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2027 Electric and Natural Gas Integrated Resource Plans

Technical Advisory Committee Meeting No. 12 Agenda

Wednesday, July 15, 2026

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

Topic	State	Audience
• Introduction and Questions from TAC 11		
• Resource Adequacy Analysis	WA/ID	Electric
• Electric Load & Resource Balance Methodology	All	Electric
• Non-Energy Impacts	All	E&G
• Draft Preferred Resource Strategy Results	All	Electric

Microsoft Teams meeting
Join: https://teams.microsoft.com/meet/281784079089866?p=dTRvinf5f4CrWB6MIw
Meeting ID: 281 784 079 089 866
Passcode: zB6J2mZ2

Need help? | System reference
Dial in by phone
+1 509-931-1514,,181108978# United States, Spokane
Find a local number
Phone conference ID: 181 108 978#
For organizers: Meeting options | Reset dial-in PIN

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Introductions 2027 Electric & Gas Integrated Resource Planning

TAC 12 – July 15, 2026

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

TAC 12 Agenda

- Introduction and Questions from TAC 10
- Resource Adequacy Analysis
- Electric Load & Resource Balance Methodology
- Non-Energy Impacts
- Draft Preferred Resource Strategy Results

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

Questions from May TAC – Idaho Gas Efficiency Filing

1. What are the impacts on Oregon and Washington if Idaho gas efficiency programs are discontinued?
   - Energy Efficiency employees directly assign their time based on the work they perform.
   - Idaho gas program is a small piece of our overall conservation efforts
   - Administrative cost impacts to other programs should be minimal
   - Continued trailing costs as Idaho gas programs sunset and honoring existing contracts
   - Can continue charging admin costs to Idaho gas, as programs may resume and tariff dollars are available

- Will Avista propose anything from an IRP perspective in the filing?
  - Filing made on June 12, 2026 (Case NO. AVU-G-26-01) and did not propose anything IRP related.
  - Staff questions about restarting the programs if avoided costs allow cost-effective programs, which we will do.
  - From an IRP perspective, the avoided costs from the IRP inform these decisions.

TAC 11 Technical Modeling Workshop – Rescheduling, TBD		
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 13 – Monday, August 17, 2026 (13:00 – 16:00 PDT)		
Topic	**State**	**Audience**
ETO Energy Savings	OR	Gas
Preferred Resource Strategy Results	All	E & G
Oregon Non-Pipe Alternatives	OR	Gas
IRP/Progress Report Outlines	All	E & G
Next Steps	All	E & G

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September 17 – 18, Avista GRC Hearings

TAC 14 – Thursday, September 17, 2026 (13:00 – 16:00 PDT) Reschedule?		
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/ID	Electric

Other Key 2027 IRP 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

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Resource Adequacy Analysis

TAC 12 – July 15, 2026

Mike Hermanson – Senior Power Supply Analyst

Topics

- Methodology
- Resource Adequacy (RA) Metrics
- Market Reliance
- Resource Adequacy (RA) Analysis Results
- Planning Reserve Margin (PRM)
- Next Steps

Methodology

- Goal is to run the system with varied inputs with instances that stress the system (low water, high load, outage on large resource, etc.) to test whether there is sufficient capacity to still meet load.
- Monte Carlo simulation with stochastic inputs
- Stochastic inputs:
  - Hydro – 30 Year Rolling Average (2028-2050)
  - Wind – 30 correlated wind shapes
  - Load shapes – 10 1-year hourly load shapes, and forecasted peak and energy
  - Weather – a trend of the last twenty years was used to develop the peak forecast
  - Forced outages – forced outage varies by unit, but generally around 5%
- 1,000 simulations are run with varied stochastic inputs and each hour the system cannot meet load the quantity of the short fall is recorded.

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Methodology

- Changed model for 2027 RA analysis
  - The 2025 IRP RA analysis used an Excel based model with a third-party solver (ARAM). It simulates our system at an hourly time step with stochastic inputs.
  - The 2027 IRP RA analysis utilizes an Aurora model in place of ARAM. The Aurora model is based on the model we use for other parts of the IRP and is more efficient than the Excel model.
  - We used the 2030 resource portfolio and load from the 2025 IRP and did an RA analysis using the Aurora model and compared it to the results from the ARAM Model to ensure results from the Aurora model would be comparable to the values from past IRPs.

RA Metrics

- Metrics
  - **LOLP** – *Loss of Load Probability*: Calculated by counting the number of iterations where there is unserved load and dividing by the total number of iterations.
    - *Can be used to determine the probability or likelihood of events due to insufficient capacity. In the 2025 IRP we used **0.05 LOLP** as the target for reliability*
  - **LOLE** – *Loss of Load Expectation:* Calculated by counting the days where there is unserved load and dividing by the total number of iterations.
    - *Used to establish if a system has sufficient capacity. The industry standard is **0.1 LOLE** per year.*
  - **LOLH** – *Loss of Load Hours:* Calculated by summing the number of hours with unserved load or unmet reserves and dividing by the total number of iterations.
    - *LOLH is computed by a large number entities in the North America, however it is not often used as a reliability criterion.*
  - **EUE** – *Expected Unserved Energy:* Calculated by summing all of the unserved MWhs over the study period and dividing by the number of iterations.
    - *EUE is useful in estimating the size of the loss of load events so planners can estimate the cost and impact of loss of load events*

Source: NERC, Probabilistic Adequacy and Measures Report, July 2018

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2030 Comparison from 2025 IRP

- Comparison of the ARAM and Aurora RA model

Metric	ARAM	Aurora RA
Loss of Load Probability (LOLP)	0.07	0.07
Loss of Load Expectation (LOLE)	0.23	0.23
Loss of Load Hours (LOLH)	2.586	2.541
Expected Unserved Energy (EUE)	468	450

Market Reliance

- A key consideration is determining how much the model is allowed to rely on market purchases to serve load.
- There is no industry standard for the amount of market purchases allowed in an RA study.
- 330 MW is utilized in the 2027 IRP RA study, which is based on a number of considerations.

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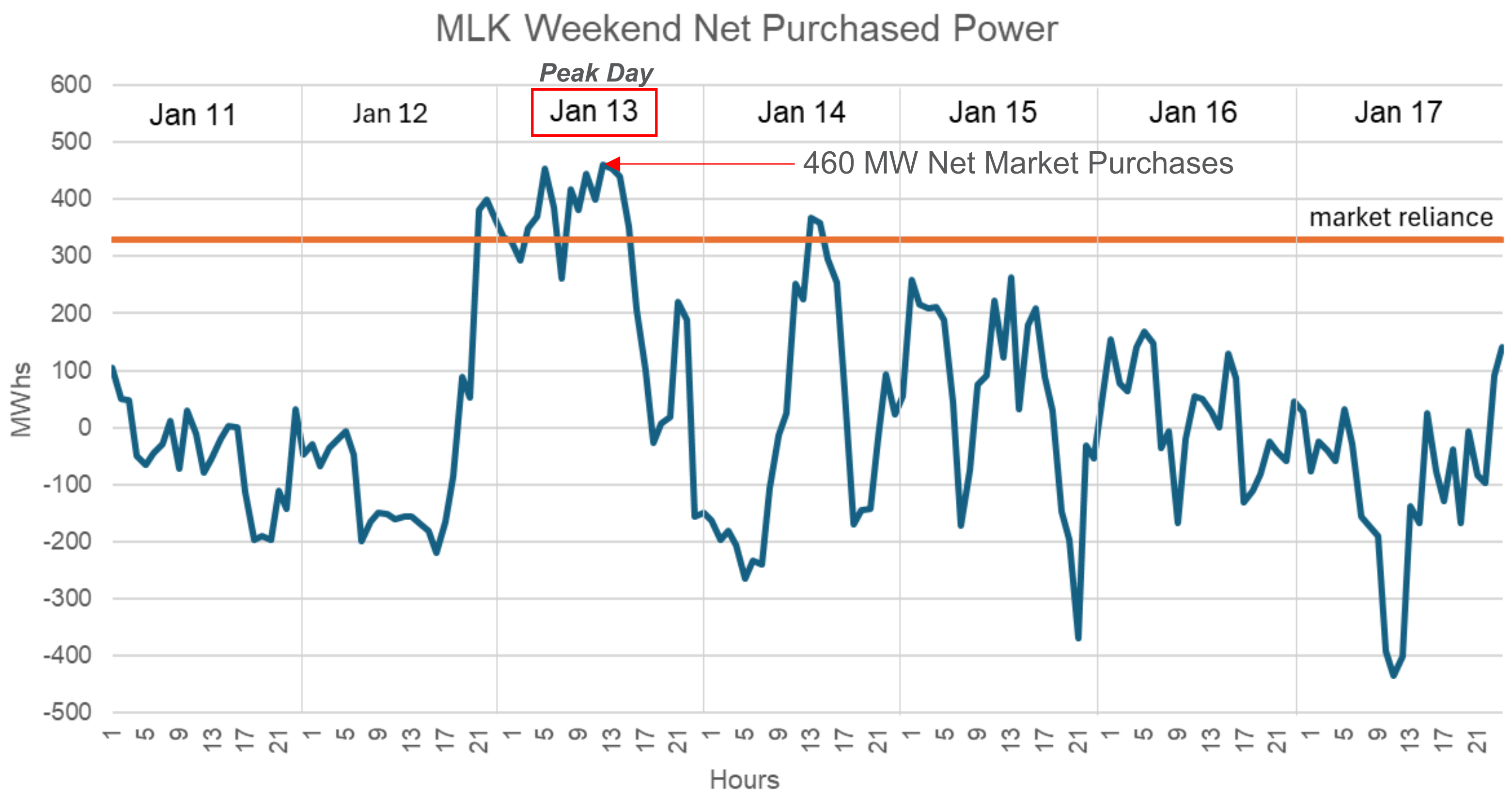
Market Reliance During January 2024 MLK Winter Event



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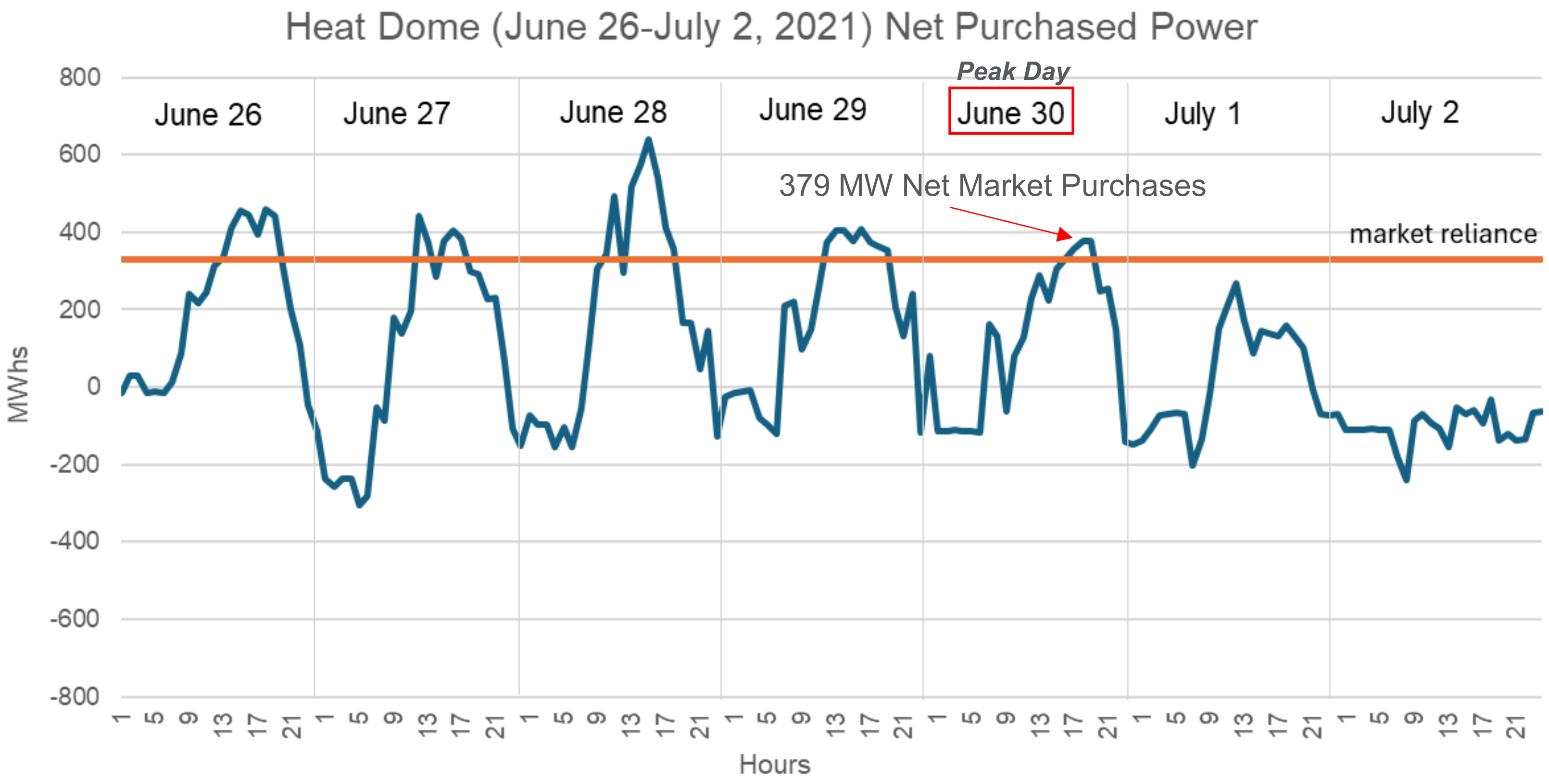
Market Reliance During June 2021 Heat Dome Event



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Market Reliance

- The WRAP methodology was used to calculate our market reliance. Winter is 480 MW and Summer is 353 MW.

- Avista's portion of regional studies was also evaluated:
  - The NWPCC RA study assumed a winter market reliance of 2500 MW, and 1,250 MW for the summer. Avista is 4.7% of the region's load so the summer market reliance would be 58.75 and the winter market reliance would be 117.5.
  - The E3 Resource Adequacy study assumed a market reliance limit of 3,750 MW for the region. Avista's portion of that would be 115 MW
  - The NWPCC evaluated the 2024 MLK weekend event and determined there were 6,500 of net imports. Avista's portion of that is 306 MW.

- Transmission
  - Avista has firm transmission of 1,199 MW for imports/exports to and from our system which is sufficient to support our 330 MW market reliance modeling assumption.

RA Analysis Results

- The model was run with 2028 current resources, additions from the most recent all source RFP, and retirements that occur during the analysis period along with growth in peak load.

RA Analysis Results

Year	LOLP	LOLE	LOLH	EUE	Winter LOLE	Summer LOLE
2028	0.048	0.104	0.865	124	0.069	0.035
2029	0.065	0.147	1.282	205	0.101	0.046
2030	0.054	0.095	0.689	90	0.042	0.053
2031	0.088	0.152	1.220	172	0.081	0.071
2032	0.069	0.136	0.904	121	0.030	0.106
2033	0.066	0.130	0.967	150	0.029	0.101
2034	0.171	0.377	3.083	537	0.169	0.208
2035	0.203	0.496	4.016	587	0.321	0.175
2036	0.314	0.875	7.421	1,263	0.470	0.405
2037	0.342	1.057	8.396	1,527	0.477	0.580
2038	0.456	1.562	12.441	2,266	0.757	0.805
2039	0.661	2.961	23.054	4,632	1.217	1.744
2040	0.732	5.496	57.886	12,097	2.414	3.082
2041	0.977	14.339	110.691	25,117	6.737	7.602
2042	1.000	90.613	990.167	280,532	57.147	34.466

- In previous IRPs the reliability target was 0.05 LOLP, in the 2027 IRP the reliability target is 0.01 LOLE per month, which matches the WRAPs reliability target.

2035 RA Analysis Results with Current Resources

- The following chart presents the sum of the hourly average loss of load over 1,000 iterations by month and hour in MWhs

2035 No Additional Resources

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	2.2	1.7	1.5	1.8	1.8	3.4	7.3	13.4	14.7	13.5	13.5	9.6	7.6	8.7	7.8	7.6	12.2	22.4	20.3	16.7	11.6	5.0	2.5	1.4
2	1.1	1.1	0.7	0.7	1.3	2.5	5.5	6.6	5.5	5.3	4.1	2.9	2.9	2.6	2.0	1.3	3.0	5.8	5.5	4.6	4.6	2.6	1.9	0.6
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.6	0.9	1.3	1.9	1.3	0.3	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.4	2.9	9.9	12.7	18.9	16.9	20.8	22.3	22.3	16.9	7.5	2.3	1.3	0.4	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.1	0.0
11	0.1	0.2	0.1	0.1	0.2	0.6	2.3	4.0	4.1	4.5	4.4	3.1	3.7	2.9	2.4	2.7	6.2	8.6	7.3	4.9	4.4	1.8	0.7	0.3
12	2.7	1.9	1.8	1.7	1.9	1.6	3.0	3.4	3.5	3.8	3.9	3.2	2.8	2.8	3.5	3.1	4.4	3.8	4.5	3.9	2.8	2.1	2.0	1.7

Planning Reserve Margin

- The planning reserve margin (PRM) is the extra generating capacity a system requires above its expected peak demand.
- To own generating capacity or contracts to cover every contingency is too costly, so we allow some probability that a loss of load event will occur.
- We use the same reliability target as WRAP, which is 0.01 LOLE per month, and focus on additional perfect capacity that results in 0.01 LOLE in January and August.

Planning Reserve Margin

- Loads and resources in 2035 were used to develop the PRM.
- In 2035, without additional resources, the yearly LOLE is 0.496 or a monthly LOLE of 0.0413, so there is not enough capacity to reach our reliability target of 0.01 monthly LOLE in January and August, the highest peak load months
- The first step in determining the PRM is to add pure capacity in an iterative process until 0.01 LOLE in January and August is reached.
- The result is that an additional 182 MW of pure capacity is required in January and 225 MW in August to get to a monthly LOLE of 0.01.

2035 RA Analysis Results with Capacity Additions

- The following chart presents the sum of the hourly average loss of load over 1,000 iterations by month and hour in MWhs
- Capacity was added to achieve a 0.01 LOLE per month

2035 with 182 MW of Winter Capacity and 225 of Summer Capacity

	Hour																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1	0.1	0.1	0.1	0.1	0.2	0.6	0.4	1.6	2.2	1.4	1.4	0.9	1.2	1.3	1.6	1.4	2.5	4.0	4.2	3.2	1.7	0.7	0.4	0.2
2	0.1	0.0	0.0	0.0	0.1	0.2	0.8	0.9	0.5	0.2	0.4	0.0	0.0	0.0	0.0	0.0	0.3	0.7	1.1	1.3	0.3	0.4	0.4	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	2.7	3.8	4.8	4.3	6.1	5.4	5.3	4.1	1.6	0.8	0.4	0.1	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.0	0.2	0.2	0.1	0.1	0.0	0.2	0.2	0.1	0.1	0.2	0.1	0.0	0.0
12	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.3	0.3	0.1	0.4	0.3	0.3	0.2	0.1	0.0

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Planning Reserve Margin

- Calculation of the Planning Reserve Margin:

$$\left[\frac{\text{Portfolio QCC + Pure Capacity}}{\text{Net Load}}\right] -1 = \text{PRM}$$

Month	2035 Peak Load	DR Load Reduction	Net Load	2035 Total QCC	Pure Capacity	Planning Reserve Margin	Proposed Planning Reserve Margin	2025 IRP Planning Reserve Margin
January	2,021	-41	1,980	2,306	182	25.66%	26%	24%
August	2,126	-51	2,075	2,190	225	16.41%	17%	16%

Next Steps

- Once the Preferred Resource Strategy (PRS) is finalized, those resources will be added to the RA model.
- The model will be run for the entire IRP study period to determine if the PRS meets reliability requirements.
- Selected scenarios will also be run to determine if they meet reliability requirements.

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Loads & Resources Methodology - Electric

TAC 12 – July 15, 2026

Jon Lee, Resource Planning Analyst

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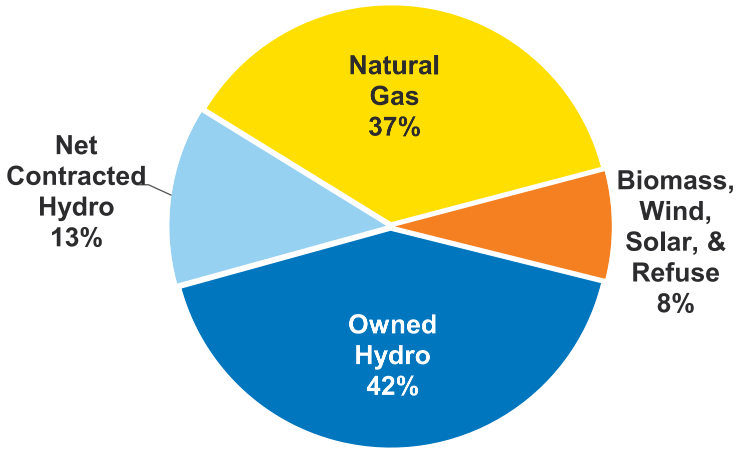
Peak Planning Assumptions

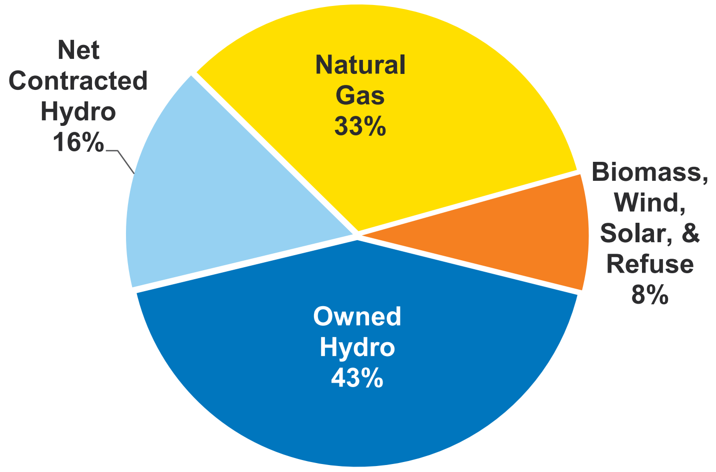
- Peak load forecast (as discussed in TAC 10)
  - Utilized growth rate of Cadmus peak forecast applied to the base value to estimate monthly peak load for the study period
  - Added in EVs, customer solar, energy efficiency, and large industrials
  - Demand Response programs reduced Total Obligation (per WRAP's methodology)
- Planning reserve margins
  - Winter – 26% (2025 IRP 24%)
  - Summer – 17% (2025 IRP 16%)
  - Inclusive of Regulation (10 MW) and Operating Reserves
- Used the WRAP's Qualifying Capacity Credits (QCC) for generation and demand response resources
  - Not incorporating the WRAP's planning reserve margins, but will share how they compare to the above PRMs (slide 9)
- Developed a maintenance plan for Thermals and Hydro units
  - 10-year history of planned maintenance by Plant/Unit to develop a reoccurring monthly average by hours out x plant capacity
- Including RFP-selected resources in our assumptions as they continue to work through the contract negotiation phase (final results may vary as a result)

Avista System Seasonal Capability

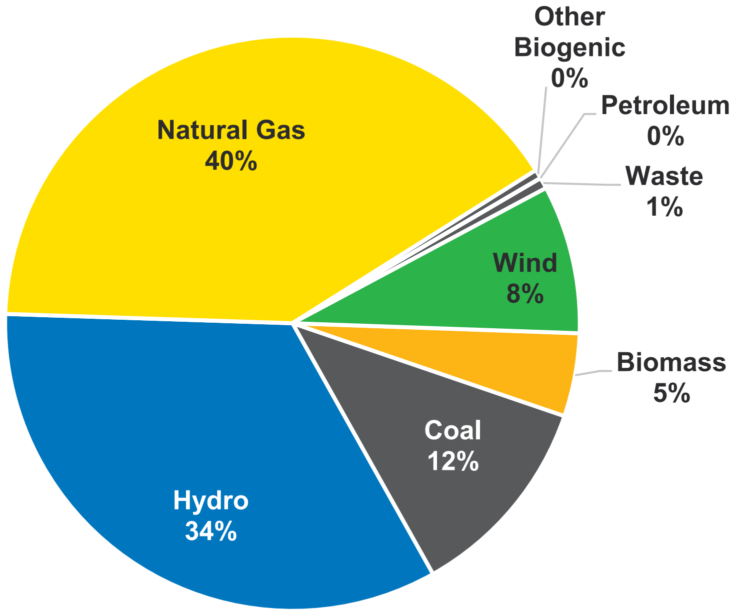
Winter Capability



Summer Capability



Avista's WA State Fuel Mix Disclosure (2024)



*As reported by the Washington State Department of Commerce

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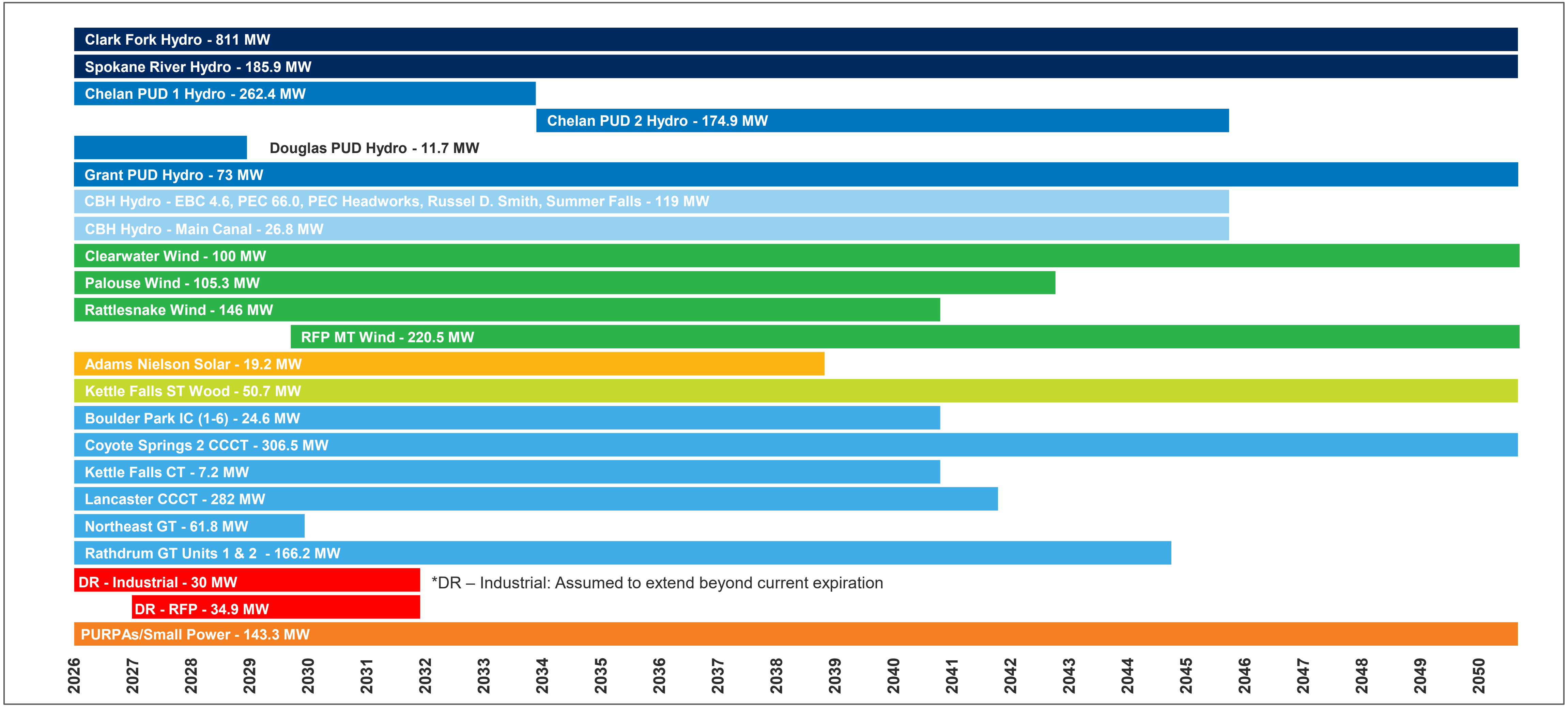
Portfolio Timeline – Owned and Contracted



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WRAP Assigned QCCs by Source

Resource	Summer 2027 QCC (MW)	Winter 27/28 QCC (MW)
Owned Hydro	926.8	979.2
Contracted Hydro	330.9	273.6
Wind	50.0	70.6
Solar	19.5	1.0
Wood	48.7	49.8
CCCT	534.5	597.8
Peakers	193.9	271.2
PURPA/Small Power	69.0	79.7
Demand Response	-42.2	-37.7
Totals	**2,131.0**	**2,285.2**

- WRAP evaluates resource adequacy on a seasonal basis for both summer and winter reliability needs
- Participants submit historic performance and operational data, with ownership and capacity rights
- WRAP runs their reliability models and assigns accredited capacity values by individual resource
- Forward Showings occur approximately 7 months before the applicable season
- Summer 2028 Draft Modeling Outputs expected by 9/15

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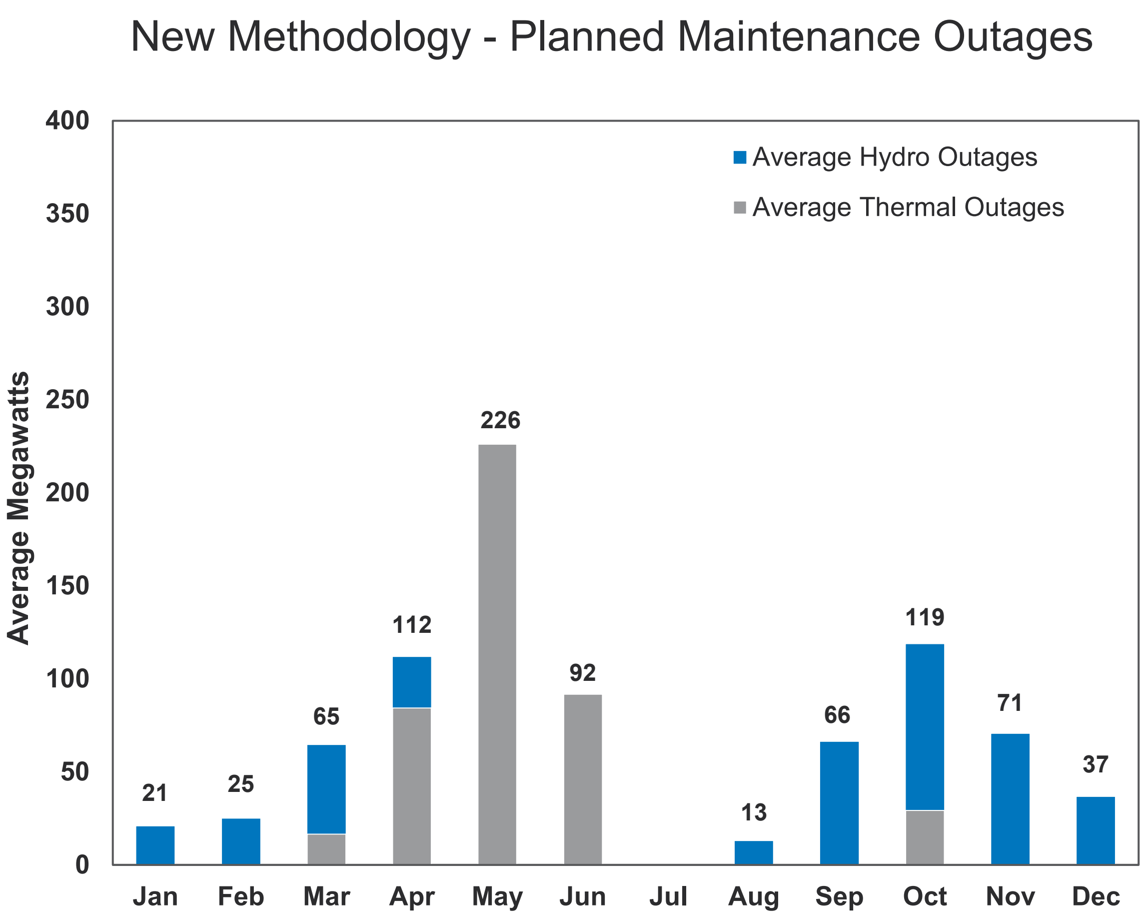
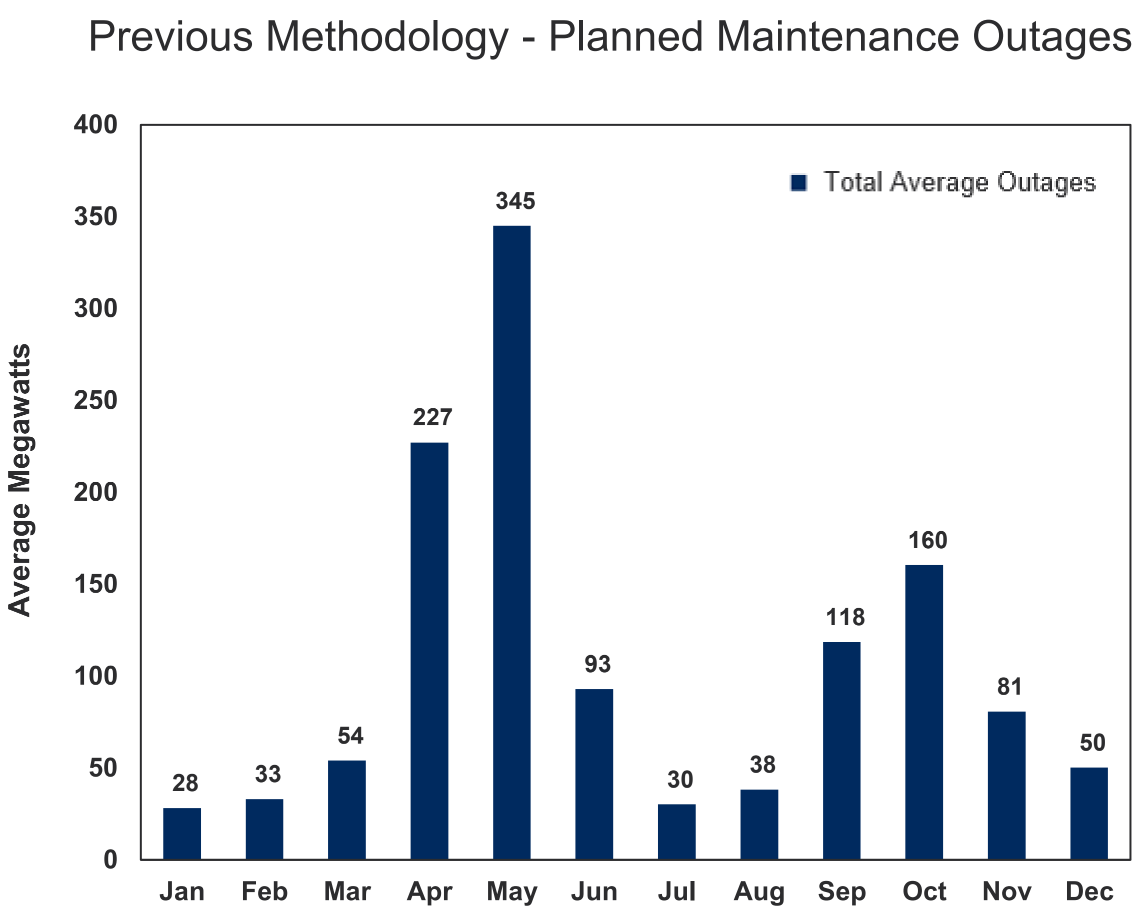
Maintenance Planning





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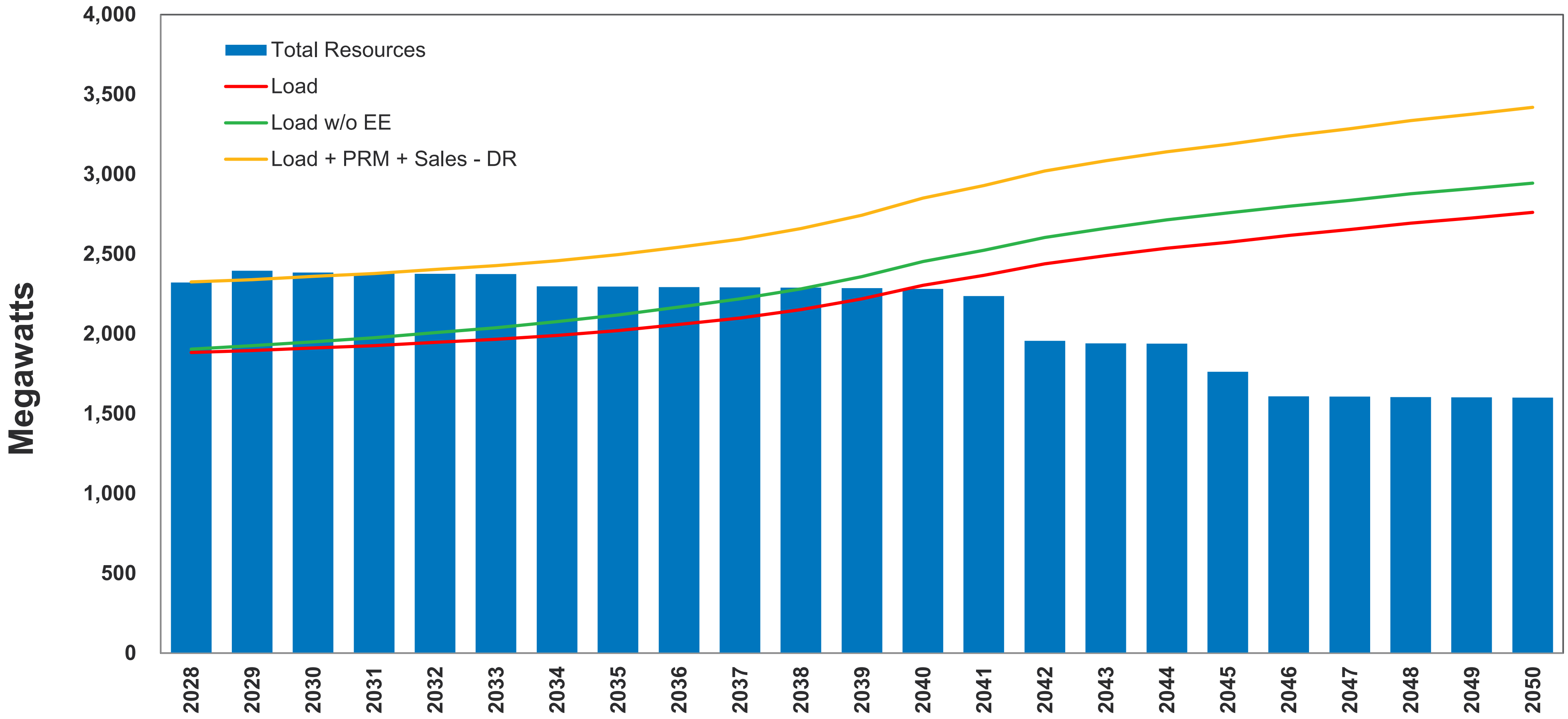
Winter Peak Load & Resource Balance

Moving into a short position beginning 2032



*January Peak

*Note: Does not include North Plains Connector Transmission Project (~218 MW of Import Capability)

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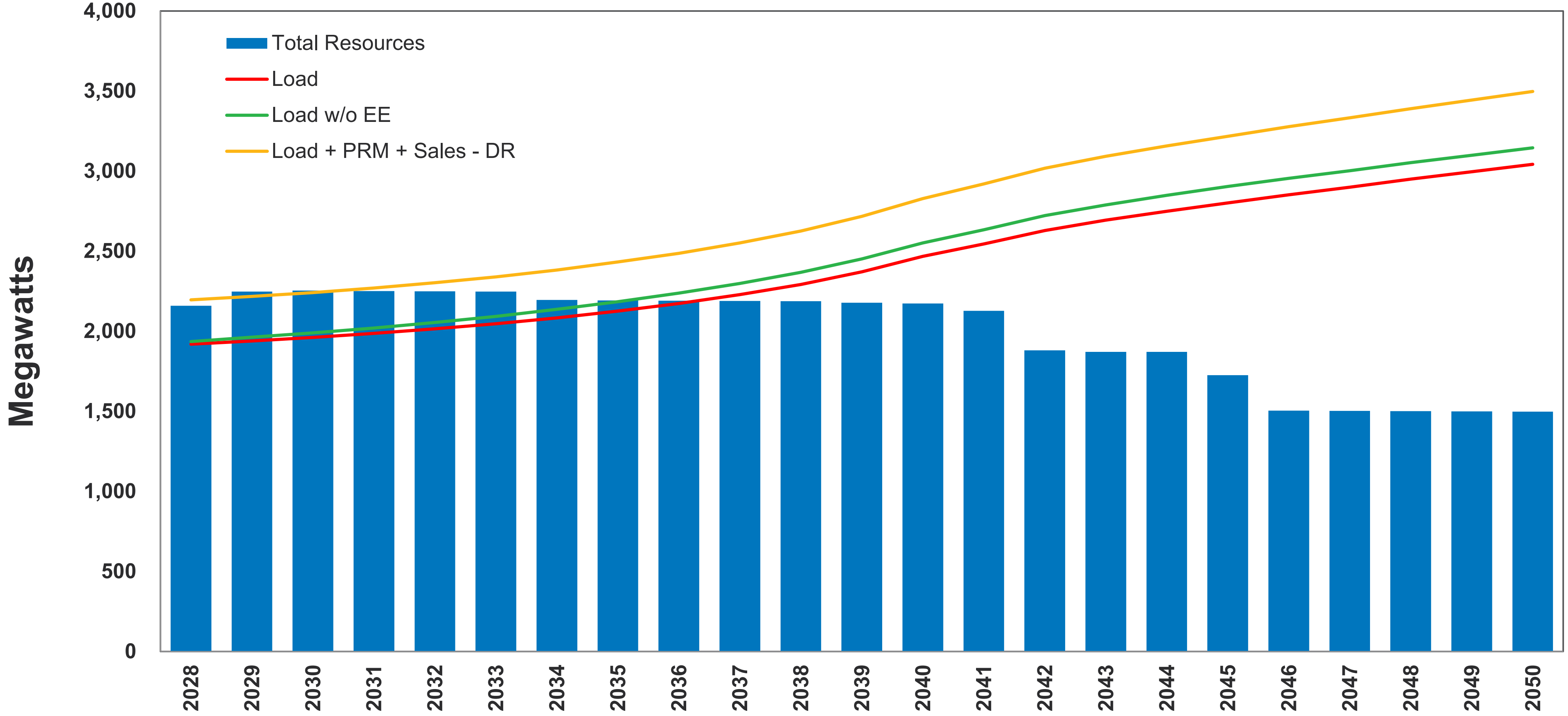
Summer Peak Load & Resource Balance

Short in 2028 and then again beginning in 2031



*August Peak *Note: Does not include North Plains Connector Transmission Project (~218 MW of Import Capability)

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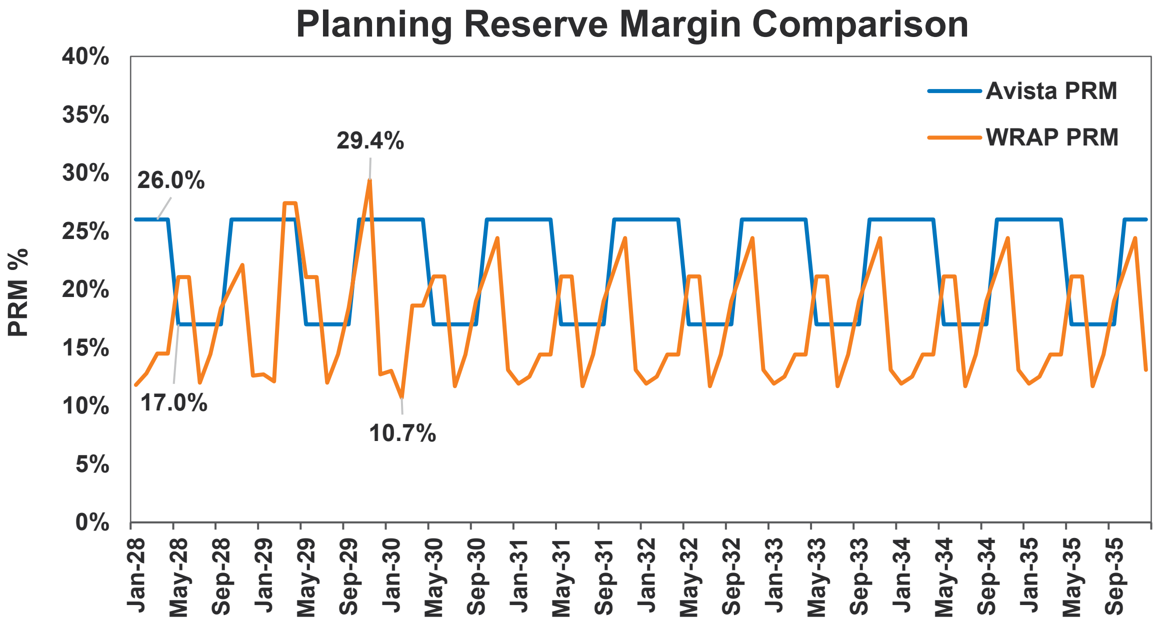
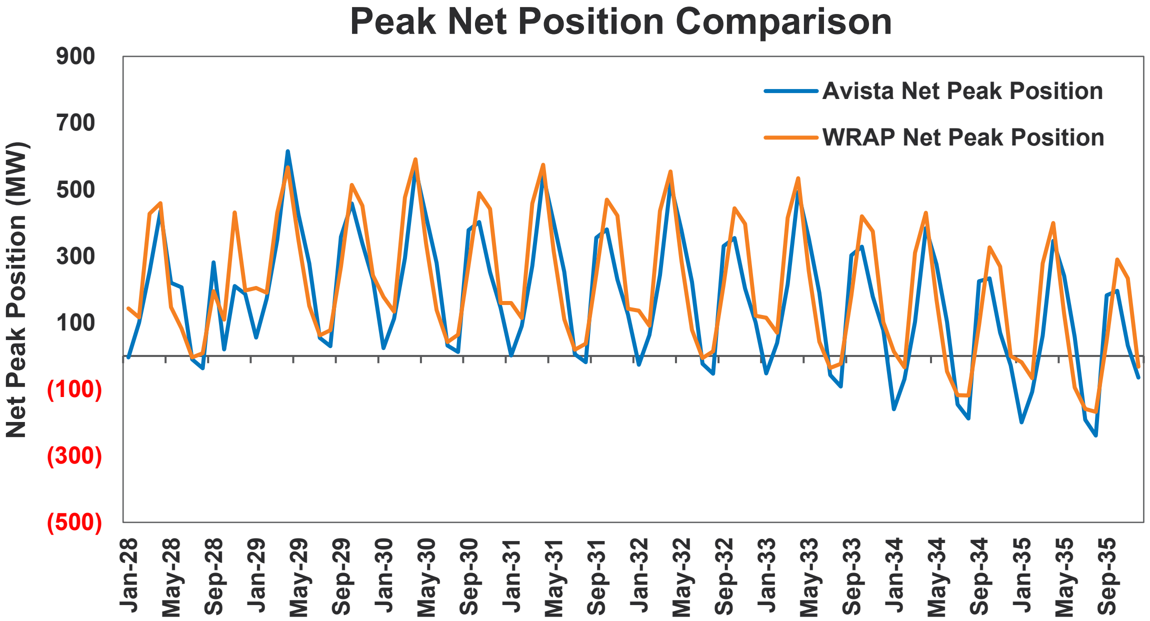
Planning Reserve Margin Comparison

WRAP's PRM is more volatile by month, but lower in the critical peak months





- The WRAP completed Advanced Assessments through winter 2027/28 and used a Load Growth Factor specific to the LOLE Study to estimated PRM to March 2031
- In the study, November contributed the most to the Mid-C weather years driving the 0.1 LOLE
- PRM averaged 12.5% in January and 15.2% in August

WRAP PRM Impact:

- Higher peak net position in January and August, but generally lower in the shoulder months
- Delayed short positions, especially for January

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Energy Planning

- Expected energy load forecast (as discussed in TAC 10)
  - Avista's medium term (5-year) forecast extended to 2050 using Cadmus' growth rate forecast
  - Includes EVs, customer solar, energy efficiency, large industrials, and energy losses
- Production capability generation forecast
  - 30-Year rolling average hydro generation by project
  - Thermal machine hour limits
  - Thermal and hydro maintenance, as well as forced outage rates (thermal)
  - Energy storage discharge and recharge assumptions
- Includes contingency for changes in load and variable generations

Energy Contingency

- Difference between average generation and load conditions with extreme conditions
- Developed a dataset of load and renewables generation (varying hydro, wind and solar) for the period 1948-2025
  - The average, median, 10th percentile, 5th percentile, and 1st percentile of renewable generation
  - The average, median, 90th percentile, 95th percentile, and 99th percentile of load
- Used the 95th percentile minus the Average of the net of load to renewable generation

Energy Contingency for Load and Renewable Variability 2028 (aMW)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg
Previous IRP	232	231	224	268	193	333	320	178	122	124	173	135	211
2027 IRP	238	233	233	283	254	366	366	159	117	109	163	142	222
Change	6	2	9	15	61	33	46	-19	-5	-5	-10	7	11

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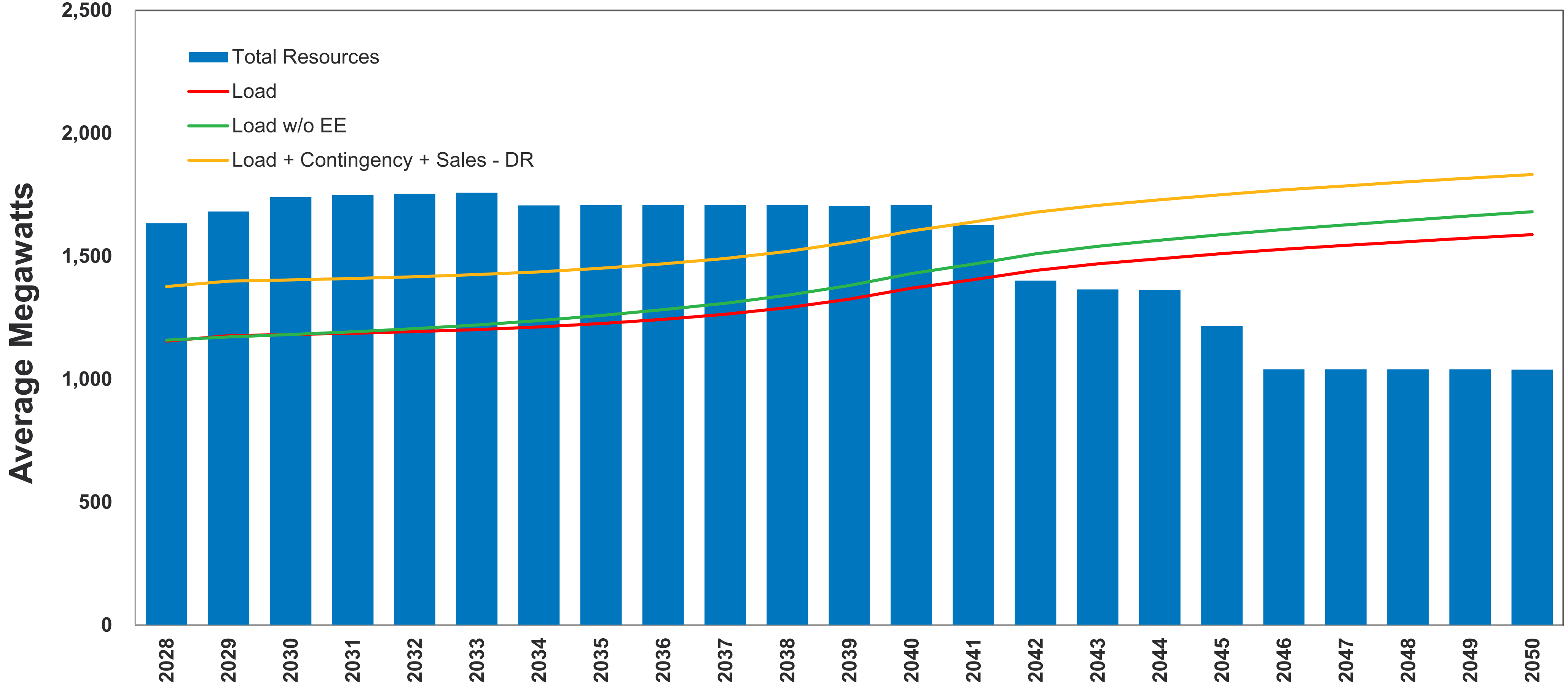
System Planning Energy Position – Monthly (aMW)

In a long energy position until 2041



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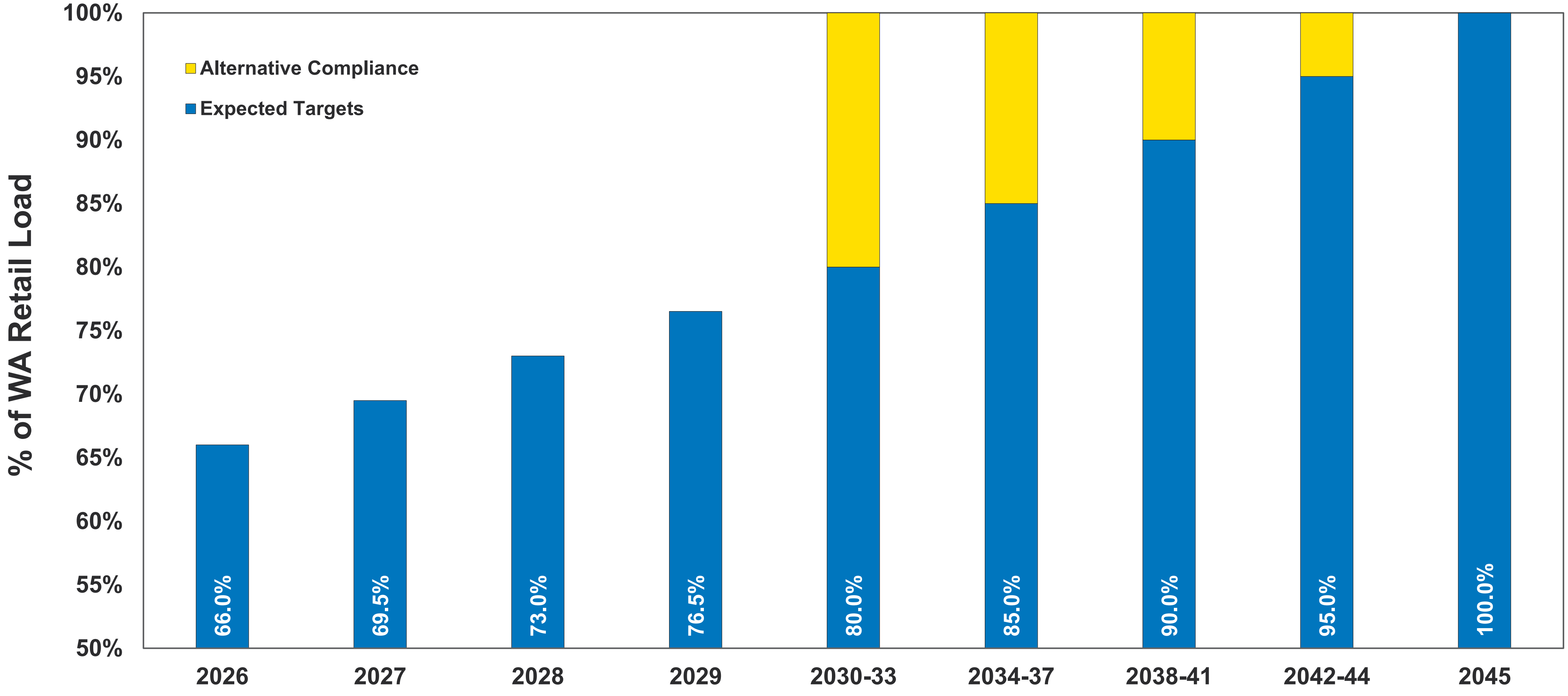
Proposed CETA's Clean Energy Goals



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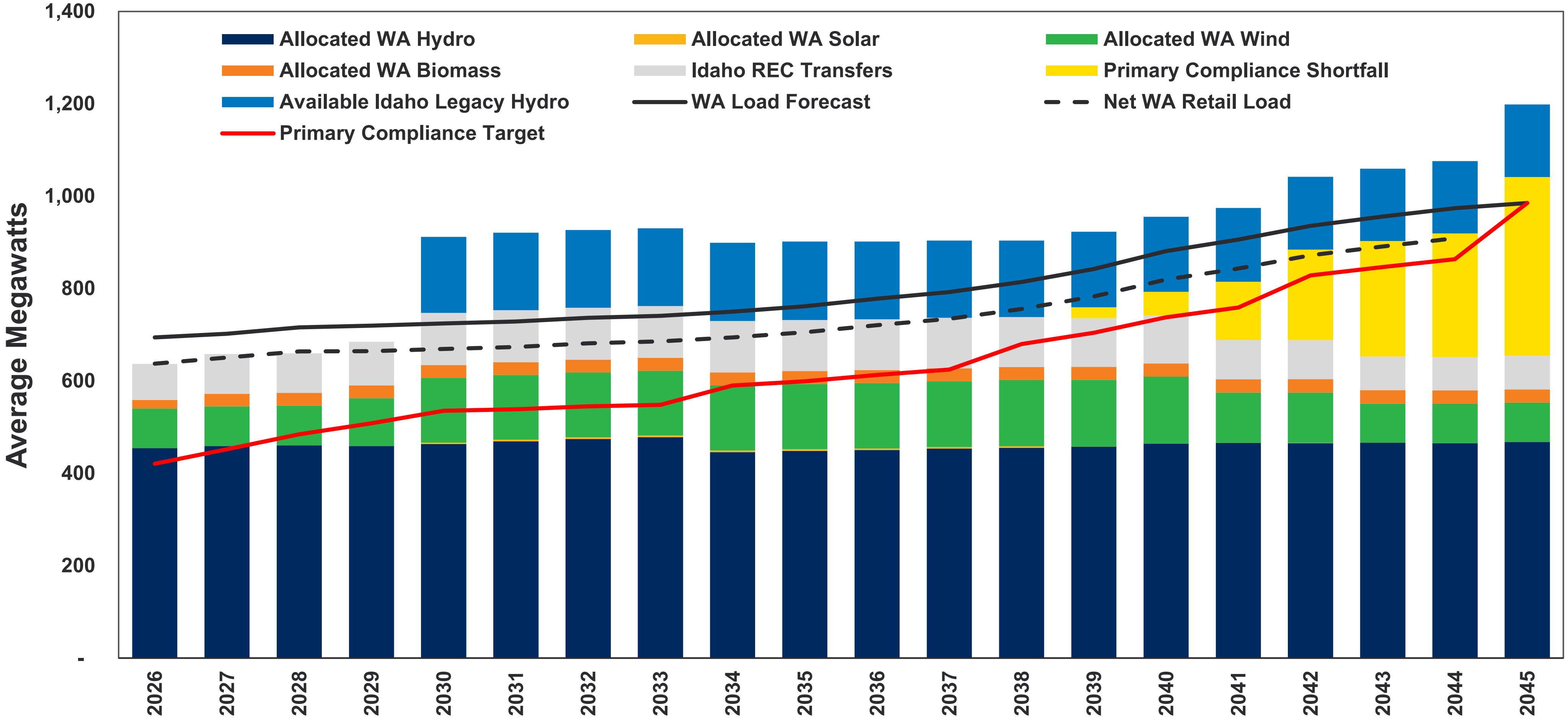
Washington Clean Energy Position

WA allocated resources meet primary compliance target until 2038



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Non-Energy Impacts

TAC 12 – July 15, 2026

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

NEIs Background

- Non-energy impacts or NEIs are the metrics that can be used to approximate environmental, health or safety impacts beyond capital or operating costs of resources
- Last IRPs included NEI costs for safety, health, and economic impacts of different resource types plus estimates of societal costs of CO_2e, SO_2, NO_x and PM2.5.
- Will not include the economic impacts in the 2027 IRPs
  - IMPLAN program used to estimate the impacts used the same factors when calculating different resource types. This led to no differentiation between the impact per MWh between a gas plant or a solar plant.
- NEIs may change if we are able to get additional data

2028 Costs of Emissions

Resource	NOx	SOx	PM2.5
Northeast Eastern	$ 5,975	$ 12,715	$ 44,887
Spokane County	$ 7,492	$ 14,023	$ 92,734
Rural Oregon	$ 3,953	$ 17,213	$ 32,179
North Idaho	$ 7,657	$ 15,412	$ 78,738

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Electric Resource Safety NEI

Resource	Safety ($/MWh)
Solar (Washington)	0.29
Solar (Out of State)	
Wind (Washington)	0.59
Wind (Out of State)	
Natural Gas SCCT	0.19
Natural Gas CCCT	
Power to Gas SCCT	
Storage	N/A
Wood Biomass	0.24
Small Modular Nuclear Reactor	0.16
Pumped Hydro	0.38
Hydrogen Fuel Cell	0.18
Geothermal	0.18

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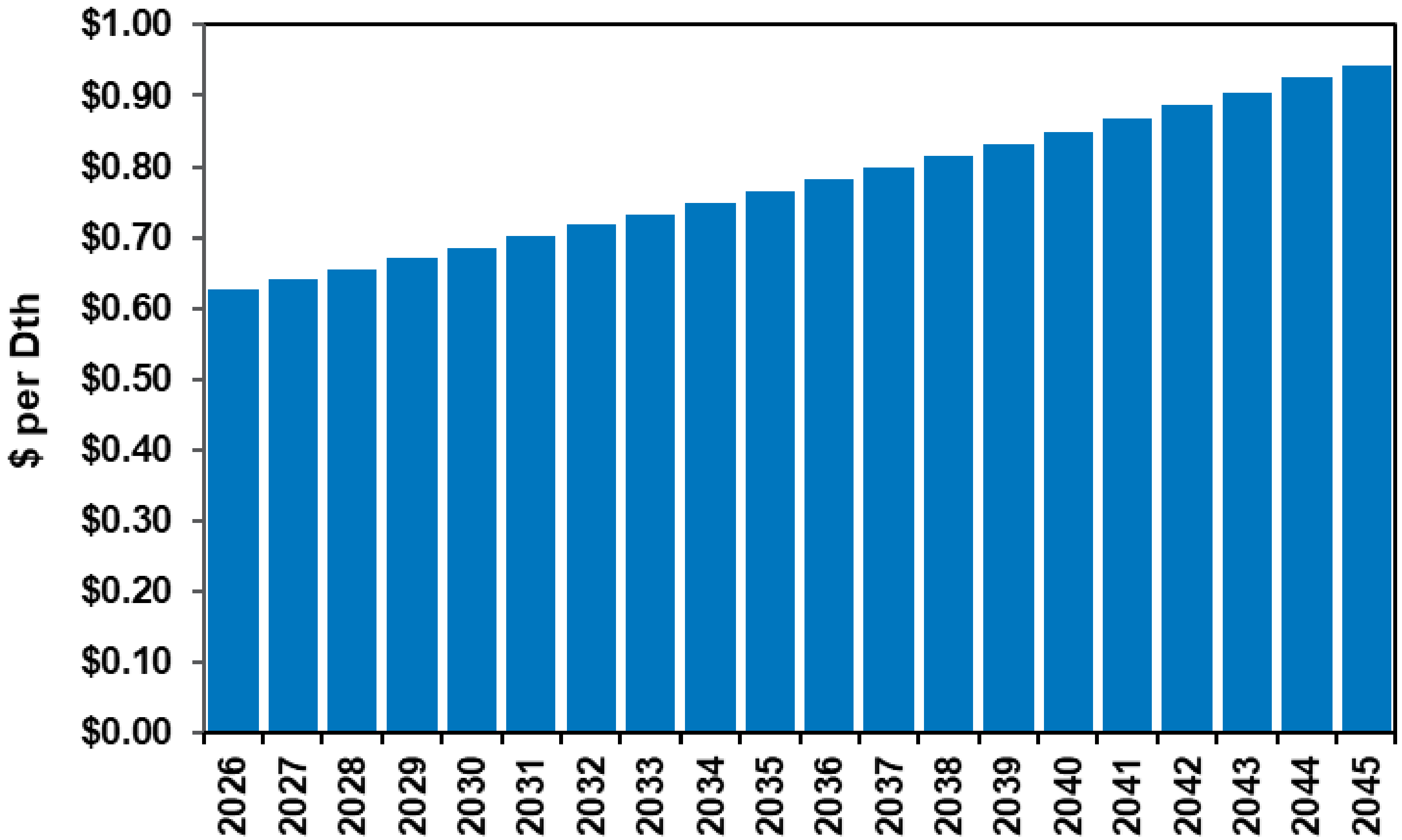
Gas Customer Safety Impact



Avista LDC Specific Natural Gas Emissions

Combustion	Avista Specific Natural Gas	
	lbs. GHG/MMBtu	lbs. CO2e/MMBtu
CO_2	116.88	116.88
CH_4	0.0022	0.06556
N_2O	0.0022	0.6006
Total Combustion		117.61
Upstream		
CH_4	0.406	12.55
Total		130.09

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Social Cost of Carbon (TAC 4 – January 2026)

- WUTC DOCKET U-190730 ORDER 06 – "Greenhouse gas emissions impact costs throughout the economy, and the broad measure of the BEA's GDP price index thus appropriately reflects inflation of the cost of greenhouse gas emissions."

Table 1: Adjusted Cost of Greenhouse Gas Emissions

Year	*Social Cost of CO2 (using 2.5% discount rate in 2007 dollars)	**GDP Index (2007 dollars/metric ton)	**GDP Index (2024 dollars/metric ton)	Inflation Adjusted Social Cost of CO2 (using 2.5% discount rate in 2024 dollars)
2010	$50	86.352	125.231	**$73**
2015	$56	86.352	125.231	**$81**
2020	$62	86.352	125.231	**$90**
2025	$68	86.352	125.231	**$99**
2030	$73	86.352	125.231	**$106**
2035	$78	86.352	125.231	**$113**
2040	$84	86.352	125.231	**$122**
2045	$89	86.352	125.231	**$129**
2050	$95	86.352	125.231	**$138**

https://apiproxy.utc.wa.gov/cases/GetDocument?docID=30&year=2019&docketNumber=190730

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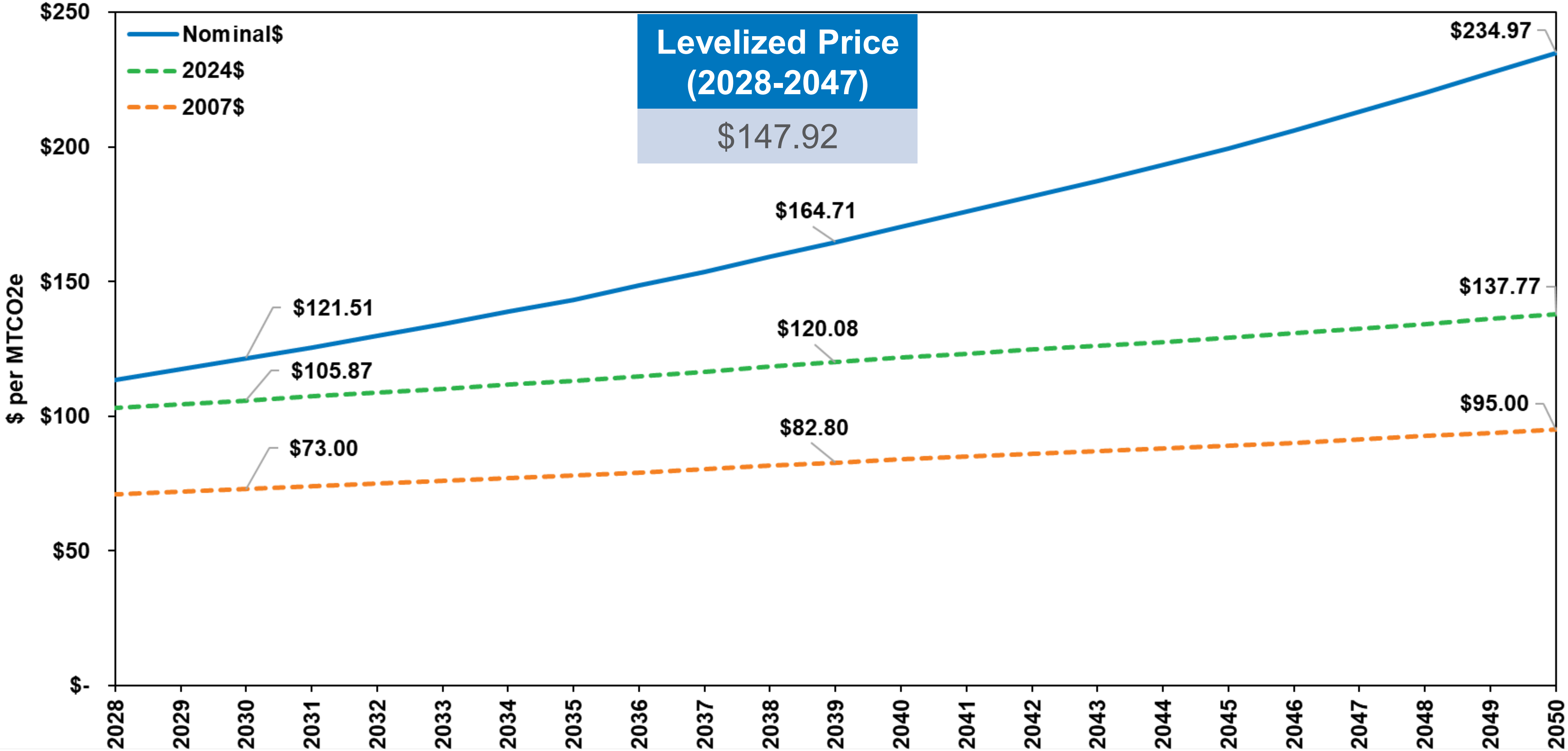
Social Cost of Carbon – Forecast (TAC 4 – Jan. 2026)



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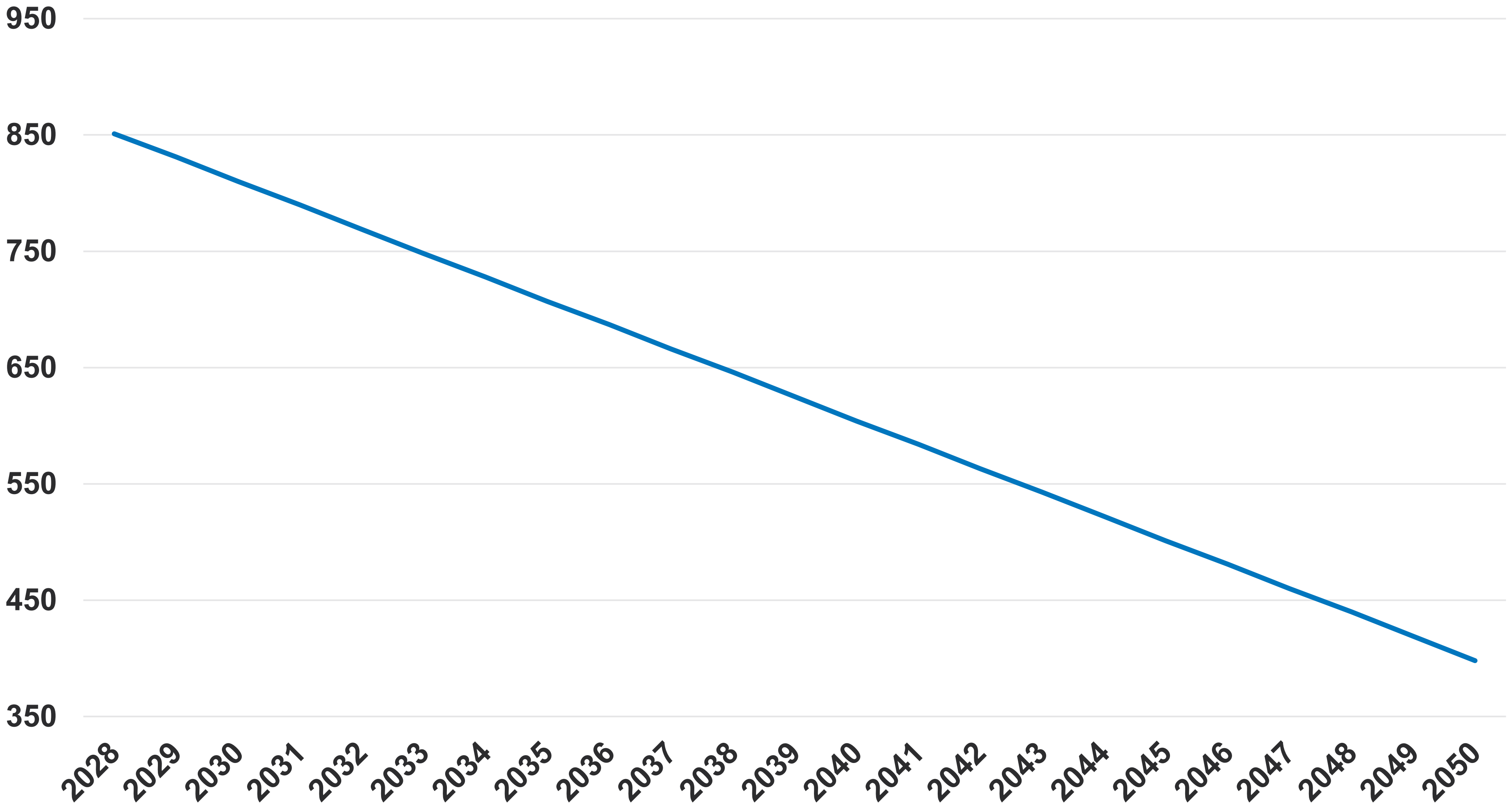
WA Greenhouse Gas Emissions Benefit EE



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Electric Preferred Resource Strategy - Draft

TAC 12 – July 15, 2026

Jacob Heimbigner – Resource Planning Analyst

PRS Resources

- PRS modeling is still in process – slides will be available at the TAC 12 meeting on July 15, 2026