AVISTA

2027 Electric and Natural Gas Integrated Resource Plans

Technical Advisory Committee Meeting No. 5 Agenda

Friday, February 20, 2026

Virtual Meeting – 1:00 pm to 4:00 pm Pacific Time

Topic	State	Audience

• Introduction and Questions from TAC 4
    ○ RCP 4.5 vs. RCP 8.5
    ○ CO_2 Transportation Update		

• DER Forecast Impact on Electric Distribution System	WA	Electric
• Sub-Hourly DER Resource Value Analysis	WA/ID	Electric
• New Electric Resource Options and Cost Forecast	WA/ID	Electric
• Electrification Assumptions and Scenarios	All	E&G
• Wholesale Electric Price Forecast	WA/ID	Electric

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For organizers: Meeting options | Reset dial-in PIN

Introductions 2027 Electric & Gas Integrated Resource Planning

TAC 5 – February 20 , 2026

John Lyons, Ph.D. – Senior Resource Policy Analyst

TAC 5 Agenda

- Introduction and Questions from TAC 4, John Lyons
  - RCP 4.5 vs. RCP 8.5
  - CO_2 Transportation Update
- DER Forecast Impact on Electric Distribution System, Erik Lee
- Sub-Hourly DER Resource Value Analysis, Jacob Heimbigner
- New Electric Resource Options and Cost Forecast, Robert Hughes
- Electrification Assumptions and Scenarios, James Gall
- Wholesale Electric Price Forecast, Robert Hughes

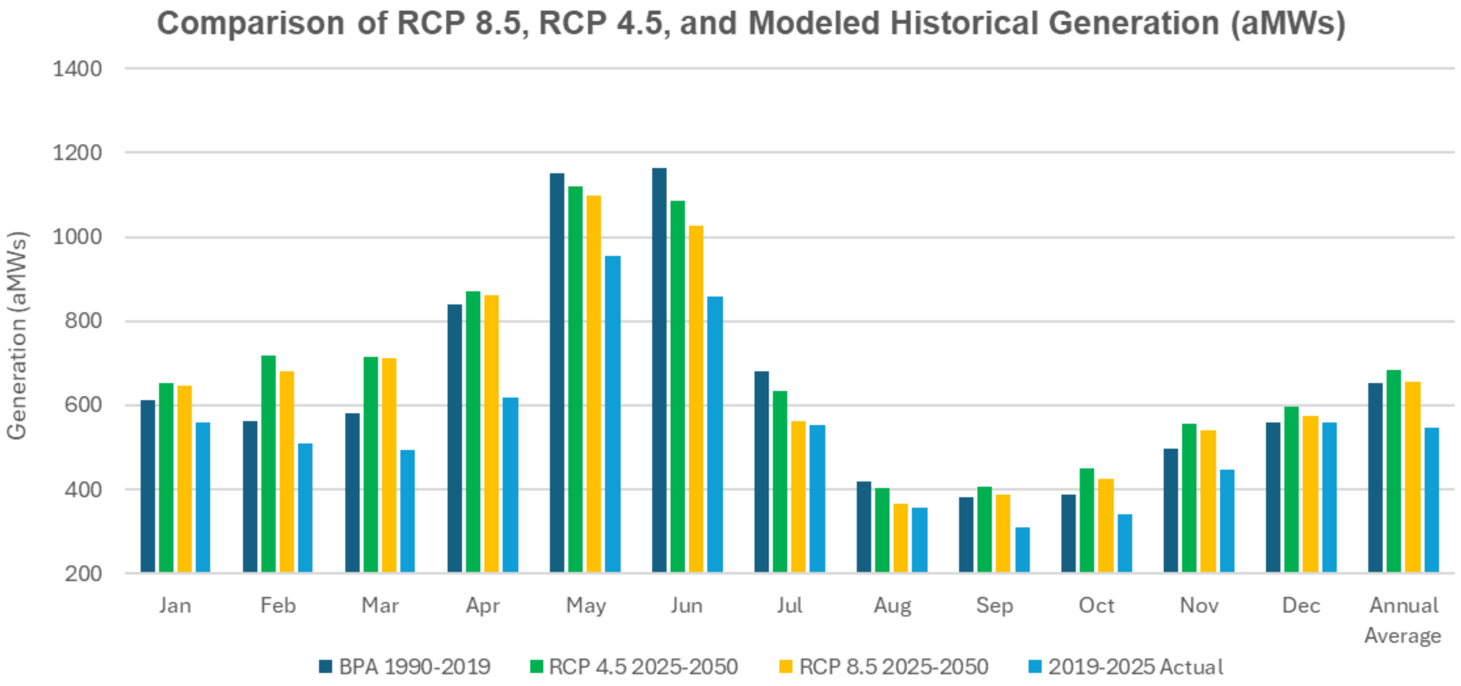
Meeting Guidelines

- IRP team is in office Monday – Wednesday; also available by email, phone and Teams for questions and comments
- Stakeholder feedback responses shared with TAC at meetings, in Teams and in Appendix
- Working IRP data posted to Teams
- All TAC meetings will be virtual on Teams
- Draft TAC presentations emailed three days before each meeting
- Final TAC presentations, meeting notes and recordings posted on IRP page

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Raise hand or use the chat box for questions or comments
- Respect the pause
- Please try not to speak over the presenter or a speaker
- Please state your name before commenting for the note taker
- This is a public advisory meeting – presentations and comments will be documented and recorded

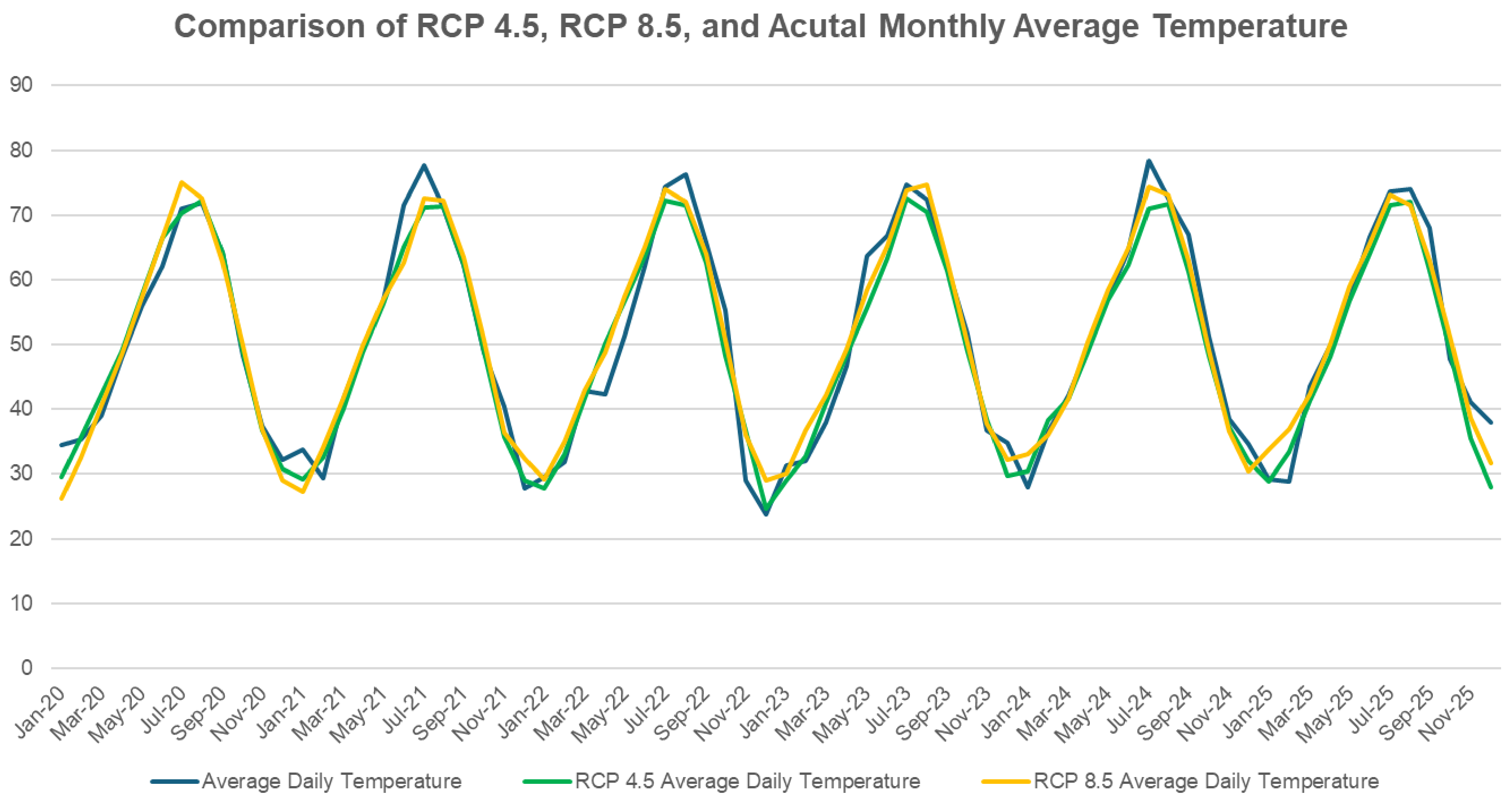
Hydro Update: RCP 4.5 vs. RCP 8.5



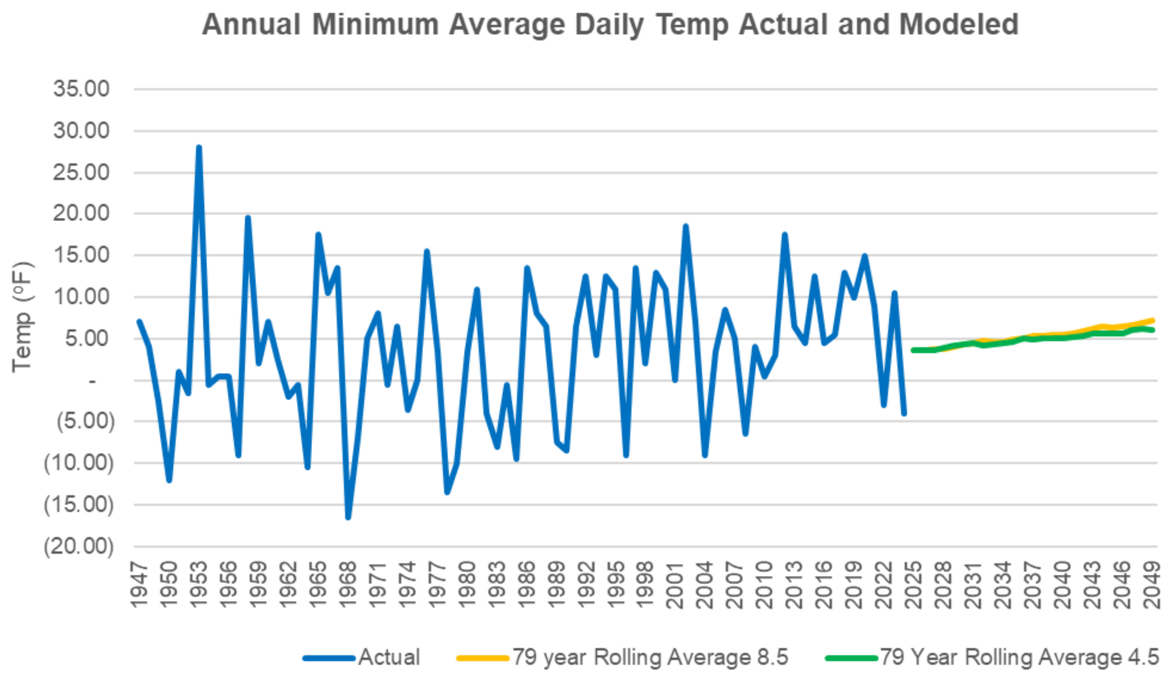
Generation includes Avista Storage Projects, Avista Run of River, and Avista Share of Mid- Columbia Contracts

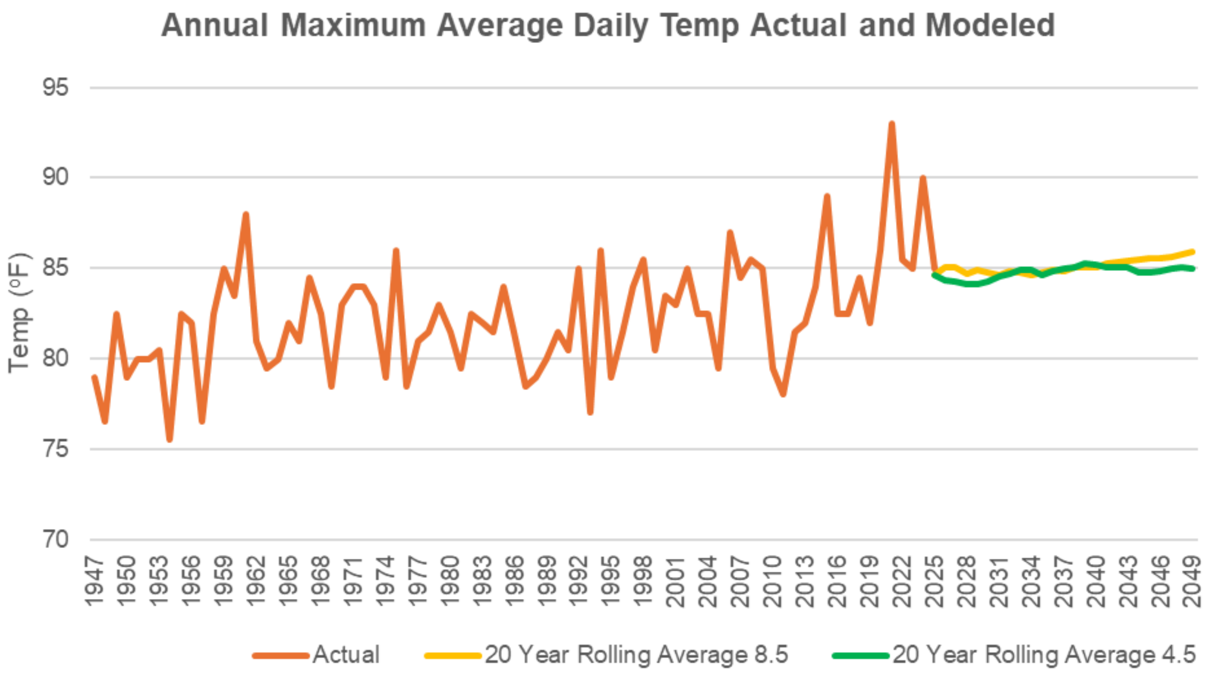
- Both RCPs have more generation in the spring, less in the summer, and slightly more in the fall in comparison to BPA modeled flows and generation.
- On an annual basis, both RCPs have more generation as compared to the BPA modeled historical flows.

Update: RCP 4.5 vs. RCP 8.5



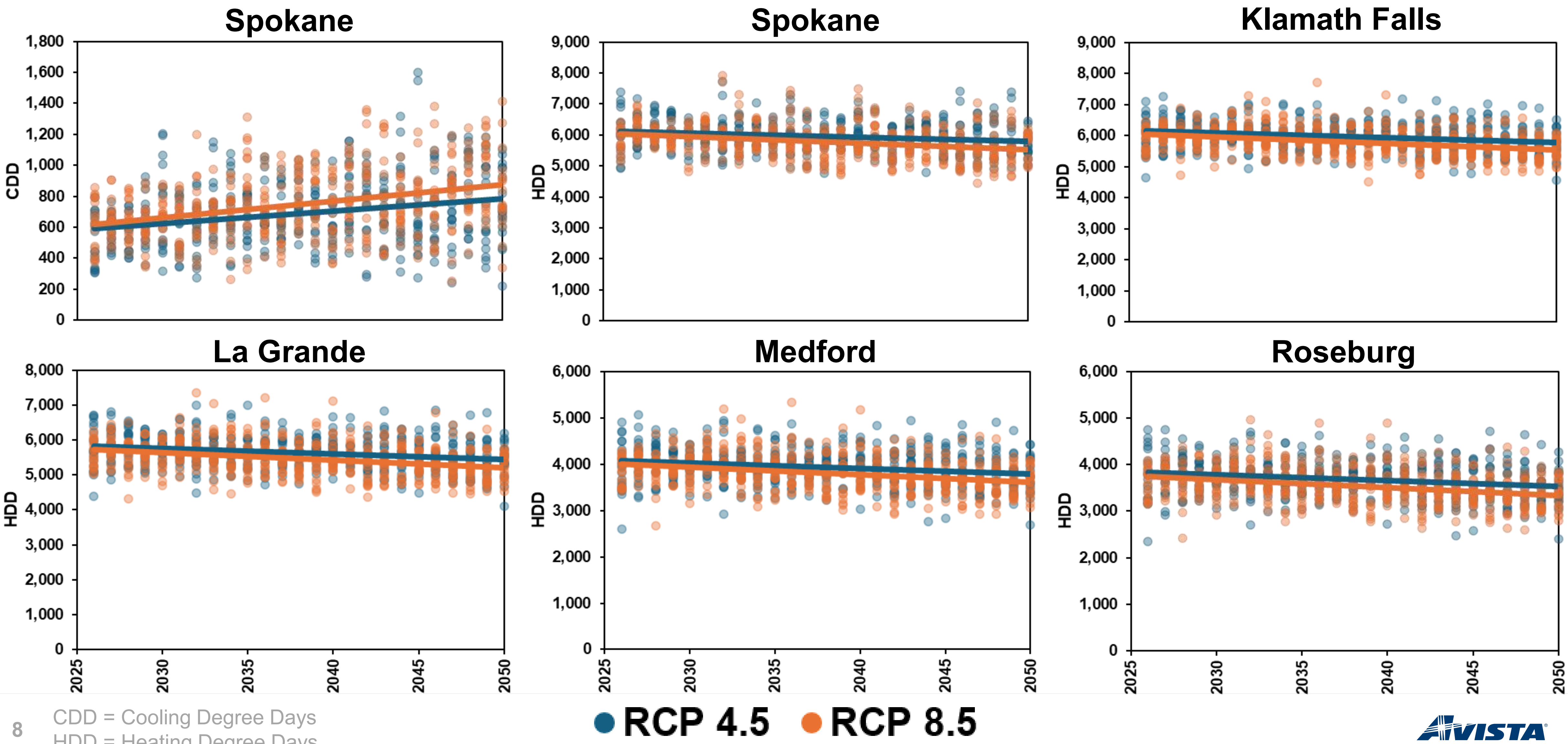
Update: RCP 4.5 vs. RCP 8.5





- Annual Minimum Average Daily Temperature: RCP 8.5 is 1.11º F greater than RCP 4.5 at the end of the forecasted period.
- Annual Maximum Average Daily Temperature: RCP 8.5 is 0.9º F greater than RCP 4.5 at the end of the forecasted period.

RCP 4.5 & RCP 8.5 Comparison: Annual Degree Days



CDD = Cooling Degree Days
HDD = Heating Degree Days

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Summary Forecast Update: Year 2050 RCP 4.5 → 8.5

Area	Heating Degree Days: Hist. 20y Avg.	Heating Degree Days: RCP 4.5	Heating Degree Days: RCP 8.5	Cooling Degree Days: Hist. 20y Avg.	Cooling Degree Days: RCP 4.5	Cooling Degree Days: RCP 8.5	Peak Day: COR	Peak Day: RCP 4.5	Peak Day: RCP 8.5
Spokane	6,453	6,091	5,890	586	794	850	-16.5	-14.9	-14.7
Klamath Falls	6,762	6,355	6,156	258	367	440	-7.0	-6.2	-5.4
La Grande	6,172	5,776	5,582	413	562	657	-10.0	-9.0	-8.3
Medford	4,197	3,899	3,778	1,023	1,226	1,337	4.5	4.8	6.1
Roseburg	3,929	3,613	3,492	680	866	963	10.5	11.1	11.8

COR = Coldest on Record

Cost Assumptions for CO_2 Pipeline

Input	Measurement	Cost	Annual O&M for 100-mile Segment ($mm)	Annual Electricity Cost 100-mile Segment ($mm)
CO_2 Pipeline Diameter Size	10 inches	$237,793 per Inch-Mile	$4.5	$0.3
CO_2 Pipeline Diameter Size	12 inches	$246,206 per Inch-Mile	$6.0	$0.6

*20 Year Pipeline Life

* Wall thickness 0.4 inches

Number of Trucks Required to Truck or Rail CO_2

Input	Number of Trucks
To Rail 25 Miles Away	30
To Rail 100 Miles Away	52

TAC 6 – Monday, March 16, 2026 (13:00 – 16:00 PDT)		
Topic	**State**	**Audience**
★ New Gas Resource Options	All	Gas
★ Liquified Natural Gas Analysis	All	Gas
Wholesale Market Price Scenarios	WA/ID	Electric
All-Source RFP Update	WA/ID	Electric
Economic Forecast and Five-Year Load Forecast	All	E&G

TAC 7 – Wednesday, April 15, 2026 (13:00 – 16:00 PDT)		
Topic	**State**	**Audience**
Energy Efficiency Savings Since 2025 IRP	OR	Gas
Hybrid Heat Pump Program Update	OR	Gas
Gas Avoided Cost	All	E & G
Long-Run Load Forecast	All	E & G
End-Use Load Forecast	All	E & G
★ Wholesale Price Forecast – Stochastic	WA/ID	Electric

TAC 8 – Monday, April 20, 2026 (13:00 – 16:00 PDT)		
Topic	**State**	**Audience**
Conservation Potential Assessment	All	E & G
Demand Response Potential Assessment	All	E & G

TAC 9 – Friday, May 15, 2026 (13:00 – 16:00 PDT)		
Topic	**State**	**Audience**
IRP Generation Option Transmission Planning Studies	WA/ID	Transmission
Distribution System Planning within the IRP	WA/ID	Dist.
Transmission Project Example Evaluation	WA/ID	Transmission
QCC Forecast	WA/ID	Electric
Gas Distribution Update	All	Gas
Natural Gas Availability & Resiliency	All	Gas

TAC 10 – Wednesday, May 27, 2025 (9:00 – 12:00 PDT)		
Topic	**State**	**Audience**
CEIP Update	WA	Electric
CETA Interim/Energy Compliance Report	WA	Electric
Load Forecast Update	All	E & G

TAC 11 Technical Modeling Workshop – Monday, June 15, 2026 (13:00 – 16:00 PDT)		
Topic	**State**	**Audience**
PRiSM Model Tour	All	E & G
Aurora Resource Adequacy Model Tour	WA/ID	Electric
New Resource Cost Model	All	E & G

TAC 12 Wednesday, July 15, 2026 (TDB)		
Topic	**State**	**Audience**
Load & Resource Balance and Methodology	WA/ID	Electric
Loss of Load Probability	WA/ID	Electric
WRAP Update	WA/ID	Electric
Draft Preferred Resource Strategy Results	All	E & G
ETO Energy Savings	OR	Gas

TAC 13 – Monday, August 17, 2026 (13:00 – 16:00 PDT)

Topic	State	Audience
Preferred Resource Strategy Results	All	E & G
Oregon Non-Pipe Alternatives	OR	Gas
Aldyl-A Analysis and Targeted Voluntary Electrification	OR	Gas
IRP/Progress Report Outlines	All	E & G
Next Steps	All	E & G

TAC 14 – Thursday, September 17, 2026 (13:00 – 16:00 PDT)

Topic	State	Audience
Portfolio Scenario Analysis	All	E & G
Avoided Cost	All	Electric
Resource Adequacy Results	WA/ID	Electric
CBI Forecast and Results/Energy Burden	WA/OR	E & G
Final Report Overview and Comment Plan	All	E & G
Action Items	All	E & G

Electric Transmission & Distribution 5-Year Plan – October 7, 2026 (10:00 – 12:00 PDT)		
Topic	**State**	**Audience**
Electric Trans Transmission & Distribution 5-Year Plan	WA/OR	Electric

Other Key Dates

- Oct 15, 2026 – Draft Electric IRP Released to TAC
- Nov TBD 2026 – Virtual Public Meeting
    - Noon-1pm
    - 6-7pm
- Jan 1, 2027 – Final Electric IRP Filed
- Feb 15, 2027 – Draft Gas IRP Released to TAC
- Apr 1, 2027 – Final Gas IRP Filed

DER Potential Study: Feeder Impacts

February 20, 2026

TAC 5 Meeting

Erik Lee – Distribution System Planning Engineer

Agenda

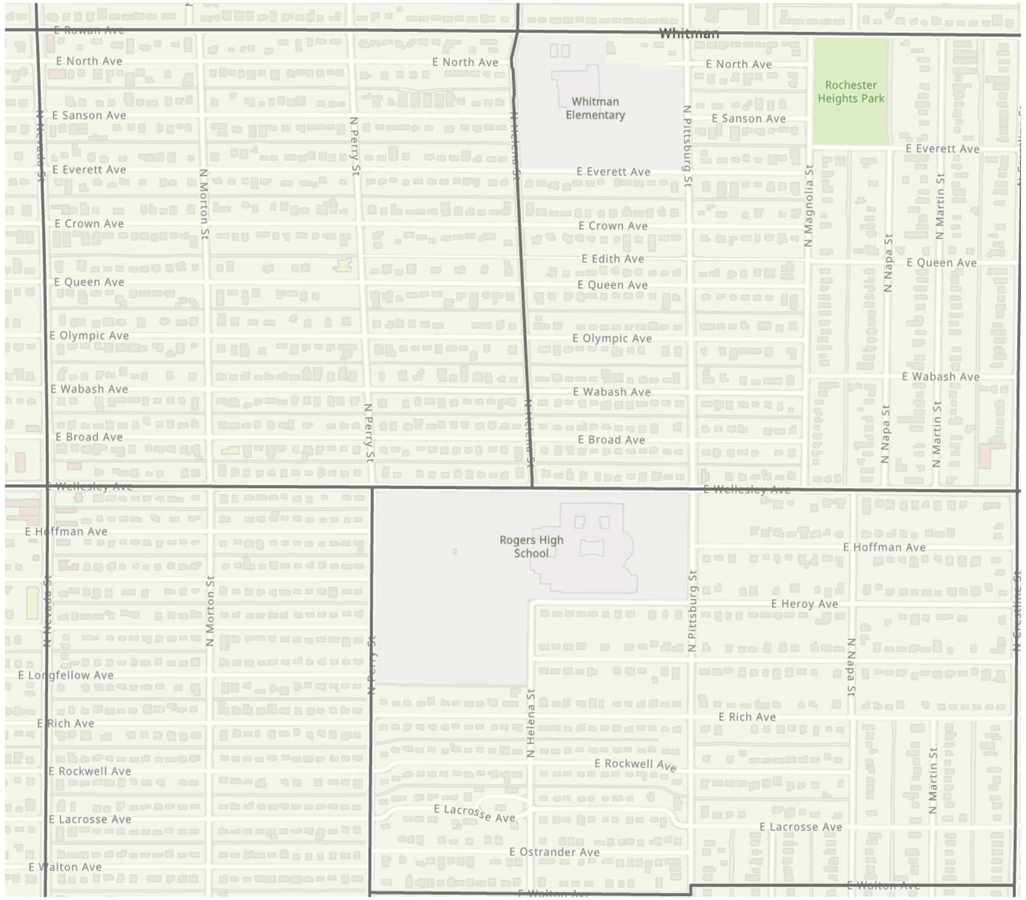
- DER Potential Study Review
- Review Consultant Methodology
- Analysis Visualization Examples
  - Census Block Group w/Largest Fleet EV Load
  - Feeder w/Portion of Above Allocated to it
  - 2035 Feeder Capacity Issues from DER (Spoiler: low impact)
  - 2045 Feeder Capacity Issues from DER (Spoiler: higher impact)
- Key Observations

DER Potential Study Review

- Motivation: WA Clean Energy Implementation Plan (CEIP)
- Goal: "To determine a reasonable potential of new generation, storage, and controllable load impacts on a localized basis"
- Time Horizon: 2024 – 2050
    - *Distribution Planning Criteria Specifies a 10 Year Time Horizon*
- Limited to WA Service Territory
- Results Presented June 2024 by Consultants (AEG/Cadeo/Verdant)
- ***Final Task: Apply DER Loads to Feeder Load Models & Analyze Feeder Impacts***

Review of Methodology: Spatio-Temporal Approach

- Spatial Granularity: By Census Block Group (476 Polygons)
- Temporal Granularity: Hourly Annual Load Shape Model (576-Style)
- Base & High Incentive Scenarios
- Load Model Components:
  - Solar
  - Battery Storage
  - EV Charging (classes 1-8)
  - Wind *(unused)*
- ***104 Million Rows of Data***



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Review of Methodology: EV

- LDV market share reaches 100% EV in the 2040–2050 period, depending on segment
- Named Communities lag market adoption by ~10 years unless incentives intervene
- Public fleets electrify faster due to state mandates
- *Tool: NREL EVI-Pro Lite modeling*

Review of Methodology: PV

- Adoption modeled using NREL dGen tool, adjusted for Avista's rates and NEM policy

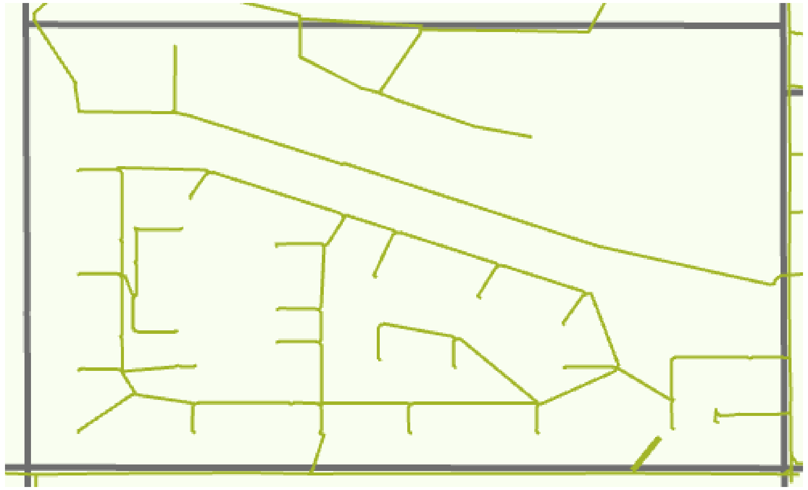
- Residential adoption varies by propensity scores developed from ACS demographics

Review of Methodology: Storage

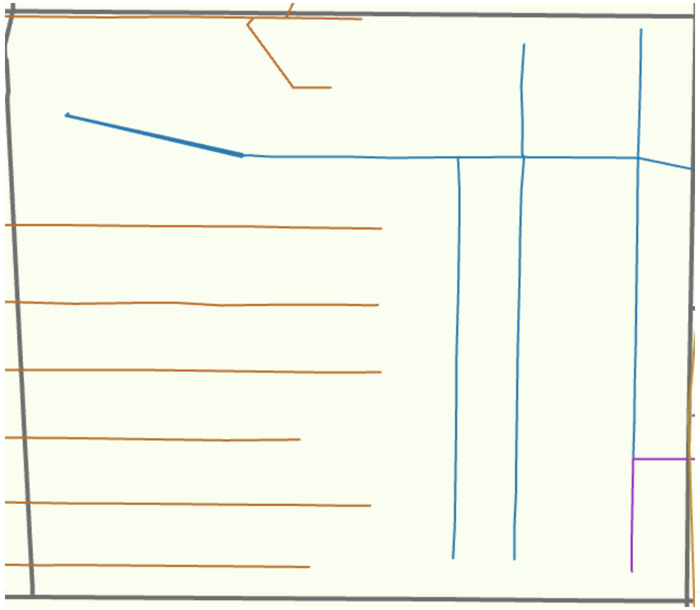
- Minimal existing storage today
- Adoption in the Reference case remains low under current tariffs
- High Incentive scenario adds TOU rates and higher resiliency valuation to increase storage adoption

Spatial Partition (Census Block Group) → Feeder Allocation

- Grid Model Spatial Coincidence
  - Allocate by Feeder Aggregate Circuit Length

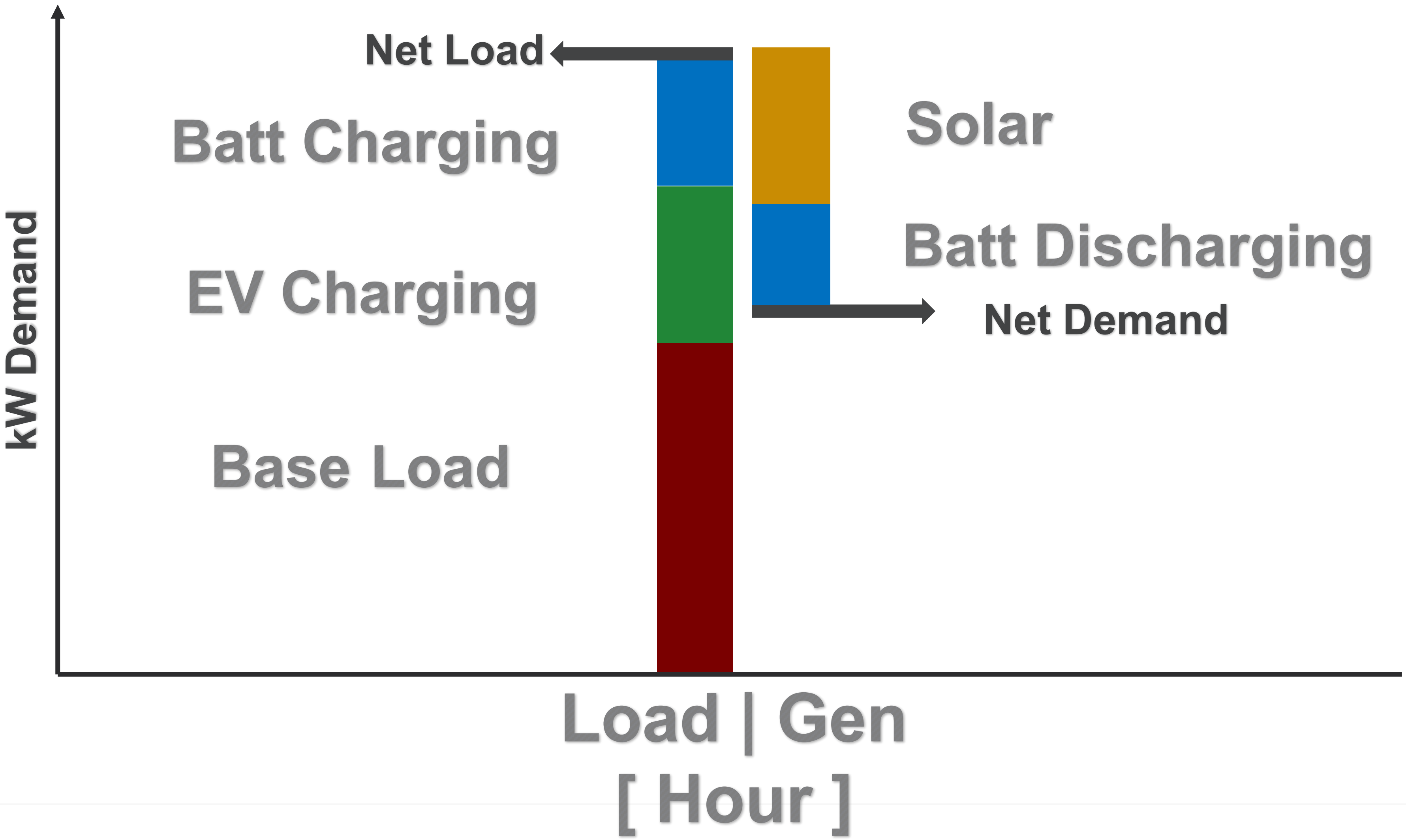


Single Feeder Allocation →



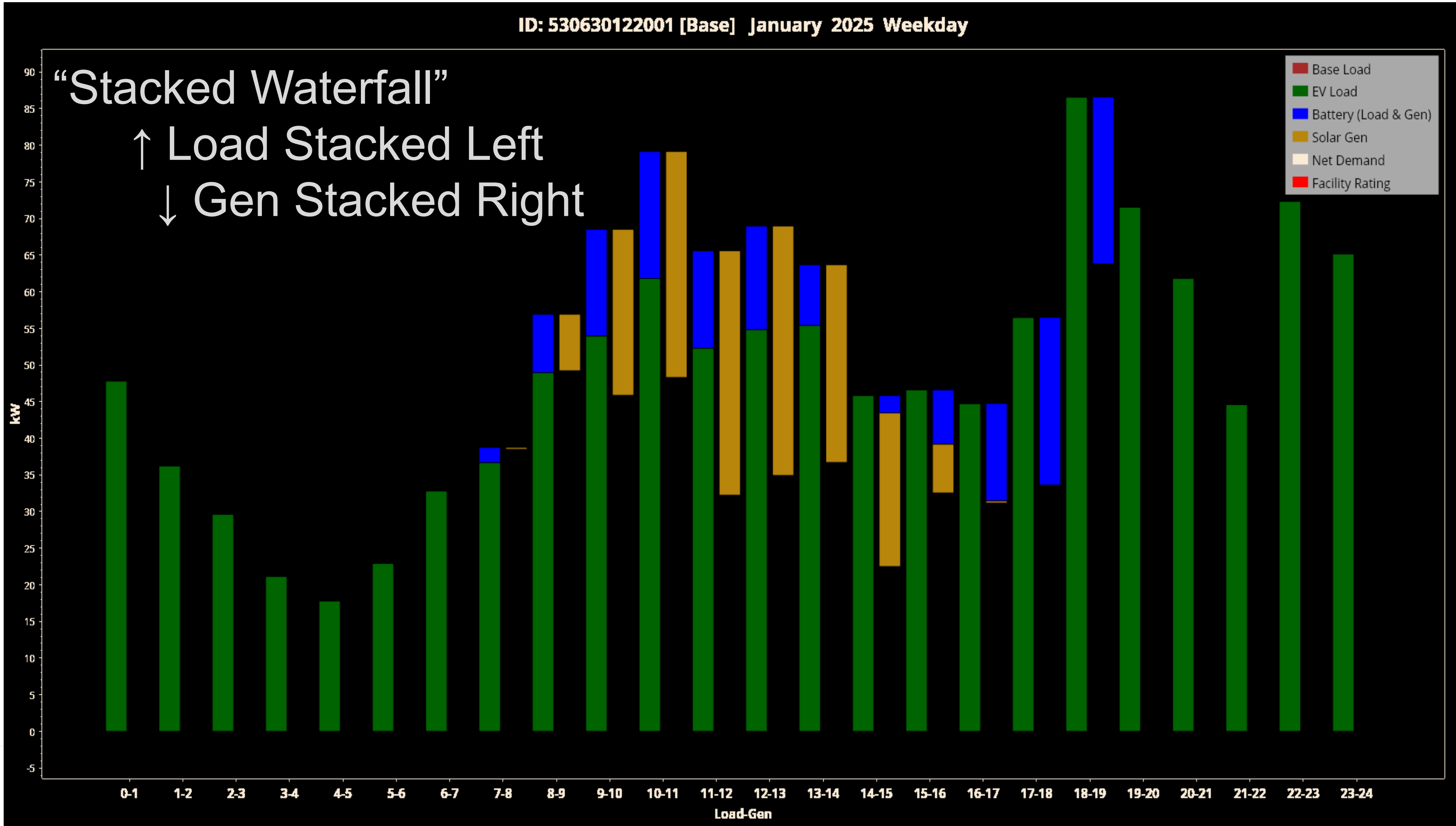
← Three Feeder Allocation (Orange, Blue & Purple intersect)

Stacked Waterfall Hourly Plot



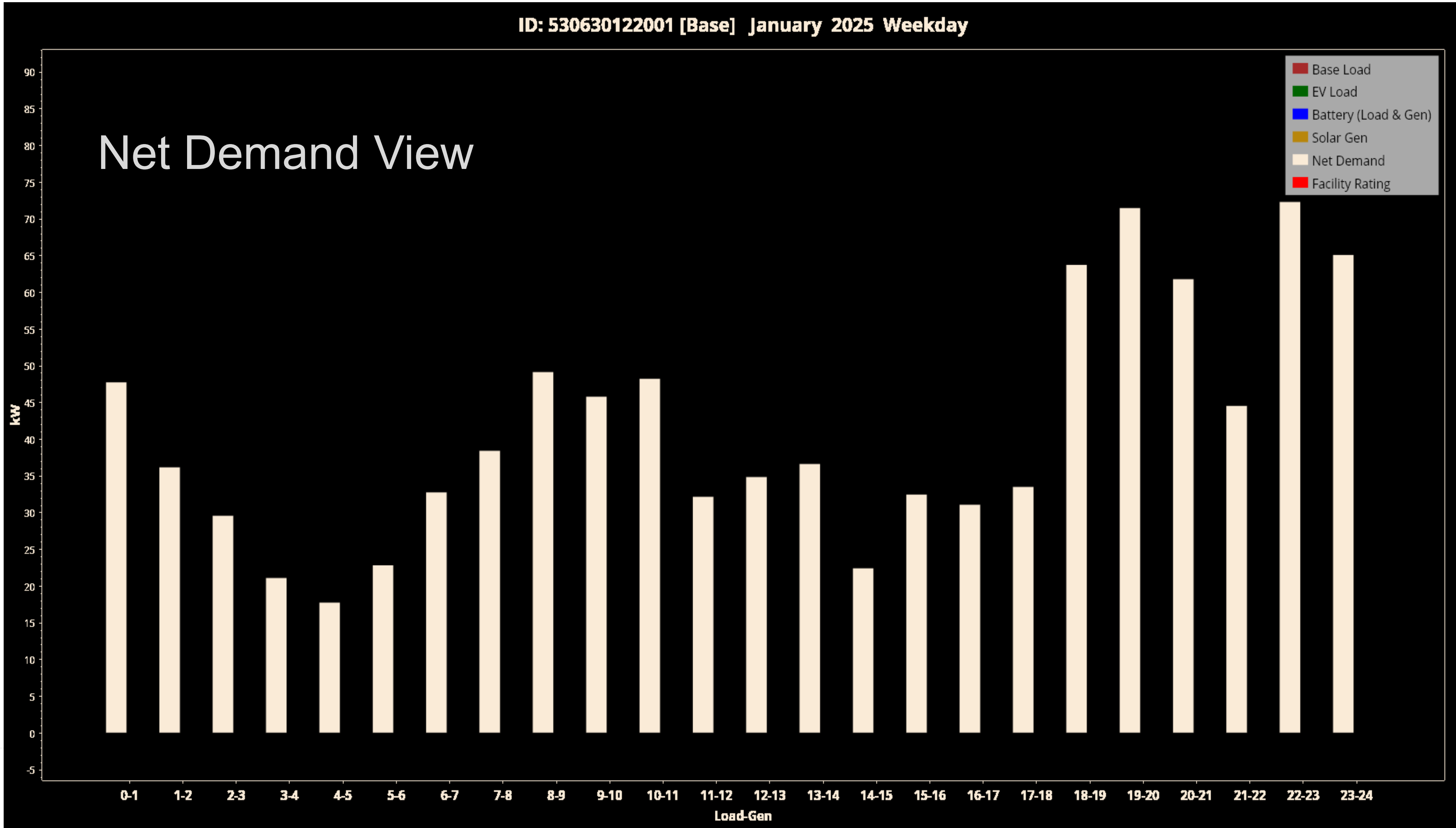
Census Block Group (w/ Largest Fleet EV) 2025

- E Trent Ave Area
- Allocated to:
  - BEA12F1
  - BEA12F6
  - 9CE12F3



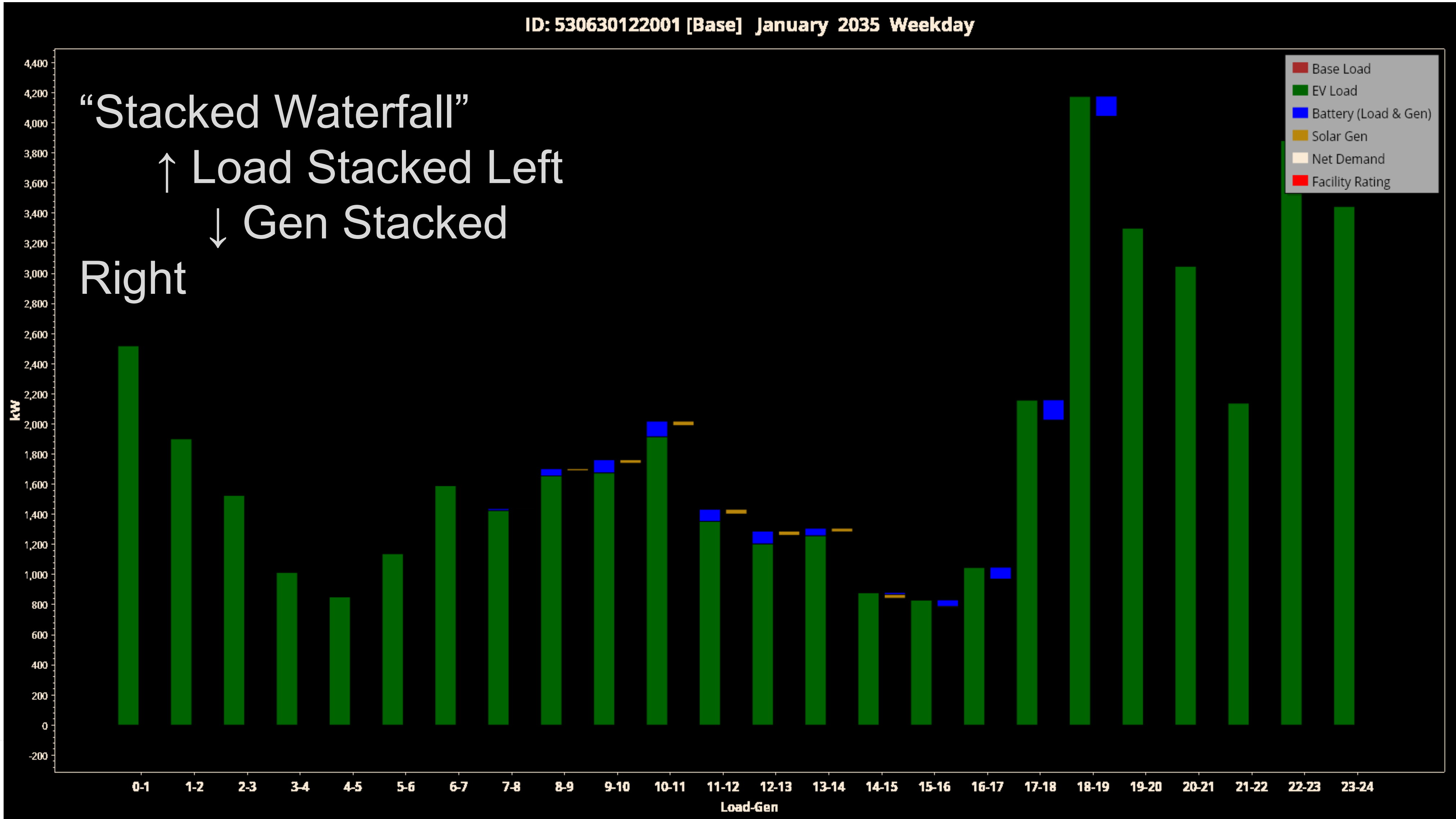
Census Block Group (w/ Largest Fleet EV) 2025

- Allocated to:
  - BEA12F1
  - BEA12F6
  - 9CE12F3
  - ***~75 kW***

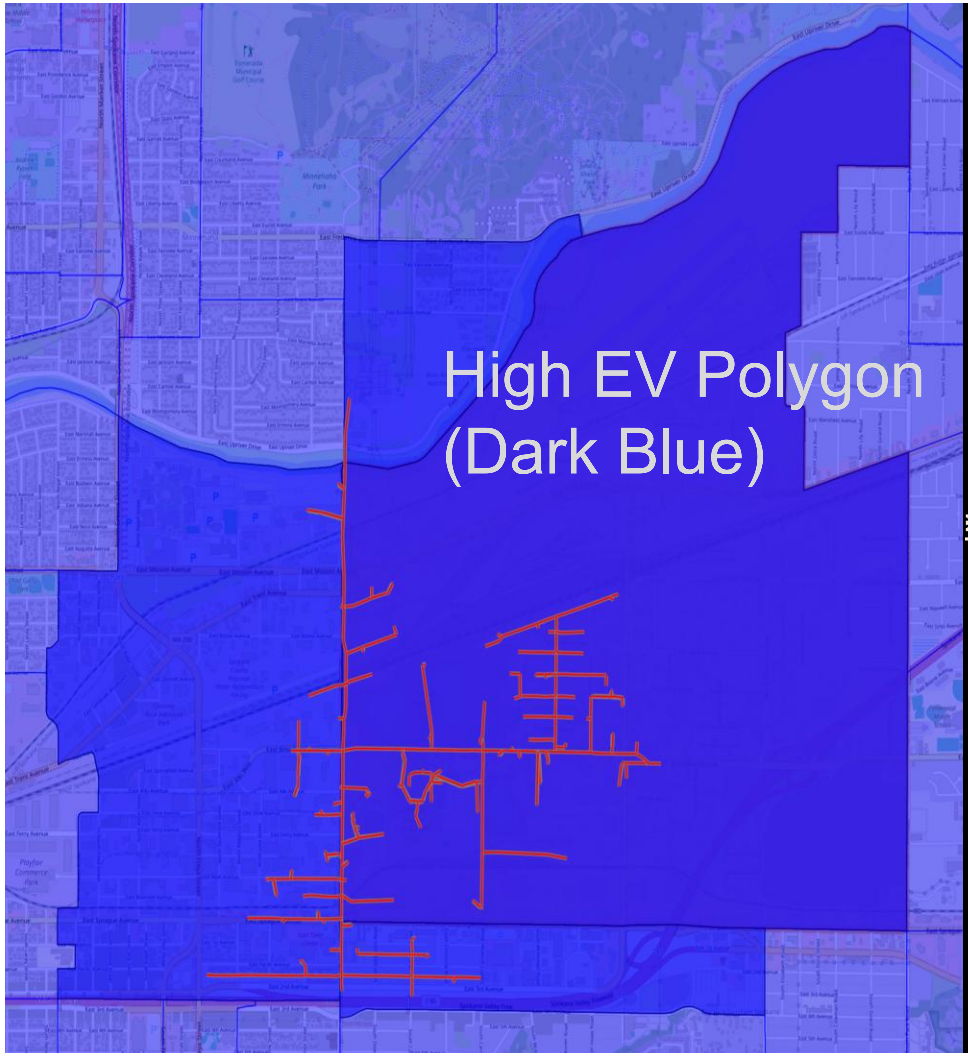


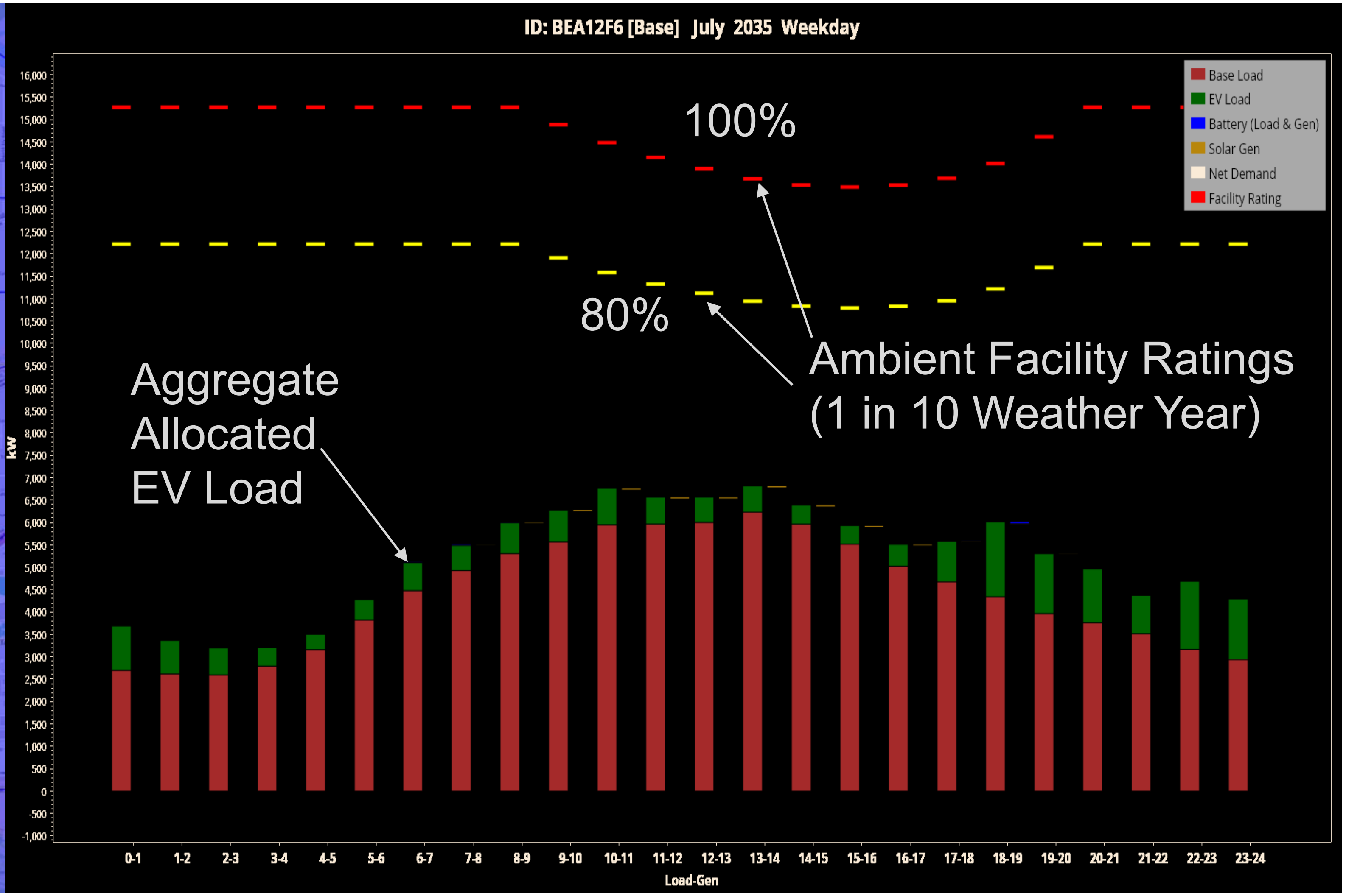
Census Block Group (w/ Largest Fleet EV) 2035

- ***~4,100 KW Net Peak***
- ***~16 MW in 2045!***



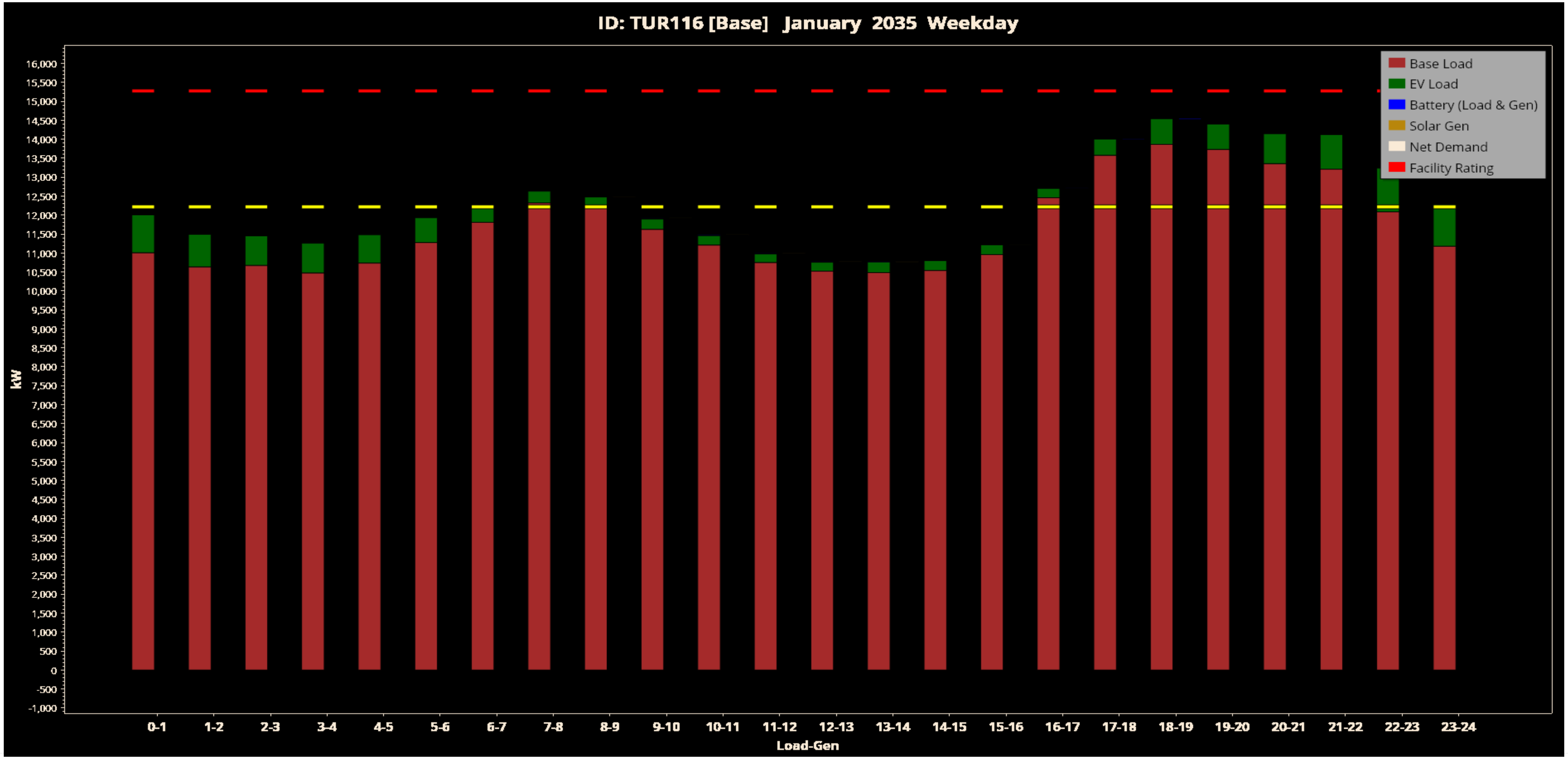
Feeder Example: BEA12F6 2035 (Commercial/Fleet)



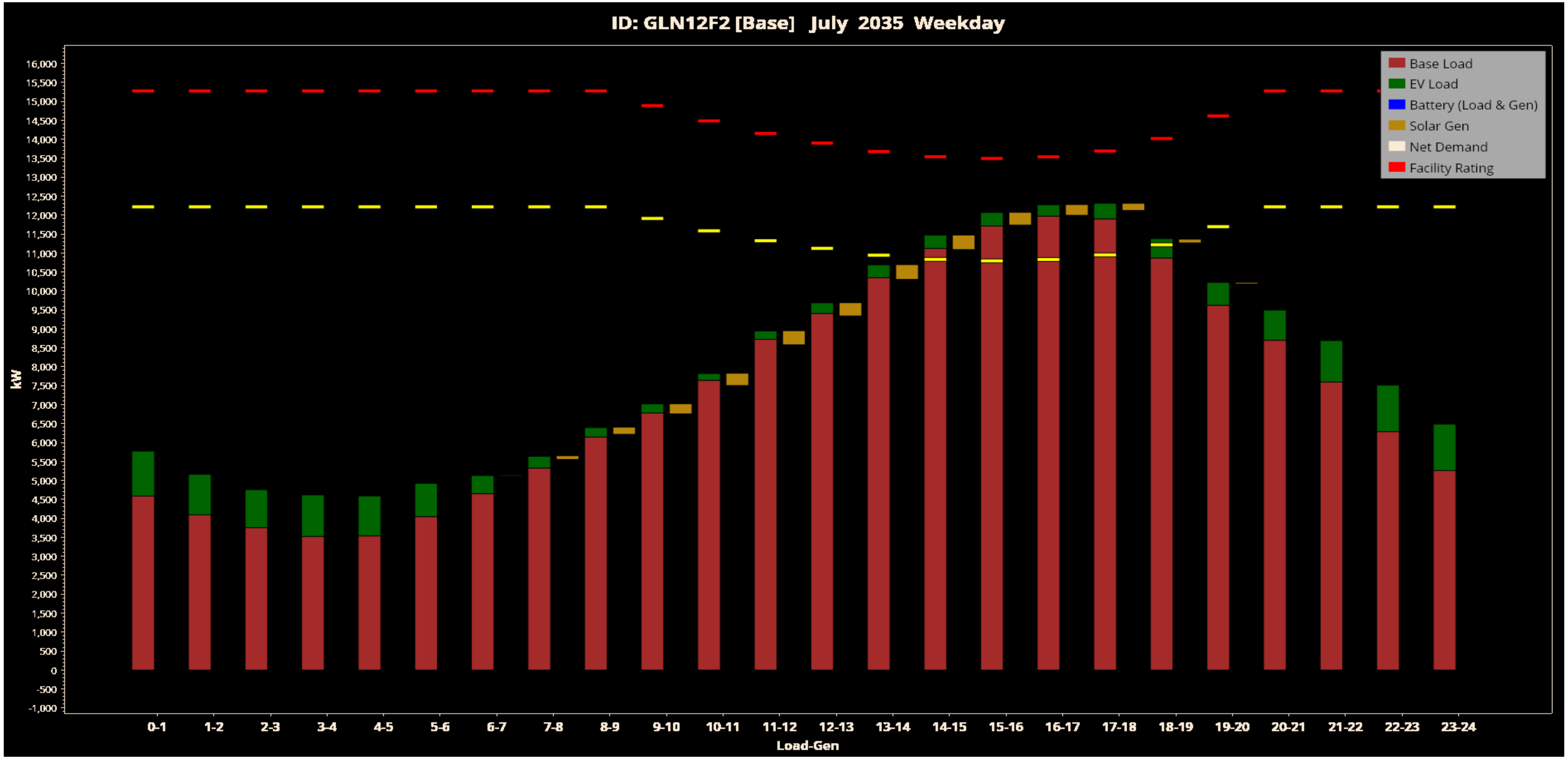


Existing Capacity Issue Examples (Summer & Winter)

TUR116 2035 (Winter Constraint)



GLN12F2 2035 (Summer Constraint)

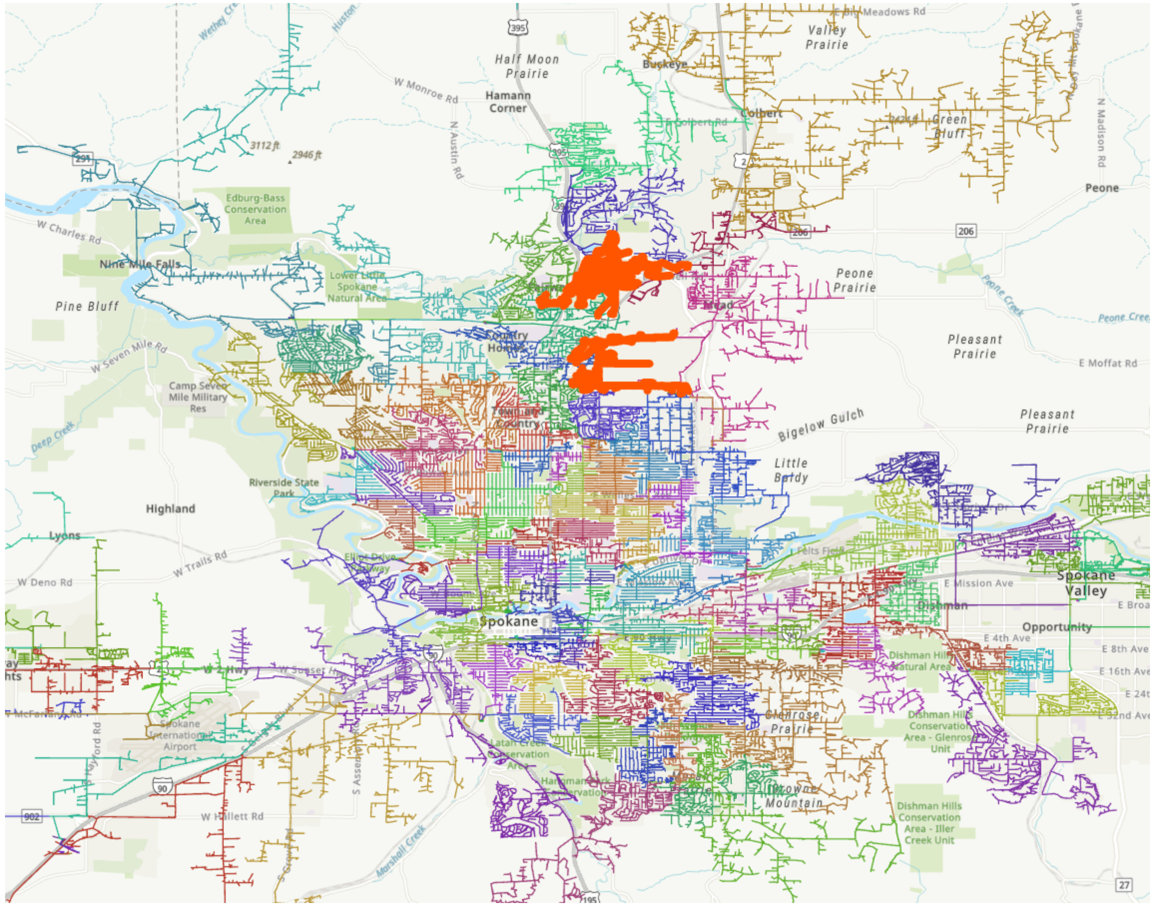


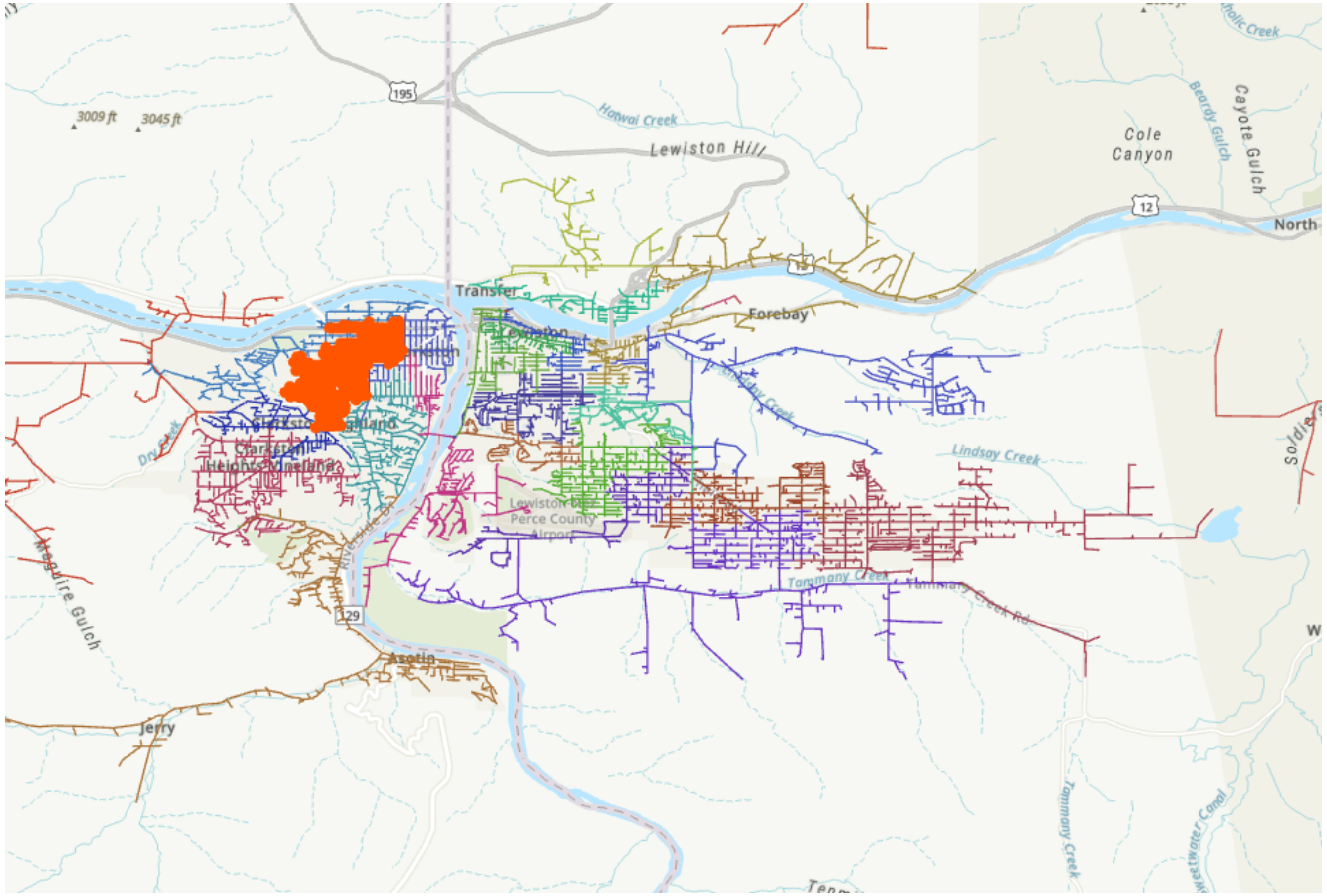
New Capacity Issues in 2035 from DER Load (3 Feeders)

- All 3 Already Very Close to 80% Threshold
- Small Differential

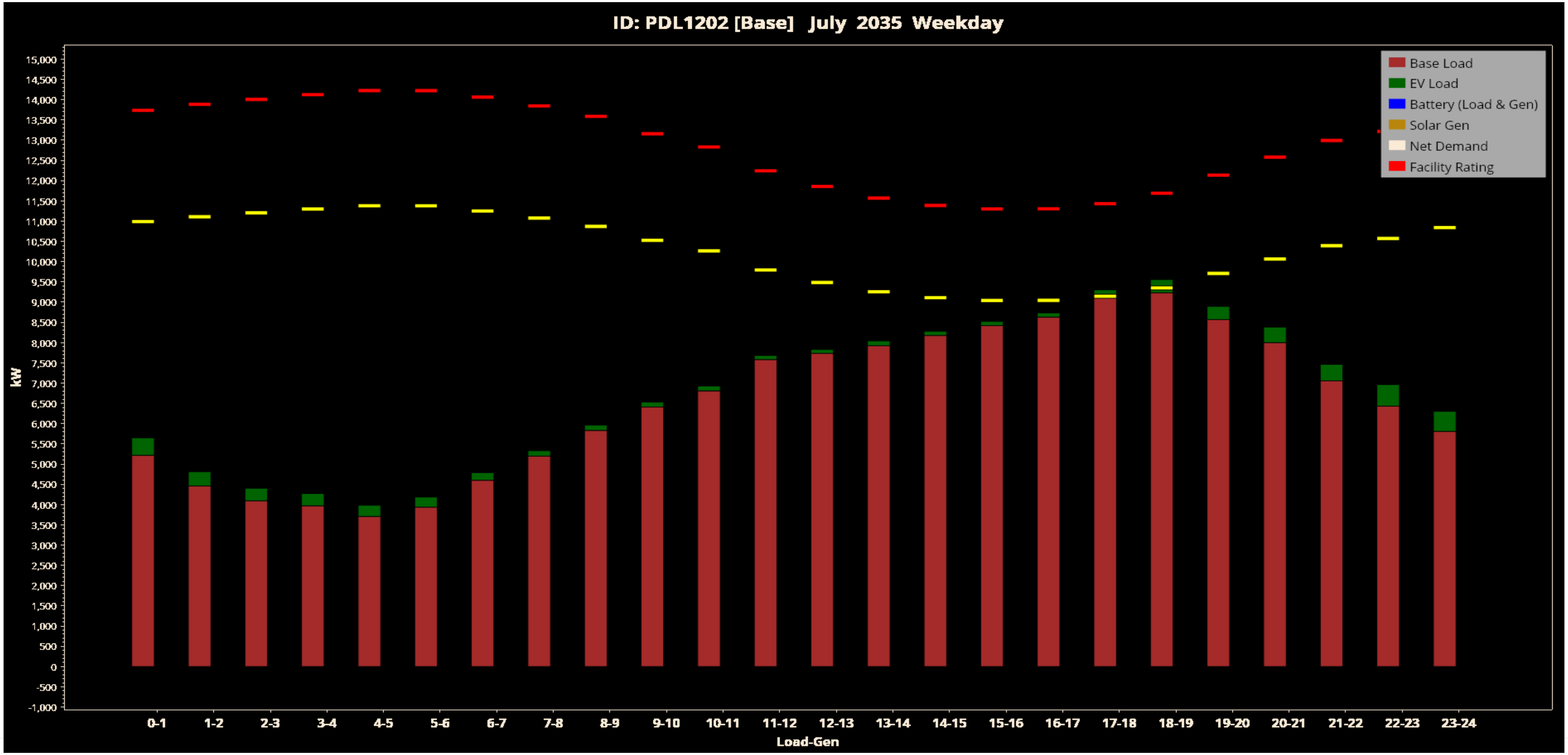
FEEDER	MONTH	PK_PCT_BASE	PK_PCT_NET	DIFF
MEA12F1	July	79.4	80.7	1.3
PDL1202	July	79.7	81.6	1.9
NE12F2	July	79.2	82.6	3.4

Maps: Spokane (Left), Lewiston-Clarkston (Right)

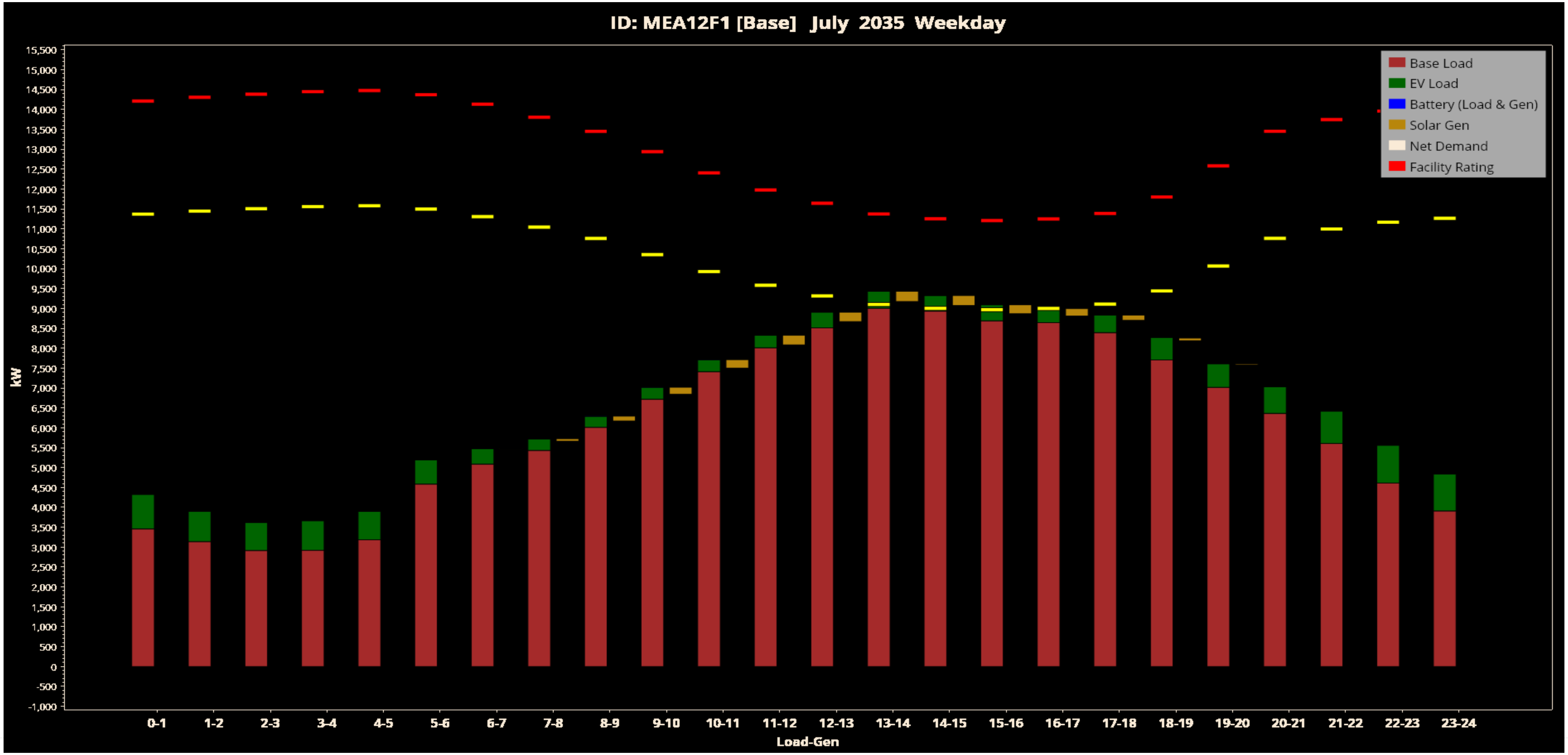




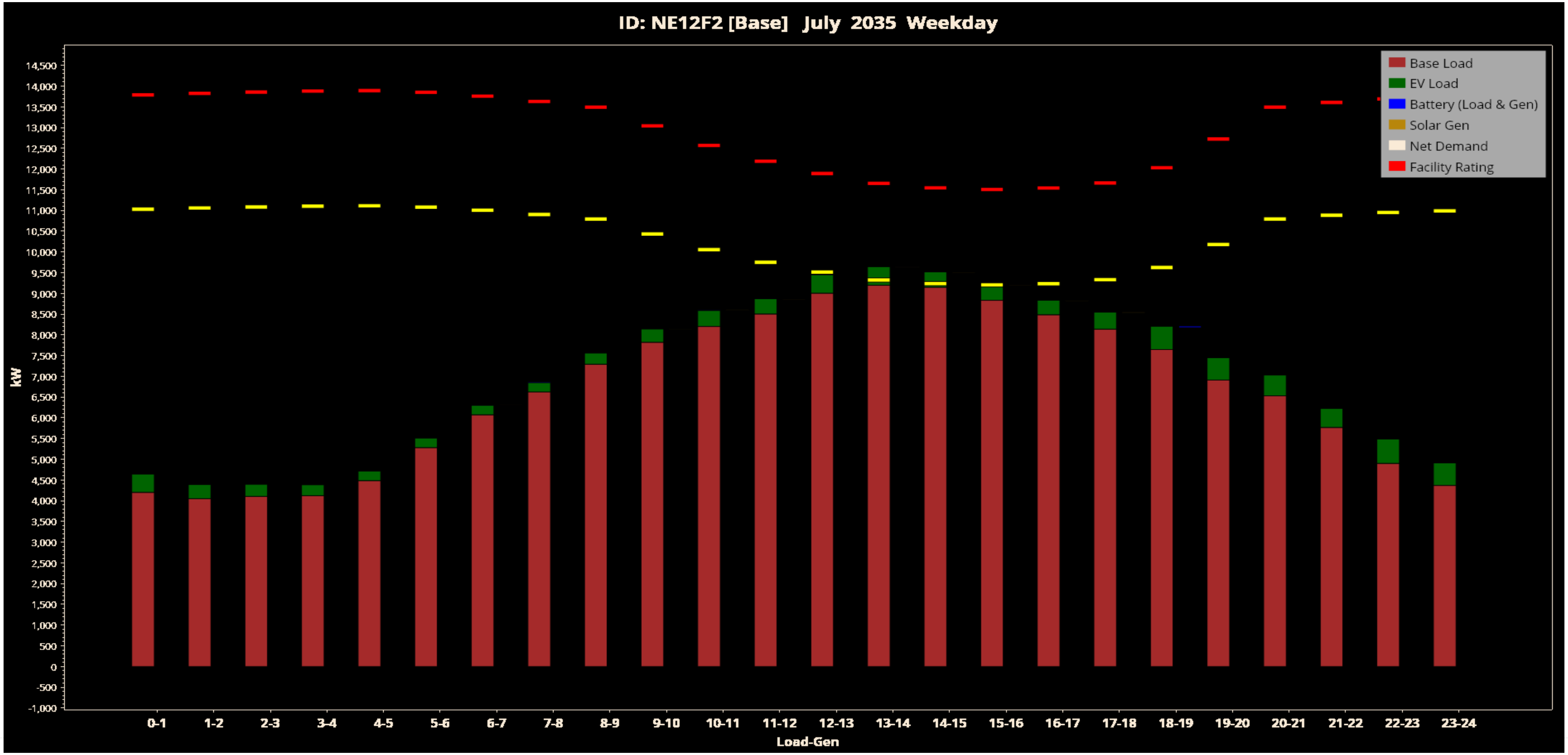
PDL1202 2035 (Clarkston)



MEA12F1 2035 (N Spokane)



NE12F2 2035 (N Spokane)



New Capacity Issues in *2045 From DER Load* (21 Unique Feeders)

FEEDER	MONTH	PK_PCT_BASE	PK_PCT_NET	DIFF
3HT12F4	July	78.1	83	4.9
3HT12F5	January	55.7	95.2	39.5
3HT12F5	July	59.2	96.7	37.5
3HT12F7	July	56.7	98.1	41.4
BEA12F2	January	62.8	82.9	20.1
BEA12F3	July	52.1	81.1	29
BEA12F5	January	76.5	85.3	8.8
C&W12F2	January	72.3	96	23.7
C&W12F3	January	54.3	90.9	36.6
C&W12F3	July	61	87.2	26.2
CHE12F1	July	76.1	81.5	5.4
DEP12F1	January	76.9	90.5	13.6
DEP12F2	January	77.2	91.1	13.9
NE12F1	January	54.5	99.3	44.8
NE12F1	July	65.8	107.3	41.5
NE12F3	January	55.4	80.4	25
NW12F1	July	68.6	81	12.4
PDL1201	July	72.8	81.1	8.3
PDL1202	July	79.9	89.5	9.6
PDL1203	July	76.7	85.4	8.7
RDN12F1	January	68.1	84.8	16.7
SE12F2	January	70.2	82.1	11.9
SLW1368	July	79.3	82.5	3.2
WAK12F3	July	71.2	81.3	10.1

- Mainly Commercial Feeders
- Split between Summer & Winter Issues

Key Observations

- EV Load is the Biggest Contributor
  - Improves Utilization Factor (Assuming Shape Hold True)
  - Commercial/Industrial Area Focus (Fleets Especially)
- Solar Offsets Some EV Impact In Summer Peaks
- Battery Storage is Negligible
- Most Impacts Occur Outside of Current Planning Window
  - Assuming These Forecasts Hold True

Thank you!

Sub-hourly DER Resource Value Analysis

Technical Advisory Committee Meeting No. 5

February 20, 2026

Jacob Heimbigner, Resource Planning Analyst

Why

- Only Model Hourly in Aurora Stochastic.
- Commission staff requested DER sub-hourly analysis to ensure Avista captures the full value. Which they believe could materially affect future PRS selections and improve real world operational decisions.

Analysis

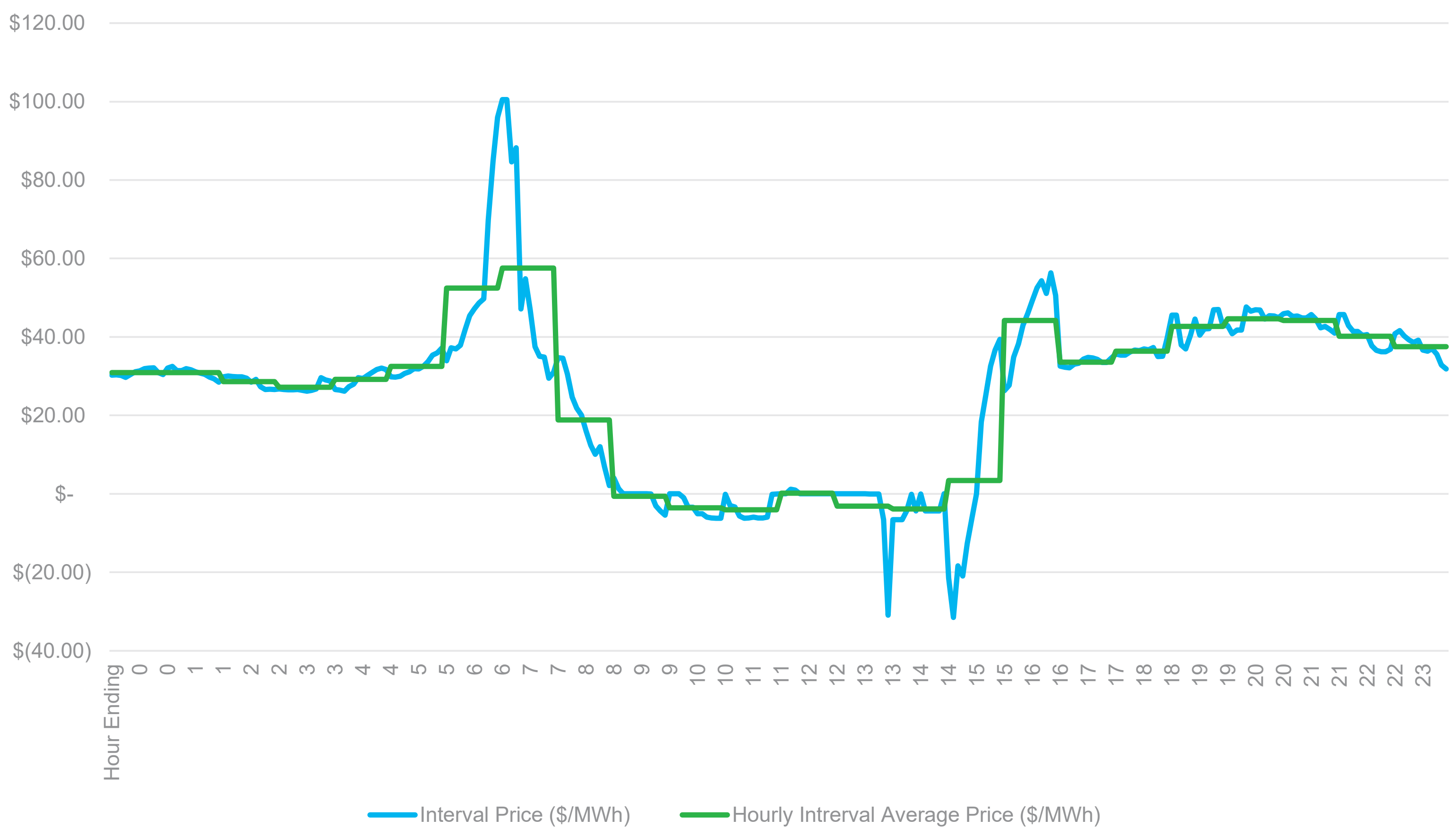
- Utilized AVA Load Real Time Dispatch (RTD) pricing for sub-hourly(5 min) and average RTD for hourly dispatch.
  - Allows to understand the true benefit between hourly and sub-hourly dispatch.
  - Pricing through CAISO Energy Imbalance Market (EIM).
- Modeled Battery Energy Storage System (BESS) & Demand Response(DR) with immediate snapback requirement.

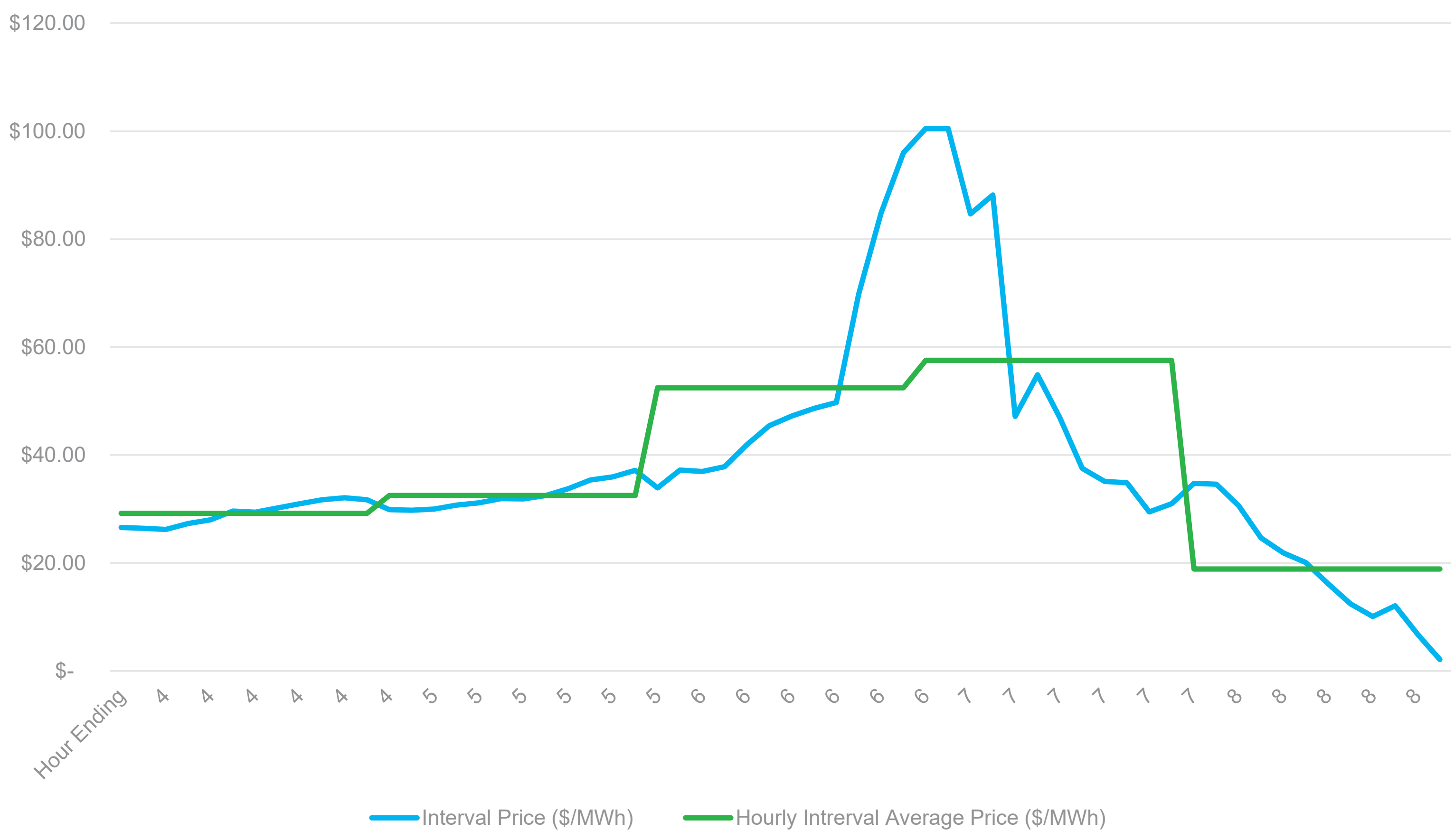
EIM Avista Load Price

	RTD	
	2024	2025
Min Price	(386.20)	(100.79)
Max Price	1,973.80	1,050.54
Spread	2,360.00	1,151.33
Average Price	41.23	32.69
Median Price	30.79	31.44

	Hourly AVG RTD	
	2024	2025
Min Price	(94.49)	(57.45)
Max Price	1,527.30	492.94
Spread	1,621.79	550.38
Average Price	41.23	32.69
Median Price	30.93	31.80

Actual Day Price Trend

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Interval Price ($/MWh)
Hourly Intreval Average Price ($/MWh)

BESS Logic

Max Storage MWh	100
Min Storage MWh	10
Max MW Dispatch	25
Max MW Charge	25
Cycles Per year	365
Round Trip Efficiency	88%

BESS Hourly vs. Sub-Hourly Benefit

	2024 Dispatch	2025 Dispatch
Hourly Revenue	1,206,153	804,856
RTD Revenue	1,426,845	962,935
RTD Benefit (Loss)	220,692	158,079
RTM Benefit (Loss) %	18.3%	19.6%

Demand Response with Immediate Snapback

Events	24
Dispatch Hours	3
Snapback Hours	4
MW Dispatch	5
MW Charge	4
MWh Dispatch Total	360
MWh Snapback Total	360

DER with Snapback Analysis

	2024 Dispatch	2025 Dispatch
Hourly Revenue	72,914	24,517
RTD Revenue	74,626	25,194
RTD Benefit (Loss)	1,712	677
RTD Benefit (Loss) %	2.3%	2.8%

Supply Side Resource Options

Technical Advisory Committee Meeting No. 5

February 20, 2026

Robert Hughes, Resource Planning Analyst

Overview and Considerations

- IRP supply-side resources are near commercially available technologies with potential for development within or near Avista's service territory.
- Resource costs vary depending on location, equipment, fuel prices and ownership; while IRPs use point estimates, actual costs will be different.
- Certain resources will be modeled as purchase power agreements (PPA) while others will be modeled as Avista "owned". These assumptions do not mean they are the only means of resource acquisition.
- No transmission or interconnection costs are included at this time.
  - Interconnect included for off-system resources.
- An Excel file will be distributed with all resources, assumptions and cost calculations for TAC members to review and provide feedback.

Resources Not Modeled in the 2027 IRP

- Coal
- Wave/Tidal
- Advanced Geothermal
- Fusion Reaction
- Allam Fetvedt Cycle Power Plants

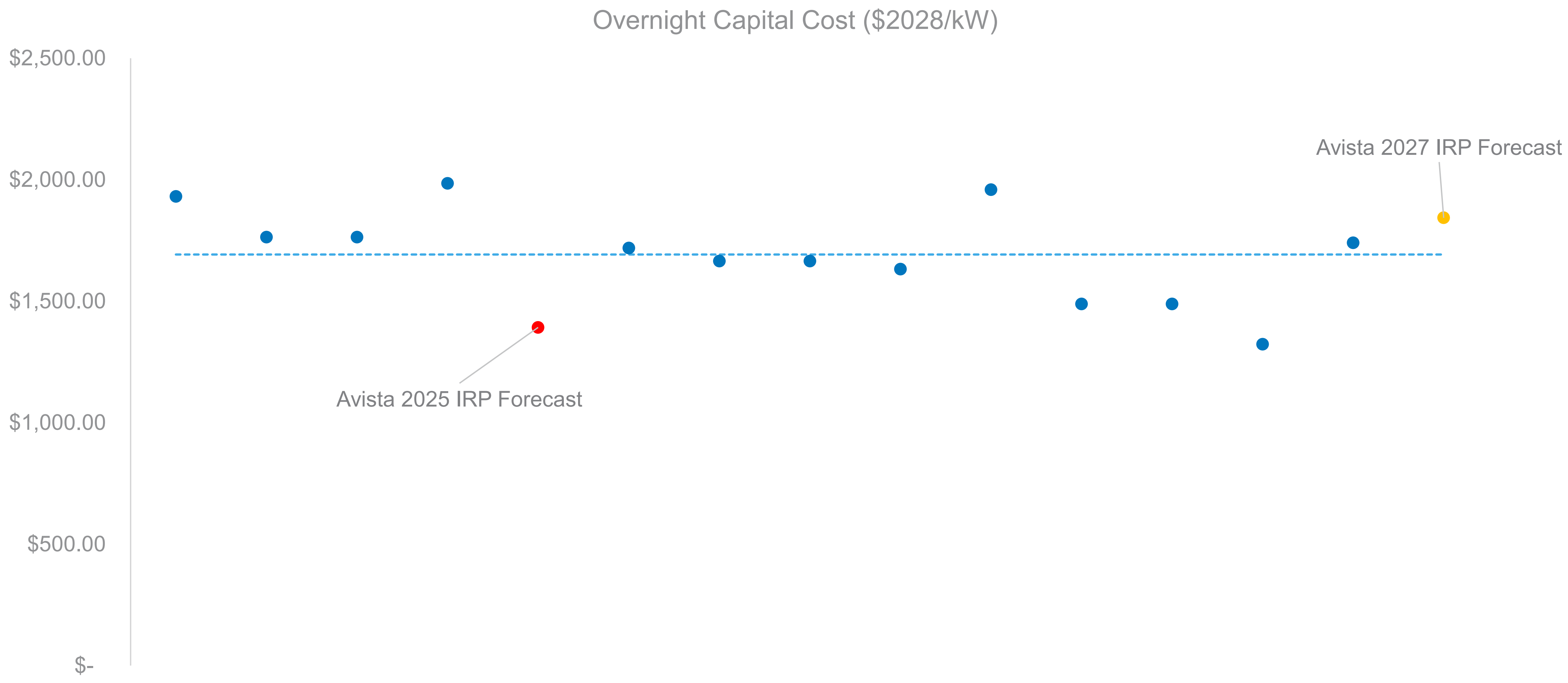
Resources Modeled

Resource	Fuel Source	MW	Capacity Factor %	Heat Rate MMBTU / MWh	Capital $/kW(2028)	Available Year	FOM $kW-yr (2028)	VOM $/MWh (2028)
CT Frame	Natural Gas	290		10.010	$1,795	2030	$7.15	$5.86
CT Frame	Ammonia	145		10.010	$1,944	2030	$19.92	$7.03
CT Frame	RNG	145		10.010	$1,795	2030	$19.92	$7.03
Reciprocating Engine	Natural Gas	185		8.300	$2,139	2030	$6.74	$10.26
Combined Cycle	Natural Gas	385		6.792	$2,359	2030	$45.69	$7.13
Combined Cycle + 95% Carbon Capture	Natural Gas	438		7.675	$3,714	2035	$80.84	$12.12
Linear Generator	Natural Gas	25		8.530	$2,578	2030	$5.86	$9.60
Linear Generator	Ammonia	25		8.530	$2,778	2030	$5.86	$9.60
Small Modular Reactor	Uranium	300		9.180	$11,681	2040	$253.08	$3.28
AP1000	Uranium	1000		10.497	$9,106	2040	$239.02	$3.98
Wind (On System)	Wind	100	35%		$1,954	2030	$37.45	
Wind (Off System)	Wind	100	35%		$2,071	2030	$33.54	
Offshore Wind (Off System)	Wind	100	46%		$6,996	2035	$95.57	
Conventional Geothermal (Off System)	Earth	20	90%		$5,821	2030	$141.91	
Enhanced Geothermal (Off System)	Earth	20	80%		$15,358	2040	$265.16	
Kettle Falls 2nd Biomass Unit	Wood Waste	58	50%	13.361	$5,437	2030	$33.68	$4.50
Kettle Falls Upgrade	Wood Waste	11	60%	13.361	$3,182	2030	$33.68	$4.98
Hydrogen Fuel Cell	Hydrogen	25		5.687	$6,275	2035	$211.74	

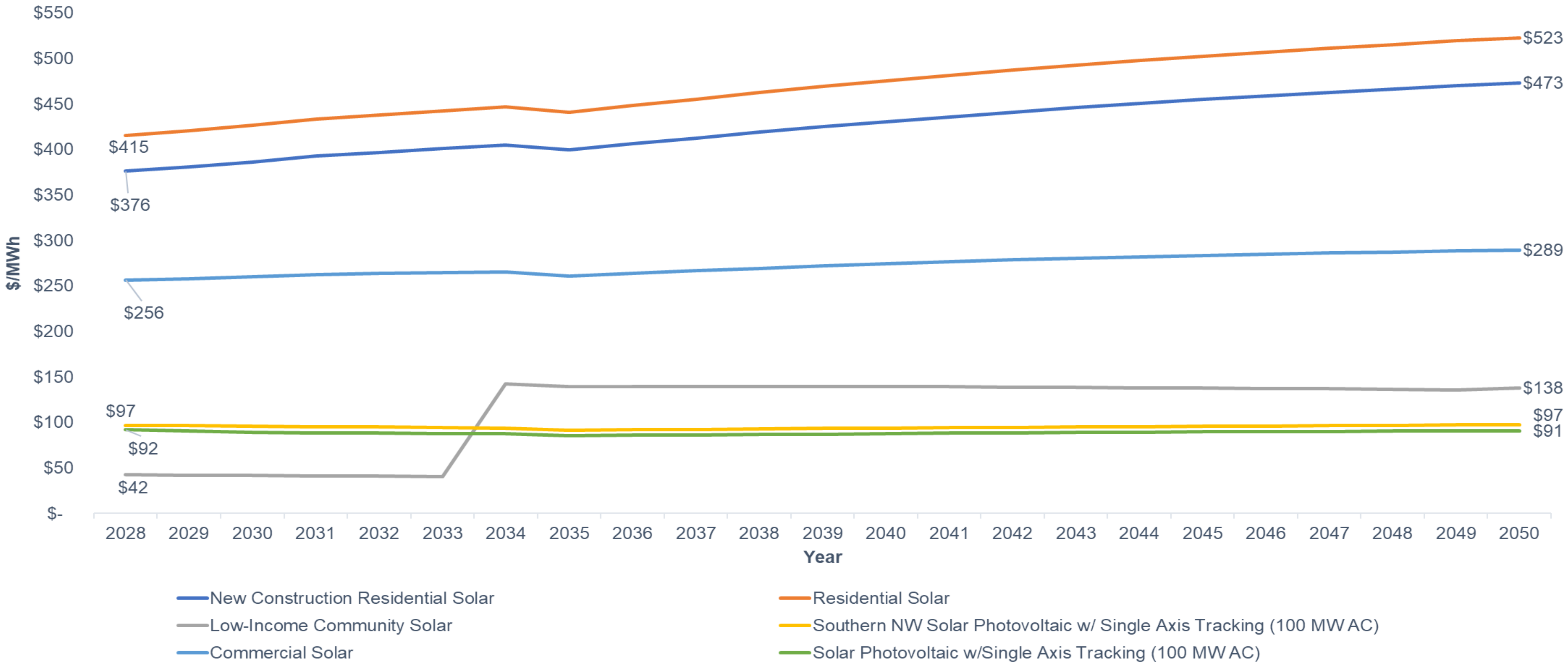
Resources Modeled Continued

Resource	Fuel Source	MW	MWhs	Capacity Factor/ RTE	Capital $/kW (2028)	Available Year	FOM $kW-yr (2028)	VOM $/MWh (2028)
Pumped Hydro	Water	400	3,200	80%	$4,961	2030	$23.61	$0.76
Pumped Hydro	Water	100	2,400	80%	$4,477	2030	$23.61	$0.76
Adams Neilson Repower	Solar	25		24%	$1,380	2039	$24.41	
Palouse Repower	Wind	120		36%	$1,563	2030	$37.45	
Rattlesnake Repower	Wind	180		27%	$1,563	2030	$37.45	
Residential PV (New Construction)	Solar	0.006		16%	$5,334	2030	$34.20	
Residential PV	Solar	0.006		16%	$5,798	2030	$34.20	
Commercial PV	Solar	1		18%	$3,170	2030	$21.28	
Low Income Community PV	Solar	1.5		25%	$616	2030	$34.20	
Utility PV (Fixed)	Solar	5		30%	$3,081	2030	$34.20	
Utility PV (Single Axis Tracking)	Solar	100		30%	$1,843	2030	$23.94	
Utility PV Southern NW (Single Axis Tracking)	Solar	100		33%	$2,019	2030	$23.94	
Distribution Scale 4hr	BESS	5	20	88%	$2,608	2030	$58.71	
Distribution Scale 8hr	BESS	5	40	88%	$3,732	2030	$88.05	
Transmission Scale 4hr	BESS	25+	100+	88%	$1,975	2030	$41.02	
Transmission Scale 8hr	BESS	25+	200+	88%	$2,827	2030	$72.83	
Long Duration Energy Storage 100hr	BESS	100	10,000	37%	$3,269	2030	$41.01	
4hr Flow	BESS	25	100	70%	$2,121	2030	$85.19	

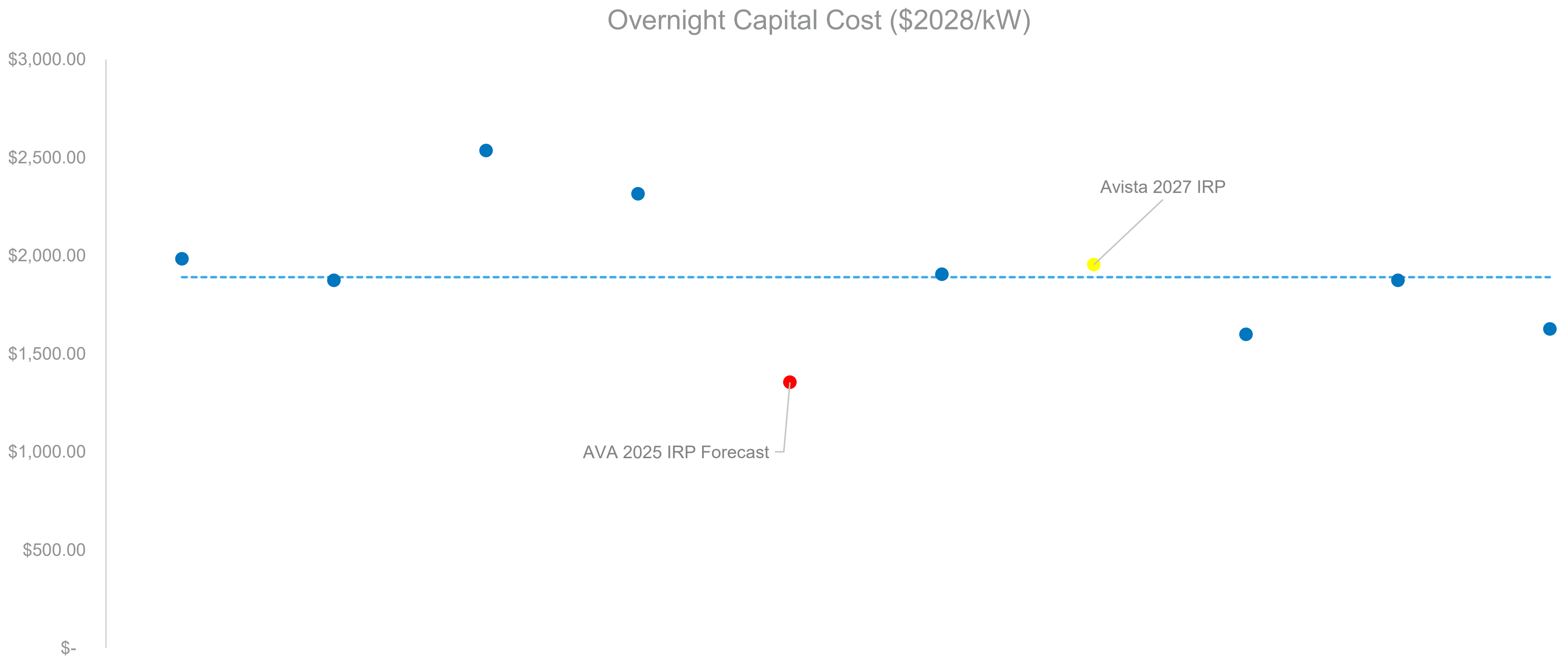
Solar Capital Costs



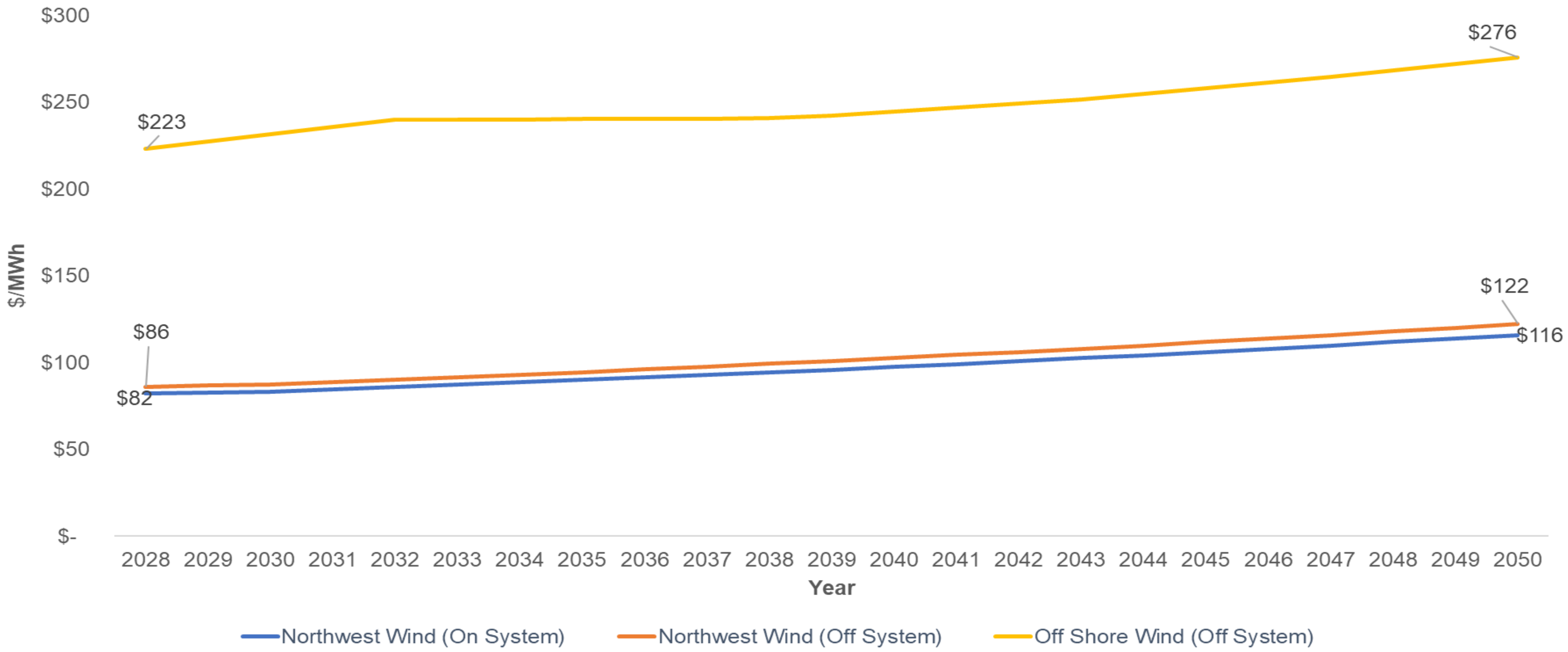
Solar PPA Price/Implied Energy Payment



Wind Capital Costs



Wind PPA Price/Implied Energy Payment



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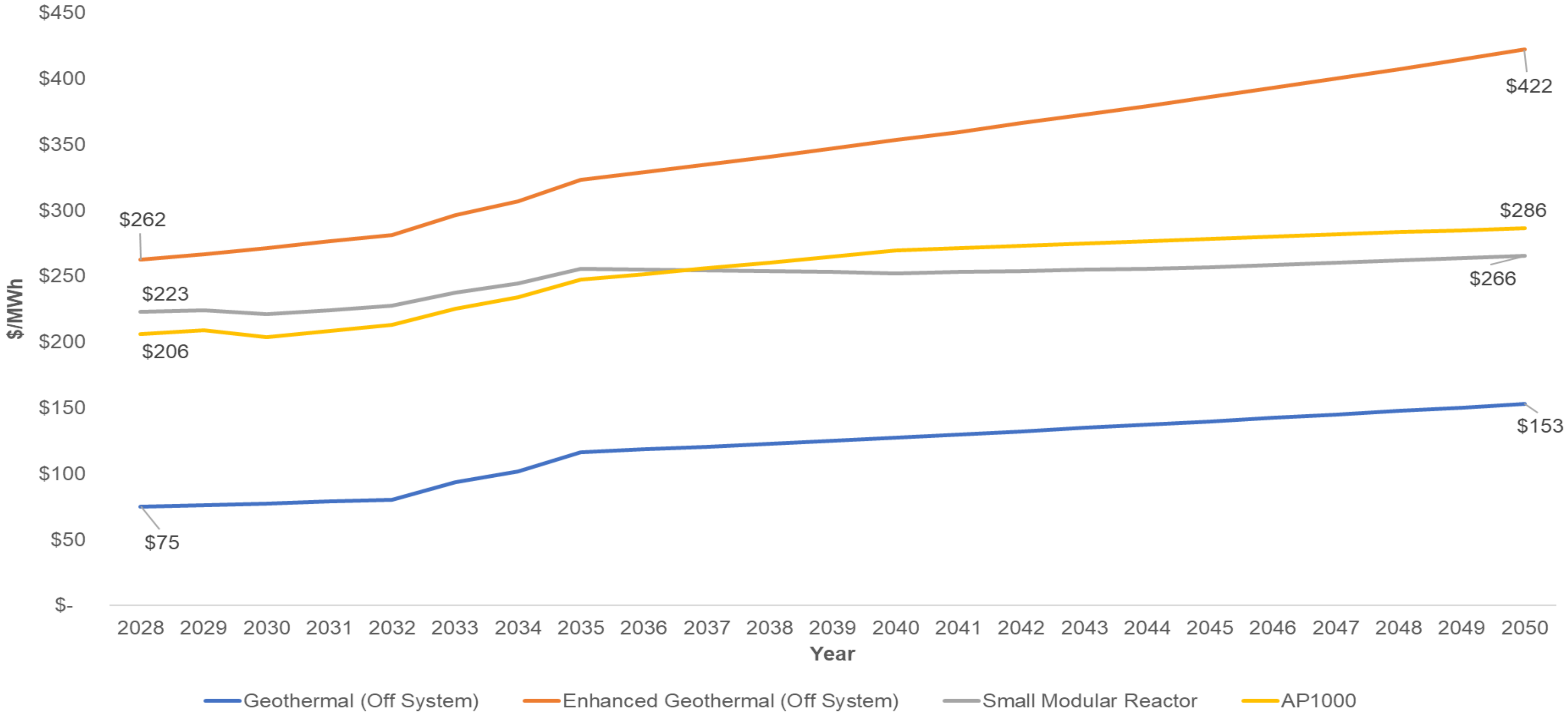
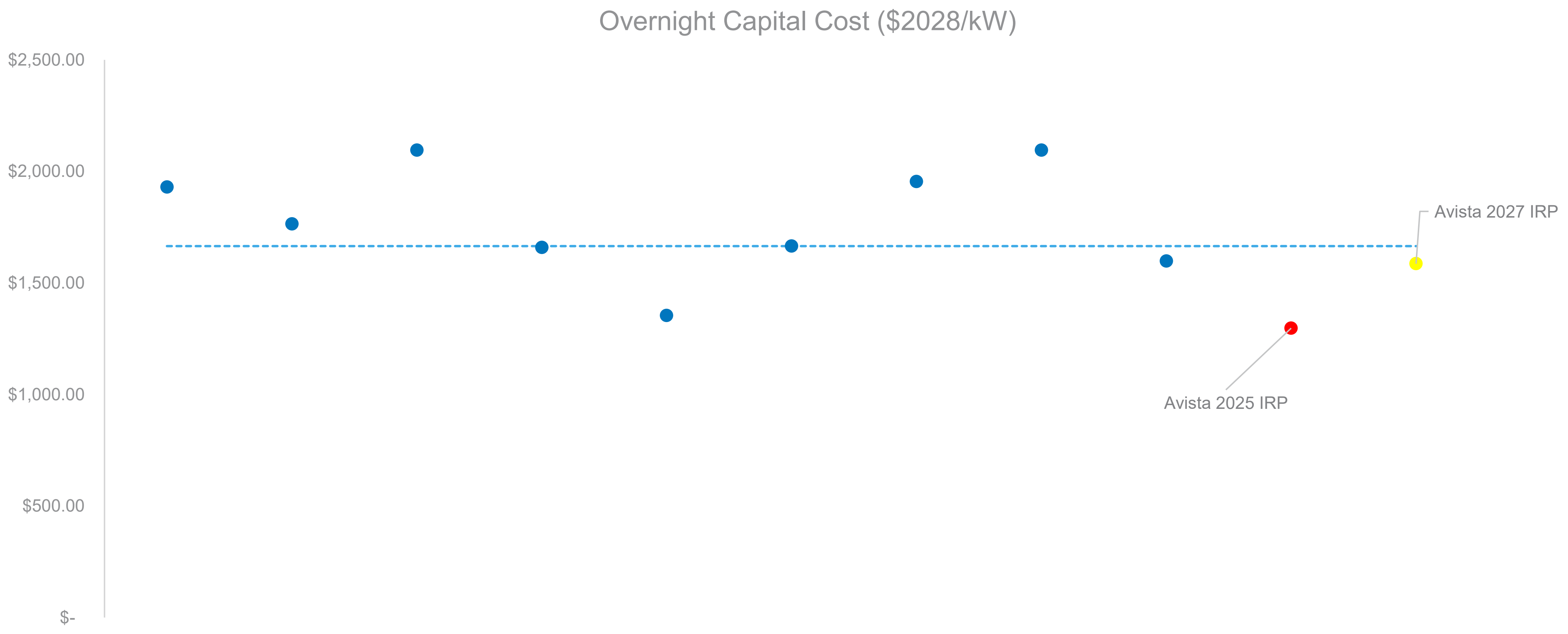
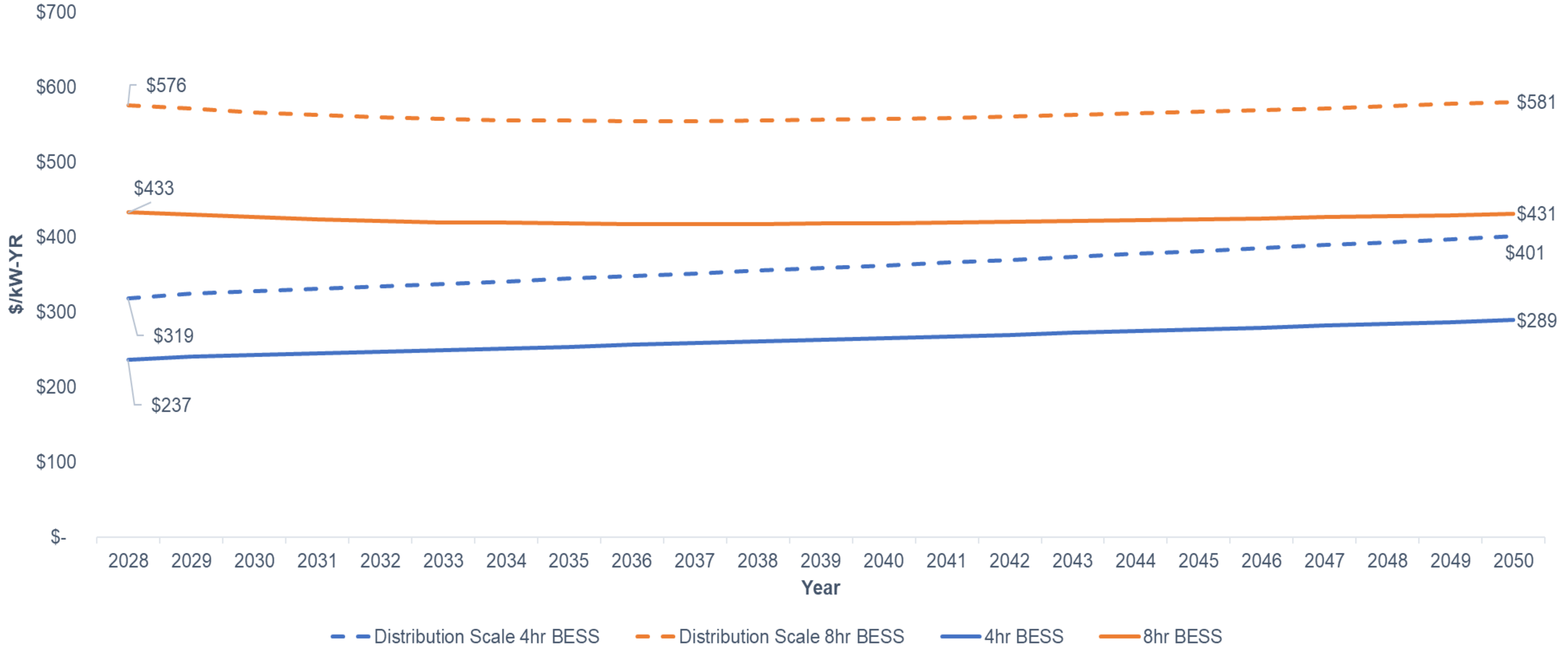
Baseload Clean Energy



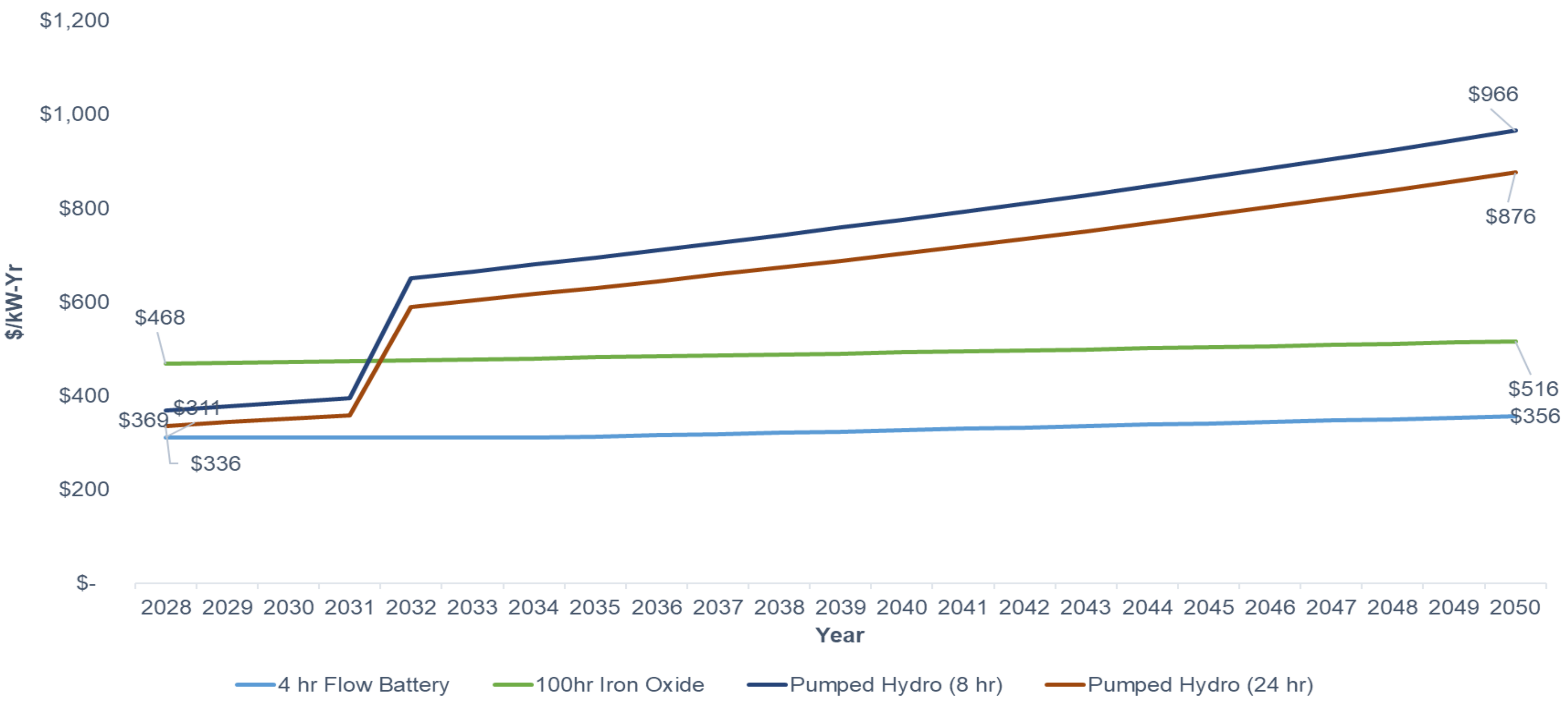
4 Hour Battery Capital Costs



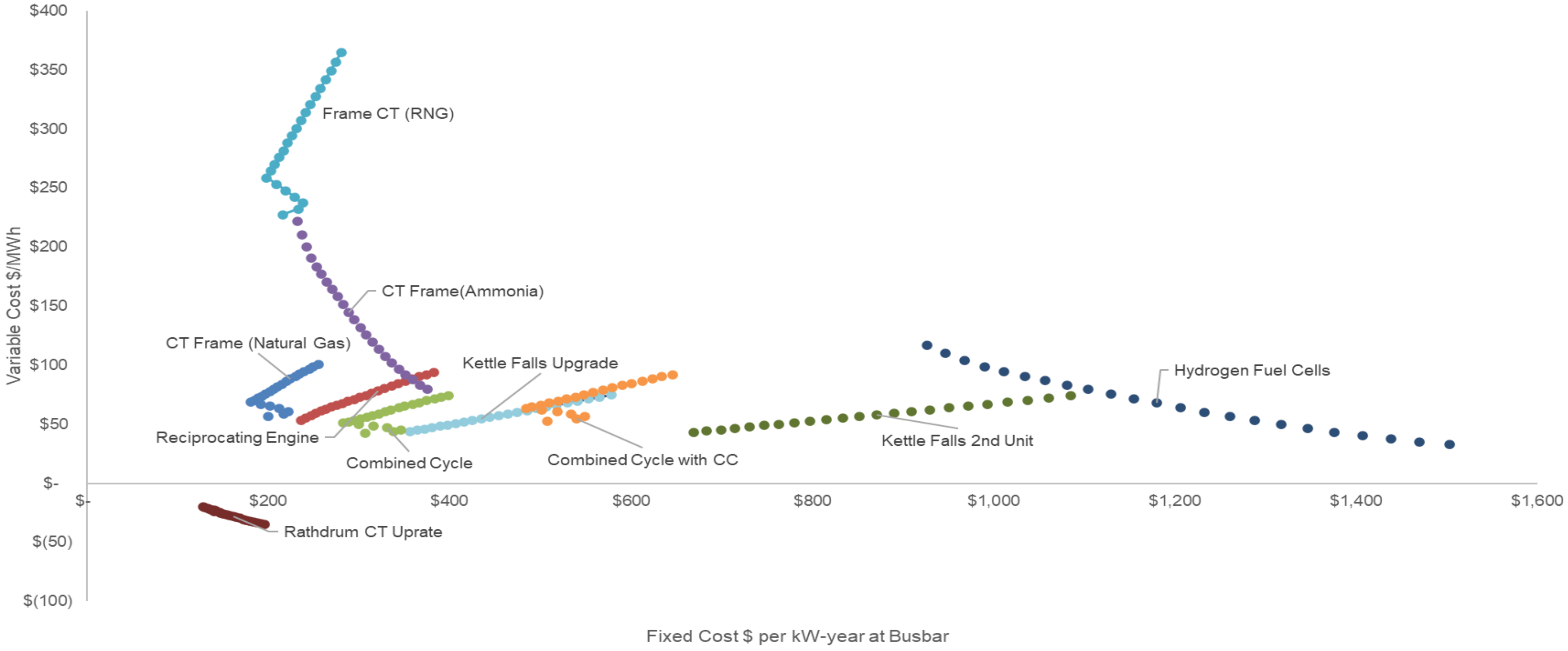
Energy Storage PPA Price/Implied Capacity Payment



Energy Storage PPA Price/Implied Capacity Payment



Dispatchable Resource Variable vs Fixed Cost



Q&A

Thank you!

Electrification Analysis Assumptions

TAC 5 – February 20, 2026

James Gall, Manager of Resource Analysis

Overview of Methodology

- The load forecast will include customer choice/code electrification.
  - Cadmus will provide its methodology at the April TAC meeting
- Additional electrification will be a resource option in the integrated resource selection model (PRiSM)
  - If electrification is selected, electric loads will increase/ gas load decrease.
    - New electric loads will have to be met with new electric generation and T&D costs.
  - For non-Avista electric customer w/ gas (i.e. Oregon/Inland customers), the model will include an electric cost based on an electric rate forecast.
- Electrification will be modeled as linear customer reduction from 2029 to 2050, if all electrification was selected by 2050, only 20% of today's demand would remain for this analysis.
- Electrification Options
  - Res/Com Water Heat
  - Res/Com Space Heat (Heat Pump >36º)
  - Res/Com Space Heat (Resistance/Heat Pump <36º)
  - Res Other (no commercial "other" will be modeled at this time)

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Electrification Costs Per Customer (2026$)

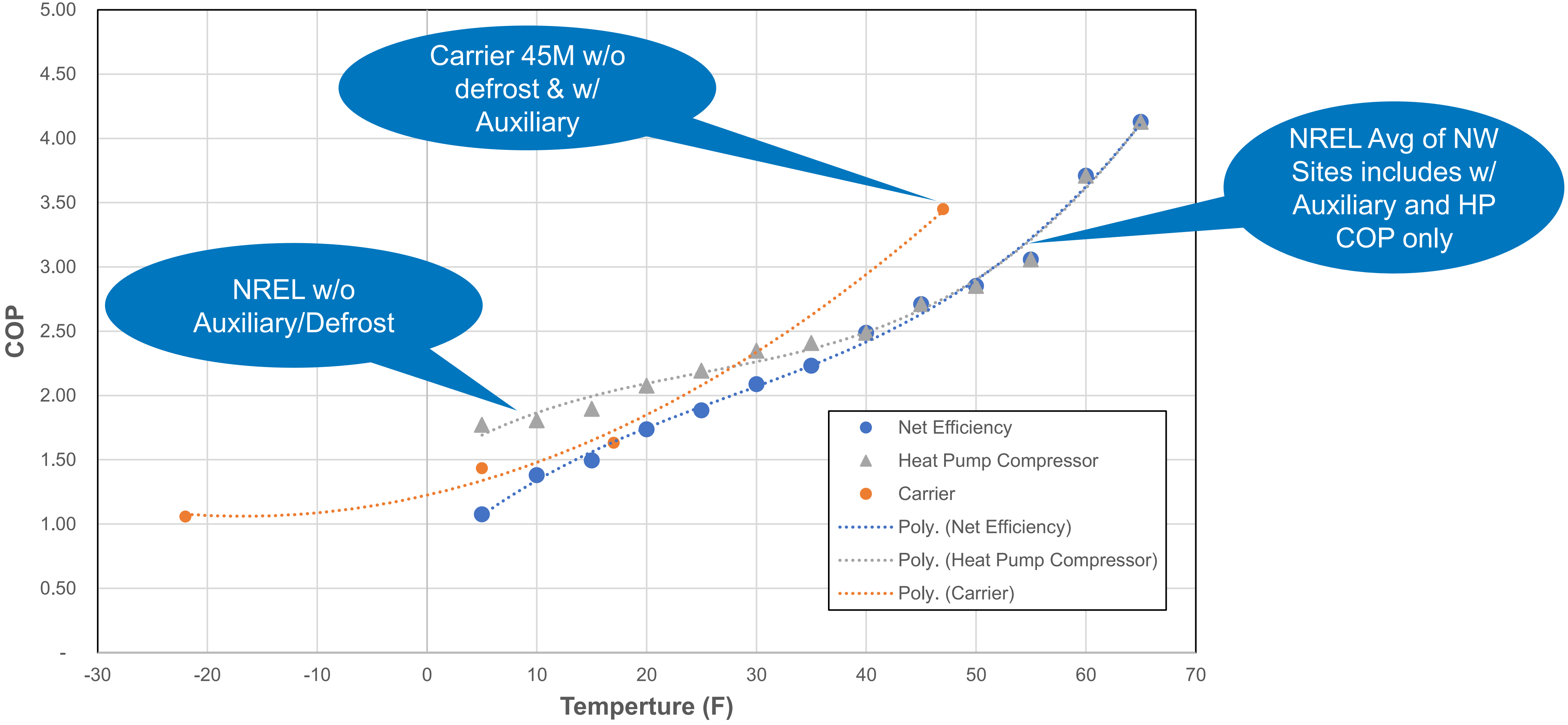
- Assumes utility energy efficiency applicable rebate
- Assumes appliances replaced at end of life (subtracts equivalent equipment replacement from install cost)
- Sales tax is the difference in cost between states
- Other represents an impact of clothes dryer or range/oven

Net Customer Cost	Washington	Oregon	Idaho	2025 IRP
Res. Electric Furnace (above HP)	$5,051	$4,625	$4,877	$1,068
Com. Electric Furnace (above HP)	$23,778	$22,500	$23,123	$4,275
Res. HP coupled with existing NG Furnace	$13,132	$11,300	$12,713	$3,350
Com. HP coupled with existing NG Furnace	$15,933	$13,865	$15,337	$13,398
Res. HPWH	$2,476	$2,025	$2,379	$1,744
Com. HPWH	$6,325	$5,550	$6,091	$6,975
Other	$1,092	$1,000	$1,055	$447

Commercial assumes very small commercial 10,000 sqft and less, larger building will be higher

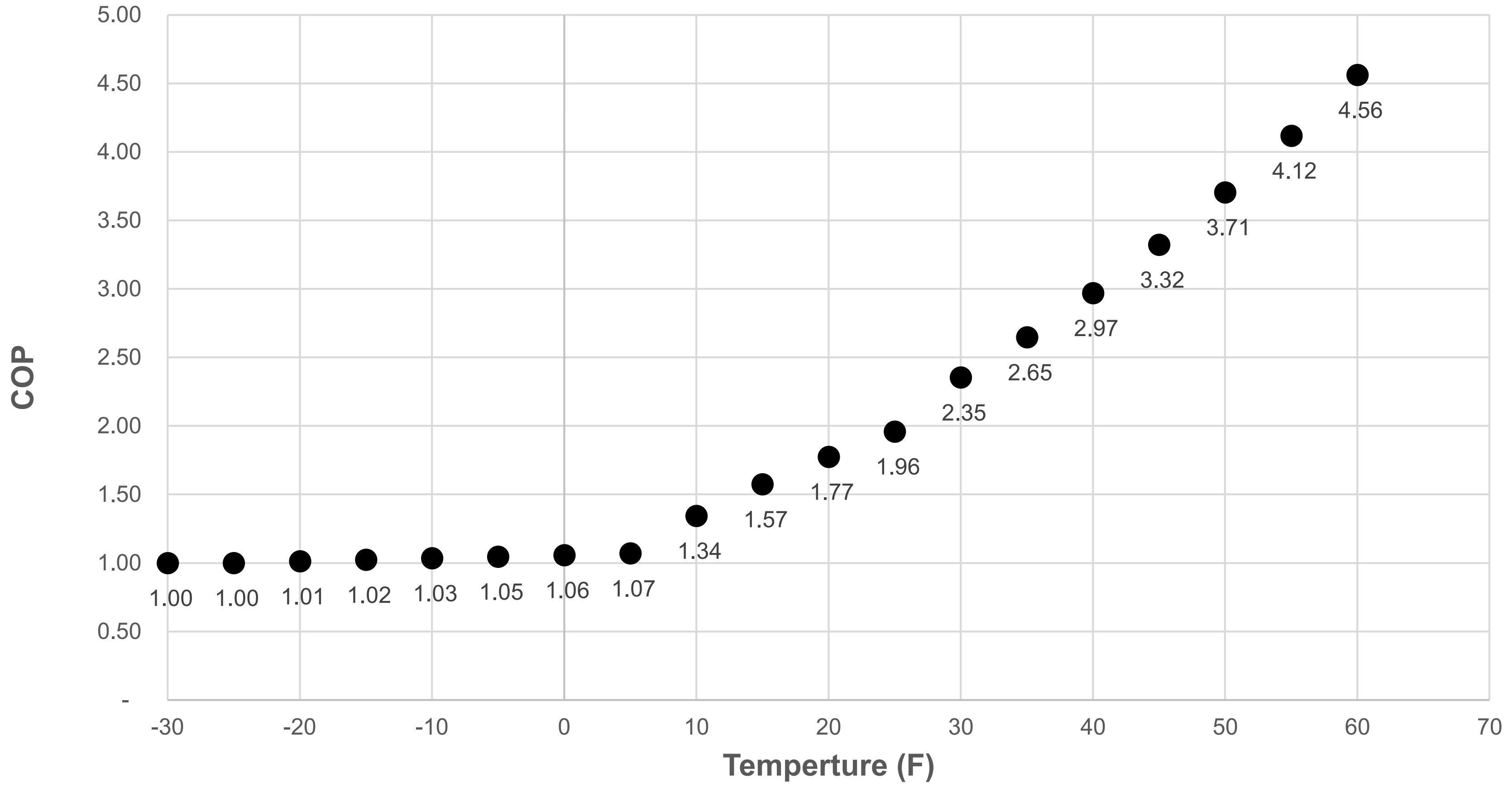
Updated costs are AI generated based on the average of a high and low cost for med size building for each category

Residential Space Heating Efficiency Curves



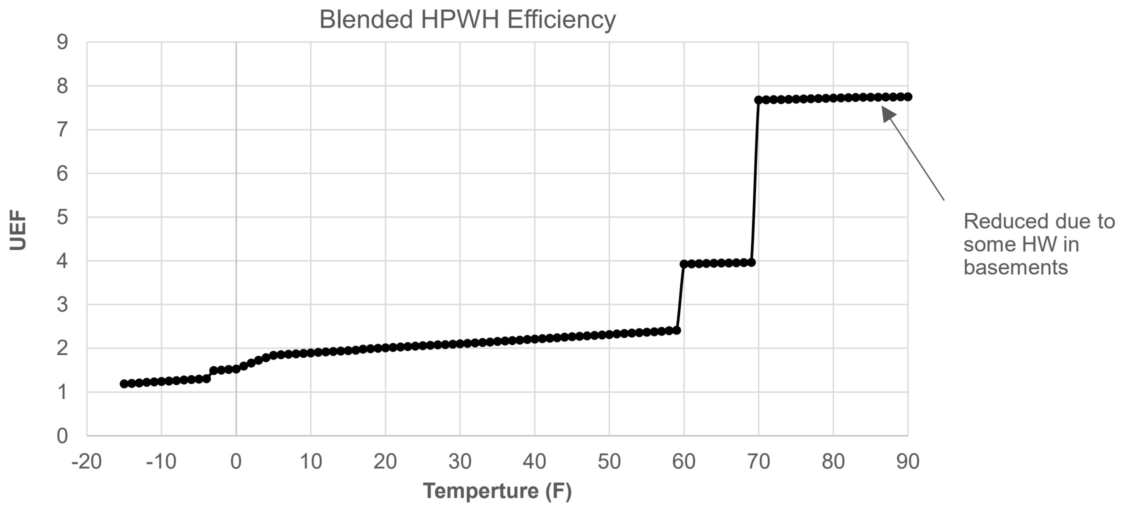
 https://ashp.neep.org/ for Carrier, NREL: Field Validation of Air-Source Heat Pumps for Cold Climates, May 2023

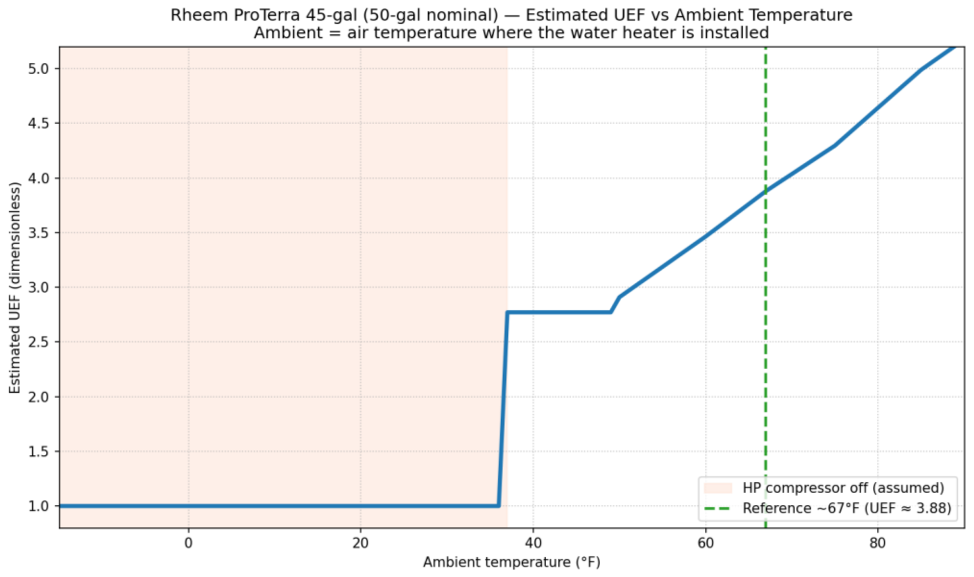
Proposed Space Heating Efficiency Curve

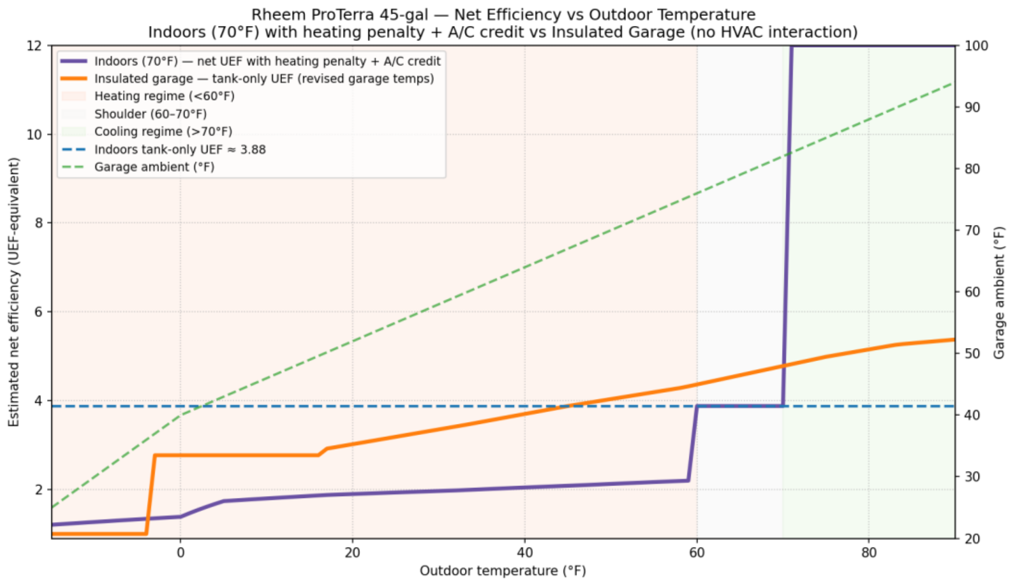


Heat Pump Water Heating

- Assumes 3.88 UEF water heater @ 67º
- What heater placement determines net COP (garage vs indoors)
- Must include make-up heat for indoor placed units
- Blended garage at 90% in house and 10% garage



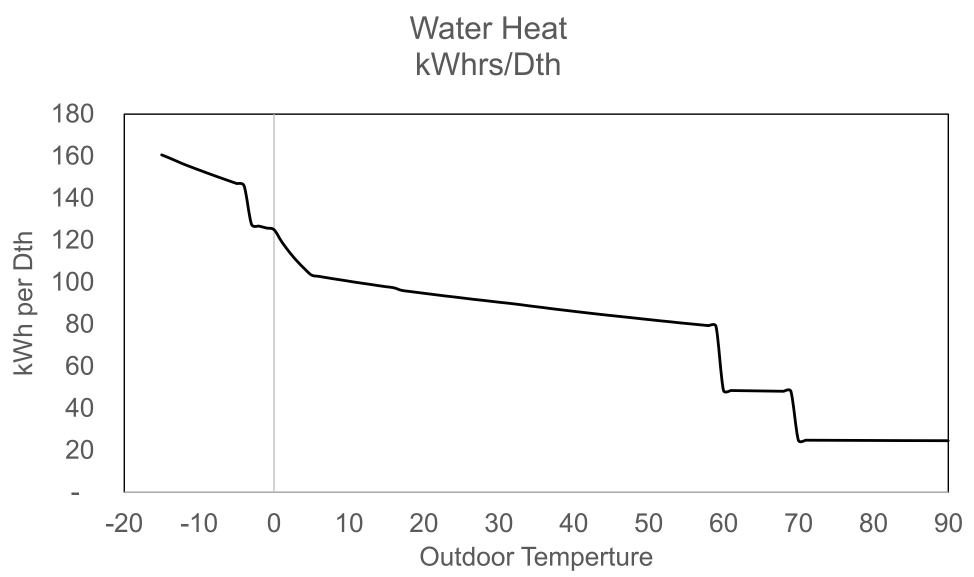


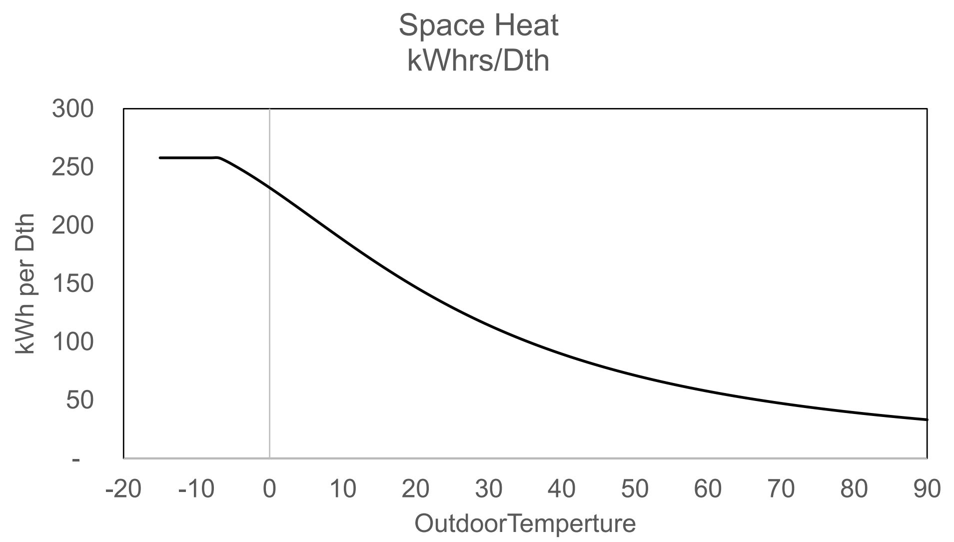


Microsoft Co-Pilot used to determine these efficiency rates

Modeling Methodology

- Determine how much natural gas is used each month for each fuel switching category per customer.
- Use kWh/Dth efficiency curve for water and space heat to estimate electric energy impacts to electric system
- Other gas uses will assume 293 kWh/dth
  - i.e. 100% efficiency
- Assume 0.5% efficiency improvement each year
- Assumes commercial is 10% less efficient then residential for space/water heat

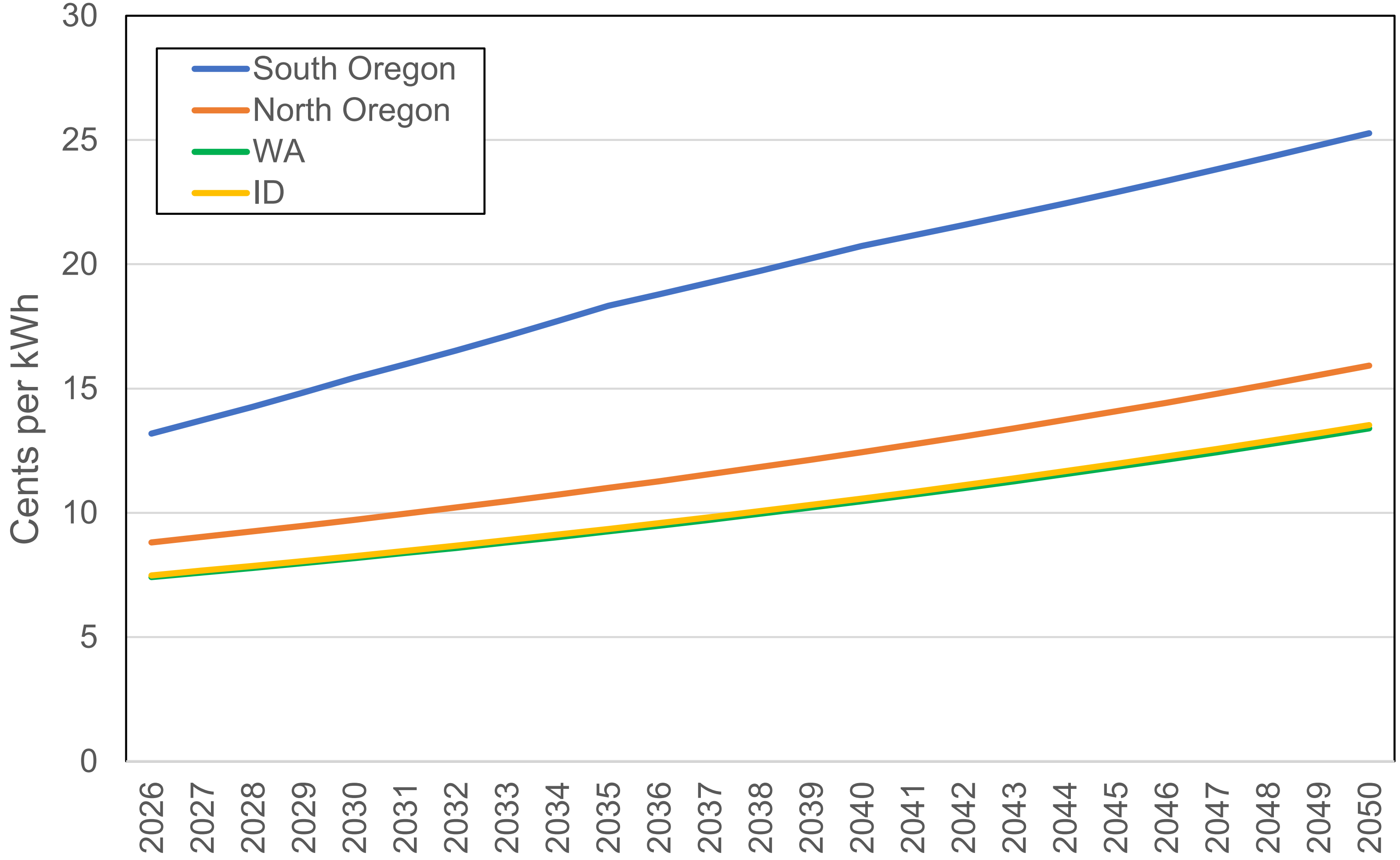




Residential Space/Water Heat Impacts (Washington Example- DRAFT)

	Electric (Additions)			Natural Gas (Reductions)	
Appliance	Net Annual (kWh)	Winter Peak (kW)	Summer Peak (kW)	Annual Therms	Peak Day Therms
Res HPWH	1,298	0.2	0.0	170	0.3
Com HPWH	10,587	3.0	0.5	1,307	2.0
Res HP w/ NG Backup	1,977	0.0	0.0	248	0.0
Res HP w/ Elec Backup	3,959	4.8	0.0	455	8.2
Com HP w/ NG Backup	10,315	0.0	0.0	1,178	0.0
Com HP w/ Elec Backup	20,660	25.2	0.0	2,158	49.0
Other	562	0.1	0.0	19	0.1

Electric Rate Forecast for Non-Avista Service Area



WA Gas usage on non-Avista electric assumed be at 22% and Idaho gas usage on non-Avista electric assumed at 27%

Wholesale Electric Market Price Forecast

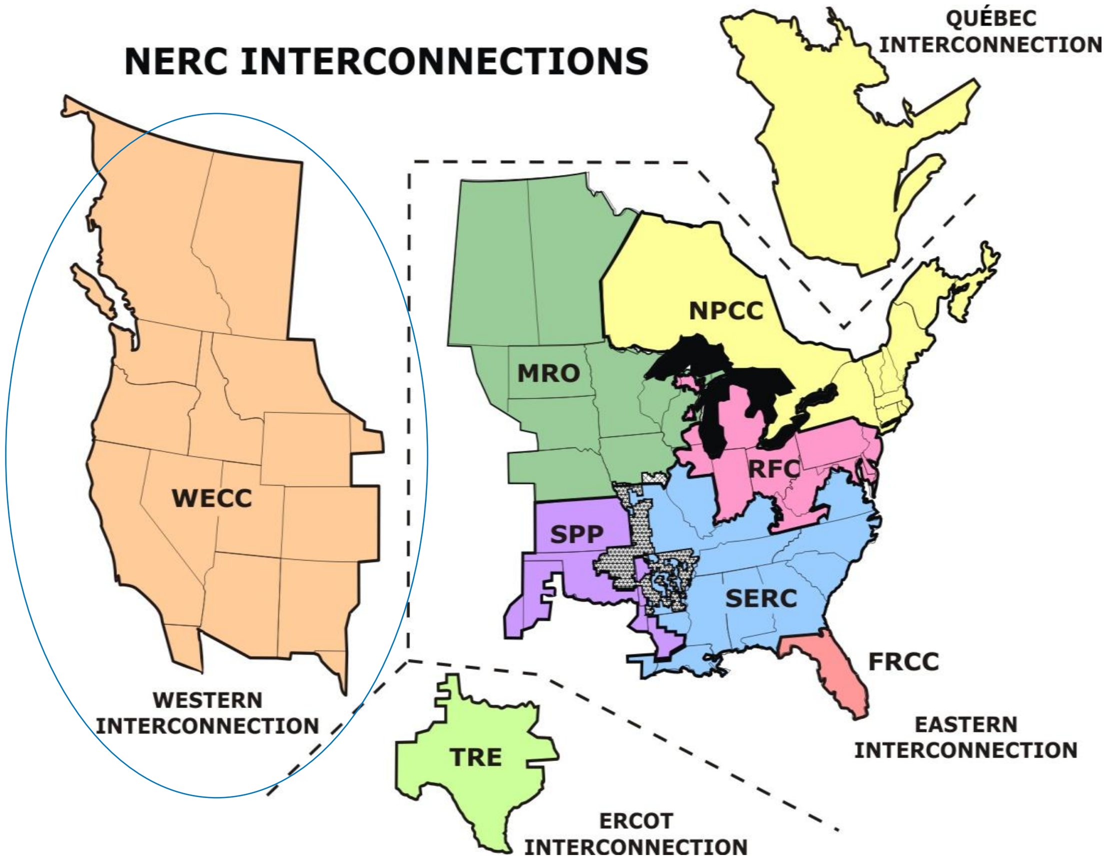
Technical Advisory Committee Meeting No. 5

February 20, 2026

Robert Hughes, Resource Planning Analyst

Market Price Forecast – Purpose

- Estimate "market value" of resource options for the IRP
- Estimate dispatch of "dispatchable" resources
- Informs avoided costs
- May change resource selection if resource production is counter to needs of the wholesale market

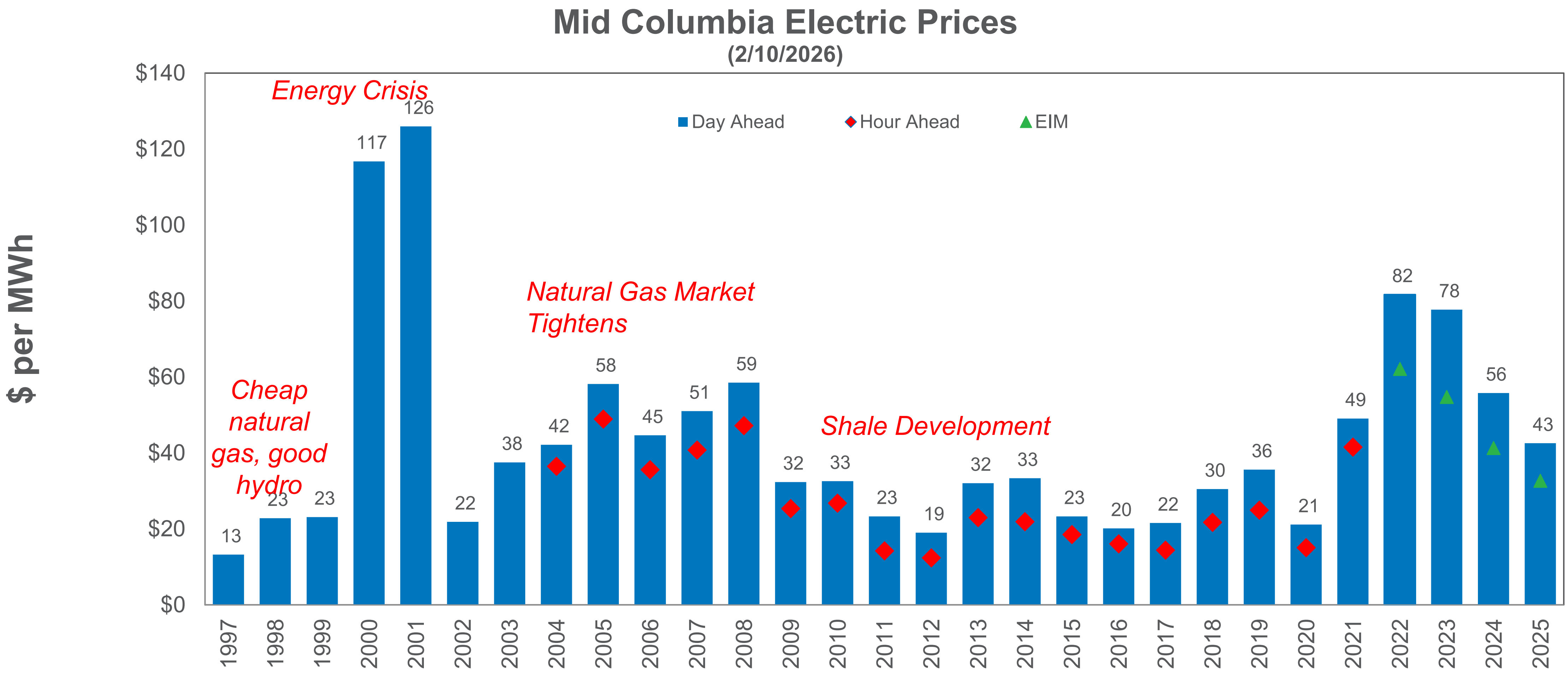


Source: NERC

Methodology

- 3rd party software - Aurora by Energy Exemplar
- Electric market fundamentals - production cost model
- Simulates generation dispatch to meet regional load
- Outputs:
  - Market prices (electric)
  - Regional energy stack
  - Transmission usage
  - Greenhouse gas emissions and cost
  - Power plant margins, generation levels, and fuel costs
  - Avista's variable power supply costs

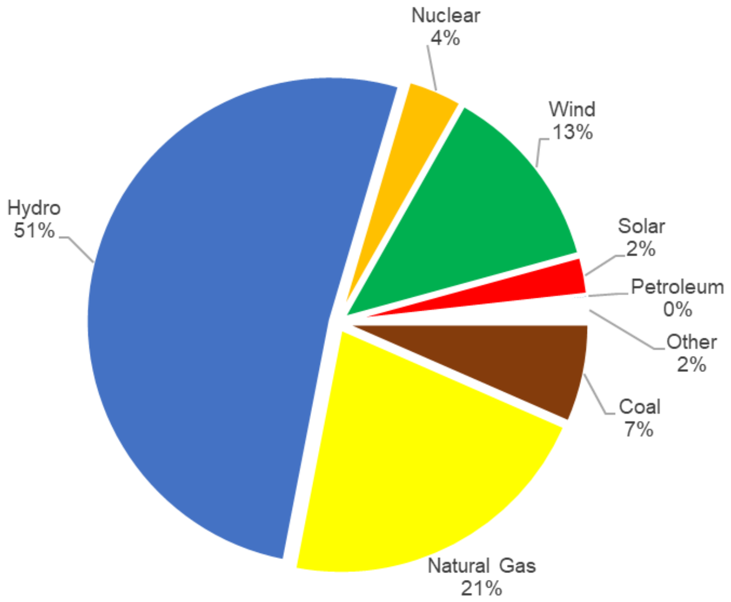
Wholesale Mid-C Electric Market Price History



2025 Fuel Mix

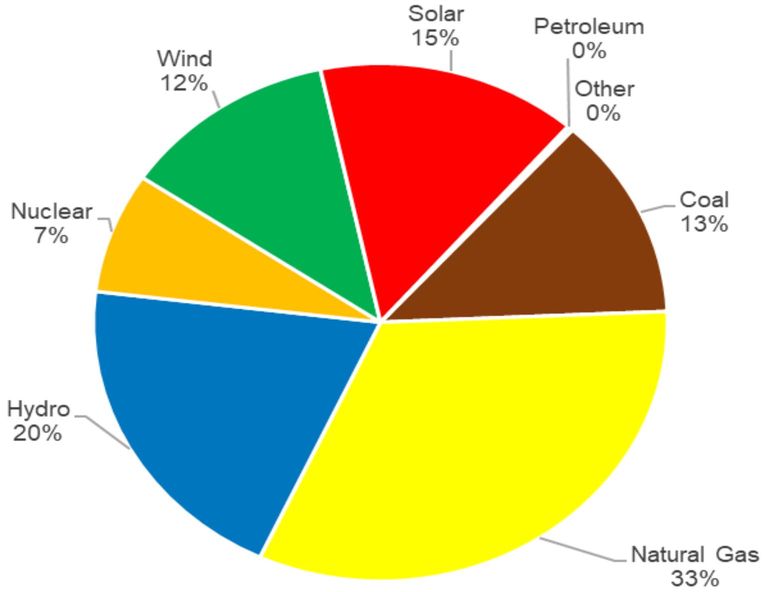
Northwest

72% GHG Emission Free



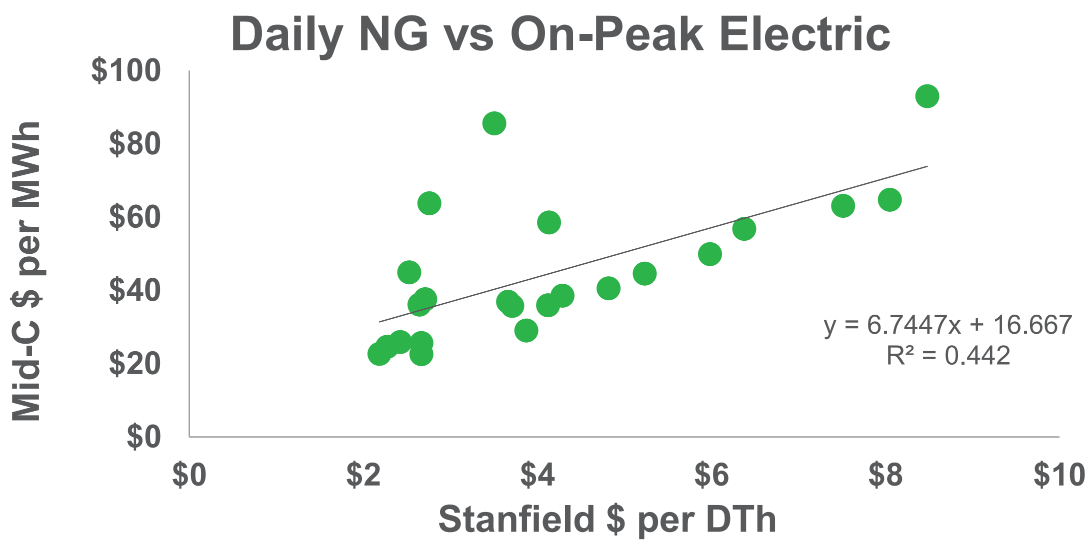
U.S. Western Interconnect

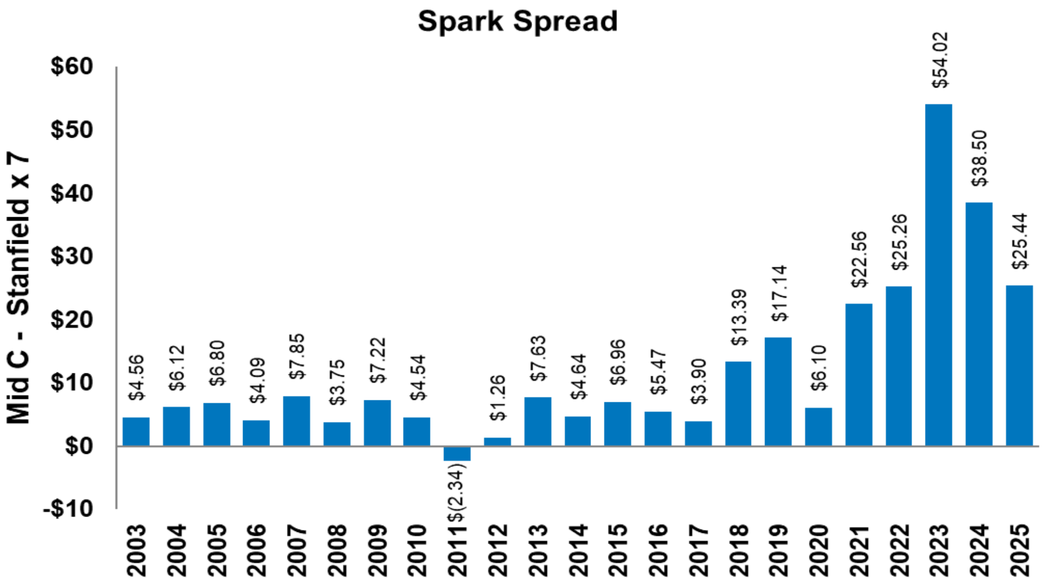
53% GHG Emission Free

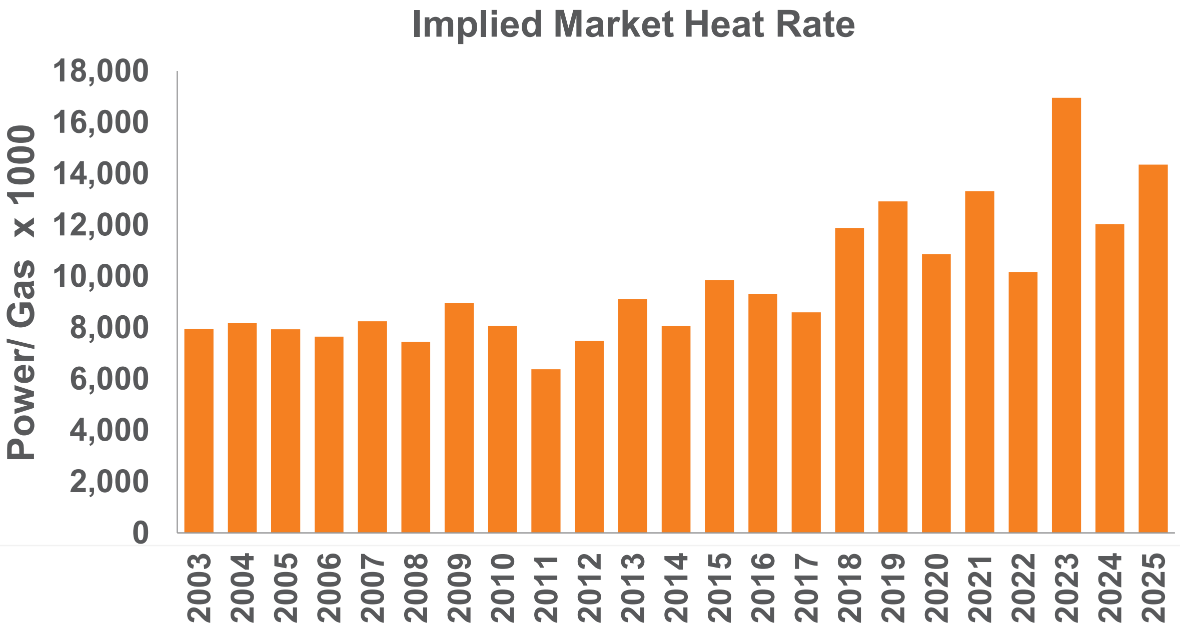


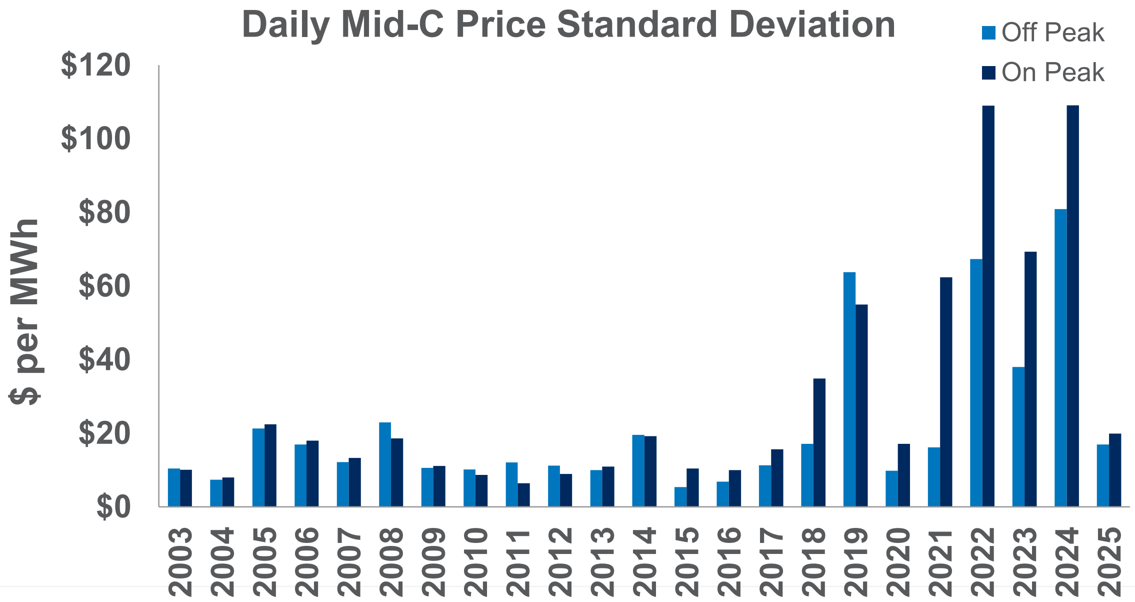
Source: EIA Annual Generation By State and Producer Report

Market Indicators

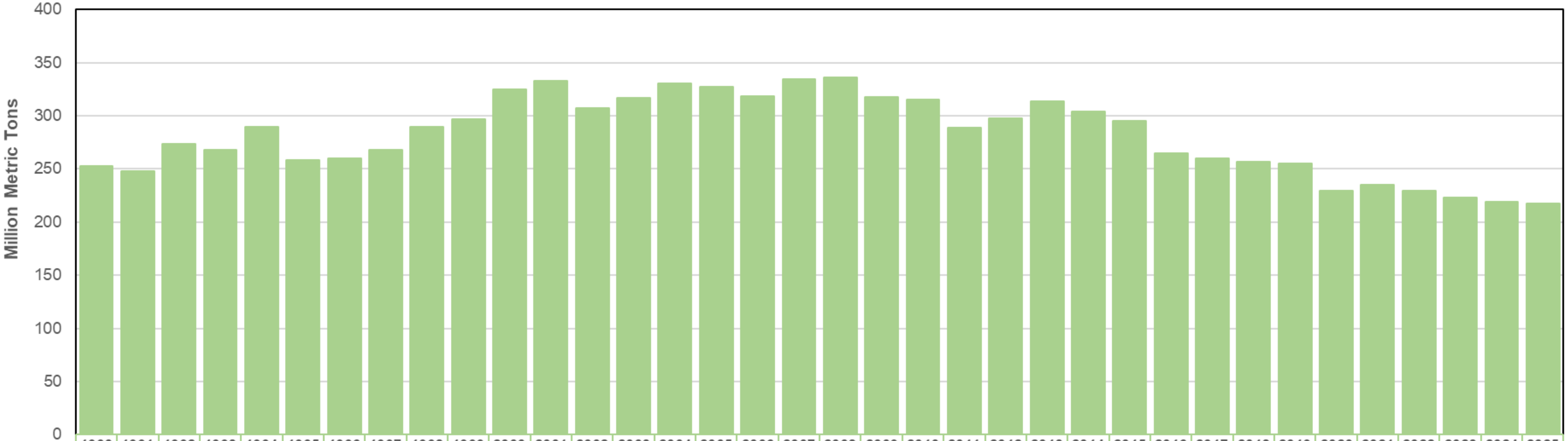








Electric Greenhouse Gas Emissions
U.S. Western Interconnect



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
WY	36	35	38	36	39	36	37	36	40	38	40	40	39	39	40	39	39	40	40	38	39	38	40	43	41	40	37	37	37	33	32	31	32	31	30	31
WA	9	9	11	11	13	10	12	10	13	12	16	16	13	15	15	15	10	13	14	14	14	8	7	13	12	12	10	11	11	15	12	11	11	10	9	9
UT	29	28	30	31	32	30	30	31	32	33	33	33	34	35	36	36	37	39	39	37	36	34	32	36	35	34	28	28	29	28	26	30	26	26	26	27
OR	2	4	5	5	6	3	4	3	7	7	8	9	7	9	9	9	7	11	11	9	10	7	7	9	8	9	8	8	9	11	9	9	8	7	7	7
NM	27	23	26	27	28	28	28	29	30	30	31	31	29	31	31	32	32	31	30	31	27	29	27	27	23	23	21	21	16	18	16	15	11	11	11	11
NV	17	18	19	18	20	18	19	19	21	21	25	24	21	23	25	26	17	17	18	18	17	15	15	16	16	15	15	13	14	14	13	14	18	18	17	17
MT	16	17	18	15	18	17	14	16	18	18	17	18	16	19	19	19	19	20	20	17	20	17	16	17	17	18	16	16	15	16	10	13	14	14	14	14
ID	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	1	2	2	2	2	2	2	3	2	2	2	2
CO	32	31	32	32	34	33	35	35	36	36	40	42	42	41	41	41	42	44	42	39	40	40	40	39	38	37	36	36	35	34	29	31	30	30	30	29
CA	53	50	58	54	62	50	47	50	53	58	68	72	60	56	60	55	60	63	63	59	55	48	59	57	58	55	47	44	44	41	43	45	44	42	42	41
AZ	33	33	36	38	39	33	33	36	39	41	46	47	46	47	53	52	54	56	59	54	56	54	52	55	54	50	45	44	47	44	36	34	33	32	31	30

Source: EIA
Emissions are adjusted for generation within the Western Interconnect

Modeling Process

We are here

1 Vendor Database
(2025 North American)

2 Input Changes
30 yr. hydro with climate change
NG prices
Regional Loads
Avista Resources/Loads
Operational Detail

3 Capacity Expansion
Add new resource forecast
(Capacity/RPS)
Include known retirements
Model adds resources to meet planning targets

4 Preliminary Deterministic Study

5 Test Year Stochastic Study
Test Resource Adequacy

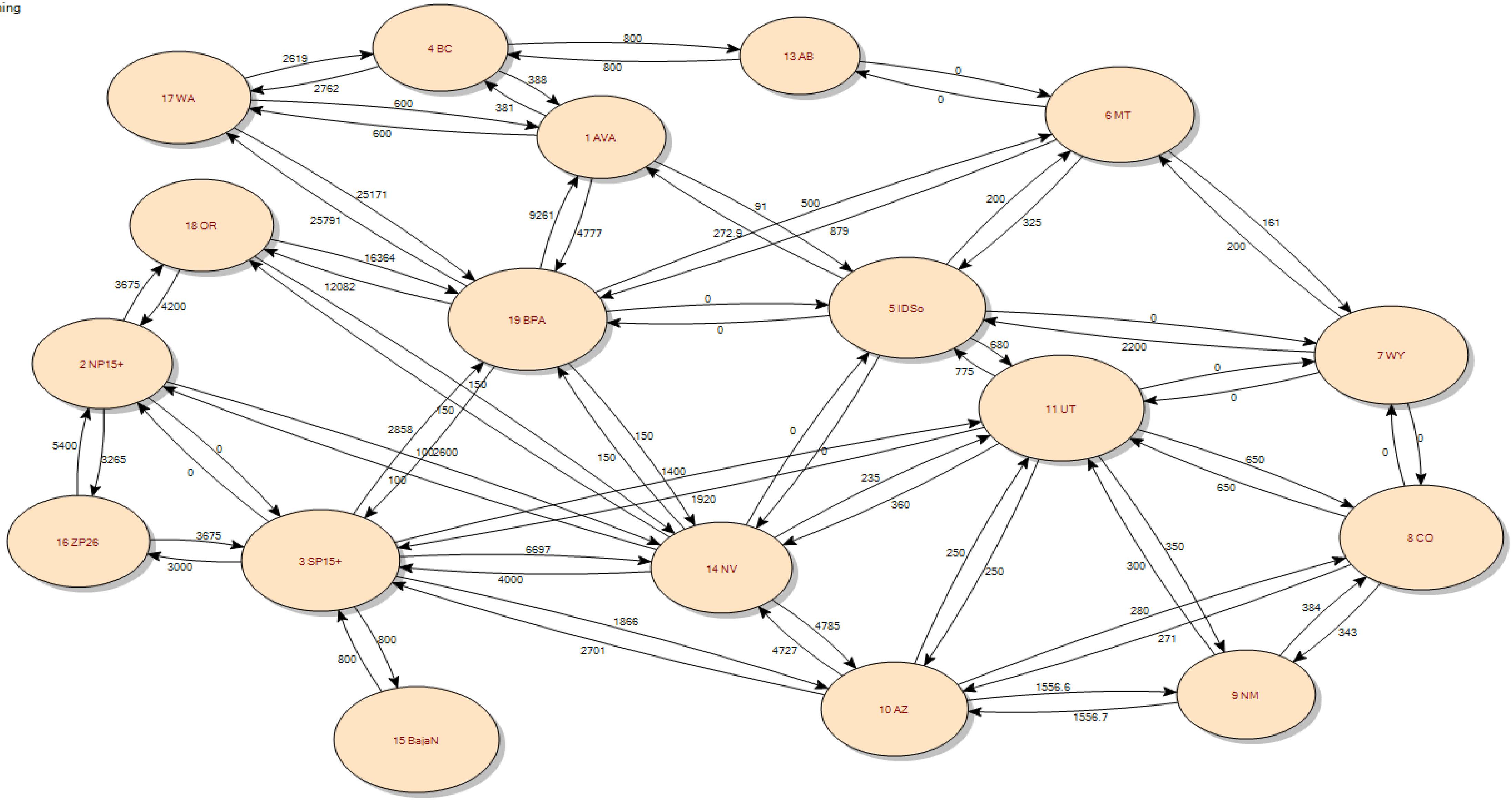
6 Re-Run Capacity Expansion
Increase/Decrease Planning Margin Targets

7 Run Full Forecast
Stochastic & Deterministic

8 Run Scenarios
Deterministic
Stochastic (if necessary)

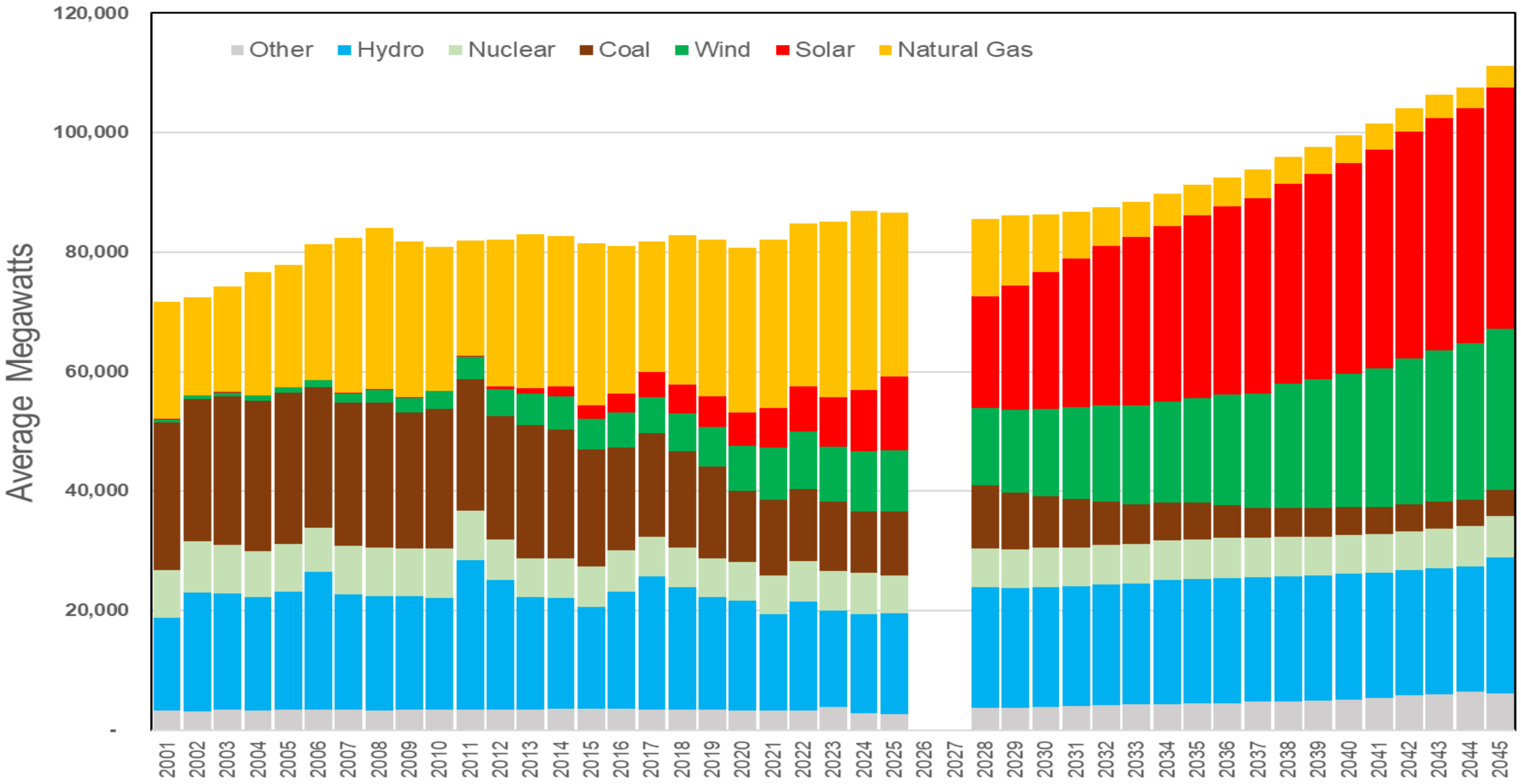
Aurora Zonal System Map

lot running



Draft forecast

U.S. West Resource Type Forecast

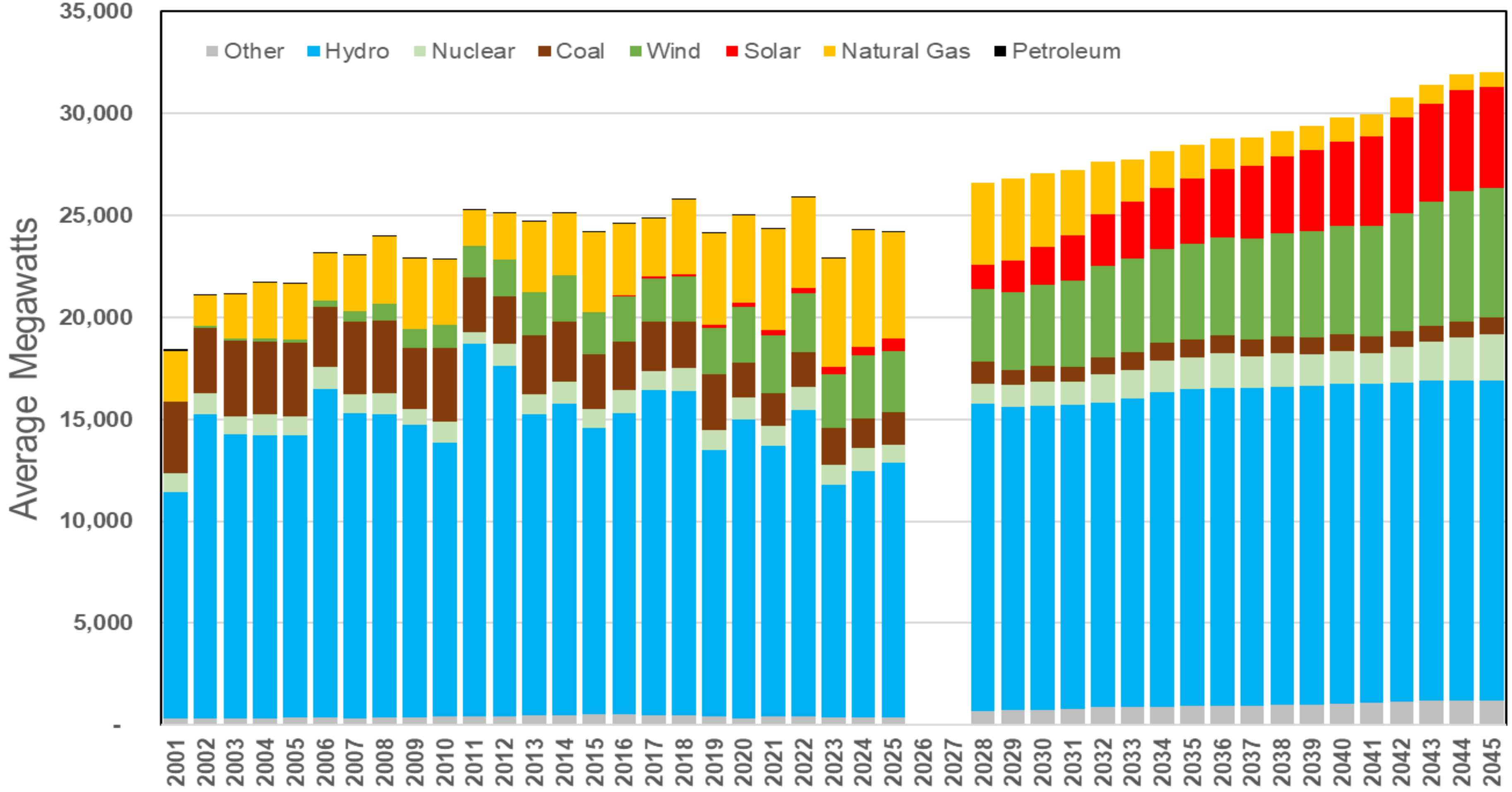


Significant changes 2045 to 2028 (aGW)

Solar:	+ 21.7
Wind:	+ 13.9
Nat Gas:	- 9.3
Coal:	- 6.1
Nuclear:	+ 0.5
Other:	+ 0.2
Total:	+ 20.9

Draft forecast

Northwest Resource Type Forecast



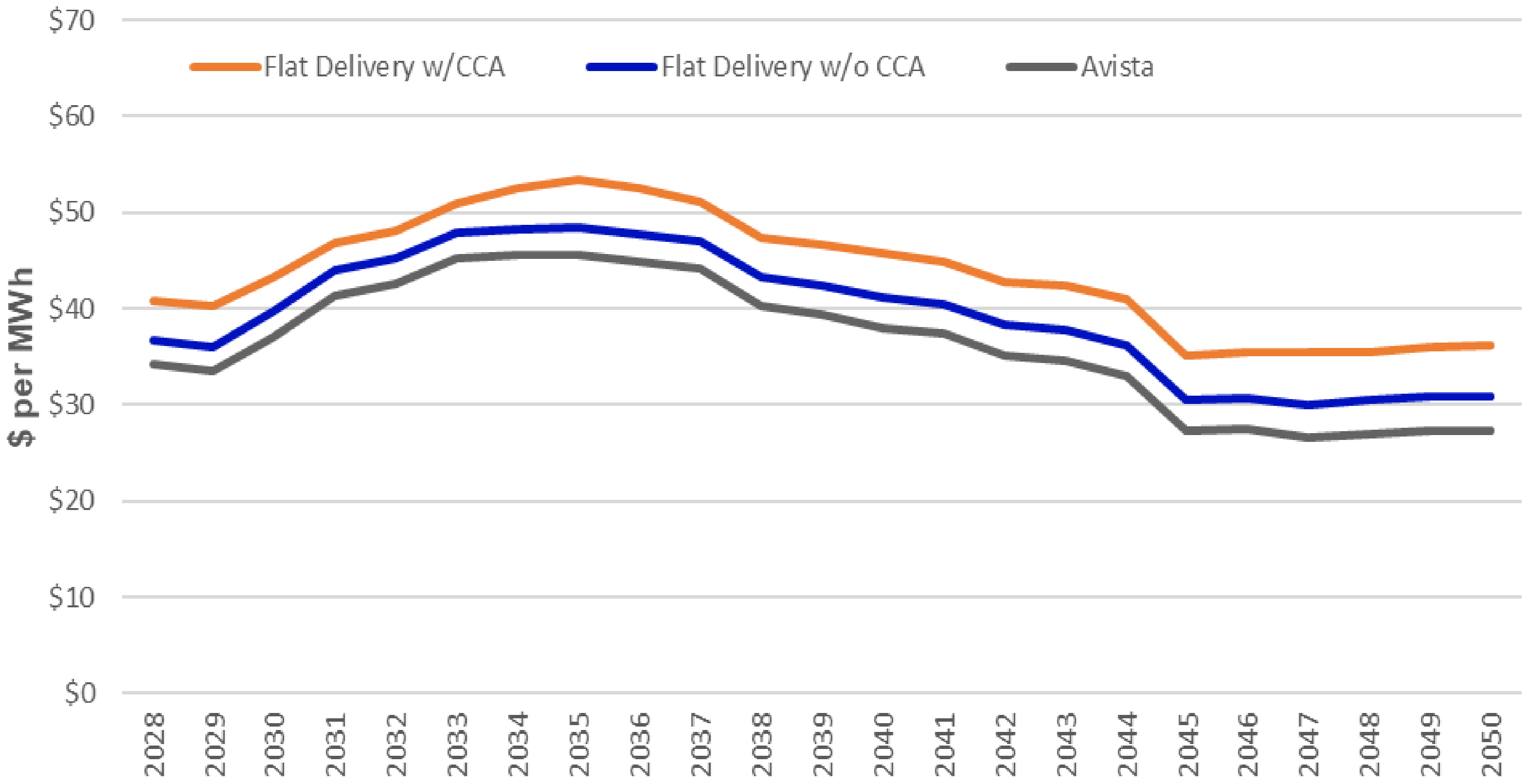
Significant changes 2045 to 2028 (aGW)

Solar:	+ 3.7
Wind:	+ 2.8
Nat Gas:	- 3.3
Coal:	- 0.2
Nuclear:	+ 1.3
Hydro:	+ 0.6
Other:	+ 0.5
Total:	+ 5.3

AVISTA

Draft forecast

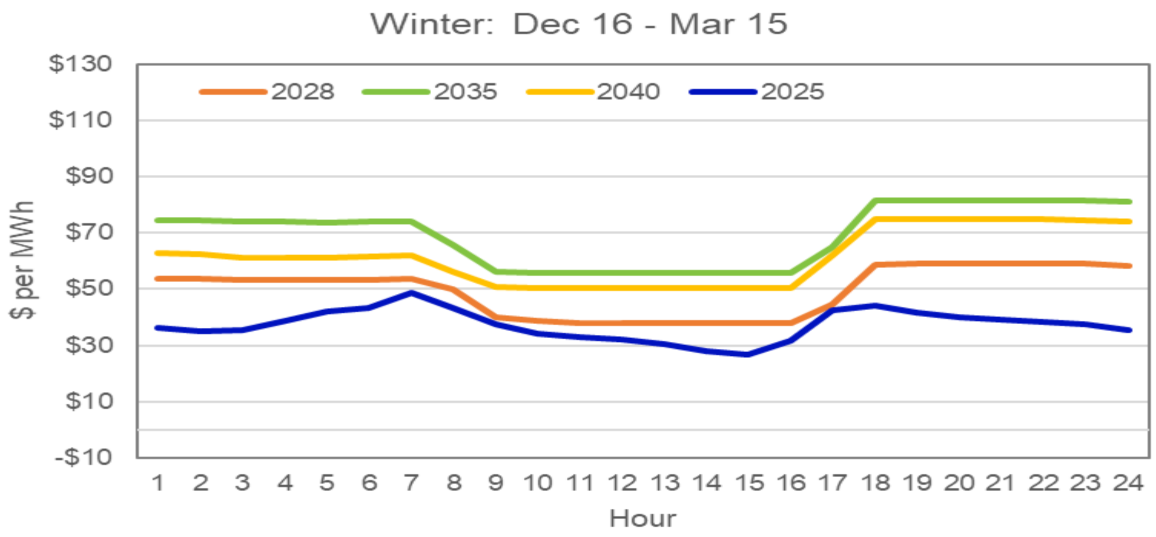
Mid-C Electric Price Forecast

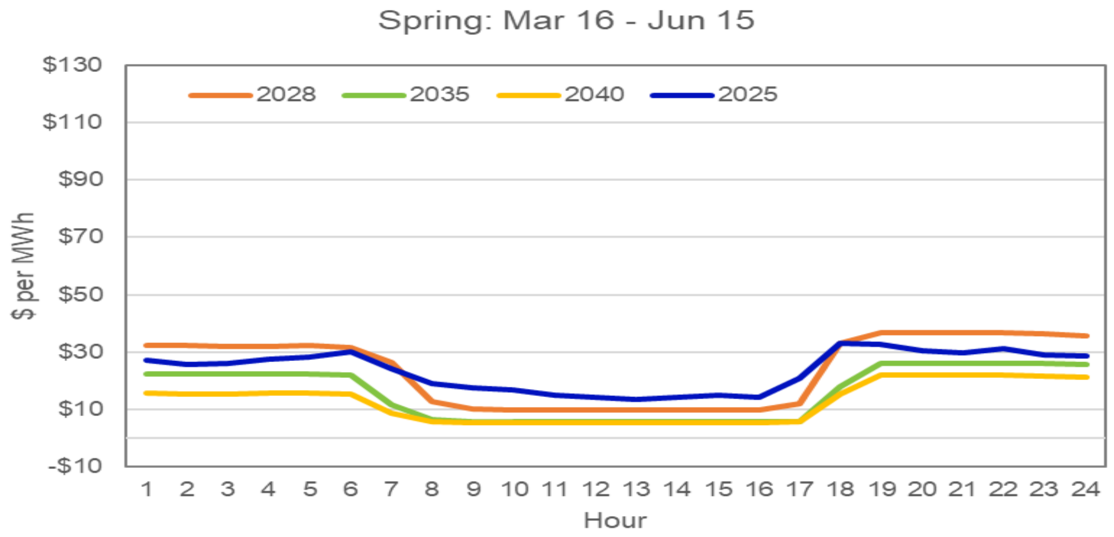


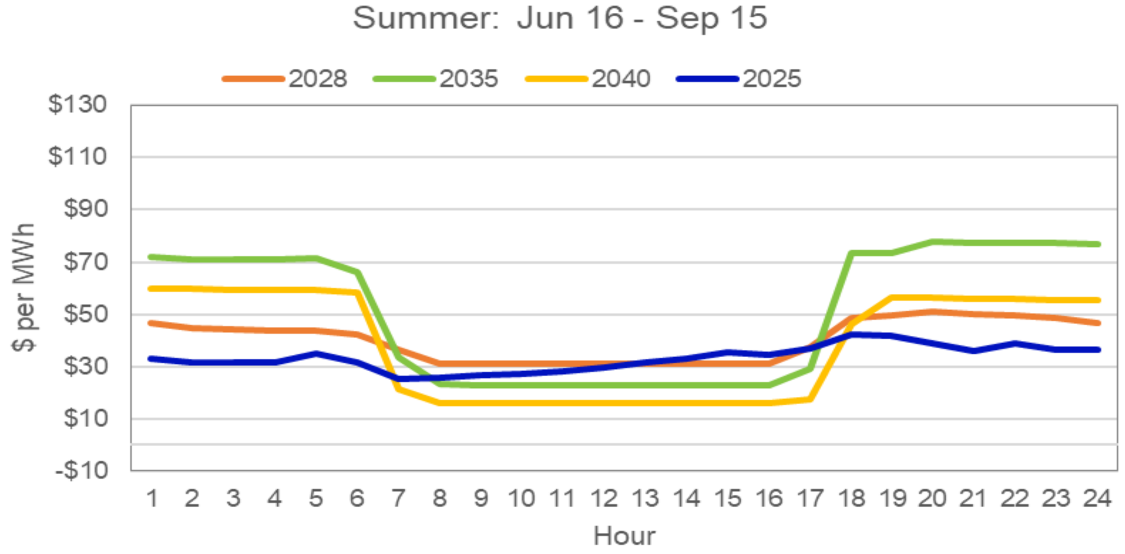
- Levelized Prices:
  - $44.95/MWh w/CCA
  - $40.80/MWh w/o CCA
  - $37.95/MWh Avista
- Forecast includes expected resource additions
- Potential for increased prices if new resources don't come online

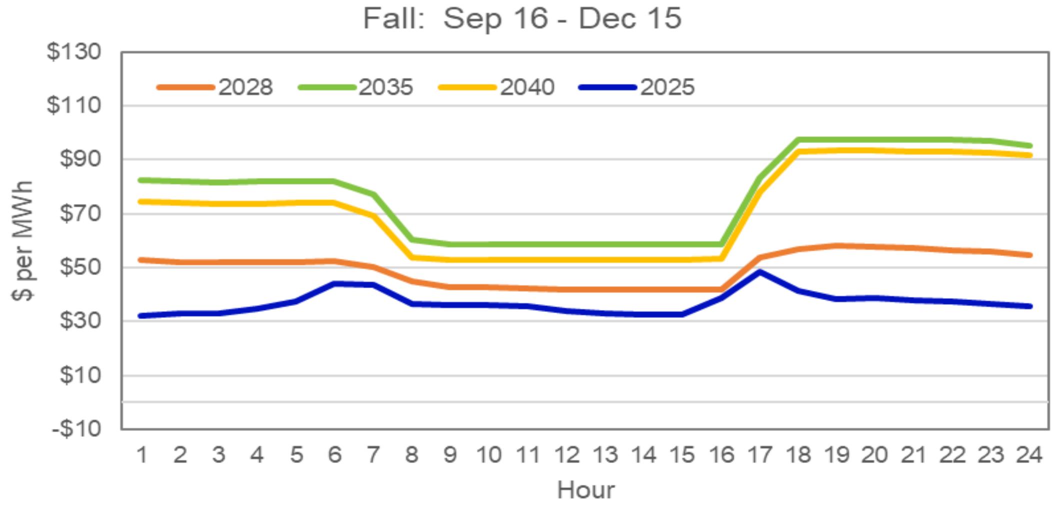
Hourly

Draft forecast









Next Steps

- Finalize deterministic case
- Conduct stochastic studies and verify resource adequacy
- Run scenarios (deterministic/stochastic as appropriate)