Integrated Resource Plan
2021 IRP Public Input Meeting
October 22, 2020




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Agenda

- Introductions
- Supply-Side Resource Table Results
- Conservation Potential Assessment Final Results
- Lunch Break (45 min) 11:15am PT/12:15pm MT
- Energy Efficiency Bundling Methodology
- Market Reliance Assessment
- Plexos Benchmark Update
- Environmental Policy: Regional Haze Update
- Stakeholder Feedback Form Recap
- Wrap-Up/ Next Steps

Supply-Side Resource Table Results




Supply-Side Resources Review

- Background
  - Data sources
  - General assumptions
- Resource Update and Overview
  - Renewables
    - Solar PV
    - Wind
    - Energy Storage
  - Nuclear
  - Gas
  - Carbon Capture Utilization & Sequestration

Solar Resources

Performance and Cost Summary (2018$)

Resource	Elevation (AFSL)	Net Capacity (MW)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
Idah Falls, ID, 100 MW, CF: 26.1%	4,700	100	1,429	0.00	16.20	0.12	35.00
Idah Falls, ID, 200 MW, CF: 26.1%	4,700	200	1,302	0.00	16.10	0.12	35.00
Lakeview, OR, 100 MW, CF: 27.6%	4,800	100	1,444	0.00	16.20	0.12	35.00
Lakeview, OR, 200 MW, CF: 27.6%	4,800	200	1,330	0.00	16.10	0.12	35.00
Milford, UT, 100 MW, CF: 30.2%	5,000	100	1,422	0.00	17.60	0.12	35.00
Milford, UT, 200 MW, CF: 30.2%	5,000	200	1,297	[illegible]	[illegible]	0.12	35.00
Rock Springs, WY, 100 MW, CF: 27.9%	6,400	100	1,423	[illegible]	[illegible]	0.12	35.00
Rock Springs, WY, 200 MW, CF: 27.9%	6,400	200	1,297	0.00	17.60	0.12	35.00
Yakima, WA, 100 MW, CF: 24.2%	1,000	100	1,486	0.00	17.60	0.12	35.00
Yakima, WA, 200 MW, CF: 24.2%	1,000	200	1,357	0.00	17.60	0.12	35.00
Idah Falls, ID, 100 MW, CF: 26.1% + BESS: 50% pwr, 4 hours	4,700	100	2,351	0.00	30.00	0.12	255.00
Idah Falls, ID, 200 MW, CF: 26.1% + BESS: 50% pwr, 4 hours	4,700	200	2,161	0.00	28.95	0.12	255.00
Lakeview, OR, 100 MW, CF: 27.6% + BESS: 50% pwr, 4 hours	4,800	100	2,329	0.00	30.00	0.12	255.00
Lakeview, OR, 200 MW, CF: 27.6% + BESS: 50% pwr, 4 hours	4,800	200	2,154	0.00	28.95	0.12	255.00
Milford, UT, 100 MW, CF: 30.2% + BESS: 50% pwr, 4 hours	5,000	100	2,283	0.00	31.40	0.12	255.00
Milford, UT, 200 MW, CF: 30.2% + BESS: 50% pwr, 4 hours	5,000	200	2,102	0.00	30.45	0.12	255.00
Rock Springs, WY, 100 MW, CF: 27.9% + BESS: 50% pwr, 4 hours	6,400	100	2,312	0.00	31.40	0.12	255.00
Rock Springs, WY, 200 MW, CF: 27.9% + BESS: 50% pwr, 4 hours	6,400	200	2,128	0.00	30.45	0.12	255.00
Yakima, WA, 100 MW, CF: 24.2% + BESS: 50% pwr, 4 hours	1,000	100	2,405	0.00	31.40	0.12	255.00
Yakima, WA, 200 MW, CF: 24.2% + BESS: 50% pwr, 4 hours	1,000	200	2,217	0.00	30.45	0.12	255.00

Sales tax added to all Base Capital costs.

Base Capital formula corrected for solar + storage.

Wind Resources

Performance and Cost Summary (2018$)

Resource	Elevation (AFSL)	Net Capacity (MW)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
Pocatello, ID, 200 MW, CF: 43.0%	4,500	200	1,365	0.00	29.43	0.35	12.50
Arlington, OR, 200 MW, CF: 43.0%	1,500	200	1,315	[illegible]	[illegible]	0.35	12.50
Monticello, UT, 200 MW, CF: 36.1%	4,500	200	1,306	[illegible]	[illegible]	0.35	12.50
Medicine Bow, WY, 200 MW, CF: 48.6%	6,500	200	1,356	0.00	29.43	0.35	12.50
Goldendale, WA, 200 MW, CF: 43.0%	1,500	200	1,390	0.00	29.43	0.35	12.50
Pocatello, ID, 200 MW, CF: 43.0% + BESS: 50% pwr, 4 hours	4,500	200	2,152	0.00	42.28	0.23	232.50
Arlington, OR, 200 MW, CF: 43.0% + BESS: 50% pwr, 4 hours	1,500	200	2,086	0.00	42.28	0.23	232.50
Monticello, UT, 200 MW, CF: 36.1% + BESS: 50% pwr, 4 hours	4,500	200	2,061	0.00	42.28	0.23	232.50
Medicine Bow, WY, 200 MW, CF: 48.6% + BESS: 50% pwr, 4 hours	6,500	200	2,136	0.00	42.28	0.23	232.50
Goldendale, WA, 200 MW, CF: 43.0% + BESS: 50% pwr, 4 hours	1,500	200	2,211	0.00	42.28	0.23	232.50

Sales tax added to all Base Capital costs.

Base Capital and O&M Costs reduced to reflect updated market prices.

Energy Storage Resources

Performance and Cost Summary (2018$)

Pumped Hydro, Swan Lake	N/A	400	3,095	0.00	12.50	0.00	Not available
Pumped Hydro, Goldendale	N/A	1,200	$\boxed{2,833}$	0.00	$\boxed{12.50}$	0.00	Not available
Pumped Hydro, Seminoe	N/A	750	3,461	0.37	16.00	0.00	Not available
Pumped Hydro, Badger Mountain	N/A	500	[illegible]	[illegible]	[illegible]	[illegible]	ot available
Pumped Hydro, Owyhee	N/A	600	[illegible]	[illegible]	[illegible]	[illegible]	ot available
Pumped Hydro, Flat Canyon	N/A	300	[illegible]	[illegible]	[illegible]	[illegible]	ot available
Pumped Hydro, Utah PS2	N/A	500	3,237	0.37	28.00	0.00	Not available
Pumped Hydro, Utah PS3	N/A	600	3,371	0.37	20.00	0.00	Not available
Pumped Hydro, Banner Mountain	N/A	400	3,276	0.00	28.50	0.00	Not available
Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	N/A	150	1,954	6.50	12.67	0.00	12.14
Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	N/A	150	2,189	6.50	12.67	0.00	12.14
Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	N/A	150	2,445	6.50	12.67	0.00	12.14
Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	N/A	300	1,557	6.50	9.33	0.00	12.14
Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	N/A	300	1,692	6.50	9.33	0.00	12.14
Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	N/A	300	2,016	6.50	9.33	0.00	12.14
Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	N/A	500	1,549	6.50	6.60	0.00	12.14
Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	N/A	500	1,762	6.50	6.60	0.00	12.14
Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	N/A	500	1,930	6.50	6.60	0.00	12.14

Base Capital and O&M Costs reduced to reflect updated information.

Added demolition costs.

Gas Resources

Performance and Cost (2018$)

Resource	Elevation (AFSL)	Net Capacity (MW)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
SCCT Aero x3	5,050	139	1,777	9.04	0.00	0.03	12.14
Intercooled SCCT Aero x2	5,050	187	1,363	6.09			12.14
SCCT Frame "F" x1	5,050	199	841	17.04			12.14
Brownfield SCCT Frame "F" x1	5,050	199	811	17.03			12.14
IC Recips x 6	5,050	111	2,065	10.39	0.00	0.03	12.14
CCCT Dry "H", 1x1	5,050	350	1,687	2.14	0.00	0.01	12.14
CCCT Dry "H", DF, 1x1	5,050	51	470	0.05	0.00	0.00	0.00
CCCT Dry "H", 2x1	5,050	686	1,252	2.10	0.00	0.02	12.14
CCCT Dry "H", DF, 2x1	5,050	102	358	0.05	0.00	0.00	0.00
Brownfield CCCT Dry "H", DF, 2x1	5,050	686	1,251	1.33	0.00	0.03	12.14
CCCT Dry "J", 1x1	5,050	504	1,299	1.81	0.00	0.01	12.14
CCCT Dry "J", DF, 1x1	5,050	63	397	0.06	0.00	0.00	0.00
CCCT Dry "J", 2x1	5,050	1,004	966	1.76	0.00	0.02	12.14
CCCT Dry "J", DF, 2x1	5,050	126	309	0.06	0.00	0.00	0.00

Added demolition costs.

Conservation Potential Assessment
Final Results




Energy Efficiency Updates

- Draft measure database added to https://www.pacificorp.com/energy/integrated-resource-plan/support.html - 9/10/20
- Energy Trust of Oregon forecast updates
  - Energy Trust provided updated budget forecasts for calibration
  - Aligned industrial savings with NWPCC assumptions where appropriate
  - Resulted in ~20% increase in achievable technical potential, bringing results more in line with other states
- Added incremental Home Energy Report supply curve bundles in all states

Updated Oregon Energy Efficiency Potential

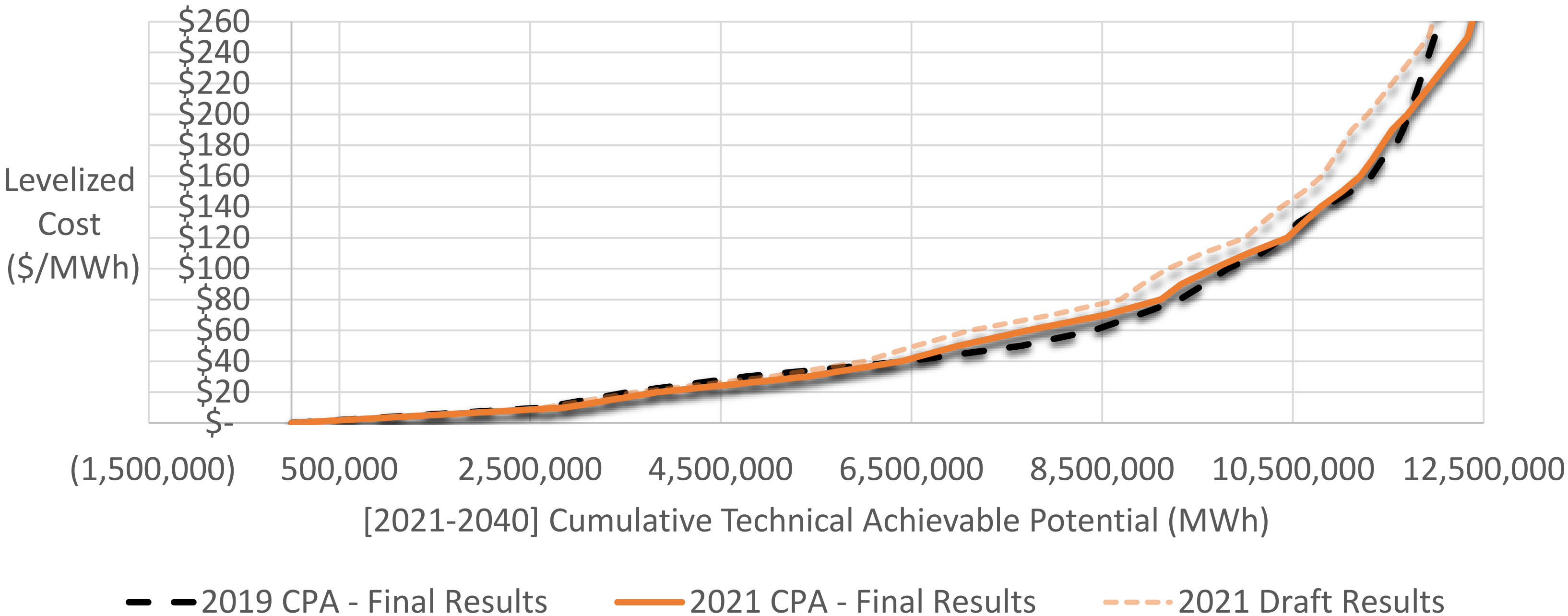
Measure Type	Final 2021 CPA: 20-Year Cumulative Potential	% of Total	*Draft 2021 CPA (Aug): 20-Year Cumulative Potential*	*% Change from Draft*
HVAC	764,778	25.4%	*660,002*	*15.9%*
Lighting	474,636	15.8%	*402,684*	*17.9%*
Whole Building/Home	420,129	14.0%	*379,532*	*10.7%*
Ind (Motor/Pump/Other)	313,618	10.4%	*252,156*	*24.4%*
Weatherization	253,916	8.4%	*205,695*	*23.4%*
Water Heating	209,235	6.9%	*157,208*	*33.1%*
Behavioral/EM	163,181	5.4%	*130,754*	*24.8%*
Appliance/Plug Load	112,464	3.7%	*89,846*	*25.2%*
Refrigeration	105,473	3.5%	*85,981*	*22.7%*
Agriculture/Irrigation	86,939	2.9%	*79,676*	*9.1%*
Compressed Air	85,106	2.8%	*64,384*	*32.2%*
Cooking	21,132	0.7%	*17,819*	*18.6%*
Total	**3,010,607**	**100.0%**	***2,525,737***	***19.2%***

Home Energy Report Updates

- PacifiCorp is considering expanding the reach of existing Home Energy Reports (HERs) in all states, including working with Energy Trust to start an HER program in Oregon in 2021
  - Savings in the 2021 IRP are incremental to existing HERs - impacts of existing programs area assumed to be captured in the load forecast and are not included as potential
  - To account for short (1-2 year) measure lives, incremental HER impacts are bundled separately from all other measures
  - Incremental HER program costs vary significantly by state

State	Existing Program?	Incremental HER LCOE ($/MWh)	2021 Incremental MWh	2022 Incremental MWh	2023 Incremental MWh
Idaho	Yes	$6.76	7,000	-	-
Utah	Yes	$9.67	66,000	-	-
Wyoming	Yes	$8.98	5,000	-	-
California	No	$1,358.75	11	11	-
Oregon	No	$17.78	10,876	9,063	10,876
Washington	Yes	$56.15	494	230	-
Total		**NA**	**89,381**	**9,304**	**10,876**

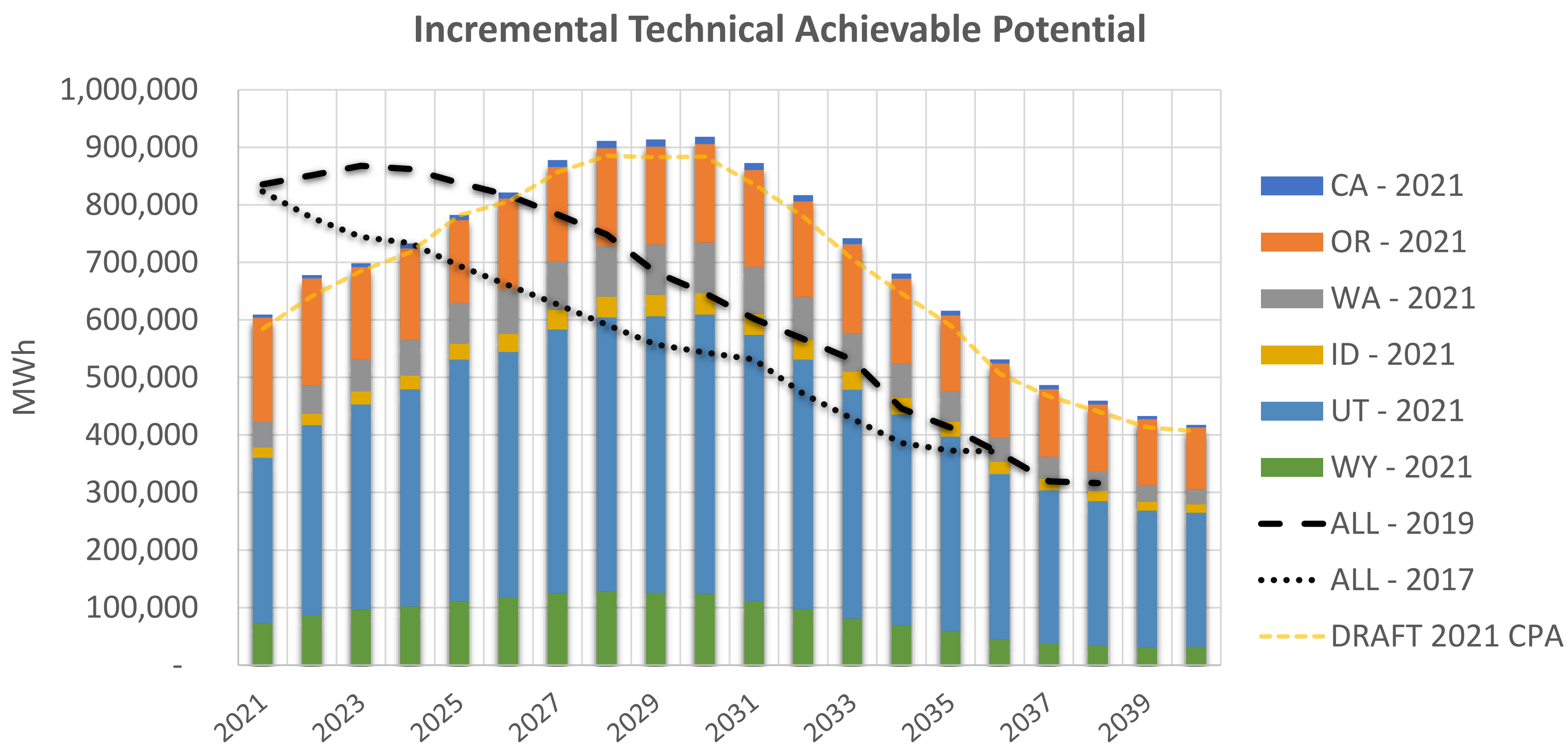
Final Technical Achievable Potential Supply Curve Comparison (All States – Cumulative MWh)



Total Cumulative 20-year Potential Comparison (MWh)			
2021 CPA October Final Results	*2021 CPA August Draft Results*	2019 CPA Results	% Difference (Oct Final compared to 2019 CPA)
13,892,417	*13,516,192*	13,163,531	+5.5%

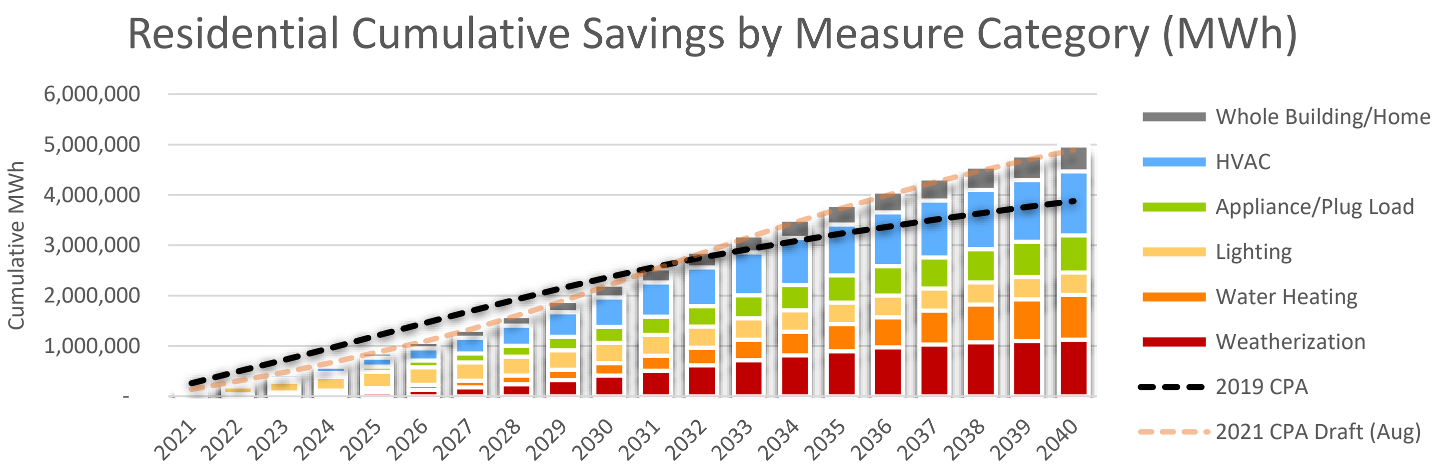
**Increase in final potential is primarily a result of updates to the Oregon results*
***Graph does not include incremental Home Energy Reports*

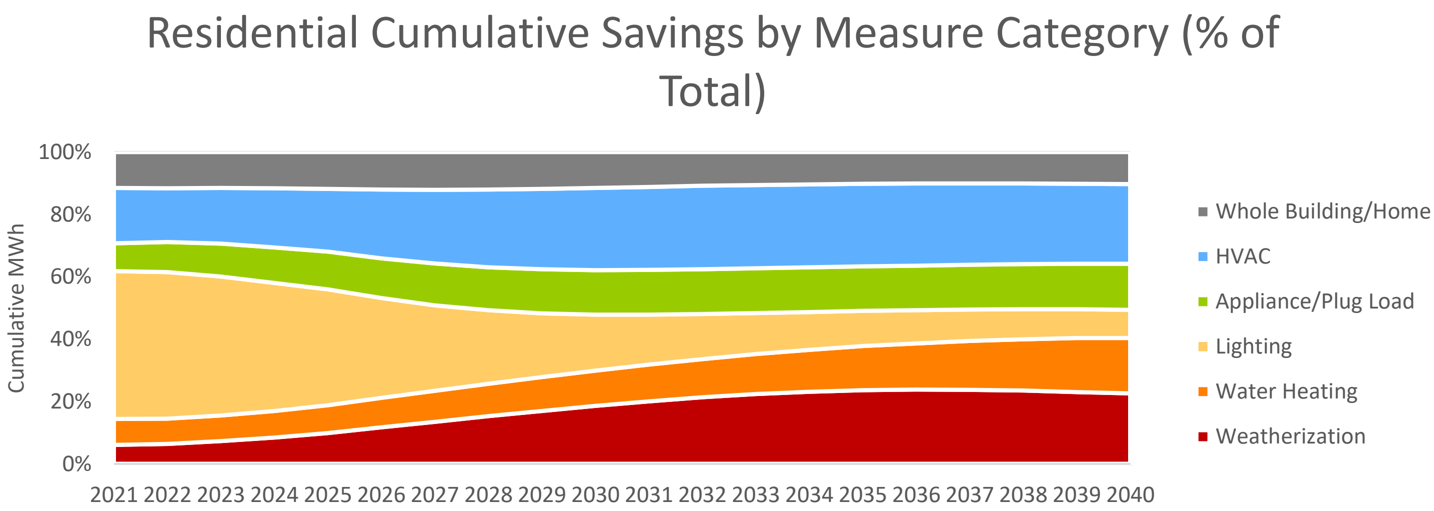
Final Technical Achievable Potential Comparison (All States - Incremental MWh)



**Graph does not include Incremental Home Energy Reports*

Residential Final Results (All States)

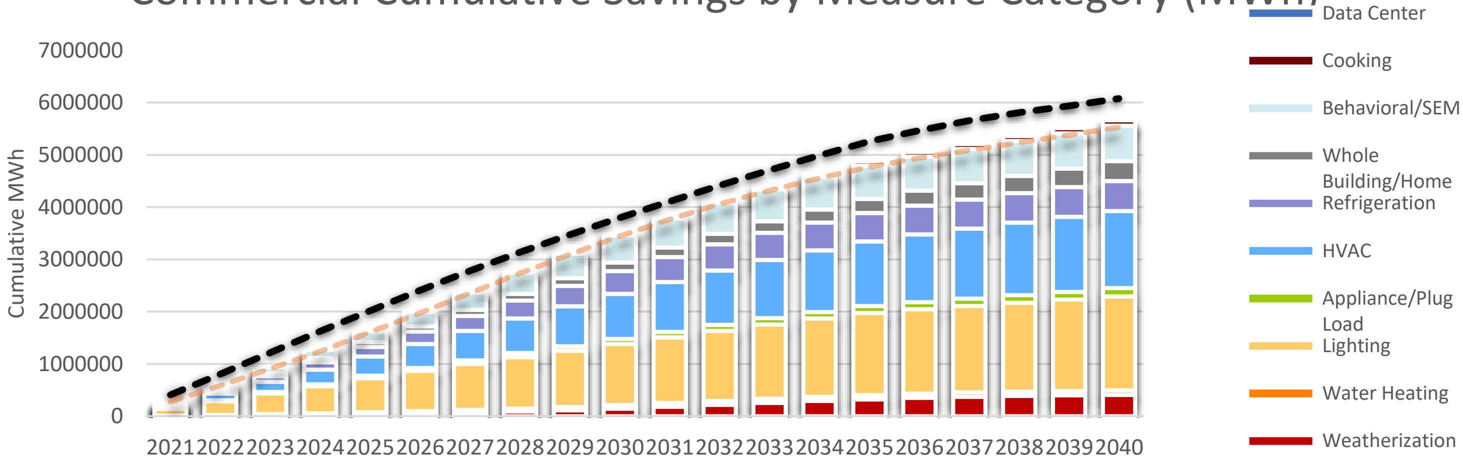




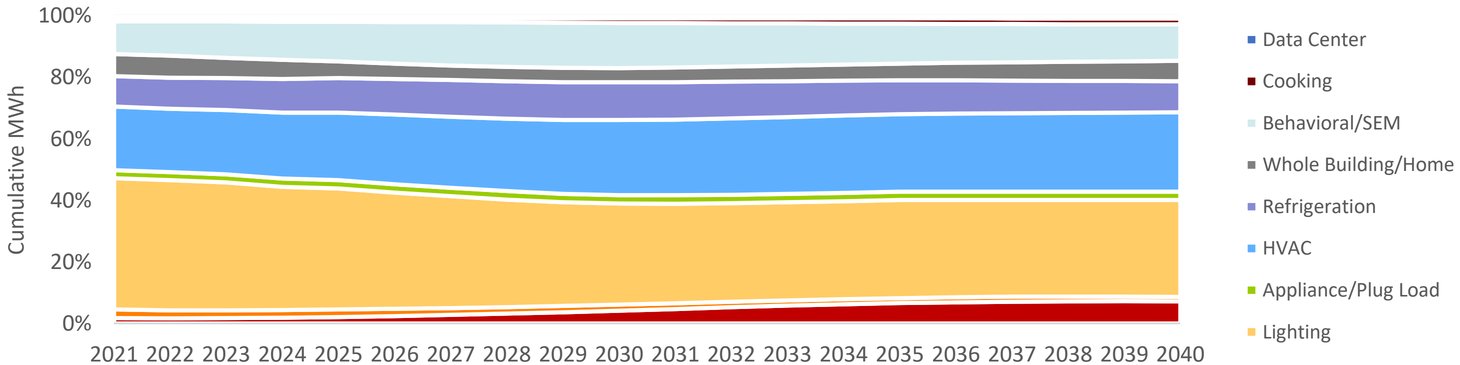
**Graphs do not include incremental Home Energy Reports*

Commercial Draft Results (All States)

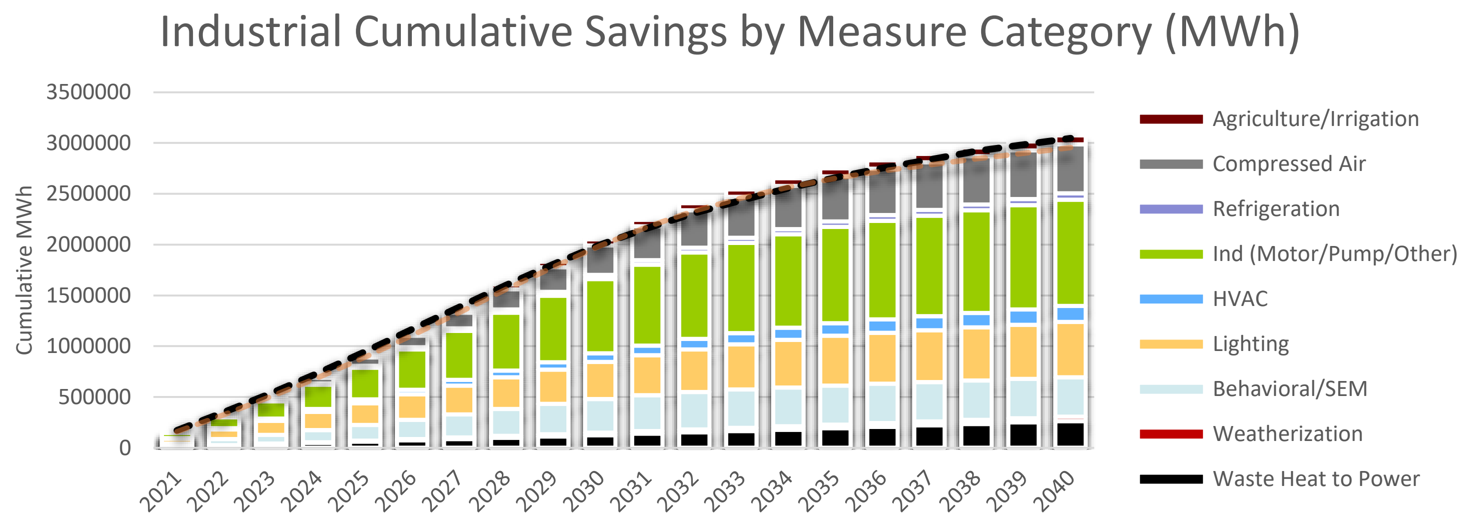
Commercial Cumulative Savings by Measure Category (MWh)

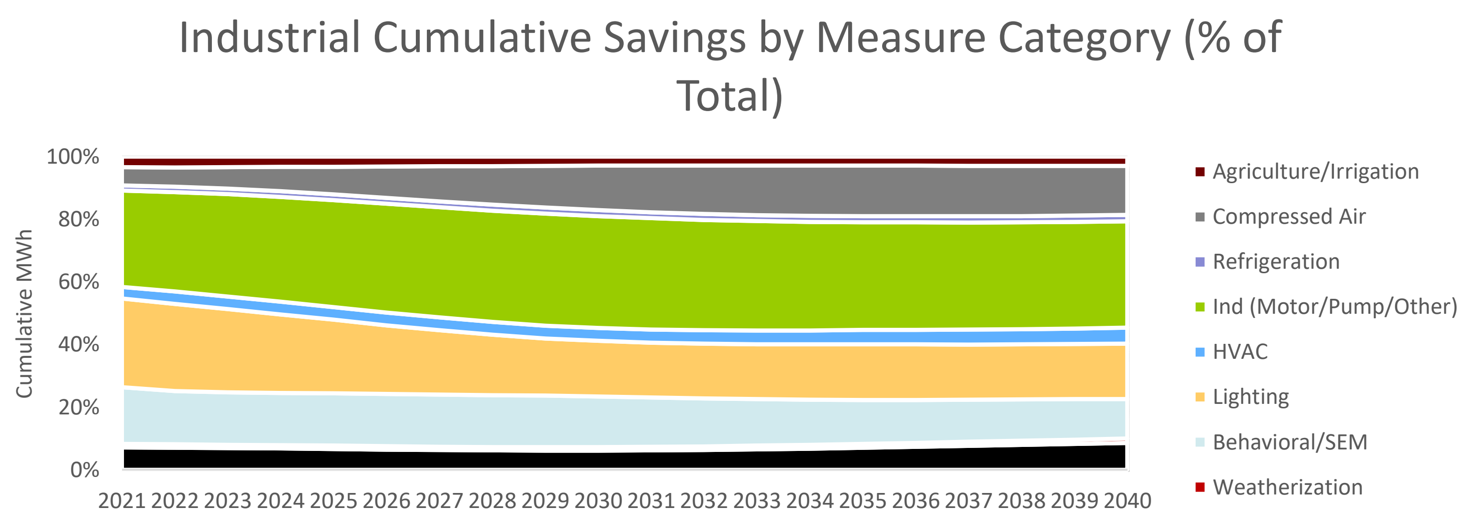


Commercial Cumulative Savings by Measure Category (% of Total)



Industrial Draft Results (All States)





Demand Response Updates

- Ramp Rates
  - Previous CPA assumed new program would not begin until the third year of the IRP and that participation would ramp up over 3 years.
  - Current CPA assumes programs could begin in the second year (2022) and ramp up over three years
  - Existing programs are assumed to be able to increase participation beginning in 2021
- Battery Energy Storage Assumptions
  - Proposed assumptions were presented at the August CPA Workshop
  - Final assumptions and results are provided on the following slides
- Costs
  - Incorporated stakeholder request to include scenarios around participant costs for Pacific Power states

Demand Response
Battery Energy Storage Assumptions

Customer Generation Rate Structure	Traditional Net Metering	Time of Export Net Billing*
Customer Storage Benefits	Resiliency, Demand Reduction (Non Res)	Maximize Energy Value, Resiliency, Demand Reduction (Non Res)
Installation Assumption for Customers with Solar	20%	60%
Program Participation	60%	60%
Capacity Impact (kW) - Sustained Duration	90%	75%
Capacity Impact (kW) - Short Duration	90%	90%

System Sizes and Impacts		
Battery Characteristic	**Residential kW/participant**	**Non-Residential kW/participant**
Rated Capacity	7	75
Discharge Rate - Sustained Duration	5	50
Discharge Rate - Short Duration	5	75

* New solar installations in Utah, Idaho, and California are assumed to be on time of export net billing.

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Battery Energy Storage Potential – Year-20

- Using the assumptions from the previous slide, demand response potential from customer-sited batteries is significant by the end of the study period
- Potential ramps up based on solar adoption forecast and program participation assumptions
- Due to battery discharge characteristics, available load reductions is larger for shorter duration events

	MW Impacts – Sustained Duration		
State	Residential	Non-Residential	Total
CA	4	15	19
ID	22	10	32
OR	62	26	89
UT	180	74	254
WA	2	5	7
WY	8	7	16
System	**279**	**138**	**417**

	MW Impacts – Short-Duration		
State	Residential	Non-Residential	Total
CA	7	26	33
ID	37	19	56
OR	87	40	127
UT	295	131	426
WA	3	8	11
WY	12	11	23
System	**441**	**235**	**676**

Developing Demand Response Resource Costs

- DR Programs generally have both upfront and ongoing costs
- Recall that DR costs are amortized over an assumed contract period of 5 years, aligning with current procurement practices
- As in the 2019 CPA, resource costs for Pacific Power states are based on a Total Resource Cost perspective and Rocky Mountain Power states are based on a Utility Cost Test perspective.
    - UCT: Count full incentive, exclude participant costs
    - TRC: Count participant costs (capital costs to participant + value of service lost + transaction costs), assumed to be a percentage of the incentive payment. Assessing three different participant cost scenarios based on stakeholder request
- Levelized costs are typically presented in $/kW-year

Types of Demand Response Costs

Costs of demand response programs generally fall into three buckets. Examples:

One-Time Fixed Costs	One-Time Variable Costs	Ongoing Costs
Program Development Costs *($/program)*	Equipment Costs *($/participant)*	Administrative Costs *(shared costs)*
DR Management System (DRMS) (set up cost)	Marketing Costs *($/participant)*	O&M *($/participant)*
	Incentives *($/participant or $/kW)*	Incentives *($/participant or $/kW)*

- As in previous studies, certain costs are shared across states (e.g., program development and administration costs could be shared across RMP or PP states)
- Utility DRMS costs have not been included in the past. Costs to control equipment have been included in vendor costs
- Incentives may be one-time and/or ongoing depending on the program design

Calculating Levelized Costs

where:

x= cost type

t = year

and:

program costs included vary by test perspective

Calculate the annual costs by type	$Cost_{xt} * Participants_t = TotalCost_{xt}$
Take the NPV of each annual cost stream	$NPVCost_x = \sum_{t=0}^{n} \frac{TotalCost_{xt}}{(1+0.069)^t}$
Sum the NPV of each cost type to get total cost	$NPV\ Program\ Cost = \sum_{x=0}^{n} NPVCost_x$
Take the NPV of the annual MW stream	$NPV\ MW = \sum_{t=0}^{n} \frac{MW_t}{(1+0.069)^t}$
Divide NPV Costs by NPV MW	$Levelized\ Cost = \frac{NPV\ Program\ Cost}{NPV\ MW}$

Example: Residential Grid-Interactive Water Heaters

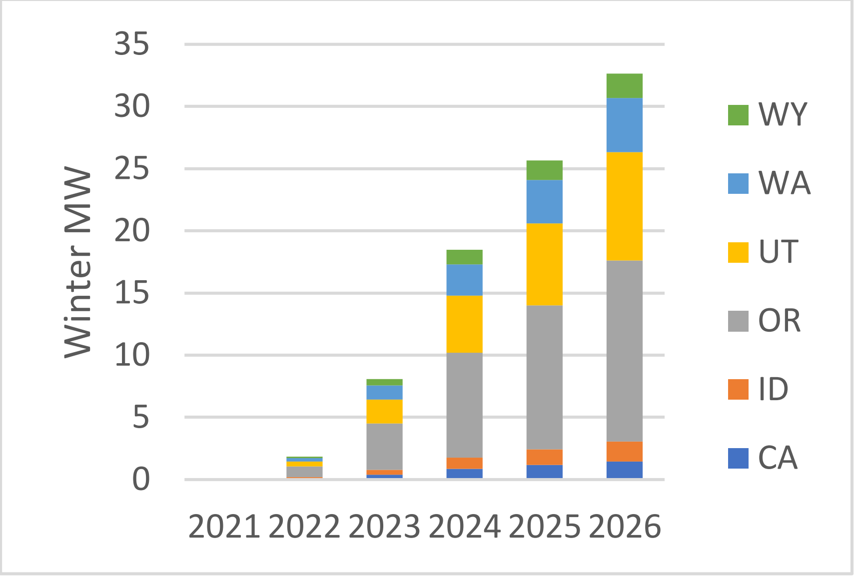
Type	Unit	Pacific Power	Rocky Mountain Power
Program Development [1]	$/program	$37,500	$37,500
Administrative Cost [2]	$/program/yr	$75,000	75,000
O&M Cost [3]	$/participant/yr	$7.50	$7.50
Marketing [3]	$/new participant	$30	$30
Equipment [3]	$/new participant	$50	$50
Incentive [3,4]	$/participant/yr	$10	$40

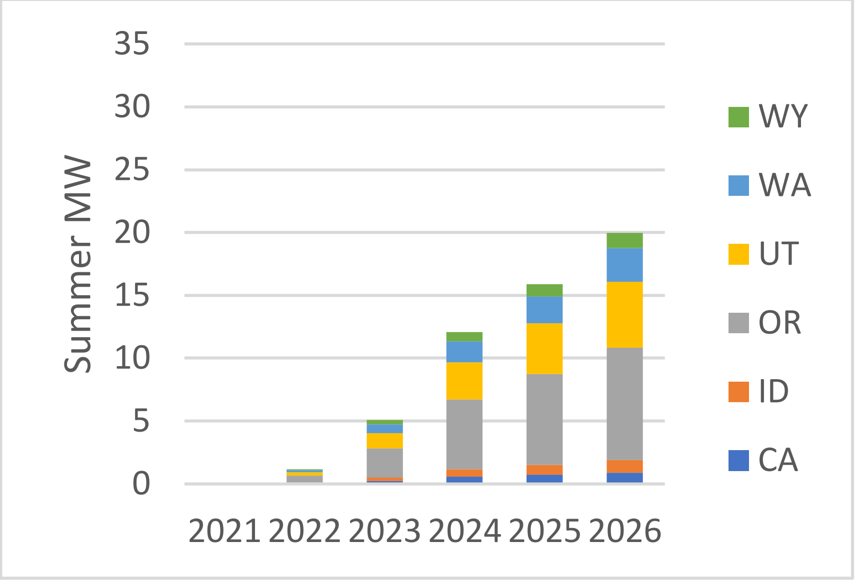
Notes:

1. Program Development costs are assumed to be $75,000 and are shared between residential and C&I and allocated to each state based on share of MW
2. Administrative costs reflect 1 FTE per year per territory shared between residential and C&I and allocated to each state based on share of MW
3. Remaining costs are from the NWPCC 2021 Plan, O&M costs leverage PSE's reported costs
4. Incentives costs for PP reflect that in the base case, participant costs are assumed to be 25% of the incentive payment

Ramped Grid Interactive Water Heater Potential – Sustained Duration

- Potential is higher in the winter than in the summer due to residential water heating alignment with system peak
  - Ramp up for new programs begins in 2022
  - 3-year ramp up to maximum participation rate
  - Assumed installation of grid-interactive equipment during equipment turnover and new construction creates new eligible participants over time





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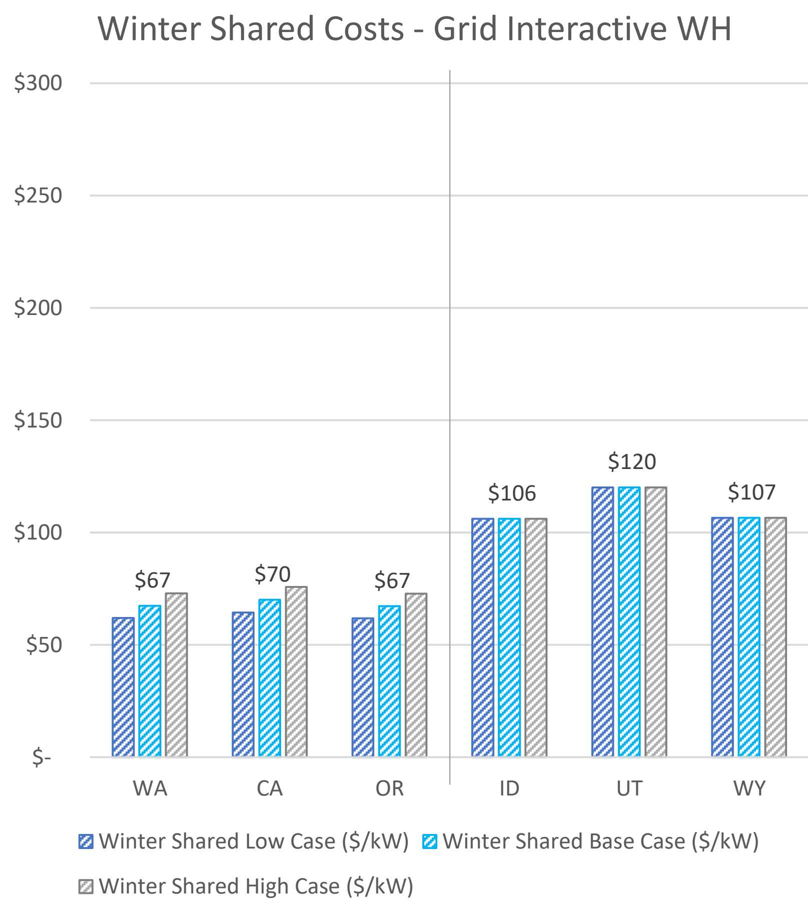
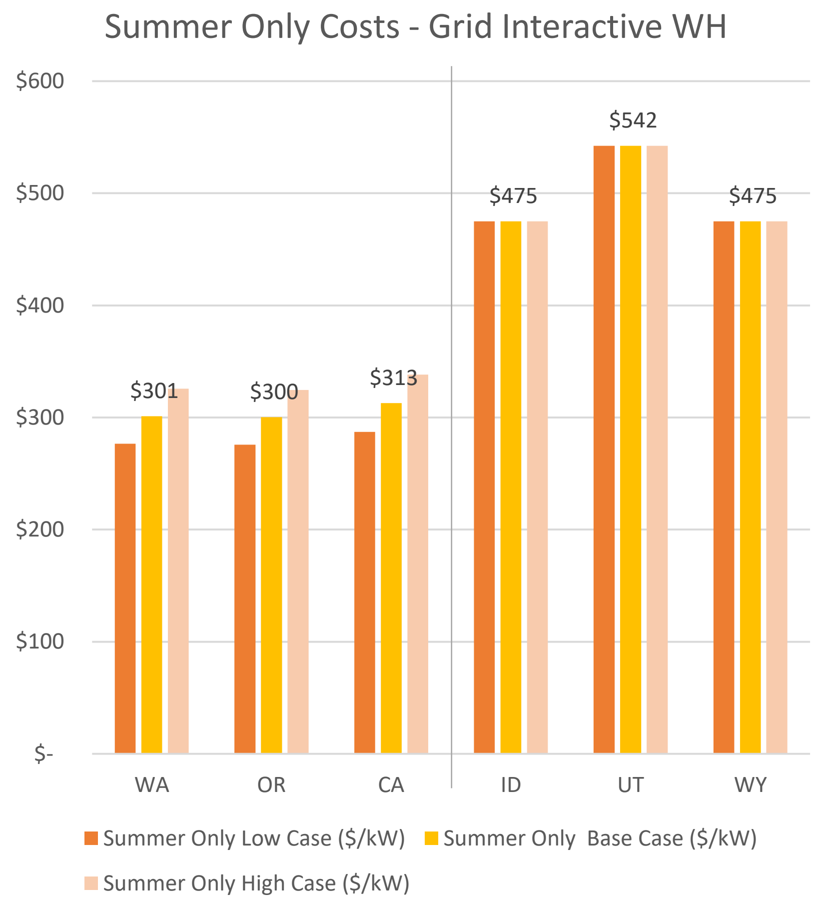
Example Levelized Costs by State - Winter



Example Levelized Costs by State - Summer



Demand Response Cost Bundles

Heating/Cooling or both

Measure	Bundle
Air-Source Heat Pump - DLC	HVAC DLC
Geothermal Heat Pump - DLC	HVAC DLC
Electric Furnace - DLC	HVAC DLC
CAC – DLC	HVAC DLC
Room AC – DLC	HVAC DLC
RTU - DLC	HVAC DLC
Thermostat - Connected	Smart Thermostats
Connected Line-Voltage Thermostat	Smart Thermostats
ENERGY STAR - Connected Thermostat	Smart Thermostats

DLC Equipment Measures

Measure	Bundle
Battery Energy Storage	Battery DLC
Connected EV Supply Equipment	EV DLC
EV Supply Equipment - DLC	EV DLC
Home Energy Management System (HEMS)	HEMS
Pool Pump - DLC	Pool Pump DLC
Pumps (<100 HP) - ADR	Irrigation DLC
Pumps (<100 HP) - DLC	Irrigation DLC
Pumps (100 HP+) - ADR	Irrigation DLC
Pumps (100 HP+) - DLC	Irrigation DLC

Water Heaters

Measure	Bundle
Grid Interactive ER Water Heater	Grid Interactive WH DLC
Grid Interactive HPWH Water Heater	Grid Interactive WH DLC
ER Water Heater DLC	WH DLC
HPWH Water Heater - DLC	WH DLC

Process/Energy Management

Measure	Bundle
Material Handling	Third Party
Ventilation	Third Party
Process Cooling	Third Party
Process Electrochemical	Third Party
Process Heating	Third Party
Process Refrigeration	Third Party

Lighting

Measure	Bundle
Interior Lighting - Embedded Fixture Controls	Third Party
Interior Lighting - Networked Fixture Controls	Third Party

Equipment Measures

Measure	Bundle
Pumps	Third Party
Compressed Air	Third Party
Fans & Blowers	Third Party
Other Motors – DLC	Third Party
Air-Cooled Chiller – ADR	Third Party
Air-Cooled Chiller – DLC	Third Party
Water-Cooled Chiller – ADR	Third Party
Water-Cooled Chiller – DLC	Third Party
Reach-in Refrigerator/Freezer	Third Party
Walk-in Refrigerator/Freezer	Third Party
Glass Door Display	Third Party
Energy Management Systems	Third Party

Energy Efficiency Bundling Methodology

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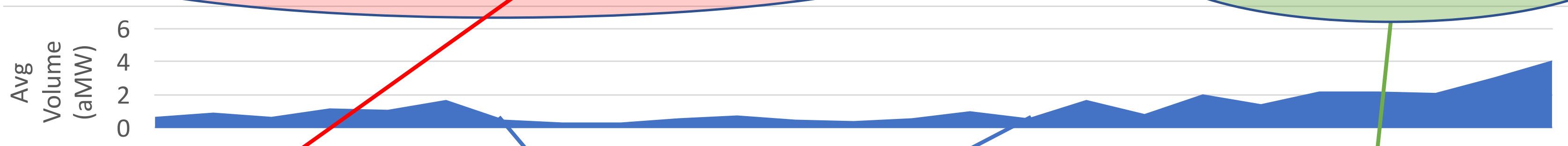
Energy Efficiency Bundling Background

- In the past, energy efficiency measures have been grouped into 27 bundles per state by levelized cost of energy. Sample data (not final Conservation Potential Assessment) is used throughout this section:

Levelized Volume (aMW), by Levelized Cost of Energy ($/MWH) *Bundles not selected* **Cost Bundles Selected in 2019 IRP Pref. Port.**

	$1000-9999	$750-1000	$500-750	$400-500	$300-400	$250-300	$200-250	$190-200	$180-190	$170-180	$160-170	$150-160	$140-150	$130-140	$120-130	$110-120	$100-110	$90-100	$80-90	$70-80	$60-70	$50-60	$40-50	$30-40	$20-30	$10-20	up to $10
CA	1	0	0	0	0	0	1	0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
ID	4	1	0	0	1	1	1	0	0	0	0	0	0	1	0	0	0	1	1	1	1	1	1	2	1	1	5
WA	3	1	2	2	2	2	2	1	1	0	1	2	1	0	1	2	1	1	1	5	2	3	3	3	3	4	9
WY	2	1	1	0	1	1	2	0	0	0	1	0	1	0	1	2	1	5	1	1	2	4	4	3	7	10	38



Breaking out lots of high cost bundles doesn't add modeling value if none of them get picked.

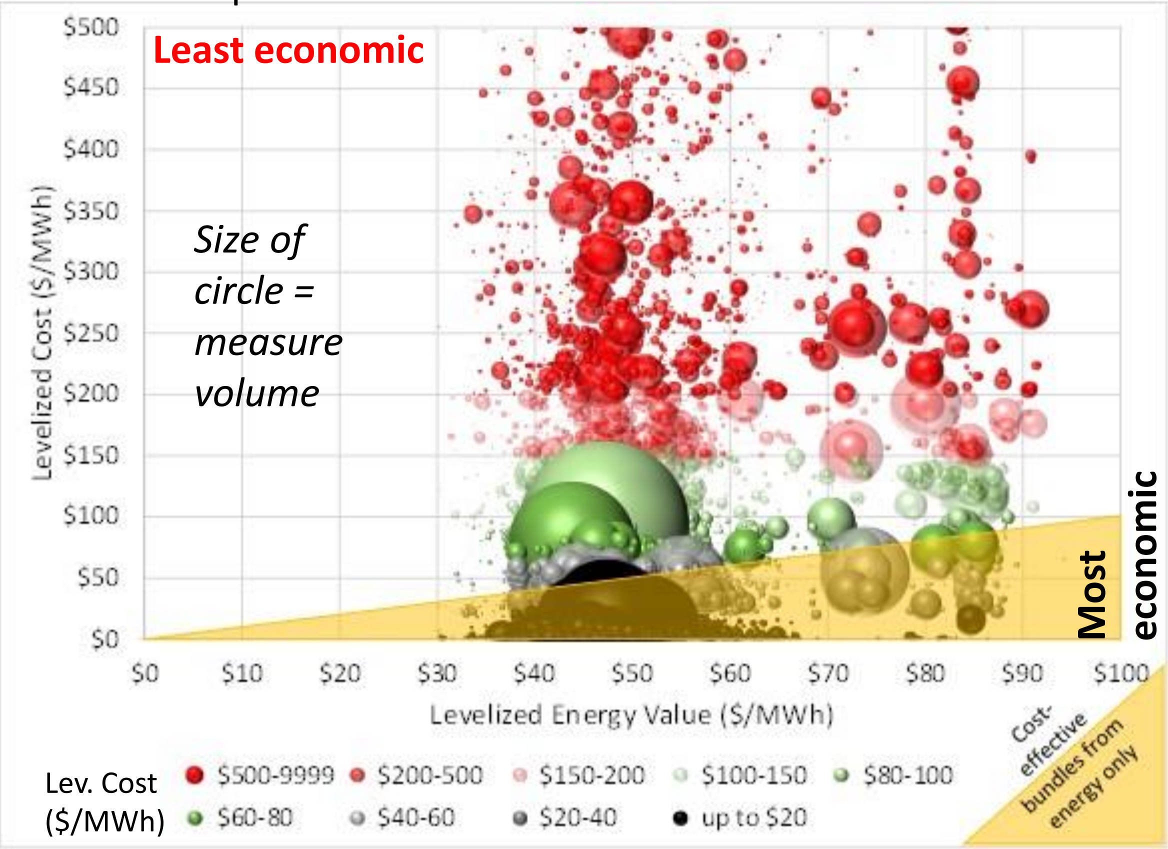
Bundle sizing in $10/MWh increments leaves lots bundles with small volumes between $100-$200/MWh.

Breaking out lots of low cost bundles doesn't add modeling value if they always get picked.

- Conclusion: there are more bundles than are necessary for modeling levelized cost of energy.
- Is there another metric we can use to differentiate measures with desirable characteristics?

Levelized Cost vs Levelized Value of Energy

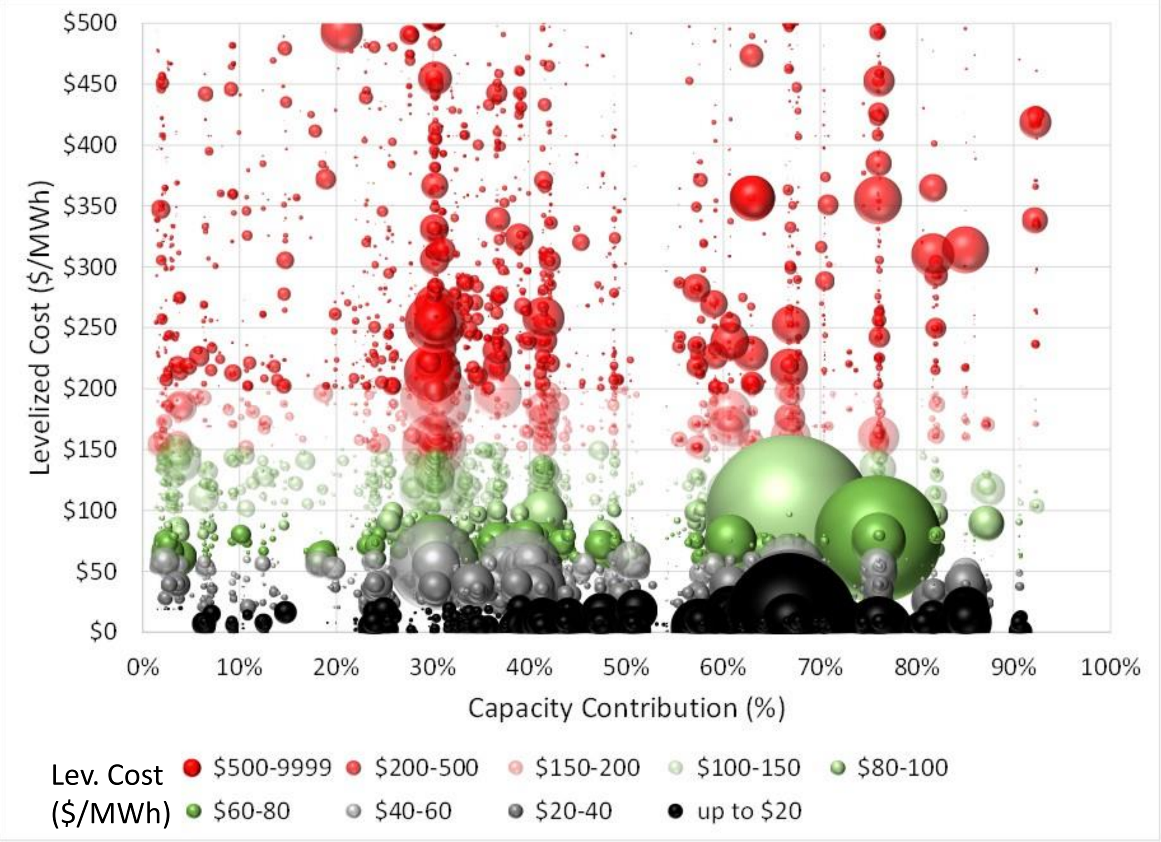
- Not all MWhs of energy efficiency are equal – value is dependent on the profile of the load reduction, which is tied to the end use.
- Measure savings are spread across applicable end use profiles for different customer types. There are over 100 profiles for each state.
- The timing of load reductions makes some measures in a given cost bundle more economic.
- Can we target measures with greater benefits relative to costs?



Levelized Cost vs Capacity Contribution

- Energy savings profiles also impact capacity contribution
- Within each levelized cost bundle, some measures have capacity contributions above 90%, others are near 0%.

Least economic

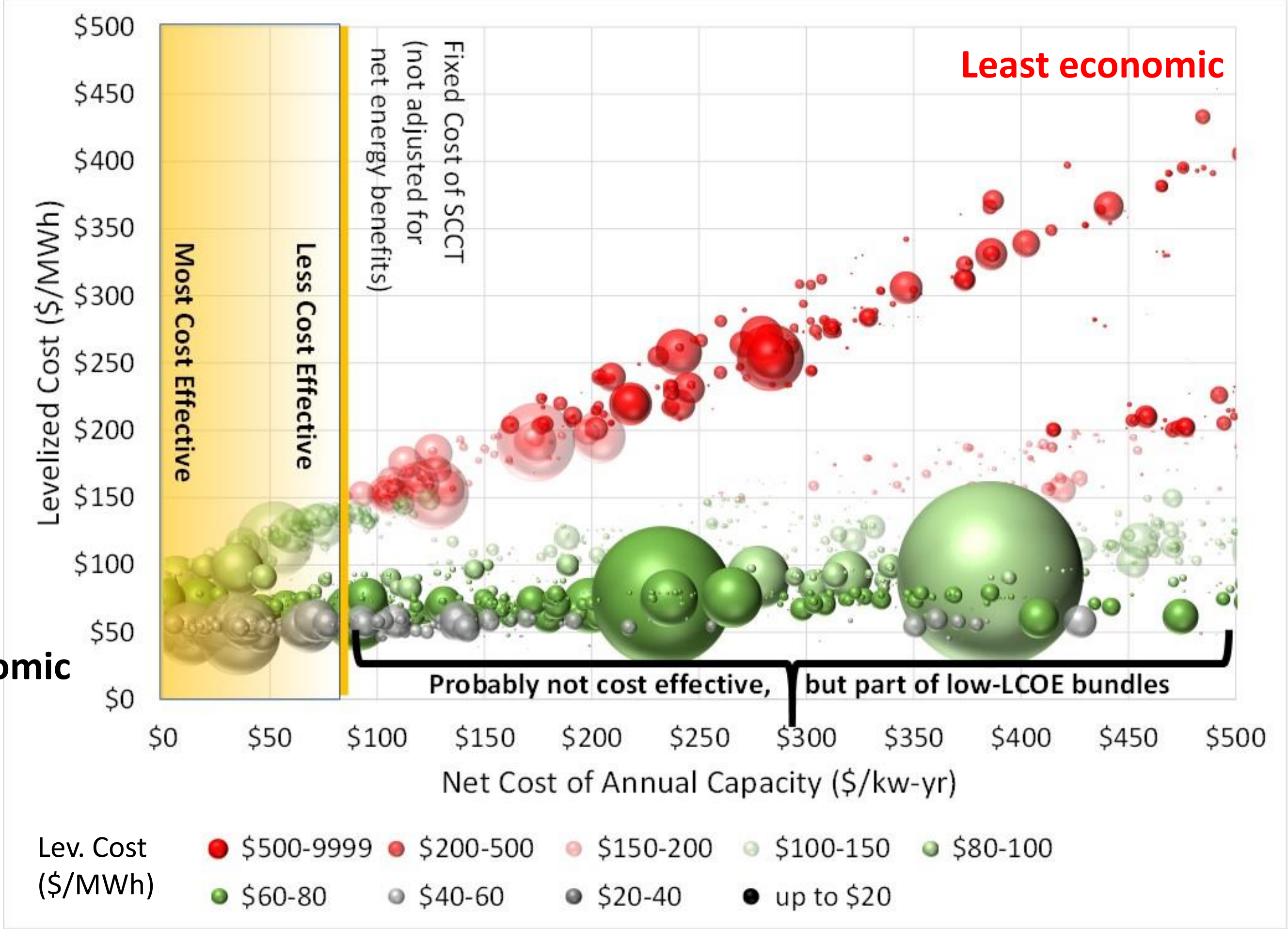


Most economic

Levelized Cost vs Net Cost of Capacity

- We can combine Energy Value and Capacity Contribution.
- Net Cost of Capacity = (Measure Cost - Energy Value) / Cap. Contribution

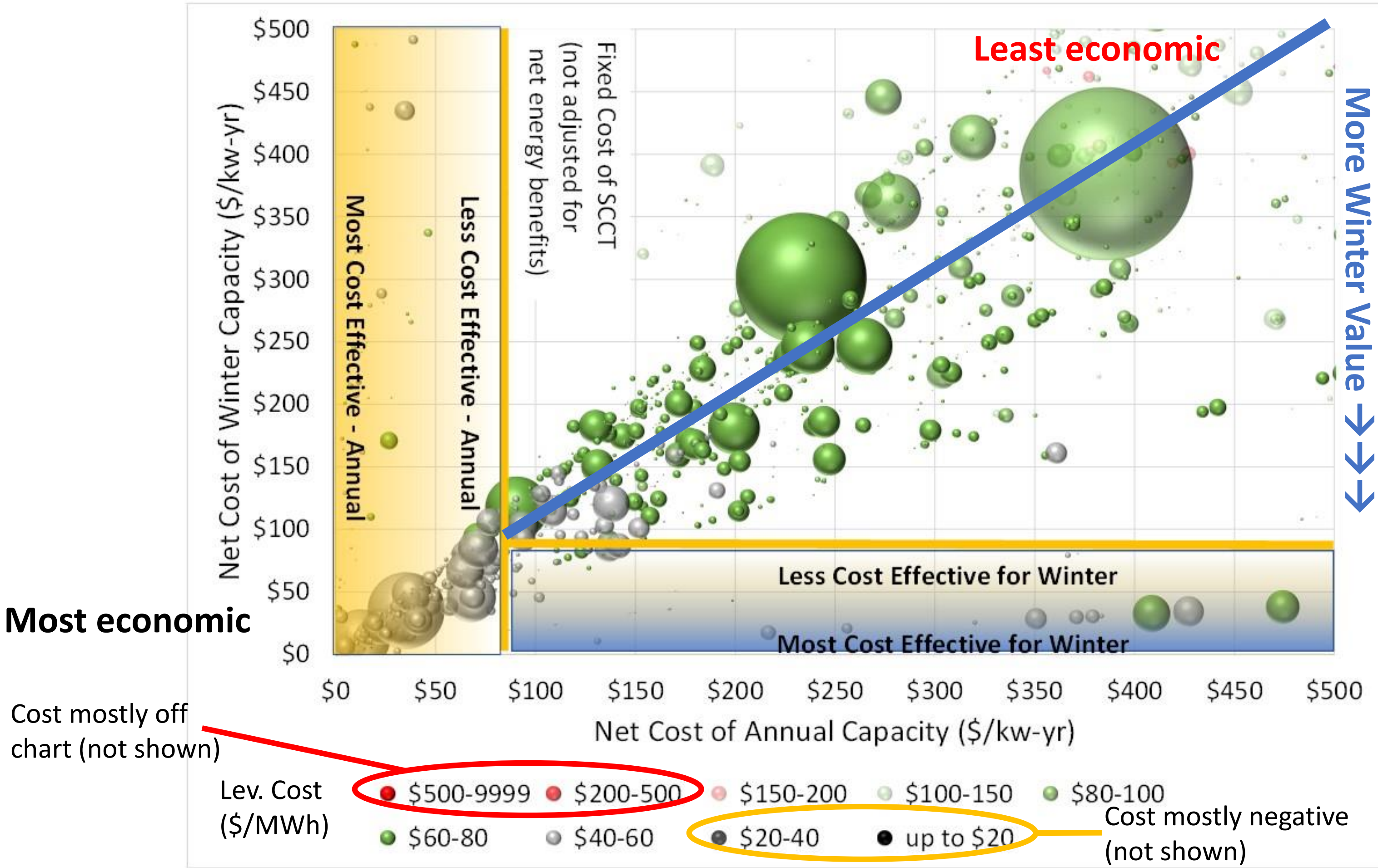
Most economic



This metric is used for scoring in PacifiCorp's 2020 All-Source Request For Proposals.

Targeting Winter Capacity

- There may be additional value in targeting other characteristics.
- For example, some measures may be economic for winter capacity requirements



Possible Bundling Principles

- Ensure sufficient volume in each bundle
- Reduce LCOE granularity to allow for bundling on other characteristics
- Example shown below identifies 11 bundles , vs. 27 in current practice, i.e. there is room to incorporate more granularity or other characteristics, such as winter measures
- Additional Feedback on Bundling is welcome. 2-4 bundling strategies will be studied and presented at a future meeting

Volume (aMW), Ranked by Net Cost of Annual Capacity

Most economic

LCOE ($/MWh)	<$50/kw-yr	$50-$100/kw-yr	$100-$150/kw-yr	$150-$200/kw-yr	>=$200/kw-yr
up to $20	16.0	-	-	-	-
$20-40	4.7	-	0.0	0.0	-
$40-60	3.0	0.5	0.2	0.0	0.1
$60-80	0.8	0.3	0.2	0.4	1.5
$80-100	0.3	0.0	0.1	0.0	1.8
$100-150	0.1	0.5	0.1	0.0	1.7
$150-200	-	0.0	0.5	0.3	1.5
$200-500	-	-	-	0.1	4.1
$500-9999	-	-	-	-	4.0
Total	**24.9**	**1.3**	**1.1**	**0.8**	**14.7**

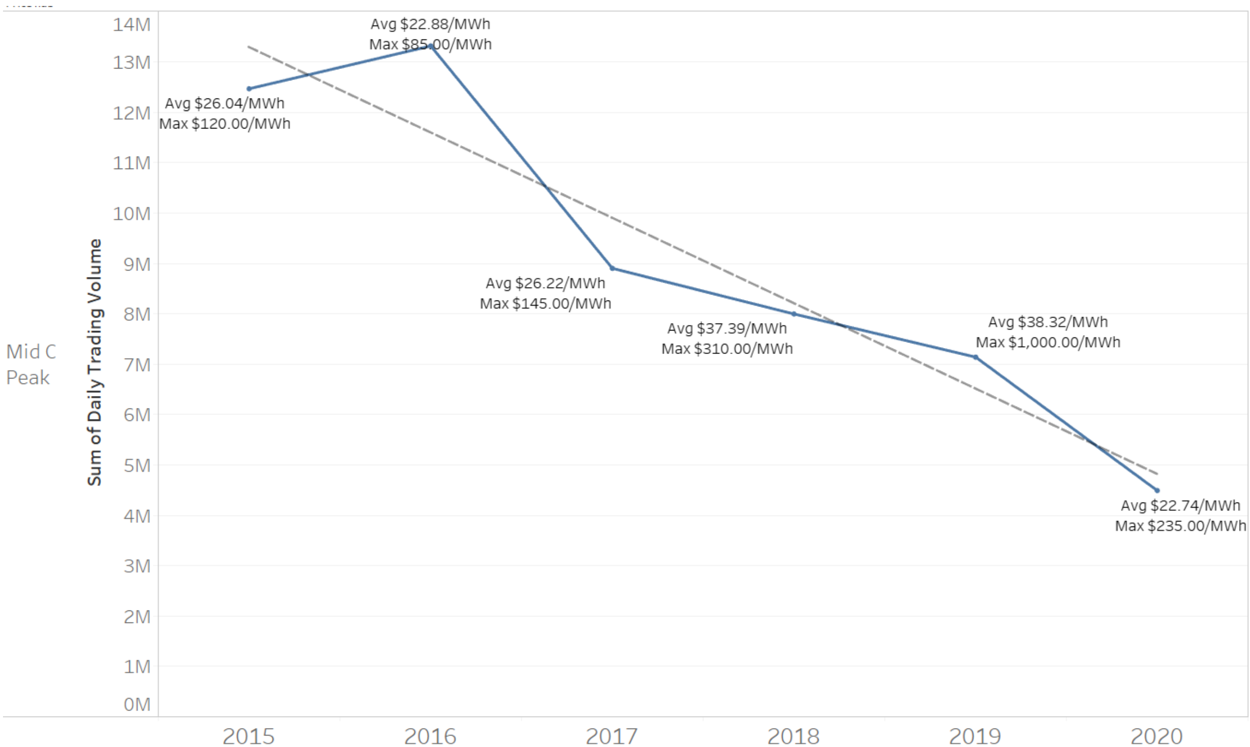
Volumes reflect average bundle sizes for CA/ID/WA/WY, bundles for OR/UT would be larger but likely have similar distribution.

Least economic

Market Reliance Assessment




Declines in Trading Volume



- In 2015 the total trading volume at the MidC market on the intercontinental exchange (ICE) was 12,466,400 MWh and it is estimated to be approximately 6,360,000 MWh in 2020, which is a 49% decline
- In addition, the maximum prices of energy traded is going up
- All data is sourced from the EIA website for ICE daily trades

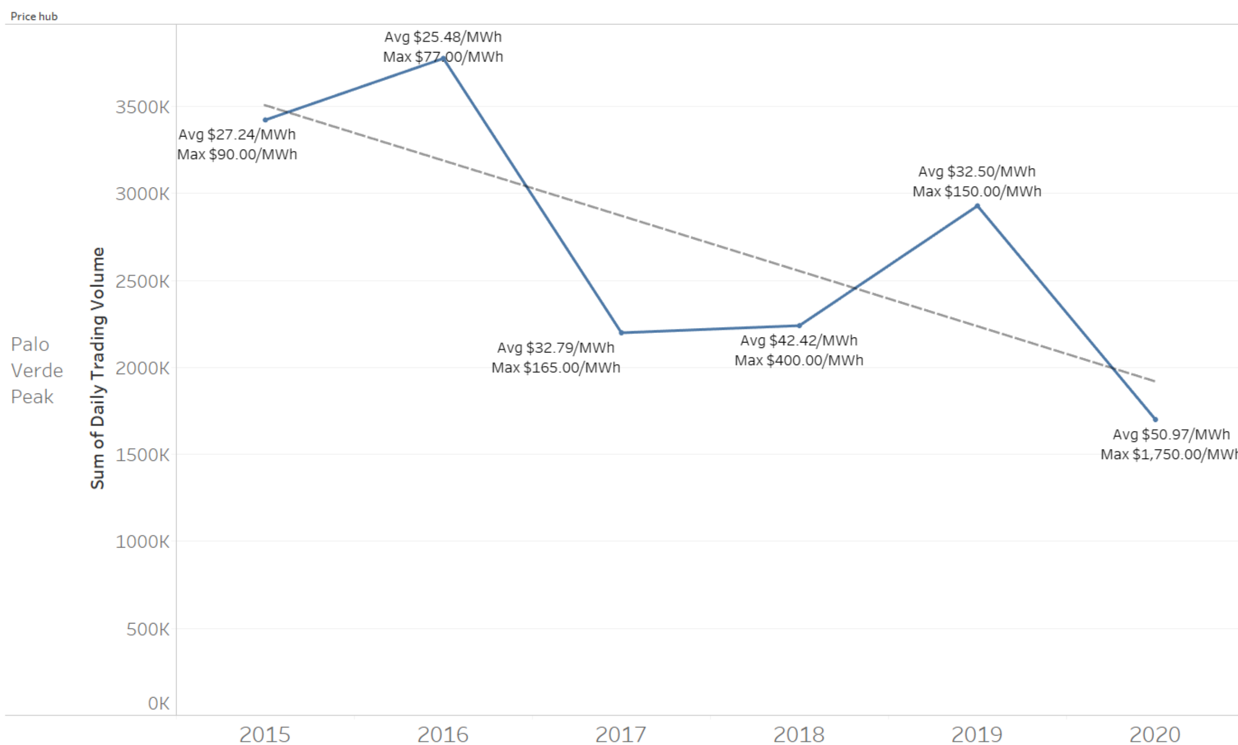
Declining Trend at the Monthly Level

Price hub	Mid C Peak

Sum of Daily volume MWh	Year					
Month	2,015	2,016	2,017	2,018	2,019	2,020
1.00	1,197,200	1,287,200	872,800	755,600	602,000	538,000
2.00	1,348,800	1,281,200	854,000	840,800	718,800	518,000
3.00	1,030,400	1,651,200	971,600	796,000	579,200	486,000
4.00	1,072,400	1,379,200	656,400	876,800	714,800	583,600
5.00	773,200	1,134,400	772,400	884,800	582,800	570,400
6.00	1,234,000	1,197,600	989,200	733,600	564,400	566,800
7.00	1,025,600	1,084,400	786,800	458,400	549,600	570,400
8.00	1,132,400	882,800	746,400	500,400	471,200	390,000
9.00	917,600	713,200	577,600	438,800	487,600	267,600
10.00	838,000	830,000	539,600	605,600	665,600	
11.00	815,200	1,001,200	535,600	600,400	621,600	
12.00	1,081,600	873,200	599,200	504,400	582,000	
Grand Total	12,466,400	13,315,600	8,901,600	7,995,600	7,139,600	4,490,800

As shown by the volume of trades in each month across the last five years, the majority of months realize a decline in the volume of trades at the MidC market.

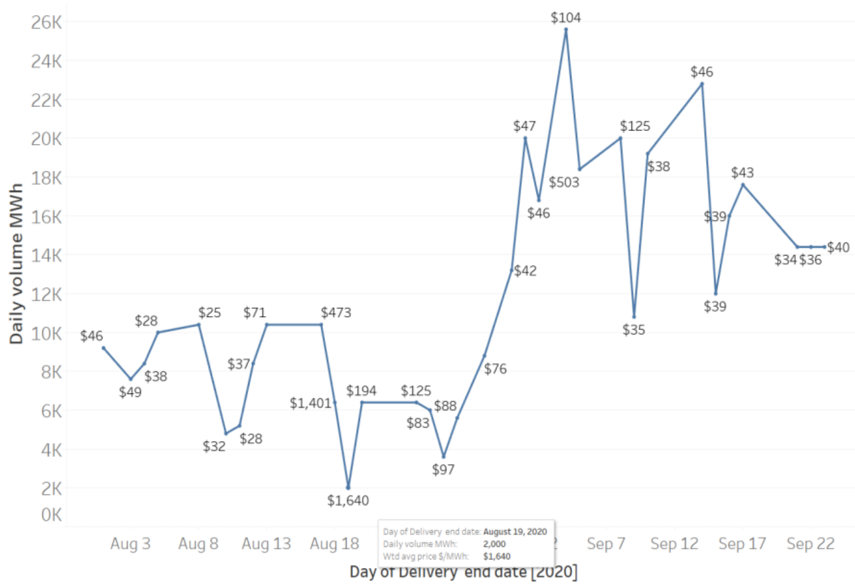
Palo Verde Liquidity Trend



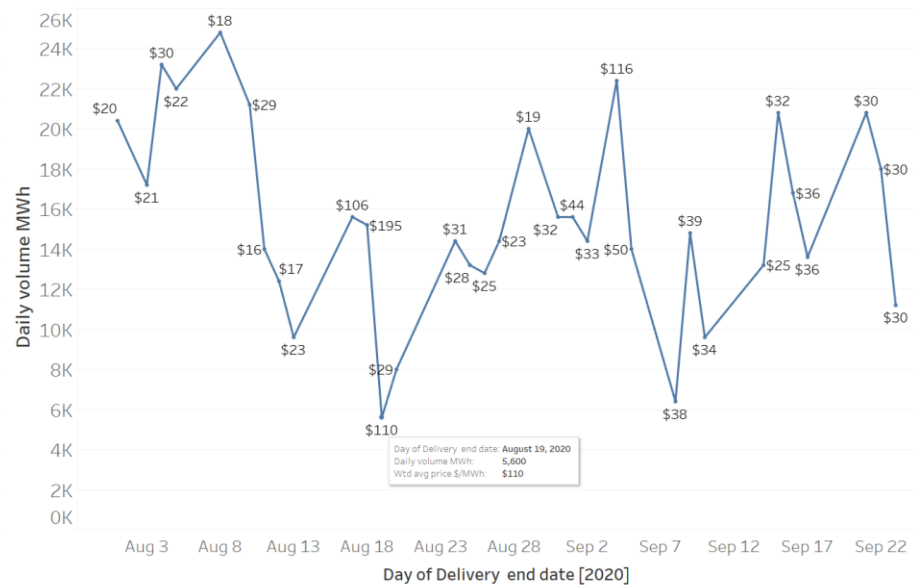
- Similar to the Mid C market, the Palo Verde Market has also seen a decrease in traded volumes over the last five years, with 2020 expected to end at an all-time low
- Prices peaked at $1,750/MWh on August 19, 2020
- All data is sourced from the EIA website for ICE daily trades

August Event Liquidity

Palo Verde August Daily Trades



Mid Columbia August Daily Trades



- Peak load days in August saw significantly reduced volumes of 2,000 MWh and 5,600 MWh for Palo Verde and Mid C respectively
- Due to reduced liquidity in the market multiple entities had to declare Energy Emergency Alerts from August 14 – 19, 2020

Market Reliance Expectations

- The California ISO issued its root cause analysis of the August heat wave events citing an increased need for resources
  - Resource Adequacy program enhancements are expected to include increased forward contracts for capacity and energy in the Pacific Northwest which will cause less energy to be traded in the northwest during the summer period at the Mid Columbia trading hub
- Multiple studies in the last few years have indicated a need for new resources, including the 2019 E3 study of Resource Adequacy in the Pacific Northwest
- The CAISO has been concerned with resource adequacy for years, but did not expect the confluence of events in August to lead to rolling blackouts

External Studies

- Updated forecasts indicate Pacific Northwest energy and capacity surplus will become deficit between 2021 and 2026.
    - NPCC: "Pacific Northwest Power Supply Adequacy Assessment for 2022" - deficit year 2021 → 2022
    - PNUCC: "2020 Northwest Regional Forecast" - winter peak deficit year 2023 → 2024
    - BPA: "2018 Pacific Northwest Loads and Resources Study" - deficit year 2020 → 2021
- Note, these external studies conservatively restrict resources according to planning and construction status and assume extreme hydro conditions. They do not consider PacifiCorp's unique circumstances:
    - ➢ Access to multiple market hubs
    - ➢ Diverse geographic location of resources and transmission (e.g., California / EIM)
    - ➢ Don't include planned future projects

Front Office Transaction Limits

Market Hub (Proxy FOT Product Type)	Availability Limit (MW)			
	2021 IRP		2019 IRP	
	Summer (June-Sept.)	Winter (Jan. , Dec.)	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)				
Annual Flat or Seasonal Heavy Load Hour	350	350	Reduced from 400	
Seasonal Heavy Load Hour	150	0	Reduced from 375	
California-Oregon Border (COB)				
Seasonal Heavy Load Hour	0	250	Removed in summer only	
Nevada-Oregon Border (NOB)				
Seasonal Heavy Load Hour	0	100	Removed in summer only	
Mona				
Seasonal Heavy Load Hour	0	300	Removed in summer only	
Total	500	1,000	1,425	1,425

- Limits represent maximum *available* front office transaction (FOT) capacity by market hub.
- Markets closely tied to California are reduced to zero in the summer. Mid-C decreased by 275 MW in the summer and 425 MW in the winter.
- Annual flat products are “7x24”; heavy load hour (HLH) products are “6x16”.
- PacifiCorp develops its FOT limits based on active participation in wholesale power markets, its view of physical delivery constraints, market liquidity/depth, and with consideration of regional resource supply.

Plexos Benchmark Update




Plexos Benchmark Update

- Key Benchmark Challenges Met:
  - Core optimization math principals are the same as in the 2019 IRP
  - Granularity –
    - Benchmark approximates System Optimizer's day types (Weekday, Saturday, Sunday) and blocks (On-peak , Off-peak, Super Peak) using 4 blocks in every month, peak and off-peak
    - 2021 IRP granularity will balance performance and granularity
  - Reliability –
    - Benchmark uses 13% Planning Reserve Margin plus reliability for a single-pass solution
    - Benchmark assumes a summer Capacity Reserve Margin (CRM)
    - 2021 IRP will incorporate loss of load probability (LOLP) in the expansion
  - Endogenous transmission –
    - Benchmark transmission option modeling functions better than expected:
      - Uses math constraints
        - No copies of every resource or faux topology constraints
        - All constraints modeled together (brownfield, interconnect, incremental)
    - 2021 IRP will include options relying on multiple transmission lines where needed
  - Inputs –
    - Benchmark is loaded with 2019 IRP inputs for re-optimization of the portfolio

Model Features Leveraged

- Flexible interface –
  - Closely integrated with Excel, with advanced copy & paste support
  - File pointer options for most inputs: loads, prices, capacity ratings, etc. (no data loading required beyond CSV formatting of inputs)
  - Straightforward queries for validation and reporting
- Version protection – production changes are always promoted to a new version
- On-board help, documentation built into the model
- Custom constraints flexibility –
  - Example: Customer Preference renewables are modeled directly as a percent of load rather than using generation as a load proxy

Benchmark Process

Input Processing

Gather Inputs

- Resources
- Emissions
- Reserves
- Topology
- Fuel
- Storage
- DSM
- Transmission
- Markets
- Loads
- Prices

Load Templates

Formatting and validation

Modeling / Database

Objects

- Memberships
- Properties

Constraints

- Interconnection
- Customer preference
- Capacity contribution

Variables

- Stochastics parameters
- Data variables

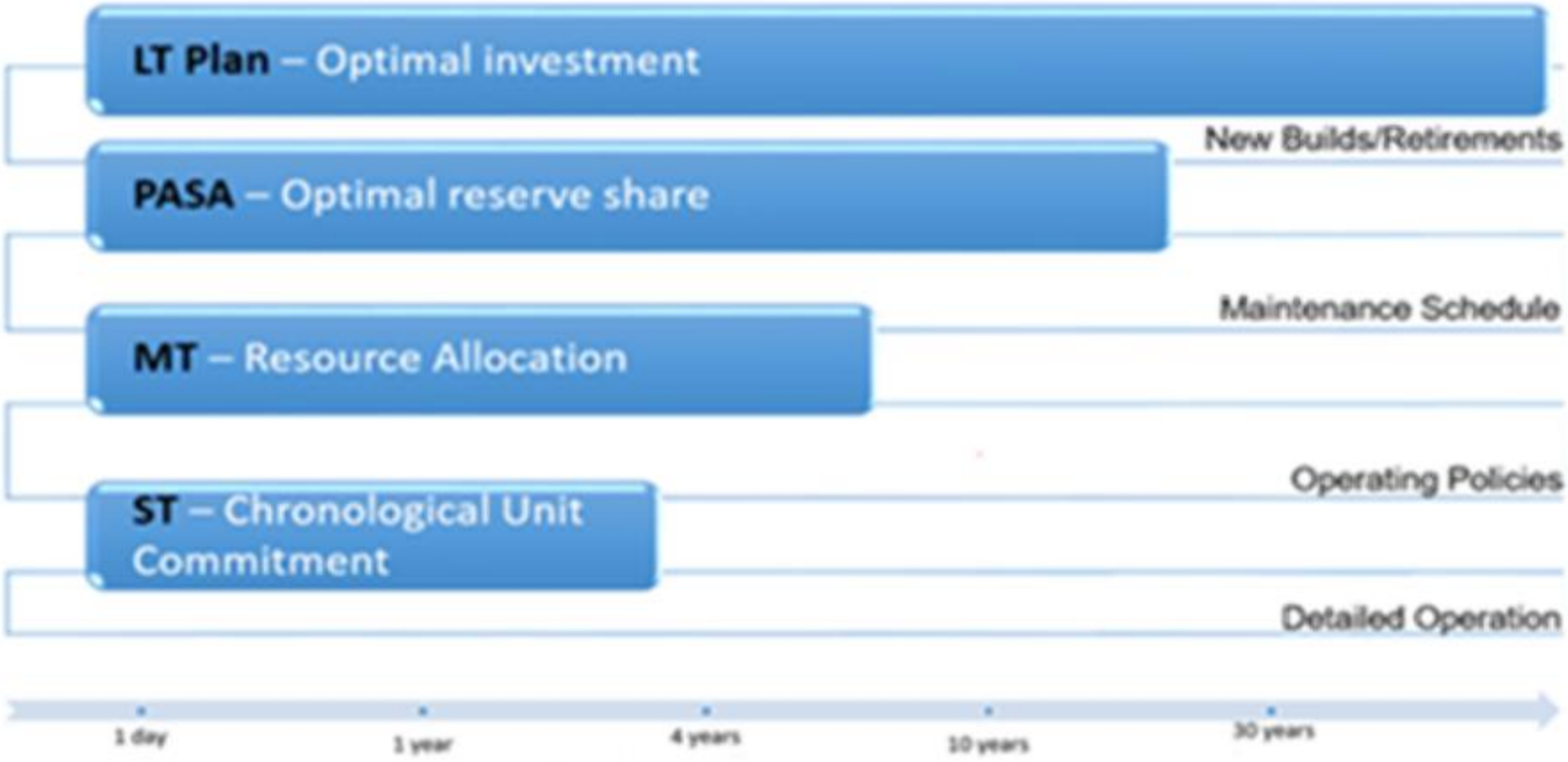
Simulation Phases

LT Plan – Expansion
PASA – Reserve share
MT – Resource allocation
ST – Detailed operation

Reporting

- Queries
- Outputs
- Post-processing
- Formatting
- Validation / Analysis

Plexos Model Simulation Phases



Benchmark Initial L&R Comparison

Plexos - System Resources by Category	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	8,139	8,386	7,999	7,999	7,999	7,645	7,645	7,206	7,124	6,221	5,862	5,615
Hydroelectric	954	966	772	787	803	749	784	785	774	785	779	780
Class 1 DSM	326	326	323	323	323	323	323	323	323	323	323	323
Renewable	425	448	954	894	892	882	881	863	861	857	854	820
Other	1	1	1	1	1	1	1	1	1	1	1	1
Purchases	251	251	223	223	223	223	123	123	123	123	123	123
Qualifying Facilities	873	899	870	852	841	785	780	774	738	733	707	699
Interruptible	195	195	195	195	195	195	195	195	195	195	195	195
Existing DSM	81	81	81	81	81	81	81	81	81	81	81	81
Sales	(821)	(821)	(336)	(285)	(285)	(228)	(228)	(146)	(80)	(80)	(78)	(78)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
Plexsos Initial Resources	**10,387**	**10,695**	**11,044**	**11,033**	**11,035**	**10,619**	**10,547**	**10,168**	**10,102**	**9,202**	**8,810**	**8,521**

EPM - System Resources by Category	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	8,139	8,386	7,999	7,999	7,999	7,645	7,645	7,206	7,124	6,221	5,862	5,615
Hydroelectric	954	966	772	787	803	749	784	786	774	785	779	780
Class 1 DSM	326	326	323	323	323	323	323	323	323	323	323	323
Renewable	425	448	954	894	892	882	881	863	861	857	854	820
Other	1	1	1	1	1	1	1	1	1	1	1	1
Purchases	250	250	223	223	223	223	123	123	123	123	123	123
Qualifying Facilities	873	899	870	852	841	785	780	774	738	733	707	699
Interruptible	195	195	195	195	195	195	195	195	195	195	195	195
Existing DSM	81	81	81	81	81	81	81	81	81	81	81	81
Sales	(821)	(821)	(336)	(285)	(285)	(228)	(228)	(146)	(80)	(80)	(78)	(78)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
EPM Initial Resources	**10,387**	**10,695**	**11,044**	**11,032**	**11,035**	**10,619**	**10,547**	**10,168**	**10,102**	**9,202**	**8,810**	**8,521**
Delta	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Next Steps

- Finalize benchmark
  - Model remaining simulation phases
  - Analyze outcomes
  - Prepare reporting for November IRP public input meeting
- Continue development of 2021 IRP inputs and portfolio modeling

Environmental Policy
Regional Haze Update

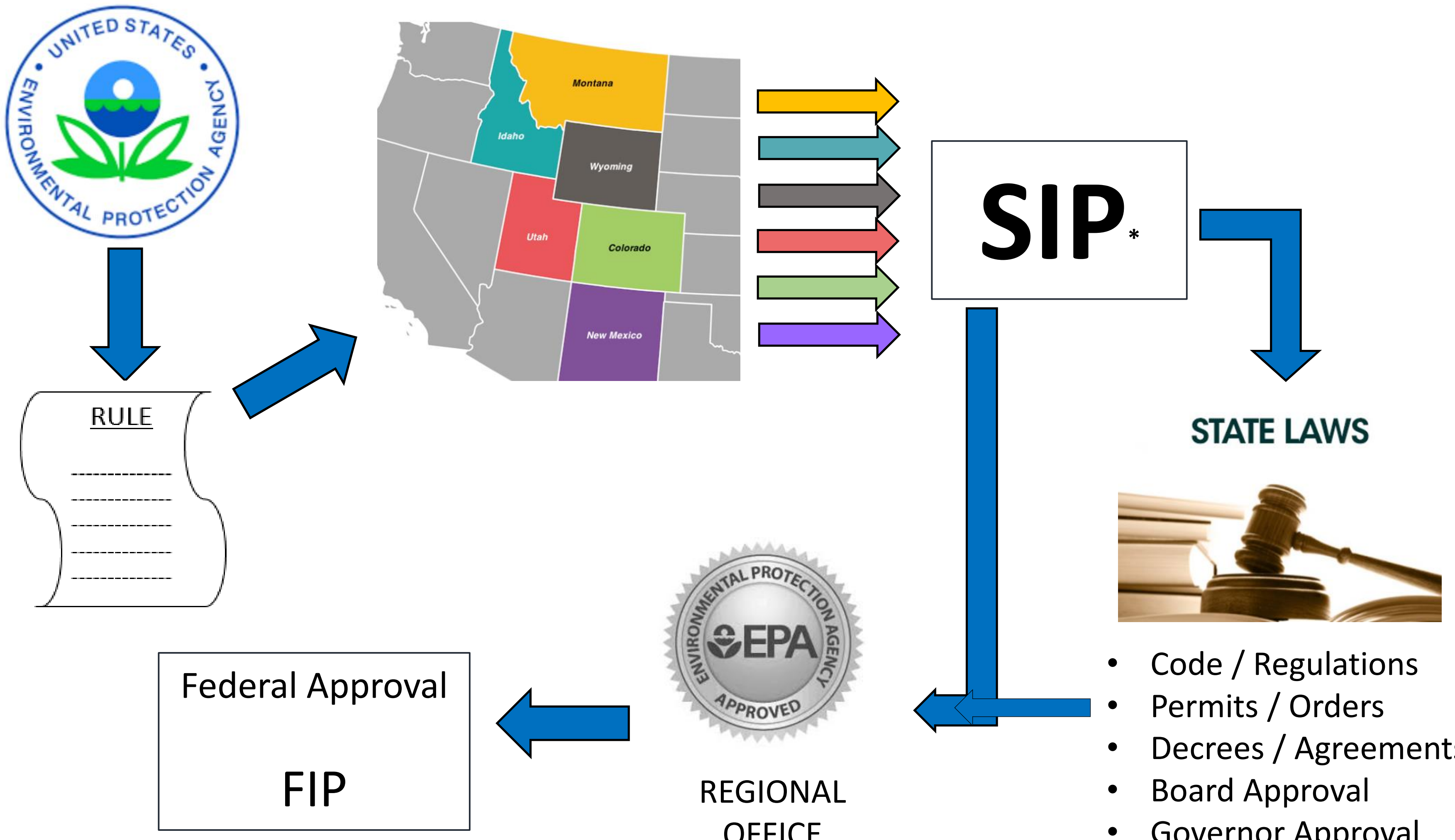



Regional Haze Overview

- The Regional Haze Rule was promulgated pursuant to the Clean Air Act; the Rule's focus is regulating the emission of 'haze-causing pollutants' (NOx, SO2, PM) to achieve visibility improvements at Class I Areas.

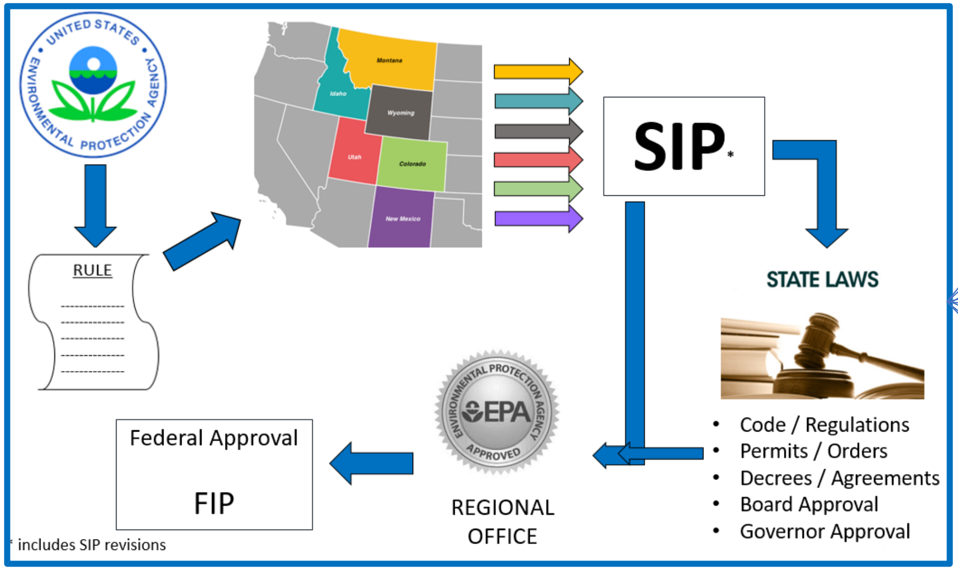

- The Rule has decadal phases or 'planning periods' - each designed to create progress towards visibility improvements at Class I Areas.

State Implementation Plans

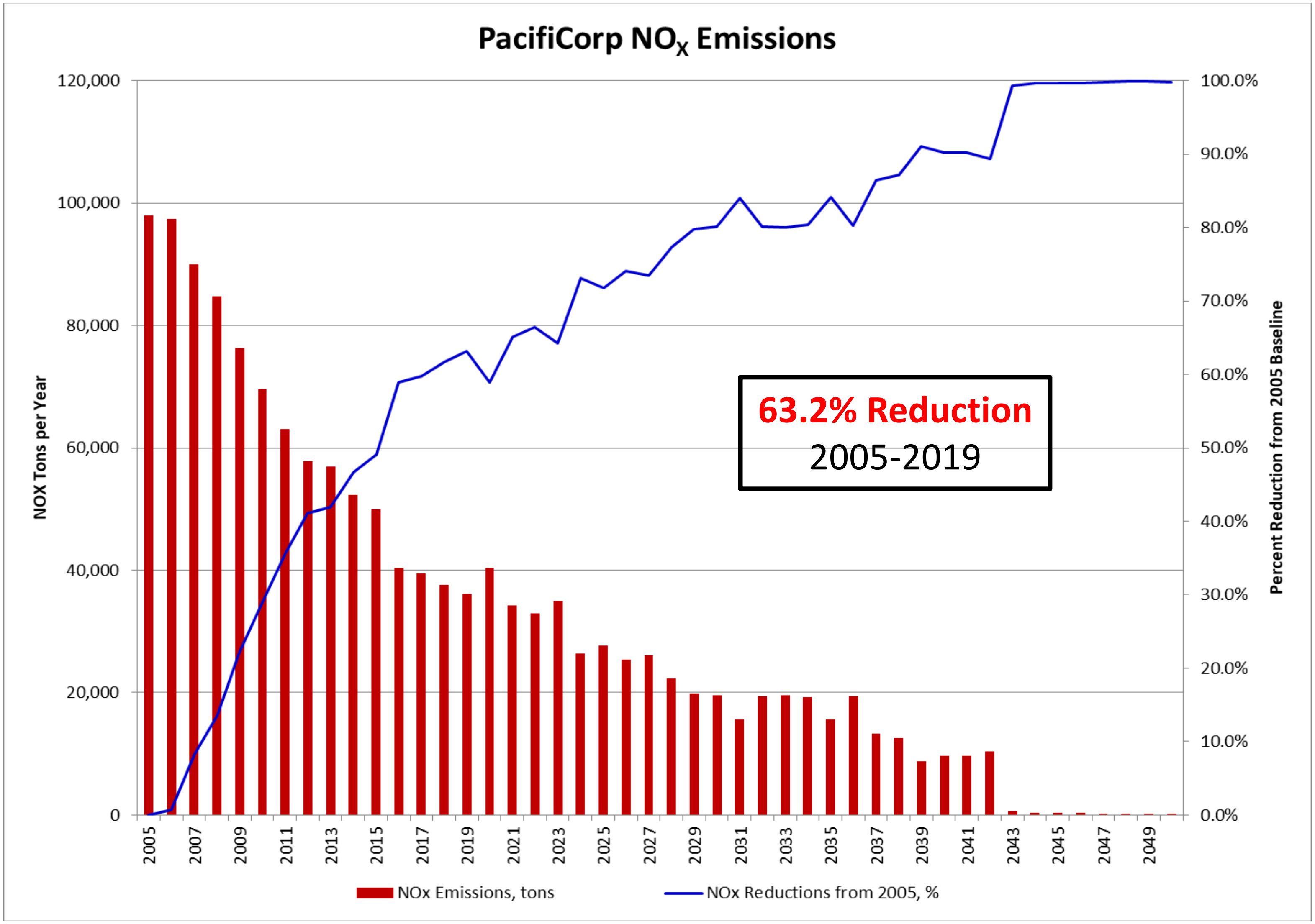


* includes SIP revisions

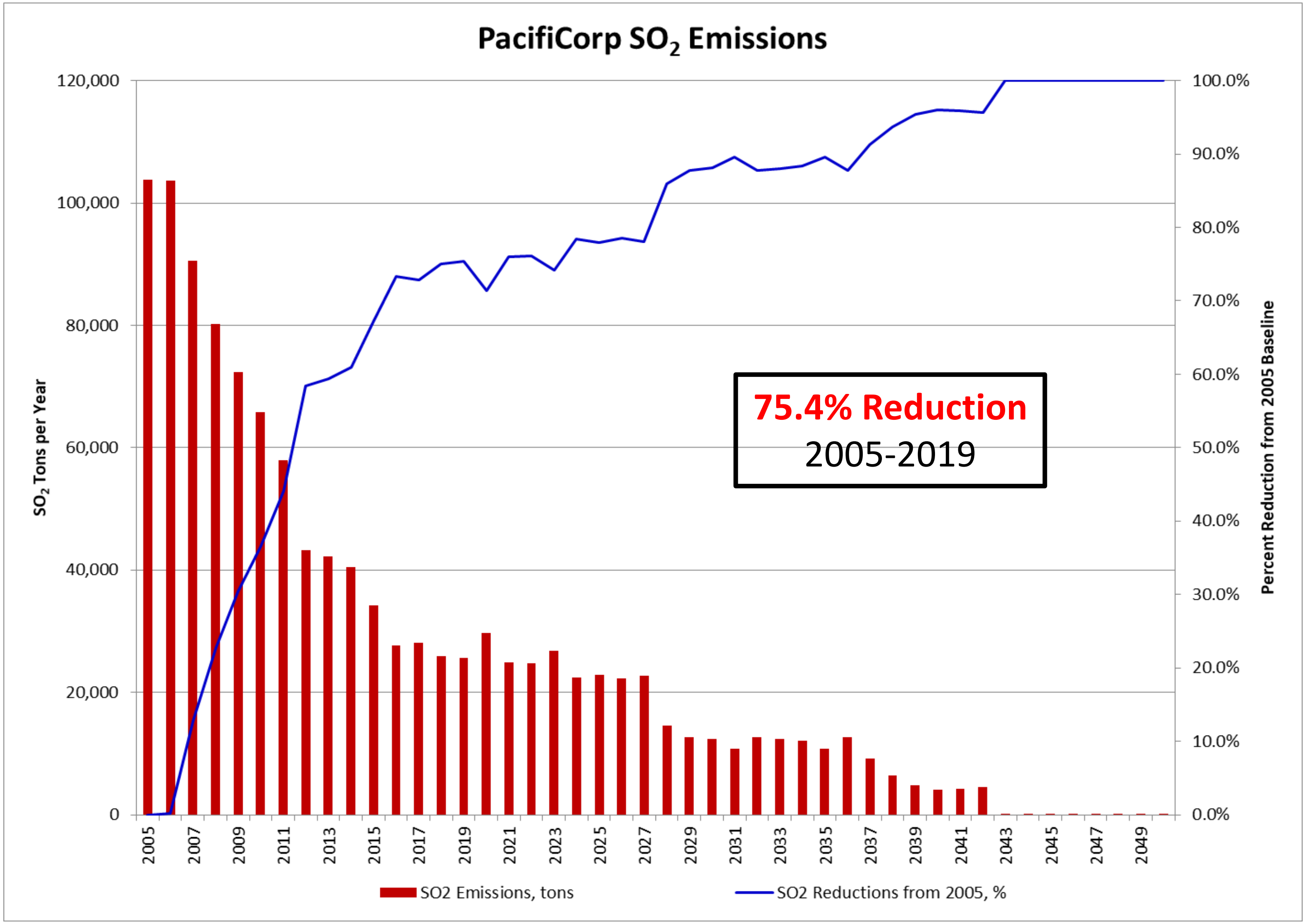
State Implementation Plans



- Public Comments
- Public Hearings
- Mandatory Consultations
- Stakeholder Outreach
- Agency Collaboration
- Industry Collaboration
- Advocacy Group Input
- Legal Challenges



PacifiCorp NO$_X$ Emissions
120,000
100,000
80,000
60,000
40,000
20,000
0
NOX Tons per Year
100.0%
90.0%
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Percent Reduction from 2005 Baseline
63.2% Reduction
2005-2019
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
2047
2049
NOx Emissions, tons
NOx Reductions from 2005, %


PacifiCorp SO_2 Emissions
120,000
100,000
80,000
60,000
40,000
20,000
0
SO_2 Tons per Year
100.0%
90.0%
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Percent Reduction from 2005 Baseline
75.4% Reduction
2005-2019
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
2047
2049
SO2 Emissions, tons
SO2 Reductions from 2005, %

Utah Regional Haze Compliance

<u>Hunter / Huntington</u>

- On June 24, 2019, the Utah Air Quality Board unanimously voted to approve the Utah Regional Haze SIP Revision which incorporates and adopts the Utah BART Alternative into Utah's Regional Haze SIP.
- The BART Alternative makes the shutdown of PacifiCorp's Carbon plant enforceable under the SIP and removes the requirement to install SCR on Hunter Units 1 and 2, and Huntington Units 1 and 2.
- Utah submitted a corresponding SIP Revision to EPA for review on July 3, 2019. Utah's final rule was published in the Utah Bulletin on July 15, 2019, with an effective date of August 15, 2019.
- EPA published its proposed approval of the Utah Regional Haze SIP Alternative on January 10, 2020. EPA held a public hearing on February 12, 2020, in Price, Utah, on EPA's proposed approval of the Utah SIP.
- A final decision from EPA is expected before the end of 2020.

Wyoming Regional Haze Compliance

Jim Bridger

- PacifiCorp submitted a SIP Revision for the Jim Bridger plant, called the "Reasonable Progress Reassessment". The Reasonable Progress Reassessment is an innovative proposal that implements new plant-wide emission limits at Jim Bridger, in lieu of the requirement to install SCR equipment on Jim Bridger Units 1 and 2
- Wyoming's proposed approval of the Bridger SIP proposal was published for public comment on July 20, 2019. A public hearing was held August 23, 2019 in Rock Springs, Wyoming.
- On May 5, 2020, the Wyoming issued permit P0025809 which approves PacifiCorp's proposed monthly and annual NOx and SO2 emission limits included in the Jim Bridger Reasonable Progress Reassessment application and removes the SCR requirements from Units 1 and 2. The new emission limits will become effective January 1, 2022.
- Wyoming submitted the SIP Revision to EPA on May 14, 2020; a proposed approval from EPA is expected before the end of 2020.

Wyoming Regional Haze Compliance

Wyodak

- Jan 2014, EPA issued a regional haze FIP partially approving certain parts of the state of Wyoming's SIP.
- Wyodak was required to install SCR within five years of the final rule (challenged by PacifiCorp); multiple appeals were consolidated.
- PacifiCorp, Wyoming and Basin Electric submitted motions requesting the court hold all of the consolidated appeals of challenged portions of the Wyoming Regional Haze FIP in abeyance while the Basin Electric settlement was finalized.
- The 10th Circuit Court of Appeals granted the motion to hold entire case in abeyance pending Basin's settlement.
- Case remains in abeyance - PacifiCorp is currently in the process of finalizing settlement, which requires notice and comment rulemaking.

Second Planning Period

<u>Utah / Wyoming</u>

- On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to the Wyoming Department of Environmental Quality which analyzed second planning period requirements for PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants.
- On April 21, 2020, PacifiCorp submitted to the Utah Department of Environmental Quality a Regional Haze Reasonable Progress Analysis for PacifiCorp's Huntington and Hunter plants.
- The analyses were requested by the States as part of their Second Planning Period State Implementation Plan development process. The analyses provide PacifiCorp's recommendations on how each facility should be analyzed for the Regional Haze Rule's second planning period, based on guidance provided by the Environmental Protection Agency.
- Each state must development SIPs for the Rule's second planning period, which are due to EPA in July of 2021.

Stakeholder Feedback Form Update

Stakeholder Feedback Form Update

- 52 stakeholder feedback forms submitted to date.
- Stakeholder feedback forms and responses can be located at pacificorp.com/energy/integrated-resource-plan/comments
- Depending on the type and complexity of the stakeholder feedback received 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.
- Stakeholder feedback following the previous public input meetings is summarized on the following slides for reference.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Oregon Public Utility Commission staff (032)	Sept 10, 2020	June public input meeting	Questions related to topics presented in the June 18-19, 2020 public input meeting: Conservation Potential Assessment and battery storage.	Targeted response the week of October 26, 2020.
Oregon Public Utility Commission staff (033)	Sept 10, 2020	July public input meeting	Questions related to topics presented in the June 18-19, 2020 public input meeting: Load Forecasting, Supply-side resources, and distribution system planning.	Targeted response the week of October 26, 2020.
Oregon Public Utility Commission staff (034)	Sept 15, 2020	CPA and DER	Questions regarding Conservation Potential Assessment demand response participant costs, participant costs for residential space heating and cooling, participant costs for direct load control, and CPUC protocols for demand response.	Targeted response to be sent by October 23, 2020 and discussion at the October 22, 2020 public-input meeting.
City of Kemmerer (035)	Sept 17, 2020	Natural Gas	Request to consider different elevations while studying natural gas efficiency.	Response provided.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Utah Clean Energy (036)	Sept 18, 2020	CPA	Questions regarding Conservation Potential Assessment available technical potential in Utah, LED market adoption customer surveys, Whole Building/Home measure and building shell measures in Utah.	Targeted response the week of October 26, 2020.
Oregon Public Utility Commission staff (041)	Sept 28, 2020	Private Generation & energy efficiency	Request related to the private generation study and suggestions related to energy efficiency bundling.	Targeted response to be sent by October 23, 2020.
Wyoming Public Service Commission Staff (042)	Sept 29, 2020	Portfolio Development	Suggestions and questions related to portfolio development.	Targeted response the week of October 26, 2020.
Wyoming Public Service Commission Staff (043)	Sept 29, 2020	Supply-side Resources, Plexos	Requests related to supply-side resources and the supply-side resource table, and questions regarding the Plexos model.	Targeted response the week of October 26, 2020.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Wyoming Public Service Commission Staff (044)	Sept 29, 2020	Portfolio Development	Suggestions and questions related to portfolio development.	Targeted response to be sent by October 23, 2020.
Wyoming Public Service Commission Staff (045)	Sept 30, 2020	Portfolio Development	Suggestions and questions related to portfolio development.	Targeted response to be sent by October 23, 2020.
Renewable Northwest (046)	Oct 2, 2020	Portfolio Development	Suggestions and questions related to portfolio development.	Targeted response to be sent by October 23, 2020.
Washington Utilities & Transportation Commission staff (047)	Oct 2, 2020	Sept PIM	Questions and suggestions related to the September public input meeting including supply-side resources, resource cost and performance, CETA considerations, and portfolio development.	Targeted response to be sent by October 23, 2020.

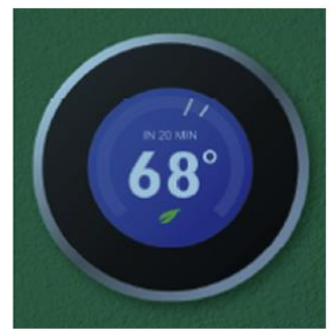
Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Cadmus Group (048)	Oct 4, 2020	CPA	Request for the conservation supply curves.	Targeted response to be sent by October 23, 2020 and discussion at the October 22, 2020 public-input meeting.
Southwest Energy Efficiency Project (049)	Oct 9, 2020	CPA	Suggestions and questions related to portfolio development.	Targeted response the week of October 26, 2020 and discussion at the October 22, 2020 public-input meeting.
Oregon Public Utility Commission Staff (050)	Oct 16, 2020	CPA	Clarifying questions regarding CPA presentation.	Targeted response the week of October 26, 2020 and discussion at the October 22, 2020 public-input meeting.
Idaho Public Utility Commission Staff (051)	Oct 19, 2020	Plexos	Questions related to validation of Plexos.	Targeted response the week of November 2, 2020 and discussion at the October 22, 2020 public-input meeting.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Sierra Club (052)	Oct 19, 2020	Modeling and Resource Assumptions	Questions related to a variety of modeling and resource assumptions.	Targeted response the week of November 2, 2020 and discussion at the October 22, 2020 public-input meeting.

Additional Information/Next Steps



Additional Information

- Public Input Meeting and Workshop Presentation and Materials:
  - pacificorp.com/energy/integrated-resource-plan/public-input-process
- 2021 IRP Stakeholder Feedback Forms:
  - pacificorp.com/energy/integrated-resource-plan/comments
- IRP Email / Distribution List Contact Information:
  - IRP@PacifiCorp.com
- IRP Support and Studies:
  - pacificorp.com/energy/integrated-resource-plan/support

Next Steps

Upcoming Public Input Meeting Dates:

- November 16, 2020 – Public Input Meeting
- December 3-4, 2020 – Public Input Meeting
- January 14-15, 2021 – Public Input Meeting
- February 25-26, 2021 – Public Input Meeting
- April 1, 2021 – File the 2021 IRP

**meeting dates are subject to change*