PRIVATE GENERATION FORECAST

Behind-The-Meter Resource Assessment

PacifiCorp

Date: February 2, 2023

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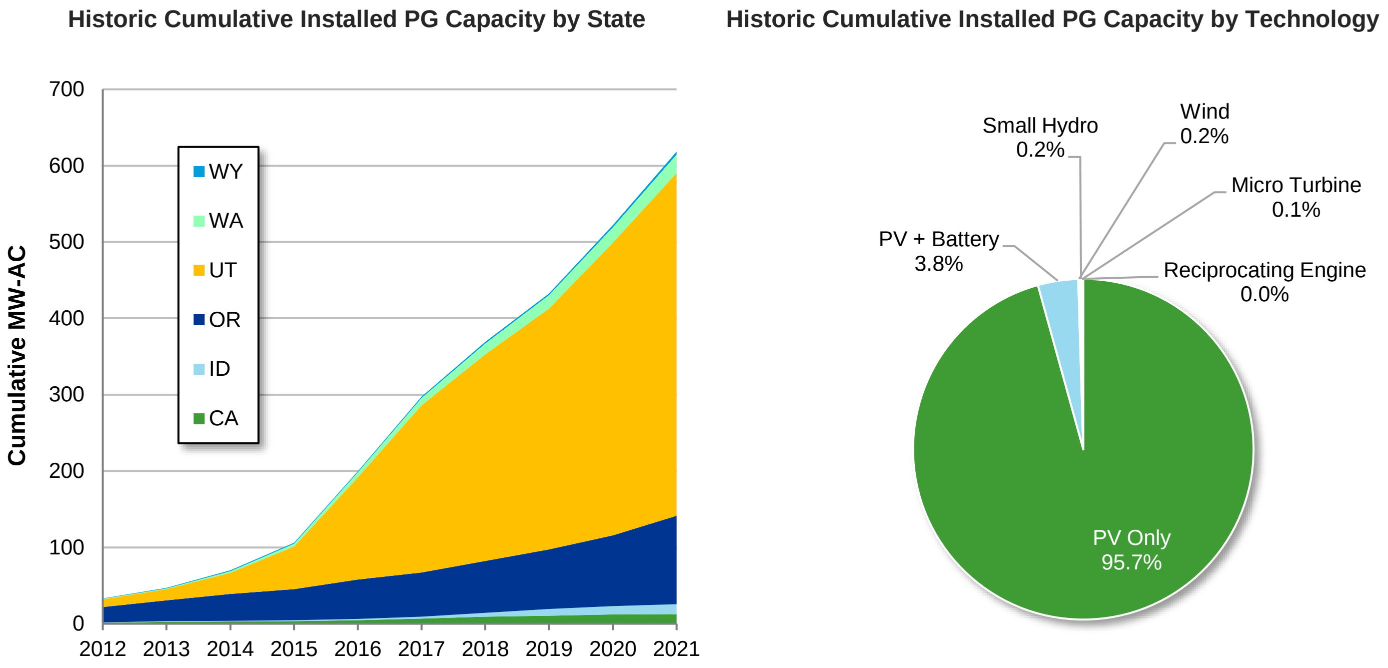
1 EXECUTIVE SUMMARY

DNV prepared the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp (the Company) covering their service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington to support PacifiCorp's 2023 Integrated Resource Plan (IRP). This study evaluated the expected adoption of behind-the-meter (BTM) distributed energy resources (DERs) including photovoltaic solar (PV only), photovoltaic solar coupled with battery storage (PV + Battery), small wind, small hydro, reciprocating engines and microturbines over a 20-year forecast horizon (2023-2042) for all customer sectors (residential, commercial, industrial, and agricultural). The adoption model DNV developed for this study is calibrated to the current[1] installed and interconnected capacity of these technologies, shown in Figure 1-1.

Figure 1-1 Historic Cumulative Installed Private Generation Capacity, PacifiCorp, 2012-2021



Historic Cumulative Installed PG Capacity by State

Historic Cumulative Installed PG Capacity by Technology

To date, the majority of PG installed capacity and annual growth in capacity has been in Utah, which represents the largest portion go PacifiCorp's customer population—about 50% of all PacifiCorp customers are in the Company's Utah service territory. Roughly 99 percent of existing private generation capacity installed in PacifiCorp's service territory is PV or PV + Battery. To inform the adoption forecast process, DNV conducted an in-depth review of the other technologies and did not find any literature to suggest that they would take on a larger share of the private generation market in the Company's service territory in the future years of this study.

For each technology and sector, DNV developed three adoption scenarios: a base case, a high case, and a low case. The base case is considered the most likely projection as it is based on current market trends and expected changes in technology costs and retail electricity rates; the high and low cases are used as sensitivities to test how changes in costs and retail rates impact customer adoption of these technologies.

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[1] PacifiCorp private generation interconnection data as of February 2022.

All scenarios use technology cost and performance assumptions specific to each state in PacifiCorp's service territory in the base year (2022) of the study. The base case uses the 2022 federal income tax credit schedules[2] and state incentives, retail electricity rate escalation from the AEO[3] reference case, and a blended version of the NREL Annual Technology Baseline[4] moderate and conservative technology cost forecasts as inputs to the modelling process. In the high case, retail electricity rates increase more rapidly, and technology costs decline at a faster rate compared to the base case. For the low case, retail electricity rates increase at a slower rate than the base case and technology costs decrease at a slower rate.

1.1 Study Methodologies and Approaches

The forecasting methodologies and techniques applied by DNV in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. The methods used to develop the state and sector-level results are described in more detail below.

1.1.1 State-Level Forecast Approach

DNV developed a behind-the-meter net economic perspective that includes, as costs, the acquisition and installation costs for each technology less the impact of available incentives and, as benefits, the customer's economic benefits of ownership such as energy and demand savings and export credits. For this study we assumed that the current net metering or net billing policies and tariff structures in each state continued throughout the study horizon. This resulted in the model incorporating benefits associated with net metering in Oregon, Washington, and Wyoming and net billing in Utah and California. We assumed customers in Idaho would accrue benefits based on the net billing policy in Utah throughout the study.

This analysis incorporated the current rate structures and tariffs offered to customers in PacifiCorp's service territories. Time-of-use rates, tiered tariffs and retail tariffs that include high demand charges increased the value of PV + Battery configurations compared to PV-Only configurations while other factors such as load profiles and DER compensation mechanisms minimized the impact of such tariffs on the customer economics of PV + Battery systems. The DER compensation mechanism in Oregon, Washington, and Wyoming — traditional net metering — does not incentivize PV + Battery storage co-adoption. In net metering DER compensation schemes, customers receive export credits for excess PV generation at the same dollar-per-kWh rate that they would have otherwise paid to purchase electricity from the grid. Net billing—the mechanism modelled in California, Idaho, and Utah—does incentivize PV + Battery storage co-adoption, as customers can lower their electricity bills by charging their batteries with excess PV generation and dispatching their batteries to meet on-site load during times of day when retail energy prices are high. From the perspective of utility bill savings alone, PV + battery systems are often not the most cost-effective option for most customers. Customers who seek the reassurance and reliability of backup power show more of a willingness to pay for this product, especially if they reside in areas that are prone to outages and severe weather events.

DNV combined technical feasibility characteristics of the identified PG technologies and potential customers with an economic analysis to calculate cost-effectiveness metrics for each technology, within each state that PacifiCorp serves, over the analysis timeframe. DNV then used a bass diffusion model to estimate customer PG adoption based on technical and

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[2] H.R.5376 - Inflation Reduction Act of 2022 (https://www.congress.gov/bill/117th-congress/house-bill/5376/text). Since the passing of the Inflation Recovery Act of 2022, the federal Investment Tax Credit (ITC) has been extended past its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034.

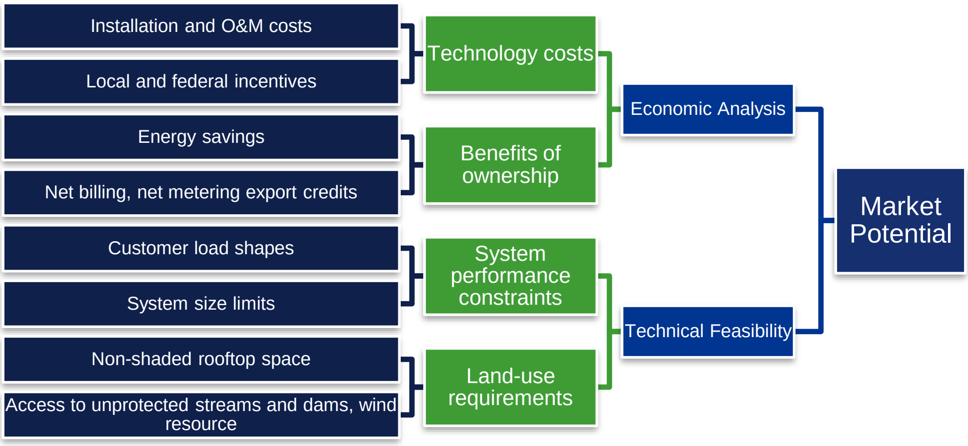
[3] U.S. Energy Information Administration, Annual Energy Outlook 2022 (AEO2022), (Washington, DC, March 2022).

[4] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

economic feasibility and incorporated existing adoption of each PG technology by state and customer segment as an input to the adoption model.

Technical feasibility characteristics were used to identify the potential customer base that could technically support the installation of a specific PG technology, or the maximum, feasible, adoption for each technology by sector. These factors included overall PG metrics such as average customer load shapes and system size limits by state, and specific technology factors such as estimated rooftop space and resource access based on location (for hydro and wind resource applicability). Simple payback was used in the customer adoption portion of the model as an input parameter to bass diffusion curves that determined future penetration of all PG technologies. The methodology and major inputs to the analysis are shown in Figure 1-2. Changes to technology costs and retail electricity rates used in the high and low cases impact the economic portion of the analysis.

Figure 1-2 Methodology to Determine Market Potential of Private Generation Adoption



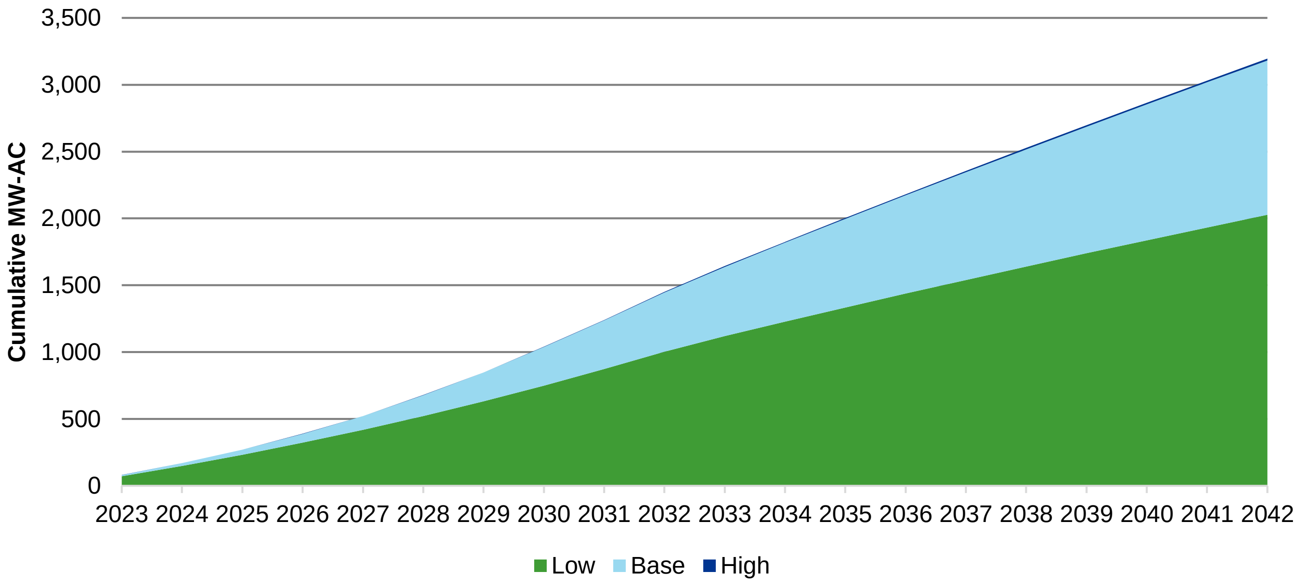
DNV developed Bass diffusion curves customized for each technology, state, and sector that also accounted for variation in willingness-to-adopt as cost effectiveness changes over time. The Bass diffusion curves were used to model annual and cumulative market adoption. Bass diffusion curves are widely used for forecasting technology adoption. Diffusion curves typically take the form of an S-curve with an initial period of slow early adoption that increases as the technology becomes more mainstream and eventually tapers off amongst late adopters. The upper limit of the curve is set to the maximum level of market adoption. In this analysis, the long-term maximum level of market adoption was based on payback. As payback was calculated by year in the economic analysis to capture the changing effects of market interventions over time, the maximum level of market adoption in the diffusion curves vary by year in the study.

The Bass diffusion curves used in the market potential analysis are characterized by three parameters—an innovation coefficient, an imitation coefficient, and the ultimate market potential. Together, these three parameters also determine the time to reach maximum adoption and overall shape of the curve. The innovation and imitation parameters were calibrated for each technology and sector, based on current market penetration and when PacifiCorp started to see the technology being adopted in each of its service territories. The calibrated curves show some segments still in the very early phases of adoption, while other markets are more mature.

1.2 Private Generation Forecast

In the base case scenario, DNV estimates 3,181 MW of new private generation capacity will be installed in PacifiCorp's service territory over the next twenty years (2023-2042). Figure 1-3 shows the base, low and high case scenarios. The low case scenario estimates 2,028 MW of new capacity over the 20-year forecast while the high case estimates 3,196 MW of new private generation capacity installed by 2042.

Figure 1-3 Cumulative New Capacity Installed by Scenario (MW-AC), 2023-2042



The sensitivity analysis showed a much greater margin of uncertainty on the low side than the high side. The Inflation Reduction Act of 2022 (IRA) extends tax credits for private generation that create very favorable economics for adoption, and those are embedded in the base case. We therefore limited our upper bound forecast to lower technology costs and higher retail electricity rates, and these produced only a small boost to adoption for technologies that were already cost effective under the IRA. In contrast, when we modelled our lower bound, we found that the increases to customer payback period were enough to tamp down adoption by a wider margin. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. The low case forecast is 36% less than the base case, while the high case cumulative installed capacity forecasted over the 20-year period is just 0.5% greater than the base case.

Figure 1-4 shows the base case forecast by state, compared to the previous (2020) study's total base case forecast.[5] This figure indicates that Utah and Oregon will drive most PG installations over the next two decades, which is to be expected given these two states represent the largest share of PacifiCorp's customers and sales. The base scenario estimates approximately 1,447 MW of new capacity will be installed over the next 10 years in PacifiCorp's territory—55% of which is in Utah, 32% in Oregon, and 6% in Idaho. Since the 2020 study, the federal Investment Tax Credit (ITC) has been extended for ten years at its original base rate levels and expanded to include energy storage. The tax credit increase and extension lowered the customer payback period for all technologies, making the customer economics of this study's base case more

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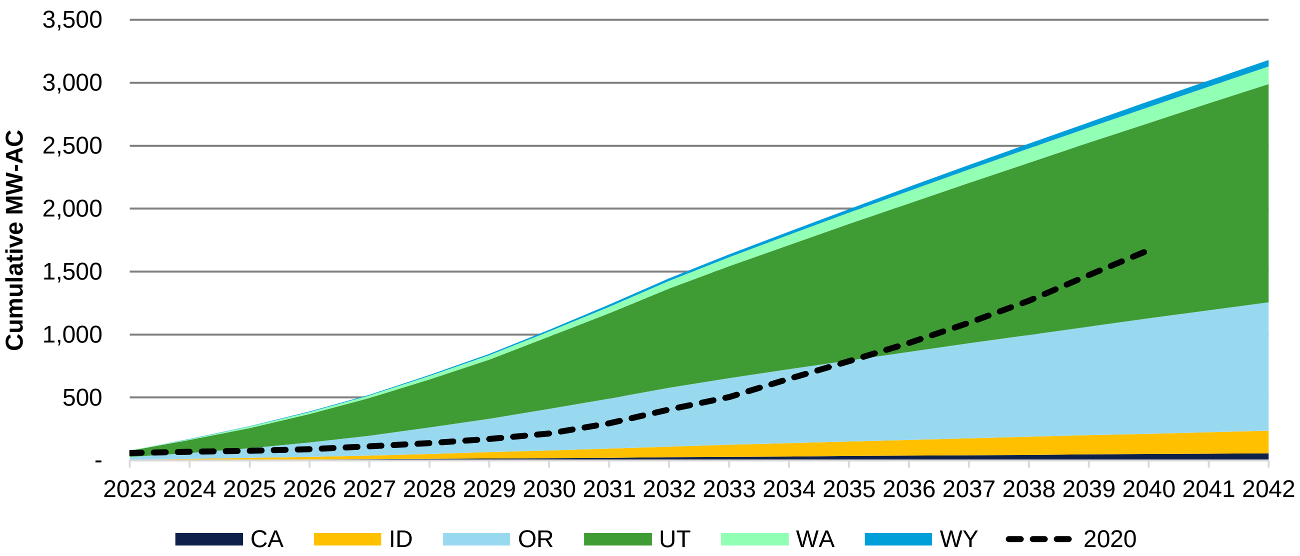
[5] Cumulative capacity is adjusted to account for the difference in the forecast starting years (2021 in the previous study, versus 2023 in this study). Source: Navigant. 2020. "Private Generation Long-Term Resource Assessment (2021-2040)"

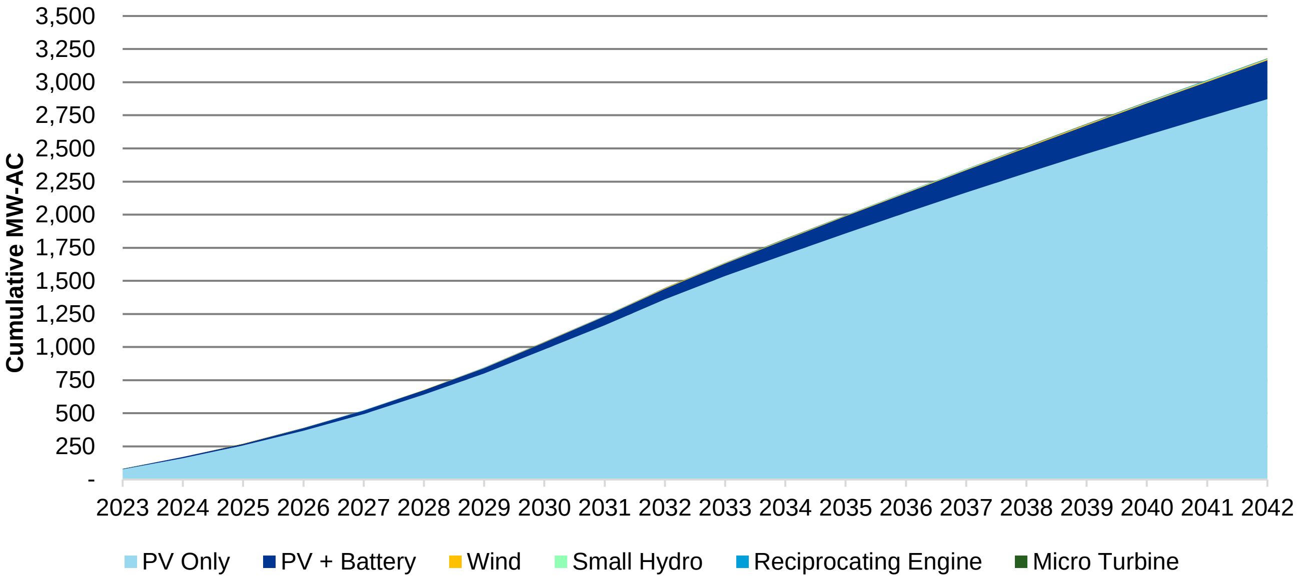
similar to the previous study’s high case. In addition to the change in customer economics, projected PV capacity is expected to grow at a faster rate in the early years and at a slower rate towards the end of the forecast period. The key drivers of these differences include larger average PV system sizes, a steeper decline in PV + Battery costs at the start of the forecast period, and the maturity of rooftop PV technology.

Figure 1-4 Cumulative New Capacity Installed by State (MW-AC), 2023-2042, Base Case



In Figure 1-5 below, the base case forecast is presented by technology for all states in PacifiCorp’s service territory. First year PV Only is estimated to grow by 76 MW and PV + Battery by 3 MW. These two technologies make up 99% of new installed private generation capacity forecasted. The results section of the report contains results by technology for the high, base, and low sectors. Additionally, total PV capacity forecasted is presented by sector in that section as well.

Figure 1-5 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Base Case



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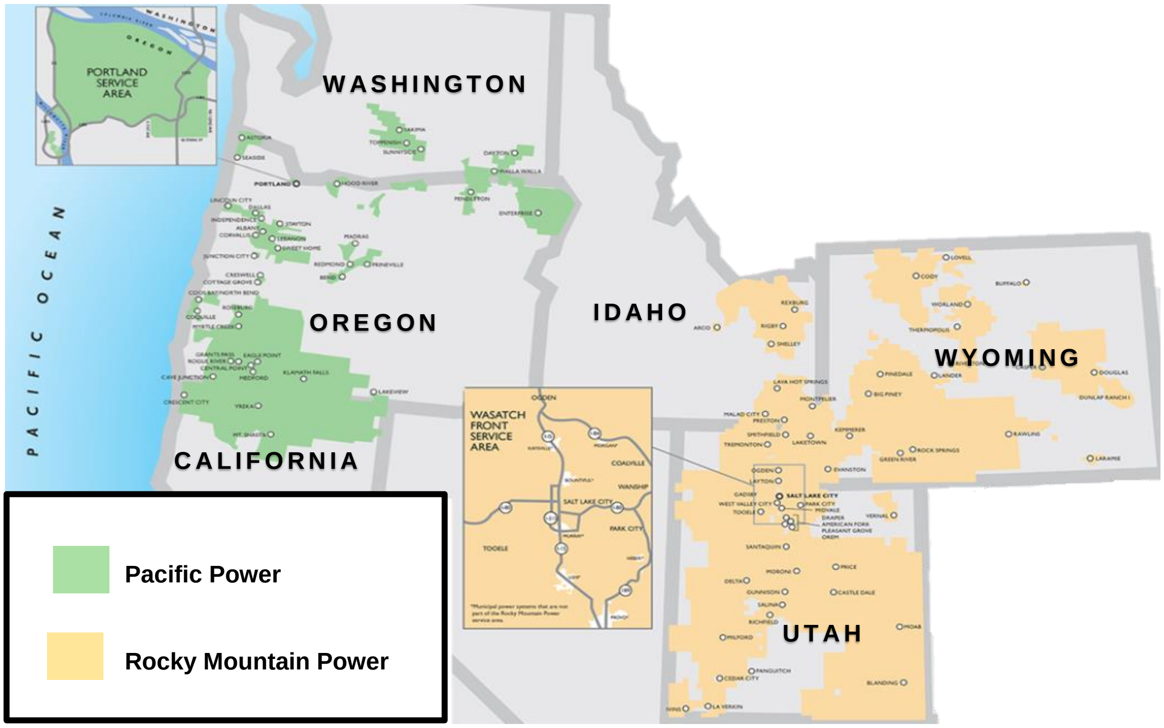
2 STUDY BACKGROUND

DNV prepared this Private Generation Long-term Resource Assessment on behalf of PacifiCorp and representing their service territory in six states—shown in Figure 2-1—California, Idaho, Oregon, Utah, Washington, and Wyoming. In this study, private generation technologies provide behind-the-meter energy generation at the customer site and are designed for the purpose of offsetting customer load and/or peak demand. The purpose of this study is to support PacifiCorp's 2023 Integrated Resource Plan by projecting the level of private generation resources PacifiCorp's customers may install over the next two decades under base, low, and high adoption scenarios. In addition to private generation, DNV also considered the cost-effective potential for high-efficiency cogeneration in Washington, consistent with the 480-109-060 (13) and 480-109-100 (6) of the Washington Administrative Code (WAC).

Figure 2-1 PacifiCorp Service Territory



Although there have been six previous studies involving private generation, DNV developed its assumptions, inputs, methodologies, and forecasts independently from these prior assessments that had been performed for PacifiCorp. The forecasting methodologies and techniques applied by DNV in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. This study evaluated the expected adoption of behind-the-meter technologies over the next 20 years, including:

1. Photovoltaic (Solar PV) Systems
2. Solar PV Paired with Battery Storage
3. Small Scale Wind
4. Small Scale Hydro
5. Reciprocating Engines

6. Microturbines

Project sizes were determined based on average customer load across the commercial, irrigation, industrial and residential customer classes for each state. The project sizes were then limited by each state’s respective system size limits. Private generation adoption for each technology was estimated by sector in each state in PacifiCorp’s service territory.

3 STUDY APPROACH AND METHODS

DNV used applicability/ technical feasibility, customer perspectives towards PGs, and project economics as the basis for forecasting expected market adoption of each private generation technology.

3.1 Technology Attributes

The technology attributes define the reference systems and their key attributes such as capacity factors, derate factors, and costs which are used in thepayback and adoption analyses. A full list of detailed technology attributes and assumptions by state and sector is provided in Appendix A. The following information provides a high-level summary of the key elements of the technologies assessed in this analysis.

3.1.1 Solar PV

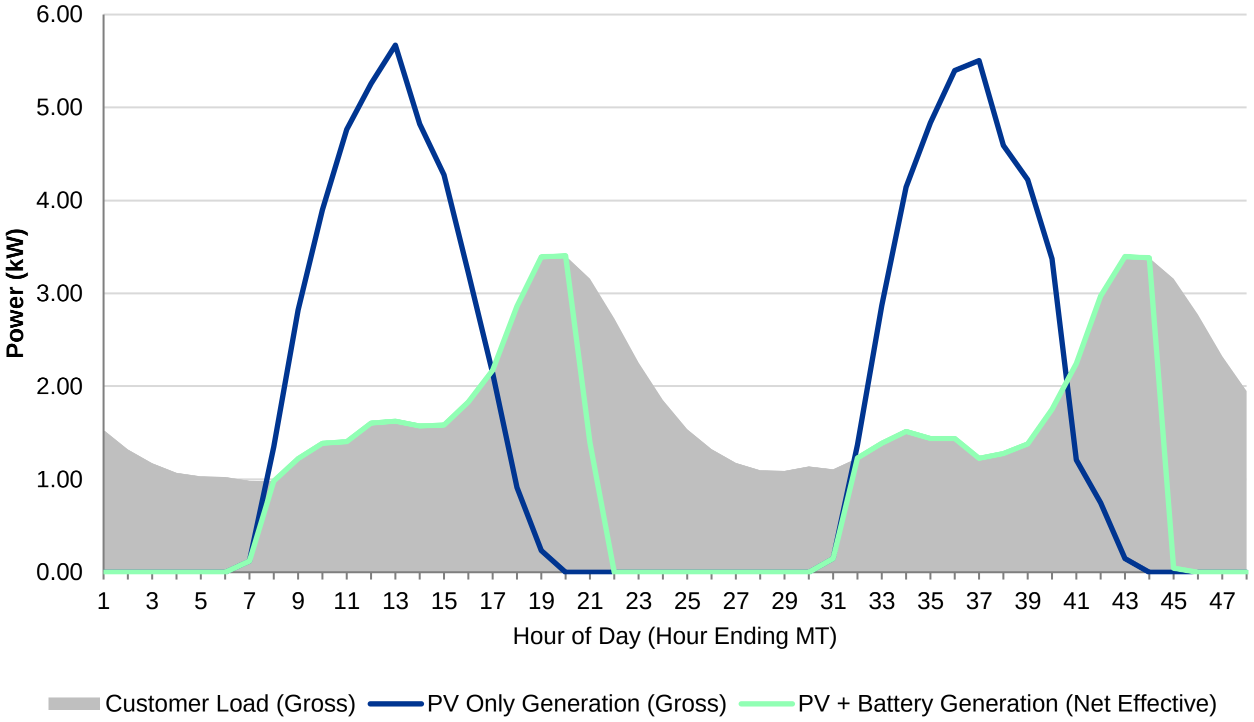
Solar photovoltaic (PV) systems convert sunlight into electrical energy. DNV modeled representative PV system energy output for residential and non-residential systems in each state to estimate first-year production. To model hourly production, DNV leveraged its SolarFarmer and Solar Resource Compass APIs. DNV’s Solar Resource Compass API accesses and compares irradiance data from multiple data providers in each region. Solar Resource Compass also generates monthly soiling loss estimates for both dust soiling and snow soiling, as well as a monthly albedo profile. By incorporating industry standard models and DNV analytics, precipitation and snowfall data is automatically accessed and used to estimate the impact on energy generation.

Total PV capacity is forecasted by two different technology configurations: PV Only and PV + Battery.The PV technology in the PV + Battery systems were modeled using the same specifications as the PV Only technology, with the exception of nameplate capacity. DNV determined that average system sizes for PV + Battery configurations are on average larger than PV Only systems.

DNV further segmented the PV + Battery technology by new PV + Battery systems installed together and a Battery Retrofit case—where a battery is added to an existing PV system. The PV Only forecast presented in the results section of this report is net of customers who later adopt an add-on battery system (Battery Retrofit), and therefore become a part of the PV + Battery forecast. DNV assumes that customers in the Battery Retrofit case do not represent new incremental PV MW-AC capacity, however the generation profile of the customer changes from PV Only to PV + Battery.

An example residential customer load profile for two summer days is presented in Figure 3-1 to illustrate the difference between the generation profiles of PV Only and PV + Battery systems in this analysis.

Figure 3-1 Example Residential Summer Load Shape Compared to PV Only and PV + Battery Generation Profiles



3.1.1.1 PV Only

Table 3-1 provides the representative system specifications used to model residential standalone PV adoption. DC/AC ratio assumptions are derived from DNV's experience in the residential PV industry.

Table 3-1 Residential PV Only Representative System Assumptions

System Performance	Units	CA	ID	OR	UT	WA	WY
Nameplate Capacity	kW-DC	6.5	6.0	6.8	5.5	10.0	5.5
Module Type	n/a	c-Si	c-Si	c-Si	c-Si	c-Si	c-Si
PV Inverter	n/a	Microinverter					
Installation Requirements	n/a	Fixed-tilt Roof Mounted					
Capacity Factor	kWh/(kW-DC x 8760 hrs/yr)	13%	15%	16%	15%	13%	16%
DC/AC Derate Factor	n/a	1.118	1.123	1.121	1.129	1.132	1.118

Table 3-2 provides the representative system specification used to model non-residential standalone PV adoption. DC/AC ratio assumptions are derived from Wood Mackenzie's H1 2022 US solar PV system pricing report. The nameplate capacity of the system is dependent on the average customer size for each non-residential sector and state.

Table 3-2 Non-Residential PV Only Representative System Assumptions

System Performance	Units	CA	ID	OR	UT	WA	WY
Nameplate Capacity	kW-DC	30-150	37-100	30-115	60-750	20-100	18-25
Module Type	n/a	c-Si	c-Si	c-Si	c-Si	c-Si	c-Si
PV Inverter	n/a	Three-phase string inverter					
Installation Requirements	n/a	Flat Roof Mounted					
Capacity Factor	kWh/(kW-DC x 8760 hrs/yr)	14%	13%	12%	14%	12%	12%
DC/AC Derate Factor	n/a	1.30	1.30	1.30	1.30	1.30	1.30

The full list of nameplate capacity assumptions by sector and state can be found in Appendix A. For all PV systems, DNV assumed a linear degradation rate of 0.5% across the expected useful life of the system.

3.1.1.2 PV + Battery

Technology attributes consist of a representative system, operational data, cost assumptions, and capital costs which are used in conjunction to develop a total installed cost in dollars per kW. DNV reviewed PacifiCorp's history of interconnected projects to develop its customer level assumptions for number of batteries, usable energy capacity, and rated power at the state level. The resulting representative composite system is used for operational parameters and costs to be used for long-term adoption and forecasting purposes.

DNV assumes a fully integrated battery energy storage system (BESS) product for the residential sector, which will include a battery pack and a bi-directional inverter based on leading residential battery energy storage manufacturers such as Tesla, Enphase, and Sonnen providing fully integrated BESS solutions. Table 3-3 presents the representative residential PV + Battery system assumptions used in this analysis. The system specifications for the commercial, industrial, and irrigation sector are listed in Appendix A.

Table 3-3 Residential PV + Battery Representative System Assumptions

Technology	System Performance	Units	CA	ID	OR	UT	WA	WY
PV	Nameplate Capacity	kW-DC	9.5	8.8	10.6	8.1	13.6	8.6
BESS	Total Usable Energy Capacity	kWh	12.5	12.5	14.0	12.5	14.0	10.0
	Total Power	kW	5.0	5.0	7.0	5.0	7.0	5.0
	Battery Duration	Hrs	2.5	2.5	2.0	2.5	2.0	2.0
	Roundtrip Efficiency	%	89%					
	Battery Pack Chemistry	n/a	Lithium-ion NMC (Nickel, Manganese, Cobalt)					

Residential and non-residential BESS can be installed as a standalone system, added to an existing PV system, or the system can be installed with a new PV system. DNV assumed all battery installations would be co-located with a PV system in an AC-coupled configuration, as standalone systems are ineligible for the federal ITC—explained further in section 3.2.5.

Battery adoption was forecasted separately for PV + Battery systems installed together, and the Battery Retrofit case—where a battery is added to an existing PV system. The basis of the Battery Retrofit forecast is the existing PV capacity in PacifiCorp’s service territories and the PV Only capacity forecasted in this analysis. For the purpose of forecasting private generation capacity, the Battery Retrofit forecast is presented in the results section as a part of the PV + Battery capacity forecast. In the behind-the-meter battery storage capacity forecast, presented in Appendix E, the Battery Retrofit case is split out in the presentation of the results.

Battery degradation was modeled using DNV’s Battery AI, a data-driven battery analytics tool that predicts short-term and long-term useable energy capacity degradation under different usage conditions. It combines laboratory cell testing data with artificial intelligence (AI) technologies to provide an estimation for battery energy capacity degradation over time. In this analysis, Battery AI models several current-generation, commercially available Nickel Manganese Cobalt (NMC) cells were used to predict expected degradation performance of “generic” cells. These cells were tested in the lab over periods of 6 – 12 months at multiple temperatures, C-rates, SOC ranges, and cycling/resting conditions. Predictions are generally constrained to within the bounds of the testing data. DNV has not explicitly modeled battery end-of-life (EOL), due to a lack of testing data in this region of operation. Earlier of 20-years or 60% capacity retention is generally considered to represent EOL.

Both cycling and calendar effects were considered in the degradation assessment. It is also assumed the battery cell temperature will be controlled to be around 25°C for majority of the time with proper thermal management (ventilation, HVAC). DNV notes that temperature plays a key role in battery degradation. Continuous operation under extreme low or high temperatures will accelerate degradation in battery state of health.

Cost Assumptions

Cost assumptions are used in conjunction with representative system parameters to develop system costs. The costs are developed for each state and sector, inclusive of hardware, labor, permitting and interconnection fees, as well as provisions for sales and marketing, overhead, and profit. For labor costs, we used state level data from the US Bureau of Labor Statistics (BLS) for electricians, laborers (construction), and electrical engineers.

Total installed costs (or capital expenditures) are based on cost assumptions that were developed on a bottom-up basis—including hardware, installation/interconnection, as well as a provision for sales, general, and administrative costs and overhead. Capital expenditures (Cap-Ex) are expenditures required to achieve commercial operation in a given year. Pricing is indicative of a cash sale, not a lease or PPA, and it does not account for ITC or local rebates. Examples of total installed costs by category for residential and commercial customers in Utah are shown in Figure 3-2 and Figure 3-3, respectively. The full set of cost and incentive assumptions used in the analysis can be found in Appendix A.

Figure 3-2 Cost of Residential PV Standalone, Battery Storage Retrofit to Existing PV, and PV + Battery Systems from DNV Bottom-up Cap-Ex Model, Utah

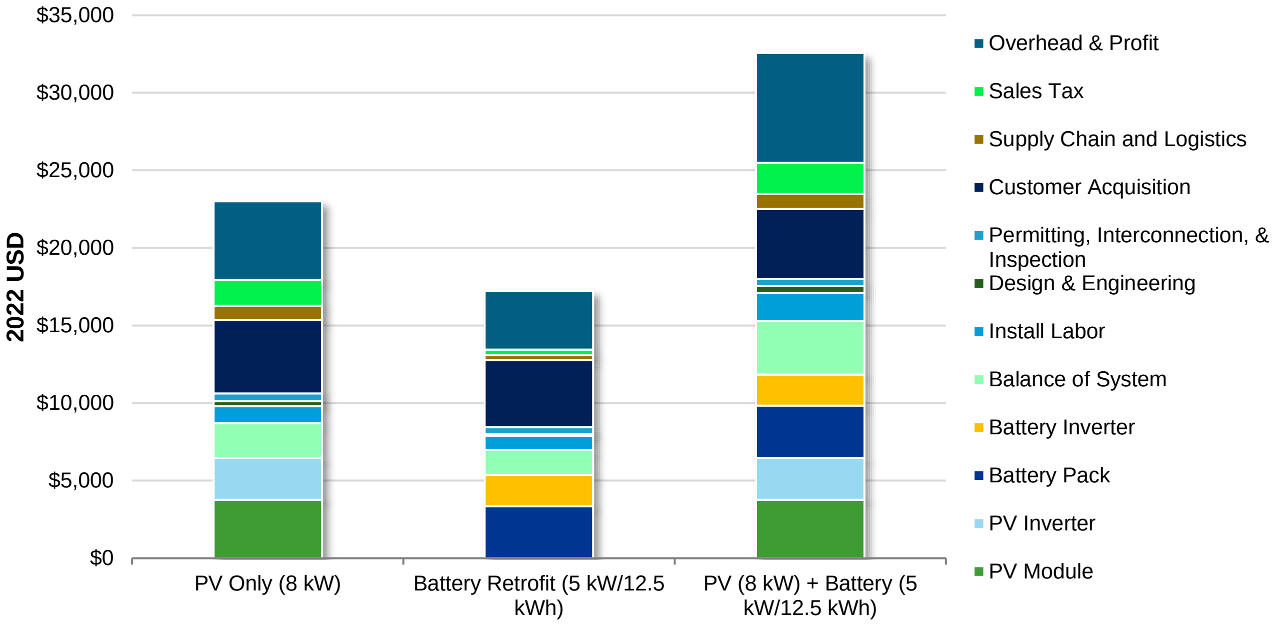
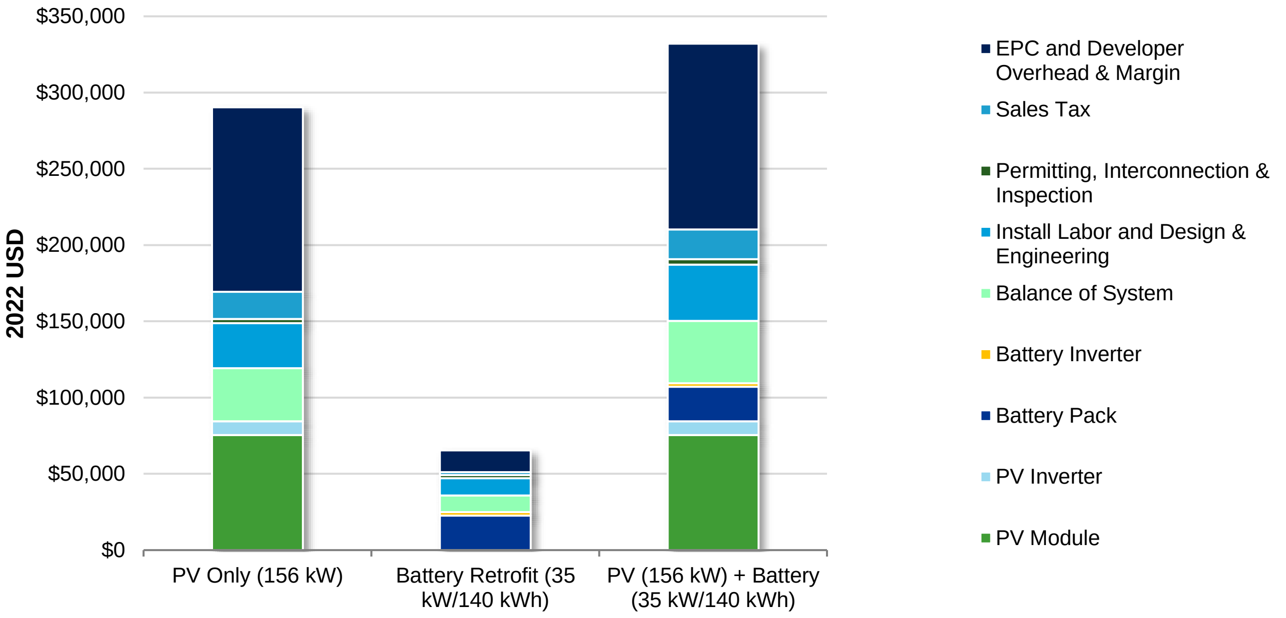


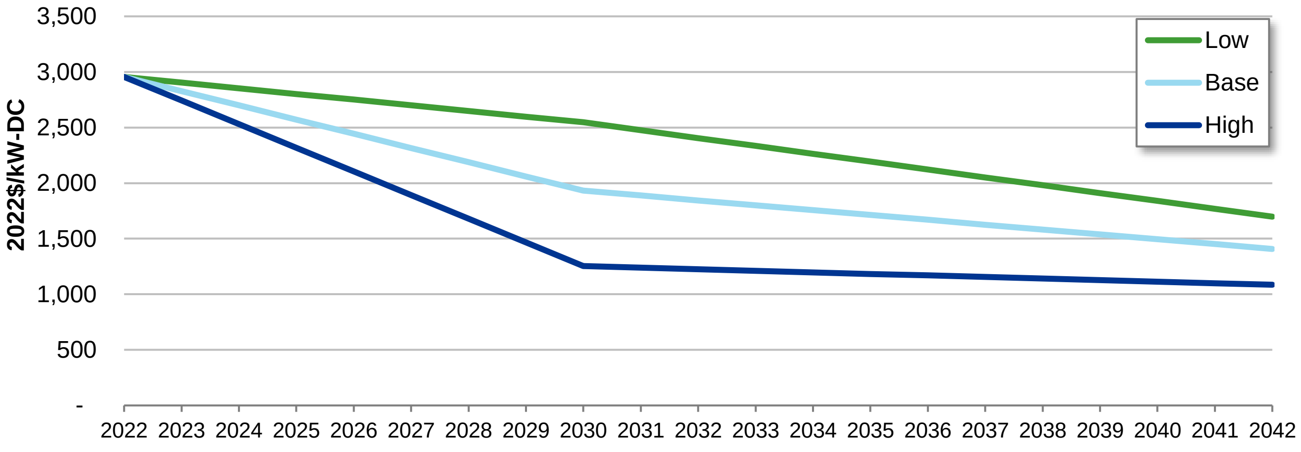
Figure 3-3 Cost of Commercial PV Standalone, Battery Storage Retrofit to Existing PV, and PV + Battery Systems from DNV Bottom-up Cap-Ex Model, Utah



DNV has estimated all CapEx categories for the projects based on Wood Mackenzie's US 2022 H1 cost model, which has been found to be reasonable relative to actual CapEx that DNV has observed on projects it's reviewed in the past. DNV estimated the benchmark CapEx values based on the project capacity, location, and technology assumptions for each state and sector. When technology assumptions were unavailable, DNV made reasonable assumptions. Combined PV + Battery systems were assumed to have cost efficiencies in certain categories that would reduce the total cost of the system when installed at the same time. Cap-Ex categories assumed to have cost efficiencies for combined systems include electrical and structural balance of system, installation labor, design & engineering, permitting, interconnection & inspection costs, customer acquisition costs, supply chain and logistics, and overhead and profit costs.

DNV used a blended version of the NREL Annual Technology Baseline[6] moderate and conservative solar PV and battery energy storage system technology cost forecasts in the base case of this private generation forecast. The average residential and non-residential PV system cost forecasts are presented in Figure 3-4 and Figure 3-5, and the average residential and non-residential battery cost forecasts are shown in Figure 3-6 and Figure 3-7. DNV reviewed the costs presented in the NREL dataset and found that the moderate cost decline forecast for solar PV was much more aggressive than what DNV's national cost models are predicting and what has been seen in the market historically. The technology cost forecast used in the base case has a 37% price decrease in the first 10 years, as opposed to the 50% decrease forecasted in the NREL moderate case.

Figure 3-4 Average Residential Solar PV System Costs, 2023-2042



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[6] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

Figure 3-5 Average Non-Residential Solar PV System Costs, 2023-2042

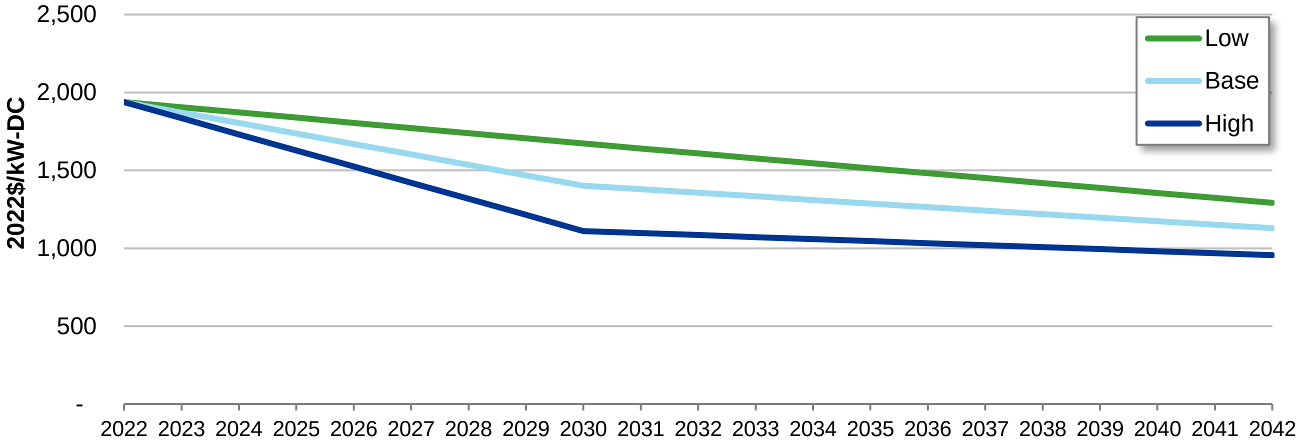


Figure 3-6 Average Residential Battery Energy Storage System (AC-Coupled) Costs, 2023-2042

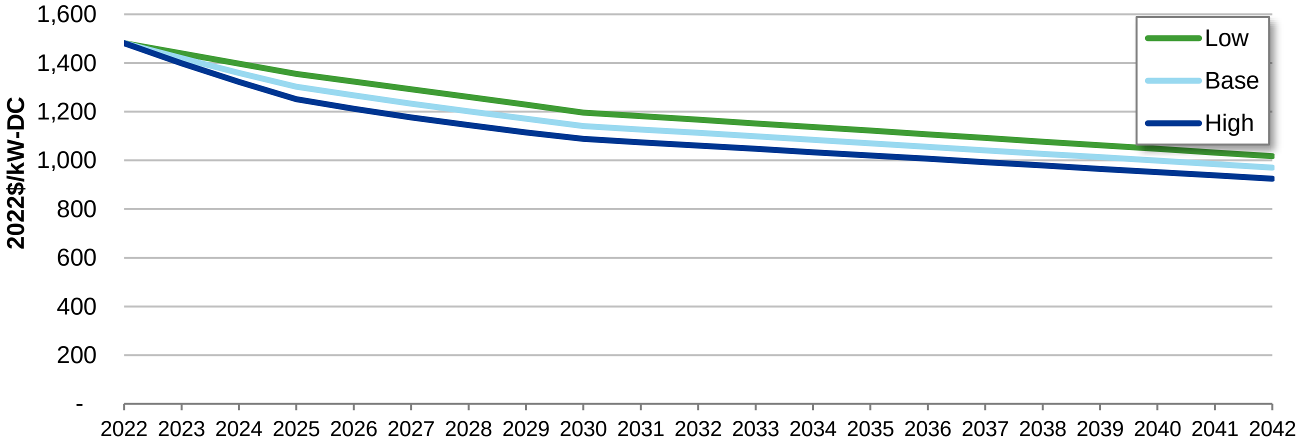
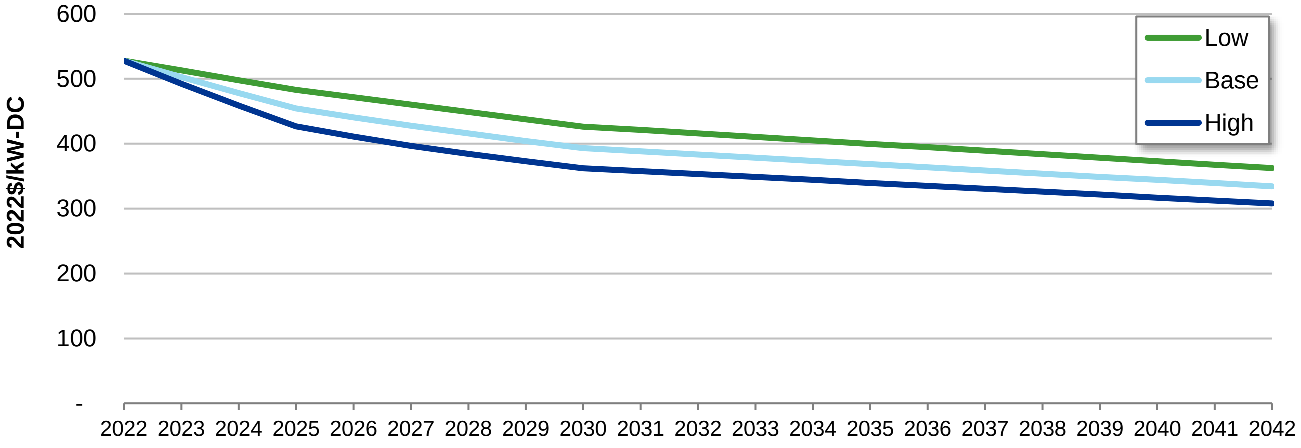


Figure 3-7 Average Non-Residential Battery Energy Storage System (AC-Coupled) Costs, 2023-2042



3.1.2 Small-Scale Wind

Distributed wind technology is a relatively mature DER. Small-scale wind systems typically serve rural homes, farms, and manufacturing facilities due to their size and land requirements. Wind turbines generate electricity by converting kinetic energy in the wind into rotating shaft power that spins an AC generator.

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Table 3-4 provides the cost and performance assumptions used in the small-scale wind forecast and the source for each.

Table 3-4 Small Wind Assumptions

Cost & Performance Metric	Units	Residential (20 kW or less)	Commercial (21-100 kW)	Midsize (101-999 kW)	Sources
Installed Cost	2022$/kW	$6,185	$4,686	$3,015	NREL, 2022. Distributed Wind Energy Futures Study. https://www.nrel.gov/docs/fy22osti/82519.pdf
Annual Installed Cost Change	%, 2022-2042	-1.9%			NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Fixed O&M	2022$/kW-yr	$38	$38	$38	NREL, 2022. Distributed Wind Energy Futures Study. https://www.nrel.gov/docs/fy22osti/82519.pdf
Annual Fixed O&M Cost Change	%, 2022-2042	-3.5%	-1.9%	-1.9%	NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Capacity Factor (dependent on state)	%	7.7-10.8%	15.1%-18.5%	15.2%-18.4%	System Advisor Model Version 2021.12.2. National Renewable Energy Laboratory. Golden, CO. https://sam.nrel.gov

3.1.3 Small-Scale Hydropower

Hydroelectric power is an established, mature technology, but small-scale systems are a newer permutation of the technology and therefore are still quite costly compared to other private generation technologies. Small hydro systems generate electricity by transforming potential energy from a water source into kinetic energy that rotates the shaft of an AC generator. Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Table 3-5 provides the cost and performance assumptions used in the small hydro forecast and the source for each.

Table 3-5 Small Hydro Assumptions

Cost & Performance Metric	Units	Micro-hydro (100 kW or less)	Mini-hydro (100 kW-1 MW)	Sources
Installed Cost	2022$/kW	$5,190	$3,892	International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower"

Annual Installed Cost Change	%, 2022-2042	-0.2%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Fixed O&M	2022$/kW-yr	$208	$156	International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower"
Annual Fixed O&M Cost Change	%, 2022-2042	-1.9%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Capacity Factor	%	45%	45%	International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower"

3.1.4 Reciprocating Engines

Combined heat and power (CHP), or cogeneration, is a mature technology that has been used in the power sector and as a private generation resource for decades. The two most common CHP technologies for commercial and small- to medium-industrial applications are reciprocating engines and microturbines, used to produce both onsite power and thermal energy.

Reciprocating engines are a mature, reliable technology that perform well at part-load operation in both baseload and load following applications. Reciprocating engines can be operated with a wide variety of fuels; however, this analysis assumes natural gas is used to generate electricity as it is the most commonly used fuel in CHP applications. A reciprocating engine uses a cylindrical combustion chamber with a close-fitting piston that travels the length of the cylinder. The piston connects to a crankshaft that converts the linear motion of the piston into rotating motion. Reciprocating engines start quickly and operate on normal natural gas delivery pressures without additional gas compression. The thermal energy output from system operation can be used to produce hot water or low-pressure steam, or chilled water with the additional of an absorption chiller. Typical CHP applications for reciprocating engine systems in the Pacific Northwest include universities, hospitals, wastewater treatment facilities, agricultural applications, commercial buildings, and small- to medium-sized industrial facilities.[7]

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Two representative reciprocating engine sizes were used in this analysis based on the ability to meet average customer minimum electric load, ranging from less than 100 kW to 1 MW. Table 3-6 provides the cost and performance assumptions used in the reciprocating engine forecast and the source for each.

Table 3-6 Reciprocating Engine Assumptions

Cost & Performance Metric	Units	Small (100 kW or less)	Medium (100 kW-1 MW)	Sources
Installed Cost	2022$/kW	$4,189	$3,183	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Installed Cost Change	%, 2022-2042	-0.5%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/

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[7] U.S. Department of Energy Combined Heat and Power and Microgrid Installation Databases (2022). Available at: https://doe.icfwebservices.com/chp

Variable O&M	2022$/MWh	$28	$25	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Variable O&M Cost Change	%, 2022-2042	-1.9%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Electric Heat Rate (HHV)	Btu/kWh	11,765	9,721	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.

3.1.5 Microturbines

Microturbines are another CHP application that are commonly used in smaller commercial and inustrial applications. They are smaller combustion turbines that can be stacked in parallel to serve larger loads and provide flexibility in deployment and interconnection at customer sites. Microturbines can use gaseous or liquid fuels, but for CHP applications natural gas is the most common fuel. Therefore for this analysis DNV assumed microturbines will use natural gas to generate electricity and thermal energy at customer sites. Microturbines operate on the Brayton thermodynamic cycle where atmospheric air is compressed, heated by burning fuel and then used to drive a turbine that in turn drives an AC generator. A microturbine can have exhaust temperatures in the range of 500 to 600ºF, which can be used to produce steam, hot water, or chilled water with the additional of an absorption chiller in CHP applications. Microturbine efficiency declines significantly as load decreases, therefore the technology is best suited to operate in base load applications operating at or near full system load. Common microturbine CHP installations in the Pacific Northwestinclude small universities, commercial buildings, small manufacturing operations, hotels, and wastewater treatment facilities.[7]

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Two representative microturbine sizes were used in this analysis based on the ability to meet average customer minimum electric load, ranging from less than 100 kW to 1 MW. Table 3-7 provides the cost and performance assumptions used in the reciprocating engine forecast and the source for each.

Table 3-7 Microturbine Assumptions

Cost & Performance Metric	Units	Small (less than 100 kW)	Medium (100 kW-1 MW)	Sources
Installed Cost	2022$/kW	$3,742	$3,686	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Installed Cost Change	%, 2022-2042	-0.6%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Variable O&M	2022$/MWh	$19	$15	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Variable O&M Cost Change	%, 2022-2042	-1.9%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/

Electric Heat Rate (HHV)	Btu/kWh	13,648	11,566	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.

3.2 Customer Perspectives

Customers' attitudes towards, and general understanding of, private generation technologies, projects, and initiatives currently being promoted in the market today will vary based on a variety of factors covered in this section. DNV has combined internal expertise with an aggregation of customer-focused research from reputable sources to understand overall trends in customer sentiment and insights specifically related to private generation for residential or nonresidential buildings.. Some of the key motivators and barriers to private generation technology adoption are presented in Table 3-8.

Table 3-8 Motivators and Barriers for Private Generation Technology Adoption

TECHNOLOGY	MOTIVATORS	BARRIERS
ALL	• Cost savings • Reducing carbon footprint	• Educational awareness • Proactive involvement from customer • Minimal understanding of technology applications
SOLAR PV	• Cost savings • Reducing carbon footprint • Attractive financing options	• Initial investment • Infrastructure requirements i.e., physical space and roof quality • Perception as a technology for the affluent
BATTERY STORAGE	• Cost savings • Resilience/backup power • likelihood to experience to severe weather • Reduce peak consumption	• Low levels of awareness and understanding • Short duration capability for backup • Limited monetization opportunities • Physical space and roof quality • Initial investment • Limited use cases for storage-only
SOLAR + BATTERY	• Resilience/backup power • ITC applicability window • Maximize solar generation • Cost savings • Reducing carbon footprint	• Initial investment • Infrastructure requirements of solar

Customer adoption of solar, storage, and other PG-related solutions is primarily influenced by financial viability of the overall project and the associated return on investment or payback period. However, while the financial parameters and payment options for a project are certainly an important feature, customers will also face different barriers or motivators that will either encourage or discourage them from adoption despite the financial benefits.

For these reasons, research organizations have typically viewed adoption of new and innovative technologies by customer segments ranging from early adopters and enthusiasts to the majority and the laggards. Some customers may even be considered opposed to the innovation and will never adopt the technology. On the other hand, there also exists a consumer group that will move forward with adoption of DER offerings even when the financial numbers don't show the most desirable ROI or payback. This consumer group is more easilyinfluenced by sales and marketing strategies even when the numbers don't "add up" to a clear economic play. The following sections will provide further insights on how customer awareness, knowledge of energy costs and systems, and incentives can impact customer adoption of PG technologies.

3.2.1 Customer Awareness

While DERs, the term most commonly used to describe PG technologies is a common term within the energy industry, it is not commonly understood by the average consumer. Less than 10% of residential customers are clear on exactly what the term means and how it applies to them. Consumers are lacking a sound understanding of how DERs work, the tangible benefits they provide, and how they would operate within a home or business.

Customer education to build awareness is likely to lead to more growth of PG. Educational outreach and marketing should focus on accessible, feasible use-cases for technology applications in “real-world” settings that customers can relate to and see themselves using. Customers have a desire to improve their understanding of PG opportunities by obtaining quality information – most prefer their electricity provider as the source – about the savings potential of these technologies and details on how they work. [8]

3.2.2 Motivating Factors for Adoption

The primary motivators that prompt customers to consider implementing PG technologies are how much savings they can realize through a project and the level of incentives being awarded. Second to these financial motivators, customers are interested in PG opportunities as a method of reducing their environmental impact. Customers who are aware of PG opportunities often have a curiosity and desire to increase their understanding of the opportunities available to them as committing to a PG system or product requires the customer to have a greater level of involvement in their electricity generation, consumption, and management. While understanding and awareness of PG is a clear barrier to adoption, customers have the desire to obtain information to help them better understand these technologies. Energy providers can prioritize informative, engaging communication to increase the customers’ understanding of DER opportunities, thus increasing their likelihood of adoption and participation.[7]

3.2.3 Barriers to Adoption

Trust and finances are common barriers to PG adoption– customers are often skeptical that these projects will perform as advertised and save the amount of money that is claimed. Customers need quality information to help them validate the investment in certain new technologies or programs that they do not have experience with. If the customer’s goal for a PG system is to save money and they express the need to understand how much money the projects will save, accurate information needs to be available to prove those cases to the customer. Successful implementation of PG technologies and solutions will require changing the behavior and perception of a large portion of the customers.[7]

3.2.4 Other Considerations

Customers who participate in demand response programs are more likely to own a hybrid or electric vehicle, energy management system (EMS), or solar + storage system than customers who do not participate in demand response programs. A foundational piece for growing participation in DER initiatives can be first focusing on demand response programs as a way for customers to get started on their clean energy journeys. This concept of “DER stacking” enables a utility to prioritize targeting customers who are already participating in some form of demand response or PG-related program, thus giving the customer a more holistic solution for their energy management and consumption.[7]

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[8] SECC (Smart Energy Consumer Collaborative). 2019. Distributed Energy Resources: MEETING CONSUMER NEEDS. Pages 7 – 13.

3.2.5 Incentives Overview

Since the passing of the Inflation Recovery Act of 2022, the federal Investment Tax Credit (ITC) has been extended past its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC would be set at 26 percent. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers. The bill also includes a 5-year MACRS depreciation schedule for non-residential energy storage. The federal tax credits in Table 3-9 were included in the economic analysis of all private generation forecast scenarios.

Table 3-9 Federal Investment Tax Credits for DERs

Cells in green represent the transition to a technology-neutral ITC for clean energy technologies with 0 gCO2e emissions per kWh, under section 48D.

INCENTIVE	SYSTEM SIZE (KW)	TECHNOLOGY	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Residential/ Business ITC	< 1000	PV	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Residential/ Business ITC	< 1000	Energy Storage	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	26%	0%
Residential/ Business ITC	< 1000	Small Wind	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 1000	Microturbines	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 1000	Reciprocating Engines	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 150	Small Hydro (hydropowered dams)	30%	30%	30%											
Business ITC	< 25	Small Hydro (Hydrokinetic pressurized conduits)	30%	30%	30%											
Business ITC	< 1000	Small Hydro				30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%

A summary of the state incentives included in the economic analysis are provided below in Table 3-10.

Table 3-10 State Incentives for DERs

STATE	RESIDENTIAL		NON-RESIDENTIAL
Oregon[9]	**PV-Only:** Up to $5,000	**PV + Battery:** Up to $2,500	$0.20/watt up to $20,000
Utah[10]	**PV:** 2022—$800 2023—$400	**Non-PV:** Up to $2,000	Up to 10 percent of the eligible system cost or up to $50,000*
Idaho[11]	Annual maximum of $5,000, and $20,000 over four years**		None
California	None		None
Washington	None		None
Wyoming	None		None

* Solar PV, wind, geothermal, hydro, biomass or certain renewable thermal technologies
** Mechanism or series of mechanisms using solar radiation, wind or geothermal resource

3.3 Current Private Generation Market

To date, about 99 percent of existing private generation capacity installed in PacifiCorp's service territory is PV or PV + Battery[12]. To inform the adoption forecast process, DNV conducted an in-depth review of the other technologies and did not find any literature to suggest that they would take on a larger share of the private generation market in the Company's service territory in the future years of this study. Figure 3-8 shows the current share of private generation capacity by technology in each of PacifiCorp's six-state service territory.

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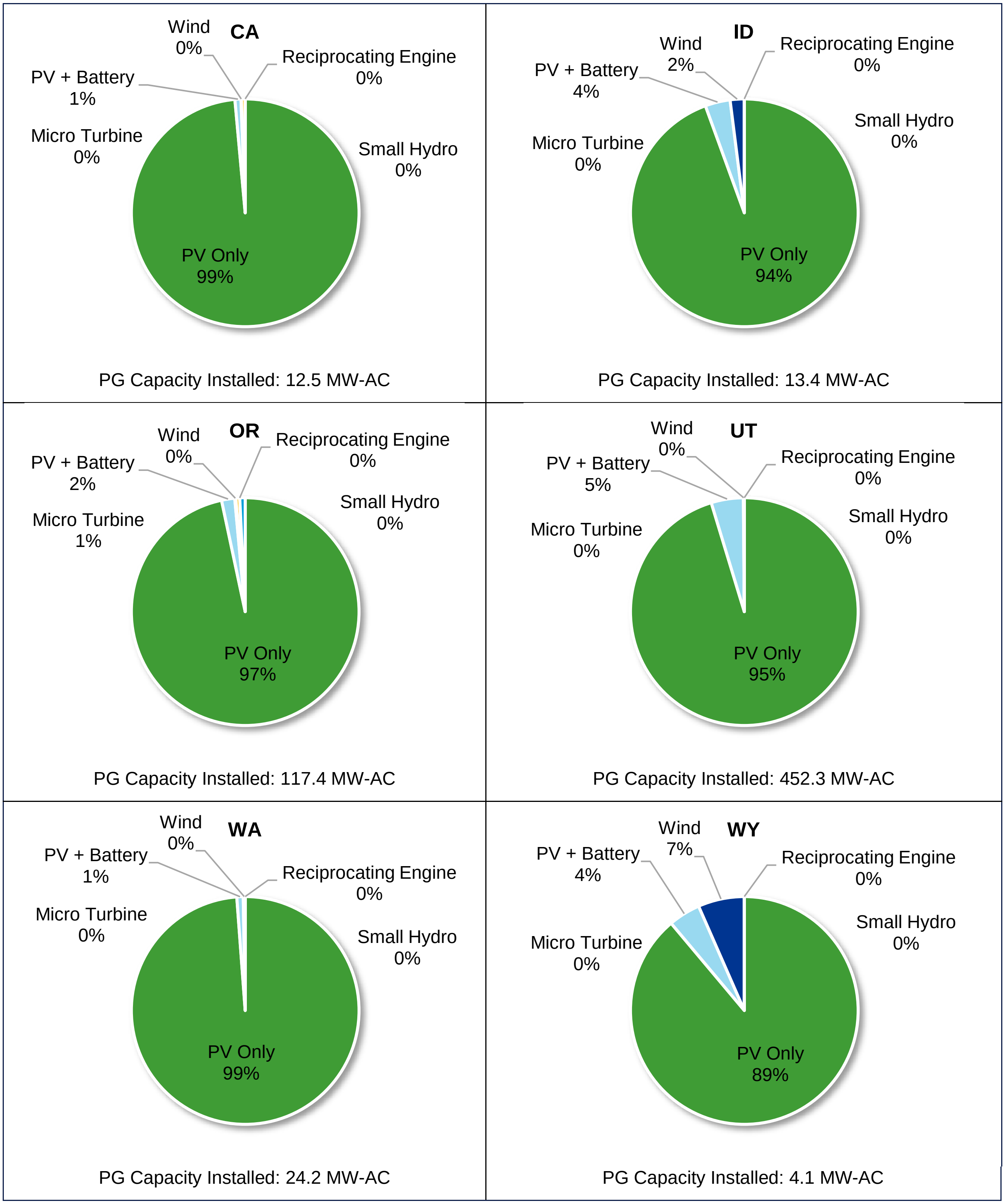
[9] Incentives provided through Energy Trust of Oregon (Solar for Your Home, Solar Within Reach and Solar for Your Business) and Oregon Department of Energy (Solar + Storage Rebate Program for Low-Moderate Income and Non-Income Restricted Homeowners). https://energytrust.org/programs/solar/ https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx

[10] Incentives provided through Utah Office of Energy Development Renewable Energy Systems Tax Credit. https://energy.utah.gov/tax-credits/renewable-energy-systems-tax-credit/

[11] Incentives provided through the State of Idaho Renewable Alternative Tax Deduction. https://legislature.idaho.gov/statutesrules/idstat/title63/t63ch30/sect63-3022c/

[12] PacifiCorp private generation interconnection data as of February 2022.

Figure 3-8 Historic Cumulative Installed Private Generation Capacity by Technology, YTD



PG Capacity Installed: 12.5 MW-AC

PG Capacity Installed: 13.4 MW-AC

PG Capacity Installed: 117.4 MW-AC

PG Capacity Installed: 452.3 MW-AC

PG Capacity Installed: 24.2 MW-AC

PG Capacity Installed: 4.1 MW-AC

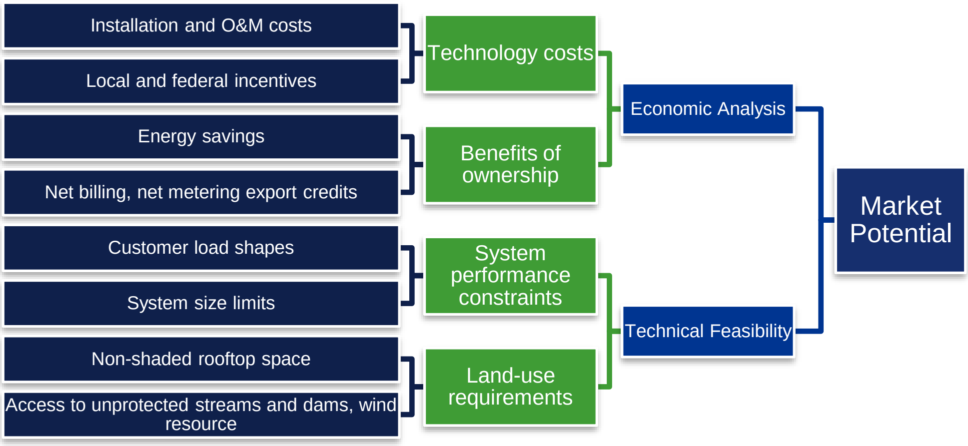
Section 3.4.3 describes in further detail how the historic private generation adoption data is used in the private generation forecast modelling process.

3.4 Forecast Methodology

DNV combined technical feasibility characteristics of the identified PG technologies and potential customers with an economic analysis to calculate cost-effectiveness metrics for each technology, within each state that PacifiCorp serves, over the analysis timeframe. DNV then used a bass diffusion model to estimate customer PG adoption based on technical and economic feasibility and incorporated existing adoption of each PG technology by state and customer segment as an input to the adoption model.

Technical feasibility characteristics were used to identify the potential customer base that could technically support the installation of a specific PG technology, or the maximum, feasible, adoption for each technology by sector. These factors included overall PG metrics such as average customer load shapes and system size limits by state, and specific technology factors such as estimated rooftop space and resource access based on location (for hydro and wind resource applicability). Simple payback was used in the customer adoption portion of the model as an input parameter to bass diffusion curves that determined future penetration of all PG technologies. Figure 3-9 provides a visual representation of how different inputs were used in different portions of the model. Additional detail on the economic and adoption approaches used in this analysis are provided in the subsequent sections.

Figure 3-9 Methodology to Determine Market Potential of Private Generation Adoption



3.4.1 Economic Analysis

The economic analysis portion of overall customer adoption was used a key factor in the Bass diffusion model that calculated future PG adoption. DNV used simple payback as the preferred method of estimating economic viability for PG based on customer perspectives given its widespread use in similar adoption analyses, ability to reflect customer decision making in forecasting efforts, and ease of estimation.

DNV developed a behind-the-meter net economic perspective that includes, as costs, the acquisition and installation costs for each technology less the impact of available incentives and, as benefits, the customer's economic benefits of ownership such as energy and demand savings and export credits. For this study we assumed that the current net metering or net billing policies and tariff structures in each state continued throughout the study horizon. This resulted in the model incorporating benefits associated with net metering in Oregon, Washington, and Wyoming and net billing in Utah and California. We assumed customer's in Idaho would accrue benefits based on the net billing policy in Utah throughout the study. DNV has been following the ongoing Idaho Public Utilities Commission (PUC) review of Idaho Power Company's (Idaho Power) Value of Distributed Resources (VODER) study filing. Idaho Power's VODER study found that excess power generated by rooftop solar owners is worth less than half of retail rate energy and serves as the basis of Idaho Power's proposal for a new compensation rate structure for solar owners. If approved by the Idaho PUC, Idaho Power's proposed compensation rate structure would more closely resemble the current net billing structure in place in Utah[13] and DNV assumed PacifiCorp would implement a similar rate structure in their Idaho territory.

A detailed breakdown of the simple payback calculation and different elements is shown below.

$$\boldsymbol{Simple\ Payback} = \frac{Cumulative\ Net\ Costs}{Cumulative\ Net\ Benefits}$$

$$\boldsymbol{Cumulative\ Net\ Costs} = (Upfront\ System\ Cost - Year\ One\ Incentives) + NPV(Annual\ O\&M\ Costs + Annual\ Fuel\ Costs)$$

$$\boldsymbol{Cumulative\ Net\ Benefits} = NPV(MACRS\ Savings + \ Self\ \ Consumption\ Savings + Export\ Credits + Peak\ Demand\ Savings)$$

DNV also used an annual hourly profile analysis to estimate electric bill savings and excess generation for each PG technology by customer segment. This analysis used hourly generation and customer load profiles, and tiered, time-of-use (TOU), and peak demand rates for each customer and technology permutation. DNV integrated the energy savings, excess generation, and peak demand benefits into the lifetime simple payback estimation using customer load and individual rate forecasts provided by PacifiCorp. A full breakdown of all inputs used in the economic analysis is provided in Table 3-11 below.

Table 3-11 PG Forecast Economic Analysis Inputs

INPUT TYPE	COST / BENEFIT CATEGORY	SOURCE
TECHNOLOGY COST DATA – INSTALLED COST	PG cost data compiled in \$/kW (AC & DC) – used in determining year one installed system costs	DNV
TECHNOLOGY COST DATA – ANNUAL O&M	PG fixed (\$/kW) & variable (\$/kWh) O&M data – used in determining annual system costs	DNV
FUEL COST DATA	Natural gas cost data (\$/MMBtu)	EIA Annual Energy Outlook 2022
TECHNOLOGY GENERATION PROFILES	Hourly generation profiles for each PG technology by state – used in calculating self-consumption savings, excess generation credits, and peak demand savings	DNV
CUSTOMER LOAD PROFILES	Hourly average customer load profiles by state – used in calculating self-consumption savings, excess generation credits, and peak demand savings	PacifiCorp

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[13] As of December 19, 2022, the Idaho Power VODER study has been approved by the Idaho PUC. https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2222/OrdNotc/20221219Final_Order_No_35631.pdf

INPUT TYPE	COST / BENEFIT CATEGORY	SOURCE
CUSTOMER RATES	Customer tiered, TOU, and peak demand rates by size, segment, and state – used in calculating self-consumption savings, excess generation credits, and peak demand savings	PacifiCorp
TECHNOLOGY COST FORECASTS	PG cost data forecasts for installed system costs and annual O&M costs – used in determining year one installed system costs and future year annual system costs	NREL ATB
CUSTOMER & LOAD FORECASTS	Individual customer count and load (kWh) forecasts by segment and state – used in calculating future year system costs and benefits	PacifiCorp
CUSTOMER RATE FORECASTS	Rate forecasts applied to each customer segment – used in calculating future year self-consumption savings, excess generation credits, and peak demand savings	EIA Annual Energy Outlook 2022

DNV calculated simple payback for each PG technology (solar PV, solar PV + battery, wind, hydro, reciprocating engines, and microturbines) by applicable individual customer segments (residential, commercial, industrial, and irrigation) for each installation year in the analysis timeframe (2023 – 2035). These payback results were combined with technical feasibility by customer segment and integrated into the bass diffusion adoption model to determine annual PG penetration throughout PacifiCorp's territory.

3.4.2 Technical Feasibility

The maximum amount of technical feasible capacity of private generation was determined individually for each technology considered in the private generation forecast. Each technology was generally limited by customer access factors, system size limits, and energy consumption. The customer load shapes, provided by PacifiCorp, were used to calculate annual energy use (kWh) cutoffs used in identifying the total number of customers that could technically support the installation of a specific PG technology. Other data sources specific to each technology were used to determine the amount of capacity that can be physically installed within PacifiCorp's service territory, such as:

- Hydropower potential data and environmental attributes for all HUC10 watersheds in PacifiCorp's service territory[14]
- Building rooftop hosting area and suitability for solar PV[15]
- Wind resource potential data by state[16]

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[14] Kao, Shih-Chieh, Mcmanamay, Ryan A., Stewart, Kevin M., Samu, Nicole M., Hadjerioua, Boualem, Deneale, Scott T., Yeasmin, Dilruba, Pasha, M. Fayzul K., Oubeidillah, Abdoul A., and Smith, Brennan T. New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. United States: N. p., 2014. Web. doi:10.2172/1130425.

[15] Gagnon, P., R. Margolis, J. Melius, C. Phillips, and R. Elmore. 2016. Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. NREL/TP-6A20-65298. Golden, CO: National Renewable Energy Laboratory.

[16] Draxl, C., B.M. Hodge, A. Clifton, and J. McCaa. 2015. "The Wind Integration National Dataset (WIND) Toolkit." Applied Energy 151: 355366.

3.4.3 Market Adoption

DNV modeled market adoption using Bass diffusion curves customized to each state, technology, and sector. The Bass diffusion model was developed in the 1960s and is widely used to model market adoption over time.

The formula for new adoption of a technology in year t is given by[17]

$$s(t) = m\frac{(p+q)^2}{p}\frac{e^{-t(p+q)}}{(1+\frac{q}{p}e^{-t(p+q)})^2}$$

Where:

s(t) is new adopters at time *t*

m is the ultimate market potential

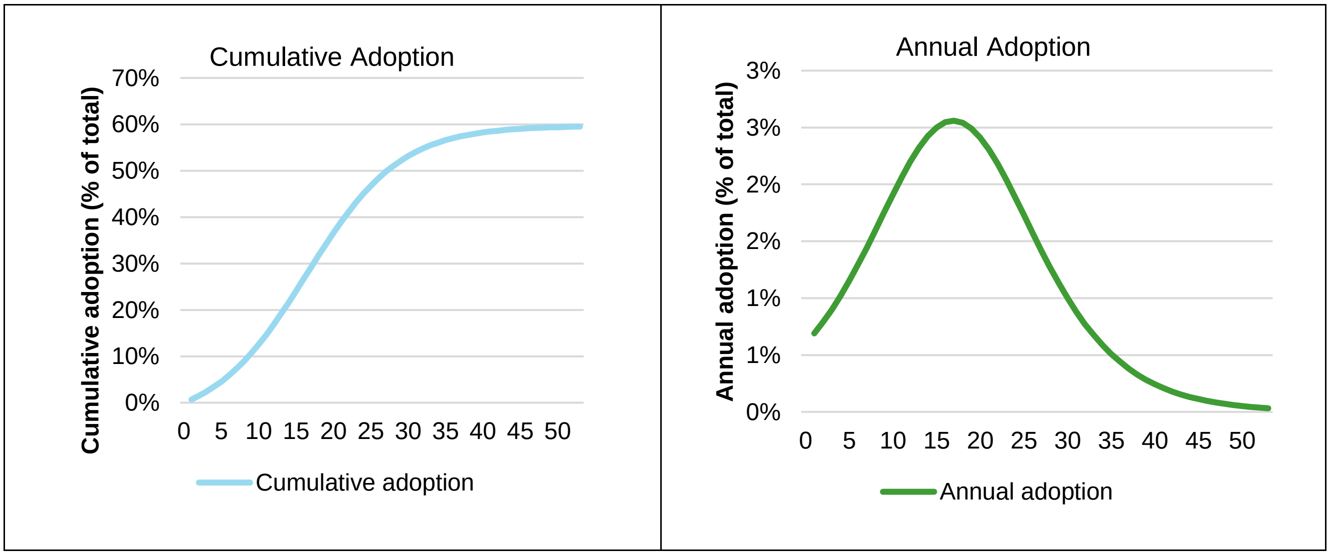
p is the coefficient of innovation

q is the coefficient of imitation

t is time in years

Figure 3-10 shows a generalized Bass diffusion curve. The cumulative adoption curve takes a characteristic “S” shape with a new unknown and unproven technology having relatively slow adoption that accelerates over time as the technology becomes more familiar to a wider segment of the population. As the pool of potential buyers who have not yet adopted the technology shrinks, the rate of adoption (as a percent of the total pool of potential adopters) decreases until eventually everyone who will adopt has adopted. The corresponding chart shows the rate of annual new adoption.

Figure 3-10 Bass Diffusion Curve Illustration



In the illustration, the cumulative curve approaches 60% market penetration asymptotically, corresponding to the value of *m* (ultimate market potential) that we chose for the illustration. For our adoption models, we tied the value of *m* to payback,

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[17] Bass, Frank (1969). "A new product growth for model consumer durables". Management Science. 15 (5): 215–227

following Sigrin and Drury's[18] survey findings on willingness to pay for rooftop photovoltaics based on payback. Because payback varied by technology, state, and sector, so did the Bass diffusion curve.

Due to regional and sectoral differences, we made significant adjustments to the willingness-to-adopt curves to better align with the observed relationship between historic cost effectiveness and current market adoption by technology, state, and sector in PacifiCorp's service territory. Based on PacifiCorp data on current levels of PG adoption, Utah in particular showed higher adoption than published willingness-to-pay curves would suggest, which we believe may be due to regional variation in how customers value resilience. To account for this variation across states, we developed three willingness-to-adopt curves to capture observed state variation. Table 3-12 shows which willingness-to-adopt curve was used for solar for each state and sector. Current adoption for the other modeled technologies was too low to discern variation across state, so we assumed average propensity to adopt for wind, small hydro, reciprocating engines and microturbines.

Table 3-12 Solar Willingness-to-Adopt Curve used by State and Sector

AVERAGE PROPENSITY TO ADOPT	HIGH PROPENSITY TO ADOPT	LOW PROPENSITY TO ADOPT
• California residential, commercial, irrigation • Idaho residential • Oregon residential • Washington all sectors	• Utah all sectors • Oregon commercial, industrial, irrigation	• Wyoming all sectors • Idaho commercial, industrial, irrigation • California industrial

Figure 3-11 shows the willingness-to-adopt curves for residential, commercial, and industrial sectors assuming an average propensity to adopt (the "Mid" case). There was too little irrigation adoption to assess the sector independently, so we used the commercial curves for the irrigation sector. The right-hand chart in Figure 3-11 shows the high, mid, and low adoption curves for the residential sector only. The high and low curves for the other sectors show similar variation.

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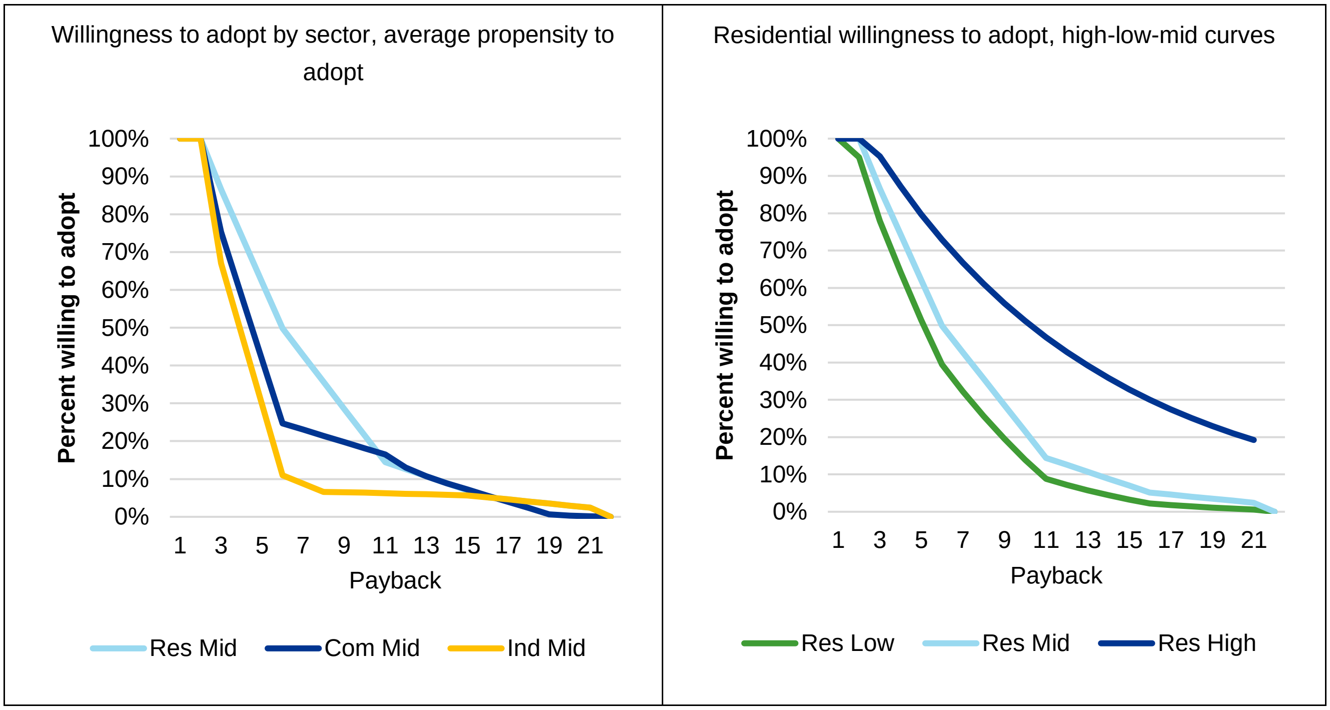
[18] Sigrin, Ben and Easan Drury. 2014. Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics. Energy Market Prediction: Papers from the 2014 AAAI Fall Symposium

Figure 3-11 Willingness to Adopt Based on Technology Payback



The willingness-to-adopt curves established a different *m* parameter for each diffusion curve. In addition to varying by technology, state, and sector, *m* also changed over time due to changing payback resulting from changing technology costs, incentives, and tax credits, among other economic factors).

The timing of our modeled adoption also varied, as we set t_0 for each diffusion curve based on the earliest adoption of each technology by state and sector. For example, the first residential PV installed in PacifiCorp's Oregon service territory was in 2000, while the first commercial PV installation in its Idaho service territory wasn't until 2010. For technology/state/sectors where there is currently no adoption, we assumed that the first adoption would occur in 2023.

The *p* and *q* parameters of the Bass diffusion curves were calibrated so that the predicted cumulative adoption from t_0 through 2021 was equal to the current market penetration of each technology by state and sector (we fixed the relationship between *p* and *q* at $q = 10p$ to make it possible to solve for p). For technology/state/sectors where there is currently no adoption, we assumed average values for *p* and *q*.

The result of this process were Bass diffusion curves customized for each technology, state, and sector that also accounted for variation in willingness-to-adopt as cost effectiveness changes over time. The calibrated curves show some segments still in the very early phases of adoption, while other markets are more mature. Our forecast of annual adoption reflects all of these differences.

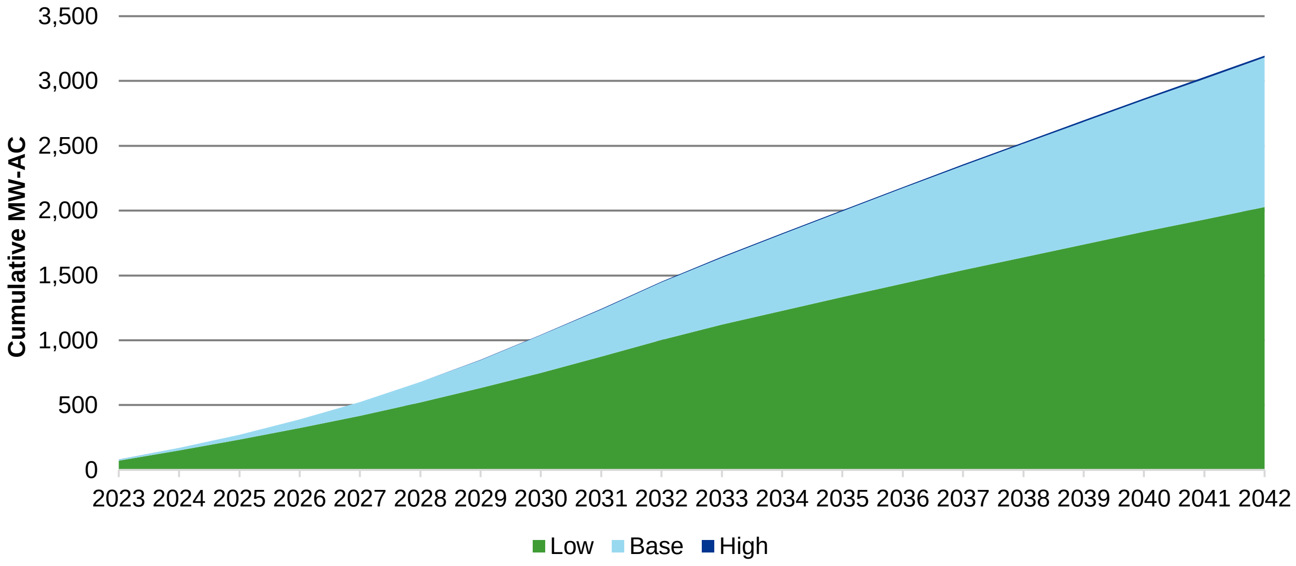
4 RESULTS

In the base case scenario, DNV estimates 3,181 MW of new private generation capacity will be installed in PacifiCorp's service territory over the nest twenty years (2023-2042). Figure 4-1 shows the relationship between the base case and low and high case scenarios. The low case scenario estimates 2,028 MW of new capacity over the 20-year forecast period—compared to base case, retail rates increase at a slower rate and technology costs decrease at a slower rate. In the high case, retail rates increase at a faster rate and technology costs decrease at a faster rate—this results in 3,196 MW of new private generation capacity installed by 2042.

Table 4-1 Cumulative Adopted Private Generation Capacity by 2042, by Scenario

SCENARIO	CUMULATIVE CAPACITY (2042 MW-AC)
Base	3,181
Low	2,028
High	3,196

Figure 4-1 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), 2023-2042



The sensitivity analysis showed a much greater margin of uncertainty on the low side than the high side. The Inflation Reduction Act of 2022 (IRA) extends tax credits that for private generation that create very favorable economics for adoption, and those are embedded in the base case. We therefore limited our upper bound forecast to lower technology costs and higher retail electricity rates, and these produced only a small boost to adoption for technologies that were already cost effective under the IRA. In contrast, when we modelled our lower bound, we found that the decreases in cost effectiveness were enough to tamp down adoption. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. The low case forecast is 36% less than the base case, while the high case cumulative installed capacity forecasted over the 20-year period is just 0.5% greater than the base case.

Figure 4-2 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Base Case

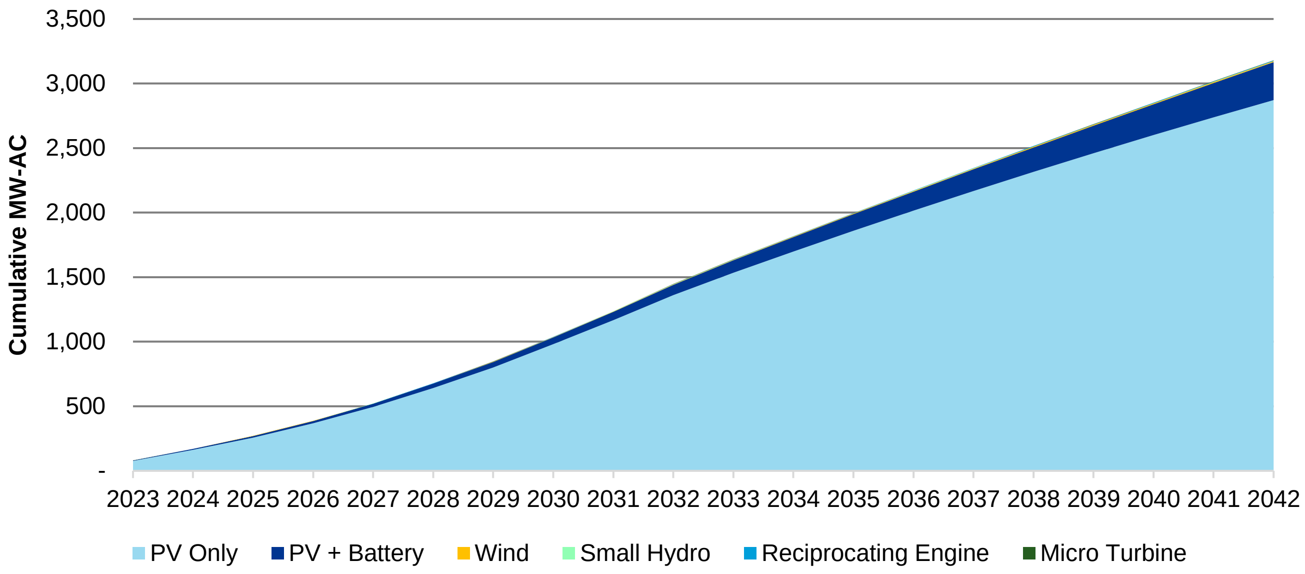


Figure 4-3 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Low Case

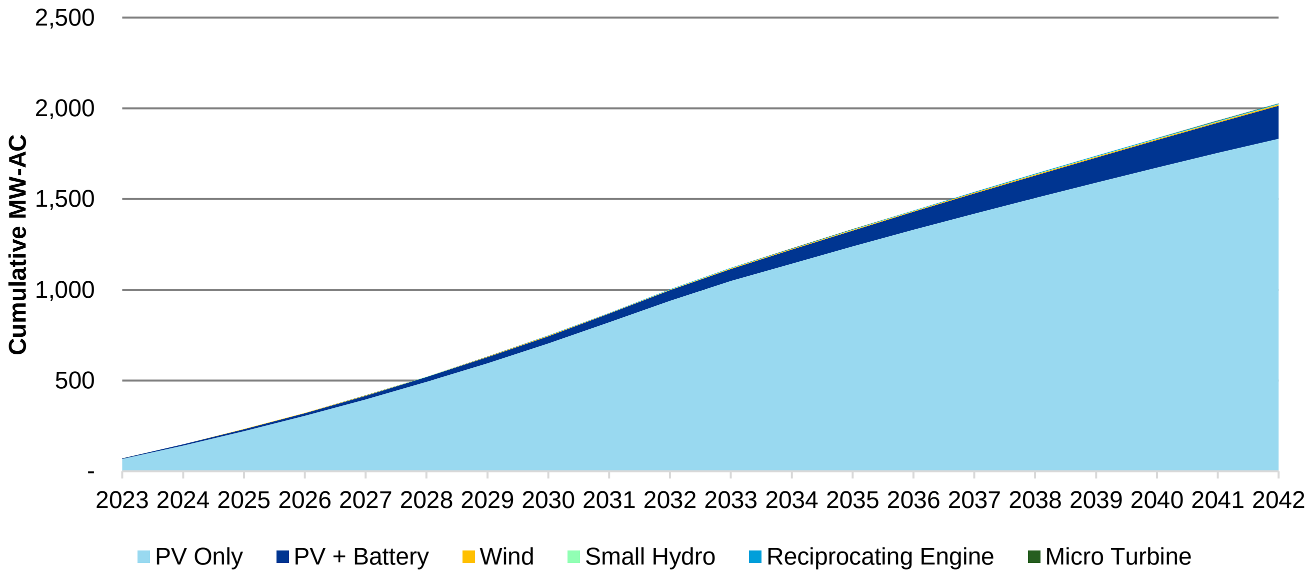
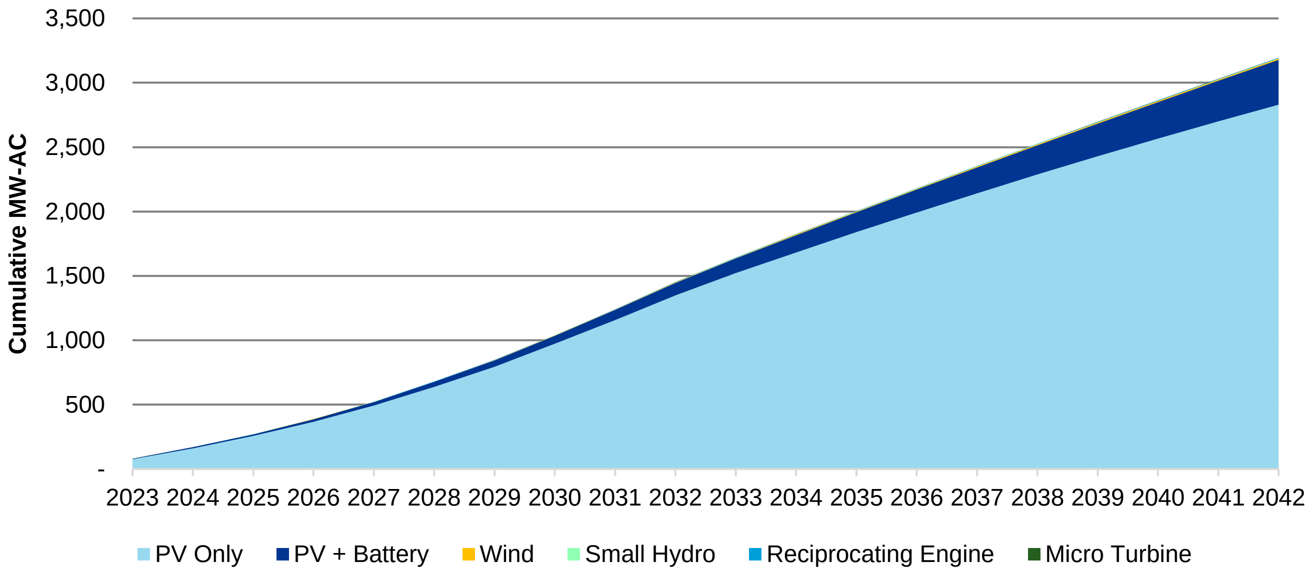


Figure 4-4 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, High Case



4.1 Generation Capacity Results by State

The following sections present the results by state for each forecast scenario. Additional exhibits for total PV capacity forecasted are provided by sector. PV Only and PV + Battery capacity make up at least 95% of each states' projected private generation capacity, so providing results for the other technologies by sector would not provide useful context to the results. The full set of results by state, sector, and new/existing construction for the forecasts is provided in Appendix B.

Figure 4-5 shows the base case forecast by state, compared to the previous (2020) study's total base case forecast[19]. This figure indicates that Utah and Oregon will drive most PG installations over the next two decades, which is to be expected given these two states represent the largest share of PacifiCorp's customers and sales. The base scenario estimates approximately 1,447 MW of new capacity will be installed over the next 10 years in PacifiCorp's territory—55% of which is in Utah, 32% in Oregon, and 6% in Idaho. Since the 2020 study, the federal Investment Tax Credit (ITC) has been extended for ten years at its original base rate levels and expanded to include energy storage. The tax credit increase and extension lowered the customer payback period for all technologies, making the customer economics of this study's base case more similar to the previous study's high case. In addition to the change in customer economics, projected PV capacity is expected to grow at a faster rate in the early years and at a slower rate towards the end of the forecast period. The key drivers of these differences include larger average PV system sizes, decreases in PV + Battery costs, and the maturity of rooftop PV technology. The adoption model DNV developed for this study was calibrated to existing levels of technology adoption for each state and sector. Technology adoption follow an S-curve with adoption initially increasing at an increasing rate, but eventually passing an inflection point where adoption continues to increase at a decreasing rate.

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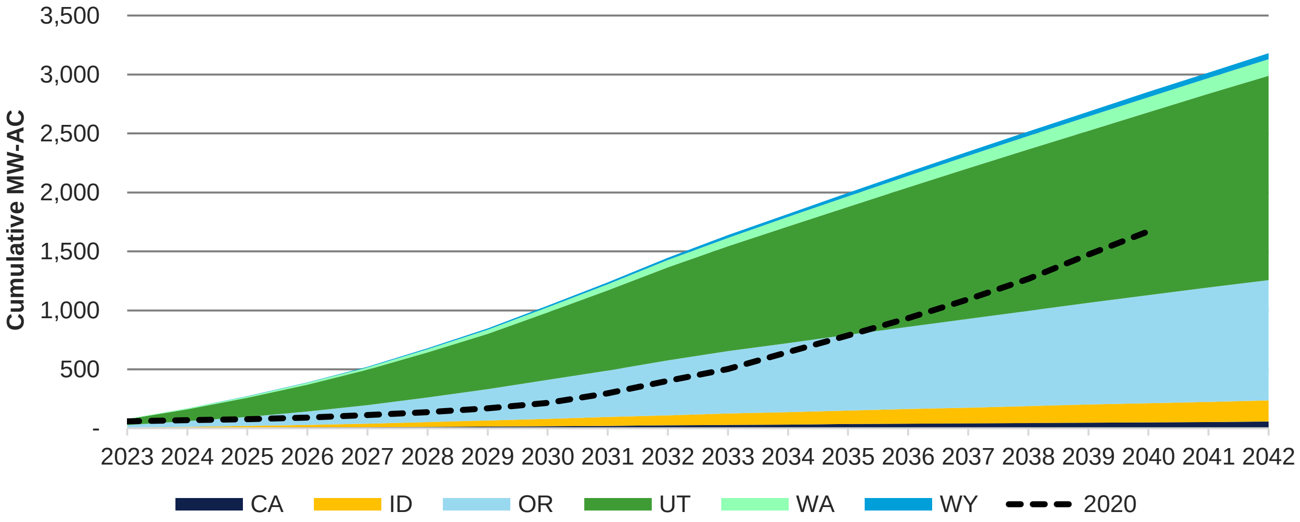
[19] Cumulative capacity is adjusted to account for the difference in the forecast starting years (2021 in the previous study, versus 2023 in this study). Source: Navigant. 2020. "Private Generation Long-Term Resource Assessment (2021-2040)"

Figure 4-5 Cumulative New Capacity Installed by State (MW-AC), 2023-2042, Base Case



4.1.1 California

Customers in PacifiCorp's service territory in northern California are projected to install about 57 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is about 1% greater than the base case and the low projection is 24% less than the base case, or 57.4 MW and 43 MW, respectively.

California does not currently have any state incentives available for private generation, and uses a net billing structure for DER compensation. The residential sector has the largest share of the private generation capacity, ranging from 59% in the low case to 67% in the high and base cases. The next largest share of the capacity is forecasted in the commercial sector, ranging from 31% in the low case to 24% in the base and high cases.

Figure 4-6 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), California, 2023-2042

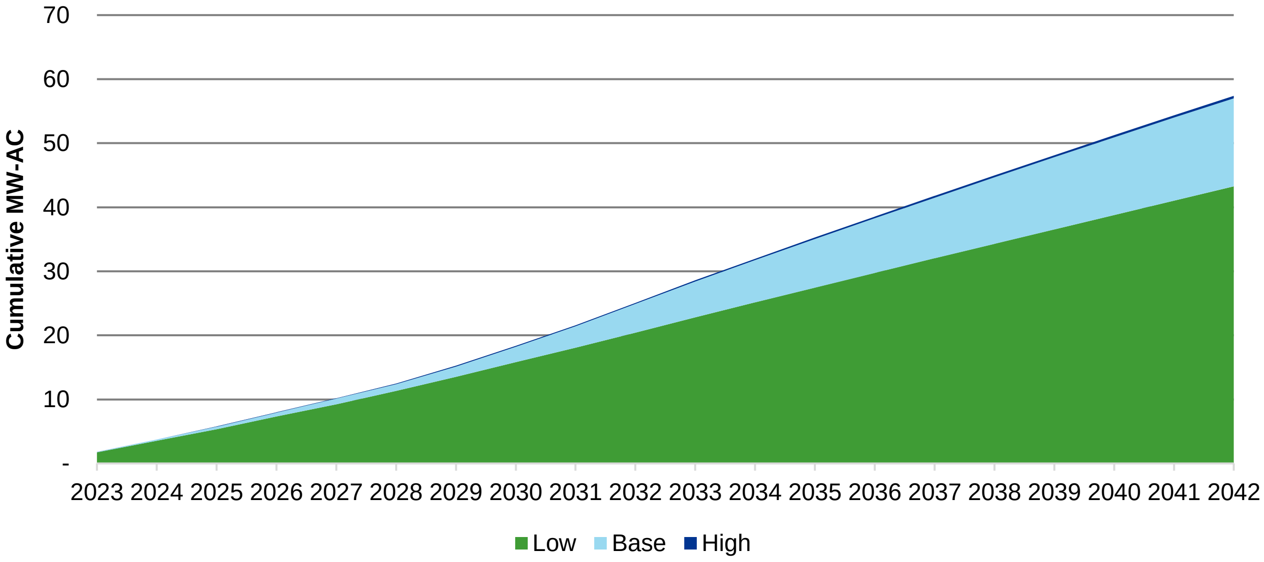


Figure 4-7 Cumulative New Capacity Installed by Technology (MW-AC), California Base Case, 2023-2042

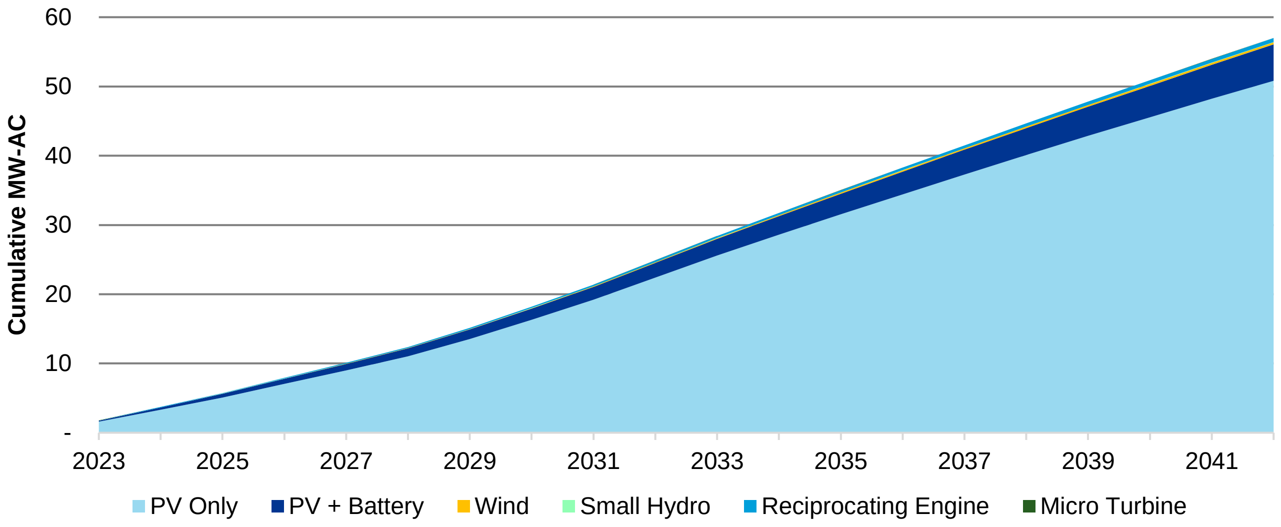


Figure 4-8 Cumulative New Capacity Installed by Technology (MW-AC), California Low Case, 2023-2042

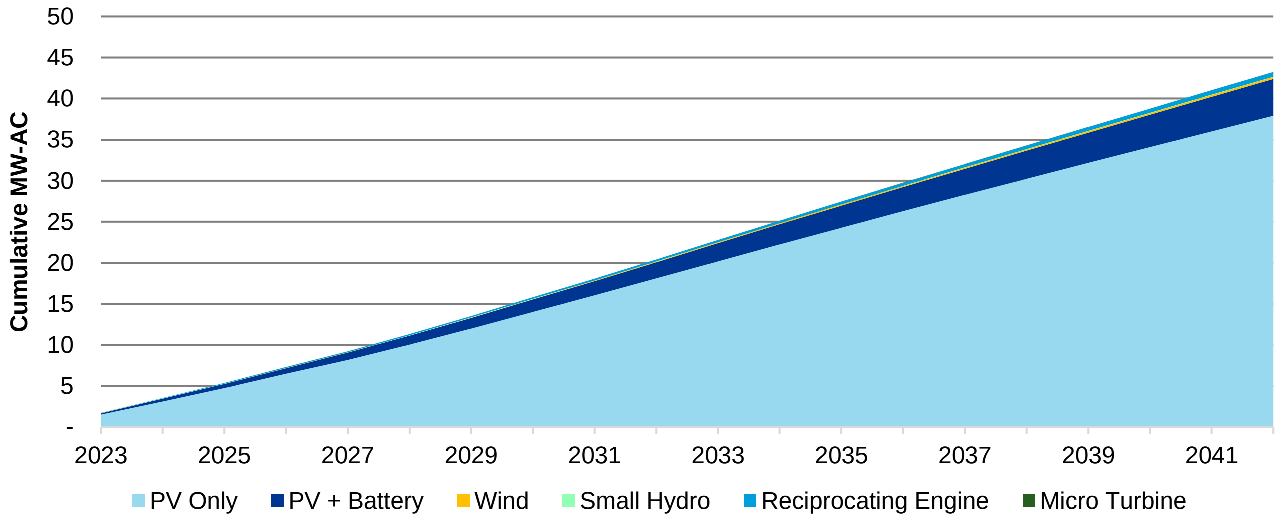
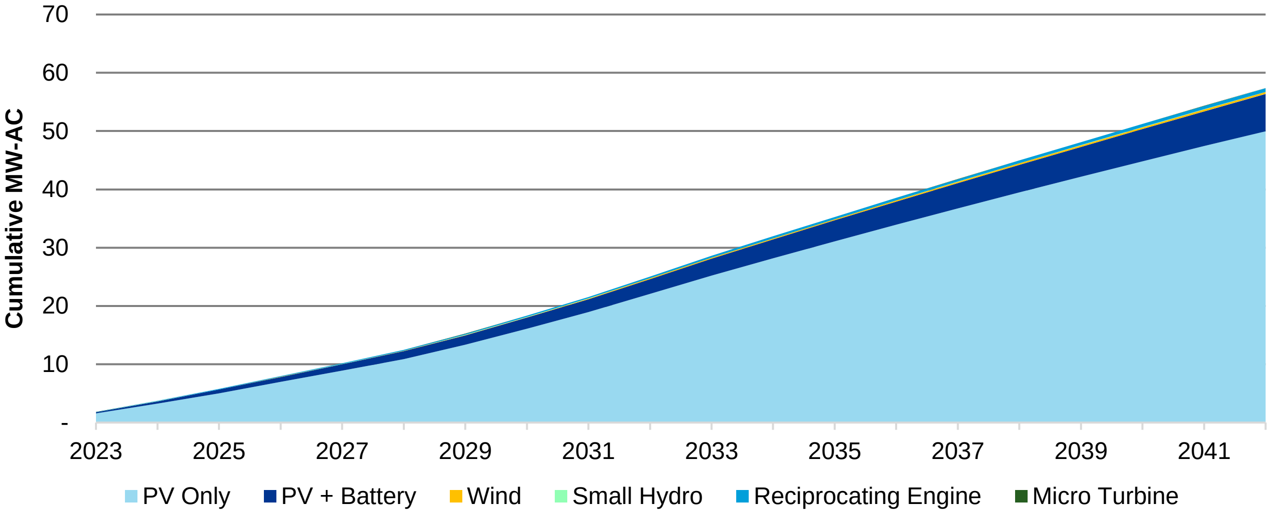


Figure 4-9 Cumulative New Capacity Installed by Technology (MW-AC), California High Case, 2023-2042

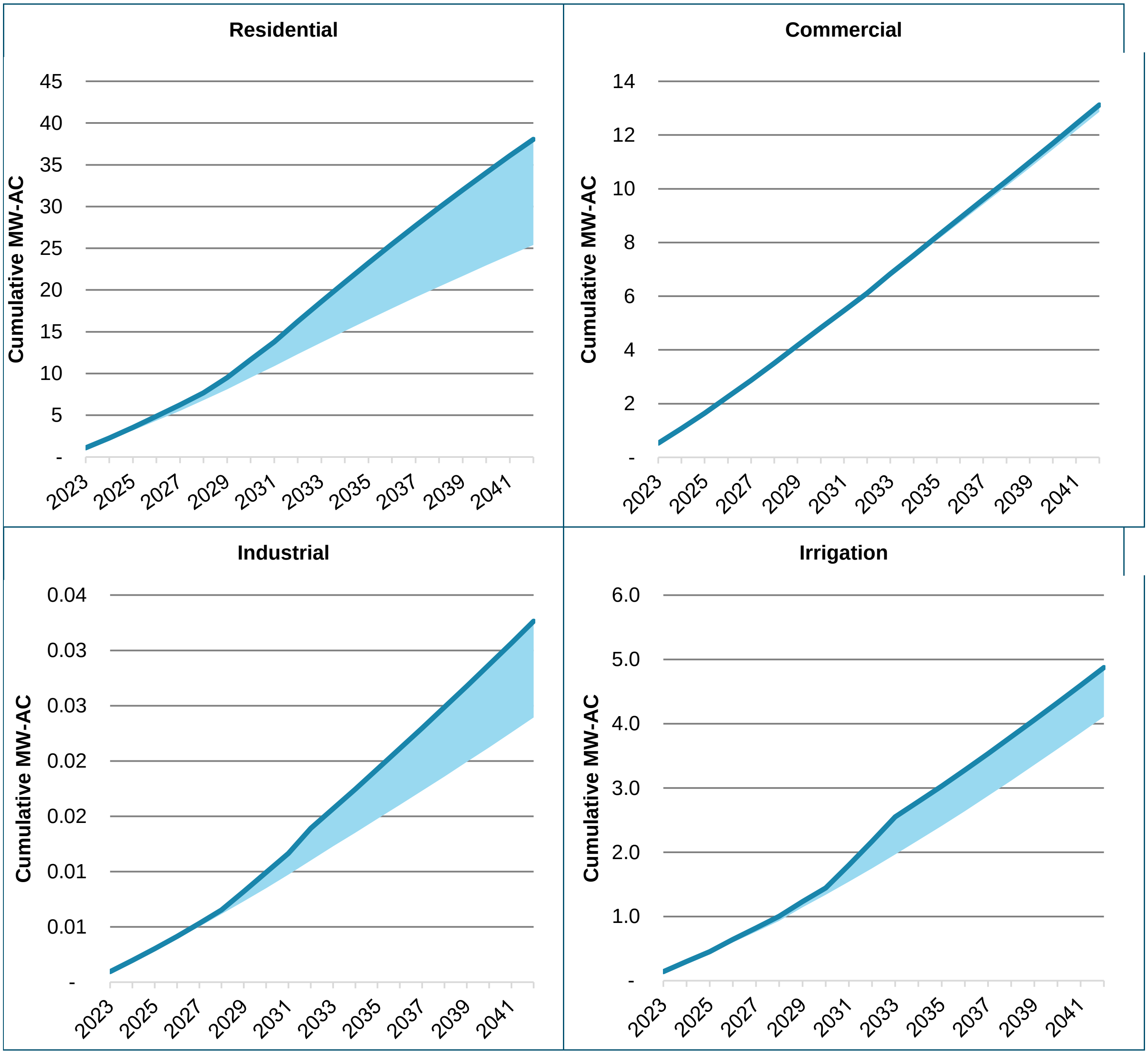


4.1.1.1 California PV Adoption by Sector

The impact of the three different scenarios on PV adoption by sector is shown in the following charts, which present the differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors. In the residential sector, the share of PV + Battery capacity is about 8% of total PV capacity in 2042 for the high case. The share of PV + Battery capacity is about 20% of total commercial PV capacity in 2042 for the high case. The irrigation sector has a similar portion of its PV capacity in PV + Battery configurations, at 14% of total capacity in the high case. The industrial sector did not have any PV + Battery adoption forecasted.

Figure 4-10 Cumulative New PV Capacity Installed by Sector Across All Scenarios, California, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.2 Idaho

PacifiCorp's customers in Idaho are projected to install about 179 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is about 1% greater than the base case and the low projection is 33% less than the base case, or 181 MW and 121 MW, respectively.

Idaho has a fairly generous incentive program for residential customers that boosted the sector's adoption, compared to the other sectors. The incentives are provided through the Residential Alternative Energy Income Tax Deduction, discussed in section 3.2.5. DNV assumed Idaho would use the same net billing structure for DER compensation as Utah for the study period (2023-2042). The residential sector has the largest share of the private generation capacity, ranging from 54% in the base and high cases to 48% in the low case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 38% in the low case to 34% in the base and high cases.

Figure 4-11 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Idaho, 2023-2042

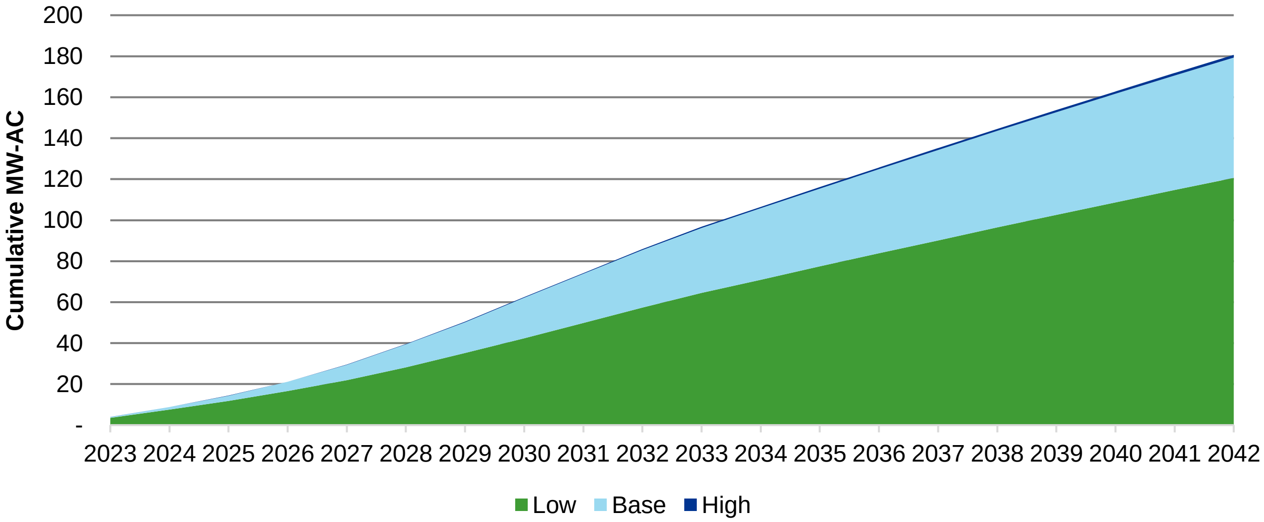


Figure 4-12 Cumulative New Capacity Installed by Technology (MW-AC), Idaho Base Case, 2023-2042

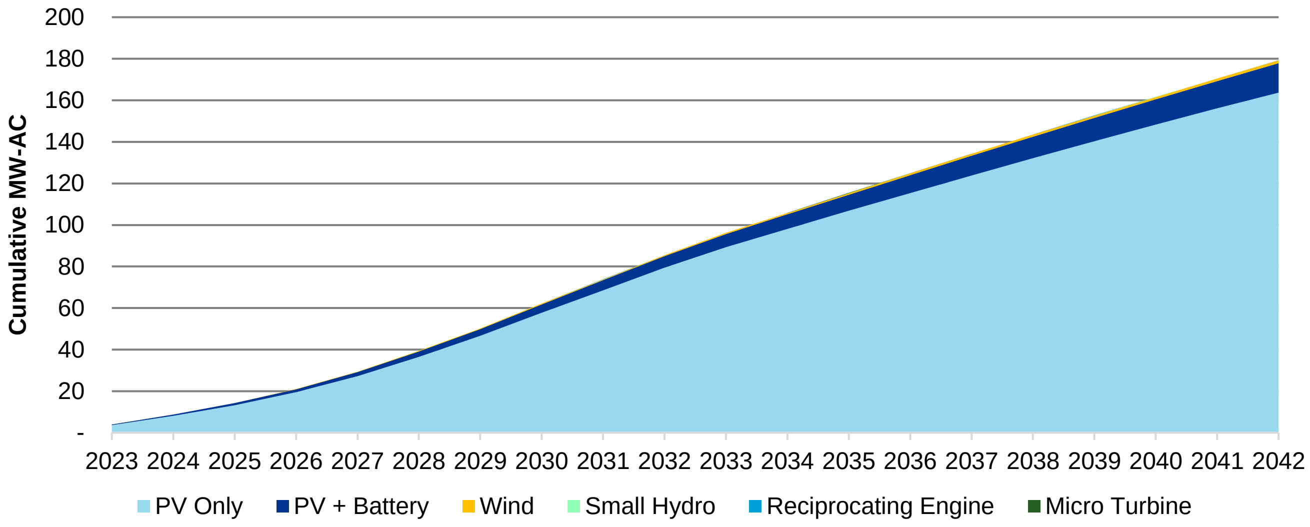


Figure 4-13 Cumulative New Capacity Installed by Technology (MW-AC), Idaho Low Case, 2023-2042

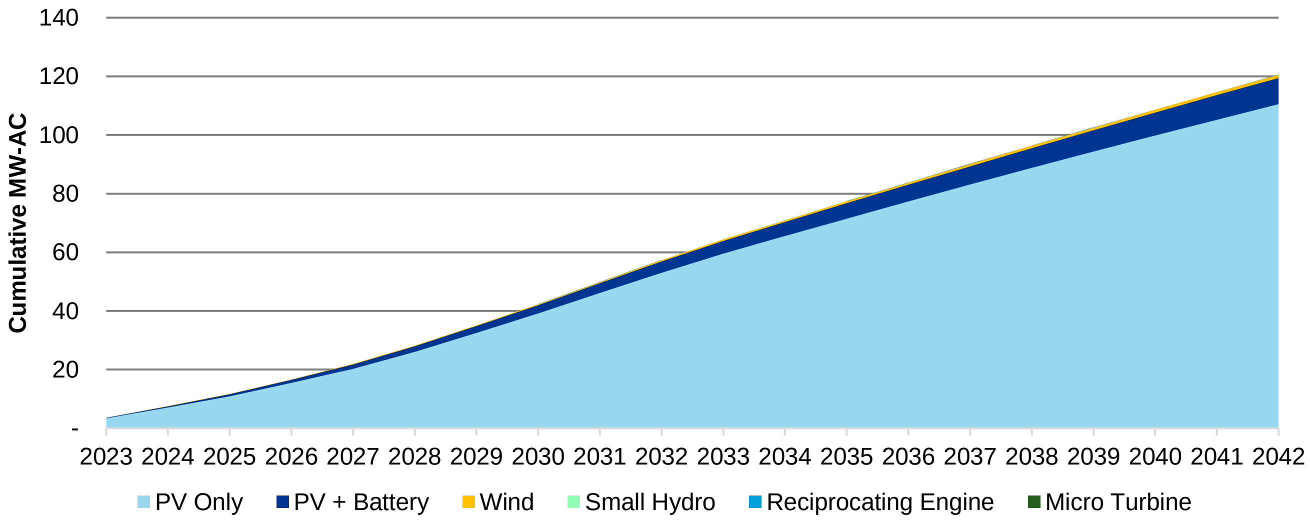
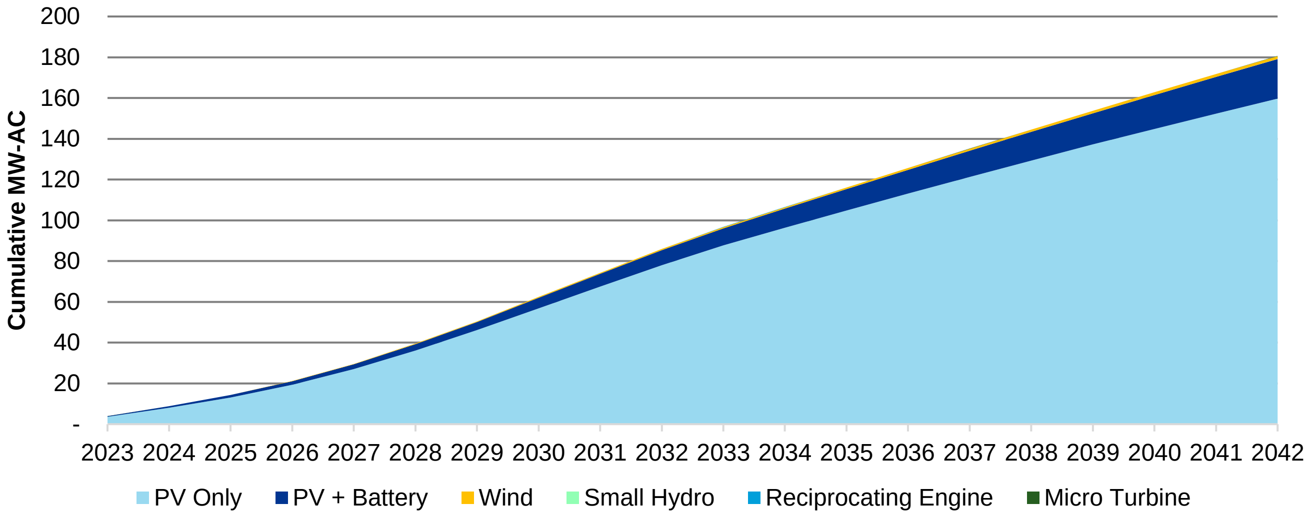


Figure 4-14 Cumulative New Capacity Installed by Technology (MW-AC), Idaho High Case, 2023-2042

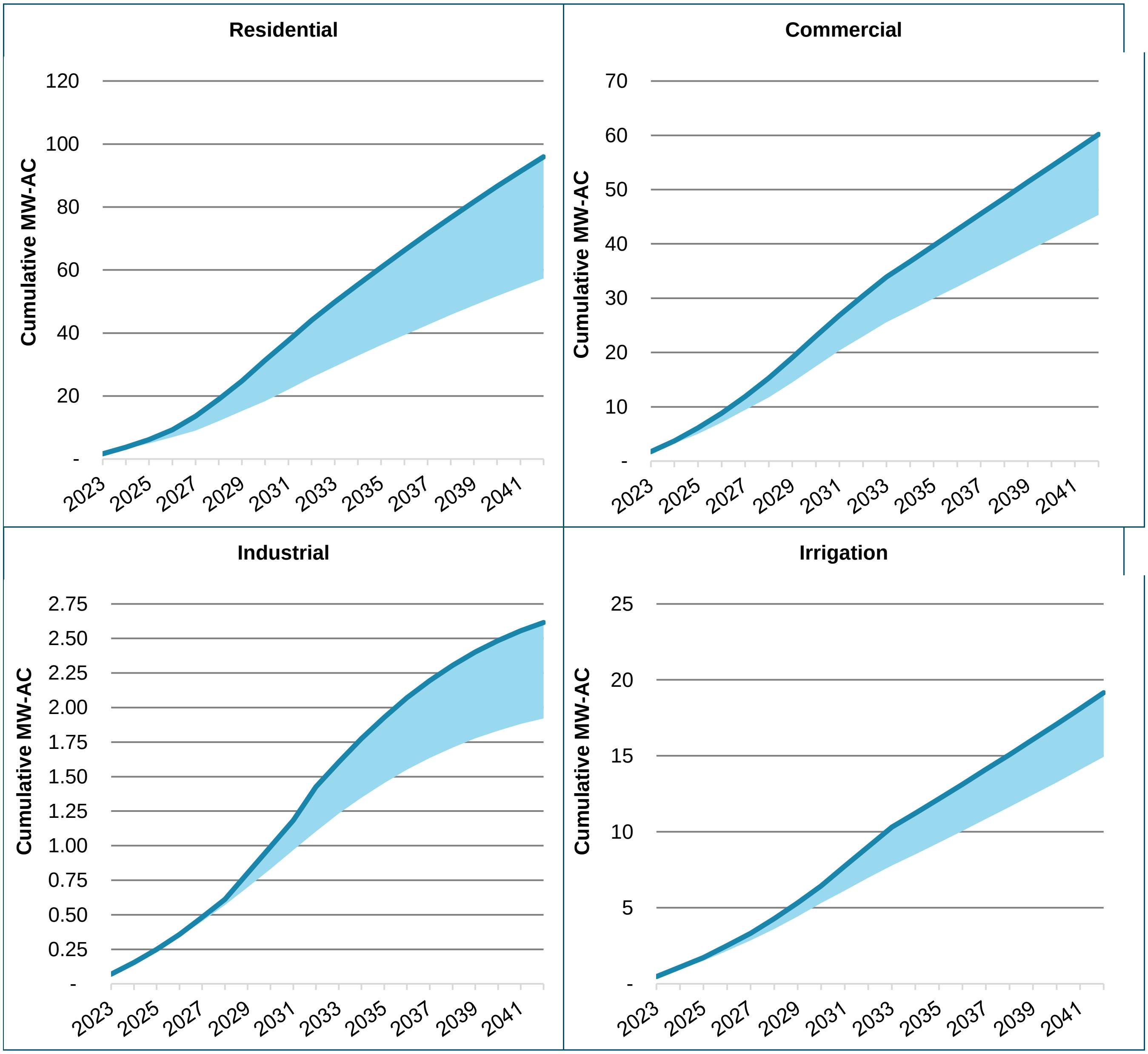


4.1.2.1 Idaho PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the high case share of PV + Battery capacity is about 15% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 8% of total commercial PV capacity in 2042. The irrigation sector has a slightly higher portion of its PV capacity in PV + Battery configurations, at 4% of total capacity. The industrial sector did not have any PV + Battery adoption forecasted.

Figure 4-15 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Idaho, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.3 Oregon

PacifiCorp's customers in Oregon are projected to install about 1,020 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is slightly higher than the base case and the low projection is 39% less than the base case, or 1,022 MW and 623 MW, respectively.

Oregon has incentives available through the Oregon Department of Energy (DOE) for PV + Battery systems and the Energy Trust of Oregon (ETO) for PV Only configurations. The ETO offers incentives for both residential and business customers, while the Oregon DOE provides incentives for residential customers only. Both the Oregon DOE and ETO provide increased incentives for households with low- to moderate-incomes. Oregon is the only state in PacifiCorp's territory, at this time, that provides different incentives for residential customers by income level. As the residential private generation forecast was not segmented by income level, DNV had to develop a single incentive value for the economic analysis. In order to incorporate the higher incentives for the income-qualified customers, DNV developed a weighted average incentive for Oregon residential customers. The income-level weights were calculated from the demographic data of the pool of potential adopters for each technology, in order to best represent the total technology cost (net of incentives) that Oregon residential customers are making their purchasing decisions based off of. Annual household income was included in the census-tract-level demographic data that DNV incorporated into PacifiCorp's Oregon Distribution System Plan circuit-level private generation forecast. While the higher incentive for income-qualified customers provides a boost to customer economics, it does not address the other larger barriers to adoption, such as lack of access to capital and home ownership status. Therefore representation of low- to moderate-income households in the pool of potential adopters for the PV and PV + Battery technologies is still very low.

The PV + Battery incentives offered for residential customers by the Oregon DOE provided a boost to customer economics that led to the majority of PV + Battery adoption growth being in the residential sector. The majority of the PV Only adoption growth in the early years of the forecast is in the commercial sector, with the residential sector following closely behind and eventually overtaking the forecast in the later years. Oregon's net metering policies were assumed to stay in place throughout the study, providing more favorable economics for PV Only—compared to PV + Battery systems.

Figure 4-16 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Oregon, 2023-2042

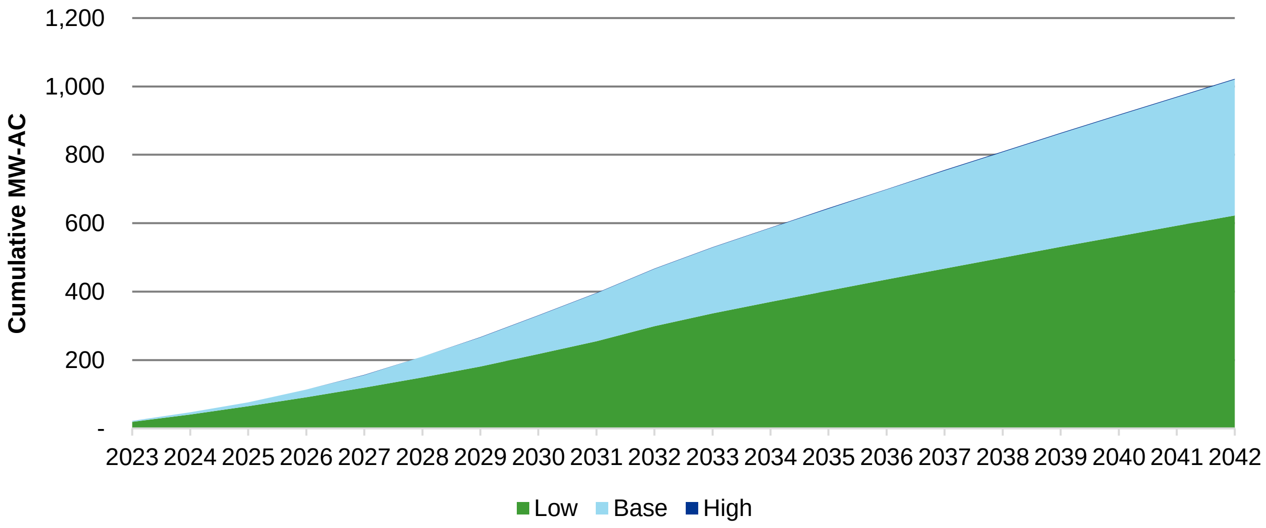


Figure 4-17 Cumulative New Capacity Installed by Technology (MW-AC), Oregon Base Case, 2023-2042

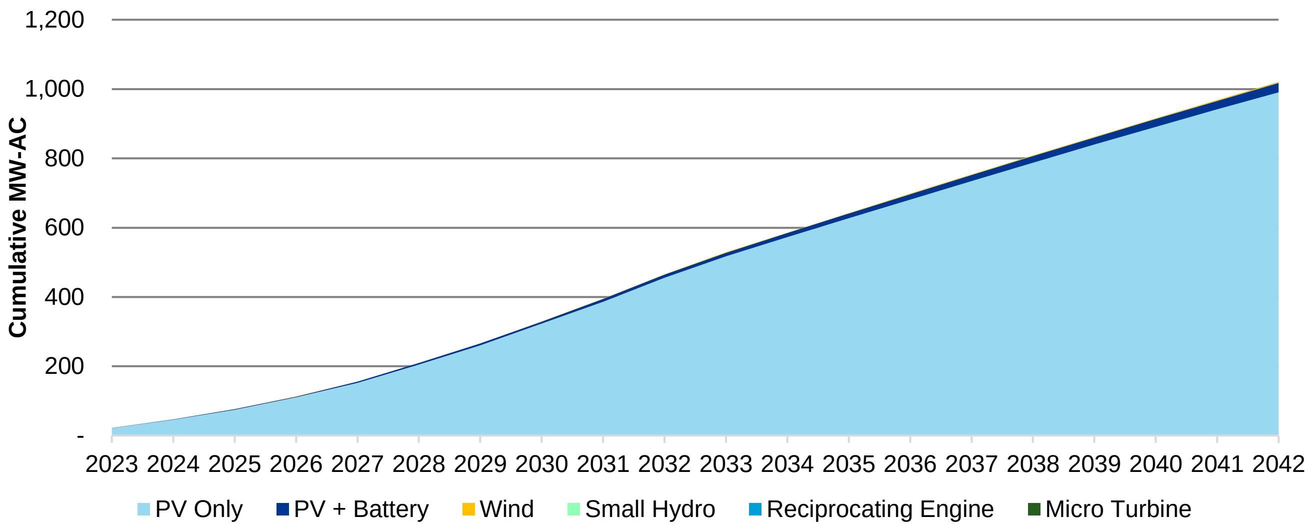


Figure 4-18 Cumulative New Capacity Installed by Technology (MW-AC), Oregon Low Case, 2023-2042

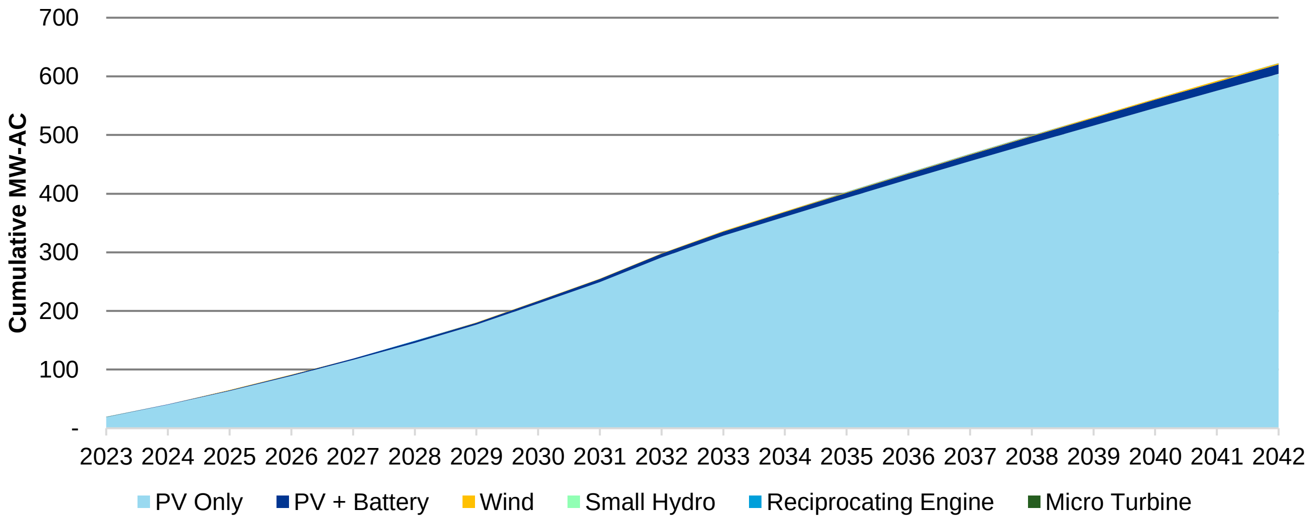
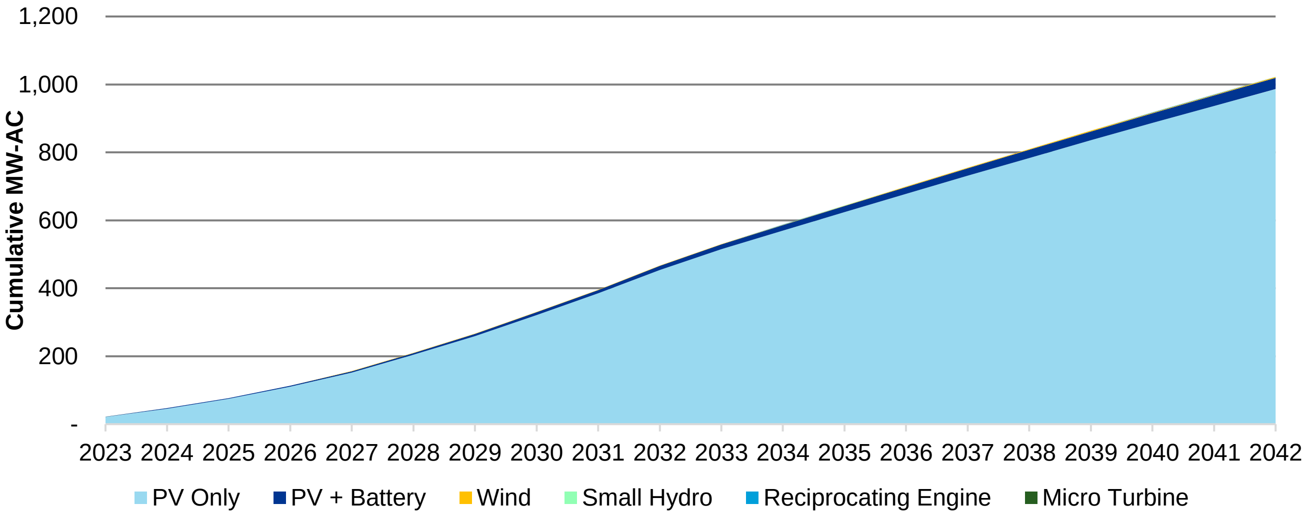


Figure 4-19 Cumulative New Capacity Installed by Technology (MW-AC), Oregon High Case, 2023-2042

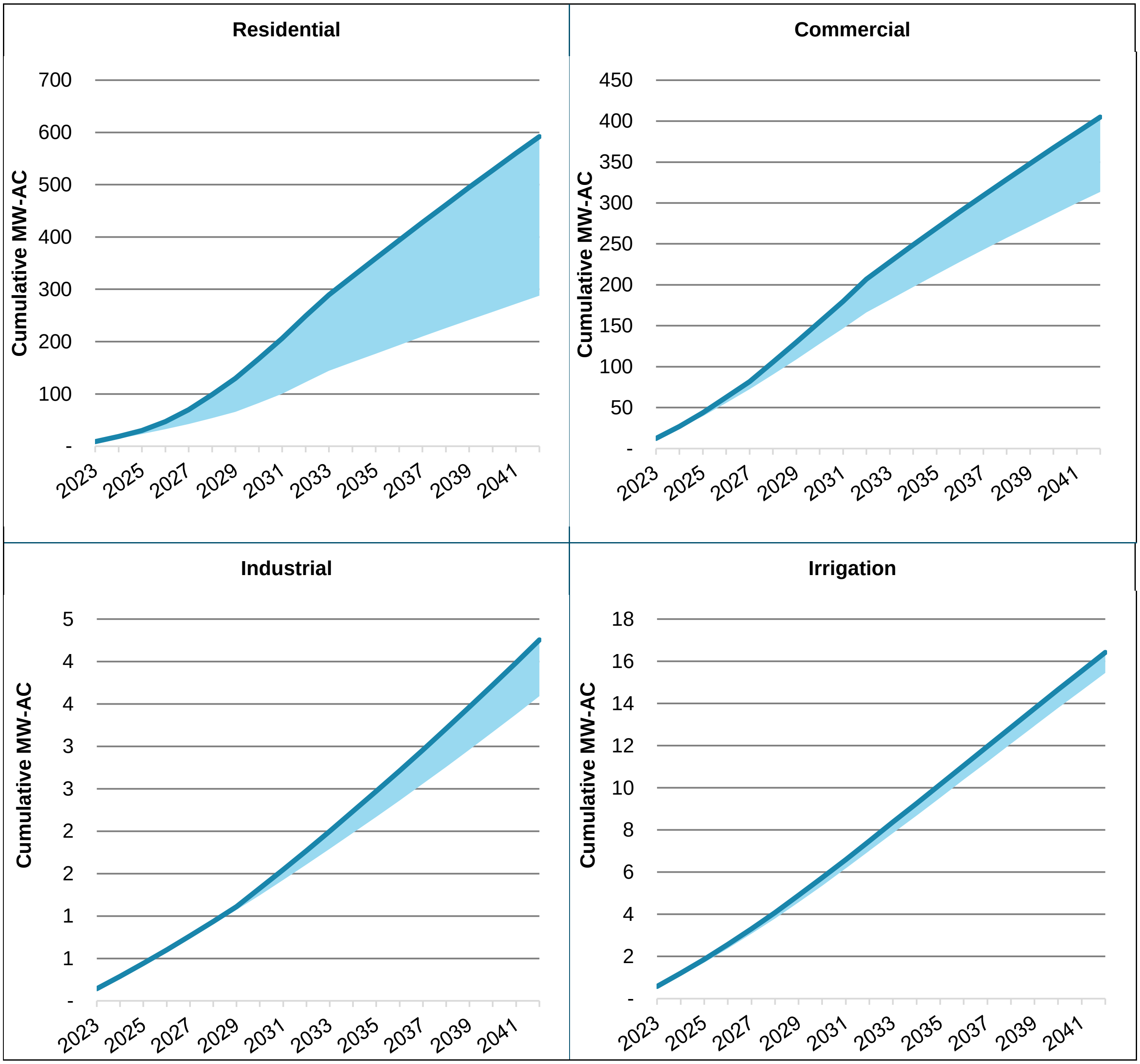


4.1.3.1 Oregon PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is about 4% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 2% of total commercial PV capacity in 2042. The irrigation sector has a similar portion of its PV capacity in PV + Battery configurations, at 3% of total capacity. The industrial sector did not have any PV + Battery adoption forecasted.

Figure 4-20 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Oregon, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.4 Utah

PacifiCorp’s customers in Utah are projected to install about 1,733 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is less than 1% greater than the base case and the low projection is 34% less than the base case, or 1,742 MW and 1,140 MW, respectively.

Utah has an incentive program for residential and business customers, but the residential PV incentive expires in 2023. The incentives are provided through through Utah Office of Energy Development Renewable Energy Systems Tax Credit, discussed in section 3.2.5. DNV assumed Utah’s net billing policies would remain in place throughout the study. In all cases, the commercial sector has the largest share of the private generation capacity forecasted—ranging from 50% to 58% in the high and low cases, respectively. The residential sector represents the 42% of the capacity forecast in the high and base scenarios, but only 33% in the low case.

Figure 4-21 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Utah, 2023-2042

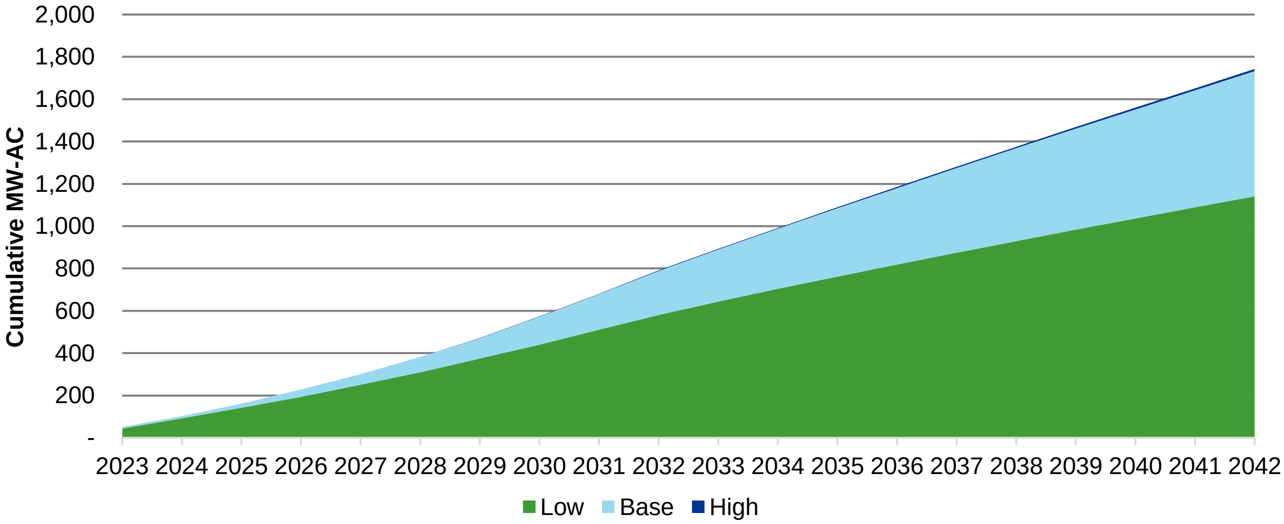


Figure 4-22 Cumulative New Capacity Installed by Technology (MW-AC), Utah Base Case, 2023-2042

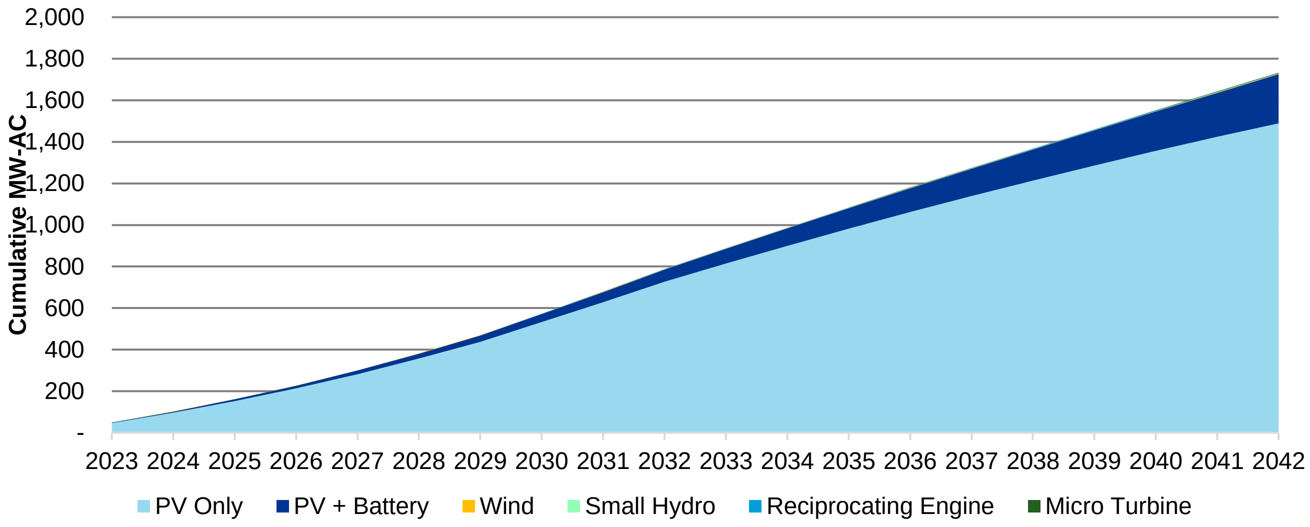


Figure 4-23 Cumulative New Capacity Installed by Technology (MW-AC), Utah Low Case, 2023-2042

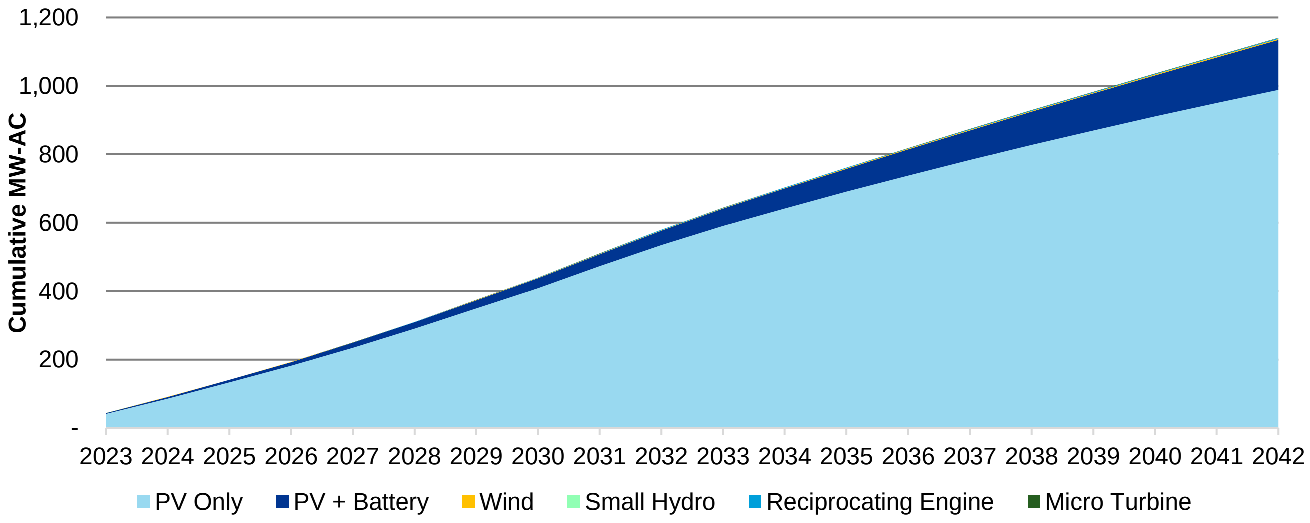
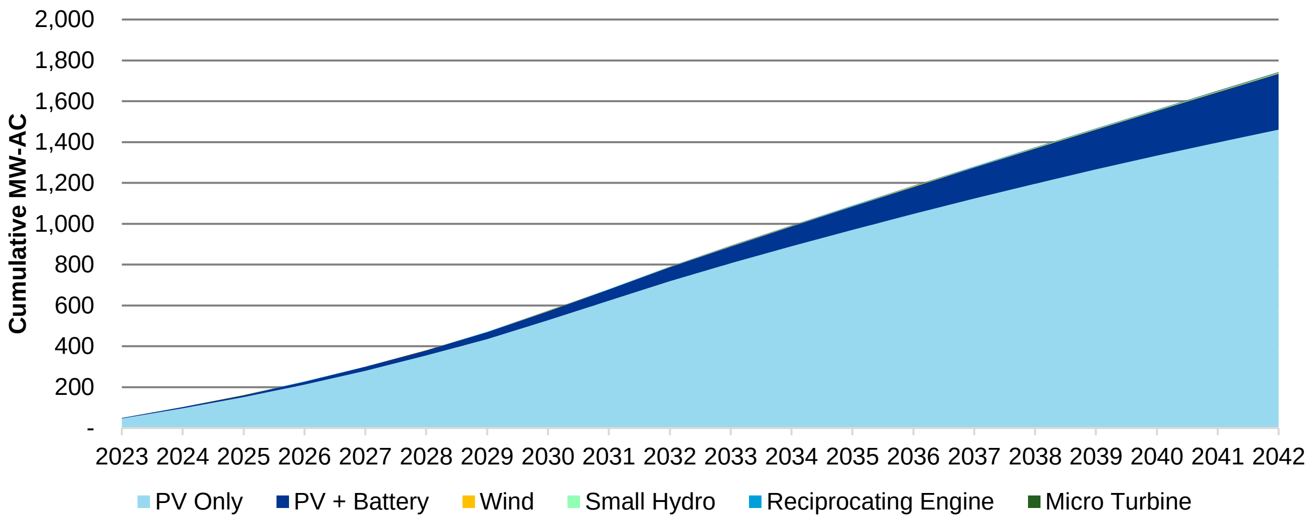


Figure 4-24 Cumulative New Capacity Installed by Technology (MW-AC), Utah High Case, 2023-2042

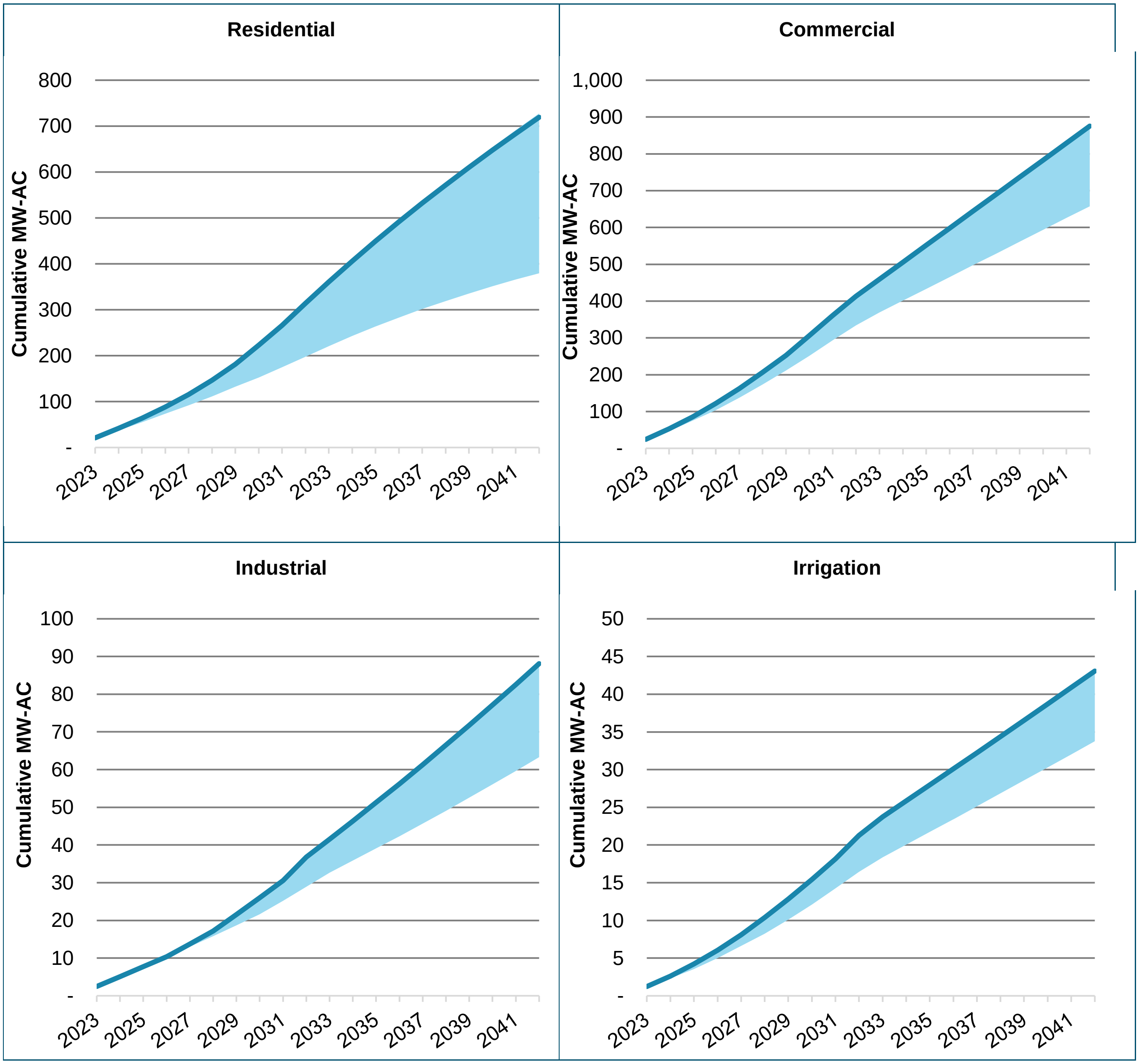


4.1.4.1 Utah PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is between 28 and 32% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 4% of total commercial PV capacity in 2042. The industrial sector has a lower portion of its PV capacity in PV + Battery configurations, at 1% of total capacity. About 5% of the irrigation sector PV capacity forecasted in in a PV + Battery configuration.

Figure 4-25 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Utah, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.5 Washington

PacifiCorp's customers in Washington are projected to install about 140 MW of new private generation capacity over the next two decades in the base case. The 20-year low projection is about 47% less than the base case, or 74 MW. The high case is nearly the same as the base case, seen in Figure 4-26.

Washington state currently offers no incentives for private generation technologies. The residential sector has the largest share of the private generation capacity, ranging from 68% in the base and high cases to 55% in the low case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 41% in the low case to 29% in the base and high cases. Washington's net metering policies were assumed to stay in place throughout the study, providing more favorable economics for PV Only—compared to PV + Battery systems.

Figure 4-26 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Washington, 2023-2042

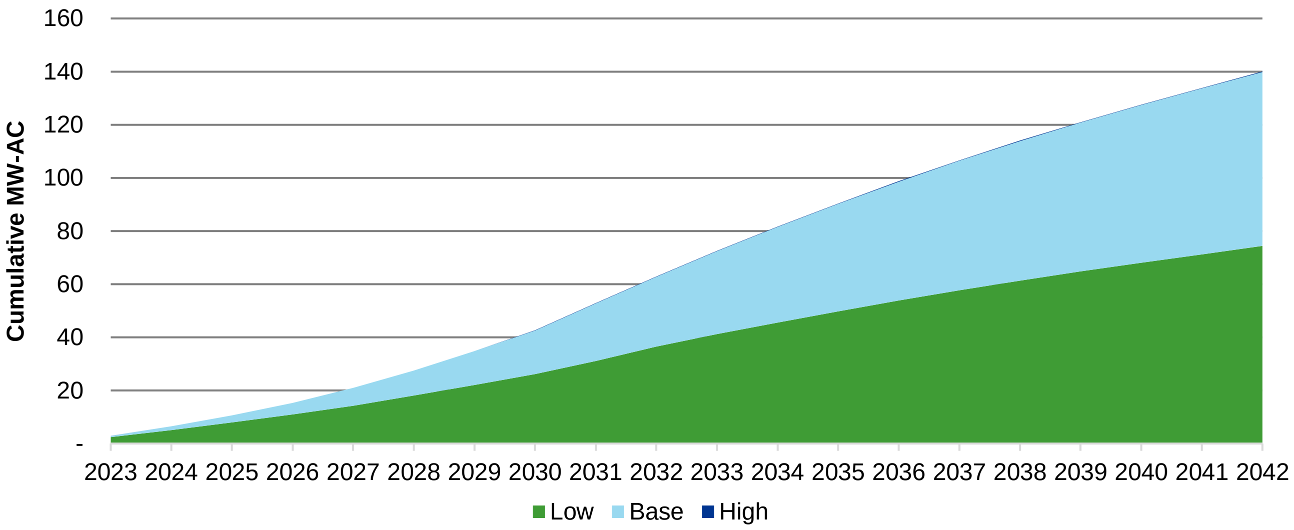


Figure 4-27 Cumulative New Capacity Installed by Technology (MW-AC), Washington Base Case, 2023-2042

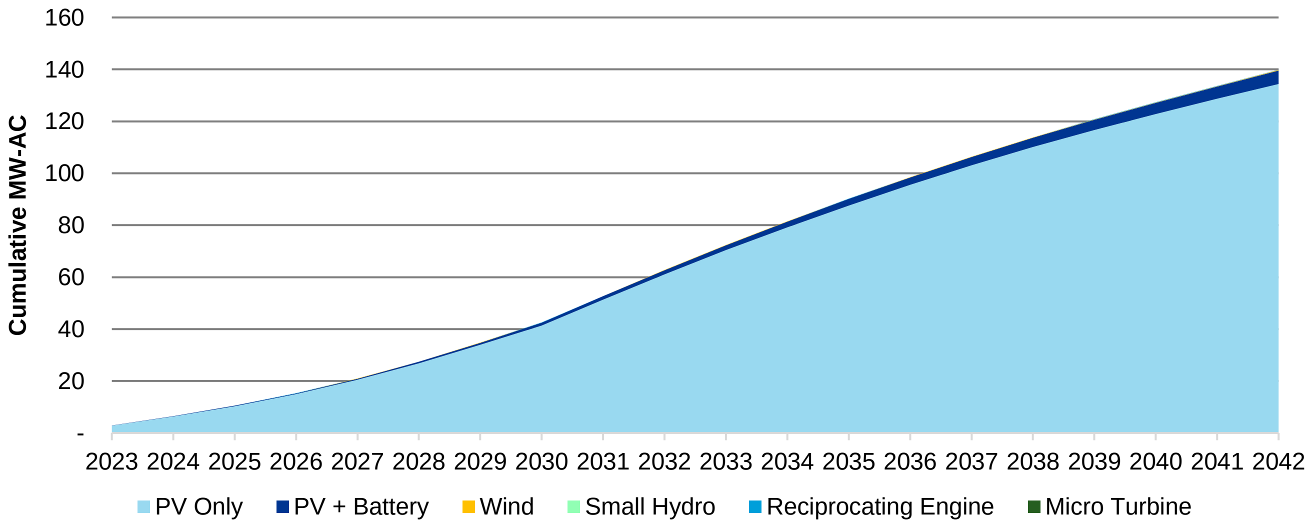


Figure 4-28 Cumulative New Capacity Installed by Technology (MW-AC), Washington Low Case, 2023-2042

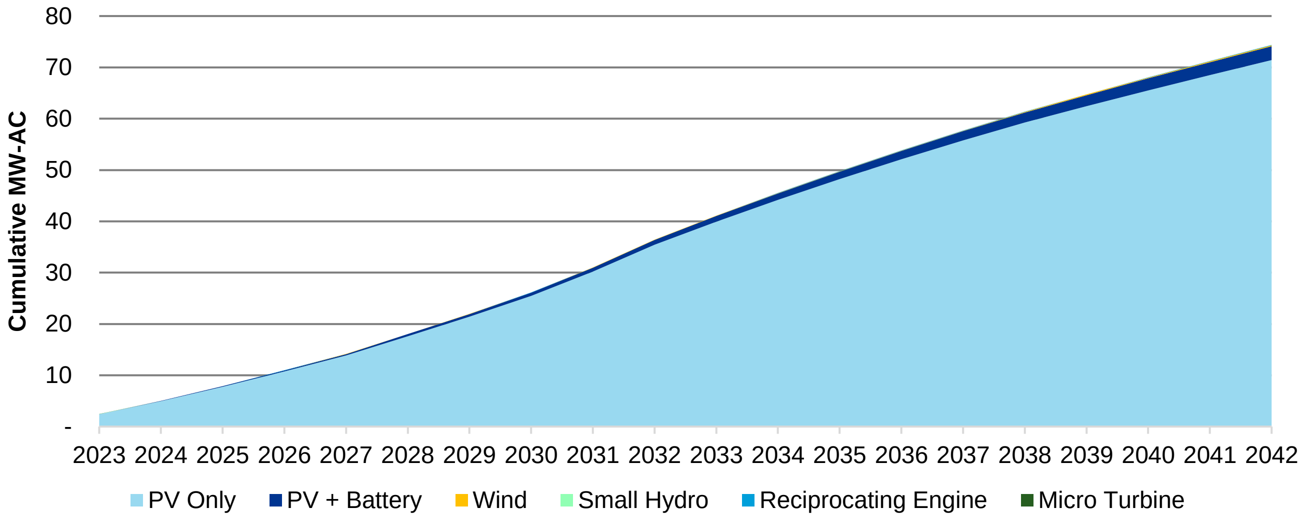
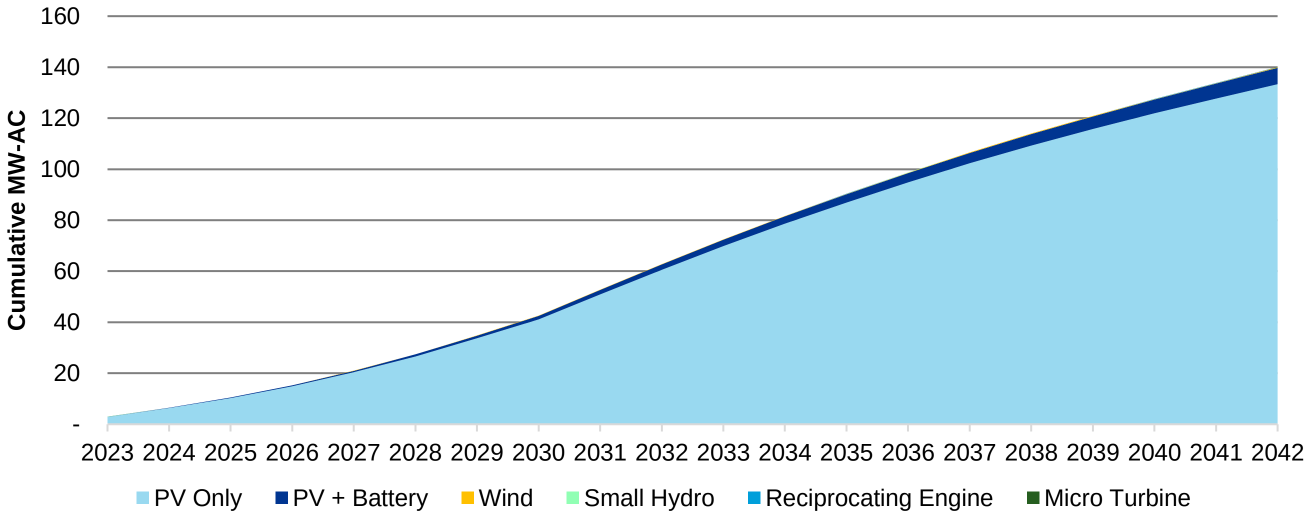


Figure 4-29 Cumulative New Capacity Installed by Technology (MW-AC), Washington High Case, 2023-2042

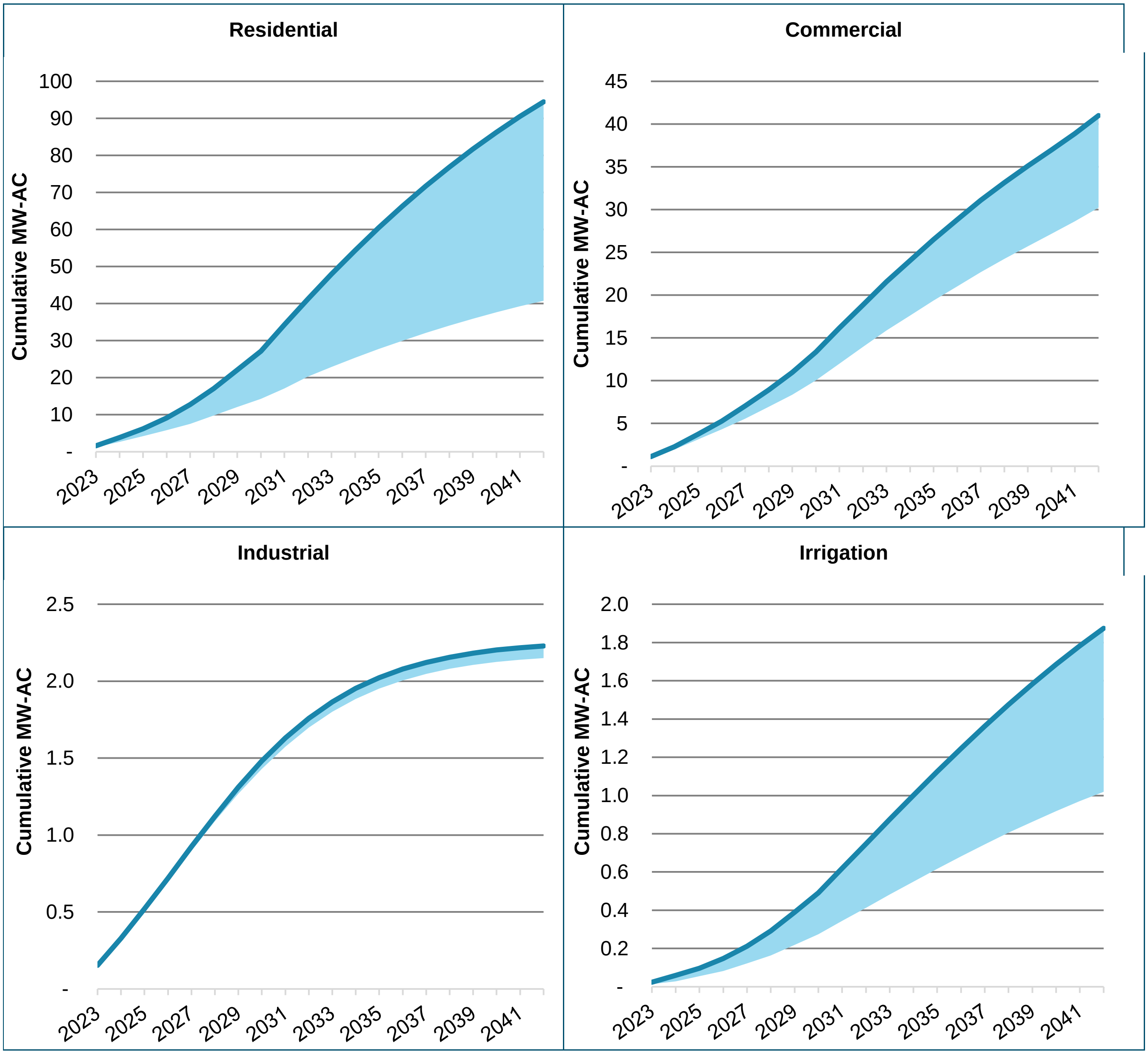


4.1.5.1 Washington PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is about 4% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 3% of total commercial PV capacity in 2042. The industrial sector has a higher portion of its PV capacity in PV + Battery configurations, at 8% of total capacity. In the irrigation sector, the share of PV + Battery capacity is between 2% and 4%, depending on the forecast scenario, of total irrigation PV capacity in 2042.

Figure 4-30 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Washington, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.6 Wyoming

PacifiCorp's customers in Wyoming are projected to install about 51 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is approximately 2% greater than the base case and the low projection is about 50% less than the base case, or 52 MW and 26 MW, respectively.

Wyoming currently offers no incentives for private generation technologies. The residential sector has the largest share of the private generation capacity, ranging from 64% in the low case to 71% in the high and bae cases. The next largest share of the capacity is forecasted in the commercial sector, ranging from 28% in the high and base cases to 34% in the low case. Wyoming's net metering policies were assumed to stay in place throughout the study, providing more favorable economics for PV Only—compared to PV + Battery systems.

Figure 4-31 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Wyoming, 2023-2042

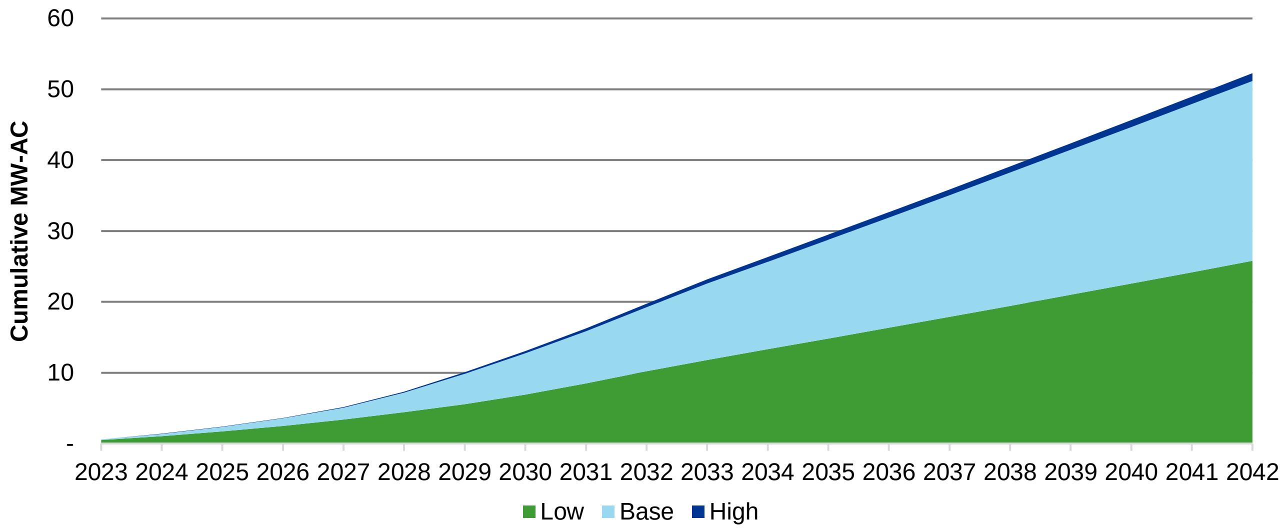


Figure 4-32 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming Base Case, 2023-2042

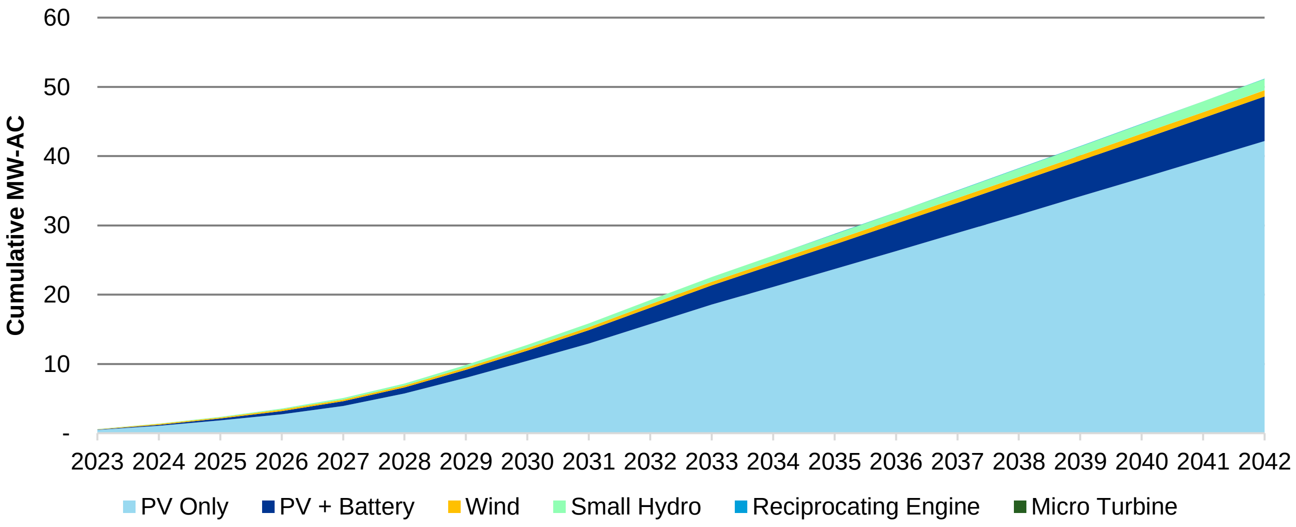


Figure 4-33 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming Low Case, 2023-2042

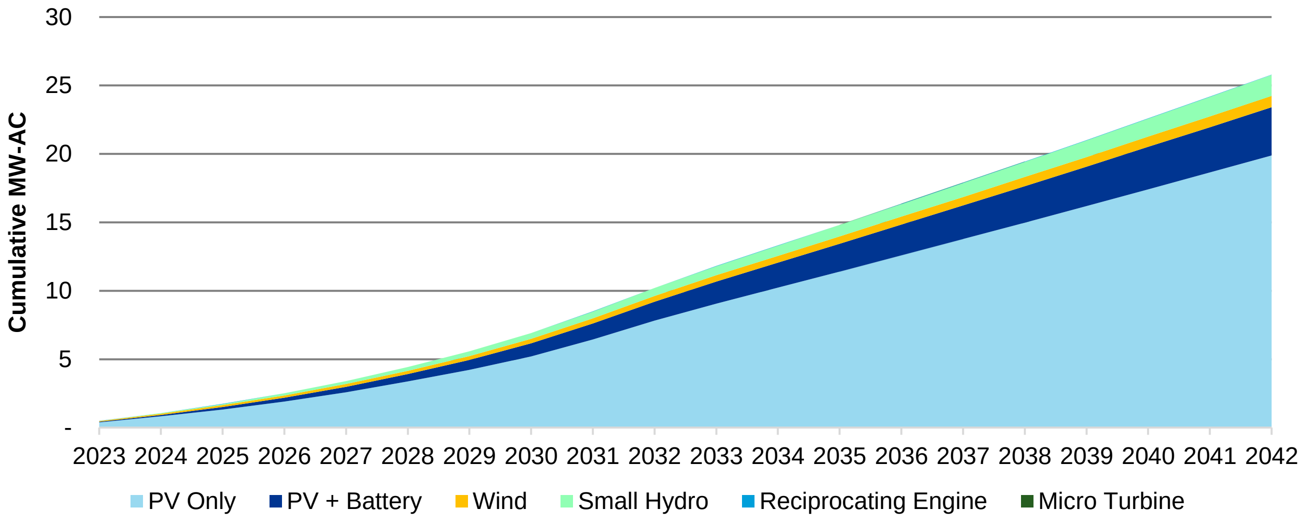
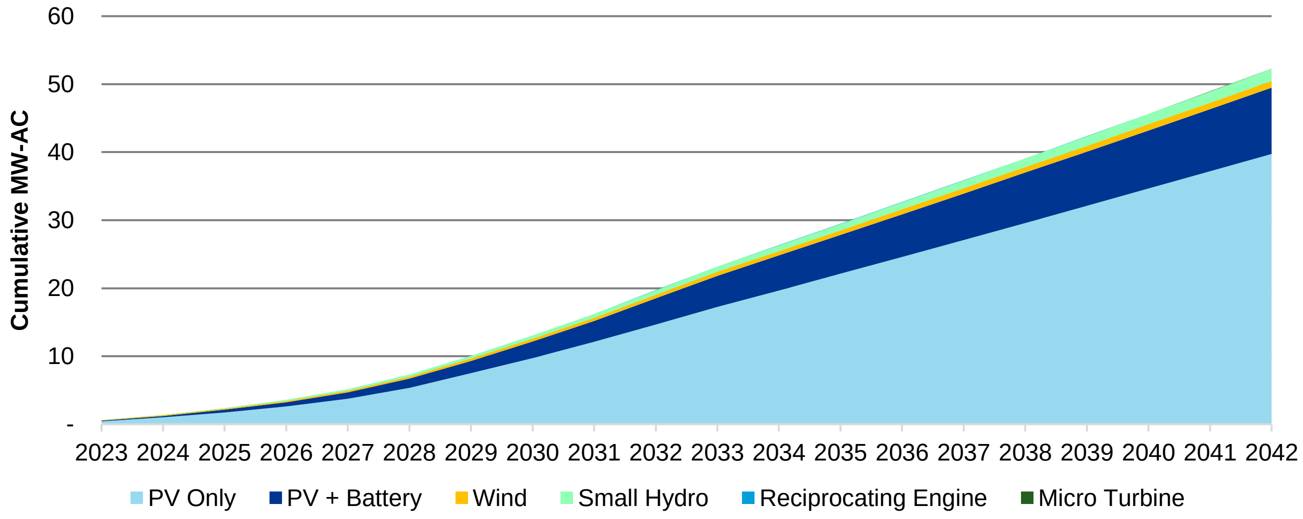


Figure 4-34 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming High Case, 2023-2042

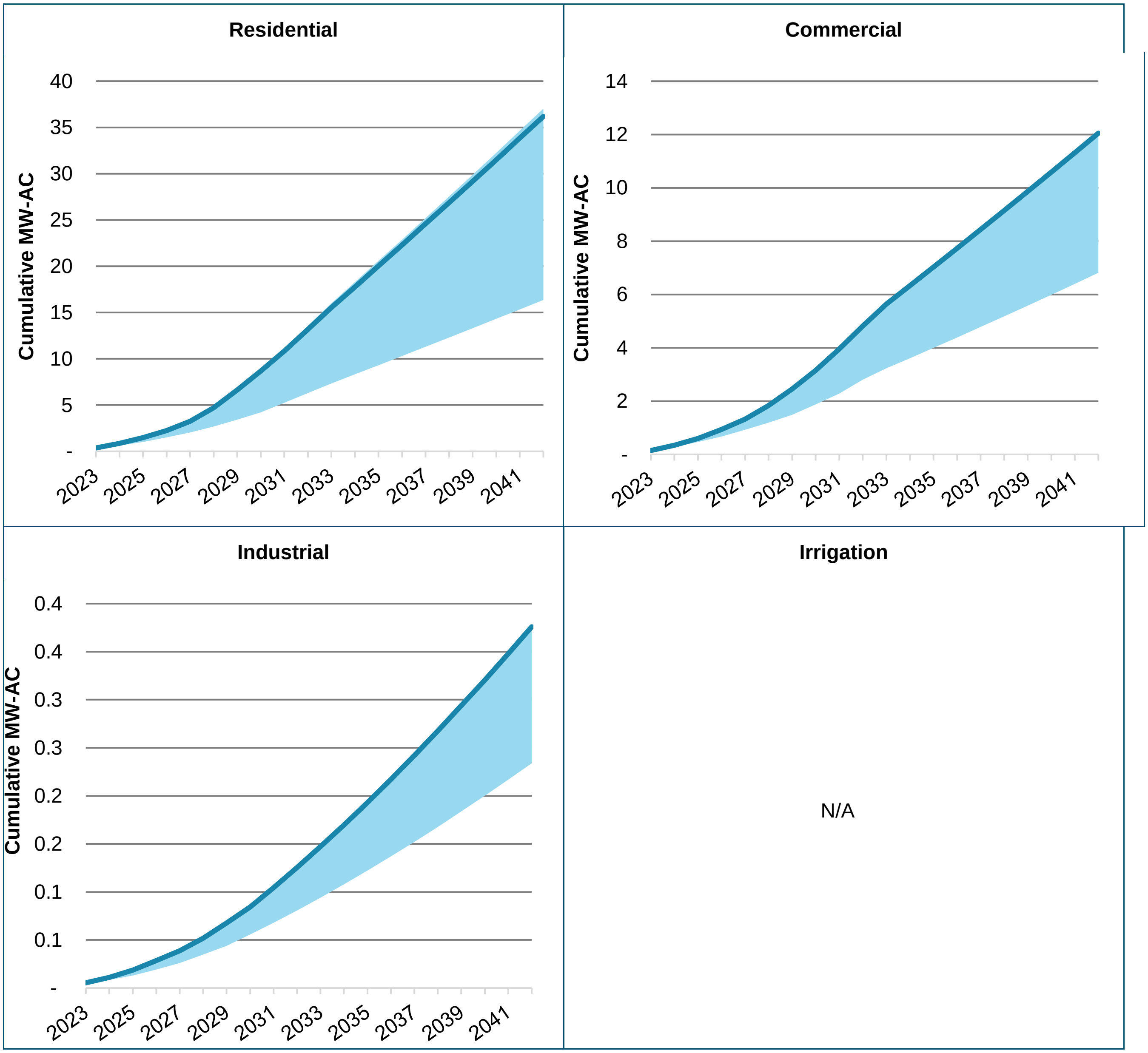


4.1.6.1 Wyoming PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is between 19% and 23% of total residential PV capacity in 2042, depending on the forecast scenario. The share of PV + Battery capacity is about 6% of total commercial PV capacity in 2042. The industrial sector has a lower portion of its PV capacity in PV + Battery configurations, at 5% of total capacity. The irrigation sector did not have any PV (PV Only or PV + Battery) adoption forecasted.

Figure 4-35 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Wyoming, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



APPENDIX A TECHNOLOGY ASSUMPTIONS AND INPUTS

Appendix A.xlsx

APPENDIX B DETAILED RESULTS

Appendix B.xlsx

APPENDIX C WASHINGTON COGENERATION LEVELIZED COSTS

Section 480.109.100 of the Washington Administrative Code establishes high-efficiency cogeneration as a form of conservation that electric utilities must assess when identifying cost-effective, reliable, and feasible conservation for the purpose of establishing 10-year forecasts and biennial targets. This appendix provides the levelized cost of energy (LCOE) for the two CHP technologies analyzed in this report for three 10-year periods. LCOE is defined as the present cost of electricity generation for the specified technology over its useful lifetime.

Assumptions for the LCOE analysis of both reciprocating engines and microturbines in Washington state are provided in Table C-1and Table C-2 below, with additional information on the specific source for each metric. Similar to previous studies, the cost of system heat recovery was removed from the total system cost component, resulting in LCOE based only on electric power generation for each system. Where applicable, assumptions are presented nominally ($USD).

Table C-1 Reciprocating Engine LCOE Assumptions

METRIC	EXPECTED USEFUL LIFE (EUL)	INSTALLED COST *(INCLUDES INCENTIVES)*	VARIABLE O&M COST	FUEL COST	WACC
UNITS	Years	$/kW	$/MWh	$/MMBtu	%
2022	20	$2,565	$23	$5.67	6.88%
2030	20	$2,655	$27	$4.34	6.88%
2040	20	$2,721	$32	$6.61	6.88%
SOURCE	EPA Catalog of CHP Technologies (Sep. 2017)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	PacifiCorp Natural Gas Forecast for Washington State	PacifiCorp IRP Assumption

Table C-2 Microturbine Engine LCOE Assumptions

METRIC	EXPECTED USEFUL LIFE (EUL)	INSTALLED COST *(INCLUDES INCENTIVES)*	VARIABLE O&M COST	FUEL COST	WACC
UNITS	Years	$/kW	$/MWh	$/MMBtu	%
2022	25	$3,135	$23	$5.67	6.88%
2030	25	$3,229	$27	$4.34	6.88%
2040	25	$3,294	$32	$6.61	6.88%
SOURCE	EPA Catalog of CHP Technologies (Sep. 2017)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	PacifiCorp Natural Gas Forecast for Washington State	PacifiCorp IRP Assumption

The results of the CHP LCOE analysis are shown below. The calculated levelized costs for both technologies are similar in each analysis year.

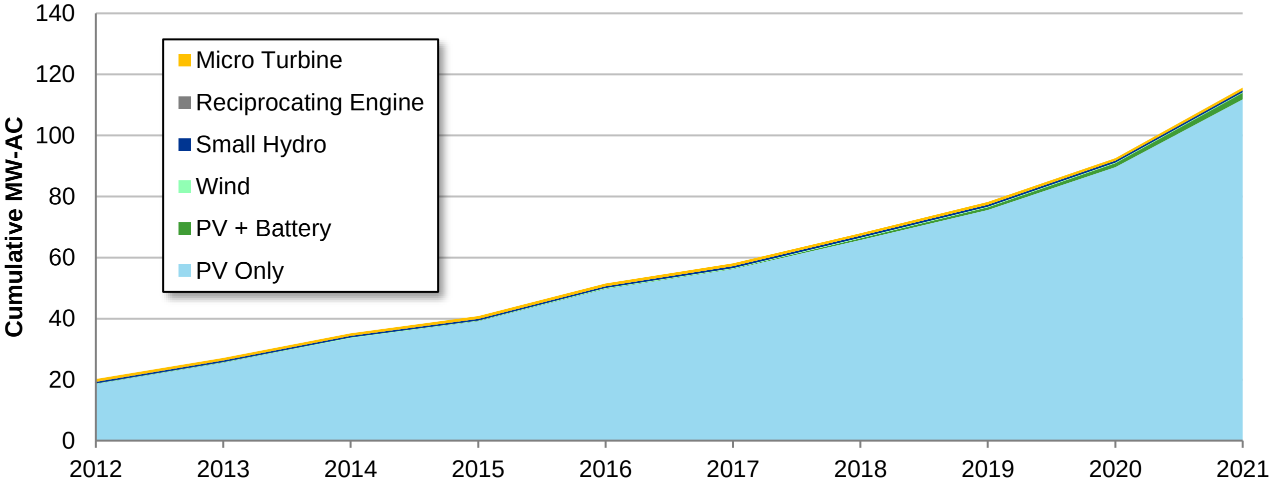
Table C-3 LCOE Results for CHP Systems in Washington State

TECH	RECIPROCATING ENGINES	MICROTURBINES
UNITS	$/MWh	$/MWh
2022	$89.3	$92.8
2030	$99.4	$99.9
2040	$121.4	$116.3

APPENDIX D OREGON DISTRIBUTION SYSTEM PLAN RESULTS

DNV prepared the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp's Oregon distributed energy resource (DER) adoption forecast at the circuit level to support PacifiCorp's 2023 Oregon Distribution System Plan (DSP). This study evaluated the expected adoption of behind-the-meter DERs including photovoltaic solar (PV only), photovoltaic solar coupled with battery storage (PV + Battery), wind, small hydro, reciprocating engines and microturbines for a 20-year forecast horizon (2023-2042). The adoption model DNV developed for this study is calibrated to the current[20] market penetration of these technologies, shown in Figure D-1**.**

Figure D-1 Historic Cumulative Installed PG Capacity by Technology, PacifiCorp, Oregon, 2012-2021



To date, about 99 percent of existing private generation capacity installed in PacifiCorp's Oregon service territory is PV or PV + Battery. To inform the adoption forecast process, the Company conducted an in-depth review of the other technologies and did not find any literature to suggest that they would take on a larger share of the private generation market in Oregon in the future years of this study.

For each technology and sector, PacifiCorp developed three scenarios: a base case, a high case and a low case. The base case is considered the most likely projection as it is based on current market trends and expected changes in costs and retail rates; the high and low cases are used as sensitivities to test how changes in technology costs and retail rates impact customer adoption of these technologies. These scenarios use technology cost and performance assumptions specific to PacifiCorp's Oregon service territory in the base year of the study. The base case assumes the current federal income tax credit schedules and state incentives, retail electricity rate escalation from the AEO[21] reference case, and a blended version of the NREL Annual Technology Baseline[22] moderate and conservative technology cost forecasts. In the high case, retail rates increase more rapidly, and technology costs decline at a faster rate compared to the base case to incentivize greater adoption of PG. For the low case, retail rates increase at a slower rate than the base case and technology costs decrease at a slower rate.

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[20] PacifiCorp private generation interconnection data as of February 2022.

[21] U.S. Energy Information Administration, Annual Energy Outlook 2022 (AEO2022), (Washington, DC, March 2022).

[22] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

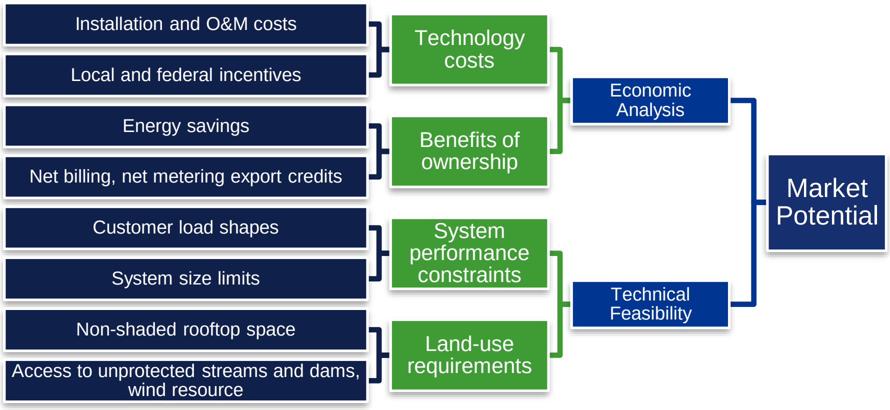
D.1 Study Methodologies and Approaches

The forecasting methodologies and techniques applied by PacifiCorp in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. To forecast private generation adoption at the circuit-level, the Company first developed an adoption model to estimate total PG potential for PacifiCorp's Oregon service territory and then disaggregated these results to develop PG potential estimates for each circuit. The methods used to develop the territory and circuit level results are described in more detail below.

D.1.1 State-Level Forecast Approach

DNV developed a behind-the-meter net economic perspective that includes the acquisition and installation costs for each technology and incorporates the available incentives and economic benefits of ownership as offsets which assumed that the current net metering policies for Oregon remained in place throughout the study horizon. The economic analysis calculated payback by year for each technology by sector. A corresponding technical feasibility analysis determined the maximum, feasible, adoption for each technology by sector. The results of the technical and economic analyses were then used to inform the market adoption analysis. The methodology and major inputs to the analysis are shown in Figure D-2. Changes to technology costs, retail rates, and federal tax credits used in the high and low cases impact the economic portion of the analysis.

Figure D-2 Methodology to Determine Market Potential of Private Generation Adoption



PacifiCorp used technology and sector-specific Bass diffusion curves to model market adoption and derive total market potential. Bass diffusion curves are widely used for forecasting technology adoption. Diffusion curves typically take the form of an S-curve with an initial period of slow early adoption, adoption increasing as the technology becomes more mainstream, and eventually a tapering off among late adopters. The upper limit of the curve is set to maximum market potential, or the maximum share of the market that will adopt the technology regardless of the interventions applied to influence adoption. In this analysis, the long-term maximum level of market adoption was based on payback. As payback was calculated by year in the economic analysis to capture the changing effects of market interventions over time, the maximum level of market adoption in the diffusion curves vary by year in the study.

The model is characterized by three parameters—an innovation coefficient, an imitation coefficient, and the ultimate market potential. The last of these we set equal to the payback-based maximum level of adoption. Together, these three parameters also determine the time to reach maximum adoption and overall shape of the curve. The innovation and imitation parameters were calibrated for each technology and sector, based on current market penetration and when PacifiCorp started to see the technology being adopted in the Company's Oregon service territory.

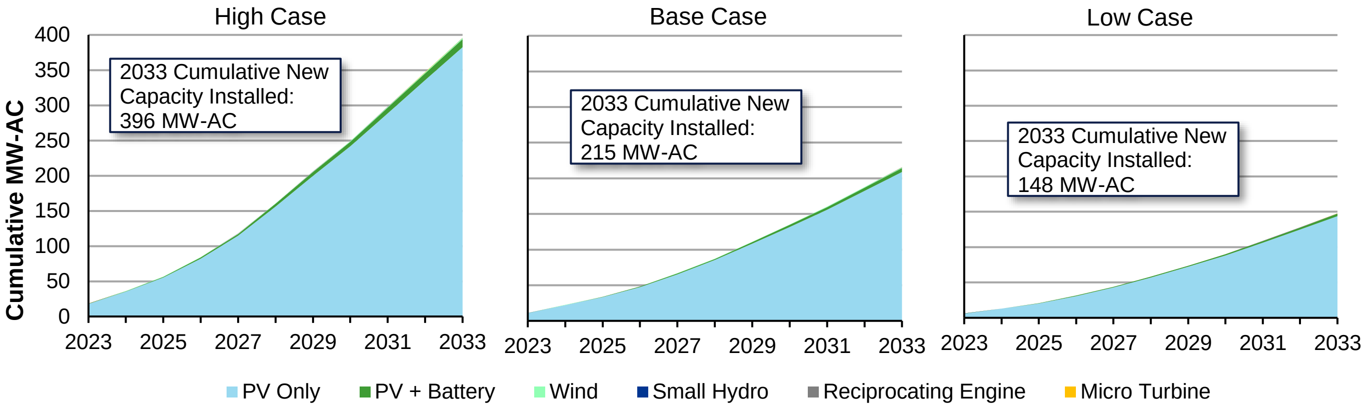
D.1.2 Circuit-Level Forecasting Approach

PacifiCorp conducted a bottom-up approach to develop circuit-level adoption models for each sector and technology. The approach chosen for developing circuit-level forecasts was to disaggregate the state-level forecast described in the previous section. This was due to the use of adoption drivers from data at varying levels of geographic granularity. The circuit-level adoption models incorporated county-level private generation installation data and resource availability by technology[23], census-tract-level demographic data[24] and circuit-level reliability data. The Company used circuit-level customer counts by sector to further segment the localized adoption models by sector and technology. The Company ultimately used a bottom-up approach to develop circuit-level adoption models for each circuit, but due to the above data gaps, their purpose was only to develop factors to allocate the state-wide analysis to each circuit.

D.2 Private Generation Forecast Results

Figure D-3 compares the new service territory-level private generation capacity, in cumulative MW-AC by 2033, projected for each scenario evaluated. The capacity forecasted is incremental to what is already installed in PacifiCorp's Oregon service territory, shown in Figure D-1.

Figure D-3 Private Generation Forecast by Technology, PacifiCorp Oregon, All Cases



Similar to the trends observed in current installed capacity, solar PV[25] makes up 99% of the new PG capacity forecast throughout the study period in all cases. By 2033, the cumulative new PV Only capacity in the base case is 209 MW and PV + Battery capacity is 5 MW. Compared to the base case, the low case forecasts 31% less PV Only capacity, and about 40% percent less PV + Battery capacity. The PV Only cumulative new capacity in the high case in 2033 is 83% greater than the base case. In the high case, 2033 PV + Battery cumulative new capacity is forecasted to be more than double the base case, at 11 MW.

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[23] Conditions suitable for wind and hydro vary widely by region, and the economics of solar adoption is affected by local weather patterns.

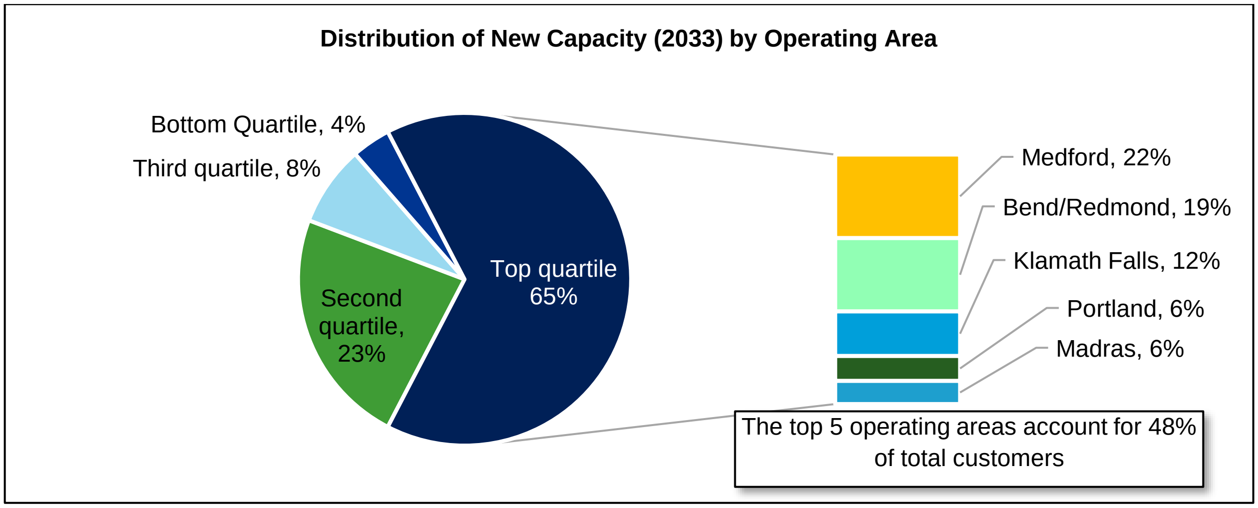
[24] Data including household income, education-level, and home ownership.

[25] The term solar PV, here, is inclusive of PV Only and PV + Battery systems.

D.2.1 Circuit-Level and Substation-Level Results Findings

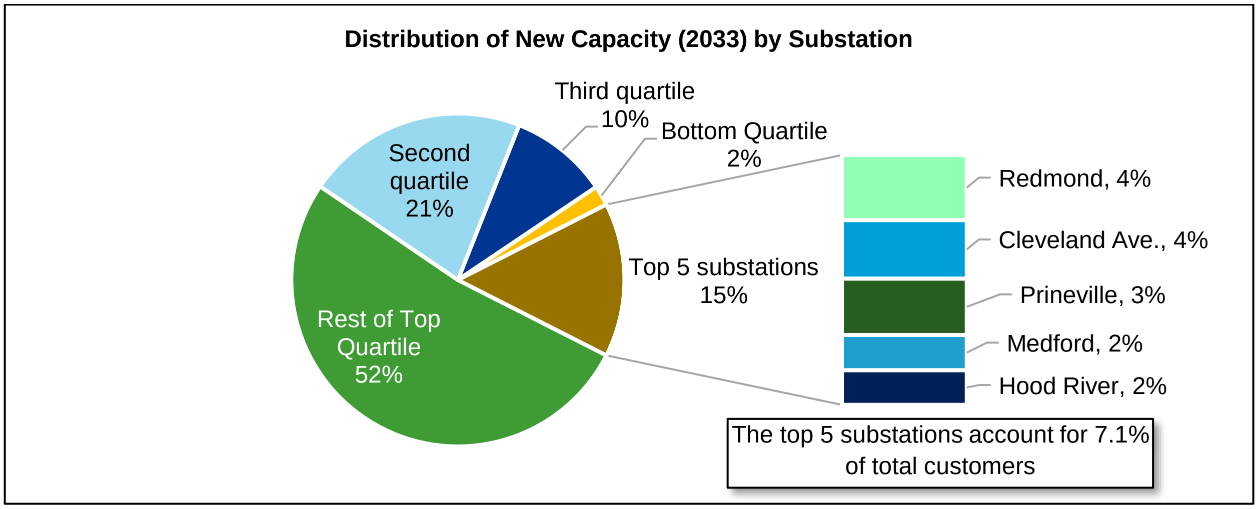
The charts in Figure D-4, Figure D-5, and Figure D-6 show the distribution of new capacity in 2033 by operating area, substation, and circuit within the base case private generation forecast.

Figure D-4 Private Generation Forecast Disaggregation by Operating Area, PacifiCorp Oregon, Base Case



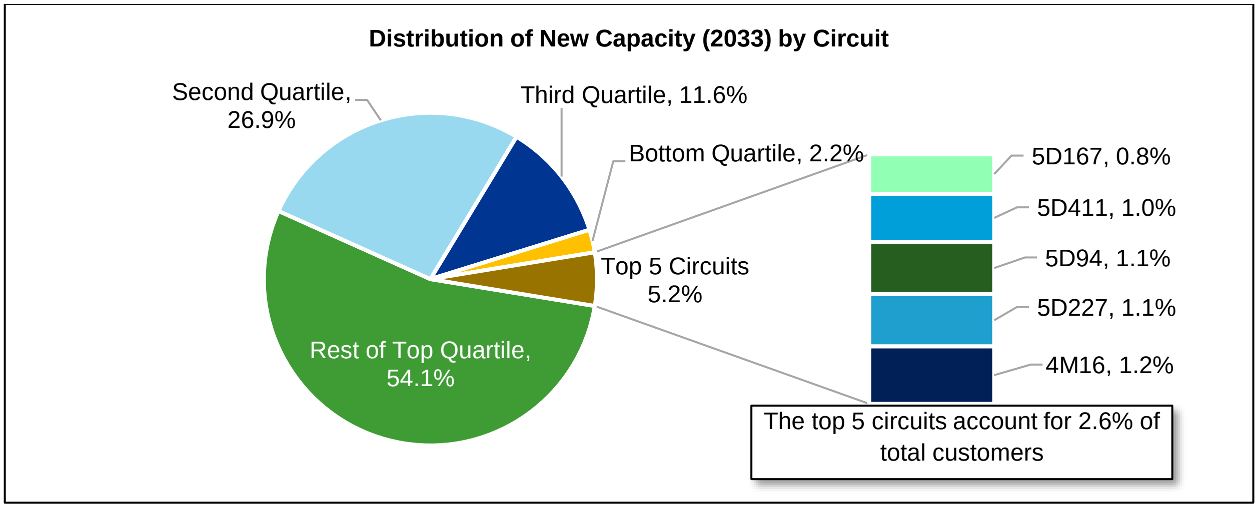
The top five (ranked by new capacity) of PacifiCorp's 22 Oregon operating areas account for 65% of the total forecast capacity in 2033 while only accounting for 48% of total customers.

Figure D-5 Private Generation Forecast Disaggregation by Substation, PacifiCorp Oregon, Base Case



The top five of PacifiCorp's 193 substations account for 15% of 2033 forecast capacity (compared to 7% of customers), with the entire top quartile (representing 49% of customers) accounting for 67%.

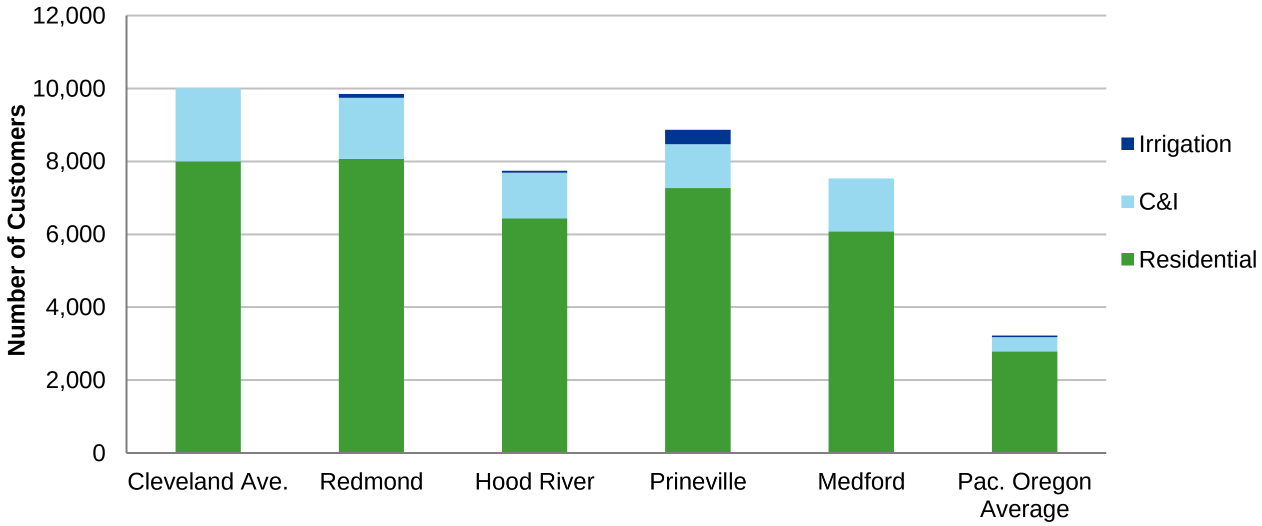
Figure D-6 Private Generation Forecast Disaggregation by Circuit, PacifiCorp Oregon, Base Case



Of the 504 circuits analyzed, the top five (representing 2.6% of customers) account for 5.2% of total forecast capacity, with the top quartile (representing 36% of customers) accounts for 59%.

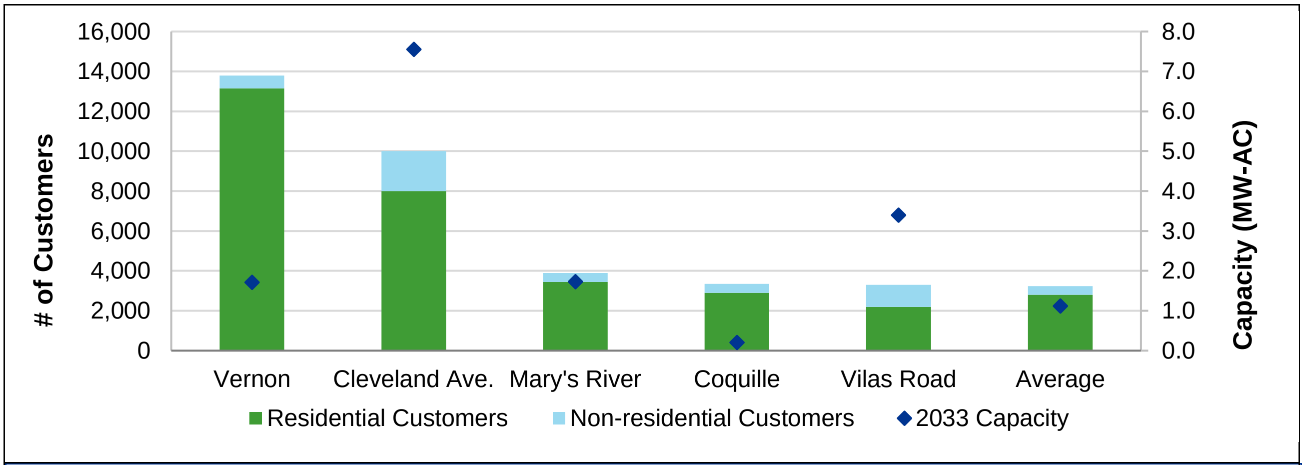
Figure D-7 shows the breakdown of customers, by sector, at the top five substations. Because capacity sizes are larger for irrigation, commercial and industrial customers than for residential (four times larger for irrigation, nine times for commercial and 17 times for industrial), C&I customers contribute to capacity totals disproportionately to their share of the customer population. New construction has a two-fold impact on the capacity forecast: Directly, since there are customers on the substation who could adopt private generation, and indirectly, since new construction has a higher propensity to adopt solar (with and without storage) than existing buildings. All substations except Hood River are in areas where population growth is higher than the statewide average.

Figure D-7 Customer Mix of Top Five Substations Compared to the Average of All Substations



With 193 substations across the state and so many factors influencing the disaggregated forecast, it is not feasible to conduct a deep dive of each substation's capacity forecast. Instead, we selected five substations to illustrate how different underlying factors affected their capacity allocations (see Figure D-8). These substations were chosen to illustrate a range of characteristics influencing adoption, not because they are of special interest for planning.

Figure D-8 Customer Attributes of Selected Substations Compared to Average PacifiCorp Oregon Substation



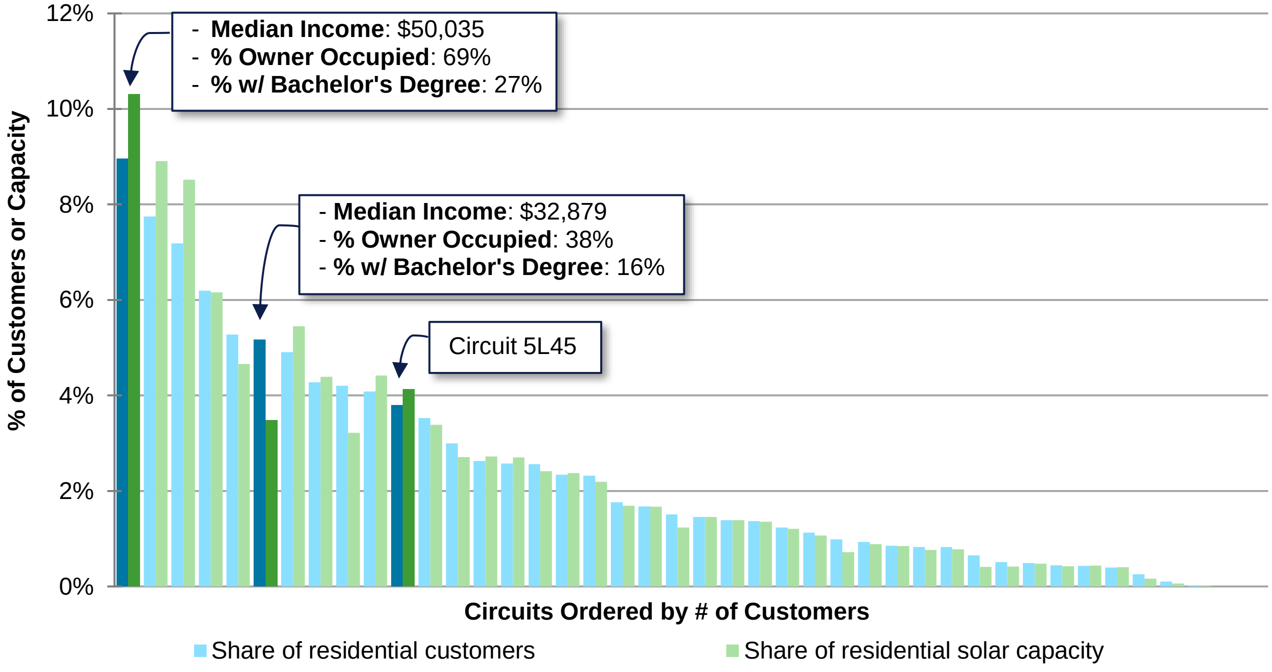
Substation Attribute	Vernon	Cleveland Ave.	Mary's River	Coquille	Vilas Road	Average
Operating Area	Portland	Bed/ Redmond	Corvallis	Coos Bay/Coquille	Medford	--
Climate (for Solar)	Less favorable	More favorable	Less favorable	Less favorable	More favorable	--
Population Growth	1.0%	2.0%	1.3%	0.0%	1.7%	1.0%
% Non-res. Customers	5%	20%	12%	13%	34%	16%
Current Res. Solar Penetration	1.4%	3.0%	3.1%	0.9%	2.4%	1.8%
Home Ownership Rate	70%	55%	61%	77%	75%	65%
Avg. Household Income	$108,604	$136,460	$102,301	$74,543	$58,752	$87,499

Vernon and Cleveland Avenue are among PacifiCorp's top substations by number of customers but have very different climates and customer mixes. Cleveland Avenue lies on the east side of the Cascades and receives more sunshine, while Vernon is in the Portland operating area, which has more rain and more cloudy days which impacts solar generation and thus adoption. Nonresidential PV systems are larger than residential systems (modeled commercial systems are 9 times larger; industrial systems are 17 times larger), so Cleveland Ave's higher share of nonresidential customers (20%) increases its capacity forecast compared to Vernon, with only 5% nonresidential customers. Cleveland Avenue also has double the rate of expected population growth that Vernon does over the next decade.

The remaining three substations shown each have a total customer count close to the state-wide average, but very different capacity forecasts. Mary's River has high historic adoption and higher-than-average population growth, but less non-residential and a lower home ownership rate than average resulted in a share of capacity almost proportional to the number of customers. Coquille has very low historic adoption, perhaps due to its less favorable climate for solar generation, and no expected population growth. Those factors, paired with lower-than-average income and low share of non-residential customers led to a very low level of forecast private generation capacity. The last substation we wish to highlight is Vilas Road in the Medford operating Area. This substation has a very high share of non-residential customers at 34%, and the higher capacity systems for these customers drives up the forecast. A favorable climate for solar with high historic adoption (residential and commercial) led to this substation being allocated a higher-than-proportional share of capacity.

Figure D-9 zooms in on the Klamath Falls operating area to compare how the allocation of PV only capacity compares to the distribution of customers by circuit. For each circuit in the Klamath Falls operating area, the chart shows the share of residential customers to the corresponding share of the 2033 residential PV Only capacity forecast. The figure demonstrates visually that more favorable factors for adoption, such as higher rates of home ownership, higher income, higher education, etc. result in a higher than proportional allocation of capacity.

Figure D-9 Share of Residential Customers vs. Share of Residential PV Only Capacity in 2033, Klamath Falls Operating Area



D.3 Conclusions

As part of the DSP, PacifiCorp evaluated each of the previously discussed private generation scenarios. However, as the baseline DSP private generation forecast, PacifiCorp considers the base case forecast to be most appropriate for planning, given current technology costs, incentive levels and net metering policies in place in Oregon.

Our analysis incorporated the current rate structures and tariffs offered to customers in Oregon. Time-of-use rates, tiered tariffs and retail tariffs that include high demand charges increased the value of PV + Battery configurations compared to PV-Only configurations while other factors such as load profiles and DER compensation mechanisms minimized the impact of such tariffs on the customer economics of PV + Battery systems. The DER compensation mechanism in Oregon — traditional net metering — does not incentivize PV + Battery storage co-adoption.

The sensitivity analysis found a greater difference between the base case and the upper bound of private generation adoption than the base case and lower bound of adoption. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. For the high case, an assumed extension to the residential federal investment tax credit provided a significant boost to adoption alongside the lower technology costs and higher retail electricity rates used in that analysis. The resulting new capacity in 2033 is about 31% less than the base case, while the high case is 84% greater than the base.

D.3.1 Future Work

Developing the circuit-level adoption models within the Oregon adoption model revealed additional areas of research related to private generation and behind-the-meter battery storage adoption that would enhance future work. The following is a list of potential future enhancements to this study:

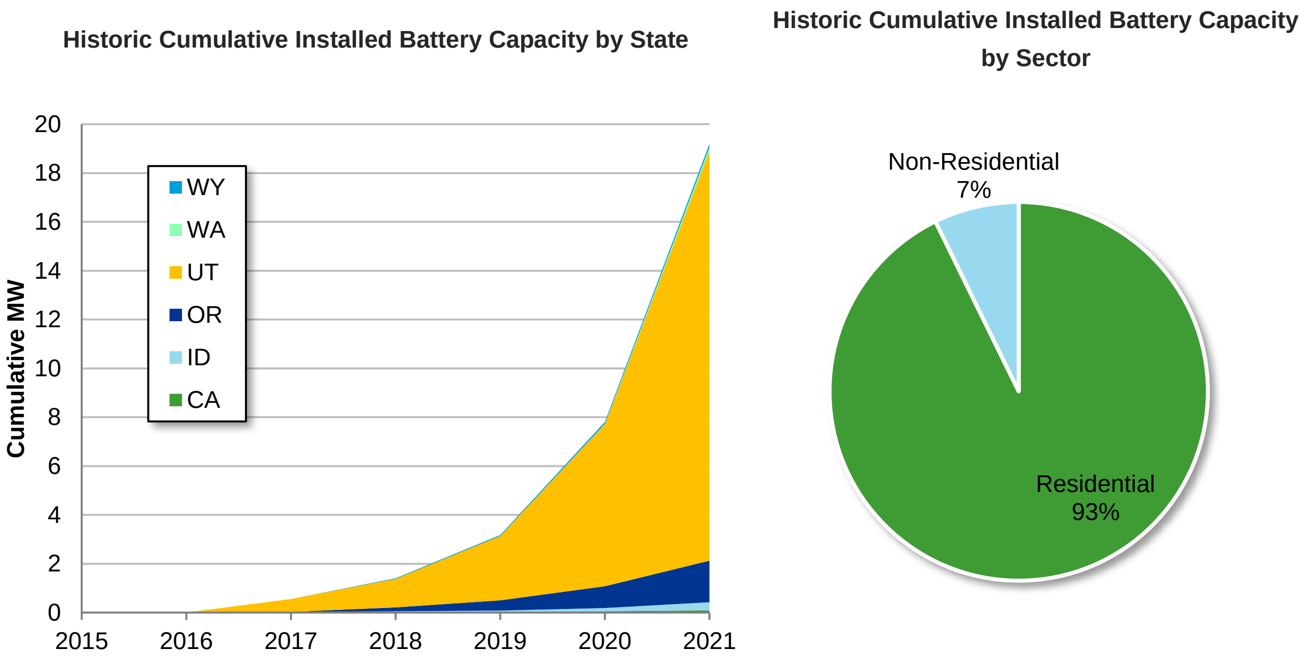
1. A more nuanced approach to the new construction forecast would consider the creation of new circuits in high-growth areas. The current study allocates new construction only to existing circuits.
2. The distribution analysis requires integrating data at different geographical resolutions (state, county, census tract and circuit). While PacifiCorp’s data mapped circuits geographically, there were challenges in matching customer billing data to circuits. This study also used existing customer counts by sector by circuit, but corresponding energy use could not be calculated at the circuit-level. Similarly, existing private generation could only be mapped at the county level since interconnection data had incomplete customer circuit information. Future studies will benefit from the circuit-level load forecasts PacifiCorp is developing for this DSP.
3. Storage dispatch modeling would benefit from a finer disaggregation of large commercial and industrial load shapes. Technology that is not broadly cost-effective could still be beneficial for customers with certain load profiles that were not visible using class-level load shapes.
4. Resilience appeared to be a significant driver of adoption. For PV + Battery storage, resilience could be a more significant driver of adoption than economics. A deeper understanding of what customer-types value resilience and how that affects their willingness to pay would help refine the forecast.

APPENDIX E BEHIND-THE-METER BATTERY STORAGE FORECAST

DNV prepared a behind-the-meter battery storage forecast as a part of the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp covering their service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington to support PacifiCorp's 2023 Integrated Resource Plan (IRP). This study evaluated the expected adoption of behind-the-meter battery storage systems coupled with PV systems over a 20-year forecast horizon (2023-2042) for all customer sectors (residential, commercial, industrial, and agricultural). Residential and non-residential battery energy storage systems (BESS) can be installed as a standalone system, added to an existing PV system, or the system can be installed together with a new PV system. DNV assumed all battery installations would be paired with a PV system in an AC-coupled configuration, as standalone systems are ineligible for the federal ITC—explained further in section 3.2.5.

The adoption model DNV developed for this study is calibrated to the current[26] installed and interconnected behind-the-meter battery capacity that is paired with a PV system, shown in Figure E-1.

Figure E-1 Historic Cumulative Installed Behind-the-Meter Battery Storage Capacity, PacifiCorp, 2012-2021


Historic Cumulative Installed Battery Capacity by State

Historic Cumulative Installed Battery Capacity by Sector

E.1 Study Methodologies and Approaches

DNV modelled two technologies in the behind-the-meter battery storage forecast:

1. **PV + Battery**: BESS product installed together with a new PV system,
2. **Battery Retrofit**: BESS product installed as an add-on to an existing PV system.

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[26] PacifiCorp private generation interconnection data as of February 2022.

DNV used the same forecasting methodologies and approaches for the BTM battery storage forecast as the private generation forecast. The methods used to develop the results of the forecast are described in detail in section 3.4 of the report.

Data on battery system costs used in the BTM battery storage forecast is explained in detail in section 3.1.1.2 of the report. That section includes current and projected future costs of battery storage systems used in the forecast for the different sectors. The detailed assumptions for the system configurations, including system sizes, in each sector and state can be found in Appendix A.

E.1.1 Battery Dispatch Modelling

DNV utilized its proprietary solar plus storage operational modeling tool—Lightsaber—to model battery dispatch. Battery dispatch strategy dictates the flow of energy between the PV system, battery, and the grid. The battery dispatch model includes strategies such as peak shaving, energy arbitrage, and manual dispatch. Self consumption was modelled for all sectors' BESS control strategy, which utilizes the battery by charging only from excess PV and discharging if PV production falls below load. For residential customers, the dispatch model used energy arbitrage to reduce time-of-use charges. For non-residential customers, the dispatch model used energy arbitrage to reduce demand charges and time-of-use charges, where applicable.

E.2 Results

In the base case scenario, DNV estimates 227 MW of new battery storage capacity will be installed in PacifiCorp's service territory over the nest twenty years (2023-2042). Figure E-2 shows the relationship between the base case and low and high case scenario forecasts. The low case scenario estimates 151 MW of new capacity over the 20-year forecast period—compared to base case, retail rates increase at a slower rate and technology costs decrease at a slower rate. In the high case, retail rates increase at a faster rate and technology costs decrease at a faster rate—this results in 264 MW of new private generation capacity installed by 2042. The twenty year total new capacity forecasted in the high case is about 16% greater than the base case, while the low case is 34% less.

Table E-1 Cumulative Adopted Battery Storage Capacity by 2042, by Scenario

SCENARIO	CUMULATIVE CAPACITY (2042 MW)
Base	227
Low	151
High	264

Figure E-2 Cumulative New Battery Storage Capacity Installed by Scenario (MW), 2023-2042

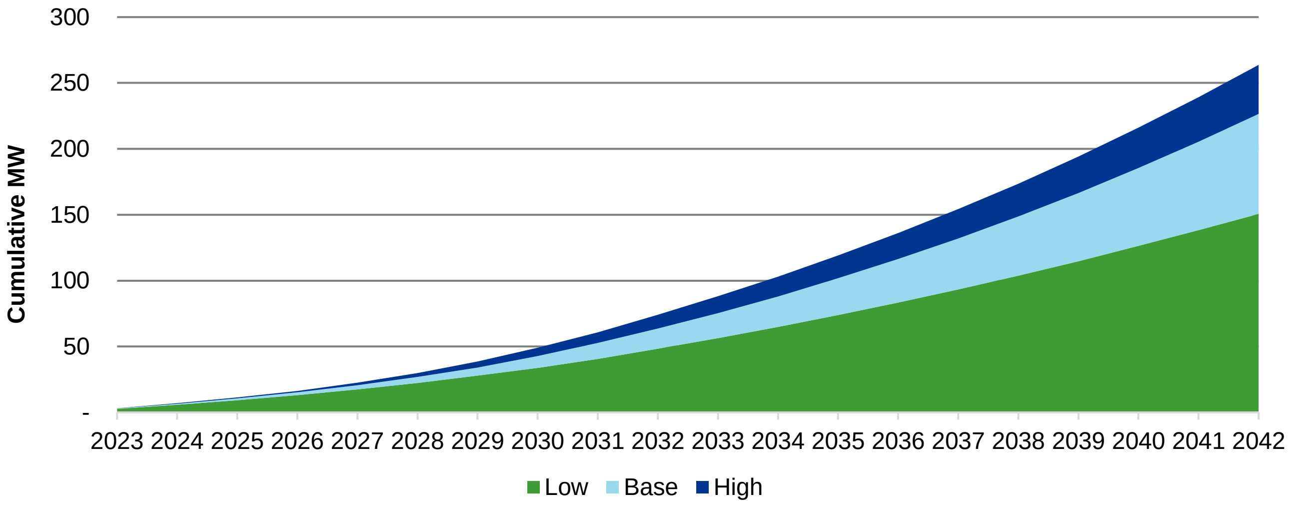


Figure E-3, Figure E-4, and Figure E-5 show the forecasts by customer sector and technology for each scenario. In all scenarios of the forecast, the residential sector represents about 90% of the new battery storage capacity forecasted to be installed over the next twenty years. The commercial, industrial, and irrigation sectors have been bundled into a single “Non-Residential” sector for the purpose of presenting the results in the report, as the capacity forecasts in the individual sectors are very small relative to the total forecast. PV + Battery systems represent the greatest share of the new battery capacity forecasted in the base and high cases. Battery Retrofit systems representing a greater share of the new battery capacity forecasted in the low case indicates that customers are more likely to adopt a PV Only system over a PV + Battery system when technology costs are higher and electricity rates are lower.

Figure E-3 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, Base Case

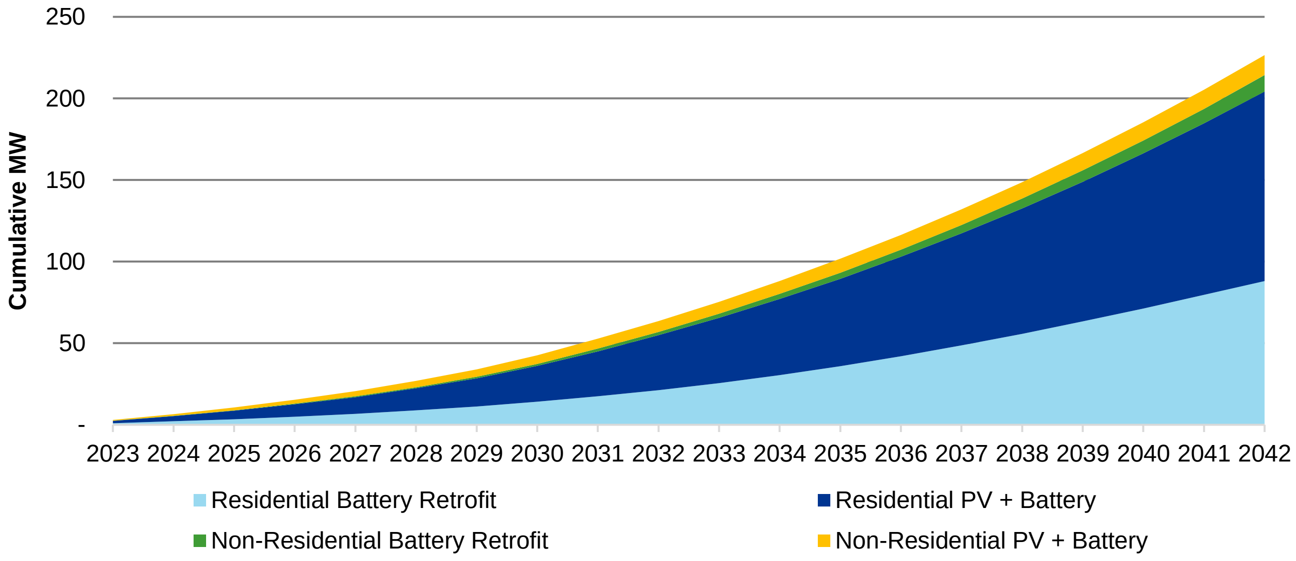


Figure E-4 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, Low Case

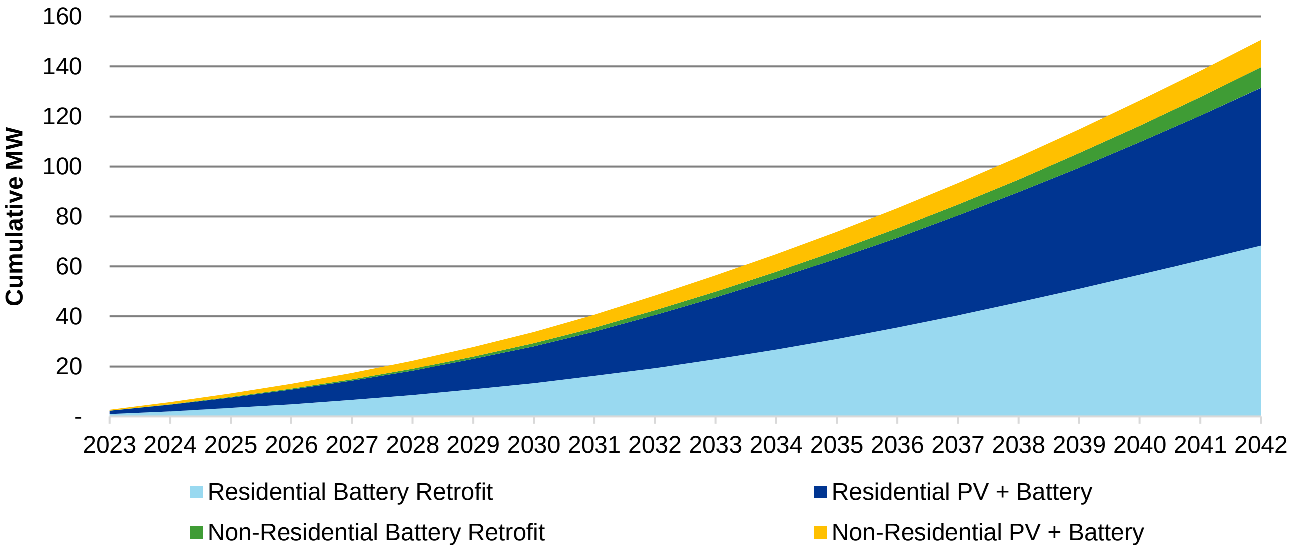
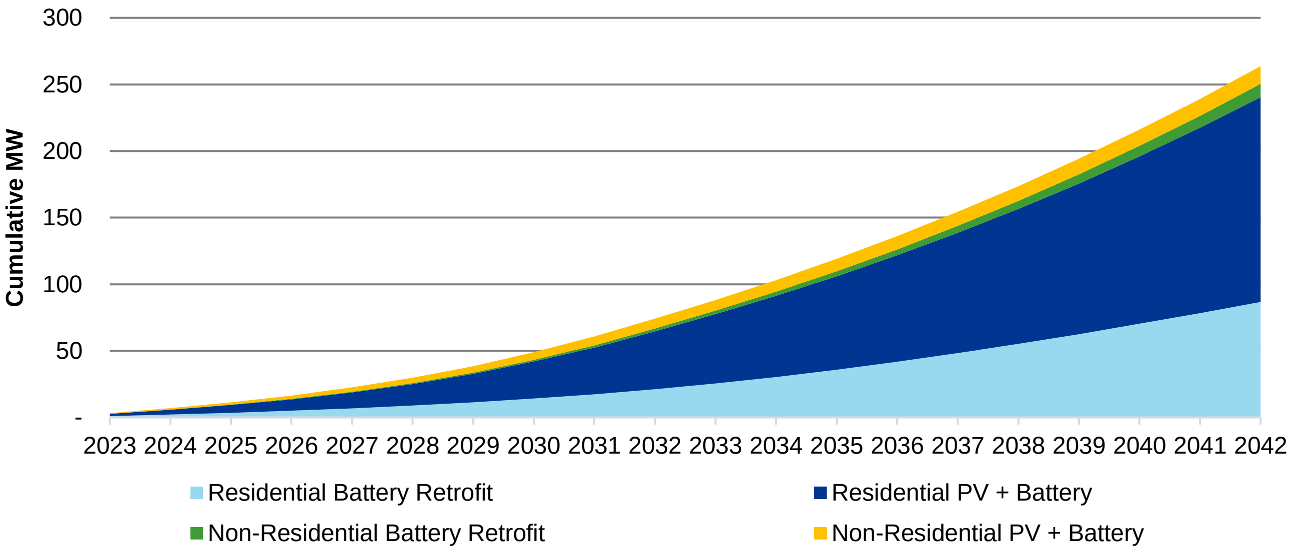


Figure E-5 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, High Case



E.3 Storage Capacity Results by State

As was the case in the private generation forecast, Utah represents the largest share of the battery capacity forecast. To date, the majority of installed battery storage capacity and annual growth in storage capacity has been in Utah, which represents the largest portion go PacifiCorp’s customer population. Battery adoption is expected to continue to grow in Utah, with the state’s share of total new capacity reaching between 81% and 84%, depending on the scenario, over the next twenty years. The net billing structure in place in Utah incentivizes PV + Battery storage co-adoption more so than traditional net metering, as customers can lower their electricity bills by charging their batteries with excess PV generation and dispatching their batteries to meet on-site load during times of day when retail energy prices are high. Oregon represents the second largest portion of the new capacity forecasted, between 8% and 10%. Net metering is the DER compensation mechanism in place in Oregon, but customer economics are boosted by PV + Battery incentives provided through the Oregon Department of Energy[27].

Figure E-6 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, Base Case

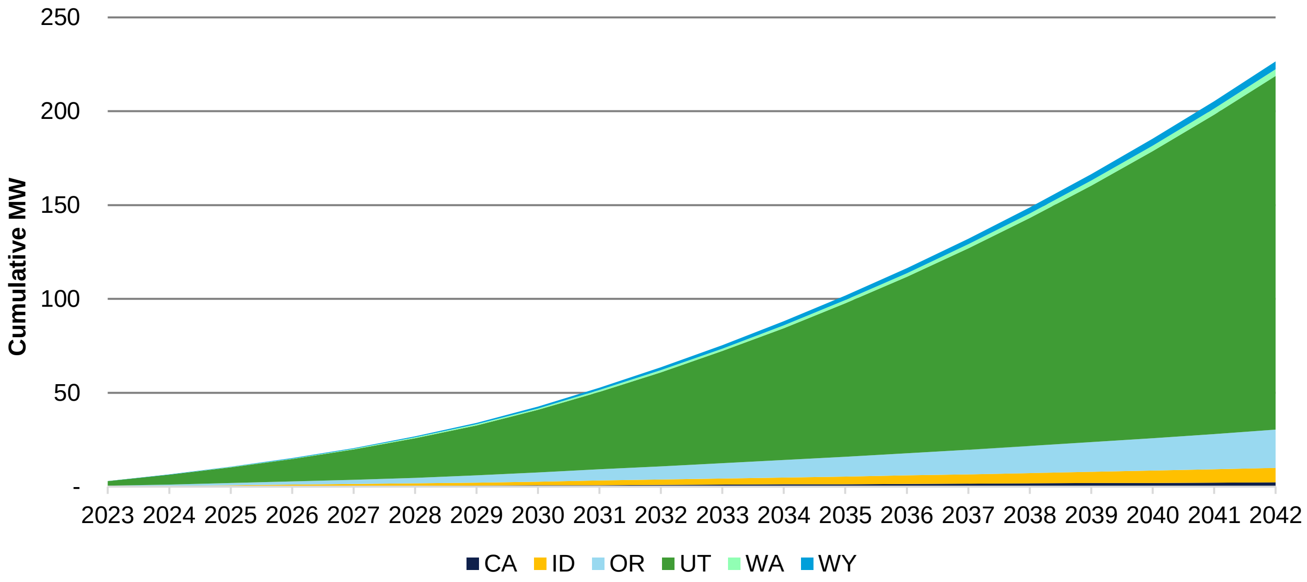
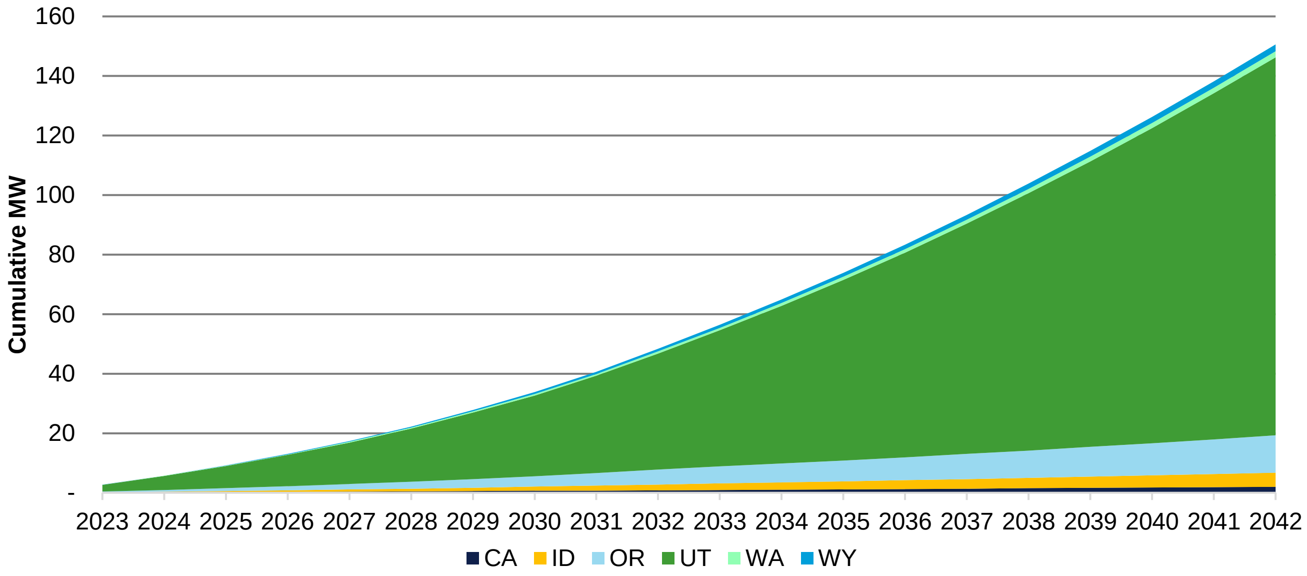


Figure E-7 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, Low Case



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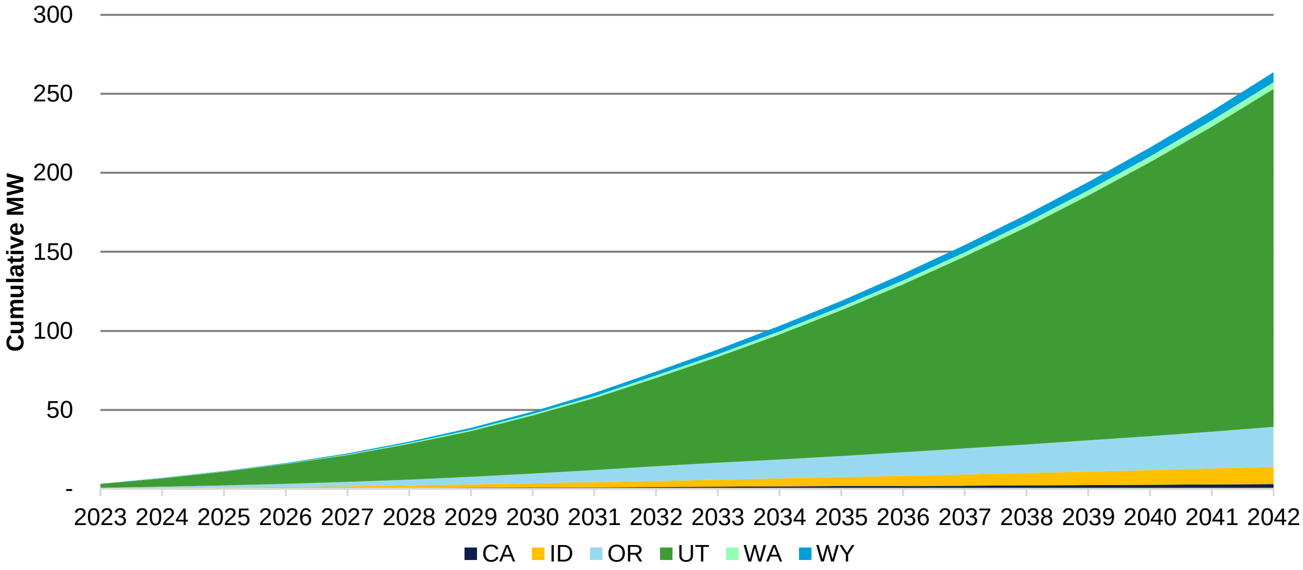
[27] https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx

Figure E-8 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, High Case



The following figures show the state-level forecasts in more detail. Background and commentary on the individual states' results can be found in section 4.1 of the report.

California

Figure E-9 Cumulative New Battery Storage Capacity Installed by Scenario (MW), California, 2023-2042

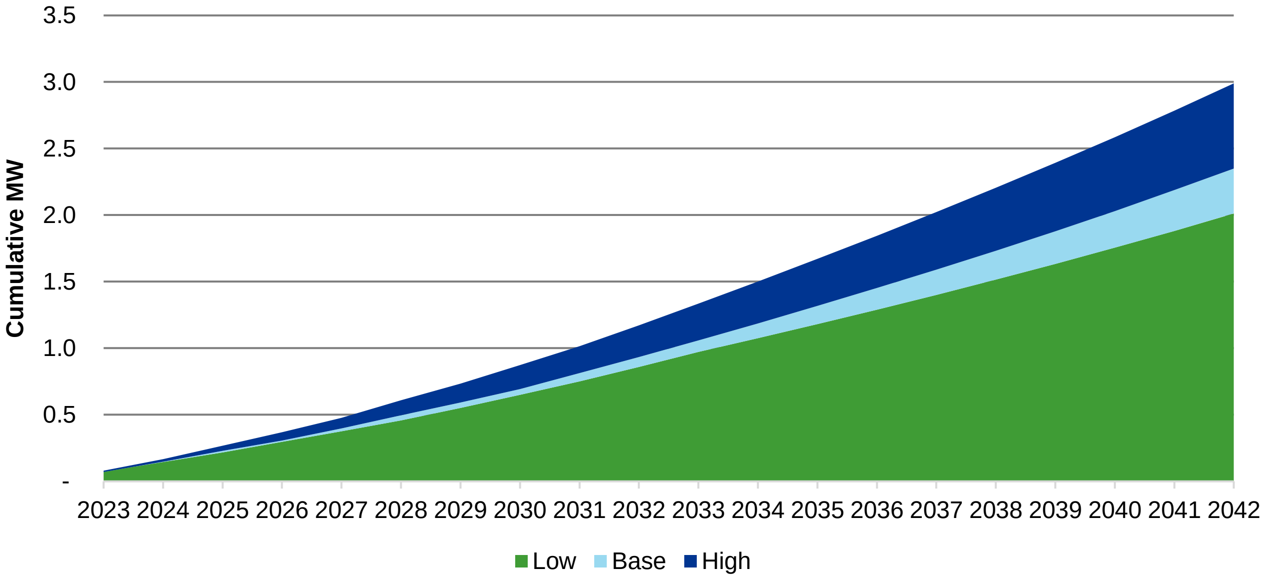
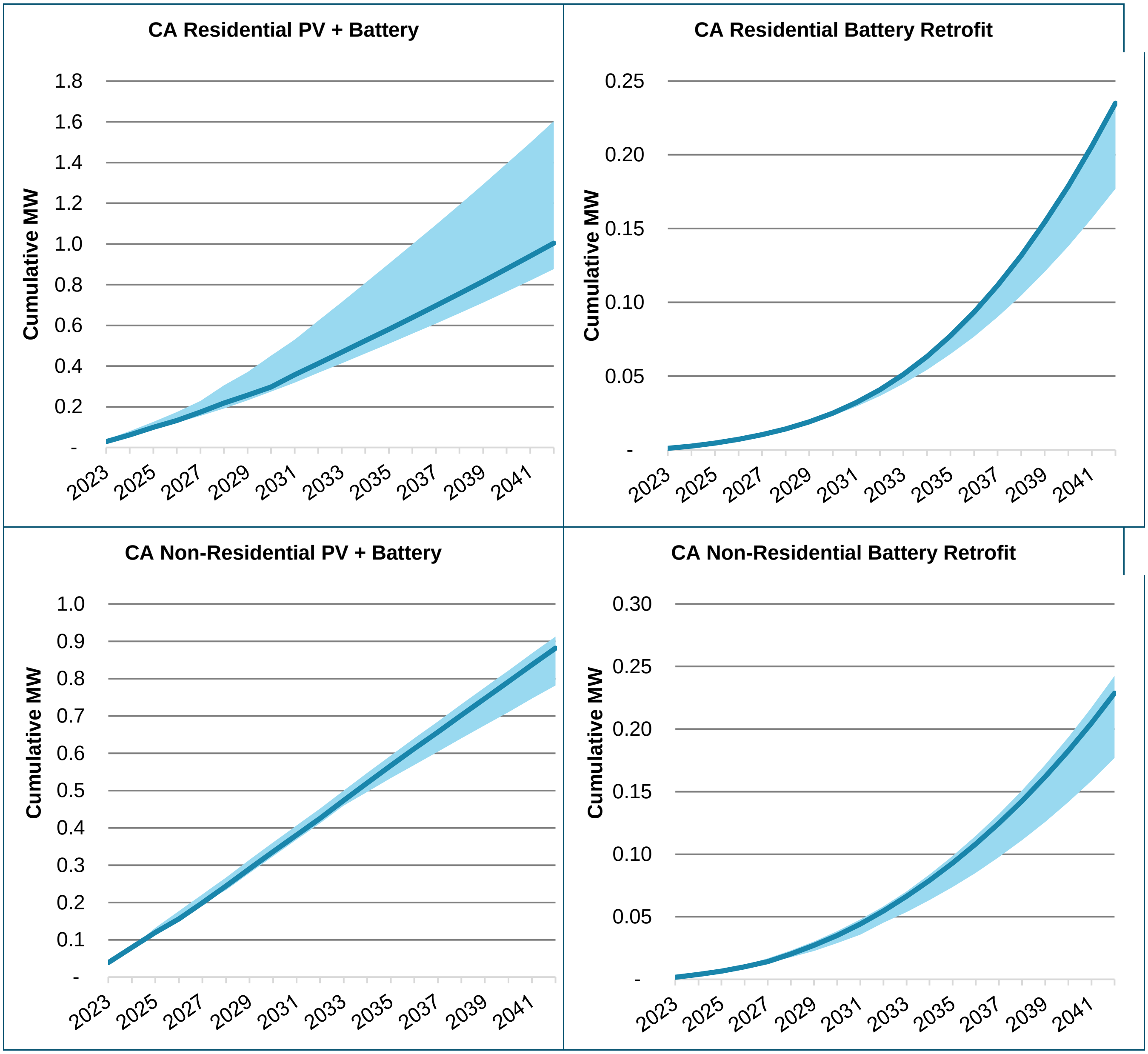


Figure E-10 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), California, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



Idaho

Figure E-11 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Idaho, 2023-2042

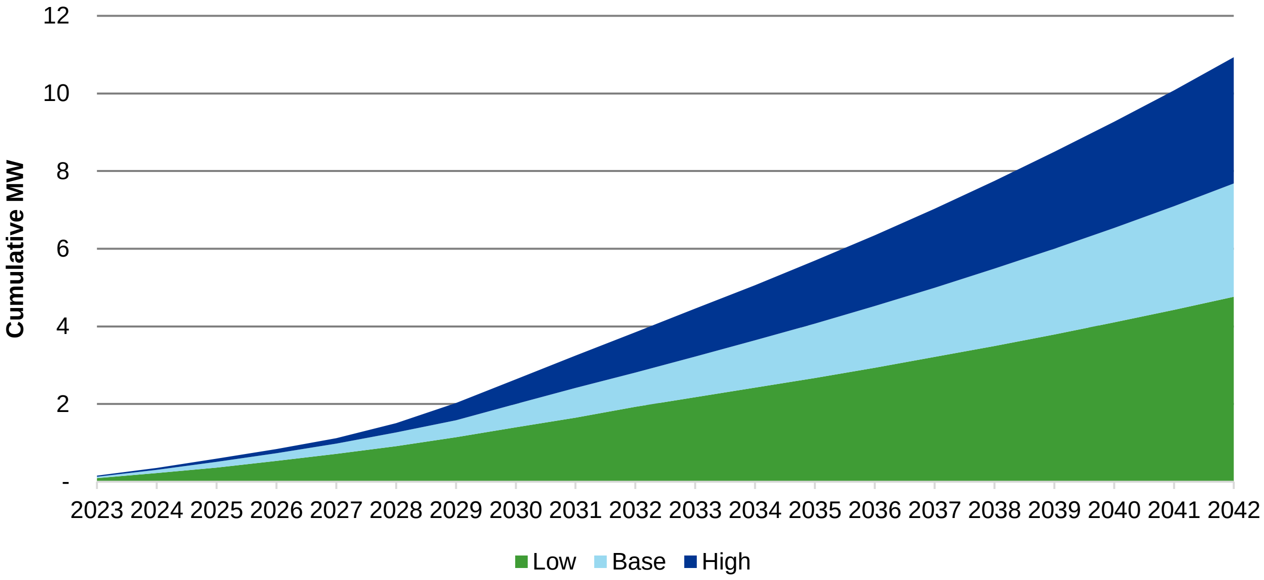
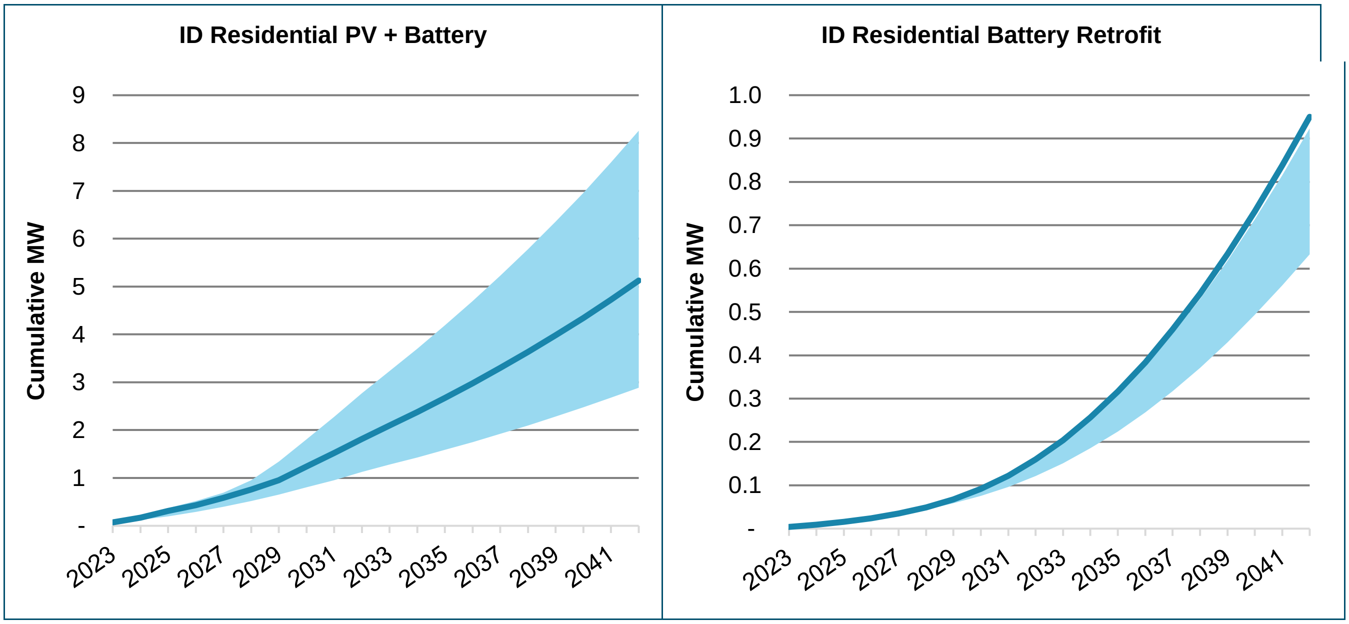
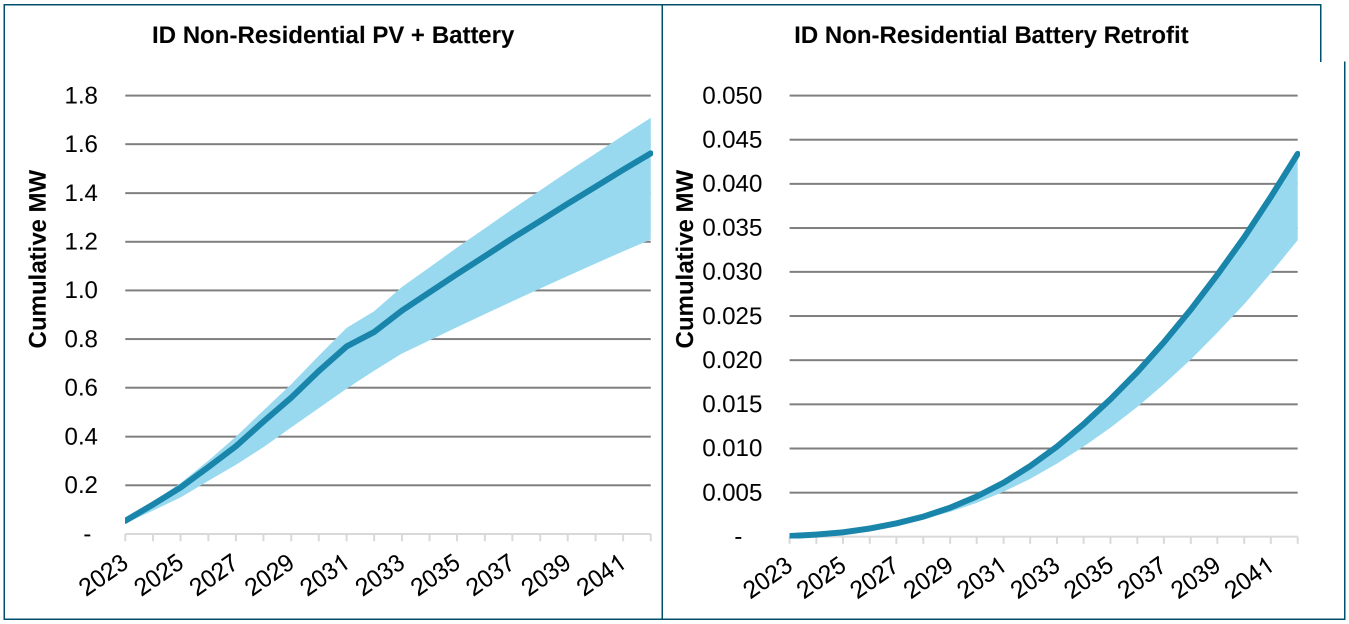


Figure E-12 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Idaho, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.




ID Non-Residential PV + Battery

ID Non-Residential Battery Retrofit

Oregon

Figure E-13 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Oregon, 2023-2042

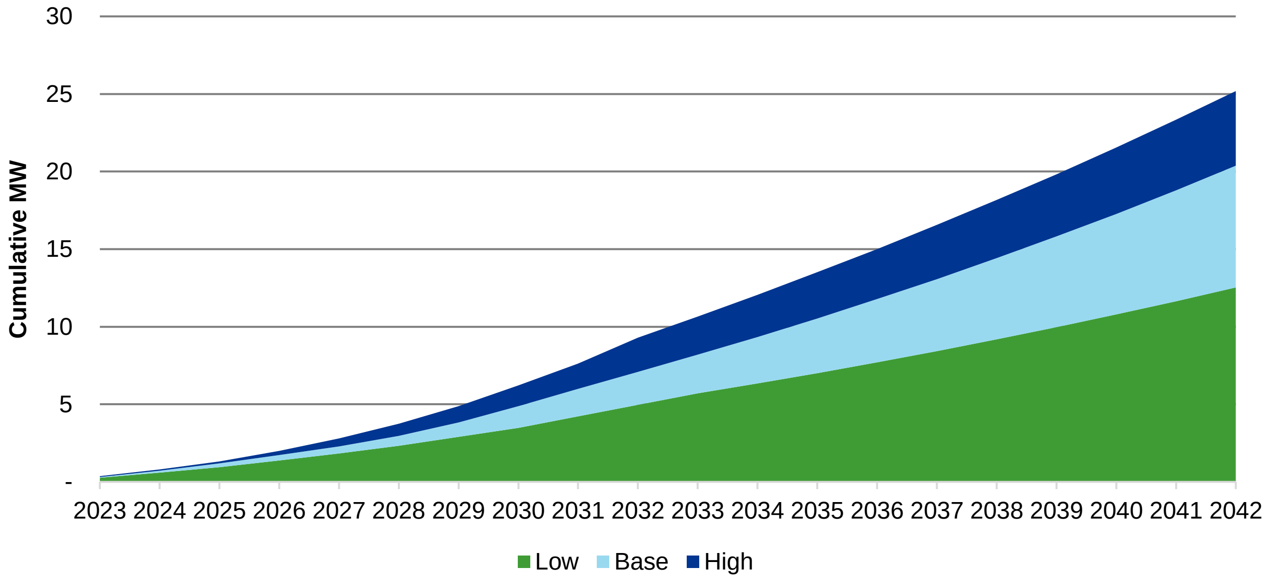
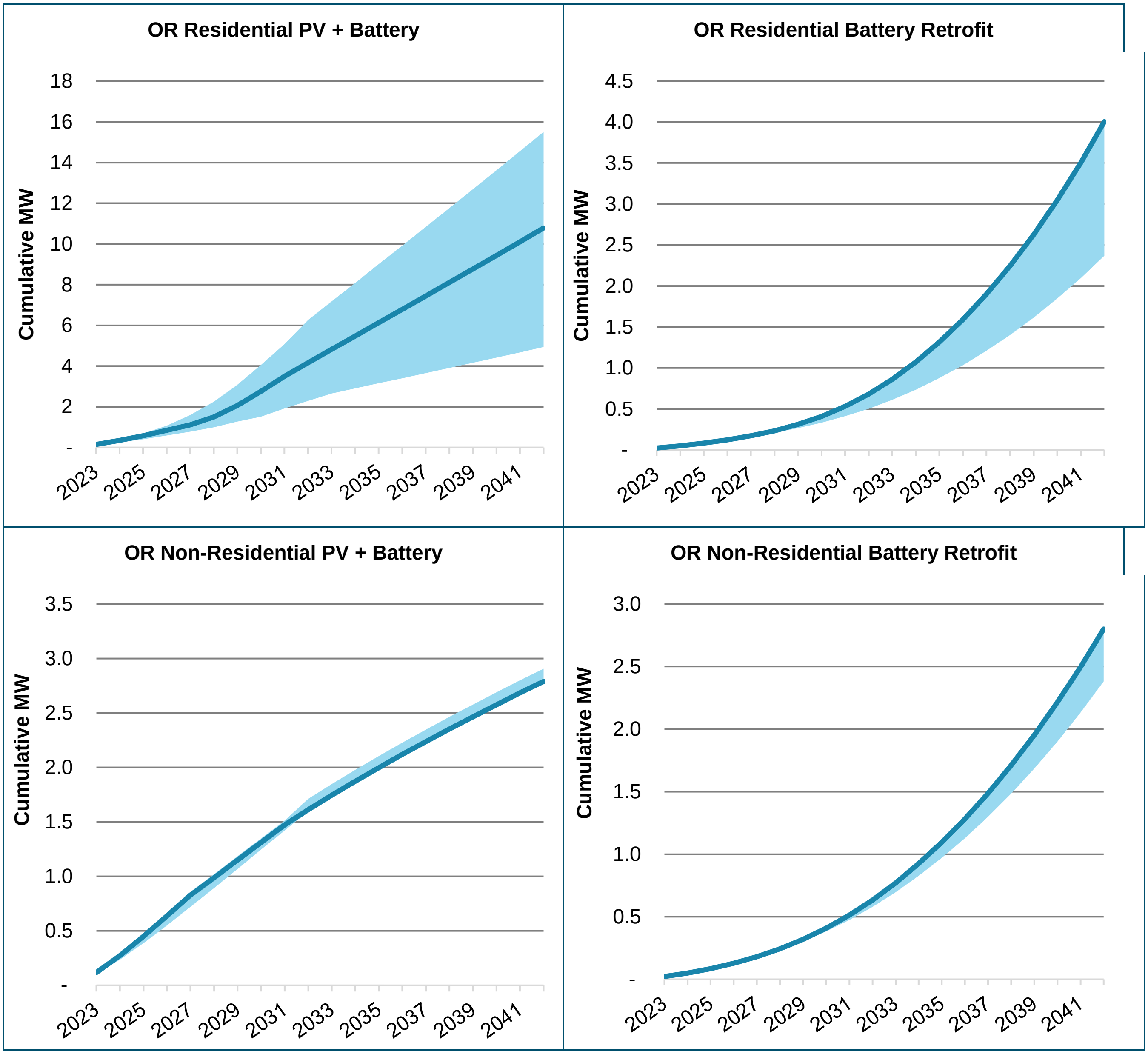


Figure E-14 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Oregon, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



Utah

Figure E-15 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Utah, 2023-2042

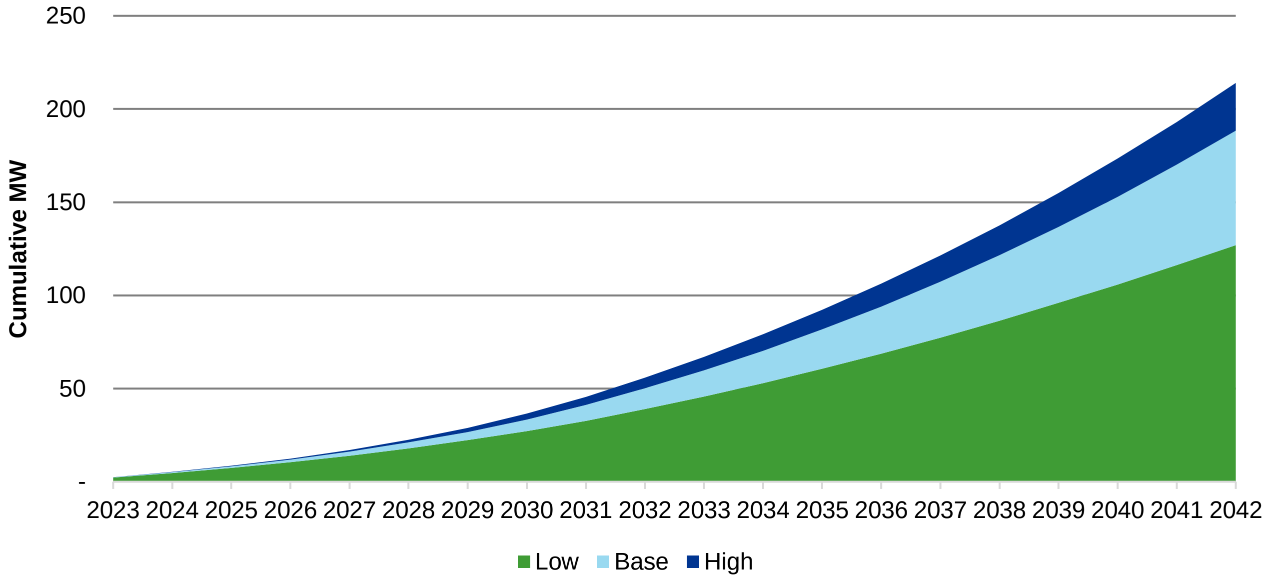
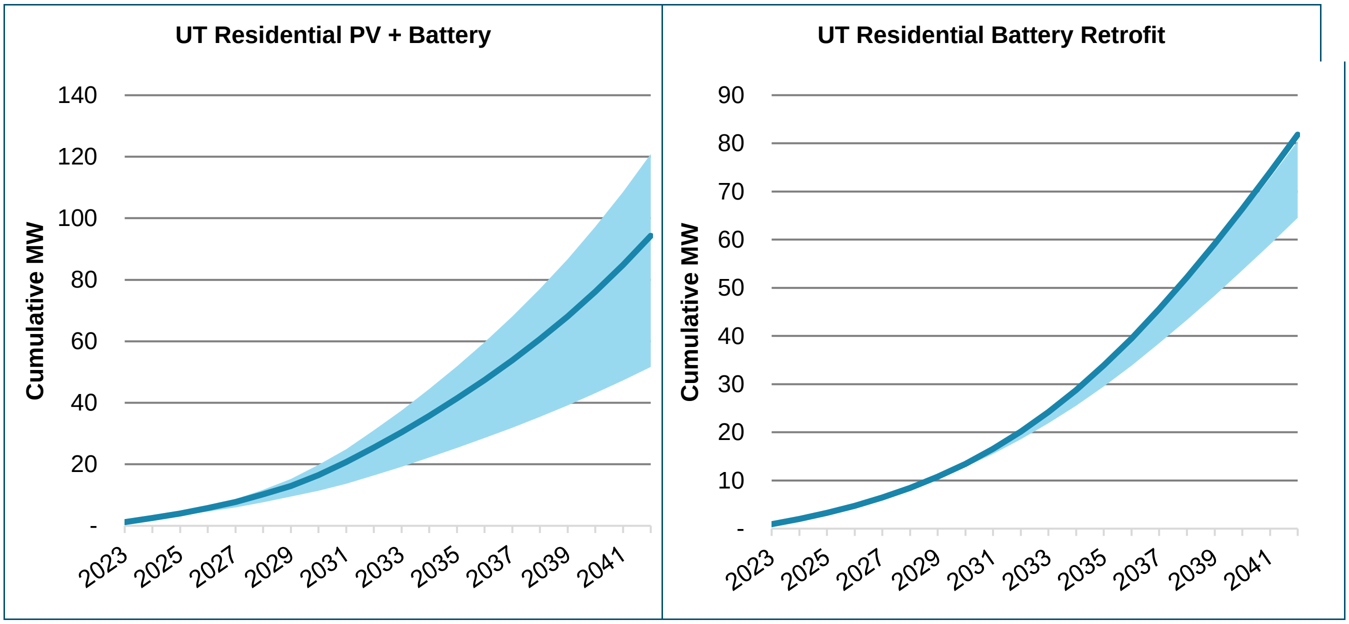
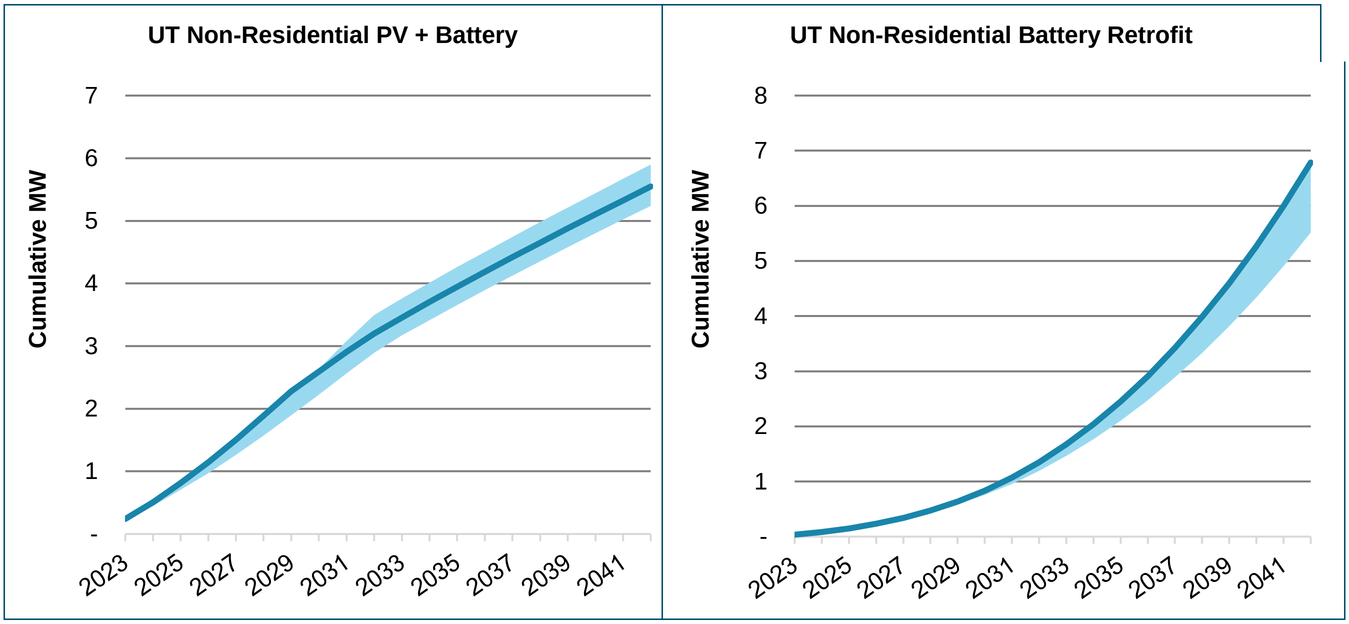


Figure E-16 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Utah, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.





Washington

Figure E-17 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Washington, 2023-2042

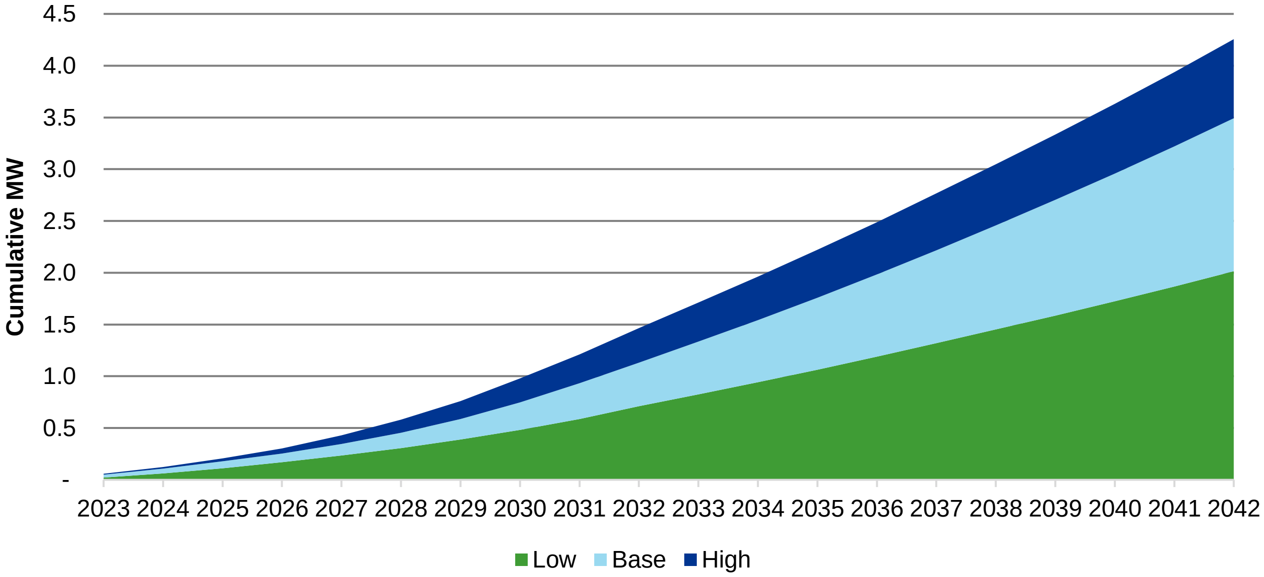
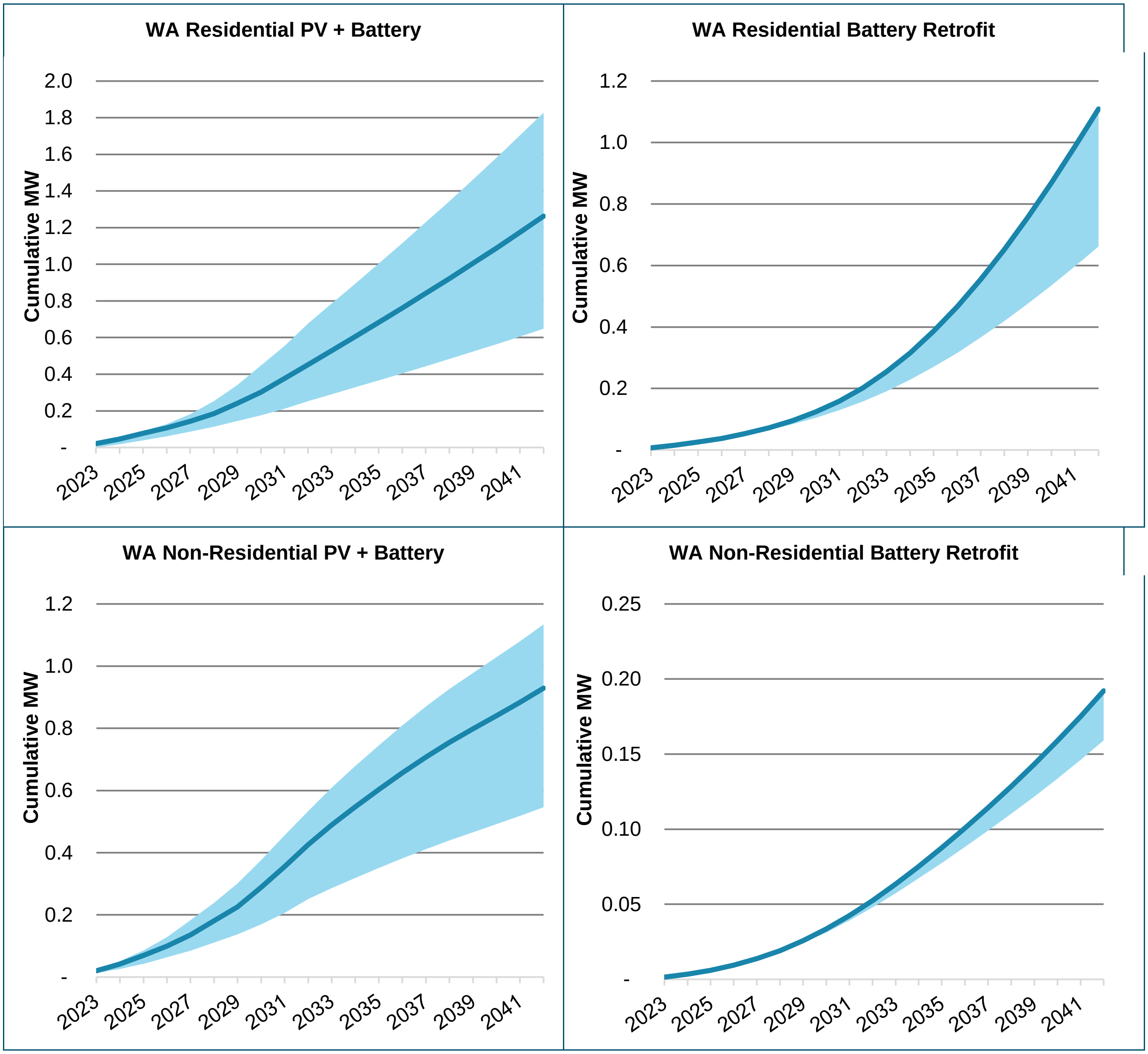


Figure E-18 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Washington, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



WA Residential PV + Battery

WA Residential Battery Retrofit

WA Non-Residential PV + Battery

WA Non-Residential Battery Retrofit

Wyoming

Figure E-19 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Wyoming, 2023-2042

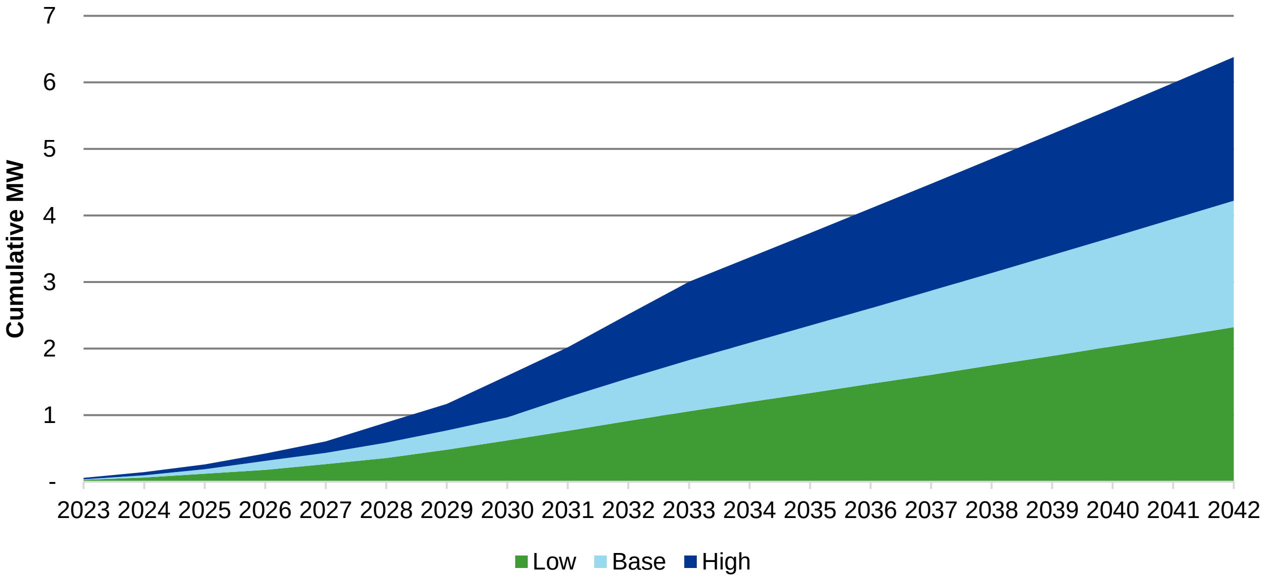
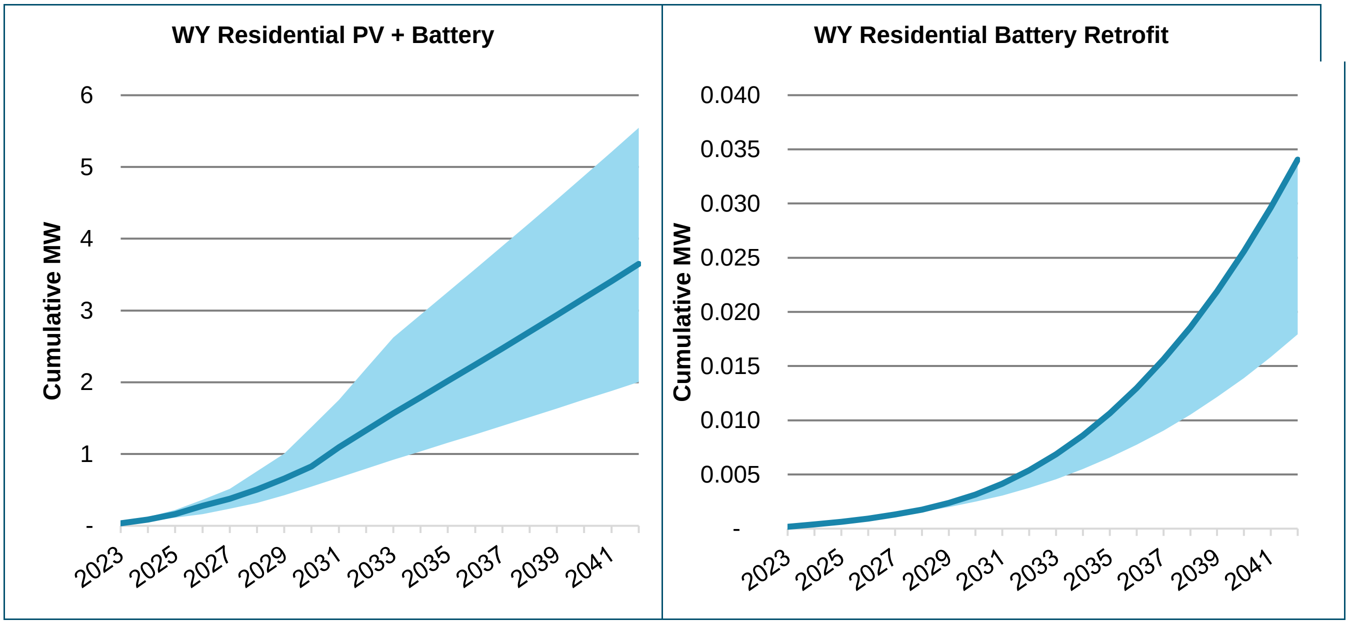
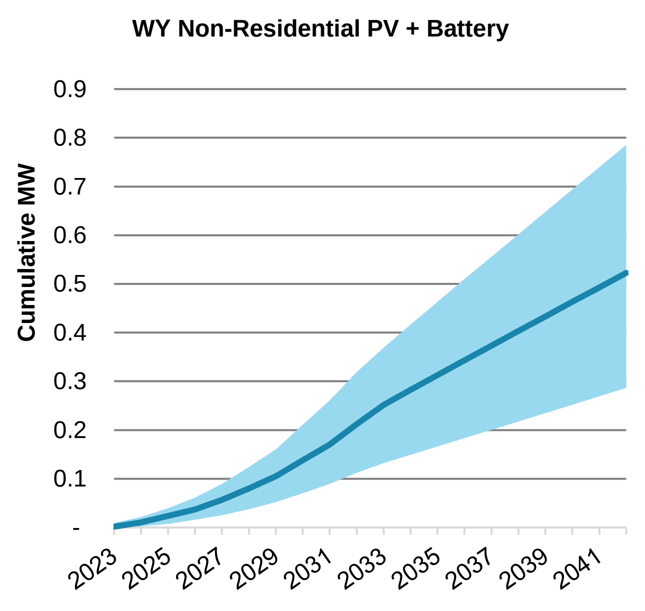
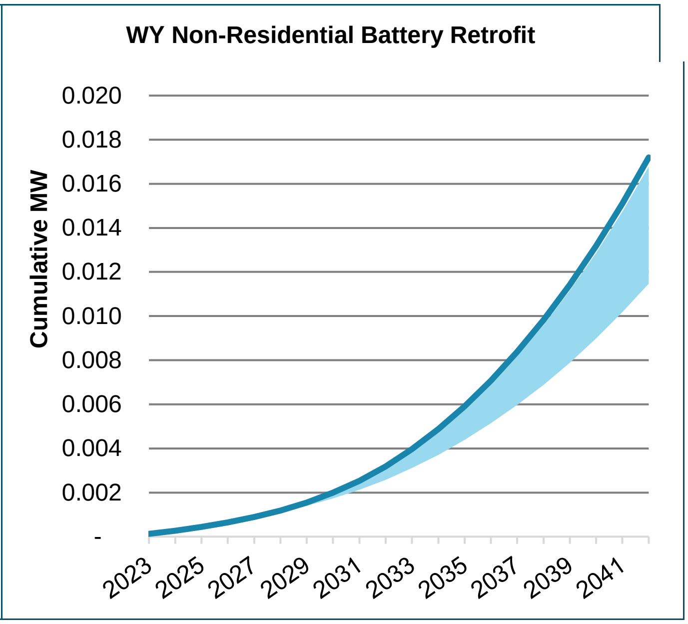


Figure E-20 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Wyoming, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.




WY Non-Residential PV + Battery
Cumulative MW
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
-
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041


WY Non-Residential Battery Retrofit
Cumulative MW
0.020
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
-
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041

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