FRANKLIN PUD

THE POWER IS YOURS

2024 INTEGRATED RESOURCE PLAN

PREPARED IN COLLABORATION WITH:

TEA THE EnergyAuthority

JULY 2024

CONFIDENTIAL & PROPRIETARY

Section 1 Executive Summary

1.1 Background

Public Utility District No. 1 of Franklin County (FPUD) is required by Washington State law, Chapter 19.280 of the Revised Code of Washington (RCW), to develop "a comprehensive resource plan that explains the mix of generation and demand-side resources it plans to use to meet its customers' electricity needs in both the long term and the short term." The law stipulates that FPUD produce a comprehensive plan every four years and provide an update to that plan every two years. The Integrated Resource Plan (IRP) analysis must include a range of load forecasts over a ten-year time horizon; an assessment of feasible conservation and efficiency resources; an assessment of supply-side generation resources; an economic appraisal of renewable and nonrenewable resources; a preferred plan for meeting the utility's requirements; and a formal action plan.

The goal of this 2024 IRP is to forecast the future electric demand of our customers and to identify the optimal mix of resources that is affordable and reliable while meeting regulatory requirements and social expectations of our community. FPUD's previous IRP was adopted by the Board in August 2020. The 2020 IRP analysis showed that FPUD's existing long-term Bonneville Power Administration (BPA) power supply contract and its other owned and contracted resources can provide enough energy to meet its forecast need on an average annual basis through 2030. The 2020 IRP also identified a strategy to meet the short- and long-term electricity needs of FPUD customers and Washington State renewable portfolio standard (RPS) obligations for the 2020 through 2030 study period. The preferred portfolio included relying on market purchases for any short-term capacity deficits and procuring renewable energy credits (RECs) to address a projected shortfall in renewable portfolio standard compliant generation beginning in 2025.

FPUD developed a Progress Report in 2022 that reviewed the changing conditions in the wholesale energy market and planning environments as well as its progress in carrying out the strategy and formal action plan of the 2020 IRP. The Progress Report is consistent with the State of Washington's regulatory requirements (RCW 19.280.030).

FPUD contracts with The Energy Authority Inc. (TEA) for a suite of services including Portfolio Management, load forecasting, bilateral power trading, regulatory reporting, and integrated resource plans (IRPs). TEA's clients are located throughout the United States, operating in both bilateral and organized markets, including MISO, CAISO, ERCOT, SPP, and PJM. Founded by three public power owners to address changes in the electric utility industry, enhance the use of its clients' electric generating assets in the wholesale electric energy market, and optimize power sales and purchases for their systems, TEA's commitment to public power utilities has fueled its growth. Since 1997, TEA has expanded to seven owners and now serves over 60 total clients across the nation with generating assets and contract rights exceeding 25,000 megawatts. TEA has over 270 employees operating from its offices in Jacksonville, FL, and Bellevue, WA.

1.2 Franklin Public Utility District

Franklin Public Utility District (FPUD) provides electric service to approximately 33,500 residential, commercial, industrial, and street lighting customers countywide. FPUD purchases most of its wholesale power from the Bonneville Power Administration (BPA) at cost, through the long-term Slice and Block Power Sales Agreement.

Most of the BPA power supply comes from the Federal Columbia River Power System (FCRPS) hydroelectric projects. BPA also markets the output of the Columbia Generating System (nuclear plant) near Richland, WA, and makes miscellaneous energy purchases on the open market. FPUD augments its remaining energy and capacity requirements primarily through contracts for portions of the Nine Canyon and White Creek wind projects and the PowerEx, Packwood Lake, and Esquatzel Canal hydroelectric generating facilities.

1.3 Future Load and Resource Balance

FPUD's load was forecast for this IRP using linear and non-linear regression models developed by TEA and trained on historical weather, customer demand, and econometric data for the period from 2004 – 2024. The load forecast provides hourly granularity for the full study period from 2025 – 2044 based on econometric forecasts for Franklin County from Woods and Poole. In addition, the load forecast used in this study incorporates additional load growth due to building and vehicle electrification in excess of what has been seen historically. This growth was forecast separately using regression models trained on data from S&P Global Commodity Insights (S&P Global) and the National Renewable Energy Laboratory (NREL).

In aggregate, these models forecast average energy and peak demand growth of 1.6% per year over the 2025 to 2044 time period. In addition to the reference case scenario that is based on this base case load forecast, FPUD considered high and low load scenarios. The high load was developed by increasing the base load growth rate by 0.5% per year. The low load reduced the base load by 0.5% per year.

FPUD is currently forecast to have sufficient resources available to meet average energy demand through 2028. However, on a capacity basis, FPUD is currently at a deficit and is projected to grow that deficit to 231 MW of summer capacity and 131 MW of winter capacity by the end of the study period absent additional resource procurement. That deficit is partially exacerbated by the additional capacity required to comply with the Western Resource Adequacy Program (WRAP), which is modeled to take effect in November 2027.

1.4 Resources to Meet Future Growth and CETA Requirements

New resources are needed to address this substantial capacity deficit. Due to significant lead times required for construction and interconnecting a resource to the electric system, timely planning for each new resource is critical to ensure capacity requirements are met. To ensure compliance with the requirements of the Clean Energy Transformation Act (CETA), FPUD evaluated only carbon-free supply-side resource options including solar, wind, lithium-ion battery storage, geothermal, small-modular nuclear reactors, BPA Tier 2 power, market-based PPAs, and extensions of existing PPA contracts.

1.5 Conclusions

FPUD is currently meeting the energy demand of its customers with 90% carbon-free electric power and is projected to maintain balance between its load and resources in spite of a roughly 1.6% year-over-year projected load growth through the study period. However, on a capacity basis, FPUD has a considerable deficit and, without the implementation of a comprehensive and well-planned strategy, would likely see that deficit increase to as much as 231 MW by 2044.

FPUD will leverage all the tools available to meet this need reliably, affordably, and sustainably. First, FPUD will maximize use of Bonneville Power Administration (BPA) Tier 1 power, which is the cheapest low-carbon capacity resource available to the utility. FPUD will also acquire all cost-effective conservation measures and monitor opportunities for demand response and distributed generation investments. FPUD will continue to explore opportunities for adding both utility-scale renewables and behind-the-meter renewable resources, such as community solar projects, to its resource portfolio. FPUD will consider the possible extension of current renewable PPA contracts that are set to expire during the study period. In addition, FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. FPUD will also consider BPA Tier 2 opportunities and market-based purchases. FPUD continues to monitor the emerging technologies, including geothermal, hydrogen, and small-modular nuclear reactors (SMR) for possible future procurement.

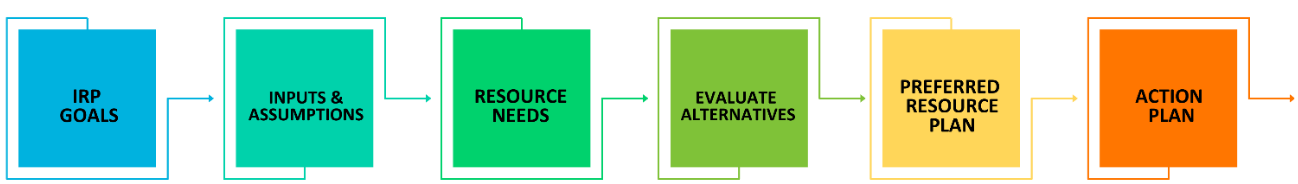
Section 2 IRP Methodology

Integrated Resource Planning (IRP) is a comprehensive and strategic planning process that FPUD performs on a regular basis to ensure the utility is utilizing an optimal mix of resources that minimize future costs while meeting the goals of FPUD and its community. Key outputs of the process are Net Present Value of Revenue Requirements (NPVRR), Levelized Cost of Energy (LCoE), and the amount of carbon emissions. Energy Exemplar's PLEXOS capacity planning model was utilized in the development of this 2024 IRP study.

The following are the steps taken by FPUD to develop this resource planning study:

1. IRP goals: IRP methodology begins with identification and establishment of the objectives of the IRP process. FPUD's goals include delivery of safe, reliable and cost-effective service while maintaining environmental responsibilities and regulatory compliance.
2. Inputs and Assumptions: This step involves identifying potential future resource options, developing assumptions for costs and operating characteristics of current and potential resources, and estimating future electric demand.
3. Resource Needs: The third step compares capacity contributions from existing resources with load forecast estimates to identify expected timing and magnitude of future capacity shortfalls.
4. Alternatives Evaluation: The capacity planning model is used to identify resource plans that meet utility objectives. To identify operational risks, resource plans are developed under multiple scenarios and sensitivities. This comprehensive evaluation helps FPUD to develop strategies that mitigate risk and ensures resilience in the face of unforeseen circumstances.
5. Preferred Resource Plan: A preferred resource plan is selected based on its performance across multiple scenarios and sensitivities. A resource plan is considered effective if it is capable of meeting FPUD's goals listed in the first step of the process.
6. Action Plan – A series of steps is developed to carry out the preferred resource plan. These steps may include developing additional studies, issuing requests for proposals (RFPs), and procuring and contracting for additional resources.

IRP 6-Step Process



Section 3 Policy And Regulation

3.1 Integrated Resource Planning

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3.2 Energy Independence Act

In 2006, Washington State voters approved the Energy Independence Act (EIA), RCW 19.285 (I-937). The act stipulates that any utility servicing over 25,000 customers must serve load with an increasing proportion of renewable energy. In 2012, 3% of retail load was required to be sourced from renewable generation, 9% in 2016, and finally 15% in 2020. The goal is that eventually renewable energy will become the sole energy provider within a utility's portfolio. Furthermore, the EIA requires that the District outlines its achievable cost-effective conservation potential every two years, as well as a focus on the ten-year energy efficiency potential. The EIA defines the following as eligible resources: water, wind, solar energy, geothermal energy, landfill gas, wave, ocean or tidal power, gas for sewage treatment plants and biodiesel fuel and biomass energy.

FPUD was initially exempt from the EIA and only came into compliance in 2016 when The District surpassed 25,000 customers. As a result, Franklin's compliance mandate is on a different timeline compared to those affected by the EIA when it first came into law. The first compliance mandate is 3% starting in 2021, then 9% in 2025, and 15% in 2029. If the District fails to meet the requirement, it will be assessed a penalty of $50/MWh, in 2007 dollars, equating to approximately $76/MWh in 2024 dollars.

3.3 Washington Climate Commitment Act

The Climate Commitment Act (CCA) was passed by the Washington State Legislature in 2021 and went live on January 1st, 2023. The act establishes a Cap-and-Invest program which places a declining cap on statewide emissions to help reach the State's 2050 goal of eliminating 95% of emissions. Business types covered under this program include fuel suppliers, natural gas and electric utilities, waste-to-energy facilities (starting in 2027), and railroads (starting in 2031). Additionally, electric utilities, natural gas utilities, and EITEs (emissions intensive trade exposed) receive "no cost" allowances. Entities that emit over 25,000 metric tons of CO_2e are required to retire allowances for compliance. Further, entities emitting more than 10,000 metric tons of CO_2e are required to report emissions annually. These reports are due June 1st of the following year for electric power entities, and March 31st of the following year for any other entities. As noted in Table 1, 63.2M allowances were distributed in 2023 across all sectors, and the no cost allowance budget decreases by 7% annually for the first compliance period. In 2023, 17.5M allowances were distributed to the electric sector at no cost.

Table 1. Total program allowance budget for the first compliance period (CP1) where 1 allowance equals 1 MT CO2e

Emissions Year	Total Covered Emissions ($MT\ CO_2e$)
2023	63, 288, 565
2024	58, 524, 909
2025	53, 761, 254
2026	48, 997, 598

FPUD and other electric utilities who are subject to CETA were allocated allowances for the first compliance period based on the cost burden effect. The cost burden effect calculations emissions from load served by coal, natural gas, Asset-Controlling Supplier resources (such as BPA), non-emitting resources, and unspecified generation. Franklin's allowance allocation, in Table 2 is assumed to provide sufficient allowances for compliance over the first compliance period. These allowances may be sold at auction or retired for compliance.

Table 2. Franklin Public Utilities allowance allocation for the first compliance period of the Cap-And-Invest program.

	2023	2024	2025	2026
FPUD Allowances	140,118	140,609	141,274	TBD

The most recent cap and invest auction at the time of the IRP took place in June 2024. At the June 2024 Auction, 7.8M vintage 2023 and 2024 allowances were offered, and all allowances sold at a price of $29.92/MTCO2s. Additionally, 1,317,000 2027 vintage allowances were sold at advanced auction at the floor price of $24.02 leaving 883,000 vintage 2027 allowances unsold. Any allowances that go unsold are offered again at the following auction. Notably, the settlement price for current vintage allowances decreased from its peak of $63.03 in Auction 2 to $29.92 in Auction 6.

Initiative 2117 (I-2117) will be voted on in Washington State in the November 2024 election. If passed, I-2117 would eliminate the Climate Commitment Act and prohibit the existence of any cap-and-trade programs within the state of Washington. Given that at the time of the IRP the outcome of this initiative is unknown, the IRP assumes that the Cap-and-Invest program will continue as planned, and thus includes the cost of carbon as an input to the market simulation. If the CCA is repealed, FPUD would no longer be subject to any compliance obligation, and the no cost allowances distributed to FPUD would lose all value. FPUD contracts with TEA to actively manage risks associated with the Cap and Invest program.

3.4 Clean Energy Transformation Act (CETA)

The Clean Energy Transformation Act (CETA) (SB 5116, 2019) was signed into Washington law by Governor Jay Inslee in May 2019, and requires utilities to be 80% clean and GHG neutral by 2030 and prohibits the use of fossil fuel electricity production by the year 2045. Alongside this requirement, there are objectives that need to be achieved on time. The first one, completed in 2022, required utilities to create a clean energy implementation plan (CEIP) outlining actions regarding energy efficiency and renewable energy. CEIPs must be submitted every four years, and accompanying progress reports will be required starting in 2026. Further, all utilities must remove coal-fired electricity by 2025. As a result of this requirement, the Centralia Steam Plant, in Centralia, Washington, is on schedule to be retired by the end of 2025. Units 1 and 2 of the Colstrip Plant, in Colstrip, Montana, were retired in January 2020, and Units 3 and 4 will likely retire in the early 2030s. These retirements are included in the IRP market simulation. The “no coal” restriction also excludes coal that may be acquired through unspecified forward market purchases for terms greater than 1 month. As a result, utilities will be less able to rely on unspecified physical forward market purchases as a mechanism for hedging market exposure and may therefore face reduced hedging liquidity or higher prices in the forward market.

3.5 Western Resource Adequacy Program (WRAP)

As a result of increasing concern across the region about capacity sufficiency, the Western Resource Adequacy Program (WRAP) was created. This program is designed to leverage load and resource diversity and deliver resource adequacy efficiencies to participants. The WRAP has a forward showing program and an operational program. The forward showing program requires that 7 months prior to each season (Winter or Summer), participants in WRAP need to demonstrate that they have obtained sufficient capacity to meet their P50 Peak Load plus an additional Planning Reserve Margin (PRM). The operational program occurs each day of the season with 7 days of consideration before said operating day and calculates if WRAP participants have a shortage or surplus of their resources. Additionally, the program looks at the larger forward showing forecast and compares it to a forecast consisting of a few days ahead. Based on these forecasts and if a participant is at a deficit or surplus there will be allocations of energy to ensure all participants meet their energy needs.

Franklin is currently participating in the WRAP non-binding program through the TEA Load Serving Entity (LSE) group. Participating as a single LSE allows Franklin to take advantage of the diversity benefit that is provided by aggregating obligations and resources with three other utilities who have load in different locations. While in a planned product contract such as Slice/Block Franklin is considered the Load Responsible Entity, under a Load Following contract, BPA would be WRAP LRE on Franklin’s behalf. BPA made the decision to participate in the WRAP binding program in 2022.

3.5.1 Qualifying Capacity Contribution

Qualifying Capacity Contribution (QCC) is a vital metric in capacity planning, used to evaluate and quantify the reliable contribution of energy resources to the overall capacity mix. It specifically refers to the capacity of a resource that meets defined criteria to contribute to the energy supply or capacity needs of a system or grid. QCC considers factors such as resource availability, variability, and the capability to dispatch power as required. However, QCC assessments focus solely on evaluating the resource type and do not address associated transmission deliverability requirements. Table 3 shows the percentage of installed capacity by resource type for QCC requirements.

Table 3. WRAP QCC Capabilities by Resource Type

Month	Season	BPA Product	Wind (VER1)	Solar (VER1)	ESR / Hybrid (Mid-C)	Thermal / Geothermal (Mid-C)	RoR (Mid-C)
January	Winter	100%	6%	3%	86%	90%	15%
February	Winter	100%	9%	3%	82%	90%	22%
March	Winter	100%	14%	5%	100%	90%	36%
April	Spring						
May	Spring						
June	Summer	100%	23%	29%	100%	90%	60%
July	Summer	100%	16%	17%	77%	90%	59%
August	Summer	100%	14%	12%	88%	90%	50%
September	Summer	100%	11%	6%	88%	90%	45%
October	Fall						
November	Winter	100%	8%	1%	100%	90%	22%
December	Winter	100%	7%	3%	100%	90%	19%

The WRAP QCC is not fixed; it can be adjusted as the WRAP initiative develops. The WRAP specifically targets two seasons—winter and summer—to fulfill capacity requirements.

3.6 Federal Policies & Regulations

3.6.1 PURPA

The Public Utility Regulatory Policies Act of 1978 (PURPA) directs state regulatory authorities and non-FERC jurisdictional utilities (including FPUD) to consider certain standards for rate design and other utility procedures. FPUD is operating in compliance with these PURPA ratemaking requirements. The FERC could potentially assert jurisdiction over rates of licensees of hydroelectric projects and customers of such licensees under the Federal Power Act. The FERC has adopted maximum prices that may be charged for certain wholesale power. FPUD may be subject to certain provisions of the Energy Policy Act of 2005, relating to transmission reliability and non-discrimination. Under the Enabling Act, FPUD is required to establish, maintain, and collect rates or charges that shall be fair and nondiscriminatory and adequate to provide revenues sufficient for the payment of the principal of the interest on revenue obligations for which the payment has not otherwise been provided and for other purposes set forth in the Enabling Act.

PURPA established a new class of generating facilities known as qualifying facilities (QFs) which would receive special rate and regulatory treatment, including qualifying small power production facilities "of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources."

The FERC defers to the states to determine the implementation of PURPA-based contracts, and this has had a significant impact on how many QFs have been built in each state. Idaho had a short-lived solar surge until the state PUC shortened the length of negotiated QF contracts from 20 years to 2 years. In June 2016, the Montana Public Service Commission (PSC) issued an emergency order suspending guaranteed PURPA contracts to small solar farms in response to a large number of applications from solar developers (as many as 130 solar projects). Oregon, however, has many PURPA facilities in the pipeline. In March 2016, the Oregon PUC decided to keep its 20-year guaranteed contracts in place with 15 years of fixed prices, which pleased renewable developers. Washington, on the other hand, doesn't have a required standard contract length for QFs. In addition, the depressed wholesale market prices (when compared to other markets) due to low-cost hydro makes the avoided cost of power too low for PURPA projects in Washington to be economically viable to developers. FPUD is currently a purchaser of RECs from Idaho PURPA solar generation facilities, which contribute to satisfying CPU's EIA renewable requirements.

The FERC announced its intention to review PURPA citing reports from utilities that developers may be unfairly applying PURPA rules to maximize economic returns. The FERC applies a test, known as the "one-mile rule," to determine whether adjacent facilities should be counted as one or multiple facilities. PURPA limits each facility's generation capacity to 80MW; thus, breaking a single large facility into multiple, smaller facilities increases the generation capacity allowance. The one-mile rule states that facilities located within one mile of each other are considered a single facility, whereas those greater than one mile apart are separate facilities. With wind plants stretched out over an extremely wide geographic footprint relative to other generation technologies, the FERC decided to review and clarify its one-mile rule. The rule is still under review as of the publication of this IRP.

3.6.2 Inflation Reduction Act (IRA)

On August 16th, 2022, President Biden signed the Inflation Reduction Act into law. The Act includes provisions for healthcare reform and clean energy investment, with a specific focus on the reduction of greenhouse gas emissions. The IRA allocates $370 billion for clean energy investments, supporting the development of carbon-free electricity generation through tax incentives, grants, and loan guarantees. The Act impacts numerous sectors including energy, manufacturing, environmental, transportation, agriculture, and water, with a primary focus on the electric industry.

The IRA extends investment tax credits (ITC) and production tax credits (PTC) to incentivize the creation of carbon-free resources and enable tax-exempt entities to maintain project ownership. The ITC is awarded based on the total investment upon project completion, while the PTC is paid over a decade based on the project's energy output. Both Sections 48E ITC and 45Y PTC offer technology-neutral credits for facilities with zero or negative greenhouse gas emissions. Facilities for new solar, wind, geothermal, and nuclear energy qualify for these tax credits, as do battery storage facilities for ITC.

Section 48E ITC: Section 48E of the U.S. tax code outlines a technology-neutral ITC for qualifying facilities constructed and operational after December 2024. The base ITC value for eligible energy projects is 6% of the capital investment upon project completion. This can be increased to 30% if the project meets certain prevailing wage and apprenticeship criteria. Additional bonus credits of 10% are available if the project complies with domestic content requirements and is located in an energy community area such as a brownfield or fossil fuel community.

Section 45Y PTC: Section 45Y of the U.S. tax code details a clean energy PTC paid over ten years for qualifying facilities constructed after December 31, 2024. The base PTC amount is 2.75 cents per kilowatt-hour (kWh) of electricity produced and sold, adjusted for inflation. If the project meets certain prevailing wage and registered apprenticeship criteria. Additional 10% bonus credits are available for projects meeting domestic content requirements and for those located in a designated energy community area.

A significant provision of the IRA allows direct payments to nonprofit organizations like municipal electric utilities instead of tax credits. This shift from the previous system, where municipal utilities had to sign a Power Purchase Agreement (PPA) with a renewable developer to receive the tax credit, allows entities like FPUD to develop a self-build renewable project and receive PTC or ITC credits. However, for this study, TEA modeled FPUD renewable participation as PPA agreements.

3.6.3 Renewable Electricity Production Tax Credit (PTC)

The federal renewable electricity production tax credit (PTC) is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service for all facilities placed in service after August 8, 2005. The PTC for generators with a construction commencement vintage of 2017 was $19/MWh. That rate will be reduced to approximately $14.25/MWh for generators with a 2018 vintage and $9.50/MWh for those with a 2019 vintage. The PTC for new wind construction was sunset entirely by the end of 2019 before being extended until the end of 2020 and restored to $9.50/MWh for facilities that start construction during the 2020 calendar year.

Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by the Inflation Reduction Act of 2022 as described in section 3.6.2. Previously it had been extended by the American Recovery and Reinvestment Act of 2009 (H.R. 1 Div. B, Section 1101 & 1102) in February 2009 (often referred to as "ARRA"), the American Taxpayer Relief Act of 2012 (H.R. 8, Sec. 407) in January 2013, the Tax Increase Prevention Act of 2014 (H.R. 5771, Sec. 155) in December 2014, and the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) in December 2015, and the Taxpayer Certainty and Disaster Tax Relief Act of 2019.

3.6.4 Renewable Energy Investment Tax Credit (ITC)

The Renewable Energy Investment Tax Credit (ITC) allows taxpayers to claim a credit for expenditure on renewable generation assets installed on homes owned and lived in by the taxpayer. The taxpayer can elect whether to use the ITC or the PTC to best fit their needs. The ITC may be preferable in locations with lower expected generation as the ITC is not dependent on the unit's generation.

Expenditures with respect to the equipment are treated as made when the installation is completed. If the installation is at a new home, the "placed in service" date is the date of occupancy by the homeowner. Qualified expenditures include labor costs for on-site preparation, assembly, original system installation, and for piping or wiring to interconnect a system to the home. If the federal ITC exceeds tax liability, the excess amount may be carried forward to the succeeding taxable year.

Most recently, the ITC has been expanded by the 2022 Inflation Reduction Act as described in section 3.6.4.

Section 4 Load Forecast

4.1 Load Forecast Summary

Projected system load is the amount of electric energy FPUD's customers require for heating, lighting, motors, and other end-uses prior to accounting for conservation, demand response, rooftop solar, and other distribution system resources. The load forecasts for FPUD used in this study were developed using historical load, weather, and econometric data for Franklin County for the period from 1970 to 2024. Unlike previous IRP analyses, this IRP developed a load forecast down to the hourly level to better capture the challenges presented by integrating a high volume of renewables in a capacity-short market environment.

A linear regression model was trained to forecast annual load growth at monthly granularity through 2044 based on econometric forecasts by Woods and Poole. A non-linear regression machine learning model was then trained to resolve the forecast down to hourly demand over the study time horizon. Forecasts for the rate of building and vehicle electrification were then added. Low and high load scenarios were then developed at matching hourly granularity based on the range of historical growth rates. These scenarios are used to understand FPUD's power resource needs under different futures.

4.2 Monthly Forecast

The monthly load forecast incorporates the long-term impacts of economic demographics according to the steps below:

1. 20 years of historical monthly system total and peak load data (2003-2022) was collected from data provided by Franklin.
2. 20 years of historical weather data for the KPSC weather station (Jan. 2004 – Jan. 2024) was collected from DTN weather. A normalized weather pattern based on temperature was determined using the rank and median method and applied to historical years and forecast horizon years. For both the historical and normalized weather data, heating and cooling degree days were then calculated using the formula below for each day. For hours with temperatures above 65˚ F, heating degree days were set to zero. This same methodology was used for cooling degree days in hours with temperatures below 65˚ F. These heating and cooling degree days were then summed to the monthly level.

$$Cooling\ Degree\ Day = \sum \frac{(Hourly\ Temperature - 65^{\circ}\ F)}{24}$$

$$Heating\ Degree\ Day = \sum \frac{(65^{\circ}\ F - Hourly\ Temperature)}{24}$$

3. Econometric data for Franklin County was obtained from Woods & Poole's 2022 Complete Economic and Demographic Data Source[1]. This dataset included both historical data from 1970 to 2022 and forecasted data extending from 2023 to 2060. Eight different economic metrics for Franklin County were obtained and total number of households was determined to have the best fit to the historical load data when weather normalized. **Error! Reference source not found.** below shows the total number of households in F ranklin County.

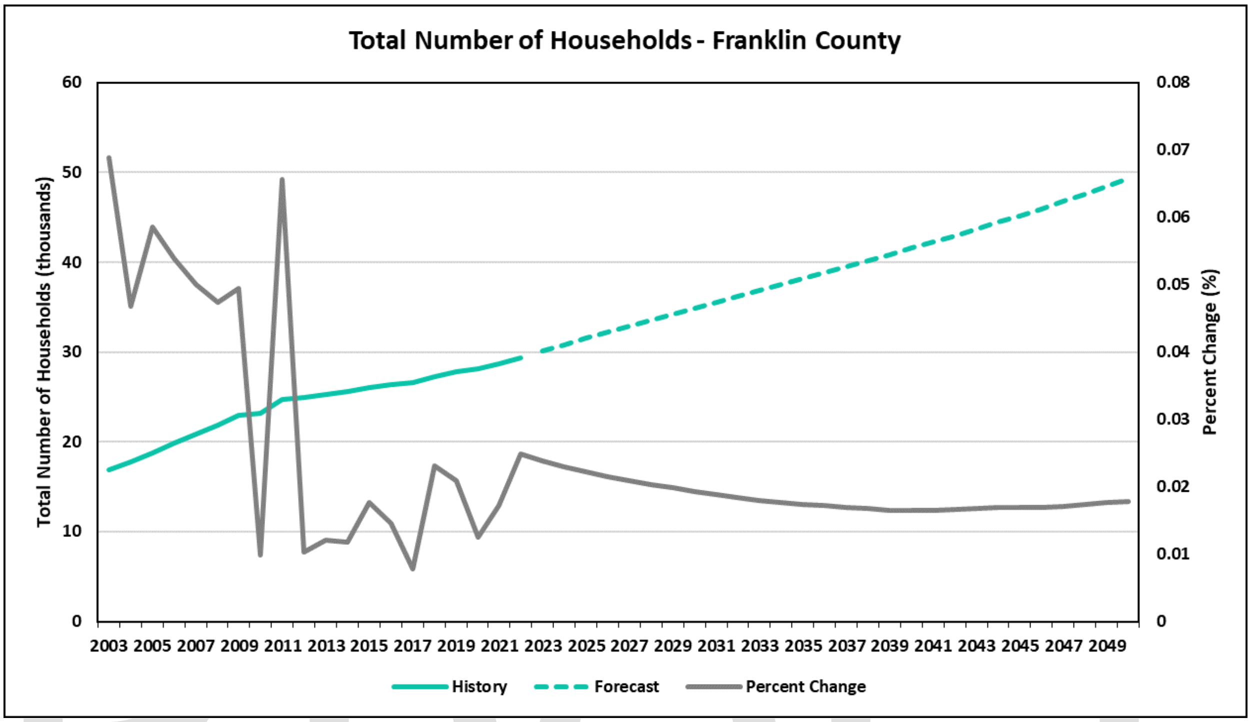

Figure 1. History and Forecast of Total Number of Households in Franklin County 2003 – 2050

4. Linear regression models were trained for predicting total and peak monthly load using the month of the year, historical heating/cooling degree days, and historical number of households.
5. These regression models were then used to project total and peak monthly load using the month of year, normalized weather, and economic projections for number of households in Franklin County. Figure 2 below is a visual of annual total and peak load calculated from the monthly history and regression model projections.

[1] **Woods & Poole Economics, Inc.** "2022 Complete Economic and Demographic Data Source (CEDDS)®." 2022. Woods & Poole Economics, Inc. Accessed, 2023. https://www.woodsandpoole.com/our-databases/united-states/cedds/.

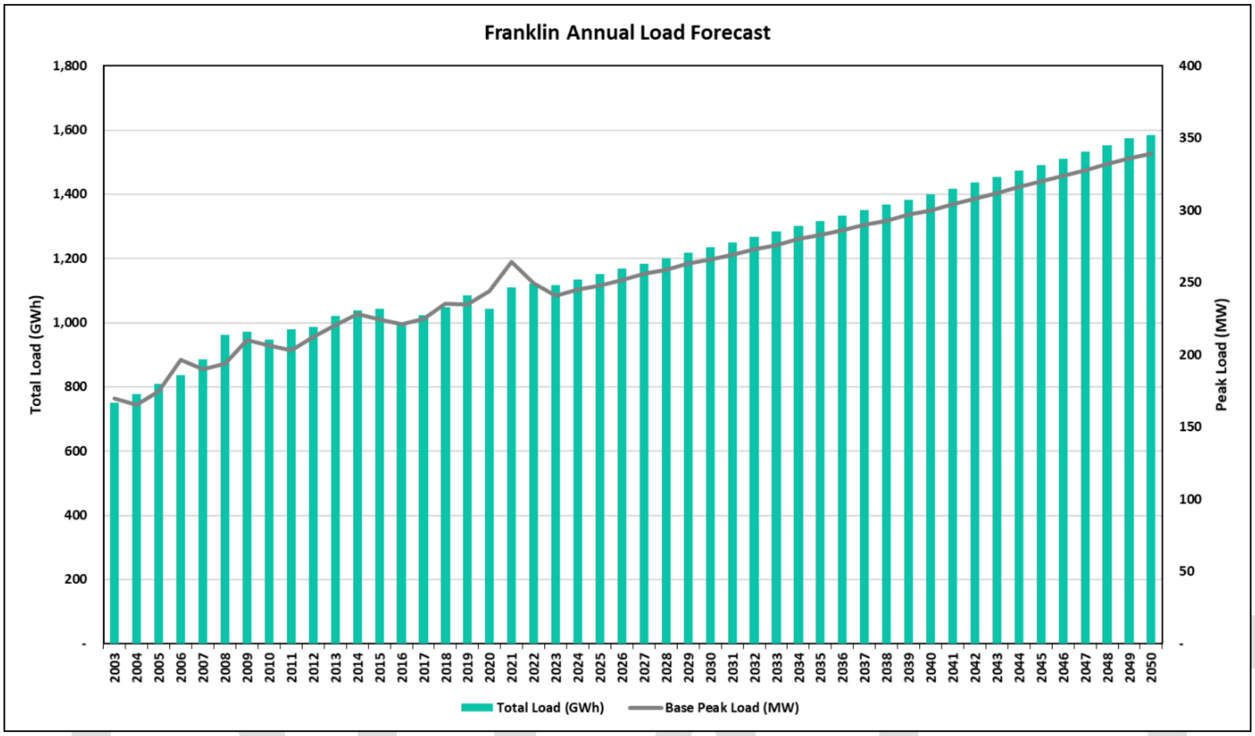

Figure 2. FPUD annual load history and forecast from 2003 – 2050

4.3 Hourly Forecast

The hourly load forecast was developed with the following steps:

1. Hourly historical meter-level load data was obtained for the last 5 years of load history. This CPOD level data was aggregated to calculate hourly system historical load for 2018-2022.
2. Hourly historical weather data for the KPSC weather station was collected from DTN weather. 10 years of historical weather data was then used to calculate hourly normalized weather using the rank and median method for the forecast horizon.
3. A non-linear machine learning model (GBM) was trained to predict load values given the historical weather data, actual system load, and time series features including hour of the day, month, and day of the week.
4. The trained model was then used to predict future load using the normalized weather forecast.
5. The hourly forecasted load was then fitted to the monthly total and peak load projections shown in the previous section. This was done to ensure congruency between the two predictions, since this hourly model has no feature which incorporates long-term load growth.

4.4 New Load Additions

Several large new customers are expected to begin service with Franklin PUD over the next few years. These expected new loads were added into the load forecast after the base forecast was developed. For simplicity, these new customers are assumed to have a flat load shape, consuming the same amount of energy every hour after beginning service. The impact of these new load additions on the projected peak and total load is shown in Figure 3 below.

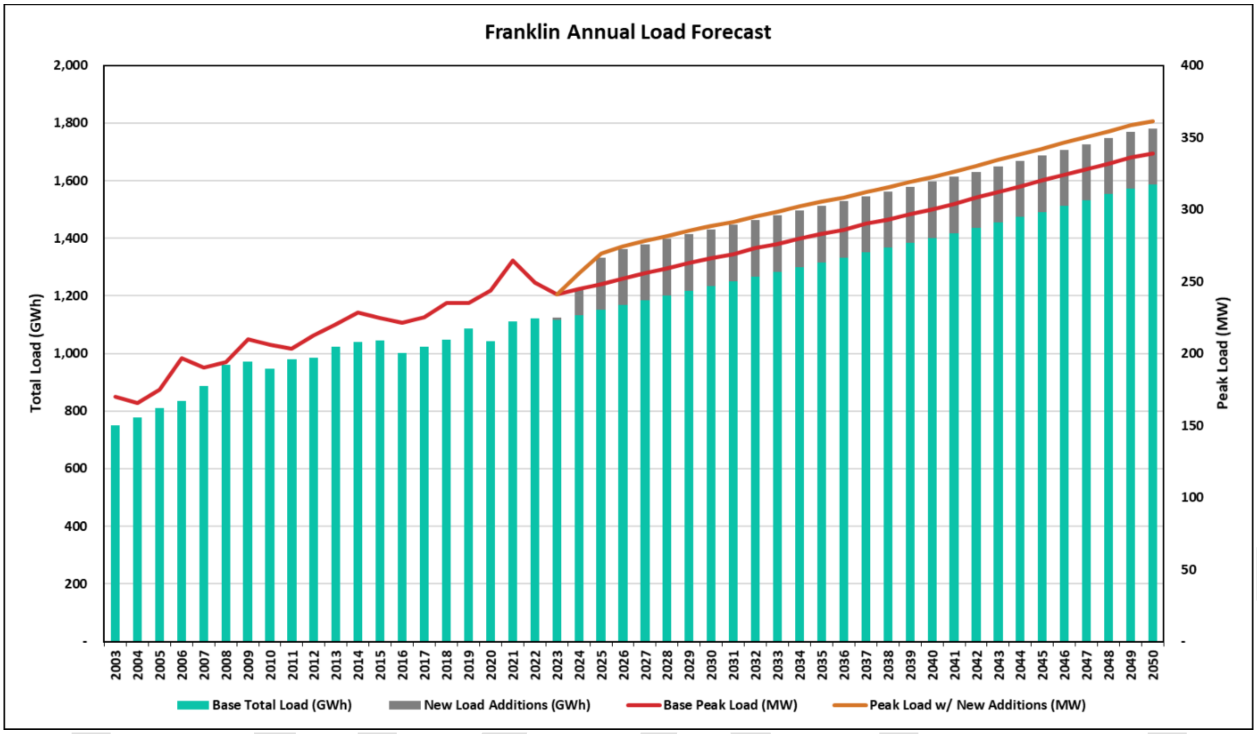

Figure 3. FPUD annual load history and forecast from 2003 - 2050 with new load additions

4.5 EV Forecast Methodology

The electric vehicle (EV) charging load forecast was developed separately and added on top of the base load forecast using the steps below.

1) A regression model was trained to project EVs as a percentage of total vehicles on the road by year. State-level data on the percentage of EVs on the road for 5 different years was sourced from S&P Global[2]. Additionally, economic projections of income per capita by state were obtained from Woods & Poole. The economic projections were assumed to be the primary driver in EV growth, particularly in the near-term. After model training using this state-level data, annual per-capita income projections for Franklin County, Washington were then input into the regression model to project the percentage of vehicles on the road that are EVs. These percentages were multiplied by the total number of vehicles on the road, obtained for Franklin County from Washington Department of Transportation data[3].

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[2] **S&P Global Mobility.** "State Electric Vehicle Forecast." S&P Global Mobility. Accessed Apr., 2023. https://www.spglobal.com/mobility/en/index.html.

[3] **Washington State Department of Transportation.** "Registration Activity by Fiscal Year and Primary Use." data.wa.gov. Accessed Jan, 2024. https://data.wa.gov/Transportation/Registration-Activity-by-Fiscal-Year-and-Primary-U/f8kb-pm6f.

2) The EVI-Pro Lite tool from the National Renewable Energy Laboratory (NREL) provides an hourly charging load shape[4]. This tool requires several inputs, listed below.
   a) EV count projections by year, obtained from the previous step.
   b) Average temperature, which is varied by month depending on the average monthly temperature from the last 10 years at the Pasco/Tri Cities Airport (KPSC).
   c) Average miles traveled per day for an EV owner – assumed to be 35 miles.
   d) Full EV vs. plug-in hybrid – assumed to be an even split between the two.
   e) EV Sedans vs SUVs – assumed to favor sedans.
   f) Assumed EV owners who have access to a home charger and prefer to charge at home, both assumed to be 100%.
   g) Charger type, assumed to be an even split between level 1 and level 2 for home chargers and favor level 2 for public chargers.
   h) Charging strategy – assume customer charging behavior pattern follows immediate strategy, where customers charge their vehicles as quickly as possible once plugged in.
3) The EVI-Pro Lite tool provided the output of the hourly EV charging shape given the assumptions above. This hourly forecast was then added on top of the base load forecast, enabling the load forecast to be available with and without forecast EV charging impacts. The below figure shows the annual energy and peak load resulted by EVs for Franklin County. Figure 4**Error! Reference source not found.** below shows FPUD's annual load from 2003 through 2050 after including new load additions and EV charging load.

[4] **National Renewable Energy Laboratory (NREL).** "EVI-Pro Lite Tool." NREL. Accessed May 2023. https://www.nrel.gov/transportation/evi-pro.html.

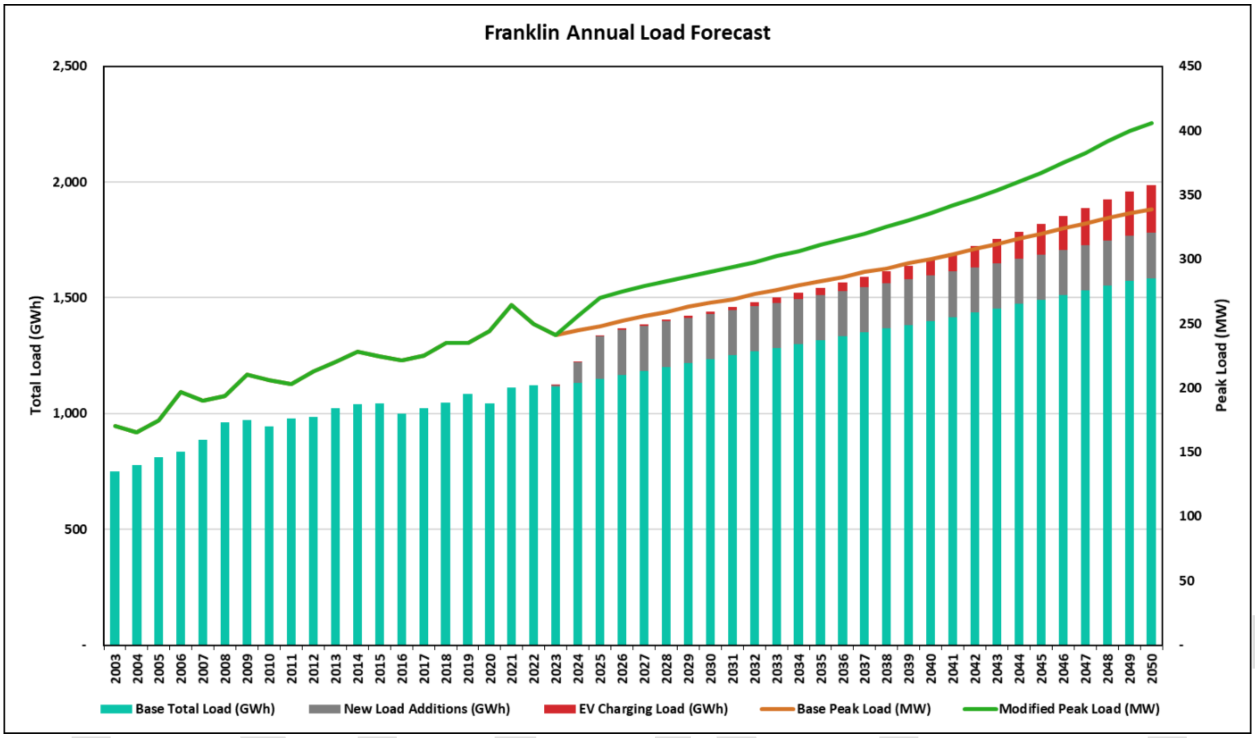


Figure 4. FPUD Load from 2003 - 2050 with New Load Additions and EV Charging Load

4.6 High and Low Load Scenarios

In addition to the base load scenario (the expected case), high and low scenarios are provided to account for uncertainties and multiple possible futures in the forecast model. Figure 5 below shows the base, high, and low energy forecasts. Figure 6 shows the base, high, and low peak demand forecasts.

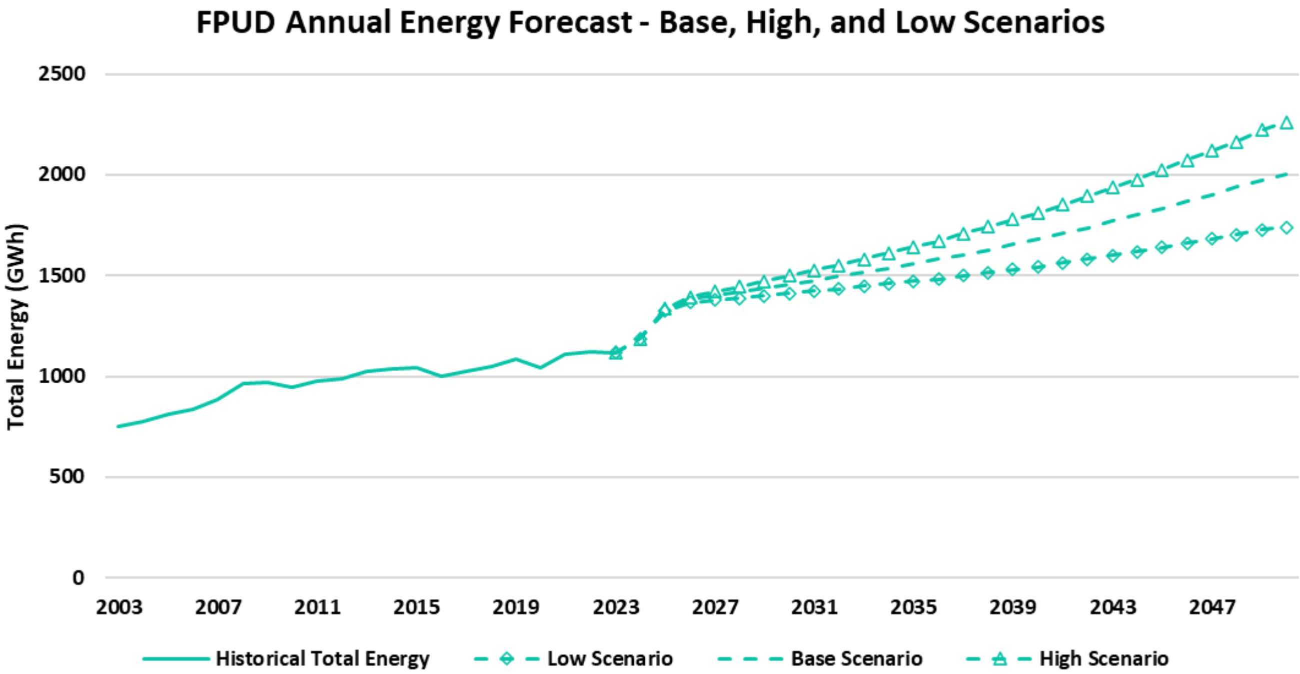


Figure 5. FPUD Annual Load Forecast Scenarios

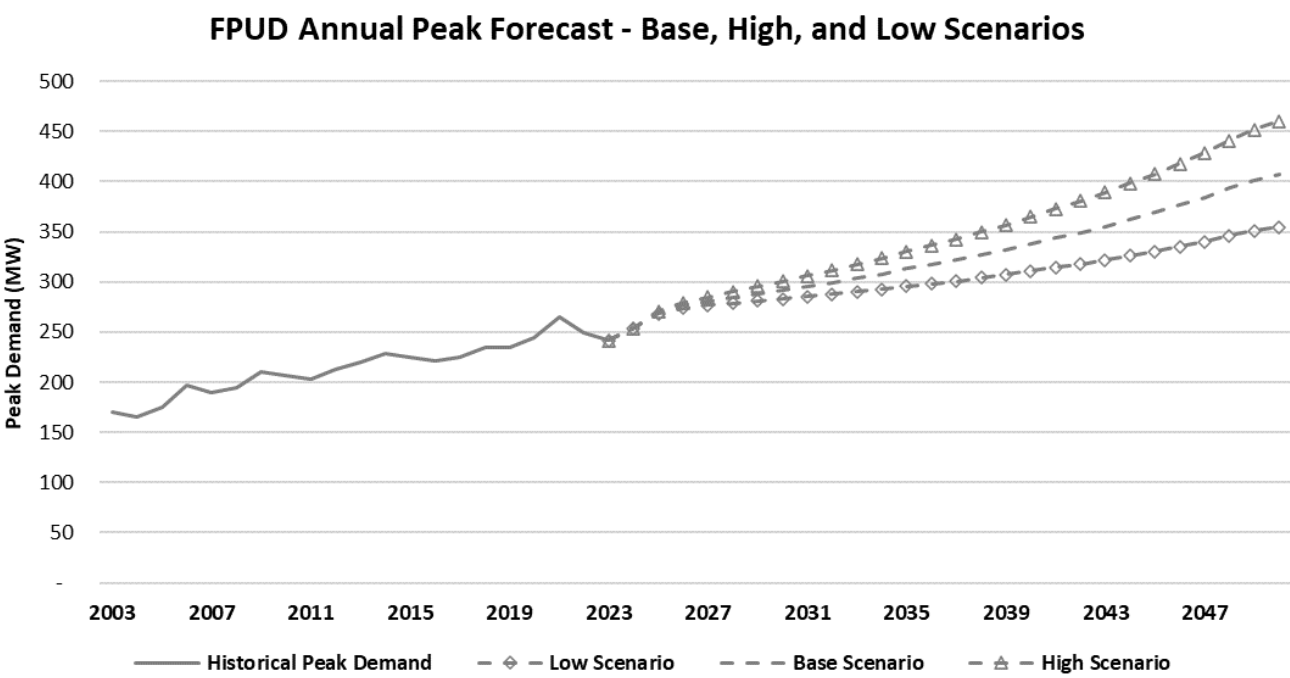


Figure 6. FPUD Annual Peak Demand Forecast Scenarios

Additionally, Table 4 below provides the annual projected growth rates and year-over-year change for different scenarios.

Table 4. FPUD Annual Load Forecast Scenarios

	Low Scenario				Base Scenario				High Scenario			
	Total Energy (GWh)		Peak Demand (MW)		Total Energy (GWh)		Peak Demand (MW)		Total Energy (GWh)		Peak Demand (MW)	
Year	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change
2025	1,323		268		1,329		270		1,336		271	
2026	1,367	3.4%	274	2.1%	1,381	3.9%	277	2.6%	1,395	4.4%	279	3.1%
2027	1,379	0.9%	277	1.0%	1,400	1.4%	281	1.5%	1,421	1.9%	285	2.0%
2028	1,387	0.6%	279	0.7%	1,419	1.4%	284	1.3%	1,444	1.6%	290	1.7%
2029	1,401	1.0%	281	0.9%	1,437	1.2%	288	1.4%	1,473	2.0%	296	1.9%
2030	1,412	0.8%	283	0.7%	1,455	1.3%	292	1.2%	1,499	1.8%	300	1.7%
2031	1,423	0.8%	285	0.8%	1,474	1.3%	296	1.4%	1,526	1.8%	306	1.9%
2032	1,432	0.6%	288	0.8%	1,495	1.4%	300	1.3%	1,551	1.6%	312	1.8%
2033	1,447	1.0%	290	1.0%	1,515	1.3%	304	1.5%	1,583	2.1%	318	2.0%
2034	1,459	0.9%	293	0.8%	1,536	1.4%	308	1.3%	1,613	1.9%	323	1.8%
2035	1,472	0.9%	296	1.1%	1,557	1.4%	313	1.6%	1,643	1.9%	330	2.1%
2036	1,482	0.7%	298	0.8%	1,581	1.5%	317	1.3%	1,671	1.7%	336	1.8%
2037	1,499	1.2%	301	0.8%	1,604	1.4%	322	1.4%	1,708	2.2%	342	1.8%
2038	1,514	1.0%	304	1.2%	1,628	1.5%	327	1.7%	1,742	2.0%	350	2.2%
2039	1,530	1.0%	307	0.9%	1,654	1.6%	332	1.4%	1,778	2.0%	357	1.9%
2040	1,543	0.8%	311	1.2%	1,681	1.7%	338	1.8%	1,811	1.9%	365	2.3%
2041	1,563	1.3%	314	1.2%	1,708	1.6%	344	1.8%	1,853	2.3%	373	2.2%
2042	1,581	1.2%	318	1.0%	1,738	1.7%	349	1.5%	1,894	2.2%	380	2.0%
2043	1,600	1.2%	322	1.3%	1,768	1.8%	355	1.8%	1,937	2.2%	389	2.3%
2044	1,617	1.0%	326	1.3%	1,801	1.9%	362	1.9%	1,976	2.1%	398	2.3%
2045	1,641	1.5%	330	1.3%	1,833	1.8%	369	1.9%	2,025	2.5%	408	2.4%
2046	1,662	1.3%	335	1.5%	1,867	1.8%	377	2.1%	2,072	2.3%	418	2.5%
2047	1,683	1.3%	340	1.5%	1,902	1.9%	384	2.1%	2,121	2.3%	429	2.6%
2048	1,702	1.1%	346	1.7%	1,939	2.0%	393	2.3%	2,166	2.1%	441	2.8%
2049	1,727	1.5%	351	1.5%	1,974	1.8%	401	2.0%	2,221	2.5%	452	2.5%
2050	1,741	0.8%	354	0.9%	2,001	1.4%	407	1.5%	2,261	1.8%	460	1.9%

Section 5 Current Resources

5.1 Overview of Existing BPA Resources

About 75% of FPUD's power is currently supplied through its Slice/Block agreement with the Bonneville Power Administration (BPA), the federal agency that markets the Federal Columbia River Power System (FCRPS). The FCRPS is managed and operated by a collaboration of three federal agencies: BPA, the U.S. Army Corps of Engineers (Corps of Engineers), and the Bureau of Reclamation. It consists of 31 multipurpose hydroelectric dams, the Columbia Generating Station, and a small amount of generation from contracts with wind farms. The dams provide the region with power generation, flood control, protection of migrating fish, irrigation, navigation, and recreation. Inside the dams are hundreds of turbines, the largest of which can generate 800 MW. The FCRPS has an aggregate generation capacity of 22,060 MW (Bonneville Power Administration, n.d.). Due to the size of the system, up to 10,000 MW of generation capacity can be offline for maintenance at any given time. Hydroelectric generation is variable by nature and fluctuates with overall water supply conditions. Electricity production is highly correlated to overall hydrological conditions, i.e. higher precipitation years generally equate to higher power generation years and vice versa. Hydrological conditions are catalogued by measuring the quantity of water runoff at a specific point for a specific period. BPA water years, which begin in October and end in September, are categorized by total water runoff in million acre-feet (MAF) at The Dalles between January and July. Hydrological conditions at The Dalles have been recorded since 1929. In that period, total runoff has varied between 53.3 MAF in 1977 and 158.9 MAF in 1997. The variability that can be seen from year to year (1949-2023) is illustrated in Figure 7.

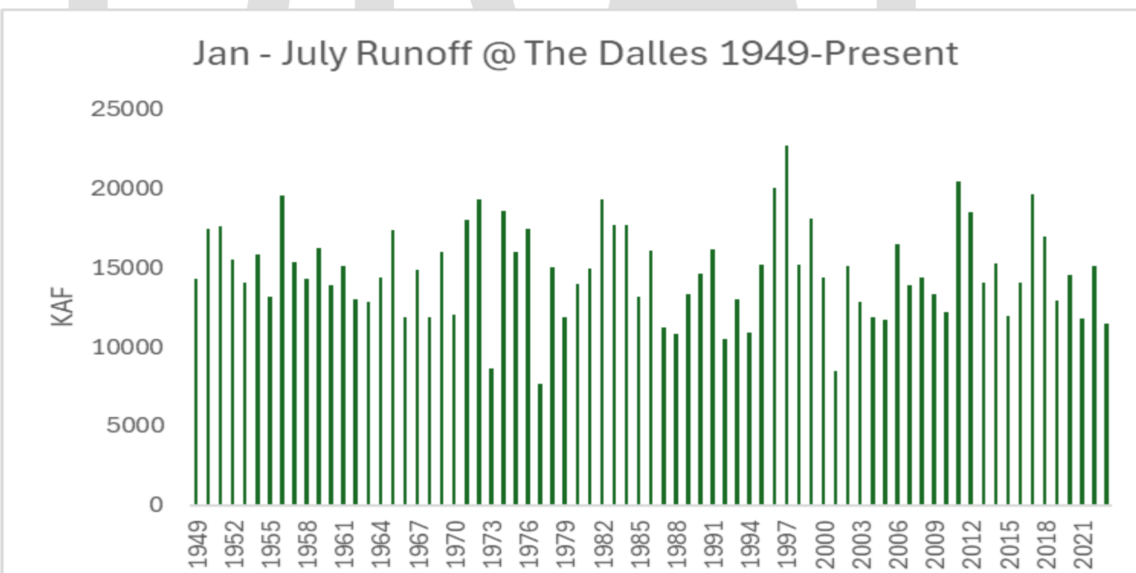


Figure 7. Historical Water Years (1949-2023)

The 1937 water year streamflows represented the worst (lowest) on record and was chosen as the benchmark "critical water" year to represents baseline system capability. Until 2022, BPA conservatively measured the system capability by determining its average annual energy output in critical water conditions. In October 2022, BPA shifted from using the 1937 water year to using a "P10" approach for determining the firm generation for the federal system. In this approach, the monthly 10th percentile of the most recent 30 years of streamflows are used to set the firm generation expectation. This change in methodology is intended to capture the impact of climate change on system generation, and it resulted in an 87 average megawatt decrease in annual generation.

As a BPA Slice/Block customer, FPUD receives a fixed monthly block of guaranteed generation and a variable allotment (Slice) of the Federal Columbia River Power System (FCRPS) output. The Slice portion is an allocated share of the total FCRPS for FPUD to operate and manage to serve FPUD's load while observing constraints for with water conditions, fish migration and spawning, migratory bird considerations, and flood control. BPA Tier 1 customers' FCRPS power allocation is referred to as the Contract High Water Mark (CHWM). CHWMs under the current contract were calculated to achieve load-resource balance between Tier 1 energy and a utility's 2010 adjusted loads less the utility's resources used to serve load (dedicated resources). The amount of power a Tier 1 customer is entitled to purchase in each rate period is then adjusted from the CHWM for any changes in FCRPS capability and is referred to as the Rate Period High Water Mark (RHWM). FPUD's share of annual Slice output is roughly 72 aMW in an average water year but can vary substantially depending on hydrological conditions. This source of power is assumed to be 94% clean and CETA compliant based on BPA's fuel mix report from 2021-2023.

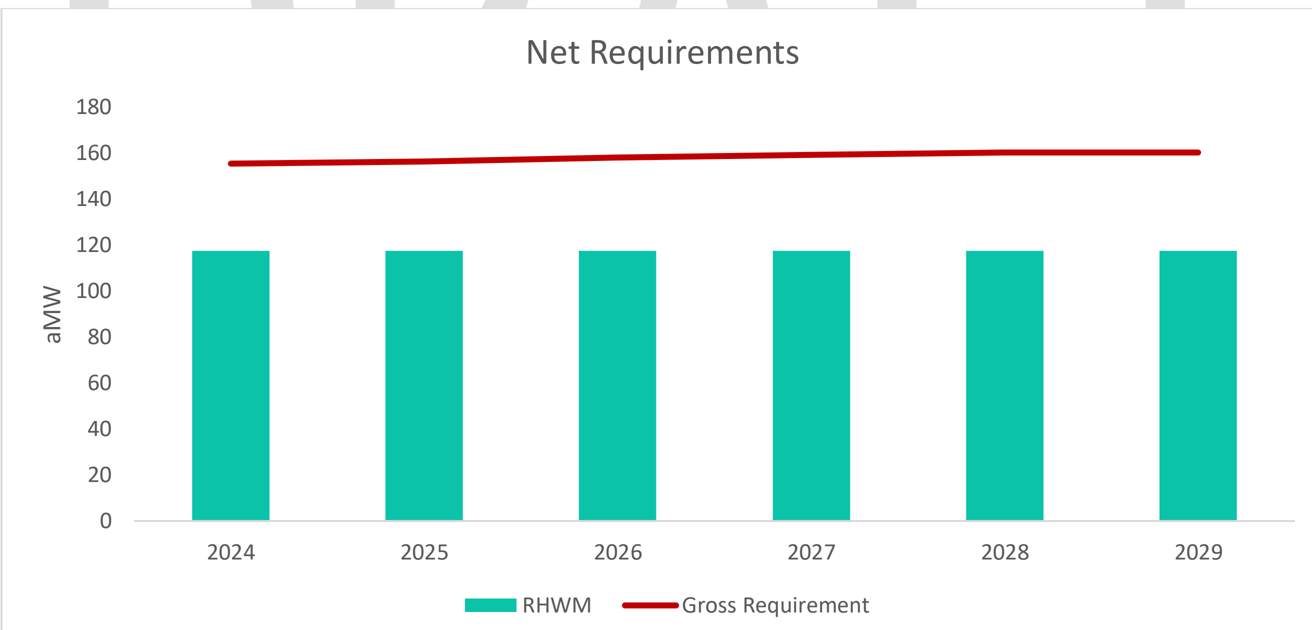


Figure 8. Retail Load vs. BPA Contract High Water Mark

The system allocation is calculated by dividing a utility's RHWM (or net requirements, whichever is lower) by the sum of all utilities RHWM (which is approximately equal to the Tier 1 system capability under critical hydrological conditions) resulting in a Tier One Cost Allocator (TOCA).

The Tier 1 rate is based on the cost of the existing federal system with very little augmentation. If preference customers choose to buy more power from BPA beyond their RHWM, this power is sold at a Tier 2 rate, which fully recovers BPA's incremental costs of securing additional resources to serve this load. Major components of the Tiered Rate Methodology include:

- ✓ Tier 1 priced at cost of existing system
- ✓ Tier 2 priced at marginal cost of new BPA purchases and/or acquisitions (i.e., equal to the cost of market or new resource)
- ✓ Public utilities can buy from BPA at Tier 2 rates, or acquire their own resources, to serve loads in excess of their HWM

The Slice/Block product is divided into two components: fixed and variable. The fixed component, or "Block," is a known and guaranteed quantity of power that FPUD receives from BPA, irrespective of the hydro conditions. Whether it is a critical water year or the highest on record, the quantity of Block power that BPA delivers to FPUD does not change. The power is shaped in advance into monthly blocks, which follows FPUD's monthly load profile. In other words, more Block power is delivered in higher load months; the converse is also true. The average energy output from the Slice system is expected to average 8,100 MW for the current two-year rate period, but daily generation will fluctuate from between 4,000 MW to greater than 15,000 MW. The FCRPS is a multipurpose system and power generation achieves only one of the system's goals. The need to fulfill other system obligations, such as fish migration, navigation, and flood control may at times compete with the power generation aspect of the river system. It may require the dams to hold back water when additional power generation may be beneficial or release additional water through the dams when there is already too much power available. FPUD accepts these operational risks as a Slice customer. It accepts fluctuations in actual federal system output and takes responsibility for managing its percentage share of the federal system output to serve its load. There is no guarantee that the amount of Slice output made available, combined with the firm Block power, will be sufficient to meet load obligations, be it hourly, daily, weekly, monthly, or annually. Being a Slice customer requires FPUD to, at times, fulfill its load obligations with resources other than what is provided by BPA and FPUD's contracted non-federal resources.

5.1.1 BPA POST-2028 PRODUCT OPTIONS

Figure 9 shows BPA's Provider of Choice (POC) Timeline updated June 2024. Source: BPA Provider of Choice

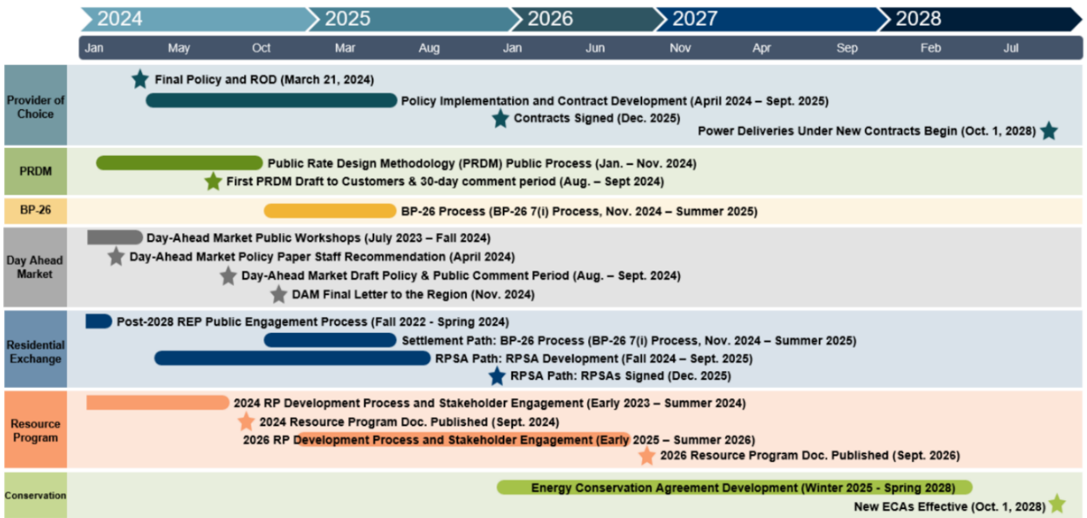


Figure 9. BPA's Provider of Choice (POC) Timeline

BPA's goal is that preference customers execute new power contracts by the end of 2025. As of the time the IRP, BPA has three main product options which include Load Following, Block Products, and Slice/Block.

Bonneville will continue offer the Load Following product in Provider of Choice (POC), which will serve a utilities' hourly energy and peak net requirements load. The Load Following product is not expected to change materially under POC. Load Following customers will continue to have load service certainty, and BPA will continue to require resource shaping services to integrate non-federal resources that have been declared to serve load.

BPA will continue to offer the Block Product which provides a planned amount of firm power to meet a utilities' Net Requirements. The Block Product will be offered in a flat annual amount, a monthly shaped amount, and a Block with Shaping Capacity option. BPA has made significant changes to the Block with Shaping Capacity product which was not selected by any utility under the Regional Dialogue (RD) contract. As proposed at the time of the IRP, the Block with Shaping Product provides a monthly volume that is shaped to the customer's load. These MWhs may be shaped by the utility prior to the Day-Ahead Market based on a fixed set of criteria including a maximum hourly volume, and minimum hourly volume, and a half-month usage constraint. Additionally, BPA has proposed offering a Peak Load Variance Service which will provide capacity up to a customer's P10 Load. BPA has not yet indicated how P10 load will be defined.

The Block with Shaping Capacity product as proposed appears to be a viable option for consideration given a similar risk profile to Load Following but better flexibility to integrate non-federal resources than Load Following. However, the viability of this product is contingent on how BPA chooses to define specific elements of the product, particularly the Peak Load Variance Service offering.

BPA has stated that they intend to continue to offer the Slice/Block product. However, Bonneville has suggested that they require that a sufficient group of customers indicate interest in Slice/Block to continue developing the product. At the time of the IRP, BPA's proposed POC Slice/Block Product is similarly structured to the RD Slice product, and differences between the two contracts largely stem from changes that BPA view as necessary to apply the product in an organized market. As with the current contract, the block portion of the contract provides a fixed amount of power, and the slice portion of the contract is based on a percentage share of BPA's generation resources. This share fluctuates based on the generation output of BPA's generation assets which predominately consist of the hydroelectric projects that make up the Federal Columbia River Power System (FCRPS) and the Columbia Generating Station nuclear facility. Unlike the RD Slice product, BPA proposes that in POC Slice, the schedule be locked down on a day-ahead basis and may not be changed in real-time.

At the time of the IRP, BPA has floated the concept of adding "Federal Surplus" to a Block with Shaping Capacity Product. This concept is in its infancy, and there is not certainty whether Bonneville will offer this option. However, a Block with Shaping Capacity Product with Federal Surplus may prove to be a viable option for consideration given its potential for a similar risk profile to Load Following and similar flexibility to Slice.

5.2 Product Comparison

This section provides a summary of the products that BPA is considering offering to its customer utilities at the time of the IRP.

Proposed Product Attributes

Product	Fit to Load Shape	Anticipated Capacity Specific Charges	Capacity Provided above P50	Non-Fed Resource Flexibility	PNR Check
Slice/Block	Least	No Embedded	System Dependent	Yes	No @ 50/50
Block: Stand-Alone	Partial	No Embedded	No	Yes	No
Block: w/Shaping Capacity	Partial	Yes Embedded +	No	Yes	≤XX% No >XX% Yes
NEW! Block: w/ Shaping Capacity + Peak Load Variance Service	Partial	Yes Embedded ++	Yes	Yes	Yes
Load Following	Most	Yes Embedded ++	Yes	Limited	No

5.2.1 Cost Comparison

At the time of the IRP, the Public Rate Design Methodology (PRDM) for the Provider of Choice contracts has yet to be finalized, so there will not be certainty regarding how the products compare from a rate standpoint until mid-2025. In general, all products will have similar costs in the long-term, given that BPA's rate design is intended to provide mechanisms for adjustments based on actual costs. While the costs are expected to be similar overall, there are some key differences in rate structure between the three products including capacity or demand charges and resource integration or Resource Support Services (RSS) charges. Slice/Block and Standalone Block, as proposed at the time of the IRP, have no anticipated charges for capacity or demand. This means that a utility would be responsible for meeting their net requirements load and capacity requirements in excess of the capability of the selected BPA Tier 1 product with non-federal resources or market mechanisms.

5.2.2 WRAP Comparison

Under a Load Following contract, BPA would be the Load Responsible Entity (LRE) under WRAP. Alternatively, for planned product options such as Slice/Block and Block with Shaping, FPUD would be the LRE. Peak Load Variance Service (PLVS) has been proposed as an add on to the Block with Shaping Capacity product to provide capacity up to a P10 load. At the time of writing, it is unclear exactly how much capacity PLVS would provide to FPUD. The Slice/Block product is anticipated to provide capacity based on the WRAP QCC of the FCRPS. FPUD is anticipated to need to purchase additional capacity providing resources to serve above-HWM load regardless of product choice. The Slice product is anticipated to provide the least amount of capacity out of all three products, so to be WRAP compliant with this product, FPUD would need to add significant capacity resources (see Figure 10).

5.3 Columbia Generating Station

The largest non-hydro generation asset is the Columbia Generating Station (CGS) located in Richland, WA, with a generation capacity of 1,190MW. It is owned and operated by Energy Northwest (ENW), a joint operating agency that consists of 28 public utilities in Washington State. FPUD's share of output from CGS is equivalent to its Slice system allocation.

5.4 Nine Canyon Wind Project

The Nine Canyon Wind Project is an Energy Northwest-owned wind generation resource situated on dryland wheat farms approximately eight miles southeast of Kennewick in the Horse Heaven Hills. Phase I of the project consists of 37 wind turbines, with a total capacity of 48 MW. Phase II consists of an additional 12 wind turbines, totaling 15.6 MW of capacity. Phase III consists of 14 wind turbines with a total capacity of 32 MW. The aggregate capacity of the Project is 95.6 MW.

Franklin PUD entered into a power purchase agreement with Energy Northwest for 10.5 percent of the generation capacity of the project, including the environmental attributes it produces, that extends through June 2030, and the IRP assumes this contract will extend through the study period. These attributes will help Franklin PUD fulfill its EIA renewable requirements. Nine Canyon has an expected capacity factor of 30 percent, also equating to an average energy output of 3 aMW.

5.5 White Creek Wind Project

Located just northwest of Roosevelt, WA in Klickitat County, the White Creek Wind Project consists of 89 turbines, each with 2.3 MW of capacity, with a combined capacity of 205 MW. It came online and began generating electricity in November 2007. White Creek provides renewable energy and environmental attributes that will help Franklin PUD meet its Energy independence Act (EIA) renewable requirements. Franklin PUD has contractual rights to a portion of the project's output, including all associated environmental attributes, through 2027.

With a capacity factor of around 30 percent, Franklin PUD receives an average energy output of 3 aMW from the project.

5.6 Packwood Lake Hydroelectric Project

The Packwood Lake Hydroelectric Project has a generation capacity of 27.5 MW, a firm output of 7 aMW, and an average output of approximately 10 aMW. It is owned and operated by Energy Northwest, but 12 Washington PUDs are participants in the project with "ownership-like" rights. It is located 5 miles east of Packwood, Washington in Gifford Pinchot National Forest. Franklin PUD receives a 10.5% share of the output from the project, .7 aMW under critical water conditions, and approximately 1.3 aMW under average water. The project does not qualify as a renewable resource and does not help Franklin PUD meet its obligations under the EIA.

5.7 Esquatzel Canal Hydro Project

The Esquatzel Canal, which discharges into the Columbia River, is located about 5 miles north of Pasco, in Franklin County. In 2011, Green Energy Today, LLC installed a hydroelectric generation turbine at the confluence of the canal and the Columbia River to capture the kinetic energy of the flowing water and convert it into electricity. Franklin PUD purchased all of the rights to the power and environmental attributes generated by the .9 MW Esquatzel Canal Hydroelectric Project through 2031, and has an option to extend the contract. The IRP therefore assumes that Esquatzel will remain as a resource through the study period. The project produces roughly 6,000 MWh of power annually.

Esquatzel is a run of the river project. Its generation cannot be turned on and off since neither Green Energy Today nor Franklin PUD controls the timing or quantity of water flows through the canal. Esquatzel is an EIA eligible renewable resource, and because its generating capacity is less than 5 megawatts, it is also classified as "distributed generation," which allows its environmental attributes (RECs) to count double.

5.8 PowerEx Hydro PPA

In 2020, the District signed a PPA with PowerEx Corporation, the marketing arm of BC Hydro, for a hydro energy purchase of 40 MW around-the-clock for the 3rd Quarter period (July through September) and 25 MW around-the-clock for all other months of the year. The PPA began in July 2023 and continues through the end of 2028, with an option to extend the contract upon mutual approval.

5.9 Solar PPAs

FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity (approximately 13 aMW of annual generation) through participation in the Ruby Flats and Palouse Junction projects. Both solar projects are expected to begin producing power in 2026, are 100 percent carbon-free, and qualify as renewable energy under the EIA and CETA.

5.10 Conservation

Franklin PUD has been actively engaged in conservation/energy efficiency resources for 30 years. Since 2002, the District's programs have resulted in the acquisition of over 10 aMW of conservation resources. More emphasis will be focused on conservation planning and acquisition in the future. Along with a renewable portfolio requirement, the EIA requires that qualifying utilities pursue all cost-effective conservation. For the sake of this IRP, cost effective conservation is assumed to be implicit in the load forecast and is therefore not treated separately as a resource to avoid double counting.

5.11 Existing Transmission

BPA Transmission Services (BPAT) as the Balancing Authority (BA) is the entity obligated to meet FPUD's peak load. Each BPA Slice customer sets aside and cannot access its share of Slice capacity to allow BPAT to meet all its within hour requirements. This includes regulation, imbalance, and contingency reserves (spinning and supplemental). BPAT reimburses BPA Power (BPAP) for any revenues it receives from use of this capacity. These revenues include regulation, imbalance charges, Contingency Reserves, and both Variable and Dispatchable Energy Resources Balancing Service charges (VERBS and DERBS). Slice customers receive their share of these revenues as an offset to the Composite Charge. BPAT uses this capacity to meet changes in both load and resources that occur within the hour. These changes can be an increase in net load (requiring these resources to increase output (INC)), or a decrease in net load (requiring these resources to decrease (DEC)). By virtue of purchasing these services from BPAT (Regulation, Imbalance, and Contingency Reserves) and contractually giving up its share of capacity for within hour services, FPUD has handed over its obligation for these services to the BA and does not need to include capacity for these services in its capacity planning for the IRP. Since BPAT has the responsibility for meeting this load, it will not be addressed in the IRP.

5.12 Load/Resource Balance with Existing Resources

Figure 10 illustrates FPUD's current resource qualifying capacity in relation to average energy consumption, peak demand load, and WRAP reserve margin requirements. FPUD's existing resources fulfill average energy consumption needs until late 2028. However, comparing resource capacity to peak load and WRAP requirements shows a shortfall ranging from 46 MW to 231 MW. Presently, peak demand is met through market purchases. Therefore, additional peaking or immediate capacity will be necessary to satisfy capacity requirements and energy needs effectively.

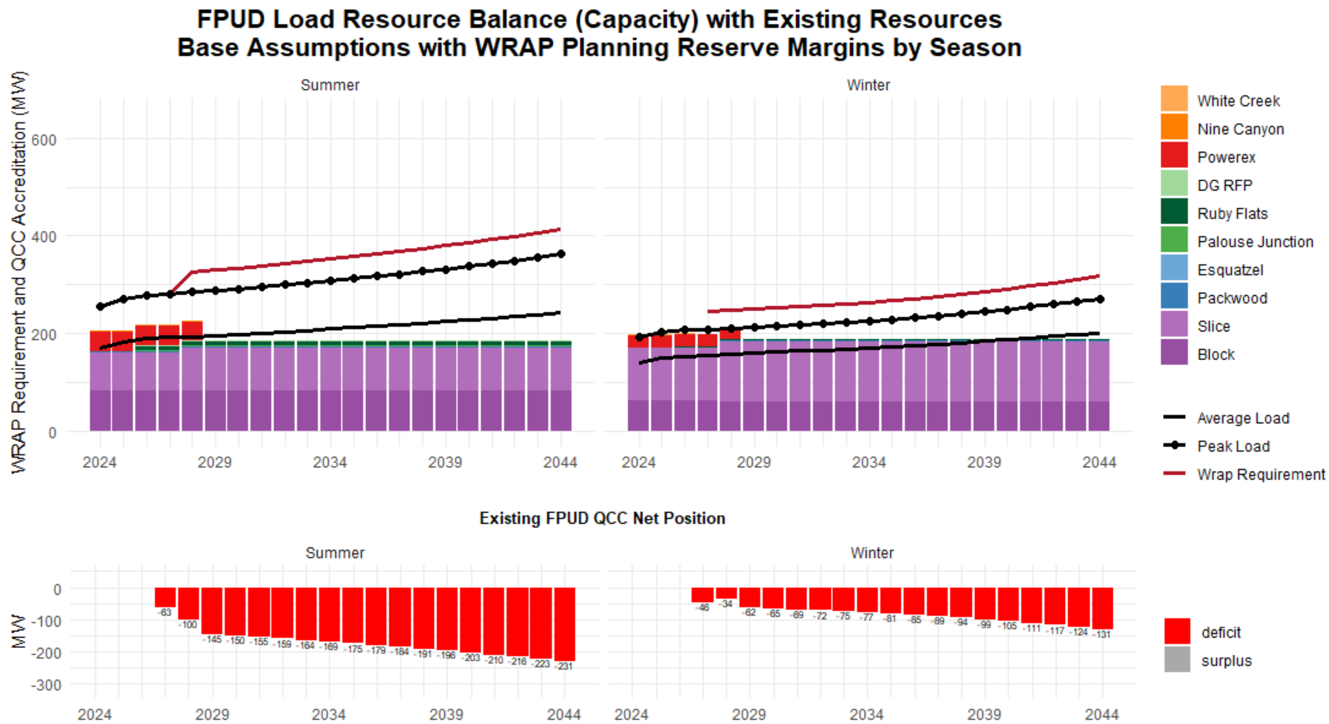


Figure 10. Existing Load Resource Balance

Section 6 New Resource Alternatives

New resources are needed to accommodate load growth and the retirement of aging generation units. Due to significant lead times required for construction and interconnecting a resource to the electric system, timely planning for each new resource is critical to ensure capacity requirements are met.

The requirements of the Clean Energy Transformation Act (CETA), which became effective on January 1, 2020, were major factors in determining the viability of potential resource alternatives. CETA requires that all utilities in Washington must supply carbon-neutral electricity by 2030. Although FPUD retains the flexibility to include carbon-emitting resources in its portfolio equal to up to 20 percent of its retail load until 2045, any carbon emissions generated from these resources must be offset by the procurement of renewable energy credits or the investment in renewable energy projects. In addition, when contemplating such resources, the societal cost of carbon must be included in the evaluation. CETA stipulates that by 2045, utilities must eliminate all carbon emissions by producing power exclusively with renewable and other non-emitting sources. For these reasons, FPUD evaluated only carbon-free supply-side resource options. The following supply options are considered currently or potentially viable within the study period and were included in this IRP analysis:

6.1 Solar PPA

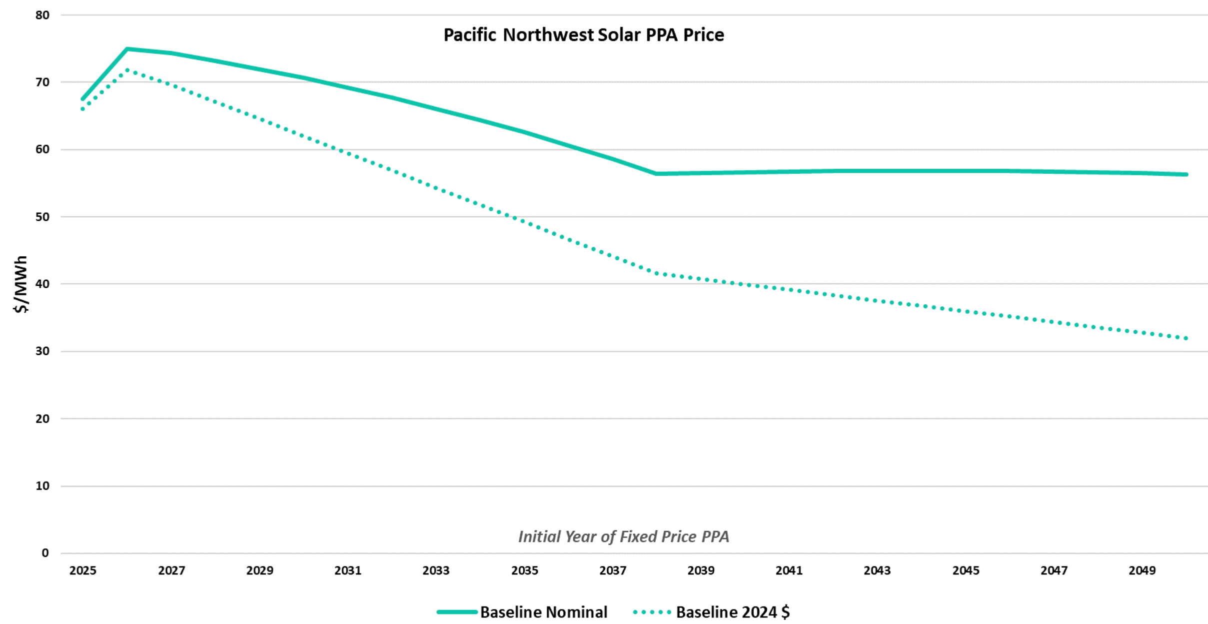
Solar resources were modeled as 20 MW PPAs based on large-scale solar photovoltaic projects. This option satisfies the long-term requirements of CETA. The rapid growth in electric generation from solar resources across the U.S. has been driven by declining costs, supportive governmental policies, and the increasing demand for carbon-free renewable energy. Installed utility-scale solar capacity in the U.S. has risen from less than 1 GW in 2010 to approximately 100 GW[5] by the end of 2023 and provided approximately 4%[6] of the total electric generation in the U.S. in 2023.

FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. Additional solar resources considered by FPUD are assumed to have a 3-year construction period and to be located in southeastern Washington within the BPA balancing authority. Based on market data, the cost of energy from a solar PPA, fixed for the duration of a 15-year term, is assumed to be $75/MWh for a project with a 2026 commercial date. Prices in subsequent years were based on expected changes in construction costs and subsidies available through the Inflation Reduction Act. Future overnight capital cost assumptions were provided by The National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL projects utility-scale solar capital costs to decline by an average of

[5] **Buttel, Lindsey**. America's Electricity Generation Capacity 2024 Update, American Public Power Association. [America's Electricity Generation Capacity Report, 2024 Update (publicpower.org)](), accessed on 7/1/2024.

[6] **Fitzgerald Weaver, John**. "Solar generated 5.5% of U.S. electricity in 2023, a 17.5% increase." PV Magazine USA. https://pv-magazine-usa.com/2024/02/29/solar-generated-5-5-of-u-s-electricity-in-2023-a-17-5-increase/, accessed on 7/1/2024.

2.9%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. The following exhibit shows the projected solar PPA prices assumed in the study.



6.2 Wind PPA

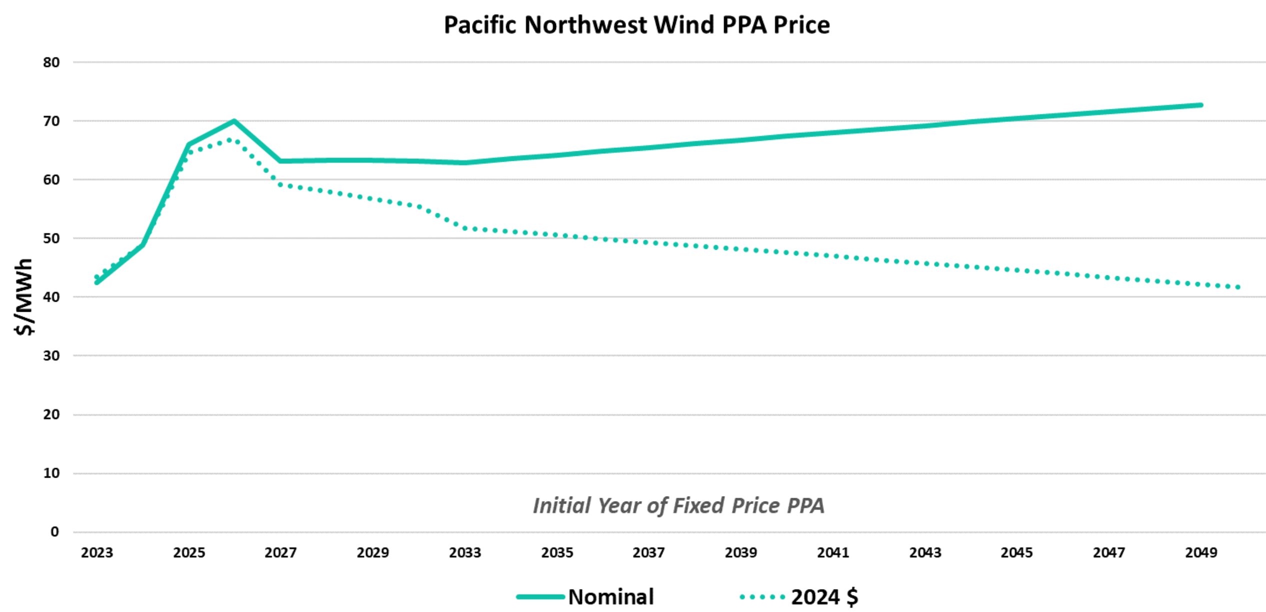
Wind resources were modeled as 25 MW PPAs based on utility-scale on-shore wind projects. Wind resources also satisfy the long-term requirements of the EIA and CETA. As with solar, the strong growth of wind generation has also benefitted from declining costs, supportive governmental policies, and the increasing demand for carbon-free renewable energy. Installed utility-scale wind capacity in the U.S. has grown from 46 GW in 2010 to over 150 GW[7] today. In 2023 wind generation provided over 10% of the total electric generation[8,9] in the US.

[7] Buttel, Lindsey. America's Electricity Generation Capacity 2024 Update, American Public Power Association. URL: America's Electricity Generation Capacity Report, 2024 Update (publicpower.org), accessed on 7/1/2024.

[8] Morey, Mark, and Jell, Scott. "Wind generation declined in 2023 for the first time since the 1990s." U.S. Energy Information Administration (EIA), April 30, 2024. URL: https://www.eia.gov/todayinenergy/detail.php?id=61943, accessed on 7/1/2024.

[9] Form EIA-923 detailed data with previous form data (EIA-906/920). U.S. Energy Information Administration (EIA). URL: https://www.eia.gov/electricity/data/eia923/, accessed on 7/1/2024.

Wind resources considered by FPUD are assumed to have a three-year construction period and to be located within the BPA balancing authority. Based on market data, the cost of energy from a wind PPA, fixed for the duration of a 15-year term, is assumed to be $70/MWh for a project with a 2026 commercial date. Prices in subsequent years were based on expected changes in construction costs and subsidies available through the Inflation Reduction Act. Future overnight capital cost assumptions were provided by The National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL projects utility-scale wind capital costs to decline by an average of 1.3%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. The following exhibit shows the projected wind PPA prices assumed in the study.



6.3 Battery Storage PPA

Battery storage allows energy from the power grid or renewable resources such as wind or solar to be stored for later use. Enabling the storage and dispatch of power from renewable resources is vital in the transition towards cleaner, more sustainable energy and achieving full reliance on renewable and carbon-free generation by 2045.

Currently, most utility-scale battery storage installations rely on lithium-based battery chemistry. Advantages include high energy density, long cycle life, and a history of declining costs. For utility peak shaving or load shifting applications, a Li-ion battery can discharge at its rated capacity level for up to a 4-hour duration.

Battery storage is modeled as a Li-ion battery PPA with 4-hour discharge capability. Storage projects are assumed to have a 3-year construction period and to be located within the BPA balancing authority. The first year of availability is assumed to be 2027. Based on market data, the cost of battery storage, fixed for a 15-year term, is assumed to be $144/kW-yr in 2027. Prices in subsequent years are based on expected changes in construction costs and investment tax credits available through the Inflation Reduction Act. Future overnight capital cost assumptions are from the National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL projects utility-scale battery storage capital costs to decline by an average of 2.7%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. The following exhibit shows the projected battery storage PPA prices assumed in the study.

6.4 Geothermal PPA

Geothermal power is a renewable energy source that uses the natural heat stored beneath the earth's surface to generate carbon-free electricity. The U.S. is the world leader in geothermal electric generation with approximately 4 GW of installed capacity.

Conventional geothermal resources naturally contain the presence of hot rocks, fluid, and underground permeability. In these locations, wells are drilled to harness the naturally occurring reservoirs of steam or hot water to drive turbines and generate electricity. These reservoirs are typically found in limited regions with high geothermal activity.

New or Advanced Geothermal resources refer to emerging techniques that can be used to harness geothermal energy in areas without naturally occurring reservoirs. One such technique is Enhanced Geothermal Systems (EGS). EGS involves drilling deep into the earth's crust, injecting water into the rock to create fractures, and then circulating the water through the fractures to create steam and generate electricity. This method can theoretically be used anywhere, as heat is always present deep in the earth's crust, making it more versatile than traditional geothermal energy. These emerging geothermal technologies also include methods to improve efficiency and reduce environmental impact. For example, some systems are designed to reinject used geothermal fluids back into the ground to sustain the pressure of the geothermal reservoir and to prevent surface disposal of these fluids.

Given the limited options to supply the carbon-free generation required by CETA, FPUD considers electric generation using geothermal energy as a potential option in the future. In this IRP's Reference Portfolio Scenario, a 25 MW block of traditional Geothermal generation was assumed to be available to FPUD beginning in 2035 as well as 75 MW of new geothermal. New geothermal refers to Enhanced Geothermal Systems (EGS) which involves drilling into the earth's crust and injecting high pressure water to create artificial geothermal reservoirs. The heated water is then brought back to the surface and used to generate power. New geothermal is more expensive than traditional geothermal but may be able to expand the use of geothermal generation which is now currently limited to geologically active sites. The cost of energy from a 25-year PPA based on traditional geothermal is assumed to be $90/MWh in 2024 dollars while the cost of energy from a 25-year PPA based on new geothermal is assumed to be $105/MWh. These costs are escalated at the inflation rate of 2.2%/year.

6.5 Small Modular Reactor (SMR) PPA

SMR is an emerging technology that could play a significant role in decarbonizing the electric generation industry in the future. If brought successfully to market, the technology will provide flexible nuclear power generation in a smaller size than the current base load nuclear plants that typically exceed 1,000 MW. The compact designs can be factory-fabricated and transported by truck or rail to a designated site.

The modular design of SMRs allows for less on-site construction, increased containment efficiency, and enhanced safety due to passive nuclear safety features. Co-location of multiple modules of approximately 60 MW each would provide precise amounts of generating capacity in locations where power is specifically needed. SMRs are part of a new generation of nuclear technology and have the potential to reduce the financial burden and risk associated with nuclear power. SMR technology may prove to be a source of significant carbon-free electric generation in the future.

Given the requirements of CETA and the inability to utilize natural gas-fired generation beyond 2045, FPUD has been open to considering the inclusion of SMRs in its future resource portfolio and would prefer to purchase SMR generation through a PPA. In this IRP's Reference Portfolio Scenario, the first year of SMR availability is assumed to be 2035. Based on The Energy Information Administration's January 2024 report, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," developed by Sargent & Lundy, the cost of energy from SMRs is assumed to be approximately 45% higher than that of traditional geothermal; therefore, energy from a 25-year SMR PPA is assumed to cost $130/MWh in 2024 dollars and is escalated at the inflation rate of 2.2%/year.

6.6 Other Resource Options

Several additional opportunities are modeled in the study.

- Extension of existing PPA contracts
    - White Creek wind – a 10-year extension is assumed to be available from 2027 through 2036 at a cost of approximately $75/MWh in 2024 dollars escalated at the 2.2%/ annual inflation rate.
    - PowerEx hydro – two 5-year extensions are assumed to be available in 2029 and 2034 with a market-based variable charge and a fixed charge of approximately $110 to $120/kW-year
    - Nine Canyon wind – a 10-year extension is assumed to be available from 2030 through 2039 at a cost of approximately $83/MWh in 2024 dollars and escalated at the 2.2% annual inflation rate.
- BPA Tier 2

  From 2026 through 2028, up to 10 MW is assumed to be available in 5 MW blocks at a cost of $80 per MWh.

  From 2029 through 2035, up to 20 MW is assumed to be available in 5 MW blocks at a cost of $85 per MWh.

- Short-Term Contract

  Short-term (1-year) contracts of up to 125 MW in 25 MW block sizes are assumed to be available during the 2026-2034 period prior to the availability of geothermal and SMR PPAs. The energy price is assumed to be $90/MWh in 2024 dollars with no escalation.

Options considered in this study are summarized in Table 5.

Table 5. Supply Resource Options

Supply Options	Max Build (MW)	First Available (Date)	Economic Life (Years)	Unit Size (Net MW)	Contract Price (2024$/MWh)	FOM (2024$/kW-yr)	Escalation rate (%)
4-Hr Storage PPA	200	2027	15	25	0.00	144.00	Note[10]
BPA Tier 2 (2026-2028)	10	2026	1	5	80.00	0.00	0.00%
BPA Tier 2 (2029-2035)	20	2029	1	5	85.00	0.00	0.00%
Geothermal PPA (New)	75	2035	25	25	105.00	0.00	2.20%
Geothermal PPA (Traditional)	25	2035	25	25	90.00	0.00	2.20%
Nine Canyon (2030-2039)	10	2030	10	10	82.83	0.00	2.20%
PowerEx (2029-2033)	25/40	2029	5	25/40	Index	111.28[11]	0.00%
PowerEx (2034-2038)	25/40	2029	5	25/40	Index	116.85[11]	0.00%
SMR	100	2035	25	25	130.00	0.00	2.20%
Solar PPA	Note[12]	2027	15	20	75.00	0.00	Note[10]
ST Contract (2026-34)	125	2026	1	25	90.00	0.00	0.00%
White Creek (2027-2036)	10	2027	10	10	74.95	0.00	2.20%
Wind PPA	40	2027	15	5	75.00	0.00	Note[10]

Distributed Energy Resources (DER)

Instead of traditional, one-way delivery of electricity from large, central station power plants located far from demand, technologies are now available that allow customers to generate their own electricity. Due to a combination of maturing technology and financial incentives, many of these technologies, such as rooftop solar, are currently affordable to many customers. Costs are expected to continue to trend down, and more technologies are expected to become available in the near future as research progresses, allowing more customers to adopt DERs. Understanding how DERs impact the grid itself, including reliability, is an important factor to be considered. Alternatively, understanding where, when, and how DER can benefit the grid is of equal value. While the economic signals may not yet be fully developed, technology has advanced to the point where consumers can respond to price changes, reduce (or increase) demand when useful to the system, or store electricity for later use.

DER are typically defined as small grid-connected power sources that can be aggregated to meet electric demand. Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. DER are being adopted at increasing rates due to favorable policies from both state and federal governments, improvements in technology, reduction in

[10]Emerging technologies like solar and storage follow a unique growth curve to accommodate for advancements in technology and government incentives.

[11]Powerex FOM is projected based on existing rates, with a 5% increase for each extension.

[12]The solar installed capacity will gradually be permitted, allowing up to 200MW by 2029, then up to 400MW by 2033, and after 2040, there will be no limits.

costs, and identifiable customer benefits, both at the individual and grid levels. Once DER adoption passes certain levels, DER can begin to cause significant issues for traditional rate making, utility models, and the delivery of electricity which can result in a cost shift among classes of ratepayers. It is important for electric utilities to identify potential economic and grid issues and benefits from DER. DER are becoming more widespread with increasing commercial availability, decreasing costs, and evolving consumer preferences. FPUD is proactively investigating and exploring programs and strategies that will lead to greater benefits for the public, customers, developers, and utilities alike. The DER space is evolving at a pace as rapid as any industry – it is imperative to develop a plan flexible enough to adapt to increased levels of DER.

Section 7 Market Simulation

7.1 Methodology Overview

Long-term resource planning requires a fundamental price forecast used to value existing and future capacity resource options. Operators, participants, and other market entities utilize a production cost model to simulate future market conditions to forecast prices. This following section details the methodologies used to create a market environment outlook that can generate prospective power prices.

7.1.1 Modeling Approach

Electric price simulation is generated using a fundamental production cost model. Figure 11 provides an overview of the process used to create the price simulation. The progression can be broken down into three principal phases. In the first phase, fundamental and legislative factors were modeled and integrated, including load forecasts, regional generation portfolio changes, carbon penalty assumptions, and regional renewable portfolio standards. The second phase of the study uses the inputs from the first step to run a capacity expansion analysis. The capacity expansion model optimally adds hypothetical resources to the existing supply stack over a 20-year time horizon. In the third and final phase, the long-term production cost model performs a 20-year dispatch of the entire Western Interconnect using the modified supply stack to simulate market prices. The following sections will describe how the model assumptions and inputs were derived, and the price simulation in further detail.

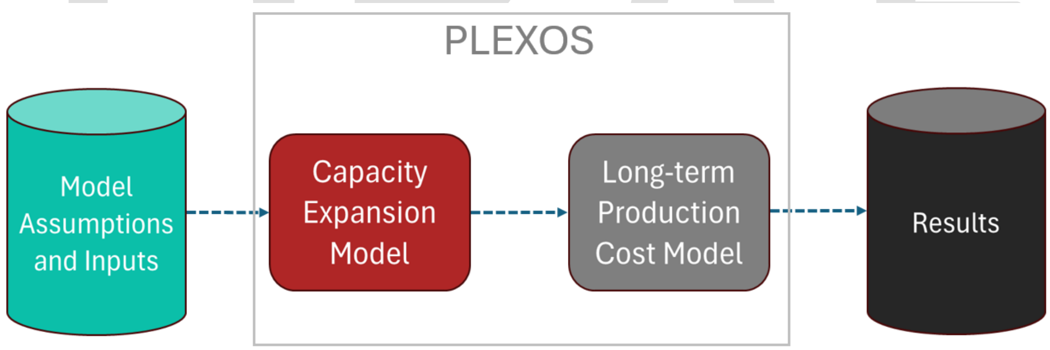


Figure 11. Modeling Approach

7.1.2 Model Structure

The primary tool used to determine the long-term market environment is PLEXOS. PLEXOS is a production cost software, licensed through Energy Exemplar LLC, that simulates the supply and demand fundamentals of the physical power market and ultimately produces a long-term power price forecast. Using factors such as economic and performance characteristics of supply resources, regional demand profiles, and zonal transmission constraints, PLEXOS then simulates a Western Electricity Coordinating Council (WECC) system expansion to produce a generation portfolio capable of satisfying future electricity demand. The model simulates resource dispatch which is then used to create long-term price and capacity expansion forecasts.

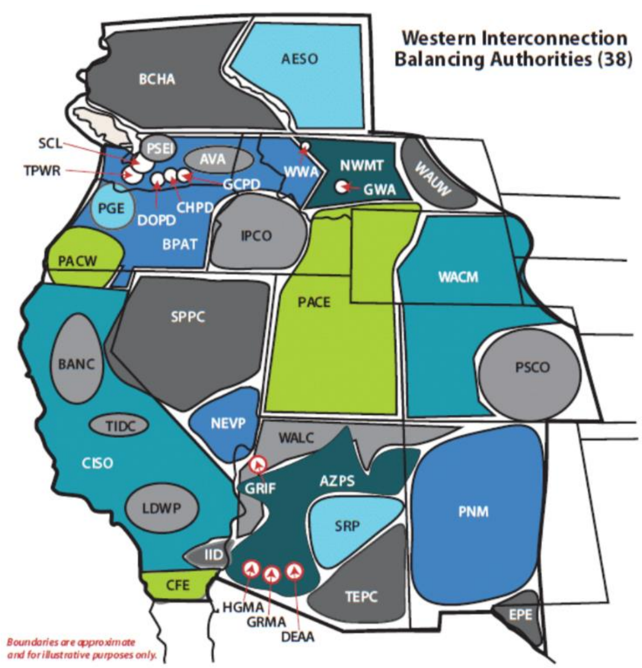
PLEXOS is utilized for three main purposes:

1. To determine a long-term deterministic view of resource additions and retirements.
2. Establish an expected long-term forecast price.
3. Perform scenario analysis on the expected price forecast by changing key inputs and assumptions.

Forecast drivers were either created or leveraged from reputable third-party vendors for such key variables as regional load growth rates, planning reserve margins, natural gas prices, hydro generation, and carbon prices. Renewable resource additions were set to correspond to the regional load growth and renewable portfolio standard set by each state. Upon the completion of a WECC footprint capacity expansion study, a set of scenario analyses was conducted using various combinations of natural gas and carbon prices. These scenarios were used to generate a long-term price forecast for the Mid-Columbia (Mid-C) trading hub.

7.1.3 WECC-Wide Forecast

The WECC is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, which encompasses the 14 western-most states in the U.S., parts of Northern Mexico and Baja California, as well as Alberta and British Columbia.



The WECC region is the most geographically diverse of the eight Regional Entities that have delegation agreements with the North American Electric Reliability Corporation (NERC). PLEXOS was used to model numerous zones within the Western Interconnect based on geographic, load and transmission constraints. The analysis focuses mainly on the Northwest region, specifically Oregon, Washington, and Idaho. Although the study forecast focuses on the Mid-C electricity market, it is important to model the entire region due to how fundamentals in other parts of the WECC can exert a strong influence on the Pacific Northwest market. The ability to import electricity from or export to other regions, the generation and load profiles of another region can have a significant impact on Mid-C power prices. As such, to create a credible Mid-C forecast, it is imperative that the economics of the entire Western Interconnect are captured.

7.1.4 Long-Term Fundamental Simulation

A vital part of the long-term market simulation is the capacity expansion analysis. The study utilized PLEXOS to determine what types of generation resources will likely be added in the WECC over the next 20 years, given our current expectations of future load growth, natural gas prices, and regulatory environment. PLEXOS' WECC dataset includes known or projected retirement dates for existing resources as well as online dates for proposed resources. PLEXOS then conducts a capacity expansion simulation in which load increases, resources are retired or derated due to regulatory requirements, and new generating resources are added to serve load requirements and meet planning reserve margins and renewable portfolio standards. The resources that are chosen are the best economic performers – i.e. the resources which provide the most regional benefit for the lowest price based on the constraints previously detailed.

7.2 Principal Assumptions

Market conditions change regularly, driven by a multitude of factors. Energy demand, regulations, fuel and capital costs, and environmental goals all influence the future economic viability of generating resource options. As regional resource portfolios transform, power price values and shapes will shift. The intent of this section is to detail the methodologies used to model the expected changes across the WECC footprint during the 2020's through the 2040's that will best capture the impact to future power prices that will be used in the portfolio analysis.

7.2.1 WECC Load

PLEXOS's default annual demand forecasts for zones in the WECC region are based on WECC's Data Archives and FERC-714 filings. The data available in the PLEXOS WECC database includes load for 34 regions through 2054. FERC only published forecast data for ten years and to account for the additional years the final three-year average of the FERC growth is applied to generate load, by region, for the subsequent years. For example, on average annual peak load is expected to increase at a 0.86% rate.

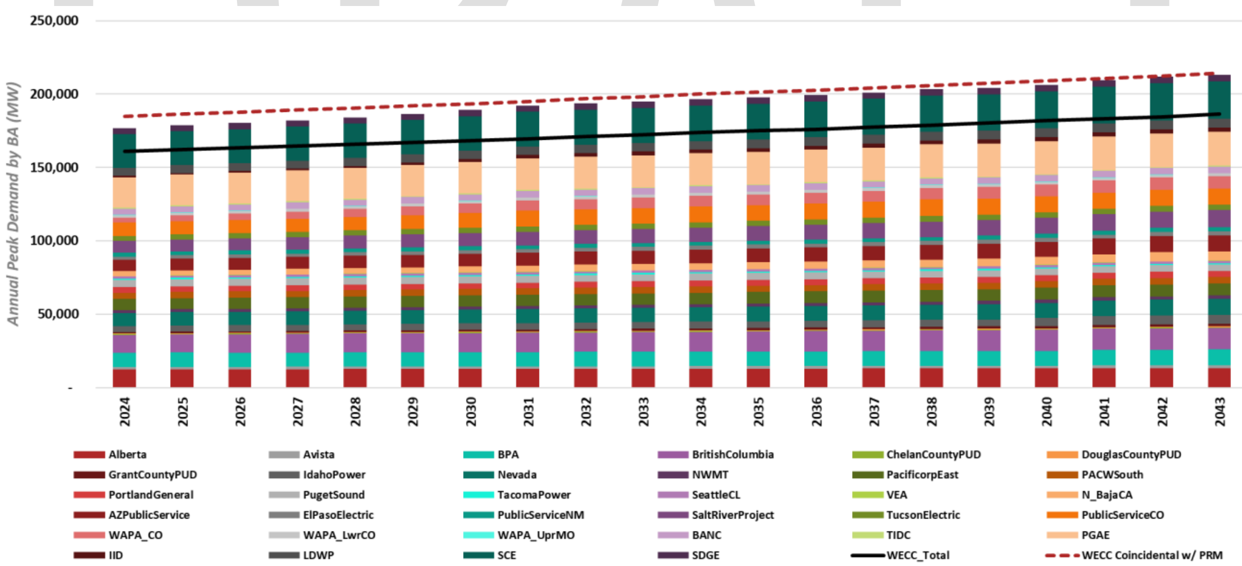


Figure 12. WECC Annual Peak Load Projections

Annual load projections are then shaped at the hourly level using three-year historical hourly load data and Energy Exemplar's "Smooth-Ranked" methodology, which removes volatility and creates a typical hourly load profile. The typical load profile, in conjunction with the total and peak energy inputs and PLEXOS build function, are used to develop the hourly load forecast in PLEXOS through 2054 for each region.

7.2.2 Regional Planning Reserve Margins (PRM)

To ensure there will be sufficient generating capacity to meet demand, a defined amount of generating reserve capacity is built into the market. These operating reserves are often extra generating capacity at existing operating plants, or fast-start generators, which can start-up and reach maximum capacity within a short amount of time. Historically these fast-start resources have been natural gas-fired generators, but the shift to batteries or other energy storage resources is on the rise.

Planning reserve margins (PRM) are a long-term measurement of the operating reserve capacity within a region, used to ensure there will be sufficient capacity to meet operating reserve requirements. The PRM is an important metric used to determine the amount of new generation capacity that will need to be built in the future. A 15% planning reserve margin on each zone was modeled during the capacity expansion simulation, consistent with WECC reliability assumptions in the 2021 WECC Western Assessment of Resource Adequacy.

7.2.3 WECC Renewable Portfolio Standards (RPS)

Renewable portfolio standards (RPS) are state-level requirements that require electric utilities to serve a certain percentage of their load with eligible renewable electricity sources by a certain date. The goal of these requirements is to increase the amount of renewable energy being produced, in the most cost-effective way possible. Currently, there are not federally mandated RPS requirements, instead states have set their own based on their environmental, economic, and political needs.

Among states in the WECC, California has the highest RPS requirement at 60% by 2030, with Oregon following shortly behind it with a 50% requirement for its IOUs by 2040. In Washington, there is a 15% RPS requirement, but with the 2019 enactment of the Clean Energy Transformation Act (CETA), there is now also an 80% carbon-free requirement by 2030. A wide variability in the requirements exists between states in the region, which could have a sizeable effect on electricity pricing within the region. Figure 13 details the RPS goals for each state or province included in the PLEXOS WECC database.

State/Province	Program Type	Description
Alberta	RPS	30% renewable energy by 2030
Arizona	RPS	15% renewable energy by 2025
California	RPS	60% renewable energy by 2030
Colorado	RPS	30% renewable energy by 2020
Neveda	RPS	50% renewable energy by 2030
Neveda	PRS_Solar	6% solar energy by 2030
New Mexico	RPS	80% renewable energy by 2040
New Mexico	PRS_Solar	4% solar energy by 2040
Oregon	RPS	50% renewable energy by 2040
Utah	RPS	20% renewable energy by 2025
Washington	RPS	15% renewable energy by 2020

Figure 13. PLEXOS WECC RPS Assumptions

7.2.4 Carbon Goals and Pricing

Initiative 2117 (I-2117) is to be voted on in the November 2024 election. If passed, I-2117 would eliminate the Climate Commitment Act and prohibit the existence of any cap-and-trade programs within the state of Washington. Given at the time of the IRP the outcome of this initiative is unknown, the IRP assumes that the Cap-and-Invest program will continue as planned, and thus includes the cost of carbon as an input to the market simulation. Figure 14 details the Carbon Reduction goals for each state or province included in the PLEXOS WECC database.

State/Province	Program Type	Description
British Columbia	Carbon	93% renewable of zero-carbon by 2020
California	Carbon	100 zero-carbon by 2045
Neveda	Carbon	100 zero-carbon by 2050
New Mexico	Carbon	100 zero-carbon by 2045
Oregon	Carbon	100 zero-carbon by 2040
Washington	Carbon	100 zero-carbon by 2045

Figure 14. PLEXOS WECC Carbon Goal Assumptions

For carbon pricing the IRP uses recent auction settlements and bilateral Washinton Carbon Allowance (WCA) and California Carbon Allowance (CCA) trades on ICE as inputs to the expected case in Figure 15. The WCA 2024 expected price of $52/MT CO2e was based on an average of the most recent 100 days of WCA '24 settlements on ICE as of February 2024. Similarly, the CCA 2024 expected price of $42/MT CO2e was based on an average of the most recent 100 days of WCA '24 settlements on ICE as of February 2024. From 2027 onward, one carbon price was assumed for both Washington and California given the expectation that Washington and California will link markets after Washington's first compliance period ends. The WCA floor price and ceiling prices were set to Ecology's 2024 floor and ceiling prices of $24/MT CO2e and $88/MT CO2e respectively. All prices were escalated by 5% annually based on the WAC 173-446-335 rule that states floor and ceiling prices will be escalated by 5% plus inflation annually.

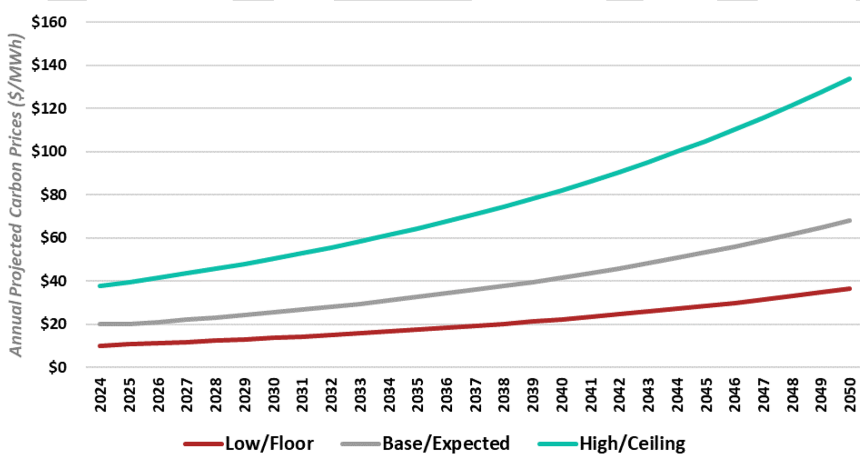


Figure 15. Washington Carbon Allowance Price Assumption in $/MWh in nominal dollars. Uses the $/MT CO2e price assumption multiplied by the unspecified per MWh emissions.

7.2.5 Natural Gas Price

TEA developed a base case forecast of Pacific Northwest natural gas prices that was used in all scenarios. The forecast was based on February 7, 2024 NYMEX prices through 2027 and Henry Hub price forecasts developed by S&P Global for the remainder of the study period. S&P Global price forecasts are based on a detailed analysis of natural gas supply and demand fundamentals. The forecasts referenced were from the January 2024 short-term and September 2023 long-term outlooks.

In addition to the base case forecast, TEA has high and low natural gas price forecasts. The high forecast is based on the Low Gas and Oil Supply Availability forecast from the 2023 Annual Energy Outlook (AEO23) produced by the Energy Information Administration (EIA). The low forecast is based on the AEO23 High Gas and Oil Supply Availability forecast. These forecasts are shown below in Figure 16.

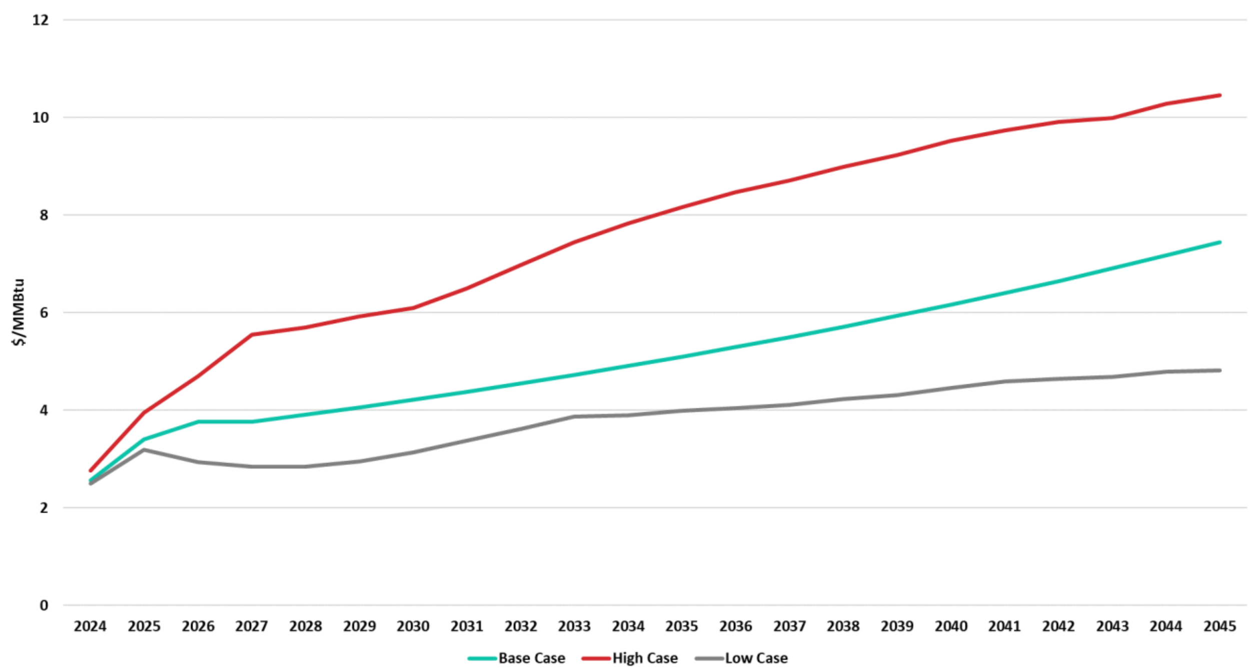


Figure 16. Annual average natural gas price, by price scenario

In the base case, Henry Hub prices in nominal dollars grow from an average of $2.56/mmBtu in 2024 to $7.45/mmBtu in 2045. See Figure 17 below. The average annual growth rate during this period is 5.2%. Future U.S. LNG exports and an eventual shift to higher cost natural gas basins are the major factors driving this price increase.

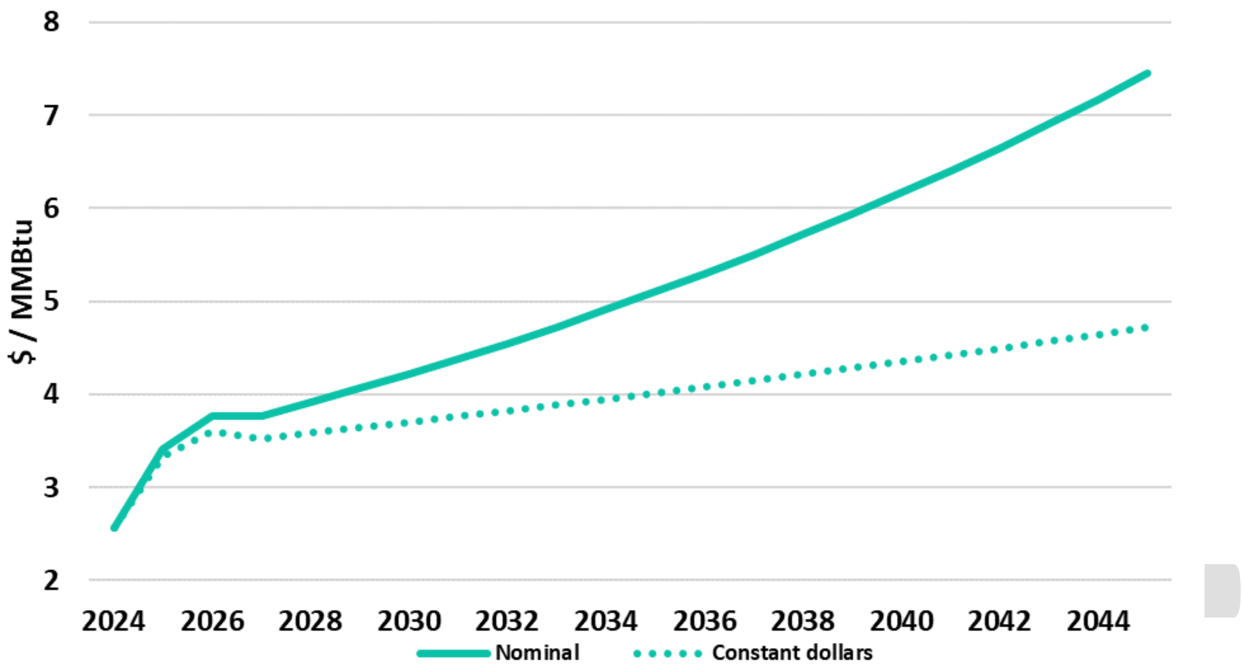


Figure 17. Natural gas prices at Henry Hub in nominal and constant 2024 dollars per mmBtu.

FPUD receives natural gas for its River Road combined cycle facility from Canada through the Sumas Hub in northwest Washington and from the south through the Stanfield Hub in north central Oregon. TEA added a basis estimate to the Henry Hub price forecast to estimate future prices delivered to Washington and specifically to the River Road facility. Projected basis was derived by comparing forward price curves from April 8, 2024 for Sumas and Stanfield to NYMEX. Based on historical data, TEA assumed that 58% of deliveries would come through Sumas and 42% through Stanfield. The price of natural gas delivered to the Pacific northwest and the natural gas price at Henry Hub are shown in Figure 18 below.

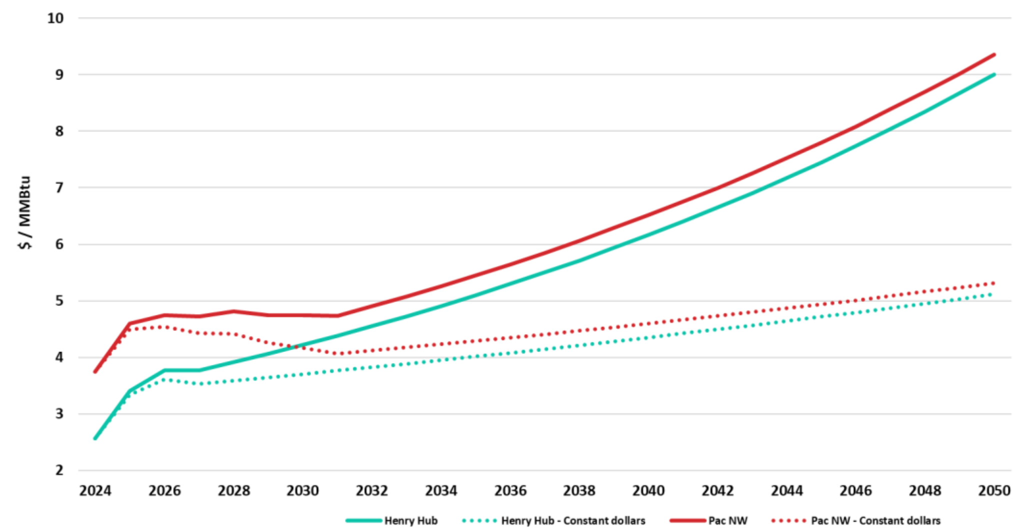


Figure 18. Annual natural gas prices delivered to the Pacific northwest for the 2024 through 2045 period.

Figure 19 below compares the Pacific Northwest pricing to that of Henry Hub. Note that the basis differential between Henry Hub and the Pacific Northwest is typically negative for April through October and positive for the winter months of November through March.

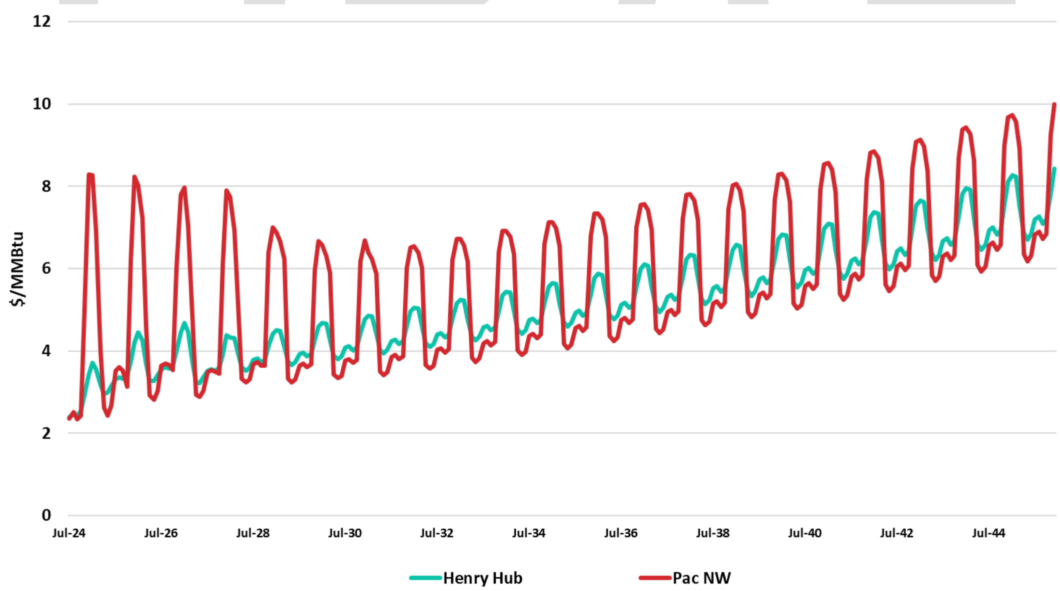


Figure 19. Henry Hub versus Delivered Pacific Northwest Natural Gas Prices

7.3 Simulations

After the development of the market model and assumptions, the model itself can be used for various purposes. First, a capacity expansion simulation was conducted where resources are removed and added to the market footprint based on constraints and market drivers. Second, the resulting portfolio was in a market dispatch simulation that produced forward power prices. These forward power prices are a fundamental input to the portfolio analysis that determines the least cost solution to meet future capacity needs. The following sections detail the process.

7.3.1 Capacity Expansion & Retirements

The generation options considered when modeling new resource additions in the region included nuclear, simple and combined cycle natural gas, solar, wind, storage, hydro, geothermal, and biomass. The PLEXOS WECC dataset contained economic assumptions for each resource options' such capital cost, variable operation and maintenance, fixed operation and maintenance, heat rate (thermal efficiency), performance standards such as forced and scheduled maintenance rates, and generation shapes for variable energy resources. The update to existing resources resulted in significant changes in the pattern and volume of new natural gas, wind, and solar capacity built as WECC continues to divest its interest in conventional energy resources for more sustainable/renewable sources.

Figure 20 details the base line year-by-year capacity retirements and additions across the WECC system from 2023-2040 prior to the capacity expansion simulation. Announced retirements for existing resources are input into the model with their scheduled retirement dates, which include many coal resources set to retire throughout the decade. In addition to coal resources, the Diablo Canyon Nuclear facility, the last nuclear plant in California, will retire by 2029. Just under 28 GW of capacity is expected to be retired with 90% of that being either coal or natural gas. Over 33 GW of known capacity is estimated to be installed in the system by 2032; of which 45% is expected from solar generators, followed by natural gas at 27%, 24% wind, and 2% hydro.

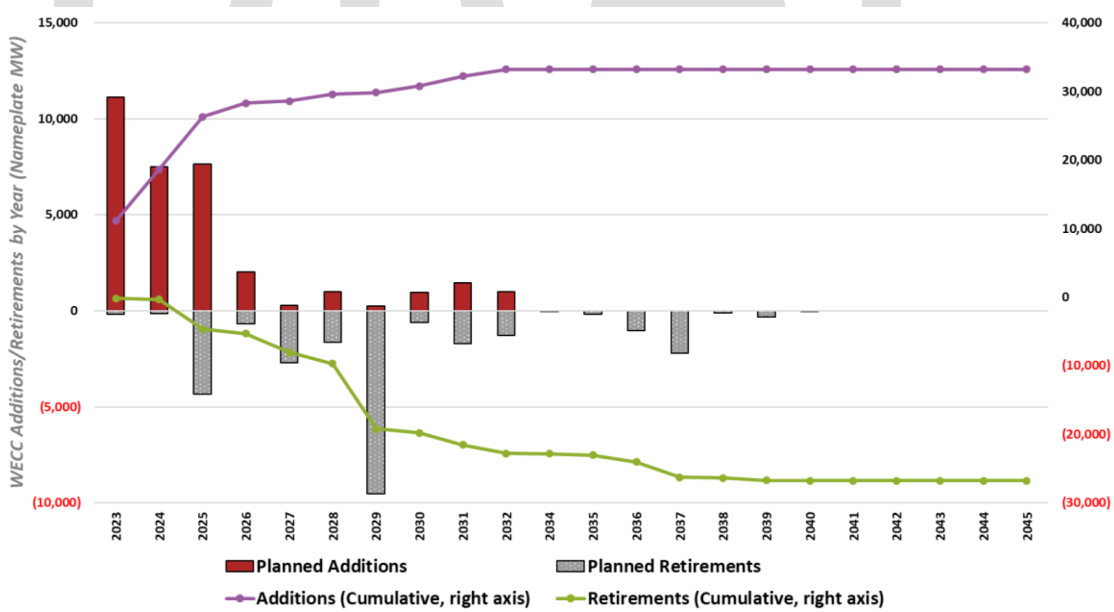


Figure 20. WECC Generation Additions and Retirements (pre-Capacity Expansion)

Based on the parameters outlined above, PLEXOS then determines the ideal mixture of new resource additions and further retirements to meet the inputs constraints in the most economical way. In conjunction with the expected retirements and additions noted above and the PLEXOS baseline capacity expansion simulation the 2023 Western Assessment of Resource Adequacy was used to supplement the resource additions. A summary of the near-term, mid-term, and long-term period additions can be seen in Figure 21.

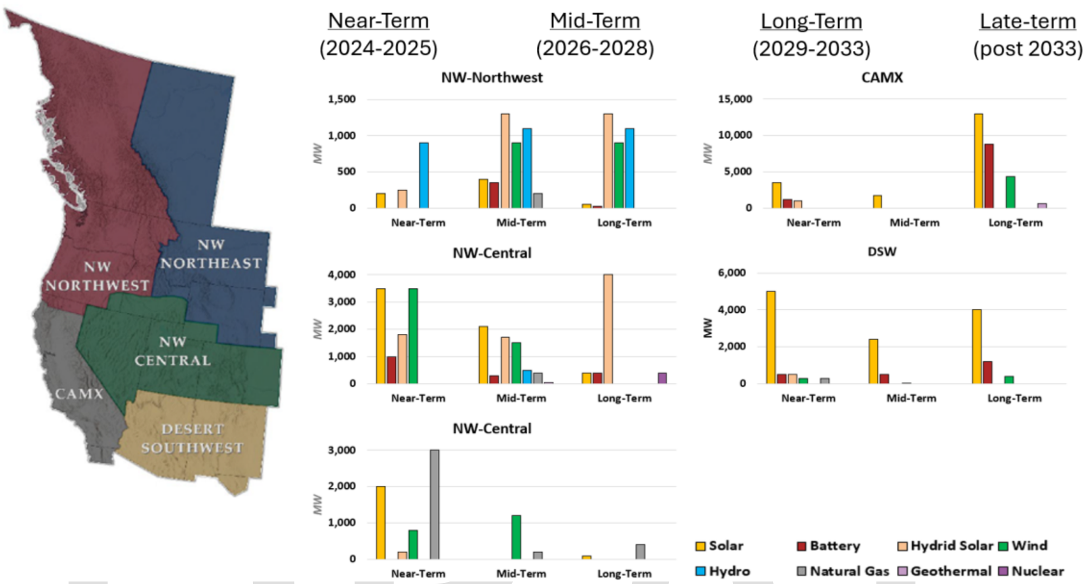


Figure 21. WECC Generation Additions and Retirements (post-Capacity Expansion)

Resources added post-2033 were done so exclusively by PLEXOS for meeting either demand needs or RPS goals. Figure 22 illustrates the total additions, year by year, across the entire WECC capacity expansion simulation.

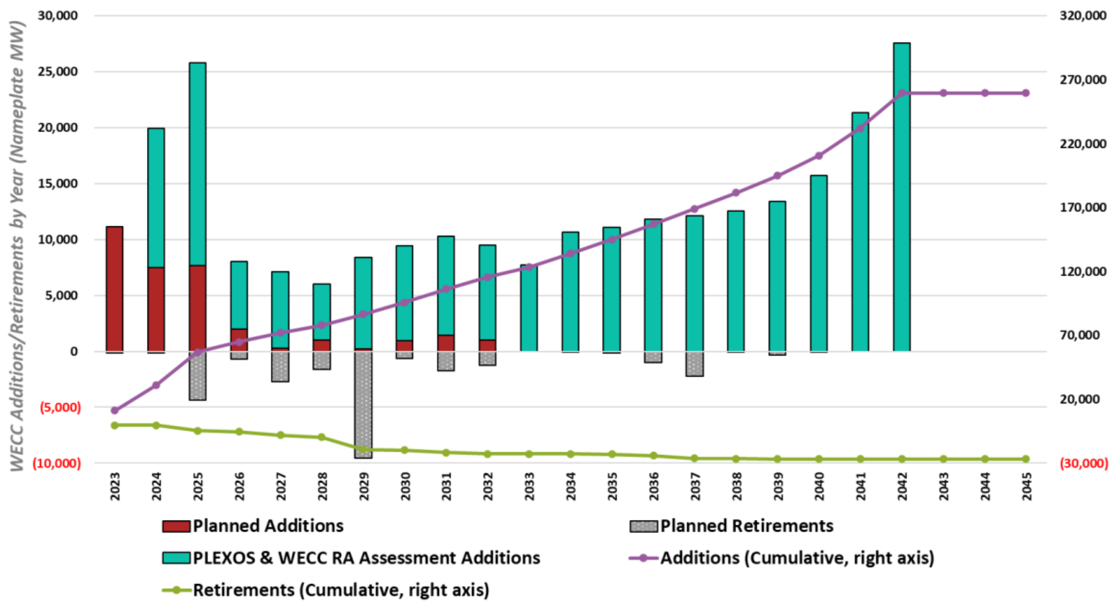


Figure 22. Annual nameplate capacity retirements and additions

Over 90 GW of new generation is added to the WECC footprint by 2033 with Wind or Solar making up 53 GW and Batteries or Hybrid making up 28 GW. By 2042, the final year of the capacity expansion simulation, nearly 260 GW of new generation is available to WECC. The notable drivers for adding this volume of new generation is due to the reduction in capacity accreditation for standalone wind and solar project, but the added need for these resources in order to meet the carbon reduction goals, most of which hit their 100% adoption in the 2040's. A breakdown in percentage of fuel type is represented in Figure 23.

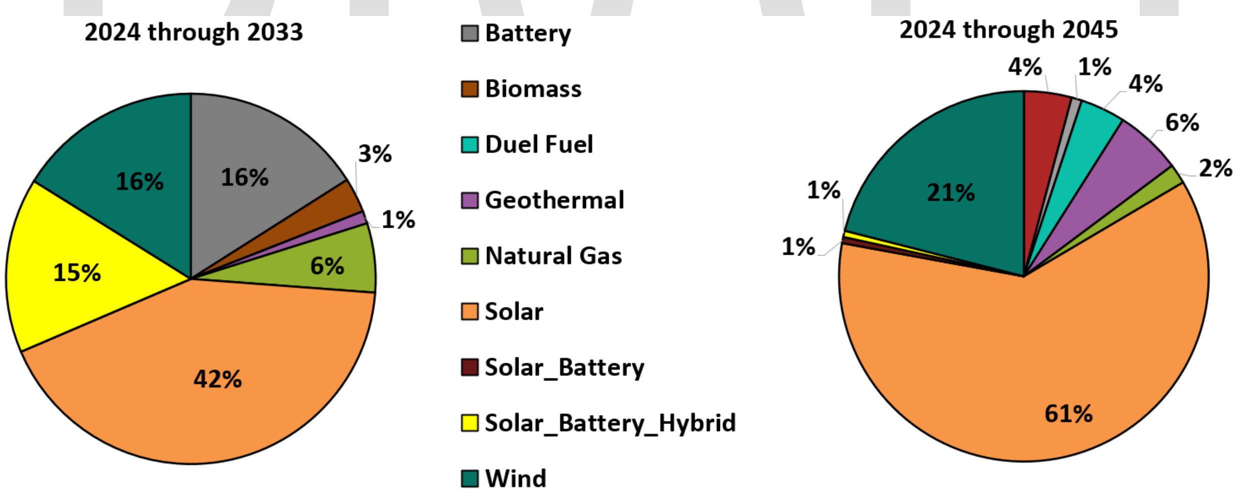


Figure 23. WECC Capacity Additions Percentages (Nameplate), by Fuel Type

Figure 24 and Figure 25 illustrate the expected new resource expansion and retirements through 2042 in the Pacific Northwest and California/Mexico regions.

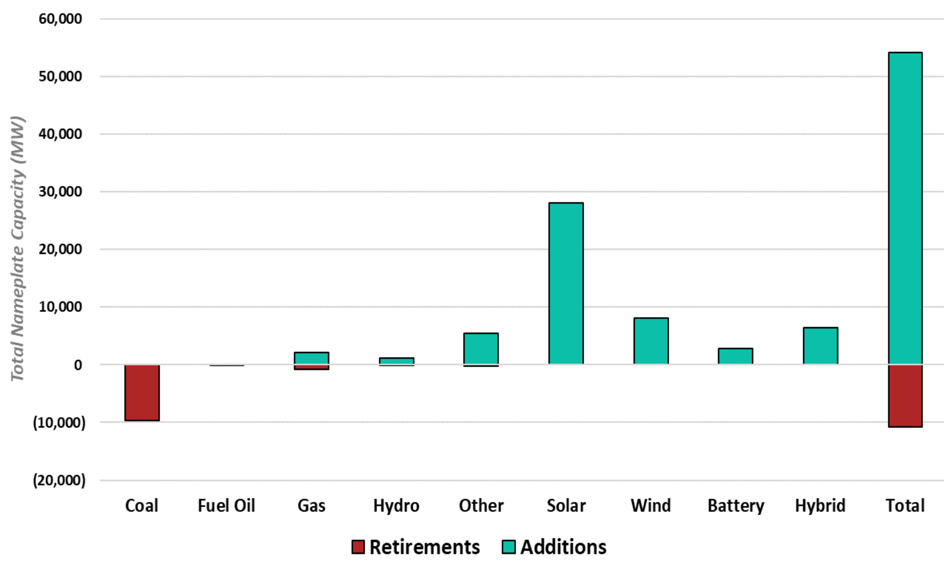


Figure 24. Forecasted Pacific Northwest Generation Capacity Retirements and Additions through 2042, by Fuel Source

Within the Northwest Power Pool region, which includes the Canadian providences of British Columbia and Alberta, and the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, Utah, and a small portion of northern California, hydro will remain the largest single generating resource through the study period. All coal plants in the region are projected to retire (or be converted into natural gas units) by the end of 2030.

Solar is the renewable fuel type of choice for fulfilling RPS requirements across the simulation. A shift to batteries or hybrid resources does occurs in the mid-term and long-term periods. The cumulative expansion in the Pacific Northwest over the study period is over 54 GW, of which 8 GW comes from wind, 28 GW from solar, and 9 GW from batteries or hybrid resources.

In addition to a significant build out of solar in the region, just 2,100 MW of Combined Cycle (CCGT) or Combustion Turbine (CT) Gas generation is added. This addition largely offsets some of the lost capacity from retiring coal generation. Due to the assumption of increasing loads across the WECC, more capacity will be required to serve load, and this build-out of natural gas resources, coupled with the addition of storage, supports the growing need for capacity in the region. The additional cost of carbon and future carbon reduction goals, however, puts thermal resources at a disadvantage for meeting overall energy needs, preventing a higher buildout of this resource type.

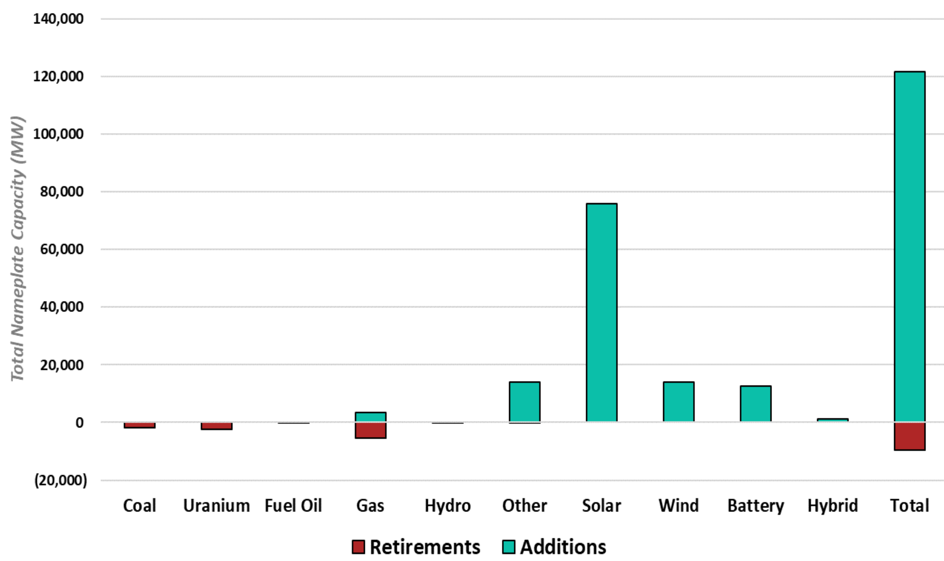


Figure 25. Forecasted California Generation Capacity Requirements and Additions through 2042, by Fuel Source

In California, there are substantial natural gas and coal resource retirements, and the retirement by 2030 of Diablo Canyon, the final nuclear facility in CAISO. Like in the Northwest, most of the generation expansion is from solar (76 GW), wind (14 GW) and batteries/hybrid (14 GW), but there is also over 14 GW of geothermal expected to be added. By 2042 over 121 GW of new generation is projected to be added to meet California/Baja demand, RPS, and carbon reduction goals.

7.3.2 Power Price Simulation

Using the hourly dispatch logic and assumptions outlined previously, hourly Mid-Columbia electricity prices were obtained for various future scenarios. **Error! Reference source not found.**Figure 26 shows the average monthly nominal heavy load hourly (HLH) and light load hourly (LLH) Mid-C power prices from the long-term WECC dispatch simulation.

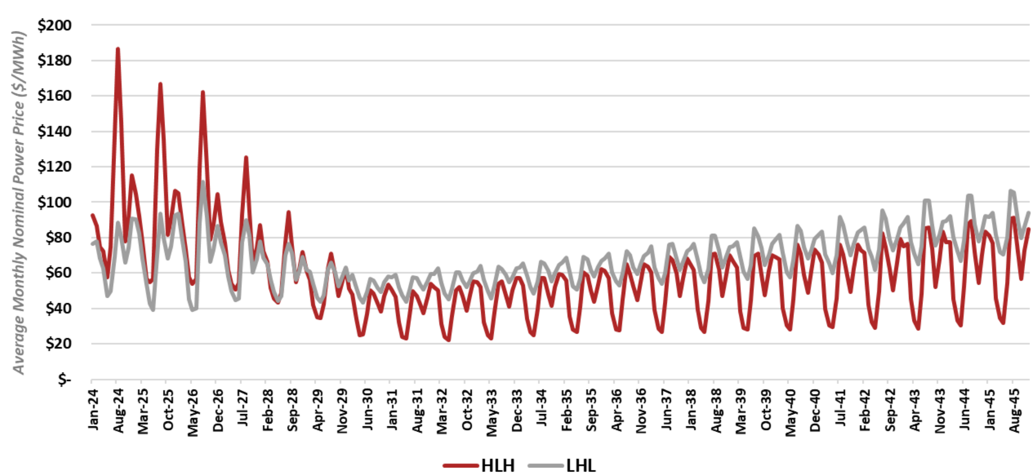


Figure 26. Mid-C Prices

Within the past couple of years, a paradigm shift has started in some US-based markets and regions. Where traditional HLH prices have been at a premium to LLH, some months of the year have begun to post pricing for LLH above HLH. This is a dramatic shift in the power market and correlated to the implementation of large volumes of Solar generation. During the spring hydro runoff period, low loads, and low natural gas prices, when combined with an increase in renewable generation, lead to the collapse of the HLH premium. Results from the WECC market simulation project an annual switch from HLH to LLH being the premium time-of-use product to occur in the late-2020's as seen in Figure 27.

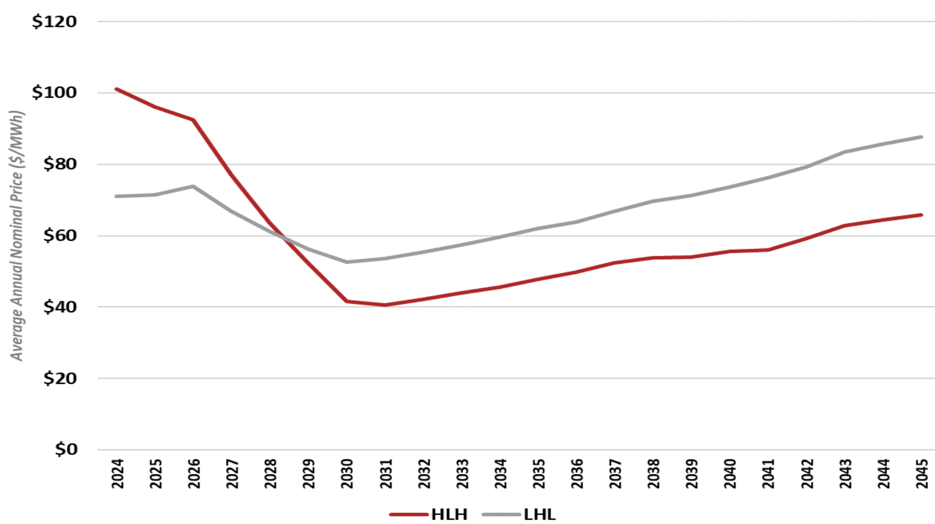


Figure 27. Projected Annual Mid-C Prices

Figure 28 below shows the average 24-hour profile of Mid-Columbia power prices, by season, across various years in the simulation. This view is intended to show the expected change in the shape of Mid-C prices as volumes of renewable generation is added to the system. The "Duck Curve" traditionally seen in California prices begin to take shape in the northwest power markets by the late 2020's. As mentioned earlier, the spring hydro runoff, low load, and now high renewable generation are expected to push power prices down to the $0/MWh level for extended hours of the during the Spring season.

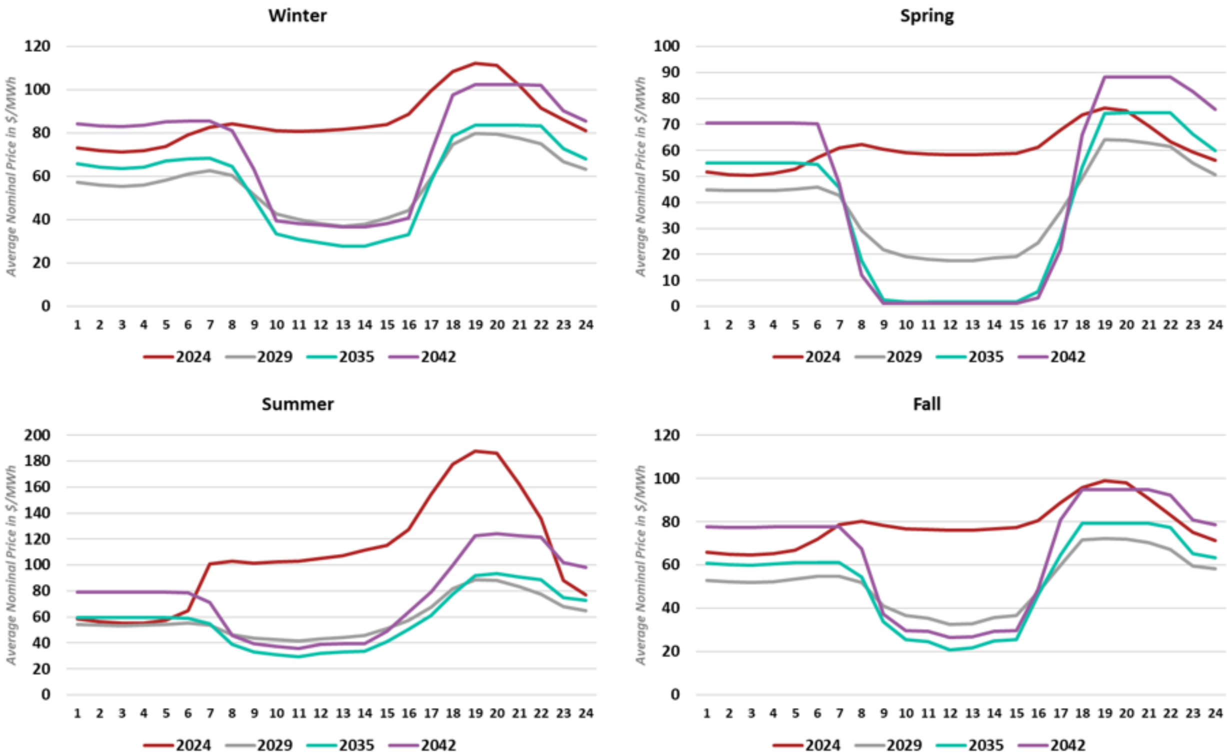


Figure 28. Projected Mid-C Average Hourly Price Profile, by Season, for 2024, 2029, 2035, and 2042

7.4 WECC Simulation Scenario Analysis

In addition to the above Base Case scenario, three alternative scenarios were considered. Although not used in the IRP analysis itself, these scenarios are intended to stress two of the key assumptions, natural gas and carbon prices, that went into the market simulation, and based on the IRP team's judgment, could potentially change in the future. The goal of the scenario analysis is to project a range of outcomes contingent upon changes in key underlying assumptions that are included in the market simulation. These three alternative scenarios include:

1) Base Natural Gas and No Carbon Prices: Although this scenario did not consider a change in the natural gas prices it did remove the additional cost on the WECC system associated with carbon pricing in the Northwest. This scenario was intended to simulate a future where I-2117 is passed and the Washington Cap-and-Invest program is eliminated.

2) High Natural Gas and Ceiling Carbon Prices: Carbon reduction goals across the US become more progressive. A future where added pressure on natural gas production and usage is very plausible. In this future it is also believed that in order to curtail natural gas usage and further development in the generation technology added costs to carbon production would be needed as well. This scenario is meant to simulate this type of future.

3) Low Natural Gas and Floor Carbon Prices: In the case of higher than anticipated renewable and low carbon buildout, both Natural Gas and WCA prices would see a commensurate reduction compared to the base case.

In Figure 29 the annual average nominal Mid-C price for all four scenarios is presented. In all four scenarios the years 2024 and 2025 are held to be the same. Starting in 2026, prices begin to diverge as the impact of having different natural gas and carbon prices in the simulations take hold.

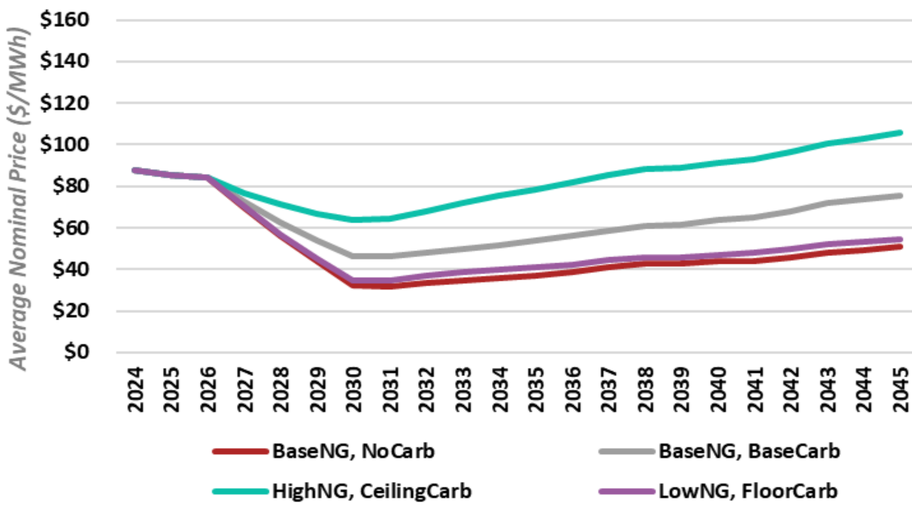


Figure 29. Projected Mid-C Average Nominal Price, by Scenario

As expected, removing the carbon price, and reducing the natural gas and carbon prices produces a market environment details the change in price for the alternative scenarios as compared the Base Case across the 2024-to-2045-time horizon.

	BaseNG, NoCarb	BaseNG, BaseCarb	HighNG, CeilingCarb	LowNG, FloorCarb
Average Price	$49.03	$63.53	$83.14	$51.68
Price Difference ($/MWh)	-23%		31%	-19%
Price Difference (%)	($14.50)		$19.61	($11.85)

Figure 30. Variance from Base Natural Gas and Base Carbon Scenario

Section 8 Risk Analysis and Portfolio Selection

FPUD's objectives are to develop an optimal resource plan capable of managing uncertainties in projected monthly peak demands and to meet the WRAP requirements. The IRP process is a strategic approach used to achieve these objectives. It evaluates and plans for future capacity and energy requirements while considering various objectives and constraints. It involves a comprehensive analysis integrating technical, economic, environmental, and regulatory factors to develop a balanced and optimal resource plan. The IRP process also uses scenario and sensitivity analysis to detect gaps, communicate insights, and identify risks and opportunities.

Scenarios typically involve key business decisions or pathways based on varying one or more assumptions. The assumptions can encompass changes in an organization's portfolio, the timing of decisions, or regulatory factors impacting the organization. These scenarios allow the organization to explore a range of possibilities and assess how different factors might influence the outcomes of the IRP.

Sensitivity analysis is used to evaluate how sensitive the outcomes of the IRP are to varying input variables. Its use is important in assessing reliability, understanding uncertainty, and enhancing the robustness of resource plans. It quantifies the impact of changes in each input variable on the outputs by varying one input at a time while holding all others constant. This analytical approach supports developing plans that are resilient and adaptable to changing conditions, thereby mitigating risks effectively.

The IRP incorporates several key assumptions guiding FPUD's decisions on future energy and capacity resources:

- **20-year demand forecast:** A prediction of electricity consumption over two decades guiding capacity planning and infrastructure investment decisions.
- **Existing and planned resource dispatchable variable cost:** The operational costs associated with current and future dispatchable resources, influencing operational decisions and cost projections.
- **Supply-side generation resource options:** Estimation of factors such as availability, capital expenditures, fixed costs, and variable costs for the development and procurement of various generating technologies.
- **Fuel, economic and market product costs:** Projections of fuel prices, economic indicators such as inflation and discount rates, and market prices for electricity and related products.

These assumptions, among others, provide a comprehensive framework for FPUD to make informed decisions regarding existing capacity resources and strategically plan for future requirements. They form the basis for developing a resilient and cost-efficient plan that aligns with regulatory requirements and market dynamics.

This study uses a long-term generation expansion model to determine the least cost replacement and expansion resource mix. The PLEXOS electricity production cost model is used to simulate FPUD's production cost and interactions within the electric market. PLEXOS integrates the system and resource assumptions to optimize and select the least cost resource mix.

The primary goal of PLEXOS is to minimize the incremental Net Present Value of Revenue Requirements (NPVRR) while complying with system and regulatory requirements. NPVRR represents the net cost that must be recovered for all resources in FPUD's portfolio, adjusted for the time value of money. This includes capital costs for new resources, variable costs, and fixed costs incurred during the study period. It excludes existing debt service costs, sunk costs prior to the study period, and costs incurred 5 years beyond the study period.

The model provides a mathematically optimal selection of future resources based on defined input assumptions, diverse resource types and capacities, and specific constraints such as import limits and minimum reserve margins.

8.1 Scenario Cases and Results

FPUD has considered two scenarios to help meet their objectives: the Reference Portfolio and a Renewable portfolio. The Reference Portfolio is used as a baseline to compare against other scenarios and sensitivities. For the Reference Portfolio the following assumptions were provided:

- Inflation rate of 2.2% and a discount rate of 4.75%.
- WRAP reserve requirements, as detailed in Section 3.5, include additional constraints aimed at ensuring seasonal adequacy rather than focusing solely on peak month demands.
- Base Load as described in Section 4.2.
- Operating information and variable costs for existing owned and contracted resources.
- Supply-side generation resource options in accordance with 0.
- Base natural gas price and market price forecast as discussed in Sections 7.2.5 and 7.3.2 respectively.

In the Reference Portfolio, FPUD assumes that the WRAP implementation starts in November 2027 and continues through the entire planning horizon.

Acknowledging the cost competitiveness and environmental benefits of renewable energy initiative, FPUD also assumes a scenario to explore more aggressive implementation of wind and solar energy sources. Restrictions on the adoption have been removed from both wind and solar energy sources, but limits remain on battery storage adoption. Table 6 outlines how the scenarios are incorporated into the IRP.

Table 6. Scenario Analysis Assumptions

Scenario	Load	NG Price	Carbon	WRAP Implementation	Technology
Reference Portfolio	Base	Base	Base	11/2027	Base
Renewable Portfolio	Base	Base	Base	11/2027	Unlimited wind & solar

8.1.1 Reference Portfolio Results

The PLEXOS modeling software optimized a cost-effective portfolio, illustrated in Figure 31, to fulfill FPUD’s seasonal WRAP requirements throughout the study horizon. The figure depicts existing resources and proposed additions optimized to meet the WRAP requirements. Resources identified by PLEXOS are labeled as “New” with their respective source type, ST Contract or Tier 2. Existing resources are projected to satisfy average energy consumption through 2028, highlighting a need for intermediate to peak resources to bridge the gap thereafter. Powerex 10-year extension has been selected to meet average energy, complemented by the integration of battery storage and short-term energy solutions. Battery storage selection incorporates capacity and operational advantages. Initially, Short-term energy and capacity needs are fulfilled by Teir 2 and ST contracts later transitioning on to battery storage. Solar additions are progressively expanded to meet the remaining capacity and energy needs.

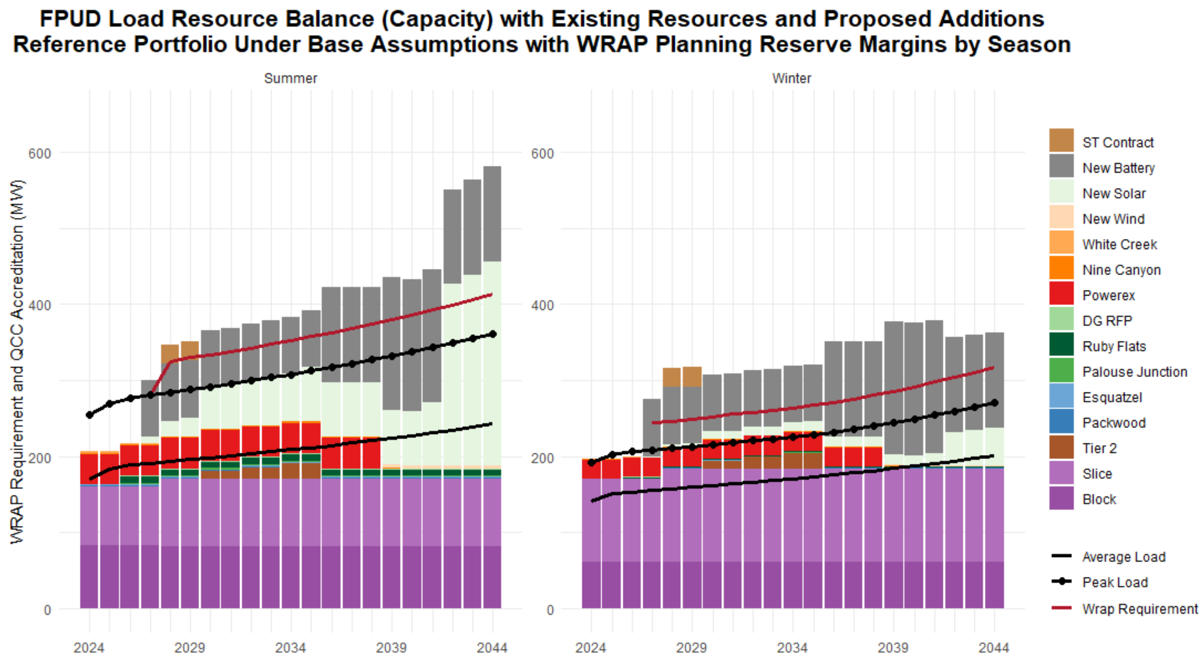


Figure 31. Demand and Resource Load Balance for Reference Portfolio

Figure 32 displays the seasonal energy generated by the existing and proposed resource additions in average megawatts (aMW) per year. This measure is derived by dividing the resource's seasonal energy production by the total number of hours in a season. FPUD's current resources, including the Powerex extensions, meet average energy consumption through 2038. Beyond 2039, when the Powerex contract expires, solar and wind energy sources will be utilized to fill the energy gap. The intermittent nature of these sources reduces the system flexibility; however, integrating battery storage and leveraging the market can enable economic sales and enhance energy management capabilities.

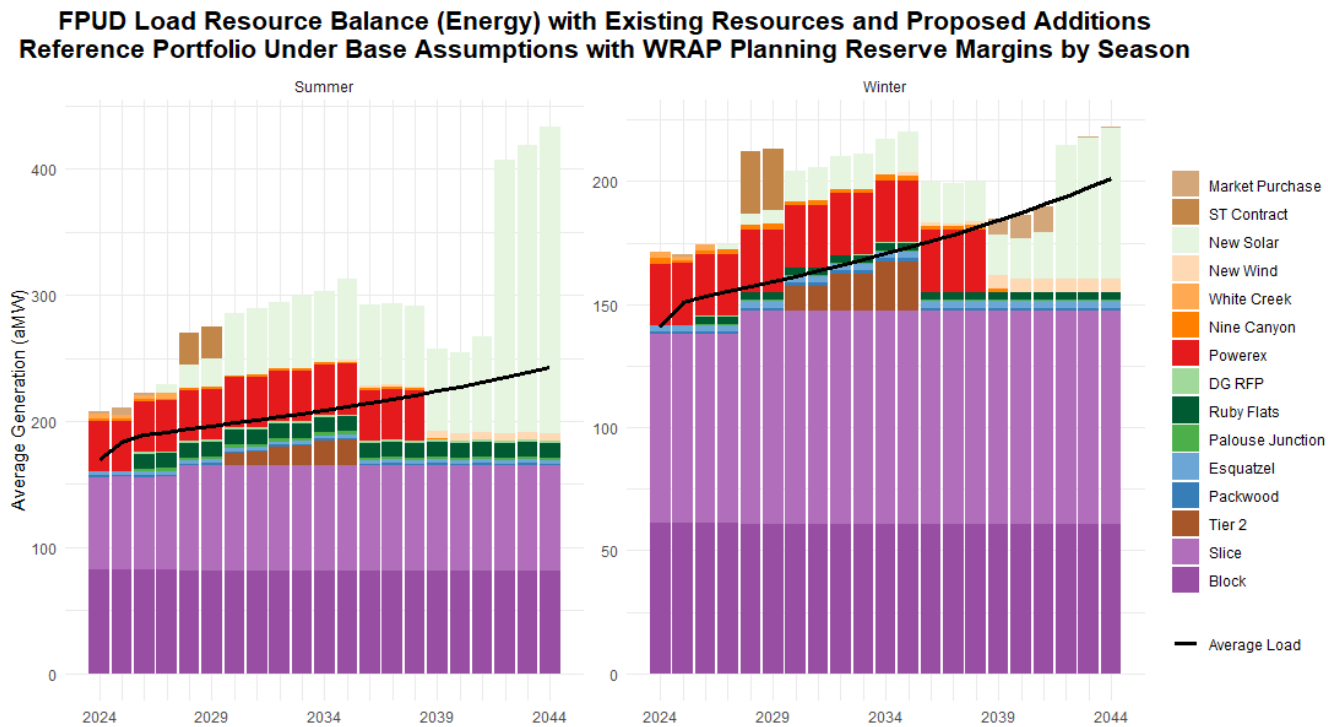


Figure 32. Energy Resource Load Balance for Reference Portfolio

Figure 33 shows the annual variable and incremental revenue requirements with qualifying capacity changes for the Reference Portfolio. This analysis excludes existing debt servicing costs and sunk costs prior to the study period.

The Variable Operations and Maintenance (VOM) cost is tied to current resources. When Powerex goes offline in 2039, the VOM cost decreases. The Fixed Operations and Maintenance (FOM) cost correlates with batteries, which increases gradually as battery storage is integrated into the portfolio. The Construction (Build) cost is linked to the installation of wind and solar additions. The cumulative incremental NPVRR for the Reference Portfolio totals to $947 million over the study period. This amount serves as the benchmark for scenario comparisons and sensitivity analyses.

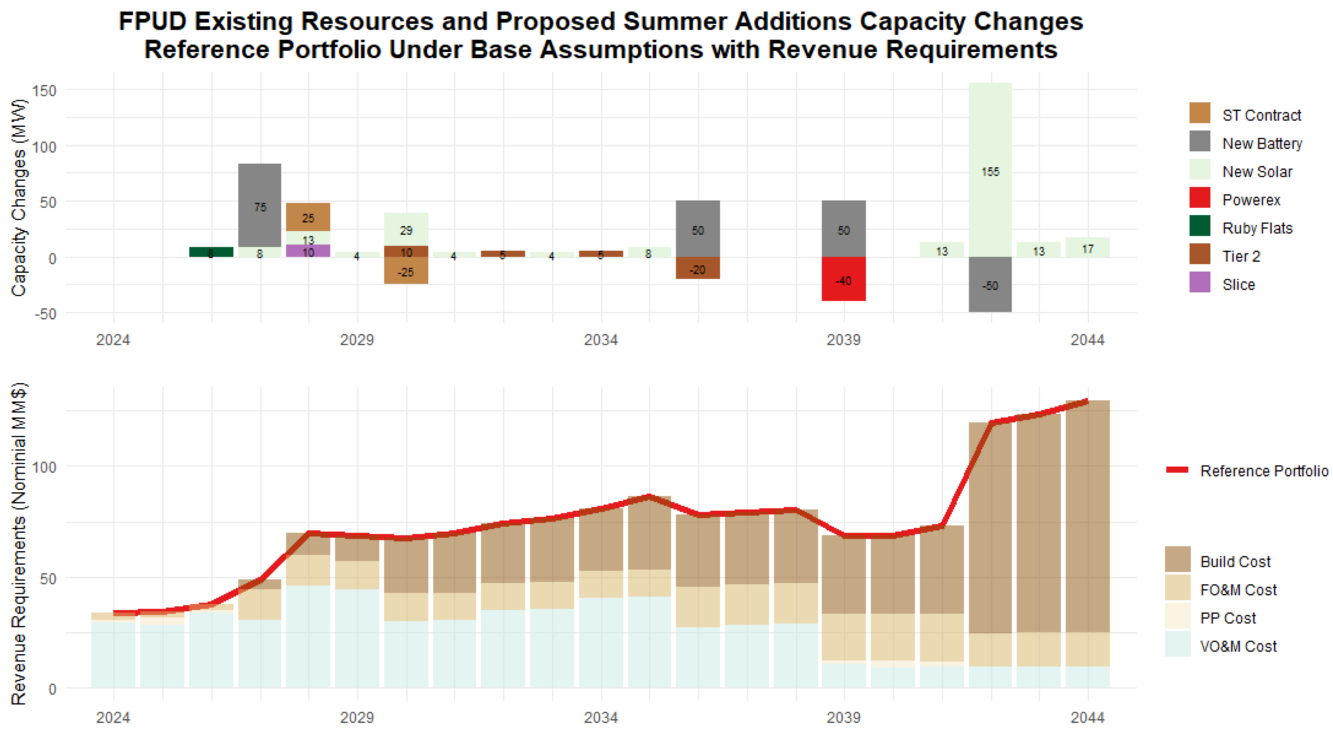


Figure 33. Nominal Revenue Requirements for Reference Portfolio

Battery storage, with its distinctive characteristics unlike traditional thermal sources, functions both as a load and a capacity resource. It can store significant amounts of energy and shift it to periods when the system faces shortages in energy supply. This capability is advantageous for a portfolio of this scale, especially in later years when numerous intermittent resources are installed. Figure 34Figure 34 provides a simulated view of how this is accomplished within FPUD's portfolio after the adoption of significant amounts of renewable energy.

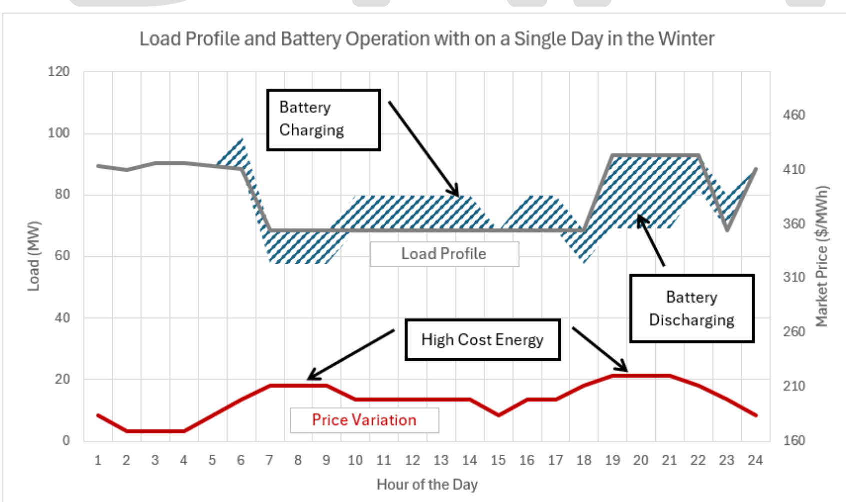


Figure 34. PLEXOS Simulated Output of Energy Shifting Within FPUD Reference Portfolio

The Reference Portfolio includes resources that enhance system resiliency while renewable energy capacity is increasing significantly. Battery storage plays a crucial role in bridging short-term capacity gaps due to changing WRAP requirements. Battery operation will allow flexibility for effectively integrating over 1,200 MW of renewable energy into the portfolio, ensuring adaptive and sustainable energy management strategies.

8.1.2 Renewable Portfolio Results

The renewable portfolio was introduced to understand the economic opportunities and cost associated with transitioning to a low carbon and sustainable energy system. This analysis provides insights into the resources required using current technology options and help provide strategic pathways necessary to achieve a sustainable energy future.

Figure 35 shows FPUD's current energy portfolio is well-balanced and capable of meeting average energy consumption with minimal exposure to market price fluctuations. Before 2027, there are no economic opportunities for resource selection. In the renewable portfolio, restricting the portfolio to renewable resources preserves the reliance on battery storage. While wind plays a smaller role in meeting energy and capacity needs, solar capacity expands within the portfolio. These dynamics highlight the evolving mix of renewable sources and emphasize strategic adjustments to enhance reliability and sustainability in energy supply.

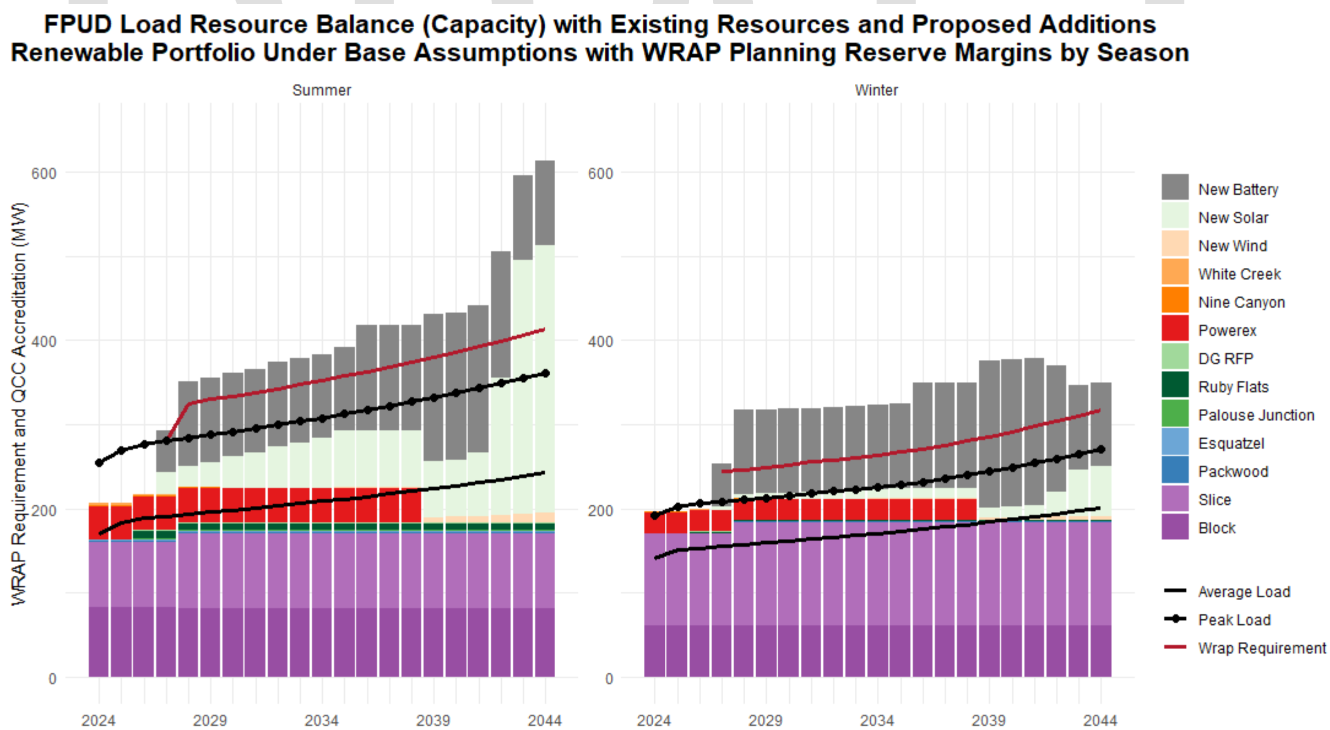


Figure 35. Demand and Resource Load Balance for Renewable Portfolio

Figure 36 displays the seasonal energy generated by the existing resources and proposed additions in average megawatts (aMW) per year for the Renewable Portfolio. The renewable portfolio reflects similar characteristics as the reference cases solution, including an overbuild of intermittent energy to ensure capacity requirements are met. Existing resources remain the primary source of energy for the portfolio.

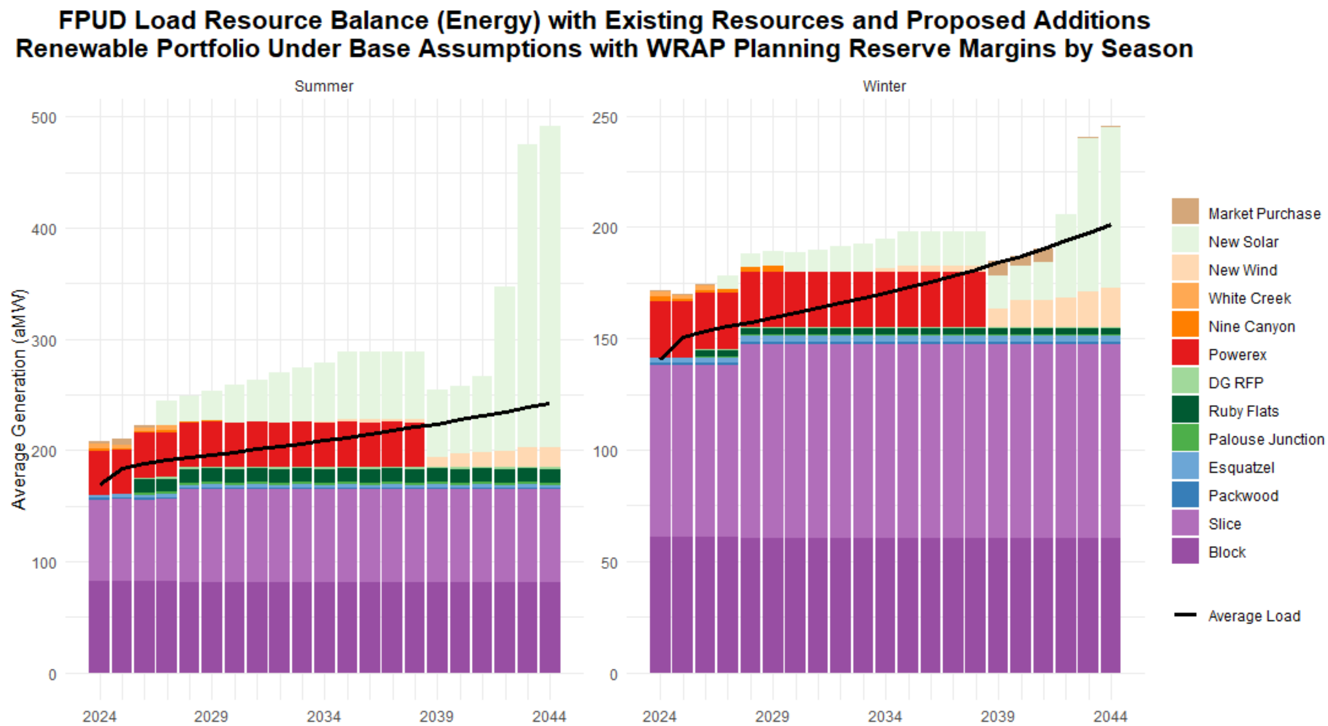


Figure 36. Energy Resource Load Balance for Renewable Portfolio

Figure 37 illustrates that the NPVRR of the renewable portfolio is lower than that of the reference portfolio. The renewable analysis enables the model to strategically choose renewable resources for the portfolio. Unrestricted solar additions provide further benefits by optimizing resource allocation, including larger solar installations in 2027. Moreover, this approach mitigates the need for costly short-term solutions like ST Contracts and Tier 2 option.

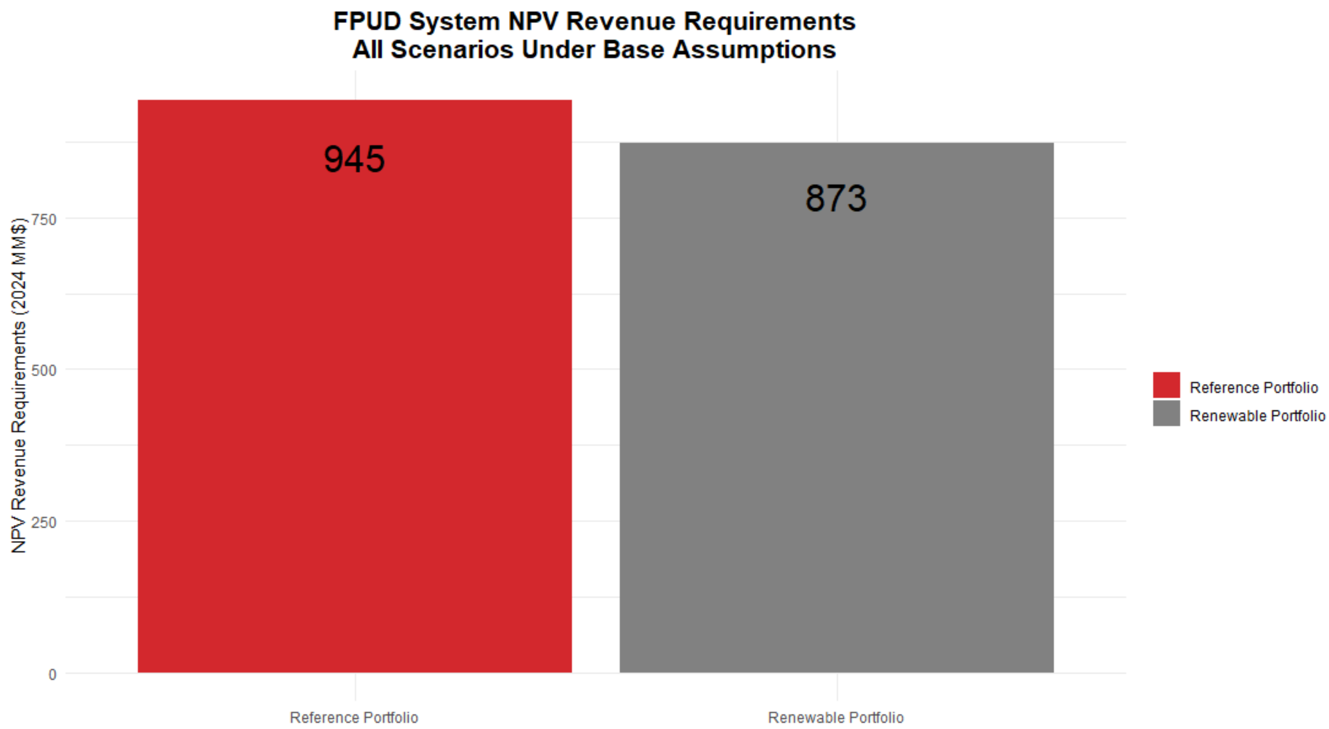


Figure 37. 20-year NPVRR for All Scenarios

FPUD performed a comparison between two portfolios: the reference portfolio, which imposes restrictions on the integration of solar and wind resources, and the renewable portfolio, removing these constraints. Both portfolios were limited to 200MW battery storage in which both used optimally 175 MW. The remaining capacity requirements are fulfilled through increased solar adoption, requiring an overbuild of solar energy to meet these obligations.

In the reference portfolio, which utilizes short-term contracts for capacity needs, these options proved costly and offered no additional flexibility compared to the renewable portfolio. The availability of renewable energy technologies played a crucial role in effectively meeting FPUD's capacity requirements.

Overall, the study highlights the advantages of a flexible approach to renewable energy integration, demonstrating how removing constraints on solar and wind installations can lead to cost savings, increased flexibility (compared to fixed contract energy), and more efficient capacity management within FPUD's portfolio.

8.2 Sensitivity Analysis and Results

FPUD has incorporated sensitivity analysis to address the uncertainty surrounding its load forecast. The load forecast is a key driver for future infrastructure investments required to maintain system reliability. Understanding the potential impact load can have on these investments is crucial to this IRP process. The IRP includes three load sensitivity analyses: low (annual demand growth of 1.1%), base (annual demand growth of 1.6%), and high (annual demand growth of 2.1%). Table 7 outlines how sensitivity analyses are incorporated into the IRP.

Table 7. Sensitivity Analysis Assumptions

Sensitivity	Load	NG Price	Carbon	WRAP	Technology
Low Load	Low	Base	Base	Base	Base
Base Assumptions	Base	Base	Base	Base	Base
High Load	High	Base	Base	Base	Base

These analyses offer understanding of how FPUD's current and future resource needs would change under different possible load growth scenarios.

Figure 38 presents the load resource balance using existing and proposed resources across various scenarios and sensitivity combinations. Instead of depicting changes over 20 years, specific years are highlighted. The year 2028 marks a full year of WRAP implementation in the Reference Portfolio scenario. Years 2033 and 2036 represent periods before and after resources such as SMR and geothermal become available under the same scenario. Finally, 2044 marks the conclusion of the IRP study.

At a high level, resource selection remains uniform across all scenario and sensitivity variations. Battery storage remains the primary resource for meeting capacity requirements, with solar adoption progressively increasing to fulfill both capacity and energy demands. Capacity levels adjust accordingly across different studies, showing increased adoption in response to higher load levels.

Resource selection remains consistent across most scenario and sensitivity combinations:

- In sensitivities with incremental restrictions on solar additions, short-term products are added in the reference cases.
- High load sensitivity introduces additional resources such as wind and geothermal into the mix.
- Throughout all studies, battery storage and solar remain primary resources.

After the completion of the load forecast used for this IRP, Franklin PUD received a new population growth forecast from the City of Pasco that likely implies a higher load growth than the high scenario used in this study. A portion of the City of Pasco's load falls outside of the service territory of FPUD, so it is unclear how much of the projected new load will impact FPUD. However, if FPUD's load growth exceeds that forecasted in the high scenario in this study, this analysis indicates that the portfolio of resources would be unlikely to change. Instead, the same resources would likely remain cost-effective and simply be needed in larger quantities.

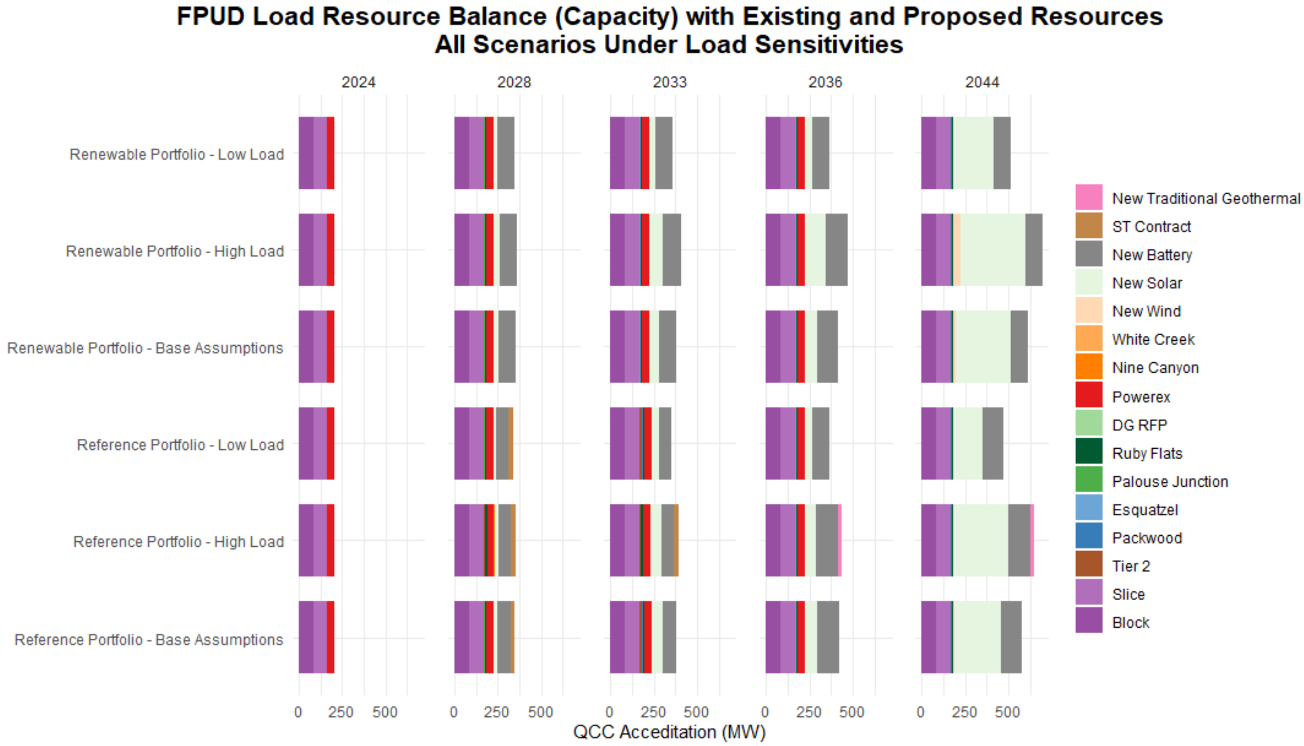


Figure 38. Sensitivity Load Resource Balance

Figure 39 compares the NPVRR of each of the sensitivities. The NPVRR graph reveals insights into the financial dynamics of renewable adoption within the portfolio. It demonstrates increasing the deployment of renewables results in cost savings, ranging from $7 to $59 million, with the most significant savings observed under conditions of high load sensitivity. Moreover, there is a clear correlation between load levels and costs: as load decreases, costs also decrease, whereas higher loads correspond to increased costs. The reference case exhibits greater cost variability due to fluctuations in load, highlighting the critical role of load management in optimizing financial outcomes. These findings give emphasis to the economic advantages of scaling renewable integration while emphasizing the strategic importance of load-sensitive planning in achieving cost efficiency.

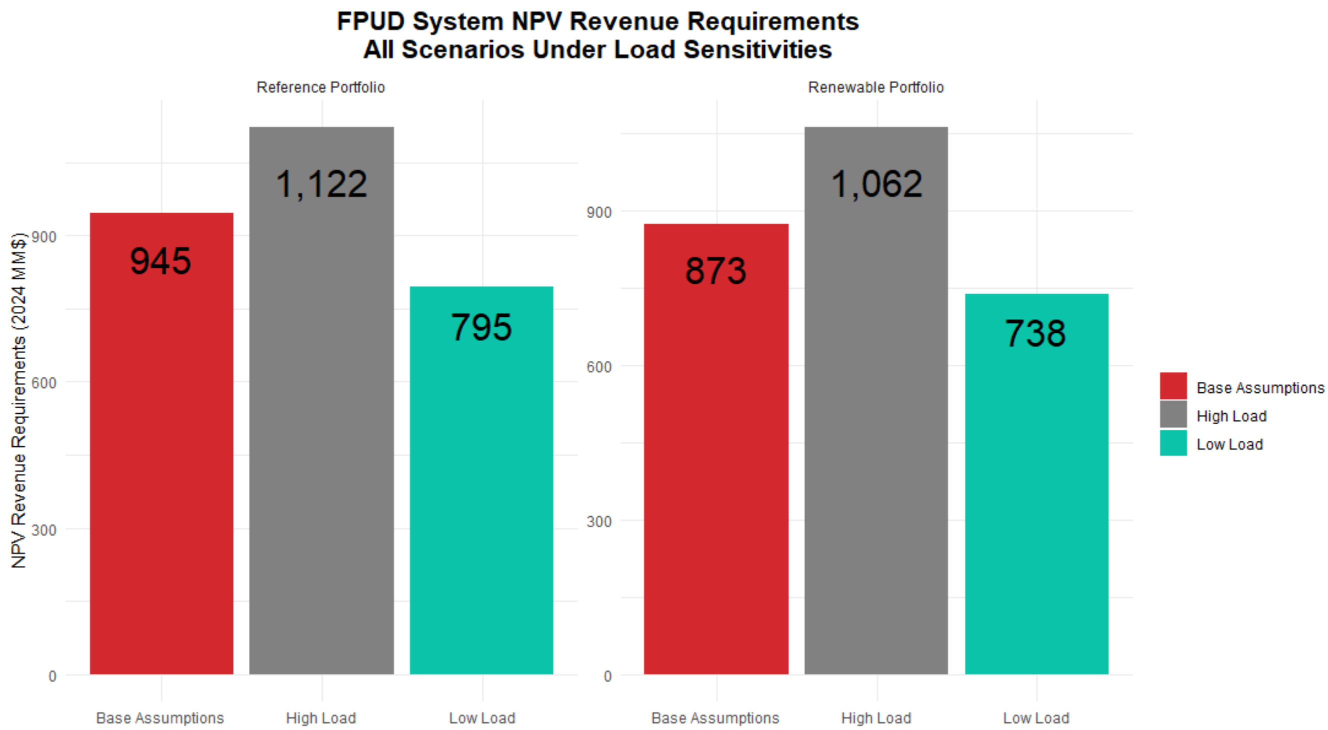


Figure 39. Sensitivity NPVRR

Battery storage and solar power play pivotal roles in meeting both capacity and energy requirements for FPUD. Effectively scaling renewable integration is crucial to mitigating potential cost escalations. Planning for future load growth is key to managing costs effectively. By strategically managing these resources, FPUD not only optimizes energy allocation but also enhances overall infrastructure efficiency, ensuring sustainable and reliable energy solutions for future demands.

8.3 BPA Load Following

FPUD will have the option of changing products with Bonneville Power Administration (BPA) under the next BPA power contract, known as the Provider of Choice (POC) contract. Neither the design of the products nor the rates for those products under the POC have yet been finalized. FPUD will review all BPA product offerings carefully once these products have been defined and select the option the best fits the needs of FPUD's customers.

Section 9 Conclusions

FPUD is currently meeting the energy demand of its customers with 90% carbon-free electric power and is projected to maintain balance between its load and resources in spite of a roughly 1.6% year-over-year projected load growth through the study period. However, on a capacity basis, FPUD has a considerable deficit that could grow to as much as 231 MW by 2044 if not addressed through additional conservation and power procurement. In addition, the introduction of the Western Resource Adequacy Program (WRAP) in 2027 would significantly increase the effective capacity need of Franklin Public Utility District.

The menu of options available to FPUD to meet this growing deficit is constrained but several environmental policies in the State of Washington. These include Washington's Renewable Portfolio Standard (RPS), the Clean Energy Transformation Act (CETA), as well as the Climate Commitment Act (CCA). In combination, these policies make it either economically infeasible or illegal to procure additional greenhouse-gas emitting resources. As such, Franklin will pursue all options available to meet its capacity needs using carbon-neutral resources.

First among these options, FPUD will maximize use of Bonneville Power Administration (BPA) Tier 1 power, which is the cheapest low-carbon capacity resource available to the utility. Notably, 2028 marks the start of a new 20-year contract with BPA in which FPUD will have the opportunity to re-evaluate it's BPA product choice. At this time, the BPA products and rates that will be offered in 2028 have not yet been defined. FPUD will remain fully engaged with the BPA process crafting these products and will carefully evaluate the product options once they are defined to select the product that offers the best fit for FPUD's needs over the next 20-year contract period.

In addition to maximizing BPA Tier 1 power, FPUD will continue to evaluate both opportunities for procuring additional resources and consider the extending current PPA contracts that are otherwise set to expire during the study period. The findings in this study indicate that a new resource portfolio dominated by solar and utility-scale batteries would be the most cost-effective way to meet its needs while complying with state environmental policies. FPUD is already in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. FPUD will also consider BPA Tier 2 opportunities and market-based purchases wherever competitive.

FPUD continues to monitor several emerging technologies, most notably geothermal, hydrogen, and small-modular nuclear reactors (SMR) for possible future procurement. At this time, these resources do not appear to be cost-competitive with solar and batteries, but technological innovations may change that dynamic within the timeframe of the study.

Finally, FPUD will acquire all cost-effective conservation measures and monitor opportunities for demand response and distributed generation investments that could cost-effectively reduce it's need for new capacity resources.