2020 Resource Program

March 6, 2020

Marcus Eikenberry 2002

BPA Resource Program

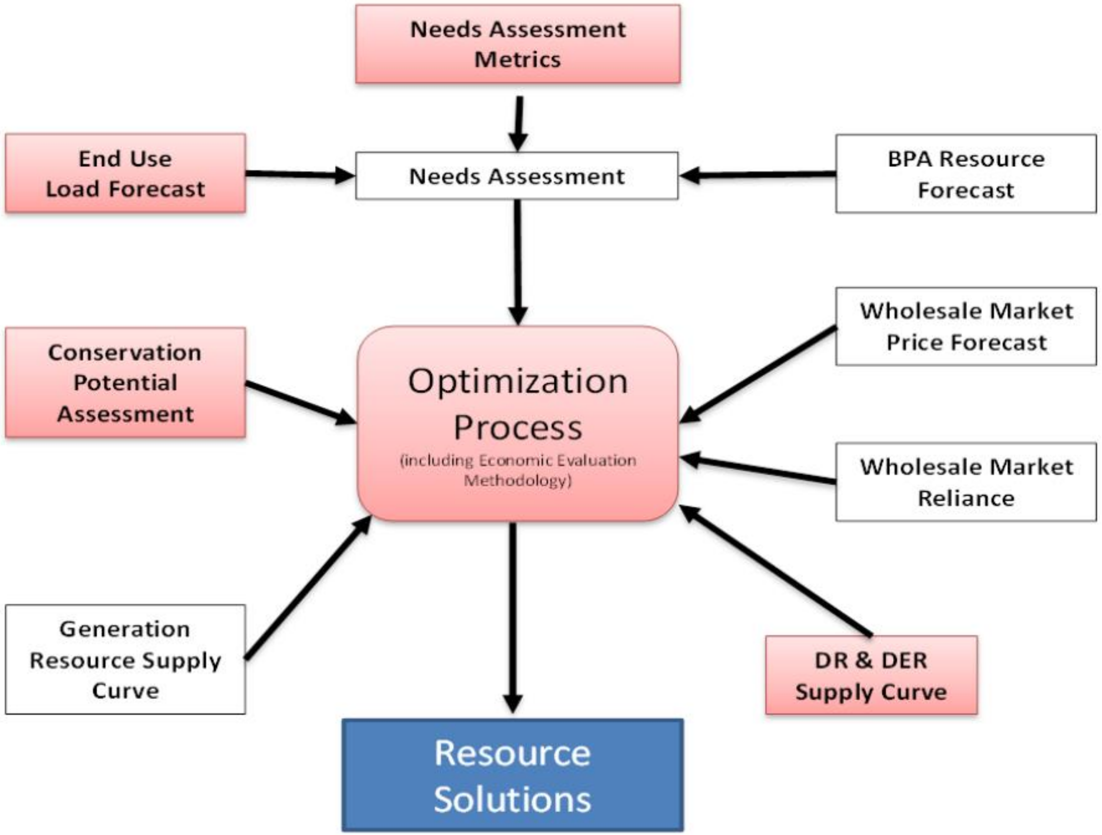
The Resource Program:

- Begins with a forecast of BPA load obligations and existing resources and then determines needs
- Identifies and evaluates potential solutions to meeting those needs
  - Energy efficiency, demand response, market purchases, wind, solar, gas plants, etc.
- Identifies least-cost method of meeting future needs

The Resource Program is not:

- A decision or policy document such as an Administrator’s Record of Decision
- A requirement of law or a regulating body such as FERC or NERC

2018 Resource Program Process Overhaul



- Red boxes are significant changes in 2018 from prior Resource Programs
- 2020 is a “Refresh” of some underlying data

2020 Preserved the 2018 Process

- The 2020 refresh serves as a pulse check
- To accomplish the refresh, certain inputs were updated:
  - Needs Assessment
    - Load Forecasts
    - Resource Forecasts
  - Market Price Forecast
  - Conservation Potential Assessment
  - Resource costs

Key Findings in 2020

- <u>Each of these will be addressed in more depth later in the presentation</u>

- Changes from the 2018 Resource Program (RP) to the 2020 Refresh
  - The load forecast declined
  - Changes to modeled hydro operations had variable impacts across months on BPA's forecast for Federal energy and capacity
  - The Needs Assessment showed a general decline in BPA's need for resources to meet its obligations
    - Including a flip from a forecast summer capacity deficit to a surplus
  - The market price forecast declined

Implications

- At the intersection of all of these changes to model inputs, the results of the optimization suggest that BPA can meet its obligations in a reliable and least-cost manner with Energy Efficiency (EE) and market purchases

- The 2020 RP Refresh results are generally consistent with the results from the 2018 RP
  - BPA does not anticipate any major changes to its EE acquisition strategy based on the 2020 results
  - Demand response is now not in the least cost portfolios

- We will now hear from the relevant SMEs about their planning processes that feed into the Resource Program

Load Forecast

Implementing End-Use Forecasting

- Goal: Implement End-Use forecasting to provide a frozen efficiency forecast for the BPA Resource Program with
  - Process that is transparent to and involves our customers
  - Consistency with the Council forecast data
  - Representative of the BPA service territory
  - Integrates in with our other BPA forecasting and planning activities
- Status: Moving forward as planned
  - Of 148 customer, 27 have end-use (SAE) models
  - Continuing to use existing process on pre-conservation energy for those not converted
  - Will be doing a frozen efficiency and expected case forecast each year

Updated Forecast Results

- Used the spring 2019 forecast (same as BP 2020 rate case)
  - Major reductions from delay in large site additions
  - Some new major facilities were canceled
  - Some new facilities use less load than expected when finished
- Remaining conditions were basically unchanged
  - Minor ups and downs resulting in little difference from prior forecast

Needs Assessment – Obligations, Resources and Needs

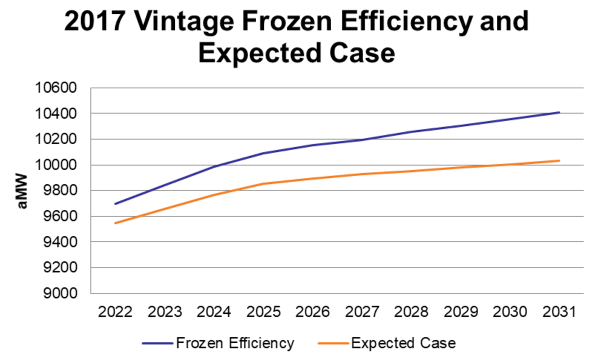
Needs Assessment - Overview

- The 2019 Needs Assessment studies rely on the same models, methodologies, and metrics as past Needs Assessments
- Include routine forecast updates
- Obligations:
  - Spring 2019 forecasts (BP20 Rate Case expected case)
  - Expected Case Forecasts increased by factors, to Frozen Efficiency obligations
    - Factors derived from Frozen Efficiency vs Expected Case forecasts from 2017 Needs Assessment
- Resources:
  - Hydro based on the same base studies as BP20, re-ran to include the 125 Flexible Spill
    - Not the CRSO Preferred Alternative hydro study

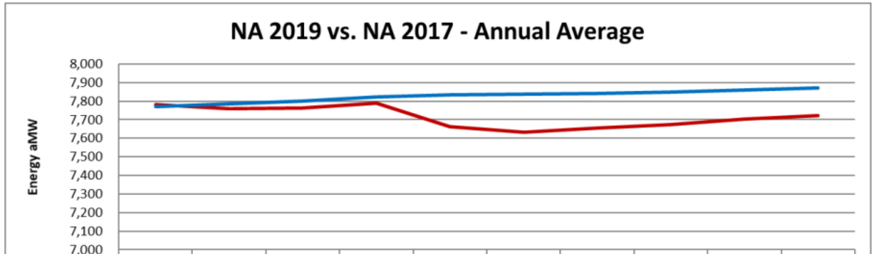
- Results in general show less deficits

Needs Assessment - Obligation Updates

- No Frozen efficiency forecast produced in 2019:
  - Expected Case Forecasts increased by factors
  - Factors based on 2017 vintage Total Retail Load differences



- Significant Obligation changes between 2017 and 2019 Needs Assessments:
  - Above High Water Mark load service election changes *(reduced T2 obligation)*
  - Alcoa contract termination *(reduced obligation)*
  - PGE capacity sales *(increased obligation)*
  - Flattened/reduced load forecast for RD customers *(reduced T1 obligation)*



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2019 NA	7,783	7,760	7,764	7,790	7,661	7,631	7,654	7,675	7,702	7,722
2017 NA	7,773	7,787	7,800	7,822	7,835	7,839	7,840	7,849	7,861	7,872
Delta	11	(27)	(36)	(31)	(173)	(208)	(187)	(175)	(158)	(150)

Needs Assessment - Resource Updates

- Regulated hydro projects
  - Hydro based on the same base studies as BP20,
  - Re-ran to include the 125 Flexible Spill Operation
  - Treaty operations (2020-2024 Assured Operating Plans)

1937	Oct	Nov	Dec	Jan	Feb	Mar	Apr I	Apr II	May	Jun	Jul	Aug I	Aug II	Sep	annual Average
2017 NA	5293	7395	7188	5838	6050	6011	5451	5130	8495	7203	6478	7071	5990	5657	6455
2019 NA	5525	7329	7071	5722	6084	5910	5130	4276	5788	8429	6930	6799	6437	5811	6326
difference	232	(66)	(117)	(116)	34	(101)	(321)	(854)	(2707)	1226	452	(272)	447	154	(129)

80yr Average	Oct	Nov	Dec	Jan	Feb	Mar	Apr I	Apr II	May	Jun	Jul	Aug I	Aug II	Sep	annual Average
2017 NA	5547	7826	8551	9601	9356	9126	8260	9558	11042	11158	9497	8121	7139	6108	8691
2019 NA	5738	7610	8459	9833	9621	8856	7760	7769	9500	10652	9362	7911	7732	6066	8435
difference	191	(216)	(92)	232	265	(270)	(499)	(1789)	(1542)	(506)	(135)	(211)	592	(42)	(256)

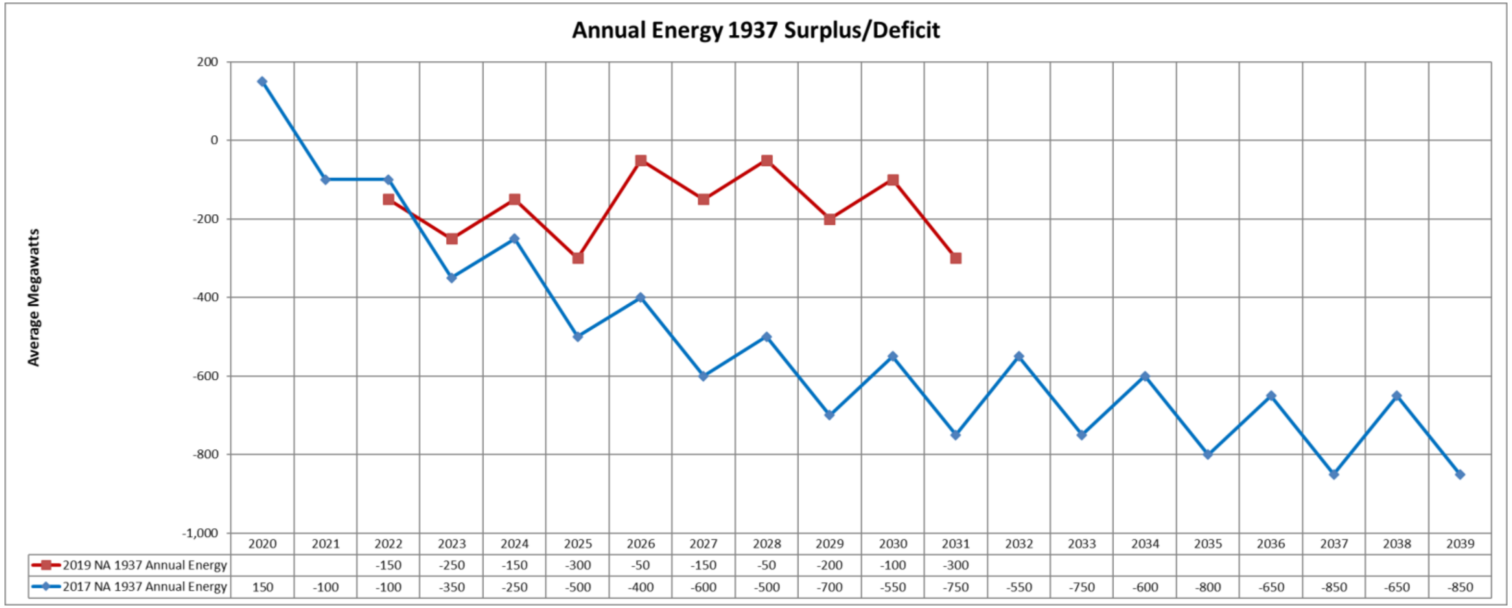
P10	Oct	Nov	Dec	Jan	Feb	Mar	Apr I	Apr II	May	Jun	Jul	Aug I	Aug II	Sep
2017 NA	5054	6889	7045	6320	6057	6221	5192	5970	8433	7146	6478	6612	5781	5320
2019 NA	5247	6688	6813	6749	6612	6274	5169	4276	6194	7686	6585	6342	6195	5347
difference	193	(201)	(232)	429	555	53	(23)	(1694)	(2239)	540	107	(270)	414	27

Needs Assessment - Metrics

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

Results: Annual Energy

- **Annual Energy** deficits of 150 aMW in fiscal year (FY) 2022, growing to 300 aMW by FY 2025, recovering to a deficit of 50 aMW in FY2026 growing to 300 aMW again by FY2031

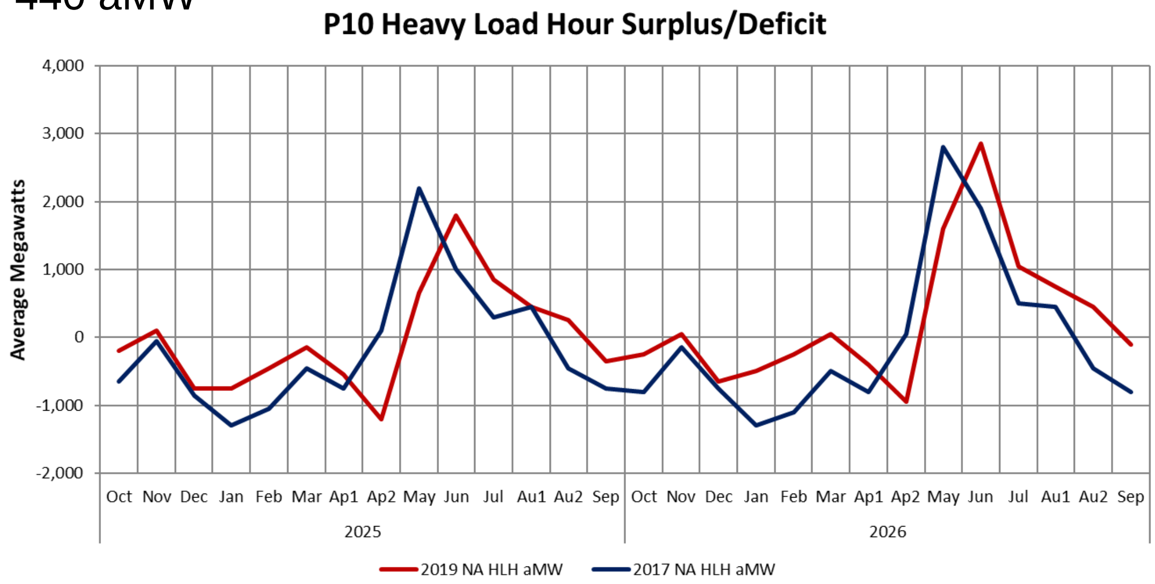


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
2019 NA 1937 Annual Energy			-150	-250	-150	-300	-50	-150	-50	-200	-100	-300								
2017 NA 1937 Annual Energy	150	-100	-100	-350	-250	-500	-400	-600	-500	-700	-550	-750	-550	-750	-600	-800	-650	-850	-650	-850

- The larger deficits in odd years represent Columbia Generating Station maintenance/refueling outages
- Change between 2025 and 2026 is the expiration of contracts

Results: P10 Heavy Load Hour

- The largest **P10 Heavy Load Hour** deficits occur in winter (Dec/Jan), and the second half of April
- Change from 2017: 1-5 year average needs decreased by 110 aMW, 5-10 year average needs decreased by 440 aMW

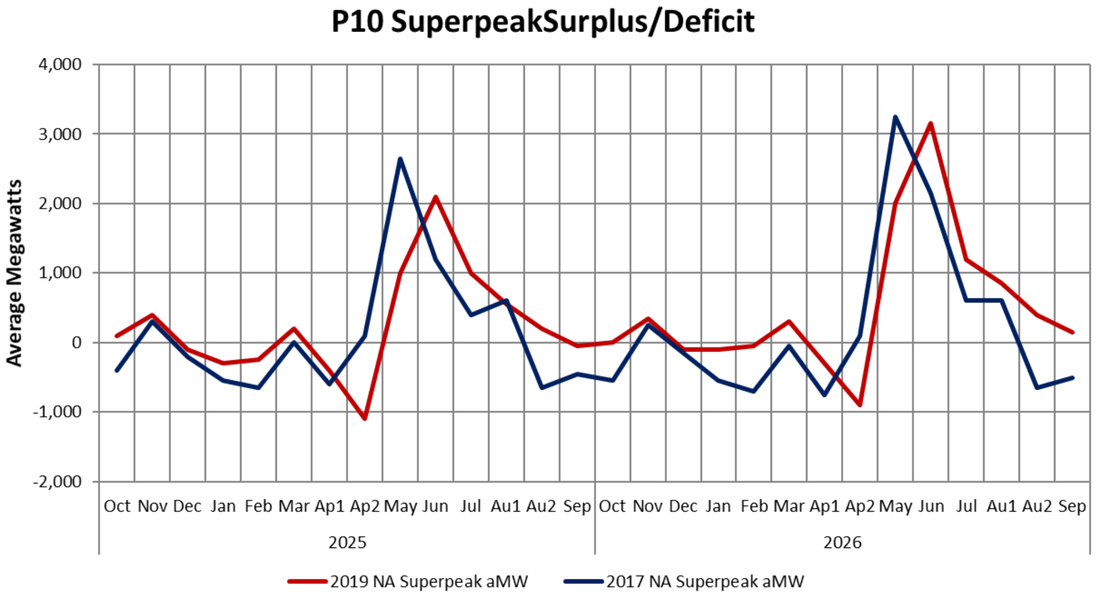


- Spill operation causes shift in largest deficit to shift to second half of April in low water conditions

  (becomes surplus at P24)
- Inventory position shifts between 2025 and 2026 is driven by expiration of contracts

Results: P10 Superpeak

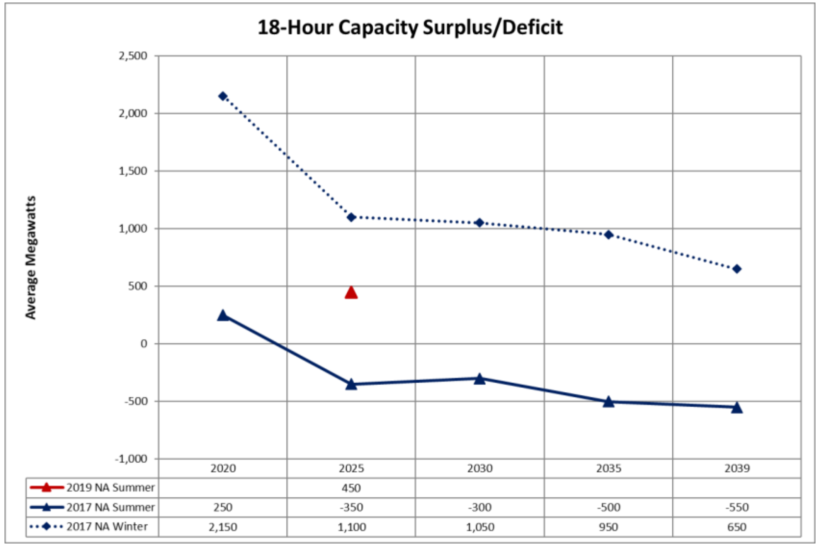
- The largest **P10 Superpeak** deficits occur in winter, the second half of April



- The P10 Superpeak deficits are smaller than the P10 Heavy Load Hour deficits across the study period
- Spill operation causes shift in largest deficit to shift to second half of April in low water conditions *(becomes surplus at P24)*
- Inventory position shifts between 2025 and 2026 is driven by expiration of contracts

Results: 18-Hour Capacity

- **Winter 18-Hour Capacity** – 2017 Needs Assessments showed surplus' over the study horizon
- **Summer 18-Hour Capacity** – 2019 Needs Assessment shows a surplus of 450 aMW in FY 2025, the 2017 Needs Assessments showed summer deficit of 350 aMW in FY 2025.



	2020	2025	2030	2035	2039
2019 NA Summer		450			
2017 NA Summer	250	-350	-300	-500	-550
2017 NA Winter	2,150	1,100	1,050	950	650

- Change from 2017 - Eliminated capacity shortfall shown in 2017, now see a capacity surplus
- The summer 18-Hour Capacity deficits are smaller than the P10 Superpeak and P10 HLH deficits

Aurora
Market Prices and Purchase Limits

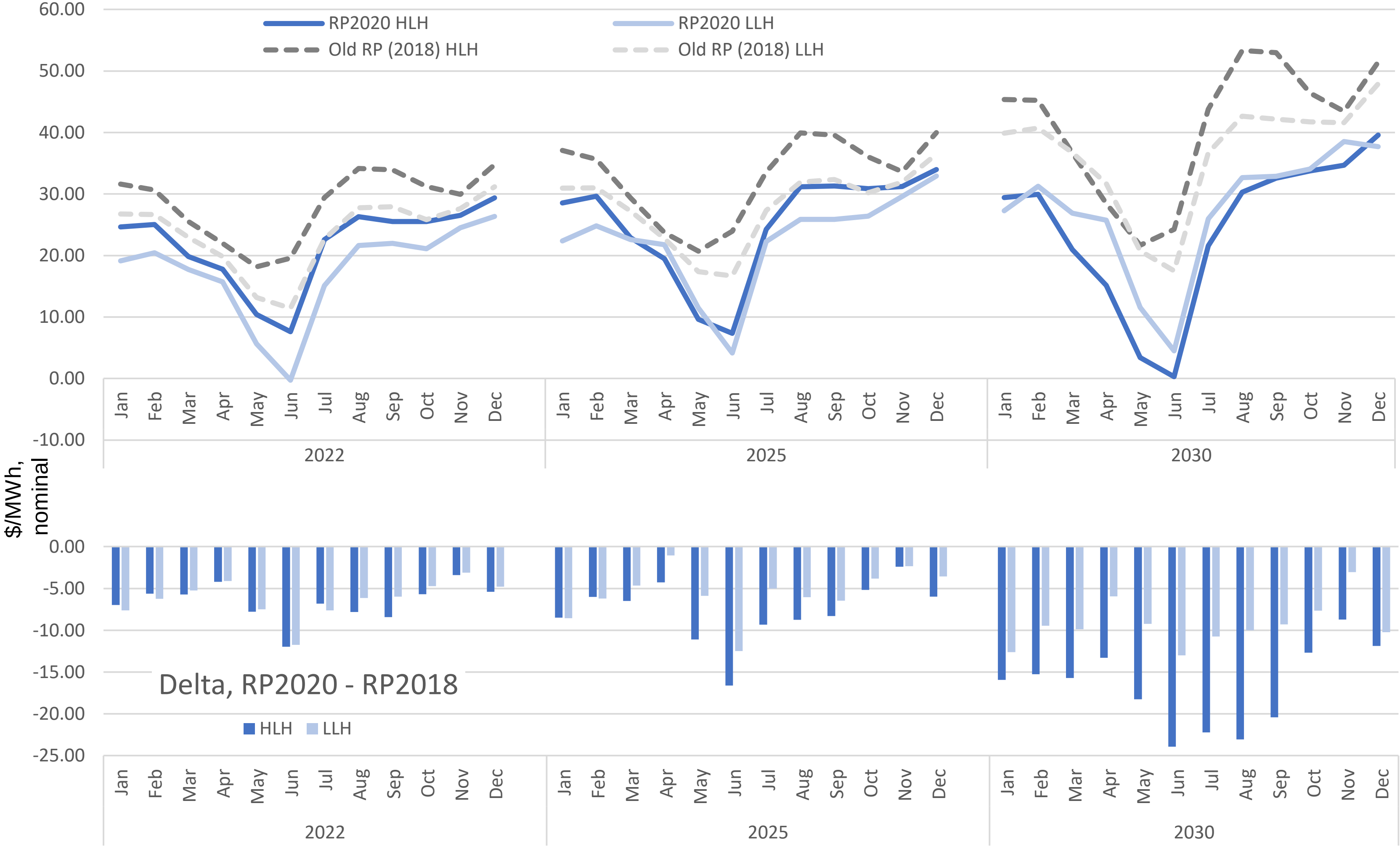
Aurora Refresher

- Aurora is a third party production cost model used globally by utilities, regulators, system operators, planning entities, consultants, and investment firms to model the economics of wholesale electricity grids
- BPA has used Aurora to forecast electricity prices in every rate case since 2000
- Aurora uses a linear program to minimize the cost of meeting load in the Western Interconnection on an hourly basis, subject to a number of operating constraints. Given the solution (an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. **It is assumed that the marginal cost of producing and delivering electricity approximates the price.**
- **Limitations**
  - No market design differentiation (no: forward curves / contracts / forecast error & day-ahead vs real-time markets/ source & sink/local commitment considerations), **all of the WECC is effectively modeled as a single ISO**
  - No behavioral components of power markets (in reality, bids may differ from actual marginal cost)
  - No AC flows / nodal prices, and transmission system is fixed (Aurora has the capability, not yet implemented)
  - No ancillary services (again, Aurora has the capability, not yet implemented)
  - No thermal resource duct firing / peak heat rate
- AURORA is a deterministic model**, we produce a distribution of price forecasts** by using a Monte Carlo of input distributions using historical variation for: loads, hydro generation, gas prices, transmission capability, wind generation, and CGS availability

BPA Uses Aurora Price Forecasts for:

- Net secondary revenue forecast in the rate case
- Resource program (prices and market depth)
- CRSO and other fish operations
- Outage planning
- Competitiveness analysis
- Treaty negotiations
- Other one-off analysis

Market Price Forecast



Mid-C Prices

(Month Avg.)

- About half of the downward pressure is due to lower natural gas prices.
- Notice 2030 price deltas tend to coincide with expected solar generation profile (largest decreases in the summer)

Aurora Resource Build: LT Capacity Expansion

- First step in an Aurora price forecast is to generate a long-term resource build
  - Start with existing resources
  - Lock in high likelihood builds and retirements over the duration of the next rate period
  - Allow AURORA to build and retire additional resources based on economics, ensuring pool planning reserve margins are satisfied and all relevant, modeled state policies (primarily Renewable Portfolio Standards) are met
- Default planning reserve margins are about 15%

State Policies

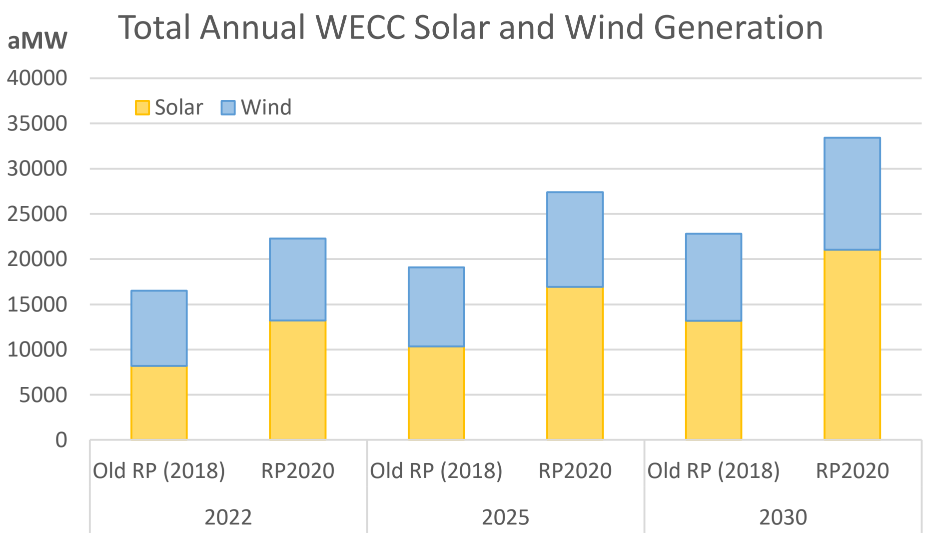
- Renewable Portfolio Standards (RPS), 2030 goals (updates since 2018 RP in **red**):
  - **CA 60%** (formerly 50%)
  - **NV 50%** (formerly 25%)
  - **NM 50%** (formerly 20%)
  - OR 50% by 2040 (effectively closer to 35%)
  - **Alberta 30%**
  - CO 30%
  - WA 20%
  - AZ 15%
  - MT 15%
- WA CETA (2030: 80% zero emission, 20% subject to penalties if not zero emission)
- Other, longer-term low or zero carbon emission mandates are not modeled

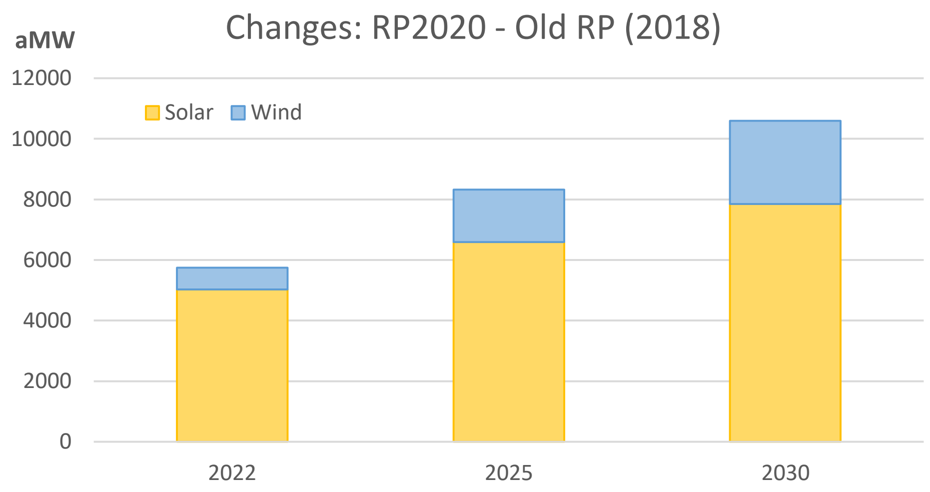
Other Aurora Updates

The 2020 RP market price forecast was generated in September 2019 and is mostly consistent with BP-20 FP Aurora assumptions. Updates since the 2018 RP forecast:

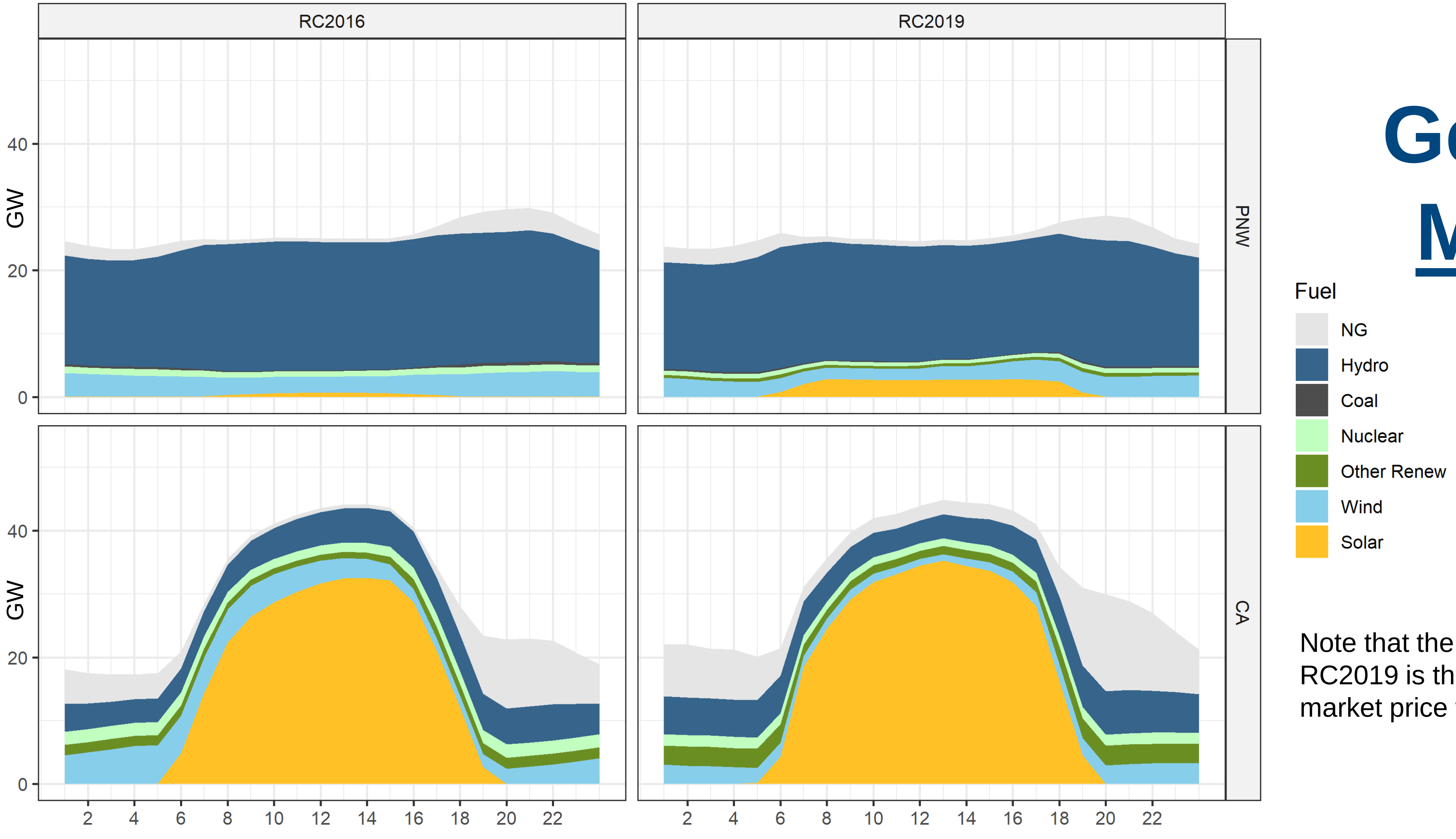
- New natural gas price forecast (accounts for roughly half of the declines in forecast prices)
- New transmission risk model
- New Aurora version that accounts for renewable curtailment in buildout
- Updated thermal resource minimum generation levels

Renewable Energy



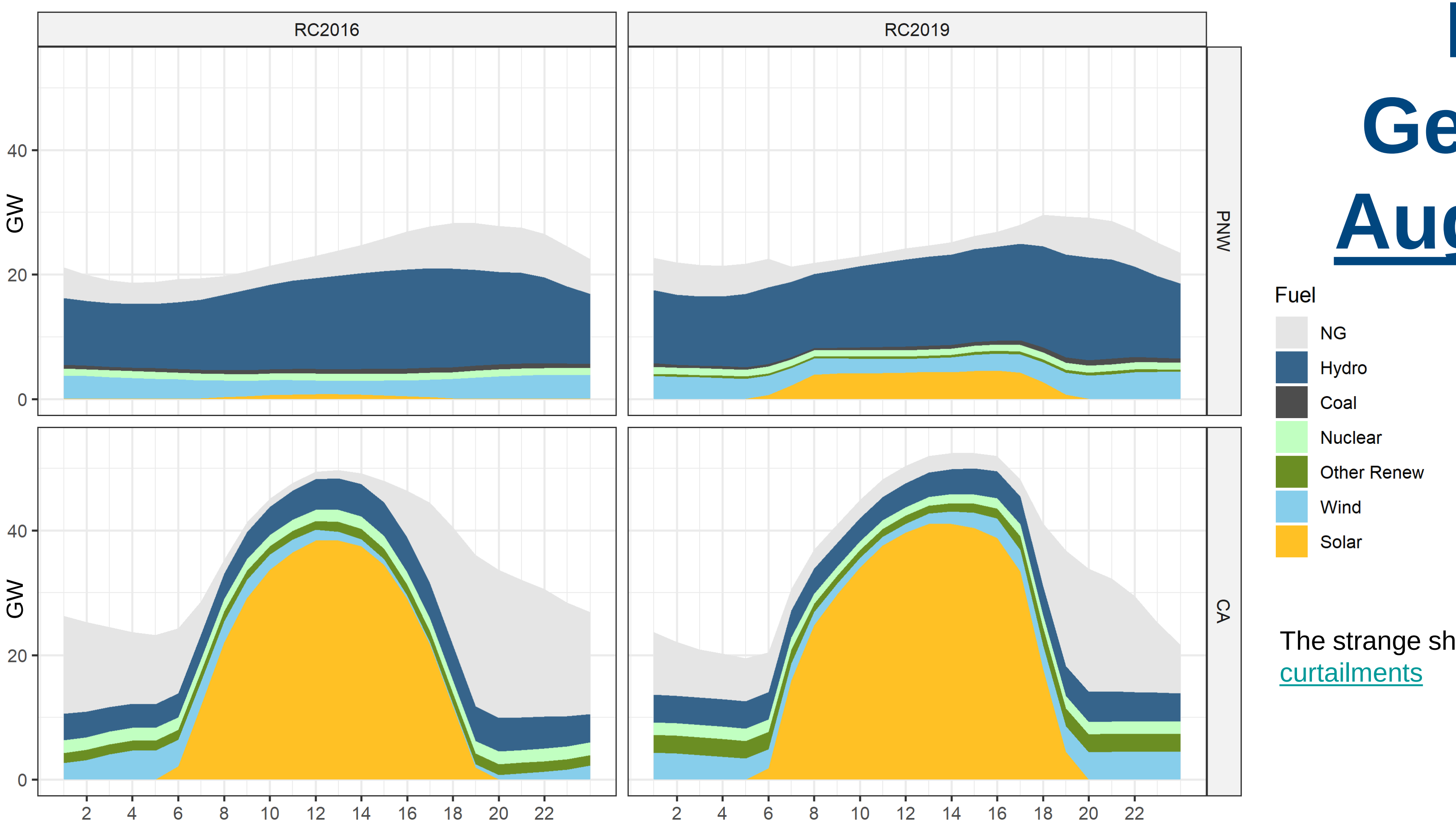


Hourly Generation May 2030



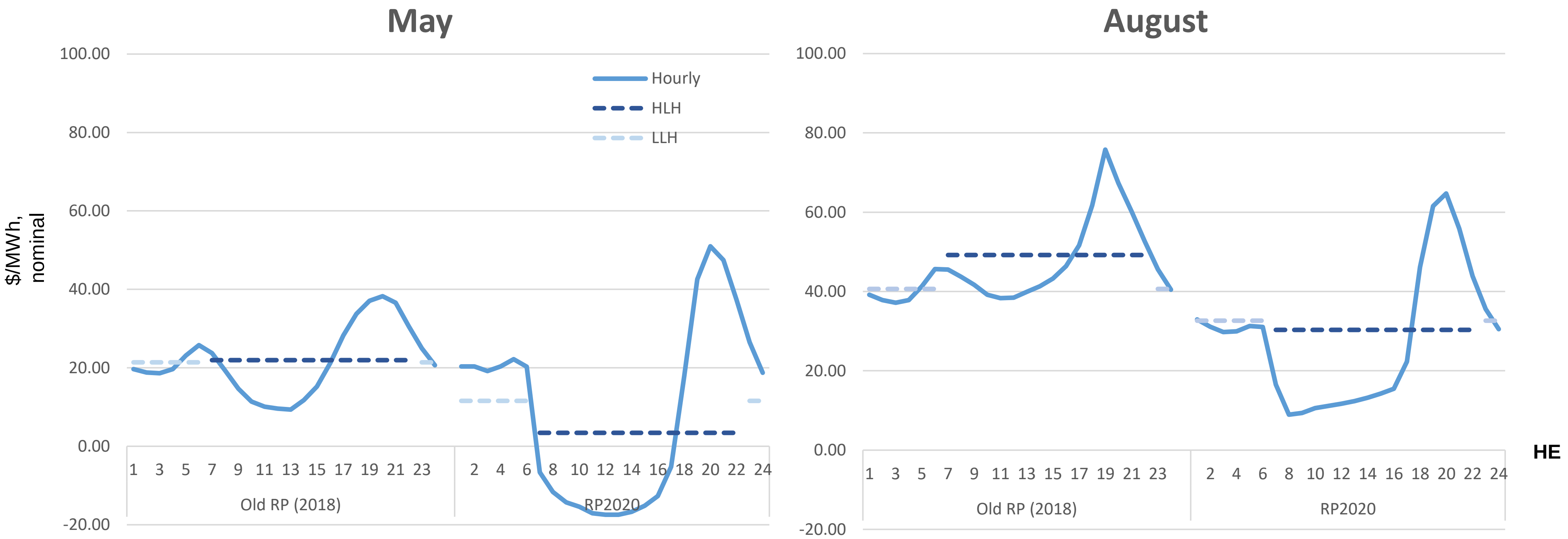
Note that the graphic is from a different presentation, RC2019 is the resource build used for the RP 2020 market price forecast.

Hourly Generation August 2030



The strange shape of CA solar is driven by curtailments

Mid-C Average Hourly Prices, 2030

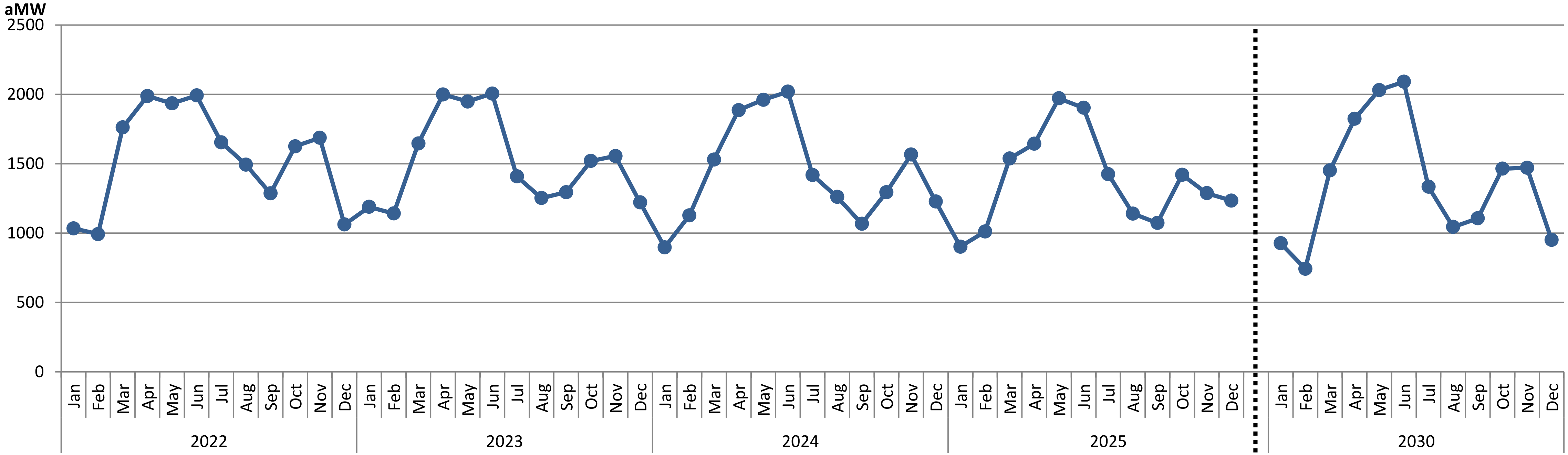


Key Uncertainties

- Policy and technology are fundamentally altering the electricity landscape; the associated range of price uncertainty should not be underestimated
- While this is a solar heavy build, it is likely *underestimating* future solar buildout
  - Assumes zero rooftop solar outside of the Desert Southwest
  - Assumes zero new Carbon / RPS legislation
- Timing of RPS build could change: acceleration to capture tax credits / delay for reliability?
- Hydro shaping and storage resources
  - Likely dampen the extreme impacts
- New technologies (offshore wind, hydrogen, new storage, seasonal storage, something else?)
- Negative price severity depends on:
  - Storage / hydro shaping
  - Policy relaxation
  - Alternative new technologies
- Potential climate change impacts not modeled
- The resource build reflects one load forecast

Market Limits

RP2020 AURORA Average Monthly HLH Market Limits*



This study was not refreshed for the 2020 RP, values are the same as the 2018 RP.

*In our analysis, no loss of load events occurred in LLH

Assessing Market Liquidity & Reliance Limits

Old

- Trading floor looked back at recent scarce conditions and assessed how much more energy the market could have sustained using a number of techniques
- Conservative values from the lookback are then projected forward to set limits on average monthly HLH energy in winter and summer months

New

- Leverage assumptions about future resource builds and retirements used in our AURORA setup to produce the market price forecast
- Minor modifications are made to assess loss of load events and allocate potential liquidity to BPA
- Details provided in the following slides

Market Limits in Aurora

Given longer duration of this Resource Program and expected evolution of resource mix over the planning horizon, we adopted a method that relies on AURORA. In order to ascertain market depth:

1. Start with our base resource build used to project future marginal costs of meeting load (market prices), this meets a ~15% planning reserve margin in the PNW

2. Simulate scarcity conditions by reducing PNW hydro generation to monthly p10 level and allow all other risk models to operate normally (loads, transmission, wind, CGS, and natural gas prices)

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

4. On a monthly basis, determine level at which greater market reliance causes region to exceed 5% LOLP (as roughly approximated with AURORA)

5. Allocate a share of the market reliance to BPA and accept this as our market reliance limit

Market Limits in AURORA, Visual

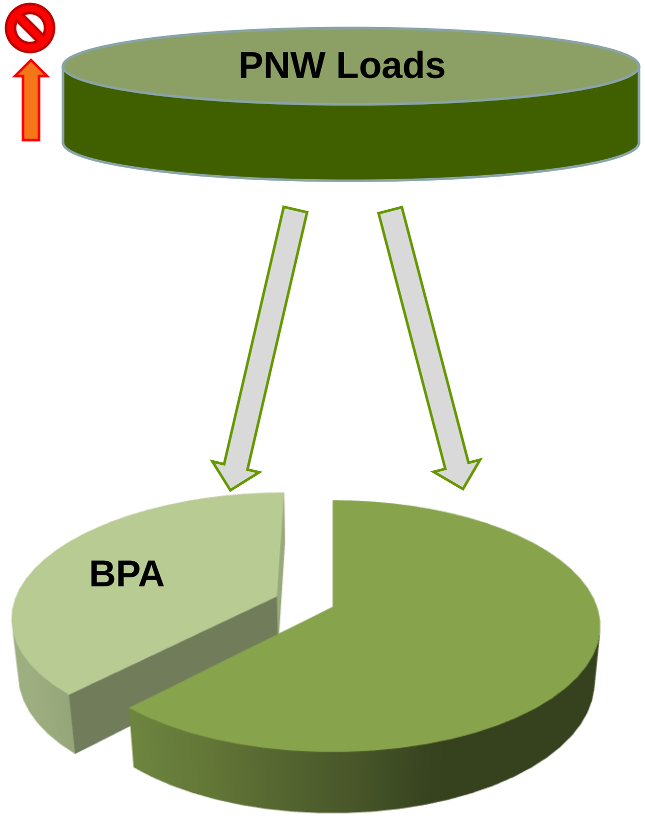
Start with baseline loads and resources

This approach focuses on physical load-resource balance across the system, no modifications have been made to reflect frictions / improvements driven by changing market structures

Incrementally increase PNW regional loads until loss-of-load events exceed threshold

(5% LOLP proxy)

Determine BPA's share (proportional to BPA load obligation / PNW regional loads) and use this as our market reliance limit



LOLP runs in AURORA

- 20 year (2020-2039) study with 3200 AURORA iterations, all iterations have PNW hydro fixed at monthly p10 levels

- PNW Loads are incrementally increased by 5%, 10%, 12.5%, 15%, … 40%
  - Achieved by a flat load increase in each PNW AURORA zone
  - For example, if the BPA Washington zone has 3,000 aMW in a month, the iterations testing a 10% increase would have an additional 300 MW of load for every hour of the month

- Each increased load level gets randomly assigned to 200 AURORA iterations

Example, December 2030

2020 and 2030 PNW Load Increases, aMW

% Load+	0%	5%	10%	12.50%	15%	17.50%	20%	22.50%	25%	27.50%	30%	32.50%	35%	37.50%	40%
Jan-20	0	1291	2582	3227	3872	4518	5163	5808	6454	7099	7744	8390	9035	9680	10326
Feb-20	0	1221	2442	3053	3664	4274	4885	5495	6107	6717	7327	7938	8549	9159	9770
Mar-20	0	1120	2240	2800	3360	3920	4480	5040	5599	6159	6719	7279	7839	8399	8959
Apr-20	0	1085	2170	2712	3255	3797	4340	4882	5424	5967	6509	7052	7594	8137	8679
May-20	0	1067	2133	2666	3200	3733	4266	4799	5333	5866	6399	6933	7466	7999	8533
Jun-20	0	1103	2207	2759	3310	3862	4414	4966	5517	6069	6621	7172	7724	8276	8828
Jul-20	0	1171	2342	2928	3513	4099	4684	5270	5856	6441	7027	7612	8198	8783	9369
Aug-20	0	1153	2307	2884	3460	4037	4614	5191	5768	6344	6921	7497	8075	8651	9228
Sep-20	0	1067	2133	2666	3200	3733	4266	4799	5333	5866	6399	6933	7466	7999	8532
Oct-20	0	1055	2109	2636	3164	3691	4219	4746	5273	5800	6328	6855	7382	7910	8437
Nov-20	0	1214	2428	3035	3642	4249	4856	5463	6070	6677	7284	7891	8498	9105	9712
Dec-20	0	1309	2618	3272	3926	4581	5235	5890	6544	7198	7853	8507	9161	9816	10470
Jan-30	0	1355	2709	3386	4064	4741	5418	6095	6773	7450	8127	8804	9482	10159	10836
Feb-30	0	1316	2632	3290	3947	4605	5263	5921	6579	7237	7895	8553	9211	9869	10526
Mar-30	0	1182	2363	2954	3545	4135	4726	5317	5908	6499	7090	7680	8271	8862	9453
Apr-30	0	1148	2296	2870	3444	4018	4592	5165	5739	6313	6887	7461	8035	8609	9183
May-30	0	1131	2262	2827	3392	3958	4523	5089	5654	6219	6785	7350	7916	8481	9046
Jun-30	0	1169	2339	2924	3509	4094	4679	5263	5848	6433	7018	7603	8188	8773	9357
Jul-30	0	1236	2471	3089	3707	4325	4943	5561	6178	6796	7414	8032	8650	9268	9886
Aug-30	0	1218	2436	3045	3653	4263	4871	5480	6089	6698	7307	7916	8525	9134	9743
Sep-30	0	1132	2264	2830	3396	3962	4528	5094	5660	6226	6792	7358	7924	8490	9056
Oct-30	0	1115	2230	2787	3345	3902	4460	5017	5574	6132	6689	7247	7804	8362	8919
Nov-30	0	1278	2556	3195	3835	4474	5113	5752	6391	7030	7669	8308	8947	9587	10226
Dec-30	0	1372	2745	3431	4117	4803	5490	6176	6862	7548	8234	8921	9607	10293	10979

Count of games (out of 200) with at least one loss of load event:

% Load+	0%	5%	10%	12.50%	15%	17.50%	20%	22.50%	25%	27.50%	30%	32.50%	35%	37.50%	40%
Jan-20	0	0	0	0	0	0	0	0	2	11	12	16	37	42	82
Feb-20	0	0	0	0	0	0	0	0	1	5	3	11	18	32	82
Mar-20	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
Apr-20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May-20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun-20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul-20	0	0	0	0	0	0	0	0	0	0	1	1	1	4	6
Aug-20	0	0	0	0	0	0	0	0	0	0	1	1	1	13	21
Sep-20	0	0	0	0	0	0	0	0	0	0	2	2	4	6	10
Oct-20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Nov-20	0	0	0	0	0	0	0	0	0	0	0	4	0	2	10
Dec-20	0	0	0	0	0	0	1	0	0	10	10	31	34	73	107
Jan-30	0	0	0	8	7	15	19	46	34	90	115	108	126	164	184
Feb-30	0	0	1	7	14	18	29	64	71	111	124	145	173	188	192
Mar-30	0	0	0	0	0	0	0	1	1	5	18	17	20	46	65
Apr-30	0	0	0	0	0	0	0	0	0	0	0	1	2	18	20
May-30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun-30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Jul-30	1	0	0	0	0	0	0	1	6	11	13	22	36	59	93
Aug-30	0	0	3	0	3	3	3	9	26	29	55	46	86	112	136
Sep-30	0	0	0	1	1	2	8	6	25	25	58	60	71	108	130
Oct-30	0	0	0	0	0	0	0	0	2	3	8	9	29	39	68
Nov-30	0	0	0	0	0	1	3	8	3	14	24	37	70	99	128
Dec-30	0	0	0	1	1	$\boxed{9}$	12	26	39	69	109	135	148	189	188

Shaded cells indicate 5% LOLP exceeded

Example, December 2030

Region 5% LOLP proxy exceeded with a 17.5% load increase (~4,800 aMW)

We set regional market depth one level below that (15% = 4,117 aMW)

Finally, we allocate a share of the regional market depth to BPA. BPA's December 2030 load is ~23% of the region, so BPA's corresponding market reliance limit becomes 951 aMW (0.23 * 4,117)

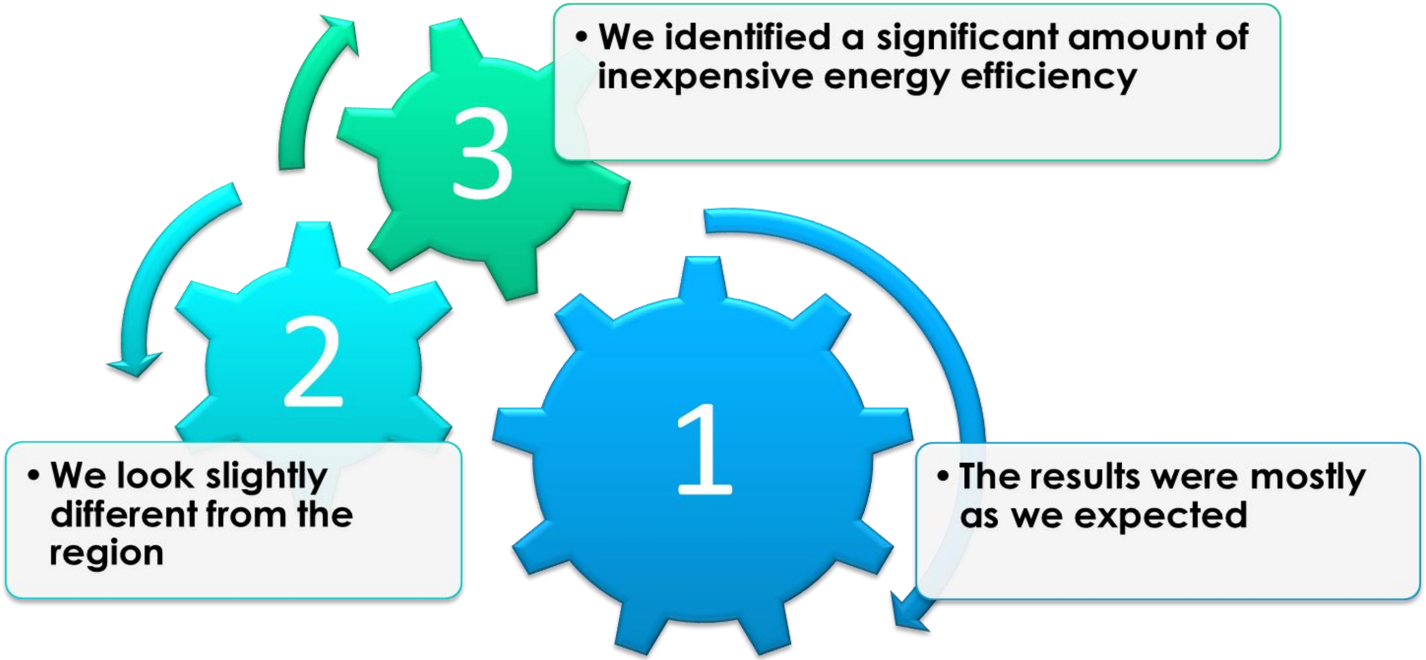
Resources in the Optimization

Energy Efficiency

BPA Conservation Potential Assessment

- Developed in 2017
- Based on Council's 7th Plan, adjusted for BPA territory specific attributes
- Data provided to Resource Program

Key Findings



What we learned about public power

01 We have more electric heating load

02 We have 38% of all single family homes

03 We have 36% of all commercial sq footage

04 We have 48% of the industrial sales

05 We have 34% of all irrigated acres

06 We have 30% of substations > 40,000 MWh

2019 CPA Update

- Removed savings achieved in 2018-2019
- Removed forecasted savings for 2020-21
- No updates to measure specifics or available measure set
- New CPA developed in 2022 after release of 8th Plan

Demand Response

BPA Has Done Advance Work to Prepare for the Use of Demand Response

Entity	Max MW	Timing	Product Demonstrated	Performance
City of Port Angeles	30	2013 - 2014	Imbalance Capacity	56% / 92%
Public Power Aggregator	35	2014 – 2016	Imbalance Capacity	94%
Commercial Aggregator	17	2015 - 2017	Winter Peak Shave	86%[2]
Public Power Aggregator	36	Summer 2017	Summer Power Multi-use	100%
South of Allston	46	Summers 2017 - 2018	Transmission Deferral	100%
Total Portfolio	164			

- BPA tested **164MW** of Demand Response (DR) in demonstrations from 2013 – 2018.
- Worked with **15+** power customer utilities and their end-consumers.
- Showed high reliability of demand response.
- Readied the organization for commercial roll-out, to be applicable when BPA and its power customers and the end-consumers have **a compelling business case and cost effective price signal.**

In 2019, Cadmus Completed a DR Potential Study; This was an Input into the 2020 Resource Program

2019 Cadmus Study 20 year Levelized Cost and Achievable Potential

Product	Summer			Winter		
	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer	Levelized Cost ($/kW-year) Summer	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Levelized Cost ($/kW-year) Winter
Residential DLC—Space Heating	0	0.0%	N/A	214	1.4%	$52
Residential DLC—Water Heating*	259	2.0%	$167	354	2.3%	$122
Residential Water Heater Timers*	194	1.5%	$98	264	1.7%	$72
Residential DLC—CAC	166	1.3%	$71	0	0.0%	N/A
Residential DLC—Smart T-stat*	147	1.1%	$47	268	1.7%	$85
Residential BYOT*	39	0.3%	$80	75	0.5%	$42
Residential CPP	57	0.4%	$12	168	1.1%	$10
Residential Behavioral DR	13	0.1%	$111	37	0.2%	$110
Small Commercial DLC	15	0.1%	$108	14	0.1%	$56
Med Commercial DLC	55	0.4%	$25	23	0.2%	$32
Commercial Lighting Controls	55	0.4%	$32	44	0.3%	$32
Commercial Thermal Storage	9	0.1%	$51	0	0.0%	N/A
Industrial Curtailment	315	2.4%	$29	311	2.0%	$29
Large Commercial Curtailment	196	1.5%	$42	133	0.9%	$42
C&I Interruptible Tariff	69	0.5%	$73	62	0.4%	$73
Industrial RTP	5	0.0%	$34	5	0.0%	$35
Large Farm Irrigation DLC	323	2.5%	$36	n/a	n/a	n/a
Small/Medium Irrigation DLC	219	1.7%	$50	n/a	n/a	n/a
DVR	232	1.8%	$14	392	2.6%	$14
Total*	**2,369**	**18.3%**		**2,363**	**15.4%**	

- Per Guidance of the Action Plan of the **7th Power Plan**, BPA conducted a DR Potential study, contracting with Cadmus.
- The Cadmus Potential Study found **2,300 MW** of achievable Summer and Winter DR with BPA's public power customers.
- These supply curves were **reviewed and vetted** with Council staff and BPA's Resource Program.
- The Resource Program modeling **did not select DR** based on the lack of a capacity need, nor did the model dispatch DR as an alternative to market purchases.

Other Resources

All Included Resources

- Resources to included in portfolio modeling
  1. Wind – $1,366/kW* in 2025 (in 2017 real $)
     1. GRAC had $1,450/kW
  2. Solar – $1,242/kW* in 2025 (in 2017 real $), single axis tracking
     1. GRAC has $1465 - $1350/kW, single axis tracking
  3. Natural gas (LMS100) – $1,047/kW in 2025 (in 2017 real $) + variable costs
     1. GRAC had LMS 100 at $1,000/kW, frame at $550/kW
  4. Market purchases
  5. EE – The CPA supply curves were updated to remove 90aMW of planned EE acquisitions in the 2020-2021 timeframe and 56aMW of market transformation and momentum savings
  6. DR – **Biggest change**: Correcting the methodology used to load DR costs into AURORA significantly increased the cost of DR, relative to the 2018 Resource Program
     1. DR costs have continued to be refined, for example, costs are now summer specific if targeting a summer capacity need

* Before tax credit

2020 Resource Program Preliminary Results

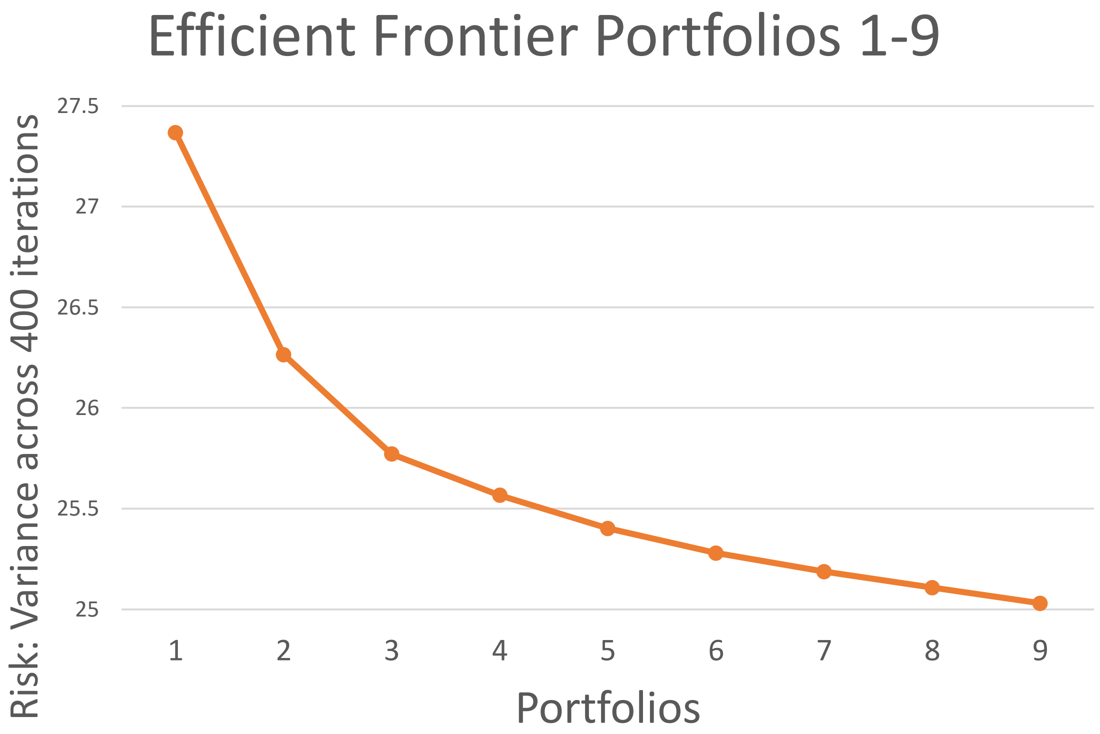
Refresher: Portfolio Optimization

- **Step 1**: Find Portfolio 1, the "least-COST" mix of resources that meet P10 HLH Energy needs and don't violate Market Purchase Limit

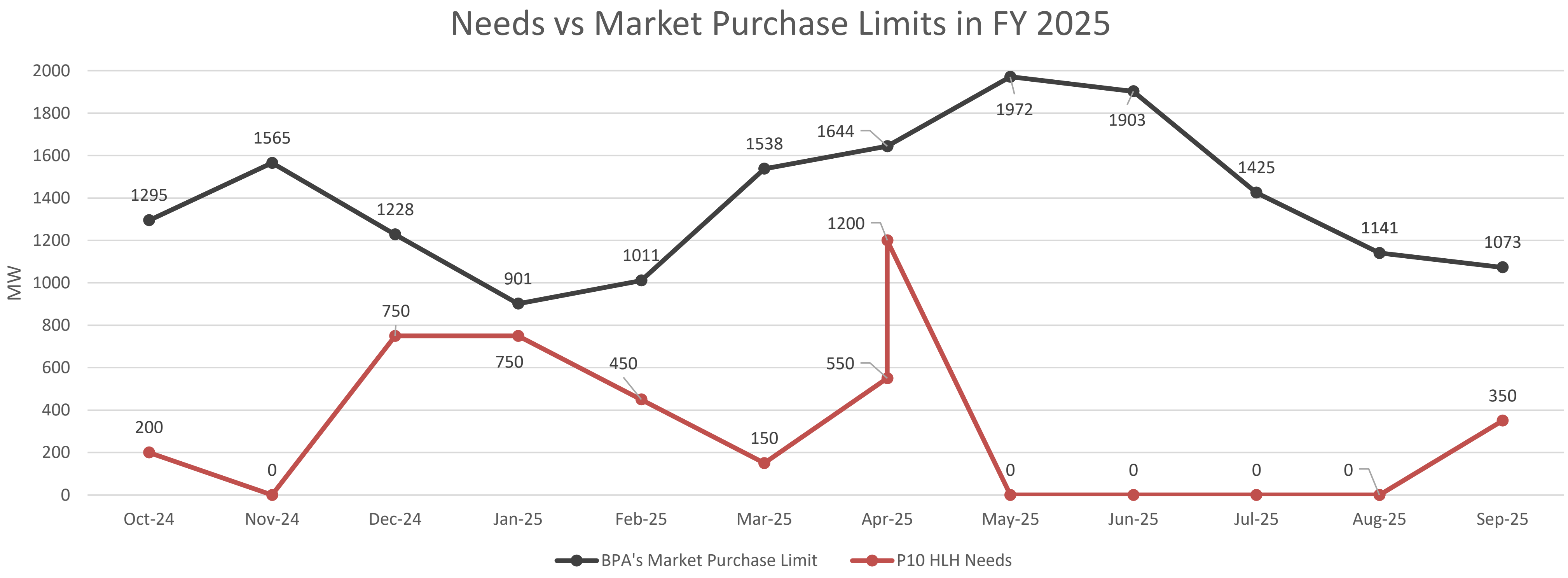
- **Step 2**: Find Portfolio 40, the "least-RISK**" mix of resources that meet P10 HLH Energy needs and don't violate Market Purchase Limit

- **Step 3-40**: Incrementally add budget to Portfolio 1's budget value and remix resources to find risk minimizing combination at given budget level

**Where risk is measured as variance in the total cost of the portfolio across iterations, with market prices being the main source of said variance



Putting Two Pictures Together – MPLs and Needs in 2025



EE Results in Portfolio Optimizer

- Each portfolio meets BPA's needs while respecting the Market Purchase Limits

2020RP Cumulative Savings (aMW)

	2-year	4-year	10-year
Portfolio 1	111	229	506
Portfolio 2	123	250	501
Portfolio 3	126	256	505

2018RP Cumulative Savings (aMW)

	2-year	4-year	10-year
Portfolio 1	121	259	665
Portfolio 2	154	328	838
Portfolio 3	161	342	892

Concurrent Planning Efforts

- The final draft of the 2021 Plan is scheduled to be published in 2021
  - The Northwest Power and Conservation Council is finishing up it's draft EE supply curves right now

- 2020RP Portfolio 1's EE Savings over 2021 Plan Timeline:

Corresponding to NWPCC 2021 Plan Timeline (Cumulative aMW of EE)

	2022	**2023**	**2024**	**2025**	**2026**	**2027**
2020 Port 1	54	111	168	229	292	352

- The 2022 Resource Program plans to use EE supply curves from the 2021 Plan