968	2079483	613873	86842
34	**Mar-24**	1795824	3756562	791019	2159539	1216901	2101273	846568	1100910	439851	1100009	206863	2075725	675314	78791
35	**Apr-24**	1656946	3505420	725697	1961795	1158647	2190016	744296	1045294	386002	1082188	208026	1893347	774227	68361
36	**May-24**	1649115	3576931	747223	1815815	1304969	2649566	691692	1090752	352524	1236836	241660	1834274	944685	66754
37	**Jun-24**	1632094	3888676	847755	1788649	1552246	3274691	640624	1128671	339292	1529439	293144	1956034	870407	77148
38	**Jul-24**	1793144	4583239	983593	1882871	1784537	3698946	683110	1252477	355923	1645826	336416	2257606	936668	95905
39	**Aug-24**	1855177	4248158	954146	1899127	1786784	3607598	682801	1258937	358231	1658714	325037	2167664	910447	87175
40	**Sep-24**	1639987	3566375	804594	1795291	1487034	3159081	660241	1113485	337740	1451773	271255	1884604	898682	68511
41	**Oct-24**	1707904	3618208	766612	2004323	1245386	2438634	735667	1086153	390763	1187286	237575	1874765	765443	67305
42	**Nov-24**	1772060	3698689	782060	2185173	1195535	2070102	823316	1097272	418376	1091753	213124	1920227	667849	71686
43	**Dec-24**	2106206	4149960	882554	2477033	1360054	2335906	949710	1209478	487995	1203946	220373	2127060	703151	91700
44	**Jan-25**	2085648	4140311	872620	2532422	1367727	2320497	949275	1187573	492423	1208853	216388	2255184	680839	94083
45	**Feb-25**	1718642	3678808	760508	2141753	1165054	2040441	830487	1062742	434603	1065638	196195	2010870	612986	83866
46	**Mar-25**	1816409	3776097	792631	2169172	1226542	2125195	845746	1113317	437767	1106192	208127	2077009	682488	78944
47	**Apr-25**	1677338	3525076	727304	1971572	1167827	2213841	741852	1057686	384089	1088316	209297	1894140	781512	68535
48	**May-25**	1669314	3596709	748824	1825735	1315308	2673294	688012	1103130	350303	1242908	243136	1834474	952080	66949
49	**Jun-25**	1652101	3908574	849351	1798712	1564544	3298323	641285	1141033	337718	1535456	294935	1955833	877913	77371
50	**Jul-25**	1813096	4603119	985185	1892937	1798675	3722327	680568	1264776	354008	1651790	338471	2256884	944153	96117
51	**Aug-25**	1875210	4267881	955734	1909054	1800939	3630574	680149	1271125	356098	1664629	327023	2166507	917778	87352
52	**Sep-25**	1660101	3585940	806178	1805080	1498815	3181651	660627	1125561	335800	1457637	272912	1883000	905860	68656

Figure 1: Basis Locations

Figure 2: Natural Gas Price Risk Model Henry Hub Percentiles (Nominal $/MMBtu)



	Oct 23	Nov 23	Dec 23	Jan 24	Feb 24	Mar 24	Apr 24	May 24	Jun 24	Jul 24	Aug 24	Sep 24	Oct 24	Nov 24	Dec 24	Jan 25	Feb 25	Mar 25	Apr 25	May 25	Jun 25	Jul 25	Aug 25	Sep 25
95th Percentile	11.09	11.29	11.48	11.33	10.68	10.07	9.82	10.71	11.09	11.24	11.31	11.25	11.33	11.17	10.93	11.26	11.02	10.37	10.23	11.35	11.47	11.56	11.29	11.52
Median	5.11	5.03	5.29	5.46	5.07	4.75	4.18	3.79	3.81	3.86	3.93	3.85	3.84	4.18	4.40	4.83	4.60	4.93	4.53	4.35	4.15	4.27	4.27	4.41
5th Percentile	2.44	2.53	2.72	2.81	2.68	2.50	2.06	2.10	2.04	2.08	2.07	2.01	2.02	2.30	2.40	2.80	2.69	2.64	2.27	2.19	2.16	2.22	2.26	2.30

Figure 3: Aurora Zonal Topology

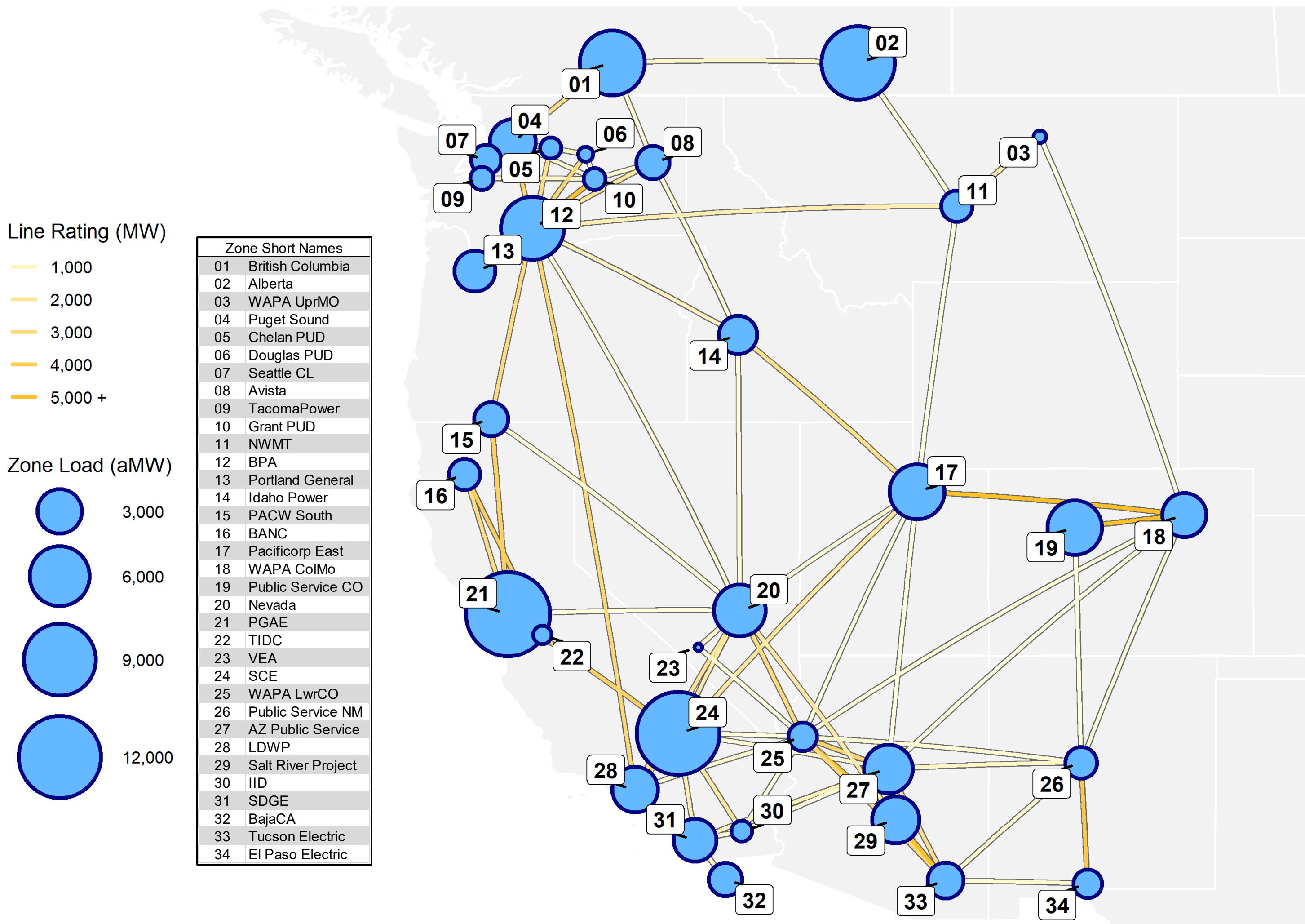
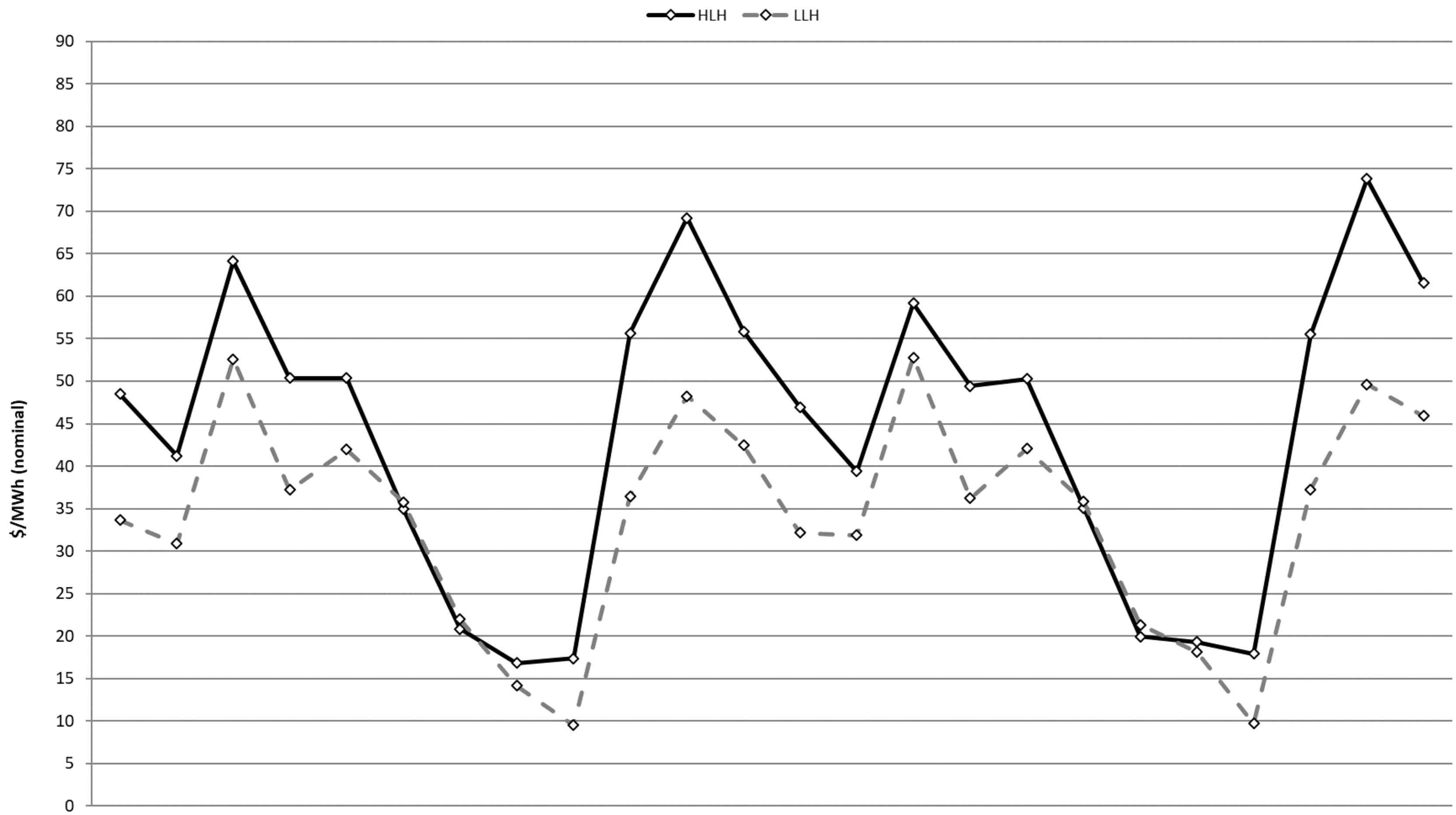
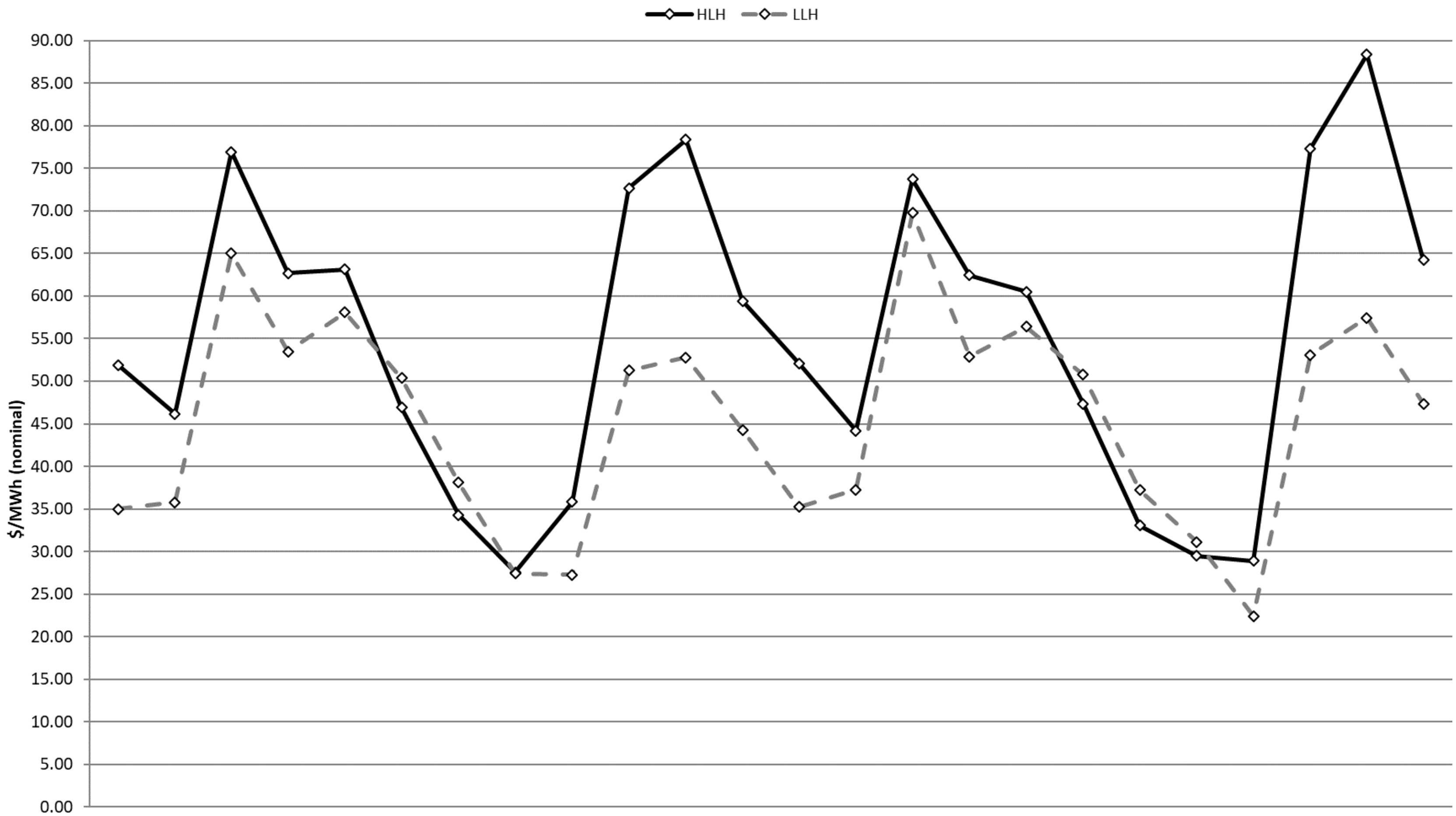


Figure 4: Monthly Average Mid-C Market Price for FY 24/FY 25 30 Water Years



	Oct 23	Nov 23	Dec 23	Jan 24	Feb 24	Mar 24	Apr 24	May 24	Jun 24	Jul 24	Aug 24	Sep 24	Oct 24	Nov 24	Dec 24	Jan 25	Feb 25	Mar 25	Apr 25	May 25	Jun 25	Jul 25	Aug 25	Sep 25
HLH	48.49	41.22	64.11	50.35	50.39	34.99	20.82	16.83	17.36	55.67	69.21	55.86	46.94	39.39	59.15	49.42	50.26	35.11	19.95	19.3	17.9	55.53	73.83	61.53
LLH	33.65	30.89	52.59	37.23	41.95	35.78	21.98	14.15	9.5	36.48	48.23	42.45	32.17	31.89	52.79	36.24	42.06	35.83	21.32	18.1	9.69	37.27	49.62	45.91

Figure 5: Monthly Average Mid-C Market Price for FY 24/FY 25 Firm Water



	Oct 23	Nov 23	Dec 23	Jan 24	Feb 24	Mar 24	Apr 24	May 24	Jun 24	Jul 24	Aug 24	Sep 24	Oct 24	Nov 24	Dec 24	Jan 25	Feb 25	Mar 25	Apr 25	May 25	Jun 25	Jul 25	Aug 25	Sep 25
HLH	51.90	46.18	76.93	62.68	63.12	46.89	34.28	27.54	35.85	72.69	78.38	59.41	52.12	44.21	73.74	62.46	60.52	47.33	33.08	29.47	28.90	77.32	88.34	64.23
LLH	34.99	35.78	65.02	53.48	58.09	50.39	38.12	27.41	27.28	51.24	52.78	44.29	35.24	37.26	69.75	52.90	56.43	50.75	37.22	31.15	22.41	53.11	57.45	47.36

BONNEVILLE POWER ADMINISTRATION
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