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May 3, 2022

MEMORANDUM

TO: Council Members

FROM: Jennifer Light

SUBJECT: Bonneville's Resource Program, Part 1

BACKGROUND:

Presenter: Bonneville staff: Ryan Egerdahl, Steve Bellcoff, and Eric Graessley

Summary:

Bonneville staff will present on its Resource Program. Bonneville's Resource Program develops forecasts of federal system energy, capacity, and balancing needs, and evaluates resource development solutions to meet those needs. The timeframe for the next Bonneville Resource Program is 2024-2033, which aligns with the beginning of the next rate case.

This presentation is part one of a two-part presentation to the Council's Power Committee. The topics for Part 1 include:

- (1) An overview of the Resource Program planning process.
- (2) A discussion of the needs assessment.
- (3) Bonneville's wholesale market price forecast.
- (4) Bonneville's estimate of wholesale market depth and its available share of the wholesale market.

Bonneville will come back to the Power Committee at its June meeting to provide its findings from the conservation and demand response potential assessments, and the findings from the resource program.

Relevance:

The Resource Program is an analysis by Bonneville of its potential system needs and the resources available to meet those needs. While the Resource Program is informational and not a decision-making process, nor a decision document, the Resource Program and the results of this process do inform Bonneville's resource acquisition strategies. Though it is prudent for Bonneville to study its needs and examine resource availability, under the Act, Bonneville's resource acquisition decisions are to be consistent with the Council's power plan (Section 4(d)(2)).

Background:

Summary of Bonneville's Resource Program

As noted above, Bonneville uses its Resource Program to help inform its acquisition strategies, including energy efficiency, demand response, contract purchases, and generation. It has been through several iterations over the years. For this 2022 Resource Program, Bonneville has made updates to its frozen efficiency load forecast, needs assessment, resource forecast, wholesale market price forecast and market limit assumptions, conservation potential assessment, and demand response potential assessment. This information all feeds an optimization process that provides insight to inform Bonneville's resource acquisition strategy

How Bonneville's Resource Program Relates to the Council's 2021 Power Plan

Bonneville's resource acquisition strategy is also a subject for the Council's power plan under the Northwest Power Act. To summarize briefly and at a high level, the Council's power plan is to set forth a scheme for implementing conservation measures and developing resources to reduce or meet Bonneville's obligations (Section 4(e)(2)) and the power plan is to include: a conservation program to be implemented under this Act (Section 4(e)(3)(A)); a forecast of the amount of power resources estimated by the Council to be required to meet Bonneville's obligations and portions of such obligations that can be met by resources in each of the priority categories; and the approximate amounts of power the Council recommends should be acquired by Bonneville, with an estimate of the type of resources from which such power should be acquired (Section 4(e)(3)(D)).

In turn, the Act specifies that all of Bonneville's actions to acquire resources pursuant to Section 6 of the Act are to be consistent with the Council's power plan except as otherwise specifically provided for in the Act (e.g. Sections 4(d)(2), 6(a), 6(b)). This includes acquiring conservation resources, with Section 6(a)(1) obligating Bonneville to acquire conservation and implement conservation measures "as the Administrator determines are consistent with the [Council's power] plan", as well as the acquisition of other resources, with Section 6(b)(1) adding that "[e]xcept as specifically provided in this section, acquisition of resources under this Act shall be consistent with the plan, as determined by the Administrator." Therefore, Bonneville's resource authorities and decisions are tied to the Council's power plan through a consistency obligation.

The Council's 2021 Power Plan provides specific recommendations to Bonneville, informed by the analysis in the plan, including a Bonneville specific scenario. The recommendations to Bonneville around resource acquisitions include:

- Acquire between 270 and 360 aMW of cost-effective energy efficiency by the end of 2027, of which at least 243 aMW must be from programmatic savings, and at least 865 aMW by 2041, and additionally:
 - Use the Council's methodology and associated parameters for determining which energy efficiency is cost-effective
 - Contribute to all aspects of the regional conservation program
- Work to enable and encourage its customer utilities to pursue low-cost and high-value demand response, including time-of-use rates and demand voltage regulation
- Look to mid-term and long-term market resources for additional energy when needs are beyond those met by the recommended energy efficiency and demand response resources
- Compare market products, both in price and capacity, to renewable power purchase agreements to ensure that the lowest-cost product that suffices to meet any need is identified

Our understanding of the current iteration of Bonneville's Resource Program is that it is intended to work within that framework. And the Council's ultimate interest is in seeing Bonneville make resource decisions consistent with the Council's power plan as provided for under the Act.

Bonneville and Council staff have been meeting periodically to discuss the analysis the agency is preparing for the Resource Program. These discussions have focused on Bonneville's methodology. Bonneville has also shared initial results from its needs assessment, details of the conservation and demand response potential assessments, and methodology and results of the wholesale market price forecasts. These elements, along with the load forecast and cost and availability of all resource options, will be used to develop an optimal strategy based on the study parameters. Council staff have not yet seen results of any resource strategy analysis as of the date of this packet but will have a chance to review those results soon.

Differences Between the 2021 Power Plan and Bonneville's Resource Program

There are fundamental differences between the Council's 2021 Power Plan and Bonneville's Resource Program.

Cross-Cutting Assumptions

- **Timeframe:** The Council's Power Plan, as with all power plans under the Act, provides a resource strategy for a 20-year period (2022-2041), with an obligation to review the plan within five years. The Resource Program focuses on the 10-year period of 2024-2033.
- **Scope:** Bonneville's Resource Program is designed to focus specifically on its needs and resources to inform near-term acquisition, whereas the Council's plan

is to ensure the region an adequate, efficient, economical and reliable power supply, looking at the region's needs in planning for Bonneville's resource strategy.

- Climate Change: Bonneville is not including climate change hydro or temperatures in its analysis. This results in important differences in needs and resources. For example, without climate change there is a greater diversity in the timing of the capacity need across the WECC, whereas under a climate change future the timing of need in the Northwest need shifts towards summer and overlaps with that of the rest of the WECC, potentially requiring greater WECC-wide builds and impacting market prices.

Needs Assessment

The Council's current regional standard of 5% Loss of Load Probability (LOLP) is not an appropriate metric for any specific utility, including Bonneville, to use in assessing needs. Instead, Bonneville explored four different metrics for its needs assessment that are more focused on assessing needs of their system. Bonneville ultimately is using its P10 Heavy Load Hour metric for assessing needs, as it is the most constraining for their system. This metric looks at the 10th percentile surplus/deficit over heavy load hours by month, given the variability in hydro generation, loads, and Columbia Generating Station output.

Bonneville uses a different model to estimate its needs. For this Resource Program, Bonneville has moved to a new Riverware Model for river operations, which Bonneville believes has more realistic modeling of several projects relative to its previous tool (HOSS).

Wholesale Market Price Forecast

Bonneville's baseline wholesale market price forecast is showing significantly lower builds across the WECC and higher prices, particularly during the middle of the day. In addition to the cross-cutting assumptions outlined above (in particular the exclusion of climate change futures), key differences in this study include:

- Lower Loads: In addition to lower loads from not including climate change, Bonneville is not assuming as much electrification load for California in the base scenario as assumed in the Council's plan.
- Bid Adder: Bonneville included an additional bid adder into the model other than a flat, negative REC price on hydro and renewables, which reflects the prices actually bid into the market over and under the fundamentals of the resource to reflect risk position and opportunity. This approach was different than the Council's increasing negative REC price, resulting in similar price differentials throughout the day, but notably higher prices across all hours (in the evening and mid-day).
- Clean Policies: The Council's 2021 Power Plan assumed that all clean policies across the west are met. Bonneville relaxed the requirements by discounting pseudo goals by 20 percent and allowing 10 percent of incremental needs for targets to be met on a pooled basis.

- Economic Retirement of Existing Plans: Bonneville allowed Aurora to economically retire both gas and coal plants, whereas the Council only included announced retirements. This results in significant higher assumed retirements of natural gas in Bonneville's analysis.
- No Gas Limitations: Bonneville did not limit gas build out in the west as much as was done in the Council's plan. This resulted in more new gas builds, although not significantly more when considering the economic retirement of some existing gas.
- Resource Options: Bonneville included different resources options than in the Council's 2021 Power Plan price forecast. Of particular note is the inclusion of a small modular reactors as a zero emissions firm and flexible resource in Bonneville's analysis. This particular resource was attractive to the model, especially in out years, as an alternative to renewables. The Council did not include this in its baseline analysis, as it is considered an emerging technology. Additionally, Bonneville placed fewer limits on wind resources in California, which likely results in an increase of wind development and a significant drop in solar, due to the diversity of the shape of those resources.

These differences are a result of a mix of policy considerations (e.g. the Council's decision to only include announced retirements and limit new gas builds in the west) and analytical choices (e.g. incorporating a bid adder). Collectively, these decision point tend to result in a smaller WECC build out and higher market prices than what was seen in the Council's Power Plan, which ultimately will drive different decisions during their resource optimization.

Market Limits

Bonneville's assumed market reliance is calculated based on trying to find the difference between regional availability when all regional balancing authorities plan and build for zero market reliance and when they increase market reliance up to an adequacy threshold. Bonneville then assumes a share of the market reliance would be available and assumes it would be the market reliance limit for their further work.

- Market reliance is embedded in all fundamental analysis, BPA approximates as the net market imports into the Pacific Northwest as an approximation (values range from 1,000 to 5,000 average megawatts).
- This range is significantly discounted especially in the summer acknowledging the risks of relying on external to the region energy.
- This methodology resulted in less market reliance in heavy load hours than previous method used in the resource program.

The Council method for assumed market reliance for all scenarios in the 2021 Power Plan (excepting the increased market reliance limit scenario) and adequacy work has traditionally set by agreed upon net regional import limits after much discussion in the Resource Adequacy Advisory Committee.

Other Materials:

[2021 Plan Market Supply Assumptions table](#)

2021 BPA Needs Assessment

Northwest Power & Conservation Council Power Committee
May 11, 2022



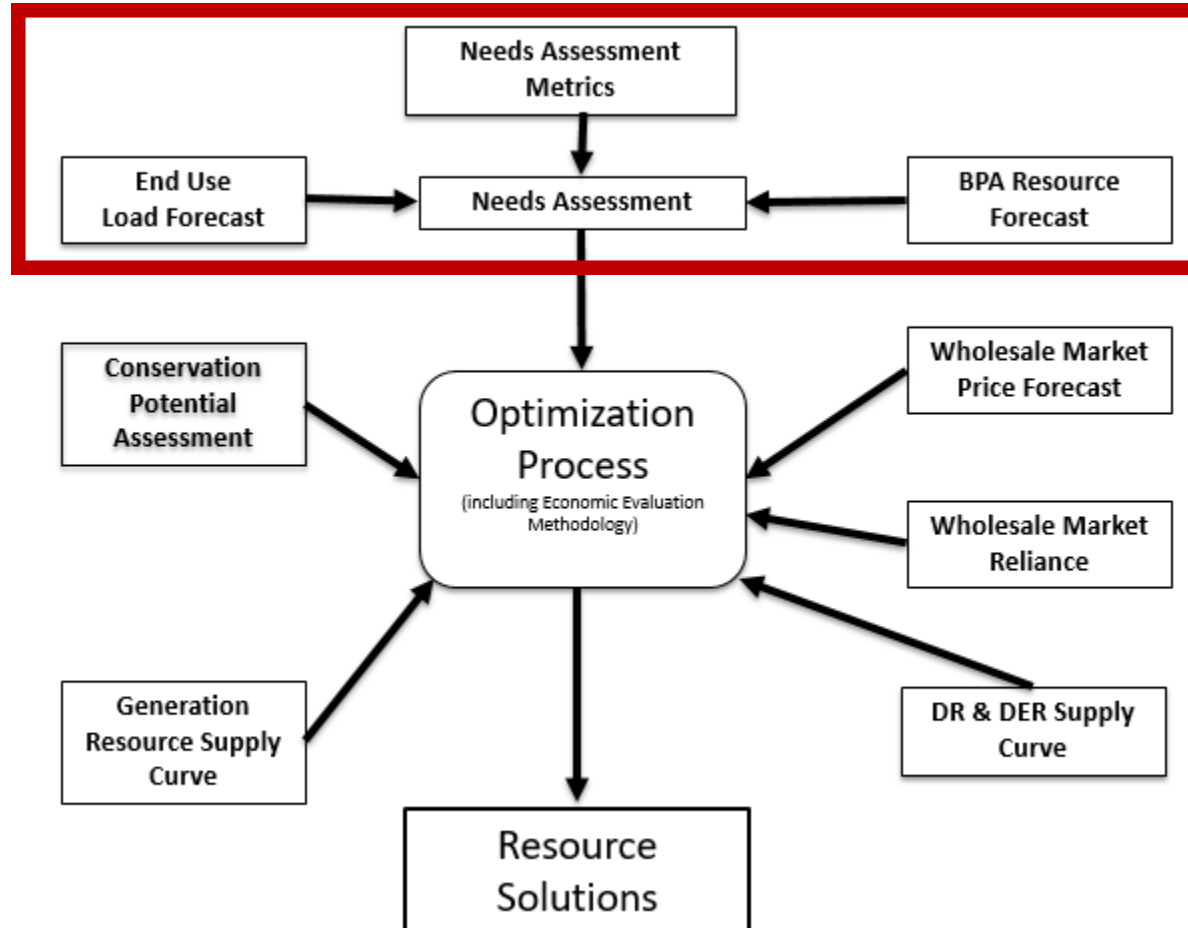
Agenda

- Review 2021 BPA Needs Assessment
- Address questions as we go
- Provide update on next steps in BPA Resource Program

Background

- BPA began its Resource Program after the passage of the Pacific Northwest Electric Power Planning and Conservation Act in 1980 which gave BPA the authority to acquire power to serve growing regional loads
- The purpose of the Resource Program is to assess BPA's long term need for power and then develop a resource strategy for meeting those needs
- Results in this presentation are part of the **draft 2022 BPA Resource Program** which is underway and scheduled to be published this summer

BPA Resource Program Process



Overview

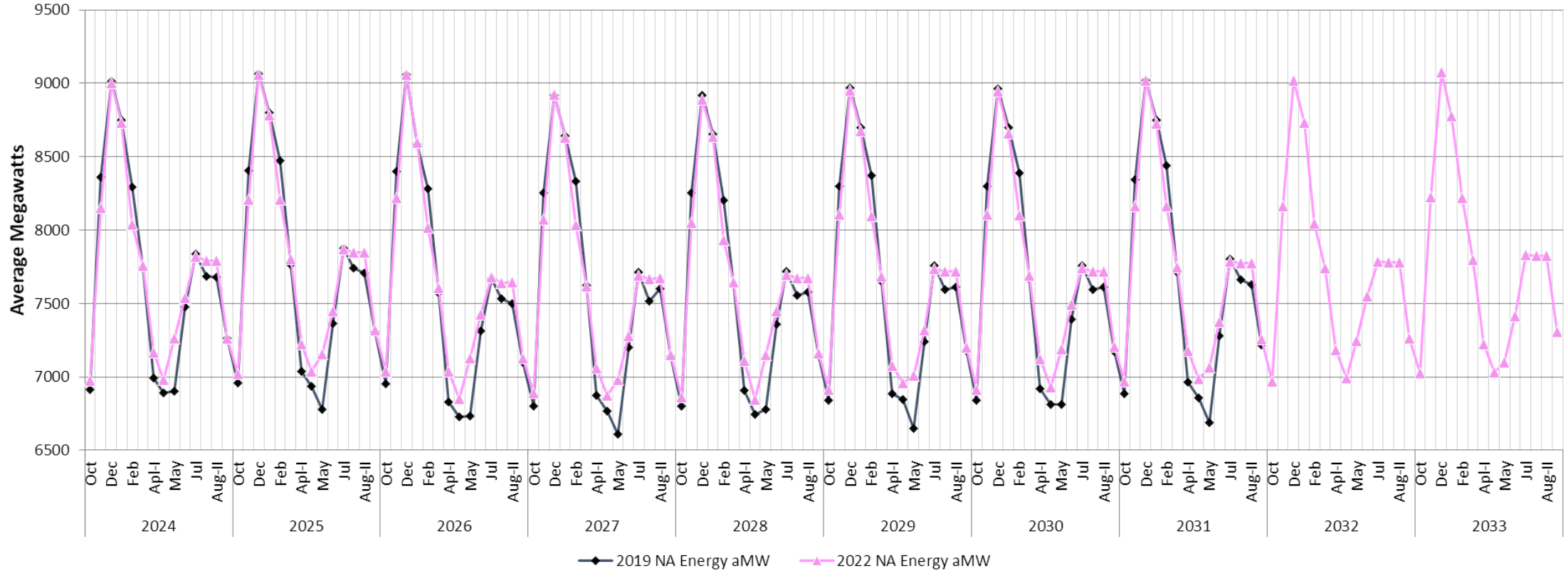
- Needs Assessment (NA) provides forecasts of Federal system energy and capacity needs (deficits) by assessing generating resources and load obligations for 2024 - 2033
- 2021 Needs Assessment relied on a new hourly hydro generation forecasting model
 - Riverware is the new hourly hydro model
 - HYDSIM (Hydro System Simulator) is still our monthly hydro model; same model used by BPA and Council to run classic GENESYS
- Studies include:
 - Obligations – new Frozen Efficiency Load Forecasts from BPA’s load forecasting group
 - Resources – hydro operations based on BP22 Final Rates Proposal (same as CRSO Final EIS Preferred Alternative)
 - Impacts of both 80 and more recent 30 years of historical streamflows modelled independently

Frozen Efficiency Load Forecasts

- Based on hybrid of Statistically Adjusted End-Use (SAE) implementation and econometric approaches.
 - BPA has over 135 power customers. Approximately 40 of those are modeled using SAE today and we continue to migrate customers into this evolving process established in 2018

- SAE Data Sources
 - Saturations – RBSA, Utility data
 - Efficiencies- Northwest Power & Conservation Council model results
 - UEC- Northwest Power & Conservation Council model results
 - Economic Data- IHS Markit

Frozen Efficiency Load Obligations

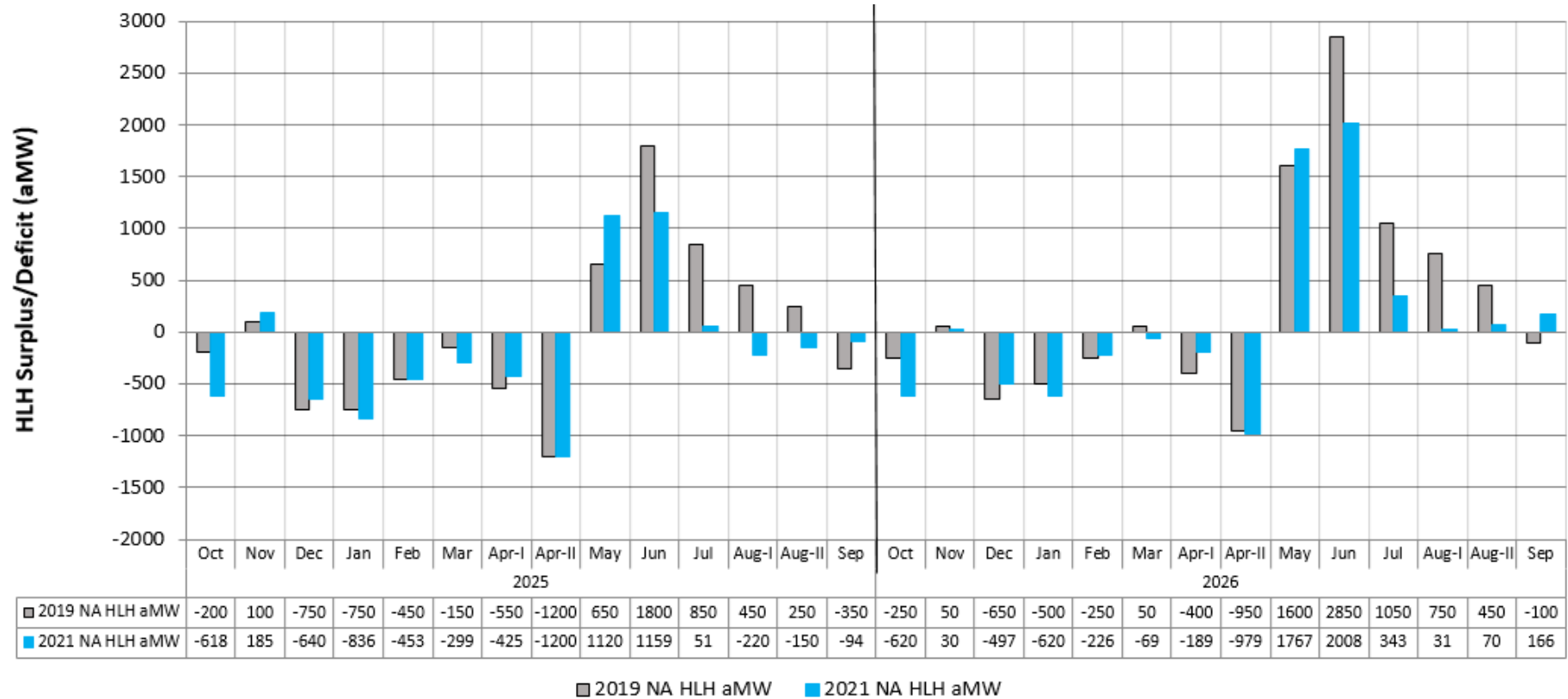


Needs Assessment Metrics

- **Annual Energy**
 - Evaluates the annual energy surplus/deficit under 1937-critical water conditions
- ***P10 Heavy Load Hour (HLH)***
 - Evaluates the 10th percentile (P10) surplus/deficit over heavy load hours by month, given variability in hydro generation
- **P10 Superpeak**
 - Evaluates the P10 surplus/deficit over the six peak load hours per weekday by month, given variability in hydro generation
- **18-Hour Capacity**
 - Evaluates the ability to meet the six peak load hours per day over three-day extreme weather events

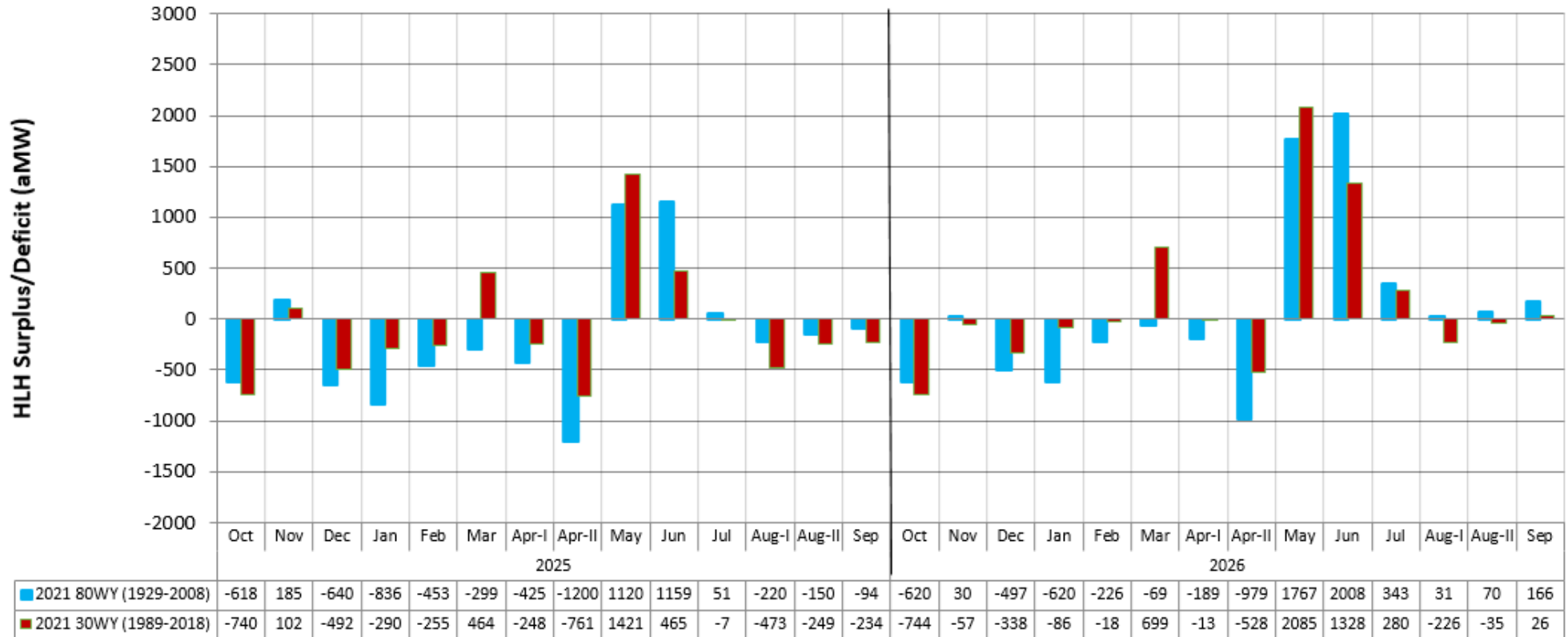
P10 Heavy Load Hour

** 80 Water Year



- Riverware modeling results in reduced HLH-block in summer due to better alignment with river operations
- Inventory position shifts upwards 200 aMW as of Jan 2026 with expiration of PGE sales contracts
- Largest deficits occur in October, winter, and second half of April (aka April II)
- 2025 includes CGS refueling in May / June

P10 HLH – Climate Change Planning Updates ** 80 vs 30 WY



■ 2021 80WY (1929-2008) ■ 2021 30WY (1989-2018)

- 30 years of historical streamflows results in more generation in winter and less generation in summer, compared to the 80 years of history

Conclusion

- 2021 Needs Assessment results continue to demonstrate that BPA is energy (hydro fuel) limited
 - P10 Heavy Load Hour deficits are the most constraining results compared to the other metrics being evaluated
- More recent 30 years of historical streamflows results in more generation in winter and less generation in summer, compared to the 80 years of history
- Next steps: come back in June and present draft resource options to meet the forecasted P10 HLH needs

BPA Long-Term Power PCM

WECC Resource Build, Prices, and Market Limits

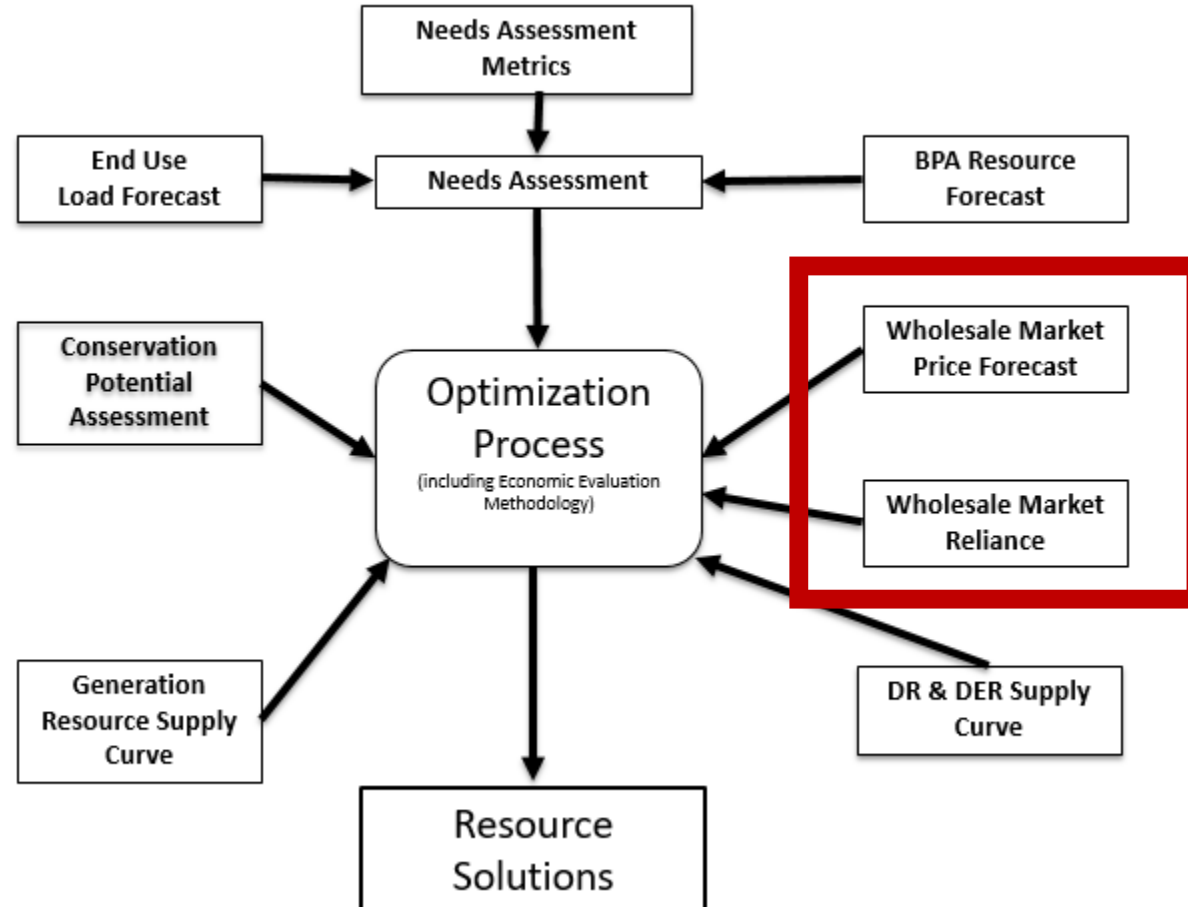
May 11th, 2022



Outline

- ❖ Long-Term Capacity Expansion (LTCE) and additional assumption details
- ❖ Prices
- ❖ Market Limits

BPA Resource Program Process



Long-Term Capacity Expansion (LTCE) Assumptions and Builds



Aurora Resource Build: LT Capacity Expansion

1. Start with existing resources
2. Lock in high likelihood builds and retirements over the duration of the next rate period (-2023) – sources include IRPs, data from consultants, EIA, and the BPA generation interconnection queue (exceptions being Diablo Canyon retirement, some OTC generation in CA, and Site C in BC)
3. Allow Aurora to build and retire additional resources based on economics, ensuring pool planning reserve margins are satisfied and all relevant state policies (Renewable Portfolio Standards (RPS) / zero emission targets) are met
 - Use dynamic peak credits for variable resources (wind and solar), updated iteratively
 - Get policy constraint shadow prices which should help inform expectations of costs of policy compliance and negative price behavior (see appendix)

New Resource Options

- CA offshore wind, consistent with SB100 modeling assumptions (up to 10 GW)
- PNW offshore wind (Oregon only, up to 2 GW)
- Two types of firm flexible zero emission resources in high policy states coupled with no new gas ~2030+
 - Base: High fixed cost, low variable cost resource. Modeled after SMR, characteristics, also comparable to traditional fossil fuel base resource with CCS
 - Peaker: Low fixed cost, high variable cost resource. Modeled after H2 combustion turbine with onsite electrolysis and storage, also ~comparable to combustion turbine running on other bio/renewable fuels / traditional resource
- **'New natural gas' builds can represent:**
 - **Deferment of retirement, coal to gas conversions, or a new plant**

Case / Scenario Definitions

Base

Our expected outcome *given*:

- Assumed technology costs and availability
- Base case gas prices, loads, and hydro (80/30WY EIS)
- Current, explicit carbon policy
- Current behavior when clean policy is confronted with reliability shortcomings
- Represents a more conservative estimate of how rapidly the system transitions to zero emission resources
 - More responsive to short-term economics and reliant on traditional resources to meet reliability

High Policy (HP)

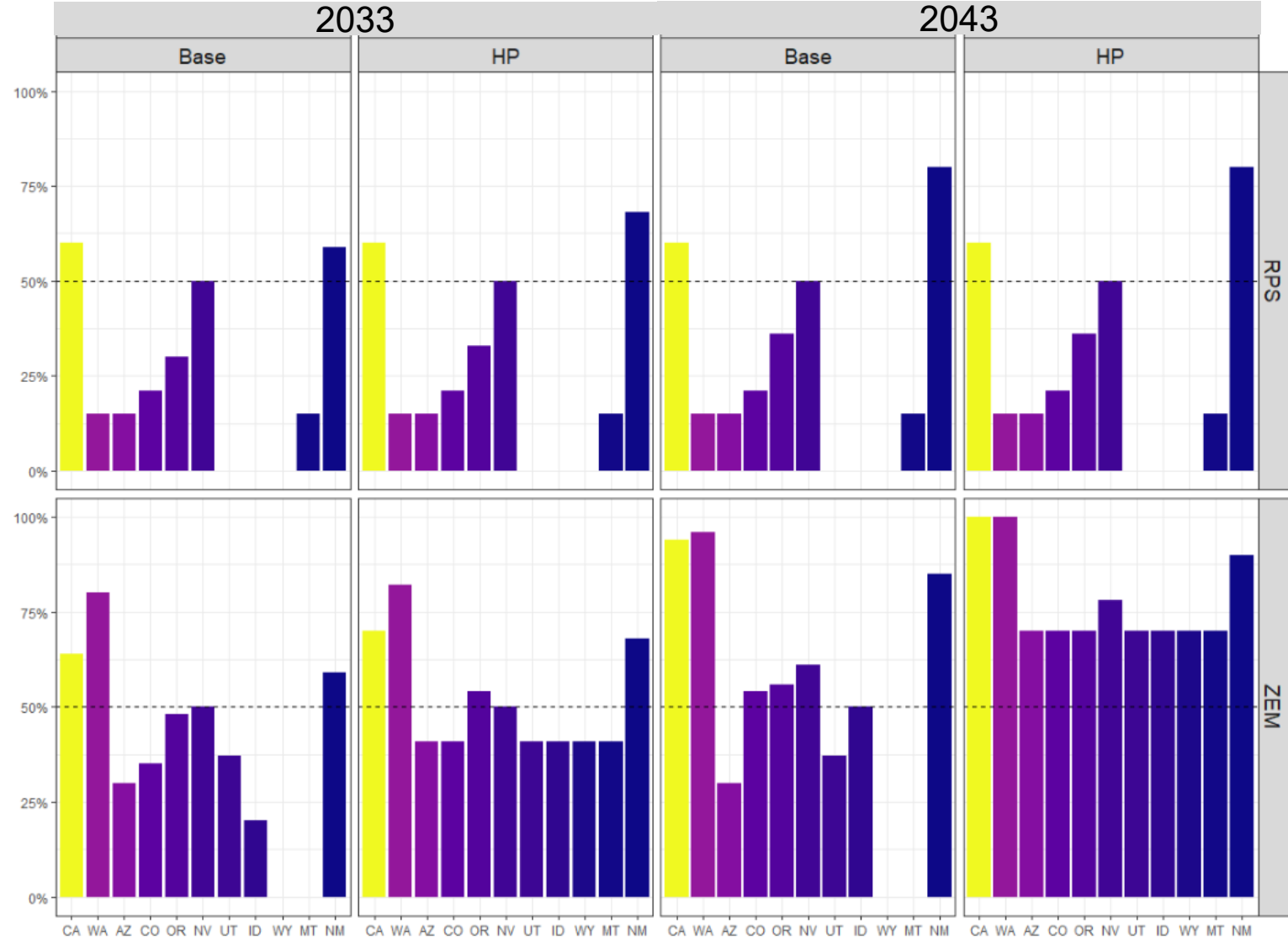
Our expected outcome *given*:

- Rapid transition / Accelerated decarbonization
 - CA carbon price in OR and WA
 - WECC wide carbon price beginning 2030
 - All base case goals are accelerated
 - All states aim for 100% ZEM by 2050
- Reduced solar, wind, and storage resource costs
- More electrification in loads
- 30WY EIS hydro
- Lower gas price forecast
- Represents a 'plausibly high' case, not intended to be a rigorous study of how or if the WECC achieves zero / net zero emissions, or how quickly it could do so

Policy Constraints

RPS and ZEM requirements were updated to be consistent with Council's ~June 2020 WECC policy survey (including municipal and utility clean goals, 'pseudo goals')

- We discount pseudo goals by 20%
- For all targets, we allow 10% of incremental needs to be met on a pooled basis (anywhere in the WECC)



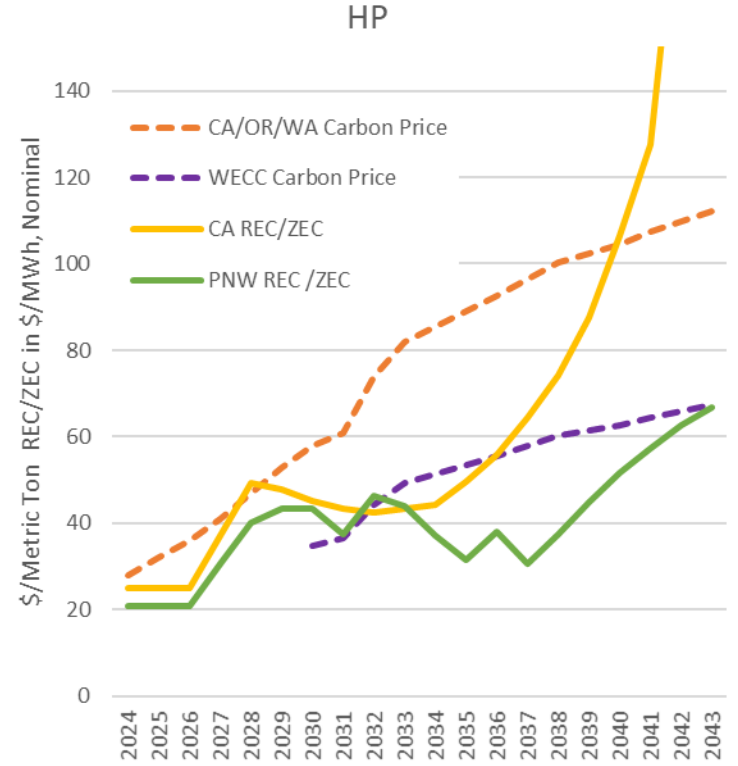
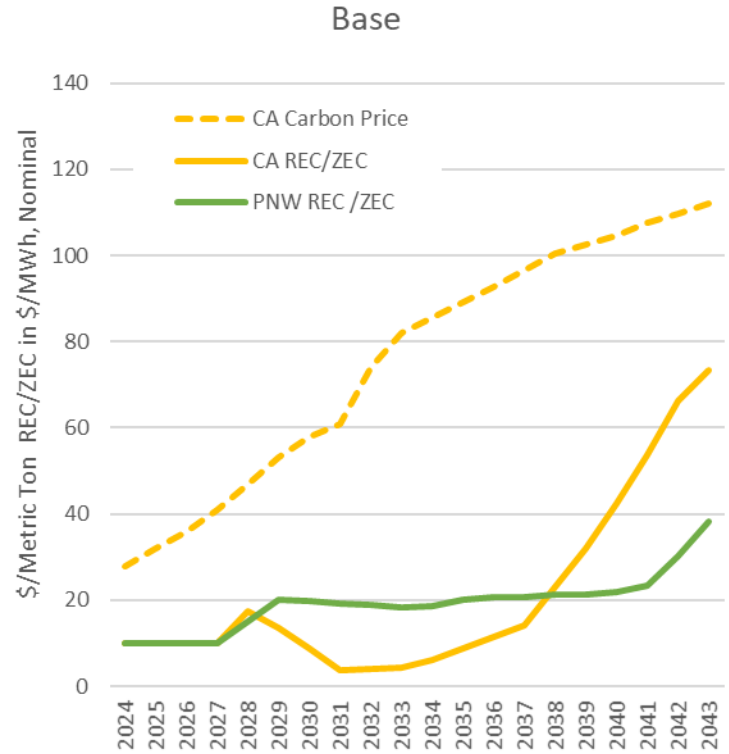
Carbon Policy Constraints

Carbon prices:

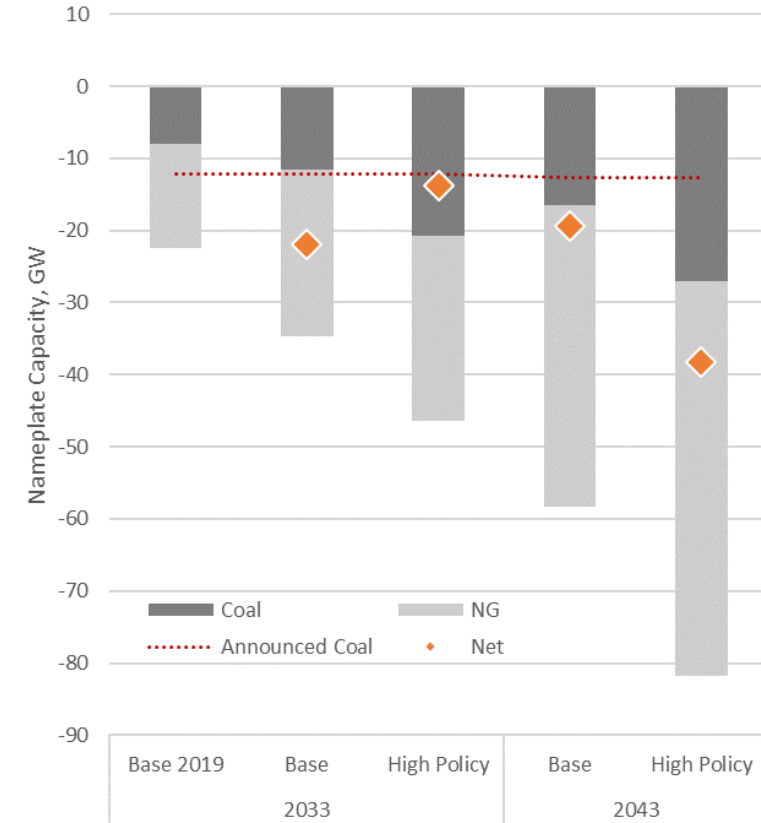
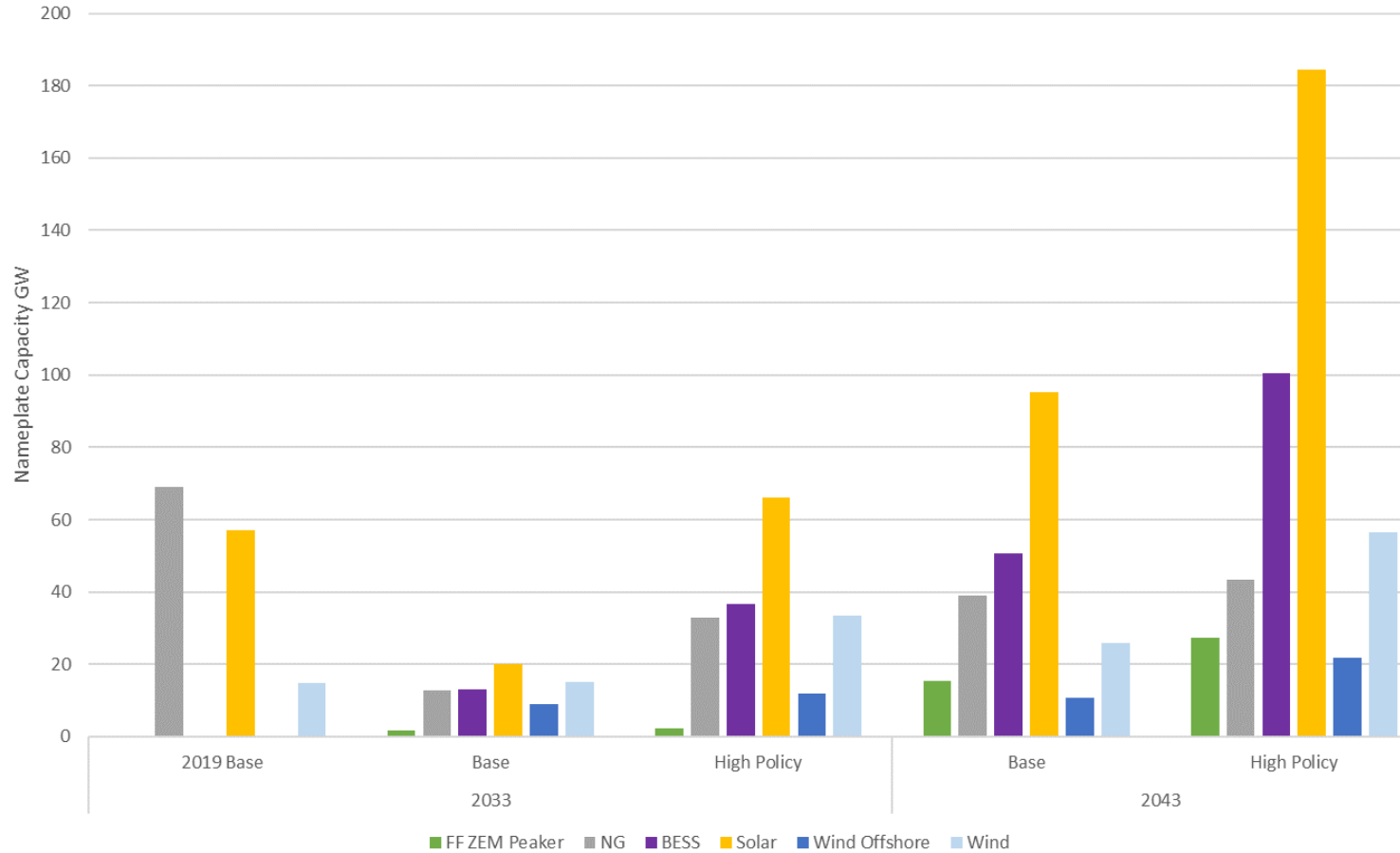
- Base: CA and AB
- HP: CA/OR/WA adopt CA price, rest of WECC adopts lower price beginning 2030

Include emission penalties on WA thermals after 2030 and ensure 80% of WA loads are met with zero emission generation, ramping up to 100%

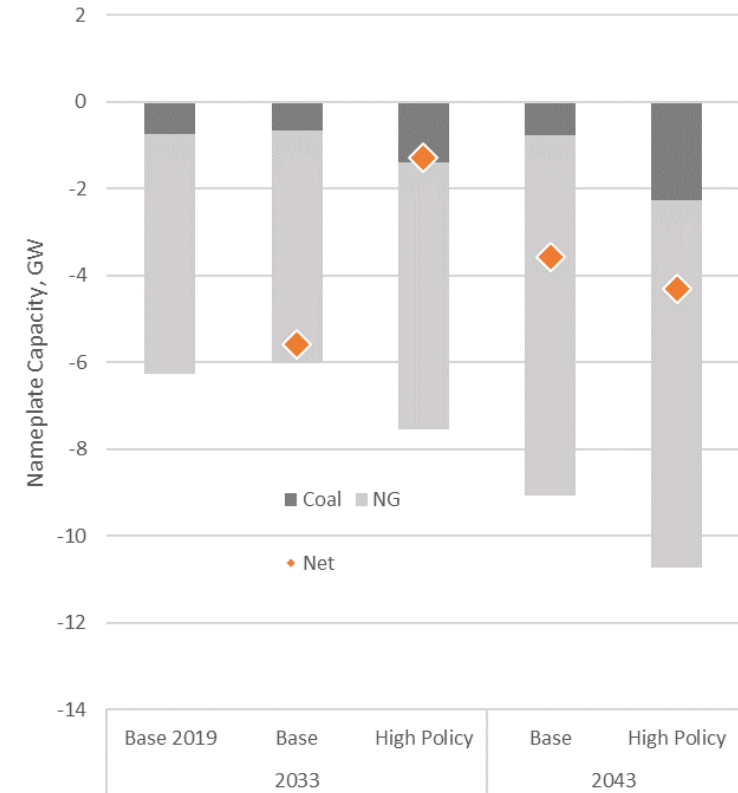
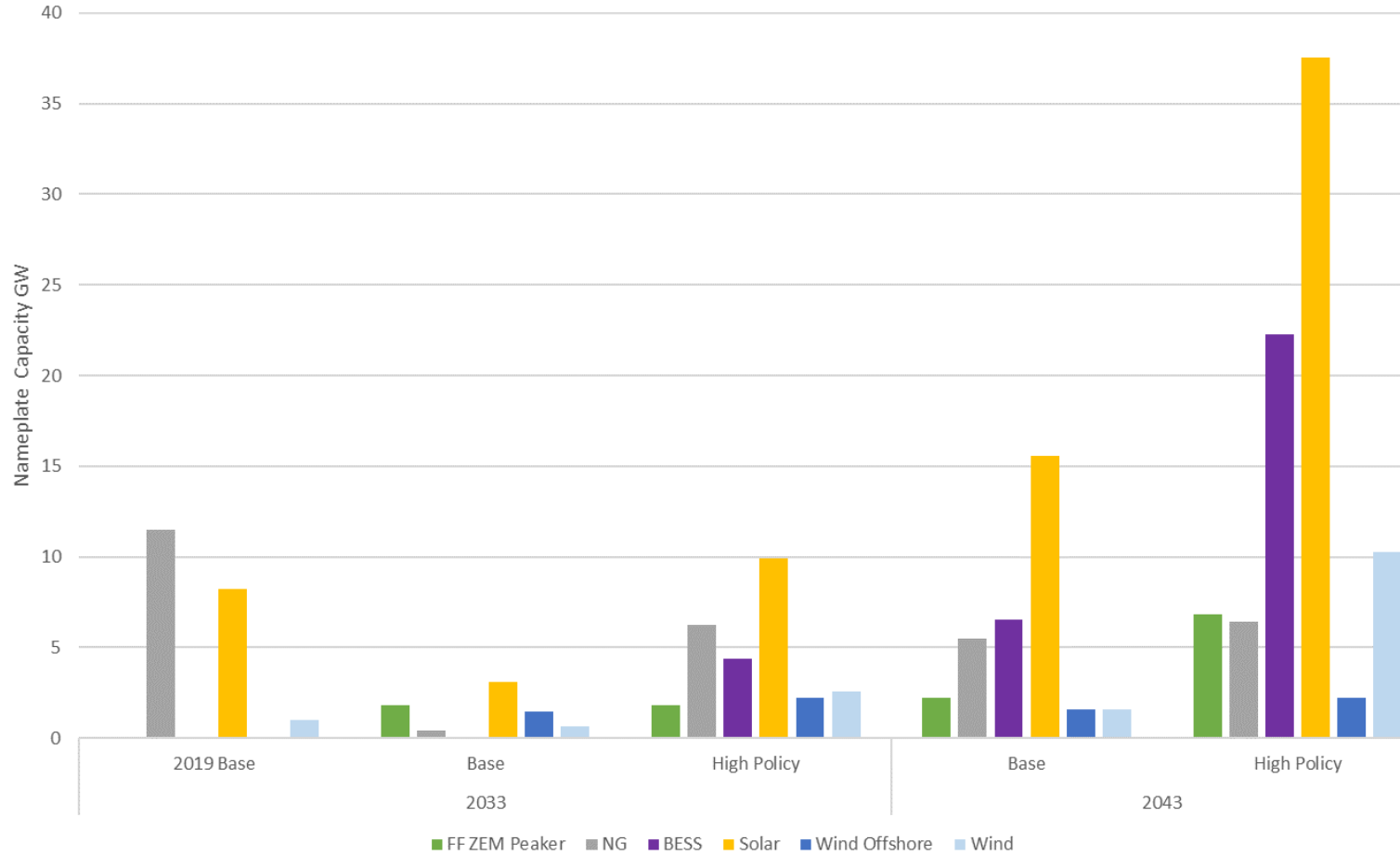
Include OR CO2 emission caps



Cumulative WECC Builds & Retirements



Cumulative PNW Builds & Retirements



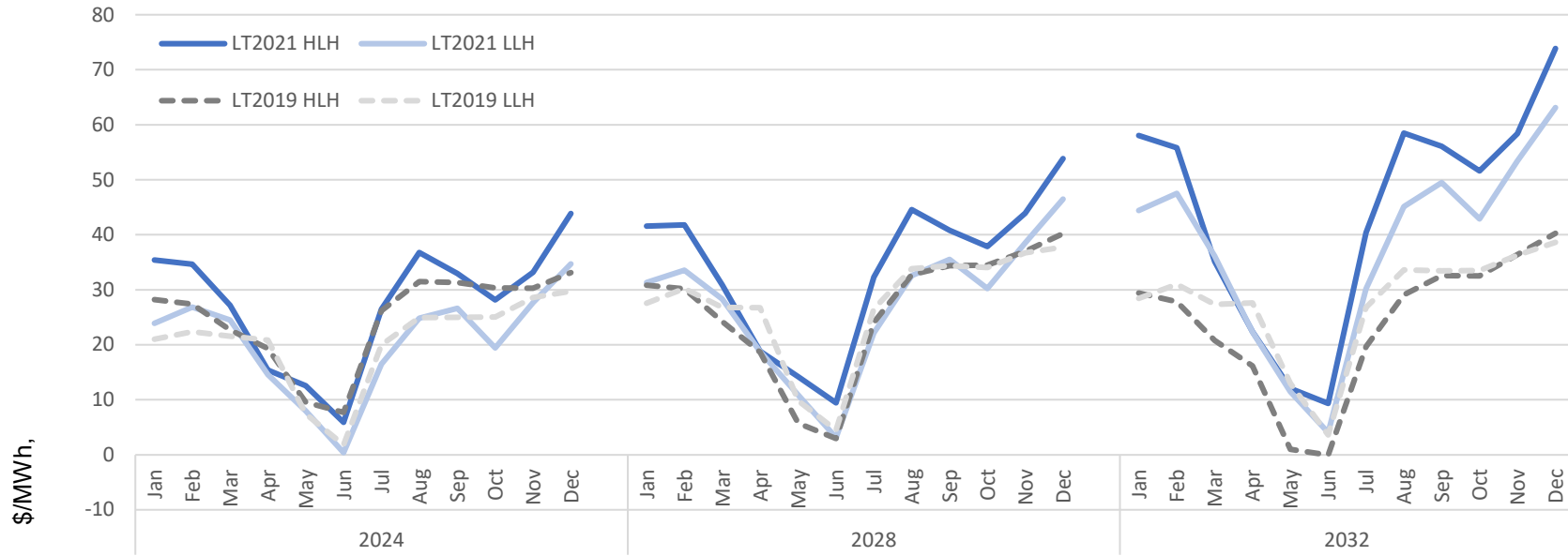
Prices

Updates, Values, Distributions, and Negative Prices



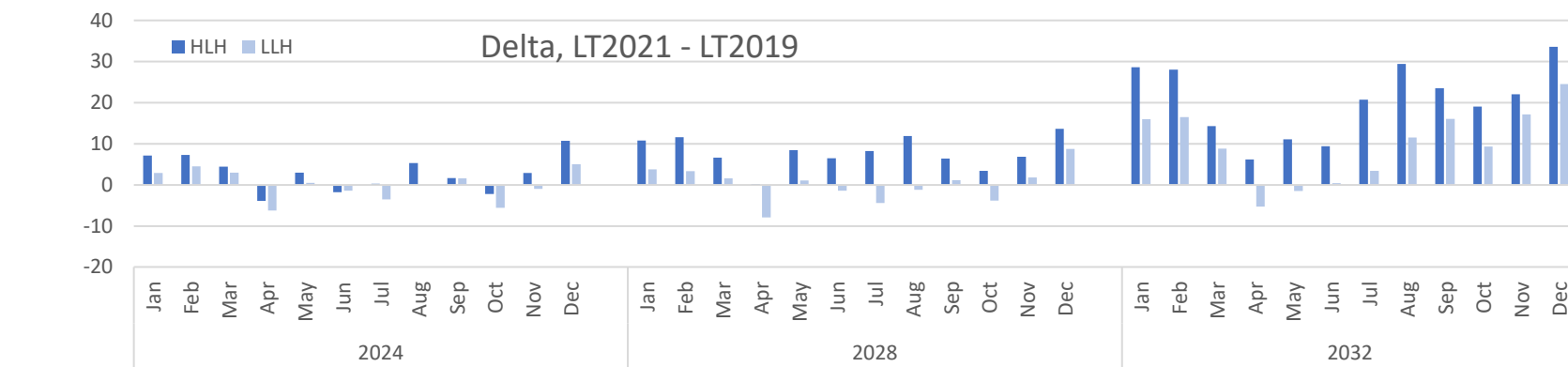
Aurora 2021 LT Base Updates since 2019 LT Base

- ↑ **Bid Adders (recalibrated since BP22 FP)**
- ↓ Gas prices
- ↓ Load forecasts
 - DG forecasts in DSW, including CA
- ↑ Elimination of carbon adders on southern intertie
- ↑ CA Carbon prices
- ↑↓ Dynamic peak credits for variable resources (ELCC proxy)
- ↓ Resource costs & options
 - Lower storage and renewable costs
 - Small amounts of offshore wind
 - Adding firm flexible zero emission resource options ~ 2030+
- ↑↓ **Policy updates**
 - **Higher / additional RPS and *now including zero CO2 emission constraints***

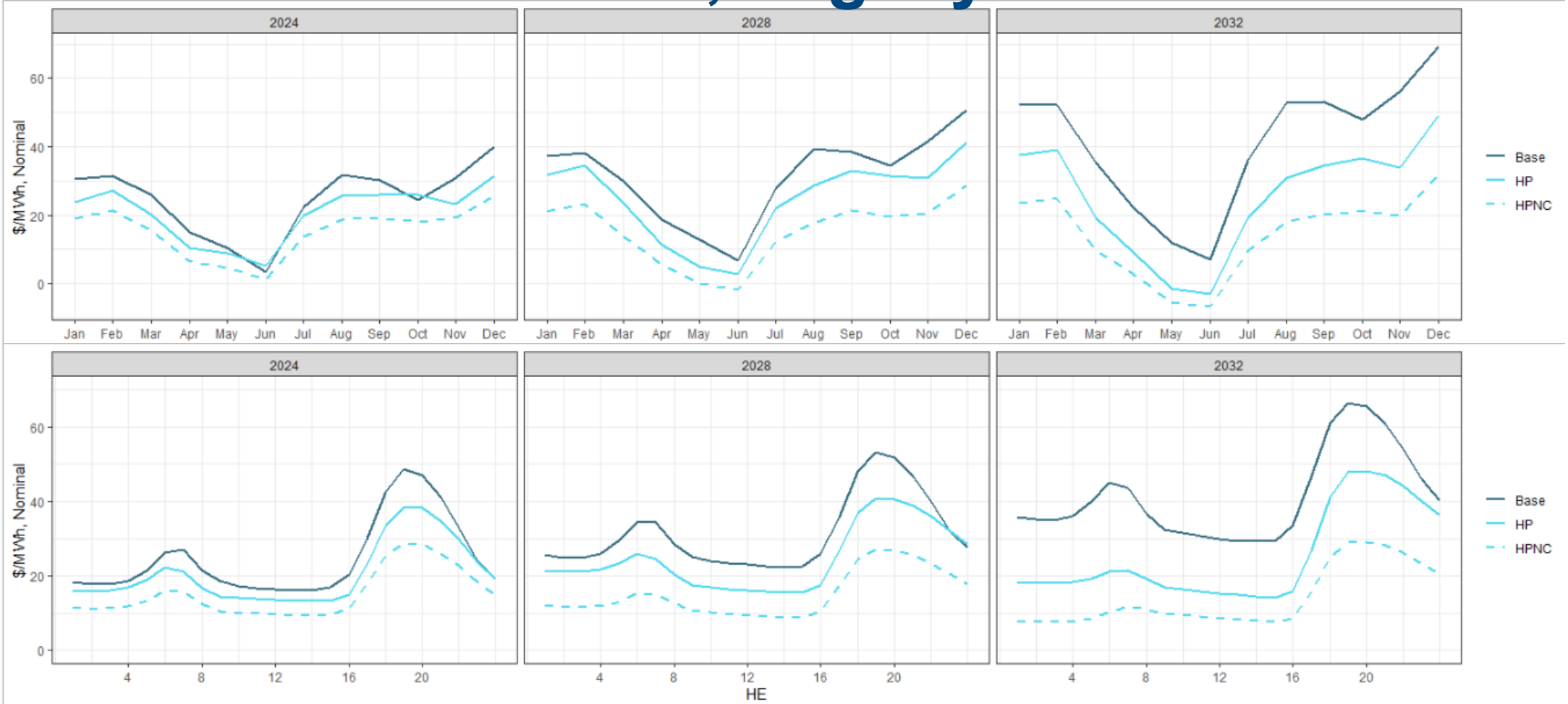


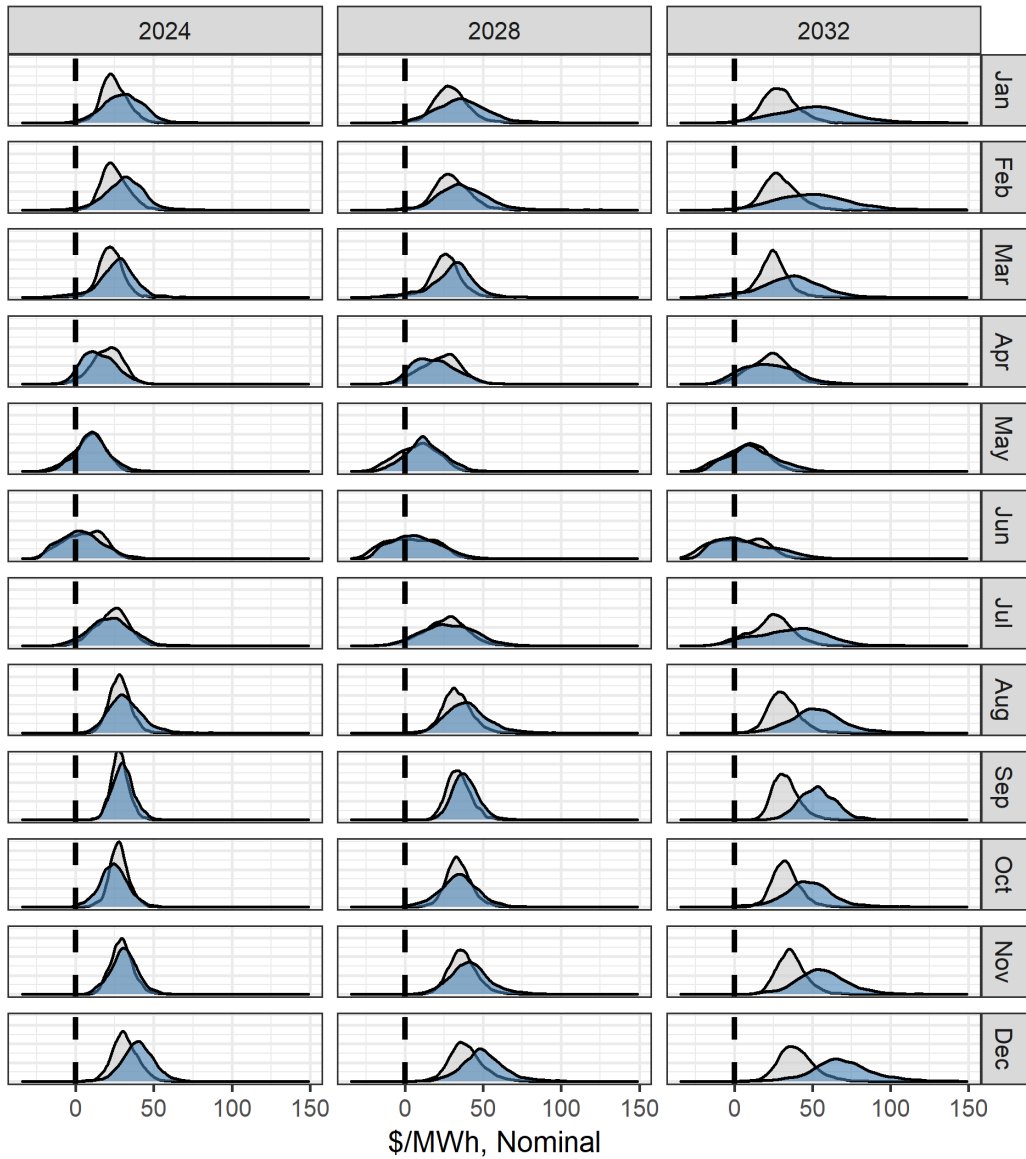
PNW Prices Diurnal Month Avg.

LT2019 Base vs LT2021 Base



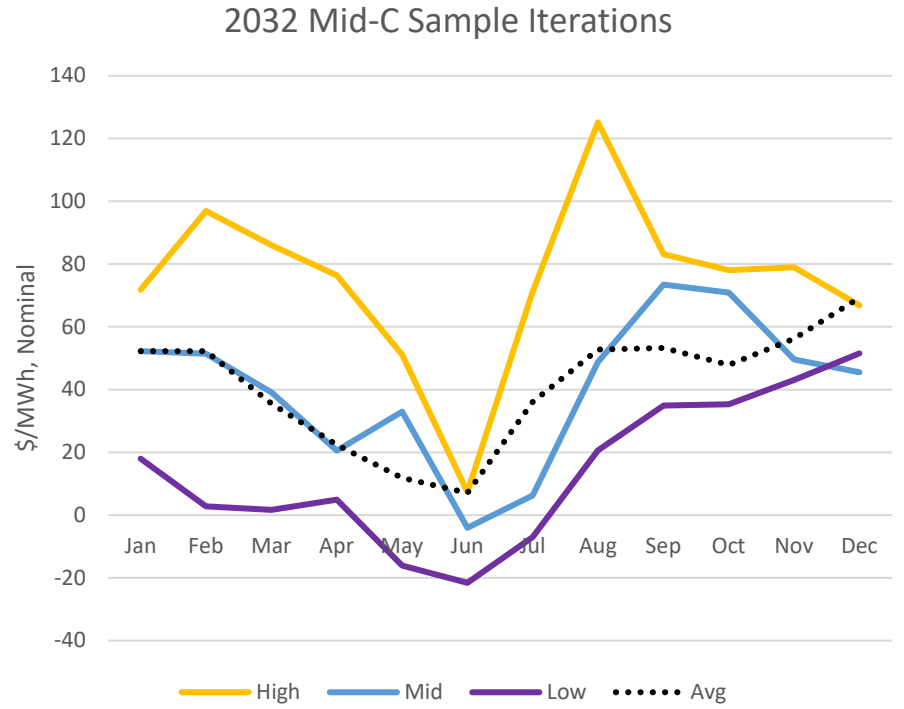
LT2021 PNW Prices, Avg. by Month and Hour

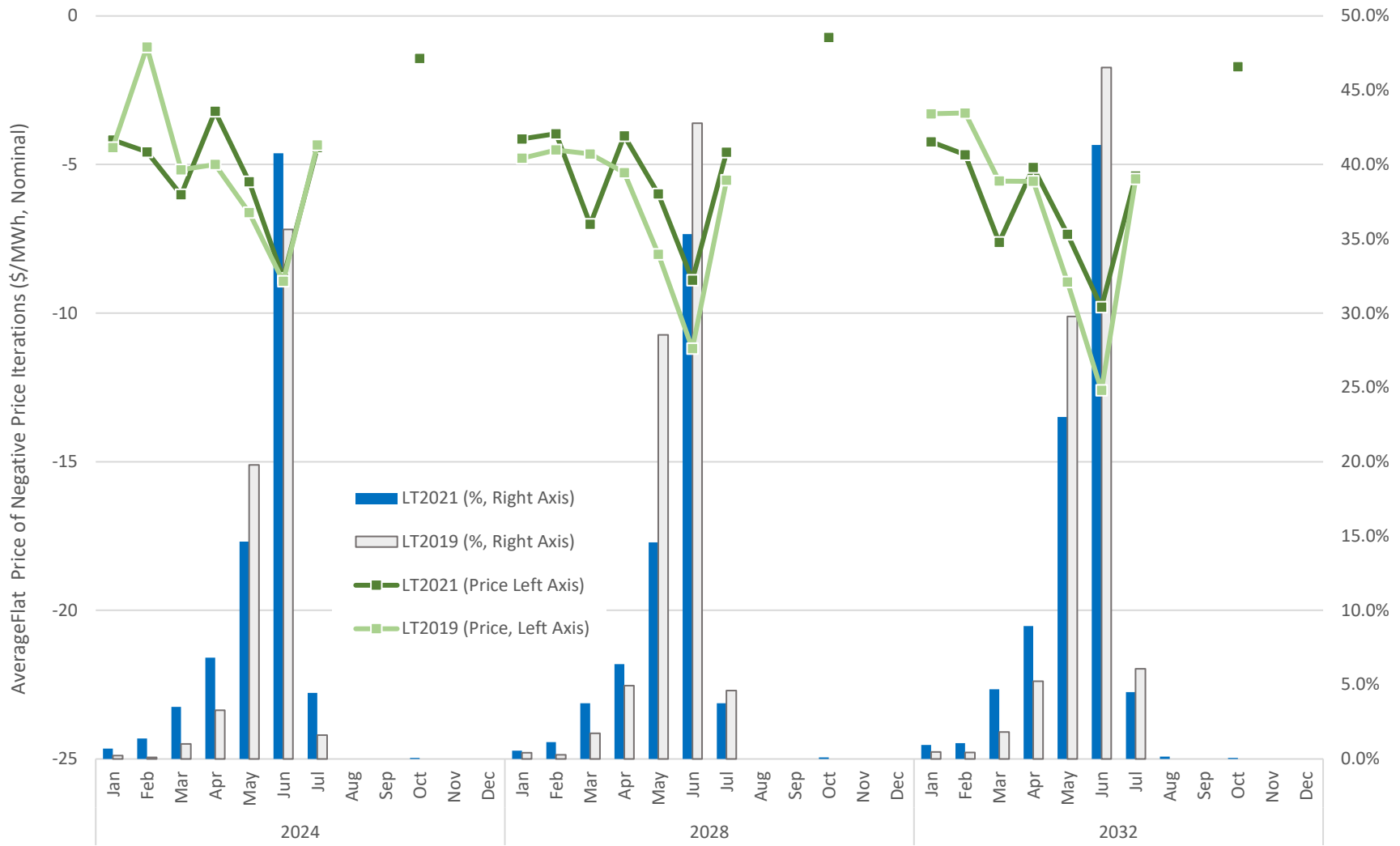




PNW Price Distributions

- Month flat avg. PNW prices, **gray is LT2019, blue is LT2021**
- More volatile over time, and price variability is more significant in tighter months (winter & summer)
- Note the difference between average of Aurora forecasts and individual iterations (futures)





Base Case Negative Price Expectations

Still seeing significant likelihood of negative prices in the spring. More modest changes since our last forecast, and over time

Market Limits



Market Limits in Aurora

- Prior to the 2018 Resource Program, market limits were set using historical liquidity assessments and SME judgment.
- 2018 changed to rely on a fundamentals based method using Aurora, primarily to capture more forward looking considerations.
- Our 2022 estimate (based on the LT2021 base build) highlighted a key shortcoming of the approach and required an update.

Fundamental Method Review

We're trying to find the difference between regional energy availability (considering **physical** load resource balance and ignoring contractual obligations) when all participants / BAs plan and build for zero market reliance*, and when all regional participants increase market reliance right up to the reliability threshold (building fewer new resources / retiring more resources than the 'no reliance' base). Keep in mind:

- Relying on the market **does not increase WECC loads**.
 - Our expectations of loads is not changing, it's a question of which resources will serve loads and whether we can serve expected load with fewer resources than a zero market reliance base.
- Relying on the market **does not require regional surplus generation**
 - Even when the region just meets reliability requirements, there's still significant room for market reliance by leveraging load and resource diversity within and among regions.

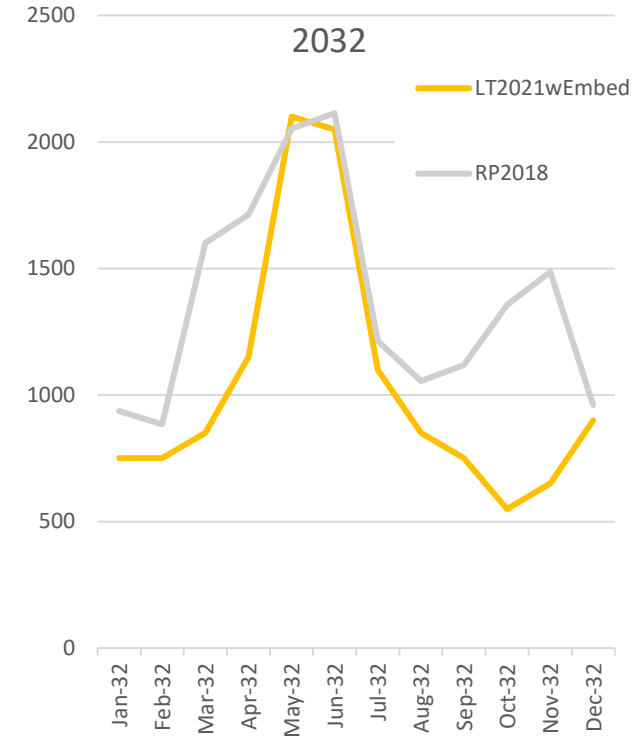
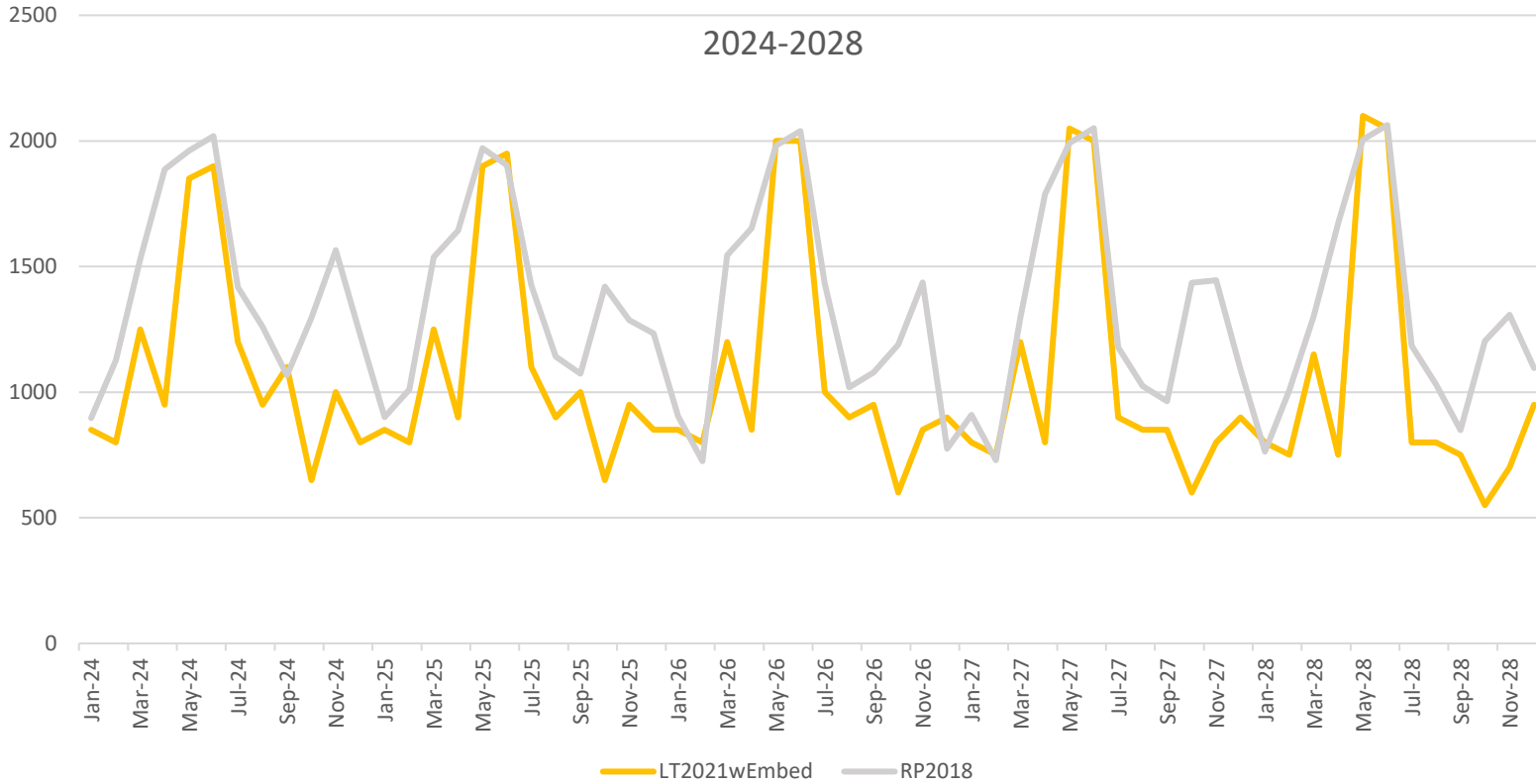
*Zero market reliance for the region means that each BA builds resources to meet 100% of their individual needs (energy, capacity, and clean policies). This produces an overbuilt system for the region.

Fundamental Method Review, cont'd

1. **Start with our base resource build and assume this reflects zero market reliance in the region.***
2. Add incremental load increases to approximate greater resource retirements / fewer resource additions associated with higher levels of regional market reliance
3. On a monthly basis, determine level at which greater market reliance causes region to exceed 5% LOLP
4. Allocate a share of the market reliance to BPA and accept this as our market reliance limit

***The LT2021 base build does not reflect zero market reliance, so we used net region imports to approximate embedded market reliance in the base and added these amounts to the market limit estimates.**

BPA Market Limit Results, Month HLH aMW



Key Limitations

- **We use the base price buildout and assume it reflects a buildout with zero regional market reliance (the LT2021 Base Aurora build clearly violates this assumption and the method required additional adjustments).**
- We assume benefits of market reliance are allocated by share of regional load, ignoring contractual obligations and potential for free riding / planning misalignments (different metrics, forecast methodologies, etc)
- Aurora is simplistic depiction of the grid (no nodal topology/AC flows) and operations—might overestimate resource capabilities / underestimate ability to better utilize existing resources
 - Single time step (~Aurora runs are most analogous to DA market) misses impacts of load / renewable forecast error
 - No ancillary services (do we need more resources or can we just run the system with more reserves?)
- Risk modeling in Aurora has room for improvement.
 - Models operate independently and rely on historical, observed fundamental variation
 - Resource outages are not stochastic (other than CGS)
 - No pipeline outages / derates (potentially overestimates reliability contributions of NG resources)

Appendix



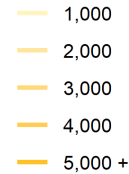
Aurora Refresher

- Aurora is a versatile **production cost model** widely used to evaluate the economics, evolution, and operation of wholesale electricity grids (utilities, regulators, system operators, planning entities, consultants, and investment firms across the globe)
- Production cost models solve for least cost method of meeting load, given resource and transmission constraints (resource limits, line capability, wheeling costs, and losses), and assume the marginal cost (cost of the next incremental MW) of producing and delivering energy is a good proxy for energy prices.
- **We calibrate the model based on recent DA prices (2014-2019), but we do not explicitly account for the following:**
 - Market design differentiation (**NO**: forward curves / firm contracts / DA - RT markets & forecast error, source & sink, local commitment considerations), **all of the WECC is effectively modeled as a single ISO** (centrally optimized and dispatched)
 - Behavioral components of power markets (in reality, bids may differ from actual marginal cost)
 - AC flows / nodal prices, and transmission system is fixed over time (Aurora has the capability, not yet implemented)
 - Ancillary services (again, Aurora has the capability, not yet implemented)
 - No thermal resource duct firing / peak heat rates / unit dependency
- Aurora is a deterministic model, **we produce a distribution of price forecasts** by using a Monte Carlo technique that draws from **historical variation of: loads, hydro generation, gas prices, transmission capability, wind generation, and CGS availability**. There are 1600 iterations, 20 iterations x 80-water years
- We use a 46 zone topography of the Western Interconnection that is mostly aligned with BAs (see next slide), and solve for *hourly* prices

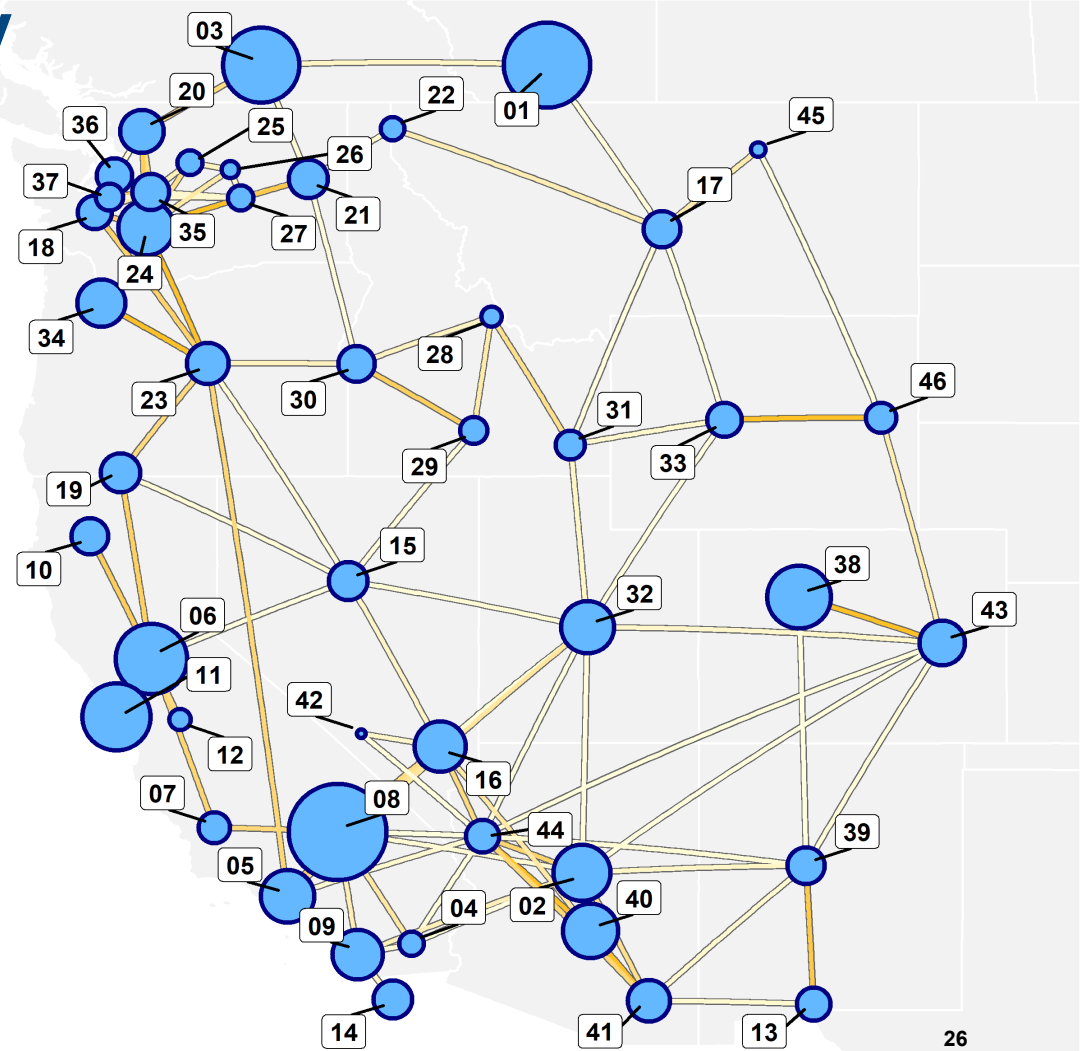
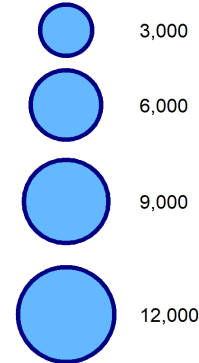
Aurora Topology

Zone Short Names	
01	Alberta
02	APS
03	BC
04	IID
05	LADWP
06	PG&E North
07	PG&E ZP26
08	SCE
09	SDG&E
10	BANC
11	PG&E Bay Area
12	TIDC
13	EPE
14	Baja
15	NV North
16	NV South
17	NW MT
18	Olympia
19	PAC W
20	Puget North
21	Avista
22	BPA IDMT
23	BPA OR
24	BPA WA
25	Chelan
26	Douglas
27	Grant
28	ID Power FE
29	ID Power MV
30	ID Power TV
31	PAC E ID
32	PAC E UT
33	PAC E WY
34	Portland GE
35	Puget East
36	Seattle CL
37	Tacoma
38	PS CO
39	PS NM
40	Salt River
41	Tuscon
42	VEA
43	WAPA CO
44	WAPA LwCO
45	WAPA UprMO
46	WAPA WY

Line Rating (MW)



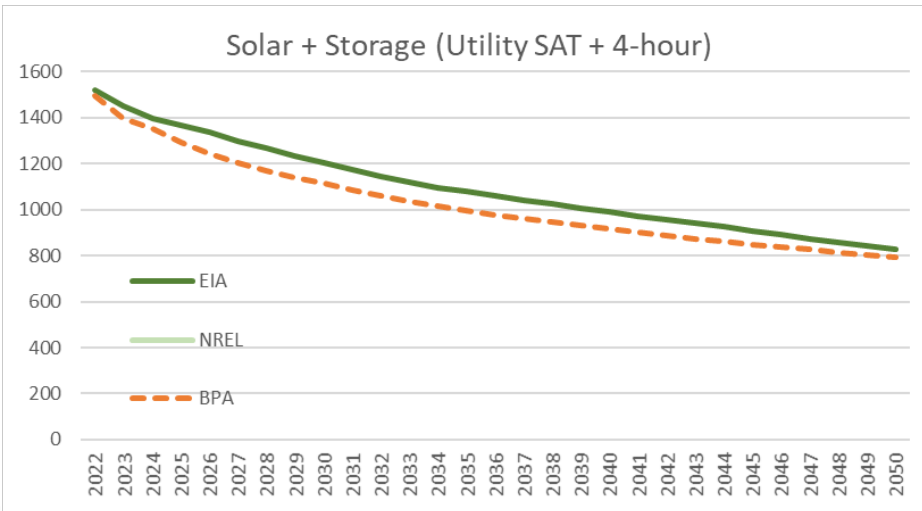
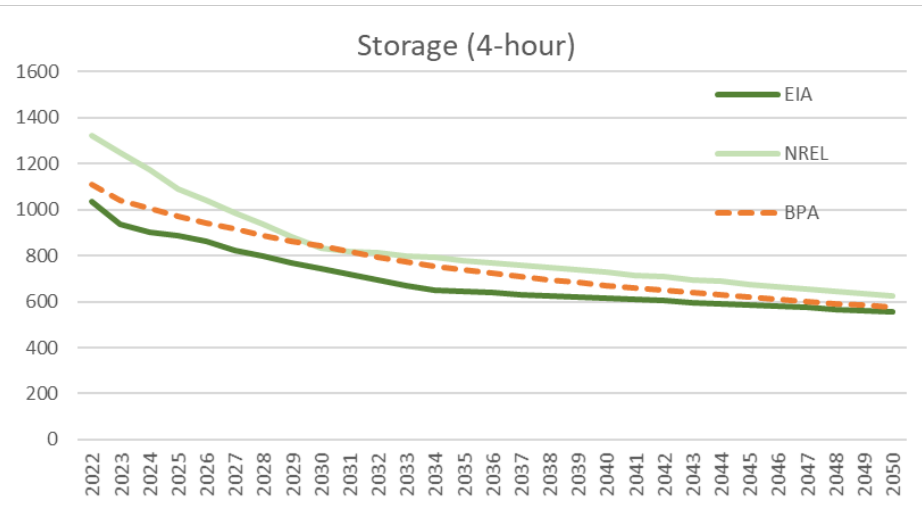
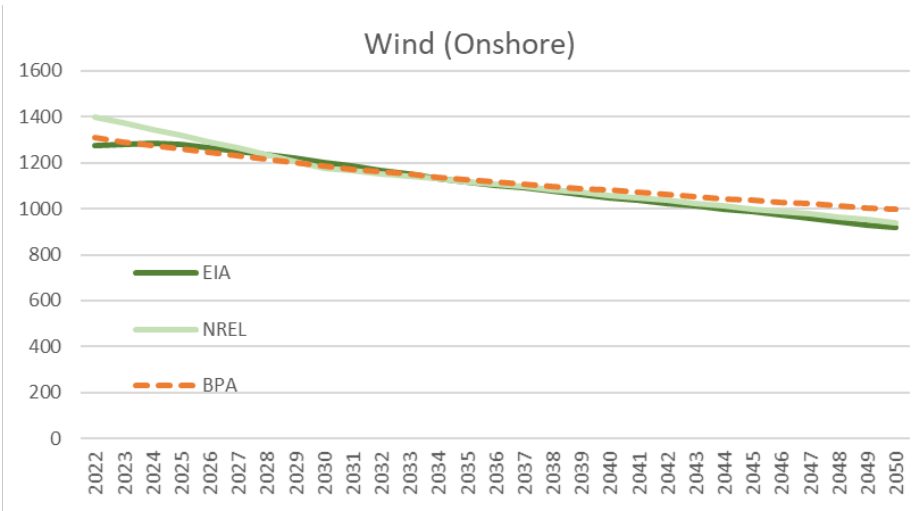
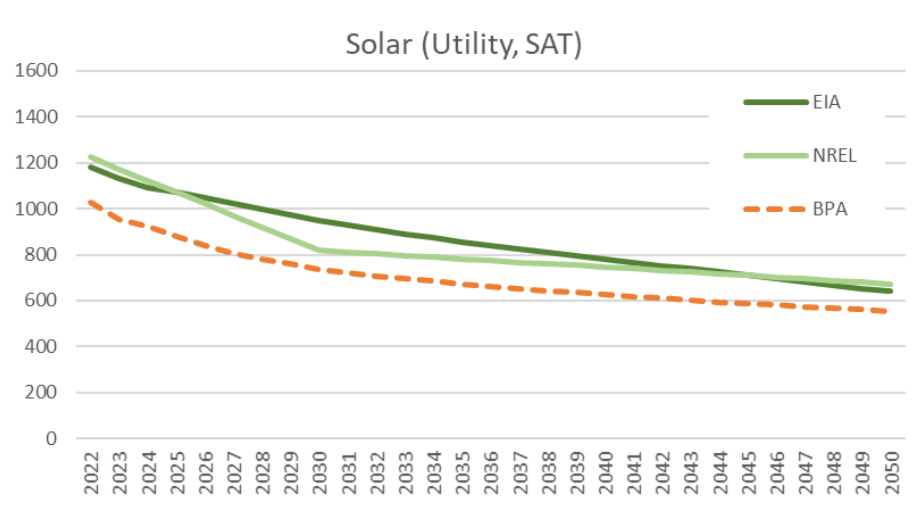
Zone Load (aMW)



Aurora and Market Design (EIM / RA)

- Aurora does not explicitly account for differences in market structure (bilateral vs ISO or different time horizons). It simulates the interconnect as if the WECC were centrally dispatched in a single ISO, and we assume that prices will tend to converge on the marginal cost of generating & delivering electricity.
- Aurora has capabilities to model components of the EIM, but these tend to be computationally prohibitive and incompatible with existing models and methodologies. For example:
 - Sub-hourly (incompatible with risk and rate case models, requires significant investment)
 - Nodal topography (Locational Marginal Prices—LMP, including congestion, this change requires significant investment)
 - Can use commitment logic to lock in DA commitment, and add deviations load and renewable resources + reliability commitments to better approximate RT – DA dynamics
- Alternatively, attempting to modify Aurora to depict price differences resulting from the current bilateral structure of NW markets would be highly speculative (we could adjust wheeling adders... but by how much?)
- Aurora assumes regions will meet reliability targets in a coordinated, efficient manner. Effectively, the base assumption is that RA efforts are successful and well-designed throughout the interconnection
- **Ultimately, we are not making any adjustments to account for possible differences resulting from EIM / RA participation**

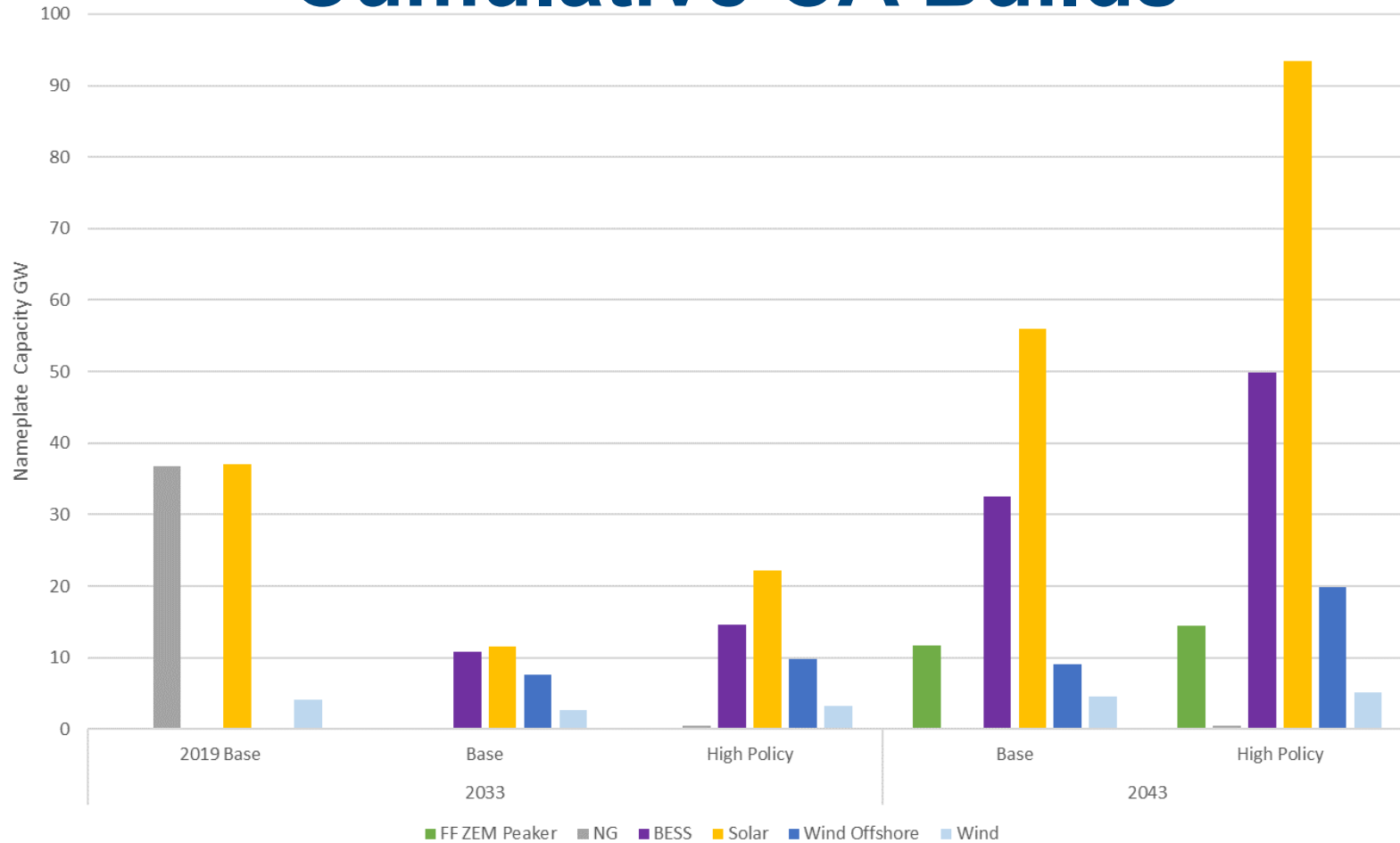
Overnight Capital Costs, 2019 \$ / kW



Major Price/Build Uncertainties

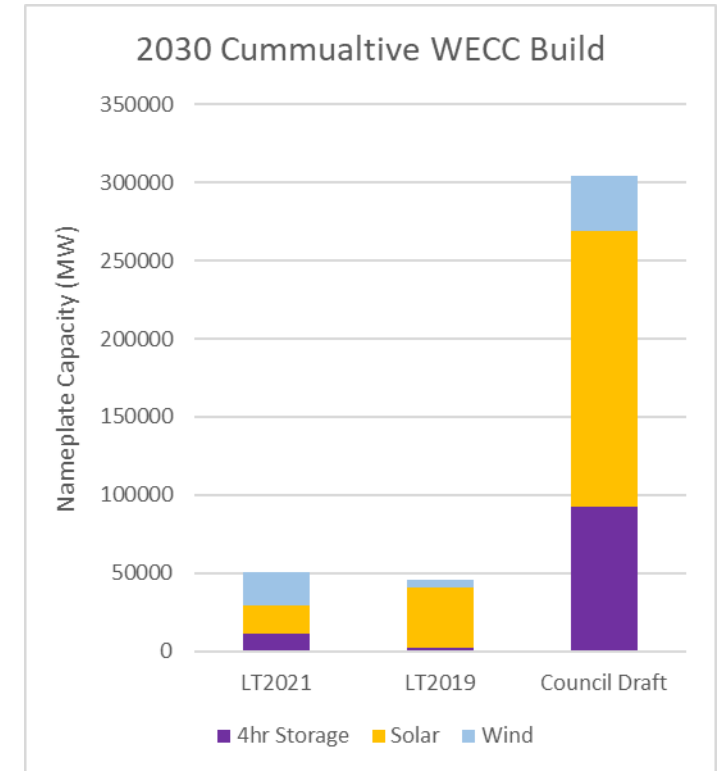
- Global drivers
 - Events in Ukraine could accelerate reduction of fossil fuel reliance
 - COVID 19 economic/supply chain impacts: recent trends in rapidly declining costs of renewable and storage resources could halt or even reverse. Further load impacts?
- Accelerated decarbonization (mixed impacts, mostly downward pressure)
 - More prevalent carbon prices included in energy price
 - Likely increasing solar build, depressing afternoon prices and increasing ramping needs / evening peak prices
 - Could combine with additional rooftop solar installations across WECC
- Additional thermal resource retirement or lower than expected new additions (upward pressure), more scarcity pricing
- Growth of storage from lower installed costs / greater policy mandates (storage resources moderate impacts from renewables, can reduce renewable overbuild, and reduce peaking resource needs)
- Higher rates of electrification (including EVs)
 - Personal vehicle charging at home exacerbates evening ramp
 - Commercial charging in afternoon relieves downward mid-day price pressure
- Potential changes in climate
- *Risk models artificially constrain risk through independent sampling of all variables, and are limited to recent historical patterns*
- Simplistic resource outage modeling, and effectively no gas pipeline outages/derates modeled

Cumulative CA Builds



Comparing to the Council's Draft Base

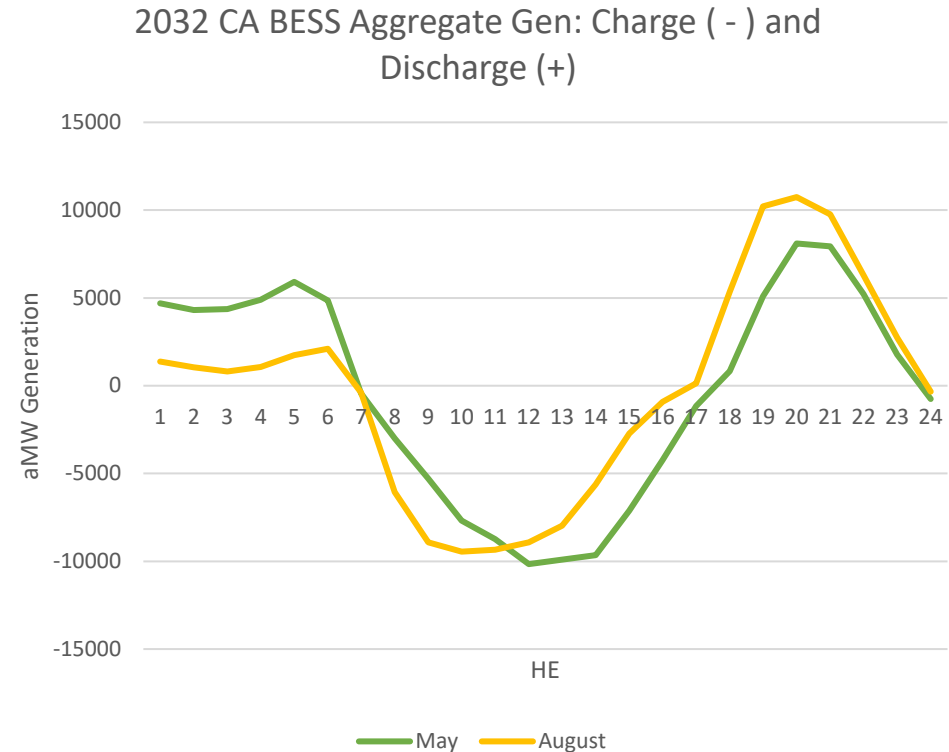
- The base cases reflect fundamentally different realities and expectations
- High level: **we model current policy as fixed and allow the system to develop based primarily on economics & recent observed behavior, while the council leans primarily on policy intent and desired behavior under a climate change future**
- Our model also contains:
 - Lower PNW and CA loads (not using CA high electrification or climate change loads in our base)
 - Allowing for firm flexible zero emission resource options
 - Far fewer restrictions on new gas resources (more consistent with current policy and practices)
 - RPS and zero emission resources are tied to geographic area of the policy
 - Consideration of energy revenue when deciding on new resource additions
 - Higher likelihood of negative prices



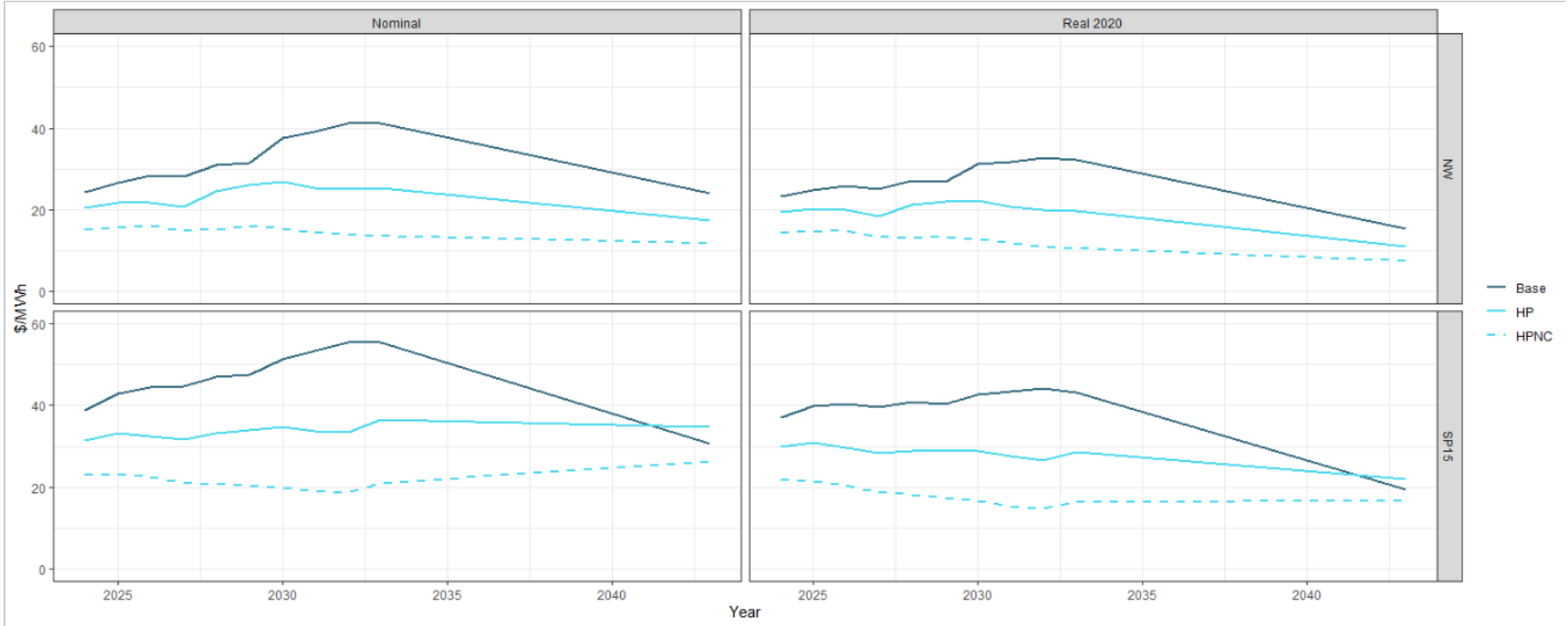
Aurora 2021 LT Base Updates: Commitment Optimization

Incorporated unit commitment optimization

- Holding everything else constant, new logic has significant downward price pressure—**more than just improving storage resource behavior, all commitment units are used more effectively**
- **Optimized unit commitment resulted in substantial reduction in buildout** (~40%, representing significant gains from improved commitment and coordination?)
- Combination of reduced buildout and recalibrated bid adders resulted in modest overall price changes, on average

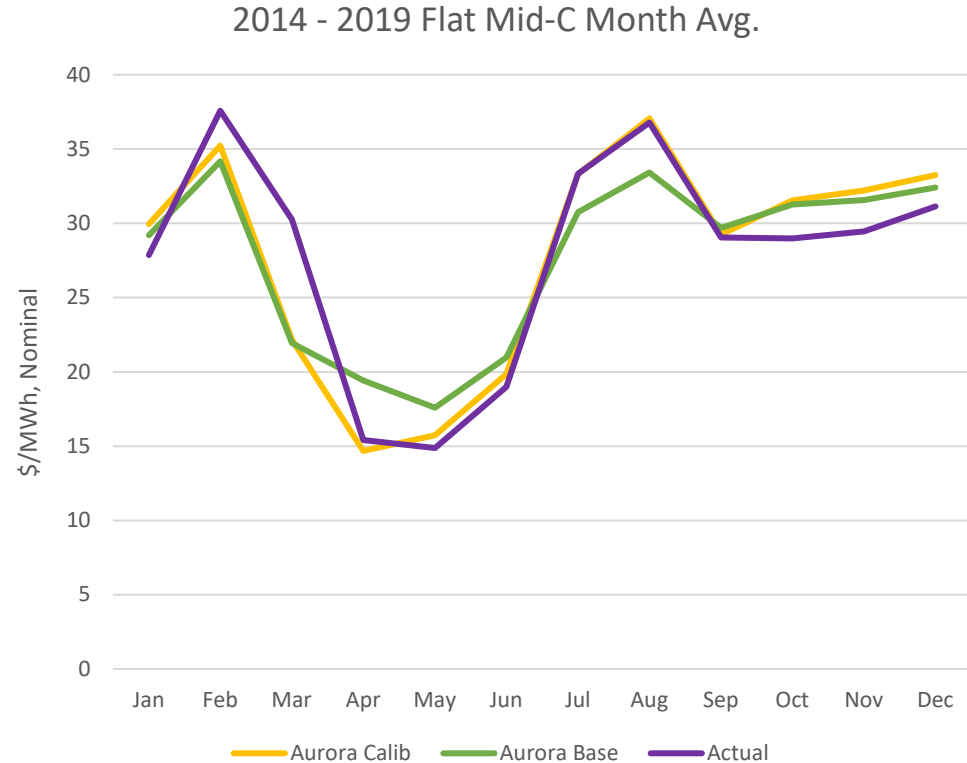


LT2021 Annual Avg. Prices



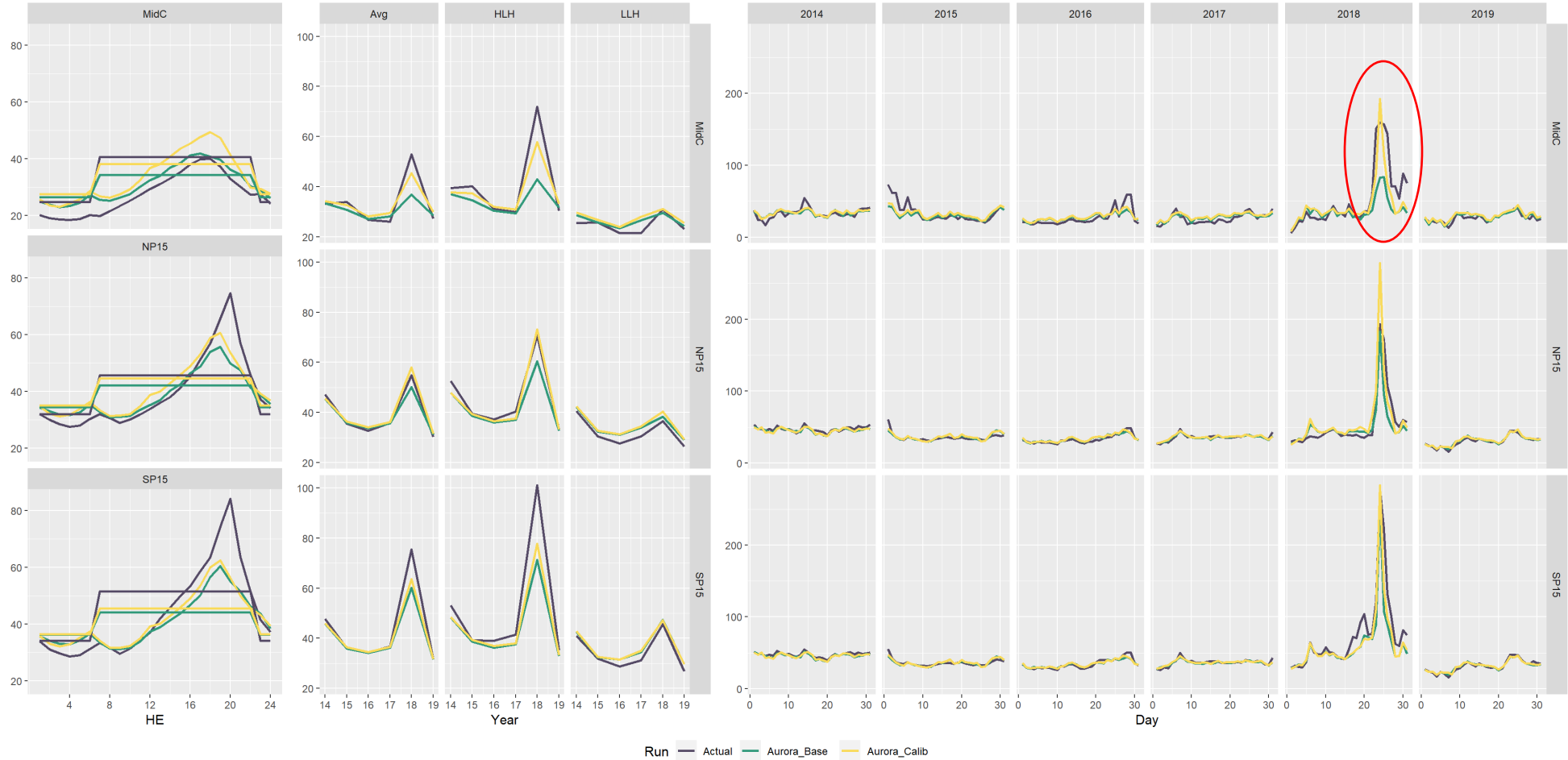
Aurora Calibration 2014-2019

- There are two main reasons Aurora price forecasts are wrong:
 - 1) Get the fundamentals wrong
 - 2) Get the relationship between fundamentals and prices wrong (not capturing important details of how markets and the grid work / behavioral effects)
- Benchmarking (running Aurora with actual fundamentals and comparing results to actual prices) allows us to isolate and address the 2nd problem through calibrating thermal resource bid behavior

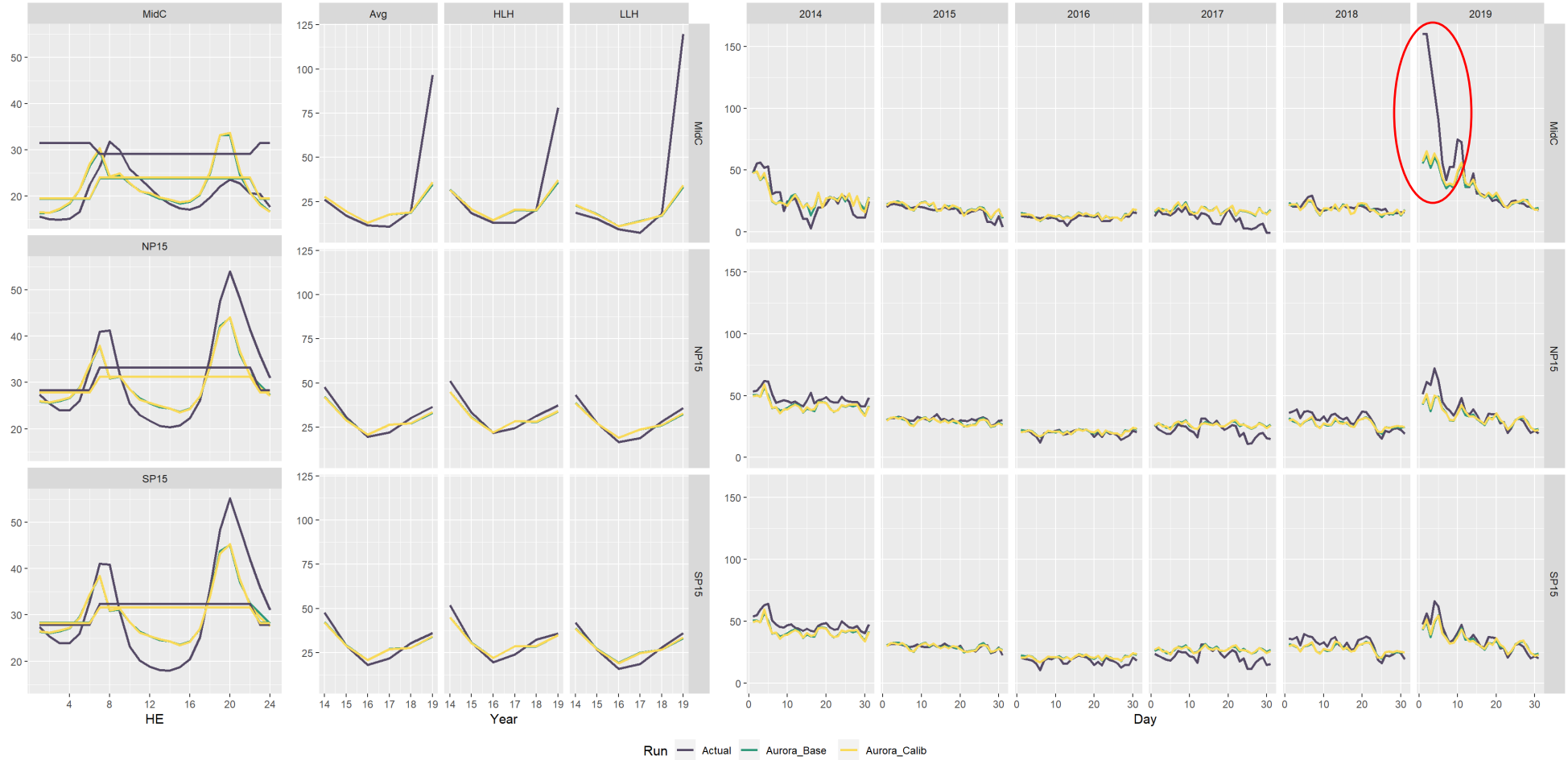


‘Fundamentals’= load, hydro generation, gas prices, transmission capability, and renewable generation

July Calibration, 2014-2019



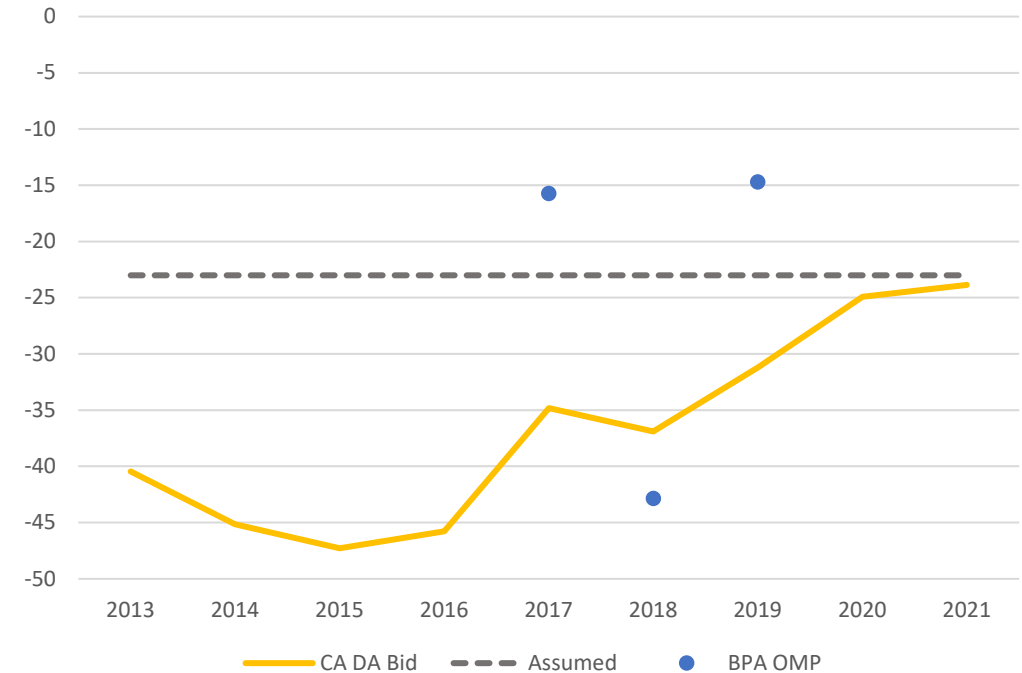
March Calibration



Negative Prices, Approach and Observations

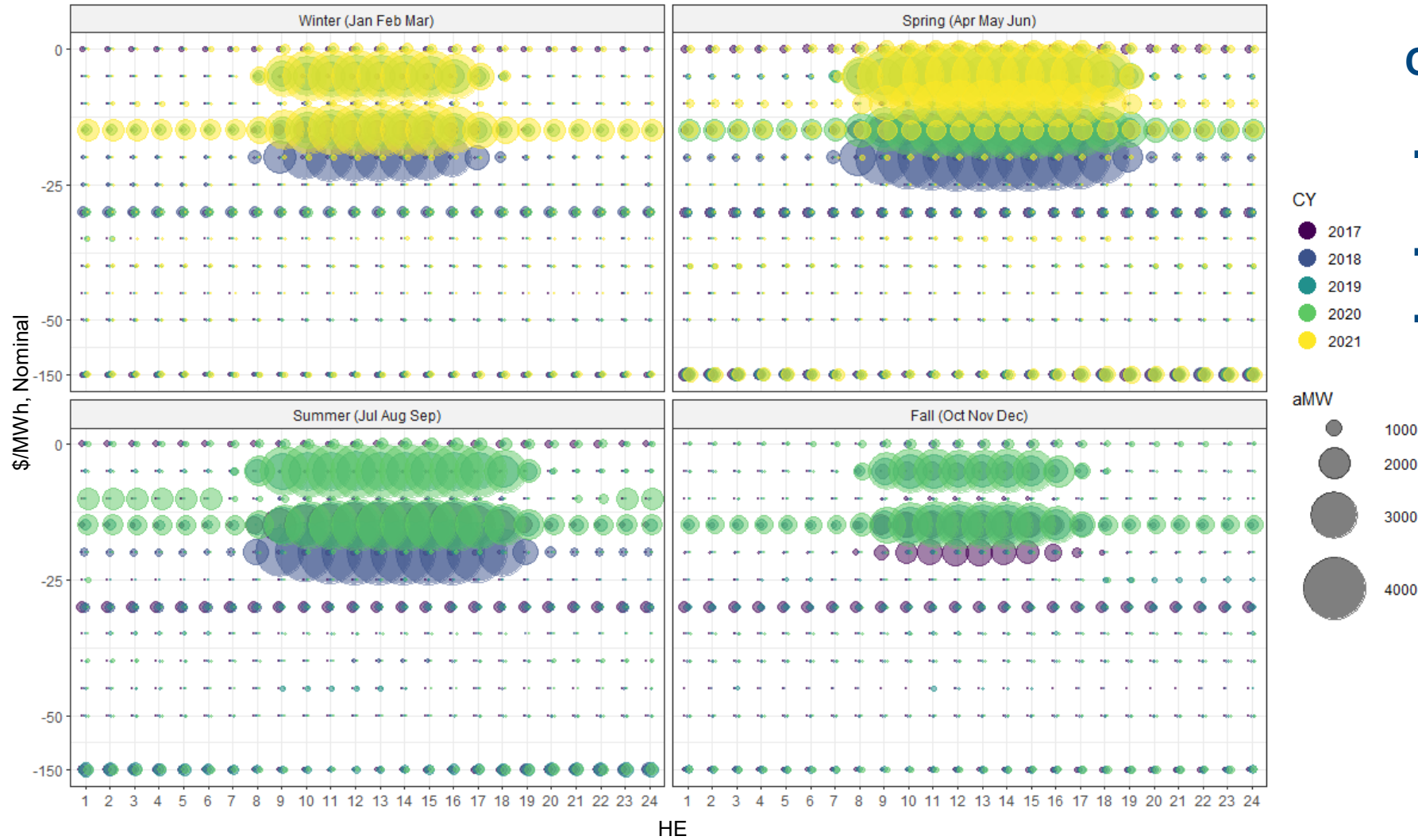
- Main drivers: policy. Incentives and requirements introduce costs to curtailing renewable resources
 - Forgone REC's / PTC's / PPA revenue / Potentially having to build additional resources
 - 'replacement cost' of renewable energy
- Generally, consultants and other production cost modelers tend *not* to include negative prices
- **We model all renewables bidding at about negative \$23/MWh**
- We include mechanisms to reflect maximum hydro spill up to latest TDG limits and set BPA BA wind to curtail at \$0/MWh, approximating OMP effects

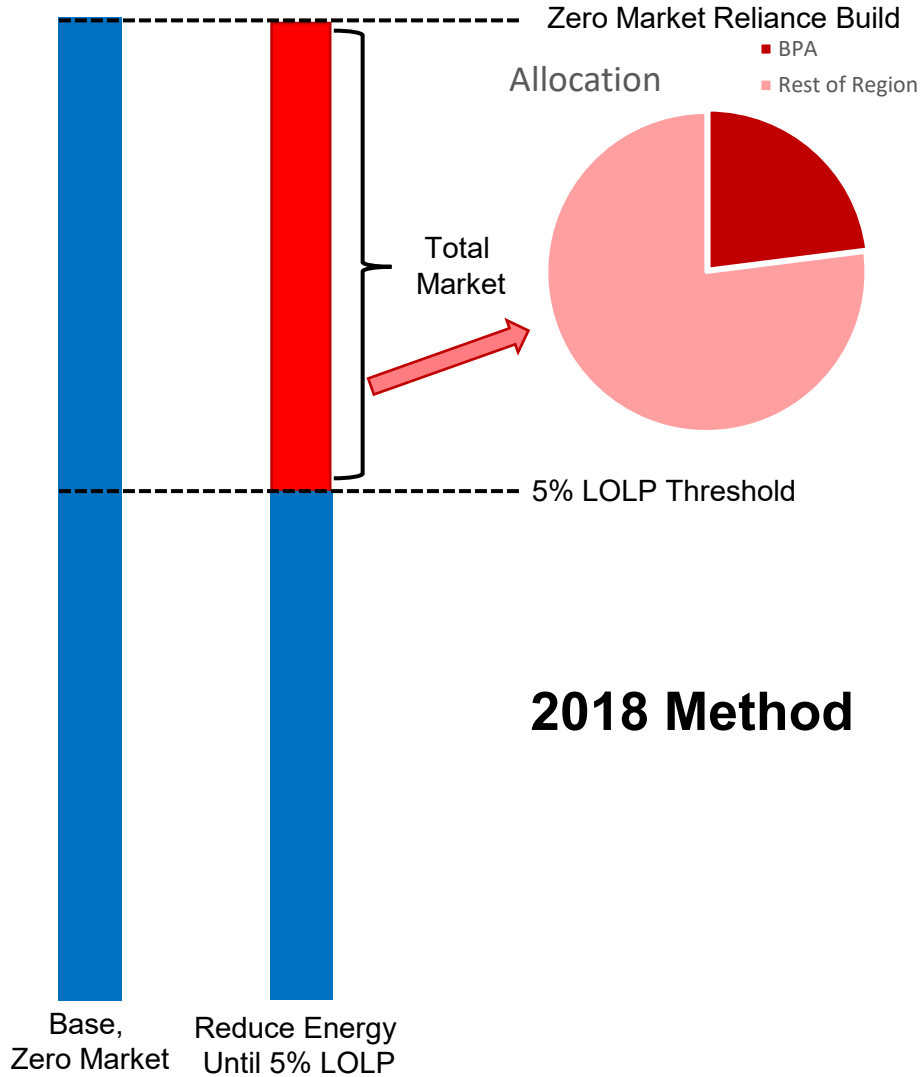
Negative Prices, Observed and Assumed



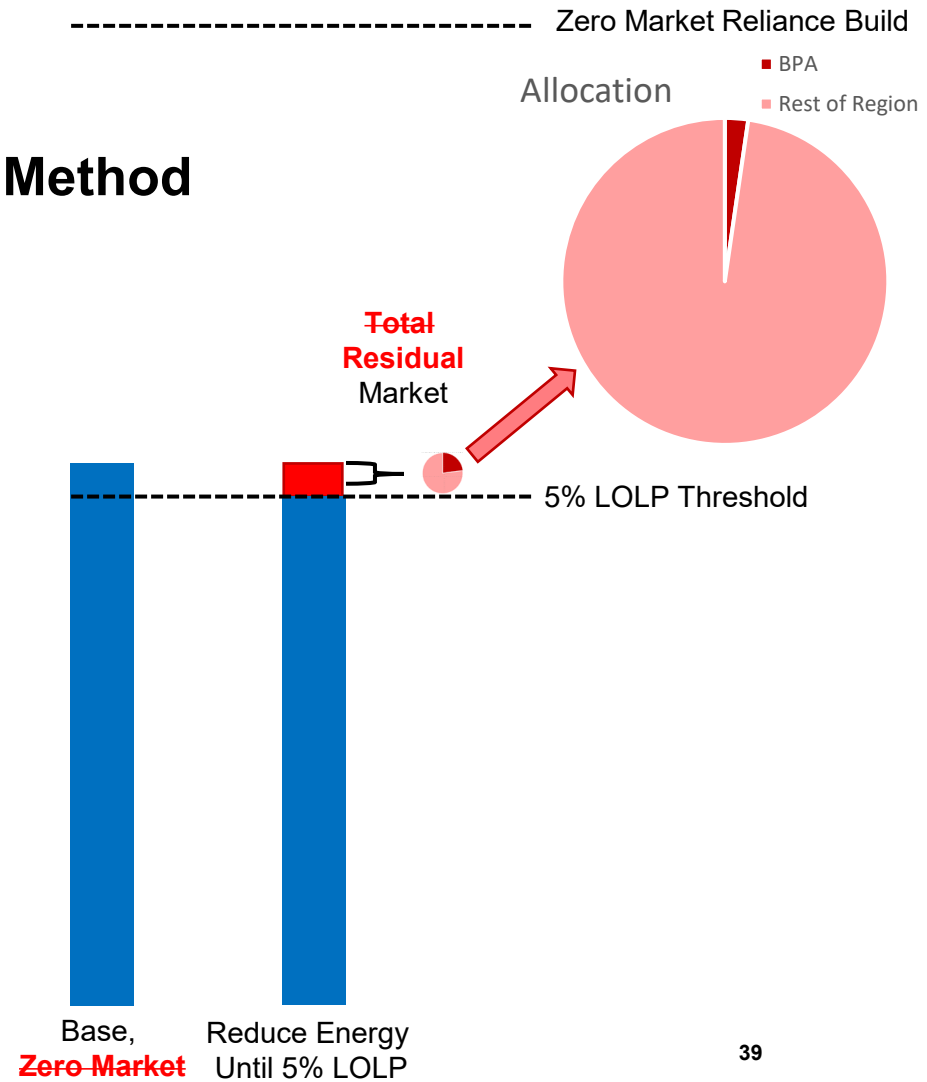
CAISO DA Bids

- Quantities are increasing over time
- Concentrated in mid-day
- Levels have been getting less negative





2022 Method



Images are illustrative and not drawn to scale

An Updated Option

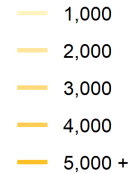
- The issue with our updated market reliance limit analysis is that the base starts at very high levels of embedded market reliance
- While we cannot estimate the full levels of this embedded reliance, we can look at net regional imports into the PNW as a conservative approximation
- **The update:**
 - Measures regional net imports while the system is tight but still adequate (values generally range between 1,000 aMW to 5,000 aMW),
 - Significantly discounts the regional net imports by around 50%*, acknowledging risks of relying on external energy
 - Allocates a share of the risk-adjusted, regional net imports to BPA, proportionally
 - Adds this to the 2021 BPA market limit estimate, so the total now conservatively accounts for embedded market reliance (yellow line, following summary slide)

*The discount varies, ranging up to 90% in July and August

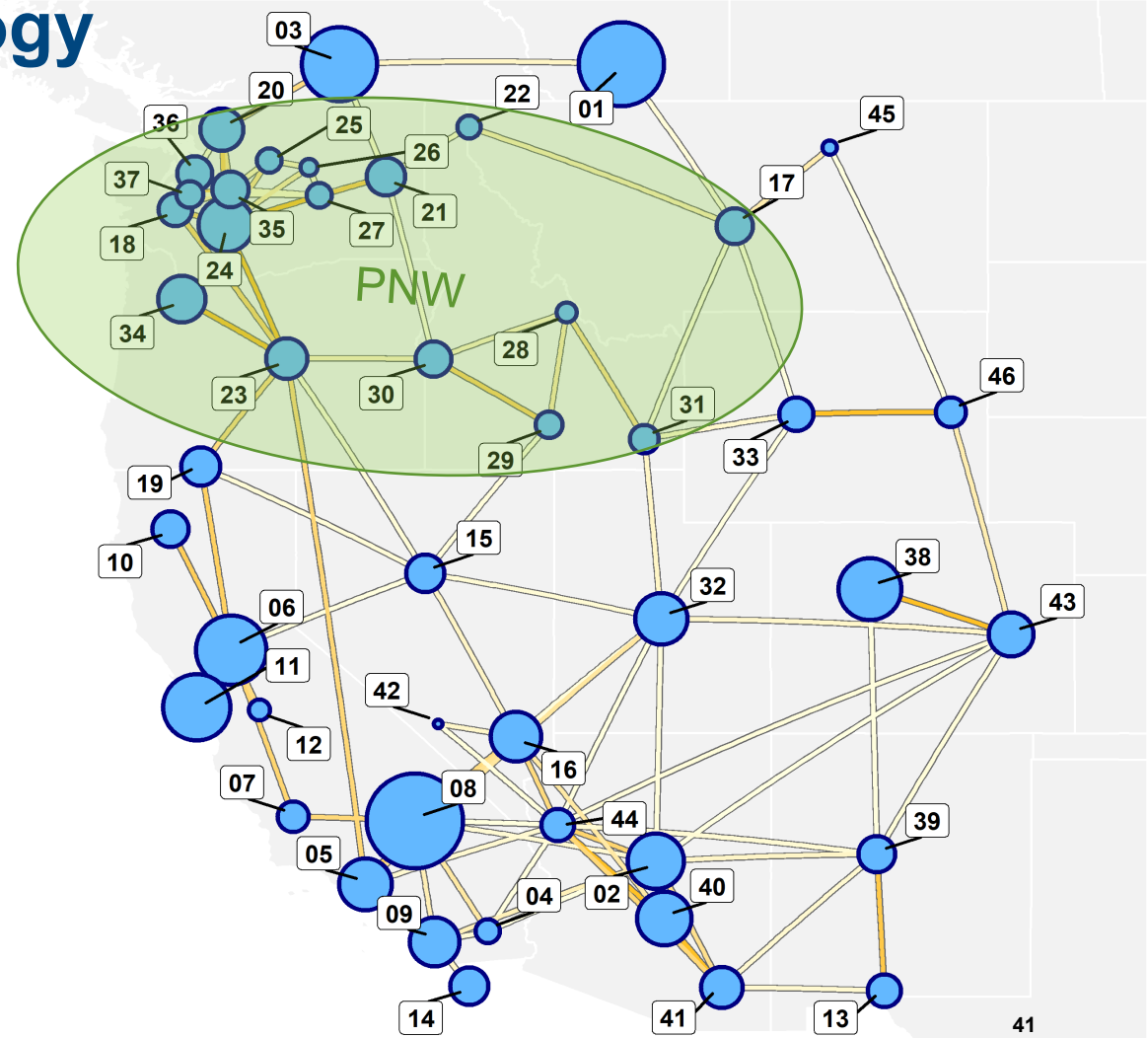
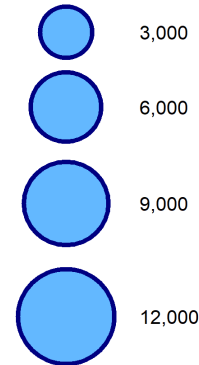
Aurora Topology

Zone Short Names	
01	Alberta
02	APS
03	BC
04	IID
05	LADWP
06	PG&E North
07	PG&E ZP26
08	SCE
09	SDG&E
10	BANC
11	PG&E Bay Area
12	TIDC
13	EPE
14	Baja
15	NV North
16	NV South
17	NW MT
18	Olympia
19	PAC W
20	Puget North
21	Avista
22	BPA IDMT
23	BPA OR
24	BPA WA
25	Chelan
26	Douglas
27	Grant
28	ID Power FE
29	ID Power MV
30	ID Power TV
31	PAC E ID
32	PAC E UT
33	PAC E WY
34	Portland GE
35	Puget East
36	Seattle CL
37	Tacoma
38	PS CO
39	PS NM
40	Salt River
41	Tuscon
42	VEA
43	WAPA CO
44	WAPA LwCO
45	WAPA UprMO
46	WAPA WY

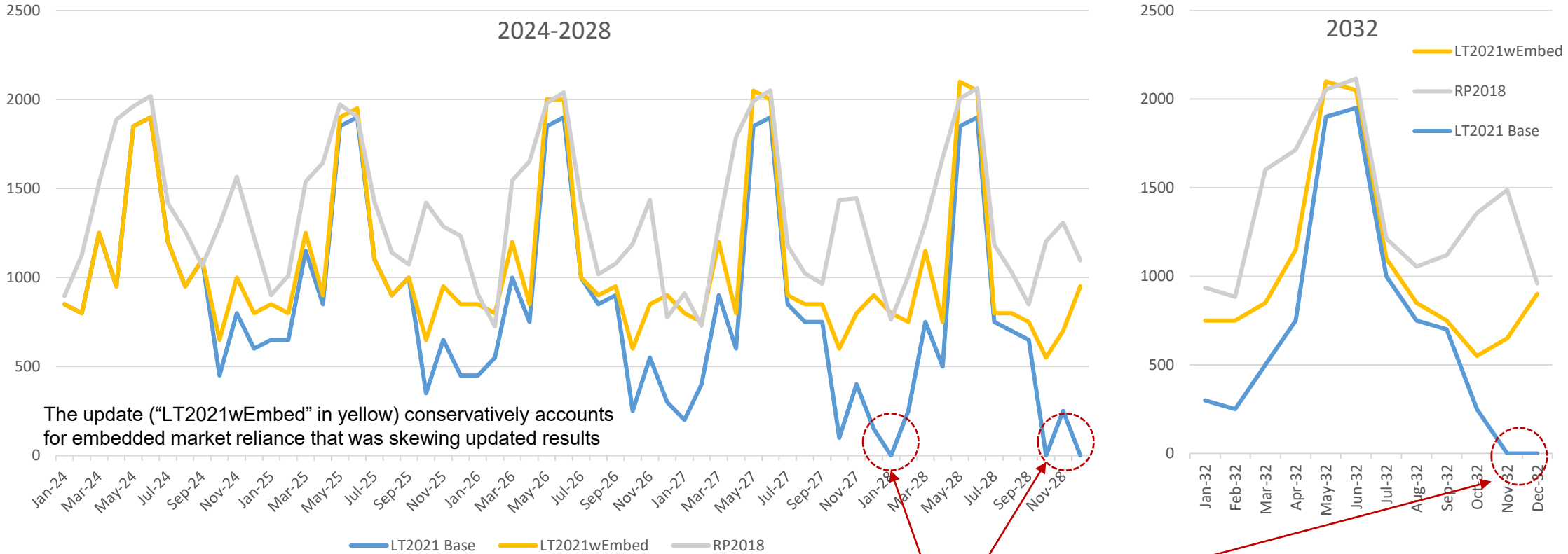
Line Rating (MW)



Zone Load (aMW)



BPA Market Limit Results, Month HLH aMW



The 2022 update results in estimates of zero market depth for BPA because the base includes high levels of region market reliance, rather than reflecting a reasonable and consistent starting point of no region market reliance. This is a substantial change from the 2018 study.

PNW Outage Shares by hour, month, and year

HE\Month	2024												2028												2032												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Month Total:	238	84	32	18	3	0	117	69	80	63	158	126	29	53	19	18	39	7	432	96	65	28	83	164	389	471	35	88	8	0	100	94	44	244	15	142	
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	6%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	1%	0%	6%	6%	0%	0%	0%	0%	0%	2%	1%	1%	0%	0%	5%	6%	0%	0%	0%	0%	2%	4%	0%	0%	1%	0%	6%	8%	0%	0%	0%	0%	0%	0%	0%	0%	2%
7	5%	0%	38%	22%	33%	0%	0%	0%	0%	16%	6%	1%	3%	0%	26%	39%	0%	0%	0%	0%	6%	11%	7%	0%	3%	5%	23%	23%	0%	0%	0%	0%	2%	13%	0%	4%	
8	8%	8%	9%	11%	33%	0%	0%	0%	0%	6%	4%	4%	3%	11%	0%	22%	0%	0%	1%	0%	3%	11%	7%	4%	7%	11%	9%	16%	0%	0%	0%	1%	2%	5%	0%	6%	
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17	9%	2%	0%	0%	0%	0%	15%	16%	5%	6%	11%	17%	0%	4%	0%	0%	10%	0%	9%	16%	8%	4%	7%	13%	6%	4%	0%	1%	0%	0%	14%	11%	2%	6%	0%	10%	
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20	7%	20%	22%	22%	0%	0%	5%	6%	21%	13%	7%	10%	17%	15%	37%	11%	8%	0%	6%	9%	25%	14%	7%	10%	12%	12%	26%	14%	0%	0%	6%	17%	33%	11%	14%	8%	
21	6%	10%	3%	6%	0%	0%	4%	1%	4%	5%	6%	6%	7%	8%	5%	6%	3%	0%	5%	2%	6%	0%	6%	8%	5%	4%	6%	7%	0%	0%	6%	4%	5%	3%	0%	4%	
22	1%	2%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	0%	0%	0%	0%	0%	0%	2%	0%	2%	0%	4%	1%	3%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	

PNW Outage Shares by zone, month, and year

Zone\Month	2024												2028												2032											
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
Month Total:	164	164	104	50	4	0	71	78	107	92	229	149	48	58	57	34	36	5	70	131	183	67	97	116	245	350	69	151	5	0	126	158	106	317	24	140
Avista	5%	4%	3%	8%	25%	0%	7%	9%	7%	8%	5%	5%	0%	0%	0%	0%	0%	3%	1%	2%	1%	4%	3%	3%	3%	1%	2%	0%	0%	0%	1%	0%	3%	0%	2%	
Bonneville_IDMT	3%	4%	2%	4%	0%	0%	4%	3%	2%	4%	3%	3%	2%	3%	2%	3%	14%	20%	9%	11%	2%	3%	4%	4%	6%	7%	6%	9%	20%	0%	9%	9%	8%	3%	0%	5%
Bonneville_OR	2%	4%	2%	4%	0%	0%	3%	1%	0%	2%	3%	3%	2%	0%	2%	0%	0%	4%	2%	2%	1%	4%	3%	5%	4%	1%	3%	0%	0%	4%	3%	3%	3%	0%	3%	
Bonneville_WA	7%	6%	9%	6%	0%	0%	7%	3%	9%	8%	9%	6%	2%	2%	2%	0%	0%	3%	3%	2%	3%	4%	4%	4%	4%	3%	3%	0%	0%	3%	4%	1%	3%	0%	3%	
ChelanCountyPUD	4%	4%	3%	4%	0%	0%	1%	1%	2%	3%	4%	3%	10%	14%	11%	6%	6%	0%	7%	7%	7%	7%	8%	5%	7%	7%	5%	0%	0%	6%	8%	9%	6%	4%	7%	
DouglasCountyPUD	5%	5%	5%	4%	0%	0%	1%	4%	7%	4%	5%	5%	2%	5%	2%	3%	3%	0%	3%	1%	3%	4%	4%	4%	4%	4%	3%	4%	0%	0%	4%	2%	3%	3%	0%	3%
GrantCountyPUD	5%	5%	6%	4%	0%	0%	3%	4%	10%	7%	5%	5%	8%	2%	5%	6%	0%	0%	3%	4%	7%	7%	5%	4%	5%	6%	6%	5%	0%	0%	4%	6%	9%	6%	0%	5%
IdahoPowerFE	1%	2%	1%	0%	0%	0%	3%	4%	0%	1%	2%	2%	4%	5%	5%	6%	8%	0%	3%	4%	7%	4%	4%	5%	6%	5%	9%	8%	20%	0%	5%	7%	11%	6%	0%	4%
IdahoPowerMV	1%	2%	2%	0%	0%	0%	4%	5%	0%	1%	2%	2%	0%	0%	0%	0%	0%	0%	3%	1%	2%	1%	4%	3%	3%	3%	1%	1%	0%	0%	3%	1%	0%	0%	0%	0%
IdahoPowerTV	1%	3%	2%	0%	0%	0%	18%	10%	1%	1%	3%	3%	0%	0%	0%	0%	0%	0%	3%	1%	2%	1%	4%	3%	3%	3%	1%	1%	0%	0%	4%	3%	0%	0%	0%	2%
NorthwesternMT	2%	2%	2%	0%	0%	0%	1%	1%	0%	2%	2%	3%	2%	0%	2%	0%	0%	0%	6%	3%	2%	1%	4%	3%	3%	3%	1%	2%	0%	0%	6%	5%	0%	3%	0%	2%
Olympia	5%	5%	4%	4%	0%	0%	3%	3%	2%	5%	5%	4%	4%	5%	5%	3%	3%	0%	4%	3%	5%	4%	4%	5%	5%	5%	3%	5%	0%	0%	4%	3%	3%	3%	0%	4%
PacificCorpEastID	1%	2%	1%	0%	0%	0%	3%	3%	0%	1%	2%	2%	2%	0%	2%	3%	0%	0%	3%	4%	3%	4%	4%	3%	4%	4%	3%	3%	0%	0%	3%	5%	0%	3%	0%	3%
PACWSouth	3%	4%	2%	2%	0%	0%	4%	1%	2%	2%	3%	3%	0%	0%	0%	0%	0%	0%	3%	1%	2%	0%	4%	3%	3%	3%	1%	1%	0%	0%	0%	1%	0%	0%	0%	0%
PortlandGeneral	5%	5%	4%	6%	0%	0%	6%	9%	5%	7%	6%	5%	4%	5%	5%	3%	3%	0%	6%	6%	7%	4%	4%	6%	5%	5%	3%	5%	0%	0%	7%	5%	7%	6%	0%	5%
PugetSoundCentral	10%	7%	11%	10%	25%	0%	7%	8%	11%	9%	10%	8%	13%	14%	14%	12%	14%	20%	9%	11%	12%	10%	7%	9%	8%	8%	10%	9%	20%	0%	7%	9%	12%	11%	17%	8%
PugetSoundNorth	8%	7%	11%	8%	0%	0%	7%	5%	9%	9%	9%	7%	10%	14%	11%	6%	11%	20%	7%	8%	10%	9%	7%	9%	6%	8%	9%	6%	0%	0%	6%	9%	9%	3%	13%	7%
SeattleCL	16%	15%	16%	20%	25%	0%	8%	15%	17%	13%	11%	17%	17%	16%	18%	26%	19%	20%	11%	17%	13%	16%	10%	11%	13%	10%	16%	15%	20%	0%	14%	11%	13%	22%	35%	19%
TacomaPower	15%	13%	16%	16%	25%	0%	8%	12%	16%	13%	11%	14%	17%	16%	16%	24%	19%	20%	11%	15%	13%	13%	9%	11%	13%	10%	14%	14%	20%	0%	13%	9%	13%	19%	30%	17%