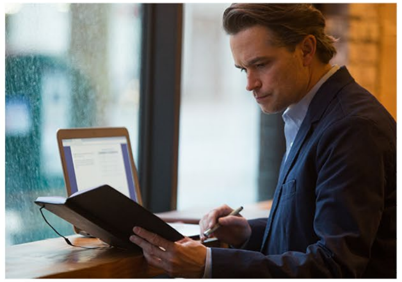
2025 Integrated Resource Plan Public Input Meeting
May 2, 2024





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Purpose Statement

The primary focus is the customer

- ❖ Transparency
  - Assumptions
  - Constraints
- ❖ Close the gap between planning, implementation, and execution
- ❖ Agnostic to technology
  - Cost driver
  - Reliability driver

Multi-State Approach

- ❖ Specific timing for milestones in six states
- ❖ Stakeholder feedback is critical to improving the quality of the work product
- ❖ Milestones will be delivered based on the most restrictive state timing
- ❖ Abide by each state's specific policies if applicable

Agenda

– This meeting will be recorded and made publicly available –

SCHEDULE*	TOPIC
9:00 AM – 9:15 AM	Introduction
9:15 AM – 10:30 AM	Conservation Potential Update
10:30 AM – 11:30 AM	Distributed Generation Study Overview
11:30 AM – 12:00 PM	Transmission Modeling Strategy
12:00 PM – 12:45 PM	Break
12:45 PM – 1:00 PM	March price curve update
1:00 PM – 2:00 PM	2023 IRP Update Outcomes
2:00 PM – 2:15 PM	Stakeholder Feedback
2:15 PM – 2:30 PM	Summary & Next Steps

* Timing and arrangement are approximate and subject to change.

Conservation Potential Assessment - Update

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Schedule and Milestones

Throughout the 2025 CPA development process, we will continue to request feedback from interested parties.

Timeframe	Milestone	Public Input Request
~~January 25, 2024~~	~~Present on Scope of Work~~	~~Additional input on scope~~
~~March 14, 2024~~	~~Share Draft EE & DR Measure List~~	~~Provide feedback on included measures~~
~~April 8, 2024~~	~~Finalize Measure List~~	~~Feedback incorporated~~
May 2, 2022	Share Key Drivers of Potential and Assumptions	Review methodology and resources
September 2024	Present Draft Results and Share Measure Data	Review materials and provide feedback
October 2024	Present Final Supply Curves	Review changes made due to feedback
November 2024	Draft CPA for Review	Provide input on draft report
January 2024	Publish Final Report	With feedback incorporated

Energy Efficiency Measures






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Baselines & Considerations

AEG will develop baselines unique to how DSM planning is conducted in each state. Examples include:

- State Building Codes
  - ASHRAE 90.1, IECC or State-Specific (see table below)
- Federal equipment efficiency standards with applicable state-specific adjustments
- Baseline market data for equipment and measure saturation
  - PacifiCorp surveys, project data
  - Regional Technical Forum and California CPUC/eTRM
  - National and census region-specific saturation data

State	Residential Energy Code Used	Non-Residential Energy Code Used
California	2022 Building Energy Efficiency Standards, Title 24	2022 Building Energy Efficiency Standards, Title 24
Washington	Washington State Energy Code (WSEC) 2021	Washington State Energy Code (WSEC) 2021
Idaho	2018 IECC with amendments	2018 IECC
Utah	2021 IECC with amendments	2021 IECC
Wyoming	2018 IECC with adjustments	2018 IECC with adjustments

Baselines & Considerations, Cont.
Federal Policy

- Tax incentives introduced on January 1, 2023 for the Inflation Reduction Act (IRA), focused primarily on low- and moderate-income households and disadvantaged communities by supporting upgrades in heating, cooling, weatherization, and comprehensive home improvements.
- In the 2023 IRP, AEG collaborated with PacifiCorp to integrate IRA and IIJA impacts into their study by adopting faster ramp rates for measures targeting specific customer groups.
- This approach updates the 2021 Power Plan's ramp rates to reflect quicker adoption due to federal legislation.

Baselines & Considerations, Cont.
State Code Adoption

- Dynamic State Energy Codes:
  - State energy codes adapt swiftly to changing circumstances.
  - RTF energy code assumptions may lag behind these transformative changes.
  - AEG identifies future code adoptions intervals and incorporates final rulemaking assumptions into technology and building code measure forecasts (i.e. WSEC 2021)

Drivers of Difference in Forecasted Potential by State






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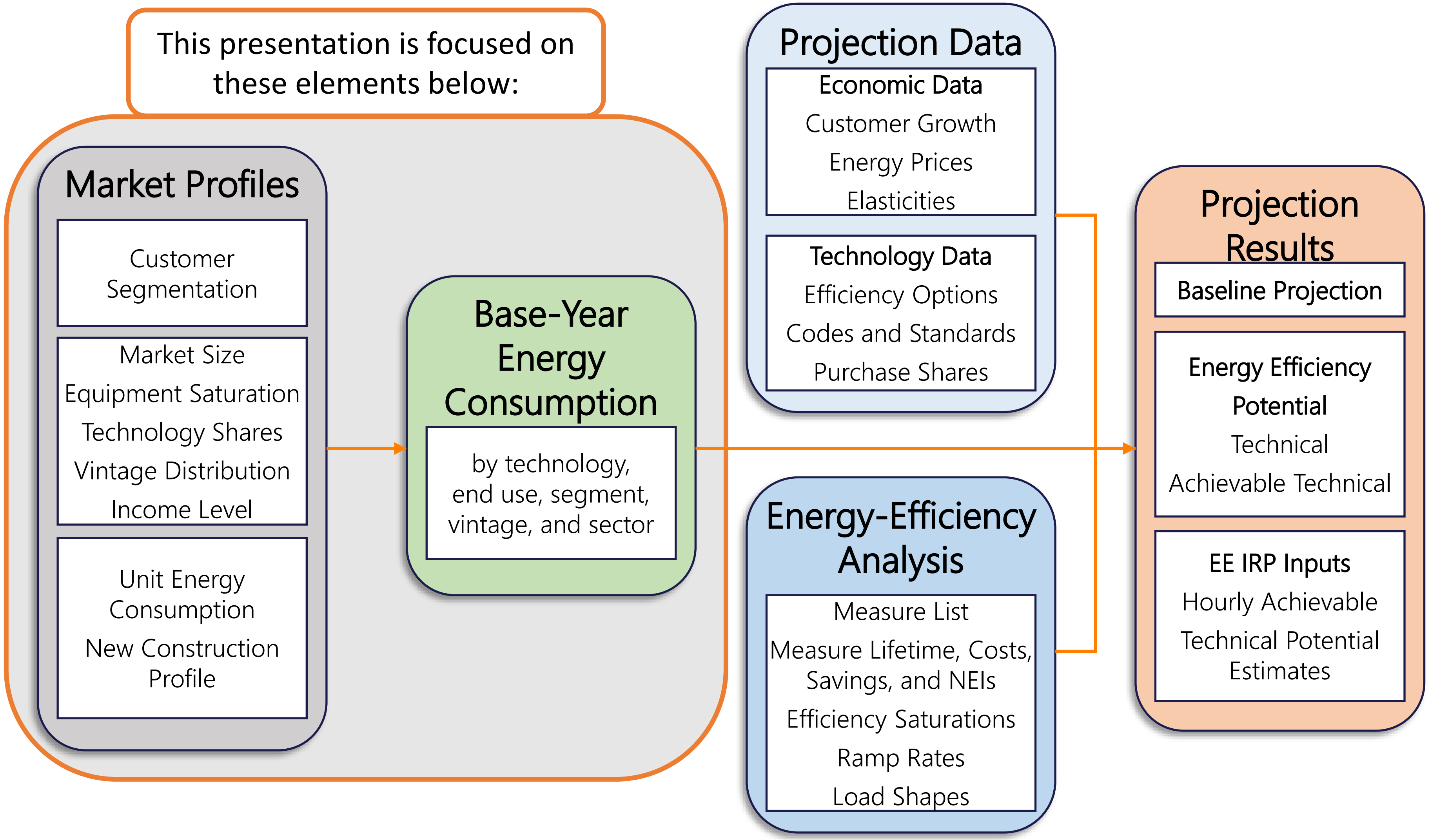
CPA Methodology



Key Drivers of Differences between States

- Technical Drivers:
  - Distribution of Customers and Sales by Sector Forecasts by Sector
  - Sub-Sector Share of Load
  - Sector-Specific Measures
  - Climate
  - Equipment Saturations
  - Ramp Rates
- Other Drivers:
  - Cost-Effectiveness Requirements by State
  - Measure Sourcing Requirements
  - Stringency of Local Building Codes and Standards

This presentation is focused on these technical drivers

Baseline Load Considerations and Effects on Potential

Residential Low-Income Segmentation

- Threshold definitions for base year 2023 (same as Residential Survey year)
  - Three income categories: low, moderate, and regular-income
  - Combination of federal poverty guidelines (FPG) and state median income (SMI), depending on LIHEAP annual income and household size levels

Jurisdiction	**Threshold Definitions**		
	Low-Income:	**Moderate-Income:** Above LI and Below:	**Above-Moderate Income:**
CA	≤ 60% SMI	≤ 100% SMI	> 100% SMI
ID	≤ 200% FPG		
OR	≤ 200% FPG		
UT	≤ 200% FPG		
WA*	≤ 60% SMI ≤ 200% FPG		
WY	≤ 60% SMI		

**WA low-income was split by household size.*
If less than 7 people per household, used 60% of SMI and if greater than 7, used 200% FPG.

Differences in Consumption by Sector

- State-level consumption by sector drives overall savings opportunities
  - States with higher industrial and irrigation loads tend to have lower savings potential compared to overall load due to fewer opportunities
  - Different measure-level opportunities by sector and sub-sector
- Residential and commercial sectors generally have higher savings potential
  - More measure options
  - Often, more mature programs have more potential in early years due to more advanced ramp rates

Drivers of Residential Differences Across States

Location and Climate	Overall Household Energy Use	Saturation of Equipment
• Differences in climate and location drive the saturation of cooling equipment and the run time of heating equipment • More rural communities have higher saturations of electric heating equipment due to lack of natural gas access	• Differences in household usage drives difference in certain end uses • Example: types of existing heating equipment varies by home type, which drives the amount of heating potential	• Higher saturations of electric heating and water heating equipment increase overall household baseline energy use and present more savings opportunities

Drivers of Commercial Differences Across States

Building Type

- Certain equipment is more applicable to certain building types
- **Example**: Compared to offices, grocery has more refrigeration consumption, lodging has more water heating consumption

Climate and Location

- Much like residential, climate can have a large impact due to varying runtimes
- Access to natural gas service affects saturation of electric space and water heating

Data Sourcing

- Data sourcing is more of a driver of difference than residential because third-party sources are required for commercial
- **Example**: Different sources for RMP and Pacific Power states – CBECS and CBSA

Drivers of Industrial Differences Across States

Industry Type

- The industry type drives the savings potential
- Example: Some industrial facilities may look more like a warehouse while others are heavy processing, presenting different savings opportunities due to equipment types and operation schedules

Applicable Measures

- Opportunities differ by what equipment types are present in the facility. Some industries have high compressed air loads, others may be driven more by motors or lighting loads.
- Projects tend to be highly customized, capital-intensive, and may require interruptions to operations, affecting their technical feasibility.

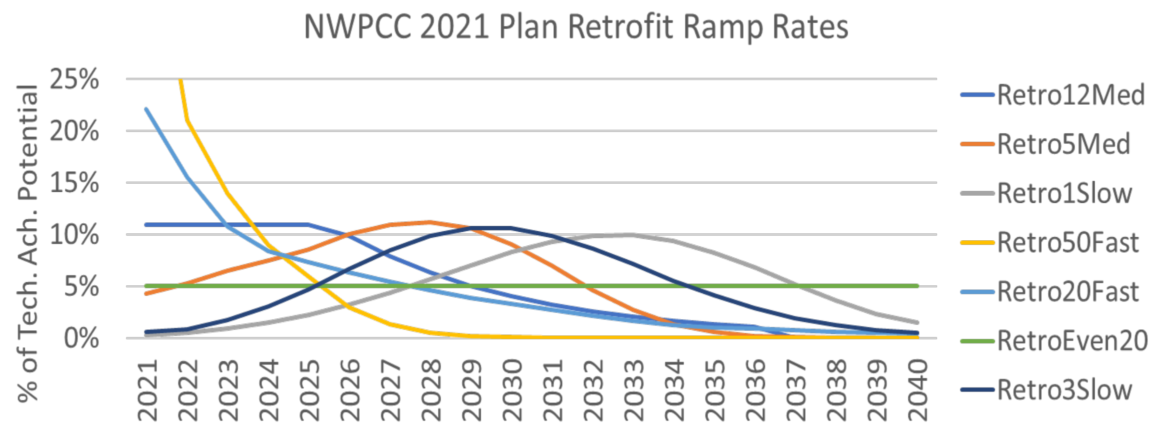
Data Sourcing

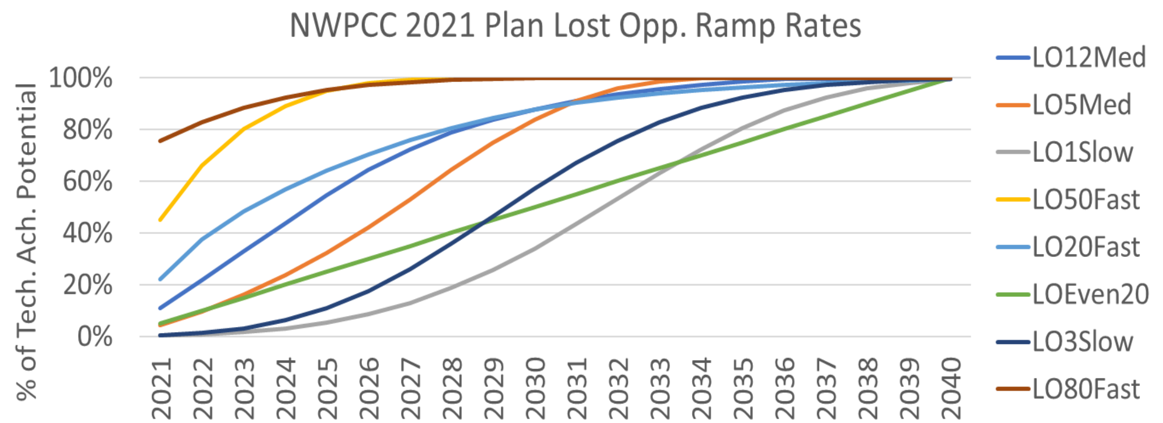
- Data sourcing is more of a driver of difference than residential because third party sources are required for industrial saturations.
- Example: Different sources for RMP and PAC states – MECS for RMP and NWPCC for Pacific Power

Climate is a much lower driver of difference in industrial than in other sectors

Ramp Rates

- Ramp rates dictate the pace at which the potential is assumed to be achievable, separately for lost opportunity and retrofit measures
  - Lost Opportunity rates indicate the percent of equipment up for replacement in a given year that is assumed to be upgraded
  - Retrofit rates indicate the share of the 20-year potential assumed to be acquired in a given year
- The study uses a set of S-shaped diffusion curves developed by the Northwest Power and Conservation Council
- AEG analyzes PacifiCorp's recent state-specific program history to determine which ramp rate is most appropriate to apply





Levelized Costs

Similar to savings, measure costs vary by jurisdiction.

Assumptions presented from Table 2-3 in 2023 CPA Volume I report:

The table below walks through the adjustments that AEG makes prior to levelizing measure costs for supply curves, which are based on the state-specific cost-effectiveness test

Table 2-3 Economic Components of Levelized Cost by State

Parameter	WA	CA	WY	UT	ID
Cost Test	Total Resource Cost (TRC)		Utility Cost Test (UCT)		
Initial Capital Cost	Included (100% of incremental cost, full measure cost for retrofit measures)		Utility Incentive		
Annual Incremental O&M[19]	Included	Not Included			
Secondary Fuel Impacts[19]	Included	Not Included			
Non-Energy Impacts	Included	Not Included			
Administrative Costs (% of incremental cost)	48%	45%	48%	22%	40%
Incentive Costs (% of incremental cost)	n/a[20]		43%	38%	39%

Field	Washington	California	Oregon	Wyoming	Utah	Idaho
CE Test	TRC, 10% adder	TRC	TRC	UCT	UCT	UCT
Measure Cost	$1,000	$1,000	$1,000	n/a	n/a	n/a
Incentive Paid	n/a	n/a	n/a	$430 (43%)	$380 (38%)	$390 (39%)
Utility Admin %	48%	45%	29%	48%	22%	40%
Admin Spend	$480	$450	$290	$480	$220	$400
Cost for Bundling	$1,480	$1,450	$1,290	$910	$600	$790

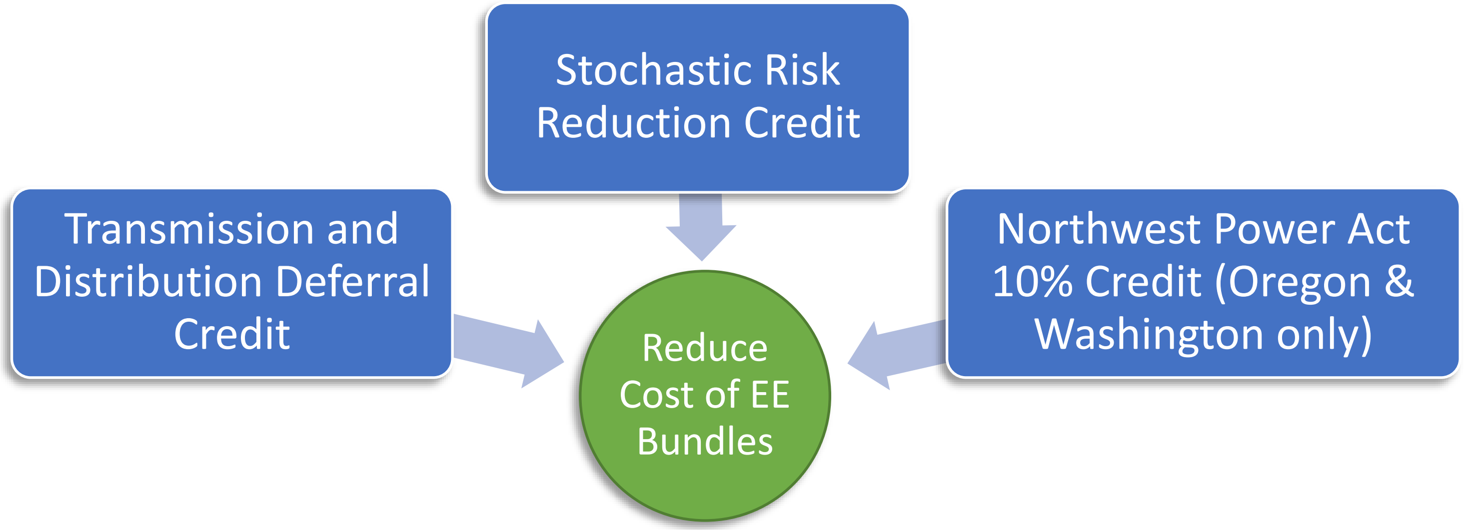
** Administrative costs will be updated during the 2025 study

Levelized Cost Inputs by State

Perspective	Total Resource Cost			Utility Cost			Included In:
	WA	CA	OR	ID	UT	WY	
State/Sector-Specific Line Losses	✓	✓	✓	✓	✓	✓	Potential Study
Customer Cost	✓	✓	✓				Potential Study
Utility Investment	✓	✓	✓	✓	✓	✓	Potential Study
Annual Incremental O&M	✓		✓				Potential Study
Secondary Fuel Impacts	✓						Potential Study
Non-Energy Impacts	✓		✓				Potential Study
10% Conservation Credit	✓		✓				IRP Modeling
T&D Deferral Benefits	✓	✓	✓	✓	✓	✓	IRP Modeling
Risk Mitigation Benefits	✓	✓	✓	✓	✓	✓	IRP Modeling

IRP Credits

The IRP incorporates three credits that reduce the modeled cost of energy efficiency bundles competing with supply-side resources in IRP modeling:



These credits are intended to capture benefits of energy efficiency that would otherwise not be reflected in IRP modeling.

These credits are consistent with industry standards and with the Northwest Power and Conservation Council.

IRP Credits, Cont.
T&D Deferral Credit

Table 7.8 from Volume I of the 2023 IRP shows the T&D credits used

Table 7.8 – State-specific Transmission and Distribution Credits

State	Transmission Deferral Value ($/KW-year)	Distribution Deferral Value ($/KW-year)	Total
California	$5.09	$8.38	$13.47
Oregon	$5.09	$10.46	$15.55
Washington	$5.09	$10.69	$15.78
Idaho	$5.09	$12.57	$17.66
Utah	$5.09	$12.90	$17.99
Wyoming	$5.09	$5.76	$10.85

Transmission & Distribution (T&D) Credit

- The T&D value is applied to each EE cost bundle to convert it to a $/MWh credit.

$$\frac{T\&D\ Value \times Seasonal\ PCF \times 1000}{\text{EE 1–Year Bundle Hours [between 1 and 8760]}}$$

- **Example:**

$$\frac{\$15.55 \text{ x } 0.57 \text{ x } 1000}{5750} = \text{\$1.54/MWh reduction in the EE cost bundle}$$

*PCF = Peak Coincident Factor

IRP Credits, Cont.
Stochastic Risk Reduction Credit

The stochastic risk reduction credit is intended to reflect the value energy efficiency provides in terms of reducing portfolio risk.

This credit is calculated by:

- Determining the difference in present-value revenue requirement (PVRRd) between stochastic studies and deterministic studies with and without energy efficiency.
- Dividing the delta of the two PVRR(d) results by the net present value of the energy efficiency savings (MWh) yields the $/MWh assumed value of stochastic risk reduction.

The 2023 IRP credit value was $2.25/MWh, and this will be updated for the 2025 IRP.

IRP Credits, Cont.
NW Power Act 10% Credit

Northwest Power Act 10-Percent Credit

- Oregon & Washington only
- The formula for calculating this $/MWh credit is:

$$\frac{Bundle\ price\ - (1st\ year\ MWh\ savings \times Market\ Value \times 10\% + 1st\ year\ MWh\ Savings \times T\&D\ Deferral \times 10\%)}{1st\ year\ MWh\ savings}$$

Northwest **Power** and **Conservation** Council

Demand Response Resources





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Defining Demand Response

Demand Response (DR): *Resources from fully dispatchable or scheduled firm capacity product offerings/programs such as a load control*

- Previously Class 1 DSM

Demand Response Program: one or more DR technologies which can be called to perform one or more grid services during a utility DR event.

This approach will be used in the 2025 CPA.

- Grid Service Provided: Peak Shaving, Fast DR, etc.
- Control Mechanism: Smart Thermostat, DLC Switch, etc.
- Technology Controlled: Central AC, Irrigation Pumps, HPWH
- **Example: HVAC Direct Load Control (Cool Keeper).** A central AC with a direct load control switch cycling during a peak event. Program specific to one control mechanism and one technology.

Resource Options

- The IRP primarily focused on sustained events due to modeling at the hourly level. However, the 2025 CPA will include an analysis of fast events, representing an improvement upon the 2023 CPA.
- Will continue to model third-party program potential with these two categories.

Sustained Events: represent an event lasting at least one hour and providing customers either day-ahead or day-of notification in advance.

Fast Events: represent an event lasting less than one hour and providing customers advanced notification of fifteen minutes or less with a near-instantaneous response.

Resource Options, Cont.

Program Category	Program Bundle	Mechanism / Description	Eligible for Fast Event Potential?*	Current Offering
Direct Load Control (Conventional)	Electric Vehicle Connected Charger Direct Load Control (DLC)	Automated, level 2 EV chargers that postpone or curtail charging during peak hours. Can potentially be used for energy storage.	✓	UT, Planned for OR, WA
	HVAC DLC	DLC switch installed on customer's heating and/or cooling equipment.	✓	UT
	Irrigation Load Control	Automated pump controllers or DLC switch installed on customer's equipment.	✓	ID, UT, OR, WA
	Pool Pump DLC	DLC switch installed on customer's equipment.	✓	-
	Domestic Hot Water Heater (DHW) DLC	DLC switch installed on customer's equipment.	✓	OR & WA
Direct Load Control (Smart / Interactive)	DLC of Smart Home	Internet-enabled control of operational cycles of white goods appliances, electronics, and lighting. Controlled by a central smart hub or smart speaker.		-
	Grid Interactive Water Heater	CTA-2045 or other integrated communication port. Can also be used for energy storage.	✓	OR & WA
	Connected Thermostats DLC	Internet-enabled control of thermostat set points.		OR & WA
Energy Storage	Battery Energy Storage DLC	Internet-enabled control of battery charging and discharging.	✓	UT, WY, ID (Pilot)
Curtailment	Third-Party (Fast Event)	Customers enact their customized, mandatory curtailment plan. May use stand-by generation. Penalties apply for non-performance. Customers must have EMS for automated compliance.	✓	UT, OR, WA, ID
	Third-Party (Sustained Event)	Customers volunteer a specified amount of capacity during a predefined "economic event" called by the utility in return for a financial incentive.		UT, OR, WA, ID

*All program bundles eligible for sustained events, some are eligible for fast events

Resource Assumptions

AEG conducts research to develop a comprehensive list of DR measure/program assumptions. PacifiCorp-specific program data is used where available.

Event Assumptions

- Capacity Reductions
- Seasonal Availability
- Climate Zone & Curtailable Load
- Event Ramp Up (Time until Full Response)
- Event Duration
- Maximum Events per Year

DR Program Data Assumptions

- Comparable Program Assumptions (Key Sources)
- Measure Dependencies (AMI)
- Participation (including state-specific assumptions, WA CTA-2045)
- Regulatory Lead Time (years)
- Levelized Cost Methodology

Resource Costs

The following components are typically included within demand response program costs:

- Measure Costs
  - Energy-using technology cost (e.g. ENERGY STAR Connected EV Charger)
  - Enabling technology cost (e.g. DLC Switch, Smart Thermostat, HEMS)
  - “Bring-Your-Own” program designs can lower measure costs substantially and will be considered where possible
- Incentives (annual, per-event, or both)
  - In states utilizing the California DR Cost-Effectiveness Protocol, only a portion of the incentive is counted to estimate the customer’s cost to participate (see next slide)
- Utility administrative costs*
  - Utility staff to manage program (X FTEs at $Y/yr. allocated across multiple programs)
  - Program development costs (up-front $ for each new program)
  - Marketing costs ($/yr.)

**Can be transitioned to a third-party aggregator in some circumstances*

Participant Costs

- In Pacific Power states, participant costs are estimated to satisfy requirements of Total Resource Cost test.
  - Not applicable to Rocky Mountain Power: participant cost assumptions have no impact on levelized cost from Utility Cost Test perspective
- PacifiCorp uses the California DR Cost-Effectiveness Protocol methodology to estimate participant costs as a percentage of incentives.
  - Lower percentages used to reflect programs that are less intrusive to customers
  - See assumptions from 2025 CPA below:

Program	Participant Cost (% of Incentive)
HVAC Direct Load Control (DLC)	35%
Domestic Hot Water Heater (DHW) DLC	25%
Grid-Interactive Water Heaters	25%
Connected Thermostat DLC	35%
Smart Appliances DLC	75%
DLC of Pool Pumps	75%
Electric Vehicle DLC Smart Chargers	75%
Battery Energy Storage DLC	75%
Third Party Contracts	75%
Irrigation Load Control	75%

Resource Examples

The examples of DR program assumptions to the right highlight some of the unique considerations between jurisdictions.

[1] Savings weighted by electric heating and cooling saturations

[2] Assuming bring-your-own program designs; DR model linked to connected thermostat saturations in EE model.

[3] Washington House Bill 1444 set an appliance standard mandating CTA-2045 communication ports on all new water heaters in the state

Connected Thermostats DLC	Washington	Utah
Summer kW Reduction	0.53 kW	0.97 kW
Winter kW Reduction[1]	1.01 kW	0.21 kW
Eligible Market	Connected Thermostats	Connected Thermostats not enrolled in Cool Keeper
Equipment Costs[2]	$0	$0

Water Heater DLC	Washington	Utah
Summer kW Reduction	0.58 kW	0.58 kW
Winter kW Reduction	0.58 kW	0.58 kW
Eligible Market	**All** electric water heaters at turnover[3]	Electric water heaters, limited by customer choice
Equipment Costs	$0	$315 switch + installation

Demand Response (DR) Credits

The 2023 IRP incorporated two credits that reduced the modeled cost of DR bundles competing with supply-side resources in IRP modeling. These credits are intended to capture benefits that would otherwise not be reflected in IRP modeling.

Transmission and Distribution Deferral Credit

- Applied same credit to DR as described in the EE measure section of this presentation.

Operating Reserve Credit

- In this case, for Contingency and Regulation Reserves

Distributed Generation Study Overview

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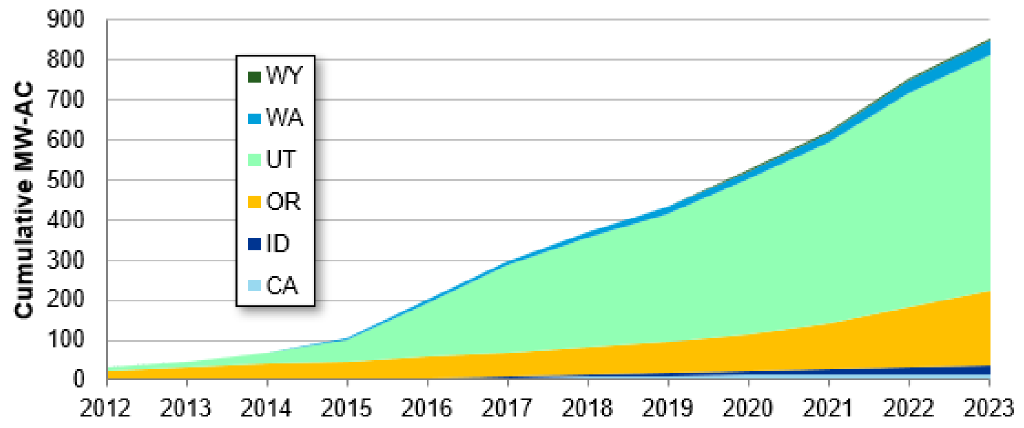
- Methodology Overview
- Data Development
- Modeling
- Forecast Scenarios
- Q&A

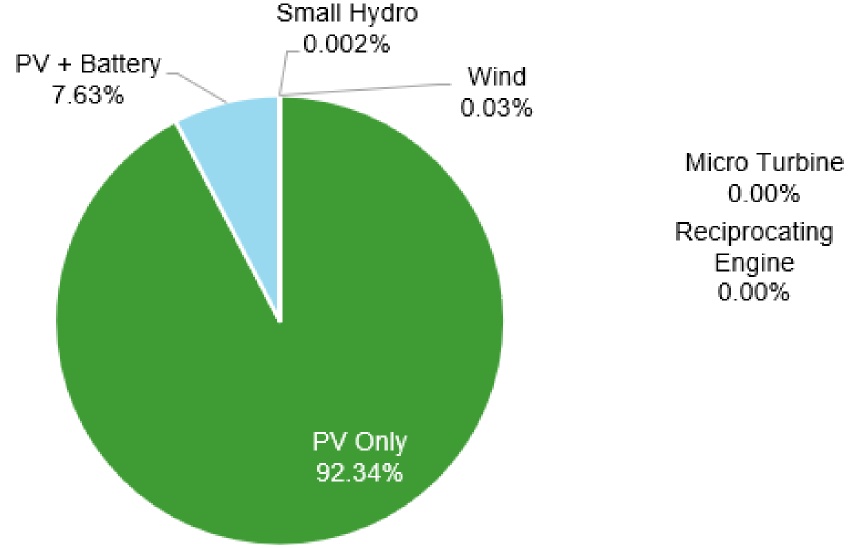
Introduction and Background

- DNV prepared the Long-Term Distributed Generation Resource Assessment for PacifiCorp covering the service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington.
- This study evaluated the expected adoption of behind-the-meter (BTM) technologies including photovoltaic solar, photovoltaic solar coupled with battery storage, small scale wind, small scale hydro, reciprocating engines, and microturbines for a 20-year forecast horizon.
- DNV has provided projections for 3 cases: base, high, and low adoption.
- The distributed generation projections will be used in support of PacifiCorp's 2025 Integrated Resource Plan.
- DNV developed its assumptions, inputs, methodologies, and forecasts independently from prior Distributed Generation Assessments that have been previously performed for PacifiCorp.

PacifiCorp Historic* Cumulative Installed PG Capacity by State

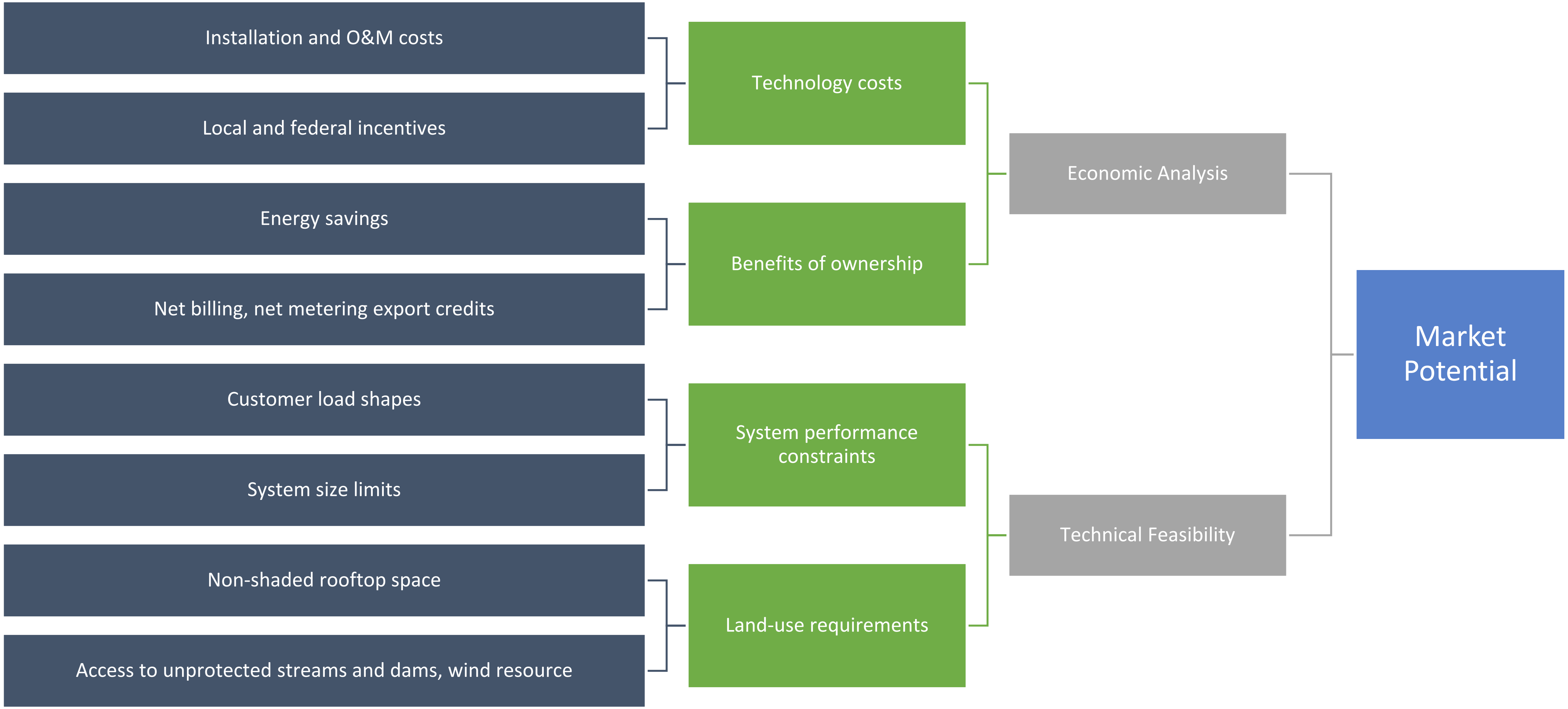


PacifiCorp Historic* Cumulative Installed PG Capacity by Technology, YTD



*PacifiCorp interconnection data as of December 2023

Approach Overview



Data Source Hierarchy – Customer Data

#	Data Description	Source	Details
1	Customer Segments	PacifiCorp billing data	Additional segmentation compared to 2022 study: Residential (2), Commercial (5), Industrial (1), Irrigation (1)
2	Segment-Level Load Shapes	Residential: Northwest Energy Efficiency Alliance (NEEA) load shapes & PacifiCorp billing data Commercial: NREL ComStock load shapes & PacifiCorp billing data Industrial & Irrigation: PacifiCorp billing data	Additional customer segmentation provided the opportunity for more granular load shape creation and thus, more accurate billing analysis for individual technologies
3	**Segment-Level** Rates	PacifiCorp tariff indexes & price summaries	Updated January 2024
4	**Segment-Level** Rate Forecast	EIA Annual Energy Outlook (AEO) for energy, demand, and load size rate forecast(s) PacifiCorp IRP-developed avoided costs for export rates for net-billing states only	Separate AEO forecast cases used for base, high, and low forecast scenarios Avoided cost forecast from IRP used to forecast export rates for non-billing states
5	Rate Periods & Seasons	PacifiCorp tariff indexes & price summaries	By customer segment, used in 8760 billing analysis
6	Historical Adoption Data	PacifiCorp customer interconnection data (2000-2023)	Used to calibrate Bass diffusion curves by customer segment and technology
7	Segment-Level Willingness-to-adopt Parameters	Various market research reports and internal DNV data	Available at total residential, commercial, and industrial levels – applied to relevant sub-segments
9	Segment-Level Customer Forecast	PacifiCorp internal forecast	By segment and state, used in characterizing future population of potential adopters, and new construction estimates

Data Source Hierarchy – Technology Data

#	Data Description	Source	Details
1	Technology Performance Data & Generation Shapes	Solar PV & Battery Storage: DNV SolarFarmer & Lightsaber Tools Wind: PNNL Distributed Wind Market Report & data, NREL SAM Hydro: NREL SAM CHP: DOE CHP Fact Sheets	Generation shapes aligned w/system sizes for each customer segment and location (state)
3	**Technology Cost Data**	Solar PV & Battery Storage: Wood Mackenzie PV system pricing, NREL ATB Wind: PNNL Distributed Wind Market Report & data, NREL ATB Hydro: NREL ATB CHP: DOE CHP Fact Sheets	Cos data aligned w/system sizes for each customer segment and location (state)
4	**Technology Cost Forecasts**	NREL Annual Technology Baseline (ATB)	Separate ATB forecast cases used for base, high, and low forecast scenarios
5	**Technology Incentives**	PacifiCorp tariff indexes & price summaries, and individual state incentive summaries	Conservative scaling to future years based on best available information related to future program funding levels, etc.
6	Fuel Costs	EIA Annual Energy Outlook (AEO) annual natural gas price forecast	By customer segment, used in billing & economic analysis for CHP (natural gas-fueled) technologies

Distributed Generation Technologies

Cost & Performance Metric	Solar PV	Solar PV + Battery	Wind	Hydro	Microturbine	Recip. Engine
Installed Cost – Residential ($/kW, 2024)	$2,802-2,895/kW-DC (depending on state)	$4,198-4,350/kW-DC (depending on state)	$7,054/kW-AC	N/A	N/A	N/A
Installed Cost – Non-Residential ($/kW, 2024)	$1,953-2,053/kW-DC (depending on state)	$2,912-4,029/kW-DC (depending on state)	$2,913-6,015/kW-AC (depending on state)	$3,992-5,190/kW-AC (depending on state)	$3,134-3,742/kW-AC (depending on state)	$3,125-4,189/kW-AC (depending on state)
Annual Installed Cost Change (%, 2024-2045)	Scaled from base year installed costs using NREL Annual Technology Baseline (ATB) annual scaling factors specific to technology & size					
Fixed O&M – Residential ($/kW-yr, Base Year)*	$25.4-43.3/kW	$31.8-33.04/kW	$38.0/kW	N/A	N/A	N/A
Fixed O&M – Non-Residential ($/kW-yr, Base Year)*	$15.6-26.5/kW	$28.0-32.8/kW	$38.0/kW	$207.6/kW	N/A	N/A
Variable O&M ($/kWh, Base Year)	N/A	N/A	N/A	N/A	$0.016-0.0019/kWh	$0.020-0.028/kWh
Annual O&M Cost Change (%, 2022-2064)	Scaled from base year O&M cost using NREL Annual Technology Baseline (ATB) annual scaling factors specific to technology & size					
Capacity Factor (%)	14.6-18.5%	14.6-18.5%	7.7-10.8% - Residential 17.9-42.6% - Non-Res.	45%	43% - Commercial 51% - Industrial	48% - Commercial 58% - Industrial
Fuel Cost & Annual Cost Change ($/MMBtu, %)	N/A	N/A	N/A	N/A	$11.6/MMBtu – Com., $6.6/MMBtu – Ind. Scaled from AEO 2023 Pacific Region Forecast	
Electric Heat Rate (Btu/kWh, HHV)	N/A	N/A	N/A	N/A	11,566-13,648	9,721-11,765
DC/AC Derate Factor (%)	76.9-89.5% (based on customer type & size)	76.9-89.5% (based on customer type & size)	N/A	N/A	N/A	N/A

*Fixed O&M costs for solar PV and solar PV + Battery are in $/kW-DC-yr; all other technologies are in $/kW-AC-yr

Customer Segmentation Approach

- Compared to the 2022 study: Additional segments provide increased granularity in load shape development, and greater accuracy in the final billing/economic analysis within the adoption model
- Includes both existing and new construction customers

Sector	Segment(s)	Technologies
Residential	Residential non-LMI	Solar PV (standalone) Solar PV + Storage Storage (retrofit) Wind Micro-hydro
	Residential LMI	
Commercial	Commercial Small	
	Commercial Large	
	Commercial School	
	Commercial Hotel	
	Commercial Other	
Irrigation	Irrigation All	
Industrial	Industrial All	Solar PV (standalone) Solar PV + Storage Storage (retrofit) Wind Mini-hydro Recip. Engine Microturbine

Incentives

Federal Incentives Overview

Incentive	System Size (kW)	Technology	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Residential / Business ITC	< 1,000	PV	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
	< 1,000	Energy Storage	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	26%	0%
	< 1,000	Small Wind	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 1,000	Microturbines	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
	< 1,000	Reciprocating Engines	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
	< 150	Small Hydro (hydropower dams)	30%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	< 25	Small Hydro (Hydrokinetic pressurized conduits)	30%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	< 1,000	Small Hydro	0%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%

Other Applicable Incentives

- **Modified Accelerated Cost-Recovery System (MACRS)**
  - Eligible technologies: Solar Photovoltaics, Wind (All), Wind (Small), Micro turbines
  - Eligible sectors: Commercial, Industrial, Irrigation

State Incentives

State	Residential		Non-Residential
Oregon	**PV-Only:** $450/home, $3,000 max/home	**Battery Storage:** $250/kWh, $3,000 max/home	**PV-Only:** $0.15/W (up to 480 kW)
Utah	**PV-Only:** None (expired in 2023)	**Non-PV:** 25% of eligible system cost (up to $2,000)	Up to 10 percent of the eligible system cost or up to $50,000*
Idaho	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

Other Programs and Sources of Funding for Distributed Generation

U.S. EPA Solar for All

- $7 billion Notice of Funding Opportunity in 2023
- 60 grants to states, territories, Tribal governments, municipalities, and nonprofits – create and expand programs that provide financing and technical assistance to bring residential solar to low-income and disadvantaged communities

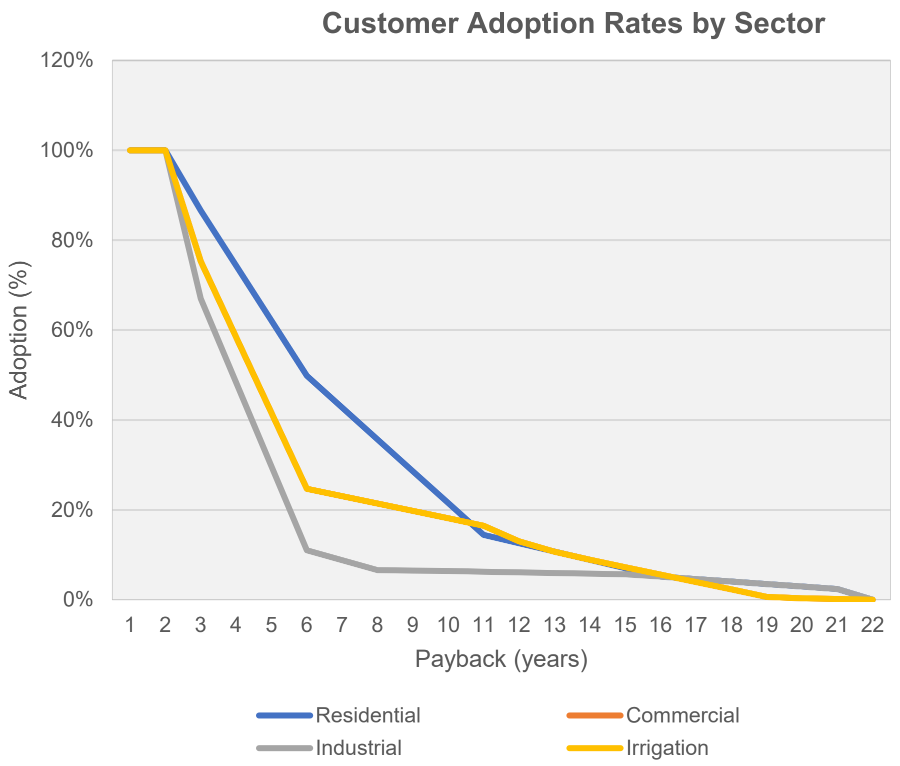
↓

- Funding availability assumptions incorporated into state-level incentives for solar PV aligned with residential LMI segments

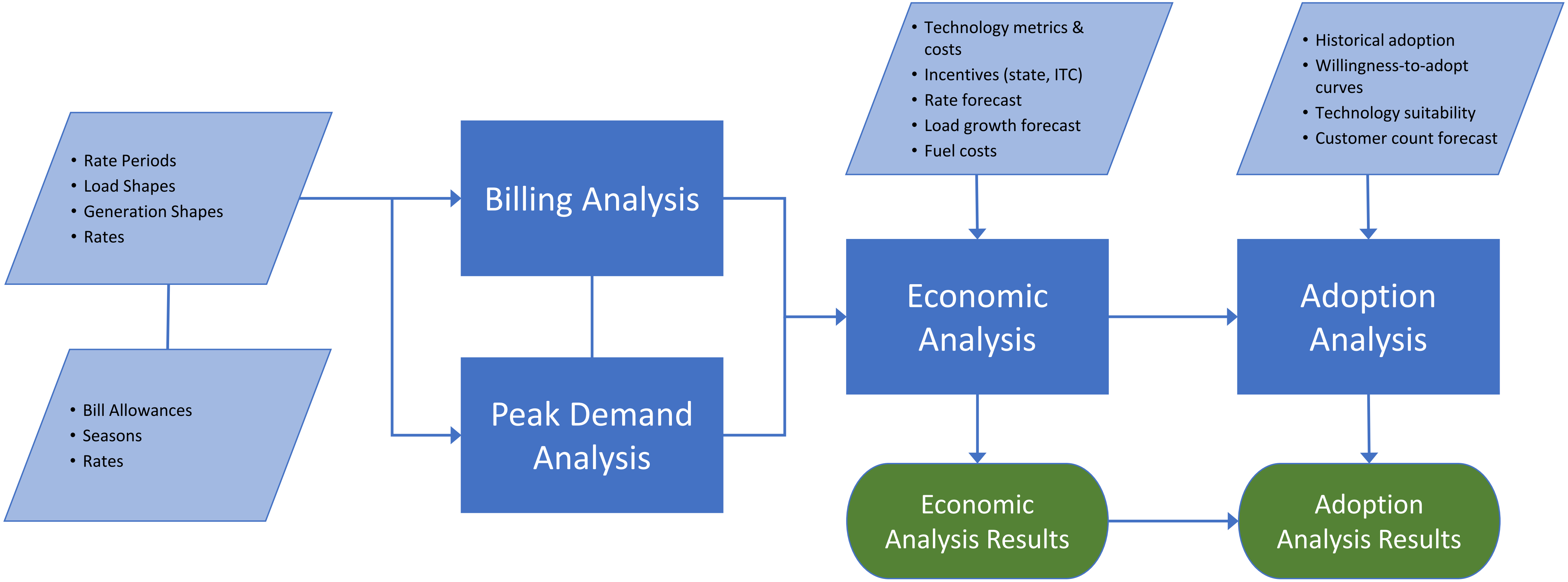
Forecasting Model

Technology Adoption Methodologies and Approach

- **DNV developed a behind-the-meter (BTM) economic perspective including**
  - Costs to acquire and install each technology net of available incentives
  - Benefits of ownership including energy cost savings (8760 billing analysis)
- **Calculated payback by year for each technology, state, and customer sector**
- **Estimated technical feasible applications by technology, state, and customer sector**
- **Utilized Bass diffusion curves to model annual adoption**
  - Adoption trend over time is characterized by three parameters
    - Innovation coefficient – External influence (marketing) on customer adoption
    - Imitation coefficient – Internal influence (neighbor effect) on customer adoption
    - Ultimate market potential – Determine by customer counts and technical suitability
  - We tied ultimate market potential to payback; market interventions shift the diffusion curve
  - Innovation and imitation are calibrated to current penetration for each technology, segment, and state



Modeling Approach



Forecast Descriptions and Assumptions

Key Assumptions	Base	Low	High
Technology Cost Forecasts	Average of NREL Conservative and Moderate ATB	NREL Conservative ATB	NREL Moderate ATB
Retail Electricity Rate Forecasts	AEO Reference	AEO High Oil & Gas Supply	AEO Low Oil & Gas Supply
Value of Backup Power	None	*Base case assumption*	Included in customer benefits of PV + Battery technology
Incentive Levels (starting in model year 2024)	Applicable state and federal incentives based on current legislation	*Base case assumption*	*Base case assumption*
Market Barriers (non-monetary)	Assumptions vary by measure but do not change over time	*Base case assumption*	Base assumptions for Year 1, then reduced over time

Value of Backup Power
PV + Battery – High Case

To analyze if the ability to provide backup power drives adoption of battery storage, we included a new value stream in the economic analysis for the PV + Battery technology.

- This value stream is intended to reflect the monetized value provided by the battery storage system as a source of backup power to customers in the case of planned or unplanned system outages
- Values were developed by state, sector, and segment

DNV estimated the cost of electric service interruptions using Lawrence Berkeley National Laboratory's Interruption Cost Estimate (ICE) Calculator methodology

- Interruption costs were assigned to specific sectors and states by multiplying the value (in USD) per event for each sector by the number of expected events per year (sourced from SAIFI and SAIDI data reported in PacifiCorp's service territories in EIA-861 data)

Note: The value of backup power was not included in the analysis of Microturbines or Reciprocating Engines. DNV assumes that customers installing these systems for backup power would not enter the system under a net metering interconnection agreement– the systems would be used as standby power.

Q&A

Thank you!

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Transmission Modeling

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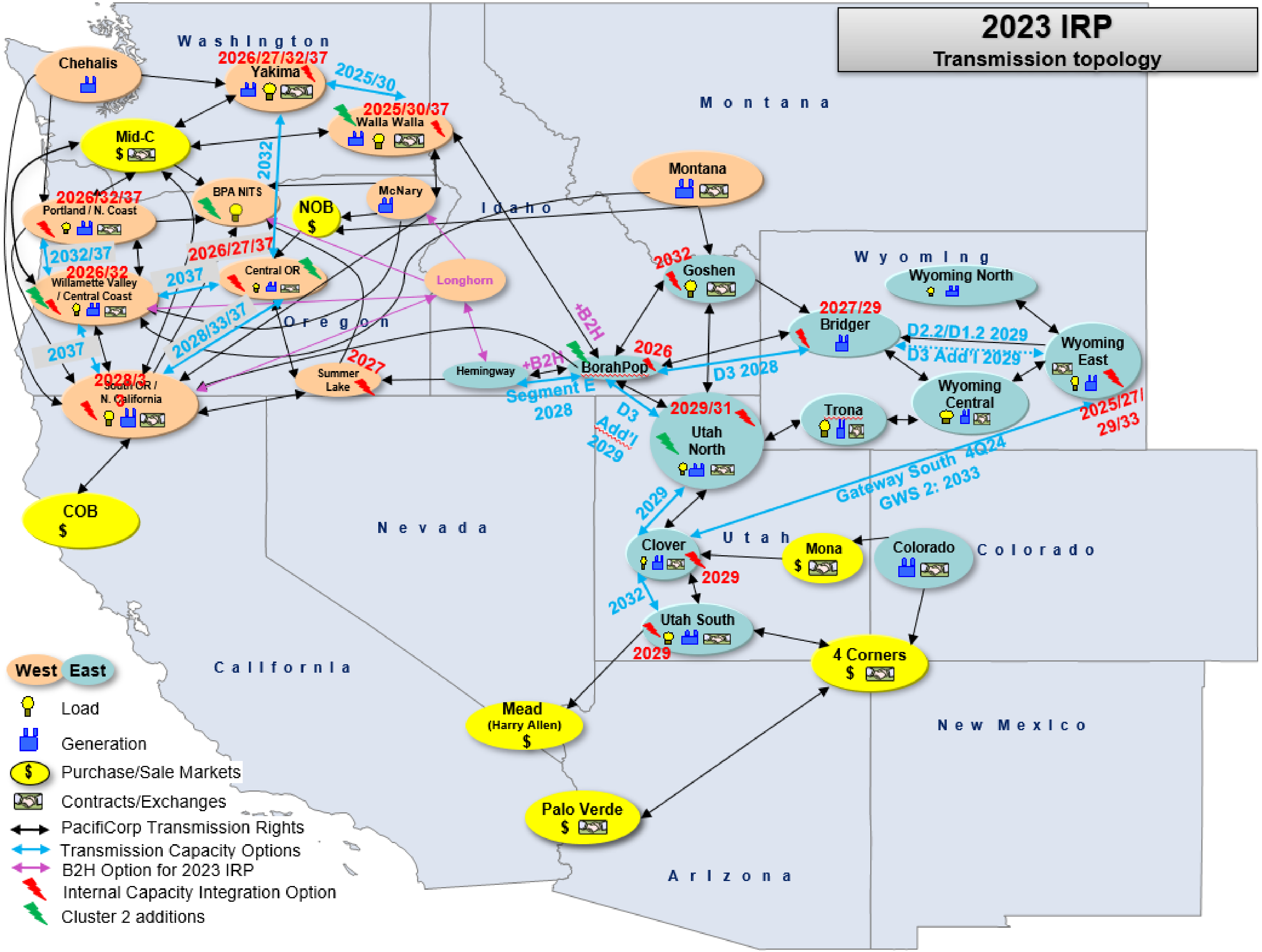
2023 IRP
Transmission topology



Dates reflect the first year transmission options were available in the 2023 IRP

Transmission Overview

- There are two types of transmission options:
  - **Incremental** options include transmission capability between topology bubbles, and usually also allows new resources to be added
  - **Interconnection** options do not add transmission capability but rather add resource build capacity
- Incremental options use transmission *properties* to determine transfer capability
- Both types of options use *constraints* to limit the amount of generation any resource addition is capable of on an hourly basis

New for 2025 IRP

- Granularity Adjustments on Transmission lines
  - Just as resources have different values in the LT and ST, so do transmission lines
  - When a line is congested (i.e. full) the LMP will be higher at one end than the other. PLEXOS reports an import margin (for flows in one direction) and export margin (for flows in the other direction)
  - The margin is the difference in LMP from one end and the other, multiplied by the volume in that hour.
- EXAMPLE: Bridger>Borah Populus 2031 (Energy Gateway Segment D3)
  - This line increases the transfer capability from the Jim Bridger to Borah/Populus
  - In the LT – congestion on this path results in a margin of $28/kw-yr in 2037
  - In the ST – congestion on this path results in a margin of $82/kw-yr in 2037
  - The ST is $54/kw-yr higher than the LT in 2037
  - In the 2025 IRP, a credit of $54/kw-yr would be applied to D3’s fixed costs in 2037 within the LT model to account for its greater ST value
- The granularity adjustment can also impact Interconnection transmission options that don’t have flows to other bubbles – the interconnection limit is comparable to congestion.

Transmission Properties and Constraints

- Properties
  - "Max Flow" - sets the maximum allowable flow (in megawatts) on the line between two transmission bubbles, i.e., from A to B
  - "Min Flow" - sets the limit on flow in the opposite direction, i.e., from B to A. It can also be zero, if flow is uni-directional.
- Constraints
  - "Export Capacity Coefficient" defines the relationship between the Max Flow and the amount of allowed resource generation
  - For example, if the coefficient is 0.5 (read as 50%) on a line with 100 MW available transfer capability (ATC), then up to 50 MW of resources are able to generate in any given hour due to the upgrade

Transmission Options

Object	Property	Value	Data File	Units	Date From	Date To	Scenario	Memo
CON Central OR > TxCON 2027	Units	0		-				
CON Central OR > TxCON 2027	Project Start Date	1/1/2027		-				
CON Central OR > TxCON 2027	Max Flow	400		MW				
CON Central OR > TxCON 2027	Min Flow	0		MW				
CON Central OR > TxCON 2027	Export Capacity Coefficient	-1		MW				

- Units = 0
  - This flag tells Plexos that it is a selectable option and not planned or existing
- Project Start Date = 1/1/2027
  - This is the earliest year for the model to choose this option
- Max Flow = 400, Export Capacity Coefficient = -1
  - As an Interconnection option, flow is between Central Oregon and a “faux” topology bubble called “TxCON”.
  - Export Capacity Coefficient is used to limit hourly generation from interconnected resources to 400 MW
  - The Company is considering replacing the generic “TxCon” bubble with an individual bubble “Central Oregon Resource” to better capture impacts of the hourly generation limit
- Min Flow
  - This is the capacity in the opposite direction, from TxCON to Central Oregon, not relevant currently.

Transmission Generation Constraints

Object	Constraint Name	Property	Value
System	TxCON Central OR Max Resource Build	Sense	<=
System	TxCON Central OR Max Resource Build	RHS	0
PV_.PX.COR._.___.PV	TxCON Central OR Max Resource Build	Generation Coefficient	1
WD_.PX.COR._.___.WD	TxCON Central OR Max Resource Build	Generation Coefficient	1
BAT.PX.COR._.___.Lithium-ion	TxCON Central OR Max Resource Build	Generation Coefficient	1
BAT.PX.COR._.___.Lithium-ion	TxCON Central OR Max Resource Build	Load Coefficient	-1
CON Central OR > TxCON 2028	TxCON Central OR Max Resource Build	Export Capacity Coefficient	-1
INC Central OR > Willamette Valley 2037	TxCON Central OR Max Resource Build	Export Capacity Coefficient	-0.44

- The Export Capacity coefficient and the amount of hourly generation are balanced in a constraint
- Sense = “<=“
  - The hourly generation of resources must be less than or equal to the transmission capacity
- Generation and Load Coefficients
  - Any MW of hourly generation count against the hourly limit
  - Any MW of resource loaded into the battery ADDS to the hourly limit
- Constraint is the same construction for existing sites – all items at Bridger must generate within the hourly limit, allowing for surplus resource additions

Break

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March Price Curve Update

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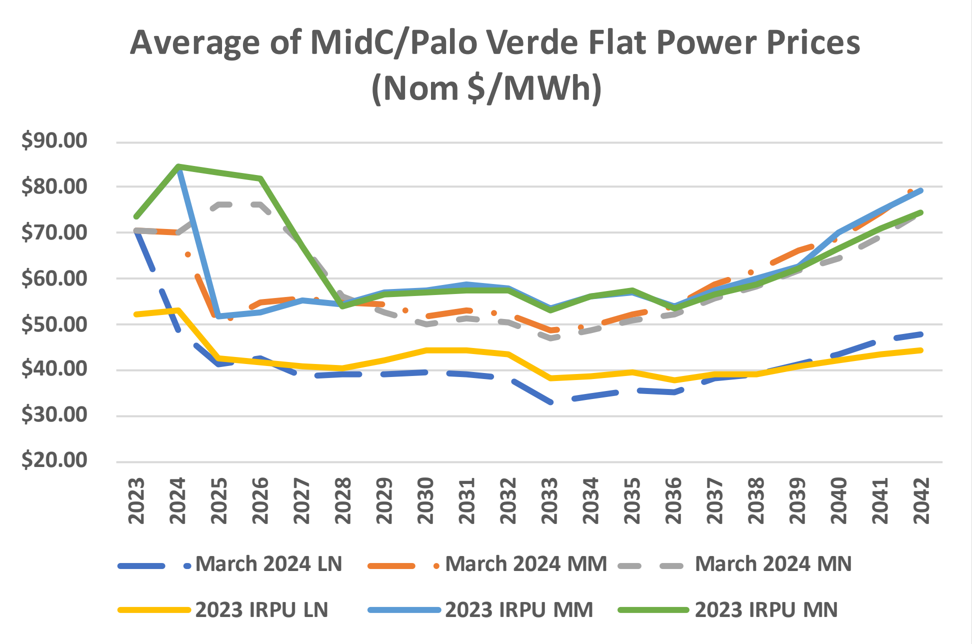
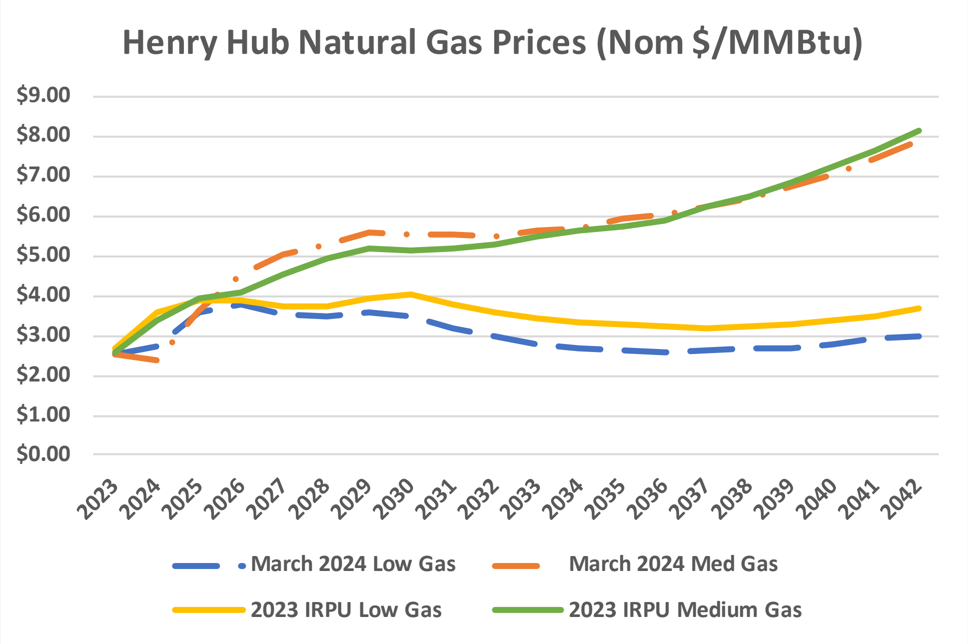
Price Curve Development Update

- The Company's 2023 IRP Update reflected market prices for electricity and gas from September 2023, based on a range of assumptions for natural gas prices and greenhouse gas costs.
- The figures below provide a comparison to more recent pricing from March 2024, with the same range of no/medium greenhouse gas assumptions used in the 2023 IRP and 2023 IRP Update.
- Power prices are expected to decline over the next few years.
- Higher renewable resource penetration from state mandates is expected to lead to lower average power prices.
- After updating greenhouse gas assumptions (discussed on a later slide) updated market prices will be developed for use in the 2025 IRP, likely in September 2024.





CO_2 Price Development

- In the 2023 IRP, the CO_2 price was developed using a variety of public, external, data points.
  - These various CO_2 prices were taken and aggregated
    - Prices were averaged to generate the Medium and High cases
  - Sources included:
    - 3 paid data sources – Wood Mackenzie, IHS Markit, Siemens
    - Nevada Power's IRP
    - Idaho Power's IRP
    - California IEPR
    - US Energy Information Association
    - Social Cost of Greenhouse Gases, per Washington statute
- PacifiCorp is open to other sources
- CO_2 prices will be finalized this summer for use as inputs to market price scenarios that will be developed in September 2024.

2023 IRP Update Outcomes

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Study PVRRs – No Risk Adjustment

Period	Case	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
10-YEAR	Preferred Portfolio	**$ 18,139**	**$ -**	Y	Y	Y	MM
10-YEAR	Systemwide	$ 18,238	$ 100	N	N	Y	MM
10-YEAR	MM Base	$ 18,481	$ 342	N	N	Y	MM
10-YEAR	No CCUS	$ 18,481	$ 342	Y	Y	Y	MM
10-YEAR	OR Compliance	$ 18,629	$ 490	Y	N	Y	MM
10-YEAR	SC Base	$ 30,124	$ 11,986	N	N	Y	SC
10-YEAR	WA Compliance CETA	$ 38,643	$ 20,504	N	Y	Y	SC
10-YEAR	WA Compliance CAGW	$ 29,953	$ 11,814	N	Y	Y	SC

Period	Case	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	Preferred Portfolio	**$ 32,807**	**$ -**	Y	Y	Y	MM
20-YEAR	Systemwide	$ 32,912	$ 105	N	N	Y	MM
20-YEAR	MM Base	$ 33,510	$ 703	N	N	Y	MM
20-YEAR	No CCUS	$ 33,553	$ 746	Y	Y	Y	MM
20-YEAR	OR Compliance	$ 34,309	$ 1,502	Y	N	Y	MM
20-YEAR	SC Base	$ 47,504	$ 14,697	N	N	Y	SC
20-YEAR	WA Compliance CETA	$ 76,941	$ 44,134	N	Y	Y	SC
20-YEAR	WA Compliance CAGW	$ 47,209	$ 14,402	N	Y	Y	SC

Study PVRRs – MN, MM, SC

Period	Case Under MN	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	MN Base	$ 29,519	$ 748	N	N	Y	MN
20-YEAR	Preferred Portfolio	$ 28,823	$ 52	Y	Y	Y	MN
20-YEAR	Systemwide	**$ 28,771**	$ -	N	N	Y	MN
20-YEAR	No CCUS	$ 29,245	$ 474	Y	Y	N	MN
20-YEAR	No Nuclear	$ 29,252	$ 480	Y	Y	Y	MN
20-YEAR	Bridger 3 & 4 GC	$ 29,321	$ 550	Y	N	Y	MN

Period	Case Under MM	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	MM Base	$ 33,510	$ 703	N	N	Y	MM
20-YEAR	Preferred Portfolio	**$ 32,807**	$ -	Y	Y	Y	MM
20-YEAR	Systemwide	$ 32,912	$ 105	N	N	Y	MM
20-YEAR	No CCUS	$ 33,553	$ 746	Y	Y	N	MM
20-YEAR	No Nuclear	$ 33,464	$ 657	Y	Y	Y	MM
20-YEAR	Bridger 3 & 4 GC	$ 33,506	$ 700	Y	N	Y	MM

Period	Case Under SC-GHG	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	SC Base	$ 47,504	$ 350	N	N	Y	SC
20-YEAR	Preferred Portfolio	**$ 47,153**	$ -	Y	Y	Y	SC
20-YEAR	Systemwide	$ 47,730	$ 576	N	N	Y	SC
20-YEAR	No CCUS	$ 48,031	$ 877	Y	Y	N	SC
20-YEAR	No Nuclear	$ 48,493	$ 1,340	Y	Y	Y	SC
20-YEAR	Bridger 3 & 4 GC	$ 47,965	$ 812	Y	N	Y	SC

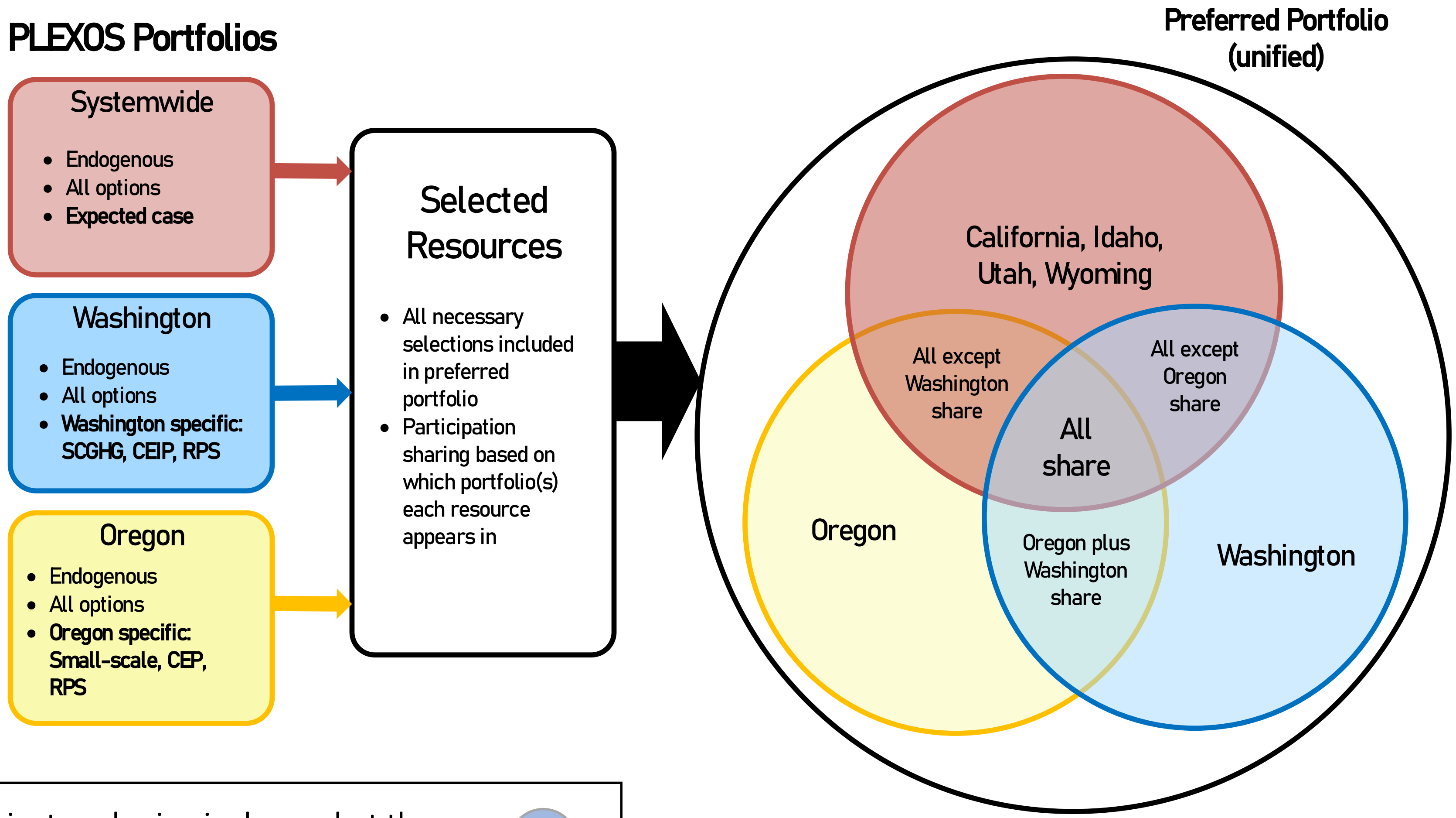
Study PVRRs – LN, HH

Period	Case Under LN	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	LN Base	$ 29,241	$ 1,447	N	N	Y	LN
20-YEAR	Preferred Portfolio	$ 28,042	$ 249	Y	Y	Y	LN
20-YEAR	Systemwide	**$ 27,794**	$ -	N	N	Y	LN
20-YEAR	No CCUS	$ 28,441	$ 647	Y	Y	N	LN
20-YEAR	No Nuclear	$ 28,212	$ 418	Y	Y	Y	LN
20-YEAR	Bridger 3 & 4 GC	$ 28,357	$ 563	Y	N	Y	LN

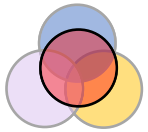
Period	Case Under HH	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	HH Base	**$ 41,622**	$ -	N	N	Y	HH
20-YEAR	Preferred Portfolio	$ 41,658	$ 36	Y	Y	Y	HH
20-YEAR	Systemwide	$ 42,252	$ 630	N	N	Y	HH
20-YEAR	No CCUS	$ 43,005	$ 1,384	Y	Y	N	HH
20-YEAR	No Nuclear	$ 43,047	$ 1,425	Y	Y	Y	HH
20-YEAR	Bridger 3 & 4 GC	$ 43,013	$ 1,392	Y	N	Y	HH

Preferred Portfolio Integration

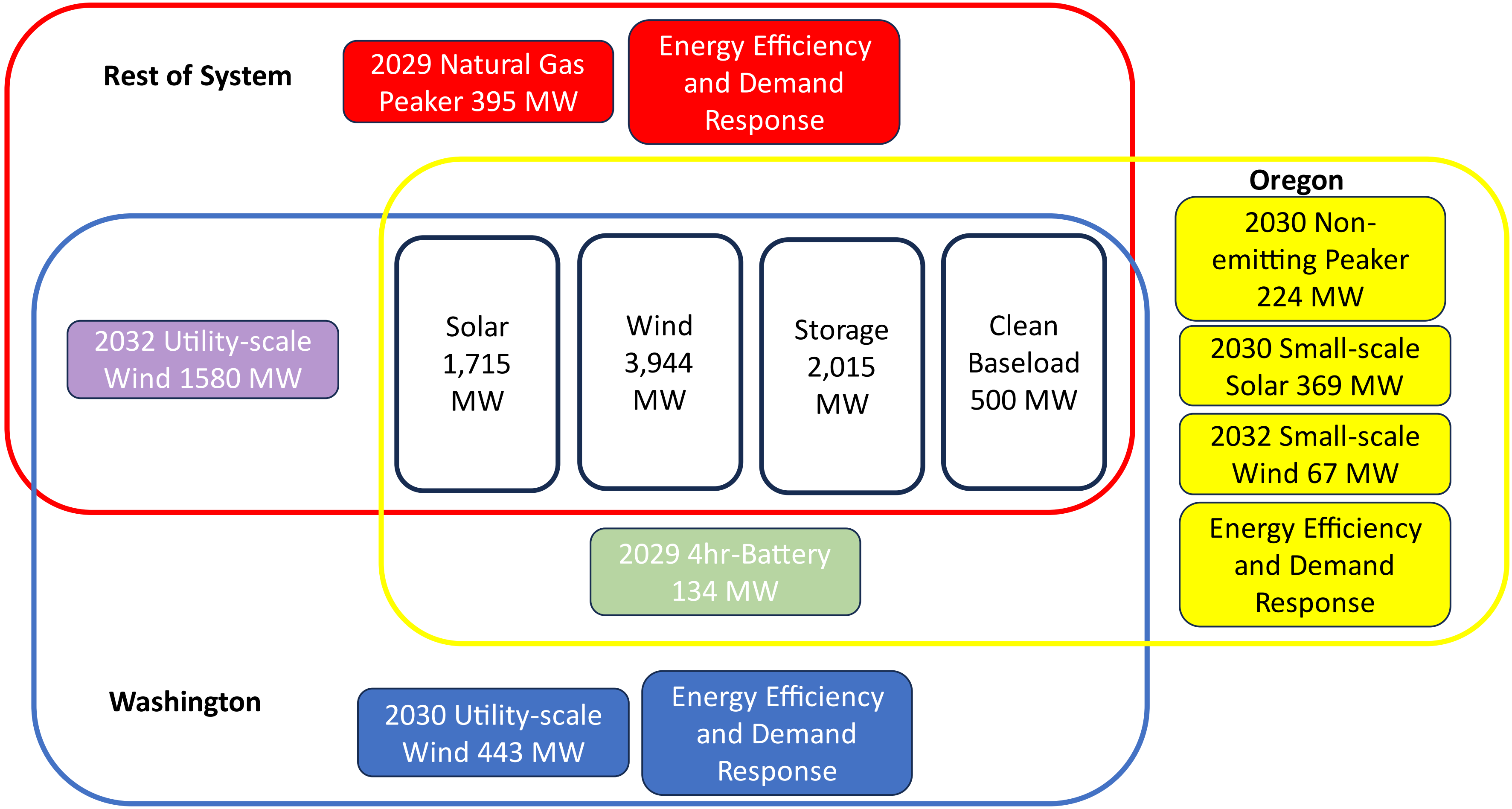
Preferred Portfolio Integration Plan



Oregon and Washington sharing is shown, but the process is the same for other states. Showing more states is more difficult to visualize.



Integration Outcome through 2032



Integration Outcome 2029-2042

Preferred Portfolio Resource Integrations (Installed Capacity, MW)

Situs/Partial Share Resources	Oregon	Washington	OR and WA	WA and Sys	OR and Sys	No OR/WA								
Category	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Natural Gas	395	-	-	-	-	-	-	-	-	836	-	3122	749	-
NonEmitting Peaker	-	224	-	-	-	-	-	-	59	-	-	-	-	-
Utility Scale Wind	-	443	-	1580	15	-	-	-	-	-	-	-	-	-
Small Scale Wind	-	-	-	67	172	-	-	-	-	-	-	-	-	-
Utility Scale Solar	-	-	-	-	449	93	-	-	1009	-	-	-	-	-
Small Scale Solar	-	369	5	-	-	-	-	-	109	-	-	-	-	-
Clean Baseload	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4hr Battery	134	-	11	8	-	3	-	-	78	-	-	17	9	-
Storage (Long Duration)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	529	1036	16	1655	636	96	0	0	1255	836	0	3139	758	0

Oregon vs. Systemwide 2029-2034

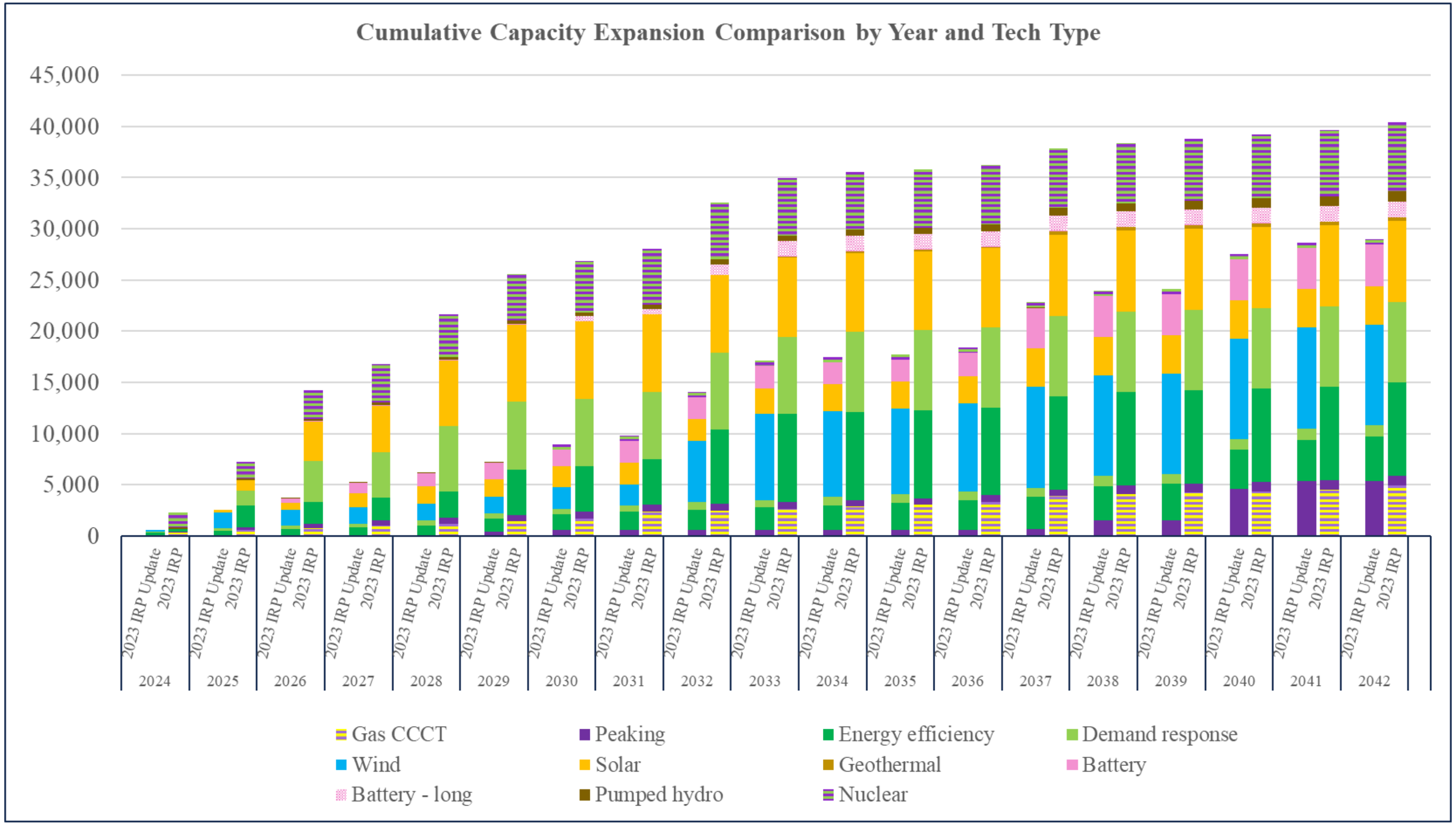
Resource	2029	2030	2031	2032	2033	2034
Expansion Options						
Gas - Peaking	(466)	-	-	-	-	-
NonEmitting Peaker	-	224	-	-	-	-
DSM - Energy Efficiency	25	29	38	23	26	30
DSM - Demand Response	(29)	(12)	(5)	(36)	13	(38)
Renewable - Wind	-	-	111	(1,625)	1,297	2,629
Renewable - Utility Solar	-	369	5	-	(599)	(124)
Renewable - Geothermal	-	-	-	-	-	-
Renewable - Battery	535	-	(44)	-	-	-

Washington vs. Systemwide 2029-2034

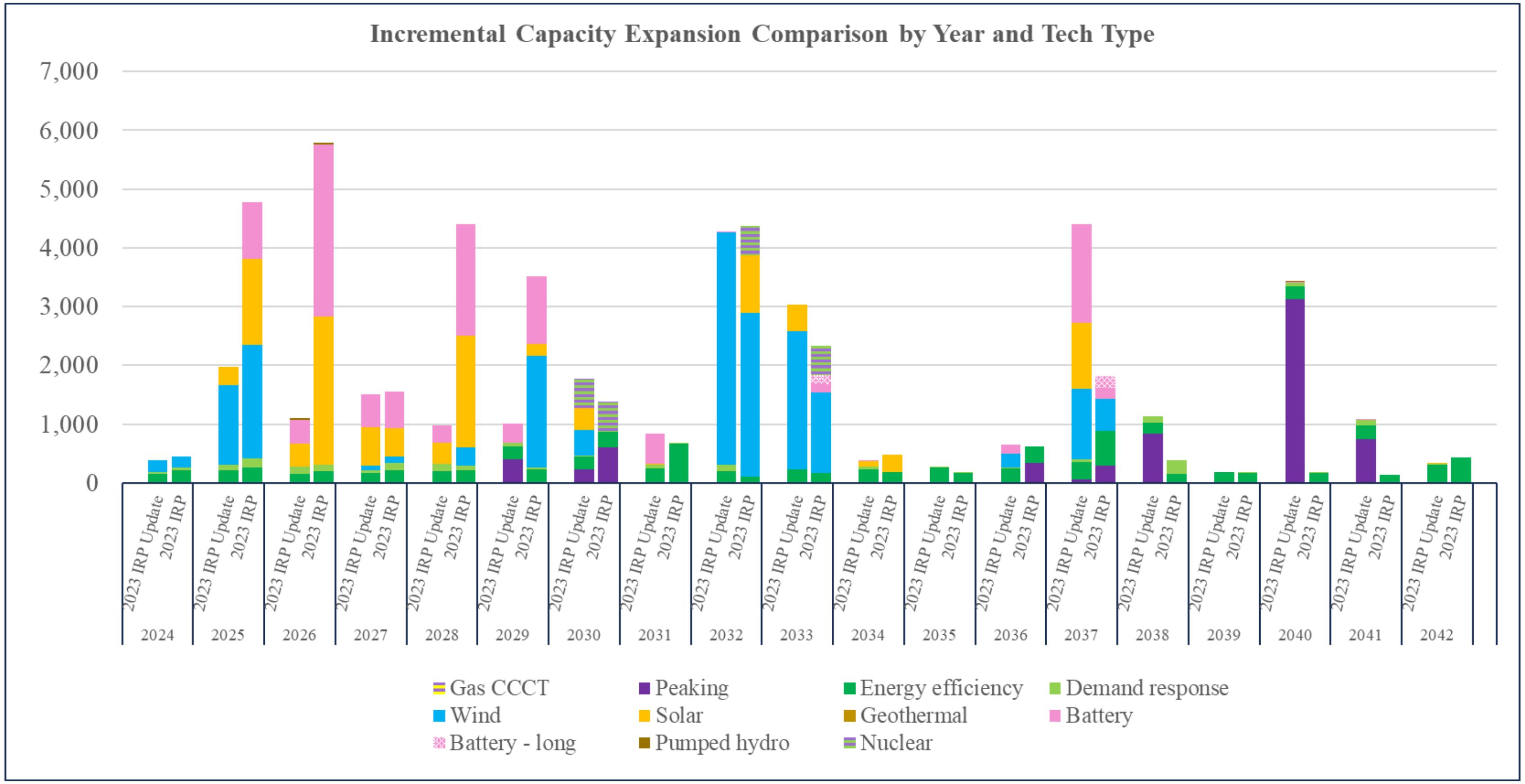
Resource	2029	2030	2031	2032	2033	2034
Expansion Options						
Gas - CCCT	500	-	-	-	-	-
Gas - Peaking	(635)	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-
DSM - Energy Efficiency	(2)	2	(25)	3	(5)	(6)
DSM - Demand Response	92	(8)	11	(16)	13	(16)
Renewable - Wind	-	-	346	2,444	(1,842)	-
Renewable - Utility Solar	-	-	-	41	1,127	(124)
Renewable - Geothermal	-	-	-	-	-	-
Renewable - Battery	21	-	(68)	528	-	66

2023 IRP Update
Preferred Portfolio

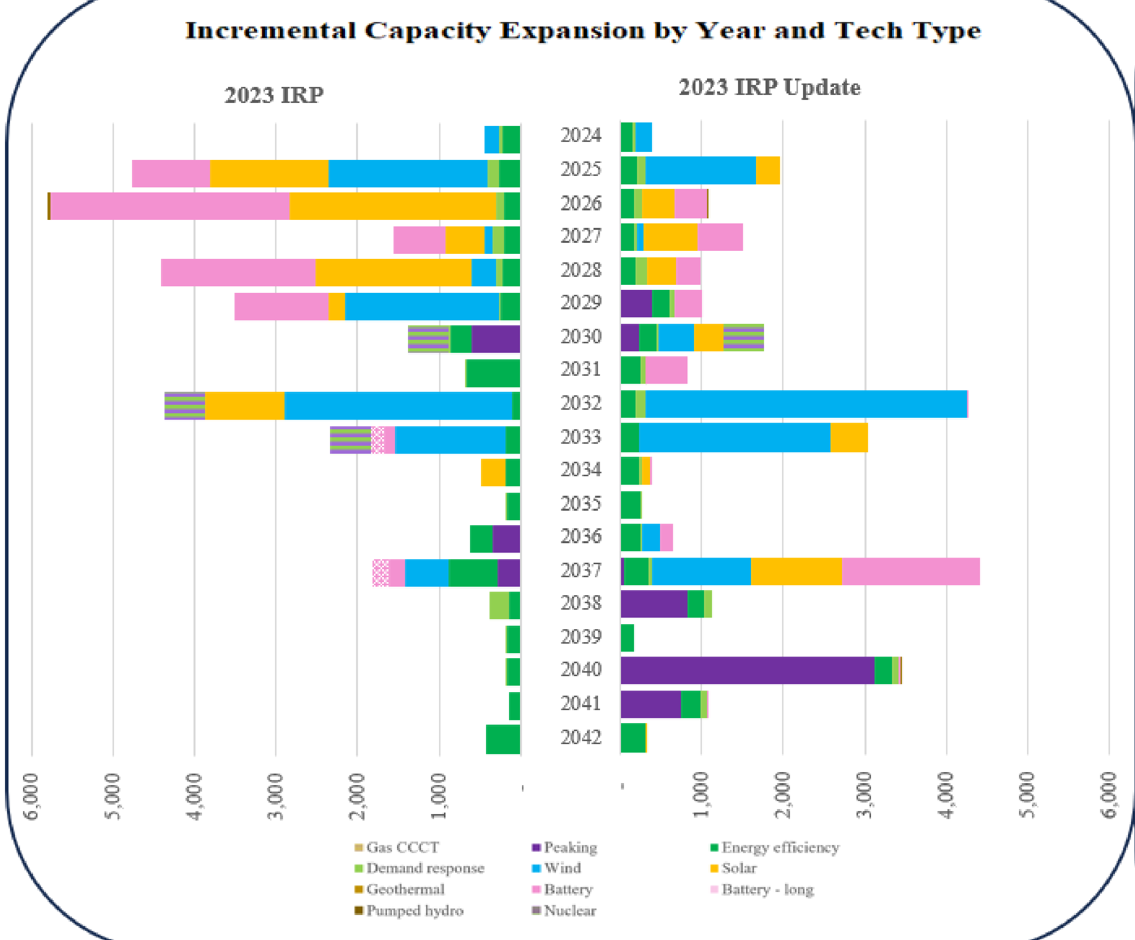
Cumulative Capacity Compare: 2023 IRP Update and 2023 IRP

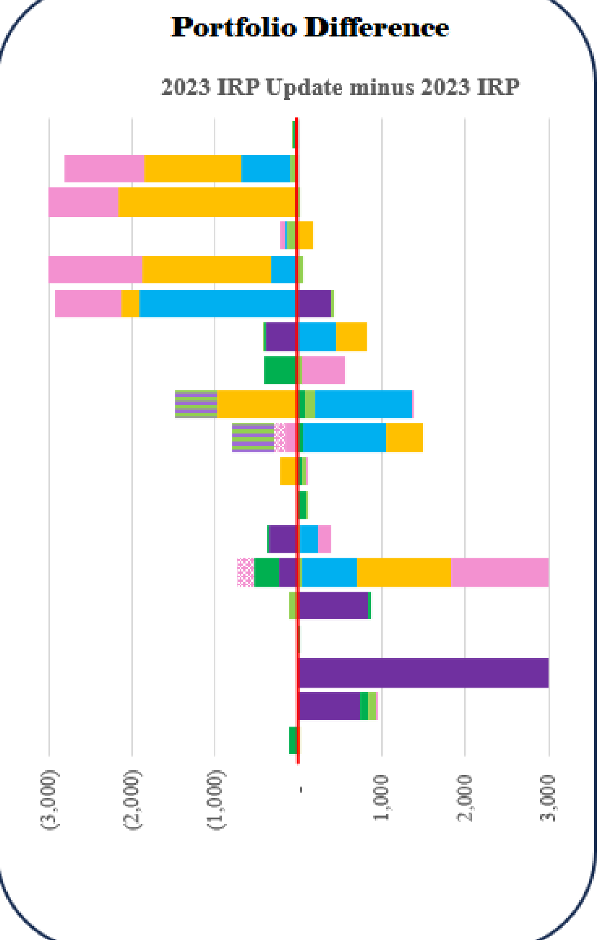


Incremental Capacity Compare: 2023 IRP Update and 2023 IRP



Incremental Capacity Compare and Delta: 2023 IRP Update and 2023 IRP





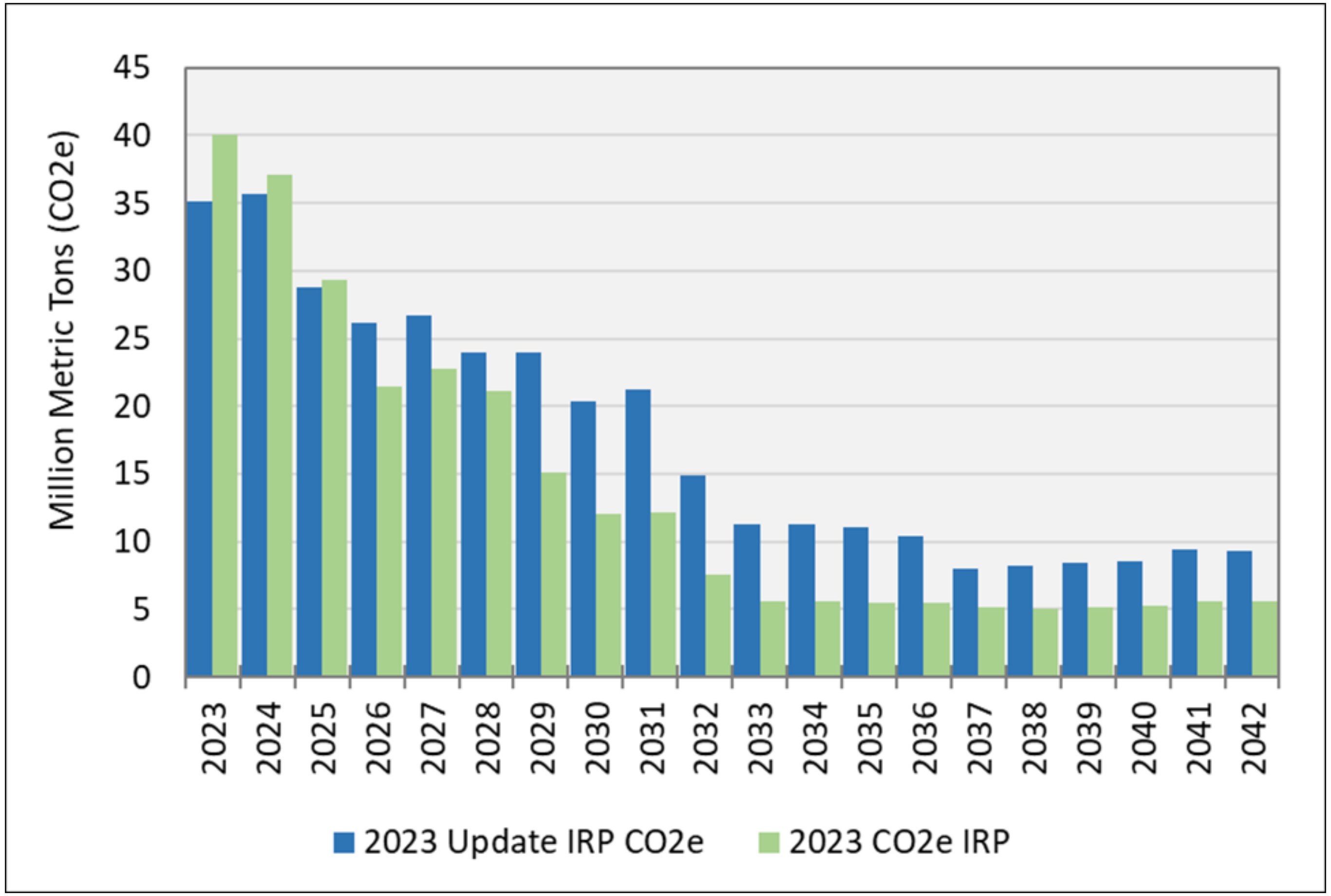
Transmission Selections

Line Name	1st Year Build %	Years Built	Total % Built	Total Cost (MM)
GWS	100%	2025	100%	2,605.52
B2H - Idaho Power Asset Transfer	32%	2026, 2027	100%	-
B2H	0%	2026, 2027	68%	894.56
B2H - Longhorn Load	0%	2026, 2027	68%	144.27
B2H - IPC PTP Eastbound (grossed up PTP rate)	32%	2026, 2027	100%	282.77
Cluster 2 Area 5 - Borah	14%	2027	14%	1.91
Cluster 2 Area 8 - Utah North	2%	2027, 2029, 2037, 2040, 2042	94%	35.11
Cluster 2 Area 23 - Willamette Valley	10%	2027	18%	5.01
Cluster 1 Area 10 - Yakima	25%	2027	25%	6.51
Cluster 2 Area 15 - Walla Walla	7%	2028, 2031, 2032	100%	21.49
Transition Cluster Area 8 - Central Oregon	4%	2029, 2030, 2031, 2032	100%	38.85
Union Gap-Midway 230 kV Line and substation - Yakima	68%	2030, 2031, 2033, 2040	100%	28.80
Antelope-Borah and Populus Terminal 345 kV lines plus reinforcement	10%	2030	10%	103.67
Cluster 2 Area 6 - Goshen	44%	2031, 2032	100%	56.00
Walla Walla - Wine Country 230 kV line and project intergration	70%	2032, 2042	72%	255.97
Del Norte-Central Oregon 500kV	48%	2033, 2037	57%	1,032.21
Cluster 2 Area 4 - Bridger-Populus & D3	7%	2037	7%	3.79
Birdsdale 230-115 kV and Portland 115 kV reinforcement	5%	2037	5%	4.99
D2.2/D1.2	7%	2037	7%	78.46
Segment D3	7%	2037	7%	132.22
D3 supporting projects (west)	7%	2037	7%	-
D3 supporting projects (east)	7%	2037	7%	3.67
GWS2+ (future expansion option)	7%	2037	7%	197.28
500-230 kV Birdsdale. 500 kV Birdsdale-Dixonville, S. Lebanon 500-230	19%	2037	19%	61.65
S. Lebanon 500-230 kV, 500 kV to Dixonville, Dbl-Ckt Fry-S.Lebanon 230 kV	19%	2037	19%	137.85
Cluster 2 Area 16 - Yakima	2%	2040, 2041, 2042	43%	94.87
B2H.2+ (future expansion option)	18%	2040	18%	404.68
Segment E	32%	2040	32%	663.64
Goshen-Populus 345 kV line and reinforcement	4%	2041	4%	39.28

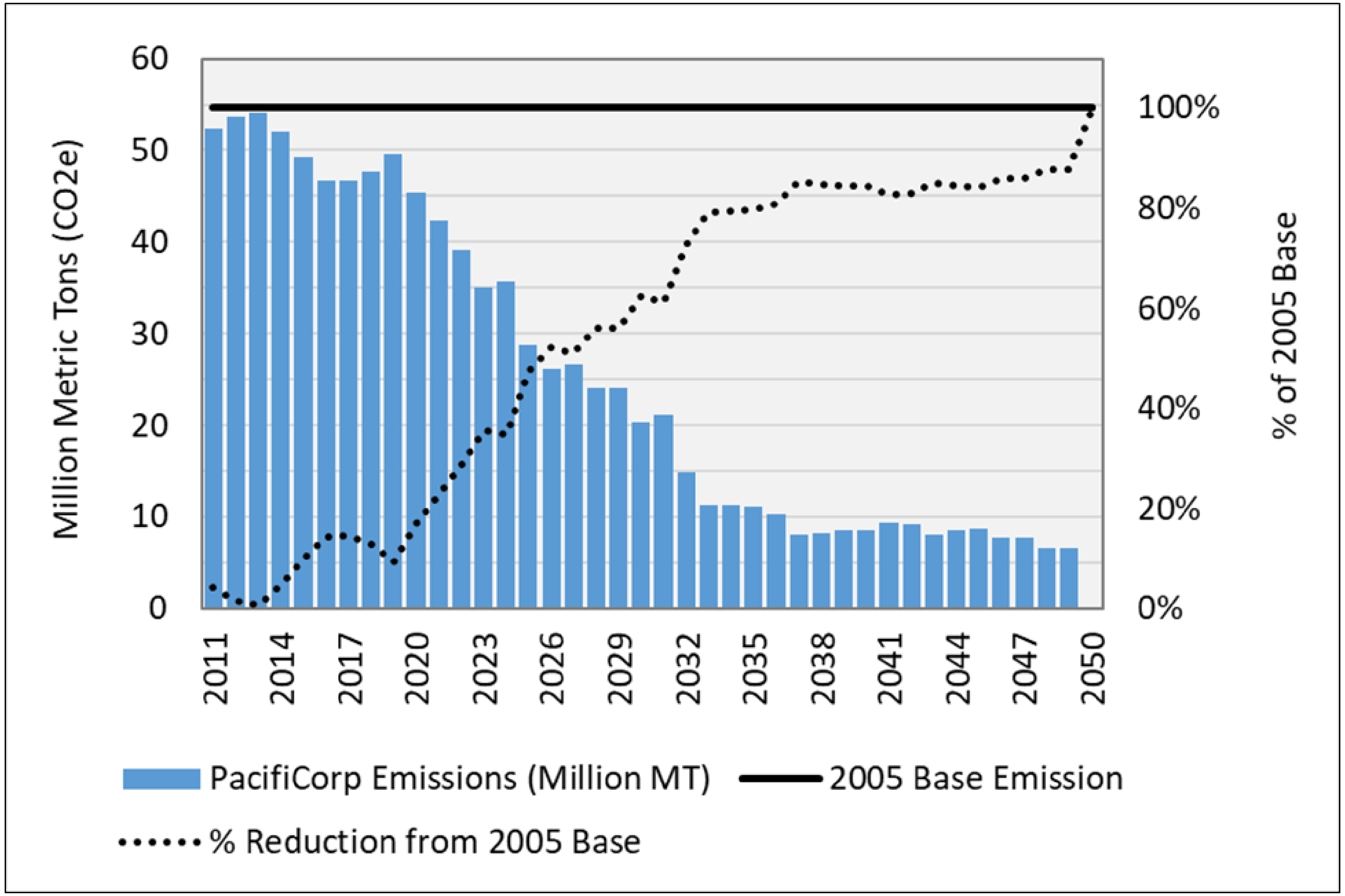
Coal Retirements:
2023 IRP Update and 2023 IRP

Coal			
Unit	2023 IRP Retirement Year (12/31/__)	2023 IRP Update Retirement Year (12/31/__)	Delta to 2023 IRP (Years)
	As Selected	As Selected	
Colstrip 3	2025	2025	-
Colstrip 4	2029	2029	-
Craig 1	2025	2025	-
Craig 2	2028	2028	-
DaveJohnston 1	2028	2028	-
DaveJohnston 2	2028	2028	-
DaveJohnston 3	2027	2027	-
DaveJohnston 4	2039	2039	-
Hayden 1	2028	2028	-
Hayden 2	2027	2027	-
Hunter 1	2031	2042	11
Hunter 2	2032	2042	10
Hunter 3	2032	2042	10
Huntington 1	2032	2036	4
Huntington 2	2032	2036	4
JimBridger 1	2037	2037	-
JimBridger 2	2037	2037	-
JimBridger 3	2037	2039	2
JimBridger 4	2037	2039	2
Naughton 1	2036	2036	-
Naughton 2	2036	2036	-
Wyodak	2039	2039	-

CO2e Emissions:
2023 IRP Update and 2023 IRP



CO2e Emissions Trajectory



Stakeholder Feedback

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Feedback Form Update

- Two feedback forms submitted to date, the second of which is new from Western Resource Advocates.
- Feedback forms and responses can be located at:
  [IRP Stakeholder Feedback (pacificpower.net)]
- Depending on the type and complexity of the feedback, responses may be provided in a variety of ways including, but not limited to, a written response, a follow-up conversation, or incorporation into subsequent public-input meeting material
  - Generally, written responses are provided with the feedback form and posted online at the link above

Next Steps

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2025 IRP Public Input Meeting Schedule

2025 IRP Upcoming Meeting Dates and Milestones *Calendar Year 2024*[1,2]
Wed-Thurs June 26-27, 2024 – General Public Input Meeting 4
Wed-Thurs August 14-15, 2024 – General Public Input Meeting 5
Wed-Thurs September 25-26, 2024 – General Public Input Meeting 6
➢ September timeframe – Assumptions are locked down for November and December model runs
Wed-Thurs November 6-7, 2024 – General Public Input Meeting 7
Wed-Thurs December 18-19, 2024 – General Public Input Meeting 8
Calendar Year 2025
➢ January 1, 2025 - Distribution of the 2025 Draft IRP
Wed-Thurs January 22-23, 2025 – General Public Input Meeting 9
Wed-Thurs February 26-27, 2025 – General Public Input Meeting 10
➢ March 31, 2025 – Filing of the 2025 IRP

1. *Washington law accelerates the IRP draft and final filing by 3 months. Alignment for Washington has been achieved through approved parts of a waiver request. The CEIP schedule remains out-of-sync.*
2. *The Public Input Meeting schedule has been reviewed to reasonably avoid conflicts with State Commission schedules and known events affecting stakeholders.*

Additional Information

- 2025 IRP Upcoming Public Input Meetings:
  - May 2, 2024 (Thursday)
- Public Input Meeting and Workshop Presentation and Materials:
  - Public Input Process (pacificorp.com)
- 2025 IRP Feedback Forms:
  - IRP Stakeholder Feedback (pacificpower.net)
- IRP Email / Distribution List Contact Information:
  - IRP@PacifiCorp.com
- IRP Support and Studies:
  - IRP Support & Studies (pacificorp.com)