BPA Long-Term Power PCM

WECC Resource Build, Prices, and Market Limits

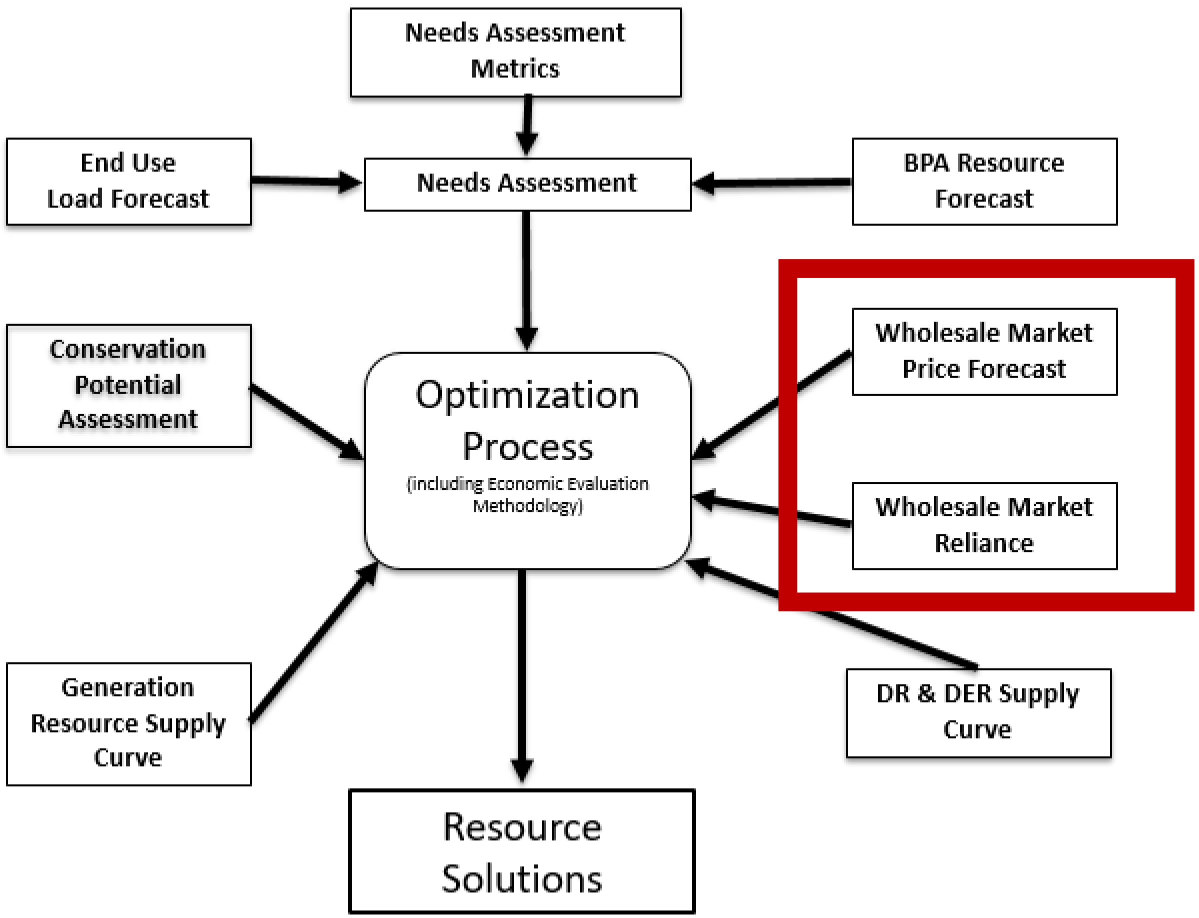
BPA Resource Program Public Workshop

May 24th, 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 Once Through Cooling 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 CA Senate Bill 100 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 Small Modular Nuclear Reactor characteristics, also comparable to traditional fossil fuel base resource with Carbon Capture & Sequestration
  - 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% Zero Emissions (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)

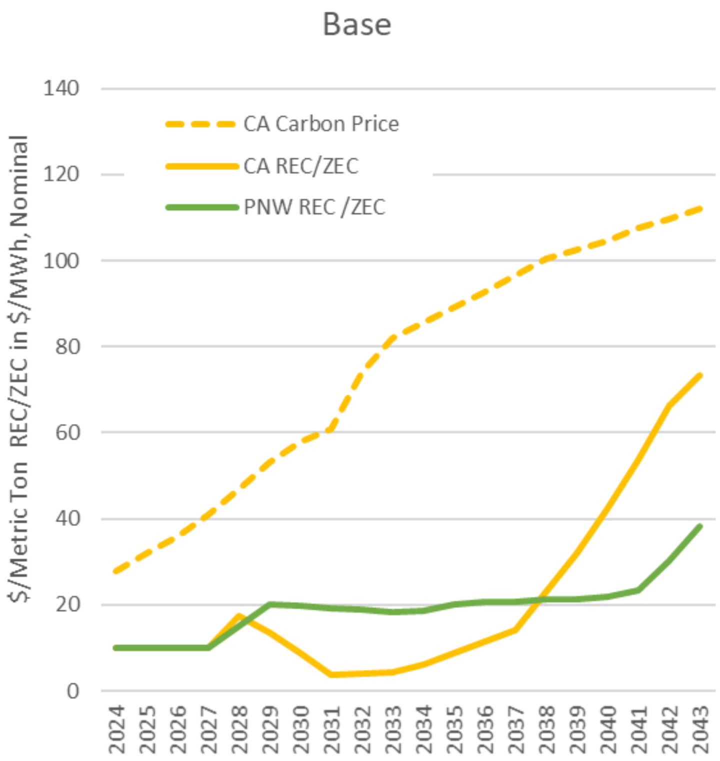
Carbon Policy Constraints

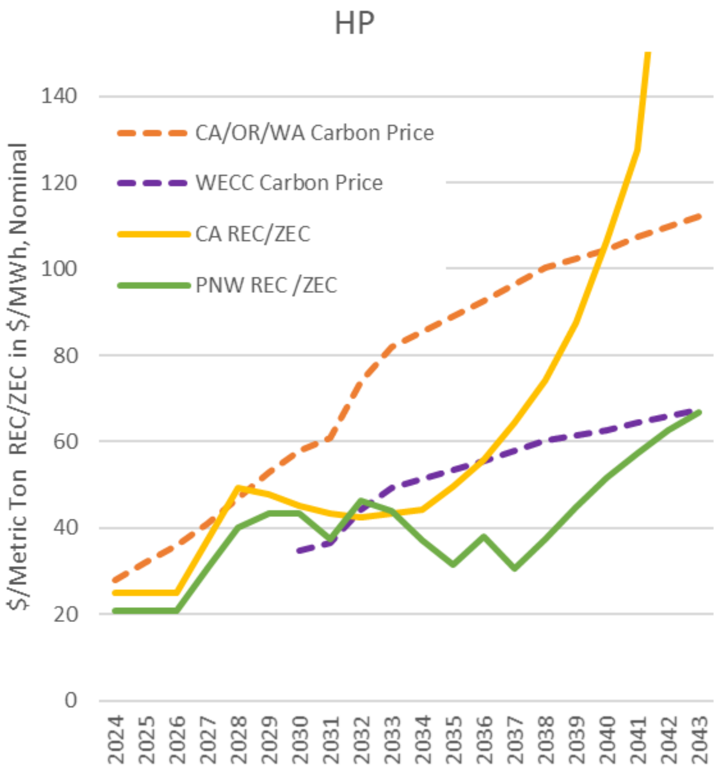
Carbon prices:

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

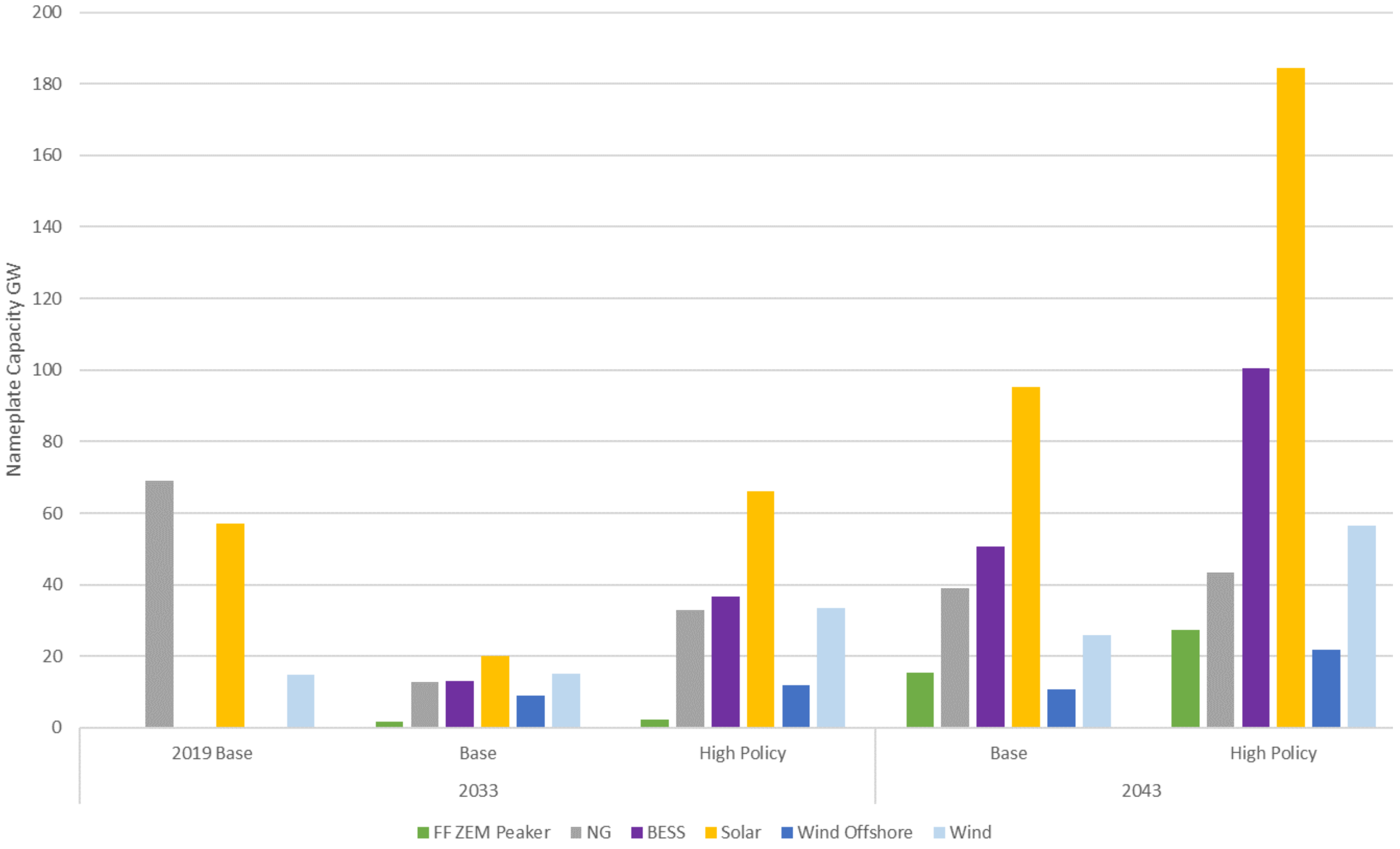
Include emission penalties on WA thermals after 2030 and ensure 80% of WA loads are met with zero emission generation, ramping up to 100%

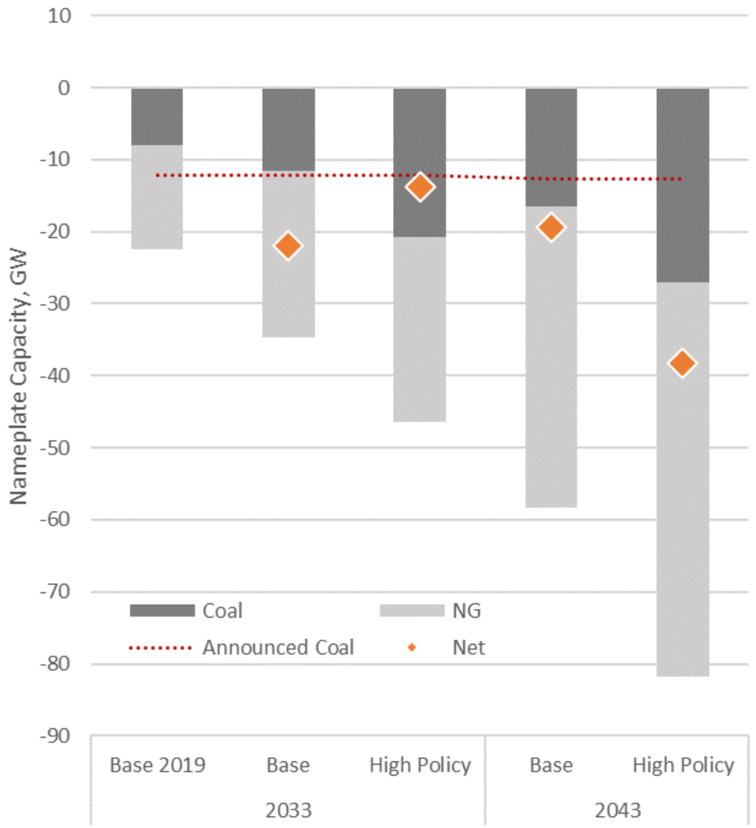
Include OR CO2 emission caps



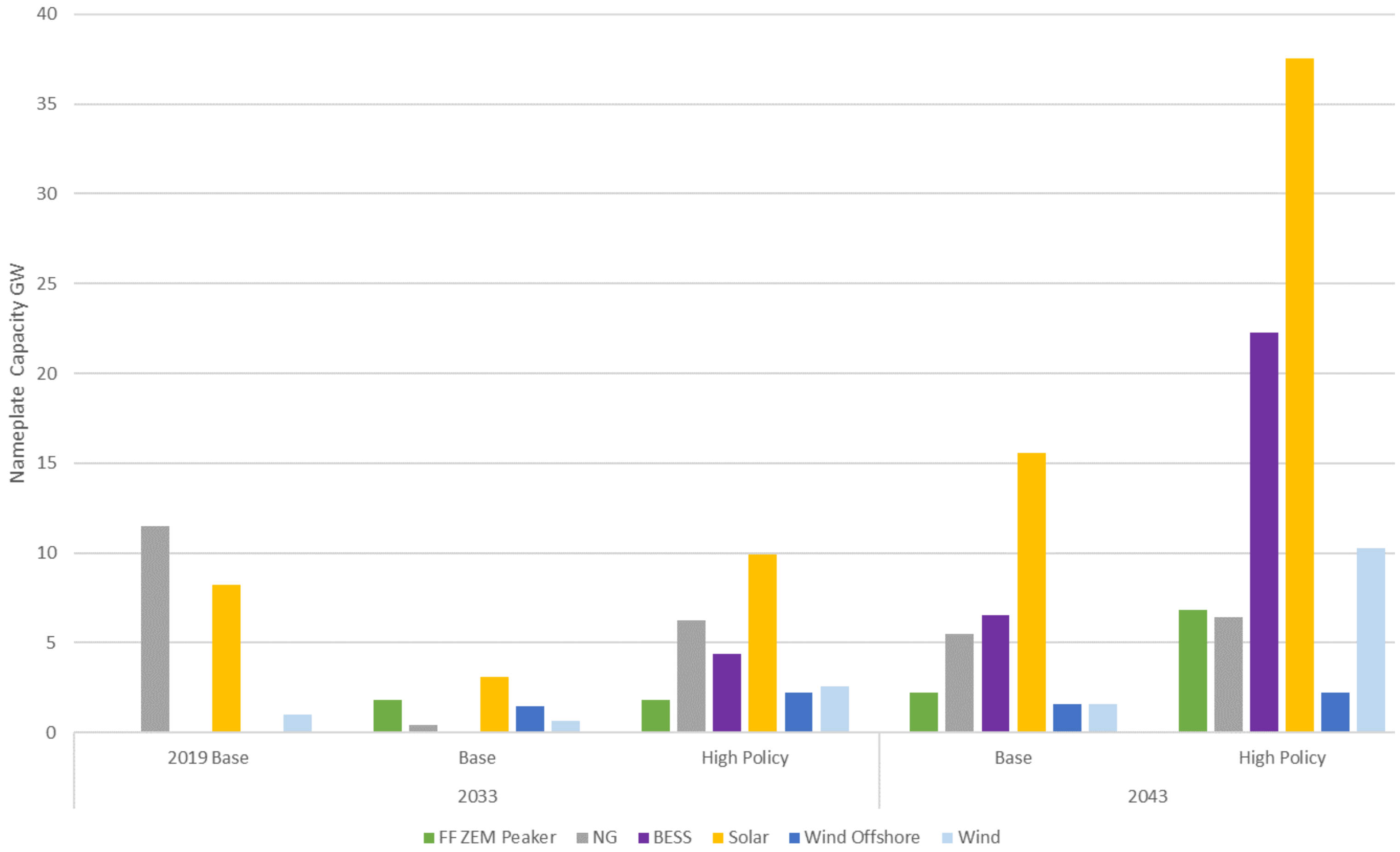


Cumulative WECC Builds & Retirements





Cumulative PNW Builds & Retirements

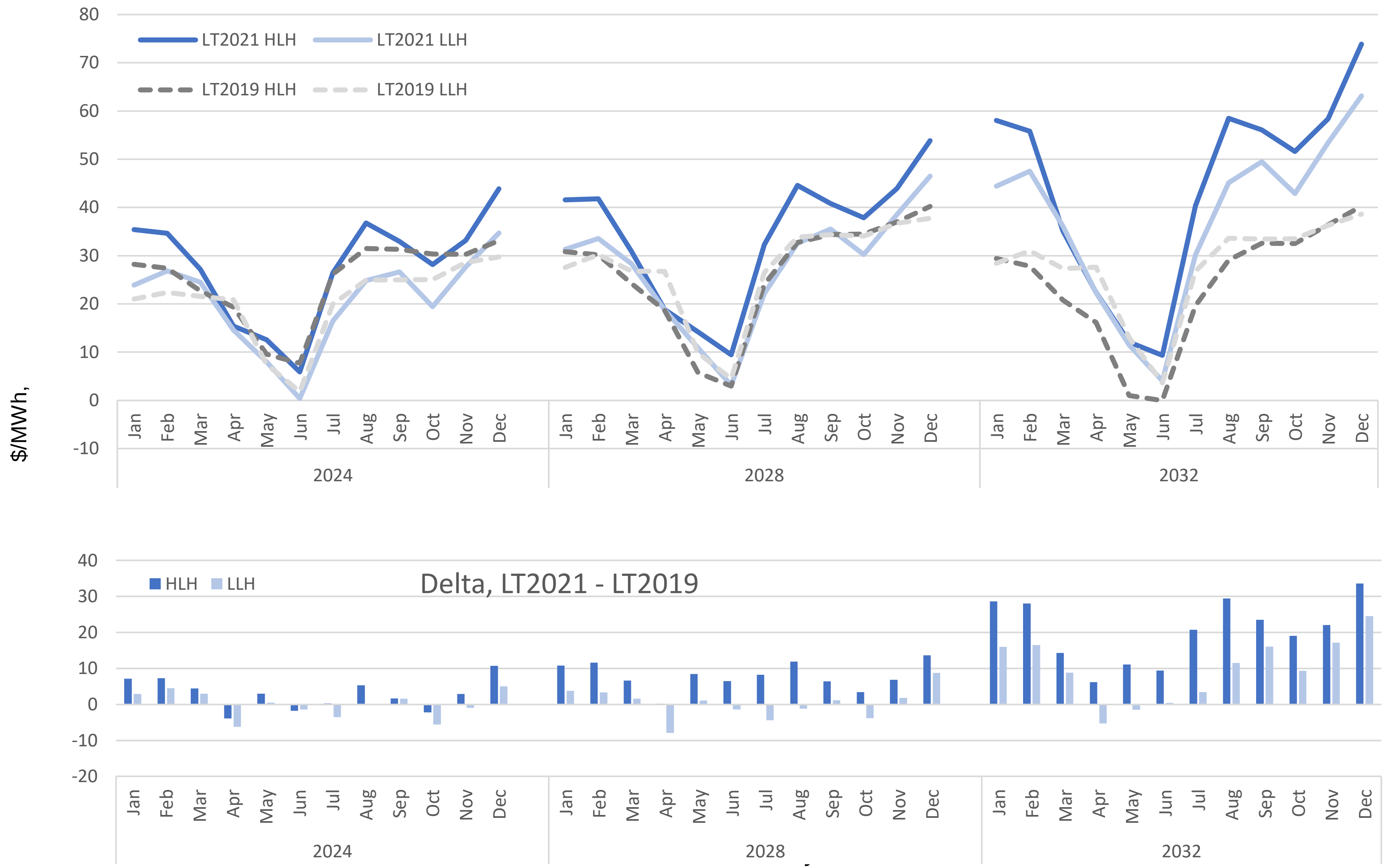


Prices

Updates, Values, Distributions, and Negative Prices

Aurora 2021 LT Base Updates since 2019 LT Base

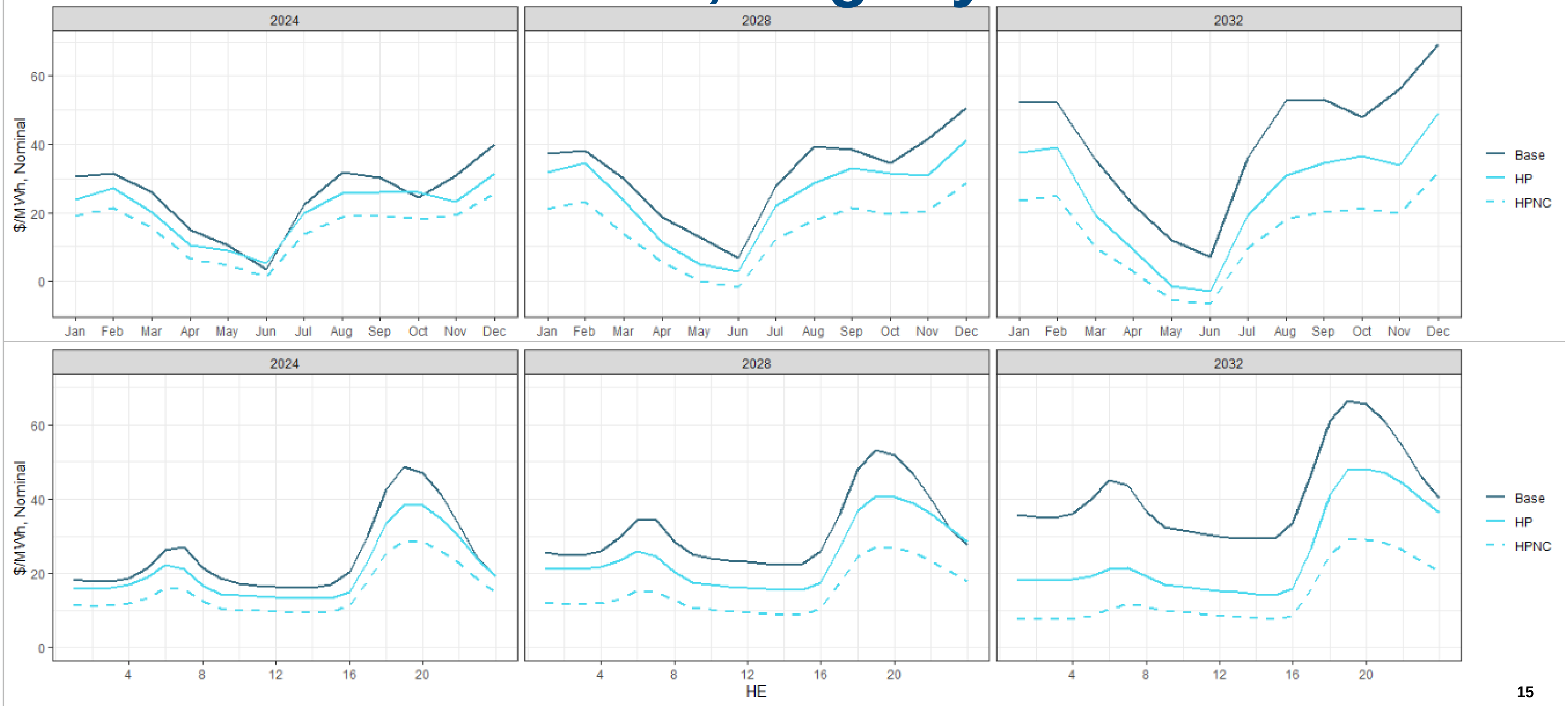
- ⬆ **Bid Adders (recalibrated since BP22 FP)**
- ⬇ Gas prices
- ⬇ Load forecasts
  - DG forecasts in Desert Southwest, including CA
- ⬆ Elimination of carbon adders on southern intertie
- ⬆ CA Carbon prices
- ⬆⬇ Dynamic peak credits for variable resources (ELCC proxy)
- ⬇ Resource costs & options
  - 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***

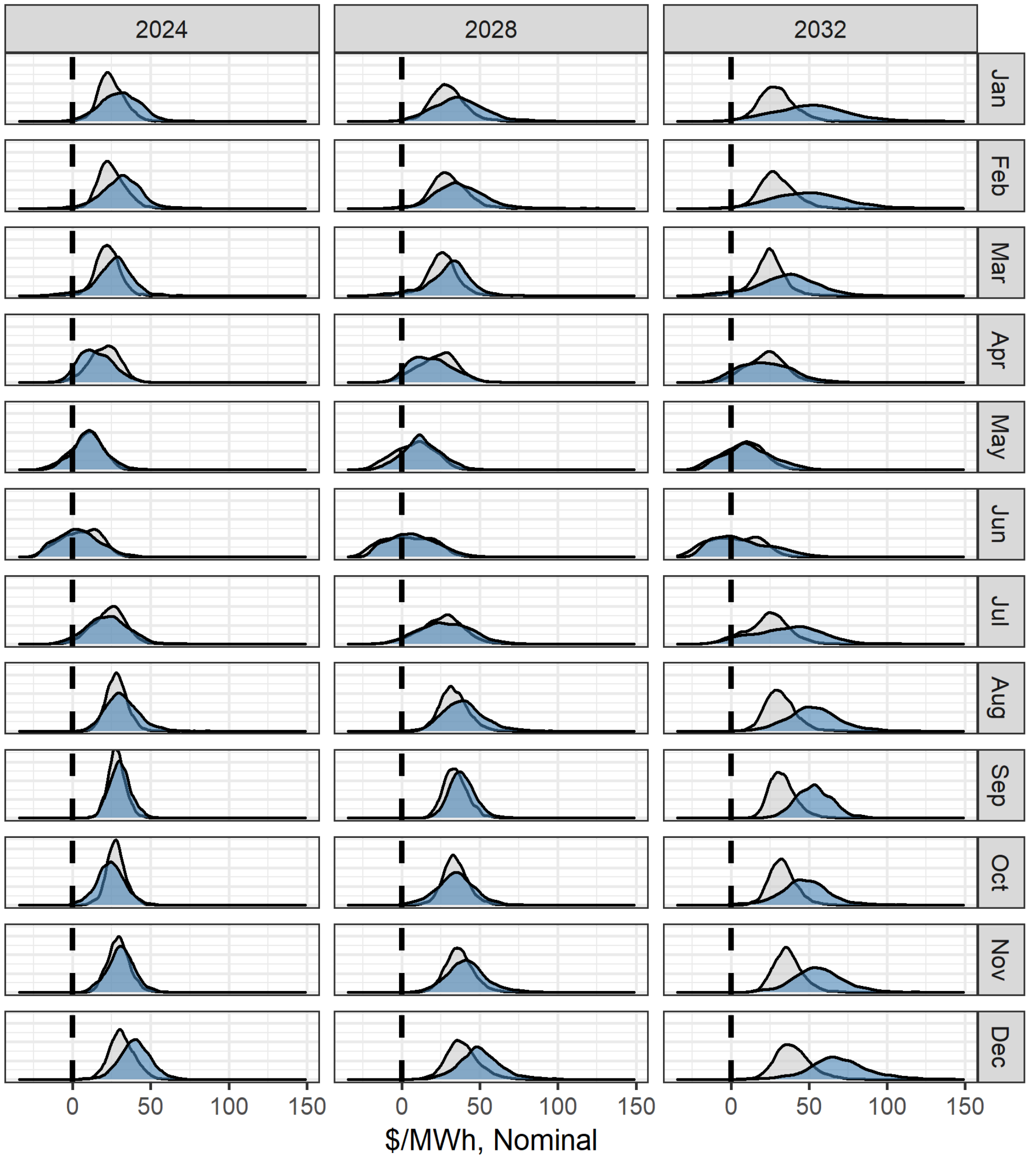


PNW Prices Diurnal Month Avg.

LT2019 Base vs LT2021 Base

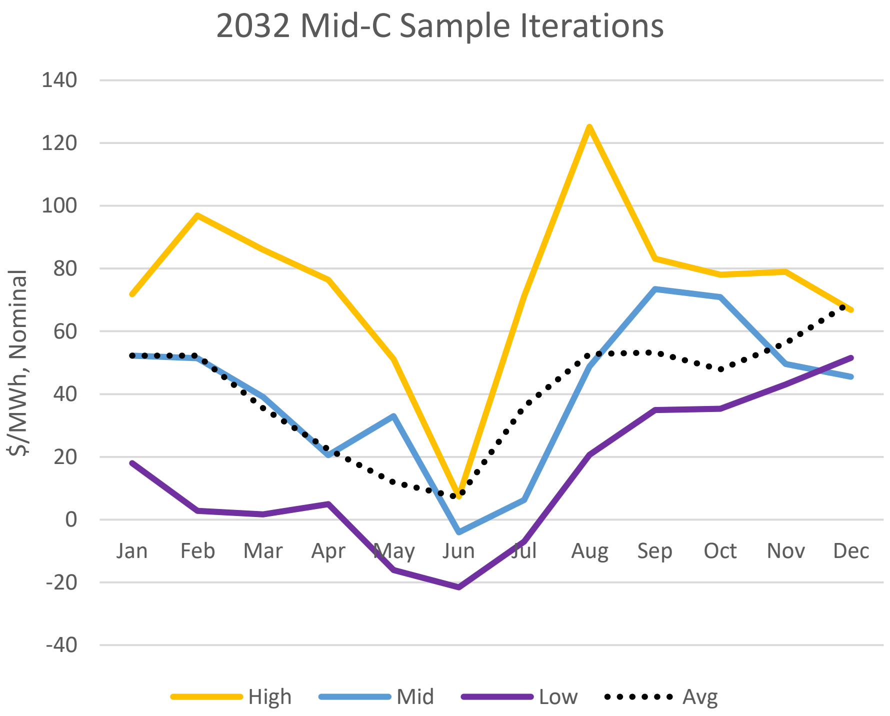
LT2021 PNW Prices, Avg. by Month and Hour

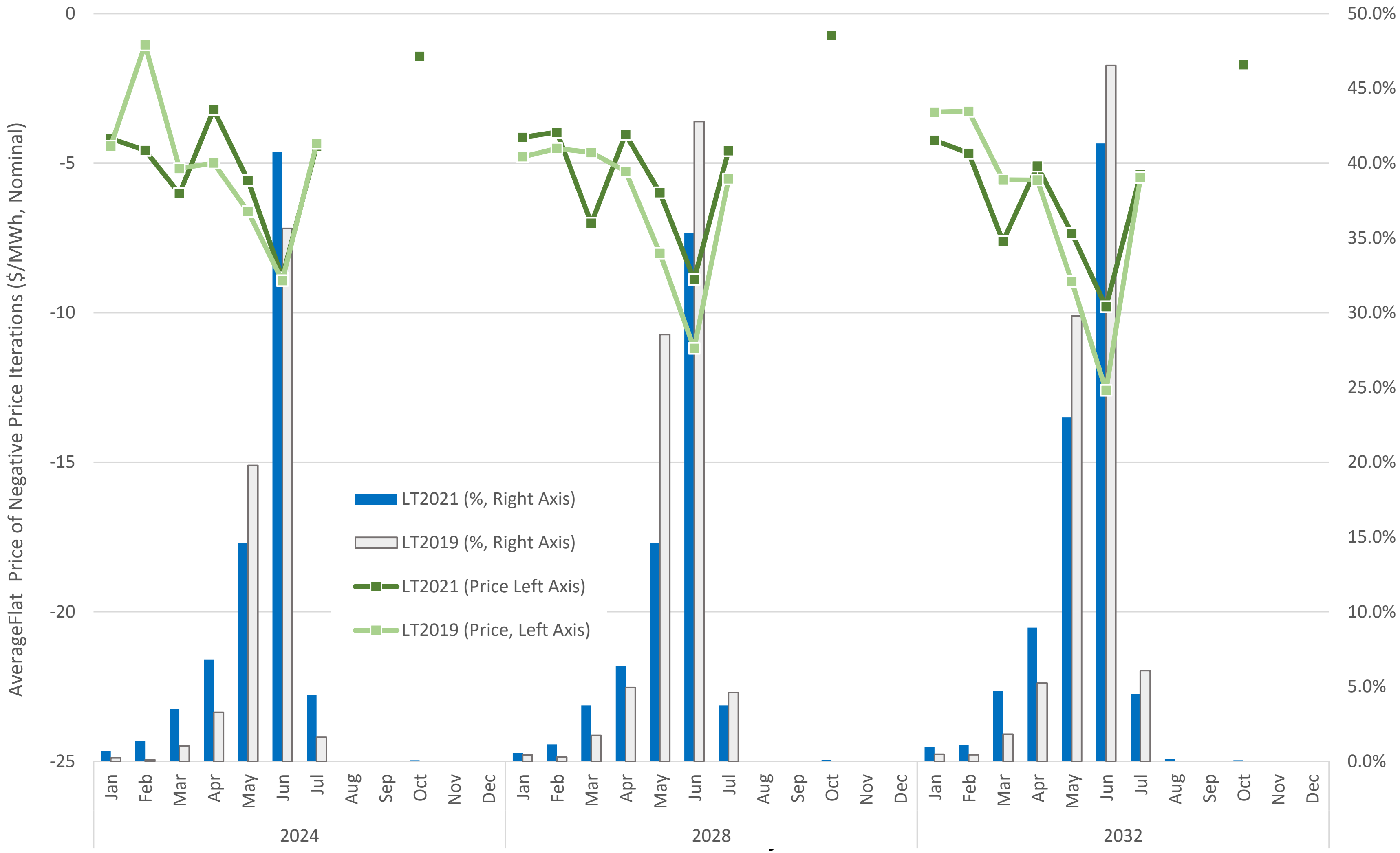




PNW Price Distributions

- 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.***

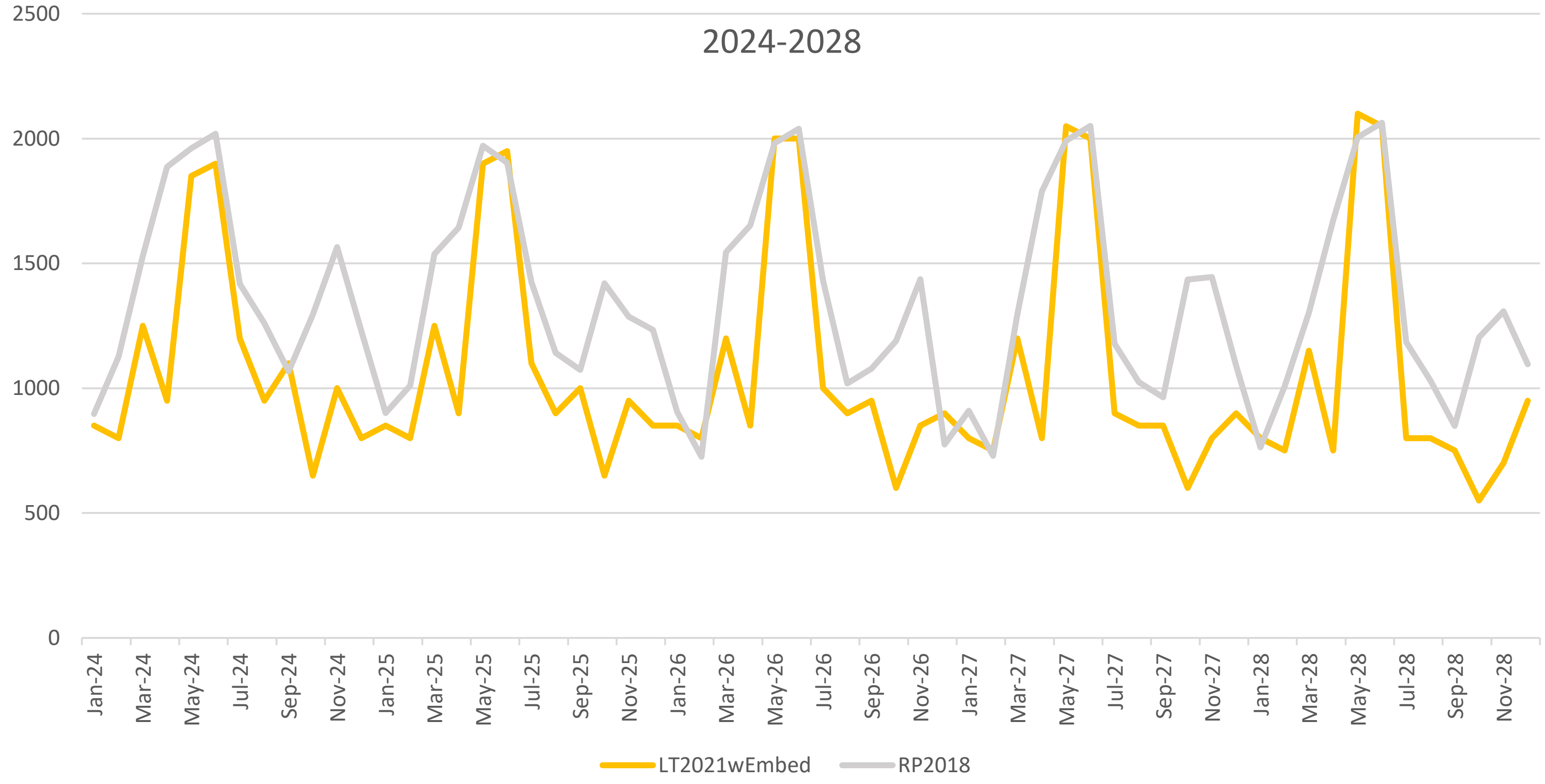
2. Add incremental load increases to approximate greater resource retirements / fewer resource additions associated with higher levels of regional market reliance

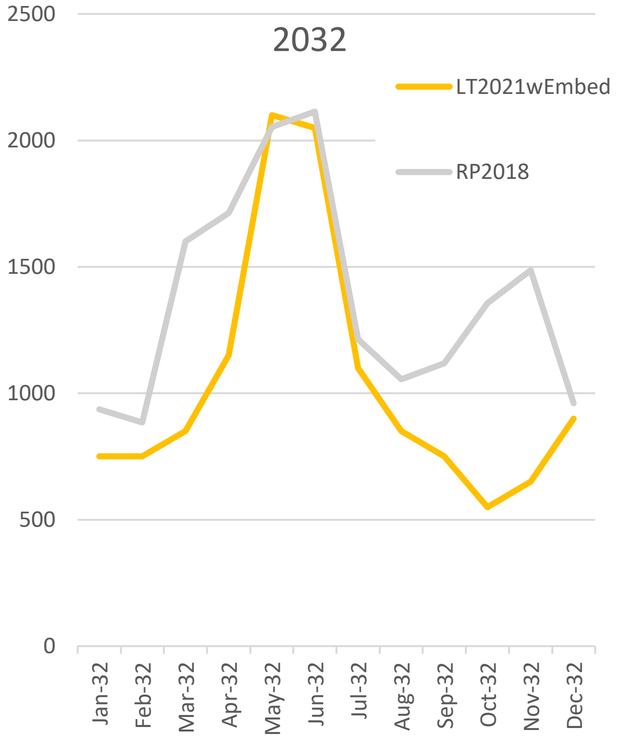
3. On a monthly basis, determine level at which greater market reliance causes region to exceed 5% LOLP

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 Day Ahead 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.

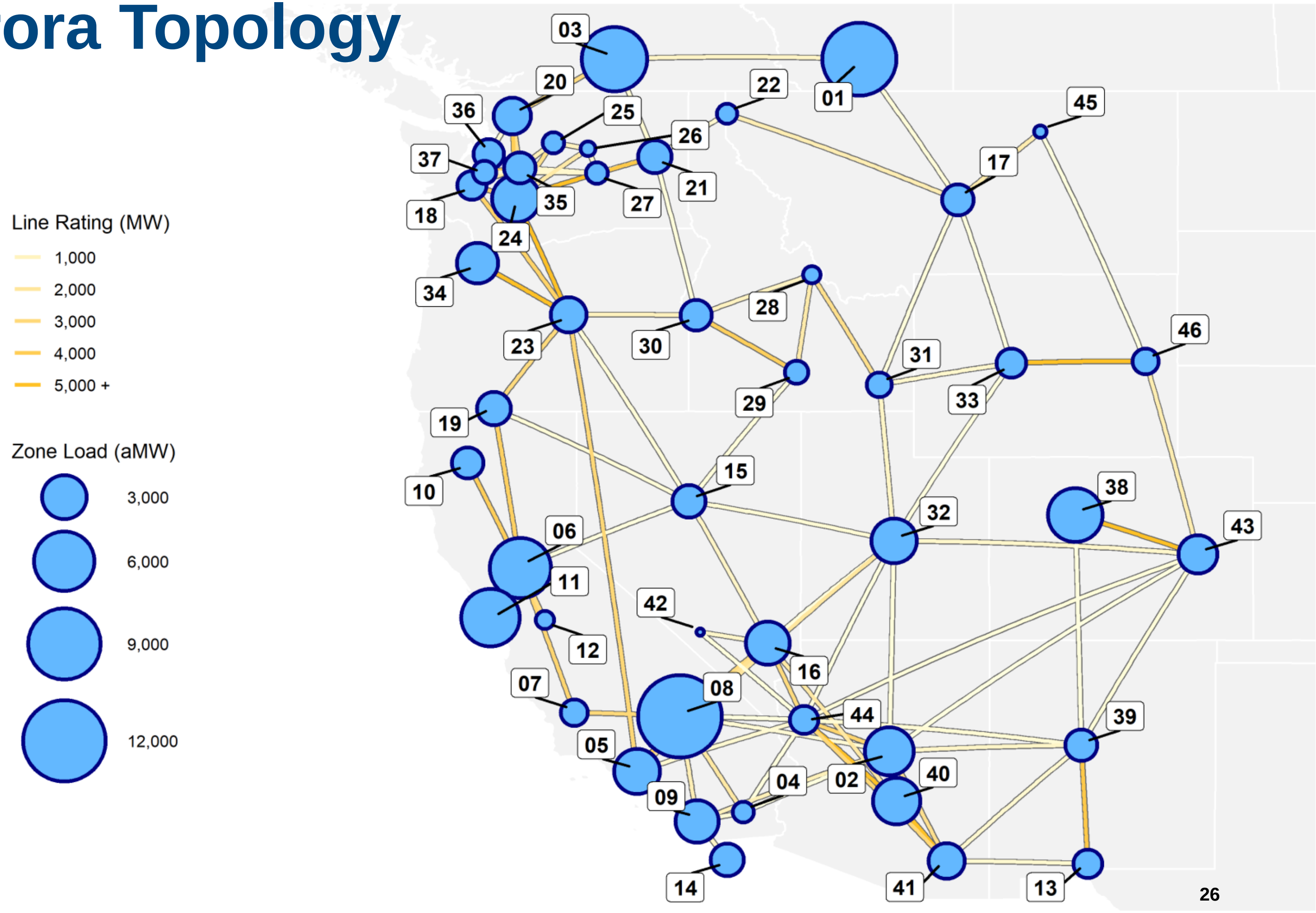
- **We calibrate the model based on recent DA prices (2014-2019), but we do not explicitly account for the following:**
  - Market design differentiation (**NO**: forward curves / firm contracts / DA - RT markets & forecast error, source & sink, local commitment considerations), **all of the WECC is 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



Aurora and Market Design (EIM / RA)

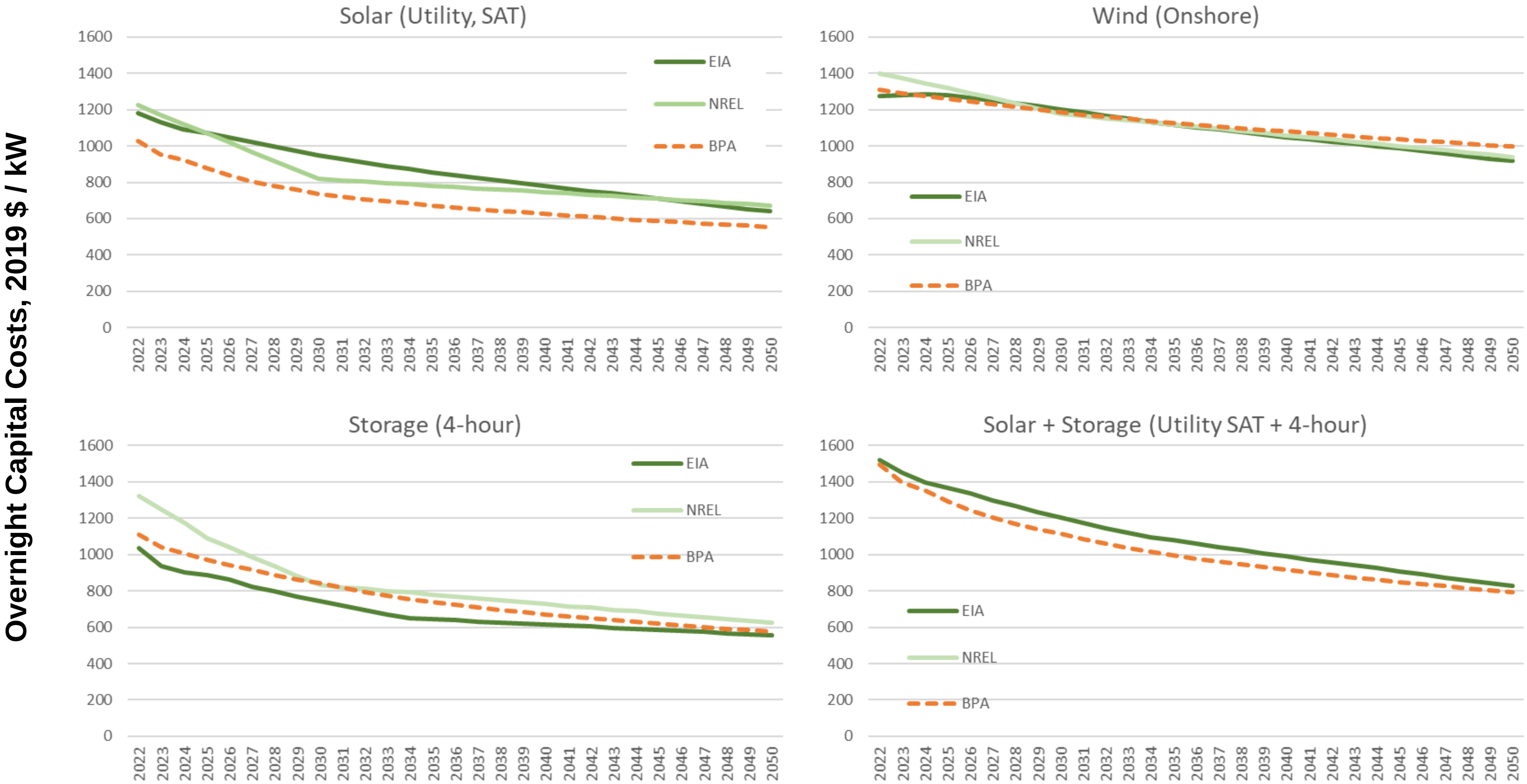
- Aurora does not explicitly account for differences in market structure (bilateral vs ISO or different time horizons). It simulates the interconnect as if the WECC were centrally dispatched in a single ISO, and we assume that prices will tend to converge on the marginal cost of generating & delivering 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
Solar (Utility, SAT)
Wind (Onshore)
Storage (4-hour)
Solar + Storage (Utility SAT + 4-hour)
EIA
NREL
BPA
0
200
400
600
800
1000
1200
1400
1600
2022
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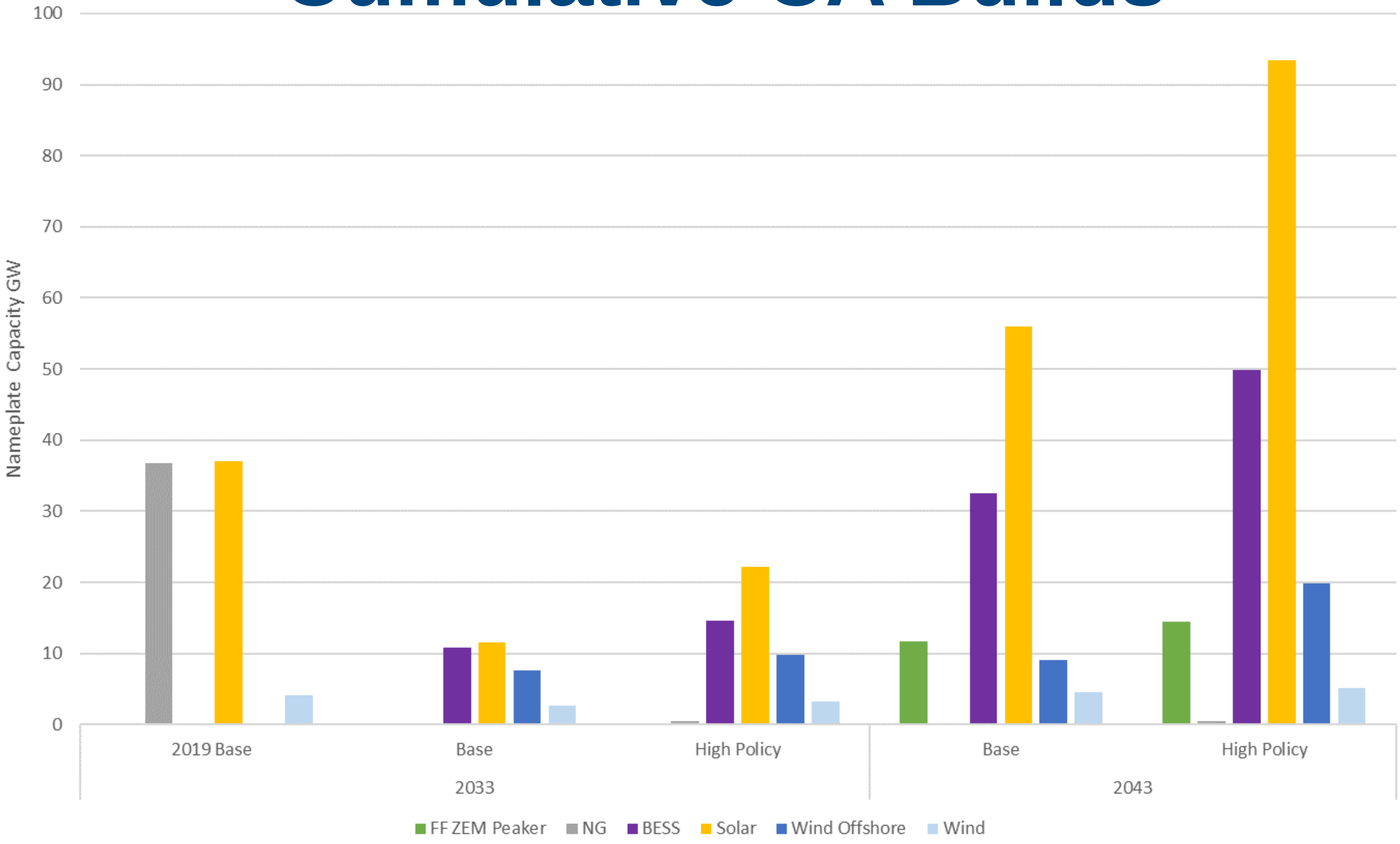
Major Price/Build Uncertainties

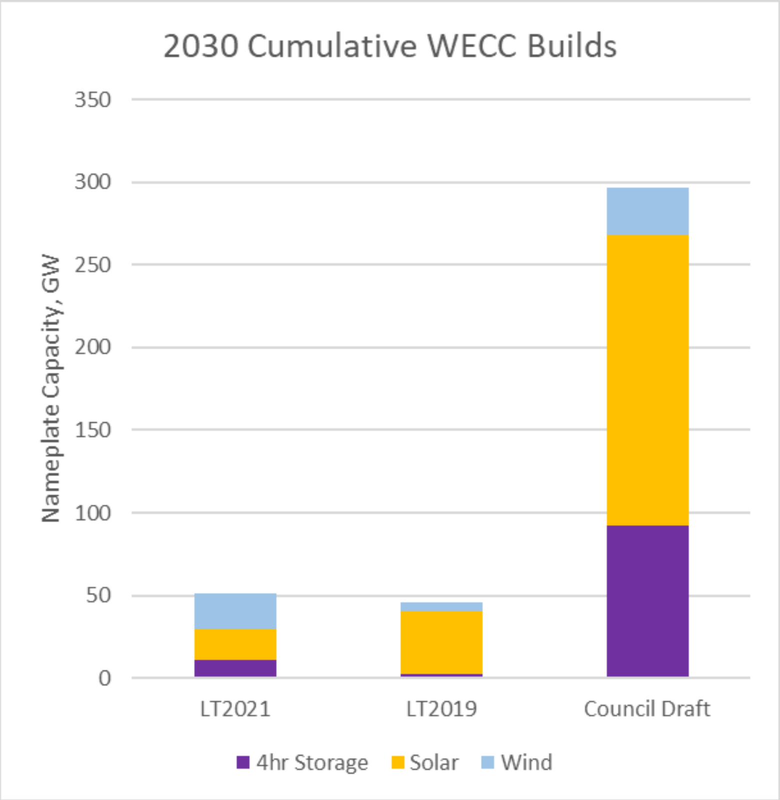
- Global drivers
  - Events in Ukraine could accelerate reduction of fossil fuel reliance
  - COVID 19 economic/supply chain impacts: recent trends in rapidly declining costs of renewable and storage resources could halt or even reverse. Further load impacts?
- Accelerated decarbonization (mixed impacts, 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

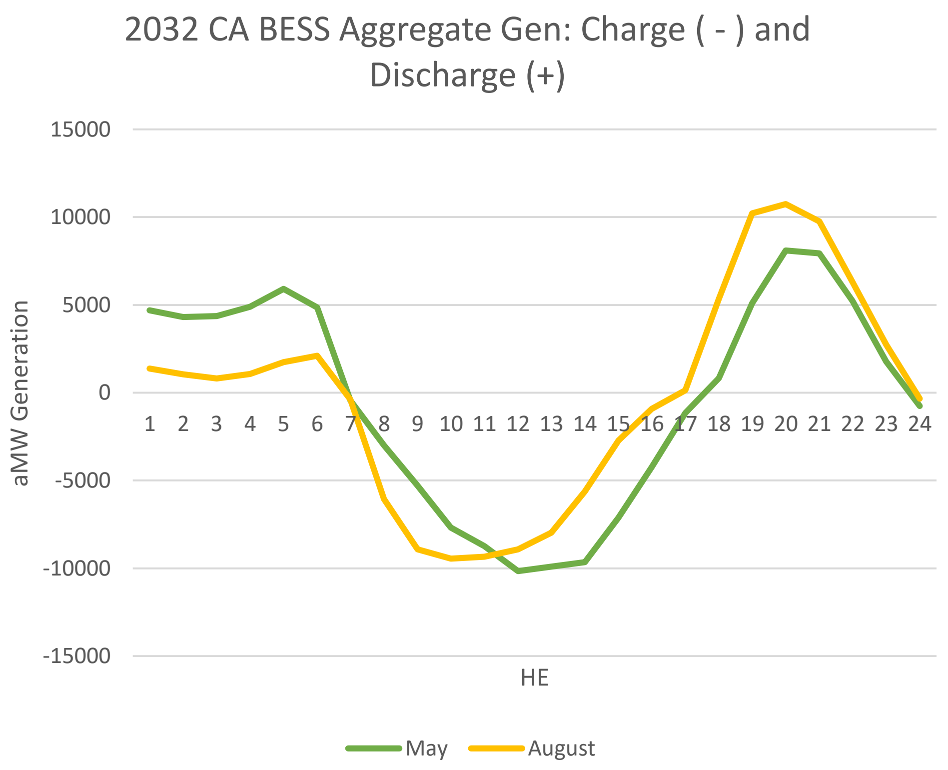
- The base cases reflect fundamentally different realities and expectations
- High level: **we model current policy as fixed and allow the system to develop based primarily on economics & recent observed behavior, while the council leans primarily on policy intent and desired behavior under a climate 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



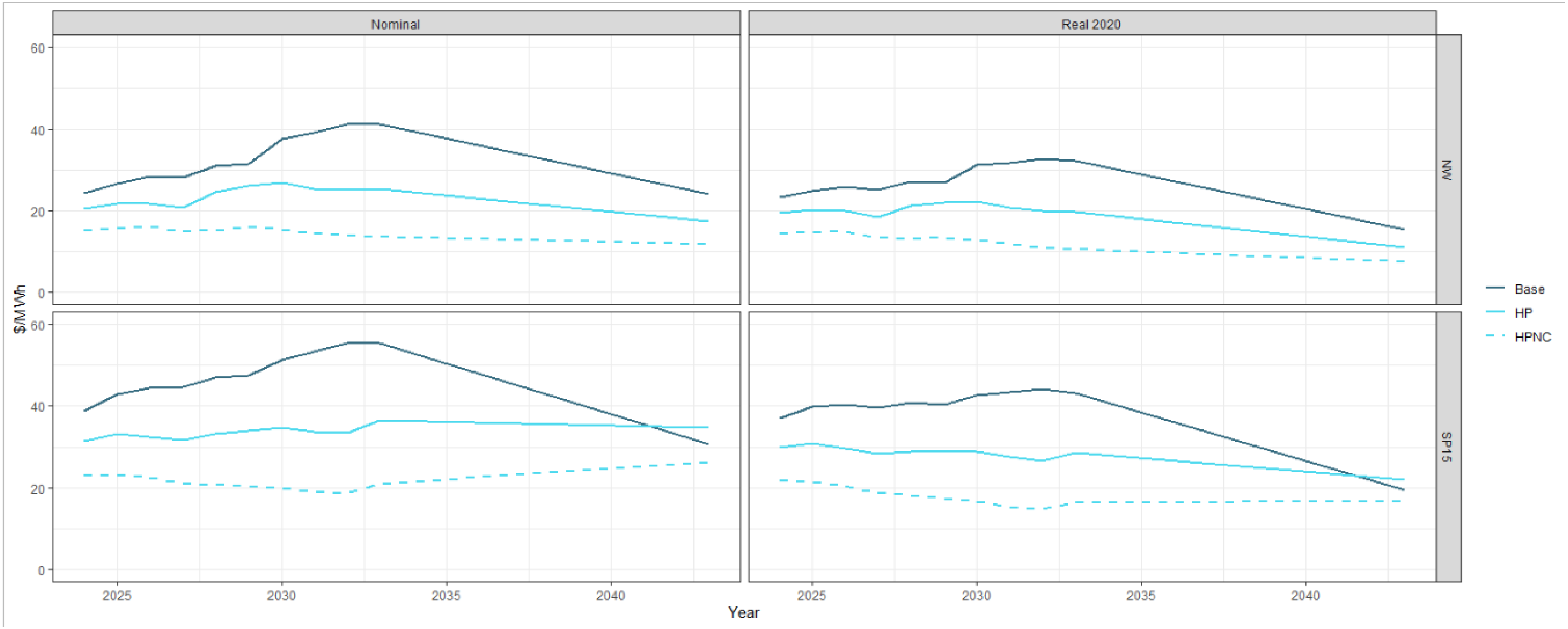
Aurora 2021 LT Base Updates: Commitment Optimization

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



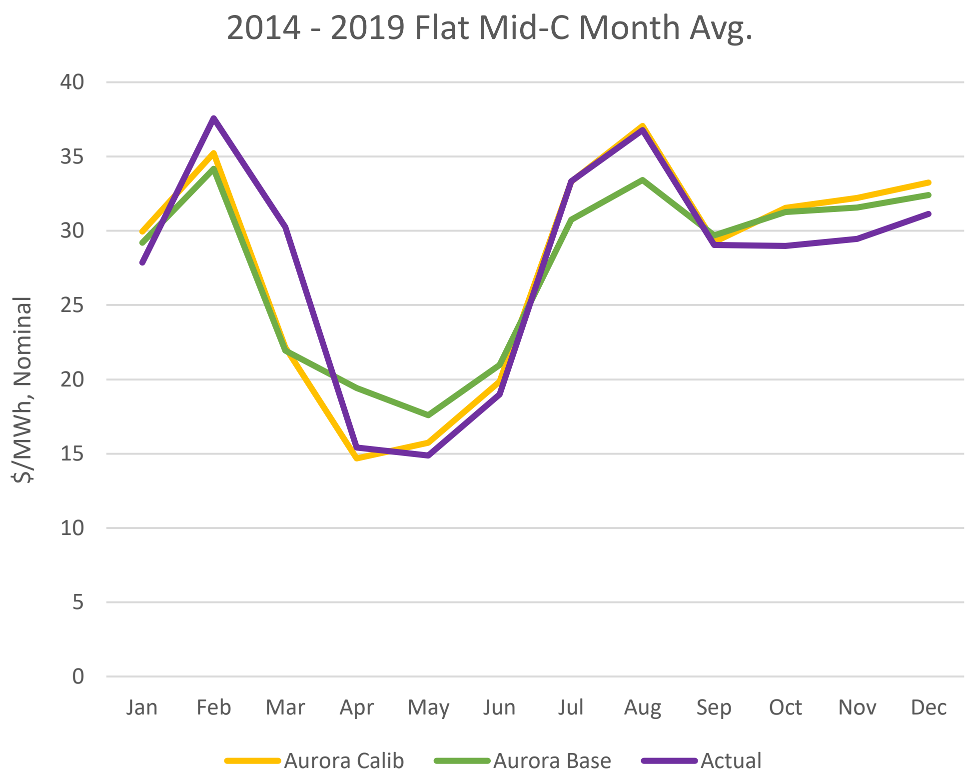
Aurora Calibration 2014-2019

- There are two main reasons Aurora price forecasts are wrong:

  1) Get the fundamentals wrong

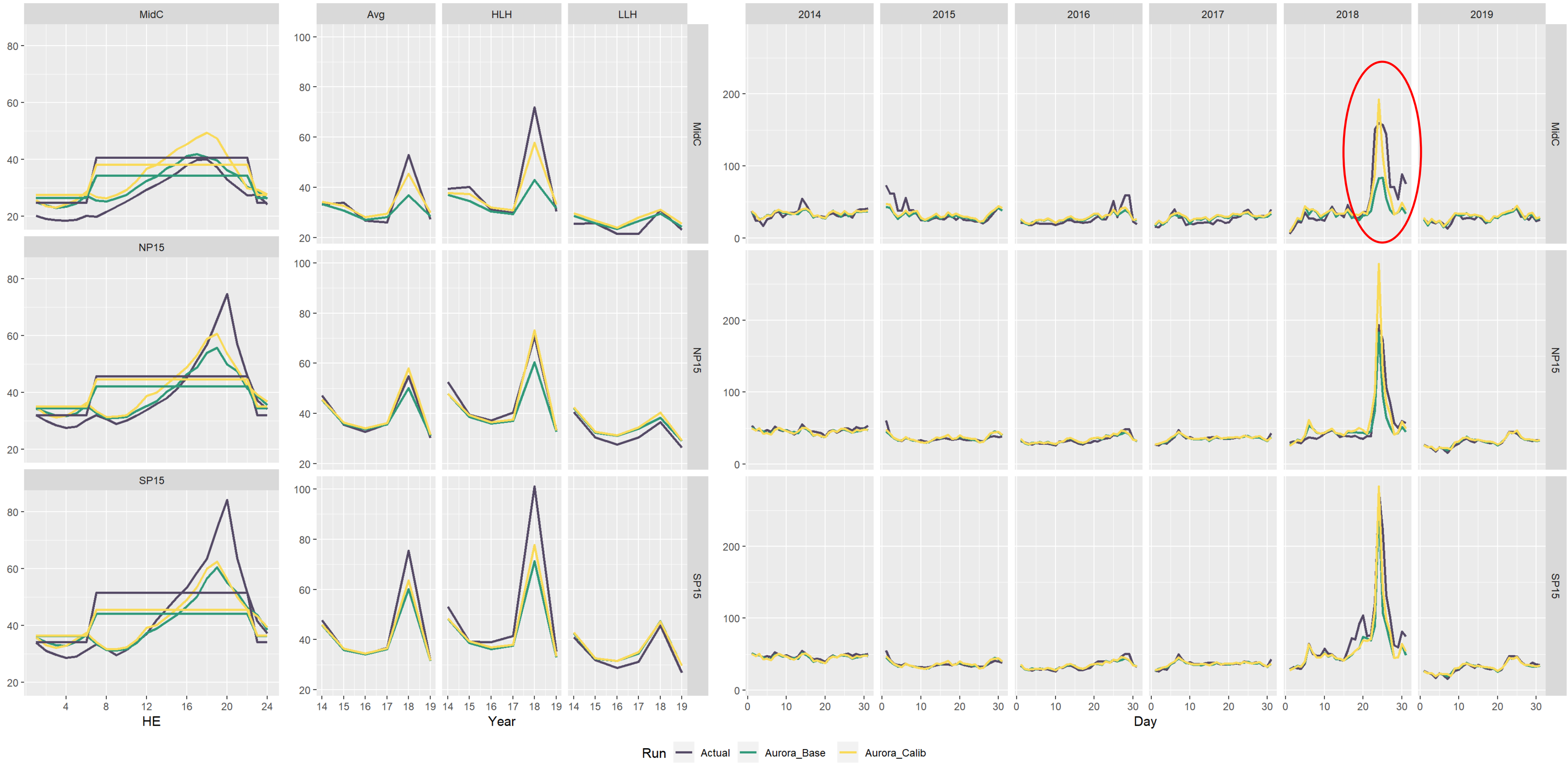
  2) Get the relationship between fundamentals and prices wrong (not capturing important details of how markets and the grid work / behavioral effects)

- 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

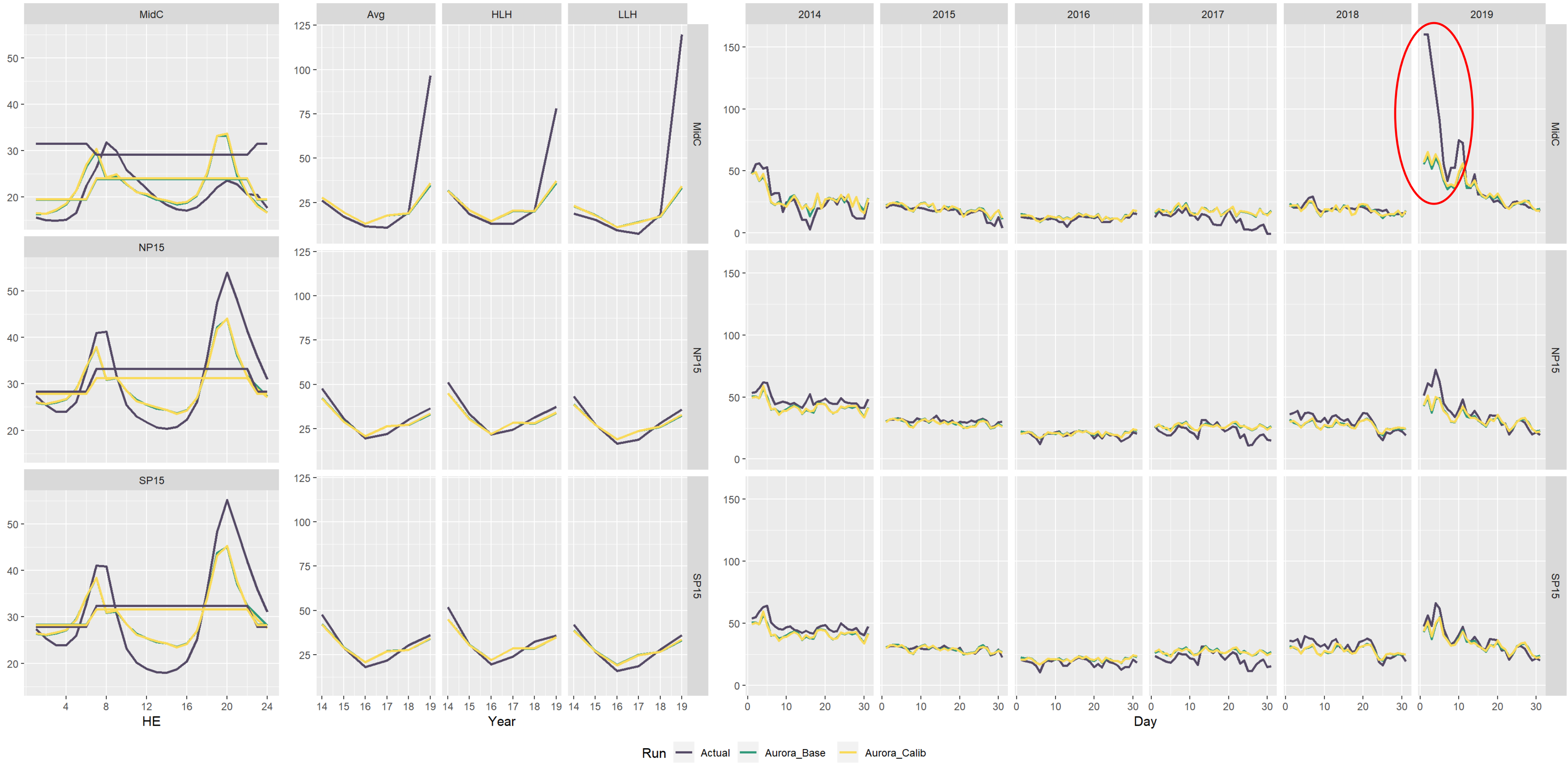


‘Fundamentals’= load, hydro generation, gas prices, transmission capability, and renewable generation

July Calibration, 2014-2019

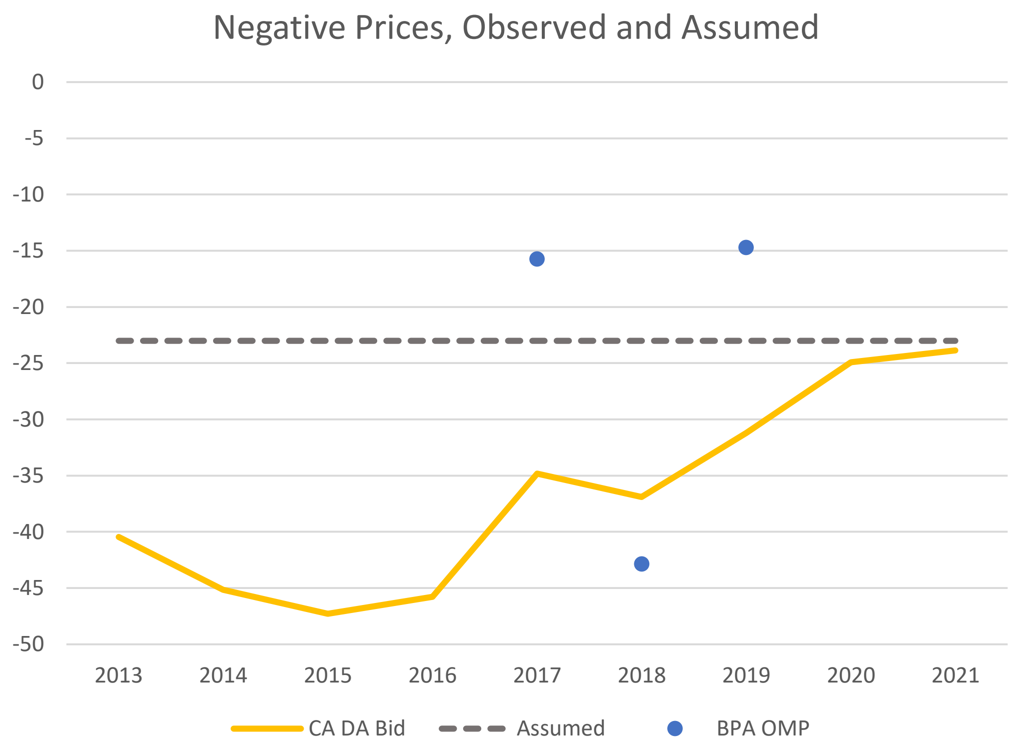


March Calibration

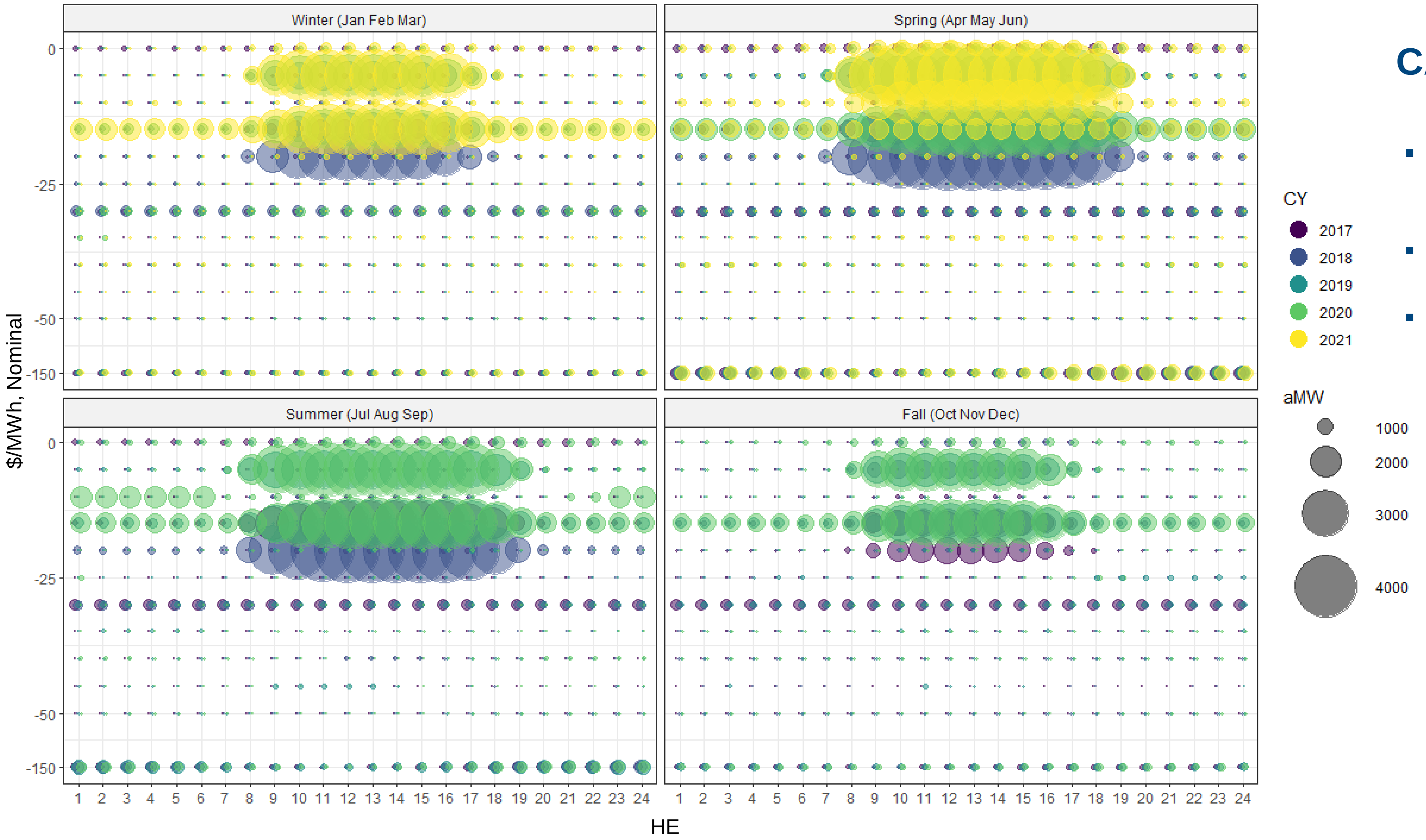


Negative Prices, Approach and Observations

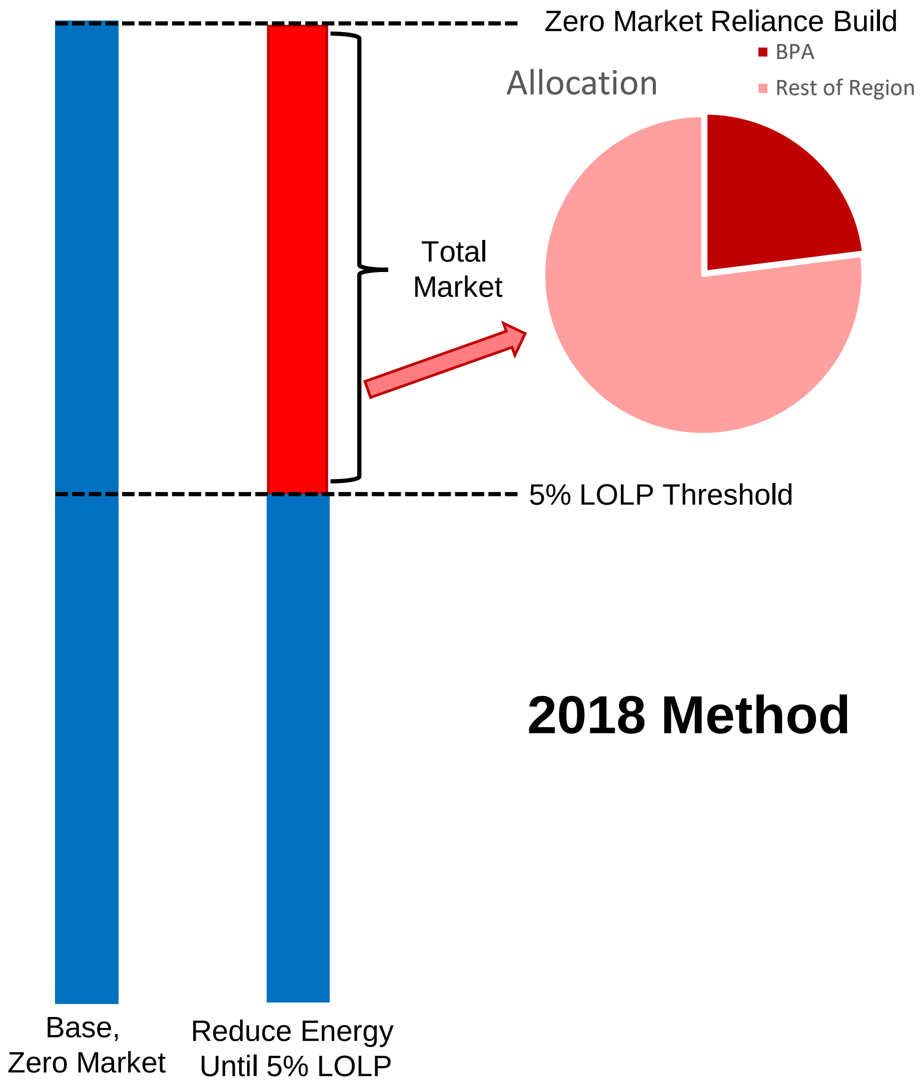
- Main drivers: policy. Incentives and requirements introduce costs to curtailing renewable resources
  - Forgone RECs / PTCs / PPA revenue / Potentially having to build additional resources
  - ‘replacement cost’ of renewable energy
- Generally, consultants and other production cost modelers tend *not* 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 Oversupply Management Protocol effects

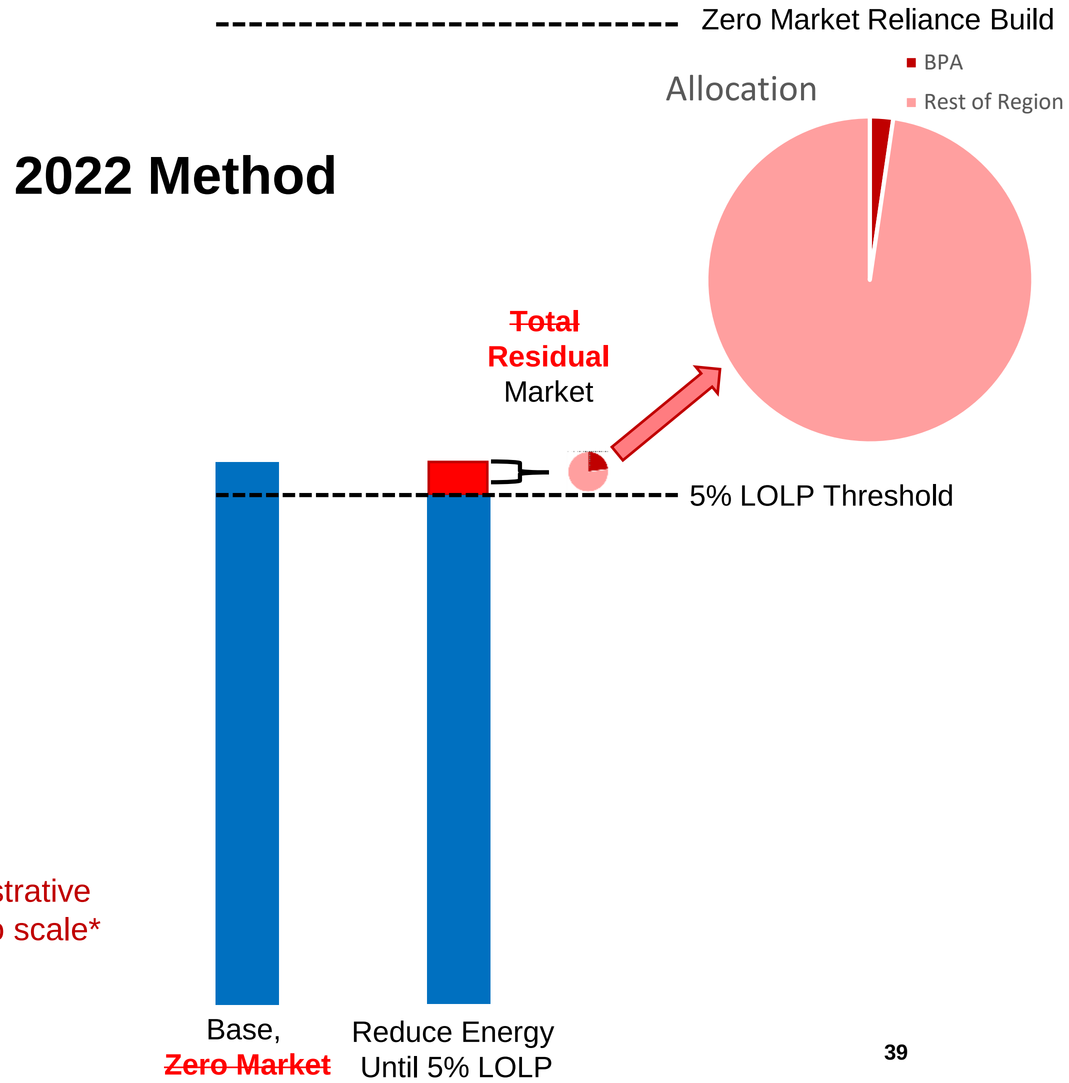


CAISO DA Bids



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





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 sill 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

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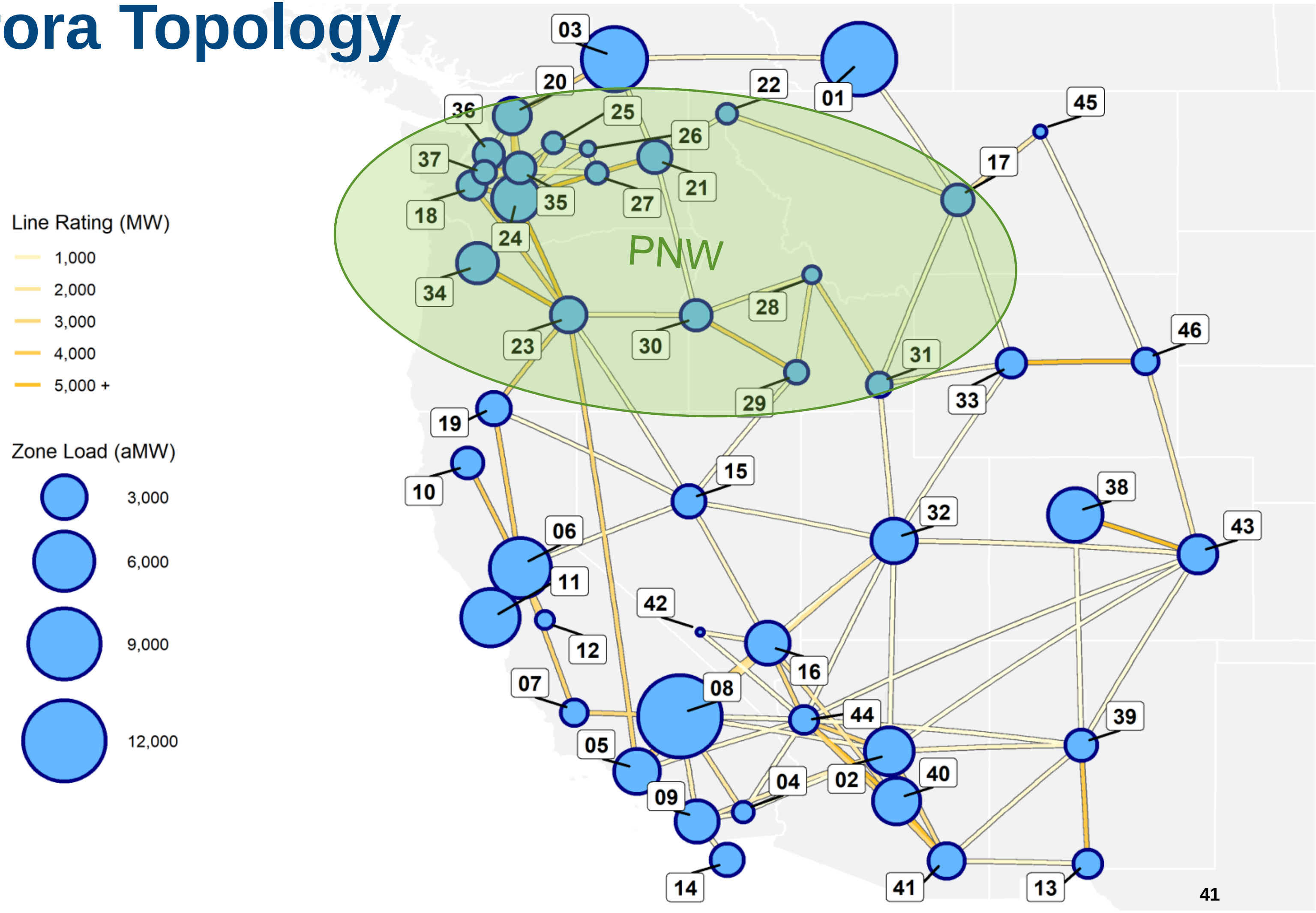
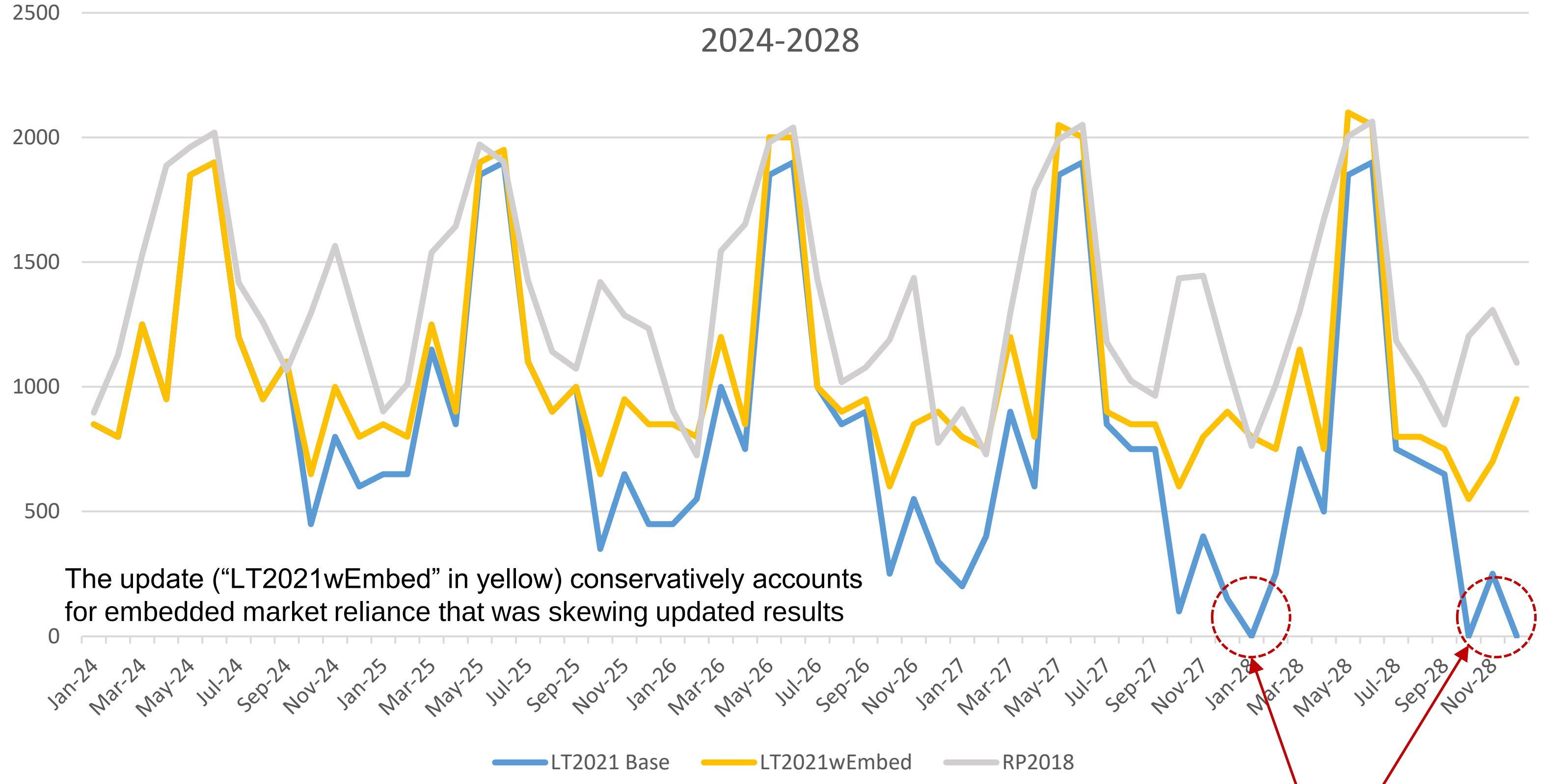
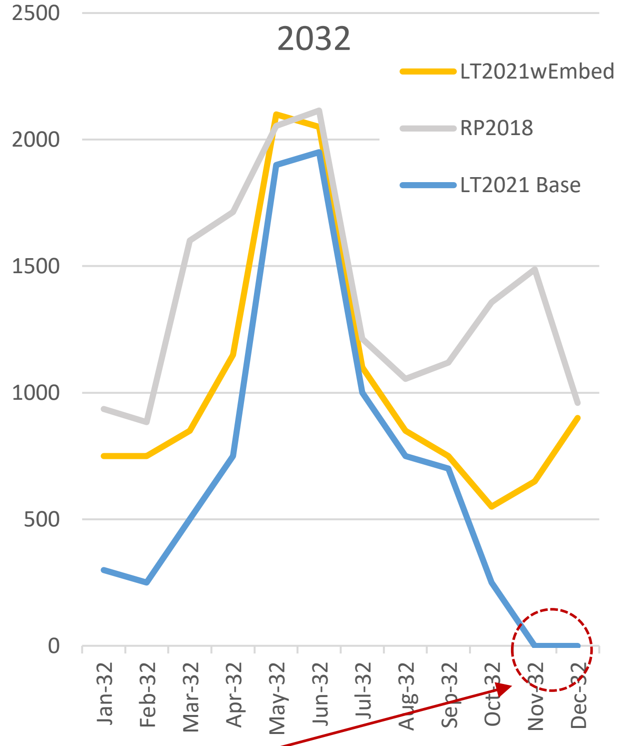
08	SCE
09	SDG&E
10	BANC
11	PG&E Bay Area
12	TIDC
13	EPE
14	Baja
15	NV North
16	NV South
17	NW MT
18	Olympia
19	PAC W
20	Puget North
21	Avista
22	BPA IDMT
23	BPA OR
24	BPA WA
25	Chelan
26	Douglas
27	Grant
28	ID Power FE
29	ID Power MV
30	ID Power TV
31	PAC E ID
32	PAC E UT
33	PAC E WY
34	Portland GE
35	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



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

2024

HE\Month	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
1	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%
3	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%
5	0%	0%	0%	6%	0%	0%	0%	0%	0%	0%	0%	0%
6	1%	0%	6%	6%	0%	0%	0%	0%	0%	2%	1%	1%
7	5%	0%	38%	22%	33%	0%	0%	0%	0%	16%	6%	1%
8	8%	8%	9%	11%	33%	0%	0%	0%	0%	6%	4%	4%
9	8%	4%	0%	6%	33%	0%	1%	0%	0%	5%	6%	2%
10	7%	4%	3%	11%	0%	0%	1%	1%	1%	3%	6%	2%
11	5%	1%	3%	6%	0%	0%	3%	1%	1%	2%	5%	2%
12	3%	0%	0%	0%	0%	0%	5%	1%	4%	0%	4%	1%
13	3%	0%	0%	0%	0%	0%	9%	1%	4%	0%	3%	1%
14	2%	0%	0%	0%	0%	0%	10%	6%	4%	0%	3%	1%
15	2%	1%	0%	0%	0%	0%	18%	9%	6%	0%	1%	2%
16	2%	0%	0%	0%	0%	0%	11%	12%	5%	2%	6%	3%
17	9%	2%	0%	0%	0%	0%	15%	16%	5%	6%	11%	17%
18	19%	23%	3%	0%	0%	0%	11%	23%	14%	19%	16%	27%
19	13%	25%	13%	6%	0%	0%	7%	22%	31%	22%	13%	21%
20	7%	20%	22%	22%	0%	0%	5%	6%	21%	13%	7%	10%
21	6%	10%	3%	6%	0%	0%	4%	1%	4%	5%	6%	6%
22	1%	2%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2028

HE\Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Month Total:	29	53	19	18	39	7	432	96	65	28	83	164
1	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%
3	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%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	5%	6%	0%	0%	0%	0%	2%	4%	0%	0%
7	3%	0%	26%	39%	0%	0%	0%	0%	6%	11%	7%	0%
8	3%	11%	0%	22%	0%	0%	1%	0%	3%	11%	7%	4%
9	7%	4%	0%	0%	5%	14%	3%	0%	0%	0%	7%	5%
10	7%	4%	0%	0%	8%	14%	4%	1%	2%	0%	5%	5%
11	3%	2%	0%	0%	8%	14%	7%	4%	2%	0%	4%	5%
12	0%	2%	0%	0%	10%	14%	8%	6%	2%	0%	4%	4%
13	3%	2%	0%	6%	8%	14%	9%	7%	2%	0%	4%	4%
14	0%	2%	0%	6%	8%	14%	9%	9%	2%	0%	4%	2%
15	0%	2%	0%	0%	8%	14%	9%	9%	2%	0%	4%	1%
16	0%	4%	0%	0%	8%	0%	9%	10%	2%	0%	4%	5%
17	0%	4%	0%	0%	10%	0%	9%	16%	8%	4%	7%	13%
18	28%	17%	0%	0%	10%	0%	9%	11%	11%	32%	12%	17%
19	21%	25%	26%	6%	8%	0%	8%	14%	28%	25%	13%	15%
20	17%	15%	37%	11%	8%	0%	6%	9%	25%	14%	7%	10%
21	7%	8%	5%	6%	3%	0%	5%	2%	6%	0%	6%	8%
22	0%	0%	0%	0%	0%	0%	2%	0%	2%	0%	4%	1%
23	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2032

HE\Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Month Total:	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%
2	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%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	1%	0%	6%	8%	0%	0%	0%	0%	0%	0%	0%	2%
7	3%	5%	23%	23%	0%	0%	0%	0%	2%	13%	0%	4%
8	7%	11%	9%	16%	0%	0%	0%	1%	2%	5%	0%	6%
9	6%	9%	3%	10%	13%	0%	1%	1%	0%	8%	0%	7%
10	6%	6%	6%	7%	13%	0%	2%	1%	0%	6%	0%	6%
11	4%	4%	3%	6%	13%	0%	2%	2%	0%	0%	0%	6%
12	2%	3%	3%	2%	25%	0%	3%	5%	0%	0%	0%	4%
13	3%	2%	0%	1%	13%	0%	6%	4%	2%	0%	0%	3%
14	2%	2%	0%	1%	13%	0%	9%	7%	0%	0%	0%	2%
15	1%	2%	0%	1%	13%	0%	12%	8%	0%	0%	0%	3%
16	2%	2%	0%	1%	0%	0%	12%	8%	0%	0%	7%	4%
17	6%	4%	0%	1%	0%	0%	14%	11%	2%	6%	0%	10%
18	17%	13%	3%	1%	0%	0%	13%	12%	14%	26%	43%	18%
19	16%	17%	14%	1%	0%	0%	14%	18%	38%	21%	36%	14%
20	12%	12%	26%	14%	0%	0%	6%	17%	33%	11%	14%	8%
21	5%	4%	6%	7%	0%	0%	6%	4%	5%	3%	0%	4%
22	3%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
23	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

PNW Outage Shares by zone, month, and year

2024

Zone\Month	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
Avista	5%	4%	3%	8%	25%	0%	7%	9%	7%	8%	5%	5%
Bonneville_IDMT	3%	4%	2%	4%	0%	0%	4%	3%	2%	4%	3%	3%
Bonneville_OR	2%	4%	2%	4%	0%	0%	3%	1%	0%	2%	3%	3%
Bonneville_WA	7%	6%	9%	6%	0%	0%	7%	3%	9%	8%	9%	6%
ChelanCountyPUD	4%	4%	3%	4%	0%	0%	1%	1%	2%	3%	4%	3%
DouglasCountyPUD	5%	5%	5%	4%	0%	0%	1%	4%	7%	4%	5%	5%
GrantCountyPUD	5%	5%	6%	4%	0%	0%	3%	4%	10%	7%	5%	5%
IdahoPowerFE	1%	2%	1%	0%	0%	0%	3%	4%	0%	1%	2%	2%
IdahoPowerMV	1%	2%	2%	0%	0%	0%	4%	5%	0%	1%	2%	2%
IdahoPowerTV	1%	3%	2%	0%	0%	0%	18%	10%	1%	1%	3%	3%
NorthwesternMT	2%	2%	2%	0%	0%	0%	1%	1%	0%	2%	2%	3%
Olympia	5%	5%	4%	4%	0%	0%	3%	3%	2%	5%	5%	4%
PacificorpEastID	1%	2%	1%	0%	0%	0%	3%	3%	0%	1%	2%	2%
PACWSouth	3%	4%	2%	2%	0%	0%	4%	1%	2%	2%	3%	3%
PortlandGeneral	5%	5%	4%	6%	0%	0%	6%	9%	5%	7%	6%	5%
PugetSoundCentral	10%	7%	11%	10%	25%	0%	7%	8%	11%	9%	10%	8%
PugetSoundNorth	8%	7%	11%	8%	0%	0%	7%	5%	9%	9%	9%	7%
SeattleCL	16%	15%	16%	20%	25%	0%	8%	15%	17%	13%	11%	17%
TacomaPower	15%	13%	16%	16%	25%	0%	8%	12%	16%	13%	11%	14%

2028

Zone\Month	1	2	3	4	5	6	7	8	9	10	11	12
Month Total:	48	58	57	34	36	5	70	131	183	67	97	116
Avista	0%	0%	0%	0%	0%	0%	3%	1%	2%	1%	4%	3%
Bonneville_IDMT	2%	3%	2%	3%	14%	20%	9%	11%	2%	3%	4%	4%
Bonneville_OR	2%	0%	2%	0%	0%	0%	4%	2%	2%	1%	4%	3%
Bonneville_WA	2%	2%	2%	0%	0%	0%	3%	3%	2%	3%	4%	4%
ChelanCountyPUD	10%	14%	11%	6%	6%	0%	7%	7%	7%	7%	7%	8%
DouglasCountyPUD	2%	5%	2%	3%	3%	0%	3%	1%	3%	4%	4%	4%
GrantCountyPUD	8%	2%	5%	6%	0%	0%	3%	4%	7%	7%	5%	4%
IdahoPowerFE	4%	5%	5%	6%	8%	0%	3%	4%	7%	4%	4%	5%
IdahoPowerMV	0%	0%	0%	0%	0%	0%	3%	1%	2%	1%	4%	3%
IdahoPowerTV	0%	0%	0%	0%	0%	0%	3%	1%	2%	1%	4%	3%
NorthwesternMT	2%	0%	2%	0%	0%	0%	6%	3%	2%	1%	4%	3%
Olympia	4%	5%	5%	3%	3%	0%	4%	3%	5%	4%	4%	5%
PacificorpEastID	2%	0%	2%	3%	0%	0%	3%	4%	3%	4%	4%	3%
PACWSouth	0%	0%	0%	0%	0%	0%	3%	1%	2%	0%	4%	3%
PortlandGeneral	4%	5%	5%	3%	3%	0%	6%	6%	7%	4%	4%	6%
PugetSoundCentral	13%	14%	14%	12%	14%	20%	9%	11%	12%	10%	7%	9%
PugetSoundNorth	10%	14%	11%	6%	11%	20%	7%	8%	10%	9%	7%	9%
SeattleCL	17%	16%	18%	26%	19%	20%	11%	17%	13%	16%	10%	11%
TacomaPower	17%	16%	16%	24%	19%	20%	11%	15%	13%	13%	9%	11%

2032

Zone\Month	1	2	3	4	5	6	7	8	9	10	11	12
Month Total:	245	350	69	151	5	0	126	158	106	317	24	140
Avista	3%	3%	1%	2%	0%	0%	0%	1%	0%	3%	0%	2%
Bonneville_IDMT	6%	7%	6%	9%	20%	0%	9%	9%	8%	3%	0%	5%
Bonneville_OR	5%	4%	1%	3%	0%	0%	4%	3%	3%	3%	0%	3%
Bonneville_WA	4%	4%	3%	3%	0%	0%	3%	4%	1%	3%	0%	3%
ChelanCountyPUD	5%	7%	7%	5%	0%	0%	6%	8%	9%	6%	4%	7%
DouglasCountyPUD	4%	4%	3%	4%	0%	0%	4%	2%	3%	3%	0%	3%
GrantCountyPUD	5%	6%	6%	5%	0%	0%	4%	6%	9%	6%	0%	5%
IdahoPowerFE	6%	5%	9%	8%	20%	0%	5%	7%	11%	6%	0%	4%
IdahoPowerMV	3%	3%	1%	1%	0%	0%	3%	1%	0%	0%	0%	0%
IdahoPowerTV	3%	3%	1%	1%	0%	0%	4%	3%	0%	0%	0%	2%
NorthwesternMT	3%	3%	1%	2%	0%	0%	6%	5%	0%	3%	0%	2%
Olympia	5%	5%	3%	5%	0%	0%	4%	3%	3%	3%	0%	4%
PacificorpEastID	4%	4%	3%	3%	0%	0%	3%	5%	0%	3%	0%	3%
PACWSouth	3%	3%	1%	1%	0%	0%	0%	1%	0%	0%	0%	0%
PortlandGeneral	5%	5%	3%	5%	0%	0%	7%	5%	7%	6%	0%	5%
PugetSoundCentral	8%	8%	10%	9%	20%	0%	7%	9%	12%	11%	17%	8%
PugetSoundNorth	6%	8%	9%	6%	0%	0%	6%	9%	9%	3%	13%	7%
SeattleCL	13%	10%	16%	15%	20%	0%	14%	11%	13%	22%	35%	19%
TacomaPower	13%	10%	14%	14%	20%	0%	13%	9%	13%	19%	30%	17%