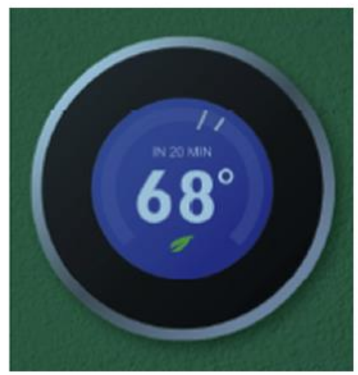
Attachment A

Supporting Materials Presented as Part of the 2021 IRP Public-Input Meetings

Integrated Resource Plan

2021 IRP Public Input Meeting

June 18-19, 2020



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Agenda

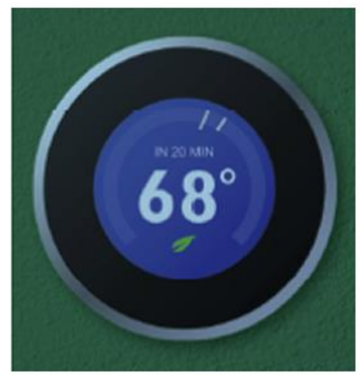
June 18, 2020

- Introductions
- Stakeholder Feedback Form Update
- Conservation Potential Assessment Update
- Optimization Modeling
- Lunch Break (45 min) 11:15am PT/12:15pm MT
- Modeling Updates
- Modeling Energy (Battery) Storage
- Break 2:30pm PT/3:30pm MT
- Wrap-Up/ Next Steps

June 19, 2020

- 2019 IRP Highlights / 2021 IRP Topics and Timeline
- Request for Proposal (RFP) Update
- Lunch Break (45 min) 11:30 PT/12:30 MT
- Transmission Overview and Update
- Break 1:15pm PT/2:15pm MT
- Q&A/ Wrap-Up

Stakeholder Feedback Form Update



Stakeholder Feedback Form Update

- The stakeholder feedback form process is being updated June 26, 2020 to include a web-based form. The new form will:
  - Allow stakeholders to enter their feedback and submit it without downloading a word document.
  - Allow for attachments to maintain flexibility.
  - Automatically be emailed to the IRP inbox.
- The new interactive stakeholder feedback form will be linked on PacifiCorp's existing website at: pacificorp.com/energy/integrated-resource-plan/comments
- Stakeholder feedback forms are being assigned numbers in the 2021 IRP cycle.
- Stakeholder feedback forms and responses will continue to be posted on PacifiCorp's website.

Stakeholder Feedback Form Recap

- 12 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)
Utah Valley Earth Forum	Dec 31, 2009	CPA Draft Scope of Work	Request to include renewable-fuel power, and combined heat and power in CPA.	PacifiCorp considers these resource types outside the CPA process.
Southwest Energy Efficiency Project/Utah Clean Energy	Jan 3, 2020	CPA Draft Scope of Work	Questions regarding demand response potential and energy efficiency potential in the Conservation Potential Assessment, and request that draft measures be made available.	PacifiCorp made requested changes where possible and posted updated draft measures.
Utah Valley Earth Forum	Feb 4, 2020	CPA Draft Measures	Suggested a list of measures to be included in the CPA.	PacifiCorp advised where list items are being considered in CPA.
Washington Utilities and Transportation Commission Staff	Feb 10, 2020	CPA Draft Measures	Requested changes to the draft measures, and changes to how they are shared with stakeholders.	PacifiCorp detailed intent of format and timeline, and made some requested changes.
Utah Clean Energy	Feb 14, 2020	CPA Draft Measures	Questions and recommendations on emerging technology, requested changes to residential and non-residential measure list.	PacifiCorp provided clarification and made requested changes.

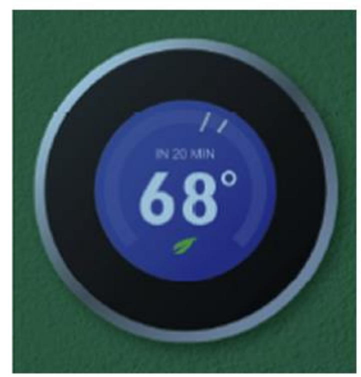
Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Oregon Citizens' Utility Board	Feb 20, 2020	Demand Response in CPA	Questions on smart thermostats program, suggestions on irrigation load control program, TOU demand rate for electric vehicles, time of use demand rates, and third party contracts for demand response.	PacifiCorp advised what programs are underway, and referred to dockets where other programs could be considered.
Utah Clean Energy	April 2, 2020	CPA Measure Lists	Questions and suggestions regarding demand-side management and demand response measure lists.	Provided clarity on measure questions, and incorporated recommendations.
Utah Valley Earth Forum	April 23, 2020	CPA Workshop April 16, 2020	Questioned the reported percent penetration for electric vehicles from the April 16, 2020 public input meeting workshop presentation.	PacifiCorp explained how to the value was calculated.
Utah Clean Energy	April 30, 2020	CPA DSM Measures	Resource suggestions and feedback on the major measure lists, including water heater – solar system, pool heater – solar water heating system, solar assisted gas water heating, high-SEER heat pump water heater, and a GIWH DR measure to include solar PV.	PacifiCorp will consider the resource suggestions, and GIWH DR is included under the Tier 4 emerging tech HPWH.
Oregon Public Utilities Commission Staff	May 4, 2020	CPA Demand Response	Questioned if the costs for residential smart thermostat control program have been updated with AMI deployment completion.	PacifiCorp explained how program costs with and without AMI are calculated in the CPA.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Oregon Public Utilities Commission Staff	May 4, 2020	CPA Demand Response	Questioned if more detailed estimates of the IT-related costs for implementing a PTR programs have been developed, updated, or impacted by AMI deployment.	PacifiCorp advised that cost estimates have not been developed or updated.
Oregon Public Utilities Commission Staff	May 4, 2020	CPA Demand Response	Questioned if the costs demand response pilot programs have been updated to reflect the benefits of AMI deployment.	PacifiCorp explained how program costs with and without AMI are calculated in the CPA.

Conservation Potential Assessment Update



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2021 CPA Workshops

Date	Major Topics Recap
January 21, 2020	• Feedback on CPA work plan • Study methodology and updated approaches • EE source data hierarchy and ramp rates by state • New measures, EE and DR • New DR approach ideas
February 18, 2020	• EE Measure list changes (205) • Major measures identification • Baseline development, regional and state variation • Savings and cost variations drivers • Cost credits – risk reduction, NW Power Act, T&D deferral • DR measure mapping of grid services
April 16, 2020	• Announced shift in schedule, Draft supply curve in August • Technical drivers of differences between states • Load and potential differences

(1) OPUC docket UM-551, ORS 757.054 and OR SB1547

2021 CPA Next Steps

Presentations

- Draft CPA Technical Potential Results in August 2021 IRP Stakeholder Meeting
- Discuss feedback received and planned updates in September 2021 IRP Stakeholder Meeting
- Final CPA Technical Achievable Potential results in October 2021 IRP Stakeholder Meeting

CPA/IRP Analysis

✓ Market Profiles posted for Stakeholder review

✓ Jurisdictional Incentive and Administrative Cost analysis posted for Stakeholder review

- Finish Measure Characterization and Develop Supply Curves
- Determine modeling methodology for CPA (EE & DR) in IRP
    - Includes EE Bundling approach
    - DR grid services
    - Applicable cost credits

2019 IRP – DR Actions Update

Demand Response 2019 Preferred Portfolio Selections by Year through 2029 (MW)													
State	Product	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
OR	Ancillary Services	-	-	-	-	-	-	-	-	-	-	7.5	7.5
WA	Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	1.9
UT	Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	13.6
UT	Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	34.9
UT	Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	116.7
WY	Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	3.0
	TOTAL	4.1	-	7.0	-	18.2	-	8.3	7.2	-	-	132.8	177.6

In 2019 IRP Action Plan

- Stakeholder comments questioning limited uptake of DR in West
- Other flexible resource selections include 600MW energy storage by 2023 with solar PV
- Request to discuss DR pilot ideas and RFP potential

Demand Response - OR/WA/CA Discussion

April 14, 2020 Meeting

- Review of existing programs, 2019 IRP DR selections and comments
- Potential assessment results, areas of focus
- Ideas for next steps – Two paths to explore

Pilot

- An experiment or trial undertaking prior to full-scale operation or use
- Oregon examples: energy storage, transportation electrification
- Test customer behavior, technical challenges, actual performance vs estimated
- Cost recovery structure / process for justification and approval vs. cost effective resource acquisition for system need
- Scope / Magnitude limitations

RFP

- Results in best combination of proven resources to meet system needs
  - Cost competitive with other options
  - Price and non price aspects to ranking / scoring
- Multi-staged – 1st DR vs DR, 2nd Short list with 2020 All-Source finalists to determine best combination of resources
- Potential for significant scale expectations in short term

2019 IRP DR Conditions to Acknowledgement

Oregon LC 70, Order No. 20-186

- Action Item 4 acknowledged with conditions
- For DR:
  - PacifiCorp pursue demand response acquisition with a demand response RFP. To the extent practicable, demand response bids may considered with bids from the all-source RFP.
  - PacifiCorp should work with non-bidding stakeholders from OR and other interested states to determine whether PacifiCorp should move forward with cost-effective demand response bids, or with a demand response pilot, or both.
  - PacifiCorp and/or Staff are to provide an update on demand response efforts at a regular public meeting before the 2021 IRP is filed.

Proposed Draft DR RFP Schedule

<table>
<tr><th></th><th colspan="2">Q2 2020</th><th colspan="3">Q3 2020</th><th colspan="2">Q4 2020</th><th>Q1 2021</th><th>Q2 2021</th></tr>
<tr><td>DR RFP</td><td>Stakeholder meeting 4/14</td><td>LC 70 - Oregon acknowledgement with DR conditions, 5/7</td><td colspan="3">DR Valuation, Stakeholder RFP response sorting (Oregon conditions)</td><td>Draft RFP</td><td>RFP Released Nov / Dec</td><td>Short list Evaluation</td><td rowspan="2">Combined Evaluation</td></tr>
<tr><td>All Source RFP</td><td colspan="5"></td><td>Oct 15 Short list</td><td colspan="2">Transmission Cluster Study</td></tr>
<tr><td>CPA - DR Potential</td><td colspan="3">Measures Defined</td><td>Draft Supply Curve</td><td></td><td>Final Supply Curve</td><td colspan="3"></td></tr>
<tr><td>2021 IRP</td><td colspan="8">IRP stakeholder meetings</td><td>2021 IRP Filed</td></tr>
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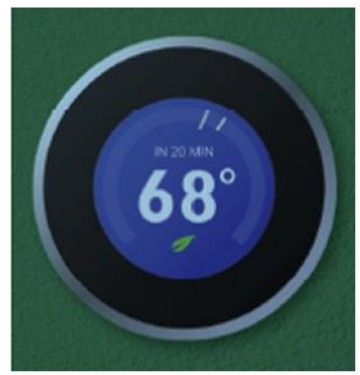
Optimization Modeling



Optimization Modeling Topics

- Optimization Principals
  - Meaning
  - Compare/Contrast
    - Stepwise Modeling Approach
    - Optimization Modeling Approach
  - Optimization Modeling Example
  - Advantages and Complexities

- 2019 IRP Optimization Challenges
  - Model Alignment
    - Capacity Expansion, Stochastics
    - Granularity
    - Operating Reserves
  - Endogenous Option Modeling
  - Batteries

- 2021 IRP Optimization Updates
  - Plexos
  - Next steps

Optimization Principles

Optimization Principles

- Optimization Modeling (OM) is also referred to as:
  - IRP Optimization means Linear Programming or Linear Optimization

- OM can be meaningfully compared to the alternative of “stepwise” problem solving

- Key Features:
  - OM is a mathematical model
  - OM math achieves the best (optimal) outcome (such as the lowest Present Value Revenue Requirement (PVRR))
  - OM solutions recognize and obey constraints, requirements, parameters and relationships (e.g., reserves requirements, unit capabilities, transmission constraints, market prices, etc.)
  - OM math avoids the need to examine every possible combination of inputs and options to determine the correct optimal solution

Stepwise Approach

- Solves a problem by executing a series of intuitive steps
- Example: If you know that you must hold reserves on your energy system, some of your steps might be:
  - Rank your generators by reserve carrying cost, low to high
  - Hold reserves on each unit, in order, until reserve requirements are met
  - Determine how much generating capacity is left after reserves
  - Rank order your units by energy production cost, low to high
  - Generate from each unit, in order, until all loads are met
  - Calculate remaining generating capability ("excess energy")
  - Sell excess energy at market:
    - …when economic; compare production cost to market prices
    - …when deliverable; keep a running total of transmission usage
- Repeat your steps for every hour (or other period) of every year, accounting for what you did in the prior hour (e.g., unit commitment)

OM Approach

- OM mathematically determines the best (optimal) solution:
  - By eliminating solutions that cannot meet requirements (infeasible)
  - By eliminating feasible solutions that cannot be the optimal solution
  - By assessing linear relationships to get as close to the optimal solution as possible and;
  - Provides available output about the best solution. Possible output includes:
    - Discrete decisions (e.g., add capacity at a particular site, acquire a particular DSM package)
    - Energy production of modeled resources, usage of transmission, purchases of capacity or energy from markets

- Not all information is needed to provide a solution
  - Example:
    - No need for a reserve stack
    - No need to assign reserves to specific units

Simple OM Example

How much gas energy and how much coal energy should we generate?

Objective: Minimize system costs assuming two generating units (one gas, one coal), one transmission line, and one load area, operating for a period of one hour.

Relationships: A transmission line conveys energy to the load area.

Parameters and Constraints (in a single hour):

- Generate up to 120 MW from our gas unit
- Generate up to 150 MW from our coal unit
- Transmission capacity and load requirement are both 200 MW

Run cost:

- 1 MWh of gas-power costs $2 to generate
- 1 MWh of coal-power costs $3 to generate
- Failure to meet load costs $100/MW

OM Simple Example, continued

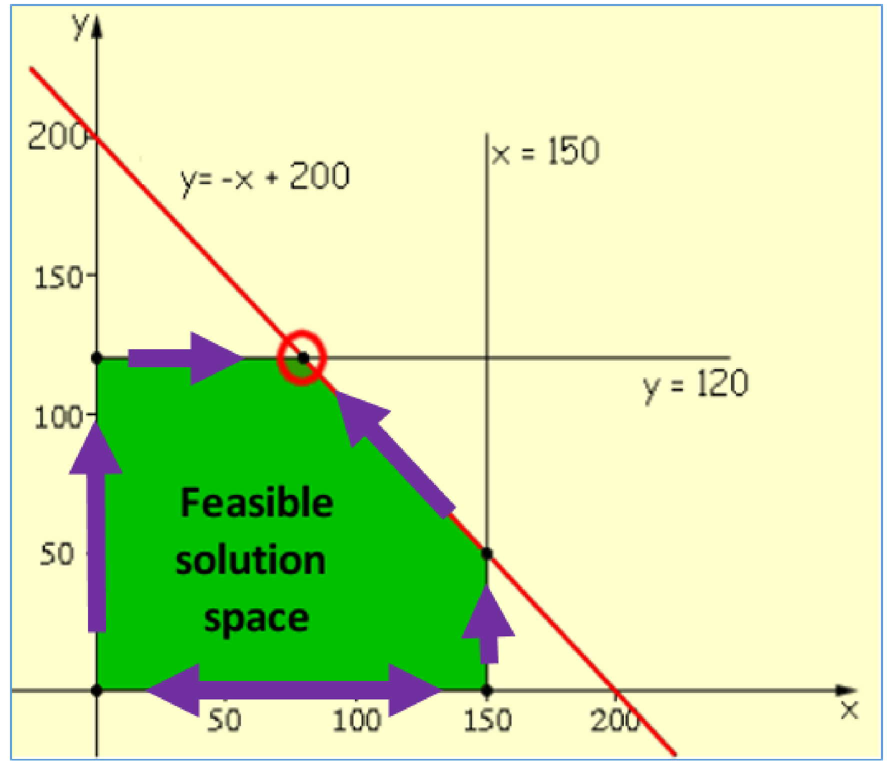
- Modeled constraints and objectives become mathematical constraints and objectives, expressed as inequalities:

Linear Inequalities	Purpose
$x \leq 150$	Coal can generate up to 150 MW
$y \leq 120$	Gas can generate up to 120 MW
$x + y \leq 200$	Total generation cannot exceed transmission
$x \geq 0$	Coal generation cannot be negative
$y \geq 0$	Gas generation cannot be negative

- The model uses these inequalities to define a "feasible solution space" – a range of possible solutions that *might* be the right answer
- Load *requirement* compared to load *constraint*

OM Simple Example, continued

- The graph at right illustrates how the math defines the "feasible solution space"
- The load requirement dictates that only solutions along the red line could be the right answer. (At each point on the red line, the generation total is 200 MW, avoiding the $100/MW penalty for not meeting load.)
- The model "searches" for the edge of the feasible solution space, then examines other solutions along that edge to see if moving in one direction or the other improves the solution (lower PVRR).
- The model quickly arrives at the optimal solution, found at one end (vertex) of the 200 MW load requirement.
- This vertex meets all requirements and constraints, and produces the lowest PVRR. No other solution does this.



OM Advantages and Complexities

- You get the best (i.e., optimal) answer
  - Complexity: The best answer may not be immediately intuitive
  - (However, if it isn't intuitive you investigate for related setup errors)

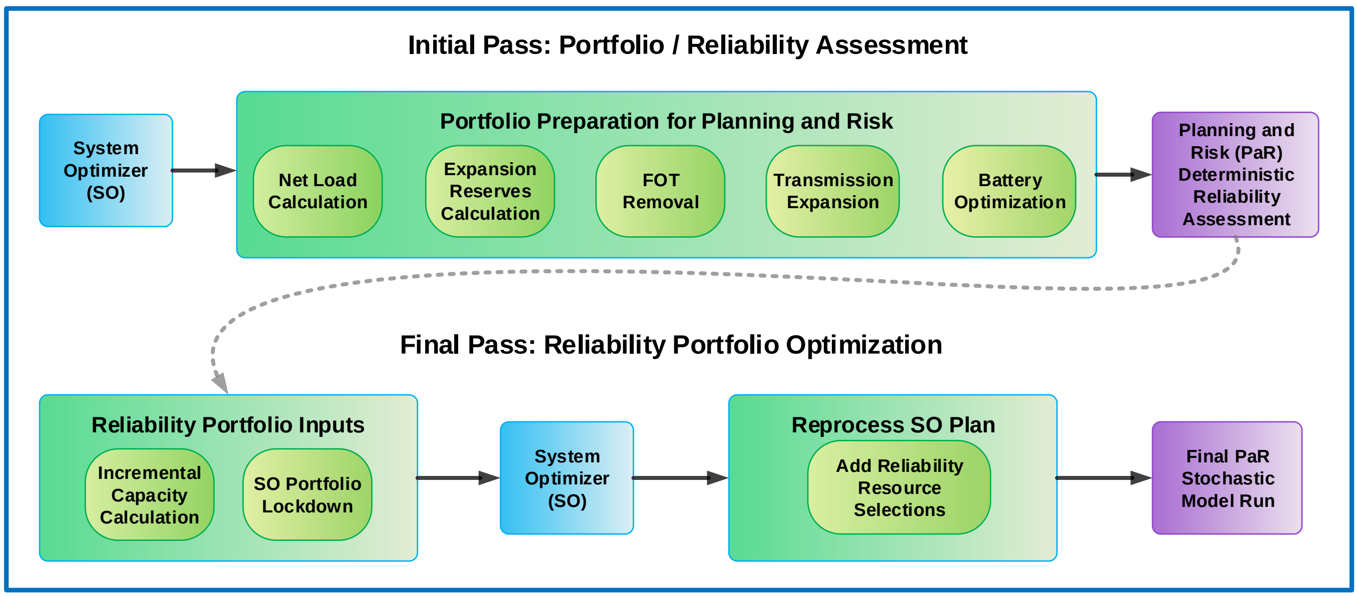
- Multi-dimensional problem solving; detailed precision and accuracy that non-optimization approaches cannot match
  - Complexity: Determining an acceptable amount of complexity
  - Complexity: Tremendous amounts of data are required
  - Complexity: Time required to produce and analyze results

- OM math is incredibly fast for what it does; has the ***effect*** of examining every possibility
  - Complexity: All desired outputs may not be readily available

2019 Optimization Challenges

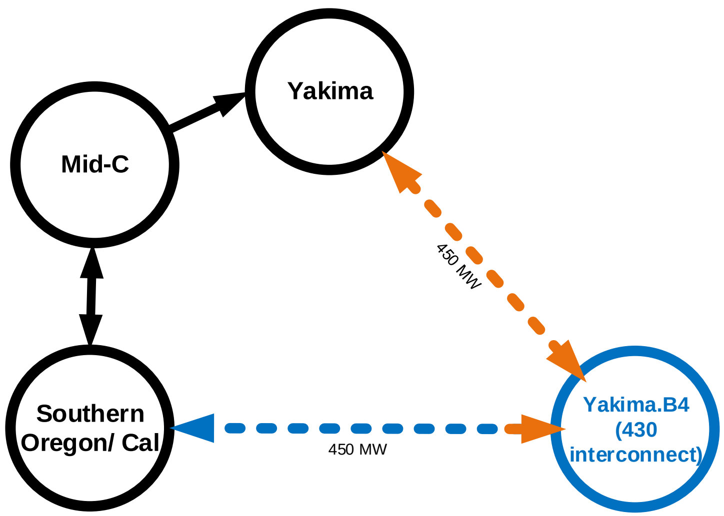
2019 IRP Challenges, Alignment

- Model Alignment - Capacity Expansion and Dispatch Modeling, Stochastics
  - Granularity adjustment
    - Aggregation differences had solar generating at night
  - Operating Reserves, Reliability
    - Expansion model saw only the Planning Reserve Margin
    - Reliability Assessment added 10 new steps and many weeks



2019 IRP Challenges, Transmission

- Prior to the 2019 IRP, transmission options were addressed through true-ups
- Endogenous transmission modeling
  - In the 2019 IRP we created a way to allow for endogenous selection



  - Drawbacks
    - 2, 3 or even 4 copies of every resource
    - Modeling intensive
    - Performance intensive
    - Limited to single-path

2019 IRP Challenges, Retirements

- Retirements
  - Interrelationships between units and plants make endogenous retirements highly impractical
  - Addressed through modeling many, many retirement scenarios
    - Unit-by-unit
    - Alternate year
    - Stacked studies
    - Family tree
  - Challenges in the 2019 IRP Approach
    - Modeling intensive
    - Performance intensive
    - Cannot model every possible combination

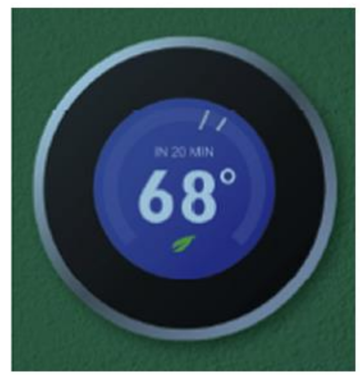
2021 IRP Optimization Updates

2021 IRP - Plexos

- The optimization math remains the same
- The interface, organization and available modeling objects are much more aligned with our needs.
- Challenges addressed:
  - Granularity – significantly more control over model alignment and aggregation sampling
  - Reliability – reserves and loss of load probability (LOLP) can be incorporated into the expansion planning in addition to the planning reserve margin (PRM)
    - Zero extra steps, gaining months back in the IRP process
  - Endogenous transmission
    - No complex topology additions or analytics, just math constraints
    - No need to create multiple copies of every resource
    - Multiple paths can be modeled as one option
  - Retirements – IRP is exploring how to best leverage the new model’s capabilities

Modeling Energy (Battery) Storage



Energy Storage Topics

- Planned projects
- Operating parameters (modeling inputs)
- Combined Resource + Battery interactions
- Grid services
- Capacity-contribution of energy-limited resources

Energy Storage Overview

- What are energy storage resources?
  - Act as resources when discharging and as loads when charging
  - Typically very flexible when controlled by system operator

- Key benefits of energy storage
  - Energy: moves from low-value periods to high-value periods
  - Capacity: can be an alternative to generation, transmission, and/or distribution additions.

- Planned energy storage projects in Oregon and Utah will help further refine cost, performance and benefit information

Planned Energy Storage Projects

Utility-scale projects:

- Utah SB 115–The Sustainable Transportation and Energy Plan (STEP)
  - Panguitch Battery Storage project (1 MW/5MWh) was placed in commercial operation on March 9, 2020
- Oregon HB 2193
  - If authorized by Commission, procure energy storage by 1/1/2020 with at least 5 MWh and no more than 1% of 2014 Oregon system peak load.
    - The Commission approved a stipulation supporting a 2MW/6MWh project with a 2021 COD.
    - Contracts are in progress to design and procure energy storage.

Energy Storage Operating Parameters

- **Discharge capacity**: The maximum output to the grid, in megawatts (MW), a.k.a. nameplate capacity.
- **Storage capacity:** The maximum output to the grid, starting from a full charge, in megawatt-hours (MWh).
- **Hours of storage:** The length of time an energy storage system can operate at its maximum discharge capacity, when starting from fully charged, measured in hours.
- **Charge capacity:** The maximum input from the grid, in MW.
- **Round-trip efficiency:** The output of the energy storage system to the grid, divided by the input necessary to provide that level of output, stated as a percentage.
- **Station service:** Some energy storage systems draw power for temperature control and other needs.

Energy Storage Operating Parameters

(continued)

- **State of charge:** How full a storage system is, calculated by dividing the available MWh of output at a given charge level by the storage capacity, stated as a percentage.
- **Storage capacity degradation:** Storage capacity often degrades as part of charge-discharge cycles, and can be measured as the degradation per thousand cycles.
- **Cycle life:** This is the total number of full charge and discharge cycles that energy storage equipment is rated for. 3,000 cycles in common for lithium-ion resources.
- **Depth of discharge:** Operating at a very high or very low state of charge, particularly for an extended period of time, can cause more rapid degradation.

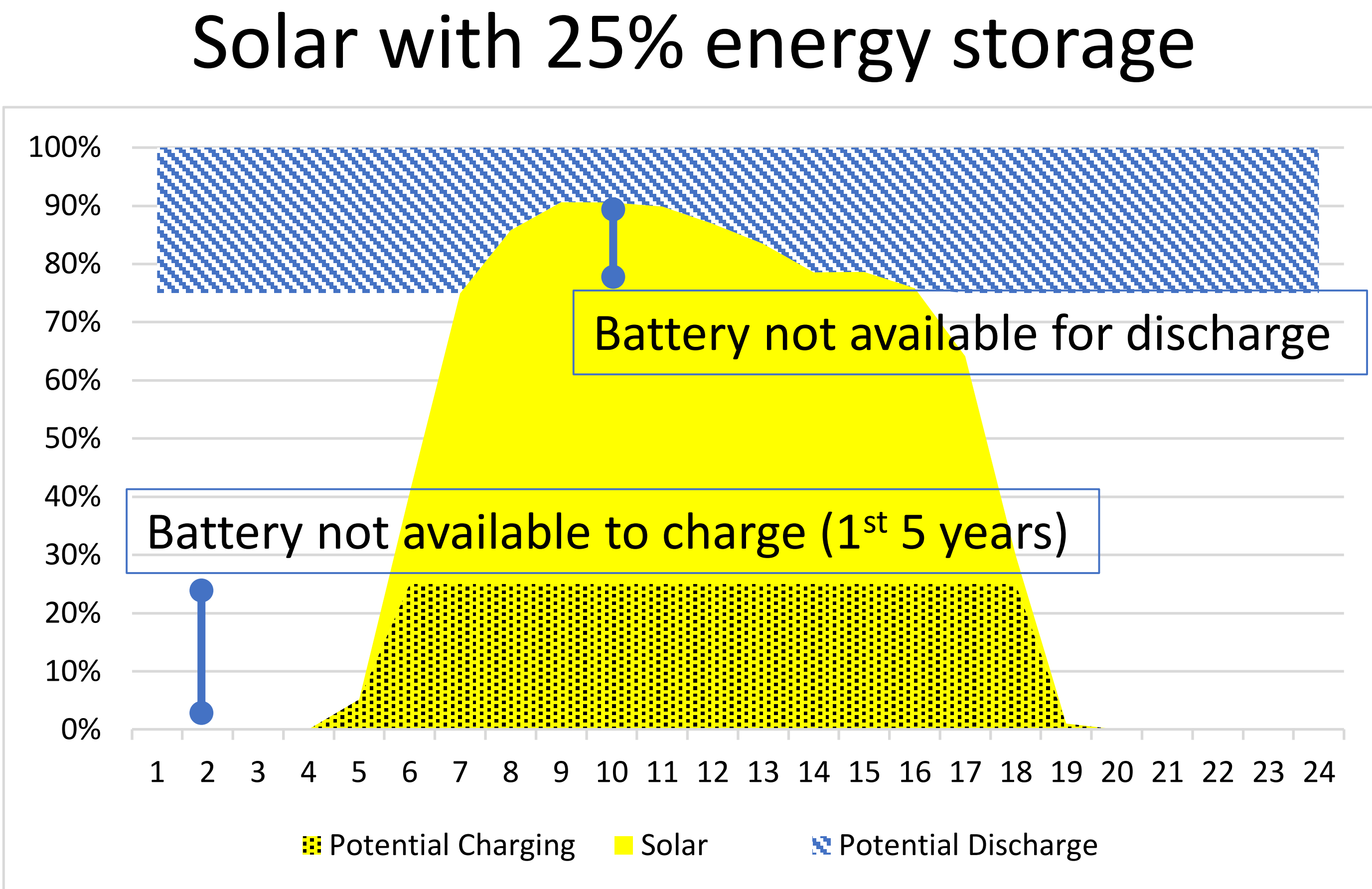
Energy Storage Operating Parameters

(continued)

- **Augmentation/Variable degradation cost:**
  - Lithium-ion energy storage modules can be gradually replaced (or supplemented) to maintain the desired storage capacity, can be augmented at a single point in time, or can be replaced when cycle limits are reached
  - Absent frequent augmentation, battery systems will generally have some level of degradation.
  - In the 2019 IRP, the replacement cost of storage equipment was included as a $/MWh cost whenever batteries were discharged.
  - For the 2021 IRP, PacifiCorp expects to revisit the modeling options in Plexos related to degradation as well as the contractual structures for batteries.

Combined Battery Interactions

- Output limited by interconnection.
- Storage may be able to charge from grid, but restricted in the first five years operation if solar investment tax credit (ITC) is claimed.

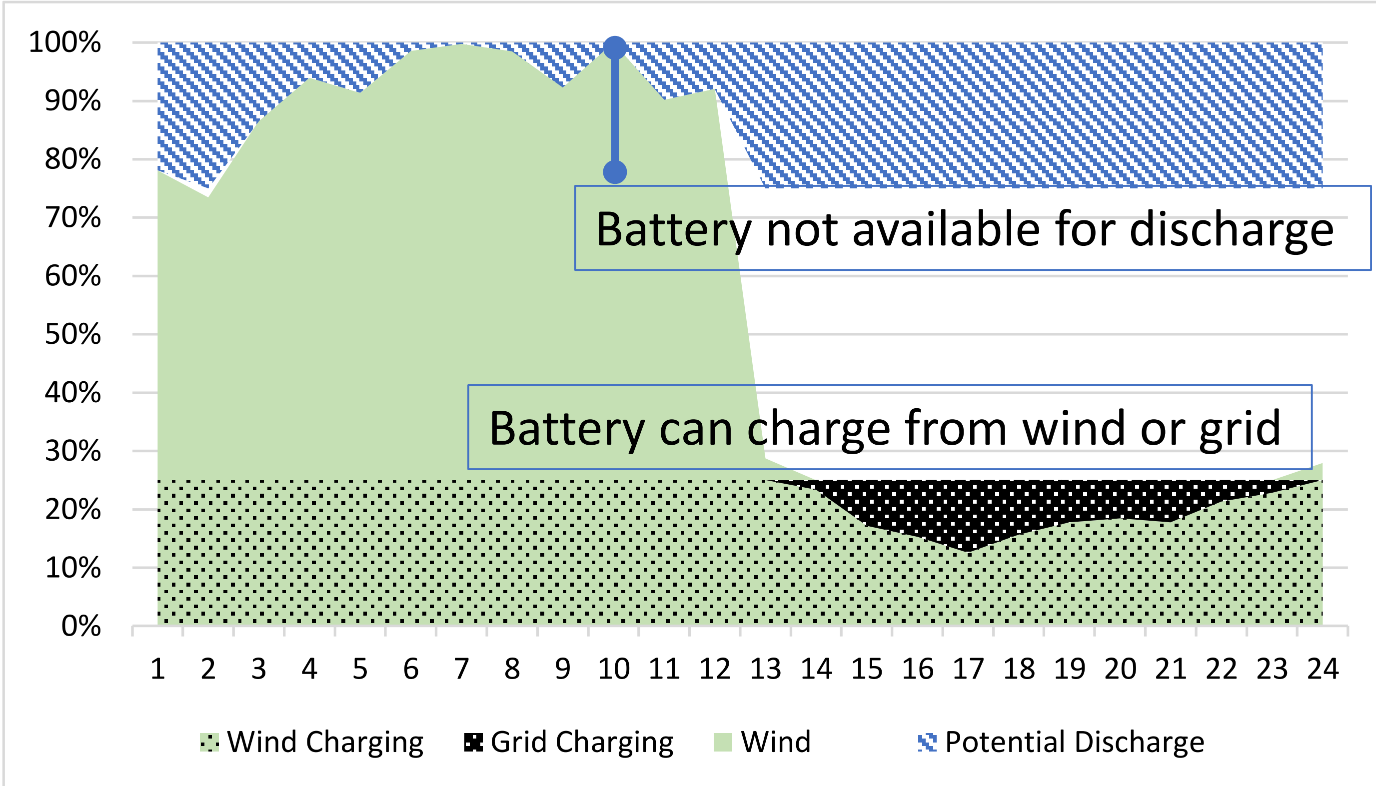


- Reduced capacity contribution vs. stand-alone storage
  - Capacity already assigned to solar resource can't be double-counted
  - Impact is small – contribution of solar in the middle of the day is low.
  - Impact increases as storage as a percentage of nameplate increases.

Combined Battery Interactions

- Output limited by interconnection.
- Storage likely to be able to charge from grid from day 1.
- Incremental discharge capability less certain than with solar – may get locked in for long duration.

Wind with 25% energy storage



- Reduced capacity contribution vs. stand-alone storage
    - Capacity already assigned to wind resource can't be double-counted
    - Impact varies with wind contribution and unused discharge capacity.
    - Impact increases as storage as a percentage of nameplate increases.

Energy Storage Grid Services

Captured within IRP models:

- **Energy arbitrage:** charging, discharging, and losses
- **Operating reserves:** spin, non-spin, and regulation reserve
- **Generation capacity:** ensuring reliability targets are met

Not captured in IRP models:

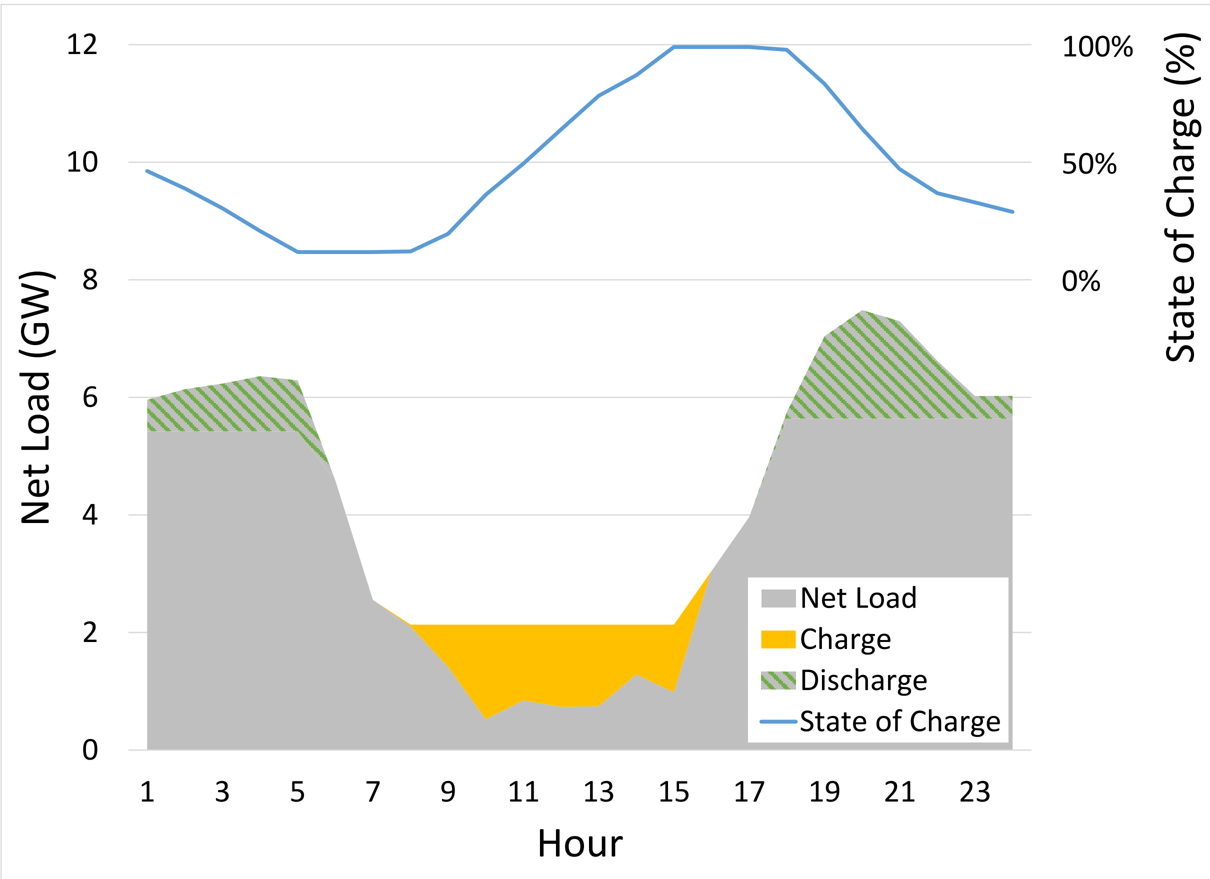
- **Transmission and Distribution Capacity**
  - These services are location-specific with higher granularity than is represented in the IRP model.
  - PacifiCorp uses an "Alternative Evaluation Tool" to assess where distributed resources, including energy storage, could be competitive with a traditional T&D solution for a specific forecasted needs in the next ten years.
- **Intra-hour dispatch**
  - IRP modeling has hourly granularity, so it does not capture intra-hour dispatch, for instance in the Energy Imbalance Market.
  - An Intra-hour Flexible Resource Credit was proposed in the 2019 IRP, but was informational only, and did not impact modeling or portfolio selection.

Energy: Dispatch Optimization

Storage resources primarily follow system requirements, rather than fluctuations of their combined resource.

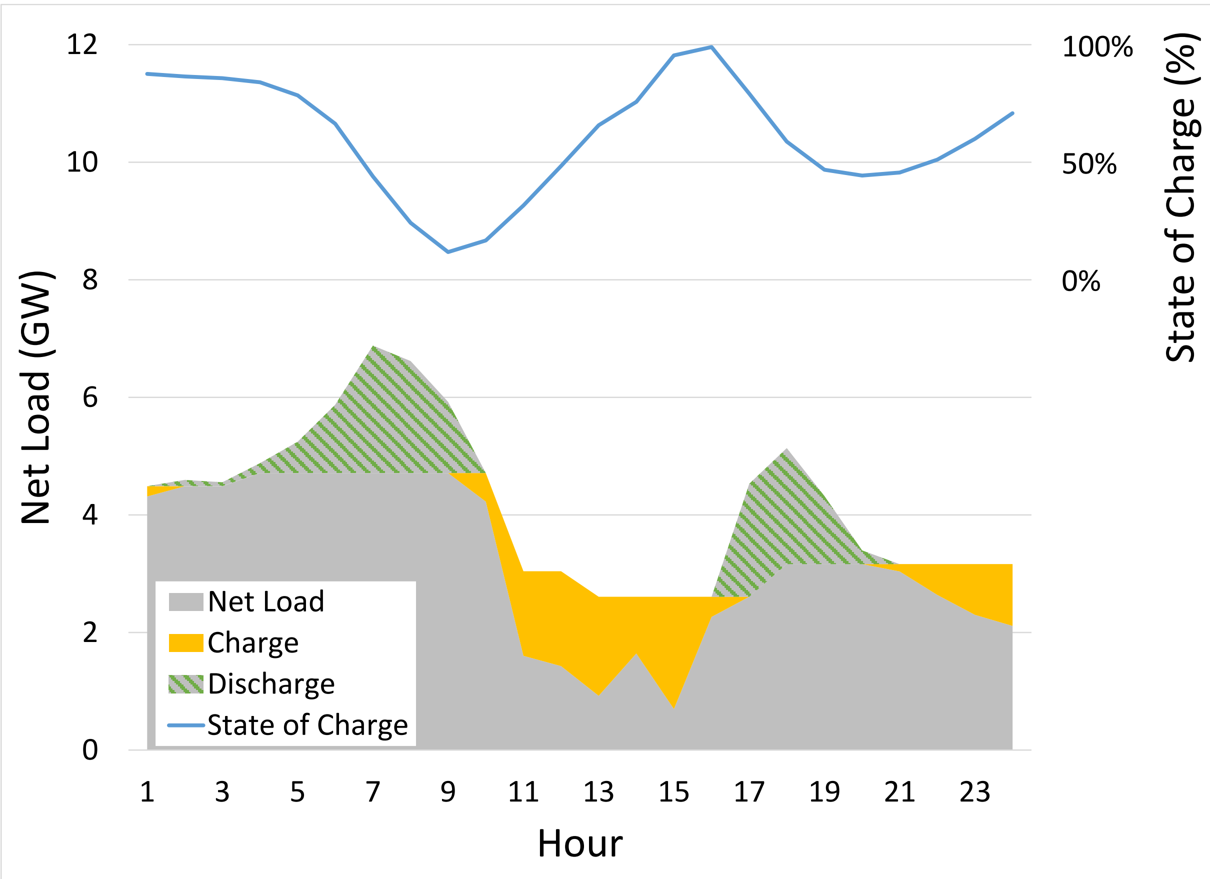
- "Smoothing" onsite resource output ignores potentially offsetting variations of variable resources elsewhere.
- Cycling hydro or thermal plants is cheap – use more fuel/water now and use less fuel/water later, net is close to zero.
- Cycling a battery is expensive due to efficiency losses and degradation
  - This creates a price spread between charging and discharging – more economic options should be deployed before switching between the two.
  - Short duration adjustments while other units catch up or rapid changes while not crossing zero may be economic.

2019 IRP Methodology
Peak-Shave/Valley-Fill Energy Storage



- Sample summer day, 2038
- 2,400 MW energy storage capacity
- Dispatch calculated using constrained linear optimization
- Minimum 30 minutes of discharge held in battery to provide reserves
- Minimum storage in hour-ending 5
- Maximum storage in hour-ending 15

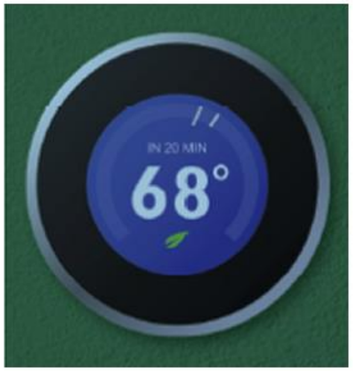
2019 IRP Methodology
Peak-Shave/Valley-Fill Energy Storage



- Sample winter day, 2038
- 2,400 MW energy storage capacity
- Minimum 30 minutes of discharge held in battery to provide reserves
- Morning and evening discharge and fill
- Minimum storage in hour-ending 9
- Maximum storage in hour-ending 16

2019 IRP Highlights/
2021 IRP Topics and Timeline
June 19, 2020



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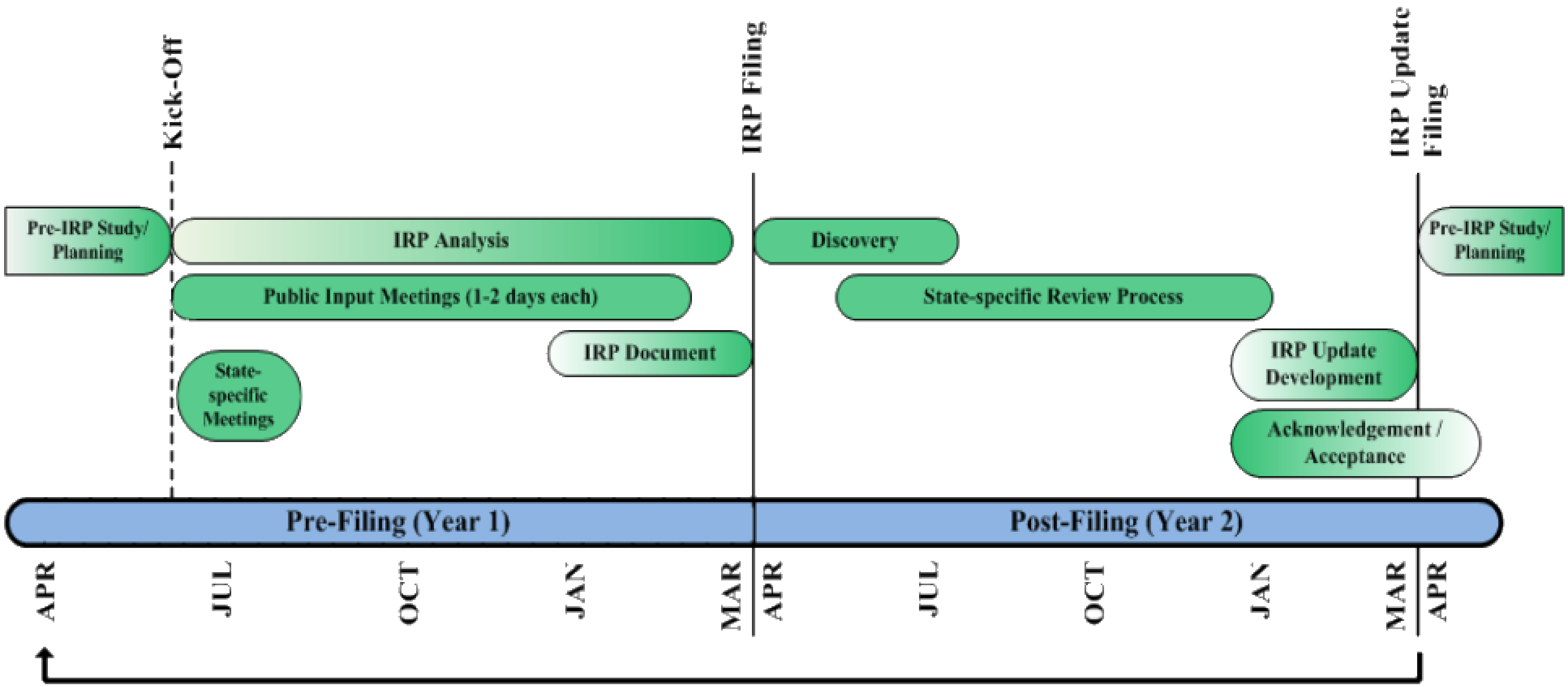
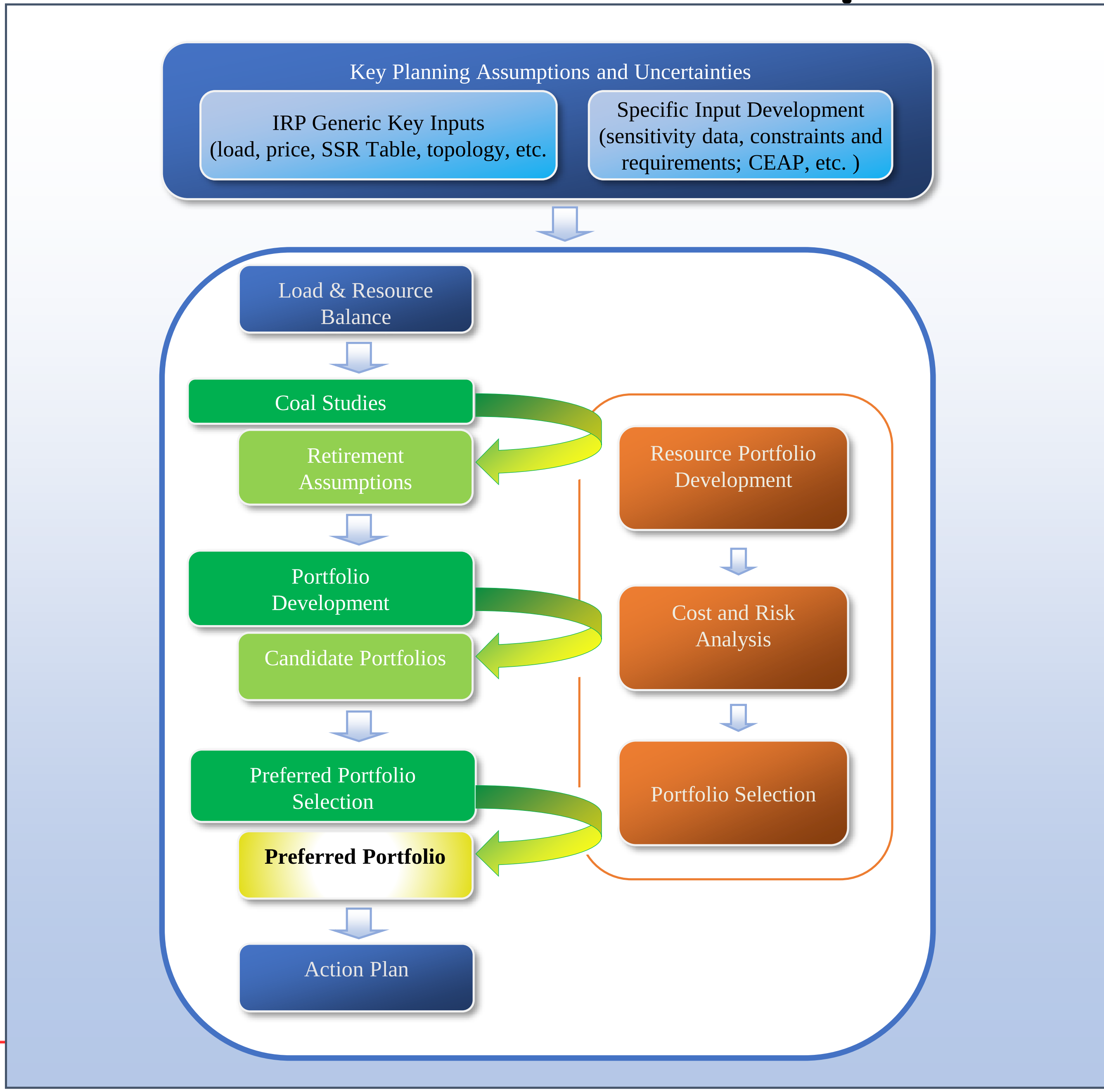
2021 Integrated Resource Plan Topics and Timeline

IRP Process Overview*



** Stakeholder participation milestones, timing and activities shown above are illustrative and subject to change.*

IRP Portfolio Development



2021 IRP Supplemental Studies

- Loss of Load Probability Study (LOLP) / Planning Reserve Margin (PRM)
- Wind and Solar Capacity Contribution Study
- Flexible Capacity Reserve Study (wind / solar integration costs and to consider natural gas / storage)
- Conservation Potential Assessment (DSM potential study)
- Private Generation Market Penetration Study
- Stochastic Parameter Updates
- Resource Adequacy / Market Reliance Assessment

2021 IRP Modeling Assumptions

Key Modeling Assumptions:

- Corporate Tax Rate (Tax Reform Act)
- Production Tax Credits
- Energy Storage
- Stochastic Parameters
- Flexible Reserve Study
- DSM Cost Bundles

Other Items:

- Distribution System Planning
- Multi-State Protocol

2021 IRP Public Input Meetings

Tentative Public Input Meeting Schedule and Topics *(topics are tentative and subject to change)*

- June 18-19, 2020
  - Conservation Potential Assessment Update, Modeling Optimization, Modeling Update, Modeling Battery Storage
  - IRP Process Overview, 2019 IRP Highlights, RFP Update, Transmission Update
- July 30-31, 2020
  - Load Forecast, Distribution System Planning, Supply-side Resource Efforts, Private Generation Study, Coal Study Discussion
  - Market Reliance Assessment, Environmental Policy Update, 2021 IRP Modeling Assumptions and Updates
- August TBD, 2020
  - Conservation Potential Assessment Workshop

2021 IRP Public Input Meetings

Tentative Public Input Meeting Schedule and Topics *(topics are tentative and subject to change)*

- September 17-18, 2020
  - Draft Supply-side Resource Table, Transmission Overview and Updates, Flexible Reserve Study Cost Results, Planning Reserve Margin Results, Portfolio Discussion, Coal Studies, Clean Energy Transformation Act (CETA)
- October 22-23, 2020
  - Supply-side Resource Table Levelized Costs, Intra-Hour Flexible Resource Credits, Updated CO2 Assumptions, Modeling Improvements, Storage Modeling Improvements, Coal Studies Discussion, CPA Final Supply Curves, DSM Bundling Methodology
- December 3-4, 2020
  - Coal Studies Discussion

2021 IRP Public Input Meetings

Tentative Public Input Meeting Schedule and Topics *(topics are tentative and subject to change)*

- January 14-15, 2021
  - Portfolio Analysis Results, Additional Portfolios Under Development
- February 25-26, 2021
  - Preferred Portfolio and Action Plan, Portfolio Analysis Results, Transmission Analysis Results
- April 1, 2019 – 2021 IRP Filing Date

2019 IRP Order Requirements and Action Plan Updates

2019 IRP Acknowledgement Process

- 2019 IRP was acknowledged / accepted:
  - Oregon – June 8, 2020; Docket No. LC 70
  - Washington – No action taken; Docket No. UE-180259
  - Idaho – Comments expected August 2020: Docket No. PAC-E-19-16
  - Utah – May 13, 2020; Docket No. 19-035-02
  - Wyoming – Hearing scheduled for July 13-17, 2020; 20000-522-EA-19
  - California – Filing requirements tied to RPS compliance reporting, no order yet

2019 IRP Order Requirements

State	Order / Letter Reference	Description
OR	Order 20-186, P.9	Direct PacifiCorp to include in its 2021 IRP development process an updated analysis identifying the most cost-effective coal retirements individually and in combination.
OR	Order 20-186, P.10	PacifiCorp is to work with stakeholders on the judgement calls where SCR can be reasonably avoided or not.
OR	Order 20-186, P.10	PacifiCorp is to update its inputs for correct Jim Bridger cost assumptions, as well as update its assumptions to reflect changes to the economy associated with COVID-19.
OR	Order 20-186, P.10	PacifiCorp is to provide a workshop or update for the Oregon Commission on PacifiCorp's timeline and sequence for incorporating nodal pricing and other MSP issues and EDAM into its IRP process.
OR	Order 20-186, P.13	Direct PacifiCorp to provide a workshop or presentation on how it calculates the capacity contribution of renewables (including solar and wind co-located with battery storage) for its 2019 and 2021 IRPs.
OR	Order 20-186, P.13	Regarding the QF issues, we accept PacifiCorp's commitment to produce a sensitivity or other explanation of the impact of renewing QFs on its load resource balance and direct PacifiCorp to include this in its 2021 IRP.
OR	Order 20-186, P. 14	We find that PacifiCorp reasonably allowed for additional flexible reserves, given its initial reliability analysis in this IRP, but we also agree with Staff and stakeholders that, for future IRPs, PacifiCorp needs to improve the analytical foundations for incorporating additional reliability resources into the IRP.

2019 IRP Order Requirements

State	Order / Letter Reference	Description
OR	Order 20-186, P.21	Regarding conditions relating to non-wires alternatives, we accept PacifiCorp's offer of a Commission workshop before the 2021 IRP is filed. The workshop should address how PacifiCorp's IRP relates to its long-term transmission plan.
OR	Order 20-186, P.23	PacifiCorp should work with stakeholders and Staff in the 2021 IRP development process to select two to four bundling strategies in an effort to identify the highest level of cost-effective energy efficiency by state and across the system. The collaborative decision process should consider bundling energy efficiency measures by energy cost, capacity contribution cost and measure type, as well as potentially by other metrics. The company should report on the collaborative process, bundling methods chosen, and any results in a filing before the filing of the 2021 IRP. PacifiCorp may hire a third party to conduct this analysis if needed due to resource constraints, but should coordinate with stakeholders on the scope of the work and timing.
OR	Order 20-186, P.23	PacifiCorp and/or Staff are to provide an update on demand response efforts at a regular public meeting before the 2021 IRP is filed.
OR	Order 20-186, P.23	Staff recommends that PacifiCorp conduct a Class 3 DSM workshop. PacifiCorp agreed to provide a stakeholder workshop during 2021 IRP development. We ask that the 2021 IRP summarize the timeframes and participation rates of any existing or planned Class 3 DSM pilots or schedules.

2019 IRP Order Requirements

State	Order / Letter Reference	Description
OR	Order 20-186, P.24	We acknowledge this action item (6b) and accept PacifiCorp's agreement to add detail to this language in the 2021 IRP to more clearly explain its REC management for states with and without RPS requirements management of RECs.
OR	Order 20-186, P.24	Require PacifiCorp include a proposal for the scope of a potential climate adaptation study in its 2021 IRP. This will also allow PacifiCorp to use its next IRP process to solicit stakeholder feedback on the scope of its plan. Additional discussion in the 2021 IRP of adaptation actions already taking place in the course of normal business, such as changes to modeling inputs such as heating and cooling days or water constraints, is encouraged in the meantime.
OR	Order 20-186, P.25-26	We ask PacifiCorp and Staff to review the Oregon compliance list, to determine which items they both agree are no longer relevant or necessary, and to provide an update on the list in the 2021 IRP docket. If certain items are not agreed upon or require our review, we ask Staff to bring those to a public meeting before the 2021 IRP.
UT	P.13	Any FERC queue reform will certainly impact some of the issues addressed by the 2019 IRP, but the ongoing nature of that process does not impact whether PacifiCorp substantially complied with the Guidelines in the development of the 2019 IRP. Other dockets, including future integrated resource planning, are appropriate venues to evaluate the implications of the results of queue reform.
UT	P.15	Reliability assessments will only become more crucial as PacifiCorp’s resource mix changes in the future, and those assessments must become an increasingly core aspect of future IRP processes.

2019 IRP Action Item Updates

- Action Item 1a – Existing Resource Actions - Naughton Unit 3:
  - PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. Initiate procurement of materials in Q4 2019. Conversion completed in 2020.
- Action Item 1b – Existing Resource Actions - Cholla Unit 4:
  - PacifiCorp will initiate the process of retiring Cholla Unit 4, and will remove Cholla Unit 4 from service no later than January 2023.
  - PacifiCorp will continue to coordinate with the plant operator to transition employees, develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans and confirm joint-ownership obligations; complete required regulatory notices and filings; administer termination, amendment, or close-out of existing permits, contracts and other agreements; and coordinate with state and local stakeholders as appropriate.By Q1 2020, the plant operator will be requested to develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans, and confirm joint-ownership obligations.
  - By the end of Q1 2020, the plant operator will be requested to develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans, and confirm joint-ownership obligations
  - By Q2 2020, the plant operator will be requested to file required transmission interconnection and transmission services unit retirement notices/request for study.
  - By Q4 2020, PacifiCorp will finalize an employee transition agreement with the plant operator.

2019 IRP Action Item Updates

- Action Item 1c – Existing Resource Actions - Jim Bridger Unit 1:
  - PacifiCorp will initiate the process of retiring Jim Bridger Unit 1 by the end of December 2023, including completion of all required regulatory notices and filings. By the end of Q2 2020, file a request with PacifiCorp transmission to study the year-end 2023 retirement of Jim Bridger Unit 1. By the end of Q2 2021, confirm transmission system reliability assessment and year-end 2023 retirement economics in 2021 IRP filing.
  - By the end of Q2 2021, finalize an employee transition plan.
  - By the end of Q2 2021, develop a community action plan in coordination with community leaders.
  - By the end of Q4 2021, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Jim Bridger Unit 1.
  - By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
- Action Item 1d – Existing Resource Actions – Naughton Units 1-2:
  - PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. By the end of Q2 2022, file a request with PacifiCorp transmission to study the year-end 2025 retirement of Naughton Units 1 and 2.
  - By the end of Q2 2022, finalize an employee transition plan.
  - By the end of Q2 2022, develop a community action plan in coordination with community leaders.

2019 IRP Action Item Updates

- Action Item 1d (continued)– Existing Resource Actions - Naughton Units 1-2:
  - By the end of Q2 2023, confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing.
  - By the end of Q4 2023, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2.
  - By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
- Action Item 1e – Existing Resource Actions - Craig Unit 1:
  - The plant operator will be requested to administer termination, amendment, or close-out of existing permits, contracts, and other agreements to support retiring Craig Unit 1, including completion of all required regulatory notices and filings, by the end of December 2025.
- Action Item 2a – Customer Preference Request for Proposals:
  - PacifiCorp will work with customers to achieve their respective resource preference requirements. By the end of Q4 2019, sign a fifteen year 80 megawatt (MW) Power Purchase Agreement (PPA) for Utah solar for six Utah Schedule 34 customers. By the end of Q4 2019, sign two 20-year PPAs of approximately 80 MW for a large Utah Schedule 34 customer. Monitor the finalization of rules by the Public Service Commission of Utah for House Bill (HB) 411 (anticipated by the end of Q1 2020), that provides a path forward for development of a program for participating communities to begin procuring renewable resources.

2019 IRP Action Item Updates

- Action Item 2b – All Source Request for Proposals:
  - PacifiCorp will issue an all-source request for proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2023.
  - By the end of Q4 2019, file a request for interconnection queue reform with the Federal Energy Regulatory Commission (FERC) and make state filings to initiate the process of identifying an independent evaluator.
  - In Q1 2020, file a draft all-source RFP with the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, as applicable.
  - In Q2 2020, receive approval from FERC to reform the interconnection queue.
  - In Q2 2020, receive approval of the all-source RFP from applicable state regulatory commissions and issue the RFP to the market.
  - In Q3 2020, identify a preliminary final shortlist from the all-source RFP and initiate transmission interconnection studies consistent with queue reform as approved by FERC.
  - In Q2 2021, identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable.
  - By Q2 2022 execute definitive agreements with winning bids from the all-source RFP.
  - By Q4 2023, winning bids from the all-source RFP achieve commercial operation.

2019 IRP Action Item Updates

- Action Item 3a – Energy Gateway South:
  - By December 31, 2023, PacifiCorp will seek to build the approximately 400-mile, 500-kilovolt (kV) transmission line from the Aeolus substation near Medicine Bow, Wyoming to the Clover substation near Mona, Utah.
  - By Q2 2021, receive the final CPCN from the Wyoming Public Service Commission and the Public Service Commission of Utah (initial filing dates for the CPCN to be determined after stakeholder engagement).
  - By the end of Q4 2021, issue full notice to proceed to construct Energy Gateway South.
  - In Q4 2023, construction of Energy Gateway South is completed and placed in service.
- Action Item 3b – Utah Valley Reinforcements:
  - Utah Valley Reinforcements: As necessary to facilitate interconnection of customer-preference resources, PacifiCorp will proceed with system reinforcements in the Utah Valley.
  - In Q2 2020, complete the Spanish Fork 345 kV/138 kV transformer upgrade.
  - In Q4 2020, complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley.
- Action Item 3c – Northern Utah Reinforcements:
  - Rebuild two miles of the Morton Court –Fifth West 138 kV line.
  - Loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond.
  - Complete identified plan of service supporting 2019 IRP preferred portfolio for resource additions in northern Utah.

2019 IRP Action Item Updates

- Action Item 3d – Utah South Reinforcements:
  - Develop plan of service in support of 2019 IRP preferred portfolio for resource additions in southern Utah.
  - Complete rebuild of the Mona –Clover #1 & #2 345 kV lines.
  - Identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah.
  - Yakima Washington Reinforcements: To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests.
  - In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process).
  - By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.
- Action Item 3e – Yakima Washington Reinforcements:
  - To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests.
  - In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process).
  - By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.

2019 IRP Action Item Updates

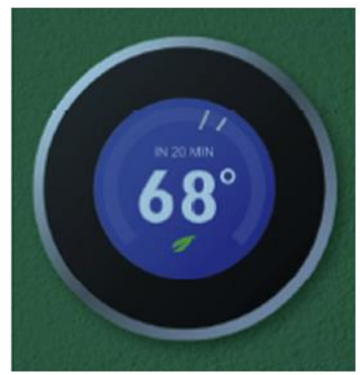
- Action Item 3f – Boardman to Hemmingway:
  - Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project (B2H) Joint Permit Funding Agreement.
  - Continue to participate in the development and negotiations of the construction agreement.
  - Continue analysis in efforts to identify customer benefits that may include contributions to reliability, interconnection of additional resources, geographical diversity of intermittent resources, Energy Imbalance Market, and resource adequacy.
  - Continue negotiations for plan of service post B2H for parties to the permitting agreement..
- Action Item 3g – Energy Gateway West:
  - Energy Gateway West Segment D.2, continue construction with target in-service date of 12/31/2020.
  - Continue permitting for the Energy Gateway transmission plan, with near term targets as follows:
  - For Segments D.3, and E, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. Also, continue to support the projects by providing information and participating in public outreach.
- Action Item 4 – Demand-Side Management Actions
  - PacifiCorp will acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio.
  - Energy Efficiency Bundling: PacifiCorp will continue to evaluate alternate bundling methodologies of Class 2 DSM in the 2019 IRP.

2019 IRP Action Item Updates

- Action Item 4 (continued) – Demand-Side Management Actions
  - Direct-Load Control: PacifiCorp will acquire cost-effective Class 1 DSM (i.e., demand response) in Utah targeting approximately 29 MW of incremental capacity from 2020 through 2023.
- Action Items 5– Front Office Transactions
  - Acquire short-term firm market purchases for on-peak delivery from 2019-2021 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.
  - Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.
  - Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
- Action Items 6a– Renewable Portfolio Standards
  - PacifiCorp will pursue unbundled RFPs to meet its state RPS compliance requirements.
  - As needed, issue RFPs seeking then current-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2020. As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.
- Action Items 6b– Renewable Energy Credit Sales
  - Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

PacifiCorp 2020 All-Source Request for Proposals (RFPs)



Purpose and Scope of 2020AS RFP

- The 2020 all-source RFP (2020AS RFP) is seeking resources to meet the company's projected needs as identified in the 2019 IRP, which included 1,823 megawatts (MW) of new proxy solar resources co-located with 595 MW of new proxy battery energy storage system (BESS) capacity and 1,920 MW of new proxy wind resources. Except for long-lead projects like pumped storage, the 2020AS RFP is seeking new resources that can achieve commercial operation by the end of 2024 to align with the federal production tax credit being extended after the 2019 IRP was filed.
- 2020AS RFP targets exclude resource capacity added to meet assumed customer preference targets that are included in the 2019 IRP preferred portfolio.
- PacifiCorp will also accept bids from new and existing resources that meet the December 31, 2024 on-line date but will allow for pumped storage hydro to bid as a long-lead time resource requiring time to develop and construct, placing completion beyond December 31, 2024.
- Proposals must be capable of interconnecting with or delivering to PacifiCorp's transmission system in its east or west balancing authority areas (PACE and PACW, respectively).
- PacifiCorp is not submitting any self-build ownership proposals (benchmark resources) or accepting any bids from any PacifiCorp affiliate.
- Bid fee(s) of $10,000 will be required for each base proposal and two (2) alternatives. Bidders will also be allowed to offer up to three (3) additional alternatives at a fee of $3,000 each.
- Intent to bid form and bidder credit information will be required prior to bid submittal(s).

Resource Types

RESOURCE TYPE	BID STRUCTURE ACCEPTED		
	PPA	**BSA**	**BTA**
Renewable	X		X
Renewable Plus Battery Storage	X		X
Non-renewable	X		X
Standalone Battery Storage		X	X
Pumped Storage Hydro		TOLL	X

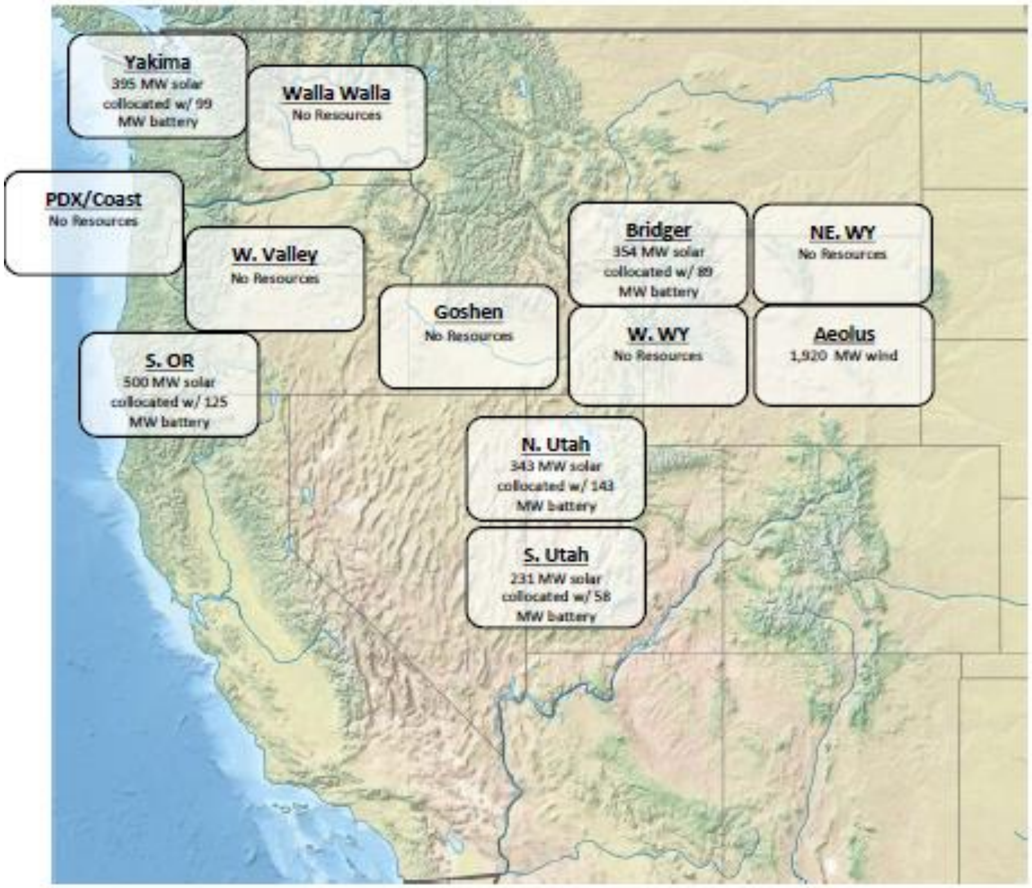
- Bids will be accepted from existing operating facilities with certain conditions.
- All renewable capacity, energy, and associated environmental attributes go to PacifiCorp.
- BTA bids MUST directly interconnect to PacifiCorp's system.
- Proposed BTA projects must be constructed to PacifiCorp standards and specifications.

Bid Structures

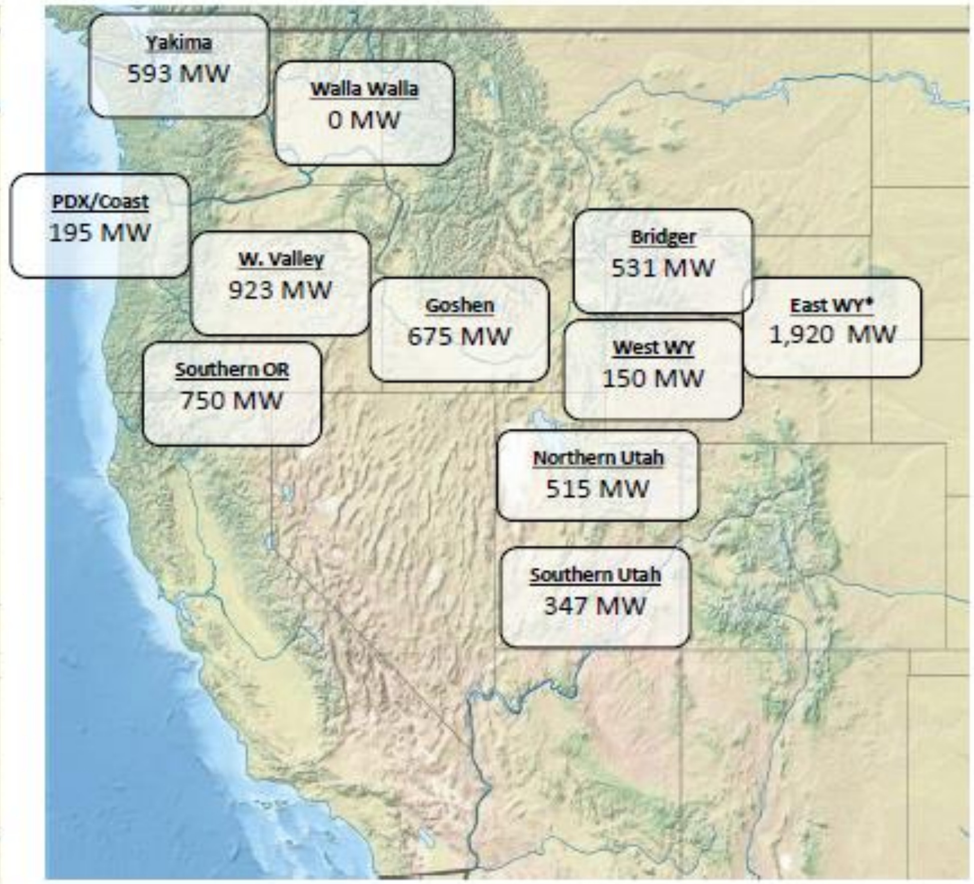
- Build-transfer transaction whereby the bidder develops the project, assumes responsibility for construction and ultimately transfers the asset to PacifiCorp in accordance with the terms of a build-transfer agreement (BTA). Under this transaction structure, the bidder will be responsible for all development, design, equipment supply, construction, commissioning, and performance testing, and will be required to design and construct the resource in conformance with PacifiCorp's specifications.
- Power-purchase agreement (PPA) with exclusive ownership by PacifiCorp of any and all capacity and environmental attributes associated with all energy generated with terms up to 25 years. PacifiCorp provides two forms of PPA; resource only and BESS collocated with a renewable resource.
- Control of the output of a BESS as a standalone BESS through a Battery Storage Agreement (BSA).
- Pumped storage hydro will be transacted through an individually negotiated tolling agreement.

Locational Capacity Limits

2019 IRP Preferred Portfolio Resources Online by Year-End 2023
(Excludes Customer Preference Resources)



Locational Initial Shortlist Capacity Limits
(1.5x Pref. Port. or 1.5x Assumed Interconnection Limit)

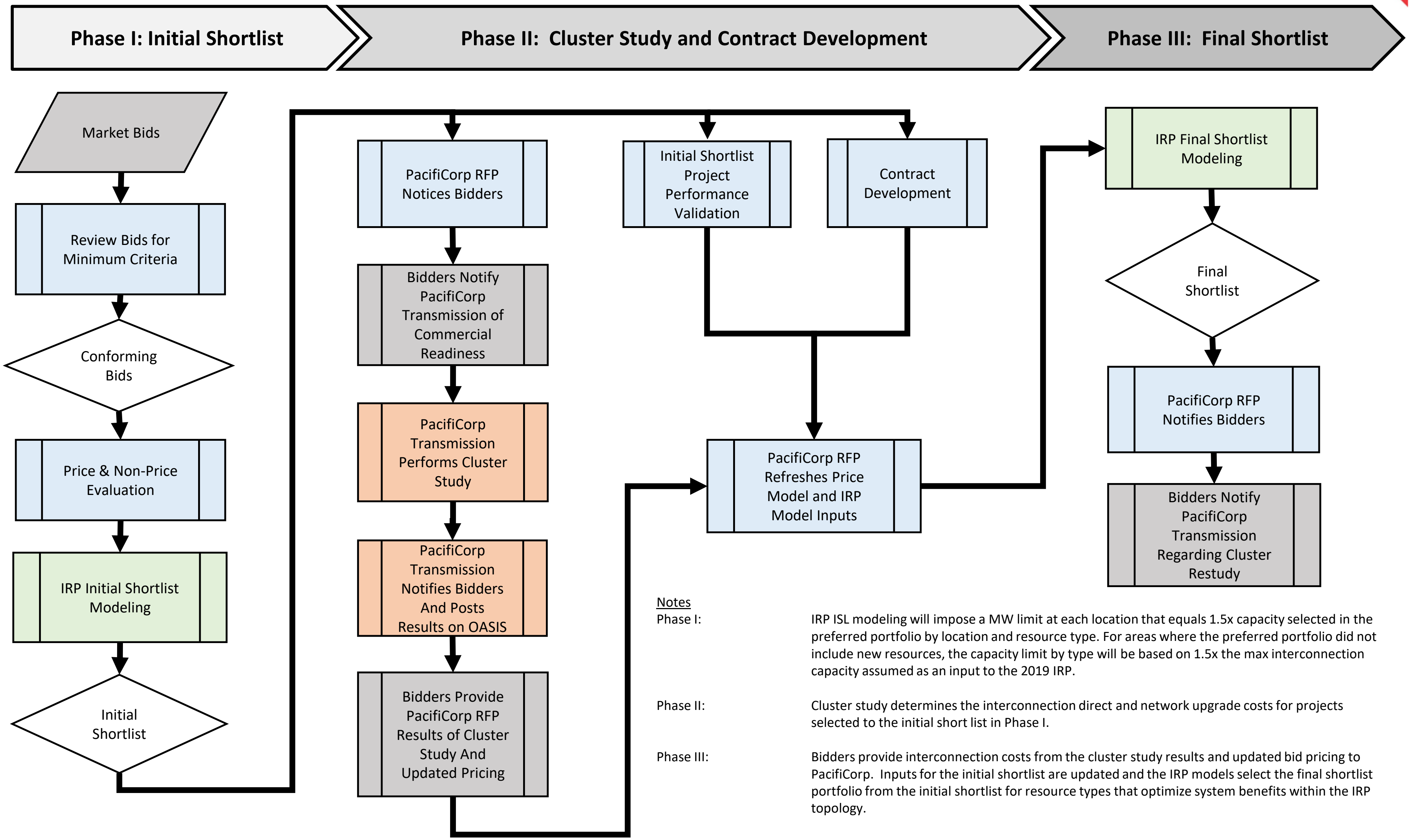


*Note, eastern Wyoming includes Aeolus and NE Wyoming, which combined, will be limited to 1,920 MW.

Interconnection Queue Reform Impact on RFP

- PacifiCorp Transmission has received approval from Federal Energy Regulatory Commission (FERC) reforming its interconnection study process set forth in its Open Access Transmission Tariff (OATT). PacifiCorp Transmission has replaced its long standing "serial queue" interconnection study process with a "first-ready, first-served, cluster" interconnection study approach.
- PacifiCorp's process for bid evaluation, scoring, modeling, and selection reflects PacifiCorp Transmission's proposed interconnection queue reform process as described in the OATT.
- Costs for any direct assigned and transmission network upgrades associated with the interconnection of a proposed project to PacifiCorp's transmission system will not be a bid requirement or included in the initial shortlist price evaluation.
- PacifiCorp will review the bidder's interconnection documentation to confirm it aligns with the bid submittal.
- Bidders should be aware of and clearly understand the specific steps, criteria, milestones and schedule of PacifiCorp Transmission queue reform and transition cluster study process.
- Bidders selected to the initial shortlist who are rejected by PacifiCorp Transmission for not meeting all of PacifiCorp Transmission's non-commercial readiness criteria necessary to be included in the transition cluster study will be removed by PacifiCorp from the initial shortlist and deemed a non-conforming bid.

Evaluation Process



<u>Notes</u>

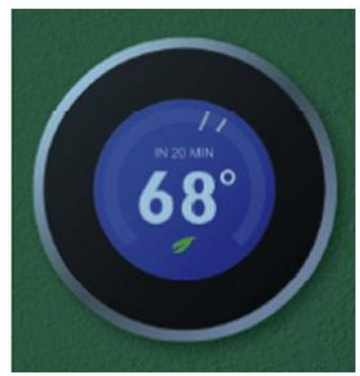
Phase I:	IRP ISL modeling will impose a MW limit at each location that equals 1.5x capacity selected in the preferred portfolio by location and resource type. For areas where the preferred portfolio did not include new resources, the capacity limit by type will be based on 1.5x the max interconnection capacity assumed as an input to the 2019 IRP.
Phase II:	Cluster study determines the interconnection direct and network upgrade costs for projects selected to the initial short list in Phase I.
Phase III:	Bidders provide interconnection costs from the cluster study results and updated bid pricing to PacifiCorp. Inputs for the initial shortlist are updated and the IRP models select the final shortlist portfolio from the initial shortlist for resource types that optimize system benefits within the IRP topology.

RFP Milestones / Schedule (Subject to Change)

Milestone	Date	Day
RFP Issued to market	07/06/2020	Monday
Notice of Intent to Bid due	07/20/2020	Monday
Last day for RFP questions to IEs for Q&A	08/03/2020	Monday
RFP bids due	08/10/2020	Monday
Bid eligibility screening completed	08/17/2020	Monday
Initial Shortlist (ISL) scoring/ranking completed	09/04/2020	Friday
IRP modeling generates ISL	10/05/2020	Monday
IEs' review of ISL completed	10/09/2020	Friday
PacifiCorp notifies bidders selected to ISL	10/14/2020	Wednesday
ISL bidders notify Pac Trans to enter cluster study	10/15/2020	Thursday
Capacity factor and BESS evaluation on ISL started	10/19/2020	Monday
Begin contract review and negotiations with ISL (subject to OAR waiver)	10/19/2020	Monday
Capacity factor and BESS evaluation on ISL completed	01/31/2021	Sunday
Complete contract negotiations on near final draft with bidders	03/31/2021	Wednesday
Cluster study results posted to OASIS / bidders notified by Pac Trans	04/15/2021	Thursday
Bidders provide ISL price update including cluster study results	04/22/2021	Thursday
Submit updated bids to IRP modeling	04/27/2021	Tuesday
IRP modeling generates Final Shortlist (FSL)	05/20/2021	Thursday
Final Shortlist (FSL) selected	05/25/2021	Tuesday
IEs' review of FSL Completed	06/01/2021	Tuesday
Complete negotiation of T&Cs for resource agreements	10/15/2021	Friday
Execute Agreements	11/08/2021	Monday
Winning Bid Guaranteed COD	12/31/2024	Tuesday

Transmission Overview and Updates



Transmission Overview Agenda

- Regional Planning Update
- Energy Gateway
    - Segment C – Oquirrh to Terminal
    - Segment D2 – Aeolus to Bridger/Anticline
    - Segments D1, D3, E – Gateway West
    - Segment F – Gateway South
    - Segment H – Boardman to Hemingway
- 2019 IRP Transmission Modeling Enhancements

FERC Order 1000 Regional Planning

- FERC Order No. 1000 is a Final Rule that reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers.
- The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods.
- Pre 2020 to meet the requirements of FERC Order 1000 PacifiCorp was a member of the Northern Tier Transmission Group (NTTG)
- Beginning in 2020 PacifiCorp became a member of the newly formed NorthernGrid, combining ColumbiaGrid and NTTG, regional planning organization to continue to meet the requirements of FERC Order 1000.
- Jurisdictional and non-jurisdictional entities have formed a single transmission planning association – NorthernGrid – that will facilitate regional transmission planning across the Pacific Northwest and Intermountain West. The association members have executed a Planning Agreement that will provide the region with:
    - One common set of data and assumptions
    - More opportunities to identify regional transmission projects
    - A single stakeholder forum
    - Elimination of duplicative administrative processes

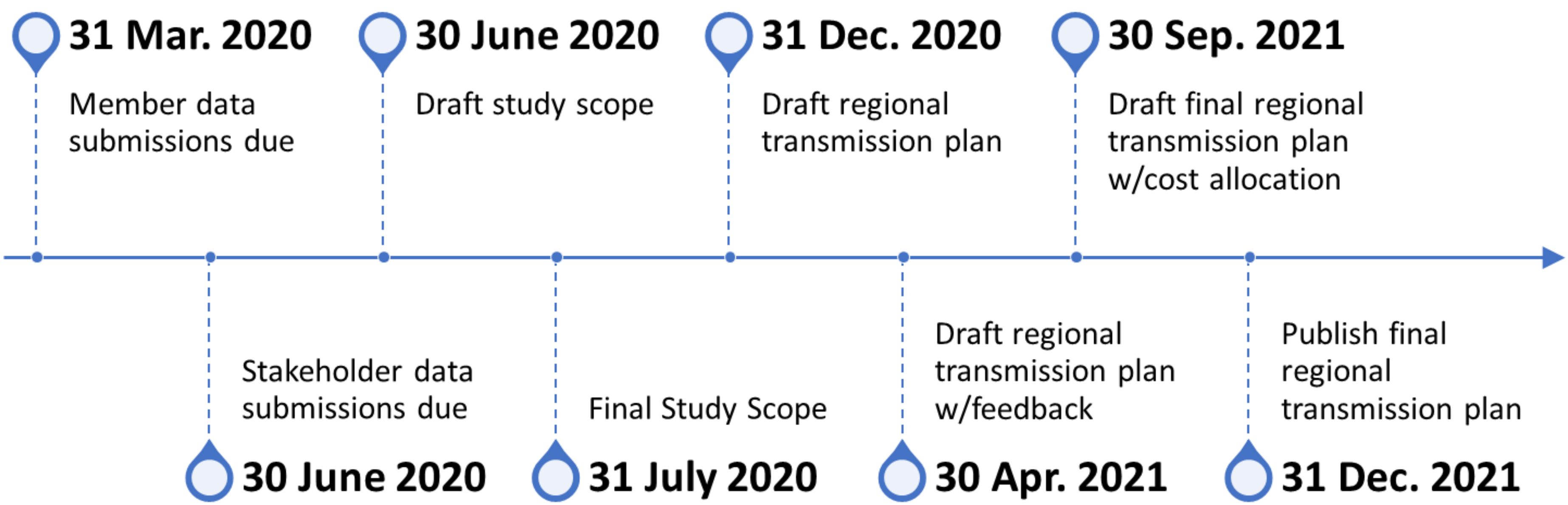
Regional Planning

- NorthernGrid regional planning organization is made up of PacifiCorp, Idaho Power, NorthWestern Energy, Portland General Electric, Avista, BHE Canada, Bonneville Power Administration, Chelan County PUD, Enbridge, Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power.
- NorthernGrid web page: https://www.northerngrid.net
- The wide participation envisioned in this process (including transmission owners, customers and state regulators) is intended to result in transmission expansion plans that meet a variety of needs and have a broad basis of support.
- NorthernGrid currently facilitates compliance with FERC requirements (including Order Nos. 890 and 1000) for those utilities that are required (or elect) to comply with such requirements, including cost allocation, when applicable.
- Through PacifiCorp's participation the Energy Gateway Project has been and will continue to be fully vetted through the regional planning process.

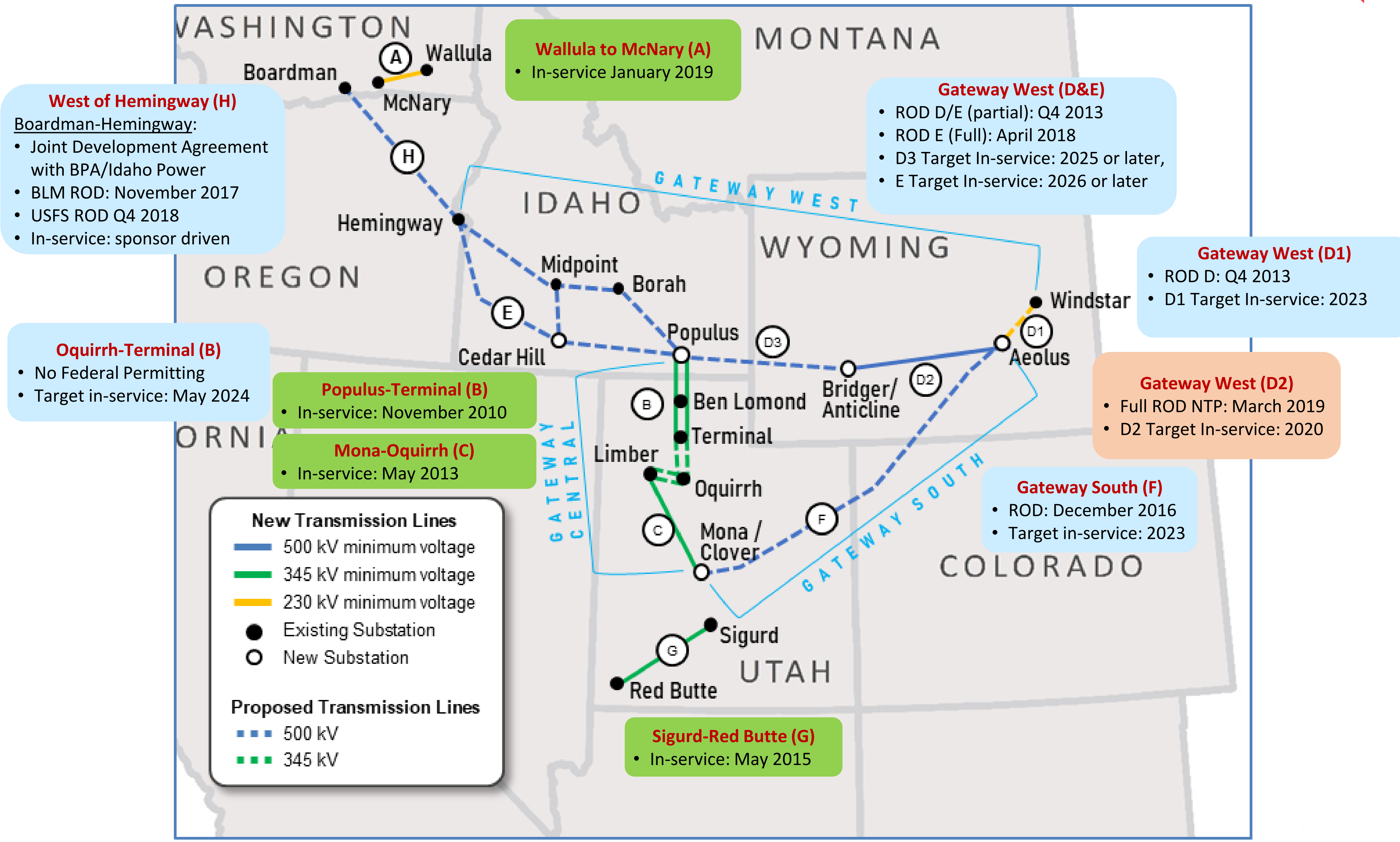
Regional Planning

NorthernGrid 2020-2021 Planning Cycle

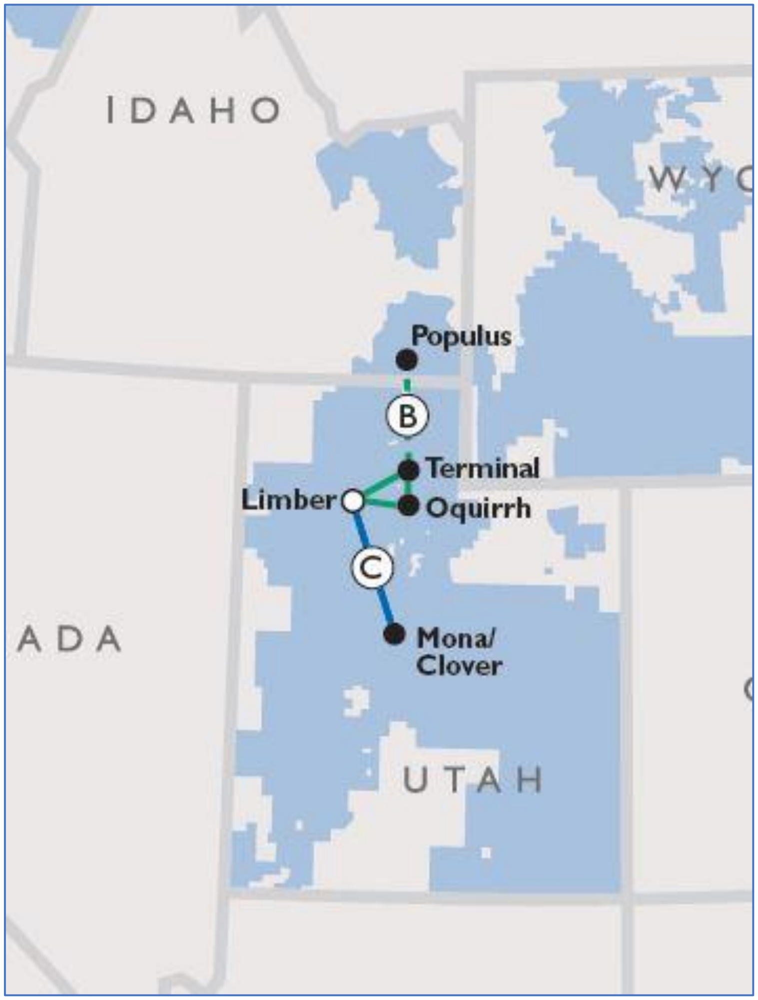
General Schedule and Deliverables



Energy Gateway Program Status



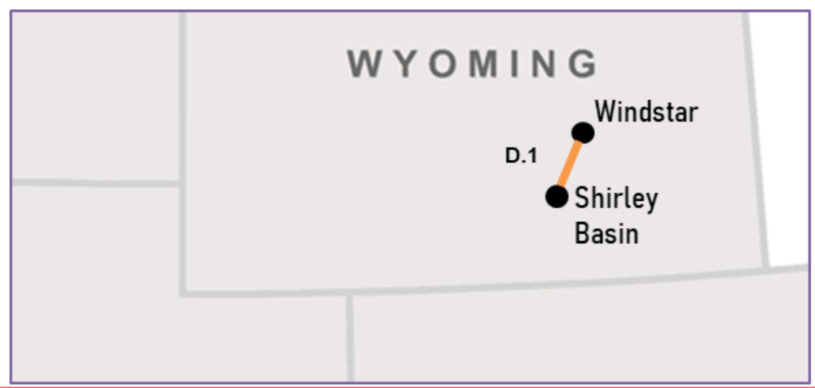
Oquirrh-to-Terminal (Segment C)



- 14-mile, double-circuit 345-kilovolt line, Oquirrh-to-Terminal
- Line route is within existing right of way that includes realignments to accommodate construction of the Utah Department of Transportation Mountain View Corridor project
- No federal permitting required
- Adds 650MW of transfer capacity on Path C (south) and 500MW of transfer capacity on Wasatch Front South
- Reinforces the Gateway Central north to south transmission path improving overall load serving capability to the Wasatch Front.
- Provide a parallel line to existing Wasatch Front 345 kV lines improving the reliability of northern Utah for loss of multiple 345 kV lines.
- Strengthens the Wasatch Front transmission system (increased fault duty) by more tightly coupling the northern Utah and southern Utah transmission systems, allowing additional generation resources to be transferred into northern Utah from eastern Wyoming and southern Utah.
- Improves grid reliability by providing better operational control of the backbone transmission system during outage conditions.
- Supports the company's NERC TPL-001-4 transmission system reliability efforts, which are necessary to improve grid reliability performance
- Target in-service date: May 2024

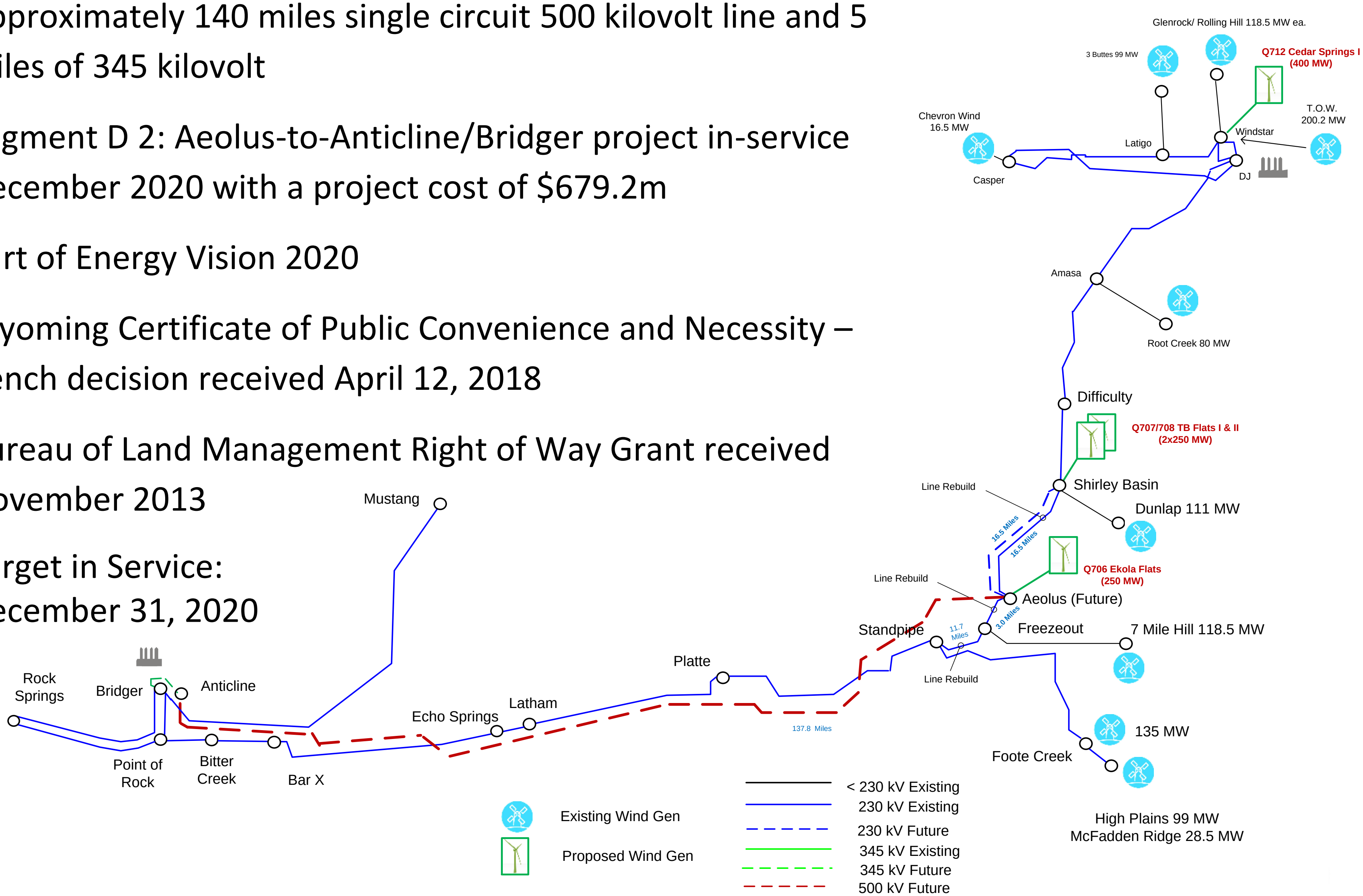
Gateway West (Segment D1)

- Gateway West (including Segment D.1) Windstar to Shirley Basin) Record of Decision was issued in November 2013 and the Right of Way Grant was received in December 2013 – 60 miles of single-circuit 230 kilovolt transmission plus rebuild 60 miles of single-circuit 230 kilovolt transmission
- Remaining federal permitting related right of way activities needed (Wyoming only)
  - Biological surveys for special status plant species
  - Paleontological surveys
  - Cultural surveys on all federal lands
  - Wetland delineations of all right of way and access road areas
- Remaining state/private permitting related right of way activities needed (Wyoming only)
  - Cultural surveys on all state lands and private lands
  - Geotechnical surveys
  - Sage grouse working group sessions
  - Wyoming Industrial Siting Permit: First jurisdictional meeting will be held in July, 2020, application will be filed in January, 2021 and the permit is expected to be approved in April, 2021.
  - Conditional use permits required in Carbon and Natrona counties will be initiated in September 2020
- Target in Service: 2023



Gateway West (Segment D2)

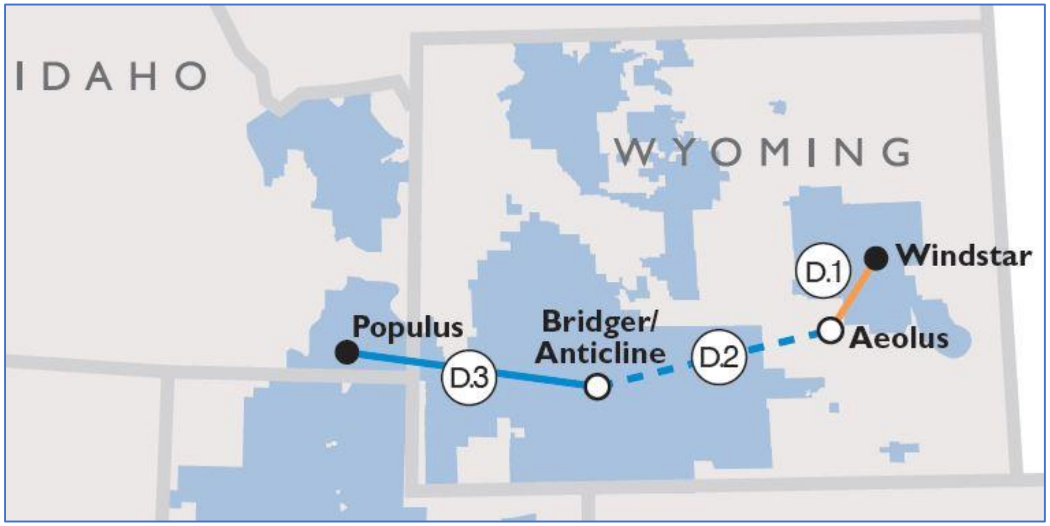
- Approximately 140 miles single circuit 500 kilovolt line and 5 miles of 345 kilovolt
- Segment D 2: Aeolus-to-Anticline/Bridger project in-service December 2020 with a project cost of $679.2m
- Part of Energy Vision 2020
- Wyoming Certificate of Public Convenience and Necessity – bench decision received April 12, 2018
- Bureau of Land Management Right of Way Grant received November 2013
- Target in Service: December 31, 2020



Gateway West (Segment D2) Transmission/Substation Construction Update

- 500/345kV transmission line construction on track for October 31, 2020, substantial completion: 100% structure foundations; 91% structure erection; 51% wire stringing
- 500kV Substation construction on track for October 31, 2020, substantial completion:
  - Aeolus – excavation, piping, cable trench, grounding and 230kV bus installation 100% complete; conduit – 95%; station steel – 97%; equipment setting – 91%; 230kV yard mechanically complete
  - Anticline – excavation, cable trench and station steel 100% complete; piping – 99%; grounding – 95%; equipment setting – 89%; bus installation – 94%
  - Jim Bridger – excavation and grounding 100% complete; steel – 88%
  - Latham substation expansion – 100% complete
- Transformer factory testing complete; all transformers in transit or delivered
- All reactors onsite and being assembled; all circuit breakers delivered and being installed
- Latham STATCOM installation on track for October 31, 2020, substantial completion
- 230kV Network Upgrades:
  - Transmission line construction behind schedule due to BLM 2019-2020 winter range restrictions; however, a contingency solution (shoofly connection) has been instituted to supply back-feed power to Ekola Flats by the June 15, 2020 required date. All work on track for October 31, 2020, substantial completion.
  - Substation construction/modifications at all locations are on track for October 31, 2020, substantial completion: Windstar – underway; Shirley Basin – underway; Freezeout – 100% complete; wind farm collector substations – underway

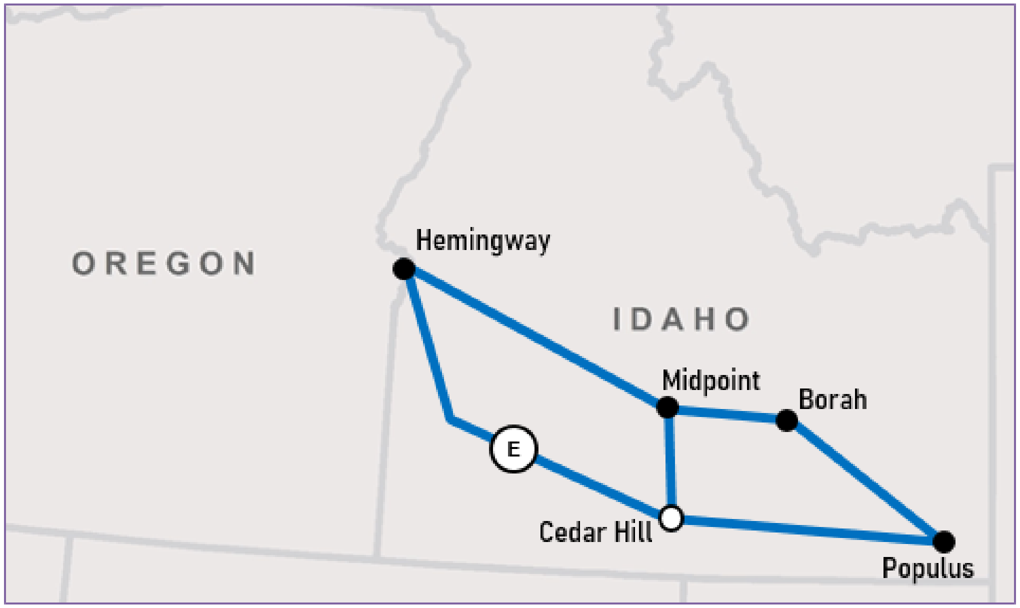
Gateway West (Segment D3)



- 200-mile, 500-kV Energy Gateway West (GWW) Segment D.3 transmission line, from Bridger/Anticline to Populus by year-end 2025 or later
  - Adds 1700 MW of transfer capability from south-central Wyoming (Bridger/Anticline) to southeastern Idaho
  - Allows interconnection of an additional 228 MW of renewable generation resources in central Wyoming and 249 MW in south eastern Idaho
- Completes the east to west transmission link between eastern Wyoming and southwest Idaho, support higher levels of wind integration in eastern Wyoming.
- The project supports higher transfers levels from eastern Wyoming across southern Wyoming to southeast Idaho and into to northern Utah.
- Provides a parallel path to Bridger West 345 kV transmission system improving the reliability of southwest Wyoming and southeast Idaho during line outage conditions.
- Strengthens the southwest Wyoming and southeast Idaho transmission system (increased fault duty) by more tightly coupling the two areas, allowing additional generation resources to be interconnected.
- Improves the Bridger West transmission system reliability by providing congestion relief on the 345 kV lines during outage conditions
- Supports the company's NERC TPL-001-4 transmission system reliability efforts, which are necessary to improve grid reliability performance.
- Bureau of Land Management Right of Way Grant received November 13, 2013
- Target in Service: 2025 or later

Gateway West (Segment E)

- 450 miles, 500 kilovolts Energy Gateway West – Segment E transmission line, from Populus to Hemingway
  - Adds 630 megawatts of transfer capability from eastern Idaho (Populus) to central Idaho (Hemingway)
  - Allows interconnection of an additional 500 megawatts of renewable generation resources in southeastern Idaho
- Completes the east to west transmission link between southeast Idaho and southwest Idaho, support higher levels of renewable integration in southeast Idaho
- The project supports higher transfers levels from east to west across Idaho, supporting new Wyoming resources being delivered to Treasure Valley of southwest Idaho and the Pacific Northwest (via the Boardman – Hemingway project)
- Provides a parallel path to Populus West and Midpoint West 345 kilovolts and 230 kilovolts transmission system improving the reliability of southern Idaho during line outage conditions
- Strengthens the PacifiCorp and Idaho Power transmission systems (increased fault duty) by interconnecting the geographically diverse areas of southwest Idaho and southeast Idaho together, allowing additional generation resources to be interconnected or transferred
- Improves grid reliability by providing better operational control of the southern Idaho backbone transmission system during outage conditions



- Improves the southern Idaho transmission system reliability by providing congestion relief on the 345 kilovolts and 230 kilovolts lines during outage conditions
- Supports PacifiCorp's NERC TPL-001-4 transmission system reliability efforts, which are necessary to improve grid reliability performance
- Bureau of Land Management record of decision and right of way grant issued November 2013 for sub-segments 1-7 and 10
- Bureau of Land Management Record of Decision and Right of Way Grant issued on May 2018 for sub-segments 8 and 9
- Target in service: 2026 or later

Gateway South (Segment F)

Gateway South Segment F (Aeolus to Mona/Clover)

- 2019 Integrated Resource Plan Preferred Portfolio
- Delivers long-term customer savings
- Addresses transmission reliability and interconnection constraints
- Adds approximately 1,700 MWs of transfer capability from eastern Wyoming (Aeolus) to the central Utah energy hub (Mona/Clover)
- Allows interconnection of an additional 1,920 MWs of renewable generation resources in eastern Wyoming
- Final Environmental Impact Statement issued May 2016
- Record of Decision issued December 13, 2016
- Target in-service date: 2023

Gateway South (Segment F) Permitting Update

- Gateway South Segment F (Aeolus to Mona) Record of Decision was issued in December 2016 and the Right of Way (ROW) Grant was received in January 2017
- Remaining federal permitting related right of way activities
  - Bureau of Land Management and U.S. Forest Service full notice to proceed, target date May 1, 2021
  - Conduct the required preconstruction surveys through early 2021 to support full agency full notice to proceed by May 1, 2021. These include biological, noxious weeds, paleontological, cultural resource surveys
  - Wetland delineations of all right of way and access road areas where project crosses to minimize wetland mitigation requirements
  - Mitigation discussions for any identified impacts with the U.S. Fish and Wildlife Service, Utah Department of Natural Resources, Colorado Department of Wildlife, and Wyoming Game and Fish
  - Development of adaptive management plans for impacted species via mitigation
- Remaining state/private permitting activities
  - Certificates of Public Convenience and Necessity required in Wyoming and Utah. Filings are planned in April 2020
  - Wyoming Industrial Siting permitting initiated in January 2020, hearing scheduled October 21, 2020
  - 9 county conditional use permits required across the project. Applications will begin in May 2020

- Cross Mountain Ranch Conservation Easement Colorado
- Sage grouse working group sessions to develop habitat equivalency analysis for final impact run based on final transmission design right of way and subsequent mitigations for state agency mitigation in Wyoming, Colorado, and Utah
- Climatology studies for conductor/towers initiation

Boardman-to-Hemingway (Segment H)

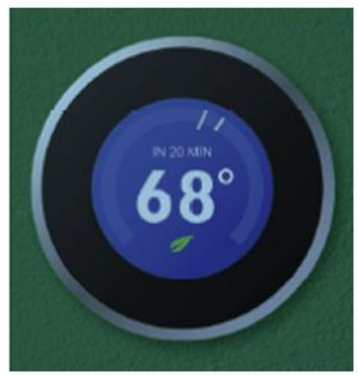
- 290 miles, 500kV single circuit transmission line
- Benefits to PacifiCorp customers include reducing reliance on third party transmission service, cost savings that result from arbitrage of low cost northwest markets relative to southwest markets, capacity benefits resulting from winter and summer peaking differences across PacifiCorp's system, and increased load serving capability in Central Oregon
- Idaho Power has identified Boardman to Hemingway in its preferred resource portfolio with an in-service date in 2026 and initiated contractual owner negotiations in Q2 2019 to proceed with building the line

- Current project schedule
  - Pre-construction activities start Q4 2019 – Q3 2022
  - Oregon final order and site certificate – Q1 2022
  - BLM Notice to Proceed / Plan of Development – Q3 2023
  - Line construction start Q2 2023
  - Substation construction start Q1 2024
  - Project in-service mid-year 2026

- Project participants: Idaho Power, Bonneville Power Administration, PacifiCorp
- Final environmental impact statement published November 25, 2016
- BLM Record of Decision received November 2017
- USFS ROD received November 2018
- Oregon Energy Facility Siting Council proposed order expected to be issued 2020; Site Certificate expected 2022.

2019 IRP
Post-filing IRP Discussion



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2019 IRP Timeline

- Following an 18-month public-input process, PacifiCorp filed its 2019 IRP in its six states – October 18, 2019
  - 2019 IRP data discs and supplemental information filed – October 25, 2019
  - 2019 IRP second supplement and data disc replacement files filed – November 8, 2019
- On October 30, 2019 – the Public Utility Commission of Oregon issued its procedural schedule, Docket LC-70.
- On November 6, 2019 – the Public Utility Commission of Utah issued its procedural schedule, Docket 19-035-02.
- On November 7, 2019 – the Washington Utilities and Transportation Commission approved staff's petition to not take action on the 2019 IRP (Docket UE-180259) and to focus on completion of the clean energy legislation implementation rulemaking and IRP rulemaking to inform the 2021 IRP.
- On November 7, 2019 – the Public Service Commission of Wyoming opened an investigation into the 2019 IRP, Docket 20000-552-EA-19.
- The Public Utility Commission of Idaho has not yet taken action on the 2019 IRP, Docket PAC-E-19-16.

Transmission Information and Outcomes in the IRP

- In the IRP Document:
    - Volume I, Chapter 4 (Transmission): Discussion of specific transmission projects, reliability standards, system constraints, etc.
    - Volume I, Chapter 6 (Resource Options), pages 168-169: Summary of materials in this workshop.
    - Volume II, Appendix M (Case Study Fact Sheets): Case-by-case summary of incremental transmission additions plus transmission and resource maps.
- On the Confidential Data Disk, System Optimizer Portfolio Summary
    - "Portfolio Sum" tab
        - The second table of this tab shows a summary of selected incremental transmission, including the year and added capacity.
    - "TieBuild" tab
        - The table reports the year, project, topology bubbles, capacity and capital cost for all potential upgrades.
        - Filter the "Capital Cost" to exclude zeroes, which will result in a filtered list of the selected options.
        - This view shows both incremental additions and transmission "recovered" after retirements.

Transmission Planning

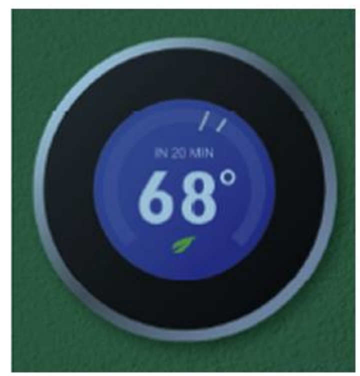
- PacifiCorp transmission planning considered known transmission capacity and limitations of WECC rated paths and internal paths to provide inputs to the IRP model for baseline transmission capacity between IRP bubbles and the estimated amount of new generation that could be added in various locations.
- Transmission planning also provided a list of estimated incremental transmission capacity additions that the IRP model could select when the model selected generation resource additions within an IRP bubble that exceeded the baseline transmission capacity of that bubble. Incremental transmission capacity selection options were based on the following information:
- Planned network system improvements (projects included in proposed budget, local transmission plan and/or regional transmission plan)
- Completed generator interconnection studies
    - megawatt size
    - location
    - system improvements identified
- Estimated cost for construction based on voltage class, line mileage and substation integration requirements.

Interconnection Queue Reform Overview

- Since Open Access in 1996, PacifiCorp has increased its owned generation resource portfolio through a combination of: (1) "greenfield" projects, where PacifiCorp requests and holds a position in the interconnection queue and develops the project from its inception; and (2) third-party acquisitions, where the third party requests and holds a position in the interconnection queue and develops the project until commercial operation (or near commercial operation) before selling the resource to PacifiCorp
- PacifiCorp must largely bring on incremental generation by conducting a highly regulated competitive solicitation process. Participation by both company and third-party projects in PacifiCorp's requests for proposal not only increases the likelihood that PacifiCorp's state commissions will find they satisfy regulatory metrics, but also that PacifiCorp will receive competitively priced bids
- While the queue congestion levels affected PacifiCorp's ability to hold high-priority queue positions in some areas, PacifiCorp has nevertheless been able to maintain its desired level of low-cost resource development thus far, and it sought to proactively address the issue with its recent FERC queue reform proposal to ensure that success continues
- If the Federal Energy Regulatory Commission approves PacifiCorp's request for reformed interconnection processing rules, it will facilitate more competitive access to PacifiCorp's system in the short to medium term, but it will not impact projects with signed large generator interconnection agreements and thus no impact to the 1,920 MWs projects in the queue behind Gateway South Segment F Aeolus to Mona and Gateway West Segment D.1 Windstar to Aeolus
- Current status of PacifiCorp's queue reform effort is as follows:
  - On March 6, 2020, the Federal Energy Regulatory Commission issued a deficiency letter seeking additional information about a limited number of issues. PacifiCorp filed a response on March 13, 2020
  - On April 10, 2020, 12 entities filed comments on PacifiCorp's March 13, 2020 response arguing for modifications to PacifiCorp's proposals on the timing of and eligibility requirements associated with the first cluster study, commercial readiness criteria, and technical modeling adjustments. PacifiCorp is preparing a concise response to make limited clarifications and indicate areas of compromise, which is due on April 27, 2020
  - The Federal Energy Regulatory Commission approved PacifiCorp's tariff revisions on May 12, 2020. The order included a January 31, 2020 cutoff date for interconnection requests to be included in the transition cluster study. At least one intervenor has filed for re-hearing at this point.

Additional Information / Next Steps



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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 – CPA Draft Documents
  - pacificorp.com/energy/integrated-resource-plan/support

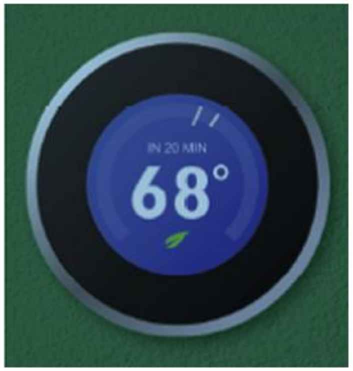
Next Steps

- Upcoming Public Input Meeting Dates:
  - June 18-19, 2020 – General Public Input Meeting
  - July 30-31, 2020 – Public Input Meeting
  - August (TBD), 2020 – Conservation Potential Assessment Technical Workshop
  - September 17-18, 2020 – Public Input Meeting
  - October 22-23, 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

**meeting dates are subject to change*

Integrated Resource Plan
2021 IRP Public Input Meeting
July 30-31, 2020



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Agenda

July 30, 2020

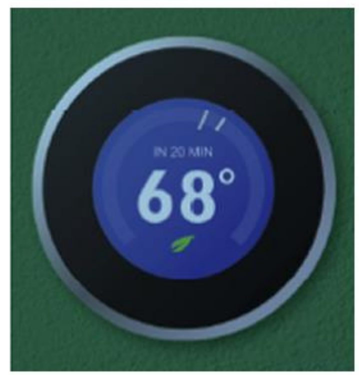
- Introductions
- Load Forecast Update
- Distribution System Planning
- Lunch Break (45 min) 11:15am PT/12:15pm MT
- Supply-Side Resource Study Efforts
- 2021 IRP Modeling Assumptions and Study Updates
  - Planning Reserve Margin
  - Capacity Contribution Studies
  - Stochastic Parameters Update
  - Intra-Hour Dispatch Credit
- Coal Studies Discussion
- Q&A/ Wrap-Up

July 31, 2020

- Environmental Policy
- Renewable Portfolio Standards
- DSM Bundling Portfolio Methodology
- Lunch Break (45 min) 11:30 PT/12:30 MT
- Private Generation Study
- Stakeholder Feedback Form Recap
- Wrap-Up/ Next Steps

Load Forecast Update

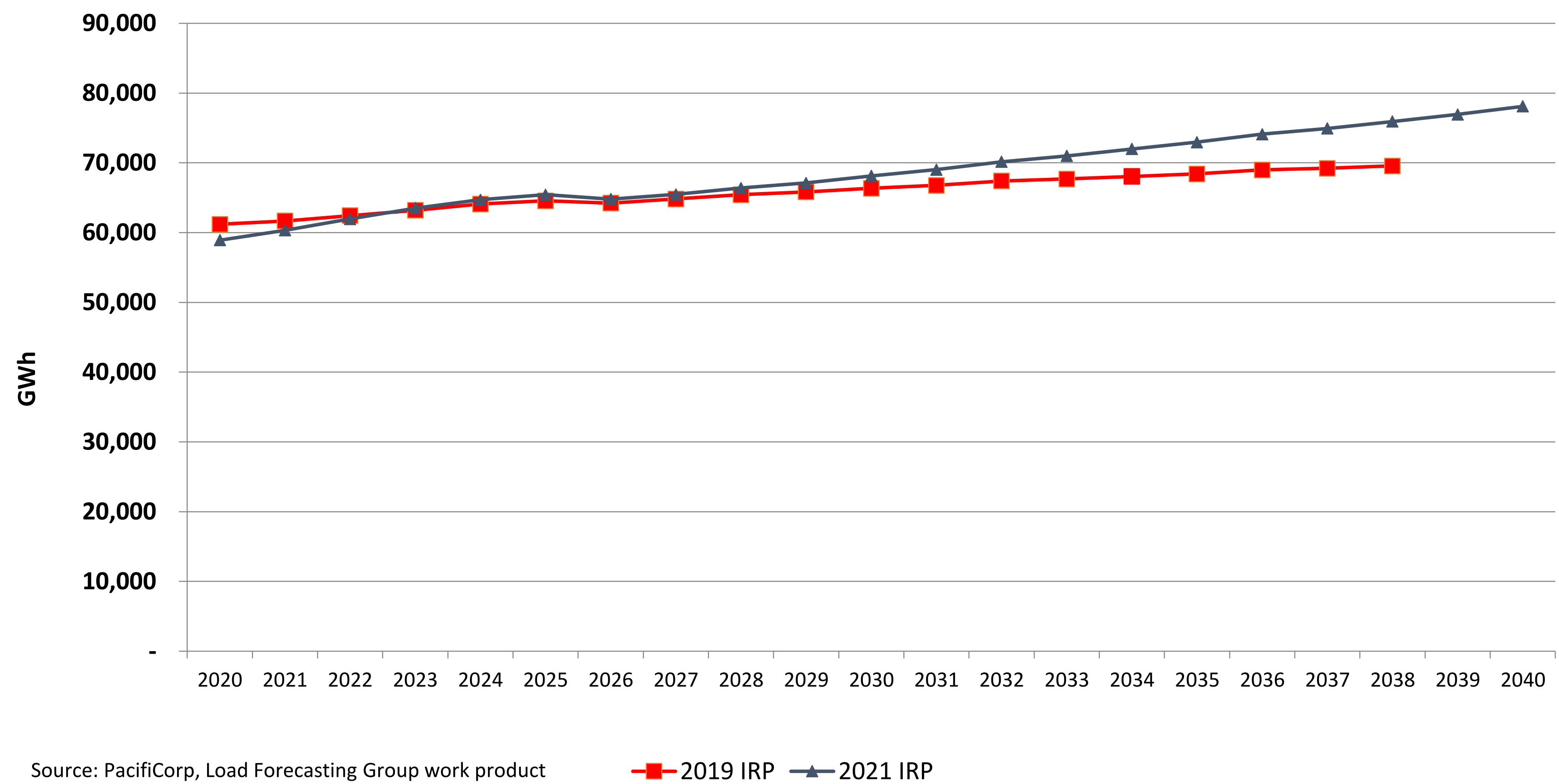


Load Forecast Summary

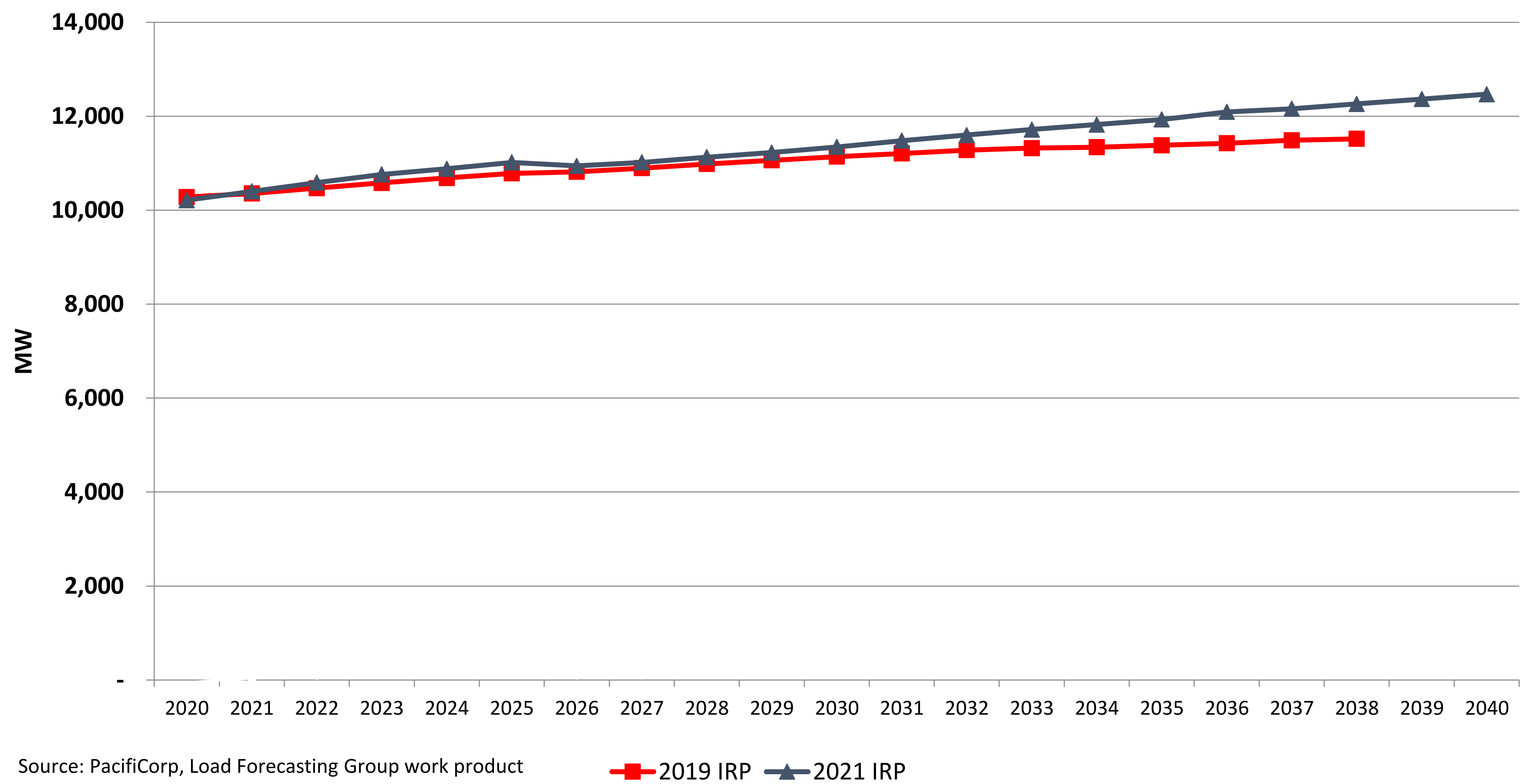
- Over the 2020 through 2022 timeframe, a lower load forecast is being driven by adverse economic impacts resulting from COVID-19 and low commodity prices
- Beginning in 2023, the load forecast is driven higher by projected residential demand and commercial customer demand
    - Codes and standards rollback
    - Electric vehicles and building electrification
    - Data centers
- Peak forecast is higher than the 2019 IRP forecast over the 2021 through 2040 timeframe
    - Peaks continue to be driven by summer cooling load

System Energy Load Forecast Change



Source: PacifiCorp, Load Forecasting Group work product

System Peak Load Forecast Change



Source: PacifiCorp, Load Forecasting Group work product

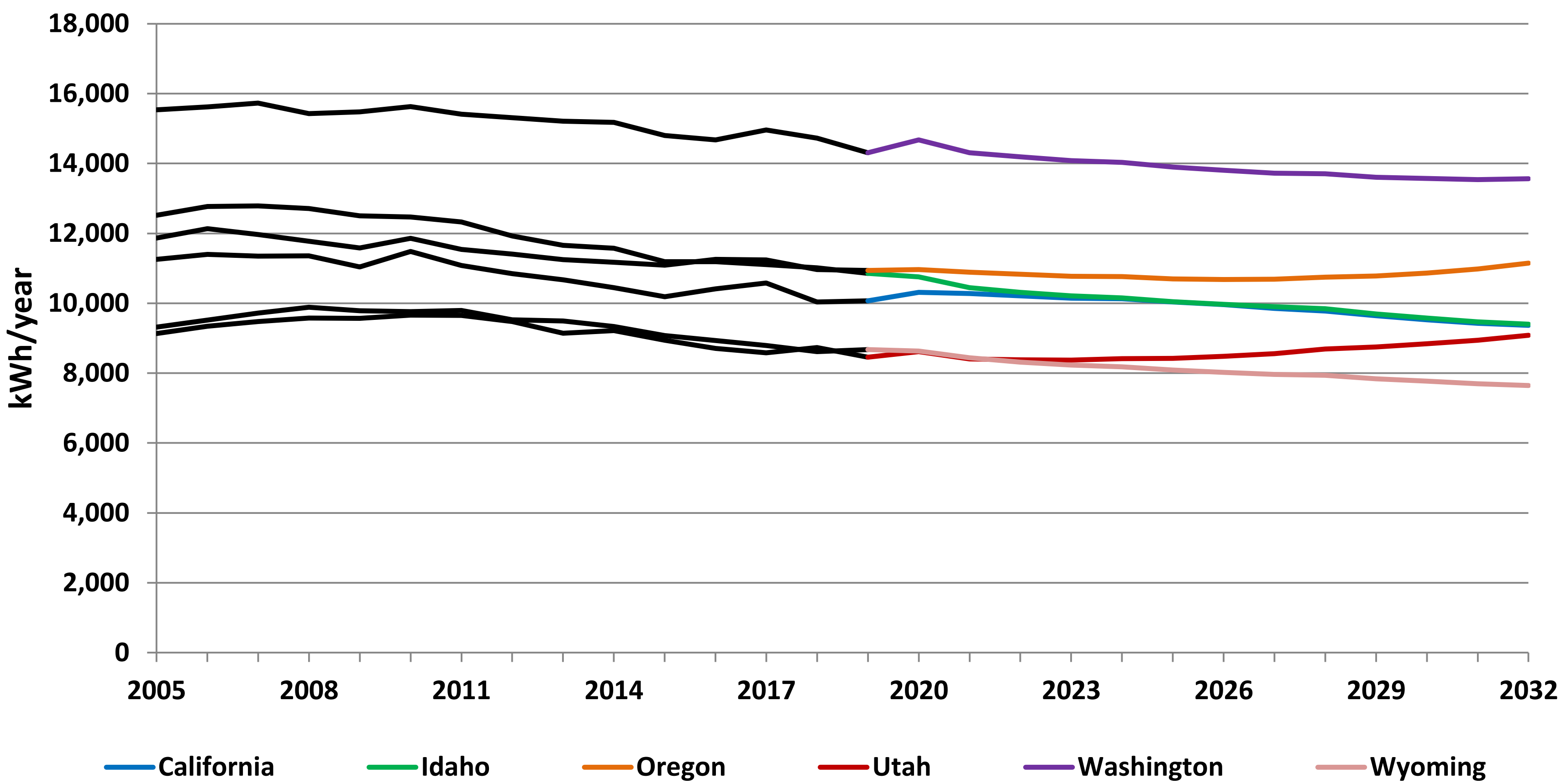
Forecast Drivers

- COVID-19 stay-at-home impacts having adverse impact on load forecast over the 2020 timeframe
- Longer-term COVID-19 impacts based on IHS Markit economic driver data released late-March 2020
- Wyoming industrial class forecast adjusted to account for recent commodity price shocks
- Rollback of Phase 2 of the Energy Independence and Security Act (originally slated to take effect January 2020) results in increase to load forecast
- Electric-vehicle adoption and building electrification is expected to increase. The Company has incorporated forecasts for electric vehicles in all states and building electrification in Utah

2019 Residential Survey

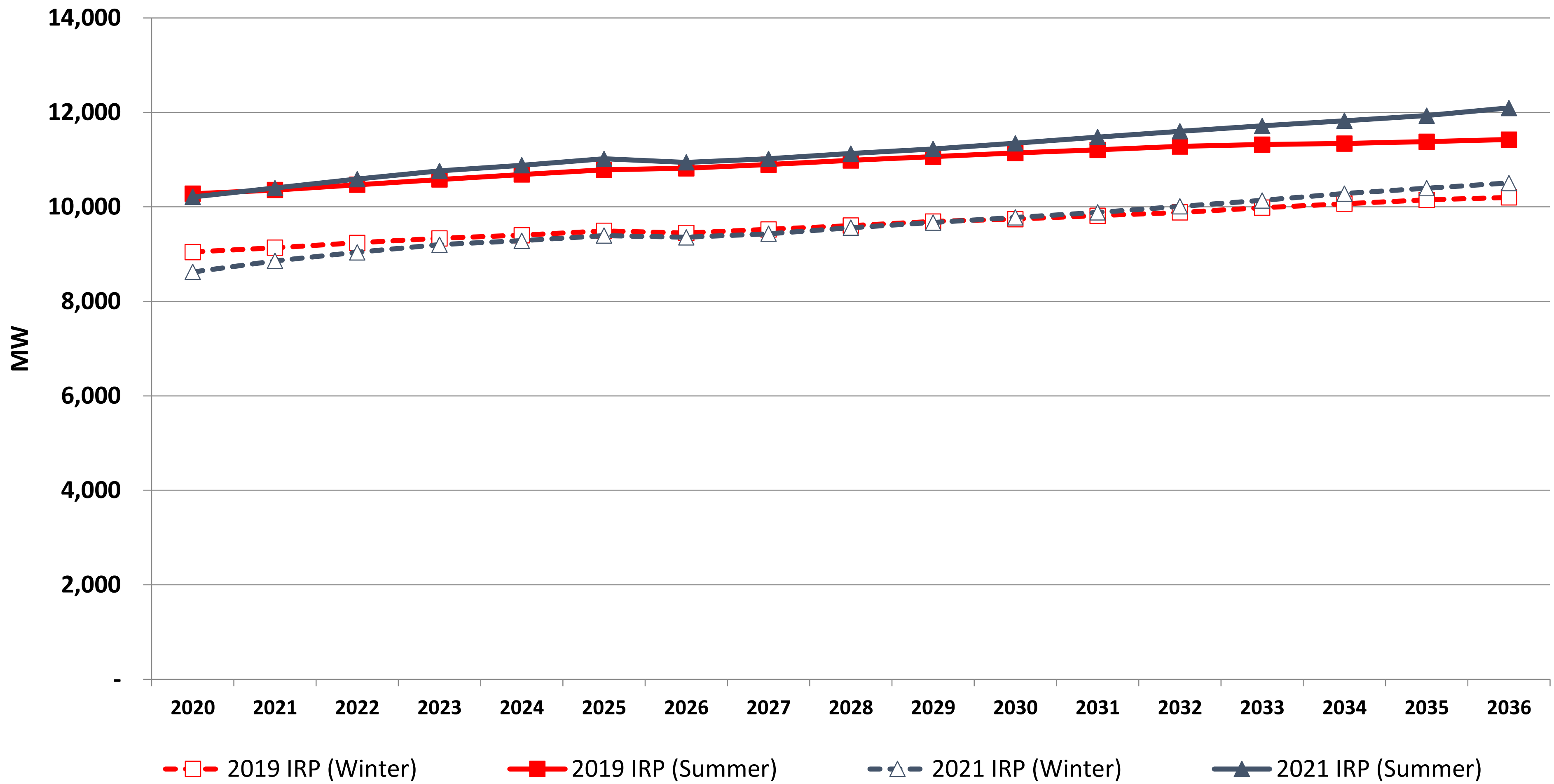
- In Oregon, Idaho and Wyoming, the saturation of central AC and heat pumps for cooling continues to increase relative to the saturations observed in prior surveys. In Washington, California and Utah, the saturation has held relatively steady since 2017
- 2.0 percent of customers report having electric vehicles, of which approximately 42% also had roof-top solar
- 0.7 percent of customers report having in-door agriculture equipment

Weather Normalized Average Use per Residential Customer



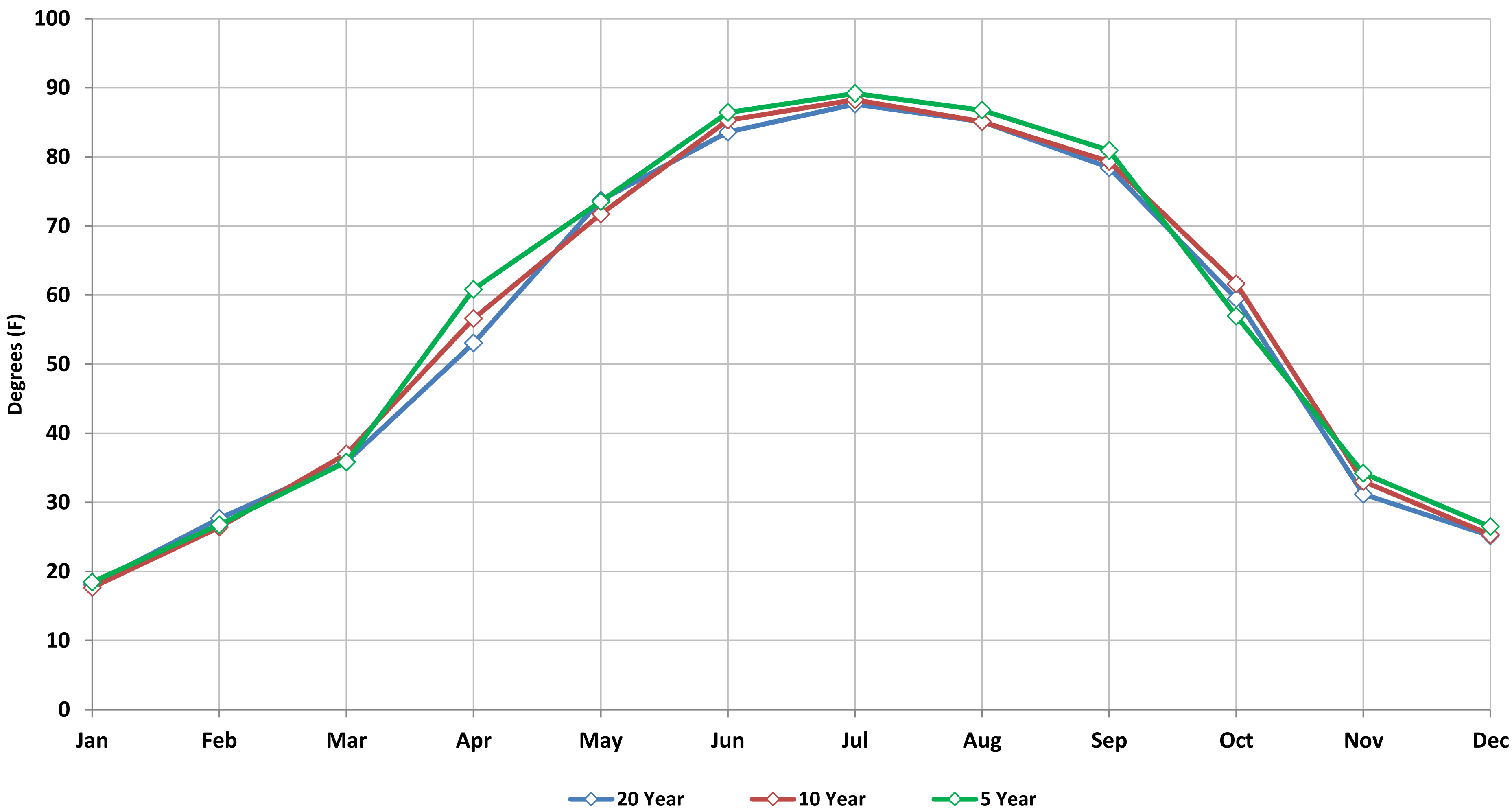
Source: PacifiCorp, Load Forecasting Group work product

Winter and Summer System Peak Load Forecast



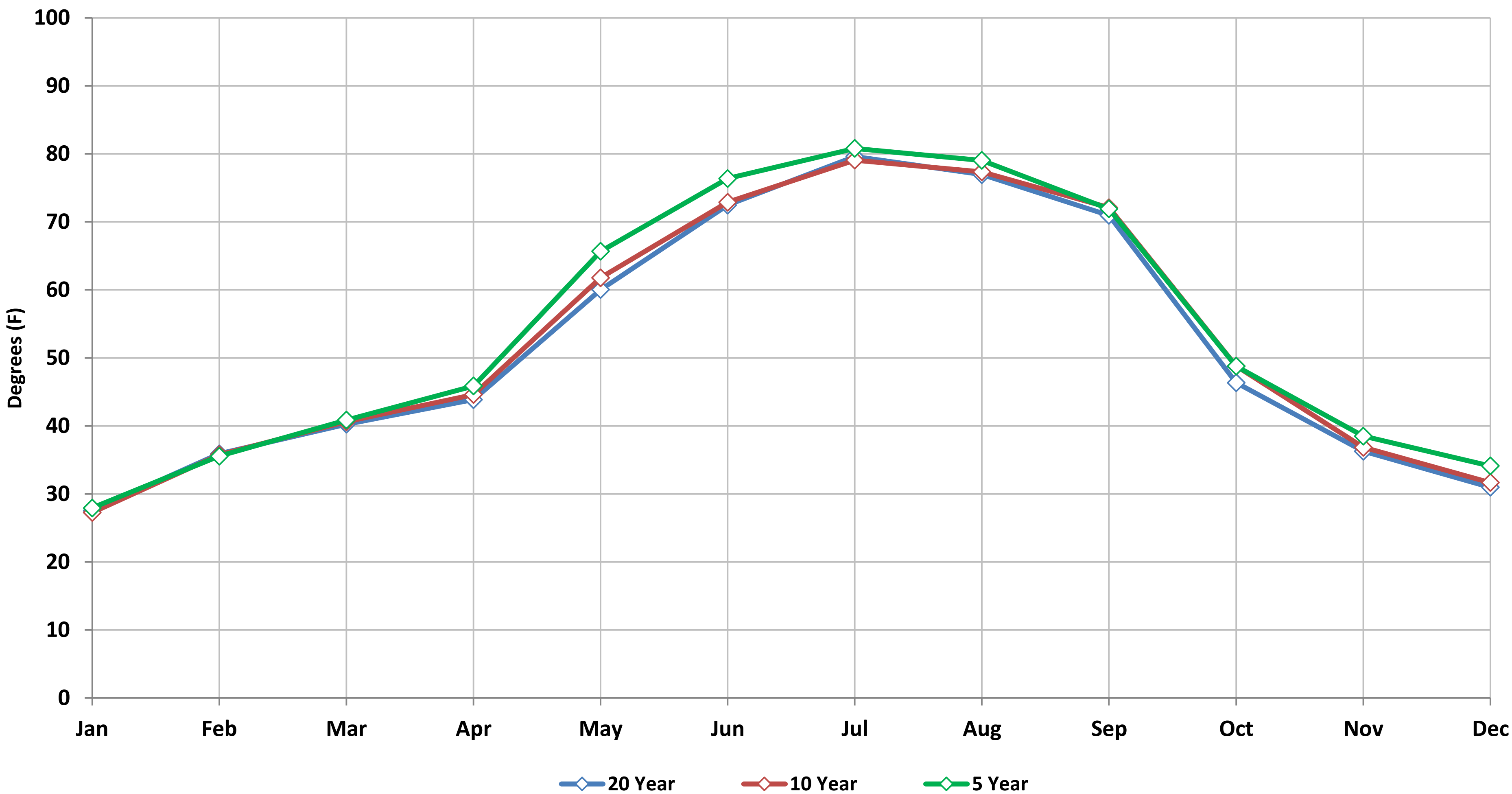
Source: PacifiCorp, Load Forecasting Group work product

Utah Peak Producing Weather



Source: Radiant Solutions, Salt Lake City Airport Weather Station

Oregon Peak Producing Weather



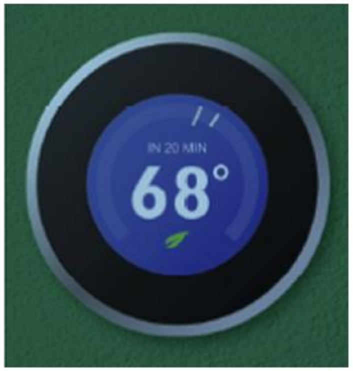
Source: Radiant Solutions, weighted average for Medford Airport, Portland Airport, Salem Airport, Klamath Falls Airport, Redmond Airport, North Bend Airport, and Astoria Airport Weather Stations

Load Forecast 2021 IRP Sensitivities

- 2021 IRP load forecast sensitivities:
  - 1-in-20 year (5 percent probability) extreme peak producing weather scenario
  - High and low load scenarios
    - High and low economic growth
    - 95% confidence intervals
  - High and low private generation

Distribution System Planning Processes

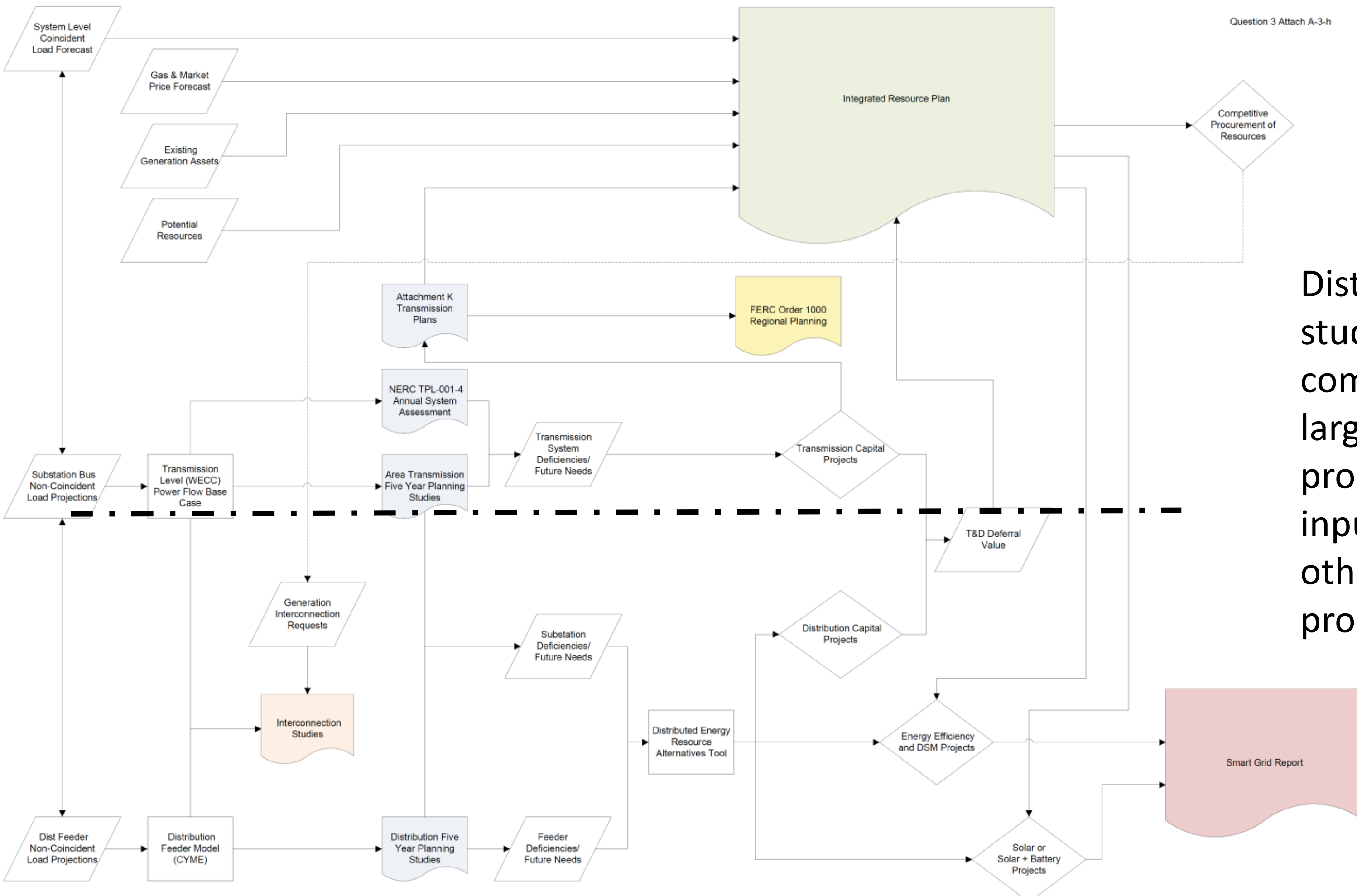


PacifiCorp Planning Processes

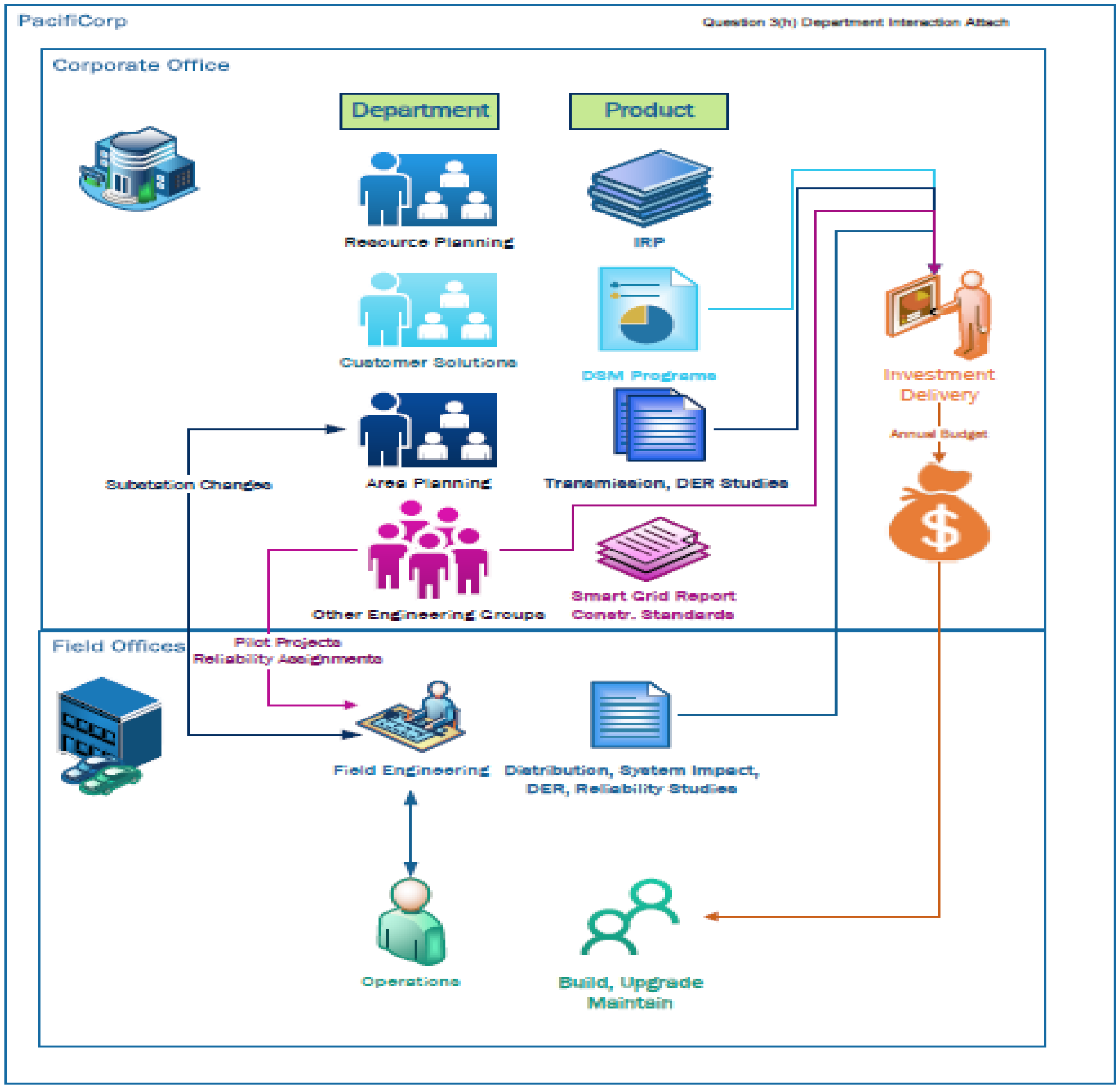
- Integrated Resource Plan
- NERC TPL-001-4 Annual System Assessment
- Local Area Transmission and Subtransmission Five Year Studies
- Distribution Studies
- Generation Interconnection Requests
- Transmission Service Requests

Multiple Planning Processes / Drivers



Distribution system studies are a component of the larger planning process, providing input into many other studies and processes

Department Interaction Diagraph



Planning Processes and Study Horizons

- Area planning and distribution five year studies
    - Evaluate limiting conditions on equipment (e.g., transformers, regulators, reclosers, wires)
    - Seasonal peak and minimum load conditions, 20% exceedance
    - Limiting credible distributed generation dispatch cases
    - 5 / 10 year horizon
- Long term resource planning (IRP, etc.)
    - Average system peak loads, 50% exceedance
    - Ensure ability to meet adequacy requirements in all hours, not just credible extremes
    - 20 year horizon
- Transmission level studies (NERC TPL, FERC Order 1000)
    - Meet specific system performance criteria for peak and credible stressed conditions
    - Bulk power transmission across larger areas
    - 1, 5 and 10 year horizon

Distribution Planning Studies

- Periodic Five Year Planning Studies
  - All distribution system planning studies are completed on a 5 year cycle. Studies can vary in frequency class from one to five
    - Class 1 studies are scheduled to be updated each year
    - Class 5 studies are scheduled to be updated every five years
  - Study schedules are evaluated each year and studies may be shifted to occur sooner or later depending on a number of factors
- Ad-hoc Studies
  - Typically driven by load, generation interconnection service or transmission service requests
  - Study is generally focused on a limited area, and the immediate effects of the request on reliability and load service

Distribution Plan Underlying Drivers

- Net load changes
  - Constantly changing loads from customer driven needs such as adding a operational shift, major renovations, closures, new load requests or generation
  - Planning for the future customer needs and preferences
  - Feeder and substation seasonal peak loads and growth rates
  - Feeder and substation minimum and daylight minimum loads
  - Anticipated block load additions (short term and high probability)
  - Electric vehicle adoption targeted studies
  - Generation scenarios (high and low output)
- Reliability
  - Outage Data Collection for Reliability Analysis
  - Cost Effective Improvements
- Distribution resources
  - Generation interconnection requests
  - Net metering requests
  - Demand side management
- Preparing the grid for the future
  - Substation and feeder SCADA analog and status capability upgrades
  - Bi-directional controls and protection

As the uses of the delivery system changes the number of credible scenarios rapidly expand. For example, light loading conditions.

Distributed Energy Resource Planning Studies and Tools

Studies	Tools

• Conservation Potential Assessment (CPA)
  • Energy Efficiency
  • Demand Response
• Private Generation
  • Reciprocating Engines
  • Micro-turbines
  • Small Hydro
  • Solar Photovoltaics
  • Small Wind
• Bulk Energy Storage Study
	• Transmission
	  • Production cost model (GRIDVIEW)
	  • Power flow model (PSS/E)
	  • SCADA / PI Historian
	  • ASPEN
	• Distribution
	  • Power flow model (CYME)
	  • CYME Gateway (Data)
	  • FAAR/Fastmap
	  • Reliability model (GREATER, FIRE)
	  • SCADA / PI Historian
	  • DER Screening tool
	  • ASPEN
	• Customer
	  • Production/load resource meters
	  • AMI meters

Distribution Projects and Typical Timelines

Distribution Feeder & Substation Capacity Increases

- Typically short time horizon both for specific localized planning (small changes in local load significantly impact need and timing) and project implementation
- Solutions range from distribution feeder transfers to:
    - upgrade existing distribution feeders to adding new feeders.
    - replacing existing transformers to constructing new distribution substations

Distribution Feeder High Level Project Timelines

- Feeder transfers: 3-18 months
- Upgrade existing feeders: 6-18 months
- New feeders: 6-24 months

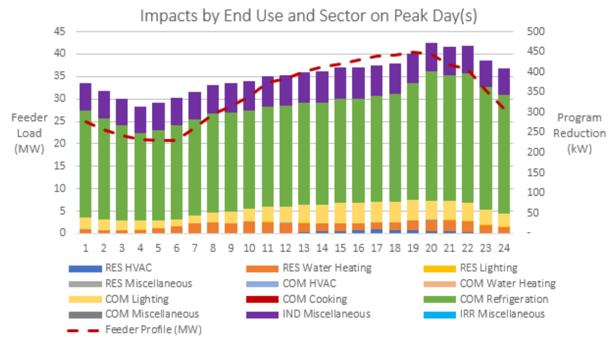
Distribution Substation High Level Project Timelines

- Feeder transfers: 6-18 months
- Transformer replacements: 12-24 months
- Substation rebuild/expansion: 18-30 months
- New substations: 18-60 months

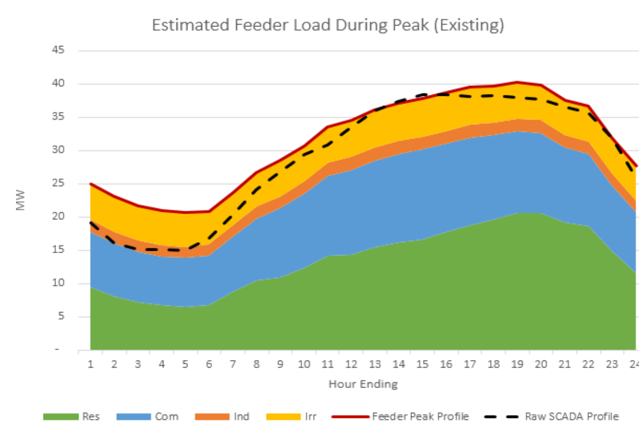
DER Impact Tool

- Evaluation Process
  - Review all capitals projects for DER: demand response, solar, and storage alternatives.
  - Step 1: Screening criteria
    - Estimated capital cost ≥ $1 M
    - 3 – 5 years out
    - Within 25% of traditional project costs
    - Must meet capacity reductions at time of need
  - Step 2: Conduct further review of sites that meet above screening criteria
    - Determine feasibility of location and customer mix
    - Determine appropriateness of reduction shape
- Integration of Data
  - GREATER
  - Customer Billing Data
  - Load Forecast
  - Load Research
  - EE End-use Loadshapes
  - Feeder Loadshapes
  - Energy efficiency

	Start	End
Years of Interest:	2016	2019



Load Composition



Sector	Usage (MWh)	Feeder Peak (MW)	Customers
	Feeder/Substation/System Load		
Residential	95,586	18.2	6,301
Commercial	78,610	13.1	461
Industrial	16,233	1.9	438
Irrigation	20,113	5.7	428
Total	**210,542**	**38.9**	**7,628**

Grid Modernization Projects

The development of an objective grid modernization road map must consider the economic value of individual components, technology maturity, and system interdependencies.

Planned smart grid projects are listed at right.

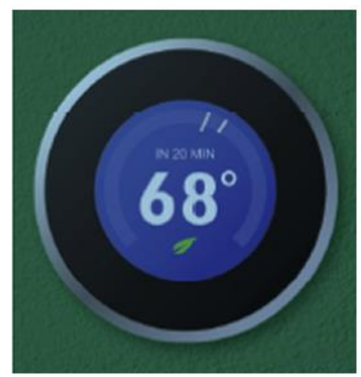
In addition, smart grid technologies expected to be leveraged by the implementation of Advanced Metering Infrastructure (AMI), such as data analytics, outage management and distribution automation (DA) are planned.

- Replacing Equipment (transformers, circuit breakers/reclosers, disconnect switches)
- Distribution Highlights
  - AMI
  - Distribution Substation Metering
  - Automation
  - Fuse Saver
  - Reclosers
  - Line Scopes
  - Fault Detection, Isolation Recovery
  - Communicating Fault Indicators
  - CYME software
  - PDX-Low Voltage Secondary Network
  - Targeted Communities Pilot

Distribution Planning Evolution

- In recent years, DSP has begun to incorporate more dynamic and holistic view to inputs and outputs from the following:
  - DER
  - EV
  - Customer preferences
  - Policy and opportunity driven trends
  - Integration with neighborhood/community/city plans and goals
- Improved planning models, information and assumptions
  - DER Screening Tool → DER Impact Tool (Locational Planning)
- Improved system operation and flexibility
- Modernization of the energy grid / increased deployment of advanced technologies
- Customer side solutions
- More efficient utilization of existing system capacity

Supply-Side Resource Study Efforts



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Supply-Side Resource Table

- Selection/catalog of commercially available competitive generating resources
- Includes performance, operating characteristics, emissions, and costs: capital, AFUDC, property and sales taxes
- Resources included in the 2021 IRP:
  - Solar (and combined solar + energy storage)
  - Wind (and combined wind + energy storage)
  - Energy Storage (batteries, pumped hydro, CAES, gravity systems)
  - Gas turbines
  - Nuclear (small modular reactors)
- Common resource characteristics:
  - Costs expressed in mid-2020 dollars
  - Construction cost based on turn-key, EPC contract
  - Capital includes Owner’s direct costs
  - Equipment costs and performance by equipment vendors
  - Facility construction costs and performance by third party consultant
  - Includes property and sales taxes
  - Owner’s costs and capitalization by PacifiCorp

Renewables

- Similar to the last IRP cycle, a single RFP has been released to study the following renewable resources in support of the IRP:
  - Solar
  - Wind
  - Energy Storage
  - Solar + Energy Storage
  - Wind + Energy Storage

- The report will include
  - Current capital and O&M costs
  - 10 year forecast trend of expected capital costs
  - Decommissioning concerns and costs if available
  - Performance data

Renewables - Energy Storage

- Project sizes:
  - Pumped Hydro: Actual projects within the PacifiCorp transmission area ranging from 300 to 750 MW, with 4 to 10 hour durations.
  - Adiabatic Compressed Air Energy Storage (CAES): 150, 300 and 500 MW options with 4, 8 and 12 hour duration options.
  - Lithium Ion: 1 MW with 30 minute, 1, 4 and 8 hour duration options & 50 MW with 4 hour duration
  - Flow Battery: 1 MW with 1, 4 and 8 hour duration options & 20 MW with 8 hour duration

- “New” Technology Discussed in The Report
  - Liquid Air Energy Storage (LAES)
  - Gravity Energy Storage: Vertical Shaft, Crane Lift

Renewables – Solar & Solar + Energy Storage

- Solar Project sizes:
  - 100 MW AC
  - 200 MW AC

- Proxy locations:
  - Milford, UT
  - Lakeview, OR
  - Additional locations are being considered

- Solar + Energy Storage Project sizes:
  - Solar: same as above
  - Energy storage:
    - 4 hours at 50% nominal power of the solar plant

Renewables – Wind & Wind + Energy Storage

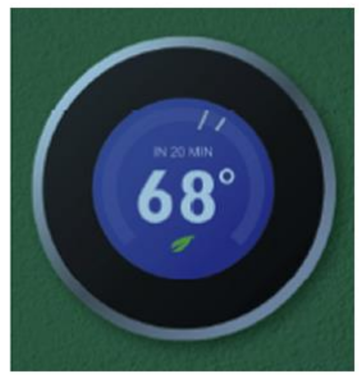
- Wind Project size:
  - 200 M
- Proxy locations:
  - Arlington, OR - (Class 2 A wind regime)
  - Goldendale, WA - (Class 2 A wind regime)
  - Pocatello, ID - (Class 2 A wind regime)
  - Monticello, UT - (Class 2 A wind regime)
  - Medicine Bow, WY - (Class 1 B wind regime)
- Wind + Energy Storage Project sizes:
  - Wind: same as above
  - Energy storage: 4 hours at 50% power

Natural Gas

- Resources
  - Combined Cycle Combustion Turbine
    - G/H, 1X1 w/ duct firing – approx. 390 MW at 5,050 feet elev.
    - G/H, 2X1 w/ duct firing – approx. 780 MW at 5,050 feet elev.
    - J/HA, 1X1 w/ duct firing – approx. 480 MW at 5,050 feet elev.
    - J/HA, 2X1 w/ duct firing – approx. 950 MW at 5,050 feet elev.
  - Simple Cycle
    - Aeroderivative SCCT 3X0 – approx. 110 MW at 5,050 feet elev.
    - Intercooled Aero. SCCT 2X0 – approx. 170 MW at 5,050 feet elev.
    - F Frame SCCT 1X0 – approx. 190 MW at 5,050 feet elev.
    - Reciprocating 6X0 – approx. 110 MW
  - Elevations studied
    - Sea level, 1,500 ft, 3,000 ft, 5,050 ft, 6,500 ft

2021 IRP Modeling Assumptions and Study Updates



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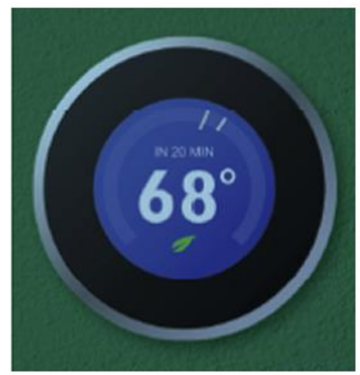
2021 IRP Modeling Assumptions and Study Updates Agenda

- Planning Reserve Margin
- Capacity Contribution Studies
- Stochastic Parameters Update
- Intra-Hour Dispatch Credit

Planning Reserve Margin (PRM)



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What is Reliability?

- Perfectly reliability would result in all load being served and all operating reserve requirements being met in every hour.
- If requirements can't be met, firm load would need to be curtailed and a loss of load event would occur. The more load that is lost, the lower the reliability.
- Loss of load events can be measured in terms of magnitude, frequency, and duration:
  - **Expected Unserved Energy ("EUE")**: Measured in gigawatt-hours ("GWh"), EUE reports the expected (mean) amount of load that exceeds available resources over the course of a given year. EUE measures the magnitude of reliability events.
  - **Loss of Load Hours ("LOLH")**: LOLH is a count of the expected (mean) number of hours in which load exceeds available resources over the course of a given year. A LOLH of 2.4 hours per year equates to one day in 10 years, a common reliability target in the industry. LOLH measures the duration of reliability events.
  - **Loss of Load Events ("LOLE")**: LOLE is a count of the expected (mean) number of reliability events over the course of a given year. An LOLE of 0.1 events per year equates to one event in 10 years, a common reliability target in the industry. LOLE measures the frequency of reliability events.
- None of these is the "right" measure – together they provide a more complete picture of system reliability.

Planning Reserve Margin

- The planning reserve margin (PRM) is a percentage of coincident system peak load used in resource planning to meet a desired level of reliability.
- PRM covers both near-term and long-term uncertainties, but the uncertainties covered depend on how load and resource capacity contribution are measured.
  - Contingency reserves for load (+3%) and for resources to serve load (+3%)
  - Outages on traditional resources (thermal/hydro/baseload):
    - Higher PRM — Capacity contribution = nameplate: PRM covers <u>all</u> outages
    - Lower PRM — Cap. contrib. = Unforced Capacity (UCAP) = nameplate * (1 – outage rate): PRM covers <u>above average</u> outage conditions
  - Changes in customer load, if PRM measured on:
    - Higher PRM — 1 in 2 year peak: PRM covers above average peak load conditions
    - Lower PRM — 1 in 10 year peak: PRM covers load in excess of 1 in 10 year peak
  - Regulating reserves:
    - Higher PRM — If not included in the capacity contribution of renewable resources (higher renewable contribution), then PRM must cover regulating reserves.
    - Lower PRM — If included in the capacity contribution of renewable resources (lower renewable contribution), then PRM does not cover regulating reserves.
- These assumptions can result in varying PRM values <u>with the same reliability</u>.

2019 IRP PRM Analysis

In the SO model, the PRM determines how much capacity (and by extension, resources) must be added, based on the capacity contribution of the available resource options.

- Each resource has two capacity values (summer/winter) – SO views a MW of summer capacity as interchangeable with any other MW in a location.

The 2019 IRP PRM target of 13% was selected as follows:

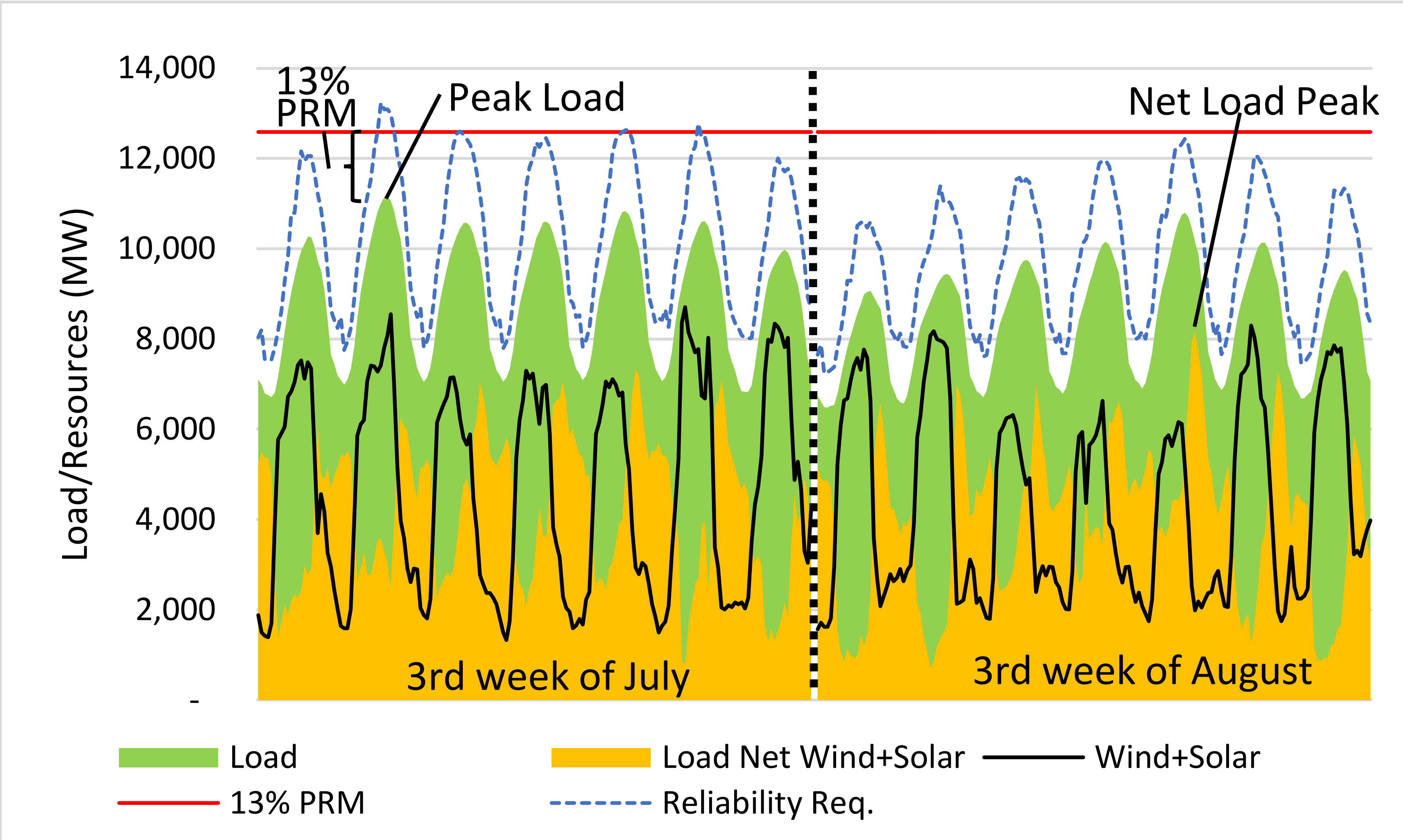
- SO model selects optimized resource portfolios at PRM ranging from 11% to 18% above 1-in-2 coincidental peak load (in summer and winter)
- PaR evaluates portfolio cost and reliability under stochastic conditions for portfolios corresponding to each PRM:
  - Stochastic parameters are load, hydro conditions, thermal outages, and prices.
  - 50-iteration stochastic production cost modeling
  - 500-iteration stochastic reliability modeling

As PRM increases, loss of load events decline and costs increase. The lowest PRM that provides a reasonable level of reliability is selected.

BUT, PRM in the SO model is only as accurate as the capacity contribution inputs.

- PacifiCorp identified declining capacity contribution with increasing wind and solar penetration. But, as part of a diverse portfolio, wind, solar, and batteries can have a higher effective contribution than those resources would have been assumed to achieve on their own.
- To compensate for variations among portfolios, the Reliability Assessment process in the 2019 IRP helped ensure all portfolios met minimum levels of reliability.

2019 IRP Peak Requirements



- Reliability Assessment compared hourly resources and requirements.
- High renewable penetration changes the timing of PacifiCorp's peak resource needs.
- Uncertainty in renewable output drives the net load peak.

2021 IRP PRM Analysis

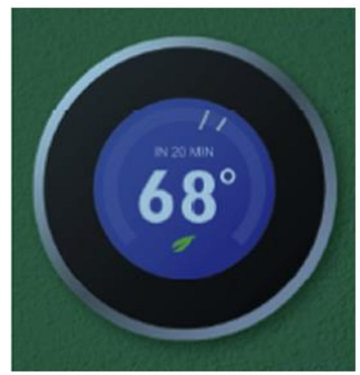
In the Plexos model, capacity contribution can be represented on an hourly level.

- Portfolios can be built to meet a reliability metric directly, rather than to a proxy measure such as PRM.
- Instead of just summer and winter values, a resource could effectively have up to 8760 capacity contribution values in a year, calculated within the model, endogenously replicating PacifiCorp's Reliability Assessment in the 2019 IRP.
- Plexos can identify resources, and combinations of resources, that best align with the periods with loss of load risk.
- Practical limits on granularity and reliability metrics are pending further analysis.

While no longer required model inputs, PRM and capacity contribution provide a measure of the resources available to cover uncertainty and aid in the interpretation of the results.

- PacifiCorp proposes to measure PRM based on 1-in-2 coincident peak loads.
  - PRM will cover contingency reserves: up to 6%
  - PRM will cover load uncertainty: above 1-in-2 conditions
- Where possible, resource-specific uncertainty should be assigned to specific resources.
  - Traditional resource capacity contribution will use the UCAP methodology
  - Renewable resource uncertainty needs to be revisited: regulation reserve requirements only cover uncertainty from hour-ahead forecasts.

Capacity Contribution Studies



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Capacity Contribution

- Capacity contribution indicates how much a resource contributes to reliable operation.

- **First-in Contribution** measures a resource relative to peak load requirements, as if the rest of the portfolio was composed of pure capacity resources, with assumed uniform availability in every hour.
- **Last-in Contribution** measures a resource relative to requirements after accounting for the contributions of all other portfolio resources.
  - This represents the marginal contribution for portfolio additions or removals.
  - PacifiCorp's past IRP's have used marginal capacity contribution values for portfolio development.
  - A marginal capacity contribution value is only accurate to the extent the underlying portfolio is reasonably similar.
- **Portfolio Contribution** represents the total or average capacity of all of the components in a portfolio.
  - This will be in between the first-in and last-in value, but it is not the average of the two
  - Attributing inter-related contributions to individual resource types is somewhat arbitrary, as the order of the analysis matters.

Capacity Contribution – Resource Effects

- Some resource's capacity contributions are independent of the portfolio:
  - **Baseload**: a resource with a 5% outage rate will average 95% availability in every hour, regardless of any other resource availability.

- Lots of resource types have availability that is linked to other portfolio resources:
  - **Hydro**: dry hydro conditions impact many hydro resources simultaneously.
  - **Solar**: covers a limited portion of the day, so they are highly correlated. Solar also has weather-related uncertainty that can impact regional output.
  - **Wind**: significant regional correlation and large day-to-day variation (windy days vs. calm days).
  - **Energy storage**: availability is duration-limited. Ability to cover long events diminishes as more are added.

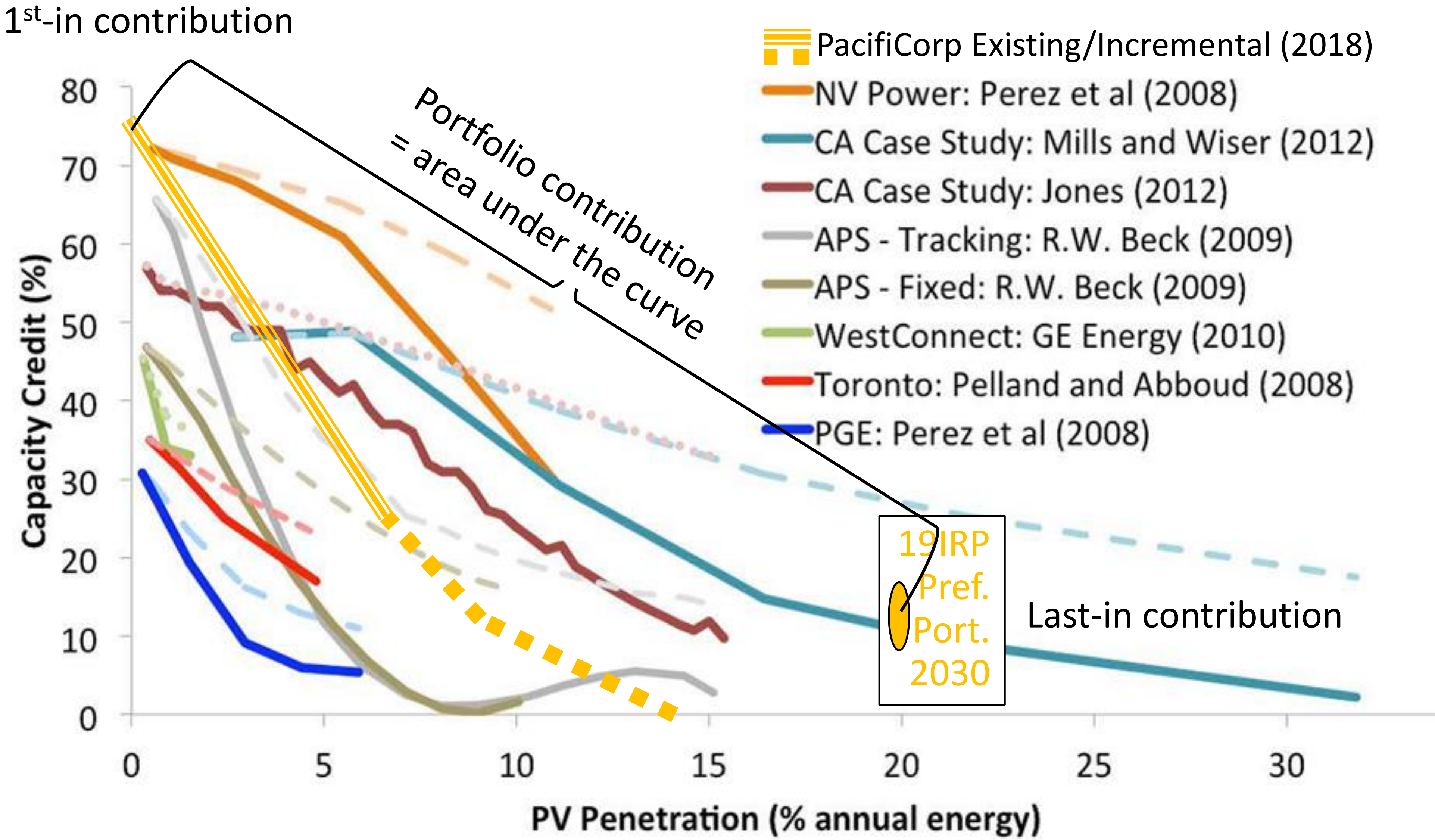
- Each incremental addition of a single resource type with correlated availability will have a lower capacity contribution.

- Combinations of correlated resource types may result in either higher or lower effective contributions.

2019 IRP Capacity Contribution

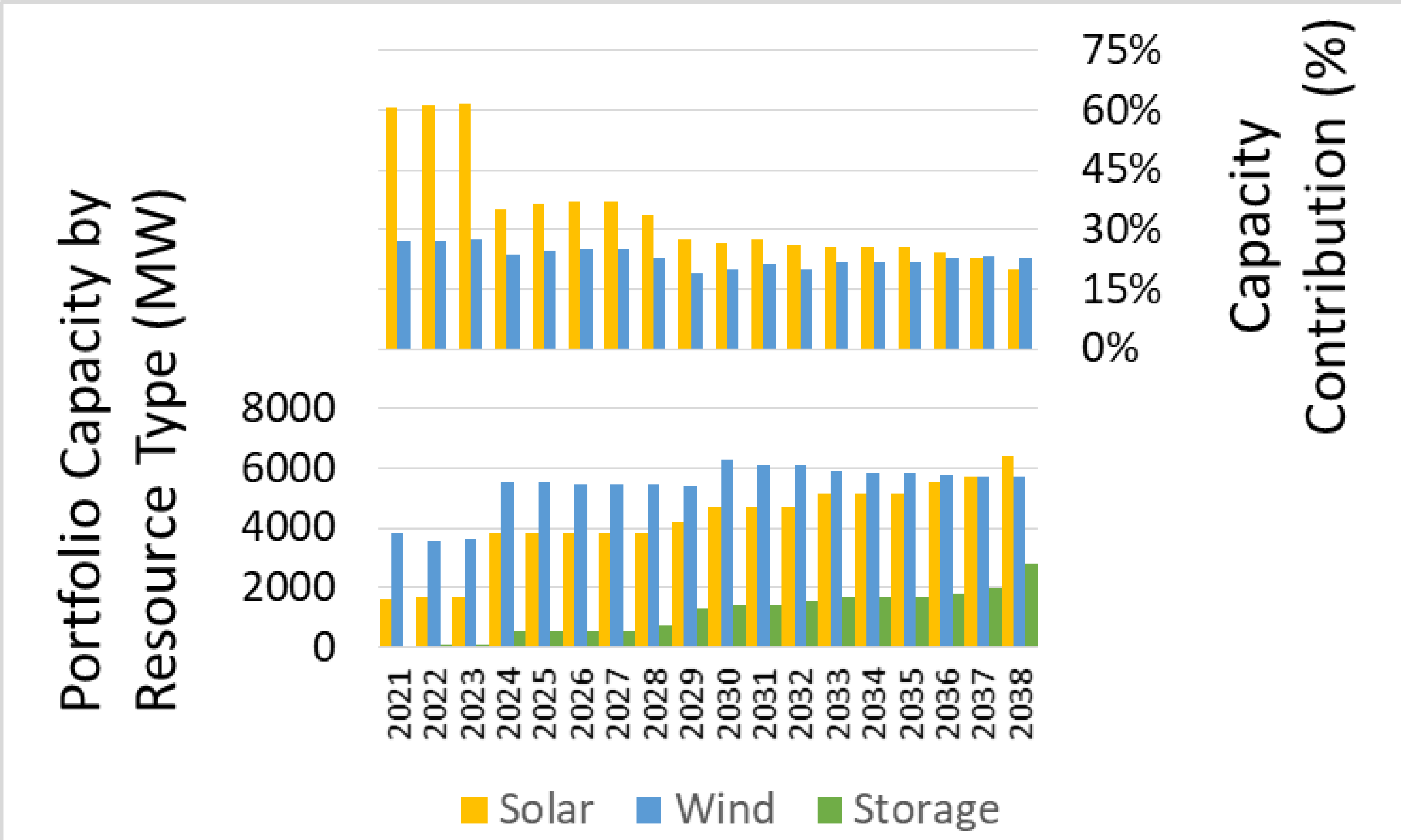
- PacifiCorp prepared capacity contribution values at the start of the 2019 IRP.
- Capacity contributions for wind and solar were designed to step down as capacity increased.
- During portfolio analysis, PacifiCorp found that portfolios with equivalent assumed capacity contributions were not resulting in comparable levels of reliability.
- A Reliability Assessment was implemented to ensure portfolios achieved equivalent reliability.
- The Reliability Assessment doesn't identify the capacity contribution of specific resources, and compensates for shortfalls by drawing from a limited resource pool selected to not exacerbate portfolio-related impacts.
    - No extra wind or solar could be added to address shortfalls.
- At the end of the 2019 IRP, PacifiCorp prepared updated capacity contribution values reflecting a near-final portfolio. Values indicate synergistic effects, likely related to interactions between energy storage, solar, and wind.

Comparison of Solar Capacity Contribution Studies



Non-PacifiCorp source: Mills, Andrew, and Ryan Wiser. 2012. "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes." LBNL-5933E, Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory.

2019 IRP Portfolio Contribution



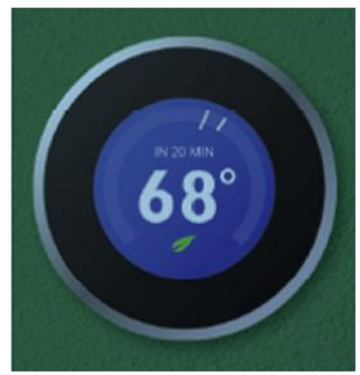
- Estimated contribution of solar declines as more is added.
- Interactions with wind and energy storage are complex. Regional diversity also likely plays a role.

2021 IRP Capacity Contribution

- Plan is to allow Plexos to address capacity and reliability endogenously, based on resource characteristics, rather than assigned capacity contribution value.
- An earlier slide showed studies of capacity contribution for solar as a function of a single variable (solar capacity).
- Plexos should allow for a multi-variate solution, accounting for the contribution of solar as a function of the characteristics of all other resources (i.e. wind and storage).
- Thankfully, we do not need to identify that relationship to be able to model it.
- All else equal, capacity contributions for wind and solar will still step down as capacity increases.
- An additional Reliability Assessment process will no longer be necessary, as Plexos allows reliability to be a requirement, rather than a proxy-driven measured outcome.
- Plexos is not limited in the resource types that can be used to address shortfalls.

Stochastic Parameters Update



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Overview of Stochastic Parameters

- Stochastic parameters are used to generate stochastic processes on key long term planning variables such as load, fuels, etc., which evolve over time to create a spread of possible outcomes over a statistical distribution.

- Plexos modeling simulates mean reverting stochastic processes. It uses mean reversion, volatilities, and correlations across the key decision variables as input parameters. Under a mean reversion process, the distribution of possible outcomes would reach a steady state as time to delivery increases.

- Short term (S.T) parameters updated using historical PacifiCorp data:
  - Load: 1/1/2016 thru 12/31/2019 (4 years)
  - Hydro: 1/1/2015 thru 12/31/2019 (5 years)
  - Gas Prices: 1/1/2016 thru 12/31/2019 (4 years)
  - Power Prices: 1/1/2016 thru 12/31/2019 (4 years)

Short-Term Volatility Comparison

(2021 IRP vs 2019 IRP)

- Volatility is a measure of variation in time-series data that is observed over time.
- Positive change indicates increase in volatility vs 2019 IRP; negative change indicates decrease in volatility vs 2019 IRP.

2021 IRP S.T Volatility estimates

	CA	ID	Portland	OR Other	UT	WA	WY
Winter	4.75%	3.65%	3.84%	4.37%	2.25%	4.98%	1.59%
Spring	4.38%	6.37%	3.46%	3.65%	3.03%	3.86%	1.79%
Summer	3.82%	5.31%	5.48%	4.12%	4.75%	4.97%	1.68%
Fall	4.54%	4.19%	3.61%	4.01%	3.25%	4.05%	1.71%

	4C	COB	Mid-C	PV
Winter	13.22%	16.31%	19.81%	12.11%
Spring	17.19%	28.78%	63.03%	13.81%
Summer	21.99%	33.94%	25.97%	20.17%
Fall	17.41%	17.32%	16.00%	15.02%

	East Gas	West Gas
Winter	11.48%	16.65%
Spring	9.05%	20.30%
Summer	9.91%	13.06%
Fall	10.07%	17.14%

	Hydro
Winter	27.40%
Spring	18.91%
Summer	20.97%
Fall	29.81%

Change in S.T Volatility estimates from 2019 IRP to 2021 IRP

	CA	ID	Portland	OR Other	UT	WA	WY
Winter	0.10%	0.18%	-0.01%	0.14%	0.13%	-0.35%	-0.04%
Spring	0.19%	-0.11%	0.17%	0.22%	0.24%	0.18%	0.01%
Summer	0.00%	0.19%	0.49%	-0.07%	0.27%	-0.08%	0.07%
Fall	-0.40%	-0.04%	-0.25%	-0.18%	-0.30%	-0.26%	0.03%

	4C	COB	Mid-C	PV
Winter	3.38%	2.87%	3.26%	2.89%
Spring	6.79%	2.65%	15.56%	6.35%
Summer	6.52%	3.97%	4.69%	6.09%
Fall	7.28%	7.13%	5.65%	5.19%

	East Gas	West Gas
Winter	0.34%	4.65%
Spring	5.15%	14.23%
Summer	7.45%	8.19%
Fall	6.45%	12.76%

	Hydro
Winter	6.25%
Spring	2.73%
Summer	4.18%
Fall	-0.27%

Short-Term Mean Reversion Comparison

(2021 IRP vs 2019 IRP)

- Mean reversion represents the speed at which a disrupted variable will return to its mean.
- Positive change indicates increase in speed vs 2019 IRP; negative change indicates decrease in speed vs 2019 IRP.

2021 IRP S.T Mean Reversion estimates

	CA	ID	Portland	OR Other	UT	WA	WY
Winter	0.2083	0.1794	0.1573	0.1518	0.2782	0.1494	0.2262
Spring	0.1926	0.2712	0.2253	0.2492	0.5349	0.1787	0.2702
Summer	0.2231	0.1350	0.2578	0.1904	0.2955	0.1908	0.2236
Fall	0.2380	0.1841	0.2845	0.2941	0.2031	0.2256	0.2320

	4C	COB	Mid-C	PV
Winter	0.0886	0.0702	0.0897	0.0860
Spring	0.1803	0.2576	0.4614	0.1506
Summer	0.3119	0.3951	0.1959	0.1462
Fall	0.1974	0.1783	0.1196	0.1625

	East Gas	West Gas
Winter	0.0613	0.0309
Spring	0.1605	0.1396
Summer	0.5032	0.2872
Fall	0.0461	0.0223

	Hydro
Winter	0.7219
Spring	0.4326
Summer	1.1489
Fall	0.3683

Change in S.T Mean Reversion estimates from 2019 IRP to 2021 IRP

	CA	ID	Portland	OR Other	UT	WA	WY
Winter	-0.0596	0.0267	-0.0196	-0.0301	-0.0850	-0.0314	-0.0464
Spring	-0.0252	0.0669	-0.0154	-0.1299	-0.0601	-0.1620	0.0166
Summer	0.0378	0.0402	-0.0227	-0.0043	0.0823	0.0342	-0.0113
Fall	-0.0731	-0.0344	0.0430	0.0414	-0.0456	0.0225	-0.0346

	4C	COB	Mid-C	PV
Winter	-0.0367	-0.0493	-0.0500	-0.0236
Spring	-0.2535	-0.2935	-0.0895	-0.0603
Summer	-0.0259	-0.0681	-0.0750	-0.0738
Fall	-0.1730	-0.0782	-0.1591	-0.2528

	East Gas	West Gas
Winter	-0.0489	-0.0615
Spring	0.0087	-0.1257
Summer	0.4013	0.1826
Fall	-0.0247	-0.0849

	Hydro
Winter	0.0900
Spring	-0.0689
Summer	-0.3628
Fall	-0.4943

2021 IRP Short-Term Correlations

- Correlation represents a meaningful measure of strength and direction of a linear relationship between two variables.
- Plexos shocks (index mechanisms) are purely dedicated to deviations from the expected, i.e. the random portion of the key variables. Correlations are calculated from residual errors on the random portion (or deviations) of the key variables.
- Typically, variables may exhibit high correlations on deterministic or expected shapes of the variables. For example, hydro dispatch being shaped to load net renewables, or price formation being shaped by demand.
- However, the uncertainty portion of the key variables are low correlated. For example, deviations on hydro generation being dependent weather pattern (La Nina-El Nino), or deviations in renewable generation vs deviations in load being driven by different temperature abnormalities.

Short-Term Correlations – Winter

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	34%	41%	38%	32%	49%	10%	2%	17%	16%	17%	20%	3%	-1%
SUMAS	34%	100%	24%	30%	29%	25%	13%	13%	12%	12%	15%	19%	9%	-2%
4C	41%	24%	100%	62%	54%	79%	16%	-8%	17%	20%	23%	25%	5%	-3%
COB	38%	30%	62%	100%	76%	59%	17%	-5%	21%	25%	23%	33%	8%	4%
Mid-C	32%	29%	54%	76%	100%	56%	15%	0%	26%	32%	21%	36%	9%	6%
PV	49%	25%	79%	59%	56%	100%	13%	-8%	11%	15%	16%	19%	6%	-4%
CA	10%	13%	16%	17%	15%	13%	100%	12%	32%	70%	30%	35%	19%	2%
ID	2%	13%	-8%	-5%	0%	-8%	12%	100%	19%	20%	34%	29%	24%	-5%
Portland	17%	12%	17%	21%	26%	11%	32%	19%	100%	69%	43%	65%	23%	-6%
OR Other	16%	12%	20%	25%	32%	15%	70%	20%	69%	100%	44%	64%	20%	8%
UT	17%	15%	23%	23%	21%	16%	30%	34%	43%	44%	100%	45%	40%	-5%
WA	20%	19%	25%	33%	36%	19%	35%	29%	65%	64%	45%	100%	28%	13%
WY	3%	9%	5%	8%	9%	6%	19%	24%	23%	20%	40%	28%	100%	-3%
Hydro	-1%	-2%	-3%	4%	6%	-4%	2%	-5%	-6%	8%	-5%	13%	-3%	100%

Gas to Gas	Gas to Electric	Electric to Load
Electric to Electric	Gas to Load	Electric to Hydro
Load to Load	Gas to Hydro	Load to Hydro
Hydro to Hydro		

- Deviation events which impact one part of PacifiCorp's system do not necessarily affect other parts of the system, due to its geographic diversity and transmission constraints.
- The correlation between these different deviations can be low if the deviations are caused by different drivers.

Short-Term Correlations – Spring

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	56%	20%	14%	10%	22%	7%	7%	13%	14%	12%	13%	9%	1%
SUMAS	56%	100%	19%	21%	17%	10%	1%	6%	12%	13%	10%	17%	8%	-6%
4C	20%	19%	100%	34%	42%	63%	8%	11%	27%	21%	22%	23%	18%	1%
COB	14%	21%	34%	100%	64%	33%	14%	1%	28%	24%	13%	31%	14%	9%
Mid-C	10%	17%	42%	64%	100%	28%	12%	3%	21%	15%	8%	27%	11%	8%
PV	22%	10%	63%	33%	28%	100%	10%	13%	21%	17%	24%	23%	16%	-1%
CA	7%	1%	8%	14%	12%	10%	100%	16%	35%	68%	24%	40%	12%	-7%
ID	7%	6%	11%	1%	3%	13%	16%	100%	6%	17%	46%	20%	20%	-18%
Portland	13%	12%	27%	28%	21%	21%	35%	6%	100%	69%	19%	60%	25%	1%
OR Other	14%	13%	21%	24%	15%	17%	68%	17%	69%	100%	30%	67%	23%	-3%
UT	12%	10%	22%	13%	8%	24%	24%	46%	19%	30%	100%	21%	32%	-22%
WA	13%	17%	23%	31%	27%	23%	40%	20%	60%	67%	21%	100%	22%	0%
WY	9%	8%	18%	14%	11%	16%	12%	20%	25%	23%	32%	22%	100%	-17%
Hydro	1%	-6%	1%	9%	8%	-1%	-7%	-18%	1%	-3%	-22%	0%	-17%	100%

Gas to Gas
Electric to Electric
Load to Load
Hydro to Hydro

Gas to Electric
Gas to Load
Gas to Hydro

Electric to Load
Electric to Hydro
Load to Hydro

- Deviation events which impact one part of PacifiCorp's system do not necessarily affect other parts of the system, due to its geographic diversity and transmission constraints.
- The correlation between these different deviations can be low if the deviations are caused by different drivers.

Short-Term Correlations – Summer

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	67%	7%	16%	12%	6%	-2%	1%	5%	4%	0%	9%	0%	0%
SUMAS	67%	100%	4%	10%	8%	0%	-12%	-4%	2%	-3%	-3%	2%	-1%	3%
4C	7%	4%	100%	22%	23%	44%	25%	13%	23%	28%	29%	23%	17%	-8%
COB	16%	10%	22%	100%	80%	45%	14%	7%	37%	31%	10%	27%	6%	5%
Mid-C	12%	8%	23%	80%	100%	54%	21%	8%	48%	41%	12%	30%	2%	1%
PV	6%	0%	44%	45%	54%	100%	27%	16%	34%	33%	27%	26%	16%	0%
CA	-2%	-12%	25%	14%	21%	27%	100%	44%	37%	66%	35%	52%	18%	-9%
ID	1%	-4%	13%	7%	8%	16%	44%	100%	13%	27%	51%	22%	24%	-10%
Portland	5%	2%	23%	37%	48%	34%	37%	13%	100%	79%	10%	62%	-1%	8%
OR Other	4%	-3%	28%	31%	41%	33%	66%	27%	79%	100%	21%	80%	8%	2%
UT	0%	-3%	29%	10%	12%	27%	35%	51%	10%	21%	100%	22%	48%	-15%
WA	9%	2%	23%	27%	30%	26%	52%	22%	62%	80%	22%	100%	5%	-1%
WY	0%	-1%	17%	6%	2%	16%	18%	24%	-1%	8%	48%	5%	100%	-12%
Hydro	0%	3%	-8%	5%	1%	0%	-9%	-10%	8%	2%	-15%	-1%	-12%	100%

Gas to Gas	Gas to Electric	Electric to Load
Electric to Electric	Gas to Load	Electric to Hydro
Load to Load	Gas to Hydro	Load to Hydro
Hydro to Hydro		

- Deviation events which impact one part of PacifiCorp's system do not necessarily affect other parts of the system, due to its geographic diversity and transmission constraints.
- The correlation between these different deviations can be low if the deviations are caused by different drivers.

Short-Term Correlations – Fall

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	36%	21%	25%	23%	17%	19%	3%	7%	18%	7%	11%	6%	-11%
SUMAS	36%	100%	13%	20%	23%	16%	16%	-4%	10%	17%	5%	6%	6%	-13%
4C	21%	13%	100%	29%	28%	61%	14%	5%	16%	12%	23%	13%	7%	-6%
COB	25%	20%	29%	100%	60%	40%	21%	3%	26%	24%	19%	23%	13%	-13%
Mid-C	23%	23%	28%	60%	100%	43%	22%	6%	29%	30%	18%	29%	9%	-7%
PV	17%	16%	61%	40%	43%	100%	10%	5%	17%	8%	18%	10%	10%	0%
CA	19%	16%	14%	21%	22%	10%	100%	26%	56%	80%	38%	64%	31%	-4%
ID	3%	-4%	5%	3%	6%	5%	26%	100%	18%	20%	39%	21%	28%	-12%
Portland	7%	10%	16%	26%	29%	17%	56%	18%	100%	80%	46%	71%	35%	4%
OR Other	18%	17%	12%	24%	30%	8%	80%	20%	80%	100%	46%	81%	40%	1%
UT	7%	5%	23%	19%	18%	18%	38%	39%	46%	46%	100%	43%	41%	-2%
WA	11%	6%	13%	23%	29%	10%	64%	21%	71%	81%	43%	100%	36%	4%
WY	6%	6%	7%	13%	9%	10%	31%	28%	35%	40%	41%	36%	100%	-2%
Hydro	-11%	-13%	-6%	-13%	-7%	0%	-4%	-12%	4%	1%	-2%	4%	-2%	100%

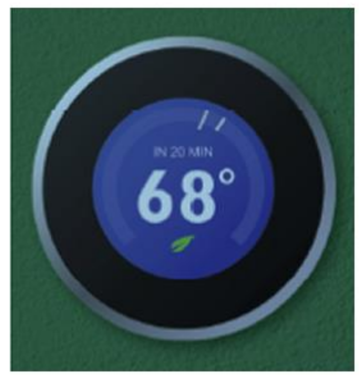
Gas to Gas	Gas to Electric	Electric to Load
Electric to Electric	Gas to Load	Electric to Hydro
Load to Load	Gas to Hydro	Load to Hydro
Hydro to Hydro		

- Deviation events which impact one part of PacifiCorp's system do not necessarily affect other parts of the system, due to its geographic diversity and transmission constraints.
- The correlation between these different deviations can be low if the deviations are caused by different drivers.

2021 IRP Wind and Solar Stochastics

- A stochastic technique for wind and solar output is under consideration.
- The current wind and solar modeling has a static 8760 profile
  - For the 2021 IRP, profiles reflect 2018 historical data, adjusted to match expected output.
  - Profiles for resources that are not yet online are shaped using nearby existing resources, and adjusted to match expected output.
- The Plexos model can draw one day per day in each month, from among a pool of ~30 days per month in the 2018 historical data.
- May draw separately for different locations. For example,
  - For existing solar: PACW, Southern Utah, Other (western Wyoming);
  - New resources to be assigned to one of these draws, or to an independent/correlated draw.

Intra-Hour Dispatch Credit



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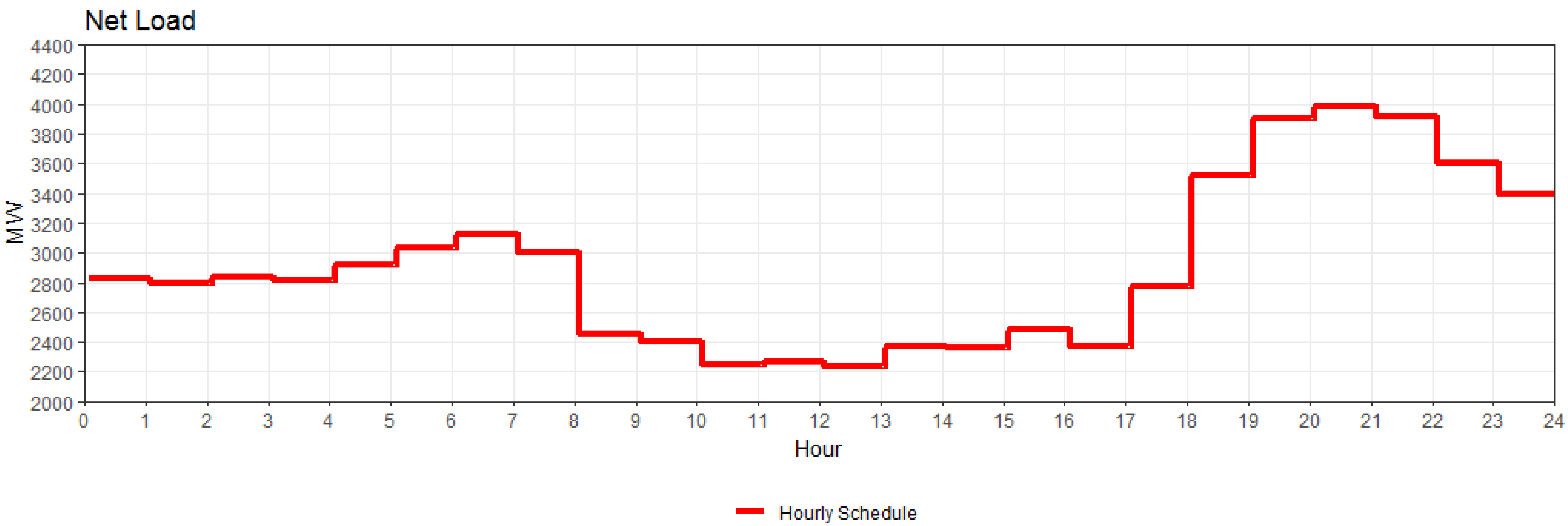
Intra-Hour Dispatch Credit

- To operate the system reliably, PacifiCorp must have the capability to move its resources within the hour to manage variations in load, solar and wind resources.
    - The Flexible Reserve Study identifies regulating reserve capacity needed to compensate for intra-hour changes and uncertainty in load, wind, and solar.
    - In the 2019 IRP, the PaR model held specified levels of regulating reserves, but that capacity was never dispatched either up or down.
    - In the 2021 IRP, PacifiCorp is not proposing changes to this modeling technique – reserves would not be assumed to be deployed.
    - Ignoring intra-hour dispatch undervalues flexible resources, and understates the cost of following changes in load, wind, and solar.
- Today, the CAISO coordinates intra-hour dispatch across the EIM footprint.
    - By drawing from a larger pool of resources across the EIM footprint, the cost of following changes in load, wind, and solar is reduced.
    - Flexible resources can still provide incremental intra-hour value in EIM operations.

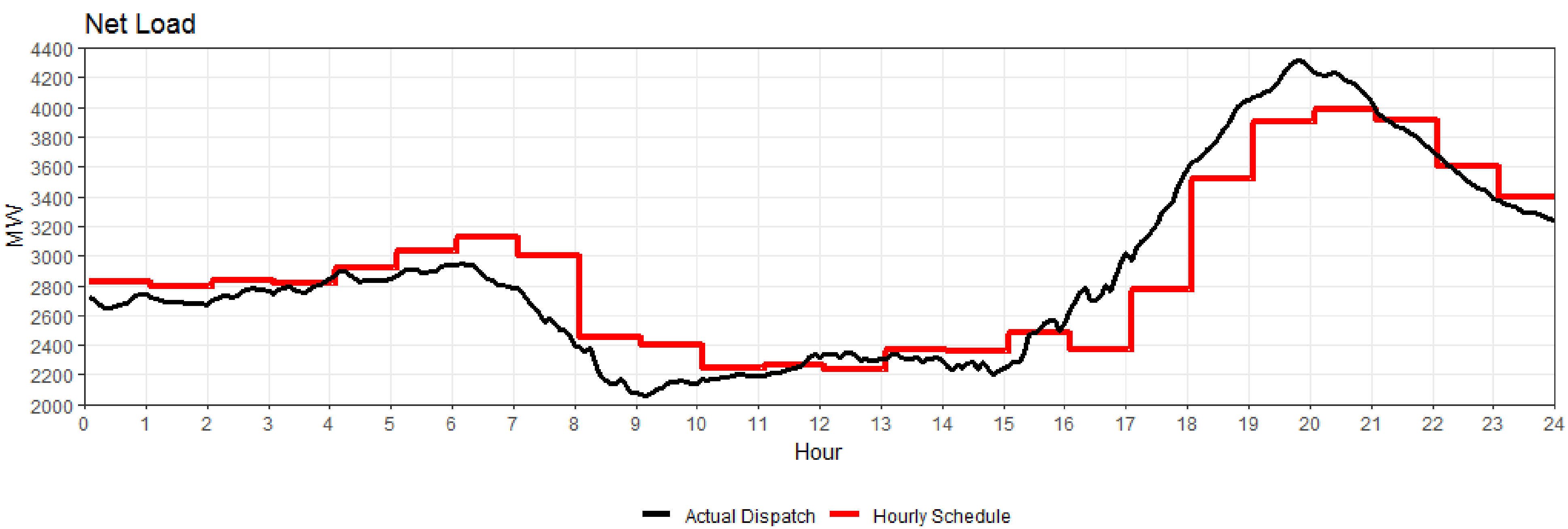
Hourly Models

- IRP modeling balances load and resources at an hourly granularity.
  - *Plexos can operate at sub-hourly time scales, but doing so would require sub-hourly load, resource, and price forecasts that PacifiCorp has not yet developed. Plus it would be a significant increase in data.*
- Hourly production cost models balance with hourly market purchases, but current markets in actual operations are not as flexible. Most transactions are multi-hour block products in 25 MW increments.
- This chart illustrates the observed hourly net load profile of a specific day.



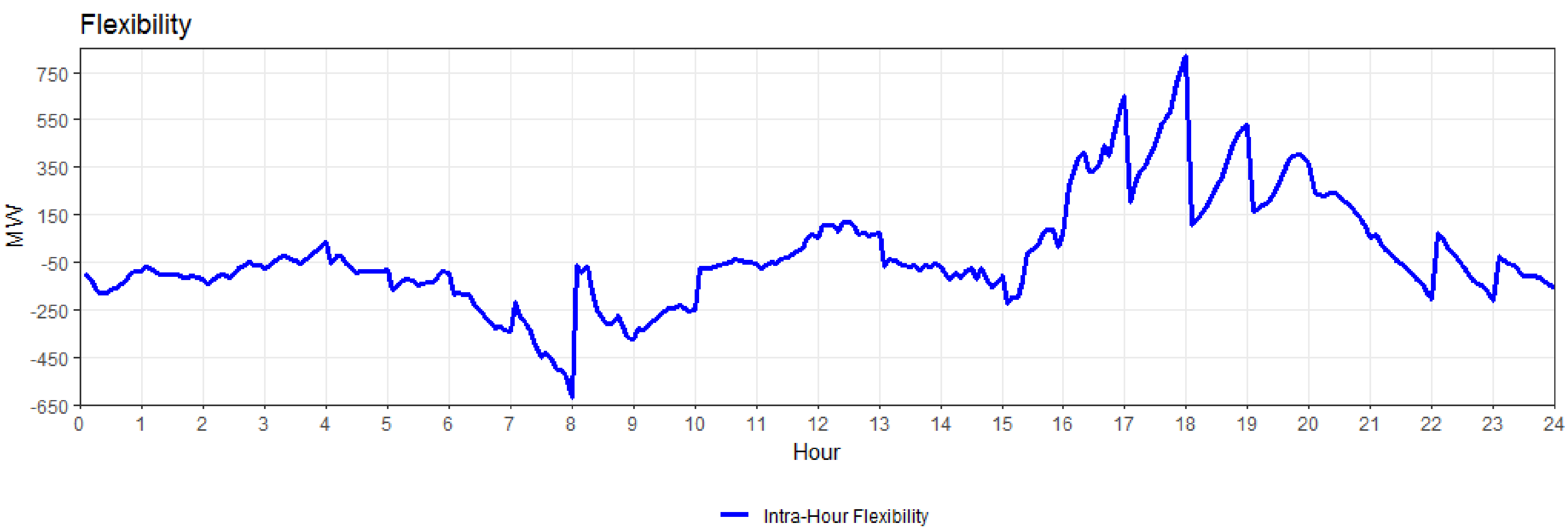
Actual Operations

- The following chart illustrates the actual net load profile for the same day.
- In actual operations, hourly market purchases cannot maintain the load-resource balance when changes occur across an hour or when the actual load and resource balance deviates from the hour-ahead forecast.
- Intra-hour variations in load, wind, and solar also create challenging ramp requirements.
- These requirements amplify the value of dispatchable resources relative to the hourly scenario.



Flexible Dispatch

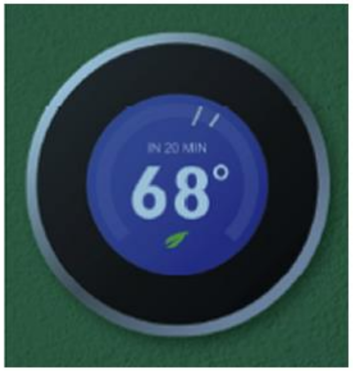
- The below chart demonstrates the relative flexibility of dispatchable resources relative to the hourly scenario (Actual Dispatch – Hourly Schedule of the prior charts).
- The costs of dispatching generation to compensate for these varying requirements is not captured in the hourly IRP modeling.



Intra-Hour Dispatch Credit

- In the 2019 IRP, PacifiCorp calculated intra-hour dispatch credits for a variety of resource types, based on expected economic dispatch relative to historical EIM sub-hourly pricing (see Table Q.2 in Appendix Q: Energy Storage Potential Evaluation).
  - Energy storage had the highest intra-hour benefits.
  - Thermal resources provided moderate intra-hour benefits.
  - Curtailing wind and solar resources can provide small intra-hour benefits.
- Stakeholders expressed a number of concerns with the intra-hour dispatch credit concept, and it was not incorporated in portfolio development or ranking.
- While intra-hour dispatch is “real”, impacts relative to the hourly IRP modeling are difficult to quantify, and may diminish in importance as the EIM footprint grows and highly flexible resources such as energy storage become more prevalent as expected over time.
  - For energy storage in particular, limits on storage duration and bidding structures may reduce the dispatch margin earned.
- In addition, the magnitude of imbalance pales in comparison with the solar ramp: all solar output ceases over a few hours in the evening, so a lot of intra-hour dispatch costs may already be reasonably reflected in the IRP modeling. Saturation of flexible resources to meet the daily ramp may diminish intra-hour margins in other periods.
- For the 2021 IRP, PacifiCorp intends to focus on enhancements to hourly modeling, and is not planning to adopt any intra-hour dispatch credits.

Coal Studies Discussion



Preliminary Coal Study Discussion

- Objectives for the 2021 IRP
  - Evaluate potential benefits of accelerated coal retirements
  - Improve how this is achieved relative to the process implemented in the 2019 IRP

- There are two “book-end” approaches

  - Trial-and-error cases to inform direction and areas for further analysis (2019 IRP)
    - Limited combinations; limited years and limited units in each case
    - Data/labor intensive
    - Customized data sets for a specific case
    - No endogenous alternatives within each case

  - Retirements endogenously determined for all alternatives
    - All combinations; all years, all units in each case
    - Even more data/labor intensive
    - Computationally intensive
    - No practical way to establish customized data sets for a specific case

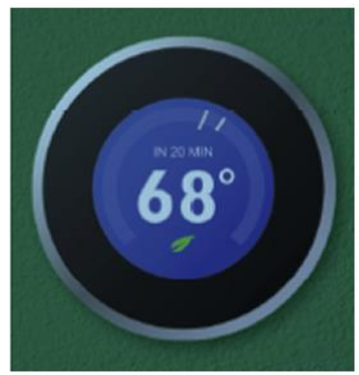
- Is there a way to find a workable compromise between these two approaches?

Coal Study Conceptual Endogenous Retirement Approach

- Objective: Many alternatives (not all), but completely endogenous.
- Treat existing coal units as “new” resources that can be selected as an element of a resource portfolio—no initial capital like a new asset, but inputs would include all forward-looking operating costs
- Allow the model to “build” a limited number of variations of asset life for each unit (i.e., variant A might assume operation from 2021 through 2025; variant B might assume operation from 2021 through 2029, etc.)
- Data sets can be customized for each variant (i.e., reduced run-rate capital toward the end of an asset’s life)
- The model would be limited to pick only one variant for a given unit
- Variations would be tied to cost-driving events that the model can see as avoided costs if retired before those events occur (i.e., major overhauls, major upgrade costs, etc.)
- Some level of post-model review and potential adjustments to fixed costs would be required
- Significant expansion of combinations relative to the 2019 IRP (70-80 retirement portfolios in the 2019 IRP vs. over 260,000 combinations considered in a single model run conservatively assuming just 2 variants for 18 of 22 coal units)

Environmental Policy Update



Environmental Policy Overview

- State Greenhouse Gas (GHG) Emissions Policy Update
- Renewable Portfolio Standards
- Washington Clean Energy Transformation Act (SB 5116)

State Greenhouse Gas Emissions Policy Update

Greenhouse Gas - California

- Emissions Performance Standard applies to new financial commitments – limited to 1,100 lbs CO_2/MWh
- California Cap-and-Trade and Mandatory Reporting Regulation (MRR) enabled by Assembly Bill 32 Global Warming Solutions Act of 2006
  - Achieve 1990 greenhouse gas emission level by 2020 with long-term goal of 80% reduction from 1990 levels by 2050
  - Regulates greenhouse gas sources in California as well as "first jurisdictional deliverer" of electricity
- PacifiCorp subject to MRR and the Cap-and-Trade program for wholesale sales to California, retail service, and transfers made via the energy imbalance market
- In 2016, California passed Senate Bill 32, raising its goal for greenhouse gas emissions to 40 percent below 1990 levels by 2030
- In July 2017, Governor Brown signed AB 398, which extended California's Cap-and-Trade program through 2030
  - Accordingly, in August 2017, the California Air Resources Board finalized allowance allocations through 2030 for electrical distribution utilities

Greenhouse Gas - Oregon

- Emissions Performance Standard applies to new financial commitments – limited to 1,100 lbs CO_2/MWh
- Clean Electricity and Coal Transition Plan (SB 1547) passed March 8, 2016
  - Reduces Oregon greenhouse gas emissions from the electric sector
  - Requires the elimination of coal from Oregon's allocation of electricity, as reflected in retail rates, by 2030
  - Designed to ensure that Oregon's greenhouse gas emission reductions goals are met, as they apply to the electric sector
- On May 7th, 2020, Oregon DEQ adopted amendments to its greenhouse gas reporting rules to require third-party verification of greenhouse gas data
- On March 10, 2020, Governor Brown issued Executive Order No. 20-04 requiring a series of actions under existing law to meet Oregon's greenhouse gas goals
  - Directs the Oregon PUC to help utilities achieve emissions reductions goals

Greenhouse Gas - Washington

- Emissions Performance Standard applies to new financial commitments – limited to 925 lbs CO_2/MWh
- Washington Department of Ecology proposed Clean Air Rule (CAR) issued June 1, 2016, which would require greenhouse gas emissions reductions from point-sources in Washington
    - For PacifiCorp, this would apply to the Chehalis natural gas plant
- After the CAR was challenged by stakeholder groups, in December 2017, Washington's Superior Court concluded that the Department of Ecology did not have the authority to impose the Clean Air Rule without legislative approval
- In January 2020, the Washington Supreme Court upheld the lower court's opinion invalidating the portion of the law that applies to "indirect emitters"
- The Department of Ecology suspended CAR compliance requirements in 2017 and has not indicated next steps with regarding to the rule

Renewable Portfolio Standards

Renewable Portfolio Standard - Oregon

- Enacted by Senate Bill 838 (SB 838) in 2007, requiring Oregon utilities to deliver at least 25 percent of electricity from eligible renewable resources by 2025
- Expanded by the Clean Electricity and Coal Transition Plan (Senate Bill 1547) which passed March 8, 2016. Key provisions include:
  - Elimination of coal from Oregon rates by 2030
  - Increased RPS targets

2015 - 2019	2020 - 2024	2025 - 2029	2030 - 2034	2035 - 2039	2040 Onward
15%	20%	27%	35%	45%	50%

  - Elimination of solar capacity standard (previously mandated by House Bill 3039)
    - Required that by January 1, 2020, the total solar photovoltaic generating nameplate capacity of all Oregon utilities be at least 20 MW_{AC}. PacifiCorp's share of that was 8.7 MW_{AC}, of which 7 MW_{AC} have been developed.

Renewable Portfolio Standard - Oregon

- **Community Solar Program**
  - For residential and commercial customer to own off-site solar
  - At least 10% of program capacity set aside for low-income customers
  - The program opened to Project Managers in the Spring of 2020.
  - The initial projects are in early stages of project development. The Company anticipates that projects will begin to go live in 4th quarter of 2020, with approximately 65 MW of projects online by 2023.
- **Small-scale Renewables**
  - Requirement rather than goal
  - By 2025, at least 8% of state's aggregate electrical capacity to come from renewables 20 MW or less
- **Transportation Electrification**
  - Investor-owned utilities required to propose programs to accelerate transportation electrification
  - Pacific Power is investing $9.7 million to develop electric transportation programs throughout rural and urban communities.
  - The company has developed programs in all three west coast states with a focus on: EV fast chargers along underserved key corridors; developing interest and engagement with electric vehicles across all service areas; providing technical assistance; and creating partnership opportunities with community grants and larger-scale transit funding

Renewable Portfolio Standard - Oregon

- **Eligible Resources**
  - Operational after January 1, 1995
    - Pre-1995 Hydro – eligible if certified by the Low Impact Hydro Institute, and only up to 50 average megawatts of utility-owned and 40 average megawatts not owned by the utility annually (total 90 aMW per year)
    - Pre-1995 Biomass and Solid Waste – eligible for use immediately, with the passing of SB 1547; previously not recognized as eligible until 2026
  - RPS-certified by Oregon Department of Energy
  - Located within the Western Electricity Coordinating Council (WECC)
  - Technologies – Wind, Solar, Solar Thermal, Geothermal, Wave, Tidal, Ocean Thermal, Hydro located outside protected water areas, Incremental Hydro (efficiency upgrades), Biomass, Municipal Solid Waste, Thermal RECs from Biomass (SB 1547 addition)

Renewable Portfolio Standard - Oregon

- **Renewable Energy Certificates (RECs)**
  - Must be issued in Western Renewable Energy Generation Information System (WREGIS)
  - Can be a combination of Bundled and Unbundled RECs (unbundled limited to 20% of annual RPS target
    - Qualifying Facilities (QFs) located in Oregon do not contribute to unbundled REC limit)
  - Retirement of RECs no longer required to follow first-in-first-out rule (SB 1547)

- **Banking Provisions (SB 1547)**
  - REC life limited to five years (previously unlimited)
  - Exceptions (Unlimited REC life):
    - Long-term resources coming online between bill passage and the end of 2022 generate RECs with unlimited REC life for the first five years of the resource's life
    - Existing REC bank (anything generated prior to bill passage)

Renewable Portfolio Standard - Oregon

- **Cost Controls**
  - Alternative compliance payments can be used in lieu of meeting the RPS requirement with renewables ($90 per megawatt-hour for 2018 and 2019)
  - Cost Cap – a utility is not required to comply with the RPS if the incremental cost of the RPS exceeds 4 percent of annual revenue requirement in a compliance year

- **Penalties**
  - Oregon Public Utilities Commission (OPUC) can impose penalties for failing to comply with the RPS in an amount determined by the OPUC

Renewable Portfolio Standard - California

- Established in 2002; expanded in 2011 under Senate Bill 2 (SB2-1X) requiring at least 33% renewable resources by 2020
- Senate Bill 350, the Clean Energy and Pollution Reduction Act was signed into law on October 7, 2015, which requires the state to procure 60% of electricity from renewable resources by 2030
  - Starting 2021, at least 65% of procurement must be from long-term resources (10 or more years)
  - Increased flexibility in banking bundled RECs
- Senate Bill 100, passed in 2018, requires that renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers

Renewable Portfolio Standard - California

- **Eligible Resources**
  - RPS-certified by California Energy Commission
  - Located within the Western Electricity Coordinating Council (WECC)
  - Technologies – Wind, Solar, Solar Thermal, Geothermal, Wave, Tidal, Ocean Thermal, Biomass, Landfill Gas, Municipal Solid Waste, Digester Gas, Fuel Cells, Hydro*

    * Hydro – eligible if capacity of 30 megawatts or less and procured or owned as of effective date of act

- **Renewable Energy Certificates (RECs)**
  - Must be issued in Western Renewable Energy Generation Information System (WREGIS).
  - California procurement is defined by Portfolio Content Categories (buckets) which increasingly limit the use of unbundled RECs over time. The policy is intended to encourage the procurement of in-state renewables.
  - As a multijurisdictional utility serving California load, PacifiCorp is exempt from the bucket limitations.

Renewable Portfolio Standard - California

- **Cost Controls**
  - No cost controls in place however, the California Public Utilities Commission (CPUC) is tasked with developing a Procurement Expenditure Limitation as part of SB 350

- **Penalties**
  - CPUC has the authority to impose penalties for not meeting RPS targets
  - SB 350 tasked CPUC with developing those penalties

Renewable Portfolio Standard - Washington

- Enacted by Initiative 937 (I-937) in 2006, requiring the use of at least 15% eligible renewables by 2020
- **RPS Targets**

2012-2015	2016-2019	2020 Onward
3%	9%	15%

- **Eligible Resources**
  - Operational after March 31, 1999
  - Located within the Pacific Northwest as defined by Bonneville Power Administration; for multijurisdictional utilities, resource can be located in any state served by the utility
  - Technologies – Wind, Solar, Solar Thermal, Geothermal, Wave, Tidal, Ocean Thermal, Incremental Hydro (only upgrades after March 1999), Biomass, Anaerobic Digestion

Renewable Portfolio Standard - Washington

- **Renewable Energy Certificates (RECs)**
  - Must be issued in Western Renewable Energy Generation Information System (WREGIS)
  - Can be a combination of Bundled and Unbundled RECs
    - No limit on unbundled RECs
  - Resources outside of 'Pacific Northwest' must be utility-owned or long-term contract (more than 12 months)
- **Banking Provisions**
  - RECs can be produced during the compliance year, the preceding year or the subsequent year
- **Cost Controls**
  - Utility is not required to comply with the RPS if the incremental cost of the RPS exceeds 4 percent of annual revenue requirement in a given year
- **Penalties**
  - $50 per megawatt-hour of shortfall

Washington Clean Energy Transformation Act (SB 5116)

Washington Clean Energy Transformation Act

Enacted 2019 as Senate Bill 5116, establishes three primary standards:

- **2025 No-coal in Rates**
  - Coal-fired resources not included in rates by December 31, 2025
- **2030 Greenhouse Gas Neutral**
  - Retail sales of electricity must be greenhouse gas neutral by January 1, 2030
  - Multi-year compliance periods
    - January 1, 2030-December 31, 2033
    - January 1, 2034-December 31, 2037
    - January 1, 2038-December 31, 2041
    - January 1, 2042-December 31, 2044
- **2045 100% Renewable and Non-Emitting**
  - 100% of Washington retail load must be met by renewable and non-emitting resources by January 1, 2045
- **Equity Considerations**
  - Equitable distribution of energy and non-energy benefits and reduction of burden to vulnerable populations and highly impacted communities

Washington Clean Energy Transformation Act

- **Eligible Resources**
  - Water, wind, solar, geothermal, renewable natural gas, renewable hydrogen, wave, ocean, or, tidal, biodiesel (with qualifications), biomass,
- **Cost controls**
  - Alternative compliance – a utility is considered in compliance if the incremental cost exceeds 2 percent of weather-adjusted retail sales year over year.
- **Penalties**
  - $100/MWh x multiplier
    - 1.5 for coal
    - 0.84 for gas-fired peaking plants
    - 0.60 for gas-fired combined cycle plants

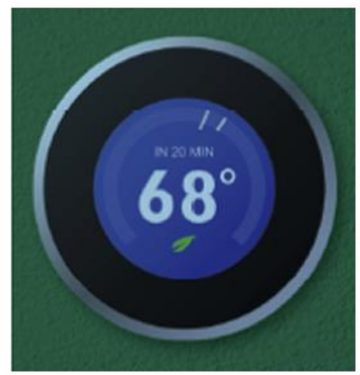
Washington Clean Energy Transformation Act

Implementation

The Washington Utilities and Transportation Commission and Washington Department of Commerce are currently leading rulemaking processes to implement the legislation.

- Phase 1 Rules - Regarding long-term planning and compliance, will be adopted by December 31, 2020
- Utilities to file first Clean Energy Implementation Plan late 2021.

DSM Bundling Portfolio Methodology

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DSM Modeling for 2021 IRP

Modeling Enhancements in Plexos

- PacifiCorp will be testing the use of full 20-year shapes instead of a one-year shape that repeats
  - This will allow for shapes that more accurately reflect the hourly contribution of energy efficiency as it changes over time
  - 20 year shapes can be developed to better align with the load forecast as well

- We will also be testing breaking out the DSM potential by load bubble instead of just by State (Washington is already broken out between Walla Walla and Yakima)
  - The previous model run times and input processing limitations prevented the breakout at this level of detail

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2021 CPA Next Steps

Presentations

- **Draft CPA results** at August 20th IRP Stakeholder Meeting
- Discuss feedback received and planned updates at September IRP Stakeholder Meeting
- **Final CPA results** at October IRP Stakeholder Meeting

CPA/IRP Analysis

✓ Market Profiles posted for Stakeholder review

✓ Jurisdictional Incentive and Administrative Cost analysis posted for Stakeholder review

- Develop Supply Curves
- Determine modeling methodology for CPA (EE & DR) in IRP
  - EE Bundling approach – ***continued discussion at August 20th meeting***
  - DR grid services
  - Applicable cost credits

DSM Bundling Portfolio Methodology

- The conservation potential assessment contains thousands of energy efficiency measures, with a variety of costs and load shapes. To simplify the inputs for modeling purposes, measures are grouped into 27 bundles for each state.
- The current methodology groups measures that have a similar levelized cost of energy (LCOE) on a $ per MWh basis.
- In the 2019 IRP PacifiCorp identified "DSM bundling" as a case to be considered in its portfolio development process. PacifiCorp proposed and tested an alternative bundling methodology based on the net cost of capacity ($/kw-yr). Cost inputs for each measure were unchanged and adjustments for stochastic risk reduction, the Northwest Power Act, and T&D deferral continued to apply.
- In the 2019 IRP, rebundling DSM resulted in SO relying more on capacity from DSM, but it did not translate into cost savings in PaR.
  - This may reflect the disconnect between capacity contribution estimates and the requirements identified in the Reliability Assessment.
  - The transition to the Plexos model and modifications to the modeling of capacity contribution may help align estimated and modeled benefits.
- PacifiCorp believes there is value in further exploration of ways to identify DSM measures that provide the greatest benefits, and seeks stakeholder feedback on this topic.

LCOE Methodology (Current)

- Resources are ranked and bundled by their LCOE.
- Consider the measures in the 2019 IRP Utah $60-$70/MWh bundle shown below:
  - Summer capacity contribution ranges from 0% to 86%, average 46%
  - Winter capacity contribution ranges from 0% to 84%, average 40%
  - Load factor ranges from 4% to 84%, average 39%
  - Shaped energy value ranges from $40 to $55/MWh, average $47/MWh
- The characteristics of a sample of measures:

Sample Data from 2019 IRP

Type	$/MWh LCOE	% CC Summer	% CC Winter	% Load Factor	$/MWh Energy Value
Microwave	62.39	40%	44%	19%	54.17
Strategic Energy Management	60.17	47%	27%	35%	47.06
Exterior Lighting - Bi-Level Parking Garage Fixture	65.80	48%	32%	46%	46.11
Advanced New Construction Designs	67.11	34%	30%	38%	43.61
Office Equipment - Advanced Power Strips	68.40	48%	48%	63%	43.17
Exterior Lighting - Enhanced Controls	60.74	36%	38%	48%	42.75
Insulation - Wall Cavity Installation	63.25	17%	32%	13%	50.30
Linear Lighting	63.56	35%	68%	40%	50.00
Doors - Storm and Thermal	62.44	0%	47%	15%	45.24
Space Heating - Heat Recovery Ventilator	62.95	0%	9%	4%	39.82

Note the range of energy and capacity contribution values

- Some $60-$70/MWh measures could be economic even if the entire bundle is not.

Net Cost of Capacity Methodology (Alternative 1)

- Resources are ranked and bundled by their net cost of capacity.
- Resources whose winter capacity contribution was more than 150% of their summer contribution were bundled separately based on their winter contribution.

Net cost of capacity per kW-yr = (LCOE - Energy Value) * (Load Factor * Hrs/yr) / Cap. Contrib. / (kW/MW)

Column reference: [h *or* i] = (a - e) * (d * 8760) / [b *or* c] / 1000

- The bundle assignments shown in column j distinguish measures based on their economics.

Sample Data from 2019 IRP

Type	a $/MWh LCOE	b % CC Summer	c % CC Winter	d % Load Factor	e $/MWh Energy Value	f % Winter Ratio	g Season	h $/kW-yr Net Cost Summer	i $/kW-yr Net Cost Winter	j $/kW-yr Bundle
Microwave	62.39	40%	44%	19%	54.17	1.1	Summer	50	50	SD. $25-50
Strategic Energy Management	60.17	47%	27%	35%	47.06	0.6	Summer	150	500	SH. $125-150
Exterior Lighting - Bi-Level Parking Garage Fixture	65.80	48%	32%	46%	46.11	0.7	Summer	175	275	SI. $150-175
Advanced New Construction Designs	67.11	34%	30%	38%	43.61	0.9	Summer	325	375	SM. $300-400
Office Equipment - Advanced Power Strips	68.40	48%	48%	63%	43.17	1	Summer	300	300	SL. $250-300
Exterior Lighting - Enhanced Controls	60.74	36%	38%	48%	42.75	1	Summer	225	200	SK. $200-250
Insulation - Wall Cavity Installation	63.25	17%	32%	13%	50.30	1.9	Winter	700	375	WZ. $300-1000
Linear Lighting	63.56	35%	68%	40%	50.00	1.9	Winter	150	75	WV. $50-100
Doors - Storm and Thermal	62.44	0%	47%	15%	45.24	>10	Winter	>1000	50	WU. $25-50
Space Heating - Heat Recovery Ventilator	62.95	0%	9%	4%	39.82	>10	Winter	>1000	100	WV. $50-100

Net Cost of Capacity Bundles vs LCOE Bundles

- The figure shows how each LCOE bundle was split into Net Cost of Capacity bundles.
  - Each column sums to 100% of the LCOE bundle volume.
  - Measures in the green box are relatively economic and could now be selected before other bundles.
  - Measures in the red box are relatively uneconomic and could now be selected after other bundles.

2038 Achievable Technical Potential Savings (MWh) % by Original Bundle

LCOE Selection: Mostly Left to Right →→→

Net Cost of Capacity Selection: Top to Bottom, for each season

Sample Data from 2019 IRP

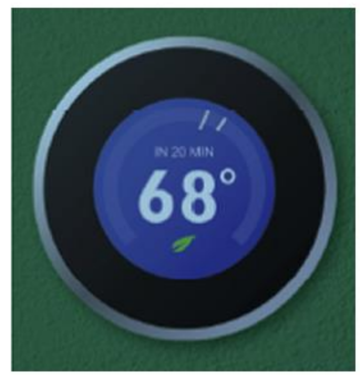
	Current LCOE $/MWh																										
Proposed $/kW-yr	<10	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200	250	300	400	500	750	>1k
SA. up to -$50	86%	86%	66%	71%	20%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SB. -$50-0	0%	0%	-	0%	34%	1%	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC. $0-25	0%	0%	0%	0%	27%	4%	0%	1%	1%	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SD. $25-50	0%	0%	0%	3%	3%	6%	4%	0%	0%	0%	0%	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SE. $50-75	0%	-	0%	0%	1%	14%	1%	0%	0%	0%	0%	0%	0%	-	0%	-	-	-	-	-	-	-	-	-	-	-	-
SF. $75-100	0%	-	-	2%	0%	32%	0%	3%	0%	0%	-	0%	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SG. $100-125	0%	-	0%	0%	0%	3%	8%	1%	1%	2%	0%	0%	-	0%	-	-	0%	0%	-	-	-	-	-	-	-	-	-
SH. $125-150	0%	-	-	0%	0%	1%	5%	0%	1%	2%	0%	0%	0%	0%	-	-	-	-	-	-	-	-	-	-	-	-	-
SI. $150-175	0%	-	-	-	0%	2%	17%	2%	0%	1%	0%	1%	-	0%	-	0%	0%	-	-	0%	-	-	-	-	-	-	-
SJ. $175-200	0%	-	0%	0%	0%	13%	2%	3%	0%	1%	3%	1%	0%	0%	0%	-	-	0%	0%	-	-	0%	-	-	-	-	-
SK. $200-250	0%	-	-	0%	0%	5%	14%	9%	4%	0%	1%	5%	1%	1%	0%	0%	4%	-	0%	0%	9%	-	-	-	-	-	-
SL. $250-300	0%	-	-	-	0%	1%	14%	27%	18%	1%	0%	0%	0%	5%	2%	1%	0%	0%	0%	-	10%	-	0%	-	-	-	-
SM. $300-400	0%	-	-	-	0%	5%	7%	26%	26%	27%	2%	1%	3%	26%	62%	1%	16%	7%	1%	2%	0%	0%	0%	1%	-	-	-
SN. $400-500	0%	-	0%	0%	1%	0%	0%	2%	28%	29%	10%	5%	1%	1%	1%	8%	15%	3%	31%	26%	5%	4%	15%	1%	0%	-	-
SO. $500-750	0%	-	0%	0%	2%	1%	0%	0%	3%	22%	44%	19%	18%	23%	5%	5%	4%	22%	7%	16%	15%	23%	3%	4%	6%	3%	-
SP. $750-1000	-	-	-	-	-	-	0%	0%	0%	-	3%	15%	32%	17%	6%	39%	7%	10%	4%	12%	7%	16%	11%	14%	17%	9%	0%
SQ. $1000-9999	-	-	-	-	-	-	-	-	-	-	-	-	4%	1%	1%	0%	11%	19%	19%	20%	19%	30%	13%	50%	43%	51%	85%
WR. up to -$50	14%	14%	33%	23%	1%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WS. -$50-0	-	-	-	0%	6%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WT. $0-25	-	-	-	0%	2%	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WU. $25-50	-	-	-	-	1%	7%	5%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WV. $50-100	-	-	-	-	0%	2%	15%	10%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WW. $100-150	-	-	-	-	-	0%	1%	2%	7%	1%	-	3%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WX. $150-200	-	-	-	-	-	1%	0%	1%	5%	6%	1%	1%	-	5%	-	-	-	-	-	-	-	-	-	-	-	-	-
WY. $200-300	-	-	-	-	-	1%	2%	5%	3%	1%	28%	10%	17%	1%	2%	9%	2%	-	-	-	-	-	-	-	-	-	-
WZ. $300-1000	-	-	-	-	0%	0%	3%	8%	2%	7%	8%	38%	25%	20%	21%	34%	38%	37%	38%	22%	35%	22%	47%	0%	-	-	-
WZZ. $1000-9999	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3%	2%	3%	0%	1%	1%	4%	11%	28%	34%	36%	15%

Sample Data from 2019 IRP

DSM Bundling Next Steps

- PacifiCorp intends to continue to evaluate both LCOE and Net Cost of Capacity bundling during the 2021 IRP.
- Net Cost of Capacity bundling was intended to distinguish the value of load profiles and allow for targeted summer and winter measures.
- <u>*Are there other distinguishing factors that could be used to target the most cost-effective energy efficiency measures?*</u>

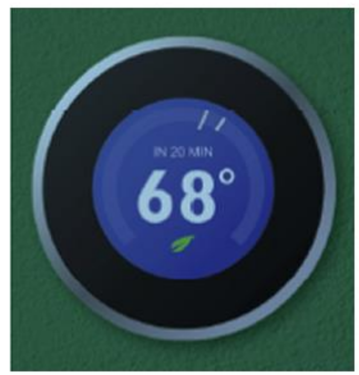
Private Generation Study



Please refer to stakeholder presentation Navigant Private Resource Assessment, July 31, 2020.

Stakeholder Feedback Form Recap



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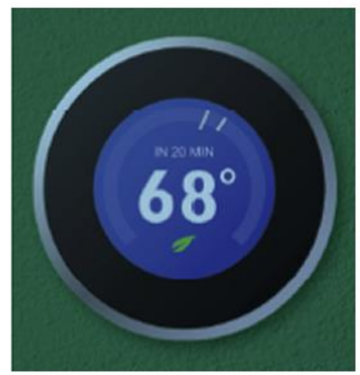
Stakeholder Feedback Form Recap

- 17 stakeholder feedback forms submitted to date.
- The stakeholder feedback form process was updated July 20, 2020 to include a web-based form.
- 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)
Washington Utilities and Transportation commission	June 26, 2020	June PIM	Questions related to topics presented in the June 18-19, 2020 public input meeting: coal retirements, Conservation Potential Assessment, energy storage, modeling methodology, supplemental studies, demand response, load forecasting, 2019 IRP action plan, all-source RFP, and public participation.	PacifiCorp provided responses and will consider recommendations made on specific topics.
Utah Valley Earth Forum	June 27, 2020	Battery Storage	Recommendation made regarding type of batteries that could be used in battery storage.	PacifiCorp appreciates this recommendation.
Renewable Northwest	June 29, 2020	Battery Storage	Recommendations for further refinement of modeling efforts for energy storage	PacifiCorp will consider incorporating these recommendations.
Oregon Public Utility Commission – Administrative Hearings Division	July 23, 2020	June PIM	Questions and recommendations related to topics presented in the June 18-19, 2020 public input meeting: on Optimization Modeling, 2021 IRP Topics and Timeline, and Transmission Overview and Update.	Target response week of August 10, 2020.
Utah Valley Earth Forum	July 25, 2020	Solar Panels	Question on solar panel technology choices being modeling in the 2021 IRP.	Target response week of August 10, 2020.

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 – CPA Draft Documents
  - pacificorp.com/energy/integrated-resource-plan/support

Next Steps

- Upcoming Public Input Meeting Dates:
  - August 20, 2020 – Conservation Potential Assessment Technical Workshop
  - September 17-18, 2020 – Public Input Meeting
  - October 22-23, 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

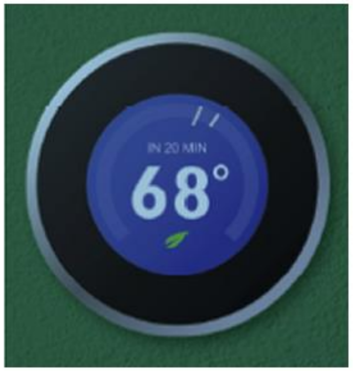
**meeting dates are subject to change*

Conservation Potential Update

2021 IRP Public Input Meeting – Technical Workshop

August 28, 2020



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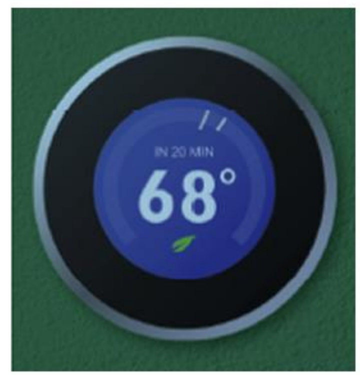
Agenda

August 28, 2020

- Introductions
- 2021 CPA Process Review
- Energy Efficiency Potential – Draft Results
- Demand Response Potential – Draft Results
- Wrap-Up/ Next Steps

2021 CPA Process Review



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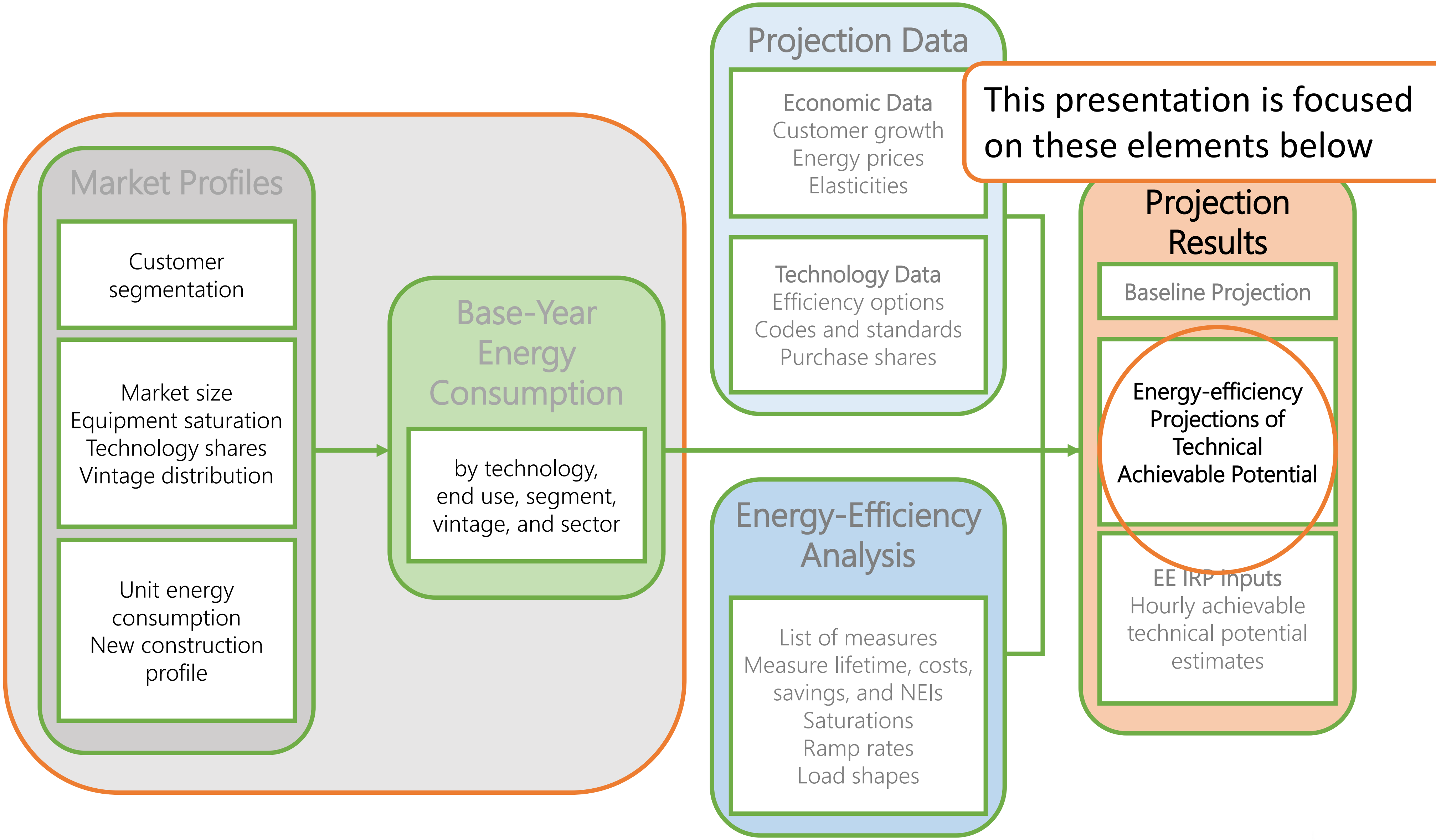
CPA Stakeholder Process To-Date

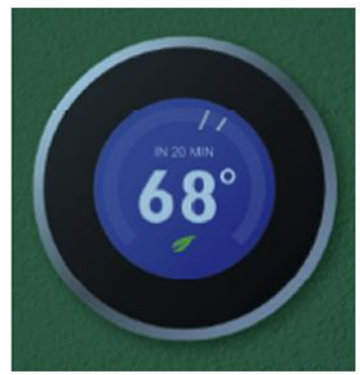
- **December 2019:** Draft CPA Work Plan provided to stakeholders for review and comment
- **January 2020:** CPA Workshop #1. CPA overview and planned changes from 2019 CPA.
  - Study methodology
  - EE source data hierarchy
- **February 2020:** Draft Resource List, CPA Workshop #2.
  - Major measures identification
  - Baseline development, regional and state variation
  - Savings and cost variation drivers
- **April 2020:** Draft Measure List, CPA Workshop #3.
  - Technical drivers of differences between states
  - Load and potential differences
  - Market profiles, incentive and administrative costs posted
- **August 2020:** Presentation of Draft Results

CPA Methodology (Except OR)



Energy Efficiency Draft Results



2021 CPA Analysis Themes

CPA Forecasting is Dynamic	• CPA forecasting is dynamic and markets change quickly • Analysis every two years to capture these changes
Lighting Changes	• LED adoption has been significant since the last CPA • EISA 2020 & Market baseline assumptions
Ramp Rates	• Refresh of ramp rates to NWPCC 2021 Plan assumptions • Adjusted ramp rates by state based on participation analysis
State Specificity	• Regional measure and market data sourcing • State specific codes, standards and lighting assumptions

Energy Efficiency Drivers of Change

Key Changes Relative to the 2019 CPA

Change Area	Detail
State-Specific Adjustments	RMP and PP specific measure* and market data sourcing
	Updated residential survey and load forecast data by state
	Major market profile data sourcing overhaul
	Codes & Standards
	Ramp Rates – Refreshed to 2021 Plan and participation analysis results
Forecasting Methodology	Treatment of equipment measures for technical potential
	Max achievability (some measures above 85%)
	No Streetlighting Model – market is transformed in the Load Forecast
	Residential Low Income segments added for WA
	Lighting savings methods (market baseline and EISA)
Other	Other updated secondary sources (AEO purchase shares and trends)
	New emerging technologies (higher SEER AC, more HP Dryer options)
	Applicability and Saturation Sourcing Updates (RBSA II, CBSA, 2021 Plan)
	Incremental HERs for all states, including OR***

* State-specific measure adjustments are for weather-dependent and major measures only
** Ramp Rates were refreshed based on the 2021 Power Plan then adjusted based on the Participation Analysis
*** Incremental HERs to existing program savings are still being finalized and will be included in the final results

State Specific Adjustments

- Region Specific Measure Sour
- Updated load research and su
  PacifiCorp
- WA: Residential Low Income r
- Codes and Standards:
  - WA: Adheres to HB1444
  - CA: Title 24
  - Federal Codes & Standards incl
- Oregon results will change wit
  savings before final results in October

State Specific Measure Sourcing	
WA & ID	1) RTF UES Measures 2) 2021 Power Plan 3) Idaho Power TRM 4) Other
UT & WY	1) Rocky Mt. Power Measures* 2) Xcel Energy CO TRM 3) RTF with Adjustments† 4) Other
CA	1) Non-DEER Workpapers 2) DEER 3) RTF with Adjustments† 4) Other
OR	1) ETO Measure Approval Documents 2) RTF UES Measures 3) 2021 Plan 4) Other

Lighting Baselines and EISA 2020 by State

- The 2019 CPA utilized a **frozen efficiency baseline** and **accounted for impacts of the EISA 2020 45 lumen/Watt Backstop Provision**
- Since that time:
  - US DOE rolled back the 2020 backstop provision
  - Washington HB 1444 codified the 45 lm/W standard for bulbs sold in the state
  - California lighting measures were aligned to the approved statewide work papers in DEER.
- The 2021 CPA incorporates current state-specific standards and requirements for screw-in lighting standards and RTF market baselines where applicable

State	Lighting Baseline Condition Modeled	EISA 2020 Standard Included?
California	100% LED Baseline	In 2019
Idaho	RTF Market Baseline	Not Included
Utah	2018 Frozen Baseline	Not Included
Washington	RTF Market Baseline	In 2020
Wyoming	2018 Frozen Baseline	Not Included
Oregon	RTF Market Baseline	Not Included

Commercial Lighting Differences by State

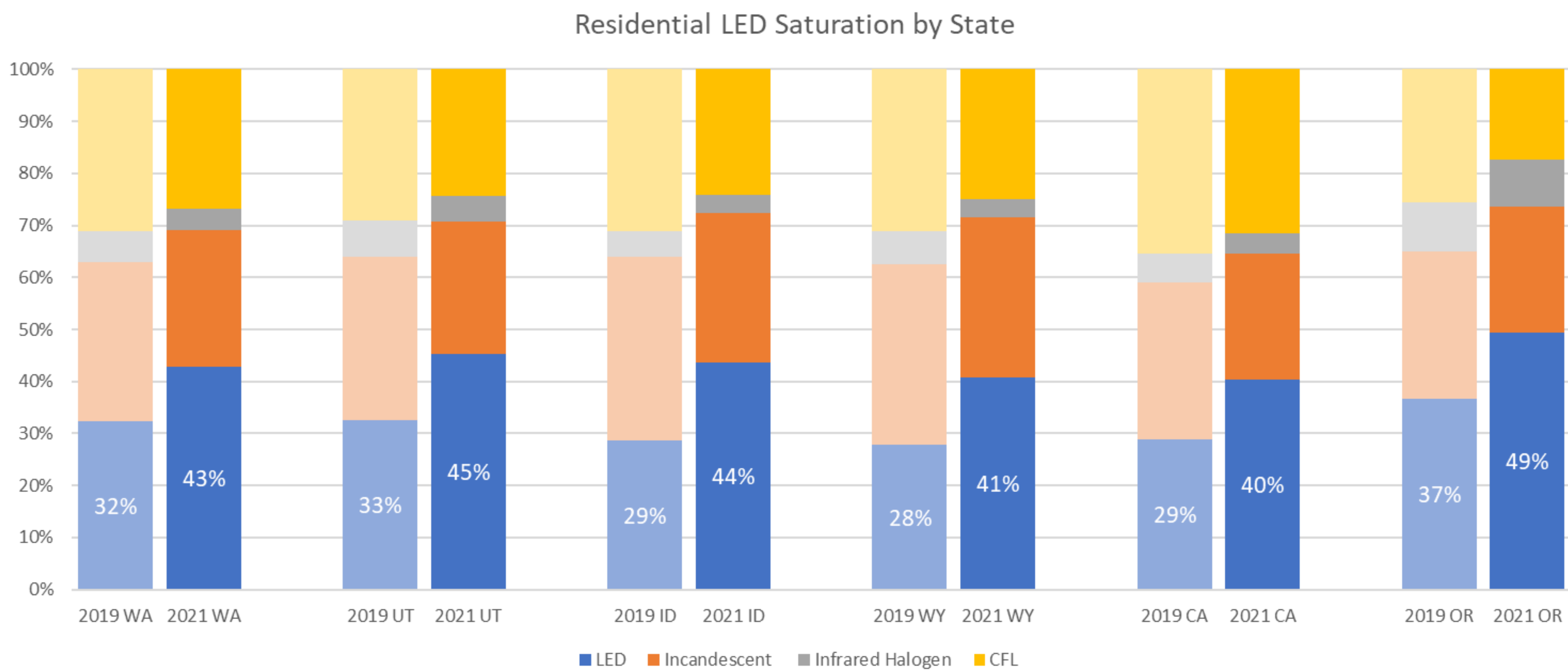
- Commercial LPDs were updated to better align with 2021 Power Plan LPDs and be as regionally specific as possible
  - WA, CA & OR utilized the 2021 Plan LPDs outright
    - OR utilized the 7th plan baseline with saturation adjustments in the 2019 CPA
  - UT and ID utilize an average of CBSA 2014 and 2021 Plan – *About 15% higher*
  - WY utilizes CBSA 2014 outright – *About 30% higher*

Commercial Lighting Baseline LPD Comparison by State (Watts/1000 SqFt)

CPA Year	State	Large Office	Small Retail	Warehouse	School	Lodging	Misc.
2019 CPA Baseline LPD	All States (ex. OR)	1,399	1,193	772	988	993	885
2021 CPA Baseline LPD	California	801	872	454	771	552	693
	% Difference	*-43%*	*-27%*	*-41%*	*-22%*	*-44%*	*-22%*
	Idaho	901	1,006	541	846	677	776
	% Difference	*-36%*	*-16%*	*-30%*	*-14%*	*-32%*	*-12%*
	Utah	901	1,006	541	846	677	693
	% Difference	*-36%*	*-16%*	*-30%*	*-14%*	*-32%*	*-22%*
	Washington	801	872	454	771	552	693
	% Difference	*-43%*	*-27%*	*-41%*	*-22%*	*-44%*	*-22%*
	Wyoming	1,002	1,140	629	921	801	859
	% Difference	*-28%*	*-4%*	*-18%*	*-7%*	*-19%*	*-3%*
Oregon	2019 CPA Baseline	970	1,016	495	885	736	855
	2021 CPA Baseline	801	872	454	771	552	693
	% Difference	*-17%*	*-14%*	*-8%*	*-13%*	*-25%*	*-19%*

And LED Residential Lighting Shares are Increasing

- PacifiCorp residential customer surveys suggested a 10-15% increase in LED saturation over the past two years



Source: Internal PacifiCorp Survey Data

Forecasting Methodology Changes

- C&I Lighting
  - Updated stock turnover model to force more turnover in early years
    - Accounts for the fact that retrofits of additional fixtures often happen when fixtures burn out.
  - Aligns with DOE SSL Methodology
- Max Achievability
  - NWPCC 2021 Plan allows some measures max achievability to reach up to 100% of technical potential
  - 7th Power Plan and 2019 CPA had a max achievability of 85%
  - AEG has aligned assumptions with the 2021 Plan and measures such as lighting reach greater than 85%
  - Oregon follows this methodology as well
- No Streetlighting model in this CPA
  - Market becomes 100% LED in the Load Forecast
  - Transformation happens quickly for most states (by 2030)

Measures examples over 85% Achievability:

- All Lighting
- Washers/Dryers
- Dishwashers
- Refrigerators/Freezers
- Circulation Pumps
- Thermostats
- C&I Fans

Other Notable CPA Changes

Load Forecast

- Large UT Res increase
- COVID-19 Impacts
- EVs and Electrification

Secondary Source Updates

- Market Profile Sourcing Updates
- EIA Annual Energy Outlook 2019

Emerging Techs

- New Emerging Technologies
- More Efficient Options (HP Dryer UCEF 8.0, SEER 24 AC)

Applicability & Saturation Updates

- NWPCC 2021 Power Plan
- RBSA II / CBSA 2014
- Expand sourcing for UT and WY

State-Level Administrative, Incentive & Participation Analysis Results

Administrative Cost Analysis

2021 CPA Administrative Cost as Percent of Incremental Customer Costs							
Program Year	**UT**	**WA**	**CA**	**ID**	**WY**	**OR**	**Notes**
2014	17%	34%	54%	60%	49%	n/a	
2015	19%	34%	35%	36%	41%	n/a	
2016	19%	37%	48%	36%	27%	n/a	
2017	22%	45%	83%	44%	37%	n/a	
2018	24%	43%	67%	64%	43%	n/a	
5-year Average to Utilize	**20%**	**38%**	**54%**	**46%**	**37%**	**28%**	*OR based on 2019 Program Data**

2019 CPA Administrative Cost as Percent of Incremental Customer Costs							
Program Year	**UT**	**WA**	**CA**	**ID**	**WY**	**OR**	**Notes**
2014	17%	34%	54%	*n/a*	*n/a*	*n/a*	*Excluded ID & WY as outliers in 2019 CPA*
2015	19%	34%	35%	36%	*n/a*	*n/a*	*Excluded WY as outlier in 2019 CPA*
2016	19%	37%	48%	36%	27%	*n/a*	
Utlized 3-year average	**18%**	**35%**	**44%**	**36%**	**27%**	**20%**	*OR utilized 7th Plan assump. in 2019 CPA*

2019 CPA to 2021 CPA Administrative Cost % of Customer Cost Comparison							
CPA Year	**UT**	**WA**	**CA**	**ID**	**WY**	**OR**	**Notes**
2019 CPA	18%	35%	44%	36%	27%	20%	*ID & WY identified as outliers in some years*
2021 CPA	20%	38%	54%	46%	37%	28%	*Include all years in 2021 CPA*
% Change from 2019 CPA	*10%*	*10%*	*21%*	*27%*	*36%*	*40%*	

** 2019 Program Data not available in time for analysis for all other states*

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Incentive Cost Analysis

- First time this analysis has been performed in the CPA process
- Affects UT and ID, which utilize the UCT as the primary cost-effectiveness criterion, rather than TRC

2021 CPA Incentive Cost as Percent of Incremental Customer Costs						
Program Year	**UT**	**WA**	**CA**	**ID**	**WY**	**Notes**
2014	41%	41%	33%	45%	35%	
2015	40%	42%	32%	41%	47%	
2016	33%	44%	29%	39%	28%	
2017	38%	39%	35%	44%	40%	
2018	37%	44%	38%	46%	52%	
5-year Average to Utilize	**38%**	**42%**	**33%**	**43%**	**40%**	

2019 CPA Incentive Cost as Percent of Incremental Customer Costs
This incentive analysis was not part of the 2019 CPA. The 2019 CPA utilized 70% of customer incremental cost for all states and all measures except Non-Res Lighting, which utilized 50%.

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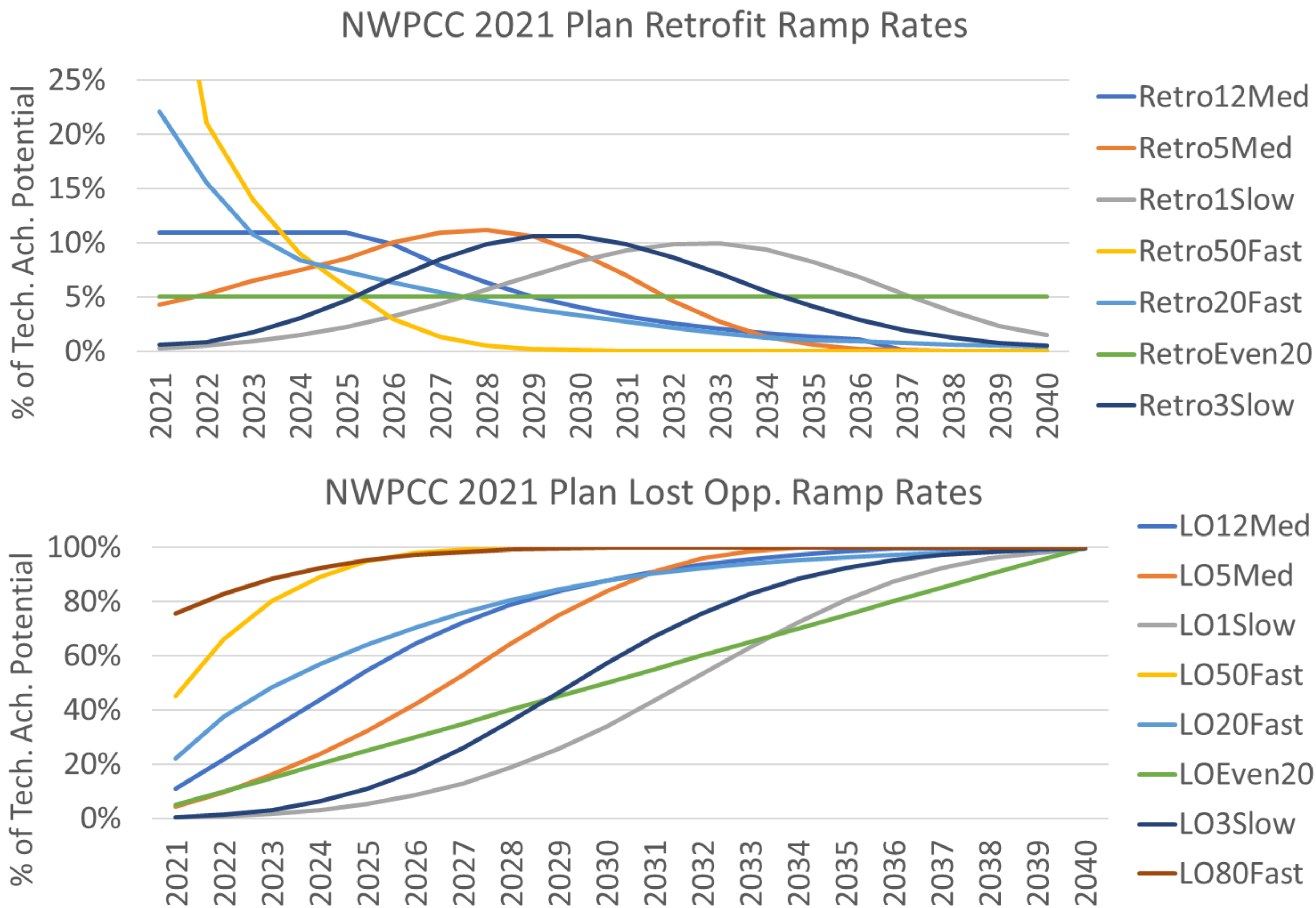
Participation Analysis Overview

- Utilized the 2017/2018 annual report cost-effectiveness workbooks at the measure level to estimate participation for all states except OR, which has its own participation calibration
- Compared kWh savings from the annual to the 2019 CPA technical potential at the measure category level
- Informs ramp rates and beginning saturations of potential – akin to Energy Trust's program forecast calibration, but looking at program history
- Results for all states except OR were used to determine which Ramp Rate from the NWPCC 2021 Power Plan is most appropriate for the analysis. This did not create new Ramp Rates
- Several Ramp Rates were adjusted from the 2021 Power Plan base ramp rate based on the participation analysis (discussed on next slides)

NWPCC 2021 Plan Ramp Rates



Residential Ramp Rate Adjustments by State

Sector(s)	Measure Category	Equipment or Non-Equip	2019 CPA Ramp Rate	*2021 Plan Ramp Rate*	Ramp Rate Updates Implemented in 2021 CPA CA	WA	UT	ID	WY
Res	Appliances	Equipment	LO1Slow	*LO12Med*	NA	LO1Slow	LO1Slow	NA	LO1Slow
Res	Building Shell	Non-Equipment	Retro12Med	*NA*	Retro1Slow	Retro1Slow	Retro1Slow	Retro1Slow	Retro1Slow
Res	Energy Kits	Non-Equipment	Aerators Retro3Slow, SH Ret12Med	*Retro3Med*	Retro12Med	Retro12Med	Aerator Retro3Slow, SH Ret12Med	Aerators Retro3Slow, SH Ret12Med	Retro12Med
Res	HVAC	Equipment	LO5Med CAC, LO1Slow RAC	*LO5Med CAC, LO12Med RAC*	LO5Med	LO12Med	LO12Med	LO5Slow	LO5Med CAC, LO12Med RAC
Res	HVAC	Non-Equipment	Thermostat Retro5Med, DHP Retro3Slow	*Thermostat Retro5Med, DHP Retro5Med*	Retro5Med	Thermostats at Retro5Med, DHP to Retro3Slow	Tstat Retro5Med, DHP Retro3Slow	Tstat Retro5Med, DHP Retro3Slow	DHP to Retro3Slow, no Tstat mapped in program
Res	Lighting	Equipment	LO12Med & LO20 Fast	*LO20Fast*	LO50Fast	LO80Fast	LO80Fast	LO50Fast	LO50Fast
Res	Water Heating	Equipment	LO3Slow	*LO5Med*	LO3Slow	LO5Med	LO1Slow	LO1Slow	LO1Slow
Res	Whole Home	Non-Equipment	LOEven20	*NA*	-	LOEven20	LO20Even	LOEven20	NA
Res	Electronics	Non-Equipment	Retro3Slow	*Retro3Slow*	NA	NA	NA	Retro5Med	Retro5Med

- Many residential categories were adjusted to faster ramp rates
  - Residential programs have already transitioned away from lighting
- NWPCC 2021 Plan Ramp Rates included for reference

Legend:
Faster Ramp
Slower Ramp
No Change
**compared to 2019 CPA Ramps*

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Commercial & Industrial Ramp Rate Adjustments by State

Sector(s)	Measure Category	Equipment or Non-Equip	2019 CPA Ramp Rate	*2021 Plan Ramp Rate*	Ramp Rate Updates Implemented in 2021 CPA				
					CA	WA	UT	ID	WY
C&I	Building Shell	Non-Equipment	RetroEven20	*Retro1Slow*	NA	Retro1Slow	Retro1Slow	Retro1Slow	Retro1Slow
C&I	Compressed Air	Both	Retro5Med, Retro12Med	*Retro5Med, Retro12Med*	NA	Retro3Slow, Retro5Med	Retro3Slow	Retro5Med	Retro3Slow
C&I	Energy Management	Non-Equipment	Retro12Med	*Retro5Med*	Retro5Med	Retro5Med	Retro12Med	Retro5Med	Retro5Med
C&I	Food Service Equipment	Equipment	LO5Med, LO12Med	*LO3Slow, LO1Slow*	NA	LO3Slow, LO1Slow	LO5Med, LO12Med	LO12Med	LO5Med, LO12Med
C&I	HVAC	Equipment	LO5Med, LO20Fast	*LO5Med, LO12Med*	NA	LO5Med, LO12Med	LO5Med, LO20Fast	LO5Med, LO20Fast	LO5Med, LO20Fast
C&I	HVAC	Non-Equipment	RetroEven20, Retro12Med, Retro3Slow, Retro1Slow	*Retro12Med, Retro5Med*	Retro12Med, Retro5Med	Retro1Slow	Retro3Slow	Retro5Med	Retro3Slow
C&I	Irrigation	Non-Equipment	Retro12Med mostly	*RetroEven20*	RetroEven20	RetroEven20	RetroEven20	RetroEven20	RetroEven20
C&I	Lighting	Equipment	LO20Fast/LO50 Fast	*LO80Fast*	LO80Fast	LO80Fast	LO80Fast	LO80Fast	LO80Fast
C&I	Motors	Non-Equipment	Retro12Med	*Retro12Med*	Retro5Med	Retro5Med	Retro12Med	Retro5Med	Retro12Med
C&I	Refrigeration	Both	Retro12Med	*Retro5Med*	Retro3Slow	Retro5Med, Retro12	Retro5Med	Retro3Slow	Retro3Slow

- In general, only the C&I Lighting category went to a faster ramp rate
- Many Retrofit measures slowed compared to the 2019 Ramp Rates
- NWPCC 2021 Plan Ramp Rates included for reference

Legend:
Faster Ramp
Slower Ramp
No Change or NA
**compared to 2019 CPA Ramps*

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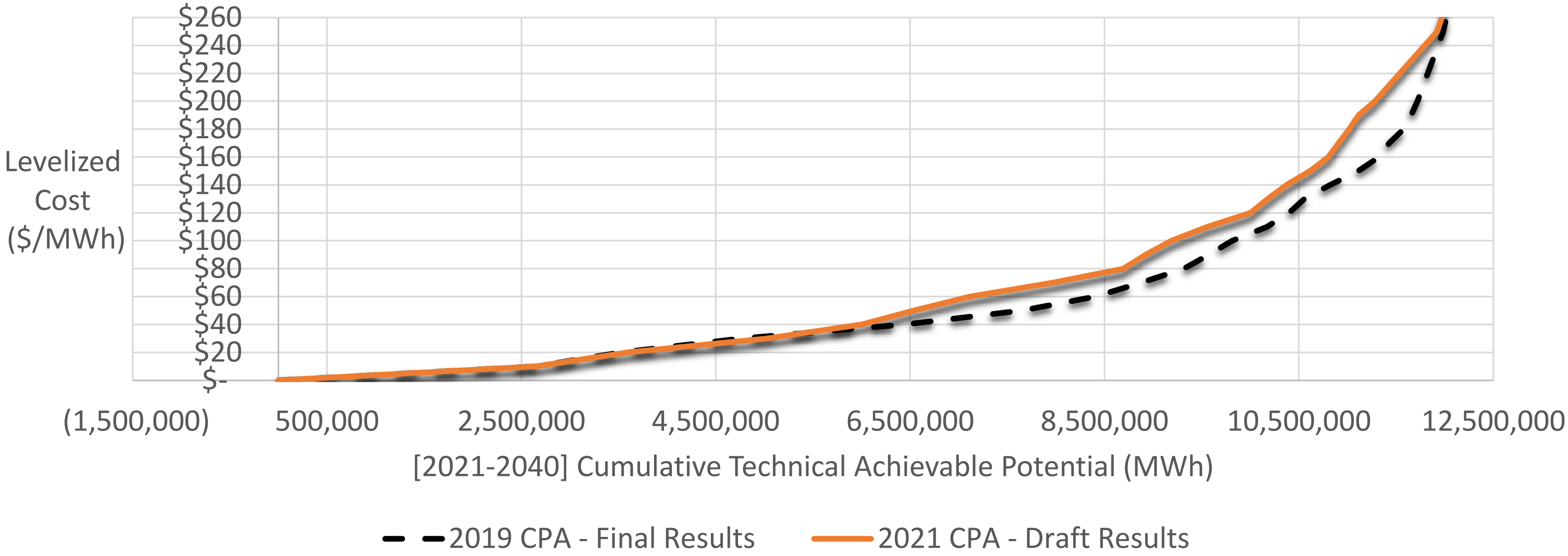
2021 CPA Results

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



Total Cumulative 20-year Potential Comparison (MWh)		
2021 CPA	2019 CPA	% Difference
13,516,192	13,163,531	+2.7%

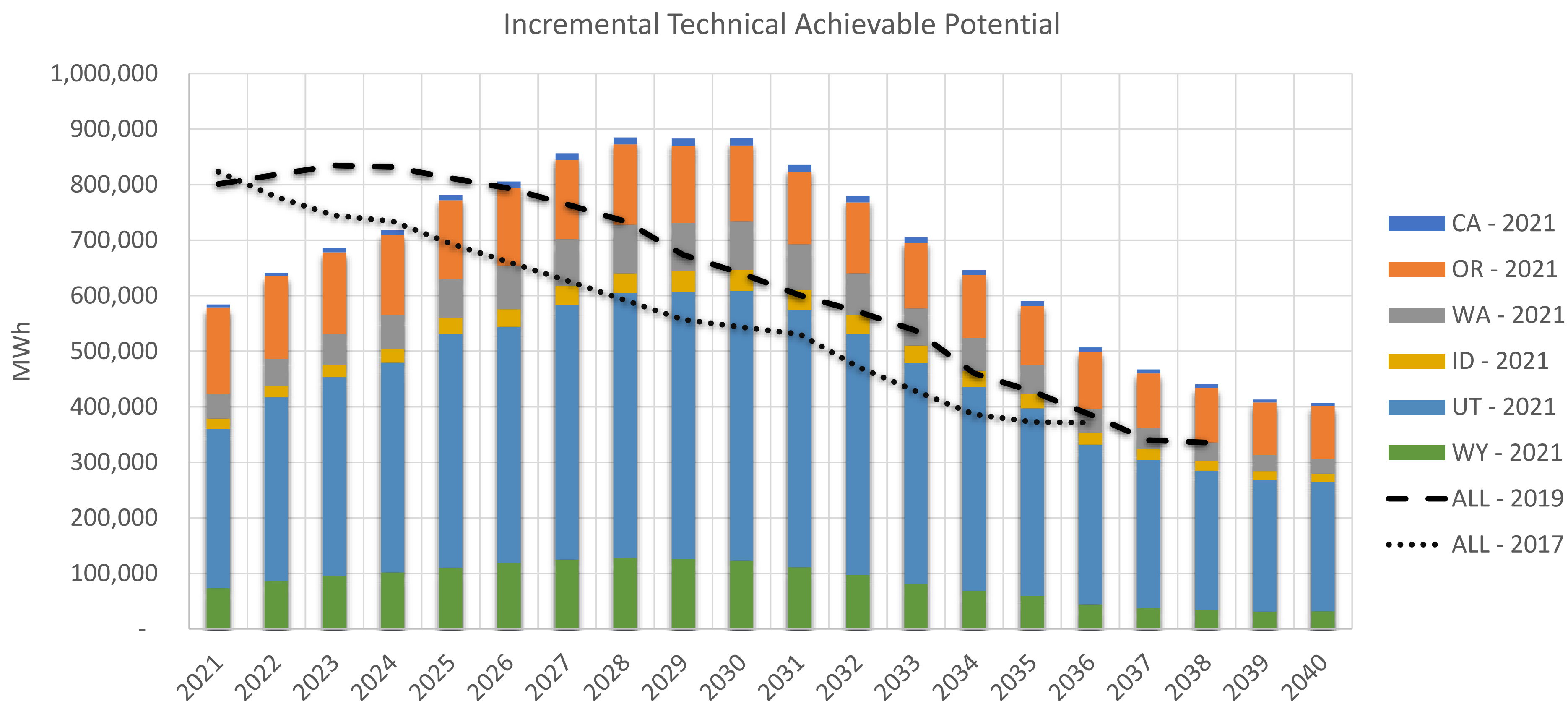
Total 20-year cumulative potential is slightly higher than the previous study, but savings are more expensive because of the decrease in cheaper lighting savings

Cost bundles represent the technical achievable potential, ***not economic potential***

Each cost bundle represents a different weighted average load shape based on the measures within it.

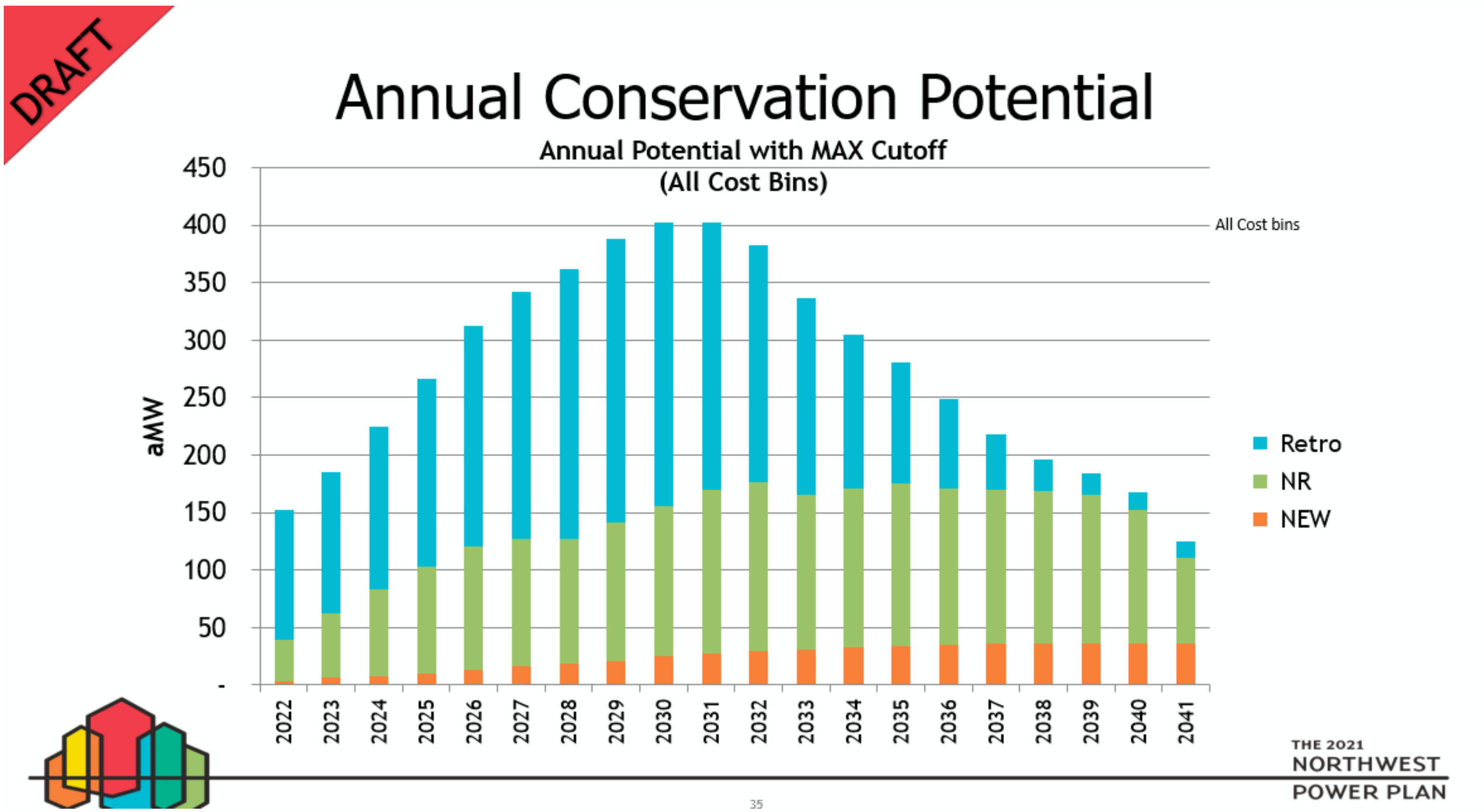
Cost bundles are selected in the IRP based on economics and their ability to contribute to the system in competition with all other supply-side resources.

Technical Achievable Potential Comparison (All States - Incremental MWh)



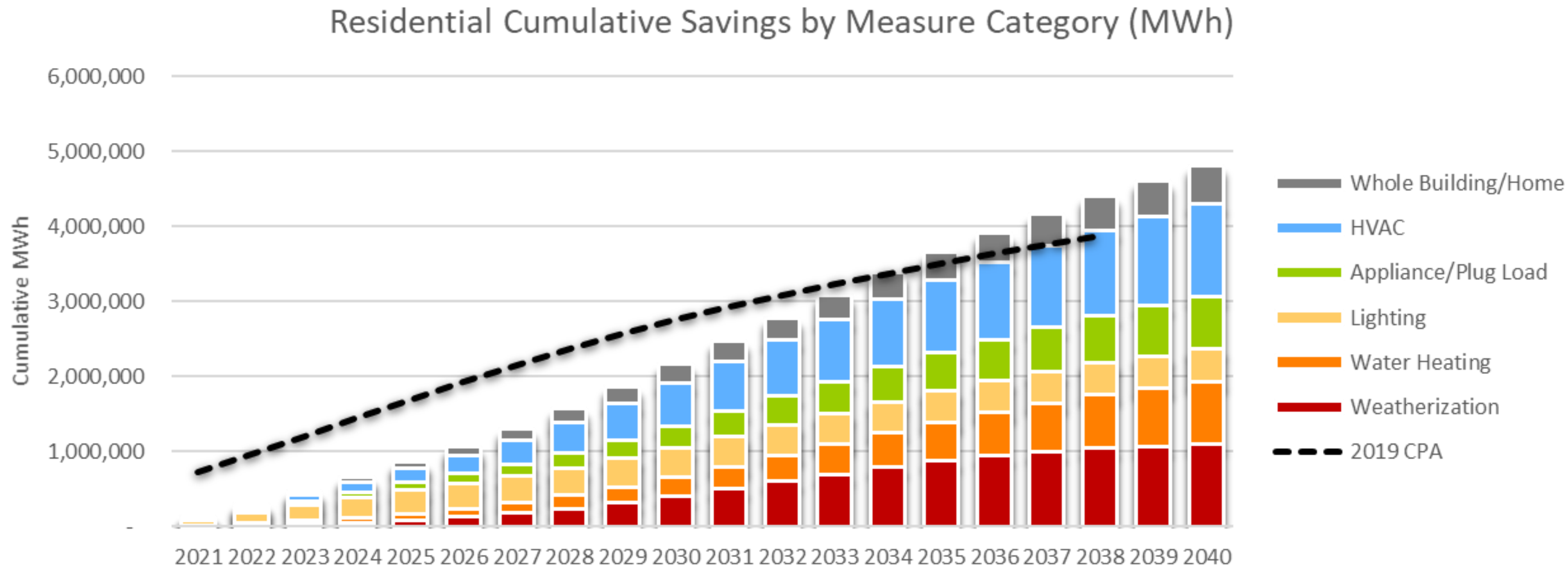
- Incremental savings opportunities have been moved out in time
  - Lighting savings decreases and ramp rate adjustments
- LEDs have a large impact on early year savings opportunities compared to previous
  - Similar trend in NWPCC 2021 Plan (next slide)
- Graph illustrates the dynamic nature of energy efficiency and forecasting

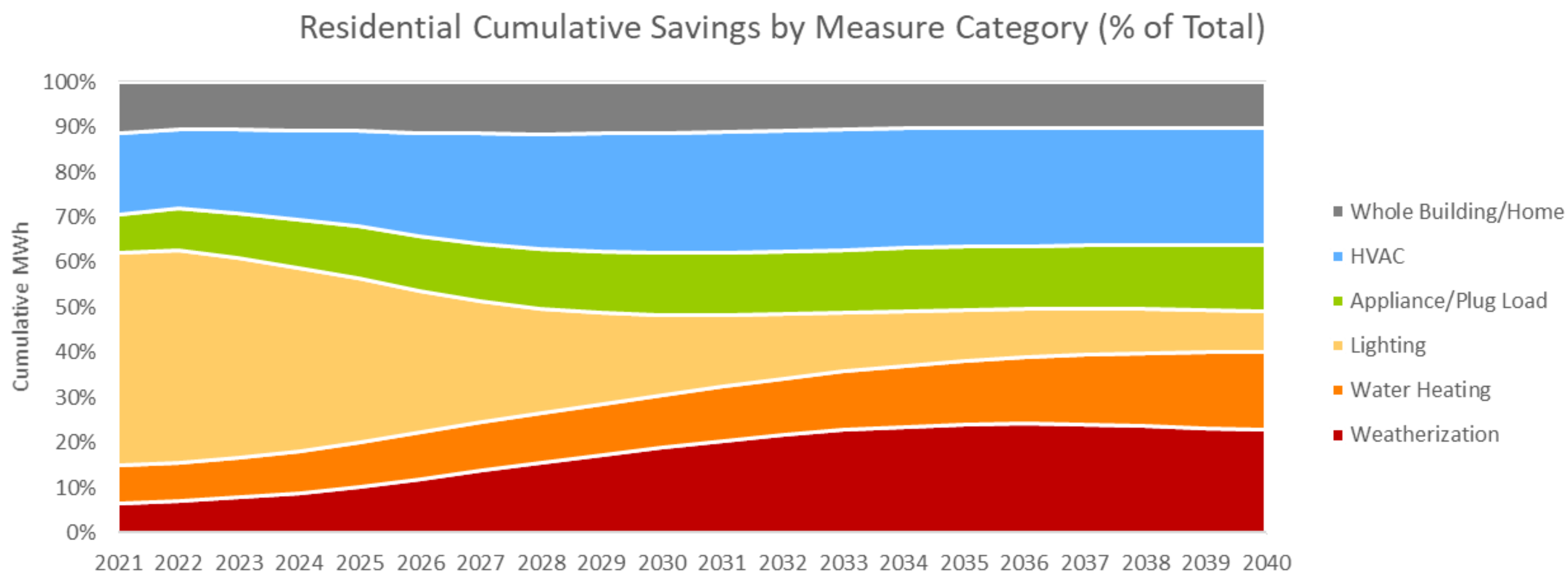
Comparison to NWPCC 2021 Power Plan Incremental MWh Tech. Ach. Results



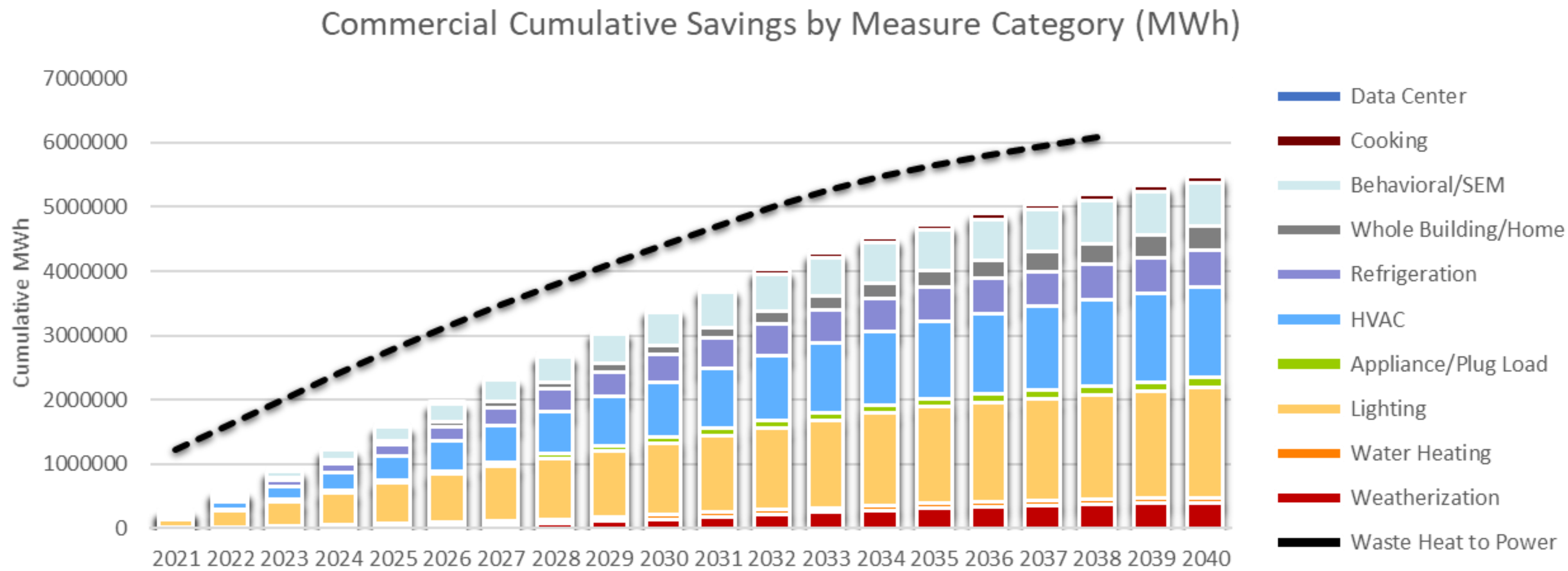
- Similar overall shape to the PacifiCorp 2021 CPA Draft Results
- Curve is starts even lower due to lighting market baselines for all states, not just some states as in the PacifiCorp 2021 CPA Draft Results
- *Source: NWPCC https://nwcouncil.app.box.com/s/f7v6uhiw4k8qwp0c7ovzvrqom9o71hre*

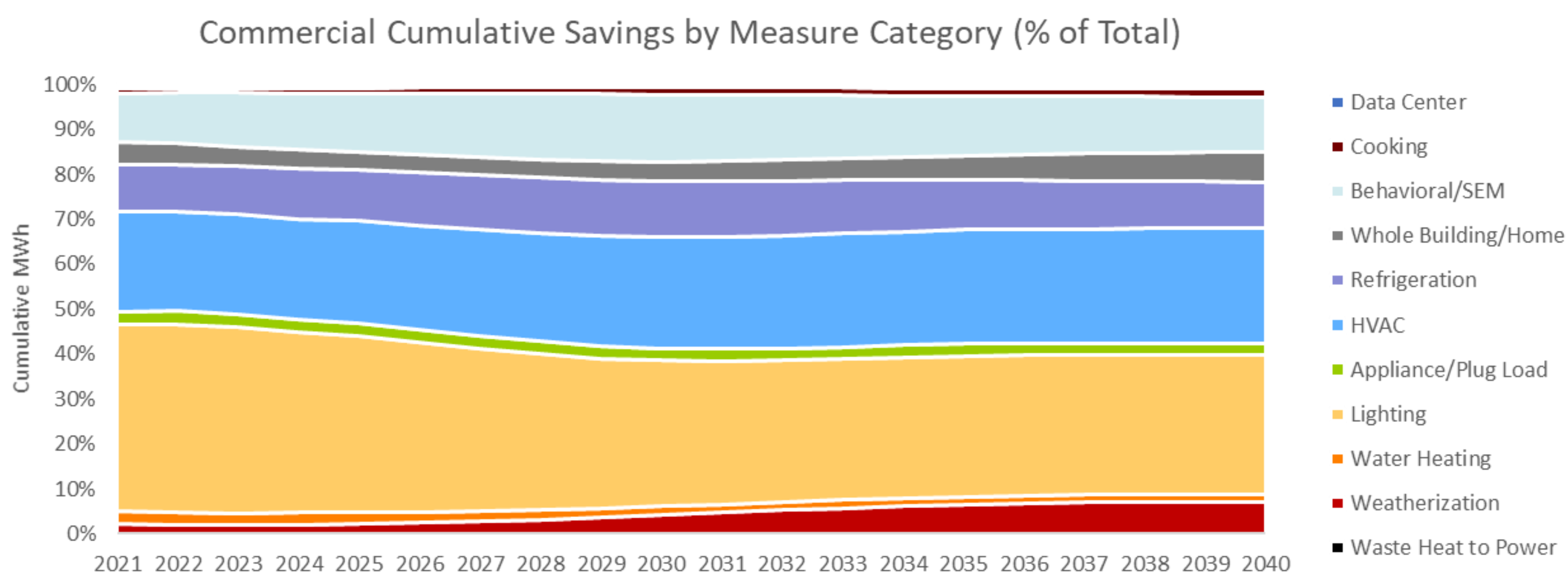
Residential Draft Results (All States)





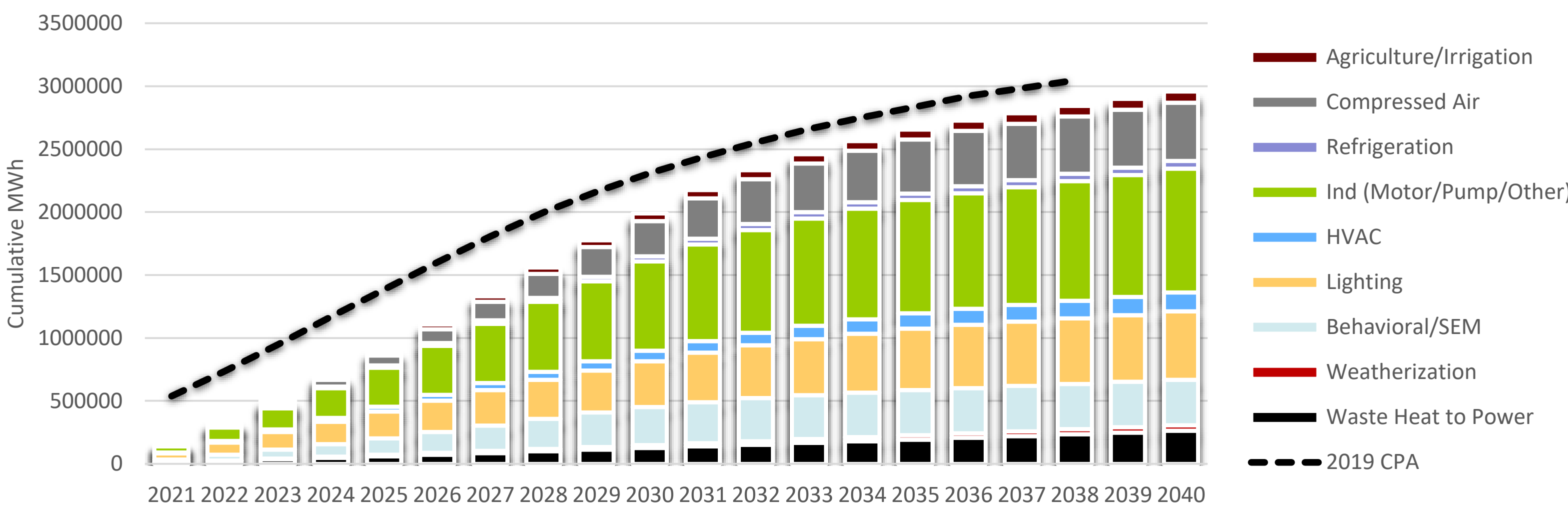
Commercial Draft Results (All States)



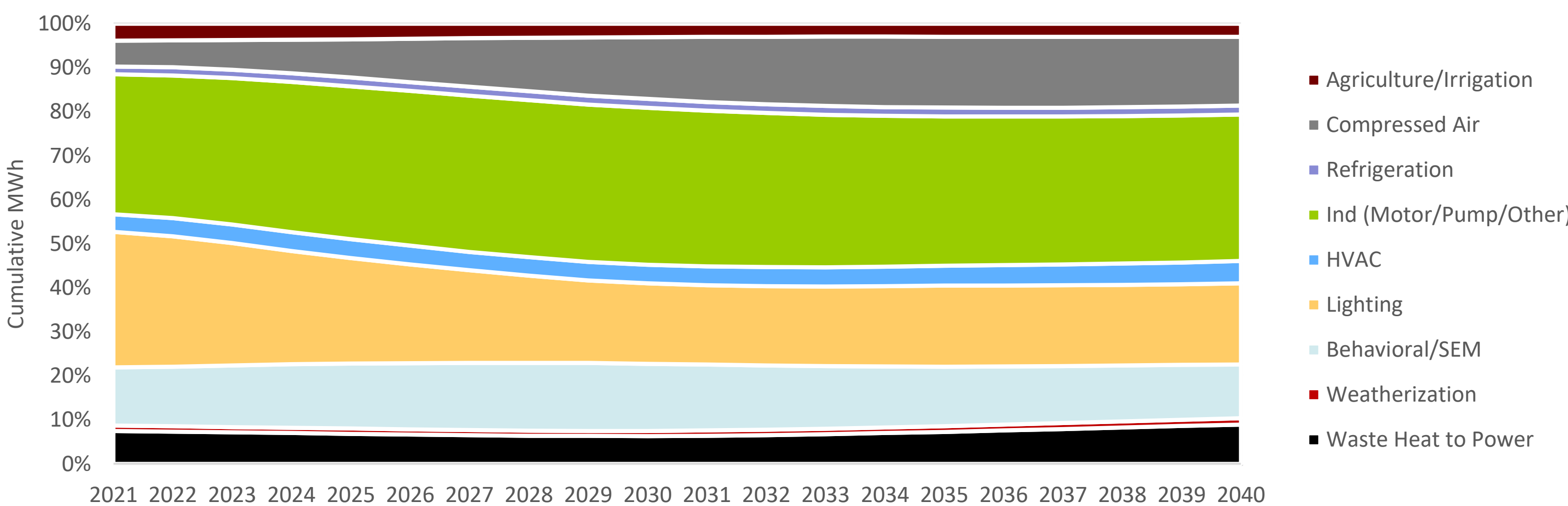


Industrial Draft Results (All States)

Industrial Cumulative Savings by Measure Category (MWh)



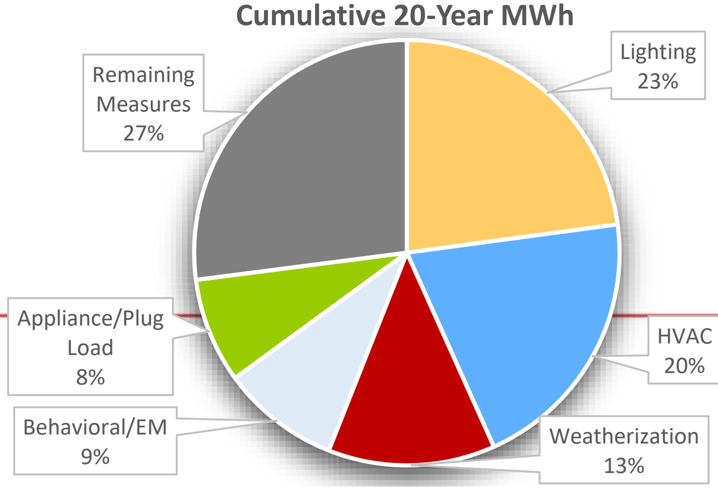
Industrial Cumulative Savings by Measure Category (% of Total)



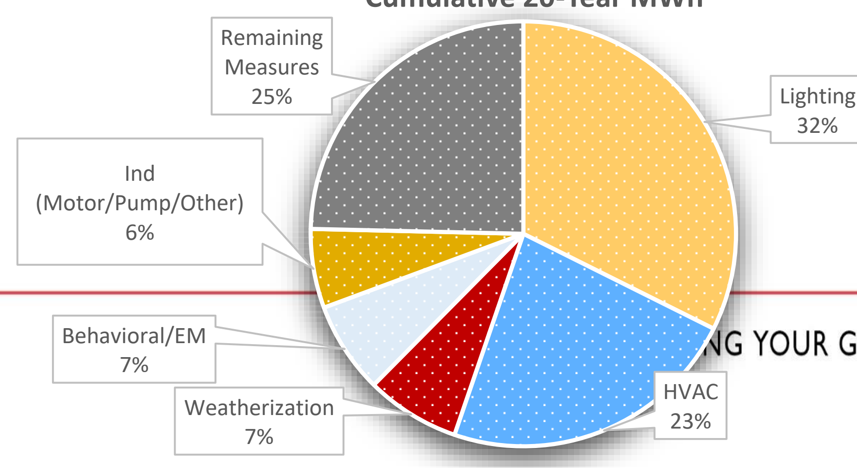
Utah - Top Measures (MWh)

2040 Rank	Measure Type	2021 CPA Draft: 20-Year Cumulative Potential	% of Total	2019 CPA 20 Year Cumulative Potential	% Change
1	Lighting	1,686,728	22.9%	1,955,444	-13.7%
2	HVAC	1,505,509	20.4%	1,382,225	8.9%
3	Weatherization	936,397	12.7%	432,601	116.5%
4	Behavioral/EM	662,245	9.0%	419,183	58.0%
5	Appliance/Plug Load	589,442	8.0%	273,043	115.9%
6	Water Heating	526,470	7.1%	329,590	59.7%
7	Whole Building/Home	362,607	4.9%	273,062	32.8%
8	Refrigeration	316,864	4.3%	143,810	120.3%
9	Ind (Motor/Pump/Other)	310,137	4.2%	363,476	-14.7%
10	Waste Heat to Power	206,937	2.8%	150,698	37.3%
11	Compressed Air	128,913	1.7%	162,429	-20.6%
12	Cooking	63,523	0.9%	99,210	-36.0%
13	Data Center	52,776	0.7%	23,884	121.0%
14	Agriculture/Irrigation	25,806	0.3%	32,277	-20.0%
	Total	**7,374,352**	**100.0%**	**6,040,931**	**22.1%**

Utah, Technical Achievable Savings 2021 CPA Cumulative 20-Year MWh

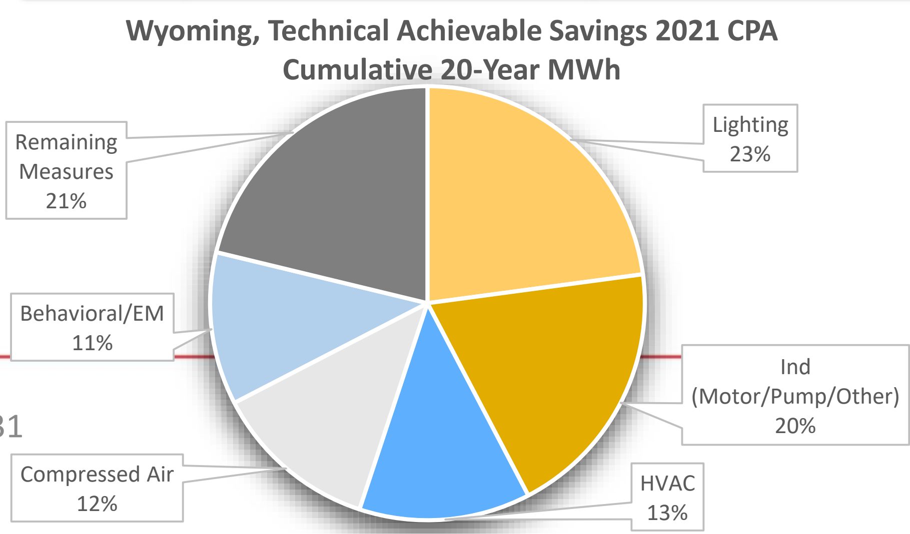


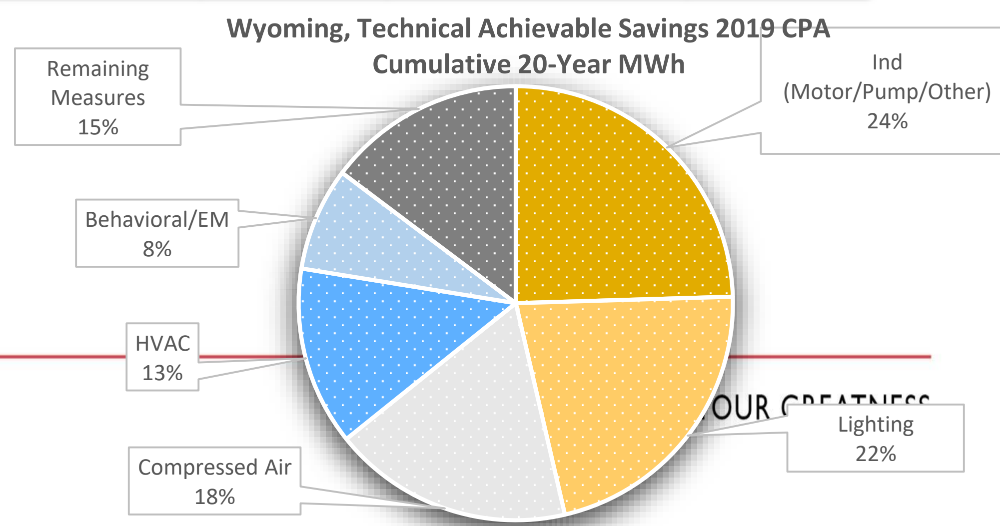
Utah, Technical Achievable Savings 2019 CPA Cumulative 20-Year MWh



Wyoming - Top Measures (MWh)

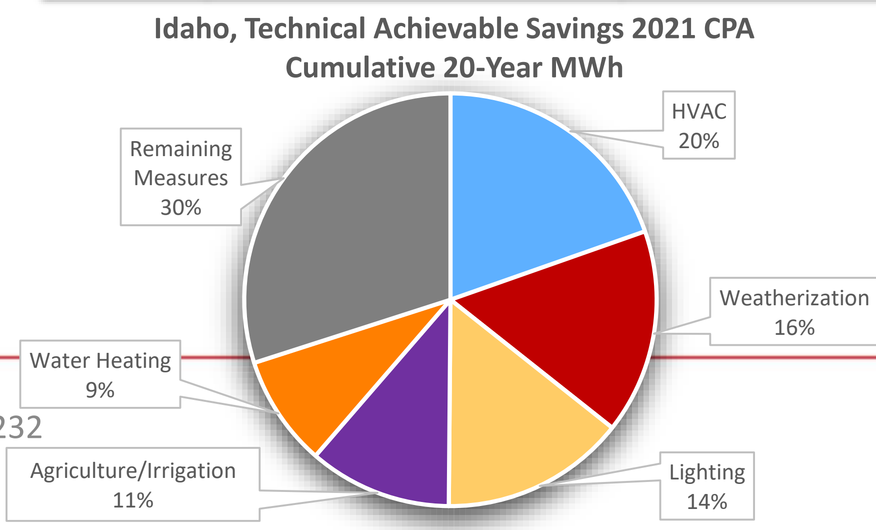
Rank	Measure Type	2021 CPA Draft: 20-Year Cumulative Potential	% of Total	2019 CPA 20 Year Cumulative Potential	% Change
1	Lighting	385,020	22.9%	379,848	1.4%
2	Ind (Motor/Pump/Other)	327,392	19.4%	426,479	-23.2%
3	HVAC	214,536	12.7%	231,657	-7.4%
4	Compressed Air	207,772	12.3%	310,768	-33.1%
5	Behavioral/EM	191,406	11.4%	133,840	43.0%
6	Weatherization	110,122	6.5%	52,190	111.0%
7	Appliance/Plug Load	61,657	3.7%	33,096	86.3%
8	Water Heating	56,008	3.3%	70,293	-20.3%
9	Refrigeration	49,271	2.9%	27,770	77.4%
10	Waste Heat to Power	33,973	2.0%	27,515	23.5%
11	Whole Building/Home	33,481	2.0%	25,765	29.9%
12	Cooking	8,531	0.5%	14,440	-40.9%
13	Agriculture/Irrigation	4,180	0.2%	5,029	-16.9%
14	Data Center	13	0.0%	310	-95.8%
	Total	**1,683,363**	**100.0%**	**1,739,002**	**-3.2%**

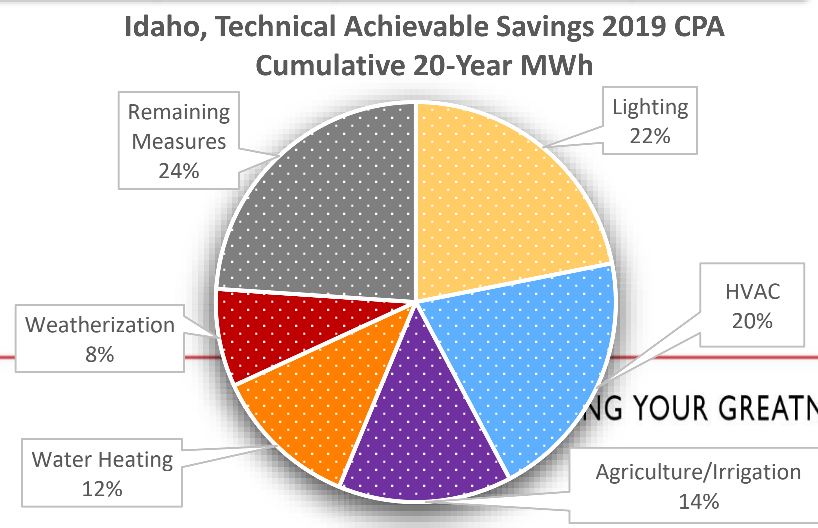




Idaho - Top Measures (MWh)

Rank	Measure Type	2021 CPA Draft: 20-Year Cumulative Potential	% of Total	2019 CPA 20 Year Cumulative Potential	% Change
1	HVAC	105,876	19.6%	105,157	0.7%
2	Weatherization	86,446	16.0%	40,902	111.4%
3	Lighting	78,111	14.5%	113,223	-31.0%
4	Agriculture/Irrigation	60,553	11.2%	72,579	-16.6%
5	Water Heating	46,910	8.7%	61,458	-23.7%
6	Appliance/Plug Load	38,975	7.2%	22,386	74.1%
7	Behavioral/EM	35,602	6.6%	28,369	25.5%
8	Whole Building/Home	28,480	5.3%	21,696	31.3%
9	Refrigeration	24,182	4.5%	12,944	86.8%
10	Compressed Air	14,681	2.7%	8,808	66.7%
11	Ind (Motor/Pump/Other)	13,585	2.5%	17,625	-22.9%
12	Cooking	3,380	0.6%	8,862	-61.9%
13	Waste Heat to Power	2,642	0.5%	2,984	-11.5%
14	Data Center	31	0.0%	155	-80.2%
	Total	**539,454**	**100.0%**	**517,148**	**4.3%**





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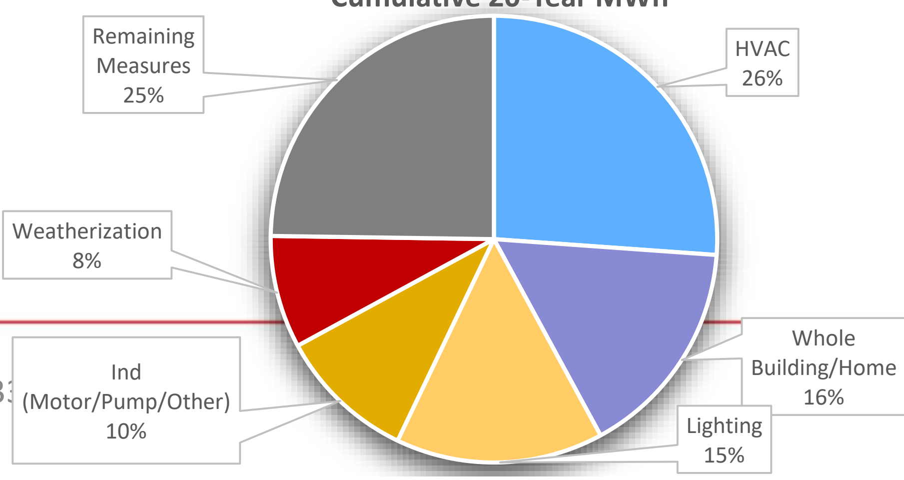
Oregon - Top Measures (MWh)

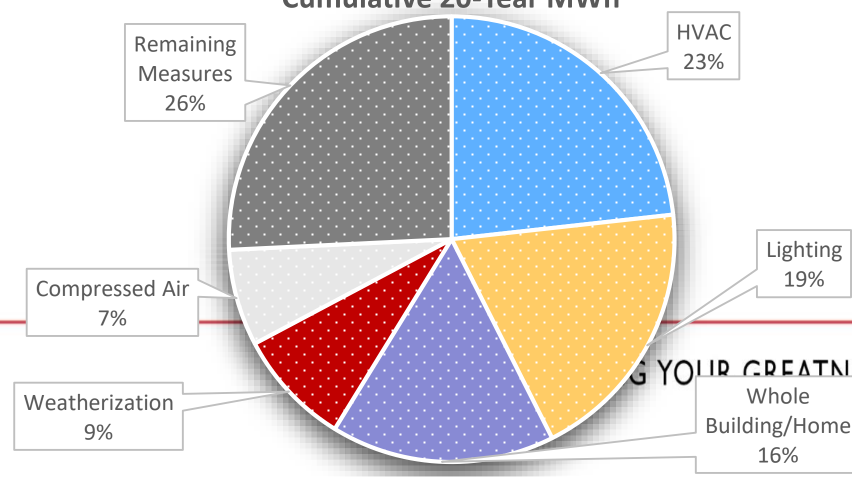
2040 Rank	Measure Type	2021 CPA Draft: 20-Year Cumulative Potential	% of Total	2019 CPA 20 Year Cumulative Potential	% Change
1	HVAC	660,002	26.1%	823,842	-19.9%
2	Whole Building/Home	402,684	15.9%	575,256	-30.0%
3	Lighting	379,532	15.0%	684,512	-44.6%
4	Ind (Motor/Pump/Other)	252,156	10.0%	246,802	2.2%
5	Weatherization	205,695	8.1%	299,495	-31.3%
6	Water Heating	157,208	6.2%	243,458	-35.4%
7	Behavioral/SEM	130,754	5.2%	110,903	17.9%
8	Refrigeration	89,846	3.6%	59,378	51.3%
9	Agriculture/Irrigation	85,981	3.4%	46,774	83.8%
10	Appliance/Plug Load	79,676	3.2%	183,412	-56.6%
11	Compressed Air	64,384	2.5%	248,007	-74.0%
12	Cooking	17,819	0.7%	22,489	-20.8%
	Total	**2,525,737**	**100.0%**	**3,544,327**	**-28.7%**

**The 2019 CPA included a large project adder every year, which accounted for 5% of OR's cumulative savings in 2019 - The large project adder has been removed from the forecast in 2021 CPA*
*** Oregon's numbers will change with updated budget forecasts currently under development before final results to input into the IRP*

Oregon, Technical Achievable Savings 2021 CPA Cumulative 20-Year MWh



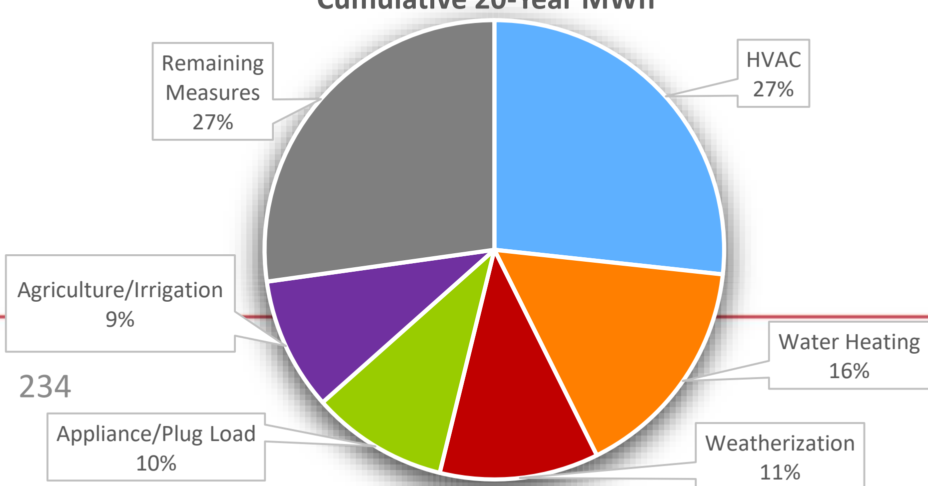
Oregon, Technical Achievable Savings 2019 CPA Cumulative 20-Year MWh



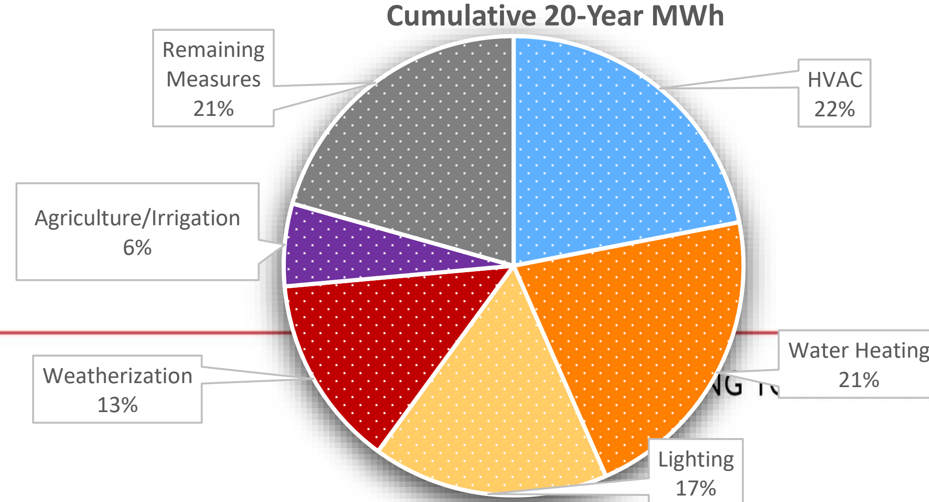
California - Top Measures (MWh)

Rank	Measure Type	2021 CPA Draft: 20-Year Cumulative Potential	% of Total	2019 CPA 20 Year Cumulative Potential	% Change
1	HVAC	48,975	26.7%	46,449	5.4%
2	Water Heating	29,215	15.9%	45,388	-35.6%
3	Weatherization	20,506	11.2%	28,600	-28.3%
4	Appliance/Plug Load	17,620	9.6%	11,461	53.7%
5	Agriculture/Irrigation	17,145	9.4%	12,285	39.6%
6	Refrigeration	15,206	8.3%	6,649	128.7%
7	Behavioral/EM	13,486	7.4%	10,145	32.9%
8	Lighting	7,892	4.3%	35,150	-77.5%
9	Whole Building/Home	5,470	3.0%	5,095	7.4%
10	Ind (Motor/Pump/Other)	2,778	1.5%	5,109	-45.6%
11	Cooking	2,297	1.3%	3,426	-33.0%
12	Compressed Air	1,779	1.0%	1,418	25.4%
13	Waste Heat to Power	996	0.5%	269	270.0%
14	Data Center	1	0.0%	52	-97.2%
	Total	**183,366**	**100.0%**	**211,495**	**-13.3%**

California, Technical Achievable Savings 2021 CPA Cumulative 20-Year MWh



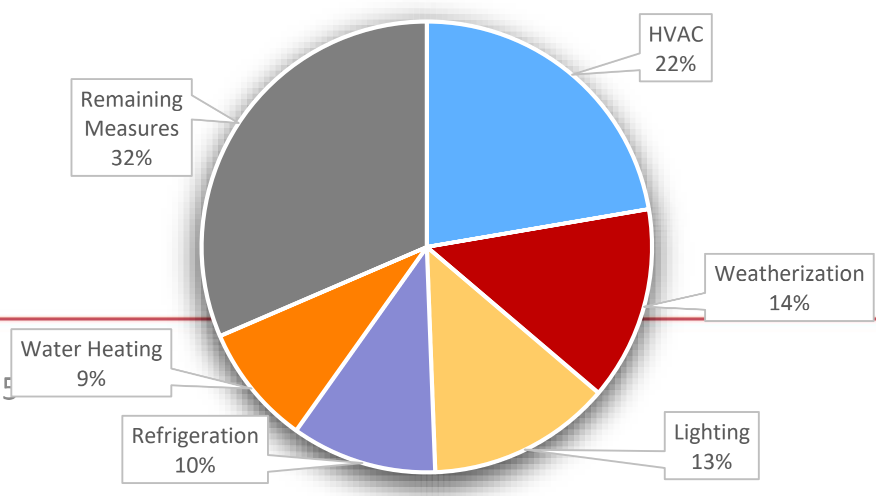
California, Technical Achievable Savings 2019 CPA Cumulative 20-Year MWh



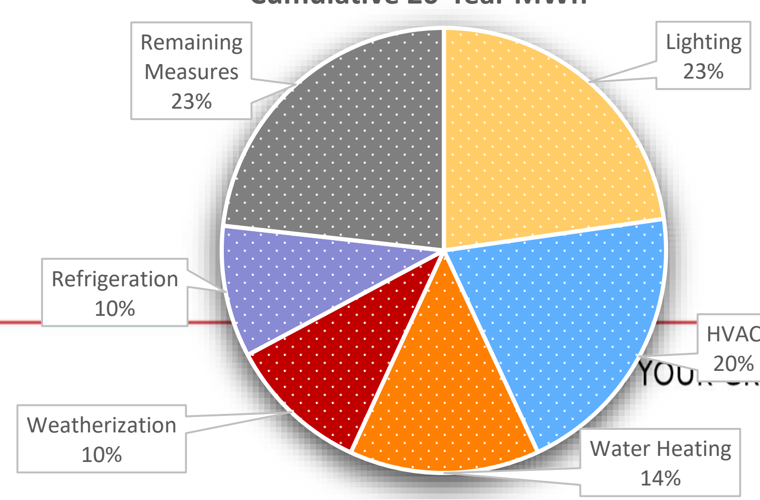
Washington - Top Measures (MWh)

Rank	Measure Type	2021 CPA Draft: 20-Year Cumulative Potential	% of Total	2019 CPA 20 Year Cumulative Potential	% Change
1	HVAC	269,983	22.3%	225,646	19.6%
2	Weatherization	168,126	13.9%	114,776	46.5%
3	Lighting	159,645	13.2%	252,504	-36.8%
4	Refrigeration	126,416	10.4%	106,112	19.1%
5	Water Heating	105,030	8.7%	153,662	-31.6%
6	Behavioral/EM	89,917	7.4%	39,234	129.2%
7	Ind (Motor/Pump/Other)	77,472	6.4%	65,967	17.4%
8	Appliance/Plug Load	68,298	5.6%	41,874	63.1%
9	Compressed Air	45,258	3.7%	24,047	88.2%
10	Whole Building/Home	40,238	3.3%	29,738	35.3%
11	Agriculture/Irrigation	31,848	2.6%	23,432	35.9%
12	Waste Heat to Power	19,615	1.6%	14,777	32.7%
13	Cooking	7,952	0.7%	18,484	-57.0%
14	Data Center	124	0.0%	374	-66.8%
	Total	**1,209,920**	**100.0%**	**1,110,628**	**8.9%**

Washington, Technical Achievable Savings 2021 CPA Cumulative 20-Year MWh



Washington, Technical Achievable Savings 2019 CPA Cumulative 20-Year MWh

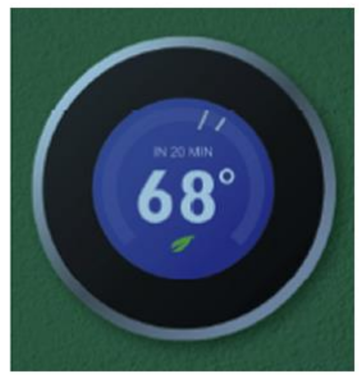


WA Low Income Results

- PacifiCorp requested AEG segment low income from standard income in WA in compliance with HB1444
- Low Income cutoff defined at 200% of the federal poverty level
- AEG adjusted baseline saturations from segmented residential survey data
- Analysis only completed for WA

Segment	2022 MWh	2025 MWh	2030 MWh	2040 MWh	% of 2040
Single Family	10,111	37,389	129,745	276,801	55.2%
Multi-Family	638	2,419	8,572	20,472	4.1%
Mobile Home	1,518	6,113	22,567	48,053	9.6%
Single Family - LI	3,213	11,995	41,425	87,330	17.4%
Multi-Family - LI	935	3,578	12,854	31,315	6.2%
Mobile Home - LI	1,220	4,868	17,724	37,154	7.4%
Total	*17,634*	*66,362*	*232,885*	*501,125*	*100.0%*

Demand Response Draft Results



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Demand Response Stakeholder Process

Stakeholder Process To-Date

- **December 2019:** Draft CPA Work Plan provided to stakeholders for review and comment
- **January 2020:** CPA Workshop #1. CPA overview and planned changes from 2019 CPA.
- **February 2020:** Draft Resource List, CPA Workshop #2. Defining demand measures:
  - Definitions
  - Evolving considerations
  - Research of impacts and costs
  - Resource Options
  - Consideration of customer-sited energy storage
- **April 2020:** Draft Measure List, CPA Workshop #3. Follow-up discussion on grid services and energy storage.
- **August 2020:** Presentation of Draft Potential Results

Key Changes Relative to the 2019 CPA

- New areas of focus based on recent PacifiCorp experience and stakeholder interest
  - Grid services view of DR; previously focused only on peak shaving
  - Control of pool pumps
  - Customer-sited energy storage
- Updates to AEG methodology:
  - Technology-based vs. program-based
  - Incorporates changes in equipment efficiency and adoption of enabling technology from energy efficiency forecast
  - Hourly potential estimation to allow flexibility in hours of interest
  - Assessment of impacts from short- and sustained-duration events
- Washington standard requiring new residential electric water heaters to include a modular DR communications port
- Development of the Northwest Power and Conservation Council's 2021 Power Plan, including demand response assumptions

DR Resources Assessed

State	Residential	Commercial	Industrial	Irrigation	New for 2021 CPA
Central Cooling	✓	✓	✓		
Zonal Cooling	✓				
Central Heating	✓	✓	✓		
Connected Thermostats	✓	✓			
Connected Consumer Goods	✓				
Water Heating	✓	✓			
Electric Vehicle Chargers	✓				
Pool Pump	✓	✓			
Battery Energy Storage	✓	✓			✓*
Interior Lighting Controls		✓	✓		✓**
Ventilation		✓	✓		✓**
Refrigeration		✓			✓**
Thermal Energy Storage		✓	✓		✓**
Motors and Process			✓		✓**
Irrigation Pumps				✓	

* Still under development
** Previously combined into "Third Party Contracts" program

Demand Response Assessment Methodology

Transition to Grid Services View of DR

- Previous CPAs have only assessed DR impacts during PacifiCorp's summer and winter system peak periods (Capacity & Energy)
- The 2021 CPA will assess DR's ability to provide value through events beyond peak shaving to align DR's capabilities with PacifiCorp's potential use cases.
- Demand response programs and technologies have been mapped to grid services based on their ability to meet the required performance characteristics of those services

Market Participation	Grid Services	DR Products	Advance Notice (mins)	Full Deployment (mins)	Duration (mins)	CPA Shed Duration
PAC BAA	Capacity & Energy	Capacity & Energy	55+	55+	60	Sustained
PAC BAA	Regulation	Regulation	<1-30	<30	<1-60	Short
EIM	Flexibility & Regulation	EIM Capacity & Energy	52.5	60	60+	Sustained
EIM	Flexibility & Regulation	EIM Capacity & Energy FMM	22.5	15	15+	Sustained
EIM	Flexibility & Regulation	EIM Capacity & Energy RTD	2.5	5	5+	Short
PAC BAA	Non-Spinning Reserves	Non-Spinning Reserves	10	10	60	Sustained
PAC BAA	Spinning Reserves	Spinning Reserves	<1	10	60	Sustained
PAC BAA	Frequency Response	Frequency Response	<1	<1	1	Short

Terminology and Key Sources

- **Total Market Size:** Number of applicable pieces of equipment (e.g., Utah residential central air conditioners), tied to energy efficiency forecast
- **Total Hourly Load:** Applicable load in any given hour of the year. Calculated as Total Market Size x average annual consumption, spread over hourly load shape
- **Controllability:** Percent of equipment controllable/eligible for DR, based on energy efficiency forecast and technology characteristics
- **Sheddability:** Fraction of controllable load that can be shed during a DR event
  - Some technologies have different factors for short vs. sustained duration events
  - Informed by LBNL California DR Potential Study, PacifiCorp program experience and draft 2021 Power Plan
- **Program Participation:** Percent of eligible customers assumed to participate
  - Informed by draft 2021 Power Plan and PacifiCorp program experience
- **Participation Ramp Factor (Next Steps):** Annual ramp rate as a % of market potential
  - Previous study assumed 2-year lag and 3-5 year ramp up period for new programs
  - To be informed by program experience, draft 2021 Power Plan assumptions, and IRP timing

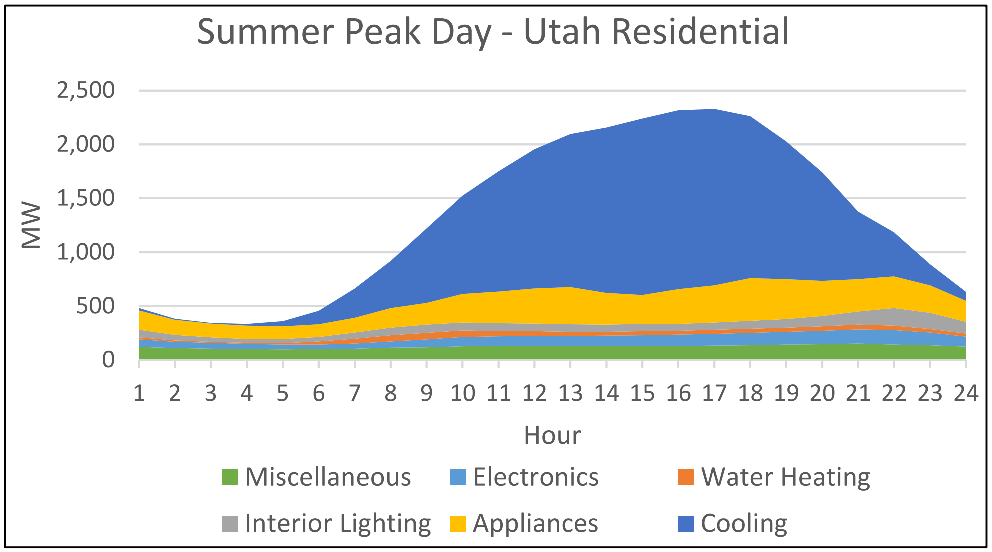
Assessing Customer-Sited Battery Energy Storage for Demand Response

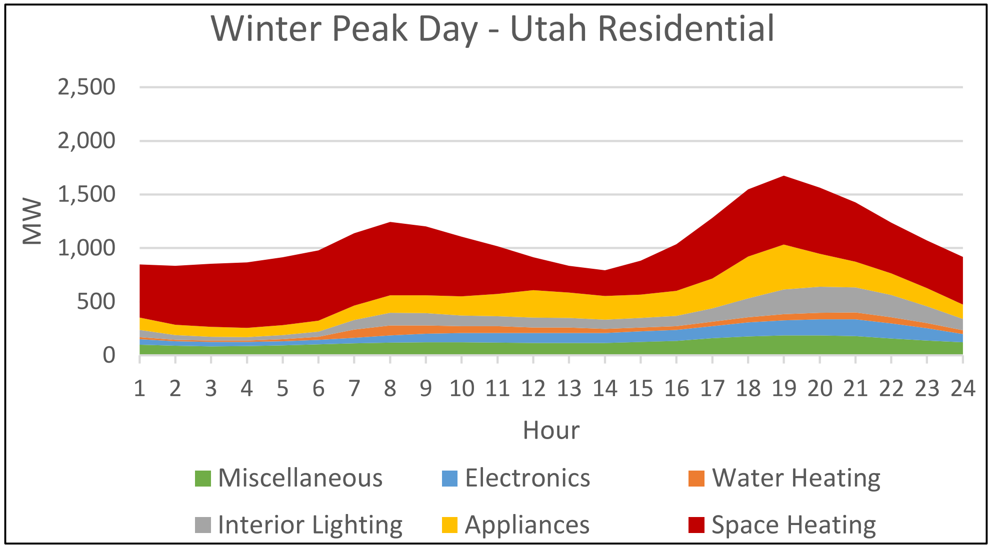
- Modeling customer-sited battery energy storage as a demand response resource is new for the 2021 CPA
- This is a limited use case of energy storage, assessing the potential for PacifiCorp to discharge customer-sited batteries based on the types of events considered in the DR analysis
- Key assumptions in development to assess potential:
  - Program design: “Bring your own” program model, considering lease

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 %	50 %
Program Participation	50-75 %	50-75 %
Capacity Available for Control	80%	50% (limited by customer demand)

Process for Developing DR Potential

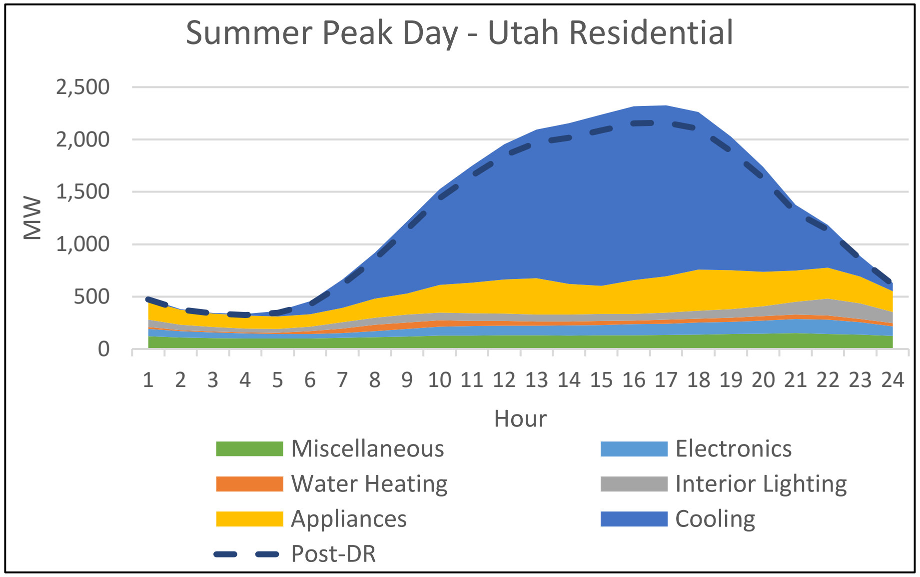
- Step 1. Identify Hourly Market Size by Technology
  - Use same forecast from energy efficiency analysis to identify total market size and associated annual consumption
  - Spread annual consumption over hourly 8760 load shapes to identify estimate load by technology in each hour of the year





Process for Developing DR Potential (Continued)

- Step 2. Calculate Potential Demand Reduction
  - Identify controllable equipment and apply shed rates (% reduction) to controllable load to identify resource size. Shed rates may vary by event duration
  - Apply participation rates (% of eligible load participating) to identify long-run market potential
  - Account for interaction between competing options to avoid double-counting
  - Apply ramp rates to account for time required to achieve maximum participation
- Step 3. Identify Impacts During Period(s) of Interest
  - Previous studies have only assessed impacts during peak periods, but the value of demand response is evolving
    - Net peak load
    - Grid services
    - Ability to call many short events instead of a few longer events



Developing Demand Response Resource Costs

- Unlike most energy efficiency programs, where costs are incurred up-front and savings persist over a period of time, demand response resources generally require upfront startup costs plus ongoing costs to continue to realize impacts.
- To account for this, demand response resource costs for IRP modeling are amortized over an assumed contract period
  - For the 2021 IRP, PacifiCorp plans to assume a 5-year amortization period to align with current procurement practices
- As in the 2019 CPA, resource costs for Pacific Power will be based on a Total Resource Cost perspective and Rocky Mountain Power will be based on a Utility Cost Test perspective. The difference is in the treatment of participant costs and incentives:
  - 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. California protocol default is 75% of incentive.
- Levelized costs are typically presented in $/kW-year, but the available kW value can vary significantly based on the use case, as shown in results slides

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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) (shared across programs)	Marketing Costs *($/participant)*	O&M *($/participant)*
	Incentives *($/participant or $/kW)*	Incentives *($/participant or $/kW)*

- In previous studies, certain costs have been 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

Draft Potential Results

How to Interpret Potential Results

- Results represent the potential in the 20th year of the study – time will be required to ramp up to full participation
- Impacts presented are during PacifiCorp's summer and winter system peaks and may not align with state, sector, or technology peaks
- Potential accounts for interaction between competing resources to avoid double counting (e.g., DLC of central AC and controllable thermostats)
- Potential includes impacts of existing PacifiCorp programs – to be netted out when assessing new resource options within the IRP
- Potential for customer-sited energy storage is still to be added

Key Trends in Potential Relative to 2019 CPA

- Adoption of grid-enabled technologies create new opportunities for demand response
- Certain end uses and equipment can provide additional potential during short-duration events
- Water heating potential has increased, due to the emergence of grid-interactive equipment, new standards, and the modeling of a standalone control option
- Higher forecasted electric vehicle adoption has increased the potential for control of electric vehicle chargers

20-Year Potential Summary - Summer

	MW Impacts – Sustained Duration				
State	**Residential**	**Commercial and Industrial**	**Irrigation**	**Total**	**% Peak Reduction**
UT	191	127	12	330	5%
ID	5	8	120	133	28%
WY	5	39	1	44	3%
OR	89	56	9	154	5%
WA	24	19	3	46	5%
CA	3	2	2	7	6%
System	**318**	**252**	**146**	**715**	**6%**
2019 CPA	**359**	**325**	**211**	**896**	

	MW Impacts – Short-Duration				
State	**Residential**	**Commercial and Industrial**	**Irrigation**	**Total**	**% Peak Reduction**
UT	395	141	12	548	9%
ID	9	9	120	139	29%
WY	9	33	1	43	3%
OR	159	62	9	229	8%
WA	44	20	3	67	7%
CA	5	3	2	10	7%
System	**622**	**268**	**146**	**1,035**	**9%**

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20-Year Potential Summary - Winter

	MW Impacts – Sustained Duration				
State	**Residential**	**Commercial and Industrial**	**Irrigation**	**Total**	**% Peak Reduction**
UT	120	99	0	219	5%
ID	9	6	0	15	4%
WY	9	36	0	44	3%
OR	107	50	0	157	5%
WA	30	16	0	46	5%
CA	7	2	0	8	5%
System	**283**	**207**	**0**	**490**	**5%**
2019 CPA	**286**	**173**	**0**	**459**	

	MW Impacts – Short-Duration				
State	**Residential**	**Commercial and Industrial**	**Irrigation**	**Total**	**% Peak Reduction**
UT	145	98	0	243	5%
ID	12	6	0	18	5%
WY	11	28	0	40	3%
OR	167	51	0	218	6%
WA	38	15	0	53	5%
CA	8	2	0	10	6%
System	**382**	**200**	**0**	**583**	**5%**

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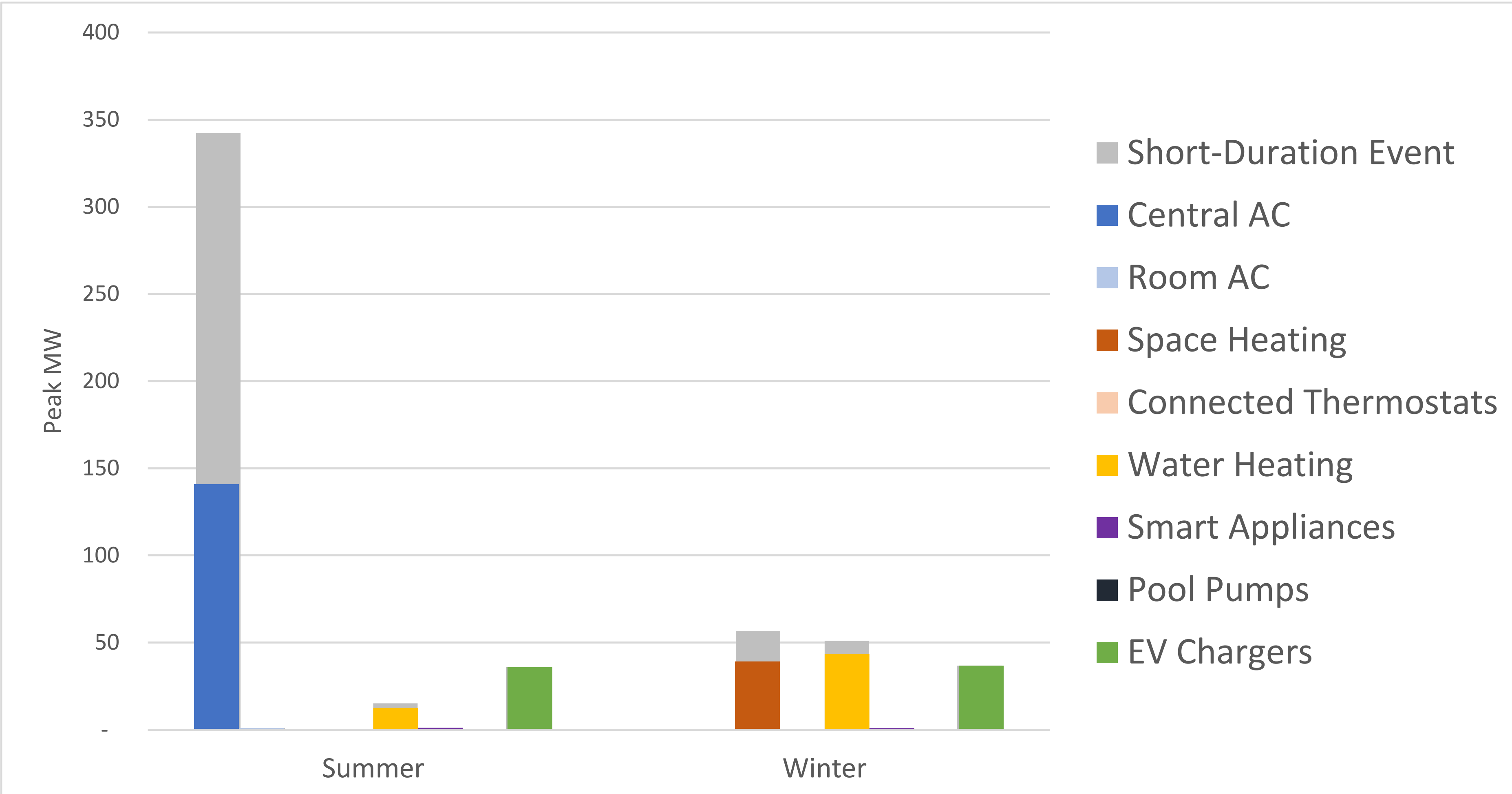
20-Year Potential: Utah Residential



* The assumption in RMP states is that potential for central cooling and heating would be captured through switches, not connected thermostats.

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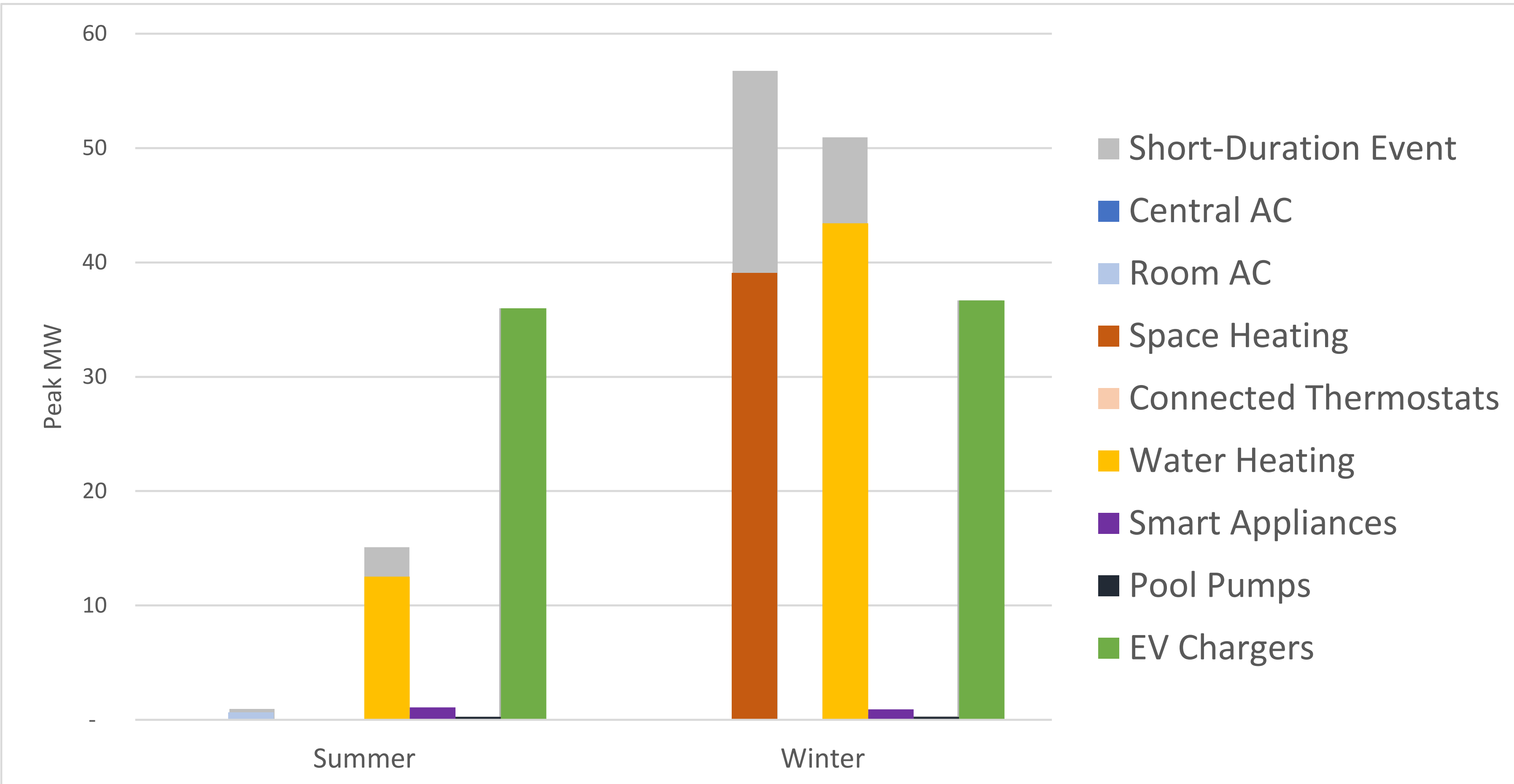
20-Year Potential: Utah Residential, Excluding Cool Keeper



* The assumption in RMP states is that potential for central cooling and heating would be captured through switches, not connected thermostats.

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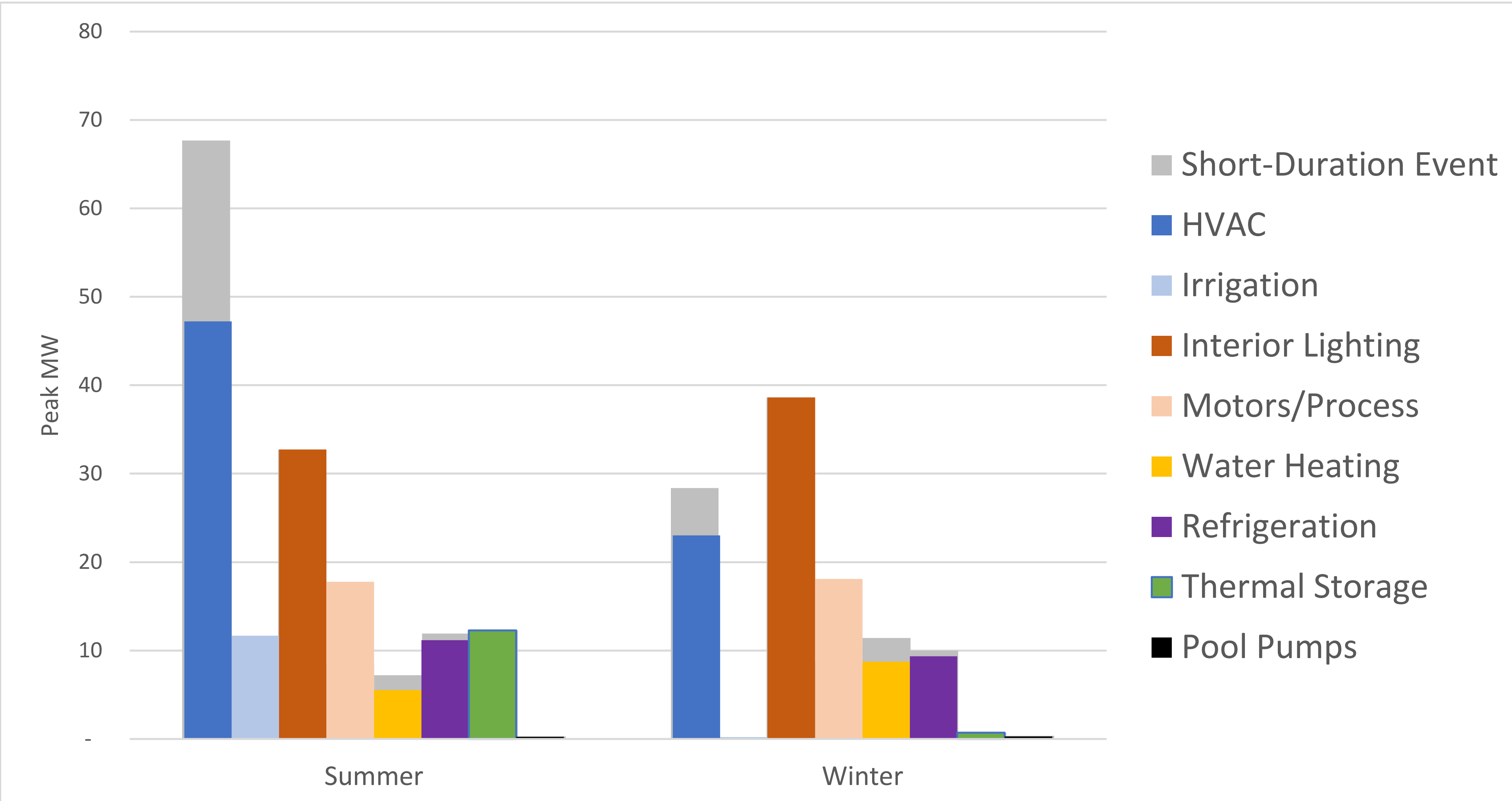
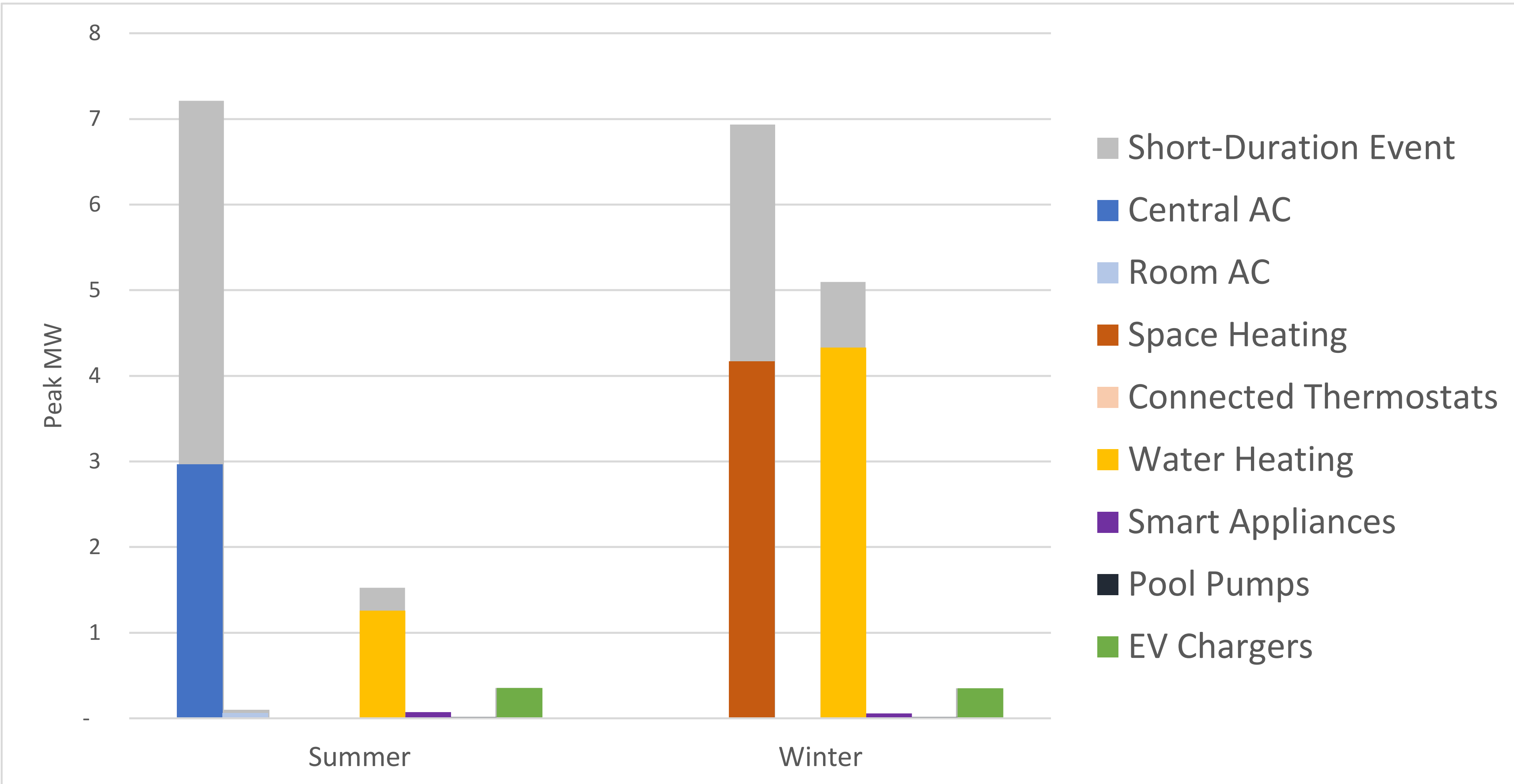
20-Year Potential: Utah Non-Residential



20-Year Potential: Idaho Residential



* The assumption in RMP states is that potential for central cooling and heating would be captured through switches, not connected thermostats.

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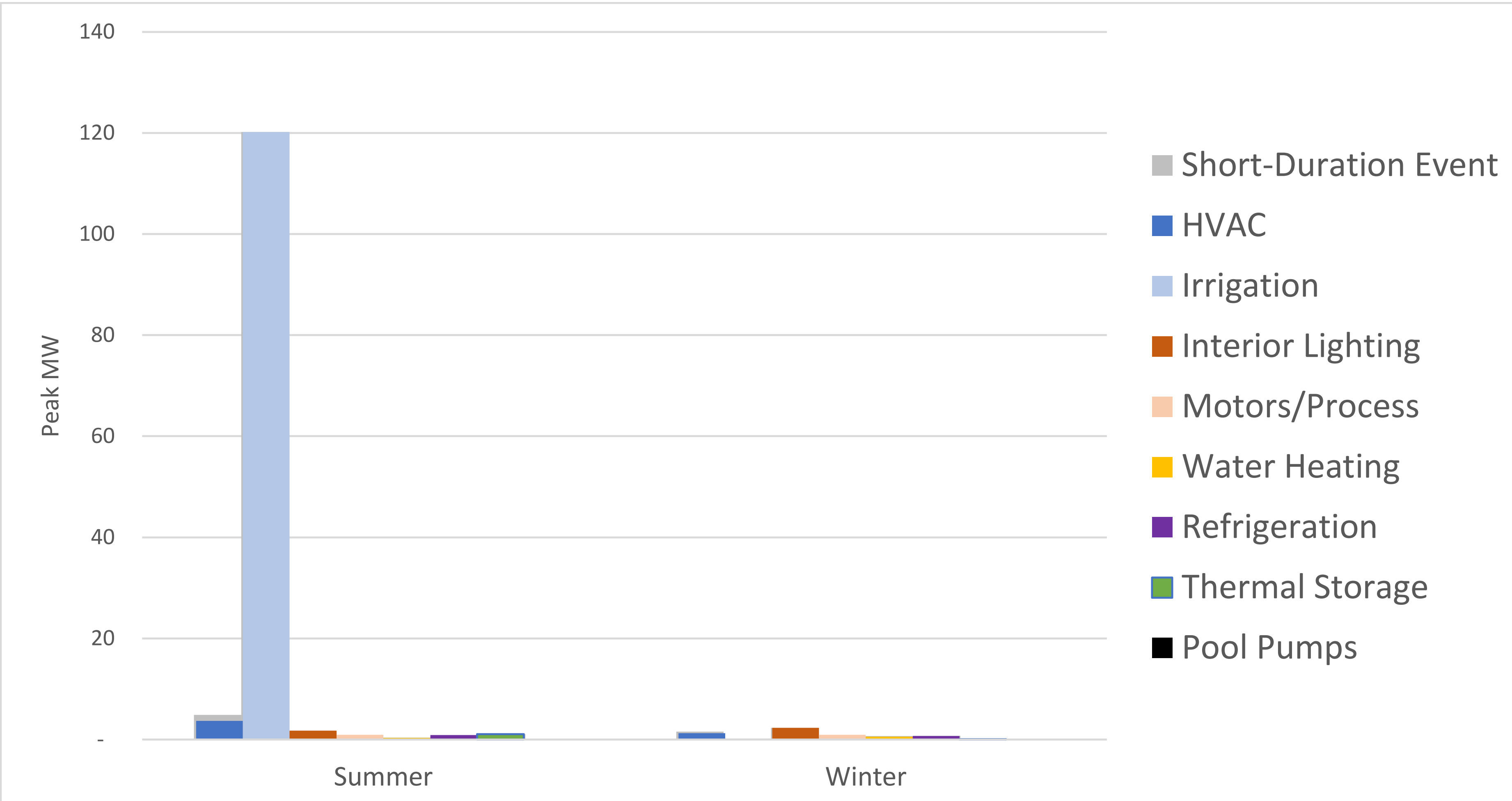
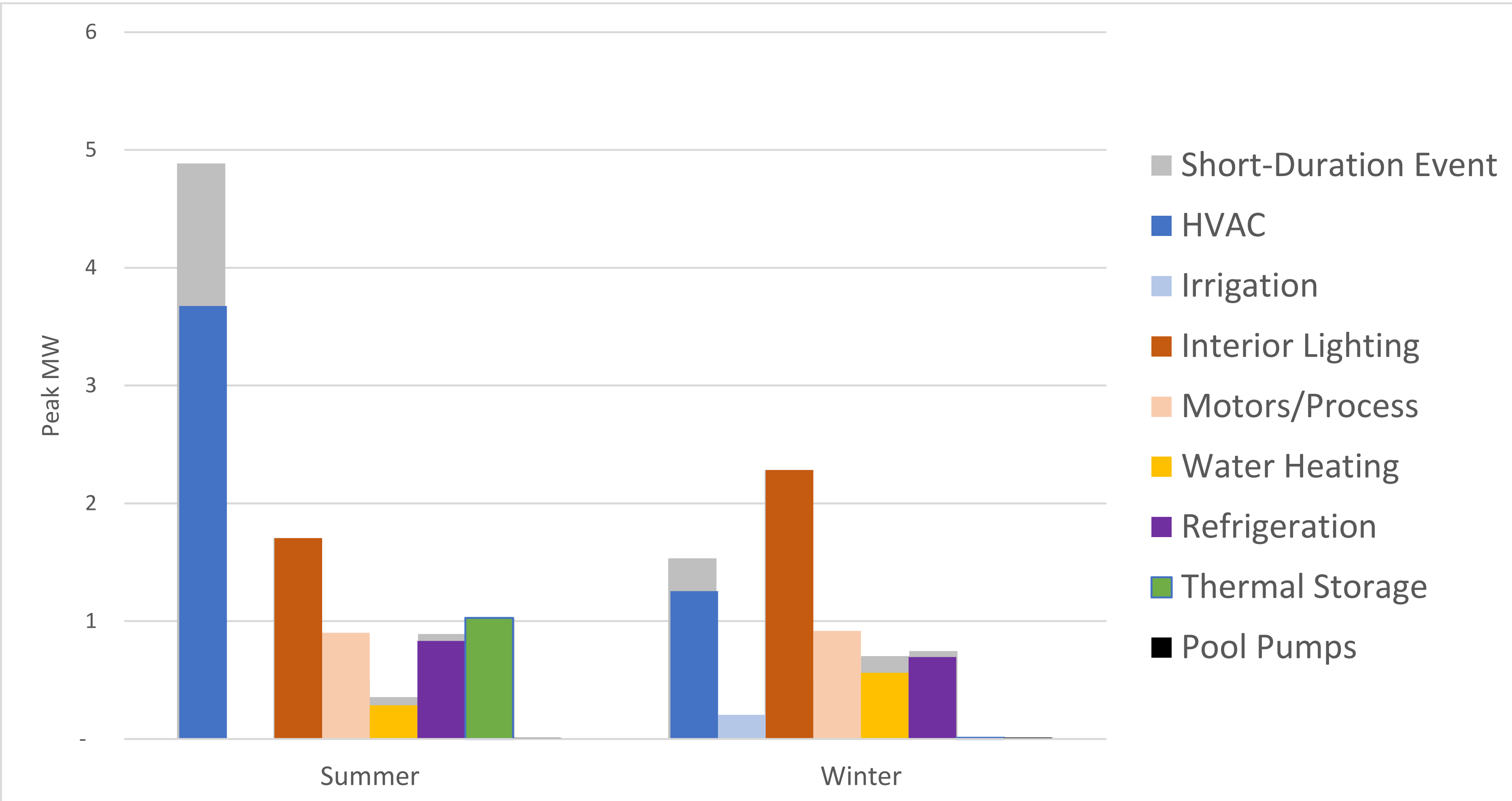
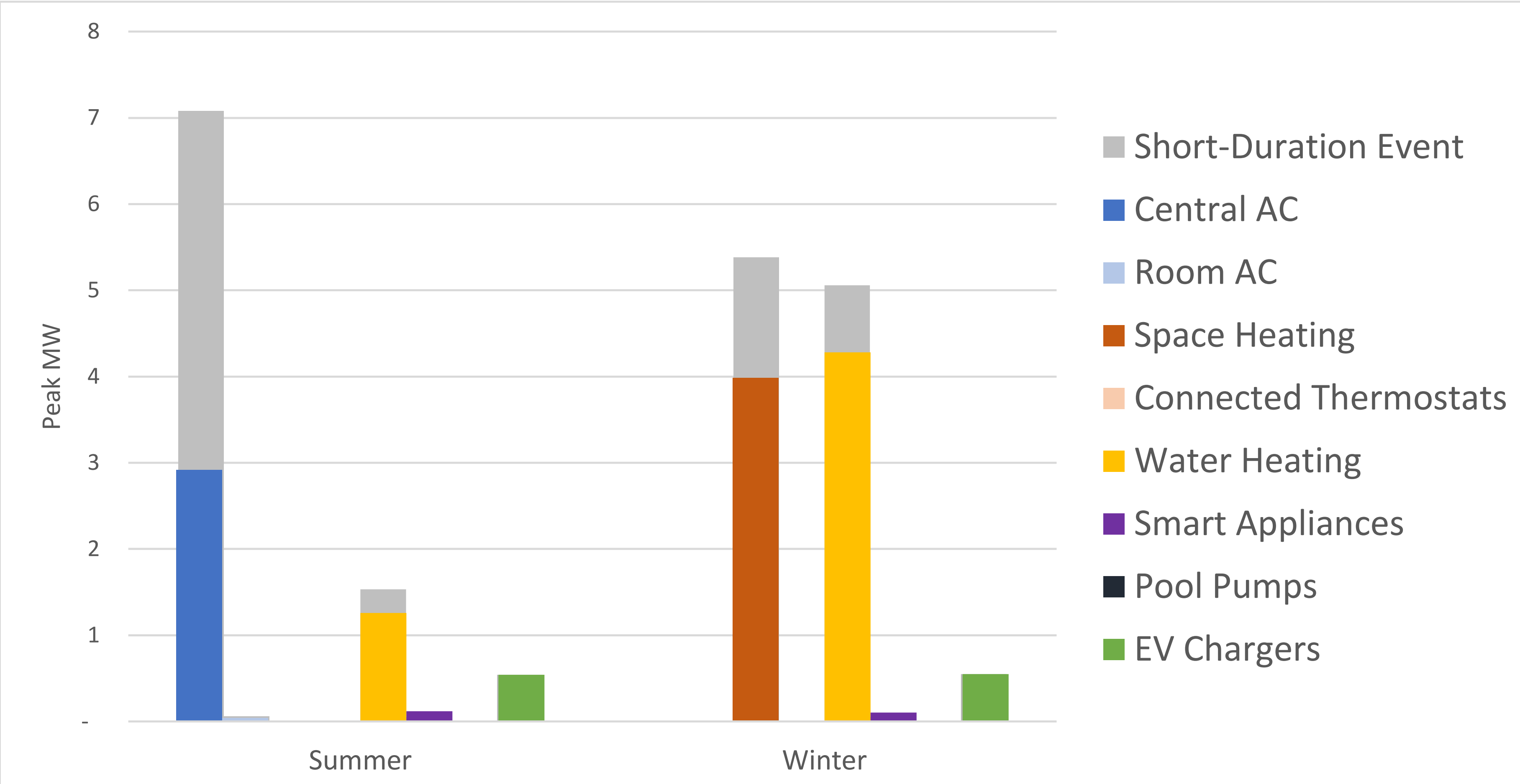
20-Year Potential: Idaho Non-Residential



20-Year Potential: Idaho Non-Residential, Excluding Irrigation Load Control

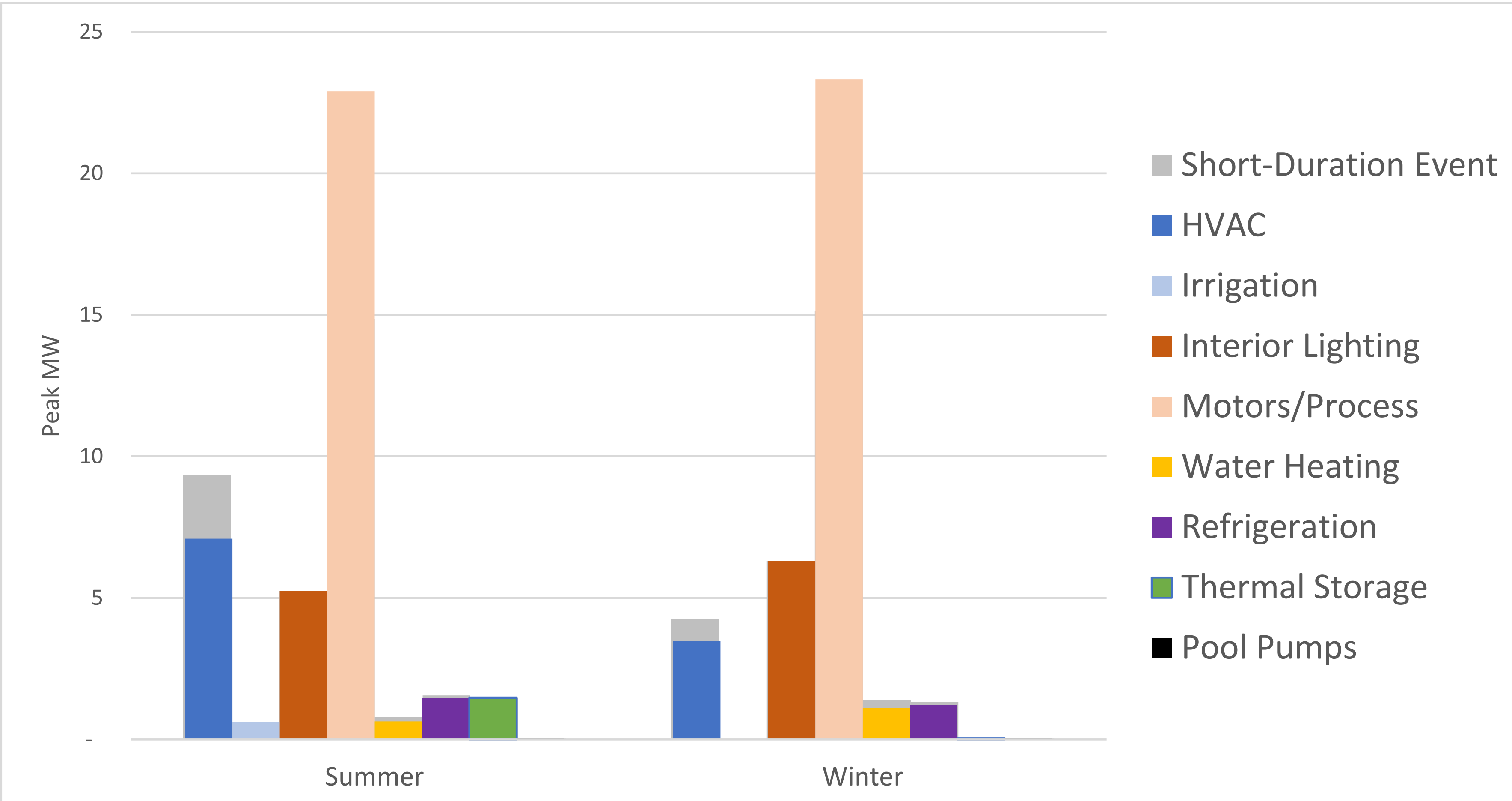


20-Year Potential: Wyoming Residential



* The assumption in RMP states is that potential for central cooling and heating would be captured through switches, not connected thermostats.

20-Year Potential: Wyoming Non-Residential



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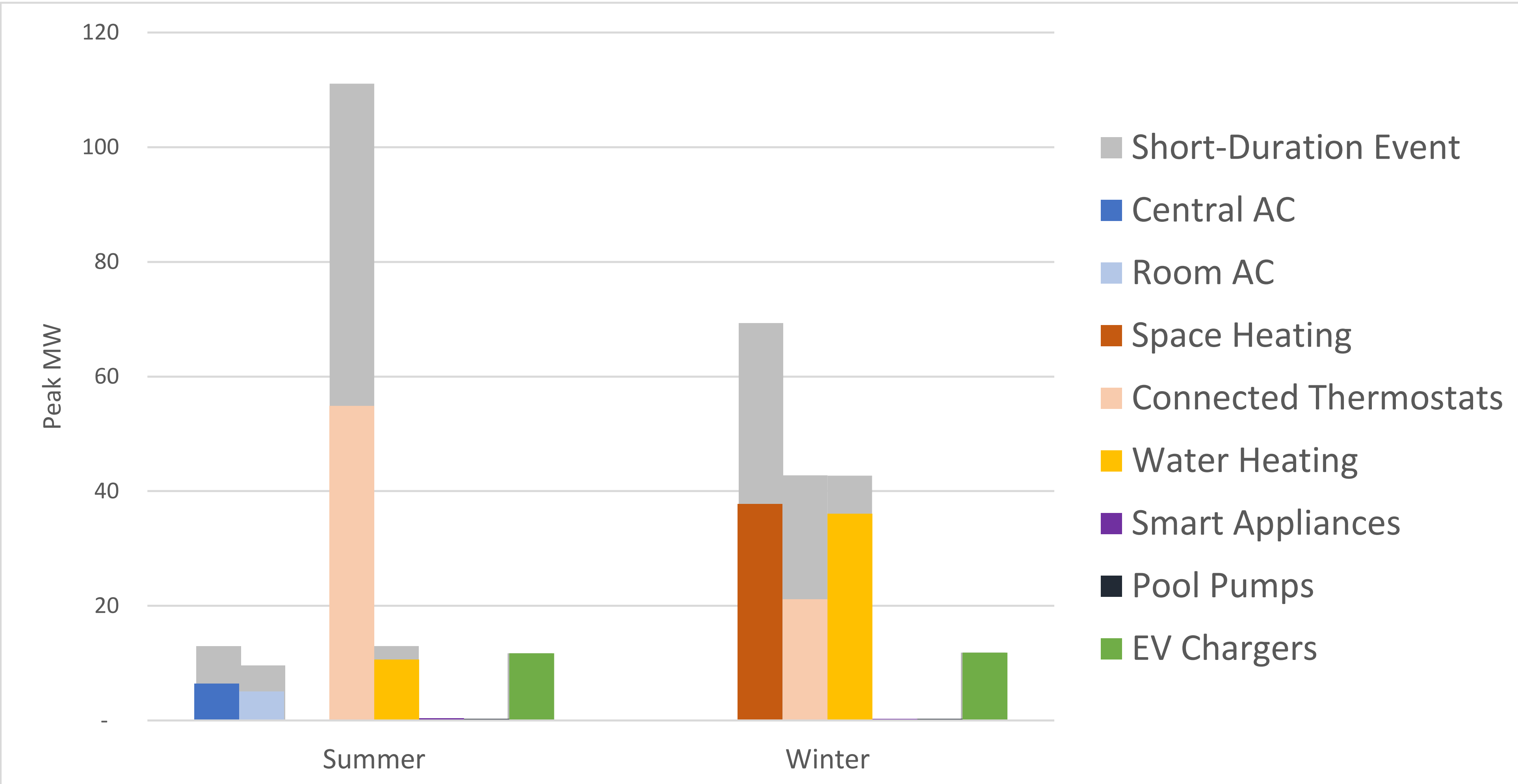
20-Year Potential: Oregon Residential



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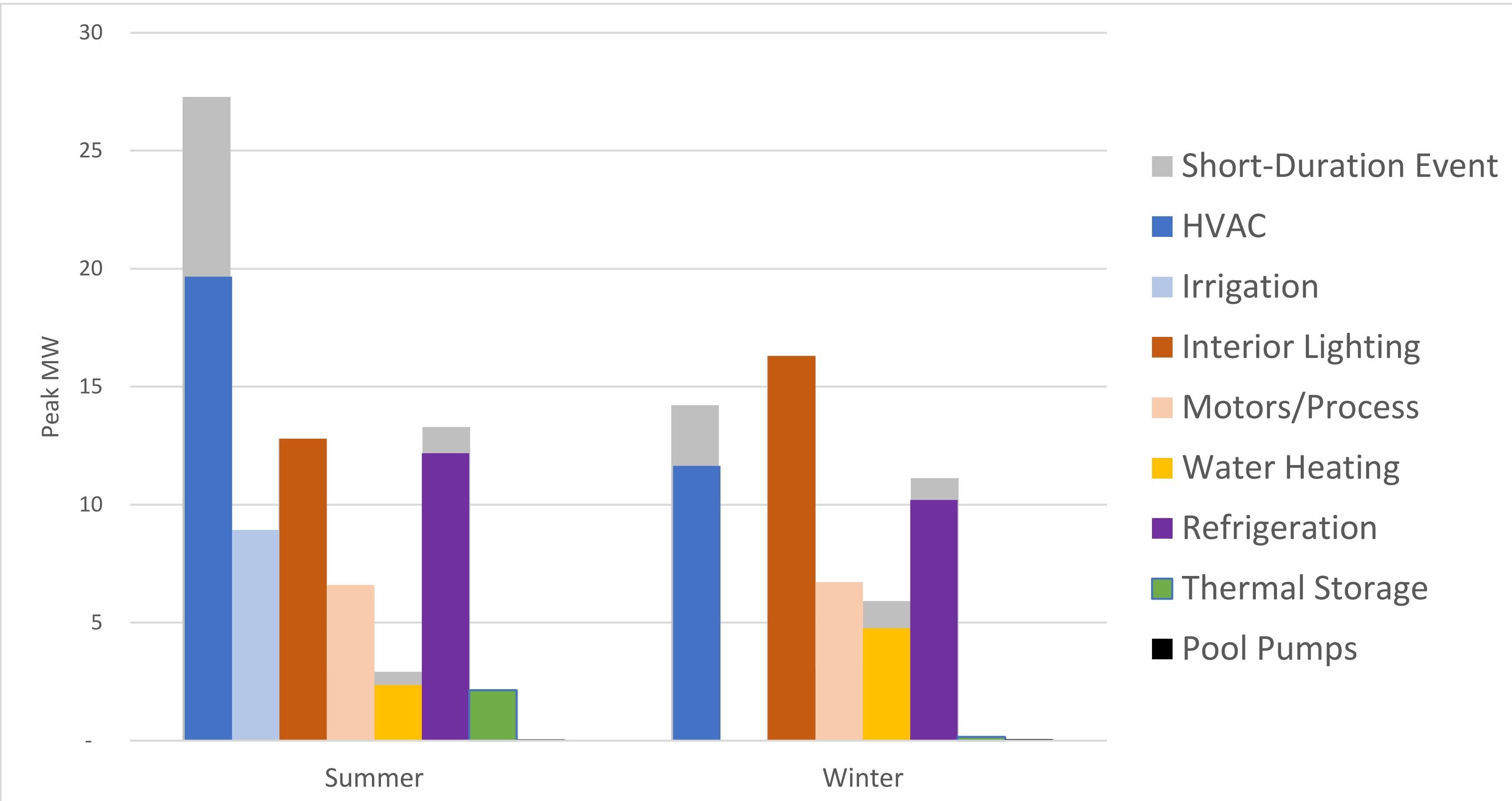
20-Year Potential: Oregon Non-Residential



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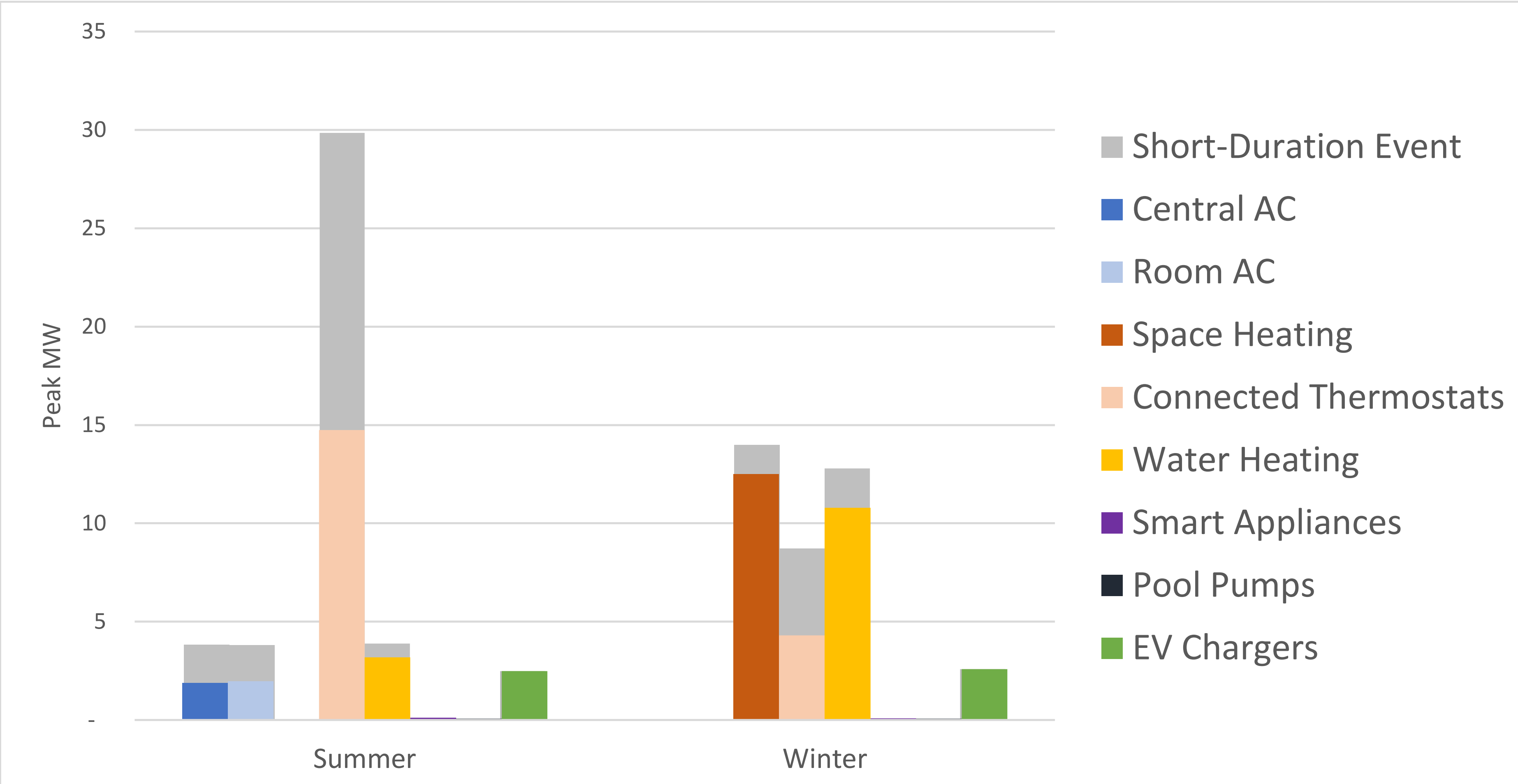
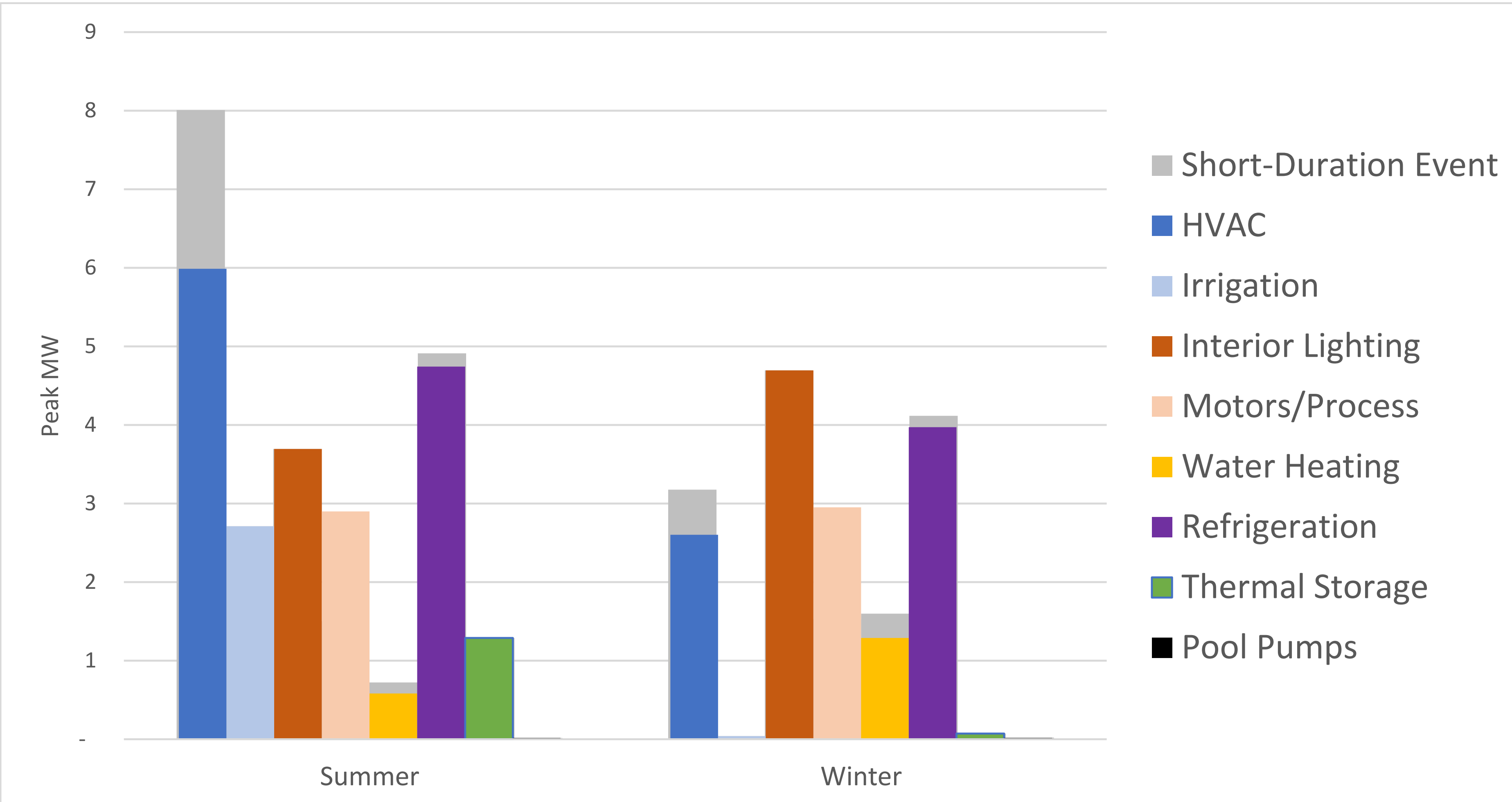
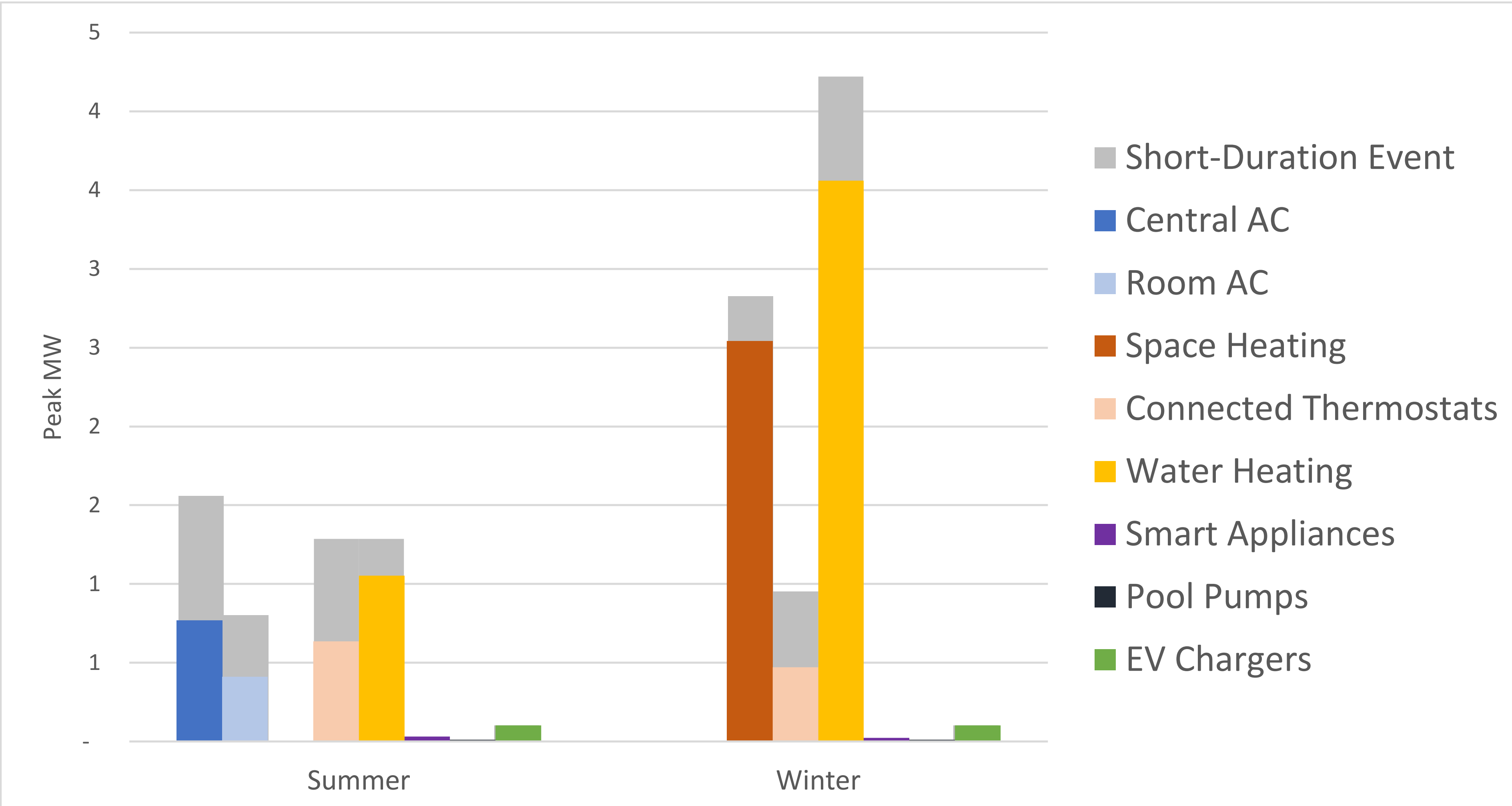
20-Year Potential: Washington Residential



20-Year Potential: Washington Non-Residential



20-Year Potential: California Residential



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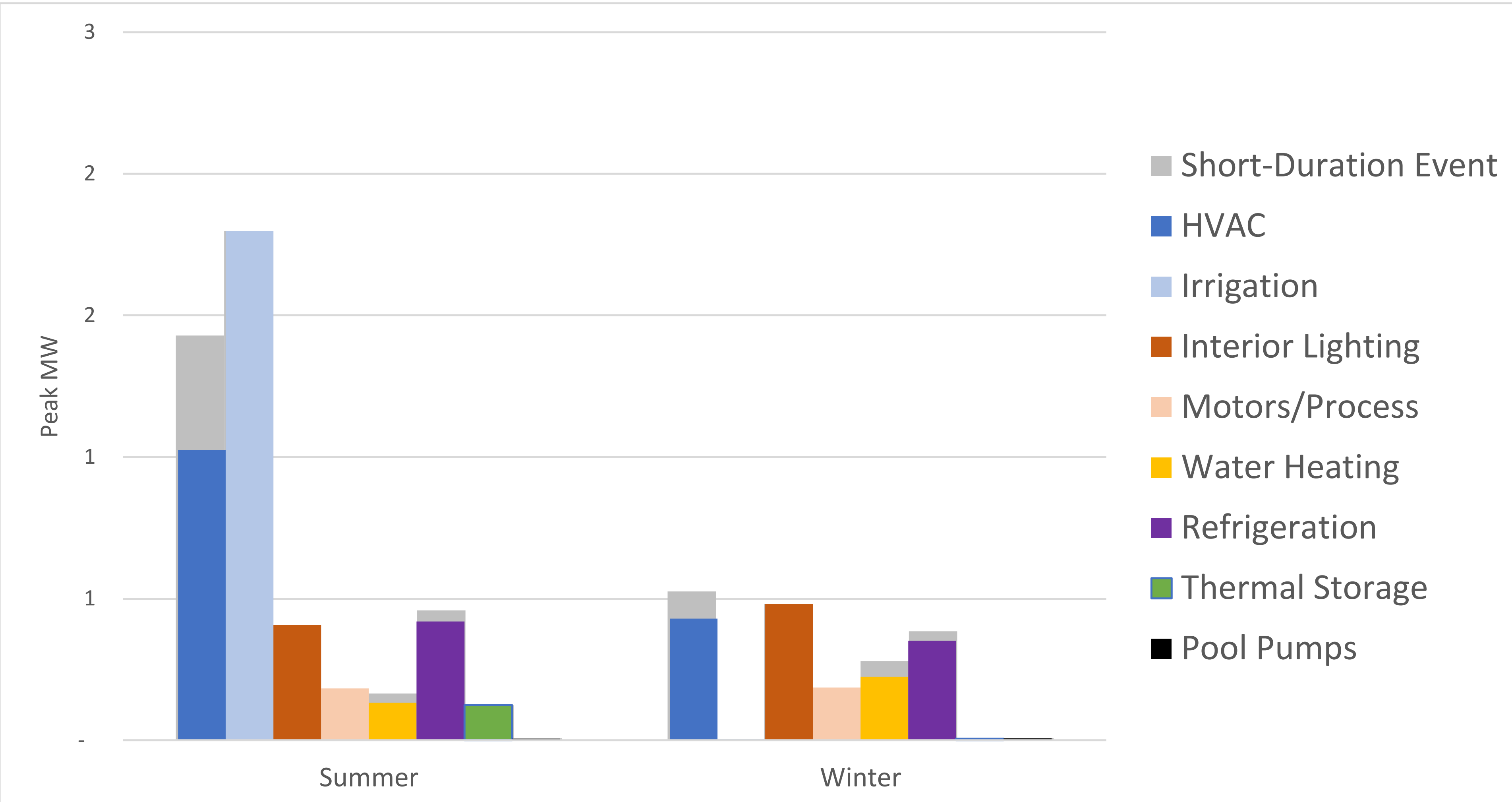
20-Year Potential: California Non-Residential



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Demand Response RFP Update

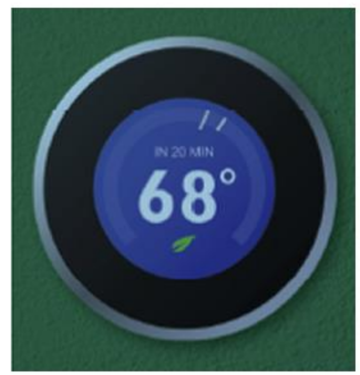
- Oregon Order No. 20-186 related to acknowledgement of the 2019 IRP directed PacifiCorp to issue a DR RFP
- Scope for Pacific Power (OR, WA, CA)
- Conduct 1-2 meetings with non-bidding stakeholders as per OR IRP order to discuss program/pilot consideration (late Sept., Oct.)

  "Working with non-bidding stakeholders to assess the DR results and whether they indicate that PacifiCorp should:

    - *Proceed with available cost-effective winning DR bids, or*
    - *Move forward with a DR pilot if no cost-effective DR is yet available, or*
    - *Move forward with both cost-effective DR and a DR pilot"*

- January 2021 release, final bids evaluated with AS 2020 RFP bids spring 2021

Additional Information/ Next Steps



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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 – CPA Draft Documents
  - pacificorp.com/energy/integrated-resource-plan/support

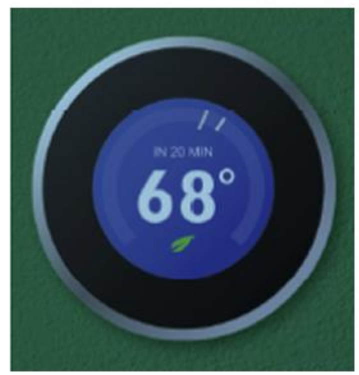
Next Steps

- Upcoming Public Input Meeting Dates:
  - September 17-18, 2020 – Public Input Meeting
  - October 22-23, 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

**meeting dates are subject to change*

Integrated Resource Plan
2021 IRP Public Input Meeting
September 17, 2020



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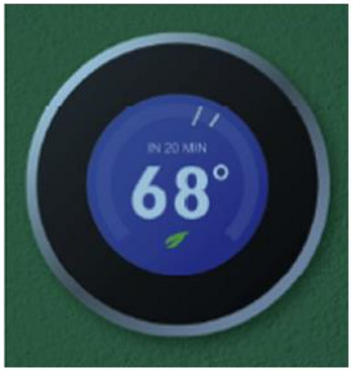
Agenda

September 17, 2020

- Introductions
- Supply-Side Resources
  - Supply-Side Resource Table
  - Carbon Capture
- Portfolio Development Discussion
- Lunch Break (45 min) 11:15am PT/12:15pm MT
- State Policy Update
  - Wyoming and Utah (SF159, HB200, & HB411)
  - WA Clean Energy Transformation Act
- Conservation Potential Assessment Update
- Stakeholder Feedback Form Recap
- Wrap-Up/ Next Steps

Supply-Side Resource Table



Supply-Side Resources

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

Background

- Data Sources
  - Third-Party Engineering Studies (performance and cost estimates)
  - Recent projects & Request for Proposal Bids
  - Engineer-Procure-Construct Contractors
  - Original Equipment Manufacturers (OEMs)
  - Developers
- General Assumptions
  - Mid-2020 dollars
  - Capacities and costs adjusted to “proxy site” parameters and general locations
  - Capital costs based on “greenfield” sites for gas-fueled resources
  - Capital costs include:
    - Direct: costs: Engineering-Procure-Construct (EPC) costs to in-service year; include applicable sales taxes, insurance and contractor’s contingency
    - Owner’s costs: Development, permitting, project management/engineering, water, “outside the fence” linears, land, legal costs, interconnection, capital spares and owner’s contingency
    - Owner’s financial costs: Allowance for Funds Used During Construction (AFUDC), capital surcharge and capitalized property taxes

SSR Table Improvements

- Supply-Side Resource (SSR) Table changes since 2019 IRP cycle
  - Added demolition costs
  - Added detail for O&M costs
  - Updated energy storage options
- Trends
  - Forecasts indicate costs for solar, wind and energy storage will continue to decline

Renewables Combined Study

- Burns & McDonnell is providing a single study of the following renewable resources:
  - Solar
  - Wind
  - Energy Storage
  - Solar + Energy Storage
  - Wind + Energy Storage
  - Solar + Wind + Energy Storage
- The report includes:
  - Current capital and O&M costs
  - (10) year forecast trend of expected capital costs
  - Performance data

Performance and Cost Summary Solar (2020$)

Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Demolition Cost ($/kW)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency
Idah Falls, ID, 100 MW, CF: 26.1%	4,700	100	2023	25	1,425	0.00	16.20	35.00	n/a
Idah Falls, ID, 200 MW, CF: 26.1%	4,700	200	2023	25	1,300	0.00	16.10	35.00	n/a
Lakeview, OR, 100 MW, CF: 27.6%	4,800	100	2023	25	1,444	0.00	16.20	35.00	n/a
Lakeview, OR, 200 MW, CF: 27.6%	4,800	200	2023	25	1,330	0.00	16.10	35.00	n/a
Milford, UT, 100 MW, CF: 30.2%	5,000	100	2023	25	1,422	0.00	17.60	35.00	n/a
Milford, UT, 200 MW, CF: 30.2%	5,000	200	2023	25	1,297	0.00	17.60	35.00	n/a
Rock Springs, WY, 100 MW, CF: 27.9%	6,400	100	2023	25	1,420	0.00	17.60	35.00	n/a
Rock Springs, WY, 200 MW, CF: 27.9%	6,400	200	2023	25	1,295	0.00	17.60	35.00	n/a
Yakima, WA, 100 MW, CF: 24.2%	1,000	100	2023	25	1,481	0.00	17.60	35.00	n/a
Yakima, WA, 200 MW, CF: 24.2%	1,000	200	2023	25	1,353	0.00	17.60	35.00	n/a
Idah Falls, ID, 100 MW, CF: 26.1% + BESS: 50% pwr, 4 hours	4,700	100	2023	25	1,626	0.00	30.00	255.00	85%
Idah Falls, ID, 200 MW, CF: 26.1% + BESS: 50% pwr, 4 hours	4,700	200	2023	25	1,546	0.00	28.95	255.00	85%
Lakeview, OR, 100 MW, CF: 27.6% + BESS: 50% pwr, 4 hours	4,800	100	2023	25	1,644	0.00	30.00	255.00	85%
Lakeview, OR, 200 MW, CF: 27.6% + BESS: 50% pwr, 4 hours	4,800	200	2023	25	1,575	0.00	28.95	255.00	85%
Milford, UT, 100 MW, CF: 30.2% + BESS: 50% pwr, 4 hours	5,000	100	2023	25	1,619	0.00	31.40	255.00	85%
Milford, UT, 200 MW, CF: 30.2% + BESS: 50% pwr, 4 hours	5,000	200	2023	25	1,538	0.00	30.45	255.00	85%
Rock Springs, WY, 100 MW, CF: 27.9% + BESS: 50% pwr, 4 hours	6,400	100	2023	25	1,621	0.00	31.40	255.00	85%
Rock Springs, WY, 200 MW, CF: 27.9% + BESS: 50% pwr, 4 hours	6,400	200	2023	25	1,538	0.00	30.45	255.00	85%
Yakima, WA, 100 MW, CF: 24.2% + BESS: 50% pwr, 4 hours	1,000	100	2023	25	1,751	0.00	31.40	255.00	85%
Yakima, WA, 200 MW, CF: 24.2% + BESS: 50% pwr, 4 hours	1,000	200	2023	25	1,651	0.00	30.45	255.00	85%

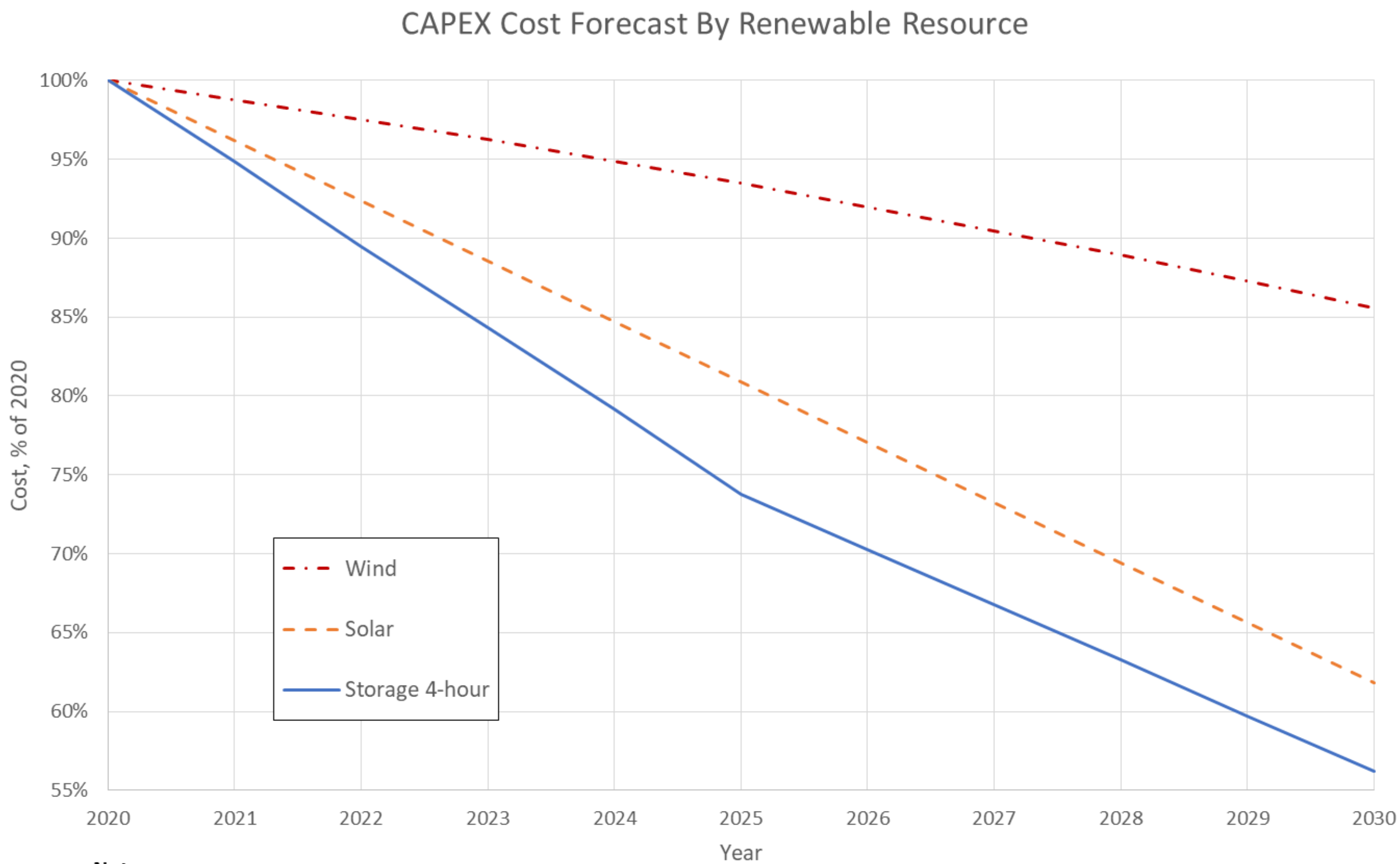
Performance and Cost Summary Wind (2020$)

Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Demolition Cost ($/kW)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency
Pocatello, ID, 200 MW, CF: 43.0%	4,500	200	2024	30	1,369	0.00	28.00	12.50	N/A
Arlington, OR, 200 MW, CF: 43.0%	1,500	200	2024	30	1,374	0.00	28.00	12.50	N/A
Monticello, UT, 200 MW, CF: 36.1%	4,500	200	2024	30	1,364	0.00	28.00	12.50	N/A
Medicine Bow, WY, 200 MW, CF: 48.6%	6,500	200	2024	30	1,364	0.00	28.00	12.50	N/A
Goldendale, WA, 200 MW, CF: 43.0%	1,500	200	2024	30	1,374	0.00	28.00	12.50	N/A
Pocatello, ID, 200 MW, CF: 43.0% + BESS: 50% pwr, 4 hours	4,500	200	2024	30	2,123	0.00	40.85	232.50	85%
Arlington, OR, 200 MW, CF: 43.0% + BESS: 50% pwr, 4 hours	1,500	200	2024	30	2,145	0.00	40.85	232.50	85%
Monticello, UT, 200 MW, CF: 36.1% + BESS: 50% pwr, 4 hours	4,500	200	2024	30	2,119	0.00	40.85	232.50	85%
Medicine Bow, WY, 200 MW, CF: 48.6% + BESS: 50% pwr, 4 hours	6,500	200	2024	30	2,119	0.00	40.85	232.50	85%
Goldendale, WA, 200 MW, CF: 43.0% + BESS: 50% pwr, 4 hours	1,500	200	2024	30	2,145	0.00	40.85	232.50	85%

Performance and Cost Summary Energy Storage (2020$)

Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Demolition Cost ($/kW)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency
Pumped Hydro, Swan Lake	N/A	400	2027	60	3,095	0.00	12.50	Not available	78%
Pumped Hydro, Goldendale	N/A	400	2031	60	8,866	0.00	37.50	Not available	78%
Pumped Hydro, Seminoe	N/A	750	2029	80	3,461	0.37	16.00	Not available	80%
Pumped Hydro, Badger Mountain	N/A	500	2027	80	2,621	0.37	28.00	Not available	80%
Pumped Hydro, Owyhee	N/A	600	2029	80	3,203	0.37	20.00	Not available	80%
Pumped Hydro, Flat Canyon	N/A	300	2029	80	4,046	0.37	53.33	Not available	80%
Pumped Hydro, Utah PS2	N/A	500	2027	80	3,237	0.37	28.00	Not available	80%
Pumped Hydro, Utah PS3	N/A	600	2029	80	3,371	0.37	20.00	Not available	80%
Pumped Hydro, Banner Mountain	N/A	400	2028	50	3,276	0.00	28.50	Not available	81%
Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	N/A	150	2024	50	1,954	6.50	12.67	Not available	60%
Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	N/A	150	2024	50	2,189	6.50	12.67	Not available	60%
Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	N/A	150	2024	50	2,445	6.50	12.67	Not available	60%
Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	N/A	300	2024	50	1,557	6.50	9.33	Not available	60%
Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	N/A	300	2024	50	1,692	6.50	9.33	Not available	60%
Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	N/A	300	2024	50	2,016	6.50	9.33	Not available	60%
Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	N/A	500	2024	50	1,549	6.50	6.60	Not available	60%
Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	N/A	500	2025	50	1,762	6.50	6.60	Not available	60%
Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	N/A	500	2025	50	1,930	6.50	6.60	Not available	60%
Li-Ion Battery, , 1 MW, 0.5 MWh	N/A	1	2023	20	1,948	n FOM	40.00	55.00	85%
Li-Ion Battery, , 1 MW, 1 MWh	N/A	1	2023	20	2,058	n FOM	50.00	110.00	85%
Li-Ion Battery, , 1 MW, 4 MWh	N/A	1	2023	20	3,167	n FOM	70.00	440.00	85%
Li-Ion Battery, , 1 MW, 8 MWh	N/A	1	2023	20	4,608	n FOM	100.00	880.00	85%
Li-Ion Battery, , 50 MW, 200 MWh	N/A	50	2023	20	1,828	n FOM	27.60	440.00	85%
Flow Battery, , 1 MW, 1 MWh	N/A	1	2023	20	4,719	n FOM	13.00	Not available	70%
Flow Battery, , 1 MW, 4 MWh	N/A	1	2023	20	5,051	n FOM	13.00	Not available	70%
Flow Battery, , 1 MW, 8 MWh	N/A	1	2023	20	7,268	n FOM	27.00	Not available	70%
Flow Battery, , 20 MW, 160 MWh	N/A	20	2023	20	4,686	n FOM	30.50	Not available	70%

Renewables Cost Forecast



Notes:

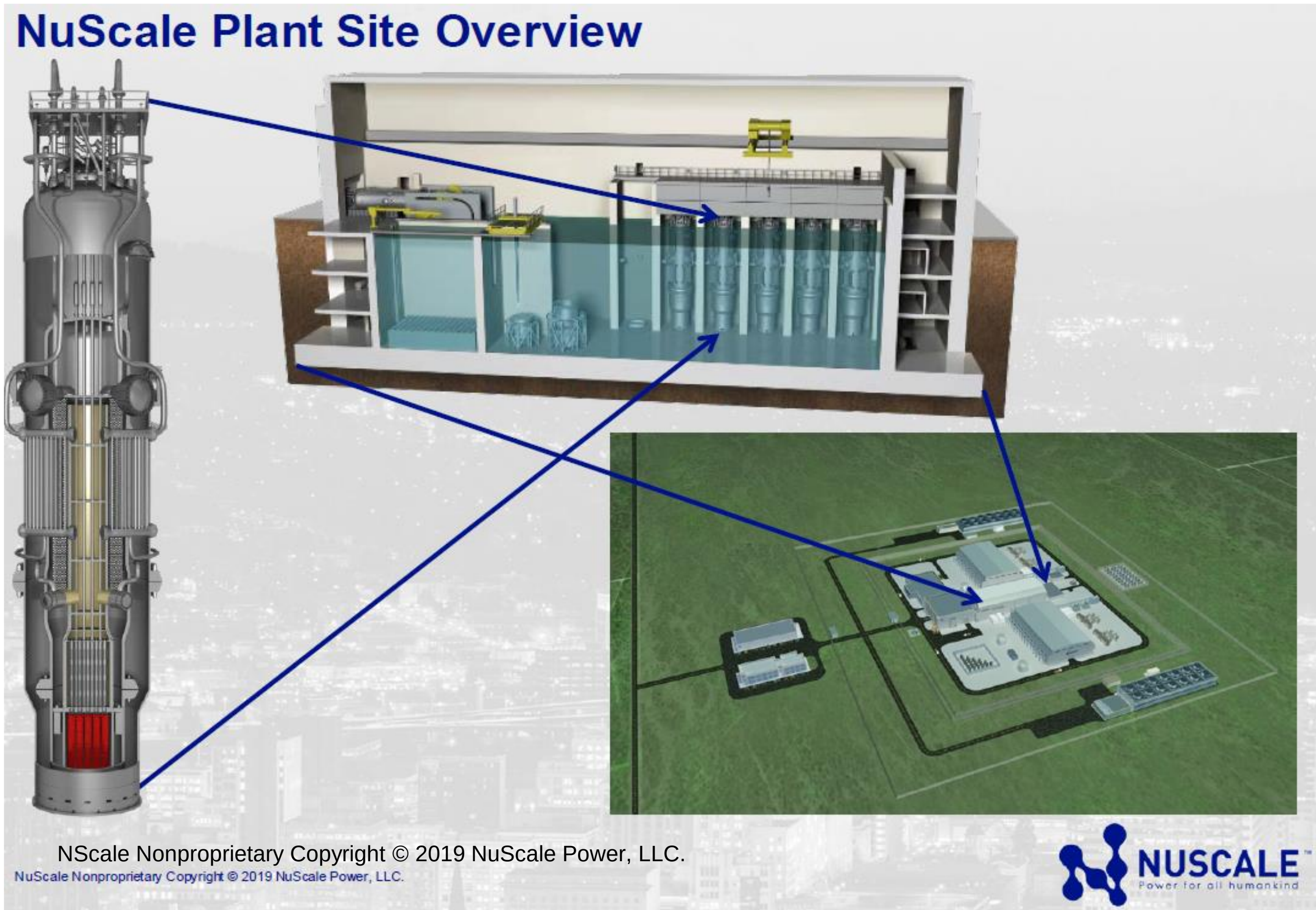
1. The declining cost curve for onshore wind was developed using NREL Land-Based Wind Classes (Class) moderate overnight cost inforamtion. The costs for Class 2, Class 6, and Class 8 were averaged to represent the Pacificorp identified sites based on average wind speed.

2. The declining cost curve for utility solar photovoltaic was developed using NREL mid overnight cost inforamtion.

3. The declining cost curve for battery storage was developed using NREL mid overnight CAPEX cost information for a storage device with 15-year life and 85% round-trip efficiency for 4- hour storage.

Nuclear

Small Modular Reactor



Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Demolition Cost ($/kW)
Small Modular Reactor	5,000	684	2028	60	6,229	16.01	179.12	Not available

Gas Resources

Performance and Cost (2018$)

Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Demolition Cost ($/kW)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency
SCCT Aero x3	5,050	139	2025	30	1,777	9.04	0.00	Not Available	9,400
Intercooled SCCT Aero x2	5,050	187	2025	30	1,363	6.09	0.00	Not Available	8,816
SCCT Frame "F" x1	5,050	199	2025	35	841	17.04	0.00	Not Available	9,936
Brownfield SCCT Frame "F" x1	5,050	199	2025	35	811	17.03	0.00	Not Available	9,936
IC Recips x 6	5,050	111	2026	40	2,065	10.39	0.00	Not Available	8,292
CCCT Dry "H", 1x1	5,050	350	2026	40	1,687	2.14	0.00	12.14	6,362
CCCT Dry "H", DF, 1x1	5,050	51	2026	40	470	0.05	0.00	0.00	8,545
CCCT Dry "H", 2x1	5,050	686	2027	40	1,252	2.10	0.00	12.14	6,487
CCCT Dry "H", DF, 2x1	5,050	102	2027	40	358	0.05	0.00	0.00	9,470
Brownfield CCCT Dry "H", DF, 2x1	5,050	686	2027	40	1,251	1.33	0.00	12.14	6,874
CCCT Dry "J", 1x1	5,050	504	2026	40	1,299	1.81	0.00	12.14	6,352
CCCT Dry "J", DF, 1x1	5,050	63	2026	40	397	0.06	0.00	0.00	9,452
CCCT Dry "J", 2x1	5,050	1,004	2027	40	966	1.76	0.00	12.14	6,373
CCCT Dry "J", DF, 2x1	5,050	126	2027	40	309	0.06	0.00	0.00	9,456

Sources of Information

- Carbon Capture and Storage Database
  - National Energy Technology Laboratory
  - "Project cost"
- Wyoming Carbon Capture, Utilization, and Storage (CCUS) Study
- Dave Johnston CC/EOR Feasibility Studies
- Constructed Full Scale Facilities
  - Petra Nova - Mothballed
  - Boundary Dam - Operating

Key Requirements

- Size – Minimum economic CO_2 production
- Minimum production requirement
- Continuous, consistent operation requirement
    - No or less economic dispatch of generating unit
    - Changes to state regulations
- Utilities
    - Electric power, Steam, Cooling
- Carbon dioxide marketing and sales

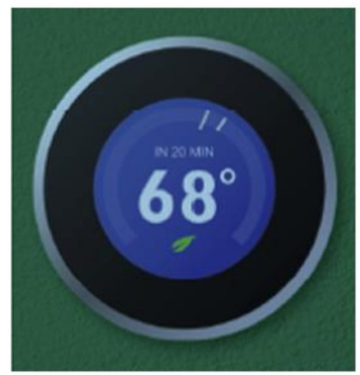
Carbon Capture Utilization and Sequestration

Risks

- Immature technology
- Capital cost
- Operations and maintenance costs
- Financial backstop
- Carbon capture forced outage rate
- Oil prices / carbon dioxide prices
- Regulatory risk – economic dispatch
- Marketing and sale of carbon dioxide
    - Not PacifiCorp's core business

Portfolio Discussion



Portfolio Development

<u>Med Gas/Med CO2</u>
- BAU*
- Limited new gas
- No new gas
- Market reliance
- Other

<u>High Gas/High CO2</u>
- BAU*
- Limited new gas
- No new gas
- Market reliance
- Other

<u>Low Gas/No CO2</u>
- BAU*
- Limited new gas
- No new gas
- Market reliance
- Other

<u>Social Cost of Carbon</u>
- BAU*
- Limited new gas
- No new gas
- Market reliance
- Other

Plexos

Load
Private generation
Existing transmission
New transmission options
Existing contracts
Existing resources
Coal retirement options
Customer preference
New resource options
New DSM options
Market purchases/limits
Market prices
CO_2 Prices

Outputs

New Resources
New DSM
New Transmission

Costs
Emissions
Reliability Metrics

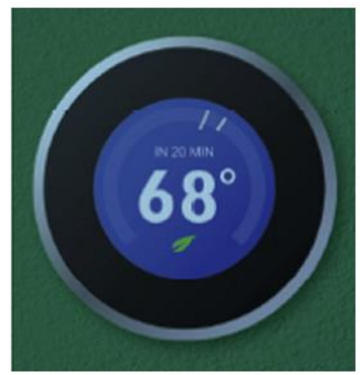
*BAU = Business as Usual

Sensitivities

- Relative to top performing case(s) and BAU case(s)
  - High load
  - Low load
  - 1-in-20 load
  - High private generation
  - Low private generation
  - High customer preference
  - No customer preference
  - Business plan (per UT requirement)
  - Technology specific (i.e., pumped storage, carbon capture)
  - Other

State Policy Update



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Wyoming Legislative Update

- **Senate File 159 – New Opportunities for Wyoming Coal-Fired Generation (2019)**
  - Requires Rocky Mountain Power to attempt to sell certain coal-fired generation units
  - Customer protection language requires the Public Service Commission to determine if accepting an offer would reduce costs/risks to customers as compared to retiring the facility
  - If the Public Service Commission determines that the public utility did not make a good faith effort to sell the retired coal fired generation plant, a public utility can not include any recovery of or earnings on specific new capital costs

- **Senate File 21 - Coal Fired Electric Generation Facilities (2020)**
  - This bill amends S.F. 159 to allow the purchaser to sell the output directly to a Rocky Mountain Power customer with load greater than 1 MW

Wyoming Legislative Update

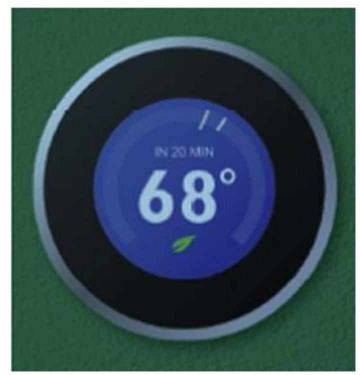
- **House Bill 200 – Reliable and Dispatchable Low-Carbon Energy Standards (2020)**
    - The Wyoming Public Service Commission is required to put in place a standard specifying a percentage of PacifiCorp's electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030
    - This requirement would only apply to generation allocated to Wyoming customers
    - Cost caps specified in the legislation limited to 2% total customer impact

Utah Legislative Update

- **House Bill 411, Community Renewable Energy Act (2019)**
  - Creates 100% net renewable energy program for cities that choose to participate
  - Participating cities required to adopt a 100% renewable energy resolution before Dec 31, 2019
  - Customers within a participating community may opt out of the program and maintain existing rates
  - The legislation outlines the roles and rule making authority for the Public Service Commission including the setting of rates to avoid cost shifting to other customers.

Clean Energy Transformation Act (CETA) Update



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Washington Clean Energy Transformation Act

- Enacted in 2019 as Senate Bill 5116; establishes three primary standards:

2025 – No coal in Washington allocation of electricity

Coal-fired resources cannot be included in customer rates as of December 31, 2025

2030 – Greenhouse Gas Neutral

Retail sales of electricity must be GHG neutral by January 1, 2030

Multi-year compliance periods:

- January 1, 2030 – December 31, 2033
- January 1, 2034 – December 31, 2037
- January 1, 2038 – December 31, 2041
- January 1, 2042 – December 31, 2044

2045 – 100% Renewable and non-emitting

100% of Washington retail load must be met by renewable and non-emitting resources by January 1, 2045

CETA also directs equitable distribution of energy and non-energy benefits and reduction of burden to vulnerable populations and highly impacted communities

Implementation Plan

Phase I
(to complete by December 31, 2020)

- Electric IRP Updates Rulemaking (includes Clean Energy Action Plan)
- Used and Useful Policy Statement
- Energy Independence Act Rulemaking
- Clean Energy Implementation Plan (CEIP) Rulemaking
- Acquisition (RFP) Rulemaking

Phase II
(to complete by June 30, 2022)

- Cumulative Impact Analysis Rulemaking
- Carbon and Electricity Markets Rulemaking
- Natural Gas Conservation Rulemaking
- Natural Gas IRP Rulemaking

Phase III
(to complete by December 31, 2023)

- Interconnection Standard Rulemaking
- Capital Budgeting Rulemaking
- Distribution System Planning Rulemaking
- Reliability and Resiliency Rulemaking
- Pricing Signals Policy Statement

CETA components of long-term planning (rulemakings in progress)

Clean Energy Action Plan (CEAP)

- Will be filed with IRPs and will be informed by the Conservation Potential Assessment.
- CEAP will contain high-level targets for potential CETA compliance, as well as Preliminary identification of compliance strategy
- Includes energy and non-energy impacts

Integrated Resource Plan (IRP)

- Comprehensive decision support tool and roadmap for meeting the company's objective of providing reliable and least-cost electric service to all of our customers.
- Includes finding of resource need, focusing on the first 10 years of a 20-year planning period; the preferred portfolio of supply-side and demand-side resources to meet this need;
- Included energy and non-energy impacts

Clean Energy Implementation Plan (CEIP)

- Includes three major items that will drive CETA compliance:
  - Setting interim targets
  - Providing additional detail regarding specific actions to be taken during upcoming four-year period, identify and isolate system costs directly attributable to Washington
  - Calculating incremental cost
- CEIP also includes discussion of equitable distribution of benefits, and will incorporate the Cumulative Impact Analysis

Procurement/RFP

- Incorporate existing work on RFPs from Washington Docket U-161024 from 2016
- Ensure that the CETA standard is met in construction and acquisition of property and in the provision of electric service
- Incorporates resource adequacy/resource need consideration

Compliance Pathways

Hydro, wind, solar, geothermal, renewable natural gas, renewable hydrogen, wave, ocean or tidal, biodiesel (with qualifications), biomass

Eligible Resources

Alternative Compliance

Penalties for non-compliance

Utility is considered in compliance if the incremental cost exceeds legislative thresholds

OR

Utility is able to pursue energy transformation Projects to count toward compliance

$100/MWh with a multiplier if utility is unable to otherwise comply

Next Steps

Planning Activities

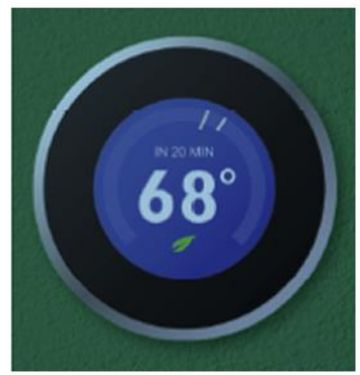
- IRP due April 2021
- First CEAP due April 2021 (filed with IRP)
- First CEIP due late 2021

Rulemaking Activities

- Phase I rulemakings complete and rules adopted by December 31, 2020.
- Phase II rulemakings begin early 2021

Conservation Potential Assessment Update



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Updates

- August 28, 2020 Draft Results Workshop
- Measure Database of Draft EE results posted on website:
  - pacificorp.com/energy/integrated-resource-plan/support
- Display of results by state by year included in database file
- PacifiCorp is working to respond to feedback forms received
- Presentation of Final CPA Results at Oct 22-23, 2020 IRP meeting

Key Changes Relative to the 2019 CPA

Change Area	Detail
State-Specific Adjustments	RMP and PP specific measure* and market data sourcing
	Updated residential survey and load forecast data by state
	Major market profile data sourcing overhaul
	Codes & Standards
	Ramp Rates – Refreshed to 2021 Plan and participation analysis results
Forecasting Methodology	Treatment of equipment measures for technical potential
	Max achievability (some measures above 85%)
	No Streetlighting Model – market is transformed in the Load Forecast
	Residential Low Income segments added for WA
	Lighting savings methods (market baseline and EISA)
Other	Other updated secondary sources (AEO purchase shares and trends)
	New emerging technologies (higher SEER AC, more HP Dryer options)
	Applicability and Saturation Sourcing Updates (RBSA II, CBSA, 2021 Plan)
	Incremental HERs for all states, including OR***

* State-specific measure adjustments are for weather-dependent and major measures only
** Ramp Rates were refreshed based on the 2021 Power Plan then adjusted based on the Participation Analysis
*** Incremental HERs to existing program savings are still being finalized and will be included in the final results

Other Notable CPA Changes

- Large UT Res increase
- COVID-19 Impacts
- EVs and Electrification

Load Forecast

- Market Profile Sourcing Updates
- EIA Annual Energy Outlook 2019

Secondary Source Updates

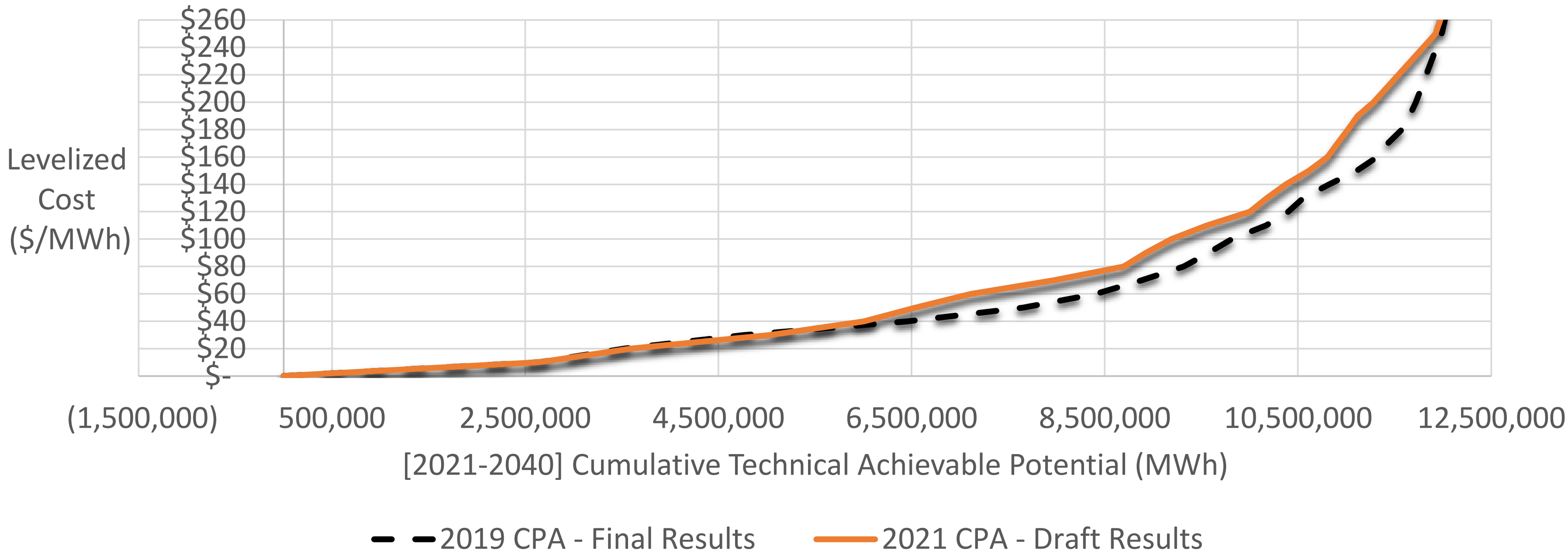
Emerging Techs

- New Emerging Technologies
- More Efficient Options (HP Dryer UCEF 8.0, SEER 24 AC)

Applicability & Saturation Updates

- NWPCC 2021 Power Plan
- RBSA II / CBSA 2014
- Expand sourcing for UT and WY

Draft Technical Achievable Potential Supply Curve Comparison



Draft 2021 CPA	2019 CPA	% Difference
13,516,192	13,163,531	+2.7%

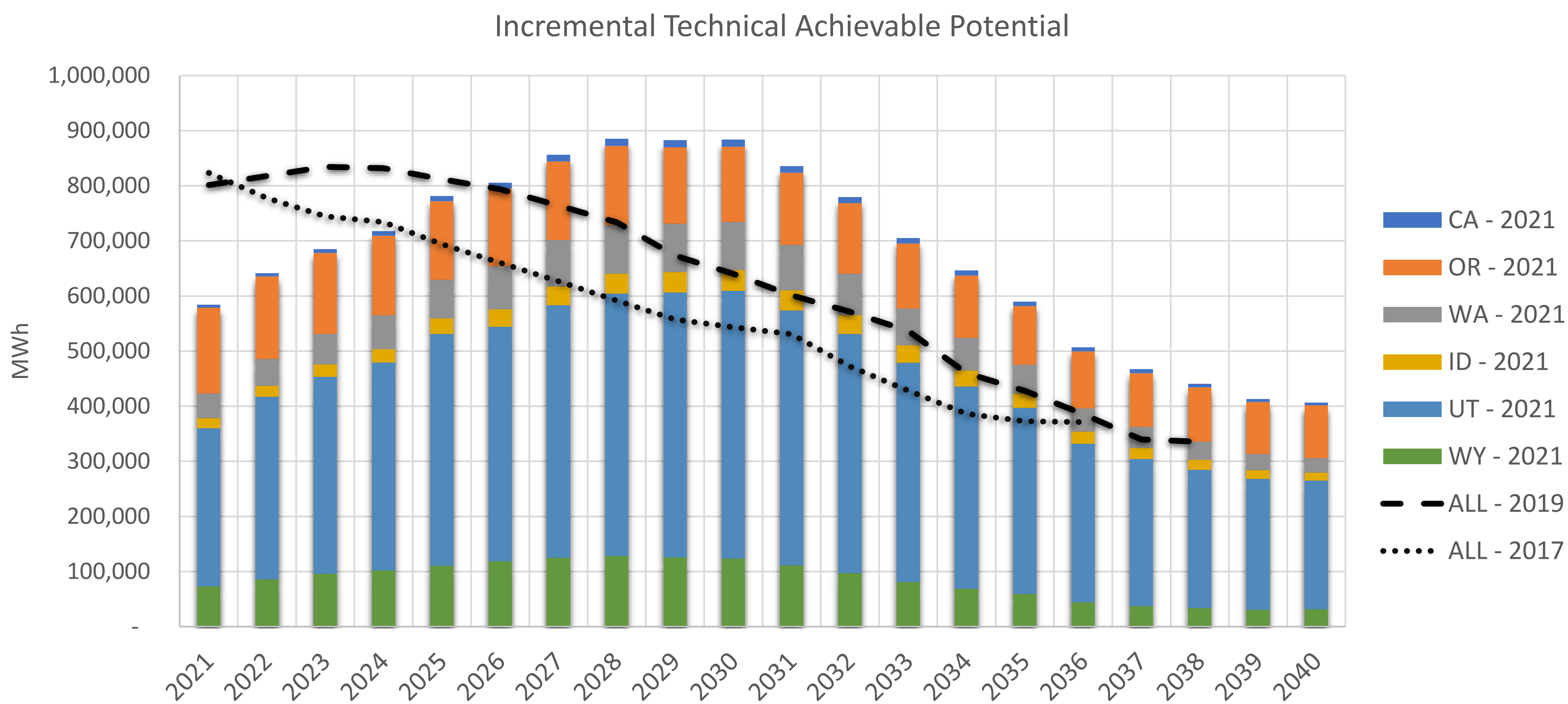
Total 20-year cumulative potential is slightly higher than the previous study, but savings are more expensive because of the decrease in cheaper lighting savings

Cost bundles represent the technical achievable potential, ***not economic potential***

Each cost bundle represents a different weighted average load shape based on the measures within it.

Cost bundles are selected in the IRP based on economics and their ability to contribute to the system in competition with all other supply-side resources.

Draft Technical Achievable Potential Comparison



- Incremental savings opportunities have been moved out in time
  - Lighting savings decreases and ramp rate adjustments
- LEDs have a large impact on early year savings opportunities compared to previous
  - Similar trend in NWPCC 2021 Plan (next slide)
- Graph illustrates the dynamic nature of energy efficiency and forecasting

DRAFT 20-Year DR Potential Summary - Summer

	MW Impacts – Sustained Duration				
State	Residential	Commercial and Industrial	Irrigation	Total	% Peak Reduction
UT	191	127	12	330	5%
ID	5	8	120	133	28%
WY	5	39	1	44	3%
OR	89	56	9	154	5%
WA	24	19	3	46	5%
CA	3	2	2	7	6%
System	**318**	**252**	**146**	**715**	**6%**
2019 CPA	**359**	**325**	**211**	**896**	

	MW Impacts – Short-Duration				
State	Residential	Commercial and Industrial	Irrigation	Total	% Peak Reduction
UT	395	141	12	548	9%
ID	9	9	120	139	29%
WY	9	33	1	43	3%
OR	159	62	9	229	8%
WA	44	20	3	67	7%
CA	5	3	2	10	7%
System	**622**	**268**	**146**	**1,035**	**9%**

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DRAFT 20-Year DR Potential Summary - Winter

	MW Impacts – Sustained Duration				
State	Residential	Commercial and Industrial	Irrigation	Total	% Peak Reduction
UT	120	99	0	219	5%
ID	9	6	0	15	4%
WY	9	36	0	44	3%
OR	107	50	0	157	5%
WA	30	16	0	46	5%
CA	7	2	0	8	5%
System	**283**	**207**	**0**	**490**	**5%**
2019 CPA	**286**	**173**	**0**	**459**	

	MW Impacts – Short-Duration				
State	Residential	Commercial and Industrial	Irrigation	Total	% Peak Reduction
UT	145	98	0	243	5%
ID	12	6	0	18	5%
WY	11	28	0	40	3%
OR	167	51	0	218	6%
WA	38	15	0	53	5%
CA	8	2	0	10	6%
System	**382**	**200**	**0**	**583**	**5%**

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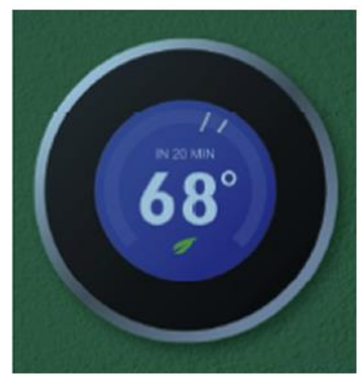
Next Steps

- Stakeholder feedback on draft results requested by 9/18/20
- PacifiCorp to respond to Stakeholder Feedback Forms
- Presentation of Final CPA Results at Oct 22-23, 2020 IRP meeting

Stakeholder Feedback Form Update



Stakeholder Feedback Form Update

- 33 stakeholder feedback forms submitted to date.
- The stakeholder feedback form process was updated July 20, 2020 to include a web-based form.
- 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)
Utah Clean Energy	August 6, 2020	July PIM	Questions related to topics presented in the July 30-31, 2020 public input meeting: EV Forecast, building electrification forecast, air-source heat pumps, DER impact tool, CSP, and solar technology.	PacifiCorp provided responses and will consider recommendations made on specific topics.
Washington Utilities and Transportation commission	August 7, 2020	July PIM	Questions related to topics presented in the June 18-19, 2020 public input meeting: climate change, electric vehicles, distribution planning, DER impact tool, demand response, grid modernization, GHG, and the Washington Clean Energy Transformation Act.	PacifiCorp provided responses and will consider recommendations made on specific topics.
City of Kemmerer	August 28, 2020	Energy Efficiency	Recommending holding a technical conference discussing supply-side energy efficiency.	PacifiCorp will consider incorporating this recommendation.
City of Kemmerer	August 28, 2020	IRP Resource	We request that in additional to your plan to put the smaller nuclear reactors into your IRP, that given the proven technology to make coal even cleaner (carbon capture and coal gasification) that you also put coal-fired power back into your IRP.	PacifiCorp will consider incorporating these recommendations.
City of Kemmerer	August 28, 2020	Natural Gas	Given the uncertainty and unproven technology of battery storage for baseload power, new proven clean coal technologies should be given a fair consideration with your data analysis.	PacifiCorp will consider incorporating these recommendations.

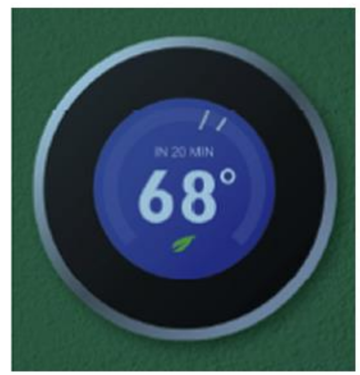
Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
City of Kemmerer	August 28, 2020	WY Legislation	Just as legislation on the West Coast and in Utah is being considered in the IRP 2021, we want Wyoming's Senate File 159 and House Bill 200 considered.	This topic will be addressed at the September 17, 2020 public input meeting.
City of Kemmerer	August 28, 2020	Carbon Capture	Factor in what carbon capture and coal gassification can factor into the Pacificorp IRP, given that the IRS gules have now been established.	This topic will be addressed at the September 17, 2020 public input meeting.
City of Kemmerer	August 28, 2020	Economic Power Grid	Request for a scenario to remove HYDRO power and replace it with coal-fired power.	PacifiCorp will consider incorporating these recommendations.
City of Kemmerer	August 28, 2020	Tax Credits	Recommend changing assumptions regarding to add coal-fired power and smaller nuclear modular reactors to the portfolio.	PacifiCorp will consider incorporating these recommendations.
City of Kemmerer	August 28, 2020	Social Cost of Carbon	Stressed the important of being transparent about what coal-fired and natural gas power actual do to both our wealth and the wealth of impoverished nations.	PacifiCorp will consider incorporating these recommendations.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Oregon Public Utility Commission staff	Sept 3, 2020	June public input meeting	Questions related to topics presented in the June 18-19, 2020 public input meeting: 2019 IRP Action Item Updates, and transmission.	Targeted response the week of September 21, 2020.
Washington Utilities and Transportation commission	Sept 4, 2020	CPA Workshop	Questions related to topics presented in the August 28, 2020 CPA technical workshop.	Targeted response the week of September 21, 2020.
Oregon Citizen's Utility Board	Sept 9, 2020	Battery Storage & Demand Response	Will PacifiCorp perform a battery storage assessment by State or is it only the system as a whole? Will the IRP account for interactive effects of Direct Load Control and Price-based Demand Response programs?	Targeted response the week of September 21, 2020.
Oregon Public Utility Commission staff	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 September 28, 2020.
Oregon Public Utility Commission staff	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 September 28, 2020.

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 – CPA Draft Documents
  - pacificorp.com/energy/integrated-resource-plan/support

Next Steps

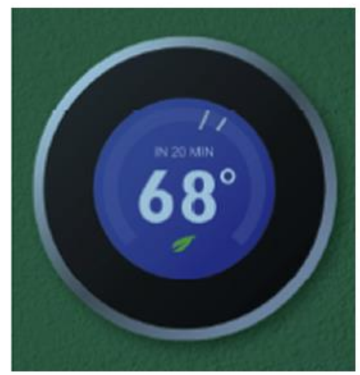
- Upcoming Public Input Meeting Dates:
  - October 22-23, 2020 – Public Input Meeting
  - December 3-4, 2020 – Public Input Meeting
  - January 14-15, 2021 – Public Input Meeting
  - February 25-26, 2021 – Public Input Meeting
  - April 1, 2021 – File the 2021 IRP

**meeting dates are subject to change*

Integrated Resource Plan

2021 IRP Public Input Meeting

October 22, 2020



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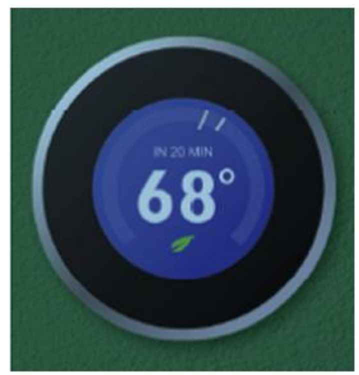
Agenda

- 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



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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	[illegible]	[illegible]	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	2,833	0.00	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

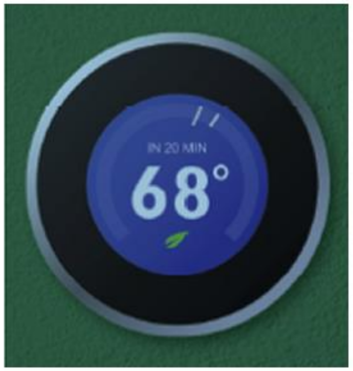
Performance and Cost (2018$)

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



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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

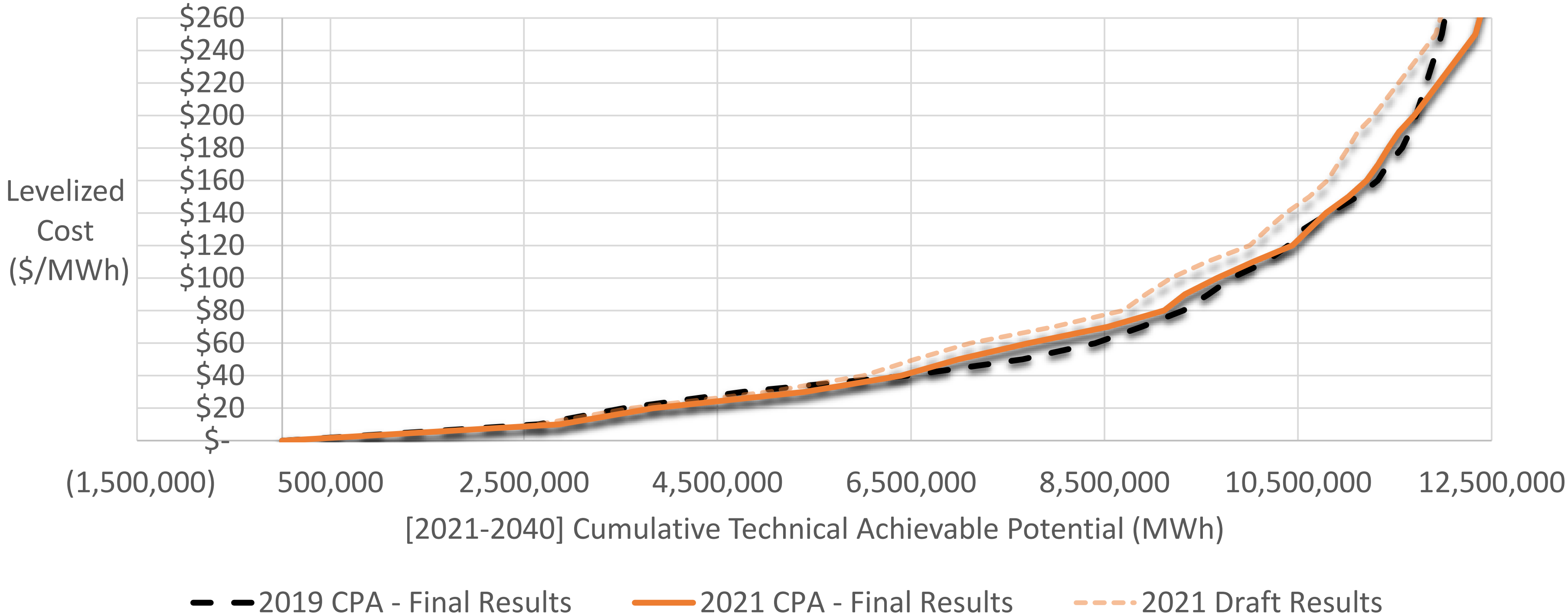
Measure Type	Final 2021 CPA: 20-Year Cumulative Potential	% of Total	*Draft 2021 CPA (Aug): 20-Year Cumulative Potential*	*% Change from Draft*
HVAC	764,778	25.4%	*660,002*	*15.9%*
Lighting	474,636	15.8%	*402,684*	*17.9%*
Whole Building/Home	420,129	14.0%	*379,532*	*10.7%*
Ind (Motor/Pump/Other)	313,618	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**

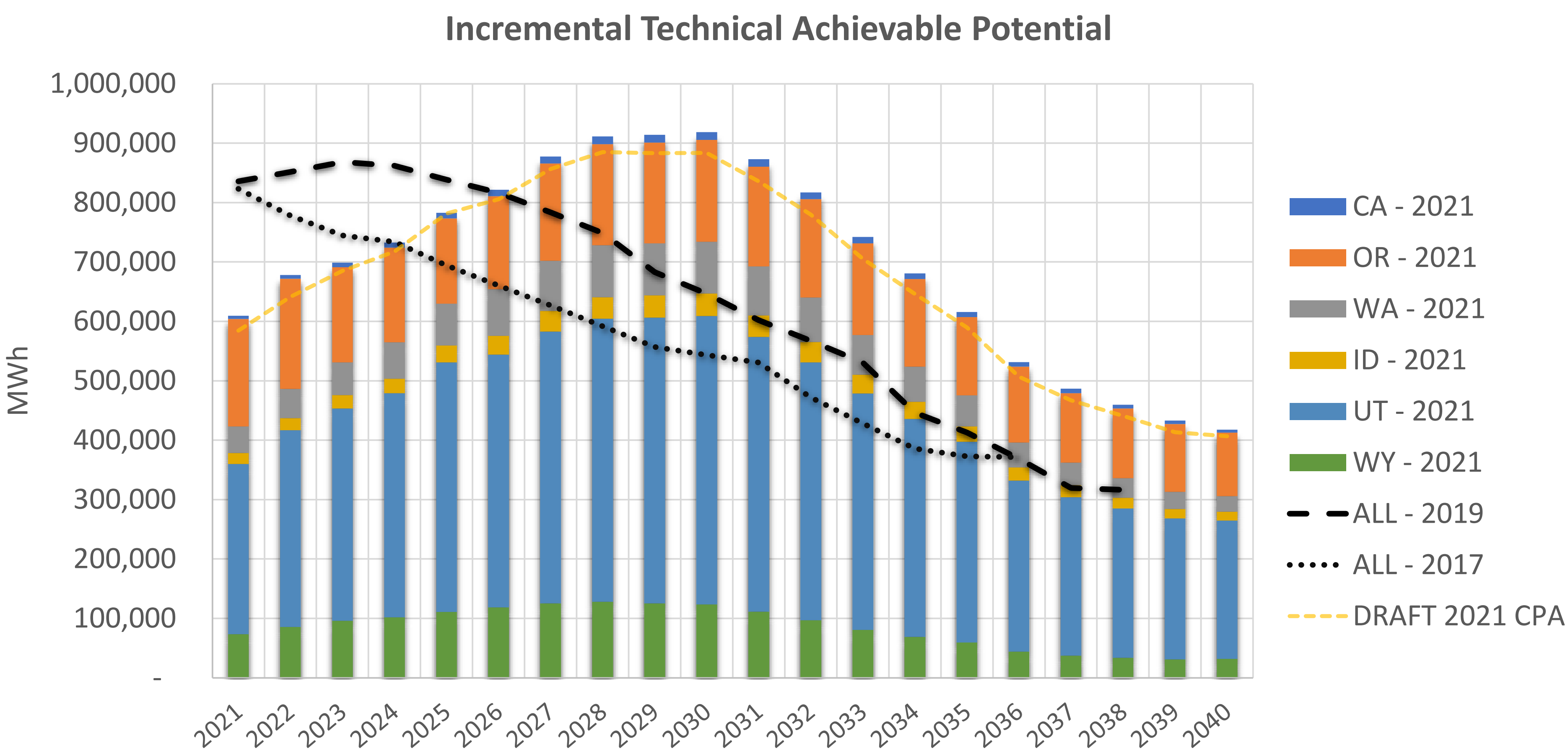
Final Technical Achievable Potential Supply Curve Comparison (All States – Cumulative MWh)



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%

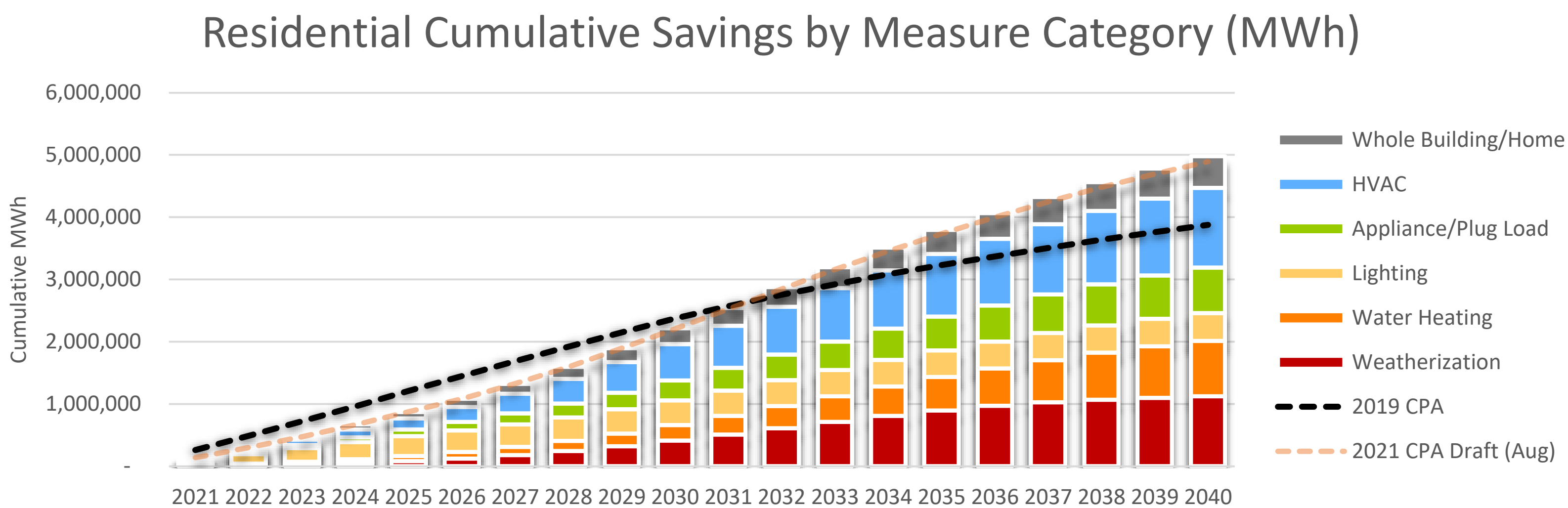
**Increase in final potential is primarily a result of updates to the Oregon results*
***Graph does not include incremental Home Energy Reports*

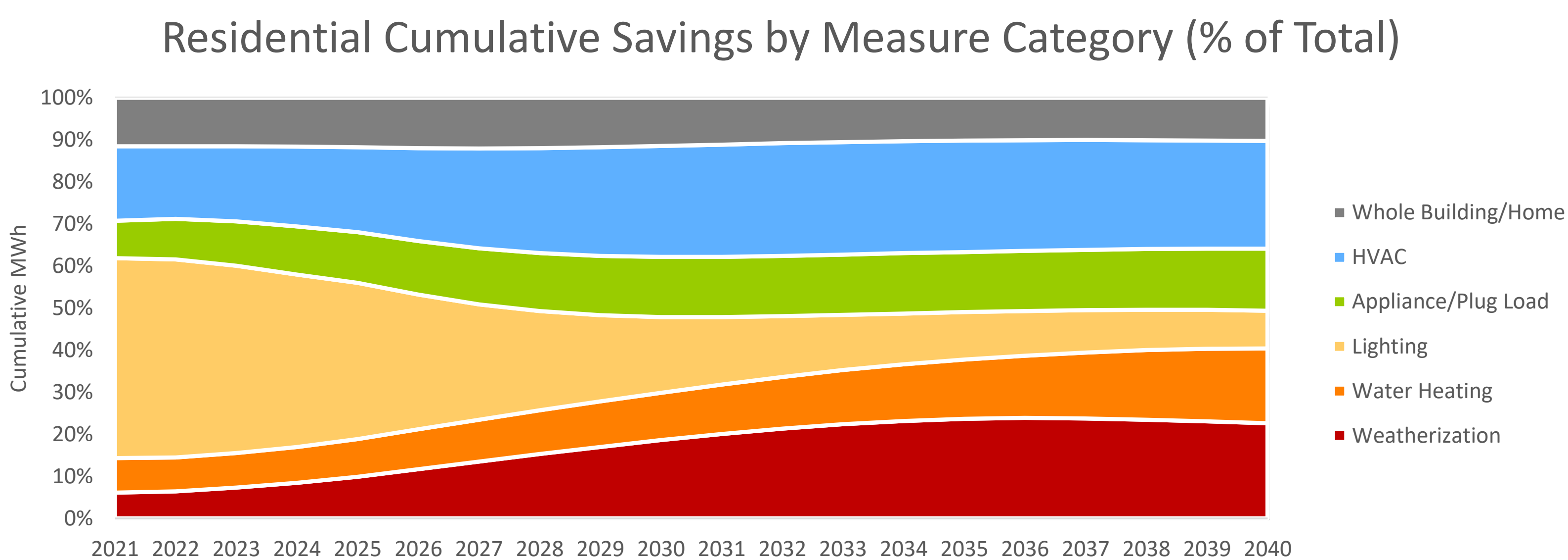
Final Technical Achievable Potential Comparison (All States - Incremental MWh)



Graph does not include Incremental Home Energy Reports

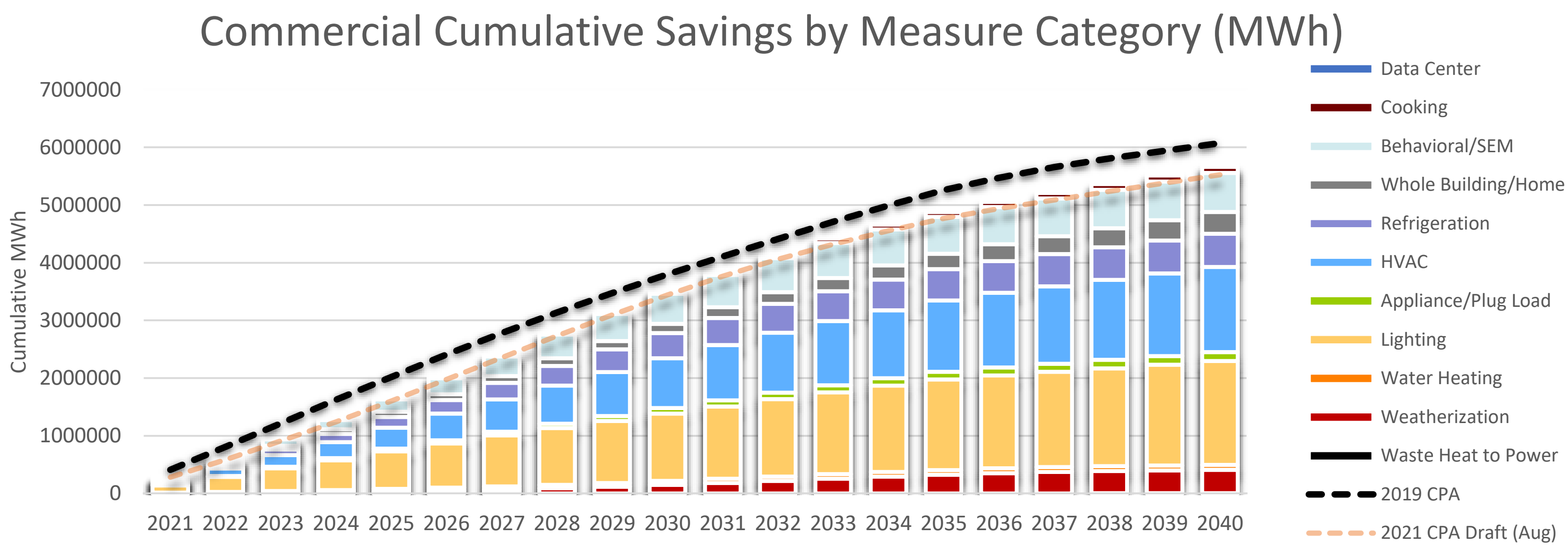
Residential Final Results (All States)

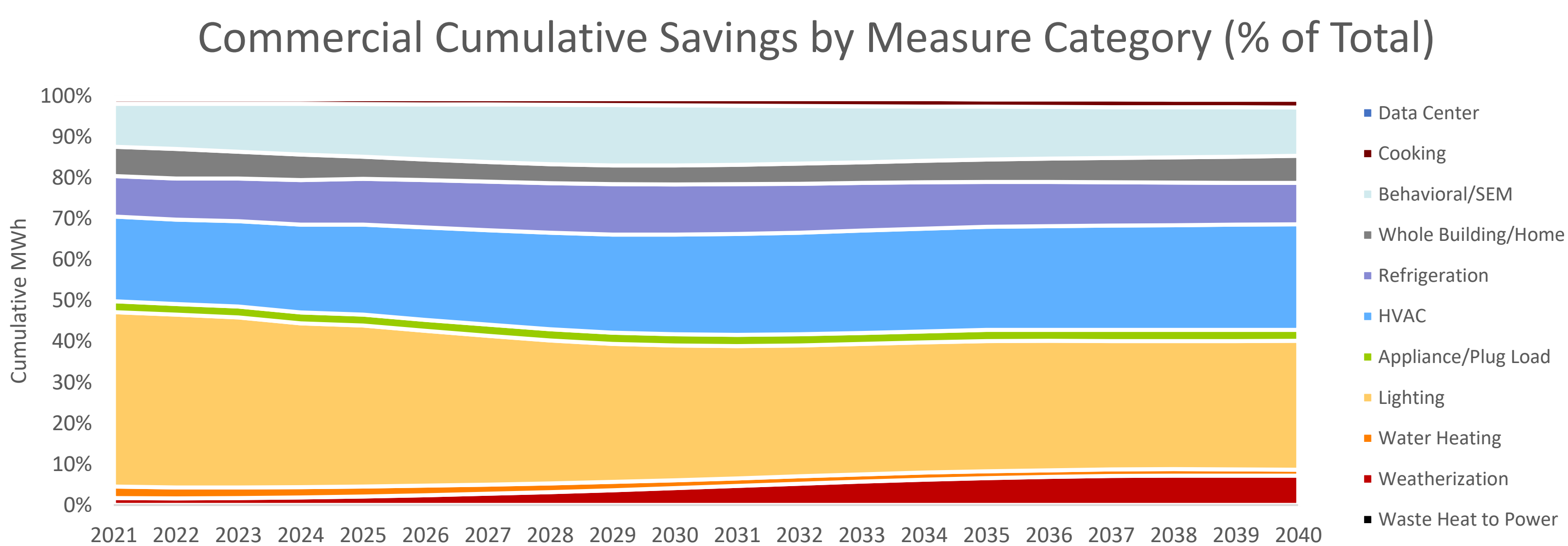




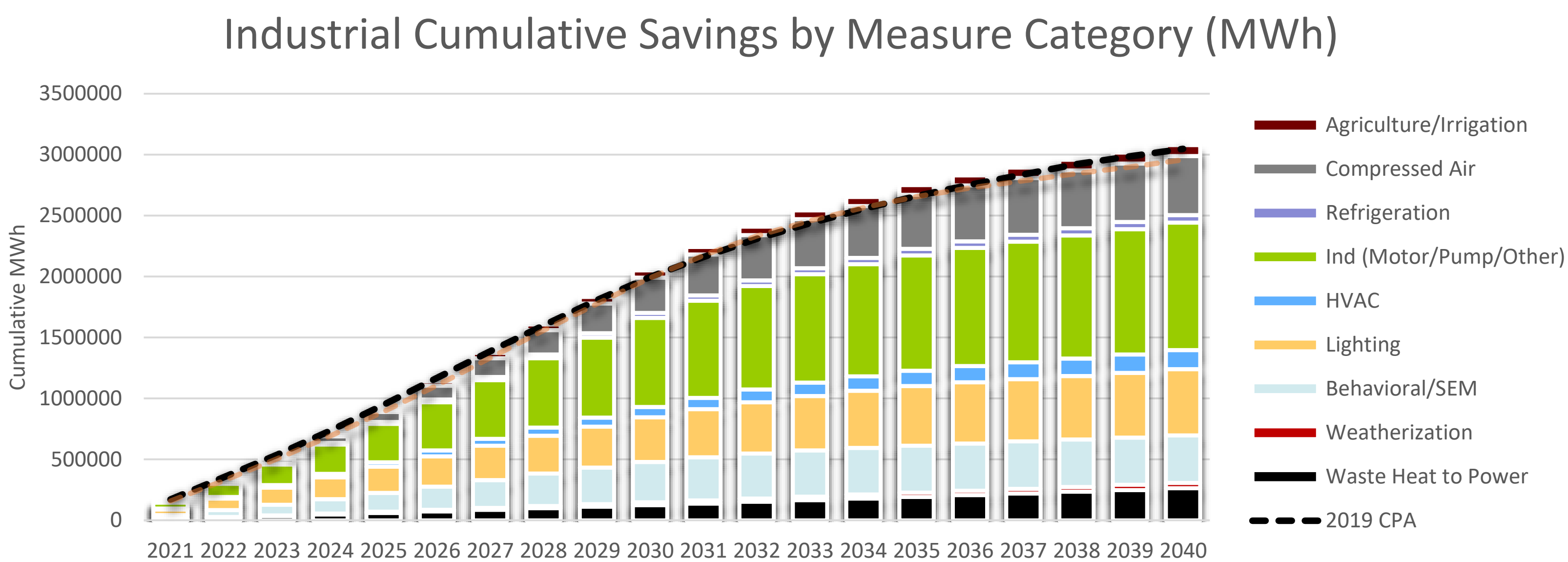
**Graphs do not include incremental Home Energy Reports*

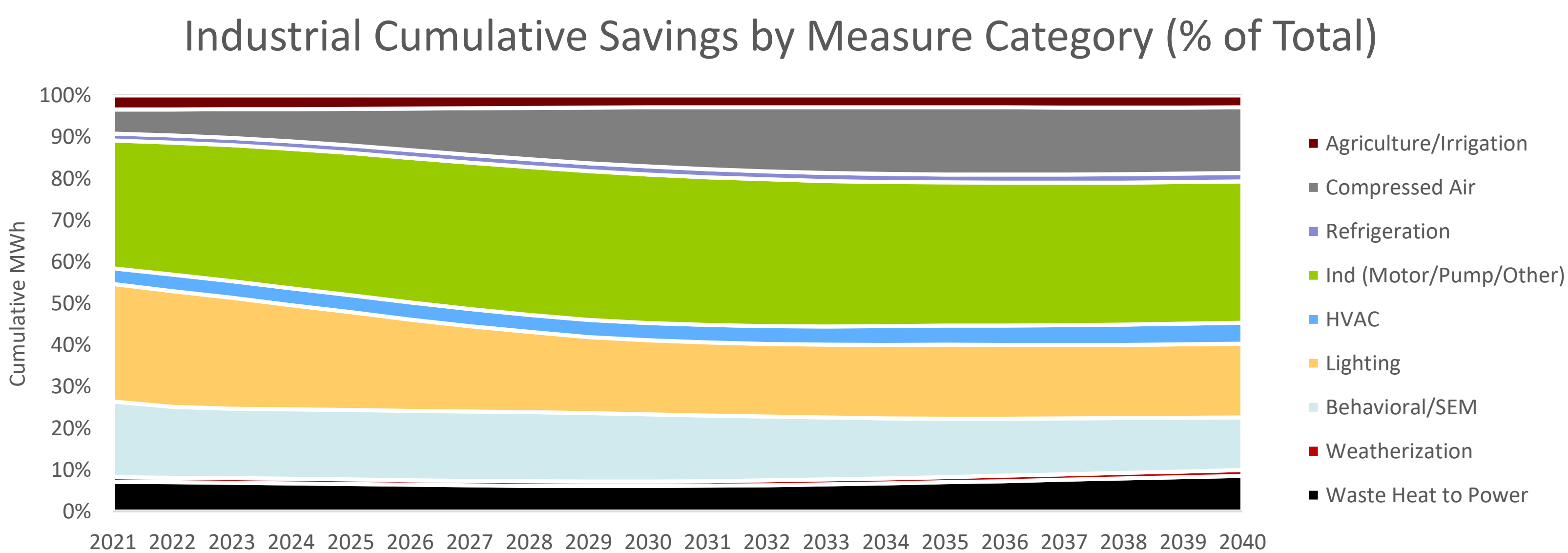
Commercial Draft Results (All States)





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

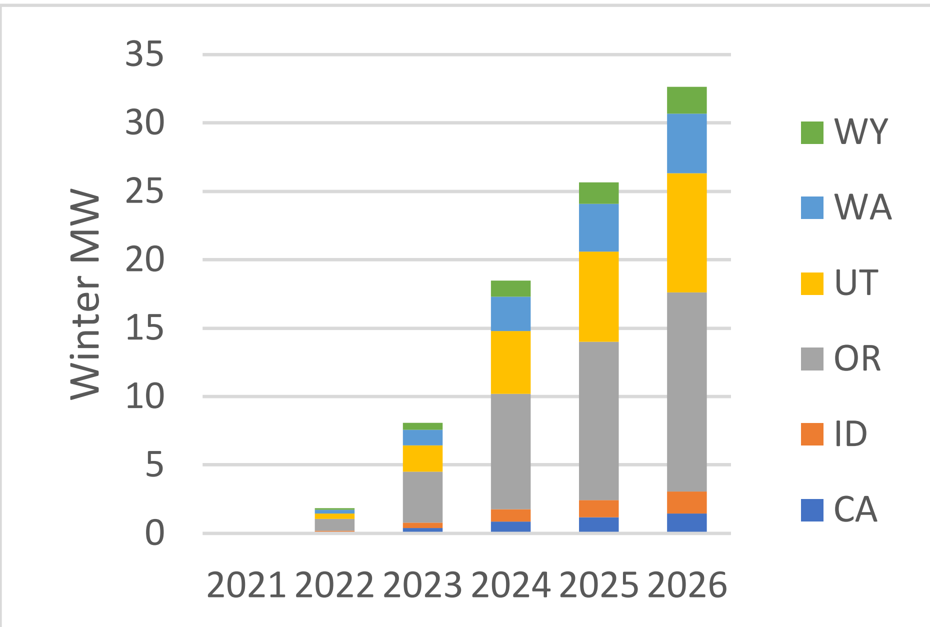
Type	Unit	Pacific Power	Rocky Mountain Power
Program Development [1]	$/program	$37,500	$37,500
Administrative Cost [2]	$/program/yr	$75,000	75,000
O&M Cost [3]	$/participant/yr	$7.50	$7.50
Marketing [3]	$/new participant	$30	$30
Equipment [3]	$/new participant	$50	$50
Incentive [3,4]	$/participant/yr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

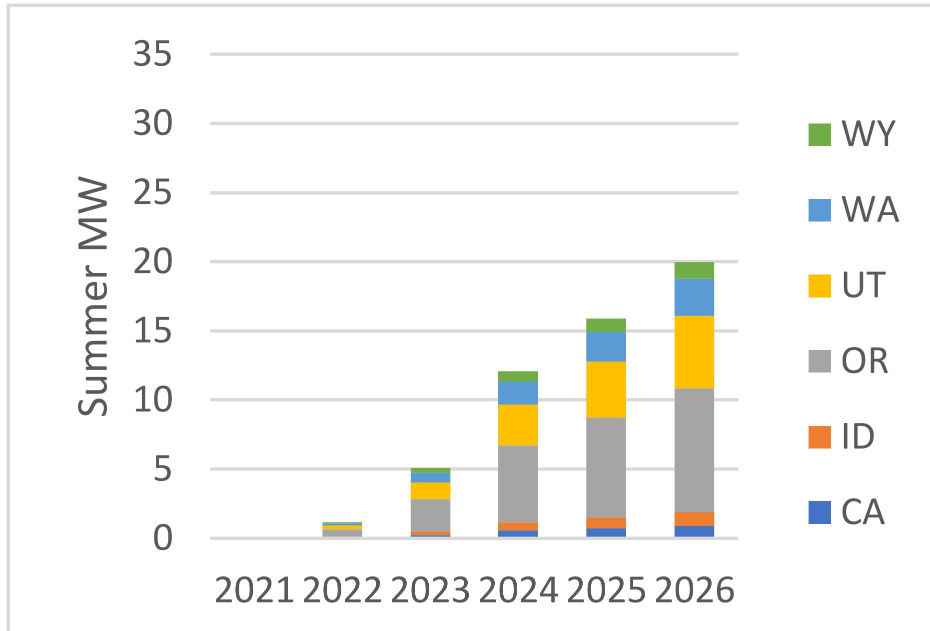
Notes:

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

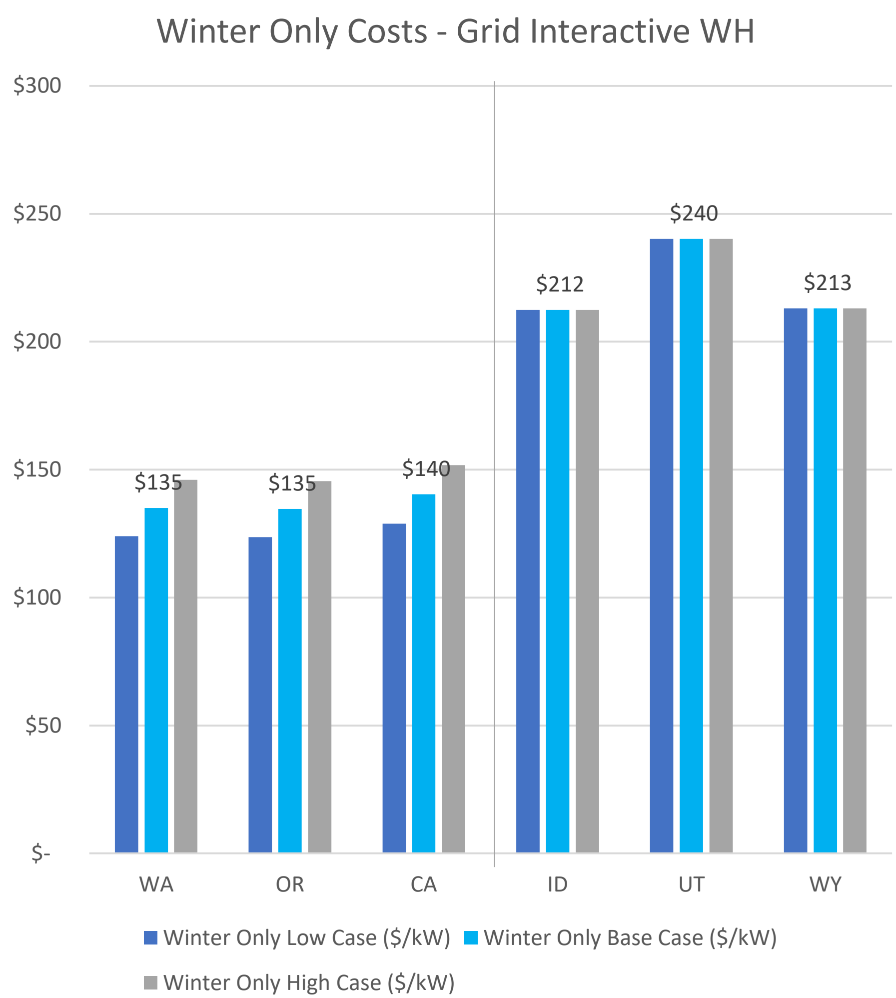
Ramped Grid Interactive Water Heater Potential – Sustained Duration

- 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





Example Levelized Costs by State - Winter



Example Levelized Costs by State - Summer

Demand Response Cost Bundles

Heating/Cooling or both

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

DLC Equipment Measures

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

Water Heaters

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

Process/Energy Management

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

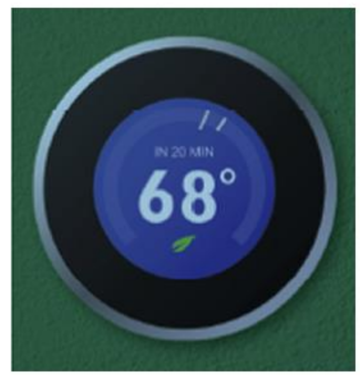
Lighting

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

Equipment Measures

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

Energy Efficiency Bundling Methodology



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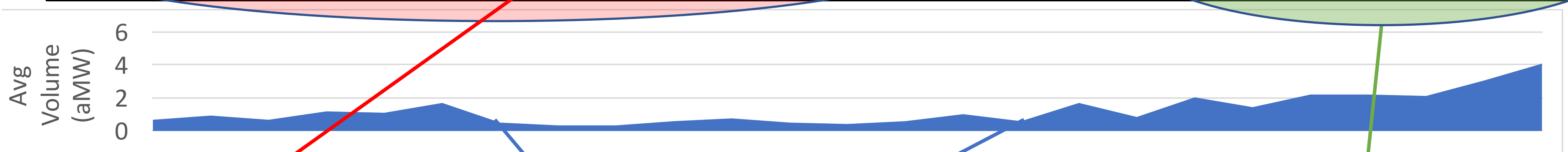
Energy Efficiency Bundling Background

- 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.

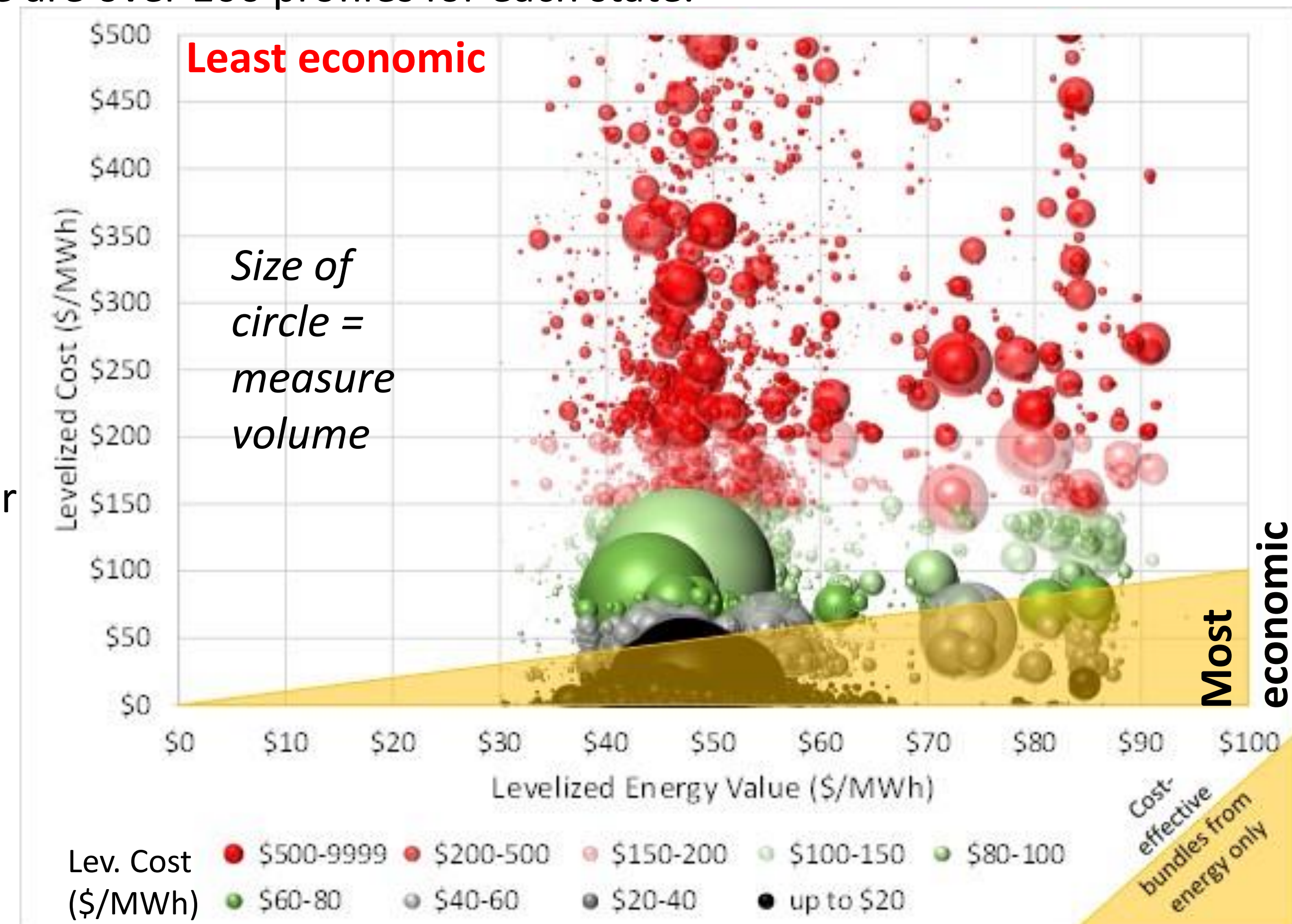
Bundle sizing in $10/MWh increments leaves lots bundles with small volumes between $100-$200/MWh.

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

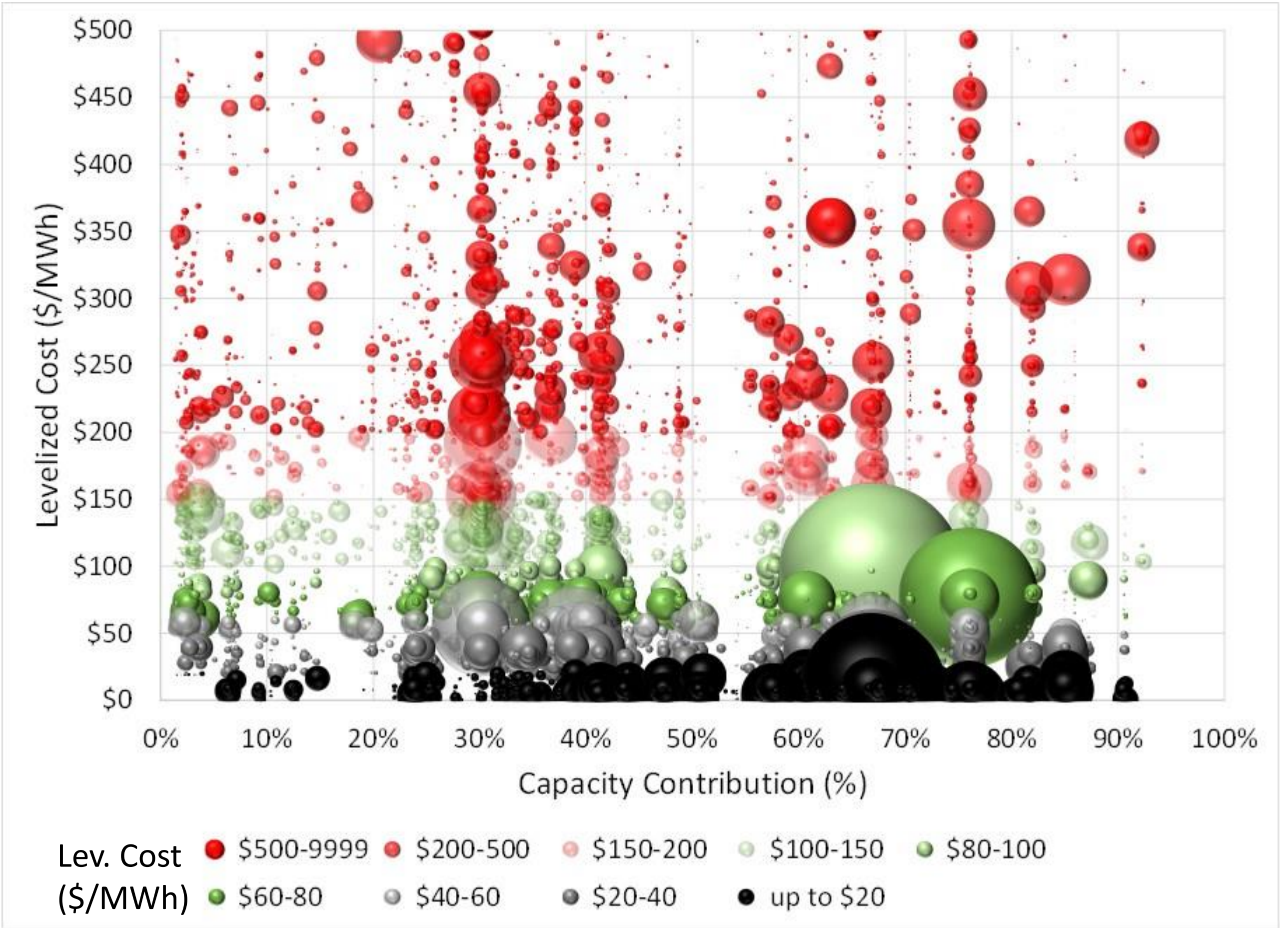
- Not all MWhs of energy efficiency are equal – value is dependent on the profile of the load reduction, which is tied to the end use.
- Measure savings are spread across applicable end use profiles for different customer types. There are over 100 profiles for each state.
- The timing of load reductions 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

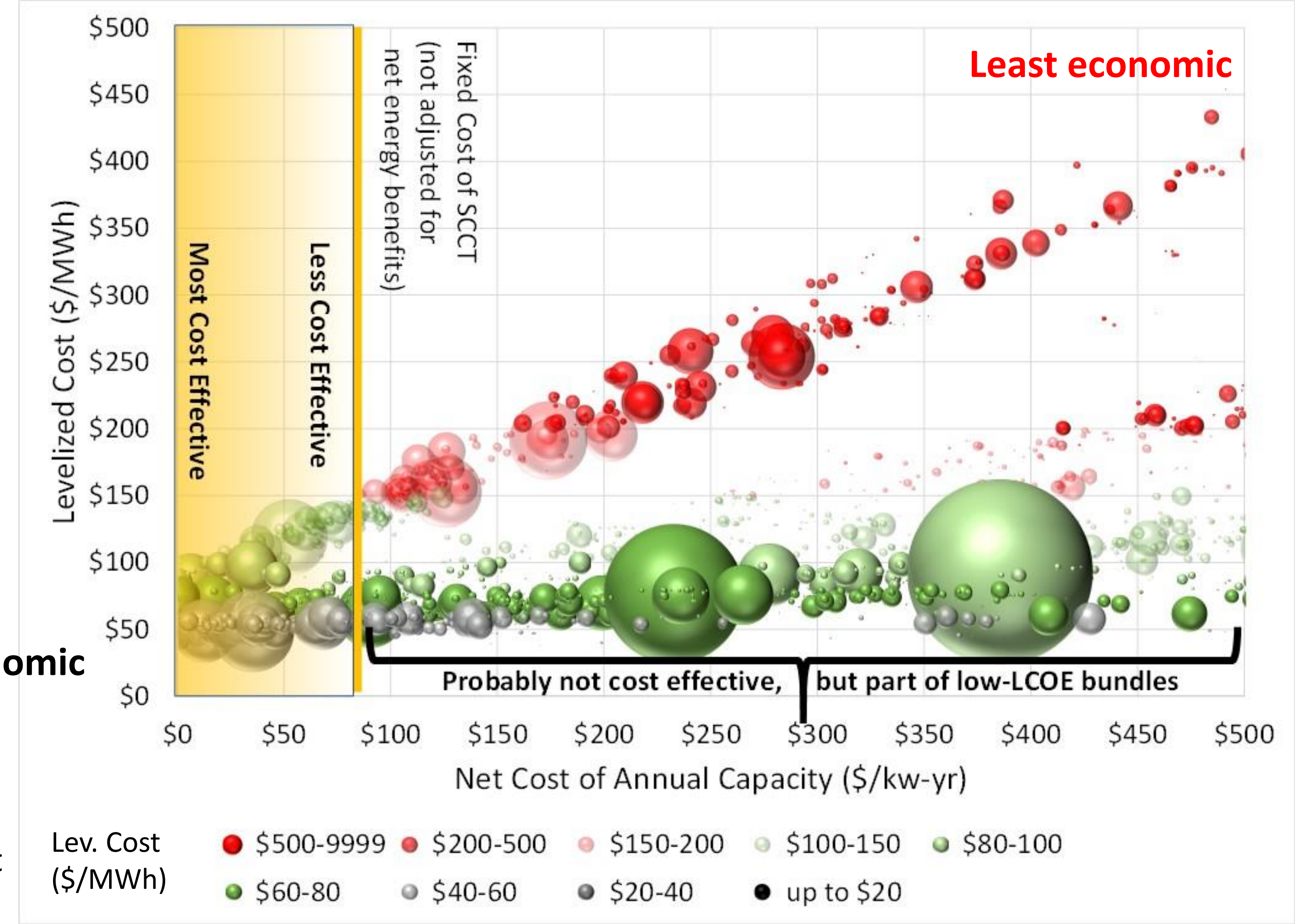


Most economic

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

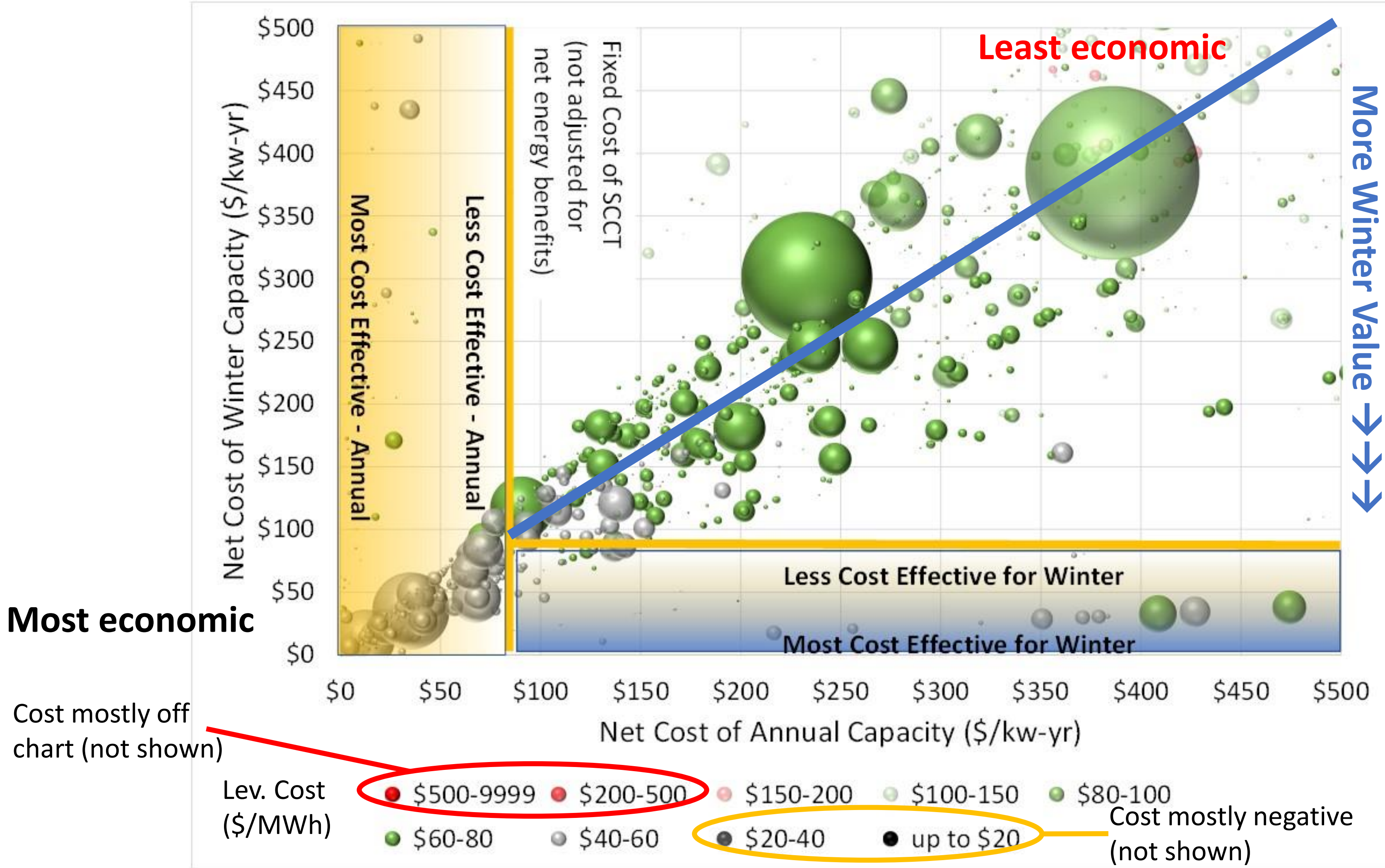
Most economic



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

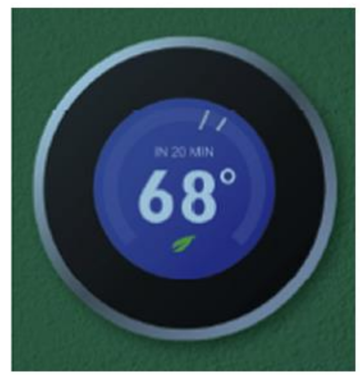
LCOE ($/MWh)	<$50/kw-yr	$50-$100/kw-yr	$100-$150/kw-yr	$150-$200/kw-yr	>=$200/kw-yr
up to $20	16.0	-	-	-	-
$20-40	4.7	-	0.0	0.0	-
$40-60	3.0	0.5	0.2	0.0	0.1
$60-80	0.8	0.3	0.2	0.4	1.5
$80-100	0.3	0.0	0.1	0.0	1.8
$100-150	0.1	0.5	0.1	0.0	1.7
$150-200	-	0.0	0.5	0.3	1.5
$200-500	-	-	-	0.1	4.1
$500-9999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

Most economic

Least economic

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

Market Reliance Assessment



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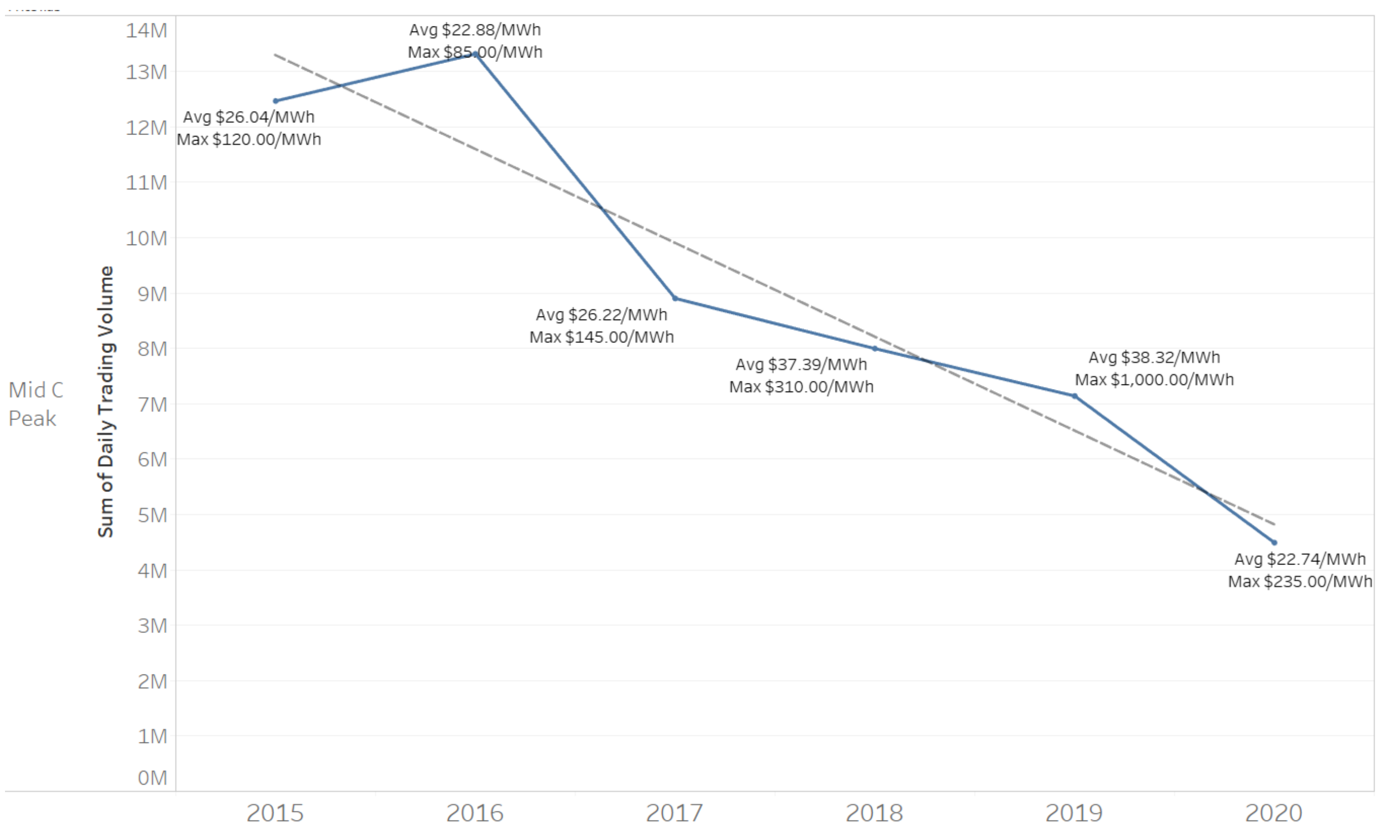
Declines in Trading Volume



- 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

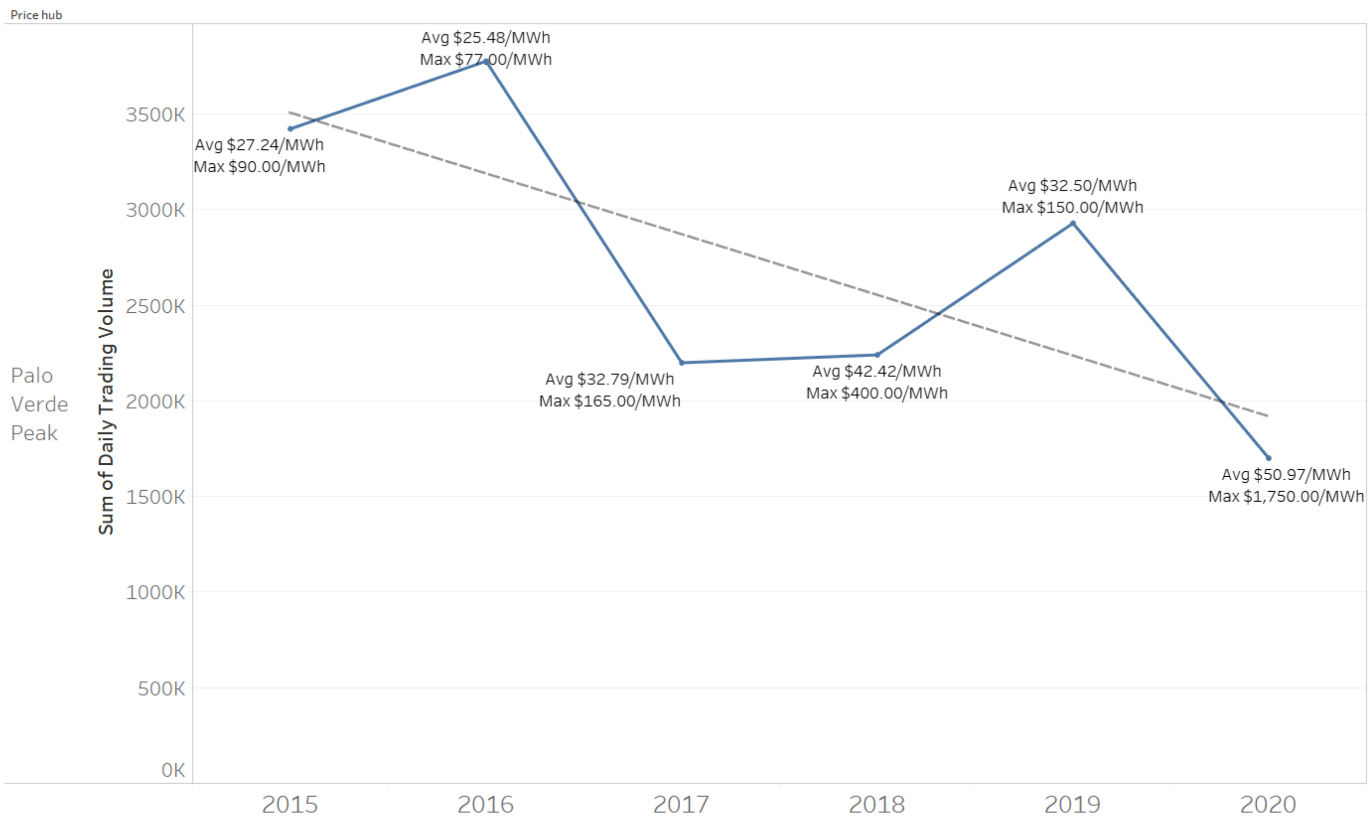
Declining Trend at the Monthly Level

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.

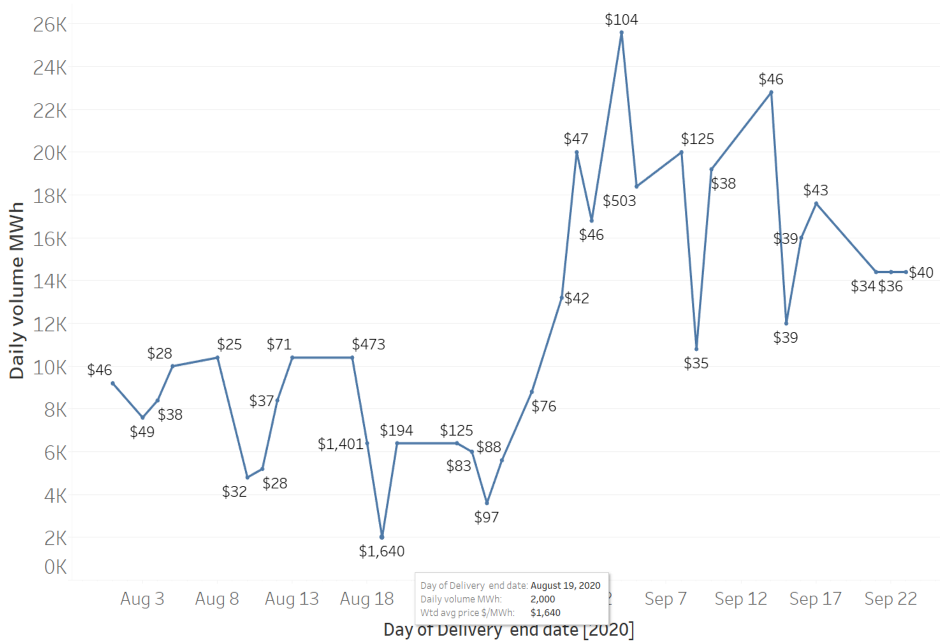
Palo Verde Liquidity Trend



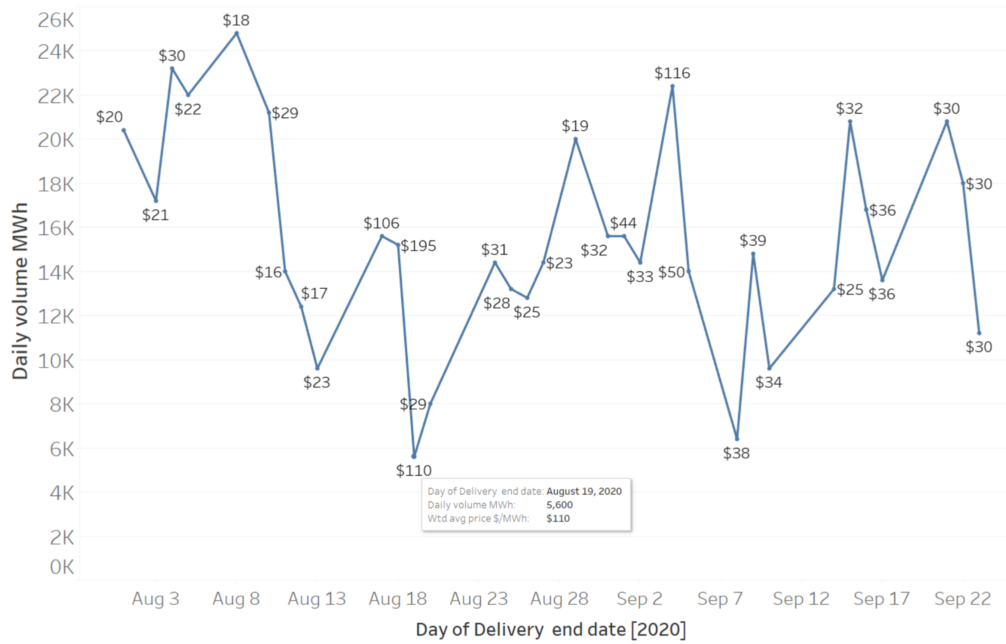
- Similar to the Mid C market, the Palo Verde Market has also seen a decrease in traded volumes over the last five years, with 2020 expected to end at an all-time low
- Prices peaked at $1,750/MWh on August 19, 2020
- All data is sourced from the EIA website for ICE daily trades

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

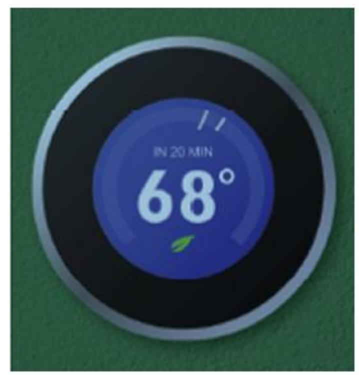
- Updated forecasts indicate Pacific Northwest energy and capacity surplus will become deficit between 2021 and 2026.
  - NPCC: “Pacific Northwest Power Supply Adequacy Assessment for 2022” - deficit year 2021 → 2022
  - PNUCC: “2020 Northwest Regional Forecast” - winter peak deficit year 2023 → 2024
  - 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



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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

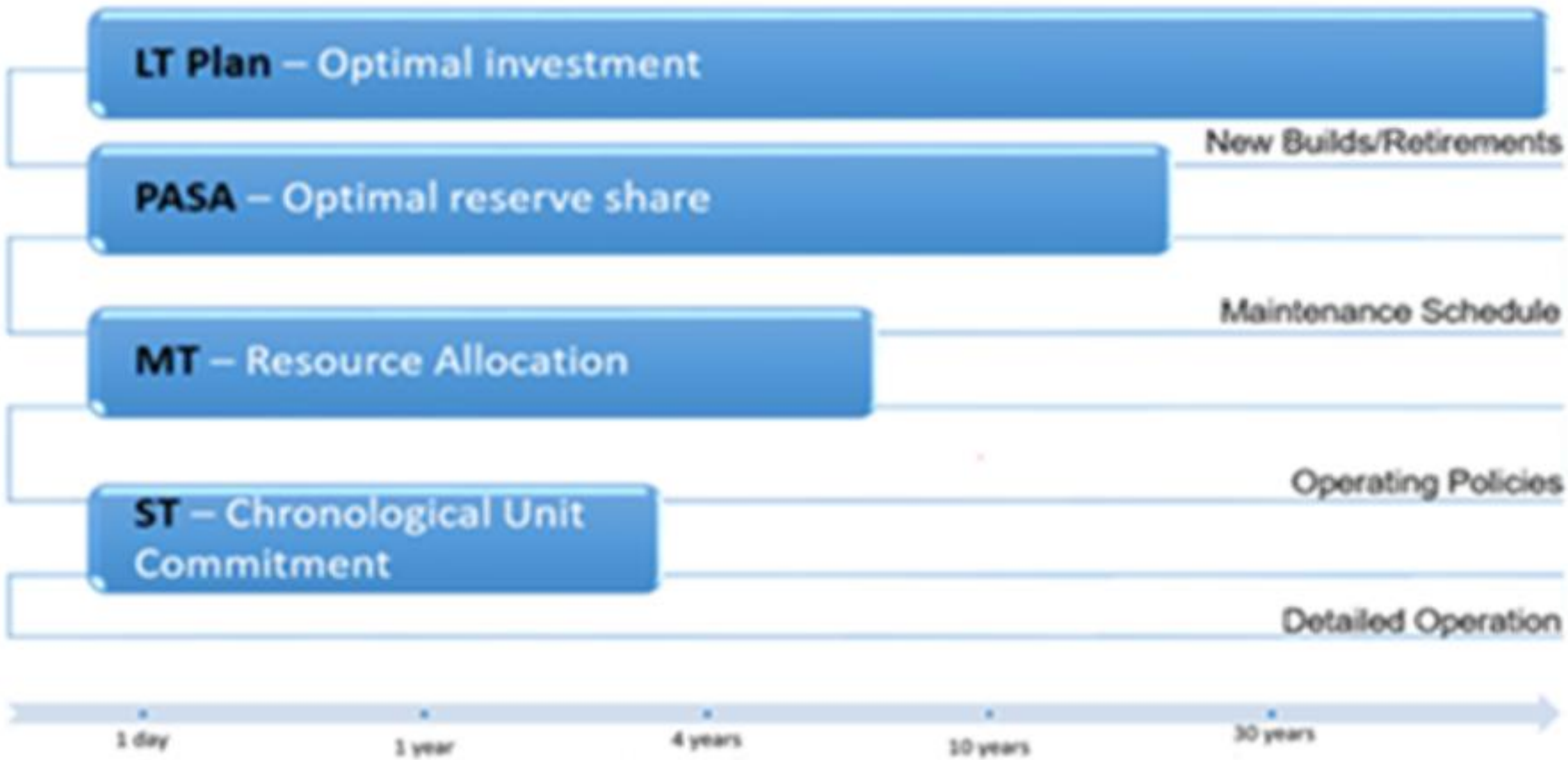
Simulation Phases

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**

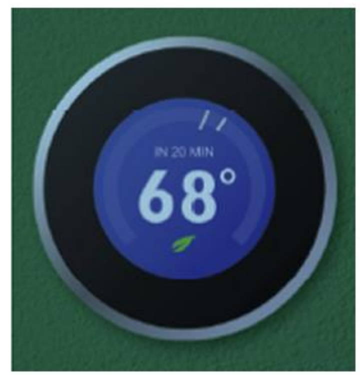
EPM - System Resources by Category	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	8,139	8,386	7,999	7,999	7,999	7,645	7,645	7,206	7,124	6,221	5,862	5,615
Hydroelectric	954	966	772	787	803	749	784	786	774	785	779	780
Class 1 DSM	326	326	323	323	323	323	323	323	323	323	323	323
Renewable	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



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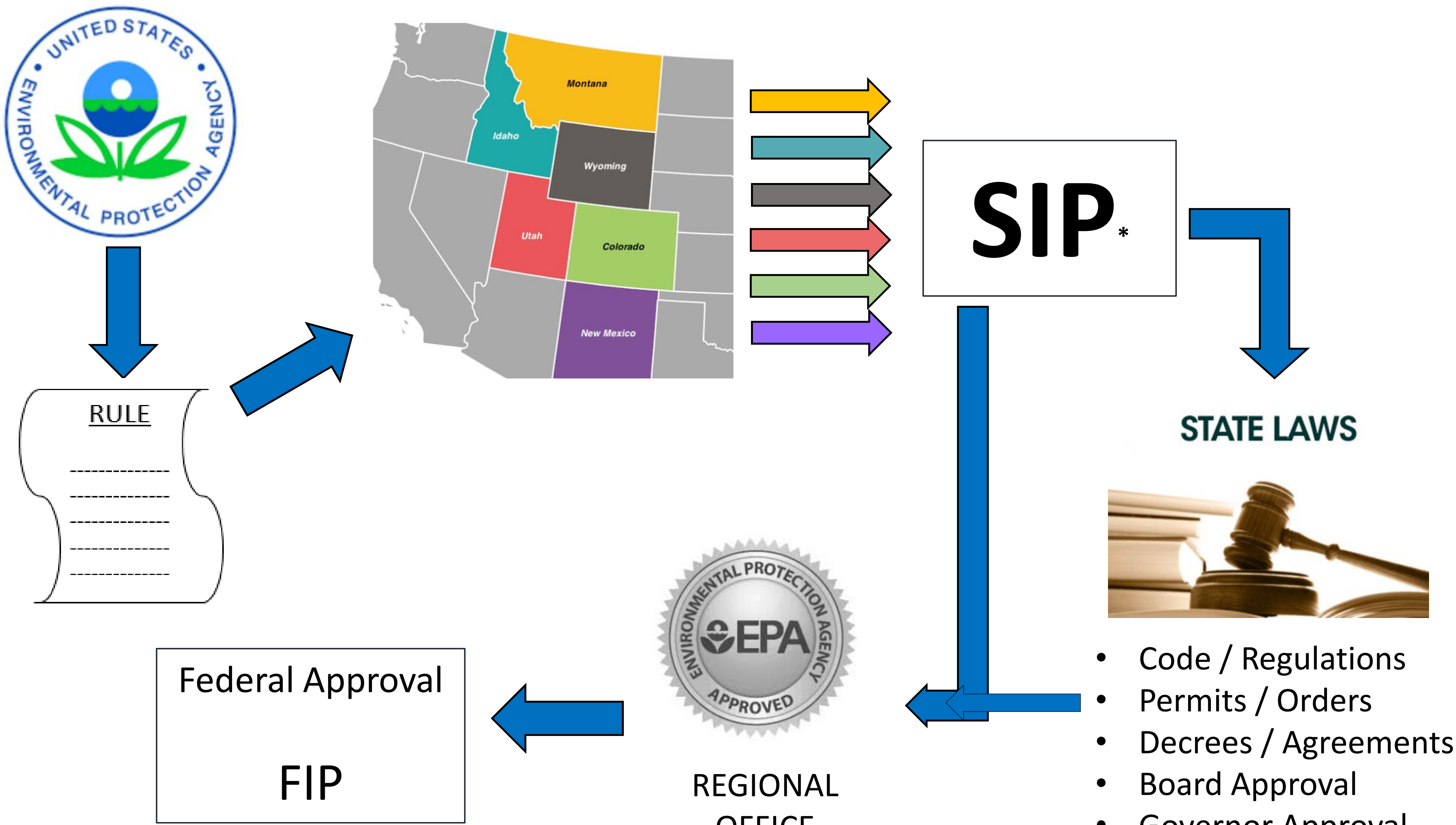
Regional Haze Overview

- 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.

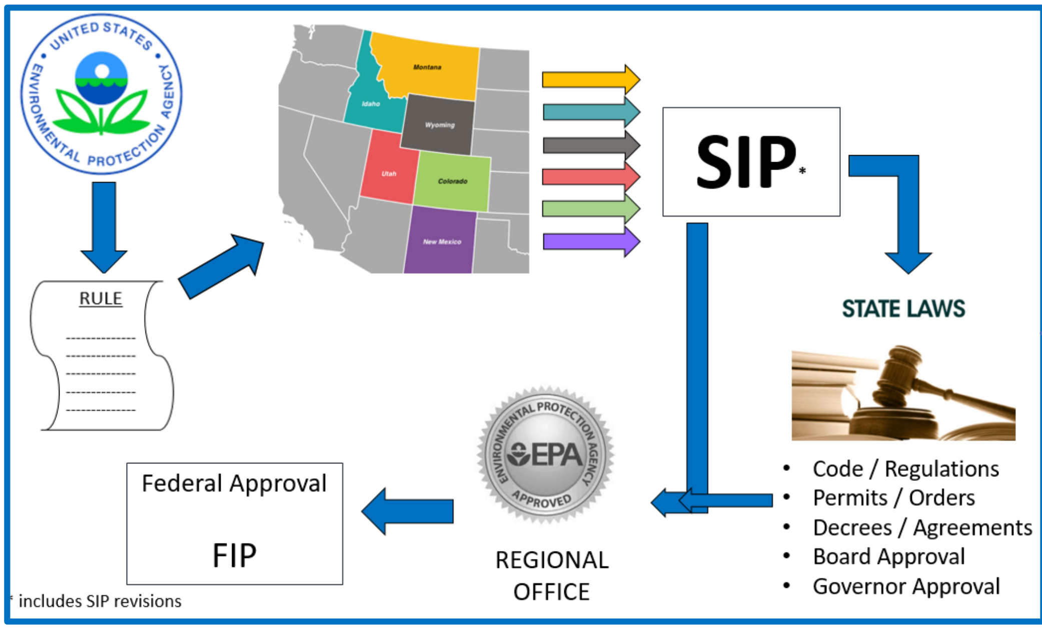
- The Rule has decadal phases or 'planning periods' - each designed to create progress towards visibility improvements at Class I Areas.

State Implementation Plans

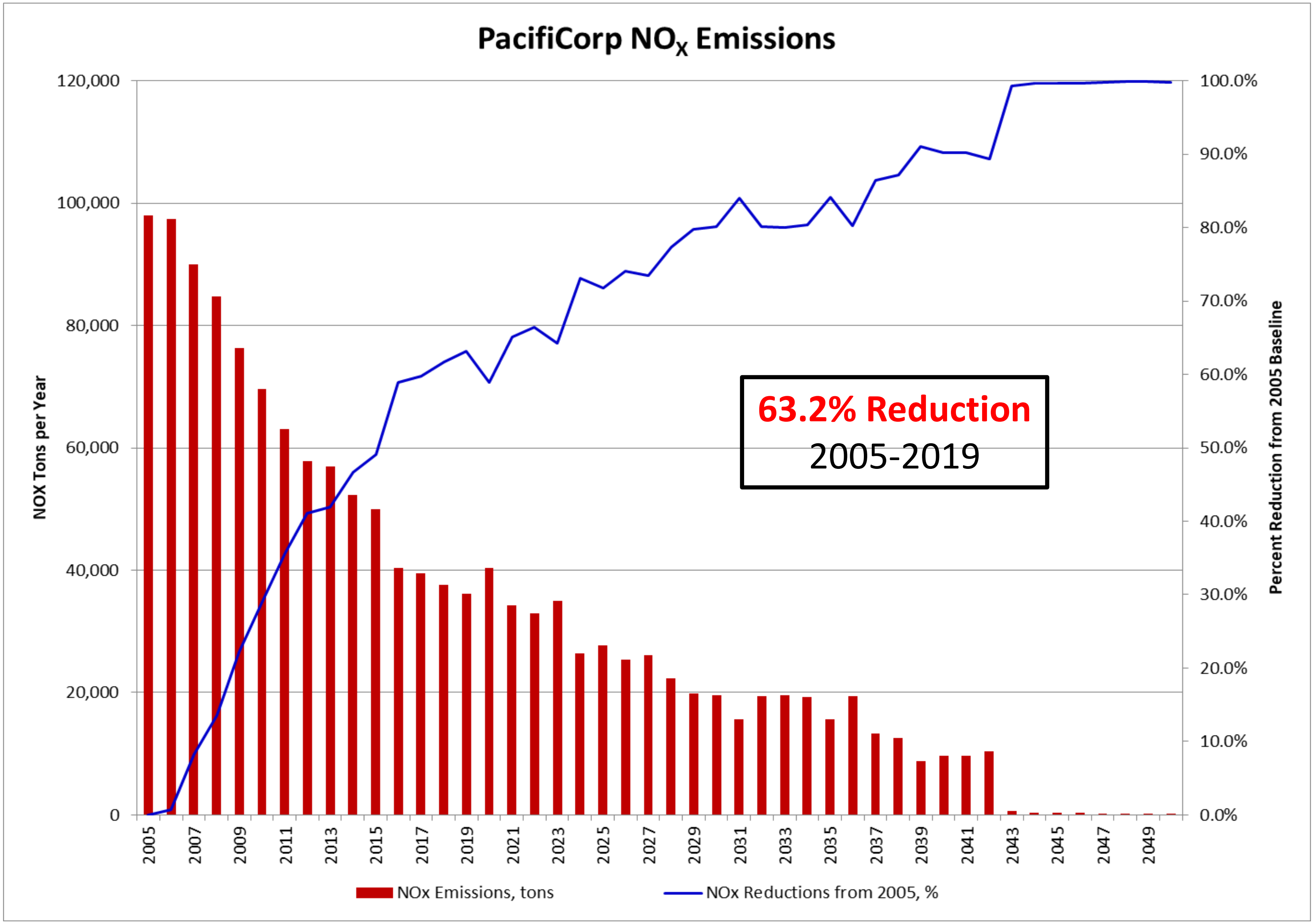


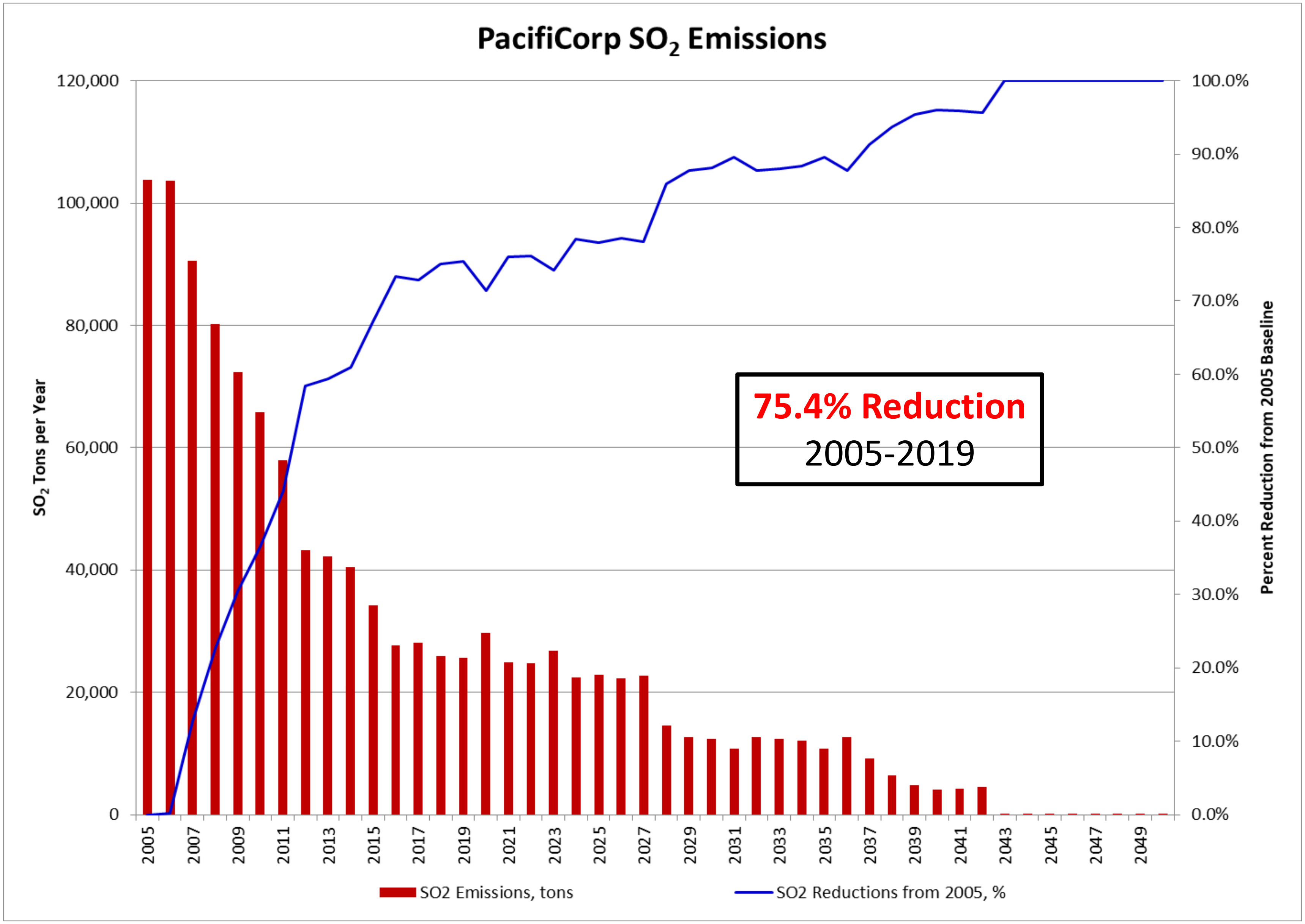
* includes SIP revisions

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

Hunter / Huntington

- 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

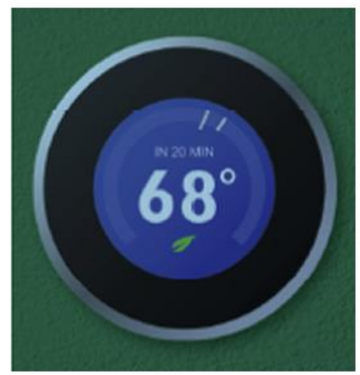
- Jan 2014, EPA issued a regional haze FIP partially approving certain parts of the state of Wyoming's SIP.
- Wyodak was required to install SCR within five years of the final rule (challenged by PacifiCorp); multiple appeals were consolidated.
- PacifiCorp, Wyoming and Basin Electric submitted motions 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

Utah / Wyoming

- 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

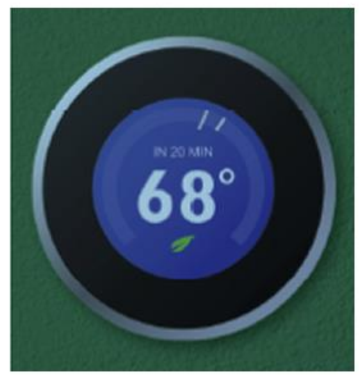
Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Cadmus Group (048)	Oct 4, 2020	CPA	Request for the conservation supply curves.	Targeted response to be sent by October 23, 2020 and discussion at the October 22, 2020 public-input meeting.
Southwest 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



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Additional Information

- Public Input Meeting and Workshop Presentation and Materials:
  - pacificorp.com/energy/integrated-resource-plan/public-input-process
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  - IRP@PacifiCorp.com
- IRP Support and Studies:
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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

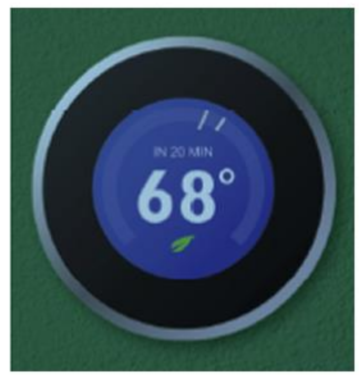
**meeting dates are subject to change*

Integrated Resource Plan

2021 IRP Public Input Meeting

November 16, 2020



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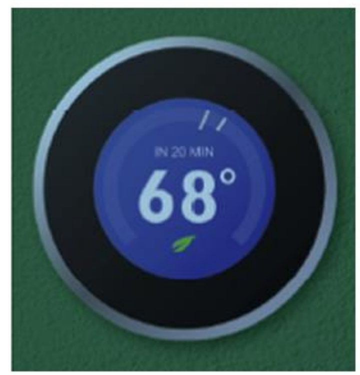
Agenda

- 9:00am-9:15am pacific – Introductions
- 9:15am-10:15am pacific – Plexos Benchmark Result
- 10:15am-11:45am pacific – Modeling Assumptions Update
- 11:45am-12:30pm pacific – Lunch Break
- 12:30pm-1:30pm pacific – All-Source Request for Proposals Update
- 1:30pm-1:45pm pacific – Stakeholder Feedback Form Recap
- 1:45pm-2:00pm pacific – Wrap-Up/Next Steps

Plexos Benchmark Result



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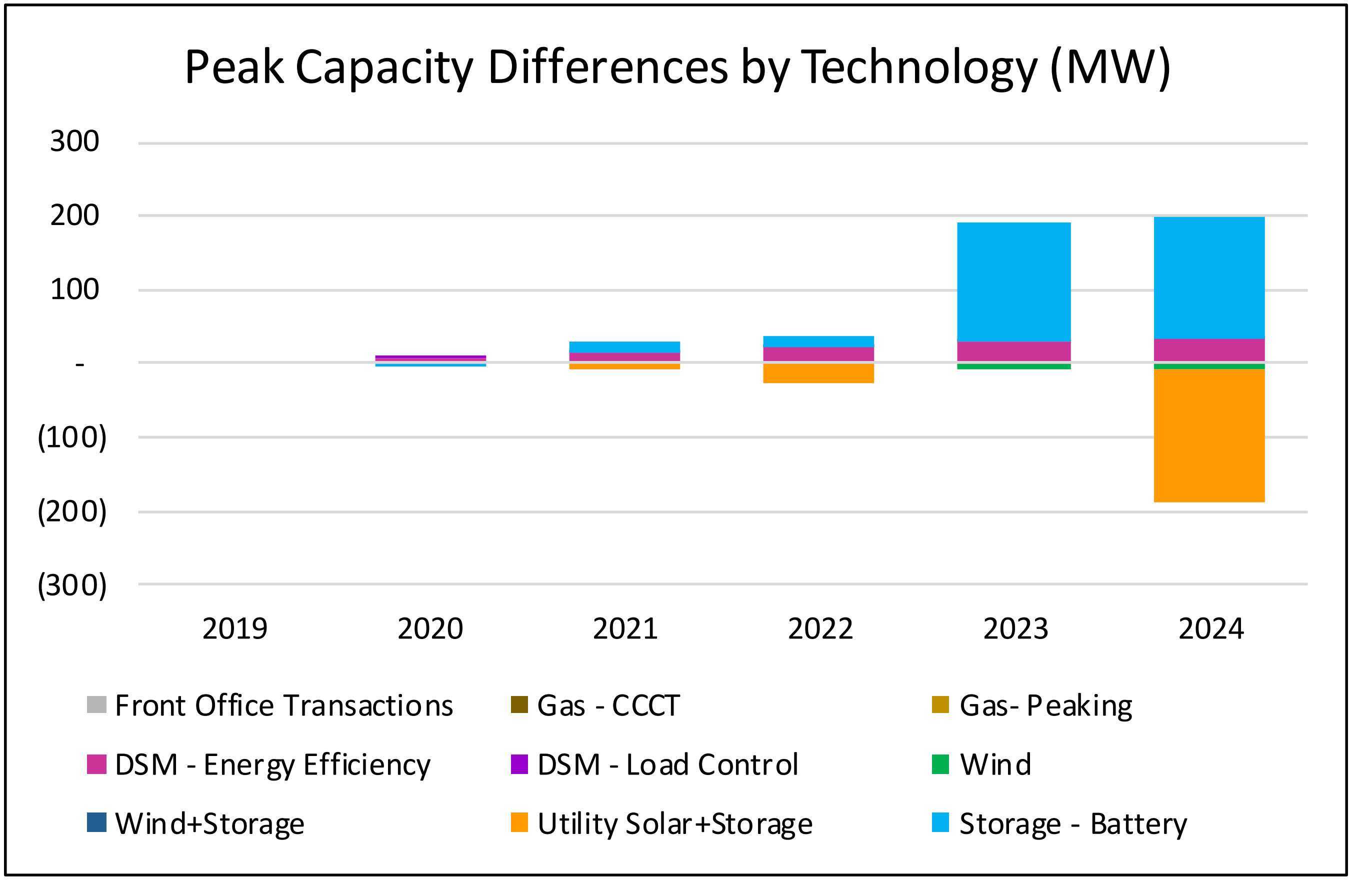
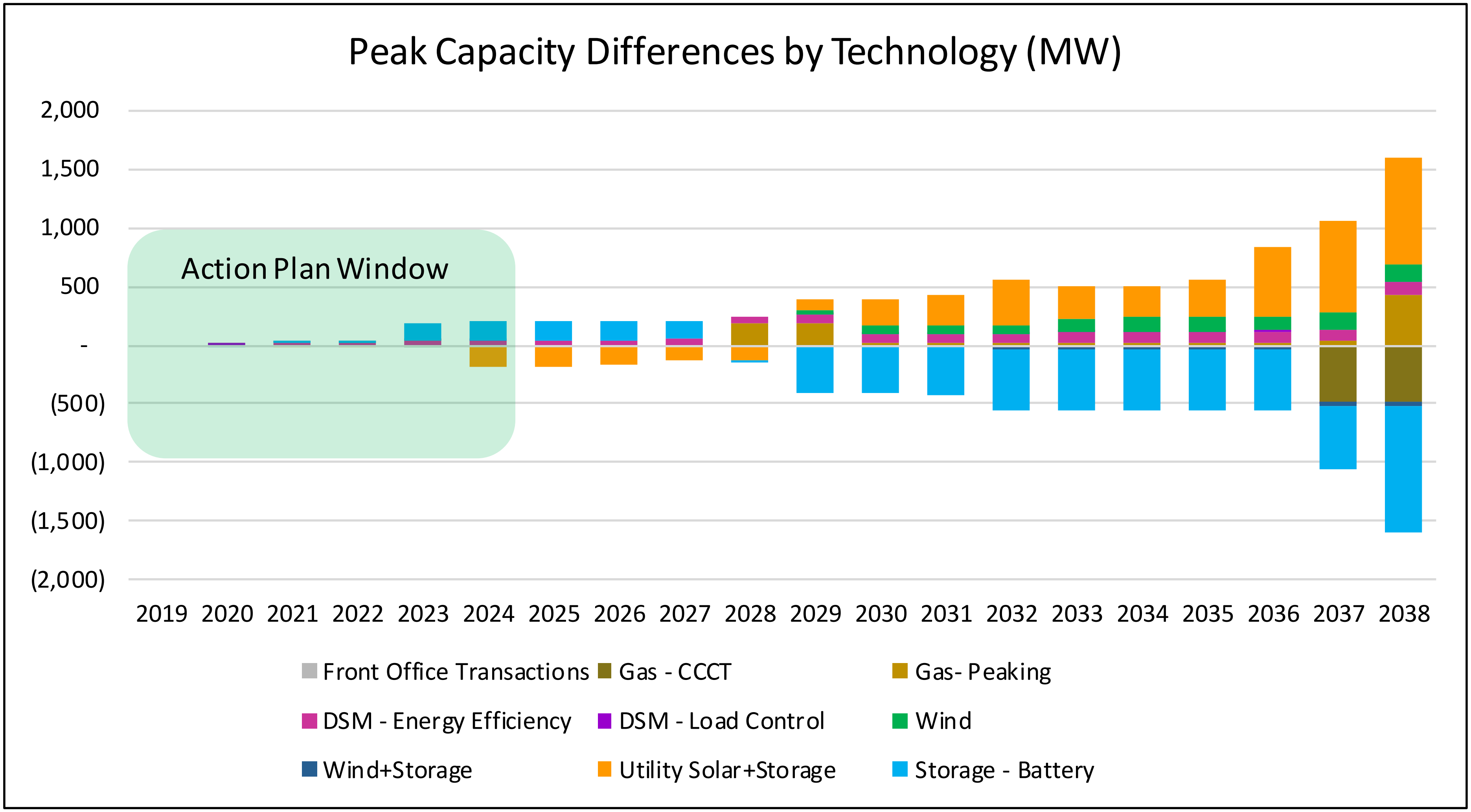
Plexos Benchmark Result Overview

- The benchmarking exercise confirms that the 2019 IRP action plan would not have changed if Plexos were used to develop PacifiCorp's preferred portfolio
- Relative to the preferred portfolio, the Plexos portfolio accelerates less than 200 MW of peak capacity from 2024 into 2023
    - Selects stand-alone battery and DSM over additional solar
    - Allows battery to support the portfolio one year earlier
- On a peak-capacity basis, the benchmark load and resource balance is within 0.15% of the 2019 IRP preferred portfolio by 2024 and within 0.22% by 2038
- Endogenous transmission selections are unchanged in several key areas:
    - Energy Gateway South is selected in 2024 in both the benchmark and 2019 IRP preferred portfolio
    - Brownfield recovered transmission is the same in Utah and Bridger
- Differences in endogenous transmission selection include:
    - Selection of Walla Walla to Yakima 200 MW transmission in 2024
    - Acceleration of Yakima to Southern Oregon/California 400 MW from 2036 to 2030
    - Deferral of Goshen to Utah S 800 MW from 2030 to 2033

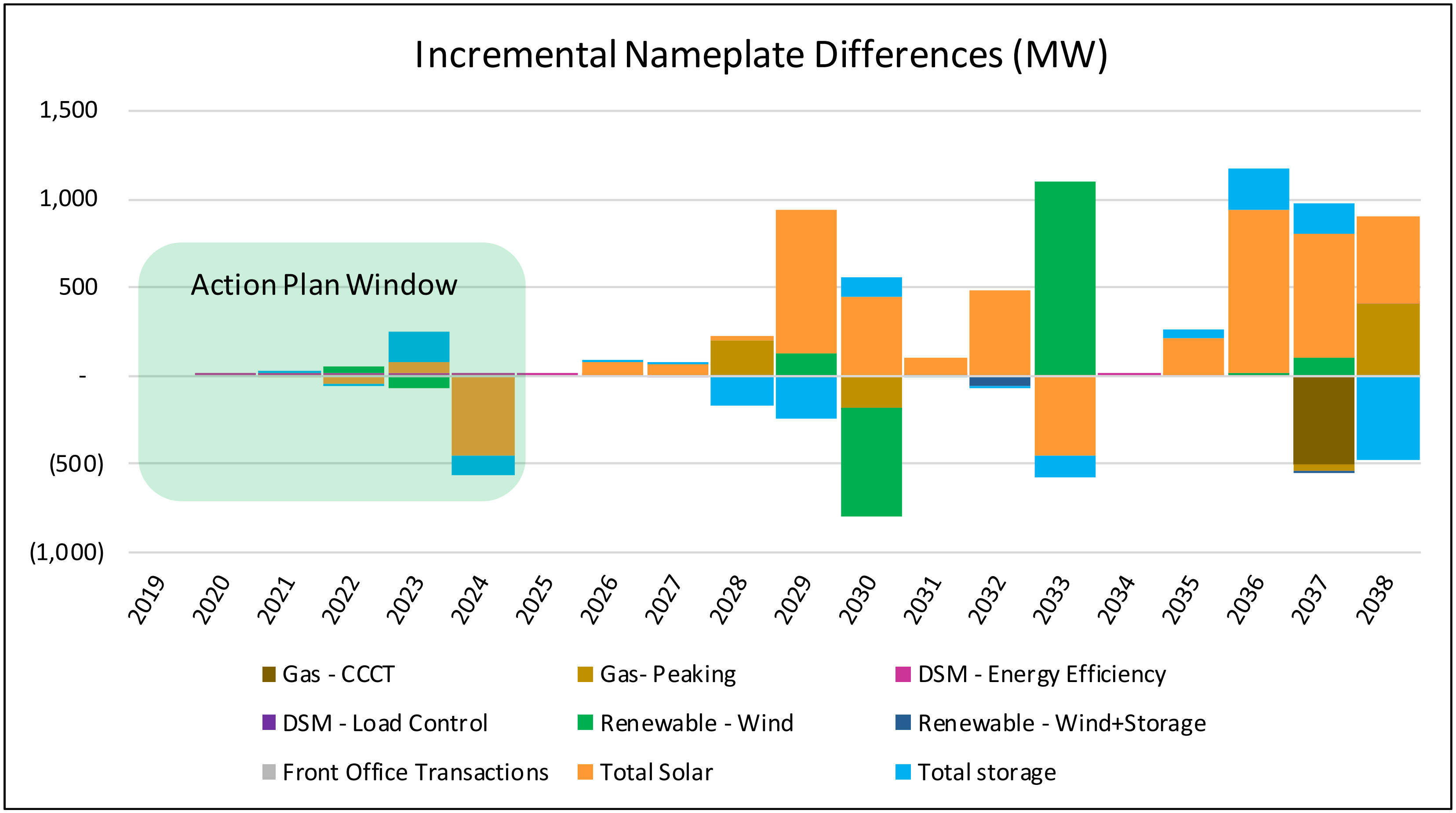
Plexos Benchmark to SO L&R Compare - Action Plan Window



Plexos Benchmark to SO Portfolio L&R Compare – 20 Year Planning Period



Plexos Benchmark to SO Nameplate Comparison



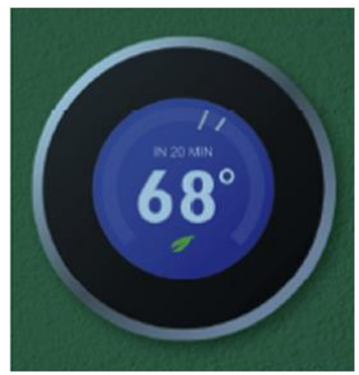
- Nameplate differences in the Plexos benchmark are largely outside of the action plan window
- 446 MW of nameplate solar + storage reduction includes 112 MW of battery
- 180 MW "increase" in 2023 battery nets to a 68 MW increase

Plexos Next Steps

- Currently testing stochastic modeling
- Portfolio development for the 2021 IRP

Modeling Assumptions Update



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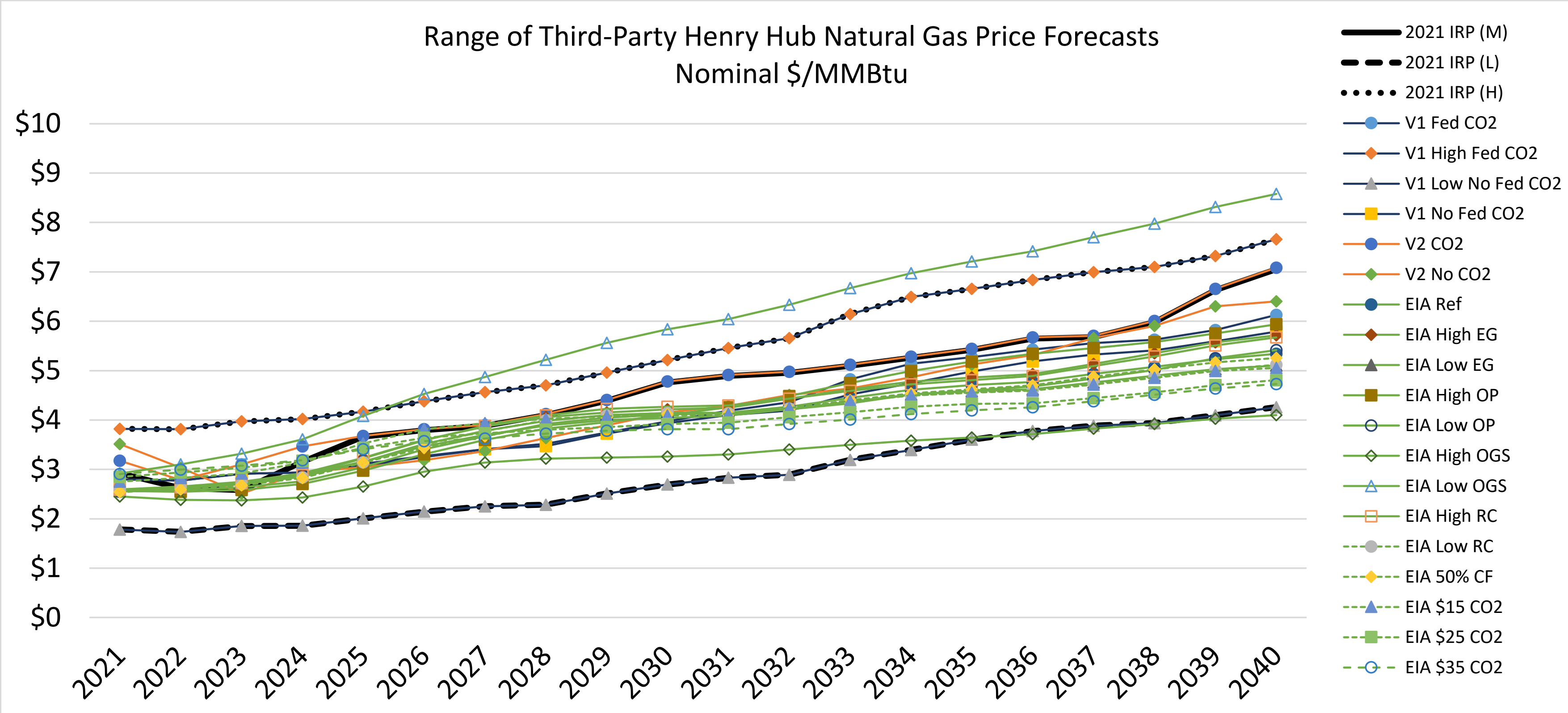
Price-Policy Scenarios

Scenario Short Name	Gas Price	CO2 Cost	Power Price
MM	Medium	Medium	Under Development
MN	Medium	None	Completed
HH	High	High	Under Development
LN	Low	None	Under Development
SCC-GHG	Medium	Social Cost of Green House Gases	Under Development

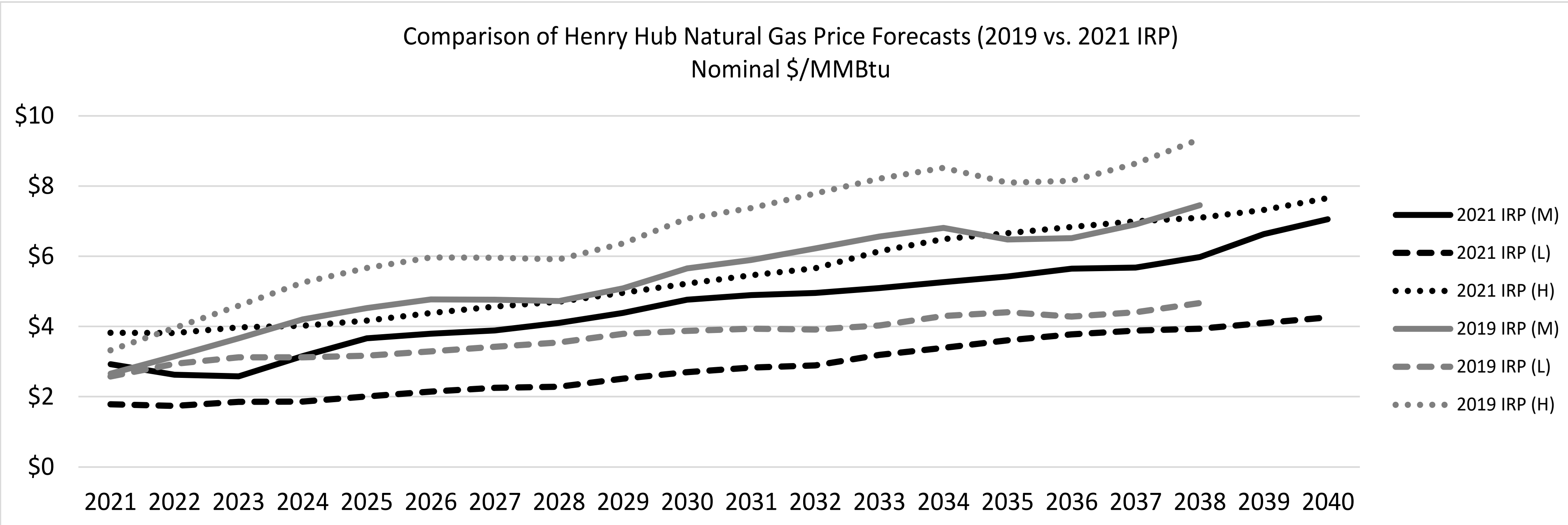
- power prices.
- Power prices are produced using Aurora and incorporate as inputs the gas price and CO_2 cost assumptions for a given price-policy scenario.
- All but the MN price-policy scenario is under development.
- Price-policy scenarios being developed for the 2019 IRP are intended to capture a reasonable range of variables that will reasonably capture how these assumptions might influence resource outcomes during the portfolio development phase of the IRP.
- Price-policy scenarios also help inform the acquisition path analysis, which identifies how future resource procurement might be influenced by changes in the planning environment.

Natural Gas Price Forecasts



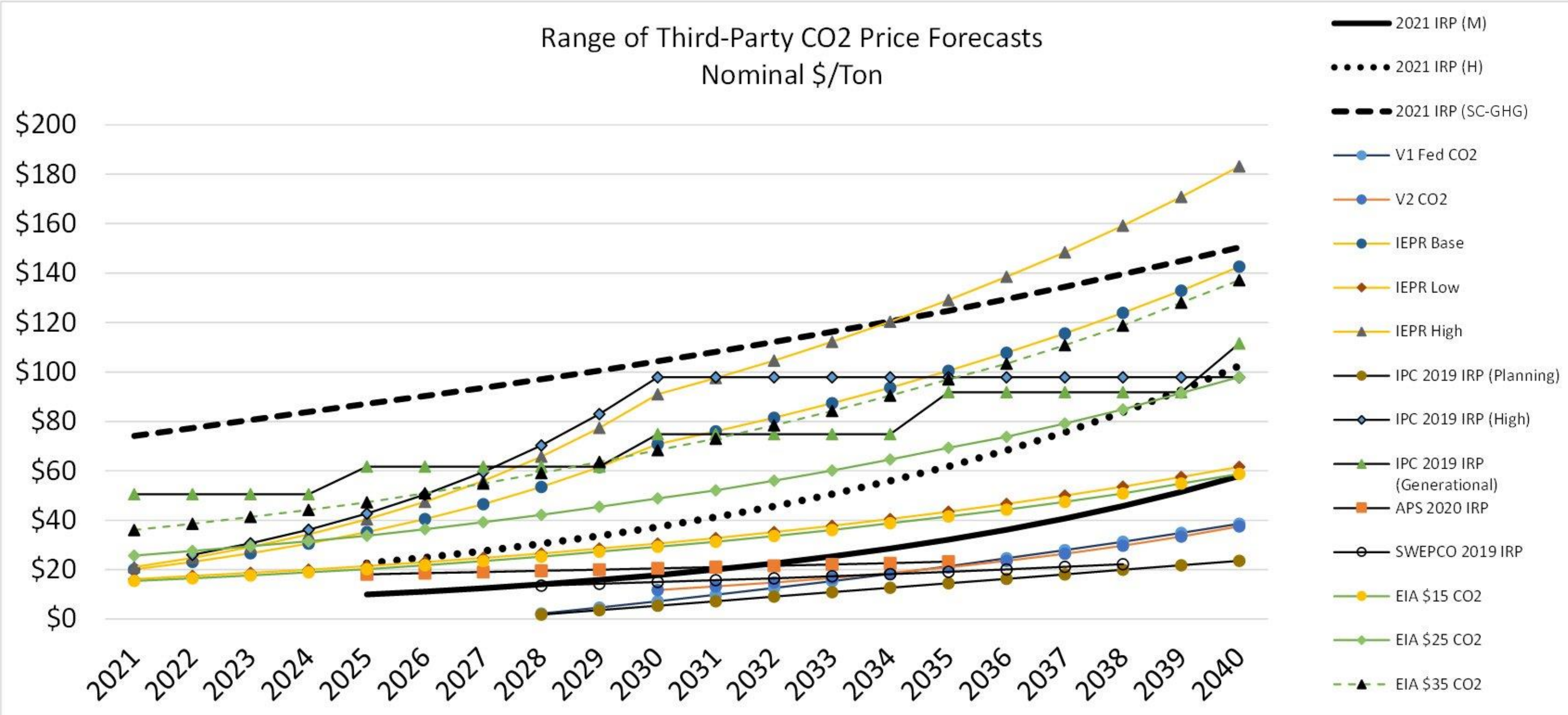
- Henry Hub natural gas prices from two third-party vendors (vendor 1 = “V1” and vendor 2 = “V2”) and from the 2020 Annual Energy Outlook published by the U.S. Department of Energy's Energy Information Administration (EIA) are shown.
- EIA scenarios include: high and low economic growth (“High EG” and “Low EG”, respectively); high and low oil prices (“High OP” and “Low OP”, respectively); high and low oil & gas supply (“High OGS” and “Low OGS”, respectively); high and low renewable cost (“High RC” and “Low RC”, respectively); a 50% carbon free case (“50% CF”); and three different CO_2 price cases (“$15 CO2”, “$25 CO2”, and “$35 CO2”).
- The medium, low and high gas price scenarios for the 2021 IRP are within the range of forecasts provided by these entities.
- Gas price assumptions are being used to generate an accompanying power price forecast using Aurora.

Natural Gas Price Scenarios



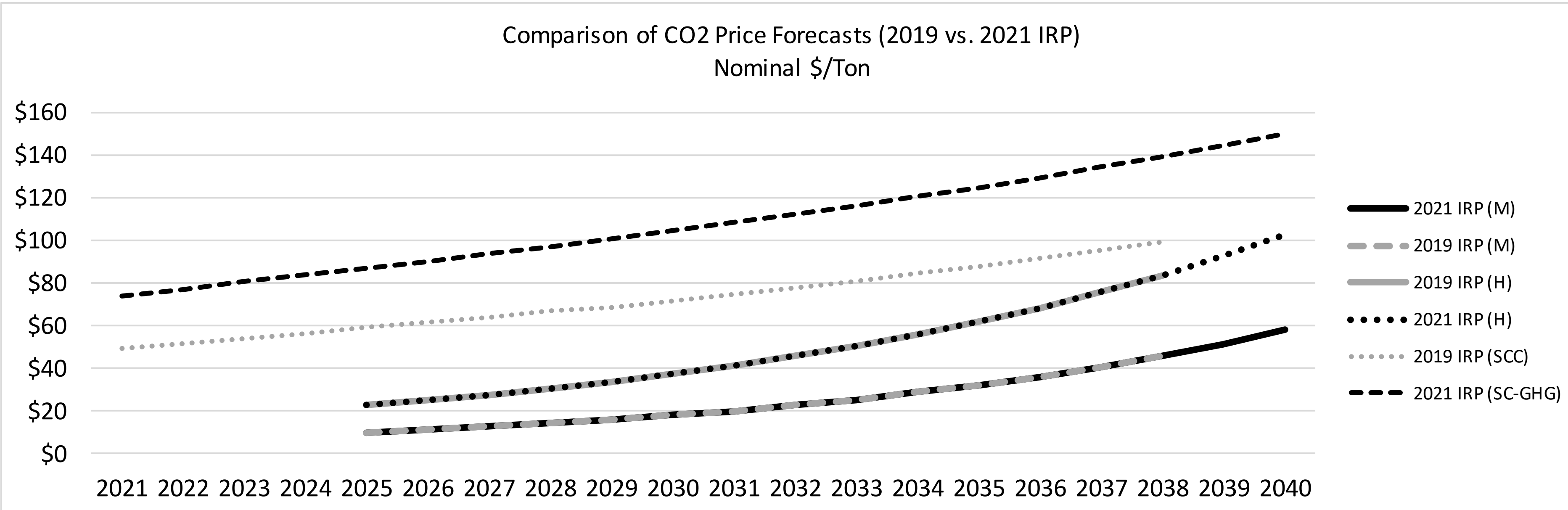
- Gas price scenarios for the 2021 IRP are lower than those assumed in the 2019 IRP.
  - Medium case levelized price from 2021-2038 = $4.02/MMBtu, down about 18% relative to the $4.88/MMBtu levelized price from the 2019 IRP
  - Low case levelized price from 2021-2038 = $2.46/MMBtu, down about 30% relative to the $3.52/MMBtu levelized price from the 2019 IRP
  - High case levelized price from 2021-2038 = $4.90/MMBtu, down about 20% relative to the $6.11/MMBtu levelized price from the 2019 IRP

CO_2 Cost Forecasts



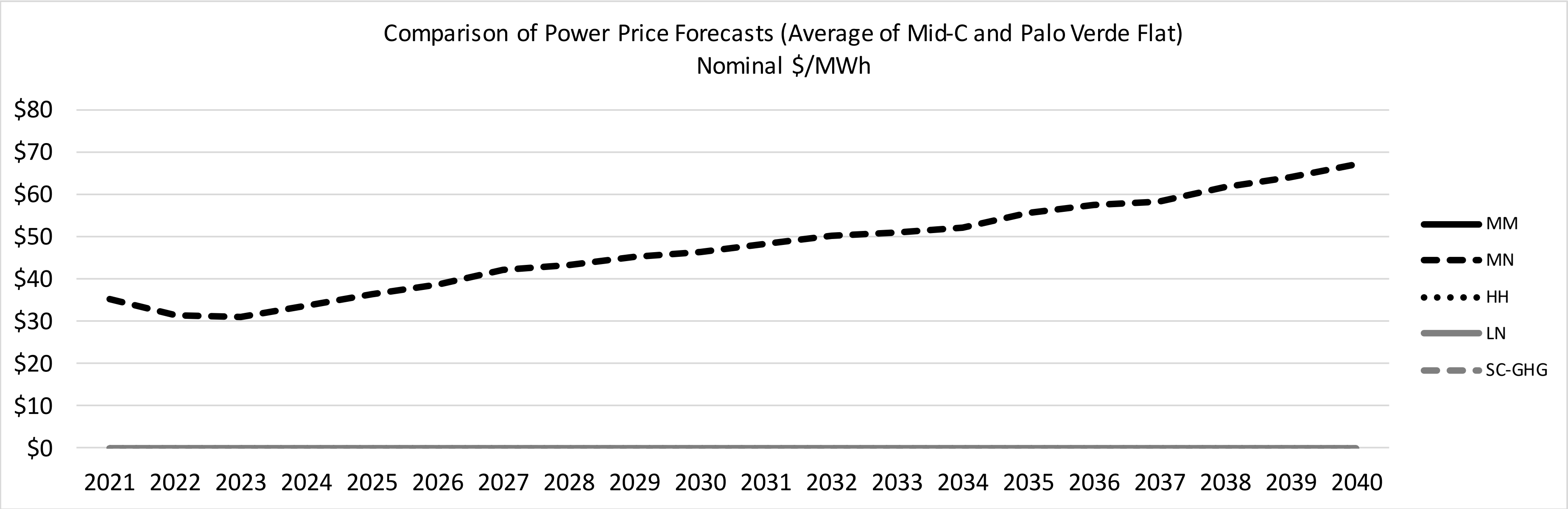
- CO_2 price assumptions from two third-party vendors (vendor 1 = "V1" and vendor 2 = "V2"), the Integrated Energy Policy Report ("IEPR") prepared by the California Energy Commission, other utility IRPs (Idaho Power or "IPC", Arizona Public Service or "APS", and Southwestern Electric Power Company or "SWEPCO"), and from the 2020 Annual Energy Outlook published by the U.S. Department of Energy's Energy Information Administration (EIA) are shown.
- The medium, low and high gas price scenarios for the 2021 IRP are within the range of forecasts provided by these entities and are reasonable for planning purposes (note, not shown, PacifiCorp will continue to analyze a zero CO_2 scenario).
- CO_2 price assumptions are being used to generate an accompanying power price forecast using Aurora.

CO_2 Cost Scenarios



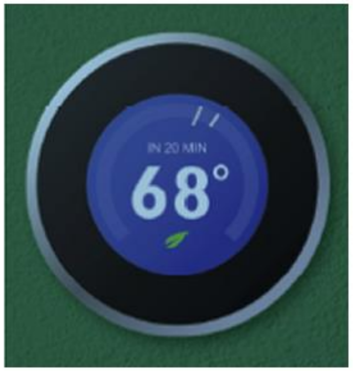
- Based on third-party forecasts, the medium and high CO_2 price assumptions from the 2019 IRP remain reasonable and are unchanged.
- The social cost of carbon (SCC) assumption has been updated to align with the Technical Support Document developed under the Interagency Working Group on the social cost of Greenhouse Gases using the 2.5% discount rate as required under Washington's Clean Energy Transformation Act or "CETA"—the 2019 IRP used prices aligned with a 3.0% discount rate.
- The social cost of carbon (SCC) has also been relabeled as social cost of greenhouses gases (SC-GHG) consistent with the data source and with recent language emphasis in legislative rules.

Power Price Scenarios



- The medium gas/medium CO_2 price-policy scenario is the only forecast that has been completed.
- The remaining forecasts are on track to be done before the December public-input meeting.

Modeling Assumptions Update – Transmission Topology



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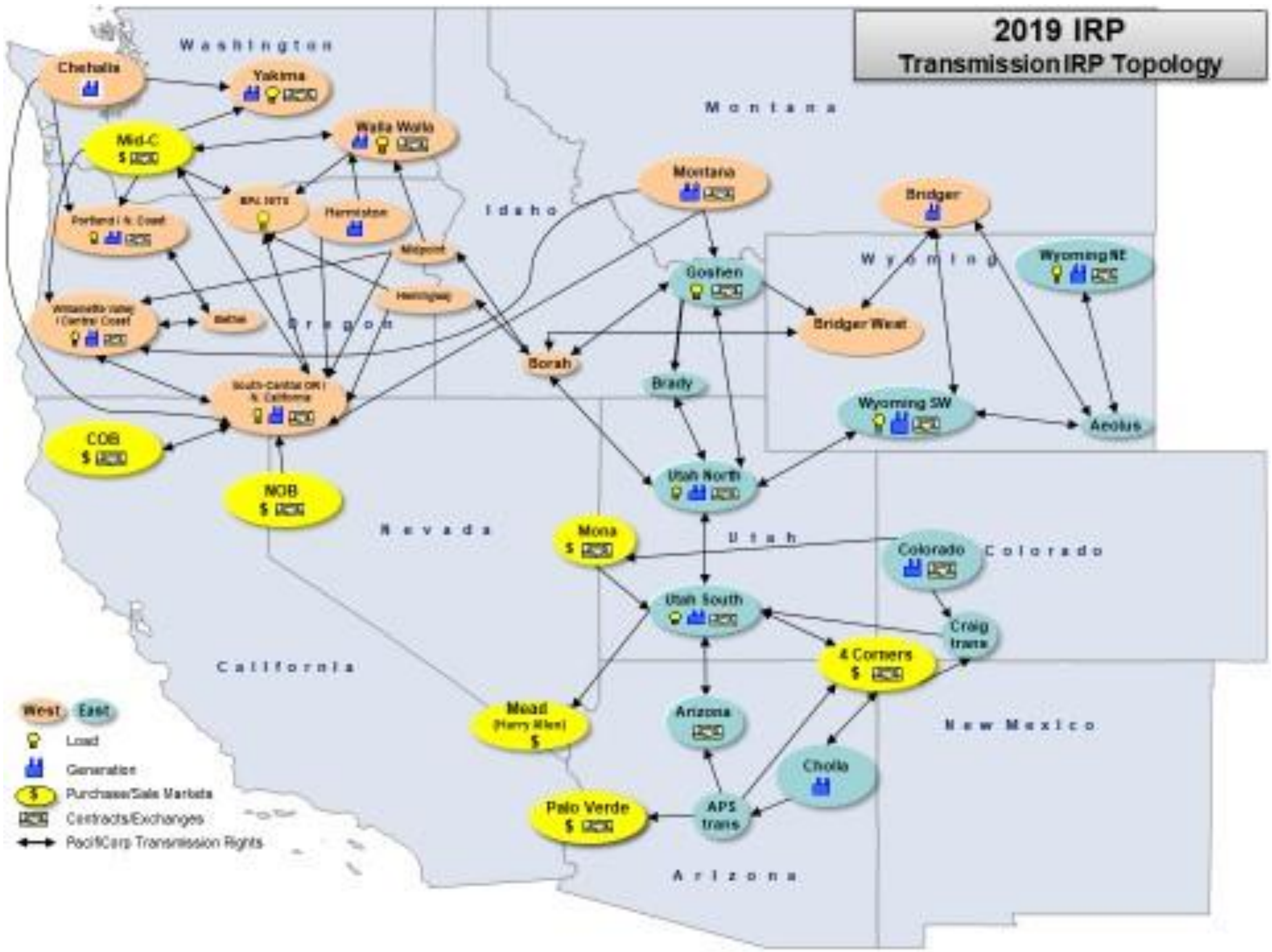
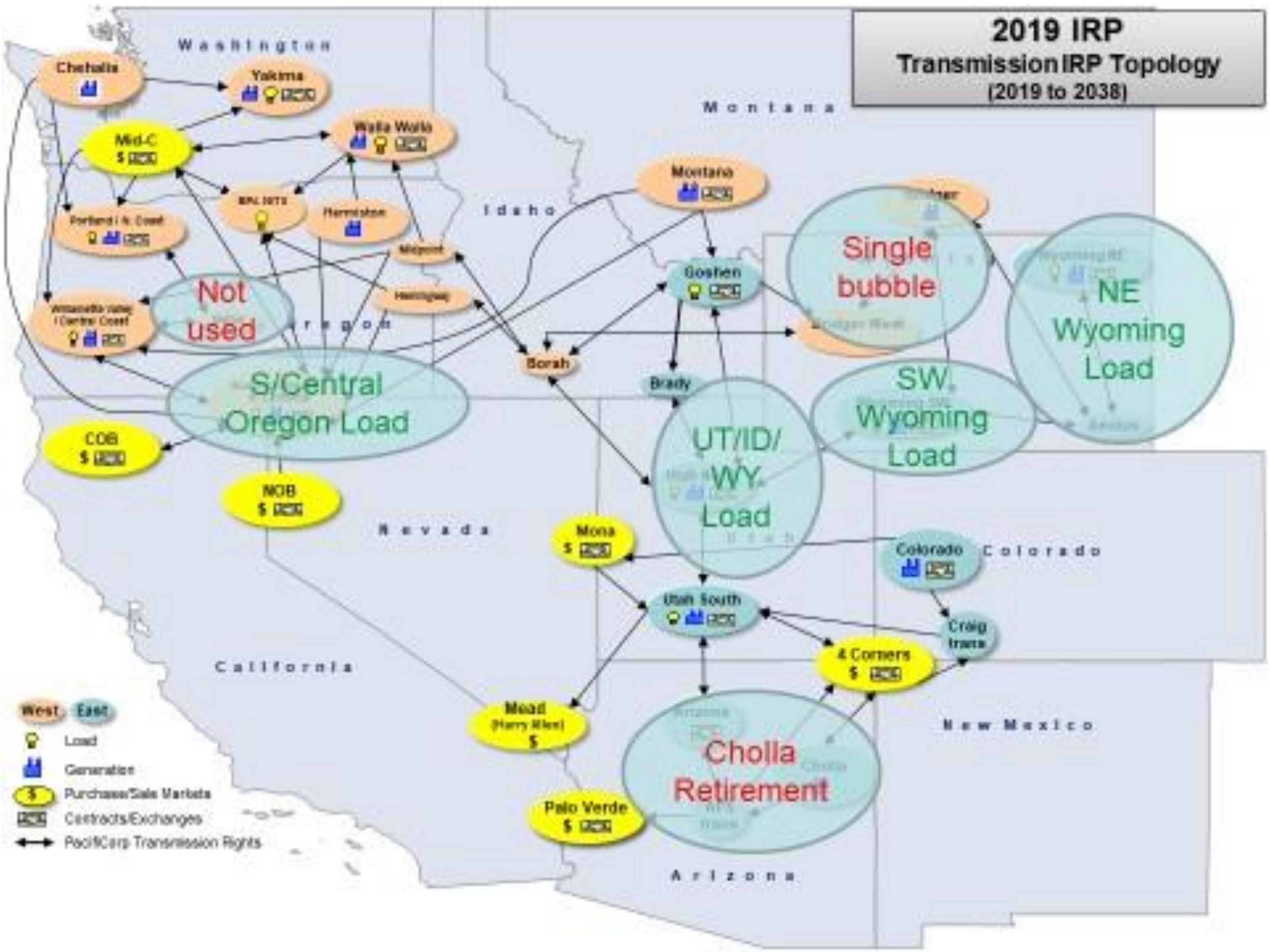
Transmission Topology Updates

- PacifiCorp has refreshed its modeled transmission topology for the 2021 IRP
  - Removed obsolete elements
  - Updated transmission ratings
  - Breaking out areas with additional detail
- Retail load and DSM is modeled by state, even for areas w/ multiple states:
  - NUT: UT/ID/WY
  - Southern Oregon-N. California
  - Walla Walla: OR/WA
  - BPA NITS: OR/WA
- Transmission upgrade options for the 2021 IRP will be presented at a future public input meeting

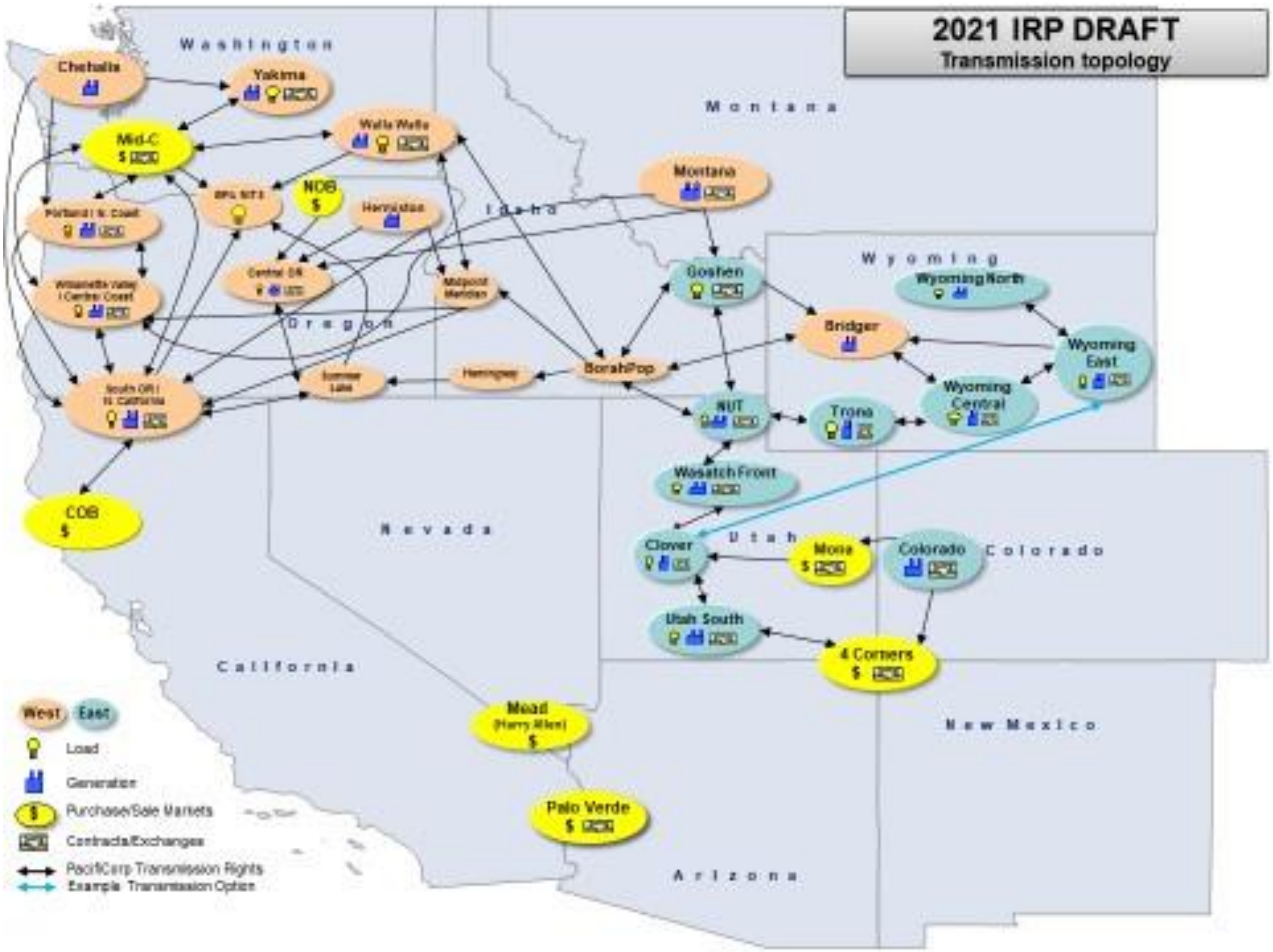
2019 IRP Topology



2019 IRP Topology Changes



2021 IRP Topology - DRAFT



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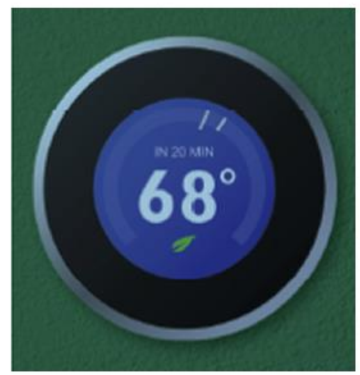
All-Source 2020 Request for Proposals Update



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Introduction

- The 2020 All-Source Requests for Proposals (2020AS RFP) seeks to secure least-cost, least-risk resources consistent with the 2019 Integrated Resource Plan (IRP).
- The 2019 IRP preferred portfolio includes approximately 1,823 megawatts (MW) of new proxy solar resources co-located with 595 MW of new proxy battery energy storage system (BESS) capacity and 1,920 MW of new proxy wind resources by the end of 2024.
- Bids were accepted from new and existing resources that could achieve a December 31, 2024 on-line date—long-lead resources (i.e., pumped storage) could offer proposals having a later on-line date.
- 2020AS RFP bids were due August 10, 2020.
- Bidders were notified by PacifiCorp whether their bids were selected to the initial shortlist (ISL) on October 30, 2020.

Initial Shortlist Approach

- The 2020AS RFP ISL was established based on specific criteria.
  - Price and non-price scores were used to identify the highest-ranking bids and bid variants by technology and location while considering the total volume of capacity with signed large generator interconnection agreements (LGIAs) in relation to 2020AS RFP regional capacity limits.
  - The cost and performance attributes of these highest-ranking bids by technology and location were loaded into the System Optimizer (SO) model, which was used to establish the least-cost combination of bids needed to reliably serve PacifiCorp’s retail customers.
- SO model selections do not reflect costs for interconnection network upgrades—these costs will be assessed after the transition cluster study process is completed and will be evaluated when determining the final shortlist (FSL).
- In accordance with ongoing discussions with the independent evaluators, the ISL also includes high-ranking bids (the “Additional Projects”) that could trigger significant interconnection costs (based on planning assumptions used to develop the 2019 IRP)—these bids are included so that the FSL analysis can be used to determine whether such costs would eliminate them from the least-cost portfolio of bids after the transition cluster study process is completed.

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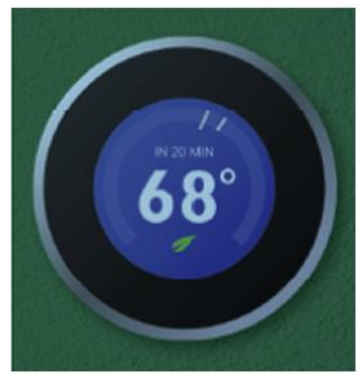
Initial Shortlist Results

- 5,852 MW (SO model selections = 4,860 MW; Additional Projects = 992 MW); representing approximately 89% of the system-wide limit in Appendix H of the 2020AS RFP.
- 3,173 MW of solar or solar + storage projects (includes 1,330 MW of collocated storage capacity); 2,479 MW of wind projects; 200 MW of stand-alone storage.
- 5,140 MW offered as a power-purchase agreement/toll and 712 MW offered as build-transfer agreements.
- PacifiCorp anticipates that the final shortlist will include less total capacity relative to the ISL—network upgrade costs are expected to make some bids uneconomic.

Next Steps

- PacifiCorp Transmission is conducting its interconnection transition cluster study with an expected completion date of April 15, 2021.
- In parallel with the transition cluster study, PacifiCorp will have outside consultants review the energy performance report and capacity factor as well as additional due diligence on the ISL projects.
- PacifiCorp will begin review of pro-forma contract issues and contract development with the selected bidders during the transition cluster study window.
- Selected bids representing the 2020AS RFP final shortlist will be determined in May/June 2021 after the interconnection cost results from the PacifiCorp Transmission transition cluster study results are available and bidders have provided a bid update.
- PacifiCorp anticipates "projecting" bid selections for consideration in the portfolio development process by including ISL projects with estimates of network upgrade costs derived from projects that have interconnection studies—projects without studies will be assigned an estimate based on other projects that have studies posted on OASIS.

Stakeholder Feedback Form Update



Stakeholder Feedback Form Update

- 59 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

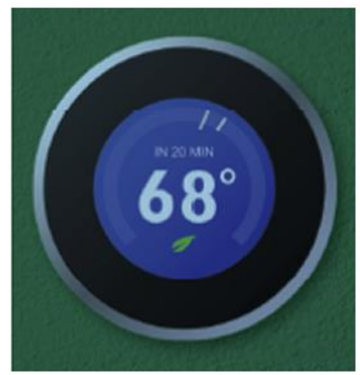
Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Powder River Basin Resource Council (053)	Oct 24, 2020	Portfolio Development	Questions regarding how the second phase of regional haze planning will be modeled in the 2021 IRP.	Response provided.
Powder River Basin Resource Council (054)	Oct 24, 2020	Portfolio Development	Question regarding how PacifiCorp will incorporate risk, cost, and benefits regarding water use and water rights in the 2021 IRP for both coal plants planned to be early retired and those planning to run longer.	Response provided.
Able Grid Energy Solutions (055)	Oct 26, 2020	Plexos, Supply-side resources, Performance cost summary	Suggestions for market data and analytics sources for battery energy storage systems.	Targeted response the week of November 16.
Washington Utilities and Transportation Commission Staff (056)	Nov 3, 2020	October PIM	Questions regarding public participation, front office transaction limits, Plexos benchmark update, Conservation Potential Assessment results, energy efficiency bundling methodology, distributed energy resources, and recommended scenarios.	Targeted response the week of November 16.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Oregon Public Utility Commission Staff (057)	Nov 6, 2020	October PIM, Front Office Transactions	Question regarding front office transaction limits.	Targeted response the week of November 16.
Wyoming Industrial Energy Consumers (058)	Nov 10, 2020	Business as Usual Cases	Recommendations for two business as usual cases to be modeled in the 2021 IRP.	Targeted response the week of November 23.
Oregon Public Utility Commission Staff (059)	Nov 10, 2020	October PIM, supply-side resources, DR, Regional Haze	Questions regarding October PIM, Conservation Potential Assessment, Demand Response, Regional Haze, and supply-side resources.	Targeted response the week of November 23.

Additional Information/Next Steps



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Next Steps

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- January 14-15, 2021 – Public Input Meeting
- February 25-26, 2021 – Public Input Meeting
- April 1, 2021 – File the 2021 IRP

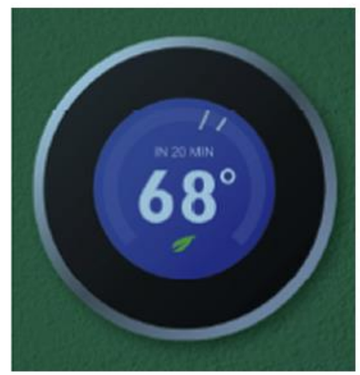
**meeting dates are subject to change*

Integrated Resource Plan

2021 IRP Public Input Meeting

December 3, 2020



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Agenda

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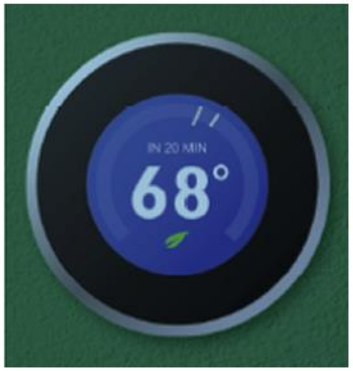
- 9:15am-11:30am pacific – Portfolio Development
- 11:30am-12:00pm pacific – Lunch Break
- 12:00pm-1:30pm pacific – Carbon Capture Supply-Side Resource Table
- 1:30pm-2:30pm pacific – Price Curve and Customer Preference Updates
- 2:30pm-3:30pm pacific – Transmission Modeling Assumptions
- 3:30pm-3:45pm – Stakeholder Feedback Form Recap
- 3:45pm-4:00pm pacific – Wrap-Up/Next Steps

Portfolio Development



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Modeling Approach for Coal Units

- Coal retirement dates specific to coal units will be selected in each Plexos run
- For owned/operated coal units, potential retirement dates are based upon avoiding major overhauls, assuming a unit would be able to operate five years after an overhaul
- For minority-owned coal units, assumed retirement dates are informed by ongoing discussions with joint owners
- Regional Haze assumptions and carbon capture retrofit options are being incorporated into the methodology

Jim Bridger Units 1 and 2 Operating Variants

Jim Bridger Unit 1	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2023		Op Limit 1		Retired																
Coal-Ret 2028		Op Limit 1							Retired											
Coal-Ret 2032		Op Limit 1							Op Limit 2				Retired							
Coal-Ret 2037		Op Limit 1							Op Limit 2									Retired		
Coal-CCUS Retrofit		Op Limit 1				CCUS Retrofit Operation														

Jim Bridger Unit 2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2023		Op Limit 1		Retired																
Coal-Ret 2027		Op Limit 1						Retired												
Coal-Ret 2031		Op Limit 1							Op Limit 2			Retired								
Coal-Ret 2035		Op Limit 1							Op Limit 2							Retired				
Coal-Ret 2037		Op Limit 1							Op Limit 2									Retired		

- Proposed operating limits approved by the state of Wyoming are expected to comply with the Regional Haze second planning period and are effective beginning 2022--limits are discussed on a later slide
- For the third Regional Haze planning period, it is assumed that tighter operating limits will apply beginning 2029 (25% reduction from the limits applicable beginning 2022)—limits are discussed on a later slide
- A CCUS retrofit future will be applied to Jim Bridger Unit 1 beginning 2026—a discussion of why units were selected for CCUS retrofit options is provided in a later slide

Jim Bridger Units 3 and 4 Operating Variants

Jim Bridger Unit 3	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2025		Op Limit 1				Retired														
Coal-Ret 2029		Op Limit 1							OL2	Retired										
Coal-Ret 2033		Op Limit 1							Op Limit 2					Retired						
Coal-Ret 2037		Op Limit 1							Op Limit 2									Retired		
Coal-CCUS Retrofit		Op Limit 1				CCUS Retrofit Operation														

Jim Bridger Unit 4	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2026		Op Limit 1					Retired													
Coal-Ret 2030		Op Limit 1							OL2		Retired									
Coal-Ret 2034		Op Limit 1							Op Limit 2						Retired					
Coal-Ret 2037		Op Limit 1							Op Limit 2									Retired		
Coal-CCUS Retrofit		Op Limit 1				CCUS Retrofit Operation														

- Proposed operating limits approved by the state of Wyoming are expected to comply with the Regional Haze second planning period and are effective beginning 2022--limits are discussed on the next slide
- For the third Regional Haze planning period, it is assumed that tighter operating limits will apply beginning 2029 (25% reduction from the limits applicable beginning 2022)—limits are discussed on the next slide
- A CCUS retrofit future will be applied to Jim Bridger Units 3 and 4 beginning 2026

Jim Bridger Regional Haze Operating Limits

Effective Beginning 2022	Plant NO_X Emission Limit (Monthly Average Basis)	Plant SO_2 Emission Limit (Monthly Average Basis)
January	2,050 lb/hour	2,100 lb/hour
February	2,050 lb/hour	2,100 lb/hour
March	2,050 lb/hour	2,100 lb/hour
April	2,050 lb/hour	2,100 lb/hour
May	2,200 lb/hour	2,100 lb/hour
June	2,500 lb/hour	2,100 lb/hour
July	2,500 lb/hour	2,100 lb/hour
August	2,500 lb/hour	2,100 lb/hour
September	2,500 lb/hour	2,100 lb/hour
October	2,300 lb/hour	2,100 lb/hour
November	2,030 lb/hour	2,100 lb/hour
December	2,050 lb/hour	2,100 lb/hour

- In addition to the plant-wide monthly limits shown above, Jim Bridger will be subject to a plant-wide emission cap of 17,500 tons/year of combined NO_X and SO_2 emissions
- For modeling purposes, the annual/combined limit will be imposed for PacifiCorp's 66% share (11,550 tons/year) either through an emissions constraint or through another operating metric (i.e., maximum annual capacity factor) that will capture the effect of the emission limit on plant operations
- For the third Regional Haze planning period (beginning 2029), Units 1 and 2 will be constrained to half of PacifiCorp's 66% share of the 2022 plant-wide combined annual limit reduced by 25% (4,331 tons/year) and Units 3 and 4 will be constrained to half of PacifiCorp's 66% share of the 2022 plant-wide combined annual limit (5,775 tons/year)

Naughton Units 1 and 2 Operating Variants

Naughton Unit 1 and 2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2025						Retired														
Coal-Ret 2028 (Oct)									Retired											
Coal-CCUS Retrofit						CCUS Retrofit Operation														

- Coal boilers and coal combustion residual (CCR) ponds must achieve final closure by October 2028 for Naughton Units 1&2
- To achieve final closure of ponds by 2028, coal boilers will need to cease operation by the end of 2025
- Coal operations beyond 2025 will require new ponds
- With planned closure no later than October 2028, no Regional Haze operating limits will be imposed
- A CCUS retrofit option will be made available to both Naughton units beginning 2026 (EPA would need to approve continued operation of the coal boilers and new ponds would be required)

Dave Johnston Units 1-4 Operating Variants

Dave Johnston 1	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2022			Retired																	
Coal-Ret 2027								Retired												

Dave Johnston 2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2024					Retired															
Coal-Ret 2027								Retired												
Coal-CCUS Retrofit						CCUS Retrofit Operation														

Dave Johnston 3	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2025						Retired														
Coal-Ret 2027								Retired												

Dave Johnston 4	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2023				Retired																
Coal-Ret 2027								Retired												
Coal-CCUS Retrofit						CCUS Retrofit Operation														

- Dave Johnston units 1 and 2 have effluent limitation guidelines imposed in 2023 and 2028 (high-recycle rate system if not retired)
- PacifiCorp has a commitment to cease operating Dave Johnston 3 at the end of 2027 and without a planned operations beyond 2027, no Regional Haze operating limits will be imposed
- A CCUS retrofit option will be made available to Dave Johnston 2 and 4 beginning 2026—a discussion of why units were selected for CCUS retrofit options is provided in a later slide

Wyodak
Operating Variants

Wyodak	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2023				Retired																
Coal-Ret 2027								Retired												
Coal-Ret 2031									Op Limit			Retired								
Coal-Ret 2035									Op Limit							Retired				
Coal-Ret 2039									Op Limit											Ret
Coal-CCUS Retrofit						CCUS Retrofit Operation														

- A Regional Haze planning period three operating limit is assumed beginning 2029 for PacifiCorp's 80% share of Wyodak (4,294 tons/year of NO_X and SO_2 emissions)
- A CCUS retrofit option will be made available on Wyodak beginning 2026

Hunter
Operating Variants

Hunter 1	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2023		Op Limit 1		Retired																
Coal-Ret 2027		Op Limit 1						Retired												
Coal-Ret 2031		Op Limit 1							Op Limit 2			Retired								
Coal-Ret 2035		Op Limit 1							Op Limit 2							Retired				
Coal-Ret 2042		Op Limit 1							Op Limit 2											

Hunter 2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2024		Op Limit 1			Retired															
Coal-Ret 2028		Op Limit 1							Retired											
Coal-Ret 2032		Op Limit 1							Op Limit 2				Retired							
Coal-Ret 2036		Op Limit 1							Op Limit 2								Retired			
Coal-Ret 2042		Op Limit 1							Op Limit 2											

Hunter 3	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2025		Op Limit 1				Retired														
Coal-Ret 2029		Op Limit 1							OP2	Retired										
Coal-Ret 2033		Op Limit 1							Op Limit 2					Retired						
Coal-Ret 2037		Op Limit 1							Op Limit 2									Retired		
Coal-Ret 2042		Op Limit 1							Op Limit 2											

- Operating limits proposed to comply with the Regional Haze second planning period would likely become effective beginning 2022—PacifiCorp's 85% share of plant-wide NO_X and SO_2 at 14,450 tons/year
- For the third Regional Haze planning period, it is assumed that tighter operating limits will apply beginning 2029 (25% reduction from the limits applicable beginning 2022)—PacifiCorp's 85% share of plant-wide NO_X and SO_2 at 12,283 tons/year

Huntington
Operating Variants

Huntington 1	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2023		Op Limit 1		Retired																
Coal-Ret 2027		Op Limit 1						Retired												
Coal-Ret 2031		Op Limit 1							Op Limit 2			Retired								
Coal-Ret 2036		Op Limit 1							Op Limit 2								Retired			

Huntington 2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal-Ret 2024		Op Li	Op Limit 1		Retired															
Coal-Ret 2028		Op Li	Op Limit 1						Retired											
Coal-Ret 2032		Op Li	Op Limit 1						Op Limit 2				Retired							
Coal-Ret 2036		Op Li	Op Limit 1						Op Limit 2								Retired			

- Operating limits proposed to comply with the Regional Haze second planning period would likely become effective beginning 2022—plant-wide NO_X and SO_2 at 10,000 tons/year
- For the third Regional Haze planning period, it is assumed that tighter operating limits will apply beginning 2029 (25% reduction from the limits applicable beginning 2022)—plant-wide NO_X and SO_2 at 7,500 tons/year

Other Jointly Owned Coal Units Operating Variants

Colstrip	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Colstrip 3-Ret 2025						Retired														
Colstrip 4-Ret 2025						Retired														

Craig	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Craig 1-Ret 2025						Retired														
Craig 2-Ret 2028 (Sep)									Retired											

Hayden	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Hayden 1-Ret 2030											Retired									
Hayden 2-Ret 2030											Retired									

- For minority-owned coal units, assumed retirement dates are informed by ongoing discussions with joint owners

Business As Usual Case Requests

Four stakeholder feedback forms requested specific Business As Usual Case(s):

Requesting Party	Requested Case Summary
Wyoming Office of Consumer Advocate (Form 037)	Begin with current generation and transmission portfolio and reflect analysis on customer impacts of changes to portfolio to accommodate load growth and environmental compliance obligations. Exclude early coal retirement as that is analyzed elsewhere in the IRP.
Wyoming Public Service Commission (Form 045)	Carry forward the 2019 IRP preferred portfolio, with updates due to regulatory changes, no additional assumed early retirements, and exclude externalities that are not currently required by law to be evaluated.
Renewable Northwest (Form 046)	Include a BAU case that incorporates reliability issues in California, Front Office Transaction assumptions and state energy policy.
Joint Parties (Utah Association of Energy Users, Utah Division of Public Utilities, Wyoming Industrial Energy Consumers, and Wyoming Office of Consumer Advocate (Form 058)	Two BAU cases – one based on the 2019 IRP preferred portfolio and one based on the 2017 IRP Update preferred portfolio with all commitments since the 2019 IRP included in BAU case.

- Based on this feedback, PacifiCorp plans to develop to stakeholder-defined BAU cases
    - One based on existing assets that we will assume operate through the end of their life operating life (no early retirement); contracts expire at the end of their term
    - One that is reasonably aligned with the 2019 IRP preferred portfolio (resource types and size, but with updated cost and performance); new proxy resources can be added as needed to reliably meet load (ensuring sufficient resources are added to accommodate changes in load from the 2019 IRP)

Required Cases and Sensitivity Requests

Oregon

Requirement	Summary
Cost-effective Coal Retirements (Order 20-186)	Include in the 2021 development process an updated analysis – identifying the most cost-effective coal retirements individually and in combination.

Washington

Requirement	Summary
Alternative Lowest Reasonable Cost (CETA Draft Rules)	Analysis of lowest reasonable cost portfolio that the utility would have implemented if not for compliance with CETA requirements.
Future Climate Change (CETA Draft Rules)	Analysis should incorporate best available science on impacts of snowpack, streamflow, rainfall, heating/cooling degree days, and load changes from climate change.
Maximum Customer Benefit (CETA Draft Rules)	Scenario should model customer benefit (per RCW 19.405.040(8)) prior to balancing against other goals.

Preliminary Set of 2021 IRP Portfolio Development Cases

Case "Name"	Price-Policy	Existing Coal	Existing Gas	Other Existing Resources	Proxy Resources
BAU1-MM	MM	End of Life	End of Life	End of Life	Optimized
BAU1-MN	MN	End of Life	End of Life	End of Life	Optimized
BAU1-LN	LN	End of Life	End of Life	End of Life	Optimized
BAU1-HH	HH	End of Life	End of Life	End of Life	Optimized
BAU1-SC-GHG	SC-GHG	End of Life	End of Life	End of Life	Optimized
BAU2-MM	MM	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
BAU2-MN	MN	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
BAU2-LN	LN	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
BAU2-HH	HH	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
BAU2-SC-GHG	SC-GHG	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
P01-MM	MM	Optimized	End of Life	End of Life	Optimized
P01-MN	MN	Optimized	End of Life	End of Life	Optimized
P01-LN	LN	Optimized	End of Life	End of Life	Optimized
P01-HH	HH	Optimized	End of Life	End of Life	Optimized
P01-SC-GHG	SC-GHG	Optimized	End of Life	End of Life	Optimized

Preliminary Set of 2021 IRP Portfolio Development Cases (Cont'd)

Case "Name"	Price-Policy	Existing Coal	Existing Gas	Other Existing Resources	Proxy Resources
P02-MM	MM	Optimized	End of Life	End of Life	No New Gas
P02-MN	MN	Optimized	End of Life	End of Life	No New Gas
P02-LN	LN	Optimized	End of Life	End of Life	No New Gas
P02-HH	HH	Optimized	End of Life	End of Life	No New Gas
P02-SC-GHG	SC-GHG	Optimized	End of Life	End of Life	No New Gas
P03-MM	MM	Retired by 2030	End of Life	End of Life	No New Gas
P03-MN	MN	Retired by 2030	End of Life	End of Life	No New Gas
P03-LN	LN	Retired by 2030	End of Life	End of Life	No New Gas
P03-HH	HH	Retired by 2030	End of Life	End of Life	No New Gas
P03-SC-GHG	SC-GHG	Retired by 2030	End of Life	End of Life	No New Gas

- This preliminary set of cases would produce 25 unique resource portfolios—each will be assessed using the MM, MN, LN, and HH price-policy assumptions
- Portfolios generated with SC-GHG price-policy assumptions are consistent with RCW19.280.030 in Washington
- Additional cases may be developed once preliminary results are available (i.e., as required to achieve RPS targets or Clean Energy Transformation Act requirements)

Other Studies

Sensitivities (top-performing cases and stakeholder-defined BAU cases)

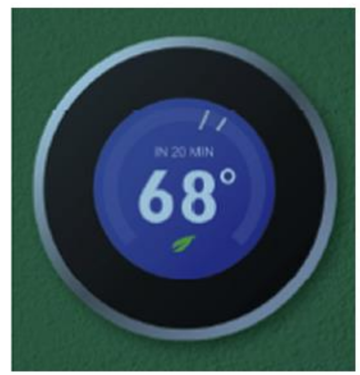
- High/low load, 1-in-20 load
- High/low private generation
- High/no customer preference
- Market reliance
- Forced CCUS/WY HB200
- SC-GHG applied as a dispatch adder in operations[1]

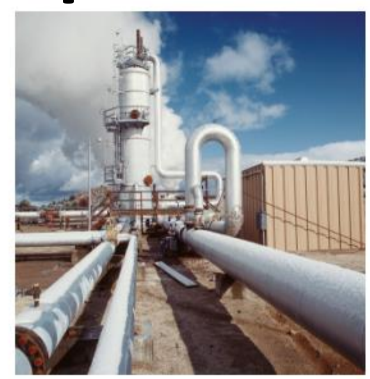
- Reliability (top-performing cases and stakeholder defined BAU cases)
  - Evaluation of portfolio performance under strained system/regional conditions (i.e., sustained weather events) based on actual events that have occurred in recent years
- Other?

[1]These sensitivities are consistent with RCW19.280.030 in Washington

Carbon Capture Utilization & Sequestration (CCUS) Supply-Side Resource Table Update





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Supply Side Resources Review

- Carbon Capture Utilization & Sequestration
- Background
- Supply Side Resource
  - Proxy Sites
  - Existing Generating Facilities
- Revenue
  - 45Q Tax Credit
  - Oil Price Forecast
  - CO_2 Price Forecast

Background

- Sources of information
  - Petra Nova adjusted by learning curve
  - Carbon capture developer
  - Longforecast.com
  - World Bank
  - U.S. Energy Information Administration
  - Dept. of Commerce, Bureau of Economic Analysis
  - Wyoming Carbon Capture, Utilization, and Storage (CCUS) Study

Background

- Costs are incremental – costs shown are for the technology only and do not include the cost of operating the generating unit
- Heat rate and emissions are for the entire generating unit
- Assumes that the operating life is 20 years for after the retrofit date
- Adding carbon capture requires meeting the Federal Implementation Plan (FIP) and State Implementation Plan (SIP) for air emissions
- Post-combustion carbon capture meets the FIP and SIP

Background

- PacifiCorp owns and operates the carbon capture facility
- Proxy generating facilities meet the NO_x and SO_2 flue gas requirements prior to installation of carbon capture
- Some existing unit scenarios require additional emission controls
- Costs are on a 100% share basis
- Costs are in 2020 dollars

Thermal Resources – Carbon Capture Utilization & Sequestration

Proxy Sites

Description		Resource Characteristics				Costs			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/kW-yr)	Demolition Cost ($/kW)
Coal	SCPC with CCS	4,500	526	2028	40	6,488	7.00	72.22	127.00
Coal	IGCC with CCS	4,500	466	2028	40	6,282	11.77	58.20	60.00
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	4,500	-115	2026	20	2,971	3.29	28.18	37.00
Coal	SCPC with CCS	6,500	692	2028	40	7,348	7.58	67.09	127.00
Coal	IGCC with CCS	6,500	456	2028	40	7,113	14.11	63.40	60.00
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	6,500	-115	2026	20	2,971	3.29	28.18	37.00

Description		Operating Characteristics				Environmental			
Fuel	Resource	Avg. Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Coal	SCPC with CCS	13,087	5.0	5.0	1,004	0.0085	0.070	0.022	20.5
Coal	IGCC with CCS	10,823	8.0	7.0	394	0.0085	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	14,372	5.0	5.0	450	0.0050	0.070	1.200	20.5
Coal	SCPC with CCS	13,242	5.0	5.0	1,004	0.0085	0.070	0.022	20.5
Coal	IGCC with CCS	11,047	8.0	7.0	394	0.0085	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	14,372	5.0	5.0	450	0.0050	0.070	1.200	20.5

- Costs are incremental to the generating unit
- Heat rate and emissions are for the entire generating unit

Existing Generating Facilities

Plant / Unit	Net Dependable Capacity	Post CC Capacity	Carbon Capture Equipment			NOx Control Equipment			SO_2 Control Equipment		
			Capital	Variable O&M	Fixed O&M	Capital	Variable O&M	Fixed O&M	Capital	Variable O&M	Fixed O&M
	MW	MW	$/kW	$/MWh	$/kWyr	$/kW	$/MWh	$/kWyr	$/kW	$/MWh	$/kWyr
Dave Johnston 1	99	76	$ 2,970.73	$ 3.29	$ 28.18	$ 339.28	$ 0.68	$ 2.24	$ 800.51	$ 0.75	$ 0.98
Dave Johnston 2	106	82	$ 2,970.73	$ 3.29	$ 28.18	$ 339.28	$ 0.68	$ 2.24	$ 800.51	$ 0.75	$ 0.98
Dave Johnston 3	220	169	$ 2,970.73	$ 3.29	$ 28.18	$ 46.00	$ 1.25	$ 1.61	$ 13.64	$ 1.09	$ 0.98
Dave Johnston 4	330	254	$ 2,970.73	$ 3.29	$ 28.18				$ 13.64	$ 1.09	$ 0.98
Jim Bridger 1	531	409	$ 2,970.73	$ 3.29	$ 28.18				$ 13.64	$ 1.09	$ 0.98
Jim Bridger 2	539	415	$ 2,970.73	$ 3.29	$ 28.18				$ 13.64	$ 1.09	$ 0.98
Jim Bridger 3	523	403	$ 2,970.73	$ 3.29	$ 28.18				$ 13.64	$ 1.09	$ 0.98
Jim Bridger 4	526	405	$ 2,970.73	$ 3.29	$ 28.18				$ 13.64	$ 1.09	$ 0.98
Naughton 1	156	120	$ 2,970.73	$ 3.29	$ 28.18	$ 46.00	$ 1.25	$ 1.61	$ 13.64	$ 1.09	$ 0.98
Naughton 2	201	155	$ 2,970.73	$ 3.29	$ 28.18	$ 46.00	$ 1.25	$ 1.61	$ 13.64	$ 1.09	$ 0.98
Wyodak	335	258	$ 2,970.73	$ 3.29	$ 28.18				$ 13.64	$ 1.09	$ 0.98

- Costs are incremental to the generating unit

Existing Generating Facilities

	Plant / Unit	Net Dependable Capacity	Post CC Capacity	Total Capital	Total Variable O&M	Total Fixed O&M
		MW	MW	$/kW	$/MWh	$/kWyr
	Dave Johnston 1	99	76	$ 4,111	$ 4.72	$ 31.39
*	Dave Johnston 2	106	82	$ 4,111	$ 4.72	$ 31.39
	Dave Johnston 3	220	169	$ 3,030	$ 5.63	$ 30.76
*	Dave Johnston 4	330	254	$ 2,984	$ 4.38	$ 29.15
*	Jim Bridger 1	531	409	$ 2,984	$ 4.38	$ 29.15
	Jim Bridger 2	539	415	$ 2,984	$ 4.38	$ 29.15
*	Jim Bridger 3	523	403	$ 2,984	$ 4.38	$ 29.15
*	Jim Bridger 4	526	405	$ 2,984	$ 4.38	$ 29.15
*	Naughton 1	156	120	$ 3,030	$ 5.63	$ 30.76
*	Naughton 2	201	155	$ 3,030	$ 5.63	$ 30.76
*	Wyodak	335	258	$ 2,984	$ 4.38	$ 29.15

- Costs are incremental to the generating unit

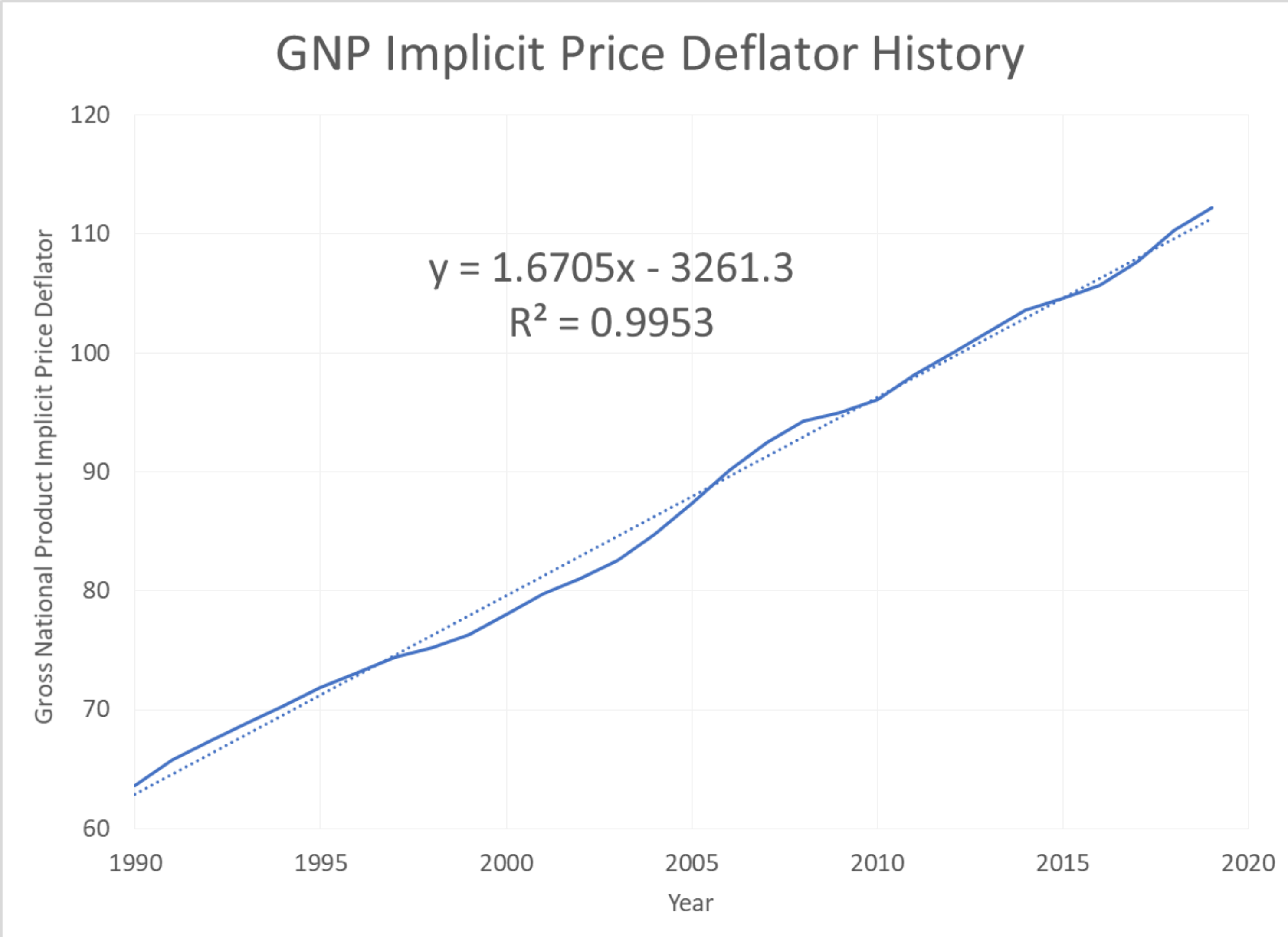
Existing Generating Facilities

- Units selected
  - A FEED study is in progress on Dave Johnston Unit 2
  - Feasibility studies have been carried out on Dave Johnston Unit 4 and this unit does not require additional emission controls
  - Jim Bridger Unit 1 is slated for the soonest closure
  - SCR is already installed on Jim Bridger Units 3 and 4
  - Naughton Units 1 and 2 are combined to meet the minimum capacity for economies of scale
  - Wyodak is a single unit facility and does not require additional emission controls
- Units not selected
  - Dave Johnston Unit 1 is the smaller of Units 1 and 2 and is not undergoing a FEED study
  - Dave Johnston Unit 3 has a federally enforceable closure commitment (in 2027)
  - Jim Bridger Units 1 and 2 are similar in size and Jim Bridger Unit 2 is slated to retire later than Unit 1

45Q Tax Credit

- Requirements
  - Credit Life: 12 Years
  - Construction must start by: January 1, 2024
  - Carbon dioxide minimum capture: 500,000 tonnes/year
- Two Options for 45Q Tax Credits
  - Enhanced Oil Recovery – $35/tonne in 2026
  - Sequestration – $50/tonne in 2026
- Adjusted by Gross National Product Implicit Price Deflator

45Q Tax Credit



45Q Tax Credit

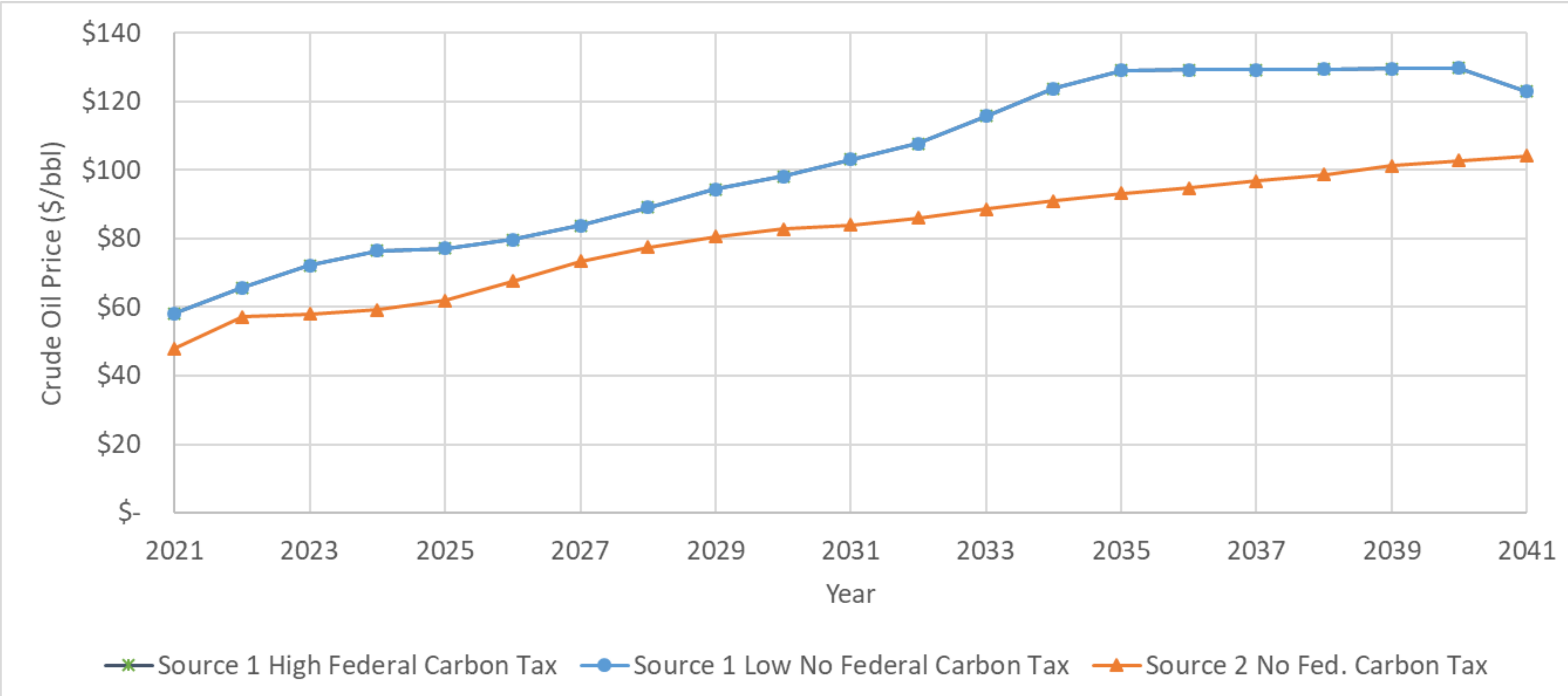
- Linear Regression
- Source
  - Dept. of Commerce, Bureau of Economic Analysis
  - Table 1.1.9. Implicit Price Deflators for Gross Domestic Product
  - apps.bea.gov/iTable/iTable.cfm?reqid=19&step=3&isuri=1&1921=survey&1903=13#reqid=19&step=3&isuri=1&1921=survey&1903=13
  - October 29, 2020

Credit Life	Year	EOR	Sequestration
		$/tonne	$/tonne
1	2026	$ 35.00	$ 50.00
2	2027	$ 35.68	$ 50.97
3	2028	$ 36.38	$ 51.96
4	2029	$ 37.10	$ 53.00
5	2030	$ 37.84	$ 54.06
6	2031	$ 38.61	$ 55.16
7	2032	$ 39.41	$ 56.30
8	2033	$ 40.24	$ 57.48
9	2034	$ 41.09	$ 58.70
10	2035	$ 41.97	$ 59.95
11	2036	$ 42.88	$ 61.25
12	2037	$ 43.82	$ 62.60
	2038	$ 44.79	$ 63.99
	2039	$ 45.80	$ 65.43
	2040	$ 46.84	$ 66.92
	2041	$ 47.92	$ 68.45

Oil Price Forecast

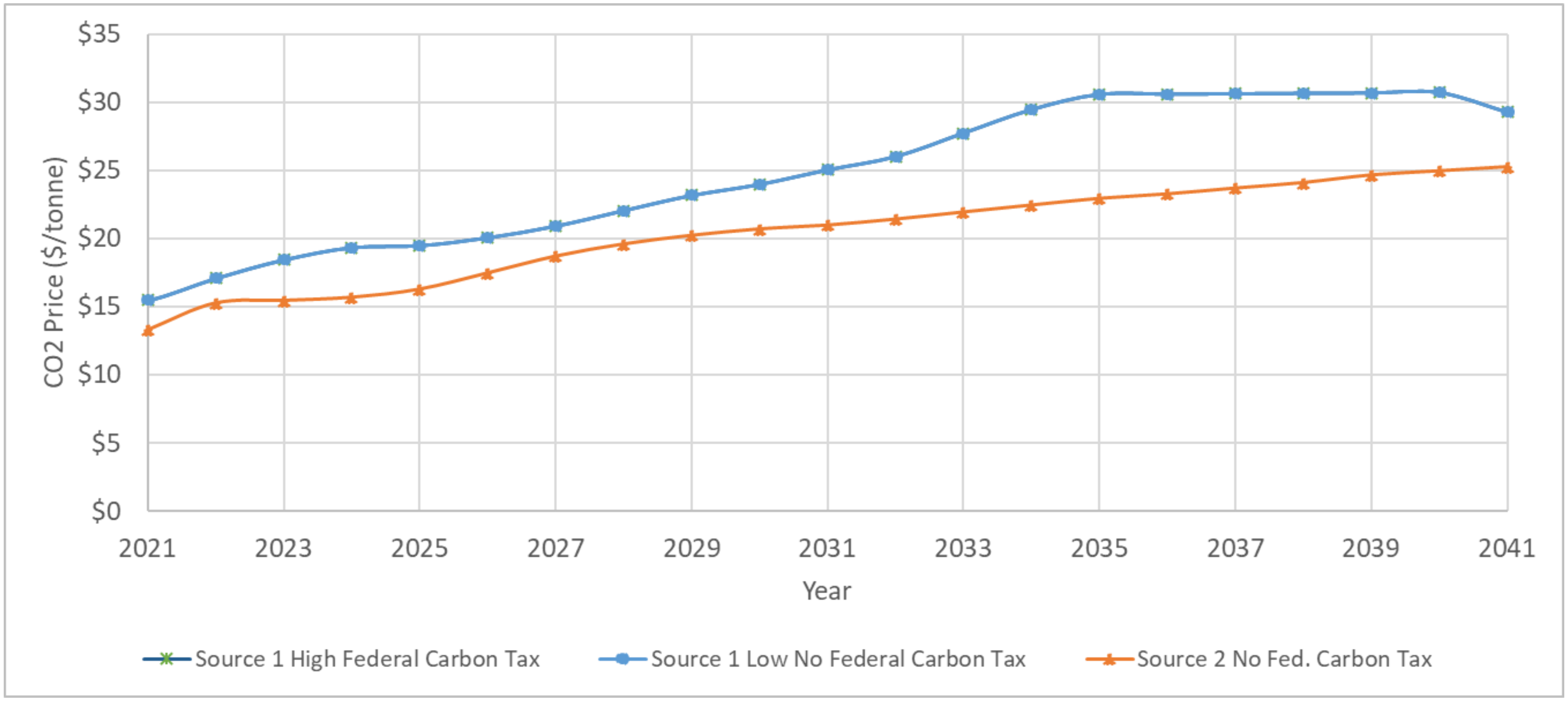
- Energy Information Administration (EIA) (Wyoming Crude Oil First Purchase Price)
  - January to August 2020 average – $31.91/bbl
- Longforecast.com (West Texas Intermediate (WTI) Crude)
  - November 2020 – $36.65/bbl
- World Bank Commodity Markets Outlook
  - 2021 – $44.00/bbl
- EIA Short-term Energy Outlook
  - 2021 – $44.24/bbl
- IRP natural gas information sources – 2020
  - Source A – $35.98/bbl
  - Source B – $38.87/bbl

Oil Price Forecast



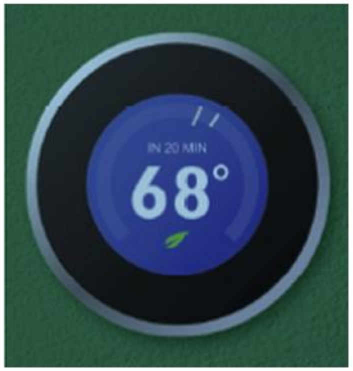
- Price Source
  - Same two sources used for natural gas prices for a total of three cases
  - Without federal carbon tax – Source 1 and Source 2
  - With federal carbon tax – Source 1
  - Source 1 prices for oil with and without federal carbon tax were the same

CO_2 Revenue Price Forecast For EOR



- CO_2 revenue price forecast assumptions are from Wyoming's Carbon Capture Utilization and Storage (CCUS) Study's linear regression from natural CO_2 prices and WTI crude oil prices.

Price Curve and Customer Preference Assumptions



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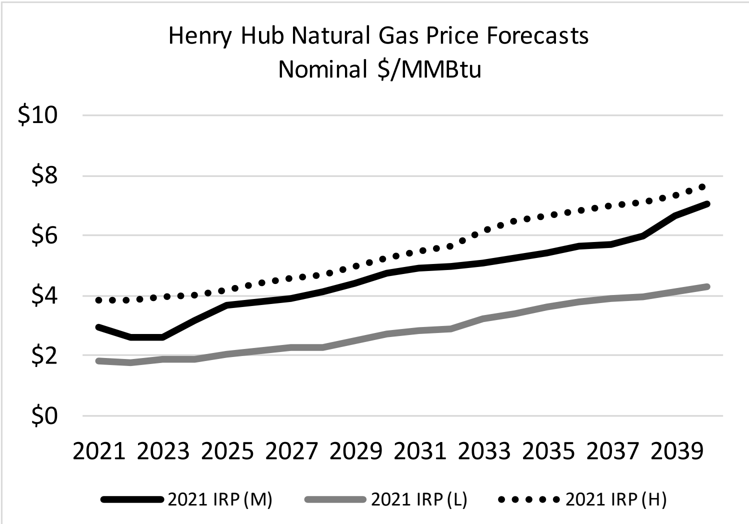
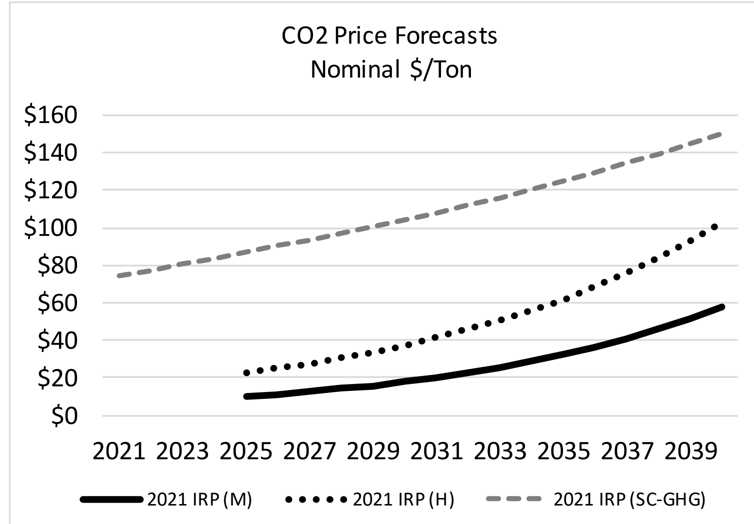
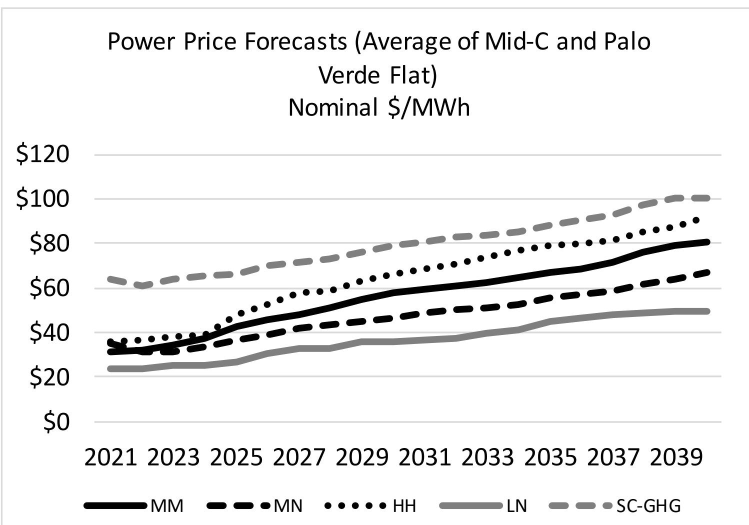
Price-Policy Scenario Update



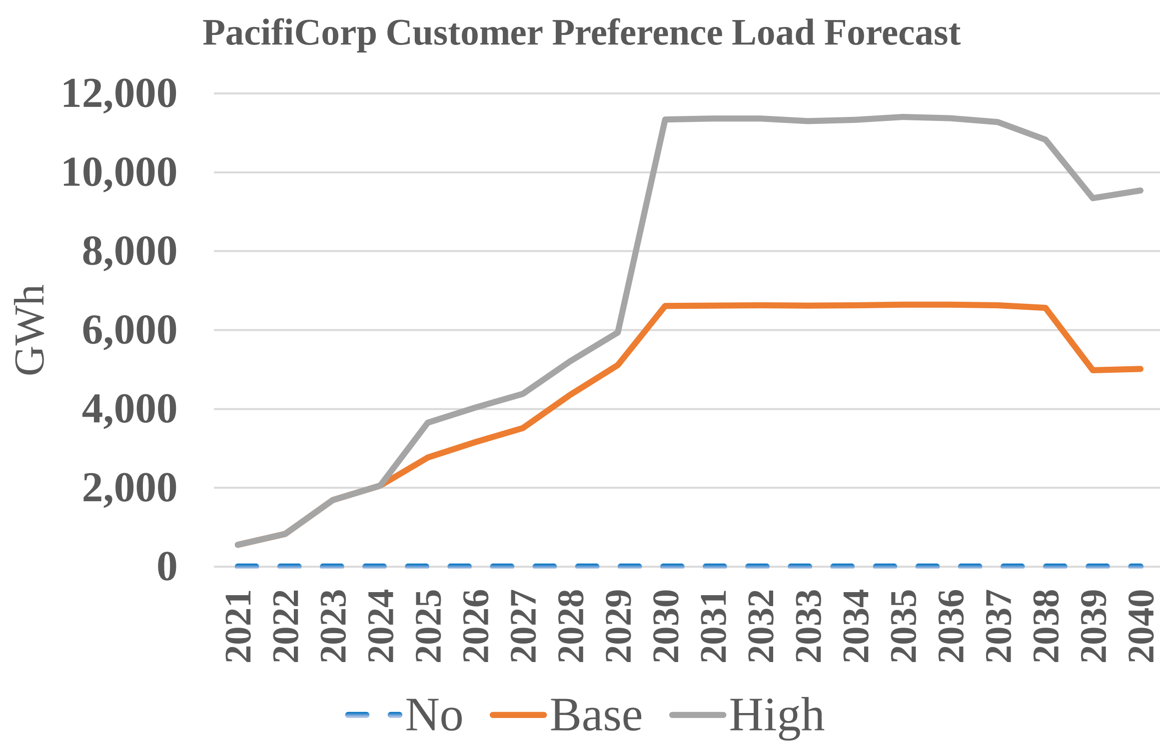




- The information here is consistent with the assumptions presented at the November 2020 public-input meeting
- The power price forecasts for the five price-policy scenarios being considered in the 2020 IRP have been completed (only the “MN” scenario was presented in the November 2020 materials)
- Note, the base assumption for the SC-GHG price-policy scenario is that it will drive portfolio outcomes, that once established will operate in an MM price-policy market environment

Accounting for Customer Preference

- Customer Preference load forecasts estimate load from customers and communities that seek to meet renewable energy targets with incremental renewable resources beyond the anticipated fuel mix for all customers
- The base case assumes a certain percentage of load attributable to preference customers is met with incremental renewables, depending on the customer/community and maturity of incremental renewable programming
- 2021 IRP runs will also include a “no customer preference” sensitivity (reflecting no incremental renewable adds addressing customer preference) and a high sensitivity (reflecting greater customer preference load met with renewables)

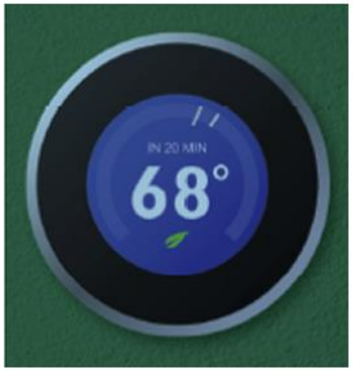


Accounting for Customer Preference, cont.

- The majority of customer preference load is attributed to communities and customers that have signaled specific target dates for reaching renewable energy goals and may participate in an incremental renewables offering
- In Pacific Power territory, OPUC has begun a regulatory process to explore programming to address community renewable goals
- In Rocky Mountain Power territory, Utah has three specific renewable tariffs in place to facilitate customer preference renewable resources; ID and WY do not currently have renewable tariffs, but large special contract customers may seek respective state commission approval for specific renewable solutions
- Customer preference forecasts are developed assuming customers account for system renewables

2021 IRP Transmission Option Assumptions



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Endogenous Transmission Modeling

- Plexos modeling allows endogenous selection of incremental transmission construction to connect areas with resource surplus to areas where load needs to be served
- New to the 2021 IRP is the option for the Plexos model to endogenously select construction of the Boardman-Hemingway (B2H) 500 kV line to support the resource selection process
- The IRP group is currently testing endogenous inclusion of remaining Gateway options
- Existing generators, generators with executed LGIAs and transmission service requests are accounted for in the IRP modeling
- Scopes and costs for incremental transmission upgrade options are high level planning estimates.
- OATT Credit of 20% applied to costs based on PacifiCorp ESM share of monthly coincident peak network load of approximately 80%

Transmission Integration by Location and Capacity Increment (PACW)

IRP Bubble	Added Resource MW		IRP Year	Description of Integration	Affected Topology Path(s)		
	Min	Max			Incremental Capacity (if any)	From Bubble	To Bubble
Portland/N. Coast	1	130	2026	Portland area local reinforcement	-	-	-
	131	580	2030	Portland area (Troutdale) to Albany area 230 kV transmission	450	Portland	Willamette
Willamette	1	615	2026	Albany area local reinforcement	-	-	-
Yakima	1	405	2023	Yakima area local reinforcement	-	-	-
	406	585	2027	Yakima area 230 kV transmission	-	-	-
	586	685	2027	Yakima area 230 kV transmission	-	-	-
	686	835	2032	Yakima area to Bend area 230 kV transmission	1500	Yakima	Central Oregon
	836	1490	2037	Bend area to Willemette Valley 230 kV transmission	1500	Central Oregon	Willamette
Walla Walla	1	100	2026	Walla Walla area to Yakima 230 kV transmission	200	Walla Walla	Yakima
Southern Oregon	1	500	2023	Medford area 500-230 kV and 230 kV reinforcement	-	-	-
	501	960	2027	Medford area 500-230 kV and 230 kV reinforcement	-	-	-
Central Oregon	1	140	2023	Central Oregon area local reinforcement	-	-	-
	141	240	2027	Central Oregon area local reinforcement	-	-	-

Note: The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given project and the type of equipment proposed for any given project.

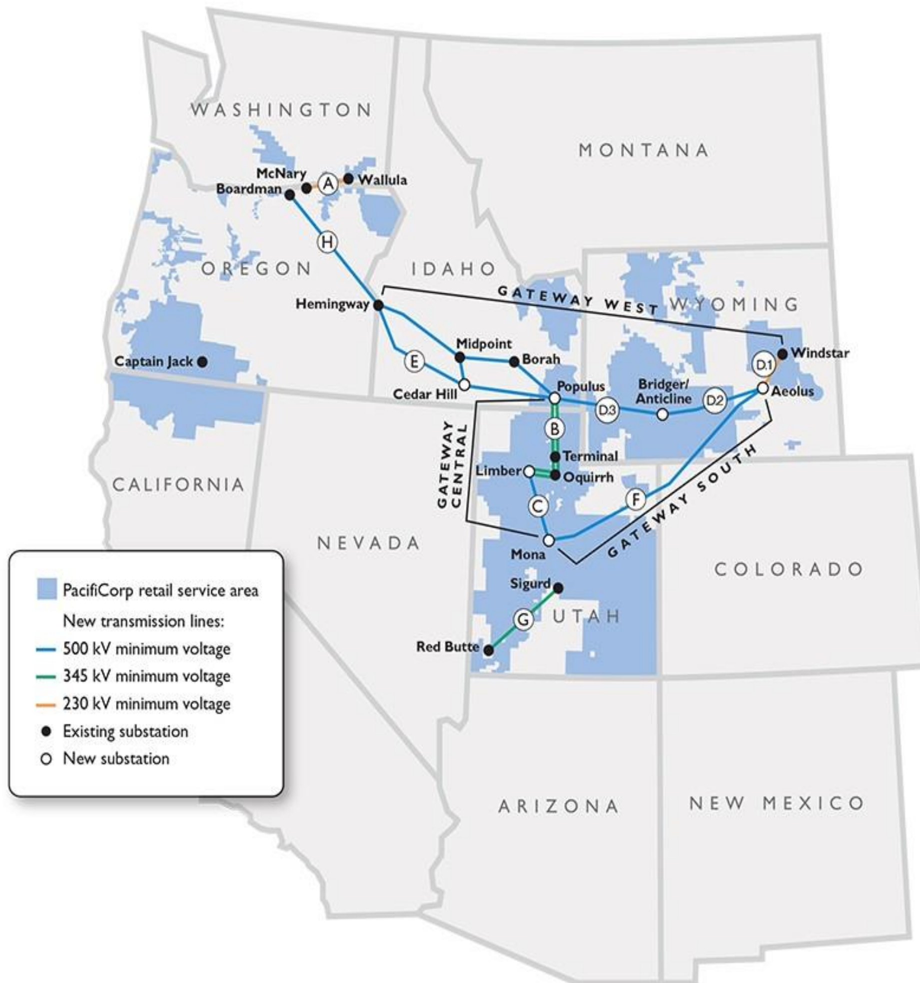
Transmission Integration by Location and Capacity Increment (PACE)

IRP Bubble	Added Resource MW		IRP Year	Description of Integration	Affected Topology Path(s)		
	Min	Max			Incremental Capacity (if any)	From Bubble	To Bubble
Goshen	1	152	2023	Southern Idaho reinforcement	-	-	-
Wyoming East	1	1930	2024	Energy Gateway segments D.1 (Windstar - Shirley Basin 230 kV line) and F (Aeolus-Clover 500 kV transmission line)	1200	Wyoming East	Clover
Utah North	1	245	2023	Northern Utah 345 kV reinforcement	-	-	-
	246	730	2024	Northern Utah 345 kV reinforcement	-	-	-
Utah South	1	256	2024	Utah Valley area 345-138 kV and 138 kV local reinforcement	-	-	-
	257	956	2031	Southern Utah 345 kV reinforcement	800	Utah South	Clover
B2H	1	tbd	2027	Segment H Boardman - Hemingway 500 kV	tbd		

Note: The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given project and the type of equipment proposed for any given project.

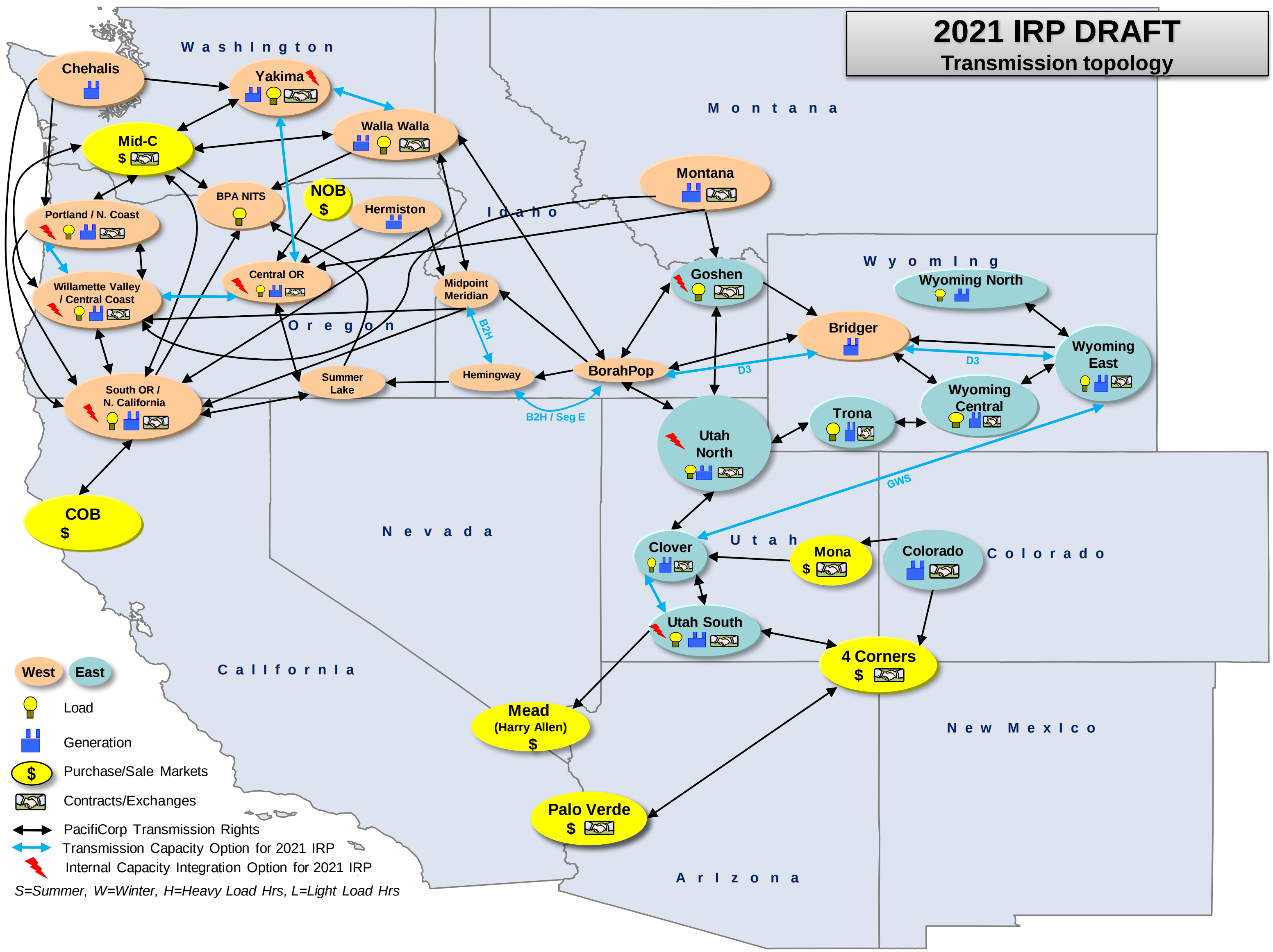
Energy Gateway

- Endogenous modeling of each of the Energy Gateway Projects in the Long Term Transmission Plan is being tested
- If successful, each option will include incremental transmission over multiple topology links and costs associated with the addition of the Energy Gateway segment(s)
- If the model does not endogenously select some options, they may be run as sensitivities to study cost implications
- Any options that are determined cannot be endogenously modeled due to performance or complexity considerations will be treated as sensitivities, similar to the 2019 IRP



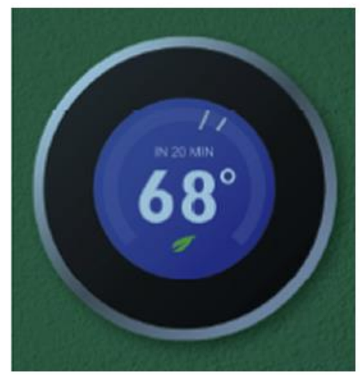
This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

2021 IRP Topology - DRAFT



Stakeholder Feedback Form Update



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Stakeholder Feedback Form Update

- 66 stakeholder feedback forms submitted to date (seven since last public input meeting).
- 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.
- During November 16, public input meeting, PacifiCorp received suggestions to clarify the stakeholder feedback form, that process is underway.

Summary - Recent Stakeholder Feedback Forms

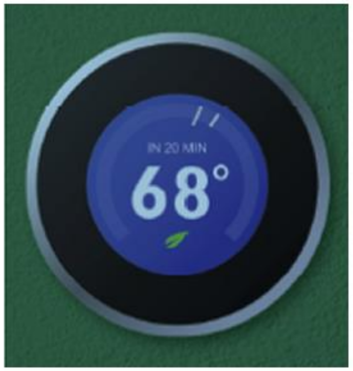
Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Western Resource Advocates (060)	Nov 16, 2020	Transmission Topology	Request to provide incremental transmission topology.	Targeted response the week of November 30.
Oregon Public Utility Commission Staff (061)	Nov 17, 2020	recommended cases/scenarios	Recommendation to include a low market price, high volatility sensitivity in the IRP to determine PAC's optimal portfolio in a future where additional renewables mandates result in more renewables and less gas buildout WECC-wide	Targeted response the week of December 7.
Wyoming Public Service Commission (062)	Nov 18, 2020	Carbon Capture	Request regarding CCS/CCUS technologies	Targeted response the week of December 7.
Oregon Public Service Commission (063)	Nov 18, 2020	Efficiency Measure Bundling	Questions on decision process regarding energy efficiency measure bundling.	Targeted response the week of December 7.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
Interwest (064)	Nov 25, 2020	Brownfield Transmission, Modeling changes in response to WY proceedings	Questions regarding whether PacifiCorp has made any modeling changes in response to the 2019 Wyoming IRP proceeding or any ongoing proceedings, question regarding network service transmission capacity.	Targeted response the week of December 7.
Washington Utilities and Transportation Commission Staff (065)	Nov 25, 2020	11/16/2020 PIM and DERs	Questions regarding the November PIM; DERs and distribution system planning	Targeted response the week of December 7.
Renewable Northwest (066)	Nov 30, 2020	Supply side resource costs, PLEXOS benchmark updates and power price forecasts.	Recommendations for cost assumptions for supply side resources, recommendation for PLEXOS benchmark updates and results, and a recommendation for a power price forecast input.	Targeted response the week of December 14.

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:

- 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*