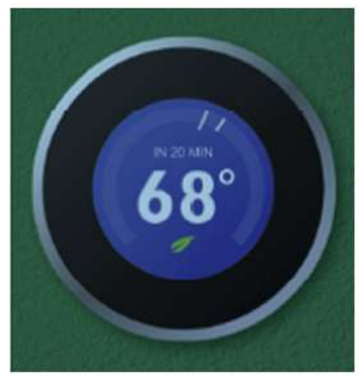
Integrated Resource Plan
2021 IRP Public Input Meeting
July 30-31, 2020



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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




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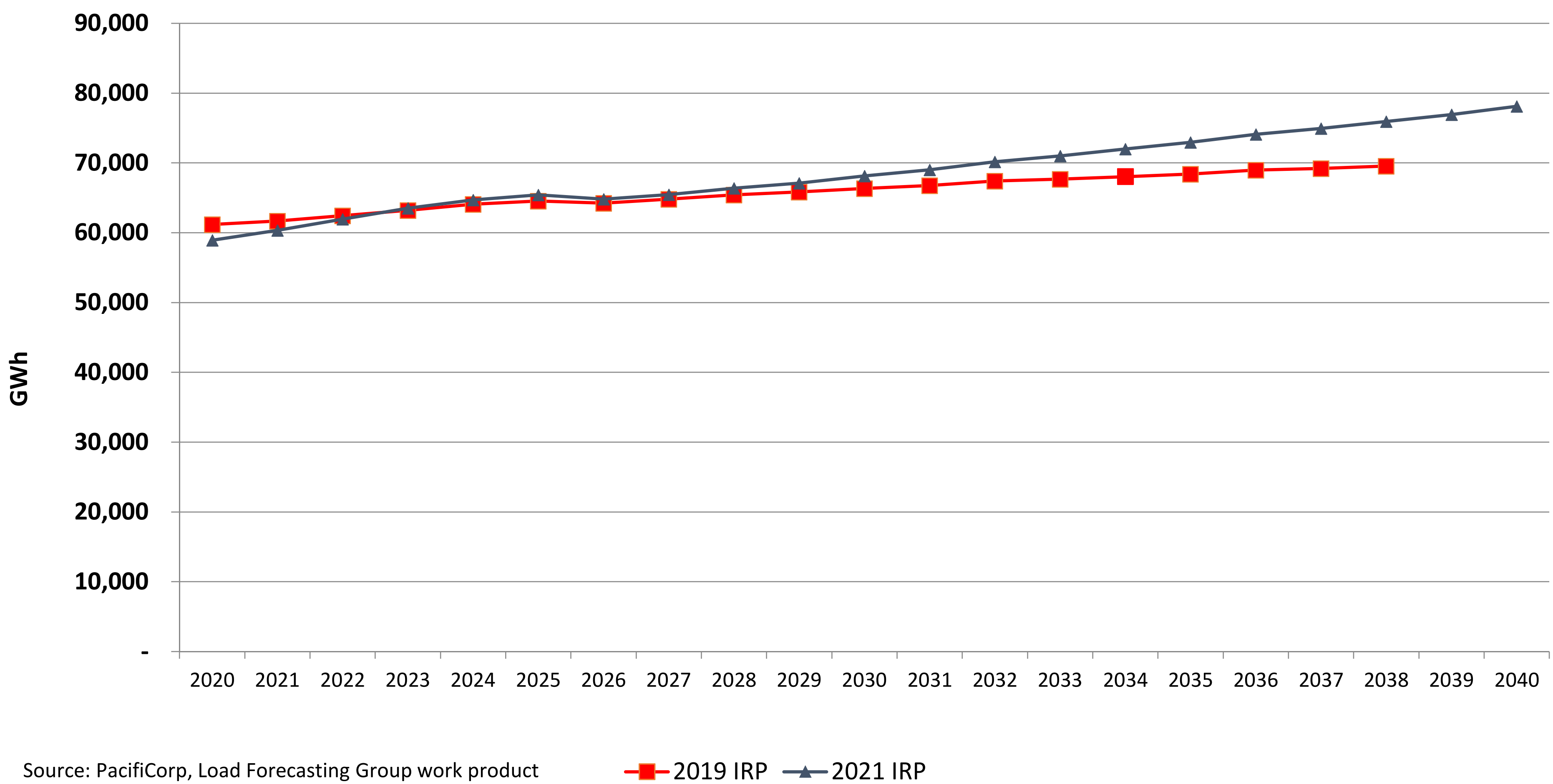
Load Forecast Summary

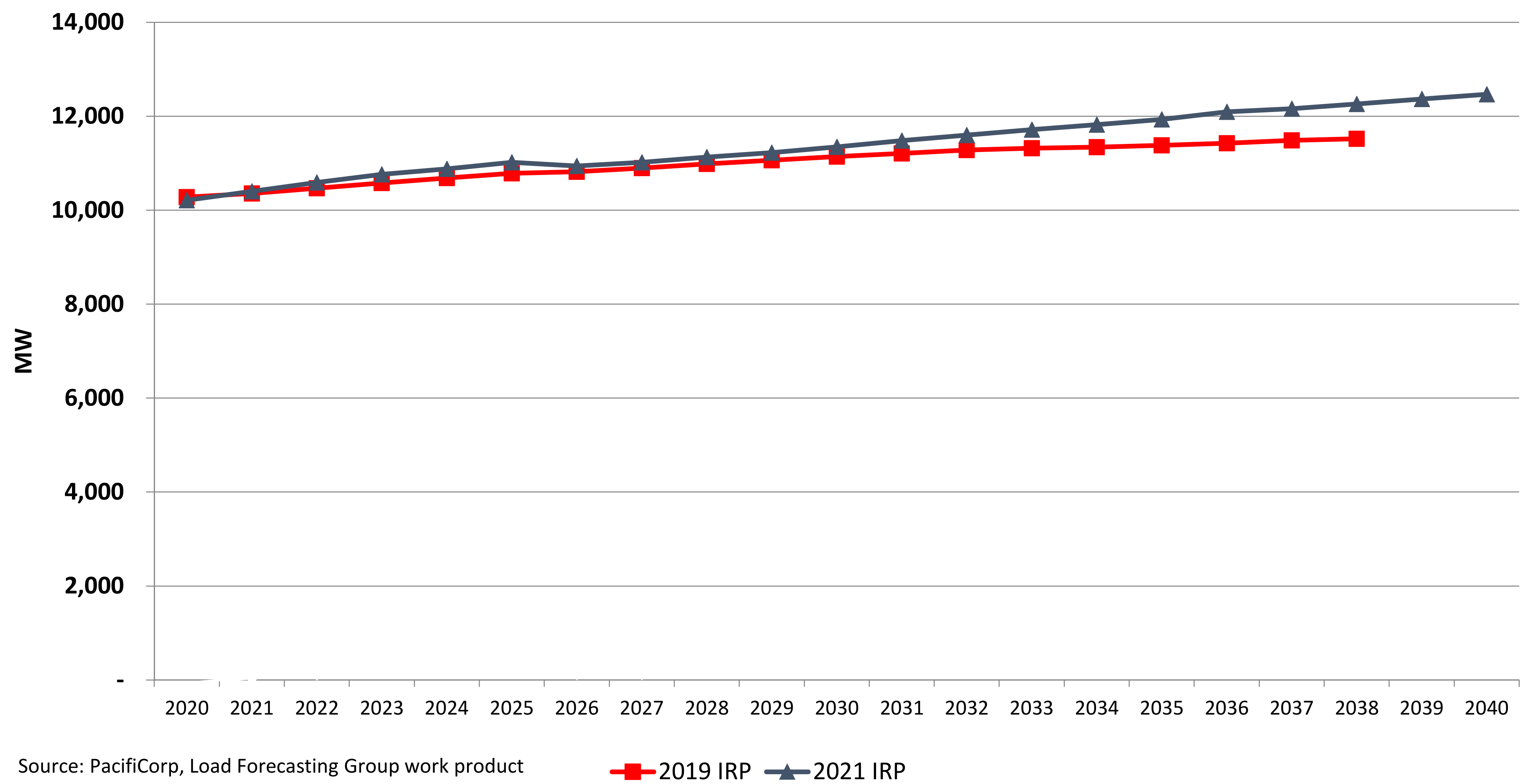
- Over the 2020 through 2022 timeframe, a lower load forecast is being driven by adverse economic impacts resulting from COVID-19 and low commodity prices
- Beginning in 2023, the load forecast is driven higher by projected residential demand and commercial customer demand
    - Codes and standards rollback
    - 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

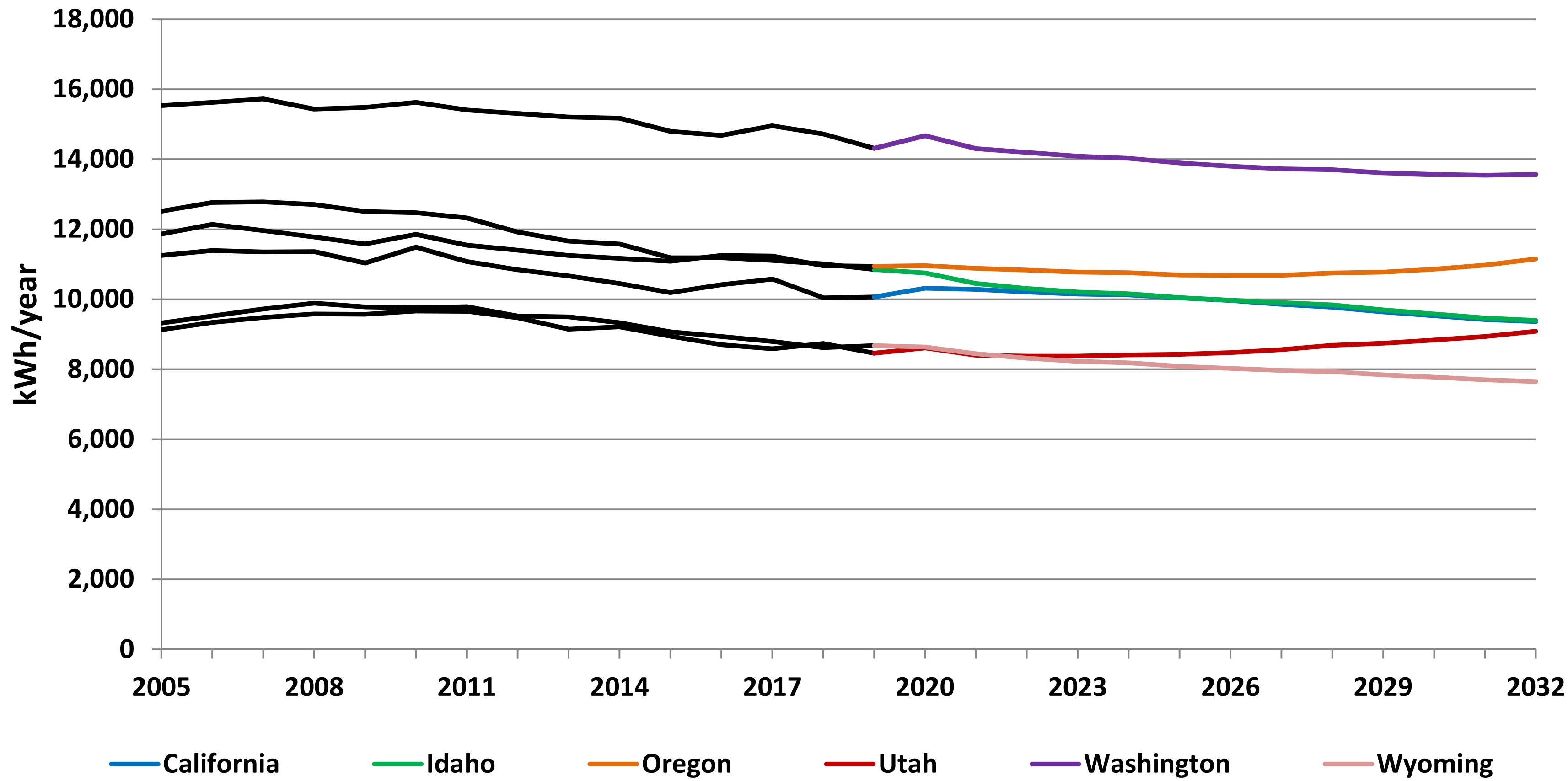
Forecast Drivers

- 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

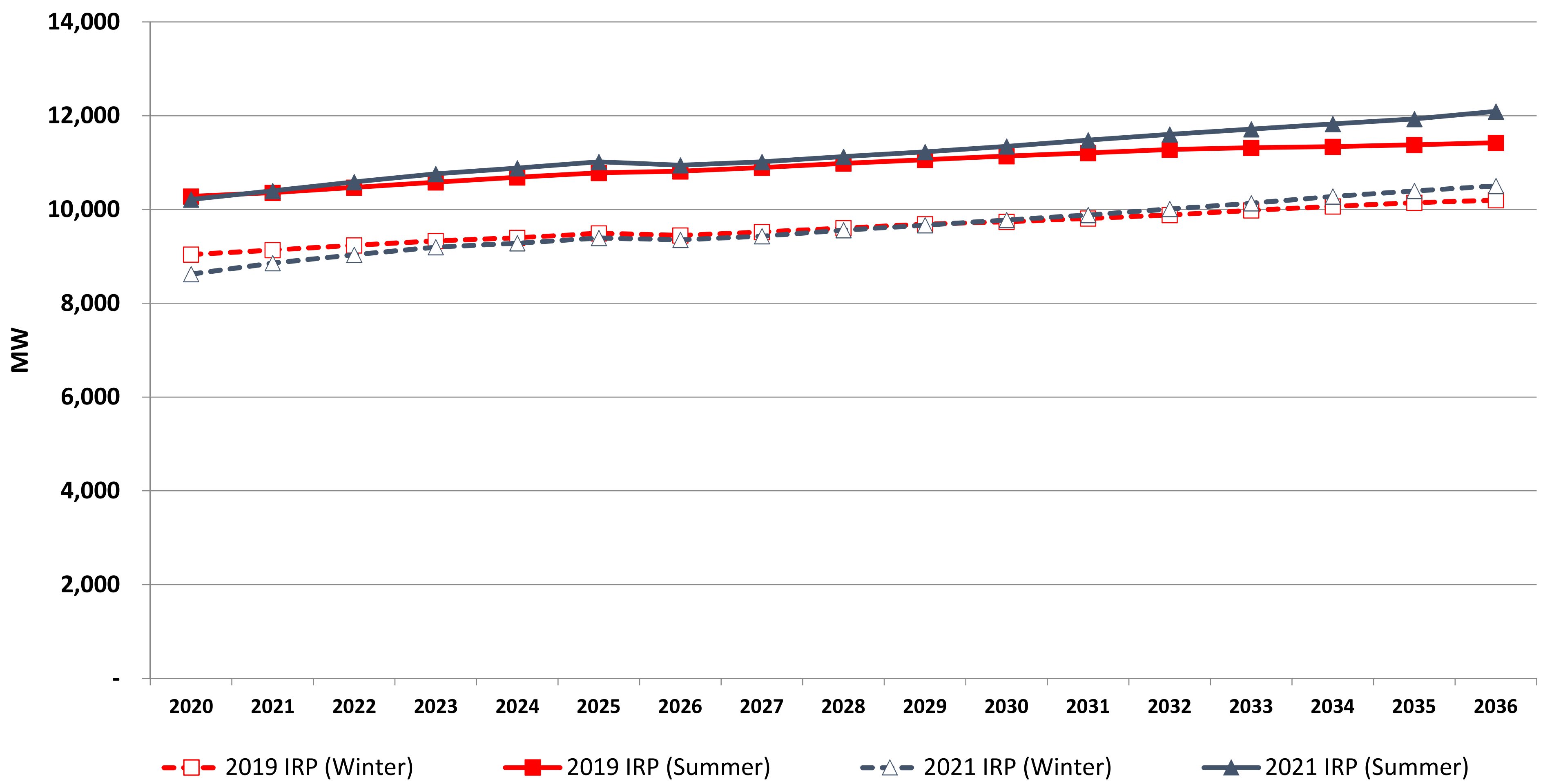
- In Oregon, Idaho and Wyoming, the saturation of central AC and heat pumps for cooling continues to increase relative to the saturations observed in prior surveys. In Washington, California and Utah, the saturation has held relatively steady since 2017
- 2.0 percent of customers report having electric 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



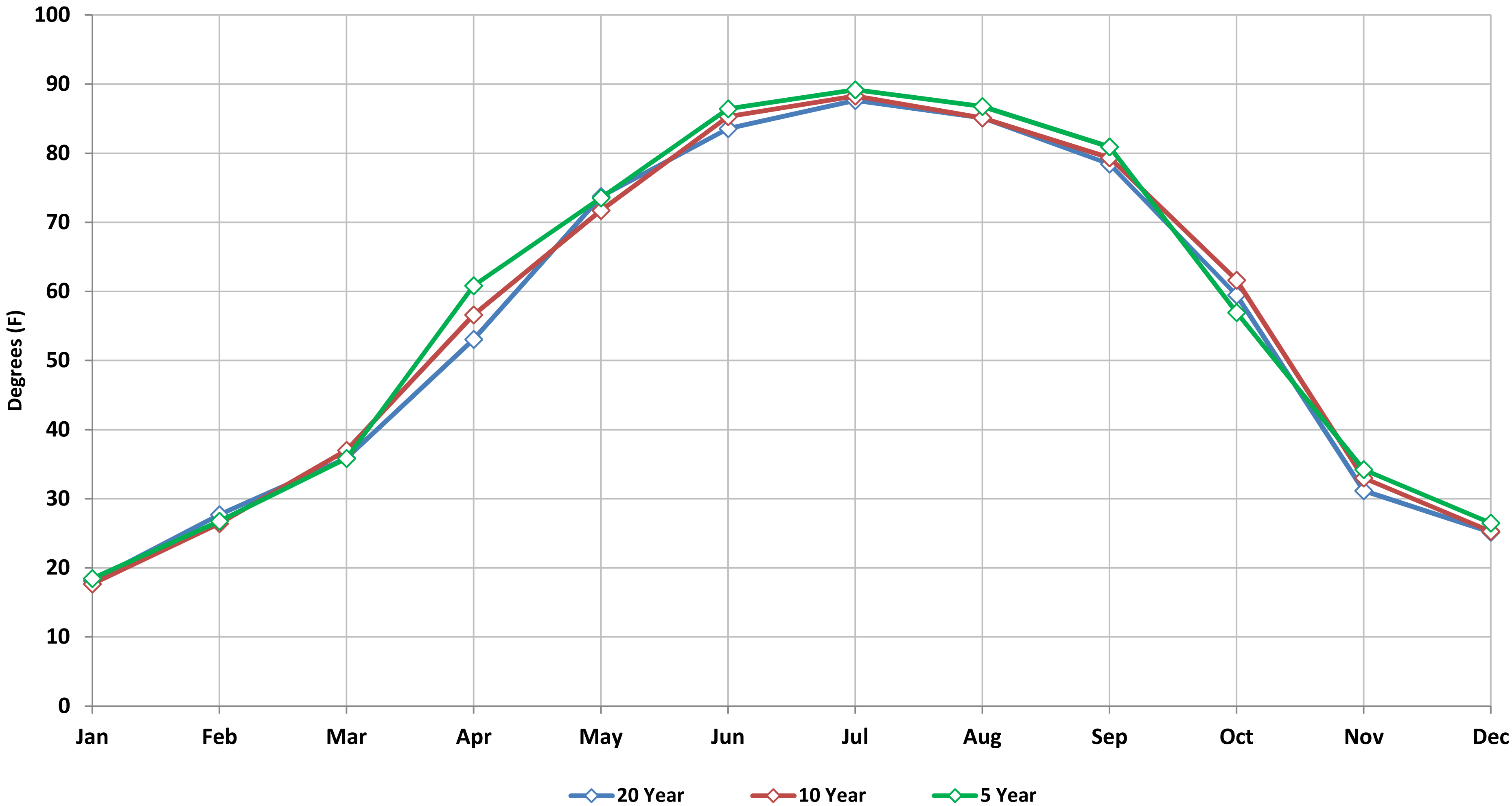
Source: PacifiCorp, Load Forecasting Group work product

Winter and Summer System Peak Load Forecast



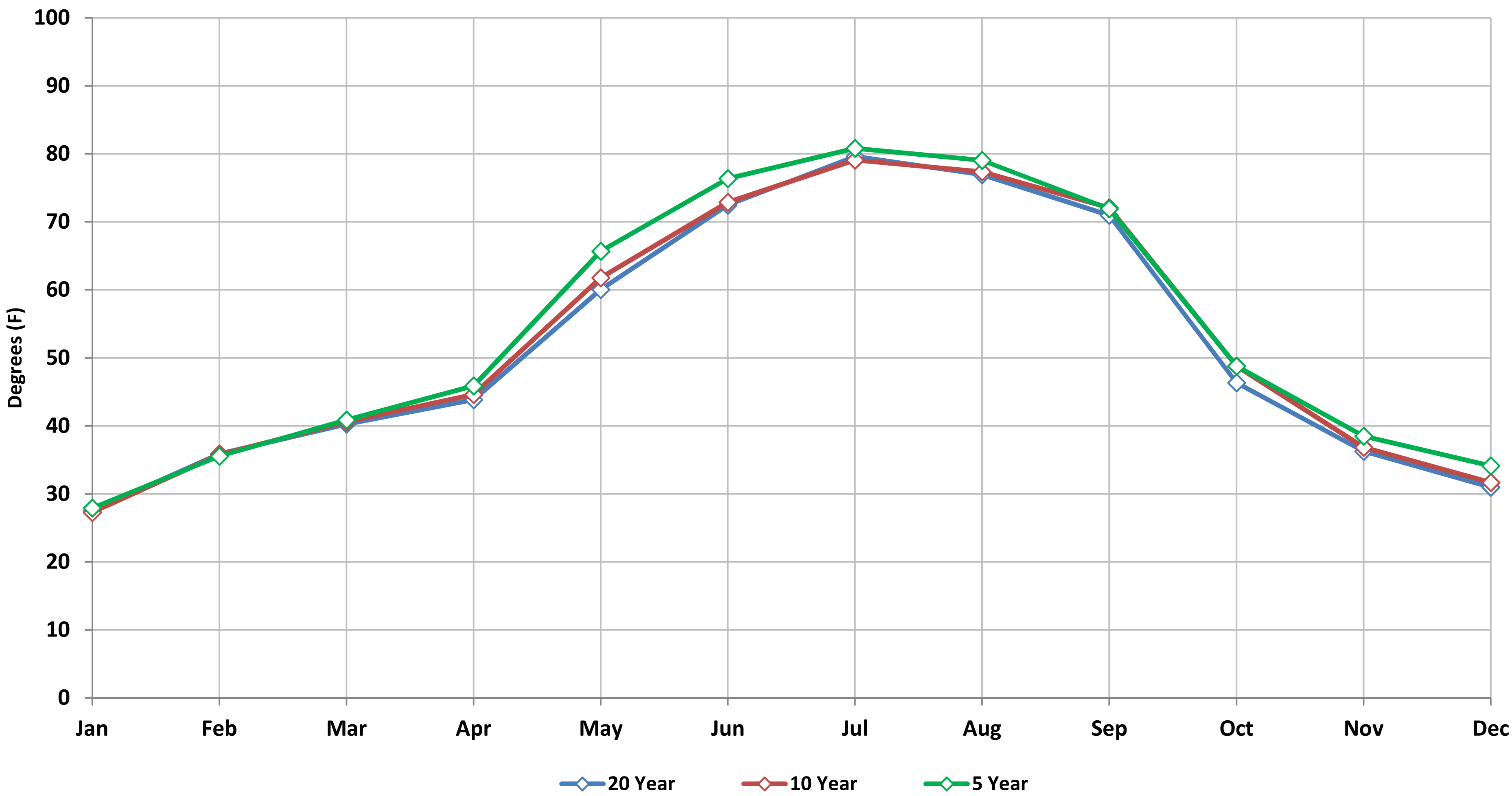
Source: PacifiCorp, Load Forecasting Group work product

Utah Peak Producing Weather



Source: Radiant Solutions, Salt Lake City Airport Weather Station

Oregon Peak Producing Weather



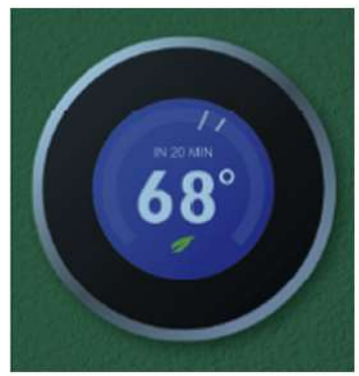
Source: Radiant Solutions, weighted average for Medford Airport, Portland Airport, Salem Airport, Klamath Falls Airport, Redmond Airport, North Bend Airport, and Astoria Airport Weather Stations

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

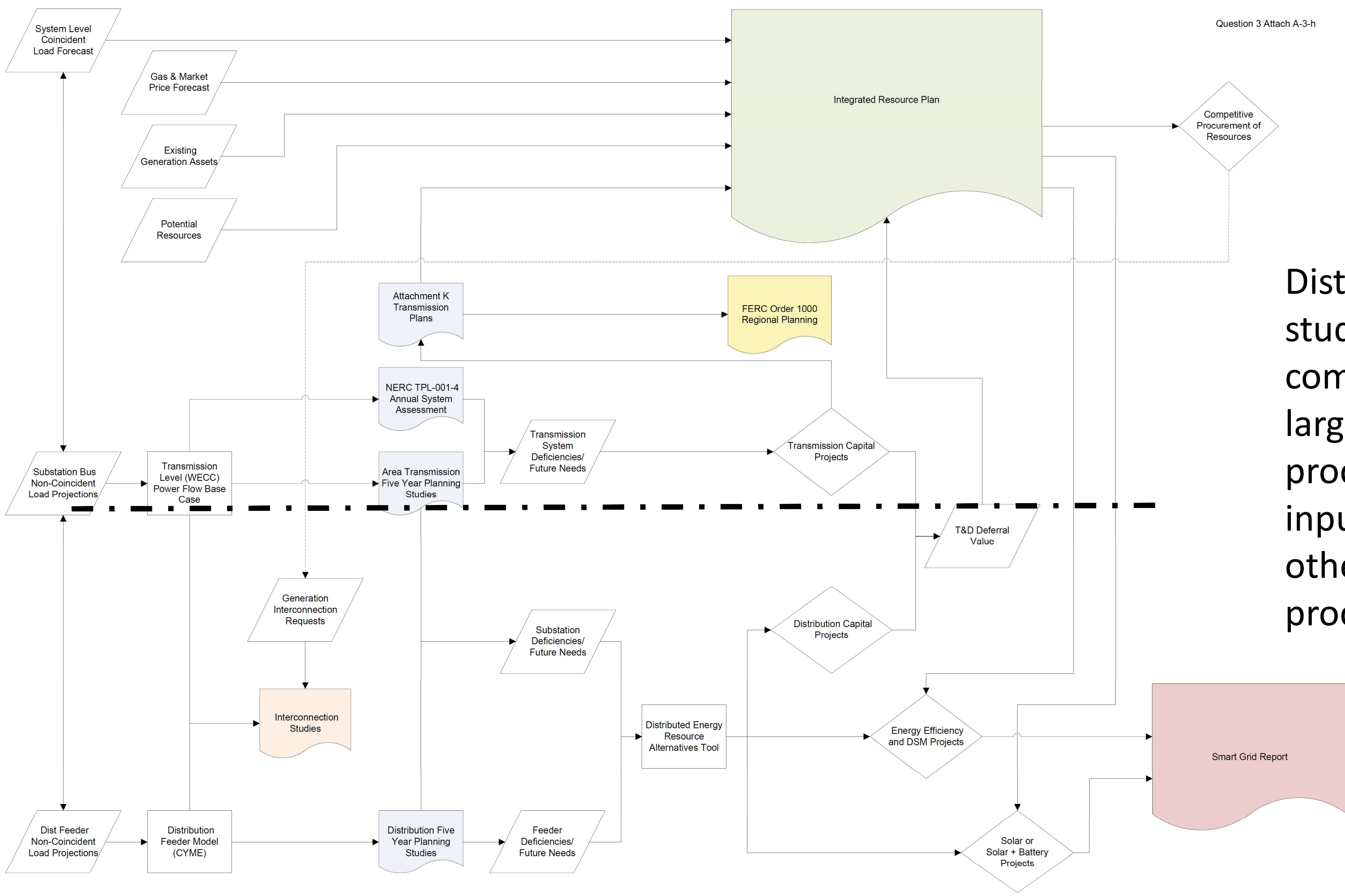


PacifiCorp Planning Processes

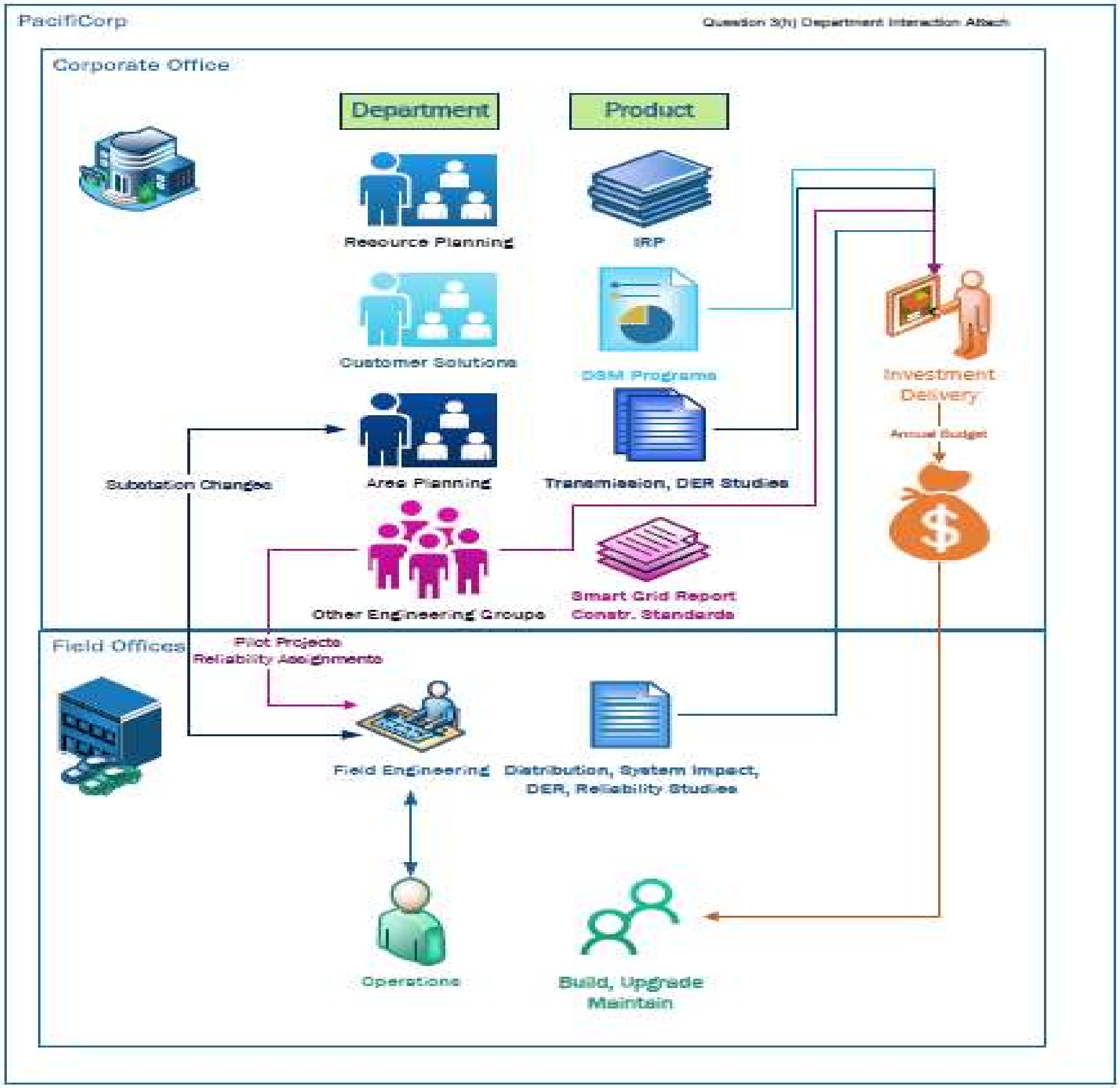
- Integrated Resource Plan
- NERC TPL-001-4 Annual System Assessment
- Local Area Transmission and Subtransmission Five Year Studies
- Distribution Studies
- Generation Interconnection Requests
- Transmission Service Requests

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



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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

- Conservation Potential Assessment (CPA)
  - Energy Efficiency
  - Demand Response
- Private Generation
  - Reciprocating Engines
  - Micro-turbines
  - Small Hydro
  - Solar Photovoltaics
  - Small Wind
- Bulk Energy Storage Study

Tools

- 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

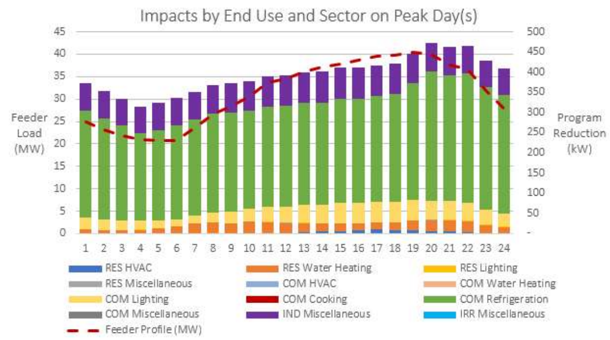
- Feeder transfers: 6-18 months
- Transformer replacements: 12-24 months
- Substation rebuild/expansion: 18-30 months
- New substations: 18-60 months

22

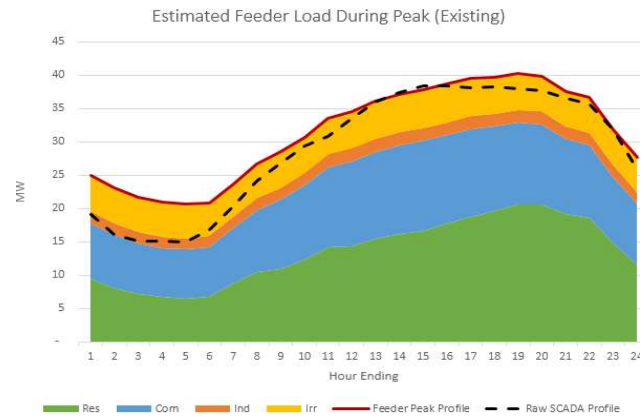
DER Impact Tool

- 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	Feeder/Substation/System Load Usage (MWh)	Feeder Peak (MW)	Customers
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.

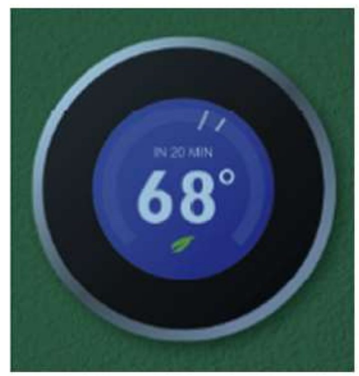
- Replacing Equipment (transformers, circuit breakers/reclosers, disconnect switches)
- Distribution Highlights
  - AMI
  - Distribution Substation Metering
  - Automation
  - Fuse Saver
  - Reclosers
  - Line Scopes
  - Fault Detection, Isolation Recovery
  - Communicating Fault Indicators
  - CYME 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




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)




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 all outages
    - Lower PRM — Cap. contrib. = Unforced Capacity (UCAP) = nameplate * (1 – outage rate): PRM covers above average 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 with the same reliability.

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:

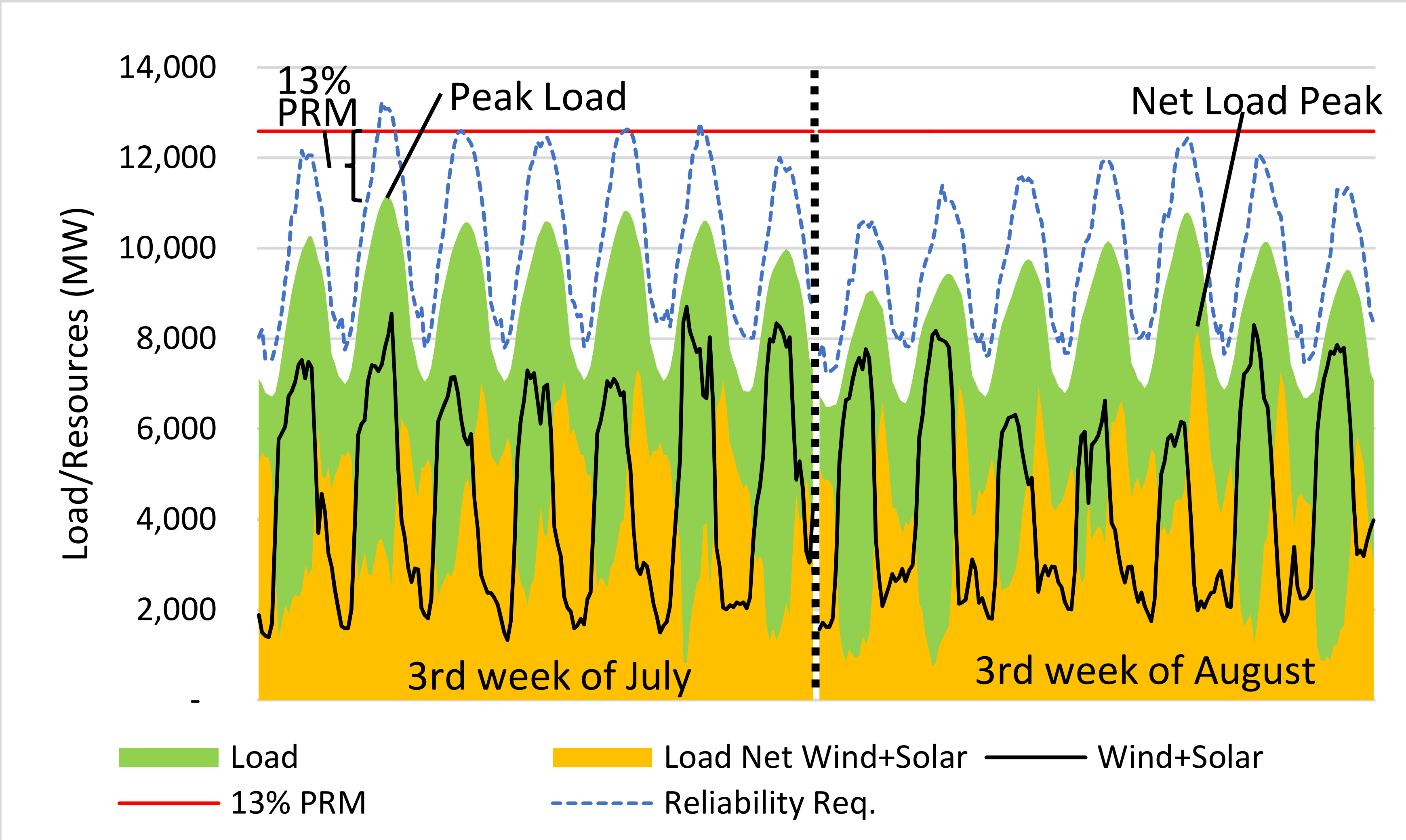
- SO model selects optimized resource portfolios at PRM ranging from 11% to 18% above 1-in-2 coincidental peak load (in summer and winter)
- PaR evaluates portfolio cost and reliability under stochastic conditions for portfolios corresponding to each PRM:
  - Stochastic parameters are load, hydro conditions,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

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.

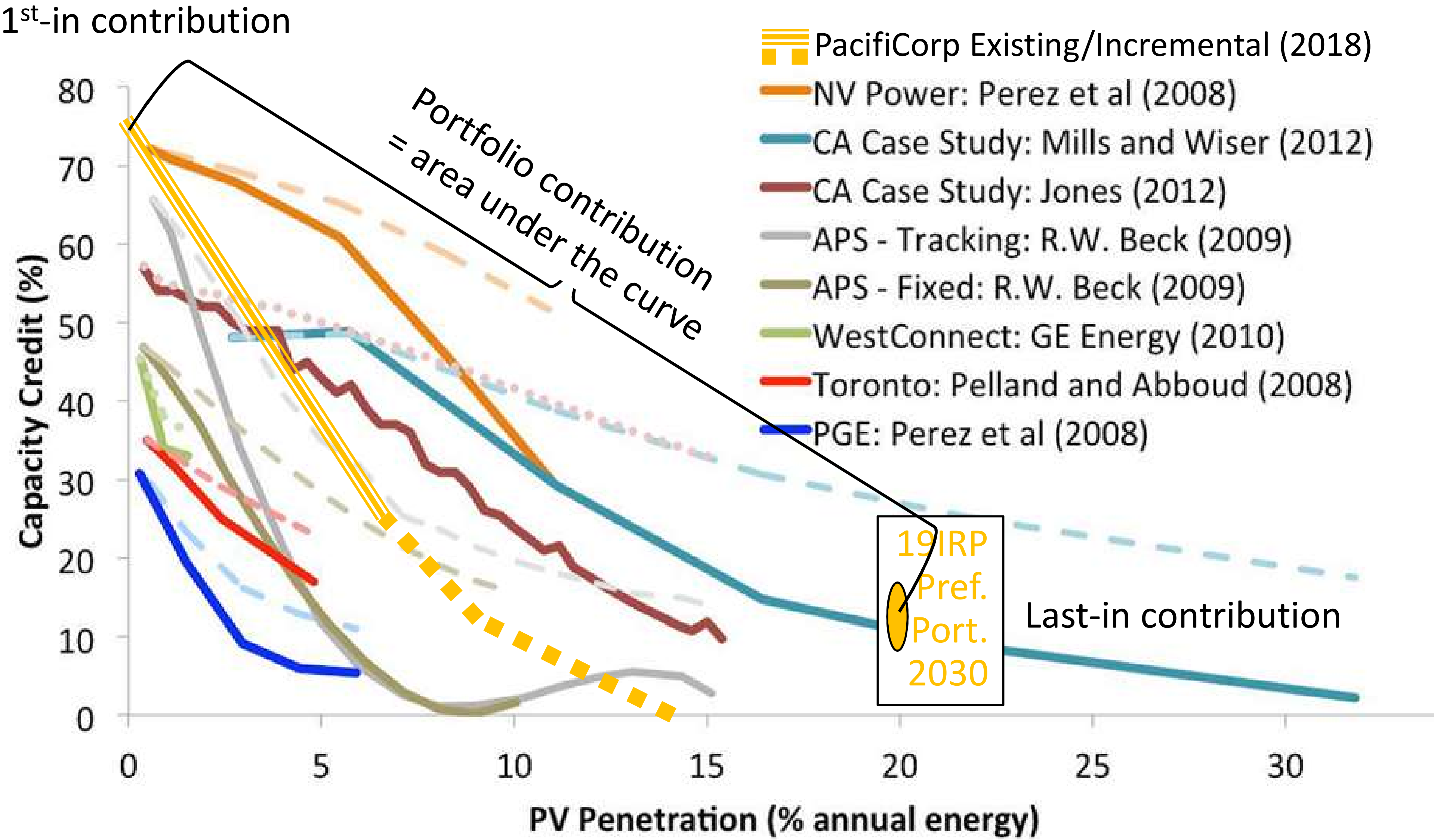
Capacity Contribution – Resource Effects

- 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

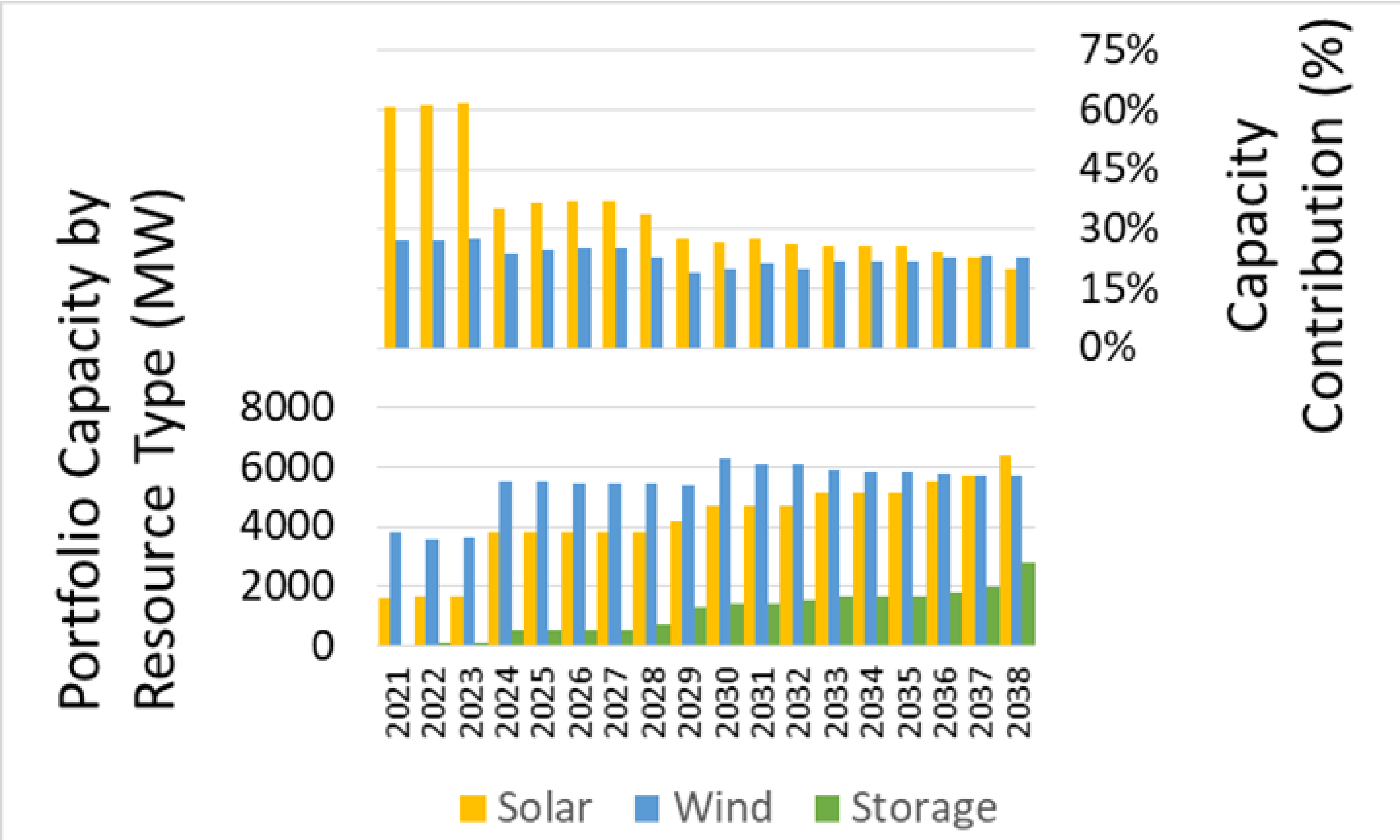
- PacifiCorp prepared capacity contribution values at the start of the 2019 IRP.
- Capacity contributions for wind and solar were designed to step down as capacity increased.
- During portfolio analysis, PacifiCorp found that portfolios with equivalent assumed capacity contributions were not resulting 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

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	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 – 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.

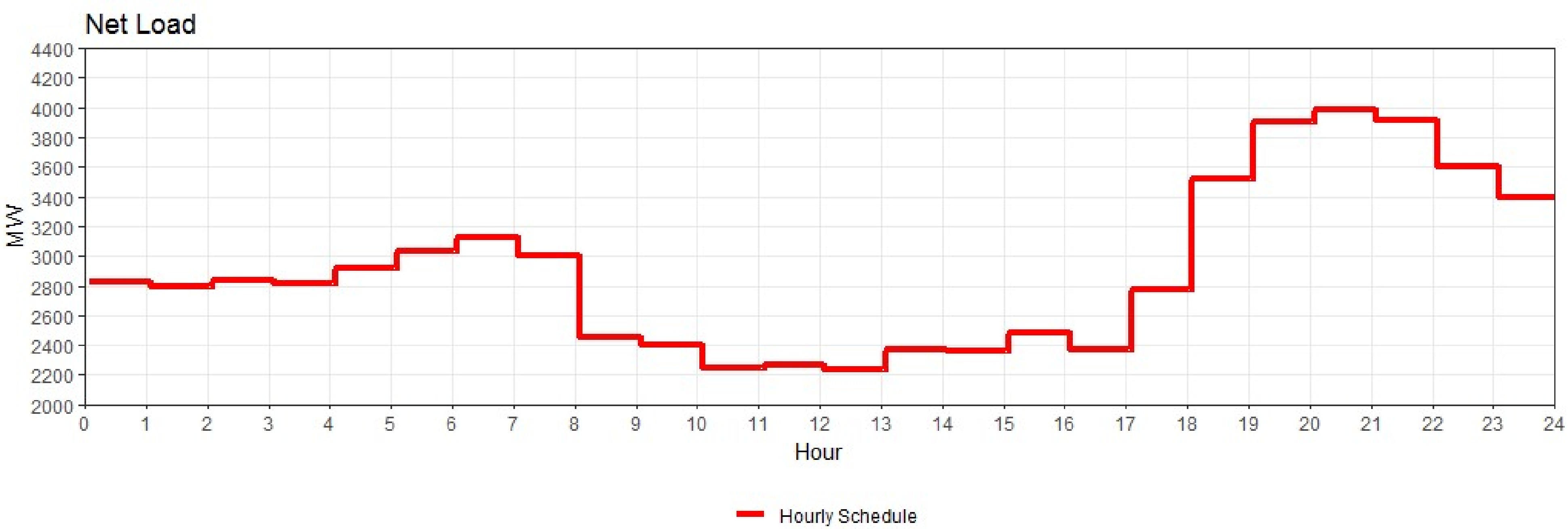
Intra-Hour Dispatch Credit

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.

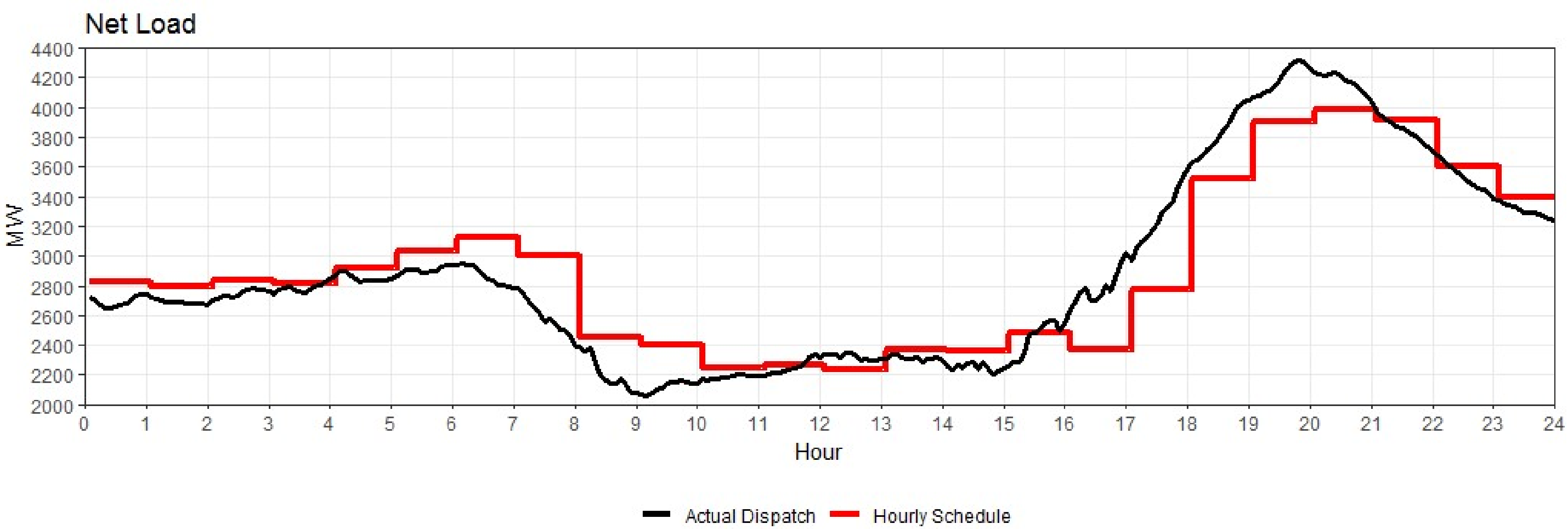
Hourly Models

- 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.



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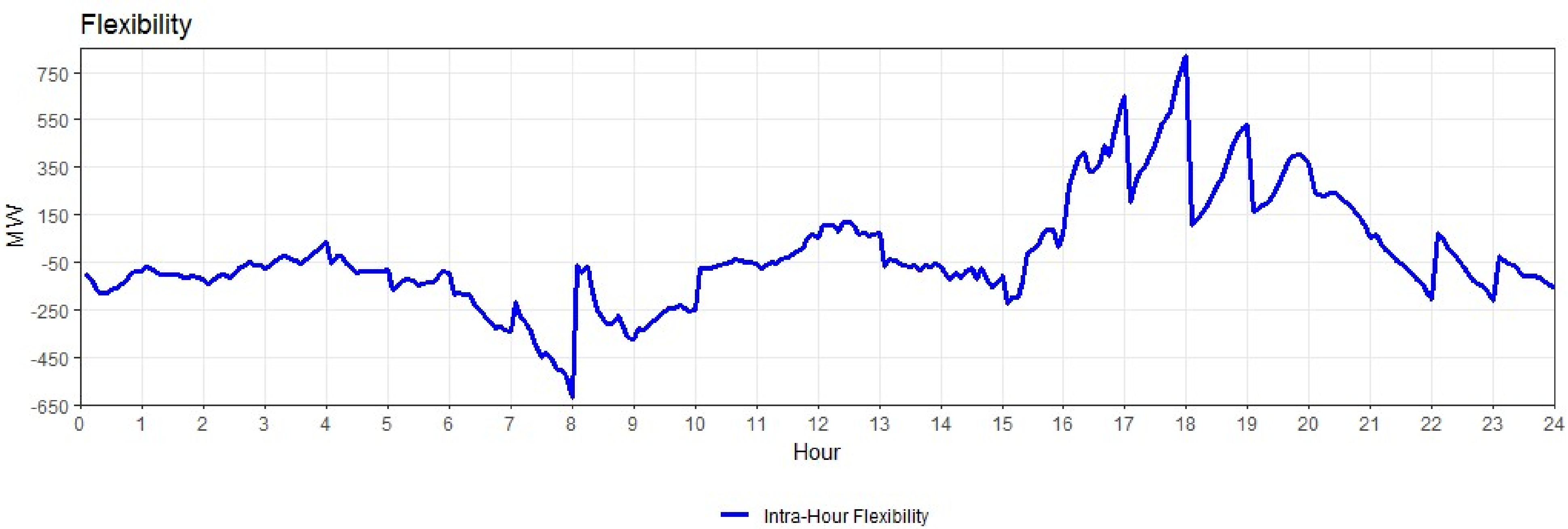
Flexible Dispatch

- 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

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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




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

Proposed $/kW-yr \ Current LCOE $/MWh	<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




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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:
  - 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*