Grant County
PUBLIC UTILITY DISTRICT

Integrated Resource Plan

2022

Resolution 8996

Exhibit A

August 23, 2022

Letter from Wholesale Marketing and Supply

The next 10 years hold significant challenges and opportunities for Grant PUD. These challenges include the magnitude of our load growth, wholesale energy market transformations, clean energy regulations, and regional resource adequacy concerns. This 2022 Integrated Resource Plan (IRP) is Grant's roadmap for navigating this uncertain but exciting future.

Load Growth

Load growth continues to be the largest driver of our plans for the future. Grant PUD has experienced significant load growth over the prior ten-year period, with an annual average growth rate of approximately 3%. Most of this growth originates from increases in the demand of a few large industrial customers. Sustained load growth is forecasted to continue over the next ten years, with most of the projected growth to again come from a few large industrial customers. This load concentration introduces a significant amount of uncertainty in future resource needs as the current applications for new service could quickly change.

With projected load growth, we are forecasted to be energy deficient at the expiration of our pooling agreement in September 2025 and capacity deficient beginning in 2026.

New Wholesale Markets

Over the past decade, the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) has grown from two Northwest participants to nineteen, with an additional three participants planning to join in 2023. This real-time energy imbalance market is in direct competition to the current real-time energy market, the Mid-Columbia trading hub (Mid-C), that we rely on to meet our hourly energy needs.

The CAISO also has plans for an Extended Day-Ahead Market (EDAM) to supplement the current real-time EIM. This proposed day-ahead market could further reduce liquidity at the Mid-C, making it more difficult for us to meet our future energy needs with traditional tools.

We continue to monitor CAISO's progress in each of these markets and will look for ways to take advantage of this evolving marketplace in the future. We are also engaged in the Southwest Power Pool's Markets+ initiative, which could provide similar services to the CAISO EIM and EDAM products.

Washington State's Clean Energy Transformation Act (CETA)

In 2019, Washington Governor Jay Inslee signed into law the Clean Energy Transformation Act (CETA). This Act commits Washington utilities to being greenhouse gas neutral by 2030 and, by 2045, supplying 100% of their electricity from renewable, non-carbon emitting resources. Our existing hydropower resources can contribute toward CETA compliance, though doing so would require contractual adjustments to how we have typically utilized these hydropower systems. Selecting additional resources in the next few years that comply with CETA, while maintaining our low-cost competitiveness for customers will be challenging.

Resource Adequacy

Historically the Northwest has been one of the least capacity constrained regions of the electric grid due to the abundance of hydro-electric generating resources which produced a system rich in generating capacity and flexibility. However, as the region has retired many thermal power plants, increased integration of renewable resources, and as the hydro-electric system flexibility has declined, the region finds itself transitioning into a peak-constrained system. In 2019, many of the Western Power Pool (WPP) entities began an effort to create a voluntary Resource Adequacy (RA) program to set regional standards for planning methods and metrics, provide load and resource diversity savings, and establish a robust procurement process. We support this effort and are using the work of the WPP RA effort to help determine our future resource needs.

The next 10 years are sure to be exciting ones for Grant PUD. Growth in our customers' requirements as well as regional changes and concerns are creating complex and interrelated uncertainties. Wholesale Marketing and Supply's mission is to navigate these uncertainties and provide the most value possible to our customers. This requires maximizing the potential of our hydro projects while finding the most reliable, least-cost, and lowest-risk options to meet customer needs. This 2022 IRP is our roadmap to achieving these goals.

Rich Flanigan
Senior Manager of Wholesale Marketing and Supply

Resolution No. 8996

A RESOLUTION AUTHORIZING AND APPROVING THE 2022 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 1, 2022, Grant PUD adopt an Integrated Resources Plan which includes:

   (a) A range of forecasts, for at least the next ten years, 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 ten-year forecast of the availability of regional generation and transmission capacity on which the utility may rely to provide and deliver electricity to its customers;

   (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; and

(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 26, 2022;

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 General Manager/Chief Executive 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 23 rd day of August 2022.

Judy H. Wilson
President

ATTEST: Tom Flint
Secretary

Vice President

Commissioner

Larry Schaapman
Commissioner

List of Contributors

Rich Flanigan	Senior Manager Wholesale Marketing and Supply	IRP Core Team
Dr. Wesley Cole	Project Specialist	IRP Core Team
Michael Frantz	Senior Power Supply Analyst	IRP Core Team
Phillip Law	Term Marketer	IRP Core Team
Lisa Stites	Lead Financial Analyst	IRP Core Team
Richard Cole	Customer Solutions Program Supervisor	Energy Efficiency
Mitchell Delabarre	General Counsel/Chief Legal Officer	Legal
Melissa Lyons	Senior Term Marketer	Policy and Regulations
Susan Manville	Manager of Transmission	Transmission and Deliverability
Rodney Noteboom	Transmission Services	Transmission and Deliverability
Amanpreet Singh	Economist	Load Forecasting
Louis Szablya	Senior Manager Large Power Solutions	Large Power Customers
Lindsay Thompson	Communications Specialist	Communications

Table of Contents

List of Figures

List of Tables

List of Acronyms and Abbreviations

Acronym: Definition

A

aMW: Average MegaWatt ·
ARS: Automatic Resource Selection ·

B

BPA: Bonneville Power Administration ·

C

CAISO: California Independent System Operator ·
CCA: Climate Commitment Act ·
CEAP: Clean Energy Action Plan ·
CEIP: Clean Energy Implementation Plan ·
CETA: Clean Energy Transformation Act ·
CPA: Conservation Potential Assessment ·

D

DC: Direct Current ·

E

EIA: Energy Independence Act ·
ELCC: Effective Load Carrying Capability ·
EUDL: Estimated Unmet District Load ·

G

GHG: Greenhouse Gas ·

I

IRP: Integrated Resource Plan ·

K

kcfs: Thousand cubic feet per second ·

M

Mid-C: Mid-Columbia Trading Hub ·

MVA: Megavolt amperes ·
MW: MegaWatt ·

N

NWPP: Northwest Power Pool ·

P

PRP: Priest Rapids Project ·
PUD: Public Utility District ·
PV: Photovoltaic ·

R

RCW: Revised Code of Washington ·
RECS: Renewable energy credits ·
RICE: Reciprocating Internal Combustion Engine ·
RPS: Renewable Portfolio Standard ·

S

SMR: Small Modular Reactor ·
SPP: Southwest Power Pool ·

W

WECC: Western Electric Coordinating Council ·
WEIM: Western Energy Imbalance Market ·
WPP: Western Power Pool ·
WRAP: Western Resource Adequacy Program ·

Z

ZEV: Zero Emissions Vehicle ·

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. Analysis shows that load growth, increased focus on system adequacy concerns, and resource-specific regulatory requirements, including the Energy Independence Act (EIA) and the Clean Energy Transformation Act (CETA), will require us to acquire additional capacity and energy resources over the 10-year planning period.

Utilizing our current portfolio, and considering our 2021 Sales and Load Forecast, Grant PUD:

- has sufficient resources to meet forecast energy requirements through the expiration of our pooling agreement in 2025
- will need to obtain additional capacity resources to increase our capacity margin for potential future resource adequacy requirements
- has sufficient resources to meet the renewable portfolio standard of the EIA through 2028
- will need to obtain additional clean energy resources to meet primary CETA compliance beginning in 2030.

Given current projections of future load growth, technology performance and resource costs, this analysis determines that obtaining the following additional resources, as well as utilizing wholesale markets, alternative regulatory compliance including the purchase of renewable energy credits (RECs), and continued investment in cost-effective conservation, would reliably provide for customer needs and clean energy requirements through 2031. Resources could be obtained either through purchase agreements or built by Grant PUD. Acquisition of clean energy resources beyond what is required for interim CETA compliance could be utilized to benefit customers through a decrease in revenue requirements.

Table 1. Modeled portfolio additions by year, nameplate capacity in MW

Technology	Present – 2025	2026 - 2028	2029 - 2031	Total
Solar	170	300	200	670
Solar with Battery Storage	100	0	70	170
Wind	100	0	0	100
Gas – RICE	180	90	0	270
Total	550	390	270	1,210

While the portfolio additions proposed here were assessed under currently available information as the most cost-efficient means of reliably meeting customer needs into the future, we commit to continued, ongoing evaluation of available alternatives. Alternatives or complements to the modeled portfolio warranting additional evaluation include, but are not limited to, Bonneville Power Administration (BPA) Tier 1 or Tier 2 power, and small modular nuclear reactor (SMR) technology. Prior to any resource acquisition or contractual agreement, additional evaluation of alternate strategies will occur.

In compliance with RCW 19.280, we will submit the following integrated resource plan cover sheet to the Department of Commerce by September 2, 2022.

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

	Base Year			5-Year Estimate			10-Year Estimate		
Estimate Year	2021			2026			2031		
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	MW	MW	aMW	MW	MW	aMW	MW	MW	aMW
Loads	833.57	929.18	639.33	1008.99	1146.55	821.73	1134.57	1289.25	923.95
Exports									
Resources:									
Future Conservation/Efficiency				8.14	8.40	8.27	17.91	18.91	18.41
Demand Response									
Cogeneration									
Hydro	114.46	124.00	117.74	1089.19	1011.29	628.70	1142.00	1059.18	638.90
Wind	0.93	1.56	3.52	8.74	12.85	50.10	7.80	10.47	46.82
Other Renewables				62.95	82.30	93.85	114.40	149.41	210.57
Thermal – Natural Gas				198.00	198.00	11.51	270.00	270.00	5.91
Thermal – Coal									
Net Long-Term Contracts	702.73	788.18	401.59						
Net Short-Term Contracts			110.57			23.90			-2.06
BPA	15.44	15.44	5.90	15.44	15.44	5.40	15.44	15.44	5.40
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	833.57	929.18	639.33	1382.46	1328.28	821.73	1567.55	1523.41	923.96
Load Resource Balance	0.00	0.00	0.00	373.47	181.73	0.00	432.98	234.16	0.00

2 | Requirements and Objectives

Grant PUD has developed this IRP to assess our 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 should be viewed as a decision support tool as we continually work to support our mission:

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

REQUIREMENTS FOR INTEGRATED RESOURCE PLANNING AND OBJECTIVES

The state of Washington has provided regulations for 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. The intent of this chapter of the Revised Code of Washington (RCW) is to encourage the development of safe, clean, and reliable energy resources. Information from the integrated resource plans that are developed will 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 ten-year forecast of the availability of regional generation and transmission capacity on which the utility may rely to provide and deliver electricity to its customers;

(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;

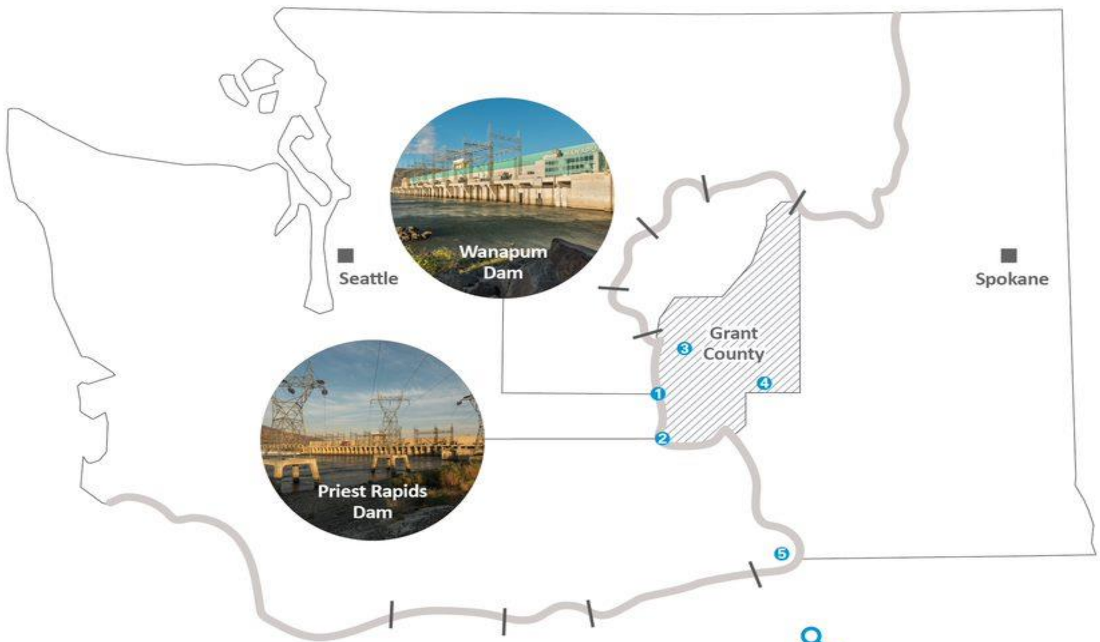
(1k) An assessment, informed by the cumulative impact analysis conducted under RCW 19.405.140, of: Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and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

3 | Existing Resources



❶ WANAPUM DAM

Generation Units 10
Rated Capacity . . . . .1,221.7 MW
Concrete/Earthfill Length . . . . 8,637 FT
Rated Head . . . . 80 FT
Construction Started 1959
First Power Generation 1963

❷ PRIEST RAPIDS DAM

Generation Units 10
Rated Capacity . . . . 950 MW
Concrete/Earthfill Length . . . . .10,103 FT
Rated Head . . . . 78 FT
Construction Started 1956
First Power Generation 1959

❸ QUINCY CHUTE HYDROELECTRIC PROJECT

Rated Capacity . . . . .9.4 MW
First Power Generation 1985

❹ POTHOLES EAST CANAL HEADWORKS PROJECT

Rated Capacity . . . . .6.5 MW
First Power Generation 1990

❺ NINE CANYON WIND PROJECT

12.5% of Project Peak Capacity . . . . 12 MW
First Power Generation 2003

Figure 1. Map of Grant County PUD existing electric generating resources.

SUPPLY SIDE RESOURCES

Figure 1 illustrates the portfolio we currently utilize to generate and deliver power to our customers. The backbone of this portfolio are the two Columbia River dams, Wanapum and Priest Rapids, collectively referred to as the Priest Rapids Project (PRP). In addition to 63.31% of the physical resources of PRP, Grant PUD also holds financial rights to up to an additional 30% of the project. Additionally, our portfolio includes contracts for the output of two irrigation projects, a share of a wind facility, and resources supplied by BPA. Each of these is described in more detail below.

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 18 miles upstream of the Priest Rapids Development, the Wanapum Development includes certain switching, transmission, and other facilities necessary to deliver electric output to the transmission networks of Grant PUD, BPA, and certain other power purchasers. We hold the 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 certain switching, transmission, and other facilities necessary to deliver the electric output to the transmission networks of Grant PUD, BPA, and certain other power purchasers. We hold the rights to 63.31% of this development.

Together, Wanapum and Priest Rapids Developments, collectively called PRP, provides Grant PUD with attributes including energy, capacity, ancillary services, energy storage, and carbon-free attributes. These large hydroelectric resources have been Grant PUD's foundational supply of carbon-free electricity.

EUDL Market Purchases

Grant PUD has the right to receive financial resources from the Priest Rapids Project to purchase power to serve the Estimated Unmet District Load (EUDL). These financial resources are limited to approximately 30% of the market value of the output of PRP. The amount of the 30% limit available to us is calculated annually based on our load requirements and portfolio resources. The EUDL mechanism allows us to serve load up to this approximate 30% of PRP output at the net cost of PRP production. This is a financial position that must be converted to a physically firm position though the course of our hedging strategy. The energy and capacity derived from this financial resource is not received directly from PRP output but through using the share of revenue to procure market purchases.

Figure 2 illustrates the total proceeds from the sale of 30% of PRP versus our contractual share of those proceeds for the period 2014 through 2022. While the EUDL proceeds have been sufficient to meet system load requirements in the past, it is anticipated that, at forecasted load growth rates, the cost of unmet load requirements will exceed the funds available through the EUDL mechanism by 2025.

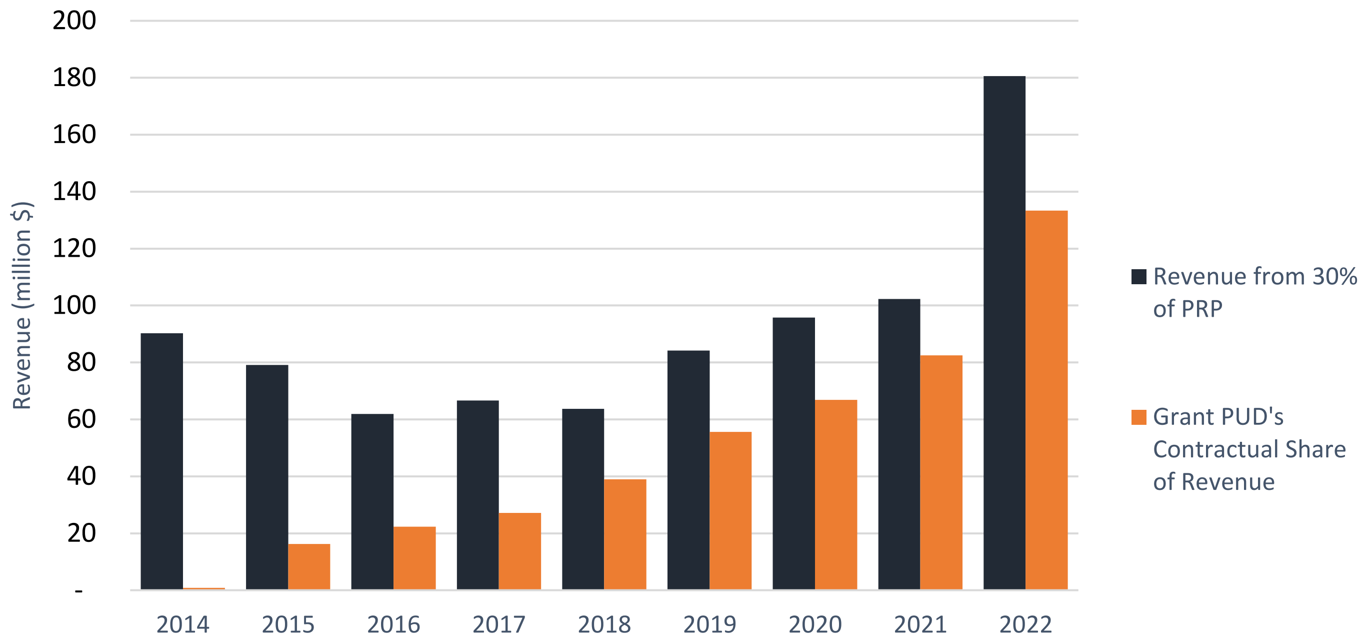


Figure 2. Revenue from sale of 30% of Priest Rapids Project and revenue allotted to Grant PUD for the EUDL

Quincy Chute Project

Under an agreement with the East, 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. We financed, designed, and constructed the project and are 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 East, 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. We financed, designed, and constructed the project and are 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.

DEMAND SIDE RESOURCES

Conservation and Efficiency

In accordance with the EIA, in 2021 we conducted a biennial Conservation Potential Assessment (CPA) to estimate the conservation potential for the 20 year planning period of 2022 to 2041. The CPA evaluated four sectors: residential, commercial, industrial, and agricultural. The industrial sector is where we could potentially receive the greatest gains by installation of more energy efficient cooling and power supplies in data centers, converting to more efficient lighting, upgrading refrigeration storage, and performing cold storage equipment tune-ups and retrofits. The commercial sector represents the second greatest potential for conservation from lighting and HVAC upgrades.

Table 3 illustrates CPA findings of the cost-effective capacity and energy potential of the sectors examined. The full CPA report is attached as Appendix 3.

Table 3. Cost effective conservation energy potential from 2021 CPA (aMW)

Sector	2-Year	4-Year	10-Year	20-Year
Residential	0.13	0.65	2.57	7.01
Commercial	0.43	1.20	6.63	20.68
Industrial	3.98	4.32	8.71	18.13
Agricultural	0.02	0.06	0.50	1.33
Total	4.57	6.24	18.41	47.15

Demand Response

In 2021, we conducted an Electric Demand Response Potential Assessment in a manner consistent with requirements of the Washington Clean Energy Transformation Act. The study evaluated resources available over the period 2022-2031. Results showed demand response resources to be relatively expensive compared to supply side resources. We do not currently offer demand response programs to our customers.

EXISTING 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, we have entered into wholesale slice and pooling agreements to sell capacity and energy from our retained 63.3% share of the PRP output. We also participate 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 our ability to maintain a strong financial position while maintaining stable and predictable retail prices.

Slice Contracts

We employ 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 our PRP capacity and energy to buyers who then assume the associated water availability and wholesale price risks. We then use 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. The slice agreements are paid in equal monthly installments over the term of each agreement. We regularly monitor our 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. We obtain stable revenues from these contracts and realize 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 and ultimately reducing the energy burden of our customers. However, these contracts impact our ability to claim PRP output for EIA and CETA compliance (See Section 4.) Currently, we have two slice contracts for a total of 30% of PRP output, the last of which expires December 31, 2024.

Pooling Agreements

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

Under the terms of our 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 our load. The counterparty provides this power regardless of the actual output of the PRP. The counterparty also provides certain 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 made accordingly. Our current pooling agreement, for 33.31% of PRP expires September 29, 2025.

Under our current pooling agreement, to meet compliance with the EIA and CETA, we have 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 our ability to claim PRP output toward EIA and CETA compliance.

For the years 2019-2025, our 63.3% retained share of PRP output has been allocated to pooling and slice agreements as shown in Figure 3.

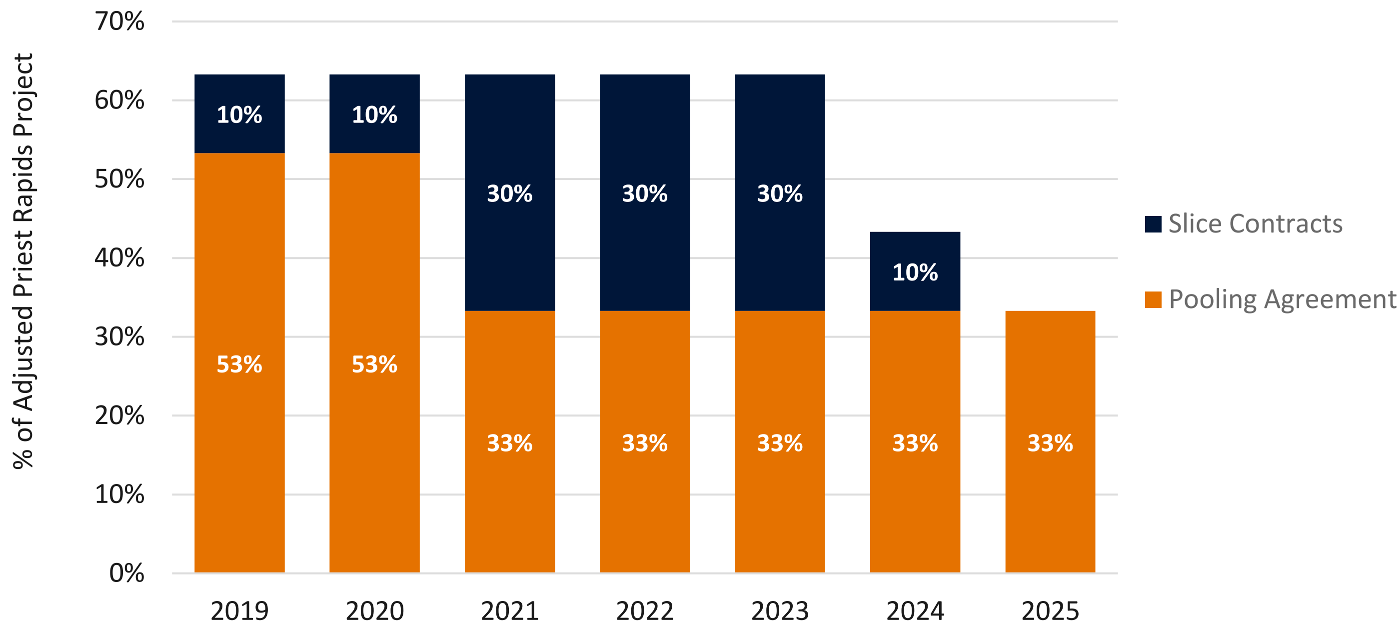


Figure 3. Priest Rapids Project slice contracts and pooling agreements from 2022-2025.

Bonneville Power Administration Contracts

Grant PUD holds a priority firm power contract with BPA, effective October 1, 2011, and terminating October 1, 2028, that provides for service of our loads in the Grand Coulee area. The priority contract covers a small area not interconnected to our transmission system, representing roughly 1%, or approximately 5 aMW, of our total load. We do not currently have a contract with BPA to serve other load but do have the option to exercise our statutory rights to apply for more priority power from BPA after 2028. We intend to maintain this option to secure a significant post-2028 priority contract with BPA and are actively working with the region's preference customers and participating in BPA's Provider of Choice process that will determine the structure of new contracts offered by BPA.

Wholesale Trading

Grant PUD engages in wholesale trading activity to moderate portfolio risk and to stabilize energy costs and revenue. We currently operate within the Western Electric Coordinating Council (WECC). Within the WECC, there are numerous bilateral trading hubs. We currently rely 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 our customers' energy needs.

4 | Key Considerations

As we have worked to develop plans for meeting our customers' long-term power supply needs, several key considerations have been assessed. We expect these considerations, discussed below, to be significant drivers of uncertainty, and change for us over the next decade and beyond. We believe an informed understanding and ongoing evaluation of these factors is essential for ensuring we meet our objective of providing a reliable, cost-effective power supply for our customers.

LOAD

Evolving Customer Requirements

Early in our history, Grant PUD's retail load consisted primarily of irrigation, residential, and small commercial customers with traditional Industrial customers accounting for less than 20% of our load. Beginning in the early 1980's, this began to change. Within a decade, while our total load grew by 70%, industrial loads grew by almost 250%. This period of rapid industrial growth can be clearly seen in Figure 4 as starting in the early 1980's and continuing through 1991. That initial rapid growth in the 1980's was followed by a period of lackluster growth, and from 1991 to 2000, while the total loads grew by over 30%, industrial loads grew only 3%. It was not until the early 2000's that there was a noticeable change in the growth rate of Industrial loads. Data Centers were not the initial increase during that period but have, since 2010, grown to dominate load growth in the sector. Over the last 10 years, Industrial class load growth has made up an ever-increasing portion of our total retail load.

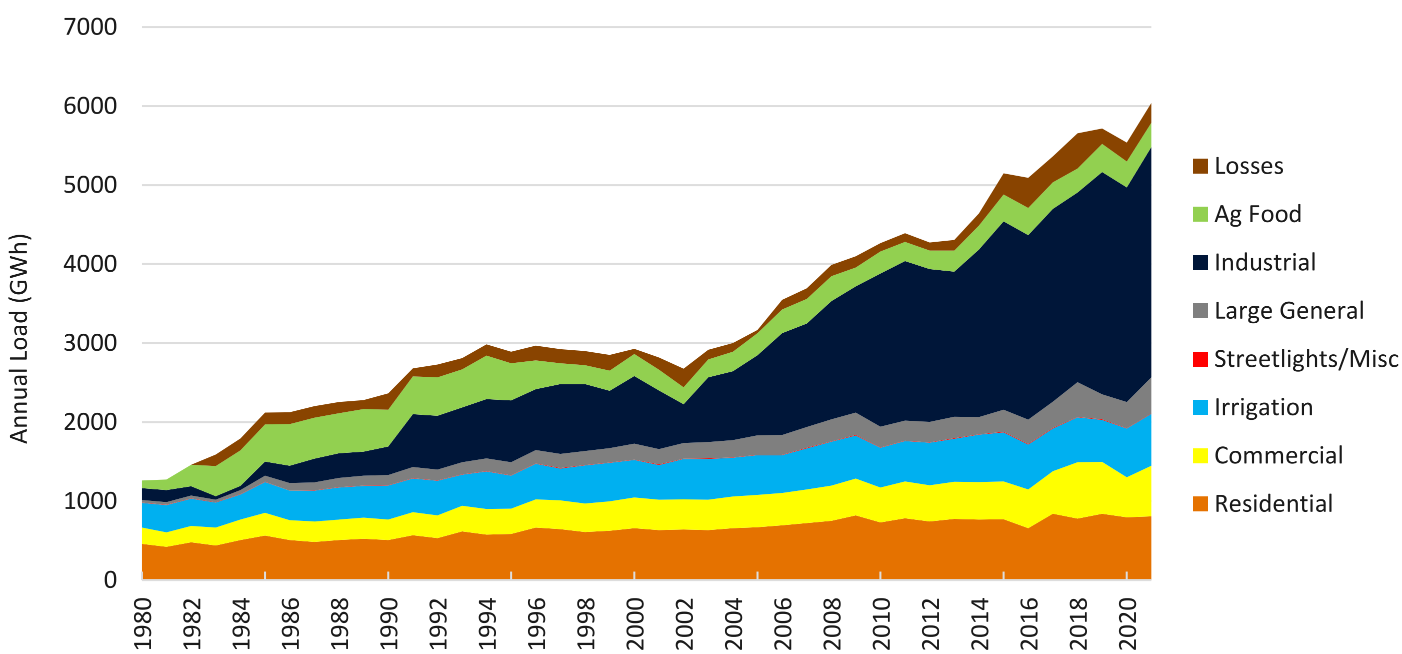


Figure 4. Grant PUD retail load by customer class, 1980 through 2021

The Source of Growth

In addition to the Industrial class, two other rate classes have experienced growth rates greater than the average: Large General, Industrial and Ag Food.

Large General, Industrial and Agricultural Food Processing loads which are generally greater than 500 kW make up a group we categorize as Large Loads. Large Load accounts are spread among seventeen industries as show in Table 4 below.

Table 4. 2021 Large Loads by industry

Industry	Average Number of Service Agreements	Load (aMW)	Average Size (MW)
Data Center	14	203.3	14.5
Chemical	6	40.9	6.8
Ag. Processing	59	39.8	0.7
Electronics	1	26.5	26.5
Automotive	3	25.6	8.5
Cryptocurrency	18	14.4	0.8
Gas / Fluids	3	7.0	2.3
Ag. Storage	12	6.6	0.6
Minerals / Metals	7	6.1	0.9
Medical / Health	6	5.7	1.0
Manufacturing	6	3.9	0.7
Utility / Government	19	2.4	0.1
Retail	12	2.4	0.2
Education	13	1.6	0.1
Aerospace	4	1.2	0.3
Cannabis	6	0.8	0.1
Construction	4	0.2	0.1
Total	**193**	**388.4**	**2.0**

Figure 4 shows that growth of the Large Load Group constitutes the bulk of the total growth over the last ten years to the point that in 2021, Large Load Customers represented over 60% of our total load. Between 2012 and 2021, Large Loads have grown at a compound annual growth rate of 3.9% while all remaining load classes grew at only 1.8%. In the last 20 years Large Loads compound annual growth rate is 5.7% compared to the remaining loads' 1.9% rate. We believe that this is long term trend of load growth concentration in the Large Load customer classes could continue into the future. 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 (see Figure 4 for the period 2000 through 2004 for example.)

The ten-year compound annual load growth varies materially between customer class as shown in Figure 5. Residential loads have been growing at a rather staid 0.3% but Commercial and Irrigation loads have seen much more growth at 3.3% and 2.6% respectively, for a total compound annual growth rate for those classes of 1.9%. Streetlights show negative growth, largely due to increased efficiencies associated with LED adoption.

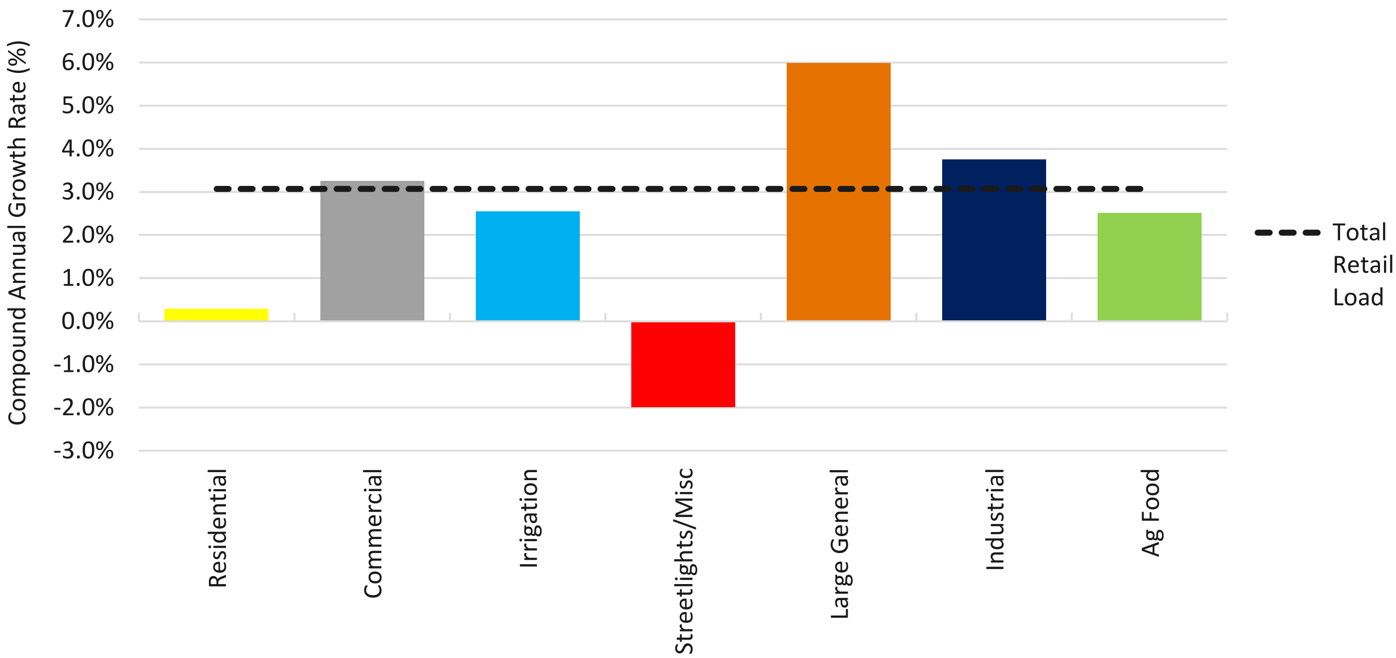


Figure 5. Grant PUD ten-year compound annual growth rate by customer class

Forces Driving Customer Demand

Understanding the forces currently driving customer energy demand, and anticipating future trends, is key to deriving a plan to meet those needs. We believe customers are attracted by Grant PUD's competitive electric rates, advantageous location, and potential for green energy supply. We have received input from Large Load customers that their current and future energy demands are sensitive to many market pressures including environmental and social goals but that the cost of the energy we supply is the dominant factor. We believe competitive rates are critical to both retaining existing Large Loads and to attracting significant growth in the sector. Conversely, we believe upward pressure on rates could lead to decreased levels of load growth.

Customer loads are also sensitive to power quality including voltage, harmonics, and outage frequencies and durations. Data centers, the industry with the current largest load share of our Large Load customers, are particularly demanding. These customers are high load factor power consumers, with consistent high-quality power availability critical to their operational success. We realize that any plan crafted to meet customer needs into the future must consider resource capacity factors, as well as reliability and deliverability characteristics.

Price, reliability, and deliverability sensitivity in the fastest growing rate classes introduces a 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 expectations of customers, and will incorporate these concerns into our long-term planning.

Load Forecast

This IRP uses Grant PUD's 2021 Annual Sales and Load Forecast to inform the analysis of customer energy demands 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. The models forecast monthly load by individual rate schedule. Rate schedules are described in Table 5.

Table 5. Customer Class and Rate Schedules

Customer Class	Rate Schedule	Description
Residential	1	Single family dwelling, individual apartment, and farmhouse with single-phase service
Commercial	2	Loads not exceeding 500 kW for general service, commercial, multi-residential and miscellaneous outbuilding requirements and single-phase loads not exceeding 500 Watts.
Irrigation	3	Irrigation, orchard temperature control and soil drainage loads not exceeding 2,500 horsepower and other miscellaneous power needs including lighting
Streetlights	6	Street lighting
Large General	7	Loads not less than 200 kW or more than 5,000 kW demand for general service lighting, heating, and power requirements.
Industrial	14 and 15	Industrial customers, with a distinction between demand less than or greater than 15 MW/MVA
Ag Food	16	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	17	Groups of industries or uses that collectively consume r could consume more than 5% of the 's total load and that present concentration risk and either business or regulatory risk.
Ag Food -Boiler	85	Electric boilers which are separately metered and primarily used for the purpose of processing, canning, or freezing agricultural food crops
New Large Load	94	All New Large Loads, as defined by the District's Customer Service Policies.

Once monthly loads are forecast by rate class, they are then aggregated and 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 2021 Annual Demand Forecast are referred to throughout this document as the reference load growth case. Figure 6 illustrates both the monthly forecasted energy for load, as well as the forecast monthly peak requirements from the reference case.

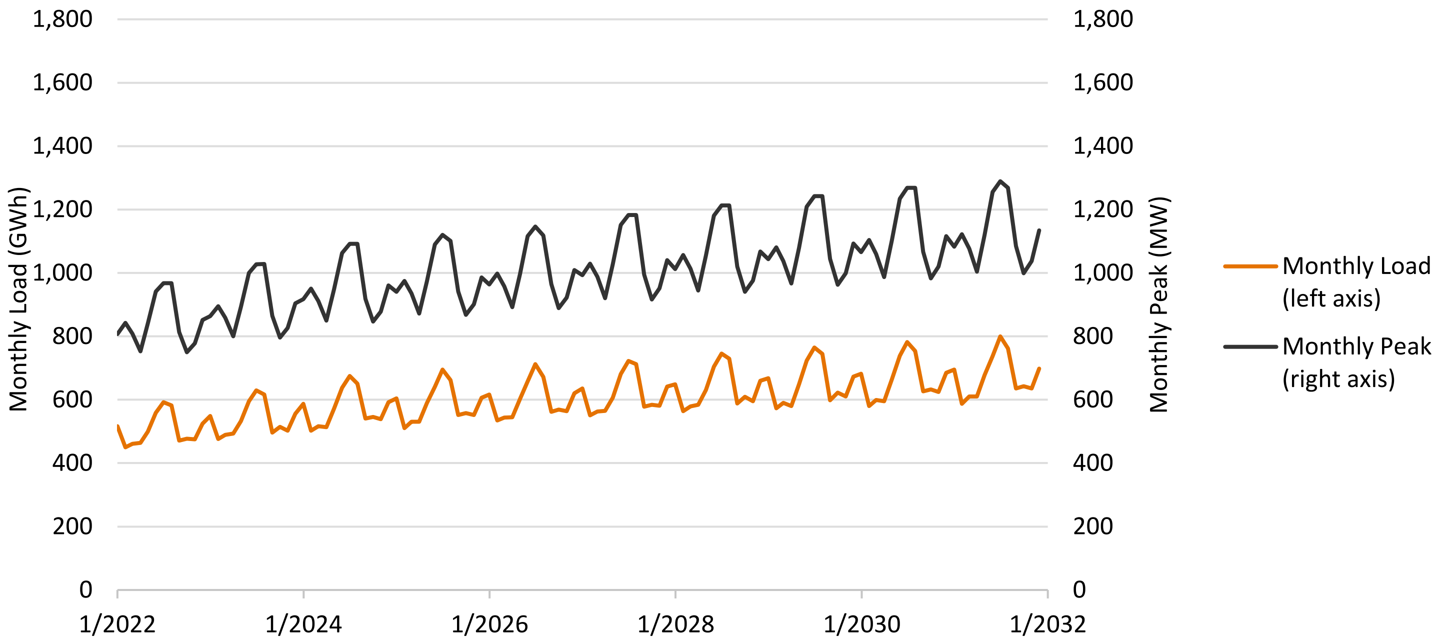


Figure 6. Monthly projected load and monthly projected peak for reference case used in modeling work

Figure 7 shows both historic values through 2021 and the reference case forecast by customer class for 2022 through 2031, illustrating the expected variation in load growth between customer classes and highlighting the forecast increase in load share of our industrial customer class.

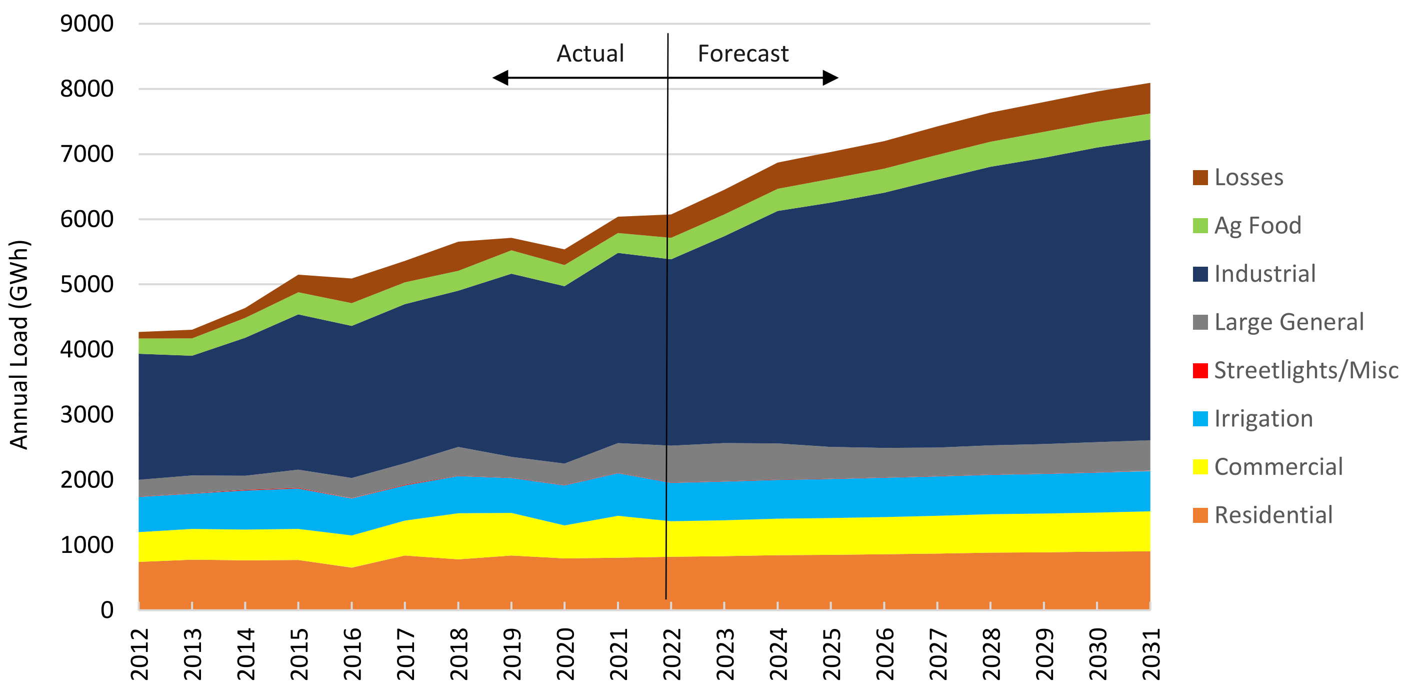


Figure 7. Actual and forecasted load, 2012-2031

Because load growth is both a key driver of resource needs and is highly uncertain, this plan considers two additional load growth sensitivities:

- Low Load: defined as an overall system growth rate 50% lower than the reference load growth case
- High Load: defined as an overall system growth rate 50% higher than the reference load growth case

These alternative load growth scenarios, illustrated in Figure 8, are not intended as predictions but used only to explore the impact of load growth on the type, timing, and magnitude of resource selections. It should be noted that the high load growth condition is unlikely to be currently feasible from an infrastructure standpoint. Evaluation of load growth conditions higher than our reference case also serves to help determine what type of infrastructure might be required to accommodate higher than expected load growth.

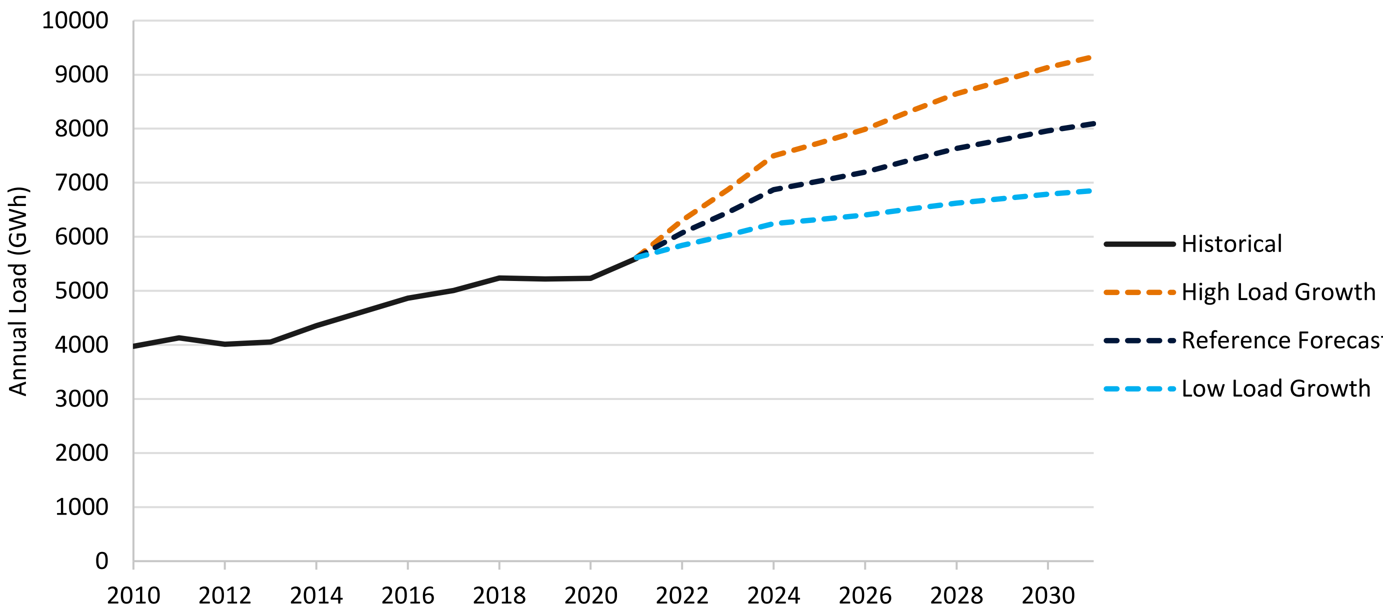


Figure 8. Forecasted annual load for Grant PUD service territory for three conditions of load growth.

Using the reference case load forecast, we can formulate expectations of the ability of our current resource portfolio to meet customer requirements. Figure 9 shows the projected generation capability of our current resource portfolio versus forecast system load. Our portfolio is well positioned to meet customer energy requirements through the expiration of our pooling agreement in 2025. Please note that that while we routinely rely on wholesale market participation to provide energy to our customers, to moderate portfolio risk, and to stabilize energy costs and revenue, to highlight our current portfolio, market resources and participation are not reflected in Figure 9. This in no way indicates our intent to discontinue those trading practices.

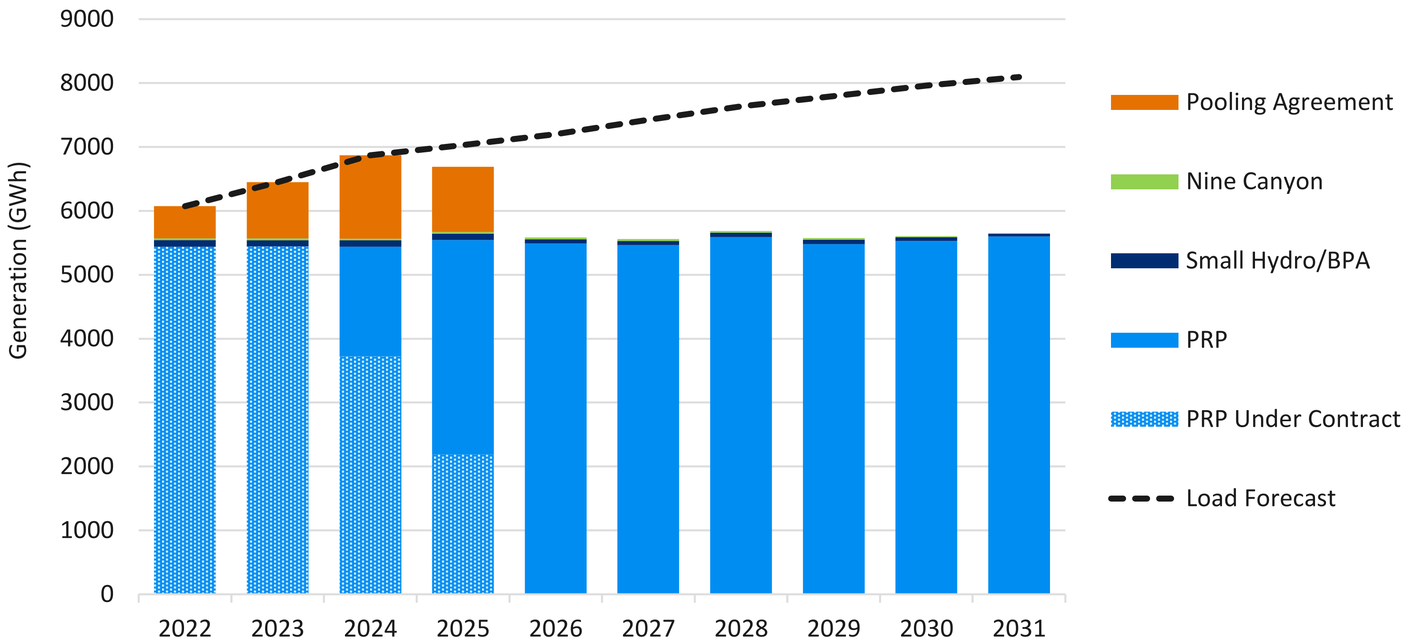


Figure 9. Annual energy generation expectations vs. load forecast, current portfolio

CHANGING POWER MARKETS AND SYSTEM CONDITIONS

Western Resource Adequacy Program (WRAP)

The Pacific Northwest's bulk electricity system is in transition. Historically it has been one of the least capacity constrained regions of the electric grid due to the presence of a significant amount of hydro-electric generating resources. These resources produced a system rich in generating capacity and flexibility, though subject to annual variations due to variable precipitation and snowpack. As the region adds increasing amounts of renewable resources, retires greenhouse gas emitting generation sources, and as hydro-electric system flexibility declines, the region finds itself transitioning into a capacity-constrained system.

Currently, most utilities in the Northwest conduct their own reliability studies. This lack of centralized planning, and use of varying methods and metrics, contains inherent risks for meeting region-wide and utility-specific goals to provide reliable power into the future. This risk is increased due to the changes in market participation, and policy driven shift to clean energy sources taking place in the region.

In response to growing concerns, in 2019 a coalition of stakeholders, acting through Northwest Power Pool (NWPP, Now WPP, Western Power Pool) began an effort to develop a voluntary resource adequacy (RA) program. The proposed RA program, referred to as the Western Resource Adequacy Program (WRAP), aims to set regional standards for planning methods and metrics, provide load and resource diversity savings, and establish a robust procurement process.

WRAP is expected to have a forward-showing period in which participating entities would be called on to prove they meet established regional metrics that ensure reliability. Penalties would be assessed if these metrics could not be proved. The program would also have an operational component that would unlock the load and resource diversity benefits in times of stress across the region. Currently 26 participants across the west, representing over 66 GW of summer peak load, are taking part in a non-binding preliminary phase. Current timelines project that WRAP be fully operational by summer 2025 (WPP 2022).

There are many challenges that will need to be overcome for establishing an RA program unique to the Northwest, including the lack of an organized market administrator, the large number of public utilities, the significant amount of hydropower resources and the size and role of Bonneville Power Administration (BPA). In addition, questions remain on how WRAP might coexist with energy imbalance and day-ahead markets. We are currently participating in the design of WRAP and using this effort to better understand and design our own RA response.

In recognition of the developing WRAP, and our internal need to ensure an adequate and reliable energy supply to its customers, a 15% planning reserve margin, calculated as a percentage of each forecast annual peak load, is used in the development and selection of the resource plan shown in this IRP. This planning capacity margin is intended to be adequate to cover most prolonged resource outages, variations in weather and water availability, and uncertainty in load projections. It is also consistent with values used by other regional entities including the planning reserve margin adopted by the California Public utilities Commission for CAISO (Dupre et al. 2021) and used by WECC in its 2021 "Western Assessment of Resource Adequacy" (WECC 2021).

Using the reference case load forecast and the 15% planning reserve margin, we are able to formulate expectations of the ability of our current portfolio to meet potential future capacity requirements. Figure 10 shows the forecast ability of our current resource portfolio to meet potential firm capacity requirements. The portfolio is able to meet expected peak requirements through 2025. It should be noted that although we have, in the past, used market purchases to meet capacity requirements, and may choose to continue to do so in the future, for purposes of this illustration, market participation is not shown in Figure 10.

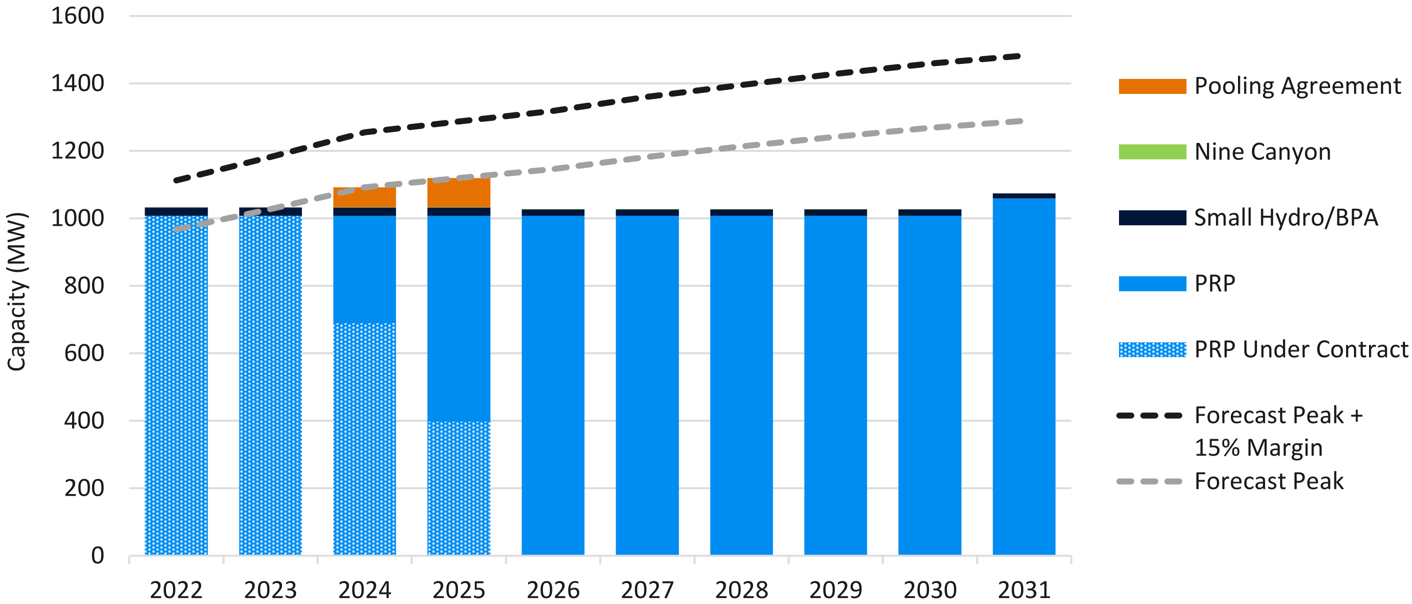


Figure 10. Current portfolio capacity vs. potential capacity requirements under WRAP

Real-Time Electricity Market

Many of the same forces driving RA concerns, and development of the WRAP, impact the increasing value of real-time electricity markets in the Northwest. Real-time markets enable participants to essentially pool their generating resources to more reliably and cost effectively dispatch those resources to serve load, reducing operational costs, improving integration of renewable resources, potentially reducing individual participants' needs to hold reserves, and improving overall grid reliability.

In 2014, the California Independent System Operator (CAISO) began operation of the Western Energy Imbalance Market (WEIM.) Through the WEIM, CAISO extends the benefits of a real-time market to participants outside of its territory. According to a WEIM calculation comparing their market dispatch to a counterfactual dispatch without WEIM, participants have received more than $2 billion in benefits since market opening (CAISO 2022b).

As of May 2022, the WEIM has nineteen active participants with three additional entities anticipating entry in 2023. Figure 11 shows the current footprint of participant boundaries and illustrates that Grant PUD is geographically surrounded by WEIM participants. With growing WEIM participation, we believe that non-participants will become increasingly economically distinct from participants.

Figure 11. Footprint of active and pending WEIM participants (CAISO 2022b)

For the purposes of this IRP, we do not make assumptions regarding our future real-time market participation. However, the impacts of WEIM are indirectly captured through forward-looking trading hub assumptions used in this plan. This IRP does assume that we will retain the ability to participate in wholesale trading activity.

Day-Ahead Electricity Market

While energy imbalance markets, including WEIM, provide a venue for trading energy in real time, and have led to considerable operational savings in the West, the energy traded on the imbalance markets represents a relatively small share of the overall energy traded across the West. Day-head markets facilitate joint unit commitment along with real-time energy trading and have the potential to deploy resources more efficiently across the region. Coordinated day-ahead markets serve to lower production costs and increase utilization of renewable energy resources that might otherwise be curtailed.

Though no day-ahead market currently exists in the West outside of California, both CAISO and the Southwest Power Pool (SPP) are pursuing day-ahead market frameworks for the West, via the Extended Day-Ahead Market and Markets+, respectively. In May 2022 CAISO released a strawman proposal for the Extended Day-Ahead Market (CAISO 2022a), and SPP has plans to release a strawman proposal in late 2022 (SPP 2022). Both market operators are attempting to move quickly while providing robust solutions for interested stakeholders.

For the purposes of this IRP, we do not make assumptions regarding our future day-ahead market participation. However, the impacts of these markets are indirectly captured through forward-looking trading hub assumptions used in this plan. This IRP does assume that Grant PUD will retain the ability to participate in wholesale trading activity.

Regional Resource Mix Evolution

The Western Interconnection is undergoing rapid change, both in the market structure that can facilitate the sharing of resources across Western utilities, as well as in the resource mix used to serve regional load. Figure 12 shows the share of existing capacity by fuel type for the Pacific Northwest as of January 2021 (NWPCC 2022).

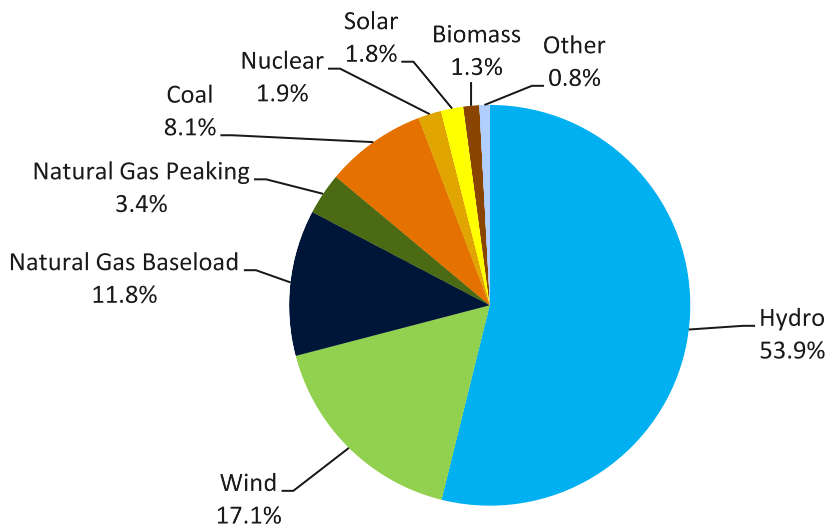


Figure 12. Percentage of capacity by fuel type in the Power Act region or contracted to Pacific Northwest loads. Other includes geothermal, petroleum, pumped hydropower storage, and battery storage. Total installed nameplate capacity is 64,340 MW. Values are from January 2021 and based on inputs to the 2021 Power Plan (NWPCC 2022).

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 (EIA 2021). However, new regional capacity is expected to come from other resource types, reducing the overall percentage share of hydropower. Figure 13 shows the projected capacity additions for the Pacific Northwest from the Northwest Power and Conservation Council's 2021 Northwest Power Plan (NWPCC 2022). The projection relies heavily on the addition of variable renewable energy and storage, and, with the exception of natural gas, does not show much growth in resources that have traditionally been used to serve the bulk of the load in the region. The shift in resource mix expected from these additions is driven by cost reductions, state and federal policy actions, and voluntary procurement of clean energy resources, and will change the way the grid operates and how utilities in the region transact power with one another.

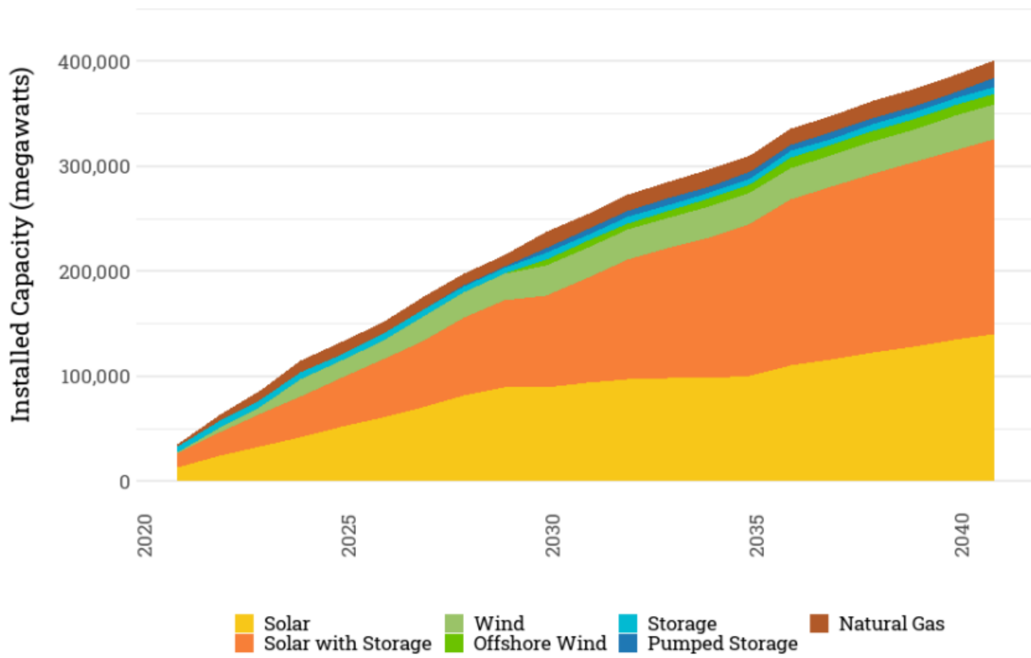


Figure 13. Projected new capacity from the Northwest Power and Conservation Council's 2021 Northwest Power Plan for the Pacific Northwest (NWPCC 2022)

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 our 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 seen a significant depression in daytime prices and an increase in evening prices due to the large buildout of solar resources (Mills et al. 2019). With the anticipated large buildout of wind and solar resources in the region, similar pricing dynamics are likely to manifest themselves in the Pacific Northwest.

POLICY AND REGULATIONS

Grant PUD faces uncertainty regarding the full magnitude and cost of clean energy and carbon-focused legislative action. Washington State has passed significant carbon emission reduction legislation with the adoption of CETA and the Climate Commitment Act (CCA). While the rule making for CETA is largely finished, the implementation impacts are not fully known. The law serves to eliminate the use of coal-sourced generation by 2025, requires carbon neutral generation by 2030 and has an ultimate target of 100% greenhouse gas (GHG) emission-free generation by 2045. The CCA is a cap-and-invest program which caps and reduces carbon emissions from the state's largest emitting resources, including the electricity sector, starting in 2023. The program allows for the sale and tracking of tradable emissions allowances and the rules are designed to allow for linking the program with similar programs in other jurisdictions. The CCA rulemaking is ongoing and is not anticipated to be finalized until late 2022.

Clean Air Rule

In 2008, the Washington State Legislature passed, and the governor signed, legislation requiring reductions in GHG emissions, initiating GHG reporting requirements, and requiring the Department of Ecology to make recommendations for the development of a market-based cap and trade system (RCW 70.235). In 2016, the Washington State Department of Ecology adopted the Clean Air Rule (WAC 173-442), which addressed the major sources of greenhouse gases, including certain electric generators and fuel suppliers in Washington and required businesses that are responsible for large amounts of greenhouse gas emissions to cap and reduce their carbon emissions. Grant PUD is not a covered entity under the rule. However, implementation of the law affects the electric sector and potential demand for clean electricity in Washington State. Some large industrial customers in Grant County could be affected.

In March 2018, Thurston County Superior Court ruled that parts of the Clean Air Rule were invalid. The Superior Court's ruling prevented Ecology from implementing the Clean Air Rule regulations. On January 16, 2020, the Washington State Supreme Court ruled that the portions of the rule that applied to stationary sources were upheld, but that the portions that applied to indirect sources, such as natural gas distributors and fuel suppliers, representing the majority of emissions, were invalid. The Supreme Court remanded the case to Thurston County Superior Court to determine how to separate the rule.

While this rule is not currently affecting Grant PUD or its industrial customers, we will continue to monitor efforts to modify the rule or to grant additional authority to Ecology to regulate indirect GHG emissions.

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 by 2020.

Beginning in 2010, qualifying utilities are required to, biennially, make public a target for conservation consistent with its identification of achievable opportunities. Qualifying utilities are required to meet their targets during the subsequent two-year period. Opportunities for conservation are identified using methodologies consistent with those used by the Pacific Northwest Electric Power and Conservation Planning Council.

In compliance with EIA, Grant PUD has completed our 2021 conservation potential assessment, covering the time period 2022 – 2041. The report of this assessment is attached as Appendix 1. By adoption of Resolution No. 8974 in November of 2021, the Commission of Grant PUD has established a ten-year conservation potential of 161,272 MWh and a two-year conservation target of 40,033 MWh. A conservation potential assessment, and adoption of targets will be completed every two years and we will work to meet adopted targets during the subsequent two-year periods.

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 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 hydro 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

14, with our current share of incremental hydro and the wind generation contained in our portfolio, we are positioned to meet the EIA RPS requirement through 2028.

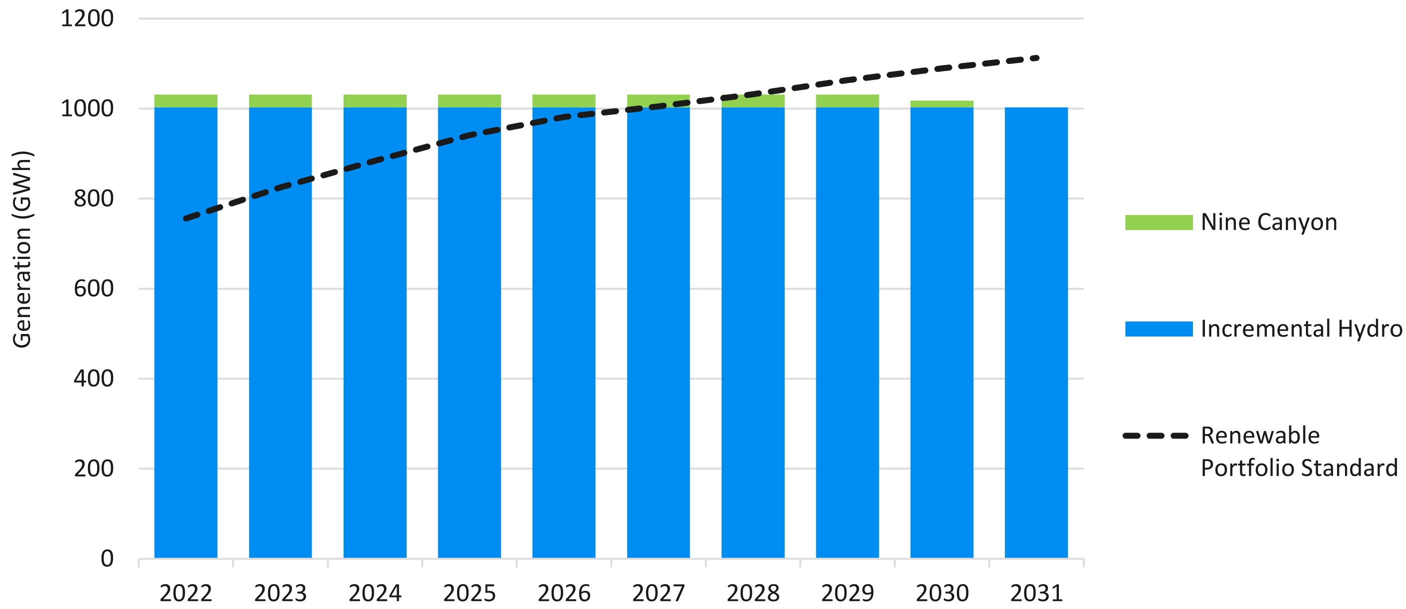


Figure 14. Grant PUD forecast RPS requirement and contribution of eligible resources in current portfolio

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 a 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 load 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 load. By January 1, 2045, all sales of electricity to retail customers must be from non-emitting and renewable resources.

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 we provide 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. Our next CEIP, for the period 2026 – 2029 will be available by the end of 2025.

Our 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.

While there will be compliance costs and reporting requirements going forward, due to our current renewable portfolio, we are well-positioned to meet the greenhouse gas neutral standard beginning in 2030 (see Figure 15). Our current CEIP and subsequent CEIPs will determine interim targets and actions to be taken under CETA.

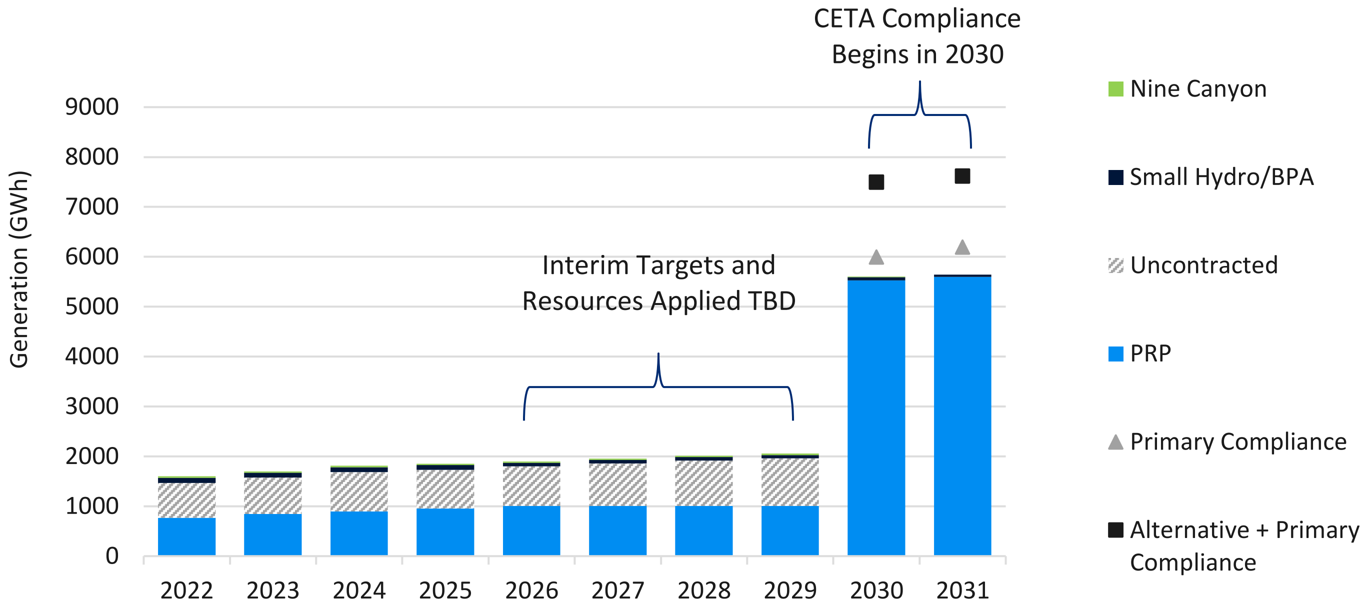


Figure 15. Grant PUD forecast CETA clean energy requirements and contribution of current portfolio

Our current CEIP includes development of targeted energy assistance and energy conservation programs aimed to assist our 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 include outreach for in-home energy audits and related actions, assistance programs including our internal Share the Warmth program and third-party programs with the Opportunities Industrialization Center, Salvation Army, and the Large Industrial Pay It Forward program.

Per the CETA requirement for pursuit of cost-effective conservation and efficiency measures, it is our intent to perform, biennially, a Conservation Potential Assessment and Demand Response Potential Assessment to aid in this compliance. Per our Commission Resolution No. 8797, we have established a two-year conservation target of 40,033 MWh.

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. Our plan is included in Section 7 of this document.

The Washington State Department of Commerce, the Washington Utilities and Transportation Commission, and the Washington Department of Ecology are finalizing the rules to implement CETA. Currently, there are no penalty provisions in the event a utility does not meet the 100% clean energy obligation beginning in 2045. There are some cost-cap provisions and regulatory relief related to electric reliability standards and transmission availability. Moderate risk is inherent in the implementation phase as we manage regulatory and reporting requirements. We have and will continue to actively participate in the rulemaking and implementation process.

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) by 2050, reduce emissions to 95 percent below 1990 levels.

Beginning in 2023, the CCA will establish emission allowance budgets with the total number of allowances decreasing over time to align with statutory limits. The program will cover 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. No-cost allowances will be allocated to utilities, in alignment with the CETA requirements, to cover the "cost burden" associated with the CCA. Utilities who receive no cost allowances can either use those allowances to satisfy direct CCA compliance obligations or consign the allowances to auction and use the proceeds to offset costs incurred due to the CCA. Any allowances not freely allocated will be auctioned with the auction 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, therefore we do not expect to have a direct compliance obligation under the program. However, there is potential Grant PUD may be directly regulated if BPA elects to not be a covered entity under the program as the compliance obligation associated with BPA electricity imports would then transfer to downstream entities. Also, the CCA will impact wholesale energy prices as they increase to reflect the cost of allowances needed to cover the emissions associated with fossil-fuel generation. As a result of our market participation and potential for assuming a compliance obligation associated with BPA imports, we do expect to be allocated no-cost allowances to cover our cost burden under the CCA.

The Washington State Department of Ecology has begun developing rules to implement the CCA. Moderate risk is inherent in the rulemaking process to the extent there are unintended market impacts, and the associated cost burden may not be fully covered by no-cost allowances. Grant PUD is actively participating in the rulemaking process to ensure that implemented rules appropriately address the cost burden and are supportive of regional wholesale markets. We will continue to monitor the impacts of the CCA and evaluate potential changes to our hedging strategy.

Emerging Carbon Polices

New and emerging emission reduction policies have focused on the electrification of the building and transportation sectors. In 2019, the Clean Buildings bill was signed into law. The law targets lower costs and pollution from fossil fuel consumption in the state's existing buildings and has led to changes to the state's building codes. In 2020, Governor Jay Inslee signed the Zero Emissions Vehicle Standard requiring automakers to deliver a certain number of zero emission vehicles each year (Department of Ecology 2022b). In 2021, the Clean Fuel Standard, which will require fuel suppliers to reduce the carbon intensity of their fuels by 20% by 2038 (Department of Ecology 2022a) was enacted. Also in 2021, the Legislature directed the State Building Code Council to adopt rules for electric vehicle infrastructure at new and retrofitted buildings. These and other policies will drive increased electricity demand as Washington State looks to electrification to help meet emission reduction targets in these other sectors. We will continue to monitor all legislative activity related to emission reductions for potential effects on operations and market position.

Federal Policy

Although many factors of federal policy can impact our resource selection, the two current uncertainties that we give the highest consideration are the potential for an extension or expansion of the federal tax credits for clean energy technologies, and the potential requirements for faster adoption of clean energy resources.

The production tax credit for wind phased out at the end of 2021, and the investment tax credit for solar is scheduled to phase down to 10% in 2026. Both tax credits have faced phaseouts or phasedowns in the past, and in every instance, they have been extended (Frazier, Marcy, and Cole 2019), though in some cases that has happened retroactively. 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 to 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 current administration has a goal of having 100% clean electricity generation by 2035. This goal is more aggressive than the current Washington state CETA requirement which does not require 100% clean electricity until 2045. Although a goal is not a law or regulation, it signals the administration's interest in promoting clean energy adoption at a rapid pace. Efforts by the administration or other lawmakers to mandate a clean energy requirement at a rate faster than CETA could impact Grant's need for clean energy resources to serve its load obligations or might change the cost and availability of contracting for resources in the broader Western interconnection.

Other potential federal policy considerations we are monitoring include federal spending on research, development, and demonstration efforts for new clean energy technologies such as advanced nuclear reactors or hydrogen efforts, requirements to accelerate vehicle electrification that may lead to more rapid load growth, and federal efforts related to transmission planning.

CLIMATE CHANGE AND WATER AVAILABILITY

Grant PUD continues to monitor and assess the impacts of possible climate change on our planning and operations. To the extent that regional warming increases the average temperature in the watershed that feeds the Columbia River, that warming could result in earlier run-off into the Columbia River, or more winter precipitation and less snowpack in the mountains in the winter months (Glabau et al. 2020). These changes could affect the timing and amount of water availability and power generation at our hydropower projects. Impacts with a medium to high likelihood of occurring within the next 10 years have been integrated into our risk management program and into this plan. Among the risks evaluated are increased ambient air temperature implications for electric load, possible impacts to fish populations associated with changing river temperatures, precipitation and snowpack effects on generation, potential extreme weather and wildfire events, and changes to water availability.

Water Availability

The principal resource in Grant PUD's portfolio is the PRP, consisting of Wanapum and Priest Rapids developments on the Columbia River (see Section 4). As hydropower resources, their ability to provide energy and capacity is a function of water availability. There is uncertainty and risk associated with the availability of water and this uncertainty exists at annual, seasonal, daily, and hourly timesteps. There is risk of the potential inability to generate power according to a desired plan over these various timesteps. When actual water availability is different from that which was assumed, changes must be made to operational plans and those changes carry price, availability, and environmental risks.

Annual Water Risk

Annual water risk affects the total volume of water available over the course of a year, usually measured from October through September in what is called a water year. Figure 16 shows the range of annual water volume, expressed as an average flow rate for the water year, measured below Priest Rapids Dam from 1949-2021. The volumes depicted are the natural, unregulated runoff volume as measured by the Northwest River Forecast Center. The lowest water year on record is 2001 with an average annual flow of 76,000 ft^3/s while the highest annual flow rate during the period was 171,000 ft^3/s in 1997. This history shows a potential swing of 62% of average to 140% of average annual flow.

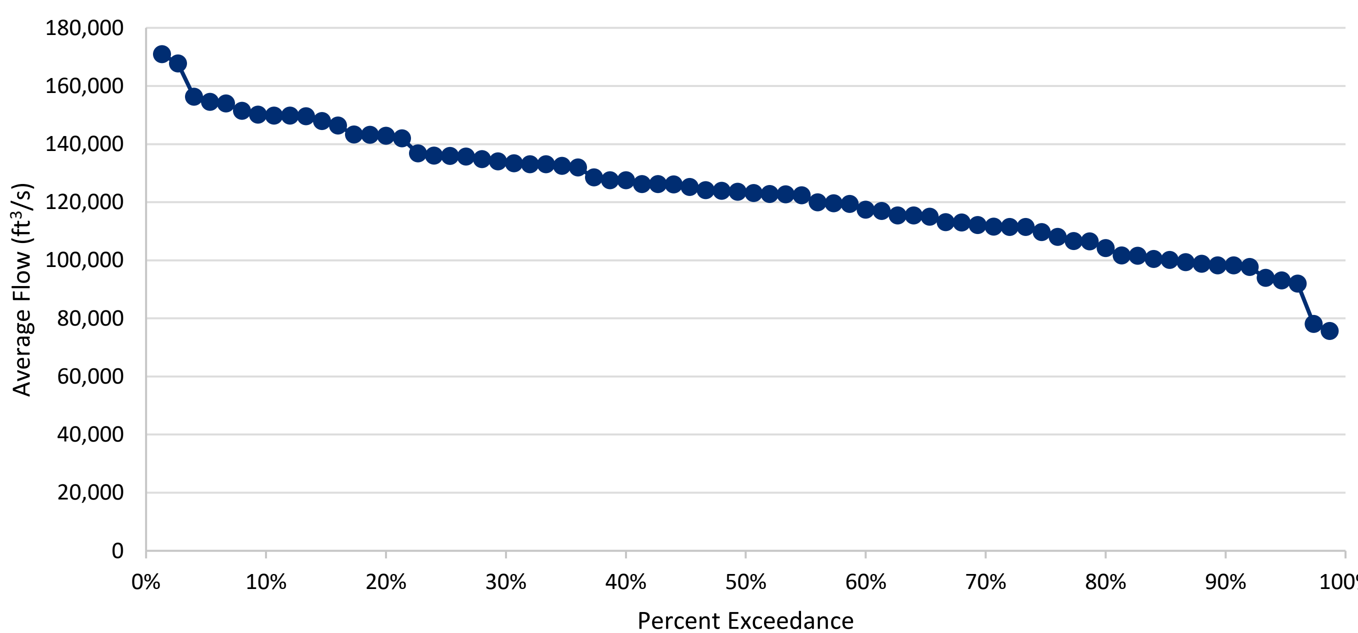


Figure 16. Northwest River Forecast Center measurements of runoff volumes on the Columbia River below Priest Rapids for water years 1949-2021

Seasonal Water Risk

The annual volume is the first timestep uncertainty associated with water. Another element of water risk involves the timing of when that water arrives within the year. The seasonal shaping is primarily determined by climate and weather, but the natural, unregulated runoff is also regulated by the large storage reservoirs in the river system used for purposes of flood control, biological goals, and energy production. The US Army Corps of Engineers and Bonneville Power Administration together coordinate the operations of the large, seasonal storage to meet the various goals of the system. While the monthly volumes are to an extent predictable, there remains a degree of uncertainty around the seasonal volumes available to Priest Rapids Project. Figure 17 shows the month average inflows to the Wanapum reservoir as well as the variability of those flows expressed by 90% and 10% exceedance values. The period of record was restricted to more recent years (1995-2021) because the monthly shaping has changed throughout time and the more recent data is more reflective of future expectations. 2001 is explicitly shown to illustrate a “worst case” hydrologic condition reflected in monthly volumes over an entire year.

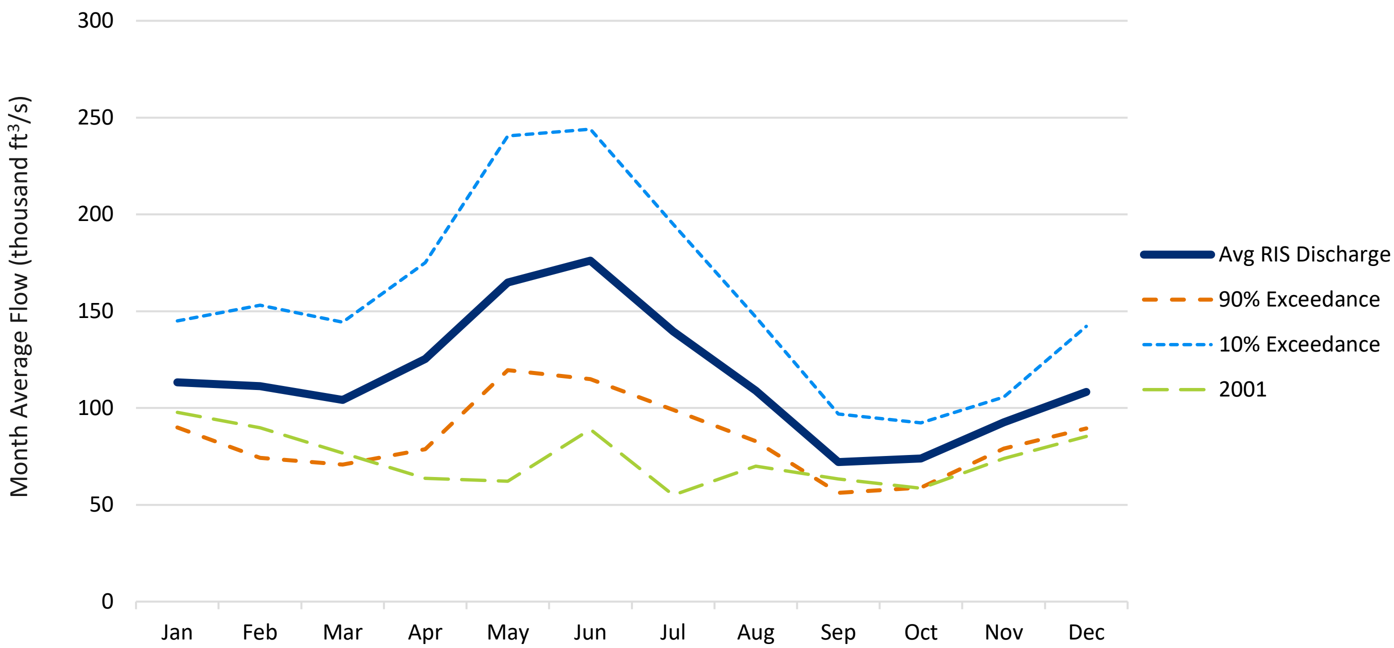


Figure 17. Average monthly inflows for the Wanapum reservoir for 1995-2021, with the 2001 year shown for reference

<u>**Daily Water Risk**</u>

Given the limited storage at both Wanapum and Priest Rapids, the daily variability of inflows to the projects represents an additional element of uncertainty and risk. The storage in the reservoirs can mitigate daily variability to an extent, but the ability to either supplement flows for near term needs or capture excess flow to use in future time periods is measured in hours, not days. Figure 18 shows the daily average inflows to the Wanapum reservoir by month with the variability captured with 95% Exceedance and 5% Exceedance values. As in the illustration of monthly inflows, only recent years are shown as they are expected to be more representative of future conditions.

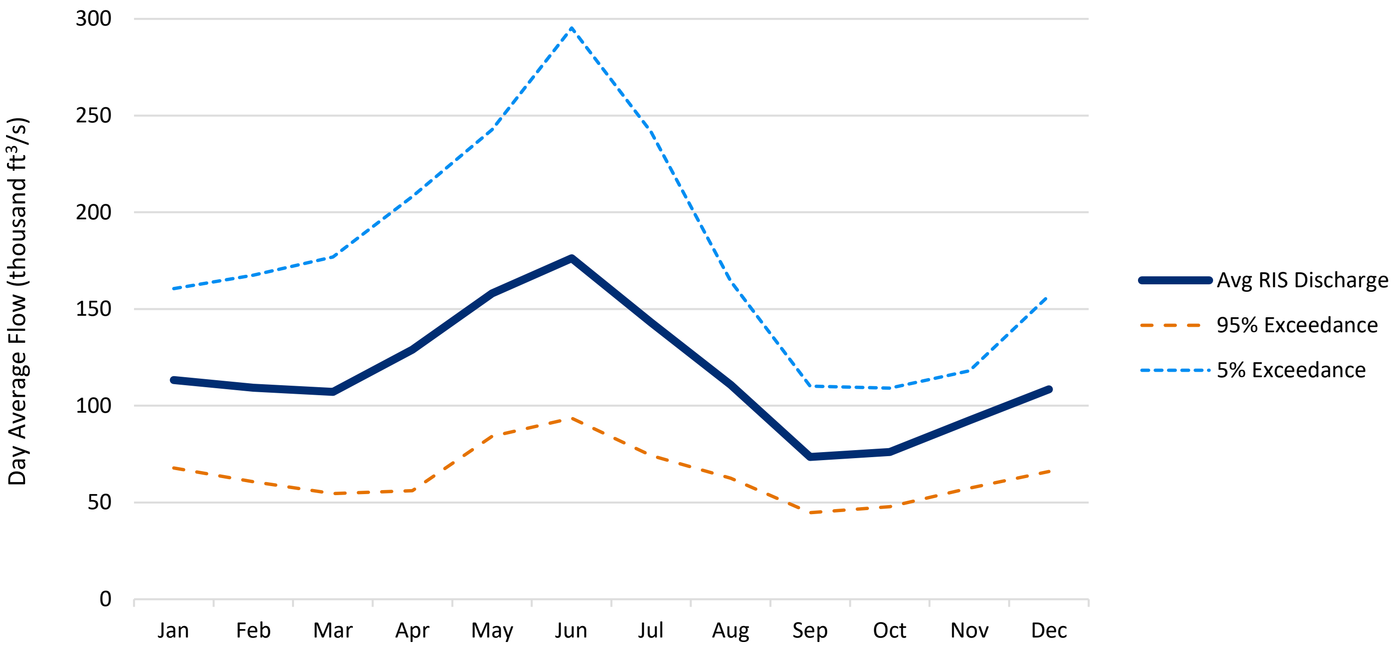


Figure 18. Average daily inflows to the Wanapum reservoir using inflow data from January 1995 through April 2022

Figure 19 shows two years, 2019 and 2021, in more detail to further illustrate how that there is variability not only between years and months, but also between days within the same year.

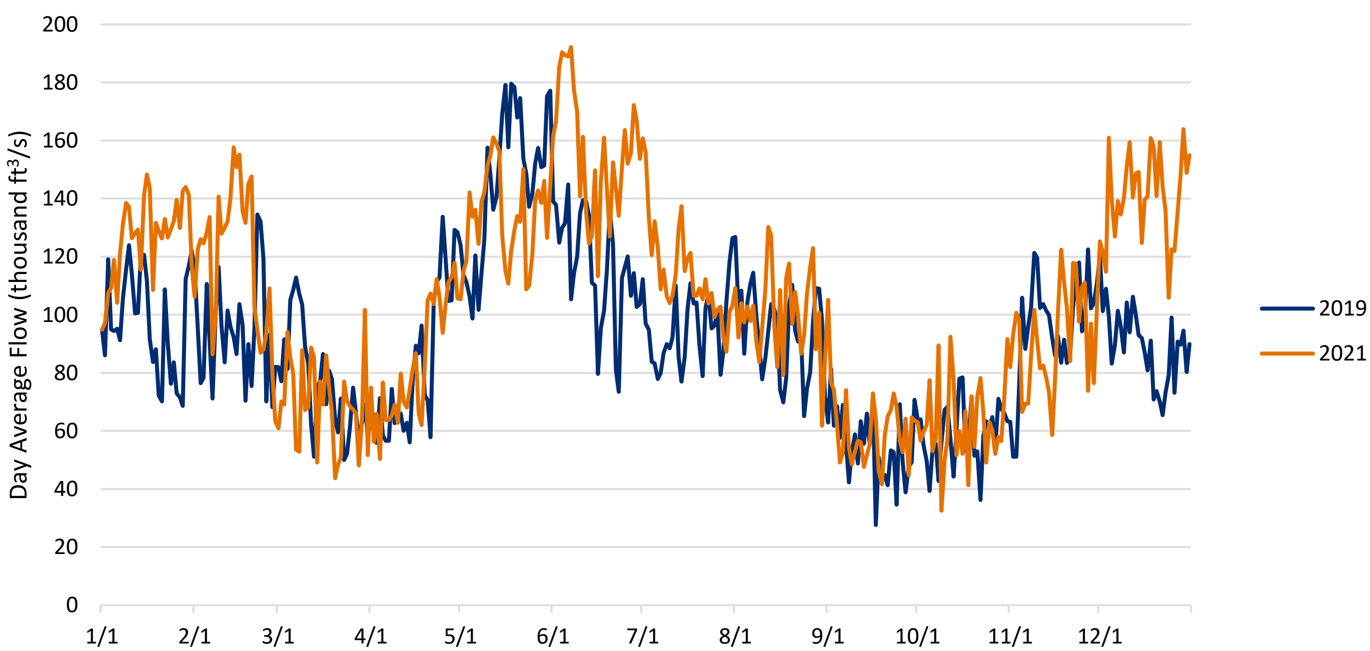


Figure 19. Average daily historical inflows to the Wanapum reservoir in 2019 and 2021

<u>Hourly Water Risk</u>

The timing of water inflows within the day also adds to the uncertainty of water availability. While somewhat predictable, hourly variability can significantly impact operations especially as that uncertainty interacts with operational constraints and biological flow requirements. Figure 20 illustrates the hourly Wanapum inflow variability for a single year. While the details are difficult to see in this hourly annual view, the takeaway is that the range of inflow rates can vary widely within relatively short periods of time. That variability must be accommodated by either using storage or matching generation to inflow. With inadequate storage or large deviations from expected flows, rapid changes to the daily plan may be required. The risk associated with hourly inflow uncertainty changes throughout the year based on total water volume and operational regimes. For example, a high-water year might have less hourly variability because the flow rates throughout the entire river system will tend to always be high to accommodate the runoff.

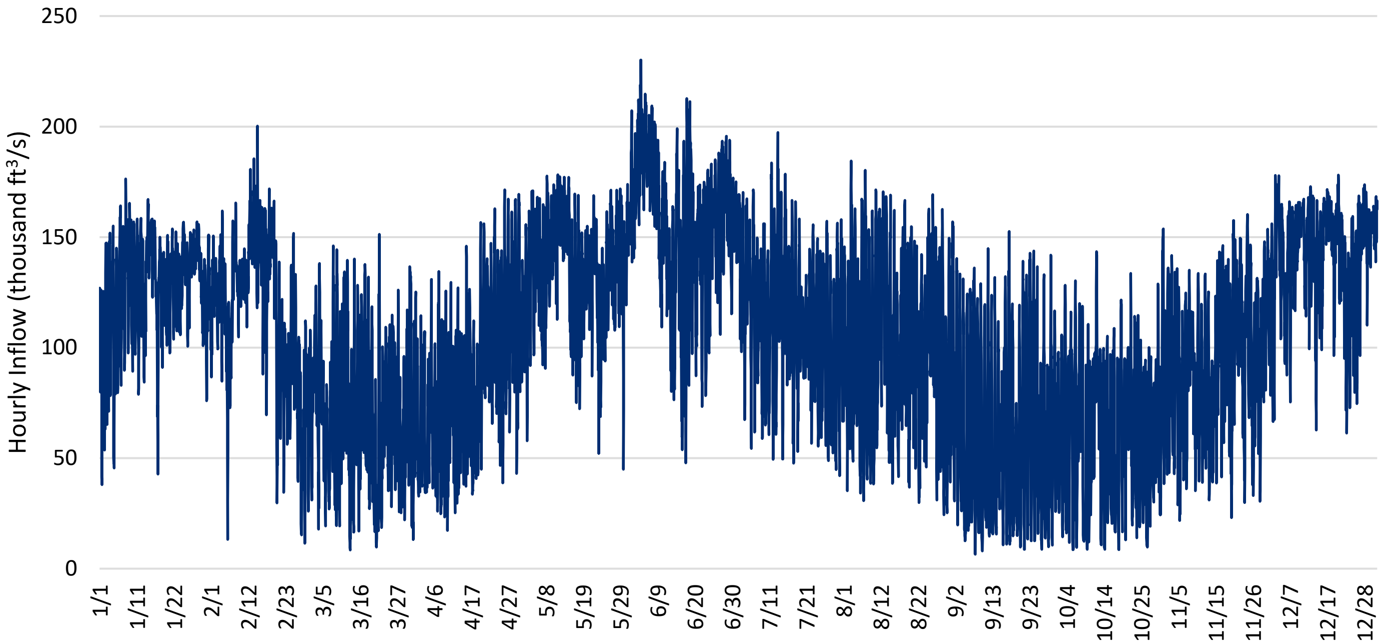


Figure 20. Hourly Wanapum Inflows as estimated by Rock Island discharges for 2021

Given that water availability is variable and somewhat uncertain, and that the potential effects of climate change may further impact our experience of this variability, we will continue to review and update these risks.

TRANSMISSION AND DELIVERABILITY

Transmission is an essential part of our service. Delivery of our product through the transmission system connects Grant PUD's electric resources with the needs of our customers. As we look to the future, and contemplate the addition of new generation resources, our plan for providing electric service depends on an evaluation of the practicality, feasibility, and cost of bringing these new resources to our customer load.

If in the future we were to import power from either a new or existing resource outside of the Grant PUD balancing authority, we anticipate that our transmission system would have the capacity to receive the import of power in quantities necessary to meet forecast load. To make such imports, we would 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, we may need to participate in a Network Open Season of a transmission provider and may also need to pay for necessary upgrades to a transmission provider's system to receive the desired service. During selection of any specific resource addition, additional analyses will need to occur to identify the particular impact of that resource on the transmission grid and to related costs.

Grant PUD has interconnection procedures and an existing queue of interconnection requests from various entities. Connection of a new generator to our transmission system would follow the same process that is currently available to independent power producers. As part of this process, a series of studies is completed for each application for interconnection to determine the impacts of the interconnection to the reliability of the Grant PUD system and to determine what facilities must be built or upgraded to accommodate the interconnection. The study process also identifies if neighboring transmission systems would be affected by the proposed interconnection and allows an opportunity for affected systems to identify any upgrades necessary for the neighboring system prior to the interconnection. Figure 21 is a simplified representation of the interconnection study process.

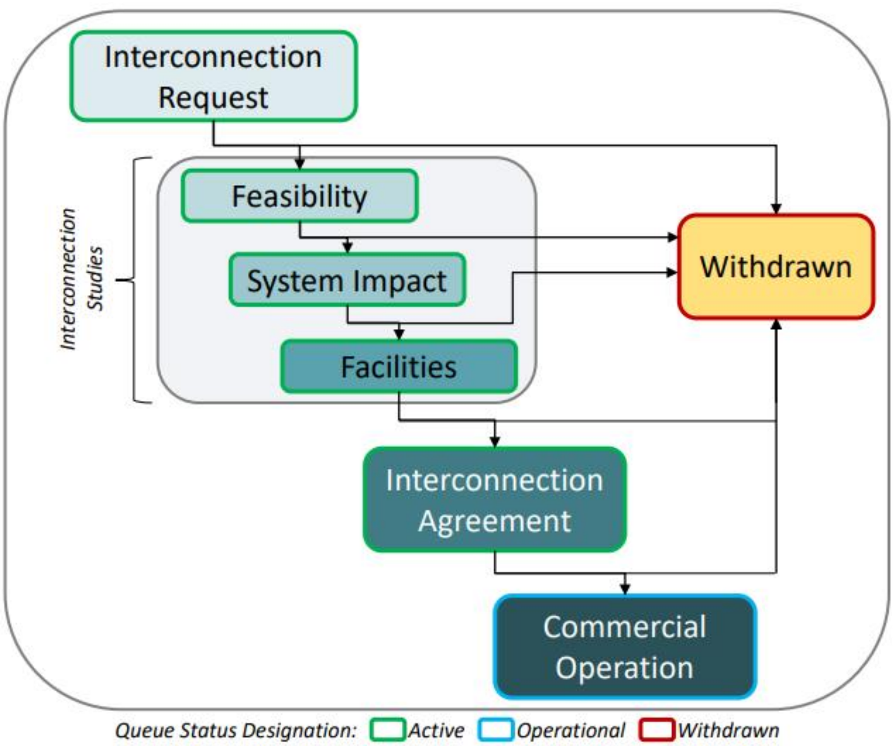


Figure 21. Simplified illustration of the interconnection study process
Figure reproduced with permission from Rand et al. (2022).

As we work to form a plan to meet our customer demands into the future, we anticipate that connection of new resources bears some availability and cost risks. This IRP attempts to quantify the costs of potential new connections using representative transmission wheeling costs based on current market values.

5 | Potential Future Resources

This section provides a summary of the potential future resources considered in development of our IRP. More detail on the specific resources evaluated is provided in Appendix 2.

SUPPLY SIDE RESOURCES

Aeroderivative Gas Turbine

Natural gas fueled 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. 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, simplified installation, and quick start-up and ramping capabilities for meeting peak or emergency generation needs, and integration of variable generation sources such as wind and solar. A major drawback of the use of gas turbines is the emission of carbon dioxide and other greenhouse gases.

Aeroderivative gas turbines considered in this plan were assumed to be 43 MW units to be owned and operated by Grant PUD.

Reciprocating Internal Combustion Engines (RICE)

RICE generators use the mechanical energy of expansions of gases to drive a piston and converts the motion of the piston to a rotating movement to spin a generator. Attractive characteristics of RICE generators are their relatively small size, ability to cycle on and off with minimal wear and tear on components, and quick start-up and ramping capabilities for meeting peak or emergency generation needs and integration of variable generation sources. When operated using natural gas, RICE generators have the disadvantage of producing greenhouse gas emissions.

RICE units considered in this plan were assumed to be 18 MW natural gas-fired units to be owned and operated by Grant PUD.

Both the aeroderivative gas turbine and RICE units are impacted by the social cost of carbon when determining their cost-effectiveness as resources. See Appendix 2 for the social cost of carbon applied during evaluation.

Solar Photovoltaics

Solar Photovoltaic (PV) resources convert sunlight into electricity using semiconductor materials. They are emission-free resources that have experienced considerable cost declines over the past several decades. Because they rely on sunlight to produce electricity, their output is influenced by cloud cover and the time of year. Their production patterns are location specific, as different locations will have different amounts of sunlight and cloud cover.

Solar PV systems considered in this plan were assumed to be one-axis tracking technology with a typical size of 100 MW and an inverter ratio of 1.3. Hourly profiles for PV generation output associated with considered resources were simulated using the National Renewable Energy Laboratory System Advisor Model (NREL 2022b) using weather data from 2018-2020 from the National Solar Radiation Database (NREL 2022a).

To provide some diversity in profiles and annual capacity factors, three generic weather locations were considered:

- Grant County (Local resource)
- South-central Oregon (Close resource)
- South-central Nevada (Far resource)

Selection of these locations resulted in the annual capacity factors and wheeling costs shown in Table 6. Solar PV resources considered in this plan were assumed to be procured through purchase power agreement.

Table 6. Summary of capacity factors and wheeling cost for solar resource locations

	Annual Capacity Factor	Wheeling Cost ($/kW/month)
Solar PV - Local Resource	25%	0
Solar PV - Close Resource	29%	1.96
Solar PV - Far Resource	33%	4.96

Solar Photovoltaic/Battery Hybrids

Solar PV resources have the option to be paired with battery storage. Solar/Battery hybrid units considered in this plan were 4-hour duration battery storage sized at 50% of the solar PV inverter, and tightly DC coupled, meaning they can charge only through the PV array. Storage coupled with PV is eligible for the investment tax credit if it charges at least 75% of the time from solar, which is a requirement of the tightly coupled DC configuration. These tax credits were applied to cost considerations of these resources. Solar/Battery hybrid resources considered in this plan were assumed to be procured through purchase power agreement.

Wind

Wind generators convert the kinetic energy of moving air into electrical energy using a wind-driven turbine connected to an electrical generator. Wind generator output is both variable and uncertain because the wind that is used to create the 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.

Wind resources considered for this plan were assumed to be 85-meter hub height systems with a typical total size of 200 MW. The wind power curves used were based on a Senvion 3 MW turbine with a 122-meter rotor diameter. Hourly wind profiles were generated using the System Advisor Model (NREL 2022b) using 2011-2013 weather data, the most recent weather data available in that model (Draxl et al. 2015).

Like the Solar PV, three generic weather locations were selected to provide diversity on production profiles and annual capacity factors:

- Grant County (Local resource)
- North-central Oregon (Close resource)
- North-western Montana (Far resource)

Selection of these locations resulted in the annual capacity factors and wheeling costs shown in Table 7. Wind resources considered in this plan were assumed to be procured through purchase power agreement.

Table 7. Summary of capacity factors and wheeling cost for wind resource locations

	Annual Capacity Factor	Wheeling Cost ($/kW/month)
Local Resource	26%	0
Close Resource	37%	1.96
Far Resource	42%	4.96

Stand-alone Battery Storage

Battery storage systems are devices that do not produce power but allow power from other sources to be stored and then released when needed. A benefit of battery storage is that they can hold power from renewable and non-carbon emitting sources and deploy that power during periods during which that resource type would not be available. Another attractive characteristic of battery storage is that it can also improve electric grid reliability using their ability to quickly go from standby mode to full power.

Stand-alone battery storage considered in this plan is assumed to be based on lithium-ion technology, with a round-trip efficiency of 85% and no leakage rate. Batteries of both 4-hour or 8-hour discharge duration were considered. To limit overuse and associated degradation, batteries are assumed to cycle no more than 365 times per year. A 15-year resource life was assumed.

Battery storage considered in this plan was assumed to be procured through purchase power agreement.

Small Modular Reactor (SMR)

Nuclear reactors use nuclear fission to generate heat to produce steam, which moves through the blades of a turbine to spin a generator. Small module reactors are advanced nuclear technologies, distinct from conventional reactors due to their size and the modular assembly of their components.

Advantages of SMRs are that they are non-greenhouse gas emitting and a reliable and efficient source of baseload energy, with the flexibility to integrate intermittent energy sources. Because of their modular design, they can be deployed incrementally. Drawbacks of SMRs are that they are currently in a development stage, expensive to build and require additional considerations for licensing and siting.

The SMR considered in this plan is based on Nth-of-a-kind cost and performance data provided by NuScale but implemented in the modeling in a generic manner to capture the uncertainty in the specific type of small modular technology that could be adopted in the future. Based on anticipated project online dates, we do not allow SMR technologies to be selected for the plan until 2030. SMR units considered in this plan were assumed to be owned and operated by Grant PUD.

Bonneville Power Administration

While we do not currently have a contract with BPA to serve any other load than that in the Grand Coulee city area, we have the option to exercise our statutory rights to apply for more priority power from BPA after 2028. We intend to maintain this option and are currently actively working with the region's preference customers and participating in BPA's Provider of Choice process that will determine the structure of new contracts offered by BPA. Because of uncertainties surrounding this process, we have chosen not to include any potential future additional contract with BPA in this plan. This should not be construed as an indication that we are not actively pursuing a post-2028 BPA priority contract as a potential economic addition to our resource portfolio.

Slice Contracts and Pooling Agreements

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 resource selection modeling for this plan.

Wholesale Trading

We currently participate in energy market trading activity and this plan reflects an intention to continue to do so into the future. When considering our future resource portfolio, we allow for both wholesale purchase and sale transactions. We expect that policy and regulatory requirements, including the push toward renewable and carbon-free power, limited available transmission capacity to move power throughout the region, and expansions of organized markets will impact future wholesale prices. Market trading considered in this plan is assumed to transact at the Mid-C trading hub and purchases are assumed to be from unspecified sources when accounting for clean energy goals and compliance. Hourly Mid-C price forecasts are provided by Ascend Analytics and are derived using Ascend Analytics' proprietary weather-driven simulation engine.

DEMAND SIDE RESOURCES

In accordance with RCW 19.405.050 and RCW 19.285.040, this IRP considers meeting projected demand by pursuing cost-effective, reliable, and feasible conservation and efficiency resources, and demand response.

Conservation and Efficiency

It is our intent to pursue cost effective conservation and efficiency identified as identified in the 2021 CPA. In November of 2021, the Commission of Grant County PUD adopted Resolution No. 8974 establishing a ten-year conservation potential of 161,272 MWh and a two-year conservation target of 40,033 MWh. We will review and update our ten-year conservation potential plan and establish a biennial acquisition target every two years. This plan assumes conservation and efficiency reduction to customer load as shown in the results of the 2021 CPA. The full results of the 2021 CPA can be found in Appendix 3.

Demand Response

Results of 2021 Electric Demand Response Potential Assessment showed demand response resources to be relatively expensive compared to supply side resources. We do not currently offer demand response programs to our customers and no utilization of these programs was considered in this IRP.

6 | Assessment of Potential 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 about 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 a 15% capacity planning reserve margin
- Maintain a 15% RPS required by the Energy Independence Act
- Meet CETA requirement of 80% primary compliance beginning in 2030

METHODS

The PowerSIMM modeling platform developed by Ascend Analytics was used to evaluate the potential future resources described in the previous section and formulate a plan to meet identified objectives. The Automated Resource Selection (ARS) module of PowerSIMM was used for selection of resource additions, and the dispatch module was used to investigate hourly operations of selected potential future resource portfolios. Ascend Analytics staff performed all modeling with input from our IRP team.

An overview of the modeling framework, indicative of what was employed for the IRP analysis is shown in Figure 22.

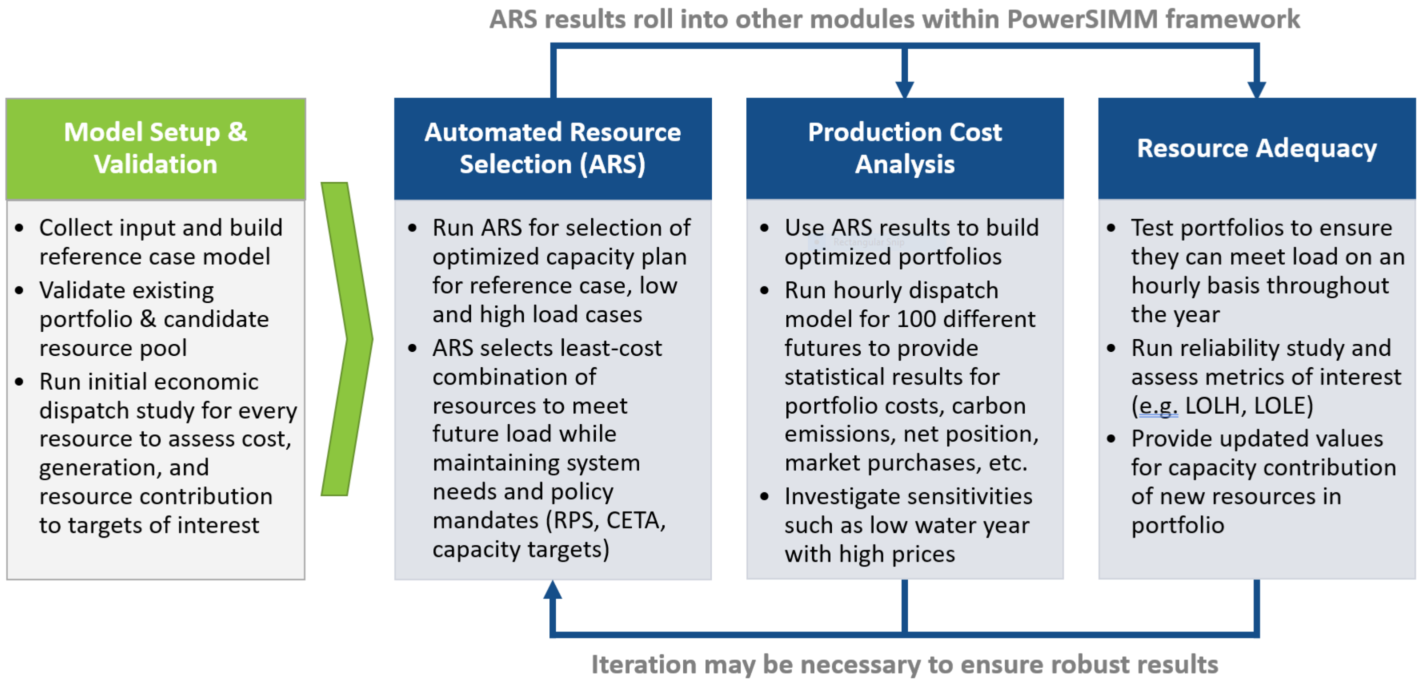


Figure 22. Modeling framework to develop compliant, reliable, and least cost portfolios in PowerSIMM.

First, historical generation data, resource specifications, cost projections, and other relevant input to set up the model was gathered. We then verified that modeled systems behaved as anticipated under alternative weather and pricing conditions. A set of economic dispatch studies were then run for every resource to assess costs, generation, and contribution to plan objectives. The results of these dispatch studies were input to the ARS module, which used the information to select resource additions based on minimizing the cost of procuring and operating new and existing resources while simultaneously meeting system requirements, including serving customer load, maintaining a sufficient planning reserve margin, meeting the RPS associated with the Energy Independence Act, and complying with CETA clean energy requirements.

Once additional resources were selected by ARS, they were incorporated into a portfolio including our existing resources and evaluated using an hourly dispatch model to understand the portfolio's operational feasibility and the overall implications of the selections. To capture the uncertainty in future conditions, these hourly dispatch studies used a stochastic framework to simulate 100 different future conditions, in which market prices, weather patterns, renewable generation, water availability, and load were varied according to distributions observed in the historical data. To capture the risk associated with the distribution of portfolio costs resulting from the 100 different futures, a risk premium metric that indicated the cost at risk or the actuarial value of the portfolio's exposure to market price volatility, variation in generation and load, and changes in weather conditions was included.

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.

MODELING RESULTS

Throughout the planning process used to formulate this IRP, we focused on several key 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 model was bound by the information and constraints we provided it, and although information used in our modeling is our current best estimate of what the future may look like, given a different view of future possibilities we would well expect the modeling effort to provide a different solution. We present the following results of our 2022 IRP modeling and commit to continued ongoing assessment and analysis to ensure we make the best decisions for our customers.

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 our existing resources, the selected portfolio includes the resources shown in Table 8. These resources include a mix of wind, solar PV, solar PV and battery hybrids, and natural gas peaking units. Market purchases are also used to help meet energy needs throughout the model horizon, while market sales serve to reduce cost.

Table 8. Modeled resource nameplate capacity addition by year, in MW

Nameplate Capacity	2025	2026	2027	2028	2029	2030	2031	Total
Solar PV – Local	100	100	100	100	100	100	0	600
Solar PV – Close	70	0	0	0	0	0	0	70
Solar PV/Battery Hybrid	100	0	0	0	30	40	0	170
Wind – Close	100	0	0	0	0	0	0	100
RICE	180	18	36	36	0	0	0	270
Total	550	118	136	136	130	140	0	1210

Per the modeling specifications, no new capacity is allowed until 2025. This delay in the addition of potential resources is used to simulate a realistic acquisition timeframe. 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. 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.

Figure 23 shows the nameplate capacity and generation values for the selected portfolio, by resource type, through 2031. Market purchases are shown in the plots as net annual amounts. Years shown on the graph as having no market purchases do not mean that there are not market purchases modeled in that year, but that annual market purchases are equivalent to annual market sales. New resources added in 2025 considerably reduce dependence on market purchases.

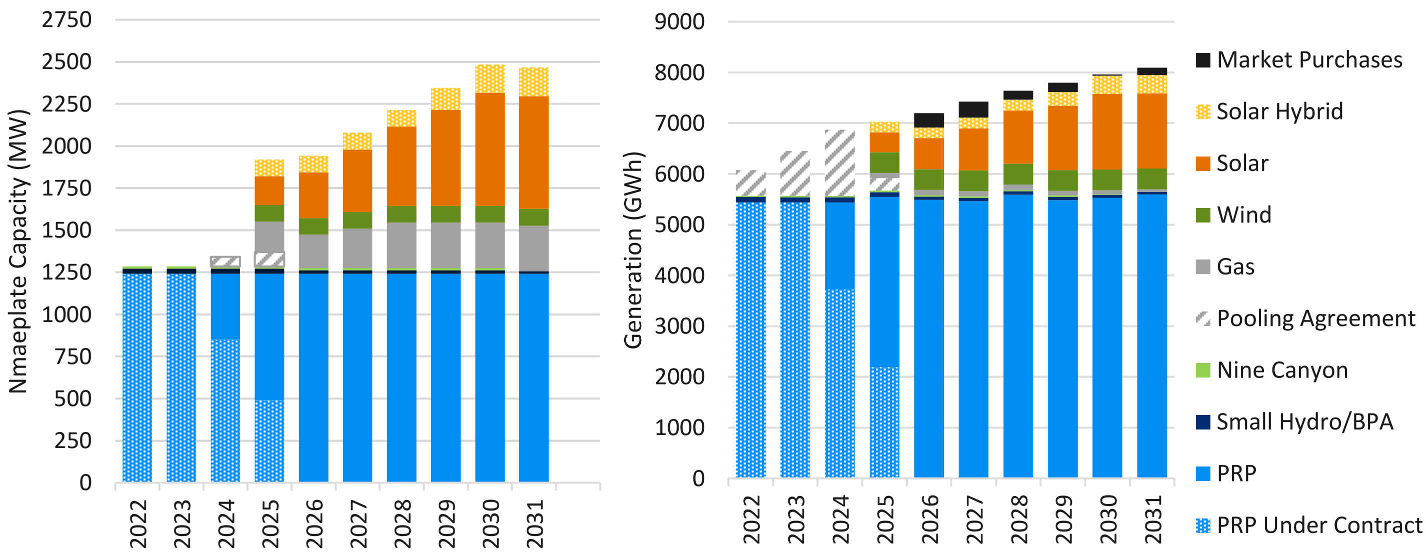


Figure 23. Nameplate capacity (left) and generation (right) of the selected portfolio from 2022 through 2031

Energy Expectations of Selected Portfolio

Given modeled inputs and constraints, the selected portfolio is chosen as the least-cost means to serve customer energy requirements. Figure 24 is a visual representation of our selected portfolio over the planning horizon showing the energy output expected from each resource as well as our reference case load expectation. Using existing resources, we are well positioned to meet load through 2025, after which time wind and solar additions make up much of the difference between the current resource capability and customer needs. The selected RICE units provide only a minimal amount of energy, their use being limited to a small number of system peaking or elevated market pricing conditions. Restraints imposed by CETA will limit the use of these gas-fired units during future compliance periods.

Note that Figure 24 is a representation only of how we may choose to serve customer demand. We currently utilize wholesale markets to economically meet customer needs, and this IRP allows that we will continue to do so into the future. Market participation is not represented in Figure 24 to highlight the energy expectations of the selected portfolio.

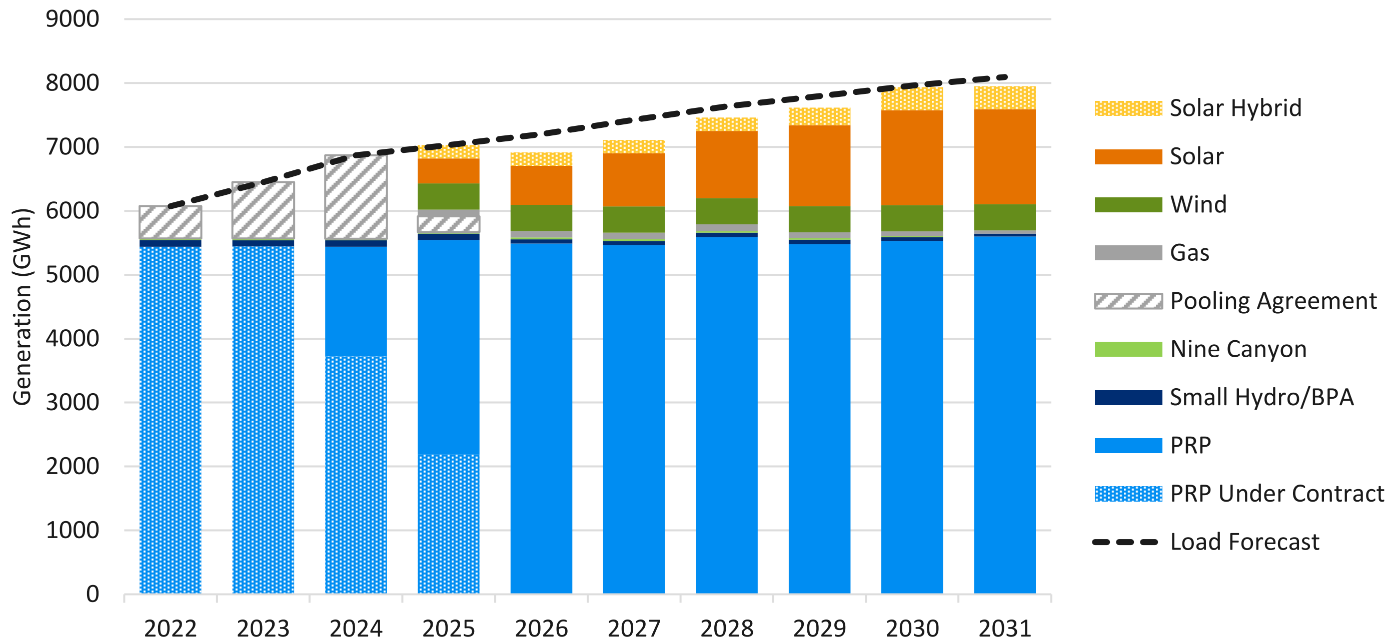


Figure 24. Generation expectations of the selected portfolio

To further illustrate the potential performance of the selected portfolio, Figure 25 and Figure 26 show weeklong snapshots of expected generation for 2030 summer and winter peak net demand periods compared to customer demand and Mid-C market price. Net demand is defined as demand minus wind and solar generation, and tends to be more indicative of times of system stress than peak demand alone (Jorgenson et al. 2021.)

In both snapshots, most of the energy supplied comes from PRP. In summer, the solar technologies have much higher generation outputs, resulting in more generation than required by load during most daytime hours. This energy above load is sold into the Mid-C market. During periods of high load and elevated Mid-C prices, the natural gas RICE units are called to generate, even with their increased cost burden due to the applied social cost of carbon.

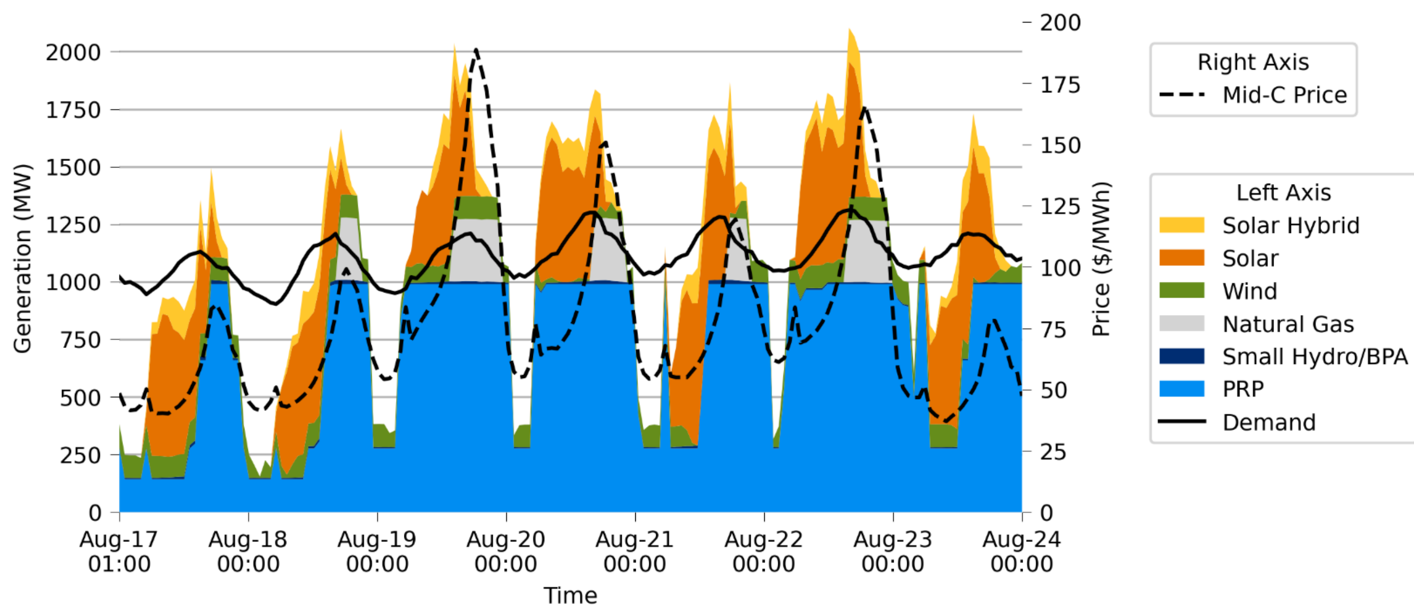


Figure 25. Hourly dispatch for the week with the highest summer peak net demand using the 2030 portfolio

During the winter, solar generation is considerably reduced. Natural gas does not dispatch during the winter net peak period.

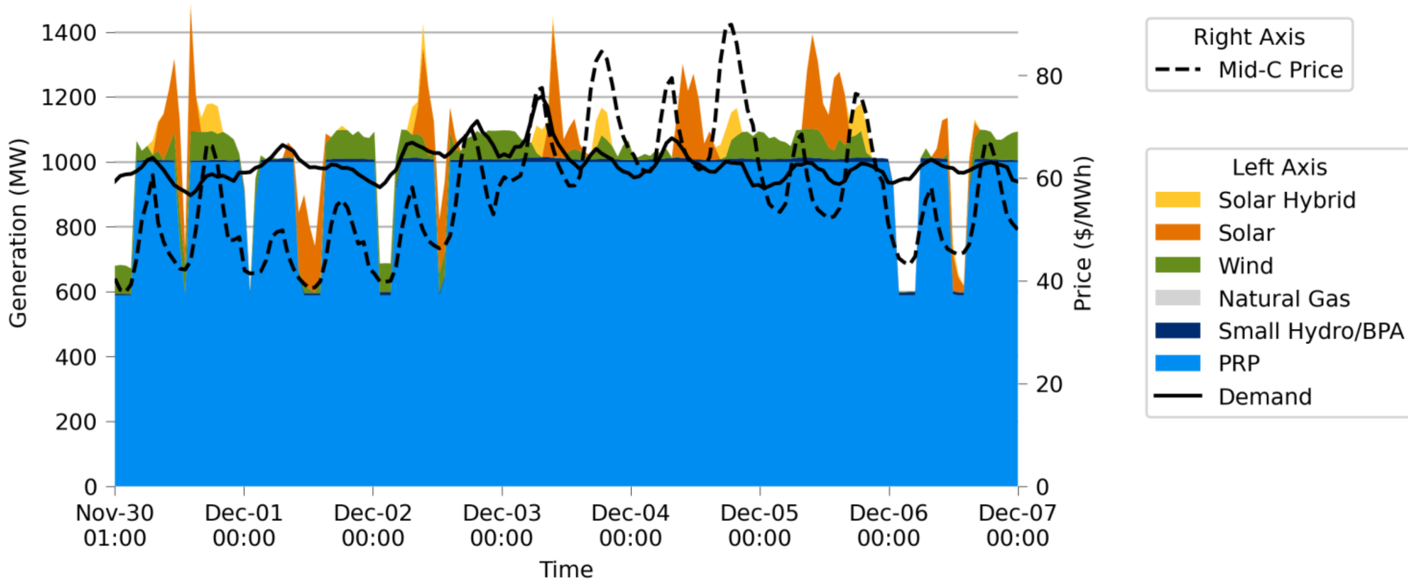


Figure 26. Hourly dispatch for the week with the highest winter net peak net demand using the 2030 portfolio

Other conditions, explored across the 100 dispatch simulations performed, result in slightly different dispatch outputs than those shown in the figures above due to differences in Mid-C prices, wind and solar resource availability, demand levels, and Wanapum reservoir inflows.

Firm Capacity of Selected Portfolio

In recognition of the developing WRAP, and our need to ensure an adequate and reliable energy supply to our customers, the modeled scenario was selected such that a 15% planning capacity margin, calculated as a percentage of each forecast annual peak load, is maintained from 2025 to the end of the planning period. Figure 27 shows how the firm capacity contributions of the resources in the selected potfolio could work to meet this requirement.

The bulk of capacity contribution comes from PRP related resources but these resources alone are not sufficient to maintain the planning reserve margin. The increase in PRP firm capacity in 2031 is due to the completion of the turbine upgrades, which will allow all 10 Priest Rapids dam units to be online beginning in that year.

As soon as the model was allowed to do so, additional resources were selected to fill capacity needs. Because wind and solar PV have relatively low firm capacity contributions (see Appendix 2 for details), they provide only small shares of firm capacity relative to their total rated capacity. The bulk of new firm capacity is provided by the natural gas RICE units. The selected porfolio has slightly more capacity in 2025 than required by the planning reserve margin as the model seeks to add resources at a favorable cost. Additional capacity above resource adequacy requirements could be used to reduce the cost burden of retail customers.

Note that Figure 27 is only a representation of how we may choose to serve customer demand. We currently utilize wholesale markets, and this IRP allows that we will continue to do so into the future. The market is not represented in Figure 27 to highlight the capacity expectations of the selected portfolio.

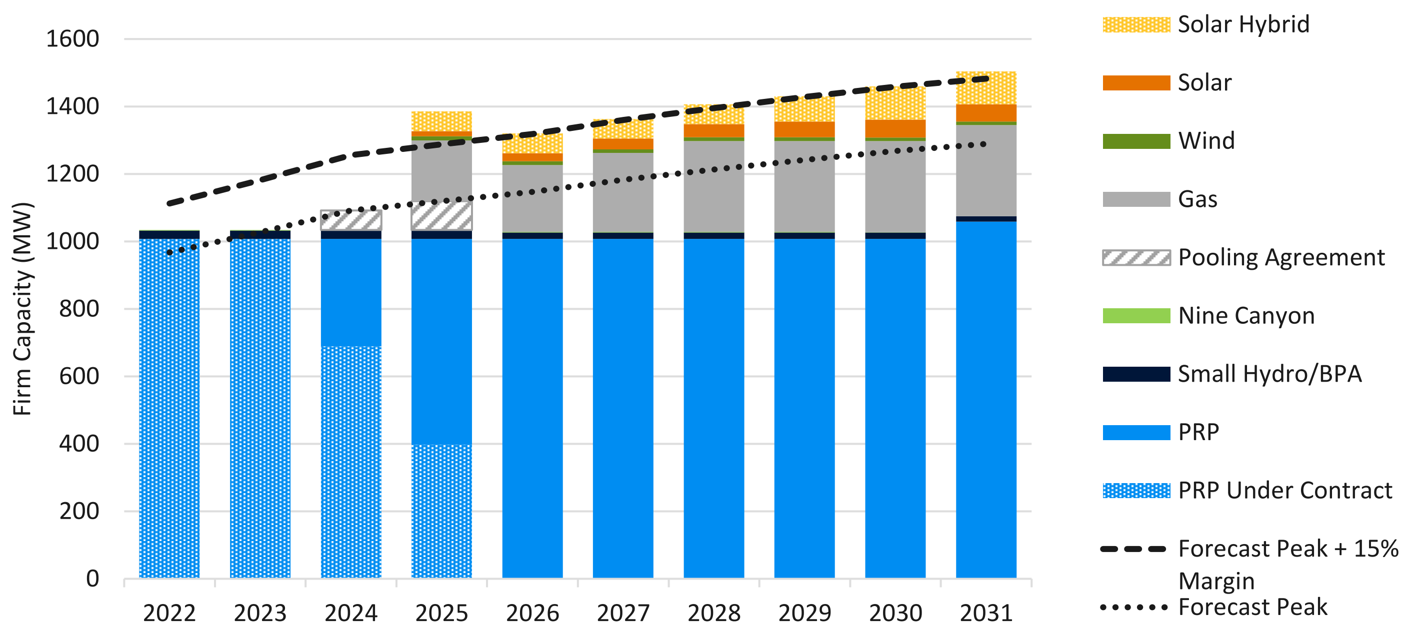


Figure 27. Firm capacity of the selected portfolio
The resource adequacy target (15% planning reserve) is shown as the dashed line and the projected peak demand as the dotted line. Shortages before 2025 are met via existing slice contracts and power sale agreements.

Potential RPS Compliance with Selected Portfolio

Even though only the portion of PRP termed "incremental hydro" qualifies for RPS compliance under the EIA, the selected portfolio has more than sufficient renewable generation to satisfy the 15% requirement.

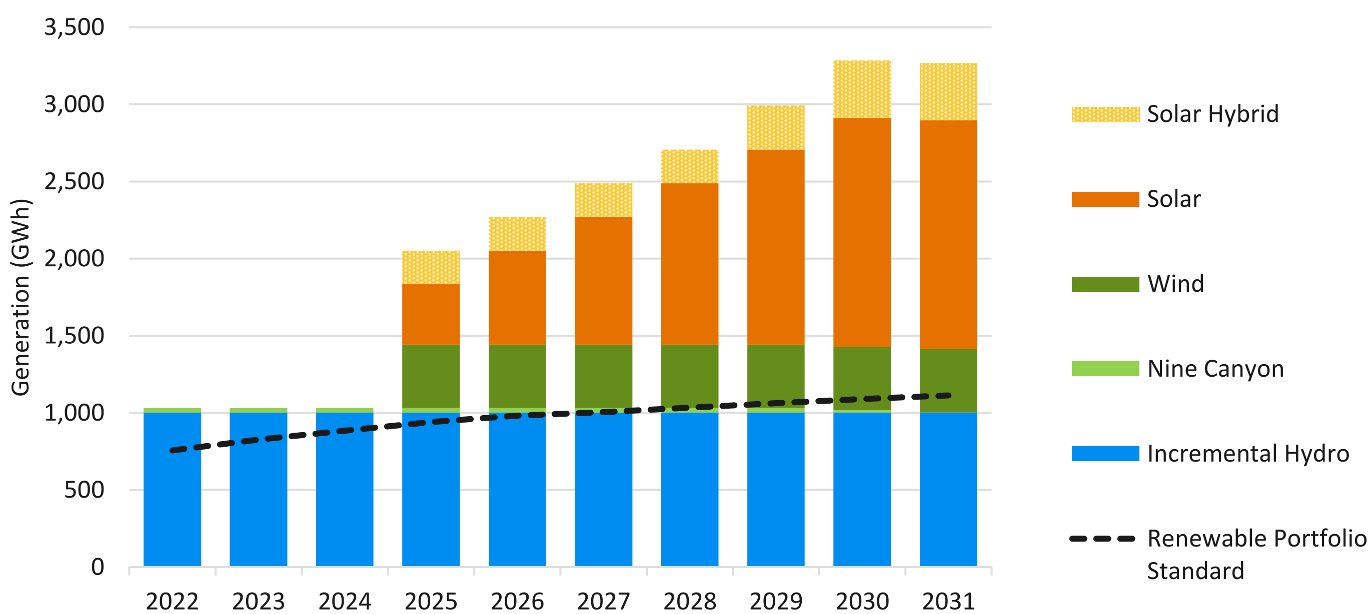


Figure 28. Potential path to RPS compliance with selected portfolio

Potential Path to CETA Compliance with Selected Portfolio

The selected portfolio was chosen such that our portfolio resources could be sufficient to meet CETA primary compliance beginning in 2030. A potential path for compliance with CETA requirements is shown in Figure 29. 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.

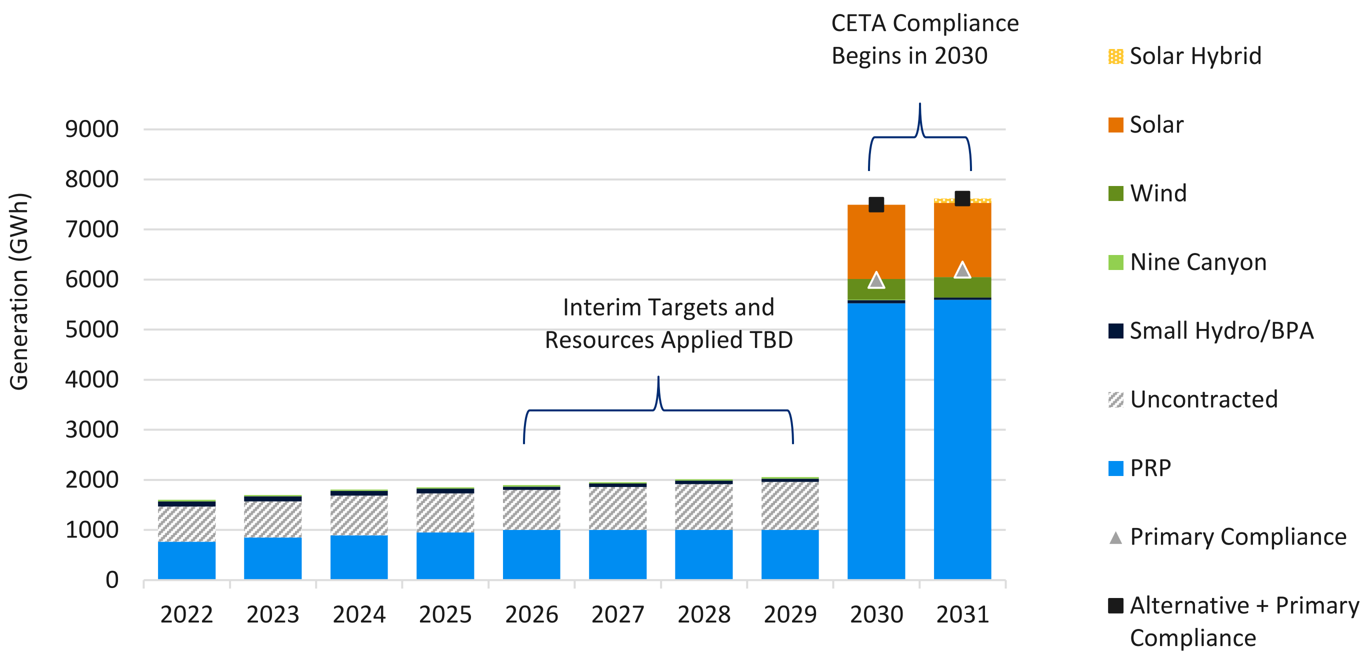


Figure 29. CETA eligible generation in selected portfolio

The 80% CETA generation requirement is indicated by the grey triangles and the 100% GHG neutral CETA requirement is shown by the black squares. Please note that the illustration for the period 2026 through 2031 does not constitute an implementation plan for meeting CETA requirements but is only a representation of resources available through the selected portfolio.

Selected Resource Mix for Low and High Load Growth Cases

Figure 30 shows the capacity buildout of the selected portfolios for the low and high load growth scenarios compared to that of the reference case. The generation mix for these scenarios is shown in Figure 31. The capacity additions in the low and high load growth scenarios rely on the same types of resources as the reference case, but the magnitude of resources added tracks with the load growth. Natural gas peaking plants are added in all three cases to help meet firm capacity needs, while wind and solar provide shares of clean energy. The low load growth scenario differs from the other scenarios in that once new resources are added there is less reliance on market purchases to meet energy needs.

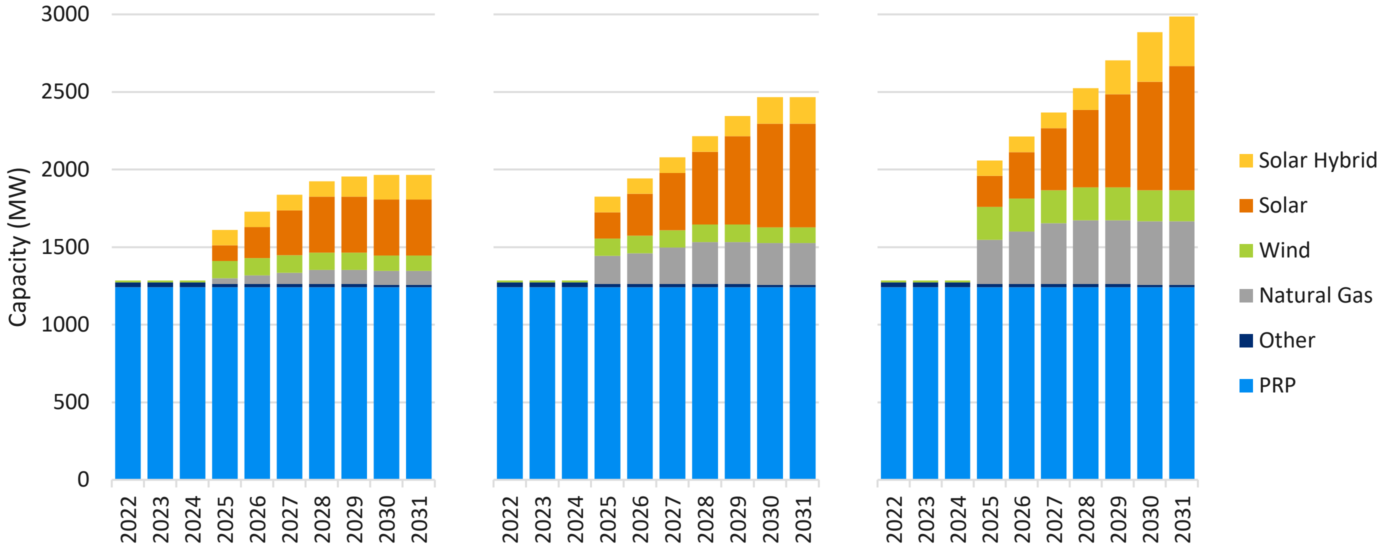


Figure 30. Capacity buildout with low (left), base (middle), and high (right) load growth assumptions. Other is Quincy Chute, Potholes East Canal, and BPA imports.

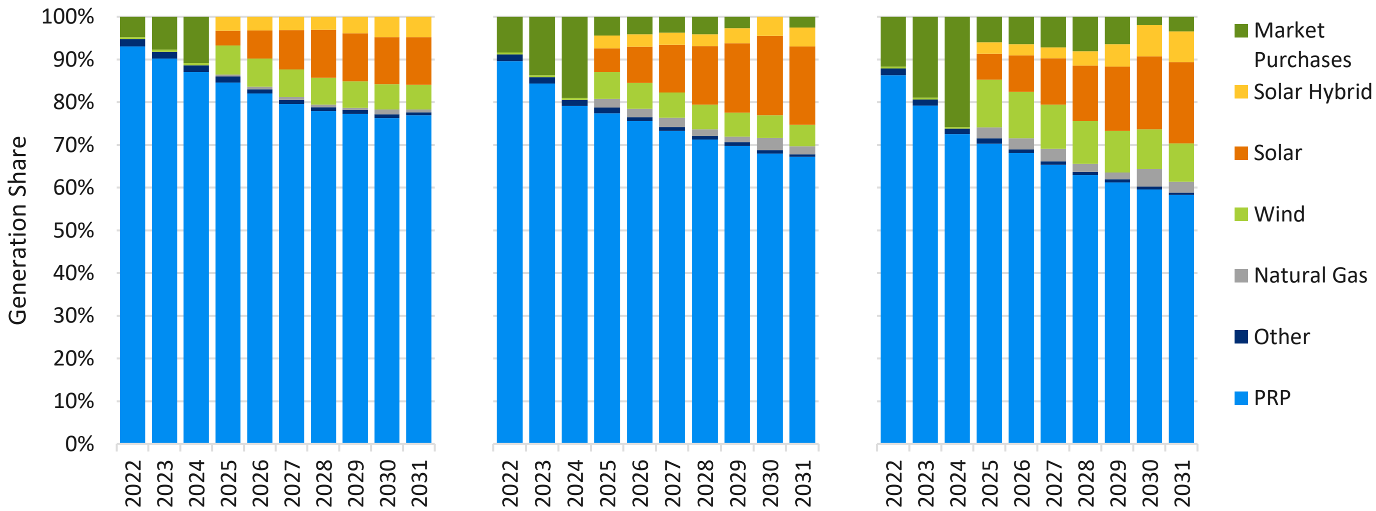


Figure 31. Generation mixes of the low (left), reference (middle), and high (right) load growth assumptions. Other is Quincy Chute, Potholes East Canal, and BPA imports.

7 | Conclusions and Action Plan

We are operating a system in a very dynamic environment with considerable uncertainty surrounding future conditions. Load forecasts show that with our current resource portfolio we will be physically short on energy at the expiration of our current pooling agreement in 2025 and physically short on capacity by 2026. To date, physical short positions have easily and cost-effectively been addressed via slice contracts, pooling agreements, and bilateral wholesale energy trading. However, detailed system modeling suggests that portfolio additions of wind, solar, solar/battery hybrid and RICE resources could be part of a least-cost solution for serving the future electricity needs of customers. The selected portfolio, containing these additions can meet energy requirements over the ten-year planning horizon, has been shown via modeling to operate robustly on an hourly basis, is capable of meeting capacity planning reserve targets, is compliant with the RPS, and provides a path for meeting 2030-2031 CETA requirements.

The magnitude of additional resources required is strongly dependent on the rate of load growth, which is a significant factor of uncertainty. Given the assumptions in this analysis, it is unlikely that changes to load growth expectations alone will change the resource mix selected.

There are other resource options under consideration, including nuclear small modular reactors, post-2028 BPA priority contracts, and continued reliance on slice contracts, pooling agreements, and bilateral trades. As further information becomes available, these options may affect future resource decisions.

ACTION PLAN

Based on the work completed in this IRP, we will take the following actions:

- Continue to develop in-house the tools and capabilities needed to assess hourly and sub-hourly dispatch of our cascaded hydropower system, variable renewable energy systems, thermal generation, and storage. This capability will be important for resource evaluation, estimating the costs and benefits of various types of market participation, and understanding the system impacts of load growth and water availability.
- Continue to enhance capabilities to assess future load growth to better understand the potential magnitude and desired characteristics of future resource needs.
- Integrate resource selection modeling capabilities with rate design and load forecasting. Integration will allow investigation into how modeled resource options might influence rates, and how rates might then influence load forecasts, enabling feedback among the various efforts to be appropriately captured.
- Quantify the value of procuring new resources relative to relying on wholesale market purchases to fill gaps in energy and capacity requirements. This will help determine the appropriate balance of reliance on the market and procurement of new resources.
- Continue to investigate demand-side resource options to improve our understanding of how those resources might cost-effectively integrate into our resource portfolio.
- Continue to actively engage in market development activities underway in the region.
- Assess the value of adding new resources within the Grant PUD service territory relative to outside the service territory to better understand the locational value of resources.
- Investigate the option of claiming additional qualified incremental hydropower from the upgrades currently underway at Priest Rapids dam.
- Continue to be attentive to the need to value the additional services that hydropower provides and assess the costs associated with potential changes to our wholesale hedging strategy.

CLEAN ENERGY ACTION PLAN

In accordance with RCW 19.280.030, Grant PUD's CEAP is included here. Per this RCW, this plan outlines our compliance with RCW 19.405.030 through RCW 19.405.050 at the lowest reasonable cost, and at an acceptable resource adequacy standard, and identifies the specific actions to be taken.

RCW 19.405.030

This chapter requires that on or before Dec 31,2025 we must eliminate all coal-fired resources from our energy allocation. While we do not hold any coal-fired resources in our resource portfolio, nor do we intend to add any of these resources in the future, we do participate in wholesale energy market trading. For compliance with this requirement, we 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, we must demonstrate compliance using a combination of non-emitting electric generation and electricity from renewable resources, or, for up to 20% of our 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 2022 IRP, the selected portfolio was chosen such that our portfolio resources could be sufficient to meet CETA primary compliance beginning in 2030. A potential path for compliance with CETA requirements is shown in Figure 29. 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 we chose to do so. Even with consideration of the social cost of greenhouse gas, the selected portfolio does include gas-fired RICE resources to help meet resource adequacy metrics in a cost-effective manner. If we do choose to acquire gas-fired capacity in the future, generation from these assets would be monitored and controlled to maintain compliance with RCW 19.405.040. As plans develop and portfolio updates are made, we will provide updated specific pathways to meeting this RCW requirement.

This chapter also requires that we pursue all cost-effective, reliable, and feasible conservation and efficiency resources to reduce or manage retail electric load. To aid in meeting this requirement we will review and update our ten-year conservation potential assessment and establish a biennial acquisition target every two years. It is our intent to pursue cost effective conservation and efficiency identified in these assessments. Based on our 2021 assessment, in November of 2021, the Commission of Grant County PUD adopted Resolution No. 8974 establishing a ten-year conservation potential of 161,272 MWh and a two-year conservation target of 40,033 MWh.

RCW 19.405.050

This chapter requires that 100% of all sales of electricity to our customers be sourced from non-emitting and renewable resources by January 1, 2045. The selected portfolio was chosen such that, for both 2030 and 2031, 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. This is consistent with moving toward 100% non-emitting and renewable resources by January 1, 2045. However, the period after 2031 is beyond the scope of this IRP. Further planning remains to be done to determine a pathway for compliance for the period after 2031 and we remain committed to determining that pathway through continued analysis and planning.

References

"Western Energy Imbalance Market Benefits Report First Quarter 2022." Folsom, CA: California ISO. https://www.westerneim.com/Documents/ISO-Western-Energy-Imbalance-Market-Benefits-Report-Q1-2022.pdf.

Department of Ecology. "Clean Fuel Standard - Washington State Department of Ecology." 2022. https://ecology.wa.gov/Air-Climate/Climate-change/Reducing-greenhouse-gases/Clean-Fuel-Standard.

"ZEV - Washington State Department of Ecology." 2022. https://ecology.wa.gov/Air-Climate/Climate-change/Reducing-greenhouse-gases/ZEV.

Draxl, Caroline, Andrew Clifton, Bri-Mathias Hodge, and Jim McCaa. 2015. "The Wind Integration National Dataset (WIND) Toolkit." *Applied Energy* 151 (August): 355–66. https://doi.org/10.1016/j.apenergy.2015.03.121.

Frazier, Allister, Cara Marcy, and Wesley J. Cole. 2019. "Wind and Solar PV Deployment after Tax Credits Expire: A View from the Standard Scenarios and the Annual Energy Outlook." *Electricity Journal* 32 (8). https://doi.org/10.1016/j.tej.2019.106637.

Glabau, B., E. Nielsen, A. Mylvahanan, N. Stephan, C. Frans, K. Duffy, J. Giovando, and J. Johnson. 2020. "Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies, Part II: Columbia River Reservoir Regulation and Operations–Modeling and Analyses." River Management Joint Operating Committee. https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-ll.PDF.

Jorgenson, Jennie, Sarah Awara, Gord Stephen, and Trieu Mai. 2021. "Comparing Capacity Credit Calculations for Wind: A Case Study in Texas." NREL/TP-5C00-80486. Golden, CO: National Renewable Energy Laboratory. https://doi.org/10.2172/1823456.

Mills, Andrew, Dev Millstein, Ryan Wiser, Joachim Seel, Juan Carvallo, Seongeun Jeong, and Will Gorman. 2019. "Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017." Berkeley, CA: Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/lbnl_-_wind_and_solar_impacts_on_wholesale_prices_approved.pdf.

NREL. 2022a. "NSRDB." 2022. https://nsrdb.nrel.gov/.

———. 2022b. *System Advisor Model* (version 2021.12.2). Golden, CO: National Renewable Energy Laboratory. https://sam.nrel.gov/.

NWPCC. 2022. "The 2021 Northwest Power Plan." Portland, OR: Northwest Power and Conservation Council. https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf.

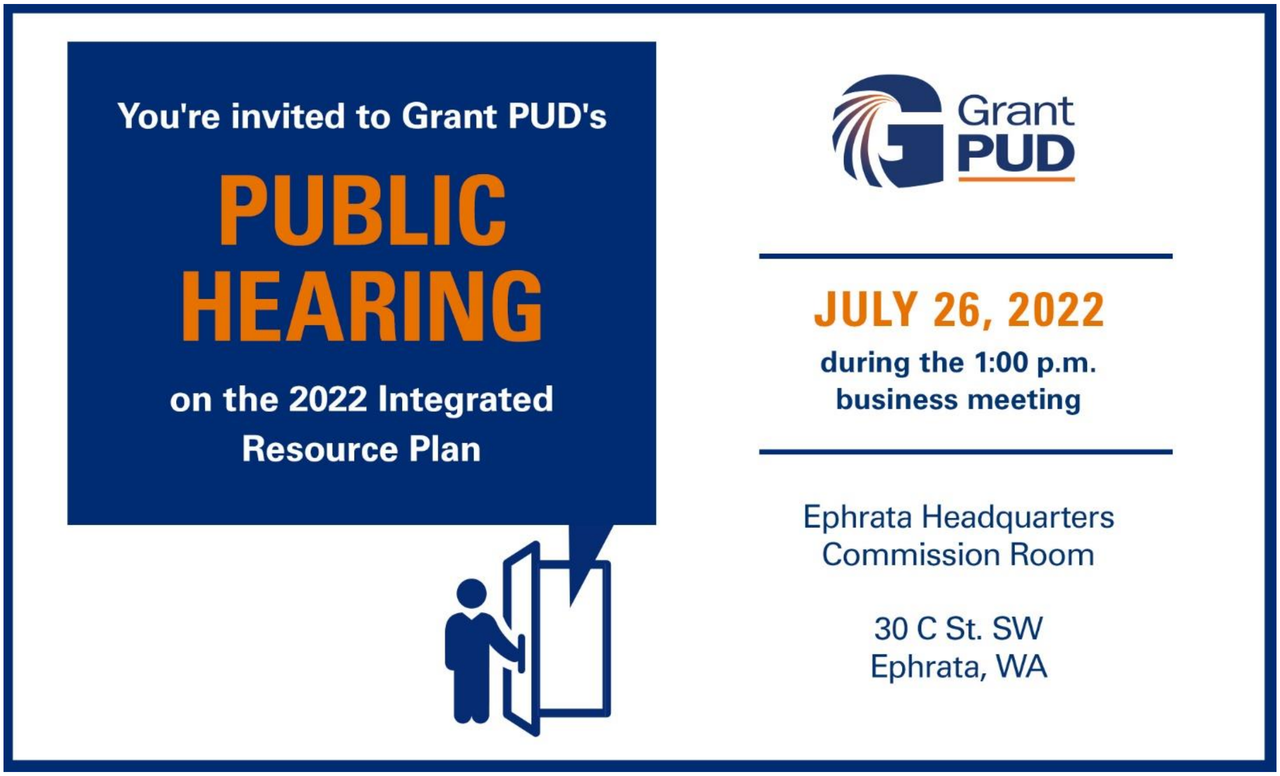
NWPP. 2021. "NWPP Resource Adequacy Program – Detailed Design." Portland, OR: Western Power Pool. https://www.westernpowerpool.org/private-media/documents/2021-08-30_NWPP_RA_2B_Design_v4_final.pdf.

Rand, Joseph, Mark Bolinger, Ryan Wiser, Seongeun Jeong, and Bentham Paulos. 2022. "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021." Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf.

Seel, Joachim, Dev Millstein, Andrew Mills, Mark Bolinger, and Ryan Wiser. 2021. "Plentiful Electricity Turns Wholesale Prices Negative." *Advances in Applied Energy* 4 (November): 100073. https://doi.org/10.1016/j.adapen.2021.100073.

SPP. 2022. "Markets+." Spp.Org. 2022. https://www.spp.org/western-services/marketsplus/.

Public Notice of IRP Hearing



Appendix 1: PowerSIMM Model Description

POWERSIMM MODEL

Ascend Analytics was contracted to perform PowerSIMM modeling of the Grant PUD system, including the evaluation of potential future resources. The PowerSIMM framework leverages the power of modern computing to solve power system optimization problems using Monte Carlo simulation techniques, stochastic optimization, and artificial intelligence. PowerSIMM was built to support planning for systems where renewables are increasing their share of system energy and can provide insight needed to make decisions that yield value for utility customers and avoid stranded asset risks. PowerSIMM is a commercial software solution for planning and portfolio management used by utilities across the United States.

Table 9 summarizes the PowerSIMM modeling philosophy and how it relates to modern resources planning for a robust power system.

Table 9. PowerSIMM modeling philosophy.

The Approach	The Reason
Simulate renewable generation, loads, and market prices as a function of weather	Weather is a fundamental driver of uncertainty, especially with renewables where weather serves as the fuel. PowerSIMM's simulation approach generates "meaningful uncertainty" which enables insight into resource value in real-world conditions, rather than relying on idealized average conditions that rarely occur.
Identify risk using a risk-premium calculation	Not all least-cost portfolios in traditional modeling are truly least cost in real life. For example, some models might rely on the average or typical week approach due to computing limitations. However, the grid with high renewables is unlikely to experience typical weeks. By simulating and probabilistically enveloping future states, including unlikely but high-impact tail events (i.e., Black Swans), the model can quantify the risk profile of different portfolios and use that information in decision analysis. PowerSIMM can 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	Before the growth of variable renewable energy resources, there was less need to simulate loss of load probability. A standard reserve margin calculation was typically enough. Now and into the foreseeable future, the grid must maintain reliability with resources of uncertain output and storage 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, the PowerSIMM modeling framework can determine the reliability impacts of different portfolios and the true capacity contribution of renewables and batteries.

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 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 32.

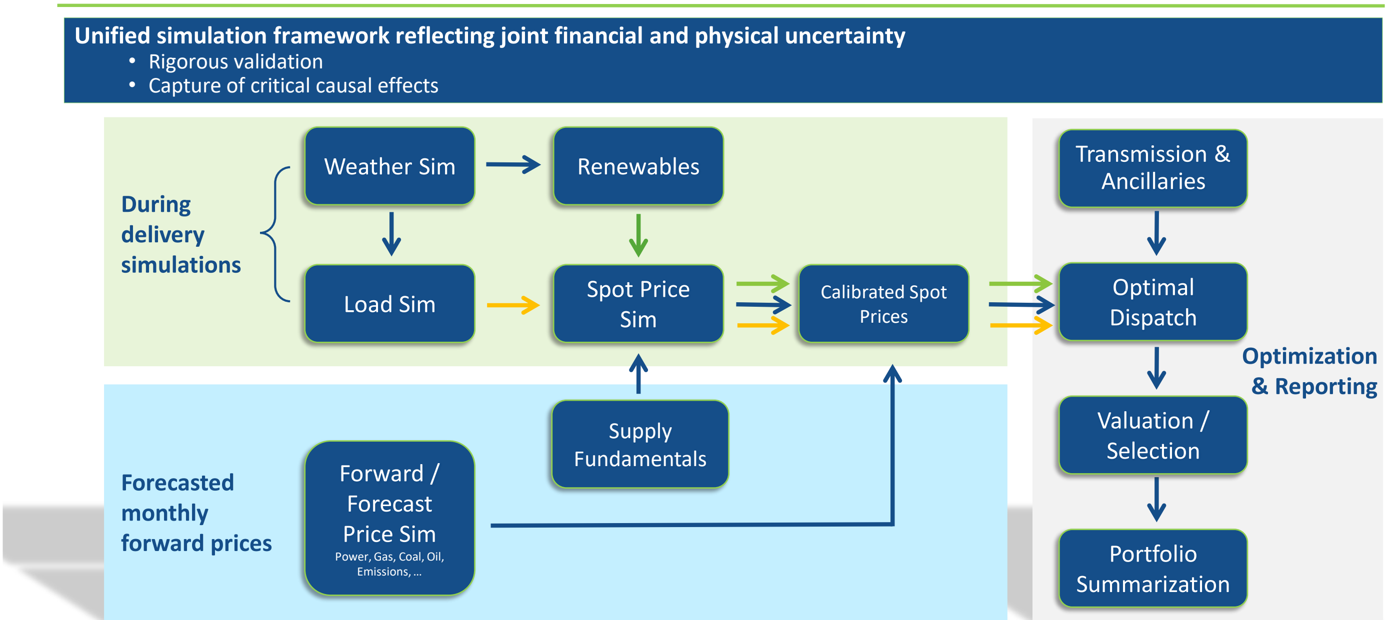


Figure 32. PowerSIMM modeling framework

PowerSIMM simulates hourly spot price conditions as a function of weather, system load, and renewable generation. 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 (refer to next section for more details). 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 and the Pacific Northwest system load, as well as output from renewable generation. In Grant PUD's IRP, 100 different future conditions (simreps) were simulated, where market prices, weather patterns, renewable generation, water availability, and load were varied. Results are summarized across these simreps to capture the full distribution of outcomes, including the mean, median, 5th percentile, and 95th percentile estimates.

FUNDAMENTAL PRICE FORECAST FOR MID-C

Energy markets are rapidly changing. Renewables and storage deployment across the US 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 resource planning and procurement decision-making. 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 33 shows the general schematic of Ascend's approach.

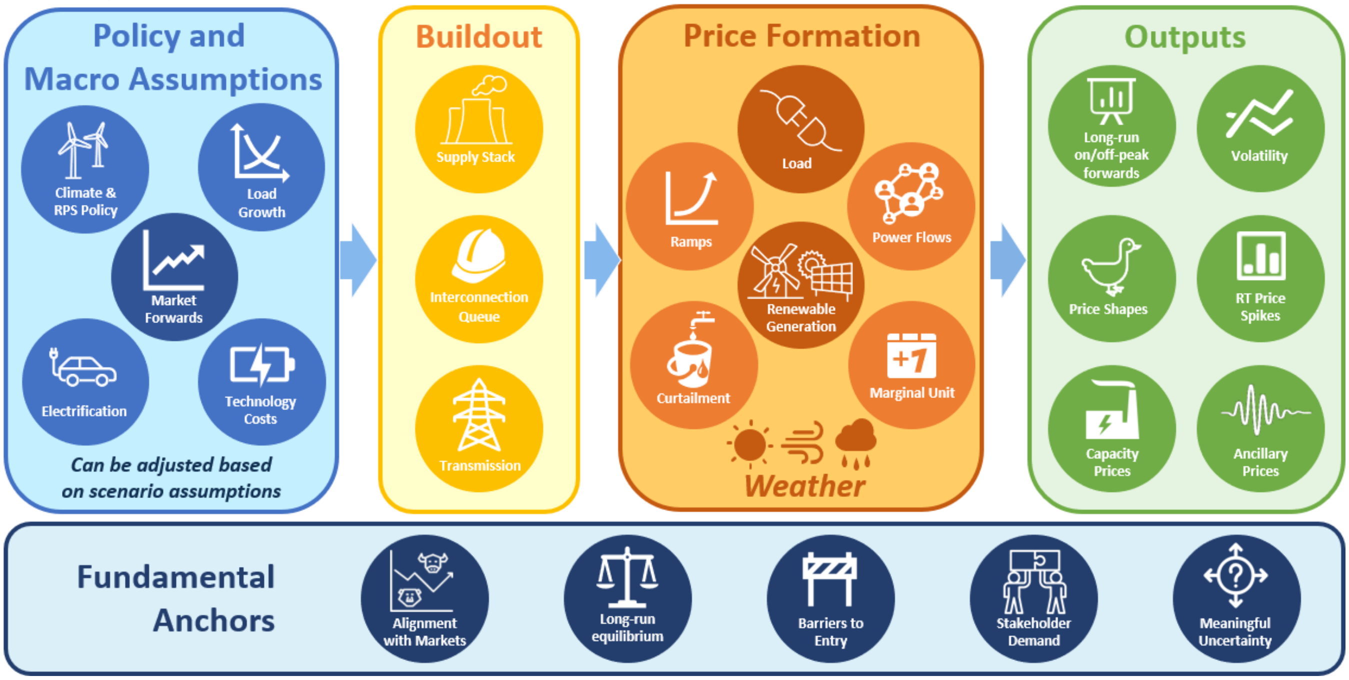


Figure 33. Ascend's fundamental wholesale market price modeling framework

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.

1.1 RESOURCE PLANNING IN POWERSIMM

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 (see Figure 34.)

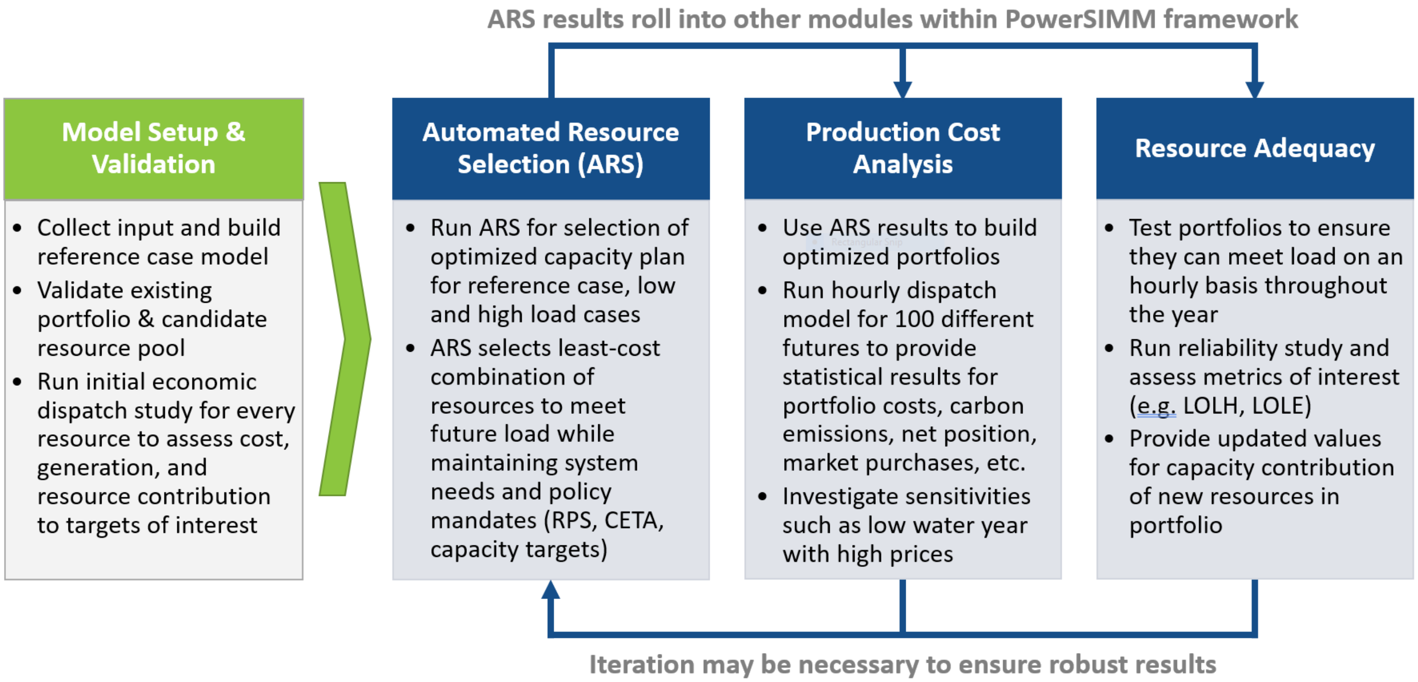


Figure 34. Modeling framework to develop compliant, reliable, and least cost portfolios in PowerSIMM.

1.1.1 Model Setup & Validation

In order to model Grant PUD's portfolio, Ascend collected information about load, generation assets, existing contracts, and market constraints. For load, Ascend uses historical data to determine weather correlations for its simulations. Ascend also has a wealth of experience working with utilities throughout the US 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 constraints and implement them in the model. After model configuration, Ascend ran a base case 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.

1.1.2 Capacity Expansion Planning

Ascend uses 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 specifies the physical and financial aspects of all candidate resources for meeting load. We also create appropriate constraints such as meeting clean energy targets, meeting an RPS goal, maintaining reliability, achieving carbon reduction targets, and maintaining 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 both cost and risk. Ascend can also perform several ARS runs with varying inputs for macro level uncertainties, according to each of the different cases to be considered. For example, runs can be performed with and without carbon costs, according to different RPS or clean energy targets, with different planning reserve margins, forcing 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."

1.1.3 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 of 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.

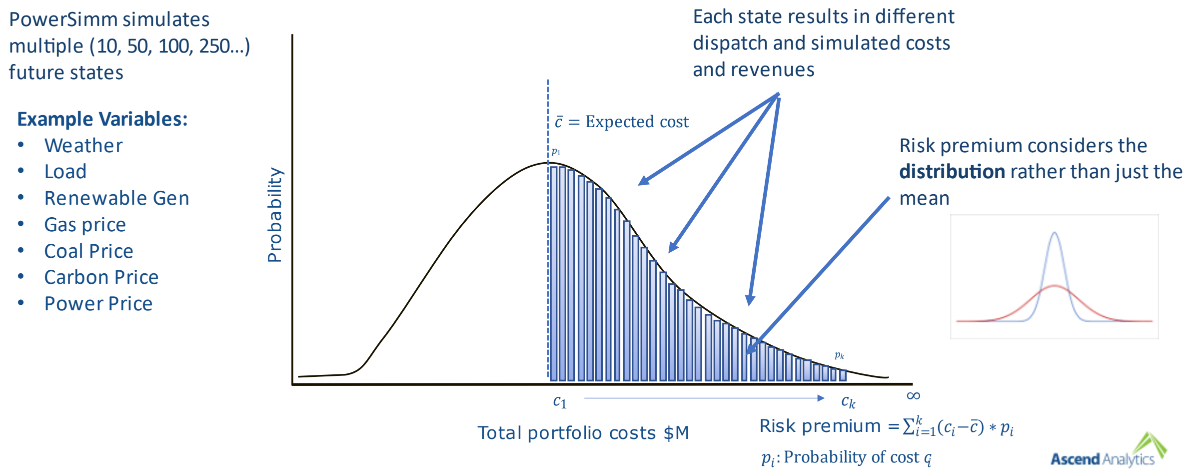


Figure 35. Risk premium concept for capturing the cost at risk associated with different portfolios

To capture the risk associated with the distribution of portfolio costs (resulting from the 100 different futures), we use the "risk premium" metric (shown in Figure 35) 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. The risk premium concept allows portfolios with different risk characteristics to be compared.

1.1.4 Reliability and Capacity Analysis

Ascend's reliability analysis is trusted by clients across the US. Our 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 are also accounted for in the reliability assessment. Ascend will evaluate this risk with hourly simulations using the standard loss of load metrics: Loss of Load Probability, Loss of Load Expectation, and Expected Unserved Energy (see Figure 36.) Additionally, Ascend 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

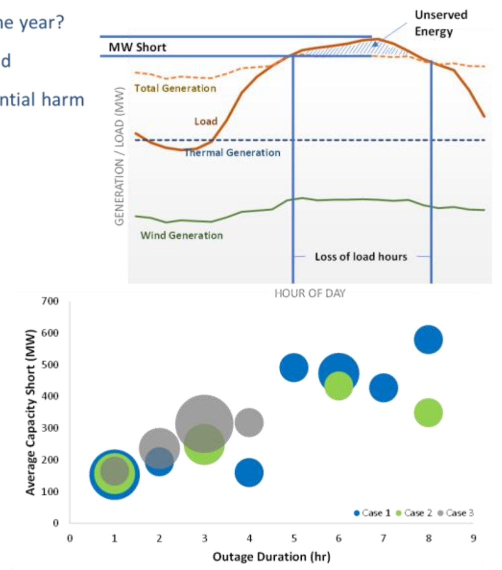


Figure 36. Overview of resource adequacy metrics and results.

Appendix 2: Modeling Inputs and Assumptions

PRIEST RAPIDS PROJECT

The Priests Rapids Project consists of the Wanapum Dam and the Priest Rapids Dam. Both dams are subject to a number of constraints, which are summarized in Table 10. Most of these constraints are intended to facilitate a healthy salmon habitat, especially in the area downstream of the Priest Rapids Dam.

Table 10. Constraints applied to the Priest Rapids Project

Constraint	Start Date	End Date	Impact
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	Varies*	Varies*	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.

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 10, 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 2015-2021, and the resources were assumed to provide as many average MWhs in future years as they did on average from 2015-2021. These three resources are assumed to retire from the Grant PUD portfolio upon the expiration of their contracts. The Nine Canyon contracts end on July 1, 2030, Quincy Chute on October 1, 2025, and Potholes East Canal on September 1, 2030.

POTENTIAL FUTURES RESOURCES

Aeroderivative Gas Turbine

Cost and operating characteristics of Aeroderivative units were provided by our consulting partner, Ascend Analytics as shown in Table 11.

Table 11. Aeroderivative modeling assumptions

Characteristic	Value
Overnight Capital Cost	$900/kW
Fixed Cost	$0.9/kW-month
Cold Start Up Cost	$500
VOM	$5.75/MWh
Min Up and Down Time	1 hour
Ramp Rate	50 MW/Min
Heat Rate	9,472 Btu/kWh
CO2 Emission Rate	118 lbs/MMBtu

AECO hub gas prices were used as fuel costs. For portfolio selection, Aeroderivative resources were available in 43 MW increments and no addition of these resources was allowed before 2025.

Reciprocating Internal Combustion Engines

Cost and operating characteristics of RICE units were provided by our consulting partner, Ascend Analytics as shown in Table 12.

Table 12. RICE modeling assumptions

Characteristic	Value
Overnight Capital Cost	$1,000/kW
Fixed Cost	$0.9/kW-month
Cold Start Up Cost	$0
VOM	$5.75/MWh
Min Up and Down Time	0 hour
Ramp Rate	90 MW/Min
Heat Rate	8,275 Btu/kWh
CO2 Emission Rate	121 lbs/MMBtu

AECO hub gas prices were used as fuel costs. For portfolio selection, RICE resources were available in 18 MW increments and no addition of these resources was allowed before 2025.

Solar PV and Wind

PPA prices for solar PV and wind are based on the cost, performance, and financing projections for utility scale solar PV and land-based wind from the NREL 2021 Annual Technology Baseline (ATB) moderate case.[1] Federal tax credit policy is assumed to follow current law as of April 2022. A 30-year project lifetime and the market factor financials from the ATB were used when calculating a PPA price. The Utility-Scale Solar, 2021 Edition shows that for the most recent 5 years of PPA pricing data, PPA prices track the levelized cost of energy (LCOE).[2] Because of that observed relationship, we assume that PPA prices will continue to track LCOE and use the LCOE values from the 2021 ATB as projections for PPA prices. The ATB lists values in real 2019$, so to convert these to nominal dollars we first converted the 2019$ to 2021$ using the consumer pricing index from 2019 to 2021 and then applied a constant inflation rate of 2.5%/year to years after 2021. The resulting PPA prices at the point of generation are shown in Figure 37.

---

[1] See atb.nrel.gov.

[2] See slide 34 at https://eta-publications.lbl.gov/sites/default/files/utility_scale_solar_2021_edition_slides.pdf.

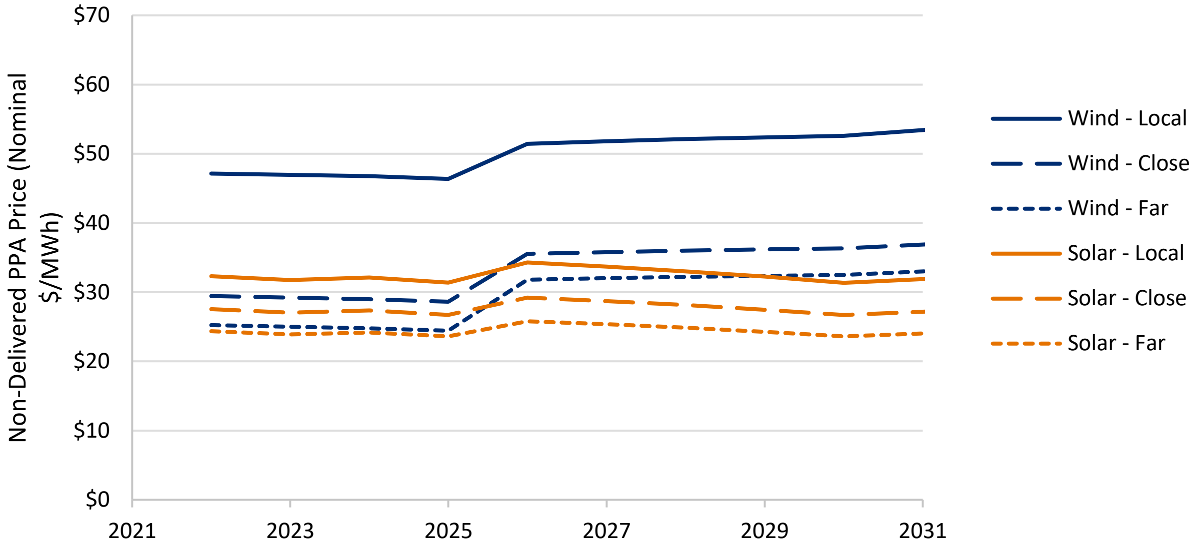


Figure 37. Assumed PPA prices for solar and wind resources at the point of generation.
"Close" and "Far" resources will need to be delivered to Grant PUD and will therefore have a higher delivered cost based on wheeling charges (see Table 6 and Table 7.)

Because the "Close" and "Far" resource locations are not located near the Grant PUD transmission system, we assume a delivery cost of wheeling the solar and wind generation to the Grant PUD system. Wheeling costs are summarized in Table 13. The "Close" wheeling cost is based on the cost of wheeling on the BPA system, and the "Far" wheeling cost is based on wheeling across the BPA system plus one other system that has an assumed wheeling cost of $3/kW/month. Wheeling capacity is procured based on the rated capacity of the wind or solar system. No attempt was made to procure lower wheeling capacity amounts to result in a lower overall cost.

Table 13. Capacity factor and wheeling costs for wind and solar resources.

	Capacity Factor (%)		Wheeling Cost ($/kW/month)		Wheeling Cost ($/MWh)	
	Wind	**Solar**	**Wind**	**Solar**	**Wind**	**Solar**
Local	26%	25%	0	0	0	0
Close	37%	29%	1.96	1.96	7.23	9.28
Far	42%	33%	4.96	4.96	16.35	20.73

The PPA price at the point of generation is combined with the wheeling cost to produce a delivered PPA price for Grant PUD. This delivered PPA price is shown in Figure 38, and is the PPA price seen by the model for selecting new resource options.

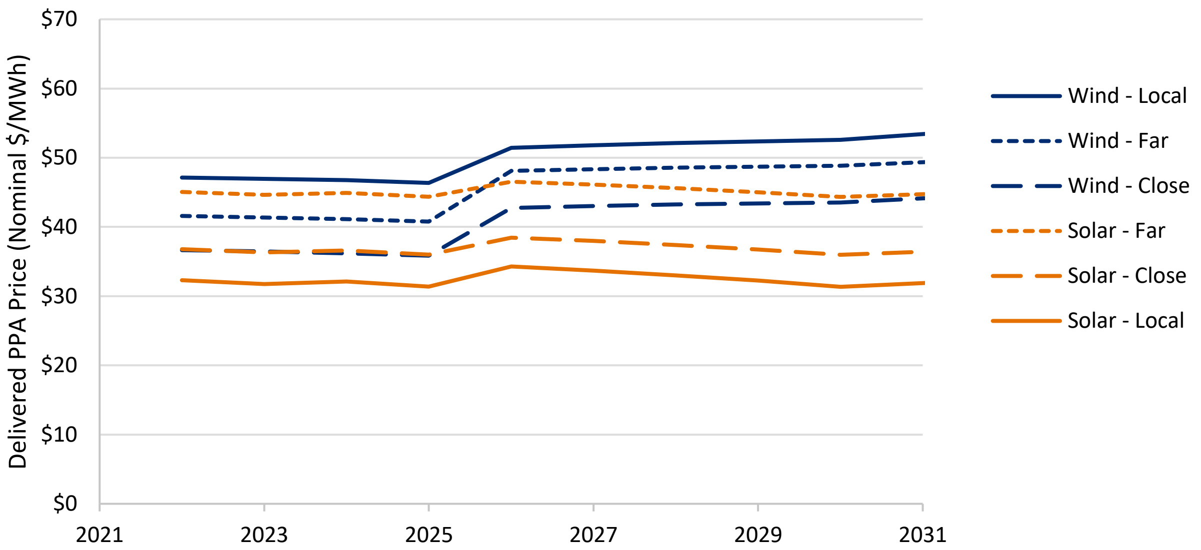


Figure 38. Assumed PPA prices for delivery to Grant PUD.
The increase from 2025 to 2026 is driven by the phase-down of the tax credits.

Battery Storage

Battery storage technologies can either be standalone with 4 or 8 hours of duration or can be hybrid resources where they are tightly DC-coupled with PV systems. When in a hybrid configuration, the storage is sized at 50% of the PV inverter capacity, and the storage is eligible for the investment tax credit. The assumed PPA prices are based on recommended values provided by Ascend Analytics and are shown in Figure 39. Any new battery storage resources are assumed to be connected to the Grant PUD system. For hybrid systems, this means that the hybrid option is only available for “Local” solar resources.

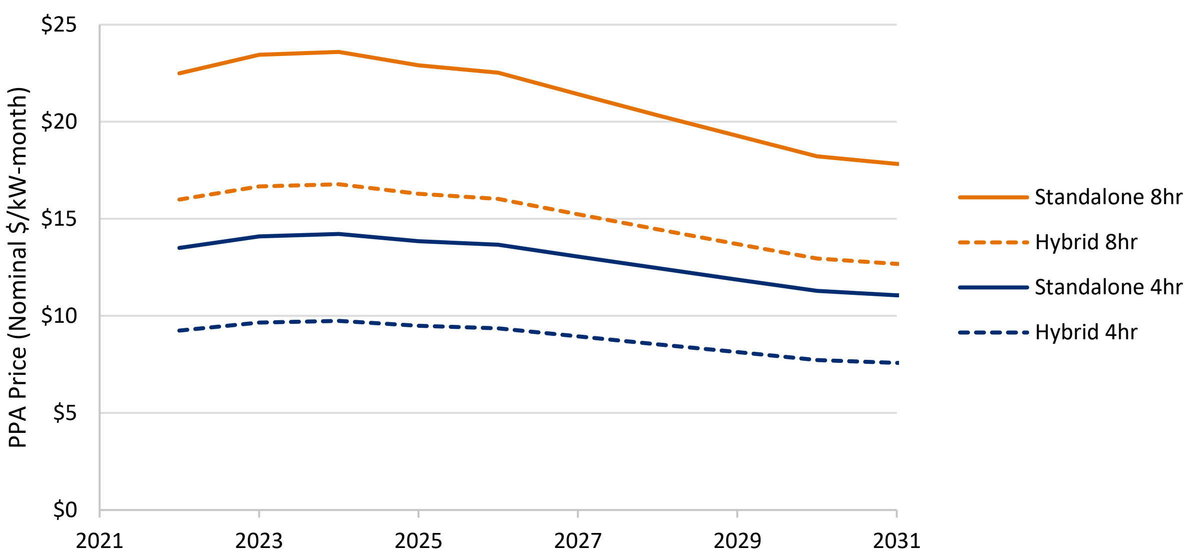


Figure 39. Assumed PPA prices for storage technologies

Battery storage technologies have an assumed lifetime of 15 years and are allowed to cycle up to 365 times per year. They have a round-trip efficiency of 85%.

Small Modular Reactor

We represent a small modular reactor with the input cost information shown in Table 14. Cost information was provided by NuScale for an nth-of-a-kind plant (NuScale 2022). The overnight capital costs include the cost of decommissioning the plant at the end of its 60-year life. We assume an availability factor of 96%, a minimum turndown of 40%, a ramp rate of 3% per minute, and a construction time of 3 years. Based on current estimated online dates for small modular reactors that are under development, we do not allow the model to select a small modular reactor until 2030.

Table 14. Input costs for a small modular reactor technology. Values in nominal dollars using a 2.5% inflation rate post 2021

Year	Overnight Capital Cost ($/kW)	FOM ($/kW-yr)	VOM ($/MWh)	Fuel Cost ($/MWh)
2030	6,163	84.5	0	8.73
2031	6,317	86.6	0	8.95

Market Purchases

Market purchases considered in this plan are assumed to transact at the Mid-C trading hub and to be from un-specified sources when accounting for clean energy goals and compliance. Hourly Mid-C price forecasts were provided by Ascend Analytics and were derived using Ascend's proprietary weather-driven simulation engine. Prices included a cost of carbon component reflecting the region's move toward carbon free power. For this analysis, market purchases were considered an energy only product and provided no capacity benefit to meet capacity margin requirements.

EFFECTIVE LOAD CARRYING CAPABILITY OF RESOURCES

New and existing resources are assigned the Effective Load Carrying Capability (ELCC) values shown in Figure 40. Natural gas units and SMRs have an ELCC of 100%. Throughout the document we refer to the ELCC capacity as firm capacity.

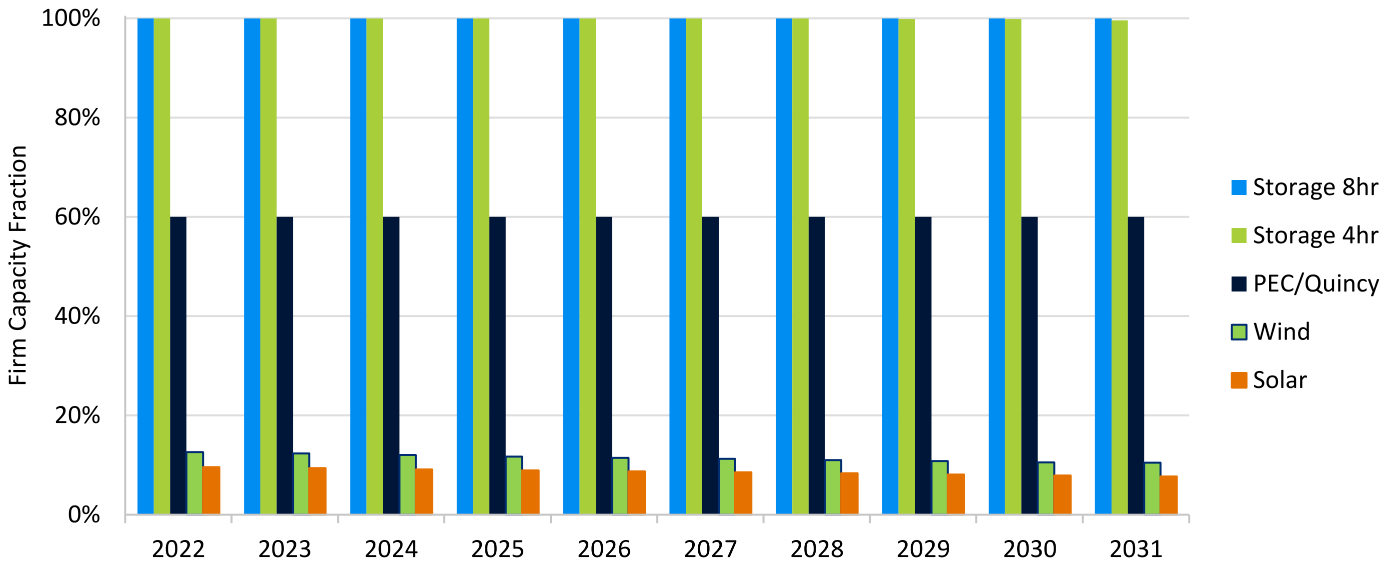


Figure 40. ELCC of new and existing resources by technology type

The firm capacity contribution of each of the PRP dams is calculated using flows and operations observed over the last 10 years and imposes all constraints shown in Table 10. Capacity values vary by month, as shown in Figure 41. During times of reliability events, the Fish Mode constraint can be violated for short periods, but that exception was not modeled when determining the firm capacity of the dams because it is unclear if the short duration of the allowed violation would be sufficient to provide additional firm capacity. For modeling purposes, we implemented an annual firm capacity contribution of 855 MW for Wanapum and 818 MW for Priest Rapids. Because of the upgrades occurring at Priest Rapids, one of the ten units is assumed to be offline through 2030 which reduces the firm capacity contribution of Priest Rapids by 10% until that time.

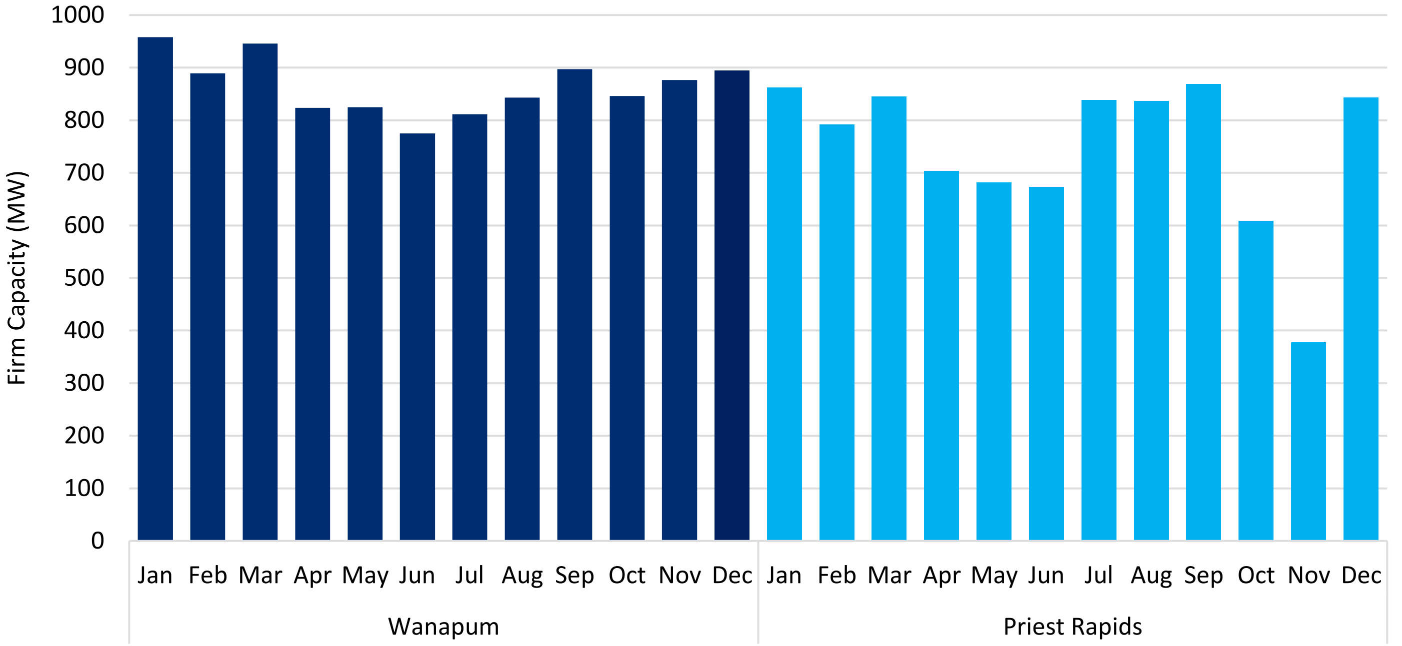


Figure 41. Firm capacity contribution of the Wanapum and Priest Rapids dams for each month of the year.

SOCIAL COST OF CARBON

The social cost of carbon is included in the modeling as shown in Figure 42. Values are from WAC 194-40-100 and are adjusted to nominal dollars.

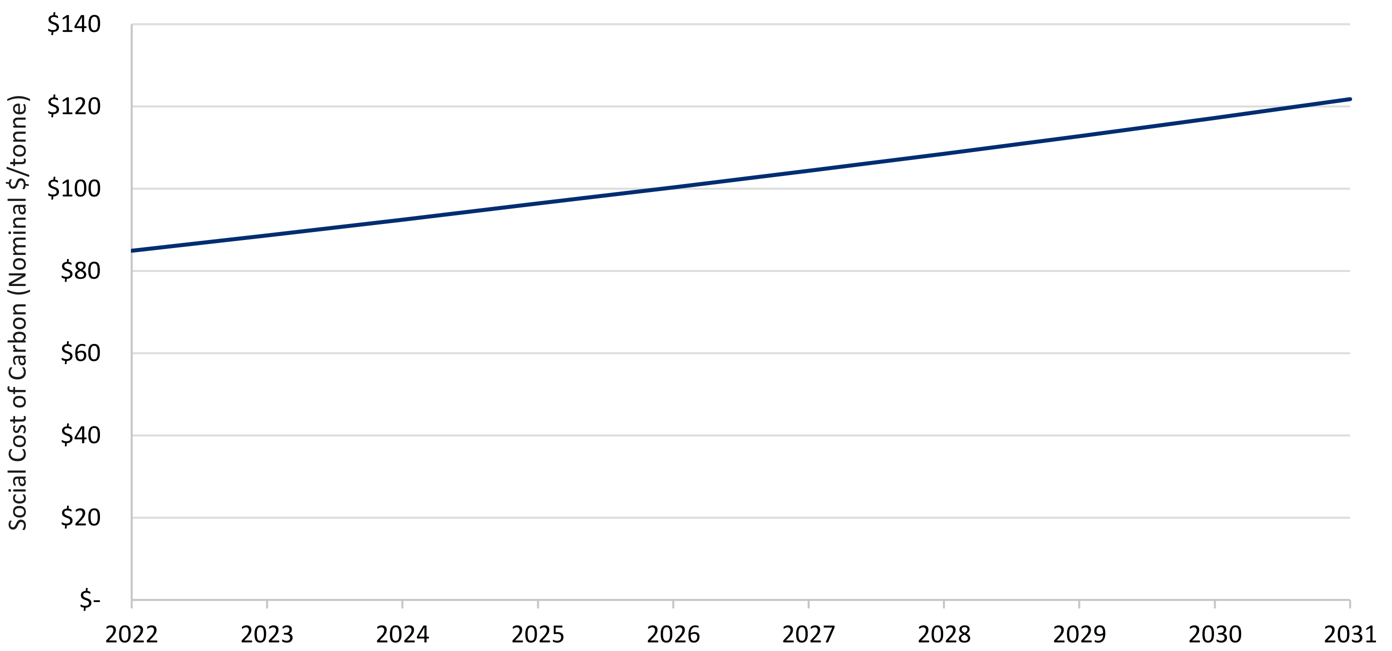


Figure 42. Social cost of carbon applied in the modeling. From WAC 194-40-100.

Because the only carbon-emitting resource considered in this IRP were the Aeroderivative Gas Turbine and the Reciprocating Internal Combustion Engine, this social cost of carbon impacts only those two resources according to their emission rates (shown in Table 11and Table 12) and the amount of energy they generate.

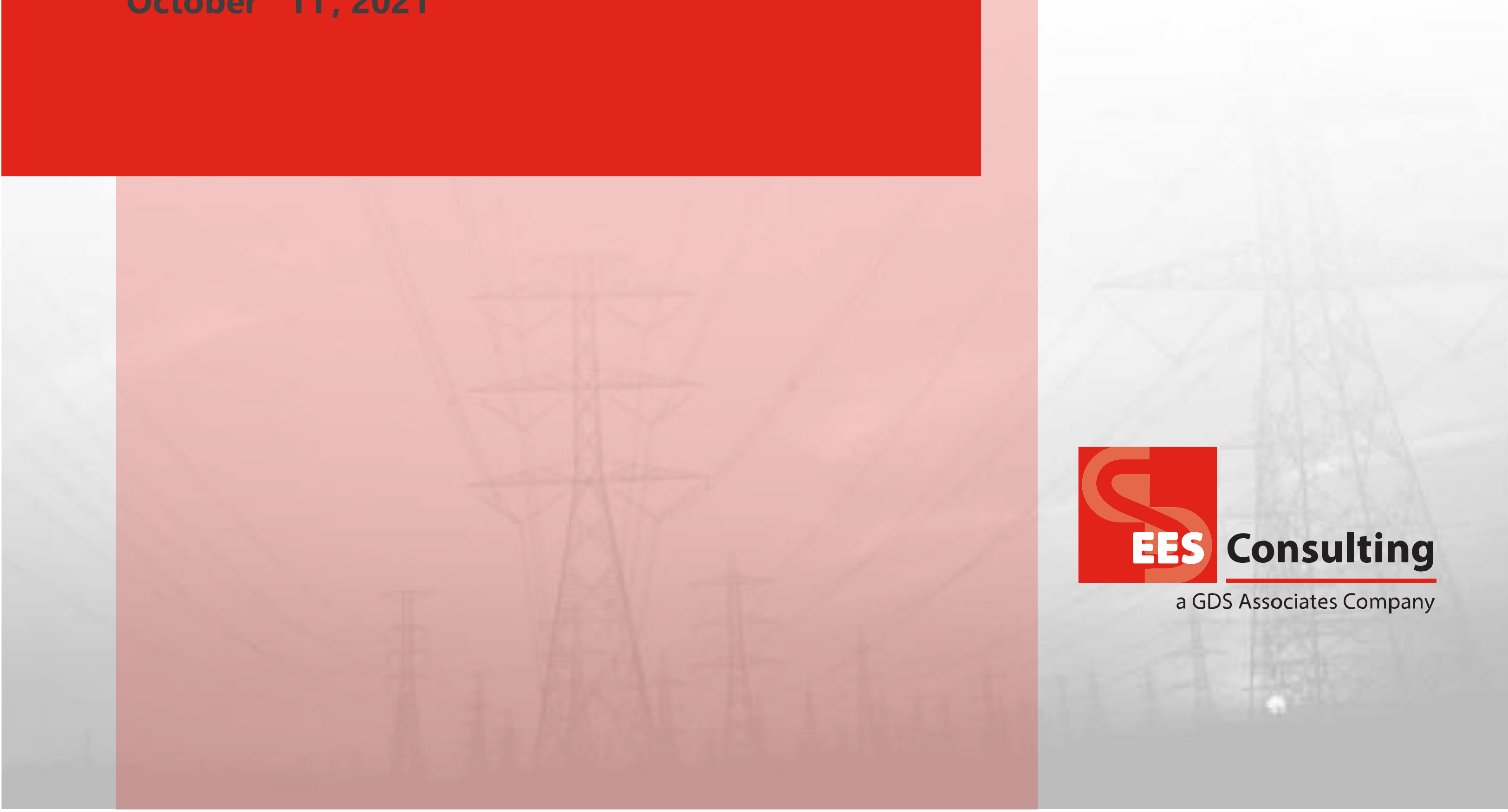
Appendix 3: Conservation Potential Assessment

PREPARED BY EES CONSULTING

Grant Public Utility District

Conservation Potential Assessment

October 11, 2021



EES Consulting

a GDS Associates Company

EES Consulting
a GDS Associates Company

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

October 11, 2021

Mr. Richard Cole
Grant PUD
P.O. Box 1519
Moses Lake, WA 98837

SUBJECT: 2021 Conservation Potential Assessment – Final Report

Dear Mr. Cole:

Please find attached the draft report summarizing the 2021 Grant Public Utility District Conservation Potential Assessment (CPA). This report covers the 20-year time period from 2022 through 2041.

The 2-year potential has increased from the 2019 CPA, largely due to the addition of data center projects expected to be completed in the 2022/2023 biennium. Potential in other sectors has decreased compared with the previous CPA due to increased efficiency baselines, program participation, and updated ramp rates that reflect the District's historic program achievement.

Respectfully,

Amber Gschwend
Managing Director, EES Consulting

Contents

1 Executive Summary

This report describes the methodology and results of the 2021 Conservation Potential Assessment (CPA) for Grant County Public Utility District No. 2 (District). This assessment provides estimates of energy savings by sector for the period 2022 to 2041. 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 over 46,900 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.

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 Seventh Power Plan. Thus, this Conservation Potential Assessment will support The District's compliance with EIA requirements.

This assessment was built on the same model used in the 2019 CPA, which was based on the completed Seventh

Power Plan. The model was updated to reflect changes since the completion of the 2019 CPA including measure data available from the draft 2021 Power Plan supply Curves and updated ramp rate assumptions. The primary model updates included the following:

- Avoided Costs
  - Recent forecast of power market prices
  - Avoided generation capacity
  - Environmental costs adjusted to meet CETA requirements
- Updated Customer Characteristics Data
  - Residential home counts and characteristics
  - Commercial floor area based on recent load data which factors in COVID impacts
  - Industrial sector consumption, which includes COVID impacts
- Measure Updates
  - Measure savings, costs, and lifetimes were updated based on the latest data available from the Regional Technical Forum (RTF) and the 2021 Power Plan draft supply curves
  - New measures not included in the Seventh Plan but subsequently reviewed by the RTF were added in the 2021 Power Plan
- Accounting for Recent Achievements
  - Internal programs
  - NEEA programs
- Adjusting measure ramp rates
  - Specific large data center analysis
  - Alignment of future potential with historic program savings

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, 6, 10, and 20-year increments. The total 20-year energy efficiency potential is 47.15 aMW. The most important numbers per the EIA are the 10-year potential of 18.41 aMW, and the two-year potential of 4.57 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 the later years. In some cases, the savings from those changes will be quantified by NEEA or through BPA's Momentum Savings work.

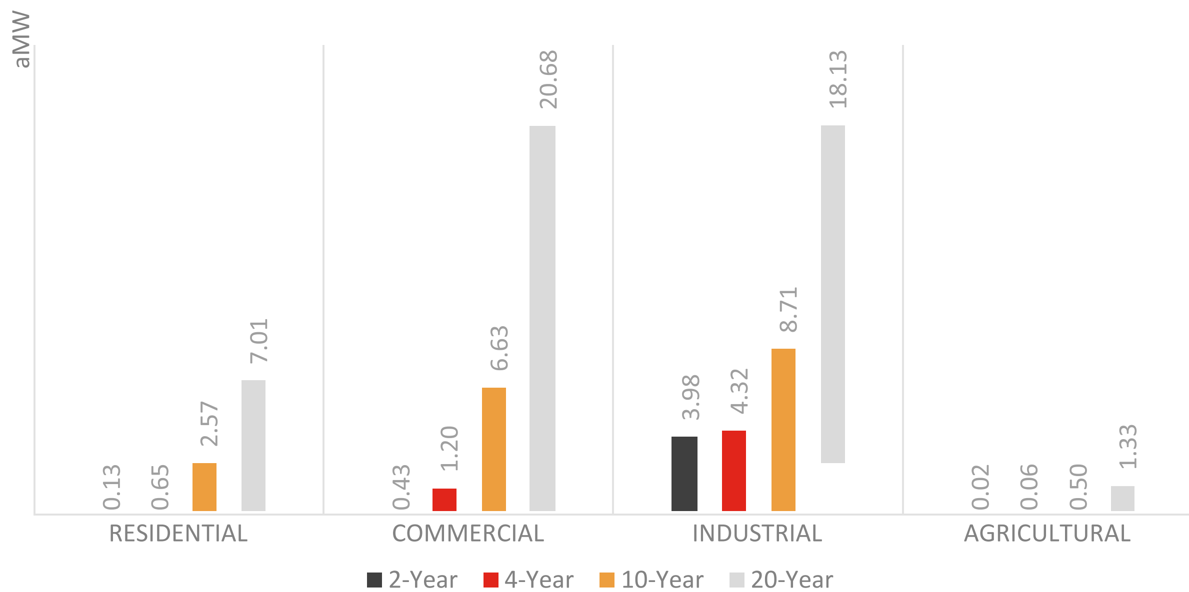
TABLE 1-1: COST-EFFECTIVE POTENTIAL (aMW)

	2-Year	4-Year	10-Year	20-Year

Residential	0.13	0.65	2.57	7.01
Commercial	0.43	1.20	6.63	20.68
Industrial	3.98	4.32	8.71	18.13
Agricultural	0.02	0.06	0.50	1.33
Total	**4.57**	**6.24**	**18.41**	**47.15**

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 Seventh Power Plan and the District-specific definition of when peak demand occurs. These unitlevel estimates are then aggregated across sectors and years in the same way energy efficiency measure savings potential is calculated. The reductions in peak demand provided by energy efficiency are summarized in Table 1-2 below.

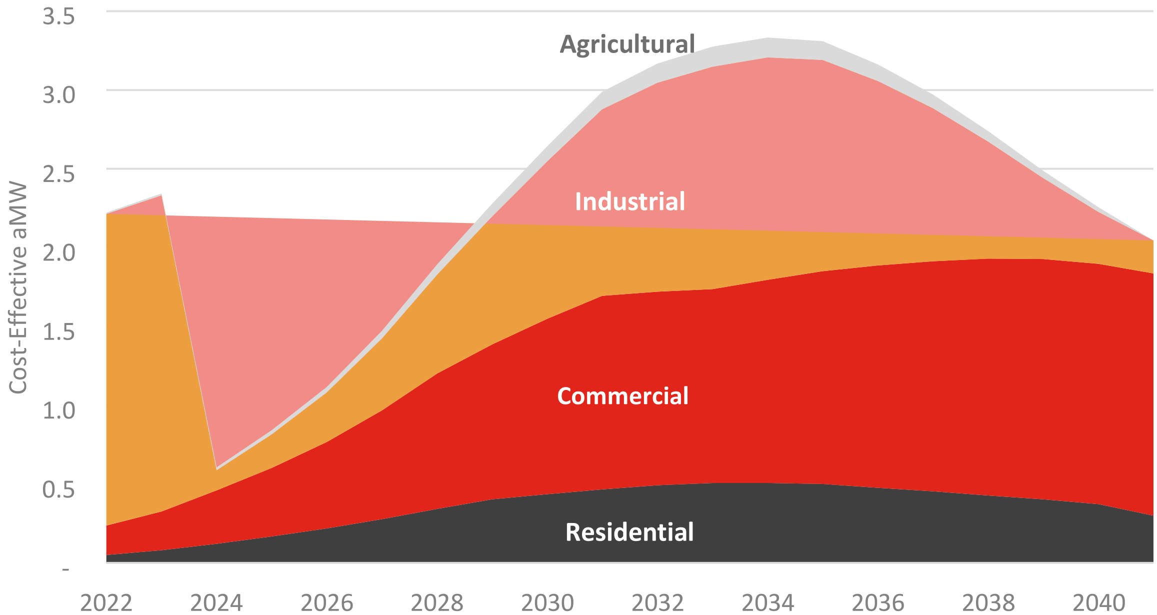
The savings from most energy efficiency measures is concentrated in those periods when energy is being used, and not evenly throughout the day. Thus, the peak demand reduction, measured in MW, is greater than the annual average energy savings. The District's annual peak occurs most frequently in summer 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	0.26	1.41	5.40	14.74
Commercial	0.33	0.83	3.54	7.44
Industrial	35.45	35.83	40.60	50.86
Agricultural	0.03	0.07	0.25	0.32
Total	**36.07**	**38.13**	**49.80**	**73.36**

The 20-year energy efficiency potential is shown on an annual basis in Figure 1-2.

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



As Figure 1-2 shows, about a 10% of the potential is in the residential sector. The largest contributing measure categories for residential applications include water heating. Measures with notable potential in this end use include:

- ✓ Efficient clothes washers
- ✓ Low flow shower heads efficiency 1.5 gallons per minute (gpm) or better
- ✓ Behavior measures

The largest share of conservation available is in the District's commercial and industrial sectors. The 20year potential in the commercial sector is higher compared with the potential estimated in the 2019 CPA. Savings in the commercial sector are spread across numerous end uses, but the primary areas for opportunity are in the HVAC and lighting categories. Notable measures in this area include:

- ✓ Residential sized and commercial sized heat pump water heaters
- ✓ Variable refrigerant flow HVAC systems
- ✓ Commercial energy management
- ✓ Commercial Lighting
- ✓ Refrigeration

Data center savings potential is responsible for the large savings in 2022/2023. The District works with new data center, and other high load factor customers such as cryptocurrency, at the time of application for new large loads. The District works with new large loads to incentivize the installation of energy efficient measures. The 2-year data center savings potential estimate is based on a planned project for a new data center load. Going forward, the District will continue to work on identifying data center projects with new loads. Current data center loads have already been optimized for energy efficiency by the customer. Therefore, future potential is based only on the load growth portion, which is updated every two years through the CPA process. Due to the uncertainty in future data center load growth, some data center saving scenarios are discussed separately in this study.

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 2019 CPA.

TABLE 1-3: COMPARISON OF 2019 CPA AND 2021 CPA COST-EFFECTIVE POTENTIAL

	2-Year			10-Year			20-Year		
	2019	**2021**	**% Change**	**2019**	**2021**	**% Change**	**2019**	**2021**	**% Change**
Residential	0.66	0.13	-80%	3.59	2.57	-29%	5.71	7.01	23%
Commercial	0.82	0.43	-47%	4.83	6.63	37%	6.94	20.68	198%
Industrial	2.42	3.98	65%	15.53	8.71	-44%	25.23	18.13	-28%
Agricultural	0.19	0.02	-90%	1.01	0.50	-50%	1.27	1.33	5%
Total	**4.09**	**4.57**	**12%**	**24.95**	**18.41**	**-26%**	**39.15**	**47.15**	**20%**

*Note that the 2019 columns refer to the CPA completed in 2019 for the time period of 2020 through 2039. The 2021 assessment is for the timeframe: 2022 through 2041.

The change in conservation potential estimated since the 2019 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 and 2021 Power Plan draft assumptions. Finally, the potential for data center savings is estimated based on individual project review for new loads. These are discussed below, and a detailed analysis is provided in the Results section of this study.

1.3.1 Measure Data

The 2021 Power Plan includes measures that impact residential lighting use including daylight exterior bulbs and lamp replacements for interior applications. These savings estimates are included in the 2021 potential estimate. Electric vehicle charging measures have increased cost-effectiveness compared with previous savings and cost assumptions. Finally, a Washington code reduced water heating savings potential beginning in 2021 by establishing a more efficient baseline for showerheads.

In the commercial sector, heat pump water heaters replace efficient tank measures increasing the 20-year potential. New commercial lighting measures such as controls equipment and lamps, were also added increasing the potential available.

1.3.2 Industrial Potential

The industrial potential for potential data center savings includes estimates for new large data centers. Savings from disaggregated servers is included in the commercial sector under "Electronics." 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. Conversely, this study evaluates data center savings for new customers at the project level. This methodology evaluates savings potential more specifically to the District's loads and unique nature of large data center operations. The bulleted list below 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 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. Due to their low incremental costs compared with savings potential, these measures are also costeffective 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.

1.3.3 Avoided Cost

An updated forecast of market prices was used to value energy savings. This forecast is lower than the forecast used in the 2019 assessment, but still higher than the 2021 draft Power Plan market price forecast. Other avoided cost assumptions remained largely the same.

1.3.4 Customer Characteristics

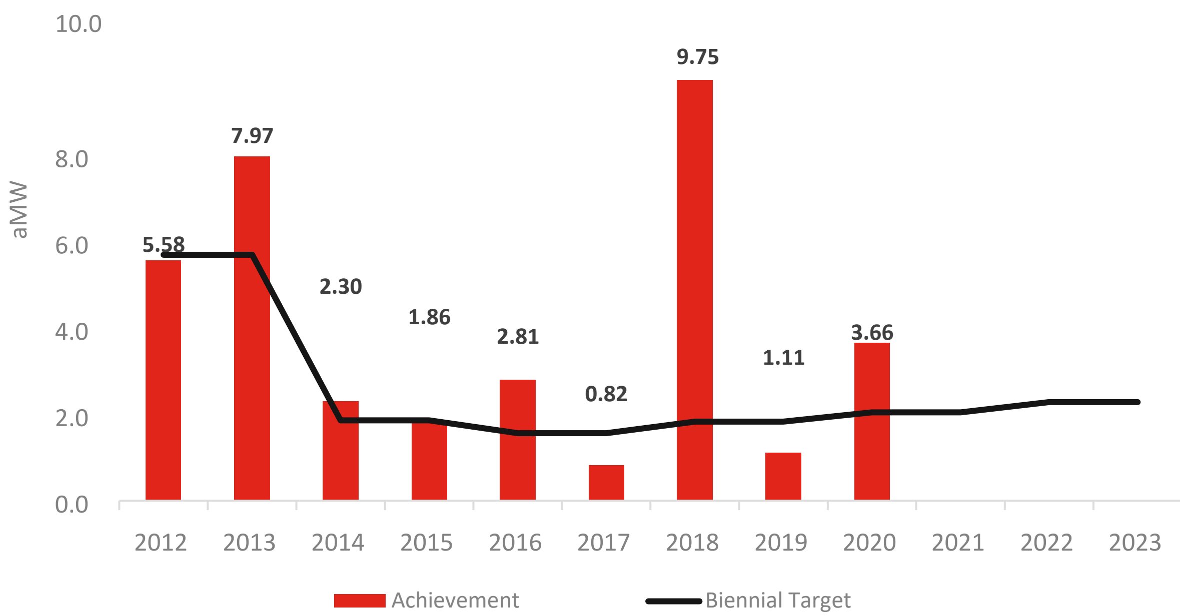
No changes were made from the last CPA. However, growth in usage and number of customers was accounted for in the update.

1.4 TARGETS AND ACHIEVEMENT

Figure 1-3 compares the District's historic achievement with its targets. The estimated potential for 2022 and 2023 is based on the Base Case scenario presented in this report and represents approximately a 12% increase over the 2020-21 biennium. This increase is due to the treatment of data center savings potential and adjusted ramp rates that better reflect the District's historic program savings trends. The figure below also shows the District has consistently met its biennial energy efficiency targets, and the potential estimates presented in this report are achievable through the Districts various programs and the District's share of NEEA savings.

FIGURE 1-3: HISTORIC ACHIEVEMENT AND TARGETS

12.0



1.5 CONCLUSION

This report summarizes the CPA conducted for the District for the 2022 to 2041 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 ramp rates from the 2021 Power Plan technical pages. The results show a total 10-year cost effective potential of 18.41 aMW and a two-year potential of 4.57 aMW for the 2022-23 biennium, which is a 12% increase from the target for the previous biennium. This increase is due primarily to savings potential in new large data centers.

2 Introduction

2.1 OBJECTIVES

The objective of this report is to describe the results of the Grant Public Utility District (District) 2021 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2022 to 2041, 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 2022 Integrated Resource Plan (IRP).

The conservation measures used in this analysis are based on the measures that were included in the Council's Seventh Power Plan and were updated with subsequent changes and new measures approved by the Regional Technical Forum (RTF) and draft 2021 Power Plan conservation supply curves. 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 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 2022. More background information is provided below.

2.3 ENERGY INDEPENDENCE ACT

Chapter RCW 19.285, the Energy Independence Act, requires, "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 costeffective 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.[3]

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 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

[3] 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 Seventh 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:

- ✓ The base year for the study is 2020, which has impacted electric usage levels and patterns due to the economic downturn, work from home paradigm, business closures, and changes to work schedules and business hours.
- ✓ The base year, 2020, was adjusted for COVID impacts as detailed for each sector.

The above considerations have been modeled in this study.

2.7 REPORT ORGANIZATION

The main 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
- ✓ Environmental Justice and Social Welfare
- ✓ Summary
- ✓ References & Appendices

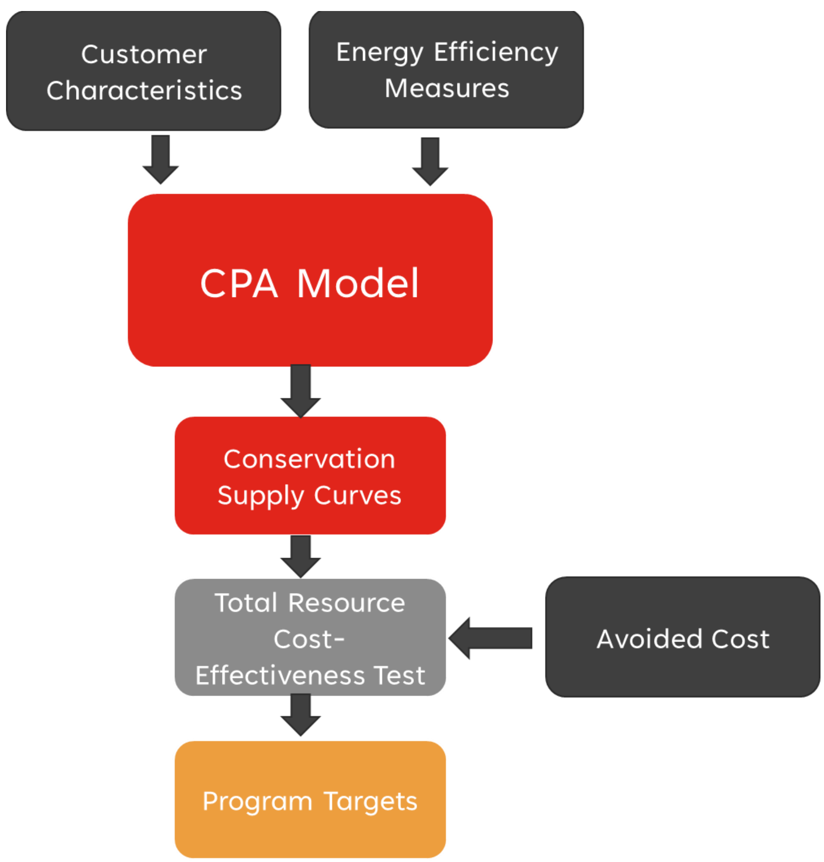
3 CPA Methodology

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 Council in developing the Seventh 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 the 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 is 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 Seventh 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 Seventh Power Plan is the primary source for conservation measure data. Where appropriate, the Council's Seventh Plan supply curve workbooks have been updated to include any subsequent updates from the RTF. New measures reviewed by the RTF were also added to the model. Finally, the Council's draft 2021 Power Plan conservation supply curves were sourced for additional measures.

The measure data include adjustments from raw savings data for several factors. The effects of spaceheating 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 financialrelated 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[4]

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

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 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 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 measureby-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 a 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. Nonenergy 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 nonenergy 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

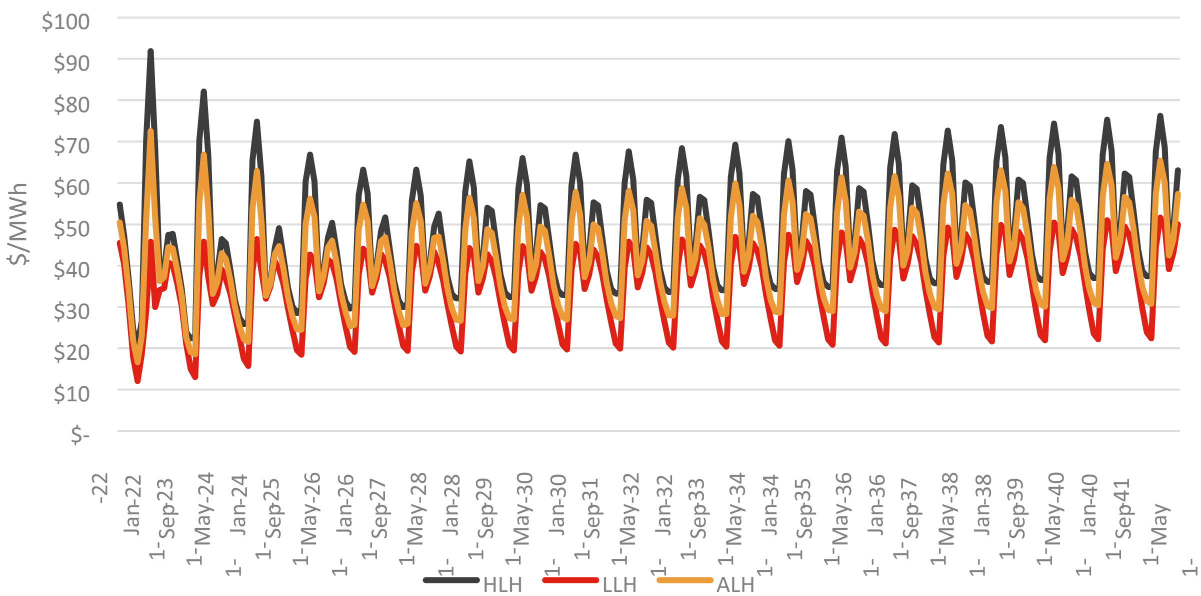
Each component of the avoided cost of energy efficiency measure savings is described below. Additional information regarding the avoided cost forecast is included in Appendix IV.

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.

Figure 3-3 shows the price forecast used as the primary avoided cost component for the planning period. The price forecast is shown for heavy load hours (HLH), light load hours (LLH), and average load hours (flat price).

FIGURE 3-3: 20-YEAR MARKET PRICE FORECAST (MID-COLUMBIA)



The EIA requires utilities "…set avoided costs equal to a forecast of market prices" and as discussed in Appendix IV, the District relies on market purchases to meet peak energy demands. Therefore, the market price forecast shown in Figure 3 is appropriate for modeling the value of avoided energy.

3.5.2 Social Cost of Carbon

The social cost of carbon is a cost society incurs when fossil fuels are burned to generate electricity. Both the EIA rules and CETA requires 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 valued used in the 2019 CPA.

TABLE 3-1: SOCIAL COST OF CARBON VALUES[5]

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 2021 dollars per metric ton)
2020	$62	$77
2025	$68	$85
2030	$73	$91
2035	$78	$97
2040	$84	$105

According to WAC 194-40-110, values may be adjusted for any taxes, fees or costs incurred by utilities to meet

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

portfolio mandates.[6] 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).[7] This is an average annual value applied to all months in the conservation potential model.[8] The resulting levelized cost of carbon is $34/MWh over the 20-year study.

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. Unbundled RECs do not have energy associated with them; therefore, the generation profile of the renewable resource is not considered in resource planning. As such, many jurisdictions exclude unbundled RECs from eligible greenhouse gas free resources. CETA rules support this methodology by allowing unbundled RECs as offsets only through 2044.

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 nonemitting 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 nonemitting 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 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 $7.18/kW-year and a transmission system credit of $3.23/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 $2021). These values were developed by Council staff in

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

[7] WAC 173-444-040 (4)

[8] For reference, the Seventh Power Plan evaluated 0.95 lbs/kWh and 0 lbs/kWh. Typically, the emissions intensity would be higher in months outside of spring run-off (June-July). The seasonal nature of carbon intensity is not modeled due to the prescriptive annual value established by Ecology in WAC 173-444-040.

preparation for the 2021 Power Plan.[9]

3.5.5 Generation Capacity

The 2020 IRP recommended the District obtain capacity resources in addition to some reliance on the market. To represent the value of capacity in the base case, the District provided a value that represents a 3 percent premium over market prices. This value is based on the opportunity cost of selling excess capacity created by energy savings in the market.

In the low scenario, it is assumed that a market will continue to be available to meet the District's needs for peak demands, so no capacity value is included.

In the Council's Seventh Power Plan,[10] a generation capacity value of $135/kW-year was explicitly calculated ($2021). This value will be used in the high scenario.

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 $9/MWh and $36/kW-year were included in the avoided cost. Note 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.

[9] 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

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

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.

In addition, the Council uses a finance rate that is developed from two sets of assumptions. The first set of assumptions describes the relative shares of the cost of conservation distributed to various sponsors. Conservation is funded by the Bonneville Power Administration, utilities, and customers. The second set of assumptions looks at the financing parameters for each of these entities to establish the after-tax average cost of capital for each group. These figures are then weighted, based on each group's assumed share of project cost to arrive at a composite finance rate.

3.7 2021 POWER PLAN METHODOLOGY CHANGES

The Council is in the process of completing the portfolio modeling for the 2021 Power Plan. As part of the target-setting approach, the Council is considering adding additional values to the avoided cost so the portfolio model selects the optimal amount of energy efficiency. These attributes are discussed in this section; however, additional avoided costs are not included at this time.

3.7.1 Adequacy

Adding efficiency to the regional system reduces the frequency, duration, and magnitude of adequacy events. Energy efficiency, as demand-side resource, is often higher quality but higher cost than alternative supply-side reserves. In particular, energy efficiency will have relatively more benefit on a solar-rich system if they reduce load in the hours following sunset, and this benefit may not be captured immediately in the capacity and energy cost forecast. This adequacy consideration addresses deferred generation benefits estimated in the Seventh Plan. While there is a time-value for adequacy, the current version of ProCost does not allow for time-varied input for adequacy costs. Since this study relies in the Seventh Plan version of ProCost,[11] the deferred generation capacity credit is used to represent adequacy benefits of energy efficiency.

3.7.2 Equity

The equity attribute refers to measures that require additional incentive or push to achieve equitable distribution of benefits. The Council defines these measures as the following:

1. Historic and long-term cost-effectiveness
2. Significant regional penetration from past program activity
3. Data demonstrating that untouched pockets are not reflective of the population (i.e. different socioeconomic status)

Equity measures are likely to be envelope measures in residential buildings. These upgrades may be expensive to homeowners or there may be a renter/landlord issue. By definition, the equity component identifies measures that are cost-effective, and have been cost-effective for a period of time. Therefore, the 2021 CPA does not add value to capture measures with equity attributes. Rather, equitable distribution of energy efficiency benefits should be addressed on the program side, rather than from the conservation target point of view.

[11] The Seventh Power Plan is the current power plan. All methodologies are designed to be consistent with the Seventh Power Plan with consideration of updates for the 2021 Power Plan scheduled to be adopted in early 2022.

3.7.3 Resilience

Resilience measures are those that support building resilience, or the ability to maintain building functions/comfort through extended power outages. The Council provides weatherization measures as resilient measures. The 2021 CPA identifies measures in the Base case that are not cost-effective but may provide building resilience benefits. The measures will be summarized in a table analysis that indicates how close to cost-effectiveness the measures are at the time of the study and what the targets may look like if those close to cost-effectiveness measures are included.

3.7.4 Flexibility

The Council defines the flexibility attribute as those measures that support grid flexibility. The rules for measure identification include the following:

1. Measures inherently include enabling technologies to support load management for grid flexibility
2. Reduce or eliminates impacts on end-use customers from load management or DR events 3. Value of measure is significant relative to its baseline

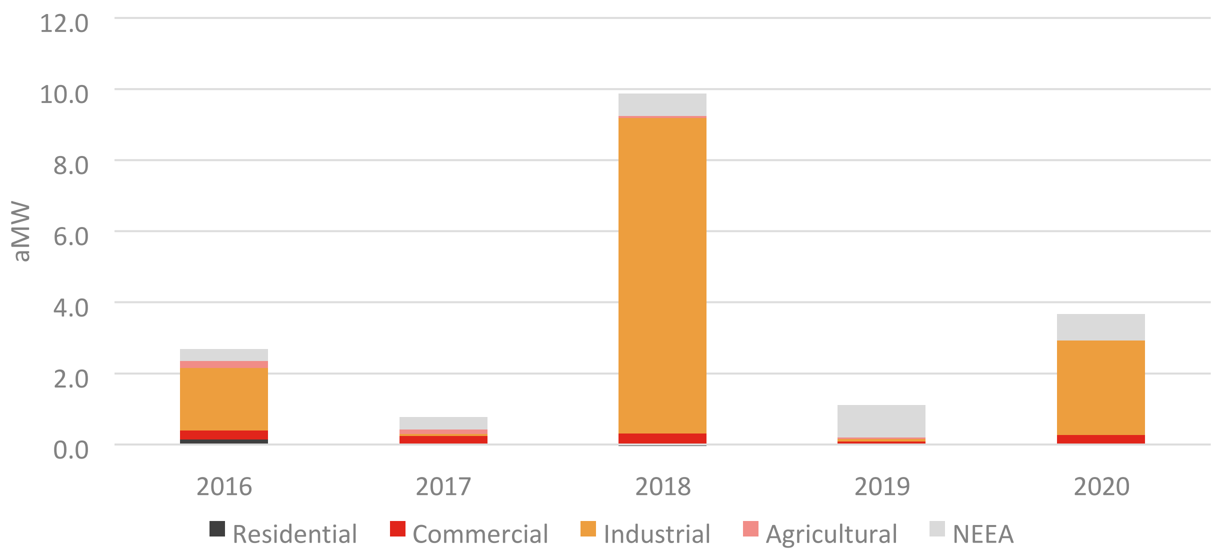
Example measures include weatherization and smart controls. Similar to the analysis for resiliency, the 2021 CPA identifies measures in the Base case that are not cost-effective but may provide grid flexibility benefits. The measures will be summarized in a table analysis that indicates how close to costeffectiveness the measures are at the time of the study and what the targets may look like if those close to cost-effectiveness measures are included.

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, Irrigation system upgrades, 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 for these savings is provided below for each sector.

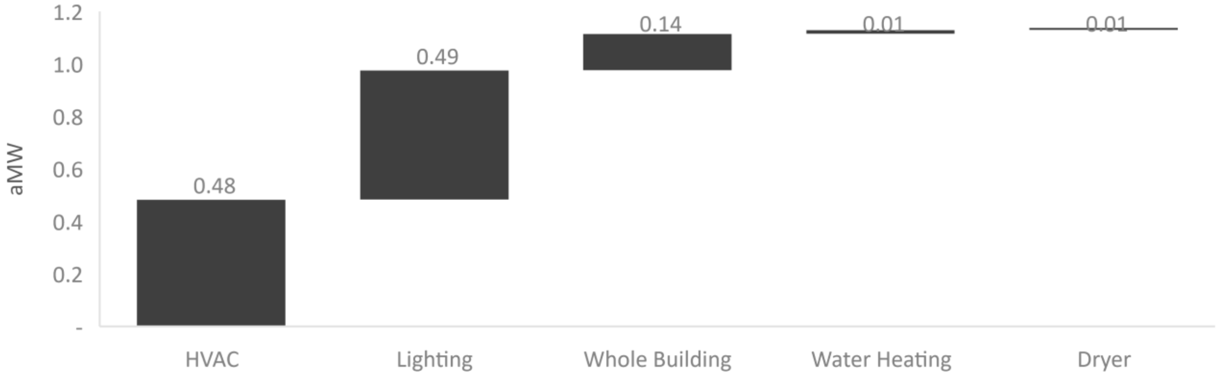
FIGURE 4-1: RECENT CONSERVATION HISTORY BY SECTOR



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.

FIGURE 4-2: 2017-2021 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 2020.

Recent industrial achievement has been acquired through custom projects at Grant PUD's large data centers as well as smaller savings from other end uses. Figure 4-5 summarizes the industrial sector achievement in 2017-20.

FIGURE 4-3: 2017-2021 COMMERCIAL SAVINGS

FIGURE 4-4: 2017-2020 INDUSTRIAL SAVINGS

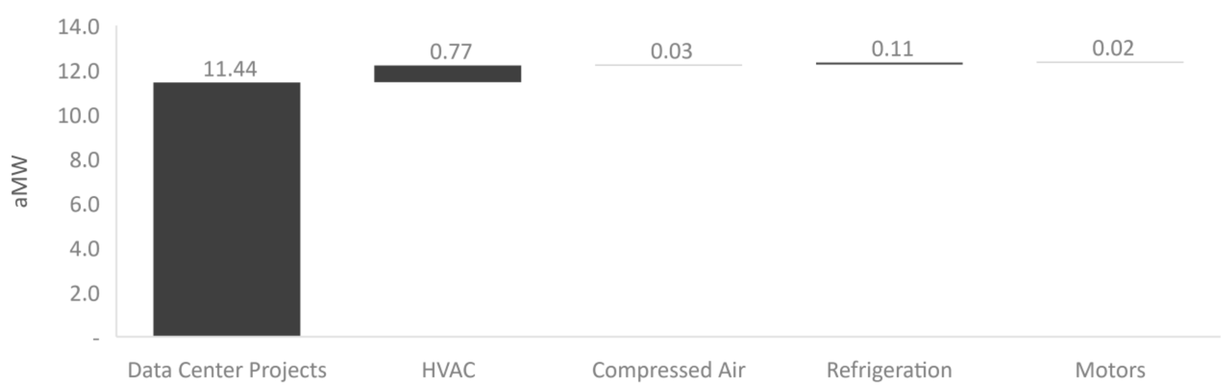
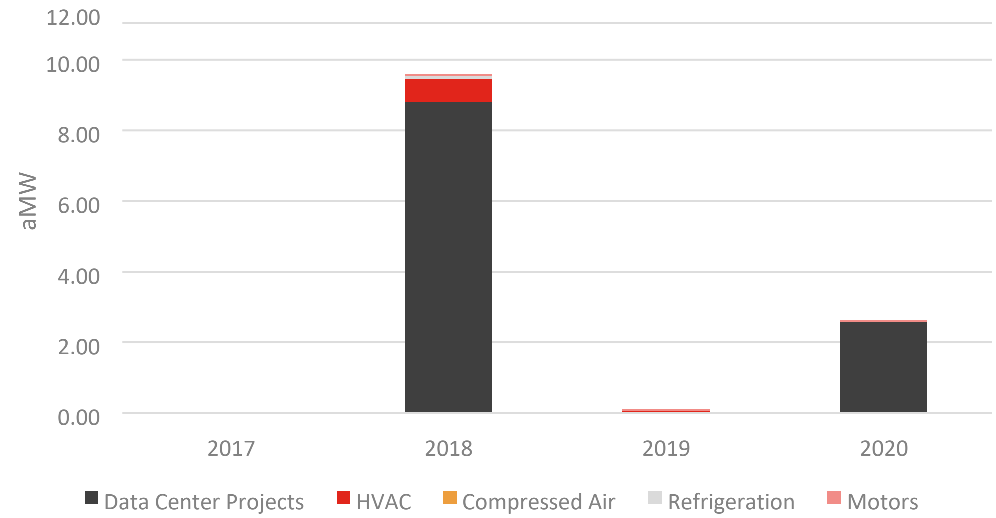


FIGURE 4-5: 2017-2020 INDUSTRIAL SAVINGS BY YEAR



4.3 AGRICULTURE

Agriculture program achievement has been acquired through irrigation hardware and other system upgrades, such as variable frequency drives. Achievement from 2016-2020 in this sector totals 0.38 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 & 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 over 46,900 electric customers in Grant County, Washington, with a service area population of approximately 100,000. 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 and 5-3 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 2022 Forecast	Total Population 2022 Forecast
1	3	3	39,797	100,994

TABLE 5-2A: EXISTING HOMES – 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 5-2B: NEW HOMES – HEATING / COOLING SYSTEM SATURATIONS

	Single Family	Multifamily - Low Rise	Manufactured
Electric Forced Air Furnace	0%	0%	74%
Heat Pump	97%	2%	26%
Ductless Heat Pump	2%	97%	0%
Electric Zonal/Baseboard	0%	0%	0%
Central Air Conditioning	97%	2%	26%
Room Air Conditioning	1%	0%	10%

TABLE 5-3A: EXISTING HOMES - APPLIANCE SATURATIONS

	Single Family	Multifamily - Low Rise	Manufactured
Electric Water Heat	97%	97%	97%
Refrigerator	129%	103%	121%
Freezer	53%	4%	43%
Clothes Washer	99%	47%	99%
Clothes Dryer	98%	47%	95%
Dishwasher	89%	78%	77%
Electric Oven	98%	97%	98%
Desktop	96%	44%	71%
Laptop	68%	26%	42%
Monitor	102%	45%	72%

TABLE 5-3B: NEW HOMES – APPLIANCE SATURATIONS

	Single Family	Multifamily - Low Rise	Manufactured
Electric Water Heat	99%	99%	99%
Refrigerator	129%	103%	121%
Freezer	53%	4%	43%
Clothes Washer	99%	47%	99%
Clothes Dryer	99%	47%	99%
Dishwasher	89%	78%	77%
Electric Oven	98%	97%	98%
Desktop	96%	44%	72%
Laptop	68%	26%	52%
Monitor	102%	45%	72%

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; however, the 2020 kWh usage data for commercial buildings was impacted by

COVID-19. Overall, commercial sector usage was 7% lower in 2020 compared with the usage data recorded in 2018. When using energy use intensity (EUI) data to translate kWh to square footage, the lower consumption would result in lower square footage. Because of these COVID impacts, the 2022 floor area estimate is based on the 2018 kWh data.

The 2018 data was developed by coding each general service customer based on the Commercial Building Stock Assessment (CBSA)[12] building definitions. The appropriate EUI is then applied to the sum of kWh for each building type resulting in estimated square feet. Table 5-4 compares the 2018 estimates with the 2020 estimates and shows the 2022 floor area estimate is the same as the 2018 estimate. These assumptions mean that commercial building usage returns to pre-pandemic levels by 2022. After 2022, a 1% growth rate is applied to commercial building growth.

TABLE 5-4: COMMERCIAL BUILDING SQUARE FOOTAGE BY SEGMENT

Segment	2018 Floor Area	2020 Floor Area based on kWh	2022 Floor Area Estimate
Large Office	22,128	34,187	22,128
Medium Office	777,053	752,724	777,053
Small Office	1,035,713	992,067	1,035,713
Large Retail	956,650	851,057	956,650
Medium Retail	773,412	732,660	773,412
Small Retail	1,723,534	1,622,449	1,723,534
School (K-12)	4,019,941	3,234,442	4,019,941
University	883,927	854,103	883,927
Warehouse	23,158,268	20,596,673	23,158,268
Supermarket	348,008	345,981	348,008
Mini Mart	203,509	203,111	203,509
Restaurant	467,747	415,549	467,747
Lodging	2,137,264	1,997,382	2,137,264
Hospital	632,421	654,052	632,421
Residential Care	42,059	46,446	42,059
Assembly	1,434,465	1,168,661	1,434,465
Other Commercial	5,640,209	5,836,101	5,640,209
Total	**44,256,309**	**40,337,646**	**44,256,309**

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

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

then disaggregates total usage by end-use shares. Estimated measure savings are applied to each sector's end-use shares.

The District provided 2020 energy use for its industrial customers. Individual industrial customer usage is summed by industrial segment in Table 5-5. Industrial usage decreased 6% in 2020 compared to the 2018 consumption used in the previous study. The decrease is likely due to COVID shutdowns and industrial shifts. Given the uncertain timing of economic recovery in the County following COVID-19, the industrial consumption is not escalated at high growth rates in the near-term. Rather, the load growth rate of 1.15% is based on the previous CPA. This load growth reflects industrial sector growth for non-data center loads.

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

Industry	2019 CPA	2021 CPA
Paper	14,914	16,587
Foundries	28,022	42,202
Frozen Food	236,214	229,975
Other Food	17,099	76,313
Silicon	50,340	9,929
Metal Fabrication	3,281	-
Equipment	140,923	21,741
Cold Storage	40,047	34,919
Fruit Storage	42,111	47,471
Refinery	158,970	70,956
Chemical	555,539	595,547
Miscellaneous Manufacturing	422,780	241,641
Total	**1,710,241**	**1,387,280**
Data Centers/Cryptocurrency	1,315,668	1,531,597

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 5-6. The USDA conducts a census of farms and ranches in the U.S. every five years. EES further refined this data based on zip code data published in an earlier census.

The District did not identify significant changes in agricultural loads, therefore, the customer characteristics in this sector are unchanged from what was used in the 2019 CPA (Table 5-6).

TABLE 5-6: AGRICULTURAL INPUTS

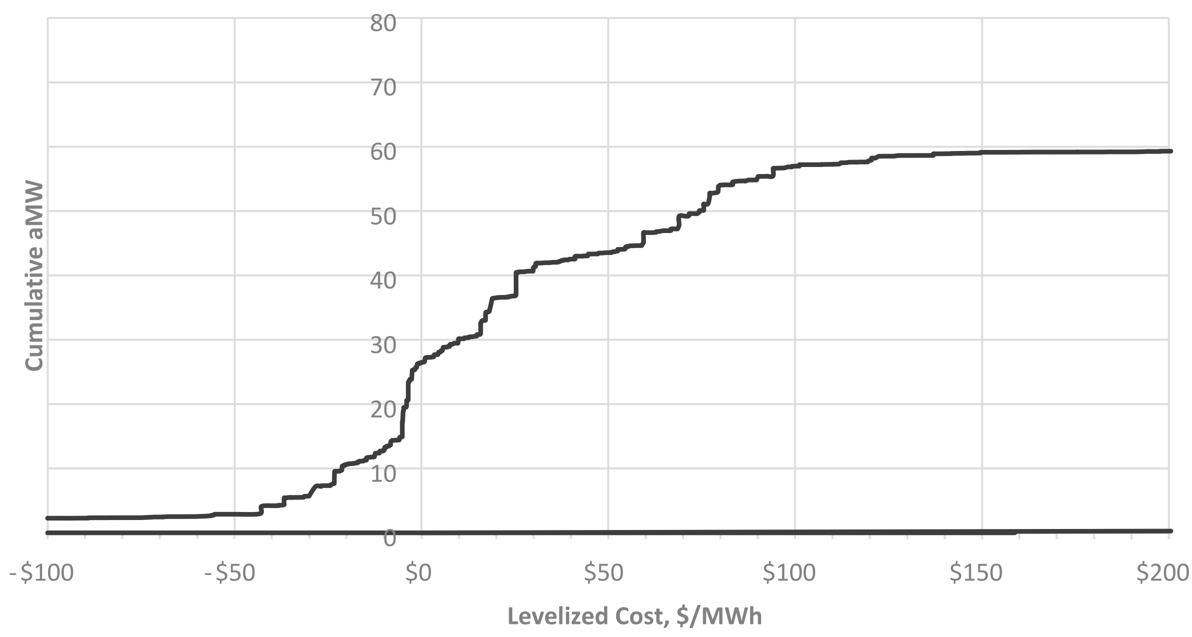
Number of Dairy Cows	28,103
Total Irrigated Acreage	406,093
Total Number of Farms	1,517

6 Results – Energy Savings and Costs

6.1 ACHIEVABLE CONSERVATION POTENTIAL

Achievable potential is the amount of energy efficiency potential 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 40 aMW of cumulative saving potential are available for less than $30/MWh.

FIGURE 6-1: 20-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE



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 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, 6, 10 and 20-year increments. Compared with the technical and achievable potential, it shows that 47.15 aMW of the total 82 aMW is cost effective for the District. The last section of this report discusses how these values could be used for setting targets.

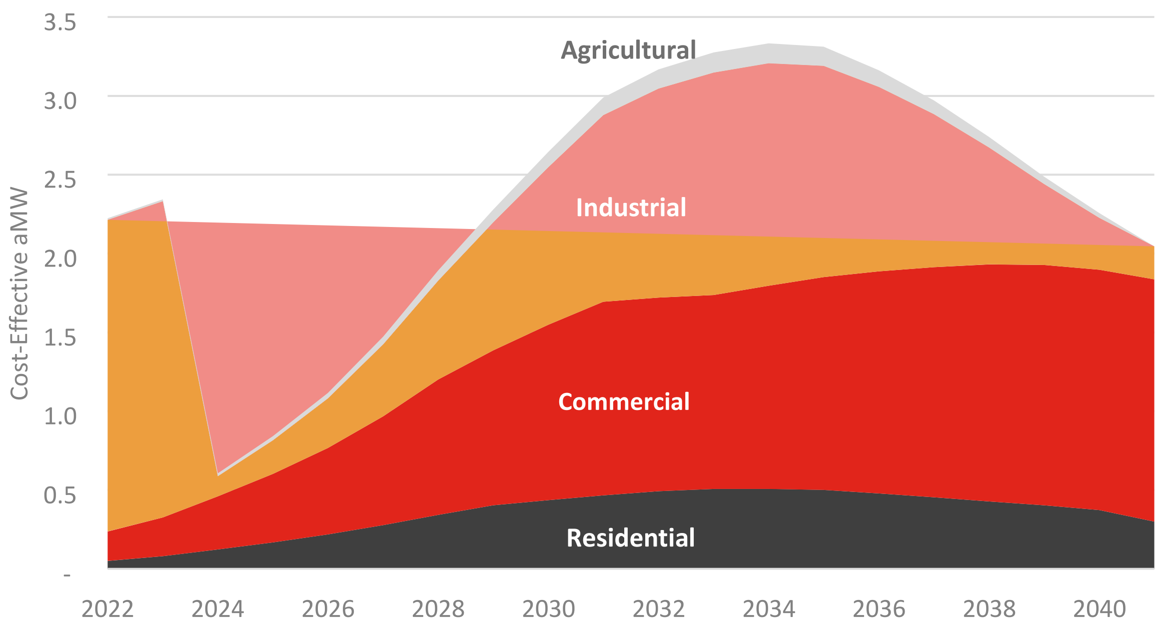
TABLE 6-1: COST-EFFECTIVE ACHIEVABLE POTENTIAL – BASE CASE (aMW)

	2-Year	4-Year	10-Year	20-Year
Residential	0.13	0.65	2.57	7.01
Commercial	0.43	1.20	6.63	20.68
Industrial	3.98	4.32	8.71	18.13
Agricultural	0.02	0.06	0.50	1.33
Total	**4.57**	**6.24**	**18.41**	**47.15**

6.3 SECTOR SUMMARY

Figure 6-2 shows economic potential by sector on an annual basis.

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



The largest share of the potential is in the commercial sector followed by substantial savings potential in the industrial sector. Ramp rates for all measures were adjusted to account for the District's historic program savings. Achievement levels are affected by factors including timing of equipment turnover and new construction, program and technology maturity, market trends, and current utility staffing and funding.

6.3.1 Residential

Near-term residential conservation potential is higher than what was identified in the 2019 assessment. 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 costeffective 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 shower heads, efficient clothes washers, and behavior measures that reduce water heater temperatures. Additional savings are available from efficient TVs (2021 Power Plan measure) and residential electric vehicle charges (whole building/meter level).

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

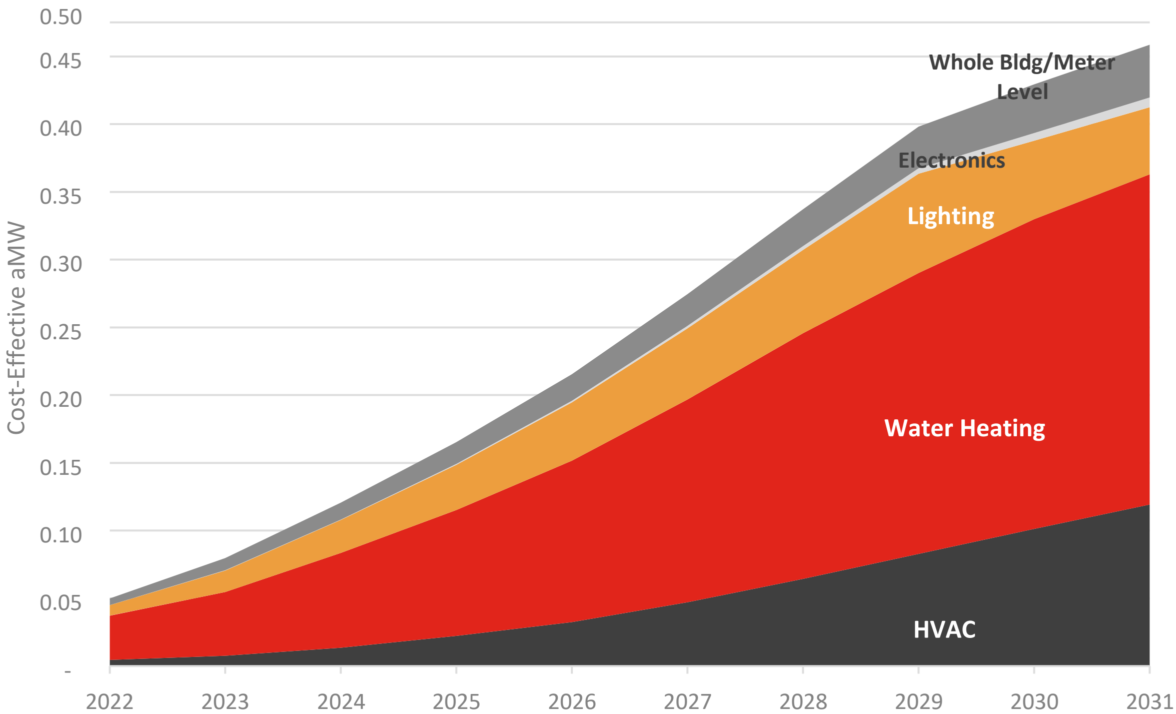


Figure 6-4 shows how the 10-year residential potential breaks down into end uses and key measure categories. The area of each block represents its share of the total 10-year residential potential.

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

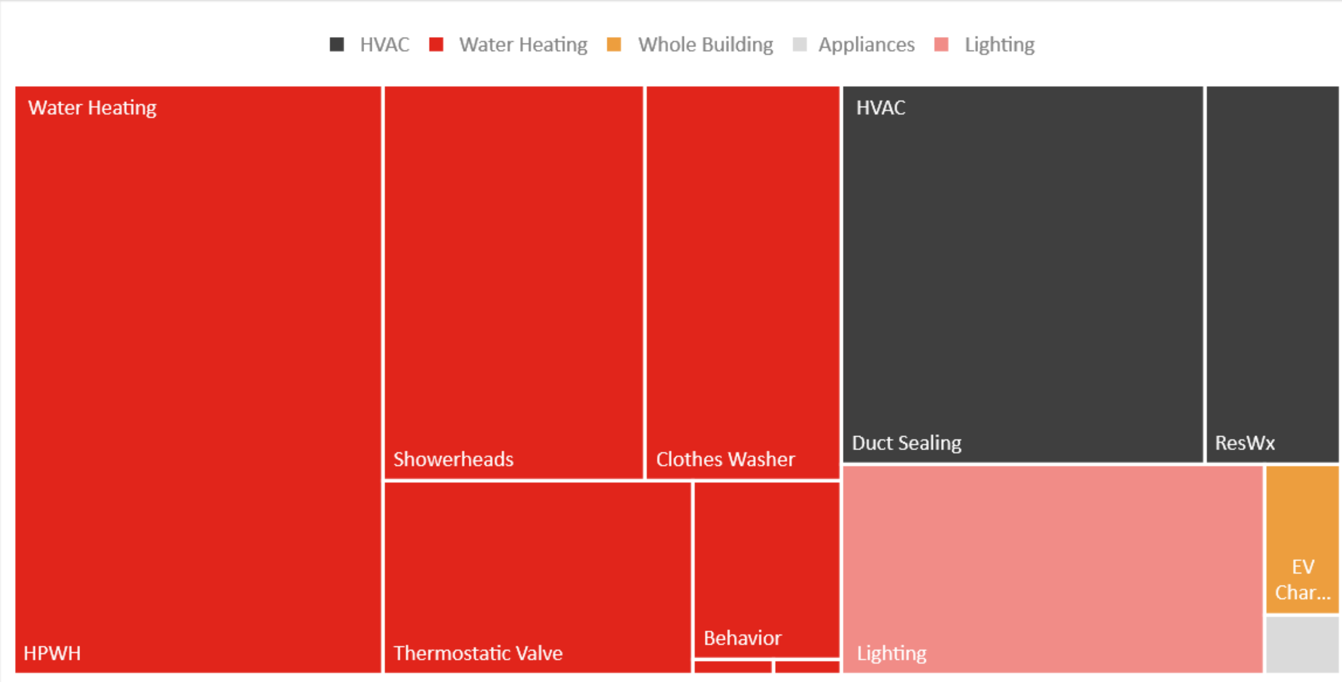


Table 6-2 compares how the savings potential has changed since the 2019 CPA.

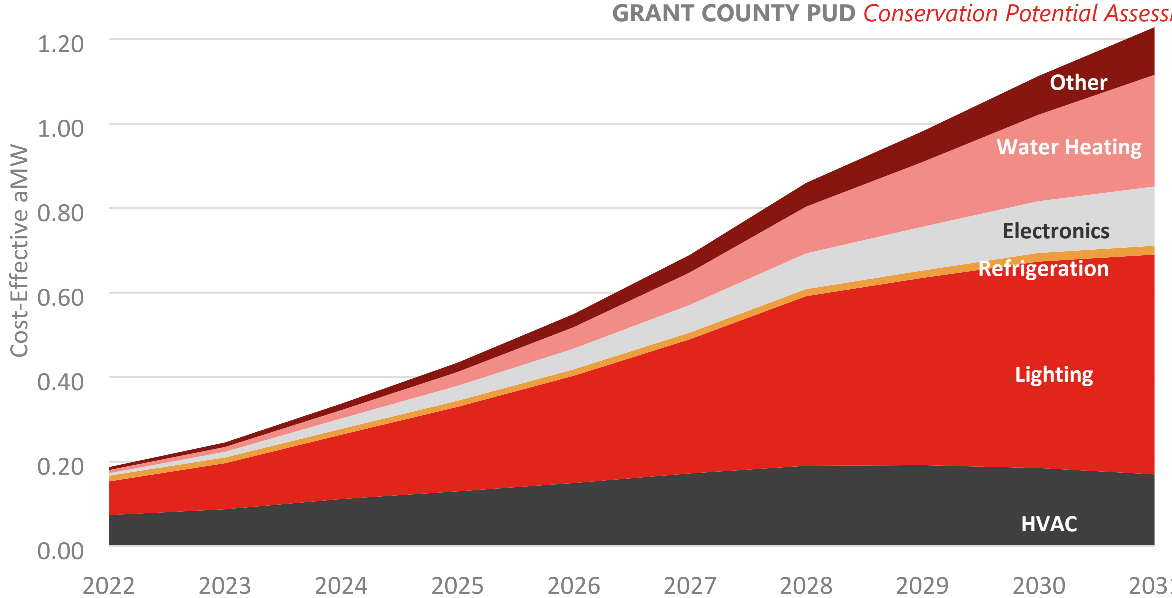
TABLE 6-2: COMPARISON RESIDENTIAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2019 CPA	2021 CPA	Discussion
Water Heating	3.63	3.62	Multiple impacts. Added additional measures from 2021 Power Plan such as Circulator Controls, Valve on ERWH an HPWH. Updated ramp rates to reflect program achievement, WA code changes for showerhead minimum efficiency.
HVAC	1.64	1.42	Ramp rate adjustment for program savings
Lighting	0.00	0.70	Added New Lighting Measures from 2021 Plan
Electronics	0.27	0.93	Added New Energy Star TV Measures
Food Preparation	0.00	0.05	Microwave measures now cost-effective.
Dryer	0.00	0.00	No Change
Refrigeration	0.00	0.10	Increased cost-effectiveness for refrigeration measures
Whole Bldg/Meter Level	0.00	0.20	Reduced cost for Level 2 EV Charger
Total	**5.54**	**7.24**	

6.3.2 Commercial

The diverse nature of commercial building energy efficiency is reflected in the variety of end-uses and corresponding measures. Beyond HVAC and lighting, additional sources of potential are available in water heating, electronics, compressed air, 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

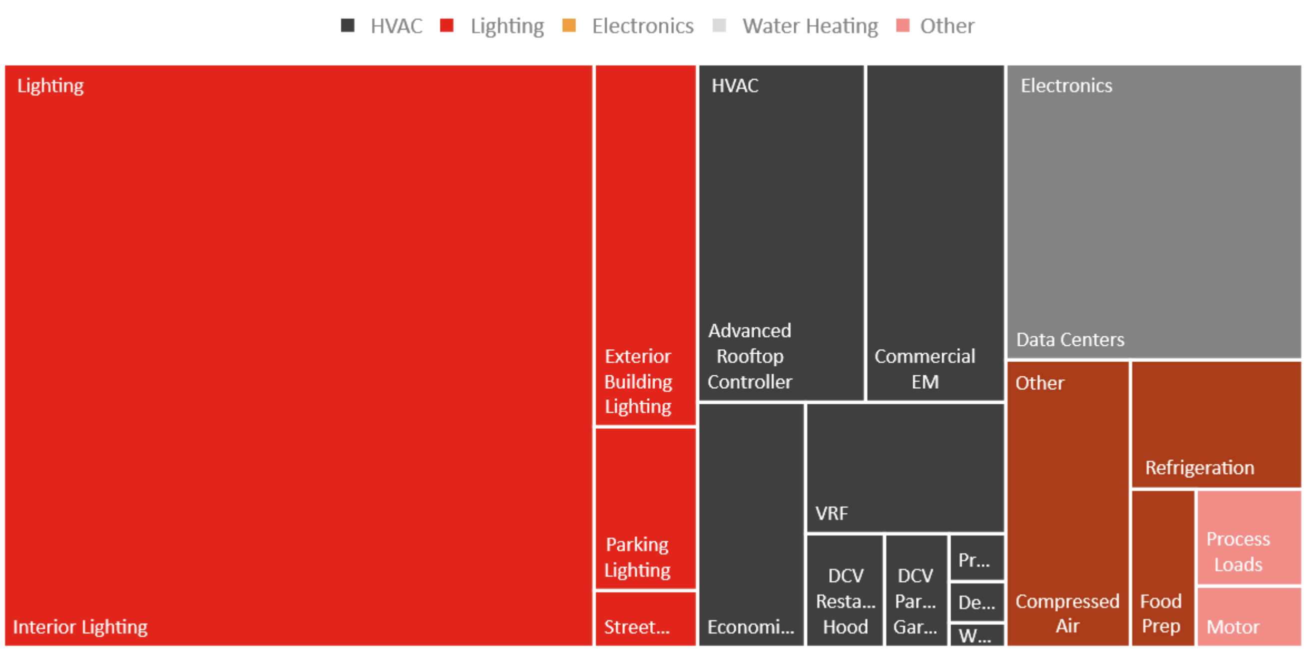


Table 6-3 provides a summary of the differences between the 2019 assessment and this 2021 CPA by enduse.

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

End Use	2019 CPA	2021 CPA	Discussion
Food Preparation	0.21	0.20	Minimal change
Lighting	3.33	8.1	Added 2021 Power Plan Measures
Electronics	0.00	0.7	Increased cost-effectiveness
Refrigeration	0.87	0.40	Added 2021 Power Plan grocery measures
Process Loads	0.09	0.09	No Change

Compressed Air	0.26	2.10	Increased ramp rates per 2021 Power Plan
HVAC	1.56	2.22	Slight increase in cost-effectiveness
Motors/Drives	0.28	0.16	Slower ramp rates applied per 2021 Power Plan and District programs
Water Heating	0.34	6.70	Added heat pump water heaters to replace all tank upgrades
Total	**13.25**	**20.68**	

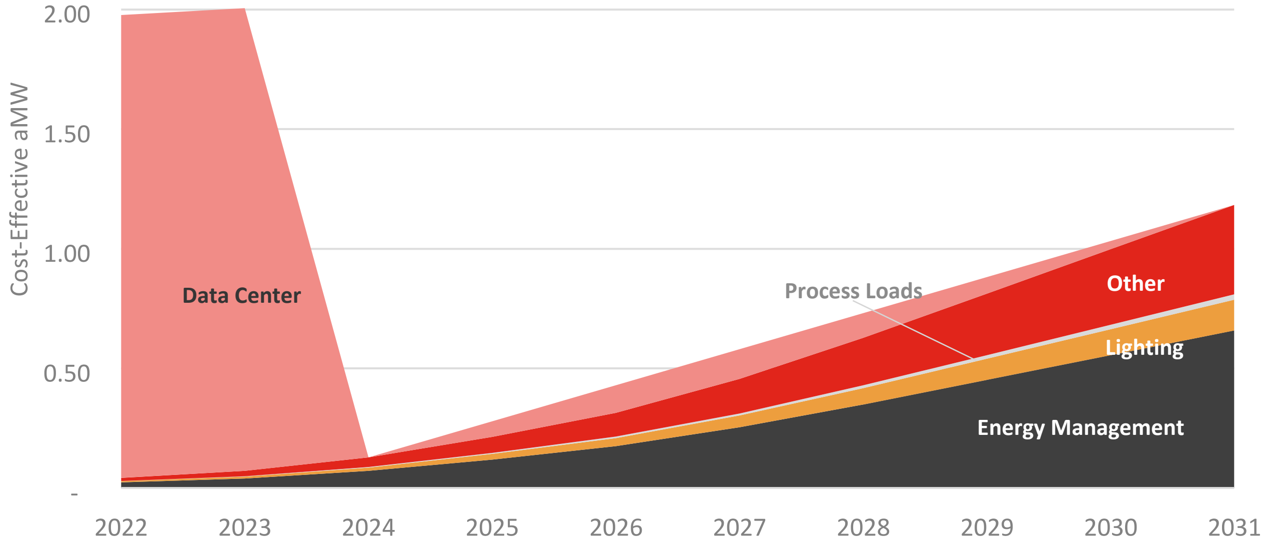
6.3.3 Industrial

Approximately half 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. Conversely, this study evaluates data center savings for new customers at the project level. This methodology evaluates savings potential more specifically to the District's loads and unique nature of large data center operations. The bulleted list below 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. Due to their low incremental costs compared with savings potential, these measures are also costeffective 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.

The other half of the District's industrial load is composed primarily of food processing and chemical facilities. These segments contribute significantly to end-use savings in the energy management measures (Figure 6-7). Energy management measures include both Strategic Energy Management and improved management of motor-driven systems. 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



If the growth in data centers continues, and the District is able to reduce future baseline energy use by 10%, the District can expect approximately 17.2 aMW in data center savings over the 20-year study period. If, future savings are not achieved at the same rate of 10% baseline usage, these savings estimates are reduced to 10.5 aMW (assuming 5% savings). Finally, it's expected that state energy codes will be updated in the near-term thereby eliminating future potential savings.

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

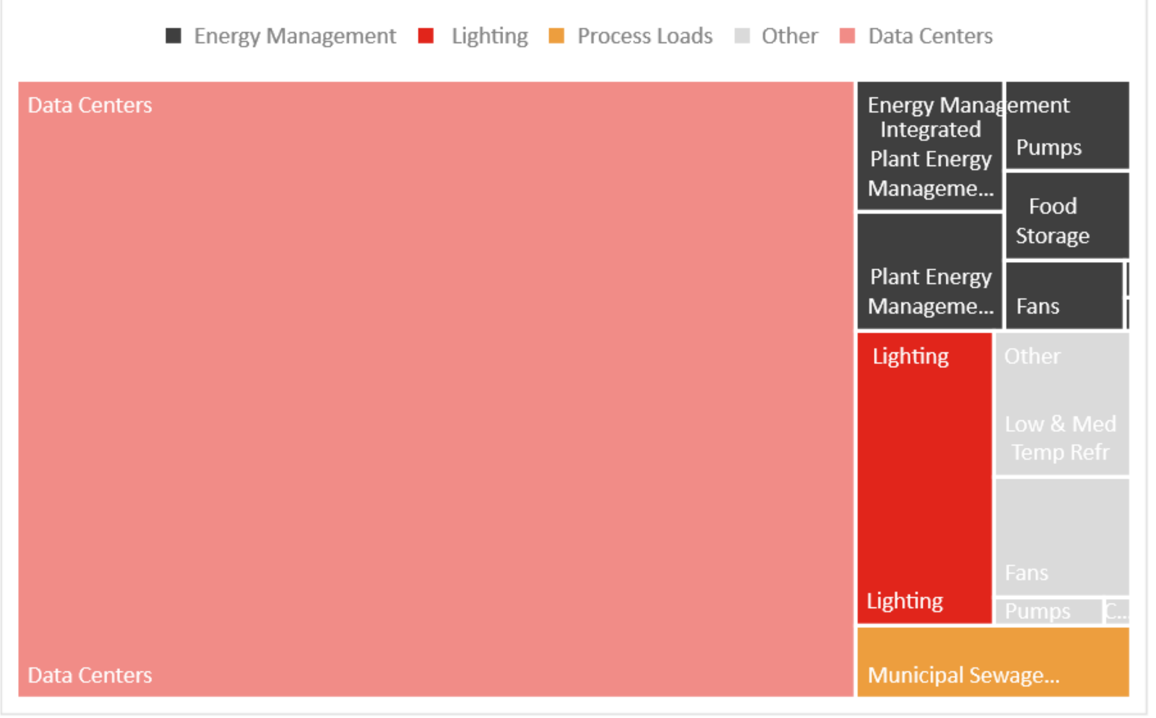


Table 6-4 compares the 20-year results to the previous CPA. The differences are typically due to shifts in industrial load (Silicon, food, chemical, fruit storage, etc.). Also, overall industrial loads were also lower for 2020 due to COVID impacts. Finally, potential for data centers was estimated using specific project analysis as detailed above.

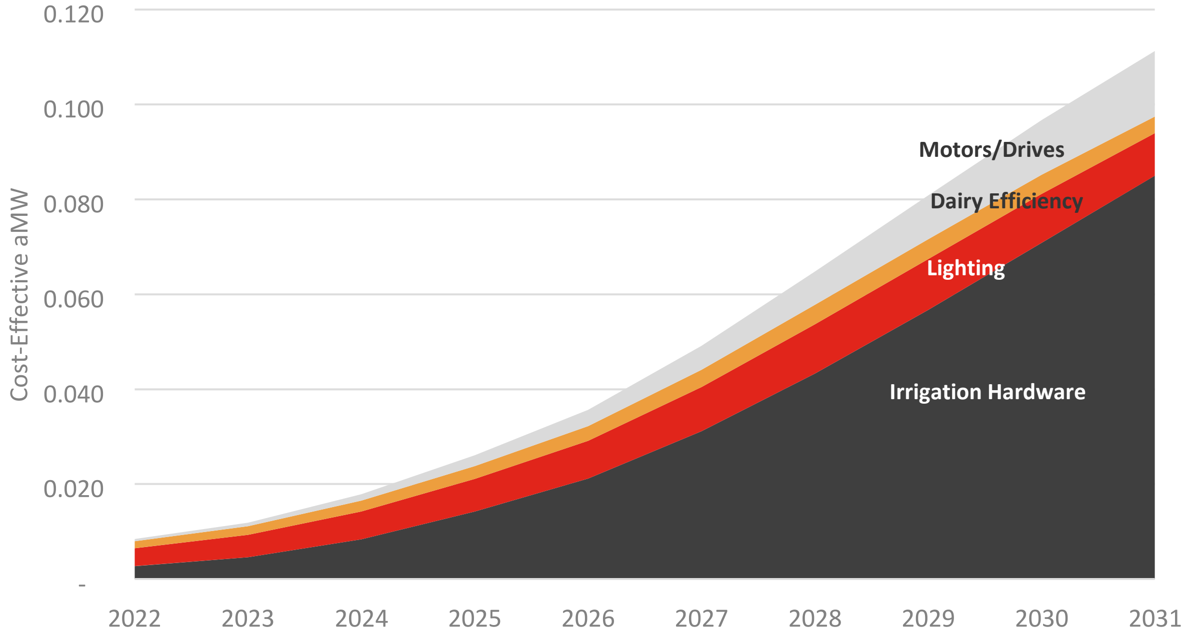
TABLE 6-4: COMPARISON INDUSTRIAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, aMW

End Use	2019 CPA	2021 CPA	Discussion
Data Centers	6.31	3.9	Updated estimation methodology
Compressed Air	0.59	0.43	Lower loads and adjusted for achievement since 2019
Energy Project Management	1.57	1.70	Updated Industrial Loads
Fans	1.92	1.25	Lower loads and adjusted for achievement since 2019
Food Processing	1.91	1.42	Lower loads and adjusted for achievement since 2019
Food Storage	2.37	1.74	Lower loads and adjusted for achievement since 2019
Hi-Tech	0.48	0.19	Lower loads and adjusted for achievement since 2019
Integrated Plant Energy Management	1.38	1.50	Lower loads and adjusted for achievement since 2019
Lighting	2.88	1.55	Lower loads and adjusted for achievement since 2019
Material Handling	0.02	0.02	No Change
Metals	0.01	0.01	No Change
Municipal Sewage Treatment	0.27	0.26	Lower loads and adjusted for achievement since 2019
Paper	0.03	0.02	No Change
Plant Energy Management	2.10	1.37	Lower loads and adjusted for achievement since 2019
Pumps	3.38	2.77	Lower loads and adjusted for achievement since 2019
Total	**25.98**	**14.26**	

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 measures, with additional savings from lighting, dairy, and pumps/motors.

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



The 10-year agricultural potential is shown in Figure 6-10, split by end use and measure categories.

FIGURE 6-10: AGRICULTURAL COST-EFFECTIVE POTENTIAL BY END USE MEASURE CATEGORY

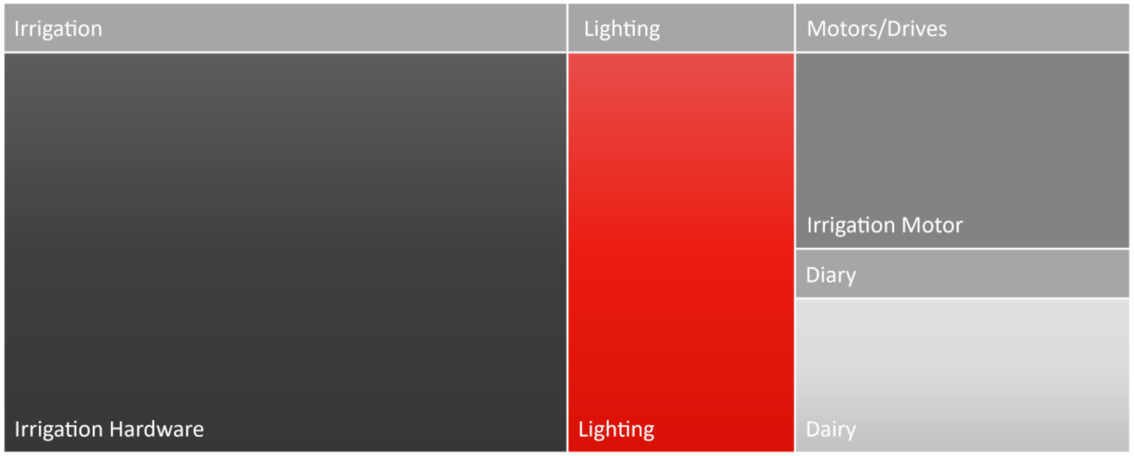


Table 6-5 compares the results of the 2019 CPA with this updated assessment. Because the inputs and measures are largely unchanged, the 20-year potential is almost identical. The small differences between the two studies are primarily in the application of ramp rates. As with other sectors, agricultural measure ramp rates were adjusted to better align with the District's historic achievement within the sector.

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

End Use	2019 CPA	2021 CPA
Dairy Efficiency	0.04	0.04
Irrigation	0.99	1.03
Lighting	0.09	0.09
Motors/Drives	0.16	0.17

Total	**1.27**	**1.33**

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 Seventh Power Plan and was unchanged in the Draft 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 approximately $1.6 million over the next biennium to realize estimated savings across all sectors excluding data centers. These costs include incentives and program administration. The bottom row of Table 6-6 shows the cost per MWh of first year savings.

TABLE 6-6: UTILITY PROGRAM COSTS (2021$)

	2-Year	6-Year	10-Year	20-Year
Residential	$190,000	$615,000	$3,926,000	$8,990,000
Commercial	$746,000	$1,999,000	$10,390,000	$31,690,000
Industrial	$622,000	$486,000	$5,173,000	$15,226,000
Agricultural	$26,000	$79,000	$564,000	$1,431,000
Total Excluding Data Centers	**$1,584,000**	**$3,179,000**	**$20,053,000**	**$57,337,000**
$/First Year MWh	$40	$155	$158	$151

The cost estimates presented in this report are conservative estimates for future expenditures since they are based on historic values. Future conservation achievement is expected to 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.

6.4.1 Cost Scenarios

To provide a range of program costs over the planning period, EES tested a range of high and low cost assumptions, relative to the expected cost assumptions above. For the high cost scenario, administrative costs were increased from 20 to 30 percent for non-residential programs and incentives are increased to 80% for residential measures to account for low income programs. The high cost scenario reflects the case where program administration costs may increase in order for the District to connect with hard-toreach customers.

For the low cost scenario, the utility share of measure capital cost is reduced from 35 to 30 percent. A situation where the utility is responsible for a lower share of measure capital cost may result from higher conservation achievement through programs for which the customer is responsible for a higher fraction of measure cost. An example of this would be if more conservation were achieved through commercial or industrial custom projects where lower incentives may be needed. Table 6-7 shows 2, 6, 10 and 20year program costs for the expected, high and low cost scenarios. Table 6-8 shows the cost per average megawatt for each of the cost scenarios. The cost for the first 2 years is low due to the relatively inexpensive data center project.

TABLE 6-7: UTILITY COST SCENARIOS FOR COST-EFFECTIVE POTENTIAL (2021$)

	2-Year	4-Year	10-Year	20-Year
Expected Case	$1,584,000	$3,179,000	$20,053,000	$57,337,000
Low Cost Case	$1,440,000	$2,890,000	$18,230,000	$52,125,000
High Cost Case	$2,075,000	$4,165,000	$26,271,000	$75,117,000

TABLE 6-8: UTILITY COST SCENARIOS FOR COST-EFFECTIVE POTENTIAL (2021$/MWH)

	2-Year	4-Year	10-Year	20-Year
Expected Case	$40	$155	$158	$151
Low Cost Case	$36	$141	$143	$138
High Cost Case	$52	$203	$207	$198

Over the next two years, conservation programs are expected to cost between $36 and $52/MWh (first year savings). Given an average measure life of 12 years, the levelized cost of energy for these programs is estimated between $3/MWh and $5/MWh. Overall, the District can expect the biennium potential estimates presented in this report to cost between $1.4 and $2.1 million for utility incentives and administrative expenditures.

6.5 ADEQUACY, EQUITY, RESILIENCY, AND FLEXIBILITY

The Council is currently evaluating how to account for benefits or attributes of conservation measures that may be excluded from previous methodology. Section 3.7 of this study introduced for attributes that could be considered in energy efficiency program planning. A high-level review is provided below.

1. **Adequacy.** Adding efficiency to the utility system reduces the frequency, duration, and magnitude of regional adequacy events. In particular, energy efficiency that reduces load in the hours following sunset and overnight would have relatively more benefit in a solar-rich renewable portfolio. This capacity value may not be captured immediately in the capacity and energy cost forecast.

2. **Equity.** The equity attribute refers to measures that require additional incentive to achieve equitable distribution of benefits. The Council defines these measures as the following:
    a. Historic and long-term cost-effectiveness
    b. Significant regional penetration from past program activity
    c. Data demonstrating that untouched pockets are not reflective of the population (i.e. different socioeconomic status)

    Equity measures are likely to be envelope measures in residential buildings. These can be highcost to homeowners or there may be a renter/landlord issue. By definition, the equity component identifies measures that are cost-effective, and have been cost-effective for a period of time.

3. **Resilience.** Resilience measures are those that support building resilience, or the ability to maintain building functions/comfort through extended power outages. The Council provides weatherization measures as resilient measures. The 2021 CPA identifies measures in the Base case that are not cost-effective but may provide building resilience benefits.
4. **Flexibility.** The Council defines the flexibility attribute as those measures that support grid flexibility. The rules for measure identification include the following:
    a. Measures inherently include enabling technologies to support load management for grid flexibility
    b. Reduce or eliminates impacts on end-use customers from load management or DR events
    c. Value of measure is significant relative to its baseline

    Example measures include weatherization and smart controls. Similar to the analysis for resiliency, the 2021 CPA identifies measures in the Base case that are not cost-effective but may provide grid flexibility benefits.

The measures will be summarized in a table analysis that indicates how close to cost-effectiveness the measures are at the time of the study and what the targets may look like if those close to cost-effectiveness measures are included.

6.5.1 Methodology

This section screens measures that do not pass the TRC test but may have passed the TRC previously, or the TRC ratio is greater than 0.5. Table 6-9 below shows the technical achievable potential for these measures and includes a high-level discussion of how a particular measure may provide benefits that fall under the 4 above categories.

TABLE 6-9: MEASURES TO CONSIDER FOR ADEQUACY, EQUITY, RESLIENCE, *OR FLEXIBILITY IMPACTS*

	20-Year Technical Achievable Potential aMW	Adequacy, Equity, Resilience, or Flexibility
Residential		
Residential and Commercial Heat Pump Water Heaters	1.3	Many Tier 1-3 level HPWH are not cost effective but provide significant annual savings of over 1,000 kWh per unit Water heating is a peak load and HPWH controls could reduce both peak demand and participate in demand response.
Weatherization	3.5	Much of the potential has been achieved and hardto reach efforts are being addressed at the program level. Weatherization has adequacy impacts and measures provide resilience. Finally, programs can target equity measures to meet CETA requirements.
Commercial		
Ductless Heat Pump	0.7	Heating and cooling are profiles coincident with winter and summer peak demand. Could provide adequacy benefits to the region.
VRF	1.25	VRF systems provide heating and AC. Savings is from improved ventilation and loss reductions. Best applications are new buildings or significant remodels where an entire system is being replaced. Impacts from VRF to heating and cooling loads may provide adequacy impacts to the region.

7 Scenario Analysis

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, all other inputs were held constant while varying avoided cost inputs. 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 summarizes the Base, Low, and High avoided cost input values.

TABLE 7-1: AVOIDED COST ASSUMPTIONS BY SCENARIO, $2021

	Base	Low	High
Energy	Market Forecast $41.93/MWh	Market Forecast $33.55/MWh	Market Forecast $50.32/MWh
Social Cost of Carbon	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	$7.18	$0.00	$7.18
Transmission System Credit, $/kW-yr	$3.23	$3.23	$3.23
Deferred Generation Capacity Credit, $/kW-yr	3% Premium	$0	$135
Implied Risk Adder, 20-year Levelized $/MWh $/kW-yr	N/A	Average: -$42/MWh -$7/kW-yr	Average: $9/MWh and $36/kW-year

Table 7-2 summarizes results across each avoided input scenario, using Base Case load forecasts and measure acquisition rates. An additional scenario is added equal to the Base Case except with the addition of projected data center savings assuming historic trends of growth.

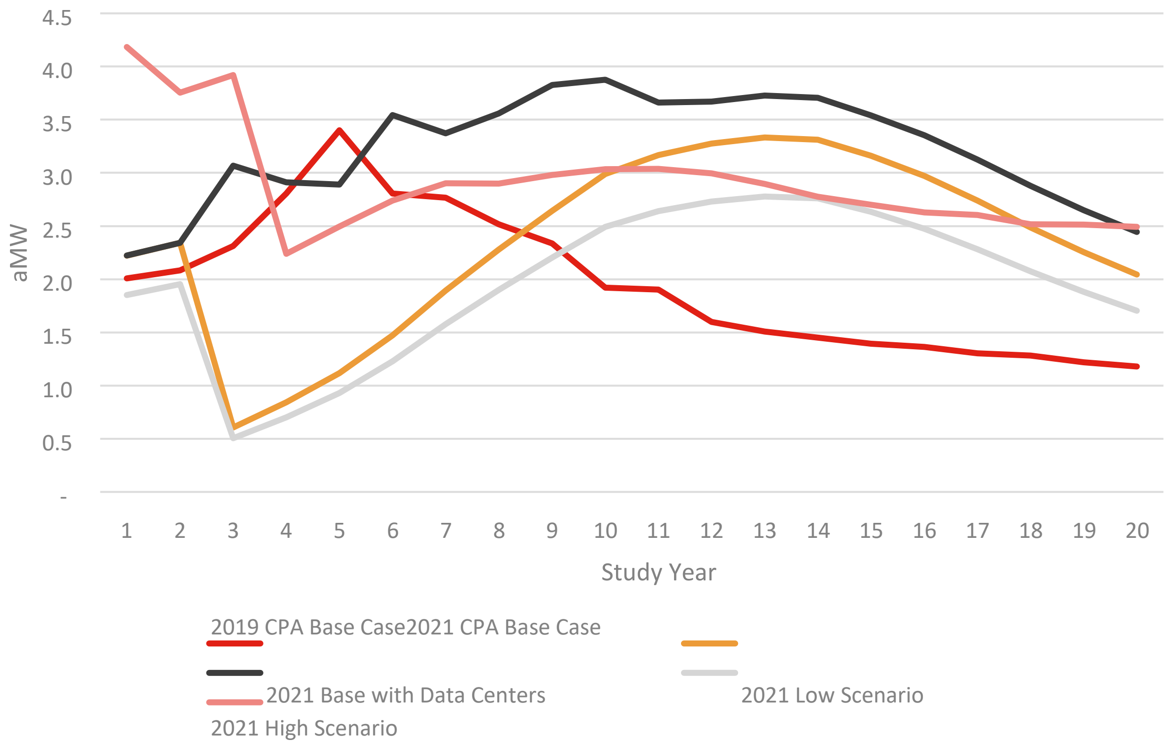
TABLE 7-2: COST-EFFECTIVE POTENTIAL – AVOIDED COST SCENARIO COMPARISON

	2-Year	4-Year	10-Year	20-Year
Base Case	4.57	6.24	18.41	47.15
Base Case with Data Centers	4.57	10.55	31.61	64.36
Low Scenario	3.81	5.01	15.34	39.30
High Scenario	7.94	14.10	31.15	58.31

Overall, energy efficiency remains a low-risk resource for the District for several reasons. First, energy efficiency is purchased in small increments over time, meaning that buying too much energy efficiency is unlikely. Second, while the different avoided cost scenarios described above are all hypothetically possible, it is unlikely that energy prices will decrease further below their already historically low values.

Figure 7-1 compares the results of the scenario analysis with the base case from the 2019 assessment. In addition to the avoided cost assumptions, the high scenario applies 2021 Plan ramp rates with no adjustment for program achievement.

FIGURE 7-1: SCENARIO COMPARISON



The greatest sensitivity in the scenario results is with regard to data center potential. The District plans to continue to update data center savings potential in future assessments based on new customer load additions.

8 Environmental Justice and Social Welfare

Environmental aspects of demand response and energy efficiency resources can be evaluated from an environmental justice and social welfare perspective.

Environmental justice (EJ) is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This goal will be achieved when everyone enjoys the same degree of protection from environmental and health hazards, and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

While this study does not identify all potential impacts on various stakeholders within or outside of the District's service area, it does analyze energy efficiency and demand response resources through an EJ lens. Specifically, the following conclusions can be made from the results of this study.

- Energy efficiency continues to be a low-cost, demand-side resource
- Energy efficiency resources avoid emissions
- Energy efficiency reduces customer bills and customer energy burden (share of income spent on energy including electricity and other fuels).

How these findings impact different groups of people within a community will vary depending on multiple factors such as program design and incentives. Programs that target low-income customers can be designed to maximize energy efficiency program potential. For example, for low-income rate discounts, customers might be required to participate in home energy audits that identify low-cost or free energy efficiency upgrades. Not only are customer bills reduced through rate discounts, but also bills are reduced through energy efficiency upgrades. Reaching these customers continues to be challenging as there may be barriers to program participation such as different languages spoken, renter/owner relationships, or reluctance for customers to share information. When these challenges are bridged, energy efficiency can meaningfully impact customer energy burdens and improve social welfare.

8.1 GEOGRAPHICAL ANALYSIS

Washington Department of Health's Washington Tracking Network tool (WTN).[13] The WTN utilizes GIS data to display various filters that demonstrate where disadvantaged communities exist and may benefit from targeted conservation programs. Disadvantaged communities are typically characterized by a combination of economic, health, and environmental burdens. These burdens include poverty, high unemployment, air and water pollution, presence of hazardous wastes, as well as high incidence of asthma and heart disease.

The above burdens are often a result of several factors including economic, social, or environmental. Some residents in Grant County may be impacted by social and economic factors such as income, language, or education. Figure 8-1 illustrates social and economic impacted populations by census block within the County. Much of the County ranks high for these factors which include education, limited English, high school diploma, transportation costs, unaffordable housing and employment.

FIGURE 8-1 SOCIOECONOMIC FACTORS

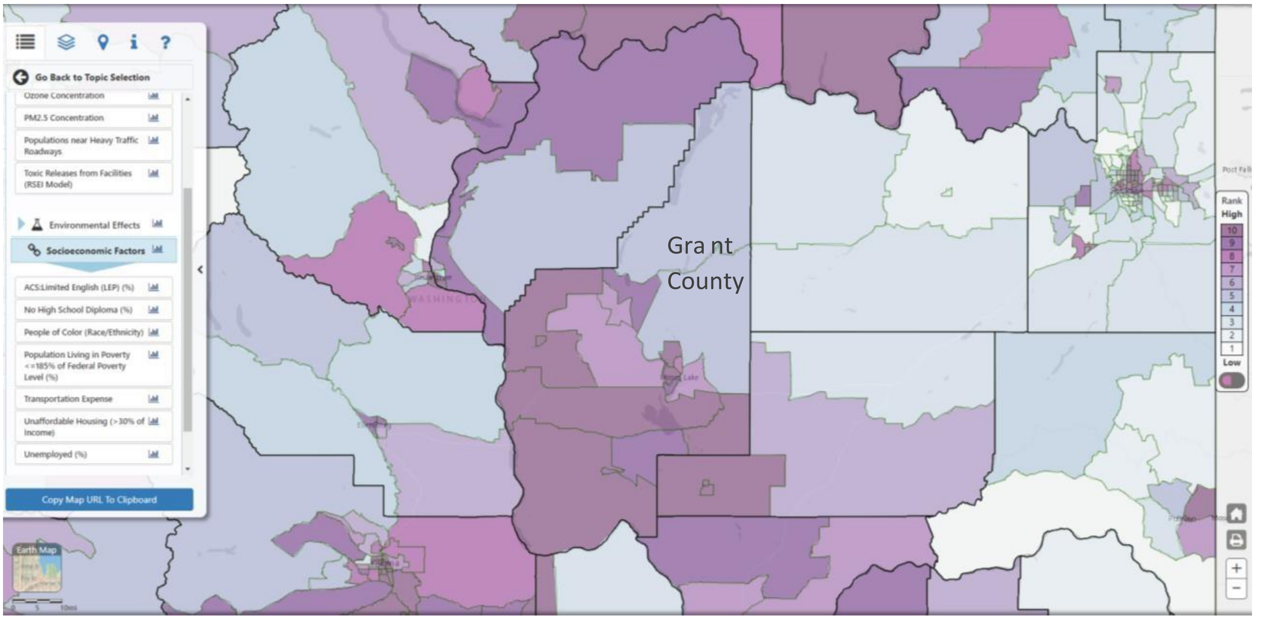
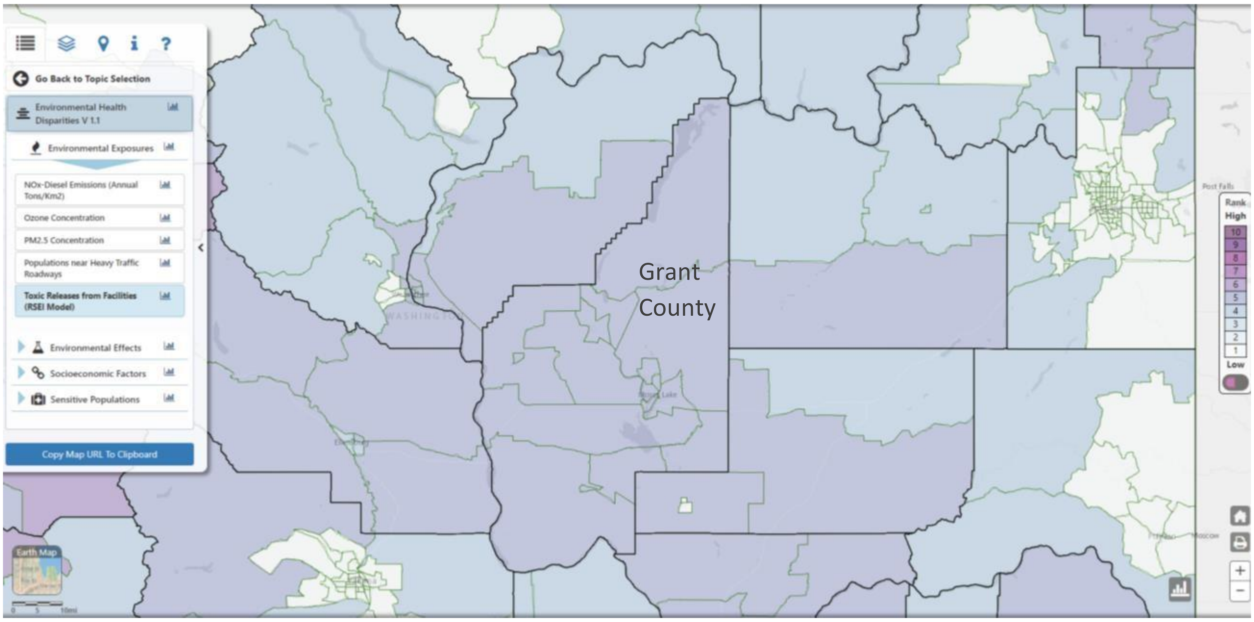


Figure 8-2 illustrates the toxic releases from facilities. This measure is often used as part of EJ analysis. Toxic releases within Grant County are rated at the middle of the scale. There are several industrial facilities identified as toxic release centers in Moses Lake and surrounding areas. None of the facilities are related to the production of electricity.

[13] https://fortress.wa.gov/doh/wtn/WTNIBL/

FIGURE 8-2 TOXIC RELEASES FROM FACILITIES (RSEI MODEL)



Based on the above high-level analysis of the available data, the District's low income energy efficiency programs are likely to create greater localized energy equity while reducing pollutants at a regional level.

9 Summary

This report summarizes the results of the 2021 CPA conducted for the District. The assessment provides estimates of energy savings by sector for the period 2022 to 2041 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 2019 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; however, the adjusted ramp rates for the new time horizon increase the near-term potential slightly compared with the 2019 results.

9.1 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. In addition to using methodology consistent with the Council's Seventh Power Plan, this assessment utilized many of the measure assumptions that the Council developed for the Seventh Plan. Additional measure updates subsequent to the Seventh Plan were also incorporated. 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 energyefficiency 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.

9.2 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 tenyear period."[14] 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 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

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

an even 20 percent.[15]

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.

9.3 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.

10 References

Cadmus Group. 2018. *Residential Building Stock Assessment II: Single family Homes Report 2016-17.* Portland, OR: Northwest Energy Efficiency Alliance.

[15] 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

Cadmus Group. 2018. *Residential Building Stock Assessment II: Multifamily Buildings Report 2016-17.* Portland, OR: Northwest Energy Efficiency Alliance.

Cadmus Group. 2018. *Residential Building Stock Assessment II: Manufactured Homes Report 2016-17.* Portland, OR: Northwest Energy Efficiency Alliance.

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

Northwest Power and Conservation Council. *Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions*. August 2007. Retrieved from: http://www.nwcouncil.org/library/2007/2007-13.htm.

Northwest Power and Conservation Council. *7th Power Plan Technical Information and Data*. April 13, 2015. Retrieved from: http://www.nwcouncil.org/energy/powerplan/7/technical

Northwest Power and Conservation Council. *Seventh Northwest Conservation and Electric Power Plan*. Feb 2016. Retrieved from: https://www.nwcouncil.org/energy/powerplan/7/plan/

Northwest Power and Conservation Council. *2021 Power Plan Technical Information and Data*. July 2020. Retrieved from: http://www.nwcouncil.org/energy/powerplan/2021/technical

Office of Financial Management. (2012). Washington State Growth Management Population Projections for Counties: 2010 to 2040. [Data files]. Retrieved from: http://www.ofm.wa.gov/pop/gma/projections12/projections12.asp

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

United States Department of Agriculture. 2012 Census of Agriculture. May 2014. Retrieved from: https://www.agcensus.usda.gov/

Washington State Energy Code, Wash. (2012)

Washington State Legislature. RCW 19.285.040 Energy conservation and renewable energy targets. Retrieved from: http://apps.leg.wa.gov/rcw/default.aspx?cite=19.285.040

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 costeffectiveness 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 Public Utilities 2021 Conservation Potential Assessment." October 11, 2021.
2) Model – "EES CPA Model-v4.0.xlsm" and supporting files
    a. MC_and_Loadshape-Grant-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 factor of 85% was 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.
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 costeffective (or economic).	Model – Benefit-Cost ratios are calculated at the individual level by ProCost and passed up to the model.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
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 Seventh 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 7th Plan, draft 2021 Power Plan Supply Curves, and RTF were used.	Model – supporting files include all of the ProCost files used in the Seventh Plan, with later updates made by the RTF. The life-cycle cost calculations and methods are identical to those used by the Council.
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 Seventh 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 Seventh 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.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**

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	A regional market price forecast for the planning period was created and provided by EES. A discussion of methodologies used to develop the avoided cost forecast is provided in Appendix IV.	Report –See Appendix IV. Model – See MC_AND_LOADSHAPE files (“Base Market Forecast” worksheet).
j) Include deferred capacity expansion benefits for transmission and distribution systems	Deferred transmission capacity expansion benefits were given a benefit of $3.23/kW-year in the cost-effectiveness analysis. A distribution system credit of $7.18/kW-year was also used ($2021). 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 equal to a 3% premium to the forecast of market prices 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 Batch Runner file. The generation capacity value was not originally included as part of ProCost during the development of the 7th Plan, so there is no dedicated input cell for this value. Instead, the value has been combined with the distribution capacity benefit since the timing of the District’s distribution system peak and the regional transmission peak occur at different times.
l) Include the social cost of carbon emissions from avoided non-conservation resources	This CPA uses the social cost of carbon values specified in Washington’s recently enacted clean energy law, SB 5116.	The MC_AND_LOADSHAPE files contain the carbon cost assumptions for each avoided cost scenario.
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 nonconservation 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.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**

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 Seventh 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 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 draft 2021 Power Plans.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
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 Seventh Power Plan.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
q) Discount future costs and benefits at a discount rate equal to the discount rate used by the utility in evaluating nonconservation 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 Seventh Plan	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
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 Batch Runner file.

Appendix IV – Avoided Cost and Risk Exposure

The 2021 Grant County Public Utility District No. 2 (District) Conservation Potential Assessment (CPA) was conducted for the period 2022 through 2041 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.

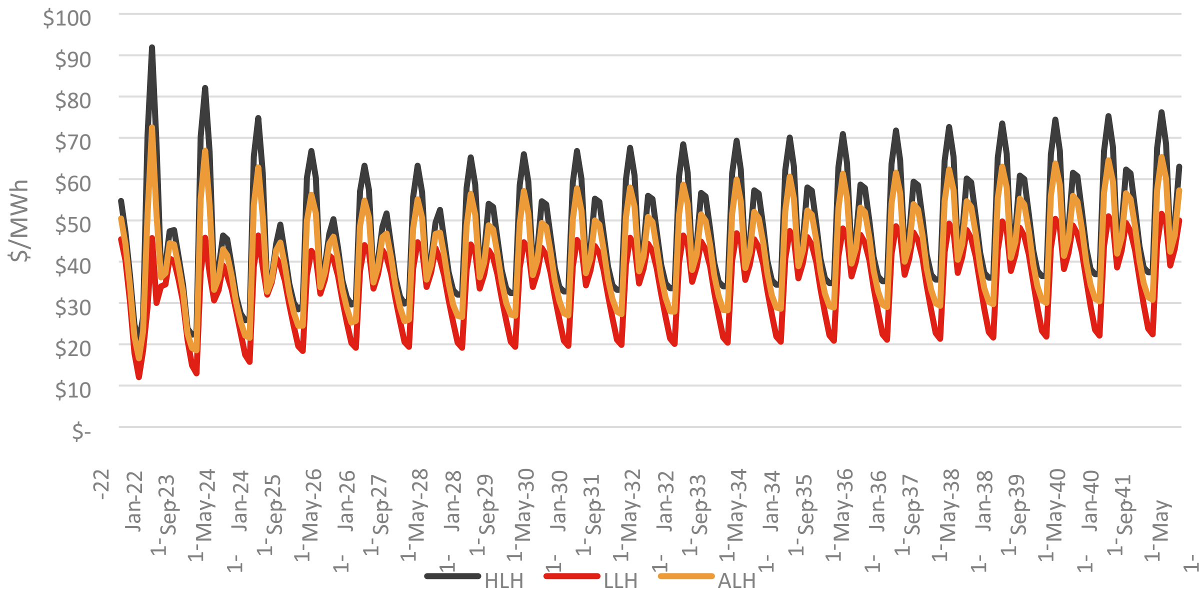
This appendix describes each of the avoided cost assumptions and provides a range of values that was evaluated in the 2021 CPA. The 2021 CPA considers three avoided cost scenarios: Base, Low, and High. Each of these is discussed below. Last, this appendix describes updates considered for the 2021 Power Plan methodology. Because the 2021 Power Plan will not be adopted until early 2022, this study relies on methodologies used in the Seventh Power Plan.

AVOIDED ENERGY VALUE

The District provided a base, low, and high forecast of market prices for use in the 2021 CPA. The forecasts are monthly diurnal starting January 2022 and ending December 2041. This section benchmarks the base forecast and compares the forecast to the market forecast used in the District's 2019 CPA.

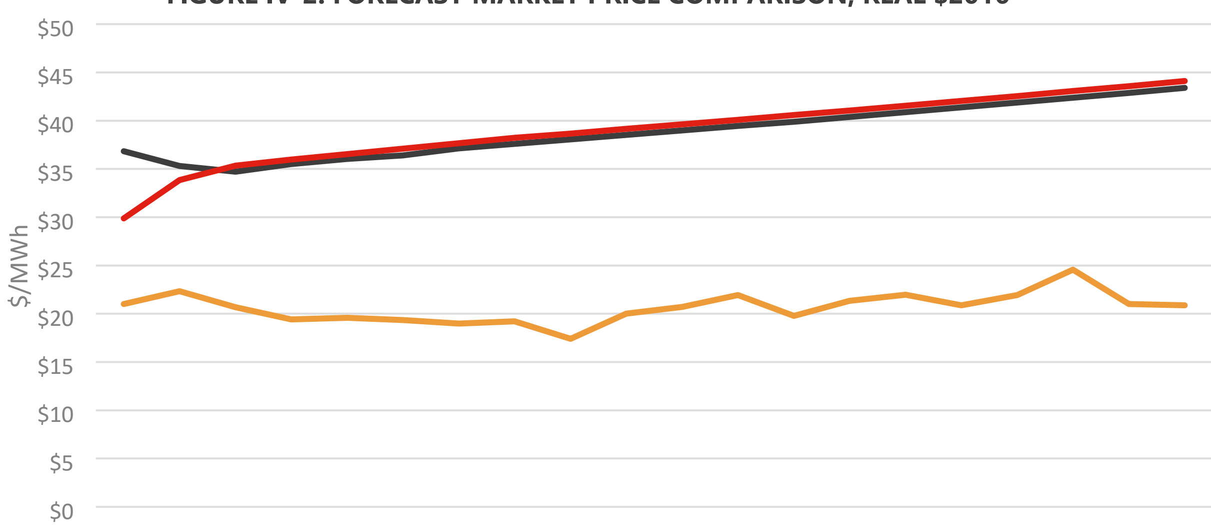
Figure IV-1 illustrates the resulting monthly, diurnal market price forecast. The levelized value of market prices over the study period is $42/MWh in 2021 dollars, assuming a 3.75 percent real discount rate.

FIGURE IV-1: FORECAST MARKET PRICES



This market price forecast is 1% higher than the market price forecast used in the District's previous CPA (the 2019 CPA). Both of the District's forecasts are higher than the forecast developed for the 2021 Power Plan.[16] Figure IV-2 compares the average annual price of the forecasts used to benchmark the District's forecast.

FIGURE IV-2: FORECAST MARKET PRICE COMPARISON, REAL $2016



[16] Wholesale Electricity Price Forecast – Final for NWPCC 2021 Power Plan. Monthly Prices. Revised January 2021. https://www.nwcouncil.org/2021-power-plan-technical-information-and-data

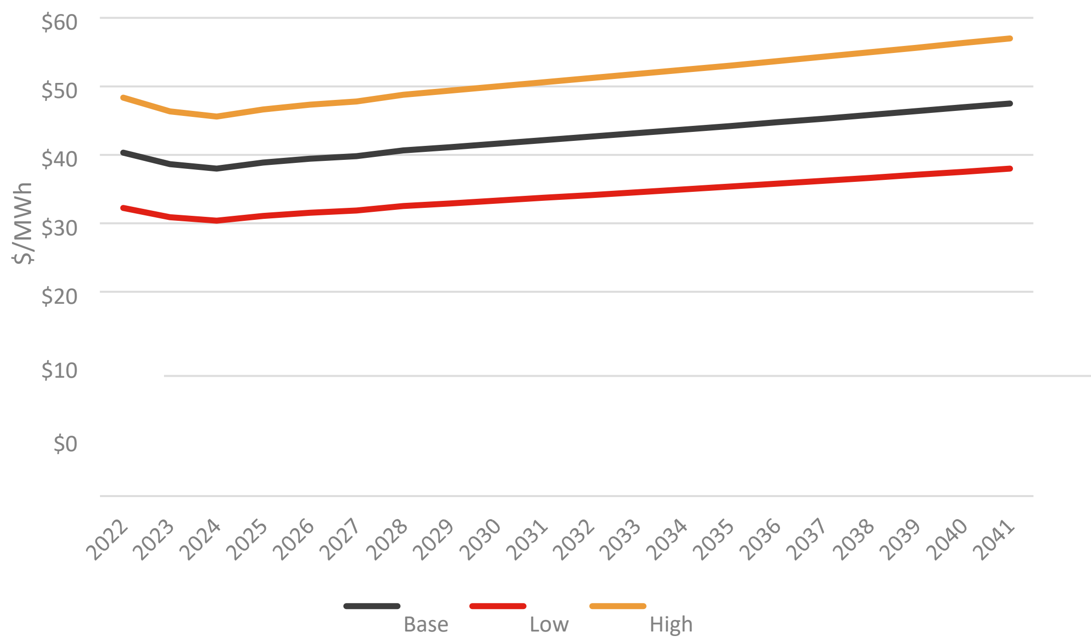
2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041

2021 CPA 2019 CPA 2021 Power Plan

10.1.1 High and Low Scenarios

To reflect a range of possible future outcomes, the District developed high and low market price forecasts. Figure IV-3 illustrate the range of forecasts.

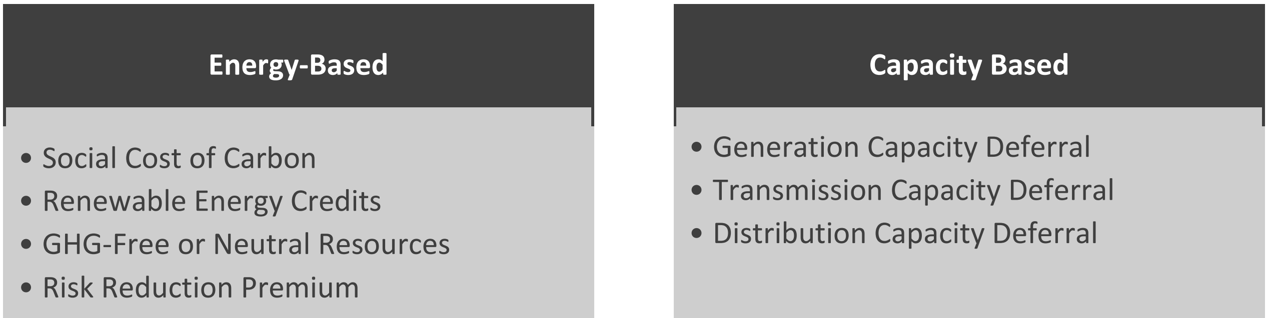
FIGURE IV-3: MARKET PRICE FORECAST SCENARIOS



10.2 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-4: OVERVIEW OF PORTFOLIO REQUIREMENTS

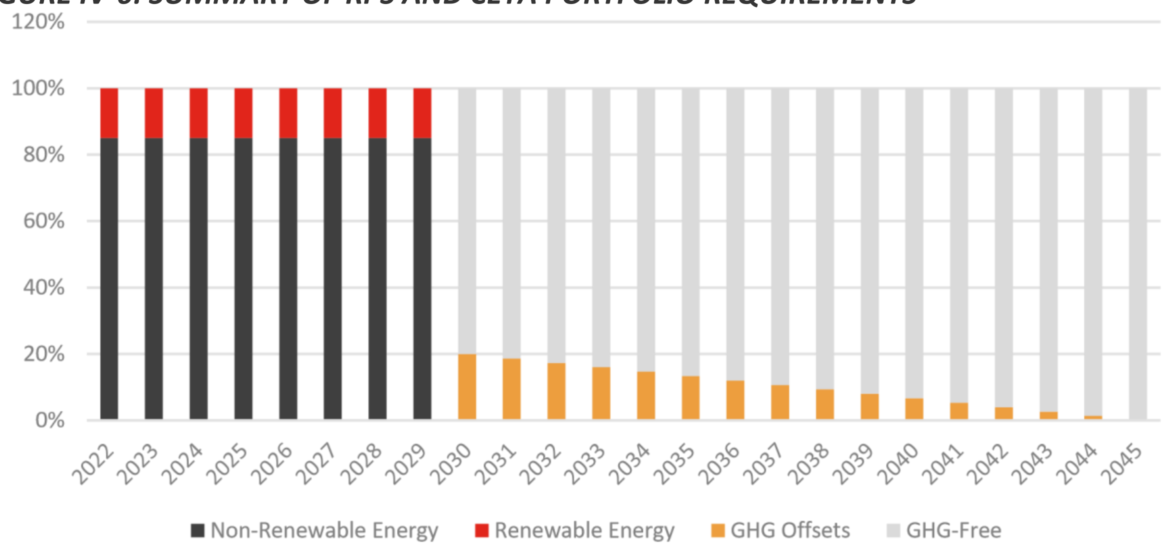


The estimated values and associated uncertainties for these avoided cost components are based on the District's 2020 Integrated Resource Plan (IRP)[15] and relevant portfolio requirements from the Clean Energy Transformation Act (CETA). The timeline below summarizes the relevant milestones for portfolio 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-5: OVERVIEW OF PORTFOLIO REQUIREMENTS

Through 2020, 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[17] or non-emitting resources.[18] 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-6.

FIGURE IV-6: SUMMARY OF RPS AND CETA PORTFOLIO REQUIREMENTS



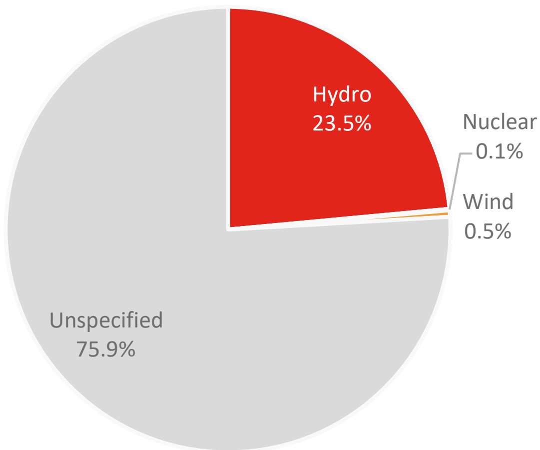
10.2.1 IRP

The District's 2020 IRP concludes that the District will need to address its long-term plan for meeting energy and capacity needs through market purchases of firm generation, power purchase agreements and call options for capacity needs. A large share of the District's loads are met with unspecified resources. As the Pacific Northwest power markets contemplate resource adequacy issues, the District will need to evaluate the risks of relying on market purchases to meet the majority of its energy requirements. The District's 2019 Fuel mix is shown in Figure IV-7.

[17] 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-71404b30-a3c2-faf8aa042651.pdf)

[18] 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-7: GRANT PUD 2019 FUEL MIX



The 2020 IRP concluded that the District has enough qualified resources to meet Washington State RPS through 2024. Beginning in 2025, the District plans to purchase renewable energy credits (RECs). Based on the above information, the District's current power supply mix is approximately 24% greenhouse gas free. In order to meet the CETA requirements illustrated in Figure IV-6, the District would need to replace approximately half of its current power supply (480 aMW, of unspecified power supply) with greenhouse gas free power by 2030. The remainder (378 aMW) would be met with greenhouse gas free power (current hydro, nuclear, and wind) and market purchases plus offsets. These offsets can be used to meet CETA requirements until 2045 when the District must phase out offsets with additional non-emitting or renewable resources. There are numerous strategies the District could pursue to meet CETA requirements; however, this strategy is assumed in the analysis for renewable energy and social cost of carbon avoidance. Alternative strategies are unlikely to materially impact the avoided cost of conservation.

10.3 *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 the table below.

TABLE IV-1: SOCIAL COST OF CARBON VALUES[19]

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

According to WAC 194-40-110, values may be adjusted for any taxes, fees or costs incurred by utilities to meet portfolio

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

mandates.[20] 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).[21] This is an average annual value applied to in all months in the conservation potential model.[22] The resulting levelized cost of carbon is $34/MWh over the 20-year study.

10.4 *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. Unbundled RECs do not have energy associated with them; therefore, the generation profile of the renewable resource is not considered in resource planning. As such, many jurisdictions exclude unbundled RECs from eligible greenhouse gas free resources. CETA rules support this consideration by allowing unbundled RECs as offsets only through 2044.

As sated 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 nonemitting 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 nonemitting resource costs as the avoided cost of energy rather than market plus the social cost of carbon.

10.4.1 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 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.

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

[21] WAC 173-444-040 (4)

[22] For reference, the Seventh Power Plan evaluated 0.95 lbs/kWh and 0 lbs/kWh. Typically, the emissions intensity would be higher in months outside of spring run-off (June-July). The seasonal nature of carbon intensity is not modeled due to the prescriptive annual value established by Ecology in WAC 173-444-040.

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. 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 2021 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 costeffective energy efficiency potential to a range of outcomes. The scenario results present a range of costeffective 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.

10.4.2 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 $3.23/kW-year and $7.18/kW-year for transmission and distribution systems, respectively ($2021).[23] These assumptions are used in the base and high avoided cost scenarios. The low avoided cost scenario assumes no value for avoided distribution system costs. The low scenario reflects historically low growth in the service area. Previous analyses assumed a $0 value for distribution system investment since capital costs have been historically due to reliability rather than growth or capacity needs. The recent growth in housing is reflected in the positive value assumed in the base case.

10.4.3 Deferred Investment in Generation Capacity

The 2020 IRP recommended the District obtain capacity resources in addition to some reliance on the market. To represent the value of capacity in the base case, the District provided a value that represents a 3 percent premium over market prices. This value is based on the opportunity cost of selling excess capacity created by energy savings in the market.

In the low scenario, it is assumed that a market will continue to be available to meet the District's needs for peak demands,

[23] 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

so no capacity value is included.

In the Council's Seventh Power Plan,[24] a generation capacity value of $135/kW-year was explicitly calculated ($2021). This value will be used in the high scenario.

10.4.4 Northwest Power Act Credit

In accordance with the Northwest Power Act, a 10% adder is included as a bonus to the avoided costs.[25]

10.5 2021 POWER PLAN METHODOLOGY CHANGES

The Council is in the process of completing the portfolio modeling for the 2021 Power Plan. As part of the target-setting approach, the Council is considering adding additional values to the avoided cost so that the portfolio model selects the optimal amount of energy efficiency. These attributes are discussed in this section; however, additional avoided costs are not included at this time.

10.5.1 Adequacy

Adding efficiency to the regional system reduces the frequency, duration, and magnitude of adequacy events. Energy efficiency, as demand-side resource, is often higher quality but higher cost than alternative supply-side reserves. In particular, energy efficiency that reduces load in the hours following sunset and overnight will have relatively more benefit, which may not be captured immediately in the capacity and energy cost forecast. This adequacy consideration addresses deferred generation benefits estimated in the Seventh Plan. While there is a time-value for adequacy, the current version of ProCost does not allow for time-varied input for adequacy costs. Since this study relies in the Seventh Plan version of ProCost,[26] the deferred generation capacity credit is used to represent adequacy benefits of energy efficiency.

10.5.2 Equity

The equity attribute refers to measures that require additional incentive or push to achieve equitable distribution of benefits. The Council defines these measures as the following:

4. Historic and long-term cost-effectiveness
5. Significant regional penetration from past program activity
6. Data demonstrating that untouched pockets are not reflective of the population (i.e. different socioeconomic status)

Equity measures are likely to be envelope measures in residential buildings. These can be high-cost to homeowners or there may be a renter/landlord issue. By definition, the equity component identifies measures that are cost-effective, and have been cost-effective for a period of time. Therefore, the 2021 CPA does not add value to capture measures with equity attributes. Rather, equitable distribution of energy efficiency benefits should be addressed on the program side, rather than from the conservation target point of view.

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

[25] in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act

[26] The Seventh Power Plan is the current power plan. All methodologies are designed to be consistent with the Seventh Power Plan with consideration of updates for the 2021 Power Plan scheduled to be adopted in early 2022.

10.5.3 Resilience

Resilience measures are those that support building resilience, or the ability to maintain building functions/comfort through extended power outages. The Council provides weatherization measures as resilient measures. The 2021 CPA identifies measures in the Base case that are not cost-effective but may provide building resilience benefits. The measures will be summarized in a table analysis that indicates how close to cost-effectiveness the measures are at the time of the study and what the targets may look like if those close to cost-effectiveness measures are included.

10.5.4 Flexibility

The Council defines the flexibility attribute as those measures that support grid flexibility. The rules for measure identification include the following:

4. Measures inherently include enabling technologies to support load management for grid flexibility
5. Reduce or eliminates impacts on end-use customers from load management or DR events
6. Value of measure is significant relative to its baseline

Example measures include weatherization and smart controls. Similar to the analysis for resiliency, the 2021 CPA identifies measures in the Base case that are not cost-effective but may provide grid flexibility benefits. The measures will be summarized in a table analysis that indicates how close to costeffectiveness the measures are at the time of the study and what the targets may look like if those close to cost-effectiveness measures are included.

10.6 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, $2021

	Base	Low	High
Energy	Market Forecast $41.93/MWh	Market Forecast $33.55/MWh	Market Forecast $50.32/MWh
Social Cost of Carbon	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	$7.18	$0.00	$7.18
Transmission System Credit, $/kW-yr	$3.23	$3.23	$3.23
Deferred Generation Capacity Credit, $/kW-yr	3% Premium	$0	$135
Implied Risk Adder, 20-year Levelized **$/MWh** **$/kW-yr**	N/A	Average: -$42/MWh -$7/kW-yr	Average: $9/MWh and $36/kW-year

**As noted above prediction intervals were used based on the last 10 years of data for high and low estimates.*

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, 2022-2023. 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 WITH POTENTIAL, AMW

_	Program History						CPA Potential	
	2017	2018	2019	2020	2021	17-'20 Avg	2022	2023
Residential	0.02	0.01	0.05	0.03		0.03	0.05	0.08
Commercial	0.24	0.30	0.04	0.25		0.21	0.19	0.25
Industrial	0.03	8.91	0.10	2.64		2.92	1.98	2.01
Agricultural	0.14	0.01	0.02	0.00		0.04	0.01	0.01
NEEA	0.34	0.63	0.90	0.74	0.77	0.68		
Total	**0.77**	**9.87**	**1.11**	**3.66**	**0.77**	**3.87**	**2.22**	**2.34**

When viewing the achievement and potential at the sector level, adjustments were found to be necessary across all sectors. The draft 2021 Power Plan assumptions are not a good fit for the District due to several factors:

- 2021 Plan ramp rates do not consider COVID impacts
- 2021 Plan ramp rates reflect regional averages and do not consider the rural nature of some utility service areas or disadvantaged communities. Some of the charactersitics of these communities create barriers to program participation.

The District plans to roll out low income programs and increase its efforts to reach customers who would not otherwise participate in energy efficiency programs. The ramp rates selected produce results that are attainable in the first two years of the study through utility programs or a mix of utility programs and NEEA savings. Because the 2021 Plan will set a new baseline for NEEA savings calculations, it's expected that the District will need to rely mostly on utility programs to meet the 2022/2023 target.

Appendix VI – Measure List

This appendix provides a high-level measure list of the energy efficiency measures evaluated in the 2021 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 utilityconservation 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 measure list used in this CPA was developed based on information from the Regional Technical Forum (RTF) and the Northwest Power and Conservation Council (Council). The RTF and the Council continually maintain and update a list of regional conservation measures based on new data, changing market conditions, regulatory changes, and technological developments. The measure list provided in this appendix includes the most up-to date information available at the time this CPA was developed.

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 Seventh Plan workbooks and the RTF's Unit Energy Savings (UES) 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
Dryer	Heat Pump Clothes Dryer	7th Plan
Electronics	Advanced Power Strips	7th Plan, RTF
	Energy Star Computers	7th Plan
	Televisions	2021 Power Plan
	Energy Star Monitors	7th Plan
Food Preparation	Electric Oven	7th Plan
	Microwave	7th Plan
HVAC	Air Source Heat Pump	7th Plan, RTF
	Controls, Commissioning, and Sizing	7th Plan, RTF
	Ductless Heat Pump	7th Plan, RTF
	Ducted Ductless Heat Pump	7th Plan
	Duct Sealing	7th Plan, RTF
	Ground Source Heat Pump	7th Plan, RTF
	Heat Recovery Ventilation	7th Plan
	Attic Insulation	7th Plan, RTF
	Floor Insulation	7th Plan, RTF
	Wall Insulation	7th Plan, RTF
	Windows	7th Plan, RTF
	Wi-Fi Enabled Thermostats	7th Plan
Lighting	Linear Fluorescent Lighting	2021 Plan
	Floor/Table Lamps	2021 Plan
	Ceiling and Wall Flush Mount	2021 Plan
	Downlight Fixture	2021 Plan
	Exterior Porch	2021 Plan
	Linear Porch	2021 Plan
	Track Lighting	2021 Plan
	Linear Base	2021 Plan
	Decorative Base	2021 Plan
Refrigeration	Freezer	7th Plan
	Refrigerator	7th Plan

Water Heating	Aerator	7th Plan
	Behavior Savings	7th Plan
	Clothes Washer	7th Plan
	Dishwasher	7th Plan
	Heat Pump Water Heater	7th Plan, RTF
	Showerheads	7th Plan, RTF
	Solar Water Heater	7th Plan
	Circulator Controls	2021 Plan
	Thermostatic Valve	RTF
	Wastewater Heat Recovery	7th Plan
Whole Building	EV Charging Equipment	2021 Plan

Table VI-2
Commercial End Uses and Measures

End Use	Measures/Categories	Data Source
Compressed Air	Controls, Equipment, & Demand Reduction	RTF
Electronics	Energy Star Computers	RTF
	Energy Star Monitors	RTF
	Smart Plug Power Strips	7th Plan, RTF
	Data Center Measures	RTF
Food Preparation	Combination Ovens	7th Plan, RTF
	Convection Ovens	7th Plan, RTF
	Fryers	7th Plan, RTF
	Hot Food Holding Cabinet	7th Plan, RTF
	Steamer	7th Plan, RTF
	Pre-Rinse Spray Valve	7th Plan, RTF
HVAC	Advanced Rooftop Controller	RTF
	Commercial Energy Management	RTF
	Demand Control Ventilation	RTF
	Ductless Heat Pumps	RTF
	Economizers	RTF
	Secondary Glazing Systems	RTF
	Variable Refrigerant Flow	RTF
	Web-Enabled Programmable Thermostat	RTF
	ARC	2021 Plan
	PTPH	2021 Plan
Lighting	Bi-Level Stairwell Lighting	7th Plan
	Exterior Building Lighting	2021 Plan
	Exit Signs	7th Plan
	Lighting Controls	7th Plan
	Interior Lighting	2021 Plan

	Street Lighting	7th Plan
Motors/Drives	ECM for Variable Air Volume	RTF
	Motor Rewinds	RTF
Process Loads	Municipal Water Supply	7th Plan
Refrigeration	Grocery Refrigeration Bundle	2021 Plan, RTF
	Water Cooler Controls	7th Plan
Water Heating	Commercial Clothes Washer	7th Plan, RTF
	Showerheads	RTF
	Tank Water Heaters	RTF
	Heat Pump Water Heaters	2021 Plan

Table VI-3
Industrial End Uses and Measures

End Use	Measures/Categories	Data Source
Compressed Air	Air Compressor Equipment	7th Plan
	Demand Reduction	7th Plan
Energy Management	Air Compressor Optimization	7th Plan
	Energy Project Management	7th Plan
	Fan Energy Management	7th Plan
	Fan System Optimization	7th Plan
	Cold Storage Tune-up	7th Plan
	Chiller Optimization	7th Plan
	Integrated Plant Energy Management	7th Plan
	Plant Energy Management	7th Plan
	Pump Energy Management	7th Plan
	Pump System Optimization	7th Plan
Fans	Efficient Centrifugal Fan	7th Plan
	Fan Equipment Upgrade	7th Plan
Hi-Tech	Clean Room Filter Strategy	7th Plan
	Clean Room HVAC	7th Plan
	Chip Fab: Eliminate Exhaust	7th Plan
	Chip Fab: Exhaust Injector	7th Plan
	Chip Fab: Reduce Gas Pressure	7th Plan
	Chip Fab: Solid State Chiller	7th Plan
Lighting	Efficient Lighting High-	7th Plan
	Bay Lighting	7th Plan
	Lighting Controls	7th Plan
Low & Medium Temp Refrigeration	Food: Cooling and Storage	7th Plan
	Cold Storage Retrofit	7th Plan
	Grocery Distribution Retrofit	7th Plan
Material Handling	Material Handling Equipment	7th Plan
	Material Handling VFD	7th Plan

Metals	New Arc Furnace	7th Plan
Misc.	Synchronous Belts	7th Plan
	Food Storage: CO2 Scrubber	7th Plan
	Food Storage: Membrane	7th Plan
Motors	Motor Rewinds	7th Plan
Paper	Efficient Pulp Screen	7th Plan
	Material Handling	7th Plan
	Premium Control	7th Plan
	Premium Fan	7th Plan
Process Loads	Municipal Sewage Treatment	7th Plan
Pulp	Efficient Agitator	7th Plan
	Effluent Treatment System Premium	7th Plan
	Process	7th Plan
	Refiner Plate Improvement	7th Plan
	Refiner Replacement	7th Plan
Pumps	Equipment Upgrade	7th Plan
Transformers	New/Retrofit Transformer	7th Plan
Wood	Hydraulic Press	7th Plan
	Pneumatic Conveyor	7th Plan

Table VI-3
Agriculture End Uses and Measures

End Use	Measures/Categories	Data Source
Dairy Efficiency	Efficient Lighting	7th Plan
	Milk Pre-Cooler	7th Plan
	Vacuum Pump	7th Plan
Irrigation	Low Energy Sprinkler Application	7th Plan
	Irrigation Hardware	7th Plan, RTF
Lighting	Agricultural Lighting	7th Plan
Motors/Drives	Motor Rewinds	7th Plan

Table VI-4
Distribution Efficiency End Uses and Measures

End Use	Measures/Categories	Data Source
Distribution Efficiency	LDC Voltage Control	RTF
	Minor System Improvements	RTF
	Major System Improvements	RTF
	EOL Voltage Control Method	RTF
	SCL Implement EOL w/ Improvements	RTF

Appendix VII –Energy Efficiency Potential by End-Use

Table VII-1 Residential Economic Potential (aMW)				
	2 Year	**4 Year**	**10 Year**	**20 Year**
Dryer	0.00	0.00	0.00	0.00
Electronics	0.02	0.08	0.42	0.93
Food Preparation	0.00	0.00	0.02	0.05
HVAC	0.01	0.05	0.49	1.42
Lighting	0.01	0.04	0.22	0.70
Refrigeration	0.00	0.00	0.01	0.10
Water Heating	0.08	0.24	1.37	3.62
Whole Bldg/Meter Level	0.00	0.00	0.02	0.20
Total	**0.13**	**0.42**	**2.57**	**7.01**

Table VII-2 Commercial Economic Potential (aMW)				
	2 Year	**4 Year**	**10 Year**	**20 Year**
Compressed Air	0.00	0.01	0.26	2.10
Electronics	0.02	0.08	0.65	0.70
Food Preparation	0.00	0.01	0.08	0.20
HVAC	0.16	0.40	1.46	2.22
Lighting	0.19	0.54	2.97	8.10
Motors/Drives	0.00	0.01	0.05	0.16
Process Loads	0.01	0.02	0.08	0.09
Refrigeration	0.03	0.06	0.16	0.40
Water Heating	0.02	0.07	0.93	6.70
Total	**0.43**	**1.20**	**6.63**	**20.68**

Table VII-3 Industrial Economic Potential (aMW)				
	2 Year	**4 Year**	**10 Year**	**20 Year**
Compressed Air	0.00	0.011	0.11	0.33
Energy Management	0.06	0.254	2.70	7.94
Fans	0.01	0.021	0.23	0.67
Hi-Tech	0.00	0.005	0.05	0.15

Integrated Plant Energy Management	0.00	0.000	0.00	0.00
Lighting	0.01	0.049	0.53	1.55
Low & Med Temp Refr	0.02	0.067	0.72	2.11
Material Handling	0.00	0.001	0.01	0.02
Metals	0.00	0.000	0.00	0.01
Misc	0.00	0.000	0.00	0.00
Motors	0.00	0.000	0.00	0.00
Paper	0.00	0.001	0.01	0.02
Process Loads	0.00	0.008	0.09	0.26
Pulp	0.00	0.000	0.00	0.00
Pumps	0.01	0.038	0.41	1.20
Transformers	0.00	0.000	0.00	0.00
Wood	0.00	0.000	0.00	0.00
Total	**0.11**	**0.456**	**4.84**	**14.26**

Table VII-4
Agricultural Economic Potential (aMW)

	2 Year	4 Year	10 Year	20 Year
Dairy Efficiency	0.00	0.008	0.03	0.04
Irrigation	0.01	0.030	0.34	1.03
Lighting	0.01	0.021	0.08	0.10
Motors/Drives	0.00	0.005	0.05	0.17
Total	**0.02**	**0.064**	**0.50**	**1.33**

PREPARED BY EES CONSULTING

Grant Public Utility District

Conservation Potential Assessment

EES Consulting
a GDS Associates Company

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

October 11, 2021

Mr. Richard Cole
Grant PUD
P.O. Box 1519
Moses Lake, WA 98837

SUBJECT: 2021 Conservation Potential Assessment – Final Report

Dear Mr. Cole:

Please find attached the draft report summarizing the 2021 Grant Public Utility District Conservation Potential Assessment (CPA). This report covers the 20-year time period from 2022 through 2041.

The 2-year potential has increased from the 2019 CPA, largely due to the addition of data center projects expected to be completed in the 2022/2023 biennium. Potential in other sectors has decreased compared with the previous CPA due to increased efficiency baselines, program participation, and updated ramp rates that reflect the District's historic program achievement.

Respectfully,

Amber Gschwend

Managing Director, EES Consulting

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	EES Consulting Procedure	Reference