2024 Resource Program

Public Workshop

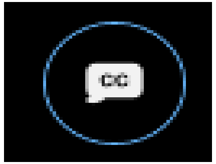
December 19th, 2024

Agenda

Start	End	Time	Topic	Presenter/Facilitator
9:00 AM	9:05 AM	5	Workshop Agenda, Format, and Safety Moment	Brian Dombeck
9:05 AM	9:10 AM	5	Introductory Remarks	Rachel Dibble *(VP, Bulk Marketing)*
9:10 AM	9:25 AM	15	Resource Program Background and Overview	Ryan Egerdahl
9:25 AM	10:25 AM	60	Updates to Needs Assessment	Esther Neuls
10:25 AM	11:30 AM	65	Candidate Resource Assessment	Bonnie Watson Carla Essenberg Eric Graessley
11:30 AM	12:00 PM	30	Market Assessment	Eric Graessley
12:00 PM	1:30 PM	90	BREAK	
1:30 PM	2:15 PM	45	Solver Review	Carla Essenberg
2:15 PM	3:45 PM	90	Resource Solutions to Scenarios and Sensitivities	Carla Essenberg Eric Graessley
3:45 PM	4:00 PM	15	Next Steps, Discussion, and Q&A	Bonnie Watson Brian Dombeck
4:00 PM			Conclusion	

Webex Accessibility tools

To enable Closed Captions



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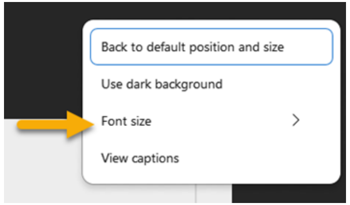

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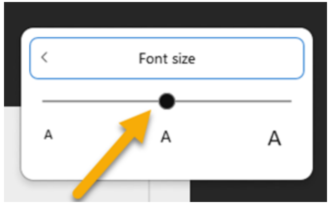

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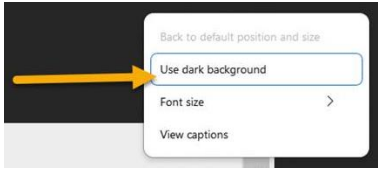
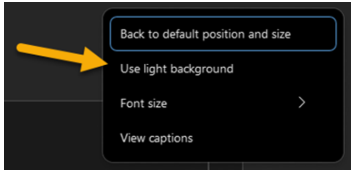




Webinar Format

- Presenters will take pauses for questions and feedback (chat and raised hands).
- Webex attendees may only chat with the Webex meeting Host. The chat will be moderated by the Host and publicly-appropriate content re-posted.
- Raised hands and chats will be addressed in the order received.
- Please remember to state your name and organization.

Safety Moment: Holiday Season Safety

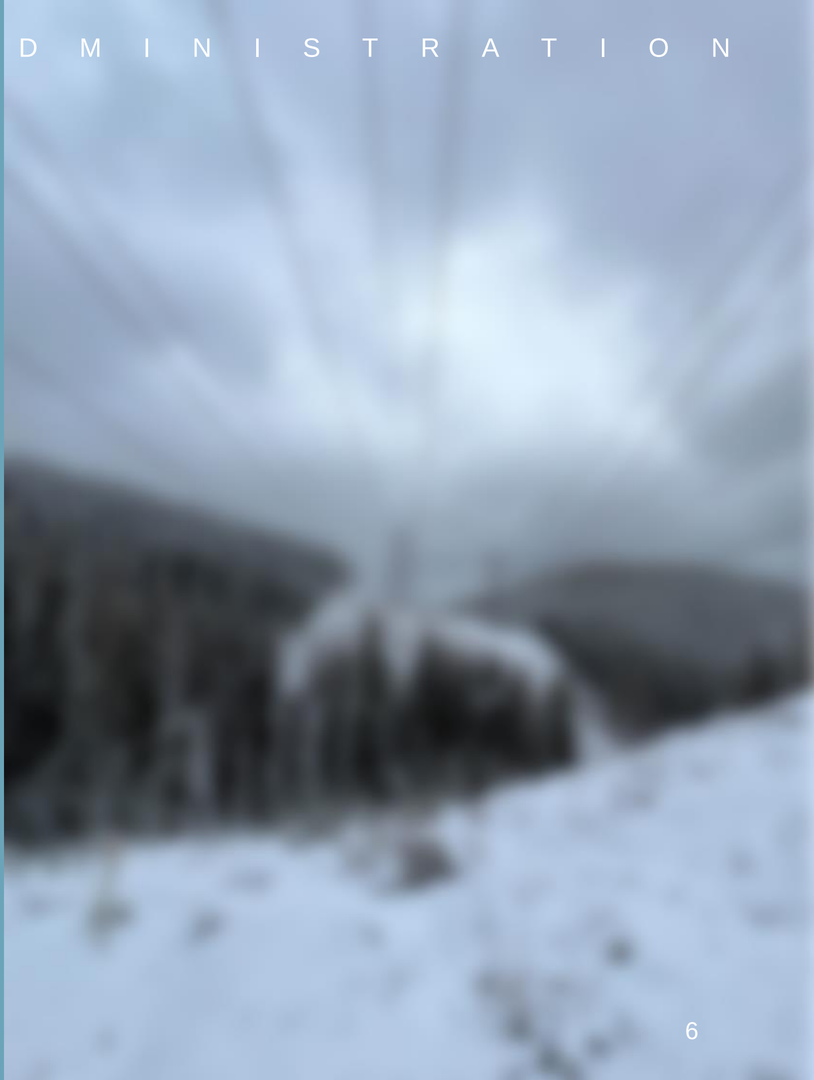
12 Safety Tips of the Holidays:

- Wash hands often to help prevent the spread of germs.
  - It's flu season. Wash your hands with soap and clean running water for at least 20 seconds.
- Bundle up to stay dry and warm.
  - Wear appropriate outdoor clothing: light, warm layers, gloves, hats, scarves, and waterproof boots.
- Manage stress.
  - Give yourself a break if you feel stressed out, overwhelmed, and out of control. Some of the best ways to manage stress are to find support, connect socially, and get plenty of sleep.
- Don't drink and drive or let others drink and drive.
  - Whenever anyone drives drunk, they put everyone on the road in danger. Choose not to drink and drive and help others do the same.
- Be smoke-free.
  - Avoid smoking and secondhand smoke. Smokers have greater health risks because of their tobacco use, but nonsmokers also are at risk when exposed to tobacco smoke.
- Fasten seat belts while driving or riding in a motor vehicle.
  - Always buckle your children in the car using a child safety seat, booster seat, or seat belt according to their height, weight, and age. Buckle up every time, no matter how short the trip and encourage passengers to do the same.
- Get exams and screenings.
  - Ask your health care provider what exams are needed when. Update your personal and family history.
- Get your vaccinations.
  - Vaccinations help prevent diseases. Everyone 6 months and older should get a flu vaccine each year.
- Monitor children.
  - Keep potentially dangerous toys, food, drinks, household items, and other objects out of children's reach. Protect them from drowning, burns, falls, and other potential accidents.
- Practice fire safety.
  - Most residential fires occur during the winter months, so don't leave fireplaces, space heaters, food cooking on stoves, or candles unattended. Have an emergency plan and practice it regularly.
- Prepare food safely.
  - Remember these simple steps: Wash hands and surfaces often, avoid cross-contamination, cook foods to proper temperatures and refrigerate foods promptly.
- Eat healthy, stay active.
  - Eat fruits and vegetables which pack nutrients and help lower the risk for certain diseases. Limit your portion sizes and foods high in fat, salt, and sugar. Also, be active for at least 2½ hours a week and help kids and teens be active for at least 1 hour a day.

Introductory Remarks

Rachel Dibble

VP for Bulk Marketing



Reminder: Power Planning at BPA

- Each year, BPA publishes the Pacific Northwest Loads and Resources Study – often referred to as the **White Book** - which analyzes BPA's projections of retail loads, contract obligations, contract purchases, and resource capabilities over a 10-year study horizon and describes expected energy and capacity surplus/deficits under varying water conditions.

- On a biennial basis, BPA conducts an IRP-like assessment collectively referred to as the **Resource Program** which examines uncertainty in loads, water supply, natural gas prices, and electricity market prices to develop least-cost portfolios of resources that meet BPA's obligations.

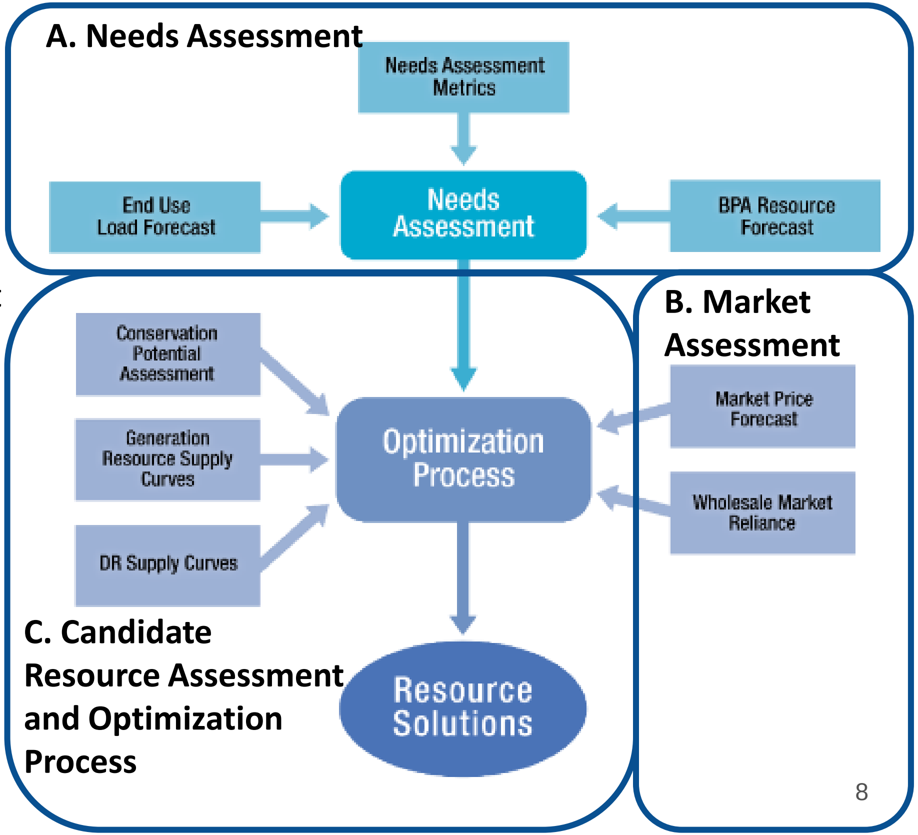
- These processes are voluntarily undertaken to inform acquisition strategies and provide valuable insight into how Bonneville can meet its obligations cost-effectively. They are neither decision documents nor a process required by any external entity.

Resource Program Process

A. The **Needs Assessment** measures the federal system's expected generating resource capabilities to meet projected load obligations

B. The **Market Assessment** simulates the evolution of power markets in the Western Interconnect to generate a long-term forecast of Mid-Columbia prices and market availability under a variety of generation, load, and economic conditions

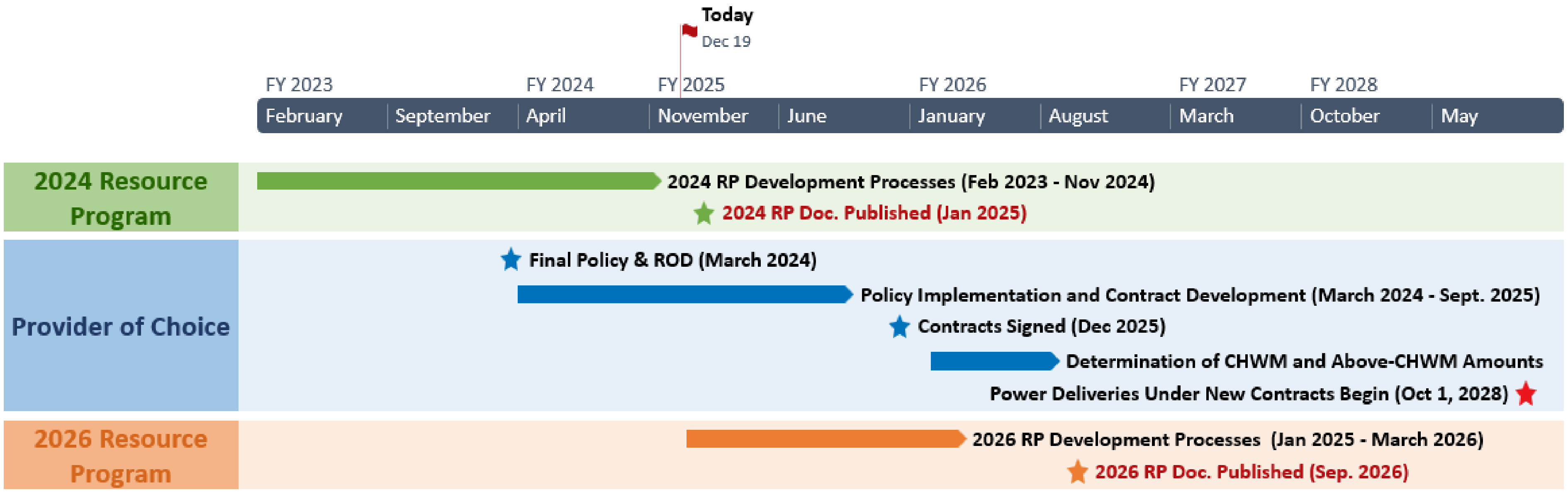
C. The **Candidate Resource Assessment and Optimization Process** explores how the varying costs, performance, and availability of candidate demand-and-supply-side resources (including conservation, demand response, market purchases, and generating resources) as well as wholesale market reliance can be used to provide a least-cost resource strategy for meeting identified needs



Where we are in the planning cycle

Sept 2026	RP26 published
Winter 2025	RP26 kicks-off
Jan 2025	RP24 published (in progress)
Ongoing	RP24 feedback review, RP26 planning (in progress)
Ongoing	**RP24 current and prior workshops** (in progress)
Dec 2024	**Needs Assessment updates; candidate resources for meeting needs; resource solutions**
Jun 2024	Needs Assessment and Market Assessment study results
Apr 2024	Needs Assessment data inputs and methods
Nov 2023	Data, methods, and results of forecasting for BPA obligations and regional TRL; Needs Assessment overview
Jun 2023	Overview of planned scope and key expected innovations for 2024 Resource Program
Feb 2023	RP24 Kicks-off

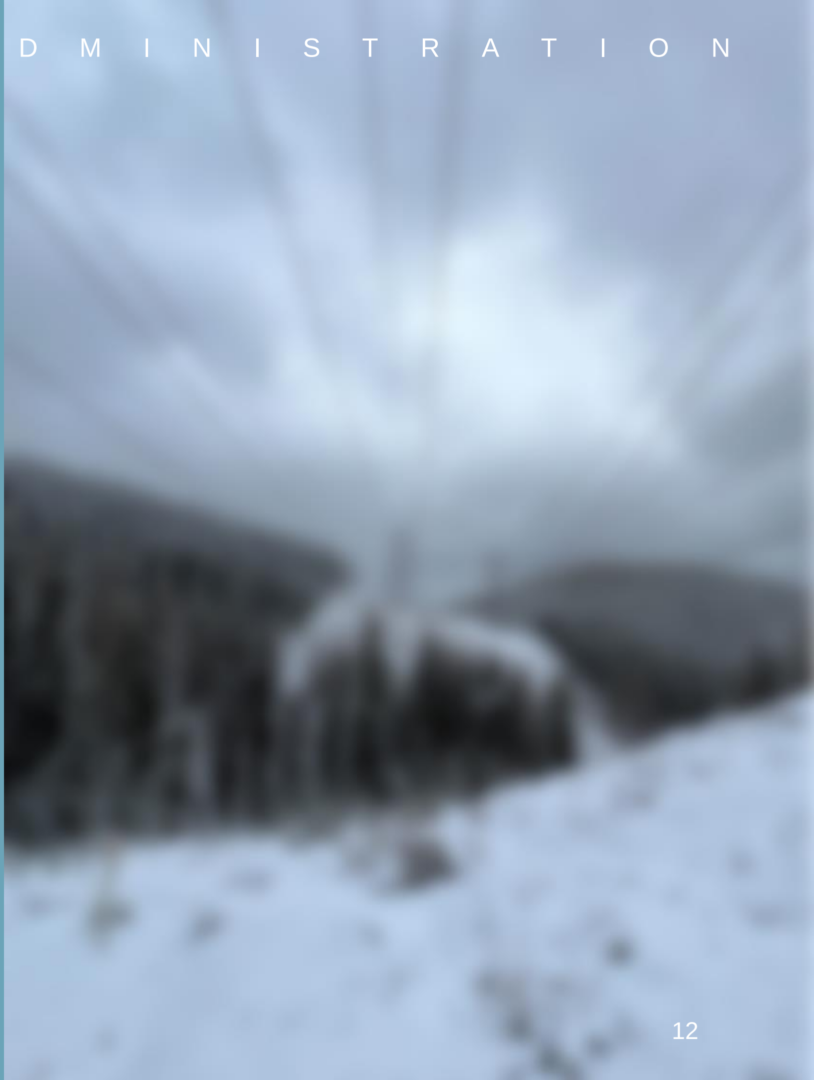
Resource Program and Provider of Choice



Possible Enhancements for RP26

- Based on feedback to RP24, BPA will consider exploring a range of modeling enhancements for RP26, including but not limited to:
  - Assess capacity metric under extreme weather and low water
  - Reintroduce balancing reserves study to Needs Assessment
  - Connect resource solutions to WRAP forward showing position
  - Include additional candidate resource options
  - Refine and refresh characteristics for candidate resources, including performance of renewables
  - Enhance linkages between resource solutions, market assessment, and needs assessment modeling
- We will also solicit additional feedback from stakeholders as RP26 planning gets underway

Needs Assessment Updates



Esther Neuls

Needs Assessment Metrics

From June 2024 RP Workshop

- Annual Energy
  - Evaluates the annual average energy surplus/deficit under p10-by-month critical water conditions
- P10 Heavy Load Hour (HLH)
  - Evaluates the monthly average surplus/deficit over heavy load hours (hours ending 7-22, Mon – Sat, excluding holidays) under p10-by-month critical water conditions
- P10 Superpeak (SPK)
  - Evaluates the monthly average surplus/deficit over the six peak HLH per weekday (Mon – Fri) under p10-by-month critical water conditions
  - The ~120 superpeak hours per month are a subset of the ~384 heavy load hours month
- 18-Hour Capacity
  - Evaluates the monthly average surplus/deficit over six peak load hours per day across three-day extreme weather load events under median water (p50) conditions
    - Cold Snap – temperatures from January 2024 event for Dec/Jan/Feb
    - Heatwave – temperatures from June 2021 event for July/August

Needs Assessment (NA) Topics to address

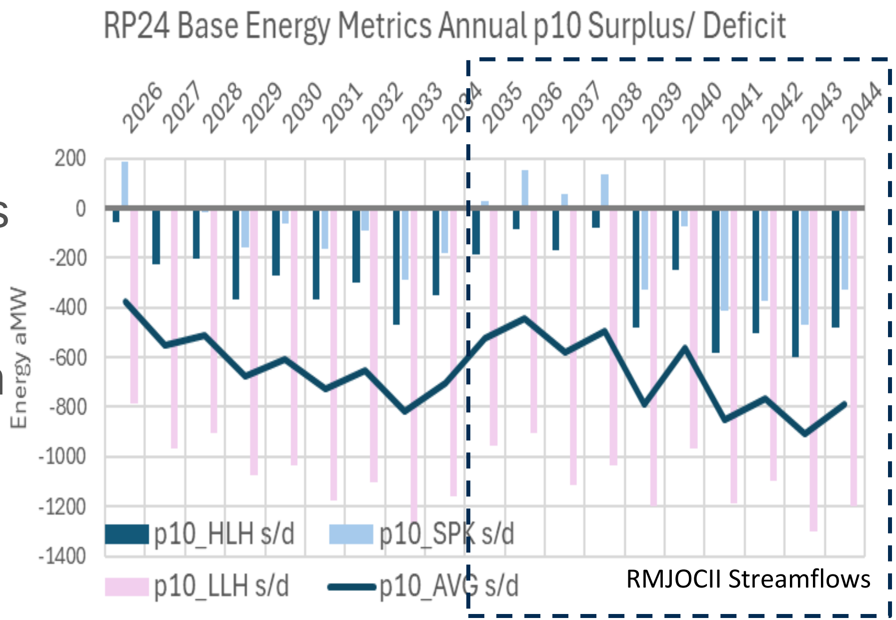
1. Adding p10 monthly Average (AVG) energy metric to existing Needs Assessment metrics:

Previous NA Metrics	Updated NA Metrics
Annual Energy	Annual Energy
P10 HLH Monthly	P10 AVG Energy
P10 SPK Monthly	P10 HLH Monthly
18Hr Capacity	P10 SPK Monthly
	18Hr Capacity

2. Columbia River Treaty (CRT) Agreement-in-principle (AIP) update to all study results

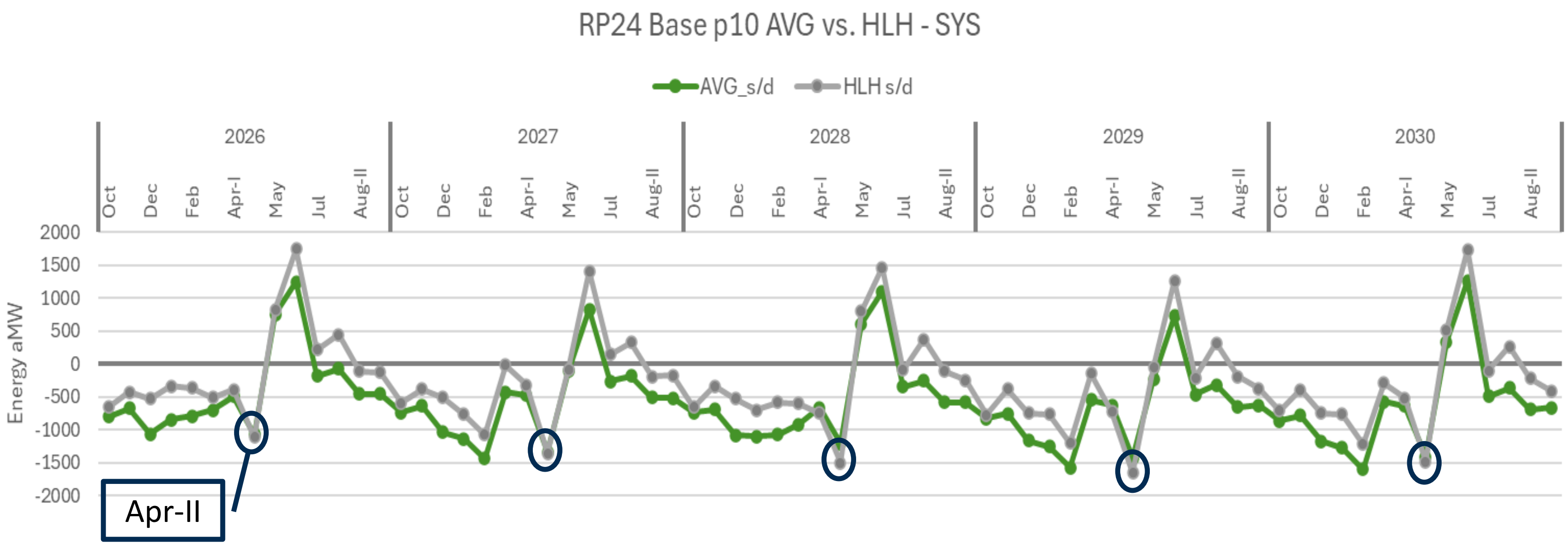
1. P10 Monthly AVG Energy metric

- Overview
  - Hourly data analyzed for Loads and Resources to determine needs
  - Monthly P10 HLH metric historically was the most constrained metric in Needs Assessment.
  - Added to support Market sensitivities on monthly AVG needs.
  - Monthly P10 AVG metric now the most deficit metric.



- Key takeaway
  - P10 AVG monthly deficits exceed P10 HLH monthly in most months, with exceptions most often in Apr-II.

P10 Monthly AVG vs. HLH Energy metric – FY26-30

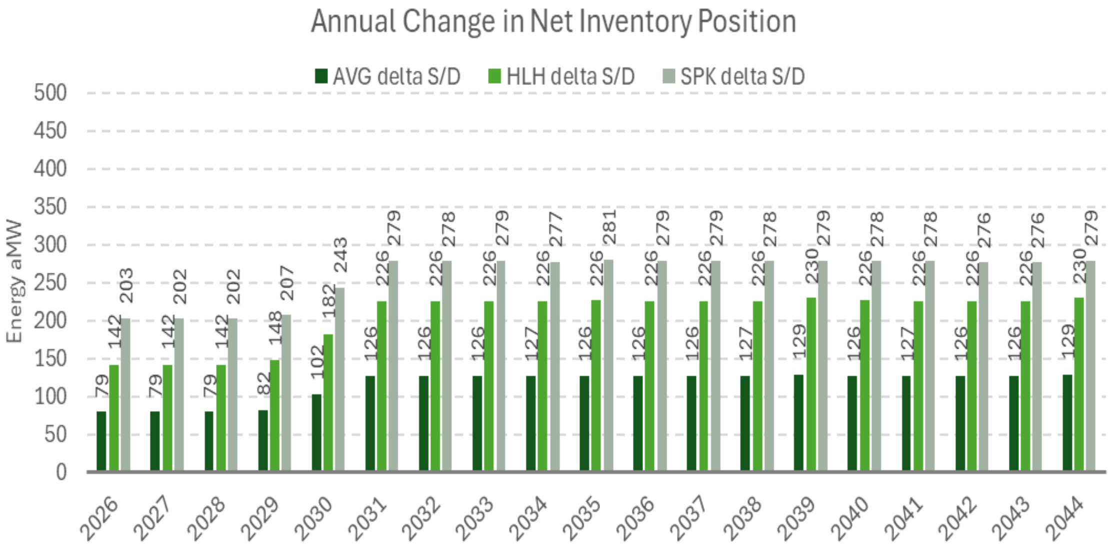


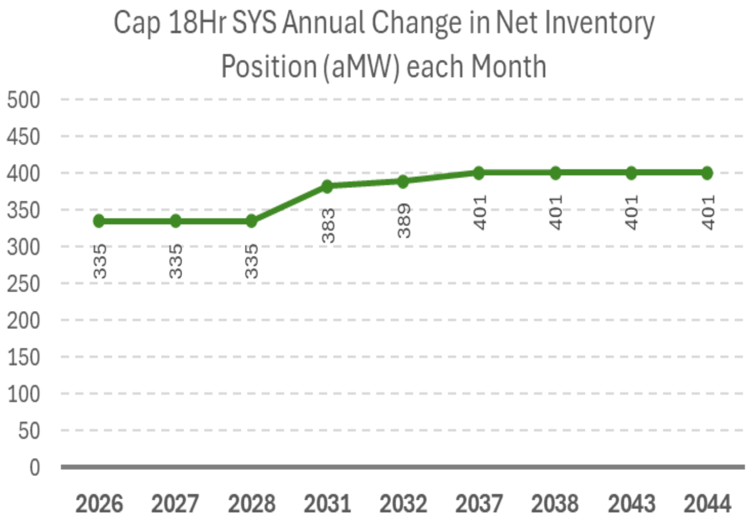
- P10 HLH (grey) deficits often exceeds P10 AVG (green) deficits in Apr-II, as hydro resources are most constrained right before run-off begins.

2. CRT AIP impact to Needs Assessment

- Overview
  - Monthly energy reduced from 454 aMW to 305 aMW in OY2025 and decreasing to 225 aMW by OY2031
  - Hourly capacity reduced from 1141 MW to 660 MW in OY2025 and decreasing to 550 MW by OY2034
  - CRT AIP incorporated in all Needs Assessment studies
- Key Takeaway
  - Historic Canadian Entitlement Allocation (CEA) take is shaped to highest-value HLH, hence net changes over SPK exceeds HLH which exceeds AVG (next slide)

CRT AIP change to Needs Assessment by Metrics



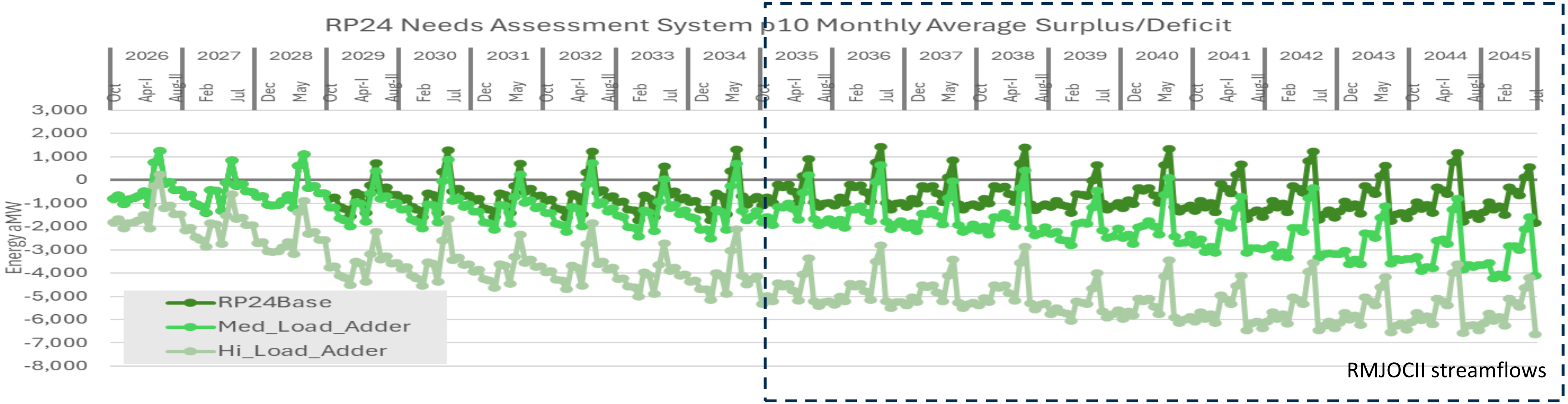


- Positive numbers indicate increase in total net inventory position
- Results based on historic CEA hourly take & shape
- Assuming previous Mid-C utility return %

CRT AIP change to Sensitivity Studies

a) Load Adders

– Annual changes matches amounts presented in the overall metrics

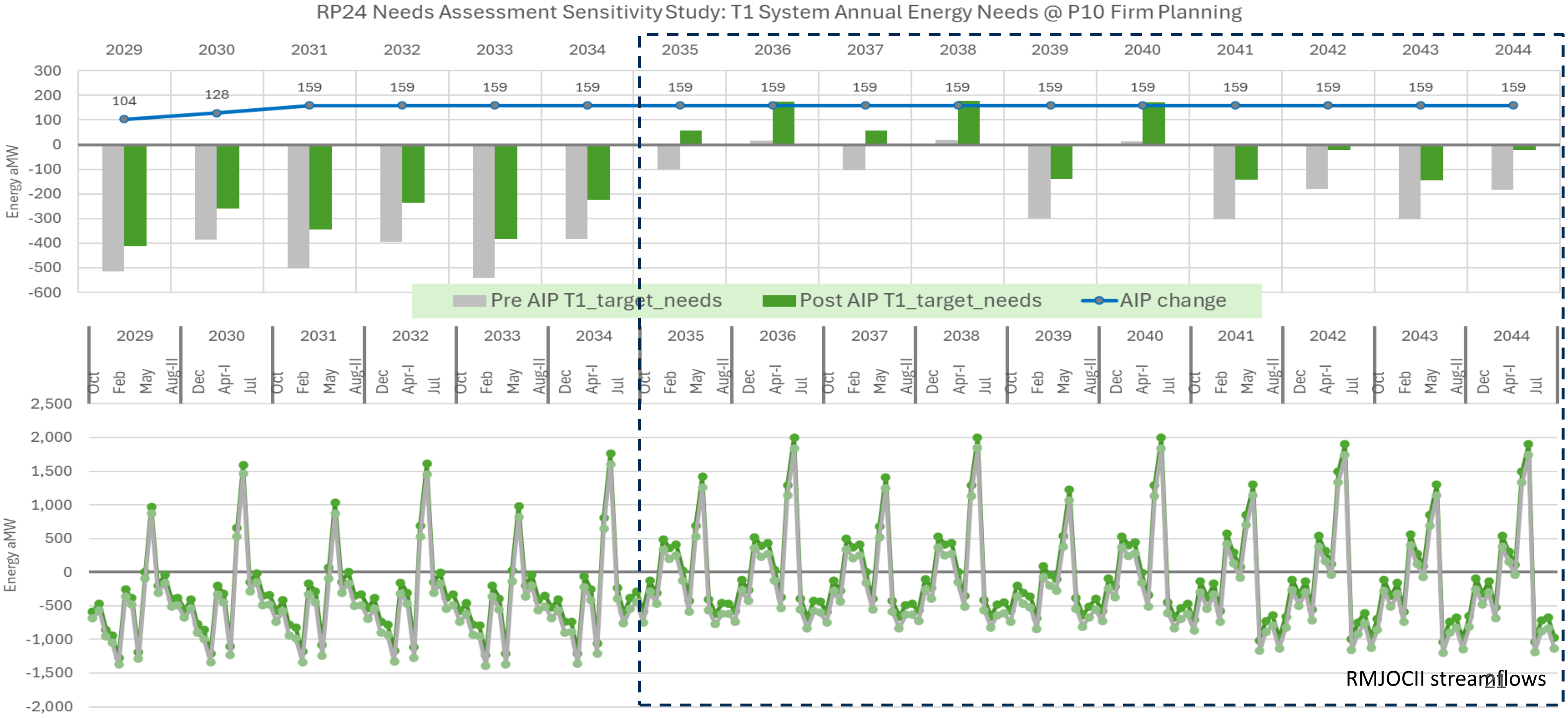


b) T1 System size

– Overall changes from AIP is larger than corresponding surplus/deficit metrics because T1SFCO is pre-Slice-Right-to-Power, and Tier one resources will be evaluated against 7250 aMW, instead (next slide)

CRT AIP change to T1 System Size

T1_Target_Needs = T1SFCO – shaped T1_target
T1_target = 7250
Negative results = Needs to be met/ solve
Zero = 7250 achieved, resource balanced



Candidate Resource Assessment

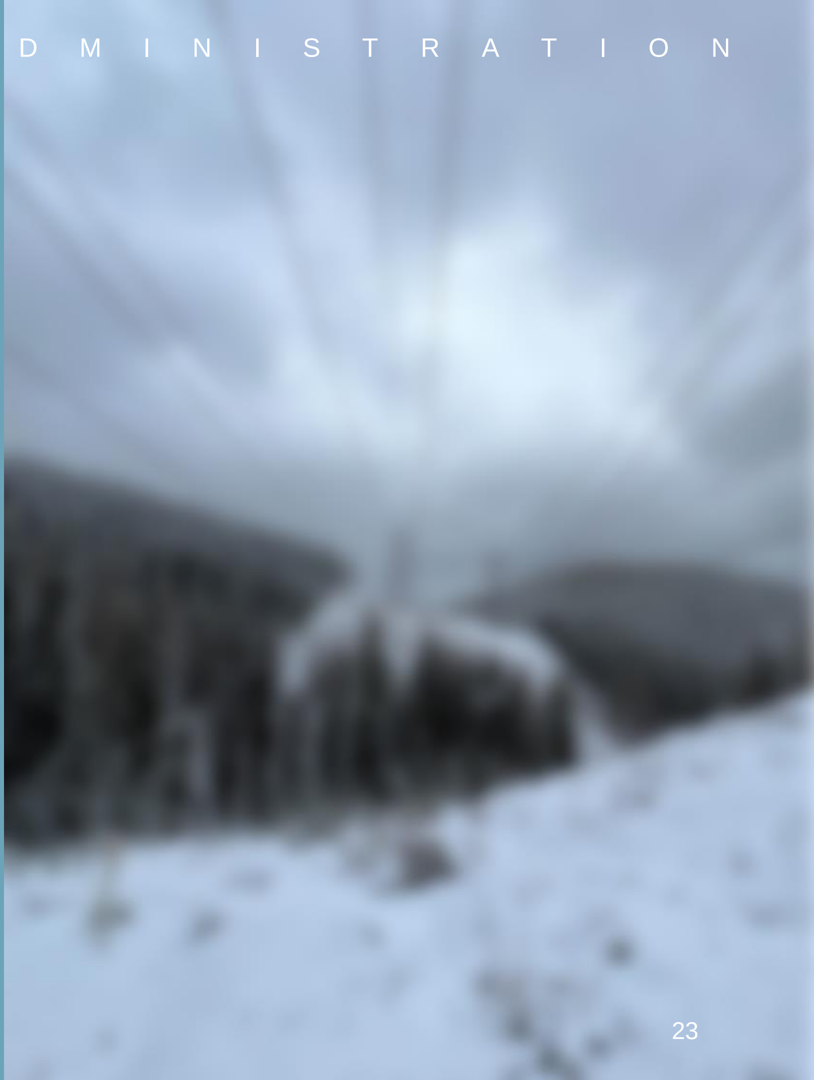
Demand-side resources

Bonnie Watson

Supply-side resources

Carla Essenberg

Eric Graessley



Conservation & Demand Response Potential Assessments

How CPA & DRPA Feed into Resource Program

CPA & DRPA

Not Technically Feasible	Technical Potential	
Not Technically Feasible	Market Barriers	Achievable Technical Potential

Resource Program

Not Technically Feasible	Market Barriers	Not Cost-Effective	Achievable Economic Potential

Parallel process taking place at the Northwest Power & Conservation Council for the 9th Plan development

Goals of the CPA & DRPA Updates

Develop **20-year estimates** of technical and achievable conservation and DR potential in BPA's service territory **(2026 – 2045)**

Produce conservation and DR **supply curves** for use in BPA's **Resource Program modeling**

Supply curve: *A quantification of the available conservation or DR at a given price point, often broken out by sector, technology, or program*

What changed in this CPA and DRPA?

Updated timeline by two years to align with RP24

Aligned climate forecast approach for consistency

Incorporated updates from Regional Technical Forum

Geographically split out SWEDE region

Included updated BPA forecast and sector growth rates

Reasons for these changes:

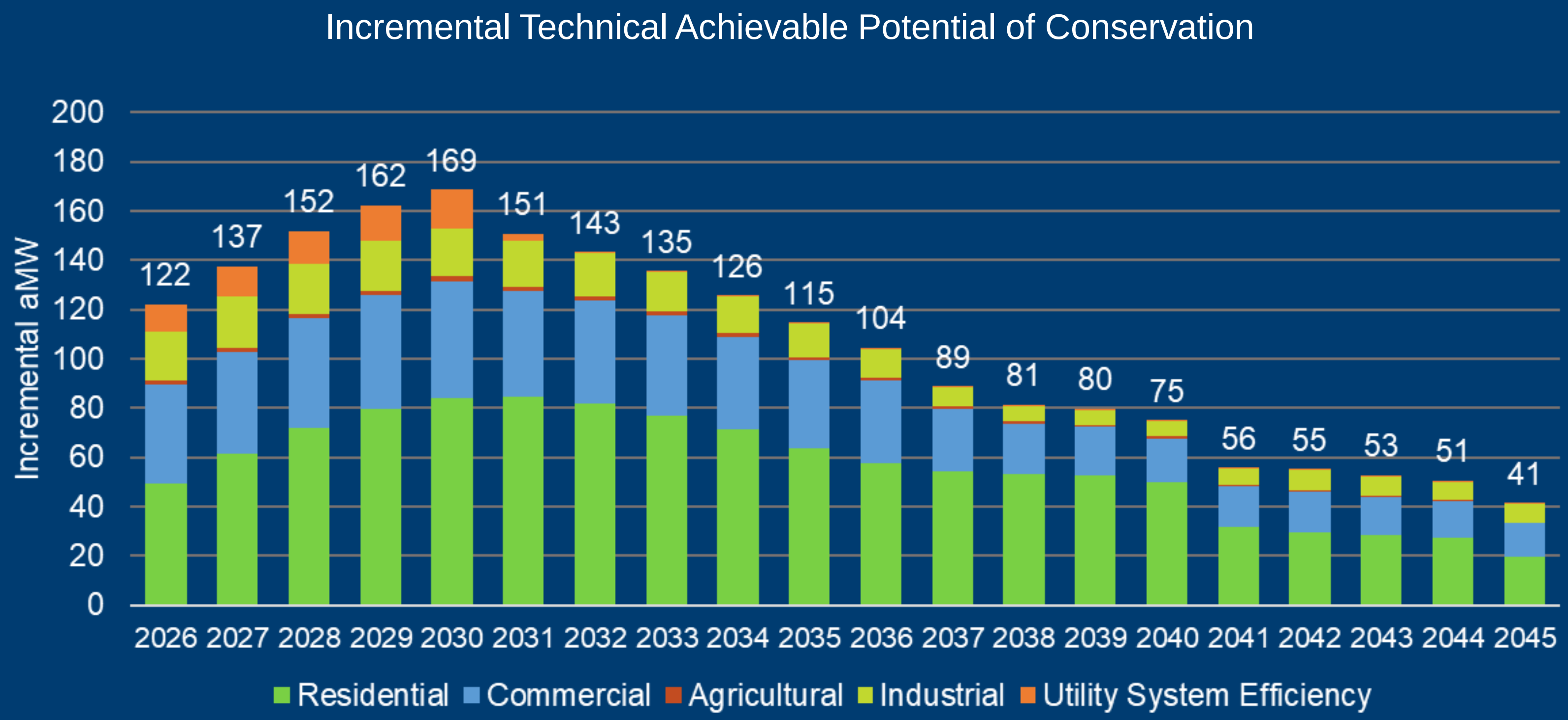
1. Ensure the CPA/DRPA output was formatted to the needs of the Resource Program
2. Make updates to conform results with RTF research and modeling
3. Ensure results take advantage of most up-to-date information

CPA & DRPA Results

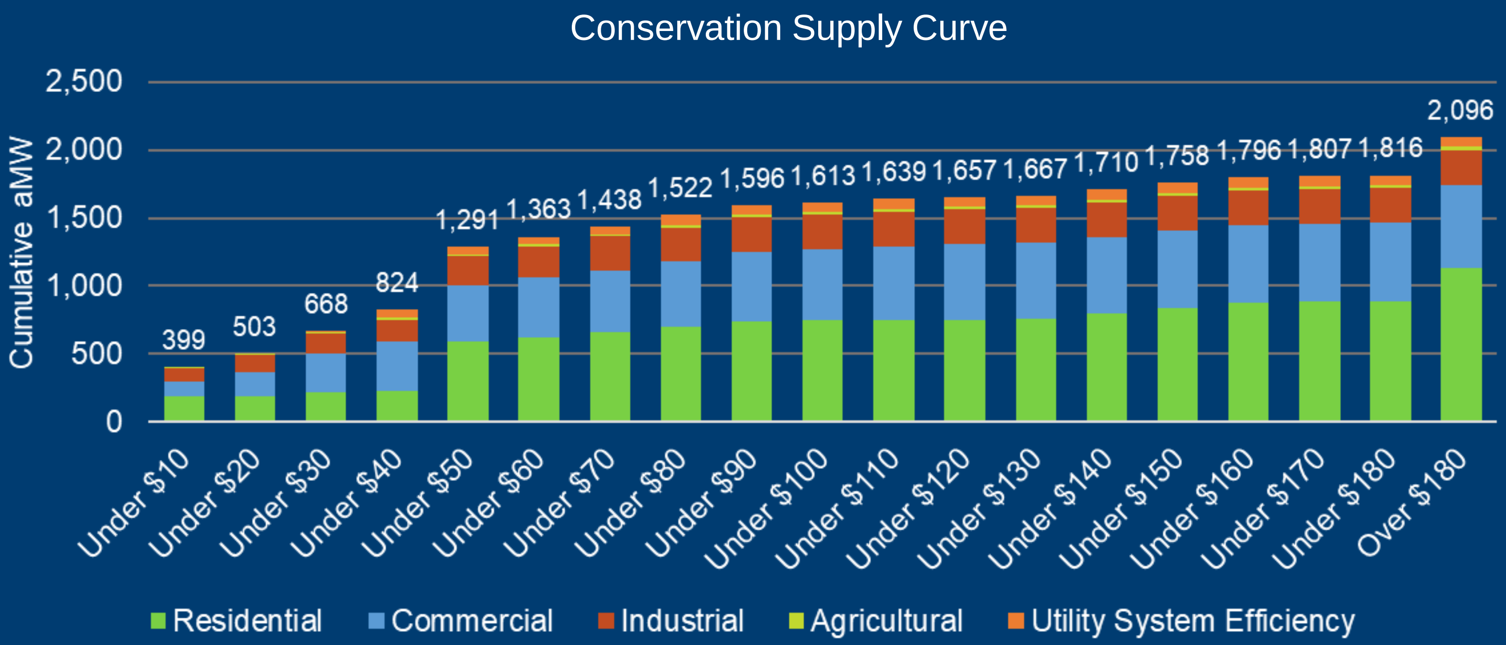
Unique Attributes of EE & DR

- Not curtailable (EE-only)
- Considered on a bundle-basis
- Programs take time to develop
- EE resources can become exhausted

Programs take time to build and eventually decrease

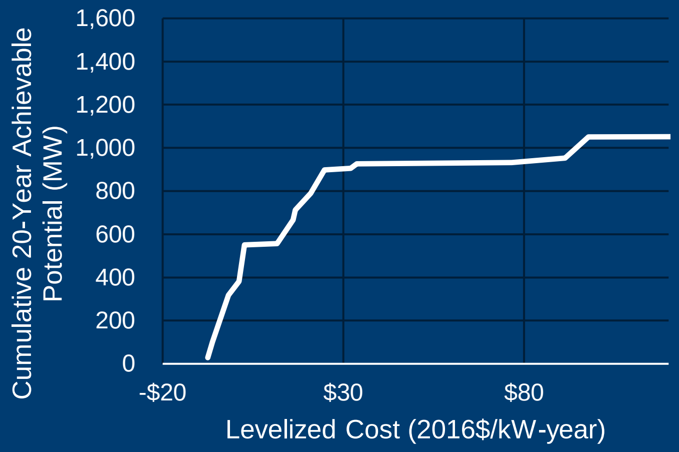


The Resource Program assesses conservation according to its sector-technology-cost bundle

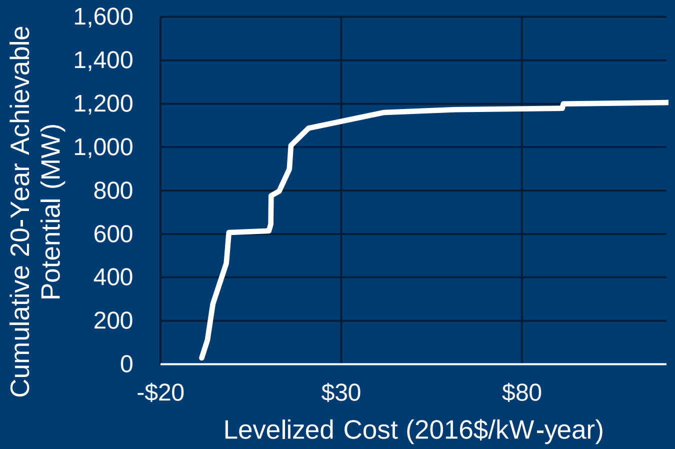


Demand response bundles are similarly assessed, but with different supply conditions

Winter



Summer



Note: *While conservation resources are studied and assumed to have a certain hourly conservation benefit, demand response resources are dispatchable in varying increments with varying frequency depending on the resource of interest*

Supply Side Resource Assessment

Supply-side resource section outline

- Context
- Options
- Contributions
- Costs
- Net Costs & flexibility

Supply-side resource context

- For the 2024 Resource Program, all supply-side resource options are representative estimates. No specific project options are included in the base case.
- For the next Resource Program and for any actual acquisition decisions, we will evaluate specific projects (including best estimates of site-specific capabilities, configurations, and costs).
- Online years of 2026, 2031, 2037, and 2043 are intended to simplify the problem and be consistent with the sampling methodology, not restrict actual acquisitions to those specific years.
- The diversity of carbon policies across the BPA service territory complicate the modeling of natural gas in the optimization process. Modeling natural gas also includes other technical challenges that led to the decision to not include it directly in the solver and to evaluate it outside of the model. Additional analysis is provided later in the resource solutions section.

Supply-side options

- Types: solar, wind, 6h and 12h storage, hybrid solar + storage, SMR, geothermal
- Dates going online: 2026*, 2031, 2037, 2043
- Interconnection cost is set higher for additions beyond 300 MW (solar, storage) or 450 MW (hybrid, SMR)**
- Geothermal has been limited to 100 MW per period and location
- Locations: MIDC***, SWEDE
- We do not include options for contracting with existing resources or for acquiring output from resources for less than their expected plant life

*2026 start not available for SMR or geothermal

**Transmission costs were estimated in collaboration with Transmission SMEs. These costs can be challenging to estimate and potentially vary significantly for each project. We will continue to refine this methodology

***There are 3 MIDC locations for solar: OR E and W of the Cascades, WA E of the Cascades

Resource contributions to meeting needs (1 of 2)

- Wind
  - Contributions to 18hr capacity and superpeak are calculated from BPA system (MIDC) and IPCO BAA (SWEDE) hourly historical wind generation data during actual superpeak periods and 18hr events
  - Contributions to flat and HLH needs are calculated from BPA data and wind risk model results (MIDC) and National Renewable Energy Laboratory data (SWEDE)
- Solar
  - Contributions are calculated from National Renewable Energy Laboratory hourly data for four locations: OR west, OR east, WA east, and ID southeast

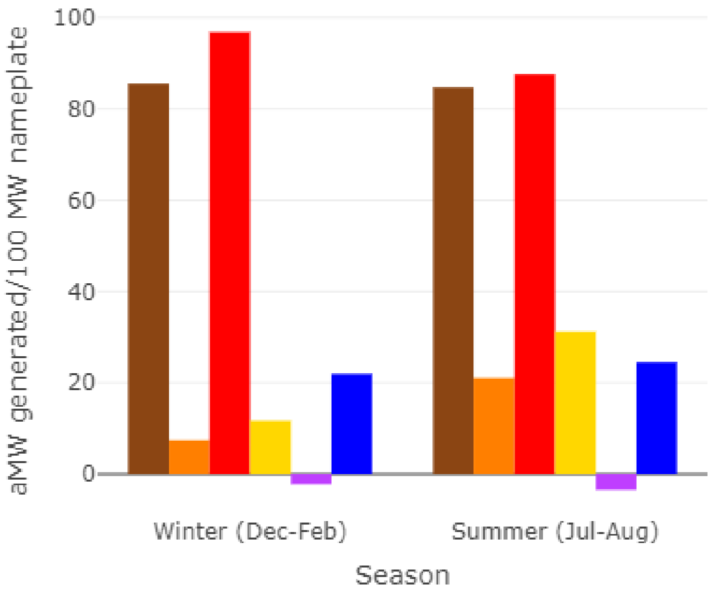
Resource contributions to meeting needs (2 of 2)

- SMR and geothermal
  - Assumed to be running during superpeak and 18hr events, barring outages*
  - Contributions to flat and HLH needs are based on performance runs with high energy prices (P85-P95), in which generators run as long as prices exceed variable costs
- Storage
  - Assumed to be discharging during superpeak and 18hr events, barring outages*
  - Contributions to flat and HLH needs are based on simulated dispatch in response to prices in performance studies, with charging requirements reflected as additional energy needs
- Hybrid solar + storage
  - We assume an AC coupled system and add contributions of both the solar and storage components for both energy and capacity

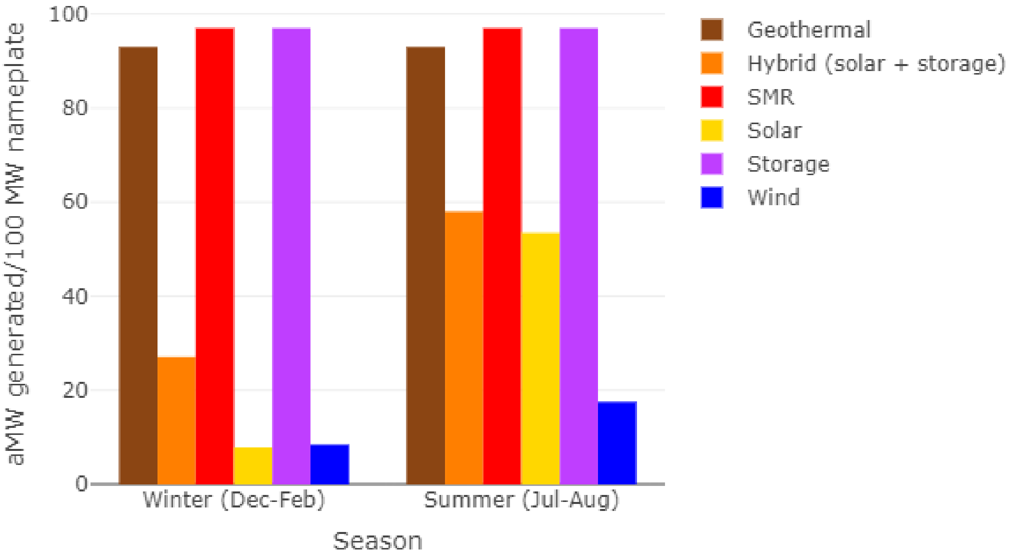
*Forced outage rates are assumed to be 7% for geothermal and 3% for storage and SMR

Supply side resources: aMW generated per 100 MW nameplate capacity

All hours:



18h events:



Values shown are averages for FY2044, MIDC. **Modeled values vary across months, across locations, and between 6h and 12h storage.**

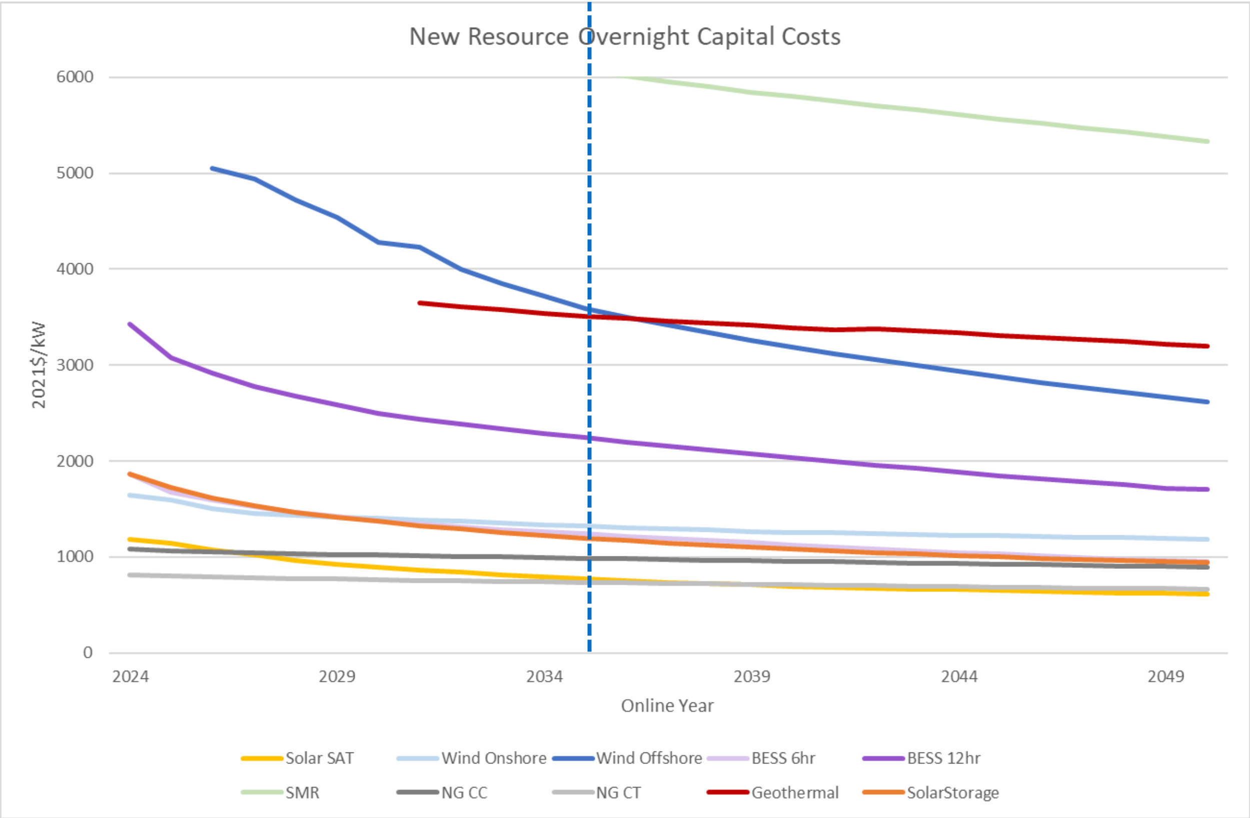
Supply Side Resource Costs

For evaluating supply-side resource cost, we have two time windows that will have substantially different assumptions. These are based on the earliest year we think a BPA financed new resource could be online.

1. 2026-2034: PPAs / partial stakes in projects that are in already in development and in the interconnection queue.
2. 2035+: Greenfield / new projects that can fully benefit by BPA financing

	2026-2034	2035+
Discount Rate (Nominal)	2.81%	
WACC (Nominal)	7%	3.96%
Inflation Rate	~2.3%	
Investment Tax Credit (ITC)	30%	40% * 85% = 34%
Production Tax Credit (2023$/MWh)	$27.50	$30 * 85% = $25.50

Capital Costs by Online Year



	Overnight Capital Costs by Online year, 2021$/kW									
Online Year	Solar SAT	Wind Ons	Wind Offs	BESS 6hr	BESS 12hr	SolarStora	SMR	NG CC	NG CT	Geotherm
2024	1183	1643		1865	3429	1865		1087	818	
2025	1143	1593		1674	3073	1723		1067	803	
2026*	**1079**	**1509**	**5050**	**1591**	**2916**	**1618**		**1054**	**793**	
2027	1021	1451	4936	1521	2781	1539		1045	784	
2028	969	1435	4720	1466	2673	1464		1037	778	
2029	927	1419	4543	1423	2588	1418		1029	771	
2030	898	1404	4276	1378	2498	1370		1022	765	
2031*	**868**	**1387**	**4233**	**1346**	**2438**	**1326**	**6451**	**1014**	**758**	**3646**
2032	842	1370	3997	1316	2383	1294	6309	1007	753	3609
2033	819	1354	3849	1288	2332	1258	6217	1001	748	3574
2034	795	1339	3715	1262	2284	1224	6142	994	744	3543
2035	773	1324	3593	1241	2244	1197	6075	987	738	3510
2036	752	1309	3500	1218	2201	1170	6012	981	733	3486
2037*	**737**	**1294**	**3414**	**1195**	**2158**	**1146**	**5954**	**975**	**728**	**3463**
2038	722	1280	3334	1172	2116	1123	5901	969	723	3440
2039	711	1267	3258	1150	2074	1102	5847	963	718	3415
2040	697	1259	3187	1129	2034	1080	5799	957	713	3392
2041	689	1251	3121	1108	1995	1063	5753	951	708	3370
2042	676	1244	3056	1088	1958	1048	5704	945	703	3380
2043*	**668**	**1236**	**2993**	**1068**	**1922**	**1030**	**5659**	**939**	**698**	**3357**
2044	660	1229	2933	1049	1885	1016	5612	933	693	3334
2045	652	1222	2876	1030	1850	1000	5564	926	688	3311
***Bold years indicate RP2024 model decision years**										
IRA Treatment	PTC	PTC	ITC	ITC	ITC	ITC	ITC	-	-	ITC
FOM (2021$/kW-year)	20	35	85	43	68	53	119	30	23	107
VOM (2021$/MWh)	0	0	0	0	0	0	3	1.9	6.44	0
Plant Life (years)	30	30	30	20	20	25	60	30	30	30
Construction time (year	1	3	3	1	1	1	6	3	3	7

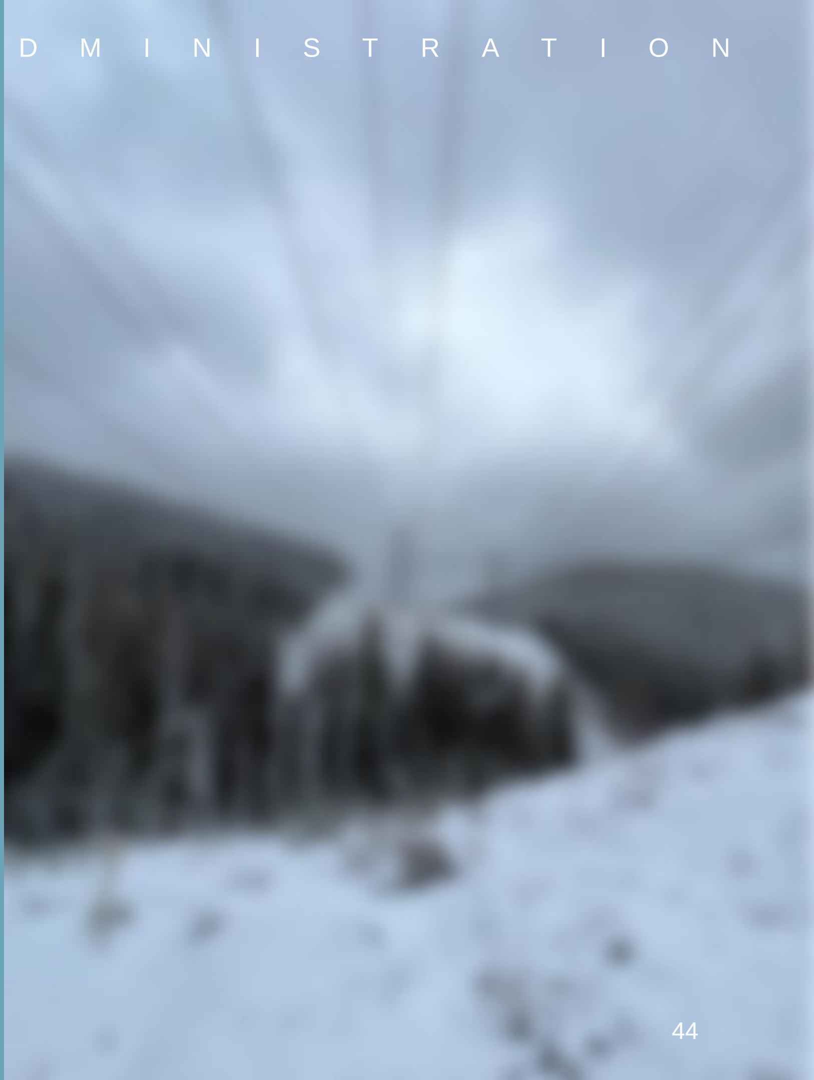
Getting to Net Costs and Valuing Flexibility

The solver evaluates each resource based on a single, net cost value over the 20-year horizon.

1. From the OCC and financing assumptions we calculate levelized fixed costs
2. Add FOM
3. VOM, Fuel costs, charging costs, and energy revenue* are calculated in the performance studies and averaged across the full distribution.
4. The costs, net of energy revenues, are discounted to NPV and summed to a single net cost for each resource option.

*The performance studies evaluate resource energy value on an hourly basis. More flexible resources are able to dispatch energy into more valuable hours and get higher energy revenues. We do not differentiate between whether the energy is avoiding a purchase or enabling a sale—all energy produced / consumed is valued at the forecast Mid-C price.

Market Assessment



Eric Graessley

Section Outline

Notes on PCM

Outline

- Key takeaways
- Aurora and topology
- Buildout
- Primary differences (calibration and negative price assumptions)
- Prices
- Market depth
- Market inputs to solver

Key Takeaways – Market Assessment

- Northwest average price forecast levels have increased moderately, and the distribution of prices across ranges of potential future conditions has increased substantially.
- Inflation Reduction Act (IRA) impacts (including electrification load increases) significantly increase expected buildouts throughout the WECC.
- The combination of additional new resource buildout and improved modeling of short duration storage resource operation resulted in an increase to projected market depth available to meet BPA energy needs.

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 the least cost method of meeting load, given resource and transmission constraints (resource limits and variable costs, 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.

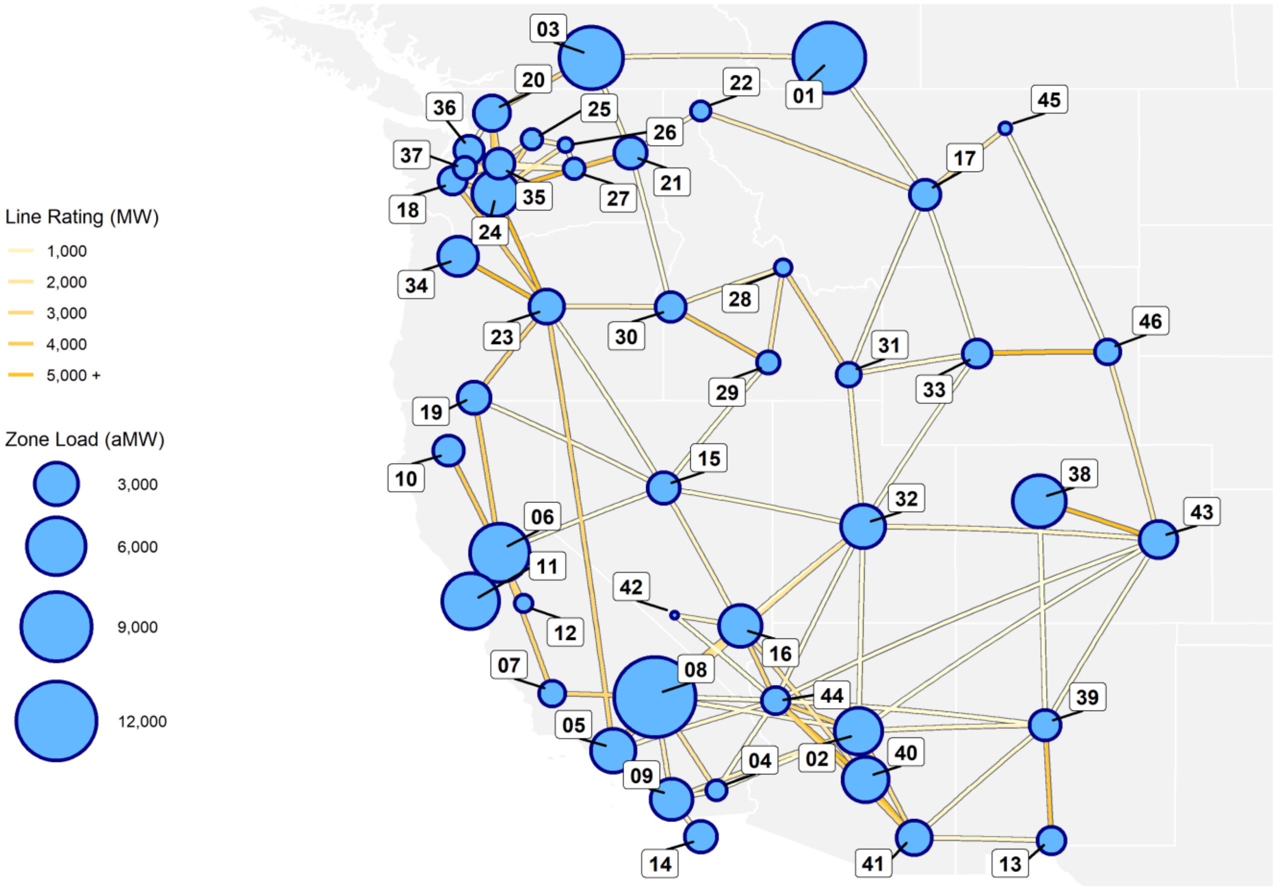
- **We calibrate the model based on recent Day Ahead (DA) prices (2018-2022), but we do not explicitly account for the following:**
  - Market design differentiation (**NO**: forward curves / firm contracts / DA - RT markets & forecast error, source & sink, local commitment considerations), **all of 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.**

- 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



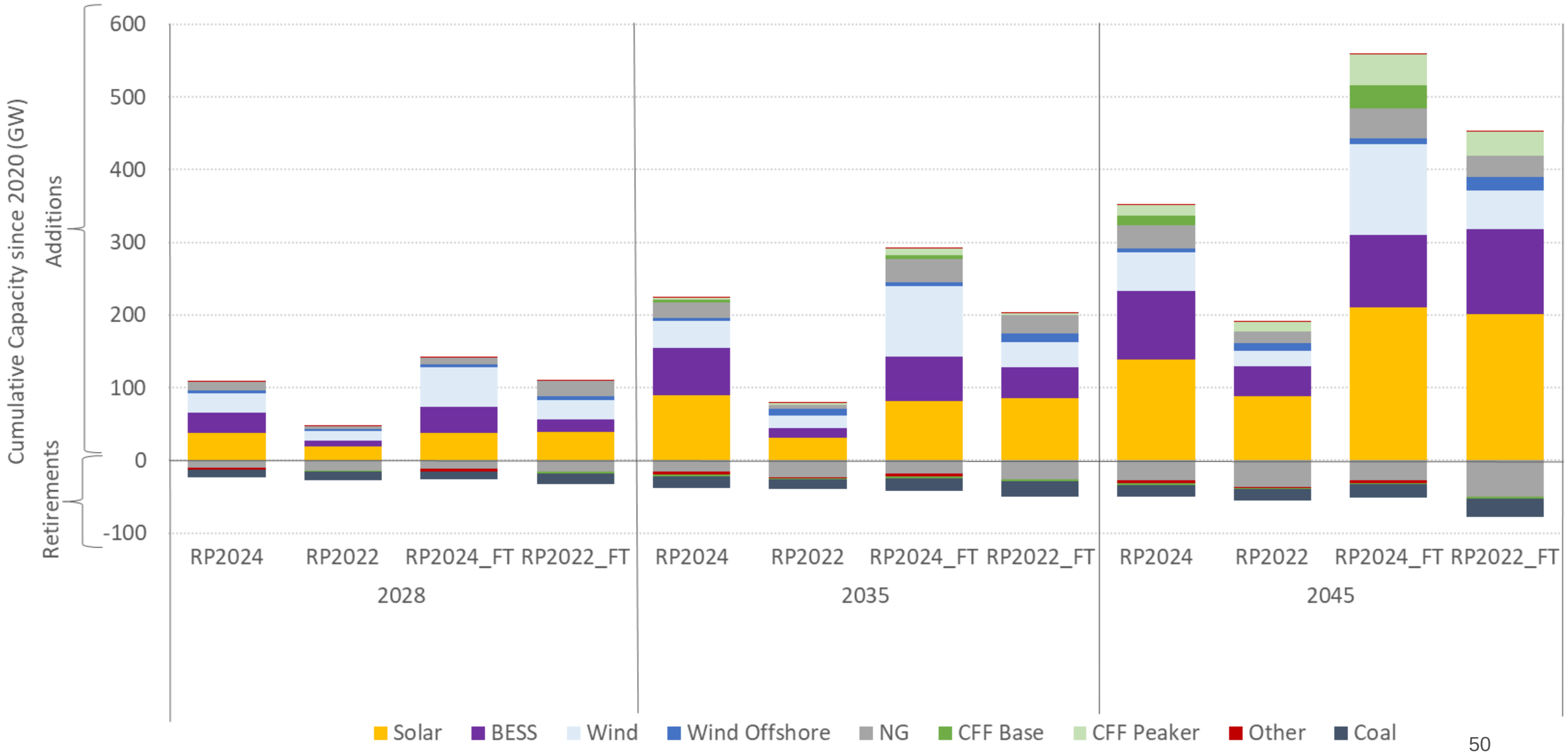
Aurora Resource Build: LT Capacity Expansion

1. Start with existing resources

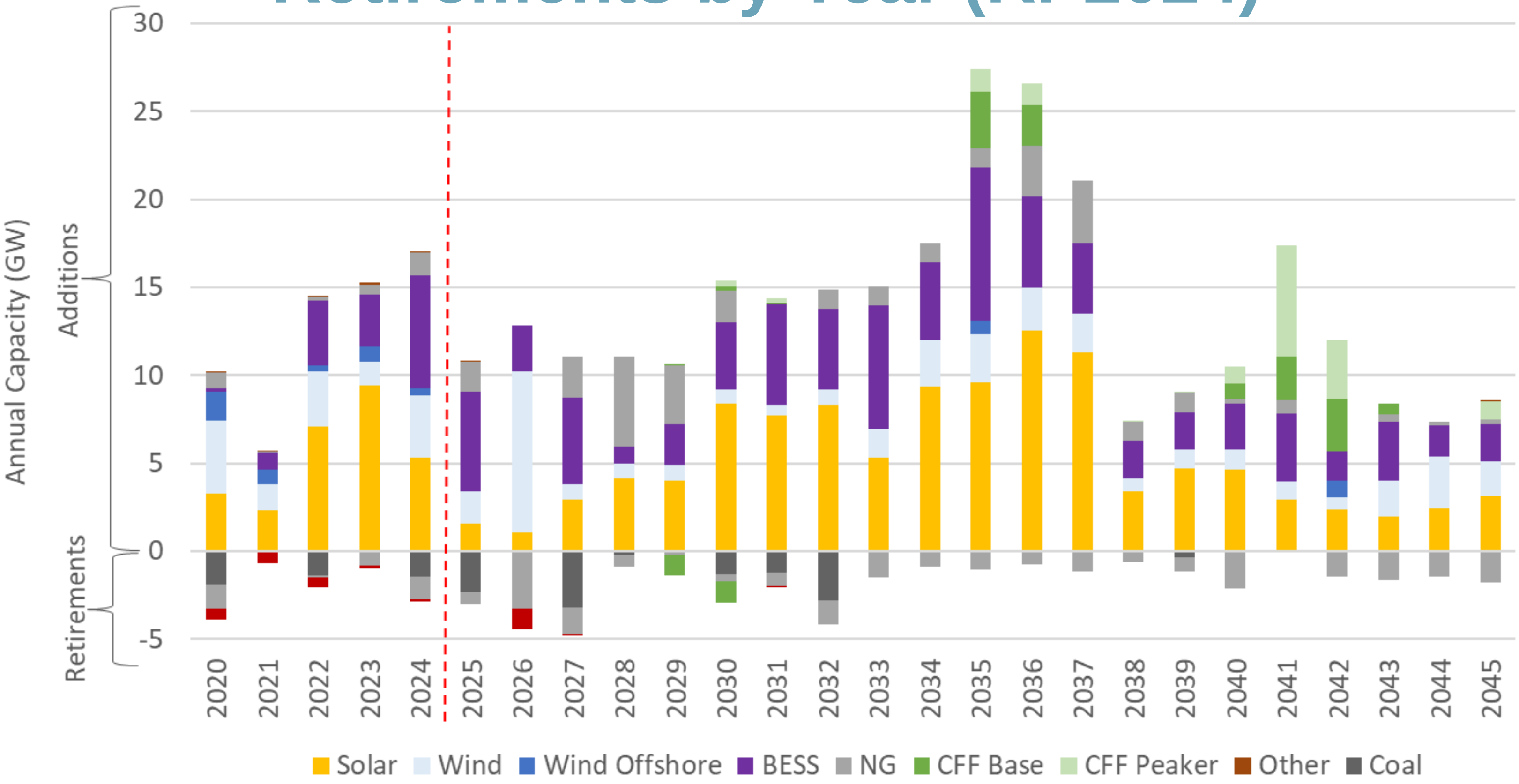
2. Lock in high likelihood builds and retirements over the duration of the next rate period (through 2028) – sources include IRPs, data from consultants, EIA, and the BPA generation interconnection queue (exceptions being Diablo Canyon retirement, some once through cooling (OTC) generation in CA, and 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

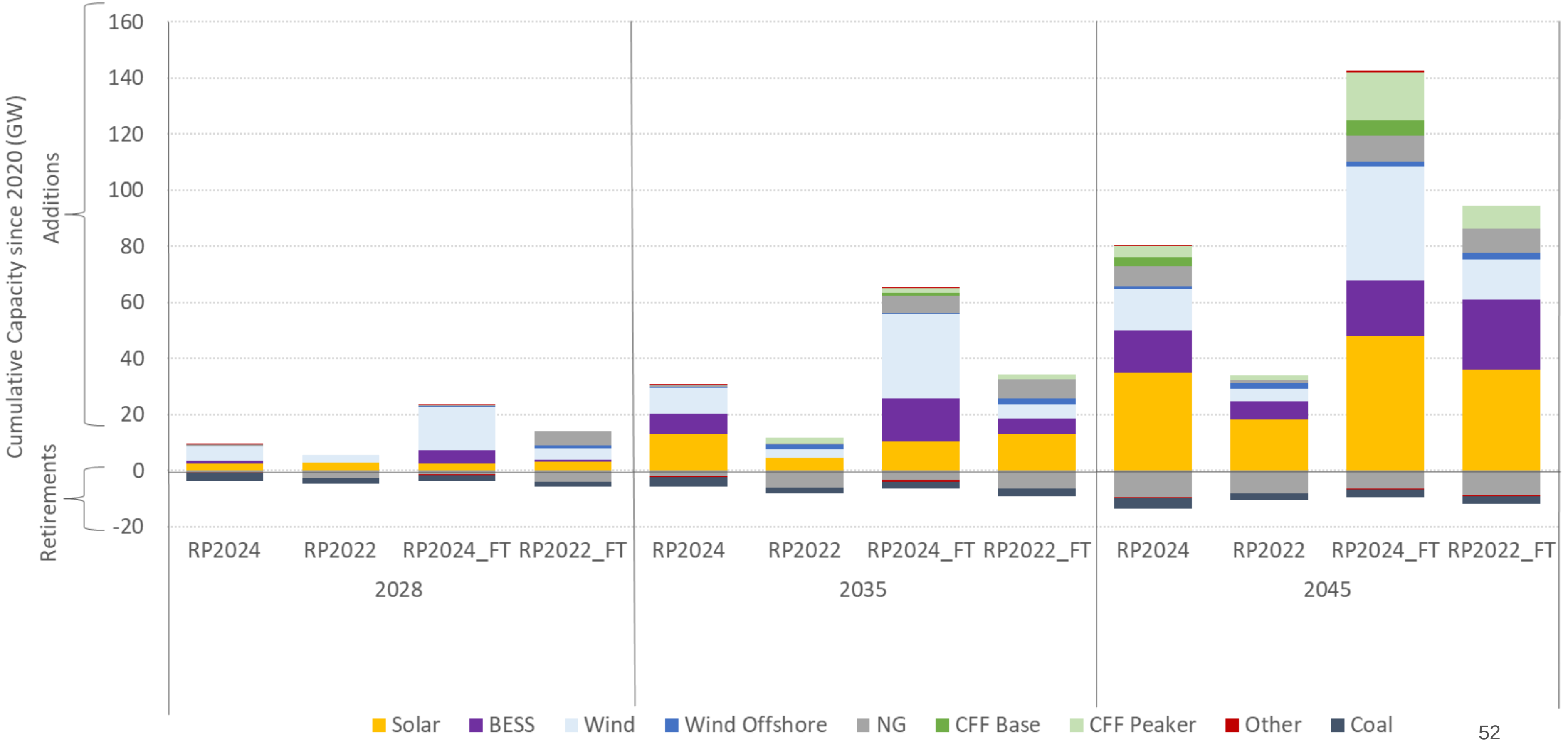
Cumulative WECC (US) Builds and Retirements (2020 Start)



Incremental WECC (US) Builds and Retirements by Year (RP2024)



Cumulative PNW (US) Builds and Retirements



Aurora Calibration 2018-2022

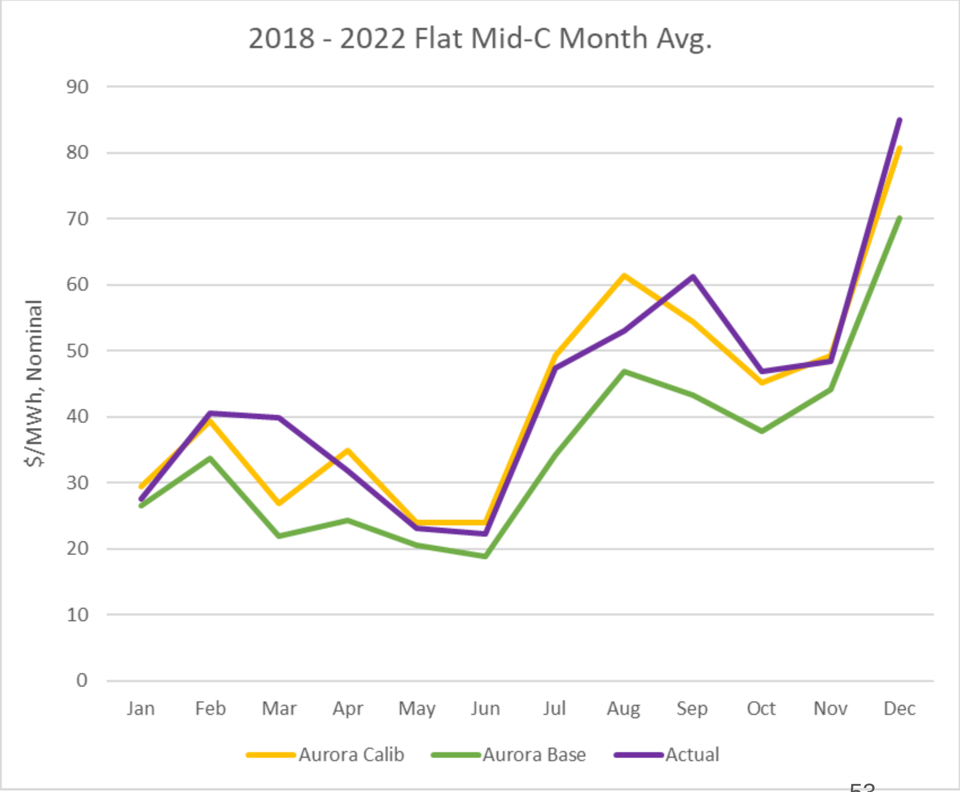
There are two main reasons Aurora price forecasts are wrong:

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’= loads, hydro generation, gas prices, transmission capability, renewable generation, etc.



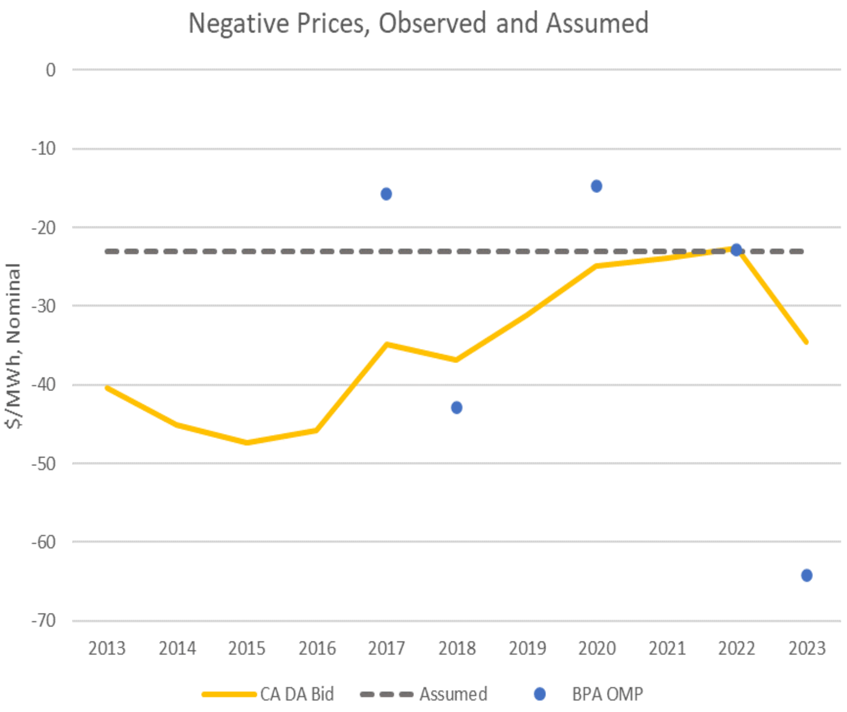
Negative Prices

- **Main drivers: policy**. Incentives and requirements introduce costs to curtailing renewable resources
  - Forgone RECs / PTCs (IRA) / PPA revenue / Potentially having to build additional resources
  - ‘replacement cost’ of renewable energy

- Generally, consultants and other production cost modelers *do not* include negative prices

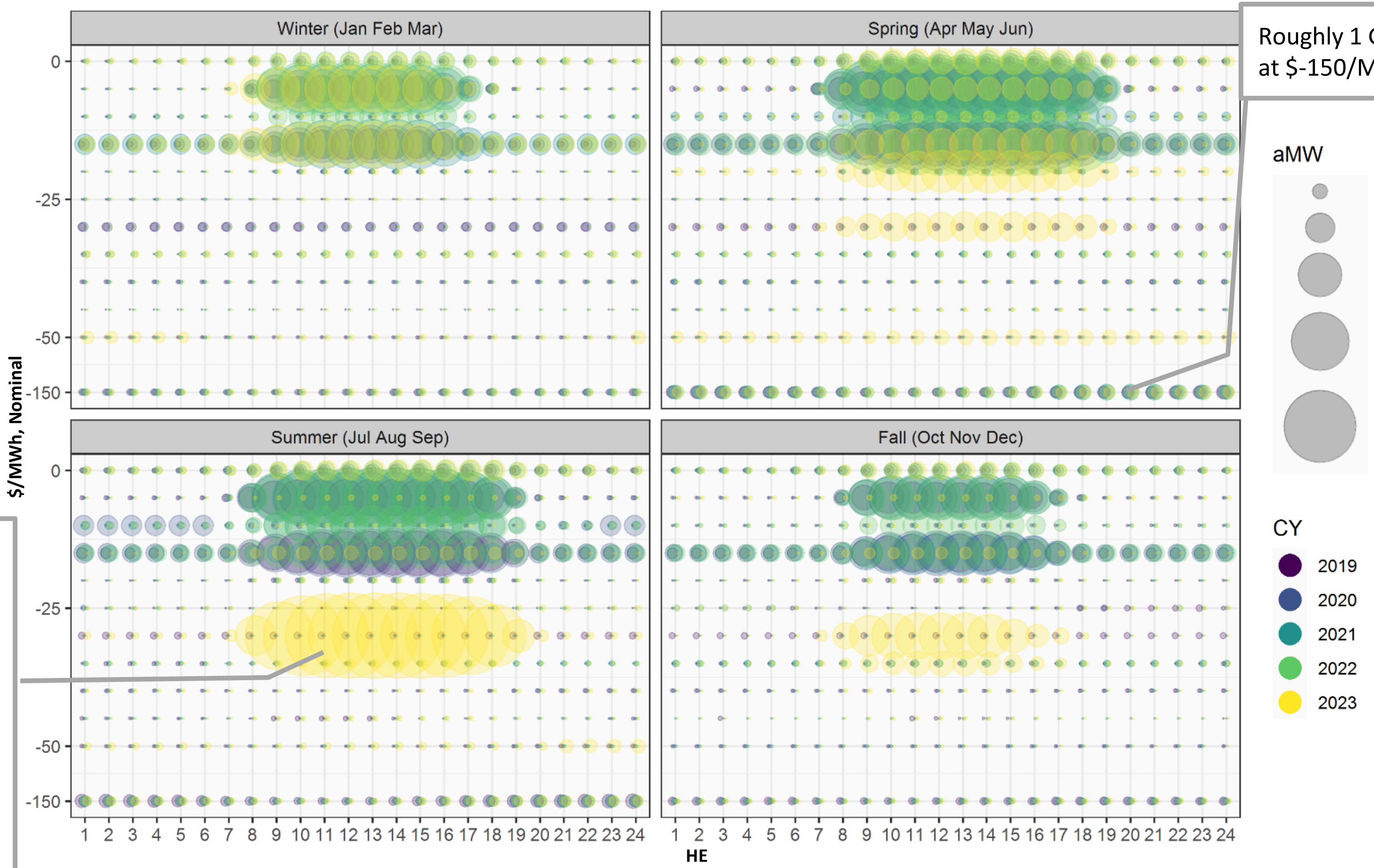
- **BPA models all renewable resources bidding at ~negative $23/MWh**

- 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 (OMP) effects. All other hydro is set to -$25/MWh, to curtail after renewables.



BPA OMP weighted avg price: ~ -$29/MWh

CAISO Negative DA Bids

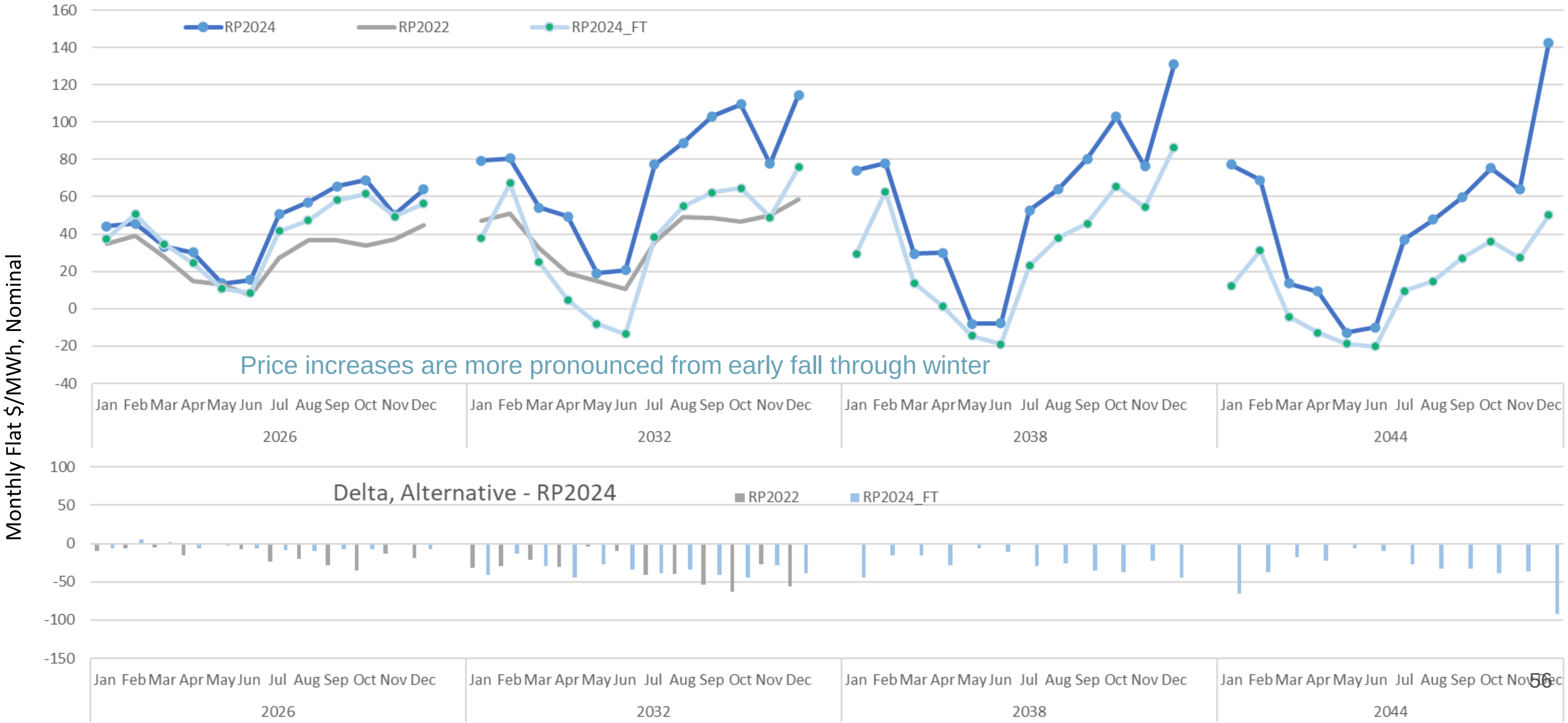


Roughly 1 GW bidding at $-150/MWh

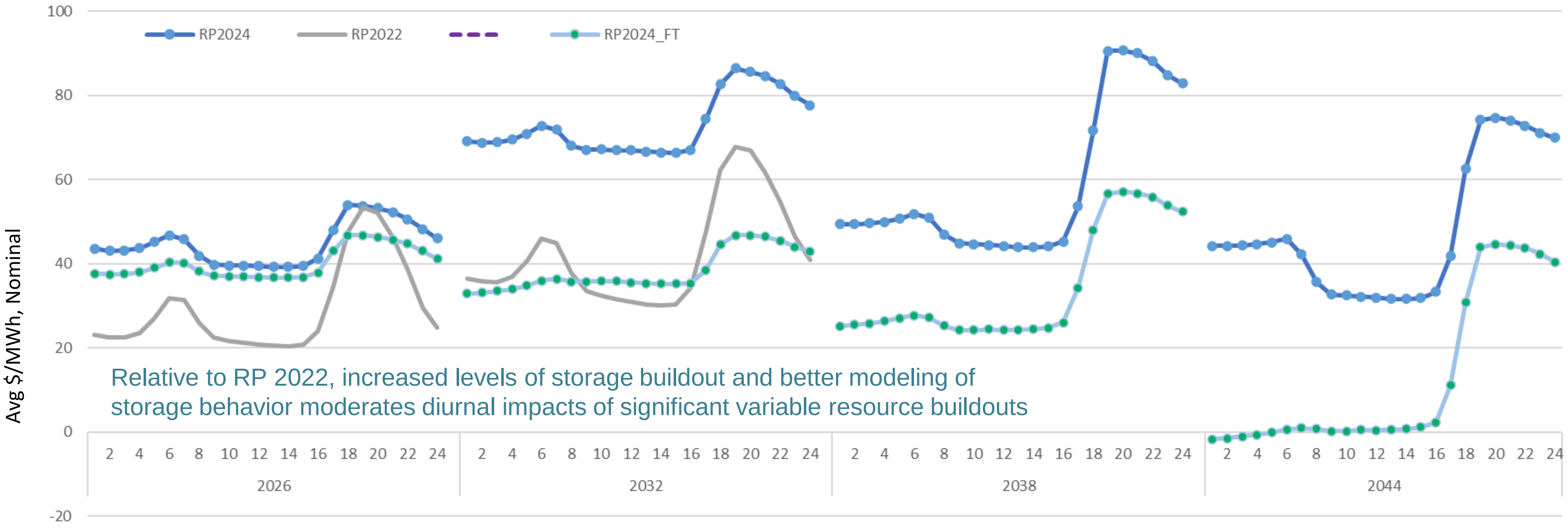
Most negative bids seem to be solar, bids are getting more negative recently.

Nearly 5 GW bidding at ~ -$30/MWh

Mid-C / NW Average Prices

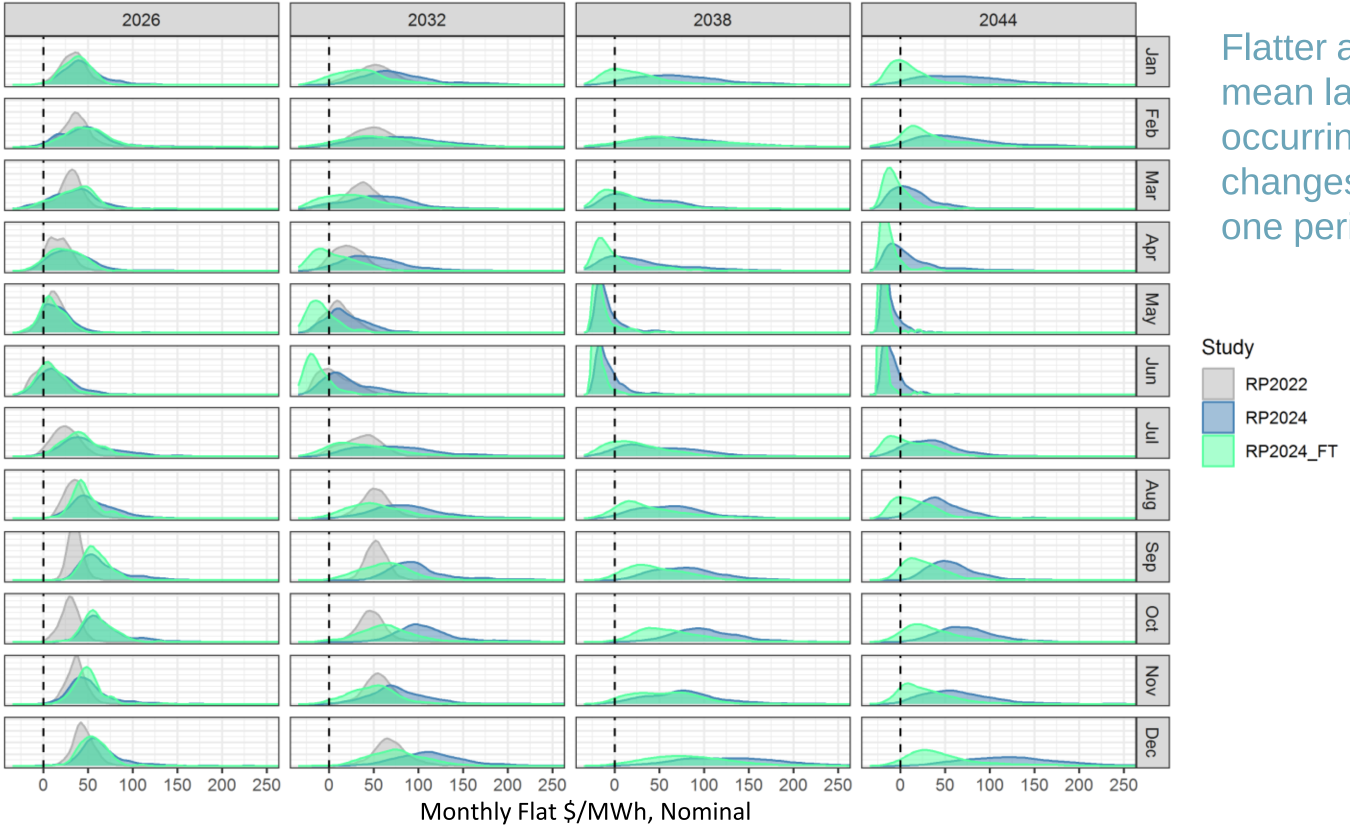


Mid-C / NW Hourly Prices



Relative to RP 2022, increased levels of storage buildout and better modeling of storage behavior moderates diurnal impacts of significant variable resource buildouts

Mid-C / NW Price Distributions



Flatter and wider distributions mean larger price swings are occurring with more moderate changes to conditions from one period to the next.

Key Market Price Uncertainties

- Clean policy and system reliability are assumed to be maintained over the study horizon. A reduced clean policy scenario (slower transition) has not been modeled for RP 2024.
- Additional load risks:
  - Have not included rapid load increases from data centers or other sources.
  - Electrification levels and differing impacts on seasonal /diurnal loads.
- Potential climate change impacts to WECC loads and resources are largely not captured, other than NW hydro
- New resource risks:
  - Other new technologies
  - Cost reductions in new resources or
  - Cost increases / lack of new resource availability from supply chain or
  - Transmission limitations.
- Impacts from longer duration / seasonal storage or changes in demand-side behavior that could mitigate occurrence of negative prices.
- Changes in ancillary service requirements associated with greater reliance on variable resources

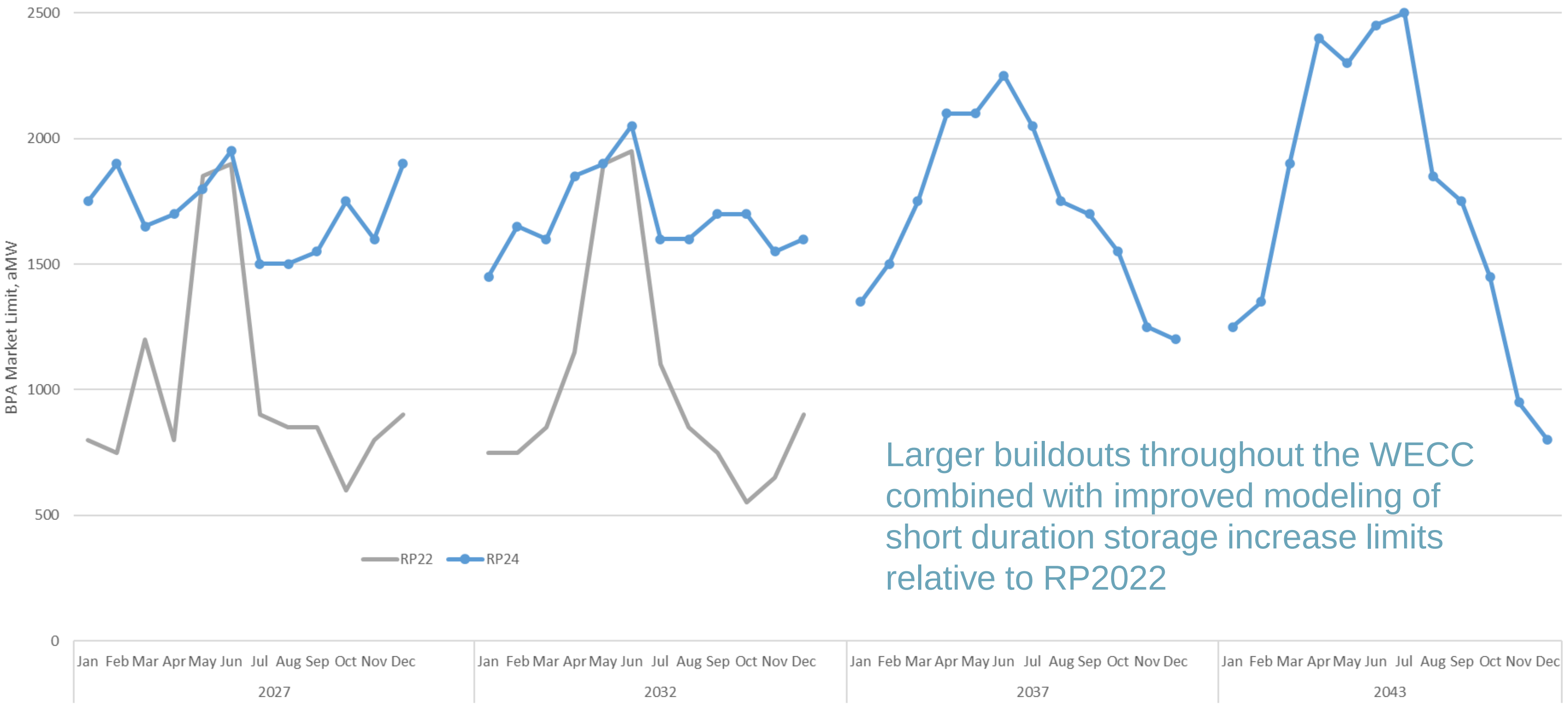
Market Limits in Aurora

- ‘Market’ definition: any combination of NW energy acquisitions from less than 5 years out, down to and including real-time, based on the projected marginal cost of producing and delivering energy.

- 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.

BPA Market Limits



Larger buildouts throughout the WECC combined with improved modeling of short duration storage increase limits relative to RP2022

Key Market Depth Uncertainties

- RP2024 assessment is more dependent on assumed overbuild of the WECC.
- Assumes 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).

Market Assessment Inputs for the solver

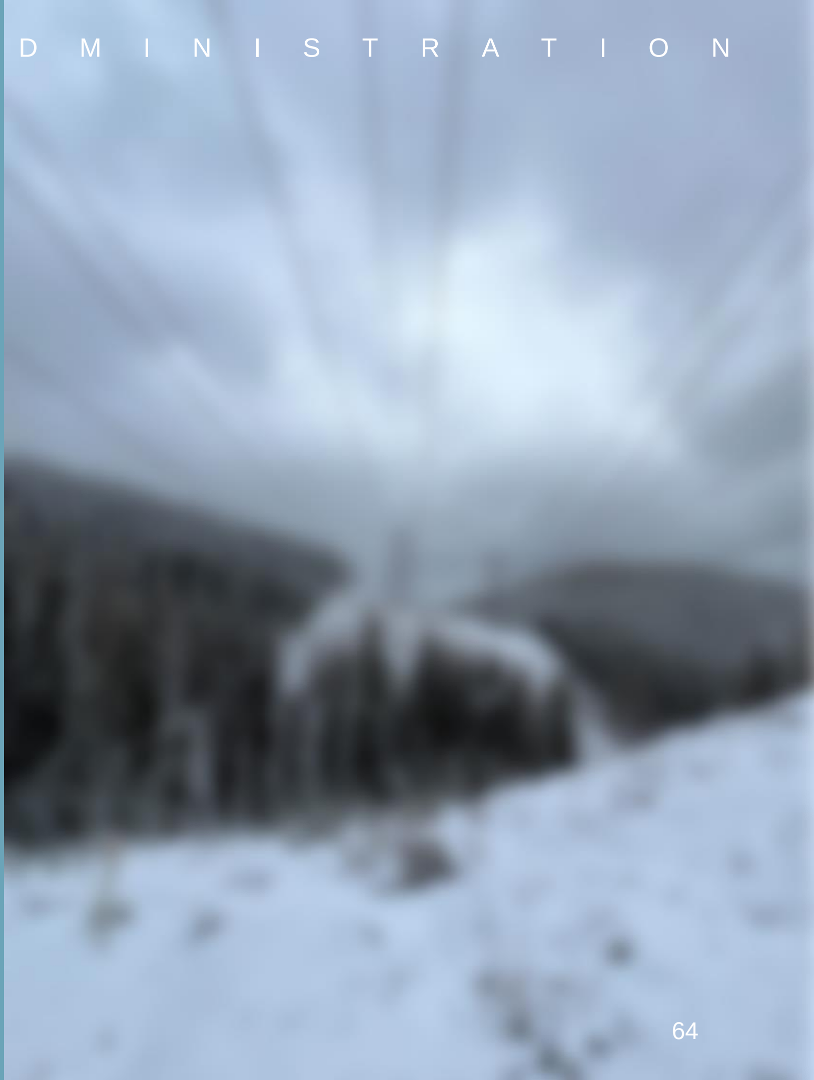
- The full distribution of hourly prices informs valuations of resource options and relying on the market to meet needs.

- Market purchases are agnostic to timing (Real-Time vs Day-Ahead vs forward), do not include capacity premiums, and do not contribute to meeting 18hr capacity needs.

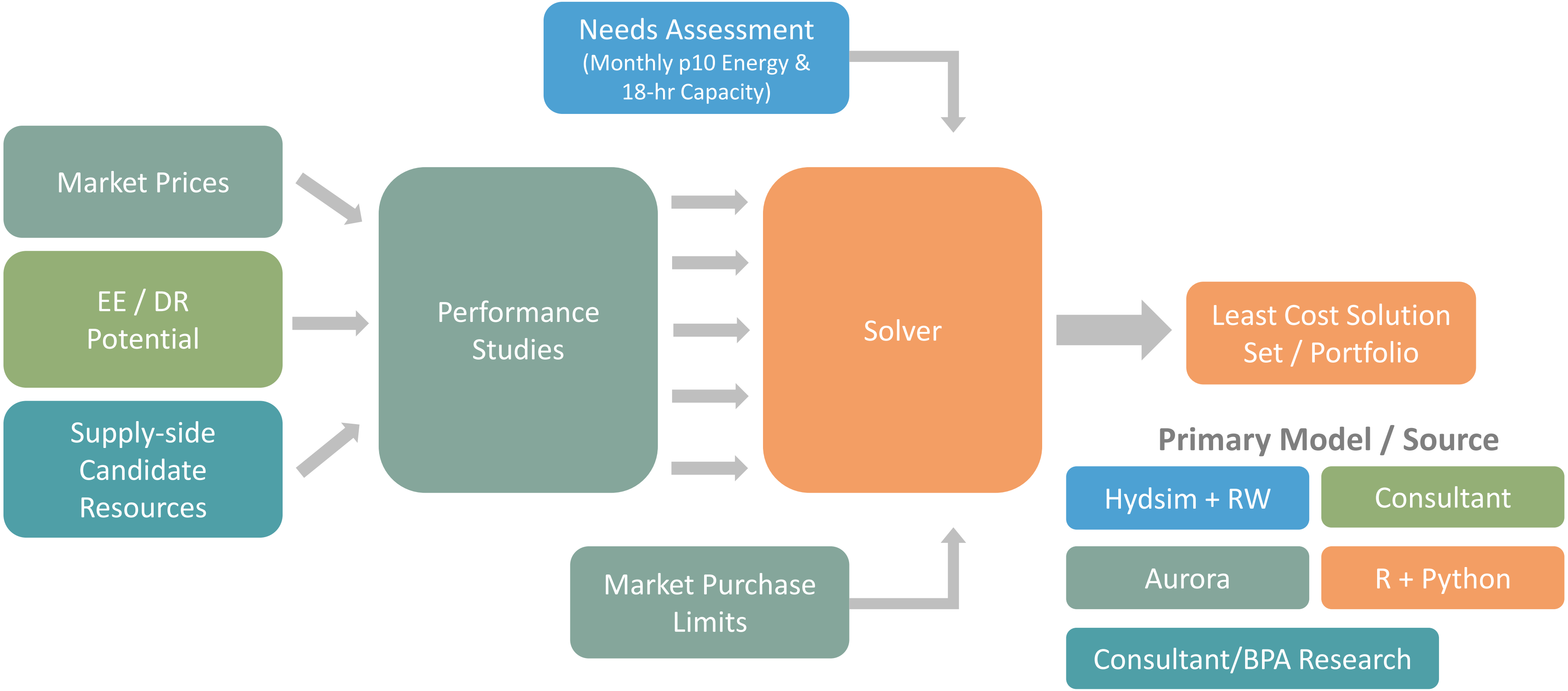
- Market limits are used as a starting point, and additional sensitivities show results of further restrictions on market.

2024 Resource Program Solver Overview

Carla Essenberg
Eric Graessley



RP2024 Modeling Framework



RP2024 Modeling Framework

Advantages

- Allows us to leverage insights from disparate and highly specialized models
- Extremely fast and flexible
- Relatively simple and transparent

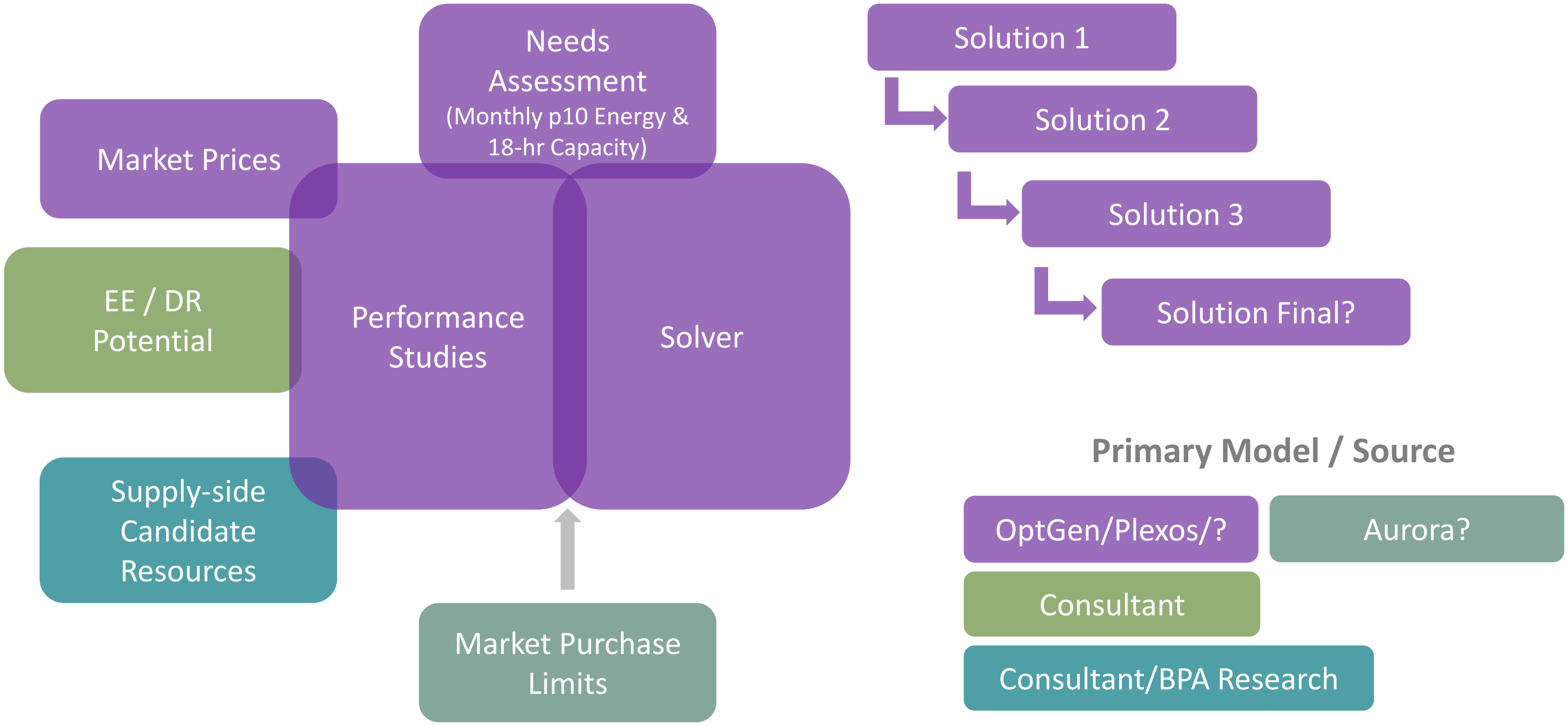
Limitations

- All components are isolated
  - Resource selections do not impact market prices, no matter how many are chosen
  - The hydro system does not adjust dispatch to new resources / market
  - New resources do not directly adjust to BPA hydro / loads
- The larger our needs and acquisitions, the less confidence we'll have in our solutions
- These limitations have been present with previous RP modeling frameworks

An Alternative

Using a single model could capture critical interactions and use an iterative approach, but this would require significant investment and would represent a major overhaul of current processes and capabilities.

Alternative Modeling Framework



The Solver uses constrained optimization to identify least-cost portfolio

- Constrained optimization:
  - Minimizes or maximizes an **objective function** (e.g., sum of resource net costs):

$$\min(c_1x_1 + c_2x_2 + \dots + c_kx_k)$$

  - Subject to **linear constraints** (e.g., energy needs are met, market purchases limits are not exceeded):

$$e_{11}x_1 + e_{12}x_2 + \dots + e_{1k}x_k > N_1$$
$$e_{21}x_1 + e_{22}x_2 + \dots + e_{2k}x_k > N_2$$
$$Etc.$$

  - With restrictions on **decision variables** (e.g., must be *proportions* of resources selected):

$$0 > x_i > 1$$

Simplified example of solver implementation (numbers adjusted for sake of illustration)

- Here we are modeling 3 months, flat energy needs only, only flat block market purchases allowed*, and 3 resources: solar, wind, hybrid
- For sake of illustration, market limits are set substantially lower than in the base scenario and applied to LLH as well as HLH periods

				Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Sum of Net Costs ($M)		
Objective Function	Resource Net Cost ($M)			$2.6	$1.0	$7.3						
	Decision Variables (proportion acquired)			x_{solar}	x_{wind}	x_{hybrid}	$x_{mkt\ (Jan)}$	$x_{mkt\ (Feb)}$	$x_{mkt\ (Mar)}$			
		Year	Month	Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Market Limit	Need	Acquired
Constraints	Energy (aMW)	2026	Jan	39	78	28	700	0	0	630	700	
		2026	Feb	36	61	48	0	652	0	665	652	
		2026	Mar	64	90	62	0	0	568	595	568	

*In the full model, market purchases can be any combination of HLH, LLH, superpeak, and flat blocks.

Simplified example of solver implementation
(numbers adjusted for sake of illustration)

Resource net costs include benefits of reduced market purchases:

Resource net cost = Levelized fixed costs + variable costs* – value of power generated**

		Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Sum of Net Costs ($M)
Objective Function	Resource Net Cost ($M)	$2.6	$1.0	$7.3				
	Decision Variables (proportion acquired)	x_{solar}	x_{wind}	x_{hybrid}	$x_{mkt\ (Jan)}$	$x_{mkt\ (Feb)}$	$x_{mkt\ (Mar)}$	

		Year	Month	Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Market Limit	Need	Acquired
Constraints	Energy (aMW)	2026	Jan	39	78	28	700	0	0	630	700	
		2026	Feb	36	61	48	0	652	0	665	652	
		2026	Mar	64	90	62	0	0	568	595	568	

*For storage resources, costs include the value of power consumed during charging.

**Value of power generated is (MWh generated) x (the modeled market price when the power is generated). This value would be realized as a combination of reduced market purchases and increased sales.

Simplified example of solver implementation
(numbers adjusted for sake of illustration)

Objective function: Sum of Net Costs*

$$\min\left((\$2.6)x_{solar} + (\$1.0)x_{wind} + (\$7.3)x_{hybrid}\right)$$

				Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Sum of Net Costs ($M)		
Objective Function	Resource Net Cost ($M)			$2.6	$1.0	$7.3						
	Decision Variables (proportion acquired)			x_{solar}	x_{wind}	x_{hybrid}	$x_{mkt\ (Jan)}$	$x_{mkt\ (Feb)}$	$x_{mkt\ (Mar)}$			
		Year	Month	Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Market Limit	Need	Acquired
Constraints	Energy (aMW)	2026	Jan	39	78	28	700	0	0	630	700	
		2026	Feb	36	61	48	0	652	0	665	652	
		2026	Mar	64	90	62	0	0	568	595	568	

*Although not shown here, to prevent market purchases from being selected when not needed, they are also included in the objective function with very low costs. Similarly, supply-side resources with negative net costs are assigned very low positive costs to prevent them from being acquired when not needed.

Simplified example of solver implementation (numbers adjusted for sake of illustration)

Constraints: Needs

Jan 2026: $(39\text{ aMW})x_{solar} + (78\text{ aMW})x_{wind} + (28\text{ aMW})x_{hybrid} + (700\text{ aMW})x_{mkt(Jan)} > 700\text{ aMW}$

				Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Sum of Net Costs ($M)		
Objective Function	Resource Net Cost ($M)			$2.6	$1.0	$7.3						
	Decision Variables (proportion acquired)			x_{solar}	x_{wind}	x_{hybrid}	$x_{mkt\ (Jan)}$	$x_{mkt\ (Feb)}$	$x_{mkt\ (Mar)}$			
		Year	Month	Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Market Limit	Need	Acquired
Constraints	Energy (aMW)	2026	Jan	39	78	28	700	0	0	630	700	
		2026	Feb	36	61	48	0	652	0	665	652	
		2026	Mar	64	90	62	0	0	568	595	568	

Simplified example of solver implementation (numbers adjusted for sake of illustration)

Constraints: Market limits*

$$\text{Jan 2026: } (700 \text{ aMW}) x_{mkt(Jan)} \leq 630 \text{ aMW}$$

		Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Sum of Net Costs ($M)
Objective Function	Resource Net Cost ($M)	$2.6	$1.0	$7.3				
	Decision Variables (proportion acquired)	x_{solar}	x_{wind}	x_{hybrid}	$x_{mkt\ (Jan)}$	$x_{mkt\ (Feb)}$	$x_{mkt\ (Mar)}$	

		Year	Month	Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Market Limit	Need	Acquired
Constraints	Energy (aMW)	2026	Jan	39	78	28	700	0	0	630	700	
		2026	Feb	36	61	48	0	652	0	665	652	
		2026	Mar	64	90	62	0	0	568	595	568	

*In the full model, market purchases can be any combination of HLH, LLH, superpeak, and flat blocks. The sums of market purchases in all blocks are not allowed to exceed market purchase limits.

Simplified example of solver implementation (numbers adjusted for sake of illustration)

Solution: Full set of decision variables

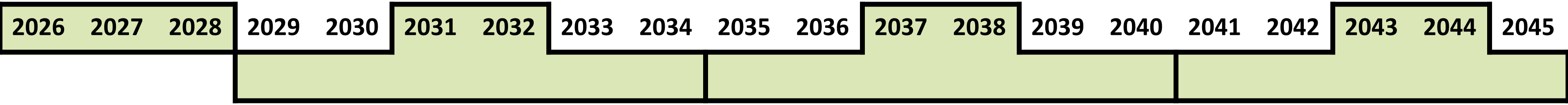
- From the decision variables, can calculate amount generated by each resource and portfolio cost*

				Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Sum of Net Costs ($M)		
Objective Function	Resource Net Cost ($M)			$2.6	$1.0	$7.3				$0.89		
	Decision Variables (proportion acquired)			**0**	**0.89**	**0**	**0.90**	**0.91**	**0.86**			
		Year	Month	Solar	Wind	Hybrid	Market (Jan)	Market (Feb)	Market (Mar)	Market Limit	Need	Acquired
Generation	Energy (aMW)	2026	Jan	0	70	0	630	0	0	630	700	700
		2026	Feb	0	55	0	0	597	0	665	652	652
		2026	Mar	0	80	0	0	0	488	595	568	568

*Portfolio cost = (sum of resource net costs, shown here) + (net cost of meeting needs identified by the Needs Assessment). The resource net costs include the value of all energy generated, modeled as revenue, so the 'net cost of meeting needs' must include the value of all energy required to meet needs.

Modeling of needs vs. costs

- Needs:
  - Assume P10 water conditions (except for 18 hr capacity)
  - Modeled explicitly only in sample years
- Costs:
  - Expected values, given the full range of needs and possible market conditions
  - Represent total costs over the full 20 years



20XX Indicates sample years that were explicitly modeled.

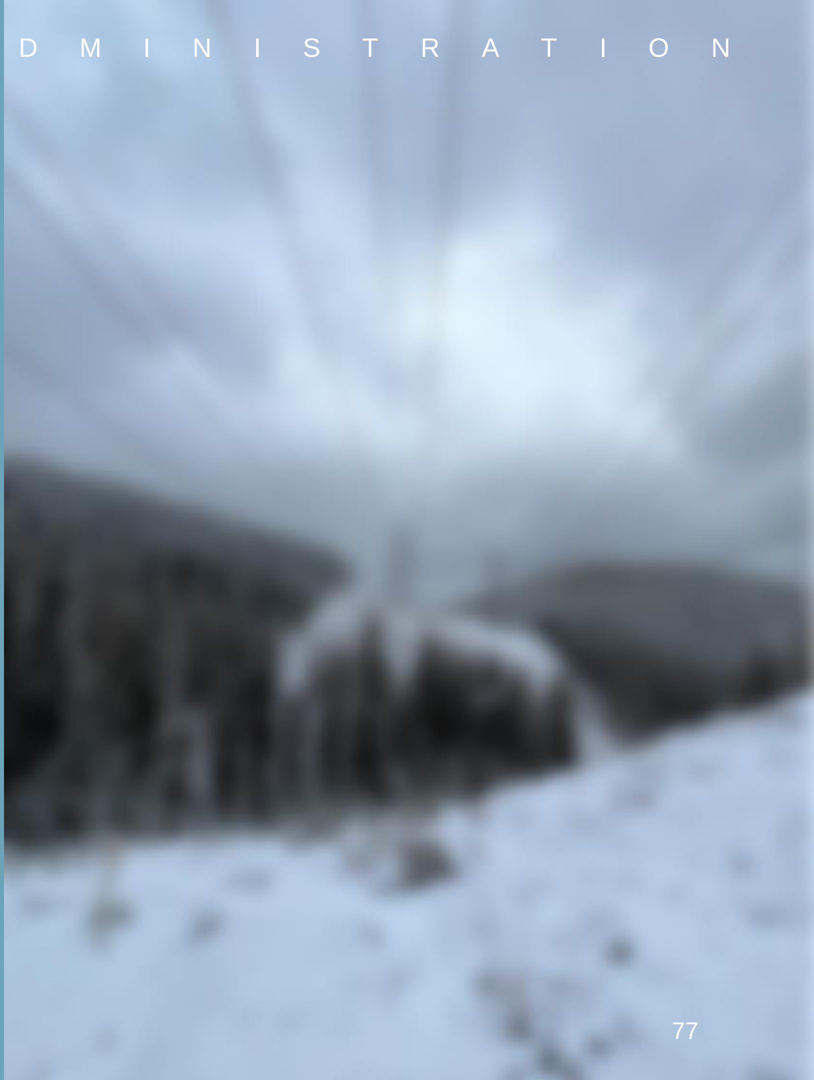
The RP2024 solver: constraints

- Needs that must be met:
  - P10 **Flat**, P10 **HLH**, P10 **superpeak** in every month
  - **18hr capacity*** in Dec, Jan, Feb, July, Aug
  - Locations: MIDC, SWEDE
- Market limits constraints:
  - Total market purchases in **HLH** and **superpeak** periods cannot exceed limits set based on market depth study
  - In some market depth sensitivities, purchases in **LLH** are also limited

*18hr capacity needs can be met only by EE, DR, and supply-side resources; market purchases are not allowed to contribute
Constraints also include rules to prevent impossible outcomes, such as the same EE or DR program being selected twice, to start in 2 different years.

Resource Solutions

Carla Essenberg
Eric Graessley



Key Takeaways – Resource Solutions

- We continue to rely heavily on **energy efficiency, demand response, and market purchases** to meet BPA needs.
- As loads grow or we add further limits on access to the market, resource acquisitions grow quickly.
- Acquisitions are driven primarily by **Flat** and **HLH energy needs**, rarely by super-peak or 18-hour capacity needs. There is not a single binding metric.
- Supply side acquisitions tend to focus on **solar** and **wind** resources due to their low costs and their contributions to energy needs.
- Supply side acquisitions in SWEDE are needed only if loads are higher than in the base scenario.
- **Resources in the model cannot meet needs in 2 sensitivities**: no market and high load. Shortfalls are in **winter/April 2026-2028**.

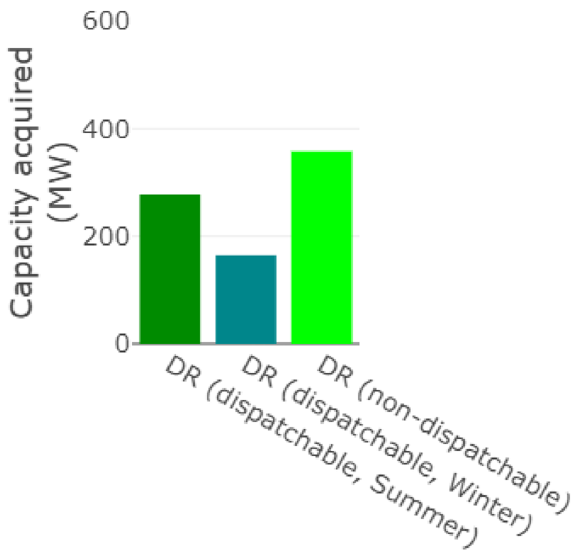
Base scenario: Key takeaways

- P10 needs are met primarily by market purchases and energy efficiency (EE)

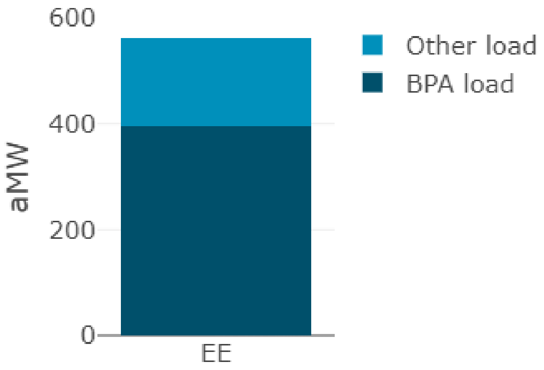
- Lowest-cost portfolio also includes several demand response (DR) programs and 300 MW solar power

Base scenario resource acquisitions

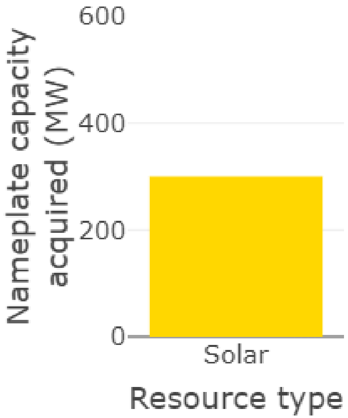
Demand response (DR):



Energy efficiency (EE):



Supply-side:



All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Base scenario: EE and DR

- Non-dispatchable DR programs acquired:
  - Residential Time of Use (TOU) Pricing
  - Utility Demand Voltage Reduction (DVR)
- Dispatchable DR programs acquired:
  - Commercial, industrial, and residential Critical Peak Pricing (CPP)
- EE achieved by 2045:
  - Total: **564 aMW**
  - Serving BPA load: **395 aMW***
- More in-depth EE + DR analysis to come

*About 70% of the total EE achieved by BPA reduces the BPA load obligation. The remainder reduces customer obligations. The percentages vary by EE measure and by customer, but for modeling purposes, we assume 70% for all EE programs.

SWEDE acquisitions

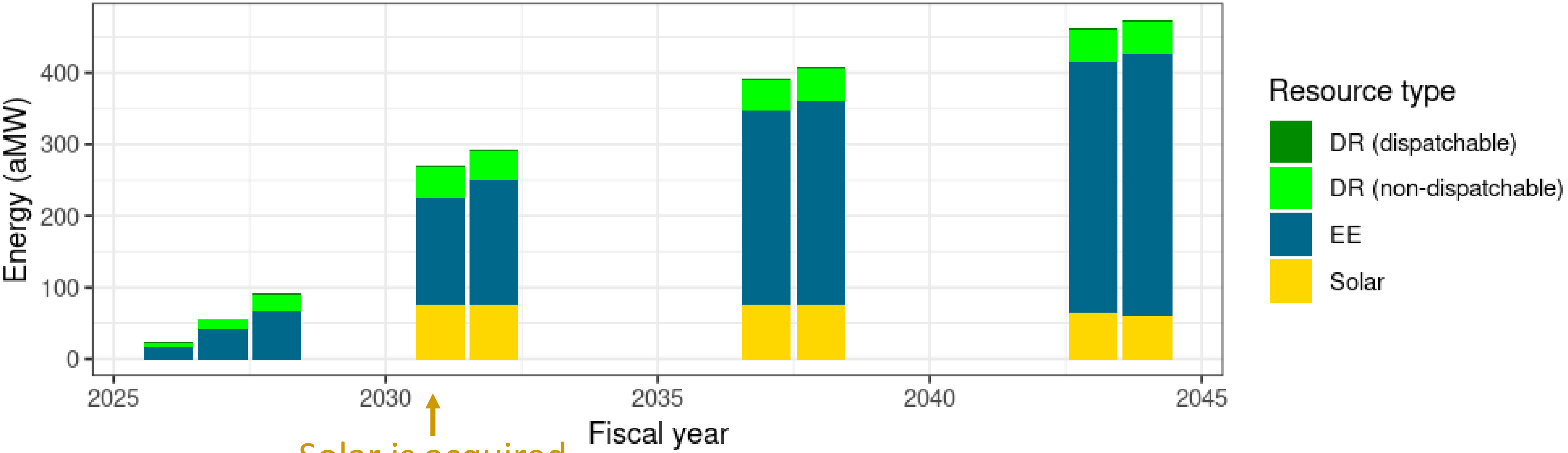
- ‘SWEDE’ = Southwest/East Diversity Exchange, including South Idaho and nearby areas. Limited connectivity to the rest of our territory.

- Every sensitivity included acquisition of SWEDE EE and DR programs

- SWEDE supply-side resources were acquired only in the load adder sensitivities

Base scenario: Mid-C annual aMW

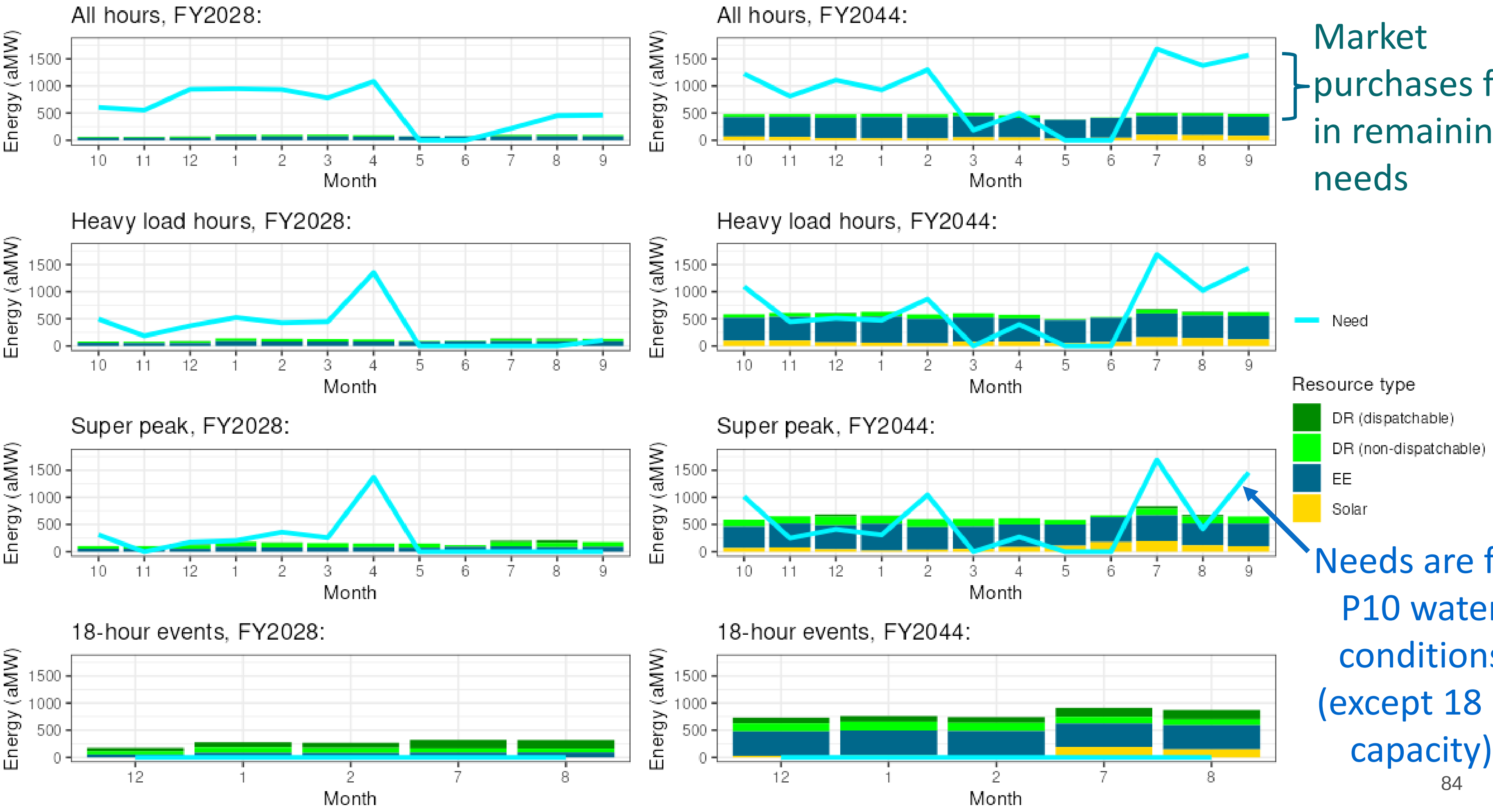
EE and DR programs are started in 2026 and ramp up over time



Solar is acquired in 2031

EE aMW shown is the portion serving BPA load. Total EE acquired in Mid-C is 30% higher.

Base scenario, Mid-C needs and resource contributions:



Market purchases fill in remaining needs

Needs are for P10 water conditions (except 18 hr capacity)

Base scenario: Portfolio cost

Cost of meeting all needs (up to P10) through market purchases

Resource net costs include revenue from selling all energy generated or conserved

Resource		Base scenario net cost (millions of $, NPV)
Net cost of meeting needs		2,576.1
Purchases to fill deficits	4,731.6	
Sales of surplus power	-2,155.5	
Energy efficiency and demand response		-1,802.1
Supply side		-1.7
Solar	-1.7	
TOTAL		772.4

If a resource has a negative net cost, that means that it is a lower-cost option than relying on market purchases. All resources acquired in the base scenario have negative net costs.

Base Scenario Sensitivities

- High market prices
- Limits on market reliance
- Load growth
- Half study horizon
- Summaries
- Natural gas assessment*

*The diversity of carbon policies across the BPA service territory complicate the modeling of natural gas in the optimization process. Modeling natural gas also includes other technical challenges that led to the decision to not include it in the model and evaluate it outside of the model. Additional analysis is provided later in the section.

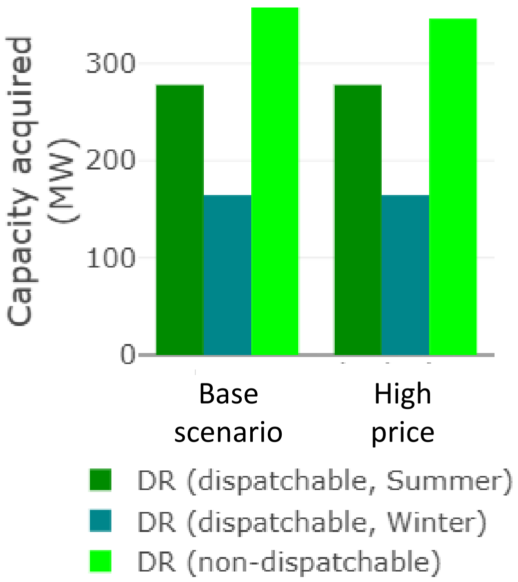
High market price sensitivity: Key takeaways

- Higher market prices increase the range of EE programs and supply-side resources that are lower-cost than market purchases

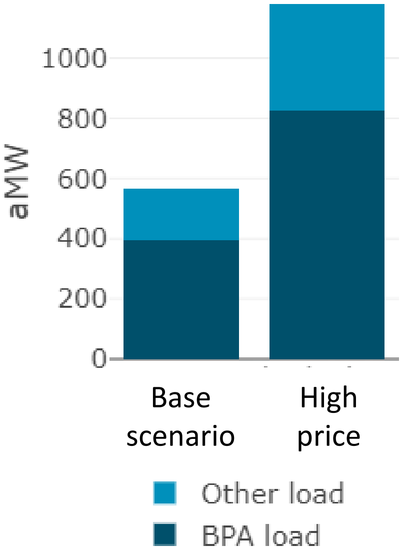
- With doubled market prices:
  - EE acquisitions double
  - Solar acquisitions >12x higher
  - Wind and geothermal also acquired

High market price sensitivity: resource acquisitions

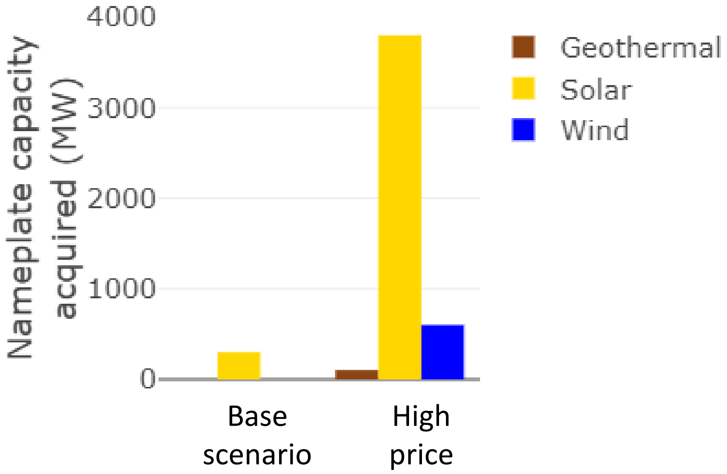
Demand response:



Energy efficiency:

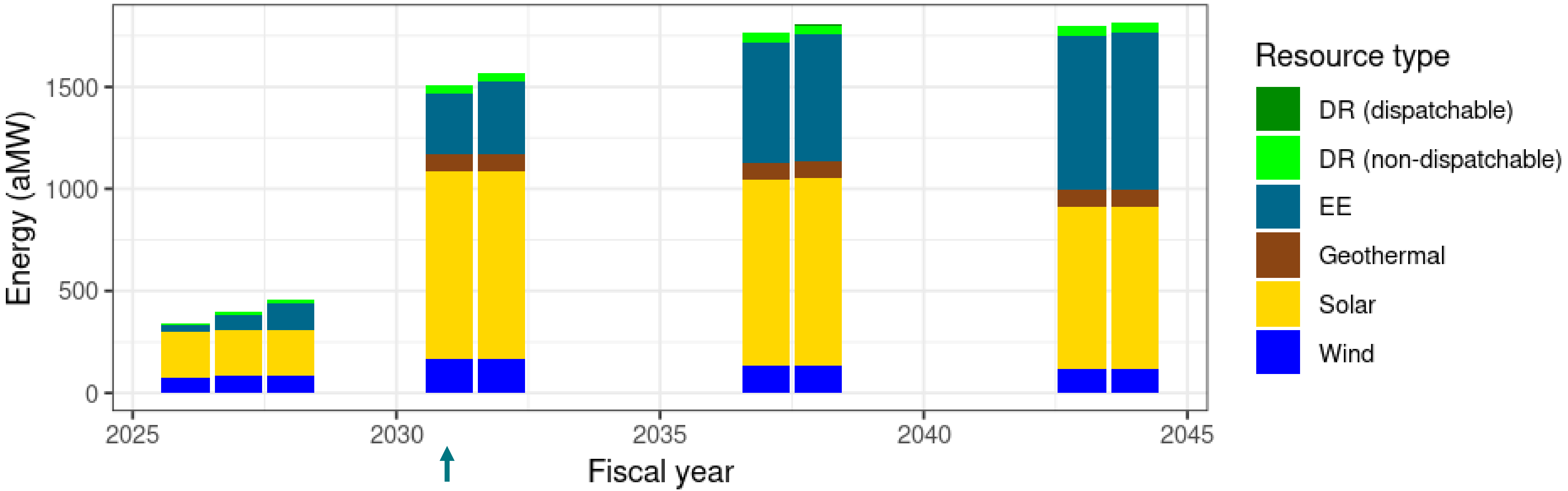


Supply-side:



All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

High market price sensitivity: Mid-C annual aMW



After 2031, no more acquisitions are needed to meet full BPA needs

Market limits sensitivities: Key takeaways

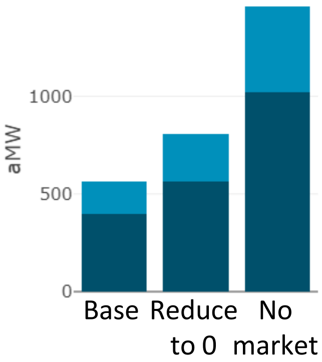
- Needs in 2026-2028 have a strong influence on results
  - Meeting needs in winter and April in this period requires large market purchases (or resources not currently in the model)
- Resource acquisitions are driven primarily by flat energy needs
- Market purchases are replaced primarily with solar and wind

Market limit sensitivities

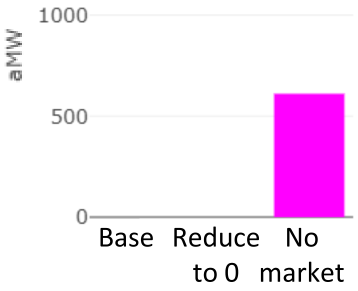
- **Reduce SPK/HLH by 25%:** Limits to SPK and HLH purchases are 75% of forecast market depth
- **Reduce SPK/HLH by 50%**
- **Reduce all market purchases by 50%**
- **Reduce to 0**: Limits start at 50% of forecast market depth and decline to 0
- **No market**: No market purchases allowed

Market limits: resource acquisitions

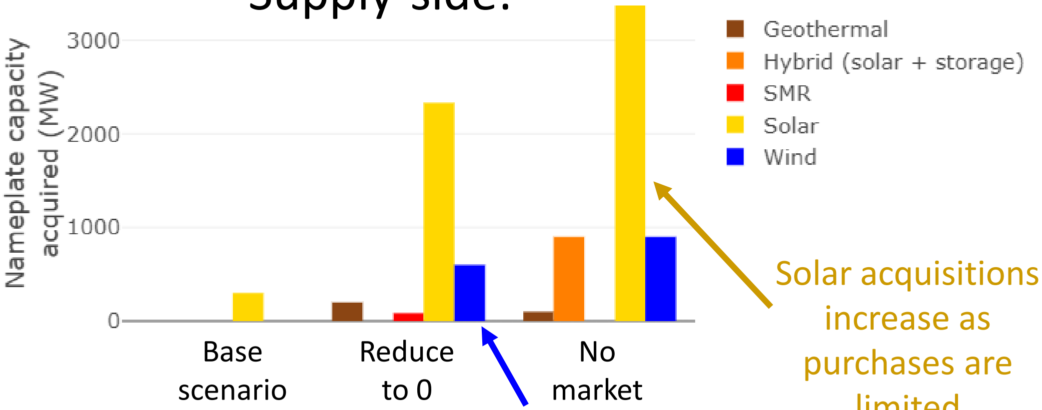
Energy efficiency:



Unmet needs:



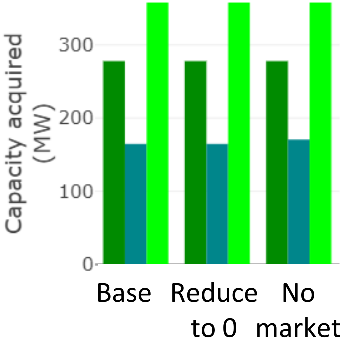
Supply-side:

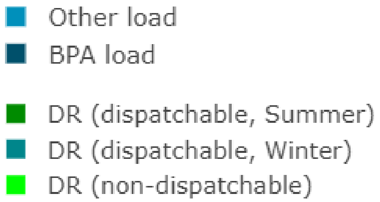


Solar acquisitions increase as purchases are limited

Wind acquisitions are present whenever LLH purchases are limited

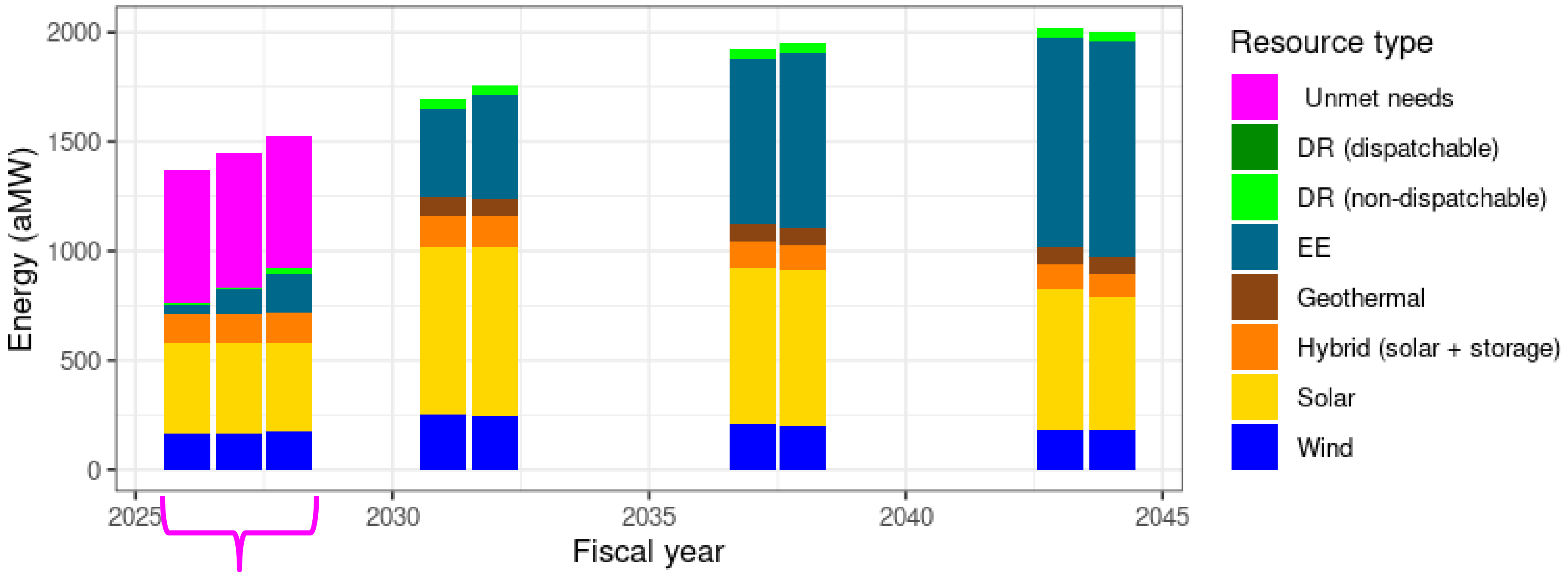
Demand response:





All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

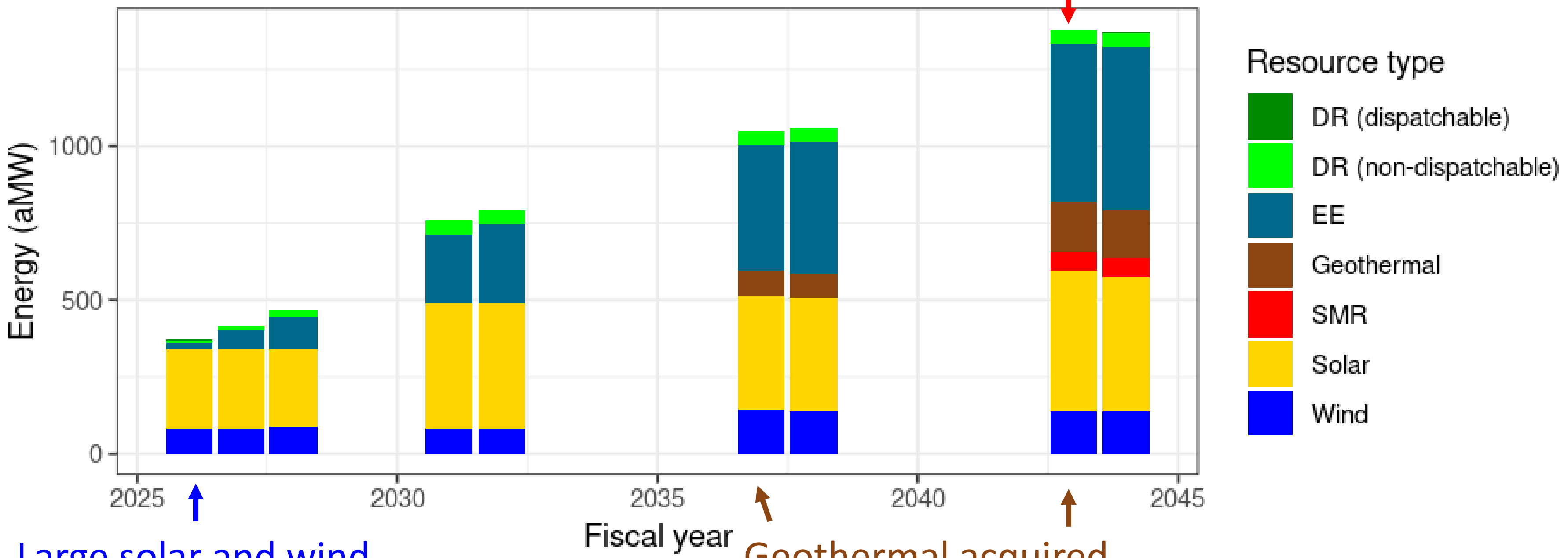
‘No market’ sensitivity: Mid-C annual aMW



Months without enough resources to meet needs: Nov – Feb and April

‘Reducing market purchases to 0’ sensitivity: Mid-C annual aMW

SMR added in 2043



Large solar and wind acquisitions in 2026, with smaller additions later

Geothermal acquired in 2037 and 2043

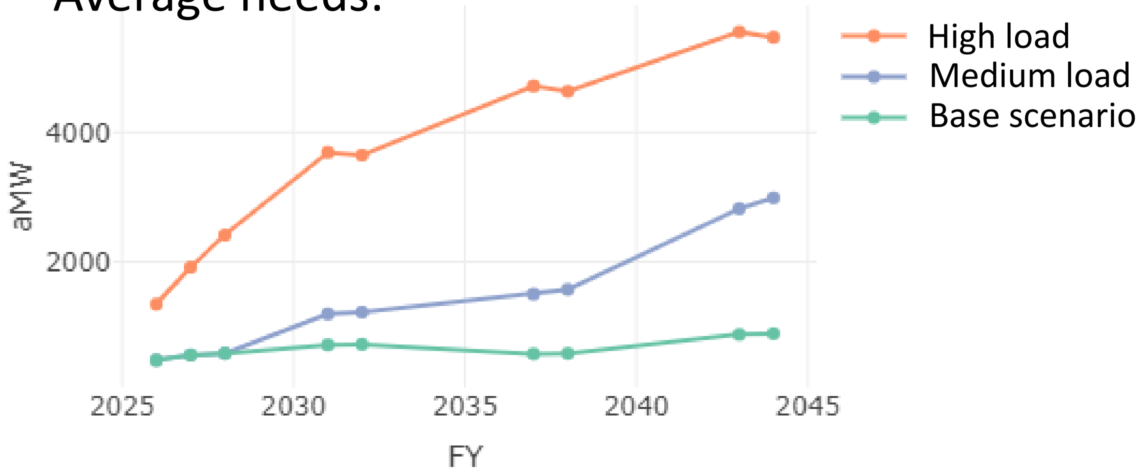
Load adder sensitivities: Key takeaways

- Acquisitions are primarily driven by HLH energy needs
- Loads in the high load adder sensitivity are difficult to serve:
  - We do not have enough resources in the model to meet needs in 2026-2028 (but the shortfall is relatively small)
  - Portfolio cost is > $35 billion
- Solutions to both sensitivities include large (1,000+ MW) acquisitions of SMR
- Most acquisitions in the medium load adder sensitivity happen late, in 2043

Load adder sensitivities

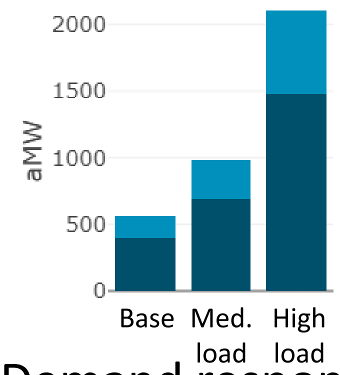
- **High load adder (aka, NR)** is a flat block load added to every hour uniformly across the year.
- **Medium load adder (aka, T2)** is shaped load added to each hour. Shaping is based on current Slice Block load shape.

Average needs:

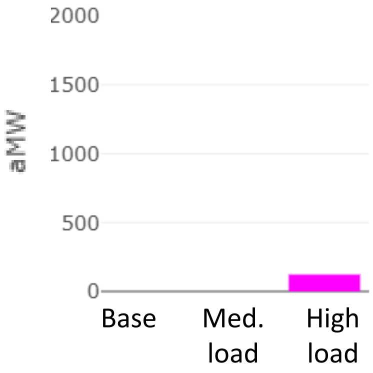


Load adder sensitivities: resource acquisitions

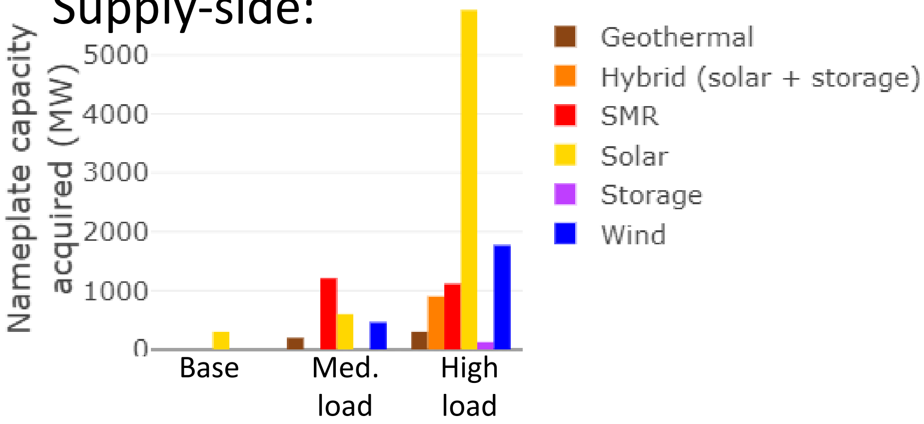
Energy efficiency:



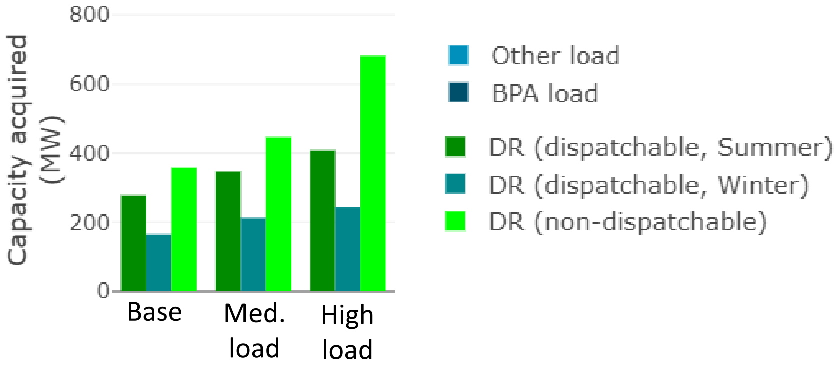
Unmet needs:



Supply-side:

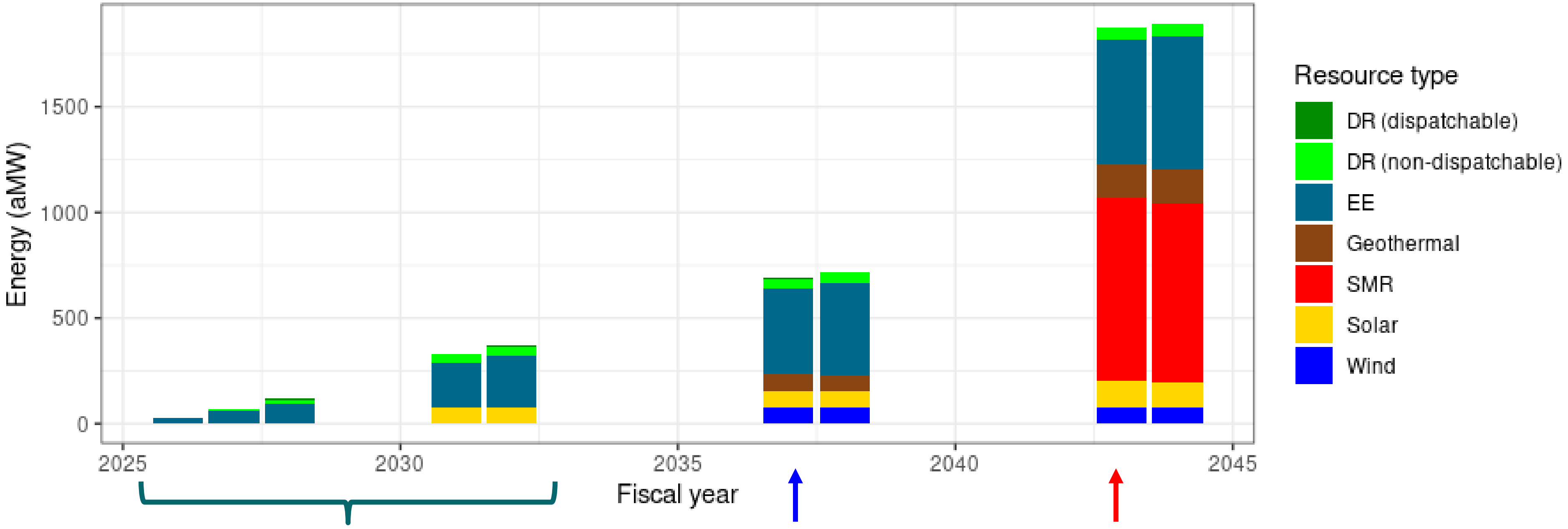


Demand response:



All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Medium load adder: Mid-C annual aMW



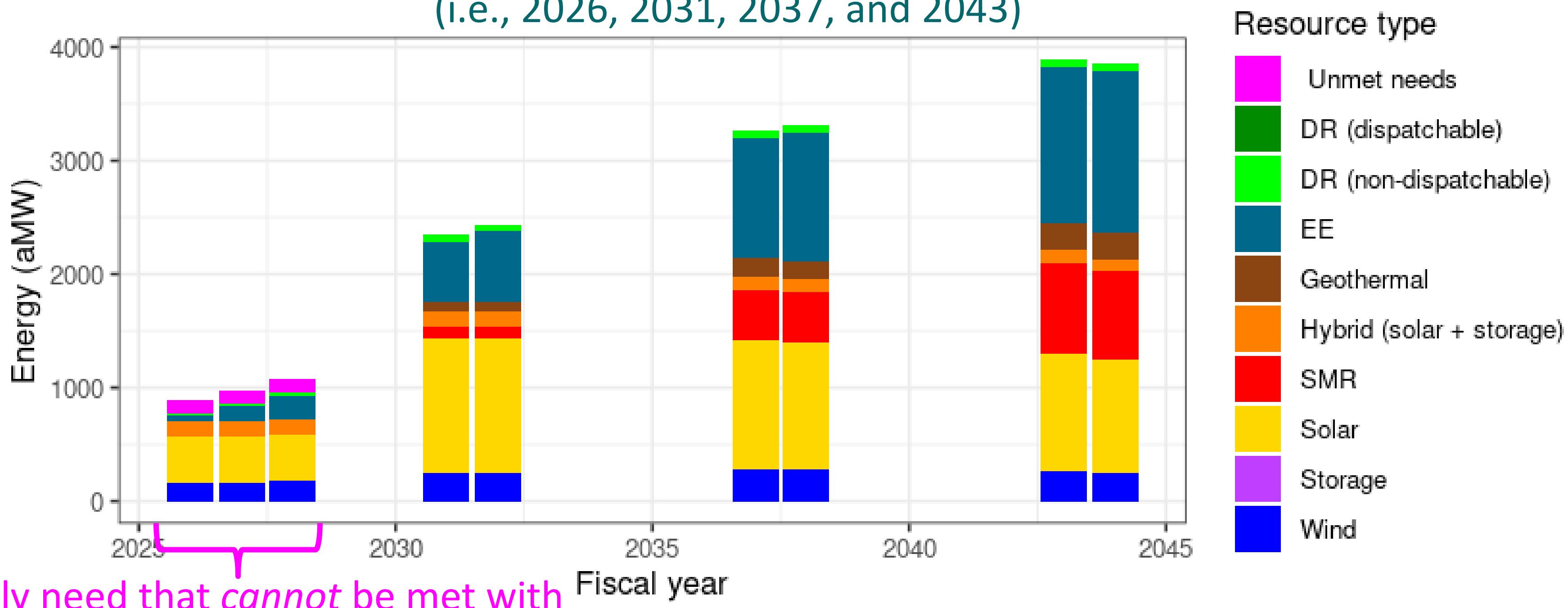
2026-2032 acquisitions same as Base Scenario

Wind and geothermal added in 2037

Most acquisitions happen in 2043

High load adder: Mid-C annual aMW

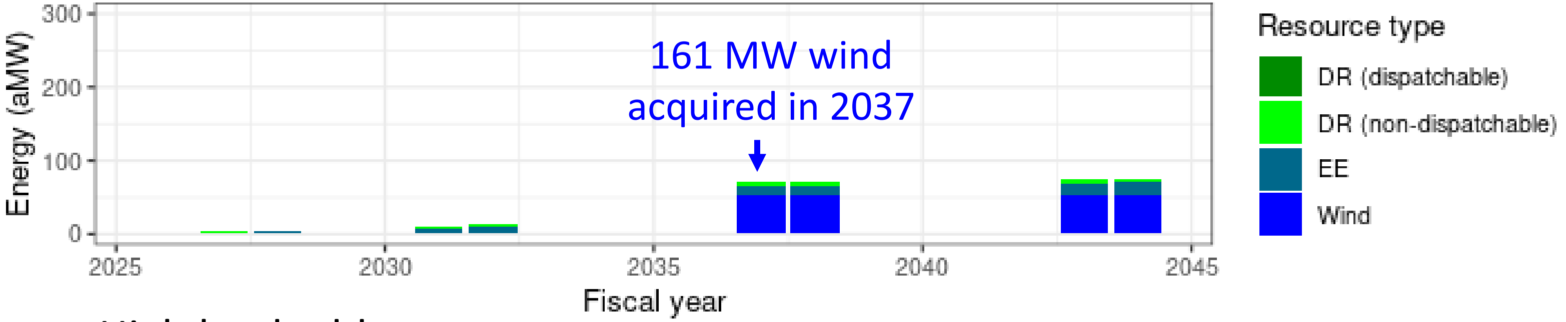
New, large acquisitions made in every available year (i.e., 2026, 2031, 2037, and 2043)



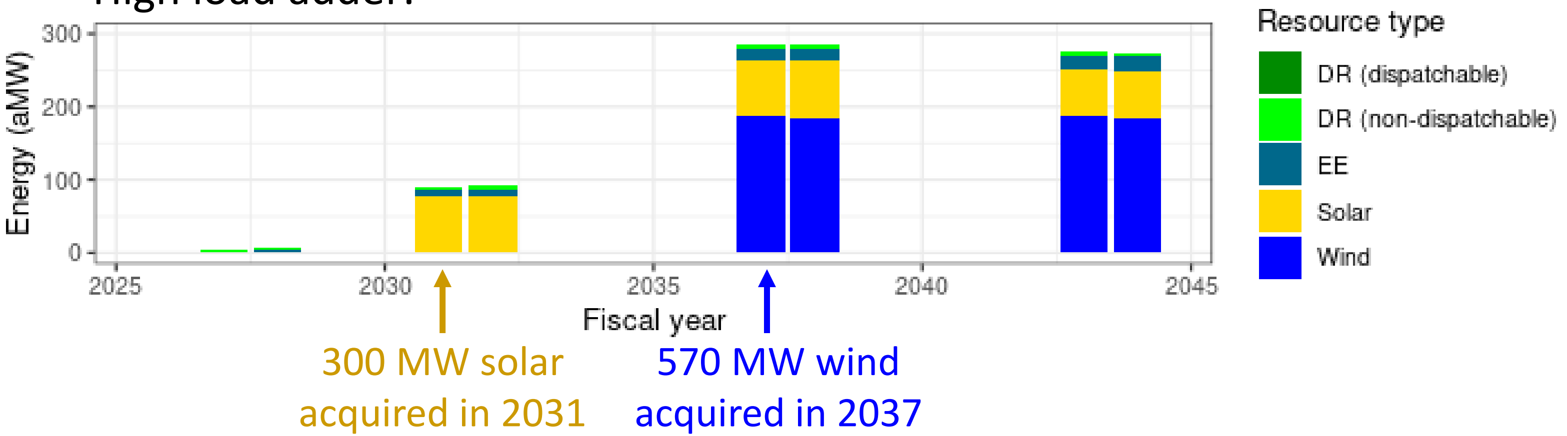
Only need that *cannot* be met with resources in the model: Apr '28 HLH

Load adders: SWEDE annual aMW

Medium load adder:



High load adder:



Tier 1 augmentation – Key takeaways

- Meeting T1 load exclusively with supply-side resources requires very substantial acquisitions:
  - P10 needs in the tightest month drive acquisitions
  - Generation greatly exceeds needs most of the time

- Augmentation is achieved with wind, solar, and geothermal power

- In the least-cost portfolio, most energy is generated in the SWEDE region

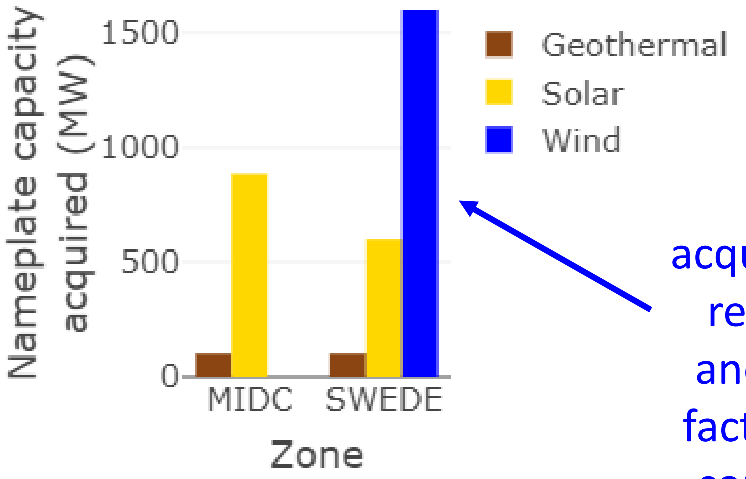
Tier 1 augmentation

- This sensitivity grows the T1 System Firm Critical Output (T1SFCO) to **7250 annual aMW** shaped to reflect **forecasted hourly shape of T1 obligations**, starting in **2029**
- Needs are modeled as average monthly energy needs at the **whole-system level** (no distinction between SWEDE and Mid-C zones)
- **Only supply-side resources** are allowed to contribute to the growth in T1SFCO
- **Current results are preliminary**: **CGS uprate** is not yet in the model. We expect to repeat this analysis when those inputs become available.

T1 augmentation: Resource acquisitions

We did not allow EE, DR, or market purchases to contribute to the T1 augmentation

Supply-side:



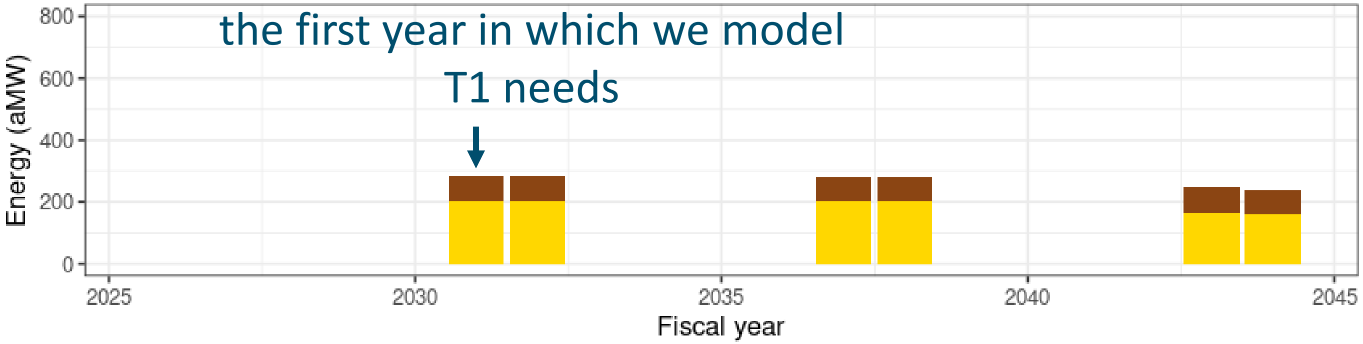
Large wind acquisitions in SWEDE reflect lower costs and higher capacity factors in that region compared to Mid-C

All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity.

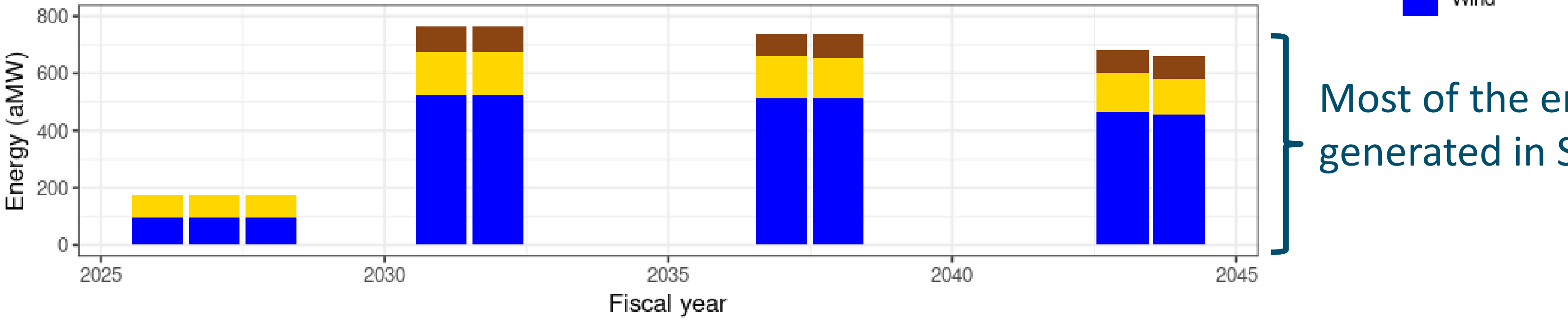
Tier 1 augmentation: annual aMW

MIDC:

Resources all acquired by 2031, the first year in which we model T1 needs



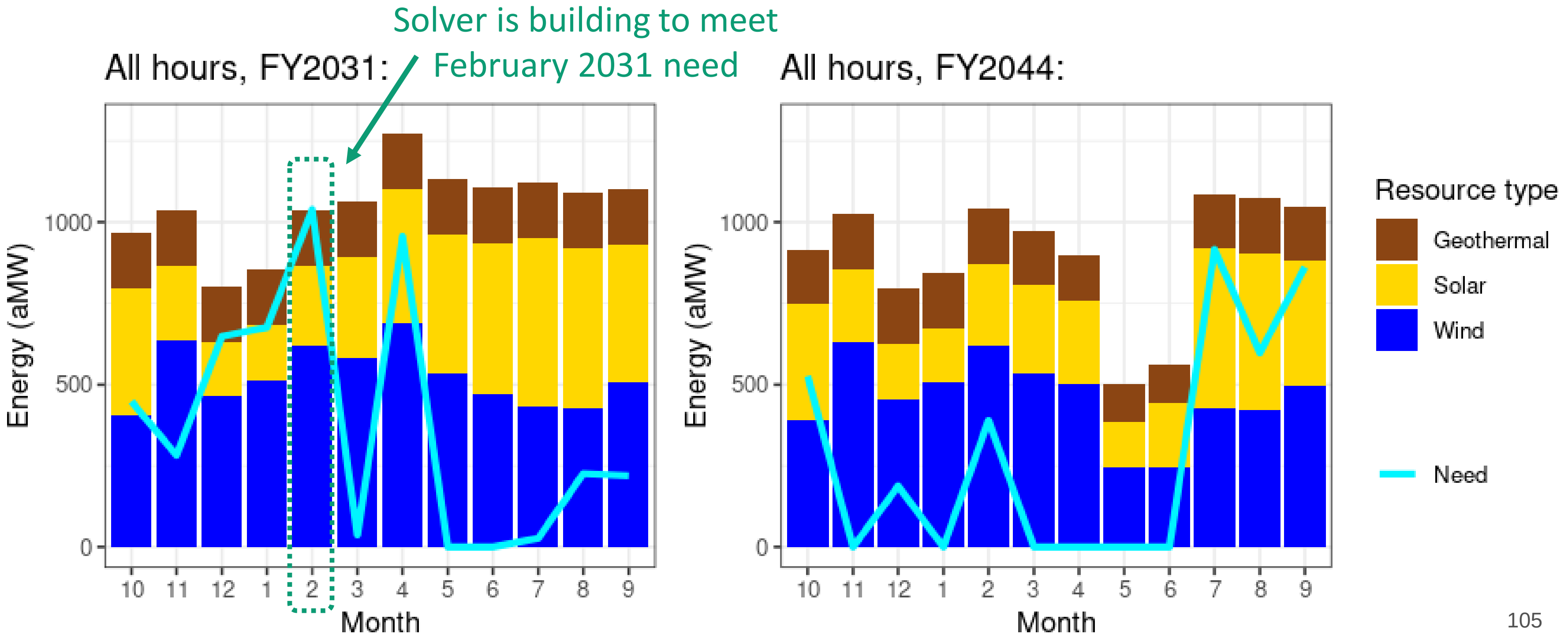
SWEDE:



Most of the energy is generated in SWEDE

Tier 1 augmentation: monthly aMW

In most months, generation is much greater than needs, even under P10 conditions

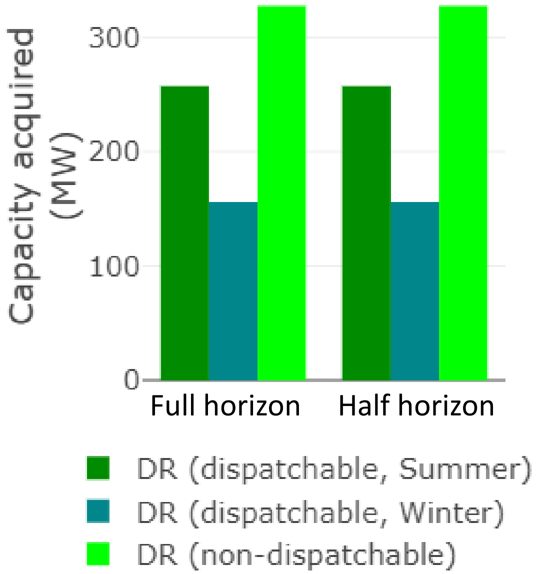


Half study horizon sensitivity: Key takeaways

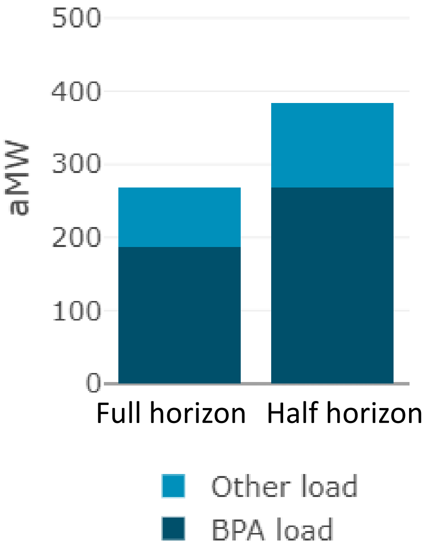
- Most resources have lower net costs in first half of the study period:
  - Prices expected to be higher early in study period
  - IRA production tax credits modeled for wind and solar pay out in first decade of plant lifespan
- So, if we only consider the first half of the study period, resource portfolio tends to include:
  - More solar and wind
  - More EE programs

Base scenario full vs. half study horizon

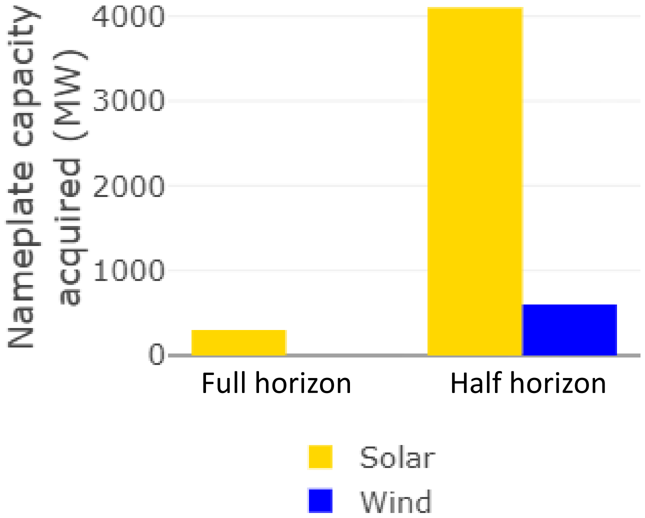
Demand response:



Energy efficiency:



Supply-side:



All values are for 2032. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Base scenario sensitivities: Summary table

	Base scenario	Market limits				High Mkt Price	Loads	
		Reduce 25%	Reduce 50%	Reduce 50% All	Path to 0		Med Load	High Load
Total NPV cost (billions of $)	$0.8	$0.8	$1.6	$2.2	$2.5	-$0.2	$9.0	> $37.5
Annual variability (avg. SD*, billions of $)	$0.24	$0.24	$0.24	$0.24	$0.24	$0.52	$0.27	$0.33
Tail variable costs (Avg. of 10 worst months, billions of $)	$0.46	$0.46	$0.43	$0.38	$0.36	$0.60	$0.55	$0.78
Carbon emissions (millions of metric tons/year)	1.0	1.0	0.7	0.4	0.3	0.2	1.8	3.6

*Variability is calculated by taking the standard deviation (SD) across performance run iterations for each FY and averaging across the study horizon

Natural Gas Assessment

- Consistent with the previous resource program, we are not including natural gas (NG) resources as options directly in the solver.
- The diversity of carbon policies across the BPA service territory complicate the modeling of natural gas in the optimization process. This would significantly expand the scope of the resource program modeling as multiple approaches would be needed for each scenario and sensitivity.
- Modeling natural gas also includes other technical challenges that led to the decision to not include it in the model.
  - Incorporation of NG price risk modeling, this model has caused significant delays and errors in other applications
  - Uncertainty around costs and availability of firm fuel
  - Uncertainty around costs and key characteristics of transitioning NG resources to clean fuels (H2 / biofuels)
- The exclusion of NG resources from the solver does not preclude BPA from acquiring any resource necessary to meet needs at the lowest cost / in a cost-effective manner, as outlined in the Northwest Power Act and consistent with sound utility practice.

- We will gather feedback on NG modeling for RP26 and determine direction for future modeling.

Natural Gas Assessment: Key takeaways

- Including new NG would not change results or lower portfolio costs for the base case or any associated sensitivities. This depends on the following assumptions:
  - A new NG plant built for BPA could not be online before 2035 and would only serve as a bridge resource until 2045
  - Carbon emission costs are considered
  - SMRs beginning operation in 2035 are available and eligible for Inflation Reduction Act tax credits, will not cost substantially more than baseline estimates, and will remain online for 60 years

- Using the above assumptions, this assessment tests whether the solver would have selected a new NG resource. The following table shows timing and sensitivities where a new natural gas plant could help reduce costs of meeting BPA needs.

Natural Gas Assessment

	Base scenario	Market limits				High Mkt Price	Loads	
		Reduce 25%	Reduce 50%	Reduce 50% All	Path to 0		Med Load	High Load
2029-2034								
*2035-2040								
2041-2045								

	Not Selected
	Likely Selected if Available
	Likely Selected

*2035 is the earliest date we've assumed BPA could have a new resource online considering EIS, interconnection, and other necessary processes.

If BPA could get a NG resource online sooner, temporarily acquire output from an existing plant, or invest in NG resources that transition to zero emissions (through clean fuels or carbon sequestration), NG resources may help reduce costs of meeting needs under more sensitivities.

Next Steps for Energy Efficiency

Results Applicability to EE & DR Planning

The 2024 Resource Program informs EE about:

1. Potential longer-term BPA resource needs and potential strategies to meet those needs

2. High-level scope and magnitude of demand-side resources that may be valuable for BPA

What is next?

- Council 9th Power Plan modeling and outcomes (end of 2026)
- RP26 results
- The next EE Action Plan (2028 and beyond)
- The measures that are practical and cost-effective for BPA to acquire

Resource Program Results: Analytical Approach

Results are presented in **sector-end use-price** bundles
(Example: Residential HVAC measures at the $30/MWh cost)

EE's Analysis Plan for RP24 Results

Compare RP24 bundle-level results:	Through comparison, we hope to learn about:
Between RP24 scenarios	• Possible futures and the EE measures we ought to think about • Resources not selected by the RP, but could be activated
RP22 results	• Changes in the last 2 years (growth, electrification, load forecasts, etc.) • Projected near-term and long-term changes
EE Action Plan results	• Measures selected or not selected due to time-value • Individual measures that make up programs
2021 Power Plan	• Similarities/differences in modeling assumptions between Power Plan and RP

Key Takeaways

- Energy Efficiency (EE) views the 2024 Resource Program as indicative of a variety of potential future needs.
- Given diversity of results and potential implications for BPA, EE will not make significant changes to the EE program.
- This is consistent with the Agency's treatment of supply-side resources.

Contact

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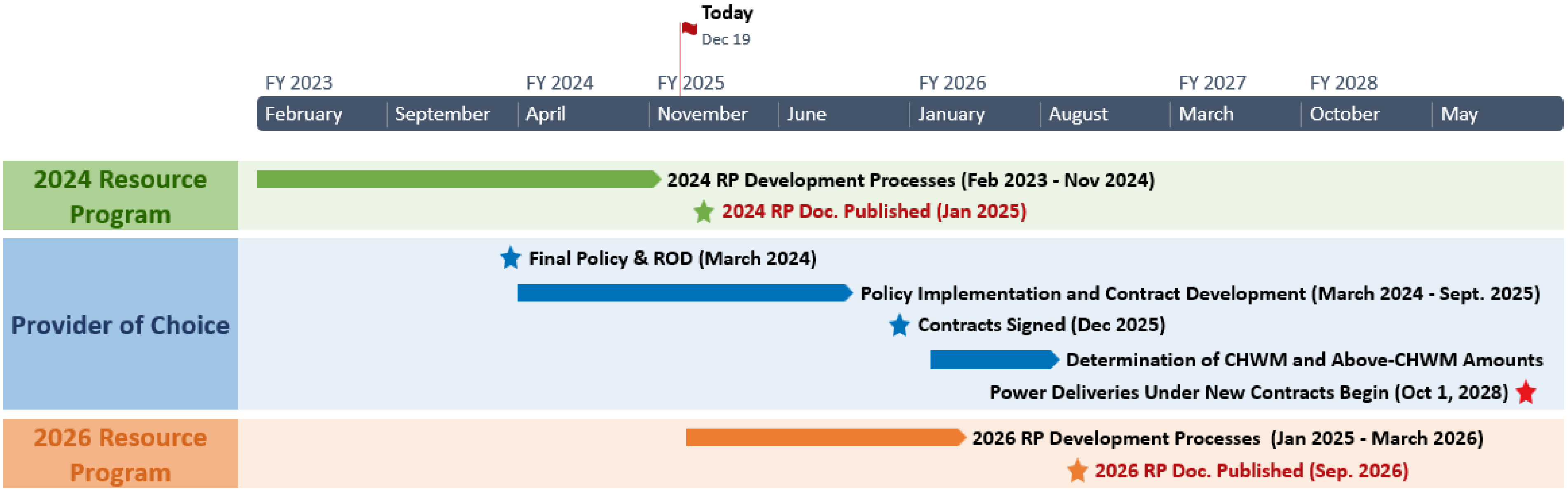
Next Steps for Resource Program

- Publication of 2024 Resource Program expected in January 2025
- Release of BPA and Energy Northwest joint CGS EPU business case and RP24 addendum study in March 2025
- 2026 Resource Program to kick off in winter 2025; publication expected September 2026

Resource Program and Provider of Choice



Get in Touch

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