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-22 Rate Proceeding

Final Proposal

Power Market Price Study and Documentation

BP-22-FS-BPA-04

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POWER MARKET PRICE STUDY AND DOCUMENTATION

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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
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 (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)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
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
KSI	key strategic initiative
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
NP-15	North of Path 15
NPCC	Northwest Power and Conservation 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
NWPP	Northwest Power Pool
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)
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
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
USACE	U.S. Army Corps of Engineers
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
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-22-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-22-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[1]

BPA uses the Aurora (version 13.5.1057) 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, Energy Exemplar Proprietary Limited, in the database labeled North American DB 2019v1. Aurora 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. 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

[11] 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 3,200 games, where necessary a bootstrap is used to produce a full distribution. 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 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-22-FS-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 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. The average of the monthly forecast of Henry Hub prices is \$2.77 per million British thermal units (MMBtu) for FY 2022 and \$2.62 per MMBtu for FY 2023. *See* Table 1 in this Study.

2.3.1.2 Methodology for Deriving Aurora Zone Natural Gas Prices

Though 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, 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 800 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. This distribution of 800 simulated forecasts is randomly sampled to provide the Henry Hub natural gas price forecast input for each game in Aurora.

The distribution of simulated natural gas prices is aggregated by month prior to being input into Aurora because the TPP calculations and the Rate Analysis Model (RAM2022), Section 2.1 of the Power Rates Study, BP-22-FS-BPA-01, 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 the West Interconnect topology, which comprises 46 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 produced a monthly load forecast for each balancing authority 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) 2019 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 balancing authorities (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 2019 and aggregated into the regions described above. The model detrends 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 400 times, which generates 400 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 400 profiles of monthly deviations around the load forecast for the duration of the forecast horizon. The 400 profiles are randomly assigned to the 3,200 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 2019. 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 3,200 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-22-FS-BPA-03, § 3.1.2.1, for a description of HYDSIM. HYDSIM produces 80 year-long records of PNW monthly hydroelectric generation, 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 2022) 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 2023 *(i.e.,* if the model uses 1929 for FY 2022, then it selects 1930 for FY 2023). Should the model sample 2008 for FY 2022, it uses 1929 for FY 2023. 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 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 1977 through 2008. 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 1970 through 2008 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 MW 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-22-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 (2012 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 (2016 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 (*e.g.,* 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 2008 to June 2018. 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

Aurora models wind generation as a must-run resource with a minimum capacity of 40 percent. This assumption implies that, for any given hour, Aurora dispatches 40 percent of the available capacity independent of economic fundamentals and dispatches the remaining 60 percent as needed. By the end of the BP-22 rate period, BPA expects a little over 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 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 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 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 2019v1.

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 2014 to 2019, 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 2019v1 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-22-FS-BPA-03, § 3.1.4. 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 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-22-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 3,200 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,

[2] Paul Deaver, *Updating Thermal Power Plant Efficiency Measures and Operational Characteristics for Production Cost Modeling*, California Energy Commission (2019), https://ww2.energy.ca.gov/2019publications/CEC-200-2019-001/CEC-200-2019-001.pdf.

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 are 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 2020, and various utility Integrated Resource Plans (IRPs) published between 2017 and 2019. 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. Additionally, energy storage resources have been added to meet

California's storage targets. The storage resource attributes such as online dates, duration, capacity, peak credit, and utility region are consistent with California Public Utilities Commission assumptions specified for its IRP process.

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-22 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 MW 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 (2016 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 (2016 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 2009 through 2020. The ratings for the rest of the interconnections are based on North American DB 2019v1.

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 2009 through 2020. 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 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 3,200 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. These auctions are subject to a floor price set to $16.68 per metric ton of CO_2 emissions (nominal) and escalating at 5 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 megawatt hour (MWh) unless the producer qualifies for a lower rate more specific to its resources (specified sources).

The California carbon market mechanisms are reflected in Aurora by applying BPA's forecast of allowance prices (which remain close to the auction floor price for the BP-22 rate period) 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 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). BPA forecasts the following allowance prices for the BP-22 rate period: $18.70, $20.20, and $22.15 per metric ton of CO_2 emissions (nominal) for calendar years 2021, 2022, and 2023, 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-22 rate period, all flows are exempted from the carbon emission adders on the AC and DC interties to California.

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 80 water years, and the critical water forecast uses hydro generation for only the critical water year, 1937. Figure 4 shows the FY 2022 through

FY 2023 monthly average HLH and LLH prices from the market price forecast. Figure 5 shows the FY 2022 and FY 2023 monthly average HLH and LLH prices from the critical water forecast. The BP-22 rate case average Mid-C price from the market price forecast is $27.20/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-22-FS-BPA-05, and numerous components of the Power Rates Study, BP-22-FS-BPA-01.

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DOCUMENTATION

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

Fiscal Year	2022	2023
Henry	2.77	2.62
AECO	2.09	1.92
Kingsgate	2.50	2.29
Opal	2.79	2.56
PG&E	2.73	2.53
SoCal City	3.62	3.35
Ehrenberg	3.67	3.27
San Juan	3.02	2.71
Stanfield	3.02	2.71
Sumas	2.68	2.40

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Table 2: Control Area Load Forecast

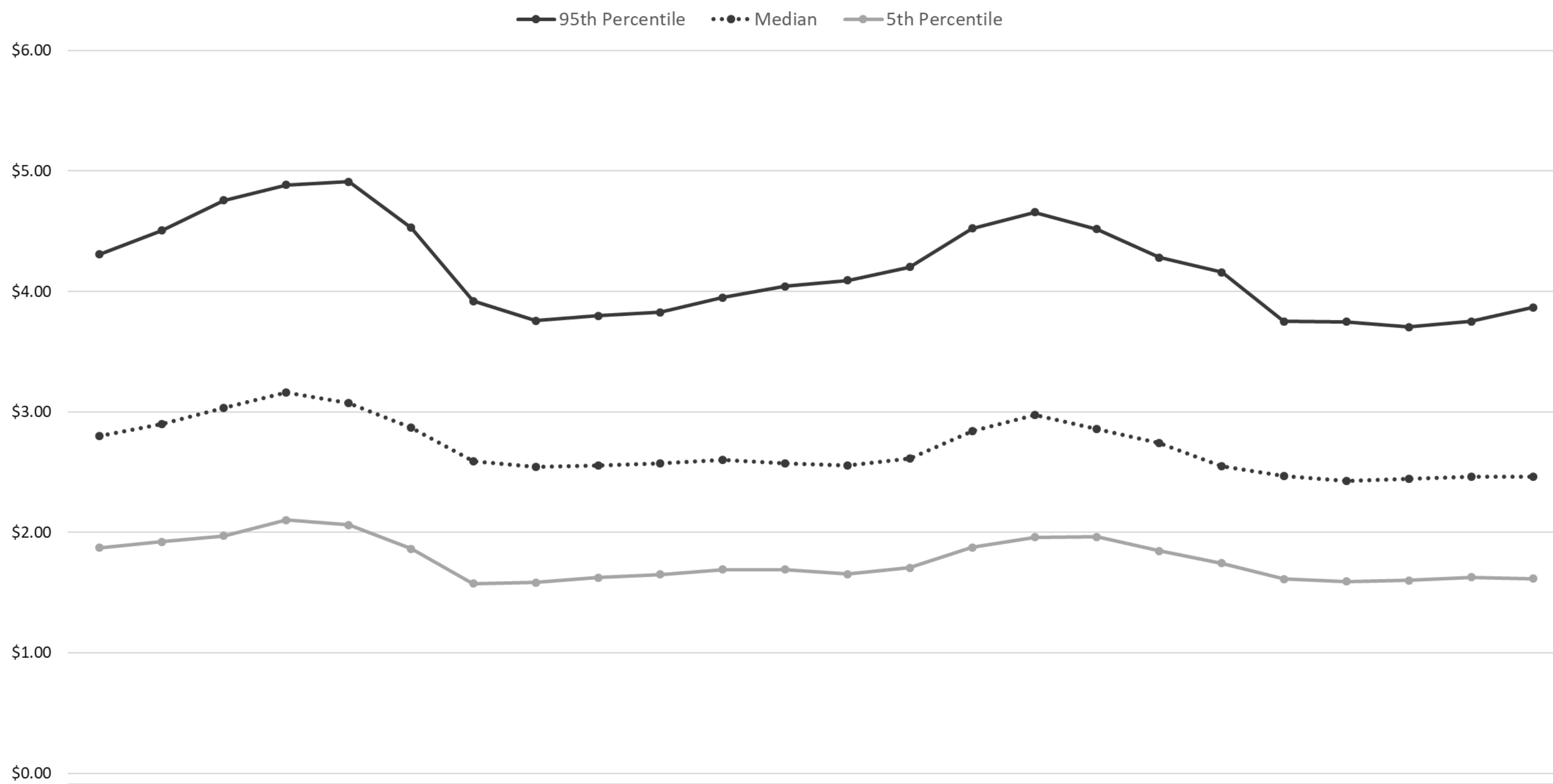
1	Table 2: Control Area Load Forecast (MWh)														
2	**Date**	**APS**	**AVA**	**BPA**	**CISO**	**CHPD**	**DOPD**	**EPE**	**GCPD**	**IPC**	**IID**	**LDWP**	**NEVP**	**NWE**	**PAC**
3	**Oct-21**	2387640	993718	4235625	17684672	139786	123683	684407	384047	1207263	294246	2074526	1767888	919930	5648351
4	**Nov-21**	2068938	1127467	4932249	16329448	155800	158758	629138	387199	1299416	233828	1906023	1651095	979298	5925525
5	**Dec-21**	2308903	1304635	5546963	17660284	172634	197533	697306	432228	1542172	240528	2037189	1818726	1090330	6396324
6	**Jan-22**	2304018	1253706	5424523	17356056	172428	197808	700541	443426	1498112	234841	2046534	1791140	1078136	6542763
7	**Feb-22**	2060720	1077161	4689031	15220450	148097	153625	615306	373987	1283021	214242	1806818	1558438	950148	5776190
8	**Mar-22**	2171257	1091922	4676872	16740299	146316	130042	645198	372298	1257923	246715	2034003	1665355	986623	5888777
9	**Apr-22**	2202047	985528	4415729	16242108	137146	121146	649732	389536	1252410	262930	1955677	1582656	884316	5515596
10	**May-22**	2543020	995052	4425144	17434284	136304	126234	717816	426048	1463516	329382	2104476	2006034	883766	5596781
11	**Jun-22**	2813559	981498	4401245	19369628	133662	125133	806769	458862	1661016	405007	2298958	2460880	896371	5856198
12	**Jul-22**	3312397	1069321	4650739	22355530	142119	148795	898541	497157	2007018	471167	2637132	2965952	1016666	6654898
13	**Aug-22**	3285732	1062844	4538646	22544426	142196	149257	897448	486329	1855077	465288	2705528	2849449	993332	6507780
14	**Sep-22**	2845934	942395	4101724	20005814	134888	123697	772822	407785	1415839	389782	2422642	2279904	884616	5590654
15	**Oct-22**	2479895	997045	4278516	17828812	142943	127346	697577	402044	1223509	296760	2088972	1789790	927623	5726835
16	**Nov-22**	2157068	1130539	4972119	16468905	158777	162293	642892	404254	1314938	236577	1917406	1671374	987233	5998495
17	**Dec-22**	2392909	1307523	5584431	17795708	175434	200941	708912	448339	1557100	242433	2045614	1837858	1098839	6465507
18	**Jan-23**	2383899	1256405	5459592	17487444	175050	201082	710708	458595	1512447	235951	2051999	1809126	1086478	6608160
19	**Feb-23**	2136478	1079667	4721698	15347810	150538	156771	623326	388214	1296756	214509	1809322	1575277	957629	5837808
20	**Mar-23**	2242892	1094283	4707757	16863952	148580	133061	652433	385596	1271171	246833	2033627	1681188	994286	5947115
21	**Apr-23**	2269558	987740	4444831	16362052	139233	124031	656896	401890	1265175	262893	1952419	1597485	891328	5570655
22	**May-23**	2600163	997114	4452463	17550522	138211	128992	724196	437448	1475793	329197	2098335	2024805	890737	5648566
23	**Jun-23**	2866594	983376	4426836	19482876	135391	127770	813076	469332	1672800	404673	2289969	2478627	903329	5905191
24	**Jul-23**	3362260	1071019	4674601	22460184	143712	151330	904119	506913	2018314	470597	2626277	2983006	1024257	6701105
25	**Aug-23**	3333361	1064358	4560780	22634860	143700	151716	903069	495576	1865886	464551	2693800	2866144	1000694	6551194
26	**Sep-23**	2891330	943764	4122192	20083464	136297	126085	777761	416535	1425934	388880	2410064	2295938	891200	5631757

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**	**PSC**	**PNM**	**PSE**	**SMUD**	**SRP**	**SCL**	**SPP**	**TPWR**	**TEP**	**TID**	**WACM**	**WALC**	**WAUW**
29	**Oct-21**	1622684	3502056	787560	1949297	1180228	2310708	762903	1042145	380903	1106230	213279	2015636	725598	61954
30	**Nov-21**	1772826	3603006	795506	2223428	1161437	1971502	853918	1056520	448914	1045577	185703	2101034	668972	69350
31	**Dec-21**	1998476	4023149	900810	2440623	1309638	2237143	899688	1169482	495341	1149906	197766	2342462	695701	83701
32	**Jan-22**	1942512	4024699	897414	2443104	1298868	2264352	934077	1148334	489032	1164666	197624	2339219	669628	88447
33	**Feb-22**	1690327	3584351	776846	2156193	1113569	1972498	817185	1024259	436135	1034255	175573	2069543	559810	76127
34	**Mar-22**	1718224	3684167	809959	2133133	1182802	2080126	819796	1075262	433604	1071870	188033	2152955	701708	75994
35	**Apr-22**	1605693	3433609	759766	1946221	1107274	2106882	765118	1020060	394020	1038266	184618	1997518	768719	63528
36	**May-22**	1612321	3491112	771847	1830917	1217096	2707152	735032	1054467	367708	1202188	223553	2024102	922724	63233
37	**Jun-22**	1552987	3713896	844010	1777464	1464722	3147745	706411	1082297	350060	1399150	257289	2026599	895719	72827
38	**Jul-22**	1749800	4296604	967260	1853811	1705002	3627098	732686	1199648	358307	1586315	292984	2427379	899525	91230
39	**Aug-22**	1780013	4138405	947340	1891781	1655432	3581025	732422	1199562	365941	1555565	288075	2337493	855756	81851
40	**Sep-22**	1584028	3499503	814599	1809602	1394105	3075973	703001	1068715	352779	1372356	247500	2030063	879156	64803
41	**Oct-22**	1650940	3559834	794697	1974063	1179727	2395005	765071	1060787	383376	1153642	216260	2041426	741866	62759
42	**Nov-22**	1800223	3658260	802189	2246787	1160606	2052003	855963	1074263	451246	1090416	188842	2125991	684429	70186
43	**Dec-22**	2025009	4076148	907084	2462574	1308366	2313843	901610	1186968	497534	1192178	200278	2366526	710478	84572
44	**Jan-23**	1968753	4075443	903275	2463648	1296607	2337251	935876	1165562	491084	1204368	199512	2362292	683725	89331
45	**Feb-23**	1716276	3632839	782300	2175330	1111160	2041594	818861	1041230	438046	1071386	176831	2091363	573228	76941
46	**Mar-23**	1743886	3730931	815203	2150863	1179978	2145414	821348	1092165	435375	1106432	189131	2174358	714434	76760
47	**Apr-23**	1631203	3478654	764801	1962543	1104190	2168363	766547	1036895	395650	1070258	185566	2018141	780755	64194
48	**May-23**	1637680	3534438	776676	1845832	1213489	2771748	736337	1071235	369197	1231612	224350	2043979	934069	63863
49	**Jun-23**	1578198	3754926	848582	1790972	1460518	3208512	707594	1098974	351408	1426001	257929	2044267	906424	73472
50	**Jul-23**	1774528	4335327	971571	1866284	1700239	3684948	733778	1216231	359553	1611208	293490	2444710	909528	91880
51	**Aug-23**	1803812	4174825	951394	1903593	1650484	3636869	733456	1216052	367121	1579108	288463	2353467	864992	82388
52	**Sep-23**	1606899	3533138	818304	1820752	1389128	3129811	703977	1084704	353893	1394553	247760	2044704	887754	65227

Figure 1: Basis Locations

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



	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23
95th Percentile	4.31	4.51	4.76	4.89	4.91	4.53	3.92	3.76	3.80	3.83	3.95	4.04	4.09	4.20	4.52	4.66	4.52	4.28	4.16	3.75	3.75	3.71	3.75	3.87
Median	2.80	2.90	3.03	3.16	3.07	2.87	2.59	2.55	2.56	2.57	2.60	2.57	2.55	2.61	2.84	2.97	2.86	2.74	2.55	2.47	2.43	2.44	2.46	2.46
5th Percentile	1.87	1.92	1.97	2.10	2.06	1.86	1.58	1.58	1.62	1.65	1.69	1.69	1.65	1.71	1.87	1.96	1.96	1.85	1.74	1.61	1.59	1.60	1.63	1.62

Figure 3: Aurora Zonal Topology

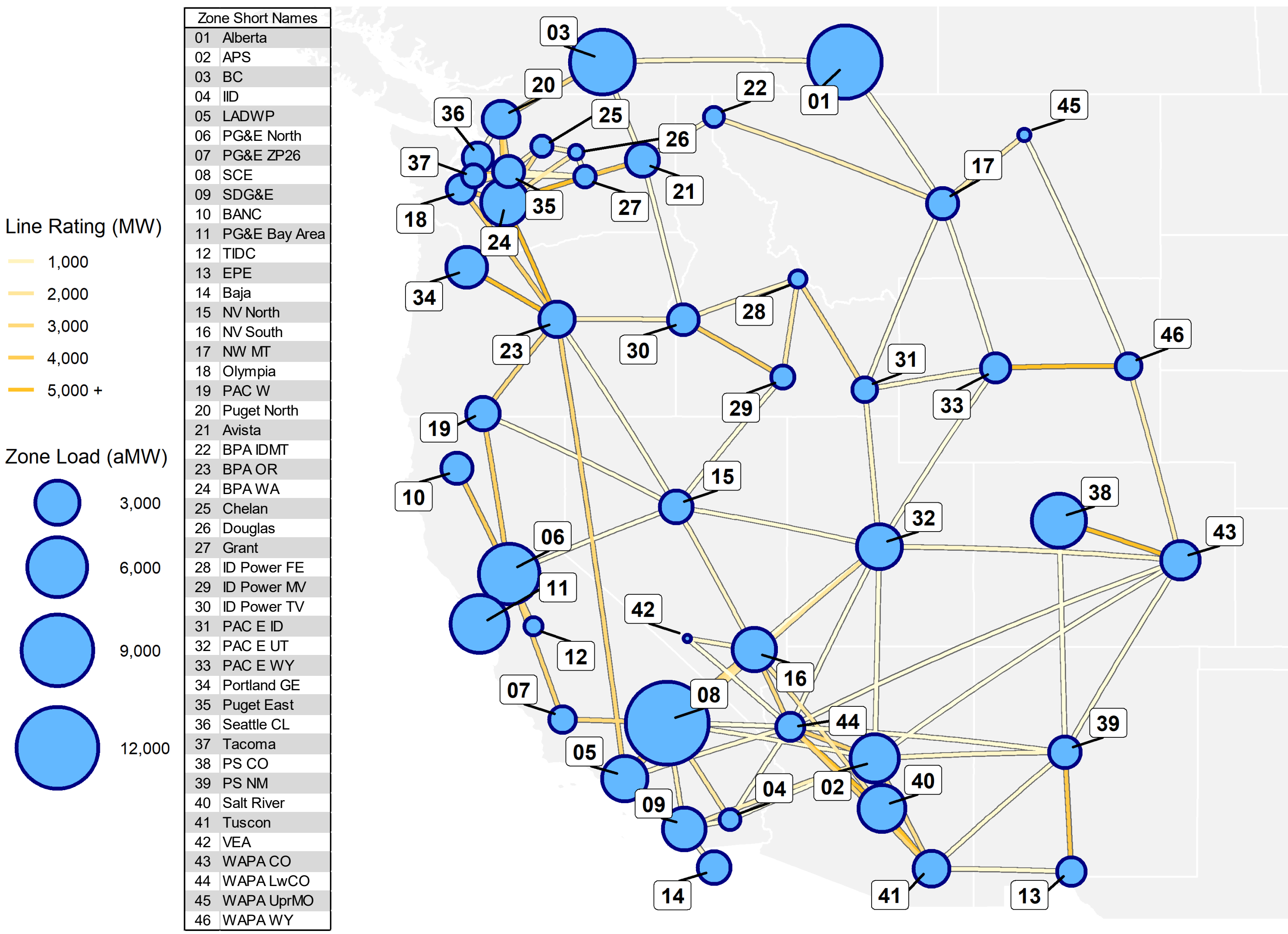
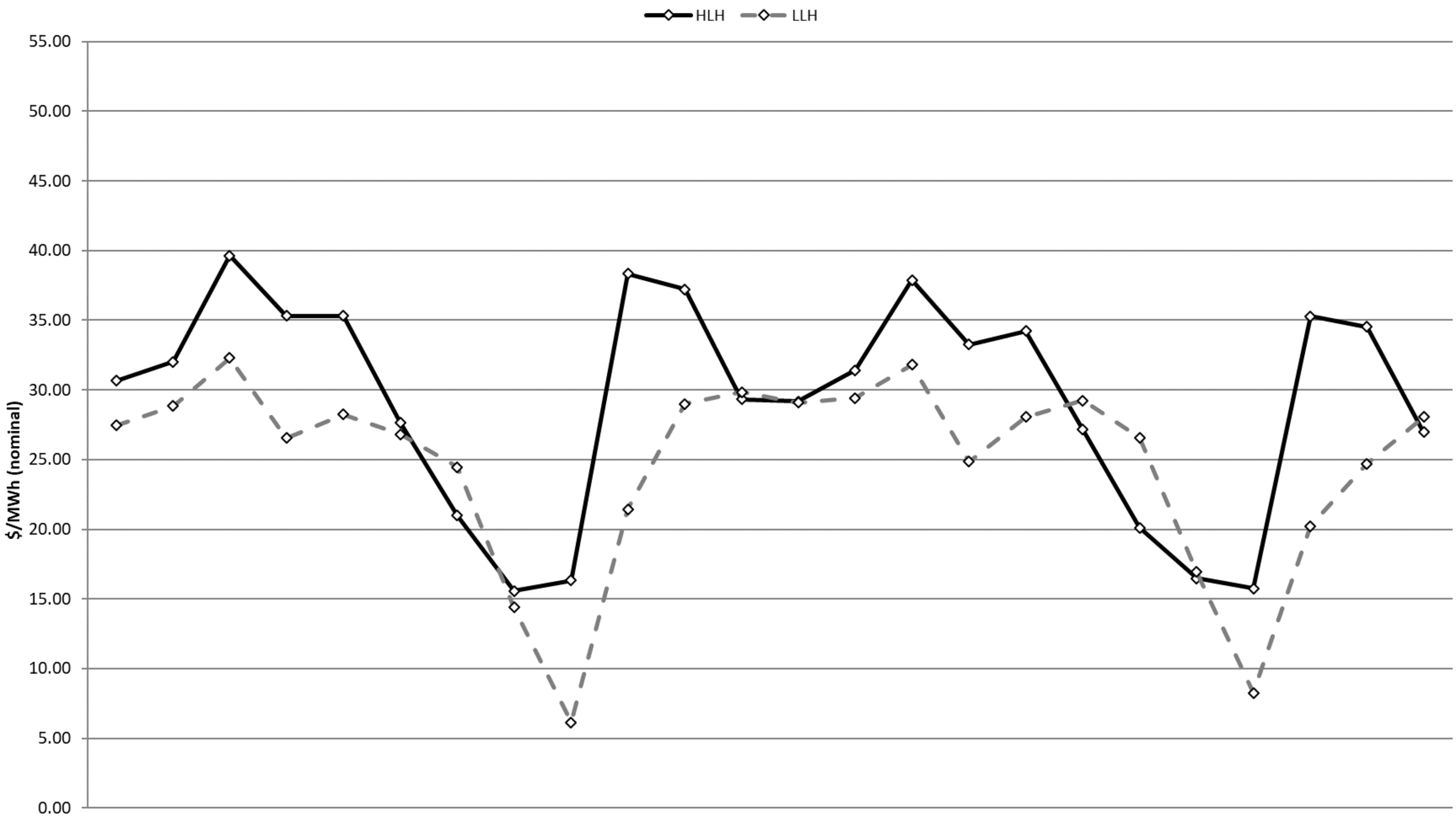
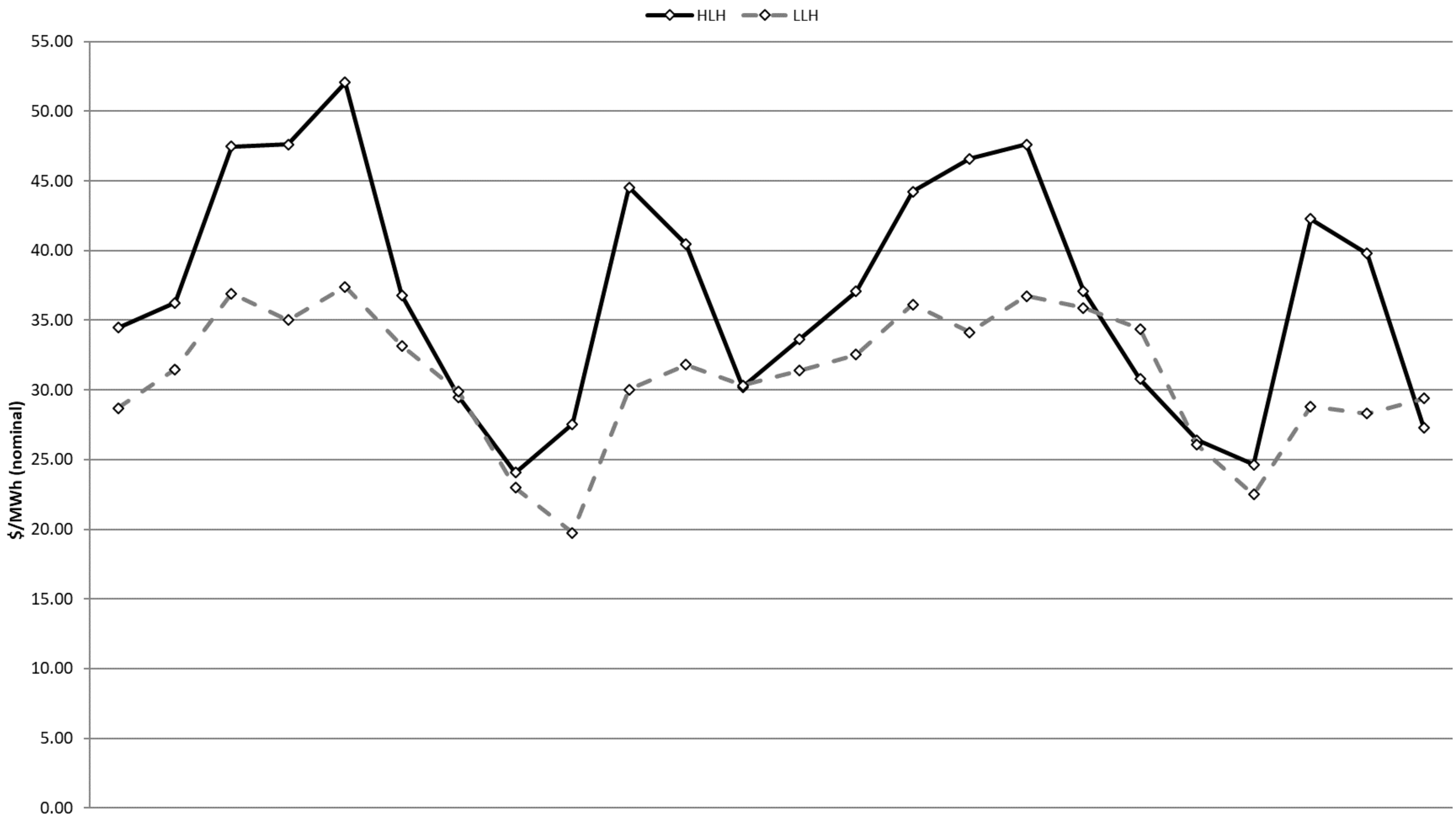


Figure 4: Monthly Average Mid-C Market Price for FY22/FY23 80 Water Years



	Oct 21	Nov 21	Dec 21	Jan 22	Feb 22	Mar 22	Apr 22	May 22	Jun 22	Jul 22	Aug 22	Sep 22	Oct 22	Nov 22	Dec 22	Jan 23	Feb 23	Mar 23	Apr 23	May 23	Jun 23	Jul 23	Aug 23	Sep 23
HLH	30.65	32.01	39.64	35.32	35.31	27.67	21.00	15.56	16.33	38.33	37.21	29.33	29.18	31.41	37.88	33.26	34.24	27.17	20.11	16.47	15.77	35.29	34.52	26.97
LLH	27.46	28.85	32.29	26.54	28.25	26.83	24.47	14.40	6.14	21.44	29.00	29.86	29.08	29.42	31.80	24.87	28.06	29.25	26.59	16.92	8.25	20.22	24.71	28.05

Figure 5: Monthly Average Mid-C Market Price for FY22/FY23 Critical Water



	Oct 21	Nov 21	Dec 21	Jan 22	Feb 22	Mar 22	Apr 22	May 22	Jun 22	Jul 22	Aug 22	Sep 22	Oct 22	Nov 22	Dec 22	Jan 23	Feb 23	Mar 23	Apr 23	May 23	Jun 23	Jul 23	Aug 23	Sep 23
HLH	34.47	36.26	47.48	47.62	52.07	36.80	29.47	24.07	27.56	44.54	40.47	30.22	33.62	37.08	44.24	46.58	47.63	37.10	30.78	26.39	24.64	42.27	39.80	27.31
LLH	28.71	31.48	36.93	35.01	37.40	33.18	29.89	22.98	19.74	30.02	31.81	30.34	31.40	32.53	36.14	34.14	36.73	35.90	34.38	26.07	22.49	28.82	28.30	29.38

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