2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 8 Agenda

Tuesday, June 4, 2024

Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Electrification Scenarios	James Gall
New Resources Options Costs and Assumptions	Michael Brutocao
2030 Loss of Load Probability Study	Mike Hermanson
Load & Resource Balance and Methodology (Moved to TAC 9)	Lori Hermanson

2025 IRP TAC 8 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 8
June 4, 2024

Today’s Agenda

Introductions, John Lyons

Electrification Scenarios, James Gall

New Resources Options Costs and Assumptions, Michael Brutocao

2030 Loss of Load Probability Study, Mike Hermanson

Load & Resource Balance and Methodology, Lori Hermanson
(Will be covered in TAC 9 meeting)

Remaining 2025 Electric IRP TAC Schedule

- **TAC 9: June 18, 2024: 8:30 to 10:00 (PTZ)**
  - Load & Resource Balance and Methodology
  - IRP Generation Option Transmission Planning Studies
  - Distribution System Planning within the IRP & DPAG update

- **Technical Modeling Workshop: June 25, 2024: 9:00 am to 12:00pm (PTZ)**
  - PRiSM Model Tour
  - ARAM Model Tour
  - New Resource Cost Model

- **TAC 10: July 16, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Washington Customer Benefit Indicator Impacts
  - Resiliency Metrics

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

Remaining 2025 Electric IRP TAC Schedule

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

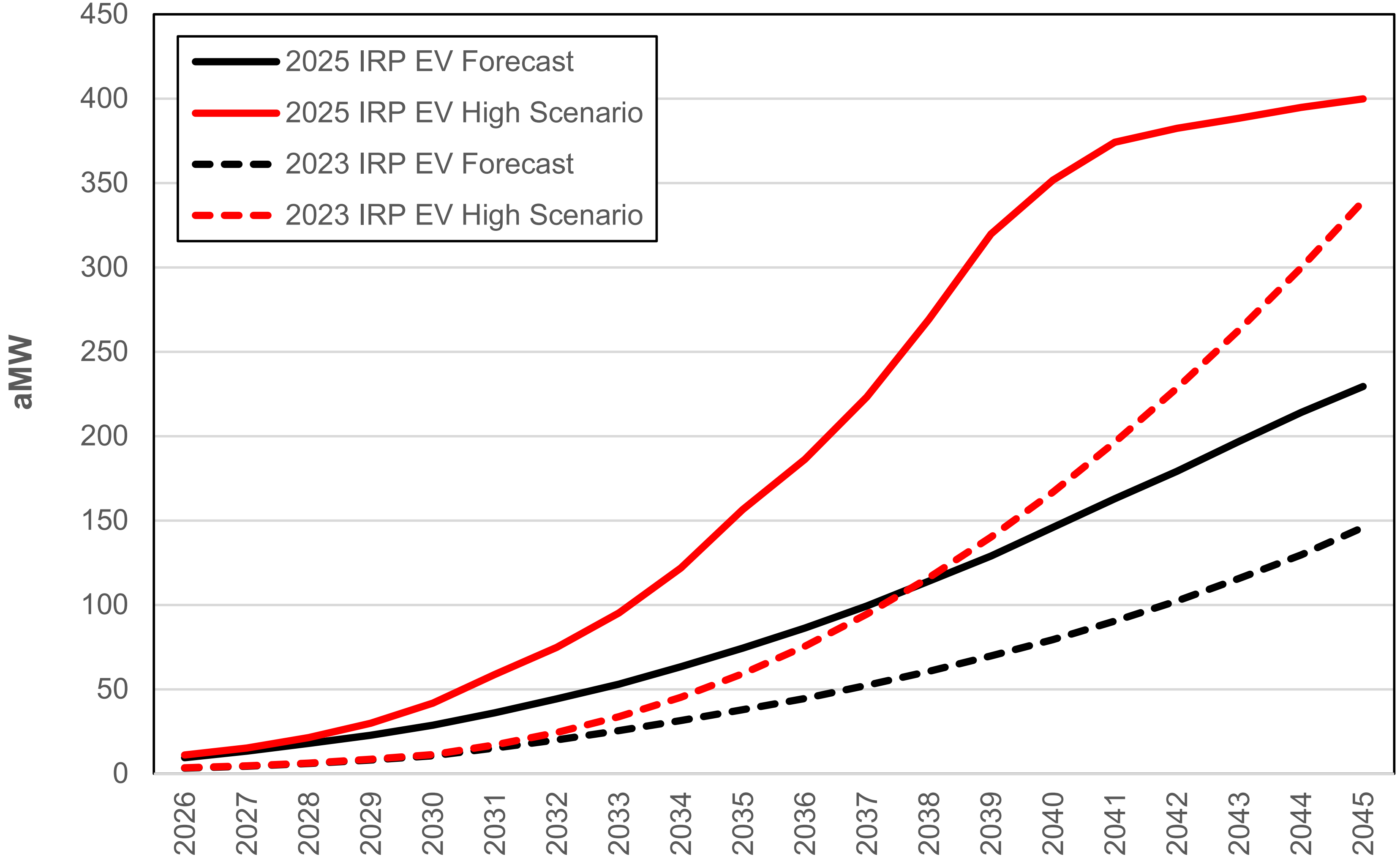
- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

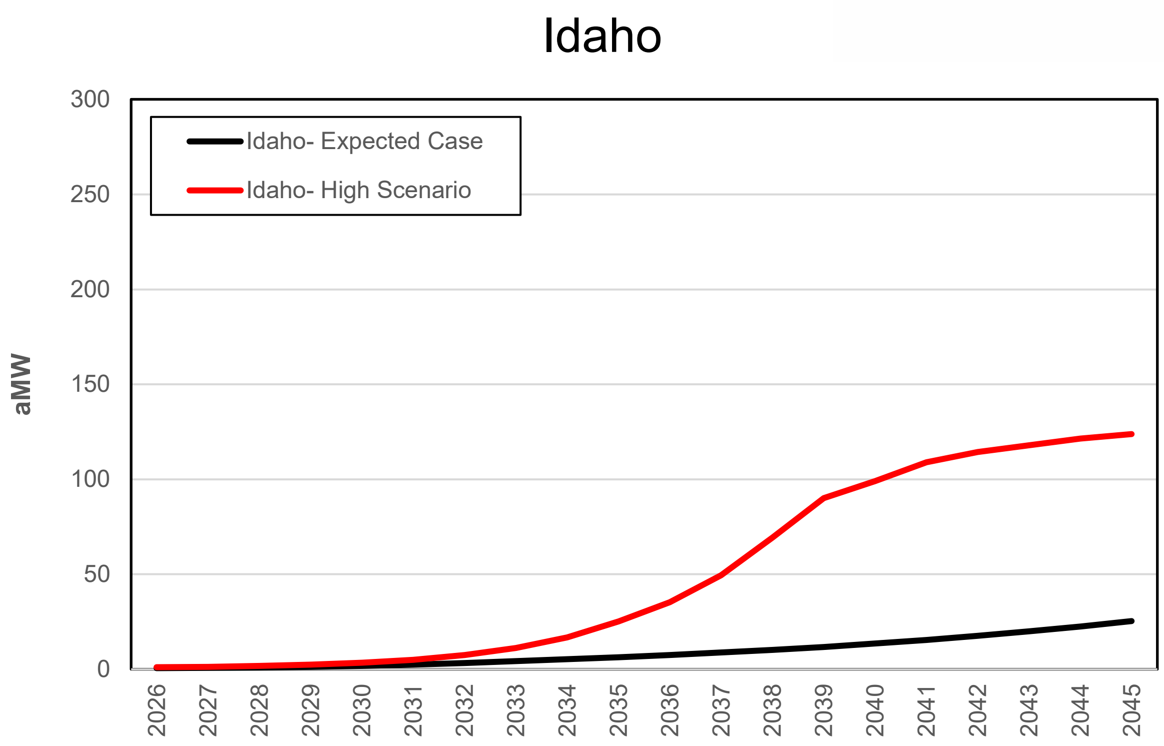
2025 IRP Portfolio Scenario Update (DRAFT)

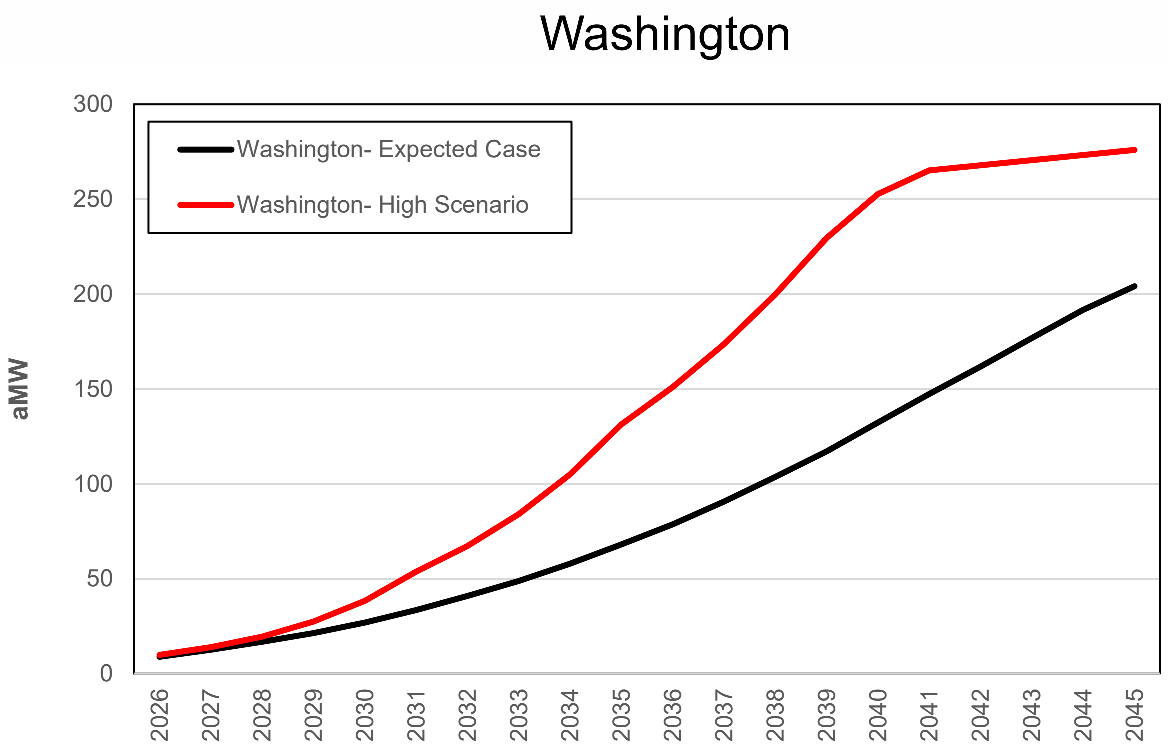
James Gall
Technical Advisory Committee Meeting No. 8
June 4, 2024

High Electric Transportation Scenario

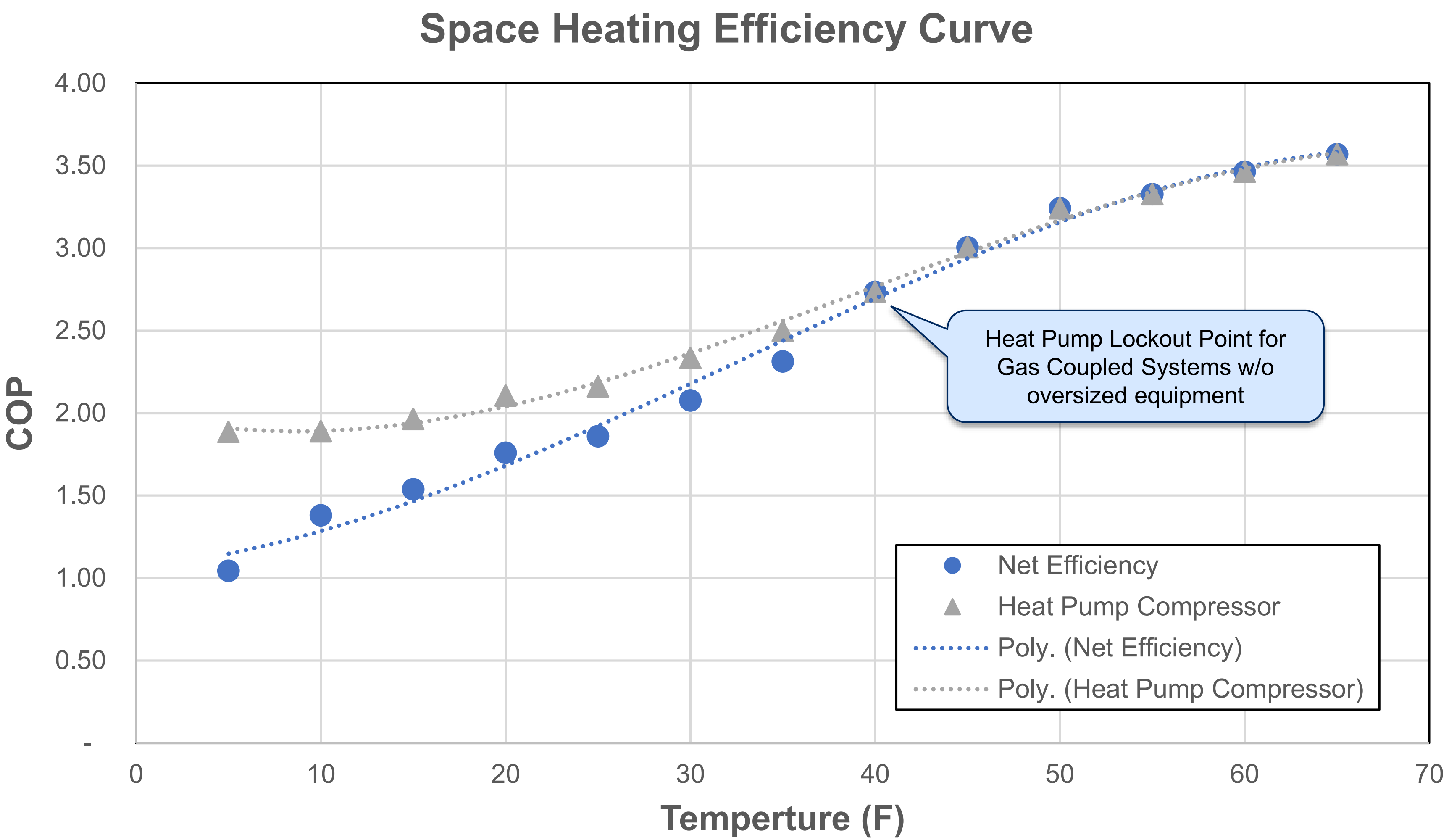


State Electric Vehicle Load Projections





Space Heat Assumptions for Building Electrification



For homes with central heating, the homeowner may find efficiency, cost, equipment longevity challenges when retrofitting to fully electric due to increased duct sizing requirements and installation cost.

Retrofit HP on NG furnace may have similar outcomes

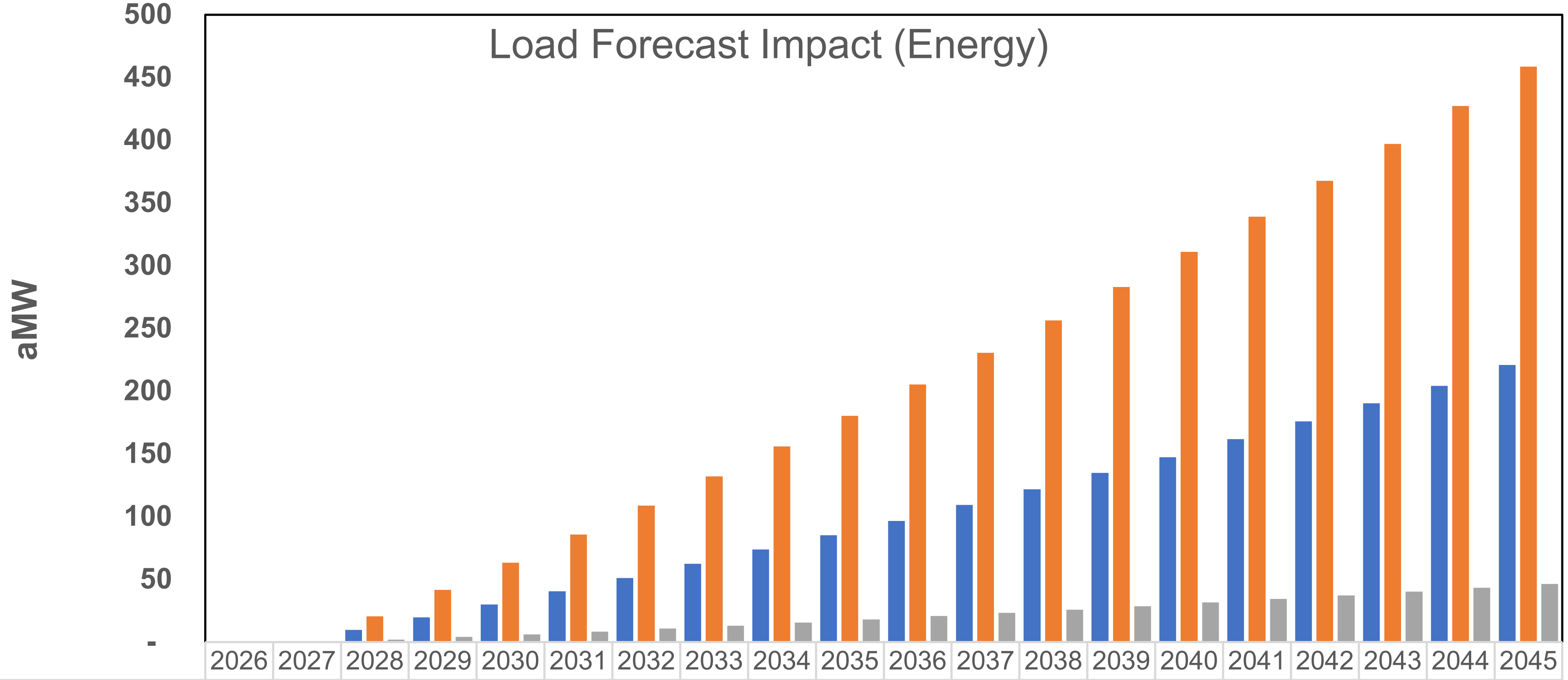
NREL Study of Actual Systems in the Northwest

Field Validation of Air-Source Heat Pumps for Cold Climates

https://www.nrel.gov/docs/fy23osti/84745.pdf

Building Electrification Electric Impacts

80% Reduction in WA/ID System Natural Gas Usage by 2045



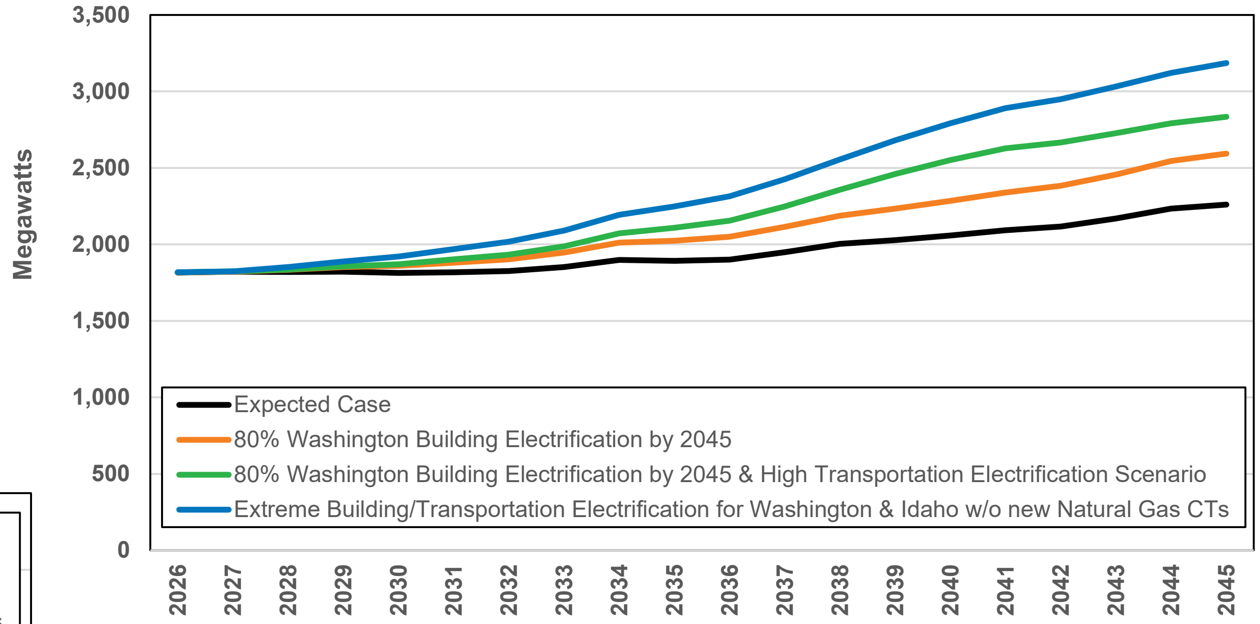
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Annual Energy	-	-	10	20	30	41	51	62	74	85	97	109	122	135	147	162	176	190	204	221
January Energy	-	-	20	42	63	86	109	132	156	180	205	230	256	283	311	339	368	397	427	458
August Energy	-	-	2	4	6	8	11	13	16	18	21	23	26	29	32	35	37	40	43	46

Assumes 75% of WA and 90% of ID natural gas customers use Avista electric

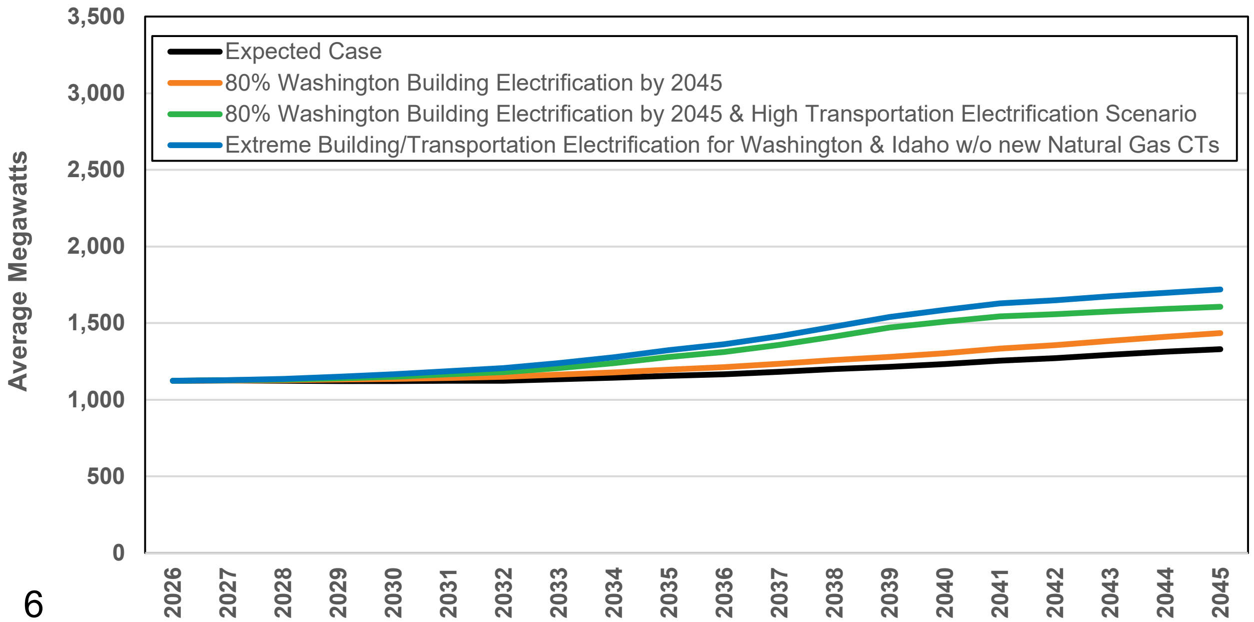
Load impact is close to even between states

Load Forecast Comparison

January Peak Forecast



Energy Forecast



Load Forecast Scenarios Still Under Development

- Load forecast data will be posted on Teams site once finalized
- Remaining scenario update:
  - Maximum Washington Customer Benefits: EV/Solar penetration to be increased in Named Communities
  - Data Center in 2030: Assume 200 MW in Idaho service area
  - RCP 8.5 Weather: in process
  - Low Growth: see assumptions below
  - High Growth: see assumptions below
  - Campus Building Electrifications: Should this be a scenario or added to existing scenario?
    - 30 MW to 60 MW winter load

Load Forecast Economic Conditions

	Expected Case	Low Growth Scenario	High Growth Scenario
2045 Area Population	941,587	857,869	1,001,564
Avg. GDP	1.80%	1.26%	2.26%

Supply Side Resource Options

2025 Electric IRP, 8th Technical Advisory Committee Meeting
June 4, 2024

Michael Brutocao, Natural Gas Analyst

DRAFT

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.

IRA Details

- Production Tax Credits ($2022 USD)
  - Geothermal, Solar, Wind and Biomass
    - $0.026 per kWh tax credit
  - Nuclear
    - $0.015 per kWh tax credit plus $0.003 base credit ($0.018 total per kWh credit)

- Investment Tax Credit (Battery Storage, Pumped Hydro, Solar)
  - Costs incurred thru 2032 qualify for a 30% tax credit
  - Credit falls to 26% in 2033, 22% in 2034, 10% in 2035/2036, and 0% in 2037
  - Additional 10% low-income tax credit
  - Domestic production adder of 10%

Resources Not Modeled

- Carbon Sequestration
- Coal
- RNG except as fuel for Frame CT
- Sodium, Vanadium, and Zinc Bromide Batteries
- Wave

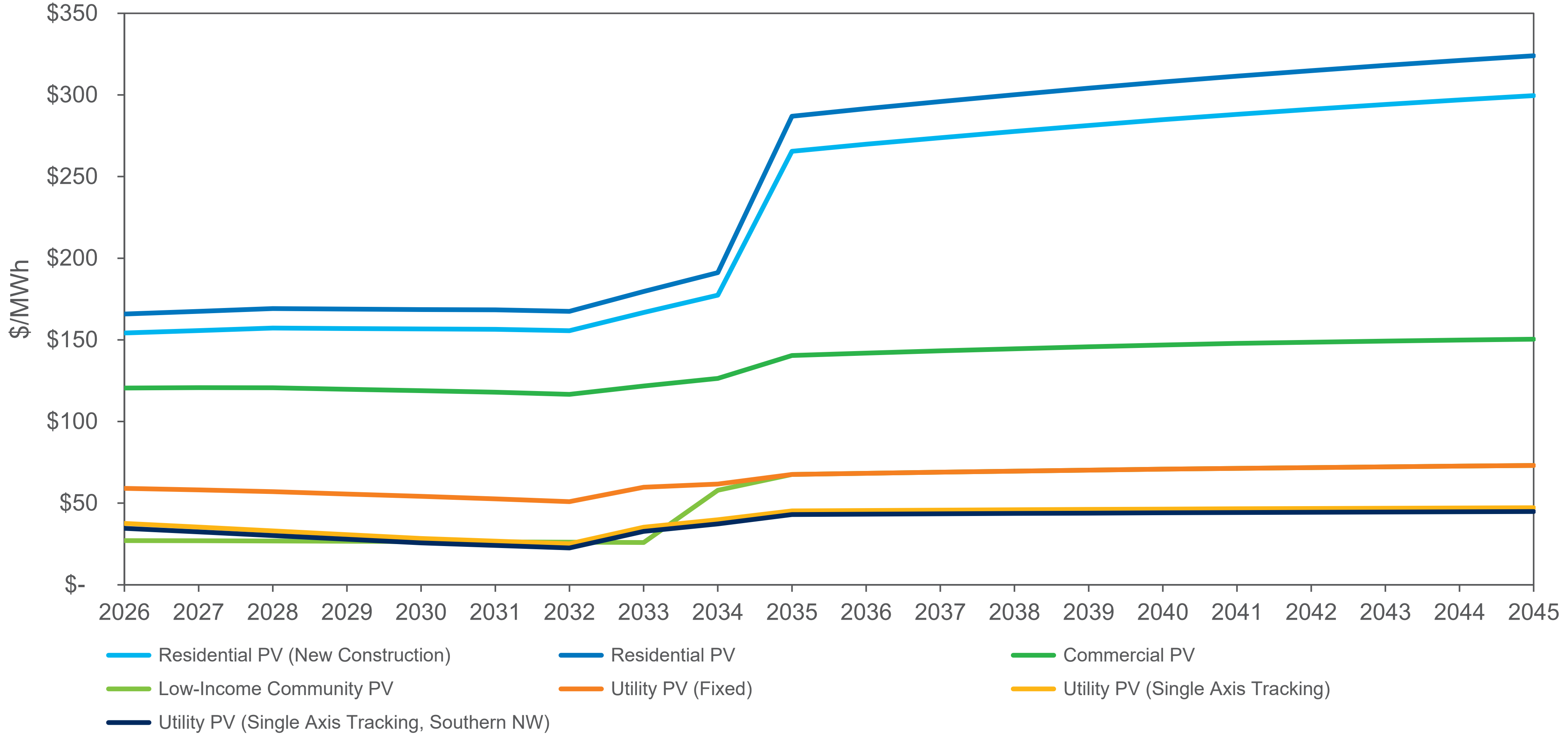
Resources Modeled

Resource	Fuel Source	MW	Capacity Factor	Capital $/kW (2026)
Frame CT	Natural Gas	180		$831
Frame CT	Ammonia	90		$1,079
Frame CT	RNG	90		$831
Reciprocating Engine	Natural Gas	185		$1,272
Combined Cycle	Natural Gas	312		$1,271
Small Nuclear Modular Reactor	Uranium	100	93%	$8,224
Wind (On System)	Wind	100	35%	$1,500
Wind (Off System)	Wind	100	35%	$1,642
Wind (Montana)	Wind	100	42%	$1,582
Wind (Off Shore/System)	Wind	100	49%	$5,220
Geothermal (Off System)	Earth	20	90%	$5,139
Hydrogen Fuel Cell	Hydrogen	25		$6,703
Kettle Falls 2nd Biomass Unit	Wood Waste	58	50%	$5,308
Kettle Falls Upgrade	Wood Waste	11	60%	$2,864
Rathdrum CT 2055 Uprates two unit operation	Natural Gas	5		$925
Rathdrum CT: Inlet Evaporation 2 unit operation	Natural Gas	10		$167
Palouse Repower	Wind	120	36%	$1,200
Rattlesnake Repower	Wind	180	27%	$1,200
Lind Repower	Solar	25	24%	$1,114

Resources Modeled (continued)

Resource	Fuel Source	MW	MWh	Capacity Factor	Capital $/kW (2026)
Residential PV (New Construction)	Solar	0.006		16%	$3,810
Residential PV	Solar	0.006		16%	$4,141
Commercial PV	Solar	1		17%	$2,297
Low-Income Community PV	Solar	<1		30%	$369
Utility PV (Fixed)	Solar	5		30%	$1,845
Utility PV (Single Axis Tracking)	Solar	100		30%	$1,392
Utility PV (Single Axis Tracking, Southern NW)	Solar	100		32%	$1,392
Distribution Scale Lithium-ion		5	20		$2,195
Distribution Scale Lithium-ion		5	40		$3,934
Lithium-ion		25	100		$1,663
Lithium-ion		25	200		$2,979
Lithium-ion		25	400		$5,613
Flow		25	100		$1,317
Flow		25	200		$1,383
Iron Oxide		100	10,000		$2,574
Pumped Hydro	Water	400	3,200		$4,070
Pumped Hydro	Water	100	1,600		$3,655
Pumped Hydro	Water	100	2,400		$3,384

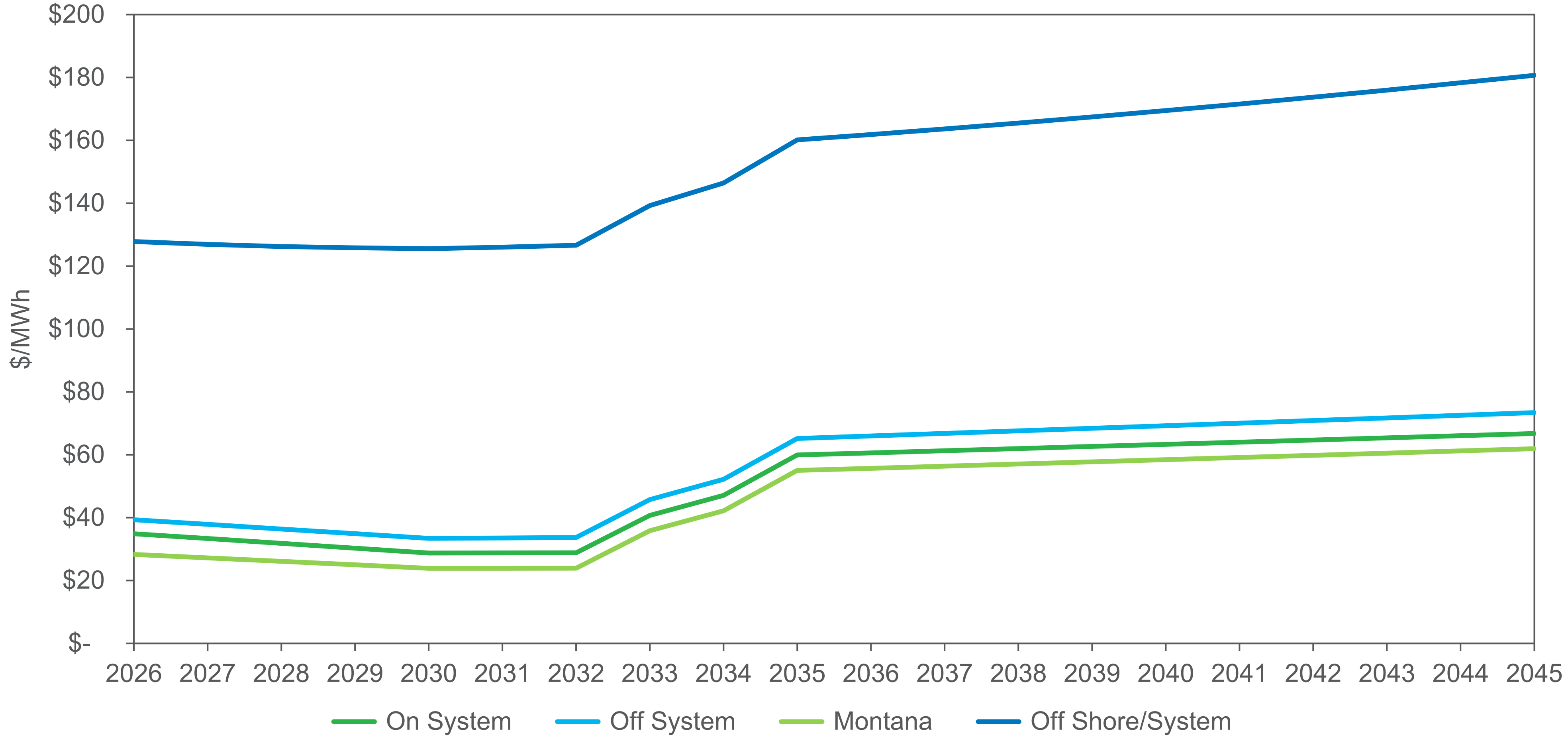
Solar PPA Price/Implied Energy Payment



*Community PV does not include administrative costs (~$25/kW-year)

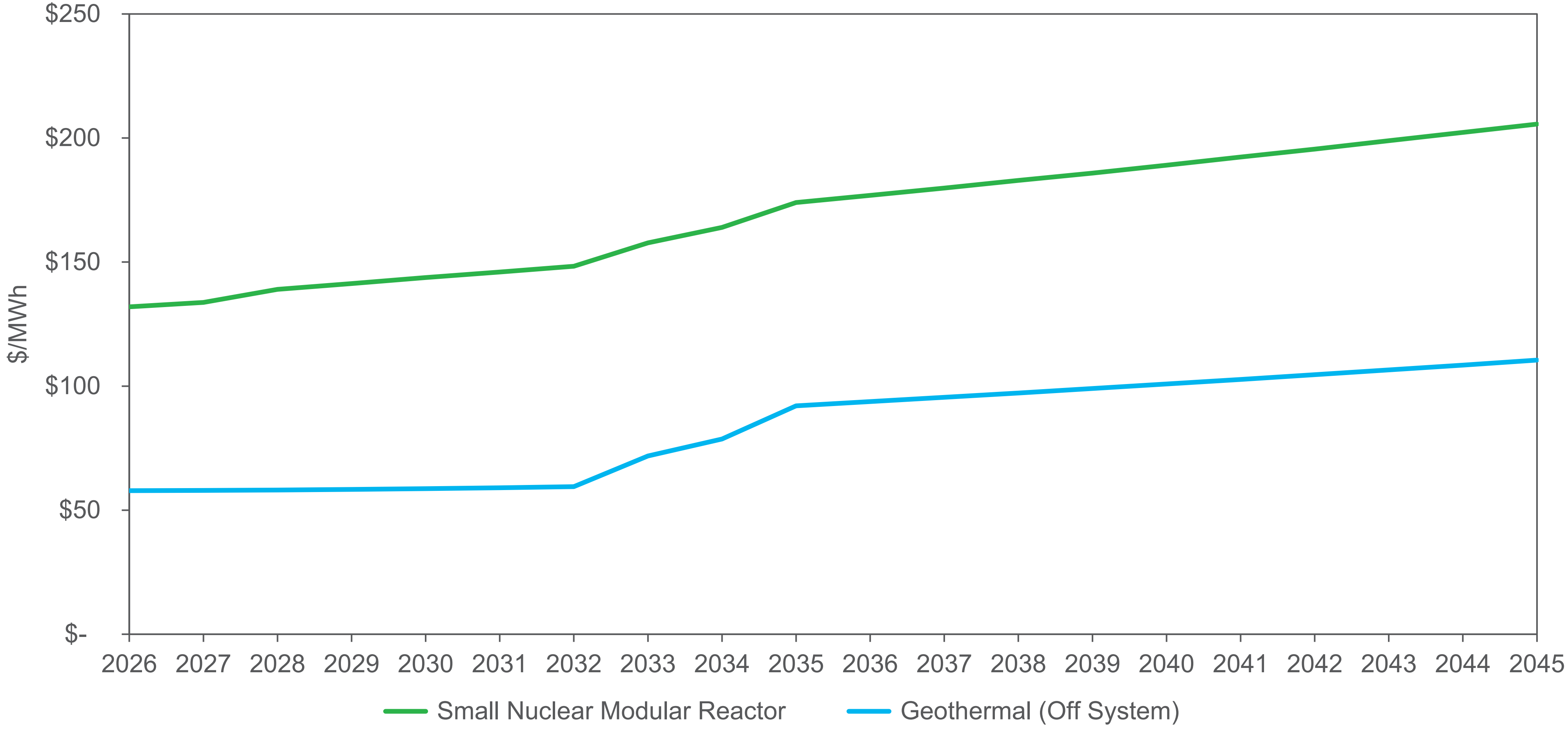
DRAFT

Wind PPA Price/Implied Energy Payment



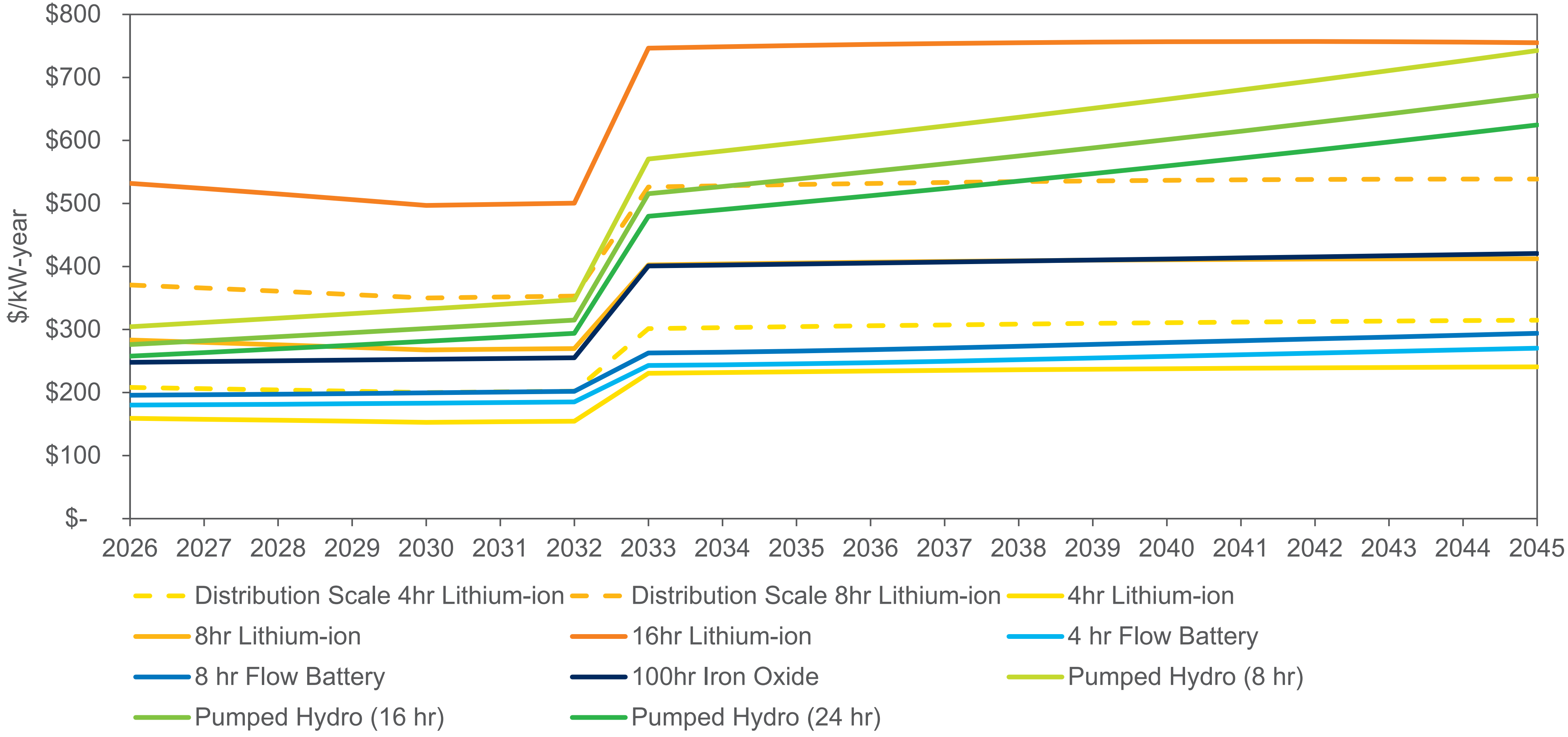
DRAFT

Baseload Clean Energy

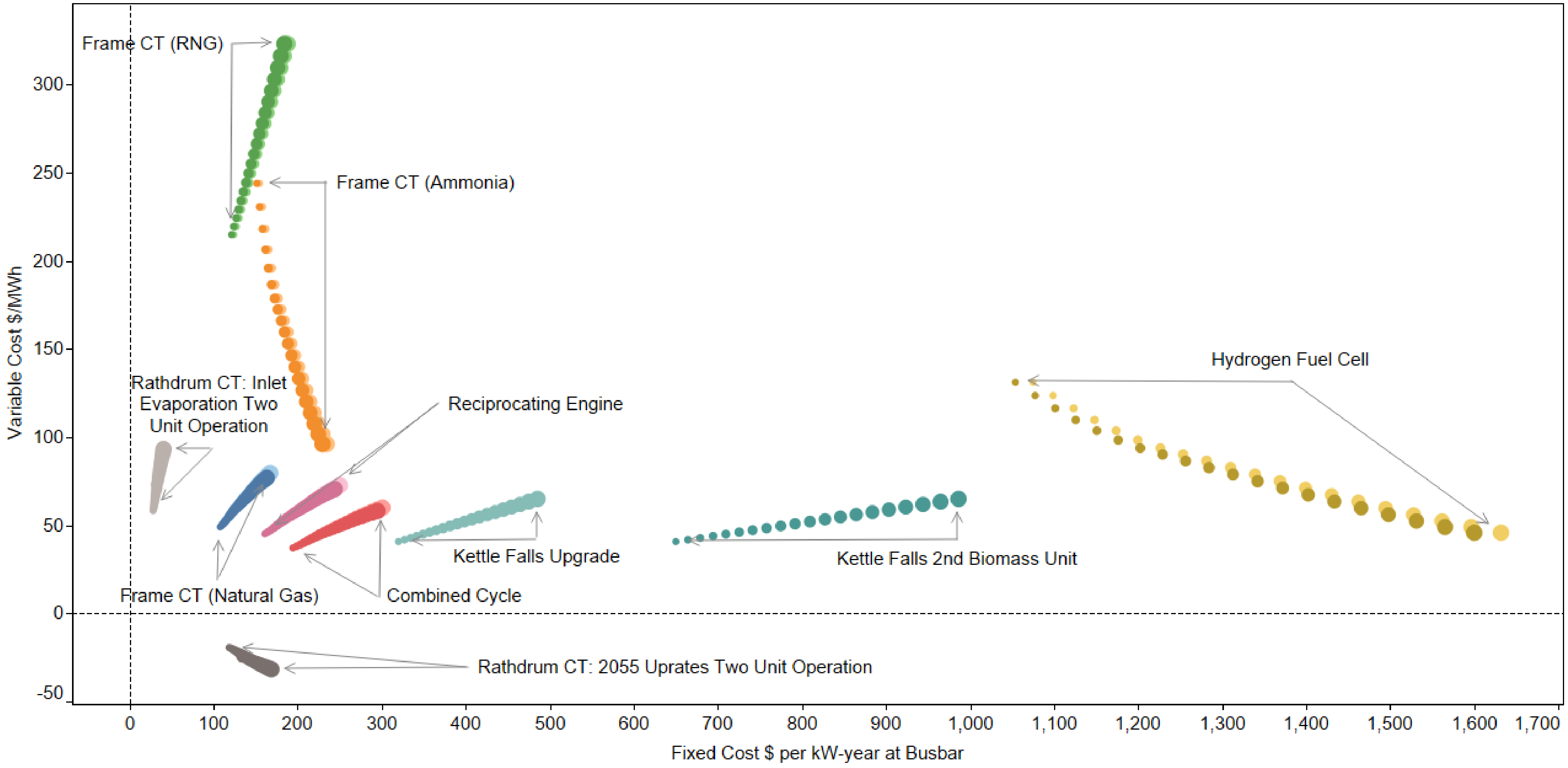


AVISTA

Energy Storage PPA Price/Implied Capacity Payment



Dispatchable Resource Variable vs Fixed Cost



Resources with lighter and darker shades indicate costs in Washington and Idaho, respectively

NEI Cost Studies to be Added

- Avista obtained licenses to run the IMPLAN model for Washington and Oregon to be able to run our own economic impact studies for each of the new resource types
- Still learning and configuring the model as this time and will report back to the TAC as the studies are completed
  - Upstream emissions estimates
  - Estimated direct, indirect and induced jobs for construction and operations
  - Reviewing additional outputs of the IMPLAN model for possible inclusion in the IRP

2030 Loss of Load Probability Study (DRAFT)

Mike Hermanson
Technical Advisory Committee Meeting No. 8
June 4, 2024

DRAFT

Topics

- LOLP Purpose
- Study Methodology
- Reliability Metrics
- Results
- Planning Margin

DRAFT

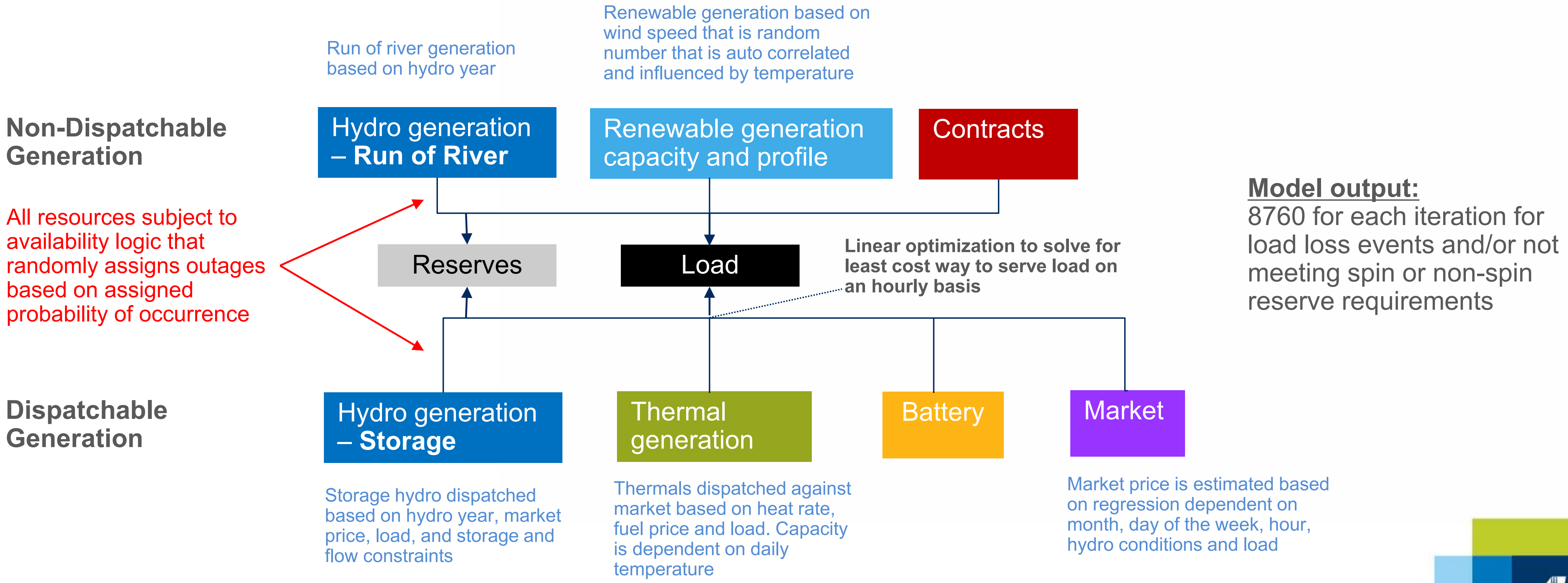
Purpose of Loss of Load Study

- Determine the ability of our system to meet load and reserves each hour when subjected to 1,000 iterations with different combinations of:
  - Water years
  - Load
  - Temperature
  - Maintenance
  - Forced outages
  - VER production
- Utilized currently expected portfolio of resources in 2030 and availability to purchase up to 330 MW from the market.
- Climate data utilized for water, load, and temperature in future years.

DRAFT

Modeling Framework

- Avista Reliability Assessment Model (ARAM) - Excel based model with VBA code and linear optimization Excel Add-in What's Best!



DRAFT

Reliability Metrics

- Studies are conducted with 1,000 iterations of the ARAM Model
- Model metrics provide insights and targets to achieve a reliable system
- Metrics
  - **LOLP** – *Loss of Load Probability*: Calculated by counting the number of iterations where there is unserved load or unmet reserves and dividing by the total number of iterations.
  - **LOLE** – *Loss of Load Expectation:* Calculated by counting the days where there is unserved load or unmet reserves and dividing by the total number of iterations.
  - **LOLEV** – *Loss of Load Expected Events*: Calculated by counting the number of consecutive blocks of unserved load or unmet reserves and dividing by the number of iterations.
  - **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.
  - **EUE** – *Expected Unserved Energy:* Calculated by summing all of the unserved MWhs over the study period and dividing by the number of iterations. Two versions are presented one with unmet reserves and one without.

Reliability Metrics

DRAFT

Metric	Use
LOLP	Can be used to determine the probability or likelihood of events due to insufficient capacity.
LOLE	The majority of entities conducting LOLE studies primarily use it to establish resource adequacy criteria. Industry standard is 0.1 days per year LOLE.
LOLH	The LOLH metric is computed by a large number of entities in North America. However, only one entity uses this metric as a reliability criterion, with their criterion set a 2.4 hours per year.
LOLEV	The LOLEV metric is useful in systems that are concerned with the frequency of events, regardless of duration or magnitude.
EUE	EUE is useful in estimating the size of the loss of load events so planners can estimate the cost and impact of the loss of load events.

Note: information taken from NERC, Probabilistic Adequacy and Measures Report, July 2018

DRAFT

2030 Existing Portfolio
12x24 Resource Deficiency

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

2030 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	10.2	11.5	13.2	14.6	15.4	20.2	31.7	39.4	32.0	28.9	25.9	22.1	20.1	14.3	16.5	14.8	17.3	17.8	18.8	19.2	19.5	17.6	14.2	12.8
2	2.4	3.2	4.3	5.8	6.9	10.0	12.2	15.8	11.0	8.8	6.3	5.5	3.9	2.3	2.4	3.2	3.6	4.0	5.6	5.5	6.7	6.5	6.1	6.1
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	0.0	0.3	0.9	1.3	0.8	0.1	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	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	1.2	0.6	0.1	0.0	0.0	0.0	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	0.1	0.1	0.1	0.1	0.1	0.1	0.4	0.1	0.2	0.4	0.3	0.1	0.0	0.1	0.1	0.2	0.3	0.0	0.3	0.0	0.3	0.2	0.3	0.1
12	9.1	8.1	9.0	12.7	14.1	19.8	27.1	29.5	28.3	29.0	23.4	21.2	19.1	14.8	15.9	16.0	18.0	20.3	20.6	22.8	21.2	22.7	19.1	15.6

DRAFT

Summary of metrics

- Planning margin determined by running model with increasing values of additional dispatchable resource

Metric	Additional Dispatchable Resources					Target
	Base	50 MW	100 MW	150 MW	200 MW	
LOLP	13%	10.4%	7.6%	5.2%	4.2%	5.0%
LOLE	0.44	0.32	0.24	0.16	0.11	
LOLH	4.98	3.66	2.48	1.71	1.12	
LOLEV	0.98	0.83	0.62	0.48	0.32	
EUE (with reserves)	1084	783	520	340	203	
EUE (without reserves)	1066	768	511	334	199	
Implied Planning Margin	21.0%	23.8%	26.6%	29.3%	32.1%	

LOLP – Loss of Load Probability
LOLE – Loss of Load Expectation
LOLH – Loss of Load Hours
LOLEV – Loss of Load Expected Events
EUE – Expected Unserved Energy

- Interpolated model runs to calculate 167 MW to achieve a 5.0% LOLP
- Consider (evaluate) moving winter planning margin from 22% to 30%