2023 ELECTRIC PROGRESS REPORT

CHAPTERS 1–9

PUGET SOUND ENERGY

2023 ELECTRIC PROGRESS REPORT

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About PSE

As Washington State's oldest local energy company, Puget Sound Energy serves more than 1.2 million electric customers and more than 900,000 natural gas customers in ten counties. Our service territory includes the vibrant Puget Sound area and covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula.

A subsidiary of Puget Energy, PSE meets the energy needs of its customers, in part, through incremental, cost-effective energy efficiency, procurement of sustainable energy resources, and far-sighted investment in the energy-delivery infrastructure. PSE employees are dedicated to providing great customer service and delivering energy that is safe, dependable and efficient. For more information, visit pse.com.

Our electric service territory includes all of Kitsap, Skagit, Thurston, and Whatcom counties, and parts of Island, King (not Seattle), Kittitas and Pierce (not Tacoma) counties.

Our natural gas service territory includes: Parts of King (not Enumclaw), Kittitas (not Ellensburg), Lewis, Pierce, Snohomish, and Thurston counties

Figure 1.1 below shows PSE's electric and gas service territories.

Figure 1.1 Puget Sound Energy Natural Gas and Electric Service Territories

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DEFINITIONS & ACRONYMS

Term/Acronym	Definition
A4, A5	A standard for converting gases to carbon dioxide equivalents using the Intergovernmental Panel on Climate Change global warming protocols.
AARG	Average annual rate of growth
AB 32	California Global Warming Solutions Act of 2006, which mandates a carbon price to be applied to all power generated in or sold into that state.
AC	Alternating current
ACE	Area Control Error
ACE Rule	Affordable Clean Energy Rule. Adopted in 2018, EPA's replacement for the Clean Power Plant Rule.
ADMS	Advanced Distribution Management System, a computer-based, integrated platform that provides the tools to monitor and control distribution networks in real time
AECO	Alberta Energy Company, a natural gas hub in Alberta, Canada
AMI	Advanced metering infrastructure
AMI	Area median income
AMR	Automated meter reading
aMW	The average number of megawatt-hours (MWh) over a specified time period; for example, 175,200 MWh generated over the course of one year equals 20 aMW (175,200 / 8,760 hours).
AOC	Administrative Order of Consent
ARMA	Autoregressive moving average
ATB	Annual Technology Baseline, an annual, publically available report published by NREL, and presents a consistent set of electricity generating technology cost and performance data
ATC	Available transmission capacity
AURORA	One of the models PSE uses for electric resource planning. AURORA uses the western power market to produce hourly electricity price forecasts of potential future market conditions. AURORA is also used to test electric portfolios to evaluate PSE’s long-term revenue requirements.
BA	Balancing Authority, the area operator that matches generation with load
BAA	Balancing Authority area
BACT	Best available control technology, required of new power plants and those with major modifications, pursuant to EPA regulations
Balancing reserves	Reserves sufficient to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves must be able to ramp up and down as loads and resources fluctuate instantaneously each hour.
BART	Best available retrofit technology, an EPA requirement for certain power plant modifications
Base Scenario	In an analysis, a set of assumptions that is used as a reference point against which other sets of assumptions can be compared. The analysis result may not ultimately indicate that the Base Scenario assumptions should govern decision-making.

Term/Acronym	Definition
Baseload combustion turbines	Baseload combustion turbines are designed to operate economically and efficiently over long periods of time. Generally combined-cycle combustion turbines (CCCTs).
Baseload resources	Baseload resources produce energy at a constant rate over long periods at lower cost relative to other production facilities; typically used to meet some or all of a region's continuous energy need.
BAU	Business-as-usual
Bcf	Billion cubic feet
BEM	Business Energy Management sector, for electric energy efficiency programs.
BES	Bulk electric system
BESS	Battery energy storage system
BIPOC	Black, Indigenous, and People of Color
BPA	Bonneville Power Administration
BSER	Best system of emissions reduction, an EPA requirement for certain power plant construction or modification.
BTU	British thermal units
CAA	Clean Air Act
CAISO	California Independent System Operator
capacity factor	The ratio of the actual generation from a power resource compared to its potential output if it was possible to operate at full nameplate capacity over the same period of time.
CAPEX	Capital expenditures required to achieve commercial operations of a generation plant. CAPEX may vary by resource type.
CAP	Corrective action plan, a series of operational steps used to prevent system overloads or loss of customer power
CAR	Washington State Clean Air Rule
CARB	California Air Resources Board
CBI	Customer benefit indicator
CCA	Climate Commitment Act
CCCT	Combined-cycle combustion turbine. Baseload generating plant that consists of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine exhaust and use it to produce additional electricity via a steam turbine generator.
CCR	Coal combustion residuals
CCS	Carbon capture and sequestration
CDD	Cooling degree day
CEAP	Clean Energy Action Plan
CEC	California Energy Commission
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CFS	Conditional Firm Service, a new transmission product offered by BPA.

Term/Acronym	Definition
CHP	Combined heat and power
CI	Confidence interval
CIA	Cumulative impact analysis
CIA	Community impact assessment
C&I	Commercial and industrial
CNG	Compressed natural gas
CO^2	Carbon dioxide
CO2e	Carbon dioxide equivalents
COE	U.S. Army Corps of Engineers
Contingency reserves	Reserves added in addition to balancing reserves; contingency reserves are intended to bolster short-term reliability in the event of forced outages and are used for the first hour of the event only. This capacity must be available within 10 minutes, and 50 percent of it must be spinning.
CPA	Conservation potential assessment
CPI	Consumer price index
CPP	federal Clean Power Plan
CPP	Critical Peak Pricing or dynamic pricing
CPUC	California Public Utilities Commission
CRAG	PSE's Conservation Resource Advisory Group
C&S	Codes and standards
CT	Combustion turbine
CVR	Conservation voltage reduction
DA	Distribution automation
DE	Distribution efficiency
DER	Distributed energy resources
Demand response	Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
Demand-side resources	These resources reduce demand. They include energy efficiency, distribution efficiency, generation efficiency, distributed generation and demand response.
DER	Distributed energy resources. Electricity generators like rooftop solar panels that are located below substation level.
DERMS	Distributed Energy Resource Management System
Deterministic analysis	Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.
DG	Distributed generation
Distributed energy resources	Small-scale electricity generators like rooftop solar panels, located below substation level.
DLC	Direct load control, one of several demand response programs

Term/Acronym	Definition
DMS	Distribution management system
DNV	An energy consultant
DOE	U.S. Department of Energy
DOH	Washington State Department of Health
DR	Demand response
DSM	Demand-side measure
DSM	Demand-side management
DSO	Dispatcher Standing Order
DSP	Delivery System Planning
DSR	Demand-side resources
Dth	Dekatherms
Dual fuel	Refers to peakers that can operate on either natural gas or distillate oil fuel.
EAG	PSE's Equity Advisory Group
EDAM	Extended day-ahead market
EE	Energy efficiency
EEI	Edison Electric Institute
EHD	Environmental health disparities
EHEB	Economic, Health and Environmental Benefits Assessment
EIA	U.S. Energy Information Agency
EIA	Washington State Energy Independence Act
EIM	The Energy Imbalance Market operated by CAISO
EIS	Environmental impact statement
EITEs	Energy-intensive, trade-exposed industries
ELCC	Effective load carrying capacity. The peak capacity contribution of a resource calculated as the change in capacity of a perfect capacity resource that results from adding a different resource with any given energy production characteristics to the system while keeping the 5 percent LOLP resource adequacy metric constant.
EMC	PSE's Energy Management Committee
Energy need	The difference between forecasted load and existing resources.
Energy storage	A variety of technologies that allow energy to be stored for future use.
EPA	U.S. Environmental Protection Agency
EPR	Electric Progress Report
EPRI	Electric Power Research Institute
EPS	Washington state law RCW 80.80.060(4), GHG Emissions Performance Standard
ERU	Emission reduction units. An ERU represents one MtCO2 per year.
ESP	Electric service platform
ESS	Energy storage systems

Term/Acronym	Definition
EUE	Expected unserved energy, a reliability metric measured in MWhs that describes the magnitude of electric service curtailment events (how widespread outages may be).
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
FIP	Final implementation plan
FLISR	Fault Location, Isolation, Service Restoration
FPL	Federal poverty level
FSC	Floating surface collector
GDP	Gross domestic product
GENESYS	The resource adequacy model used by the Northwest Power and Conservation Council (NPCC).
GHG	Greenhouse gas
GIS	Geographic Information System
GPM	Gas portfolio model
GRC	General Rate Case
GTN	Gas Transmission Northwest
GW	Gigawatt
HB 1257	Clean Buildings for Washington Act
HDD	Heating degree day
HDR	Energy consultant
HIC	Highly impacted communities
HILF	High-impact, low-frequency events
HVAC	Heating, ventilating and air conditioning
I-937	Initiative 937, Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, the Energy Independence Act.
IAP2	International Association of Public Participation
iDOT	Investment Optimization Tool. An analysis tool that helps to identify a set of projects that will create maximum value.
IGCC	Integrated gasification combined-cycle, generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier.
IIJA	Infrastructure Investment and Jobs Act
Intermittent resources	Resources that provide power that offers limited discretion in the timing of delivery, such as wind and solar power.
IOU	Investor-owned utility
IPP	Independent power producer
IRA	Inflation Reduction Act
IRP	Integrated resource plan

Term/Acronym	Definition
ISO	Independent system operator
ITA	Independent technical analysis
ITC	Investment tax credit
KORP	Kingsvale-Oliver Reinforcement Project pipeline proposal
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hours
LAES	Liquid air energy storage
LNG	Liquified natural gas
Load	The total of customer demand plus planning margins and operating reserve obligations.
LOLE	Loss of load expectation, a reliability metric that measures the number of days per year with loss of load due to load exceeding available system capacity.
LOLH	Loss of load hours (or loss of load energy), a reliability metric that measures the duration of electric service curtailment events (how long outages may last).
LOLP	Loss of load probability, a reliability metric that measures the likelihood of an electric service curtailment event happening.
LP-Air	Vaporized propane air
LSR	Lower Snake River Wind Facility
LTCE	Long-term capacity expansion model
LTF	Long-term firm transmission
LTF PTP	Long-term firm point-to-point transmission
MATS	Mercury Air Toxics Standard
MDEQ	Montana Department of Environmental Quality
MDQ	Maximum daily quantity
MDth	One thousand dekatherms or 10,000 therms
MEIC	Montana Environmental Information Center
MESA	Modular Energy Storage Architecture. A protocol for communications between utility control centers and energy storage systems.
Mid-Columbia (Mid-C) market hub	The principle electric power market hub in the Northwest and one of the major trading hubs in the WECC.
MIP	Mixed integer programming, a mathematic optimization technique with combines elements of linear programming and integer programming
MMBtu	Million British thermal units
MMtCO2e	Million metric tons of CO2 equivalent
MSA	Metropolitan statistical area
MSCG	Morgan Stanley Commodities Group
MW	Megawatt

Term/Acronym	Definition
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards, set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead.
Nameplate capacity	The maximum sustained output capacity of an electric-generating resource.
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
Net maximum capacity	The capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.
Net metering	A program that enables customers who generate their own renewable energy to offset the electricity provided by PSE.
NGV	Natural gas vehicles
NO2	Nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NOS	Network Open Season, a BPA transmission planning process.
NO_x	Nitrogen oxides
NPCC	Northwest Power & Conservation Council
NPV	Net present value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NRF	Northwest Regional Forecast of Power Loads and Resources, the regional load/balance study produced by PNUCC.
NSPS	New source performance standards, new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction.
NSRDB	NREL's National Solar Radiation Database
NTTG	Northern Tier Transmission Group
NUG	Non-utility generator
NWA	Non-wires analysis
NWE	NorthWestern Energy
NWGA	Northwest Gas Association
NWP	Northwest Pipeline
NWPP	Northwest Power Pool
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMS	Outage management system
OTC	Once-through cooling
PACE	PacifiCorp East

Term/Acronym	Definition
PACW	PacifiCorp West
PCA	Power cost adjustment (electric)
PCORC	Power cost only rate case
Peak capacity contribution	The nameplate capacity of a particular resource multiplied by the ELCC for that resource. For example, 100 MW of eastern Washington solar nameplate capacity, which has a summer ELCC of 54%, has a summer peak capacity contribution of 54 MW.
Peak need	Electric or gas sales load at peak energy use times.
Peaker or peaking plants	Peaker is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload generators.
Peaking resources	Quick-starting electric generators that can ramp up and down quickly in order to meet short-term spikes in need, or gas sales resources used to meet load at times when demand is highest.
PEFA	ColumbiaGrid's planning and expansion functional agreement, which defines obligations under its planning and expansion program.
PEV	Plug-in electric vehicle
PG&E	Pacific Gas and Electric Company
PGA	purchased gas adjustment
PGE	Portland General Electric
PHES	Pumped hydroelectric energy storage
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)
Planning reserve margin or PRM	These are amounts over and above customer peak demand that ensure the system has enough flexibility to handle balancing needs and unexpected events.
Planning standards	The metrics selected as performance targets for a system's operation.
PLEXOS	An hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real time to match changes in supply and demand on a 5-minute basis.
PM	Particulate matter
PNNL	Pacific Northwest National Laboratory
PNUCC	Pacific Northwest Utilities Coordinating Committee
PNW	Pacific Northwest
POI	Point on interconnection
POD	Point of delivery
Portfolio	A specific mix of resources to meet gas sales or electric load.
PPA	Purchased power agreement. A bilateral wholesale or retail power short-term or long-term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point.
PRP	Pipeline replacement program

Term/Acronym	Definition
PSCAA	Puget Sound Clean Air Agency
PSE	Puget Sound Energy
PSEM	Puget Sound Energy Merchant, the part of PSE responsible for obtaining and scheduling the transmission needed to serve PSE loads.
PSIA	Pipeline Safety Improvement Act (2002)
PSRC	Puget Sound Regional Council
PTC	Production Tax Credit
PTP	Point-to-point transmission service, meaning the reservation and transmission of capacity and energy on either a firm or non-firm basis from the point of receipt (POR) to the point of delivery (POD).
PTSA	Precedent Transmission Service Agreement
PUD	Public utility district
Pumped hydro or PHES	Pumped hydro facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station.
PV	Photovoltaic
R&D	Research and development
RA	Resource adequacy
RAM	Resource Adequacy Model. RAM analysis produces reliability metrics (EUE, LOLP, LOLH) that allow us to assess physical reliability.
Rate base	The amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In Washington state, rate base is valued at the original cost less accumulated depreciation and deferred taxes.
RCRA	Resource Conservation Recovery Act
RCW	Revised Code of Washington
RCW 19.285	Washington State's Energy Independence Act, commonly referred to as the state's renewable portfolio standard (RPS)
RCW 80.80	Washington State law that sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.
REC	Renewable energy credit. RECs are intangible assets, which represent the environmental attributes of a renewable generation project – such as a wind farm – and are issued for each MWh of energy generated from such resources.
RECAP	Renewable Energy Capacity Planning, E3's resource adequacy analysis model
REC banking	Washington's renewable portfolio standard allows for RECs unused in the current year to be "banked" and used in the following year.
Redirected transmission	Moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it

Term/Acronym	Definition
	has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
Regulatory lag	The time that elapses between establishment of the need for funds and the actual collection of those funds in rates.
REM	Residential Energy Management sector, in energy efficiency programs.
Repowering	Refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015.
Revenue requirement	Rate Base x Rate of Return + Operating Expenses
RFP	Request for proposal
RFQ	Request for quote
RHA	Renewable Hydrogen Alliance
RICE	Reciprocating internal combustion engine – also referred to as recip peakers.
RNG	Renewable natural gas
RPS	Renewable portfolio standard. A requirement that electricity retailers acquire a minimum percentage of their power from renewable energy resources. Washington state mandates 3 percent by 2012, 9 percent by 2016 and 15 percent by 2020.
RTO	Regional transmission organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	NREL's System Advisor Model
SAP	Systems Applications and Products in Data Processing
SCADA	Supervisory control and data acquisition that provides real-time visibility and remote control of distribution equipment
SCCT	Simple-cycle combustion turbine, a generating unit capable of ramping up and down quickly to meet peak resource need. Also called a peaker.
Scenario	A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis.
SCC	Social cost of carbon, also called SCGHG, social cost of greenhouse gases
SCGHG	Social cost of greenhouse gases
SCR	Selective catalytic reduction
SEIA	Solar Energy Industries Association
SENDOUT	The deterministic gas portfolio model used to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads.
Sensitivity	A set of data assumptions based on the Reference Scenario in which only one input is changed. Used to isolate the effect of a single variable.
SEPA	Washington State Environmental Policy Act
SIP	State Implementation Plan

Term/Acronym	Definition
SMR	Small modular reactor
SNCR	Selective non-catalytic reduction
SO2	Sulfur dioxide
SOFA system	Separated over-fire air system
Solar PV	Solar photovoltaic technology
Stochastic analysis	Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how different portfolios perform with regard to cost and risk across a wide range of potential future power prices, natural gas prices, hydro generation, wind generation, loads, plant forced outages and CO2 prices.
Supply-side resources	Resources that generate or supply electric power, or supply natural gas to natural gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources.
T&D	Transmission and distribution
TailVar90	A metric for measuring risk defined as the average value of the worst 10 percent of outcomes.
TCPL-Alberta	TransCanada's Alberta System (also referred to as TC-AB)
TCPL-British Columbia	TransCanada's British Columbia System (also referred to as TC-BC)
TC-Foothills	TransCanada-Foothills Pipeline
TC-GTN	TransCanada-Gas Transmission Northwest Pipeline
TC-NGTL	TransCanada-Nova Gas Transmission Pipeline
TEPPC	WECC Transmission Expansion Planning Policy Committee
TF-1	Firm gas transportation contracts, available 365 days each year.
TF-2	Gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only.
thermal resources	Electric resources that use carbon-based or alternative fuels to generate power.
TOP	Transmission operator
Transmission capacity	Defines the quantity of generation development available in specific geographic regions.
Transmission costs	Transmission costs model the cost of transmitting power from a generating resource to PSE's service territory
Transmission losses	This refers to energy lost to heat as power is carried from one location to another.
Transmission redirect	"Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
Tranche	A capacity segment on ELCC saturation curve
Transport customers	Customers who acquire their own natural gas from third-party suppliers and rely on the natural gas utility for distribution service.

Term/Acronym	Definition
TSR	Transmission service request
TSEP	Bonneville Power Administration's transmission service request study and expansion process.
UPC	use per customer
VectorGas	An analysis tool that facilitates the ability to model price and load uncertainty.
VERs	Variable energy resources
VPP	Virtual power plant
VVO	Volt-var optimization
WAC	Washington Administrative Code
WACC	Weighted average cost of capital
WCI	Western Climate Initiative
WCPM	Wholesale Purchase Curtailment Model
WECC	Western Electricity Coordinating Council
WECo	Western Energy Company
WEI or Westcoast	Westcoast Energy, Inc.
Wholesale market purchases	Generally short-term purchases of electric power made on the wholesale market.
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
ZLD	Zero liquid discharge

EXECUTIVE SUMMARY
CHAPTER ONE

Contents

1. Introduction

Puget Sound Energy (PSE) is Washington State's largest and oldest utility, serving 1.5 million customers in ten counties over 6,000 square miles. History reflects how PSE has shared customers' environmental concerns over the years while balancing expectations for uncompromised reliability, affordability, and safety. Puget Sound Energy was an early leader in clean energy — from our oldest hydroelectric facility, Snoqualmie Falls built in 1898, to our first wind facility, Hopkins Ridge, developed in 2005, to establishing a pathway to remove coal-fired generation by the end of 2025. Our commitment to clean energy and reducing greenhouse gas emissions has only strengthened in recent years, as evidenced by our support of the passage of the Clean Energy Transformation Act (CETA) and the Climate Commitment Act (CCA).

In this 2023 Electric Progress Report (2023 Electric Report or report), we identified the need to build and/or acquire a significant amount of resources to comply with the CETA and meet resource adequacy requirements — more than 6,700 megawatts (MW) of nameplate capacity by 2030. This report outlines the resources and actions to get us there.

A Series of Firsts

This document is PSE's first electric progress report. A product of the CETA, it is designed to streamline reporting as we work toward our clean energy goals. This report is also our first opportunity to reinforce the commitments in PSE's 2021 Clean Energy Implementation Plan (CEIP), which includes eliminating coal-fired resources by 2025, achieving greenhouse gas neutrality by 2030, and supplying 100 percent renewable and non-emitting electric energy by 2045.

This is the first resource plan to incorporate climate change temperature predictions in the analysis, and this made an unmistakable mark on our resource needs. As a result of this analysis, we learned that even though the summer peak is increasing, PSE is still a winter peaking utility. Although our most significant peak demand will still occur in winter, we must also account for summer peaks. The resources we rely on to get us through cold winter nights will not be the same as those that get us through hot summer days.

This report also expands our approach to quantifying customer benefits in the analysis to ensure a more equitable transition to clean energy. The resulting resource plan is far more diverse and relies more on clean, intermittent resources such as wind, solar, and storage. The plan also reduces market reliance compared to prior resource plans because we recognize that recent significant changes in the wholesale electric market make it increasingly risky and unreliable to rely on the market. Although markets will continue to play a critical role in optimizing PSE's portfolio, we can no longer rely on traditional energy markets to meet peak capacity needs.

An All-of-the-above Approach

All these factors drove us to look at our portfolio of resources in new and diverse ways. The portfolio builds a wide range of new renewable and storage resources — an all-of-the-above approach — at an unprecedented scale and pace. The amount of new, non-emitting generation resources PSE will need by 2030 is more than we have accumulated in our 100-year history. It will require us to develop resources rapidly while we adhere to our procurement principles and policies to meet our CETA goals.

Our analysis also revealed that we will need significant grid improvements that allow increasing amounts of intermittent resources to work in concert. The grid will require considerable development in transmission capacity to bring utility-scale wind and solar to our region and allow the rapid advancement of new and emerging technologies such as green hydrogen.

Our plan illustrates significant investment in wind and solar resources combined with energy storage will shape the foundation of the energy system of the future. We also assume that technologies emerging over the coming 15 years will help us maintain a reliable system. We are not pursuing a single long-term technology solution but will explore multiple emerging technologies in the coming years. We will take a pragmatic, diversified approach and engage with others in the region to take concrete steps to move multiple technologies forward. We will work together to ensure that future resources are available to maintain the reliability and affordability our customers expect as we create a cleaner and more equitable system.

Mitigating Risk

There is a risk that some of these technologies will not emerge as viable at the pace we need. We are mitigating that risk in several ways. For example, we assumed multiple fuel options for peaking facilities. We are active partners in establishing Washington as a green hydrogen leader, which includes working with Fortescue Future Industries and other regional interested parties to explore the development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington.[1] Although not part of the preferred portfolio, we see advanced nuclear reactors as potentially a necessary part of our region's future energy supply mix and will continue to investigate the technology as a potential fit for future PSE resource needs. Puget Sound Energy and the region will need emerging resources like hydrogen hubs and/or advanced nuclear reactors to become commercially viable to help integrate renewables and ensure a reliable grid in the future. For that reason, PSE intends on taking an active role in exploring such technologies to help ensure progress is made toward meeting the needs of our customers and successfully meeting the requirements of state policy.

We are proud to be the Pacific Northwest's largest utility producer of renewable energy, but we know that our journey toward an equitable clean energy future has only begun. The resource plan included in this 2023 Electric Report is another critical next step highlighting the opportunities for PSE to continue leading the way on renewable energy for our state and region.

2. Resource Planning Foundations

This 2023 Electric Report is an update to the 2021 Integrated Resource Plan (IRP) required under Washington Utilities and Transportation Commission (WUTC) rules for electric investor-owned utilities as of December 2020.[2] Those changes require electric utilities to file an electric IRP every four years and an update, or progress report, two

1 https://ffi.com.au/news/centralia/
2 WAC 480-100-625

years later. This 2023 Electric Report is a planning exercise that evaluates how PSE will meet customer electric supply needs. The analysis considers policies, costs, changing economic conditions, and the existing energy system to develop a plan to meet the needs of our customers at the lowest reasonable cost over the next 20+ years.

Throughout the resource planning process for this report, we focused on the following key objectives, which lay the foundation for this and all future resource plans:

- Build a reliable, diversified power portfolio of non-emitting resources
- Ensure an equitable clean energy transition for all PSE customers
- Ensure resource adequacy while delivering a clean energy transition
- Ensure resource planning aligns with PSE's Clean Energy Implementation Plan (CEIP) to meet our interim targets and CETA obligations

Recognizing that the 2023 Electric Report does not make resource or program implementation decisions is important. The report is a long-term view of what resources appear to be cost-effective while maximizing benefits and minimizing burdens, based on the best information we have today about the future. The forecasts and resource additions in the 2023 Electric Report will change in future IRPs as technology advances, customer use patterns change, clean fuel options evolve, resource costs change, the wholesale energy market evolve, and new policies are established.

3. Change Drivers

We developed this report during a time of extraordinary change as policymakers, the utility industry, and the public confront the challenge of climate change and the necessity to transition to a clean and equitable energy future. The following describes four areas of focus that impact the resource plan described in this report.

3.1. Address Regulatory Changes

The 2023 Electric Report includes updates in response to new legislation enacted since the 2021 IRP. These updates include the Climate Commitment Act, updates to CETA rules, Washington State building code efficiency improvements, and portions of the Inflation Reduction Act (IRA). We incorporated as much of the IRA as possible, resulting in an estimated savings of approximately $10 billion over the next 20+ years from production and investment tax credits. However, because the law was enacted late in our planning process, we could not consider all the nuances of the bill, nor could we incorporate the policies and rules the federal government has not developed yet to implement the IRA. We will continue to analyze and integrate the impacts of the IRA for the 2025 IRP.

➔ A complete discussion of the legislative policy updates is in Chapter Four: Legislative and Policy Change.

3.2. Embed Equity

The 2023 Electric Report represents our continued progress in a journey to embed equity into the resource planning process. We began incorporating equity in 2021 by assessing highly impacted communities and developing initial customer benefit indicators. Since then, we've made progress by defining vulnerable populations and creating customer benefit indicators with input from interested parties, including the Equity Advisory Group (EAG) formed during the 2021 CEIP process. We recognize this is one step of many toward ensuring an equitable clean energy transition. Equity is complex to measure and assess, especially in energy system planning. However, we continue to refine our analysis and work with interested parties to embed equity throughout the resource planning process.

CETA requires that all customers benefit from the transition to clean energy through the equitable distribution of energy and non-energy benefits and the reduction of burdens to vulnerable populations and highly impacted communities.

For this report, we expanded the 2021 IRP approach to building a preferred portfolio to include a portfolio benefit analysis using customer benefit indicators (CBIs) developed for the 2021 CEIP with extensive input from the EAG. Our goal in using customer benefit indicators (CBIs) is to identify a preferred portfolio that balances customer benefits with portfolio costs while reducing burdens to vulnerable populations and highly impacted communities. Our approach is evolving and will continue to improve and develop for the 2025 IRP and future CEIP cycles.

➔ Details on the portfolio benefits analysis are in Chapter Five: Key Analytical Assumptions.

3.3. Incorporate Impacts of Climate Change

The 2023 Electric Report incorporates climate change in the base energy and peak demand forecast for the first time. We heard from interested parties that it is vital to incorporate climate change because it affects future demand, and we agree. We included climate change in the base demand forecast, the resource adequacy analysis, and stochastic scenarios. Before this report, PSE used temperatures from the previous 30 years to model the expected normal temperature for the future. This approach was a common utility practice but did not recognize predicted climate change impacts on temperatures. We used climate change projections, modeled recently by climate change scientists for the region in time for this 2023 Electric Report, to calculate a normal temperature assumption that reflects climate change. No industry standards or best practices for incorporating climate change into a demand forecast exist. Including climate change in this report for the first time is a significant milestone, but we recognize this methodology needs to be refined and will evolve in future planning efforts.

➔ Please refer to Chapter Six: Demand Forecast for details regarding how we incorporated climate change into our demand forecast.

3.4. Reduce Market Reliance

The supply and demand fundamentals of the wholesale electric market have changed significantly in recent years. The availability of dispatchable generation resources is declining, and market power prices and volatility are increasing. These factors make reliance on the Western Interconnect market increasingly risky, so we plan to decrease market reliance during high demand peak hours, from almost 1,500 MW to zero MW by 2029.

For decades, PSE's customers have benefitted from an over-supplied market. Under such conditions, firm capacity was available at a low cost. The market outlook is different today. While markets will continue to play a critical role in optimizing PSE's portfolio, we can no longer rely on traditional energy markets to meet peak capacity needs.

The future of electricity consists of a diversified portfolio of non-emitting resources. A diverse portfolio reduces vulnerabilities due to market price, supply fluctuations, and political unrest. Having multiple, reliable generating resources allows a utility to continue to provide power without disruption if one energy source fails. A diverse energy portfolio reduces environmental impacts, improves reliability, and promotes innovation to meet our customers' needs. Resource diversity is the key to reducing emissions while preserving reliability and affordability.

➔ We provide more details on the various portfolios considered in Chapter Eight: Electric Analysis.

3.5. Accessibility and Plain Language

While creating the 2023 Electric Progress Report, we took measures to improve the accessibility of our written documents, public meetings, and website content. In this and future documents, we are committed to removing participation barriers and attracting more members of the public into the resource planning process. We are continuously evaluating our content and working to improve readability and accessibility for all while encouraging interested members of the public to get involved in our planning processes.

➔ Appendix A: Public Participation contains additional detailed information about public feedback in this IRP cycle.

4. Preferred Portfolio

The preferred portfolio, which requires over 6,700 MW of new generation by 2030, is a portfolio of diverse resources that can fulfill our CETA commitments and achieve carbon neutrality by 2030 and a carbon-free electric energy supply by 2045. As described in Table 3.1, this portfolio significantly increases conservation, demand response, renewable resources, and energy storage. However, given the large amounts of variable energy resources such as wind and solar, and energy-limited resources such as energy storage, we rely on newer technologies, specifically hydrogen, as a fuel to meet peak energy needs to achieve a carbon-free energy supply by 2045 while maintaining reliability and resource adequacy.

We acknowledge the risk of relying on an uncertain fuel source, so we intentionally diversified this portfolio to reduce risk. Additionally, in future IRP cycles, we will continue to evaluate and consider emerging technologies, including green hydrogen and advanced nuclear small modular reactors (SMR).

Table 1.1: Electric Preferred Portfolio, Resource Additions (Nameplate Capacity)

Resource Additions (Nameplate MW)	Total by 2030	Total by 2045
Demand-side Resources	**618**	**1,265**
Conservation[1]	281	818
Demand Response	337	446
Distributed Energy Resources	**739**	**2,392**
DER Solar	552	2,124
Net Metered Solar	*284*	*1,393*
CEIP Solar	*79*	*79*
New DER Solar	*189*	*652*
DER Storage[2]	187	267
Supply-side Resources	**5,360**	**11,174**
CETA-compliant Peaking Capacity[3]	711	1,588
Wind	1,400	3,650
Solar	700	2,290
Green Direct	100	100
Hybrid (Total Nameplate)	1,450	1,748
Hybrid Wind	*600*	*800*
Hybrid Solar	*400*	*398*
Hybrid Storage	*450*	*550*
Biomass	-	-
Advanced Nuclear (SMRs)	-	-
Standalone Storage	1,000	1,800
Total	**6,717**	**14,830**

Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
3. CETA-qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA-qualifying peaking capacity in Chapter Five: Key Analytical Assumptions and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives.

➔ Please see Chapter Three: Resource Plan for a complete description of the preferred portfolio.

CLEAN ENERGY ACTION PLAN
CHAPTER TWO

PUGET SOUND ENERGY

Contents

1. Introduction

Washington State's Clean Energy Action Plan (CEAP) is a new aspect of Puget Sound Energy's (PSE's) Integrated Resource Plan (IRP) process. Introduced in the Clean Energy Transformation Act (CETA) in 2019, the CEAP identifies steps utilities can take over the next 10 years to meet the requirements of CETA. This is PSE's first Electric Progress Report and the first to include a CEAP update. As with any new requirement or assessment, the CEAP will evolve, and future IRPs will benefit from the lessons we learned in previous planning processes.

Puget Sound Energy is committed to achieving the requirements of CETA and carbon neutrality by 2030 and a carbon-free electric energy supply by 2045, and the CEAP presented here reflects these goals. Bridging PSE's Clean Energy Implementation Plan (CEIP) and IRP, the CEAP informs our decisions about specific and interim targets and actions over ten years, per RCW 19.280.030[1].

Table 2.1 presents near-term renewable and non-emitting — or clean energy — targets starting in the 2021 IRP and progressing through this progress report. The 2021 IRP established a clean energy target with a linear ramp from existing renewable energy generation to the 80 percent target in 2030. The 2021 CEIP expanded this target to make aggressive progress near-term toward the 80 percent goal. This 2023 Electric Progress Report (2023 Electric Report) retains the 63 percent clean energy target for 2025 established in the 2021 CEIP; however, given an increase in the load forecast, this report's resource plan requires additional renewable and non-emitting generation to meet the same target.

Table 2.1: Renewable and Non-emitting Energy Targets for 2025

Document	Clean Energy Target[1] by 2025 (%)	Clean Energy Generation to Meet Target[1] (MWh)
2021 IRP	56	10,046,493
2021 CEIP	63	11,381,593
2023 Progress Report	63	12,324,846

Notes: Clean energy targets represent a percent or quantity (MWh) of renewable or non-emitting energy of delivered load. The delivered load is adjusted for projected future demand-side resources (conservation, demand response, select distributed energy resources), PURPA contracts, and voluntary renewable programs.

2. Requirements

The 2021 IRP marked a significant departure from past IRPs largely due to CETA. The new rules, WAC 480-100-620 (12),[2] outline the requirements for this report. The utility must develop a 10-year clean energy action plan for implementing RCW 19.405.030[1]□ .

In this CEAP, the utility must include the following:

- A 10-year action plan that is the lowest reasonable cost (see section 3)

1 RCW 19.280.030
2 WAC 480-100-620

- Establish resource adequacy requirement (see section 3.2)
- Identify any need to develop new or to expand or upgrade existing bulk transmission and distribution facilities (see section 5)
- Identify cost-effective conservation potential assessment (CPA) (see section 3.1)
- Identify how the utility will meet the requirements of the clean energy transformation standards (see section 4)
- Identify potential cost-effective demand response (see section 3.4)
- Identify renewable resources, non-emitting electric generation, and distributed energy resources and how they contribute to meeting the resource adequacy requirement (see section 3.3)
- Identify the nature and extend for alternative compliance reliance (see section 6)
- Incorporate the social cost of greenhouse gasses as a cost adder (see section 7)

3. Ten-year Resource Additions

From the 2023 Electric Progress Report 22-year period, Table 2.1 summarizes the 10-year outlook for the resource mix in PSE's preferred portfolio. The portfolio benefit analysis, which considers the equitable distribution of benefits and how burdens may be reduced over the CEAP's ten-year horizon, informed our final selection of resources while ensuring the preferred portfolio met PSE's peak capacity, energy and renewable needs, and addressed market risk.

Table 2.2: 10-year Annual Incremental Resource Additions Preferred Portfolio

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total 2024–2033
Conservation[1]	33	32	44	36	36	60	41	42	78	43	445
Demand Response	71	65	71	47	49	16	17	17	17	16	387
DER Solar[2]	97	75	51	70	73	93	91	98	98	102	850
Net Metered Solar	*38*	*21*	*21*	*40*	*40*	*61*	*61*	*67*	*67*	*71*	*490*
CEIP Solar	*55*	*24*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*79*
New DER Solar	*4*	*30*	*30*	*30*	*33*	*32*	*30*	*31*	*31*	*31*	*281*
DER Storage[3]	21	18	29	32	29	28	30	28	4	4	223
CETA-qualifying Peaking Capacity[4]	237	0	237	0	237	0	0	0	0	0	711
Wind	300	300	500	0	0	0	400	200	100	100	1,900
Solar	100	0	0	0	200	400	0	0	0	0	698
Hybrid Total	150	150	400	0	150	600	0	0	0	0	1449
Hybrid Wind	*0*	*100*	*200*	*0*	*100*	*200*	*0*	*0*	*0*	*0*	*600*

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total 2024–2033
Hybrid Solar	*100*	*0*	*100*	*0*	*0*	*200*	*0*	*0*	*0*	*0*	*399*
Hybrid Storage	*50*	*50*	*100*	*0*	*50*	*200*	*0*	*0*	*0*	*0*	*450*
Standalone Storage	0	100	600	300	0	0	0	0	100	100	1,200
Total	1010	740	1932	485	774	1198	579	385	396	364	7,862

Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) solar includes customer solar photovoltaic (PV), Clean Energy Implementation Plan (CEIP) solar additions, non-wires alternatives, and ground and rooftop solar additions.
3. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
4. CETA-qualifying peaking capacity is functionally similar to natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA qualifying peaking capacity in Chapter Five: Key Analytical Assumptions and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives.

3.1. Conservation Potential Assessment

We analyzed demand-side resource (DSR) alternatives in a conservation potential assessment (CPA) to develop a supply curve used as an input to the portfolio analysis. Then the portfolio analysis determines the maximum amount of energy savings the model captured without raising the overall electric portfolio cost. This study identified the cost-effective level of conservation, which includes non-energy benefits from the portfolio benefit analysis to include in the portfolio. We evaluated the amount of cost-effective conservation to meet the portfolio's capacity and energy needs, optimizing the lowest cost and considering distributed and centralized resources.

➔ See Appendix E: CPA and Demand Response Assessment for the full CPA Assessment. A complete discussion of how we chose the conservation levels for the preferred portfolio is in Chapter Three: Resource Plan.

Figure 2.3: 10-year Achievable Technical Potential Conservation Savings (Energy aMW and Peak MW)

Demand-side Resources	Total Savings (aMW)	Winter Peak Savings (MW)	Summer Peak Savings (MW)
Energy Efficiency	167	214	212
Distribution Efficiency	11	11	10
Codes and Standards	159	196	245

3.1.1. Impacts and Actions

This electric report informs the target setting process and, through this analysis, we identified 10-year savings of 167 aMW as cost-effective. We will use this to inform the draft 2023 Energy Independence Act (EIA) target for the 2024-

2025 biennium after adjusting for intra-year ramping and savings at the meter. Under the EIA, utilities must pursue all cost-effective, reliable, and feasible conservation. Puget Sound Energy fulfills these requirements by undertaking additional analysis to identify the conservation potential over 10 years and set two-year targets. Setting the final two-year targets is part of PSE's biennial conservation plan process, which will take place over the next few months and builds on the information in this electric progress report.

3.2. Resource Adequacy

We must meet capacity need over the planning horizon with firm capacity resources or contractual arrangements to maintain reliability. All resources, including renewable resources, distributed energy resources, and demand response, contribute to meeting the capacity needs of PSE's customers, but they make different kinds of contributions.

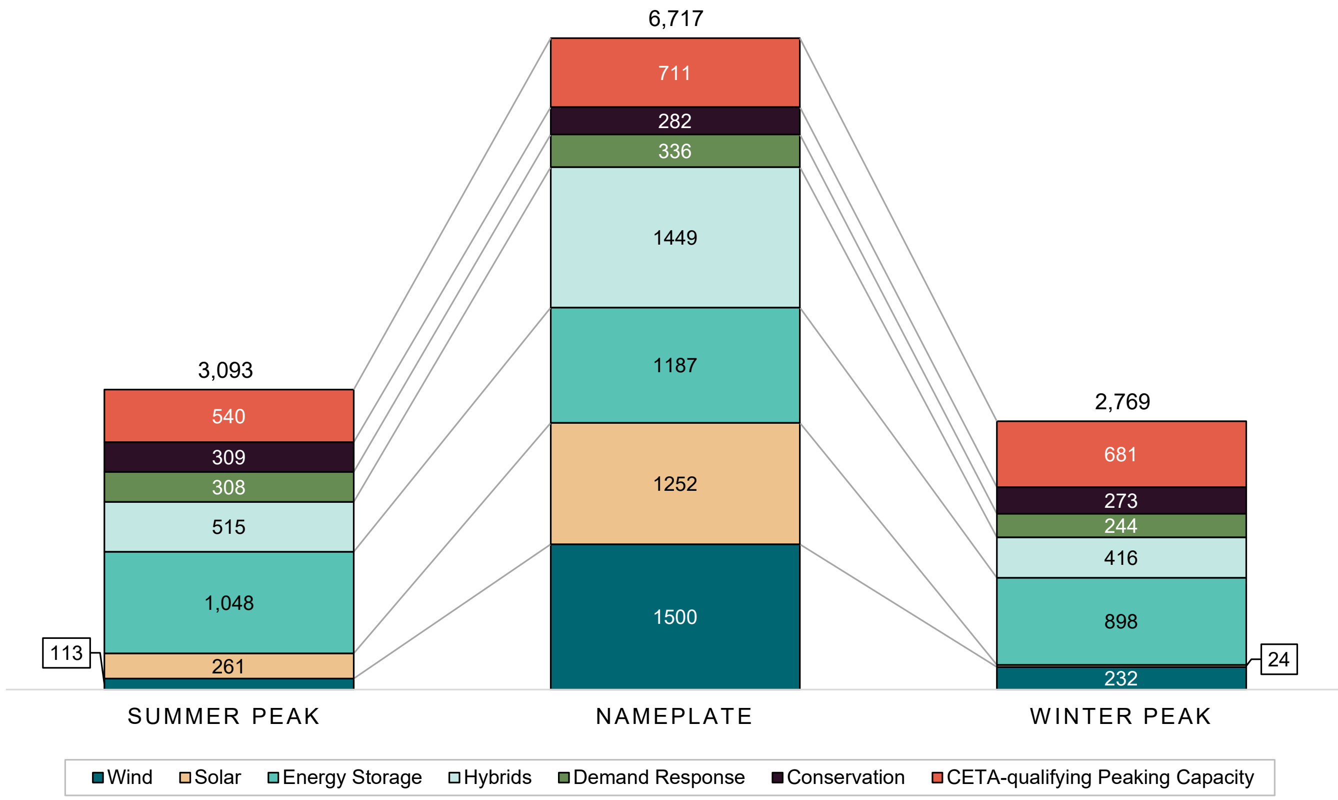
We have established a five percent loss of load probability (LOLP) resource adequacy metric to assess physical resource adequacy risk. The LOLP analysis measures the likelihood of a load curtailment event in any given simulation regardless of the frequency, duration, and magnitude of the curtailment(s). Therefore, the possibility of capacity being lower than the load anytime in the year cannot exceed five percent.

Assessing the peak capacity each resource can reliably provide is an integral part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro, and solar) and other resources (thermal, storage, demand response, and contract), we calculate the effective load-carrying capacity (ELCC) for each of those resources. The ELCC of a resource is unique to each utility and dependent on load shapes and supply availability, so it is hard to compare the ELCC of PSE's resources with those of other entities.

We analyzed summer and winter peak capacity for this report, and the analysis indicated that the winter peak is higher than the summer peak. With the increase of renewable energy and energy storage in the portfolio, those resources contribute to the summer peak need better than the winter. For example, solar has a four percent peak capacity contribution in the winter but a 55 percent contribution in the summer. We added solar to the portfolio because it meets the CETA requirement and the summer peak need, but it does very little to meet the winter peak need.

Because the peak capacity contribution of each resource does not match the nameplate energy values, we need more resources to meet the peak need. For example, solar's 24 MW winter peak capacity contribution requires over 1,200 MW of installed nameplate capacity. After adjusting for peak capacity contribution, 6,717 MW of new resources installed nameplate capacity equals 3,093 MW summer peak capacity and 2,769 MW winter peak capacity, as detailed in Figure 2.1.

Figure 2.1: Nameplate Capacity Adjusted to Peak Capacity Contributions (MW) for 2030



➔ See Chapter Seven: Resource Adequacy Analysis and Appendix L: Resource Adequacy for a complete description of the resource adequacy modeling.

3.3. Renewable and Non-emitting Resources

We modeled several types of renewable and non-emitting utility-scale resources for this Electric Progress Report. Supply-side resources provide electricity to meet the load. These resources originate on the utility side of the meter. These resources include wind, solar, pumped hydro energy storage, battery energy storage, hybrid resources (combination of wind, solar, and battery), combustion turbines using alternative fuels such as biodiesel and hydrogen, and advanced nuclear small modular reactors (SMR).

Distributed energy resources (DER) are small, modular energy generation and storage technologies installed on the distribution systems rather than the transmission system. Distributed Energy Resources are typically under 10 MW and provide a range of services to the power grid. These resources include wind, solar, storage, and demand response technologies and may be networked to virtual power plants (VPPs). This report included demand response, distributed solar, and distributed storage programs as generic DERs.

➔ A full description of resources modeled for this progress report is in Appendix D: Generic Resource Alternatives, with a brief description in Chapter Five: Key Analytical Assumptions.

3.3.1. Impacts and Actions

Biodiesel

Biodiesel is a commercially available fuel that can be combusted in existing and new peaking plants. Biodiesel provides a carbon-neutral alternative to existing backup fuels like petroleum-derived diesel. Biodiesel is energy-dense and can be stored on site for short periods — one to two months — to provide reliability in the event green hydrogen or renewable natural gas supplies are exhausted or unavailable.

We will continue to monitor and engage with regional biodiesel manufacturers to determine the limits of biodiesel fuel supply. We anticipate a shift in biodiesel supply as the transportation sector is rapidly electrified and alternative fuels, such as biodiesel, become increasingly available to other industries.

Renewable Diesel

Renewable diesel — frequently referred to as R99 — is a commercially available fuel that can be combusted in various existing and new peaking plants. R99 provides a carbon-neutral alternative to existing backup fuels like petroleum-derived diesel. R99 is energy dense and can be stored on site (for periods measured in years) to provide reliability if green hydrogen or renewable natural gas supplies are exhausted or unavailable. Puget Sound Energy successfully tested R99 fuel in the Crystal Mountain generator and is coordinating with authorities to test R99 in a Frederickson generator in 2023.

We will continue to monitor and engage with regional R99 manufacturers to determine the limits of the R99 fuel supply. We anticipate an increase in R99 supply in 2024 as the transportation sector is rapidly electrified and alternative fuels, such as R99, become increasingly available to other industries.

Biodiesel and renewable diesel are derived from non-petroleum feedstocks like vegetable oil, animal fats, municipal waste, agricultural biomass, and woody biomass. Biodiesel is produced using a transesterification separation method, and renewable diesel uses a hydrogenation process. Renewable diesel meets all of the ASTM–D975 specifications. Renewable diesel can be blended with or replace petroleum-derived diesel without affecting engine operations or air operating permit requirements. Renewable diesel has a carbon intensity of approximately 60 percent less than petroleum diesel and reduced NOx, particulate matter, and VOC emissions.

Hydrogen

Green hydrogen has the potential to aid in the decarbonization of the electric sector without compromising reliability standards. Electrolyzers convert surplus renewable energy to hydrogen gas stored for long periods until needed during a peak event. During a peak event, green hydrogen is combusted with either existing retrofitted equipment or at new peaking plants. Until recently, high costs have dissuaded the development of hydrogen infrastructure for the energy sector, but production tax credits included in the Inflation Reduction Act have the potential to put green hydrogen in cost-parity with more conventional fuels.

Puget Sound Energy aims to be a leader in developing hydrogen infrastructure to bring the benefits of green hydrogen to the Pacific Northwest. Puget Sound Energy holds a place on the board of the Pacific Northwest Hydrogen Association[3], which is seeking to establish a network of suppliers, storage, and off-takers in the region as part of the Department of Energy's Hydrogen Hub (H2Hub) Funding Opportunity as part of the Infrastructure Investment and Jobs Act (IIJA). In addition to our work with Pacific Northwest Hydrogen Association, we are also working with Fortescue Future Industries and other regional interested parties to explore the development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington[4].

Beyond these initial efforts, we may explore pilot programs soon to learn more about blending hydrogen in existing, retrofitted, and new peaking plants. We will also continue to research fuel supply and security considerations.

Advanced Nuclear and Other Emerging Technologies

Clean energy dispatched on demand will be a key element of a decarbonized power grid. Energy storage, such as batteries, improves the ability of wind and solar resources to follow demand, but the energy-limited nature of energy storage systems constrains their effectiveness in longer-duration peak events. We are currently missing cost-effective clean energy resources, which follow load and generate power through long-duration peak events. Several emerging resources have the potential to fill this niche but require advancements in operability and commercial availability. We will continue to monitor the development of technologies such as advanced nuclear small module reactors (SMR), carbon capture and sequestration, and deep-well geothermal.

Energy Storage

Energy storage will be an essential component of a decarbonized power system to shift variable energy resources and load. As energy storage is added to PSE's system, we will learn how to use this new resource to optimize operational efficiency. We are reviewing energy storage submittals as part of the ongoing 2021 All-Source Request for Proposal (RFP).

We will also monitor advances in energy storage technology, such as new battery chemistries and long-duration batteries, or other storage mediums, such as gravity- or compression-based storage systems. We will evaluate these technologies as they become commercially viable.

3.4. Demand Response

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times, requesting them to reduce their energy use. Some programs require action by the customer; others can be largely automated and are usually referred to as direct load control programs. For example, an

[3] https://pnwh2.com/
[4] https://ffi.com.au/news/centralia/

automated program might warm a customer's home or property earlier than usual with no action required on the part of the customer.

One example of a program that requires customer action is asking a wastewater plant to curtail pumping during certain peak energy need hours if they can. Because customers can always opt out of an event, demand response programs include some risk. If PSE relies on a certain amount of load reduction from demand response to handle a peak event, but customers opt out, we must use generating resources to fill the customer's needs.

We organized demand response programs modeled for this 2023 Electric Report in four categories:

- Behavioral Demand Response
- Commercial and Industrial (C&I) Curtailment
- Direct Load Control (DLC)
- Dynamic Pricing or Critical Peak Pricing (CPP)

➔ See Appendix E: Conservation Potential and Demand Response Assessments for the full CPA Assessment. We included a complete discussion of how we chose the demand response programs for the preferred portfolio in Chapter Three: Resource Plan Decisions.

Figure 2.4 lists the estimated 10-year achievable technical potential for demand response programs modeled for this report's residential, commercial, and industrial sectors. The table shows the attainable potential of each demand response program in MW, and the winter and summer peak need it fills to illustrate the total potential impact of demand response on system peak.

Table 2.4: 10-year Achievable Technical Potential Demand Response Programs for Model Year 2033 (MW)

Program	Category	Nameplate	Winter Peak	Summer Peak
Signal-capable Standard Water Heater[1]	Residential	74	61	51
Signal-capable Electric Heat Pump Water[1]	Residential	16	14	9
Signal-capable Heating, Ventilation, and Air Conditioning[1]	Residential, Commercial	102	73	98
Bring Your Own Smart (Internet-connected) Thermostat	Residential, Commercial	83	65	64
Signal-capable Electric Vehicle Charger[1]	Residential	21	15	20
Reduced (Lower) Electric Usage at Utility's Request	Commercial, Industrial	20	14	21
Time of Day Rates (Optional)	Residential, Commercial, Industrial	58	33	77
Electric Rate Allowing Electricity Cut Off in Periods of High Demand	Commercial	12	9	11

Note:
1. Capable of receiving internet, cellular, or radio signals.

3.4.1. Impacts and Actions

Distributed energy resources, including demand response, are a significant component of PSE's preferred portfolio from the 2023 Electric Progress Report and represent a piece of our strategy to achieve the targets laid out under CETA. Puget Sound Energy issued a DER Request for Proposal (RFP) in 2022. We are still working through the analysis and will have an updated target in the 2023 CEIP Biennial update.

4. Equitable Transition to Clean Energy

The Clean Energy Transformation Act (CETA) sets out important new expectations for the clean energy transition: that utilities must ensure that all customers benefit from the transition to clean energy.

4.1. Assess Current Conditions

To move toward an equitable transition to clean energy, we performed an economic, health, and environmental benefits (EHEB) assessment (the assessment) in 2021 to guide us as we developed our CEAP and CEIP. The purpose of the assessment was two-fold: first, to use the definitions we provided in our CEIP for named communities to identify highly impacted communities and vulnerable populations within our service area, and second, to measure disparate impacts to these communities using specific customer benefit indicators.

➔ See the updated assessment in Appendix J: Economic, Health, and Environmental Assessment of Current Conditions.

The initial qualitative and quantitative customer benefit indicators we developed through the assessment provide a snapshot of the economic, health, environmental, and energy security and resiliency impacts of resource planning on highly impacted communities and vulnerable populations within PSE's service territory. PSE built upon those initial customer benefit indicators in the assessment in developing its CEIP. Due to the timing of the IRP process and the CEIP adjudication, the proposed customer benefit indicators included in the CEIP may change based on the upcoming Washington Utilities and Transportation Commission decision on PSE's CEIP and in the future through public participation and input from PSE's Equity Advisory Group. The customer benefit indicators help measure progress toward achieving an equitable distribution of benefits and reducing burdens.

4.2. Customer Benefit Indicators

A key component to ensuring the equitable distribution of burdens and benefits and a reduction of burdens to vulnerable populations and highly impacted communities in the transition to a clean energy future is to include customer benefit indicators (CBIs) in the preferred portfolio development process. For this 2023 Electric Progress

Report, PSE used the CBIs established in the 2021 CEIP through extensive public participation and consultation with our equity advisory group.

We expanded on applying CBIs to the portfolio analysis with input from interested parties. First, we linked CBIs to specific portfolio modeling outputs to reflect customer benefit indicators in developing the preferred portfolio. We then combined these outputs into broader CBI areas, providing a context for interpreting the portfolio outputs. We indexed each portfolio from the sensitivity analyses on how well it performed in each CBI area to understand which benefits or burdens it may confer on our customers. Portfolios had to score well in several CBI areas to be considered in a preferred portfolio.

➔ See Chapter Three: Resource Plan, Chapter Eight: Electric Analysis, and Appendix H: Electric Analysis and Portfolio Model for more detail on the customer benefit indicator framework.

In summary, we have taken several actions that put us on a pathway to ensure all customers benefit from the transition to clean energy:

- Developed a public participation plan for the CEIP to obtain input on the equitable distribution of benefit and burdens
- Established the Equity Advisory Group
- Refined customer benefit indicators and metrics with the EAG and the CEIP public participation process
- Updated the portfolio benefits analysis to incorporate the customer benefit indicators and related metrics in the 2023 Electric Progress Report and future IRPs or CEIPs

Identifying and using customer benefit indicators is a developing process. Future IRPs will benefit from more input from the Equity Advisory Group (EAG) and the CEIP public participation process.

4.3. Vulnerable Populations and Highly Impacted Communities

As part of our work for the CEAP, we reviewed the CBI baseline data, often broken down into metrics for vulnerable populations and highly impacted communities, published in the 2021 CEIP. This report provides more detailed information about the 2020 and 2021 CBI data.

We will publish the metrics for 2022 for all CBI data included in Appendix J: Economic, Health and Environmental Assessment of Current Conditions of this report in our 2023 biennial CEIP update. We incorporate vulnerable populations and highly impacted communities in the IRP process by considering these groups while developing the achievable technical potentials for energy efficiency programs as part of the CPA discussed in Appendix E: Conservation Potential and Demand Response Assessments. The generic supply side resources we studied as part of the IRP lack detailed enough geographic information to establish relationships between resource selection and impacts on named communities.

➔ See Appendix J: Economic, Health, and Environmental Assessment of Current Conditions for details on the changes to the analyses.

5. Resource Deliverability

We will work to optimize our use of PSE's existing regional transmission portfolio to meet our growing need for renewable resources in the near term. However, the Pacific Northwest transmission system may need significant expansion, optimization, and possible upgrades in the long term to keep pace. The main areas of high-potential renewable development are east of the Cascades (Washington and Oregon), in the Rocky Mountains (Montana, Wyoming), in the desert southwest (Nevada, Arizona), and in California. Table 2.5 shows the regional transmission need for new resources outside PSE.

Table 2.5 Regional Transmission Need Based on 2023 Preferred Portfolio (MW)

Region	2030 (MW)	2033 (MW)
East of the Cascades (Central and Eastern Washington)	3,449	3,447
Rocky Mountain Region (Montana and Wyoming)	400	800
Cross Cascades Total	3,849	4,247
British Columbia	0	0

➔ See Appendix J: Regional Transmission Resources from the 2021 IRP on specific opportunities for expanding transmission capabilities and regional efforts to coordinate transmission planning and investment. The 10-year delivery system plan is in this report's Appendix K: Delivery System Planning.

Our delivery system needs investments to deliver energy to our customers from the edge of PSE's territory and to support DERs within the delivery grid. The delivery system 10-year plan described in Appendix K: Delivery System Planning identifies work needed to ensure safe, reliable, resilient, smart, and flexible energy delivery to customers, regardless of resource fuel source. This work includes specific upgrades to the transmission system to meet NERC compliance requirements, other evolving regulations related to DER integration and markets, and distribution system upgrades to enable higher DER penetration. Specific delivery system investments will become known when energy resources, whether centralized or DERs, begin siting through the established interconnection processes. The readiness of the grid and customers for DER integration will decrease the cost of interconnection and increase the number of viable locations. Proactive investments in grid modernization are also critical to support the clean energy transition and maximize benefits. We summarized the key investment areas in the following section.

5.1. Impacts and Actions

Puget Sound Energy is pursuing the acquisition of new additional transmission capacity and optimization of existing transmission capacity rights required to facilitate the delivery of its preferred resource portfolio. We are exploring ongoing opportunities to contract with the Bonneville Power Administration (BPA) for additional transmission rights by submitting transmission service requests (TSRs) and participating in BPA's annual cluster study. The BPA annual cluster study results may trigger requirements for funding BPA system reinforcement projects needed to award the requested TSR(s). Funding these reinforcement projects will be critical to adding capacity to the regional transmission system and projects delivering to PSE's system.

Puget Sound Energy seeks to repurpose specific portions of our transmission portfolio to enhance our value to align with the preferred resource portfolio. Existing Mid-C transmission capacity allocated for market purchases could be strategically redirected for new renewable projects and projects delivering to Mid-C. Colstrip Units 3 & 4 transmission rights could be repurposed for new Montana resource deliveries. In addition, standalone PSE generation facilities could be further developed to co-locate with new renewable projects for optimized energy delivery over shared transmission (e.g., Lower Snake River, Wild Horse, Goldendale).

6. Achieving CETA Compliance: 100 Percent Greenhouse Gas Neutral by 2030

Under CETA, utilities can meet up to 20 percent of the 2030 greenhouse gas neutral standard with an alternative compliance option. Utilities can use these alternative compliance options from January 1, 2030, to December 31, 2044. An alternative compliance option includes any combination of the following:

- Investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission
- Making an alternative compliance payment in an amount equal to the administrative penalty
- Purchasing unbundled renewable energy credits (RECs)

For this report, we modeled unbundled RECs to achieve CETA compliance 2030–2044, where renewable and non-emitting energy could be less than 100 percent of delivered energy annually. The preferred portfolio only incurs one alternative compliance payment in 2030 of $3.18 million worth of unbundled RECs to make up for 3.4 percent of delivered energy. For all future years of the CEAP horizon, the preferred portfolio meets the 100 percent standard without the need for alternative compliance options.

➔ See Chapter Five: Key Analytical Assumptions for a discussion on alternative compliance assumptions and costs. Appendix I: Electric Analysis Inputs and Results for portfolio modeling results.

7. Social Cost of Greenhouse Gases

The social cost of greenhouse gases (SCGHG) was included per WAC 480-100-620(12)(i).[2]

➔ General assumptions for the SCGHG are in Chapter Five: Key Analytical Assumptions, and a detailed modeling description of the SCGHG is in Appendix G: Electric Price Models.

RESOURCE PLAN

CHAPTER THREE

Contents

1. Introduction

This chapter presents Puget Sound Energy's preferred portfolio for the 2023 Electric Progress Report (2023 Electric Report). Our preferred portfolio is the result of robust Integrated Resource Plan (IRP) analyses developed with input from interested parties. Informed by our deterministic portfolio, risk, and portfolio benefit analyses, this portfolio meets the Clean Energy Transformation Act (CETA) requirements.

Puget Sound Energy is the Pacific Northwest's largest utility producer of renewable energy. We currently own and contract more than 10 million MWh of renewable and non-emitting energy, and we forecast this will grow to more than 30 million MWh by 2045.

Throughout the resource planning process for the 2023 Electric Report, we focused on the following key objectives, which lay the foundation for this and all future resource plans:

- Achieve the renewable energy targets under CETA — meet at least 80 percent of PSE's demand with renewable and non-emitting energy and achieve carbon neutrality by 2030, and meet 100 percent of PSE's demand with renewable and non-emitting resources by 2045.
- Build a reliable, diversified power portfolio of renewable and non-emitting resources.
- Continue to be a clean energy leader in the Pacific Northwest and beyond.
- Ensure an equitable transition to clean energy for all PSE customers.
- Ensure our resource planning aligns with PSE's Clean Energy Implementation Plan (CEIP) to meet our interim targets and CETA obligations.
- Ensure resource adequacy while transitioning to clean energy.

We used three distinct types of analysis to develop, refine, and identify the preferred portfolio:

1. The deterministic portfolio analysis solves for the least-cost solution and assumes perfect foresight about the future.
2. The risk analysis examines the preferred portfolio's performance concerning uncertainty in hydroelectric, wind and solar conditions, electric and natural gas prices, customer demand, and unplanned plant-forced outages.
3. The portfolio benefit analysis incorporates equity into the IRP process by measuring potential equity-related benefits to customers within a given portfolio. Because the IRP process is inherently forward-looking, this analysis seeks to identify portfolios containing a mix of electric resources that can enable more equitable customer outcomes in the future. It is important to note the IRP process generally lacks the detail to assess specific existing or future programs and actions that address equity. However, the IRP process can provide a pathway that ensures we acquire the electric resources necessary to implement more equitable programs and measures.

➔ See Chapter Five: Key Analytical Assumptions and Chapter Eight: Electric Analysis for details on these analyses, including methodologies and results.

We present this chapter in the following three sections. Section 2 summarizes the preferred portfolio and describes how the resource additions will meet our projected demand growth. Section 3 describes the contributors to our near-term capacity deficit and how this drives the resource additions in the preferred portfolio. Section 4 presents our process for developing and selecting a preferred portfolio and includes our portfolio benefit analysis results.

2. Preferred Portfolio

Puget Sound Energy is committed to reaching the CETA goals and achieving greenhouse gas (GHG) neutrality by 2030 and a GHG-free electric energy supply by 2045. The electric resource plan shows our current path to meet CETA commitments. Our plan prioritizes delivering cost-effective, reliable conservation and demand response and distributed and centralized renewable and non-emitting resources to our customers at the lowest reasonable cost. The plan reduces direct PSE emissions and achieves GHG neutrality by 2030 through clean energy investments.

We have made many updates and changes since PSE's 2021 IRP. The preferred portfolio resource additions for the 2023 Progress Report include significant increases in renewable resources to meet the CETA requirements and peak demand. We provide a detailed discussion of these changes in Chapter Eight: Electric Analysis and the following summary:

- Capacity Resources: We saw increased capacity resources due to increasing peak demands over the 2021 IRP and reduced market reliance. With the increased peak capacity contribution and lower resource costs, we saw more energy storage resources added to the 2023 preferred portfolio than the 2021 IRP preferred portfolio.

- Clean Energy Resources: Overall, there is an increase in renewable resource additions to meet CETA requirements due to the increase in the demand forecast. A complete discussion of changes to the demand forecast is in Chapter Six: Demand Forecasts.

- Conservation: Overall, the 2023 Progress Report CPA potential is down from the 2021 IRP by approximately 13 percent by 2045. The reduction in the CPA is due to the newly incorporated impact of climate change assumptions, which reduced savings in the later years of the study, and a new statutory provision requiring the state to adopt more efficient building energy codes to achieve a 70 percent reduction by 2031. We added the impact of this statute, which moved some of the potential from energy efficiency into codes and standards, and the updated building stock assessments, which have more efficiency penetration compared to the last stock assessment.

- Distributed Energy Resources: The 2023 progress report is consistent with the CEIP targets through 2025, and then we see an increase in net-metering solar based on the new forecast from current trends and economics, including rebates from the inflation reduction act.

This section presents the preferred portfolio, describes how the combination of resource additions will meet our projected demand growth, and explains how diversifying resource technology is paramount to reducing technology risk. The preferred portfolio further clarifies the following near-term and long-term priorities.

Near-term Priorities (2024–2029):

- Add diverse commercially available resources to meet CETA energy and resource adequacy needs
- Add utility-scale and distributed resources to achieve the renewable or non-emitting energy targets specified in PSE's 2021 CEIP
- Begin commercial activity to acquire bulk transmission to transport renewable energy from distant renewable energy zones to our customers
- Begin shifting our planning frameworks to align with WRAP requirements as more long-term information becomes available
- Continue to acquire conservation resources
- Continue to develop and refine methods to embed equity into resource decisions.
- Continue to participate in the Western Resource Adequacy Program (WRAP) on an operational basis
- Explore commercial opportunities for advanced nuclear small modular reactors (SMR) capacity and other non-emitting technologies
- Lead and actively participate in developing the region's hydrogen hub infrastructure
- Pursue demand response programs that can effectively help lower peak demand
- Reduce reliance on short-term market purchases in response to the changing western energy market

Long-term Priorities (2030–2045):

- Complete acquisition and development of additional transmission capacity (e.g., Cross Cascades, Idaho, Wyoming, Montana, B.C.) to deliver additional clean energy to our customers
- Develop and acquire generating resources that take longer to develop to meet CETA non-emitting generation obligations while maintaining resource adequacy and peak demand.
- Examine repowering or upgrading existing thermal resources and renewable generation to better position PSE to achieve the 2045 goal of an emission-free generation portfolio.
- Explore new capacity options to drive diversity in our energy supply

2.1. Resource Additions Summary

Table 3.1 describes our preferred portfolio of resource additions. With this combination of conservation, demand response, renewable resources, energy storage, and CETA-qualifying peaking capacity, PSE will reach GHG neutrality by 2030. However, given the large amounts of variable energy resources, such as wind and solar, and energy-limited resources, such as energy storage, we will need to rely on newer technologies, such as hydrogen, to reach a GHG-free energy supply by 2045 while maintaining reliability and resource adequacy. Although the high cost of advanced nuclear SMR deterred us from having it in the preferred portfolio, we will continue to monitor the technology.

Table 3.1: Electric Preferred Portfolio, Resource Additions Incremental Nameplate Capacity (MW)

Resource Type	2024–2025 Incremental	2026–2030 Incremental	2030 Cumulative	2031–2045 Incremental	2045 Cumulative
Demand Side Resources	**201**	**417**	**618**	**646**	**1,265**
Conservation[1]	65	216	281	537	818
Demand Response	136	201	337	110	446
Distributed Energy Resources	**212**	**527**	**739**	**1,652**	**2,392**
DER Solar	172	380	552	1,572	2,124
Net Metered Solar	*59*	*225*	284	*1,109*	*1,393*
CEIP Solar	*79*	-	79	-	*79*
New DER Solar	*34*	*155*	*189*	*463*	*652*
DER Storage[2]	40	147	187	80	267
Supply Side Resources	**1,337**	**4,023**	**5,360**	**5,814**	**11,174**
CETA-qualifying Peaking Capacity[3]	237	474	711	877	1,588
Wind	600	800	1400	2,250	3,650
Solar	100	600	700	1,590	2,290
Green Direct	-	100	100	-	100
Hybrid (Total Nameplate)	300	1,150	1450	298	1,748
Hybrid Wind	*100*	*500*	*600*	*200*	*800*
Hybrid Solar	*100*	*300*	*400*	-	*398*
Hybrid Storage	*100*	*350*	*450*	*100*	*550*
Biomass	-	-	-	-	-
Nuclear	-	-	-	-	-
Standalone Storage	100	900	1000	800	1,800
Total	**1,750**	**4,967**	**6,717**	**8,112**	**14,830**

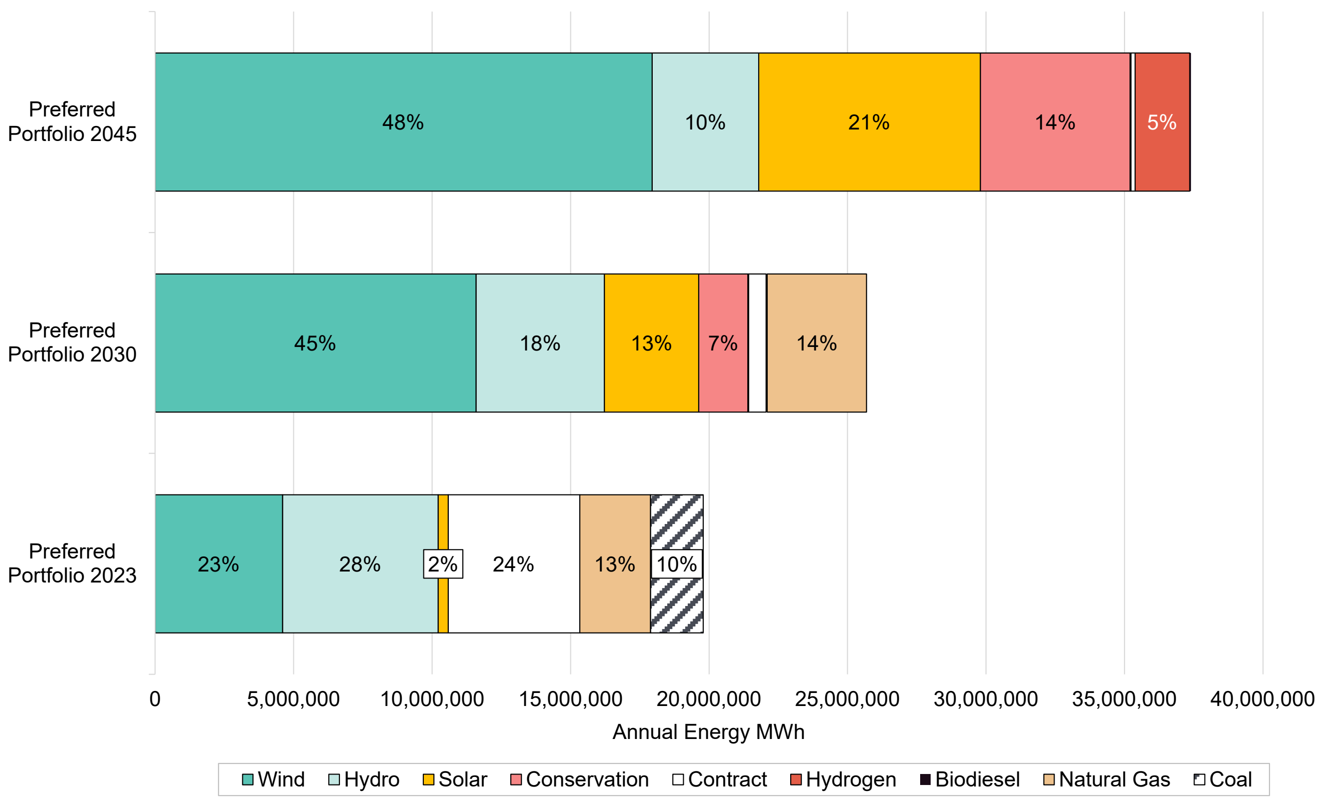
Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
3. CETA-qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel.

Figure 3.1 illustrates the projected annual energy production in 2023 and the future with the preferred portfolio. Wind resources are the largest share of capacity additions in the preferred portfolio, accounting for 36 percent of all energy-producing resources added to the planning horizon. However, wind resources produce 48 percent of the total annual energy in 2045, far more than its nameplate capacity indicates. Conversely, CETA-qualifying peaking capacity accounts for 13 percent of nameplate capacity (excluding storage) added by 2045 but supplies only 6 percent of the annual energy in 2045. Figure 3.1 illustrates that with the preferred portfolio, solar and wind remain the primary energy supply for meeting CETA, supplying nearly 70 percent of the portfolio's

CETA qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA qualifying peaking capacity in Chapter Five: Key Analytical Assumptions, and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives. **RCW 19.405.020 (34)** annual energy in 2045. While CETA-qualifying peaking capacity resources are essential for resource adequacy, as discussed later in this chapter, they don't contribute substantially to the CETA-qualifying energy need.

Figure 3.1: Forecasted Annual Energy Production (Excluding Storage Dispatch)



2.2. Meeting Future Growth

The 2023 Electric Report shows we will meet future sales growth by combining utility-scale, demand-side (conservation), and distributed energy resources (DERs) described in Table 3.1. Distributed energy resources include storage systems, solar generation, or demand response that provides specific benefits to the transmission and distribution systems and simultaneously supports resource needs. The role of DERs in meeting system needs is changing, and the planning process is evolving to reflect that change. Distributed Energy Resources make lower peak capacity contributions and have higher costs. However, they are essential in balancing utility-scale renewable investments, transmission constraints, and local distribution system needs. The 2023 analysis also shows these resources enable larger equity benefits.

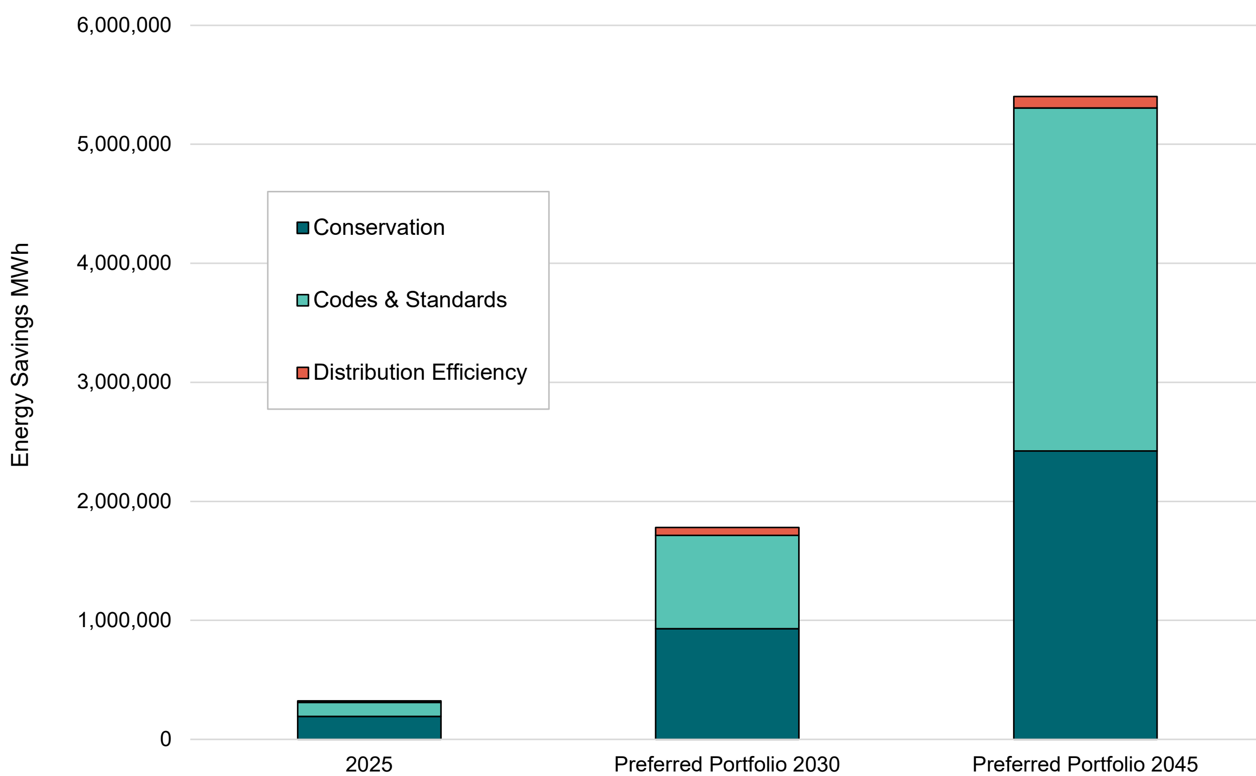
In the following section, we detail how the combination of resources in this plan will meet demand growth.

2.2.1. Conservation

For this analysis, conservation includes new energy efficiency measures, new codes and standard gains in efficiency, and distribution efficiency. Figure 3.2 describes the new energy savings from the preferred portfolio conservation measures.

➔ Appendix E: Conservation Potential Assessment contains a detailed discussion of the building codes and energy efficiency measures we modeled.

Figure 3.2: Preferred Portfolio Conservation Savings (MWh)

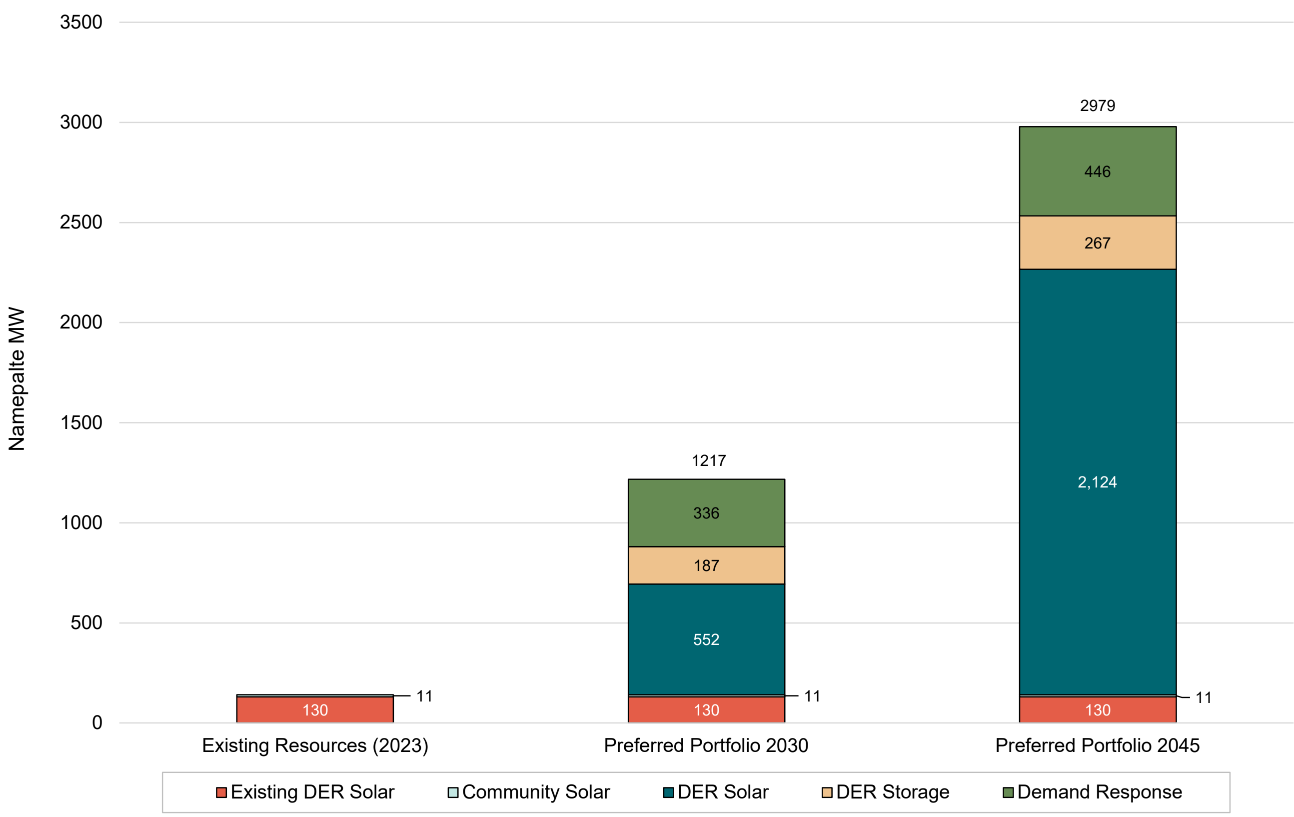


2.2.2. Distributed Energy Resources

Distributed energy resources are any resources located below the substation level. The customer or PSE can install DER. We included demand response, solar, and energy storage as distributed resources for this analysis. Our system includes 130 MW of customer-installed rooftop solar through net metering and 11 MW of community solar. We estimate we will add 552 MW of distributed solar and 187 MW of storage to the portfolio by 2030, growing to 2,124 MW of solar and 267 MW of energy storage by 2045. Demand response programs are peak savings options offered to customers, including direct load control for indoor heating and air conditioning thermostats and water heaters, managed electric vehicle charging, and critical peak pricing. Some distributed resources cost more than utility-scale programs but potentially enable larger equity benefits. Thoughtfully implemented, distributed resources can enable more equitable outcomes for customers in the clean-energy transition. We considered DERs necessary when developing our preferred resource plan, as discussed in Section 4 of this chapter.

Figure 3.3 shows the distributed resource capacity added to the preferred portfolio.

Figure 3.3: Preferred Portfolio Distributed Resource Additions (Nameplate MW)



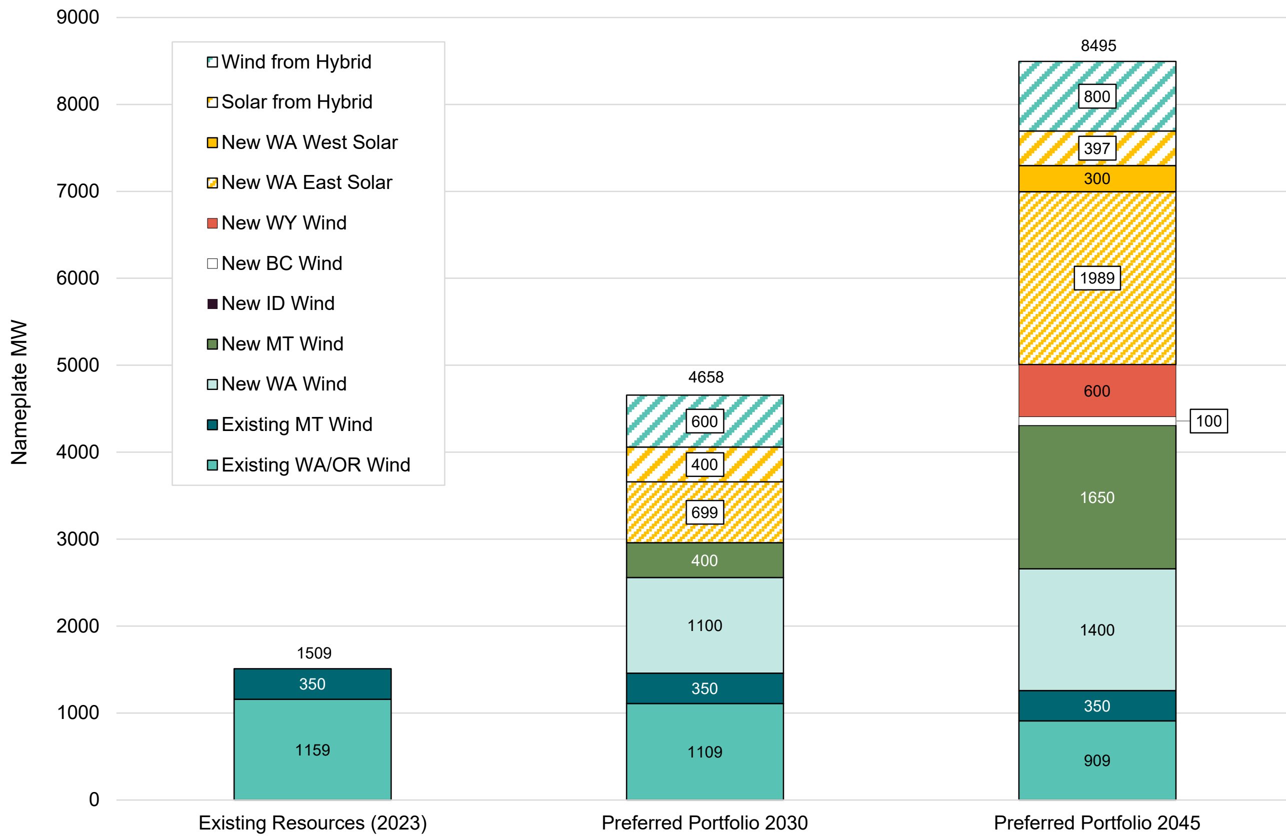
2.2.3. Clean Energy Resources

Qualifying clean energy (renewable and non-emitting) resources under CETA include wind, solar, advanced nuclear SMR, and alternative fuels such as biodiesel and hydrogen. Along with distributed energy resources, we must add many large utility-scale resources to the portfolio to meet the clean energy requirements. Figure 3.4 presents the utility-scale renewable resource additions in the preferred portfolio.

The scale and diversity of renewables PSE needs will require access to renewables outside Washington State and around the Pacific Northwest region, such as Montana, Wyoming, Idaho, and British Columbia. We will work to optimize our existing regional transmission portfolio to meet our growing need for renewable resources in the near term. However, the Pacific Northwest transmission system likely will need to be significantly expanded, optimized, and possibly upgraded to keep pace with the growing demand for clean energy. Puget Sound Energy will have to invest in the transmission system to deliver energy to customers from the edge of our territory and support the integration of distributed energy resources and demand response within the delivery grid.

The preferred portfolio adds almost 3,200 MW of new wind and solar resources to meet the CETA clean energy requirements by 2030. Of the 3,200 MW of wind and solar additions, 2,800 MW are resources in Washington State that will need cross-Cascades transmission. The remaining 400 MW are in Montana and will use Montana transmission.

Figure 3.4: Preferred Portfolio Wind and Solar Additions (MW)



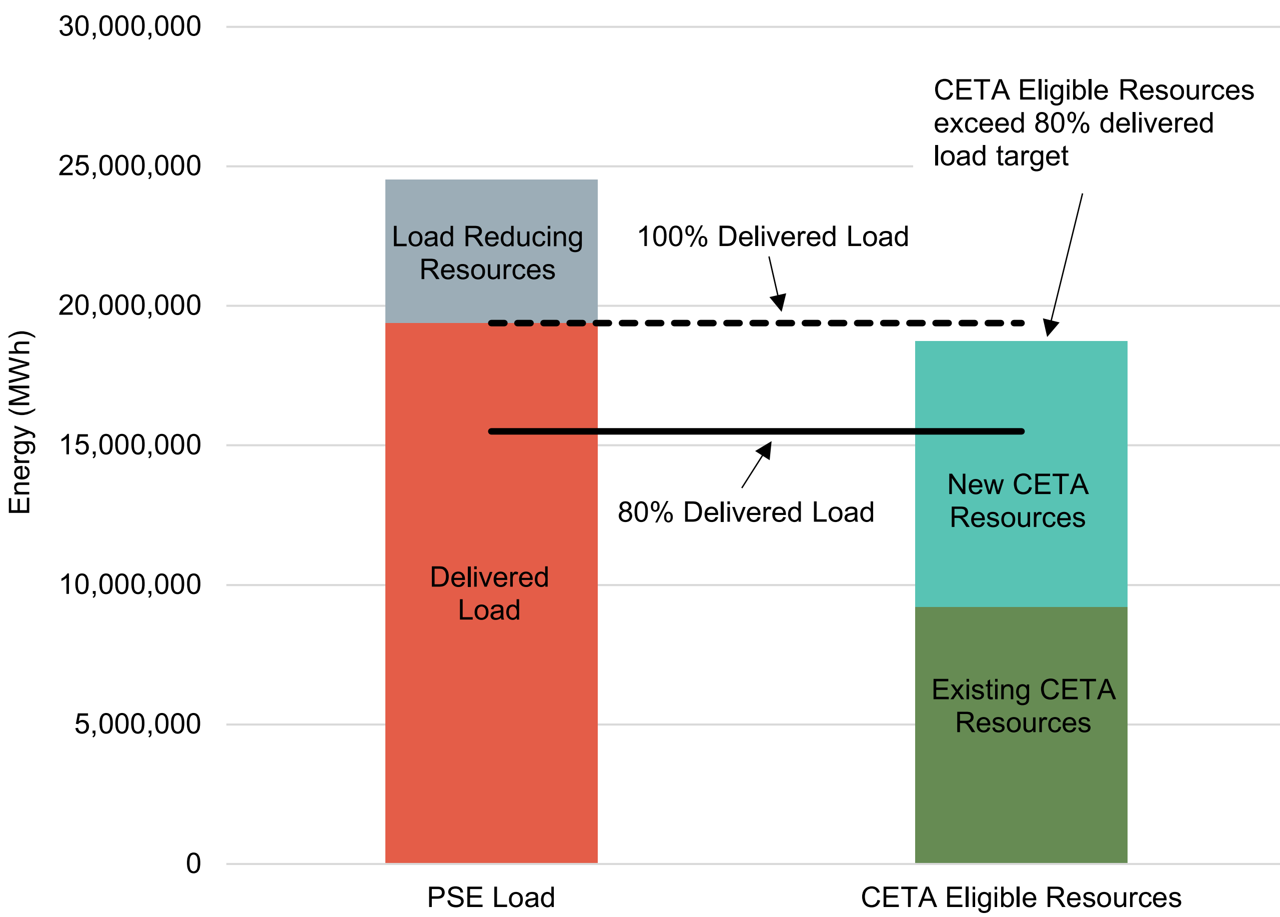
Risk of Meeting CETA Requirements

In 2030, we must meet at least 80 percent of retail sales with renewable or non-emitting resources. Figure 3.5 is the breakdown of the 2030 CETA requirement. As we can see from the chart, the preferred portfolio is well above the 80 percent requirement. For CETA compliance, we take the requirement on the adjusted retail sales after conservation, demand response, PURPA contracts[1], and voluntary renewable programs, including solar net-metering, Green Direct, and community solar. The gray bar in the chart represents the load-reducing resources, and the red bar is retail sales

[1] Public Utility Regulatory Policy Act (PURPA) qualifying facilities (QFs) are smaller generating units that use renewable resources, such as solar and wind energy, or alternative technologies, such as cogeneration.

after adjustment for load-reducing resources. The top of the red bar would be 100 percent, and the black line is 80 percent of the retail sales.

Figure 3.5: CETA Compliance in 2030 (Annual Energy MWh)



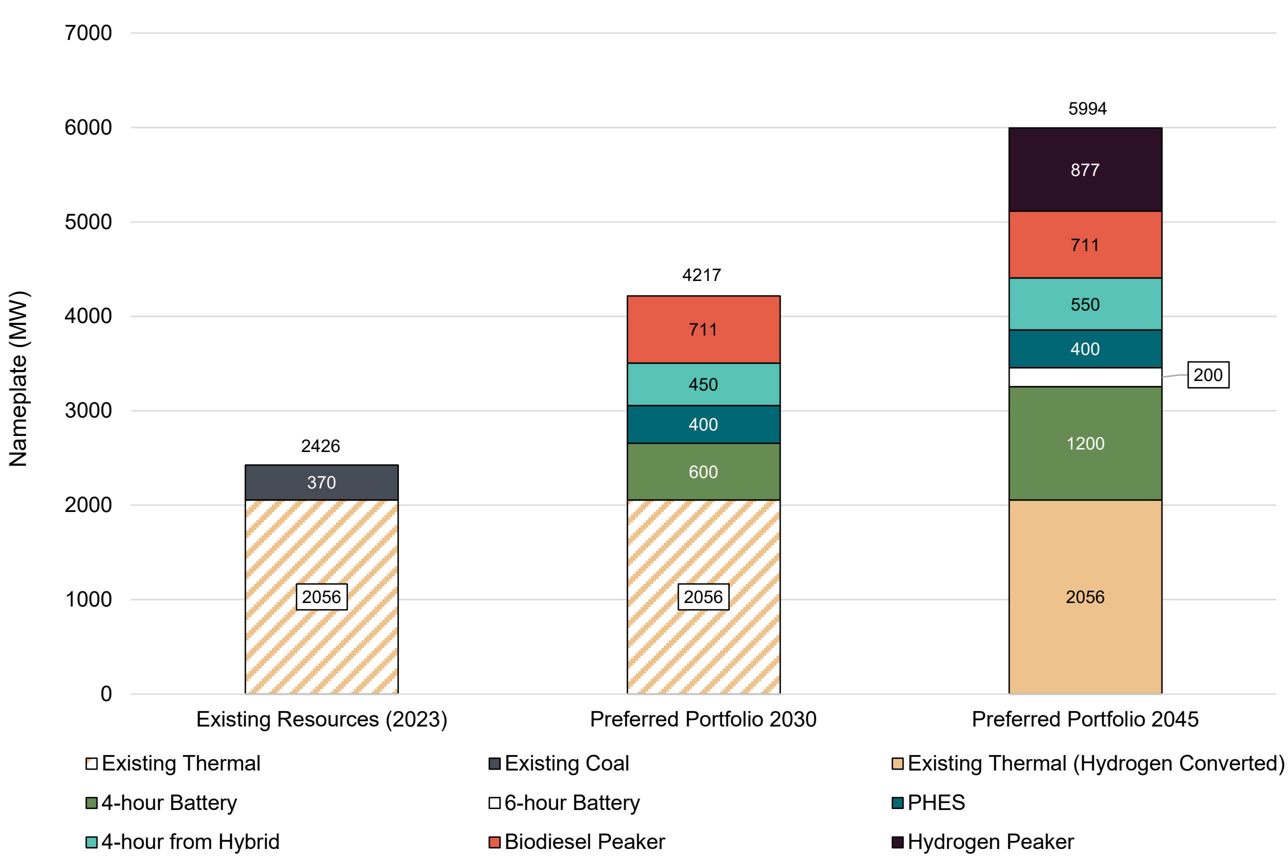
As part of the stochastic risk analysis, one of the future risks tested was whether the preferred portfolio would meet the CETA requirements under different conditions, such as changes in the demand forecast, hydroelectric generation, wind generation, and solar generation. Under all these conditions, renewable resource generation stays well above the base target for annual energy, ranging in 2030 from 80 percent at the lowest to 124 percent on the highest end, with half of the forecasted simulations in the range of 93 percent to 105 percent.

➔ Chapter Eight: Electric Analysis presents a complete discussion of the stochastic portfolio analysis.

2.2.4. Capacity Resources

Qualifying resources under CETA analyzed in this report include peaking capacity, energy storage, and advanced nuclear SMR. The peaking capacity we modeled includes CETA-qualifying fuels such as biodiesel and hydrogen, referred to herein as CETA-qualifying peaking capacity. We assumed hydrogen fuel would be available starting in 2030. We assumed natural gas to hydrogen blending would begin at 30 percent hydrogen in 2030 and increase to 100 percent by 2045. We left more than 2,000 MW of existing thermal resource capacity in the portfolio and converted it to hydrogen to maintain system reliability through resource adequacy. We modeled existing thermal resources with an option to retire them economically or convert them to hydrogen starting in 2030. As shown in Figure 3.6, the model added three additional peakers that will use biodiesel as fuel by 2030 and more than 800 MW of new hydrogen peakers by 2045. The model selected 1,450 MW of new energy storage by 2030, growing to 2,350 MW by 2045 to help meet resource adequacy and ancillary services. Energy storage resources are not energy-producing resources; they store the energy produced from other resources to be available during peak hours.

Figure 3.6: Preferred Portfolio CETA-qualifying Capacity Additions (Nameplate MW)



Hydrogen Fuel Risk

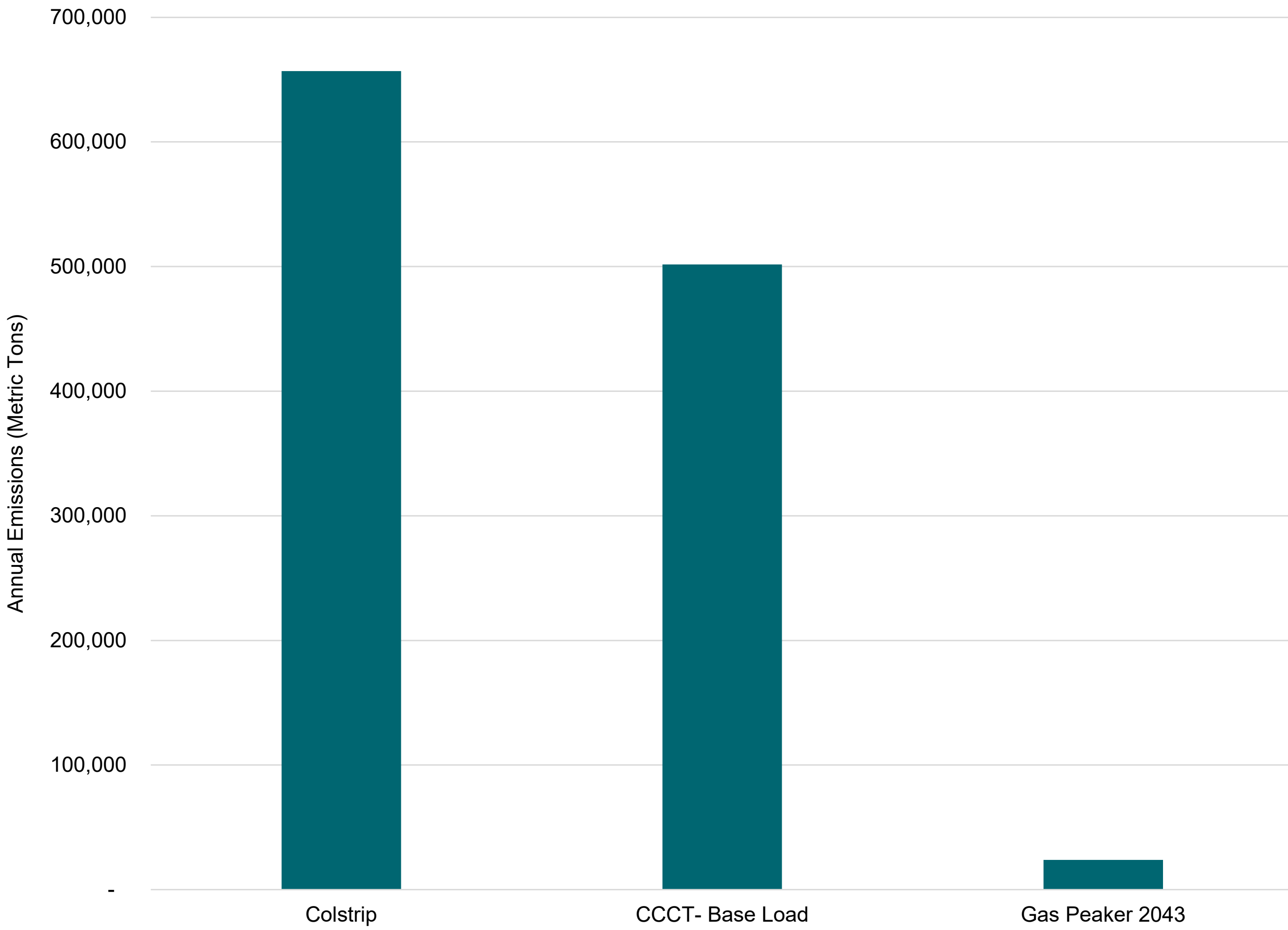
Green hydrogen has the potential to aid in the decarbonization of the electric sector without compromising reliability standards. Electrolyzers convert surplus renewable energy to hydrogen gas, which is stored for long periods until it is needed during a peak event. During a peak event, green hydrogen is combusted with either retrofitted existing equipment or at new peaking plants. Until recently, high costs have dissuaded development of hydrogen infrastructure for the energy sector, but production tax credits included in the Inflation Reduction Act have the potential to put green hydrogen in cost-parity with more conventional fuels.

In the preferred portfolio, the new hydrogen peakers start in 2039, giving us several years to understand the fuel supply before making resource acquisitions. Integrated Resource Plan meeting participants asked, "What if PSE built peakers assuming they blend to full hydrogen, but hydrogen is not available as planned?" First, we would not start building or acquiring a hydrogen peaker until 2035, which gives us more time to understand the hydrogen supply and availability. Second, we can build dual-fueled peakers using biodiesel as a backup fuel. Puget Sound Energy has eight peaking units with a backup fuel supply. We are experts in the process and requirements to set up and maintain a backup fuel supply. Like the existing peaker units, the backup is available in a tank on the property in case of primary fuel supply interruptions. Puget Sound Energy holds a place on the board of the Pacific Northwest Hydrogen Association and is working with other regional parties to explore development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington.

➔ A discussion of the work that PSE is doing on Hydrogen is in Chapter Two: Clean Energy Action Plan.

Finally, we looked at what would happen in a worst-case scenario where the frame peaker had to run on natural gas. In this event, for the limited hours the plant must run for peak contribution, the equivalent forecasted emissions would be 16,000 metric tons annually. Figure 3.7 illustrates the equivalent emissions on an equal-sized coal-fired plant (Colstrip) and a combined cycle combustion turbine (CCCT) baseload gas plant for comparison.

Figure 3.7: Annual Greenhouse Gas Emissions based on equivalent 237 MW (Metric tons CO2e)



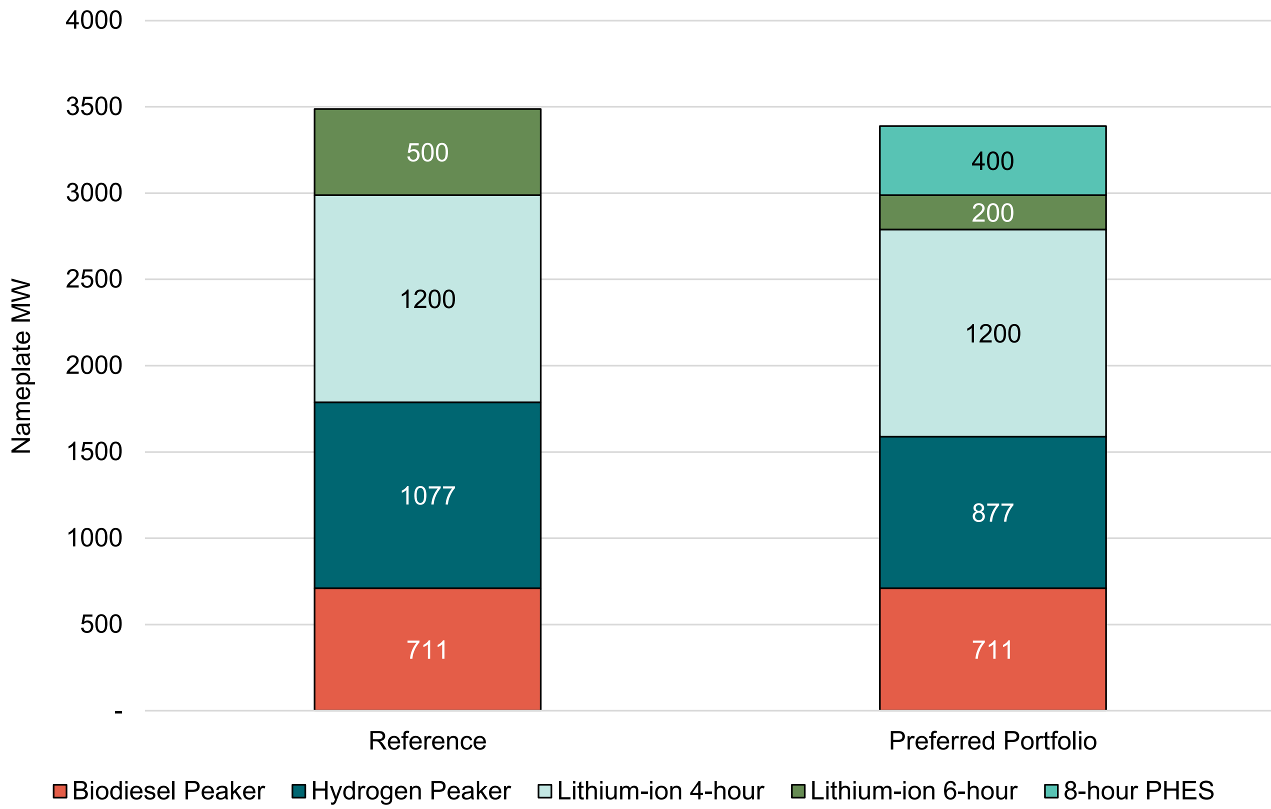
2.3. Diversifying the Portfolio

As PSE and the region seek to decarbonize systems, the future of electricity is a diverse portfolio of renewable and non-emitting resources. A diverse energy mix is essential for energy security because it is less dependent on a single fuel source, reducing vulnerabilities due to market price, supply fluctuations, and political unrest. Multiple, reliable generation sources allow a utility to provide power without disruption if one energy source fails. A diverse portfolio can reduce environmental impacts, improve reliability, and promote innovation to meet the needs of more than 1.5 million PSE customers. Resource diversity is the key to reducing emissions while preserving reliability and affordability.

The initial least-cost reference portfolio we developed for the 2023 Electric Report relies primarily on a few resources because we designed the model to select the lowest-cost resources available. However, we need to consider factors such as risk and feasibility when considering resources to include in the preferred portfolio. For example, the least-cost reference portfolio relies heavily on 4-hour batteries and hydrogen as a fuel because 4-hour batteries are the lowest-cost energy storage resource, and hydrogen is the lowest-cost, CETA-qualifying fuel source for thermal resources. To develop the preferred portfolio, we adjusted the least-cost reference portfolio to bring more diversity and lower its inherent technology and feasibility risks.

Figure 3.8 shows how we adjusted the storage resources in the preferred portfolio from the reference case to create a diverse portfolio that relies on multiple resources to meet demand. Figure 3.8 shows how diversifying storage resources results in less hydrogen peaker capacity.

Figure 3.8: New Energy Storage and Peaking Capacity Nameplate Additions by 2045 (MW)



Energy Storage

The least-cost reference portfolio will add 1,000 MW of four-hour batteries by 2030 because they are the lowest-cost energy storage resources. We adjusted the types of energy storage resources for the preferred portfolio to include more diverse technologies. For the preferred portfolio, we added 200 MW of pumped hydroelectric energy storage (PHES) in Montana and 400 MW of new Montana wind along with the existing 350 MW of wind. We added 200 MW of PHES in the Pacific Northwest to the preferred portfolio for 400 MW of PHES. The remaining energy storage is a mix of four-hour and six-hour batteries.

Advanced Nuclear Small Modular Reactors

In the least-cost reference portfolio, we modeled building more than 800 MW of new hydrogen peakers by 2045 in addition to the 2,000 MW of existing resources converted from natural gas to hydrogen. By 2045, we projected hydrogen to account for 36 percent of the peak capacity contribution. This least-cost reference portfolio relies heavily on a single fuel source with an unknown supply, creating risk. To diversify the portfolio, we can explore other technologies, such as advanced nuclear SMR, to include in future preferred portfolios. There are many unknowns around new advanced nuclear SMR technology. Although the high cost of advanced nuclear SMR deterred us from having it in the preferred portfolio, we will continue to monitor the technology. As advanced nuclear SMR technology matures, it could be a resource to help reduce the risks of relying on only a few technologies and a way to meet the CETA 100 percent requirement by 2045.

3. Resource Adequacy

The Pacific Northwest electricity industry is transitioning as governments and system planners implement major decarbonization policies. Operators and utilities are retiring significant quantities of coal-fired capacity while adding new renewable generation resources. As a result, PSE and other utilities are rethinking how we plan our systems, especially concerning resource adequacy. As we transition to 100 percent clean energy by 2045, we must ensure customers have reliable electricity and smoothly transition to a decarbonized system.

The resource adequacy analysis for this 2023 Electric Report resulted in a capacity deficit of 2,629 MW, more than double the 2021 IRP capacity deficit projected for 2029. This large deficit drives the large capacity additions in the preferred portfolio. This section describes the elements contributing to this deficit, including updates to the planning reserve margin, our reduction in market reliance, and variable resource peak capacity contributions.

3.1. Planning Reserve Margin Updates

The resource adequacy analysis for this 2023 Electric Report led us to increase the planning reserve margin to 23.8 percent in 2029, resulting in a capacity deficit of 2,629 MW. Two main elements contributed to the rise in the planning reserve margin:

- Climate change data in the load forecast and peak temperatures — when we accounted for average temperature trends, it only slightly lowered the one-in-two winter peak and increased the summer peak. Although summer peak temperatures increased, they do not come close to the winter peak level in this

2023 Electric Report's planning horizon. However, temperature volatility increased, which we accounted for in the resource adequacy and contributed to the overall increase in the planning reserve margin.

- Increase in peak demand — although the one-in-two winter peak lowered slightly, the updated electric vehicle (EV) forecast increased the demand. The increase in peak from the EV forecast was larger than the decrease from the climate change data, resulting in an overall increase to the one-in-two peak demand.

Climate change data also showed changes in the duration and frequency of loss of load events, which affected the capacity deficit. The data showed a decrease in event duration, less frequent events in the winter and more frequent events in the summer. Including climate change data increased the effective load-carrying capacity (ELCC) for solar and shorter-duration storage resources (those that discharge energy at the rated power output for less than 10 hours). Climate change data also shows the historical spring runoff is happening earlier in the year, which changes hydropower availability and the profile of hydroelectric generation and leaves less water for the summer.

3.2. Reduced Market Reliance

The western energy market has had surplus capacity for more than a decade. Given PSE's available firm transmission to the Mid-Columbia market hub, purchasing energy supply from the regional power market has been a cost-effective way to meet demand. However, the supply and demand fundamentals of the wholesale electric market have changed significantly in recent years in two important ways: supplies have tightened, and pricing volatility has increased.

In response to these changing conditions, we plan to replace short-term market supplies with firm resource adequacy qualifying capacity contracts compliant with CETA, meet our resource adequacy requirements, and align with a potential regional resource adequacy program. The preferred portfolio includes added firm capacity resources and reduced short-term market purchases.

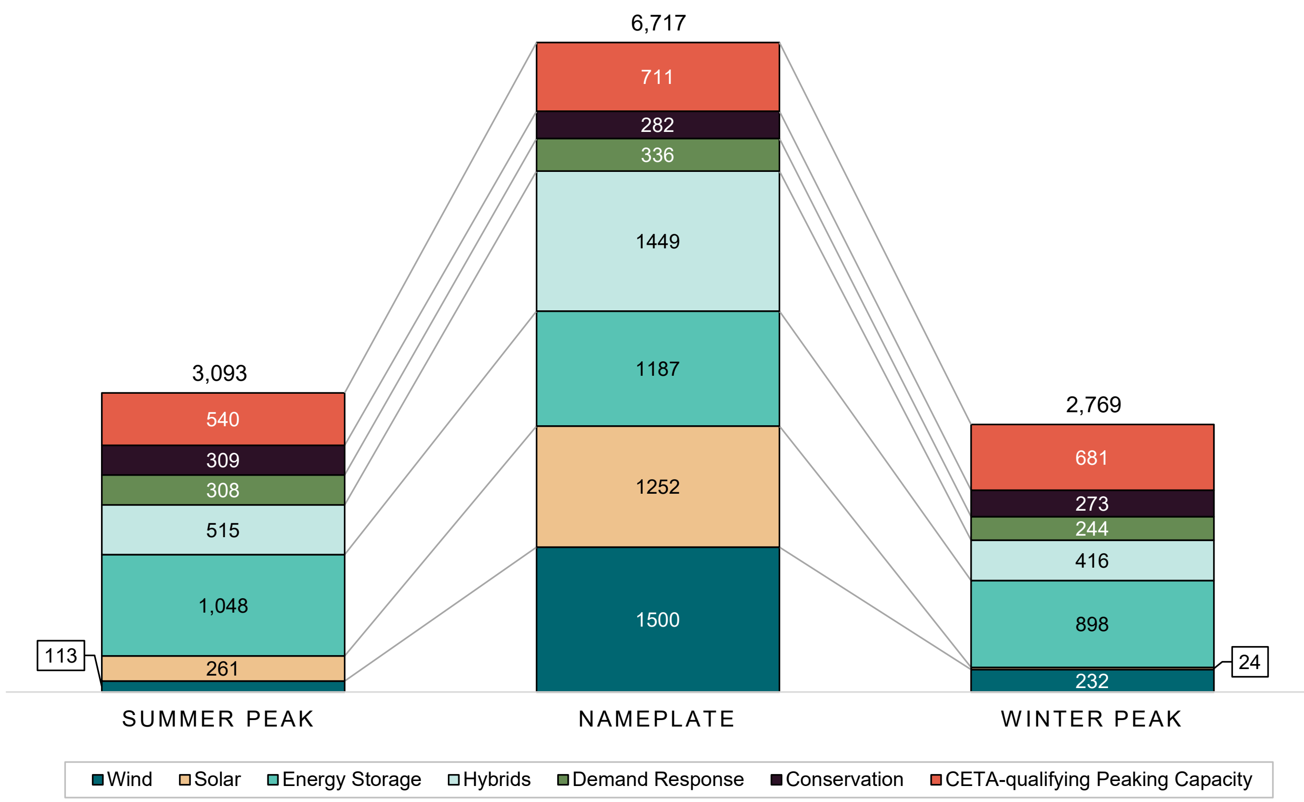
Our approach allows us to survey the market for available resource adequacy qualifying agreements and enables us to develop regional resource adequacy program requirements to help inform PSE's future needs. Given the tightening of energy markets and our preparations for possible participation in the Western Resource Adequacy Program (WRAP), we plan to reduce PSE's reliance on short-term wholesale market purchases.

This approach has challenges, such as permitting and building generating and storage resources and transmission to meet growing demands in an increasingly complex permitting landscape. Although those challenges are real, we are confident the resource plan in this 2023 Electric Report indicates a path to reach our clean energy goals and achieve the clean energy future our customers expect.

3.3. Peak Capacity Contribution

Electric resources, particularly variable resources such as solar and wind, rarely perform at nameplate capacity during peak need. Therefore, ensuring resource adequacy relies on evaluating a resource's peak capacity contribution, which is the nameplate capacity combined with the ELCC. After adjusting for the peak capacity contribution of each resource, we need more resources to meet the peak need than the nameplate capacity suggests. For example, solar's 24 MW peak capacity contribution requires over 1100 MW of installed nameplate capacity. After adjusting for peak capacity contribution, over 6,700 MW of new resources installed nameplate capacity adjusts to over 3,000 MW summer peak capacity and over 2,700 MW winter peak capacity, as detailed in Figure 3.9.

Figure 3.9: Nameplate Capacity Adjusted to Peak Capacity Contributions (MW)



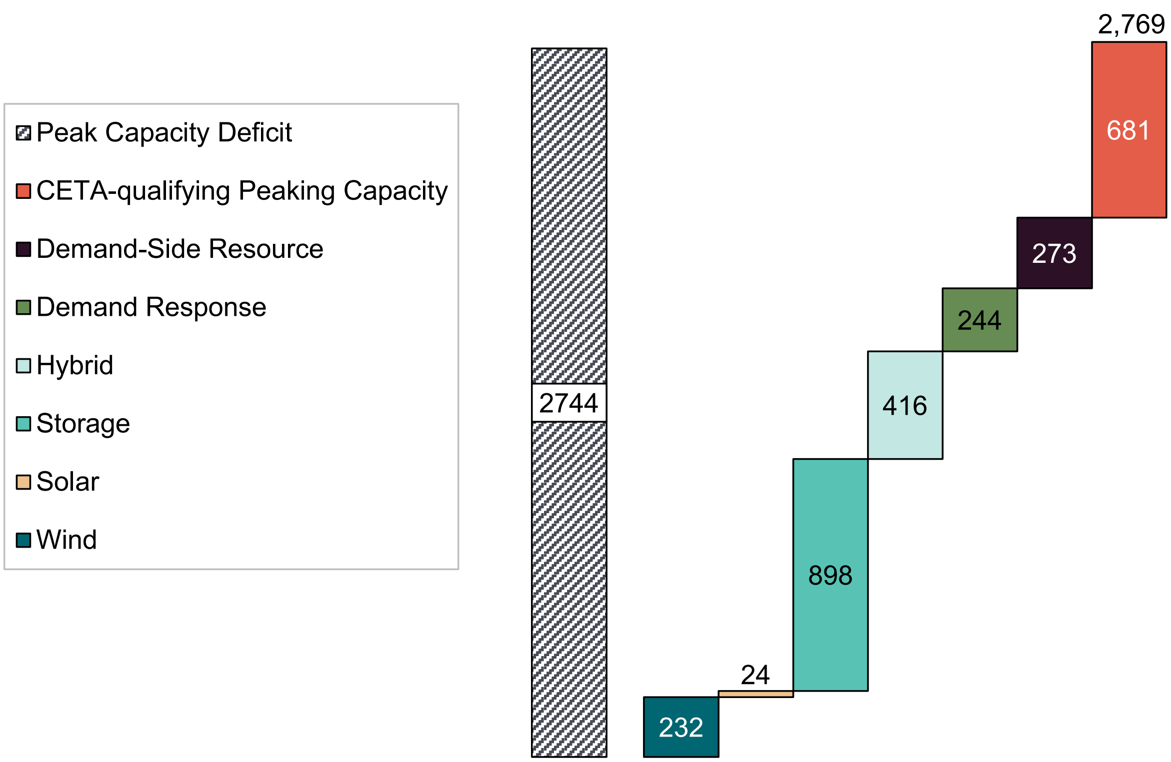
3.3.1. Winter Peak Drives Resource Capacity Additions

We analyzed summer and winter peak capacity. Consistent with prior years, the winter peak is higher than the summer peak. We noted that the increase of renewable energy and energy storage in the preferred portfolio contributed to meeting the summer peak need better than they contributed to the winter. For example, solar has a four percent peak capacity contribution in the winter but a 55 percent contribution in the summer. We added solar to the portfolio because it meets the CETA requirement and the summer peak need, but it does very little to meet the winter peak need. Given that the preferred portfolio meets the 2030 CETA target and renewable resource additions meet the summer peak capacity need, the winter peak need drives new peaking capacity in the preferred portfolio. The preferred portfolio builds 711 MW of CETA-qualifying peaking nameplate capacity by 2029 (Table 3.1), and assuming a 96 percent ELCC in winter (see Appendix D: Generic Resource Alternatives for operating assumptions), this adds 681 MW of peaking capacity. These additions balance the winter peak and create more than 250 MW summer peak surplus.

Figure 3.10 shows the breakdown of the effective winter peak capacity contribution for new resources. Note that this figure combines the nameplate capacities provided in Table 3.1 with respective ELCCs found in Appendix D: Generic Resource Alternatives.

➔ Please see Chapter Seven: Resource Adequacy Analysis for a detailed winter and summer peak needs discussion.

Figure 3.10: Meeting Winter Peak Need for 2030 — New Resource Additions Effective Capacity (MW)



4. Developing the Preferred Portfolio

This section describes how we developed candidate diversified portfolios. We also discuss the trends we observed across all candidate diversified portfolios in the near- and long-term and evaluate the costs of each candidate diversified portfolio. Finally, we present the results of our portfolio benefit analysis and summarize the selection of our preferred portfolio.

4.1. Candidate Diverse Portfolios

The first step to developing a preferred portfolio is to start with a least-cost portfolio. A least-cost portfolio meets constraints in a lowest-cost way. These constraints are:

- CETA renewable and clean-energy requirements
- Hourly customer demand for the year
- Peak capacity plus a planning reserve margin
- Reduced market reliance at peak
- Transmission access for new resources

The least-cost portfolio gave us a starting point which we then adjusted to identify a feasible portfolio of diverse resources that consider equity and create customer benefits while maintaining reliability and affordability. We refined the least-cost portfolio to maximize benefits and reduce burdens to vulnerable populations and highly impacted communities consistent with CETA. Figure 3.11 shows a progression of diversified portfolios ranging from the least diverse portfolio (11 A1) to the most diverse portfolio (11 A5), with each step adding a scheduled resource to increase the portfolio's diversity. We modeled portfolios 11 B1 and 11 B2 at the request of interested parties to exclude advanced nuclear SMR additions and are like the least and most diversified portfolios (11 A1 and 11 A5)

To create a diverse portfolio, we:

1. Start with the least cost reference portfolio,
2. Make incremental changes to the portfolio to test the sensitivity of the adjustment to resource builds and portfolio cost,
3. Create a portfolio with different options from part 2, considering equity, cost, feasibility, reliability, and diversity of energy supply.

Figure 3.11: Components of the Diverse Portfolios

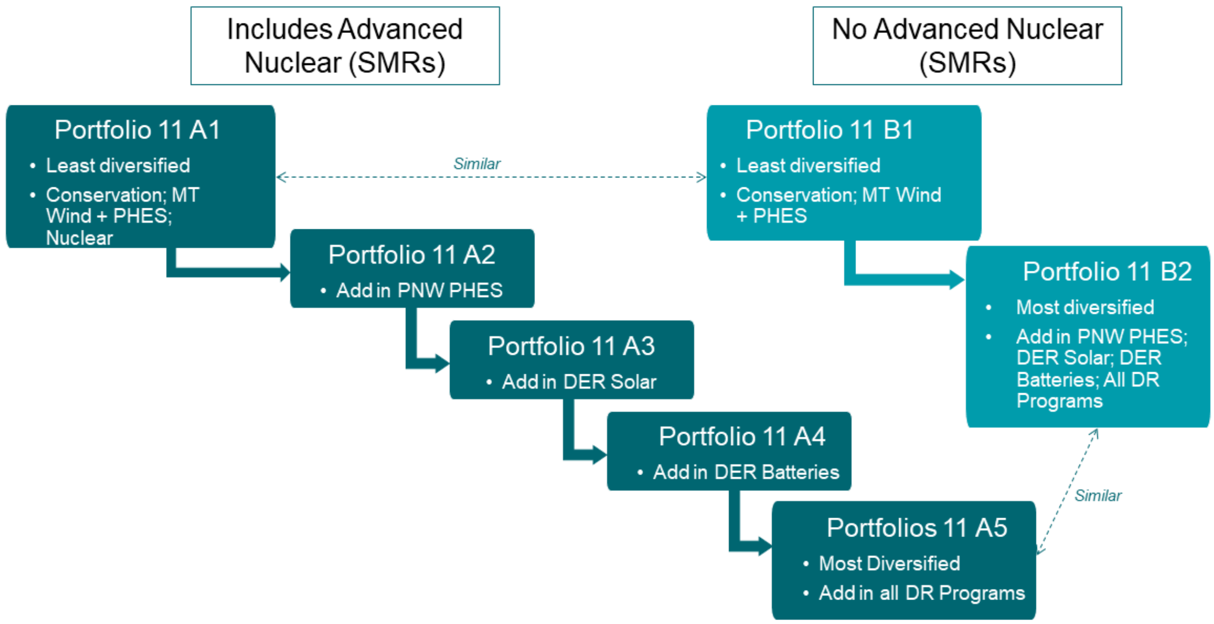
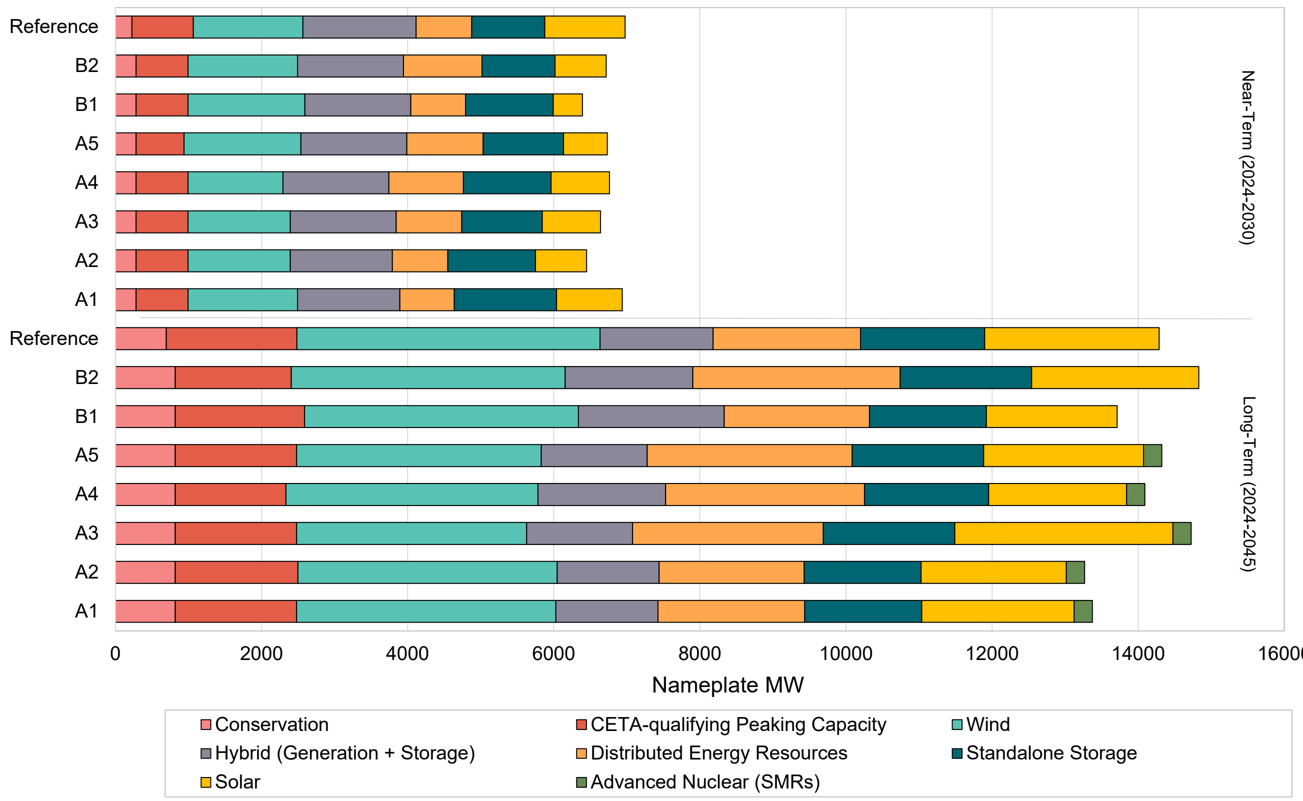


Figure 3.12 shows a breakdown of nameplate resource additions by portfolio. The portfolios are very similar in the near term (2024–2030). Puget Sound Energy needs many resources to meet CETA and resource adequacy, and there are few commercially available technologies today. All the diverse portfolios have equal amounts of conservation and CETA-qualifying peaking capacity, with the rest of the resources comprising demand response, wind, solar, energy storage, or a hybrid of renewable resources plus energy storage. For the longer term (2031–2045), the resource mix becomes more distinct between portfolios, although the need for conservation and CETA-qualifying peaking capacity is a stable addition across all portfolios.

Figure 3.12: Resource Builds (Nameplate MW)

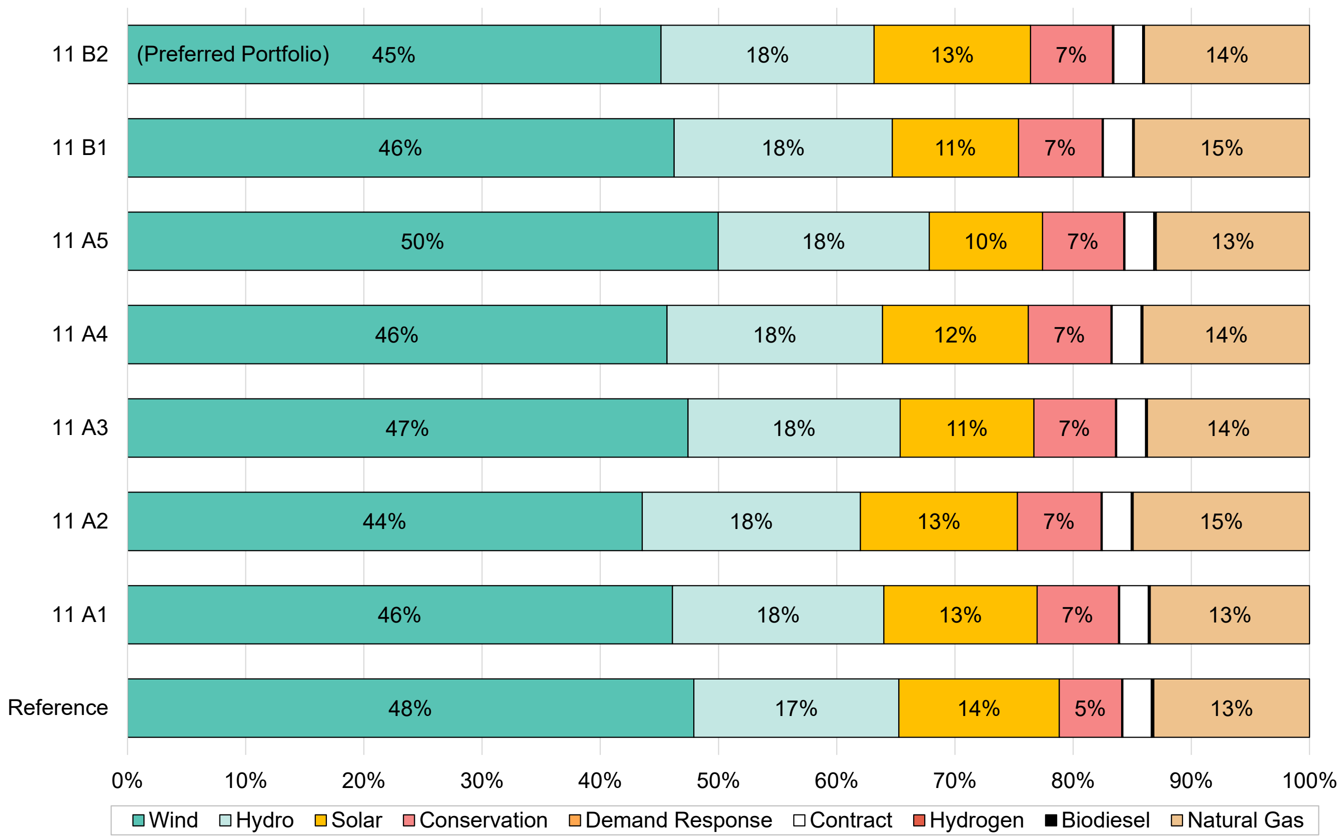


4.1.1. Near-term Resources (2024–2029)

The utility-scale and demand-side resource builds in the near term are similar across the diversified portfolios. In all the diversified portfolios, we need three peaking generation facilities by 2030 to maintain reliability as we add new variable resources. By 2030, we will add almost 1,500 MW of new energy storage to help meet resource adequacy and ancillary services. Energy storage resources are not energy-producing; they just store the energy produced from other resources, so it is available during peak hours. Given that we added more than 3,000 MW of variable energy resources by 2030 to meet the CETA requirements, we will need the energy storage resources to help store energy in low-demand hours to be used later in high-demand hours. The primary difference between the diversified portfolios is the amount of distributed energy resources. We listened to interested parties and PSE's Equity Advisory Group (EAG) and heard the importance of adding more distributed resources to the portfolio and increasing customer participation in these programs. However, no matter which portfolio we use for the preferred portfolio, the near-term resources are the same for utility-scale resources: we need to meet CETA requirements and resource adequacy, and there are limited options available to achieve these needs in the next six years.

Figure 3.13 presents each diversified portfolio's 2030 annual energy production by fuel type.

Figure 3.13: Annual Energy 2030 — Percent of Generation by Fuel Type

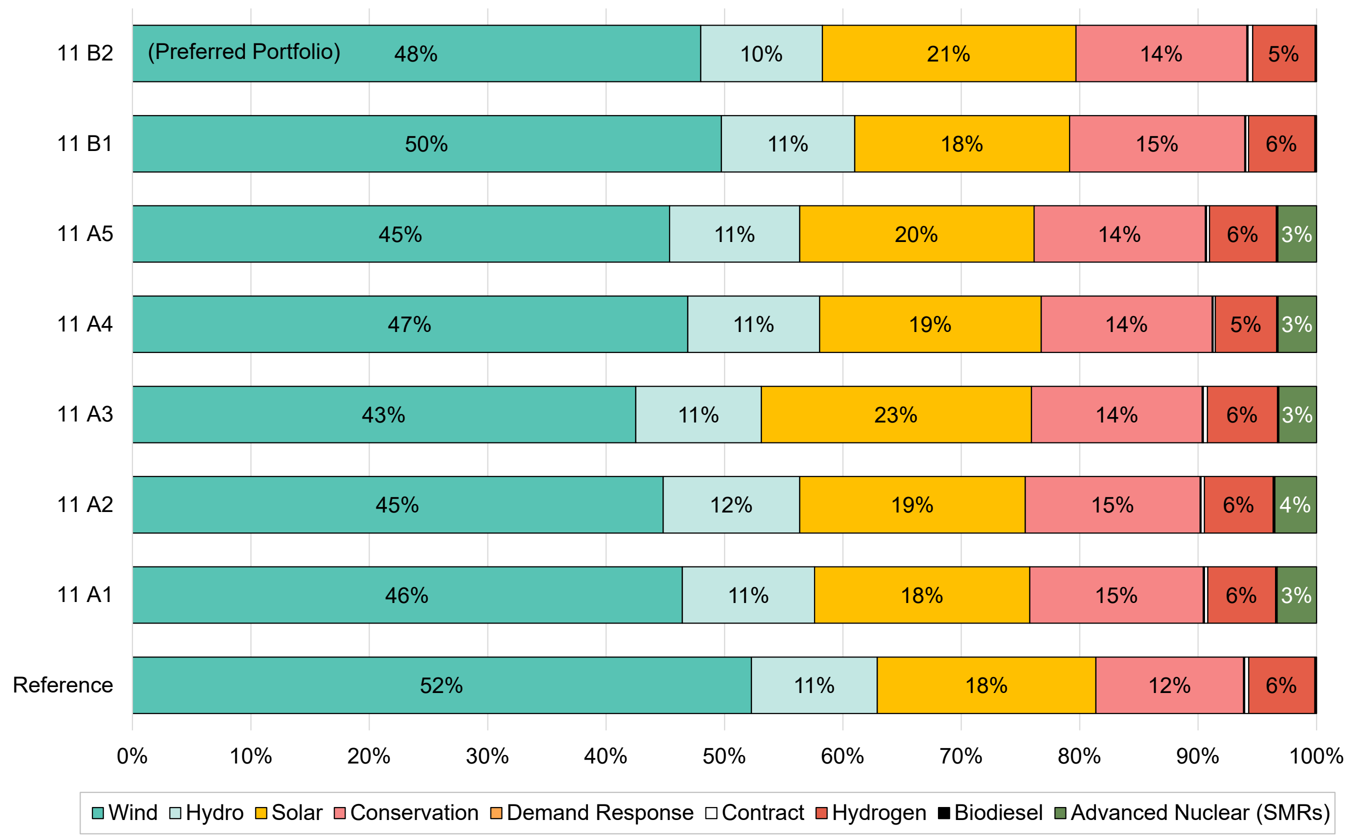


4.1.2. Long-term Resources (2030–2045)

As we look further into the future, the resources become less certain. Technological advancements are needed to achieve 100 percent clean energy by 2045. These advances could involve using alternative fuels such as hydrogen in combustion turbines or through advanced nuclear SMR technology. Both options are promising but present unique risks and costs. We will continue to explore these and other resource options in subsequent and future IRP cycles. Regardless of the technologies available long-term, it does not change near-term resources and resource options.

Figure 3.14 presents each diversified portfolio's 2045 annual energy production by fuel type.

Figure 3.14: Annual Energy 2045 – by Fuel Type (percent of generation)



4.1.3. Portfolio Costs

The portfolio costs include all those associated with construction, interconnection, transmission, fuel, and operations and maintenance of new generating resources, along with the costs to operate and maintain existing resources. We divided the portfolio costs into near-term resource additions before 2030 (Table 3.3) and longer-term, 21-year decisions for 2045 (Table 3.4). Figure 3.15 shows the annual portfolio costs for 2024–2029; annual portfolio costs for the entire planning period of 2024-2045 are in Chapter Eight: Electric Analysis.

In the near term, the combination of increasing distributed resources, conservation, demand response, and diversifying the portfolio delays adding one peaking generation facility until after 2030 but increases the cost over the reference case by $700–$880 million in the next six years.

Figure 3.15: Annual Portfolio Costs with Emissions 2024–2029 ($ Billions)

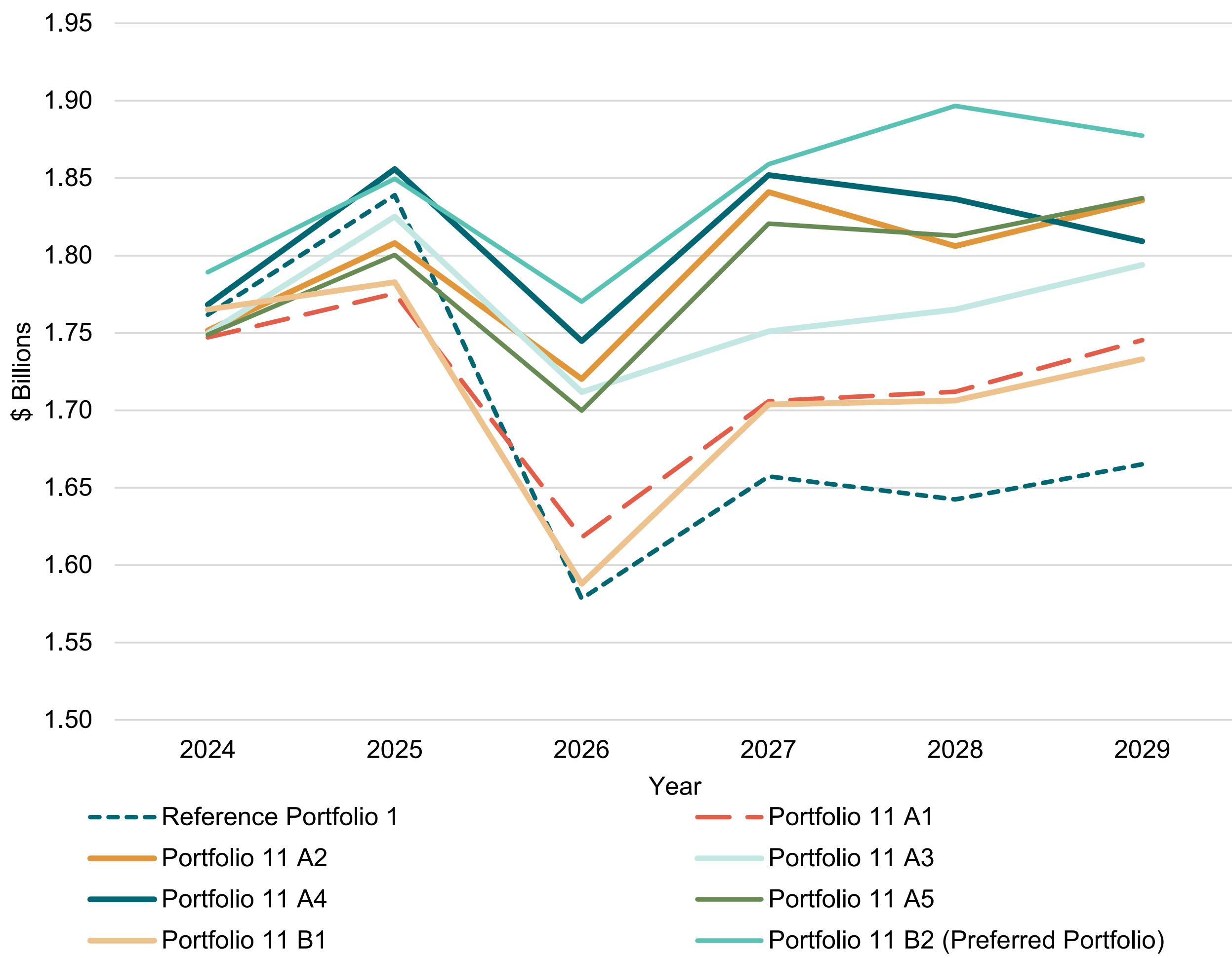


Table 3.3: Near-term (6-year) Net Present Values — 2024–2029 ($ Billions)

Portfolio	Portfolio Cost with SCGHG	Portfolio Cost without SCGHG	Social Cost of Greenhouse Gases (SCGHG)
Reference	8.14	6.05	2.08
11 A1	8.24	6.49	1.75
11 A2	8.59	6.70	1.89
11 A3	8.47	6.67	1.80
11 A4	8.68	6.75	1.93
11 A5	8.55	6.75	1.80
11 B1	8.22	6.32	1.91
11 B2 (Preferred Portfolio)	8.81	6.93	1.88

In the long-term, adding these distributed resources to the portfolio increases the cost over the reference case by $1.7 - $2.8 billion, as seen in portfolios 11 B1 and 11 A5, respectively (Table 3.4).

Diversifying the portfolio and increasing equity metrics through increased distributed resources, as described in Section 2.4.2, increases the cost of the portfolio both in the near- and long-term time horizon.

Table 3.4: Long-term (21-year) Net Present Values — 2024–2045 ($ Billions)

Portfolio	Portfolio Cost with SCGHG	Portfolio Cost without SCGHG	Social Cost of Greenhouse Gases (SCGHG)
Reference	17.61	20.85	3.24
11 A1	20.01	22.83	2.82
11 A2	20.32	23.25	2.93
11 A3	20.44	23.27	2.83
11 A4	20.74	23.64	2.90
11 A5	20.89	23.67	2.78
11 B1	18.09	21.09	3.00
11 B2 (Preferred Portfolio)	19.56	22.51	2.95

➔ Chapter Eight: Electric Analysis presents a complete discussion of portfolio sensitivity cost.

4.2. Portfolio Benefit Analysis

The Clean Energy Transformation Act requires utilities to consider equity and ensure all customers benefit from the transition to clean energy. However, AURORA, a traditional production cost model we use for portfolio modeling, only solves the least-cost solution. Therefore, we developed and used a portfolio benefit analysis tool to support our understanding of equity-related benefits and the associated costs within each portfolio and inform our work as we strive to select a portfolio best suited to enable equitable customer outcomes while also considering the cost. The preferred portfolio provides the best pathway to improve equitable outcomes of all our portfolios evaluated in this 2023 Electric Report. This outcome was driven primarily by increasing customer opportunities to participate in distributed energy and demand response programs.

The portfolio benefit analysis tool measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative customer benefit indicators (CBIs) and their metrics. Customer Benefit Indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent some of the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this 2023 Electric Report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA modeling tool could quantitatively evaluate them, i.e., AURORA already had a comparable metric. The CBIs we included in the portfolio benefit analysis are:

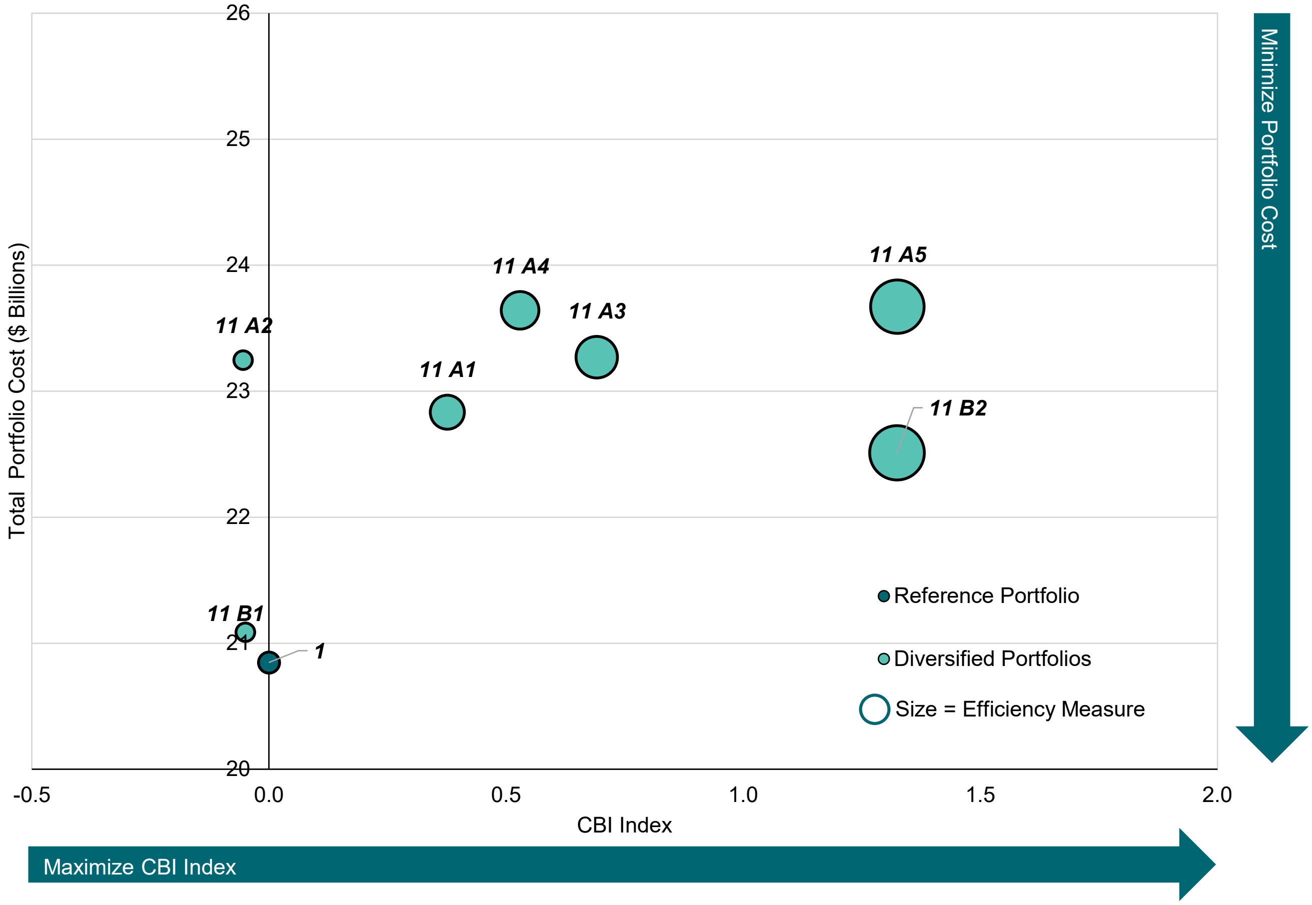
- **Improved access to reliable, clean energy** — measured by customers with access to distributed storage resources.
- **Improved affordability of clean energy** — measured by the total portfolio cost.
- **Improved outdoor air quality** — measured by sulfur oxides, nitrogen oxides, and particulate matter generated per portfolio.
- **Increase the number of jobs** — measured by the number of estimated jobs generated for each portfolio.
- **Increases participation in Energy Efficiency, Distributed Energy Resources, and Demand Response Programs** — measured by energy efficiency capacity added and the number of customers projected to participate in distributed energy resources and demand response programs.
- **Reduced greenhouse gas emissions** — measured by the total amount of CO_2-eq2 generated per portfolio.
- **Reduced peak demand** — measured by the decrease in peak demand achieved via demand response programs.

The portfolio benefit analysis generates a CBI index for each portfolio, an aggregate measure of these CBIs (sans the portfolio cost) normalized to the reference, least-cost portfolio. A higher CBI index indicates that a portfolio enables more equity-related benefits than the reference portfolio. The CBI index juxtaposes each portfolio's total cost (direct and externality costs). The plot (Figure 3.11) illustrates the tradeoff between increasing portfolio benefits and the associated metrics and costs. Compared to the reference portfolio, the most efficient portfolios have the highest CBI indices with minimal increase in portfolio cost and sit closest to the bottom right corner of the plot.

Figure 3.16 shows the results generated by the portfolio benefit analysis tool for all diversified portfolios analyzed in this 2023 Electric Report. We can see portfolio 11 B2 is the most efficient of the diversified portfolios because it lies furthest to the right with the highest CBI index, one of the reasons we selected portfolio 11 B2 as the preferred portfolio. It has the highest overall CBI index at 1.32 and is the most diversified portfolio without advanced nuclear SMR that we evaluated in the 2023 Electric Report.

[2] CO2-eq or CO2-equivelant is a measure used to compare the emissions from various greenhouse gases based on their global-warming potential (GWP). Using the GWP, other greenhouse gases are converted to the equivalent amount of carbon dioxide.

Figure 3.16: Portfolio Benefit Analysis Tool Results



The high CBI index of portfolio 11 B2 comes from improvements in all the CBIs we considered in this analysis except for jobs, which varied slightly from the reference portfolio by less than half a standard deviation (index = -0.41). The benefits in the preferred portfolio include some of the highest potential customer participation numbers for DER solar, DER storage, and demand response programs at 87,492, 18,524, and 750,943 participants, respectively. Compared to the reference portfolio, the preferred portfolio also reduces greenhouse gas and other harmful emissions (Table 3.2).

Table 3.2: Portfolio CBI Metrics

CBI Metric	1 Reference	11 A5 Diversified Portfolio	11 B2 Diversified Portfolio
Cost ($, Billions)	20.85	23.67	22.51
GHG Emissions (Short Tons)	48,824,734	41,543,008	44,372,601
SO_2 Emissions (Short Tons)	28,841	28,836	28,759
NO_x Emissions (Short Tons)	11,426	10,307	10,805
PM Emissions (Short Tons)	9,036	8,873	8,940
Jobs (Total)	45,736	40,757	43,795
Energy Efficiency Added (MW)	695	818	818

CBI Metric	1 Reference	11 A5 Diversified Portfolio	11 B2 Diversified Portfolio
DR Peak Capacity (MW)	291	320	320
DER Solar Participation (Total New Participants)	12,115	83,903	87,492
DR Participation (Total New Participants)	513,238	750,943	750,943
DER Storage Participation (Total New Participants)	8,125	18,524	18,524

The results of the portfolio benefit analysis indicate that increasingly distributed and demand-side resources significantly increase the potential for more equitable outcomes for customers. Compared to the reference portfolio, portfolio 11 B2 has the following additions:

- **Conservation** — increases to 371 MW by 2045, 113 MW above the least-cost conservation.
- **Demand Response** — increases to 446 MW by 2045, an increase of 41 MW above the least-cost portfolio.
- **Distributed solar** — added 30 MW per year from 2026–2045, a total of 630 MW added by 2045 above the least cost portfolio.
- **Distributed storage** — added 25 MW per year from 2026–2031, a total of 150 MW added distributed storage above the least cost portfolio.

Portfolio 11 B2 achieved the highest CBI index of all portfolios evaluated in this 2023 Electric Report. In pursuing this portfolio, we will adopt a pathway forward for acquiring the resources necessary for a more equitable distribution of customer energy and non-energy burdens and benefits.

4.3. Portfolio Selection

We chose portfolio 11 B2 as the preferred portfolio because it presents a diverse mix of centralized renewable and non-emitting resources, reliable conservation, demand response, and distributed resources, and enables the most equity-related benefits of all the portfolios we evaluated. Furthermore, this portfolio reduces direct PSE emissions, achieves carbon neutrality by 2030, and is non-emitting by 2045. This portfolio is higher cost than most of the other diversified portfolios we evaluated. However, this outcome was driven primarily by increasing customer opportunities to participate in distributed energy and demand response programs, which we determined with feedback from PSE's EAG and other interested parties, were essential components of a preferred portfolio.

LEGISLATIVE AND POLICY CHANGE

CHAPTER FOUR

PSE PUGET SOUND ENERGY

Contents

1. Introduction

Policy changes and the subsequent legislative changes in the energy sector have increased rapidly in the last five years. Puget Sound Energy (PSE) continues to respond to the quickly shifting landscape with plans that guide the resource acquisition process. This chapter outlines recent state and federal energy legislative and policy changes and how they informed the development of the 2023 Electric Progress Report (2023 Electric Report).

On the state level, we incorporated rules from the Clean Energy Transformation Act (CETA), the Climate Commitment Act (CCA), and new building codes. We also included the impacts of the federal Inflation Reduction Act (IRA) in this report.

2. Clean Energy Transformation Act

Clean Energy Transformation Act requires utilities to meet the following mandates:

- One hundred percent of retail utility sales must be greenhouse gas neutral by 2030, with 80 percent of those sales met with renewable and non-emitting resources and 20 percent with other clean investment options, which may include unbundled renewable energy credits.
- Renewable and non-emitting resources must meet one hundred percent of retail utility sales by 2045.
- Utilities must eliminate coal from their allocation of electricity to Washington retail customers after 2025.

This chapter addresses CETA rulemaking enacted after the 2021 IRP was published.

2.1. Washington Utilities and Transportation Commission

The Washington Utilities and Transportation Commission (Commission) concluded one CETA rulemaking in 2022, which established rules for electricity purchases from centralized markets, the prohibition of double counting, and the treatment of energy storage. The rules include additional contracting requirements, reporting contracts, and detail other data PSE must submit to the Commission.

2.1.1. Market Purchases and Double Counting

In the Market Purchases and Double Counting Rulemaking, the Commission issued an order on June 29, 2022, establishing rules for energy storage and prohibiting the double counting of clean energy attributes. This order also creates contracting and annual reporting requirements for data associated with the utility's resources and operations.

These rules require that PSE demonstrate compliance with the clean energy standards in CETA by acquiring electricity and associated renewable energy credits (RECs) or non-power attributes. Puget Sound Energy must show that we can deliver clean electricity to our system. We must also report on the source and characteristics of the electricity claimed for compliance.

This new rule did not affect modeling for the 2023 Electric Report.

2.1.2. Impact and Actions

As part of this report, we count the generation from CETA-qualifying renewable and non-emitting resources to meet CETA requirements, including wind, solar, nuclear, and renewable fuels (biodiesel and hydrogen), along with load reducers such as conservation, demand response, and customer voluntary renewable programs. Energy storage resources, such as batteries and pumped hydro storage, are treated as non-generating resources. Energy storage allows us to shift renewable energy to times of greater need, so the renewable energy used to charge those storage facilities is counted toward CETA requirements.

➔ A full description of PSE's existing CETA-qualifying resources is in Appendix C: Existing Resource Inventory, and a description of the new resources we modeled is available in Chapter Five: Key Analytical Assumptions and Appendix D: Generic Resource Alternatives.

In its order, adopting rules for market purchases, double counting, and other issues related to CETA, the Commission said further rulemaking and deliberation is needed regarding its interpretation of electricity use to ensure consistency and reliability across Washington's energy market and among electric utilities. PSE will incorporate these topics into our planning processes as appropriate as the Commission completes their rulemaking processes.

2.1.3. Incorporating Equity in Resource Planning

The CETA requires that "all customers are benefiting from the transition to clean energy through the equitable distribution of energy and nonenergy benefits and the reduction of burdens to vulnerable populations and highly impacted communities."[1] Equity is complex to measure and assess, especially in energy system planning; it is an important and new area to develop for resource planning since the enactment of CETA.

2.1.4. Impact and Actions

While PSE has considered equity in its low-income conservation programs in the past, the 2021 IRP saw a significant expansion of equity considerations. The 2021 IRP expanded its consideration of equity through the Economic, Health and Environmental Benefits Assessment (linked below) and the Customer Benefits Analysis (described in Chapter 3: Resource Plan. Since the 2021 IRP, we formed and convened an Equity Advisory Group (EAG) and engaged with this and other advisory groups, community-based organizations, and customers to better understand clean energy values in developing the 2021 Clean Energy Implementation Plan (CEIP). Input from these conversations shaped how we approached equity in this report.

The EAG comprises representatives from various community advocacy interests to advise PSE on the equitable transition to clean energy. The EAG also includes frontline customers. We encourage participation from environmental justice and public health advocates, tribes, and representatives from highly impacted communities and vulnerable populations. In the 2021 CEIP, the EAG initially advised on equity elements related to understanding the

1 RCW 19.405.060

benefits and burdens customers may face, defining vulnerability factors, guiding principles for program implementation, and helped develop customer benefit indicators used in this report.

We revised and updated the customer benefits analysis used in the 2021 IRP to enhance the portfolio benefit analysis in this 2023 Electric Report. The portfolio benefit analysis incorporates a revised set of customer benefit indicators developed in the 2021 CEIP through collaboration among PSE staff, the EAG, and interested parties. The portfolio benefit analysis also incorporates methodological updates, informed by discussion with interested parties, to better quantify the distribution of portfolio-level metrics related to the customer benefit indicators. A full description of the portfolio benefit analysis and its results is available in Chapter Eight.

We also updated the Economic, Health, and Environmental Benefits Assessment in the 2023 Electric Report to reflect recent developments in identifying named communities. Named communities are customers burdened by social, economic, health, and environmental impacts, including highly impacted communities and vulnerable populations. We defined Highly Impacted Communities in our Department of Health Cumulative Impact Analysis, which we updated in August 2022. Puget Sound Energy staff collaborated with the EAG to define Vulnerable Populations as part of the 2021 CEIP and we used that definition in this report.

➔ A full description of the Economic, Health, and environmental Benefits assessment and its results is available in Appendix J: Economic, Health and Environmental Assessment of Current Conditions.

2.2. Clean Energy Implementation Plan

The Clean Energy Implementation Plan (CEIP) is a state-mandated four-year roadmap guiding PSE's clean energy investments for 2022–2025.

2.2.1. CEIP Overview

Consistent with CETA rules, we filed the company's first CEIP in December 2021. The plan illustrated our path toward meeting the requirements of CETA and the specific actions we will take from 2022–2025 to meet those goals. The CEIP proposed an interim target of serving customers with 63 percent clean, CETA-eligible renewable resources by the end of 2025. The CEIP also proposed targets and specific actions that include:

- 23.7 MW of Demand Response
- 25 MW of Distributed Energy Resources (DER) storage
- 50 MW of utility-scale storage
- 80 MW of DER solar,
- 1,073,434 MWh of energy efficiency, as determined in the 2022–2023 Biennial Conservation Plan

By rule, the Commission can approve, deny, or approve with conditions the filed CEIP. We are still waiting for a decision from the Commission on PSE's CEIP. However, we continue moving forward on specific actions to implement the CEIP by the end of 2025. These efforts include ongoing public participation with advisory groups and interested parties, completing the All-source and DER/DR resource acquisition processes, and beginning to develop tariff filings for new DER programs.

We used the 2021 IRP as the foundation for Puget Sound Energy's first CEIP. We will use the 2023 report to inform the 2023 biennial CEIP update. The 2023 report includes critical updates to the inputs and assumptions used in the AURORA modeling, which will directly feed into the 2023 biennial CEIP Update. The 2023 Electric Report rules (WAC 480-100-625)[2] require updates for the following items: load forecast, conservation, resources costs, state and federal requirements, significant economic and market changes, and other elements identified in the CEIP.

➔ See Chapter Eight: Electric Analysis for a discussion on substantive changes for the 2023 Electric Report.

2.2.2. Impact and Actions

The 2023 Electric Report includes the following CEIP targets and actions:

- 25 MW of Distributed Energy Resources (DER) storage
- 80 MW of DER solar
- Updates to the customer benefit indicators

We did not include targets for energy efficiency and demand response from the 2021 CEIP since we conducted a new conservation potential assessment and demand response assessment for the 2023 Electric Report. We used the new assessments to create new economic and achievable energy efficiency and demand response resource options in the preferred portfolio.

Another critical CETA goal bridging the 2023 Electric Report to the 2023 biennial CEIP update is including and embedding equity in decision-making and resource selection, via the revised customer benefit indicators and the portfolio benefit analysis, as described in Section 2.1.2 and detailed in Chapter Eight.

2.3. Climate Change

Under WAC 480-100-620 (10)(b), "at least one scenario must be a future climate change scenario. This scenario should incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change."[3] Temperature data that reflects climate change is a critical piece of our planning analysis. This crucial information impacts the demand forecast and influences how much energy PSE will need to serve our customers.

[2] WAC 480-100-625
[3] WAC 480-100-620

2.3.1. PSE Actions

The 2023 Electric Report is our first effort incorporating climate change data into the baseline forecast. We incorporated climate change in two key aspects of the analysis. First, we included climate change in the load forecast, as described in Chapter Six: Demand Forecast. We also included climate change impacts on regional loads and hydro generation in this report. We also included climate change in the resource adequacy analysis, the planning reserve margin, and the peak capacity contribution of resources, as described in Chapter Seven: Resource Adequacy.

2.4. Department of Health Cumulative Impact Analysis

The Clean Energy Transformation Act (CETA) directs the DOH to develop a CETA Cumulative Impact Analysis (CIA) of the impacts of climate change and fossil fuels on population health to designated highly impacted communities. The DOH released an initial CIA in February 2021 and an update in August 2022.

2.4.1. Impact and Actions

We used the results of the CIA to inform planning in our transition to clean energy. The CIA helps us identify, measure, and track equity-related metrics in several ways. Primarily, the CIA directs which communities we should geographically identify as highly impacted. Highly impacted communities may experience more public health and environmental burdens than other segments of our service area. Identifying, measuring, and tracking equity-related metrics in highly impacted communities helps us move toward an equitable transition to clean energy. By highlighting these highly impacted communities, we can identify disparities within our service territory, target specific actions to alleviate existing burdens, and benefit frontline communities.

The CIA also provides valuable data to support equity-related analysis. The DOH Environmental Health Disparities Map is a component of the CIA that offers a range of environmental and public health metrics that we use in our Environmental, Health, and Economic Benefits and Burdens Analysis.

➔ More information is available in the Environmental, Health, and Economic Benefits and Burdens Analysis in Appendix H: Electric Analysis and Portfolio Model.

2.5. Department of Ecology

The Washington State Department of Ecology is responsible for adopting rules that provide methods for assigning greenhouse gas emission factors for electricity and establishing a process to determine what types of projects may be eligible as energy transformation projects under CETA.

Ecology adopted a new rule on January 6, 2021, that establishes: WAC-173-446[4]

- A general process to determine eligible energy transformation projects

[4] https://ecology.wa.gov/Regulations-Permits/Laws-rules-rulemaking/Rulemaking/WAC-173-446

- A process and requirements for developing standards, methodologies, and procedures to evaluate energy transformation projects
- The default unspecified emissions factor in CETA

2.5.1. Impact and Actions

We did not evaluate any specific energy transformation projects as alternative compliance in this 2023 Electric Report. Instead, we bound the cost of alternative compliance measures using a forecast of renewable energy credit purchases to represent the lower bound and a 100 percent renewable portfolio by 2030 to represent the upper bound.

➔ A full description of the alternative compliance assumptions and methodology is available in Chapter Five: Key Analytical Assumptions.

We use the unspecified emission factor for the emission rate of the unspecified market purchases in the portfolio.

➔ You will find an accounting of the emissions from generating thermal resources and unspecified market purchases in the results from Chapter Eight: Electric Analysis and App_I_Input_Carbon_Prices spreadsheet from Appendix H: Electric Analysis and Portfolio Model.

3. Climate Commitment Act

In 2021, the Washington State Legislature passed the Climate Commitment Act (CCA) establishing a comprehensive cap-and-invest program to reduce statewide greenhouse gas (GHG) emissions through a price on emissions. The law directs Ecology to develop rules to implement and administer the program beginning January 1, 2023. As part of this process, Ecology adopted the final program rules on September 29, 2022. Puget Sound Energy is preparing to comply with this state law in alignment with our Beyond Net Zero Carbon (BNZC) commitments and aspirations.

3.1. Program Overview

The cap-and-invest program sets an overall cap on state GHG emissions, which declines over time in line with the state's statutory GHG emissions limits. Covered entities must report their GHG emissions to Ecology and obtain allowances to cover them. An allowance is a mechanism created by the Ecology equal to one metric ton of GHG emissions and may be directly distributed by Ecology, purchased at auction, or traded with others in the program. The program aims to establish a greenhouse gas emissions price and create a marketplace for covered entities to find the most efficient means to reduce emissions. The CCA mandates the state to equitably invest revenues raised through state-run allowance auctions in projects that reduce emissions and address climate resiliency and environmental justice, among other priorities.

3.2. Impacts and Actions

As an electric and natural gas utility, PSE is covered under the CCA. We will report emissions and have annual compliance obligations under the program.

Electric utilities subject to CETA are allocated no-cost allowances to mitigate the cost burden of the CCA program on electric customers until 2045. Allocations must be consistent with a supply and demand forecast approved by the Commission. Utilities may consign allowances to auction for the benefit of ratepayers, deposit them for compliance, bank them for future compliance, or a combination of these actions. All proceeds from the consignment of allowances must benefit ratepayers with priority to mitigating rate impacts to low-income customers.

Natural gas utilities must also comply with the CCA, and how they do may impact electric utilities, such as through a shift to more electrification of customer end uses. Our 2023 Gas Utility IRP includes an electrification analysis citing impacts on possible future electric infrastructure requirements. The 2023 Gas IRP analysis highlights the importance of a dual-fuel energy system as we transition to a low-carbon economy. Since this is a progress and an update of assumptions from the 2021 IRP, the results for the electrification scenarios are in the 2023 Gas Utility IRP; such studies are beyond the scope of this 2023 Electric Report. Combining this analysis with the 2023 Gas IRP also allowed us to better integrate the analysis between the electric and gas portfolios. We anticipate electrification analysis may influence future electric IRPs.

Puget Sound Energy must comply with the CCA; as a result, we expect price impacts for all our customers. We will work hard to mitigate those impacts through decarbonization efforts to manage our allowances.

In this progress report, we modeled CCA prices as a direct cost applied to economic dispatch on greenhouse gas emissions to reflect the opportunity cost of emission allowances introduced by the CCA. A full explanation of the methodology and assumptions we used to model the impacts of the CCA is available in Chapter Five.

Please visit the Washington State Department of Ecology's CCA rulemaking website to learn more about this state program.

4. Energy Efficiency Technology, Codes and Standards, and Electrification

Energy efficiency technology and changing codes and standards impact customer choices and energy efficiency programs. For example, when federal minimum lighting performance standards included screw-in LED lighting, PSE could no longer offer LEDs as energy efficiency program offerings. Although LEDs continue to achieve savings, we can no longer take credit for those savings in our incentive programs.

The two energy codes that impact our customers, the Washington State Energy Code (WSEC) and the Seattle Energy Code, are transitioning to focus on greenhouse gas emissions and energy efficiency. These changes emphasize the electrification of systems formerly fueled by natural gas. Since February 2021, the 2018 WSEC no longer gives builders efficiency credits for new single-family homes that install natural gas space or water heating; instead, it gives them credits for installing electric heat pumps for heat and hot water.

4.1. Impact and Actions

The codes and standards included in the 2023 Electric Report CPA and demand forecast include:

- 2018 WSEC
- Provision of RCW 19.27A.160

In 2021, the Seattle Energy Code[5] created significant barriers to using natural gas for space and water heating in new commercial and multi-family buildings. With few exceptions, new buildings will use various types of heat pump technology to meet the demands of these systems. The Seattle Energy Code will affect the gas utility that serves the city of Seattle, but the change in demand for electricity will impact Seattle City Light, the electric utility for the city of Seattle, and will not affect PSE's electric system.

Another provision included in the 2023 Electric Report CPA is a statutory requirement (RCW 19.27A.160) that directs the WSEC revision process to achieve a 70 percent reduction in energy consumption by 2031 compared to a 2006 code baseline.[6]

➔ See Appendix E: Conservation Potential and Demand Response Assessment for details on the CPA.

The Washington State Building Codes Council (WSBCC) has proposed mandating builders install electric heat pumps in new commercial buildings and multi-family homes instead of natural gas heating and cooling technologies. The WSBCC is also developing residential building codes, which would encourage using electric heat pumps in new residential buildings and penalize using natural gas heating appliances. These proposals are currently under consideration for adoption as part of the WSEC. Although not modeled in this analysis these changes would likely affect PSE by increasing the electric energy and peak demand more than forecasted. The amount of difference in the peak demand forecast will be affected by the technology installed in these new buildings.

Washington State issued the WSBCC proposed code updates after we conducted the 2023 Electric Report CPA so, it is not included in this report.

5. Inflation Reduction Act

The Inflation Reduction Act (IRA) was passed and signed into law in August 2022 and represented the single most significant federal investment in clean energy and climate-focused solutions in U.S. history — approximately $370

5 The cities of Bellingham and Shoreline also passed similar gas bans in their jurisdictions in 2022.
6 RCW 19.27A.160

billion. The IRA addresses climate change by providing tax incentives and consumer rebates to move project developers and households toward lower-carbon or zero-carbon technologies. The two main incentives applicable to renewable projects are the Production Tax Credits (PTCs) and Investment Tax Credits (ITCs), both scheduled to phase out before the IRA was enacted.

Production Tax Credits provide an energy tax credit ($/MWh) for the first 10 years of energy output after a utility places a project in service. Before the IRA was enacted, PTCs had expired for any new projects placed in service in 2022 and beyond. The IRA bill extends PTCs to 100 percent for eligible projects placed in service before the end of 2032[7]; solar projects have also been added back into the eligible technology definitions of the PTC for the first time since 2005. The IRA also gives taxpayers new authority to transfer their credits to parties with tax appetite, providing taxpayers an additional means to monetize earned credits.

Investment Tax Credits provide an energy tax credit based on the percentage of the investment in the project. Before the IRA was enacted, the old ITC rate for projects placed in service in 2022 had phased down to 10 percent. The IRA increased the ITC rate to 30 percent through 2032[8]. Taxpayers will also have new authority to transfer their credits to parties with tax appetite, giving taxpayers an additional monetization option for earned credits.

Previously, the ITC for battery storage projects was restricted to only battery storage projects paired with solar or other renewable energy generation assets in a hybrid configuration. The IRA now extends the ITC to cover all stand-alone energy storage applications. This change ensures the tax credits support a more flexible system because the battery can charge from the grid and its paired solar project.

The IRA provides more long-term certainty in investment decisions by providing 10 years of energy tax incentive eligibility and enhanced tools to accelerate or support credit monetization. Where previous tax rules for PTC (wind) and ITC (solar) were technology-specific, the new tech-neutral credit may allow the entity receiving the credit to choose the most efficient incentive type. The rules also provide bonuses for where and how projects are built. The rules give project developers incentives to utilize domestically sourced materials, drive economic opportunity by placing projects in service in low-income communities, and leverage an existing workforce in census tracts deemed energy communities where new clean energy developments may impact fossil-fuel extraction and generation activities.

5.1. Impact and Actions

We included the updated and extended PTC and ITC tax credits in the 2023 Electric Report analysis. We also extended the ITC to stand-alone energy storage — batteries, pumped hydro storage, and nuclear. The inclusion of the IRA in the analysis results in over $10 billion in projected savings to the customer.

Many other provisions in the IRA may impact electricity demand. For example, electric vehicle adoption rates may increase due to provisions of the IRA that provide buyer and charging facility owners tax incentives, incentives to help

[7] The existing PTC and ITC are extended at full value through 2024. After 2024, the existing PTCs and ITCs will expire. In their place, functionally similar clean energy production tax credits and clean energy investment tax credits take effect with broader flexibility to capture a greater number of eligible technology neutral energy sources. The new credits are similar value and definition to the prior credits if prevailing wage and apprenticeship requirements are met. Taxpayers are allowed to elect which credit they choose when placing an eligible project into service.

[8] See footnote 3.

consumers add rooftop solar and battery storage options, rebates intended to help low and moderate-income households achieve higher levels of energy efficiency and a host of other provisions. However, because the law was enacted late in our planning process, we could not add these policies to our demand forecast and could not consider all the nuances of the bill.

KEY ANALYTICAL ASSUMPTIONS

CHAPTER FIVE

PUGET SOUND ENERGY

Contents

PUGET SOUND ENERGY

1. Introduction

This chapter describes the forecasts, estimates, and assumptions Puget Sound Energy developed for the 2023 Electric Progress Report (2023 Electric Report). These assumptions span the horizon from 2024-2045 for the 2023 Electric Report. Additional details of the analyses are in Chapter Eight: Electric Analysis and in the related appendices.

This section on electric analysis includes the assumptions we used to create different economic conditions and operational considerations that affect portfolio costs and risks. Inputs included the electric demand forecast, price assumptions for natural gas and CO_2 costs, assumptions about cost and characteristics for existing and generic resources, and transmission considerations. We also included delivery system planning assumptions.

Next, we described electric portfolio sensitivities. Sensitivities start with the optimized, least-cost reference portfolio and change resource assumptions, environmental regulations, or other conditions to examine the effect of each change on the portfolio. We used these sensitivities to help build the preferred portfolio.

Last, we described our considerations for modeling electric supply-side resources as power purchase agreements or ownership agreements in the technology model section.

2. Electric Portfolio Analysis Assumptions

We analyzed a single reference case scenario for this 2023 Electric Report. A single scenario contrasts with a full Integrated Resource Plan (IRP), where multiple scenarios are typically analyzed to test how different economic conditions impact the portfolio optimization results. Instead of numerous scenarios, we used stochastic analysis for this 2023 Electric Report to measure the robustness of the preferred portfolio across a range of economic conditions.

The following section features the primary assumptions for the reference scenario.

2.1. Embed Equity with the Portfolio Benefit Analysis Tool

AURORA, the production cost model software we used for portfolio modeling in this report, is designed to find the lowest-cost portfolio given a set of constraints. Therefore, one of the best ways to influence the results of the AURORA portfolio model is to alter the cost of resources. For example, we incorporated the SCGHG in the AURORA portfolio model as an externality cost, which increases the cost of emitting resources, discouraging the model from including emitting resources in the final portfolio selection. Unfortunately, equity metrics do not have a specified dollar value, like the SCGHG, that we can incorporate into the portfolio model.

We needed another method to embed equity into the portfolio analysis and the 2023 Electric Report, so we created the portfolio benefit analysis tool. This new tool provides a measure of equity-related metrics outside the AURORA model that we can use to inform the portfolio development iteratively.

The portfolio benefit analysis tool is a spreadsheet-based model that relates the relative value added from improving Customer Benefit Indicators (CBIs) with the cost of a given portfolio. The portfolio benefit analysis tool builds on the approach we used in the 2021 IRP to incorporate equity. The tool allowed us to add interested party input to inform our process for the 2023 Electric Report. We anticipate we will continue improving how we incorporate CBIs in portfolio modeling. We describe the methodology we deployed in the portfolio benefit analysis tool in Appendix H: Electric Analysis and Portfolio Model, the portfolio benefit analysis tool Excel workbook that contains the data and the numerical analysis results in Appendix I: Electric Analysis Inputs and Results, and a discussion of the results in Chapter Eight: Electric Analysis.

2.2. Puget Sound Energy Customer Demand

The 2023 Electric Report demand forecast used in the analysis represents an estimate of energy sales, customer counts, and peak demand over 22 years.[1] Significant inputs include the following:

- Demographic changes
- Impacts of climate change
- Information about regional and national economic growth
- Known large load additions or deletions
- Prices
- Seasonality and other customer usage and behavior factors
- Weather

Figure 5.1 shows the electric peak demand and annual energy demand forecasts without the effects of conservation. The forecasts include sales (delivered load) plus system losses, which we represented in average energy demand over the year. The electric peak demand forecast is for a one-hour low temperature in winter at Sea-Tac airport, which we represented in total demand need at peak.

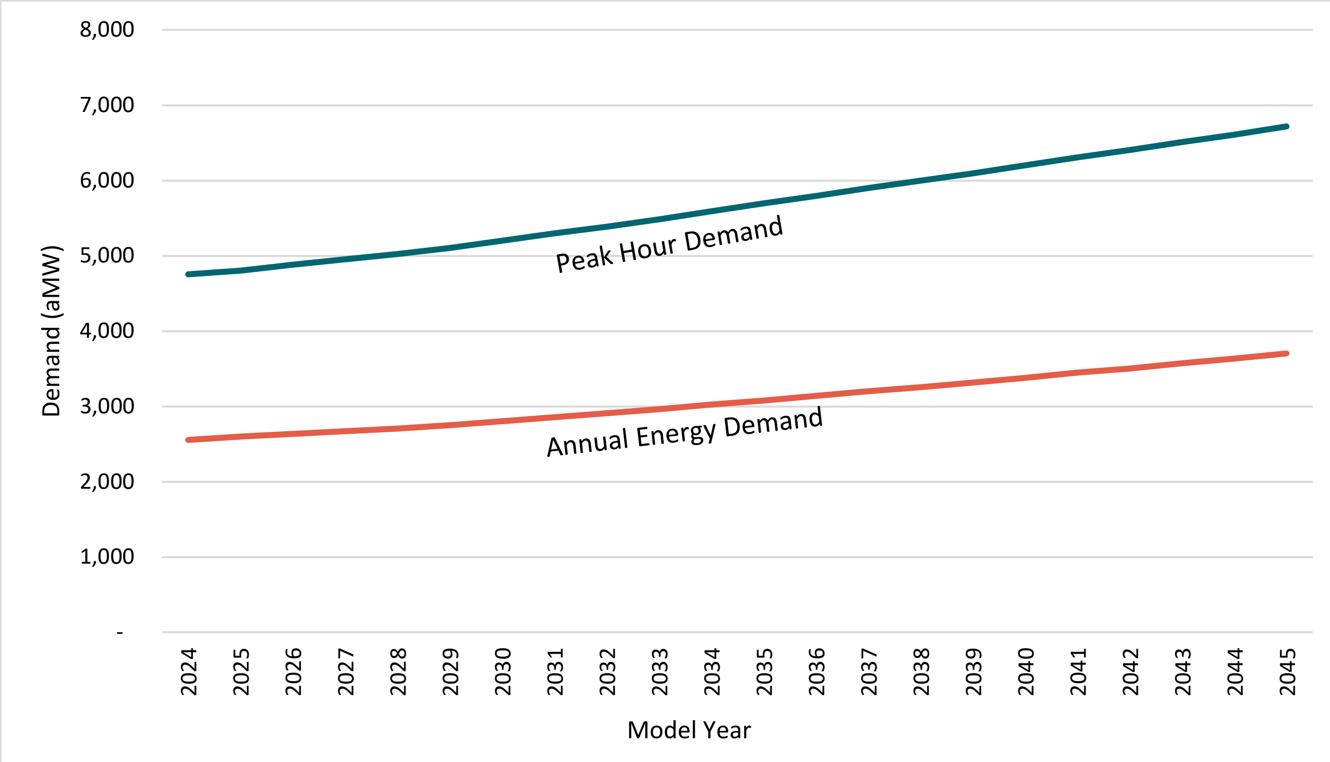
Why don't demand forecasts in rate cases and acquisition discussions match the IRP forecast?

The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs we develop. By the time the IRP is completed, we may have updated our demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but we will always present the most current forecast for rate cases or when making acquisition decisions.

➔ See Chapter Six: Demand Forecasts, for a detailed discussion of the demand forecasts and Appendix F: Demand Forecasting Models, for the analytical models used to develop them.

1 For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but, demand grows faster in some parts of the service territory than others.

Figure 5.1: 2023 Progress Report Electric Annual Energy and Peak Hour Demand Forecasts



2.3. Natural Gas Price Inputs

For natural gas price assumptions in this 2023 Electric Report, we used a combination of forward-market prices and fundamental forecasts acquired in spring 2022 from Wood Mackenzie.[2]

- Beyond 2030, we used the Wood Mackenzie long-run natural gas price forecasts published in May 2022.
- For 2029 and 2030, we used a combination of forward market prices from 2028 and selected Wood Mackenzie prices from 2031 to minimize abrupt shifts when transitioning from one dataset to another.
- From 2022–2028, we used the three-month average of forward-market prices from May 12, 2022. Forward market prices reflect the price of natural gas purchased at a given time for future delivery.
- In 2029, the monthly price is the sum of two-thirds of the forward market price for that month in 2028 plus one-third of the 2031 Wood Mackenzie price forecast for that month.
- In 2030, the monthly price is the sum of one-third of the forward market price for that month in 2028 plus two-thirds of the 2031 Wood Mackenzie price forecast for that month.

We used three natural gas price forecasts, mid, low, and high, to develop a range of gas prices for the stochastic analysis. However, we used only the mid natural gas prices in the reference scenario for this 2023 Electric Report.

[2] Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American, international factors, Canadian markets, and liquefied natural gas exports. Under our agreement with Wood Mackenzie seasonal and annual natural gas price trends are confidential and cannot be shared as part of this report.

2.3.1. Mid Natural Gas Prices

The mid natural gas price forecast uses the three-month average of forward market prices from May 12, 2022, and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in May 2022. We used the mid natural gas price forecast in the reference case for this 2023 Electric Report.

2.3.2. Low Natural Gas Prices

We developed the low natural gas price forecast using monthly adjustment factors applied to the mid natural gas price forecast. We obtained adjustment factors from the ratio of the low and mid natural gas price forecasts provided in the Northwest Power and Conservation Council's 2021 Power Plan. We used the low natural gas price forecast to develop the stochastic inputs for this 2023 Electric Report.

2.3.3. High Natural Gas Prices

We developed the high natural gas price forecast using monthly adjustment factors applied to the mid natural gas price forecast. We obtained adjustment factors from the ratio of the high and mid natural gas price forecasts provided in the Northwest Power and Conservation Council's 2021 Power Plan. We used the high natural gas price forecast to develop the stochastic inputs for this 2023 Electric Report.

Figure 5.2 illustrates the range of 22-year levelized natural gas prices used in this analysis compared to the 22-year levelized natural gas prices PSE used in the 2021 IRP.

Figure 5.2: Levelized Natural Gas Prices Used in Scenarios, 2023 Progress Report vs. 2021 IRP (Sumas Hub, 22-year Levelized, Nominal $)

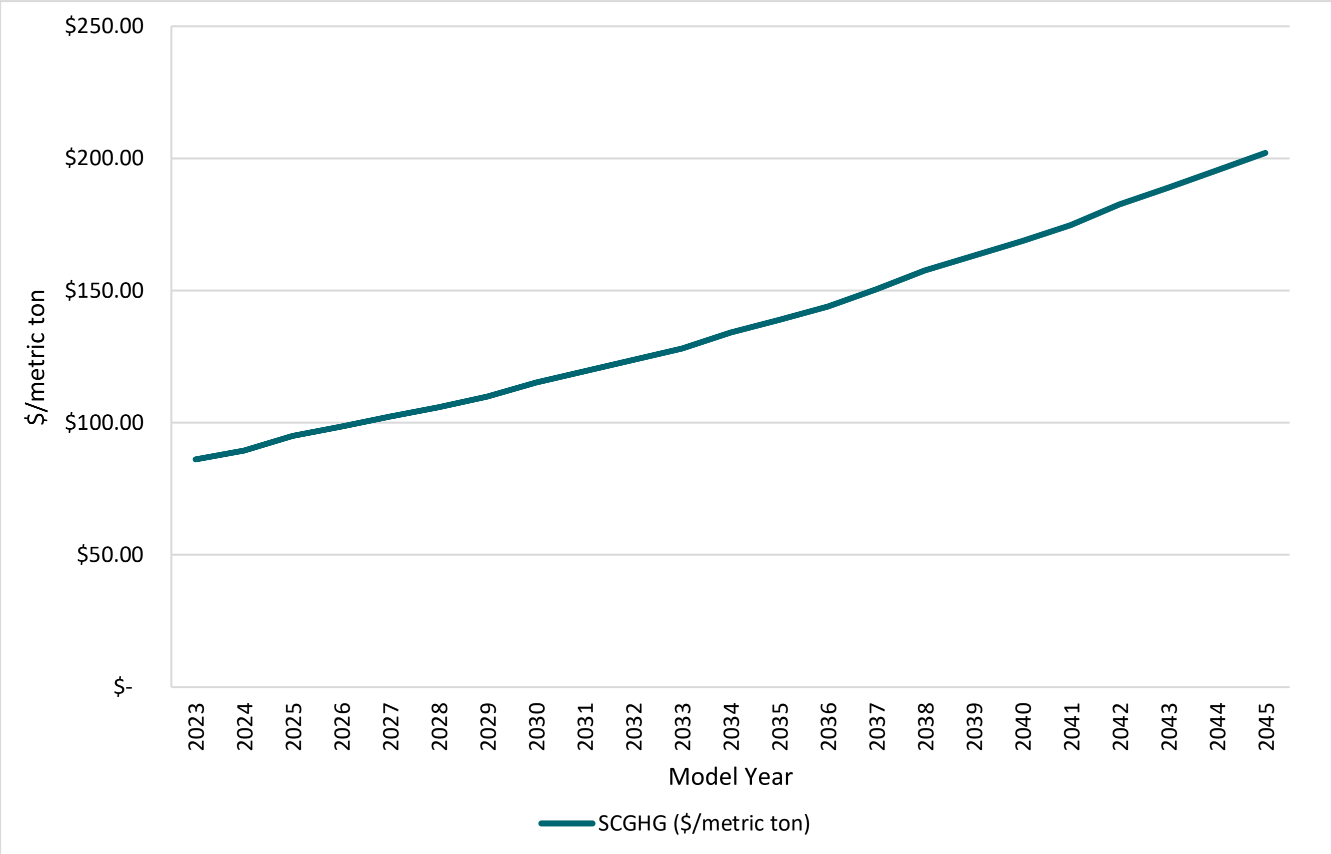
2.4. Carbon Dioxide Price Inputs

We modeled the Social Cost of Greenhouse Gases (SCGHG) and an allowance price for the Climate Commitment Act (CCA) in the 2023 Electric Report. In the following sections, we provide each price's forecasts and applications.

2.4.1. Social Cost of Greenhouse Gases

The SCGHG cited in the Clean Energy Transformation Act (CETA) comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the CO_2 prices in real dollars and metric tons. We adjusted the prices for inflation (nominal dollars) resulting in a cost range from $86 per ton in 2023 to $202 per ton in 2045, as shown in Figure 5.3.

Figure 5.3: Social Cost of Greenhouse Gases in the 2023 Progress Report



We applied the SCGHG as a planning adder on emitting resources, so the SCGHG is applied when we optimize build decisions for new resources and retirement decisions for existing emitting resources. The reference case models the SCGHG as a fixed cost adder, which does not impact the dispatch schedule of emitting resources. However, we include a sensitivity that models the SCGHG as dispatch cost.

➔ See Appendix H: Electric Analysis and Portfolio Model for the complete discussion of how we modeled the SCGHG.

2.4.2. Upstream Carbon Dioxide Emissions for Natural Gas

The upstream emission rate represents the carbon dioxide, methane, and nitrous oxide releases associated with natural gas extraction, processing, and transport along the supply chain. We converted these gases to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[3]

[3] The Environmental Protection Agency and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in Table A-1 at 40 CFR 98 and WAC 173-441-040.

For the cost of upstream CO_2 emissions, we used emission rates published by the Puget Sound Clean Air Agency[4] (PSCAA). The PSCAA used two models to determine these rates, GHGenius[5] and GREET.[6] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin. Table 5.1 provides the results of the GHGenius and GREET models.

Table 5.1: Upstream Natural Gas Emissions Rates

Model	Upstream Segment	End-Use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMBtu	= 65,203 g/MMBtu	19.9
GREET	12,121 g/MMBtu	+ 54,400 g/MMBtu	= 66,521 g/MMBtu	22.3

Note: End-use Combustion Emission Factor: EPA Subpart NN.

The upstream segment of 10,803 g/MMBtu is converted to 23 lb/MMBtu and then applied to the emission rate of natural gas plants for the SCGHG emissions. We did not apply the upstream emission rate to the CCA allowance price.

2.4.3. Climate Commitment Act Allowance Price

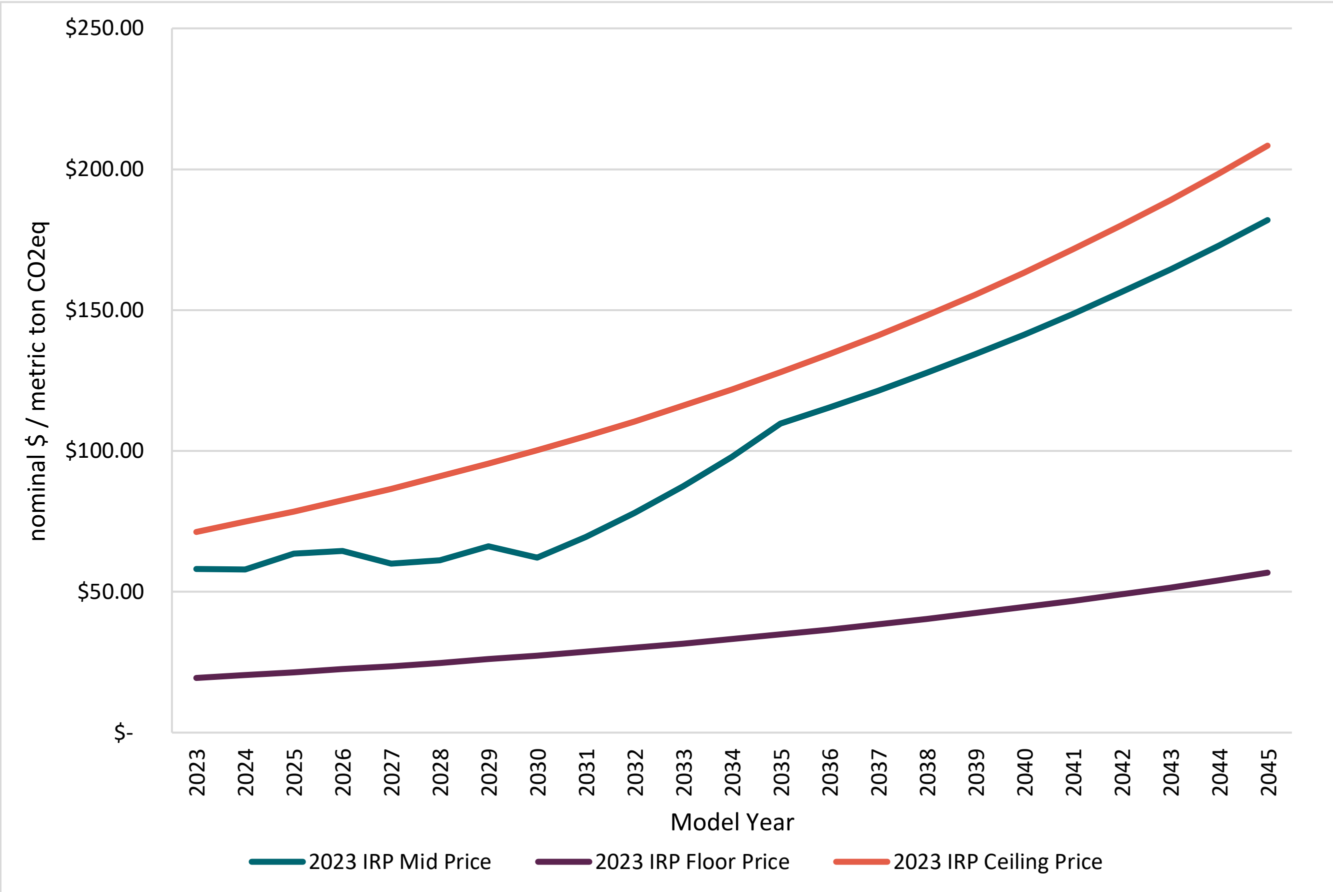
The Washington State legislature passed the CCA in 2021; it goes into effect in 2023. The CCA is a cap-and-invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances representing permitted emissions. The resulting market establishes an opportunity cost for emitting greenhouse gases. We added an emission price to greenhouse gas emissions in the electric price forecast model for emitting resources within Washington State to model this opportunity cost. In the price forecast model, we only added the emission price to Washington State emitting resources to ensure the model reflects any change in dispatch without impacting that of resources outside Washington State not subject to the rule. To accurately reflect all costs imposed by the CCA, we added a hurdle rate on transmission market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO_2eq per MWh (RCW 19.405.070).[7]

Figure 5.4 shows the emission prices we used to model the CCA allowance price, an ensemble of two price forecasts from the Washington Department of Ecology (Ecology) and the California Energy Commission (CEC). Ecology issued an analysis of the CCA, which included estimated allowance price forecasts across a range of program and market assumptions.[8] We suggest a linkage to the California carbon market is a likely scenario; therefore, we adopted an ensemble pricing scheme that begins with pricing at the rate specified by the Ecology CA Linkage 2030 case, then

4 Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019.
5 GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca.
6 GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.
7 RCW 19.405.070
8 Preliminary Regulatory Analyses for Chapter 173-446 WAC, Climate Commitment Act Program

transitions to the CEC 2021 Integrated Energy Policy Report[9] allowance price forecast for the remainder of the modeling horizon.

Figure 5.4: Climate Commitment Act Allowance Pricing in the 2023 Progress Report



2.5. Climate Change

This 2023 Electric Progress Report is the first time Puget Sound Energy has included the influence of climate change on demand and hydroelectric conditions in the Pacific Northwest (PNW) in an electric progress report. We adapted inputs incorporating climate change from the NPCC's 2021 Power Plan analysis. As the basis for their analysis, the NPCC evaluated 19 climate change scenarios developed by the River Management Joint Operating Committee (RMJOC)[10], Part II, and selected three scenarios representing a range of possible climate outcomes. Puget Sound Energy adopted these same three climate change scenarios:

- CanESM2_RCP85_BCD_VIC_P1, coded as A.
- CCSM4_RCP85_BCD_VIP_P, coded as C.
- CNRM-CM5_RCP85_MACA_VIC_P3, coded as G.

[9] 2021 Integrated Energy Policy Report (ca.gov)
[10] https://usace.contentdm.oclc.org/digital/collection/p266001coll1/id/9936

The three climate change scenarios we adopted uniquely impact the PNW load and hydroelectric input assumptions. Incorporating these disparate impacts into a single deterministic forecast presented significant modeling challenges. Therefore, the 2023 Electric Progress Report analysis averaged the effects of each climate change scenario to develop a single climate change case, which retains trends in all three climate change scenarios.

➔ For more information on assumptions for incorporating climate change, see Chapter Six: Demand Forecast.

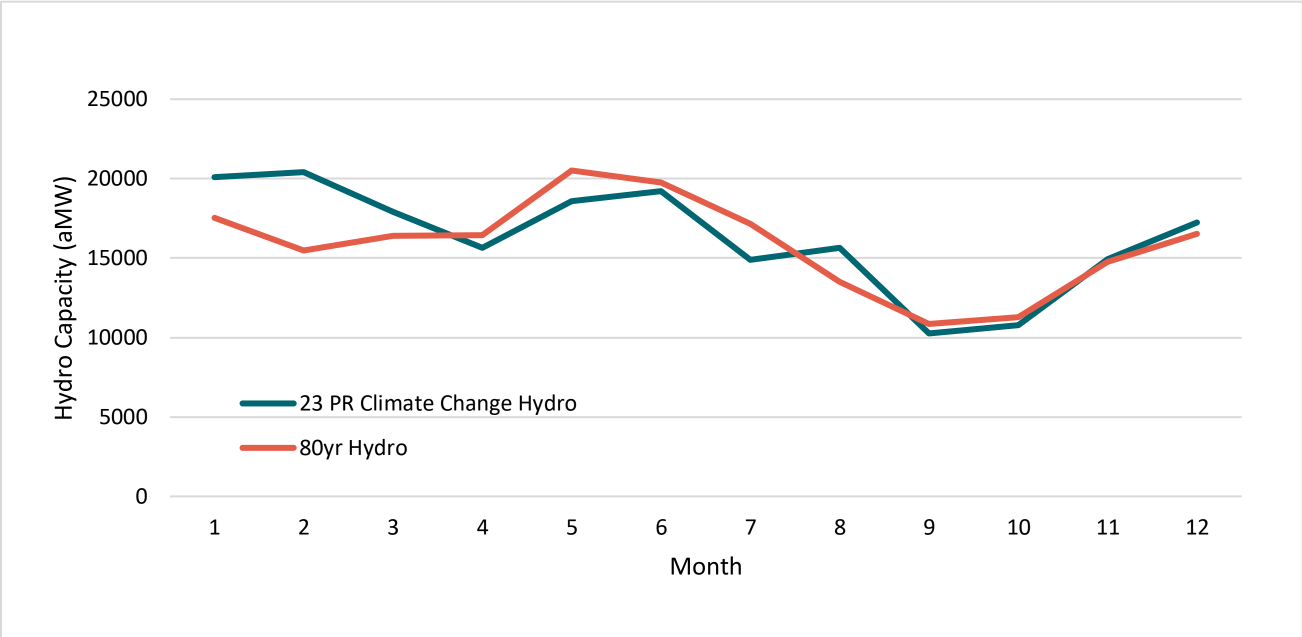
2.5.1. Hydroelectric Assumptions

We adapted the climate change hydroelectric forecast from the regional demand forecast created by the NPCC for the 2021 Power Plan. The hydroelectric forecast represents an average of all three climate change scenarios and an average of the hydroelectric conditions for the 30-year timespan of the climate change scenarios. We calculated hydroelectric capacity based on expected hydroelectric output from the GENESYS[11] regional resource adequacy model using streamflow data representative of the climate change scenarios.

We held the average hydroelectric forecast fixed for all the modeled years. Figure 5.5 presents the climate change hydroelectric forecast compared to the 80-year historic hydroelectric average forecast we used in the 2021 IRP. The forecasts are similar, but the climate change forecast trends toward more hydroelectric generation in the winter and less generation for the remainder of the year. This plot represents the PNW average hydroelectric capacity; trends for individual hydroelectric facilities will vary.

[11] https://www.nwcouncil.org/2021powerplan_genesys-model/

Figure 5.5: Pacific Northwest Climate Change Hydroelectric Forecast, Average of All Hydroelectric Facilities



2.6. Electric Price Inputs

We must create a wholesale electric price forecast as an input to the portfolio model to represent the wholesale power market. In this context, electric price does not mean the rate charged to customers; it means the price to PSE of purchasing (or selling) one megawatt (MW) of power on the wholesale market, given the prevailing economic conditions. This wholesale electric price forecast is an essential input since market purchases make up a substantial portion of PSE's existing electric resource portfolio.

Creating a wholesale electric price forecast requires performing WECC-wide AURORA model runs. The AURORA database starts with inputs and assumptions from the Energy Exemplar 2020 WECC Zonal database v1.0.1. We then include updates such as regional demand, natural gas prices, CO_2 prices, clean energy policies, and resource retirements and builds.

Figure 5.6 presents the annual average electric price forecast used in the 2023 Progress Report.

➔ See Appendix G: Electric Price Models for a detailed description of the methodology used to develop wholesale electric prices

Figure 5.6: Mid-C Wholesale Electric Price Annual Average Price Forecast Over Time (Nominal $/MWh)

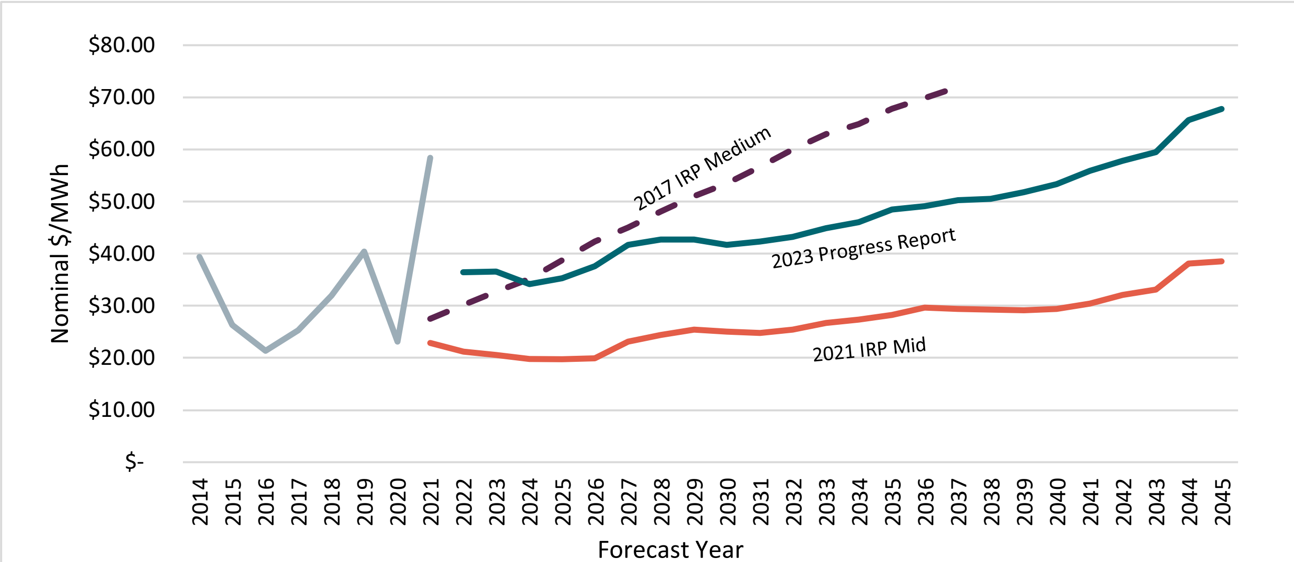
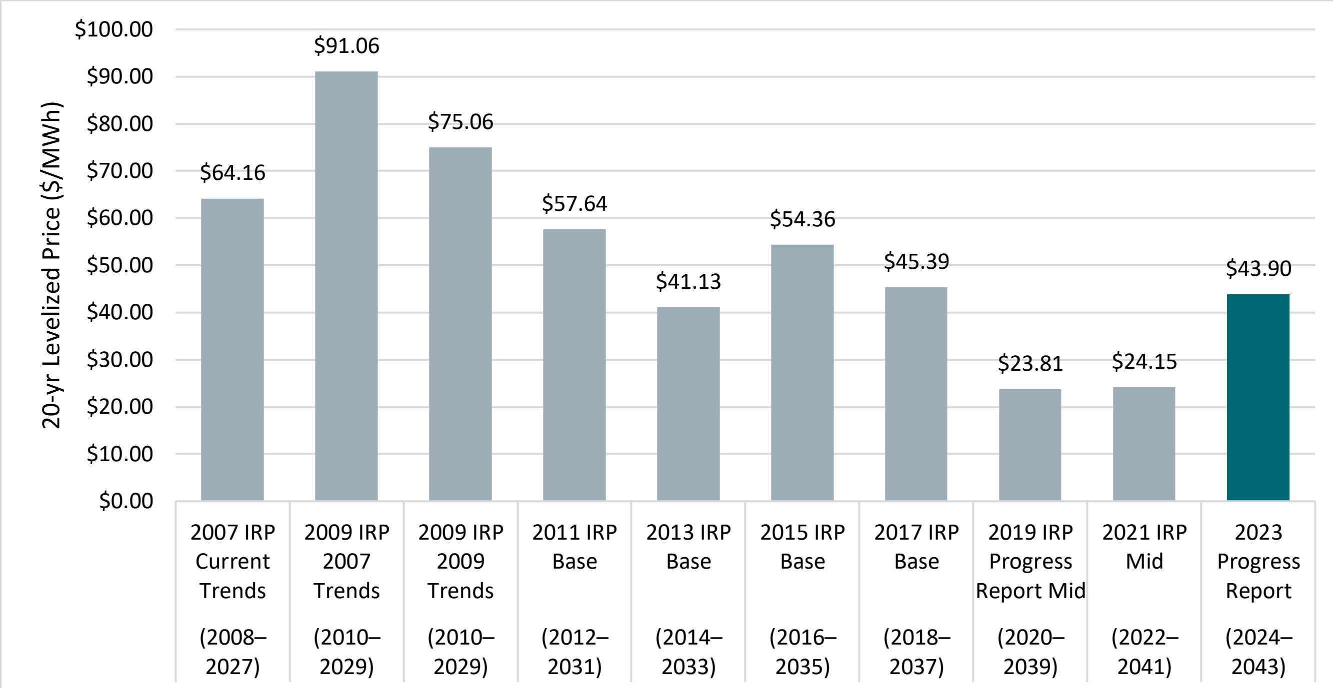


Figure 5.7 compares the 2023 electric price forecast to past IRP electric price forecasts. In previous IRPs, the downward revisions in forecast power prices corresponded to those in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by new clean energy regulations drives much of the downward revision in forecasted power prices. The 2017 IRP base scenario included CO_2 as a tax, whereas the 2021 IRP includes the social cost of greenhouse gases as an adder to resource decisions. The increase in electric prices in the 2023 Electric Progress Report is from several significant model updates, including increased natural gas prices, increased storage resources, revised methodology on clean energy policy modeling, and the addition of carbon allowance pricing from the CCA.

➔ Please find more details on the impacts of these updates in Appendix G: Electric Price Models.

Figure 5.7: Comparison of 2023 20-year Levelized Electric Prices Compared to Past IRPs ($/MWh)



2.7. Electric Resource Assumptions

We modeled the following generic resources as potential portfolio additions in this IRP analysis.

➔ See Appendix D: Generic Resource Alternatives, for detailed descriptions of the supply-side resources listed here and Appendix E: Conservation Potential Assessment and Demand Response Assessment, for detailed information on demand-side resource potentials.

2.7.1. Demand-side Resources

Demand-side resources contribute to meeting energy-need by reducing demand. An integrated resource plan includes both supply- and demand-side resources. We accounted for the contribution that demand-side programs make to meeting resource needs as a reduction in demand for the IRP analysis. Demand-side resources include energy efficiency measures (also referred to as conservation), generation efficiency measures, and distribution efficiency measures.

Energy Efficiency Measures

Energy efficiency measures reduce the level of energy used to accomplish a given amount of work. We group the wide variety of energy efficiency measures available into three categories: retrofit programs that have shorter lives; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. Codes and standards impact the demand forecast but have no direct cost to utilities. Energy efficiency also includes small-scale electric distributed generation, such as combined heat and power.

Generation Efficiency

Generation efficiency comes from improvements at PSE generating plants.

Distribution Efficiency

Distribution efficiency comes from voltage reduction and phase balancing. Voltage reduction is reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing can reduce energy loss by eliminating total current flow losses.

2.7.2. Distributed Energy Resources

Distributed Energy Resources (DER) are small, modular energy generation and storage technologies installed on the distribution systems rather than the transmission system. Distributed Energy Resources are typically under 10 MW and provide a range of services to the power grid. These resources include wind, solar, storage, and demand response technologies and may be networked to form Virtual Power Plants (VPPs). We included demand response, distributed solar, and distributed storage programs as generic DERs in this 2023 Electric Report.

Demand Response

Demand response resources are like energy efficiency in that they reduce customer peak load, but unlike energy efficiency, they are also dispatchable. These programs involve customers curtailing load when needed. The terms and conditions of demand response programs vary widely.

Distributed Solar Generation

Distributed solar generation refers to small-scale rooftop or ground-mounted solar panels close to the customer's load source. We modeled distributed solar as a residential-scale resource in western Washington. We summarize the capacity factors for solar resources modeled in Table 5.2. Consulting firm DNV provided the solar production profile data used in the AURORA model.

Table 5.2: Distributed Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
DER Ground Solar	Residential-scale, fixed-tilt, ground mounted	17
DER Rooftop Solar	Residential-scale, fixed-tilt, rooftop mounted	17

Distributed Battery Energy Storage

Distributed battery energy storage systems refer to small-scale lithium-ion battery installations close to the customer's load. We modeled distributed storage as a residential-scale, three-hour duration battery with a nameplate capacity of 5 MW.

Non-wires Alternatives

We consider non-wires alternatives when developing solutions to specific, long-term needs identified in the transmission and distribution systems. The resources we study benefit from the capacity to address system deficiencies while supporting resource needs. We can deploy them across the transmission and distribution systems, providing flexibility in addressing system deficiencies. The non-wires alternatives we considered during the planning process include energy storage systems and solar generation.

2.7.3. Supply-side Resources

Supply-side resources provide electricity to meet the load. These resources originate on the utility side of the meter and include wind, solar, pumped hydroelectric energy storage, battery energy storage, hybrid resources (combination of wind, solar, and battery), combustion turbines, and advanced nuclear small modular reactors (SMR). The following section describes the supply-side resources applied to this 2023 Electric Report.

Wind

We modeled wind in seven locations throughout the northwest United States, including eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming, and offshore Washington. A summary of capacity factors for each wind resource is in Table 5.3. Consulting firm DNV provided the wind production profile data used in the AURORA model.

Table 5.3: Wind Capacity Factors

Wind Resource	Capacity Factor (annual average, %)
British Columbia	40.9
Eastern Washington	37.2
Central Montana	41.3
Eastern Montana	47.7
Idaho	15.0
Eastern Wyoming	46.4
Western Wyoming	36.1
Offshore Washington	42.1

Solar

We modeled solar as a centralized, utility-scale resource at several locations throughout the northwest United States and as a distributed, residential-scale resource in western Washington. A summary of the capacity factors for utility scale solar resources modeled is in Table 5.4. Consulting firm DNV provided the solar production profile data used in the AURORA model.

Table 5.4: Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Idaho	Utility-scale, single-axis tracker	27.3
Eastern Washington	Utility-scale, single-axis tracker	25.0

Solar Resource	Configuration	Capacity Factor (annual average, %)
Western Washington	Utility-scale, single-axis tracker	20.2
Eastern Wyoming	Utility-scale, single-axis tracker	28.9
Western Wyoming	Utility-scale, single-axis tracker	30.0

Energy Storage

Energy storage encompasses a range of technologies capable of converting kinetic energy into stored potential energy for later use. Energy storage removes the need for electricity generation to match the energy demand instantaneously. As such, energy storage can help to mitigate some of the challenges associated with variable energy resources such as wind and solar. A wide variety of energy storage technologies exist and span a range of development conditions from theoretical to commercially available. We discuss the current status of several storage technologies in Appendix D: Generic Resource Alternatives. We modeled a subset of commercially mature and well-characterized storage technologies for this 2023 Electric Report, including two-hour, four-hour, and six-hour lithium-ion batteries and eight-hour pumped hydroelectric storage. Generic Resource Alternatives. We modeled a subset of commercially mature and well-characterized storage technologies for this 2023 Electric Report, including two-hour, four-hour, and six-hour lithium-ion batteries and eight-hour pumped hydroelectric storage.

Baseload and Peakers

Baseload generators are designed to operate economically and efficiently over long periods of time, defined as more than 60 percent of the hours in a year.

Peaker is a term used to describe generators that can ramp up and down quickly to meet spikes in need. Unlike baseload resources, they are not intended to operate economically for long periods of time.

Hybrid Resources

In addition to stand-alone generation and energy storage resources, we modeled hybrid resources, which combine two or more resources at the same location to take advantage of synergies between the resources. We modeled three types of hybrid resources: eastern Washington solar + four-hour lithium-ion battery, eastern Washington wind + four-hour lithium-ion battery, and eastern Washington wind + solar + four-hour lithium-ion battery.

Baseload Thermal Plants

Baseload thermal plants or combined-cycle combustion turbines (CCCT) are F-type, 1 x 1 engines with wet cooling towers. We assumed they would generate 348 MW plus 19 MW of duct firing and be in PSE's service territory. We designed and intended these resources to operate at base load, defined as running more than 60 percent of the hours in a year.

Frame Peakers

Frame peakers or simple-cycle combustion turbines (SCCT) are F-type, wet-cooled turbines. We assumed they would generate 237 MW and be in PSE's service territory. We modeled these resources with either natural gas or an alternative fuel as the fuel source.

Recip Peakers

Recip peakers, or reciprocating engines, are small 18.2 MW engines with wet cooling located in PSE's service territory. We modeled these resources with either natural gas or an alternative fuel as the fuel source.

Alternative Fuels

In addition to natural gas, this 2023 Electric Report includes low-carbon alternative fuels, including hydrogen and biodiesel. Given current incentives in the Inflation Reduction Act,[12] green hydrogen fuel may become cost-effective compared to natural gas after accounting for the social cost of greenhouse gases and the impacts of the CCA. Biodiesel may also provide a viable, low-carbon alternative fuel for capacity resources during peak critical hours.

➔ We provide a description and the modeling assumptions used for these alternative fuels in Appendix I: Electric Analysis Inputs and Results.

Advanced Nuclear Small Modular Reactor

We modeled advanced nuclear (SMR) for the first time in the 2023 Electric Report. An SMR is a cluster of relatively small nuclear reactors at the same site that share land and infrastructure, although each reactor may be operated independently. The reactor technology is similar to that used in nuclear-powered submarines. While the exact specifications for SMR systems can vary, we chose to model this resource with a configuration of up to a 50MW module for this 2023 Electric Progress Report.

➔ We provide a complete description of SMR technology in Appendix D: Generic Resource Alternatives.

2.8. Electric Resource Cost Assumptions

We sourced generic resource capital cost assumptions from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB)[13] for most resources in the 2023 Electric Report, consistent with our Clean Energy Implementation Plan (CEIP). This method is different from the approach we took in the 2021 IRP, which used different generic resource cost assumptions. The NREL did not include reciprocating peaker technology in the 2022 ATB; therefore, we sourced capital cost data for this generic resource from the U.S Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2022 (2022 AEO).

Interconnection costs are not included as part of the capital cost for generic resources in the 2022 ATB or 2022 AEO and can account for a significant portion of the capital cost of some resource types. We added interconnection cost

[12] https://www.congress.gov/bill/117th-congress/house-bill/5376/text
[13] https://atb.nrel.gov/electricity/2022/technologies

estimates to each resource type based on the spur line length needed to interconnect each generic resource to the transmission grid to account for this omission.

We expect generic resource capital costs to decline as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the 2022 ATB. The 2022 ATB provides three cost curves for each resource: low, mid, and constant technology cost scenarios. We selected the mid-technology cost scenario for the IRP cost curves, representing the most likely future cost projection.

We sourced generic resource O&M costs from the 2022 ATB for all generic resource technologies except thermal technologies. We sourced generic CCCT and frame peaker fixed O&M from averaging our existing costs, as reported in the 2021 FERC Form 1s. We adopted the fixed O&M that were reported for the Port Westward 2 facility as the generic reciprocating peaker fixed O&M.[14] We adopted variable O&M from the CAISO Variable Operations and Maintenance Cost Review, Final Proposal.[15]

The 2022 ATB did not provide O&M costs for most hybrid configurations presented in the 2023 Electric Report. We combined the fixed O&M for each component within the hybrid system to calculate these costs and used the respective capacities to generate a weighted average. The 2022 ATB provided a fixed O&M cost associated with a solar plus four-hour li-ion battery storage hybrid system, which is higher than the weighted average. Though the literature indicated this O&M was based on stand-alone solar and battery fixed O&M, NREL did not present the precise method of combining these costs in the 2022 ATB. To maintain consistency with other hybrid systems in the 2023 Electric Report, we used a weighted average for the solar plus battery storage hybrid resource. We show all hybrid resource fixed O&M as a time series.

➔ See Appendix D: Generic Resource Alternatives, for a more detailed description of resource cost assumptions, including transmission and natural gas transport assumptions.

Table 5.5 summarizes generic resource cost assumptions.

Table 5.5: New Resource Generic Cost Assumptions

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First Year Available	Fixed O&M ($/kW-yr)	Variable O&M[1] ($/MWh)	CAPEX ($/kW)[2]	Intercon-nection[2,3]	Total[2]
CCCT	348	2024	22.67	6.16	963	22	987
Frame Peaker	237	2024	9.52	1.02	879[4]	26	944
Recip Peaker	219	2024	14.53	1.16	2019	26	2045
WA Utility Solar East & West	100	2024	19.35	0.00	1074	156	1230
Idaho Utility Solar	400	2026	19.35	0.00	1074	463	1537

14 https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/home
15 https://stakeholdercenter.caiso.com/StakeholderInitiatives/Variable-operations-maintenance-cost-review

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First Year Available	Fixed O&M ($/kW-yr)	Variable O&M[1] ($/MWh)	CAPEX ($/kW)[2]	Intercon-nection[2,3]	Total[2]
WY Utility Solar East & West	400	2026	19.35	0.00	1074	463	1537
DER Solar — Rooftop and Ground-mounted WA West	5	2024	25.48	0.00	2,287	0	2,287
Offshore Wind	100	2030	70.78	0.00	4,137	590	4,728
BC Wind	100	2024	41.79	0.00	1,308	422	1,730
WA Wind	100	2024	41.79	0.00	1,308	156	1,464
MT Wind	100	2024	41.79	0.00	1,308	1,164	2,472
ID Wind	400	2026	41.79	0.00	1,308	463	1,772
WY Wind	400	2026	41.79	0.00	1,308	463	1,772
Pumped Storage — WA, OR, Closed Loop, 8-hour	100	2029	17.82	0.51	3,404	506	3,910
Pumped Storage — MT Closed Loop 8-hour	100	2029	17.82	0.51	3,404	198	3,602
Battery 2-hour Li-Ion	100	2024	20.12	0.00	746	58	804
Battery 4-hour Li-Ion	100	2024	32.76	0.00	1,256	58	1,314
Battery 6-hour Li-Ion	100	2024	45.49	0.00	1,765	58	1,823
DER Batteries 3-hour	5	2024	98.06	0.00	3,923	0	3,923
Wind + Battery	150	2024	38.35	0.00	1,093	217	1,310
Solar + Battery WA	150	2024	23.39	0.00	976	170[5]	1,147
Wind + Solar + Battery WA	250	2024	30.69	0.00	932	257[5]	1,190
Biomass	15	2024	151.00	5.80	4,332	573[5]	4,906
Advanced Nuclear SMR	50	2028	114.00	2.84	10,918	13	10,930

Notes:

1. Variable O&M costs do not include the cost of fuel for thermal resources.
2. Capital Costs, Vintage 2023. CAPEX (capital expenditures) required to achieve commercial operations of a generation plant. CAPEX may vary by resource type.
3. Interconnection costs consist of the transmission, substation, and natural gas pipeline infrastructure. The interconnection cost of offshore wind only includes onshore interconnection, and we included marine cable costs in the capital cost of the resource.
4. Frame peaker CAPEX includes costs for on-site biodiesel storage
5. Wind + Battery and Solar + Battery resources received a 40 percent interconnection cost-benefit, and the Wind + Solar + Battery resource received a 55 percent interconnection cost-benefit.

➔ See Appendix D: Generic Resource Alternatives for cost curve charts broken out by renewable, energy storage, and thermal resource type. See Appendix D: Generic Resource Alternatives for cost curve charts broken out by renewable, energy storage, and thermal resource type.

2.9. Flexibility Considerations

The 2023 Electric Report flexibility study reflects the financial impacts of the sub-hourly flexibility analysis in the portfolio analysis. Different resources have different sub-hourly operational capabilities. Even if the portfolio has adequate flexibility, various resources can impact costs and how the portfolio operates. For example, batteries could avoid the dispatch of thermal plants form ramping up and down.

For the sub-hourly flexibility analysis, we used a model called PLEXOS. First, we created a current portfolio case based on PSE's existing resources. We started the current portfolio case by making a simulation that reflects a complete picture of PSE as a Balancing Authority (BA) and our connection to the market. We represented PSE's Balancing Authority Area (BAA) load and generation on a day-ahead and real-time, 15-minute basis. We also included opportunities to make purchases and sales at the Mid-C trading hub in hourly increments and the Energy Imbalance Market (EIM) in 15-minute increments. For this analysis, we simulated 2029 for both hour-ahead and real-time and then took the difference in total portfolio cost between the two simulations.

We tested the impact of a range of potential new resources, each individually added to the current portfolio. If the dispatch cost of the portfolio with the new addition is lower than the existing portfolio case cost, we identified the cost reduction as a benefit of adding the new resource.

Table 5.6 shows the cost savings associated with each resource. For example, a CCCT has a cost savings of $5.17/kW-year. We applied these cost savings back to the fixed O&M of the generic resource as a reduction to the cost.

Table 5.6: Sub-hourly System Flexibility Cost Savings

Resource	Flexibility Cost Savings ($/kW-yr)
CCCT	5.17
Frame Peaker	9.65
Recip Peaker	28.14
Lithium-ion battery 2-hour	7.43
Lithium-ion battery 4-hour	47.21
Lithium-ion battery 6-hour	8.58
Pumped Storage Hydroelectric 8-hour	2.82
Demand Response	19.39

➔ See Appendix H: Electric Analysis and Portfolio Model, for a detailed description of the methodology used to develop the flexibility benefit.

2.10. Regional Transmission Constraints

Transmission constraints are a set of limits imposed on the IRP portfolio model, which seeks to model real-world transmission limitations within the WECC. These constraints include capacity limitations, transmission losses, and transmission costs.

2.10.1. Transmission Capacity Constraints

Transmission capacity constraints have become a vital modeling consideration as we transition away from thermal resources and toward clean, renewable resources to meet the goals of CETA. In contrast to thermal resources such as CCCTs and frame peakers, which we can generally site in locations convenient to transmission, produce power at a controllable rate, and dispatch as needed to meet shifting demand, renewable resources are site-specific and produce power intermittently. The limiting factors of renewable resources have two significant impacts on the power system: 1) we must acquire a greater quantity of renewable resources to meet the same peak demand as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near our service territory. A wind farm in one location will produce a different amount of power than the same wind farm in another place. This situation makes it essential to consider whether there is enough transmission capacity to carry power from remote renewable resources to our service territory.

2.10.2. Assumptions

To model transmission capacity constraints, we created eight resource group regions and set limits on the generation capacity built in each region. We based resource group regions on the geographic relationships of the generic resources modeled in the 2023 Electric Report. Table 5.7 summarizes the resource group regions and the generic resources available in each group.

Table 5.7: Resource Group Regions and Generic Resources Available in Each Region

Generic Resource	PSE Territory[1]	Eastern Washington	Central Washington	Western Washington	Southern Washington / Gorge	British Columbia	Montana	Idaho & Wyoming
CCCT	X							
Frame Peaker	X							
Recip Peaker	X							
WA Solar East — Utility Scale		X	X		X			
WA Solar West — Utility Scale	X							
Idaho Solar — Utility Scale								X
WY Solar East — Utility Scale								X
WY Solar West — Utility Scale								X
DER WA Solar — Rooftop	X							
DER WA Solar — Ground	X							
WA Wind		X	X		X			
BC Wind						X		
MT Wind East							X	
MT Wind Central							X	
ID Wind								X
WY Wind East								X
WY Wind West								X
Offshore Wind				X				
Pumped Storage		X	X		X			
Battery 2-hour Li-Ion	X							
Battery 4-hour Li-Ion	X							
Battery 6-hour Li-Ion	X							
Solar + battery		X			X			
Wind + battery		X			X			
Solar + wind + battery		X			X			
Wind + pumped storage							X	
Biomass	X			X				
Advanced Nuclear SMR		X						

Note:

1. Not including the PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed

We based capacity limits on our experience with available transmission capability (ATC) on the Bonneville Power Administration's (BPA) system, the results of BPA transmission service requests (TSRs), recent BPA TSR Study and Expansion Process (TSEP) Cluster Studies (2020, 2021, & 2022), regional transmission studies by Northern Grid, and dialogue with regional power sector organizations. Transmission planning, building, and acquisition are complex processes with various possible outcomes; therefore, we developed a range of plausible transmission limits and timelines for each region. To structure these ranges, we organized the transmission limits into tiers; uncertainty increases from tier to tier based on our ability to acquire that quantity of transmission.

The tiers include:

- **Tier 1:** Transmission capacity that we could likely acquire in 2023–2025. This transmission capacity draws primarily from repurposing our existing BPA transmission portfolio.
- **Tier 2:** Transmission capacity that we could acquire in 2025–2030 but is less certain than Tier 1. This transmission capacity adds new transmission resources to our portfolio. Tier 2 includes all Tier 1 transmission.
- **Tier 3:** Transmission capacity that we could acquire beyond 2030. Acquisition of Tier 3 transmission is less certain than Tiers 1 and 2. Capacity added in Tier 3 would likely come from adding long lead-time, major transmission system upgrades, or new transmission resources to PSE's portfolio. Tier 3 includes all Tier 1 and 2 transmission.
- **Tier 4:** Tier 4 represents a generally unconstrained transmission system.

In this report's reference case, we modeled transmission limits by tier with increasing transmission limits over time. By 2040, transmission will be unconstrained. In the context of this report, unconstrained transmission signifies there is enough time to acquire or build new transmission resources to match the resource mix provided by the model.

Table 5.8 summarizes the transmission limits by tier for each resource group region.

Table 5.8: Transmission Capacity Limitations by Resource Group Region (Added Transmission MW by Tier)

Resource Group Region	Tier 1 (by 2025)	Tier 2 (by 2030)	Tier 3 (by 2035)	Tier 4 (by 2040)
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	640	2,310	2,510	Unconstrained
Central Washington	250	600	850	Unconstrained
Western Washington	0	100	635	Unconstrained
Southern Washington/Gorge	340	2,010	2,390	Unconstrained
British Columbia	200(c)	200(c)	200(c)	Unconstrained
Montana	0	400(c)	400(c)	Unconstrained
Idaho and Wyoming	0	400	600	Unconstrained
TOTAL	1,430	6,020	7,585	Unconstrained

Notes:

a. Not including the PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed.
b. Not constrained in the resource model, assumes adequate PSE transmission capacity to serve future load.
c. Indicates we rounded transmission constraints to align with generic resource capacity ranges.

The rationale for each transmission capacity limitation by resource group region follows.

Eastern Washington

Through BPA Cluster Study requests, we may obtain 150, 600, or 650 MW for transmission to the Lower Snake River region for Tiers 1, 2, and 3, respectively. By co-locating a 150 MW solar resource at an existing wind facility, we could add 150 MW of Tier 1 transmission. We may acquire an additional 340 or 1,230 MW for Tiers 1 and 2, respectively, of third-party BPA transmission from developer submittals and resource retirements.

Central Washington

We may obtain 250, 500, or 750 MW of transmission for Tiers 1, 2, and 3, respectively, using a portion of the existing 1,500 MW of Mid-C transmission we currently use for market purchases for dual purposes. An additional 100 MW of transmission may be available in Tier 1 to deliver Kittitas area solar via the Grant County PUD system.

Western Washington

We assume no additional transmission is available in Tier 1. Tier 2 may add 100 MW of BPA transmission after the TransAlta purchased power agreement (PPA) expires in 2025. Tier 3 may add 335 MW of dual-purpose transmission to prioritize renewable generation from the Mint Farm CCCT region. Tier 3 may add 200 MW of third-party transmission rights from developer submittals, resource retirements, or offshore wind development.

Southern Washington / Gorge

We may obtain 340 or 1,230 MW for Tiers 1 and 2, respectively, of third-party BPA transmission rights from developer submittals or resource retirements. Tiers 2 and 3 may also add 330 MW of dual-purpose transmission (Tier 2 100 MW, Tier 3 230 MW) to prioritize renewable generation co-located with the Goldendale CCCT.

British Columbia

We may obtain up to 160 MW of long-term transmission from BC Hydro by 2025. Any additional transmission between PSE and British Columbia would require a transmission study and likely system upgrades.

Montana

We may obtain 370 MW for Tier 2 of transmission from repurposing transmission freed up by removing Colstrip Units 3 & 4 from the PSE portfolio.

Wyoming / Idaho

Puget Sound Energy may pursue transmission capacity on the Boardman-to-Hemingway (B2H) and Gateway West projects, adding 400 or 600 MW of transmission for Tiers 2 and 3, respectively.

Puget Sound Energy Territory

For the 2023 Electric Report, we assumed that the PSE system in western Washington is unconstrained. This assumption does not include PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan, including transmission and distribution system upgrades.

2.10.3. Transmission Loss Constraints

Transmission loss constraints model energy lost to heat as power flows through the transmission line. Many factors, including distance, line material, and voltage, impact the magnitude of transmission line losses. The BPA assumes a flat 1.9 percent line loss across its transmission network. A line loss study conducted between PSE and the Colstrip substation found the line loss to be approximately 4.6 percent. Lacking a similar study for transmission to Wyoming and Idaho, we assumed a similar loss given the similar distance. Table 5.9 summarizes the transmission line losses assumed by the resource group region.

Table 5.9: Average Transmission Line Losses by Resource Group Region

Resource Group Region	Line Loss (%)
Eastern Washington	1.9
Central Washington	1.9
Western Washington	1.9
Southern Washington/Gorge	1.9
British Columbia	1.9
Montana	4.6
Idaho and Wyoming	4.6

2.10.4. Transmission Cost Constraints

Transmission cost is another factor used in the PSE portfolio model to constrain resource-build decisions. Transmission costs include a fixed component measured in dollars per kilowatt per year ($/kW-year) and a variable component measured in dollars per megawatt-hour ($/MWh). Fixed transmission costs include wheeling tariffs and balancing service tariffs, among others. Wheeling tariffs will vary by region depending on the number of wheels required to return power to our service territory. Balancing service tariffs vary by resource type; wind balancing service tariffs are usually more expensive than solar balancing serving tariffs, given the greater inter-hour variability of wind resources. Variable transmission costs are primarily composed of spinning and supply reserve requirement tariffs and may include other penalties or imbalance tariffs. Table 5.10 summarizes fixed and variable transmission costs by generic resource type.

We based the wheeling tariffs from Idaho and Wyoming on tariff service over Gateway West, Boardman to Hemingway, and the BPA main grid. For transmission cost modeling, we assumed the cost of three wheels (PacifiCorp, Idaho Power, and BPA) with a reduction to two wheels (PacifiCorp and BPA) after the Gateway West segments are fully completed (estimated 2030 according to PacifiCorp IRP).

Table 5.10: Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-year)	Variable Transmission Cost ($/MWh)
CCCT	0.00[a]	0.00
Frame Peaker	0.00[a]	0.00
Recip Peaker	0.00[a]	0.00
WA Solar East — Utility-scale	27.80	0.26
WA Solar West — Utility-scale	5.24	0.26
Idaho Solar — Utility-scale	57.66	0.26
WY Solar East — Utility-scale	101.12[b]	0.26
WY Solar West — Utility-scale	101.12[b]	0.26
DER WA Solar — Rooftop	0.00[a]	0.26
DER WA Solar — Ground-mount	0.00[a]	0.26
WA Wind	31.21	0.26
BC Wind	61.69	0.26
MT Wind — East	59.10	0.26
MT Wind — Central	59.10	0.26
ID Wind	61.07	0.26
WY Wind East	97.31[b]	0.26
WY Wind West	97.31[b]	0.26
Offshore Wind	31.21	0.26
WA/OR Pumped Storage	22.58	0.26
MT Pumped Storage	50.47	0.26
Battery 2-hour Li-ion	0.00[a]	0.00
Battery 4-hour Li-ion	0.00[a]	0.00
Battery 6-hour Li-ion	0.00[a]	0.00
Solar + Battery	27.80	0.26
Wind + Battery	31.21	0.26
Solar + Wind + Battery	31.21	0.26
Wind + Pumped Storage	59.10	0.26
Biomass	22.58	0.26
Advanced Nuclear SMR	22.58	0.26

Notes:

a. Fixed transmission cost is not applied because we assumed the resource would be built within the PSE service territory.

b. Wyoming transmission cost reflects wheel through Idaho Power territory, reduction in cost modeled in 2030 when Gateway West transmission becomes available. See Appendix H: Electric Analysis and Portfolio Model for further details on modeled transmission cost.

2.11. Electric Delivery System Planning Assumptions

Puget Sound Energy uses a structured approach to developing infrastructure plans that support various customer needs, including effective DER integration. Our process and the associated planning assumptions are in Figure 5.8 and Table 5.11, respectively.

Figure 5.8: Delivery System Planning Operating Model

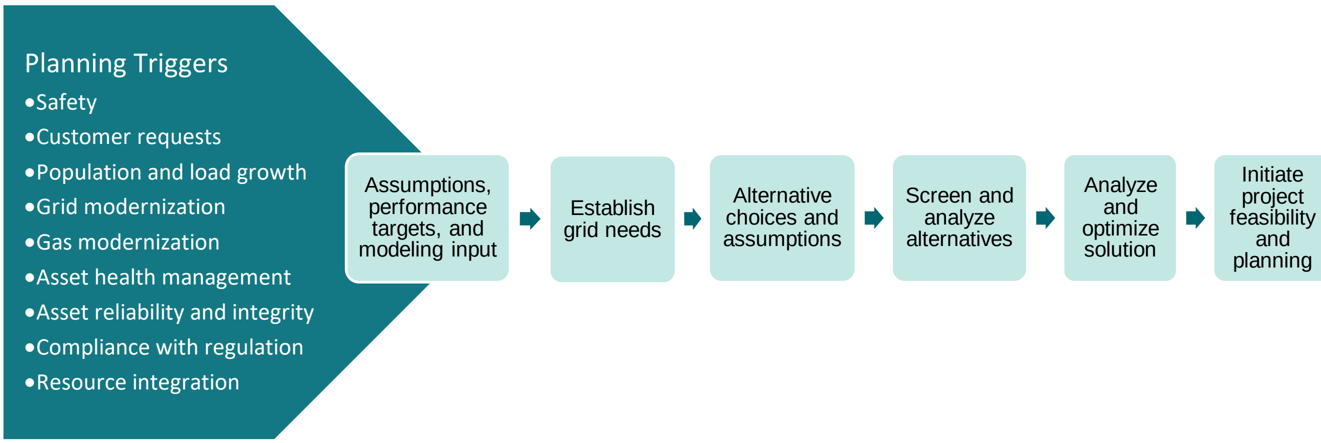


Table 5.11: Delivery System Planning Assumptions

Assumptions	Description
Demand and Peak Demand Growth	Uses county-level demand forecast applied based on historic load patterns of substations with known point loads adjusted for
Energy Efficiency	Highly optimistic 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Interconnection requests with completed Large/Small Generator Interconnection Agreements included
Aging Infrastructure	Known concerns included in the analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources	Known controllable devices are included (most current solar and battery systems are not controllable to manage peak reliably to date)
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements, including NESC, NERC, and WECC, along with addressing voltage regulation, rapid voltage change, thermal limit violations, and protection limits

2.11.1. Delivery System Planning Non-wires Alternatives Forecast

We included a distributed energy resources forecast in the 2023 Electric Report that evaluates where we identified DERs as a potential non-wires solution for meeting delivery system needs. We then extrapolated the forecast based on load growth assumptions. As needs arrive on the planning horizon, further analysis relative to specific values and potential will test these assumptions.

The non-wires alternatives we considered during the delivery system planning (DSP) process include demand response, targeted energy efficiency, energy storage systems, and solar generation, among others. We considered these resources independently and as part of hybrid resource combinations with traditional infrastructure improvements to optimize the solution. Initial analyses suggest that cost-effective solutions align with needs primarily driven by capacity or resiliency. As we continue integrating DER into system solutions, we must answer critical questions about DER's operational flexibility and associated cyber-security considerations.

We used the following assumptions to develop a DER forecast to solve identified system needs over the 0-to-10-year time frame.

- Based on industry knowledge and consultant input for summer needs, we determined 3 to 4 MW was a reasonable size for utility-scale photovoltaic (PV).
- Due to the practical sizing of DER solutions, we did not consider projects with needs larger than 20 MW.
- We applied average historical percentages to determine energy efficiency, demand response, and energy storage potential.

We used the same assumptions for needs identified in the 10- to 20-year timeframe but extrapolated the value based on the load forecast (i.e., years with lower forecasted load growth would require fewer, smaller-scale projects to meet system needs versus years with larger forecasted load growth). We made additional considerations to account for the planning process. We assumed the needs we identified before 2023 would take two to three years to complete based on a new planning process and the learning curve associated with implementing new technologies. We assumed the needs identified after 2023 would be built when it first appeared on the system as the planning process matures and we gain experience siting DER. Figure 5.9 presents the forecast of DER resources added to the system as non-wires alternatives.

Figure 5.9: Forecasted DER Installation by Year and Type

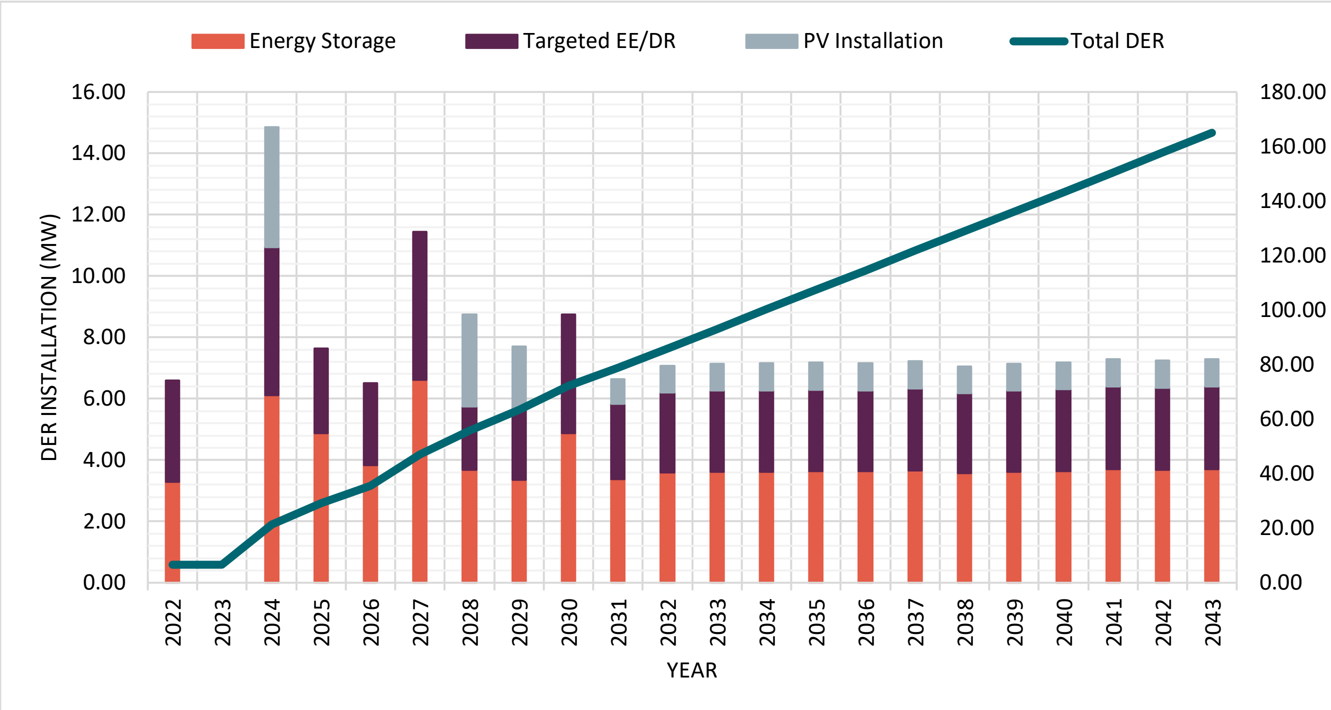


Table 5.12 presents the projected transmission and distribution deferrals resulting from the non-wires alternatives DER additions.

Table 5.12: Projected T&D Deferral by Project Type by 2040

Project Type	Energy Storage (MW)	Targeted EE/DR (MW)	PV Installation (MW)	Total DER (MW)
Planned Transmission System Projects[1]	7.1	6	0	13.1
Planned Substation Capacity Projects	17.6	12.4	3.9	33.9
Future Potential System Needs	59	42.6	16.4	118
Total	83.7	61	20.3	165

Note: [1]As identified in the PSE Plan for Attachment K

We modeled the energy storage and solar PV forecasts in the AURORA portfolio model as generating resource to represent the DSP non-wires alternatives. We included the targeted energy efficiency/demand response forecast as part of the cost-effective energy efficiency and demand response evaluation the model.

2.12. Transmission and Distribution Benefit

The transmission and distribution (T&D) benefit, also known as an avoided cost, is a benefit added to resources that reduce the need to develop new transmission and distribution lines. The T&D benefit is our forward-looking estimate of T&D system costs under a scenario where electrification requirements and electric vehicles drive substantial electric load growth. Studies of the electric delivery system identified capacity constraints on the transmission lines, substations, and distribution lines that serve PSE customers from increased load growth due to electrification and electric vehicle adoption. We used the estimated cost for the infrastructure upgrades required to mitigate these capacity constraints and the total capacity gained from these upgrades to calculate the benefit value. The 2023 Electric Progress Report included a T&D benefit of $74.70/kW-year for DER batteries. This estimated $74.70/kW-year is forecasted based on our additional transmission and delivery system needs under such a scenario. This increase is a significant change from the $12.93/kW-year we used in the 2021 IRP which used backward-looking metrics instead of the revised forward-looking scenario described.

2.13. Electric Generation Retirements

We modeled the economic retirement of existing thermal resources for this 2023 Electric Report. We assumed Colstrip would be removed from PSE's portfolio by December 31, 2025; based on economics, the model can retire Colstrip earlier. We assumed the other thermal plants would run through the planning horizon but could retire early based on economics.

When determining the retirement of a generating plant, the model looks at the economics of the power plant for meeting loads and peaks. The generating plants' valuation process considers emission and variable costs (fuel, operations, and maintenance), fixed costs (including ongoing capital for upkeep and maintenance), and decommissioning costs.

2.14. Achieving CETA Compliance: 100 Percent Greenhouse Gas Neutral by 2030

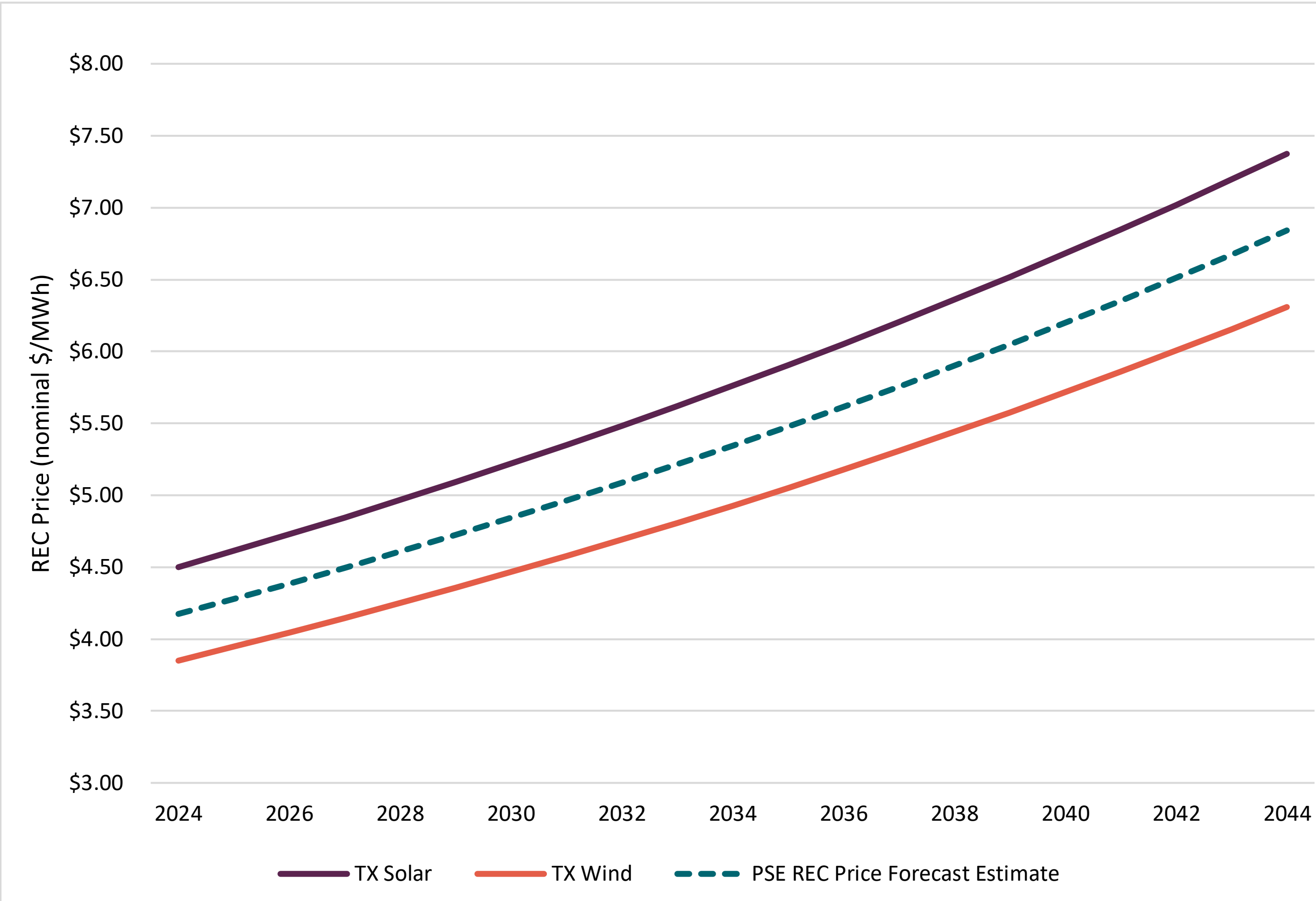
The CETA requires 100 percent greenhouse gas (GHG) neutrality by 2030, with a minimum of 80 percent of energy delivered met with renewable or non-emitting resources and the remaining energy delivered met by alternative options. Options for meeting the up to 20 percent remaining energy delivered include:

- Investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission
- Making an alternative compliance payment in an amount equal to the administrative penalty
- Purchasing carbon offsets
- Purchasing unbundled renewable energy credits

This 2023 Electric Report evaluated two methods to reach 100 percent GHG neutrality by 2030. For the first option, we assumed that we would purchase unbundled renewable energy credits (RECs) for up to 20 percent of the load not met by renewable generation starting in 2030 and decreasing to zero in 2045. The quantity of unbundled RECs purchased depends on the quantity of delivered energy not met by CETA-compliant resources. For example, if a given portfolio generated 85 percent of delivered energy with CETA-compliant resources in 2030, the remaining 15 percent would be compensated by purchasing unbundled RECs to achieve greenhouse gas-neutral compliance.

We reviewed REC markets nationwide to determine a suitable price forecast for unbundled RECs. The Texas wind and solar REC markets represent a stable, high-volume market with years of data available for review. Therefore, we selected an average of the Texas wind and solar REC price forecast as the REC price for achieving GHG neutrality compliance through the purchase of unbundled RECs. Figure 5.10 shows the Texas REC prices over the modeling horizon.

Figure 5.10: Forecasted Renewable Energy Credit Price Purchased to Achieve GHG Neutrality in Nominal $ per MWh



For the second option, we wanted to understand the impact of meeting 20 percent of the load with renewable resources to meet 100 percent of PSE's load with renewable resources by 2030. We modeled sensitivity 12 which retires all existing natural gas generation by 2030 and allows for addition of only renewable resources, thereby achieving 100 percent renewable energy by 2030.

➔ See Chapter Eight: Electric Analysis for the results of sensitivity 12 in detail.

We may meet actual compliance through other mechanisms that we are still developing. We will determine these mechanisms in the first CEIP that includes 2030, the year the greenhouse gas neutral standard takes effect. We will analyze these mechanisms as the Department of Ecology develops guidance on assigning greenhouse gas emission factors for electricity, establishes a process for determining what types of projects qualify as energy transformation projects, and includes other options such as transportation electrification.

3. Electric Portfolio Sensitivities

Sensitivity analysis is an essential component of the IRP process. After generating a reference portfolio, which is the optimized, least-cost set of resources to meet the base set of constraints, we model sensitivities that change a resource, environmental regulation, or condition to examine the effect of the change on the portfolio.

The portfolio modeling process is complex, with no shortage of potential sensitivities to investigate. In this 2023 Electric Report, we included key sensitivities necessary to develop a preferred portfolio in the analysis. We started with sensitivities that changed a single resource or assumption, such as adding more conservation programs or scheduled addition of pumped hydroelectric storage resources. These simple sensitivities provide context for how a given resource, which may not be part of the least-cost portfolio, may provide value, such as reduced greenhouse gas emissions or increased equity benefits. We then combined several of these simple changes to create diversified portfolios.

Diversified portfolios layer several minor changes to create a portfolio that provides even greater potential benefits. We modeled several diversified portfolios ranging from two to six small changes. These diversified portfolios become the candidate portfolios from which we will select a preferred portfolio based on its attributes related to cost, equity benefits, and feasibility.

The following sections provide an overview of the assumptions made for each sensitivity analyzed in this report. We provide their results and discussion in Chapter Eight: Electric Analysis. .

3.1. Reference Portfolio

The reference portfolio is a least-cost, CETA-compliant portfolio that allows the AURORA long-term capacity expansion model to optimize resource selection with as few constraints as possible. The reference portfolio is a basis against which to compare other portfolios. We used the assumptions described in the Electric Portfolio Analysis Assumptions section to develop the reference portfolio. We refer to the reference portfolio as sensitivity 1 throughout this report.

3.2. Conservation Alternatives

Adding higher conservation measures, we analyzed two sensitivities to assess portfolio builds and cost changes.

- Reference: 258 MW of new conservation will be added to the reference portfolio by 2045.
- Sensitivity 2: This sensitivity increases new conservation measures to 486 MW by 2045, an increase of 228 MW above the reference portfolio conservation.
- Sensitivity 3: This sensitivity increases new conservation measures to 382 MW by 2045, an increase of 123 MW above the reference portfolio conservation.

The reference, sensitivity 2 and sensitivity 3 portfolios all have codes and standards included for 437 MW by 2045. New energy efficiency up to bundle 3 was selected in reference portfolio for 258 MW by 2045. Although we did not select a distribution efficiency in the reference portfolio, we included a forecasted addition of distribution efficiency in sensitivity 2 and sensitivity 3 for a total of 11 MW by 2045. We included a forecasted addition of 475 MW by 2045 of energy efficiency in sensitivity 2 by having all measures through conservation bundle 10. We included a lower amount of the forecasted addition of 371 MW by 2045 of energy efficiency in sensitivity 3 by including all measures through conservation bundle 7. Table 5.13 shows the forecasted additions for demand-side resources for the portfolios.

Table 5.13: Demand-side Resources (MW for Reference, Sensitivity 2 Bundle 10, and Sensitivity 3 Bundle 7)

MW by 2045	1 Reference	2 Bundle 10	3 Bundle 7
Codes and Standards	437	437	437
New Distribution Efficiency	0	11	11
New Energy Efficiency	258	475	371
Total	695	923	818

3.3. Distributed Energy Resources Alternatives

We analyzed two sensitivities to assess changes in portfolio builds and costs with additional distributed energy resources (DERs).

- Reference: 1,494 MW of distributed solar and 117 MW of distributed storage will be added to the reference portfolio by 2045.
- Sensitivity 4: This sensitivity adds 600 MW of additional distributed solar by 2045, resulting in 2,094 MW of distributed solar by 2045.
- Sensitivity 5: This sensitivity adds 150 MW of additional distributed storage by 2045, resulting in 267 MW of distributed storage by 2045.

The reference portfolio, sensitivity 4 and sensitivity 5, all include DER forecasts for customer-sited solar, non-wires alternatives, and new programs identified in the CEIP. Based on the results of the reference portfolio, we did not find it economical to add any additional DERs due to the higher cost relative to utility-scale resources. Sensitivity 4 explores the impact of adding distributed solar above the established forecasts by adding 30 MW of distributed rooftop solar each year from 2026 to 2045. Sensitivity 5 examines the impact of adding distributed storage above the established forecast by adding 25 MW of distributed battery storage each year from 2026 to 2031.

3.4. Pumped Hydroelectric Storage Alternatives

We analyzed three sensitivities to assess changes in portfolio builds and cost by adding pumped hydroelectric storage (PHES) resources.

- Reference: PHES is selected on an economic basis, resulting in zero MW of PHES added to the reference portfolio.

- Sensitivity 6: This sensitivity adds 200 MW of Montana PHES and 400 MW of eastern Montana wind in 2026.
- Sensitivity 7: This sensitivity adds 200 MW of Montana PHES, 200 MW of central Montana wind, and 200 MW of eastern Montana wind in 2026.
- Sensitivity 8: This sensitivity adds 200 MW Pacific Northwest PHES in 2026.

Energy storage is a critical component of a CETA-compliant portfolio. The reference portfolio selected battery storage as a cost-effective storage resource. We explored diversifying the portfolio by adding PHES and battery energy storage in sensitivities 6, 7, and 8.

In sensitivities 6 and 7, we added 200 MW of Montana PHES in 2026. Energy from Montana resources currently gets to PSE via the Colstrip transmission line. The Colstrip transmission line has an available capacity of 750 MW for PSE to use. Given this restriction, we decided to overbuild Montana resources to provide surplus energy to charge the PHES resource and simultaneously maximize the throughput of energy over the Colstrip line to PSE. In sensitivity 6, we added 400 MW of eastern Montana wind to the existing 350 MW of Clearwater wind. In sensitivity 7, we added 200 MW of eastern Montana wind and 200 MW of central Montana wind in addition to the existing 350 MW of Clearwater wind. The Montana PHES and wind resources have a combined maximum output of 750 MW (the Colstrip transmission capacity limit), and excess energy is stored in the PHES resource.

In sensitivity 8, we added 200 MW of Pacific Northwest PHES in 2026. Since transmission capacity is less constrained in Washington and Oregon, we did not model any resource overbuild in sensitivity 8.

3.5. Advanced Nuclear Small Modular Reactors

We analyzed a sensitivity that added advanced nuclear SMR to the portfolio to assess changes in builds and cost.

- Reference: Advanced nuclear SMR is selected on an economic basis, resulting in zero MW of advanced nuclear SMR added to the reference portfolio.
- Sensitivity 9: This sensitivity adds 250 MW of advanced nuclear SMR in 2032.

The reference portfolio is updated to include a forecast in 2032 of 5 units of 50 MW advanced nuclear SMR resources for 250 MW. This advanced nuclear SMR provides a combination of dispatchability, reliability, and emission-free production benefits, making it an attractive alternative to traditional peaking resources as we move toward a zero-emissions portfolio.

3.6. No New Thermal Resources Before 2030

We analyzed a sensitivity where new thermal resources were unavailable before 2030 to assess changes in builds and cost.

- Reference: Thermal resources include natural gas peakers, blended natural gas and hydrogen peakers, and biodiesel peakers available for economical addition throughout the modeling horizon.
- Sensitivity 10: This sensitivity limited the availability of thermal resources before the year 2030. After 2030, we permitted natural gas, blended natural gas and hydrogen and biodiesel peakers in the portfolio.

This sensitivity aims to reduce the amount of thermal, or combustion, resources added to portfolio. No combustion resources are permitted to be added to the portfolio before the year 2030.

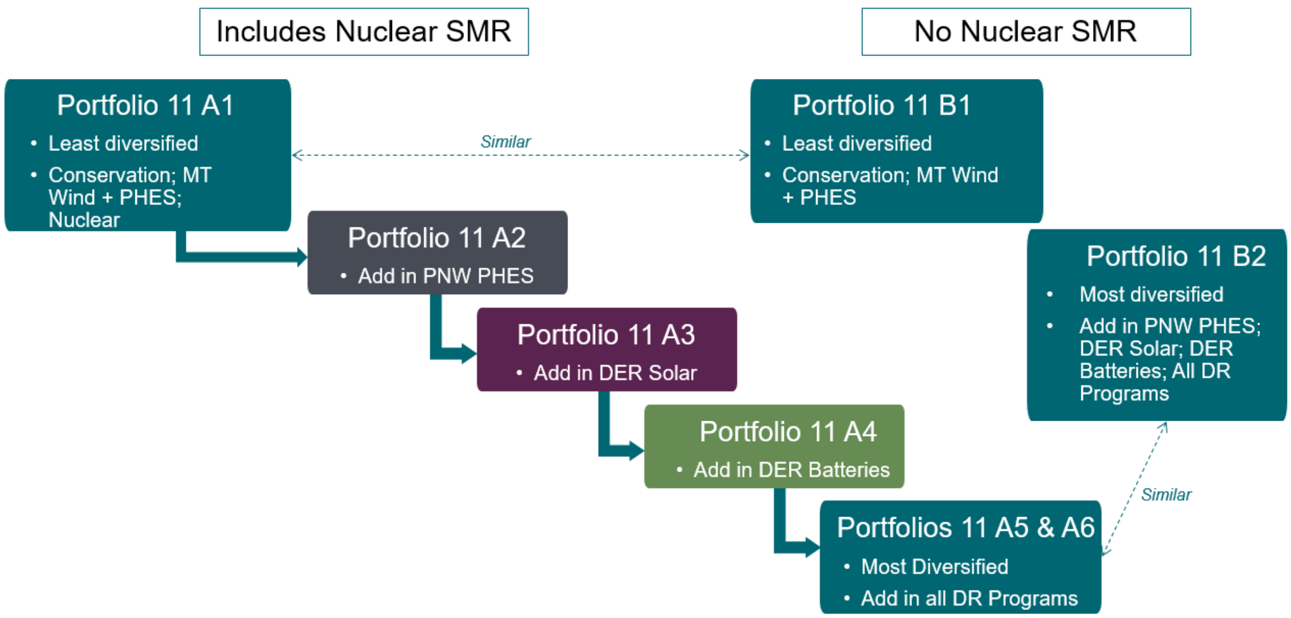
3.7. Diversified Portfolios

In comparison to the least-cost reference portfolio, the diversified portfolios broaden the resource additions, lower the technology and feasibility risks, and seek to maximize equity-related benefits. All diversified portfolios are based on the least-cost reference portfolio. Portfolios 11 A1 through 11 A5 explore layering in combinations of sensitivities 3 through 9. At the request of interested parties, portfolios 11 B1 and 11 B2 replicate the least and most diversified portfolios, 11 A1 and 11 A5, respectively, but without adding advanced nuclear SMR technology to the portfolio.

- Reference: New resources are acquired when cost-effective and needed.
- Sensitivity 11 A1: This sensitivity is the least diversified portfolio we developed in this report and therefore serves as the baseline diversified portfolio. Built on the least-cost reference portfolio, this portfolio increases conservation to 371 aMW by 2045 (Sensitivity 3), adds 400 MW of eastern Montana wind and 200 MW of Montana PHES in 2026 (Sensitivity 6), and adds 250 MW of advanced nuclear SMR in 2032 (Sensitivity 9).
- Sensitivity 11 A2: Same as 11 A1 but adds 200 MW of Pacific Northwest PHES in 2026 (Sensitivity 8).
- Sensitivity 11 A3: Same as 11 A2 but adds 30 MW of distributed solar resources annually from 2026 through 2045 (Sensitivity 4).
- Sensitivity 11 A4: Same as 11 A3 but adds 25 MW of distributed battery resources annually from 2026 through 2031 (Sensitivity 5).
- Sensitivity 11 A5: Same as 11 A4 but adds all demand response programs.
- Sensitivity 11 B1: Same as 11 A1 but without advanced nuclear SMR.
- Sensitivity 11 B2: Same as 11 A5 but without advanced nuclear SMR.

Figure 5.11 illustrates the relationships between the diversified portfolios we explored in this report.

Figure 5.11: Diversified Portfolio Schema



3.8. 100 Percent Renewable and Non-emitting by 2030

This sensitivity examines the impacts of retiring all existing thermal resources by 2030 and removing the ability to build any new thermal regardless of fuel type.

- Reference: The baseline assumes we will transition existing thermal to a 30 percent hydrogen blend starting in 2030 and ramp up to 100 percent hydrogen by 2045. New thermal fueled by natural gas, biodiesel, and hydrogen are all available as new resource options.
- Sensitivity 12: All existing thermal is retired on a ramped schedule from the late 2020s to 2030. All thermal resource options, including alternative fuels, are excluded from the modeling scenario producing a portfolio that is effectively 100 percent non-emitting by 2030.

We initially assumed we would retire existing thermal options for this sensitivity and remove new thermal options. However, we needed to adjust other assumptions to facilitate the long-term capacity expansion model. Those adjustments included removing all transmission capacity constraints, expanding available quantities of each resource type, and allowing the model to build advanced nuclear SMR in 2025. We made these changes to increase access to additional resources over the reference portfolio to help meet the large capacity deficit early in the modeling horizon.

With these changes implemented, the model solved in the preliminary stages when sampling settings were relatively coarse. But when we increased the sampling resolution for the final sensitivity run, the model could not converge on a solution.

3.9. High Carbon Price

We analyzed this sensitivity to explore the impact of a higher-than-expected greenhouse gas allowance price in the market established by the Climate Commitment Act.

- Reference: We modeled an ensemble allowance price as a direct cost on greenhouse gas emissions using the Washington Department of Ecology Linkage to California from 2024 to 2029, transitioning to the mid allowance price forecast created by the California Energy Commission in 2030.
- Sensitivity 13: We used the Washington Department of Ecology price ceiling as the allowance price as a direct cost of greenhouse gas emissions.

Figure 5.4 illustrates the relationship between the PSE ensemble price and the Department of Ecology ceiling price as described in Section 2.4 of this Chapter.

3.10. No Hydrogen Fuel Available

This sensitivity examines a future where green hydrogen fuel is unavailable for the electric sector.

- Reference: Hydrogen fuel blending at a rate of 30 percent in 2030 and increasing to 100% by 2045 is available for new blended fuel peakers and existing natural gas plants.
- Sensitivity 14: Hydrogen is unavailable, so existing natural gas plants burn only natural gas, and blended fuel peakers are not available for economic addition to the portfolio.

Interest and commercialization of large-scale green hydrogen production are at an all-time high, largely thanks to production and investment tax credits established by the Inflation Reduction Act. However, green hydrogen production is not guaranteed to materialize in the volumes needed to support the electric power sector. This sensitivity assumes a future with no green hydrogen for combustion in existing or new peaking resources modeled in this report.

3.11. Social Cost of Greenhouse Gases in Dispatch

This sensitivity compares different methodologies to apply the SCGHG as externality or dispatch costs and their effect on portfolios.

- Reference: We modeled the SCGHG as an externality cost in the long-term capacity expansion (LTCE) model. We omitted the SCGHG in the dispatch decision for emitting resources in the LTCE run.
- Sensitivity 15: We modeled the SCGHG as dispatch cost in the long-term capacity expansion model. We included the SCGHG in the dispatch decision for emitting resources in the LTCE run.

We omitted the SCGHG in the dispatch decision for emitting resources in the hourly dispatch run for the Baseline and Sensitivity 15. Figure 5.3 provides the social cost of greenhouse gases.

4. Purchasing Versus Owning Electric Resources

The 2023 Electric Report determines the supply-side capacity, renewable energy, and energy need, which sets the supply-side targets for future detailed planning in the Clean Energy Implementation Plan and the acquisition process. The Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. We also considered market opportunities outside the RFP and resource-build decisions when making prudent resource acquisition decisions. The 2023 Electric Report assumes ownership of supply-side resources since the cost of power purchase agreements (PPA) is confidential.

In build-versus-buy, build refers to resource acquisitions involving asset ownership. Ownership could occur anywhere along the development cycle of a project. The company could develop or purchase the project anytime during the development cycle. Buy refers to purchasing the output of the plant through a PPA.

In general, quantitative and qualitative evaluations for build-and-buy proposals are conducted similarly in the Request for Proposal process to meet the company's needs, consistent with WAC 480-107,[16] solving for the lowest reasonable cost for customers. We evaluate qualitative project risks in the same way for both acquisitions. Quantitative evaluations for build options include ownership costs such as operating expenses, depreciation, and return on invested capital. Developers embed similar costs in the total price of PPAs, but we have no visibility on the breakdown of those costs.

The supplier of the PPA makes the financial investment for the utility. Rating agencies view PPAs as a financial obligation to the utility, representing a debt-financed capital investment in generation capacity. Rating agencies add/impute debt to the balance sheet to reflect the financial obligations to account for the company's credit exposure. The request for proposal (RFP) process includes an adjustment for imputed debt for PPAs to account for the impact on credit ratings. The cost of imputed debt is a consideration in the evaluation process but is not recoverable in rates.

The CETA provides a provision allowing for a return on expenses incurred from the PPA of no less than the authorized cost of debt and no greater than the rate of return. We did not include the PPA return in the evaluation process. The statutorily authorized PPA return has yet to be requested or approved in a General Rate Case proceeding.

Several factors could influence pricing differences between the buy and build scenarios. Independent power producers (IPP) have tax advantages over utilities since the tax rules differ. A carve-out in the tax code allows IPPs to depreciate the cost of investments upfront, whereas utilities depreciate the cost over time. This situation provides a tax shield on the front end to IPPs. Independent power producers are also more able to maximize the benefits of investment tax credits. The tax code limits the utilities' ability to fully utilize ITC for the customer benefit on ITCs on solar. Developers have more flexibility in how they finance projects with their capital structure. In the build scenario, our equipment selection and design specifications must meet PSE standards for ownership, whereas a supplier might be more inclined to be driven by cost. We can better control how the plant operates and be good community stewards when we own it.

[16] WAC 480-107

DEMAND FORECASTS
CHAPTER SIX

PUGET SOUND ENERGY

Contents

1. Introduction

The demand forecasts Puget Sound Energy (PSE) developed for this 2023 Electric Progress Report (2023 Electric Report) calculate the amount of electricity required to meet customers' needs over the more than 20-year study period, 2024–2045. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand is the total electricity needed to meet customer needs yearly (megawatt hours [MWh], or average megawatts [aMW]).
- Peak demand is the single highest hour of electricity demanded by customers each season, winter or summer (MW).

Puget Sound Energy incorporated crucial climate change data into the demand forecast for the first time in this report. We heard from interested parties that climate change is important because it affects future demand and needs, and we agree. We included climate change in the base demand forecast and in other analyses such as the stochastic scenarios.

Climate change already affects how our electricity customers use energy, and we expect that impact will increase. We expect summer and winter average and peak temperatures to get warmer. The energy and peak demand forecasts now incorporate climate change temperature effects. We also incorporated climate change in the resource adequacy (RA) analysis, the stochastic scenarios, and the conservation potential assessment (CPA). Including climate change in energy planning is crucial since it affects our customers.

Overall, we expect electric energy demand, before additional demand-side resources (DSR) identified in the 2023 Electric Report's base demand forecast, to grow at an average annual growth rate (AARG) of 1.8 percent from 2024 to 2045. This growth rate increased our forecast from 2,551 aMW in 2024 to 3,699 aMW in 2045, faster than the 1.2 average annual energy growth rate forecasted in the 2021 Integrated Resource Plan (IRP).

We expect base peak demand before additional DSR to increase at a 1.7 percent annual growth rate, from 4,753 MW in 2024 to 6,717 MW in 2045. This rate is also faster than the 1.2 percent average annual growth rate forecasted in the 2021 IRP and resulted in higher total peak demand at the end of the study period. New customers and electric vehicles are the principal drivers of the growth. Demand from customers using electric vehicles increases residential and commercial use per customer across the entire forecast period.

The 2023 Electric Report base demand forecasts also include the effects of climate change. Warming temperatures decrease energy usage in the winter and increase it in the summer. That phenomenon increases both the winter and summer normal peak temperatures; therefore, the peak forecast includes demand decreases in the winter and increases in the summer.

Table 6.1: Drivers Included and Not Included in the Base Demand Forecasts

Drivers	Demand Forecast Before Additional DSR	Demand Forecast After Additional DSR
Climate change temperatures	Yes	Yes
PSE energy efficiency programs for 2022–2023	Yes	Yes
Codes and standards effects through 2023	Yes	Yes
Demand-side solar installed through 2023	Yes	Yes
PSE energy efficiency programs for 2024 and beyond	No	Yes
Codes and standards for 2024 and beyond (Including Bellingham natural gas ban)	No	Yes
Demand-side solar installed in 2024 and beyond	No	Yes
Electric vehicle legislation: Zero Emission Vehicle (2020) and Clean Fuel Standard (2021)	Yes	Yes
Electric vehicle legislation: Clean Cars 2030 goal (2022)	No	No
Effects of the Climate Commitment Act or additional electrification	No	No
Inflation Reduction Act effects from the investment tax credit (ITC) on behind-the-meter solar	No	Yes
Inflation Reduction Act effects for DSR projects other than solar	No	No

We prepared stochastic draws in addition to the base demand forecast to model a range of potential economic conditions, weather conditions, and modeling variance in the 2023 Electric Report analysis. These draws included variations in temperature, economic and demographic drivers, electric vehicles, and demand model uncertainty. We also used modeled climate change temperatures to project a distribution of possible future temperature-sensitive demand, thereby modeling a more comprehensive range of warmer and colder conditions than the base demand forecast.

Demand and *load* are often used interchangeably in the energy industry, but they refer to different concepts. In this IRP demand refers to the energy needed to meet customers' needs during a calendar year, including losses, and load refers to demand plus the planning margin and operating reserves required to ensure the reliable and safe operation of the electric system.

1.1. Impacts of Demand-side Resources

When we applied forward projections of additional DSR savings, as shown in Table 6.2, we reduced demand significantly. However, it is necessary to start with forecasts that do not already include forward projections of DSR savings to identify the most cost-effective amount of DSR to include in the resource plan. Throughout this chapter, charts and tables labeled before additional DSR have only DSR measures implemented before the study period begins in 2024. Charts labeled after additional DSR include the cost-effective amount of DSR we identified in the 2023 Electric Report.

1.1.1. Demand Before Demand-side Resources

Why does PSE forecast demand before DSR? The demand forecast before DSR shows us the problem. What if no one acted to change how we use energy? That is not a future we anticipate. Demand-side resources like energy efficiency and demand management programs change energy use. We expect to continue incentivizing DSR. Federal, state, and local governments will continue changing energy codes and standards, and we expect consumers to continue putting solar panels on their roofs. But how much of this will occur, and how will it change the demand forecast? To answer this question, we assume no DSR and treat DSR as a resource in the modeling process. This methodology is industry standard and set forth by WAC 480-100-620[1] as part of the content of an integrated resource plan.

Table 6.2: Effect of Demand-side Resources on Demand Forecasts

2023 Electric Report Base Demand Forecast in 2045	Before Additional DSR	After Additional DSR
Electric Energy Demand (aMW)	3,699	2,949
Electric Peak Demand (MW)	6,717	5,867

2. Climate Change

This 2023 Electric Report marks the first time PSE incorporated climate change into the base energy and peak demand forecasts. Before this 2023 Electric Report, we used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This approach to forecasting is a common utility practice, but it does not recognize predicted climate change. This section provides a detailed description of our approach to developing a normal temperature assumption.

2.1. Priorities First

Puget Sound Energy heard and heeded the clear message from interested parties that climate change is a high priority, and we should incorporate its effects into our planning processes. It is essential to consider climate change in resource planning because PSE customers use electricity to heat in the winter and keep cool in the summer. Over time, we expect less overall heating demand and more cooling demand because of a general average warming trend. We used regional data recently developed by climate change scientists to calculate a normal temperature assumption that reflects climate change.

There are currently no industry standards or best practices for incorporating climate change into a demand forecast. The team at PSE is excited to include climate change in this report and participate in future refinements and the evolution of this methodology.

[1] WAC 480-100-620

We are incorporating climate change into the demand forecast in several ways:

- Energy demand forecast
- Peak demand forecast
- Resource adequacy (RA) analysis
- Stochastic analysis

The climate projections used in the forecast were part of a recent study conducted by the River Management Joint Operating Committee (RMJOC). The RMJOC consists of the Bonneville Power Administration, the U.S. Army Corps of Engineers, and the U.S. Bureau of Reclamation. This committee worked with climate scientists to produce many downscaled climate and hydrologic models for the Northwest region as part of their long-term planning.[2] The RMJOC chose 19 downscaled models. Each model is on the representative concentration pathway (RCP) of 8.5. An RCP is a forecast of the amount of warming to the Earth. RCP 8.5 is a high yet common warming forecast used by climate scientists. It represents more warming than other common warming forecasts, such as RCP 4.5 or 6.0.

The Northwest Power and Conservation Council (NWPCC) chose three of these 19 models to work with: CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA. The NWPCC chose these three models because they reflect a wide range of temperatures and hydrologic conditions over time. We used the three climate model projections selected by the NWPCC.

2.2. Determine Climate Change Normal Temperatures

This 2023 Electric Report marks the first time PSE incorporated climate change in the demand forecast and other aspects of planning. Since there is no industry standard approach to integrating climate change, we had to establish how to incorporate this data into our forecasts. The following section explains how we approached the challenge and the questions we asked. We also presented these questions and the analysis results to interested parties on January 20, 2022, and asked them for feedback on our approach.

2.2.1. What is Normal and Why Do We Need It?

When PSE models demand, we study the relationship between historical demand and historical temperatures because the temperature significantly impacts demand. Then, to create a demand forecast, PSE must make assumptions about future temperatures to create a future demand forecast. We refer to the assumed future temperatures as normal temperatures. For energy forecasting, the average heating degree day (HDD) and/or cooling degree day (CDD) for a month expresses the new normal temperature. We used a one-in-two occurrence of a given temperature to forecast peak demand.

We wanted to achieve three goals when we created new normal temperatures:

1. Develop an objective temperature normal, which included deciding what data to use.

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[2] River Joint Management Operating Committee (RMJOC): Bonneville Power Administration, United State Army Corps of Engineers, United Stats Bureau of Reclamation (2018). Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part 1:Hydroclimate Projections and Analyses.

2. Incorporate future temperature trends into the assumptions for the base demand forecasts. We provided a scenario in the 2021 IRP with climate change temperatures, but incorporated a more comprehensive approach in this 2023 Electric Report's base demand energy and base demand peak forecasts.
3. Produce the demand forecast in the framework necessary for planning. The 2023 Electric Report's analyses have specific input requirements. For example, we could have run the demand forecast with the climate projections from each of the three models, but this would have created three base forecasts. Instead, we created one demand forecast so we did not have to run the 2023 Electric Report analyses three times.

2.2.2. Choose the Data

We considered the following questions when we decided what data to use to define a new normal temperature:

1. How many years of data should we include when calculating a new normal?

   For the base energy demand forecast, we have historically used the last 30 years of temperatures to determine the normal. This approach created a relatively stable normal, with minor changes yearly. Forecasts that use five- or 10-year derived normal can have much larger swings in the year-to-year normal, creating difficulties for planning. We wanted to avoid this difficulty, so we opted to use a 30-year calculation centered on the year of interest. We used temperatures from the prior 15 and the coming 15 years for each forecast year in the analysis. We performed this calculation for each year of the forecast.

2. Should we use one climate model to predict future temperatures or all three models the NWPCC chose to create the normal?

   Since NWPCC used three models representing a wide range of possible climate outcomes, using all the climate models allowed us to capture a broad range of possible outcomes, so we used all three.

3. Should the forecasted new normal temperature include historical data, climate model projections, or some combination of the two?

   Recent historical data is a way to link climate change projections to what has occurred recently in the region. Incorporating recent data can help determine where the forecast should start. For example, in 2021, the region saw unprecedented hot temperatures, including 107⁰ Fahrenheit at Sea-Tac Airport on June 28, 2021. However, the climate models did not predict a temperature this high until 2035. Based on this assessment, the team at PSE used historical data and forecasted temperatures to calculate a new normal temperature.

4. Should the forecast of normal temperatures be flat, as in past IRPs, or should the forecast reflect a trend?

   We wanted to reflect average temperatures warming over time, so the normal energy forecast reflected this with increasing average temperatures in the winter and increasing average temperatures in the summers.

2.3. Normal Temperature for Energy Demand Forecast

We incorporated the normal temperatures into the base energy demand forecast models through heating degree days (HDDs) and cooling degree days (CDDs). We used the HDDs and CDDs to model future energy demand. HDDs and CDDs are standard ways to express temperatures and are used to estimate how much heating or cooling a customer may operate in response to a given daily temperature. We calculate degree days using a base temperature, typically 65⁰F, and the average daily temperature. For HDDs, we calculate the value as the amount the daily temperature is below 65°F, and for CDDs, it is the amount the daily temperature is above 65°F. For example, a 70°F-day will have 5 CDDs and 0 HDDs, while a 30°F-day will have 35 HDDs and 0 CDDs, using a base of 65°F. The team used the three climate models described and historical temperatures to create HDDs and CDDs. The climate models and the historical data are from NOAA's Sea-Tac Airport station.

Previously, we calculated HDDs and CDDs using the most recent 30 years of historical temperatures and used that static calculation through the forecast period, creating a flat normal temperature. For the 2023 Electric Report, we calculated the HDDs and CDDs for each year of the forecast using a different set of temperatures. We calculated HDDs and CDDs for each forecast year using temperatures from the prior 15 and the future 15 years, including the year of interest. If the previous 15 years included years where historical temperatures were available, we used historical data. We used temperatures from each of the three climate models for future years. Figures 6.1 and 6.2 show examples of the old and new normal temperatures, which include climate change.

Figure 6.1: Heating Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (HDD base temperature 65)

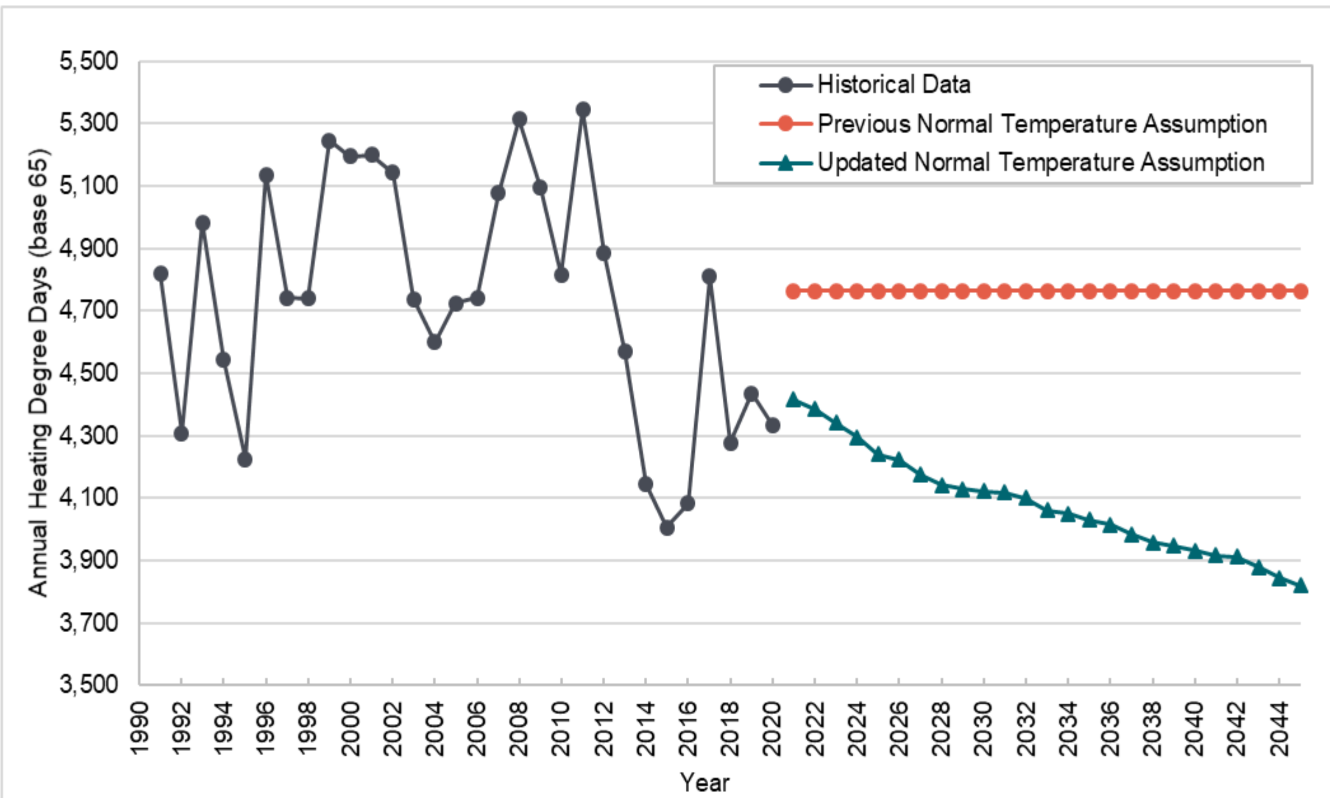
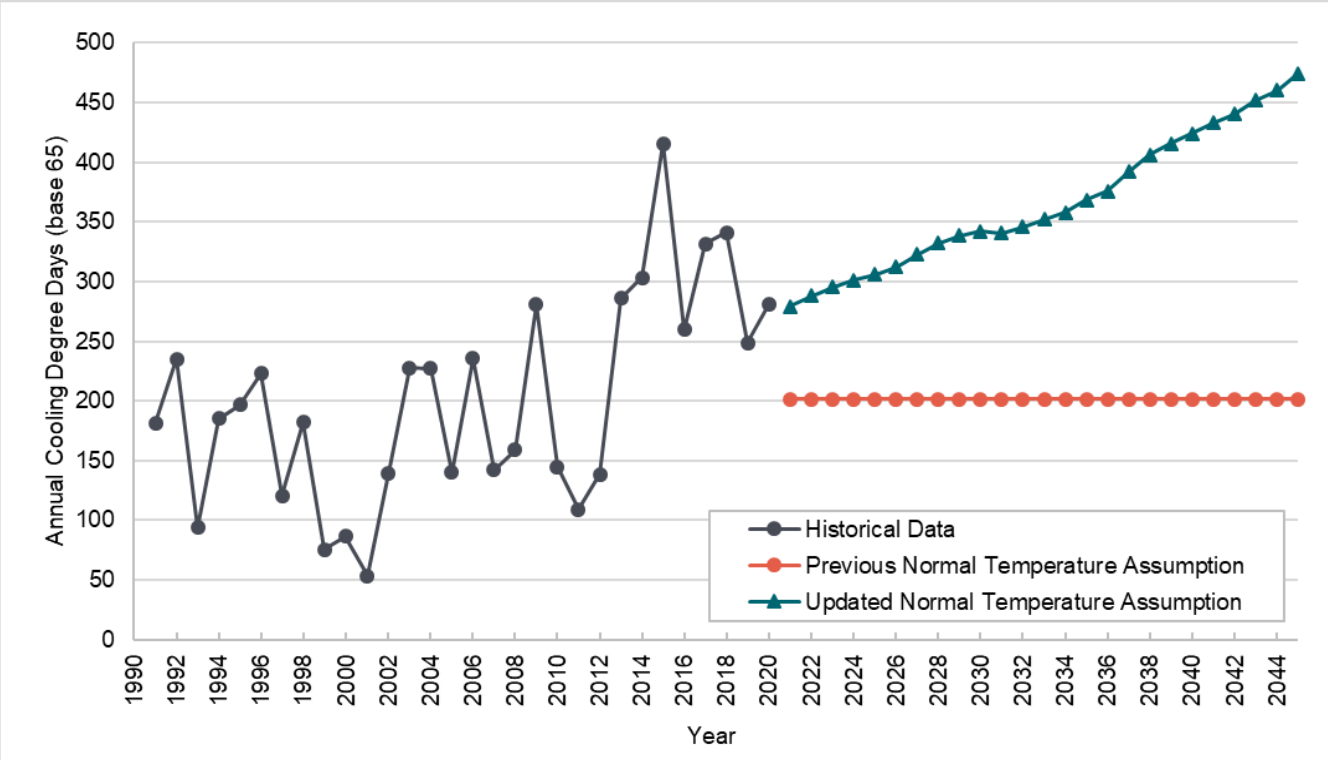


Figure 6.2: Cooling Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (CDD base temperature 65)



➔ See Appendix F: Demand Forecasting Models for more information about calculating the HDDs and CDDs that went into the demand forecast.

2.4. Normal Temperature for Peak Demand Forecast

The peak demand forecast uses a 1-in-2 seasonal peak minimum or maximum temperature during all peak hours. For the electric normal peak, we used a similar methodology as the normal energy demand forecast; we used data from 15 prior and 15 future years, including the year of interest, for the calculation. However, instead of averaging the 30 years of data for the peak, we calculated the 1-in-2 occurrence of a peak hour or median peak temperature.

We performed this calculation for each year in the forecast period: winter morning peaks, winter evening peaks, and summer peaks. The result was a 1-in-2 peak temperature of 25 in 2024, which increases to 26 degrees for winter morning peaks. For winter evening peaks, the 1-in-2 peak temperature is 27 for 2024 –2028 and rises to 28 for the rest of the forecast period. In the summer, the 1-in-2 peak is 94 for 2024–2028, 95 for 2029–2032, and 96 starting in 2033. We smoothed the peak normal temperatures to create a normal peak that increases temperature over time. We show the winter evening, winter morning, and summer peaks in Figures 6.3 and 6.4.

Figure 6.3: Normal Winter Peak Temperatures
Previous Normal and Updated Normals for Morning and Evening (ºF)

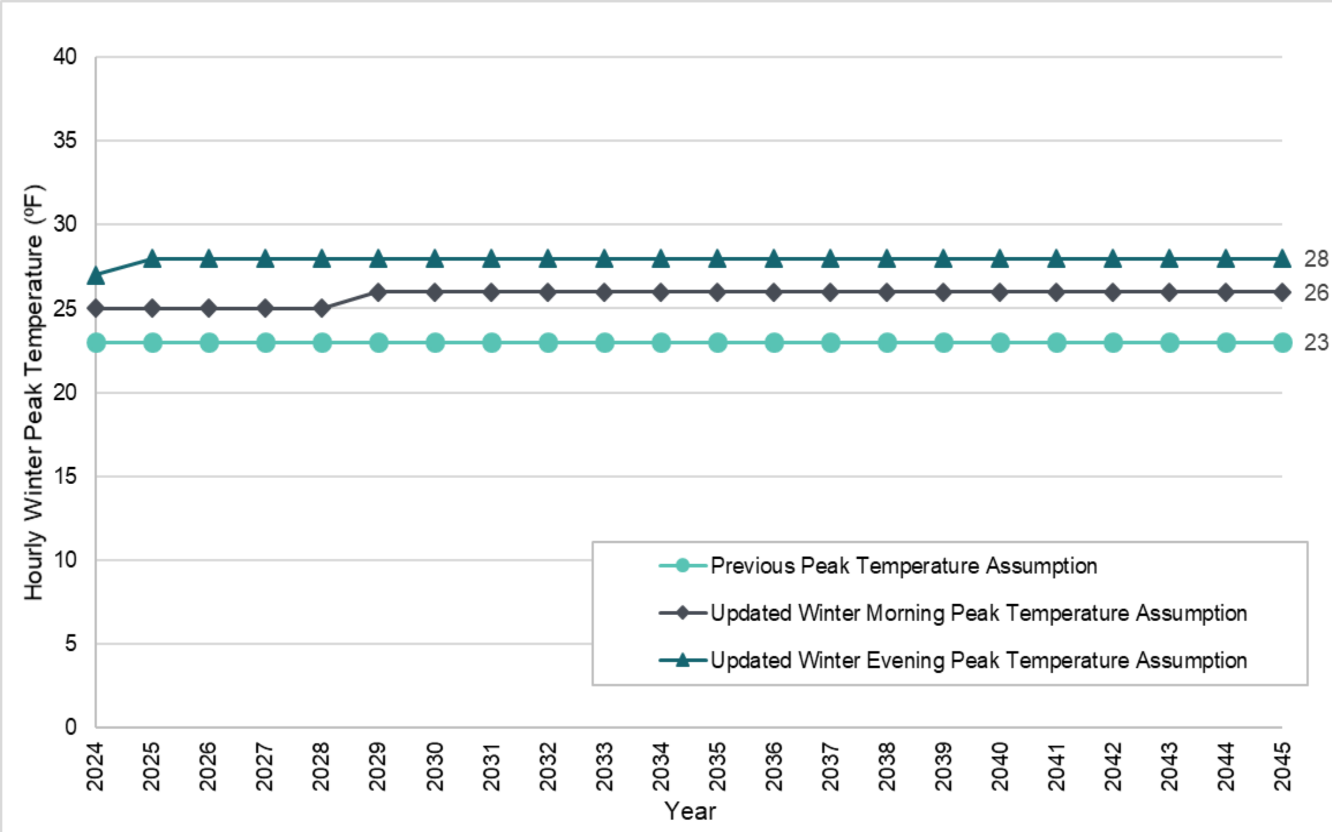
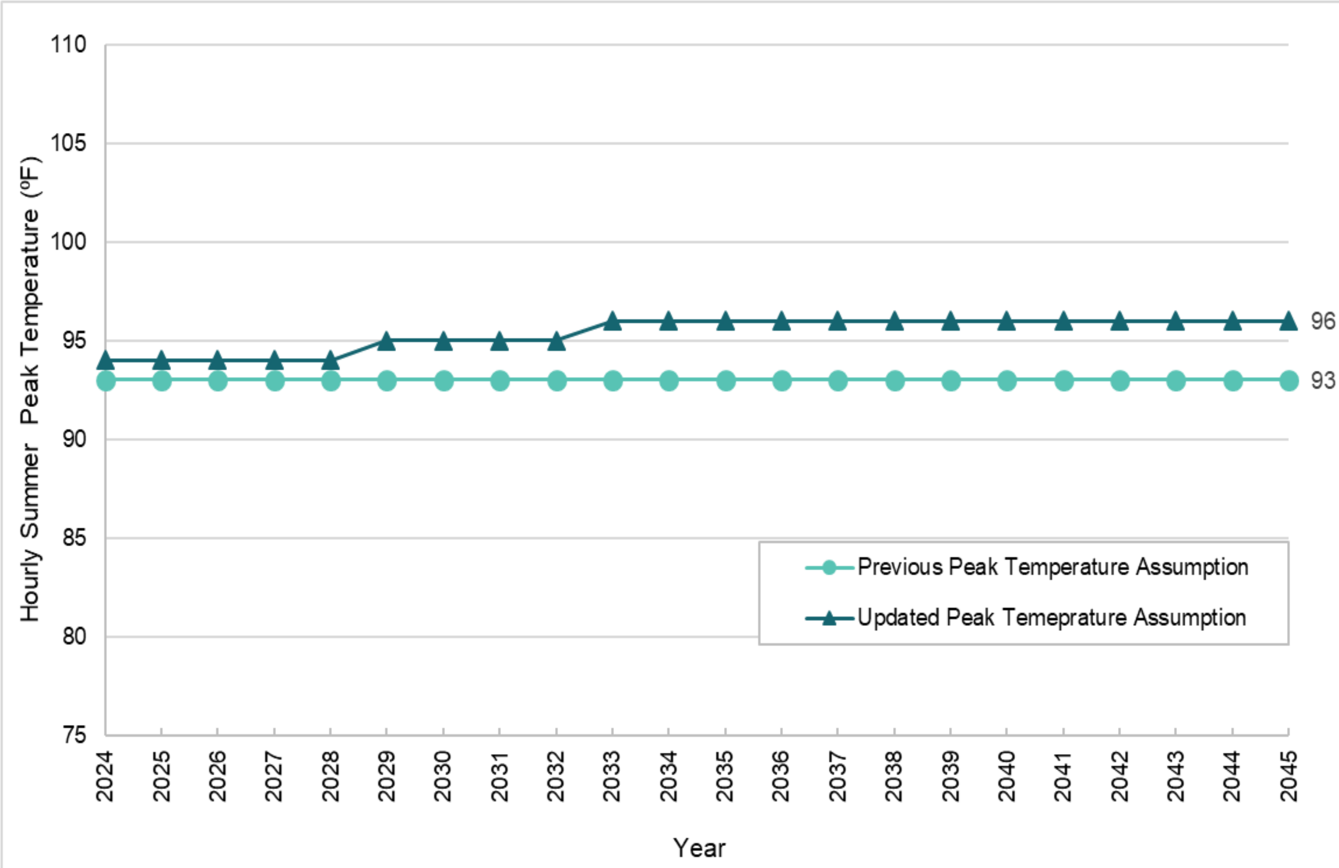


Figure 6.4: Normal Summer Peak Temperatures
Previous Normal and Updated Normal (ºF)



➔ See Appendix F: Demand Forecasting Models for a detailed discussion of the peak climate change temperature calculations.

3. Electric Demand Forecast

We present highlights of the 2023 Electric Report base demand forecast developed for the electric service area in Figures 6.5 through 6.7 and Tables 6.3 and 6.4. We summarize the population and employment assumptions for the forecast in this document's Details of Electric Forecast section and explained in detail in Appendix F: Demand Forecasting Models.

The demand forecast included only DSR measures implemented through December 2023 since the demand forecast helps determine the most cost-effective amount of DSR to include in the portfolio for subsequent periods.

3.1. Electric Energy Demand

In the 2023 Electric Report base demand forecast, we expect energy demand before additional DSR to grow at an average rate of 1.8 percent annually from 2024–2045, increasing energy demand from 2,551 aMW in 2024 to 3,699 aMW in 2045.

Puget Sound Energy serves primarily residential and commercial customers, with a minority share of energy demand associated with industrial, resale, and streetlight customer classes. Excluding losses, we projected residential and commercial customer classes to represent 49 percent and 39 percent of energy demand in 2024. During the forecast period, residential demand grows as we add new customers to the system and customers adopt electric vehicles (EVs). This demand growth is partially, but not entirely, offset by decreasing residential heating energy demand — a consequence of adopting trended normal temperatures consistent with climate change impacts.

Commercial energy demand grows similarly: we added new commercial customers to the system, and customers adopt EVs for fleet and other business purposes. The share of commercial demand associated with heating energy demand is less than residential customers; thus, climate change impacts are less severe for the commercial class.

Therefore, rising customer and EV counts drive most of the growth in energy demand and offset climate change impacts before DSR is applied.

Figure 6.5: Electric Energy Demand Forecast before Additional DSR
2023 Electric Report Base Demand Forecast versus 2021 IRP Base Demand Forecast (aMW)

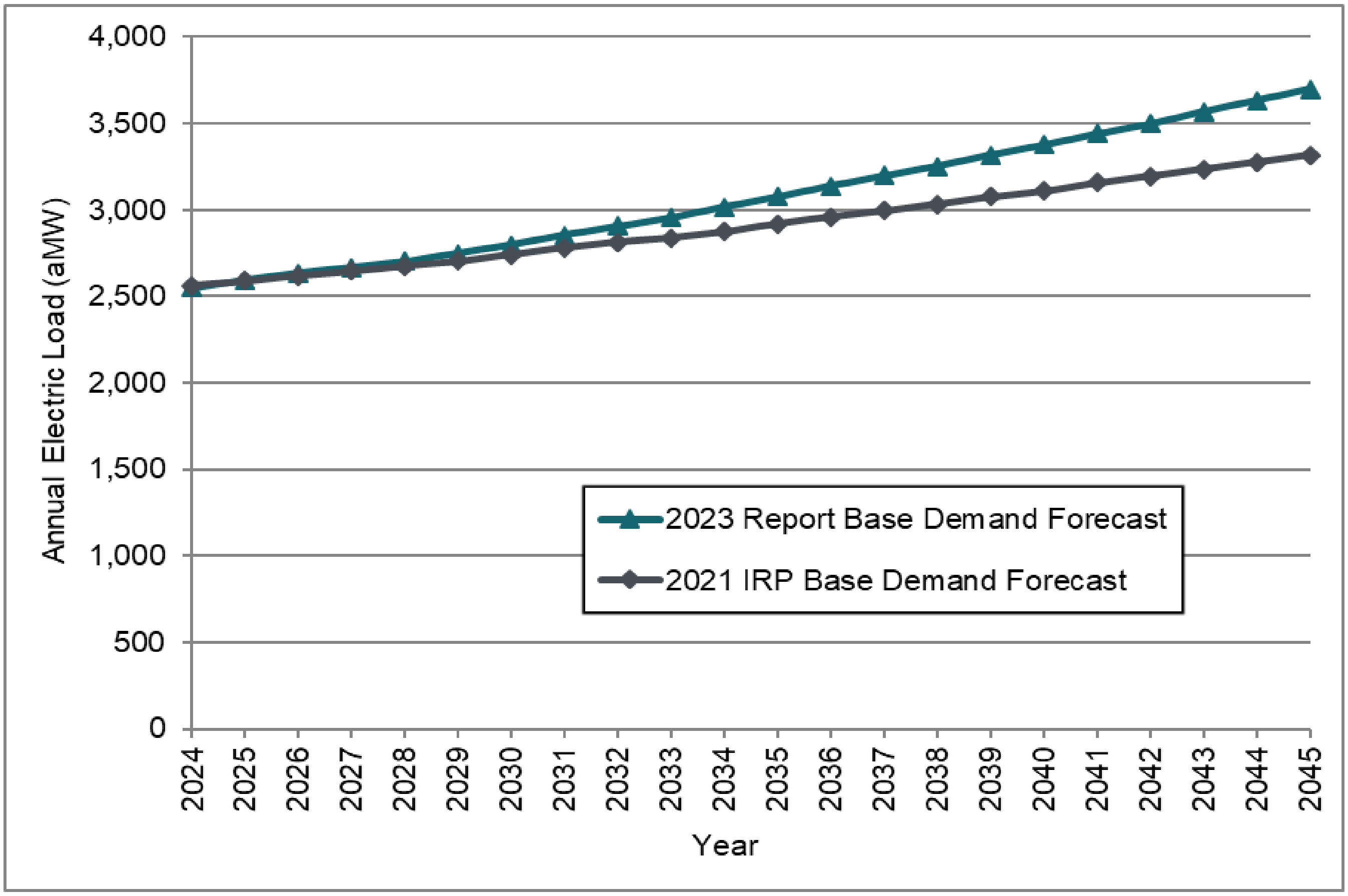


Table 6.3: Electric Energy Base Demand Forecast before Additional DSR (aMW)

Year	2024	2030	2035	2040	2045	AARG 2024-2045 (%)
Base Demand Forecast	2,551	2,799	3,076	3,378	3,699	1.8

3.2. Electric Peak Demand

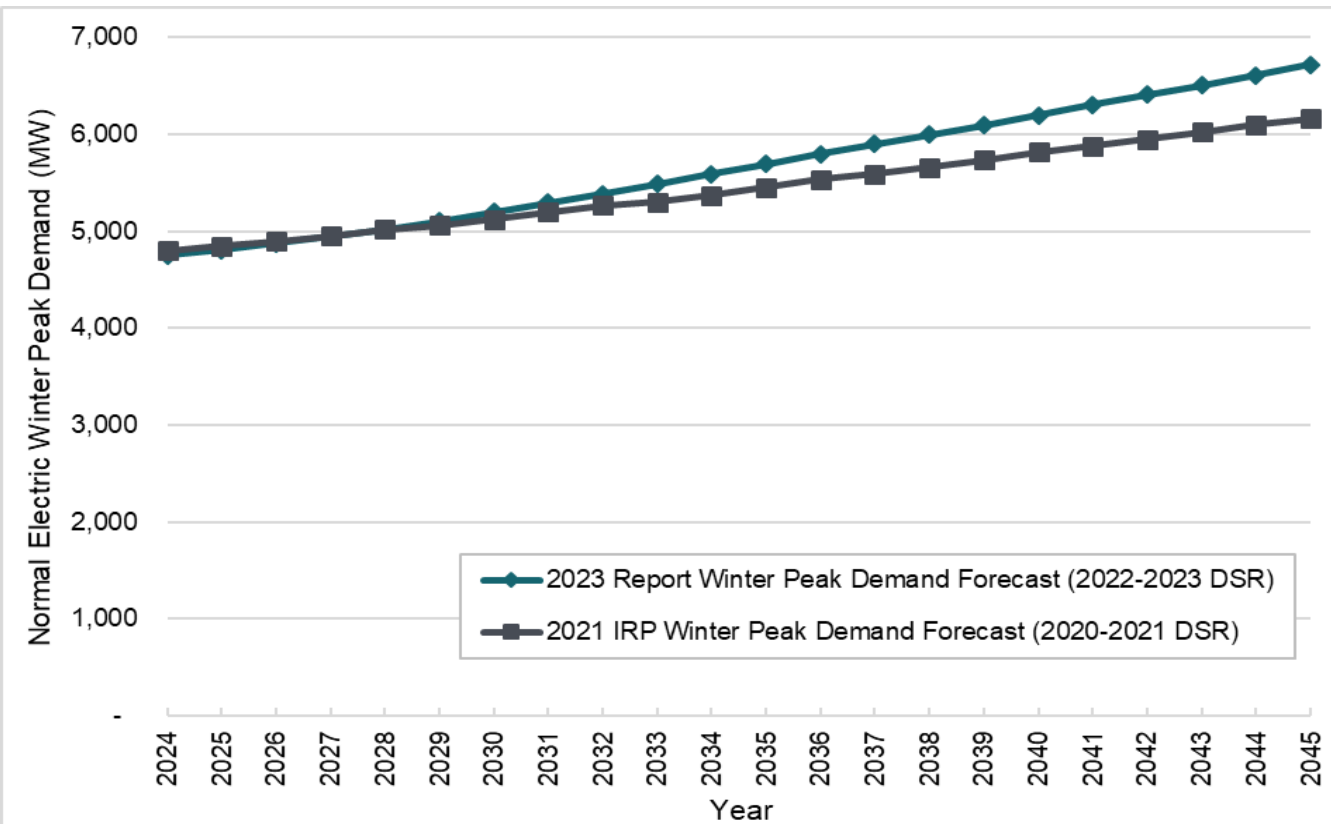
Puget Sound Energy is a winter peaking utility, which means the one hour with the highest demand of the year occurs in the winter. However, summer peaks are growing with warming summer temperatures and increased use of air conditioning and heat pumps for cooling. With the addition of data to reflect climate change modeling and the growing summer peaks, the team updated the capacity expansion model to analyze both winter and summer peaks. We provide a detailed discussion of the capacity expansion model in Appendix G, Electric Analysis Models. Different supply-side or demand-side resources may better meet a summer or a winter peak. Therefore, we consider demand during all hours of the year in resource adequacy modeling to help determine the best resources to meet the customer load. This section describes winter and summer electric peaks.

3.2.1. Winter Electric Peak Demand

We forecasted the normal electric winter peak hour demand with specific assumptions for normal peak conditions. We modeled the winter peak demand forecast with assumptions consistent with a one-in-two probability of occurrence. We define a winter peak event as a mid-week, non-holiday, and evening occurrence in December, with a temperature that reflects the climate change analysis (27- and 28-degrees Fahrenheit). We assumed these conditions because they are the expected conditions (50 percent or 1-in-2 probability) in which a peak event will occur based on historical system characteristics, forward-looking EV demand shapes, and climate change temperature projections.

It is important to note that actual winter peak demand may occur under different conditions, such as in the morning, at different temperatures, or in another month. For the base demand forecast, however, expected conditions are assumed. Please see the discussion on stochastic peak demand and hourly demand scenarios for variation in peak event conditions. Before demand-side resources, the 2023 Electric Report's base peak demand forecast grows at an average annual growth rate of 1.7 percent. This rate would increase peak demand from 4,753 MW in 2024 to 6,717 MW in 2045.

Figure 6.6: Winter Electric Peak Demand Forecast before Additional DSR
2023 Electric Report versus 2021 IRP Base Demand Forecast Hourly Annual Peak (MW)



Winter peak demand in the 2023 Electric Report base demand forecast is higher at the end of the study period (6,717 MW in 2045) than in the 2021 IRP (6,159 MW in 2045). Additionally, the 2023 Electric Report peak demand forecast has a faster average annual growth rate (1.7 percent) than the 2021 IRP (1.2 percent).

The 2023 Electric Report peak demand forecast projects faster growth than the 2021 IRP peak demand forecast because it includes a revised EV forecast that reflects more adoption and additional vehicle classes (medium and heavy duty). Observed actual customer and sales growth in 2020 and 2021 exceeded the 2021 IRP forecast, mainly due to less severe customer growth and demand declines due to economic turmoil. These positive impacts offset the step down in the forecast due to climate change and result in a forecast that starts at a point like the 2021 IRP base peak demand forecast.

3.2.2. Summer Electric Peak Demand

The team modeled the normal electric summer peak hour demand using 94 degrees Fahrenheit (2024–2029), 95 degrees Fahrenheit (2030–2033), and 96 degrees Fahrenheit (2034–2045) as the design temperatures. Summer peaks typically occur in July or August. Figure 6.7 shows the 2023 Electric Report’s base peak demand forecast for the winter and summer.

The 2023 Electric Report's base summer peak demand forecast has an average annual growth rate of 2.2 percent, increasing the summer peak demand from 3,820 MW in 2024 to 6,005 MW in 2045. Because the summer peak forecast does not exceed the winter peak forecast in the timeframe shown, we assumed PSE will continue to be a winter peaking utility for the planning period of this 2023 Electric Report.

Figure 6.7: Winter and Summer Electric Peak Demand Forecasts before Additional DSR
Hourly Annual Peak (MW)

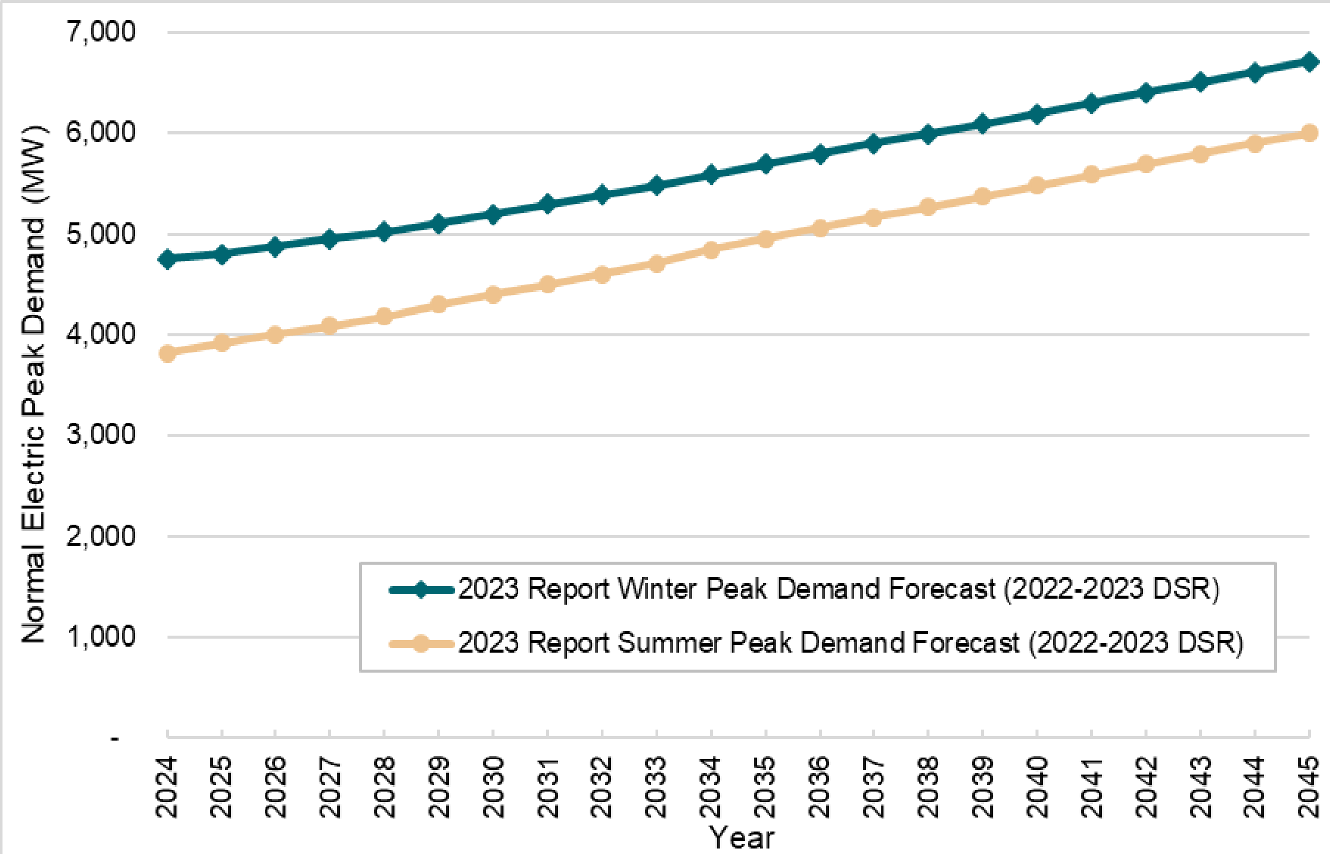


Table 6.4: Electric Peak Demand Forecast before Additional DSR
Winter and Summer Peaks, Hourly Annual Peak (MW)

Year	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Winter Demand Forecast	4,753	5,197	5,693	6,198	6,717	1.7
Summer Demand Forecast	3,820	4,401	4,953	5,481	6,005	2.2

The 2023 Electric Report's winter peak demand forecast consistently stays higher than the summer peak demand forecast for the entire planning horizon. Even with the projected higher growth rate using the climate change data for summer peak demand, the summer peak still does not come close to the winter peak. The spread between the two peaks goes from more than 900 MW in 2024 to more than 700 MW in 2045.

3.3. Impacts of Demand-side Resources

As we explained at the beginning of this chapter, the electric demand forecasts include only demand-side resources implemented through December 2023 since the demand forecast helps determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of DSR on the energy and peak forecasts, we applied the cost-effective amount of DSR determined in this 2023 Electric Report[3] to the base energy and peak demand forecasts for 2024–2045. To account for the 2013 general rate case Global Settlement,[4] we also applied an additional 5 percent of DSR for that period. Teams at PSE use forecasts with DSR for financial and system planning decisions. We illustrate the results in Figures 6.8 thru 6.10.

3.3.1. DSR Impact on Energy Demand

When we applied the DSR bundles chosen in the 2023 Electric Report portfolio analysis to the energy demand forecast:

- Electric energy demand after additional DSR grows at an average annual rate of 0.72 percent from 2024 to 2045
- Electric energy demand in 2045 will be reduced by 21 percent to 2,949 aMW

3.3.2. DSR Impact on Peak Demand

When we applied the DSR bundles chosen in the 2023 portfolio analysis to the winter evening and summer peak demand forecast:

- Electric system winter peak demand in 2045 is reduced 13 percent to 5,867 MW
- Electric system winter peak demand after additional DSR grows at an average annual rate of 1.0 percent from 2024 to 2045
- Electric system summer peak demand in 2045 is reduced 17 percent to 5,003 MW
- Electric system summer peak demand after additional DSR grows at an average annual rate of 1.3 percent from 2024 to 2045

[3] For demand-side resource analysis, see Chapter 8: Electric Analysis and Appendix E: Conservation Potential Assessment and Demand Response Assessment.

[4] For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and To Record Accounting Entries Associated With the Mechanism, Docket UE-121697 and UG-121705, Washington Utilities and Transportation Commission. Page 73 Line 162.

Figure 6.8: Electric Energy Demand Forecast (aMW), before Additional DSR and after Additional DSR

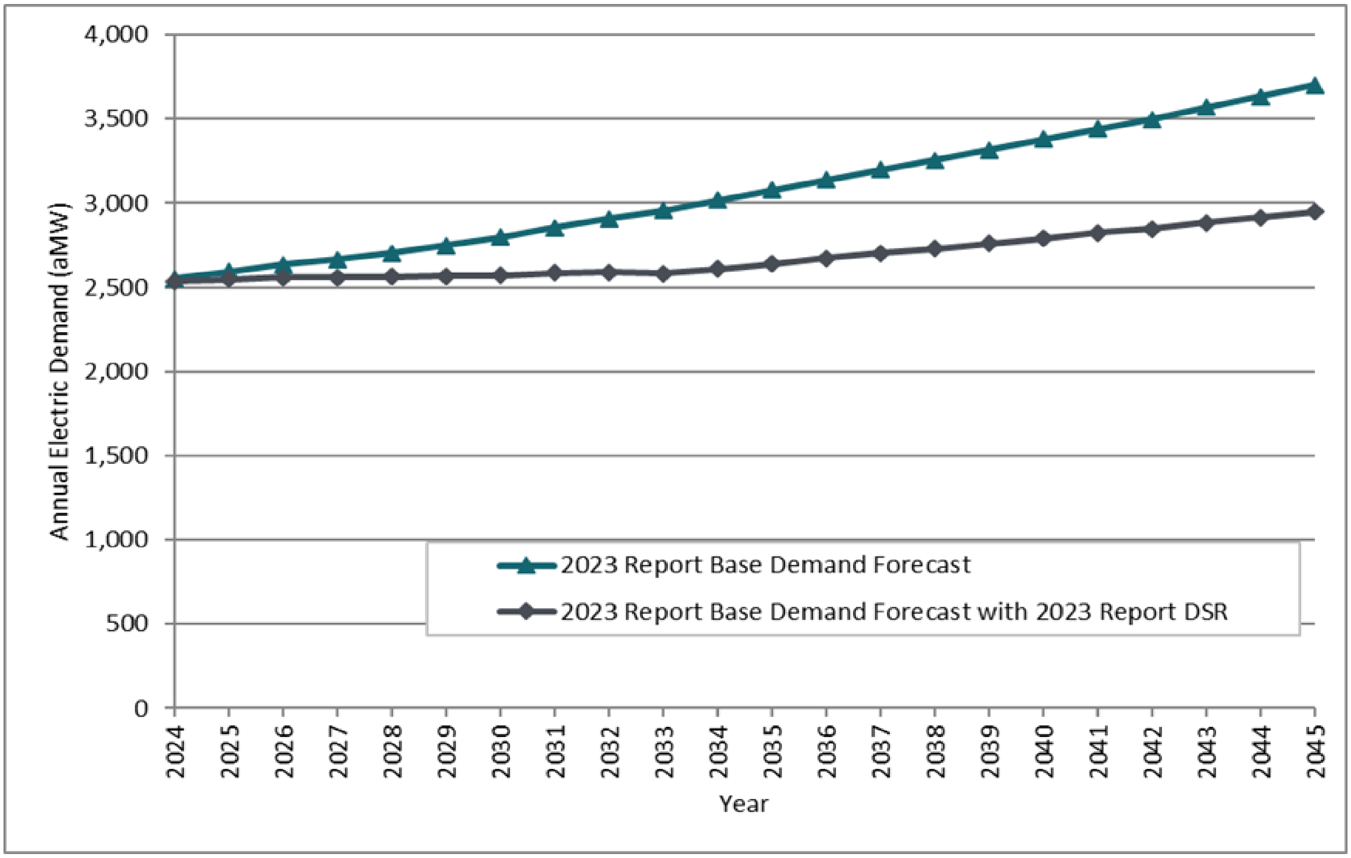


Figure 6.9: Electric Winter Peak Demand Forecast (MW), before Additional DSR and after Additional DSR

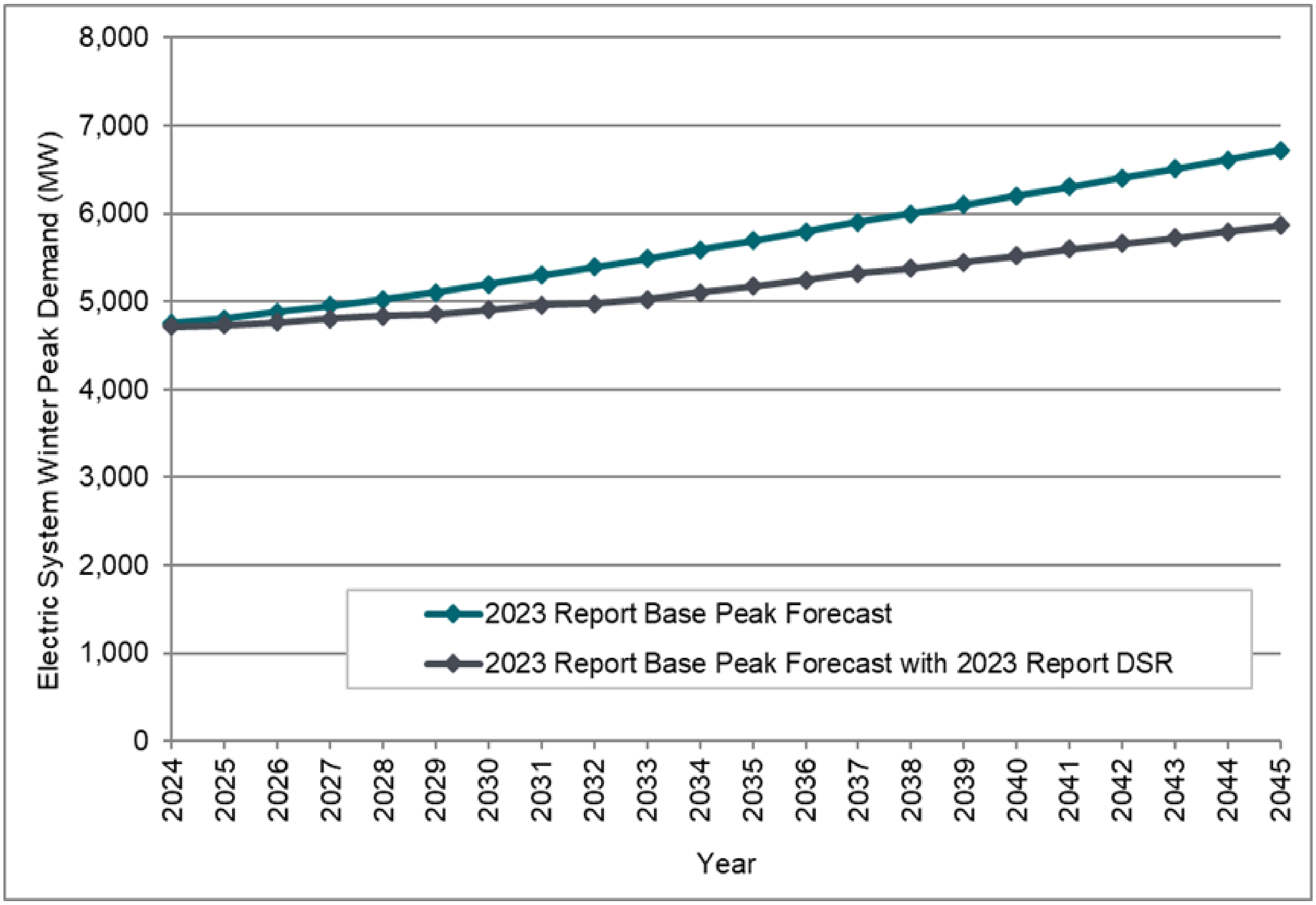
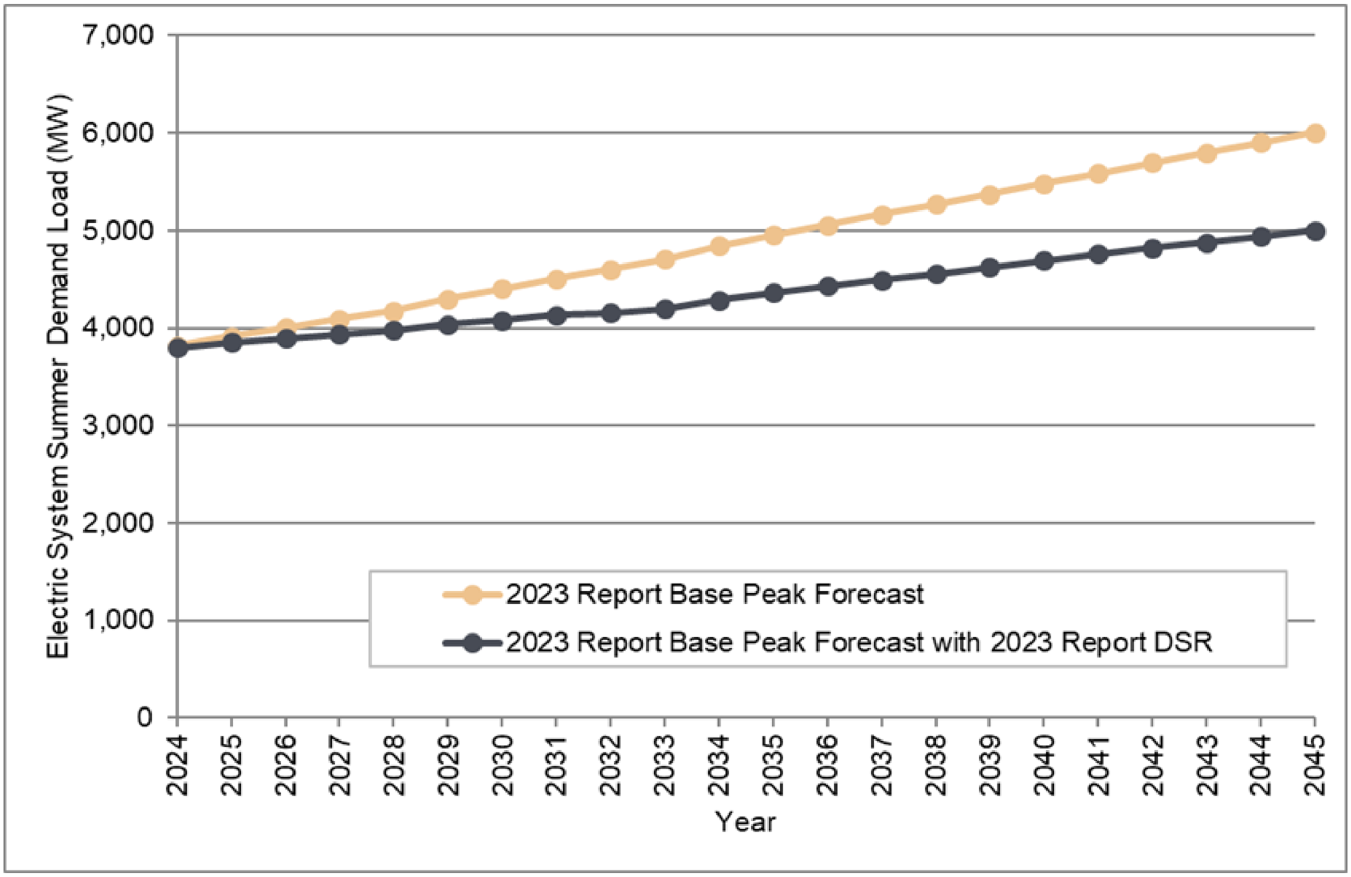


Figure 6.10: Electric Summer Peak Demand Forecast (MW), before Additional DSR and after Additional DSR



3.4. Details of the Electric Forecast

The electric forecast is comprised of demand from several different classes. These classes are residential, commercial, industrial, streetlight, and resale. We show details of each class in the following section.

3.4.1. Electric Customer Counts

We expect system-level customer counts to grow by 1.1 percent per year, from 1.25 million customers in 2024 to 1.57 million in 2045. This rate is faster than the average annual growth rate of 1.0 percent projected in the 2021 IRP base demand forecast.

Residential customers are PSE's largest customer class, with an approximately 88 percent share of electric customers by 2024. During the forecast period from 2024 to 2045, we expect residential customer counts to grow at an average annual rate of 1.1 percent per year. Commercial customers are PSE's second largest customer class, around 11 percent of total customers, and are expected to grow at an average annual rate of 1.3 percent per year over the forecast period. Industrial customer counts, around 0.3 percent of total customers, are expected to decline, following the historical trend of declining industrial activities in the service area. We expect these trends to continue as the economy in PSE's service area shifts toward more commercial and less industrial business sectors.

Table 6.5: December Electric Customer Counts by Class,
2023 Report Base Demand Forecast

Class	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Total	1,251,677	1,344,744	1,421,065	1,495,183	1,571,637	1.1
Residential	1,101,482	1,182,249	1,247,366	1,309,627	1,373,711	1.1
Commercial	138,449	149,815	160,282	171,484	183,126	1.3
Industrial	3,195	3,093	3,016	2,945	2,869	-0.5
Other	8,543	9,579	10,393	11,119	11,923	1.6

3.4.2. Electric Demand by Class

Over the next 20 years, we expect the residential and commercial classes to have positive demand growth, with the commercial class growing faster than the residential class before additional DSR. New customers and our projected rate of EV adoption create residential and commercial class demand growth.

Table 6.6: Electric Energy Demand by Class,
2023 Report Base Demand Forecast Before Additional DSR

Class	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Total	2,551	2,799	3,076	3,378	3,699	1.8
Residential	1,245	1,379	1,517	1,652	1,763	1.7
Commercial	986	1,085	1,204	1,349	1,534	2.1
Industrial	113	108	106	104	103	-0.5
Other	8	8	9	9	10	1.3
Losses	199	218	240	263	289	-

3.4.3. Electric Use per Customer

We expect residential use per customer, before additional DSR, to increase over the forecast period. Before EV adoption and climate change assumptions, residential use per customer is flat, but new demand from EVs outpaces usage losses due to lower normal HDDs due to the climate change update, resulting in positive net average use per customer demand growth. We expect commercial use per customer to increase over the forecast period due to EV adoption and higher normal CDDs. The non-residential classes have a lower share of energy demand devoted to heating, thus, are less impacted in the winter by lower normal HDDs.

Table 6.7: Electric Use per Customer,
2023 Report Base Demand Forecast Before Additional DSR

Type	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Residential	10.0	10.3	10.7	11.1	11.3	0.5
Commercial	62.8	63.7	66.1	69.4	73.7	0.7
Industrial	310.6	306.6	308.6	311.1	312.2	-0.1

3.4.4. Electric Customer Count and Energy Demand Share by Class

Table 6.8 shows customer counts as a percent of PSE's total electric customers. We show demand share by class in Table 6.9. We expect the share of residential customers and demand to remain stable over the forecast period before adjustment by the final DSR in the report analysis.

Table 6.8: December Customer Count Share by Class

Class	Share in 2024 (%)	Share in 2045 (%)
Residential	88.00	87.41
Commercial	11.06	11.65
Industrial	0.26	0.18
Other	0.68	0.76

Table 6.9: Energy Demand Share by Class, Before Additional DSR

Class	Share in 2024 (%)	Share in 2045 (%)
Residential	48.79	47.67
Commercial	38.67	41.49
Industrial	4.44	2.77
Other	0.30	0.27
Losses	7.80	7.80

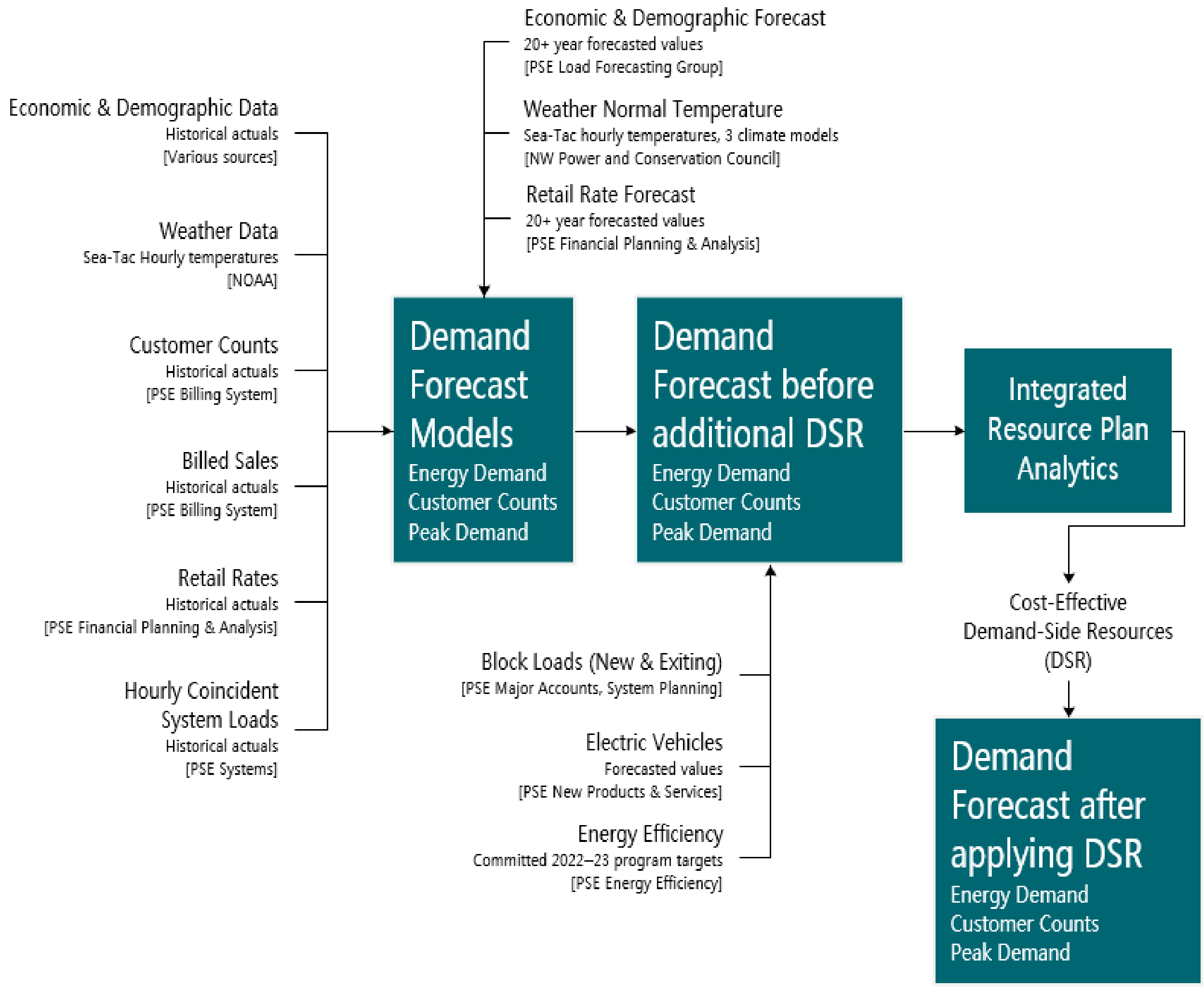
4. Methodology

We create relationships between historical growth and historical conditions to forecast customer demand. Therefore, we can use forecasted future conditions to forecast future growth. In the following section, we discuss how we forecasted demand.

4.1. Forecasting Process

Our regional economic and demographic model uses national and regional data to forecast total employment, employment types, unemployment, personal income, households, and consumer price index (CPI) for the PSE electric service area. We built the regional economic and demographic data used in the model from county-level information acquired from various sources. This economic and demographic information is combined with other PSE internal information to produce the base energy and peak demand forecasts for the service area. We illustrate the demand forecasting process in Figure 6.11 and list the economic and demographic input data sources in Table 6.10.

Figure 6.11: PSE Demand Forecasting Process



We divided customers into classes and service levels that use energy for similar purposes and at comparable retail rates to forecast energy sales and customer counts. We modeled the different classes and service levels using variables specific to their usage patterns. Electric customer classes include residential, commercial, industrial, streetlights, and resale. Although PSE provides electric transmission services to customers who purchase power from third-party suppliers, we did not include demand from these customers in the 2023 Electric Report's demand forecast.

We used multivariate time series econometric regression equations to derive historical relationships between trends and drivers and then employed them to forecast the number of customers and use per customer by class or service level. We multiplied these factors to arrive at the billed sales forecast. The main drivers of these equations include population, unemployment rates, retail rates, personal income, HDDs, CDDs, total employment, manufacturing employment, CPI, and U.S. Gross Domestic Product (GDP). We calculated demand from sales and included transmission and distribution losses in addition to sales. We based weather inputs on NOAA temperature readings at Sea-Tac Airport and incorporated historical and forecasted temperatures, including the effects of climate change. We also projected peak system demand by evaluating the historical relationship between actual peaks, the temperature at peaks, average system demand, day of the week, time of day, holidays, and estimated air conditioning trends. We forecasted peak demand with the future temperature at peak plus expected EV peak demand growth.

➔ See Appendix F: Demand Forecasting Models for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts, peak demand, hourly distribution of electric demand, and forecast uncertainty.

Table 6.10: Sources for County Economic and Demographic Data in Economic and Demographic Model

County-level Data	Source
Labor force, employment, unemployment rate	U.S. Bureau of Labor Statistics (BLS) www.bls.gov
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department (WA ESD), using data from the Quarterly Census of Employment and Wages esd.wa.gov/labormarketinfo
Personal income	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Population	WA State Employment Security Department (WA ESD) esd.wa.gov/labormarketinfo/report-library
Households, single- and multi-family	U.S. Census www.census.gov
Household size, single- and multi-family	U.S. Census www.census.gov
Aerospace employment, Regional Consumer Price Index (CPI)	Puget Sound Economic Forecaster www.economicforecaster.com

We obtained country-level economic and demographic data from Moody's Analytics.[5] The inputs into PSE's economic and demographic model from Moody's Analytics are gross domestic product (GDP), industrial production index, employment, unemployment rate, personal income, wages and salary disbursements, consumer price index (CPI), housing starts, population, conventional mortgage rate, and the three-month T-bill rate.

4.2. Stochastic Scenarios

We used stochastic analysis[6] to look at variability in our assumptions. We developed 310 stochastic scenarios to examine changes in the economic, demographic, electric vehicle, and temperature assumptions. We also examined model uncertainty in the stochastics. These 310 alternate future pathways for customer growth, energy demand per customer, and peak demand let us test the portfolio to see how it responds to conditions other than the base demand.

5 economy.com

6 Stochastic scenarios are created with a randomly determined set of inputs, which creates a probability distribution.

We created and ran 310 electric stochastic scenarios in the AURORA portfolio model to test the portfolio's robustness under various conditions. We show the range of the stochastics in Figures 6.12 through 6.14. Energy demand in 2045 ranges from 2,724 aMW to 4,743 aMW in the energy stochastic scenarios. Winter peak demand in 2045 ranges from 5,160 MW to 8,551 MW, and summer peak demand in 2045 ranges from 4,438 MW to 7,171 MW in the peak stochastic scenarios.

We develop stochastic simulations with outputs from PSE's economic and demographic model, variation in underlying econometric model uncertainty, electric vehicle adoption, and future temperatures from three climate models. We modeled electric energy and peak demand stochastic scenarios using 310 stochastic simulations. The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment, and income. The simulations also capture model uncertainty through stochastic variation of model statistics associated with underlying econometric models of average energy demand per customer, customer growth, and peak demand. We held electric vehicle assumptions constant in 250 scenarios, applied a high EV forecast to 30 scenarios with high economic outlooks relating to total employment, and applied a low EV forecast to another 30 scenarios with low economic scenarios with respect to total employment.

The stochastic scenarios use future temperatures from the CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA models, reflecting higher or lower temperature conditions. We sampled forecasted temperature years 2020–2049 from the three models for the 310 draws.

We ran the 310 electric stochastic scenarios in the AURORA portfolio model to test the portfolio's robustness under various conditions.

➔ Detailed descriptions of the stochastics are available in Chapter Eight: Electric Analysis.

Figure 6.12: Range of Energy Demand in Stochastic Scenarios Around Base Energy Demand Forecast (aMW) Before Additional DSR

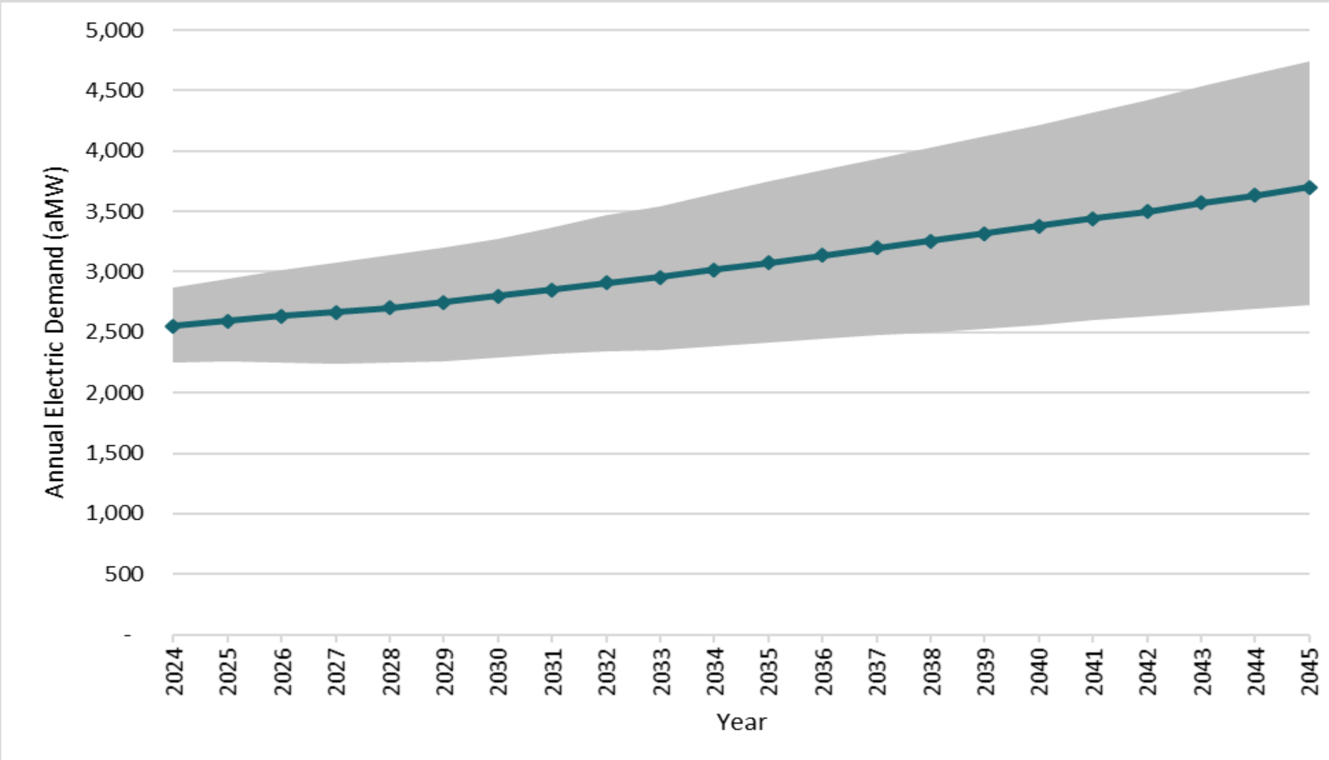


Figure 6.13: Range of Winter Peak Demand in Stochastic Scenarios around Base Peak Demand Forecast (MW) Before Additional DSR

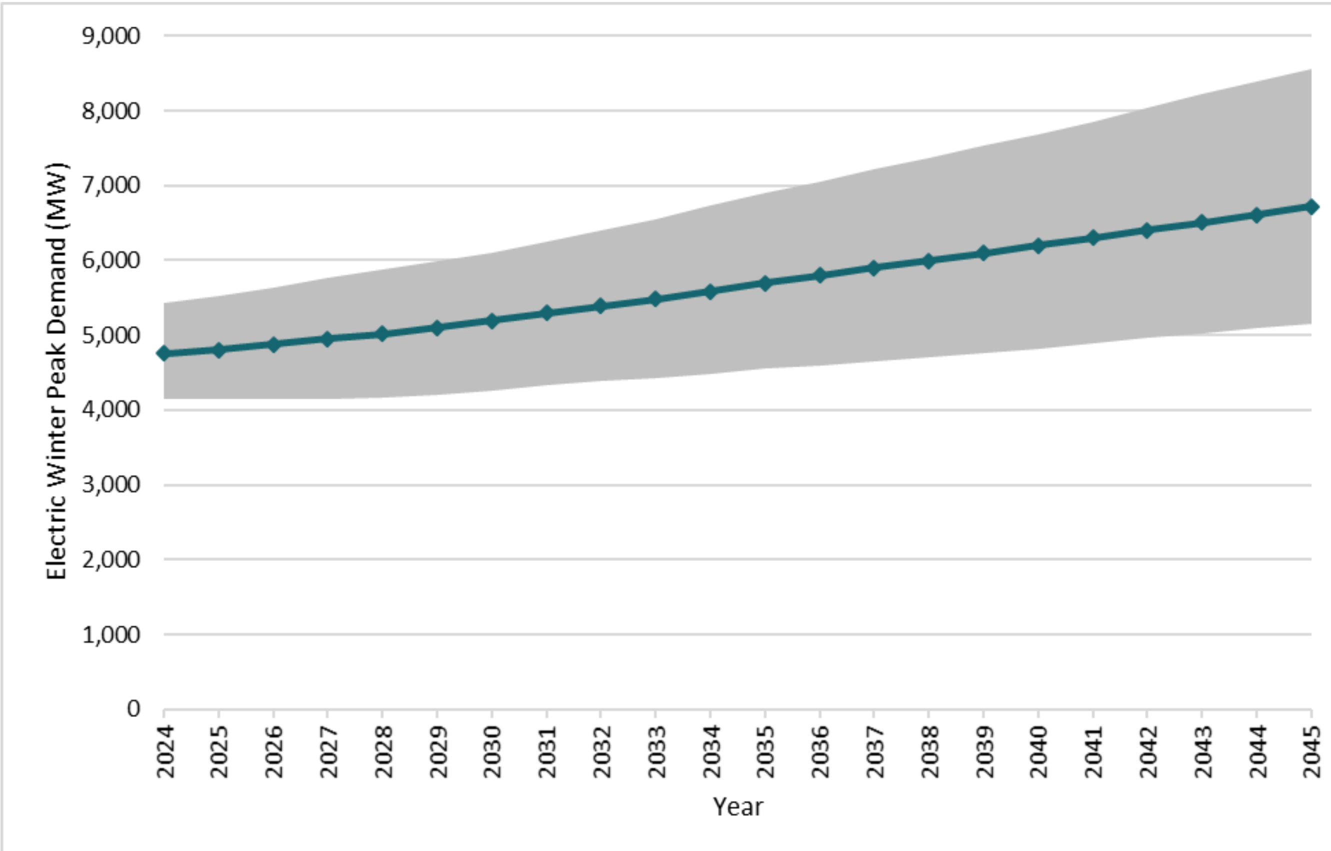
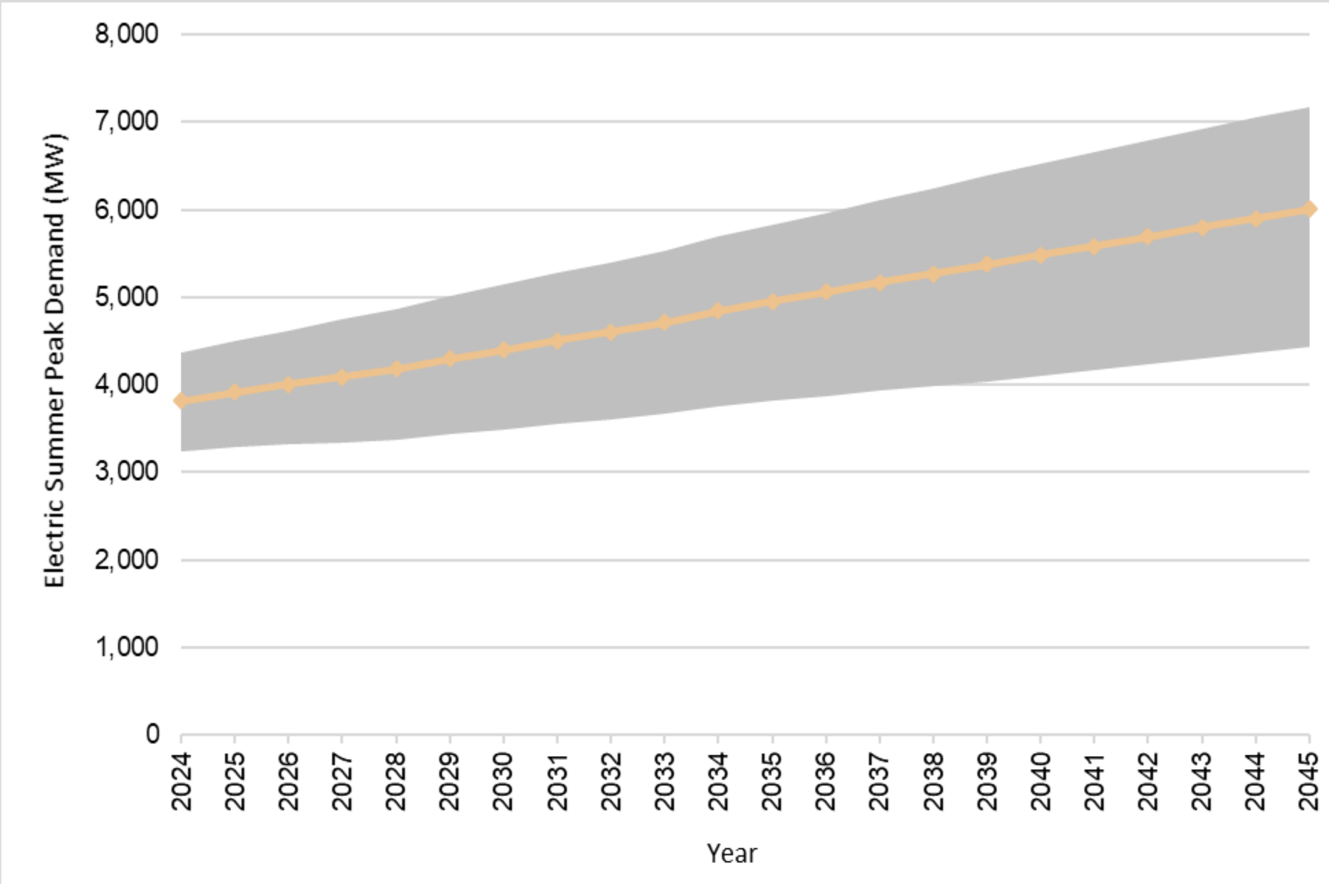


Figure 6.14: Range of Summer Peak Demand in Stochastic Scenarios around Base Peak Demand Forecast (MW) Before Additional DSR



➔ See Appendix F: Demand Forecasting Models for a detailed discussion of the stochastic simulations.

4.3. Resource Adequacy Model Inputs

In addition to the stochastic scenarios mentioned in the previous section, we also developed 90 electric demand draws for the resource adequacy (RA) model. We created these demand draws with stochastic outputs from PSE's economic and demographic model and two consecutive future weather years using the future temperatures from the climate change models. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each future heating season. We created RA demand draws for the hydro years 2028–2029 and 2033–2034.

The RA model also examines adequacy in each hour of a given year; therefore, we scaled the 90 demand draws we used for RA model inputs to hourly demand using the hourly demand model. We created each of the 90 hourly demand forecasts without electric vehicle demand to account for growth in electric vehicles, then added the hourly forecast of electric vehicle demand to each demand forecast to create the final 90 hourly demand forecasts.

We highlight the differences between the RA model inputs and the stochastic scenarios in Table 6.11.

Table 6.11: Differences between the Resource Adequacy Model Inputs and the Stochastic Scenarios

Analysis Attribute	Stochastic Scenarios	Resource Adequacy Model
Number of draws	310	90
Forecasted years	2024–2045	October 2028–September 2029 and October 2033–September 2034
Model detail level	Monthly demand and peak demand	Hourly demand
Economic and demographic variation	Included	Included
Climate change impacts	Yes	Yes
Temperature assumptions	Forecasted temperatures from years 2020–2049 were sampled from the three climate change models — one year chosen for each draw	Forecasted temperatures from years 2020–2049 were used from the three climate change models — two consecutive weather years were chosen for each draw
Electric vehicles	Base forecast used in 250 draws, high used in 30 draws, low used in 30 draws	Base forecast used in each draw
Electrification and other conversion policies	No	No
Purpose	Used in the AURORA portfolio model to test the robustness of the portfolio under various conditions	Used in the resource adequacy modeling that determines the effective load-carrying capabilities (ELCCs)

➔ See Chapter Seven: Resource Adequacy Analysis, and Appendix F: Demand Forecasting Models for a detailed discussion of the hourly model.

4.4. Updates to Inputs and Equations

The following section summarizes updates to the demand forecast inputs and equations made since the 2021 IRP.

4.4.1. Climate Change Forecast

Previous IRPs used the most recent 30 years of historical temperatures to forecast what temperatures will be during the forecast. In this 2023 Electric Report, we used three climate change models by the NWPCC to establish an assumption of future normal temperatures. Section 2 Climate Change of this chapter details how we developed and used climate models in the forecast of this chapter details how we developed and used climate models in the forecast.

4.4.2. Peak Modeling of Morning versus Evening

This 2023 Electric Report explicitly assumes an evening peak and its temperature impacts. Although a winter peak may occur in the morning or the evening, current characteristics of PSE's system demand indicate, on a weather and day-of-week normalized basis, higher levels of demand in the evening (around 200 MW) compared to the morning. This finding is consistent with historically observed December peaks (hour ending 18 on a weekday). Additionally, in the future forecast period, as the EV forecast grows, the difference between morning and evening peaks grows to be more than a few hundred MWs with larger EV peak demand in the evening, thus further decreasing the long-term likelihood of a morning peak occurrence. As part of our evaluation of the climate change temperature models, we recognized that the one-in-two minimum seasonal, hourly temperature for a winter evening is warmer than the morning. Hence, we calculated the typical effect of this assumption in the climate change datasets, which results in around two-degree warming to reflect evening conditions. This update reduced the winter peak demand forecast. This assumption does not impact summer peak temperature projections, as summer peaks always occur in the evening when the temperature is warmest.

4.4.3. 2018 Washington State Energy Code

The 2018 Washington State energy code change took effect in 2021. We considered the impact of this code change from 2021 through 2023 in the 2023 Electric Report forecast to understand the starting point for the forecast in 2024. The Conservation Potential Assessment (CPA) will determine the effects of this code change starting in 2024 and will also include the statutory requirement for the Washington State code cycle to make the code more stringent in terms of energy use. The law requires that the WA State code be improved in each code cycle update to achieve a 70 percent reduction in energy use by 2031 compared to the 2006 WA State code baseline. Therefore, a small amount of this code change is in the forecast, but we will account for most of this code change after the additional DSR forecast.

5. Key Assumptions

To develop PSE's demand forecasts, we must make assumptions about economic growth, energy prices, weather, and loss factors, including certain system-specific conditions. We describe these and other assumptions in the following section.

5.1. Economic Growth

Economic activity has a significant effect on long-term energy demand. Although the energy component of the national GDP has been declining over time, energy is still an essential input into various residential end uses such as space heating and cooling, water heating, lighting, cooking, dishwashing, clothes washing, electric vehicles, and other electric plug loads. The growth in the residential building stock, therefore, directly impacts the demand for energy over time. Commercial and industrial sectors also use energy for space heating and cooling, water heating, lighting, and other plug loads. Energy is also a critical input into many industrial production processes. Economic activities in the commercial and industrial sectors are, therefore, essential indicators for the overall trends in energy consumption.

5.1.1. National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, the 2023 Electric Report forecast begins with assumptions about what is happening in the broader U.S. economy. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. We used the November 2021 Moody's forecast for this 2023 Electric Report.

The Moody's forecast predicts:

- The economy will continue to recover from the COVID-19 pandemic with a return to full employment in 2023, and labor force participation will continue to increase as workers get healthy and children get vaccines.
- The recovery will continue through 2025. After 2025, Moody's predicts the economy will grow modestly in the long term.
- U.S. GDP will continue to grow over the forecast period with a 2.0 percent average annual growth from 2024–2045. This growth rate is lower than the Moody's forecast used in the 2021 IRP, which projected 2.2 percent average annual growth, but some of the 2021 IRP growth was from the projected recovery from COVID-19.

Moody's identified possible risks that could affect the accuracy of this forecast:[7]

- In the near term, supply constraints could cause the economy to grow less quickly.
- Rising long-term interest rates could cause a slump in the economic recovery.
- The congressional stimulus for COVID-19 could be smaller than predicted or not provide the boost to the economy that is predicted.
- The economic effects of COVID-19 are still unpredictable; additional waves that elude the vaccine could halt recovery.

5.1.2. Population Outlook

The Washington State Employment Security Department (WA ESD) average annual growth rate for the counties that make up the electric service area is 0.88 percent for 2024–2045. This rate is down from the 1.0 percent growth rate forecast in the 2021 IRP 2022–2045.

5.1.3. Regional Economic Outlook

We prepare regional economic and demographic forecasts using econometric models based on historical economic data for our service area counties and the United States macroeconomic forecasts.

Puget Sound Energy's electric service area stretches from south Puget Sound to the Canadian border and from central Washington's Kittitas Valley west to the Kitsap Peninsula. Puget Sound Energy serves more than 1.2 million electric customers in eight counties.

[7] Moody's Analytics (2021, November) Forecast Risks. Precis U.S. Macro. Volume 26 Number 8.

Within PSE's service area, demand growth is uneven. Most economic growth is driven by high-tech, information technology, or retail (including online retail). Supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for the largest share of the system electric sales demand today. Other counties are growing, but typically at lower magnitudes, and have added fewer jobs.

We used the following forecast assumptions in the 2023 Electric Report base electric demand forecast:

- We expect an inflow of 898,000 new residents (by birth or migration) to increase the local area population to 5.33 million by 2045, for an average annual growth rate of 0.88 percent. This growth rate is slightly lower than the 2021 IRP forecast, which projected an average annual population growth of 0.9 percent that would have resulted in 5.13 million electric service area residents by 2045.
- We expect employment to grow at an average annual rate of 0.46 percent between 2024 and 2045, smaller than the 0.6 percent annual growth rate forecasted in the 2021 IRP.
- We expect local employers to create about 205,681 total jobs between 2024 and 2045, mainly driven by growth in the commercial sector, compared to about 310,000 jobs forecasted in the 2021 IRP.
- We expect manufacturing employment to decline by 0.32 percent annually between 2024–2050 due to outsourcing manufacturing processes to lower wages or less expensive states or countries and the continuing trend of capital investments that increase productivity.

Table 6.12 shows the population and employment forecasts for PSE's electric service area.

Table 6.12: Population and Employment Growth, Electric Service Counties (1,000s)

Model Driver	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Population	4,436	4,716	4,938	5,136	5,334	0.88
Employment	2,215	2,291	2,340	2,380	2,421	0.46

5.2. Weather

In this 2023 Electric Report, PSE incorporated Climate Change temperatures from three climate models to calculate the normal temperatures for the base energy demand forecast and the design peak temperature for the base peak demand forecast. Section 2 Climate Change of this chapter and Appendix F: Demand Forecasting Models discuss more details of how we created this forecast.

➔ Appendix F: Demand Forecasting Models discusses more details of how we created this forecast.

5.3. Electric Vehicles

The energy consulting firm Guidehouse created an EV forecast for PSE in late 2021. This EV forecast includes two recent pieces of legislation: the Zero Emission Vehicles law of 2020 and the Clean Fuel Standard law of 2021. The forecast assumes 95,000 EVs on the road in PSE's service area in 2024, including light-, medium-, and heavy-duty vehicles. This forecast will increase to 1,147,000 EVs in 2045. Annual energy sales from new electric vehicles total 183,000 MWh in 2024 and 4,815,000 MWh in 2045.

We assumed that 74 percent of the charging from new EVs would be at residential locations, while the remaining 26 percent would be at commercial sites. This percentage changes during the forecast period as charging at commercial locations becomes more widely available. This percentage also changes as more medium- and heavy-duty electric vehicles become available and cost-effective, resulting in 35 percent of EVs charging on residential accounts and 65 percent charging on commercial accounts in 2045. Electric vehicles, especially medium- and heavy-duty models, are an emerging technology; thus, we anticipate we will revise this forecast on an ongoing basis.

The additional demand from electric vehicles grows to a 19 percent share of total peak demand by 2045 before including the cost-effective DSR identified in the 2023 Electric Report. Figure 6.15 shows the December evening peak demand, and Figure 6.16 shows the annual average energy demand from new electric vehicles. Figure 6.17 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Guidehouse also created high and low EV forecasts for PSE in late 2021. The consulting firm created the high and low EV scenarios representing the 90th and 10th percentile. Figures 6.15 and 6.16 show the high and low electric vehicle energy and peak forecasts used in the stochastic scenarios.

Figure 6.15: Electric Vehicle Average Energy Demand from New Vehicles (aMW)
Base, High, and Low

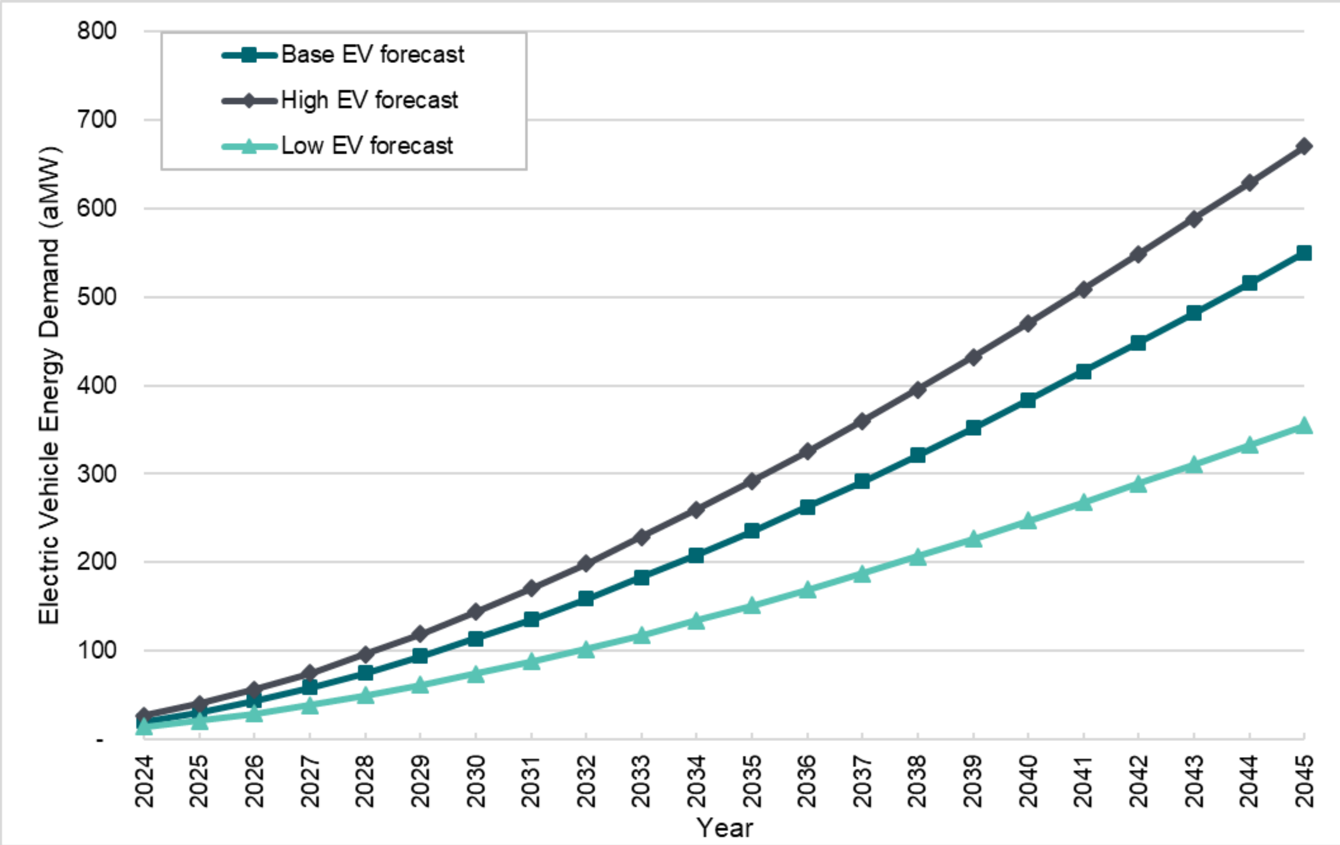


Figure 6.16: Electric Vehicle Peak Demand from New Vehicles (MW)
Base, High, and Low

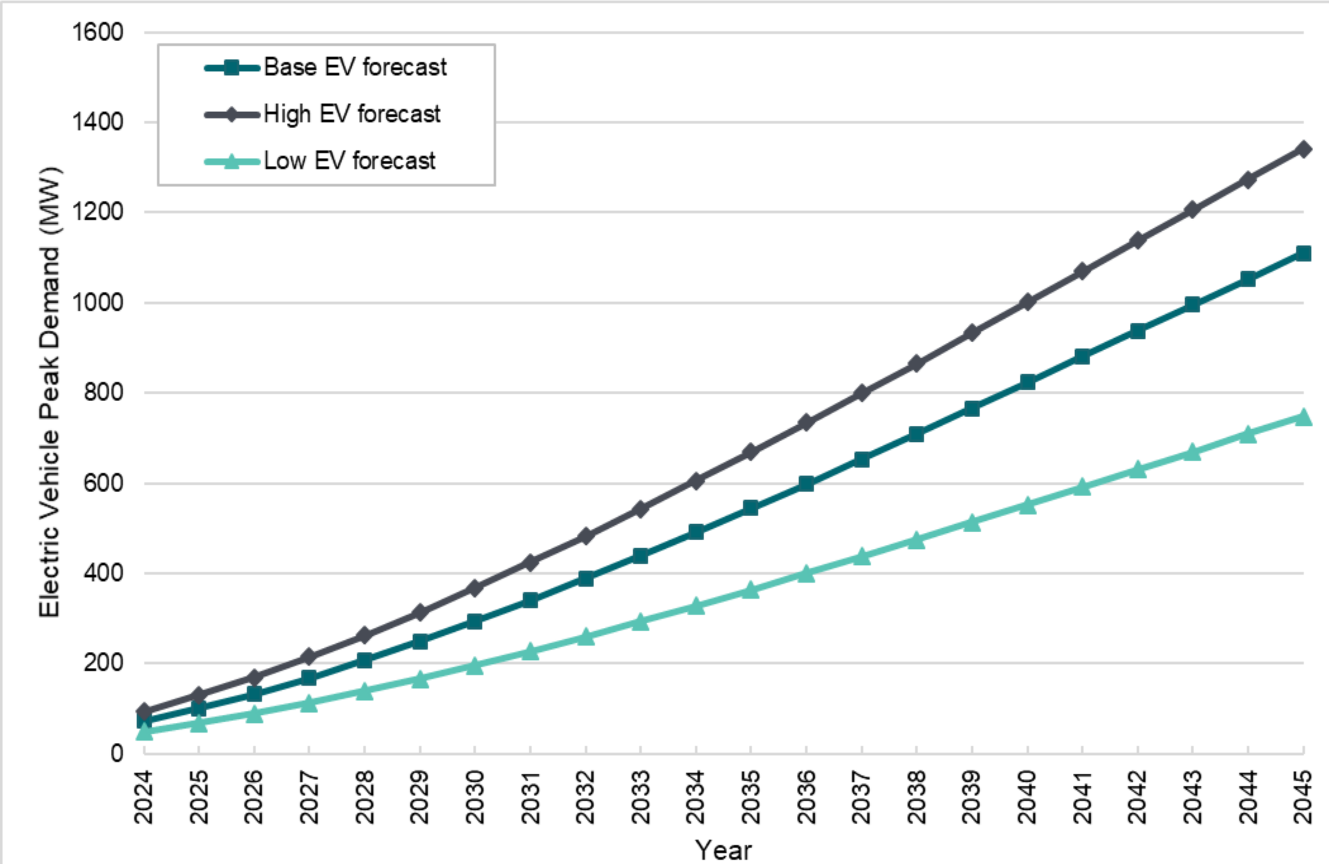
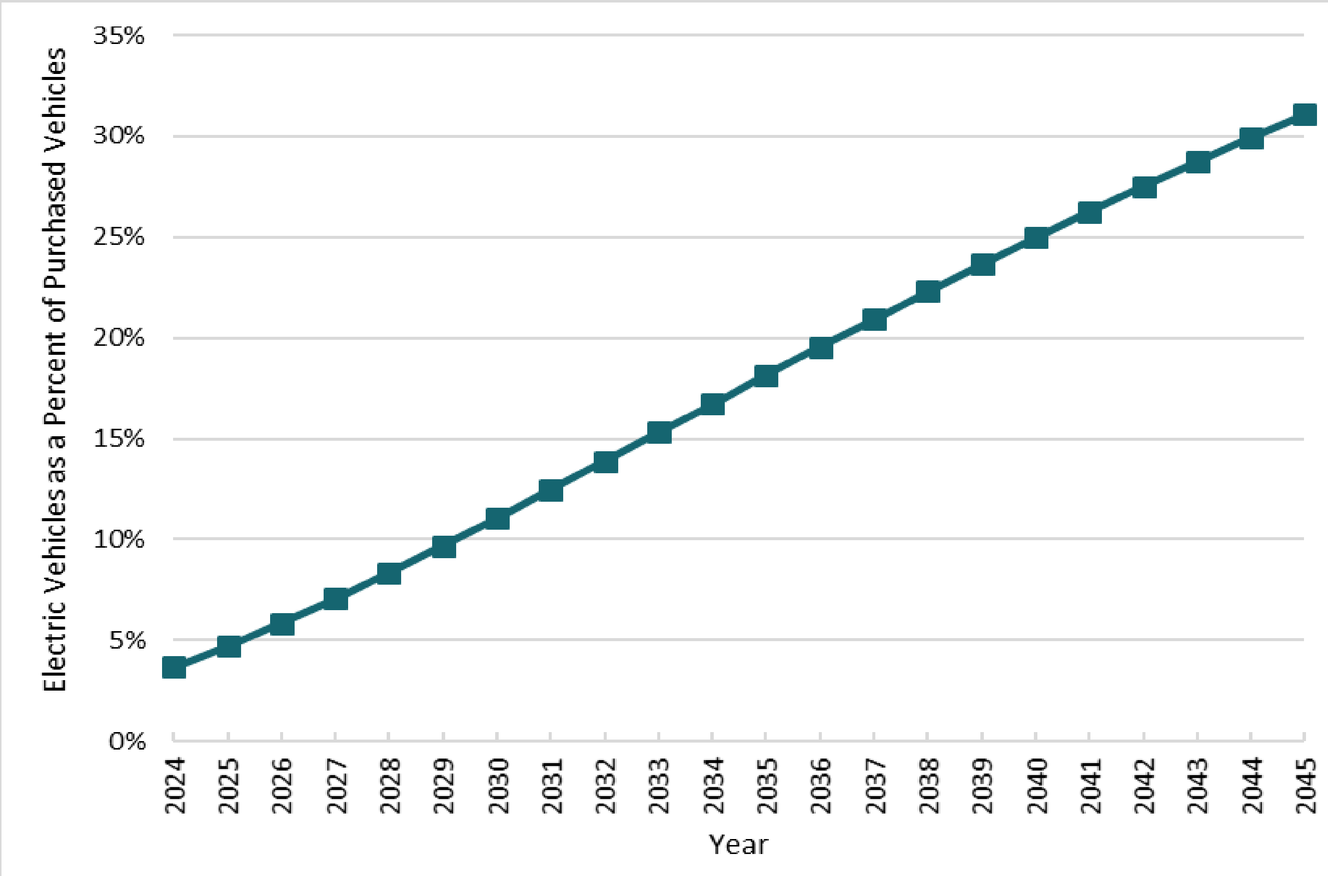


Figure 6.17: Electric Vehicles as a Percent of Purchased Vehicles



5.4. COVID-19 Impacts

After 2022, we made no explicit COVID-19 or remote work adjustments above and beyond the effects of the economic forecast incorporated into the demand forecast using the macroeconomic variables. The result is a slow recovery over the following few years and a recovered economy by 2024, with lingering effects from the recession persisting thorough out the remainder of the forecast. There exists a great deal of uncertainty around the steady state level of residential and commercial usage once behaviors developed during the pandemic settle.

We performed stochastic simulations that varied the economic forecast around this base forecast. These included simulations with better and worse economic outcomes. Since the 2023 Electric Report determines the resource need starting in 2024, the stochastic simulations show alternative ways the pandemic could resolve in the future.

5.5. Loss Factors

The electric loss factor is 7.8 percent. The loss factors we assumed in the demand forecast are system-wide average losses during normal operations for the past two to three years.

5.6. Block Load Additions

Beyond typical economic change, the demand forecast also considers known major demand additions and deletions that we would not account for through typical demand growth in the forecast. Most of these additions are from major infrastructure projects. These additions to the forecast are called block loads, and they use the information provided by PSE's system planners or major accounts. The adjustments to non-transport customers will add 85.6 MW of connected demand by 2025 for the electric system. We included these block loads in the commercial class, and King County has most of the additions.

5.7. Schedule Switching

In addition to block loads, PSE accounts for customers switching rate schedules. Customers who purchase their own electricity are called transport customers, and they rely on PSE for distribution services. In this 2023 Electric Report, we removed transport customers from the forecast before determining supply-side resource needs because PSE is not responsible for acquiring supply resources for electric transport customers.

5.8. Interruptible Demand

Puget Sound Energy has 151 electric interruptible customers; six are commercial and industrial customers, and 145 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 12 MW of coincident peak demand. In this 2023 Electric Report, we accounted for the 12 MW of demand that is interruptible from these customers

5.9. Retail Rates

We included retail energy prices — what customers pay for energy — as explanatory variables in the demand forecast models because they affect customer choices about the efficiency level of newly acquired appliances and how they are used — the energy source used to power them. The retail rate forecasts draw on information obtained from internal and external sources.

5.10. Distributed Generation

We did not include distributed generation, including customer-level generation via solar panels, in the demand forecast after 2023; we captured this energy production in the 2023 Electric Report modeling process as a demand-side resource. We include a description in Appendix E: Conservation Potential Assessment and Demand Response Assessment. .

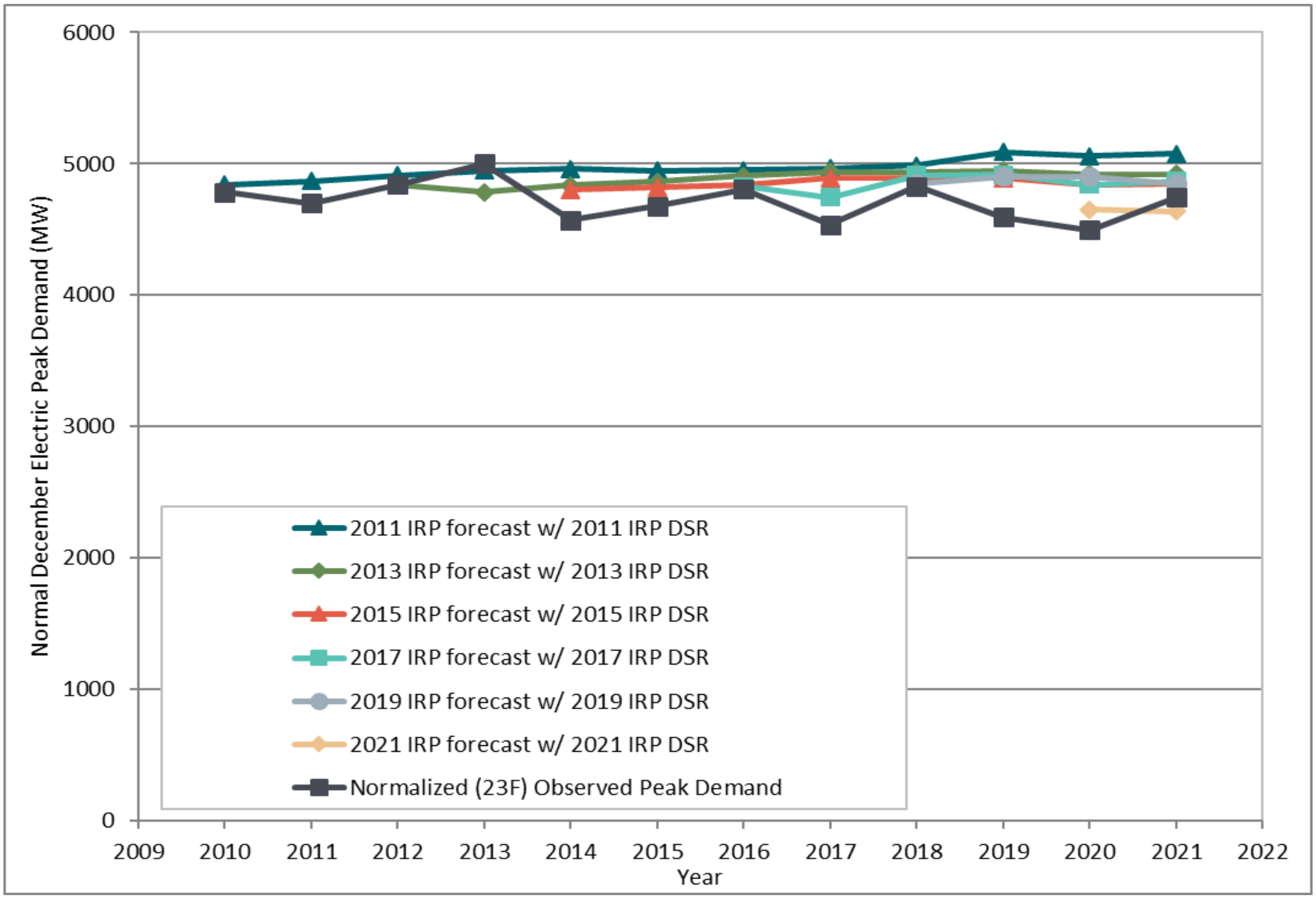
6. Previous Demand Forecasts

The following section compares actual peak demand to previous IRP forecasts. This section also identifies reasons prior forecasts may be off from current weather-normalized actual peaks.

6.1. IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6.18 compares 2011, 2013, 2015, 2017, 2019,[8] and 2021 IRPs' base peak demand forecasts after additional DSR with normalized[9] actual observations. We noted that the normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of the week and time of day of the actual peak. We present the percent difference of normalized actual values compared to each IRP forecast for each year in Table 6.12.

Figure 6.18: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



8 A formal IRP was not filed by PSE in 2019. On October 28, 2019, the Washington Utilities and Transportation Commission Staff filed a Petition for Exemption from WAC 480-100-238 pursuant to WAC 480-07-100 until December 31, 2020. On November 7, 2019 the WUTC held an Open Meeting concerning this matter and subsequently issued Order 2, exempting PSE (and other investor owned utilities in Washington) from WAC 480-100-238. Pursuant to Order 2, PSE filed an IRP Progress Report in 2019.

9 Given that the forecasts are for peaks at a design temperature, observed actual peaks are adjusted to reflect what would have been the peak if the design peak temperatures had been achieved.

Table 6.12: Weather Normalized December Electric Peak Demand and Difference from Previous IRP Forecasts

Year	2011 (%)	2013 (%)	2015 (%)	2017 (%)	2019[8] (%)	2021 (%)
2010	1.2	-	-	-	-	-
2011	3.6	-	-	-	-	-
2012	1.5	-0.1	-	-	-	-
2013	-1.0	-4.3	-	-	-	-
2014	8.5	5.8	5.1	-	-	-
2015	5.7	4.0	3.0	-	-	-
2016	3.1	2.1	0.8	0.5	-	-
2017	9.5	8.8	7.8	4.6	-	-
2018	3.3	2.3	1.2	1.7	0.5	-
2019	10.8	7.7	6.5	7.1	6.8	-
2020	12.6	9.5	7.7	7.7	9.1	3.5
2021	7.1	3.8	2.2	2.6	2.8	-2.2

6.1.1. Reasons for Forecast Variance

As explained throughout this chapter, we based the IRP peak demand forecasts on forecasts of key demand drivers, including expected economic and demographic behavior, DSR, customer usage, and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. As forecasts age, assumptions and conditions may change. Because of these changes, we expect older predictions to be farther off from observed actuals than more recent forecasts. We explain these differences in the next section.

Economic and Demographic Forecasts

Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the U.S. economy, many economists, including Moody's Analytics, assumed that the economy would recover sooner than it did. We pushed out a complete recovery with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare Moody's forecasts of U.S. housing starts and population growth that we incorporated in the 2011 IRP through the 2019 IRP with actual U.S. housing starts and population growth. Moody's too-optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Puget Sound Energy now uses county population forecasts sourced from Washington's ESD to forecast the population in PSE's service area. We included Moody's forecast of housing starts and population from May 2020 and Nov 2021 in Figures 6.19 and 6.20 for comparison.

Additionally, while the Moody's forecast used in the 2019 IRP did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects of the COVID-19 pandemic. Therefore, Moody's forecasts used before the 2021 IRP have likely overestimated economic growth in 2020, 2021, and 2022. The pandemic's repercussions on the economy and energy demand will likely be unknown during this reporting cycle.

Figure 6.19: Moody's Forecasts of U.S. Housing Starts Compared to Actual U.S. Housing Starts

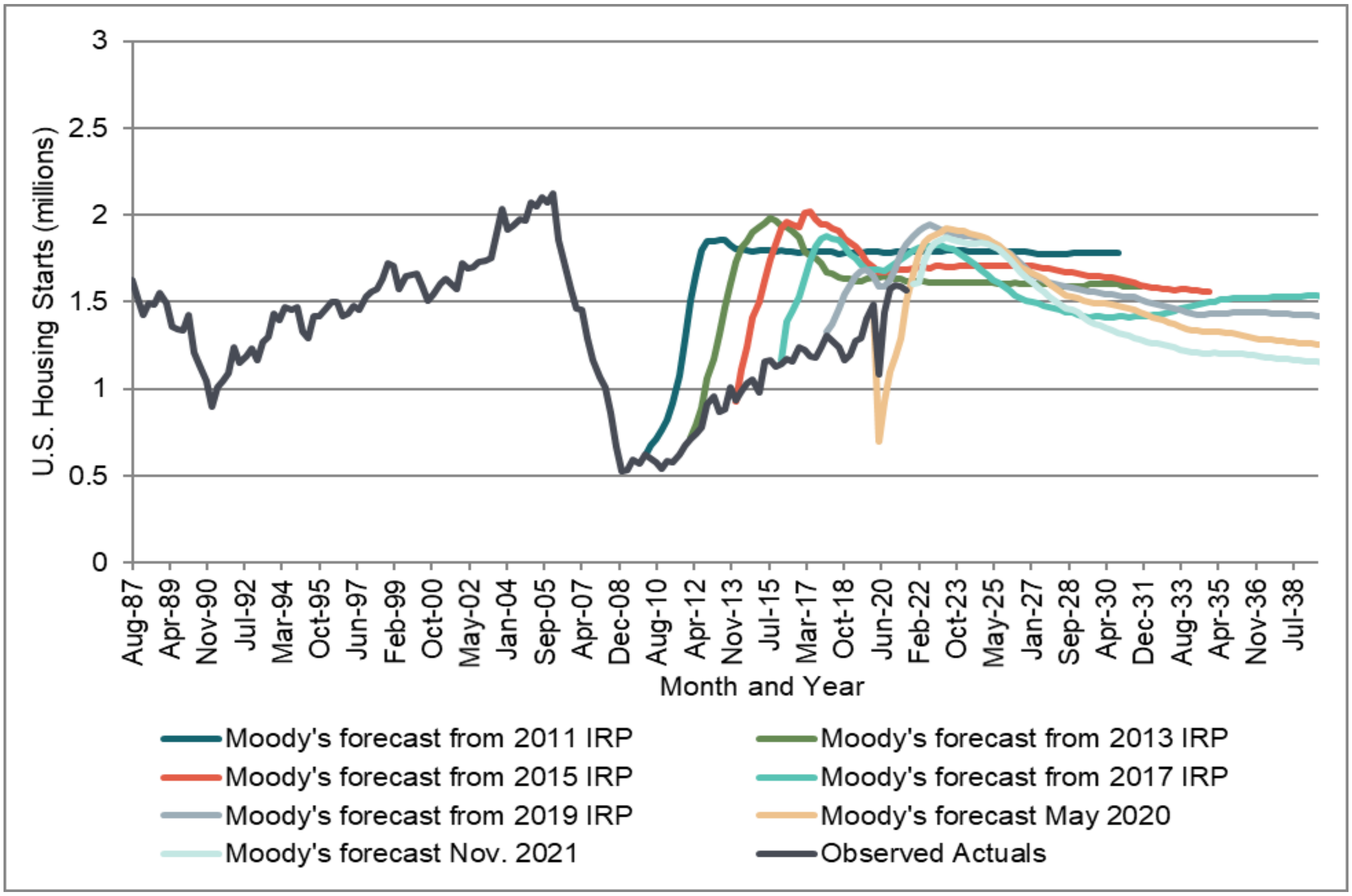
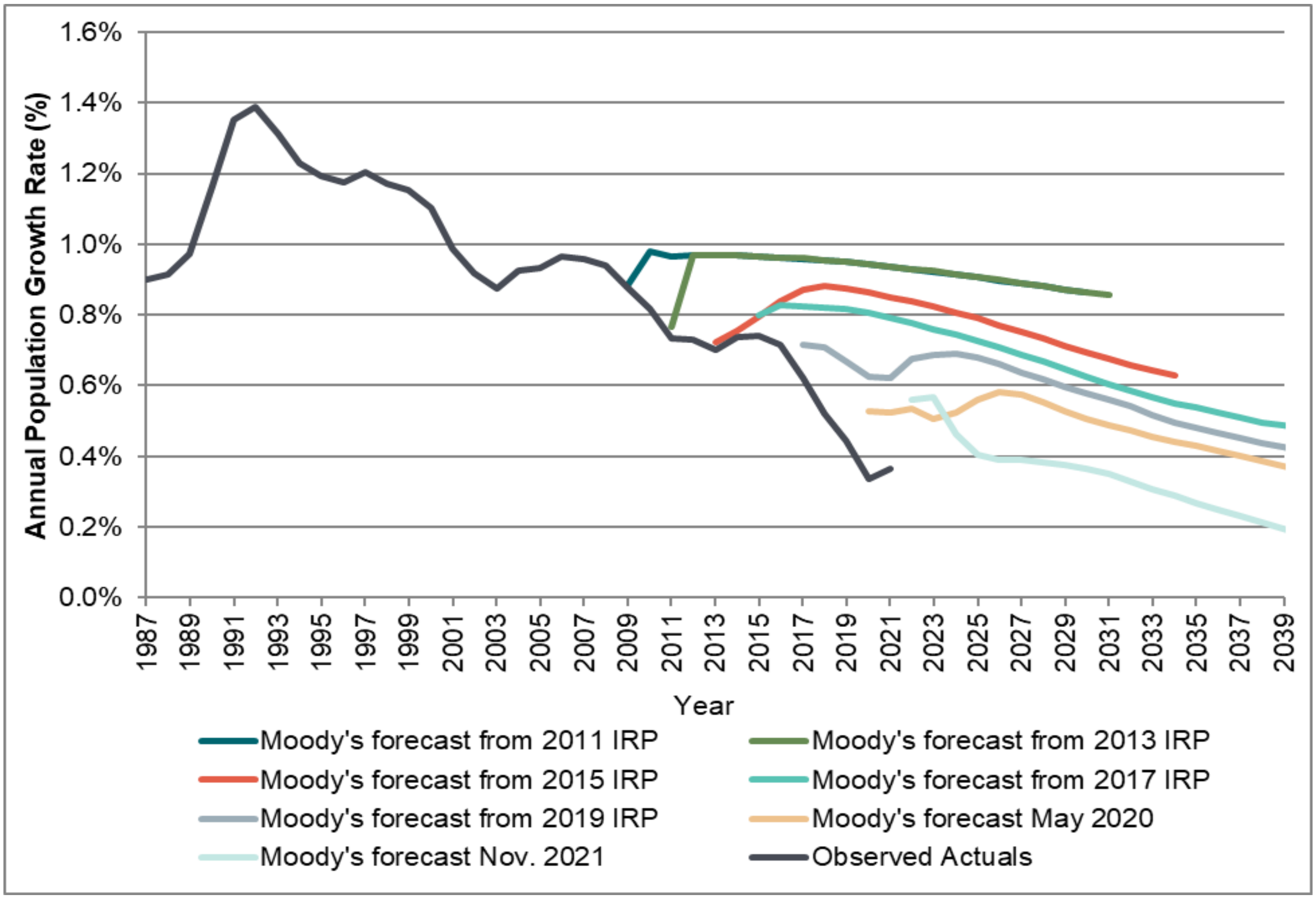


Figure 6.20: Moody's Forecasts of U.S. Population Growth Compared to Actual U.S. Population Growth



Demand-side Resources and Customer Usage

For the comparison in Figure 6.18 of weather-normalized peak observations to the IRP peak demand forecasts after additional DSR, we assumed the forecasted DSR was implemented. However, consumers can adopt energy-efficient technologies above and beyond what utility-sponsored DSR programs and building codes and standards incentivize. This consumer behavior leads to more actual DSR than we forecasted. The DSR programs can also change over time. In later IRPs, we can choose programs that were not cost-effective in the past but we now deem cost-effective. This situation can make an older forecast outdated, the DSR forecast too low, and the load forecast after additional DSR too high.

Also, the Global Settlement from the 2013 General Rate Case (GRC) PSE accelerates electric DSR by 5 percent yearly. We did not consider this additional DSR in comparing IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. We updated the normal weather assumption for the 2011 IRP to the 2021 IRP by rolling off two older years of temperature data and incorporating two new years of temperature data into the 30-year average. Over time, normal heating degree days have been declining, and the forecast of energy demand with normal weather has changed. In this 2023 Electric Report, we incorporated climate change into the normal definition, which altered the 2023 Electric Report base demand forecasts.

Additionally, over time our customers' weather sensitivity has been changing. As consumers implement energy efficiency measures, customers use less energy at a given temperature, including peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

Non-design Conditions during Observed Peaks

Peak values are weather normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand, and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days. For example, in 2014, the electric peak fell on the Monday morning after Thanksgiving weekend; in 2015, it fell on New Year's Eve; and in 2019, it fell on the day after Christmas. Usage on these days will likely differ from use on a typical non-holiday weekday peak. Therefore, when these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

Service Area Changes

In March 2013, Jefferson County left the PSE service area. We included Jefferson County usage in the electric peak demand forecast in the 2011 IRP. Therefore, when comparing that forecast to today's actuals, we expect that forecast to be higher than the actual peak demand.

RESOURCE ADEQUACY ANALYSIS

CHAPTER SEVEN

PUGET SOUND ENERGY

Contents

1. Introduction

The electricity industry in the Pacific Northwest (PNW) is transitioning as governments and system planners implement major decarbonization policies. The sector is retiring significant quantities of coal-fired capacity while adding new renewable generation resources. As a result, Puget Sound Energy (PSE) and other utilities are rethinking how we plan our systems, especially in resource adequacy (RA). As we transition to 100 percent clean energy by 2045, always having enough energy — maintaining resource adequacy — is paramount to ensure customers continue receiving reliable electricity and a smooth transition to a decarbonized system.

Puget Sound Energy contracted with the consulting firm Energy and Environmental Economics (E3) to produce the resource adequacy analysis for this 2023 Electric Progress Report (2023 Electric Report). E3 worked with our data and used their RECAP model to produce the study results. We based the work described in this chapter on the findings of E3's 2021 report, which recommended the following improvements to our resource adequacy modeling:

- Align the treatment of the first hour of loss-of-load events across the scenarios with and without battery storage
- Consider changing climate in evaluating energy demand, hydroelectric generation, and market purchases
- Consider load and renewable correlations. Puget Sound Energy did not have sufficient time to incorporate load and renewable correlations in the resource adequacy analysis. These correlations warrant study for future studies, as they could impact resource adequacy for PSE's system.
- Discharge storage at its rated capacity, for its rated duration; does not apply a minimum state of charge to the modeled energy capacity
- Incorporate hydroelectric dispatch capabilities and hydroelectric energy limitations
- Perform GENESYS sensitivity to determine if it would result in an increase in the storage ELCC; PSE did not run this sensitivity. The ELCC of energy storage is very high and there is sufficient energy to charge the energy storage. The GENESYS sensitivity would not add significant value on storage ELCC

Please see the entire docket and public comments on the UTC website.[1] We worked with E3 to meet all the modeling improvements described in the filing.

➔ See Appendix L: Resource Adequacy for more details regarding the filing and PSEs commitments.

Beyond implementing E3's recommendations, the other major change impacting the resource adequacy analysis is PSE's decision to reduce market reliance. In the past, PSE relied on purchases from the short-term wholesale energy markets as a cost-effective strategy to supplement resources to meet demand. This strategy also allowed us to avoid building significant amounts of generation capacity. Although wholesale electricity prices have remained low in recent

[1] utc.wa.gov/casedocket/2021/210220/docsets

years on average, the PNW has experienced periods of high wholesale electricity prices and low short-term market liquidity.

We expect this wholesale market volatility to limit our ability to rely on the market over time. Based on utilities' current plans, several studies discussed in this chapter's market reliance section have projected that the PNW will face a growing capacity shortage over the next decade.[2] Given the tightening of energy markets and to prepare for possible participation in the Western Resource Adequacy Program (WRAP), we plan to reduce our reliance on short-term wholesale market purchases to zero by 2029.

Peak capacity is the maximum capacity need of a system to meet loads.

Perfect capacity is the firm and reliable capacity required to maintain a chosen reliability metric.

The **planning reserve margin** is the generation resource capacity required to provide a minimum acceptable level of reliable service to customers under peak load conditions.

The **peak capacity credit** assigned to a resource is the effective load-carrying capability (ELCC). This value depends highly on the load characteristics and portfolio resource mix, which makes it unique to each utility; it is expressed as a percent of the equivalent nameplate capacity.

➔ For more information on market reliance, please refer to section four of this chapter.

Considering the projected capacity shortages for the NW region, the Western Power Pool (WPP) created the WRAP to provide a programmatic approach for utilities to work together to ensure resource adequacy throughout the region. The WRAP is the first regional reliability planning and compliance program in PNW history.[3] The Western Resource Adequacy Program is discussed in more detail later in this chapter in section six.

➔ The results of how the WRAP program will impact peak needs are in Chapter Eight: Electric Analysis.

1.1. Incorporating Climate Change

Puget Sound Energy’s 2023 Electric Report incorporates climate change in the base energy and peak demand forecast for the first time. Before this report, we used historical temperatures from the range of temperature variability to create the resource adequacy model. We then iterated through the different temperature years to create hourly load draws that we used in the modeling simulations, but the underlying data did not recognize predicted effects from climate change.

The methodology we used to incorporate climate change in this report is the first step in an evolving process. We heard from interested parties that incorporating climate change into demand forecasting is a high priority. It is essential to consider climate change in resource planning because our customers rely on PSE energy to heat in the winter and stay cool in the summer. With an overall average warming trend, we would expect, on average, less overall heating demand and more cooling demand. We used recently developed regional climate model projections to create

2 https://www.ethree.com/wp-content/uploads/2019/12/E3-PNW-Capacity-Need-FINAL-Dec-2019.pdf

3 https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

demand draws for the resource adequacy simulation that reflect climate change. We also updated the peak demand forecast, which resulted in normal peak temperatures for summer and winter that increased over time.

➔ Please refer to Chapter Six: Demand Forecast for more details regarding how we incorporated climate change into our demand forecast.

Along with incorporating climate change in the demand forecast, we also updated hydroelectric generation draws. Previously, we used the historical 80-year hydroelectric stream flow data to create a generation forecast based on current operating conditions. The same climate change data we used for the demand forecast also provided stream flow data that we turned into predicted generation for the hydroelectric facilities.

➔ For details regarding the hydroelectric forecast, refer to Chapter Five: Key Analytical Assumptions.

2. Overview of Results

Resource Adequacy measures the ability of generating resources to meet load across a wide range of system conditions, accounting for supply and demand variability. No one can plan a perfectly reliable electrical system; however, we use several reliability metrics in the industry to ensure the system has adequate generation capacity during extreme events. We apply a five percent loss of load probability metric in the resource adequacy study, which means we plan our system to have an expected loss of load event occur once in 20 years. We reflected this in our planning reserve margin in Table 7.1, which shows the 2021 Integrated Resource Plan (IRP) results and the new seasonal analysis we used in this report. Overall, the peak capacity need increased from the 2021 IRP.

Table 7.1: Planning Reserve Margin and Peak Capacity Need — Percent Above Normal and MW Need Above Normal Peak

Study Years and Seasons	2027 Winter (2021 IRP)	2031 Winter (2021 IRP)	2029 Winter (2023)	2029 Summer (2023)	2034 Winter (2023)	2034 Summer (2023)
Planning Reserve Margin (%)	20.7	24.2	23.8	21.2	23.9	26.1
Additional Perfect Capacity Need (MW)	907	1,381	1,272	1,875	1,746	2,856

Table 7.1 shows the additional perfect capacity need comparing the results from the 2021 IRP to the 2023 Electric Report study years. The 2023 Electric Report is the first time we modeled the planning reserve margin for winter and summer. When comparing the results from these two reports, it is important to compare the 2021 IRP study years to the 2023 Electric Report winter results only, as prior IRPs have only evaluated the winter months. When you compare winter results, you see a slight increase in the perfect capacity need from 2027 to the 2029 winter. From this analysis, we found that although PSE is a winter-peaking utility, the additional perfect capacity need is higher in summer. This

high summer need means there are fewer resources available in the summer than in the winter, not that the summer peak is higher than the winter peak.

Table 7.2 compares the 2023 Electric Report and 2021 IRP effective load carrying capability (ELCC) results. The ELCC measures how many megawatts of a resource PSE can plan on to meet the planning reserve margin. We modeled most of the resources with saturation effects; the more resources added of the same location or type, the less effective they are at meeting peak capacity. The results in the table are for the first tranche[4] (the first amount of MW of installed capacity) of each resource — 100 MW for renewable resources and demand response and 250 MW for storage. The ELCC for additional resources declines based on the ELCC saturation results, which we described further in the Key Takeaways section and Appendix L: Resource Adequacy. There is an increase across all renewable resource ELCCs from the 2021 IRP to the 2023 Electric Report. Most significantly, solar and batteries increased due to the seasonal analysis and other modeling changes discussed throughout this chapter in greater detail.

Table 7.2: Effective Load Carrying Capability Results for First 100 MW for Wind and Solar or First 250 MW for Storage

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029[2] Winter (%)	2029[2] Summer (%)
British Columbia	Wind	-	-	34	13
Idaho	Wind	24	27	12	17
Montana Central	Wind	30	31	39	27
Montana East	Wind	22	24	32	19
Offshore	Wind	48	47	32	41
Washington	Wind	18	15	13	5
Wyoming East	Wind	40	41	52	34
Wyoming West	Wind	28	29	39	34
Distributed Energy Resources (DER) Ground Mount	Distributed Solar	1	2	4	28
DER Rooftop	Distributed Solar	2	2	4	28
Idaho	Utility-scale Solar	3	4	8	38
Washington East	Utility-scale Solar	4	4	4	55
Washington West	Utility-scale Solar	1	2	4	53
Wyoming East	Utility-scale Solar	6	5	11	29
Wyoming West	Utility-scale Solar	6	6	10	28
Lithium-ion Battery (2-hour)	Storage	12	16	89	97
Lithium-ion Battery (4-hour)	Storage	25	30	96	97
Lithium-ion Battery (6-hour)	Storage	N/A	N/A	98	98
Pumped Storage (8-hour)	Storage	37	44	99	99
Demand Response (3-hour)	Demand Response	26	32	69	95

4 Tranche is the capacity segment of a resource on the ELCC saturation curve.

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029[2] Winter (%)	2029[2] Summer (%)
Demand Response (4-hour)	Demand Response	32	37	73	99

Notes:

1. 2021 IRP (2021 IRP modeled ELCC saturation curves for Washington wind and Washington solar only)
2. 2023 Electric Progress Report

2.1. Key Takeaways

Several elements contributed to the increase in the planning reserve margin:

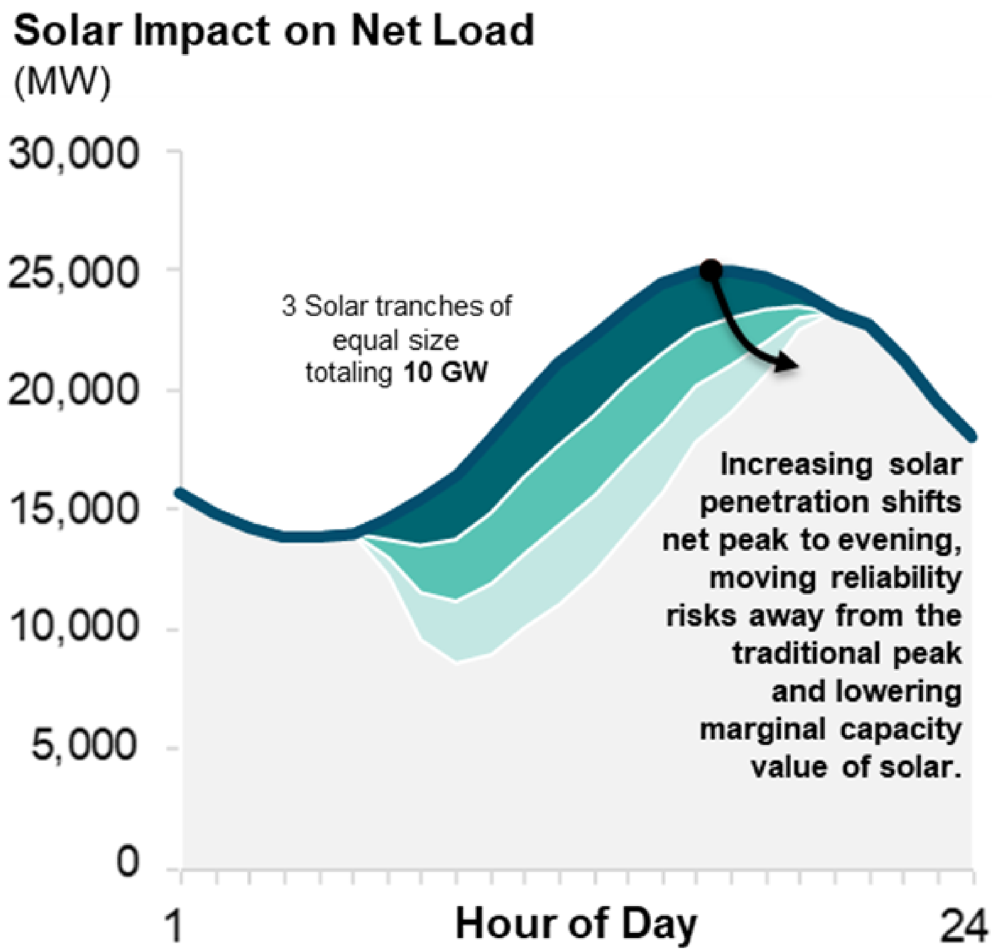
- Including climate change data in the load forecast and peak temperatures slightly lowered the normal winter peak and increased the normal summer peak. Even with the increase in normal summer peak temperatures, the summer peak does not come close to the level of the winter peak through the report's planning horizon.
- Increase in peak demand. Although climate change decreased normal winter loads, the updated electric vehicle (EV) forecast increased the demand. The increase in peak from the EV forecast was more significant than the decrease from the climate change data, resulting in an overall increase in peak demand.
- The analysis looked at winter and summer capacity needs.
- The climate change data also showed changes in the duration and frequency of outage events which impacted the results. The data shows a decrease in event duration, less frequent events in the winter, and more frequent events in the summer, increasing the ELCCs for shorter duration storage resources and solar.
- The hydro generation profile changed when we incorporated climate change into the modeling because the historical spring runoff now happens earlier in the year. The earlier spring runoff changes hydropower availability and leaves less water for the summer.

The saturation effect can have a significant impact on resource ELCCs. In the next section, we explain why it was vital to consider saturation when we evaluated the ELCC of a resource.

2.1.1. Effective Load Carrying Capability Saturation Effect

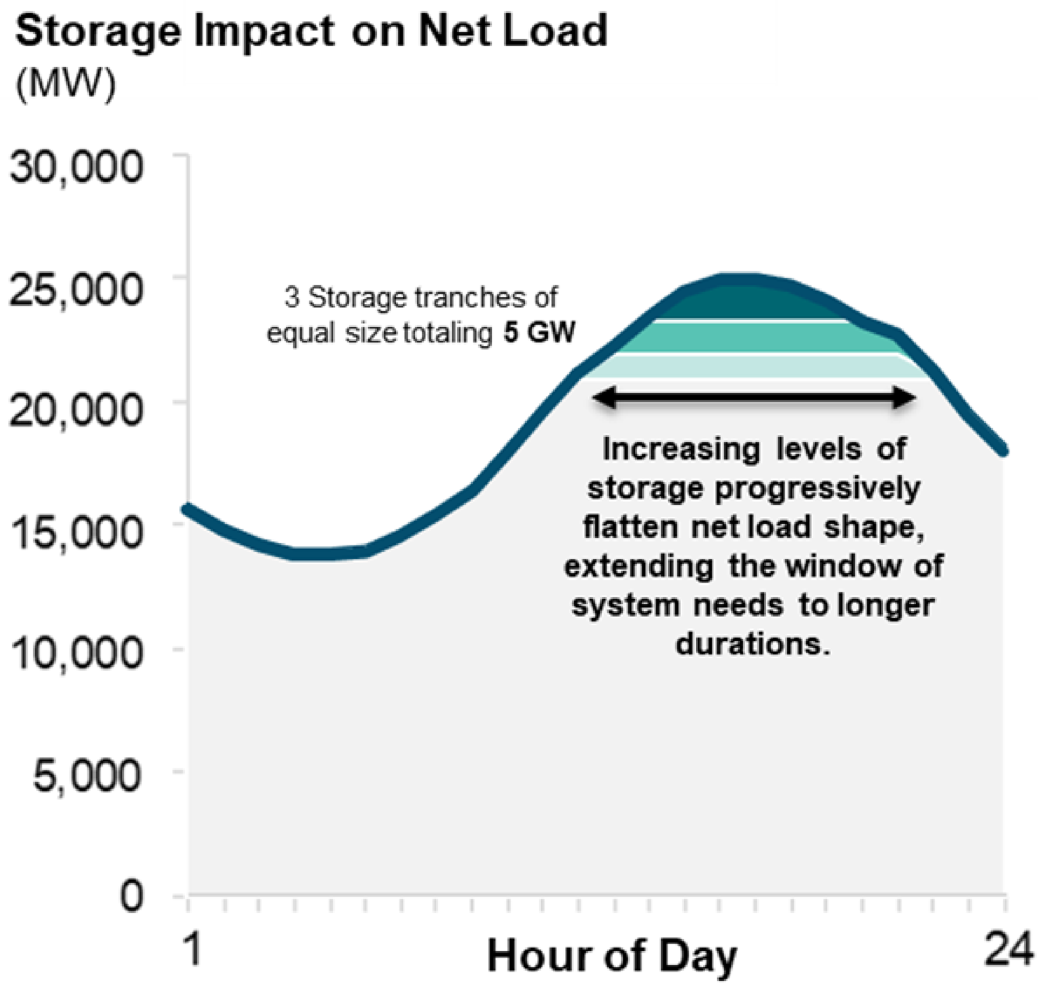
The ELCC of a dispatch-limited resource decreases as the penetration of that resource increases, known as the ELCC saturation effect. Figure 7.1 shows an example of ELCC saturation — the dynamics for solar on a peak summer day. Note that this is an illustrative example and does not represent PSE's system. The first grouping or tranche of solar produces a lot of energy during peak demand hours, showing a relatively high ELCC. However, when one adds more solar, the net peak demand (load minus renewable generation) shifts into the evening when solar generation is low. As a result, the ELCC for these later tranches is lower because the solar has mitigated most reliability concerns during the daytime but cannot contribute to the reliability needs at night. Wind resources experience this same saturation effect, except rather than shifting the net load from daytime hours to nighttime hours, wind resources shift the net load from times when wind generation is high to times when wind generation is low.

Figure 7.1: Example of ELCC Saturation Effect for Solar (Does Not Represent PSE's System)



The ELCC saturation effect applies to other dispatch-limited resources, such as energy storage and demand response. See Figure 7.2 for an example showing storage dynamics on the same peak day. Note that this is an example and does not represent PSE's system.

Figure 7.2: Example of ELCC Saturation Effect for Energy Storage (Does Not Represent PSE's System)



The first tranche of energy storage produces a lot of energy during peak demand hours, corresponding to having a relatively high ELCC. However, as one adds more energy storage, the net peak demand (load minus energy storage generation) flattens and spans a longer period, see Table 7.3. As a result, the ELCC for these later tranches is lower because the storage has already mitigated during the highest peak demand hours but can't contribute the same reliability value longer due to the limited stored energy available to discharge. Demand response resources experience this same saturation effect. The critical difference for demand response is that demand response resources generally have more restrictions on operations, including the number of calls and time between calls, in addition to the length of calls but without a need to charge.

Table 7.3: Storage ELCC Tranches in 2029

Resource	Season	ELCC 1 100 - 1,000 MW (%)	ELCC 2 1,000 – 1,500 MW (%)	ELCC 3 1,500 MW + (%)
Li-ion Battery (2-hour)	Winter	61	18	9
Li-ion Battery (4-hour)	Winter	78	21	10

Resource	Season	ELCC 1 100 - 1,000 MW (%)	ELCC 2 1,000 – 1,500 MW (%)	ELCC 3 1,500 MW + (%)
Li-ion Battery (6-hour)	Winter	86	26	11
Pumped Storage (8-hour)	Winter	92	33	12
Li-ion Battery (2-hour)	Summer	69	31	17
Li-ion Battery (4-hour)	Summer	94	52	15
Li-ion Battery (6-hour)	Summer	98	86	14
Pumped Storage (8-hour)	Summer	99	95	15

2.2. Planning Reserve Margin

The standard practice in the electricity industry is to express the total resource need as a planning reserve margin (PRM). The PRM is the difference between the total resource need and the utility's normal peak load, divided by the utility's normal peak load:

$$Planning\ Reserve\ Margin = \frac{(Total\ Resource\ Need - Normal\ Peak\ Load)}{Normal\ Peak\ Load}$$

The normal peak load is PSE's peak load forecast in MW. This normal peak load forecast is sometimes referred to as a median peak load or a one-in-two peak load because it is estimated such that there is a 50 percent probability of the true peak load being higher than this forecast and a 50 percent probability of it being lower.

The PRM represents the resource need amount beyond the normal peak load that PSE must maintain one-in-two to satisfy the total resource need and the reliability target of 5 percent loss of load probability (LOLP).

3. Resource Adequacy Analysis Results

This section describes the results of the resource adequacy analysis we prepared for this report. First, we present the capacity credit results for existing and contracted resources, representing how much existing and contracted resources contribute toward satisfying the PRM. Next, we present the total resource need and the PRM. The total resource need represents the capacity needed to satisfy PSE's reliability standard, and the PRM represents this amount relative to the median peak load. Lastly, we present the capacity contribution results for new generic resources.

3.1. Capacity Credit of Existing Portfolio

This section provides the capacity credit for all resources in PSE's portfolio, including hydroelectric, thermal, wind, and solar. This section also shows the capacity credit for other contracts and wholesale market purchases. E3 calculated the ELCC resource values for the three climate models and then averaged the results to get the final ELCC values.

3.1.1. Hydroelectric Resources

Puget Sound Energy owns three hydroelectric plants: Upper Baker, Lower Baker, and Snoqualmie Falls. E3 calculated the ELCC for each resource (see Table 7.4). The summer and winter ELCCs are similar for Upper Baker and Lower Baker. However, Snoqualmie Falls is a run-of-river hydroelectric facility; as a result, the ELCC is lower in summer due to lower summer river flows. The ELCC values in 2034 are like those in 2029.

Table 7.4: Effective Load Carrying Capability for PSE-owned Hydroelectric Resources (MW)

Hydroelectric Resources	Nameplate	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Upper Baker Units 1 and 2	107	70	69	77	79
Lower Baker Units 3 and 4	111	67	66	58	60
Snoqualmie Falls	53	39	39	11	12

We also contract with five Mid-C hydroelectric plants on the Columbia River for power. We calculate the capacity contributions based on the Pacific Northwest Coordination Agreement (PNCA) final regulation (see Table 7.5) for these plants. The capacity contributions are PSE's contractual capacity, less losses, encroachment, and Canadian Entitlement. These capacity contributions are the same for winter and summer.

Table 7.5: Capacity Credit for Mid-C Hydroelectric Resources (MW)

Hydroelectric Resources	2029	2034
Mid-C Rocky Reach	313	313
Mid-C Rock Island	121.2	121.2
Mid-C Wells	115	115
Mid-C Wanapum	6.1	6.1
Mid-C Priest Rapids	5	5

The capacity credit for the Mid-C hydroelectric resources is the same for winter and summer.

3.1.2. Thermal Resources

Puget Sound Energy owns several thermal plants. We calculate the capacity credit based on the plant's rating at different temperature levels (see Table 7.6). In winter, the capacity reflects the capacity rating when operating at an ambient temperature of 23 degrees Fahrenheit. In summer, the capacity reflects the capacity rating when operating at an ambient temperature of 96 degrees Fahrenheit. The efficiency of these thermal plants is lower at higher temperatures. As a result, the summer ratings are lower than the winter ratings.

Table 7.6: Capacity Credit for Thermal Resources (MW)

Thermal Plant	Winter	Summer
Encogen	182	149
Ferndale	266	246
Goldendale	315	268

Thermal Plant	Winter	Summer
Mint Farm	320	270
Sumas	137	117
Frederickson CC	134	104
Fredonia 1	117	91
Fredonia 2	117	91
Fredonia 3	63	46
Fredonia 4	63	46
Whitehorn 2	84	65
Whitehorn 3	84	65
Frederickson 1	84	65
Frederickson 2	84	65

Thermal plants can also have forced outages. Although forced outages do not impact the capacity credit assigned to thermal plants, E3 considered forced outages at these plants to determine the system overall resource need and PRM value The forced outage rates vary for each plant and range from 2.31 percent to 11.3 percent.

3.1.3. Wind and Solar

Puget Sound Energy owns and has contracts for power from several wind and solar projects. These projects include Hopkins Ridge Wind, Wild Horse Wind (including an expansion), Klondike Wind, Lower Snake River Wind, Skookumchuck Wind, Golden Hills Wind, Clearwater Wind, Lund Hill Solar, and Wild Horse Solar. E3 calculated the ELCC for wind and solar resources (see Table 7.7). The ELCC for wind resources is higher in winter (28 percent in 2029) than in summer (14 percent in 2029) because PSE's wind projects, in aggregate, output more energy in the winter. Conversely, the ELCC for solar resources in summer (45 percent in 2029) is higher than in winter (7 percent in 2029) because solar projects output more energy in the summer, and better align with peak demand. The ELCC values in 2034 are like those in 2029.

Table 7.7: Effective Load Carrying Capability for Wind and Solar Resources (MW)

Resources	Nameplate MW	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Wind	1,504	428	421	210	217
Solar	150	10	10	67	69

3.1.4. Other Contracts

In addition to the wind and solar contracts discussed in the proceeding section, PSE has several other contracts. We have a 300 MW power exchange contract with Pacific Gas and Electric Company (PG&E). Under this contract, PG&E must provide PSE with 300 MW of power in winter when needed, and PSE must provide PG&E with 300 MW of power in summer when needed. In addition to this contract, we have a few other small contracts.

➔ A full discussion of the contracts is in Appendix C: Existing Resource Inventory.

See E3's ELCC calculation for these contracts in Table 7.8. The ELCC in summer is negative, which means contracts result in a net increase in the overall resource need when included in the portfolio. The PG&E exchange has the most significant influence because PSE is obligated to send PG&E 300 MW of power in summer when needed, which increases PSE's overall summer resource need. Other contracts partially offset this increase. The ELCC in winter is above 350 MW. The ELCC values in 2034 are like those in 2029.

Table 7.8: Effective Load Carrying Capability for Other Contracts (MW)

Resources	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Other Contracts	382	376	-179	-185

3.1.5. Market Purchases

In addition to determining the capacity contribution of PSE's resources, E3 also estimated the ELCC of market purchases (see Table 7.9). These market purchases are how much power is available to purchase from the regional market on a short-term basis. We used the Classic GENESYS and the Wholesale Purchase Curtailment Model (WPCM) to determine the availability of market purchases. We have 2,031 MW of transmission from Mid-C to import power via market purchases, but we also use this transmission to deliver power from the Mid-C hydroelectric plants and Wild Horse Wind project.

The ELCCs show that the ELCC for market purchases is lower in summer than in winter. As discussed in Appendix L: Resource Adequacy, GENESYS and the WPCM model show that the PNW has less generation for us to call on in summer than in winter. Moreover, we project that the PNW will have less generation available in summer 2034 than in summer 2029. As a result, the ELCC for summer declines between 2029 and 2034. The ELCC for winter remains similar in 2034.[5]

Table 7.9: Effective Load Carrying Capability for Market Purchases (MW)

Resources	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Market Purchases	1,440	1,434	961	751

3.2. Total Resource Need and Planning Reserve Margin

E3 quantified the total resource need and PRM necessary to satisfy our five percent of LOLP reliability target (see Table 7.10). E3 first quantified the system's capacity shortfall, representing the additional perfect capacity needed to satisfy the reliability target. The capacity shortfall is higher in summer (1,875 MW in 2029) than in winter (1,272 MW in 2029). Although peak demand is lower in summer, the capacity contribution of resources is much lower in summer. Thermal ratings are lower due to higher ambient temperatures, the ELCC of wind and hydroelectric is lower in summer, the PG&E exchange reduces available capacity, and there are fewer market purchases available in summer.

5 https://www.pse.com/-/media/PDFs/IRP/2023/electric/appendix/21_EPR23_AppL_Final.pdf

These factors result in a more significant capacity shortfall in summer than in winter. The capacity shortfalls grow in both seasons as the load increases, but there are more in summer due to greater load growth.

E3 then calculated the total resource need. The total resource need is the sum of capacity contributions across all resources plus the additional perfect capacity needed. The total resource need is higher in winter (6,319 MW in 2029) than in summer (5,329 MW in 2029).

Lastly, E3 calculated the PRM. The PRM percentage is similar across seasons and years, ranging from 26 percent to 28 percent. The key factors influencing the PRM are load variability (beyond the median peak load), operating reserve requirements, thermal forced outages, and Mid-C hydroelectric performance (relative to its capacity contribution).

Table 7.10: Total Resource Need and Planning Reserve Margin (MW)

Resource(s)	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Thermal Plants	2,050	2,050	1,688	1,688
Mid-C Hydro	560	560	560	560
Wind, Solar, Baker, Other Contracts	997	981	244	252
Market Purchases	1,440	1,434	961	751
Additional Perfect Capacity Need	1,272	1,746	1,875	2,856
Total Resource Need	6,319	6,771	5,329	6,107
Median Peak Load	5,004	5,382	4,171	4,831
Planning Reserve Margin	26%	26%	28%	26%

In this analysis, we used one-in-two (P50) peak load forecast to calculate the planning reserve margin.

➔ See Appendix L: Resource Adequacy for more details on peak-load forecast.

3.3. Effective Load Carrying Capability for Incremental Resources

E3 evaluated the capacity contribution of incremental resources to PSE's current resource portfolio. These resources reflect a wide range of resource options, including in-state and out-of-state renewable resources, distributed solar resources, energy storage, demand response, hybrid, and thermal resources.

These resources do not represent specific wind or solar projects bid to PSE through a resource procurement. Instead, they are generic resource options that PSE would expect to receive in future procurements. We considered these generic options in our long-term portfolio analysis, and these capacity contribution values serve as inputs to the portfolio selection.

3.3.1. Generic Wind and Solar Resources

E3 calculated the ELCC for eight wind, two distributed solar, and five utility-scale solar resources (see Table 7.11). These ELCC values are the capacity contribution for the first 100 MW of incremental capacity added to PSE's system; the ELCC would be different if we added more than 100 MW to the system, as discussed in Appendix L.

In general, the ELCC for wind is higher in winter than in summer, and the ELCC for solar is higher in summer — seasonal generation patterns for these resources. The ELCC differs by location, reflecting differences in average generation and the timing of that generation. The ELCC is higher for resources with higher generation levels when PSE's system has a greater capacity need.

➔ See Appendix L: Resource Adequacy for details about the resource groups and saturation curve for the generic resource.

Table 7.11: Effective Load Carrying Capability for Generic Wind and Solar Resources (First 100 MW)

Resource	Resource Type	Winter (%)	Summer (%)
British Columbia	Wind	34	13
Idaho	Wind	1	1
Montana Central	Wind	39	27
Montana East	Wind	32	19
Offshore	Wind	32	41
Washington	Wind	13	5
Wyoming East	Wind	52	34
Wyoming West	Wind	39	34
Distributed Ground Mount	Distributed Solar	4	28
Distributed Rooftop	Distributed Solar	4	28
Idaho	Utility-scale Solar	8	38
Washington East	Utility-scale Solar	4	55
Washington West	Utility-scale Solar	4	53
Wyoming East	Utility-scale Solar	11	29
Wyoming West	Utility-scale Solar	10	28

3.3.2. Generic Energy Storage ELCC Saturation Curves

We asked E3 to model the ELCC of four types of energy storage resources (see Table 7.12). There are three lithium-ion battery storage resources, with two-hour, four-hour, and six-hour durations, and one eight-hour pumped hydroelectric storage resource. The duration metric specifies the amount of time a storage resource can continuously discharge at its rated capacity when fully charged. For example, a fully charged 100 MW Lithium-ion Battery (four-hour) can discharge at 100 MW for four consecutive hours. The roundtrip efficiency metric specifies the amount of energy conserved when charging and discharging a battery. The forced outage rate, like thermal resources, specifies the probability that a storage resource goes on a forced outage.

Table 7.12: Generic Energy Storage Resources

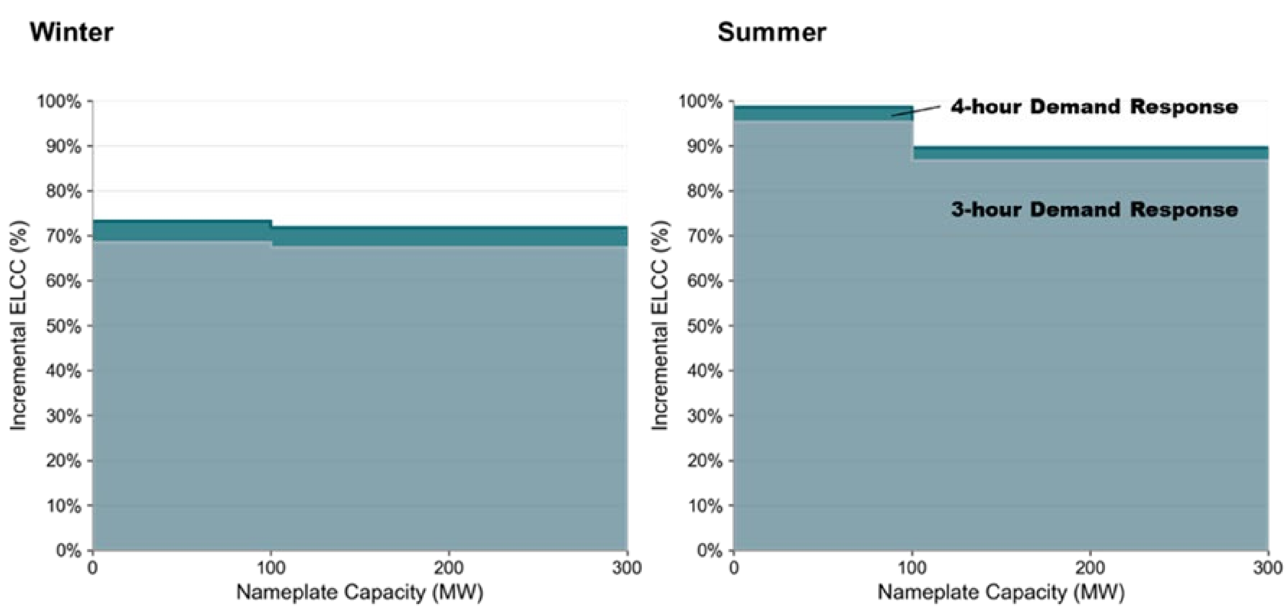
Resources	Technology	Duration	Roundtrip Efficiency (%)	Forced Outage Rate (%)
Lithium-ion Battery (2-hour)	Lithium-ion	2 hours	86	2
Lithium-ion Battery (4-hour)	Lithium-ion	4 hours	87	2
Lithium-ion Battery (6-hour)	Lithium-ion	6 hours	88	2
Pumped Storage (8-hour)	Pumped hydroelectric storage	8 hours	80	1

3.3.3. Generic Demand Response ELCC Saturation Curves

E3 calculated the ELCC saturation curves for two types of generic demand response programs: one with maximum three-hour call durations and another with maximum four-hour call durations (see Figure 7.3). E3 calculated two tranches for demand response: 0–100 MW and 100–300 MW. For both programs, we limited the number of calls to 10 in winter and 10 in summer. Also, PSE cannot call the same demand response program more than once in six hours.

As for storage, the ELCC of demand response diminishes with increasing penetration as the limited duration becomes less effective at addressing PSE's reliability needs at higher penetration levels. The ELCC for demand response is lower in winter than in summer because the duration of loss of load events is longer.

Figure 7.3: Effective Load Carrying Capability Saturation Curves for Demand Response Resources



3.3.4. Generic Hybrid Resources

PSE directed E3 to model the ELCC of four types of hybrid resources (see Table 7.13). We assumed that these hybrid resources would be in Washington State. The solar resource is Washington East Solar, the wind resource is Washington Wind, and the storage resource is Lithium-ion Battery Storage (four-hour). For each hybrid resource, we assumed that the renewable and storage resources would share the same interconnection. If the interconnection capacity is less than the capacity of the renewables plus the capacity of the storage, then this could limit how much power a hybrid resource can provide to PSE's system during some hours. Project developers often locate hybrid resources behind the same interconnection to reduce overall costs. For the Solar + Storage (Restricted Charging) resource, the battery storage resource can only charge from onsite renewable energy. The battery storage resource can charge from onsite renewable energy or the grid for other hybrid resources.

Table 7.13: Generic Hybrid Resources

Resources	Interconnection MW	Solar MW	Wind MW	Storage MW
Solar + Storage	100	100	-	50
Solar + Storage (Restricted Charging)	100	100	-	50
Wind + Storage	100	-	100	50
Solar + Wind + Storage	200	100	100	50

3.3.5. Generic Thermal Resources

In addition to calculating the ELCC of dispatch-limited resources, E3 also calculated the ELCC of three types of generic thermal resources (see Table 7.14). Three factors influence the capacity contribution of these resources: ambient temperature efficiency ratings, forced outage rates, and unit size.

PSE determined the capacity ratings of these units by season using the same ambient temperatures used for existing thermal plants. The summer rating is lower than the winter rating for combined cycle combustion turbine and frame combustion turbine units. The reciprocating internal combustion engines have the same efficiency ratings in the summer and winter.

Table 7.14: Effective Load Carrying Capability for Generic Natural Gas Resources

Resource	Nameplate Winter (MW)	ELCC Winter (%)	Nameplate Summer (MW)	ELCC Summer (%)
Combined Cycle	367	84	310	92
Frame Turbine	237	96	184	98
Reciprocating Engine	18	96	18	96

4. Market Risk Assessment

Puget Sound Energy has relied on short-term market resources to fill less than 1,500 MW of transmission capacity for more than 15 years. The total firm transmission contracts are 2,030 MW to Mid-C; we then subtract the transmission needed for resources at the Mid-C, which comes to less than 1,500 MW of available transmission left for short-term market purchases. See Appendix C: Existing Resource Inventory for the breakdown of transmission contracts. Relying on the surplus capacity of others in the region was a reasonable strategy when the region had significant surplus peak capacity. Experts predict the region soon will have no significant surplus peak capacity. They expect the region will be short of physical capacity, even under very conservative assumptions. Continuing to rely on short-term market purchases creates physical and financial risks for PSE's customers and shareholders. We need to adapt to changing market conditions.

4.1. Reduce Market Reliance

Due to the growing regional concerns about capacity in the short-term market and our interest in joining the WRAP, we will phase out reliance on short-term market purchases as we make plans to ramp into the WRAP. We reduced market reliance by more than 200 MW per year starting in 2024 and reached zero reliance by 2029 in this report.

Table 7.15 shows the ELCC adjustment to market reliance from E3's models but is not the final market reliance we used in the capacity expansion modeling described in Chapter Eight: Electric Analysis. We phased the market reliance for peak capacity down over time reaching zero by 2029.

Table 7.15: Effective Load Carrying Capability Adjusted MW of Market Reliance from E3 Model

Adjustment	Nameplate	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Transmission Capacity	2,030	2,030	2,030	2,030	2,030
Resources at Mid-C	(512)	(512)	(512)	(512)	(512)
ELCC Adjustments	0	(78)	(557)	(84)	(767)
Total Available Transmission	1,518	1,440	961	1,434	751

4.2. Changing Regional Resource Adequacy

Numerous studies and articles highlight regional resource adequacy concerns. Three respected industry-based organizations periodically issue studies about resource adequacy in the Northwest and have recently raised critical concerns. The North American Electric Reliability Corporation (NERC)[6] studies regional entities and assessment areas, including WECC-NWPP-US & RMRG (Western Interconnection, Northwest Power Pool, and Rocky Mountain Reserve Sharing Group). The Western Electricity Coordinating Council (WECC)[7] evaluates resource adequacy across the entire western interconnection (WECC) and within five subregions, including NWPP-Northwest. The Pacific Northwest Utilities Conference Committee (PNUCC)[8] covers the Northwest regional planning area. All three organization's reports cover a ten-year horizon. Across the West, utilities plan to retire nearly 26 GW coal and natural gas resources over the next decade. Each of their most recent reports concluded that demand and resource variability is increasing rapidly, creating challenges for the bulk power system to provide reliable supply in the near

[6] 2021 Long-term Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

[7] 2021 Western Assessment of Resource Adequacy" ("WARA"), https://www.wecc.org/Administrative/WARA%202021.pdf

[8] 2022 Northwest Regional Forecast, https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf

term. The WECC put it most directly, stating, "As early as 2025, all subregions (of the WECC) will be unable to maintain 99.98 percent reliability because they will not be able to reduce the hours at risk for loss of load enough, even if they build all planned resource additions and import power."[7] The PNUCC concluded, "The annual energy picture reveals a regional resource deficit by next year (2023), which is three years earlier than last year's estimate."[8] And NERC determined, "The two largest U.S. assessment areas in the Western Interconnection — California/Mexico and the Northwest-Rocky Mountain — have the potential for high load-loss hours and energy shortfalls for 2022 and beyond."[6]

While each organization approached the analysis using its own assumptions and methodologies, some common themes emerge on what is driving the increase in variability:

- Government policies and consumer sentiment are accelerating the move to clean energy
- More frequent and extreme weather events due to climate change
- Retirement of baseload resources and the addition of variable energy resources

Traditional resource adequacy approaches have been based solely on capacity, which worked well when most generation assets were dispatchable and demand was more predictable. The peak capacity shortfall typically occurred during the annual peak capacity hour. In today's climate, however, the drivers affecting the generation and load variability can lead to critical capacity shortfalls that do not coincide with peak demand. Focusing only on capacity fails to account for this variability fully. The PNUCC Northwest Regional Forecast (NRF) is the best source for detailed information on this topic.

$$\begin{aligned} &NRF \\ &= \sum (Utility\ loads\ with\ planning\ reserve\ margin) \\ &- (resource\ forecasts\ for\ those\ owned\ \&\ contracted\ by\ utilities) \\ &+ (resource, conservation, demand\ response\ additions\ based\ on\ their\ IRPs) \end{aligned}$$

Table 7.16 shows that even with very conservative adjustments to the NRF, we expect the region to be significantly short in the winter of 2029 and extremely short of capacity in the summer of 2029. We made two adjustments to the winter for the following factors:

- Independent Power Purchaser (IPP) Generation: PSE's market survey shows 1,697 MW of IPP resources available today. It may not be reasonable to assume those resources will be uncontracted as the region considers entering the WRAP, but we included those here to be conservative.
- Southwest Imports: The Northwest Power and Conservation Council's Classic GENESYS model assumed 3,400 MW of imports from California would be available to the Pacific Northwest. As California electrifies transportation and buildings, those imports may not be available. We included them in this table to ensure a conservative perspective.

Table 7.16: Adjusted NRF Table Regional Capacity Short Position (MW)

PNUCC - Northwest Regional Forecast	Winter 2029	Summer 2029	Winter 2034	Summer 2034
PNUCC — Regional NRF Short	4,830	5,240	6,060	5,950

PNUCC - Northwest Regional Forecast	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Identified Available Firm Resources in the Region (Operational)	1,700	-	1,700	-
California Imports	3,400	-	3,400	-
Net Regional Shortage	(270)	5,240	960	5,950

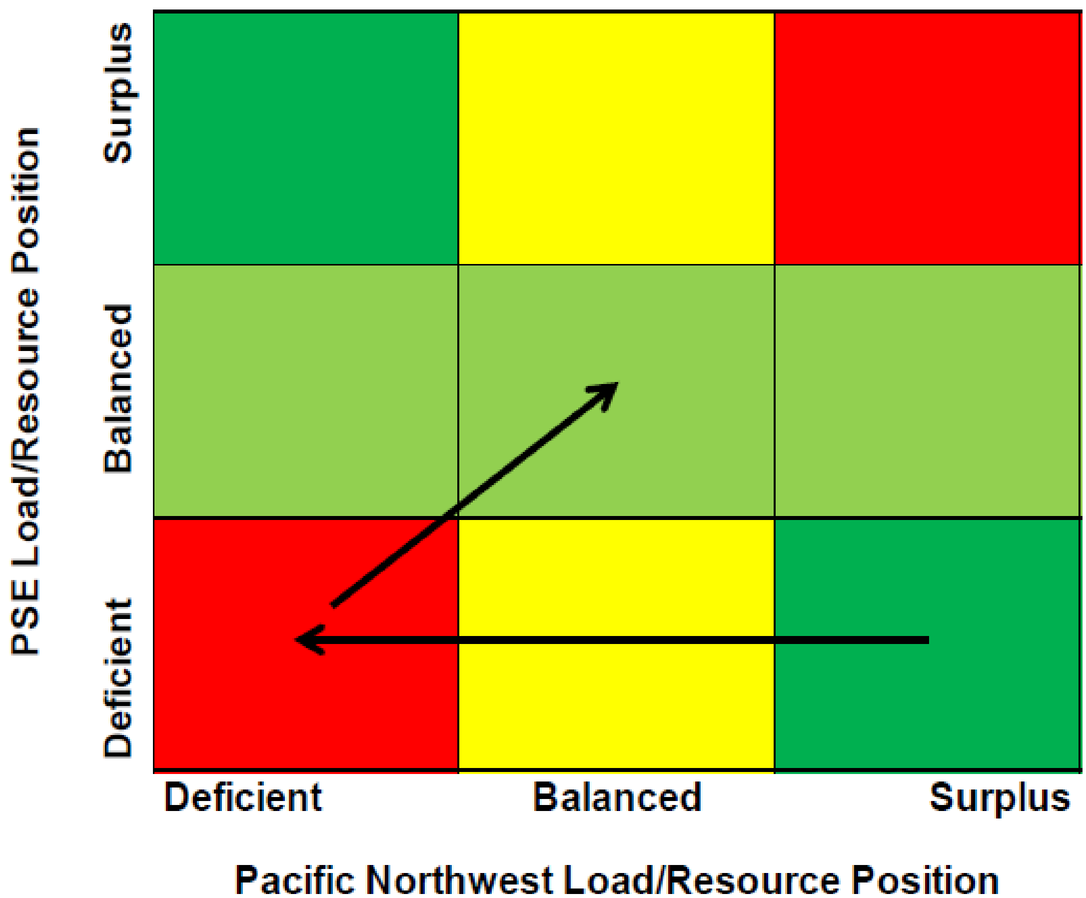
Note: PNUCC data not provided past 2031. PNUCC numbers for 2033 provided from the latest year available.

Table 7.16 highlights that the region will be short on peak capacity even with questionable assumptions on IPP resources and California imports.

4.3. Change Strategic Position

The risk matrix shown in Figure 7.4.provides an illustration of capacity position risk. When the region is surplus, it is prudent for PSE to be physically short — as illustrated by the box in Figure 7.4 with an 'X' below. In that scenario, we manage the financial risk, but we did not have to build unnecessary physical generation capacity. However, as the region grows short of capacity, PSE would shift to the 'Y' box, creating a physical and financial risk. Even if we can hedge the financial risk of relying on short-term market capacity resources, the physical reliability risk may not be manageable. We may not need to build resources to fill that entire market position, though. Puget Sound Energy could sign longer-term contracts to fill this position, if these options are available and do not leave the position to the short-term market. We must move to at least the balanced position in Figure 7.4 for our resource adequacy position going forward.

Figure 7.4: Capacity Position Risk Matrix



4.4. Market Reliance

The 2023 Electric Report reduces our reliance on the short-term market, eventually bringing market reliance to zero by 2029, as reflected in Table 7.17.

Table 7.17: Perfect Capacity Adjusted to Eliminate Short-Term Market Reliance (MW)

Resource	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Mid-C Hydro	560	560	560	560
Thermal	2,050	1,688	2,050	1,688
All other resources	997	244	981	252
Short-term Market Purchases	-	-	-	-
Additional perfect capacity for 5% LOLP	2,712	2,836	3,180	3,607
Total Resources	6,319	5,329	6,771	6,107

5. Adjustments for Portfolio Analysis

Resource adequacy is an upstream study for the 2023 Electric Report. The resource adequacy analysis calculated planning reserve margin and resource ELCCs modeled in the AURORA database to perform long-term expansion planning and hourly dispatch. The long-term capacity expansion (LTCE) and hourly dispatch optimize new builds and mimic the hourly operation of the existing resources and new builds. New to the 2023 Electric Report is the winter and summer planning reserve margin. We included only the winter planning reserve in the AURORA model in previous IRPs. Starting with the additional perfect capacity for 5 percent LOLP provided by E3, we made minor adjustments to consider more current assumptions for existing resources' ELCC contribution and to eliminate short-term market reliance. We used the resulting seasonal PRM as an input to the AURORA model to serve as a target in the long-term capacity expansion when determining new resource alternatives.

Seasonal resource ELCCs are also new in the 2023 Electric Report and reflect existing and new resources in the AURORA model. In addition, the renewable resource and storage ELCC saturation effect represented by multiple tranches added model complexity and increased run-time significantly. AURORA evaluates new resources for each of the available builds for the year, so the model ends up with a large matrix of all the resource options and costs, contributing to the long run time. A review of the AURORA model study log shows that storage scheduling also contributes to the extended run time. To manage the large-scale optimization problem run-time and meet the IRP study needs, we adjusted new resource ELCCs, consolidating from six tranches to three.

➔ See Appendix L: Resource Adequacy for additional information on new resource ELCC aggregation.

6. Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP)[9] is a compliance-based framework designed to increase regional reliability at a reduced cost for participants. The Western Power Pool (WPP) and a steering committee comprised of western region market participants have proposed a design for a capacity-based RA program. This voluntary program

9 https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

establishes a standardized way to approach the resource adequacy problem across twenty-six regional entities (participants) in the west, with an estimated combined peak load of 65,000 MW.

The WPP conducted an extensive public outreach process over the past few years to create a governance structure to give interested parties a voice in decision-making. Each entity conducts its regional planning and procurement to meet capacity RA. Each Load Responsible Entity (LRE) has its methods for calculating peak load, generation and transmission requirements, and capacity contribution. The LRE management approves new resources, which regulators regulate relative only to that LRE's need. Without transparency and coordination, LREs collectively may rely on market purchases relative to available capacity. Additionally, in the absence of regional coordination, the footprint's capacity could be contracted to other regions experiencing ever-growing capacity shortfalls or may not be scheduled in such a way as to meet the needs of participants within the footprint during capacity critical hours (CCH).

The individualized nature of the current planning framework can make it difficult for regulators, board members, interested parties, and utilities to understand whether, where, and when the region needs new capacity. The WRAP will increase visibility in the region's resources and transmission and help participants coordinate to fill these gaps collectively as they plan for the future.

The main components of the WRAP compliance framework are the forward showing program (FS) and the operational program (Ops Program) for both winter and summer seasons. These programs seek to balance reasonably conservative planning and the flexibility to protect customers from unreasonable costs.

The FS program establishes regional metrics for various resources' footprint and qualifying capacity contribution (QCC) values, sets deliverability expectations, and determines planning windows for demonstrating adequacy. Participants are required to show that they have contracted for the necessary amount of capacity resources to meet a P50 event plus a PRM. Participants must also demonstrate they have firm transmission rights to deliver at least 75 percent of their FS resources. The FS deadline for demonstrating adequate capacity and transmission is seven months before the beginning of each summer or winter season. The first binding season that a participant may elect is summer 2025. Participants must commit to go binding by summer 2028 to continue in the program.

The Ops program creates a framework to provide participants with pre-arranged access to capacity resources in the program footprint when a Participant is experiencing an extreme event, such as excess load or forced outages.

A key benefit of the WRAP is the ability to leverage the region's load and resource diversity so LREs can carry less PRM during the FS planning window than they would on a stand-alone basis. The Ops program allows participants to collectively manage the risk of capacity shortfall by prescriptively sharing available capacity and deliverability plans.

6.1. Planning Reserve Margin and Effective Load Carrying Capability

We ran a WRAP sensitivity analysis to see how the portfolio for this report would change if we used the WRAP metrics instead of the resource adequacy metrics we developed with E3.

➔ See Appendix L: Resource Adequacy for details regarding the methodology and approach the WPP used.

Table 7.18 WRAP Provided PSE Capacity Need (MW) 2029

Sensitivity	Winter 2029	Summer 2029
One-in-two Peak	4,570	3,447
PSE Planning Reserve Margin	21%[a]	14%[a]
Balancing Reserves	132	122
Less Existing Resources	(3,120)	(2,343)

Note:

a. WRAP PRM percent is an estimate.

Table 7.18 shows the estimated seasonal planning reserve margin and peak capacity shortfall in 2029. Additional resources will fill the peak capacity needs. Table 7.19 shows the resources seasonal peak capacity contribution, by ELCC. The WRAP footprint is split into two solar ELCC zones and 5 wind ELCC zones. The generic solar resources are in Zone Solar VER 1, which contains Northern states in the West, including Washington, Oregon, Idaho, Montana, and Wyoming. Generic wind resources are distributed in 5 wind zones as shown in Table 7.19.

Table 7.19 WRAP Provided ELCCs for 2029

Resource	Winter 2029	Summer 2029	WRAP Wind/Solar Zone
British Columbia Wind	25%	20%	Wind VER 5
Idaho Wind	31%	17%	Wind VER 2
Montana Central Wind	27%	13%	Wind VER 3
Montana East Wind	27%	13%	Wind VER 3
Offshore Wind* (E3's number)	31%	17%	Wind VER 2
Washington Wind	10%	18%	Wind VER 1
Wyoming East Wind	31%	15%	Wind VER 4
Wyoming West Wind	31%	15%	Wind VER 4
DER Ground Mount Solar	3%	23%	Solar VER 1
DER Rooftop Solar	3%	23%	Solar VER 1
Idaho Solar	3%	23%	Solar VER 1
Washington East Solar	3%	23%	Solar VER 1
Washington West Solar	3%	23%	Solar VER 1
Wyoming East Solar	3%	23%	Solar VER 1
Wyoming West Solar	3%	23%	Solar VER 1
Pump Storage	100%	100%	N/A
Nuclear	99%	99%	N/A
Li-ion Battery (2-hour)	40%	40%	N/A
Li-ion Battery (4-hour)	80%	80%	N/A
Li-ion Battery (6-hour)	100%	100%	N/A

Resource	Winter 2029	Summer 2029	WRAP Wind/Solar Zone
100 MW Washington Solar East Solar + 50 MW 4-hour Li-ion Battery	43 MW	63 MW	N/A
100 MW Washington Wind + 50 MW 4-hour Li-ion Battery	50 MW	58 MW	N/A
100 MW Washington Solar East + 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery	5 54MW	81 MW	N/A
200 MW Montana Wind Central + 100 MW 8-hour PHES	154 MW	126 MW	N/A
Frame Turbine	100%	91%	N/A
Reciprocating Engine	N/A	N/A	N/A
Combined Cycle	86%	80%	N/A

ELECTRIC ANALYSIS
CHAPTER EIGHT

Contents

1. Introduction

Results of the electric analysis in Puget Sound Energy's (PSE's) 2023 Electric Progress Report (2023 Electric Report) from the following four-step process are illustrated in Figure 8.1. We described steps one, two, and three in detail in this chapter. We discussed step four in detail in Chapter Three: Resource Plan of the 2023 Electric Report.

Step 1. Establish Resource Needs

We identified three types of resource needs: peak capacity, energy, and CETA-renewable and non-emitting resource needs. Chapter Seven: Resource Adequacy Analysis presents our resource adequacy analysis for the peak need. Appendix C: Existing Resource Inventory describes the existing electric and CETA-eligible resources. Chapter Six: Demand Forecast shows the demand forecast we used to establish the resource needs.

Step 2. Determine Planning Assumptions and Identify Resource Alternatives

In this chapter, we discussed the reference portfolio and sensitivities developed for the 2023 Electric Report. Chapter Five: Key Analytical Assumptions presents the key analytical assumptions and a description of the sensitivities. Appendix D: Generic Resource Alternatives describes electric resource alternatives in detail.

Step 3. Analyze Alternatives Using Deterministic Portfolio, Portfolio Benefit Analysis Tool, and Stochastic Risk Analyses

The deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet needs, given the static assumptions defined in the scenario or sensitivity. We analyzed all scenarios and sensitivities using deterministic optimization analysis.

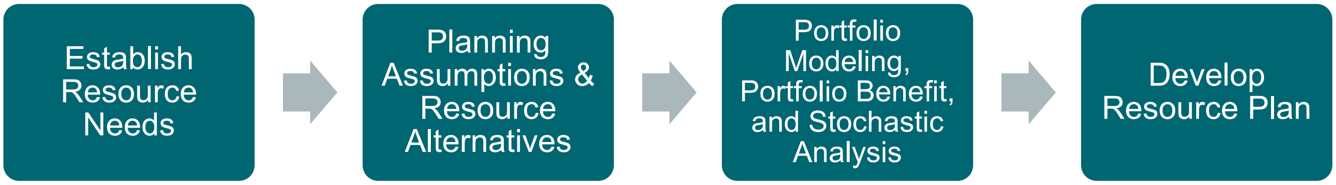
The portfolio benefit analysis tool helps support our understanding of equity-related benefits and the associated costs within each portfolio and informs our work as we strive to select a portfolio best suited to equitable outcomes for customers while also considering cost.

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis to test how the different portfolios developed in the deterministic analysis perform concerning cost and risk across a wide range of possible future power prices, gas prices, hydroelectric generation, wind generation, loads, and plant forced outages. We analyzed the reference and preferred (sensitivity 11 B2) portfolios using stochastic risk analysis.

Step 4. Develop Resource Plan

We studied the deterministic analysis, the portfolio benefits tool analysis, and the stochastic quantitative analysis results to understand the key findings that led to decisions for the preferred portfolio. We presented the analysis results in this chapter and Appendix H: Electric Analysis and Portfolio Model. Chapter Three: Resource Plan presents the resource plan decisions.

Figure 8.1: 2023 Electric Progress Report Process



2. Clean Energy Transformation Act

The 2021 Integrated Resource Plan (IRP) marked a significant departure from past IRPs due mainly to the passage of the Clean Energy Transformation Act (CETA). The new electric progress report rules, WAC 480-100-625,[1] outline the requirements for this report. Utilities must file a progress report at least every two years after the utility files its IRP, beginning January 1, 2023.

In this mandated report, the utility must update the following:

- Demand forecast
- Demand-side resource assessment, including a new conservation potential assessment
- Resource costs
- The portfolio analysis and preferred portfolio

The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.[2] The progress report must also include other updates necessary due to changing state or federal requirements or significant economic or market forces changes.

2.1. Demand Forecast

Puget Sound Energy's 2023 Electric Progress Report incorporates climate change in the base energy and peak demand forecast for the first time. Before this report, we used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This old approach was a common utility practice but did not recognize predicted climate change, which experts expect will increase temperatures, on average, over time.

> Puget Sound Energy incorporated climate change into the demand forecast for the first time in this report. We heard from interested parties that climate change is important to incorporate because it affects future demand and needs, and PSE agrees. We included climate change in the base demand forecast and the stochastic scenarios.

We know the methodology for incorporating climate change in this report is the first step, and we expect it will evolve. We heard from interested parties that incorporating climate change into demand forecasting is a high priority. Puget Sound Energy provides energy for heating in the winter and cooling in the summer. It is essential to consider climate change in resource planning because of the warming trends that we expect will likely lead to, on average, less heating demand in winter and more cooling demand in summer.

[1] WAC 480-100-625
[2] WAC 480-100-640

Climate scientists recently developed climate model projections for the region, which we will use to calculate a normal temperature assumption that reflects climate change. We also updated the peak demand forecast, which results in normal peak temperatures for summer and winter that increase over time.

We expect electric energy demand to grow at an average annual growth rate (AARG) of 1.8 percent from 2024 to 2045 before the additional demand-side resources (DSR) we identified in the 2023 Electric Report's base demand forecast. This growth rate increased our forecast from 2,551 average megawatts (aMW) in 2024 to 3,699 aMW in 2045, faster than the 1.2 average annual energy growth rate forecasted in the 2021 IRP.

➔ See Chapter Six: Demand Forecast and Appendix F: Demand Forecast Models for details regarding how PSE incorporated climate change into our demand forecast.

2.2. Demand-side Resources

We analyzed DSR alternatives in a conservation potential assessment (CPA) and demand response assessment to develop the supply curve we used as input to the portfolio analysis. The portfolio analysis then determined the potential maximum energy savings captured without raising the overall electric or natural gas portfolio cost. This analysis identified the DSR's cost-effectiveness level to include in the portfolio.

➔ The CPA updated for the 2023 Electric Report is in Appendix E: Conservation Potential and Demand Response Assessments.

Overall, the 2023 Electric Report CPA potential is down from the 2021 IRP by about 13 percent by 2045. Several updates and new data elements contributed to the reduced potential:

- The CPA incorporated a statutory provision requiring the state to adopt more efficient building energy codes to achieve a 70 percent reduction by 2031. This change in the CPA moved some of the potential from energy efficiency into codes and standards.
- The newly incorporated impact of climate change reduced savings in the later years of the study
- Updated building stock assessments, which have more efficiency penetration compared to the last stock assessment
- Updated savings from the most recent biennium program cycle

The CPA potential is also down in the 2023 Electric Report because of the following factors:

- Climate change reduced the normal winter peaks, thereby reducing the contribution of savings at the peak
- Updated conservation measure load shapes to align with the Northwest Power and Conservation Council's 2021 Power Plan[3]

3 https://www.nwcouncil.org/2021-northwest-power-plan/

- Updated PSE's system peak definition to reduce the morning and evening windows for very heavy load hours[4]

Demand response peak savings increased due to updates we made to the potential to align with the 2021 Power Plan and an increase in the transmission and distribution deferrals costs.

2.3. Resource Costs

Like the 2021 IRP, we aggregated publicly available generic resource costs from several sources, predominantly from the National Renewable Energy Laboratory's (NREL) 2022 Annual Technology Baseline.[5] We expect generic resource capital costs to decline as technological advances push costs down. The declining cost curves we applied to different resource alternatives came from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB).

➔ A breakdown of the updated generic resource costs is in Chapter Five: Key Analytical Assumptions, with details in Appendix D: Generic Resource Alternatives.

2.4. Portfolio Analysis and Preferred Portfolio

We updated the portfolio analysis for the 2023 Electric Report. The assumptions and documentation of the model are in Chapter Five: Key Analytical Assumptions and Appendix H: Electric Analysis and Portfolio Model. The analysis results are later in this chapter, and we discussed the preferred portfolio in Chapter Three: Resource Plan.

2.5. State and Federal Requirements

Policy changes in the energy industry in Washington State and the United States have rapidly increased in the last decade. The following are the key policy changes impacting this report.

2.5.1. State Laws and Regulations

At the state level, PSE incorporated rules from the Climate Commitment Act (CCA), the Clean Energy Transformation Act (CETA), the Clean Energy Implementation Plan (CEIP), and new building codes.

2.5.2. Federal Laws

The Inflation Reduction Act (IRA) became law in August 2022. The two main incentives in the act applicable to PSE'S resource costs are the Production Tax Credits (PTCs) and Investment Tax Credits (ITCs). The IRA provides more long-term certainty in investment decisions by providing 10 years of energy tax incentive eligibility and

4 In the 2021 IRP, we estimated the peak contribution from energy efficiency savings between peak hours, defined as: weekdays from hour ending (HE) 7–11 a.m. (6–11 a.m.) and HE 6–10 p.m. (5–10 p.m.); in the 2023 IRP this was updated to HE 8–10 a.m. and HE 6–7 p.m.

5 https://atb.nrel.gov/

enhanced tools to accelerate or support credit monetization. Where previous tax rules for PTC (wind) and ITC (solar) were technology-specific, the new tech-neutral credit may allow the entity receiving the credit to choose the most efficient incentive type. The rules also provide bonuses for where and how operators build projects. The rules incentivize project developers to utilize domestically sourced materials, drive economic opportunity by placing projects in service in low-income communities, and leverage an existing workforce in census tracts deemed energy communities where new clean energy developments may impact fossil-fuel extraction and generation activities. The full effects of the legislation, once implemented, are not known at this time, but we were able to include some of the known effects of the federal IRA in this report.

Production Tax Credits provide an energy tax credit ($/MWh) for the first 10 years of energy output after a utility places a project in service. Before Congress enacted the IRA, PTCs expired for any new projects placed in service in 2022 and beyond. The IRA bill now extends PTCs to 100 percent for eligible projects in service before the end of 2032. The PTCs are now technology-neutral, so solar projects now qualify for PTC. We assumed PTC for wind and solar resources as the most economical use of the tax incentives.

Investment Tax Credits provide an energy tax credit based on the project's percentage of investment. Before Congress enacted the IRA, the ITC rate for projects placed in service in 2022 had phased down to 10 percent. The IRA increased the ITC rate to 30 percent. Previously, the regulations restricted ITC for battery storage projects to hybrid battery storage projects paired with solar or other renewable energy generation assets. The IRA now extends the ITC to cover all stand-alone energy storage applications. This change makes the system more flexible because the battery can charge from the grid and its paired solar project. We assumed ITC for energy storage resources.

The IRA includes subsidies for utility-scale resources and end-use customer appliances. We do not know how the federal government will implement the subsidies yet, so we cannot incorporate their impact on our customers' behavior. As we learn more about the policies to implement these subsidies, we will reflect the effects in future IRPs.

2.6. Economic or Market Forces

We incorporated the economic and market forces that affect the electric resource plan into the electric and natural gas price forecasts.

2.6.1. Electric Price Forecast

We developed this electric price forecast as part of our 2023 Electric Report. In this context, the electric price is not the rate charged to customers but PSE's price to purchase or sell one MWh of power on the wholesale market, given the prevailing economic conditions. Electric price is an essential input to this analysis since market purchases comprise a substantial portion of PSE's existing resource portfolio. The updated electric price forecast reflects higher avoided energy costs due to updated modeling methodologies and assumptions to the electric price forecast model. The levelized nominal power price for the 2023 Electric Report is $42.90/MWh compared to the 2021 IRP, which was $23.37/MWh.

➔ A detailed account of all updates to the electric price model is in Chapter Five: Key Analytical Assumptions and Appendix G: Electric Price Models.

2.6.2. Natural Gas Price Forecast

The projection for natural gas prices increased between the 2021 IRP and the 2023 Electric Report, particularly in the near term, increasing electric prices. Recent gas prices are elevated due to energy security concerns in Europe and accelerating coal retirements domestically, which leads to additional gas demand for the power sector and demand driven by liquefied natural gas (LNG) export expansion.

➔ We discuss natural gas in further detail throughout Chapter Five: Key Analytical Assumptions.

2.6.3. Alternative Fuels

For this report, we modeled two types of alternative fuels, hydrogen and biodiesel.

Hydrogen

Hydrogen is a highly flexible commodity chemical currently used in a wide range of industrial applications and poised to become a key energy carrier in the power sector. Production tax credits in the IRA reduce the market price of green hydrogen by up to $3 per kilogram, making it a cost-competitive energy carrier. We modeled green hydrogen as a fuel source for existing and new combustion turbines starting in 2030.

Biodiesel

Biodiesel is a renewable resource under RCW 19.405.020(34)[6] of CETA. Biodiesel must not be derived from crops raised on land cleared from old-growth or first-growth forests to be considered renewable. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or dedicated crops. We modeled biodiesel as a fuel source for new combustion turbines starting in the model year 2024.

➔ Further discussion of hydrogen and biodiesel as fuel sources is in Appendix D: Generic Resource Alternatives.

[6] RCW 19.405.020

2.7. Elements Found in Clean Energy Implementation Plan

In December 2021, we filed our first CEIP. The plan illustrates PSE's four-year roadmap to meet the requirements of CETA and the specific actions PSE will take from 2022–2025 to meet those goals. The CEIP proposes an interim target of serving customers with 63 percent clean, CETA-eligible renewable resources by the end of 2025. We used the 63 percent target from the CEIP as the minimum for this 2023 Electric Report. The resource specific targets included in the CEIP and proposed in this report are:

- 25 MW of Distributed Energy Resources (DER) storage
- 80 MW of DER solar

We also applied certain customer benefit indicators (CBIs) identified in the CEIP that apply to resource planning.

3. Resource Need

Reliably meeting our customers' needs is the cornerstone of PSE's energy supply portfolio. For resource planning, the physical electricity needs of our customers are simplified and expressed as three resource needs: peak hour capacity need, energy need, and renewable and non-emitting energy need.

3.1. Peak Hour Capacity Need

We determined peak hour capacity need with a resource adequacy analysis that evaluated existing PSE resources compared to the projected peak need over the planning horizon. The capacity shown is the amount of effective capacity needed to maintain the resource adequacy target — the need after applying different resources' effective load carrying capacity (ELCC). Due to market reliance assumptions used in this 2023 Electric Report, the modeling indicates PSE could begin to experience a peak capacity shortfall starting in 2024. Before any conservation, the peak capacity need plus the planning margin required to maintain reliability is 2,629 MW by 2029. The 2,629 MW is the difference between the load forecast (the demand forecast plus the required planning margin) and the total peak capacity credit of existing resources. Figures 8.2 and 8.3 show the winter and summer peak capacity needs through 2045.

Figure 8.2: Effective Peak Capacity Need — Winter

(Physical Reliability Need, Peak Hour Need Compared to Existing Resources)

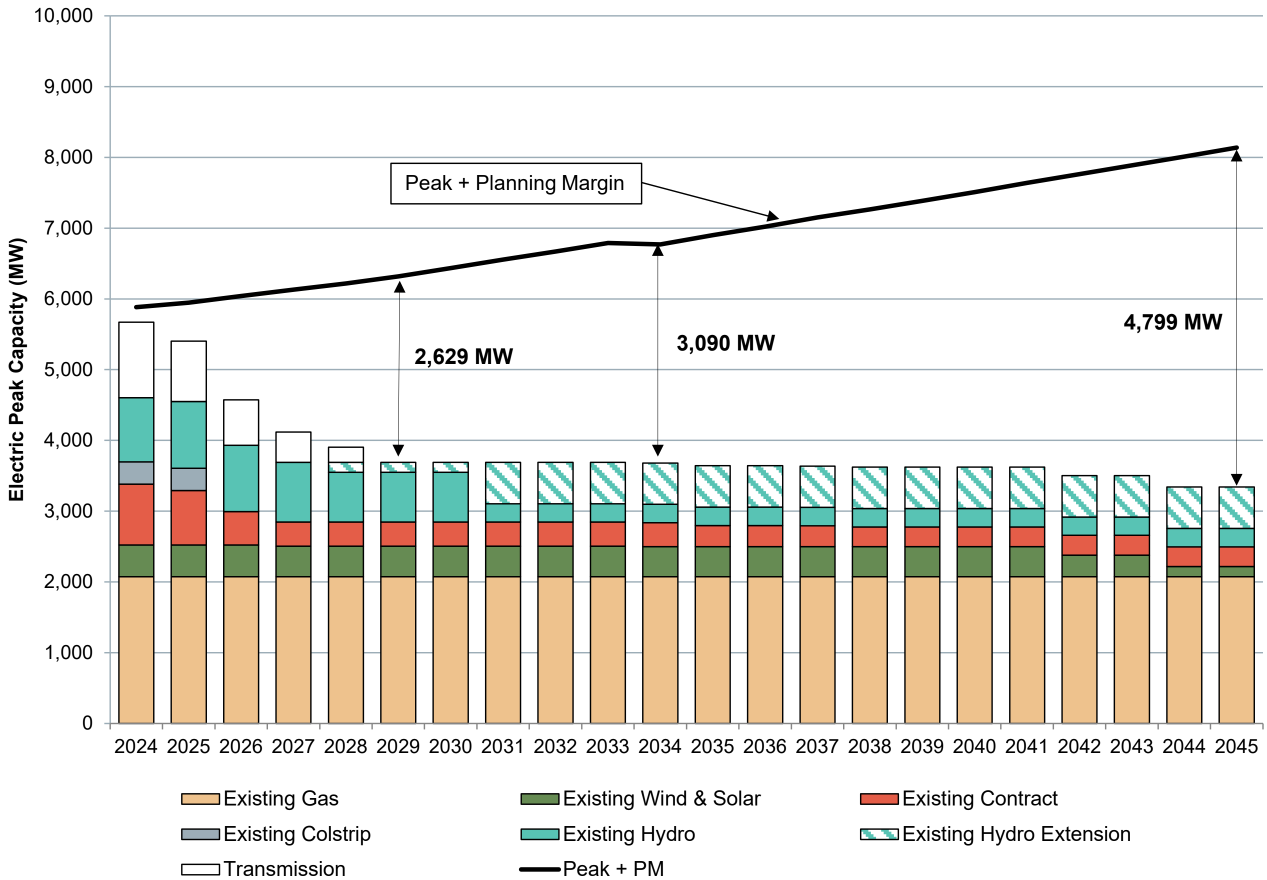
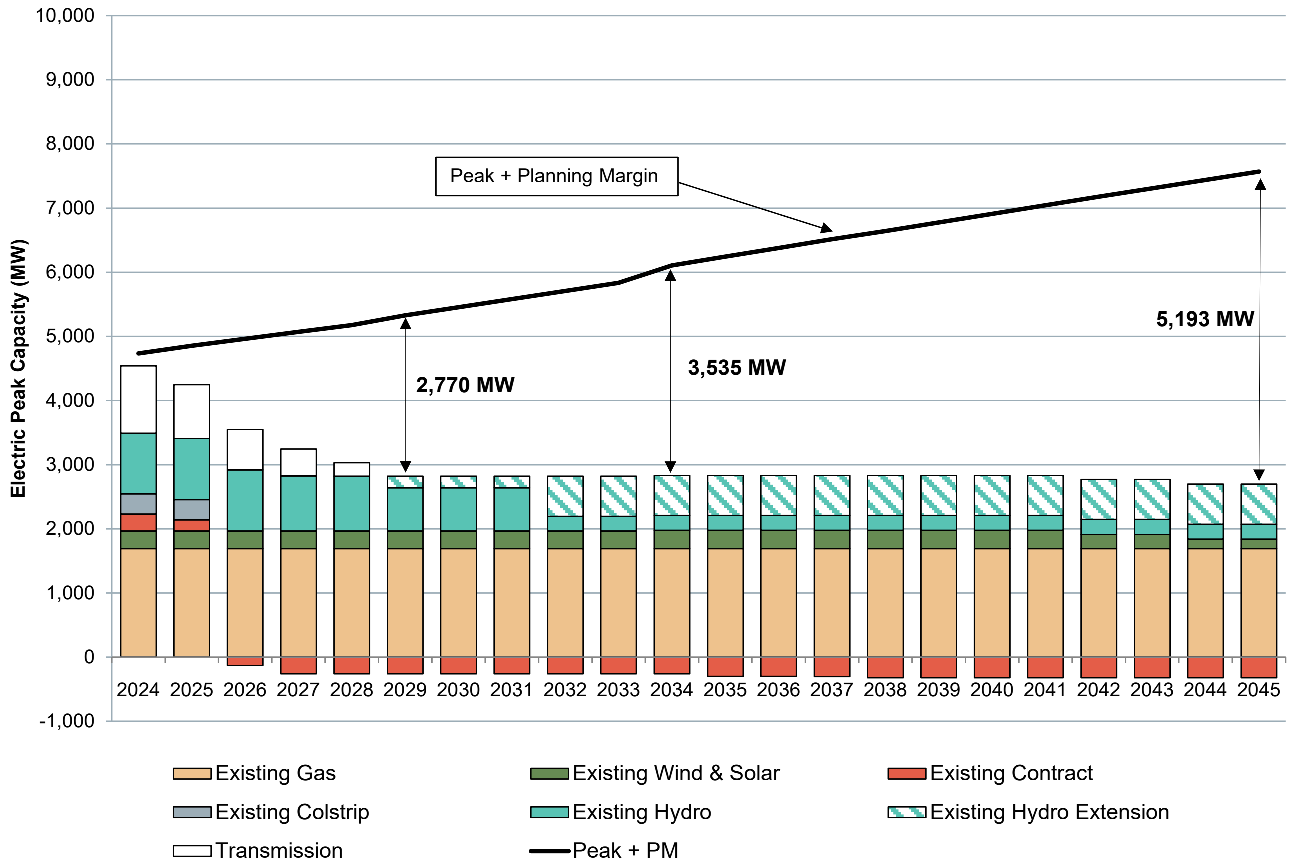


Figure 8.3: Effective Peak Capacity Need — Summer

(Physical Reliability Need, Peak Hour Need Compared to Existing Resources)



➔ See Chapter Seven: Resource Adequacy Analysis for a complete discussion of the resource adequacy analysis.

3.2. Energy Need

We must meet our customers' energy needs 24 hours a day, 365 days a year. Our models require the portfolios to supply the energy necessary to meet physical loads and examine how to do this most economically through existing resources, new resources, and purchasing and selling electricity on the energy market. Puget Sound Energy's annual energy need starts at 2,551 aMW for 2024, increases to 2,799 aMW in 2030, and reaches 3,699 aMW in 2045.

➔ See Chapter Six: Demand Forecast for a detailed discussion on energy demand.

3.3. Renewable and Non-emitting Energy Need

In addition to reliably meeting the physical needs of our customers, CETA requires that utilities meet at least 80 percent of electric sales (delivered load) in Washington State by non-emitting or renewable resources by 2030 and 100 percent by 2045.

Figure 8.4 illustrates PSE's renewable and non-emitting energy need. For the long-term IRP analysis, we assumed a linear ramp to achieve the Clean Energy Transformation Standards Act standards in 2030 and 2045 described in RCW 19.405.040;[7] however, actual resource acquisitions through implementation of the CEIP will likely produce a less linear pathway than we show. Before any conservation, the renewable energy need is over 7 million MWh in 2030 to meet the 80 percent clean energy standard. The renewable need is the difference between the green line and the teal bars in Figure 8.4.

[7] RCW 19.405.040

Figure 8.4: Qualifying Energy Need to Meet CETA Requirements

(Before Demand-side Resources)

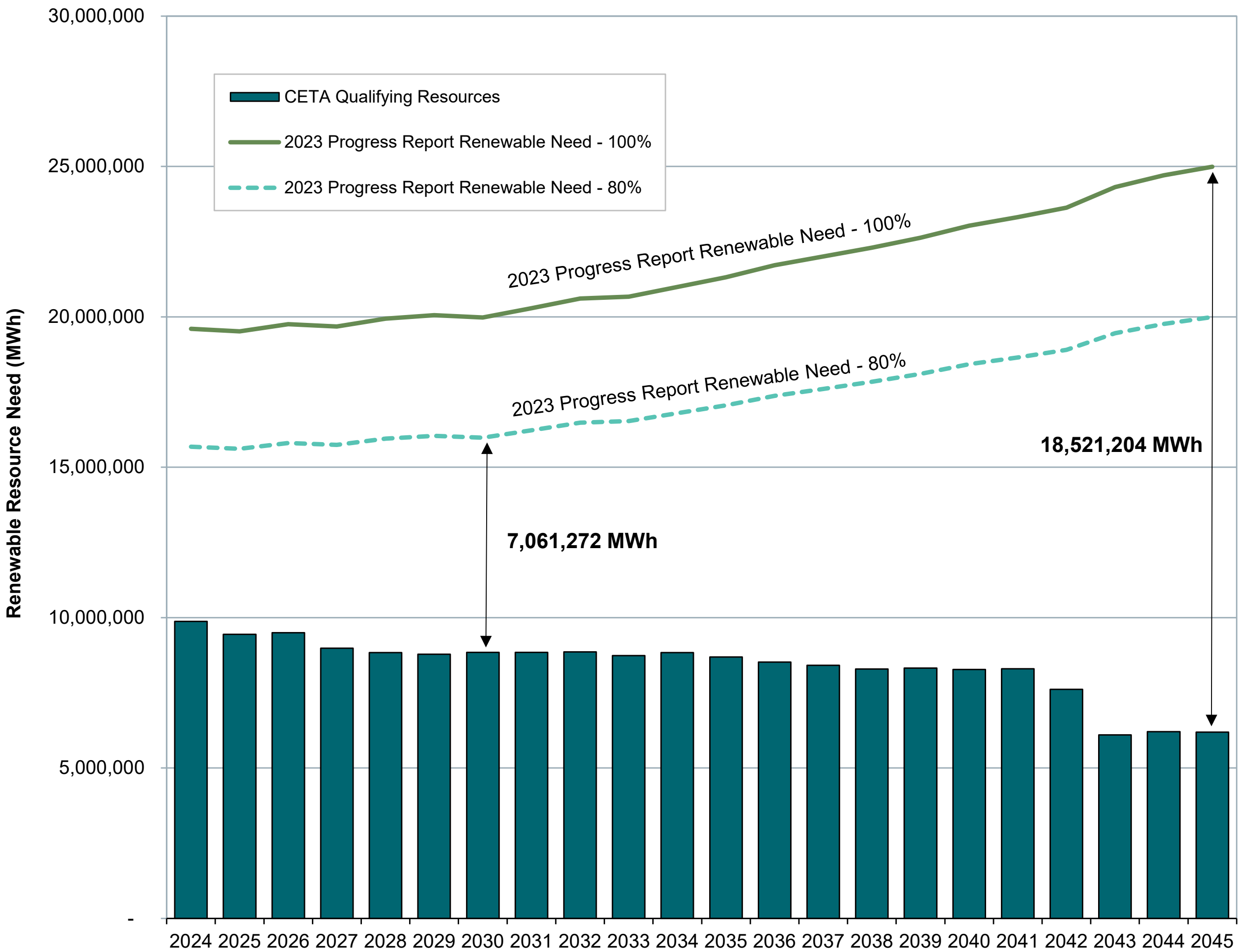
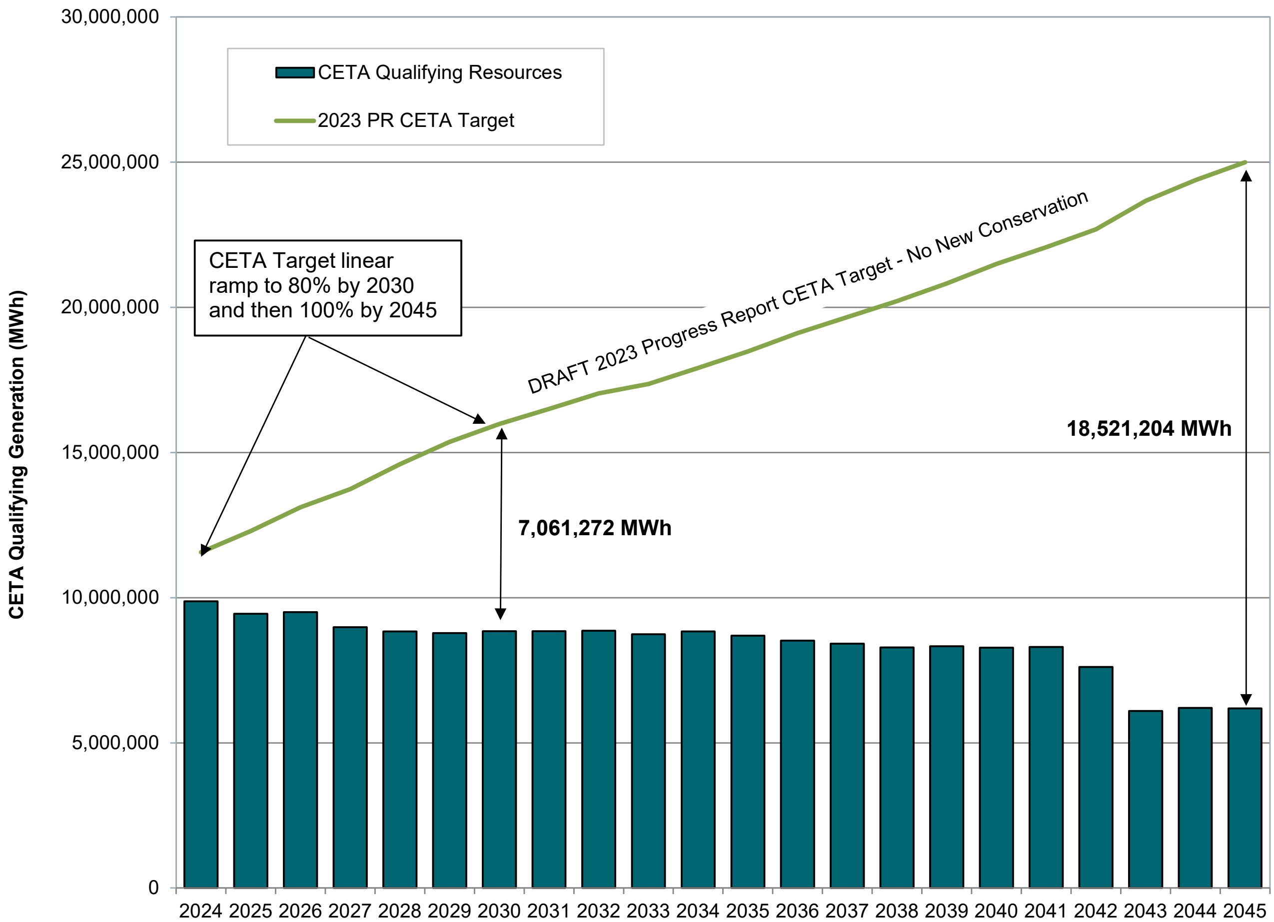


Figure 8.5 assumes a linear ramp to reach the 80 percent clean energy standard in 2030 and the 100 percent clean energy standard in 2045. We used the linear ramp to ensure the portfolio model gradually adds resources to meet clean energy standards rather than waiting until the goal's final target year to add them. The linear ramp starts in 2024, as the model assumes all new resources are self-builds, with most available to begin in 2024.

Figure 8.5: Renewable Need and Linear Ramp for CETA (Before Demand-side Resources)



4. Types of Analysis

We used deterministic optimization analysis to identify each portfolio's lowest reasonable cost. We then ran a stochastic risk analysis to test different resource strategies.[8] We used the portfolio benefit analysis to inform the equitable distribution of burdens and benefits in the resource planning process to ensure all customers benefit from the transition to clean energy.

4.1. Deterministic Portfolio Optimization Analysis

We subjected all the portfolios to deterministic analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio — the lowest-cost mix of demand-side and supply-side resources that will meet the need under the given static assumptions defined in the scenario or sensitivity. This stage helped us learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

8 To screen some resources, we also used simpler, levelized cost analysis to determine if the resource is close enough in cost to justify spending the additional time and computing resources to include it in the two-step portfolio analysis.

4.2. Portfolio Benefit Analysis

The Clean Energy Transformation Act requires utilities to consider equity and ensure all customers benefit from the transition to clean energy. However, AURORA, a traditional production cost model used for portfolio modeling, only solves for the least-cost solution. Therefore, we developed and used a portfolio benefit analysis tool to support our understanding of equity-related benefits and the associated costs within each portfolio and inform our work as we strive to select a portfolio best suited to enable equitable outcomes for customers while also considering cost.

The portfolio benefit analysis measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative CBIs and their metrics. Customer benefit indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA modeling tool could quantitatively evaluate them, i.e., AURORA already had a comparable metric. The CBIs we included in the portfolio benefit analysis are:

- **Improved access to reliable, clean energy** — measured by customers with access to distributed storage resources
- **Improved affordability of clean energy** — measured by the total portfolio cost
- **Improved outdoor air quality** — measured by sulfur oxides, nitrogen oxides, and particulate matter generated per portfolio
- **Increased number of jobs** — measured by the number of estimated jobs generated for each portfolio
- **Increased participation in Energy Efficiency, Distributed Energy Resource, and Demand Response Programs** — measured by energy efficiency capacity added and the number of customers projected to participate in distributed energy resources and demand response programs
- **Reduced greenhouse gas emissions** — measured by the total amount of CO_2-eq[9] generated per portfolio
- **Reduced peak demand** — measured by the decrease in peak demand achieved via demand response programs

The portfolio benefit analysis generates a CBI index for each portfolio, an aggregate measure of these CBIs (excluding the portfolio cost) normalized to the reference portfolio, also known as the least-cost portfolio. A higher CBI index indicates that a portfolio enables more equity-related benefits than the reference portfolio. The CBI index is then compared to its total cost (direct and externality costs).

[9] CO_2-eq or CO_2-equivelant is a measure used to compare the emissions from various greenhouse gases on the basis of their global-warming potential (GWP). Using the GWP, other greenhouse gases are converted to the equivalent amount of carbon dioxide.

➔ Appendix H: Electric Analysis and Portfolio Model includes a more detailed description of the methods used to conduct the portfolio benefits analysis.

4.3. Stochastic Risk Analysis

In this stage of the resource plan analysis, we examined how different resource strategies respond to the types of risk that reflect future uncertainty. We deliberately varied static inputs in the deterministic analysis to create simulations called draws, which we used to analyze the different portfolios.

With stochastic risk analysis, we tested the robustness of different portfolios to determine how well the portfolio might perform under various conditions. The goal is to understand the risks of varying candidate portfolios regarding costs. To assess those risks, we identified and characterized the likelihood of bad events and the likely adverse impacts they may have on a given portfolio.

To gain this understanding, we took some of the portfolios (drawn from the deterministic analysis of portfolios) and ran them through 310 draws[10] that modeled varying power prices, gas prices, hydroelectric generation, wind, and solar generation, load forecasts (energy and peak), and plant forced outages.

5. Reference Portfolio Analysis Results

The reference portfolio is the least-cost portfolio that meets CETA, energy, and reliability requirements. The reference portfolio sets the stage as the starting point that leads to an informed preferred portfolio. The reference case portfolio cost is $17.6 billion, and the social cost of greenhouse gases (SCGHG) is $3.2 billion, totaling $20.8 billion in total portfolio costs.

5.1. Reference Case Portfolio Builds

This section describes the resource additions needed for the reference portfolio to meet CETA requirements, reliability needs, and future energy growth.

5.1.1. Clean Energy Transformation Act

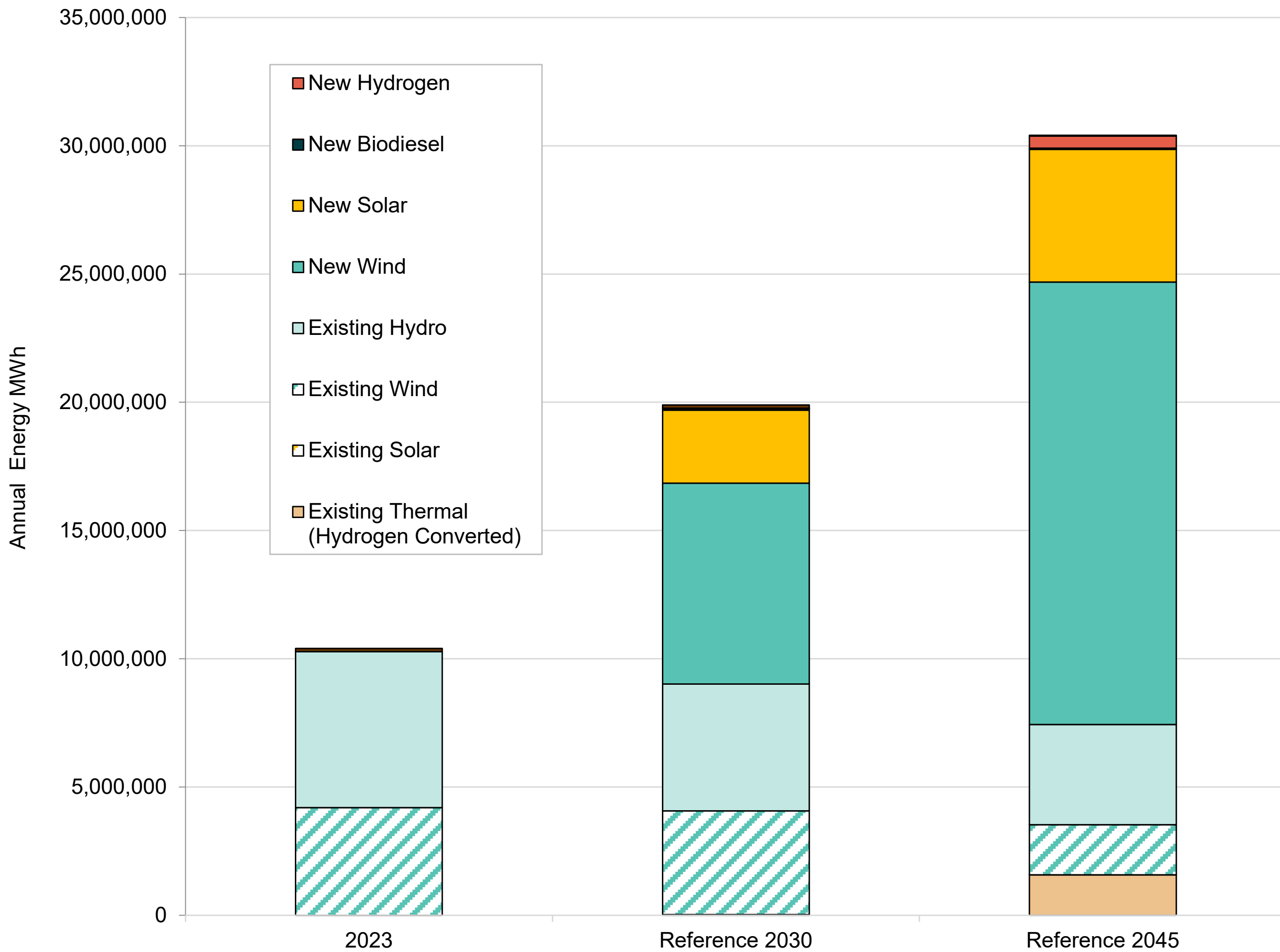
Figure 8.6 shows the energy breakdown from CETA-qualifying resources[11] for select years through 2045. Energy contribution from CETA-qualifying resources grows from over 10 million MWhs in 2023 to 20 million MWhs in 2030 and 30 million MWhs in 2045. New resources will be added to the portfolio starting in 2024, and by 2030 we will see a mix of hydroelectric, wind, solar, and hybrid resources (the renewable portion) eligible to meet CETA added to the portfolio. By 2045, energy from wind resources will make up most of the energy produced from CETA-qualifying

[10] Each of the 310 simulations is for the 22-year IRP forecasting period, 2024–2045.

[11] CETA-qualifying resources include all resources that qualify as renewable or non-emitting under CETA , which include renewables, hydrogen, biodiesel, and advanced nuclear as defined in RCW 19.405.020 (28) and (34)

resources. We also count energy from hydrogen and biodiesel peakers toward CETA achievement; however, those resources have a limited capacity factor and are mostly available to meet peak in high demand hours.

Figure 8.6: Energy for CETA-qualifying Resources — Reference Portfolio



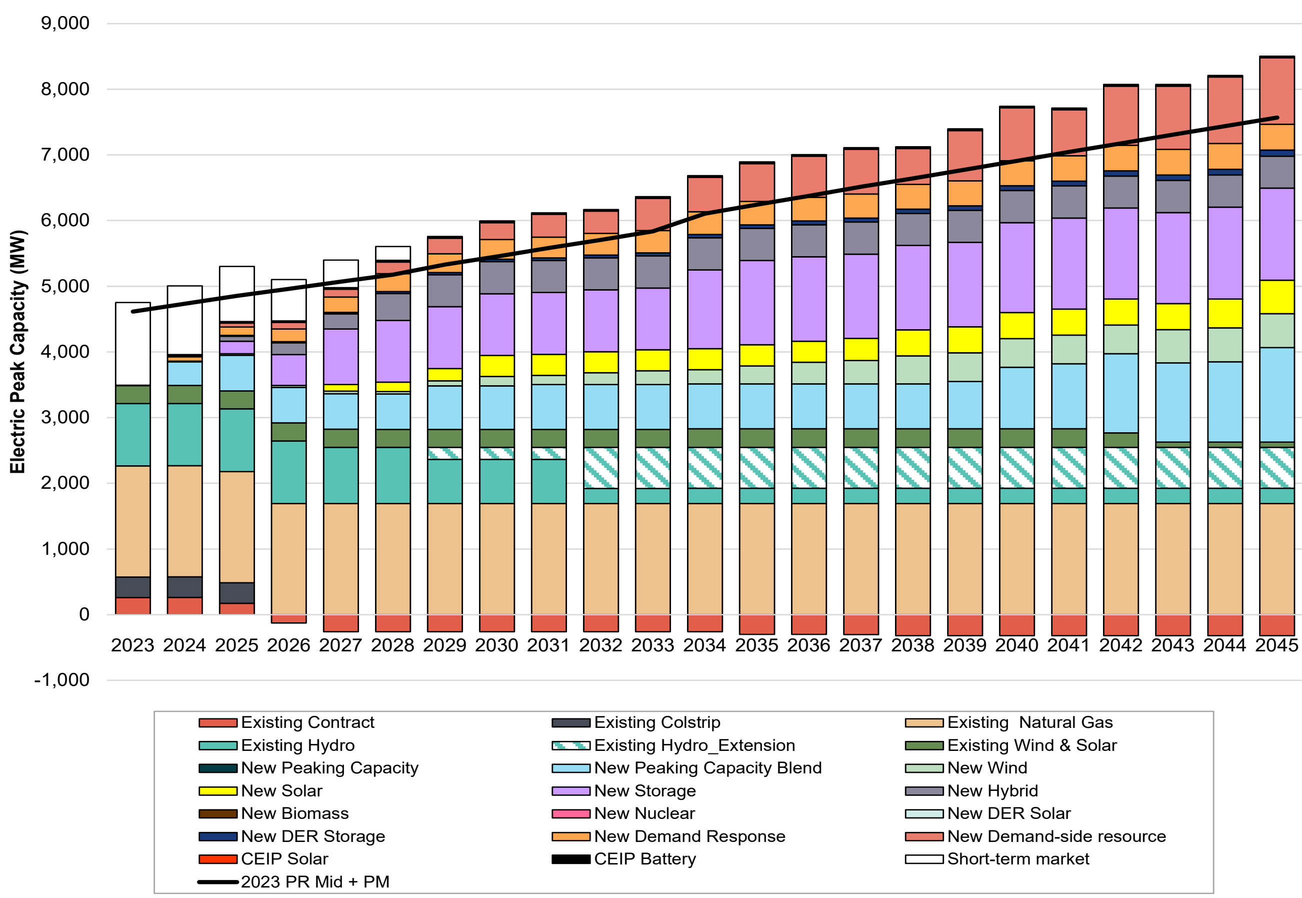
5.1.2. Meeting Reliability Needs

Many factors affect PSE's resource adequacy analysis, including climate change, electric vehicle forecast, and market reliance. Incorporating climate change data resulted in slightly lower normal winter peaks due to higher average temperatures in the winter, while the temperatures were higher on average for the summer leading to higher summer peaks. We also updated the electric vehicle forecast, which increased the winter peak demand. The increase from the electric vehicle forecast offset the decrease in normal winter peak from the climate change data.

Regarding market reliance, there is a concern about the availability of firm capacity in the short-term market. Puget Sound Energy currently has over 2,000 MW of available capacity to the Mid-Columbia (Mid-C) market, with a portion allocated to existing PSE-owned or contracted Mid-C resources, leaving PSE net about 1,400 MW to 1,500 MW of available Mid-C capacity for short term market purchases. This 1,500 MW of available Mid-C capacity was a firm resource in portfolio modeling for previous IRPs. For the 2023 Electric Report, we assumed that access to the short-term market would continue to be available but in decreasing amounts into the future. By 2029, we assumed that none of the transactions in the short-term market would be firm. The assumed reduction in market reliance increased PSE's peak needs. The winter peak need remains greater than the summer peak need through 2045.

Figure 8.7 provides a breakdown of peak capacity contribution by resource type for the summer. The solid black line in the chart represents the summer peak capacity. The combination of existing and new resource peak capacity for the reference portfolio in the summer is surplus of the summer target. Many of the resources we added to help meet CETA requirements, particularly solar resources, have a larger peak capacity contribution in the summer than in the winter. The peak contribution from energy storage resources is also larger in the summer than in the winter — PSE's system is built to meet winter peaking needs and is consequently surplus in the summer months.

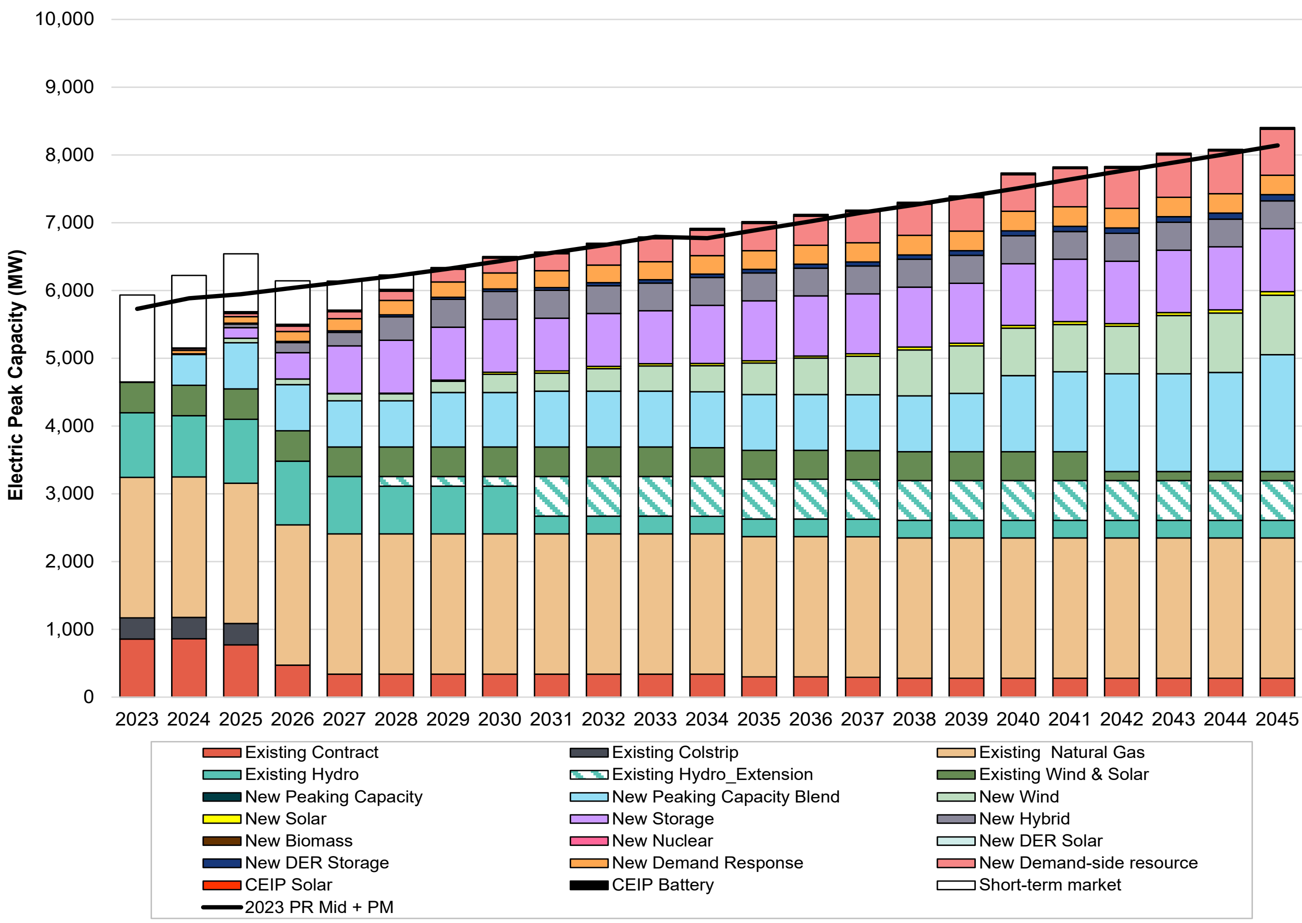
Figure 8.7: Effective Summer Peak Capacity by Resource Type – Reference Portfolio



➔ See Chapter Seven: Resource Adequacy Analysis for more details on resource adequacy.

However, new renewable resources' peak capacity is insufficient to meet winter peaks. We still need additional new peaking capacity to add to the reference portfolio. Looking at the same chart for the winter, we see the reference portfolio is no longer surplus but on target to meet the winter peak capacity. Figure 8.8 provides a breakdown of peak capacity by resource type for the winter. The solid black line in the chart represents the winter peak capacity plus the planning margin. Winter peak need drives new capacity resource builds for the reference portfolio.

Figure 8.8: Effective Winter Peak Capacity by Resource Type – Reference Portfolio



5.1.3. Meeting Future Growth

Puget Sound Energy meets our CETA, energy, and reliability requirements through a combination of conservation, demand response, distributed energy and clean energy resources, energy storage, and CETA-qualifying peaking new capacity resources. Overall cumulative capacity builds through 2045 is 14,287 MW. Table 8.1 summarizes the reference portfolio's incremental nameplate capacity for select years and the cumulative nameplate capacity.

Table 8.1: Incremental Resource Additions — Reference Portfolio (MW)

Resource Type	2024–2025 Incremental	2026–2030 Incremental	2030 Cumulative	2031–2045 Incremental	2045 Cumulative
Demand-side Resources	**184**	**369**	**553**	**547**	**1,100**
Conservation	51	175	226	469	695
Demand Response	133	194	327	78	405
Distributed Energy Resources	**182**	**252**	**434**	**1,177**	**1,612**
DER Solar	142	230	372	1,122	1,494
Net Metered Solar	59	225	284	1,109	1,393
CEIP Solar	79	-	79	0	79
New DER Solar	4	5	9	13	22
DER Storage	40	22	62	55	117
Supply-side Resources	**1,761**	**4,227**	**5988**	**5,587**	**11,575**
CETA Qualifying Peaking Capacity	711	128	839	949	1,788
Wind	600	800	1400	2,650	4,050
Solar	0	1,100	1100	1,290	2,390
Green Direct	0	100	100	0	100
Hybrid (Total Nameplate)	250	1,300	1550	0	1,550
Hybrid Wind	*100*	*800*	*900*	*0*	*900*
Hybrid Solar	*100*	*100*	*200*	*0*	*200*
Hybrid Storage	*50*	*400*	*450*	*0*	*450*
Biomass	0	0	0	0	0
Advanced Nuclear SMR	0	0	0	0	0
Standalone Storage	200	800	1000	700	1,700
Total	**2,127**	**4,849**	**6976**	**7,311**	**14,287**

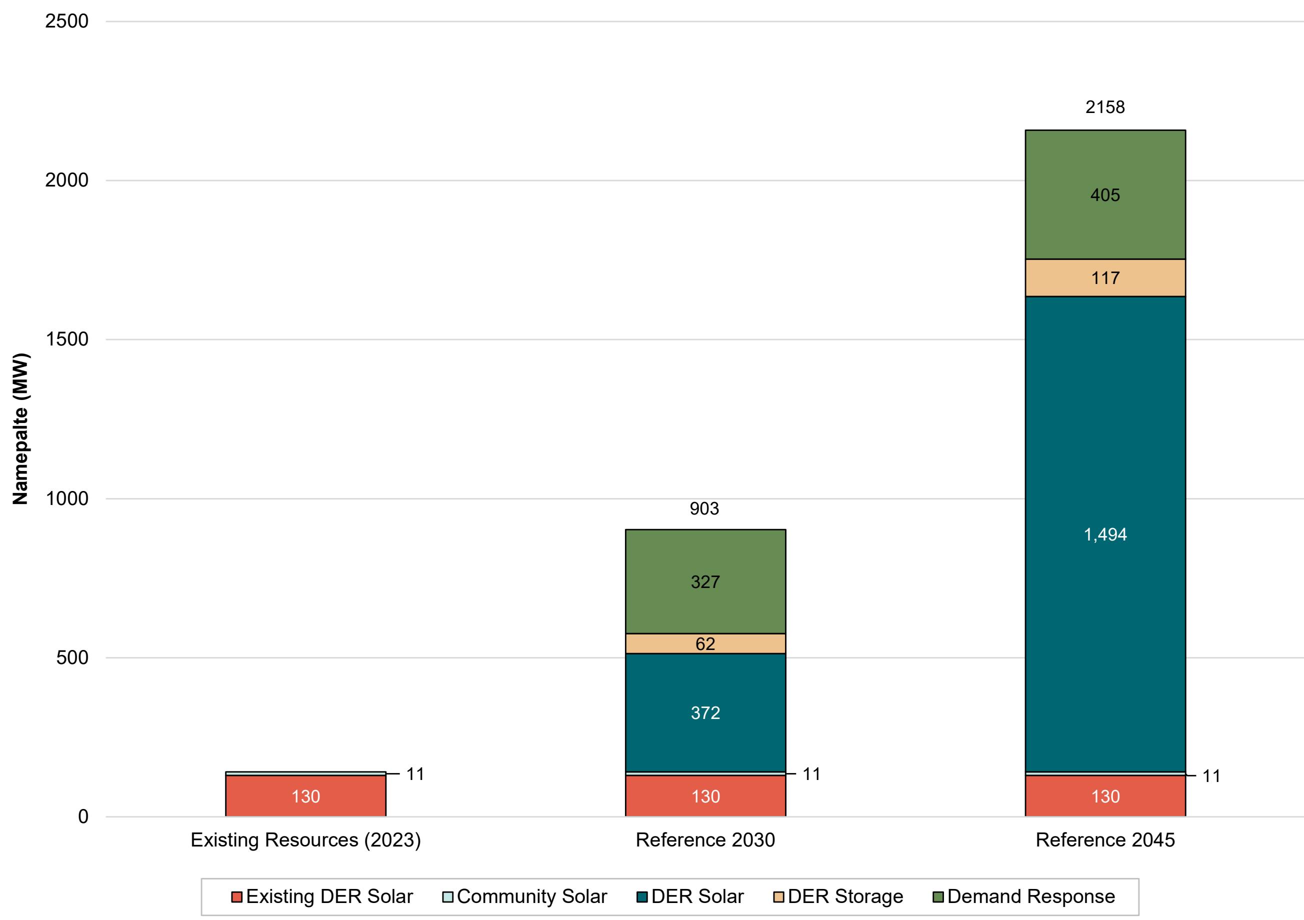
Demand-side Resources

In the AURORA model, conservation is consider a supply-side resource eligible to meet CETA requirements and competes with lower cost renewable resources during the resource selection. Conservation selected in the reference portfolio includes future effects of current Codes & Standards, Distribution Efficiency, and energy efficiency programs, with a total 695 MW added by 2045. A significant amount of demand response programs will be added to the reference portfolio for 405 MW by 2045, including a 12 MW demand response potential for interruptible customers. The high peak contribution and low program costs lead to increased amounts of demand response selected in the reference portfolio.

Distributed Energy Resources

Distributed energy resources for the reference portfolio combine net metering solar forecasts from Cadmus, PSE's forecast of DER solar additions, and DER solar targeted in the 2021 CEIP, totaling 1,494 MW by 2045. The total DER storage added to the portfolio by 2045 is 117 MW, a combination of PSE's forecast of DER storage projects and the DER storage targeted in the 2021 CEIP. Figure 8.9 shows the significant growth in distributed energy resources through 2045

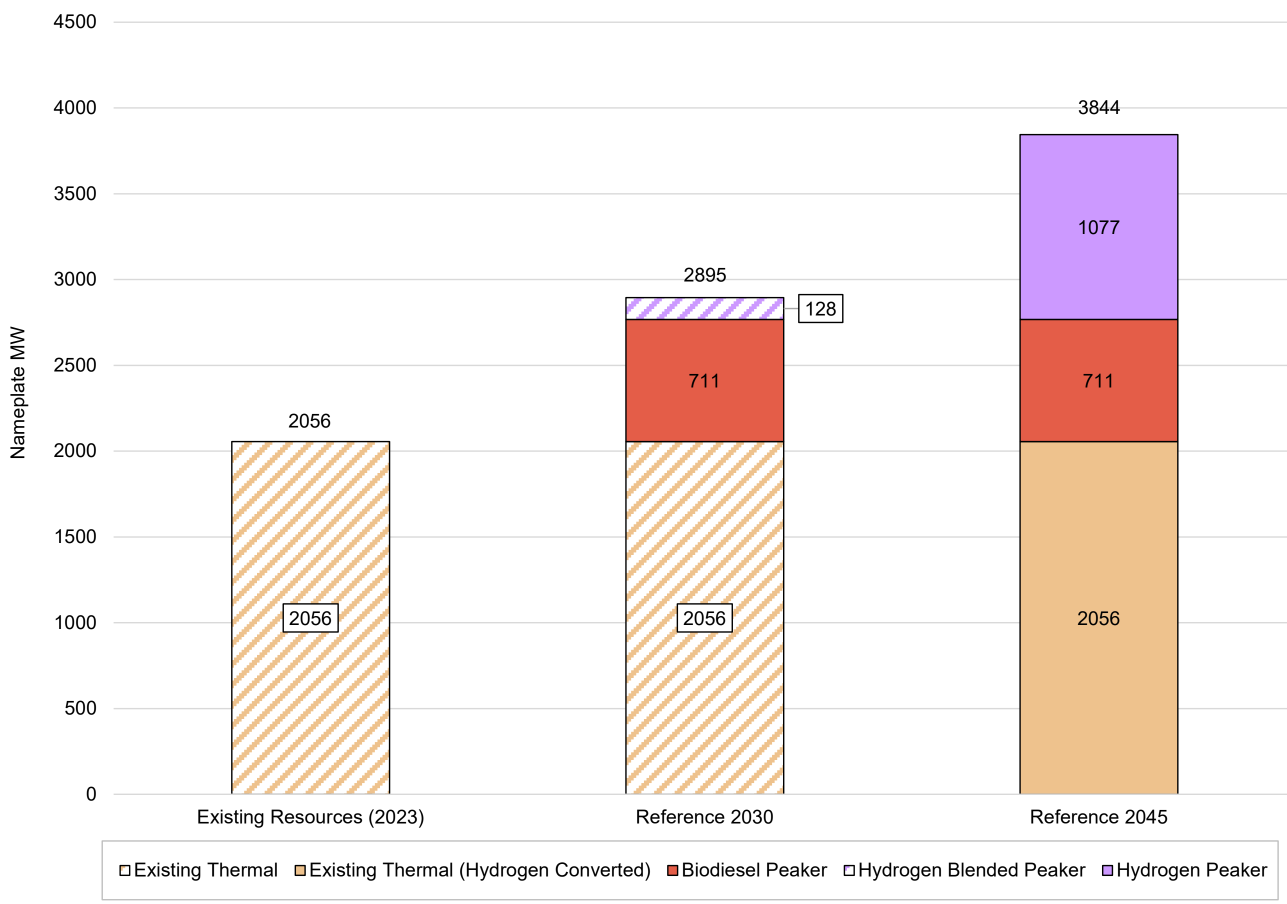
Figure 8.9: Cumulative Nameplate Capacity in MW for Distributed Energy Resources – Reference Portfolio Clean Energy Transformation Act Qualifying Peaking Capacity



CETA Qualifying Peaking Capacity Resources

By 2025, we will add 711 MW of frame peaker biodiesel plants in the reference portfolio to fill the peak need as we phase out our reliance on firm, short-term market purchases. These biodiesel peakers also help to counteract the anticipated retirement of Colstrip and Centralia power purchase agreements (PPA) by the end of 2025. By 2030, we see the addition of 128 MW of peakers using blended natural gas and hydrogen resources as firm short-term market purchases decline to zero MW. In 2031–2045, we see the addition of 711 MW of frame peaker blended natural gas and hydrogen resources and 238 MW of reciprocating peaker blended natural gas and hydrogen resources to help fill the peak needs for the portfolio in the later years. These natural gas/hydrogen blend peaking units can also have biodiesel backup capability if hydrogen is unavailable physically or economically. A discussion of the natural gas and hydrogen blending is in Appendix D: Generic Resource Alternatives. Figure 8.10 shows the cumulative additions of CETA-qualifying peaking capacity resources through 2045.

Figure 8.10: Cumulative Nameplate Capacity in MW for CETA-qualifying Peaking Capacity Resources — Reference Portfolio



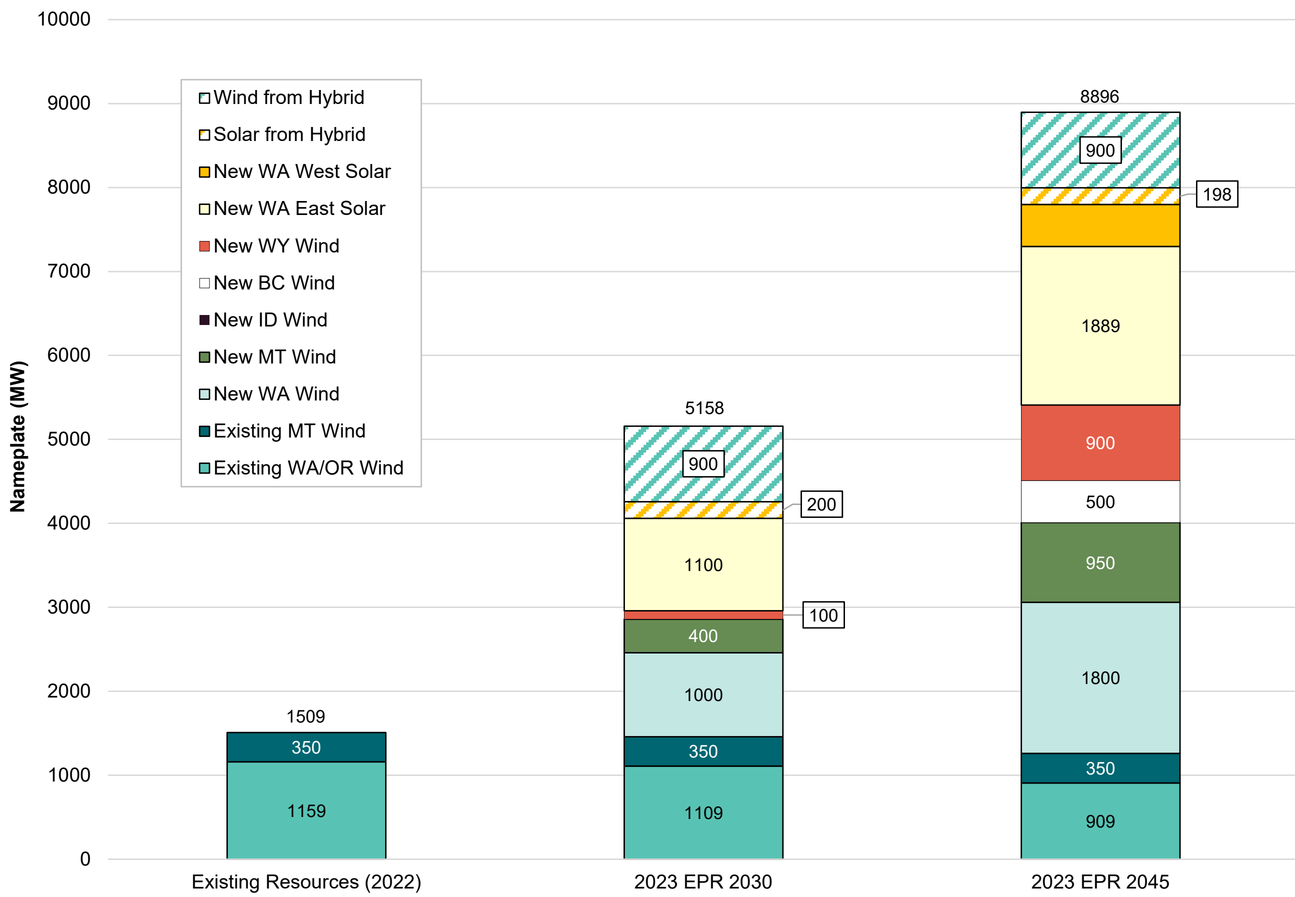
Wind and Solar Resources

We modeled multiple wind regions for this report, and we see this diversity reflected in the Reference portfolio, including Washington wind (WA), British Columbia wind (BC), Montana wind (MT), and Wyoming wind (WY) resources. Although we limited transmission for the wind resources in the near term, we assume unlimited transmission starting in 2035 for the various regions.

➔ A discussion of the transmission constraints is in Chapter Five: Key Analytical Assumptions.

By 2045, we added 5,050 MW of wind to the portfolio. This total includes a 100 MW Green Direct wind we added to the portfolio in 2026. Almost 2,100 MW of solar added to the reference portfolio comes from the WA East region and an additional 500 MW from the WA West region. We will add nearly 8,900 MW of wind and solar to the portfolio by 2045 to meet CETA requirements. Figure 8.11 shows wind and solar resources' significant growth and diversification through 2045.

Figure 8.11: Wind and Solar Resources Cumulative Nameplate Capacity – Reference Portfolio (MW)

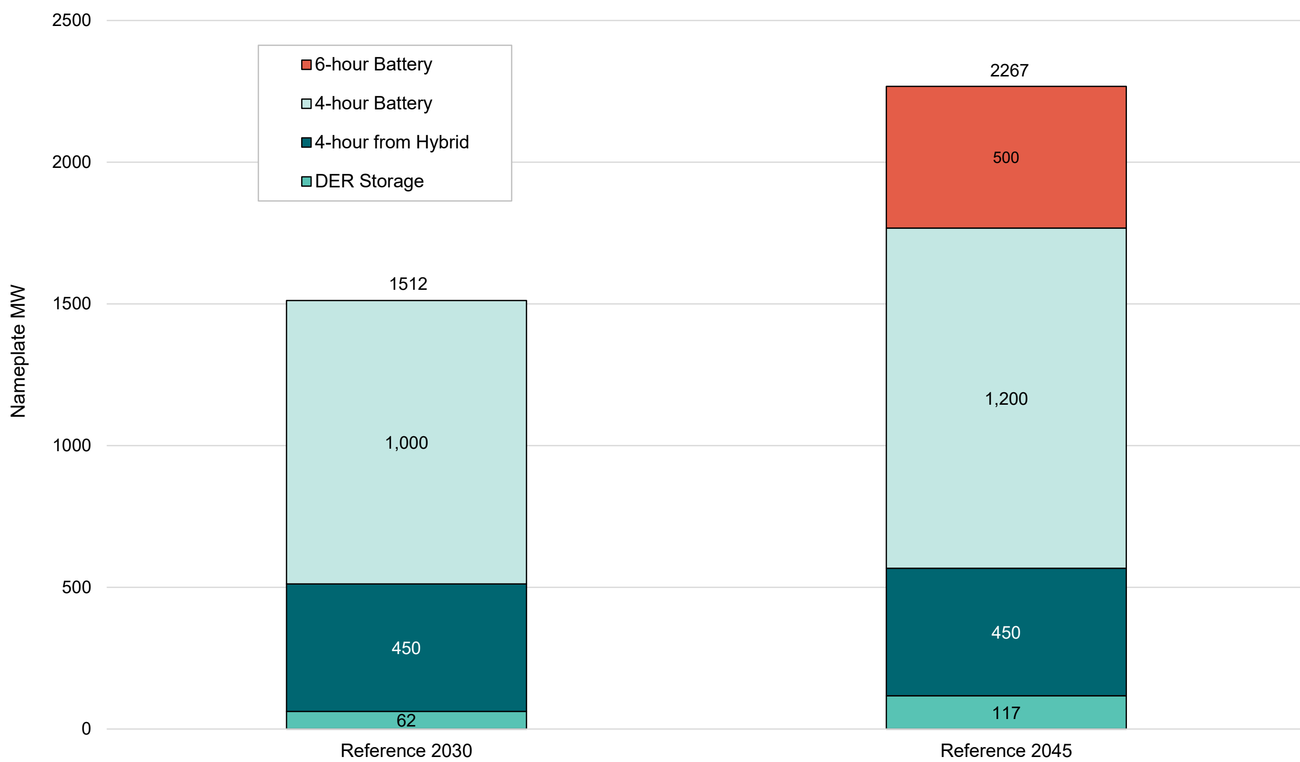


Energy Storage

Energy storage added to the portfolio comes from 1,200 MW of 4-hour batteries and 500 MW of 6-hour batteries. An additional 450 MW of 4-hour batteries are also added from the hybrid resources. Storage resources have a high effective load carrying capability (ELCC) for the first tranche of 1,000 MW, which is beneficial in meeting peak needs; however, the saturation effect can significantly impact the ELCCs. Figure 8.12 shows the storage additions through 2045.

➔ See Chapter Five: Key Analytical Assumptions for a detailed discussion of hybrid resources, and Chapter Seven: Resource Adequacy for ELCC energy storage and saturation effects.

Figure 8.12: Cumulative Nameplate Capacity in MW for Storage Resources — Reference Portfolio



Nuclear Small Modular Reactors and Biomass

Advanced nuclear small modular reactors (SMRs) and Biomass resources are CETA-qualifying resources; however, we did not add them to the reference portfolio due to higher costs than the resources.

➔ See Appendix I: Electric Analysis Inputs and Results for more detailed information on portfolio build results.

6. Sensitivity Analysis Results

Portfolio sensitivity analysis is an essential form of risk analysis that helps us understand how specific assumptions change the mix of resources in the portfolio and affect portfolio costs. Examples of a sensitivity include requiring the model to have 400 megawatts of energy storage in 2025 and 2026, relaxing transmission constraints between 2040 and 2045, or restricting any thermal resource additions during the entire planning period. This section provides the results and detailed analysis for each sensitivity.

More results, including year-by-year resource timelines, cost breakdowns, and emissions data, are in Appendix I: Electric Analysis Inputs and Results. Chapter Five: Key Analytical Assumptions includes a detailed description of the scenarios and sensitivities and the key assumptions used to create them: customer demand, natural gas prices, possible

CO_2 prices, resource costs (demand-side and supply-side), and power prices. Appendix D: Generic Resource Alternatives discusses existing electric resources and resource alternatives. Appendix J: Economic, Health, and Environmental Benefits Assessment of Current Conditions details the CBIs we used in the customer benefits analysis.

6.1. Summary of Resource Modeling Assumptions

The resource alternative sensitivities schedule targeted and isolated resource additions to explore the effects on builds, cost, and emissions. Sensitivities 2–9 explore adding additional conservation, distributed resources, pumped heat electrical storage (PHES) resources, maximizing existing Montana transmission, and pursuing advanced nuclear SMR resources.

The diversified portfolio sensitivities 11 A1 and 11 B2 take what we learned from sensitivities 2–9 and combine them in a portfolio to identify an achievable portfolio of diverse resources that maximize equity-related benefits while maintaining reliability and affordability.

We modeled sensitivities 10 and 12 through 16 following requests from interested parties.

Table 8.2 describes the sensitivities we evaluated in this 2023 Electric Report.

➔ Additional details, including assumptions, are available in Chapter Five: Key Analytical Assumptions.

Table 8.2: 2023 Electric Progress Report Portfolios and Sensitivities

ID	Name	Type	Description
1	Reference	Portfolio	Least-cost and CETA-compliant
2	Conservation Bundle 10	Resource Alternative	Reference + Increase conservation to 486 aMW by 2045
3	Conservation Bundle 7	Resource Alternative	Reference + Increase conservation to 381 aMW by 2045
4	DER Solar	Resource Alternative	Reference Portfolio + 30 MW/year of DER rooftop solar from 2026–2045
5	DER Batteries	Resource Alternative	Reference + 25 MW/year of DER batteries (3-hour Li-ion) from 2026–2031
6	MT Wind PHES, All East Wind	Resource Alternative	Reference + 400 MW MT East Wind + 200 MW MT PHES in 2026
7	MT Wind PHES, Central & East Wind	Resource Alternative	Reference + 200 MW MT East Wind + 200 MW MT Central Wind + 200 MW MT PHES in 2026
8	PNW PHES	Resource Alternative	Reference + 200 MW of PNW PHES in 2026
9	Advanced Nuclear SMRs	Resource Alternative	Reference + 250 MW of advanced nuclear SMRs in 2032
11 A1	Least Diversified Sensitivity w/ Advanced Nuclear SMRs	Diversified portfolio	Reference + more conservation (Bundle 7) + 400 MW MT East Wind + 200 MW MT

ID	Name	Type	Description
			PHES in 2026 + 250 MW advanced nuclear SMRs in 2032
11 A2	Diversified + PNW PHES	Diversified portfolio	Diversified Portfolio 11 A1 + 200 MW PNW PHES in 2026
11 A3	Diversified + DER Solar	Diversified portfolio	Diversified Portfolio 11 A2 + 30 MW per year of DER rooftop solar from 2026–2045
11 A4	Diversified + DER Batteries	Diversified portfolio	Diversified Portfolio 11 A3 + 25 MW per year of DER batteries (3hr Li-ion) from 2026–2031
11 A5	Diversified + All DR Programs	Diversified portfolio	Diversified Portfolio 11 A4 + All DR Programs
11 B1	Least Diversified w/o Advanced Nuclear SMRs (11 A1 – Adv. Nuclear SMRs)	Diversified portfolio	Reference portfolio + more conservation (Bundle 7) + 400 MW MT East Wind + 200 MW MT PHES in 2026 Similar to Diversified Portfolio A1, without Adv. Nuclear SMRs
11 B2	Most Diversified w/o Advanced Nuclear SMRs (11 A5 – Adv. Nuclear SMRs)	Diversified portfolio	Diversified Portfolio 11 A5 less 250 MW Advanced Nuclear SMRs in 2032
10	Thermal builds prohibited before 2030	Requested Sensitivity	Reference + Peaker plants use biodiesel as an alternative fuel.
12	100% Renewable/Non-Emitting by 2030	Requested Sensitivity	Reference + Existing thermal retired by 2030; no new thermal allowed
13	High Carbon Price	Requested Sensitivity	Reference + CCA ceiling price used for all carbon allowances
14	No Hydrogen Fuel Available	Requested Sensitivity	Reference + Natural gas and biodiesel fuel are available, but not hydrogen fuel
15	SGHG in Dispatch	Requested Sensitivity	Reference + Model SCGHG costs as dispatch cost in the long-term capacity (LTCE) expansion model
16	WRAP Adjustment	Requested Sensitivity	Reference + Adjust PRM and ELCCs using information from WRAP

6.2. Key Findings

This section briefly summarizes the results of each sensitivity analyzed in this report.

6.2.1. Resource Alternative Sensitivities

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7

More expensive conservation measures led to a slightly lower selection of renewable resources and increased the overall portfolio costs. Increased additions of conservation measures provided near-term benefits in greenhouse gas emission reductions. However, the impact of emission reduction in the long-term, particularly in 2045, when almost all the resources in the portfolio are considered CETA-qualifying, is less significant. A further discussion of energy efficiency measures modeled can be found in Appendix E: Conservation Potential Assessment.

Sensitivity 4 DER Solar: Scheduling in additions of DER Solar at a rate of 30MW per year did not produce a substantially different portfolio but accounted for a notable increase in solar capacity and moderate change in total portfolio cost.

Sensitivity 5 DER Storage: Significant resource movement occurred due to a relatively small incremental increase in DER storage, such as 500 MW less utility-scale solar, added to the portfolio compared to the reference portfolio. This sensitivity decreased portfolio cost by $0.14 billion and decreased the total portfolio cost with SCGHG by $0.08 billion.

Sensitivity 6 MT Wind and Pumped Hydroelectric Energy Storage (PHES), All MT East Wind: Scheduled additions of eastern Montana wind and Montana pumped hydroelectric storage delay the addition of CETA qualifying peak resources, resulting in an accelerated reduction of GHG emissions but at an overall higher portfolio cost. Compared to sensitivity 7, which adds both eastern and central Montana wind and Montana PHES, sensitivity 6 provides fewer greenhouse gas reductions but significantly lower total portfolio cost. Therefore, sensitivity 6 is a more cost-effective strategy to lower greenhouse gas emissions and diversify energy storage resources.

Sensitivity 7 MT Wind and PHES, Central and East Wind: Scheduled additions of Montana east and central wind and Montana PHES slightly accelerate the reduction of greenhouse gases compared to the reference portfolio but at a higher overall portfolio cost. Compared to sensitivity 6, which adds only eastern Montana wind and Montana PHES (no central Montana wind), the greenhouse gas emission reductions for sensitivity 7 are greater, but the overall portfolio cost is also higher. Therefore, it is not a cost-effective strategy to overbuild the capacity of Montana transmission to reduce greenhouse gas emissions and diversify the energy storage resources.

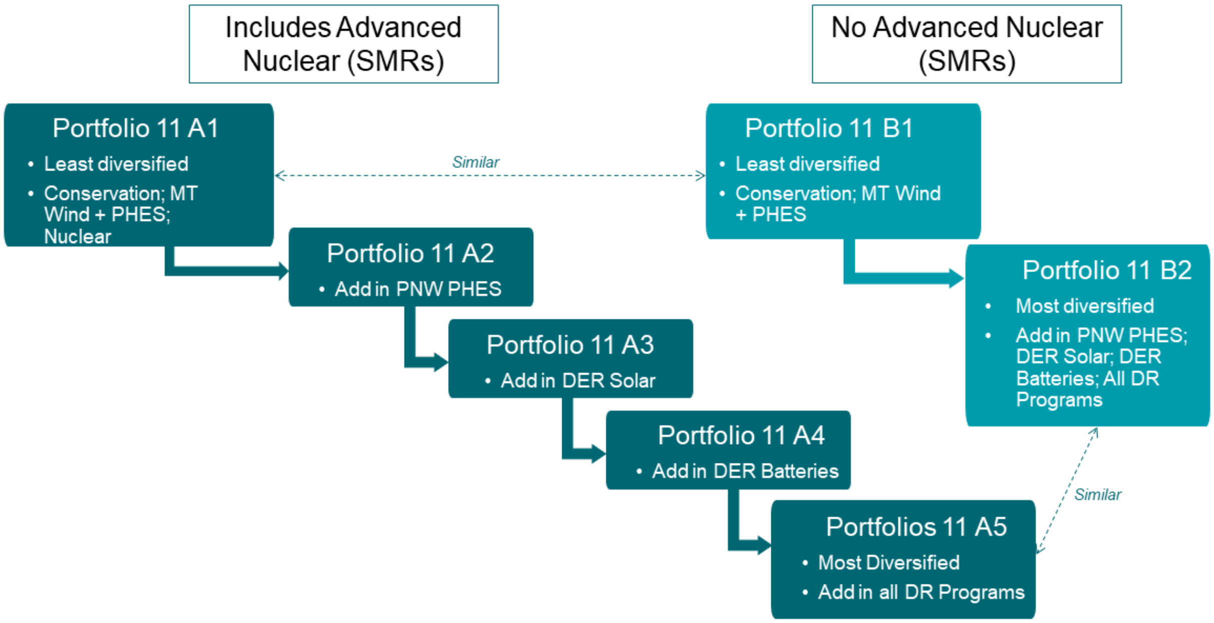
Sensitivity 8 PNW PHES: There is little difference between sensitivity 8 and the reference portfolio. Adding PNW PHES increases portfolio cost but results in little change to the overall outcome of the portfolio in terms of resource additions and greenhouse gas emissions, suggesting there is little benefit in adding PNW PHES as a means to diversify away from battery energy storage systems in the preferred portfolio.

Sensitivity 9 Advanced Nuclear Small Modular Reactors (SMRs): The ability of advanced nuclear SMRs to provide reliability and flexibility benefits for peak events while also providing the added benefit of emission-free production for meeting the CETA clean energy standards lead to the displacement of some renewable and peaking capacity resources. Overall, we see slightly lower portfolio additions by 2045 due to the addition of 250 MW of SMR; however, these advanced nuclear SMRs are more expensive and raise the portfolio costs by $1.47 billion.

6.2.2. Diversified Portfolio Sensitivities

The diversified portfolio sensitivities broaden the resource additions, lower the technology and feasibility risks, and seek to maximize equity-related benefits. Figure 8.13 illustrates the relationships between the diversified portfolios we explored in this report.

Figure 8.13 Diversified Portfolio Sensitives Map



Sensitivity 11 A1–A5 Diversified: All diversified 11 A sensitivities have higher costs than the reference portfolio. As expected, each sequential resource addition correspondingly increases the sensitivity cost: of the diversified 11 A sensitivities, 11 A1 has the least cost and 11 A5 the highest. Adding advanced nuclear SMR resources will cause an additional cost spike in 2032.

Resource additions are relatively similar across the 11 A sensitivities by 2030, with expected variation in DER resources as these are added in 11 A3 and beyond. Notably, CETA qualifying peaking capacity in 2030 is equivalent across all sensitivities, including the reference, indicating a need for dispatchable energy soon. In the longer term, the wind, solar, and hybrid resource mix becomes slightly more pronounced across the diversified 11 A sensitivities, while CETA-qualifying peaking capacity, demand-side resources, and stand-alone storage resources are relatively similar. All diversified 11 A sensitivities reduce GHG emissions compared to the reference portfolio. This reduction is greatest in sensitivity 11 A5, which produces 7 million short tons fewer emissions than the reference portfolio.

Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMR: Sensitivity 11 B1 provides a little diversification relative to the reference portfolio by adding PHES and increasing energy efficiency measures. These scheduled additions result in a markedly different overall portfolio with fewer nameplate additions, made possible by selecting resources with higher peak capacities contributions, such as hybrid resources instead of stand-alone wind and solar resources. Despite adding fewer resources overall, the early addition of hybrid and storage resources inflated the portfolio cost above the reference portfolio. Greenhouse gas emission reductions are accelerated before 2030 but align with the reference portfolio 2030–2045.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: Sensitivity 11 B2 provides diversification relative to the reference portfolio by adding distributed energy resources, PHES, and additional DSR. This diversification shifts the resource mix away from utility-scale resources toward distributed energy resources and DSR. Early additions of Montana wind and distributed solar reduce existing thermal resources dispatch and accelerate the reduction of greenhouse gases before 2030. Fewer new thermal peaking capacity resources are required in sensitivity 11 B2 due to increased additions of stand-alone storage and hybrid resources. We selected this portfolio as the preferred portfolio and explained its benefits in Chapter Three: Resource Plan of the 2023 Electric Report.

6.2.3. Requested Sensitivities

Sensitivity 10 No New Thermal before 2030 and Biodiesel as the Alternative Fuel: Delaying the availability of thermal peaking capacity resources until 2030 results in an additional 3,700 MW of battery storage and 900 MW of hybrid resources before 2030, displacing 839 MW of thermal plants built during that time. Adding over 5.0 GW of batteries in six years would be challenging to accomplish, given the magnitude. As of October 2022, only 7.8 GW of utility-scale batteries are operating nationwide.[12] After we lifted the thermal restriction in the model, it added minimal batteries due to the over-saturation of batteries in meeting peak. This sensitivity is $0.91 billion more expensive than the reference portfolio.

Sensitivity 12 100 Percent Renewable/Non-Emitting by 2030: Implementing the necessary changes for this sensitivity created substantial issues for the model. The short-term resource need became too large due to mass retirements of firm capacity, and the model could not make up for this with available new resources and transmission constraints as defined in the reference case. This sensitivity did not produce a solution, which speaks to the challenges of quickly retiring large amounts of thermal capacity.

Sensitivity 13 High Carbon Price Based on the Ceiling Price Assumption: The resource mix between the reference portfolio and sensitivity 13 is very similar, indicating that increased carbon costs do not significantly impact build decisions. This sensitivity costs less than the reference, driven primarily by a lower SCGHG. These results indicate a decrease in emitting resource dispatch, as we may expect with higher market prices for carbon allowances.

Sensitivity 14 No Hydrogen Fuel Available: There is a significant difference between sensitivity 14 and the reference portfolio. Without access to hydrogen fuel, we no longer see an accelerated reduction in GHG emissions, and portfolio costs are significantly higher, suggesting a notable benefit to hydrogen fuel as an alternative fuel option. Therefore, we should continue exploring blending hydrogen with natural gas fuel.

Sensitivity 15 SCGHG in Dispatch: Including the SCGHG in the dispatch cost for the long-term capacity expansion model adversely decreases the capacity factor of PSE's thermal plants, resulting in 2,000 MW of renewable resource additions by 2025, more than the energy needed for the year. This scenario also doubles PSE's existing renewable resources of 1,700 MW in three years. The CETA requirement is the driving factor for the resource build decisions by 2045.

Sensitivity 16 WRAP Adjustment: We cannot run the long-term capacity expansion model to evaluate sensitivity 16 due to incomplete information regarding ELCC saturation curves for renewable and storage resources from the Western Resource Adequacy Program (WRAP). We also understand that the WRAP data is not intended for long-term resource planning. Our best estimate using the WRAP PRM shows a decrease in the winter peak capacity need

[12] https://www.eia.gov/todayinenergy/detail.php?id=54939

by 300 MW and a reduction in the summer peak need by 1,200 MW in 2029. We need further study to incorporate WRAP in long-term resource planning. The WRAP estimated seasonal PRMs are in Table 8.3.

Table 8.3 PRM and Peak Capacity Needs

Sensitivity Year/Season	1 Reference 2029 Winter	1 Reference 2029 Summer	16 WRAP Adjustment 2029 Winter	16 WRAP Adjustment 2029 Summer
Peak Load (MW)	5,104	4,300	4,570	3,447
PRM (MW)	1,215	1,029	956	470
PRM%	24%	24%	21%	14%
Existing Resources Peak Capacity (MW)	3,607	2,493	3,120	2,343
Additional perfect capacity for 5% LOLP (MW)	2,712	2,837	2,406	1,574

6.3. Portfolio Costs

This section describes the changes in portfolio costs for the sensitivities evaluated in the 2023 Electric Progress Report. The portfolio cost in dollars is the levelized, net present value of the annual cost impacts for 22 years excluding SCGHG costs. This includes:

- Alternative compliance costs
- CCA costs
- Decommissioning costs as part of the economic decision of plant retirements
- Fixed and variable costs of existing resources and new resources
- Fuel costs
- Net market purchases and sales

We report the SCGHG as an externality cost separately. The sum of the portfolio costs and the SCGHG costs is what we refer to as total portfolio costs in this chapter.

6.3.1. Resource Alternative Sensitivities

Table 8.4 and Figure 8.14 show the costs associated with the Resource Alternative sensitivities 2–9 described in this section.

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7: As expected, increased distribution and energy efficiency additions led to higher portfolio costs. The portfolio cost of sensitivity 2 is $0.97 billion higher than the reference portfolio. However, the SCGHG of sensitivity 2 is $0.17 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.81 billion for sensitivity 2 compared to the reference portfolio. For sensitivity 3, the portfolio cost is $0.35 billion higher than the reference portfolio. Similar to sensitivity 2, the SCGHG of sensitivity 3 is also lower than the reference portfolio by $0.34 billion. This results in a net increase in total portfolio cost of $0.01 billion for sensitivity 3 compared to the reference portfolio.

Sensitivity 4 DER Solar: The total portfolio cost of sensitivity 4 is higher than the reference as expected by the substantial increase in DER solar resources shown to be relatively high cost by the reference case. The difference in portfolio cost between the two is significant at $0.45 billion, but with the inclusion of the social cost of greenhouse gases (SCGHG), the total portfolio cost difference is more moderate at $0.23 billion.

Sensitivity 5 DER Storage: The total portfolio costs between sensitivity 5 and the reference case were reasonably consistent. The total portfolio cost changes slightly, making sensitivity 5 $0.08 billion less over its lifetime. There is a bigger difference between the two in portfolio cost, but some of this is offset by small changes in SCGHG costs. Emissions are similar enough in both cases that the portfolio cost comparison with and without SCGHG does not vary dramatically, and the two portfolios follow similar cost trends in both instances.

Sensitivity 6 MT Wind and PHES, All MT East Wind: The portfolio cost of sensitivity 6 is $0.2 billion higher than the reference portfolio. However, the SCGHG of sensitivity 6 is $0.18 billion lower than the reference portfolio. These two components of the total cost of the sensitivity are offsetting, resulting in the total portfolio cost for sensitivity 6, which is just $0.02 billion higher than the reference portfolio. Compared to the reference portfolio, the scheduled addition of Montana east wind and Montana PHES delay the addition of 474 MW of CETA-qualifying peaking resources from 2025–2029 and offsets dispatch of existing thermal resources resulting in an accelerated reduction in GHG emissions but at a higher overall cost.

Sensitivity 7 MT Wind and PHES, Central and East Wind: The portfolio cost of sensitivity 7 is $0.7 billion higher than the reference portfolio. However, the SCGHG of sensitivity 7 is $0.37 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.33 billion for sensitivity 7 compared to the reference portfolio. Compared to the reference portfolio, the scheduled addition of Montana wind and Montana PHES delays the addition of 474 MW of CETA-qualifying peaking resources from 2025 to 2027 and offsets the dispatch of existing thermal resources resulting in an accelerated reduction in GHG emissions but at a higher overall cost.

Sensitivity 8 PNW PHES: The portfolio cost of sensitivity 8 is $0.55 billion higher than the reference portfolio. However, the SCGHG of sensitivity 8 is $0.12 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.43 billion for sensitivity 8 compared to the reference portfolio.

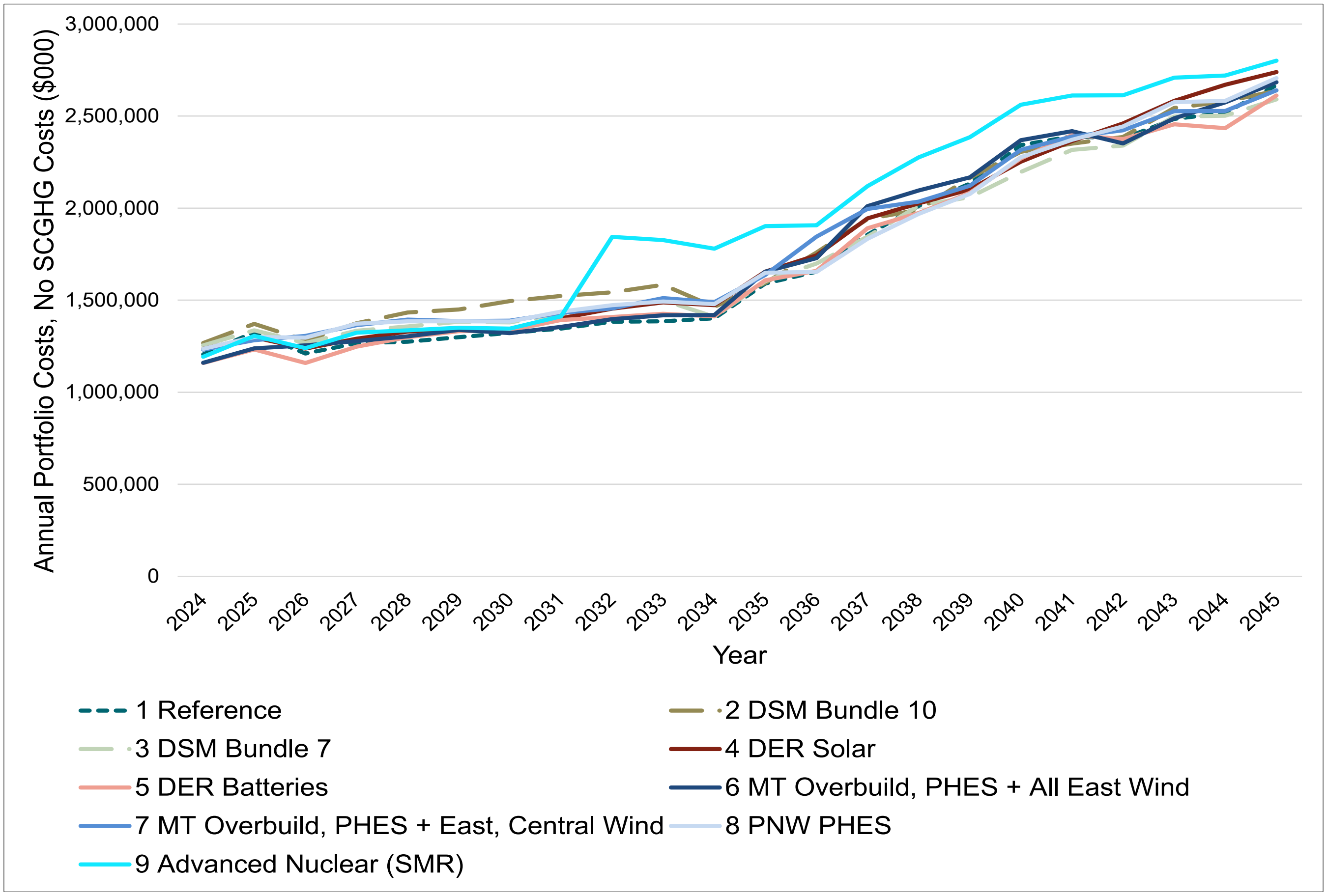
Sensitivity 9 Advanced Nuclear SMRs: Sensitivity 9 is a higher cost overall than the reference portfolio, and costs begin to diverge at a greater pace as the model added advanced nuclear SMR resources to the portfolio in 2032. This results in a net increase in total portfolio cost of $1.47 billion for sensitivity 9 compared to the reference portfolio.

Table 8.4 Resource Alternatives Portfolio Costs, 2024–2045 NPV ($ Billions)

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	-
2 DSM Bundle 10	18.58	3.07	21.65	0.81	4
3 DSM Bundle 7	17.96	2.90	20.86	0.01	0
4 DER Solar	18.06	3.02	21.08	0.23	1
5 DER Batteries	17.47	3.30	20.77	-0.08	0

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
6 MT Overbuild, PHES + All East Wind	17.81	3.06	20.87	0.03	0
7 MT Overbuild, PHES + East, Central Wind	18.31	2.87	21.18	0.34	2
8 PNW PHES	18.16	3.12	21.28	0.44	2
9 Advanced Nuclear SMRs	19.34	2.98	22.32	1.47	7

Figure 8.14: Annual Portfolio Costs — Resource Alternatives



6.3.2. Diversified Portfolio Sensitivities

The costs associated with the diversified portfolio sensitivities 11 A1-A5 and 11 B1-B2 are described in this section and summarized in Table 8.5 and Figure 8.15.

Sensitivity 11 A1 – A5 Diversified: All diversified 11 A sensitivities cost substantially more than the least-cost reference portfolio (Table 8.5). The least-diversified sensitivity, 11 A1, adds conservation, an advanced nuclear SMR power plant, and maximizes existing Montana transmission. These resource additions cost $2 billion (10 percent) more than the reference portfolio. Each subsequent resource addition, as observed in sensitivities 11 A2 through 11 A5, increases the total cost compared to the sensitivity proceeding it. However, adding DER solar and demand response programs cost approximately $0.02 billion each, whereas adding the Pacific Northwest PHES and DER batteries cost nearly twenty times this amount, approximately $0.4 billion each.

Generally, the diversified 11 A sensitivity costs are similar year to year through the 22-year planning period. Though costlier, they follow the reference portfolio trend through 2045 (Figure 8.15). Adding 250 MW of advanced nuclear SMRs is the notable exception: the spike above the reference portfolio in 2032 reflected the costs of this technology when we added this resource to the 11 A sensitivities.

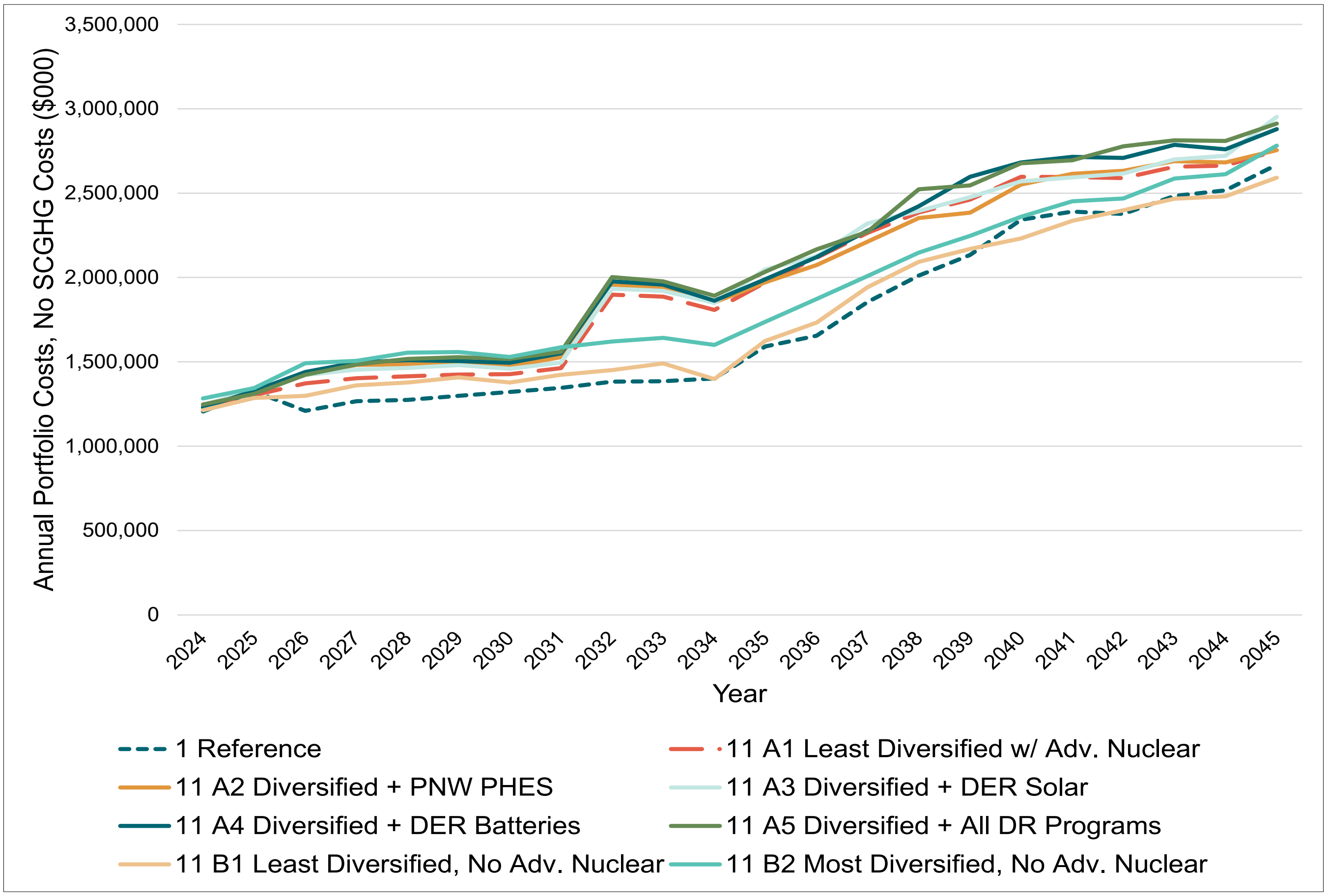
Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMRs: The cost of sensitivity 11 B1 is $0.48 billion higher than the reference portfolio. However, the SCGHG of sensitivity 11 B1 is $0.24 billion lower than the reference portfolio. This results in a net increase in the total cost of $0.24 billion for sensitivity 11 B1 compared to the reference portfolio. Early additions of hybrid and storage resources resulted in increased capital spending on resources in the years before 2030. Despite fewer nameplate additions overall, sensitivity 11 B1 results in a higher cost due to generally higher cost resources added earlier in the modeling horizon.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: The portfolio cost of sensitivity 11 B2 is $1.95 billion higher than the reference portfolio. However, the SCGHG of sensitivity 11 B2 is $0.29 billion lower than the reference portfolio. This results in a net increase in the total cost of $1.66 billion for sensitivity 11 B2 compared to the reference portfolio.

Table 8.5: 11 A Diversified Portfolio Costs, 2024–2045 NPV ($ Billions)

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	0
11 A1 Least Diversified w/ Adv. Nuclear SMRs	20.01	2.82	22.83	1.99	10
11 A2 Diversified + PNW PHES	20.32	2.93	23.25	2.40	12
11 A3 Diversified + DER Solar	20.44	2.83	23.27	2.42	12
11 A4 Diversified + DER Batteries	20.74	2.90	23.64	2.80	13
11 A5 Diversified + All DR Programs	20.89	2.78	23.67	2.82	14
11 B1 Least Diversified w/o Advanced Nuclear SMRs	18.09	3.00	21.09	0.24	1
11 B2 Most Diversified w/o Advanced Nuclear SMRs	19.56	2.95	22.51	1.66	8

Figure 8.15: Annual Portfolio Costs — Diversified Portfolios



6.3.3. Requested Sensitivities

The costs associated with sensitivities 10 and 12-16 are described in this section and summarized in Table 8.6 and Figure 8.16.

Sensitivity 10 No New Thermal before 2030 and Biodiesel is the Alternative Fuel: The portfolio cost of sensitivity 10 is $1.67 billion higher than the reference portfolio. However, the SCGHG of sensitivity 10 is $0.77 billion lower than the reference portfolio. These two components of the total cost of the sensitivity are offsetting, resulting in the total portfolio cost for sensitivity 10, which is just $0.91 billion higher than the reference portfolio. The restriction on thermal additions before 2030 results in the addition of more expensive stand-alone storage and hybrid resources in the near term and offsets dispatch of existing thermal resources resulting in reduced GHG emissions but at a higher overall cost.

Sensitivity 12 100 percent Renewable/Non-Emitting: This sensitivity did not solve due to the issues we discussed in the Key Findings section and consequently did not produce any portfolio cost metrics.

Sensitivity 13 High Carbon Price Based on the Ceiling Price Assumption: The portfolio cost without the SCGHG adder for this sensitivity is $0.50 billion higher than the reference case, likely driven by higher market prices. However, the SCGHG adder is $0.52 billion less than the reference case, resulting in an overall portfolio cost of $0.02

billion less than the reference case. This sensitivity illustrates that the higher market prices for carbon allowances result in decreased emitting resource dispatch, as shown by the lower SCGHG.

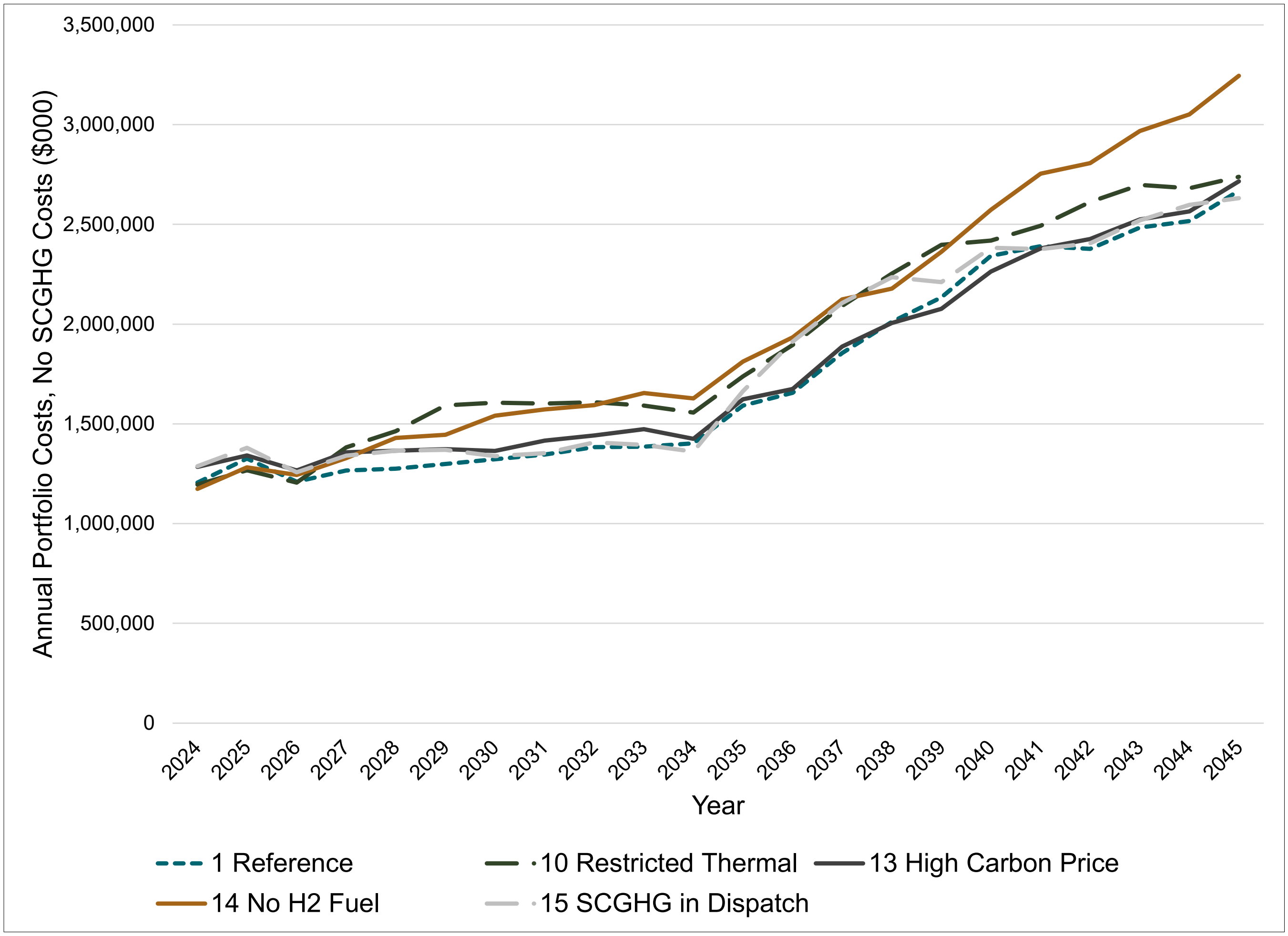
Sensitivity 14 No Hydrogen Fuel Available: The portfolio cost of sensitivity 14 is $2.03 billion higher than the reference portfolio. We also see an increase in SCGHG costs for sensitivity 14, which is $2.19 billion higher than the reference portfolio. This results in a net increase in total portfolio cost of $4.23 billion for sensitivity 14 compared to the reference portfolio.

Sensitivity 15 SCGHG in Dispatch: The portfolio costs are higher for sensitivity 15, with a portfolio cost of $18.34 billion. Though the sensitivity 15 portfolio cost is $0.73 billion higher than the reference portfolio, it greatly decreases the emission costs to $2.47 billion. The total cost of sensitivity 15 ($20.81 billion) is 0.04 billion lower than the reference portfolio total cost ($20.85 billion).

Table 8.6: Other Requested Sensitivities Portfolio Costs, 2024–2045 NPV (Billions)

Sensitivity	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	-
10 Restricted Thermal	19.28	2.47	21.75	0.91	4
13 High Carbon Price	18.11	2.72	20.83	-0.01	-0.1
14 No H2 Fuel	19.64	5.43	25.07	4.23	20
15 SCGHG in Dispatch	18.34	2.47	20.81	-0.04	0.2

Figure 8.26: Annual Portfolio Costs — Other Requested Sensitivities



6.4. Modeling Builds

This section describes the changes in resource builds for the sensitivities evaluated in this 2023 Electric Report.

6.4.1. Resource Alternative Sensitivities

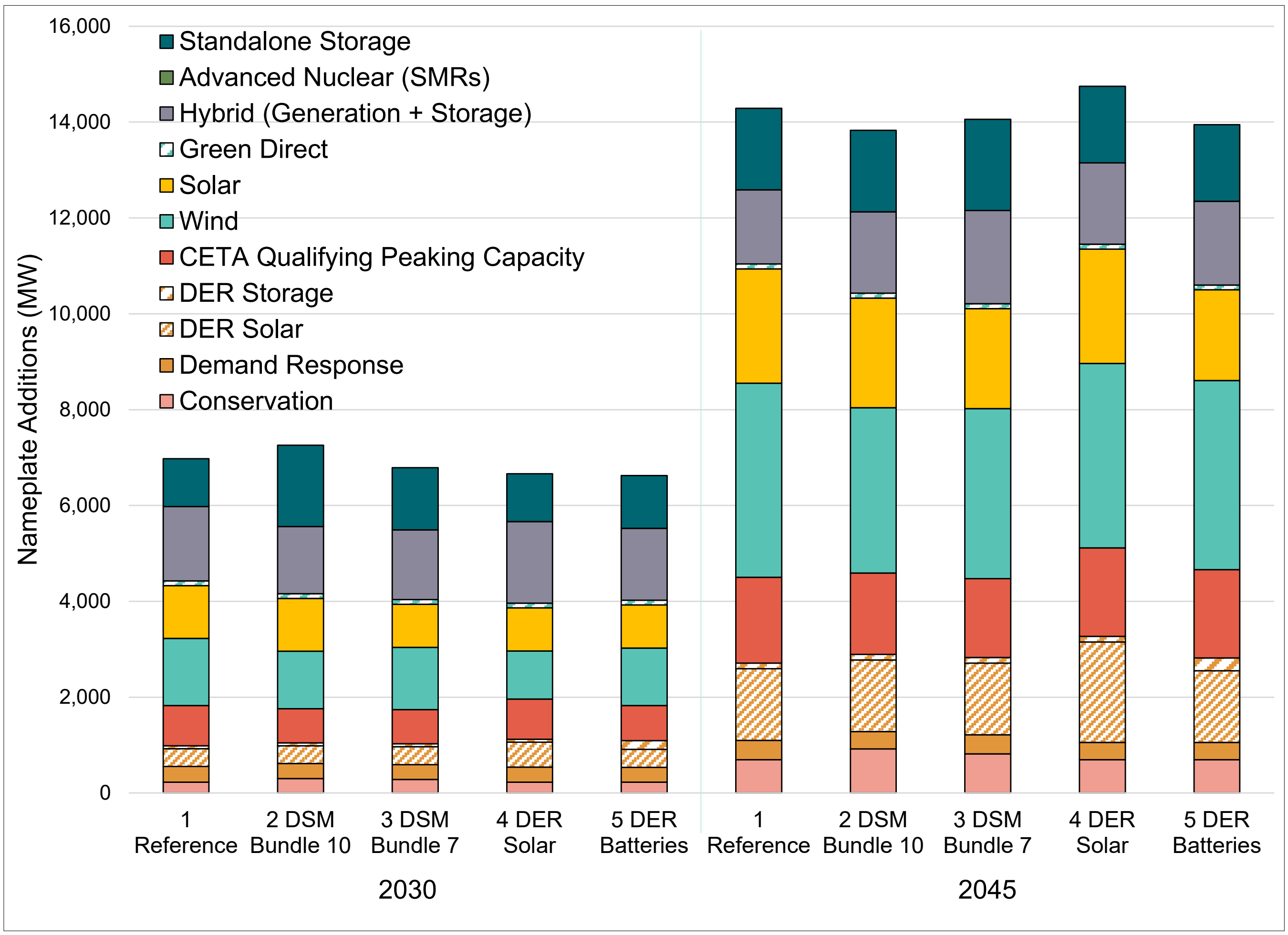
In this section, we described the resources added in the Resource Alternative sensitivities 2–9 and summarized them in Figures 8.17 and 8.18.

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7: Overall builds are similar, except for the increased addition of distributed and energy efficiency measures and slightly fewer renewable resources needed to meet CETA requirements in sensitivity 2 and sensitivity 3.

Sensitivity 4 DER Solar: Aside from the increase in DER solar capacity for sensitivity 4, it adds a similar mix of capacity by 2045 compared to the reference portfolio, although the timing of resource additions is quite different. Notable differences include a 450MW reduction in CETA-qualifying peaking capacity and a 400MW increase in utility-scale solar before 2025 for sensitivity 4. However, these resource groups end up in almost identical places at the end of the planning horizon. One consistent difference is that sensitivity 4 picks up less demand response than the reference portfolio, totaling a 41MW winter peak difference by 2045. At a coarser level, all capacity addition resource groups in sensitivity 4 are within 200 MW of their analogous group in the reference case.

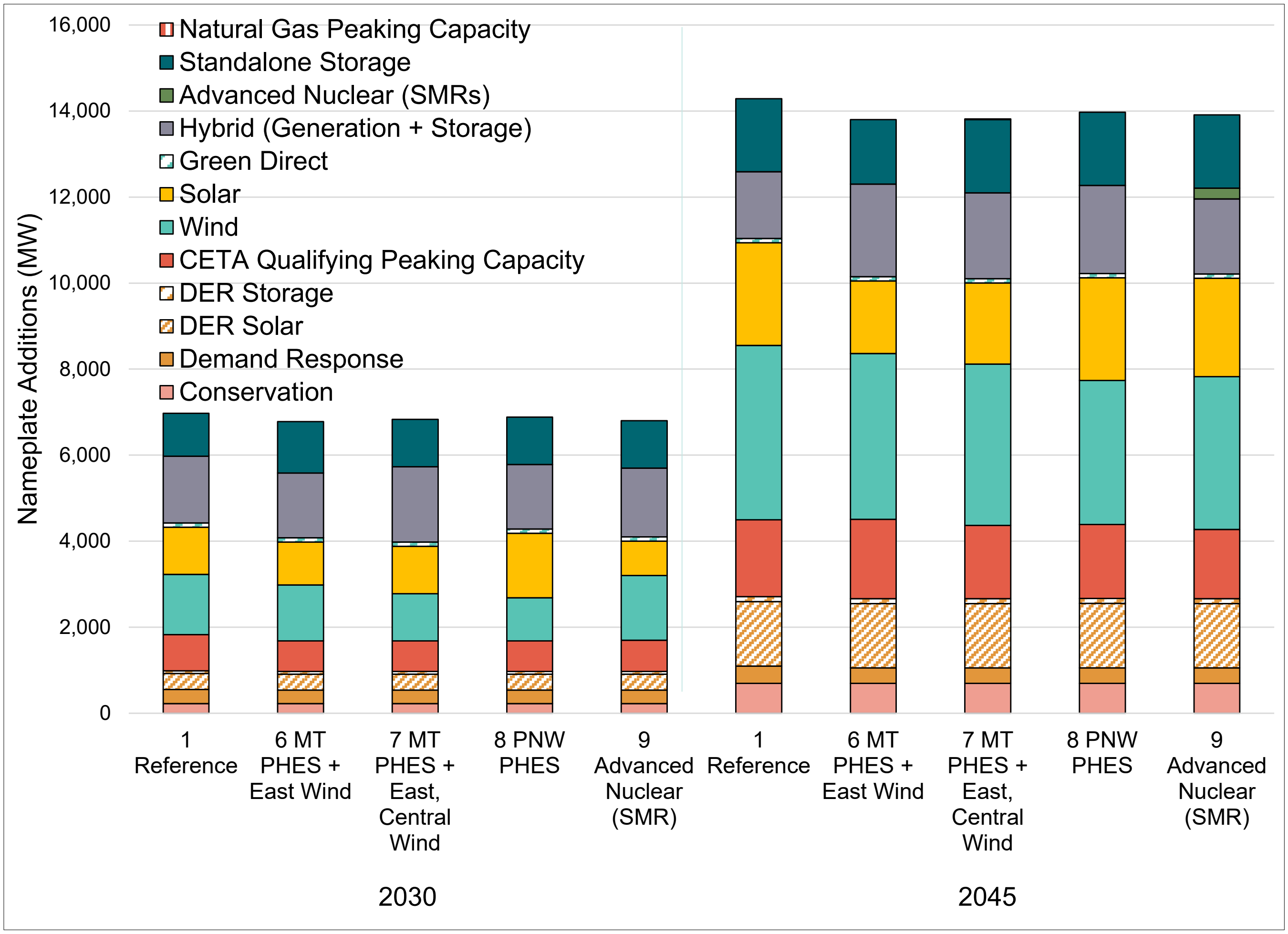
Sensitivity 5 DER Storage: A comparison between sensitivity 5 and the reference portfolio in terms of resource additions shows significant movement in certain resource groups. Most notably, by 2045, it will pick up 500 MW less solar than the reference portfolio. Other observed changes besides the prescribed DER storage increase (150 MW) include roughly 200 MW more hybrid capacity, 45 MW less demand response, a 55 MW increase in CETA-qualifying peaking capacity, and 100 MW less stand-alone storage — all by 2045. The reference portfolio builds resources earlier than sensitivity 5, building 500 MW more capacity by 2025, which lessens to a 341 MW capacity difference in 2045 at the end of the planning period.

Figure 8.37: Resource Additions — Resource Alternatives Part 1



Sensitivity 6–9: Overall builds are similar for each sensitivity and the reference portfolio, except for the scheduled addition of the resource we tested for the sensitivity.

Figure 8.48: Resource Additions — Resource Alternatives Part 2



6.4.2. Diversified Portfolio Sensitivities

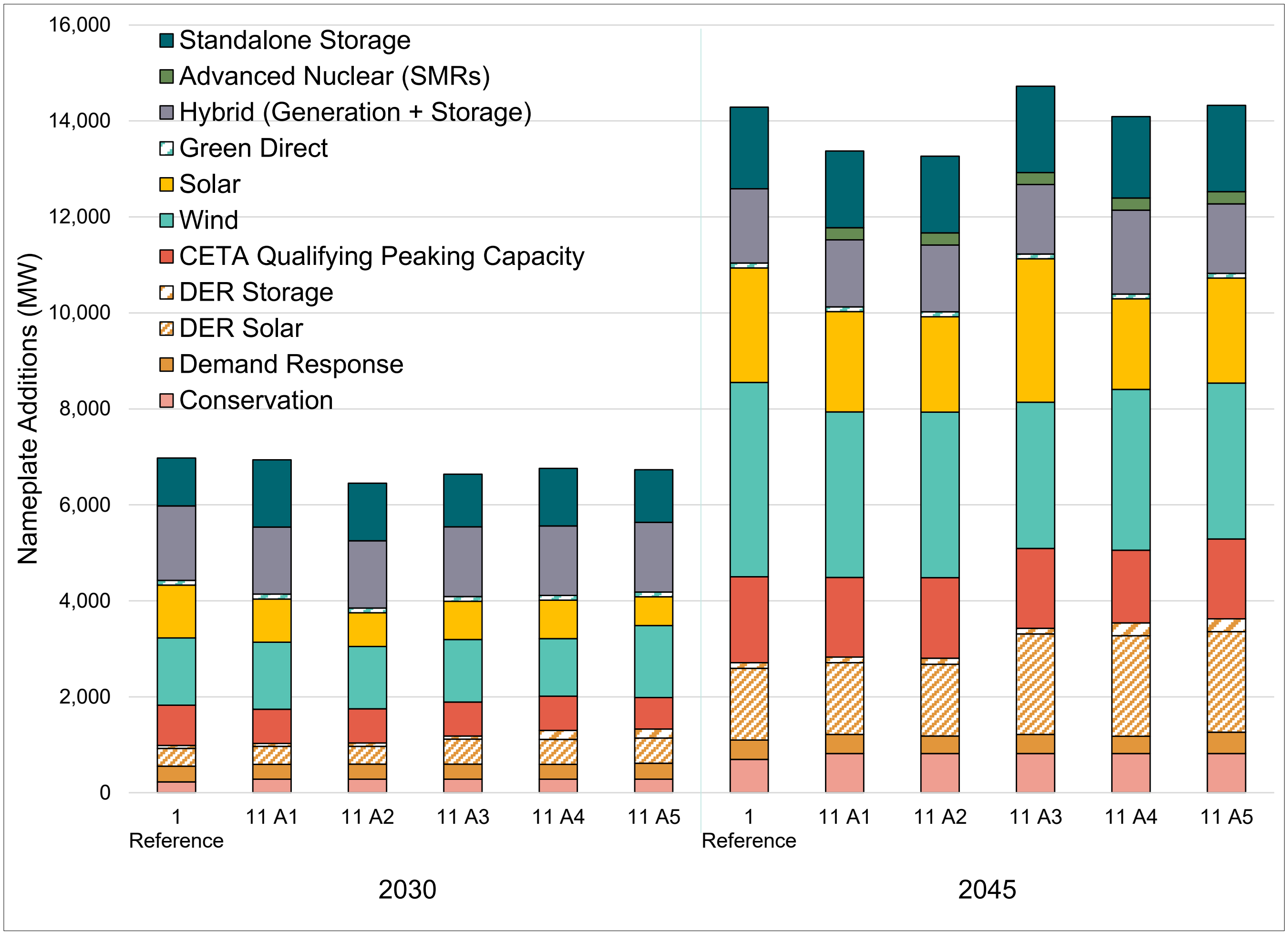
The resources added in the diversified portfolio sensitivities 11 A1–11 A5, and 11 B1–11 B2 are described in this section and summarized in Figures 8.19 and 8.20.

Sensitivity 11 A1– A5 Diversified: In the first two years of the planning period, between 2024 and 2025, the demand-side and distributed resource additions in the diversified 11 A sensitivities mirror the reference portfolio. However, this very near-term look highlights several strategies for meeting energy needs. Sensitivities 11 A1 and 11 A2 displace all three early CETA-qualifying peaking plants built in the reference portfolio with various combinations of renewable and storage resources (wind, solar, stand-alone storage, and hybrid). Peaking capacity is reduced but not replaced entirely in sensitivities 11 A3, 11 A4, and 11 A5, to 237, 474, and 18 MW, respectively. However, by 2030, CETA-qualifying peaking capacity will be equivalent across all diversified 11 A sensitivities at 711 MW, except for 11 A5, which builds slightly less at 657 MW. This indicates a constant need for dispatchable energy in the near-term planning horizon.

In the longer term, between 2031 and 2045, the resource mix becomes slightly more pronounced between the diversified sensitivities. Distributed solar and battery additions increase as expected in sensitivities 11 A3, 11 A4, and

11 A5, where we required the model to select these resource additions. Wind, solar, and hybrid resources are added in varying amounts across the 11 A sensitivities but generally sum to similar quantities by 2045. CETA-qualifying peaking capacity is a stable addition across all sensitivities, even with 250 MW of advanced nuclear SMRs, which diversifies dispatchable resources but does not displace the equivalent peaking capacity from the 11 A sensitivities. Battery storage and DSR are relatively constant across sensitivities by 2045, but both peak in 11 A5.

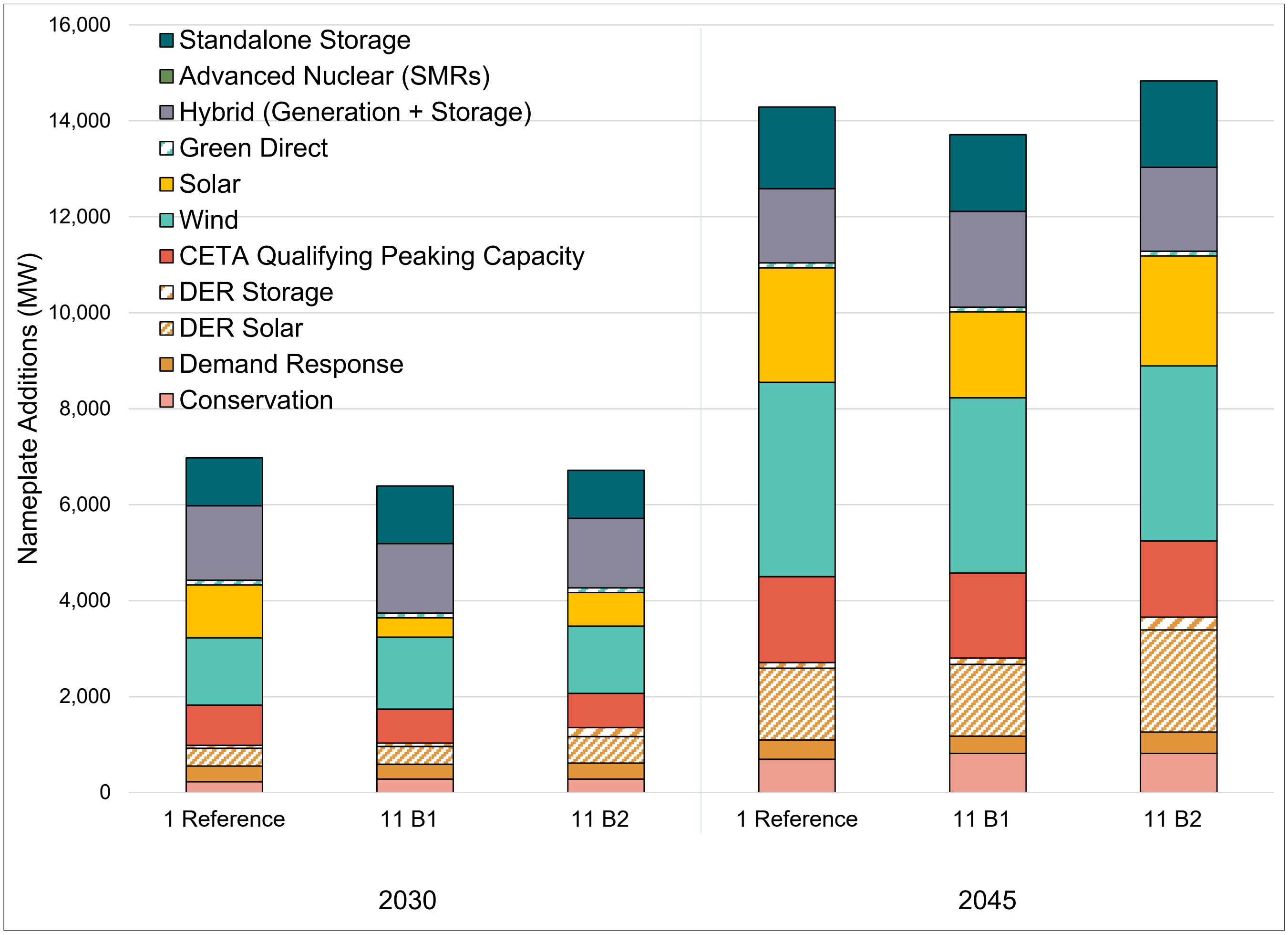
Figure 8.19: Resource Additions — Diversified Portfolio Sensitives Part 1



Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMRs: Overall resource builds are similar between the reference and sensitivity 11 B1 but with a few notable differences. Sensitivity 11 B1 results in nearly 600 MW fewer nameplate capacity additions by favoring resources with a greater peak capacity contribution, such as energy efficiency measures and shifting from stand-alone wind and solar to hybrid resources. Sensitivity 11 B1 defers the addition of thermal peaking capacity resources through the earlier addition of hybrid and storage resources compared to the reference portfolio.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: Overall resource builds are similar between the reference and 11 B2 sensitivities. Sensitivity 11 B2 incorporates 780 MW more distributed solar and storage resources through scheduled resource additions than the reference case. The distributed energy resource additions in sensitivity 11 B2 reduce the capacity of stand-alone, utility-scale wind and solar resources added to the sensitivity. The percentage of demand-side and distributed resources in the sensitivity portfolio resource mix increases from 19 percent in the reference portfolio to 25 percent in sensitivity 11 B2. Increased addition of resources with high peak capacity contributions, including stand-alone storage, hybrid resources, and energy efficiency measures, reduce the total thermal peaking capacity added to sensitivity 11 B2 by 200 MW compared to the reference portfolio.

Figure 8.20: Resource Additions — Diversified Portfolio Sensitivities Part 2



6.4.3. Requested Sensitivities

We described the resources added in sensitivities 10 and 13–16 in this section and summarized in Figure 8.21.

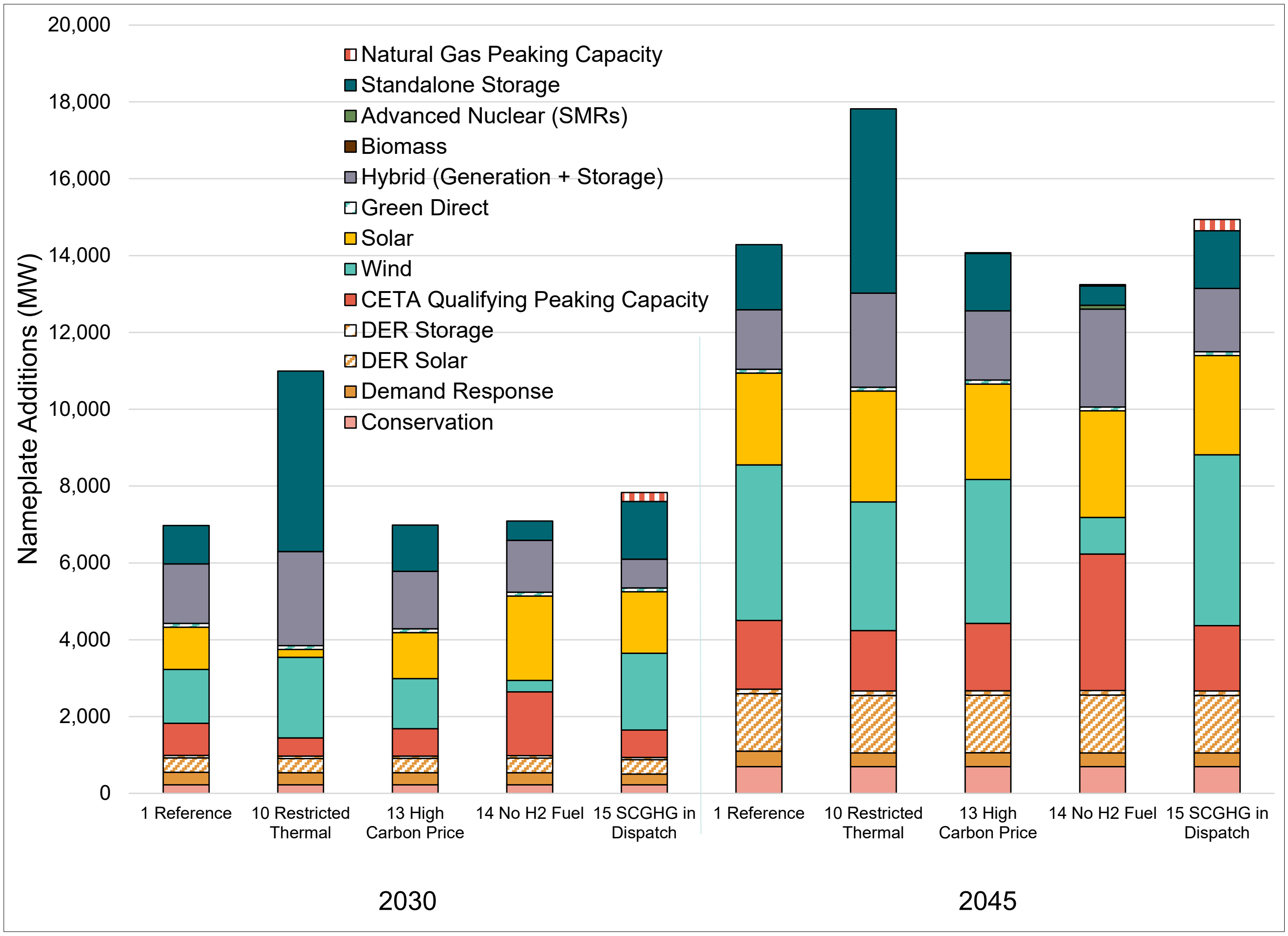
Sensitivity 10 No New Thermal before 2030, and Biodiesel as the Alternative Fuel: Sensitivity 10 adds 4,700 MW of storage to the portfolio through 2030. Once we removed the thermal restriction, an additional 1,569 MW of CETA-qualifying peaking resources were added to the portfolio, while only 100 MW of storage was added to the portfolio. The major difference between sensitivity 10 and the reference portfolio is an additional 4,000 MW of storage and hybrid resources and 200 MW less of CETA-qualifying peaking resources. We can explain this difference because as the portfolio becomes saturated with storage, the ELCC decreases.

Sensitivity 13 High Carbon Price based on the Ceiling Price Assumption: Overall builds are similar for sensitivity 13 and the reference portfolio. By 2045, sensitivity 13 has 100 MW less wind and solar resources, 50 MW less storage resources, 41 MW less of demand response, and nearly identical CETA-qualifying resources.

Sensitivity 14 No Hydrogen Fuel available: Without access to hydrogen fuel, sensitivity 14 incorporates 3,555 MW of frame peaker biodiesel resources. Interestingly, the increase in frame peaker biodiesel resources reduces the total capacity of stand-alone storage and utility-scale wind resources added to the portfolio. To meet the CETA requirement, we see a shift to increased utility-scale solar resources added in sensitivity 14. We also see the addition of 100 MW of advanced nuclear SMR resources in 2045.

Sensitivity 15 SCGHG in dispatch: Overall, we see more renewable resources added to the portfolio in the near term and a total of 8,400 MW of renewable resources added by 2045. Though surprising, we see one natural gas frame peaker and two hydrogen blend peakers added in 2024 in sensitivity 15 compared to one biodiesel peaker in the reference portfolio for the same year. These peakers are added to meet the peak capacity needs and resource adequacy requirements. The levelized cost of the capacity of the natural gas frame peaker plant with the SCGHG as an externality cost is $114/kw-yr, whereas the levelized cost of capacity with the SCGHG in dispatch is $104/kw-yr. When modeling SCGHG in dispatch, there are adverse effects on the cost of capacity of peaking resources which, in this case, led to increased resource additions earlier in the time horizon.

Figure 8.21: Resource Additions — Requested Sensitivities



7. Portfolio Benefit Analysis Results

This section describes the results of the portfolio benefit analysis.

➔ Appendix I: Electric Analysis Inputs and Results provides all underlying data, calculations, and a summary of the results in an Excel spreadsheet and may be a useful reference while reading this section.

7.1. Reference Portfolio

All results from the portfolio benefit analysis are relative to the reference portfolio. We used relative measures in this analysis because prescriptive guidelines on creating an equitable energy portfolio are currently unavailable. Relative measures provide us with an understanding of how one portfolio may enable more equitable outcomes than another.

The reference portfolio includes many aspects of an equity-enabling portfolio. The reference portfolio is the least-cost solution[13] identified by the AURORA long-term capacity expansion model: because electricity affordability is essential in enabling equitable outcomes, a low-cost portfolio is desirable. The reference portfolio produces more greenhouse gas emissions than most other portfolios analyzed but reaches zero greenhouse emissions by 2045. Similarly, the reference portfolio has higher outdoor air quality emissions (SO_2, NO_x, and PM) than most other portfolios but sees significant reductions by the end of the planning horizon.

The reference portfolio adds an estimated 45,736 jobs from new resource additions, more than many other portfolios analyzed. The reference portfolio is in the top third of portfolios for demand response peak capacity and demand response customer participation metrics. However, the reference portfolio lacks customer participation in distributed energy resources for both solar and storage. While the reference portfolio may have a CBI index of zero, it provides various customer benefits and represents a strong starting point for other portfolios.

Table 8.7 presents the reference portfolio CBI metrics against which we compared all other portfolios.

Table 8.7: Reference Portfolio CBI Metrics

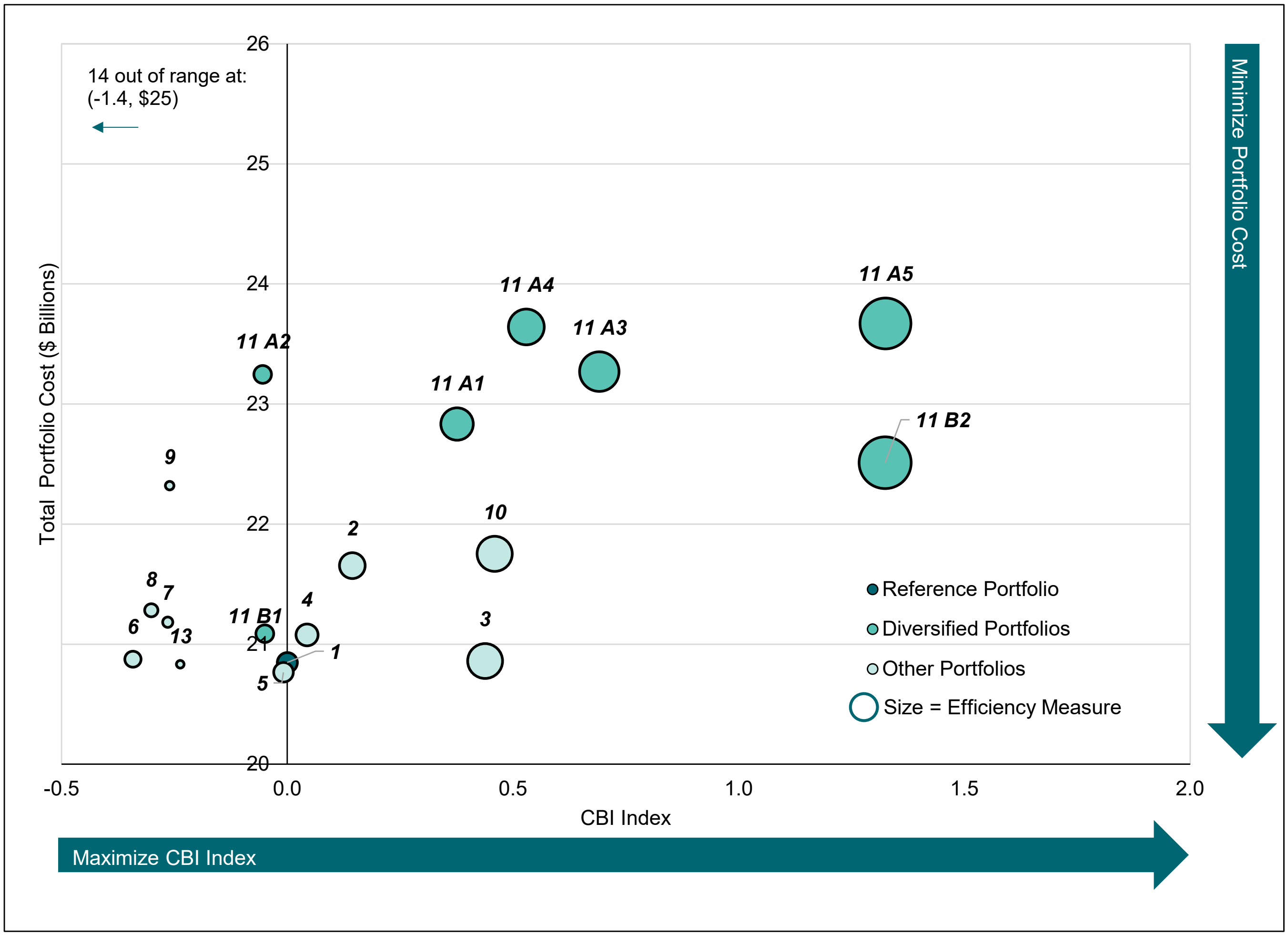
CBI Metric	Reference Portfolio
Cost (, Billions)	20.85
GHG Emissions (Short Tons)	48,824,734
SO_2 Emissions (Short Tons)	28,841
NO_x Emissions (Short Tons)	11,426
PM Emissions (Short Tons)	9,036
Jobs (Total)	45,736
Energy Efficiency Added (MW)	695
DR Peak Capacity (MW)	291
DER Solar Participation (Total New Participants)	12,115
DR Participation (Total New Participants)	513,238
DER Storage Participation (Total New Participants)	8,125

Figure 8.22 shows the results of the portfolio benefit analysis for all portfolios. Each portfolio is plotted with its CBI index value on the x-axis and total portfolio cost on the y-axis to show the tradeoff between equity enabling value and cost. The most desirable portfolios appear in the lower right corner of the plot, where cost is minimized and the CBI index is maximized. The point size estimates the CBI index per dollar spent on the portfolio, where larger points represent greater value per cost.

We plotted the reference portfolio at the CBI index equals zero line. We plotted portfolios containing elements that improve upon the reference portfolio's ability to enable equitable outcomes to the right of this line and those which may detract from equitable outcomes to the left of this line.

[13] Portfolios 5 and 13 are slightly lower cost than the reference portfolio by $80 million and $10 million, respectively. These small decreases in cost are within the 1 percent study precision tolerance of the AURORA long-term capacity expansion model.

Figure 8.22: Portfolio Benefit Analysis Results



7.1.1. Energy Efficiency

Our analysis shows portfolios that include increased energy efficiency measures tend to enable more equitable outcomes than the reference portfolio, as observed by the relationship between portfolios 2, 3, the diversified portfolios, and the reference portfolio. Portfolios 2, 3, and the diversified portfolios include increased energy efficiency measures. The reference case economically selected up to 695 aMW of conservation by 2045. We tested a large increase in energy efficiency by adding 923 aMW of conservation by 2045 in portfolio 2. This resulted in a relatively small increase in the CBI index, +0.14, but a much higher cost, +810 million. Understanding that increasing conservation results in diminishing returns, we tested slightly less conservation in portfolio 3 by adding 818 aMW and observed a larger increase in CBI index, +0.44, and a smaller increase in cost, +10 million.

The relationship between portfolios 2 and 3 illustrate the complexity of interaction between individual CBI metrics, the overall CBI index, and cost. Energy efficiency is one of the metrics used in this CBI index calculation, so intuitively, increasing its value should increase the overall CBI index. However, by reducing the amount of energy efficiency from 923 aMW to 818 aMW, portfolio 3 added other resources, which improved the CBI index for other metrics resulting in a higher overall CBI index at a lower cost.

As we developed the diversified portfolios, we incorporated 818 aMW of conservation, given the large increase in the CBI index for the relatively small increase in total portfolio cost.

7.1.2. Pumped Hydroelectric Storage

Portfolios that include PHES tend to have a lower CBI index than the reference portfolio. Portfolios 6, 7, 8, and the diversified portfolio include PHES. PHES is a costly resource and was not selected economically by any portfolios, so we tested scheduled additions of PHES to understand any benefit in diversifying energy storage away from solely battery energy storage.

We found that PHES delays the need to add thermal peaking capacity and reduces the dispatch of existing thermal resources when added to a portfolio resulting in fewer greenhouse gas emissions. Unfortunately, adding PHES tends to reduce the number of jobs expected from portfolios and reduces the amount of demand response selected by the portfolio resulting in an overall CBI index of less than zero or worse than the reference portfolio and portfolios 6, 7, and 8. Given the reduction of greenhouse gas emissions and diversification benefits of PHES, we decided to add PHES to the diversified portfolios. In portfolios 11 A5 and 11 B2, we controlled for the negative CBI index impacts of PHES by scheduling distributed solar and battery resources, discussed in Section 7.1.3, and maximizing demand response programs, resulting in portfolios with the highest overall CBI indices.

7.1.3. Distributed Energy Resources

We tested portfolios 4 and 5, which scheduled additions of distributed energy resources, solar, and storage, respectively, to understand how adding these resources would impact the cost. Distributed energy resources tend to cost more than their utility-scale counterparts and, therefore not selected in the reference portfolio. However, we created customer benefit indicators precisely to monitor customer participation in distributed solar and distributed storage technologies. We thought adding these resources to the portfolio would significantly increase the overall CBI index. However, portfolio 4, which adds distributed solar, only scores marginally better than the reference portfolio, and portfolio 5 scores worse. Adding distributed energy resources tends to reduce the number of jobs associated with the portfolio, and the amount of demand response added. These changes result in little net benefit for the increased DER participation metrics.

However, when we added DERs in coordination with other resources, the benefit became much stronger, as demonstrated in diversified portfolios 11 A3, 11 A4, 11 A5, and 11 B2, which have overall CBI indices much greater than the reference portfolio.

7.1.4. Diversified Portfolios

Diversified portfolios include several scheduled resource additions to create a diverse mix of resources within the portfolio. Increased diversification enables more equitable outcomes through greater participation in DER, more demand response programs, and lower greenhouse gas and outdoor air quality emissions. Portfolios 11 A5 and 11 B2, the most diversified portfolios, tie for the highest overall CBI index at +1.32 from the reference portfolio. Considering the tradeoff between the CBI index and cost, 11 B2 provides the better value, given that it is 1.16 billion less expensive than 11 A5.

8. Stochastic Portfolio Analysis Summary

We test the robustness of different portfolios with stochastic risk analysis to learn how well the portfolio might perform under various conditions. In this analysis, we run select portfolios through 310 simulations or draws[14] that vary power prices, gas prices, hydroelectric generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, we can quantify the risk of each portfolio. We tested two different portfolios in the stochastic portfolio analysis, as and described in Table 8.8.

Table 8.8: Portfolios Tested for Stochastic Analysis

ID	Name	Description
1	Reference Portfolio	The reference portfolio is a least-cost, CETA-compliant portfolio that allows the AURORA long-term capacity expansion model to optimize resource selection with as few constraints as possible. The reference portfolio is a basis against which to compare other portfolios.
11 B2	Preferred Portfolio	This sensitivity is the most diversified portfolio we developed in this report, but without adding advanced nuclear SMR technology to the portfolio. We built this portfolio on the least-cost reference portfolio; it increases conservation and adds pumped hydroelectric storage, distributed energy, and demand response.

8.1. Risk Measures

The results of the risk simulation allow us to calculate portfolio risk. We calculated risk as the average value of the worst 10 percent of outcomes (TailVar90). This risk measure is the same one the Northwest Power and Conservation Council (NPCC) uses in its power plans.

8.2. Stochastic Results

Our electric stochastic analysis holds portfolio resource builds constant across the 310 simulations. These resource forecasts are a guide. We will make resource acquisition decisions based on the latest information from the 2021 All-Source RFP[15] and other acquisition processes. The risk simulation results, however, indicate the portfolio costs risk range under varying input assumptions. Table 8.9 compares the portfolio costs for the deterministic run; the mean portfolio cost across 310 simulations, and the TailVar90 of portfolio cost for the two portfolios examined for the stochastic analysis. The mean portfolio cost of the 310 simulations is lower than the deterministic model runs for the reference and preferred portfolios.

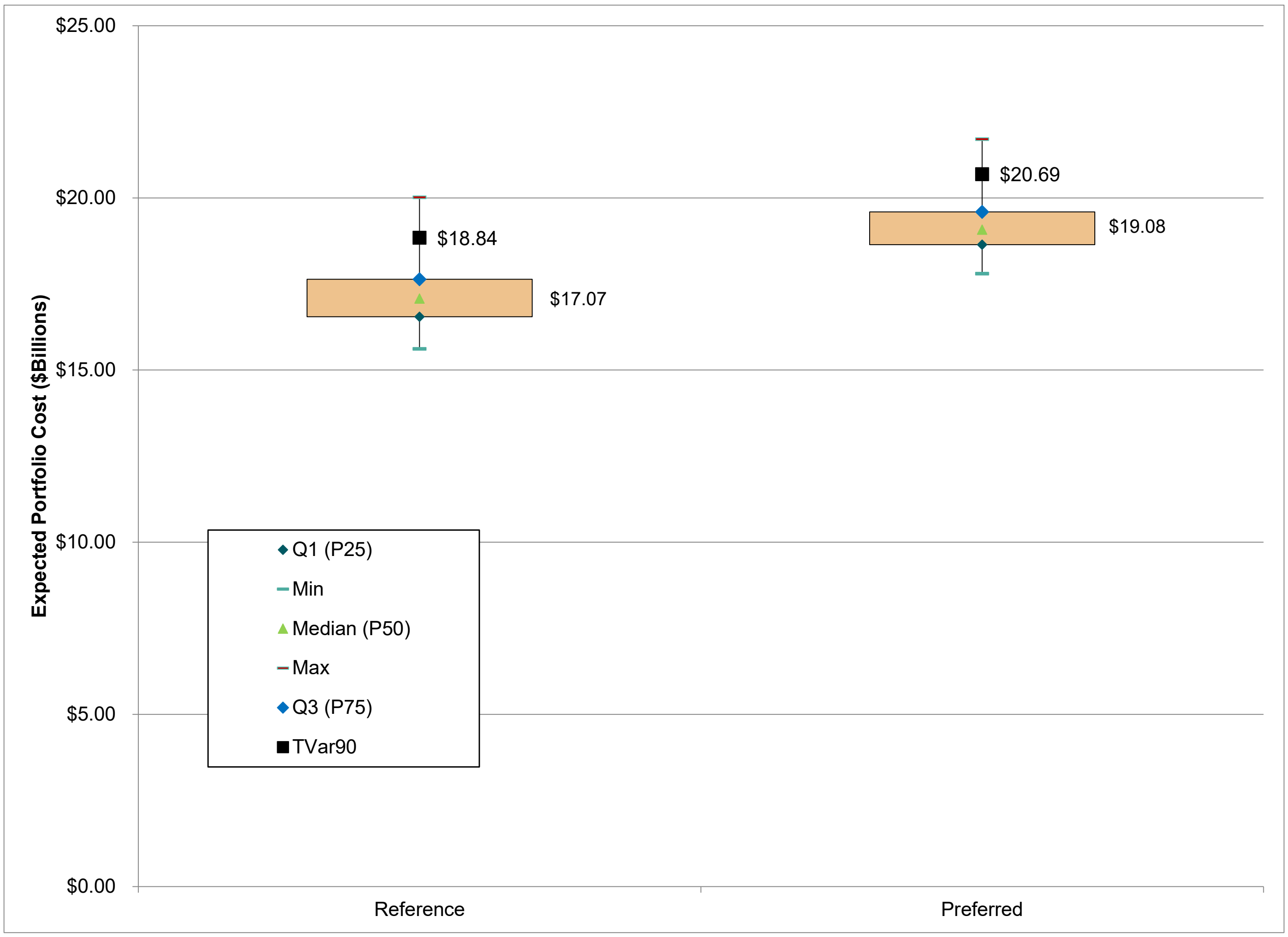
[14] Each of the 310 simulations is for the 24-year IRP forecasting period, 2022-2045.
[15] https://www.pse.com/en/pages/energy-supply/acquiring-energy

Table 8.9: Portfolio Costs Across 310 Simulations (Billion$)

Revenue Requirement	Portfolio	Deterministic ($)	Difference from Reference ($)	Mean ($)	Difference from Reference ($)	TVar90 ($)	Difference from Reference ($)
1	Reference	17.60	--	17.20	--	18.80	--
11 B2	Preferred	19.60	2.00	19.20	2.00	20.70	1.90

Figure 8.23 compares the expected portfolio costs for each portfolio. The vertical axis represents the costs, and the horizontal axis represents the portfolio. The green triangle on each box represents the median for that portfolio. The interquartile range box represents the middle 50 percent of the data. The whiskers extending from either side of the box represent the portfolio's minimum and maximum data values. The black square represents the TailVar90, the average value for the highest 10 percent outcomes.

Figure 8.23: Range of Portfolio Costs across 310 Simulations



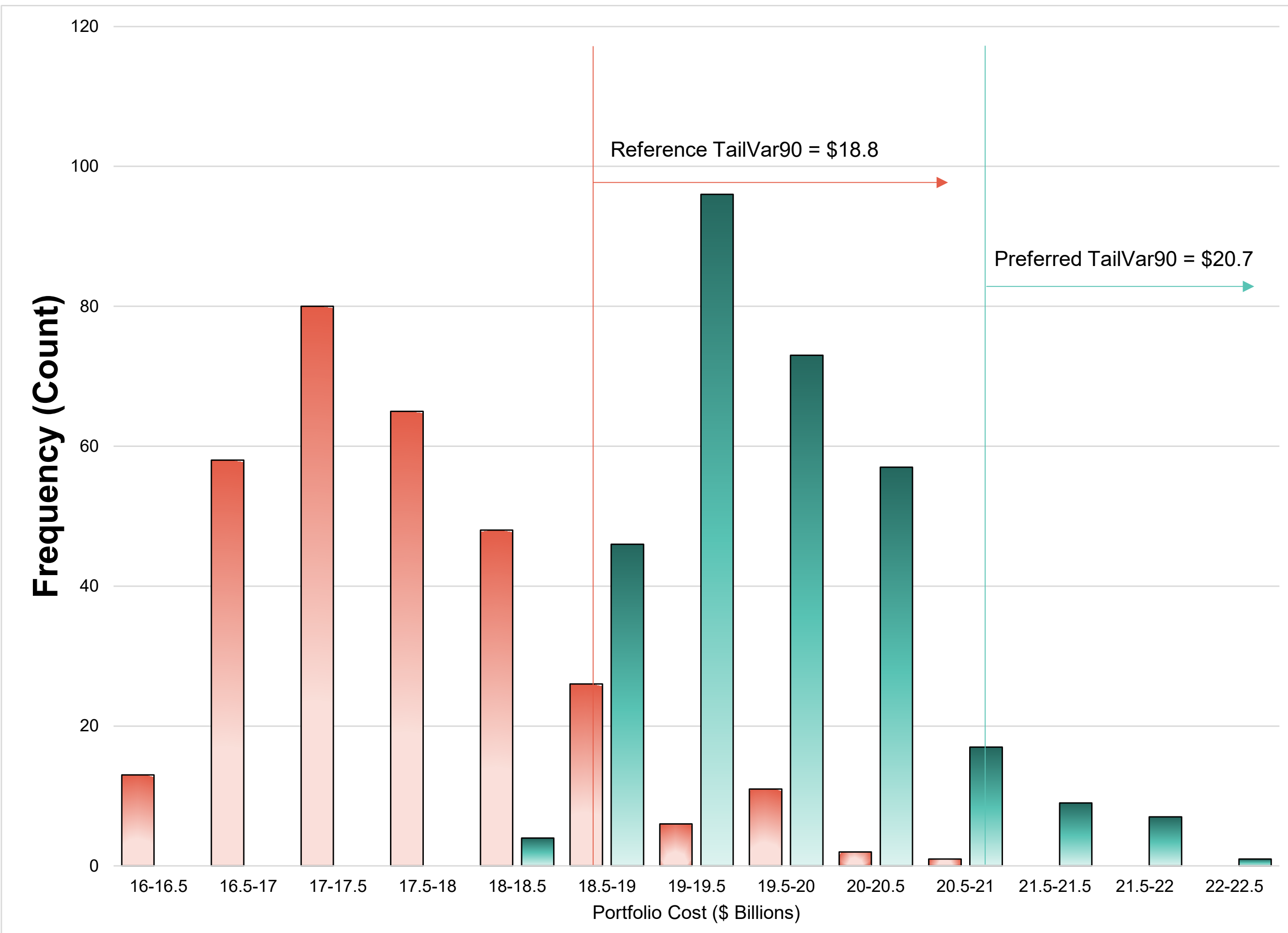
Key results of the analysis include:

- The mean value for the sensitivity 11 B2 portfolio is higher than the reference portfolio, suggesting that diversifying the resource mix results in higher portfolio costs.

- The range for sensitivity 11 B2 is narrower than the reference portfolio, indicating that the varied inputs have less of an impact on the overall portfolio costs.
- While the interquartile range for sensitivity 11 B2 portfolio is comparatively narrower than the reference portfolio, suggesting that the expected portfolio costs are less variable and higher, TailVar90, at 20.7 billion, indicates a risk of higher costs for this portfolio.

Figure 8.24 compares the reference to sensitivity 11 B2. We sorted each simulation's portfolio cost results into bins containing a narrow range of expected portfolio costs. The shorter right-hand tail and lower TailVar90 value of sensitivity 11 B2 indicate less risk associated with sensitivity 11 B2 than the reference portfolio, despite the higher average portfolio cost.

Figure 8.24: Frequency Histogram of Expected Portfolio Cost ($ Billions) — Reference vs. Sensitivity 11 B2



In addition to the expected portfolio costs, we evaluated the expected SCGHG. Table 8.10 and Figure 8.25 compare the SCGHG costs for the deterministic run, the mean across 310 simulations, and the TailVar90 of the two portfolios.

Key results of the analysis include:

- In contrast, the mean value for the sensitivity 11 B2 portfolio is higher than the reference portfolio, suggesting that diversifying the resource mix to include more conservation and distributed energy resources results in lower average emissions.
- The range for sensitivity 11 B2 is more comprehensive than the reference portfolio, indicating the inputs were varied have a bigger impact on the overall SCGHG costs.

Table 8.10: SCGHG across 310 Simulations ($ Billions)

SCGHG	Portfolio	Emissions ($)	Difference from Mid ($)	Mean ($)	Difference from Mid ($)	TVar90 ($)	Difference from Mid ($)
1	Reference	3.24	--	3.59	--	5.02	--
11 B2	Preferred	3.33	0.09	3.33	(0.26)	4.79	(0.23)

Figure 8.25: Range of SCGHG Costs across 310 Simulations