ELECTRIC PRICE FORECAST

APPENDIX G

PUGET SOUND ENERGY

Contents

1. Introduction

This appendix summarizes the electric price forecast assumptions and results Puget Sound Energy (PSE) used as a basis for the company's 2023 Electric Progress Report (2023 Electric Report).

We developed this electric price forecast as part of our 2023 Electric Report. In this context, electric price is not the rate charged to customers but PSE's price to purchase or sell one megawatt (MW) of power on the wholesale market, given the prevailing economic conditions. Electric price is essential to our analysis since market purchases comprise a substantial portion of PSE's existing resource portfolio.

We performed two Western Electricity Coordinating Council (WECC)-wide modeling runs using AURORA software, an hourly chronological price forecasting model based on market fundamentals, to create wholesale electric price assumptions.

- The first AURORA model run identifies the capacity expansion needed to meet regional loads. AURORA looks at loads, peak demand, and a planning margin and then identifies the lowest cost resource(s) to ensure all the modeled zones are balanced.
- The second AURORA model run produces hourly power prices. A complete simulation across the entire WECC region produces electric prices for all 34 zones shown in Figure G.1. The lines and arrows in the diagram indicate transmission links between zones and their transmission capacity noted in megawatts.

Figure G.1 illustrates the AURORA System Diagram, and Figure G.2 shows PSE's process to create wholesale market electric prices using AURORA, as described.

The AURORA model produces electric price forecasts for each zone included in the model's topology. We then calculate the Mid-Columbia Hub (Mid-C) electric prices in post-processing as the demand-weighted average of the zones which compose the Pacific Northwest. The Pacific Northwest zones are Avista, Bonneville Power Administration (BPA), Chelan County Public Utility District (PUD), Douglas County PUD, Grant County PUD, PacifCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, and Tacoma Power.

Figure G.2: AURORA System Diagram

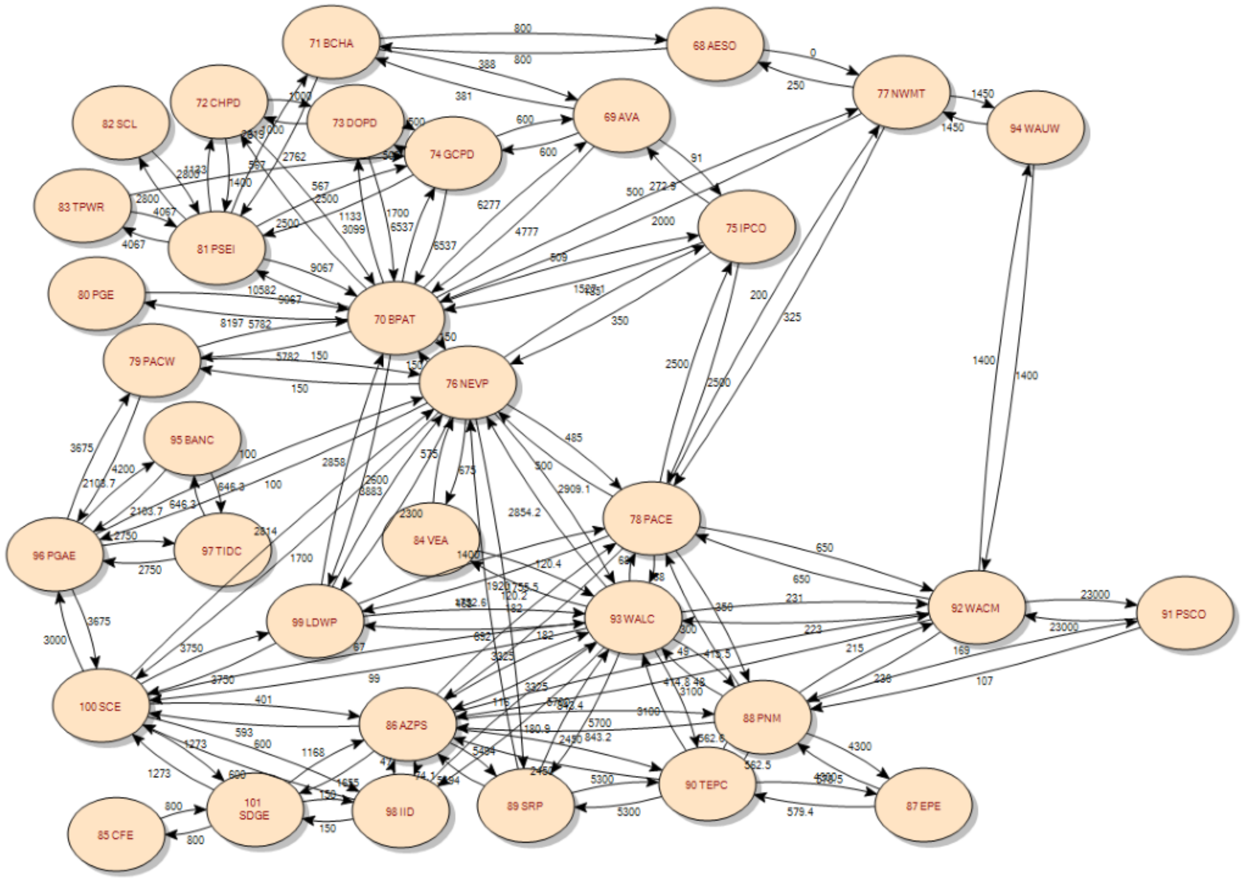
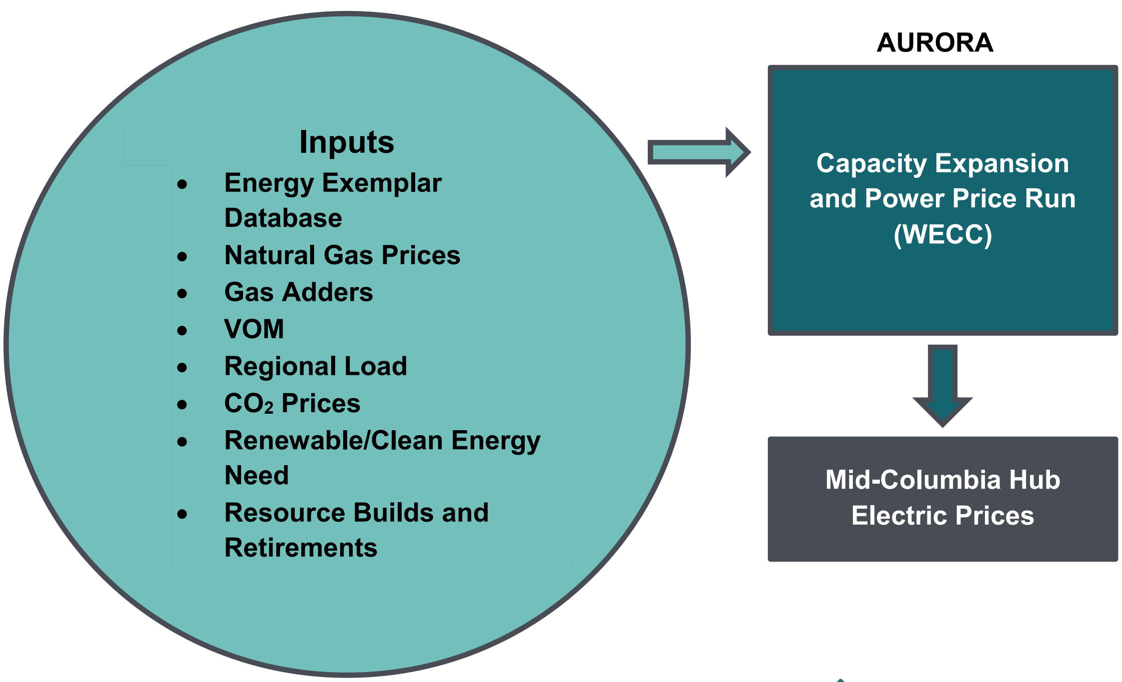


Figure G.1: PSE IRP Modeling Process for AURORA Wholesale Electric Price Forecast



2. 2021 Integrated Resource Plan

Puget Sound Energy filed the 2021 Integrated Resource Plan (IRP) in April 2021. We used inputs and assumptions from the Energy Exemplar 2018 database for AURORA price forecast modeling for the 2021 IRP. We then incorporated updates such as regional demand, natural gas prices, resource assumptions, renewable portfolio standard (RPS) needs, and resource retirements and builds. The 20-year levelized nominal power price in the Mid-C scenario for the 2021 IRP was $23.37/MWh. Details of the inputs and assumptions for the AURORA database are available for review in the 2021 IRP[1].

3. Modeling Power Prices

The electric price forecast for the 2023 Electric Report retains the fundamentals-based approach of forecasting wholesale electric prices while incorporating significant changes to some methodologies and input assumptions from the 2021 IRP process. Methodology changes include:

- Expand renewable portfolio and clean energy standards to include non-binding clean energy policies set by municipalities and utilities
- Include Washington State carbon pricing to reflect the impact of the Climate Commitment Act (CCA)
- Incorporate the impacts of climate change on demand and hydroelectric assumptions

This report documents all methodology and input assumption changes from the 2021 IRP.

3.1. Model Framework Updates

The electric price model for PSE's 2023 Electric Report includes two significant changes to the modeling framework from the 2021 IRP, updated AURORA software, and the WECC database updates.

3.1.1. AURORA Version 14.1

We updated the AURORA software from version 13.4, which we used for the 2021 IRP, to version 14.1 for the 2023 report. AURORA version 14.1 includes several changes that make it easier to use and allow greater modeling flexibility. AURORA enhancements include:

- New scripting functions
- Updates to the storage logic and limits on charging and generating in the same hour when a storage method has a minimum generation constraint

[1] PSE | 2021 IRP

3.1.2. Energy Exemplar WECC Zonal Database version 1.0.1

We updated the AURORA input database from the WECC 2018 database to the WECC 2020 database for the 2023 Electric Report. As a result of these changes, the WECC 2020 database:

- Introduces battery energy storage systems as a new resource option
- Limits the addition of new natural gas-fired power plants to years before 2030 across the WECC
- Modifies the structure of fuel price adders for increased flexibility
- Moves to a default 34-zone system topology that models each balancing authority in the WECC as a unique zone, a change from the 16-zone system topology previously used
- Updates generic resource costs
- Updates transmission assumptions

These changes result in a materially different starting point for the 2023 Electric Report and provide differing pathways for determining the solution in the long-term capacity expansion simulation from previous electric price models. We gained a more granular system topology by moving from a 16-zone to a 34-zone system that better represents the transmission constraints between balancing authorities across the WECC. Limitations on natural gas builds and adding storage as a new resource option provide more cost-effective decarbonization pathways to meet growing clean energy policy targets.

We made the following changes and updates to the WECC database:

- Adjusted clean energy policies
- Added climate change impacts
    - Updated the regional demand forecast based on climate change impacts
    - Updated the hydroelectric forecast based on climate change impacts
- Added Climate Commitment Act (CCA) impacts
- Updated natural gas prices

3.1.3. Clean Energy Policies

Clean energy policies are shaping the resource generation landscape of the WECC. For this electric price forecast, clean energy policies include a range of different targets, such as:

- Municipal clean energy goals and mandates
- Renewable portfolio standards
- Statewide clean energy goals
- Utility-set clean energy targets

These new targets depart from previous IRPs where we only modeled legislatively binding state policies (i.e., renewable portfolio standards). We include these other clean energy targets in PSE's 2023 Electric Report to reflect their impact on planning and implementing energy in the WECC. Our 2023 Electric Report includes clean energy policies aligned with the work performed by the Northwest Power and Conservation Council's (NPCC) 2021 Power Plan.

Modeling Clean Energy Policies

Puget Sound Energy's 2023 Electric Report features two modeling changes to reflect better the clean energy policies across the WECC.

In previous IRP cycles, we modeled clean energy targets by state consistent with the methodology in the Northwest Power and Conservation Council's (NPCC) Seventh Power Plan. This approach meant we had to add qualifying clean resources to the specific state which set the clean energy target. For example, an operator would have to construct a unit of Washington wind power in-state to fulfill a portion of the Washington renewable energy target.

This requirement is an unrealistic assumption because it limits utilities from sourcing energy from regions with better wind or solar resources than their home state. The NPCC realized this shortcoming and updated its methodology in the 2021 Power Plan to allow utilities to source clean resources beyond their state's boundaries. We adopted similar methods for the electric price forecast in this report. The new methodology set a WECC-wide clean energy target composed of all the clean energy targets for regional states. We then adjusted the NPCC methodology and carved out a small subset for the states of Washington and Oregon to ensure we met state policies more precisely.

In previous IRP cycles, PSE set clean energy targets only for new resources. This method subtracted contributions from existing resource generation from the total clean energy target, and only new resources counted toward meeting the clean energy target. This methodology required extensive accounting of clean energy contributions from existing resources outside the AURORA model, which may have understated the contribution of the existing clean energy resources.

In the 2023 Electric Report, we included existing and new resources in the modeled total clean energy target. We tagged both existing and new resources to contribute to the target. This approach allowed more precise accounting and better representation of all resources using AURORA's dispatch logic.

Both changes are consistent with methodologies used by NPCC in their electric price forecast AURORA model. We calculated clean energy targets using regulations, goals, and policies described in the NPCC 2021 Power Plan supplemental material[2]. We updated the NPCC clean policy targets for recent Oregon and Montana regulatory developments. Oregon adopted a 100 percent clean energy target by 2040 for investor-owned utilities, and Montana repealed its 15 percent renewable portfolio standard.

3.1.4. Gas Prices

Puget Sound Energy updated the long-term gas prices in this report to the most recent Wood Mackenzie forecasts and current forward market prices. We used the spring 2022 Wood Mackenzie Forecast, published in May 2022. The

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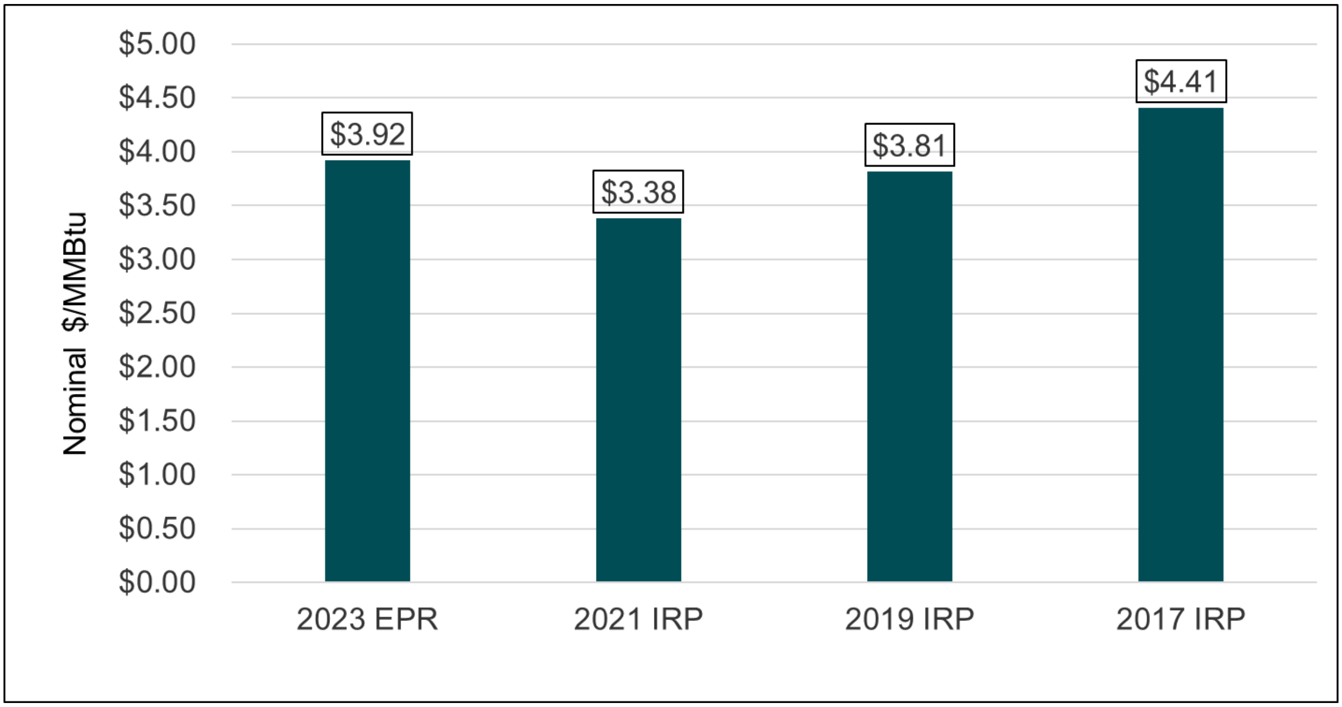
[2] 2021 Power Plan Supporting Material Site Map (nwcouncil.org)

forecast shows an increase in long-term gas prices compared to the estimates used in the 2021 IRP, shown in Figure G.3.

Figure G.3: Levelized Natural Gas Price for the Sumas Gas Hub for Recent IRP



3.1.5. Climate Change

For the first time, PSE's 2023 Electric Report includes the influence of climate change on demand and hydroelectric conditions in the Pacific Northwest. We adapted inputs incorporating climate change from the NPCC's 2021 Power Plan analysis. As the basis for their analysis, the NPCC evaluated 19 climate change scenarios developed by the River Management Joint Operating Committee (RMJOC), Part II[3], and selected three scenarios that represented a range of possible climate outcomes. PSE adopted these same three climate change scenarios:

- CanESM2_RCP85_BCSD_VIC_P1; coded as A
- CCSM4_RCP85_BCSD_VIP_P1; coded as C
- CNRM-CM5_RCP85_MACA_VIC_P3; coded as G

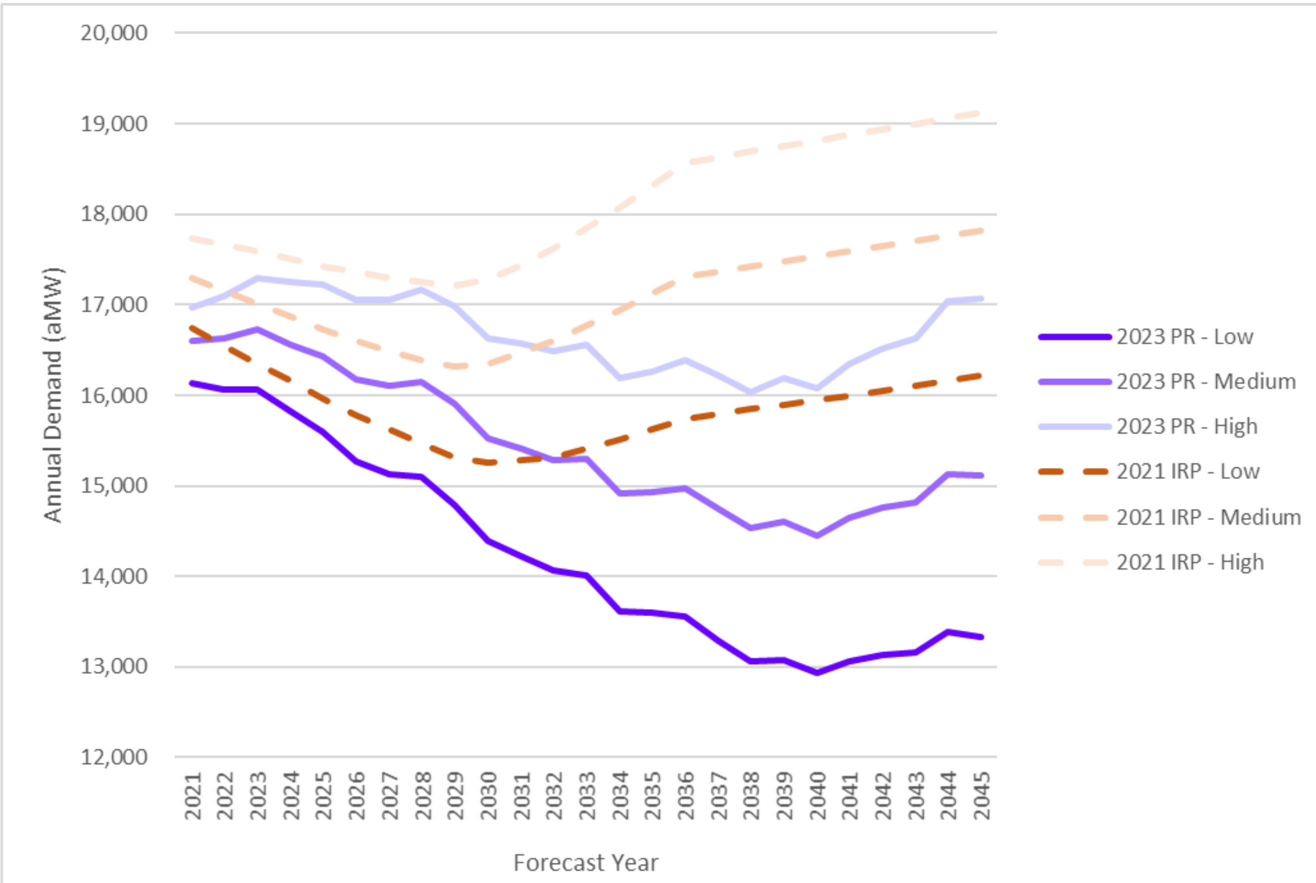
The three climate change scenarios we adopted uniquely impact the Pacific Northwest (PNW) load and hydroelectric input assumptions. Incorporating these disparate impacts into a single deterministic forecast presented significant modeling challenges. Therefore, the base electric price forecast averaged the effects of each climate change scenario to develop a single climate change case, which retains trends present in all three climate change scenarios.

[3] Climate and hydrology datasets for RMJOC long-term planning studies: Second edition (RMJOC-II) - Technical Reports - USACE Digital Library (oclc.org)

Regional Demand Forecast

For the electric price modeling, PSE used the regional demand from the NPCC 2021 Power Plan. Figure G.4 reflects the PNW regional demand forecast change from the 2021 IRP to the 2023 Electric Report. The demand forecast includes energy efficiency in all cases.

Figure G.4: Annual Average Regional Demand for the Pacific Northwest, 2023 Electric Progress Report and 2021 IRP



Climate Change Regional Demand Forecast

We incorporated the climate change regional demand forecast created by the NPCC for the 2021 Power Plan in the electric price forecast for this report. The regional demand forecast is presented seasonally in Figure G.5, with each forecast year as a separate line; darker lines represent years earlier in the planning horizon and lighter lines later in the planning horizon. We provided selected data from the 2021 IRP regional demand forecast for reference.

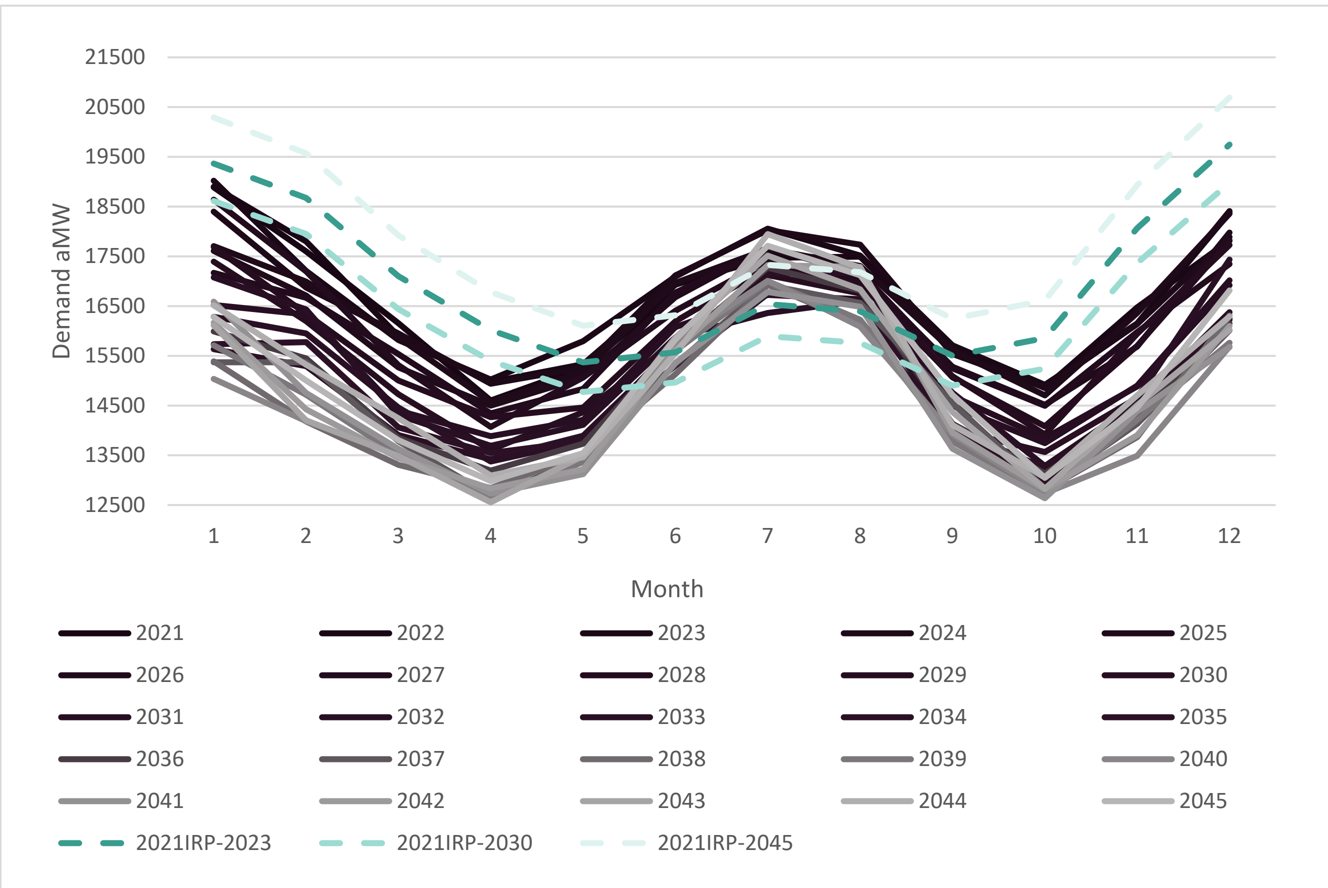
The climate change regional demand forecast shows warming winters and summers, which translates to lower demand in the winter than we modeled in the 2021 IRP and increased demand in the summer.

Climate Change Hydroelectric Forecast

We adapted the climate change hydroelectric forecast from the regional demand forecast created by the NPCC for the 2021 Power Plan. The hydroelectric forecast represents an average of all three climate change scenarios and an average of the hydroelectric conditions for the 30-year timespan of the scenarios. We calculated hydroelectric capacity based on expected hydroelectric output from the GENESYS[4] regional resource adequacy model using streamflow data representative of the climate change scenarios.

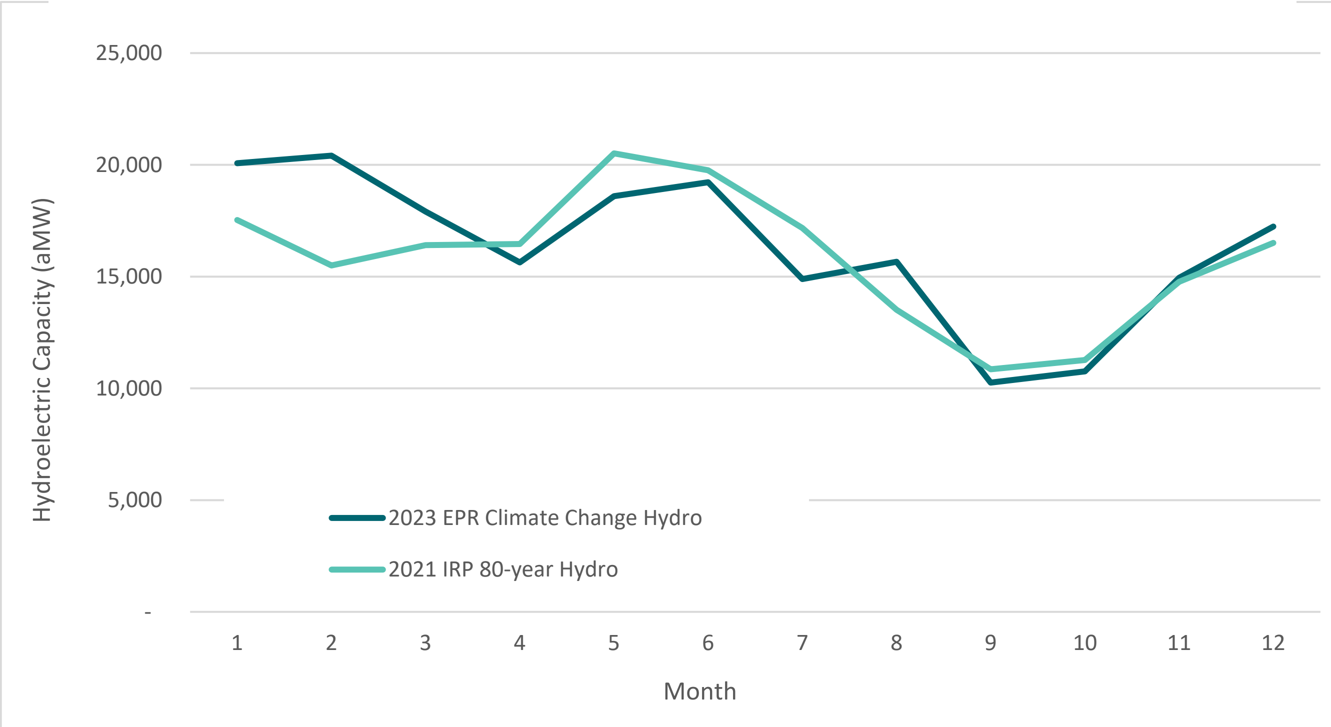
We held the average hydroelectric forecast fixed for all the modeled years. Figure G.6 presents the climate change hydroelectric forecast compared to the 80-year historic hydroelectric average forecast we used in the 2021 IRP. The forecasts are similar, but the climate change forecast trends toward more hydroelectric generation in the winter and less generation for the remainder of the year.

Figure G.5: Seasonal Regional Demand for the Pacific Northwest, 2023 Electric Progress Report and 2021 IRP



[4] GENESYS Model (nwcouncil.org)

Figure G.6: Pacific Northwest Climate Change Hydroelectric Forecast



3.1.6. Climate Commitment Act

The Washington State legislature passed the Climate Commitment Act (CCA) in 2021, which goes into effect in 2023. The CCA is a cap and invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances of permitted emissions.

The resulting market establishes an opportunity cost for emitting greenhouse gases. We added a price to greenhouse gas emissions for emitting resources within Washington State to model this opportunity cost in the electric price forecast. We only added an emission price to Washington emitting resources to ensure the model does not impact the dispatch of resources outside Washington State that are not subject to the rule.

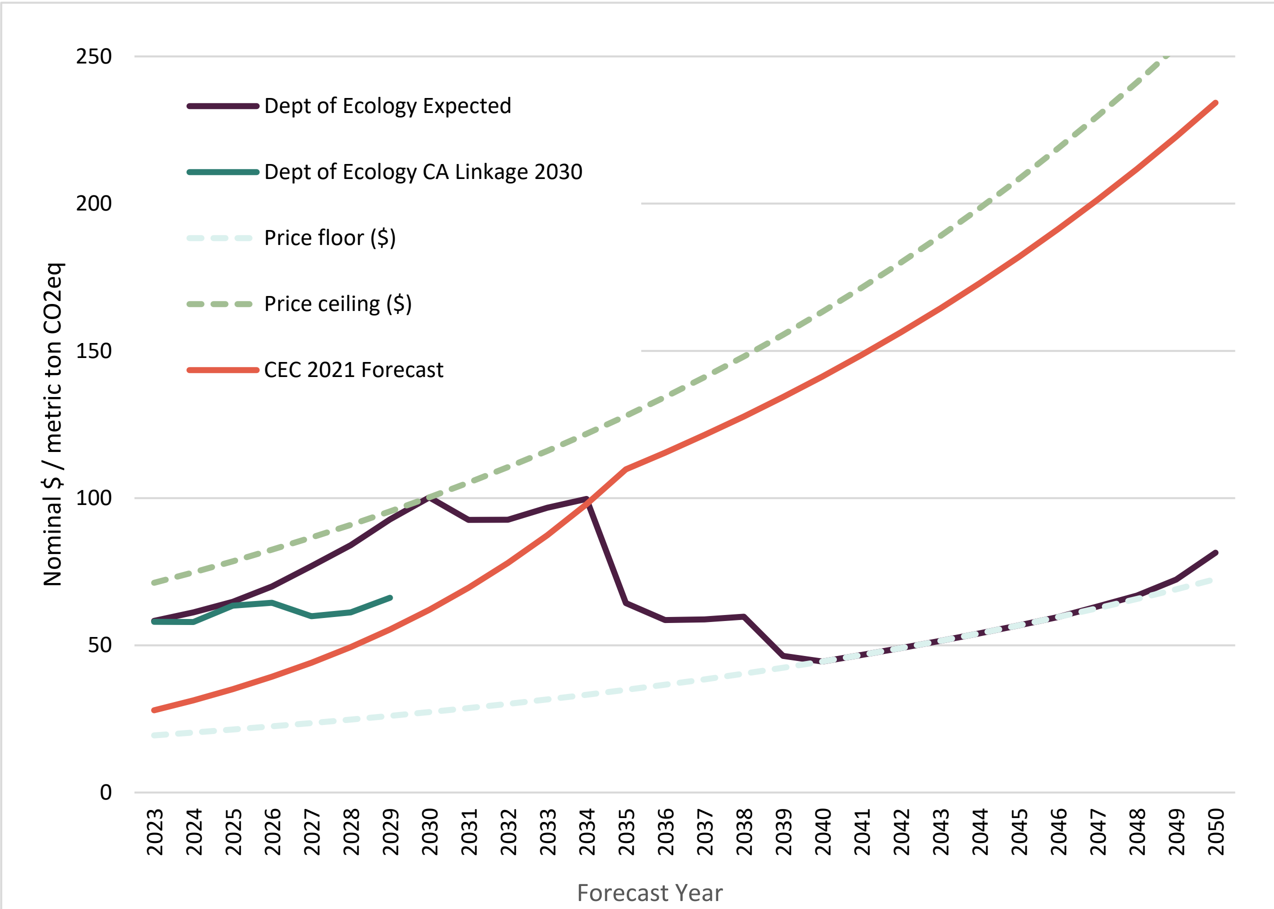
To accurately reflect all costs imposed by the CCA, we will add a hurdle rate on market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO_{2eq} per MWh.[5]

Figure G.7 presents the allowance prices considered in the electric price forecast. The expected prices of the Washington State Department of Ecology (Ecology) represent the predicted emission price, assuming no linkage to the California carbon market. We suggest that linkage to the California carbon market is the most likely scenario and has adopted a hybrid scheme that begins with pricing at the rate specified by the Department of Ecology California

[5] RCW 19.405.070

Linkage 2030[6] case, then transitions to the California Energy Commission (CEC) 2021 Integrated Energy Policy Report[7] allowance price forecast for the remainder of the modeling horizon.

Figure G.7: Climate Commitment Act Allowance Prices



4. Electric Price Forecast Results

Figure G.8 compares the annual average Mid-C wholesale electric price from the 2017 IRP to the 2023 Electric Report and the historic Mid-C wholesale electric price. Several factors contribute to the increase in electric prices from the 2021 IRP to the 2023 Electric Report:

1. **Natural gas prices**
   Natural gas prices increased between the 2021 IRP and the 2023 Electric Report, particularly in the near term, increasing electric prices.

2. **Transmission constraints**
   In the 2023 Electric Report, we modeled the WECC as a 34-zone system instead of the 16-zone system

6 Preliminary Regulatory Analyses for Chapter173-446 WAC, Climate Commitment Act Program

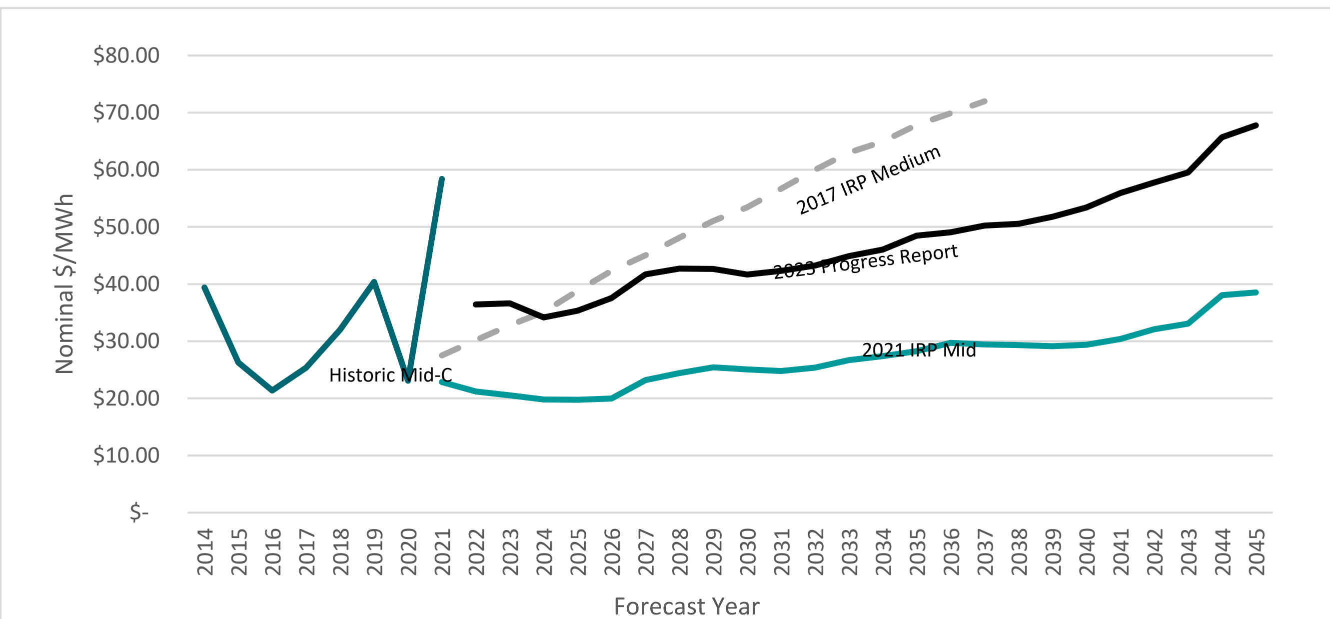
7 2021 Integrated Energy Policy Report (ca.gov)

modeled in the 2021 IRP. The increased number of zones increases transmission links within the model and increases wheeling costs as electricity is transported between zones, resulting in higher electricity prices.

3. **Clean energy needs modeling**
   Clean energy requirements accounted for existing and new resources in the 2023 Electric Report, whereas in the 2021 IRP, only new resources contributed to the clean energy targets. The method used in the 2021 IRP may have understated the contribution of existing resources and, therefore, overbuilt new solar resources, which resulted in excess hours with low-cost power, artificially driving prices lower. The method we used in this report resulted in fewer renewable energy additions to the WECC, which results in a tighter energy market and higher prices.

4. **Storage**
   Resources that store energy (e.g., batteries) were unavailable in the 2021 IRP electric price model, resulting in overbuilding of wind and solar resources to provide non-emitting capacity. Overbuilt wind and solar resources lead to lower wholesale electric prices as more hours fill with zero-cost power from these renewable resources. We added storage as an available resource in the 2023 Electric Report, which allows us to shift load and generation and dramatically reduces the number of renewable resources required to meet the load. This scenario creates a tighter market driving up wholesale electric prices overall. Storage can help reduce very high prices through arbitrage and load/generation shifts resulting in more moderate average prices.

Figure G.8: Mid-C Wholesale Electric Price Annual Average Price Forecast Over Time



Despite the addition of storage resources, volatility is still present in the wholesale electric price results for the 2023 Electric Report. Price volatility results from the substantial buildout of renewable resources across the WECC.

Figure G.9 shows electric price volatility over a day for each month of the year. Strong morning and evening peaks are present throughout the modeling horizon and will become particularly extreme in the summer months by 2045.

Figure G.10 presents volatility across all hours of each year of the modeling horizon. Price spikes become increasingly common in the latter years of the analysis.

Figure G.9: Daily Price Volatility by Month for the Years 2023, 2030, and 2045

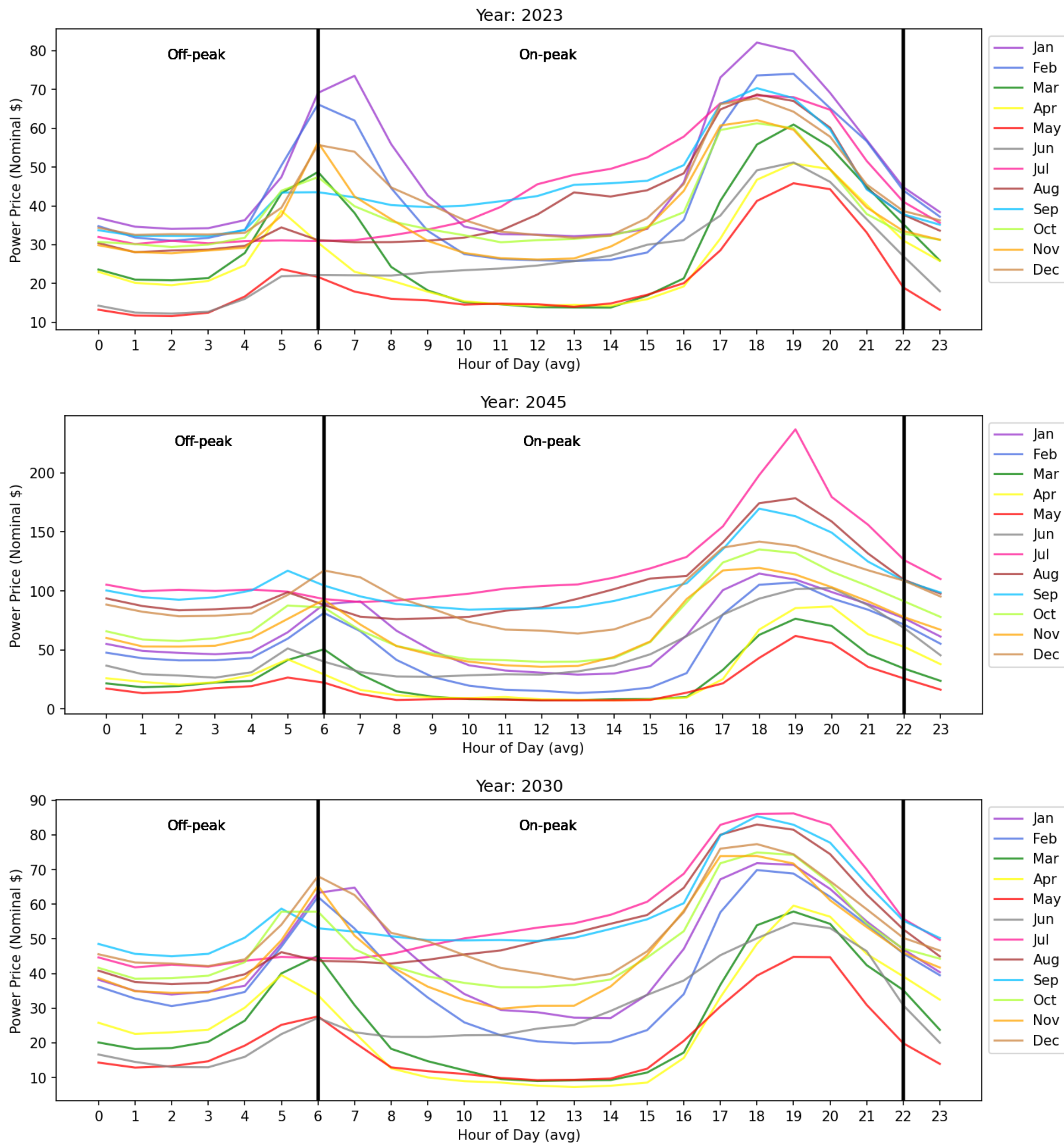
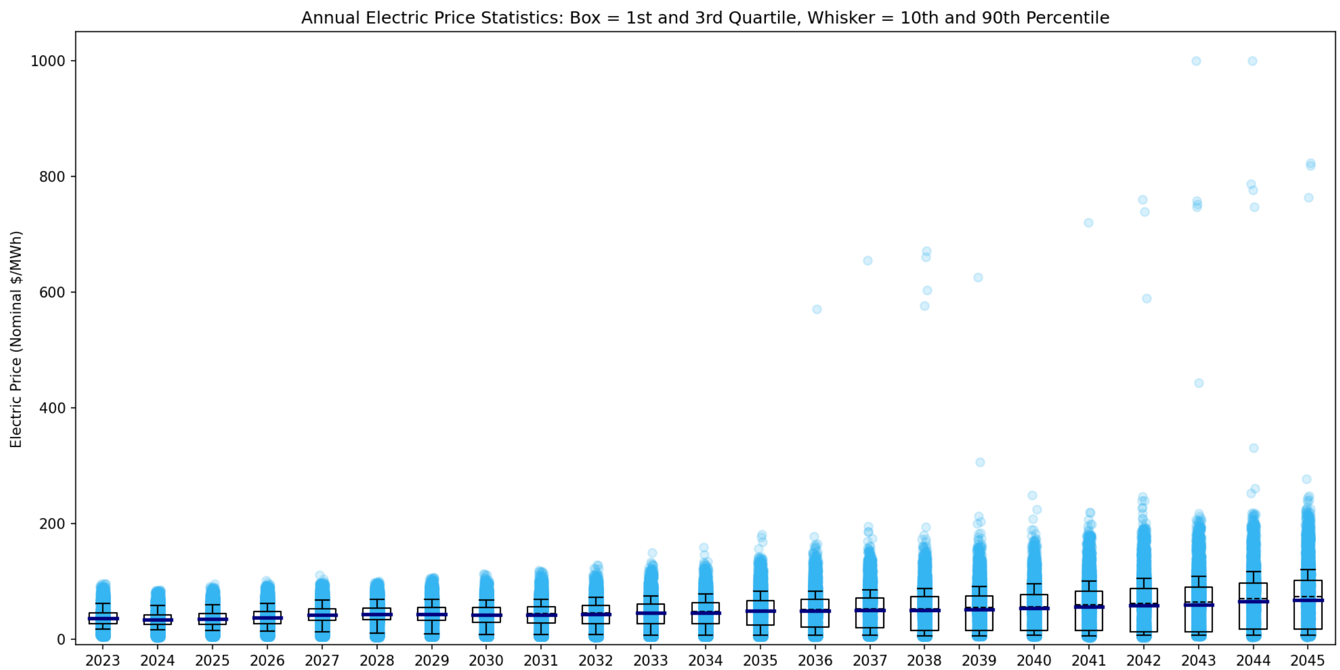


Figure G.10: Hourly Electric Prices over the Modeling Horizon



5. Electric Price Stochastic Analysis

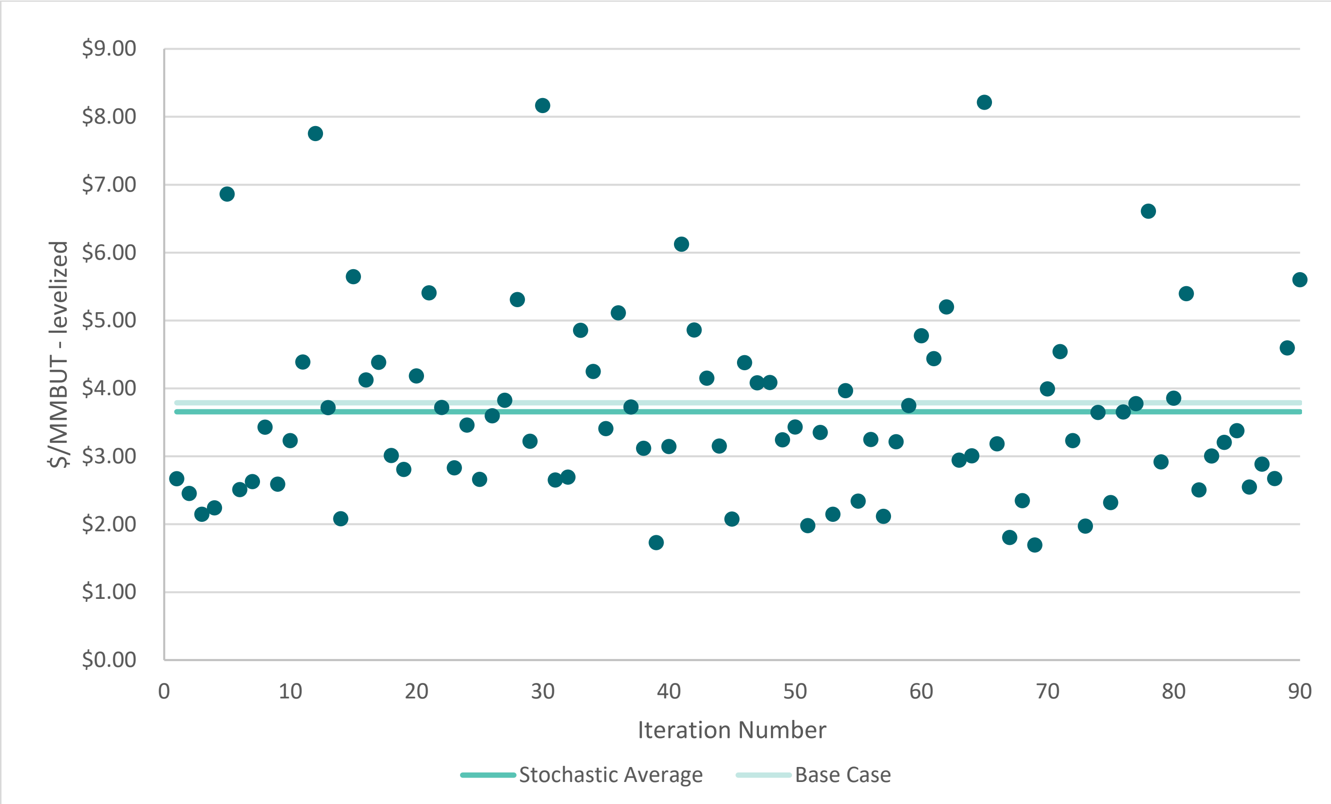
We use AURORA, a production cost model that utilizes electric market fundamentals to generate electric price draws. AURORA uses a Monte Carlo risk capability that allows users to apply uncertainty to a selection of input variables. The user can add variable input assumptions to the model as an external data source, or AURORA can generate samples based on user statistics on a key driver or input variable. This section describes the model input assumptions we varied to generate the stochastic electric price forecast.

5.1. Stochastic Natural Gas Price Inputs

We relied on AURORA's internal capability to specify distributions on select drivers, such as natural gas prices, to generate samples from a statistical distribution. The risk factor represents the model's adjustment to the base value for the specified variable for the relevant time. To calculate the risk factor on natural gas prices, we calculated the correlation of natural gas prices from Sumas, Rockies (Opal), AECO, San Juan, Malin, Topock, Stanfield, and PGE City Gate to Henry Hub with data from Wood Mackenzie's Spring 20222 Long Term View Price Update.

We also evaluated each hub's slow, medium, and high natural gas prices to determine each calendar month's average and standard deviation. We used the standard deviation as a percent of the mean for each calendar month as an input to AURORA for risk sampling. Figure G.11 illustrates the annual draws and the levelized 20-year Sumas natural gas price $/MMBtu generated by the AURORA model.

Figure G.11: Levelized 20-year Sumas Natural Gas Price $/MMBtu



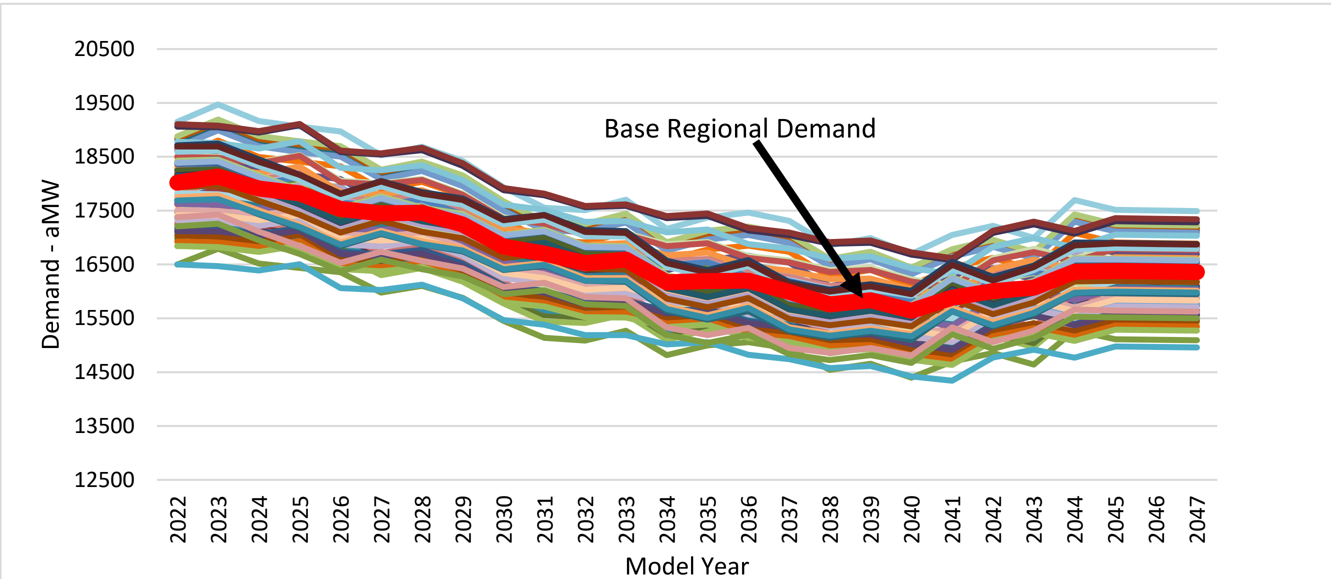
5.2. Stochastic Regional Demand

Like natural gas prices, we relied on AURORA's internal capability to generate samples from a statistical demand distribution. We evaluated low, medium, and high regional demand forecasts used in the deterministic price forecasts to determine the standard deviation as a percent of the mean for the modeling horizon. Table G.1 displays the 23-year levelized demand and the calculated standard deviation for the region. We used the standard deviation as an input to AURORA for the risk sampling of the entire WECC. Figure G.12 illustrates the 90 draws of demand AURORA generated for the Pacific Northwest.

Table G.1: 24-year Levelized Demand Statistics for PNW

2023 Electric Price Forecast Statistic	Quantity
Low - mean(aMW)	18,557
Medium - mean (aMW)	20,023
High - mean (aMW)	21,484
Mean of means	20,021
St Dev	1,195
St Dev Percent	0.06

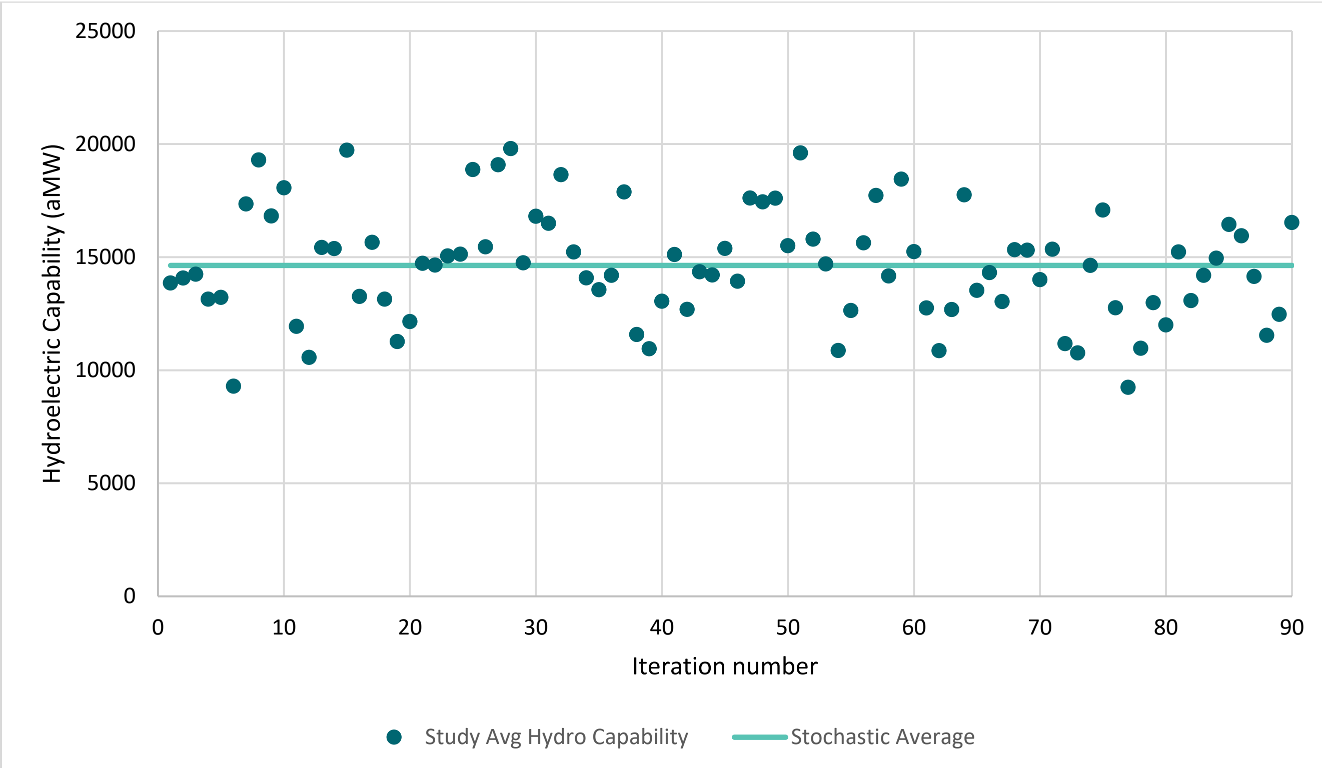
Figure G.12: Pacific Northwest Demand Draws (aMW)



5.3. Stochastic Hydroelectric Inputs

We derived stochastic hydroelectric inputs for this report's electric price forecast from the climate change hydroelectric data in this appendix. We obtained hydroelectric generation estimations for three climate change models with thirty years of data available for each model for 90 unique hydroelectric draws used in the stochastic analysis. Figure G.1 provides the 90 draws of hydroelectric capability for the Pacific Northwest.

Figure G.13: Hydroelectric Capability for the Pacific Northwest for 90 Iterations



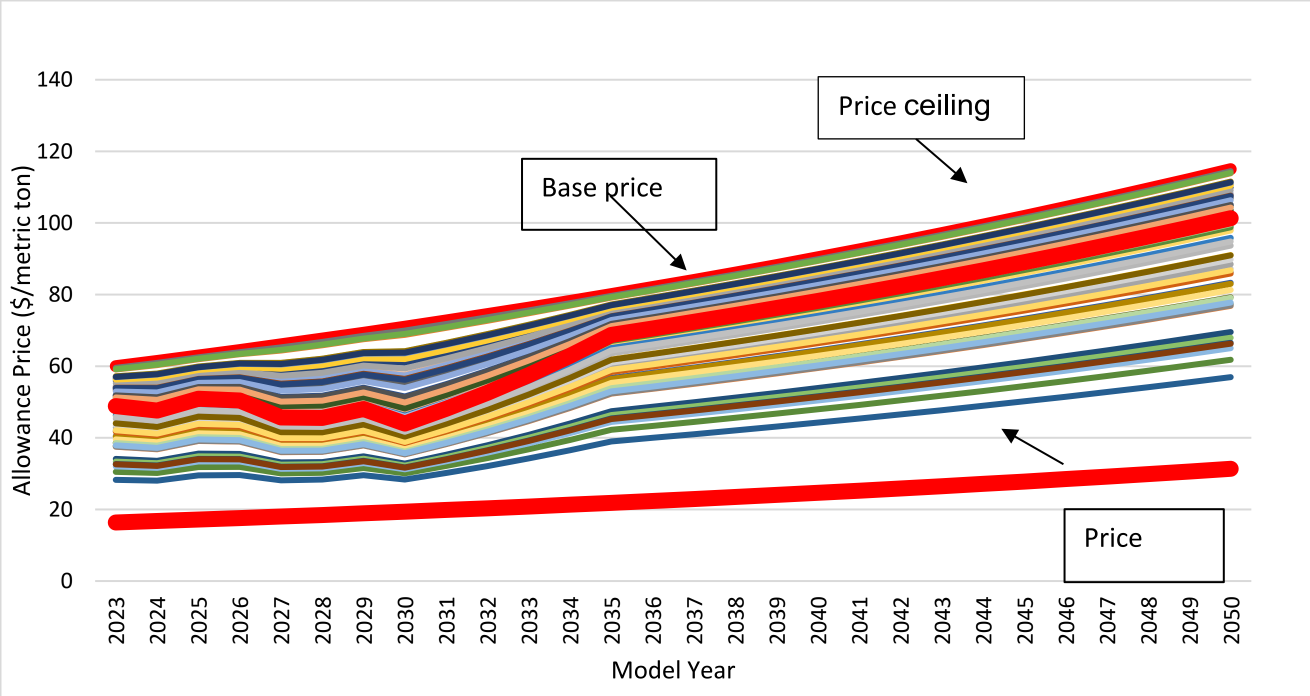
5.4. Stochastic Wind Inputs

Energy Exemplar developed wind shapes in the default AURORA database relying primarily on generation estimates from the National Renewable Energy Laboratory's (NREL) Wind Integration National Database (WIND) 2014 Toolkit, using data from the years 2007–2012. We averaged the generation from clusters of NREL wind sites with similar geography and capacity factors to form each delivered wind shape. For each wind region, we developed hourly shapes with capacity factors appropriate for three wind classes, low, medium, and high. For the electric price stochastic model, we randomly assigned an appropriate regional shape a low, medium, or high wind class for each wind project modeled in the analysis.

5.5. Stochastic Climate Commitment Act Prices

We generated 90 draws of allowance prices to represent the impact of the Climate Commitment Act in the stochastic electric price model. The ensemble price described earlier in this appendix was used as a basis and varied between the Washington Department of Ecology allowance price floor and ceiling.

Figure G.14: Climate Commitment Act Allowance Prices — 90 Iterations



5.6. Stochastic Electric Price Forecast Results

AURORA forecasts market prices and operations based on the forecasts of key fundamental drivers such as demand, fuel prices, and hydroelectric conditions. AURORA can generate 90 iterations of electric price forecast using the risk sampling for demand, fuel, and the pre-defined iteration set hydro and wind. Figure G.15 and Figure G.16 provide the stochastic electric price forecasts' annual and levelized power prices.

Figure G.15: Annual Electric Price Stochastic Results

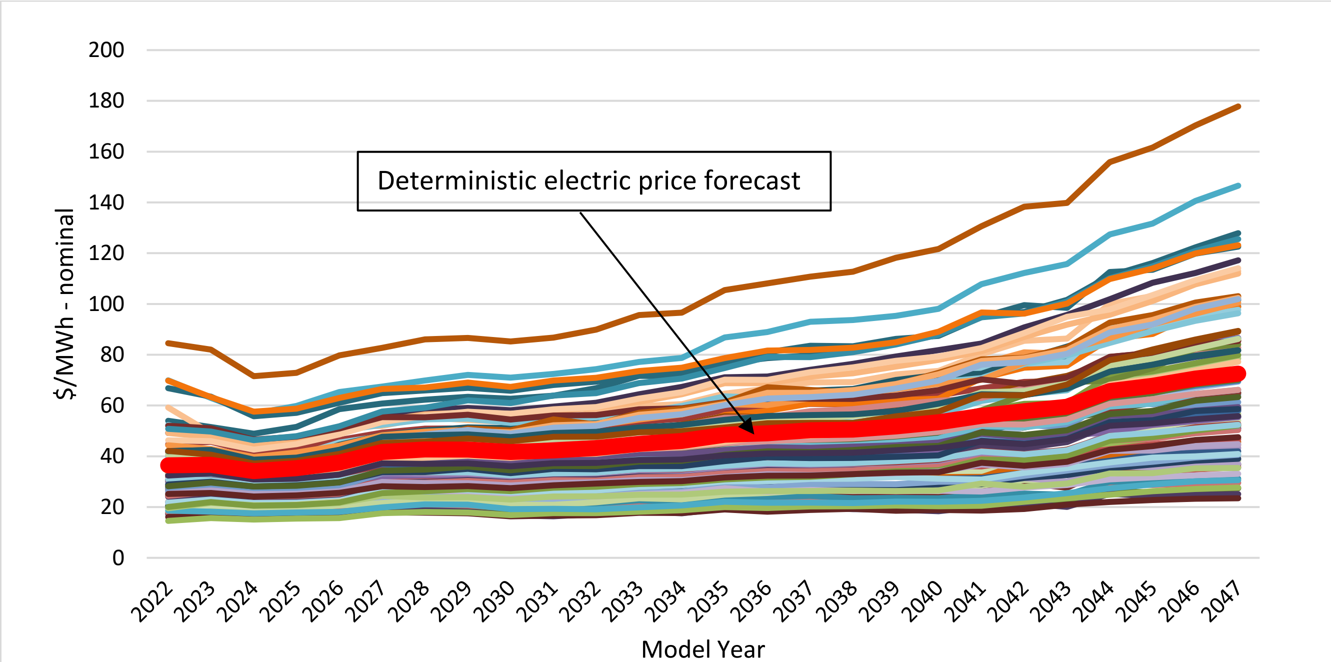


Figure G.16: Levelized Stochastic Electric Price Forecast Results - 90 Iterations