INTEGRATED RESOURCE PLAN

2024

Grant County
PUBLIC UTILITY DISTRICT

Resolution 8889 | August 14, 2024 | Exhibit A

Letter from Energy Supply Management

Every two years Grant PUD updates the Integrated Resource Plan (IRP). For most electric utilities this is a routine activity that is driven primarily by the regulatory requirement to do so. What may get overlooked by viewing the IRP as a routine updating activity is the energy and effort that needs to take place to develop the document. Further, due to the acceleration, uncertainty, and impact of change on the energy landscape over the next 10 to 20 years, the teams that do the work of electric utility planning are navigating market risks for resource investment that are the most significant in generations. This may not be true for all electric utilities, but it is the case for Grant PUD. In fact, Grant County, Washington could easily be identified as case-study for the changing energy landscape.

The drivers of this change can be described in terms of three interrelated forces. First, accelerated load growth. This is a function of growing large customer loads, but not insignificant is a broader drive to electrification related to the second force. Second, meeting government public policy goals for de-carbonization of the grid. And third, building a grid that is more reliable and resilient in the face of events with high consequence and high uncertainty. These events may be driven by weather, utility resource operations, or a combination of the two. For the modern electric utility, these three forces are not discrete. Each has an impact on the others with resulting economics that have introduced an increased need for focus and balanced solutions to utility planning process. This challenge is not unique to the electric utility industry. There are many industries that need to manage growth, de-carbonization goals, and the robustness of their supply chains. However, the electric utility industry is ground-zero for these efforts and there are few places they come together as explicitly as they do in Grant County, Washington.

From an industry perspective, two organizational efforts will assist utilities address de-carbonization and reliability challenges: The expansion of organized electricity markets and standardization of resource adequacy. The Western Interconnect will see at least one, if not two, new wholesale power markets established before the end of the decade. Currently, the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) operates throughout the Western Electricity Coordinating Council's (WECC) geography. Western U.S . utilities started integration into the EIM in 2014, growing from two participants to more than twenty now. The CAISO as well as the Southwest Power Pool (SPP) plan to offer new markets to the Western Interconnect starting in 2026 (CAISO's Extended Day-Ahead Market – EDAM) and 2027 (SPP's Markets+). Participation in either market requires a showing of resource adequacy. This is most explicit in Markets+ requirement to participate in the Western Power Pool's (WPP) Western Resource Adequacy Program (WRAP). The WRAP provides a baseline standard for utilities' resource supply to meet their respective system demands. WRAP participating utilities bolster their supply and demand balance through geographic and resource diversity as well as coordination. As much as these industry efforts are part of the solution for meeting the challenges of de-carbonization and reliability, operating within an organized market and meeting WRAP requirements are new ways of doing business and challenges in and of themselves.

Grant PUD's 2024 IRP lays out the utility's plan to meet the challenge of the future. The utility will continue to support customer needs, supporting load growth for our large customers while balancing cost concerns for our core customers (residential, commercial, and agricultural) through least cost planning. The plan also meets Washington State's Clean Energy Transformation Act (CETA) to be greenhouse gas neutral by 2030 and, by 2045, 100% non-carbon emitting. Finally, the plan highlights the path to meet WRAP participation requirements. The next decade will be one of the most challenging the electric utility industry has seen. This is especially true in the western US, Grant County, and is a focus for Grant PUD. To ensure the focus to meet these challenges, in 2024 Grant PUD stood-up the Energy Supply Management business function. The charge of this new business function is to manage the complexities of this changing energy landscape by understanding drivers of the change and the problems it generates, identify balanced solutions to those problems, and deliver actionable plans to navigate the challenges.

John Mertlich,
Chief Commercial Officer, Energy Supply Management

Resolution No. 9062

A RESOLUTION AUTHORIZING AND APPROVING THE 2024 INTEGRATED RESOURCE PLAN (IRP)

Recitals

1. RCW Chapter 19.280.010 was enacted by the Washington State Legislature in 2006 to encourage the development of new safe, clean, and reliable energy resources to meet future demand in Washington for affordable and reliable electricity;

2. The State Legislature has found that it is essential that electric utilities in Washington develop comprehensive resource plans that explain the mix of generation and demand-side resources (conservation) they plan to use to meet their customers' electricity needs in both the short term and the long term;

3. RCW 19.280.030 requires that by September 2, 2024, Grant PUD adopt an Integrated Resources Plan which includes:

   (a) A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data and customer usage;

   (b) An assessment of commercially available conservation and efficiency resources, as informed, as applicable, by the assessment for conservation potential under RCW 19.285.040 for the planning horizon consistent with (a) of this subsection. Such assessment may include, as appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;

   (c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies including a comparison of the benefits and risks of purchasing power or building new resources;

   (d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion;

   (e) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events, if applicable for the utility's resource portfolio.

   (f) An assessment and twenty-year forecast of the availability of regional generation and transmission capacity to provide and deliver electricity to the utility's customers and to meet the requirements of chapter 288, Laws of 2019 and the state's greenhouse gas emissions reduction limits in RCW 70A.45.020.

   (g) A determination of resource adequacy metrics for the resource plan consistent with the forecasts;

   (h) A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations;

   (i) An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing RCW 19.405.030 through 19.405.050

   (j) The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events and implementing RCW 19.405.030 through 19.405.050, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliable operation, and balancing of its electric system;

(k) An assessment, informed by the cumulative impact analysis conducted under RCW 19.405.140, of: Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security and risk;

(l) A ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan.

4. RCW 19.280.050 requires that Grant PUD's Commission encourage participation of its consumers in development of the Integrated Resources Plan and approve the plan after it has provided public notice and hearing which occurred on July 23, 2024;

5. Grant PUD's staff has prepared and submitted an Integrated Resources plan which meets the requirements of RCW Chapter 19.280.010 et seq., a copy of which is attached hereto as Exhibit A; and

6. Grant PUD's Chief Commercial Officer has reviewed the proposed Integrated Resources Plan and it complies with the requirements of RCW Chapter 19.280.010 et seq. and recommends its adoption by the Commission.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 2 of Grant County, Washington, that the attached Integrated Resources Plan is hereby approved, and Grant PUD's General Manager/Chief Executive Officer is directed to file the plan with the Washington Department of Commerce.

PASSED AND APPROVED by the Commission of Public Utility District No. 2 of Grant County, Washington, this 27th day of August 2024.

Tom Flint

President

ATTEST:

Terry Schaapman

Secretary

Vice President

Judy H. Wilson

Commissioner

Commissioner

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Acronyms, Abbreviations and Definitions

Term	Acronym	Definiton
Alternating Current	AC	An electric current that periodically reverses direction and changes its magnitude continuously with time.
Artificial Intelligence	AI	A branch of computer science that aims to create machines that can perform tasks that normally require human intelligence. Can also refer to the intelligence exhibited by machines, particularly computer systems.
Average Megawat	aMW	A unit of measurement for power. The ratio of energy in MWh to the number of hours in the period. 1,000,000 wats delivered continuously 24 hours a day for a year equals 1 aMW.
Automated Resource Selection	ARS	A function of PowerSIMMTM Planner which uses detailed dispatch modeling to make optimal resource planning decisions. ARS determines the least-cost and least-risk resource options to meet future load and renewable portfolio standard requirements.
Batery Energy Storage System	BESS	A type of power station that uses a group of bateries to store electrical energy.
Bipartisan Infrastructure Law	BIL	Also known as the Infrastructure Investment and Jobs Act (IIJA.) A federal statute enacted by Congress and signed into law in November 2021. Among other provisions, this statute provides funding for infrastructure projects.
Bonneville Power Administration	BPA	An American federal agency created by Congress in 1937. BPA operates as the marketing agent for power for thirty-one federally owned hydroelectric projects in the Northwest and the nuclear Columbia Generarating Station. Bonneville is one of four regional Federal power marketing agencies within the U.S. Department of Energy.
California Independent System Operator	CAISO	A non-profit Independent System Operator created in 1998 as a part of California's restructuring of electricity markets. CAISO oversees the operation of California's bulk electric power system, transmission lines, and electricity market generated and transmited by its member utilites.
Capacity		The maximum output a generating unit can produce when operating under specific conditions. Commonly expressed in megawats.
Capacity Factor		Ratio of electrical energy produced by a generating unit for a time period to electrical energy that could have been produced by the generating unit operating continuously at full power during the same time period.

Climate Committment Act	CCA	A policy passed in 2021 by Governor Jay Inslee to cap and reduce greenhouse gas emissions from Washington's largest emitting sources and industries. This program works alongside others, like CETA, to help Washington achieve its commitment to reducing greenhouse gas emissions by 95% by 2050.
Combined-Cycle Combustion Turbine	CCCT	A turbine that uses the heat generated by the combustion of natural gas or oil to generate mechanical energy.
Clean Energy		Energy that when produced or used creates little or no greenhouse gas emissions.
Clean Energy Action Plan	CEAP	A 10-year plan for implementing CETA's clean energy goals at the lowest reasonable cost and at an acceptable resource adequacy standard.
Clean Energy Implementation Plan	CEIP	A plan developed and filed by Washington's electric utilities every 4 years. It must include: a plan to reach the mandatory clean electricity targets set by CETA; interim targets to meet CETA standards prior to 2030 and between 2030 - 2045; specific targets for energy efficiency, demand response, and renewable energy; specific actions that the utility will take over the next 4 years that show progress toward meeting the clean electricity targets.
Clean Energy Transformation Act	CETA	A policy passed May 7, 2019, by Governor Jay Inslee that commits Washington to have an electricity supply that is free of greenhouse gas emissions by 2045. CETA also sets three clean electricity targets: by 2025, utilities must phase coal-fired electricity out of their state portfolios; by 2030, utilities' state portfolios must be greenhouse gas emissions neutral; by 2045, utilities must supply Washington customers with electricity that is 100% renewable or non-emitting with no provision for offsets.
Columbia Generating Station	CGS	The northwest's only commercial nuclear energy facility, first entering commercial operation in December 1984. As the third largest electricity generator in Washington state, CGS operates at 100% power, 24 hours a day, 7 days a week, but has the ability to load follow or reduce power when requested by Bonneville Power Administration. All of CGS' electricity is provided at cost to the BPA under a formal net billing agreement.
Conservation Potential Assessment	CPA	Assessment that identifies the quantity and cost of resources that are available and achievable in a utility service territory within the next 10-20 years.
Demand Response	DR	Control of load that results in temporary changes to a customer's supply of energy.
Design Build	DB	A project delivery system used in the construction industry where the design and construction services are contracted by a single entity known as the design builder. Also known as alternative delivery.
Direct Current	DC	An electric current flowing in one direction only.

Distributed Energy Resource Management System	DERMS	A technology that helps grid operators manage the flow of electricity from distributed energy resources.
Effective Load Carrying Capability	ELCC	A metric used to assess a generating resource's ability to produce energy when the grid is most likely to experience electricity shortfalls. Typically, ELCC is expressed as a percentage of a resource's nameplate capacity.
Electric Power Research Institute	EPRI	A non-profit organization that conducts research and development related to the generation, delivery and use of electricity.
Electric Vehicle	EV	A vehicle that uses one or more electric motors for propulsion. There are two main types of EVs: battery electric vehicles and plug-in hybrid electric vehicles.
Energy Imbalance Market	EIM	A voluntary market that provides a sub-hourly economic dispatch of participating resources for balancing supply and demand every five minutes. Transmission and reliability constraints would be honored.
Energy Independence Act	EIA	19.285 RCW. A clean energy initiative passed in 2006 that requires Washington electric utilities serving at least 25,000 retail customers to use renewable energy and energy conservation.
Encroachment		A condition in which operation of a hydroelectric project causes an increase in the level of the tailwater of another hydroelectric project located upstream.
Estimated Unmet District Load	EUDL	All projected electric energy loads for a specific district: all projected electric energy loads of the District as defined in Section 4 (c) (1) and determined in Section 4 (c) (3) of the District's Power Sales Contract.
Exceedance		The quantity that exceeds the anticipated amount. In relation to water availability, the amount above the mean availability.
Extended Day-Ahead Market	EDAM	A voluntary day-ahead electricity market, offered by CAISO and designed to deliver reliability, economic, and environmental benefits to balancing areas and utilities throughout the West. Aiming to increase regional coordination, support states' policy goals, and meet demand cost-effectively, EDAM is scheduled to deploy May 1, 2026.
Federal Columbia River Power System	FCRPS	A series of thirty-one hydroelectric projects in the Pacific Northwest's Columbia River Basin. The transmission system is operated by the Bonneville Power Administration to market and deliver electric power.
Federal Energy Regulatory Commission	FERC	An independent agency of the U.S. government, created by Congress in 1977. Part of the U.S. Department of Energy, FERC regulates natural gas projects, hydropower projects, and the interstate transmission of natural gas, oil, and electricity.

Greenhouse Gases	GHG	Gases in the atmosphere that raise the surface temperature of planets such as Earth by absorbing infrared radiation.
Heat Recovery Steam Generator	HRSG	A heat exchanger that recovers heat from a hot gas stream, such as a combustion turbine or other waste gas stream, producing steam that can be used in a process or used to drive a steam turbine.
Heavy Load Hours	HLH	Hours during 7 am – 10 pm, Monday – Saturday, excluding NERC designated national holidays.
High Assay Low Enriched Uranium	HALEU	Uranium fuel that is enriched to between 5% and 30% of the fissile isotope uranium-235. Used by some advanced reactor designs that require higher enrichment levels.
Hydrogen Fuel Cells	HFC	An electrochemical device that converts hydrogen's chemical energy to electricity.
Inflation Reduction Act	IRA	A federal statute enacted by Congress and signed into law in August 2022, investing in domestic energy production and promoting clean energy including credits for renewable energy projects, providing rebates for energy efficiency, funding conservation of lands and resources, and other federal programs.
Infrastructure Investment and Jobs Act	IIJA	A federal statute enacted by Congress and signed into law in November 2021. Among other provisions, this statute provides funding for infrastructure projects. Also known as the Bipartisan Infrastructure Law (BIL.)
Integrated Resource Plan	IRP	Roadmap that large utilities use to plan out generational acquisitions over 5, 10, 20, or more years.
Irradiance		The direct, diffused and reflected solar radiation that strikes a surface, with measurement usually expressed in kilowatts per square meter.
Light Load Hours	LLH	Hours during 1 am – 6 am and 11 pm – midnight, Monday – Saturday and all hours during Sundays and NERC designated national holidays.
Light Water Nuclear Reactor	LWR	A type of nuclear reactor that uses regular water as a coolant and as the neutron moderator medium. Light water reactors are currently the most common type of reactors.
Load Factor		The ratio of the energy used over a period to the theoretical maximum energy use, based on peak demand, over that period. A measure of the utilization rate. High load factor occurs with very steady loads, where energy demand remains relatively constant throughout the period.
Low Enriched Uranium	LEU	Type of uranium used to create nuclear fuel where the percent composition of uranium-235 has been increased through the process of isotope separation. This enrichment improves its ability to produce energy.

Megavolt Amperes	MVA	Unit of apparent power in an electrical circuit. 1,000,000 volts = 1 MV.
Megawatt	MW	A unit of power used to measure the output of a power plant, or the amount of power required by an electric load, equal to a million Watts.
Megawatt-hour	MWh	A unit of energy equal in value to one million watts of electricity used continuously for one hour.
Mid-Columbia Trading Hub	MID-C	One of eight electricity trading hubs in the Western United States. Represents an aggregation of the electricity market for the Northwest. Also referenced as Mid-C.
Million Tonnes	MT	Unit of measurement. 1 MT = 1000 kilograms ≈ 2204.6 lbs.
Moses Lake Transmission Expansion Plan	MTEP	Plan that includes several projects providing additional transmission capacity necessary to reliably serve additional load in the Moses Lake area. Currently in the development stage.
Nameplate Capacity		A measure of the design output capability of a generating resource as designated by the manufacturer.
North American Electric Reliability Corporation	NERC	A nonprofit corporation originally formed June 1, 1968, overseeing six regional reliability entities and all the interconnected power systems of Canada and the contiguous US. NERC assesses resource adequacy and monitors and enforces compliance with power system operation standards.
Northwest Power and Conservation Council	NWPCC	A regional organization that develops and maintains a regional power plan and a fish and wildlife program with the aim to ensure an affordable and reliable energy system while enhancing fish and wildlife in the Columbia Basin.
Northwest Power Pool	NWPP	Former name of the current Western Power Pool. A voluntary organization that includes electric generating utilities in the Pacific Northwest, British Columbia, and Alberta to provide the critical reservoir elevation limits for U.S. dams and set contingency reserve power requirements for utilities within its geographic area. Rebranded to Western Power Pool in 2022.
Open Access Transmission Tarriff	OATT	Set of rules and guidelines established by regulatory bodies to ensure fair and non-discriminatory access to transmission infrastructure.
Pacific Northwest National Laboratory	PNNL	One of the U.S. Department of Energy national laboratories.
Pacific Northwest Utilities Conference Committee	PNUCC	A not-for-profit trade association of consumer-owned and investor-owned electric utilities and other power industry partners.
Photovoltaic	PV	

PowerSIMM Planner™		A platform offered by Ascend Analytics for power planning, capacity expansion, and reliability analysis, determining least cost and least risk supply portfolios. Integrates variability in generation from weather, high volatile hourly and sub-hourly prices, and concern about greenhouse gas emissions.
PowerSIMM Portfolio Manager™		A platform offered by Ascend Analytics that captures both market expectations and fundamental variables of demand, supply, and transmission flows to determine optimal hedge strategies. Integrates physical dimensions of weather and asset operations concurrently with market price dynamics.
Priest Rapids Project	PRP	A hydroelectric project made up of the Priest Rapids and Wanapum dams on the Columbia River, owned and operated by the Grant County PUD.
Priority Firm	PF	Electricity generation that can be consistently available and dependable, regardless of external factors.
Proton Exchange Membrane	PEM	A semi-permeable membrane designed to conduct protons while acting as an electronic insulator and reactant barrier.
Provider of Choice	PoC	BPA's regional effort to engage regional public power utilities and interested parties in a policy and contract-development process to gain an understanding of electric power needs and perspectives. Will establish the long-term power sales policy and contracts that will follow the current Regional Dialogue contracts that expire in September 2028.
Public Utility District	PUD	An organization that maintains the infrastructure for a public service, often providing a service using that infrastructure. Public services considered essential include water, gas, electricity, telephone, waste disposal, and other communication systems.
Quincy Transmission Expansion Project	QTEP	A project involving: building a 32-mile, 230kV transmission line from the Wanapum switchyard to the Mountain View substation; building a new transmission line connecting the existing Columbia to Rocky Ford 230kV transmission line to the Mountain View substation; building a new line linking the existing Columbia to Rocky Ford 230kV transmission line to a proposed Monument Hill switchyard; complete a 230kV transmission loop at Monument Hill to provide a second transmission source to existing and future substations in the east Quincy area.
Renewable Energy		Energy that comes from a source that is not depleted when used and can be replenished on a human timescale. Examples include wind power, solar power, and hydropower.
Renewable Energy Credit	REC	A certificate corresponding to the environmental attributes of energy produced from renewable sources such as wind or solar. Ther Washington Energy Independence Act, 19.285 RCW, allows use of RECs to meet statutory renewable energy obligations

Renewable Portfolio Standard	RPS	An official requirement that requires a certain percentage of a utility's electricity to come from renewable energy sources. Washington's Energy Independence Act establishes a renewable portfolio standard for utilities.
Request for Proposal	RFP	A solicitation of a business proposal initiated by an organization interested in procurement of a product or service.
Resource Adequacy	RA	The ability of an electric system to provide the energy required by its customers, at all times.
Revised Code of Washington	RCW	The compilation of all permanent laws currently in force in the U.S. in the state of Washington. Published by the Washington State Statute Law Committee and the Washington State Code Reviser.
Simple-Cycle Combustion Turbine	SCCT	A type of gas turbine that has only one power cycle, unlike a combined-cycle combustion turbine which has two.
Small Modular Reactor	SMR	A class of small nuclear fission reactors designed to be built in a factory, shipped to operational sites for installation and then used to power buildings or other commercial operations. As of 2023, only China and Russia have successfully built operational SMRs.
Solid Oxide Fuel Cell	SOFC	An electrochemical device that produces electricity from oxidizing a fuel.
Southwest Power Pool	SPP	A regional transmission organization mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices on behalf of its members.
Thousands of Cubic Feet per Second	KCFS	Unit of measurement for hydropower production. 7,500 gallons per second is approximately 1 kcfs.
Variable Energy Resource	VER	A renewable energy resource that has variable production beyond control of the operator. Examples are solar and wind fueled facilities.
Western Electric Coordinating Council	WECC	The regional entity responsible for compliance monitoring and enforcement and oversees the Western Interconnection's reliability planning and assessments.
Western Energy Imbalance Market	WEIM	An energy imbalance market operated by the California Independent System Operator. Not a regional transmission operator, WEIM's market system automatically finds low-cost energy to serve real-time consumer demand across the West.
Western Interconnection		The geographic area of the synchronously operated electric grid in western North America. This includes Washington, Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, British Columbia, Alberta and parts of Montana, Nebraska, New Mexico, South Dakota, Wyoming and Mexico.

Western Power Pool	WPP	A voluntary organization that includes electric generating utilities in the Pacific Northwest, British Columbia, and Alberta to provide the critical reservoir elevation limits for U.S. dams and set contingency reserve power requirements for utilities within its geographic area. Previously known as the Northwest Power Pool.
Western Resource Adequacy Program	WRAP	A regional reliability planning and compliance program for the western U.S. that aims to improve regional coordination and leverage resource diversity for enhanced reliability and reduced customer costs.

1 | Executive Summary

Grant PUD has prepared this Integrated Resource Plan (IRP) pursuant to State requirements and as part of its long-term planning process.

Utilizing its current portfolio, and considering forecast load growth, Grant PUD:

- has sufficient resources to meet forecast energy requirements through the expiration of the current pooling agreement in 2025
- must increase its capacity margin by obtaining additional capacity resources to be able to join the binding Western Resource Adequacy Program (WRAP) in 2027 without incurring deficiency charges
- has sufficient resources to meet the 15% renewable portfolio standard of the Energy Independence Act through 2025
- must acquire additional clean energy resources to meet primary Clean Energy Transformation Act compliance beginning in 2030

Given current projections of future load growth, technology performance and resource costs, Staff's analysis determines that acquiring the resources shown in Table 1, as well as:

- utilizing wholesale markets
- attaining alternative clean energy compliance through the purchase of renewable energy credits (RECs)
- continued investment in cost-effective conservation

is the recommended and least cost path to providing for customer needs through 2045. Resources shown in Table 1 could be obtained through either purchase agreements or built and owned by Grant PUD.

Table 1. Recommended portfolio additions by five-year period, nameplate capacity in MW

Technology	2025 - 2029	2030 – 2034	2035 - 2039	2040 - 2045	Total
BPA Tier 2 Contract	40				40
Solar	490	200	420	60	1170
Wind	10				10
Lithium-ion Battery Storage	210	70	70	20	370
Demand Response	28				28
Total	778	270	490	80	1618

Demand response programs aimed at high load factor customers, including cryptocurrency miners, are an economical resource for meeting energy needs at times of high demand and are recommended in this plan. Grant PUD is currently operating a pilot for this type of program to increase understanding of implementation requirements, costs, and effectiveness. The analysis for this plan contemplated 28 MW of demand response. However, further examination of customer capabilities may reveal opportunities for additional demand response capacity.

Additions recommended for the near term, 2026 – 2028, are required to provide sufficient firm capacity for participation in WRAP. These additions also reduce dependence on short-term trading in the wholesale market. Due to time constraints on bringing projects online, resource additions in the near-term are limited to the currently commercially available technology of solar, wind and lithium-ion battery installations.

Mid-term, 2032 – 2038, additions are prompted by the need to procure clean energy for CETA compliance. Recommended additions during this period are the currently commercially available, currently least cost, solar and lithium-ion battery technologies also selected for near-term additions. Time may bring operational advancements and cost decreases to emerging technologies and Staff can envision a future in which new clean energy technologies, including small nuclear reactors, are the preferred option for serving customer needs. Staff will continue to monitor developments and include new information in future resource plan evaluations as it becomes available.

Portfolio additions recommended in this plan were assessed using currently available information as being the most cost-efficient means of reliably meeting customer needs in the future. Additional evaluation of available alternatives and consideration of alternate strategies will occur prior to any resource acquisition or contractual agreement.

In compliance with RCW 19.280, Grant PUD will submit the following integrated resource plan cover sheet to the Department of Commerce by September 2, 2024.

Table 2. Energy Integrated Resource Plan Cover Sheet for submission to Washington State Department of Commerce

Washington State Utility Integrated Resource Plan Year 2024									
Estimate Interval	**Base Year**			**5-Year Estimate**			**10-Year Estimate**		
Estimate Period	2023			2028			2033		
Season	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	MW	MW	aMW	MW	MW	aMW	MW	MW	aMW
Loads	900.63	948.94	701.06	1212.40	1339.40	966.68	1355.50	1497.40	1080.73
Exports									
Resources:									
Energy Conservation Measures				7.19	7.27	6.63	18.31	18.60	15.99
BTM Solar									
Demand Response				28.00	28.00	1.12	28.00	28.00	1.12
BPA Tier 1 or Base	15.44	15.44	5.40	200.00	15.44	55.66	200.00	200.00	200.00
BPA Tier 2				40.00	0.00	10.05	40.00	40.00	40.00
Cogeneration									
Hydro	105.16	118.16	110.37	1030.90	933.50	664.16	1030.90	929.00	659.27
Wind	8.00	0.00	2.86	1.50	10.20	3.95	0.73	1.08	1.71
Utility-Scale Solar				15.20	283.70	92.79	15.19	283.71	104.78
FTM Distributed Solar									
Biomass									
Biogas									
Landfill Gas									
Geothermal									
Nuclear									
Other Distributed Renewables									
Thermal Natural Gas									
Thermal Coal									
Market Purchases	772.03	815.34	582.43			137.20			64.08
Other				210.00	162.10	-4.88	260.00	177.50	-6.22
Imports									
Undecided									
Total Resources	900.63	948.94	701.06	1532.79	1440.21	966.68	1593.13	1677.91	1080.73
Load Resource Balance	0.00	0.00	0.00	320.39	100.81	0.00	237.63	180.51	0.00

2 | Grant County PUD

Grant County, located in the heart of central Washington, is home to world-class agriculture, a diverse industrial sector, and is a hub for data processing. Grant County PUD is a public utility serving the people of Grant County Washington since 1938 as a provider of power and since 2000 as a provider of fiber network services. It operates generation sources and delivers power over 480 miles of transmission and nearly 4,000 miles of distribution lines to more than 54,000 active customer meters throughout the county.

Grant PUD customers enjoy some of the lowest power prices in the nation. These competitive power prices have helped spur a period of growth and as we look toward the future, we anticipate that our communities will continue to thrive, resulting in strong demand for electricity.

Grant County PUD is governed by a five-member Board of Commissioners elected on a nonpartisan basis by the people of the county. Commissioners set policies, review operations, and approve budget expenditures.

Nelson Cox
Commission President

Tom Flint
Commission Vice President

Terry Pyle
Commission Secretary

Larry Schaapman
Commissioner

Judy Wilson
Commissioner

Electric System

Overhead Distribution Lines	Underground Distribution Lines	Overhead Transformers
2,810 MILES	**1,156 MILES**	**24,881**
Padmount Transformers	**115kV Transmission Lines**	**230kV Transmission Lines**
10,700	**275 MILES**	**200 MILES**

Active Meters

Residential
41,776

Industrial
281

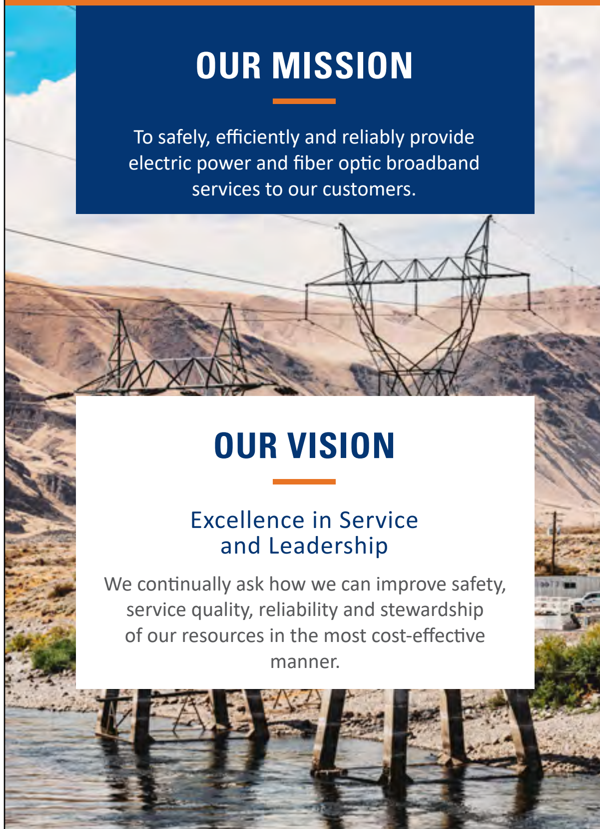
Commercial
7,914

Irrigation
5,041

Total Active Meters: **55,012**

Additional information about Grant PUD can be found on our website [Grant PUD - Powering our way of life] as well as in our Annual Report [Grant PUD: Publications].

WHO WE ARE



OUR MISSION

To safely, efficiently and reliably provide electric power and fiber optic broadband services to our customers.

OUR VISION

Excellence in Service and Leadership

We continually ask how we can improve safety, service quality, reliability and stewardship of our resources in the most cost-effective manner.

OUR VALUES

- **Safety**
  We believe that employee and public safety is paramount
- **Innovation**
  We make decisions that best serve present and future generations
- **Service**
  We are committed to excellent customer service
- **Teamwork**
  We are one team with the same mission
- **Respect**
  We honor the rights and beliefs of those we work with and serve
- **Integrity**
  We hold ourselves and others accountable to professionalism in our actions and words
- **Heritage**
  We protect, preserve and perpetuate both the spirit of the Grant PUD and the Wanapum relationship

OUR STRATEGY

Focus on our core electric customers while still ensuring the success of all our customers

Prioritizing our resources around these **5 strategic pillars:**

1. Ensuring long-term affordable rates for our core electric customers
2. Sustaining our focus on engaged, empowered & enabled employees
3. Commiting to accurate & responsive customer service
4. Developing an intentional power demand strategy
5. Caring for our communities through active engagement

Figure 1. Grant County PUD Mission, Vision, Values, and Strategy

3 | Objectives and Requirements

We have developed this IRP to assess Grant PUD's long-term power supply as required in the Revised Code of Washington, Chapter 19.280. It is our objective to continually assess customers' future energy needs and develop plans to meet those needs while addressing risks and uncertainties in the changing regional and clean-energy focused environment. This IRP is a decision support tool as we continually work to support Grant PUD's mission:

To safely, efficiently, and reliably provide electric power and fiber optic broadband services to our customers.

GRANT PUD INTEGRATED RESOURCE PLANNING OBJECTIVES

The plan and recommendations presented in this IRP aim to minimize long-term net revenue requirements while maintaining assumptions and meeting constraints. These assumptions and constraints include consideration of customer energy requirements, energy markets, State and Federal regulations, fuel and resource availability, transmission, and deliverability, all of which will be discussed in this document.

Our resource plan is actionable and is intended to direct contracting for, or building of, new resources and to outline specific strategies for meeting projected future requirements.

WASHINGTON STATE REQUIREMENTS FOR INTEGRATED RESOURCE PLANNING AND OBJECTIVES

The state of Washington provides direction on how public utility districts should develop Integrated Resource Plans and describes the uses for the information provided in these plans. We have used the requirements listed in these regulatory documents as guidance in completing this IRP. These regulatory requirements are described below.

Revised Code of Washington (RCW) Chapter 19.280

RCW 19.280 outlines the requirements of electric utility resource plans. This chapter of the Revised Code of Washington (RCW) encourages the development of safe, clean, and reliable energy resources. Information from the integrated resource plans that are developed should be used to identify and develop: new energy generation; conservation and efficiency resources; methods, commercially available technologies, and facilities for integrated renewable resources, including addressing over-generation events; and related infrastructure to meet the state's electricity needs. The requirements listed in RCW 19.280.30 for large utility districts include:

(1a) A range of forecasts, for at least the next ten years, of projected customer demand which takes into account econometric data and customer usage;

(1b) An assessment of commercially available conservation and efficiency resources, as informed, as applicable, by the assessment for conservation potential under RCW 19.285.040 for the planning horizon consistent with (a) of this subsection. Such assessment may include, as appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;

(1c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies including a comparison of the benefits and risks of purchasing power or building new resources;

(1d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion;

(1e) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events, if applicable for the utility's resource portfolio.

(1f) An assessment and 20-year forecast of the availability of and requirements for regional generation and transmission capacity to provide and deliver electricity to the utility's customers and to meet the requirements of chapter 288, Laws of 2019 and the state's greenhouse gas emissions reduction limits in RCW 70A.45.020. The transmission assessment must identify the utility's expected needs to acquire new long-term firm rights, develop new, or expand or upgrade existing, bulk transmission facilities consistent with the requirements of this section and reliability standards;

(1fi) If an electric utility operates transmission assets rated at 115,000 volts or greater, the transmission assessment must take into account opportunities to make more effective use of existing transmission capacity through improved transmission system operating practices, energy efficiency, demand response, grid modernization, non-wires solutions, and other programs if applicable;

(1g) A determination of resource adequacy metrics for the resource plan consistent with the forecasts;

(1h) A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations;

(1i) An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing RCW 19.405.030 through 19.405.050;

(1j) The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events and implementing RCW 19.405.030 through 19.405.050, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliable operation, and balancing of its electric system;

(1k) An assessment, informed by the cumulative impact analysis conducted under RCW 19.405.140, of: energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security and risk; and

(1l) A ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050 at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan.

(3a) An electric or large combination utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities pursuant to RCW 80.28.405 and the department for consumer-owned utilities, when developing integrated resource plans and clean energy action plans.

The items listed above are not a complete listing of all requirements. For a full listing, please reference RCW Chapter 19.280 (Legislature, 2024).

4 | Existing Resources

SUPPLY SIDE RESOURCES

Figure 2. Map of Grant County PUD existing electric generating resources

The Wanapum Development

The Wanapum Development consists of a dam and ten-unit hydroelectric generating station with a nameplate rating of 1,221 MW. Located on the Columbia River in Grant and Kittitas Counties, the Wanapum Development includes switching, transmission, and other facilities necessary to deliver electric output to the transmission networks of Grant PUD, BPA, and other power purchasers. Grant County PUD holds the physical rights to 63.31% of this development.

The Priest Rapids Development

The Priest Rapids Development consists of a dam and ten-unit hydroelectric generating station with a nameplate rating of 950 MW. Located on the Columbia River in Grant and Yakima Counties, 18 miles downstream of the Wanapum Development, the Priest Rapids Development includes switching, transmission, and other facilities necessary to deliver the electric output to the transmission networks of Grant PUD, BPA, and other power purchasers. Grant County PUD holds the physical rights to 63.31% of this development.

Together, Wanapum and Priest Rapids Developments, collectively called the Priest Rapids Project (PRP), provide Grant PUD with energy, capacity, ancillary services, energy storage, and carbon-free attributes. These large hydroelectric, carbon-free resources provide Grant PUD's foundational supply of electricity.

Quincy Chute Project

Under an agreement with the Quincy and South Columbia Basin Irrigation Districts, Grant PUD operates and purchases the entire capability of the Quincy Chute hydroelectric generating facility. This 9.4 MW project is located on one of Grant County's main irrigation canals of the Columbia Basin Irrigation Project. Grant PUD financed, designed, and constructed the project and is responsible for operation and maintenance during the period of the current agreement, which expires in 2025. This facility operates only during the irrigation season of March through October.

Potholes East Canal Headworks Project

Under an agreement with the Quincy and South Columbia Basin Irrigation Districts, Grant PUD operates and purchases the entire capability and output of the Potholes East Canal hydroelectric generating facility. This 6.5 MW project is located at the Potholes East Canal Headworks at the O'Sullivan Dam in southern Grant County. Grant PUD financed, designed, and constructed the project and is responsible for operation and maintenance during the period of the current agreement, which expires in 2030. This facility operates only during the irrigation season of March through October.

Nine Canyon Wind Project

Under a power purchase agreement with Energy Northwest, Grant PUD receives 12.54% of Phase I, II and III of the Nine Canyon Wind Project located in the Horse Heaven Hills near Kennewick, Washington. The Nine Canyon facility is a 63-turbine facility with a total generating capacity of 95.9 MW. The power purchase agreement is in effect until July 1, 2030.

For more detail on how existing resources were represented in the capacity expansion, portfolio or loss of load expectation modeling completed for this resource plan, please see Appendix 2.

OTHER RESOURCES

EUDL Financial Position

Through FERC mandate, Grant PUD has the right to receive financial resources from the PRP to purchase power to serve the Estimated Unmet District Load (EUDL). EUDL is the amount of load Grant PUD is unable to meet with firm power, under critical water conditions, from its rights to the physical output of PRP.

This financial resource is capped at approximately 30% of the market value of the output of PRP. The amount of the 30% limit available to Grant PUD is calculated annually based on load requirements and portfolio resources.

The energy and capacity derived from this financial resource is not received directly from PRP output but by converting the financial position to a physical position through making energy purchases in the market.

Figure 3 illustrates the growing market value of 30% of PRP along with Grant PUD's contractual share of that value for the period 2014 through 2024.

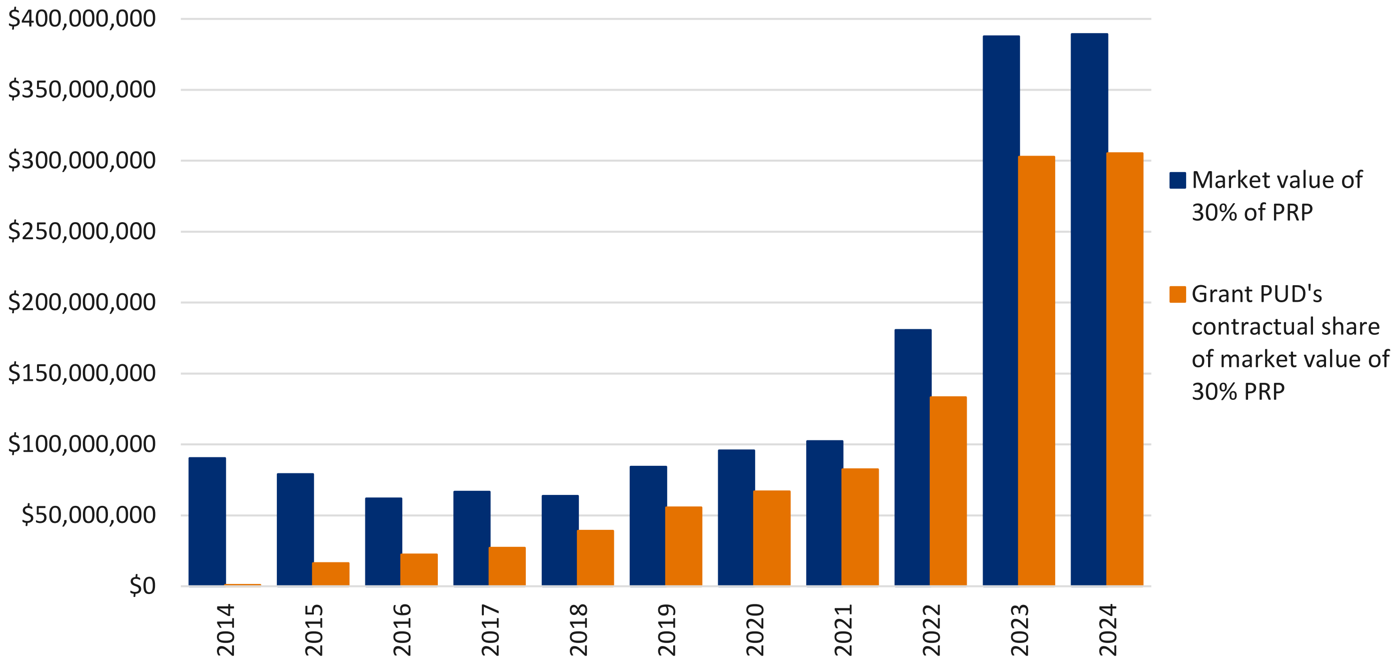


Figure 3. Market value of 30% of Priest Rapids Project and Grant PUD's contractual share of this value, allocated for the EUDL, 2014 – 2024, $

Because the value of the EUDL is not a physical position, it is not included in the capacity expansion, portfolio or loss of load expectation modeling completed for this resource plan.

CONTRACTS AND WHOLESALE TRADING

As outlined by internal policies, Grant PUD's energy risk management approach aims to capitalize on the low cost of production of the PRP without retaining an imprudent amount of water risk or price volatility risk. As a strategy to hedge against water risk, Grant PUD has entered into wholesale slice and pooling agreements to sell capacity and energy from its retained 63.3% share of the PRP output. Grant PUD also participates in wholesale trading activity to increase the predictability of net wholesale revenues by mitigating the effect of fluctuation of wholesale power prices and water variability. These contracts and trading activities directly contribute to the ability to maintain a strong financial position while maintaining stable and predictable retail prices.

Slice Contracts

Grant PUD employs a slice hedging strategy to mitigate the effects of the volatility of river flows from year to year. This hedging is accomplished by selling a portion, or slice, of PRP capacity and energy to buyers who then assume the associated water availability and wholesale price risks. Grant PUD then uses the revenues from these sales to purchase firm energy from the same counterparties. Counterparties are also required to return incremental hydro, qualified as renewable energy, or an eligible substitute to help Grant meet its Energy Independent Act (EIA) requirements. We regularly monitor Grant PUD's exposure and retain the right to call for additional assurances at any time and have the right to curtail delivery in the event of nonpayment or non-delivery of firm energy. Grant PUD obtains stable revenues from these contracts and realizes a premium associated with environmental attributes and associated ancillary services of the PRP. This strategy has proven to be an effective and low-cost approach to mitigating water availability risk and wholesale price volatility. However, these contracts impact Grant PUD's ability to claim PRP output for the Western Resource Adequacy Program (WRAP) and the Clean Energy Transformation Act (CETA) compliance. Grant PUD is currently evaluating how to effectively use its slice strategy under demands from both WRAP and CETA. Currently, Grant PUD has two slice contracts, the last of which expires December 31, 2026, for a total of 30% of PRP output.

Pooling Agreements

Pooling agreements are another strategy Grant PUD employs to mitigate the effects of river flow volatility. These agreements allow participants to satisfy differing peak demands, accommodate outages, diversify supply, and enhance the reliability of their portfolios by using a combination of pooled resources.

Under the terms of Grant PUD's current pooling agreement, the counterparty receives rights to a defined portion of the actual output of PRP, output which varies with water conditions, and in return provides firm, unspecified-source power to meet Grant PUD load. The counterparty provides this power regardless of the actual output of the PRP. The counterparty also provides certain wholesale scheduling services.

It is expected that over the life of this agreement the products exchanged will be of approximately equal value. However, there will be monthly payments owed by either the counterparty or Grant PUD due to the seasonal differences between capacity and energy amounts and loads. These payments are presented as a net of sales and purchases. Certain non-hydrological performance metrics were assumed at the beginning of the contract and differences in these metrics are trued up monthly and payment is made accordingly. The current pooling agreement, for 33.31% of PRP, expires September 29, 2025.

Under the current pooling agreement, to comply with the EIA and CETA, Grant PUD has retained the right to incremental hydro from PRP. This incremental hydro output is qualified as renewable energy. We remain aware that participation in future pooling agreements may affect the ability to claim PRP output toward EIA, CETA, and WRAP compliance, and are evaluating how to best reduce water risk while maintaining compliance in these areas.

Bonneville Power Administration Contracts

The Bonneville Power Administration (BPA), a federal power marketing agency created by Congress in 1937, markets wholesale electrical power from 31 federal hydroelectric projects in the Northwest, and the nuclear Columbia Generating Station (CGS). The U.S. Army Corps of Engineers and Bureau of Reclamation own and operate the federal dams, called the Federal Columbia River Power System (FCRPS) while Energy Northwest, a public power joint operating agency, owns and operates the CGS.

Grant PUD holds a priority firm power contract with BPA, effective October 1, 2011, and terminating October 1, 2028, that provides for service of loads in the Grand Coulee area. These loads are located in a small area not interconnected to the Grant PUD transmission system and represent roughly 1%, or approximately 5 aMW, of total load. Grant PUD has the option to exercise statutory rights to apply for more priority power from BPA upon the expiration of the current BPA contract period in 2028. Grant PUD intends to exercise this option and secure a significant post-2028 priority contract with BPA. We are actively engaged in BPA's Provider of Choice (PoC) process that will determine the structure of new contracts offered to BPA's municipal and public power preference customers. The PoC process began in 2021, with contract execution expected by the end of 2025. The PoC contracts will be effective October 1, 2028, through September 30, 2044.

We anticipate that Grant PUD will sign a BPA PoC contract or contracts, ensuring the continuity of load-following power services for the Grand Coulee area while also securing a larger block of federal power to serve other retail loads. The block power product is expected to be a significant source of power for retail loads both in Grant PUD's Balancing Area and at Grand Coulee. However, we remain committed to thoroughly evaluating all available BPA product options to find the optimal solution for customers' needs.

For this resource plan, we assume Grant PUD will secure approximately 200 MW of firm Tier 1 power through BPA's Provider of Choice contracts beginning in October 2028.

Wholesale Trading

Grant PUD engages in wholesale trading activity to moderate portfolio risk and to stabilize energy costs and revenue. Grant PUD currently operates within the Western Electric Coordinating Council (WECC). Within the WECC, there are numerous bilateral trading hubs. Grant PUD currently relies heavily on these markets with specific concentration at the Mid-Columbia (Mid-C) trading hub. The Mid-C is one of the most liquid trading hubs in North America and provides us with ready access to market energy, for both sales and purchases, as well as market price discovery. A robust and liquid wholesale energy market is vital to meeting customers' energy needs.

5 | Key Planning Considerations

To be effective, the planning process must navigate a complex and interconnected set of considerations. Ongoing evaluation of these factors is essential to our ability to craft an actionable IRP. The key considerations discussed below are expected to be significant drivers of change for Grant PUD well into the future.

POLICY AND REGULATIONS

Over the past several years there have been several state programs aimed at increasing renewable energy and reducing carbon emissions. Grant PUD faces ongoing uncertainty regarding this carbon-focused legislative action and implementation. The three primary laws impacting Grant PUD are the Energy Independence Act (I-937), the Clean Energy Transformation Act (CETA), and the Climate Commitment Act (CCA). While the rule making for CETA and CCA is largely finished, the implementation impacts are not fully known. However, we anticipate that these laws and any successor carbon focused laws will have a significant impact on Grant PUD's future resource strategy and portfolio.

Energy Independence Act

In 2006, Ballot Initiative 937 (I-937) was passed. This legislation is now incorporated into RCW 19.285, also known as the Energy Independence Act (EIA). The EIA requires large utilities to pursue cost-effective, feasible energy conservation measures as well as obtain 15% of their electricity for sales to retail customers from renewable resources beginning in 2020.

Beginning in 2010, qualifying utilities are required to make a public biennial target for energy efficiency. Qualifying utilities are required to meet their targets during the subsequent two-year period. Opportunities for energy efficiency are identified using methodologies consistent with those used by the Northwest Power and Conservation Council.

In compliance with the EIA, Grant PUD has completed its 2023 Conservation Potential Assessment, covering 2024 – 2043. The report of this assessment is attached as Appendix 3. By adoption of Resolution No. 9055 on June 25, 2024, the Grant PUD Commission established a ten-year conservation potential plan of 140,072 MWh (15.99 aMW) and a two-year conservation target of 17,520 MWh (2.00 aMW). A conservation potential assessment, and adoption of targets will be completed every two years with the next assessment anticipated to be completed in fall of 2025. Cost effective conservation and efficiency identified in the 2023 conservation potential assessment are included in this IRP.

The EIA also establishes a Renewable Portfolio Standard (RPS) such that by January 1, 2020, and every year thereafter, qualifying utilities must use eligible renewable resources or acquire Renewable Energy Certificates (RECs) to serve at least 15% of the amount of electricity delivered to its retail customers. For the purpose of calculating the annual targets, retail sales are calculated as the average of the utility's load for the previous two years.

The EIA definition of eligible resources does not include Grant PUD's total share of hydro assets but does include incremental electricity produced as a result of hydro efficiency improvements completed after March 31, 1999. EIA also dictates that renewable resources must be located in the Pacific Northwest or delivered to the state on a real-time basis to count toward the RPS. With the current share of incremental hydro and the wind generation in the portfolio, Grant PUD is positioned to meet the EIA RPS requirement through 2025. Maintaining compliance with the RPS, through generating resource acquisition or RECs is held as a firm constraint in developing this IRP.

Clean Energy Transformation Act

On May 7, 2019, Washington Governor Jay Inslee signed into law the Clean Energy Transformation Act (CETA) (E2SSB 5116 or RCW 19.405). CETA commits Washington utilities to transition to a greenhouse gas free electricity supply. There are three major milestones during this transition. By the end of 2025, utilities must eliminate coal-fired electricity from portfolios used to serve Washington load. By January 1, 2030, electric generation for all retail sales must be greenhouse gas neutral. To meet this goal, utilities must use a combination of non-emitting resources and renewable resources to meet at least 80% of their retail sales over a 4-year compliance period beginning in 2030. Alternative compliance options, such as RECs or energy transformation projects, may be used for the remaining 20% of retail sales. By January 1, 2045, all sales of electricity to retail customers must be from non-emitting and renewable resources. Renewable resources include water, wind, solar energy, geothermal energy, renewable natural gas, renewable hydrogen, wave ocean or tidal power, biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests, or biomass energy.

Starting in 2022 and every four years thereafter, CETA requires that each utility publish a clean energy implementation plan (CEIP) with interim targets for renewable and non-emitting energy provisions to retail customers, targets for energy efficiency, and methods to ensure the utility provides an equitable distribution of energy and non-energy benefits. In December 2021, Grant PUD submitted its first Commission approved CEIP to the Department of Commerce covering the period 2022-2025.

The 2021 CEIP established a target of 28% of retail load to be served by renewable sources in each year of the four-year period. The PUD initially anticipated meeting these interim targets with a combination of incremental hydropower, other renewable resources, and voluntary clean energy rate schedule options for customers. Due to an unanticipated reduction in voluntary clean energy participation from retail customers, the actual amount served by renewable sources in 2022 and 2023 was less than anticipated. Conversely, to a lesser extent, specified source carbon free purchases to serve all Grant PUD retail load customers have been higher than anticipated in the 2022 CEIP. (PUD, 2021) (PUD, 2021)

The CEIP includes development of energy assistance and energy conservation programs targeted to assist Grant PUD customers in the most need of assistance. These efforts will focus on energy burdened customers, as well as customers who reside in highly impacted communities, and includes energy discounts, outreach for in-home energy audits and related actions, and assistance programs including the PUD's Share the Warmth program, as well as third-party programs with the Opportunities Industrialization Center, Salvation Army, and the Large Industrial *Pay It Forward* program.

Per the CETA requirement to pursue cost-effective conservation and efficiency measures, it is Grant PUD's intent to perform, biennially, a Conservation Potential Assessment and Demand Response Potential Assessment to aid in this compliance. Per Commission Resolution No. 9055, the PUD established a two-year conservation target of 17,520 MWh and a ten-year conservation potential plan of 140,072 MWh. For this IRP, we assume that Grant PUD will achieve the energy and demand savings determined by the CPA.

The full CPA report is included in Appendix 3. The PUD's next CEIP, for the period 2026 – 2029 will be available by the end of 2025.

RCW 19.280.030 requires submittal of a 10-year Clean Energy Action Plan (CEAP) for implementing CETA's clean energy goals at the lowest reasonable cost and at an acceptable resource adequacy standard. Elements of the CEAP are included in this IRP analysis and include specific information described in Section 9 of this document.

Climate Commitment Act

On May 17, 2021, Washington Governor Jay Inslee signed into law the Climate Commitment Act (CCA) (E2SSB 5126 or RCW 70A.65), which establishes a comprehensive, market-based, cap-and-invest program to reduce carbon emissions and achieve the greenhouse gas reduction targets adopted by the Washington Legislature (RCW 70A.45.020). The greenhouse gas emissions reduction limits are as follows: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 45 percent below 1990 levels by 2030; (3) reduce emissions to 70 percent below 1990 levels by 2040; and (4) reduce emissions to 95 percent below 1990 levels by 2050.

Beginning in 2023, the CCA established emission allowance budgets with the total number of allowances decreasing over time to align with statutory limits. The program covers industrial facilities, certain fuel suppliers, in-state electricity generators, electricity importers, and natural gas distributors with annual carbon dioxide equivalent emissions above 25,000 metric tons. Other facilities and entities will be phased into the program beginning in 2027 and 2031.

Covered entities must either reduce their emissions or obtain allowances to cover any remaining emissions. Initial no-cost allowances for the period from 2023-2026 were allocated to utilities, in alignment with the CETA requirements, to cover the "cost burden" associated with the CCA. Utilities who received no cost allowances can use those allowances to satisfy direct CCA compliance obligations or can consign the allowances to auction and use the proceeds for ratepayer benefit. Any allowances not freely allocated will be auctioned with proceeds going to the state to support clean energy transition and assistance, clean transportation, and climate resiliency projects that promote climate justice.

Grant PUD does not own any emitting generation and is not an electricity importer as defined by CCA, however the PUD does incur a direct compliance obligation for BPA sourced energy as BPA elected to not be a covered entity under the program. Therefore, the compliance obligation associated with BPA sourced electricity imports transfers to downstream entities. Further, the CCA has increased NW wholesale energy prices to reflect the cost of allowances needed to cover the emissions associated with fossil-fuel generation. As a result of Grant's market participation and compliance obligation associated with BPA sourced imports, the PUD was allocated no-cost allowances to cover its cost burden under the CCA. For the compliance period from 2023 – 2026 the PUD was issued allowances of 9,138,589 MT CO_2e. Due to State confidentiality and manipulation regulations, additional details are not subject to public disclosure.

In 2023, Initiative 2117 was developed and submitted to the state. Initiative 2117 is intended to prohibit any state agencies from implementing a cap and trade or cap and tax program and repealing the 2021 Washington Climate Commitment Act (CCA). In the 2024 legislative session, the legislature chose not to act on Initiative 2117 so the initiative will go to ballot in November 2024. If the initiative passes it is anticipated to eliminate the requirement to provide allowances for GHG emissions for utilities and eliminate the need for, and associated value of, no cost allowances allocated to utilities. However, it is unclear how it would impact a number of CCA related issues such as future GHG emission reporting requirements for utilities.

Federal Policy

Although many facets of federal policy can impact the PUD's resource selection, the policy with the greatest potential impact on current planning are federal tax credits or incentives for clean energy technologies. These tax credits can have a significant impact on lowering the cost of qualifying resources, and if they were to be extended, would have a substantial impact on the cost of new wind or solar resources. Further, recent bills put forward by lawmakers to extend the tax credits have included expansion of the tax credits to other clean energy resources and storage technologies. These recent bills have also allowed for direct pay alternatives, which would lower the cost of financing new clean energy technologies by reducing the need for tax equity.

The Inflation Reduction Act (IRA), H.R. 5376, was passed by Congress and signed into law in August of 2022 (117th Congress, 2022). In addition to several other provisions, this legislation includes incentives for development of clean energy production, clean vehicles, as well as manufacturing and buildings tied to the clean energy sector. For renewable energy investment, investment tax credits of 30% are available through 2032. An additional 10% credit is available for locations within designated energy communities or for locations in low-income or on First Nations lands. Production tax credits of $26/MWh are available through 2032. A $3/kg credit for green hydrogen production is also included in this legislation. For our planning efforts, we assume new clean energy generating resources will have access to IRA investment and production tax credits over the planning horizon.

Tax incentives are affecting renewable project development. In 2023 a record amount of solar and battery storage capacity was installed across the U.S. while wind capacity additions remained strong. Information from the U.S. Energy Information Administration indicates an expectation that clean energy capacity expansion will continue and a growing share of our electric supply will come from renewable sources.

Figure 4 shows a history of clean energy capacity additions as well as the EIA's forecast of expected near term additions (U.S. Energy Information Administration, 2024).

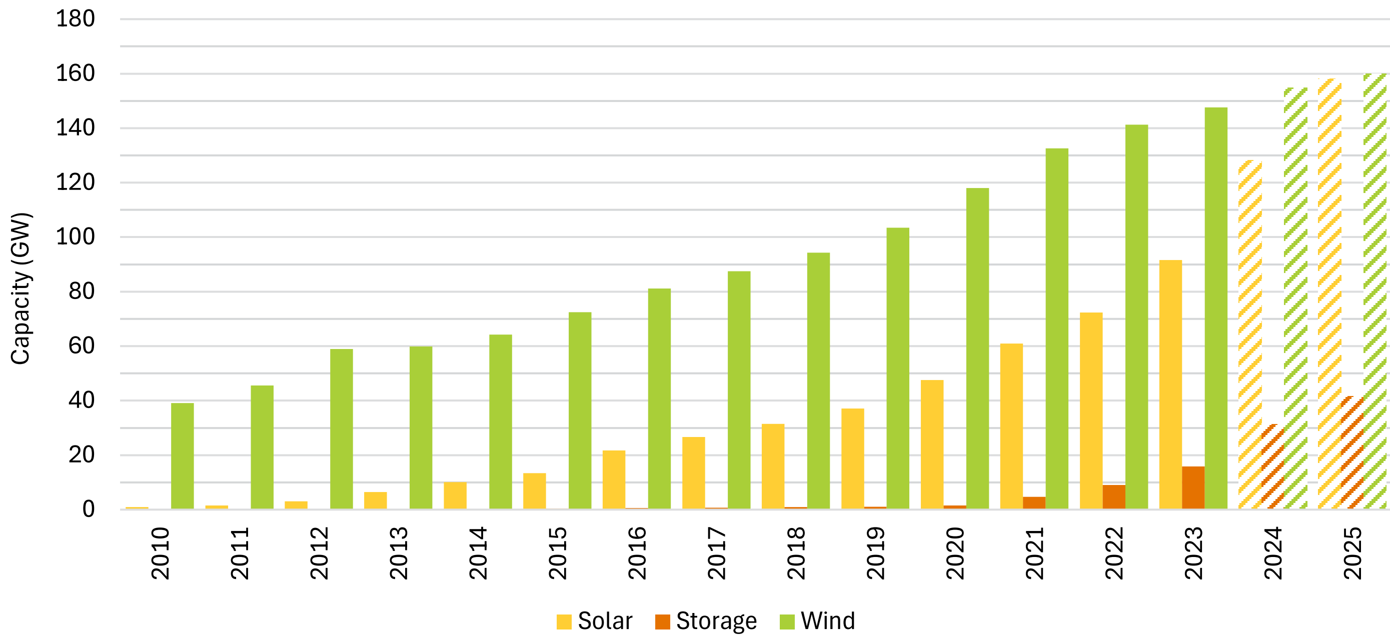


Figure 4. U.S. electric generating capacity of solar, storage and wind resources, actual 2010 - 2023, projections 2024 – 2025, GW (U.S. Energy Information Administration, 2024)

Production tax credits can also reduce the incremental dispatch cost below zero as owners benefit from the tax advantages only if they generate electricity. This will impact market pricing as well as resource dispatch.

Recent Federal policy has also been aimed at increasing the use of electric vehicles. The IRA amended and updated the Clean Vehicle Credit, through which taxpayers, under certain conditions, may qualify for a credit of up to $7,500 per vehicle. Also under the IRA, certain investments to expand or establish electric vehicle manufacturing facilities qualify for a 6% to 30% tax credit, and grants and load guarantees for the domestic production of electric vehicles and the deployment of fueling infrastructure are being made available.

While Figure 5 shows that even with recent incentives, electric vehicles still make up a small percentage of the total number of vehicles on U.S. roadways, it also illustrates the dramatic increase in the number of registered electric vehicles in each of the last few years of available data. As federal policy continues to favor an increase in the number of electric vehicles, demand for electricity to fuel them will also grow, as will the need to integrate these vehicles into the grid, with buildings and other energy systems.

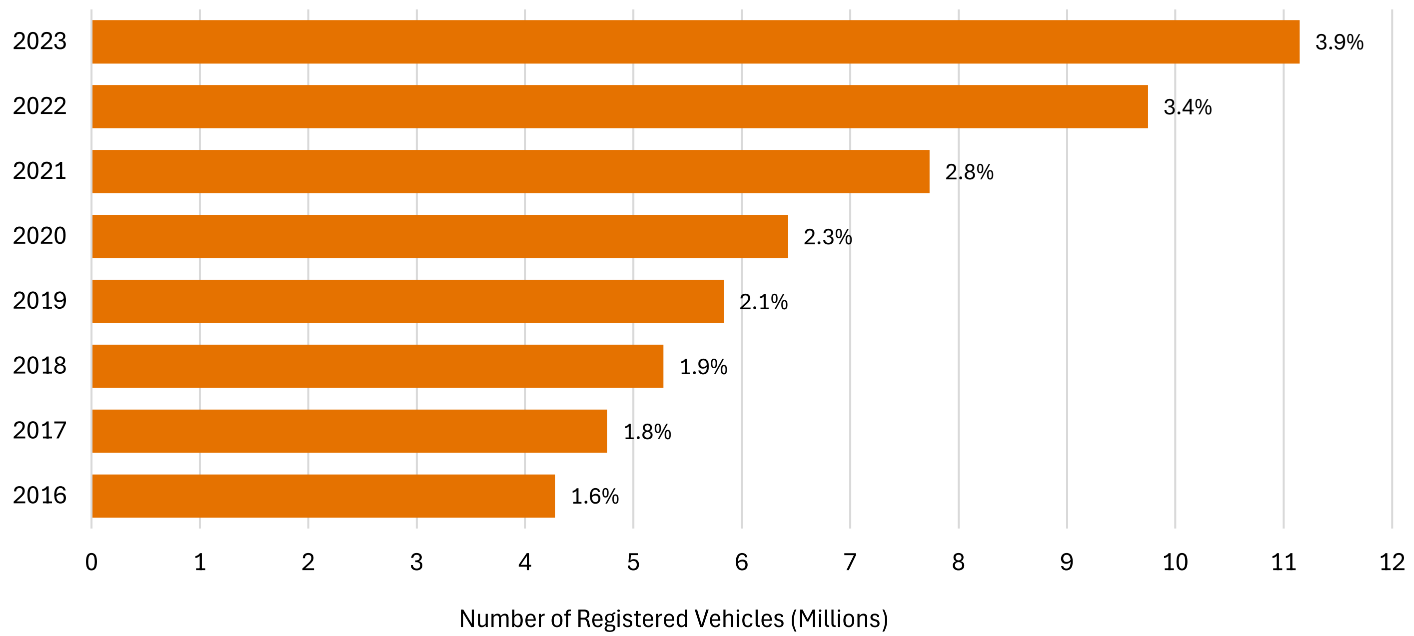


Figure 5. Total number of electric, plug-in hybrid, and hybrid electric light-duty vehicles registered in the U.S., by year, and as percent of total vehicles registered, 2018 – 2023 (U.S. Department of Energy, Energy Efficiency & Renewable Energy, 2024)

REGIONAL EVOLUTIONS

Along with changes in the market structure and focus on region-wide resource adequacy, the Western Interconnection is undergoing increased load growth and resource mix transitions.

New Energy Markets

For the past several years, Grant PUD has been following the developments of the California Independent System Operator's (CAISO) Western Energy Imbalance Market (WEIM). Grant PUD has chosen not to join this real-time energy market, instead relying on its pooling agreement to meet hourly energy imbalance needs. Now, with the high expectation of a day-ahead energy market in the WECC, Grant PUD has become involved in both the CAISO Extended Day-Ahead Market (EDAM) and the Southwest Power Pool's (SPP) Markets Plus efforts.

Day-ahead markets provide protection against price volatility by allowing participants to buy and sell electricity, as well as related products, such as regulation and operating reserves, the day before it is produced and consumed. While prices on an operating day may be higher or lower than forecast the day prior, committing to price and quantity amounts a day ahead shields participants from volatile price changes due to unanticipated events. With their use of bids to determine pricing, day-ahead markets also encourage least-cost energy dispatch, providing financial benefits to participant customers. Because day-ahead markets provide visibility of regional conditions and provide for day-ahead unit commitment scheduling, they also work to increase system reliability.

EDAM and Markets+ are currently developing key features of their design. Considerations that will be key in evaluation of Grant PUD's decision to participate in new markets include seams issues between markets and balancing authorities, associated resource adequacy requirements, greenhouse gas accounting including coordinated greenhouse gas pricing signals, and market governance issues.

The roster of a market's participants is also important to Grant PUD's decision to join a market because market efficiency and resulting energy prices are based on participant's loads and participant's resource portfolios, as well as the transmission availability between loads and resources. Figure 6 shows the current footprints of expected market participation for both EDAM and Markets+. Development is ongoing and neither of these markets is currently operable. EDAM is expected to begin onboarding participants in 2026 and WRAP is expected to launch in 2027. Ultimately, participation may be different than that depicted.

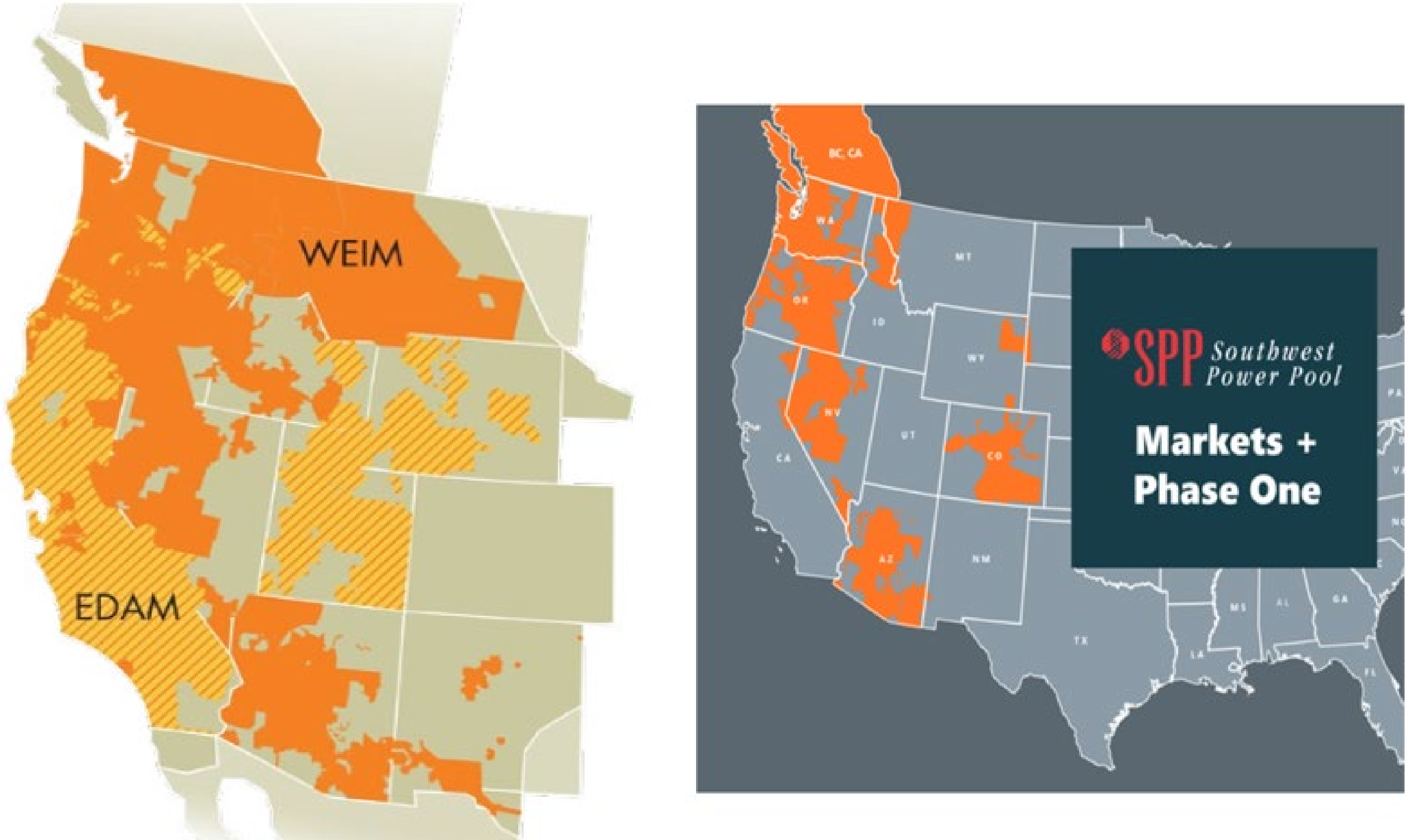


Figure 6. Map of current potential market footprints for CAISO EDAM and SPP Markets+, summer 2024 (California Independent System Operator, 2024), (Southwest Power Pool, 2024)

While we believe an integrated regional day-ahead market will deliver cost savings and enhanced reliability for the region, potential market footprints and proposed design features will impact the economic impact these new markets will have on Grant PUD. We will continue to monitor developments in both markets and incorporate likely participation in any future resource strategies.

With a limited view on how EDAM and Markets+ may develop in the future, for this plan we chose to evaluate an additional energy market price scenario, representing a potential for broad regional participation in new markets to result in a greater impact to wholesale prices than currently expected.

Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) is a region wide reliability program created through the efforts of regional stakeholders, acting through the Western Power Pool, to address resource adequacy concerns in the West. As the region adds increasing amounts of renewable resources, retires greenhouse gas emitting generation sources, as drought conditions persist across the region, extreme weather events increase, and as customer energy needs escalate, the region finds itself transitioning into a capacity-constrained system. WRAP is a planning and compliance framework designed to help ensure that, even under the most extreme conditions, western utilities have enough resources to provide service.

WRAP has two components, a planning exercise aimed at meeting established reliability metrics, called the forward showing, and an operations program through which participants with a demonstrated deficit can secure additional resources from other program participants. Currently, the program is operating in a “non-binding” mode during which program processes are followed on a voluntary basis, without any financial penalties for non-performance, and without obligation to provide resources to other participants through the operations program.

Most utilities in the Northwest conduct their own reliability studies. WRAP aims to augment individual utility practices by creating a centralized planning mechanism within the forward showing in which all participants use the same methods and analytically derived metrics to plan for the provision of reliable power across the region. During a forward-showing period, participating entities are called on to verify that they are doing their part to meet these established reliability metrics. Under "binding" participation in WRAP, penalties will be assessed if participants can't meet seasonal metrics.

There are many challenges that will need to be overcome for establishing the WRAP program, including increasing impediments to developing and interconnecting new capacity resources, acceleration of regional peak load growth, the large number and unique characteristics of utilities participating, and the interoperability of WRAP with EDAM and Markets+ markets.

Grant PUD is actively participating in the design and implementation of WRAP and using this effort to better understand and design its own resource adequacy response.

In recognition of Grant PUD's participation in and support of the WRAP, as well as the need to ensure an adequate and reliable energy supply, we use WRAP-based planning reserve margins and capacity valuation of supply resources in the development of this resource plan.

Regional Load Growth

Regional demand for electric power is growing. New data center development and electrification are pushing anticipated load growth higher than that seen in the last few decades and higher than recently forecasted. In their "2024 Northwest Regional Forecast of Power Loads and Resources, August 2024 through July 2034", the Pacific Northwest Utilities Conference Committee (PNUCC) predicts a regional 10-year annually compounded load growth of 3.1%. This anticipated growth is markedly higher than the 0.9% annual growth predicted by PNUCC in 2022 and the 2.4% growth predicted just a year ago (Pacific Northwest Utilities Conference Committee, 2024). Figure 7 shows the history of PNUCC load growth forecasts from 1980 through 2024. Each data point represents the five or ten-year average annual growth rate for a given year's Northwest Regional Forecast. Please note that 1997 – 2005 forecasts were five-year projections only.

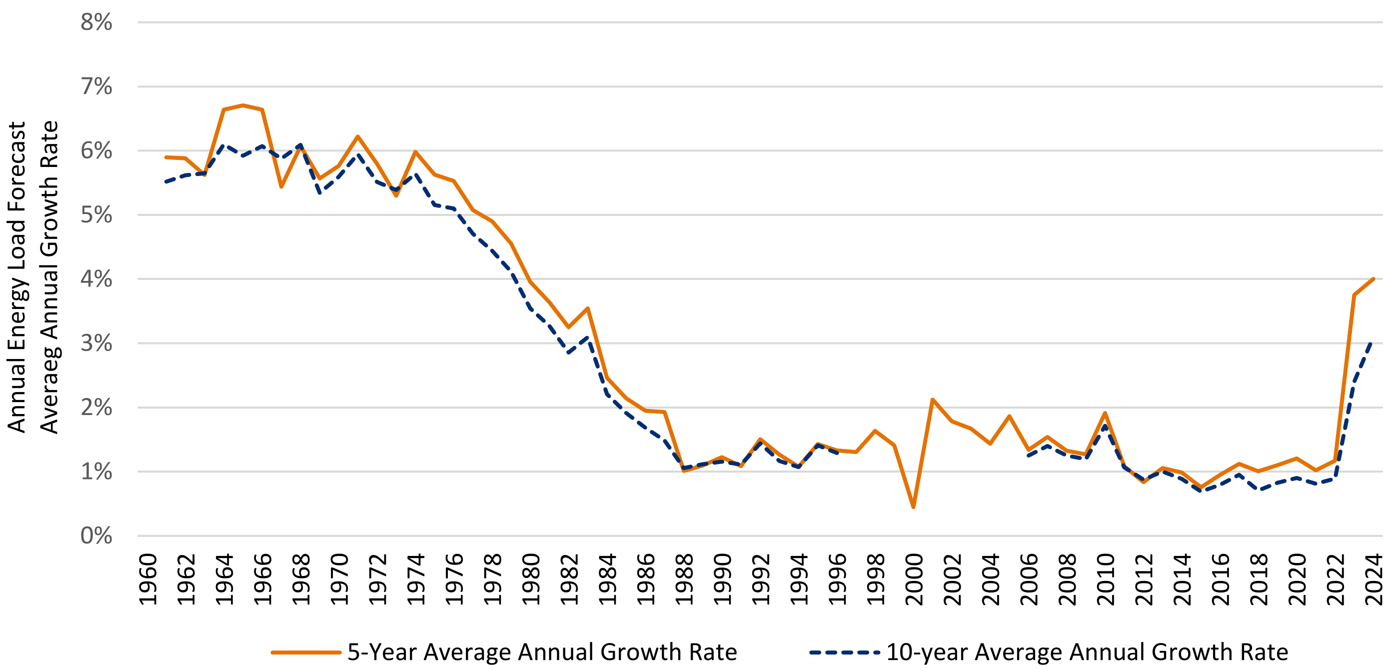


Figure 7. Pacific Northwest Utilities Conference Committee Load Growth Forecast History, 1980 – 2024 (Pacific Northwest Utilities Conference Committee, 2024)

While PNUCC forecasts represent expectations only, these expectations are created from an aggregation of participating utility's forecasts. We expect these utilities to base decisions on and take actions from their portions of this forecast.

The increase in expected load growth is somewhat surprising considering that in 2020 the Northwest Power and Conservation Council (NWPCC) stated in conjunction with the formulation of their 2021 Northwest Power Plan, that "Demand for electricity in the Northwest is expected to remain low over the next 20-30 years…." (Winkel, 2020) However, the NWPCC has since updated its 5-year hourly load forecast with higher loads than used in their 2021 Power Plan noting that this increase is in part driven by the industrial sector, data centers, and chip manufacturing (Northwest Power and Conservation Council, 2024).

This surprise in load growth expectations is also seen in the 2020 report from the Washington State Department of Commerce to the State legislature, summarizing and analyzing utility resource plans. Their "Washington State Electric Utility Resource Planning Report" states "The statewide aggregate load growth in electricity demand for 2026 and 2031 is expected to be moderate, and most of this growth will be offset through energy conservation programs operated by utilities." (Washington State Department of Commerce, 2020) If utilities now expect a growth period for customer electric demand, they will need to pivot quickly but deliberately to acquiring new generating resources.

Contributors to Regional Load Growth
Data centers, housing computer servers and network equipment, are one of the fastest growing industries worldwide, and with this rapid expansion may come rapid growth in associated energy needs. (Electric Power Research Institute, 2024) (Baxtel, 2024) Statista reports that there are currently about 5,380 data centers, housing computer servers and network equipment, in the U.S. as of March 2024. (Statista, 2024)

Regionally there are clusters of data centers with facilities located near Prineville, Portland, The Dalles, and Boardman in Oregon, near Quincy and Seattle in Washington, and near San Francisco and Los Angeles in California. (The Economist, 2012) The Washington Technology Industry Association (WTIA), in their January 2022 report on the impact of data centers in rural Washington writes that "rural Washington has become a hub of data center investment due to the Washington state sales and use tax exemption for data centers in rural counties" and that "the largest investments have occurred in Grant and Douglas counties, where thriving industry clusters have emerged." (Association, 2022)

The number and size of data centers is expected to increase in response to growth in data processing, internet traffic and artificial intelligence (AI) applications. In their 2024 white paper on "Powering Intelligence, Analyzing Artificial Intelligence and Data Center Energy Consumption", the Electric Power Research Institute (EPRI) forecasts data center energy use growth to rise from approximately 152,120,846 MWh annually in 2023 to between 196,305,818 MWh and 403,906,136 MWh in 2030 depending on future technology advancements and computational demands. (Electric Power Research Institute, 2024)

As the region experiences data expansion, it will also experience growth in energy demand. The following three graphs show EPRI's projections for electricity consumption from data center loads in Oregon, California, and Washington. These states are included in the 15 states with the highest data center demands in 2023. Each graph includes projections given low, moderate, high, and higher load growth scenarios for 2030 as well as actual values for 2021, 2022 and 2023.

Given a moderate growth rate of 5%, EPRI predicts that Oregon will go from data centers using 11.4% of its total electricity consumption in 2023 to using 14.4% in 2030.

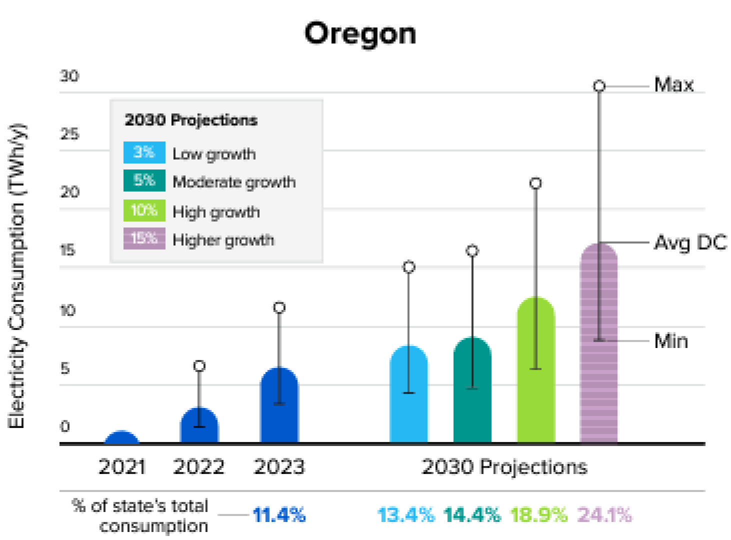


Figure 8. Oregon data center energy consumption, 2021 - 2023 history and EPRI 2030 projections, TWh per year (Electric Power Research Institute, 2024)

California and Washington can expect similar increases, going from 3.7% to 4.8% and 5.7% to 7.3% respectively.

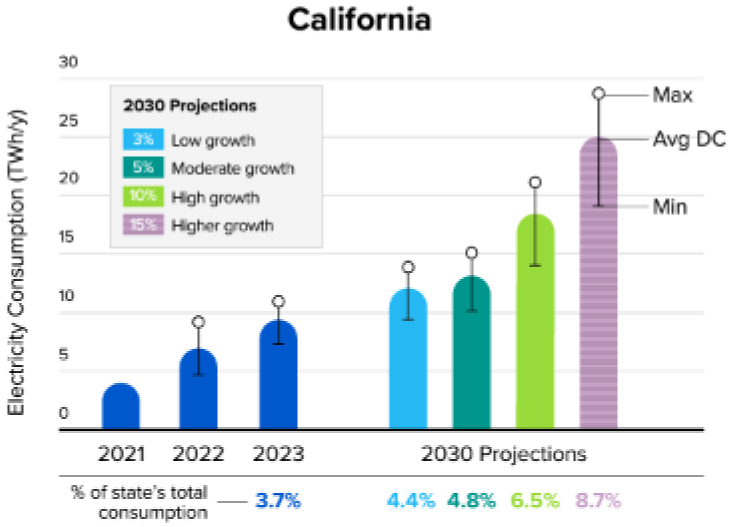


Figure 9. California data center energy consumption, 2021 - 2023 history and EPRI 2030 projections, TWh per year (Electric Power Research Institute, 2024)

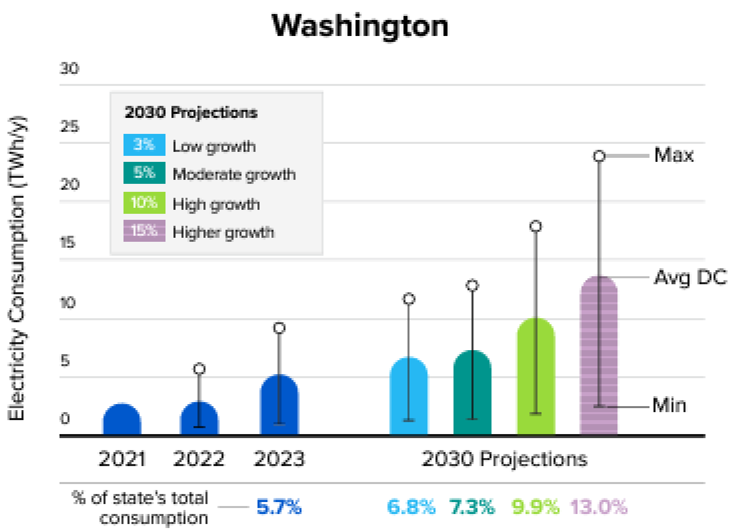


Figure 10. Washington data center energy consumption, 2021 - 2023 history and EPRI 2030 projections, TWh per year (Electric Power Research Institute, 2024)

Artificial intelligence (AI) has been in use for quite some time, with the phrase itself coined in the 1950s. (Anyoha, 2017) The release of ChatGPT in November 2022 launched a new era of the Artificial Intelligence boom. (Rotman, 2023) As AI works itself deeper into our daily lives, the potential for increasing energy demand grows. (Leffer, 2023) AI uses large amounts of energy because of the training required by AI models, the models' complexity which requires computational power, the large data sets involved, multiple tasks performed by generative models. (Berreby, 2024) It remains to be seen what impact increased use of AI will have on regional data center growth and energy requirements, but AI is a factor that regional utilities are monitoring as they forecast future load requirements.

Electrification is also a key component of regional load growth. Transitioning space and water heating, appliances, industrial processes, and transportation from fossil fuels to electrically powered sources could significantly affect the electric needs of the region.

As part of the Infrastructure Investment and Jobs Act (IIJA) and IRA, billions of dollars are available for electrification projects (117th Congress, 2021), (117th Congress, 2022). These pieces of Federal legislation, along with state legislation, provide tax credits and rebates to support electrification efforts including transitioning to heat pumps, electric water heating, and efficient electric appliances. Recent updates to Washington state building codes require installation of electric heat pumps for space and water heating in most new commercial buildings and multifamily residences with four or more floors. (DiChristopher, 2022) In Oregon, House Bill 3409, passed in 2023, sets a goal of at least 500,00 new heat pump installations by 2030 and directs creation of programs to support this goal. (Oregon State Legislature, 2023)

The adoption of electric vehicles is beginning to have a noticeable impact on electricity use. As shown earlier in Figure 5, more and more electric vehicles are being driven and fueled. Data from the EIA in Table 3 shows that the Pacific region of the U.S., defined as Washington, Oregon, and California, requires more electricity to fuel light-duty electric vehicles than any other region of the U.S. and that vehicle electric consumption is growing. (U.S. Energy Information Administration, 2024)

Table 3. Estimated annual regional consumption of electricity by light-duty vehicles, 2018 – 2023, megaWatt hours

Region	2018	2019	2020	2021	2022	2023
New England	62,275	87,619	124,522	156,907	247,568	356,732
Middle Atlantic	119,930	172,717	240,008	305,618	511,312	766,430
East North Central	130,271	162,974	221,420	272,690	443,486	623,240
West North Central	45,346	62,614	86,650	109,121	178,067	251,580
South Atlantic	182,531	241,810	363,587	483,500	781,219	1,174,938
East South Central	22,830	29,805	44,832	57,719	96,019	137,687
West South Central	74,670	94,763	140,531	189,618	331,944	521,609
Mountain	106,703	150481	223479	282179	446133	668065
Pacific	**821,296**	**1,037,850**	**1,427,814**	**1,629,783**	**2,173,282**	**3,038,984**
Alaska & Hawaii	15,854	19,241	27,457	31,662	42,751	56,248
U.S. Total	**1,581,706**	**2,059,875**	**2,900,300**	**3,518,797**	**5,251,782**	**7,595,513**

While new EVs may have lower costs to own over their useful life than similar gas fueled vehicles, their higher initial cost remains a barrier to increasing adoption. (Harto, 2020), In May 2024, Kelley Blue Book reported average cost of new EVs to be about $56,600 while the average cost of all new vehicles was notably lower at about $48,400. (Kelley Blue Book, 2024) However, EV purchase costs are currently trending down, which, if sustained, could lead to wider adoption. (Cox Automotive, 2024)

In addition to federal incentives, most states offer additional incentives for purchasing electric vehicles. Regionally, California offers rebates for plug-in hybrid and zero emission light duty vehicles, an all-electric vehicle rebate, and the City of Los Angeles offers a used electric vehicle rebate. Oregon offers rebates on the purchase of a new or used electric vehicle, including electric motorcycles, while Washington offers a retail sales and use tax exemption for certain alternate fuel vehicles, including those powered by electricity. (U.S. Department of Energy, Energy Efficiency & Renewable Energy, 2024)

A recent study by the Pacific Northwest National Laboratory (PNNL) determined that at higher levels of EV penetration in WECC, there may be increases in transmission congestion associated with delivering additional power to load centers, changes to dispatch of generation resources, increases in electric production costs, and opportunities to manage these impacts through managed charging strategies. As a region, we will need to remain cognizant of this growing source of electric demand. (Pacific Northwest national Laboratory, 2020)

Though Grant County may not be affected directly by all factors of regional load growth or affected to the same degree as other areas, increasing energy demands serve to further constrain the market of available energy. With much of Grant PUD’s energy supply coming from regional resources outside of its own resource portfolio, these factors of load growth will be felt by its customers.

Regional Resource Mix Transition

To meet anticipated growth in demand and ensure a sufficient and reliable supply while working toward clean energy goals, regional utilities will need to add an increasing number of new resources creating a shift in the region's mix of resource technologies. (Northwest Power and Conservation Council, 2023) The shift in resource mix will change the way the grid operates and how utilities in the region transact power with one another.

Figure 11 shows the share of existing nameplate capacity by fuel type for the region as compiled in PNUCC's 2024 Northwest Regional Forecast. (Pacific Northwest Utilities Conference Committee, 2024)

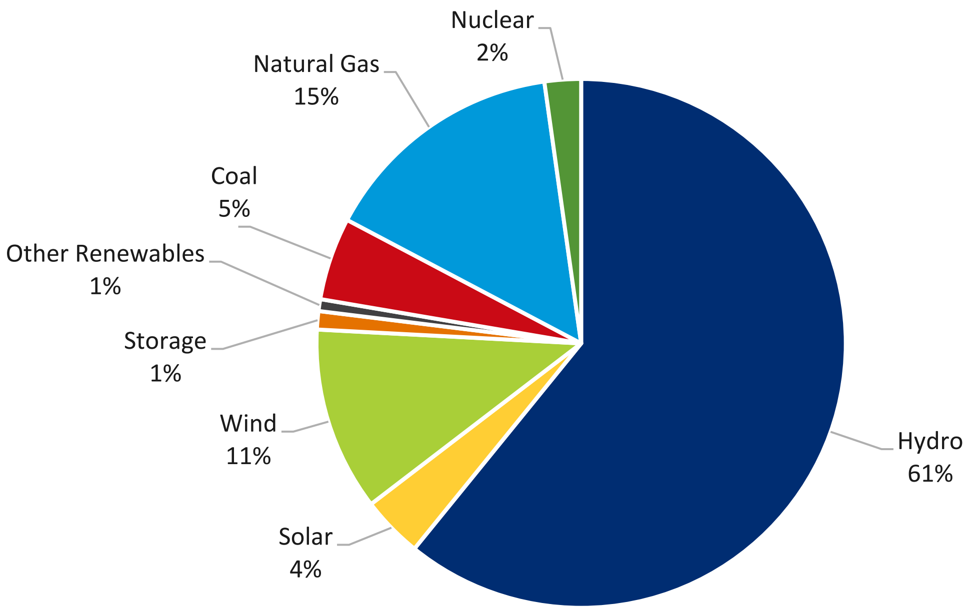


Figure 11. Current regional percentage of total nameplate capacity by technology type (Pacific Northwest Utilities Conference Committee, 2024)

Hydroelectric power is currently the dominant generating resource in the region and reliance on hydropower has kept the region's power costs low in comparison with other regions of the country. (U.S. Energy Information Administration , 2024) However, with no opportunities to develop additional hydropower resources, new regional capacity must come from other resource types.

29 states have renewable portfolio standards (RPS) and 23 states, plus the District of Columbia and Puerto Rico have 100% clean energy standards, setting targets for controlling greenhouse gas emissions now and into the future. (Barbose, 2023), (Alliance, 2024)

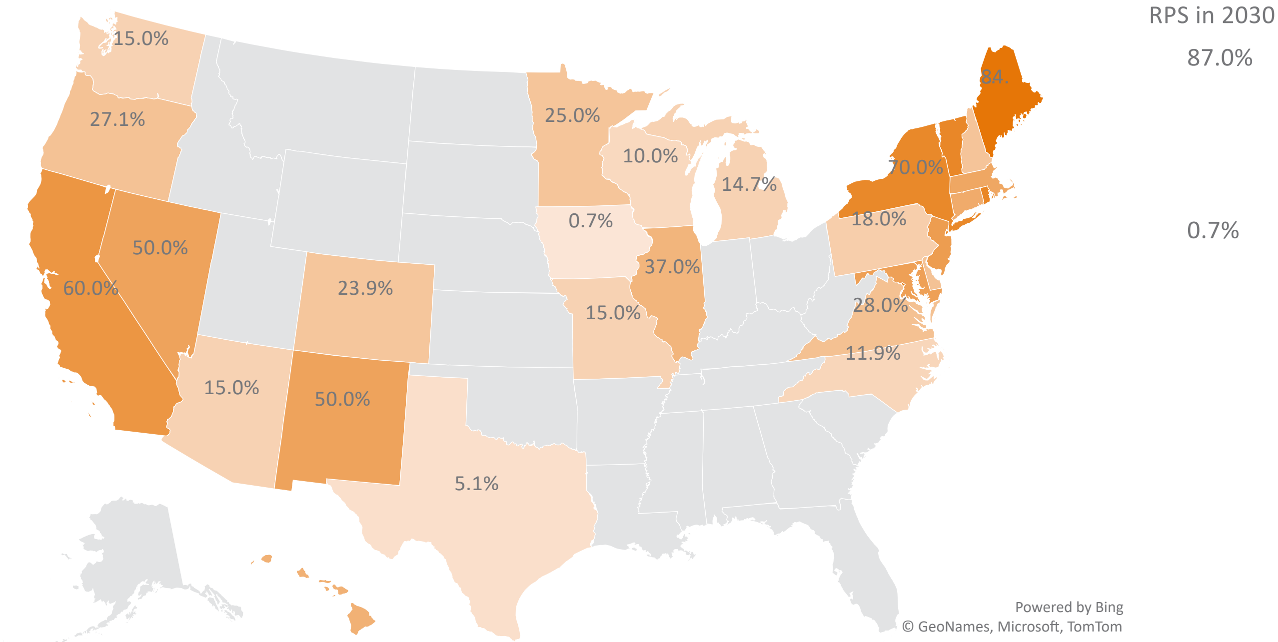


Figure 12. States with renewable energy standards as of June 2023 , as percent of load (Barbose, 2023)

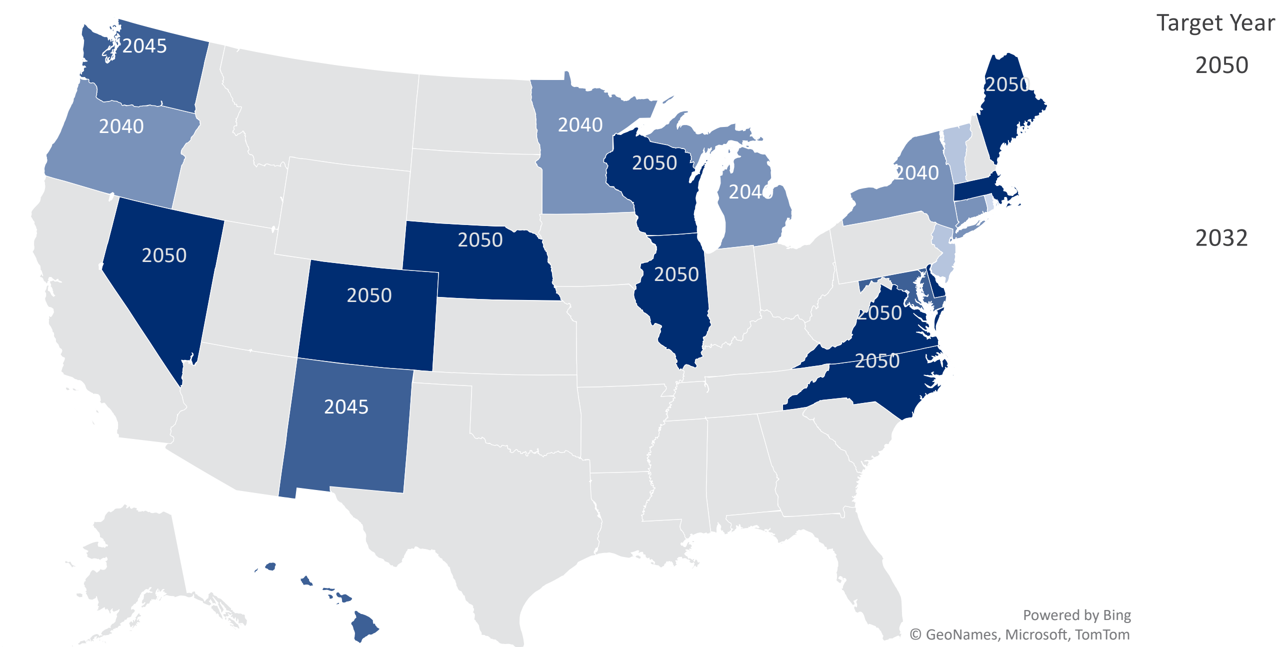


Figure 13. States with clean energy standards as of 2024, target year for 100% clean energy (Alliance, 2024)

Washington, California and Oregon have set clean energy standards that will heavily influence the selection of future generating resource additions. These states have legislated requirements for substantial decreases in greenhouse gas emissions from electricity production by 2030 and all three will eventually require no greenhouse gas emissions from production of electricity sold to consumers. Washington and California are targeting zero-emissions by 2045 and Oregon by 2040. Accomplishing these goals will necessitate a resource shift to non-emitting, non-dispatchable, variable energy resources like solar and wind.

The costs of building clean energy resources are declining. Figure 14 shows average construction costs as collected by the EIA for the years 2016 through 2021, the last year in their dataset.

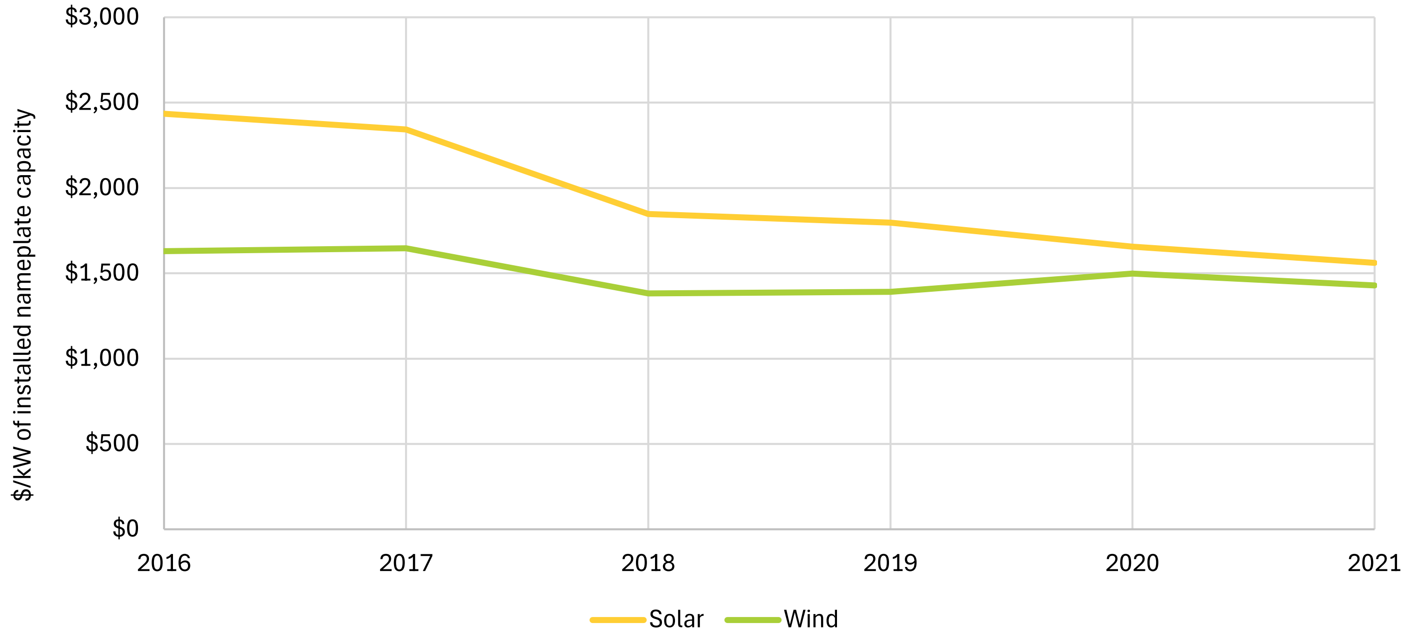


Figure 14. Average construction cost of utility scale electric generators, solar and wind, 2016 – 2021, $/kW (U.S. Energy Information Administration , 2023)

Declining construction costs, paired with federal and state incentives to build and use clean energy resources makes these technologies more appealing and accessible. Increased use of these variable energy resources is also resulting in an increase in addition of storage technologies (U.S. Energy Information Administration, 2023). Utility scale battery storge installations could possibly double in capacity value in 2024 as compared to just a year ago and states with the fastest growth of solar and wind resources account for the majority of new battery storage additions.

While hydropower capacity could be increased through optimizing existing facilities and pumped storage hydro could add to energy storage capabilities, new hydropower increases would be difficult due to lack of suitable sites (U.S. Department of Energy's Water Power Technologies Office, 2024).

Natural gas fueled resources face strong challenges for future development. Though natural gas produces about half the amount of CO_2 emissions when burned as compared to coal, it accounts for about twice as much of the electricity generated in the U.S. (U.S. Environmental Protection Agency, 2024). Reducing its use is a prime target for efforts to reduce greenhouse gas emissions. It will be impossible to meet clean energy mandates, including Washington's CETA, while maintaining current levels of natural gas fueled generation sources. Though the dispatchability and capacity value of gas fueled electric generation would be beneficial in integrating an increased level of variable resources, including wind and solar, its continued use and development is in opposition to current clean energy goals.

Because of clean energy goals, cost decreases, and available resource development potential, regional utilities are anticipating the shift to clean energy resources. Figure 15 shows the expected nameplate capacity of the region in 2034 as compiled in PNUCC's 2024 Northwest Regional Forecast. This forecast projects regional nameplate capacity to grow by nearly 29,000 MW in the next ten year, an increase of about 50% over current values.

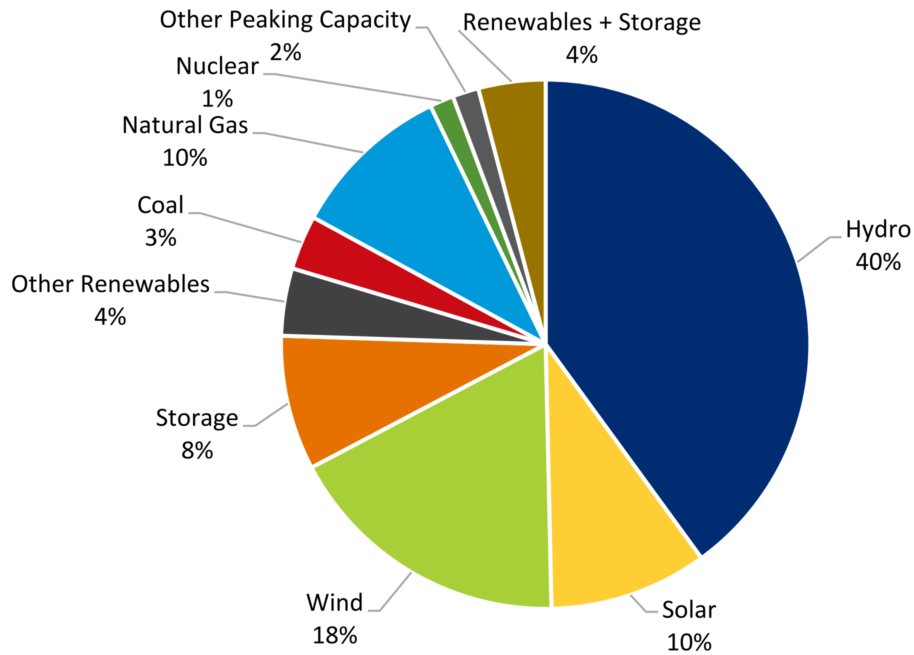


Figure 15. Forecast 2034 regional percentage of total nameplate capacity by technology type, self-reported by Northwest utilities and BPA (Pacific Northwest Utilities Conference Committee, 2024)

The majority all of the anticipated increase in name plate capacity is obtained through addition of wind and solar resources with a resulting decrease in the share of resources that have traditionally been used to serve the bulk of the load in the region, hydropower and natural gas. Hydropower's share of the total decreases by nearly 20% and natural gas by 5% while the share of renewables and storage increases by a substantial 27%. This significant shift in resource mix is predicted to occur over the course of only 10 years.

Table 4. Forecast increase in nameplate capacity by technology type, 2024 - 2034, self-reported by Northwest utilities and BPA, MW, (Pacific Northwest Utilities Conference Committee, 2024)

Resource Type	Nameplate Capacity Increase
Solar	6,063
Wind	8,625
Storage	6,304
Renewables plus Storage	3,450
Unspecified Renewables	3,066
Unspecified Peaking Capacity	1,349
Total	28,856

PNUCC's 2024 Northwest Regional Forecast show the region is poised to move away from dispatchable, high-capacity factor resources toward lower capacity factor, non-dispatchable resources. While operational capacity factor is different from peak available energy production, it is a measure of a generators contribution to serving energy needs. Lower capacity factor generators using intermittent fuels, such as solar and wind, can negatively impact electric supply during times at which their fuel is unavailable. Lower capacity resources can also lead to higher electric costs as operators must cover fixed costs with a reduced volume of energy sales. Figure 16 illustrates the range of average capacity factors over different generator types.

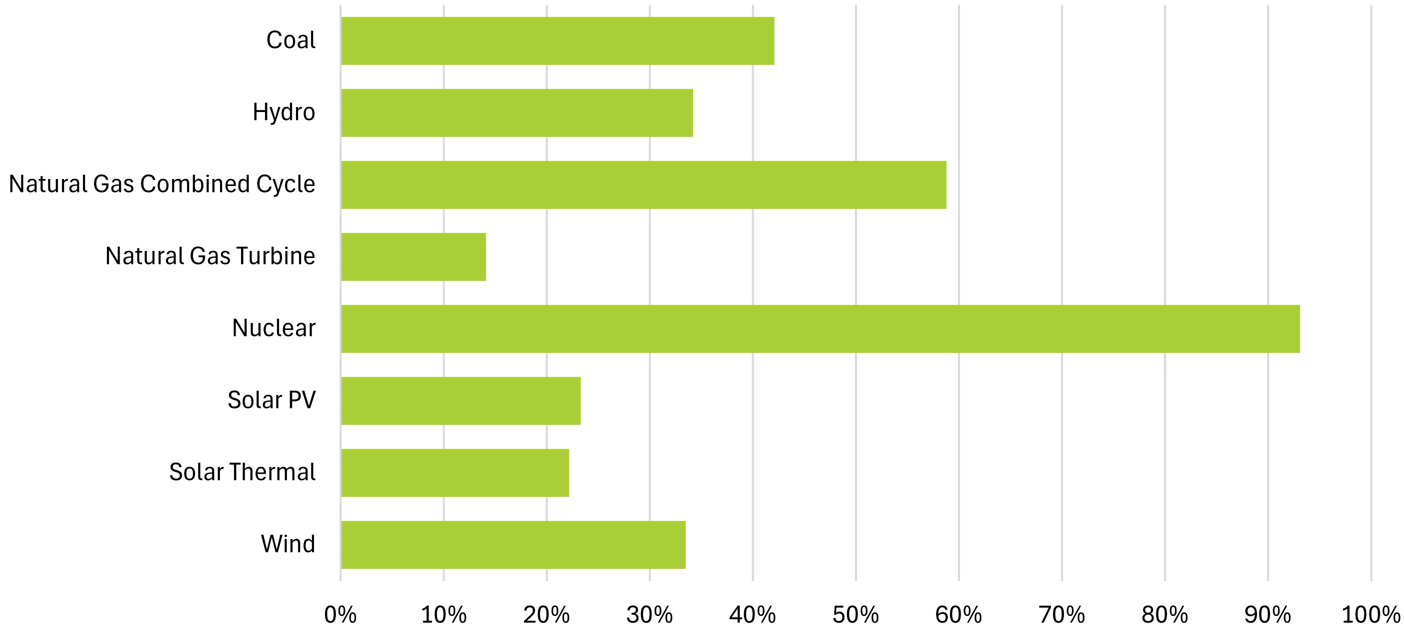


Figure 16. Average capacity factor of utility scale electricity generation in the U.S., 2023, by technology type (U.S. Energy Information Administration, 2024)

Nuclear plants have the highest factors due to their ability to operate continuously for long periods before requiring refueling or maintenance. Coal and natural gas plants have relatively controllable fuel supplies but require more downtime for maintenance than nuclear plants. Gas turbines capacity factors are lower than combined cycle units due to their normal use as peaking plants, operating when electricity demand is highest. Solar and wind plants have lower capacity factors due to the periodic unavailability of their fuel supply. Similarly, hydro plants are dependent on the availability of their fuel.

The findings of PNUCC's 2024 Northwest Regional Forecast are consistent with information revealed in recent requests for proposals (RFP) issued by regional utilities. Puget Sound Energy has issued a 2023 RFP for 85 MW and 25 MW of solar and storage and a 2024 RFP for 30 MW and 29 MW of solar and storage (Puget Sound Energy, 2024). Earlier this year, Portland General Electric issued an RFP to procure approximately 753 MW of renewable resources for its cost-of-service customers and an additional 100 MW of renewable resources for its supplied option of the Green Energy Affinity Rider (Portland General Electric, 2024). In 2023 Seattle City Light issued an RFP looking for between 35 MW and 200 MWs of capacity citing its current status of sourcing primarily from carbon emission free resources (Seattle City Light, 2023). Grant PUD's own recent RFP, while not specific to clean energy resources, received proposals that were almost exclusively from clean energy technologies (Grant PUD, 2023).

We anticipate that a change in the region's resource mix, specifically an increased presence of clean energy variable resources, will have significant impacts on Grant PUD's trading with external parties. An increased reliance on variable resources means that shortages and surpluses of energy could vary considerably within a day and across seasons. This will impact prices for both buying and selling power (Seel et al. 2021). California has already seen a significant depression in daytime prices and an increase in evening prices due to the large buildout of solar resources (Energy Information Administration, 2023). With the anticipated large buildout of wind and solar resources in the region, similar pricing dynamics are likely to manifest across the region.

ENERGY DEMAND IN THE GRANT PUD SERVICE AREA

Demand for electricity has significantly accelerated in Grant County. This trend is expected to continue well past 2030 and is the result of many of the same forces driving demand in the region and across the United States. The factors driving this growth include public-policy driving electrification, data center growth, and the reversal of globalization for industrial and manufacturing business.

Forces Driving Grant PUD Customer Demand

Federal and state decarbonization policies are mandating electrification in some instances and incentivizing it in others. Industries benefiting from Federal support through development incentives are looking for sites for facility expansion; this includes all industries supporting the manufacture of solar panels, battery storage, and wind turbines. Many of these industries are finding locations in rural Washington, including Grant County, where land and construction costs are favorable. Grant County also has existing industrial customers that can quickly expand their operations in response to demand. As these industries grow and develop in Grant County, so do their needs for electricity.

Washington State's environmental policies prompt its citizens to move away from natural gas and toward the use of electricity for heating, cooking, and other household uses. Additionally, added costs associated with CCA greenhouse gas emission allowances have increased costs to all natural gas consumers, forcing some industrial businesses using natural gas in their production processes to switch to electricity in lieu of raising their prices or moving to less costly locations. While these switches may directly impact electricity customers outside Grant County more than Grant PUD customers, the cost of serving new and increasing loads with new carbon free resources will increase costs non-uniformly across the larger region. These cost increases will impact Grant PUD customers through increased cost of wholesale market energy or resource acquisition.

Federal *Buy America* programs are increasing demand for U.S. manufactured goods and services, driving demand for new industrial development across the nation. This is fueling demand for industrial electricity for some existing industrial customers and is helping to attract new customers to Grant County. Grant County is a prime site for new industrial development similar to what has occurred in the Tri-Cities of Kennewick, Pasco, and Richland. Commonalities between the Tri-Cities and Grant County include access to major highways, affordable electric rates, lower-cost land, and inexpensive labor.

The net effect of incentives given to carbon-free capacity manufacturers, climate-related public policies, and the drive to protect U.S. manufacturing is leading us towards a rapidly expanding regional demand for power. The jobs resulting from expanding industrial load will simultaneously increase the demand for core residential and commercial power as new homes, apartment complexes, and businesses are built.

Customers are attracted by Grant PUD's competitive electric rates, advantageous location, and potential for green energy supply. Large-load customers have communicated that their current and future energy demands are sensitive to market pressures, including the cost of energy and environmental and social goals. Maintaining competitive rates is critical to both retaining existing Large-load customers and attracting growth in the sector.

Customers are also sensitive to power quality including voltage, harmonics, and outage frequencies and durations. While Grant PUD does not guarantee a particular quality of power delivered to its customers, power quality is a factor in determining customers' overall satisfaction with delivered energy. Data centers and other customers with high inductive loads, such as large motors, are particularly demanding. These customers are high load factor power consumers, with consistent high-quality power availability being critical to their operational success. We realize that any plan crafted to meet customer needs in the future must consider resource capacity factors, as well as reliability and deliverability characteristics.

Price, reliability, and deliverability to the fastest growing rate classes introduces significant potential risk in the variability of the load forecast used in this IRP. We have reviewed potential risks associated with load uncertainty, will continue monitoring the expectations of customers, and will incorporate these concerns into our long-term planning. Understanding the forces currently driving customer energy demand, and anticipating future trends, is key to deriving our plan to meet those needs.

Customer Requirements

Grant PUD's load-serving policies are driven by its customers' use of power. The next several figures illustrate use-driven load profiles for customers who use power in significantly different ways. Customers' average daily use is shown in orange while 15-minute incremental use, showing variation around this average, is shown in blue.

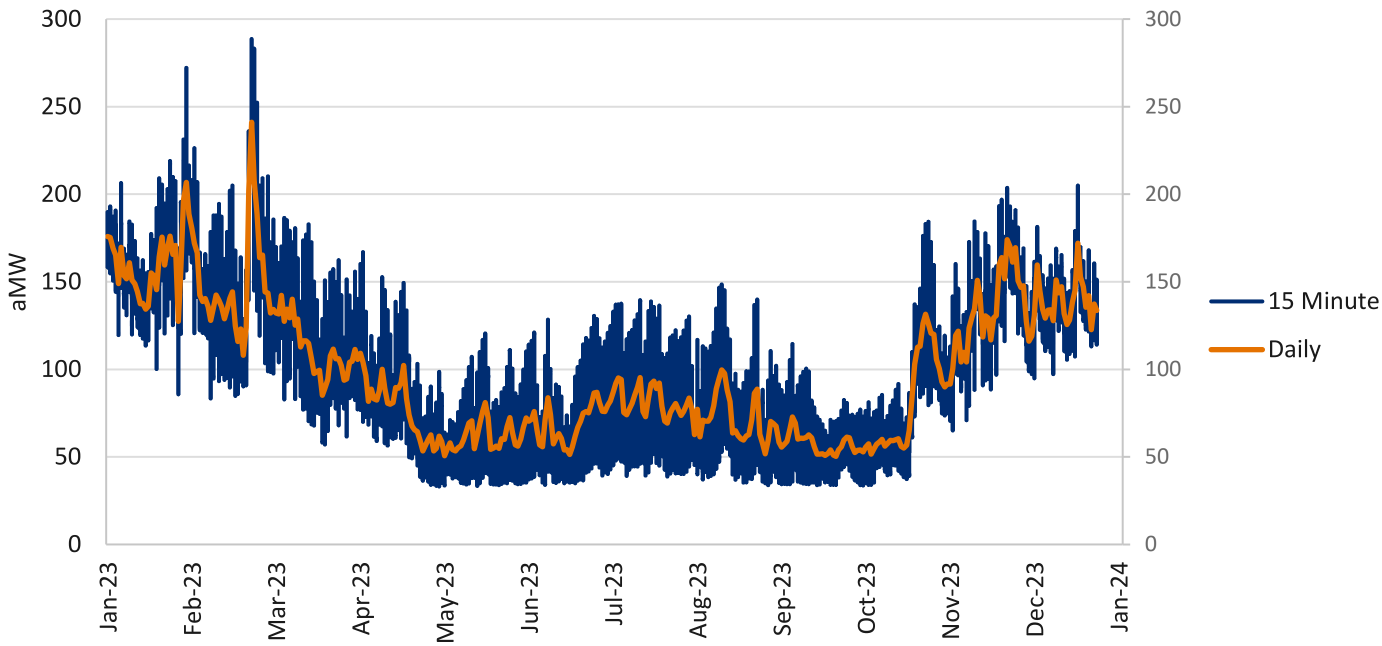


Figure 17. Residential 15-minute and daily energy consumption, 2023, aMW. Total usage: 865,903 MWh, 98.8 aMW

Residential loads, shown in Figure 17 are higher during the winter months and lower during the summer months. This is due to differing demand for heating during the winter months versus cooling during the summer months. Figure 17 shows in the variation of the 15-minute use values from the daily average that residential customers need more generation capacity throughout the day and year than their average use indicates. Grant PUD must have more generation capacity, and provide more energy, to serve these loads from moment to moment than these customers consume on average.

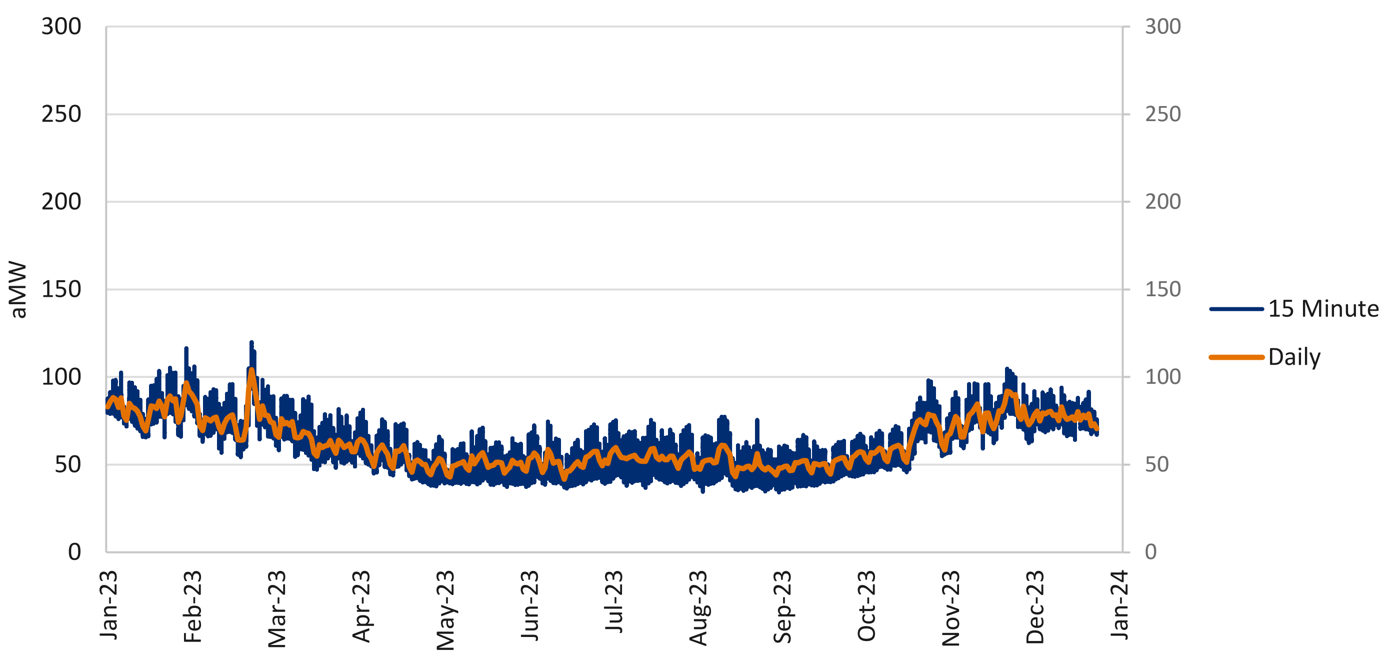


Figure 18. General Service 15-minute and daily energy consumption, 2023, aMW. Total usage: 548,409 MWh, 62.6 aMW

General service customer loads shown in Figure 18 also show higher demand during winter months and lower demand during summer months, though with less seasonal variation than residential loads. Less capacity is necessary to be held in reserve to serve general service customers because their loads are more consistent from hour to hour.

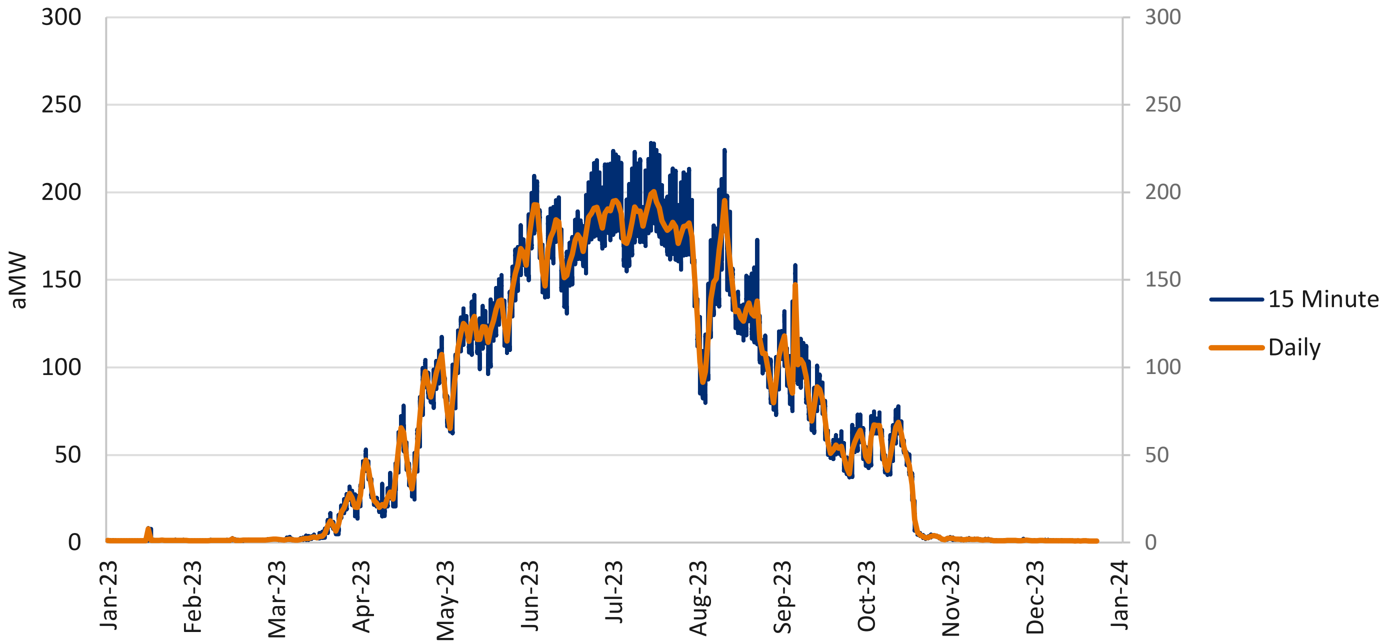


Figure 19. Irrigation 15-minute and daily energy consumption, 2023, aMW. Total usage: 585,780 MWh, 66.9 aMW

Grant PUD's irrigation customer loads are shown in Figure 19 These loads show a clear seasonal pattern with no load during the winter, increasing loads starting late March, a leveling off by mid-June, and then decreasing loads by mid-August. The capacity that is held in reserve to serve these customers is greatest during the hottest time of the year with hot windy weather from moment to moment reflected in varying demand.

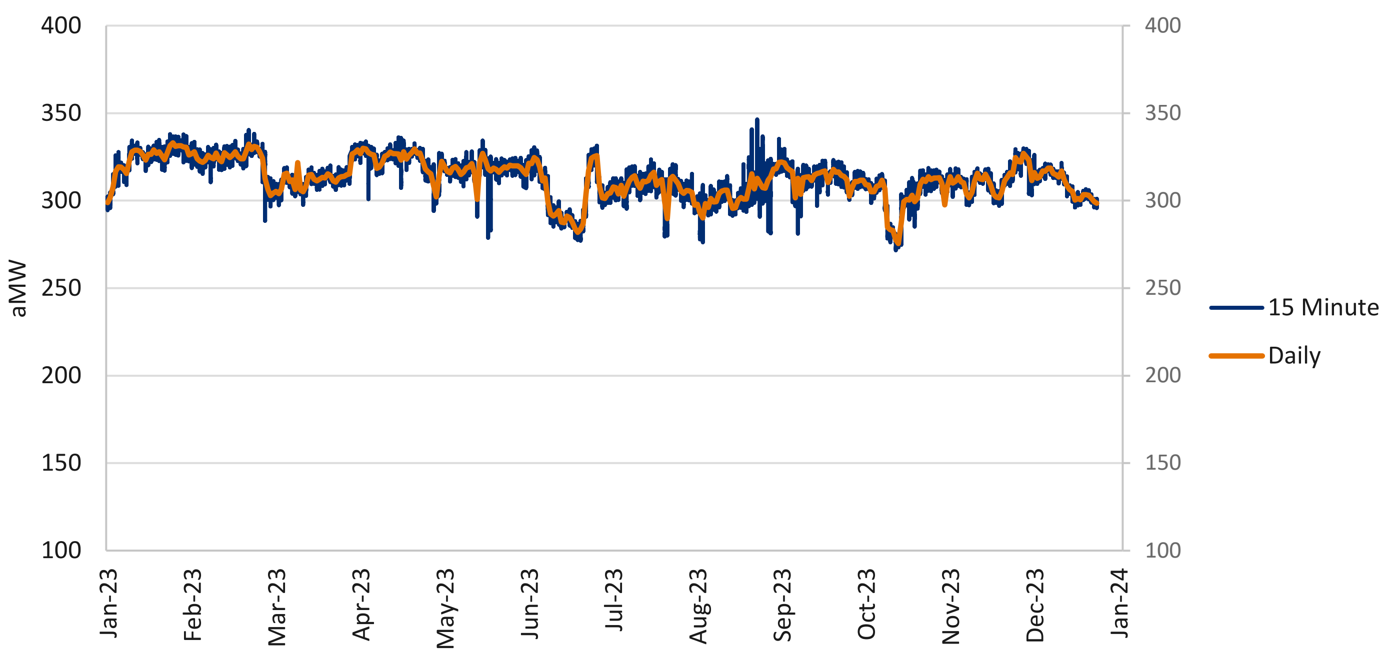


Figure 20. Large Industrial 15-minute and daily energy consumption, 2023, aMW. Total usage: 2,742,137 MWh, 313.0 aMW

Grant PUD industrial customers' loads shown in Figure 20 are reasonably constant so do not require nearly as much capacity to be held in reserve as do the other loads presented in this section. The fact that these loads possess high and stable load factors make them relatively easier to manage.

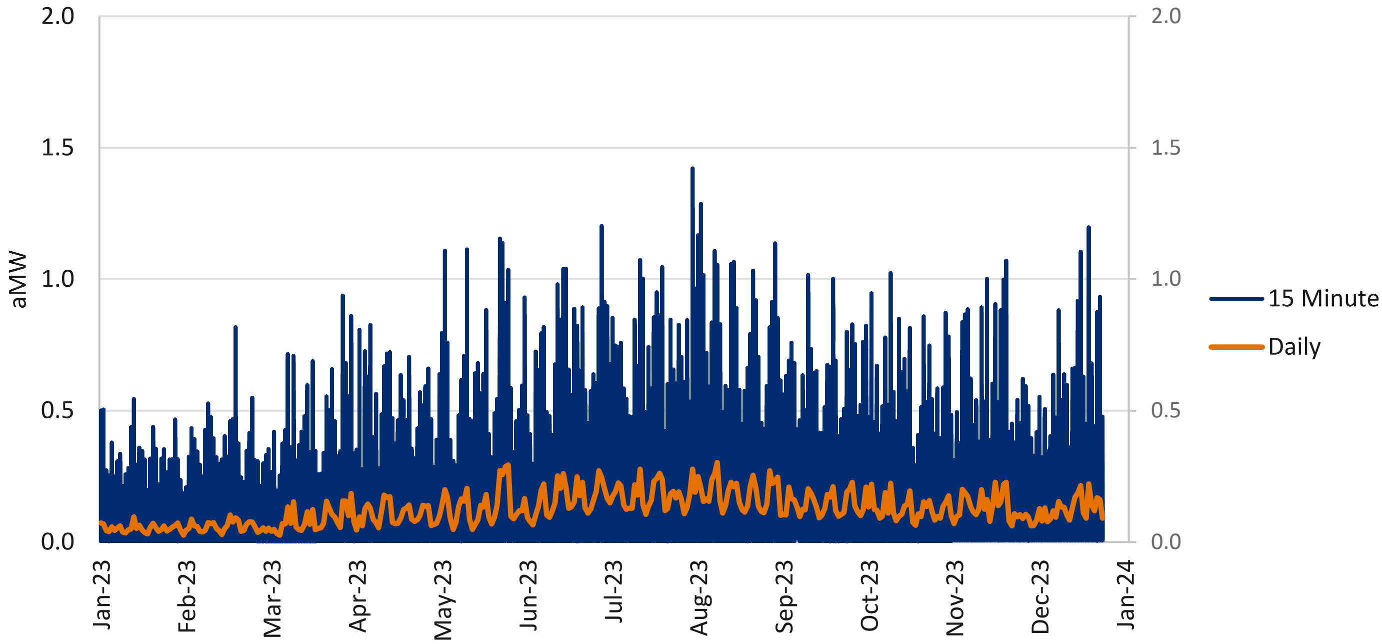


Figure 21. Fast Charging Electric Vehicle Service 15-minute and daily energy consumption, 2023, aMW. Total usage: 1,093 MWh, 0.1 aMW

Electric vehicle Level 3 charging station loads shown in Figure 21 require significant reserve capacity to meet their average energy needs. This type of charging station is known as "Fast Chargers" and are frequently associated with Tesla charging stations being set up throughout the U.S. The necessary reserve capacity margins needed to serve these stations are large, in some cases ten times the average energy used, making these loads the most expensive from the perspective of capacity required to be held in reserve to serve them.

Historic Customer Load Growth

For rate development, planning, forecasting and analytics Grant PUD categorizes its customers into the classes described in Table 5.

Table 5. Description of Grant PUD customer classes

Customer Class	Description
Residential	Single family dwelling, individual apartment, and farmhouse with single-phase service
Commercial	Loads not exceeding 500 kW for general service, commercial, multi-residential and miscellaneous outbuilding requirements and single-phase loads not exceeding 500 Watts
Irrigation	Irrigation, orchard temperature control, and soil drainage loads not exceeding 2,500 horsepower and other miscellaneous power needs including lighting
Streetlights	Street lighting
Large General	Loads not less than 200 kW or more than 5,000 kW demand for general service lighting, heating, and power requirements
Industrial	Industrial customers, with a distinction between demand less than or greater than 15 MW/MVA

Ag Food	Plants with primary purpose of processing, canning, freezing, or the frozen storage of, agricultural food crops with demand greater than 5 MW/MVA and less than 15 MW/MVA
Evolving Industry	Groups of customers in new industries or with emerging technologies or uses that present concentration risk and either business or regulatory risk. Cryptocurrency mining is classified as an Evolving Industry.
Ag Food - Boiler	Electric boilers which are separately metered and primarily used for the purpose of processing, canning, or freezing agricultural food crops
New Large Load	All New Large Loads, as defined by the District's Customer Service Policies: an increase of any load over 10 average MW of a customer's annual average load above the customer's highest annual average load since 2010.

These customer classes vary in the energy services they require as well as in the way their total energy consumption has changed over time. Grant PUD's historic customer loads from 1985 through 2023 are shown in Figure 22. As can be seen, total loads have grown considerably since the early 2000's due primarily to growing industrial loads, although residential, commercial, and large general loads have grown as well. This indicates increasing growth for the area's economy and may signify the potential for continuing economic maturation for Grant County. The ability of Grant PUD to stay ahead of the county's economic growth by skillfully deploying strategic growth initiatives will likely make a significant difference to the county's success.

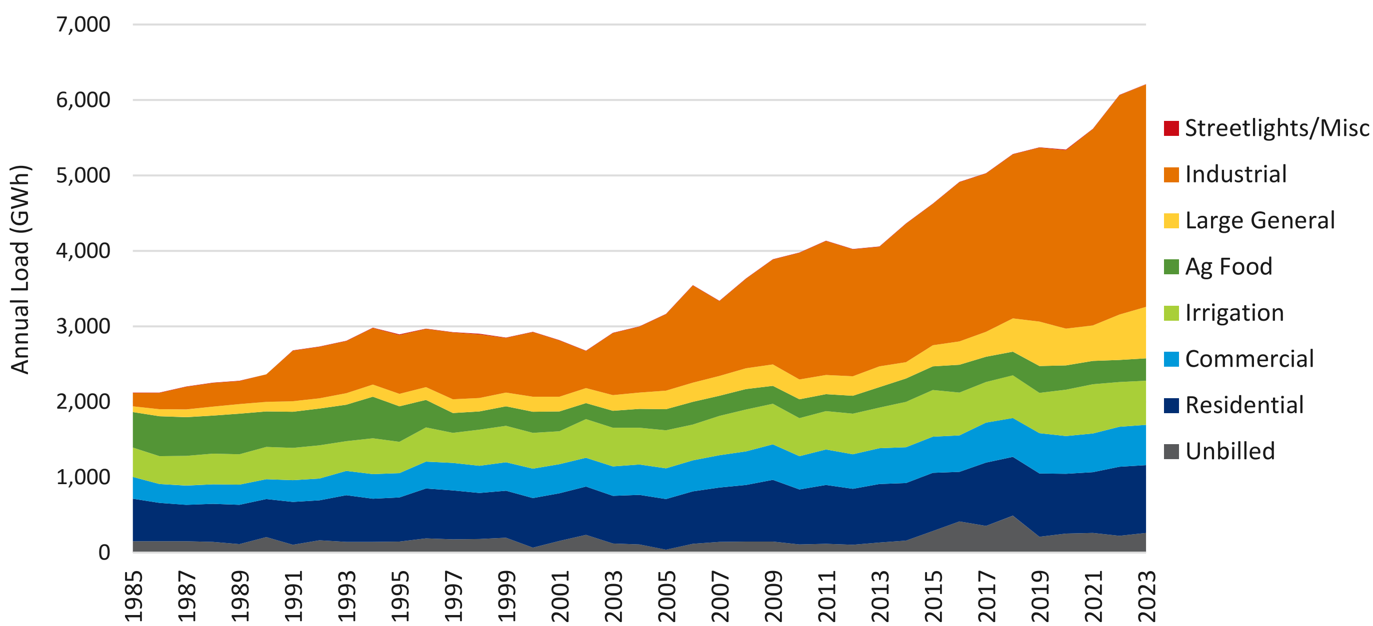


Figure 22. Grant PUD retail load by customer class, 1985 – 2023, GWh

Transitions in Load Share by Customer Class

The ten-year compound annual load growth varies materially between customer class as shown in Table 7. Residential loads have been growing at 1.5% with Commercial and Irrigation loads at 1.3% and 0.7% respectively.

Table 6. Grant PUD load growth by customer class, ten-year intervals

	10 Year 2013 - 2023		Prior 10 Year 2003 - 2013	
	CAGR	aMW	CAGR	aMW
Residential	1.5%	1.4	2.1%	1.6
Commercial	1.3%	0.7	2.0%	1.0
Irrigation	0.7%	15.5	0.5%	8.8

Ag Food	0.9%	0.3	1.9%	0.5
Large General	9.6%	4.7	2.7%	0.7
Industrial	6.4%	15.5	6.8%	8.8

This varying rate of growth has led to changes in the relative share of each customer class as a percentage of Grant PUD's total customer load. The following three figures show how each customer class's percentage of total load has changed in ten-year increments from 2003.

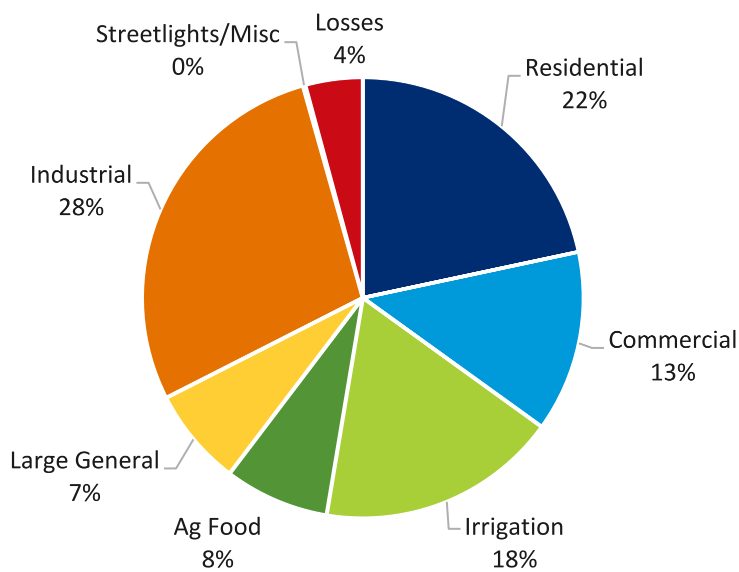


Figure 23. Grant PUD load by customer class, 2003, % of total

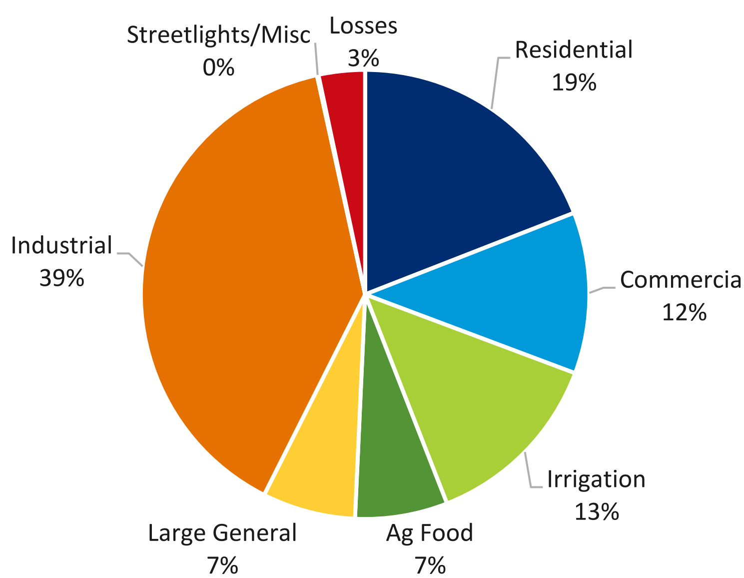


Figure 24. Grant PUD load by customer class, 2013, % of total

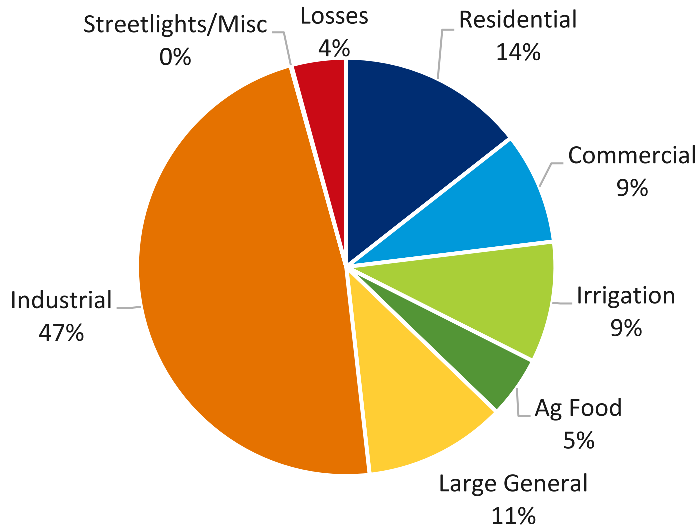


Figure 25. Grant PUD load by customer class, 2023, % of total

The progression in Figure 23, Figure 24 and Figure 25 shows the share of the core customer residential, commercial and irrigation loads transition from a 63% share twenty years ago to a 32% share today. Industrial loads have shown a converse trend, transitioning from a 28% share to a 47% share of total Grant PUD load. With a transitioning load mix, Grant PUD must remain aware of potentially changing goals, concerns and requirements of its customers and incorporate these into resource planning practices.

Snapshot of Large Load Customers

Table 6 shows Grant PUD's Large Load customer groupings by industry in 2021. By 2023, these Large Load customer groups represented over 60% of Grant PUD's total load, making planning for their requirements an increasing part of resource planning.

Table 7. Large Loads by industry, 2021

Industry	Average Number of Service Agreements	Load (aMW)	Average Size (MW)
Aerospace	4	1.65	0.41
Ag. Processing	65	48.17	0.74
Ag. Storage	12	10.93	0.91
Automotive	4	20	5
Cannabis	9	1.22	0.14
Chemical	6	46.27	7.71
Construction	8	0.4	0.05
Cryptocurrency	30	58.43	1.95
Data Center	18	267.61	14.87
Education	16	2.11	0.13
Electronics	1	26.29	26.29
Gas / Fluids	4	11.3	2.82
Manufacturing	5	4	0.8
Medical / Health	6	6.33	1.06
Minerals / Metals	7	12.18	1.74
Other	1	0	0
Retail	11	2.13	0.19
Utility / Government	20	2.45	0.12
Total	227	521.47	3.61

Between 2014 and 2023, Large Loads have grown at a compound annual growth rate of 6.4% while all remaining load classes grew at only 1.8%. Over the last 20 years, Large Load customer compound annual growth rate is 5.7% compared to the remaining loads' 2.3% rate. We believe this long-term trend of load growth concentration in the Large Load customer classes will continue. However, while the compound annual growth rate shows positive long-term growth, the volatility of the Large Loads is significantly higher than the rest of the retail load.

Grant PUD's Load Forecast

This IRP uses Grant PUD's 2023 Annual Sales and Load Forecast to inform the analysis of customer energy demand over the study period. To create the forecast, monthly historical customer sales data along with weather, economic, and demographic data are used to develop econometric regression models. These models forecast monthly load by customer class.

Customer class forecasts are then aggregated into a total system load forecast. Representative hourly load shapes, derived from historical data, are applied to produce hourly forecasts, with stochastic variability, used for modeling.

Forecast load requirements contained in the 2023 Annual Demand Forecast are referred to throughout this document as the reference case forecast. Figure 26 illustrates both the monthly forecasted load energy, as well as the forecast monthly peak requirements from the reference case.

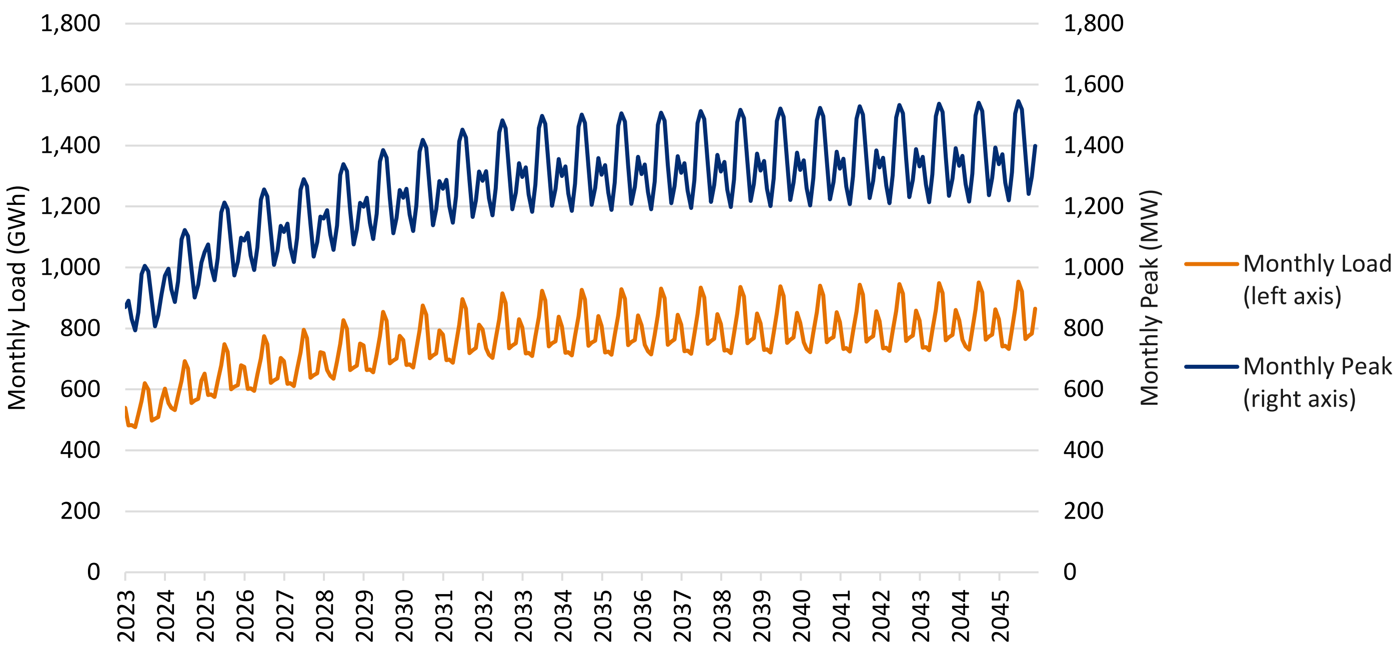


Figure 26. Monthly projected total and peak load for reference case, 2023 – 2045, GWH and MW

Figure 27 shows the reference case forecast by customer class for 2025 through 2045, illustrating the expected variation in load growth between customer classes and highlighting the forecast increase in load share of industrial class customers.

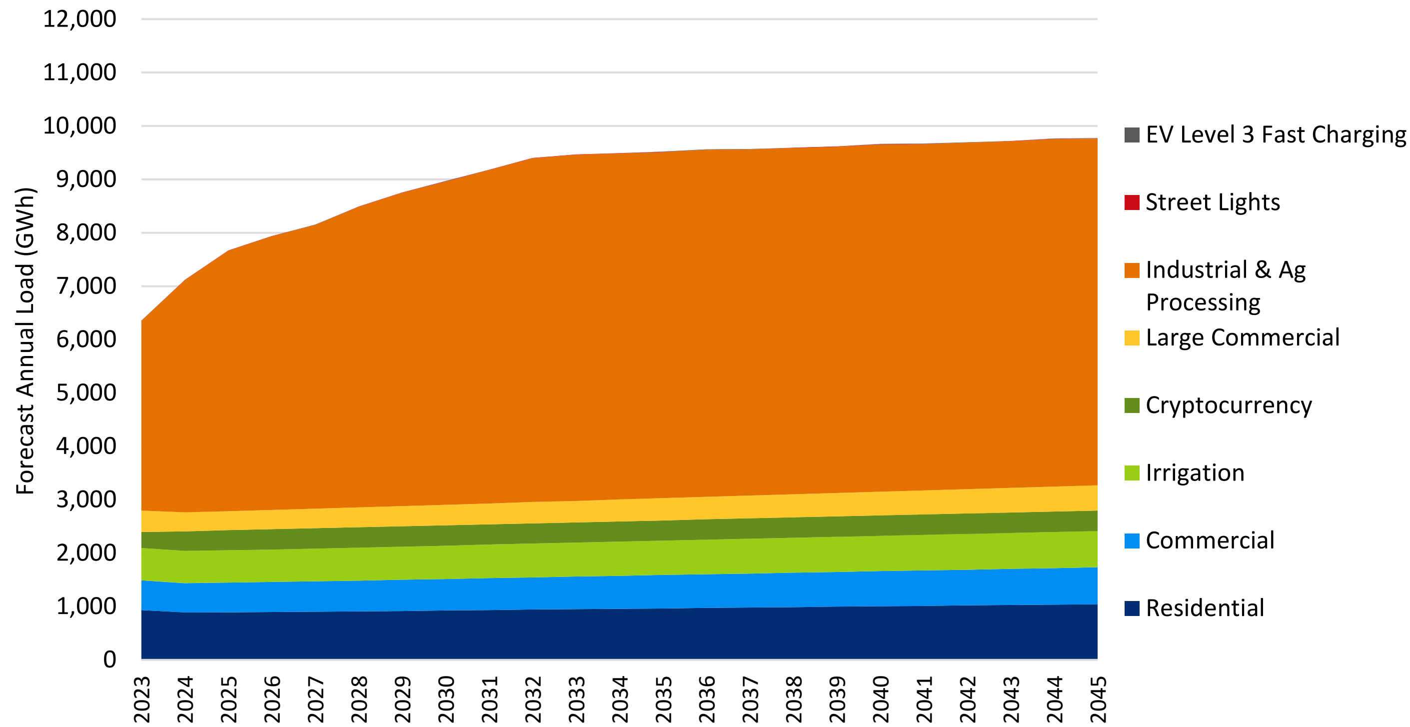


Figure 27. Grant PUD reference load forecast by customer class, 2025-2045, GWh

Alternate Load Growth Forecast

Because load growth is both a key driver of resource needs and highly uncertain, this plan considers an additional load growth sensitivity for lower load growth. Lower load growth is defined as an overall system growth rate 50% lower than the reference load growth case. This alternative load growth scenario, illustrated in Figure 28, is used to explore the impact of load growth on the type, timing, and magnitude of resource selections.

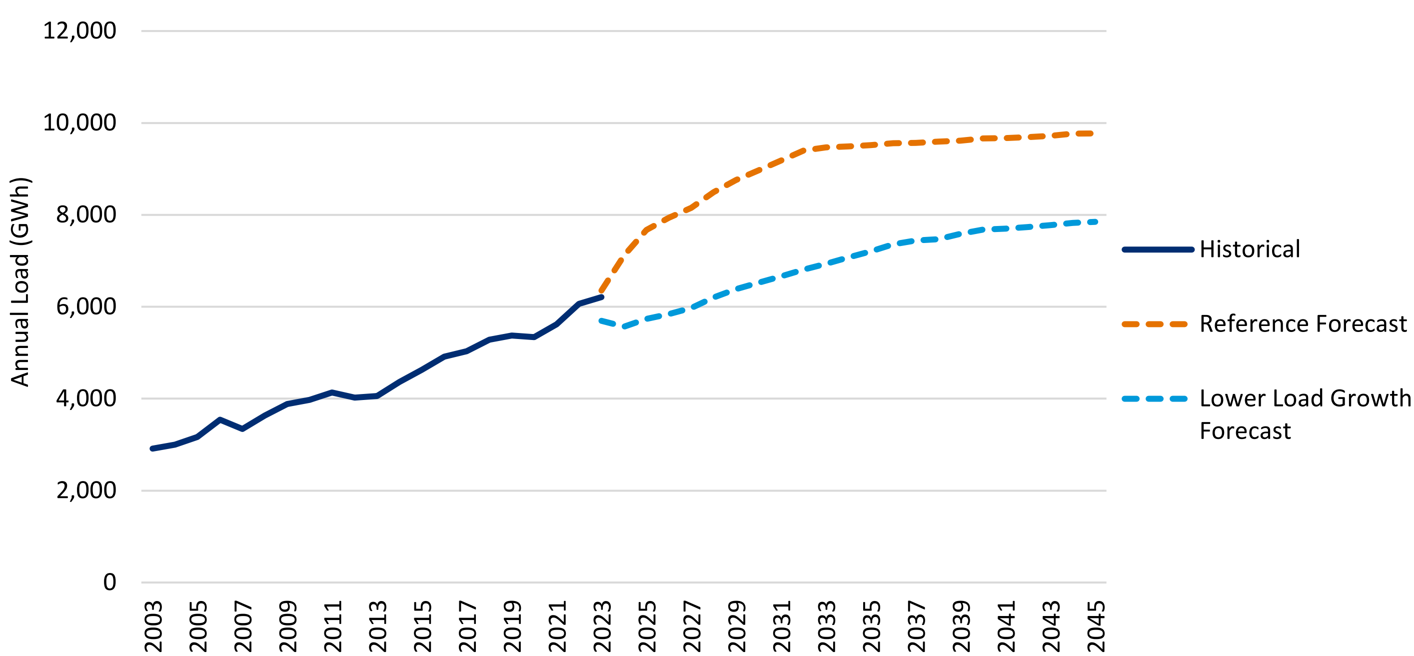


Figure 28. History and forecasted annual load for Grant PUD service territory for two conditions of load growth, 2003 - 2045, GWh

Table 8 further quantifies the differences between the reference case forecast and the lower load growth forecast.

Table 8. Compound annual growth rate of reference case forecast and lower load growth forecast, by period, %

Period	Reference Case Forecast	Lower Load Growth Forecast
2023 – 2026	8%	1%
2026 – 2033	3%	2%
2033 - 2045	1%	1%
Compound Annual Growth Rate of Historic Period 2023 – 2023 was 4%		

WATER AVAILABILITY AND RISK

The principal resource in Grant PUD's portfolio is the Priest Rapids Hydroelectric Project (Wanapum and Priest Rapids) on the Columbia River. Their ability to provide energy and capacity is a function of water availability. Uncertainty and risk associated with the availability of water exists over multiple time steps: annual, seasonal, daily, and hourly. Risk is the inability to generate according to the plan over these various time horizons. Annual risk impacts the energy and capacity assumptions in the multiyear resource plan; seasonal risk impacts those assumptions within the year, etc. When actual water availability is different from that which was assumed, changes must be made, and those changes carry both price and availability risk.

Annual Water Risk

This represents the total volume of water available over the water year (October – September). Figure 29 shows the range of annual water volume, expressed as an average flow for the year, measured below Priest Rapids Dam from 1949 to 2023. This is the unregulated runoff volume as measured by the Northwest River Forecast Center. The lowest year on record was 2001 with an average annual flow of ~76 kcfs and the highest was 1997 with ~170 kcfs. More importantly, this represents a potential swing of 62% of average to 140% of average and illustrates the large potential variance between average expectations and the amount of water available over an annual planning period.

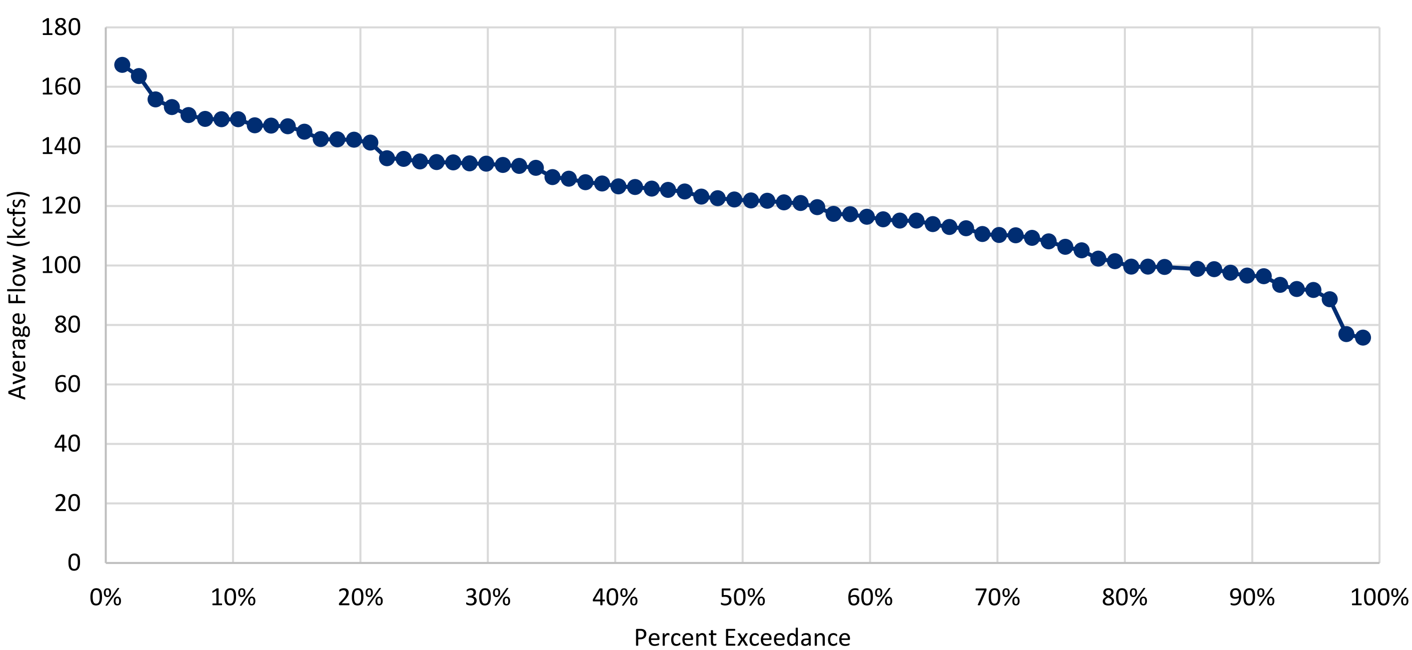


Figure 29. Northwest River Forecast Center water year runoff volumes, measured below Priest Rapids Dam, 1949-2023, kcfs (Northwest River Forecast Center, 2024)

Seasonal Water Risk

There is also uncertainty and risk associated with the timing of when water arrives within the year. The seasonal shaping of the runoff is primarily determined by climate and weather, but natural, unregulated runoff is ultimately regulated by the large storage reservoirs in the system for purposes of flood control, biological goals, and energy production. The U.S. Army Corps of Engineers and Bonneville Power Administration, through agreements with Canada, coordinate the operations of the large, seasonal storage in the system to meet the various goals. While the monthly volumes are predictable to an extent, there still remains a degree of uncertainty around the volumes available to PRP. Figure 30 shows the month average flows as well as the variability of those flows expressed by 90% and 10% exceedance values. The period of record was restricted to more current years (1995-2023) as the monthly shaping has changed throughout time and the current data is more reflective of future expectations. Calendar year 2001 is explicitly shown as an illustration of a “worst case” but actual hydrologic condition reflected in monthly volumes over the course of a year.

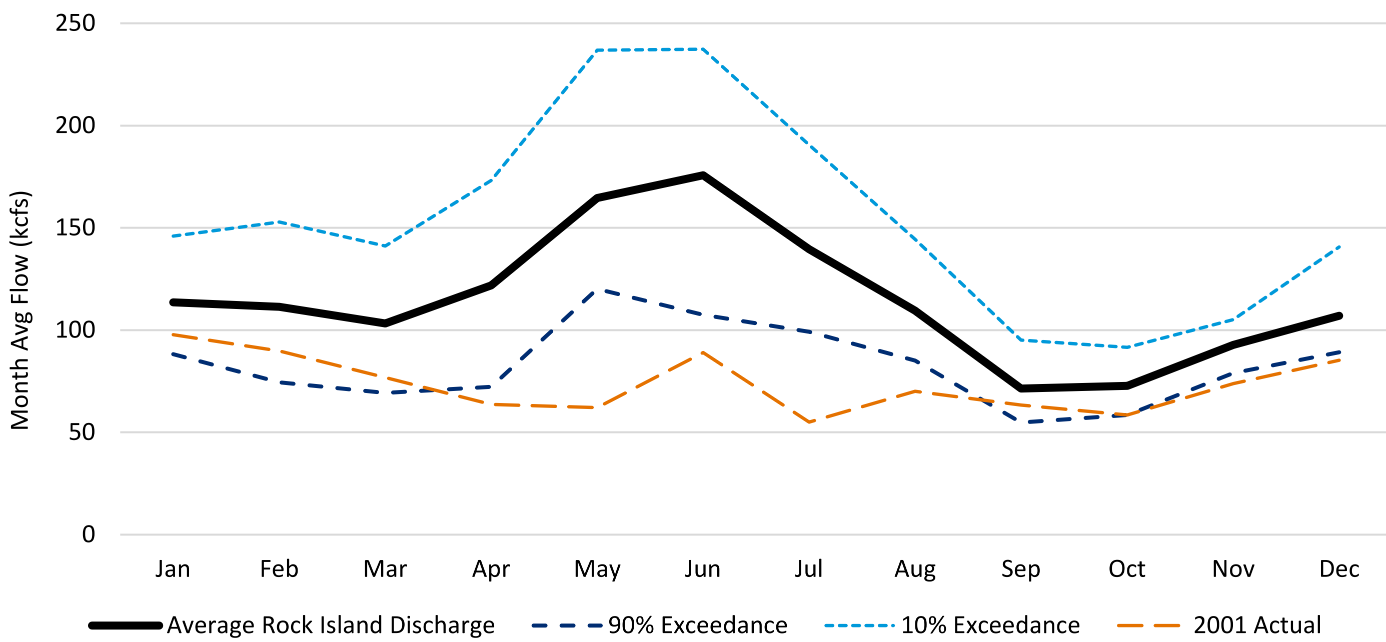


Figure 30. Month average Wanapum inflow, 1995-2023, kcfs

There are some indications that natural, seasonal water availability is changing. Findings reported by the Wahington Department of Ecology, Washington State University and the Washington Water Research Group, reported in the 2021 Columbia Basin Long-term Water Supply and Demand Forecast, forecast that timing of water supplies in the Columbia River Basin is shifting earlier in the season, especially in the Cascades watershed. This expected timing shift is due to warming temperatures and a corresponding smaller snow pack and earlier snow melt (Office of Columbia River, 2022).

Seasonal risk or water availability is amplified when there is a mismatch between water availability and customer demand for energy. Figure 31 illustrates that as flow is expected to drop through late summer and early fall, customers’ demand for energy is expected to remain fairly constant.

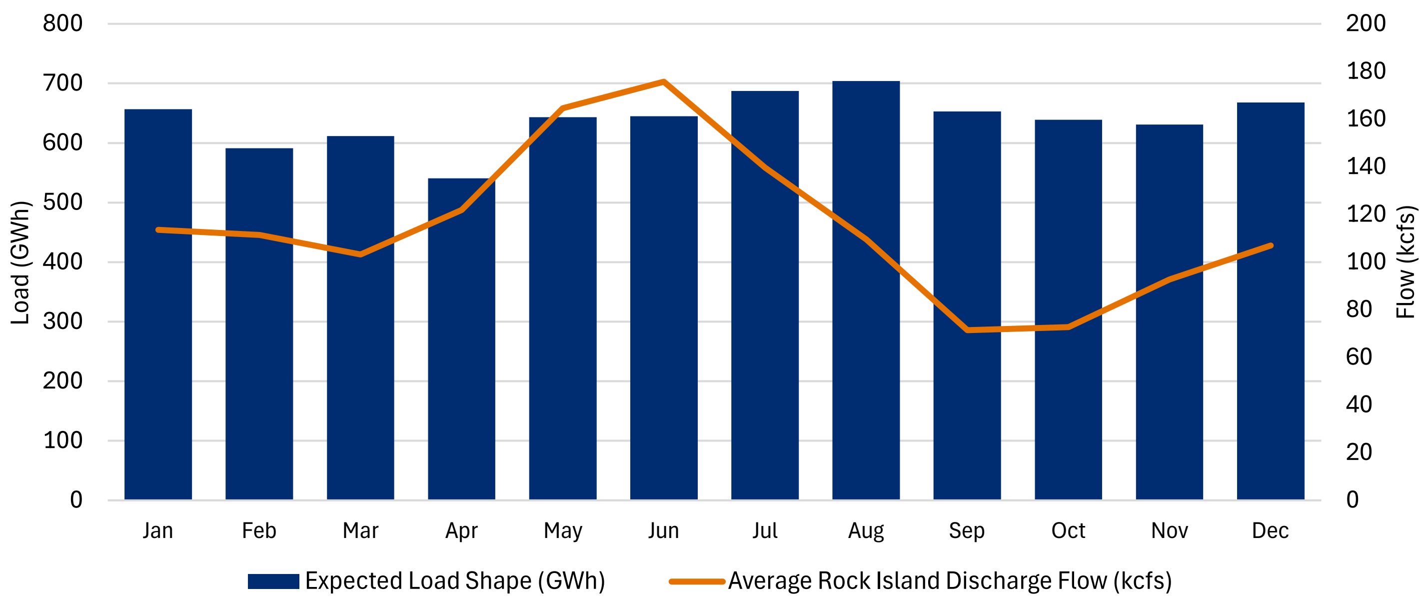


Figure 31. Expected monthly load vs. month average Wanapum inflow, GWh and kcfs

Daily Water Risk

Given the limited storage at both Wanapum and Priest Rapids, the daily variability of inflows to the projects holds an additional element of uncertainty and risk. To an extent, the storage in the reservoirs can mitigate this risk, but the limit of either supplementing flows for near term needs or capturing excess flow to use in future time periods is measured in hours, not days. Similar to the month averages shown in Figure 30, day average flows, on average have largest variance during the spring and summer while the variability September through November shows a marked decrease.

Figure 32 uses actual values from 2019, 2021, and 2023 to illustrate that daily variability is seen both between years, between days within the same year, and between days within the same month of a year.

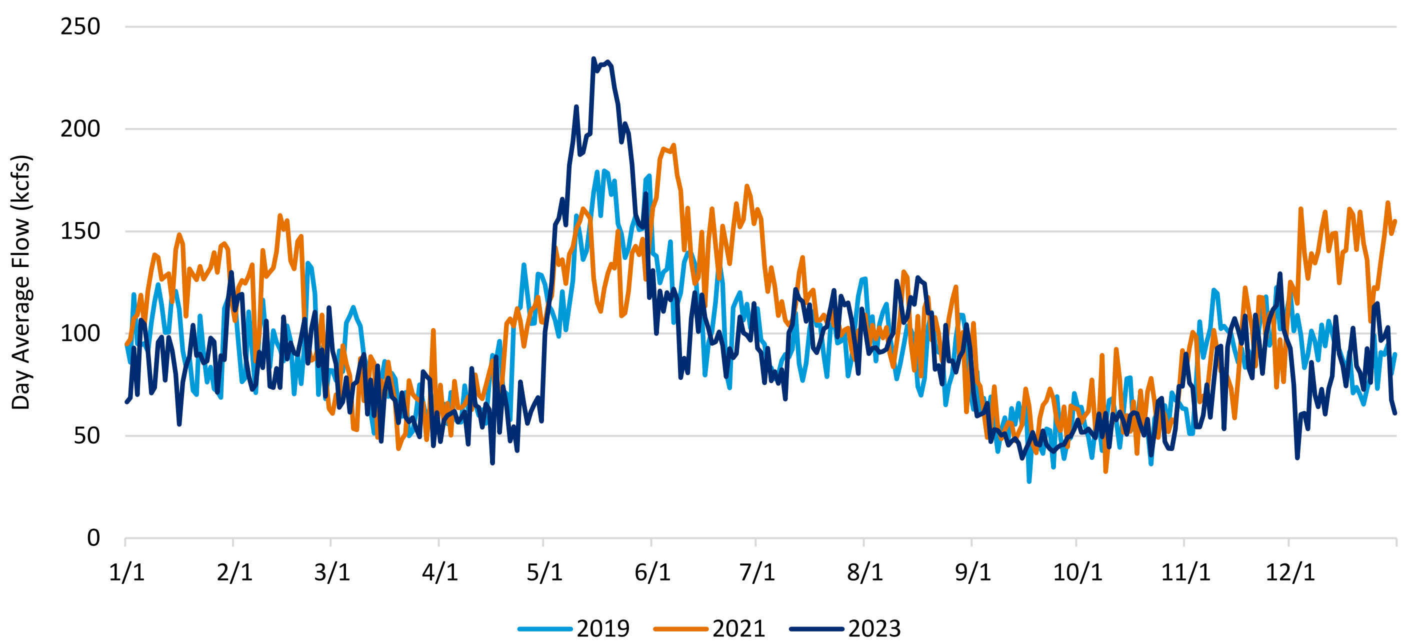


Figure 32. Day average Wanapum inflow 2019, 2021, and 2023, kcfs

Hourly Water Risk

The timing of inflows within the day also adds to the uncertainty of fuel supply. While somewhat predictable, hourly variability can still impact operations because that uncertainty interacts with operational constraints, especially biological flow requirements. Figure 33 illustrates the hourly variability for a single year. Focusing on relatively short periods of time, there is a variability of inflows that must be accommodated in some way, either by using storage or matching generation to inflow. The risk changes throughout the year based on total water volume and operational regimes.

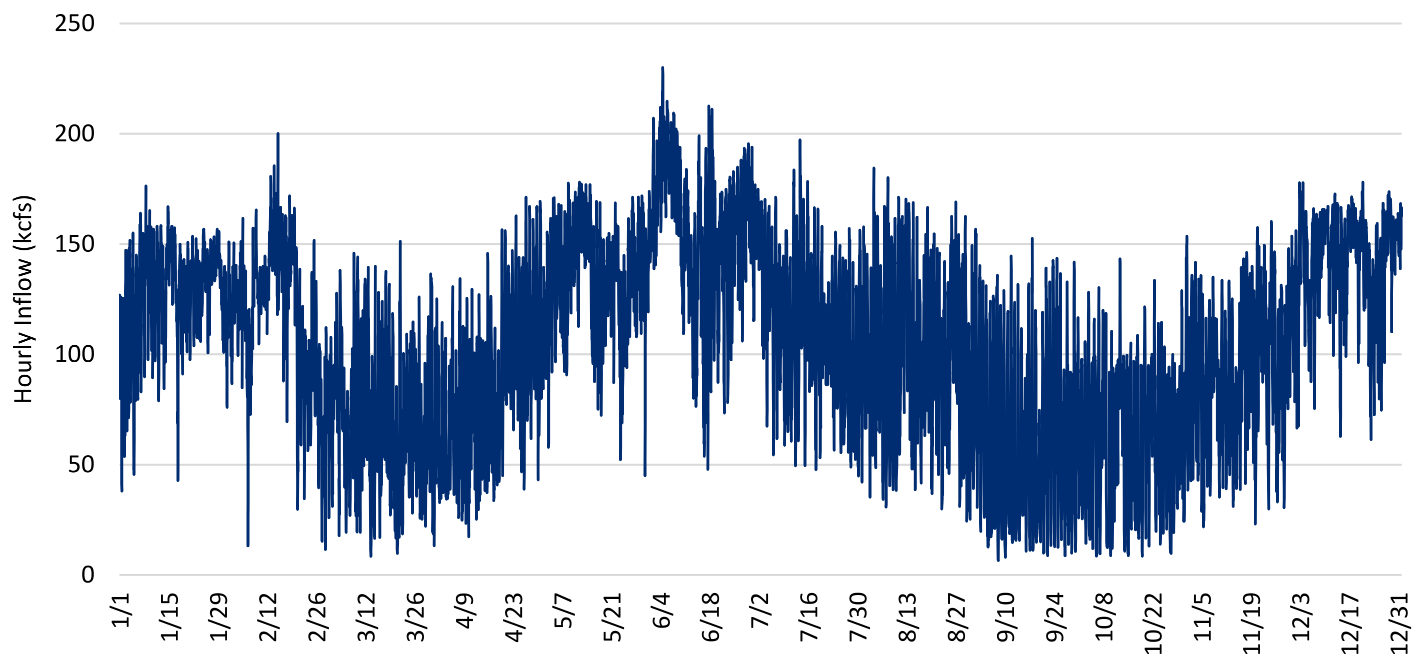


Figure 33. Hourly Wanapum inflows 2021, kcfs

To mitigate water availability risk Grant PUD has entered into slice sales and pooling agreements and plans to continue to use these mechanisms when they are beneficial. However, for the analysis used for formulating this resource plan, we have modeled Grant PUD retaining all Priest Rapids Project output at the conclusion of existing contracts. This method allows for capturing the value of PRP in the modeling process even though potential future contract terms are not yet determined. Future and subsequent optimization will include a plan for monetizing the value of PRP assets and reducing water risk.

TRANSMISSION AND DELIVERABILITY

Sufficient transmission resources are essential to meet the existing and growing demand for power. Grant PUD owns and operates a 115 kV and 230 kV transmission system that is directly connected to the systems of four other transmission owners, BPA, Avista, Puget Sound Energy and PacifiCorp. Grant PUD is looking to the future regarding both the expansion of the Grant PUD transmission system and the interconnection of new generation resources to the Grant PUD system.

Grant PUD Import Capability

We anticipate the transmission system will have the capacity to import energy from either a new or existing resource outside of the Grant PUD balancing authority sufficient quantities to meet forecast load. To make these imports, Grant PUD will need to acquire commercial transmission rights from BPA or other transmission providers. In the region, processes exist to apply for and receive this type of service. Current availability of transmission capacity to deliver to the Grant PUD system will vary on a case-by-case basis. In some cases, Grant PUD may need to participate in a Transmission Service Request Study or similar process of a transmission provider and may also need to pay for necessary upgrades to a transmission provider’s system to receive the desired service. One example of a proactive step taken to assure Grant PUD will be able to import additional power in the future is the Line and Load Interconnection Request submitted with BPA for a new 500 kV interconnection.

Grant PUD Transmission System

Grant PUD is actively working to expand and upgrade the Grant PUD Transmission and Distribution System. Current projects include Design Build 2 (DB2) and the Quincy Transmission Expansion Projects (QTEP), and the Moses Lake Transmission Expansion Plan (MTEP) is a potential future project.

Design Build 2

DB2 follows on the heels of Design Build 1, the first round of Grant PUD's design build projects, completed in 2017 that produced builds, rebuilds and improvements to eight substations within approximately 18 months. Use of the design build concept, which requires State approval, is intended to speed up and simplify multiple projects under a single contract. Project owners bundle projects together and carry them out simultaneously using the same consulting firm, designer and contractors.

DB2 is in the construction phase and includes multiple transmission and substation projects with a current budget of approximately $70 million and a 3.5-year schedule. These projects will add redundancy to reduce the impact of outages, expand capacity to allow for increased reliability and support future load growth, reduce operation and maintenance costs by rebuilding older facilities. Table 9 lists project components and status as of second quarter 2024.

Table 9. DB2 Project as of June 2024

Project Component	Status
Quincy Plains Substation	In service June 28, 2021
Burke Substation	In service March 28, 2022
Mountain View Capacitor Bank	Construction through third quarter 2024. Testing and commissioning start date to be determined
Baird Springs Substation	Ready to serve load pending customer readiness
Baird Springs Substation #2	Testing and commissioning to start Q3 2024 through Q2 2025
Red Rock Substation	Testing and commissioning to tentatively start Q2 2025
Frenchman Hills Substation	Testing and commissioning to tentatively start Q3 2025
Red Rock Transmission Line	Construction deferred to 2027
South Ephrata Substation and Ring Bus	Testing and commissioning start date to be determined
Royal Substation	In service January 12, 2023

Figure 34 shows a geographical representation of the location of some key DB2 elements.

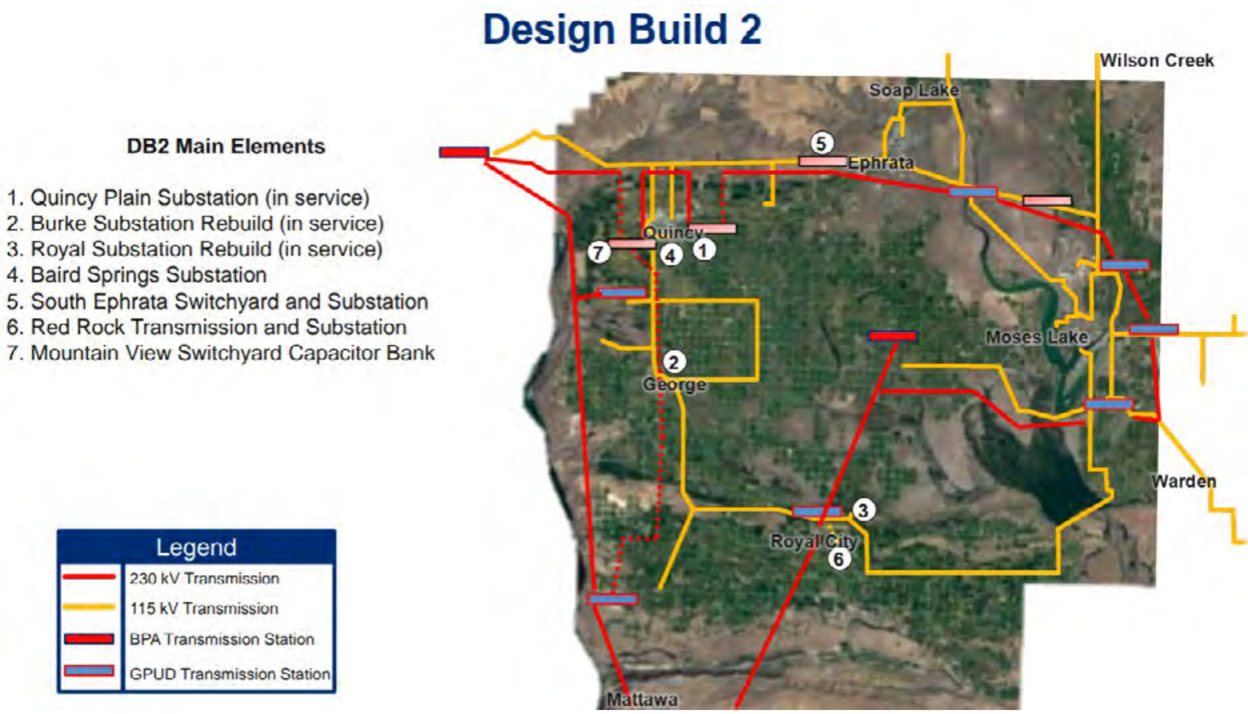


Figure 34. Diagram of DB2 main elements

The Quincy Plains Substation project will install a second transformer to serve two large new customers. The Burke substation project involves a rebuild of an existing 1950's substation to enable service to more customers and increased reliability. The Mountain View Capacitor Bank is required for voltage support and continued load growth in the Quincy area.   The Red Rock Transmission line will supply power to Red Rock Substation and enable load growth in the Port of Royal City. The Frenchman Hills Substation is for the origination of the Red Rock Transmission Line and includes the addition of new protection and control relays. The South Ephrata Substation and Ring Bus project involves installation of a ring bus for reliability and a new substation to replace the previous site. The Royal Substation is a rebuild that will address aging equipment and current maintenance and operations constraints.

To learn more about DB2, visit the Grant PUD website at [Design Build 2 (grantpud.org)](grantpud.org).

Quincy Transmission Expansion Projects

QTEP will add greater capacity and redundancy to the power grid to meet the growing demands for electricity. QTEP includes several projects in the Quincy area as well as a new 230 kV line from Wanapum Dam to the Quincy area. Projects are currently in the design and environmental review stages. Figure 35 gives a geographical representation of the main QTEP design as currently envisioned. The projected total cost for QTEP, with the scope contemplated as of March 2024 is $209 million.

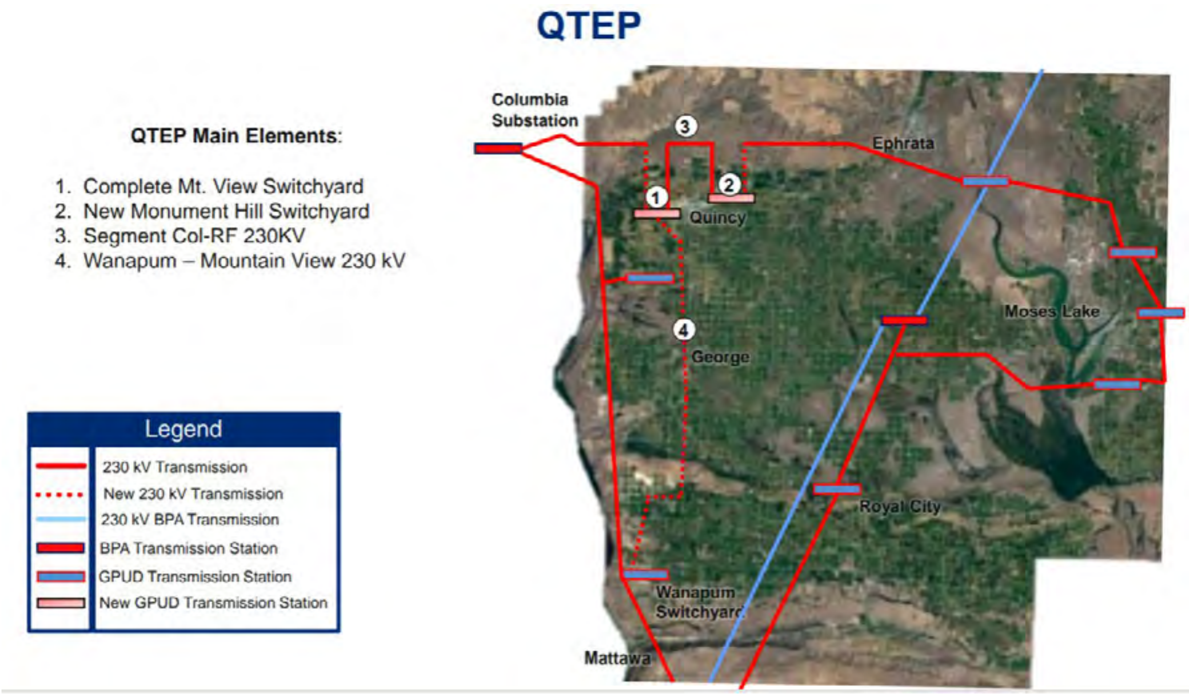


Figure 35. QTEP design elements

To learn more about QTEP, visit the Grant PUD website at [Grant PUD: QTEP].

Moses Lake Transmission Expansion Plan (MTEP)

MTEP is in the development stage and could include several projects that will provide additional transmission capacity necessary to reliably serve additional load in the Moses Lake area.

Distribution Power Quality Upgrades

With a primary focus on irrigation customers, Grant PUD is installing and upgrading capacitor banks, regulators, and conductors, while also evaluating upgrading the controllers for line devices.

Interconnection of New Generation to the Grant System

To facilitate the interconnection of new generation resources to the Transmission System, Grant PUD has interconnection procedures and a standard interconnection agreement. Connection of a new generator by Grant PUD to its transmission system would follow the same process that is currently available to independent power producers. Grant is currently transitioning from a process where interconnection requests are studied in a serial manner to a cluster approach. FERC recently issued Order 2023 requiring jurisdictional entities to implement a cluster study process, and while Grant PUD as a non-jurisdictional entity is not required to follow this Order, we have chosen to do so because we believe it will improve the interconnection process, which is the intent of the Order.

As in the previous sequential process, the new cluster process will study the interconnection requests to determine what facilities must be built or upgraded to accommodate the requests. The study process also identifies if neighboring transmission systems are affected by the proposed interconnection and allows an opportunity for affected systems to identify any upgrades necessary to the neighboring system prior to implementing the request.

The current Grant interconnection queue under the serial process contains six interconnection requests for a total of 1,250 MW. Additional requests are on hold awaiting the implementation of the new cluster process.

Open Access Transmission Tariff

Grant PUD is developing an Open Access Transmission Tariff (OATT). An OATT contains the rates, terms, and conditions under which Grant PUD will sell wholesale transmission service. The Federal Power Act, first enacted as the Federal Water Power Act in 1920 and amended many times since, requires Grant PUD, as a non-jurisdictional entity, to provide service to outside entities under rates, terms, and conditions that are comparable to how Grant PUD provides service to itself (66th Congress, 2021). While it's voluntary for a non-jurisdictional entity to have an OATT, operating under an OATT is standard across the industry for non-jurisdictional entities that have significant use of their transmission system by outside entities. Grant has traditionally served a number of entities using individual legacy contracts with terms and rates that vary from contract to contract. Given the number of independent power producers interested in connecting to the Grant transmission system, it is appropriate to develop and implement an OATT to ensure comparable service under the Federal Power Act.

6 | Grant PUD's Current Energy, Capacity and Clean Energy Position

Using information regarding existing resources, our reference case load forecast, and expected compliance obligations, we can formulate expectations of the ability of our current resource portfolio to meet customer requirements and regulatory obligations. Examining Grant PUD's current portfolio allows us to understand what changes are needed to accommodate customers' future needs.

ENERGY POSITION

Figure 36 is a representation of the projected generation capability of Grant PUD's current resource portfolio versus its forecast system load. Please note that that while Grant PUD routinely relies on wholesale market participation to provide energy to customers, to moderate portfolio risk, and to stabilize energy costs and revenue, market participation is not reflected in this chart. This in no way indicates an intent to discontinue those trading practices.

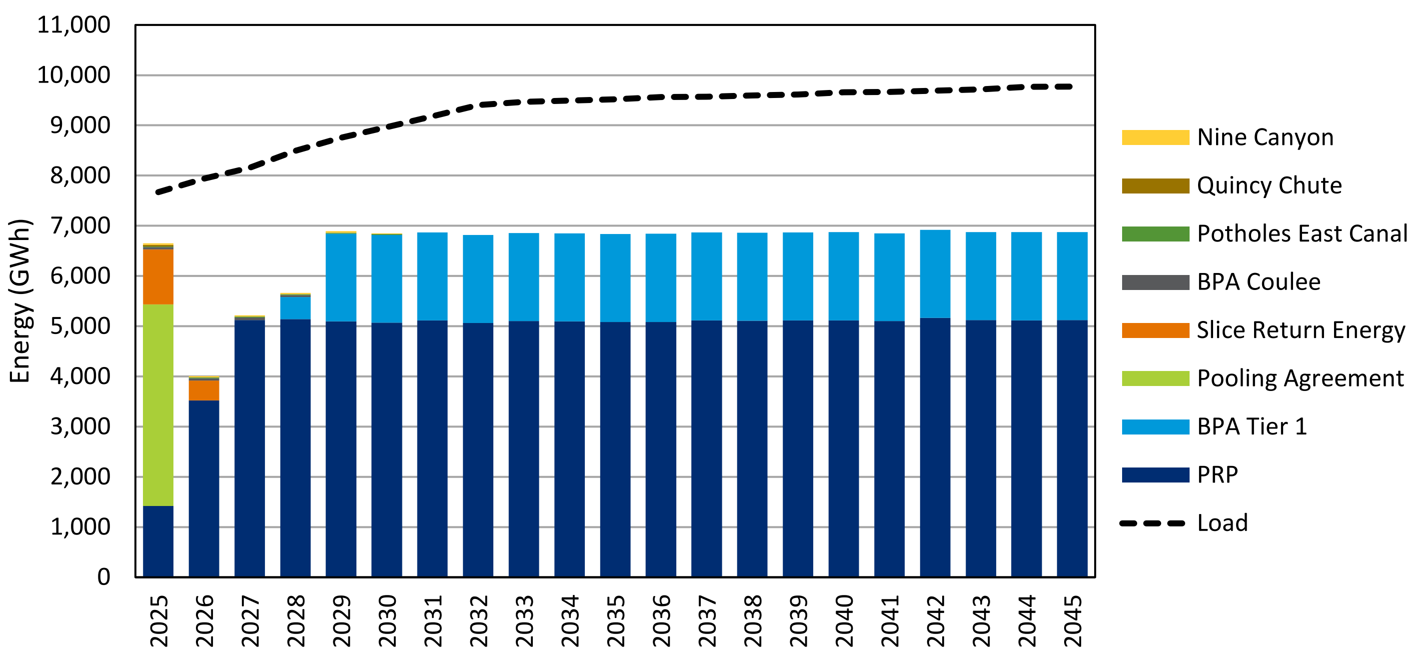


Figure 36. Resource expectations vs. load forecast, annual energy, current portfolio, 2025 – 2045, GWh

The Grant PUD portfolio is well positioned to meet customer energy requirements through the September 2025 expiration of the pooling agreement. After the expiration of that contract, Grant PUD has growing exposure to the market until the BPA PoC Tier 1 contract begins in October 2028. Even with the addition of the BPA PoC Tier 1 contract, in the absence of new portfolio resources, Grant PUD can expect to meet a significant portion of customer demand with energy obtained from the market.

The dominance of hydropower in the current portfolio produces a marked variation in seasonal energy positions. An example of expected monthly energy positions is shown in Figure 37. The first year after expiration of current slice and pooling agreements, 2027, is chosen for this illustration. This figure highlights that in the summer and fall seasons, while Grant PUD's load remains stable, energy available from hydropower decreases, increasing Grant PUD's reliance on the wholesale energy market during this period.

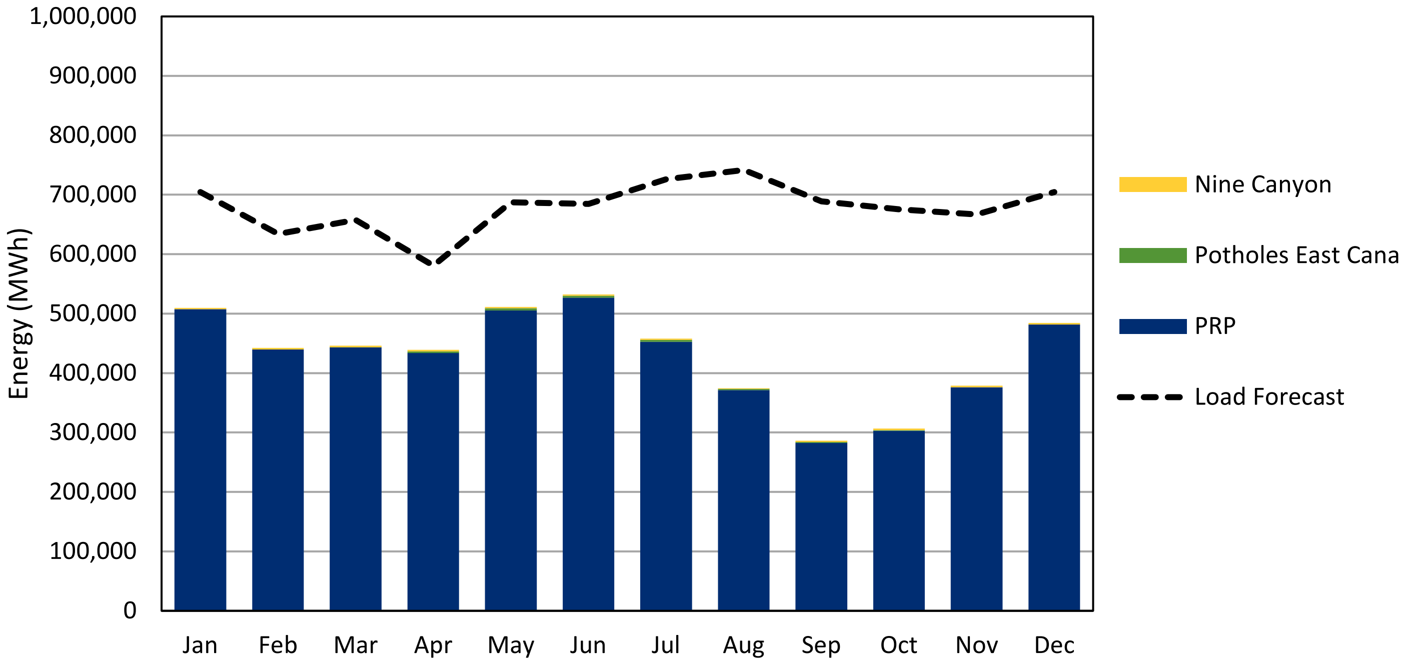


Figure 37. Month energy provision expectations vs. forecast load, current portfolio, 2027, MWh

Using current assumptions, over the planning period of 2025 – 2045, we expect Grant PUD to meet about 69% of its customer energy demand using its current portfolio. This indicates a significant exposure to both market price and market energy availability. While work remains to definitively quantify the appropriate level of reliance on market solutions, we will remain aware of the balance between serving customer needs with owned and contracted resources versus through shorter-term market solutions.

If in the future Grant PUD's rate of load growth falls from expected levels to those included in the lower load growth forecast, the current portfolio would be sufficient to meet energy requirements through 2032.

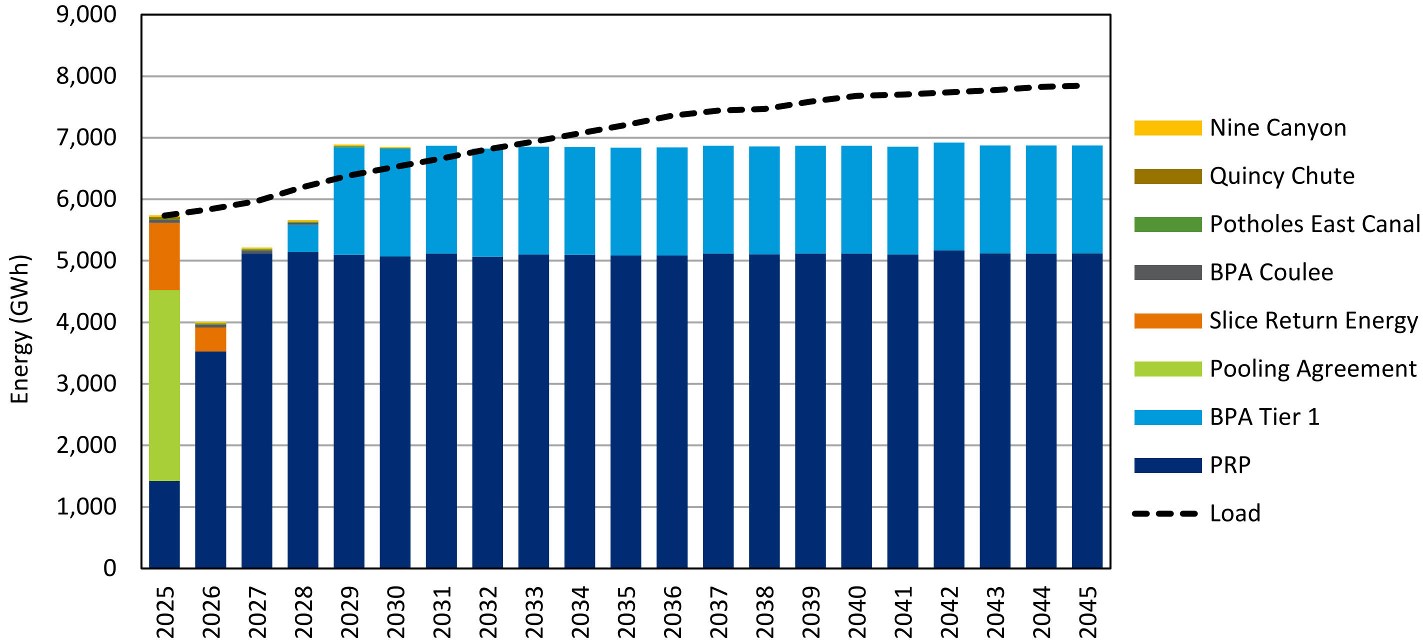


Figure 38. Resource expectations vs. lower load growth forecast, annual energy, current portfolio, 2025 – 2045, GWh

CAPACITY POSITION

As a participant in and supporter of the WRAP, Grant PUD has chosen to adopt that program's defined business practices and metrics for setting capacity planning reserve margins and determining capacity values of resource technologies. Using guidance from the WRAP business practice manuals and Tariff and Grant PUD's reference load forecast, Figure 39 illustrates the capacity position of the current portfolio.

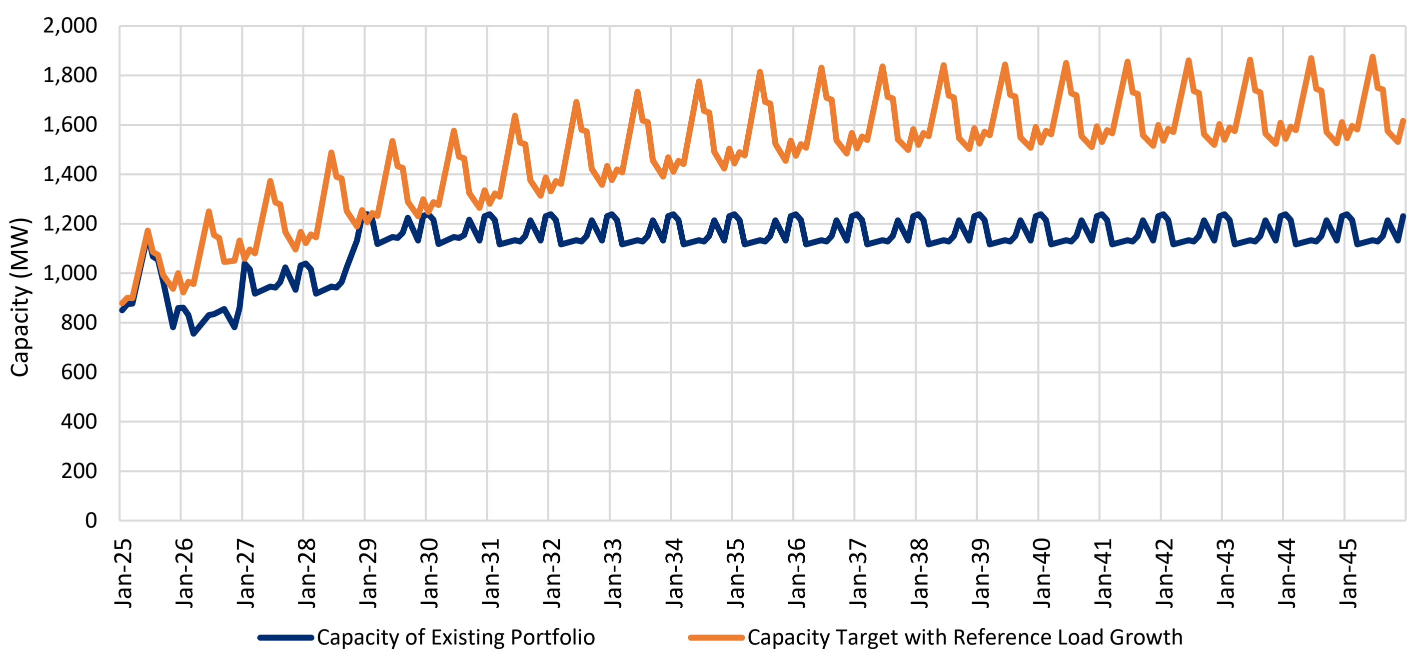


Figure 39. Existing portfolio capacity vs. forecast capacity targets based on current WRAP valuations and requirements, 2025 – 2045, MW

After expiration of the current slice sales and pooling agreement, monthly variations in capacity position are driven almost exclusively by the calculated Qualifying Capacity Contribution of Wanapum and Priest Rapids dams. Table 10 shows detail of this monthly variability. PRP capacity values peak during December, January and February and fall by about ten percent of their maximum in Mar, June, July and November. Values are calculated using the current methods employed by the WRAP program and are subject to change. This fluctuation, coupled with the monthly variation in Load and planning reserve margins results in the months of March, June, July and August being the months in which Grant PUD;s current portfolio holds the largest capacity deficit.

Table 10. Current qualifying capacity contributions of Wanapum and Priest Rapids Dams as calculated by WRAP method, MW

Month	Wanapum Dam	Priest Rapids Dam
January	998	807
February	976	793
March	903	710
June	849	791
July	843	790
August	880	787
September	971	796
November	949	689
December	991	803

Without capacity additions to its portfolio, Grant PUD will be unable to meet the resource adequacy requirements set by WRAP over any period of the planning horizon. If unfilled, this capacity deficiency could prevent Grant PUD from joining the program in a binding manner and from receiving the program benefit of sharing in the region's capacity pool. Forecast capacity deficits from the anticipated WRAP start date of 2027 through the planning horizon range from 10 to 742 MW, with an average monthly deficit of 370 MW.

If in the future Grant PUD's rate of load growth falls from expected levels, the anticipated capacity shortfall compared to WRAP requirements will also fall. Figure 40 compares the capacity of the existing portfolio to forecast capacity targets based on load forecast which considers load growth to be 50% lower than currently anticipated.

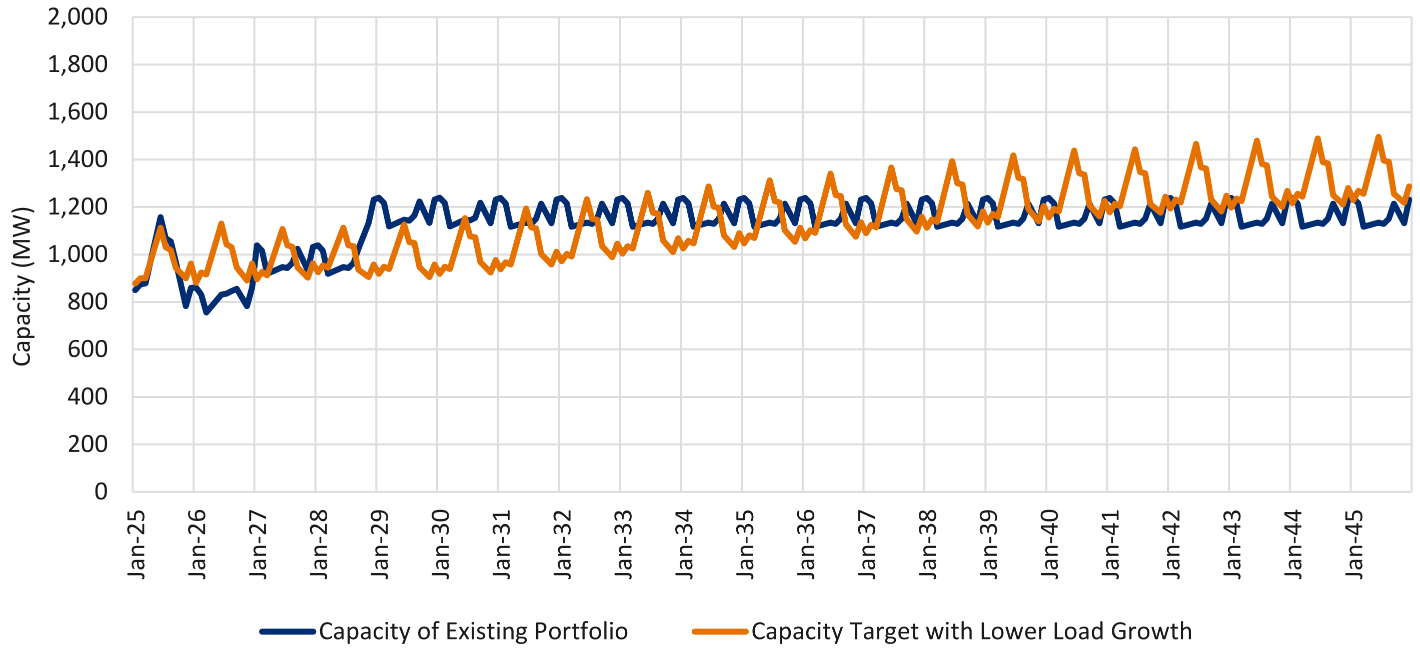


Figure 40. Existing portfolio capacity vs. forecast capacity targets based on WRAP requirements, lower load growth, 2025 – 2045, MW

Under this lower load growth scenario, Grant PUD could meet WRAP capacity targets with its existing portfolio once the BPA PoC Tier 1 contract begins until the mid-2030s, when even this lower load growth results in the need for additional resources to meet capacity targets. Under the lower growth load forecast, Grant PUD capacity deficits, from the anticipated WRAP start date of 2027 through the planning horizon range, from 6 to 362 MW with an average deficit of 129 MW.

Grant PUD is a strong proponent of WRAP. However, its current portfolio does not meet WRAP's capacity for joining the program without paying potentially substantial deficiency charges to participate. It is Grant PUD's preference to join WRAP with sufficient capacity to be a strong partner with other regional utilities in providing support for electric customers even under the most demanding conditions. A key driver in the formulation of this resource plan is to provide a sound and structured pathway to acquiring enough capacity resources to accomplish this.

RPS POSITION

The EIA establishes a renewable portfolio standard (RPS) such that by January 1, 2020, and every year thereafter, qualifying utilities must use eligible renewable resources or acquire RECs to serve at least 15% of the amount of electricity delivered to their retail customers. For purposes of calculating the annual targets, retail sales are calculated as the average of the utility's load for the previous two years.

The EIA definition of eligible resources does not include Grant PUD's total share of PRP assets, but only the incremental electricity produced as a result of efficiency improvements completed after March 31, 1999. EIA also dictates that other renewable resources must be located in the Pacific Northwest or delivered to the state on a real-time basis to count toward the RPS.

As shown in Figure 41, with the current customer sales forecast, Grant PUD is currently positioned to meet the EIA RPS requirement through 2025. Note that the position shown in the figure does not include the use of RECs. RECS are a compliance option for EIA and may be chosen by Grant PUD as part of its compliance strategy.

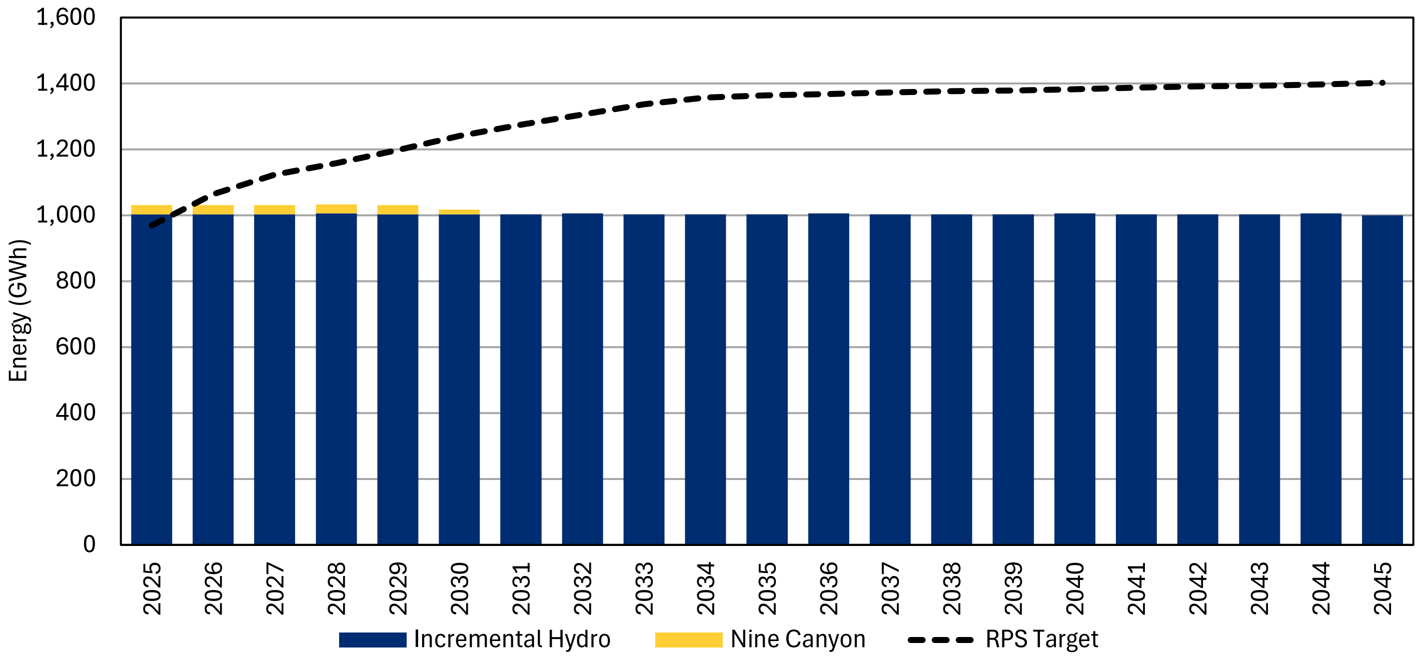


Figure 41. Forecast RPS requirement and contribution of eligible resources in current portfolio, 2025 - 2045, GWh

If in the future Grant PUD's rate of load growth falls from expected levels, the current portfolio would be sufficient to meet RPS requirements through 2034. Figure 42 illustrates this potential lower load growth position. Again, the compliance option of RECs is not included in the figure.

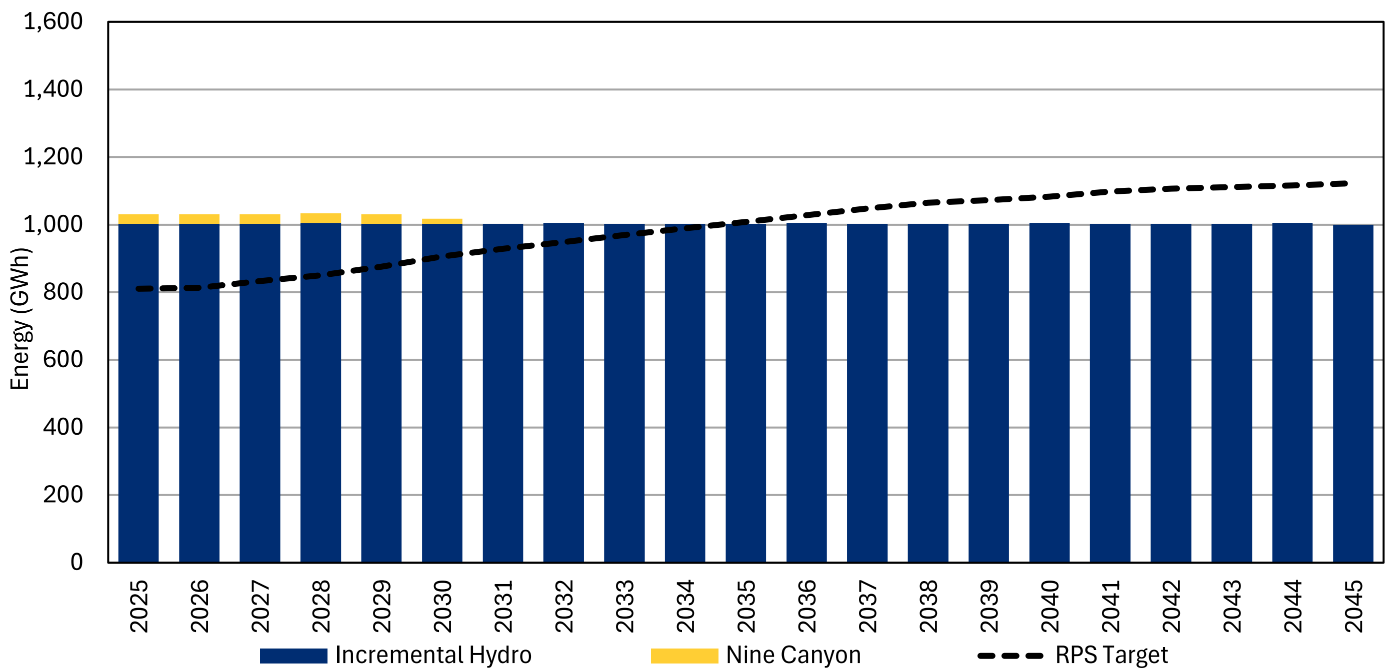


Figure 42. Forecast RPS requirement with lower load growth and contribution of eligible resources in current portfolio, 2025 - 2045, GWh

CETA POSITION

Starting in 2022 and every four years thereafter, CETA requires that each utility publish a clean energy implementation plan (CEIP) with interim targets for renewable and non-emitting energy provision to retail customers, targets for energy efficiency, and methods to ensure an equitable distribution of energy and non-energy benefits. In December 2021, Grant PUD submitted to the Department of Commerce its first Commission approved CEIP covering the period 2022-2025. Grant PUD's next CEIP, for the period 2026 – 2029 will be available by the end of 2025.

Grant PUD's current CEIP establishes a target of 28% of retail load to be served by renewable sources in each year of the four-year period. We anticipate meeting these interim targets with a combination of incremental hydropower, other renewable resources, and voluntary clean energy rate schedule options for customers.

Figure 43 illustrates both the forecast CETA clean energy targets as well as the eligible contribution potential of current portfolio resources. It's important to note that Grant PUD's compliance path has not yet been mapped out and future CEIPs will determine how the current eligible resources shown in Figure 43 will contribute to meeting CETA requirements. However, this figure illustrates that even if Grant PUD determines that all current clean energy resources should be allocated for CETA compliance, it does not currently hold sufficient resources to meet the mandate beginning in 2030.

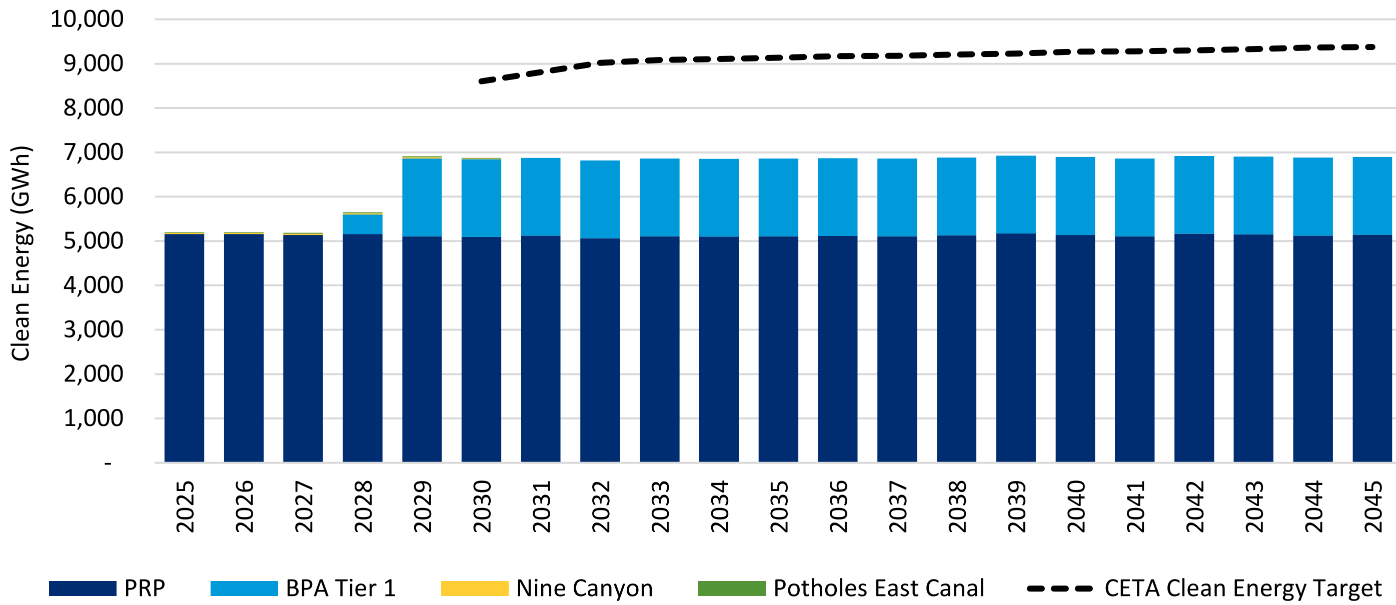


Figure 43. Forecast CETA requirement and eligible potential contribution of resources in current portfolio, 2025 - 2045, GWh

For the purposes of creating the IRP, we assume that Grant PUD will meet all CETA requirements in 2030 and through the planning period in a manner resulting in the lowest reasonable cost to customers. Not prescribing a compliance path prior to analysis allows us to devise a plan reflecting lowest cost compliance. This planning method has the potential to result in a plan in which future years have similar carbon content until 2030, when Grant PUD is required to be 80% carbon free, and in the period from 2030 through 2045, at which time Grant PUD is required to be 100% carbon free.

If in the future Grant PUD's rate of load growth falls from expected levels, the current portfolio would be sufficient to meet CETA requirements through 2034. Figure 44 illustrates this potential lower load growth position. Again, the compliance option of RECs is not included in the figure and future CEIPs will determine Grant's actual compliance path.

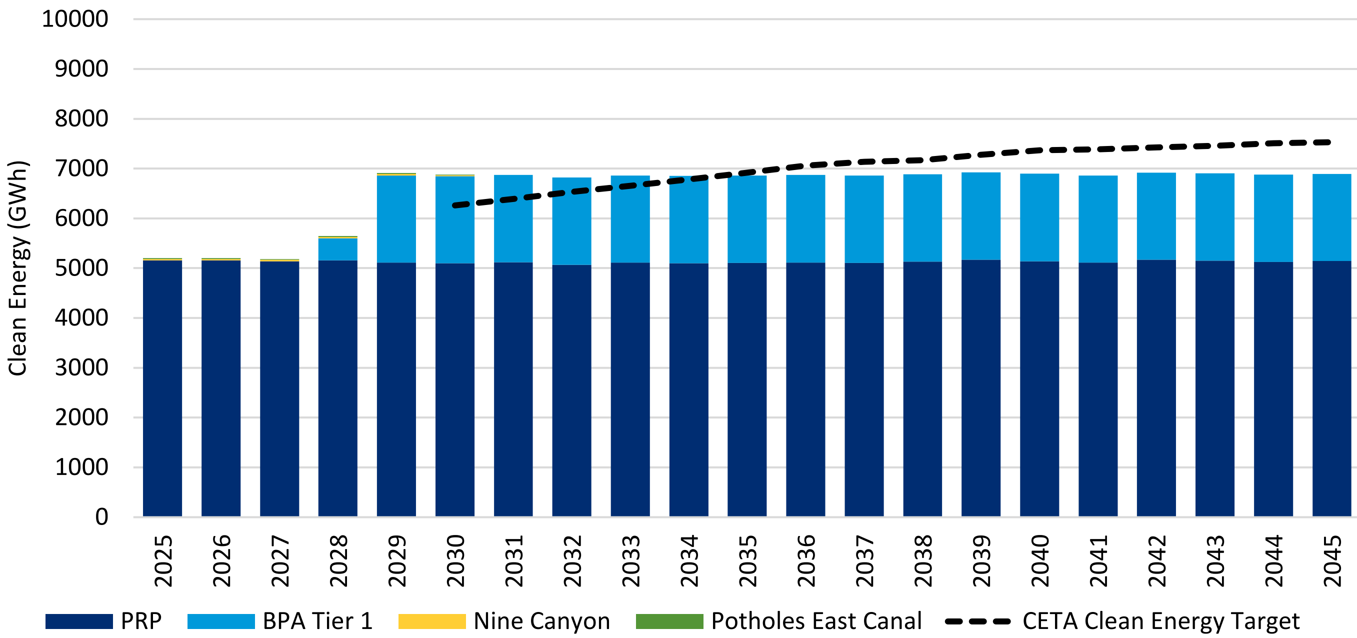


Figure 44. Forecast CETA requirement with lower load growth and eligible potential contribution of resources in current portfolio, 2025 - 2045, GWh

7 | Potential Future Resources

In developing our integrated resource plan, we have considered the following potential supply and demand resources as options for strengthening the position of Grant PUD's current portfolio. For more detail on assumptions used in the modeling of these candidate resources, please see Appendix 2.

SUPPLY SIDE RESOURCES

The following types of supply side resources were considered when formulating this IRP.

Thermal Generators

Aeroderivative Natural Gas Simple-Cycle Turbine

Natural Gas fueled aeroderivative combustion turbines produce energy by using the mechanical energy produced by the expansion of hot combustion gas moving through the blades of a turbine to spin a generator. This is accomplished using combustion of natural gas as a fuel. Aeroderivative gas turbines are a well-proven, commercially available commodity in the energy industry. Aeroderivative gas turbines are based on aircraft gas turbine engines and are relatively small and light. Favorable characteristics of aeroderivative gas turbines include their compact size, relatively modest upfront capital investiture, simplified installation, quick start up, ramping, and shut down capabilities for meeting peak or emergency generation needs, and integration of variable generation sources such as wind and solar. Aeroderivatives, as dispatchable, thermal units have favorable capacity accreditation in the WRAP program, with their QCC generally limited only by their outage and maintenance characteristics. A drawback of the use of natural gas turbines is the emission of carbon dioxide and other greenhouse gases. They are typically used for serving peak load rather than baseload needs.

Aeroderivative Hydrogen Simple-Cycle Turbine

Hydrogen fueled aeroderivative combustion turbines produce energy by using the mechanical energy produced by the expansion of hot combustion gas moving through the blades of a turbine to spin a generator. This is accomplished using combustion of hydrogen as a fuel.

Although aeroderivative gas turbines themselves are a well-proven, commercially available commodity in the energy industry, using 100% hydrogen as a fuel is not a commercially available option currently: extensive effort is being made to accelerate their readiness in the market. Aeroderivative hydrogen gas turbines are based on aircraft gas turbine engines and are relatively small and light. Favorable characteristics of aeroderivative Hydrogen gas turbines include their compact size, relatively modest upfront capital investiture, simplified installation, quick start up, ramping, and shut down capabilities for meeting peak or emergency generation needs, and integration of variable generation sources such as wind and solar.

Hydrogen fueled aeroderivatives have the same general operating characteristics as natural gas versions. However, an advantage of burning 100% hydrogen rather than natural gas is that hydrogen combustion produces no carbon dioxide emissions, helping the cause of decarbonization.

Drawbacks of the use of 100% hydrogen turbines include the availability of hydrogen as a fuel, intensive capital cost for hydrogen storage, and the current ack of commercial offerings.

Natural Gas Combined-Cycle Combustion Turbine

Natural Gas fueled Combined-Cycle Combustion Turbine (CCCT) plants produce electricity by using the mechanical energy produced by the expansion of hot combustion gas moving through the blades of a gas turbine to spin a generator and the exhaust heat, which typically would be waste heat in a simple-cycle application, is sent to a Heat Recovery Steam Generator (HRSG). The steam produced by the HRSG is used in a steam turbine to produce electricity. Overall, there is electricity produced from the gas turbine/generator as well as the steam turbine/generator in this application. A CCCT has a higher efficiency than a SCCT due to the fact that it captures heat that would otherwise be wasted and converts it to additional electricity. CCCTs have favorable capacity accreditation in the WRAP program.

The efficiency and output gains do not come without drawbacks. CCCT's have a higher upfront capital cost, as compared to a SCCT because of the added system and is not as flexible as a SCCT which has better starting, ramping, and starting performance specifications. CCCT plants are a well-proven, commercially available commodity in the energy industry but a drawback of the use of natural gas CCCTs, similar to SCCTs is the emission of carbon dioxide and other greenhouse gases. They are typically used for serving peak load rather than baseload needs.

Solar Photovoltaics

Solar photovoltaic (solar PV) technology converts sunlight directly into electricity using solar cells made of semiconductor materials, typically silicon. When photons from sunlight hit these cells, they knock electrons loose, generating a direct electric current (DC). This DC power can be transported as is or converted via an inverter to alternating current (AC). Solar PV systems consist of interconnected solar panels, mounted on rooftops or in open areas to capture sunlight.

Solar PV technology offers renewable, zero emissions, environmentally friendly energy with low operating costs and scalability. However, solar PV only produces power when actively illuminated by the sun. To combat this intermittency, solar PV can be combined with battery technology to store power for periods when the sun is interrupted. Due to its intermittency, capacity contributions of solar PV installations are far less than those of units powered by more actively manageable fuel sources. Locating solar PV installations is an important consideration for determining both the amount of energy and capacity value received from these generators.

Wind

Wind generators convert the kinetic energy of moving air into electrical energy using a wind-driven turbine connected to an electrical generator. Turbine blades rotate due to the wind, the turbine blades are linked to a hub and drivetrain that turns a generator inside the nacelle, which is the housing that is located on top of the wind tower.

Wind energy has no direct emissions or fuel costs but is not necessarily available on demand to meet and respond to market signals. Typically, utility sized wind energy consists of an array of wind turbines in areas of sufficient wind capacity factor. Wind generator output is both variable and uncertain because the wind that is used to create electricity is both variable and uncertain. Unlike solar PV generation which has a regular diurnal pattern, wind tends to have irregular generation driven by several weather and climate factors.

Energy Storage

Hydrogen Fuel Cells

Hydrogen fuel cells (HFCs) are an environmentally clean, zero carbon emitting, and efficient way to generate electricity. HFCs work by combining hydrogen and oxygen in a chemical reaction to produce electricity, with water as the only byproduct. This process occurs within a fuel cell stack, where hydrogen is fed into the anode side and oxygen from air is supplied to the cathode side. The reaction generates electricity that can power various devices or be scaled up to utility-sized generation. Unlike traditional combustion engines, hydrogen fuel cells produce no harmful emissions, making them environmentally friendly. 3 main types of fuel cells exist today, each with their own advantages and disadvantages. The 3 types are Alkaline, Solid Oxide (SOFC), and Proton Exchange Membranes (PEM). One main benefit of HFCs is they can be utilized to store electricity for use at a later time: hydrogen can be stored in tanks and used at will. This means other generation technologies, like solar power, can be utilized to produce hydrogen that can be compressed and stored for long durations. Unlike batteries that lose charge over time, hydrogen kept in tanks, not in liquid form, will not lose power over time. This makes HFCs attractive as a potential means for integrating non-baseload, intermittent green technologies like wind and solar into Grant PUD's existing grid by improving reliability and availability.

Lithium-Ion Grid Scale Batteries

Grid-scale lithium-ion batteries are large-scale energy storage systems that utilize lithium-ion battery technology to store electricity on a massive scale. The basic principle behind grid-scale lithium-ion batteries is similar to that of the lithium-ion batteries used in smaller devices such as smartphones and electric vehicles. They store electrical energy by moving lithium ions between positive and negative electrodes during charging and discharging cycles. Grid-scale lithium-ion batteries consist of numerous individual battery cells organized into modules, which are then combined to form battery packs. These packs are often housed within containers or buildings called Battery Energy Storage Systems (BESS). The size of these systems can vary widely, ranging from several megawatt-hours (MWh) to hundreds of MWh, depending on the specific application and requirements of the grid.

Most utility scale batteries currently in use in the U.S. are lithium-ion batteries. These batteries have the ability to store large amounts of electric energy in a compact size, provide fast-charging and can generally produce one charge/discharge cycle per day, can help smooth the variability of wind and solar power, and have a relatively long life.

Lithium ion-ion batteries can be costly due to the cost of raw materials and the refining process needed to produce them. Lithium-ion batteries can experience thermal runaway, a state of uncontrollable self-heating occurring when the heat generated in the battery is greater than can be dissipated. Thermal runaway can cause massive fires and explosions, which are difficult to fight.

Lithium-ion batteries are not energy generators. They serve only as storage for energy produced by other means, and so are constrained and influenced by the cost and availability of the power required to charge them.

Iron Oxide Batteries

Iron oxide batteries, also known as iron-air batteries or iron-based redox flow batteries, are a type of rechargeable battery utilizing iron and oxygen as reactants in an electrochemical process. These batteries are designed for large-scale energy storage applications, similar to grid-scale lithium-ion batteries, but with some distinctive characteristics.

In iron oxide batteries, an electrochemical reaction occurs between iron and oxygen. During charging, iron is oxidized at the negative electrode (anode), releasing electrons and forming iron ions (Fe^{2+}). Simultaneously, oxygen from the air is reduced at the positive electrode (cathode), combining with water and electrons to form hydroxide ions (OH^-). During discharge, the reverse reaction takes place, with iron ions at the negative electrode combining with hydroxide ions to form iron hydroxide plus the release of electrons, while oxygen is liberated at the positive electrode.

The main advantages of iron oxide batteries are their long storage duration and their potentially lower cost, stemming from the abundance and relatively inexpensive cost of iron as compared to materials used in other batteries like lithium or vanadium. Typically, other battery technology can provide their rated power for a maximum of 4 hours, with some vanadium flow batteries reaching 8 hours of supply. Iron oxide systems can deliver their rated power for up to 100 hours. Additionally, they have a high theoretical energy density, making them suitable for large-scale energy storage applications. Iron oxide batteries have a long cycle life and good durability. An advantage of iron oxide batteries over lithium-ion batteries is that the electrochemical reaction present in iron oxide batteries can't experience the thermal runaway possible in lithium-ion batteries.

Similar to lithium-ion batteries, iron-oxide batteries do not produce energy. They serve only as storage for energy produced by other means, and so are constrained and influenced by the cost and availability of the power required to charge them.

Pumped Hydro Storage

Typically, a pumped storage project consists of an upper and lower reservoir, a set of penstocks or conveyance tunnels, and a pumping/generation turbine unit or units. A pumped storage plant can be open or closed loop. Closed loop systems are completely disconnected from the main surface water body and only require additional water to overcome evaporative and seepage losses. Open loop systems are directly connected into the main surface water body (lake or river). In the NW, most new proposed pumped storage systems are closed loop – primarily due to environmental factors.

In pumped hydro storage, water is typically pumped up from the lower reservoir to the upper reservoir when prices are low or excess generation is available. The water is then released and used to generate power when prices are high or additional generation is needed. The capacity of a pumped storage project varies based on difference in elevation between the reservoirs and the size of the reservoirs. A typical project envisioned for the region is in the 600 MW to 1500 MW range with a storage capacity of 8 to 12 hours of full generation. A project generally requires slightly more pumping time to fill the upper reservoir than the available generation time at full power. A typical capacity factor is in the 40% range and the typical round-trip efficiency is approximately 80%.

An advantage of pumped storage projects are that the technology is mature and well understood. Pumped hydro storage has been used all over the world for decades and large utilities in the region have the in-house expertise to operate and maintain a pumped storage project. Maintenance and operations costs are relatively low, and efficiency is high. Long storage times give pumped storage advantages over the storage times of other commercially available storage solutions like lithium-ion batteries. Pumped storage projects also enjoy a long service life, with expected useful lives of greater than 60 years.

Disadvantages of pumped storage projects include development time, which including permitting and construction, is usually in excess of ten years, and the large capital investment required. Also, a pumped storage project may be too large for a single utility to effectively use. The developer must then sell slices, or shares, of the project off to multiple utilities or a consortium of utilities.

Small Modular Nuclear Reactor

Small modular nuclear reactors (SMRs) work by splitting uranium atoms to generate heat, which is used to produce steam to drive a turbine generator to produce electricity. Existing commercial nuclear reactors in the United States are almost exclusively 3rd generation design, 1,000 MW plus, low enriched uranium fueled machines. SMRs represent the next step of nuclear technology of generation 3.5 to 4th designs. These modern designs utilize numerous improvements to safety, reliability, economics, and decreased proliferation risk to produce a vastly improved nuclear reactor. The general concept behind SMRs of generation 3.5 and greater is that of a smaller, simpler, safer, and less expensive machine intended to be modular in both construction and operation. Current SMRs generally focus on sub-100 MW reactors designed to be combined to take advantage of scaling, redundancy, and factory-centric construction to lower cost and increased performance. This provides much better optionality leading to significantly improved economics.

Many SMR designs now utilize High Assay, Low Enriched Uranium (HALEU) fuel. This new fuel offers vastly enhanced performance with almost no downside. HALEU fuel can be used to provide power for up to 6 years, whereas reactors using LEU fuel require refueling every 2 years or less. The increased useful lifetime of HALEU also dramatically reduces the volumes of waste created from operation.

Benefits of SMR include their ability to generate clean, carbon-free energy on demand and at high capacity factors, and their compact but scalable design that allows them to be used in places that would not support larger conventional reactors.

Because SMR are currently developing technology their drawbacks include the current lack of knowledge of their true future construction and operation costs. SMRs also face licensing challenges as well as potential for as yet unknown and undeveloped regulatory requirements.

Bonneville Power Administration

Grant PUD has the opportunity to purchase firm power from BPA at PF Tier 2 rates for retail loads other than new large single loads. Under the Northwest Power Act, a new large single load is defined as any new load or expansion of existing load, at a single facility that grows by 10 aMW or more in any consecutive 12-month period. Tier 2 rates will be based on the actual or forecast price BPA must pay to acquire the power.

From indications received through participation in the Provider of Choice Process, we have chosen to assume that Grant PUD could receive approximately 40 aMW of PF Tier 2 power through contract with BPA in the period 2028 through 2044 and will consider such a contract as a candidate resource for our plan. From indications received through participation in the Provider of Choice Process, we have chosen to assume that Grant PUD could receive approximately 40 aMW of PF Tier 2 power through contract with BPA in the

period 2028 through 2044. For use in evaluating that potential contract we developed a forecast of Tier 2 costs based on our energy market price forecast, assumed transmission losses and projections of BPA overheads and transmission rates.

Slice Contracts and Pooling Agreements

Grant PUD has and is currently participating in slice sales of PRP and a pooling agreement. We anticipate that Grant PUD will continue to utilize slice sales and pooling agreements when they are beneficial. However, to formulate our resource plan, we modeled Grant PUD retaining all PRP output at the conclusion of existing contracts. This method of evaluation was chosen because potential future contract terms are not yet determined. Future optimization, outside of this IRP, will include a plan for monetizing the value of PRP assets and reducing water risk.

Wholesale Trading

Grant PUD currently actively participate in wholesale trading and will continue to do so in the future. For the purpose of this plan, wholesale energy transactions were assumed to be available at forecast energy market prices at quantities required. Wholesale transactions assumed in this plan were for energy only, with no clean energy or capacity attributes.

DEMAND SIDE RESOURCES

The following types of demand side resources were considered when formulating this IRP.

Conservation and Efficiency

In compliance with the EIA, with the help of EES Consulting, Grant PUD conducted a biennial Conservation Potential Assessment (CPA) to estimate the conservation potential for the 20 year planning period of 2024 to 2043. This CPA was adopted by Resolution of the Board of Commission in June 2024 and sets Grant PUD's ten-year conservation potential plan and two-year conservation target.

The CPA evaluates four sectors: residential, commercial, industrial, and agricultural and considers conservation resources that are reliable, available and cost effective. Conservation and efficiency impact both energy use as well as peak demand requirements. Table 11 illustrates CPA findings of the cost-effective energy potential of the sectors examined.

Table 11. Estimated cost effective conservation potential energy savings, aMW

Sector	2-Year	4-Year	10-Year	20-Year
Residential	0.17	0.38	1.47	3.12
Commercial	0.66	1.34	3.34	6.52
Industrial (including data centers)	1.00	2.68	9.69	19.96
Agricultural	0.18	0.49	1.49	3.01
Total	2.00	4.89	15.99	32.61

Table 12 shows the CPA findings of the potential conservation and efficiency impact to system peak.

Table 12. Estimated cost effective conservation potential demand savings, MW

Sector	2-Year	4-Year	10-Year	20-Year
Residential	0.53	1.22	4.88	10.96
Commercial	0.53	1.07	2.64	5.04
Industrial (including data centers)	1.05	2.86	10.78	22.58
Agricultural	0.02	0.05	0.29	0.70
Total	2.13	5.20	18.60	39.29

The largest share of future savings is projected to come from large data center projects and depends largely on future load growth in that sector. Commercial projects represent the second largest potential savings sector, with efficiency projects spread over several end uses, with the largest category being HVAC improvements

The EIA requires that utilities with greater than 25,000 customers pursue all cost-effective conservation resources and meet conservation targets set using a CPA. For this IRP, we assumed that Grant PUD will achieve the energy and demand savings determined by the CPA. The full CPA report is attached as Appendix 3.

Demand Response

Demand Response (DR) is a non-persistent, intentional change in electricity usage by retail customers from normal consumptive patterns in response to a request from the utility. At the most basic level, customers are compensated for reducing loads during times of need, reducing the need for utilities to invest in expensive, long-life assets. Utilities have used DR programs as an alternative to supply side resources for decades to help meet peak loads, particularly during periods of scarce supply and/or high wholesale market prices. During the energy crisis in the early 2000's, Grant PUD entered into agreements with large load customers to reduce energy consumption for this purpose. Since that time, Grant PUD has occasionally negotiated short-term arrangements with large load customers during periods of extreme wholesale prices or extended reliability events.

Historically, the Northwest has met peak load requirements with a combination of hydro and natural gas peaking units. However, while peaking needs continue to increase, developing traditional peaking resources in the current environment is challenging as described below:

- The Clean Energy Transformation Act (CETA) requires WA utilities to serve load with 100% carbon free resources by 2045. This substantially reduces the useful life of traditional carbon emitting resources such as natural gas peaking units and increases the risk of early obsolescence of those resources.
- The Climate Commitment Act (CCA) requires carbon emitting generation to consign carbon allowances to the State resulting in higher operating costs for carbon fueled resources such as natural gas.
- Widespread acceptance of the Western Resource Adequacy Program (WRAP) requirements throughout the region requires participating utilities to show they have sufficient capacity to meet projected peak demand in future years. Because market purchases do not qualify as a resource under WRAP, Grant's historical reliance on supply from the wholesale market has substantively increased the need for specific capacity resources under WRAP. Demand response programs do qualify as capacity resources under WRAP.
- Relicensing and permitting costs for hydro facilities are becoming increasingly expensive as additional environmental requirements such as fish passage and additional flow regimes are required. This has led to projects being abandoned, such as the Klamath Falls projects in California, while others have faced substantial increases in relicensing costs such as Seattle City Light's Skagit hydro facility, while BPA hydro facilities are experiencing increased spill requirements leading to reduced capacity.
- Permitting and siting of new natural gas pipelines is increasingly challenging.
- Coal plants continue to be retired reducing a source of reliable, dispatchable power, increasing the need for new capacity sources.
- There is a significant upward shift in NW load projections over the next decade driven by rapidly increasing demand from new large-load customers, particularly data centers fueled by AI computing requirements, as well as policies that encourage electrification in buildings and transportation.

For the reasons above, demand response programs are becoming more economically viable and Western utilities are increasingly investing in these programs in addition to supply side capacity resources.

Grant PUD has been working to expand its capability to offer demand response programs through research, vendor and customer engagement, and a pilot program. These ongoing efforts have provided Grant insights which will be useful in developing long term demand response programs. Specifically, two DR programs can likely be implemented faster than the time required to develop or acquire output from traditional assets such as solar, wind, and batteries. If resourced and pursued, these programs provide an opportunity to reduce anticipated near-term capacity shortfalls while the PUD pursues long term assets.

The two programs are: 1) direct load curtailment of Rate Schedule 17 (Evolving Industry) cryptocurrency customers, and 2) direct load curtailment of Rate Schedule 3, Irrigation. These two DR programs are in a mature state at various utilities throughout the country. Cryptocurrency demand response is common in Texas and has also been implemented in the Northeast and Canada, while PacifiCorp and Idaho Power have employed irrigation demand response in Oregon and Idaho for years.

Substantial work has gone into researching and evaluating these programs including a review of comparable programs at other utilities, engagement with potential participating customers, research on available quantity and term of interruption, pricing, technology, and billing. A pilot program for Rate Schedule 17 is currently ongoing which should provide additional insights into cryptocurrency load as a potential precursor to advancing to a direct load control program.

Demand response represents a way of addressing peak load capacity concerns via peak shaving but is not a means of supplying continuous energy. This means that demand response resources compete with storage technologies such as batteries and peaking assets such as combustion turbines, but not with baseload supply such as nuclear or combined-cycle gas turbines.

Demand response resources can be developed and implemented faster than other capacity resources as do not require permitting, land acquisition, engineering, construction, or other long lead time items associated with building hard assets. They do require additional investment in the following areas: 1) Distributed Energy Resource Management System (DERMS) to place customer loads directly in the control of dispatch to meet WRAP standards as a resource, 2) Product Development including matching load duration with the identification of available frequency of potential load interruption, customer requirements, penalties and exit criteria, and 3) changes to billing and accounting. Staff in the Customer Solutions and Large Power Supply groups estimate it will take two years to complete these programs once the demand response is selected as a priority for development, given the resources and investment needed to align the resource with Grant PUD's needs.

These demand response programs can only provide a portion of the estimated capacity needs for Grant PUD as the available capacity in terms of total MW and hours available is limited by customer willingness to participate at various price incentive levels. Based upon preliminary review, 30 to 50 MW is a reasonable amount that could be available through implementation of cryptocurrency and irrigation DR program in 2026, with the Irrigation Demand Response program available only for peaking needs during the irrigation season.

There may also be additional, concentrated demand response opportunities, especially in industrial rate schedules 14 and 15. The size and value of these resources are highly dependent on an individual customer's core activity, load factor, and sensitivity to load curtailment.

For this IRP, we considered a potential demand response program modeled on our current pilot program for Rate Schedule 17.

8 | Selection of Future Resources

This section describes the methods used to assess potential new resources and shows the results of the modeling exercise performed for that assessment. It also provides discussion of the implications of the modeling results.

Through the planning process used to formulate this IRP, we identified several primary objectives. These objectives, modeled as constraints inside the PowerSIMM model were to:

- Serve customer load in a least-cost, reliable manner
- Maintain planning reserve margin consistent with our current understanding of the WRAP program
- Maintain the 15% RPS required by the Energy Independence Act
- Meet the CETA requirement of 80% clean energy sales to customers beginning in 2030, and 100% clean energy sales in 2045

RESOURCE ASSESSMENT

The PowerSIMM modeling platform developed by Ascend Analytics was used to evaluate the potential future resources described in Section 7 and to formulate a resource portfolio able to meet our identified objectives. The Automated Resource Selection (ARS) module of PowerSIMM was used for selection of resource additions, for capacity expansion, and the dispatch module was used to investigate hourly operations of selected potential future resource portfolios. Finally, PowerSIMM was used to run selected portfolios under conditions of isolation from the marketplace to produce loss of load predictions. Ascend Analytics staff performed all modeling using input data provided by Grant PUD staff.

An overview of the modeling framework, indicative of what was employed for the IRP analysis is shown in Figure 45

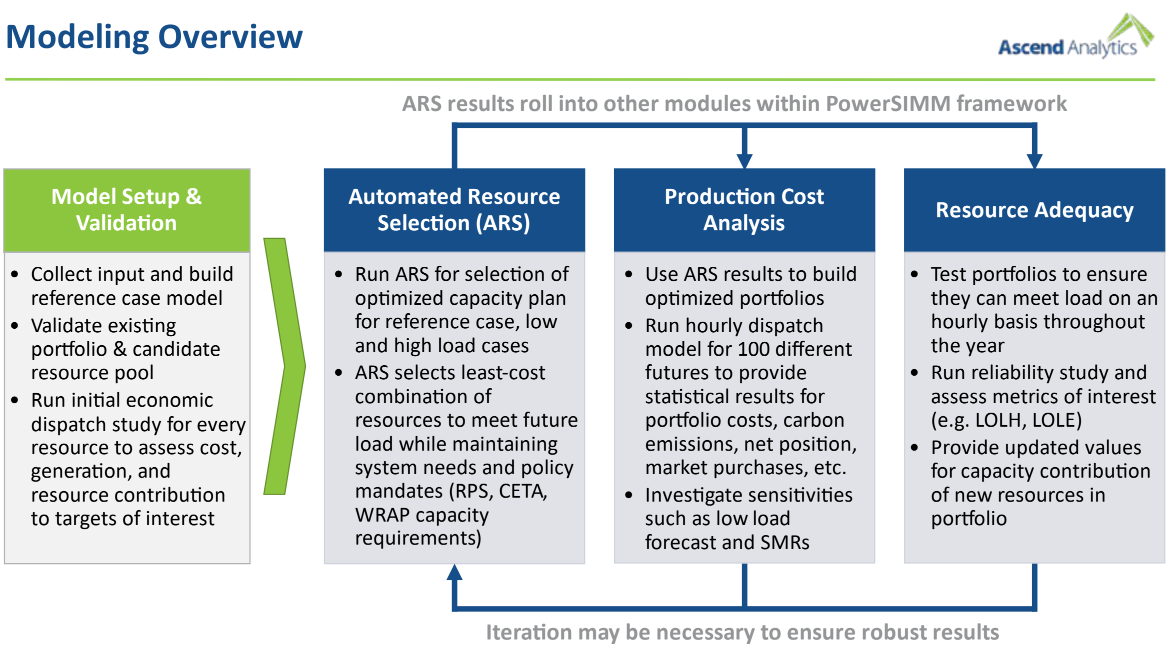


Figure 45. Modeling framework for development of least-cost, compliant and reliable portfolios using PowerSIMM software

First, historical generation data, load forecasts, market price projections, information on regulatory constraints, attributes and operating characteristics of existing and candidate resources, and other information required to model Grant PUDs current and potential future resource portfolio was gathered and entered into PowerSIMM. Then a verification that the modeled systems behaved as anticipated under alternative weather and pricing conditions was completed.

A set of economic dispatch studies were then run for every candidate resource to assess costs, generation, and contribution to plan objectives. These assessments were input to the Automated Resource Selection module, which used the information to select new additional resources for Grant PUD's portfolio resources based on the stated objectives of minimizing the net cost of procuring and operating new and existing resources while maintaining planning reserve margins, maintaining a 15% RPS, and meet the CETA requirement of 80% clean energy sales to customers beginning in 2030, and 100% clean energy sales in 2045

Once ARS selected appropriate additional resources, these resources were incorporated into a portfolio including Grant PUD's existing resources and evaluated using an hourly dispatch model. This evaluation helped understand the portfolio's operational feasibility and the overall implications of the portfolio. In order to better capture the uncertainty of future conditions, PowerSIMM's stochastic framework was used to simulate 100 different future conditions, where market prices, weather patterns, renewable generation, water availability, and load significantly vary. To capture the risk associated with the distribution of portfolio costs resulting from the 100 different futures, a "risk premium" metric that indicates the cost at risk or the actuarial value of a portfolio's exposure to market price volatility, variation in generation and load, and changes in weather conditions was applied.

The ARS selection process was completed for our base case assumptions, referred to as our reference case, as well as cases with a lower load growth forecast, a lower energy market price forecasts and case with the inclusion of two SMR models in the portfolio beginning in 2034.

Finally, Grant PUD's existing portfolio, the reference case, lower load growth and SMR portfolios were assessed for resource adequacy using loss of load hours studies. PowerSIMM was used to simulate 250 futures that capture extreme events for weather, load, hydrology and renewable generation. Each of the portfolios was dispatched to minimize unserved energy.

Additional details on the PowerSIMM model capabilities and methods employed are provided in Appendix 1. Specific details about inputs used for the modeling process are provided in Appendix 2.

SELECTED RESOURCE PORTFOLIO

The planning process used to formulate this IRP focused on several key planning considerations. Through the modeling analysis performed for this plan, a future potential resource portfolio was selected as the current best, least-cost alternative to meet customer needs while addressing these considerations. We recognize that the IRP modeling exercise is bound by the information and constraints provided to it, and although information used is our current best estimate of what the future may look like, given a different view of future possibilities, or inclusion of additional considerations, modeling would arrive at a different result.

Modeling assumptions allowed no new capacity until 2026. This delay in the addition of new resources is consistent with our current understanding of acquisition potential.

Also, while we may have the opportunity to continue to engage in utilizing slice contracts and pooling agreements after the expiration of the current contract terms, use of such a strategy was not permitted as a resource during ARS modeling. Retention of Grant PUD's physical share of PRP was modeled due to undetermined future contract terms. The exclusion of slice contracts and pooling agreements from the modeling analysis should not be construed as a reluctance to pursue these types of agreements in the future. As opportunities arise to participate and slice contracts and pooling agreements, potential contracts will be evaluated.

For more detailed information on assumptions surrounding resource cost, capacity rating, operating characteristics and availability see Appendix 2.

We present the following results of our 2024 IRP modeling and commit to continued ongoing assessment and analysis to ensure the best decisions are made on Grant PUD customers' behalf.

Resource Mix of Selected Portfolio

The selected portfolio is the modeled least-cost portfolio based on the given inputs, constraints, and reference case load growth. In addition to Grant PUD's existing resources, the selected portfolio includes 1,618 MW of nameplate additions:

- 860 MW of solar located in Grant County
- 310 MW of solar located in Oregon
- 160 MW of lithium-ion battery storage in Grant County

- 210 MW of lithium-ion battery storage in Oregon
- 10 MW of wind located in Oregon
- 40 MW of BPA Tier 2 contract
- 28 MW of demand response

Figure 46 illustrates the recommended timing of these resource acquisitions. Only the year of initial addition is shown in the chart, though all of these additions will remain in the portfolio through the planning horizon.

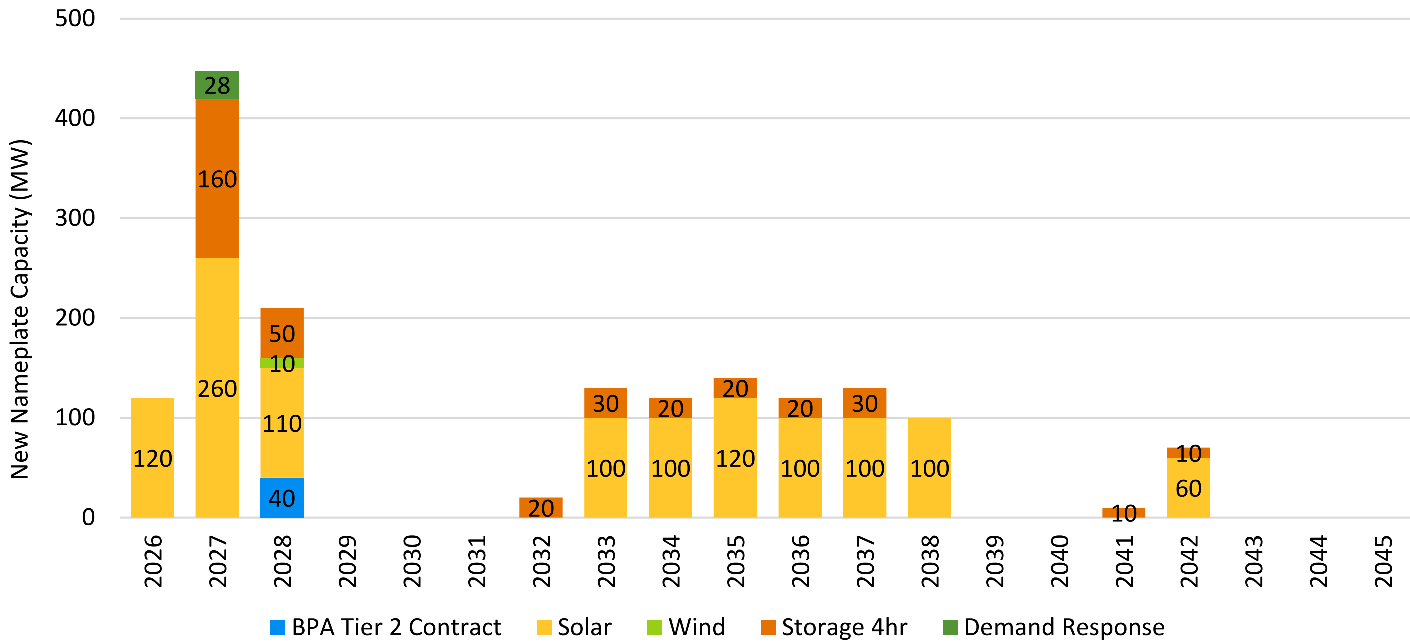


Figure 46. Resource additions of selected portfolio, by year, by technology type, nameplate MW

There are two distinct periods of resource acquisition in this plan. The near-term acquisition period, 2026 through 2028, represents acquisitions needed to increase Grant PUD's capacity position in order to participate in the operations program of WRAP. A second period of resource acquisition in the mid-period years of 2032 through 2038 while in part serves to support continued growth in capacity needs, is largely made to ramp Grant PUD's portfolio into the clean energy sources required for CETA compliance.

<u>Near-Term Resource Selections</u>

Portfolio additions from 2026through 2028 are driven by the need to acquire the capacity required for WRAP participation. Acquisitions during this period are highly constrained, being limited to either currently existing projects or projects in the latter stages of their development phase. Using these limited available resources, along with constraints to meet energy and capacity requirements in a least-cost manner, through modeling exercises the following additions were selected for addition during this period:

- 300 MW of solar located in Grant County
- 190 MW of solar located in Oregon
- 140 MW of lithium-ion battery storage in Grant County
- 210 MW of lithium-ion battery storage in Oregon
- 10 MW of wind located in Oregon
- 40 MW of BPA Tier 2 contract
- 28 MW of demand response

Of all resources evaluated, demand response is estimated to carry the least expense on both a $/MWh energy basis and a $/MW capacity basis. In the selected plan, this resource is chosen as an addition in the first year of WRAP participation.

BPA Tier 2 while slightly more costly than either solar or wind generators on a $/MWh basis, is assumed to be a firm delivery of power and so has a favorable electric load carrying capacity to help meet WRAP capacity requirements. It is selected, at the maximum possible amount, at its first availability in October 2028.

Early in the planning period, on a $/MWh basis, wind is a lower cost energy solution than solar, and the capacity expansion model selects a small tranche of Oregon-located wind generation in 2028. However, the most binding constraint in the first three years of the planning period is the need to meet WRAP capacity requirements. With the current portfolio, three of four of Grant PUD's highest capacity deficit months occur in summer. Solar has a much higher ELCC than wind in the summer. Because of this match between summer need and summer availability the least cost available solution to fill existing near-term capacity deficits is solar. Due to lower transmission costs and losses associated with bringing energy to customers, siting in Grant County is preferred. However, due to current transmission queue conditions, we recognize that Grant PUD will likely be able to connect a maximum of 300 MW of generation in the Grant PUD BA over the period 2026 – 2028. Solar capacity above that amount is expected to come from the next most economical solar resource locations. Locations in Oregon have solar profiles similar to Grant County solar profiles, have lower delivery costs than locations further from customers' point of consumption, and therefore are recommended once Grant County solar potential is reached.

210 MW of lithium-ion storage is selected in the near-term plan. Based on current knowledge of local development and transmission queue entries, no lithium-ion storage resources were considered to be available in Grant County before 2031. Locating lithium-ion batteries in Oregon was made before that 2031 entry date. Selection of the 4-hour storage technology works to provide capacity during winter months when other portfolio resources' ELCC ratings are low, and to provide protection from volatile wholesale market prices during evening and early morning hours when load is high and solar power is at less than peak production.

Mid-Term Resource Selections

The second acquisition period, from 2032 through 2038, is needed to ramp the Grant PUD portfolio into the clean energy sources required for CETA compliance.

Using available candidate resources, and considering constraints to meet energy, capacity and clean energy requirements at least-cost, our modeling exercises selected the following resources for addition during the period 2032 through 2038:

- 500 MW of solar located in Grant County
- 120 MW of solar located in Oregon
- 140 MW of lithium-ion battery storage located in Grant County

Given current forecasts of solar and battery PPA costs, acquiring clean energy resources prior to the 100% clean energy target date of 2045 is more economical than delaying. Clean energy acquisition occurring over a multi-year period also reduces the risk of failing to bring required resources online during a potential last-minute rush to meet CETA regulations. Clean energy acquired in years prior to 2045, and in excess of that needed for Grant PUD's 80% clean CETA requirements for the years 2030 through 2044, can be used produce RECS that could be sold to generate revenue. Clean energy resources selected for addition in the mid-term period also provide capacity for maintaining WRAP requirements.

As in the near-term planning period, solar and lithium-ion battery storage are selected for their relatively low-cost energy as well as their capacity values, however in this period their clean-technology characteristics are of growing importance. Solar is once again located in Grant County to take advantage of lower transmission costs and delivery losses. Once capability to locate in Grant County is met, installations sites are sought in Oregon.

Late-Term Resource Selections

The last acquisition period of 2041 and 2042 is required to maintain both WRAP and CLETA requirements with smaller additions needed as load growth moderates.

Evolving Resource Mix

The selected portfolio gradually moves Grant PUD from a virtually 100% hydropower-based portfolio to a balanced mix of hydropower, solar and storage. Figure 47 shows the nameplate capacity of our selected portfolio by resource type, including currently existing resources, through 2045. Market purchases are shown in the plots as net annual amounts.

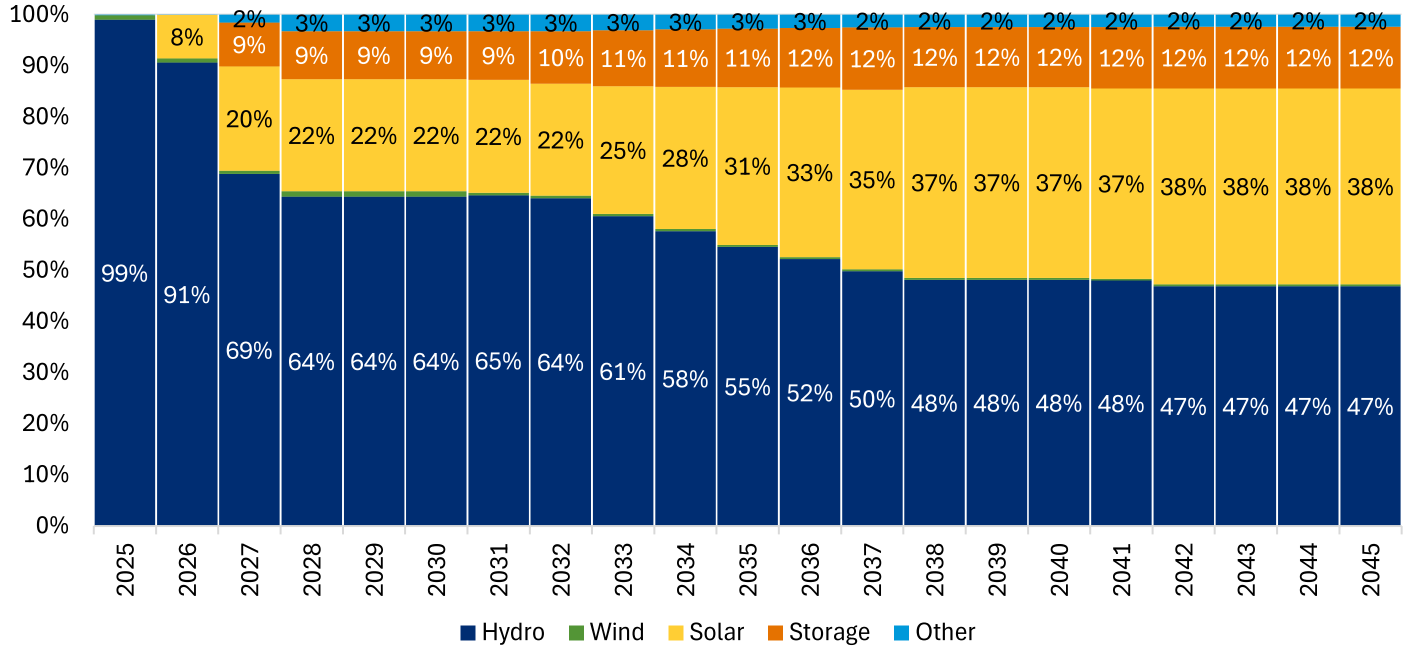


Figure 47. Selected portfolio nameplate capacity by resource type, 2025 – 2045, percent of portfolio

This resource diversity, while somewhat predicted from the mix of current commercially available technology, will be beneficial in avoiding over-reliance on a single fuel source. A portfolio with high concentration in any one technology or fuel type could leave Grant PUD customers exposed to expensive price increases if that source faces operational challenges (American Public Power Association, 2024). A diverse portfolio is also advantageous because each fuel and technology type possesses characteristics that align with specific applications and needs .

Energy Position of Selected Portfolio

The selected portfolio fills the bulk of Grant PUD's energy needs, mitigating risks of exposure to short-term markets. Figure 48 compares the annual expected energy contribution of each resource type, represented by the stacked bars, to the expected customer energy needs represented by the dotted line. Lithium-ion battery storage is not shown in Figure 48 because these resources store, but do not produce, energy. Resources from the existing Grant PUD portfolio are shown as solid-filled blocks. Recommended resource additions are shown as pattern-filled blocks.

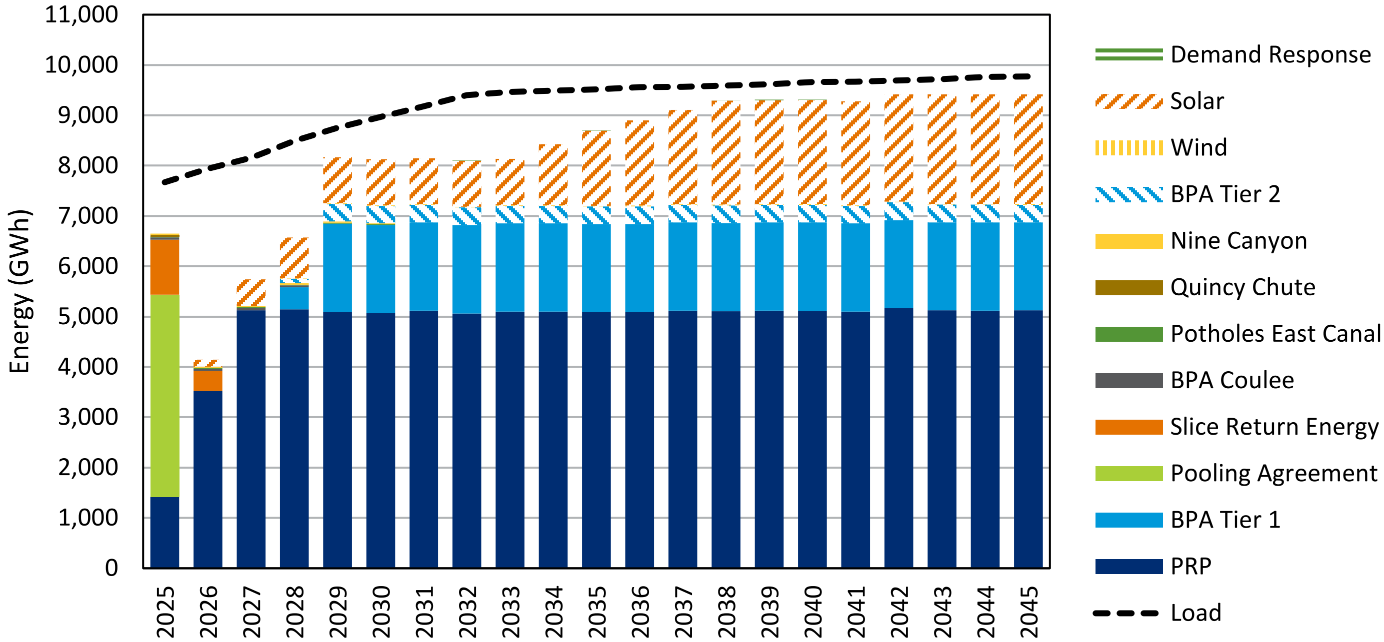


Figure 48. Selected portfolio annual energy position by resource type, 2025 – 2045, GWh

Note that Figure 48 is only a representation only of how Grant PUD may choose to serve customer requirements with the selected portfolio. Currently, slice sales, pooling agreements and the wholesale market are utilized to economically meet customer needs, and, though this strategy is not represented here, it will continue in the future when advantageous to customers. Analysis of optimizing the value of PRP will be undertaken in future analyses.

Market participation is not represented in Figure 48 or the following figures in this section in order to highlight the energy expectations of the selected portfolio. However, the gap between the stacked bar of portfolio resources and the dotted line of customer load is assumed to be filled by wholesale market transactions. Comparing the current portfolio's energy position shown in Figure 36 to the energy position of the selected portfolio in Figure 48, we can see the planning horizon reliance on the wholesale energy market moving from 30% of customer needs with the current portfolio to 13% of customer needs in the recommended portfolio.

Figure 49 illustrates the monthly variation of energy production expected from the selected portfolio in 2029, the first year after completion of all near-term additions (490 MW of solar, 210 MW of lithium-ion batteries, 40 MW of BPA Tier 2 contract, 28 MW of demand response and 10 MW of wind.)

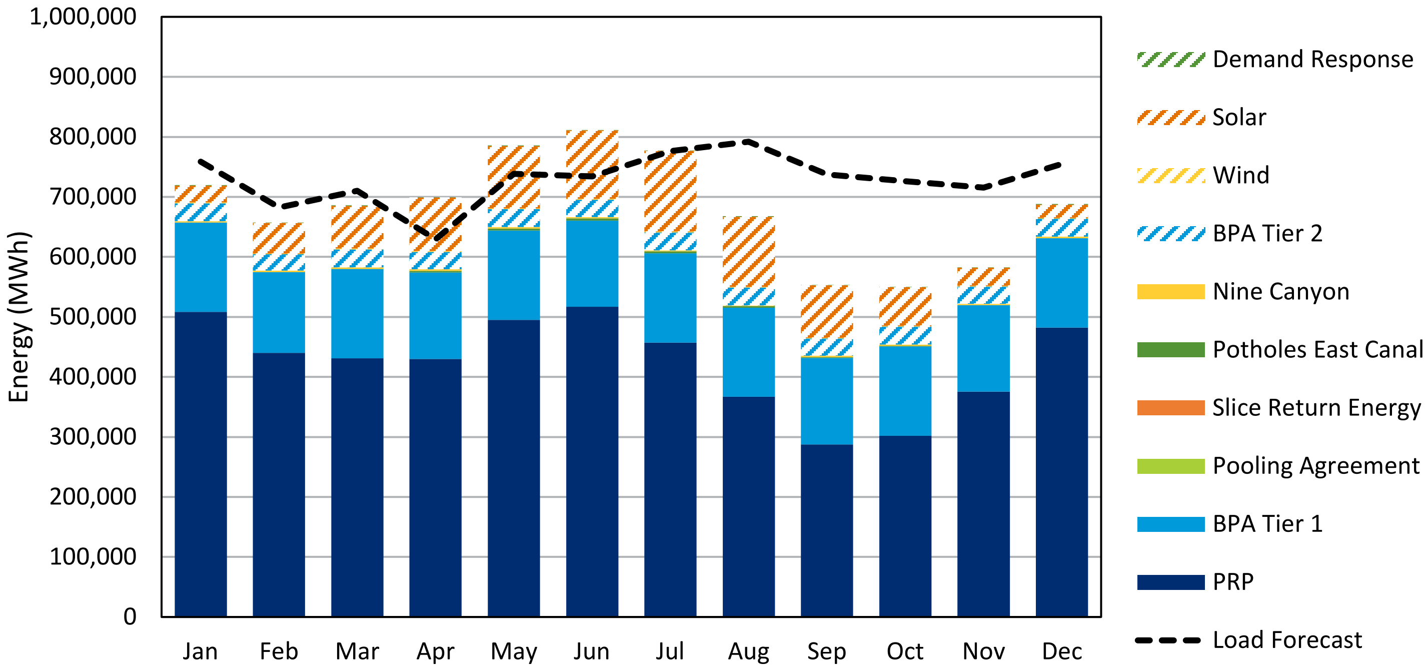


Figure 49. Selected portfolio monthly energy position by resource type, 2029, MWh

Note that the monthly potential to serve customers from the portfolio, represented by the sum of the stacked bars, roughly follows the same shape as that of the PRP portion of the portfolio. The monthly shape of the PRP resource does not follow the same shape as that of monthly customer load. This results in the need to support customer requirements with wholesale market purchases in the low water-availability months of late summer and fall.

Figure 50 illustrates the monthly variation of energy production expected from the selected portfolio in 2039, the first year after completion of both near-term and mid-term additions (1100 MW of solar, 350 MW of lithium-ion batteries, 40 MW of BPA Tier 2 contract, 28 MW of demand response and 10 MW of wind.)

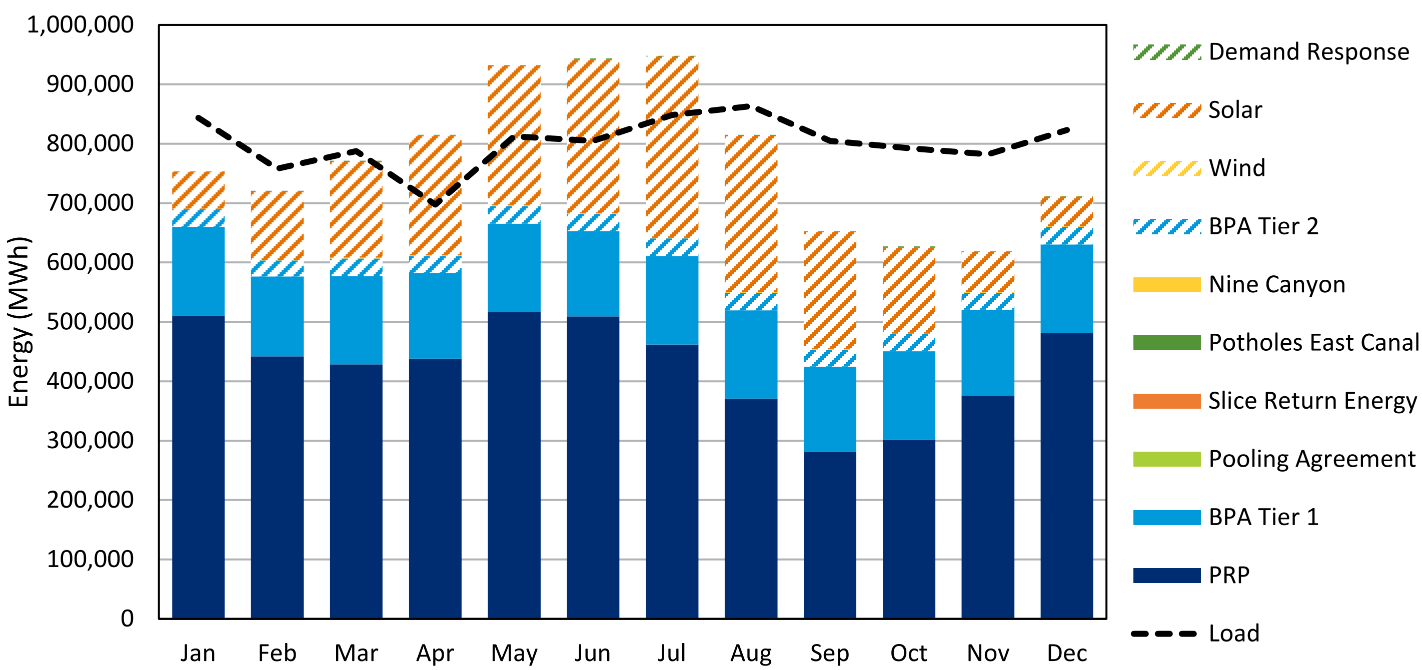


Figure 50. Selected portfolio monthly energy position by resource type, 2039, MWh

After the significant solar buildout, monthly potential to serve customers from the portfolio, represented by the sum of the stacked bars, begins to noticeably deviate from the shape of the monthly PRP energy position. The portfolio now holds a long position during the solar high-performance summer months. However, the need to support customer requirements with wholesale market purchases in the low water-availability months of late summer and fall continues now due to both lower water and lower solar availability during those months.

Capacity Position of Selected Portfolio

Figure 51 illustrates the monthly WRAP-based capacity position of the selected portfolio.

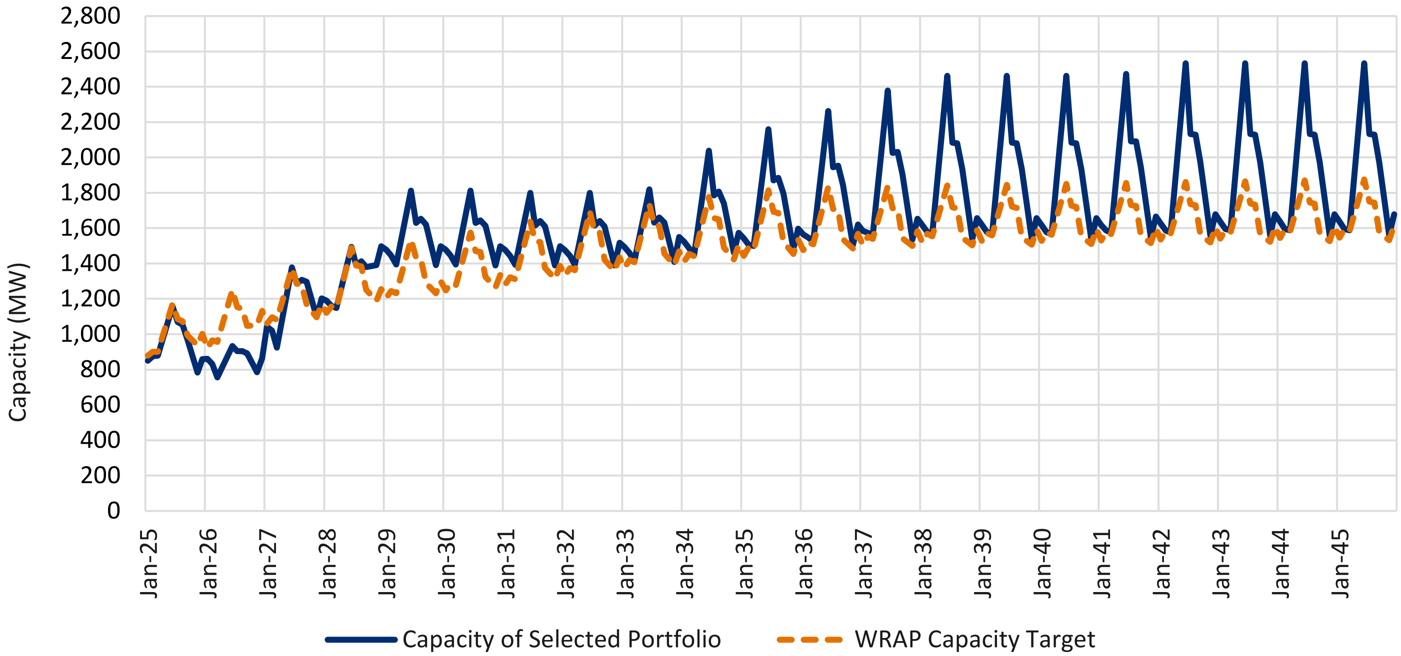


Figure 51. Selected portfolio monthly capacity position compared to forecast WRAP target, 2025 - 2045, MW

By design, the selected portfolio meets all monthly WRAP obligations beginning in 2027. Months with the portfolio's tightest capacity margins are March, November and December. In these months both PRP and solar have low qualifying capacity. Solar has its highest qualifying capacity ratings in June, July and August. As more and more solar is added to the portfolio in the mid-2030s we see the capacity margins during these months grow, though margins in March, November and December remain flat.

RPS Compliance with Selected Portfolio

The selected portfolio's additions of solar energy position Grant PUD to be able to meet the EIA RPS requirement through the planning horizon. Figure 52 shows the forecast RPS target and the potential renewable energy contribution of resources in the selected portfolio. Note that the position shown in the figure does not include the use of RECs. RECS are a compliance option for EIA and may be chosen by Grant PUD as part of its compliance strategy. The selected portfolio could produce excess clean generation that could be used to produce marketable RECs.

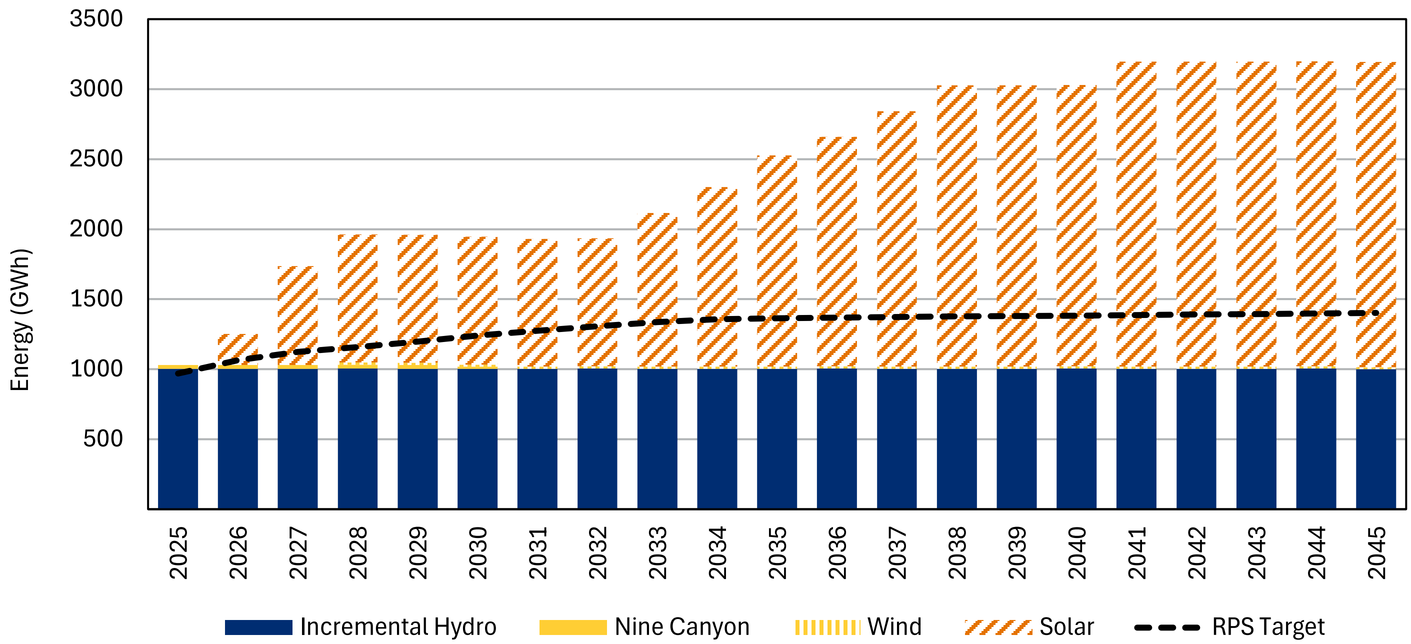


Figure 52. Forecast RPS requirement and contribution of eligible resources in selected portfolio, 2025 - 2045, GWh

CETA Compliance with Selected Portfolio

By design, the selected portfolio is able to meet CETA clean energy obligations beginning in 2030. Figure 53 illustrates both the forecast CETA clean energy targets as well as the eligible contribution potential of the selected portfolio. Future CEIPs will determine how eligible resources will contribute to meeting CETA requirements. However, this figure illustrates that if Grant PUD allocates all selected portfolio resources for CETA compliance, it would hold sufficient resources to meet the 80% clean mandate for the period 2030 through 2044. RECs could be used in the period 2030 through 2037 to reach the 100% clean level. In 2045, the portfolio could provide 100% clean energy to customers.

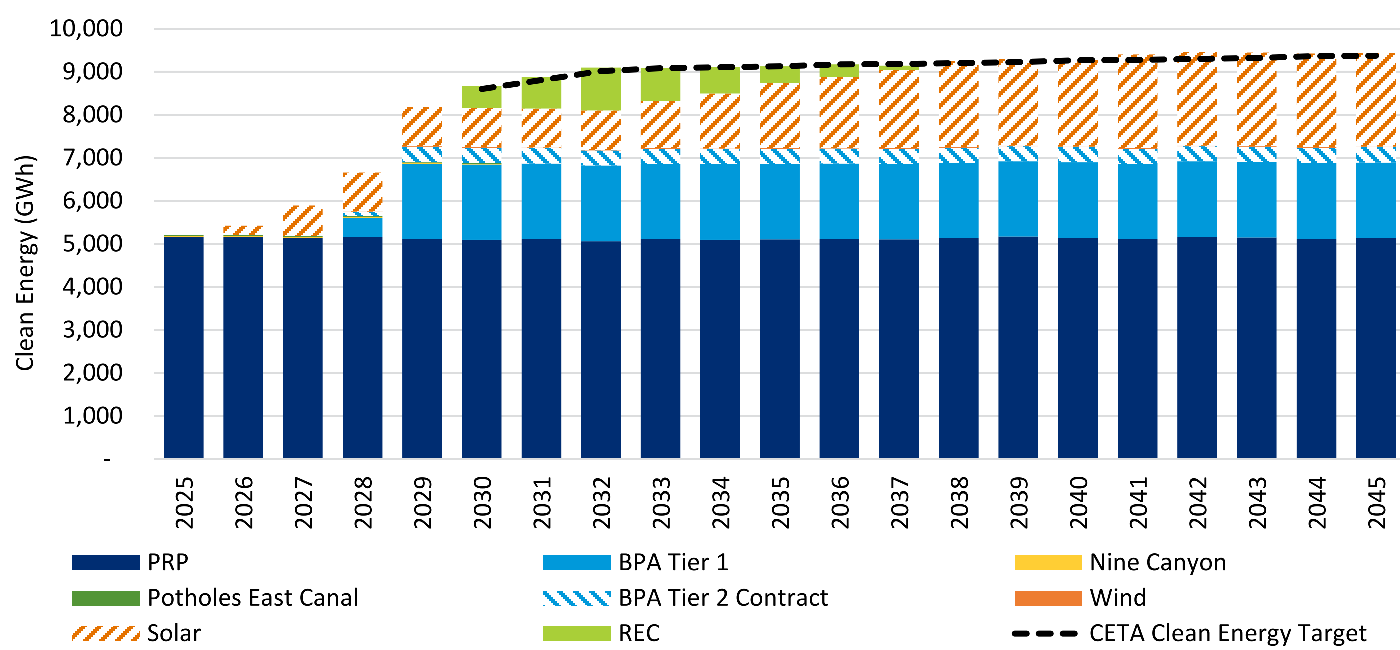


Figure 53. Selected portfolio annual CETA clean energy position, 2025 - 2045, GWh

For more detailed information on assumptions surrounding resource cost, capacity rating, operating characteristics and availability used in the selection of the recommended portfolio see Appendix 2.

Reliability Analysis of Selected Portfolio

"Loss of load" describes the situation in which available generation capacity is less than system load. Loss of load metrics were investigated using probabilistic modeling which considered variations in weather, load, water availability and risk from intermittent resources. Due to the computational complexity involved, the selected portfolio was examined for loss of load metrics for only the years 2029 and 2039. These years were selected for examination because they immediately follow the conclusion of the near-term and mid-term acquisition periods.

During loss of load simulations, the selected portfolio was dispatched to serve Grant County PUD customer load in isolation from energy markets with the objective of minimizing unserved energy. Evaluation of these simulations helps assess the reliability and adequacy of the portfolio but does not represent actual operation of the system.

Figure 54 shows the estimated number of lost load hours by hour, by month for the selected portfolio during 2029. As expected from the characteristics of PRP and solar generation, loss of load hours occur more frequently during the late summer through winter months, and during the non-daylight hours.

Loss of Load Hours - Selected Portfolio																								
Event Dates	HE00	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23
2029-01	7.9	7.9	8.0	8.5	9.2	10.3	11.7	12.8	14.0	11.9	10.0	8.6	8.2	7.5	6.8	6.4	7.7	11.3	12.4	12.3	12.2	11.8	11.2	10.5
2029-02	7.4	7.6	7.8	8.1	8.6	9.3	10.1	10.7	10.7	7.4	5.3	4.4	4.0	3.6	3.1	2.6	3.0	5.0	9.1	9.6	9.6	9.5	9.2	8.9
2029-03	6.1	6.3	6.5	6.9	7.5	8.1	8.9	8.9	7.5	4.9	3.5	2.8	2.7	2.5	2.0	1.8	2.1	3.0	5.8	7.8	7.8	7.7	7.5	7.4
2029-04	7.8	8.1	8.3	8.6	9.2	9.8	10.0	7.8	6.8	5.1	4.5	4.4	4.4	4.4	4.0	3.9	4.1	5.1	6.5	8.9	9.5	9.2	9.2	9.0
2029-05	5.9	5.9	5.9	6.0	6.4	6.7	5.6	4.0	4.1	3.7	3.5	3.8	4.1	4.0	4.1	4.0	4.0	4.6	5.4	6.1	7.2	7.2	6.8	6.6
2029-06	5.6	5.3	5.4	5.5	5.7	5.5	3.6	2.4	2.8	2.6	2.9	3.1	3.5	3.8	3.8	3.8	4.1	4.2	4.7	5.6	6.9	7.3	6.9	6.5
2029-07	17.4	17.2	17.3	17.3	17.6	17.7	15.0	11.4	11.9	11.7	12.2	12.8	13.7	14.0	14.0	14.0	14.0	14.3	14.9	16.2	18.2	18.4	18.3	18.1
2029-08	23.2	23.2	23.2	23.4	23.7	23.9	22.9	17.4	16.8	15.6	16.0	17.5	18.5	19.1	19.1	18.6	18.9	19.5	20.7	23.3	24.5	24.4	24.3	24.1
2029-09	22.0	22.1	22.3	22.8	23.2	23.7	24.0	19.4	16.5	14.0	13.9	15.1	16.5	16.7	16.4	16.2	17.5	19.5	22.7	24.5	24.4	24.1	23.8	23.6
2029-10	21.9	22.9	23.3	24.0	24.7	25.6	26.7	27.3	25.0	21.6	20.5	21.1	21.9	21.2	19.9	19.2	21.2	25.2	26.8	24.1	24.1	24.1	23.7	23.6
2029-11	16.2	17.0	17.6	18.7	19.7	20.7	23.0	25.2	25.5	23.2	21.9	21.5	21.3	20.5	19.1	19.0	21.4	24.8	24.2	18.8	19.0	19.1	19.0	18.9
2029-12	13.5	14.3	14.4	15.2	16.2	17.6	19.2	20.4	22.0	19.7	16.9	16.1	15.8	14.9	13.5	12.5	15.8	19.9	20.1	19.8	19.5	19.1	18.5	17.4

Figure 54. Selected portfolio loss of load hours, 2029

Figure 55 shows the estimated number of lost load hours by hour, by month for the selected portfolio during 2039, after the second tranche of resource acquisitions. With increased solar resources, the portfolio has a marked decrease in loss of load during the daylight hours in all months except winter. The pattern seen in 2029 of higher loss of load probability overnight remains.

Loss of Load Hours - Selected Portfolio																								
Event Dates	HE00	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23
2039-01	13.2	13.0	13.1	13.7	14.5	15.6	16.9	18.0	19.1	14.0	10.2	8.2	7.3	6.8	6.4	5.9	8.0	15.6	17.4	17.3	17.3	17.0	16.5	15.8
2039-02	9.0	9.2	9.4	9.9	10.3	10.7	11.3	11.7	10.8	4.7	2.6	1.7	1.5	1.3	1.4	1.2	1.6	3.3	9.2	9.9	9.9	10.1	10.0	10.0
2039-03	6.7	7.0	7.2	7.6	8.1	8.8	9.3	8.8	5.0	2.0	1.0	0.6	0.4	0.4	0.6	0.5	0.7	1.3	3.6	6.9	6.9	7.0	7.2	7.2
2039-04	8.2	8.8	9.3	9.6	10.5	11.3	11.0	4.7	2.2	1.0	0.5	0.5	0.4	0.4	0.4	0.5	0.7	1.2	2.7	8.2	9.9	9.2	9.5	9.2
2039-05	6.0	6.2	6.5	6.6	7.1	7.5	4.3	1.7	1.1	0.8	0.6	0.7	0.7	0.8	0.8	0.8	1.0	1.5	2.6	4.5	7.8	7.6	7.2	6.9
2039-06	5.8	5.8	6.0	6.0	6.2	5.8	2.5	1.3	1.0	0.6	0.7	0.6	0.8	1.0	1.0	0.9	1.2	1.4	1.8	3.5	6.6	7.8	7.2	6.8
2039-07	14.1	14.0	13.9	14.2	14.5	14.5	8.3	3.4	2.4	1.8	2.0	2.3	2.9	3.1	3.1	3.0	3.2	4.0	5.4	8.4	14.7	15.9	15.5	15.1
2039-08	18.9	19.1	19.3	19.5	19.7	19.9	17.7	7.1	4.4	2.5	2.6	3.2	4.1	4.7	4.8	4.0	4.7	6.3	9.2	16.6	20.1	19.9	19.8	19.7
2039-09	19.5	19.4	19.5	19.8	20.3	20.7	21.0	11.5	6.0	3.3	2.8	3.3	4.0	4.4	4.3	4.0	6.0	9.0	15.5	20.3	20.3	20.4	20.2	20.3
2039-10	22.1	22.7	23.2	23.7	24.2	24.8	25.2	25.4	15.0	7.6	5.7	6.7	7.8	7.2	6.7	6.8	9.9	17.8	24.8	23.8	23.8	23.7	23.6	23.5
2039-11	21.2	21.6	22.2	23.1	23.9	24.8	25.8	27.1	26.7	20.1	16.4	16.4	16.9	15.4	14.0	14.1	18.3	26.5	26.7	23.2	23.4	23.5	23.4	23.1
2039-12	21.3	21.8	22.2	22.8	23.5	24.5	25.5	26.2	27.2	21.9	16.1	15.7	16.4	15.8	13.8	12.6	18.3	25.7	25.9	25.7	25.6	25.4	25.0	24.5

Figure 55. Selected portfolio loss of load hours, 2039

Grant PUD does not currently have loss of load reliability metrics to help inform capacity expansion selection. The loss of load evaluations performed as part of this IRP development were staff's first quantitative efforts to address this topic as part of resource planning. While results from the loss of load evaluation of the selected portfolio are presented here and can serve as a high-level illustration of general reliability characteristics, loss of load evaluation had no impact on the selection of this IRP's recommended resource portfolio. Appropriate reliability metrics surrounding loss of load analyses will be developed and used in formation of future resource plans.

LOWER LOAD GROWTH RECOMMENDED PORTFOLIO

Because load growth is both a key driver of resource needs and highly uncertain, this plan considers an additional load growth sensitivity, lower load growth. Lower load growth is defined as an overall system growth rate 50% lower than the reference load growth case. When contemplating this plan, we considered the lower load growth forecast might result from several circumstances. This alternative load scenario is used to explore the impact of load growth on the type, timing, and magnitude of resource selections.

Resource Mix of Lower Load Growth Portfolio

The lower load growth portfolio is the modeled least-cost portfolio based on the given inputs, constraints, and lower load growth projections. In addition to Grant PUD's existing resources, the selected portfolio includes 528 MW of nameplate additions:

- 380 MW of solar located in Grant County
- 100 MW of lithium-ion battery storage in Grant County
- 20 MW of lithium-ion battery storage in Oregon
- 28 MW of demand response

Figure 56 illustrates the recommended timing of these resource acquisitions. Only the year of initial addition is shown in the chart, though all of these additions will remain in the portfolio through the planning horizon.

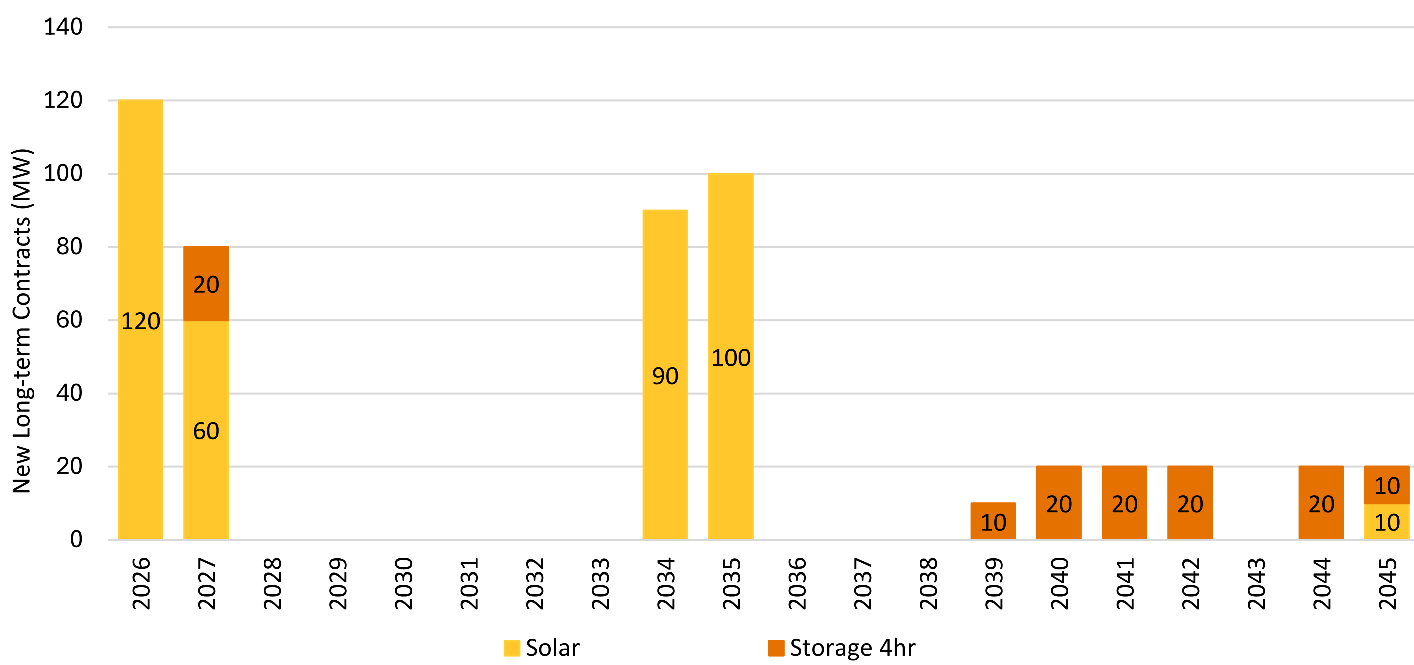


Figure 56. Resource additions of selected portfolio under lower load growth conditions, nameplate MW

Comparison of the lower growth portfolio to the selected resource portfolio reveals that many near-term and mid-term resource additions in the selected portfolio are driven by anticipated strong customer load growth. Lower load growth expectations reduces resource selection by 1,090 MW:

- 480 MW of solar located in Grant County
- 300 MW of solar located in Oregon
- 60 MW of lithium-ion battery storage in Grant County
- 190 MW of lithium-ion battery storage in Oregon
- 10 MW of wind located in Oregon
- 40 MW of BPA Tier 2 contract

Energy Position of Lower Load Growth Portfolio

The lower load growth portfolio provides sufficient energy to meet nearly all customer energy needs on an annual basis and net exposure to short-term markets is limited to the first four years of the planning period. Note that representation of energy position annually does not reveal monthly or hourly periods in which Grant PUD would be required to rely on wholesale markets to provide customer energy. Figure 57 compares the annual expected energy contribution of each resource type, represented by the stacked bars, to the expected customer energy needs, under lower load growth assumptions, represented by the dotted line. Lithium-ion battery storage is not shown because these resources store, but do not produce, energy. Resources from the existing Grant PUD portfolio are shown as solid-filled blocks. Recommended resource additions are shown as pattern-filled blocks.

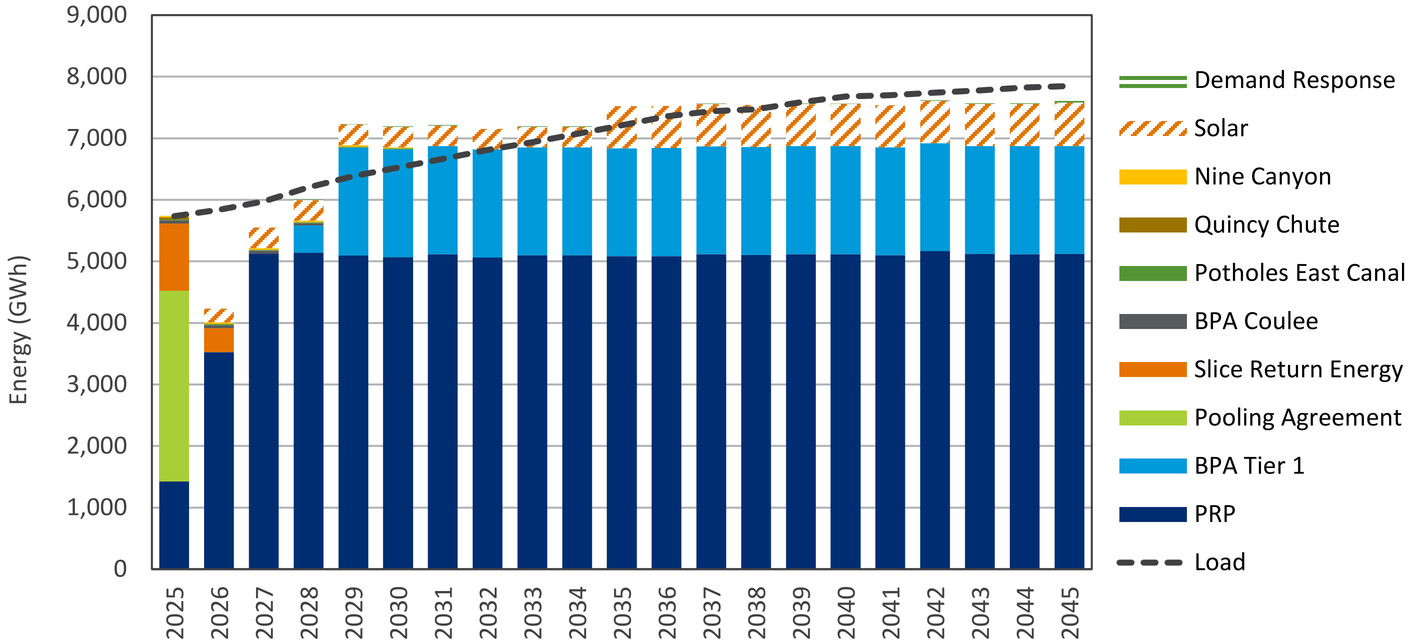


Figure 57. Lower load growth portfolio annual energy position by resource type, 2025 – 2045, GWh

Capacity Position of Lower Load Growth Portfolio

By design, the lower load growth portfolio meets all monthly WRAP obligations beginning in 2027. Months with the portfolio's lowest capacity margins are March and November, reflective of PRP's capacity rating for those months. After the start of the BPA Tier 1 contract in October 2028 the portfolio holds capacity above requirements until load growths to higher levels in the mid-2030s.

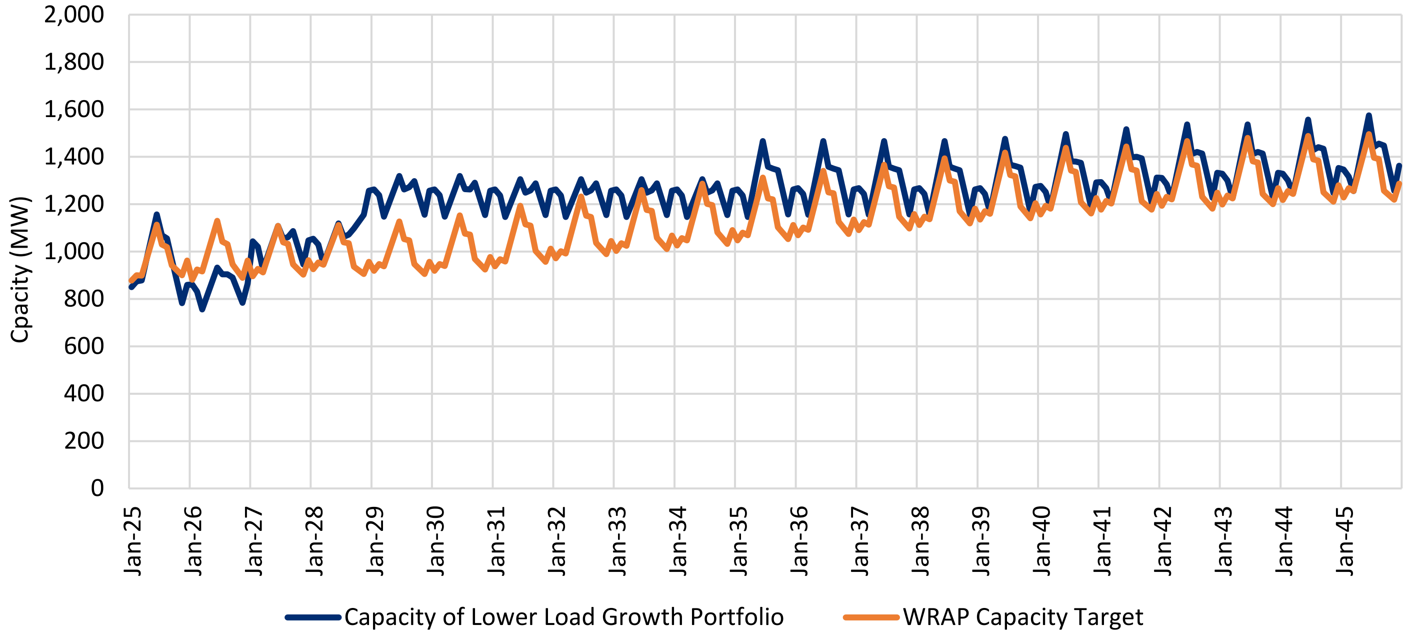


Figure 58. Lower load growth portfolio monthly capacity position compared to forecast WRAP target, 2025 - 2045, MW

RPS Compliance with Lower Load Growth Portfolio

If in the future Grant PUD's rate of load growth falls from expected levels, the current portfolio would be sufficient to meet RPS requirements through 2034. With the 380 MW of solar additions recommended in the lower load growth portfolio, RPS requirements would easily be met over the entire planning period.

CETA Compliance with Lower Load Growth Portfolio

Future CEIPs will determine how eligible resources will contribute to meeting CETA requirements. However, Figure 59 illustrates that if Grant PUD allocates all lower load growth portfolio resources for CETA compliance, it would hold sufficient resources to meet the mandate for the planning period, providing clean energy to customers without the use of RECs.

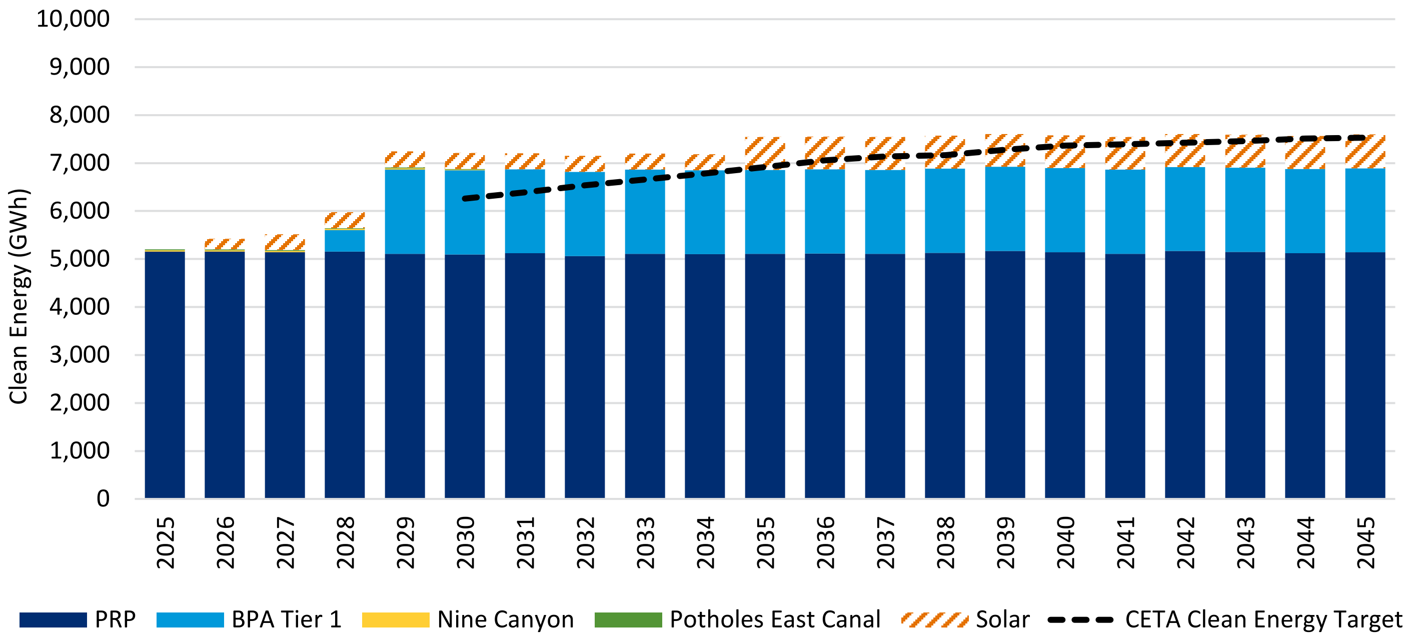


Figure 59.Lower load growth portfolio annual CETA clean energy position, 2025 - 2045, GWh

Reliability Analysis of Lower Load Growth Portfolio

Figure 60 shows the estimated number of lost load hours by hour, by month for the selected lower load growth portfolio for 2029. As expected from the characteristics of PRP and solar generation, loss of load hours occur more frequently during the late summer through early fall months. Loss of load differences between daylight and non-daylight hours are far less pronounced than in the expected reference load forecast portfolio due to the low load growth portfolio's reduced dependence on solar generation.

Loss of Load Hours - Lower Load Growth Portfolio	HE00	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23
2029-01	0.3	0.3	0.3	0.4	0.5	0.6	0.7	0.9	1.1	1.0	0.9	0.8	0.7	0.7	0.6	0.6	0.6	0.8	0.9	0.9	0.9	0.8	0.7	0.6
2029-02	0.4	0.3	0.3	0.5	0.5	0.6	0.7	0.8	0.9	0.7	0.5	0.4	0.3	0.3	0.3	0.2	0.2	0.3	0.6	0.7	0.7	0.7	0.6	0.6
2029-03	0.4	0.4	0.4	0.5	0.7	1.0	1.4	1.5	1.5	0.9	0.6	0.5	0.5	0.4	0.3	0.3	0.2	0.4	0.8	1.3	1.3	1.3	1.0	1.0
2029-04	2.4	2.6	2.6	2.8	3.2	3.7	4.1	3.0	3.6	3.0	2.7	2.6	2.6	2.6	2.4	2.4	2.5	2.8	3.2	3.9	4.2	4.1	3.8	3.7
2029-05	2.1	2.1	2.2	2.3	2.5	2.8	2.5	1.9	2.7	2.4	2.4	2.4	2.5	2.5	2.5	2.4	2.4	2.5	2.8	3.0	3.4	3.3	3.1	3.0
2029-06	1.2	0.9	0.9	0.9	1.0	1.0	0.8	0.6	1.0	1.1	1.2	1.2	1.3	1.4	1.4	1.3	1.3	1.4	1.5	1.6	1.7	1.8	1.7	1.6
2029-07	9.3	8.9	8.8	8.9	9.0	9.0	7.5	6.7	8.5	8.7	9.1	9.6	10.0	10.1	10.2	10.2	10.2	10.2	10.4	10.6	11.2	11.2	11.0	10.7
2029-08	11.3	11.3	11.2	11.4	11.8	12.2	11.6	9.6	11.4	11.4	11.9	12.4	12.9	13.2	13.3	13.2	13.2	13.4	13.4	14.1	14.5	14.3	13.8	13.5
2029-09	8.3	8.3	8.2	8.6	9.1	10.1	10.9	9.2	10.2	9.6	9.9	10.5	11.1	11.4	11.3	11.3	11.7	12.2	13.0	13.7	13.4	12.8	12.0	11.2
2029-10	6.4	6.8	7.1	7.7	8.5	9.8	11.4	14.1	14.0	12.4	11.7	12.0	12.0	11.5	10.9	10.7	11.6	13.4	13.7	10.7	10.5	10.2	9.6	9.2
2029-11	1.2	1.2	1.4	1.6	1.9	2.3	3.1	5.6	6.4	5.6	5.1	4.8	4.5	4.1	3.7	3.7	4.1	5.4	4.7	2.3	2.3	2.3	2.3	2.2
2029-12	0.6	0.7	0.7	0.8	0.9	1.0	1.4	1.6	2.0	1.8	1.6	1.4	1.2	1.2	1.1	1.0	1.2	1.5	1.5	1.5	1.4	1.4	1.3	1.1

Figure 60. Lower load growth portfolio loss of load hours, 2029

Figure 61 illustrates that by 2039 the lower load growth portfolio shows a growing number of lost load hours during the late summer through winter months, reflective of the characteristics of PRP. There is also a shift to higher lost load hours in the non-daylight hours due to the growing influence of solar generation in the portfolio by 2039.

Loss of Load Hours - Lower Load Growth Portfolio																								
Event Dates	HE00	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23
2039-01	3.1	2.9	3.1	3.4	3.8	4.3	5.1	5.8	6.6	5.8	5.0	4.3	3.9	3.5	3.2	3.0	3.6	5.3	5.7	5.8	5.6	5.4	5.0	4.6
2039-02	3.9	4.0	4.2	4.4	4.7	5.3	5.8	6.4	6.6	4.7	3.6	3.0	2.7	2.4	1.9	1.7	1.9	3.0	5.3	5.6	5.7	5.5	5.4	5.1
2039-03	3.7	3.7	3.9	4.3	4.8	5.7	6.9	6.8	5.7	3.7	2.6	2.1	2.0	1.9	1.7	1.4	1.5	2.3	4.5	6.3	6.3	6.1	5.7	5.5
2039-04	5.0	5.2	5.3	5.9	6.7	8.3	8.7	5.5	5.3	3.7	3.2	3.0	3.1	3.0	2.8	2.9	3.0	3.9	5.4	8.3	9.3	8.9	7.9	7.6
2039-05	4.4	4.4	4.5	4.6	4.9	5.4	4.4	3.0	3.5	3.0	3.1	3.4	3.5	3.6	3.5	3.5	3.5	3.8	4.7	5.5	6.7	6.6	6.2	5.8
2039-06	5.1	4.8	4.8	4.8	4.9	4.7	3.6	2.8	3.3	3.0	3.3	3.5	3.7	3.9	3.9	3.9	4.1	4.2	4.6	5.4	6.6	7.0	6.4	6.1
2039-07	15.2	14.9	15.0	15.1	15.2	15.2	13.0	10.8	11.7	11.5	11.9	12.5	13.1	13.3	13.3	13.3	13.3	13.5	13.9	14.7	16.0	16.3	16.1	15.9
2039-08	19.3	19.5	19.6	19.7	20.0	20.3	19.2	15.2	15.8	15.0	15.7	16.6	17.4	17.9	18.0	17.7	17.8	18.2	18.9	20.6	21.3	21.2	21.0	20.7
2039-09	19.1	19.0	19.3	19.6	20.1	20.8	21.2	17.4	16.0	14.1	14.4	15.5	16.5	16.8	16.7	16.4	17.2	18.7	20.7	21.9	21.8	21.5	21.1	20.9
2039-10	17.1	18.0	18.5	19.2	19.9	21.1	22.9	24.3	22.5	19.7	18.6	19.1	19.5	18.8	17.7	17.6	19.4	22.4	23.2	19.8	19.8	19.7	19.3	19.2
2039-11	9.4	9.7	10.4	11.3	12.5	13.7	16.5	20.6	21.2	18.9	17.5	17.2	16.6	15.7	14.7	14.6	16.4	20.1	17.4	11.9	12.2	12.3	12.2	12.1
2039-12	6.3	6.7	6.8	7.3	8.1	9.0	10.2	11.2	12.7	11.2	9.7	9.3	8.8	8.4	7.5	7.0	8.6	10.8	10.9	10.8	10.7	10.4	9.8	9.1

Figure 61. Lower load growth portfolio loss of load hours, 2039

Loss of load reliability metrics were not used to inform capacity expansion selection of the lower load growth case. The loss of load evaluations performed to provide a high-level illustration of general reliability characteristics.

RESOURCE PORTFOLIO INCLUDING SMALL MODULAR REACTORS

Consideration of SMR

Small Modular Reactors (SMRs) are advanced nuclear reactors designed to deliver safe, scalable, demand-following, and carbon-free electricity generation. Grant chose to examine a candidate SMR modeled after the XEnergy XE-100 77MWe reactor module. Current plant configuration offerings range from two 77MWe modules up to twelve 77 MWe modules.

The advantages of SMR over existing large-scale U.S. Commercial light water nuclear reactors (LWR) are numerous. Potential advantages of an XE-100 reactor plant, over existing large-scale nuclear include:

- Enhanced Safety Features: Passive safety features mitigate risks and enhance safety margins compared to older reactor designs. No human interaction is needed during incident conditions
- Reduced Capital Costs: Considerably lower capital costs than traditional nuclear plants
- Modularity: SMRs are designed in smaller, modular units, which allows for easy scalability and phased deployment to address increasing energy demand, future load growth, and changing economics
- Flexibility in Siting: Dry cooling allows deployment in previously unsuitable arid locations. Enhanced safety features reduce the risk to the public, allowing siting closer to the customer load.
- Improved Economics: Economies of series production can lower costs per unit of electricity generated and better fuel performance and economy with improvements between 25 to 75 percent
- Faster Construction: Modules are designed to be largely constructed in factories and assembled on-site, reducing construction time and disruption as compared to large-scale traditional reactor projects.
- Enhanced Grid Stability: Load-following capabilities between 40 and 100% of full rated power complement intermittent renewable energy resources
- Waste Minimization: Higher fuel burnup of TRISO-X fuel in XE-100 results in the need for less uranium and less non-uranium nuclear fuel components as compared to traditional nuclear reactors. TRISO-X is designed to better encapsulate waste on a long-term basis than existing LWR fuel.
- Market Adaptability: Modular design of plant configuration, coupled with load following attributes results in more flexibility in meeting varying energy demand profiles, contributing to energy security and resilience

Potential drawbacks of an XE-100 reactor are:

- Regulatory Challenges: Additional regulatory hurdles exist with SMRs compared to established large-scale reactor designs. These challenges could impact deployment timelines and cost
- Technological Risks: New designs may pose some technological risks related to reliability, operational performance, and scalability that have yet to be fully demonstrated at scale
- Limited Commercial Operation: Few SMRs have currently entered commercial operation, leading to limited operational experience and some uncertainties surrounding performance and reliability.

- Fuel Supply Challenges: The High Assay Low Enriched Uranium (HALEU) based fuel used in many SMRs is under intense investment and buildout to meet projected through-put needs. Federal financial support is beginning to address potential bottlenecks.

Nuclear Fuel

High Assay Low Enriched Uranium (HALEU) fuel has garnered attention due to its potential applications in advanced nuclear reactors, including Small Modular Reactors (SMRs), and its role in enhancing fuel efficiency and performance. HALEU is defined as uranium enriched to levels between 5% and 20% U-235. This is higher than the typical enrichment level of 3-5% used in conventional light-water reactors (LWRs). The higher enrichment levels offer several advantages for advanced reactors.

The first and most important advantage is better plant economics. Using HALEU allows for higher burnup rates, meaning more energy can be extracted from the same volume of fuel, thereby increasing efficiency and reducing fuel cycle costs. Additionally, advanced reactors designed to use HALEU can achieve higher power densities, longer fuel cycles, and improved safety margins, enhancing overall reactor performance, efficiency, and economics.

Because of these benefits provided by the use of HALEU, demand is expected to increase over the coming decades. As with any growing industrial commodity, there will be challenges to address during this expansion. Fortunately, the same facilities used today to produce existing LWR fuel can be used to produce HALEU. These facilities will require significant expansion to meet projected demand as well as regulatory approval to operate at higher enrichment levels. Outside events that place stress on the existing LWR-centered Uranium markets will also impact the economics of HALEU as they both utilize the same core industrial processes and facilities.

Private industry, as well as the U.S. government, are investing heavily to increase HALEU production in the United States. Each step of the fuel production cycle, from mining to enrichment, is being expanded. Private equity and $2.7 billion in government-allocated funding are being invested into the HALEU economy (U.S. Department of Energy, Office of Nuclear Energy, 2024).

The availability of High Assay Low Enriched Uranium (HALEU) fuel is critical for the advancement and deployment of next-generation nuclear reactors. While current production capacity is limited, existing infrastructure and growing demand present opportunities for expansion. Strategic investments, technological innovation, supportive policies, and international collaboration will be essential in overcoming challenges and ensuring a secure and sustainable supply of HALEU fuel for advanced nuclear energy applications in the future.

SMR as Part of a Resource Portfolio

This IRP does not select SMR for addition to the portfolio. However, Grant PUD continues to contemplate and explore the addition of SMR for mid-term portfolio addition. To study the effects that addition of SMR might have on the portfolio, scenarios including the addition of two 71 MW SMR modules in 2034 were modeled.

The least-cost portfolio including the addition of two SMR modules in 2034 , based on the given inputs, constraints, and reference case load growth include 1,010 MW of nameplate additions:

- 142 MW SMR located in Grant County
- 330 MW of solar located in Grant County
- 190 MW of solar located in Oregon
- 60 MW of lithium-ion battery storage in Grant County
- 210 MW of lithium-ion battery storage in Oregon
- 10 MW of wind located in Oregon
- 40 MW of BPA Tier 2 contract
- 28 MW of demand response

Figure 62 illustrates the recommended timing of these resource acquisitions. Only the year of initial addition is shown in the chart, though all of these additions will remain in the portfolio through the planning horizon.

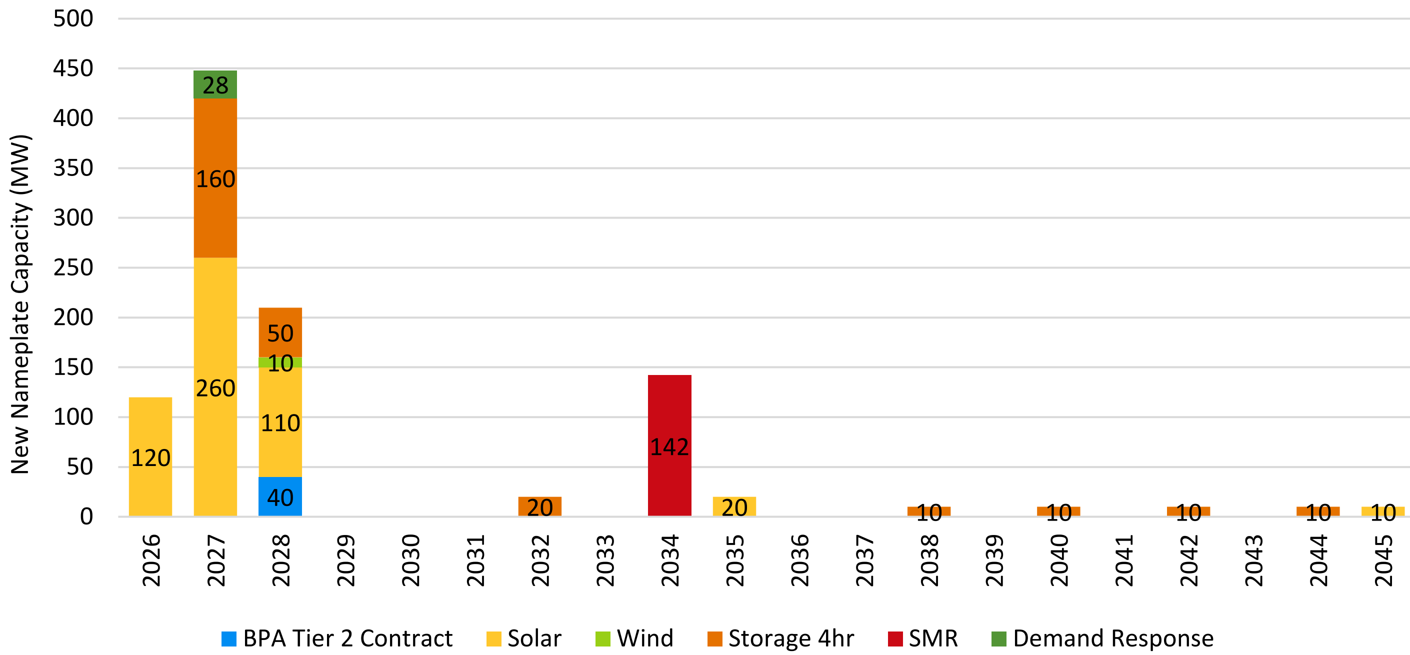


Figure 62. Resource additions of selected portfolio with SMR installation in 2034, nameplate MW

Resource additions in the first three years of acquisition are identical to the selected portfolio's additions. In the mid to late term, addition of the SMR modules reduces additions by 608 MW of nameplate capacity as compared to the selected case. This includes a reduction of 650 MW of solar, 100 MW of lithium-ion batteries offsetting the addition of 142 MW of SMR.

Though the SMR portfolio reduces the total amount of nameplate capacity that must be added to meet energy, capacity and clean energy requirements, it is significantly costlier than the selected portfolio given our current estimates.

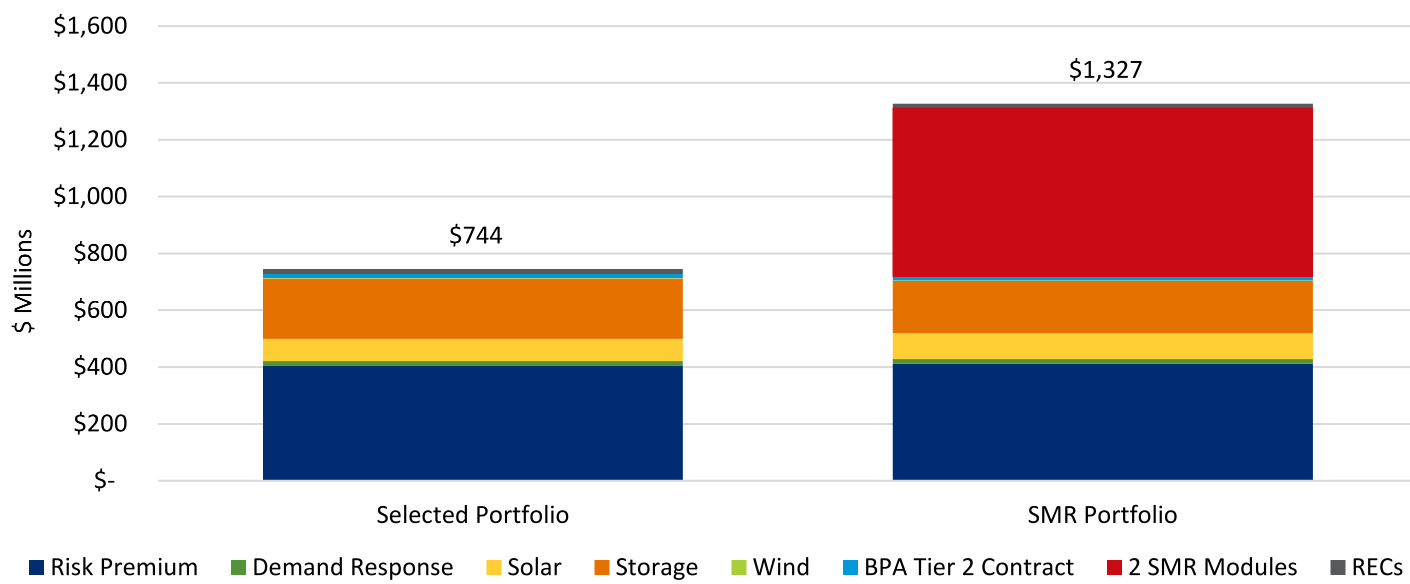


Figure 63. Net present value of net portfolio costs of selected portfolio and SMR portfolio, new additions and risk premium only, 2025 - 2045, $ Millions

Values shown in Figure 63 are net of associated wholesale revenue. The risk premium represents the distribution of net costs over the stochastic evaluation considerations variations in weather, prices and variable energy resource performance.

Loss of Load Hours - Selected Portfolio

Event Dates	HE00	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23
2039-01	13.2	13.0	13.1	13.7	14.5	15.6	16.9	18.0	19.1	14.0	10.2	8.2	7.3	6.8	6.4	5.9	8.0	15.6	17.4	17.3	17.3	17.0	16.5	15.8
2039-02	9.0	9.2	9.4	9.9	10.3	10.7	11.3	11.7	10.8	4.7	2.6	1.7	1.5	1.3	1.4	1.2	1.6	3.3	9.2	9.9	9.9	10.1	10.0	10.0
2039-03	6.7	7.0	7.2	7.6	8.1	8.8	9.3	8.8	5.0	2.0	1.0	0.6	0.4	0.4	0.6	0.5	0.7	1.3	3.6	6.9	6.9	7.0	7.2	7.2
2039-04	8.2	8.8	9.3	9.6	10.5	11.3	11.0	4.7	2.2	1.0	0.5	0.5	0.4	0.4	0.4	0.5	0.7	1.2	2.7	8.2	9.9	9.2	9.5	9.2
2039-05	6.0	6.2	6.5	6.6	7.1	7.5	4.3	1.7	1.1	0.8	0.6	0.7	0.7	0.8	0.8	0.8	1.0	1.5	2.6	4.5	7.8	7.6	7.2	6.9
2039-06	5.8	5.8	6.0	6.0	6.2	5.8	2.5	1.3	1.0	0.6	0.7	0.6	0.8	1.0	1.0	0.9	1.2	1.4	1.8	3.5	6.6	7.8	7.2	6.8
2039-07	14.1	14.0	13.9	14.2	14.5	14.5	8.3	3.4	2.4	1.8	2.0	2.3	2.9	3.1	3.1	3.0	3.2	4.0	5.4	8.4	14.7	15.9	15.5	15.1
2039-08	18.9	19.1	19.3	19.5	19.7	19.9	17.7	7.1	4.4	2.5	2.6	3.2	4.1	4.7	4.8	4.0	4.7	6.3	9.2	16.6	20.1	19.9	19.8	19.7
2039-09	19.5	19.4	19.5	19.8	20.3	20.7	21.0	11.5	6.0	3.3	2.8	3.3	4.0	4.4	4.3	4.0	6.0	9.0	15.5	20.3	20.3	20.4	20.2	20.3
2039-10	22.1	22.7	23.2	23.7	24.2	24.8	25.2	25.4	15.0	7.6	5.7	6.7	7.8	7.2	6.7	6.8	9.9	17.8	24.8	23.8	23.8	23.7	23.6	23.5
2039-11	21.2	21.6	22.2	23.1	23.9	24.8	25.8	27.1	26.7	20.1	16.4	16.4	16.9	15.4	14.0	14.1	18.3	26.5	26.7	23.2	23.4	23.5	23.4	23.1
2039-12	21.3	21.8	22.2	22.8	23.5	24.5	25.5	26.2	27.2	21.9	16.1	15.7	16.4	15.8	13.8	12.6	18.3	25.7	25.9	25.7	25.6	25.4	25.0	24.5

Loss of Load Hours - 2 SMR Module Portfolio

Event Dates	HE00	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23
2039-01	5.0	4.8	5.0	5.4	6.0	6.8	7.8	8.7	9.8	8.3	6.7	5.8	5.3	4.8	4.2	3.9	4.8	7.7	8.5	8.4	8.4	8.1	7.6	7.0
2039-02	5.3	5.4	5.6	6.0	6.4	7.0	7.7	8.2	8.2	5.4	4.0	3.1	2.8	2.5	2.2	1.8	2.2	3.7	6.9	7.3	7.4	7.3	7.0	6.6
2039-03	4.0	4.0	4.2	4.5	4.9	5.6	6.0	6.0	5.0	3.3	2.3	1.9	1.8	1.6	1.3	1.1	1.3	2.0	3.9	5.3	5.4	5.3	5.1	4.9
2039-04	5.6	5.7	5.9	6.1	6.5	7.5	7.5	5.5	4.7	3.5	3.0	2.9	3.0	3.0	2.7	2.7	2.9	3.7	5.0	6.8	7.5	7.3	6.9	6.7
2039-05	4.6	4.7	4.7	4.8	5.1	5.4	4.4	3.0	3.0	2.7	2.6	2.9	3.1	3.1	3.1	3.0	3.1	3.6	4.3	5.1	5.8	5.8	5.5	5.3
2039-06	5.7	5.5	5.5	5.5	5.7	5.6	4.0	2.9	3.1	3.0	3.2	3.4	3.7	4.1	4.0	4.0	4.2	4.4	4.9	5.6	6.8	7.0	6.8	6.4
2039-07	16.2	16.0	16.1	16.2	16.3	16.3	13.6	10.3	10.8	10.5	11.2	11.7	12.7	13.0	13.1	13.1	13.2	13.6	14.1	15.3	17.4	17.7	17.4	17.1
2039-08	20.6	20.7	20.8	21.0	21.2	21.5	20.4	15.1	14.5	13.2	13.9	15.2	16.6	17.2	17.4	17.0	17.2	17.8	19.1	21.5	22.5	22.4	22.2	21.8
2039-09	18.4	18.3	18.5	18.7	19.1	19.9	20.5	15.6	13.1	10.9	11.0	11.9	13.2	13.8	13.7	13.6	14.7	16.6	19.4	21.1	21.1	20.8	20.4	20.0
2039-10	17.3	18.0	18.5	19.3	20.1	21.4	22.5	23.4	20.1	16.1	14.9	15.4	16.1	15.3	14.5	14.0	16.0	20.4	23.1	20.4	20.3	20.1	19.7	19.3
2039-11	12.2	12.4	13.0	14.1	15.5	16.9	19.2	21.7	22.0	19.4	17.7	17.3	16.8	15.8	14.6	14.5	16.8	21.0	20.5	15.3	15.5	15.4	15.1	14.8
2039-12	9.9	10.4	10.7	11.3	12.2	13.3	14.8	16.1	17.5	15.5	12.9	12.2	11.8	11.1	9.9	9.2	11.9	15.4	15.5	15.2	15.1	14.6	14.0	13.2

Figure 64. Selected portfolio and SMR portfolio loss of load hours for comparison, 2039

Figure 64 illustrates the selected portfolio's capacity concentration mid-day and during non-winter months. In comparison, the SMR portfolio provides capacity more consistently over all hours and seasons. It also provides a reduction in both loss of load hours and unserved energy as compared to the reference case.

With no current determined metrics, the loss of load evaluation had no impact on the selection of this IRP's recommended resource portfolio. Once appropriate metrics surrounding loss of load analyses are developed and incorporated into Grant PUD's resource planning, added value from the reliability characteristics of SMR, and all evaluated technologies, will be quantified.

9 | Conclusions and Action Plan

From the IRP analysis, Staff draws the following conclusions and makes the following recommendations:

- Grant PUD has sufficient physical and contractual resources to meet customer demand through the expiration of its current pooling agreement in September 2025. We recommend that new generating resources be added to the Grant PUD portfolio to reduce its increasing dependence on wholesale markets after 2025.
- Grant PUD must obtain additional resources to increase its capacity margin in order to comply with the binding Western Resource Adequacy Program (WRAP) in 2027. To obtain the reliability benefits of WRAP for Grant PUD customers, we recommend that the capacity resource acquisition efforts begun with the 2024 All-Source Request for Proposal continue until WRAP adequacy requirements are met.
- Grant PUD has sufficient resources to meet the Energy Independence Act renewable portfolio standard through 2025. Resources acquired to meet other energy and capacity requirements should be utilized in conjunction with the current portfolio to meet RPS requirements beyond 2025.
- Grant PUD must obtain additional clean energy resources to meet primary Clean Energy Transformation Act 2030 compliance requirements. We recommend that portfolio additions to meet increasing compliance obligations begin in the early 2030s with additions made over the course of several years. Due to the time required to bring new

resources online, planning for this acquisition is in progress and will continue

- The following actions provide a least-cost solution for meeting customer demand, WRAP resource adequacy, and attainment of CETA and RPS compliance over the 2025-2045 planning horizon:
    - Implementation of a demand response program
    - Entering into a Bonneville Power Administration Provider of Choice Tier 2 contract
    - Initiating the Request for Proposal process in pursuant of power purchase agreements for, or ownership of, IRP identified resources, including, but not limited to, solar, wind, and lithium-ion battery resources, with an emphasis on firm delivery
    - Continued use of wholesale market energy purchases and use of renewable energy credits to supplement resources

Grant PUD's load includes a relatively high percentage of industrial load, and this percentage continues to grow. Future industrial loads could be significantly higher or lower than the reference forecast due to several factors, many of which are outside of Grant PUD's control. Grant PUD will continue monitoring this customer segment and develop service solutions beneficial to its customers.

Table 13 reiterates the plan's recommended resource acquisition referenced above and discussed in Section 8 of this report.

Table 13. Recommended resource additions, nameplate capacity by resource type and year, 2025 - 2045, MW

Year	Demand Response	Solar	Lithium-ion Battery	Wind	BPA Tier 2 Contract	Total
Plan Total	28	1,170	370	10	40	1,618
2025						0
2026		120				120
2027	28	260	160			448
2028		110	50	10	40	210
2029						0
2030						0
2031						0
2032			20			20
2033		100	30			130
2034		100	20			120
2035		120	20			140
2036		100	20			120
2037		100	30			130
2038		100				100
2039						0
2040						0
2041			10			10
2042		60	10			70
2043						0
2044						0
2045						0

ACTION PLAN

Based on the work completed in this IRP we will take the following actions toward execution of the recommendations contained in this plan and for further and ongoing analysis. Generally, the components of the action plan fall into three categories: Management Analysis, Planning, and Monitoring; Power Portfolio Actions; and Stakeholder Engagement and Coordination.

Management Analysis, Planning, and Monitoring

- Further integration of resource selection modeling, transmission planning, rate design, and load forecasting to increase the comprehensiveness of recommended plans
- Investigation of demand-side resource options, including demand response programs, with the goal of improving our understanding of program operations, implementation requirements, costs, and effectiveness
- Development of appropriate reliability metrics surrounding loss of load analyses and use of these metrics in development of future plans
- Maintained awareness of changes to state and federal utility industry regulations affecting Grant PUD's planning
- Monitoring advancements of developing technologies and cost movement for all resource alternatives

Stakeholder Engagement and Coordination

- Continued active participation in the WRAP
- Continued monitoring and engagement in regional market developments

Power Portfolio Actions

- Quantification of the value of the added services that hydropower provides, and assessment of the costs associated with potential changes to our wholesale hedging strategy as applied to resource planning
- Additional evaluation and consideration of alternative strategies prior to any resource acquisition or contractual agreement
- Pursuit of capacity acquisition to enable compliance with the WRAP, including future requests for proposals for capacity solutions
- Continued execution on the Request for Proposal process for power purchase agreements or ownership of IRP identified resources, including, but not limited to, solar, wind, and lithium-ion battery resources, with an emphasis on firm delivery

CLEAN ENERGY ACTION PLAN

In accordance with RCW 19.280.030, Grant PUD's CEAP is included here. This plan outlines Grant PUD's compliance with RCW 19.405.030 through RCW 19.405.050 at the lowest reasonable cost, and at an acceptable resource adequacy standard. Specific actions to be taken to complete the plan align with actions to be taken to follow the IRP roadmap.

RCW 19.405.030

This chapter requires that on or before Dec 31,2025 Grant PUD must eliminate all coal-fired resources from its energy allocation. While Grant PUD does not hold any coal-fired resources in its resource portfolio, nor does it intend to add any of these resources in the future, it does participate in wholesale energy market trading. For compliance with this requirement, Grant PUD must remain cognizant of the impacts of trading in unspecified-source power and may need to modify trading practices after 2025.

RCW 19.405.040

This chapter requires that all retail sales to customers must be greenhouse gas neutral by January 1, 2030. For the four-year compliance period beginning January 1, 2030, and for each multi-year compliance period through December 31, 2044, Grant PUD must demonstrate compliance using a combination of non-emitting electric generation and electricity from renewable resources, or, for up to 20% of its compliance obligation, use of alternative compliance options. Alternative compliance options include an alternative compliance payment, unbundled RECs produced from eligible renewable resources, investment in energy transformation projects, or use of electricity from an energy recovery facility using municipal solid waste as the principal fuel source. For this 2024 IRP, the selected portfolio was chosen such that portfolio resources could be sufficient to meet CETA primary compliance beginning in 2030. Both the primary compliance, 80% of sales to retail customers, and the alternative compliance, the additional 20% of sales to retail customers, could be met using the selected portfolio's carbon-free generation if Grant PUD chooses to do so.

This chapter also requires that Grant PUD pursue all cost-effective, reliable, and feasible conservation and efficiency resources to reduce or manage retail electric load. To aid in meeting this requirement Grant PUD will review and update its ten-year conservation potential assessment and establish a biennial acquisition target every two years. It is Grant PUD's intent to pursue cost effective conservation and efficiency identified in these assessments. Based on the 2023 assessment, on June 25, 2024, the Commission of Grant County PUD adopted Resolution No. 9055 establishing a ten-year conservation potential of 140,072 MWh and a two-year conservation target of 17,520 MWh. The Resolution also states that Grant PUD is acquiring all conservation that is cost-effective, reliable and feasible.

RCW 19.405.050

This chapter requires that 100% of all sales of electricity to customers be sourced from non-emitting and renewable resources by January 1, 2045. The portfolio selected by this IRP is consistent with moving toward 100% non-emitting and renewable resources by January 1, 2045.

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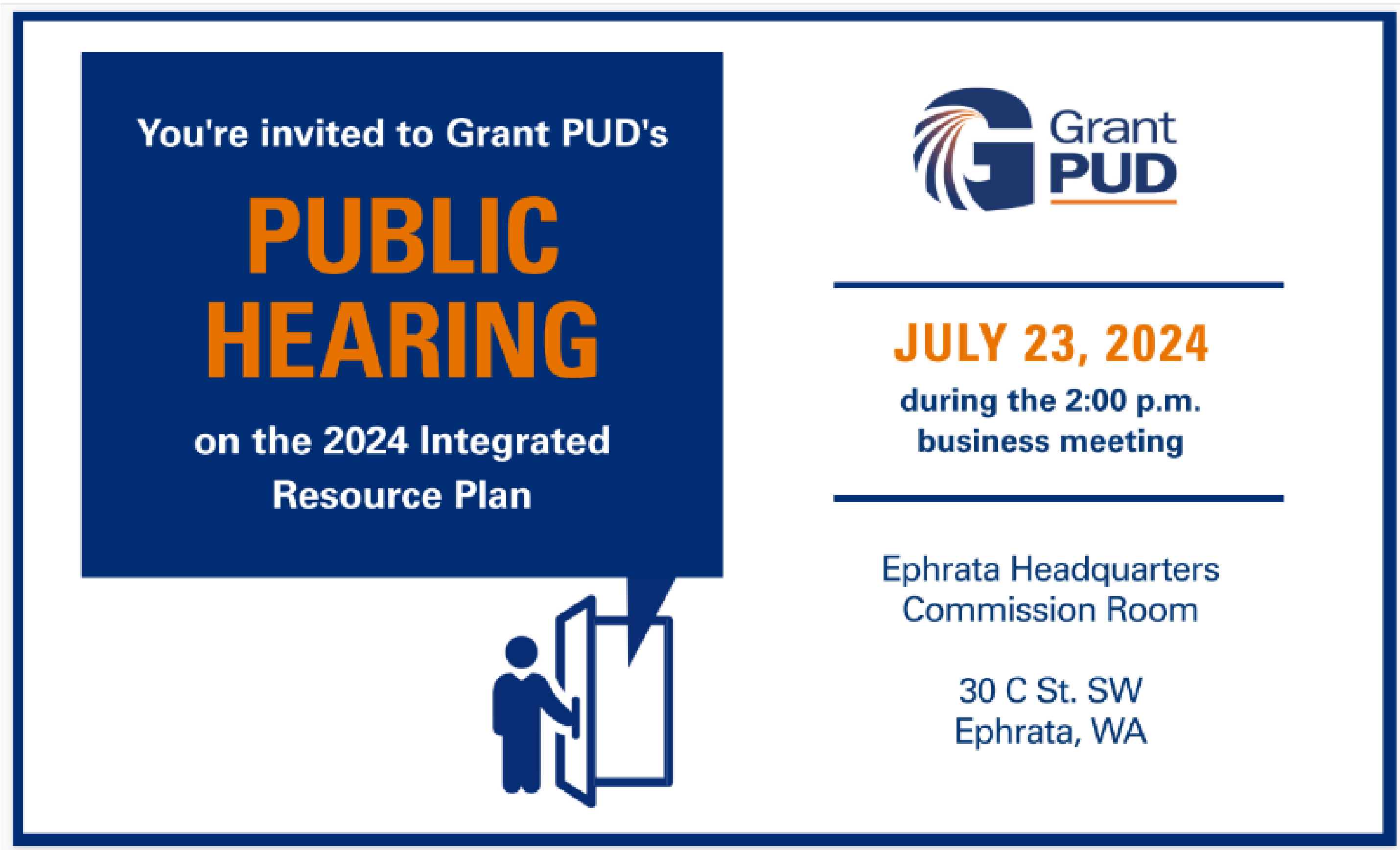
Public Notice of IRP Hearing



Appendix 1: PowerSIMM Model Description

The information provided in this appendix was graciously provided by Ascend Analytics, our consulting partner in the preparation of this IRP.

IRP MODELING WITH POWERSIMM

Ascend Analytics prides itself on being a market leader in analytical rigor and forward thinking in a rapidly changing energy landscape. We leverage the power of modern computing to solve power system optimization problems using Monte Carlo simulation techniques, stochastic optimization, and artificial intelligence. The task of planning for systems where renewables are increasing their share of system energy is a paradigm in which our PowerSIMM software excels and provides critical insight needed to make decisions that yield value for Grant PUD customers and avoid stranded asset risks. PowerSIMM is a commercial software solution for planning and portfolio management used by utilities like NorthWestern Energy, Duke, LADWP, LBWL, City of Austin, Ameren, New York Power Authority, Indianapolis Power and Light, and many others.

The following table summarizes our modeling philosophy and how it relates to modern resources planning for a low carbon power system.

Table 14. Ascend Analytics' modeling philosophy

The Approach	Why we do it
Simulate renewable generation, loads, and market prices as a function of weather	Weather is a fundamental driver of uncertainty, especially with renewables where "weather is the new fuel." Our unique simulation approach generates "meaningful uncertainty" which enables insight into resource value in real-world conditions, not idealized average conditions that, in reality, do not exist.
Identify risk using a risk-premium calculation	Not all least-cost portfolios in traditional modeling are truly least cost in real life. That is because legacy models rely on the average or typical week approach due to computing limitations. However, the grid with high renewables is unlikely to ever have a typical week. By simulating and probabilistically enveloping future states, including unlikely but high-impact tail events (i.e. Black Swans), we can quantify the risk profile of different portfolios and use that information in decision analysis. We assess a portfolio's risk exposure to volatility in power prices, fuel cost, carbon prices, etc. Portfolios that balance these risks while also keeping portfolio cost low become the most "all-weather" plan going forward into an increasingly uncertain world.
Understand reliability and resilience implications of renewables and storage using Loss of Load Probability and Effective Load Carrying Capability (ELCC) analyses	Back when all power resources were dispatchable, there was little need to simulate loss of load probability. A standard reserve margin calculation was enough. Now and into the foreseeable future, we must maintain reliability with resources of uncertain output and batteries with state of charge constraints, alongside traditional resources with forced outage rates. Reliability in a low carbon/high renewable portfolio should be viewed through the lens of loss of load probability analysis. Through simulation of weather, load, renewables, and forced outages, Ascend can determine the reliability impacts of different portfolios and the true capacity contribution of renewables and batteries through the PowerSIMM framework.

PowerSIMM works by leveraging Monte Carlo simulation, a process of using statistical distributions and randomized draws to simulate key input variables, the foremost of which is weather. Weather variables are built using over 30 years of historical data and characterized through a stochastic (e.g. random) process. Characterized weather variables then form the key driver of load, renewable generation, and electricity market prices, which in turn dictate the dynamics of the energy system physically and economically. The model diagram for PowerSIMM is shown in Figure 65.

PowerSimm Modeling Framework

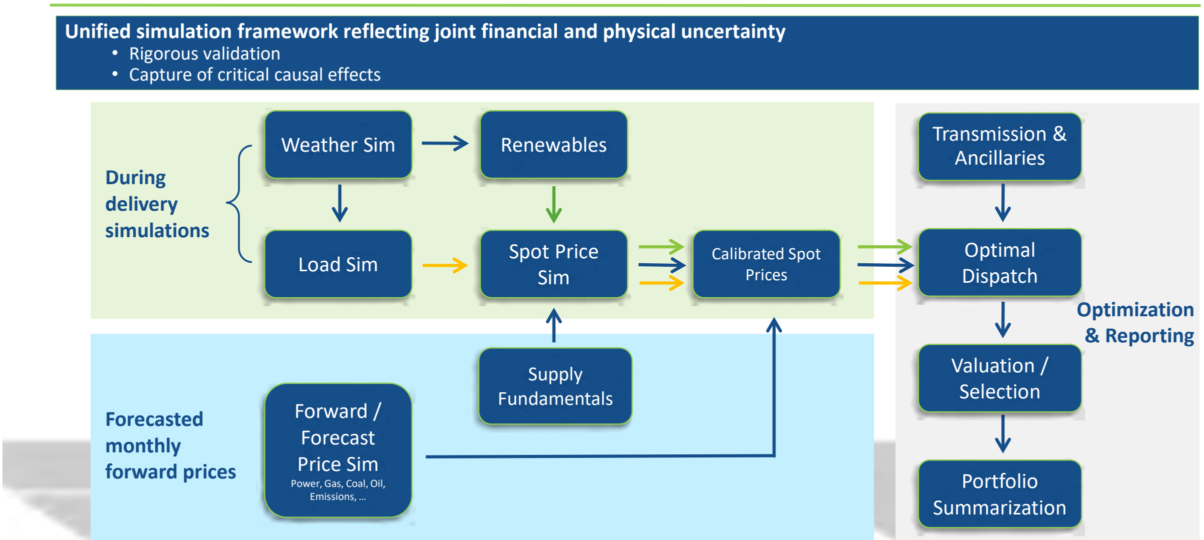


Figure 65. PowerSIMM modeling framework

PowerSIMM simulates hourly spot prices as a function of weather, system load, and renewables. The simulated spot prices are then scaled so that the average of on-peak/off-peak spot prices equal the simulated monthly forward price for that time period. These simulated forward prices blend market forward data in the near term (1-5 years) with Ascend's long-term fundamental forecasts of power prices. PowerSIMM's hybrid approach captures the uncertainty in the factors that create price risk in power markets and trading hubs, including variability in weather, load, renewable output, congestion risk, LMPs, and forward prices volatility. PowerSIMM trains its econometric "sim engine" model with extensive historical weather data to estimate the impact weather has on load and renewable production and capture extreme events. Ascend parameterizes its weather uncertainty using both time (month, day, hour) and autoregressive terms to create discrete chronological weather simulations, which are used to model Grant PUD and the Pacific Northwest system load, as well as generation from renewable resources. In Grant PUD's IRP, we simulated over 100 different future conditions (simreps), where market prices, weather patterns, renewable generation, water availability, and load were significantly varied. Results are summarized across these simreps to capture the full distribution of outcomes, including the mean, median, 5th percentile, and 95th percentile estimates.

ASCEND FUNDAMENTAL PRICE FORECAST

Energy markets are rapidly changing. Renewables and storage deployment across the U.S. are disrupting traditional approaches to fundamental price forecasting, driving the need for new approaches and fresh insights. Ascend Market Intelligence provides expert analysis and 20+ year fundamental price forecasts to support modern resource planning and procurement decision-making in a dynamic and uncertain environment. Ascend maintains a unique fundamental modeling framework to support resource planning and valuation activities, purposefully designed to capture the dynamics of structural change in the electricity sector, including price depression, curtailment and negative price formation. Figure 66 shows the general schematic of Ascend's approach.

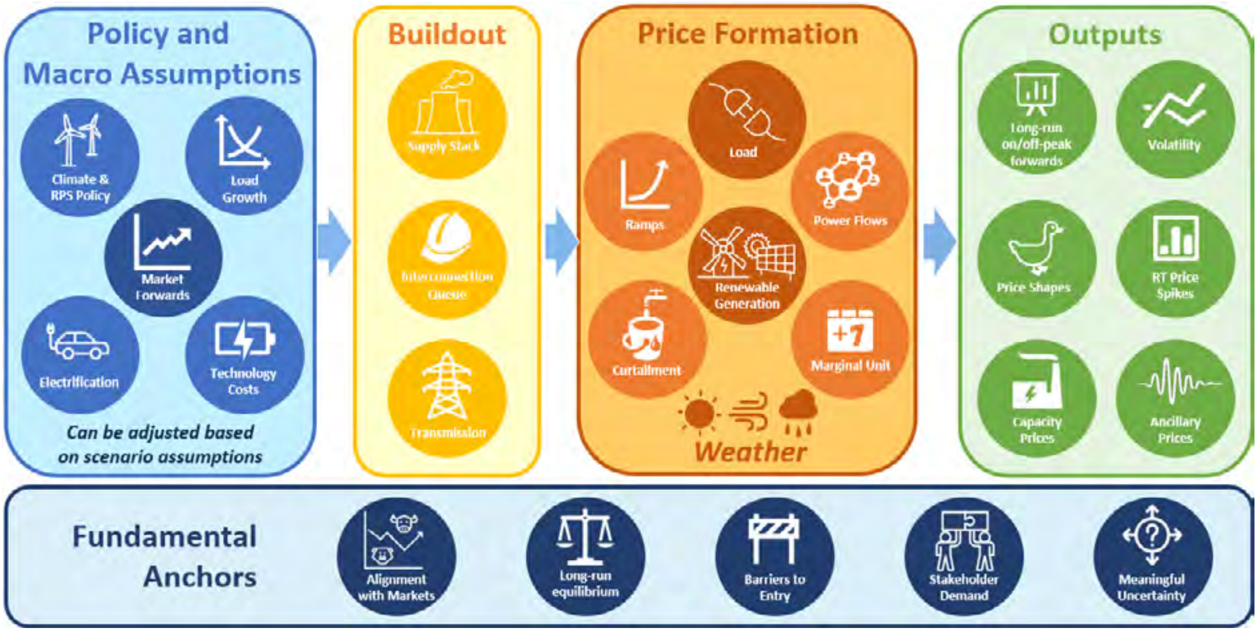


Figure 66. Ascend Analytics' Fundamental Modeling Framework

By focusing on these key policy, economic, and physical constraints that govern resource buildout and dispatch, Ascend's forecasts focus on the most important drivers of uncertainty and risk in long-term planning and valuation. Ascend's forecasting is anchored to several fundamental drivers, principally near-term market expectations paired with long-term expectations of load growth and supply changes driven by policy and economics. All forecasts align to market forwards in the near-term, which reflect the consensus market expectation of all macro level assumptions, including greenhouse gas (GHG) and renewable portfolio standard (RPS) policy, economic growth, electrification, and technology costs. For pricing after the end of the liquid forward curves, forecasts are firmly anchored to "long-run equilibrium" conditions, in which market prices for energy, ancillaries, and capacity sum up to allow new resources to earn no more than normal returns.

Ascend also forecasts price conditions at the nodal level for valuation of existing and candidate resources. Geographic barriers, such as dense populations, bodies of water, mountains, interconnect boundaries, and variation in renewable resource potential, all lead to geographic variation in returns that can persist in the long run with limited mitigation potential. Nodal prices are simulated as a basis from the hub, with a modeled evolution in basis and volatility driven by expectations of local fundamental conditions.

ASCEND FUNDAMENTAL PRICE FORECAST

Ascend used PowerSIMM to perform production cost modeling and capacity expansion modeling for Grant PUD's resource portfolio. PowerSIMM offers a suite of tools, including stochastic simulations, portfolio modeling with market interactions, Automated Resource Selection for optimal capacity expansion, and reliability analysis.

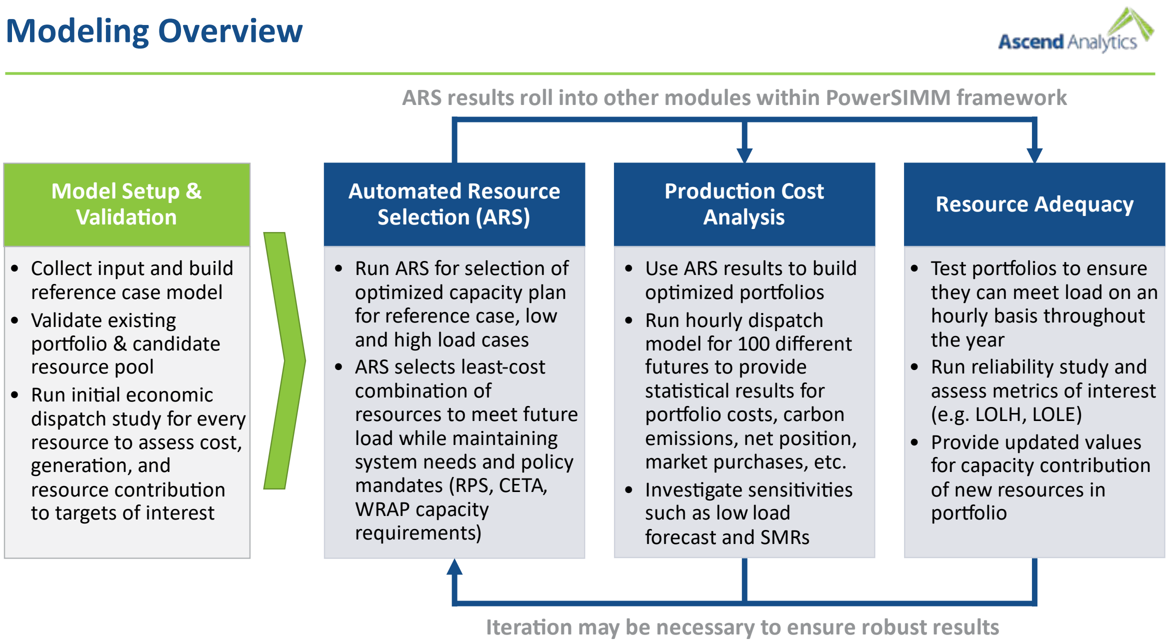


Figure 67. Modeling framework to develop compliant, reliable and leas cost portfolios in PowerSIMM

MODEL SETUP & VALIDATION

To model Grant PUD's portfolio, Ascend collected information about load, generation assets, existing contracts, and market constraints. For load, Ascend used historical data to determine weather correlations for its simulations. Ascend also has a wealth of experience working with utilities throughout the U.S. on altering forecasted load shapes to reflect growth in electric vehicles, behind-the-meter solar, and energy efficiency measures.

For generation assets, Ascend worked with Grant PUD to collect the physical and financial parameters of all Grant PUD generation resources, including all owned assets and all contractual resources. Renewables were modeled using actual historic output data and simulated National Renewable Energy Laboratory (NREL) data in some cases. For market interactions, Ascend worked with Grant PUD to define agreed-upon transmission constraints and implement them in the model. After model configuration, Ascend ran a baseline scenario with a series of validation steps to assure the simulation engine matched observed weather patterns, renewable output, load response to weather, hydro generation, and individual unit capacity factors.

CAPACITY EXPANSION PLANNING

Ascend used PowerSIMM's Automated Resource Selection (ARS) to provide a least-cost least-risk portfolio expansion plan for serving load over the planning horizon, including both supply-side and demand-side resources. Within the ARS framework, Ascend specified the physical and financial aspects of all candidate resources for meeting load. We also created appropriate constraints such as those necessary to meet clean energy targets, meet RPS goals, comply with capacity requirements under the WRAP program, maintain reliability, achieve carbon reduction targets, and maintain energy load balance.

Ascend's ARS optimizes resource additions and can also indicate economic retirement dates for existing resources. Because the model optimizes over all simulated future states, the resulting portfolio represents the best resource mix across an array of cost and risk metrics. Ascend can also perform several ARS runs with varying inputs for macro level sensitivity analysis. For example, runs can be performed with and without carbon costs, according to different RPS or clean energy targets, with different planning reserve margins, forced retirement of existing resources in specific years, forcing procurement of resources in specific years (e.g. small modular reactors), etc. The final results include one or several portfolio expansion plans to choose from as "preferred portfolios".

PRODUCTION COST ANALYSIS AND RISK CAPTURING

Once portfolios were selected, they were evaluated using an hourly dispatch model to understand their operational feasibility and the overall implications for the portfolio. In order to better capture the uncertainty in future conditions, a stochastic framework was used to simulate over 100 different future conditions, where market prices, weather patterns, renewable generation, water availability, and load were significantly varied.

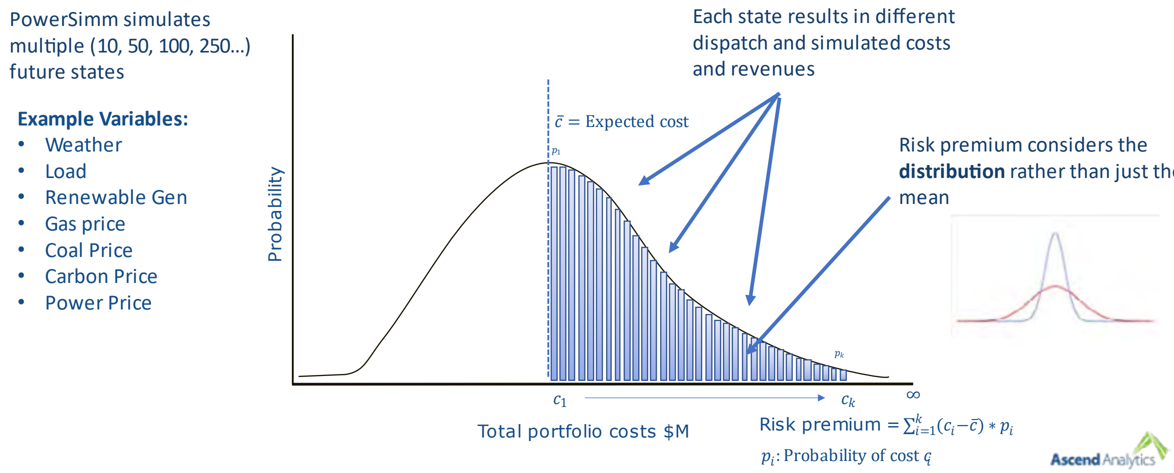


Figure 68. Risk premium concept for capturing the cost at risk associated with different portfolios

To capture the risk associated with the distribution of portfolio costs resulting from the 100 different futures, the "risk premium" metric, shown in Figure 68, that indicates the cost at risk or the actuarial value of a portfolio's exposure to market price volatility, variation in generation and load, and changes in weather conditions is used. The risk premium concept allows portfolios with different risk characteristics to be compared. The NPV calculation of each portfolio includes the risk premium, as shown in Figure 69.

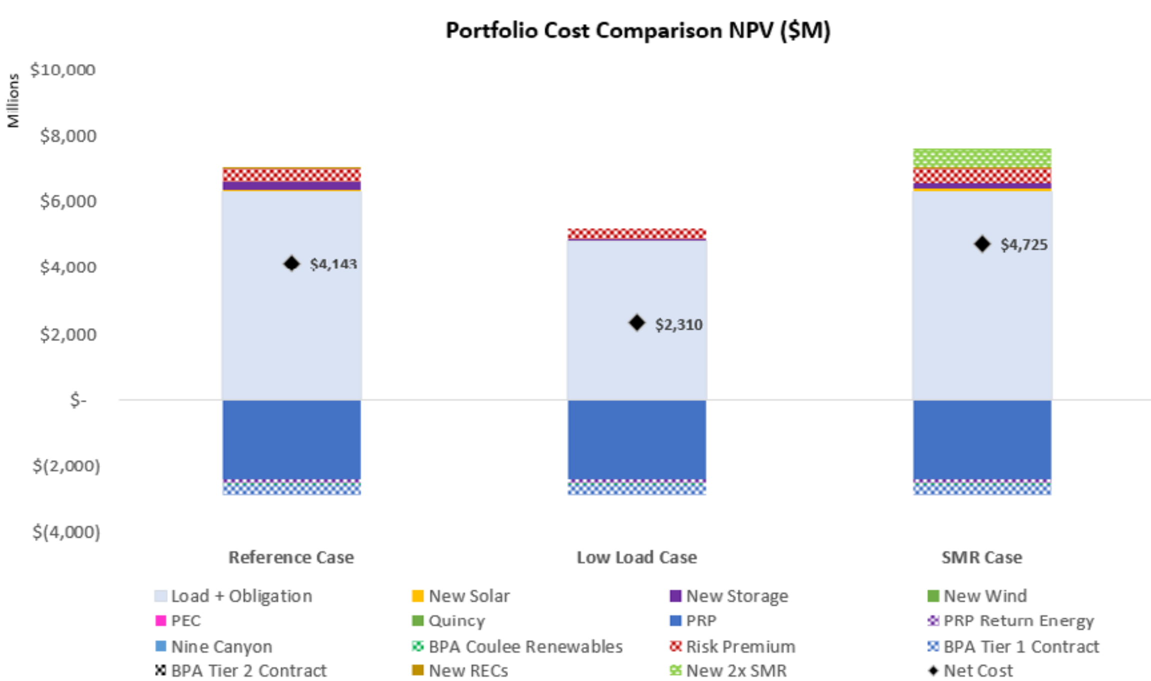


Figure 69. Example of portfolio cost comparison for three different cases

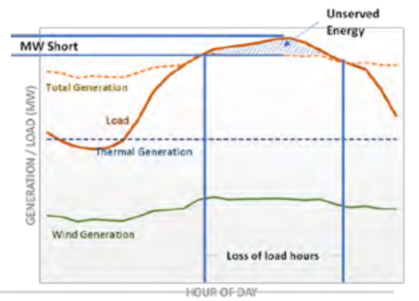
RELIABILITY AND CAPACITY ANALYSIS

Ascend's reliability analysis is trusted by clients across the US. Its Resource Adequacy model is a probabilistic tool to analyze the risk of a load serving entity not having adequate resources to meet load. A key feature of the PowerSIMM Resource Adequacy module is the use of weather, load and renewable energy simulations that maintain the relationships between these variables to properly account for reliability risk from intermittent resources. Unexpected or forced outages from thermal generation, hydro generation, or storage can also be accounted for in the reliability assessment. PowerSIMM evaluates this risk with hourly simulations using the standard loss of load metrics: Loss of Load Probability, Loss of Load Expectation, and Expected Unserved Energy (refer to Figure 70). Additionally, PowerSIMM can perform effective load carrying capacity (ELCC) analysis to estimate the capacity contribution of renewables and storage for planning purposes.

Given system uncertainty, how likely will resources supply customer load all hours of the year?

- Large sources of uncertainty include renewable generation, forced outages, and load
- Probabilistic models provide metrics on loss of load events to fully understand potential harm

Metric	Description
LOLP	**Loss of load probability** – The probability of an event where load exceeds available generation resources
LOLH/LOLE	**Loss of load hours / expectation** – The expected number of hours (LOLH) or days (LOLE) where load cannot be met with available generation resources
EUE	**Expected energy unserved** – The expected amount of load, in MWh, that cannot be met with available generation
MW Short	The largest shortfall from inadequate generation resources
ELCC	**Effective load carrying capability** – The expected capacity contribution from variable renewable resources, usually as a function of the penetration of a renewable technology in a power system



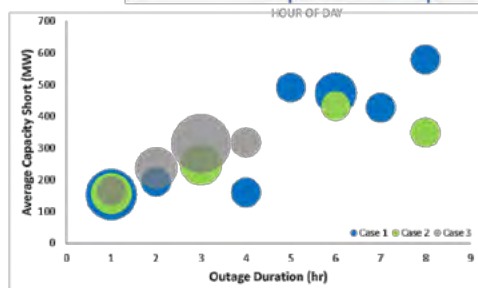


Figure 70. Overview of resource adequacy metrics and sample results not specific to Grant PUD's portfolio

Appendix 2: Modeling Inputs and Assumptions

PRIEST RAPIDS PROJECT

The Priest Rapids Project consists of the Wanapum Dam and the Priest Rapids Dam. Both dams are subject to a number of constraints, most of which are intended to facilitate a healthy salmon habitat, especially in the area downstream of Priest Rapids Dam. These flow constraints are summarized in Table 15 and a simplified representation of the salmon lifecycle influencing these constraints is included in .

Table 15. Flow protections and constraints applied to the Priest Rapids Project

Constraint	Start Date	End Date	Impact and Description
Minimum Flow	Year-round	Year-round	Priest Rapids Dam must always maintain a minimum flow of 36 kcfs.
Required Spill for Fish Ladder	Year-round	Year-round	Monthly requirements range from 0.5-2.0 kcfs for Wanapum Dam and 0.5-1.5 kcfs for Priest Rapids Dam. The higher values occur from April through August.
Stranding Bands	March 15	June 15	Daily flow fluctuations from Priest Rapids Dam must stay within a specified threshold, where that threshold varies based on the volume of inflows.
Required Spill for Fish Passage	April 15 *	August 20 *	Wanapum Dam must spill at least 22 kcfs Priest Rapids Dam must spill at least 29 kcfs.
Fish Mode	April 15 *	August 20 *	Wanapum Dam cannot operate at more than 84% capacity Priest Rapids Dam cannot operate at more than 95% capacity.
Memorial Day Recreation	Friday before Memorial Day	Memorial Day	Wanapum reservoir must be within 1 meter of full to ensure that boat docks have water access.
Independence Day Recreation	Variable **	Variable **	Wanapum reservoir must be within 1 meter of full to ensure that boat docks have water access.
Labor Day Recreation	Friday before Labor Day	Labor Day	Wanapum reservoir must be within 1 meter of full to ensure that boat docks have water access.
Reverse Load Factoring Part 1	October 15	November 20 *	The maximum daytime flow from Priest Rapids Dam during this time period becomes the minimum flow through May 15 of the following year. Based on historical experience, the maximum daytime flow is typically around 55 kcfs until the beginning of November and around 65 kcfs through the remainder of the November period.
Reverse Load Factoring Part 2 – Protection Level Flows	November 20 *	May 15	The flow from Priest Rapids Dam must always be above the maximum flow experienced in Part 1. Typically, this value is around 65 kcfs.

* Indicates an approximate date
** The period includes Independence Day through the nearest weekend

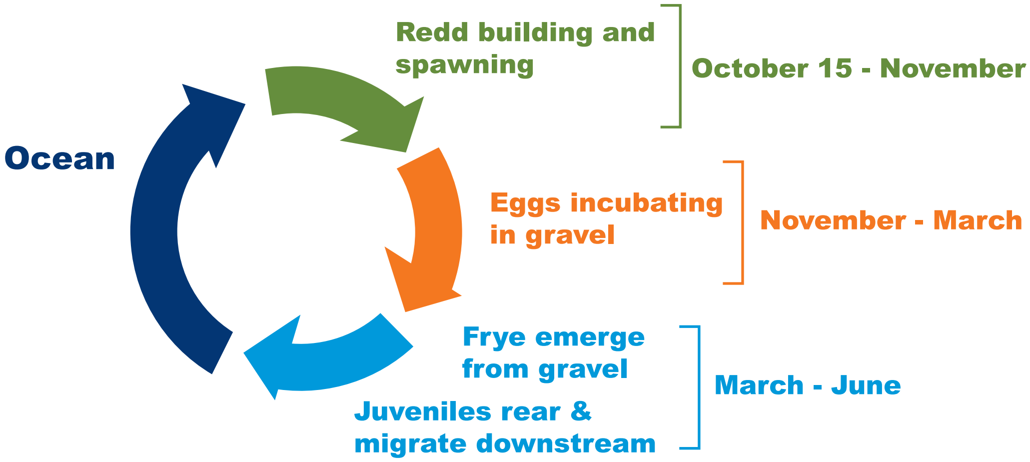


Figure 71. Salmon lifecycle

The Wanapum Dam has a nameplate capacity rating of 1,204 MW, but for this analysis we use a functional rating of 1,040 MW based on historical observations of generation. Similarly, the Priest Rapids Dam has a nameplate rating of 950 MW, but we assign it a functional rating of 920 MW. There are no ramping limits applied to the dams, though we inspect the hourly model outputs to ensure that generation behavior is not likely to be problematic. We assume a lag of 45 minutes between the Wanapum Dam and Priest Rapids Dam.

Both the Wanapum and Priest Rapids reservoirs are able to store water for later use, though neither reservoir is particularly large. The Priest Rapids reservoir is less than half the size of the Wanapum reservoir and can store a water volume equivalent to just a few hours of maximum generation. The Wanapum reservoir can store water amounts approximately equal to just under half a day of generation. Actual storage capacity varies based on the constraints shown in Table 15, especially required spill constraints, the amount of inflow, and the head height at the time of generation.

Outages for the two dams were modeled using daily expected outage data based on maintenance plans. Average annual planned outage rates are 5.9% for Wanapum and 4.1% for Priest Rapids. The turbine generator upgrades at Priest Rapids that keep one unit offline through 2030 are represented as an additional 10% planned outage. Forced outages are represented assuming a 2% forced outage rate.

Hourly inflows to Wanapum are based on historical estimated hourly discharges from Rocky Reach dam, the dam immediately upstream of Wanapum. Total annual discharges from Rocky Reach were 2% lower than the annual flows measured below Priest Rapids dam by the U.S. Geological Survey, so for this analysis, the hourly Rocky Reach discharges were uniformly increased by 2% in order to match the annual flows measured by the U.S. Geological Survey.

OTHER EXISTING GENERATION ASSETS

The Nine Canyon Wind resource, Quincy Chute, and Potholes East Canal were all represented as must-take variable renewable energy resources. Generation profiles were based on historical hourly profiles from 2019-2023, and the resources were assumed to provide as many average MWhs in future years as they did on average from that historical period. These three resources are assumed to exit the Grant PUD portfolio upon the expiration of their current contracts. The Nine Canyon contracts end on July 1, 2030, Quincy Chute on October 1, 2025, and Potholes East Canal on September 1, 2030.

ENERGY MARKET PRICES

Energy market prices used for market transactions are shown below.

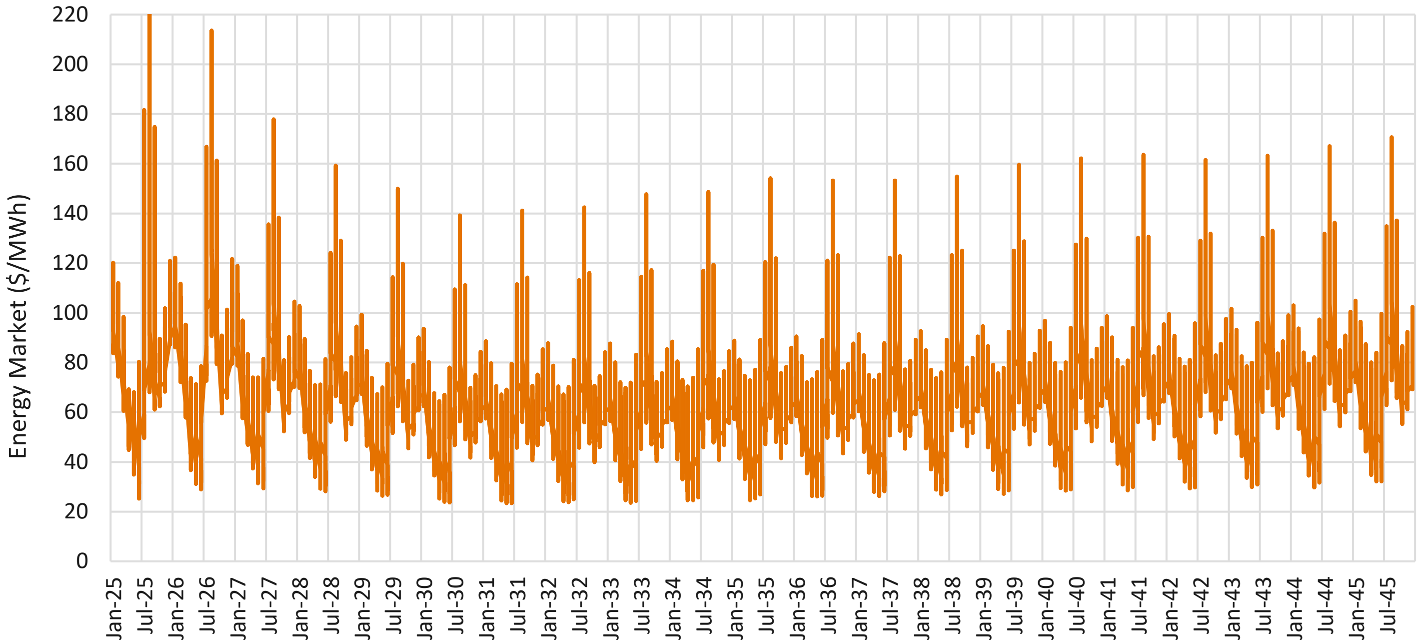


Figure 72. Forecast energy market prices, dollars per megawatt hour

New markets will capture increased resource utilization efficiency across the region, pushing market prices down. This increase in efficiency is captured in the energy market price forecast shown in Figure 72. If optimization through market mechanisms is able to capture more efficiencies than in base assumption, prices will drop even further. This higher level of efficiency is captured in our alternate price forecast shown below in Figure 73. This alternate forecast was used to evaluate performance of our selected portfolio under lower market price conditions.

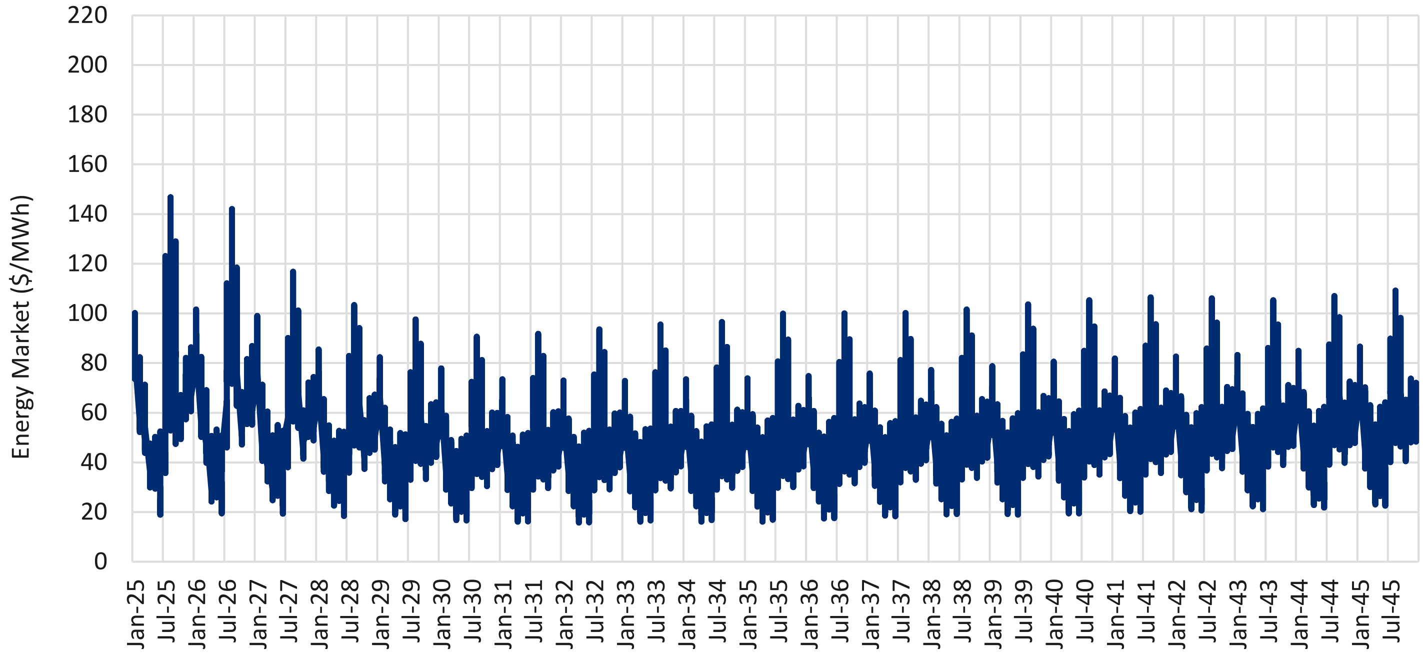


Figure 73. Forecast energy market prices, lower price scenario, dollars per megawatt hour

NATURAL GAS MARKET PRICES

Natural gas used by candidate resources was assumed to have the following market price.

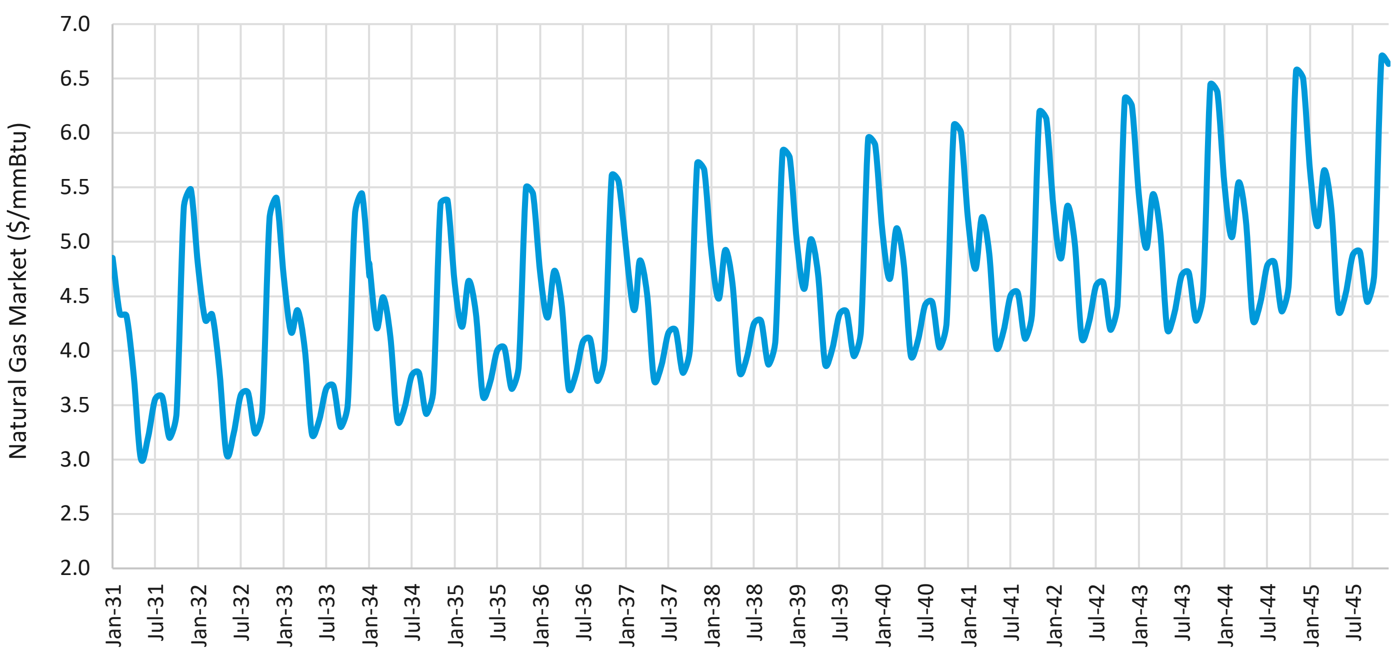


Figure 74. Forecast market cost of natural gas, dollars per mmBtu

GREEN HYDROGEN MARKET PRICES

Candidate resources fueled by hydrogen were assumed to use green hydrogen at the following market prices. These prices do not include the $/kg credit associated with the IRA.

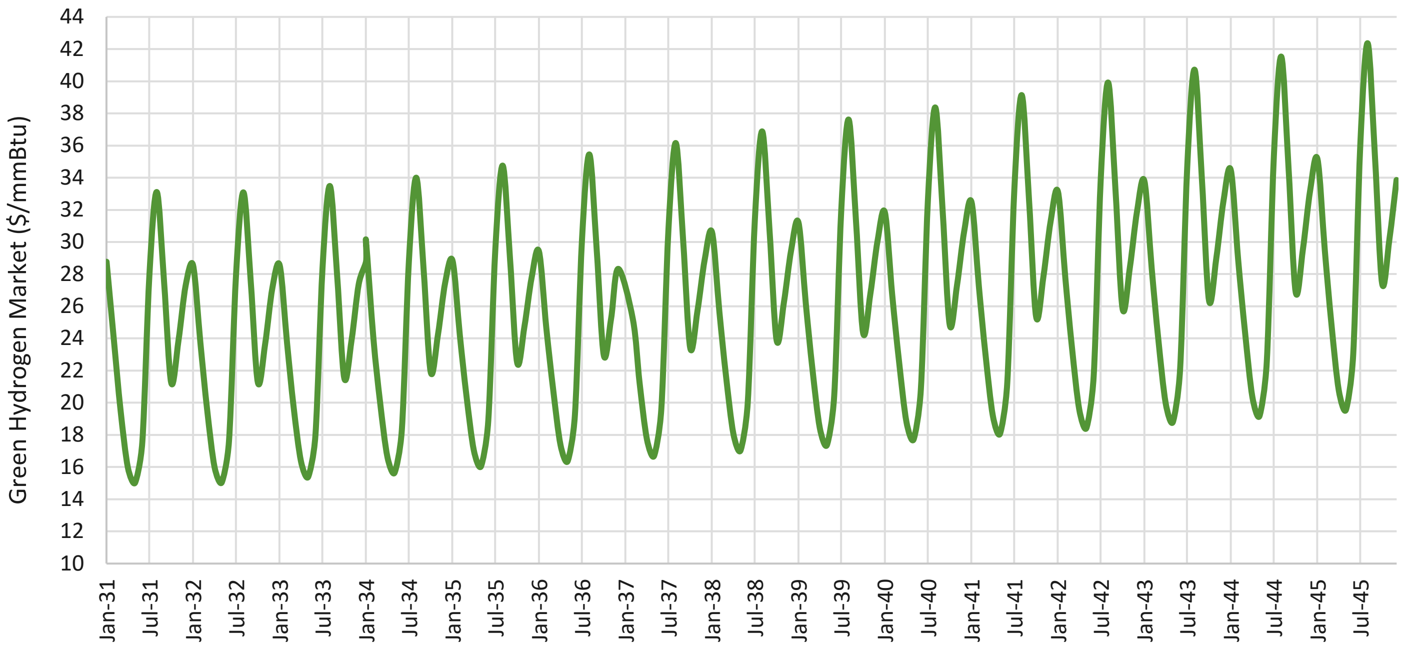


Figure 75. Forecast market cost of green hydrogen, dollars per mmBtu

SOCIAL COST OF CARBON

Per requirements of RCW 19.280, the social cost of carbon was considered in this plan. The adjusted social cost of carbon dioxide as publish by the Washington Utilities and Transportation Commission was applied to all CO_2 emitting candidate resources (Washington Utilities and Transportation Commission, 2024). These costs, presented in 2022 dollars are shown in Table 16.

Table 16. Adjusted social cost of carbon dioxide, by year, 2022 dollars per metric ton of CO_2

Year	Social Cost of Carbon
2020	85
2025	94
2030	100
2035	107
2040	116
2045	122
2050	131

RENEWABLE ENERGY CREDIT PRICE

Cost of renewable energy credits, used for alternate CETA compliance modeling are shown below.

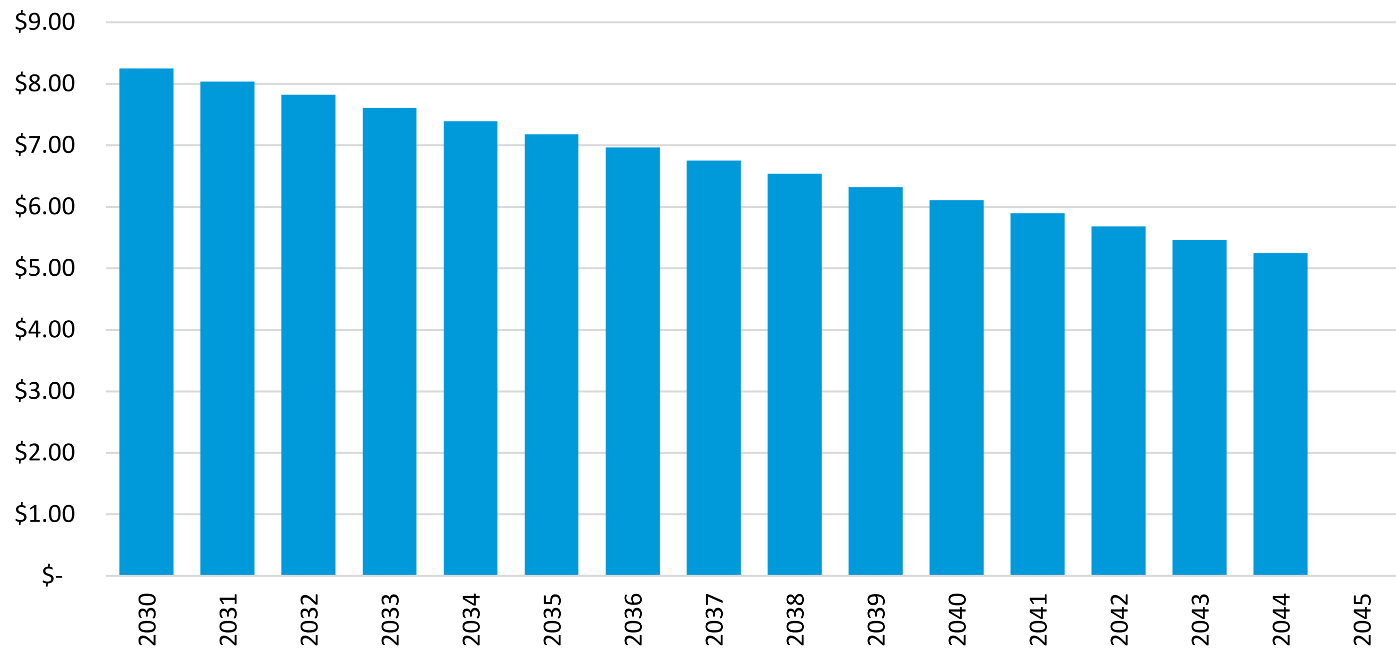


Figure 76. Forecast cost of renewable energy credits, 2030 - 2045, $/MWh

PLANNING RESERVE MARGINS

Table 17 shows the planning reserve margin (PRM), as a percentage of WRAP P50 load, used in our capacity expansion planning evaluations. WRAP P50 load differs from Grant PUD system load and is based on a 5-year look-back at actual load values as detailed in current WRAP business practices. These PRMs are based on our current understanding of the WRAP program. We expect PRM to change as regional loads evolve and as generating resources are added to or retired from the region. However, without a firm grasp of the exact nature of these changes we maintained the monthly PRMs shown over the planning horizon. For our WRAP based capacity constraint we assumed the need to carry additional operating reserves in addition to this PRM. For months when the WRAP program is not operable, we assumed no planning reserve margin constraint.

Table 17. Planning reserve margin used in capacity expansion evaluation, expressed as percent of forecast monthly WRAP P50 load

Month	PRM as Percent of WRAP P50 load
Jan	17.5
Feb	18.4
Mar	26.1
Jun	26.2
Jul	14.5
Aug	16.1
Sep	16.2
Nov	19.7
Dec	17.1

RPS TARGETS

Annual RPS targets were set at 15% of the average of the prior two years of annual sales. Annual sales were assumed to be annual load less 4.06% losses.

CETA CLEAN ENERGY PROVISION TARGETS

Annual CETA targets were set at 80% of annual sales served by clean energy and 100% of annual sales served either by clean energy or RECs for the years 2030 through 2044. For 2045, 100% of annual sales were targeted to be served by clean energy. Annual sales were assumed to be annual load less 4.06% losses.

POTENTIAL FUTURES RESOURCES

The technology types evaluated for this resource plan were:

- Solar PV
- Wind
- Lithium-ion battery, 4-hour duration
- BPA Tier 2 contract
- Pumped storage
- Iron-oxide battery
- Hydrogen fuel cell

- Hydrogen fueled aeroderivative
- Natural gas fueled aeroderivative
- Natural gas fueled combined cycle
- Small modular reactor

Demand response, based on a program for current cryptocurrency load was evaluated as a demand side option.

Acquisition of the BPA Provider of Choice Tier 2 contract was evaluated.

Wholesale purchases of market energy at the Mid-C trading hub were also evaluated as a supply option.

Information on the costs, operational characteristics, capacity ratings and other considerations of these potential future resources is described in the following sections.

Incremental Resource Size

When evaluating resource selection, incremental nameplate capacity additions considered were:

Table 18. Size of incremental candidate resource additions considered, MW

Candidate Resource	Incremental Addition Size
Solar	10
Wind	10
Lithium-ion battery	10
Pumped storage	50
Iron-oxide battery	10
Hydrogen fuel cell	10
Hydrogen fueled aeroderivative	45
Natural gas fuel aeroderivative	45
Natural gas fueled combined cycle	130
Small modular reactor	71
BPA Tier 2 contract	200
Demand Response	28

Siting Locations

Potential resources considered to be located withing Grant County and in Grant PUD's balancing area included solar PV, 4-hour duration lithium batteries, iron oxide batteries, hydrogen fuel cells, and a small modular reactor.

Solar PV located in Grant County, Oregon, Idaho, Montana and Nevada were evaluated. For purposes of determining solar capability specific locations near Quincy WA, Maupin OR, Mountain Home ID, Lavinia MT and McGill NV were selected. These selections were made after a survey of locations within targeted states and are not meant to imply a specific project or actual siting. They are meant to be representative of a location with mean solar irradiance quality from a region generally accessible to project development.

Wind farms located in Oregon, Idaho and Montana were considered. Similarly to solar candidate resource selection, wind farm location selections were made after a survey of locations within targeted states and are not meant to imply a specific project or actual siting but meant to be representative of an areas available wind quality. Wind condition s near LaGrande OR, Glenns Ferry ID and Shelby MT were used. No wind sites in Washington were considered due to a perceived lack of available sites in the State, with the exception of the currently troubled Horse Heaven Hills site currently being developed near Yakima.

Lithium-ion, 4-hour duration batteries locations considered include locations in Grant County as well as the locations selected for solar and wind candidate resources. Locating candidate resources near solar and wind candidate resources allowed for consideration of both operating these batteries paired with those solar and wind resources or as stand-alone installations.

Pumped storage was considered to be located in central Washington but outside the Grant PUD balancing area. Selection was based on knowledge of sites currently under consideration for development.

Iron-oxide batteries, hydrogen fuel cells, and hydrogen fueled aeroderivatives were considered only with installations in Grant county, inside the Grant PUD balancing area. Through pre-screening, this was thought to be the likely least-cost, highest impact siting for this type of resource.

Natural gas fueled aeroderivative and combined cycle candidates were considered to be located in Central to Southern Idaho and located on a pipeline with Opal hub pricing.

The small modular reactor module candidates were considered to be located in Grant County. We have spent considerable time and effort studying the viability of SMR and are interested in continuing to evaluate a Grant County site for a future SMR location.

Commercial Operation Date Timing and Available Capacity by Year

The following assumptions of the first available commercial operation dates and nameplate capacity of candidate resources available annually for portfolio addition were used. These dates were based on our best current knowledge of construction timelines, technology development and transmission interconnection queue processes.

Table 19. Assumed maximum nameplate capacity available for addition by year, by technology and location, 2026 – 2030, nameplate MW

Candidate Resource	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Solar Grant County	120	300	300	200	500	500	500	500	500	500
Solar OR, ID, MT, NV	150	150	150	150	150	150	150	150	150	150
Wind OR, ID, MT	150	150	150	150	150	150	150	150	150	150
Lithium-ion battery Grant County	0	0	0	0	0	80	80	80	80	80
Lithium-ion battery OR, ID, MT	300	300	300	300	300	300	300	300	300	300
Lithium-ion battery NV	150	150	150	150	150	150	150	150	150	150
Pumped storage	0	0	0	0	200	200	200	200	200	200
Iron-oxide battery	0	0	0	0	0	80	80	80	80	80
Hydrogen fuel cell	0	0	0	0	0	80	80	80	80	80
Hydrogen fueled aeroderivative	0	0	0	0	0	90	90	90	90	90
Natural gas fuel aeroderivative	0	0	0	0	0	90	90	90	90	90
Natural gas fueled combined cycle	0	0	0	0	0	130	13	130	130	130
Small modular reactor	0	0	0	0	0	0	0	0	284	284
BPA Tier 2 contract	0	0	40	0	0	0	0	0	0	0
Demand Response	28	28	28	28	28	28	28	28	28	28
Candidate Resource	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Solar Grant County	500	500	500	500	500	500	500	500	500	500
Solar OR, ID, MT, NV	150	150	150	150	150	150	150	150	150	150
Wind OR, ID, MT	150	150	150	150	150	150	150	150	150	150
Lithium-ion battery Grant County	80	80	80	80	80	80	80	80	80	80
Lithium-ion battery OR, ID, MT	300	300	300	300	300	300	300	300	300	300

Lithium-ion battery NV	150	150	150	150	150	150	150	150	150	150
Pumped storage	200	200	200	200	200	200	200	200	200	200
Iron-oxide battery	80	80	80	80	80	80	80	80	80	80
Hydrogen fuel cell	80	80	80	80	80	80	80	80	80	80
Hydrogen fueled aeroderivative	90	90	90	90	90	90	90	90	90	90
Natural gas fuel aeroderivative	90	90	90	90	90	90	90	90	90	90
Natural gas fueled combined cycle	130	130	130	130	130	130	130	130	130	130
Small modular reactor	284	284	284	284	284	284	284	284	284	284
BPA Tier 2 contract	0	0	0	0	0	0	0	0	0	0
Demand Response	28	28	28	28	28	28	28	28	28	28

This plan did not consider any additional resources prior to 2026 due to current understanding of project availability and interconnection timeframes.

In addition to annual additions, this plan assumed limits total maximum additions by technology and location. Table 20 shows these assumptions.

Table 20. Assumed planning period total maximum nameplate capacity available for addition, by technology and location, nameplate MW

Candidate Resource	2026 – 2045
Solar Grant County	800
Solar OR, ID, MT, NV	600
Wind OR, ID, MT	600
Lithium-ion battery Grant County	160
Lithium-ion battery OR, ID, MT	1,200
Lithium-ion battery NV	600
Pumped storage	200
Iron-oxide battery	160
Hydrogen fuel cell	160
Hydrogen fueled aeroderivative	180
Natural gas fuel aeroderivative	270
Natural gas fueled combined cycle	260
Small modular reactor	568
BPA Tier 2 contract	40
Demand Response	28

The 800 MW maximum addition of solar located in Grant county was further limited to 300 in the period 2026 through 2028. This was due to our current understanding that current queue capacity limits additions over that near term period.

Transmission Rate Assumptions

Transmission costs assumptions applied to candidate resources were developed by examining current transmission provider costs. These costs were then broken down by regions corresponding to the siting locations chosen for candidate resources to estimate the costs of delivering energy from a sited resource to Grant customer load. Table 21 lists transmission cost assumptions.

Table 21. Transmission costs by service, by location of generating resource

Transmission Service and Loss Accounting	Internal Grant BA	Eastern Washington Oregon and Northern Idaho	Southern Idaho	Western Montana	Eastern Montana	Desert Southwest
Point to Point transmission service ($/kw month)	2.510	1.648	4.761	2.172	6.220	7.852
Scheduling, system control and dispatch ($/kW month)	0	0.316	0.158	0.316	0.158	0.158
Reactive supply and voltage control	0	0	0	0	0	0.134
Spinning reserves ($/kW on 1.5% of hourly integrated generation)	0.000215	11.05	6.53	11.05	14.59	0.1677
Supplemental reserves ($/kW on 1.5% of hourly integrated generation)	0.000215	7.22	6.53	7.22	13.412	0.4677
Regulating reserves	0	0.358	0	0	0	0
Flex reserves	0	0	0	0	2.369	0
Solar integration ($/kW-month)	0.762	0.456	0	0.456	1.415	0.4653
Wind integration ($/kW-month)	1.2573	0.753	0	0.753	1.415	0.5577
Non-VER integration ($/kW-month)	0	0	0	0	0.112	0.2624

The following shows the assumed losses for the listed location to Grant's BA.

Table 22. Delivery losses, by location of generating resource, percent

Delivery Losses	Internal Grant BA	Eastern Washington Oregon and Northern Idaho	Southern Idaho	Western Montana	Eastern Montana	Desert Southwest
	1.30	2.04	6.12	2.04	5.32	10.42

Electric Load Carrying Capability

The following assumptions of monthly electric load carry capability (QCC), expressed as percentage of nameplate, were used to evaluate each candidate resource's contribution to assumed monthly resources adequacy targets. Although we expect the QCC values to change over time, for this evaluation monthly QCCs were held constant over the planning period. These values were derived from information available from the developing WRAP program.

Table 23. Monthly generator electric load carrying capacity as percentage of nameplate capacity , by resource type, by location

Candidate Resource	Jan	Feb	Mar	Jun	Jul	Aug	Sep	Nov	Dec
Solar Grant County, and OR	3.3	3.1	5.1	84.4	57.9	48.5	29.6	1.3	3.1
Solar Oregon	3.3	3.1	5.1	84.4	57.9	48.5	29.6	1.3	3.1
Solar Idaho	2.2	3.1	3.1	17.4	20.6	14.6	16.1	0.9	1.9
Solar Montana	3.3	3.1	5.1	84.4	57.9	48.5	29.6	1.3	3.1
Solar Nevada	15.2	15.2	10.8	30.3	27.2	21.2	17.4	5.2	10.4
Wind Oregon	5.6	8.6	13.7	13.0	10.8	10.8	11.5	8.3	7.3
Wind Idaho	21.2	27.6	27.9	23.5	24.3	20.4	25.6	21.6	23.6
Wind Montana	30.5	23.1	36.2	21.1	13.4	19.7	34.0	47.1	46.2
Lithium-ion battery Grant County, OR, ID and MT	86.2	82.1	100.0	100.0	77.0	100.0	100.0	100.0	100.0
Lithium-ion battery Nevada	63.2	67.2	60.6	84.8	90.0	85.1	100.0	64.0	71.1
Pumped storage	86.2	82.1	100.0	100.0	77.0	100.0	100.0	100.0	100.0
Iron-oxide battery	86.2	82.1	100.0	100.0	77.0	100.0	100.0	100.0	100.0
Hydrogen Fuel cell	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0
Hydrogen fueled aeroderivative	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0
Natural gas fuel aeroderivative	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0
Natural gas fueled combined cycle	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0
Small modular reactor	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0
BPA Tier 2 contract	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Demand Response	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Purchased Power Costs

The following technologies were evaluated as potential purchased power agreements (PPA):

- Solar PV
- Wind
- BPA Tier 2 contract

Purchased power contract costs were developed through consultation with our consultant, Ascend Analytics, and were further informed by responses to Grant PUD's 2024 All-Source Capacity and Energy RFP. Figure 77 illustrates variable costs assumed for PPA candidate resource evaluation, including financial impacts of estimated delivery losses.

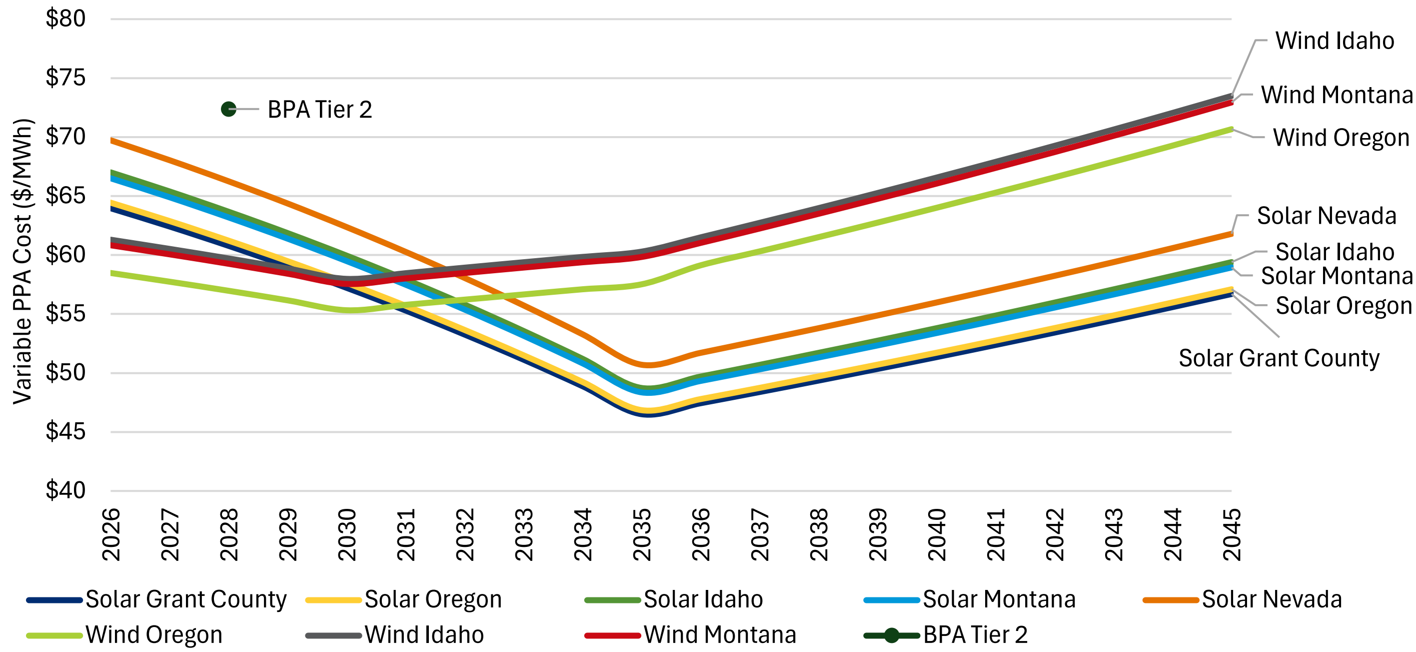


Figure 77. PPA candidate resource variable costs, determined at year of contract agreement, $/MWh, 2024 dollars

Figure 78 lists fixed costs used for PPA candidate resource evaluation, including transmission and balancing area service costs.

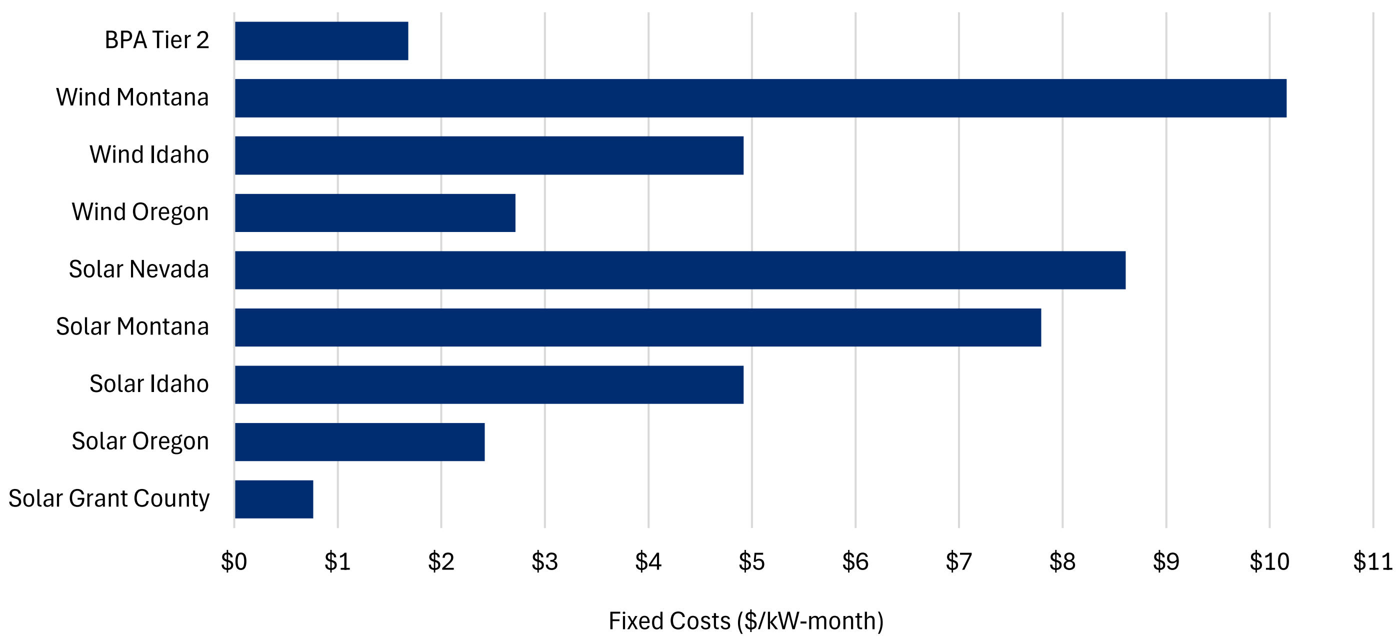


Figure 78. PPA candidate resource fixed costs, $/kW-month, 2024 dollars

Actual available PPA prices will vary, and any negotiation of resource acquisition will include evaluation of actual terms and conditions of potential contracts.

Capital Costs for Ownership

The following technologies were evaluated as potential ownership options:

- Lithium-ion battery (LIB), 4-hour duration, all locations

- Pumped storage
- Iron-oxide battery
- Hydrogen fuel cell
- Hydrogen fueled aeroderivative
- Natural gas fueled aeroderivative
- Natural gas fueled combined cycle
- Small modular reactor
- Demand response

Figure 79 illustrates capital costs assumed for evaluation of candidate resource ownership. Grant PUD staff developed all capital cost assumptions.

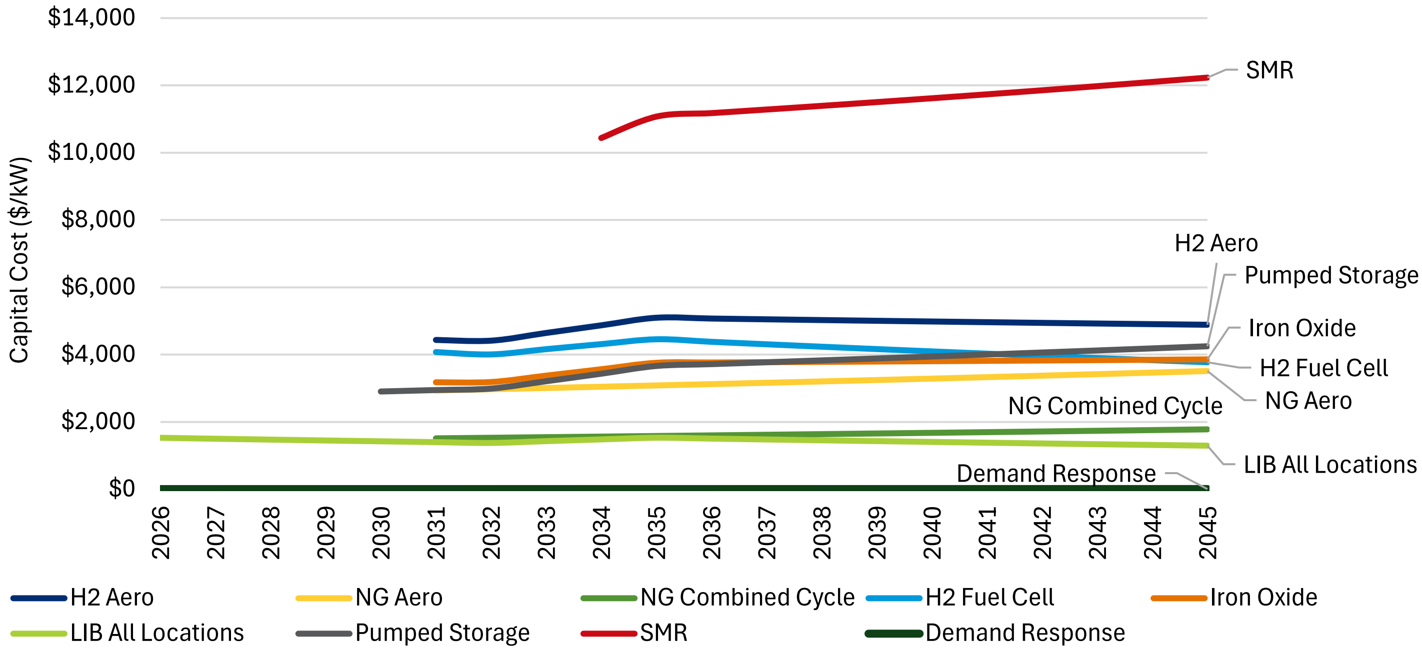


Figure 79. Candidate resource capital costs, determined at time of commercial operation date, $/kW, 2024 dollars

Figure 80 lists fixed costs used for ownership candidate resource evaluation, including transmission and balancing area service costs. Grant PUD staff developed all capital cost assumptions.

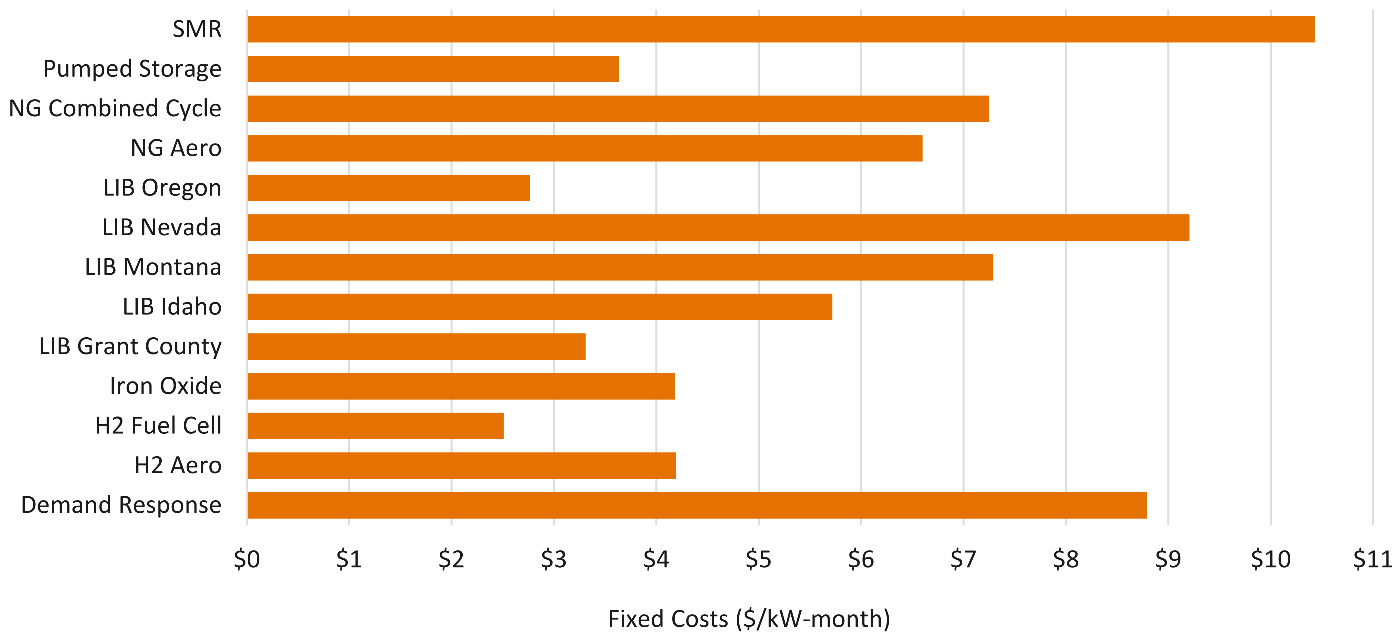


Figure 80. Ownership candidate resource fixed costs, $/kW-month, 2024 dollars

Other non-fuel variable costs used in candidate resource assessment are included in Table 24.

Table 24. Ownership candidate resource non-fuel variable costs, $/MWh, 2024 dollars

Candidate Resource	
Pumped storage	0.60
Hydrogen fueled aeroderivative	3.00
Natural gas fuel aeroderivative	3.00
Natural gas fueled combined cycle	2.26
Small modular reactor	12.5

Appendix 3: Conservation Potential Assessment

Grant PUD's 2024 Conservation Potential Assessment, prepared by EES Consulting is included in its entirety below.

PREPARED BY EES CONSULTING

Grant County Public Utility District

Amended

Conservation Potential Assessment 2024-2043

Final Report

May 3, 2024

EES Consulting

a GDS Associates Company

EES Consulting
a GDS Associates Company

Amber Gschwend, Managing Director
amber.gschwend@gdsassociates.com

May 3, 2024

Mr. Chris Buchmann
Grant County Public Utility District
P.O. Box 1519
Moses Lake, WA 98837

SUBJECT: 2023 Conservation Potential Assessment – Final Report

Dear Mr. Buchmann:

Please find attached the Amended Conservation Potential Assessment for 2024-2043.

The amended potential estimated for the 2024-2025 biennium is 2.00 aMW.

Very truly yours,

AGschwend

Amber Gschwend
Managing Director, EES Consulting

Contents

1 Executive Summary

This report describes the methodology and results of the Amended Conservation Potential Assessment (CPA) Grant County Public Utility District (the District). This assessment provides estimates of energy savings by sector for the period 2024 to 2043. The assessment considers a wide range of conservation resources that are reliable, available, and cost-effective within the 20-year planning period.

1.1 BACKGROUND

The District provides electricity service to approximately 47,990 customers located in Grant County, Washington. Over half of the District's load requirements are for serving commercial and industrial customers. The District has completed conservation potential assessments every two years since the Energy Independence Act (EIA) was effective in 2010. The EIA requires that utilities with more than 25,000 customers (known as qualifying utilities) pursue all cost-effective conservation resources and meet conservation targets set using a utility-specific conservation potential assessment methodology.

Washington's Energy Independence Act (EIA), effective January 1, 2010, requires that utilities with more than 25,000 customers (known as qualifying utilities) pursue all cost-effective conservation resources and meet conservation targets set using a utility-specific conservation potential assessment methodology.

The EIA sets forth specific requirements for setting, pursuing, and reporting on conservation targets. The methodology used in this assessment complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the 2021 Power Plan. Thus, this Conservation Potential Assessment will support the District's compliance with EIA requirements.

This assessment was built on the technical workbooks developed for the Final 2021 Power Plan. The primary model assumptions included the following changes since the previous study:

- Avoided Costs
  - Recent forecast of power market prices prepared by the Council in April 2023
  - Avoided generation capacity value updated with recent wholesale rates
- Updated Customer Characteristics Data
  - Residential home counts
  - Commercial floor area based on recent load growth
  - Industrial sector consumption based on recent load growth
- Measure Updates
  - Measure savings, costs, and lifetimes were updated based on the latest data available the 2021 Power Plan supply curves
- Accounting for Recent Achievements
  - Internal programs
  - NEEA programs

The first step of this assessment was to carefully define and update the planning assumptions using the new data. The Base Case conditions were defined as the most likely market conditions over the planning horizon, and the conservation potential was estimated based on these assumptions. Additional scenarios were also developed to test a range of conditions.

1.2 RESULTS

Table 1-1 shows the high-level results of this assessment, the cost-effective potential by sector in 2, 4, 10, and 20-year increments. The total 20-year energy efficiency potential is 32.61 aMW. The most important numbers per EIA are the 10-year potential of 15.99 aMW, and the two-year potential of 2.00 aMW. These numbers are also illustrated in Figure 1-1 below.

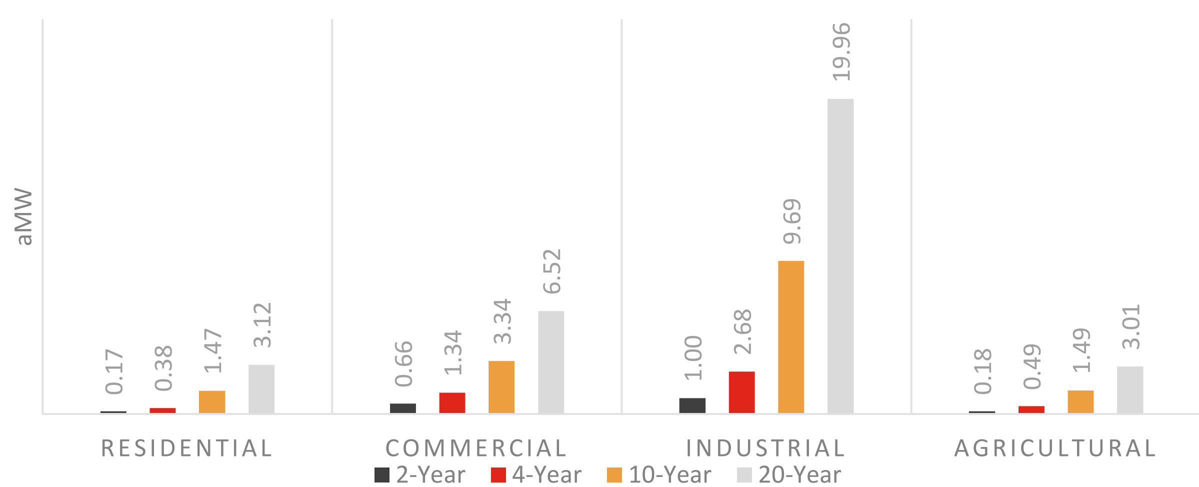
These estimates include energy efficiency achieved through the District's own utility programs and through its share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments. Some of the potential may be achieved through code and standards changes, especially in later years. In some cases, the savings from those changes will be quantified by NEEA or through BPA's Momentum Savings work.

TABLE 1-1: COST-EFFECTIVE POTENTIAL (aMW)

	2-Year	4-Year	10-Year	20-Year
Residential	0.17	0.38	1.47	3.12
Commercial	0.66	1.34	3.34	6.52
Industrial (including data centers)	1.00	2.68	9.69	19.96
Agricultural	0.18	0.49	1.49	3.01
Total	**2.00**	**4.89**	**15.99**	**32.61**

Note: Numbers in this table and others throughout the report may not add to total due to rounding.

FIGURE 1-1: COST-EFFECTIVE ENERGY EFFICIENCY POTENTIAL ESTIMATE



Energy efficiency also has the potential to reduce peak demands. Estimates of peak demand savings are calculated for each measure using the Council's ProCost tool, which uses hourly load profiles developed for the 2021 Power Plan and a District-specific definition of when peak demand occurs. These unit-level estimates are then aggregated across sectors and years in the same way that energy efficiency measure savings potential is calculated. The reductions in peak demand provided by energy efficiency are summarized in Table 1-2 below.

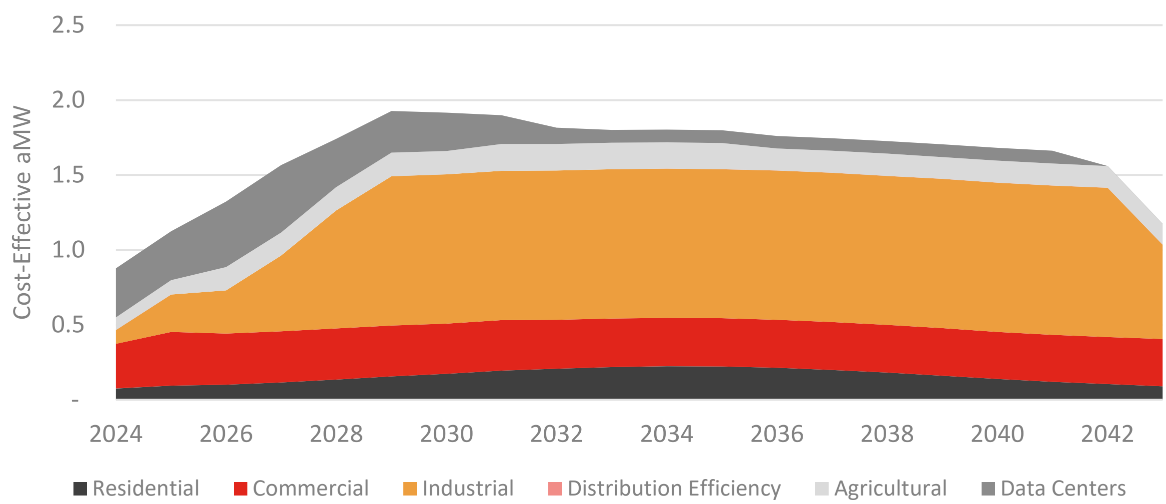
The savings from most energy efficiency measures are concentrated in those periods when energy is being used, and not evenly throughout the day. Thus, the peak demand reduction, measured in MW, is greater than the annual average energy savings. The District's annual peak occurs most frequently on summer evenings, between 4 and 6 PM. In addition to these peak demand savings, demand savings would occur in varying amounts throughout the year.

TABLE 1-2: COST-EFFECTIVE DEMAND SAVINGS (MW)

	2-Year	4-Year	10-Year	20-Year
Residential	0.53	1.22	4.88	10.96
Commercial	0.53	1.07	2.64	5.04
Industrial	1.05	2.86	10.78	22.58
Agricultural	0.02	0.05	0.29	0.70
Total	**2.13**	**5.20**	**18.60**	**39.29**

The 20-year energy efficiency potential is shown on an annual basis in Figure 1-2. This assessment shows potential starting around 0.88 aMW in 2024 and ramping up to 1.93 by 2029 and then down over the period due to uncertainty in data center savings. In the other sectors, potential also gradually decreases after 2024 as the remaining retrofit measure opportunities diminish over time.

FIGURE 1-2: ANNUAL COST-EFFECTIVE ENERGY EFFICIENCY POTENTIAL ESTIMATE



The largest share of future savings potential is projected to be from large data center projects. The savings potential estimated in the first 2 years is based on both historic levels and the projects with planned completion dates in 2024 and 2025. These larger projects take significant lead time to develop and complete. While the District has historically relied on data center projects in meeting its targets, future savings potential is uncertain. The estimates for 2026 and beyond are based on average historic values that decline over the 20-year period. Future savings will depend significantly on future load growth, which is inherently impacted by multiple factors and uncertainties. The District will continue to update this study in future reporting periods with the best available information.

The second largest share of conservation is available in the District's commercial sector. The potential in the commercial sector is higher compared with the potential estimated in the 2021 CPA. The District has also achieved significant savings in lighting measures in recent years, leaving limited remaining savings.

Savings in the commercial sector are spread across numerous end uses, but the primary areas for opportunity are in the HVAC end use. Notable measures in this area include:

- Residential Sized and Commercial-Sized Heat Pump Water Heaters
- Heat Recovery Ventilation
- Chillers and AC
- Commercial Lighting
- Refrigeration

Only 10% of the potential is in the residential sector. The largest contributing measure categories for residential applications include water heating and HVAC. Measures with notable potential in this end use include:

- Smart Thermostat
- Low Flow Shower Heads Efficiency 1.5 gallons per minute (gpm) or better
- Faucet Aerators
- Water Heater Circulator Controls and Circulators
- Air Source Heat Pump

This study identified lower potential in the industrial sector relative to the 2021 CPA due mostly to customer participation in energy efficiency programs.

1.3 COMPARISON TO PREVIOUS ASSESSMENT

Table 1-3 shows a comparison of the 2, 10, and 20-year Base Case conservation potential by customer sector for this assessment and the results of the District's 2021 CPA.

TABLE 1-3: COMPARISON OF 2021 CPA AND 2023 CPA COST-EFFECTIVE POTENTIAL

	2-Year			10-Year			20-Year		
	2021	2023	% Change	2021	2023	% Change	2021	2023	% Change
Residential	0.13	0.17	31%	**2.57**	1.47	-43%	**7.01**	3.12	-55%
Commercial	0.43	0.66	53%	**6.63**	3.34	-50%	**20.68**	6.52	-68%
Industrial	3.98	1.00	-75%	**8.71**	9.69	11%	**18.13**	19.96	10%
Agricultural	0.02	0.18	797%	**0.50**	1.49	199%	**1.33**	3.01	126%
Total	**4.56**	**2.00**	**-56%**	**18.41**	**15.99**	**-13%**	**47.15**	**32.61**	**-31%**

**Note that the 2021 columns refer to the CPA completed in 2021 for the time period of 2022 through 2041. The 2023 assessment is for the timeframe: 2024 through 2043.*

The change in conservation potential estimated since the 2021 study is the result of several changes to the input assumptions, including measure data and avoided cost assumptions. Additionally, new measures were added to the assessment and ramp rates were adjusted to account for program maturity, data center growth, lingering COVID impacts, and 2021 Power Plan assumptions. A detailed analysis is provided in the Results section of this study.

1.3.1 Measure Data

Measure data was updated to include the Final 2021 Power Plan supply curve data.

1.3.2 Avoided Cost

An updated forecast of market prices was used to value energy savings. This forecast is lower than the forecast used in the 2021 assessment. Other avoided cost assumptions remained largely the same.

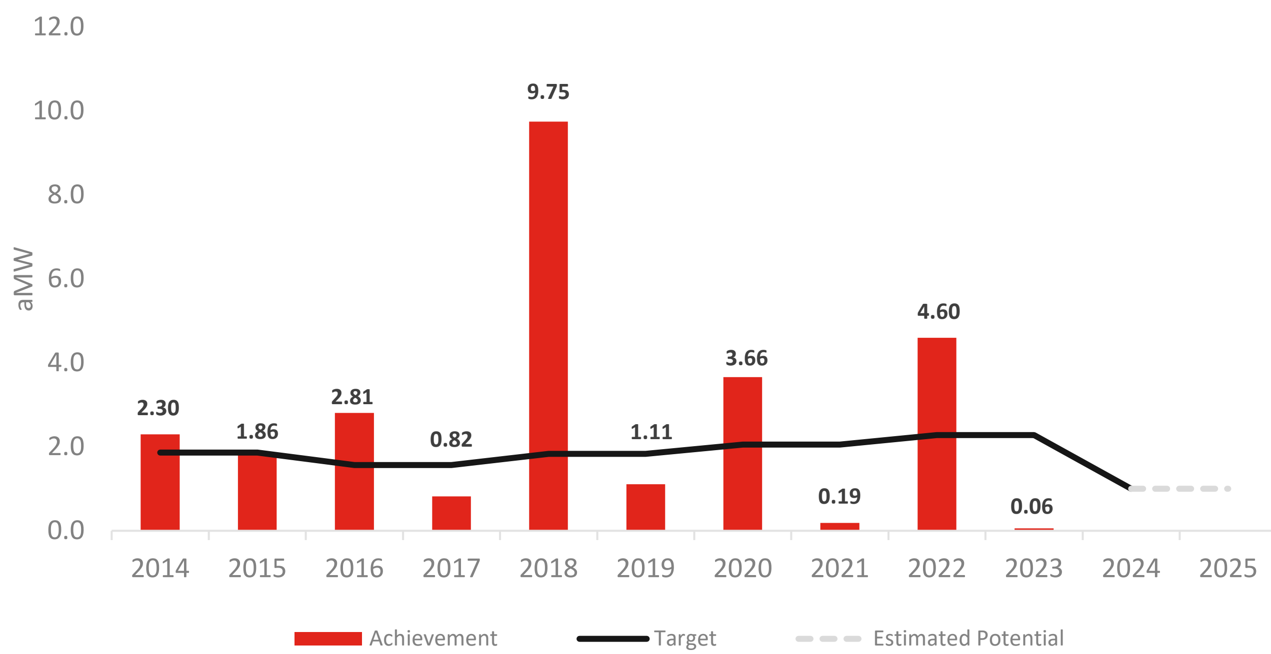
1.3.3 Customer Characteristics

No changes were made from the last CPA. However, growth in usage and number of customers was accounted for in the base year assumptions.

1.4 TARGETS AND ACHIEVEMENT

Figure 1-3 compares the District's historic achievement with its targets. The estimated potential for 2024 and 2025 is based on the Base Case scenario presented in this report and represents approximately an 56% reduction over the 2022-23 biennium. A decrease was expected based on higher efficiency baselines since the 2021 Power Plan was finalized plus the lower value of energy based on the Council's 2023 market price forecast. The figure below also shows that the District has consistently met its biennial energy efficiency targets, and that the potential estimates presented in this report are achievable through the District's various programs and the District's share of NEEA savings.

FIGURE 1-3: HISTORIC ACHIEVEMENT AND TARGETS



1.5 CONCLUSION

This report summarizes the CPA conducted for the District for the 2024 to 2043 timeframe. Many components of the CPA are updated from previous CPA models including items such as energy market price forecast, code and standard changes, recent conservation achievements, revised savings values and ramp rates for RTF and Council measures, and multiple scenario analyses.

The near-term results of this assessment are lower than the previous assessment, primarily due to the large amount of efficiency already achieved both regionally and by the District and the updated efficient baselines resulting from building codes and the 2021 Power Plan baselines. The results show a total 10-year cost- effective potential of 15.99 aMW and a two-year potential of 2.00 aMW for the 2024-25 biennium, which is a 56% decrease from the target for the previous biennium. This decrease is due primarily to reduced cost-effectiveness for some measures, program achievements, adjustments for data center potential, and updated program ramp rates that account slower adoption post COVID-19.

2 Introduction

2.1 OBJECTIVES

The objective of this report is to describe the results of the Grant County Public Utility District (the District) 2023 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2024 to 2043, with the primary focus on the initial 10 years. This analysis has been conducted in a manner consistent with requirements set forth in RCW 19.285 (EIA) and 194-37 WAC (EIA implementation) and Washington Clean Energy Transformation Act (CETA) and is part of the District's compliance documentation. The results and guidance presented in this report will also assist the District in strategic planning for its conservation programs. Finally, the resulting conservation supply curves can be used in the District's Integrated Resource Plan (IRP).

The conservation measures used in this analysis are based on the measures that were included in the Council's 2021 Power Plan. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

2.2 ELECTRIC UTILITY RESOURCE PLAN REQUIREMENTS

According to Chapter RCW 19.280, utilities with at least 25,000 retail customers are required to develop IRPs by September 2008 and biennially thereafter. The legislation mandates that these resource plans include assessments of commercially available conservation and efficiency measures. This CPA is designed to assist in meeting these requirements for conservation analyses. The results of this CPA may be used in the next IRP due to the state by September 2024. More background information is provided below.

2.3 ENERGY INDEPENDENCE ACT

Chapter RCW 19.285, the Energy Independence Act, requires that, "each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible." The timeline for requirements of the Energy Independence Act is detailed below:

- By January 1, 2010 – Identify achievable cost-effective conservation potential through 2019 using methodologies consistent with the Pacific Northwest Power and Conservation Council's (Council) latest power planning document.
- Beginning January 2010, each utility shall establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for the two-year period of the cost-effective conservation potential for the subsequent ten years.
- On or before June 1, 2012, each utility shall submit an annual conservation report to the department (the Department of Commerce or its successor). The report shall document the utility's progress in meeting the targets established in RCW 19.285.040.
- Beginning on January 1, 2014, cost-effective conservation achieved by a qualifying utility in excess of its biennial acquisition target may be used to help meet the immediately subsequent two biennial acquisition targets, such that no more than twenty percent of any biennial target may be met with excess conservation savings.

- Beginning January 1, 2014, a qualifying utility may use conservation savings in excess of its biennial target from a single large facility to meet up to an additional five percent of the immediately subsequent two biennial acquisition targets.[1]

This report summarizes the preliminary results of a comprehensive CPA conducted following the requirements of the EIA and additions made by the passage of CETA. A checklist of how this analysis meets EIA requirements is included in Appendix III.

2.4 OTHER LEGISLATIVE CONSIDERATIONS

Washington state enacted several laws that impact conservation planning. Washington HB 1444 enacts efficiency standards for a variety of appliances. Washington also enacted a clean energy law, SB 5116. CETA (2019) requires the use of specific values for avoided greenhouse gas emissions. This study follows the CETA requirements to value energy efficiency savings at the prescribed value established by the Department of Ecology. Finally, CETA requires that all sales of electricity be greenhouse gas neutral by 2030 and greenhouse gas free by 2045. This provision has been incorporated into the assumptions of this CPA. Specifically, this impacts the avoided cost of conservation, as described in Appendix IV.

2.5 STUDY UNCERTAINTIES

The savings estimates presented in this study are subject to the uncertainties associated with the input data. This study utilized the best available data at the time of its development; however, the results of future studies will change as the planning environment evolves. Specific areas of uncertainty include the following:

- Customer Characteristic Data – Residential and commercial building data and appliance saturations are in many cases based on regional studies and surveys. There are uncertainties related to the extent that the District's service area is similar to that of the region, or that the regional survey data represents the population.
- Measure Data – In particular, savings and cost estimates (when comparing to current market conditions), as prepared by the Council and RTF, will vary across the region. In some cases, measure applicability or other attributes have been estimated by the Council or the RTF based on professional judgment or limited market research.
- Market Price Forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this analysis represent a snapshot in time. Given a different snapshot in time, the results of the analysis would vary. However, different avoided cost scenarios are included in the analysis to consider the sensitivity of the results to fluctuating market prices over the study period.
- Utility System Assumptions – Credits have been included in this analysis to account for the avoided costs of transmission and distribution system expansion. Though potential transmission and distribution system cost savings are dependent on local conditions, the Council considers these credits

[1] The EIA requires that the savings must be cost-effective and achieved within a single biennial period at a facility whose average annual load before conservation exceeded 5 aMW. In addition, the law requires that no more than 25% of a biennial target may be met with excess conservation savings, inclusive of provisions listed in this section.

to be representative estimates of these avoided costs. A value for generation capacity was also included but may change as the Northwest market continues to evolve.

- Discount Rate – The Council develops a real discount rate as well as a finance rate for each power plan. The finance rate is based on the relative share of the cost of conservation and the cost of capital for the various program sponsors. The Council has estimated these figures using the most current available information. This study reflects the current borrowing market although changes in borrowing rates will likely vary over the study period.
- Forecasted Load and Customer Growth – The CPA bases the 20-year potential estimates on forecasted loads and customer growth provided by the utility. These forecasts include a level of uncertainty especially considering the recovery from COVID related load impacts.
- Load Shape Data – The Council provides conservation load shapes for evaluating the timing of energy savings. In practice, load shapes will vary by utility based on weather, customer types, and other factors. This assessment uses the hourly load shapes used in the 2021 Plan to estimate peak demand savings over the planning period, based on shaped energy savings. Since the load shapes are a mix of older Northwest and California data, peak demand savings presented in this report may vary from actual peak demand savings.
- Frozen Efficiency – Consistent with the Council's methodology, the measure baseline efficiency levels and end-using devices do not change over the planning period. In addition, it is assumed that once an energy efficiency measure is installed, it will remain in place over the remainder of the study period.

Due to these uncertainties and the changing environment, under the EIA, qualifying utilities must update their CPAs every two years to reflect the best available information.

2.6 COVID IMPACTS

Impacts from COVID-19 have been incorporated into this study in various ways such as:

- Load levels have largely recovered since the 2020 pandemic. The baseline load and customer counts reflect current and future usage levels.
- Ramp rates, in some cases, were adjusted due to the slowdown of program uptake since the pandemic began. At first, projects were stopped due to concerns over spreading the virus. In addition to the lower participation rates, supply chain issues have delayed many projects. Largely, the 2021 Power Plan draft ramp rates were applied for each measure; however, some measure ramp rates were slowed to reflect recent achievements despite the District's efforts to promote programs.

The above considerations have been modeled in this study.

2.7 REPORT ORGANIZATION

The report is organized with the following main sections:

- Methodology – CPA methodology along with some of the overarching assumptions
- Recent Conservation Achievement – The District's recent achievements and current energy efficiency programs
- Customer Characteristics – Housing and commercial building data for updating the baseline conditions
- Results – Energy Savings and Costs – Primary base case results
- Scenario Results – Results of all scenarios
- Summary
- References & Appendices

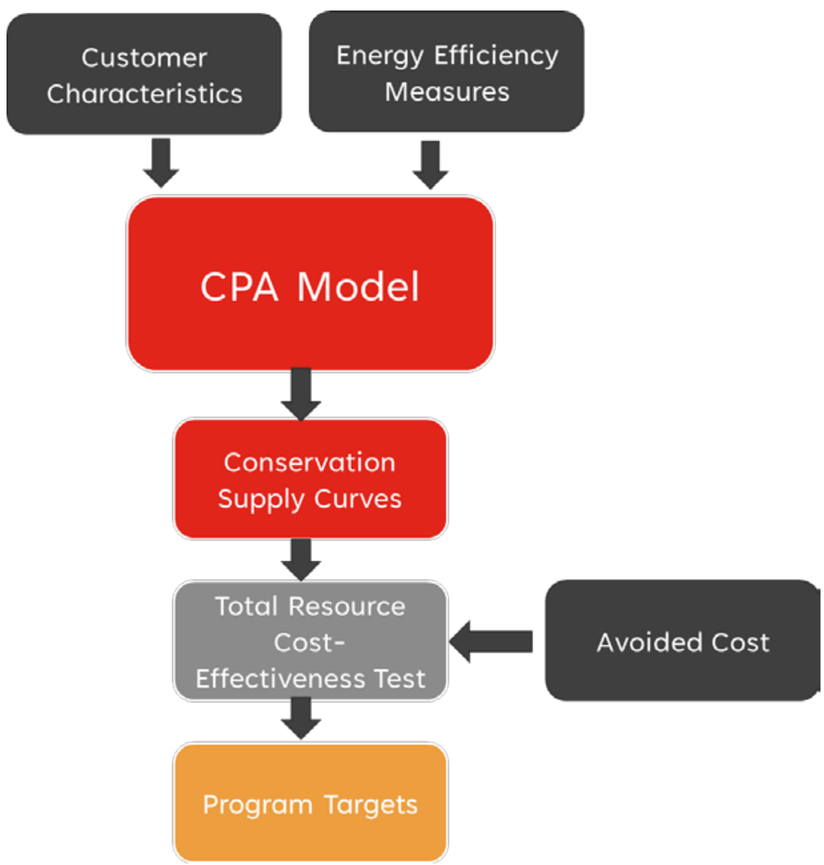
3 CPA Methodology

This study is a comprehensive assessment of the energy efficiency potential in the District's service area. The methodology complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the 2021 Power Plan. This section provides a broad overview of the methodology used to develop the District's conservation potential target. Specific assumptions and methodology as they pertain to compliance with the EIA and CETA are provided in Appendix III of this report.

3.1 BASIC MODELING METHODOLOGY

The basic methodology used for this assessment is illustrated in Figure 3-1. A key factor is the kilowatt hours saved annually from the installation of an individual energy efficiency measure. The savings from each measure are multiplied by the total number of measures that could be installed over the life of the program. Savings from each individual measure are then aggregated to produce the total potential.

FIGURE 3-1: CONSERVATION POTENTIAL ASSESSMENT PROCESS



3.2 CUSTOMER CHARACTERISTIC DATA

Assessment of customer characteristics includes estimating both the number of locations where a measure could be feasibly installed as well as the share—or saturation—of measures that have already been installed. For this analysis, the characterization of the District's baseline was determined using data provided by the District, NEEA's commercial and residential building stock assessments, and census data. Details of data sources and assumptions are described for each sector later in the report.

This assessment primarily sourced baseline measure saturation data from the Council's 2021 Plan measure workbooks. The Council's data was developed from NEEA's Building Stock Assessments, studies, market research and other sources. This data was updated with NEEA's 2016 Residential Building Stock Assessment and the District's historic conservation achievement data, where applicable. The District's historic achievement is discussed in detail in the next section.

3.3 ENERGY EFFICIENCY MEASURE DATA

The characterization of efficiency measures includes measure savings, costs, and lifetime. Other features, such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. The Council's 2021 Power Plan is the primary source for conservation measure data.

The measure data includes adjustments from raw savings data for several factors. The effects of space-heating interaction, for example, are included for all lighting and appliance measures, where appropriate. For example, if an electrically heated house is retrofitted with efficient lighting, the heat that was originally provided by the inefficient lighting will have to be made up by the electric heating system. These interaction factors are included in measure savings data to produce net energy savings. Other financial-related data needed for defining measure costs and benefits include discount rate, line losses, and deferred capacity-expansion benefits.

A list of measures by end-use is included in Appendix VI.

3.4 TYPES OF POTENTIAL

Once the customer characteristics and energy efficiency measures are fully described, energy efficiency potential can be quantified. Three types of potential are used in this study: technical, achievable, and economic or cost-effective potential. Technical potential is the theoretical maximum efficiency available in the service territory if cost and market barriers are not considered. Market barriers and other consumer acceptance constraints reduce the total potential savings of an energy efficient measure. When these factors are applied, the remaining potential is called the achievable potential. Economic potential is a subset of the achievable potential that has been screened for cost effectiveness through a benefit-cost test. Figure 3-2 illustrates the four types of potential followed by more detailed explanations.

FIGURE 3-2: TYPES OF ENERGY EFFICIENCY POTENTIAL[2]

Technical – Technical potential is the amount of energy efficiency potential that is available, regardless of cost or other technological or market constraints, such as customer willingness to adopt a given measure. It represents the theoretical maximum amount of energy efficiency that is possible in a utility's service territory absent these constraints.

Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Additionally, the number of applicable units must be estimated. Applicable units are the units across a service territory where the measure could feasibly be installed. This includes accounting for units that may have already been installed. The value is highly dependent on the measure and the housing stock. For example, a heat pump measure may only be applicable to single family homes with electric space heating equipment. A saturation factor accounts for measures that have already been completed.

In addition, technical potential considers the interaction and stacking effects of measures. For example, interaction occurs when a home installs energy efficient lighting and the demands on the heating system rise due to a reduction in heat emitted by the lights. If a home installs both insulation and a high-efficiency heat pump, the total savings of these stacked measures is less than if each measure were installed individually because the demands on the heating system are lower in a well-insulated home. Interaction is addressed by accounting for impacts on other energy uses. Stacked measures within the same end use are often addressed by considering the savings of each measure as if it were installed after other measures that impact the same end use.

The total technical potential is often significantly more than the amount of achievable and economic potential. The difference between technical potential and achievable potential is a result of the number

[2] Reproduced from U.S. Environmental Protection Agency. *Guide to Resource Planning with Energy Efficiency.* Figure 2-1, November 2007.

of measures assumed to be affected by market barriers. Economic potential is further limited due to the number of measures in the achievable potential that are not cost-effective.

Achievable Technical – Achievable technical potential, also referred to as achievable potential, is the amount of potential that can be achieved with a given set of market conditions. It takes into account many of the realistic barriers to adopting energy efficiency measures. These barriers include market availability of technology, consumer acceptance, non-measure costs, and the practical limitations of ramping up a program over time. The level of achievable potential can increase or decrease depending on the given incentive level of the measure. In the Seventh Power Plan, the Council assumes that 85% of technical potential can be achieved over the 20-year study period. This is a consequence of a pilot program offered in Hood River, Oregon where home weatherization measures were offered at no cost. The pilot was able to reach over 90% of homes. These assumptions will be updated in the next study based on a measure-by-measure analysis of maximum achievability rates as finalized in the forthcoming 2021 Power Plan. The Council also uses a variety of ramp rates to estimate the rate of achievement over time. This CPA follows the Council's methodology, including both the achievability and ramp rate assumptions.

Economic – Economic potential is the amount of potential that passes an economic benefit-cost test. In Washington State, EIA requirements stipulate that the total resource cost test (TRC) be used to determine economic potential. The TRC evaluates all costs and benefits of the measure regardless of who pays the cost or receives the benefit. Costs and benefits include the following: capital cost, O&M cost over the life of the measure, disposal costs, program administration costs, environmental benefits, distribution and transmission benefits, energy savings benefits, economic effects, and non-energy savings benefits. Non-energy costs and benefits can be difficult to enumerate, yet non-energy costs are quantified where feasible and realistic. Examples of non-quantifiable benefits might include added comfort and reduced road noise from better insulation or increased real estate value from new windows. A quantifiable non-energy benefit might include reduced detergent costs or reduced water and sewer charges from energy efficient clothes washers.

For this potential assessment, the Council's ProCost model was used to determine cost effectiveness for each energy efficiency measure. The ProCost model values measure energy savings by time of day using conservation load shapes (by end-use) and segmented energy prices. The version of ProCost used in the 2021 CPA evaluates measure savings on an hourly basis, but ultimately values the energy savings during two segments covering high and low load hour time periods.

3.5 AVOIDED COST

Each component of the avoided cost of energy efficiency measure savings is described below. Additional information regarding the avoided cost forecast is included in Appendix IV.

3.5.1 Energy

The avoided cost of energy is the cost that is avoided through the acquisition of energy efficiency in lieu of other resources. Avoided costs are used to value energy savings benefits when conducting cost effectiveness tests and are included in the numerator in a benefit-cost test. The avoided costs typically include energy-based values ($/MWh) and values associated with the demand savings ($/kW) provided by energy efficiency. These energy benefits are often based on the cost of a generating resource, a forecast of market prices, or the avoided resource identified in the IRP process.

3.5.2 Social Cost of Carbon

The social cost of carbon is a cost that society incurs when fossil fuels are burned to generate electricity. Both the EIA rules and CETA require that CPAs include the social cost of carbon when evaluating cost effectiveness using the total resource cost test (TRC). CETA further specifies the social cost of carbon values to be used in conservation and demand response studies. These values are shown in Table 3-1 below and were the same value used in the 2023 CPA.

TABLE 3-1: SOCIAL COST OF CARBON VALUES[3]

Year in Which Emissions Occur or Are Avoided	Social Cost of Carbon Dioxide $2018/metric ton	Social Cost of Carbon Dioxide $2023/short ton[1]
2020	$74	$80
2025	$81	$88
2030	$87	$94
2035	$93	$101
2040	$100	$108

**ProCost model inputs for $/CO2 are in short tons. In the modeling, 2023 dollars are converted to $2016 to be consistent with the 2021 Power Plan measure data.*

According to WAC 194-40-110, values may be adjusted for any taxes, fees or costs incurred by utilities to meet portfolio mandates.[4] For example, the social cost of carbon is the full value of carbon emissions which includes the cost to utilities and ratepayers associated with moving to non-emitting resources. Rather than adjust the social cost of carbon for the cost of RECs or renewable energy, the values for RECS and renewable energy are excluded from the analysis to avoid double counting.

The emissions intensity of the marginal resource (market) is used to determine the $/MWh value for the social cost of carbon. Ecology states that unspecified resources should be given a carbon intensity value of 0.437 metric tons of CO_2e/MWh of electricity (0.874 lbs/kWh).[5] This is an average annual value applied to in all months in the conservation potential model.[6] The resulting levelized cost of carbon is $34/MWh over the 20-year study.

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[3] WAC 194-40-100. Available at :https://apps.leg.wa.gov/wAc/default.aspx?cite=194-40-100&pdf=true.

[4] WAC 194-40-110 (b).

[5] WAC 173-444-040 (4).

[6] The seasonal nature of carbon intensity is not modeled due to the prescriptive annual value established by Ecology in WAC 173-444-040.

3.5.3 Renewable Portfolio Standard Cost

Renewable energy purchases need to meet both RPS and CETA and can be avoided through conservation. Utilities may meet Washington RPS through either bundled energy purchases such as purchasing the output of a wind resource where the non-energy attributes remain with the output, or they may purchase unbundled RECs. As stated above, the value of avoided renewable energy credit purchases resulting from energy efficiency is accounted for within the social cost of carbon construct. The social cost of carbon already considers the cost of moving from an emitting resource to a non-emitting resource. Therefore, it is not necessary to include an additional value for renewable energy purchases prior to 2045 when all energy must be non-emitting or renewable.

Beginning in 2045, the social cost of carbon may no longer be an appropriate adder in resource planning. However, prior to 2045 utilities may still use offsets to meet CETA requirements. Since the study period of this evaluation ends prior to 2045, the avoided social cost of carbon is included in each year. For future studies that extend to 2045 and beyond, it would be appropriate to include renewable energy or non-emitting resource costs as the avoided cost of energy rather than market plus the social cost of carbon.

3.5.4 Transmission and Distribution System

The EIA requires that deferred capacity expansion benefits for transmission and distribution systems be included in the assessment of cost effectiveness. To account for the value of deferred transmission and distribution system expansion, a distribution system credit value of $8.53/kW-year and a transmission system credit of $3.83/kw-year were applied to peak savings from conservation measures, at the time of the regional transmission and the District's local distribution system peaks (adjusted to $2023). These values were developed by Council staff in preparation for the 2021 Power Plan.[7]

3.5.5 Generation Capacity

The District's marginal cost for generation capacity is estimated using a benchmark: BPA demand rates. While these rates don't directly apply to the District, they are a good representation of the marginal cost of demand in the region. BPA demand rates are escalated 3% each rate period (every two years). Over the 20-year analysis period, the resulting cost of avoided capacity is $104/kW-year (2023$) in levelized terms.

In the Council's 2021 Power Plan,[8] a generation capacity value of $143/kW-year was explicitly calculated ($2023). This value is used in the high scenario.

[7] Northwest Power and Conservation Council Memorandum to the Power Committee Members. Subject; Updated Transmission & Distribution Deferral Value for the 2021 Power Plan. March 5, 2019. Available at: https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf.

[8] https://www.nwcouncil.org/energy/powerplan/7/home/.

3.5.6 Risk

With the generation capacity value explicitly defined, the Council's analysis found that a risk credit did not need to be defined as part of its cost-effectiveness test. In this CPA, risk was modeled by varying the base case input assumptions. In doing so, this CPA addresses the uncertainty of the inputs and looks at the sensitivity of the results. The avoided cost components that were varied included the energy prices and generation capacity value. Through the variance of these components, implied risk credits of up to $11/MWh and $39/kW-year were included in the avoided cost. Note that the capacity value of energy efficiency measures is associated with more uncertainty compared with the energy value. Because of the upcoming implementation of the energy imbalance market (EIM) in the Pacific Northwest, and increased renewables in the region, capacity values are expected to be more volatile compared with energy market prices.

Additional information regarding the avoided cost forecast and risk mitigation credit values is included in Appendix IV.

3.5.7 Power Planning Act Credit

Finally, a 10% benefit was added to the avoided cost as required by the Pacific Northwest Electric Power Planning and Conservation Act.

3.6 DISCOUNT AND FINANCE RATE

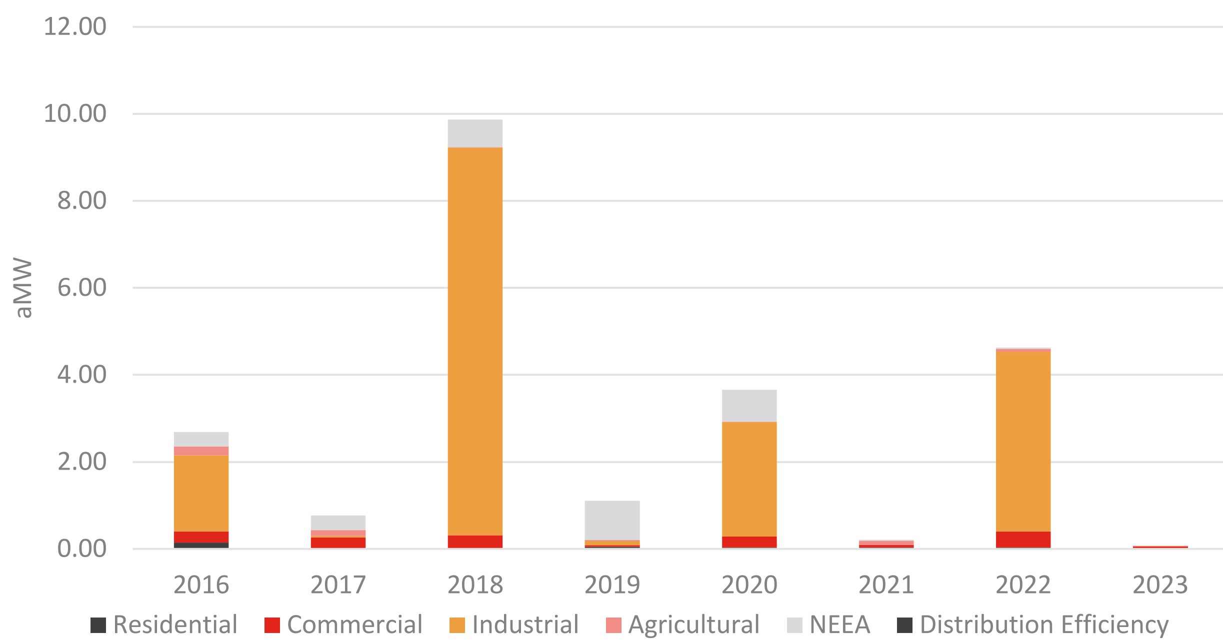
The Council develops a real discount rate for each of its Power Plans. In preparation for the 2021 Power Plan, the Council proposed using a discount rate of 3.75%. This discount rate was used in this CPA. The discount rate is used to convert future costs and benefits into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives.

4 Recent Conservation Achievement

The District has pursued conservation and energy efficiency resources for many years. Currently, the utility offers a variety of programs for residential, commercial, industrial, and agricultural customers. These include residential weatherization, new construction programs for commercial customers, and energy-efficiency audits. In addition to utility programs, the District receives credit for market-transformation activities that are accomplished by the Northwest Energy Efficiency Alliance (NEEA) in its service territory.

Figure 4-1 shows the distribution of conservation among the District's customer sectors and through Northwest Energy Efficiency Alliance (NEEA) efforts over the past five years. NEEA's work helps bring energy efficient emerging technologies, like ductless heat pumps and heat pump water heaters to the Northwest markets. Note that savings achievement for 2020 were lower than historic achievements primarily due to the COVID-19 pandemic. Economic factors and risk for COVID-19 transmission both likely contributed to fewer measures being implemented in the District's service area. More detail of these savings is provided below for each sector.

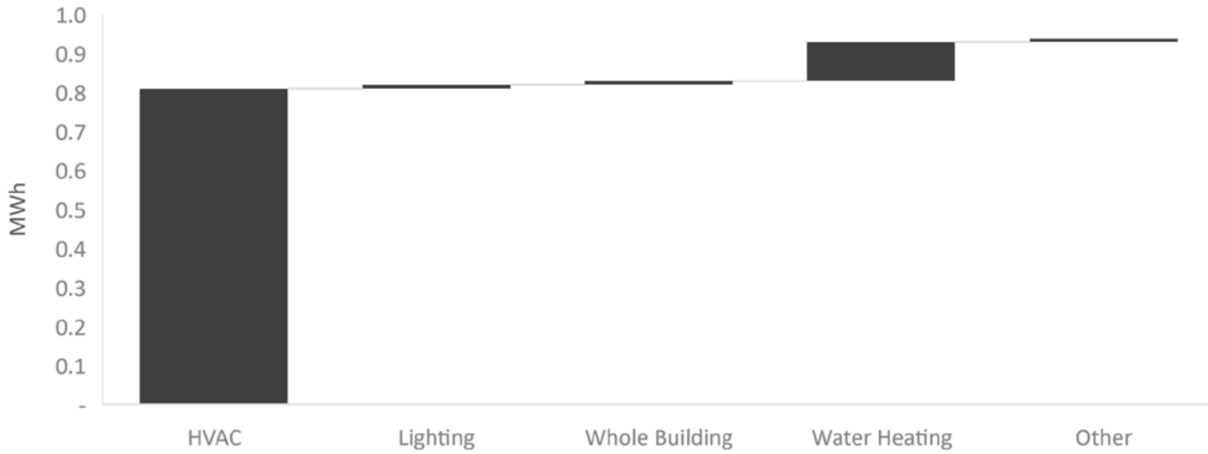
FIGURE 4-1: RECENT CONSERVATION HISTORY BY SECTOR



4.1 RESIDENTIAL

Figure 4-2 shows historic conservation achievement by end use in the residential sector. Savings from HVAC and lighting measures account for most of the savings. Note that in the figure below, HVAC includes weatherization measures. The "Other" category includes energy star appliances and consumer electronics.

FIGURE 4-2: 2017-2023 YTD RESIDENTIAL SAVINGS ACHIEVEMENT



4.2 COMMERCIAL & INDUSTRIAL

Historic achievement in the commercial and industrial sectors is primarily due to lighting, Strategic Energy Management, and custom HVAC projects. Figures 4-3 and 4-4 show the breakdown of commercial and industrial savings, respectively, from 2017 to 2023 year to date.

FIGURE 4-3: 2017-2023 YTD COMMERCIAL SAVINGS

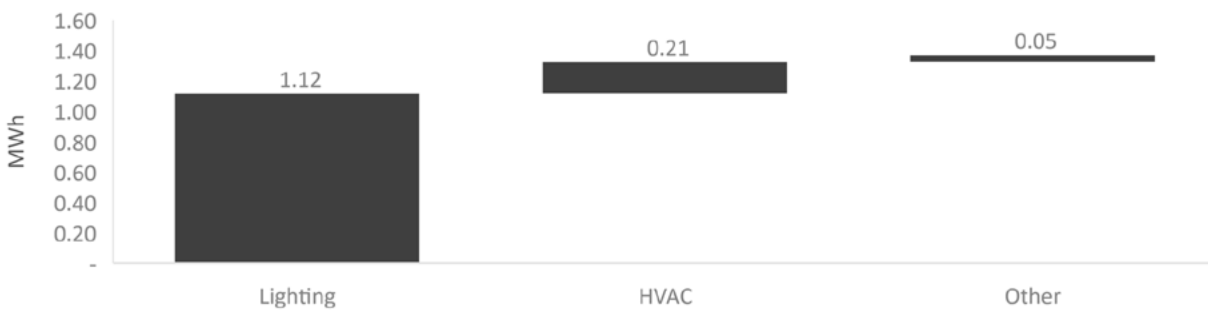
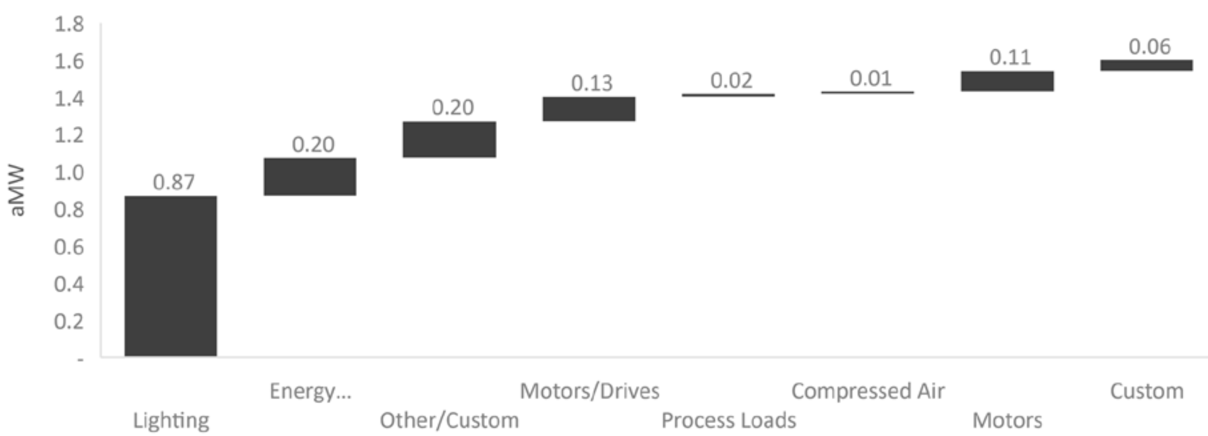


FIGURE 4-4: 2017-2023 YTD INDUSTRIAL SAVINGS



4.3 AGRICULTURE

Agriculture program achievement has been acquired through irrigation hardware and other system upgrades, such as variable frequency drives. Achievement from 2016-2023 in this sector totals 0.55 aMW.

4.4 CURRENT CONSERVATION PROGRAMS

The District offers a wide range of conservation programs to its customers. These programs include many types of deemed conservation rebates, energy audits, net metering, and custom projects. The current programs offered by the District are detailed below.

4.4.1 Residential

- *Weatherization* – This program provides rebates for both windows and insulation.
- *HVAC Rebates* – This program provides rebates for a variety of space conditioning upgrades including rebates for HVAC upgrades and conversions.

4.4.2 Commercial and Industrial

- *Lighting Energy Efficiency Program (LEEP)* – Owners of commercial buildings can apply for a lighting energy audit. Applicable rebate amounts are determined upon completion of the audit.
- *Custom Projects Rebates* – The District offers rebates for special projects that improve efficiency or process related systems including, but not limited to, compressed air, variable frequency drives, industrial lighting interactive with HVAC systems, and refrigeration. Rebates for this program vary.

4.4.3 Agriculture

- *Agricultural Rebate Program* – This program offers incentives for irrigation sprinklers, nozzles, and regulators as well as replacement.

4.5 SUMMARY

The District plans to continue to invest in energy efficiency by offering incentives to all sectors. The results of this CPA will help the District program managers to structure energy efficiency program offerings, establish appropriate incentive levels, comply with the EIA and CETA requirements and provide continued energy efficiency as a customer service.

5 Customer Characteristics Data

The District serves approximately 47,990 electric customers in Grant County PUD County, Washington, with a service area population of approximately 104,579. A key component of an energy efficiency assessment is to understand the characteristics of these customers—primarily the building and end-use characteristics. These characteristics for each customer class are described below.

5.1 RESIDENTIAL

For the residential sector, the key characteristics include house type, space heating fuel, and water heating fuel. Tables 5-1, 5-2, 5-3 and 5-4 show relevant residential data for single family, multi-family and manufactured homes in the District's service territory as analyzed in the 2019 CPA. Residential characteristics are based on data collected through home audits provided by Grant PUD. This data provides estimates of the current residential characteristics in Grant PUD's service territory and are utilized as the baseline in this study.

TABLE 5-1: RESIDENTIAL BUILDING CHARACTERISTICS

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	41,956	104,579

TABLE 5-2: HOME HEATING & COOLING SYSTEM SATURATIONS

	Single Family	Multifamily - Low Rise	Manufactured
Electric Forced Air Furnace	25%	1%	85%
Heat Pump	35%	1%	15%
Ductless Heat Pump	1%	2%	0%
Electric Zonal/Baseboard	39%	96%	0%
Central Air Conditioning	48%	2%	11%
Room Air Conditioning	42%	35%	3%

TABLE 5-3: EXISTING HOMES – APPLIANCE SATURATIONS

	Single Family	Multifamily - Low Rise	Manufactured
DHW buffer	79%	77%	94%
Refrigerator	129%	103%	121%
Freezer	53%	4%	43%
Clothes Washer	99%	47%	99%
Clothes Dryer	98%	47%	95%
Dishwasher	89%	78%	77%
Microwave	96%	96%	96%
Electric Oven	49%	40%	56%
RAC	53%	35%	38%

TABLE 5-4: NEW HOMES – APPLIANCE SATURATIONS

	Single Family	Multifamily - Low Rise	Manufactured
DHW buffer	79%	77%	94%
Refrigerator	138%	104%	117%
Freezer	39%	0%	43%
Clothes Washer	96%	53%	100%
Clothes Dryer	91%	49%	100%
Dishwasher	84%	68%	84%
Microwave	96%	96%	96%
Electric Oven	49%	40%	56%
RAC	53%	35%	38%

5.2 COMMERCIAL

Building floor area is the key parameter in determining conservation potential for the commercial sector as many of the measures are based on savings as a function of building area. Generally, floor area additions are analyzed by reviewing kWh growth in a utility's service area. The District provided floor area estimates for new buildings constructed since 2021. This data is added to the 2022 floor area estimate from the previous assessment.

The 2018 data was developed by coding each general service customer based on the Commercial Building Stock Assessment (CBSA)[9] building definitions. The appropriate EUI is then applied to the sum of kWh for each building type resulting in estimated square feet. Table 5-5 compares the 2022 estimates with the 2024 estimates. After 2024, a 1% growth rate is applied to commercial building floor area growth.

[9] Navigant Consulting. 2014. *Northwest Commercial Building Stock Assessment: Final Report.* Portland, OR: Northwest Energy Efficiency Alliance.

TABLE 5-5: COMMERCIAL BUILDING SQUARE FOOTAGE BY SEGMENT

Segment	2022 Floor Area Estimate	2024 Floor Area Estimate
Large Office	22,128	22,128
Medium Office	777,053	777,053
Small Office	1,035,713	1,066,031
Extra Large Retail Space	-	730,992
Large Retail	956,650	225,658
Medium Retail	773,412	807,090
Small Retail	1,723,534	1,787,953
School (K-12)	4,019,941	4,019,941
University	883,927	883,927
Warehouse	23,158,268	23,646,652
Supermarket	348,008	348,008
Mini Mart	203,509	204,169
Restaurant	467,747	475,984
Lodging	2,137,264	2,147,396
Hospital	632,421	639,477
Residential Care	42,059	42,059
Assembly	1,434,465	1,434,465
Other Commercial	5,640,209	5,652,806
Total	**44,256,309**	**44,911,790**

5.3 INDUSTRIAL

The methodology for estimating industrial potential is different than the approaches used for the residential and commercial sectors primarily because most energy efficiency opportunities are unique to specific industrial segments. The Council and this study use a “top-down” methodology that utilizes annual consumption by industrial segment and then disaggregates total usage by end-use shares. Estimated measure savings are applied to each sector’s end-use shares.

The 2020 usage for industrial customers was updated by applying historic and forecast growth rates from the District’s load forecast. Overall, industrial load growth is projected to increase by 2.2% from 2020 to 2024. Individual industrial customer usage is summed by industrial segment in Table 5-6. Data Center loads are shown separately.

TABLE 5-6: INDUSTRIAL SECTOR LOAD BY SEGMENT, MWH

Industry	2020 Loads	2024 Forecast
Paper	16,587	16,954
Foundries	42,202	43,137
Frozen Food	229,975	235,073
Other Food	76,313	78,004
Silicon	9,929	10,149
Metal Fabrication	-	-
Equipment/Transportation	21,741	22,223
Cold Storage	34,919	35,693
Fruit Storage	47,471	48,523
Refinery	70,956	72,529
Chemical	595,547	608,748
Miscellaneous Manufacturing	241,641	246,997
Total	**1,387,280**	**1,418,029**
Data Centers	1,531,597	2,260,080

5.4 AGRICULTURE

To determine agriculture sector characteristics in the District's service territory, EES utilized data provided by the United States Department of Agriculture (USDA) as shown in Table 5-7. The USDA conducts a census of farms and ranches in the U.S. every five years. The most recent available data for this analysis is from the 2017 census, which was published in 2019.

TABLE 5-7: AGRICULTURAL INPUTS

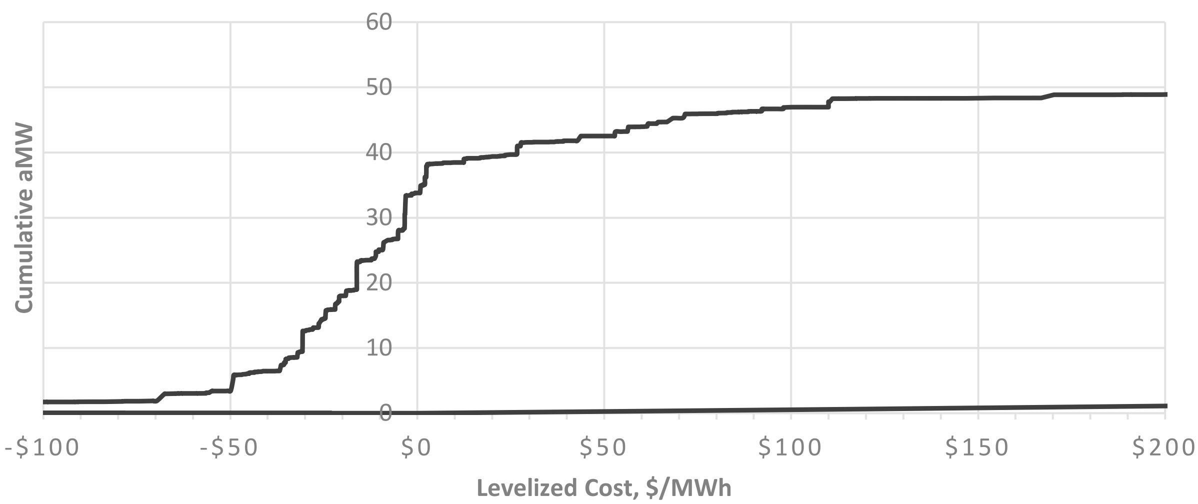
Dairy Production, 1,000 lbs	763,182
Total Irrigated Acreage	393,015
Total Number of Pumps	4,199
Total Number of Farms	1,635
Stock Tanks	711
Back-Up Generator	4

6 Results – Energy Savings and Costs

6.1 ACHIEVABLE CONSERVATION POTENTIAL

Achievable potential is the amount of energy efficiency potential that is available regardless of cost. Figure 6-1, below, shows a supply curve of 20-year achievable potential. A supply curve is developed by plotting cumulative energy efficiency savings potential (aMW) against the levelized cost ($/MWh) of the savings when measures are sorted in order of ascending cost. The potential shown in Figure 6-1 has not been screened for cost-effectiveness. Costs are levelized, allowing for the comparison of measures with different lifetimes. The supply curve facilitates comparison of demand-side resources to supply-side resources and is often used in conjunction with integrated resource plans. Figure 6-1 shows that approximately 42 aMW of cumulative saving potential are available for less than $50/MWh.

FIGURE 6-1: 20-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE, EXCLUDING DATA CENTERS



6.2 ECONOMIC CONSERVATION POTENTIAL

Economic or cost-effective potential is the amount of potential that passes the Total Resource Cost (TRC) test. This means that the present value of the benefits attributed to the conservation measure exceeds the present value of the measure costs over its lifetime.

Table 6-1 shows the economic potential by sector in 2, 4, 10 and 20-year increments. Compared with the technical and achievable potential, it shows that 29.15 aMW of the total 49 aMW is cost-effective for the District (excluding data centers). The last section of this report discusses how these values could be used for setting targets.

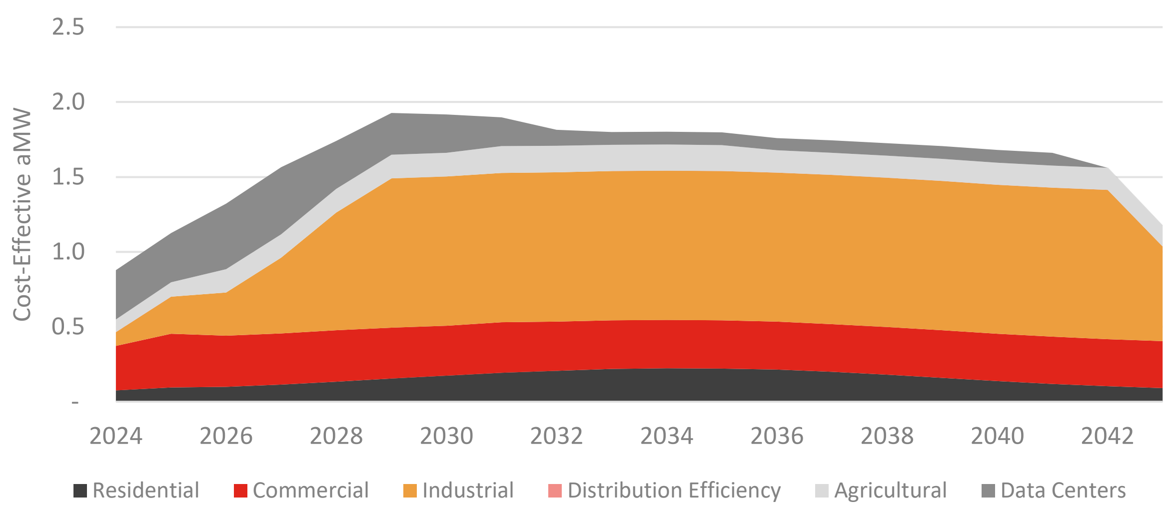
TABLE 6-1: COST-EFFECTIVE ACHIEVABLE POTENTIAL – BASE CASE (aMW)

	2-Year	4-Year	10-Year	20-Year
Residential	0.17	0.38	1.47	3.12
Commercial	0.66	1.34	3.34	6.52
Industrial excluding Data Centers	0.34	1.13	6.90	16.50
Data Centers	0.66	1.5	2.8	3.5
Agricultural	0.18	0.49	1.49	3.01
Total	**2.00**	**4.89**	**15.99**	**32.61**

6.3 SECTOR SUMMARY

Figure 6-2 shows economic potential by sector on an annual basis. In this figure, estimated data center savings are shown separately from other industrial process potential.

FIGURE 6-2: ANNUAL COST-EFFECTIVE POTENTIAL BY SECTOR



Second to data centers, the largest share of the potential is in the commercial sector followed by savings potential in the residential and agricultural sectors. Ramp rates from the 2021 Power Plan were used to establish reasonable conservation achievement levels. In some cases, alternate ramp rates were assigned to reflect the District's current rate of program achievement. Achievement levels are affected by factors including timing of equipment turnover and new construction, supply chain delays, economic factors, program and technology maturity, market trends, and current utility staffing and funding.

6.3.1 Residential

Near-term residential conservation potential is approximately the same as what was identified in the 2021 assessment. In the longer term, savings potential has been impacted by new measures added by the Council for the 2021 Power Plan, the avoided cost updates, and program achievement.

Within the residential sector, water heating and HVAC (including weatherization) measures make up the largest share of savings (Figure 6-3). This is due, in part, to the fact that the District's residential customers rely mostly on electricity for space and water heating. Many weatherization measures are no longer cost-effective due to changes in costs and in energy savings values. The large amount of potential for water heating is primarily due to 1.5 gpm or lower shower heads, efficient clothes washers, aerators, and heat pump water heaters.

FIGURE 6-3: ANNUAL RESIDENTIAL COST-EFFECTIVE POTENTIAL BY END USE

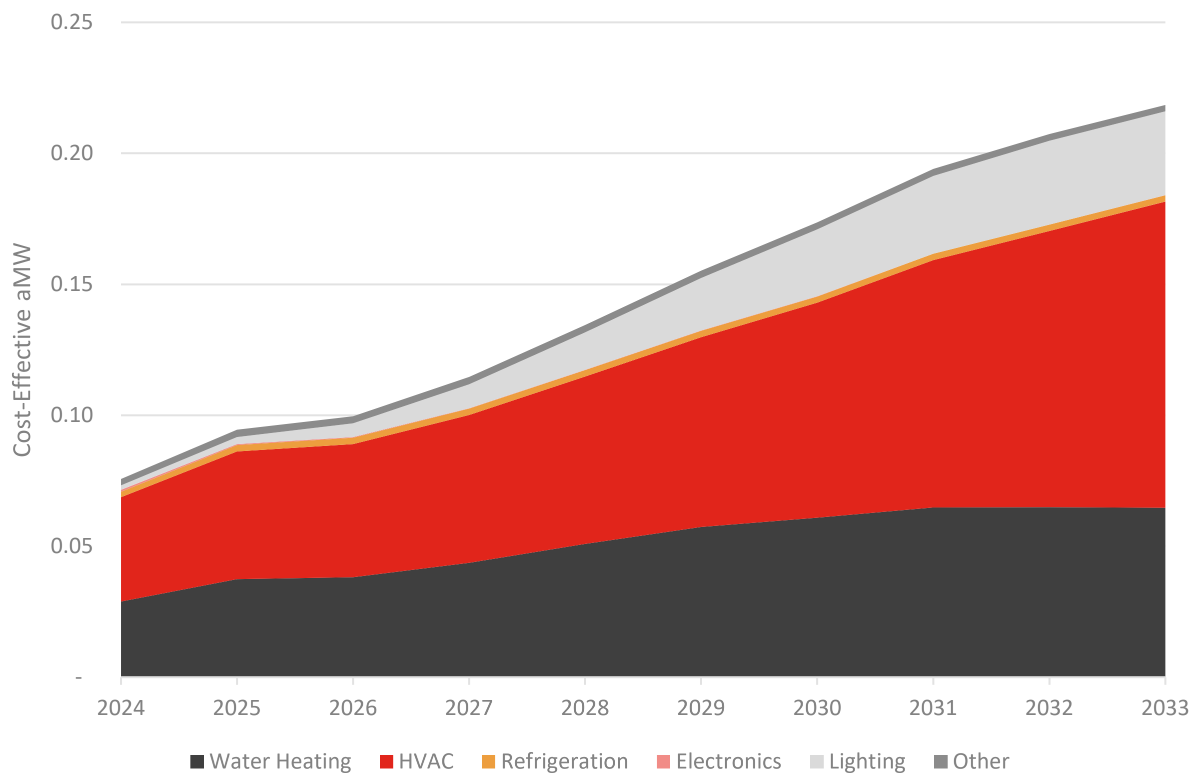


Figure 6-4 shows how the 10-year residential potential breaks down into end uses and key measure categories. The area of each block represents its share of the total 10-year residential potential.

FIGURE 6-4: RESIDENTIAL COST-EFFECTIVE POTENTIAL BY END USE AND MEASURE CATEGORY

Table 6-2 compares how the savings potential has changed since the 2021 CPA. The primary drivers are reduced cost effectiveness as well as updated measure baselines.

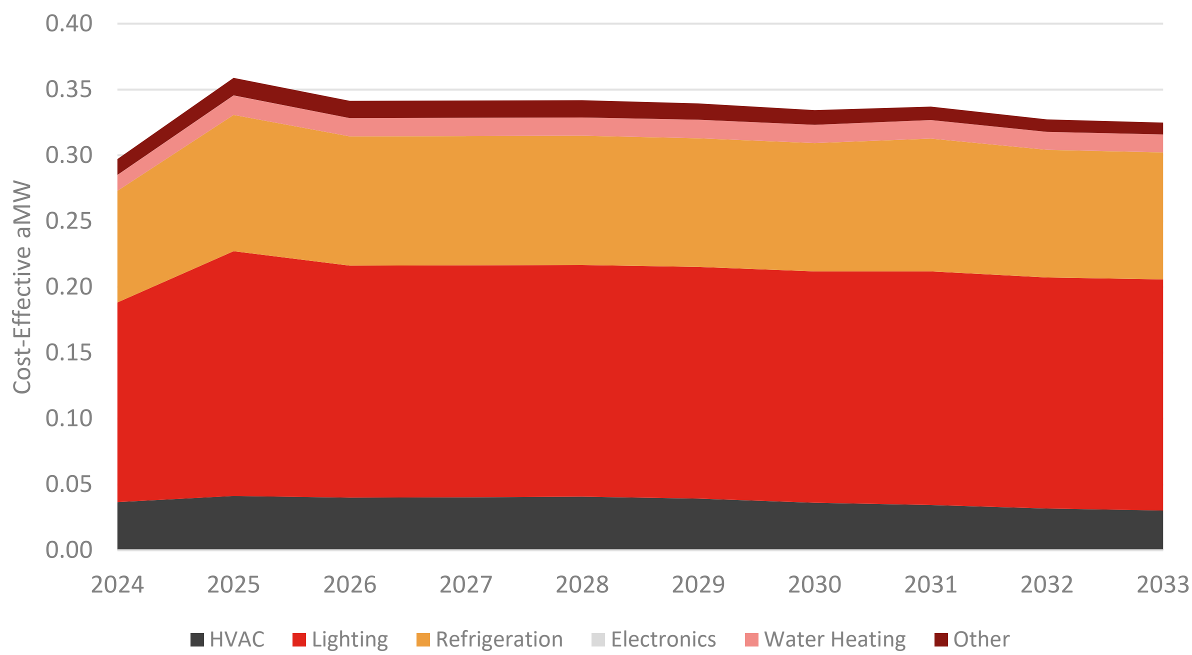
TABLE 6-2: COMPARISON RESIDENTIAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA	Discussion
Water Heating	3.63	1.01	Reduced cost-effectiveness
HVAC	1.64	1.71	Added measure permutations
Lighting	0.00	0.30	Reduced cost-effectiveness
Electronics	0.27	0.00	Updated computer measures, reduced cost-effectiveness
Food Preparation	0.00	0.00	Reduced cost-effectiveness
Dryer	0.00	0.04	Updated to 2021 Plan methodology/measures
Refrigeration	0.00	0.05	Updated saturation
Whole Bldg./Meter Level	0.00	0.00	Updated saturation/applicability, Reduced cost-effectiveness
Well Pumps	5.54	0.00	Well pumps not cost-effective
Total	**3.63**	**3.12**	

6.3.2 Commercial

The diverse nature of commercial building energy efficiency is reflected in the variety of end-uses and corresponding measures as shown in Figure 6-5. Beyond HVAC and lighting, additional sources of potential are available in water heating, electronics, motors, food preparation and process loads.

FIGURE 6-5: ANNUAL COMMERCIAL COST-EFFECTIVE POTENTIAL BY END USE



The key end uses and measures within the commercial sector are shown in Figure 6-6. The area of each block represents its share of the 10-year commercial potential.

FIGURE 6-6: COMMERCIAL COST-EFFECTIVE POTENTIAL BY END USE AND MEASURE CATEGORY

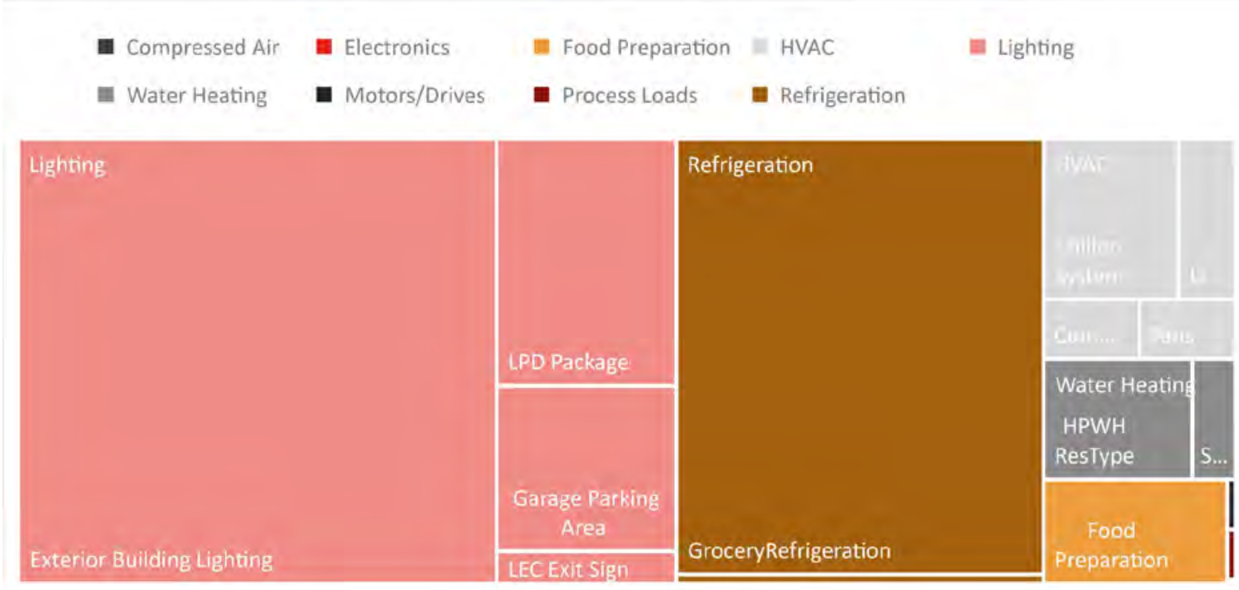


Table 6-3 provides a summary of the differences between the 2021 assessment and this 2023 CPA by end-use.

TABLE 6-3: COMPARISON COMMERCIAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA	Discussion
Food Preparation	0.21	0.18	Updated measure data/baselines
Lighting	3.33	3.50	Growth in floor area
Electronics	0.00	0.00	Updated measure data/baselines
Refrigeration	0.87	1.93	Reduced costs, added measures
Process Loads	0.09	0.00	Not cost effective
Compressed Air	0.26	0.00	Updated to 2021 Plan methodology/measures
HVAC	1.56	0.63	Reduced cost-effectiveness, Adjusted applicability
Motors/Drives	0.28	0.00	Reduced cost-effectiveness, Added Commercial Clean Water Pumps
Water Heating	0.34	0.27	Reduced cost-effectiveness; removed older water heating measures, adjusted applicability based on building type
Total	**13.25**	**6.52**	

6.3.3 Industrial

6.3.3.1 Data Centers

Approximately 60% of the District's industrial loads are in data center and cryptocurrency processes. The Council does not provide measures or savings analysis for large, centralized data centers. Historically, the District's CPAs have utilized commercial sector server measures to estimate data center potential. Beginning in 2021, savings for data centers have been evaluated for new customers at the project level. This study continues this methodology by efficiency evaluation based on the District's loads and unique nature of large data center operations. The bulleted list below from the 2021 study summarizes some of the issues identified in developing large data center energy efficiency potential estimates.

- Large data centers are often willing to work with the District at the time of new service to identify, measure, and verify energy efficiency improvements. Through its relationship with existing customers, the District has learned that existing loads are continually optimized without measurement and verification practices in place. Due to the unique nature of data center loads, customers are incentivized to choose the most efficient hardware when regular updates are made. Because these improvements are happening naturally and cannot be claimed through the State's audit process for compliance with targets, the potential for savings in existing data center loads is excluded from the target and future potential estimates.
- Historic data center project savings have been significant, saving up to 10% of new data center total load. However, this historic savings amount cannot be applied to future load growth estimates due to the nature of how energy use is evolving for large data centers. Specifically, historic savings have been achieved through cooling measures as data centers have been housed inside buildings requiring specific HVAC equipment. New data centers are typically housed in containers or other non-building structures removing a large portion of the HVAC savings potential.
- Data center measures are largely cost-effective from the utility and ratepayer perspectives. The analysis does not explicitly evaluate the benefits and costs form a TRC perspective. Rather, due to their low incremental costs compared with savings potential, it is assumed that the measures are cost-effective from a total resource cost perspective.
- The District plans to update the data center savings potential every two years for the purposes of defining an accurate 2-year savings target based on planned new loads. Scenario analysis provides a range of potential savings over the longer-term study period.

If the growth in data centers continues, and the District is able to reduce future baseline energy use by 9%, the District can expect approximately 13.6 aMW in data center savings over the 20-year study period. However, the projected data center savings are adjusted for future program design changes. While the District has historically met a large share of its conservation targets with data center projects, the District plans to focus more effort on harder to reach residential customers in order to build out those programs and achieve the potential available in the residential sector. The reprioritization of programs introduces uncertainty in the acceptance of data center savings potential. Due to this uncertainty, data center potential is reduced by 50%. Additionally, there is uncertainty in the continued growth of this sector. The majority of measures are applied to data centers when a new customer comes online. However, the District's power supply is becoming constrained which may lead to a significant slow down in data center load growth. Because of these factors, the potential from future data centers has been scaled down compared to previous studies.

6.3.3.2 Other Industrial

The other 40% of the District's industrial load is composed primarily of food processing and chemical facilities. Lighting and HVAC measures comprise the majority of non-data center industrial potential (Figure 6-7). In Figure 6-7, the Other category is largely comprised of savings in refrigeration and fan systems, as well as smaller amounts of savings from compressed air and pump systems.

FIGURE 6-7: ANNUAL INDUSTRIAL COST-EFFECTIVE POTENTIAL BY END USE EXCLUDING DATA CENTERS

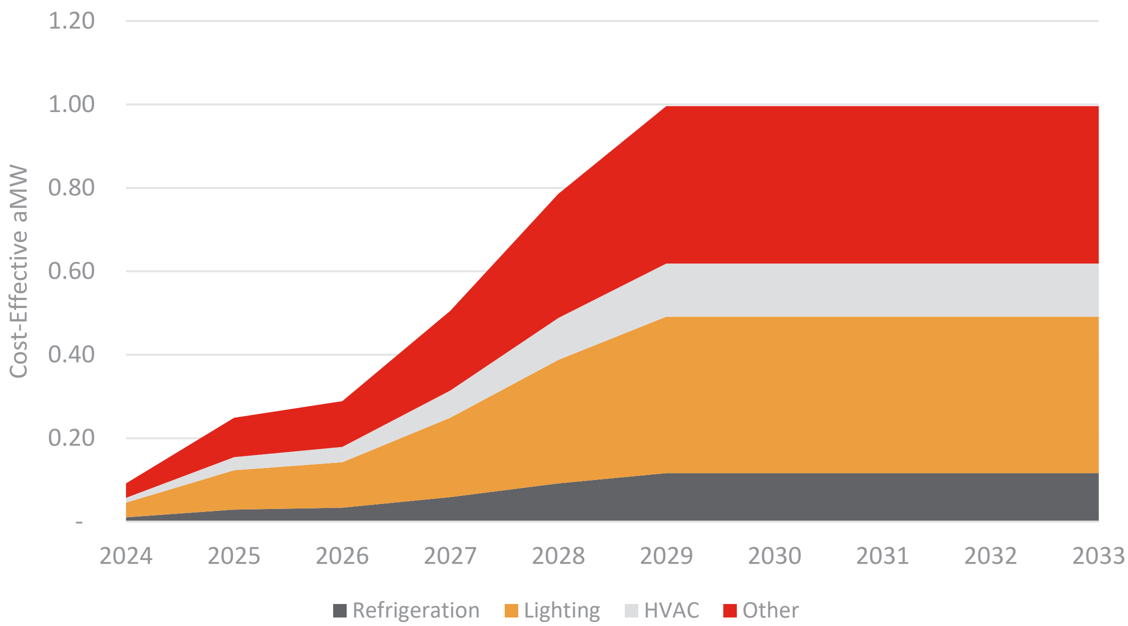
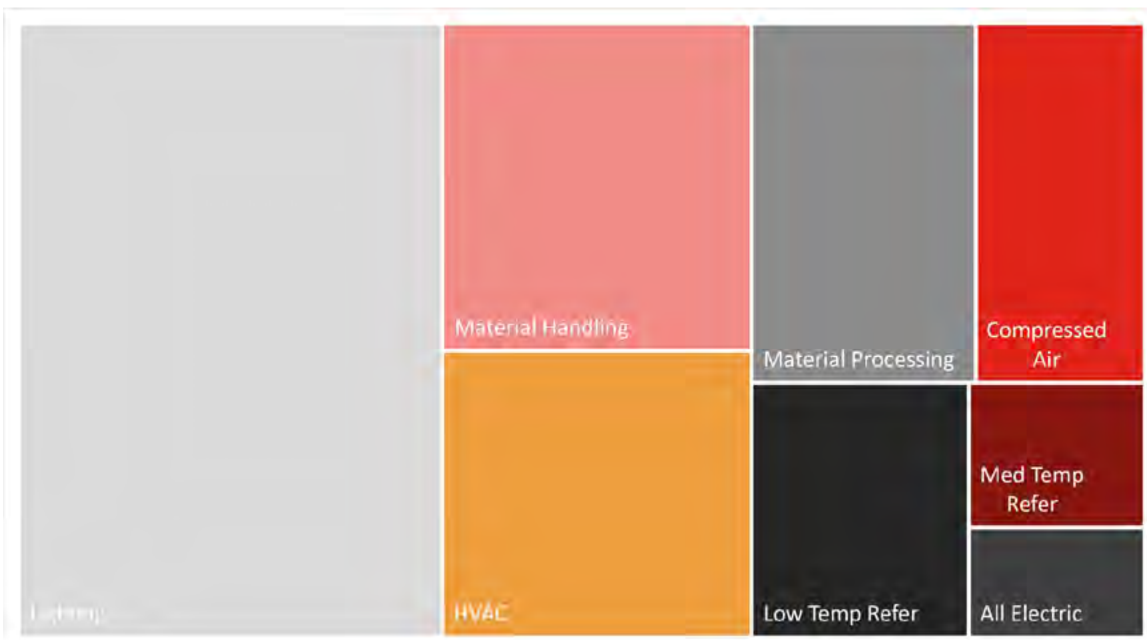


Figure 6-8 shows how the 10-year industrial potential breaks down by end use and measure categories.

FIGURE 6-8: INDUSTRIAL COST-EFFECTIVE POTENTIAL BY END USE AND MEASURE CATEGORY



The most impactful change in the industrial savings potential is the adjustment for recent program achievements. The District has completed over 2.8 aMW in energy efficiency projects since 2016. This is reflected in the updated results in the table below. Table 6-4 compares the potential estimated in this study to the 2021 assessment. The end use categories have been updated to align with the 2021 Plan Industrial Tool.

TABLE 6-4: COMPARISON INDUSTRIAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA
Data Centers (2-year)	3.90	1.32
Compressed Air	0.43	1.45
Energy Project Management	1.70	NA
Fans	1.25	0.00
Food Processing	1.42	NA
Food Storage	1.74	NA
Hi-Tech	0.19	NA
Integrated Plant Energy Management	1.50	NA
Lighting	1.55	6.21
Material Handling	0.02	NA
Metals	0.01	NA
Municipal Sewage Treatment	0.26	NA
Paper	0.02	NA
Plant Energy Management	1.37	NA
Pumps	2.77	2.11
HVAC	NA	0.38
Low Temp Refrigeration	NA	1.32
Med Temp Refer	NA	0.61
All Electric	NA	0.46
Material Processing	NA	1.92
Material Handling	NA	2.42
Melting and Casting	NA	0.00
Other	NA	0.00
Total	**14.26**	**17.82**

6.3.4 Agriculture

Potential in agriculture is a product of total acres under irrigation in the District's service territory, number of pumps, and the number of farms. As shown in Figure 6-9, most of the cost-effective conservation potential is due to irrigation pump motors. There are some dairy farms in Grant County; however, most of the dairy efficiency measures were not cost-effective.

FIGURE 6-9: ANNUAL AGRICULTURE COST-EFFECTIVE POTENTIAL BY END USE

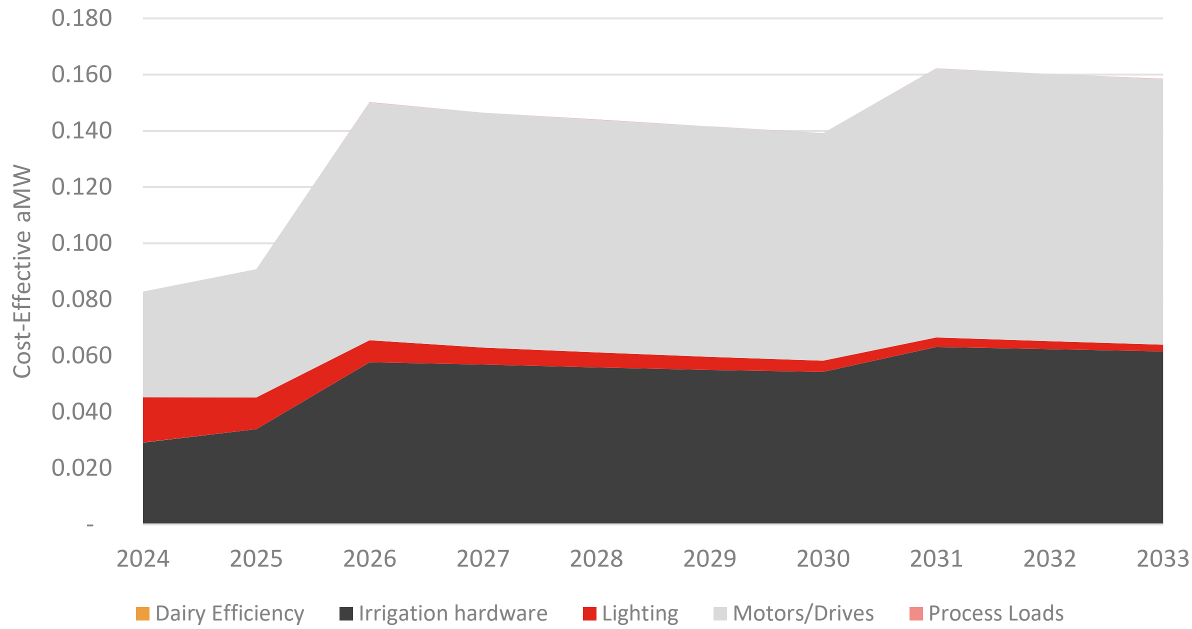


Table 6-5 compares the results of the 2021 CPA with this updated assessment.

TABLE 6-5: COMPARISON AGRICULTURAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA	Discussion
Irrigation	1.03	1.06	Updated acreage
Lighting	0.09	0.07	Updated applicability
Dairy Efficiency/ Refrigeration	0.04	0.28	New measures
HVAC	NA	0.00	New measures not cost-effective.
Motors/Drives	0.16	1.60	Updated irrigation pump measures
Process Loads	NA	0.001	Added energy free stock tanks
Total	**1.33**	**3.01**	

6.4 COST

Budget costs can be estimated at a high level based on the incremental cost of the measures (Table 6-6). The assumptions in this estimate include 20 percent of measure cost for administrative costs and 35 percent of the incremental measure costs is assumed to be paid by the utility as incentives. A 20 percent allocation of measure costs to administrative expenses is a standard assumption for conservation programs. This figure was used in the Council's 2021 Power Plan. The 35 percent utility-share of measure costs is used in all sectors except in the utility distribution efficiency category, where the District is likely to pay the entire cost of any measures implemented and no incentives will be paid. These assumptions are consistent with the District's previous CPA.

This chart shows that the District can expect to spend over $3.95 million to realize estimated non-data center savings over the next two years including program administration costs. The bottom row of Table 6-6 shows the cost per MWh of first year savings.

TABLE 6-6: UTILITY PROGRAM COSTS (2023$) EXCLUDING DATA CENTERS

	2-Year	6-Year	10-Year	20-Year
Residential	$800,000	$1,780,000	$6,350,000	$12,960,000
Commercial	$1,790,000	$3,650,000	$9,090,000	$17,630,000
Industrial	$1,020,000	$3,390,000	$20,620,000	$49,290,000
Agricultural	$340,000	$900,000	$2,740,000	$5,480,000
Total	**$3,950,000**	**$9,720,000**	**$38,800,000**	**$85,360,000**
$/First Year MWh	$335	$331	$335	$334

The cost estimates presented in this report are conservative estimates for future expenditures since they are based on historic values. Future conservation achievement may be more costly than historic conservation achievement since utilities often choose to implement the lowest cost programs first. In addition, as energy efficiency markets become more saturated, it may require more effort from the District to acquire conservation through its programs. Although not included in the above estimates, residential Low-Income programs are also significantly more costly to implement due to rebates being paid at 3 to 5 times the level of non-low-income residential programs. The additional effort may result in increased administrative costs.

TABLE 6-7: TRC LEVELIZED COST (2023$/MWH) EXCLUDING DATA CENTERS

	2-Year	4-Year	10-Year	20-Year
Residential	$52	$52	$53	$57
Commercial	$32	$32	$31	$31
Industrial	$49	$49	$49	$49
Agricultural	$18	$17	$17	$17
Total	**$36**	**$36**	**$39**	**$40**

7 Scenario Results

The costs and savings discussed throughout the report thus far describe the Base Case avoided cost scenario. Under this scenario, annual potential for the planning period was estimated by applying assumptions that reflect the District's expected avoided costs. In addition, the Council's 20-year ramp rates were applied to each measure and then adjusted to more closely reflect the District's recent level of achievement.

Additional scenarios were developed to identify a range of possible outcomes that account for uncertainties over the planning period. In addition to the Base Case scenario, this assessment tested low and high scenarios to test the sensitivity of the results to different future avoided cost values. The avoided cost values in the low and high scenarios reflect values that are realistic and lower or higher, respectively, than the Base Case assumptions.

To understand the sensitivity of the identified savings potential to avoided cost values alone, three scenarios were modeled.

Table 7-1 summarizes the Base, Low, and High avoided cost input values. Relative to the values used in the 2021 CPA, many of the avoided cost assumptions have decreased including energy and capacity estimates. These changes reduced the 20-year potential estimate due to decreased cost-effectiveness.

Rather than using a single generic risk adder applied to each unit of energy, the Low and High avoided cost values consider lower and higher potential future values for each avoided cost input. These values reflect potential price risks based upon both the energy and capacity value of each measure. The final row tabulates the implied risk adders for the Low and High scenarios by summarizing all additions or subtractions relative to the Base Case values. Risk adders are provided in both energy and demand savings values. The first set of values is the maximum (or minimum in the case of negative values). The second set of risk adder values are the average values in energy terms. Further discussion of these values is provided in Appendix IV.

TABLE 7-1: AVOIDED COST ASSUMPTIONS BY SCENARIO, $2023

	Base	Low	High
Energy	NWPCC April 2023 Baseline Price Forecast	10% Lower than NWPCC April 2023 Baseline Price Forecast	NWPCC April 2023 High Westside Demand
Social Cost of Carbon, $/short ton	WAC 194-40-100 $34/MWh	WAC 194-40-100 $34/MWh	WAC 194-40-100 $34/MWh
Avoided Cost of RPS Compliance	Included in Social Cost of Carbon		
Distribution System Credit, $/kW-yr	$8.53	$8.53	$8.53
Transmission System Credit, $/kW-yr	$3.83	$3.83	$3.83
Deferred Generation Capacity Credit, $/kW-yr	$104	$0	$143.18
Implied Risk Adder, 20-year Levelized **$/MWh** **$/kW-yr**	N/A	Average: -$1/MWh and -$104/kW-yr	Average: $11/MWh and $39/kW-year

Table 7-2 illustrates the growth assumptions modeled for each scenario.

	Residential	Commercial	Industrial	Data Centers	Population
Base	0.8%	1.15%	1.8%	3.0%	0.9%
Low	0.5%	0.5%	0.0%	1%	0.5%
High	2.5%	2%	3.0%	5%	2.5%

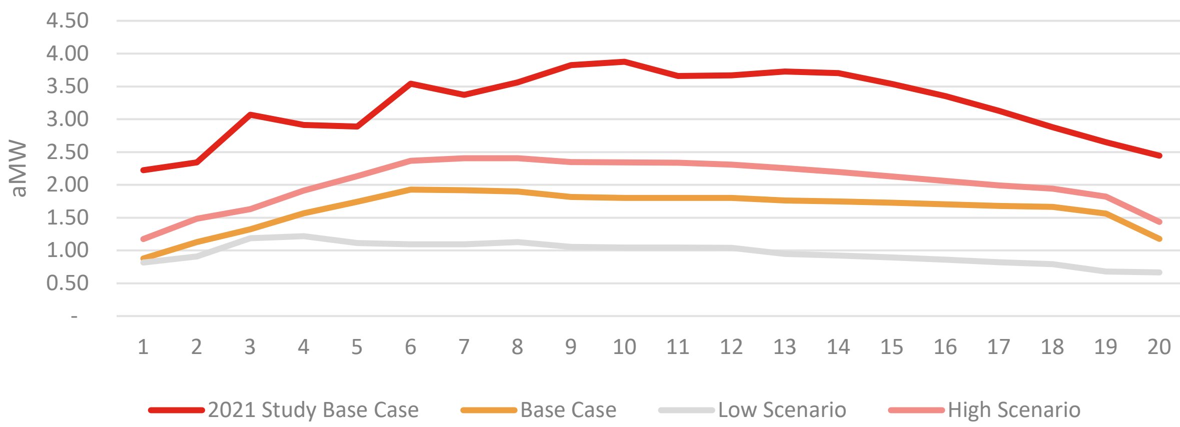
Table 7-3 summarizes results across each avoided input scenario, using Base Case load forecasts and measure acquisition rates.

TABLE 7-3: COST-EFFECTIVE POTENTIAL – AVOIDED COST SCENARIO COMPARISON

	2-Year	4-Year	10-Year	20-Year
Base Case	4.0	9.3	24.1	42.8
Low Scenario	3.7	8.5	18.8	29.5
High Scenario	4.6	19.2	28.3	50.8

Figure 7-1 compares the results of the scenario analysis with the base case form the 2021 assessment.

FIGURE 7-1: SCENARIO COMPARISON



In all cases, the 20-year economic achievable potential is lower compared with the 2021 study due to the factors described in this analysis including changes to the avoided cost, increased efficiency, data center growth, and historic achievements.

8 Summary

This report summarizes the results of the 2023 CPA conducted for the District. The assessment provides estimates of energy savings by sector for the period 2024 to 2043 with a focus on the first 10 years of the planning period, as required by the EIA. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

The cost-effective potential identified in this report is a low cost and low risk resource and helps to keep future electricity costs to a minimum. Additionally, conservation achievements inherently provide capacity savings to the District. Relative to the values used in the 2021 CPA, many of the avoided cost assumptions have decreased including energy value estimates. These changes reduced the 20-year potential estimate due to decreased cost-effectiveness.

8.1 METHODOLOGY AND COMPLIANCE WITH STATE MANDATES

The energy efficiency potential reported in this document is calculated using methodology consistent with the Council's methodology for assessing conservation resources. Appendix III documents the development of conservation targets for each WAC 194-37-070 requirement and describes how each item was completed. Utility-specific data regarding customer characteristics, service-area composition, and historic conservation achievements were used, in conjunction with the measures identified by the Council, to determine available energy-efficiency potential. This close connection with the Council methodology enables compliance with the Washington EIA.

Three types of energy-efficiency potential were calculated: technical, achievable, and economic. Most of the results shown in this report are the economic potential, or the potential that is cost effective in the District's service territory. The economic and achievable potential considers savings that will be captured through utility program efforts, market transformation and implementation of codes and standards. Often, realization of full savings from a measure will require efforts across all three areas. Historic efforts to measure the savings from codes and standards have been limited, but regional efforts to identify and track savings are increasing as they become an important component of the efforts to meet aggressive regional conservation targets.

8.2 CONSERVATION TARGETS

The EIA states that utilities must establish a biennial target that is "no lower than the qualifying utility's pro rata share for that two-year period of its cost-effective conservation potential for the subsequent ten-year period."[10] However, the State Auditor's Office has stated that:

> The term pro-rata can be defined as equal portions but it can also be defined as a proportion of an "exactly calculable factor." For the purposes of the Energy

[10] RCW 19.285.040 Energy conservation and renewable energy targets.

Independence Act, a pro-rata share could be interpreted as an even 20 percent of a utility's 10-year assessment but state law does not require an even 20 percent.[11]

The State Auditor's Office expects that qualifying utilities have analysis to support targets that are more or less than the 20 percent of the ten-year assessments. This document serves as support for the target selected by the District and approved by its Commission.

8.3 SUMMARY

This study shows a range of conservation target scenarios. These scenarios are estimates based on the set of assumptions detailed in this report and supporting documentation and models. Due to the uncertainties discussed in the Introduction section of this report, actual available and cost-effective conservation may vary from the estimates provided in this report.

[11] State Auditor's Office. Energy Independence Act Criteria Analysis. Pro-Rata Definition. CA No. 2011-03. https://www.sao.wa.gov/local/Documents/CA_No_2011_03_pro-rata.pdf.

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Appendix I – Acronyms

ALH – Average Load Hours

aMW – Average Megawatt

BCR – Benefit-Cost Ratio

BPA – Bonneville Power Administration

CETA – Clean Energy Transformation Act

CPA – Conservation Potential Assessment

DVR – Demand voltage reduction

EIA – Energy Independence Act

ERWH – Electric Resistance Water Heater

EUI – Energy Use Intensity

GPM – Gallons per minute

HLH – Heavy load hour energy

HPWH – Heat Pump Water Heater

HVAC – Heating, ventilation and air-conditioning

IRP – Integrated Resource Plan

kW – kilowatt

kWh – kilowatt-hour

LED – Light-emitting diode

LLH – Light load hour energy

MW – Megawatt

MWh – Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

RPS – Renewable Portfolio Standard

RTF – Regional Technical Forum

TRC – Total Resource Cost

UC – Utility Cost

Appendix II – Glossary

7th Power Plan: Seventh Northwest Conservation and Electric Power Plan, Feb 2016. A regional resource plan produced by the Northwest Power and Conservation Council (Council).

2021 Power Plan: A regional resource plan produced by the Northwest Power and Conservation Council (Council). At the time of this study, the Final plan is scheduled to be released in early 2022.

Average Megawatt (aMW): Average hourly usage of electricity, as measured in megawatts, across all hours of a given day, month or year.

Avoided Cost: Refers to the cost of the next best alternative. For conservation, avoided costs are usually market prices.

Achievable Potential: Conservation potential that takes into account how many measures will actually be implemented after considering market barriers. For lost-opportunity measures, there is only a certain number of expired units or new construction available in a specified time frame. The Council assumes 85% of all measures are achievable. Sometimes achievable potential is a share of economic potential, and sometimes achievable potential is defined as a share of technical potential.

Cost Effective: A conservation measure is cost effective if the present value of its benefits is greater than the present value of its costs. The primary test is the Total Resource Cost test (TRC), in other words, the present value of all benefits is equal to or greater than the present value of all costs. All benefits and costs for the utility and its customers are included, regardless of who pays the costs or receives the benefits.

Economic Potential: Conservation potential that considers the cost and benefits and passes a cost-effectiveness test.

Levelized Cost: Resource costs are compared on a levelized-cost basis. Levelized cost is a measure of resource costs over the lifetime of the resource. Evaluating costs with consideration of the resource life standardizes costs and allows for a straightforward comparison.

Lost Opportunity: Lost-opportunity measures are those that are only available at a specific time, such as new construction or equipment at the end of its life. Examples include heat-pump upgrades, appliances, or premium HVAC in commercial buildings.

MW (megawatt): 1,000 kilowatts of electricity. The generating capacity of utility plants is expressed in megawatts.

Non-Lost Opportunity: Measures that can be acquired at any time, such installing low-flow shower heads.

Northwest Energy Efficiency Alliance (NEEA): The alliance is a unique partnership among the Northwest region's utilities, with the mission to drive the development and adoption of energy-efficient products and services.

Northwest Power and Conservation Council "The Council": The Council develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. Their three tasks are to: develop a 20-year electric power plan that will guarantee adequate and reliable energy at the lowest economic and environmental cost to the Northwest; develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and educate and involve the public in the Council's decision-making processes.

Regional Technical Forum (RTF): The Regional Technical Forum (RTF) is an advisory committee established in 1999 to develop standards to verify and evaluate conservation savings. Members are appointed by the Council and include individuals experienced in conservation program planning, implementation and evaluation.

Renewable Portfolio Standards: Washington state utilities with more than 25,000 customers are required to meet defined percentages of their load with eligible renewable resources by 2012, 2016, and 2020.

Retrofit (discretionary): Retrofit measures are those that can be replaced at any time during the unit's life. Examples include lighting, shower heads, pre-rinse spray heads, or refrigerator decommissioning.

Technical Potential: Technical potential includes all conservation potential, regardless of cost or achievability. Technical potential is conservation that is technically feasible.

Total Resource Cost Test (TRC): This test is used by the Council and nationally to determine whether or not conservation measures are cost effective. A measure passes the TRC if the ratio of the present value of all benefits (no matter who receives them) to the present value of all costs (no matter who incurs them) is equal to or greater than one.

Appendix III – Documenting Conservation Targets

References:

1) Report – "Grant County PUD Amended Conservation Potential Assessment: 2024-2043". Final Report – May 3, 2024.
2) Model – "Amended 2023-Grant PUD-CPA – Base Case.xlsm" and supporting files
    a. MC_and_Loadshape-GCPUD-Base.xlsm – referred to as "MC and Loadshape file" – contains price and load shape data

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
a) **Technical Potential:** Determine the amount of conservation that is technically feasible, considering measures and the number of these measures that could physically be installed or implemented, without regard to achievability or cost.	The model includes estimates for stock (e.g. number of homes, square feet of commercial floor area, industrial load) and the number of each measure that can be implemented per unit of stock. The technical potential is further constrained by the amount of stock that has already completed the measure.	Model – the technical potential is calculated as part of the achievable potential, described below.
b) Achievable Potential: Determine the amount of the conservation technical potential that is available within the planning period, considering barriers to market penetration and the rate at which savings could be acquired.	The assessment conducted for the District used ramp rate curves to identify the amount of achievable potential for each measure. Those assumptions are for the 20-year planning period. An additional factors ranging from 85% to 95% were included to account for market barriers in the calculation of achievable potential. This factor comes from a study conducted in Hood River where home weatherization measures were offered for free and program administrators were able to reach more than 85% of home owners.	Model – the use of these factors can be found on the sector measure tabs, such as 'Residential Measures'. Additionally, the complete set of ramp rates used can be found on the 'Ramp Rates' tab.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
c) **Economic Achievable Potential**: Establish the economic achievable potential, which is the conservation potential that is cost-effective, reliable, and feasible, by comparing the total resource cost of conservation measures to the cost of other resources available to meet expected demand for electricity and capacity.	Benefits and costs were evaluated using multiple inputs; benefit was then divided by cost. Measures achieving a benefit-cost ratio greater than one were tallied. These measures are considered achievable and cost-effective (or economic).	Model – Benefit-Cost ratios are calculated at the individual level by ProCost and passed up to the model.
d) **Total Resource Cost**: In determining economic achievable potential, perform a life-cycle cost analysis of measures or programs	The life-cycle cost analysis was performed using the Council's ProCost model. Incremental costs, savings, and lifetimes for each measure were the basis for this analysis. The Council and RTF assumptions were utilized.	Model – supporting files include all of the ProCost files used in the 2021 Power Plan. The life-cycle cost calculations and methods are identical to those used by the Council.
e) Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits	Cost analysis was conducted per the Council's methodology. Capital cost, administrative cost, annual O&M cost and periodic replacement costs were all considered on the cost side. Energy, non-energy, O&M and all other quantifiable benefits were included on the benefits side. The Total Resource Cost (TRC) benefit cost ratio was used to screen measures for cost-effectiveness (i.e., those greater than one are cost-effective).	Model – the "Measure Info Rollup" files pull in all the results from each avoided cost scenario, including the BC ratios from the ProCost results. These results are then linked to by the Conservation Potential Assessment model. The TRC analysis is done at the lowest level of the model in the ProCost files.
f) Include the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes	Savings, cost, and lifetime assumptions from the Council's Final 2021 Power Plan Supply Curves, and RTF were used.	Model – supporting files include all of the ProCost files used in the 2021 Plan, with later updates made by the RTF. The life-cycle cost calculations and methods are identical to those used by the Council.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
g) Calculate the value of energy saved based on when it is saved. In performing this calculation, use time differentiated avoided costs to conduct the analysis that determines the financial value of energy saved through conservation	The Council's 2021 Power Plan measure load shapes were used to calculate time of day of savings and measure values were weighted based upon peak and off-peak pricing. This was handled using the Council's ProCost tool, so it was handled in the same way as the 2021 Power Plan models.	Model – See MC_AND_LOADSHAPE files for load shapes. The ProCost files handle the calculations.
h) Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures	Operations and maintenance costs for each measure were accounted for in the total resource cost per the Council's assumptions.	Model – the ProCost files contain the same assumptions for periodic O&M as the Council and RTF.
i) Include avoided energy costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared	The Council's April 2023 Baseline market price forecast was used to value energy in the Base Case Scenario.	Report –See Appendix IV. Model – See MC_AND_LOADSHAPE files ("2021P Electric Mid" worksheet).
j) Include deferred capacity expansion benefits for transmission and distribution systems	Deferred transmission capacity expansion benefits were given a benefit of \$3.83/kW-year in the cost-effectiveness analysis. A distribution system credit of \$8.83/kW-year was also used (\$2023). These values were developed by the Council in preparation for the 2021 Power Plan.	Model – this value can be found on the ProData page of each ProCost file.
k) Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure	Deferred generation capacity expansion benefits were given a value of \$104/kW-year in the cost effectiveness analysis for the Base Case Scenario. This is based upon the District's marginal cost for generation capacity. See Appendix IV for further discussion of this value.	Model – this value can be found on the ProData page of the ProCost V.4.006 ProData page.
l) Include the social cost of carbon emissions from avoided non-conservation resources	This CPA uses the social cost of carbon values specified in WAC 194-40-100	The MC_AND_LOADSHAPE files contain the carbon cost assumptions for each avoided cost scenario.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
m) Include a risk mitigation credit to reflect the additional value of conservation, not otherwise accounted for in other inputs, in reducing risk associated with costs of avoided non-conservation resources	In this analysis, risk was considered by varying avoided cost inputs and analyzing the variation in results. Rather than an individual and non-specific risk adder, our analysis included a range of possible values for each avoided cost input.	The scenarios section of the report documents the inputs used and the results associated. Appendix IV discusses the risk adders used in this analysis.
n) Include all non-energy impacts that a resource or measure may provide that can be quantified and monetized	Quantifiable non-energy benefits were included where appropriate. Assumptions for non-energy benefits are the same as in the Council's 2021 Power Plan. Non-energy benefits include, for example, water savings from clothes washers.	Model – the ProCost files contain the same assumptions for non-power benefits as the Council and RTF. The calculations are handled in ProCost.
o) Include an estimate of program administrative costs	Total costs were tabulated and an estimated 20% of the total was assigned as the administrative cost. This value is consistent with regional average and BPA programs. The 20% value was used in the Fifth, Sixth, Seventh Power plans and 2021 Power Plan.	Model – this value can be found on the ProData page of the ProCost V.4.006 ProData page.
p) Include the cost of financing measures using the capital costs of the entity that is expected to pay for the measure	Costs of financing measures were included utilizing the same assumptions from the 2021 Power Plan.	Model – this value can be found on the ProData page of the ProCost V.4.006 ProData page.
q) Discount future costs and benefits at a discount rate equal to the discount rate used by the utility in evaluating non-conservation resources	Discount rates were applied to each measure based upon the Council's methodology. A real discount rate of 3.75% was used, based on the Council's most recent analyses in support of the 2021 Power Plan.	Model – this value can be found on the ProData page of the ProCost V.4.006 ProData page.
r) Include a ten percent bonus for the energy and capacity benefits of conservation measures as defined in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act	A 10% bonus was added to all measures in the model parameters per the Conservation Act.	Model – this value can be found on the ProData page of the ProCost V.4.006 ProData page.

Appendix IV – Avoided Cost and Risk Exposure

The 2023 District (District) Conservation Potential Assessment (CPA) was conducted for the period 2024 through 2043 as required under RCW 19.285 and WAC 194.37. According to WAC 197.37.070, the District must evaluate the cost-effectiveness of conservation by setting avoided energy costs equal to a forecast of regional market prices. In addition, several other components of the avoided cost of energy efficiency savings must be evaluated including generation capacity value, transmission and distribution costs, risk, and the social cost of carbon.

This appendix describes each of the avoided cost assumptions and provides a range of values that were evaluated in the 2021 CPA. The 2023 CPA considers three avoided cost scenarios: Base, Low, and High. Each of these is discussed below.

Avoided Energy Value

For the purposes of the 2023, EES used the Council's April 2023 market price forecasts. The Baseline forecast is used in the Base and Low scenarios. This price forecast reflects the large amount of renewable energy forecast to come online in the next 20 years. The high scenario assumes the High Westside Demand forecast scenario developed by the Council. In this scenario, electricity demand is increased on the West side of the Region due to aggressive electrification goals.

Avoided Cost Adders and Risk

From a total resource cost perspective, energy efficiency provides multiple benefits beyond the avoided cost of energy. These include deferred capital expenses on generation, transmission, and distribution capacity; as well as the reduction of required renewable energy credit (REC) purchases, avoided social costs of carbon emissions, and the reduction of utility resource portfolio risk exposure. Since energy efficiency measures provide both peak demand and energy savings, these other benefits are monetized as value per unit of either kWh or kW savings.

FIGURE IV-1: OVERVIEW OF PORTFOLIO REQUIREMENTS

Energy-Based	Capacity Based
• Social Cost of Carbon	• Generation Capacity Deferral
• Renewable Energy Credits	• Transmission Capacity Deferral
• GHG-Free or Neutral Resources	• Distribution Capacity Deferral
• Risk Reduction Premium	

The estimated values and associated uncertainties for these avoided cost components are based on relevant portfolio requirements from the Clean Energy Transformation Act (CETA). The timeline below summarizes the relevant milestones for portfolio planning. The type of energy the District will need to procure is based on these requirements; therefore, the requirements set the avoided cost as it relates to capacity, renewable, and GHG-free power supply.

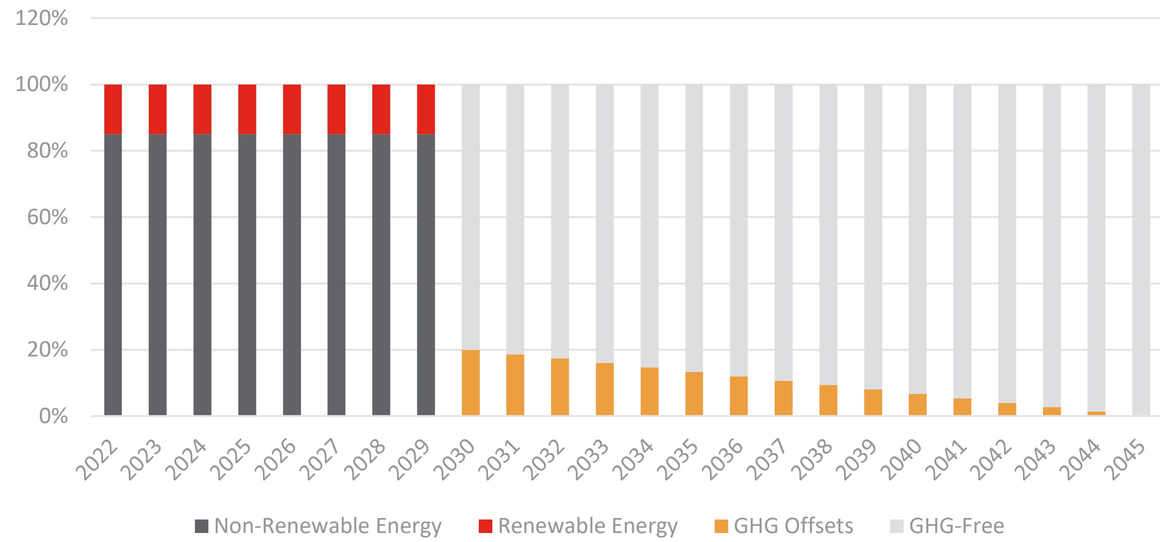
FIGURE IV-2: OVERVIEW OF PORTFOLIO REQUIREMENTS

Through 2030, the District must meet the renewable portfolio standard (RPS) set for Washington State Utilities of 15% of the system load. The RPS can be met through either bundled or unbundled RECs. Next, CETA establishes a 100% GHG neutral requirement by 2030. The requirement states that at least 80% of a utility's portfolio must be sourced directly from either renewable[12] or non-emitting resources.[13] A utility may then meet the mandate by purchasing no more than 20% of its portfolio in offsets such as unbundled REC purchases. The offsets will then be phased out by 2045 as shown in Figure IV-3.

[12] Renewable resources include water, wind, solar energy, geothermal, renewable natural gas, renewable hydrogen, wave, ocean or tidal power, and biodiesel not derived from crops raised on land cleared from old growth forest or first growth, or biomass. (Chapter 173-444 WAC available at: https://ecology.wa.gov/DOE/files/c0/c08b45ae-7140-4b30-a3c2-faf8aa042651.pdf).

[13] Non-emitting resources are those that generate electricity, or provide capacity of ancillary services to an electric utility that do not emit greenhouse gases as a by-product. *See id*.

FIGURE IV-3: SUMMARY OF RPS AND CETA PORTFOLIO REQUIREMENTS



Social Cost of Carbon

The social cost of carbon is a cost that society incurs when fossil fuels are burned to generate electricity. Both the EIA rules and CETA requires that CPAs include the social cost of carbon when evaluating cost effectiveness using the total resource cost test (TRC). CETA further specifies the social cost of carbon values to be used in conservation and demand response studies. These values are shown in Table IV-1 below.

TABLE IV-1: SOCIAL COST OF CARBON VALUES[14]

Year in Which Emissions Occur or Are Avoided	Social Cost of Carbon Dioxide (in 2007 dollars per metric ton)	Social Cost of Carbon Dioxide (in 2018 dollars per metric ton)
2020	$62	$74
2025	$68	$81
2030	$73	$87
2035	$78	$93
2040	$84	$100
2045	$89	$106
2050	$95	$113

[14] WAC 194-40-100. Available at: https://apps.leg.wa.gov/wAc/default.aspx?cite=194-40-100&pdf=true.

According to WAC 194-40-110, values may be adjusted for any taxes, fees or costs incurred by utilities to meet portfolio mandates.[15] For example, the social cost of carbon is the full value of carbon emissions which includes the cost to utilities and ratepayers associated with moving to non-emitting resources. Rather than adjust the social cost of carbon for the cost of RECs or renewable energy, the values for RECS and renewable energy are excluded from the analysis to avoid double counting.

The emissions intensity of the marginal resource (market) is used to determine the $/MWh value for the social cost of carbon. Ecology states that unspecified resources should be given a carbon intensity value of 0.437 metric tons of CO_2e/MWh of electricity (0.874 lbs/kWh).[16] This is an average annual value applied to in all months in the conservation potential model.[17]

Avoided Renewable Energy Purchases

Renewable energy purchases need to meet both RPS and CETA and can be avoided through conservation. Utilities may meet Washington RPS through either bundled energy purchases such as purchasing the output of a wind resource where the non-energy attributes remain with the output, or they may purchase unbundled RECs.

As stated above, the value of avoided renewable energy credit purchases resulting from energy efficiency is accounted for within the social cost of carbon construct. The social cost of carbon already considers the cost of moving from an emitting resource to a non-emitting resource. Therefore, it is not necessary to include an additional value for renewable energy purchases prior to 2045 when all energy must be non-emitting or renewable.

Beginning in 2045, the social cost of carbon may no longer be an appropriate adder in resource planning. However, prior to 2045 utilities may still use offsets to meet CETA requirements. Since the study period of this evaluation ends prior to 2045, the avoided social cost of carbon is included in each year. For future studies that extend to 2045 and beyond, it would be appropriate to include renewable energy or non-emitting resource costs as the avoided cost of energy rather than market plus the social cost of carbon.

Risk Adder

In general, the risk that any utility faces is that energy efficiency will be undervalued, either in terms of the value per kWh or per kW of savings, leading to an under-investment in energy efficiency and exposure to higher market prices or preventable investments in infrastructure. The converse risk—an over-valuing of energy and subsequent over-investment in energy efficiency—is also possible, albeit less likely. For example, an over-investment would occur if an assumption is made that economies will remain basically the same as they are today, and subsequent sector shifts or economic downturns cause large industrial

[15] WAC 194-40-110 (b).

[16] WAC 173-444-040 (4).

[17] The seasonal nature of carbon intensity is not modeled due to the prescriptive annual value established by Ecology in WAC 173-444-040.

customers to close their operations. Energy efficiency investments in these facilities may not have been in place long enough to provide the anticipated low-cost resource.

In order to address risk, the Council develops a risk adder ($/MWh) for its cost-effectiveness analysis of energy efficiency measures. This adder represents the value of energy efficiency savings not explicitly accounted for in the avoided cost parameters. The risk adder is included to ensure an efficient level of investment in energy efficiency resources under current planning conditions. Specifically, in cases where the market price has been low compared to historic levels, the risk adder accounts for the likely possibility that market prices will increase above current forecasts.

The value of the risk adder has varied depending on the avoided cost input values. The adder is the result of stochastic modeling and represents the lower risk nature of energy efficiency resources. In the Sixth Power Plan the risk adder was significant (up to $50/MWh for some measures). In the Seventh Power Plan the risk adder was determined to be $0/MWh after the addition of the generation capacity deferral credit. The 2021 Power Plan used the same methodology as the Seventh Plan. While the Council uses stochastic portfolio modeling to value the risk credit, utilities conduct scenario and uncertainty analysis. The scenarios modeled in the District's CPA include an inherent value for the risk credit such has higher market prices due to a number of factors including electrification, and increased renewables integrated onto the grid.

For the District's 2023 CPA, the avoided cost parameters have been estimated explicitly, and a scenario analysis is performed. Therefore, no risk adder was used for the base case. Variation in other avoided cost inputs covers a range of reasonable outcomes and is sufficient to identify the sensitivity of the cost-effective energy efficiency potential to a range of outcomes. The scenario results present a range of cost-effective energy efficiency potential, and the identification of the District's biennial target based on the range modeled is effectively selecting the utility's preferred risk strategy and associated risk credit.

Deferred Transmission and Distribution System Investment

Energy efficiency measure savings reduce capacity requirements on both the transmission and distribution systems. The Council's 2021 Power assumes these avoided costs are $3.83/kW-year and $8.5/kW-year for transmission and distribution systems, respectively ($2023).[18] These assumptions are used in all scenarios in the CPA.

Deferred Investment in Generation Capacity

Beginning in October 2023, the District will be a load following customer of BPA. As a load following customer, the District's avoided cost of capacity is built into BPA's preference rates. BPA demand rates

[18] Northwest Power and Conservation Council Memorandum to the Power Committee Members. Subject; Updated Transmission & Distribution Deferral Value for the 2021 Power Plan. March 5, 2019. Available at: https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf.

are escalated 3% each rate period (every two years).[19] Over the 20-year analysis period, the resulting cost of avoided capacity is $104/kW-year (2023$) in levelized terms.

In the Council's 2021 Power Plan,[20] a generation capacity value of $143/kW-year was explicitly calculated ($2023). This value is used in the high scenario.

Summary of Scenario Assumptions

Table IV-2 summarizes the recommended scenario assumptions. The Base Case represents the most likely future.

TABLE IV-2: AVOIDED COST ASSUMPTIONS BY SCENARIO, $2023

	Base	Low	High
Energy	NWPCC April 2023 Baseline Price Forecast	10% lower than NWPCC April 2023 Price Forecast	NWPCC April 2023 High Westside Demand
Social Cost of Carbon, $/short ton	WAC 194-40-100 $34/MWh	WAC 194-40-100 $34/MWh	WAC 194-40-100 $34/MWh
Avoided Cost of RPS Compliance	Included in Social Cost of Carbon		
Distribution System Credit, $/kW-yr	$8.53	$8.53	$8.53
Transmission System Credit, $/kW-yr	$3.83	$3.83	$3.83
Deferred Generation Capacity Credit, $/kW-yr	$104	$0	$143.18
Implied Risk Adder, 20-year Levelized $/MWh $/kW-yr	N/A	Average: -$1/MWh and -$104/kW-yr	Average: $11/MWh and $39/kW-year

[19] BP-24 Rate Proceeding. July 2023. BP-24-A-02-AP01 Available online: https://www.bpa.gov/-/media/Aep/rates-tariff/bp-24/Final-Proposal/Appendix-BFinal-Proposal-Power-Rate-Schedules-and-GRSPsBP24A02AP01Rev-1.pdf.

[20] https://www.nwcouncil.org/energy/powerplan/7/home/.

Appendix V – Ramp Rate Documentation

This section is intended to document how ramp rates were adjusted to align near term potential with recent achievements of the District programs.

Modelling work began with the 2021 Power Plan ramp rate assignments for each measure. The District's program achievements from 2020 and estimates for 2021 were compared at a sector level with the first two years of the study period, 2024-2025. This allowed for the identification of sectors where ramp rate adjustments may be necessary.

Table V-1 below shows the results of the comparison by sector after ramp rate adjustments were made.

TABLE V-1 COMPARISON OF SECTOR LEVEL PROGRAM ACHIEVEMENT AND POTENTIAL (AMW)

	Program History				CPA Potential	
	2020	2021	2022*	20-'22 Avg	2024	2025
Residential	0.12	0.12	0.12	0.12	0.08	0.09
Commercial	0.19	0.40	0.09	0.23	0.30	0.36
Industrial (Excluding Data Centers)	0.14	0.94	0.14	0.40	0.09	0.25
Agricultural	0.00	0.00	0.00	0.00	0.08	0.10
NEEA	0.64	0.69	0.13	0.49		
Total	**1.08**	**2.17**	**0.50**	**1.25**	**0.55**	**0.80**

**Projected*

When viewing the achievement and potential at the sector level, adjustments were found to be necessary in the residential and commercial sectors. The 2021 Power Plan ramp rates were found to be a good match for the District programs in the, agricultural sectors. The draft 2021 Power Plan assigns a fast ramp rate to exterior commercial lighting. The ramp rate for these measures was adjusted to smooth potential over the 20-year period (moving from Fast 80 to 20-year ramp rates. This adjustment accounts for COVID impacts in supply chain and program participation observed in 2020 and continuing into 2023. The 2021 Power Plan documents do not consider COVID impacts, therefore, it is appropriate to make the adjustments to the potential in the near-term for purposes of target setting.

Industrial sector savings (non-data center) is adjusted to reflect lower adoption rates in the near term. The District plans industrial energy efficiency projects taking advantage of when data center customers are working on projects. Due to the program funding available and staffing, the District plans to achieve a large share of its biennial savings from data center projects leaving fewer resources for non-datea center industrial programs.

Appendix VI – Measure List

This appendix provides a high-level measure list of the energy efficiency measures evaluated in the 2023 CPA. The CPA evaluated thousands of measures; the measure list does not include each individual measure; rather it summarizes the measures at the category level, some of which are repeated across different units of stock, such as single family, multifamily, and manufactured homes. Specifically, utility conservation potential is modeled based on incremental costs and savings of individual measures. Individual measures are then combined into measure categories to more realistically reflect utility-conservation program organization and offerings. For example, single family attic insulation measures are modeled for a variety of upgrade increments: R-0 to R-38, R-0 to R-49, or R-19 to R-38. The increments make it possible to model measure savings and costs at a more precise level. Each of these individual measures are then bundled across all housing types to result in one measure group: attic insulation.

The following tables list the conservation measures (at the category level) that were used to model conservation potential presented in this report. Measure data was sourced from the Council's 2021 Plan workbooks. Please note that some measures may not be applicable to an individual utility's service territory based on characteristics of the utility's customer sectors.

Table VI-1
Residential End Uses and Measures

End Use	Measures/Categories	Data Source
Appliances	Heat Pump Clothes Dryer	2021 Power Plan
	Clothes Dryer	2021 Power Plan
	Oven	2021 Power Plan
Electronics	Advanced Power Strips	2021 Power Plan
	Desktop	2021 Power Plan
	Laptop	2021 Power Plan
	Monitor	2021 Power Plan
	Air Cleaners	2021 Power Plan
Food Preparation	Electric Oven	2021 Power Plan
	Microwave	2021 Power Plan
HVAC	Air Source Heat Pump	2021 Power Plan
	Controls, Commissioning, and Sizing	2021 Power Plan
	Central Air Conditioning	2021 Power Plan
	Ductless Heat Pump	2021 Power Plan
	Ducted Heat Pump	2021 Power Plan
	Duct Sealing	2021 Power Plan
	Ground Source Heat Pump	2021 Power Plan
	Heat Recovery Ventilation	2021 Power Plan
	Attic Insulation	2021 Power Plan
	Floor Insulation	2021 Power Plan
	Wall Insulation	2021 Power Plan
	Windows	2021 Power Plan
	Cellular Shades	2021 Power Plan
	Whole House Fan	2021 Power Plan
	Wi-Fi Enabled Thermostats	2021 Power Plan
Lighting	Linear Fluorescent Lighting	2021 Power Plan
	Floor/Table Lamps	2021 Power Plan
	Ceiling and Wall Flush Mount	2021 Power Plan

Table VI-1
Residential End Uses and Measures

End Use	Measures/Categories	Data Source
	Downlight Fixture	2021 Power Plan
	Exterior Porch	2021 Power Plan
	Linear Porch	2021 Power Plan
	Track Lighting	2021 Power Plan
	Linear Base	2021 Power Plan
	Decorative Base	2021 Power Plan
Refrigeration	Freezer	2021 Power Plan
	Refrigerator	2021 Power Plan
Water Heating	Aerator	2021 Power Plan
	Water Heater Pipe Insulation	2021 Power Plan
	Clothes Washer	2021 Power Plan
	Dishwasher	2021 Power Plan
	Heat Pump Water Heater	2021 Power Plan
	Showerheads	2021 Power Plan
	Solar Water Heater	2021 Power Plan
	Circulator Controls	2021 Power Plan
	Thermostatic Valve	2021 Power Plan
	Wastewater Heat Recovery	2021 Power Plan
Whole Building	EV Charging Equipment	2021 Power Plan
	Behavior	2021 Power Plan
	Well Pump	2021 Power Plan

Table VI-2
Commercial End Uses and Measures

End Use	Measures/Categories	Data Source
Compressed Air	Controls, Equipment, & Demand Reduction	2021 Power Plan
Electronics	Desktop Computer	2021 Power Plan
	Laptop Computer	2021 Power Plan
	Smart Plug Power Strips	2021 Power Plan
	Data Center Measures	2021 Power Plan
Food Preparation	Combination Ovens	2021 Power Plan
	Convection Ovens	2021 Power Plan
	Fryers	2021 Power Plan
	Hot Food Holding Cabinet	2021 Power Plan
	Steamer	2021 Power Plan
	Pre-Rinse Spray Valve	2021 Power Plan
HVAC	Advanced Rooftop Controller	2021 Power Plan
	Chiller Upgrade	2021 Power Plan
	Commercial Energy Management	2021 Power Plan
	Demand Control Ventilation	2021 Power Plan
	Ductless Heat Pumps	2021 Power Plan
	Economizers	2021 Power Plan
	Secondary Glazing Systems	2021 Power Plan
	Variable Refrigerant Flow	2021 Power Plan
	Web-Enabled Programmable Thermostat	2021 Power Plan
	Fans	2021 Power Plan
	PTPH	2021 Power Plan
Lighting	Bi-Level Stairwell Lighting	2021 Power Plan
	Exterior Building Lighting	2021 Power Plan
	Exit Signs	2021 Power Plan
	Lighting Controls	2021 Power Plan
	Interior Lighting	2021 Power Plan
	Garage Lighting	2021 Power Plan
	Street & Roadway Lighting	2021 Power Plan
Motors/Drives	ECM for Variable Air Volume	2021 Power Plan
	Motor Rewinds	2021 Power Plan
Process Loads	Municipal Water Supply	2021 Power Plan
Refrigeration	Grocery Refrigeration Bundle	2021 Power Plan
	Freezer	2021 Power Plan
Water Heating	Commercial Clothes Washer	2021 Power Plan
	Showerheads	2021 Power Plan
	Clean Water Pumps	2021 Power Plan
	Heat Pump Water Heaters	2021 Power Plan
	Circulator Pumps	2021 Power Plan
Process Loads	Elevators	2021 Power Plan
	Engine Block Heater Control	2021 Power Plan

Table VI-3
Industrial End Uses and Measures

End Use	Measures/Categories	Data Source
Compressed Air	Air Compressor Equipment	2021 Power Plan
	Demand Reduction	2021 Power Plan
Energy Management	Air Compressor Optimization	2021 Power Plan
	Energy Project Management	2021 Power Plan
	Fan Energy Management	2021 Power Plan
	Fan System Optimization	2021 Power Plan
	Cold Storage Tune-up	2021 Power Plan
	Chiller Optimization	2021 Power Plan
	Integrated Plant Energy Management	2021 Power Plan
	Plant Energy Management	2021 Power Plan
	Pump Energy Management	2021 Power Plan
	Pump System Optimization	2021 Power Plan
Fans	Efficient Centrifugal Fan	2021 Power Plan
	Fan Equipment Upgrade	2021 Power Plan
Hi-Tech	Clean Room Filter Strategy	2021 Power Plan
	Clean Room HVAC	2021 Power Plan
	Chip Fab: Eliminate Exhaust	2021 Power Plan
	Chip Fab: Exhaust Injector	2021 Power Plan
	Chip Fab: Reduce Gas Pressure	2021 Power Plan
	Chip Fab: Solid State Chiller	2021 Power Plan
Lighting	Efficient Lighting	2021 Power Plan
	High-Bay Lighting	2021 Power Plan
	Lighting Controls	2021 Power Plan
Low & Medium Temp Refrigeration	Food: Cooling and Storage	2021 Power Plan
	Cold Storage Retrofit	2021 Power Plan
	Grocery Distribution Retrofit	2021 Power Plan
Material Handling	Material Handling Equipment	2021 Power Plan
	Material Handling VFD	2021 Power Plan
Metals	New Arc Furnace	2021 Power Plan
Misc.	Synchronous Belts	2021 Power Plan
	Food Storage: CO2 Scrubber	2021 Power Plan
	Food Storage: Membrane	2021 Power Plan
Motors	Motor Rewinds	2021 Power Plan
Paper	Efficient Pulp Screen	2021 Power Plan
	Material Handling	2021 Power Plan
	Premium Control	2021 Power Plan
	Premium Fan	2021 Power Plan
Process Loads	Municipal Sewage Treatment	2021 Power Plan
Pulp	Efficient Agitator	2021 Power Plan
	Effluent Treatment System	2021 Power Plan
	Premium Process	2021 Power Plan
	Refiner Plate Improvement	2021 Power Plan
	Refiner Replacement	2021 Power Plan
Pumps	Equipment Upgrade	2021 Power Plan
Transformers	New/Retrofit Transformer	2021 Power Plan
Wood	Hydraulic Press	2021 Power Plan
	Pneumatic Conveyor	2021 Power Plan

Table VI-3 Agriculture End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Dairy Efficiency	Efficient Lighting	2021 Power Plan
	Milk Pre-Cooler	2021 Power Plan
	Vacuum Pump	2021 Power Plan
Irrigation	Low Energy Sprinkler Application	2021 Power Plan
	Irrigation Hardware	2021 Power Plan
	Line Pressure Reduction	2021 Power Plan
Lighting	Agricultural Lighting	2021 Power Plan
Process Loads	Circulating Block Heater for Back -Up Generator	2021 Power Plan
	Energy Free Stock Tank	2021 Power Plan
Motors/Drives	Green Motor Rewinds	2021 Power Plan

Table VI-4 Distribution Efficiency End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Distribution Efficiency	ECM-1 LDC Voltage Control without VVO & AMI	2021 Power Plan
	ECM-2 & ECM 3 LDC Voltage Control with VVO & AMI	2021 Power Plan

Appendix VII –Energy Efficiency Potential by End-Use

Table VII-1
Residential Economic Potential (aMW)

	2 Year	4 Year	10 Year	20 Year
Dryer	0.01	0.01	0.02	0.04
Electronics	0.00	0.00	0.00	0.00
Food Preparation	0.00	0.00	0.00	0.00
HVAC	0.09	0.20	0.73	1.71
Lighting	0.00	0.02	0.17	0.30
Refrigeration	0.00	0.01	0.02	0.05
Water Heating	0.07	0.15	0.51	1.01
Whole Bldg/Meter Level	0.00	0.00	0.00	0.00
Total	**0.17**	**0.38**	**1.47**	**3.12**

Table VII-2
Commercial Economic Potential (aMW)

	2 Year	4 Year	10 Year	20 Year
Compressed Air	0.00	0.00	0.00	0.00
Electronics	0.00	0.00	0.00	0.00
Food Preparation	0.02	0.05	0.11	0.18
HVAC	0.08	0.16	0.37	0.63
Lighting	0.34	0.69	1.75	3.50
Motors/Drives	0.00	0.00	0.00	0.00
Process Loads	0.00	0.00	0.00	0.00
Refrigeration	0.19	0.38	0.97	1.93
Water Heating	0.03	0.05	0.14	0.27
Total	**0.66**	**1.34**	**3.34**	**6.52**

Table VII-3
Industrial Economic Potential (aMW)

	2 Year	4 Year	10 Year	20 Year
Compressed Air	0.03	0.10	0.61	1.45
Fans	0.00	0.00	0.00	0.00
Lighting	0.13	0.43	2.60	6.21
Pumps	0.00	0.00	0.00	0.00
HVAC	0.04	0.15	0.88	2.11
Low Temp Refer	0.03	0.09	0.55	1.32
Med Temp Refer	0.01	0.04	0.25	0.61
All Electric	0.01	0.03	0.19	0.46
Material Processing	0.04	0.13	0.80	1.92
Material Handling	0.05	0.17	1.01	2.42
Melting and Casting	0.03	0.10	0.61	1.45
Other	0.00	0.00	0.00	0.00
Data Centers	0.66	1.5	2.8	3.5
Total	1.00	2.68	9.69	19.96

Table VII-4
Agricultural Economic Potential (aMW)

	2 Year	4 Year	10 Year	20 Year
Irrigation	0.06	0.18	0.53	1.06
Lighting	0.03	0.04	0.06	0.07
Motors/Drives	0.08	0.25	0.78	1.59
Process Loads	0.00	0.00	0.00	0.00
HVAC	0.00	0.00	0.00	0.00
Refrigeration	0.01	0.02	0.12	0.28
Total	**0.18**	**0.49**	**1.49**	**3.01**