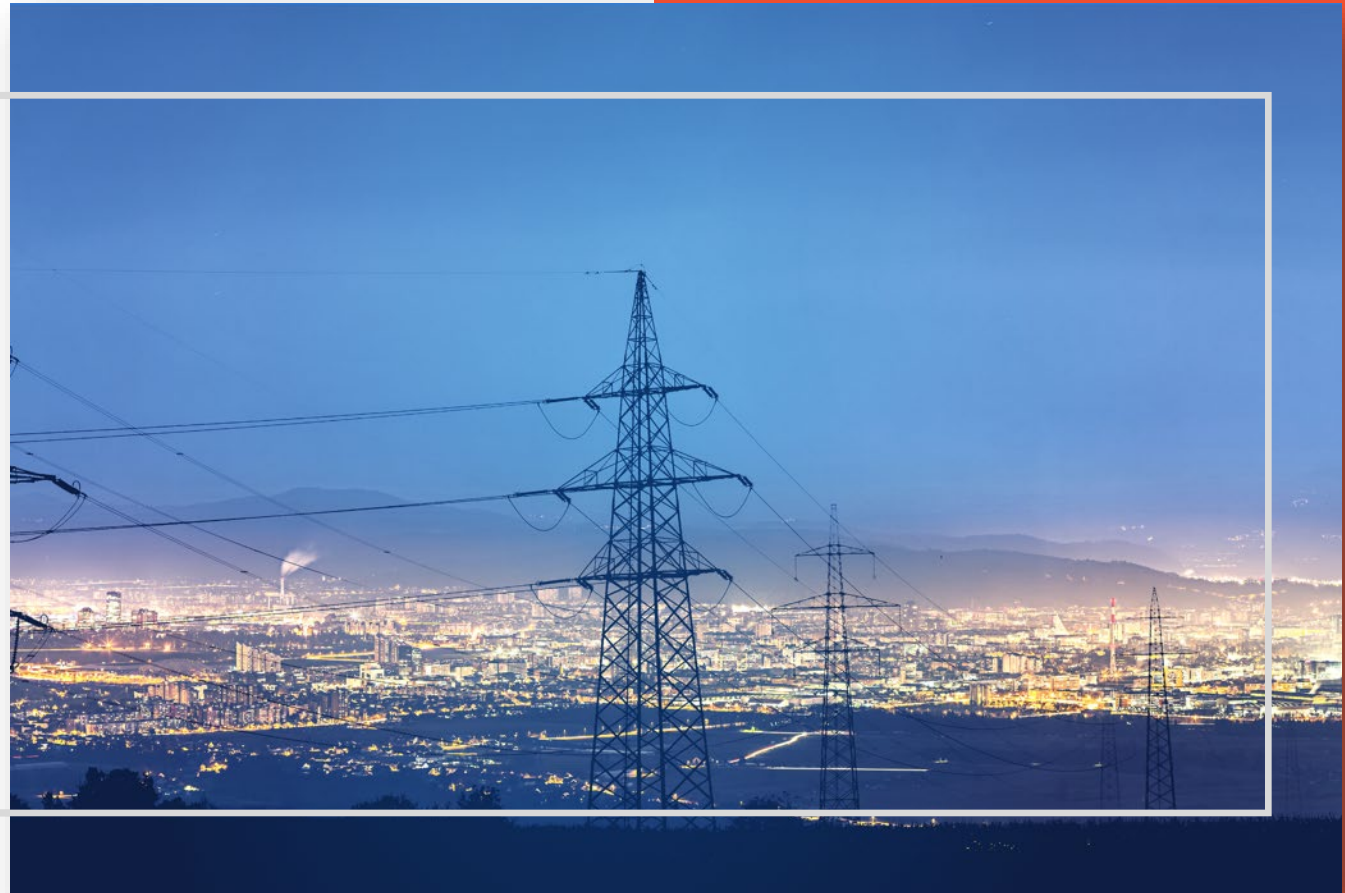


# Advancements in Resource Adequacy Assessments to Consider Transmission, Large Loads, and Flexibility

**James Okullo**

April 2, 2026  
NARUC



# About NARUC



- Founded in 1889, the National Association of Regulatory Utility Commissioners (NARUC) is a non-profit organization dedicated to representing the state public service commissions who regulate the utilities that provide essential services such as energy, telecommunications, power, water, and transportation.
- NARUC's members include all 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands.
- Our mission is to serve the public interest by improving the quality and effectiveness of public utility regulation.
- For more information, visit: [www.naruc.org](http://www.naruc.org)



# About NARUC CPI

- The NARUC Center for Partnerships & Innovation (CPI) builds relationships, develops resources, and delivers training to assist state commissions contending with complex current and emerging issues.
- CPI is funded by cooperative agreements with the U.S. Department of Energy (DOE) and the National Institute of Standards and Technology (NIST).
- CPI conducts work across five key energy areas and many topics within each: generation; transmission; distribution; customers; and critical infrastructure preparedness, response, and resilience.
- Among other events, CPI hosts a monthly innovation webinar series on a wide range of timely topics.
- For more information, visit: [www.naruc.org/cpi](http://www.naruc.org/cpi)

# Upcoming Events



## Virtual Events

- Bulk Power System Virtual Training Series: Apr 2, Apr 16, Apr 30; 2:00-4:30pm ET
- Distribution System Planning Peer Webinar Series: May 14, Jun 22, Aug 13; 3:00-4:30pm ET
- May Innovation Webinar: May 28, 3:00-4:00 pm ET

## Upcoming In-Person Events

- NCEP Annual Meeting: May 5 to 6, 2026, Charleston, South Carolina
- NARUC Summer Policy Summit: July 19 to 22, Minneapolis, Minnesota

See the full list of events and access registration links at: [www.naruc.org/events/event-list/](https://www.naruc.org/events/event-list/)

# ENERGY SYSTEMS INTEGRATION GROUP

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- ESIG is a member-driven organization that addresses technical challenges for transforming energy systems. We do this through collaboration, education and knowledge sharing.
- >300 members worldwide broadly focused on power systems transformation and integration of energy systems
- Workshops, webinars, reports available freely on our website (<https://www.esig.energy/>) and on YouTube ([@EnergySystemsIntegrationGroup](#)). Join our mailing list!
- We create task forces to address topics such as multi-value transmission benefits or grid-forming technology or large loads and these task forces do analysis, run simulations, synthesize best practices, etc.

# Large Load Training Series

- **April 2: Advancements in resource adequacy assessments to consider transmission, large loads, and flexibility**
- April 16: Forecasting large loads and harnessing flexibility to inform resource and transmission planning
- April 30: Processing large load interconnection requests

# Together with industry partners, ESIG has convened a Large Loads Task Force (LLTF) to cover multiple topics

## Load Forecasting

- Policies and practices for forecasting large loads to inform resource and transmission planning

## Interconnection Process

- Large load interconnection processes and studies

## Interconnection Performance

- Requirements and performance specifications of large loads

## Dynamics Modeling Requirements

- Modeling of power systems dynamic assessments for large loads

## Transmission Planning

- Consideration of large loads in transmission planning processes

## Resource Adequacy

- Practices for evaluating large loads in resource adequacy studies

## Markets & Operations

- Market design and operations for large loads and associated resources

## Rate Impacts

- Impacts that large loads can have on electricity rates and mechanisms to mitigate rate increases

# Agenda

- **Welcome and intro**  
Deborah Reynolds (NARUC), James Okullo (ESIG)
- **Transmission Modeling in RA Assessments: Zonal Reliability Study with SERVIM and TARA.**  
Kevin Carden (PowerGem) - 30 min
- **Evaluating the Resource Adequacy Value of Transmission in Long-Term Planning.**  
Armando Figueroa (MISO) – 25 min
- **Integrating Large Loads and Flexibility into RA Planning.**  
Derek Stenclik & Aaron Schwartz (Telos Energy) – 30 min
- **Large Load Flexibility in Practice: Opportunities, Limits, and Regulatory Implications.**  
Jeff Bladen (Verrus) – 30 min
- **Near-term winter resource adequacy challenges in the Pacific Northwest**  
Elaine Hart (Sylvan Energy Analytics) – 25 min
- **Closing,**  
Deborah and James – 5 min



# Thank You!

[james@esig.energy](mailto:james@esig.energy)

# Zonal Reliability Study with SERVM and TARA

Kevin Carden, Chief Product Officer of PowerGEM



# Zonal Reliability Study Objectives

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- Perform clustering analysis using PowerGEM's TARA model to identify clusters with similar effects on critical flowgates
- Perform transfer limit analysis using TARA to identify zone-to-zone constraints and simultaneous import and export constraints
  - With rapid evolution of ERCOT generation portfolio, it is critical to regularly review zonal composition based on congestion
- Run SERVM simulations to analyze the change in reliability for 2026 when moving from single zone representation of ERCOT to the clustered representation.

# Clustering Results

- 13 clusters were initially identified by PowerGEM
- PowerGEM worked with ERCOT and ultimately consolidated several zones
- Final clustering includes 8 zones

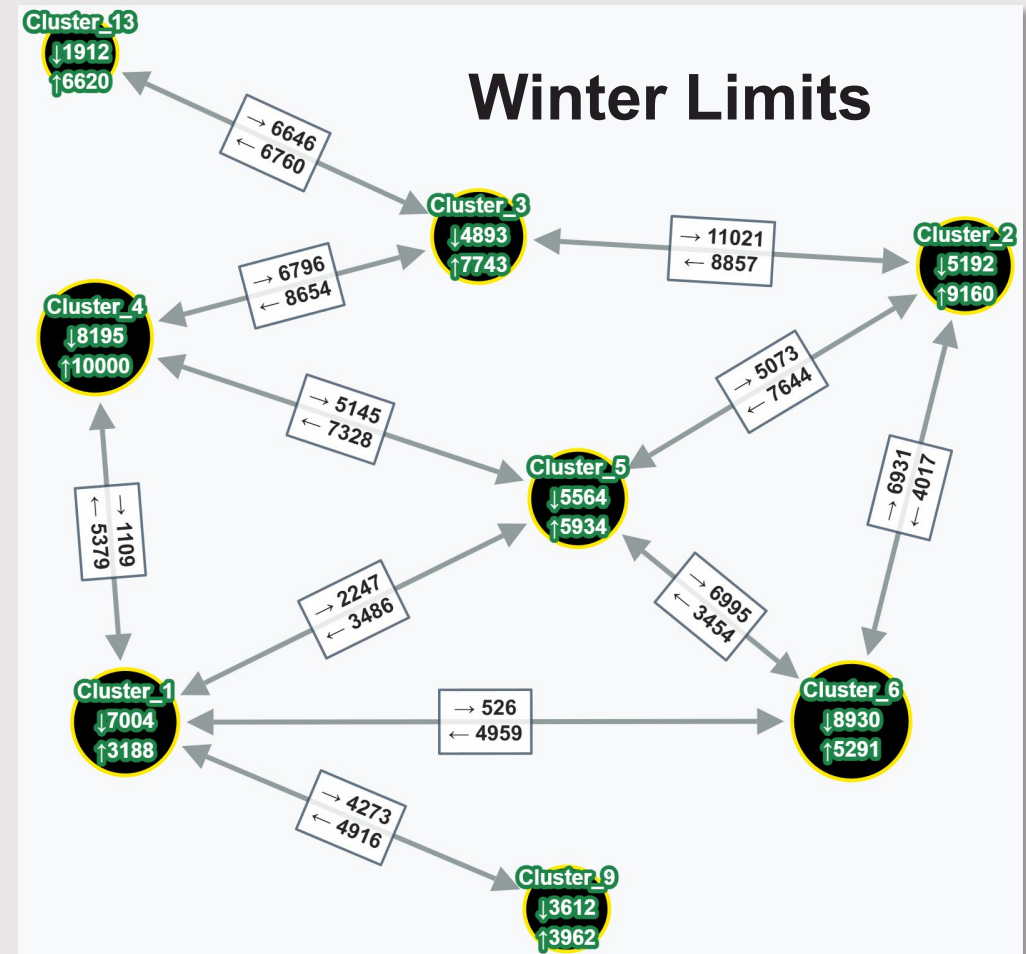
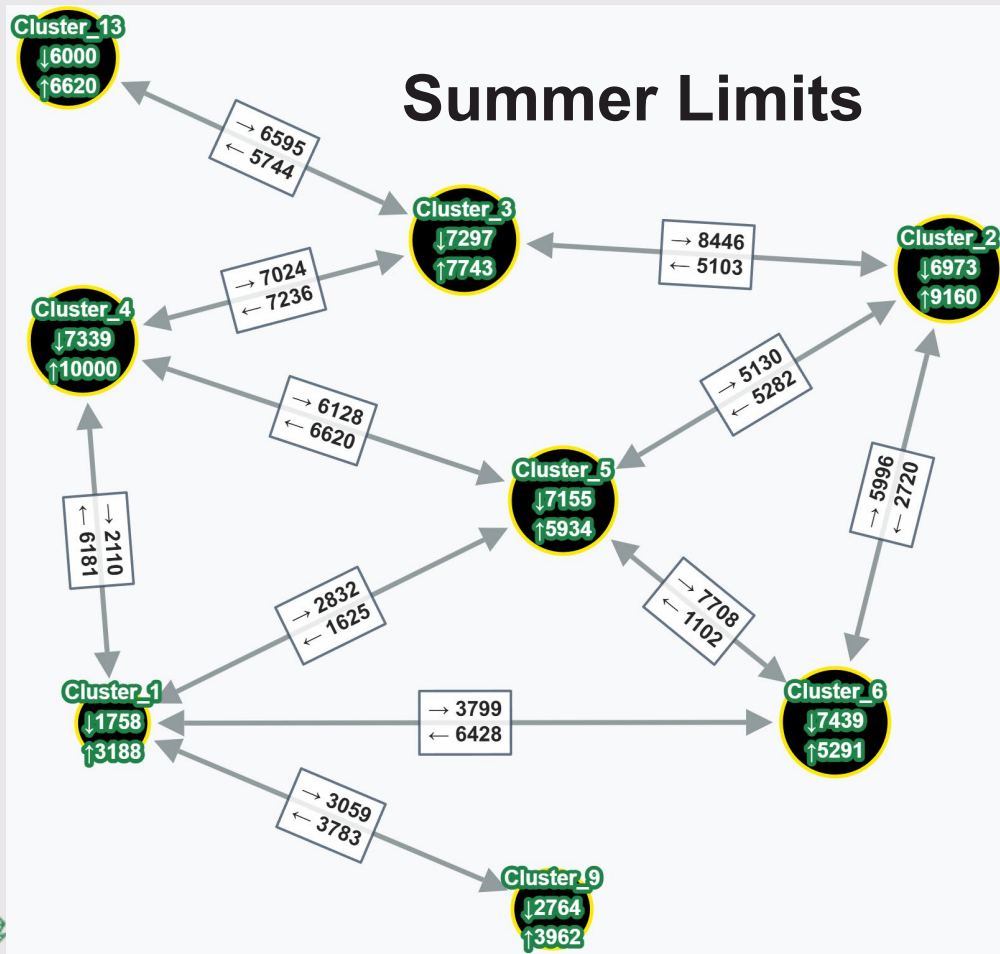


# Transfer Limit Calculations

- Transportation model used by SERVM can consider limits between zones
  - "Path Limits" will be the term used for zone-to-zone limits
  - Scale up generation in a sending zone and scale down generation in receiving zone
  - At what point does a transmission mon/con hit its rating?
  - Path flow when limit reached defines Path Limit between zones
  - Consider bi-directional transfer limits for adjacent zones
- An overall aggregate import and export limit for a zone can also be enforced
  - "Aggregate Limits"
  - Simultaneously scale up generation among all outside zones. Scale down generation inside the target zone.
  - Do vice versa to get export limit (outside down and inside up)
  - At what point does a transmission mon/con hit its Rating? This is the Aggregate Limit for a zone

# Transfer Limit Results

- Path Limits are shown in rectangles on path connectors
- Aggregate Limits are shown in the Cluster circles

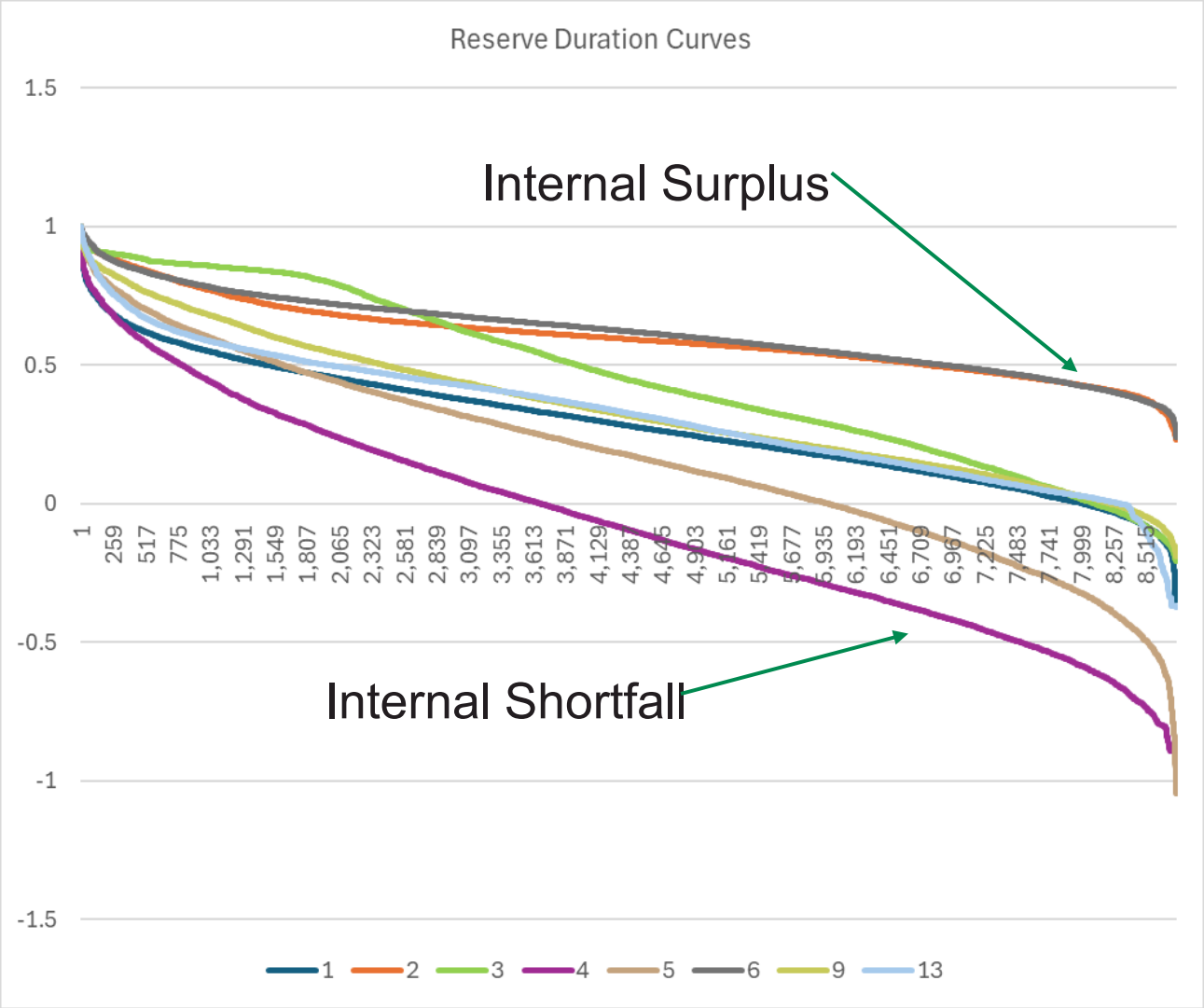
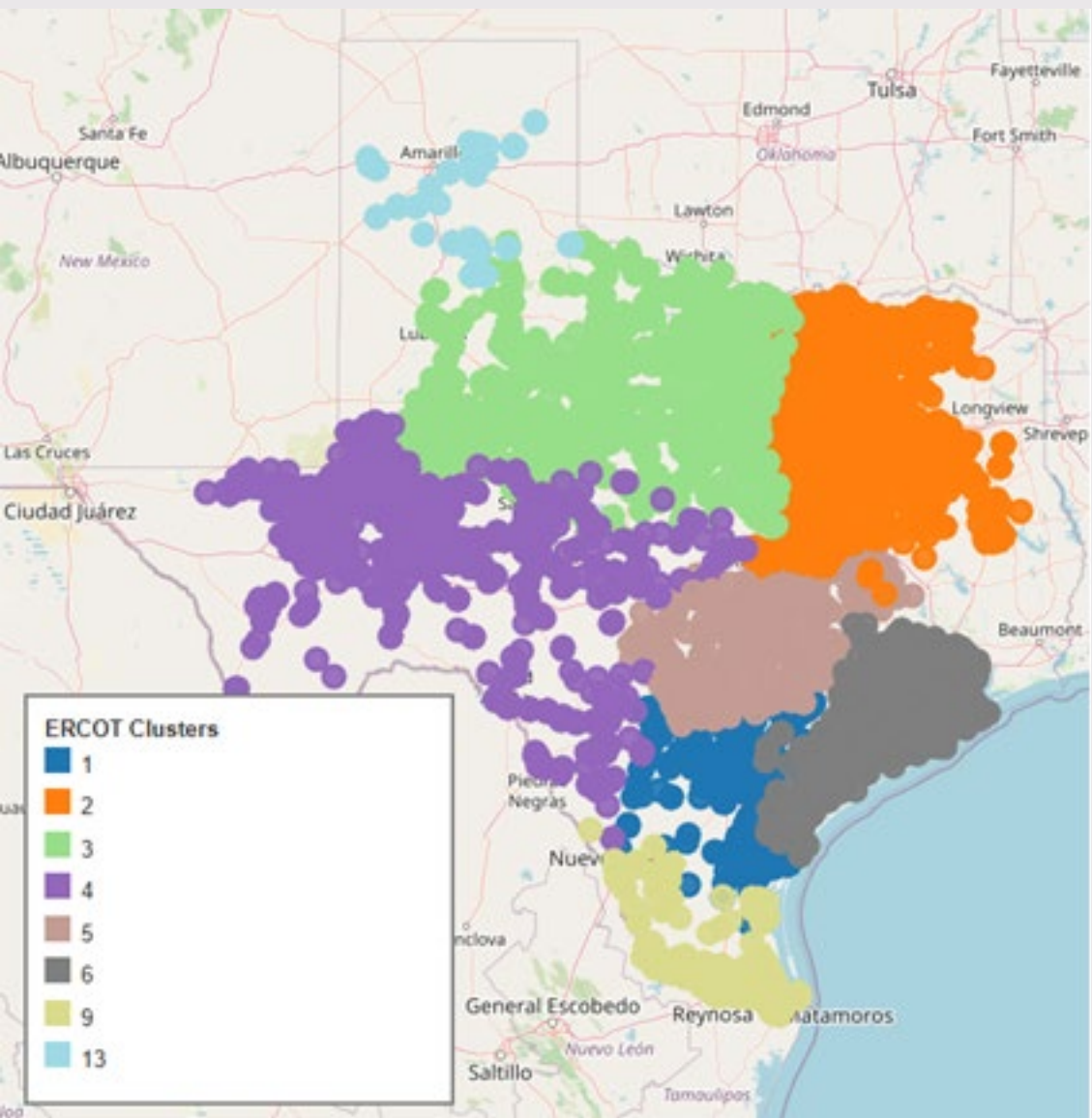


# Zonal Model Results

- Copper Sheet scenario was from an intermediate study (does not match any of the studies previously discussed)
- Aggregated constraints do not reflect emergency mitigation opportunities that would be available to operations

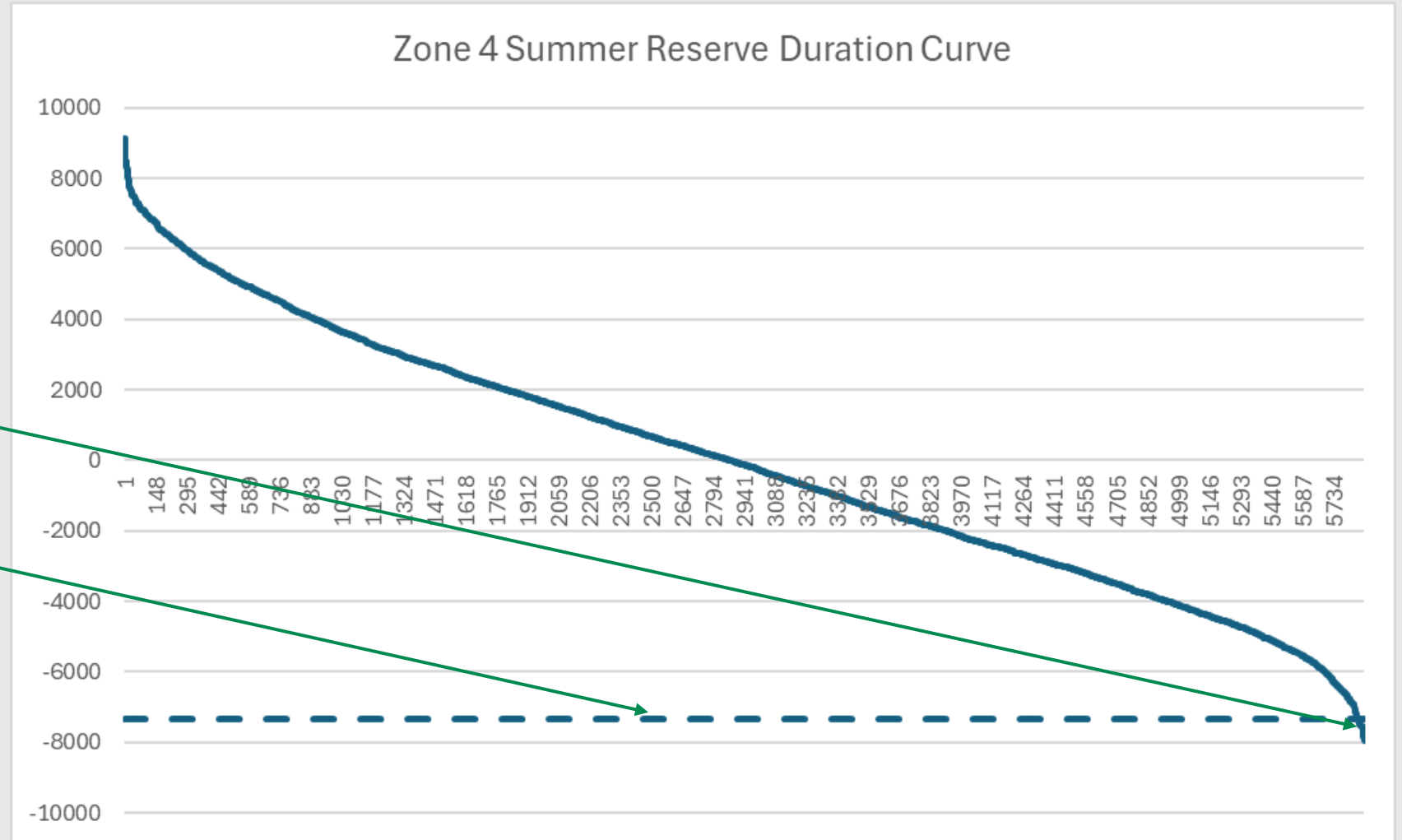
Cluster	Copper Sheet	Path Limits Only	Path Limits + Aggregated Constraints
Cluster_1	0.214	0.228	0.637
Cluster_2	0.214	0.262	0.348
Cluster_3	0.214	0.262	1.181
Cluster_4	0.214	0.262	3.760
Cluster_5	0.214	0.262	0.728
Cluster_6	0.214	0.230	0.122
Cluster_9	0.214	0.227	2.196
Cluster_13	0.214	0.262	1.460
Clusters_AGG	0.214	0.262	5.962

# Reserve Duration Curves

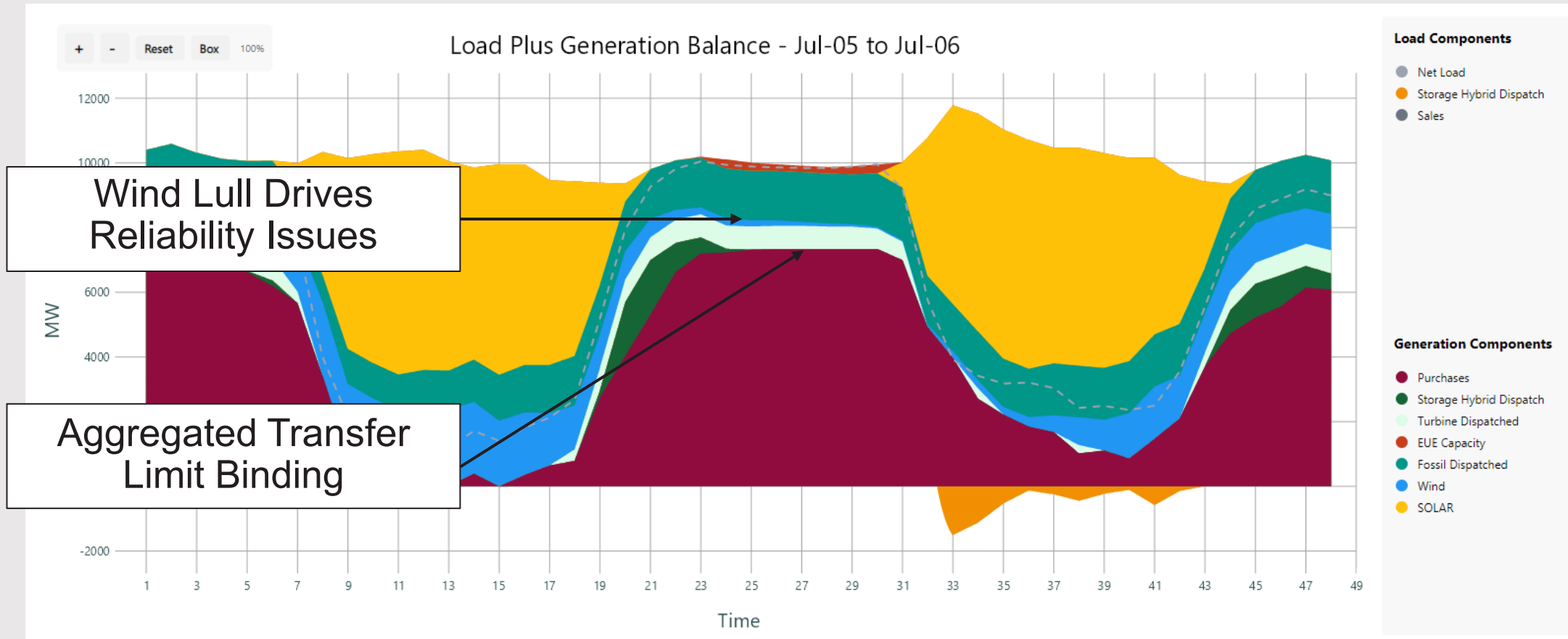


# Analyzing Transmission Effects on Resource Adequacy

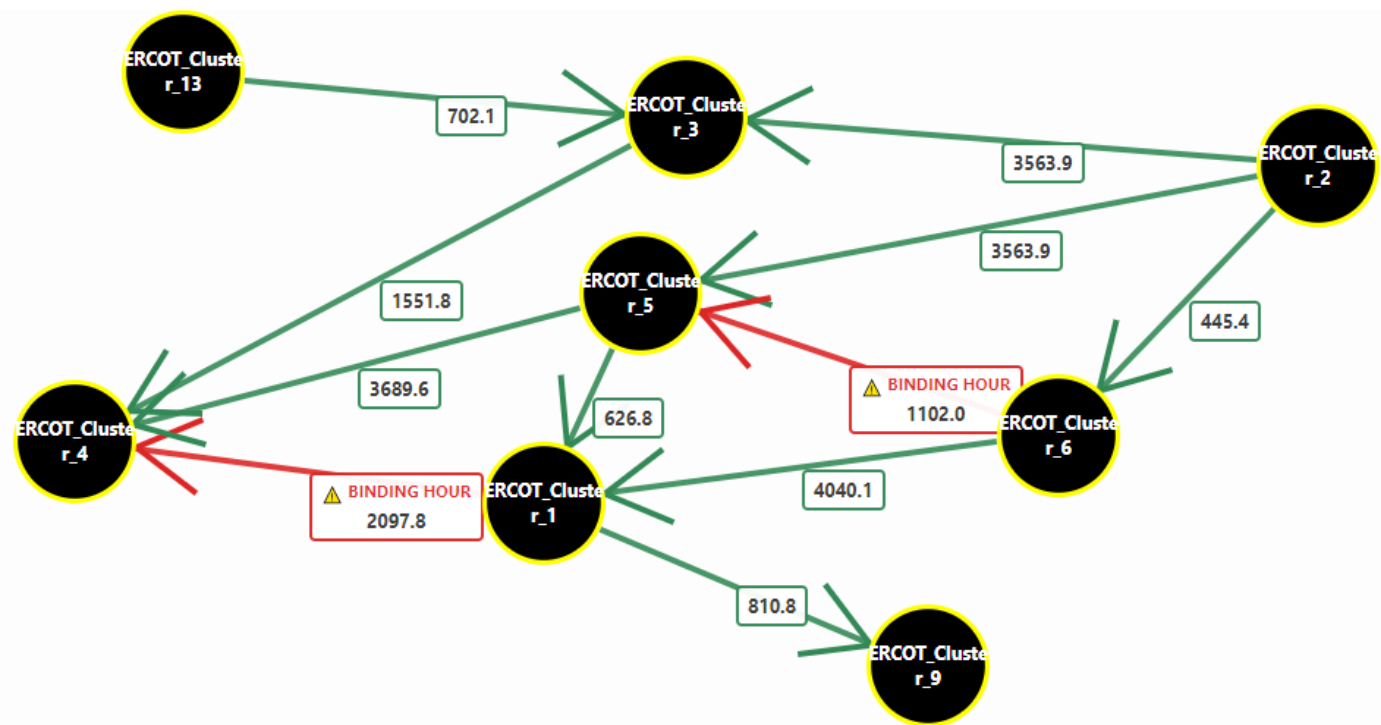
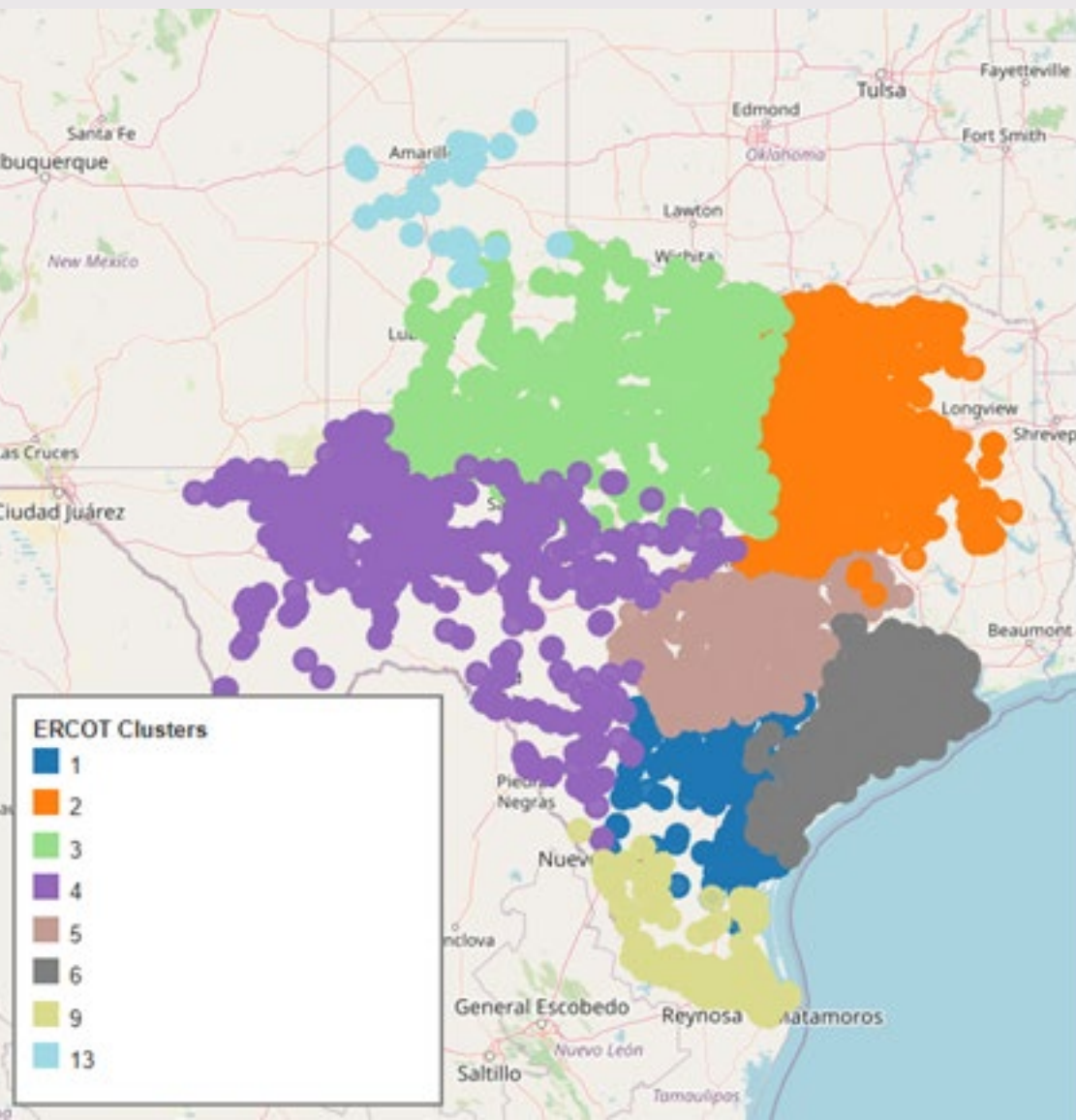
- Use SERVM to Filter to Critical Periods
- Aggregated Import Constraint



# Analyzing Transmission Effects on Resource Adequacy



# Zone 4 Deep Dive



# Mitigation Opportunities

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- Operational Mitigation
  - Re-Optimize Commitment/Outage Planning with Reliability Focus
  - Activate Demand Response
  - Relax N-1 Security Constraints
  - Shed Load
- Resource Planning Mitigation
  - Zonal Specific Expansion Planning
  - Zonal ELCC Calculation

# Supply Deliverability Study



# Overview

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- Recall limitations of transportation model and dependence of transfer limits on actual dispatch.
- Would like to evaluate SERVM dispatch scenarios in TARA to obtain actual impact of a given scenario on transmission
- SERVM exports scenario files. TARA launches with scenario inputs and evaluates each scenario.
- Currently working on adding functionality to SERVM and TARA for this feature

# SERVVM → TARA

## Heuristic to Identify Hourly Scenarios

- Sample based on:
  - Load
  - Modified Load
  - Net Load
  - Renewable Output
  - Unit Category Output
  - State of Charge
  - Forced Outages
  - Remaining Reserves
  - Imports
  - EUE

Power Flow Modeling

Number of Raw Files to Create:

Max Contingency per Raw File:

Max Contingency Depth (N-\*):

Contingency File Type:

Power Flow Group:

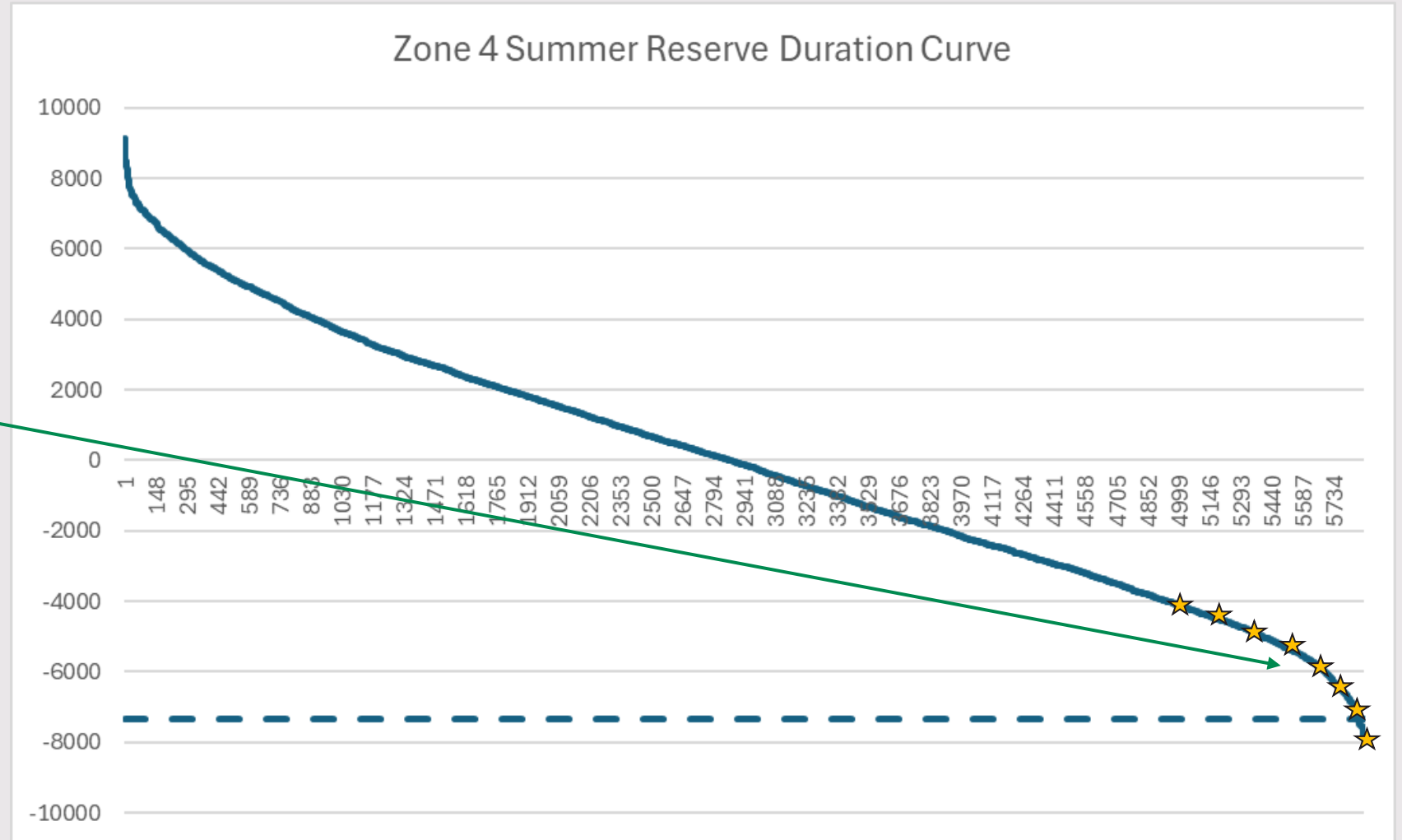
Study Region:

Percent of Raw Files per Load Level Interval

Percent	Lower Bound	Upper Bound
<input type="text"/>	<input type="text"/>	<input type="text" value="100"/>
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# Composite Reliability Metrics

- Use SERVVM to Filter to Critical Periods
- Create Scenarios to Analyze in TARA



# SERVM→TARA

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- SERVM generates CSV files describing scenarios to evaluate
  - Zonal load
    - TARA will adjust bus level loads to match SERVM zonal loads
  - Bus-level renewable generation
  - Availability of energy-limited resources according to modeled state of charge in SERVM
  - Generation outages

# Evaluating Scenarios in TARA

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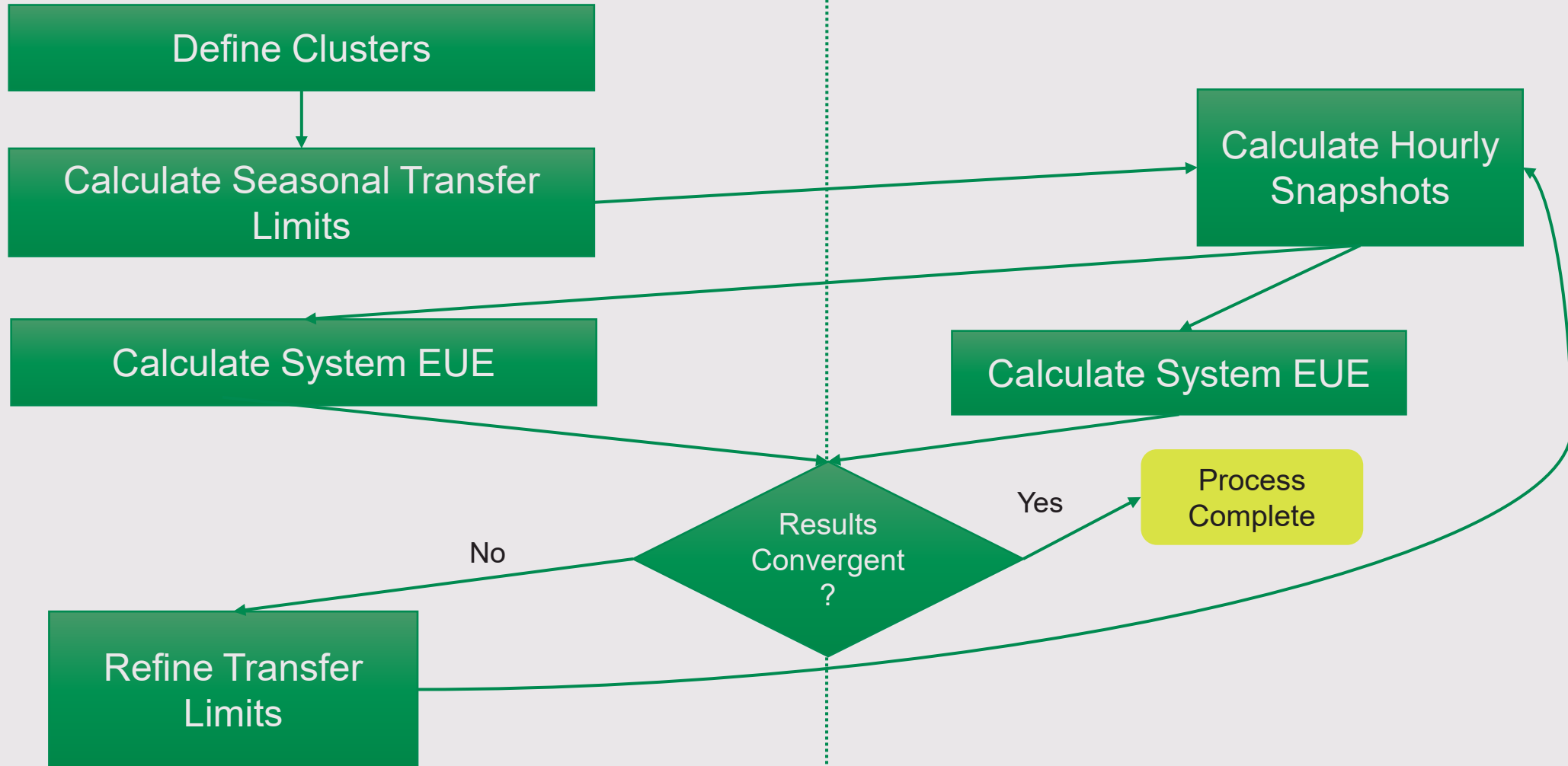
- Similar functionality as existing Generation Regional Sufficiency Tool
- Run linear Security-Constrained Redispatch for each scenario
  - Uses linear sensitivity factors for all gen/load
  - Very fast execution
- Results show
  - Which transmission constraints hit or exceed their limit
  - How much reduction (or increase) of Aggregate Import limit should occur for each zone for each scenario in order to satisfy transmission limits
  - Provide this as feedback for subsequent SERVM execution

# Composite Reliability Metrics

Snapshot	Zone 4 Internal Shortfall	SERVM Net Imports	SERVM EUE	TARA Net Imports	TARA EUE
1	(4,001)	7339	-	6,707	-
2	(4,209)	7339	-	7,833	-
3	(4,425)	7339	-	8,230	-
4	(4,637)	7339	-	7,256	-
5	(4,868)	7339	-	6,987	-
6	(5,150)	7339	-	7,661	-
7	(5,456)	7339	-	6,075	-
8	(5,862)	7339	-	6,314	-
9	(6,489)	7339	-	6,022	467
10	(7,566)	7339	227	6,348	1,218

# TARA

# SERVUM



# SERVM→TARA

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- Solve for 0.1 LOLE while respecting all nodal constraints
- Convergent reliability metrics generally require 50,000 or more 8760 simulations
  - Zonal/Nodal linked models provides the ability to determine convergent reliability models that respect all constraints

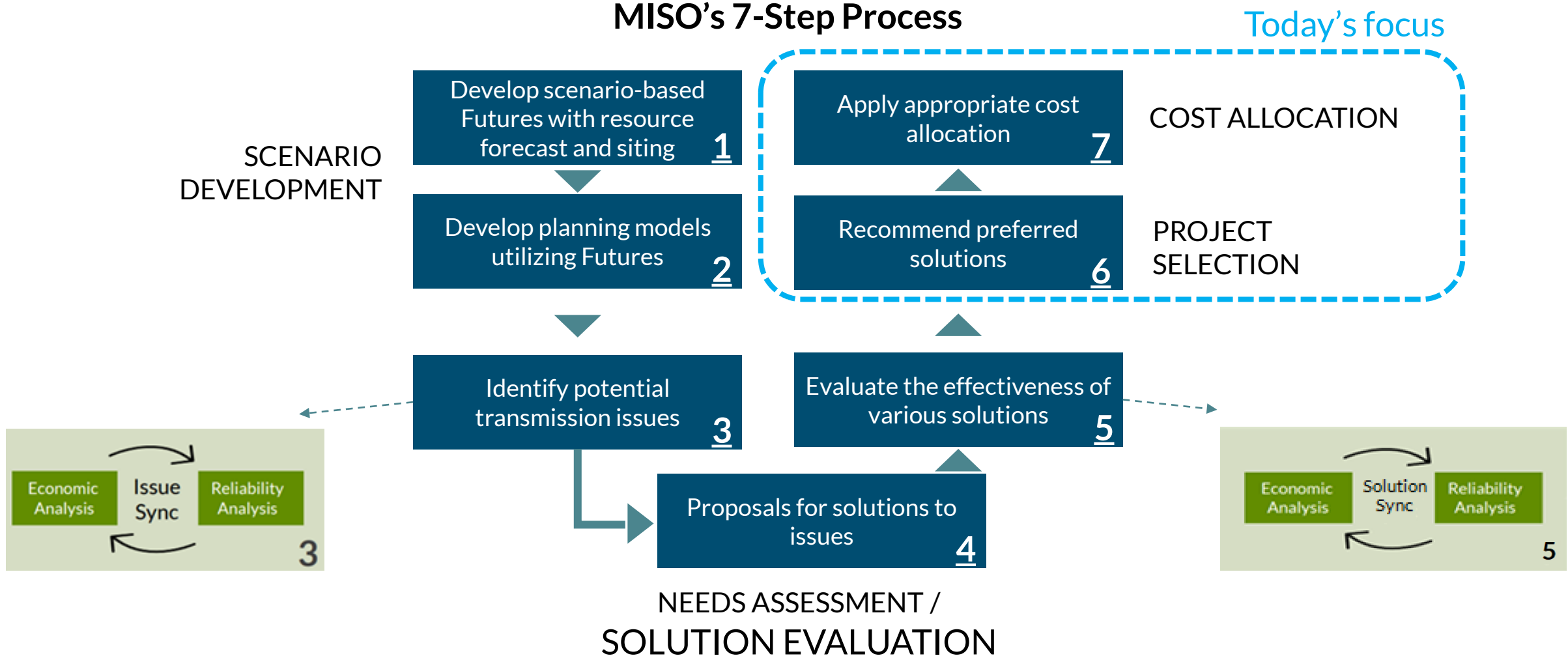


# Advancements in resource adequacy assessments to consider transmission, large loads, and flexibility

Evaluating the Avoided Capacity Cost (ACC) Benefit of Transmission in Long-Term Planning

April 2<sup>nd</sup>, 2026

# Where does the ACC benefit metric calculation fits within MISO's seven-step process?



# The ACC benefit metric is one of nine benefit metrics used in the LRTP business case

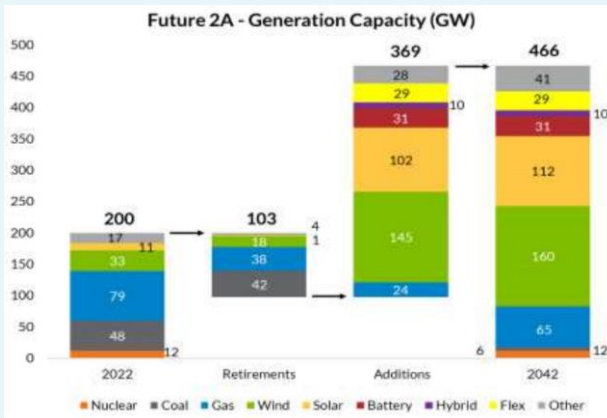
- Benefits are evaluated using assumptions defined in the Future 2A resource plan, and also Future 1A scenario to demonstrate robustness of benefits for a range of outcomes
- Leveraged methodology from ESIG’s Multi-Value Transmission Planning for a Clean Energy Future report
- Integrates probabilistic methods & reliability/transmission planning

List of LRTP T2.1 Benefit Metrics		
Energy benefits from reduced losses	Capacity benefits from reduced losses	Decarbonization
Mitigation of reliability issues	Congestion and fuel savings	Avoided transmission investments
Avoided capacity costs	Reduced risk from extreme weather impacts	Reduced transmission outage cost

# The long-range planning process begins with the creation process begins with the creation of Futures – critical planning scenarios to adequately bookend future uncertainties

## Initial Model-Build/Resource Expansion

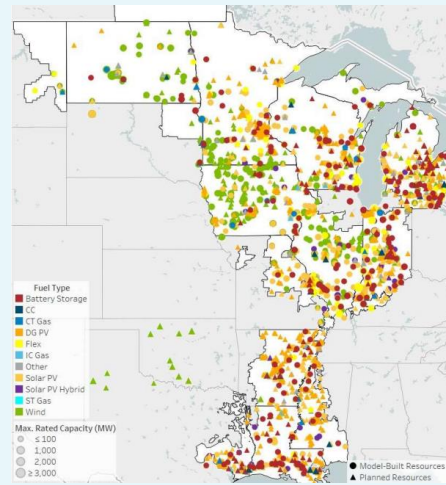
- Apply Futures assumptions
- Incorporate member plans – clean energy goals, resource additions, retirements
- Perform resource expansion to economically determine type, magnitude and timing of new resources



*Futures help account for resource gaps and highlight focus areas for planning throughout MISO*

## Siting

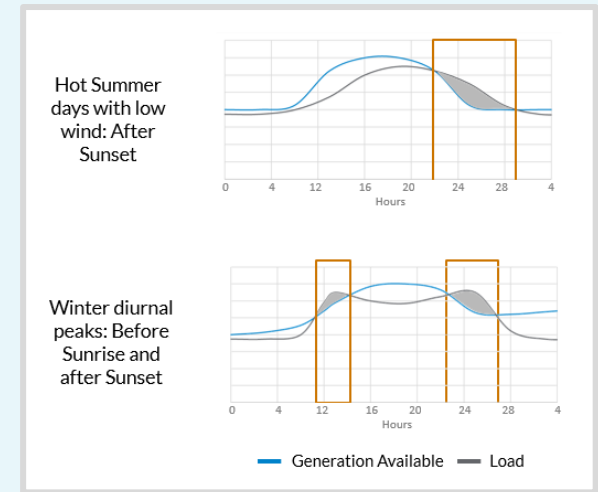
- Determine location to place each new resource in the transmission system
- Incorporate stakeholder feedback (500+ revisions) and update Siting



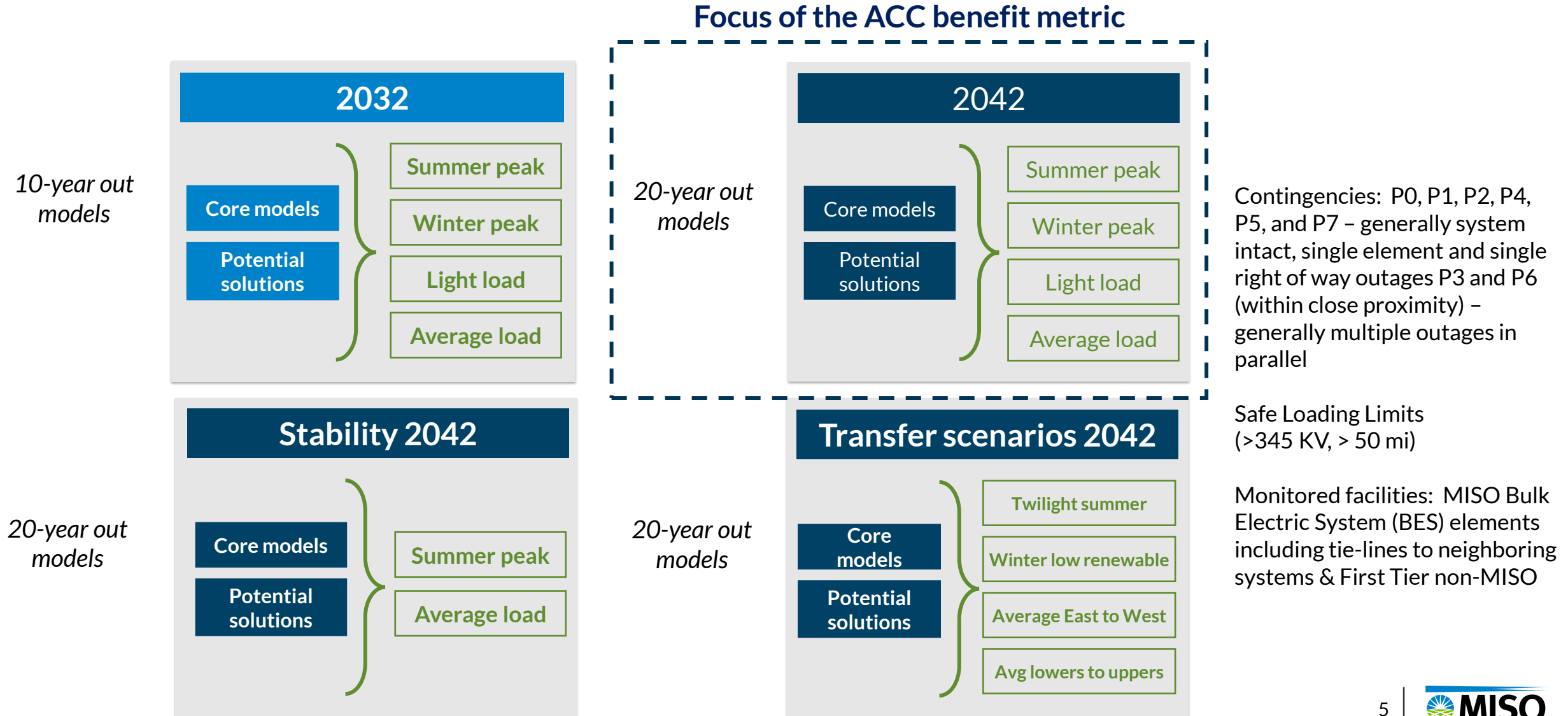
*Long-term planning analyses require sufficient resources throughout the study period, which can exceed what's currently known or publicly planned by members*

## Energy Adequacy

- Ensure all hours meet energy requirements
- Site 29 GW of resulting Flexible Attribute Unit capacity



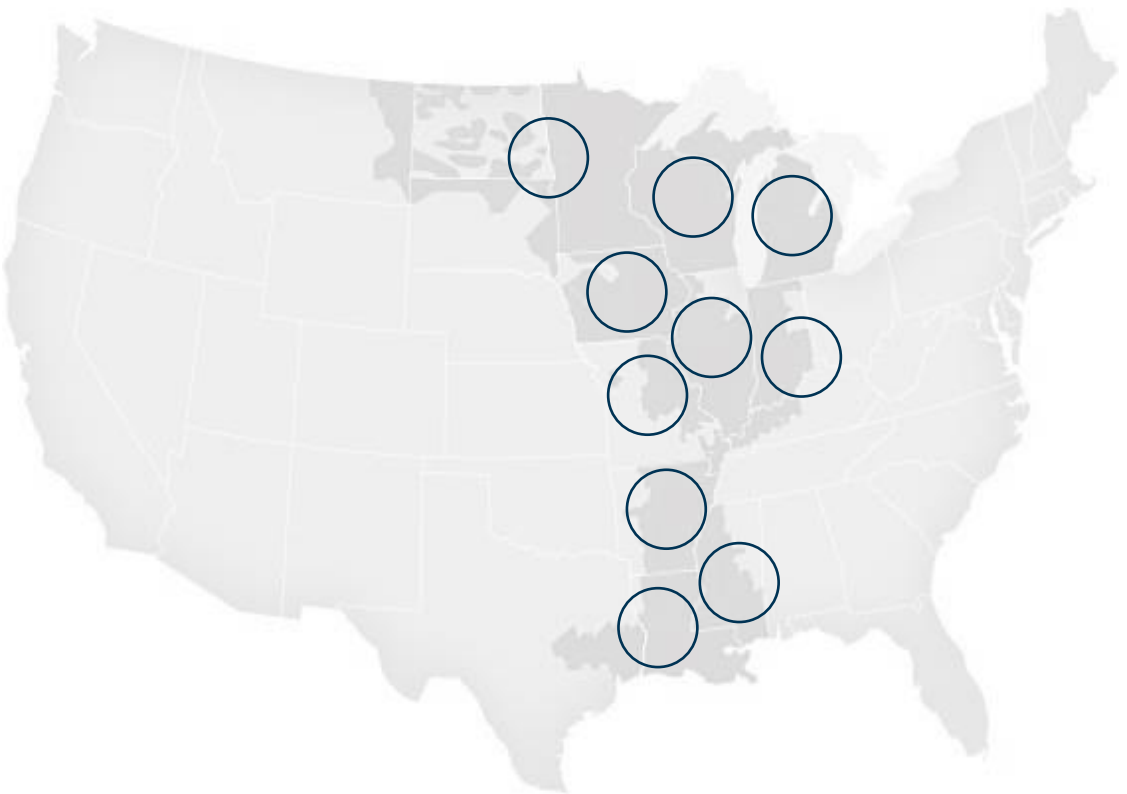
# Reliability models, with and without LRTP, are developed to calculate seasonal transfer limits for local resource zones (LRZ)



Probabilistic modeling is the core the ACC benefit methodology, which includes load and generation uncertainties, together with transfer limit constraints

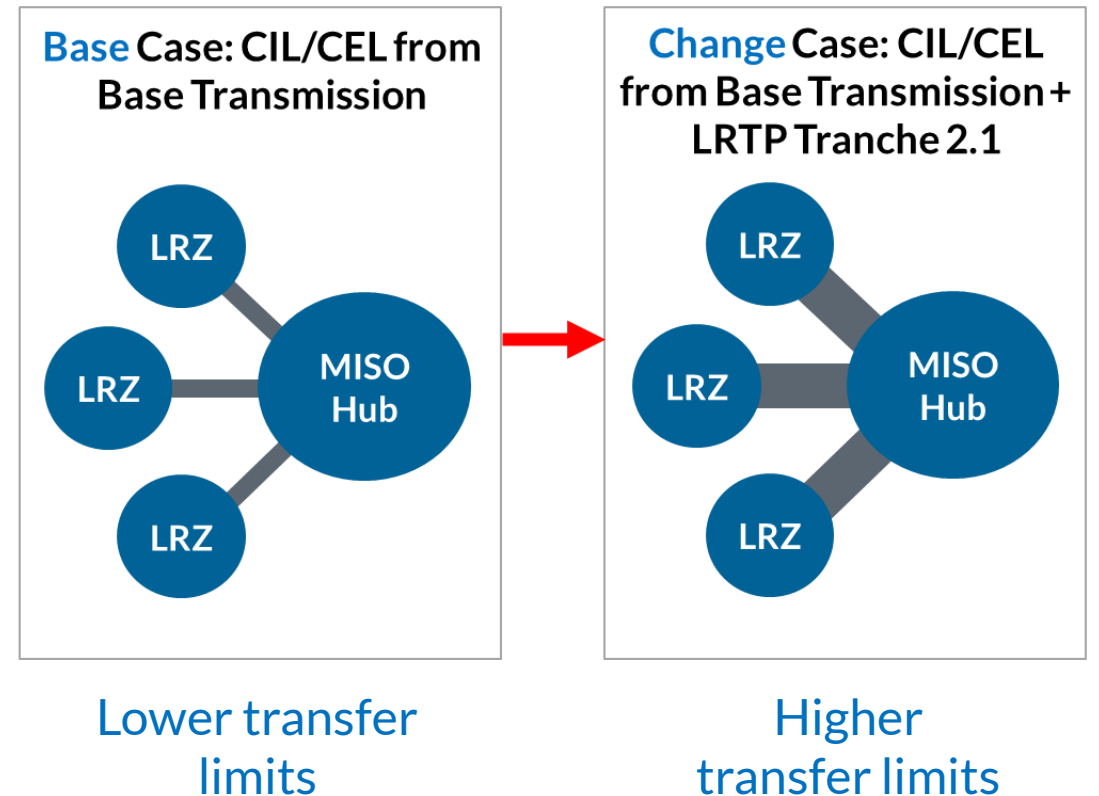
**Typical RA model**  
Unconstrained transmission

**LRTP T2.1 Probabilistic model**  
Constrained transmission



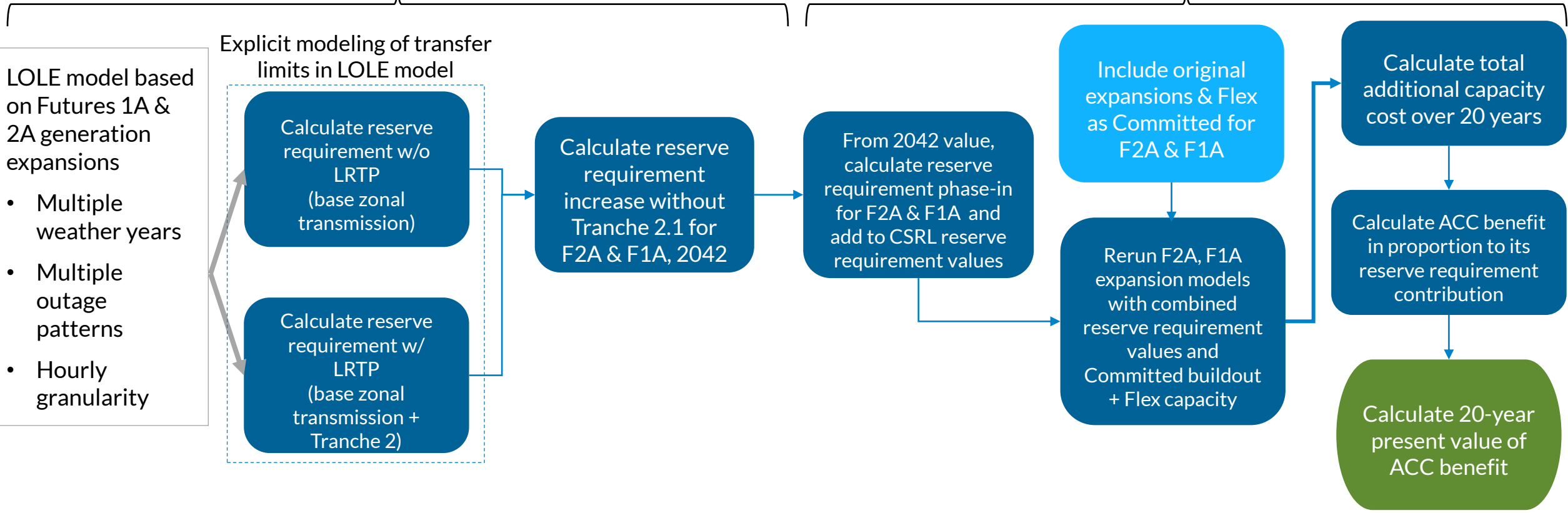
# The Avoided Capacity Cost (ACC) metric reflects the capital cost savings from the increase in transmission capability provided by LRTP, enabling access to resources over the wider MISO footprint

- This benefit leverages LOLE modeling and incorporates a simplified representation of transmission constraints
- The benefit assesses the change in loss of load expectation (LOLE) to determine the adjustment in planning reserves to meet the LOLE target with and without the LRTP portfolio
- Change in planning reserve is applied to the base PRM value used in the monetization step to determine the amount and composition of the additional resources that would be needed in the absence of LRTP



# The framework incorporates generation information from the Futures, seasonal transfers, probabilistic/LOLE modeling, and a final resource expansion used to monetize the benefit

LOLE Models:  
F2A & F1A, 2042



LOLE - Loss of Load Expectation

Base zonal and (Base zonal + Tranche 2.1) transmission was determined using a transfer analysis.

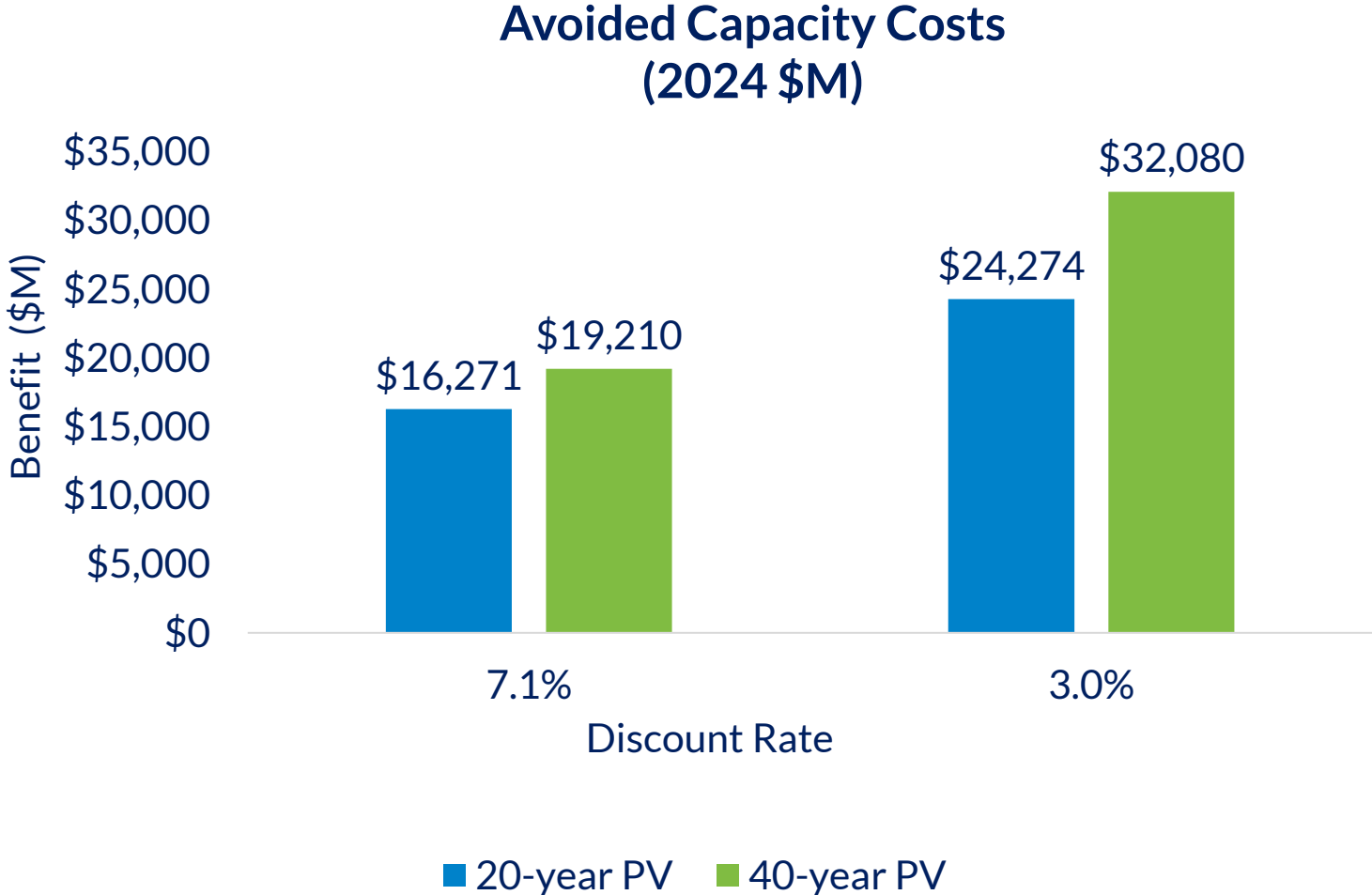
# To monetize the ACC benefit, a PRM delta value is assumed to increase over the last 10 years of the study period

- PRM is assumed constant until Tranche 2.1 projects come into service in 2032, and then increases as the expansions proceed to 2042
- Difference in PRM between the base and Tranche 2.1 cases will be added to the original 18% PRM assumption
- PRM change from base to Tranche 2.1 case calculated for 2042
- PRM change assumed to increase linearly from 2032 until 2042
- The total capacity addition is split into benefit components by the percent contribution to the additional PRM value

Combined ACC+CSRL PRM Phase-In					Avoided Capacity Costs (ACC)		Capacity Savings from Reduced Losses (CSRL)	
			Total	Total				
			PRM Enforced (%)	PRM Addition (%)	% Contribution to Total Additional PRM, 2042:			
					90%		10%	
Year	1	2023	18.05					
	2	2024	18.05					
	3	2025	18.05					
	4	2026	18.05		ACC		CSRL	
	5	2027	18.05		2032-2041 values extrapolated		Interim values interpolated	
	6	2028	18.05		from 2042 value		from 2032, 2042 values	
	7	2029	18.05					
	8	2030	18.05		Additional PRM (%) from CIL/CEL:		Additional PRM (%) from reduced losses:	
	9	2031	18.05					
Year	10	2032	19.66	1.61	0.80	2032	0.81	
	11	2033	20.47	2.42	1.59	2033	0.83	
	12	2034	21.28	3.23	2.39	2034	0.84	
	13	2035	22.10	4.05	3.19	2035	0.86	
	14	2036	22.91	4.86	3.98	2036	0.88	
	15	2037	23.72	5.67	4.78	2037	0.90	
	16	2038	24.54	6.49	5.57	2038	0.91	
	17	2039	25.35	7.30	6.37	2039	0.93	
	18	2040	26.17	8.12	7.17	2040	0.95	
	19	2041	26.98	8.93	7.96	2041	0.97	
Year	20	2042	27.81	9.76	8.76	2042	1	

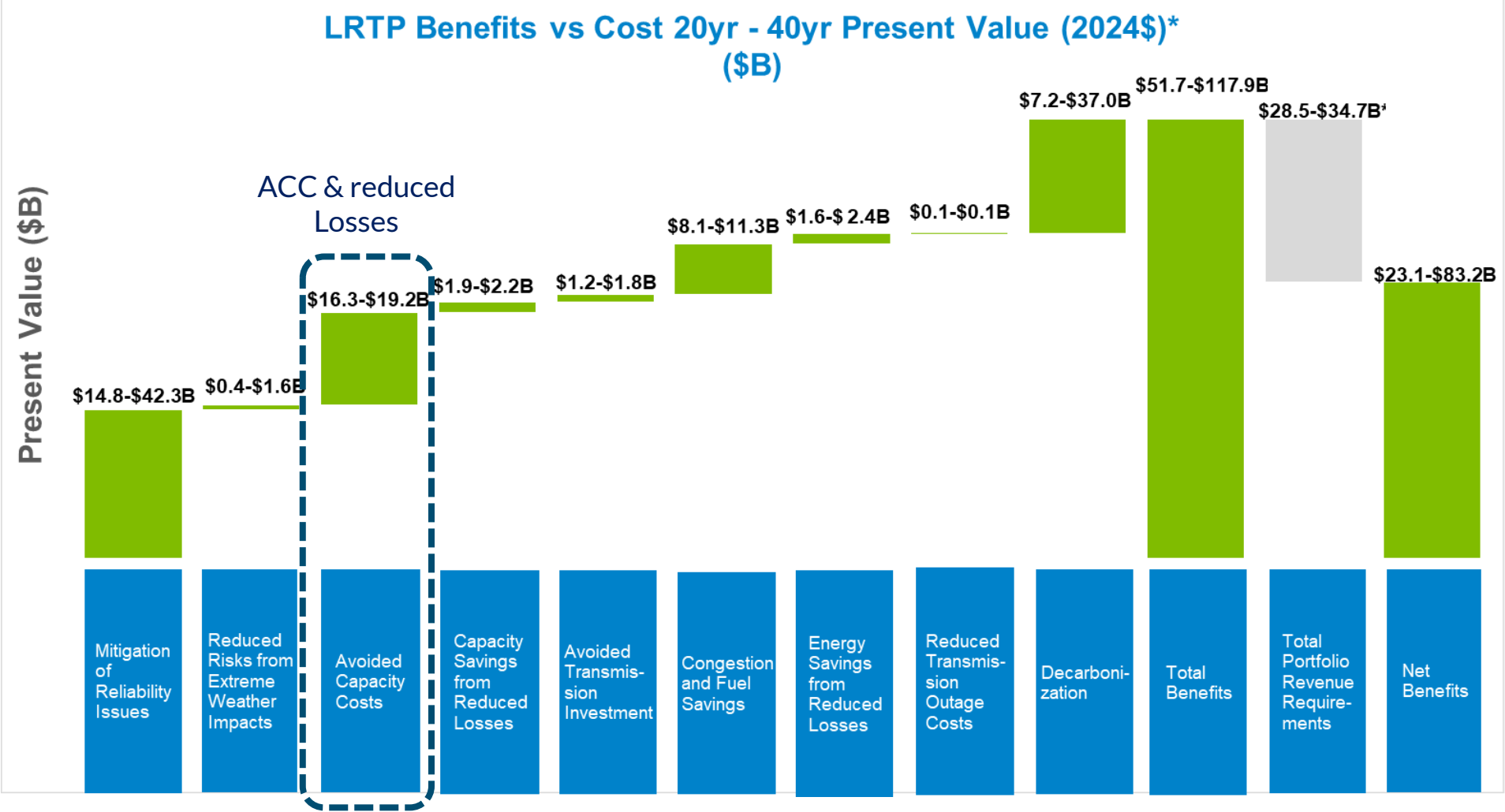
# Tranche 2.1 portfolio improves transmission capacity to provide more efficient resource investment

- LRTP Tranche 2.1 enables access to regional resources, which reduces the need additional capacity investment
- LRTP Tranche 2.1 avoids the need for 22.8GW of capacity in addition to F2A resources and provides a 20-year present value benefit of \$16.3B\*



# Tranche 2.1 portfolio under Future 2A provides a regional benefit-to-cost ratio of at least 1.8 capturing multiple types of reliability, economic and policy value

**F2A Total B/C ratio ranges from 1.8 to 3.5**



Link to LRTP Tranche 2.1 metrics [whitepaper](#).

# Questions?

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# Integrating Large Loads and Flexibility into Resource Adequacy Planning

NARUC Virtual Training | Aaron Schwartz



T E L O S E N E R G Y

# A surge in data center-driven load growth is reshaping electric power system planning

- Data center loads are growing rapidly, increasing from 1.9%-4.4% of total annual U.S. electricity consumption from 2018-2023, and projected to reach 6.7%-12.0% by 2028.<sup>1</sup>
- Globally, \$200B-\$600B in electric sector capital investment projected by 2030 at stake in planning decisions.<sup>2</sup>
- Where data centers are being considered in IRP, **planners have been making a key assumption — that data center operations are *inflexible*.**

2. <https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/the-cost-of-compute-a-7-trillion-dollar-race-to-scale-data-centers>

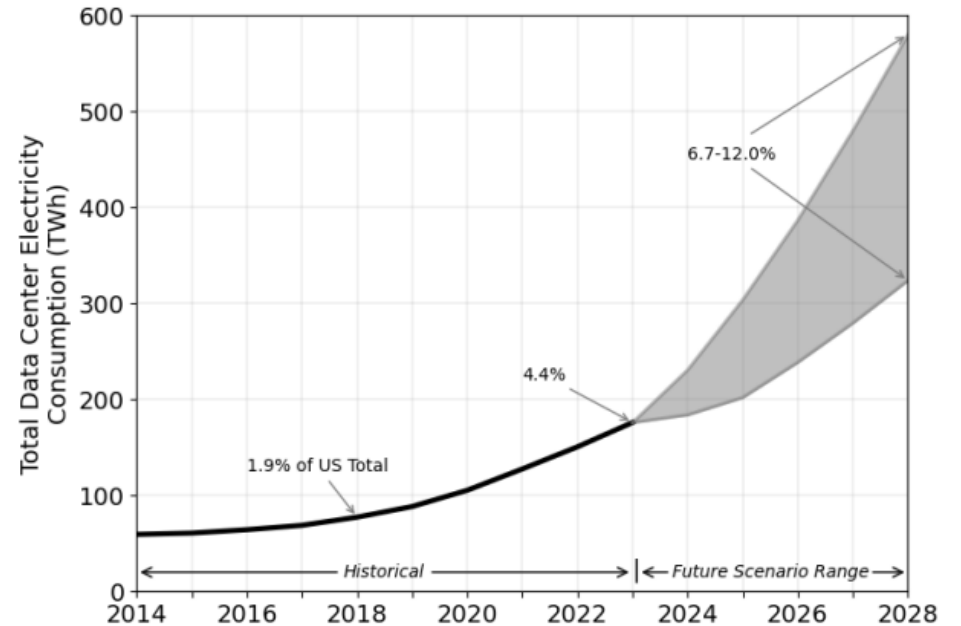
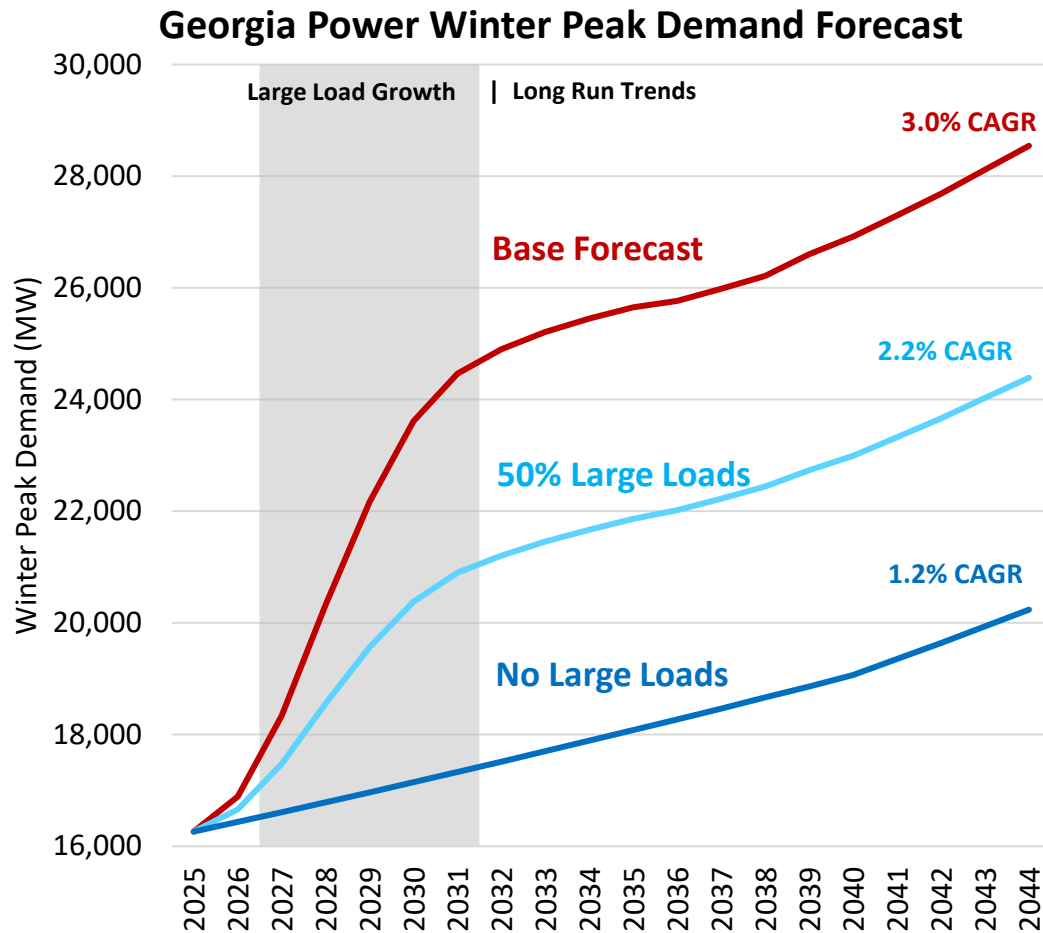


Figure ES-1. Total U.S. data center electricity use from 2014 through 2028.

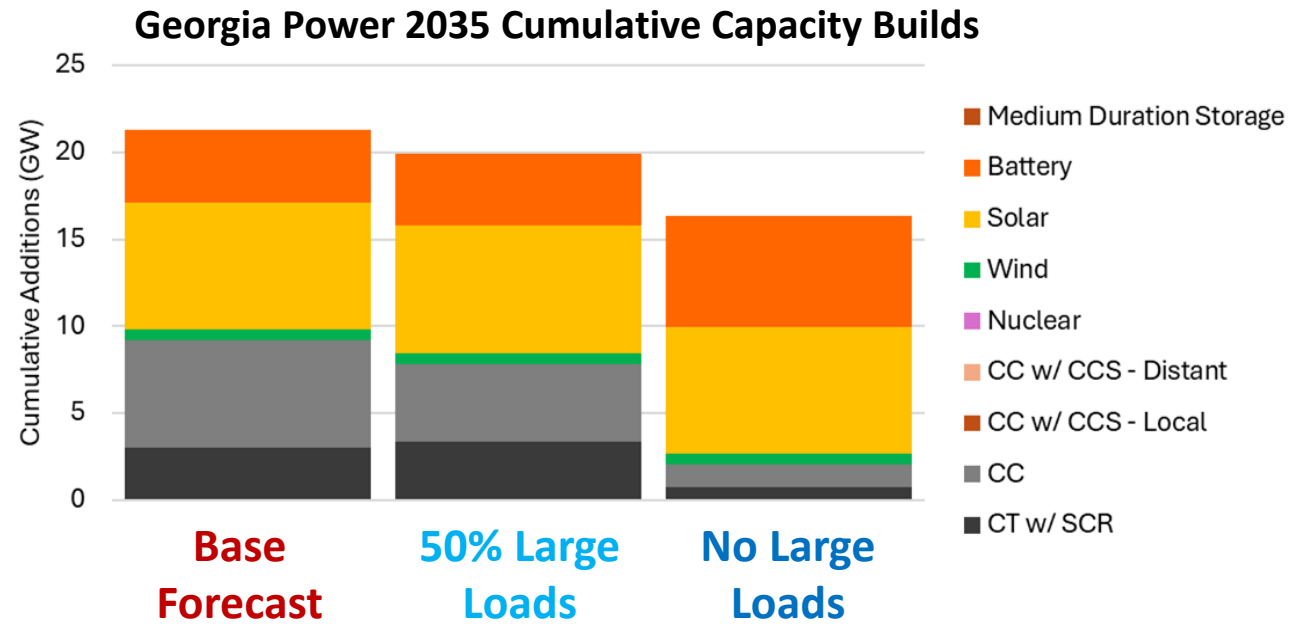
1. Source: Shehabi, A., Smith, S.J., Hubbard, A., Newkirk, A., Lei, N., Siddik, M.A.B., Holecek, B., Koomey, J., Masanet, E., Sartor, D. 2024. *2024 United States Data Center Energy Usage Report*. Lawrence Berkeley National Laboratory, Berkeley, California. LBNL-2001637



# Avoid overbuilding capacity due an uncertain large load forecast



Source: GPC 2025 IRP, [Direct Testimony of Derek Stencik](#)



- Rely on **scenario analysis** and multiple build plans at various large load levels
- Include a “No Large Loads” scenario as a **reference point**
- Utilize back-up bids in resource procurement to adjust as the forecast changes



# Use long-term contracts to determine which loads should be in the forecast

“Queue shopping” is pervasive in the industry and the risk of significantly overstating total data center demand

IRPs should not rely on queue requests or transmission cost allocation as the primary input to the load forecast...

...but rather **long-term contracts** and **upfront collateral**



[EFG: Review of Large Load Tariffs](#)

## Google’s Capacity Commitment Framework

- I. **Non-discriminatory:** applies to all large loads over XX MW, regardless of end use
- II. **Long-term Commitment:** 10+ year commitment, with clauses for ramp up periods and exit charges
- III. **Significant Minimum Charges:** pay 80% + of total demand charges regardless of usage.
- IV. **Upfront Collateral:** multiple years of up-front changes
- V. **Flexible & Transparent Modifications:** allow exits or changes but with appropriate protections



# Isolate the incremental costs or large loads to ensure fair cost allocation

IRPs can and should always include a reference point without the addition of new large loads

Serves as a counter-factual of what generation and transmission costs would be for the existing ratepayers

Can be used for **cost allocation** and to support **rate negotiations**



# Why should we be thinking about flexibility from large loads?



Decrease total capacity needs



Utilization of existing behind-the-meter generation for capacity



Key tool for maintaining resource adequacy during scarcity events



Supply chain constraints → delayed timelines/high costs for new capacity

**Important note for resource adequacy use cases...**

Flexibility is **not required on a regular basis** but can be reserved for exceedingly rare events that may only occur a couple times per year or fewer.

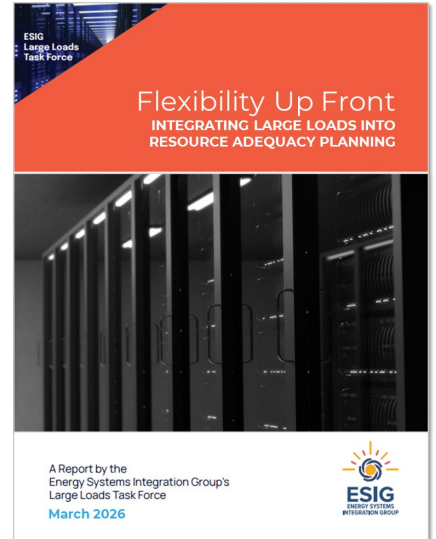
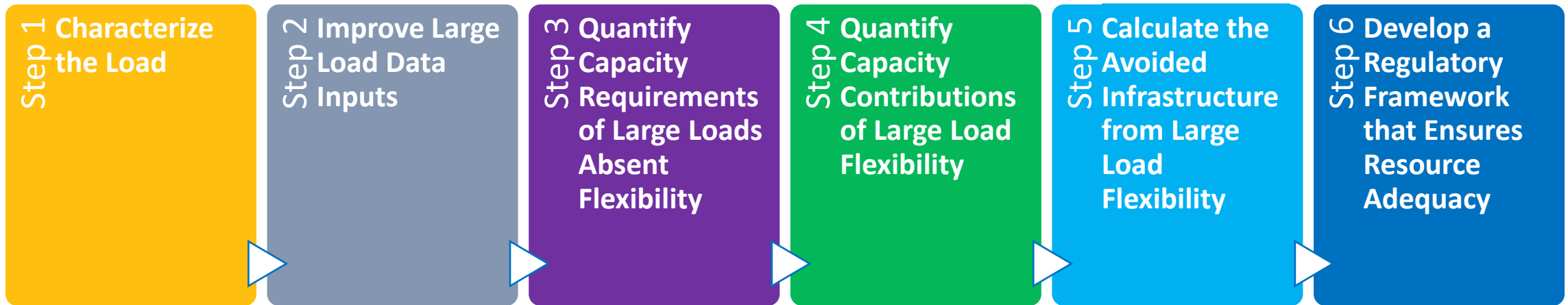
In contrast, flexibility for energy or ancillary markets would require regular, day-ahead and real-time use.



# Six-Step Process to Plan for Flexibility

**Objective:** Develop a modeling guidebook and methodology that resource planners at utilities and ISOs can implement in their IRP or capacity accreditation framework.

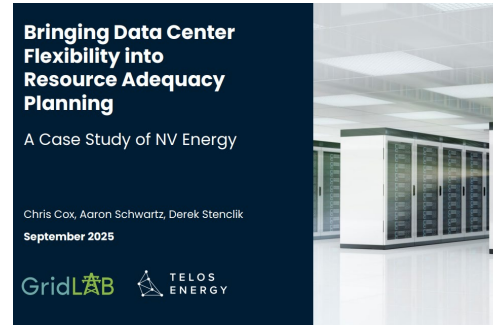
**Key Outcome:** Proactively plan for flexibility **up front** in the capacity procurement process.



**New ESIG Report  
Coming Soon!**



# Applying the Six Steps: Analytical Framework for NV Energy Data Center Flexibility Study



**A** **Step A: Prepare Load Data**

Hourly Demand

Pull Out DC Load

Adjusted DC Load

**Output:** Adjusted hourly load shapes

**B** **Step B: Run CEM Baseline w/o DC Flexibility (LT)**

Base Portfolio

**Output:** Baseline capacity, costs, & emissions

**C** **Step C: ELCC Study (MT/ST)**

	99.9%	99.7%	99.5%
1 GW	A	B	C
2 GW	D	E	F

**Output:** DC flexibility ELCCs

**D** **Step D: Run CEM Baseline w/ DC Flexibility (LT)**

ELCC Matrix Scenario A

ELCC Matrix Scenario B

ELCC Matrix Scenario C

...

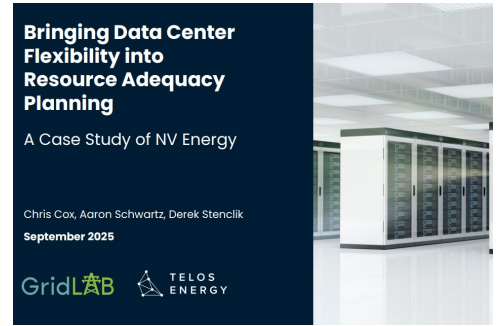
ELCC Matrix Scenario F

**Output:** Capacity, costs, & emissions across ELCC scenarios

**F** **Final Output (for each scenario):**

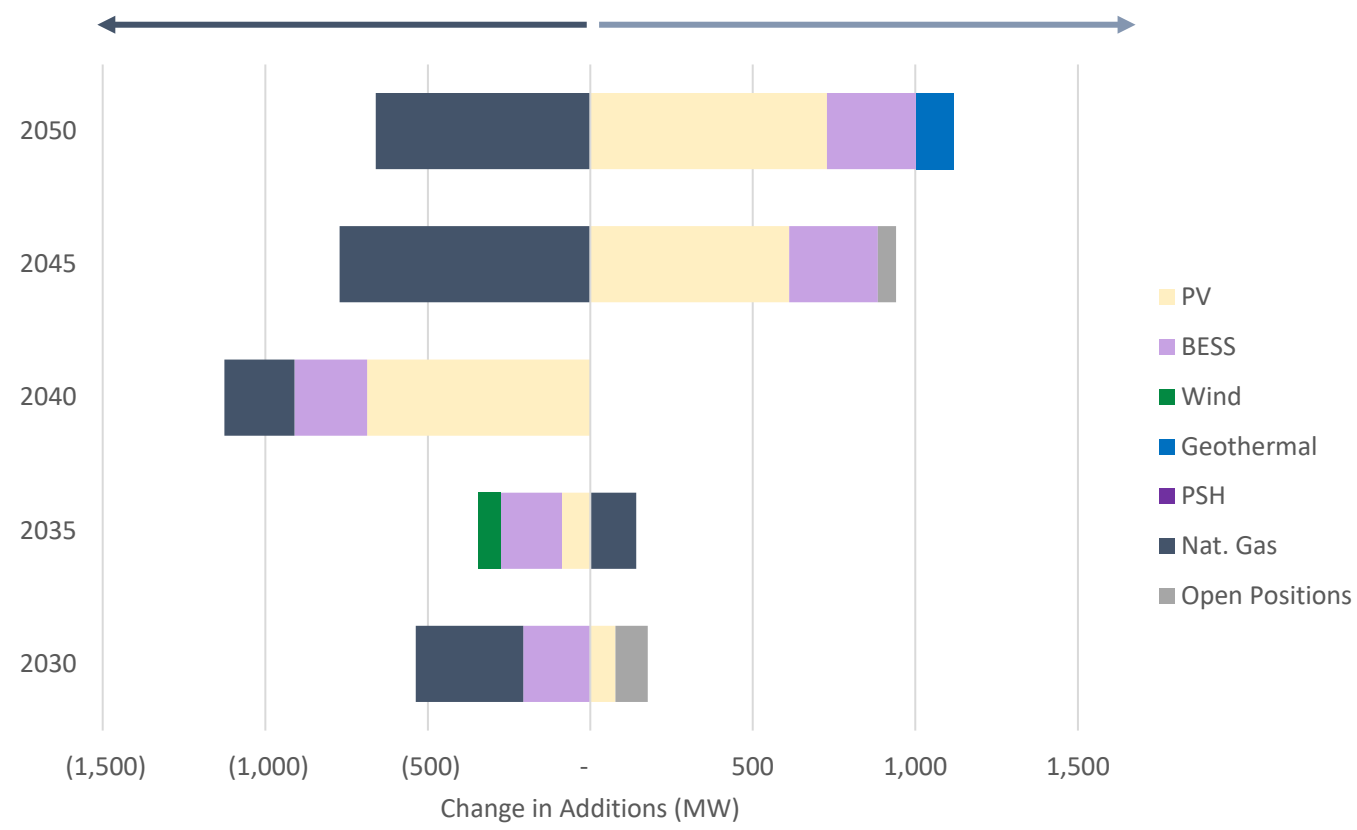
- Avoided capacity needs (MW)
- Avoided costs (NPV)
- Avoided emissions (MMT)

# Incorporating flexibility assumptions into planning can reduce capacity needs and portfolio costs



[https://gridlab.org/datacenter\\_flex/](https://gridlab.org/datacenter_flex/)

Reduced capacity additions    Increased capacity additions



## Availability (% Uptime Required by DCs)

Max Response	99.5%	99.7%	99.9%
1 GW	87%	86%	67%
2 GW	77%	66%	46%

**Benefits**  
Reduced CapEx and FO&M  
**\$586 Million**



**Costs**  
Additional OpEx  
**\$278 Million**

**NPV of Savings:**  
**\$308 Million**

# More and better data is needed to improve resource adequacy analyses with large loads

The industry in general, and resource adequacy practitioners in particular, [need more data](#)

Data Need	Current Status	Essential	Preferred
Size	●●●○	Nameplate Capacity	Annual Ramp Rate
Load Forecast Range	●●●○	Large load layers by end use & scenario without large loads	Load scenarios & probabilities
Location	●●○○	Zonal	Nodal
Hourly Characteristics	●●○○	8760 Chronological Hourly Loads	Disaggregated Profiles by Large Load
Weather Dependence	●○○○	Exclude large loads from underlying load-temperature relationship	Multiple weather years of large load data
Resource Configuration	●○○○	Load Type, On-site Generator Specs, Run-hour limitations	Market price sensitivity, Flexibility parameters



Thank you!

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T E L O S E N E R G Y

NARUC Training:

*Large-Load Flexibility in Practice: Opportunities, Limits, and Regulatory Implications*



## Verrus Data Centers

The next generation of  
data center capacity

GRID AWARE, CARBON AWARE, COMPUTE AWARE™

April 2025

# Verrus: Reimagining the Data Center as a Grid Asset

Transforming static IT load into a dispatchable, grid-responsive resource through the Verrus **Powerflow™** platform



## Innovative Design

- **Integrated Powerflow™ Platform:** A grid-aware "operating system" that synchronizes electrical hardware, server workloads, and onsite battery storage throughout the facility.
- **Dynamic Load Balancing:** Moves beyond internal power management to actively balance energy flow across the interconnect with utility-scale, asset-backed load flexibility.
- **The "Grid Shock Absorber":** Megawatt-scale optimization that improves grid asset utilization for both utilities (upstream) and AI customers (down-stream), while strengthening resiliency and reliability for both.

# Built by Veterans. Engineered for the Future.

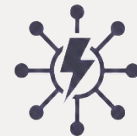


The Verrus team has led infrastructure, power, and design for the world's most sophisticated hyperscalers and utilities.



## Hyperscale DNA

We built the first generation of cloud infrastructure from inside the hyperscalers. At Verrus, we're carrying that experience forward to create the next generation of data centers - engineered to be flexible, efficient, and purpose-built for the future.



## Grid & Utility Insight

Deep expertise in energy procurement and grid stabilization allow us to unlock capacity and help the grid where others see constraints.



## Operational Excellence

Decades of experience with a proven track record of managing multi-billion dollar portfolios and delivering complex infrastructure on schedule.

We aren't just building another data center. We are building the industry's new standard.

# Opportunities

Classifying large load flexibility by category and mechanism

## Flexibility Categories

Curtailment



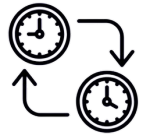
**Software-Based**  
(IT/Compute)

**Hyperscaler workload reduction:** Skipping or reducing the sample rate of log data processing temporarily during peak

**Facility-Based**  
(Infrastructure/On-site)

**Utility import reduction:** Reducing utility import and running the data center facility off behind-the-meter (BTM) gas generation at peak; mechanical load reduction via adiabatic system dispatch

Time Shifting



**Job scheduling:** Delaying AI training jobs to run only during off-peak windows

**Storage utilization:** Reducing grid import and running workloads off a Battery Energy Storage System (BESS) during peak; recharging during off-peak

Location Shifting



**Workload migration:** Moving background video transcoding workloads from the West Coast to the East Coast during peak

N/A

# What makes Verrus Flexible Data Centers different?

Verrus takes a next generation approach to data centers that:



**Consumes 99% less water** than legacy design data centers through closed-loop cooling and seasonal spray misters.



Uses **battery energy storage systems (BESS)** rather than **diesel generators** as primary backup power, for a safer, cleaner, quieter, more energy-efficient approach.



**Supports “keeping the lights on” for everyone** by using data center batteries to act as automatic “shock absorber” for the electric grid. The data center responds in seconds to reduce power demand when the grid is most strained.



Helps utilities **keep overall energy rates in check for all customers**, benefiting local residents and businesses alike. By helping pay for the existing grid less is needed from current customers to maintain the grid. Also **avoids need for new “peaking” power plants**.



Support local schools and public infrastructure with **sizable property tax contributions**



# As a big electric customer how will the data center help electric reliability and affordability?

Verrus data centers help keep energy rates in check while supporting reliability as a grid shock absorber

Verrus™ is building a new and fundamentally different kind of grid-interactive data center that serves as an asset to help the grid, rather than just an energy consumer.

Our grid-interactive facilities include a battery energy storage system (BESS) that enables the data center to act as a “shock absorber” for the electric system, reducing power import during peak times when the grid is most strained, rather than adding stress.

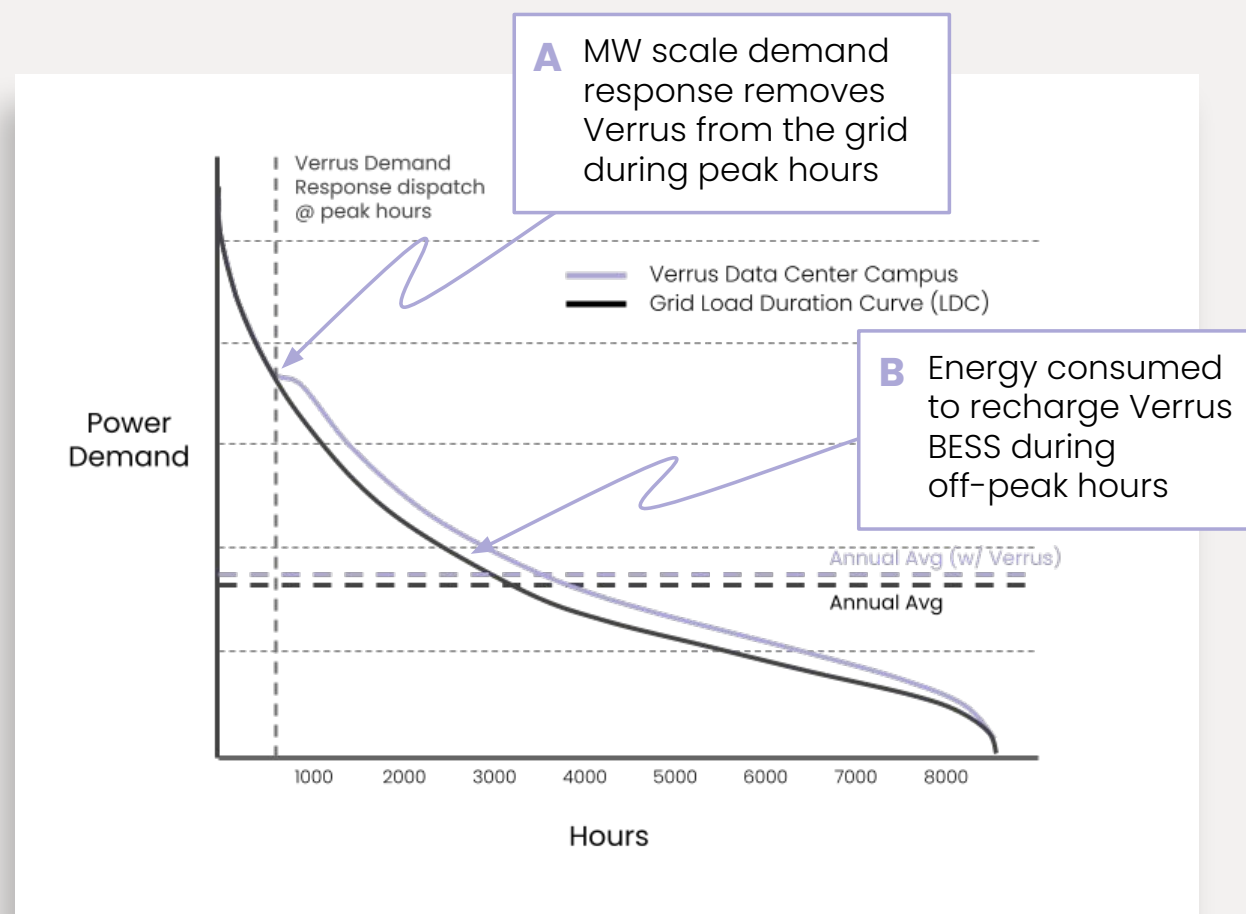
This flexible approach helps utilities **maintain reliable service** year-round and ensures either **maintenance or improvement of energy rates**, benefiting local residents and businesses alike.

Verrus™' grid-supporting capabilities were validated earlier this year in a [study conducted along with the National Lab of the Rockies \(NLR; formerly NREL\)](#), in collaboration with MISO and Xcel Energy.



# Driving Reliability and Lowering Ratepayer Costs

Decoupling load growth from infrastructure spend to keep the grid stable and affordable



Representative utility Load Duration Curve (LDC)

- **Asset-Backed Load Flexibility:** We leverage integrated battery storage and "computational shedding" to drop load instantly during grid stress, providing a high-confidence alternative to traditional firm capacity.
- **Infrastructure Avoidance (NWA):** By dynamically managing our peak demand, we reduce or eliminate the need for costly new generation and transmission backbone investments typically required to serve large-scale AI loads.
- **Downward Pressure on Rates:** Our model provides high-utilization revenue to the utility with zero or minimal incremental infrastructure cost, directly subsidizing the grid for all residential and industrial ratepayers.
- **Reliability Without Sacrifice:** Our **Powerflow™** platform ensures that while the grid sees a reduction in demand, our critical IT operations remain stable, proving that data centers can be partners in resilience, not just consumers of it.

# Verrus' Digital Twin: A Test Platform for Grid-Interactive Data Centers

Advanced simulation of delivering grid flexibility without compromising IT workload SLAs



A first-of-its-kind, 70MW-scale test platform, **"Vulcan"**, developed by Verrus in partnership with NREL, powered by the **NREL ARIES Virtual Emulation Environment**, that emulates a full-scale Verrus data center under realistic grid conditions to test and validate next-generation power control strategies.

## Why It Matters:

- Demonstrates how purpose-built data centers can act as **flexible, dispatchable grid assets** while **maintaining customer SLAs**
- Built to address urgent grid challenges posed by **surging AI-driven power demand**
- **Bridges the gap** between theoretical potential and operational reality

## What It Enables:

- ✓ **Digital Real-Time Simulation (DRTS)** of dynamic electrical behaviors across a wide range of grid and data center scenarios—including voltage sag, frequency excursions, and DER coordination—at millisecond resolution
- ✓ **Controller Hardware in-the-Loop (CHIL)** integration to test live control systems in closed-loop conditions
- ✓ Validated performance for fast load shedding, islanding, and backup transitions
- ✓ Tuning of real-time control algorithms to optimize frequency support, ramping, and ride-through capabilities

LATITUDE MEDIA | COVERING THE NEW FRONTIERS OF THE ENERGY TRANSITION

## Verrus successfully demos its flexible data center technology

The Sidewalk Infrastructure Partners' venture used an NREL testing software platform to validate its tech under real-world grid conditions.

—BIANCA GIACOBONE | MAY 15, 2025

# Partnering for a More Resilient Grid

Accelerating "Beneficial Load" interconnection to drive growth, suppress rates, and avoid infrastructure overbuild



## Key Needs from Utilities/Regulators

- **Establish "Flexible Large Load" Class** – Verifiable automated dispatchability and at a scale to matter on the grid (e.g., 25–100% load drop with 20 MW minimum corresponding with the large generation interconnection minimum)
- **Study/Value Flexibility based on NET Capacity draw** – Current study processes are inequitable because they fail to evaluate flexible loads based on their operational reality.
- **Prioritize Interconnection Based on Grid Benefits** – The "first-come, first-served" queue model is broken. It currently allows speculative, inflexible projects to clog the queue, blocking projects that are ready to support the grid.
- **Align with NERC Reliability Standards** – Flexibility cannot be a vague promise; it must be an enforceable reliability product.



Questions?

# Near-term winter resource adequacy challenges in the Pacific Northwest

A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges

**SYLVAN**  
ENERGY ANALYTICS

NARUC RA Training  
Sylvan Energy Analytics  
April 2, 2026

This work was sponsored by **GridLAB**

# Who we are



Sylvan Energy Analytics is a boutique energy consulting and software firm based in Portland, Oregon.

We specialize in integrated resource planning, capacity expansion and production cost modeling, resource adequacy, clean energy policy, and utility regulation.



GridLab is a non-profit public interest organization with a mission to provide expertise to enable grid transformation.

GridLab and Sylvan have collaborated on open-source resource adequacy analysis, clean energy planning, and novel resource portfolio optimization techniques.

# Background

- In the Fall of 2025, Energy & Environmental Economics (E3) released Phase 1 results of a study examining resource adequacy in the Pacific Northwest
  - The study was sponsored by most of the electric utilities operating in the Pacific Northwest
  - It projected a 9 GW shortfall by 2030 across the “Greater NW,” with the potential for multiday supply shortages during winter cold events and shortages as soon as 2026
  - Phase 1 results suggested limited ability for clean resources (wind, solar, and short duration battery storage) to meet the identified needs
  - Phase 2 is underway and is expected to be released in early 2026
- Given the urgency of the Phase 1 findings, Sylvan was engaged by GridLab to review E3’s analysis and findings and identify near-term opportunities to support regional RA



## Greater Northwest

Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
<b>Reliability Position Surplus (+) / Shortfall (-)</b>	<b>+1,221</b>	<b>-1,321</b>	<b>-3,354</b>	<b>-5,046</b>	<b>-7,031</b>	<b>-8,689</b>
ELCC from “In-Development” Firm Resources	-	296	407	580	770	1,114
ELCC from “In-Development” Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

\* Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime

We would like to thank E3 and the study sponsors for their time and attention in answering our questions

# High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
<b>Large load flexibility</b>	<ul style="list-style-type: none"> <li>• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2</li> </ul>	High
<b>Hydro flexibility</b>	<ul style="list-style-type: none"> <li>• E3 study may underestimate weekly energy shifting available from hydro dispatch</li> <li>• E3's load following hydro dispatch assumption may overlook contributions from short-duration storage</li> </ul>	Uncertain (requires further study)
<b>Imports and coordination with California</b>	<ul style="list-style-type: none"> <li>• E3 study assumptions may slightly underestimate import winter capability</li> <li>• Winter import capability is limited by transmission, not generation (California has several GWs of unused gas capacity available during PNW winter events)</li> </ul>	Low
<b>Retirements and conversions</b>	<ul style="list-style-type: none"> <li>• Phase 1 results slightly overstated RA challenges by treating coal-to-gas conversions as retirements in initial need evaluation</li> <li>• E3 study Phase 1 did not include Centralia coal-to-gas conversion (it had not yet been announced)</li> </ul>	Low-to-moderate

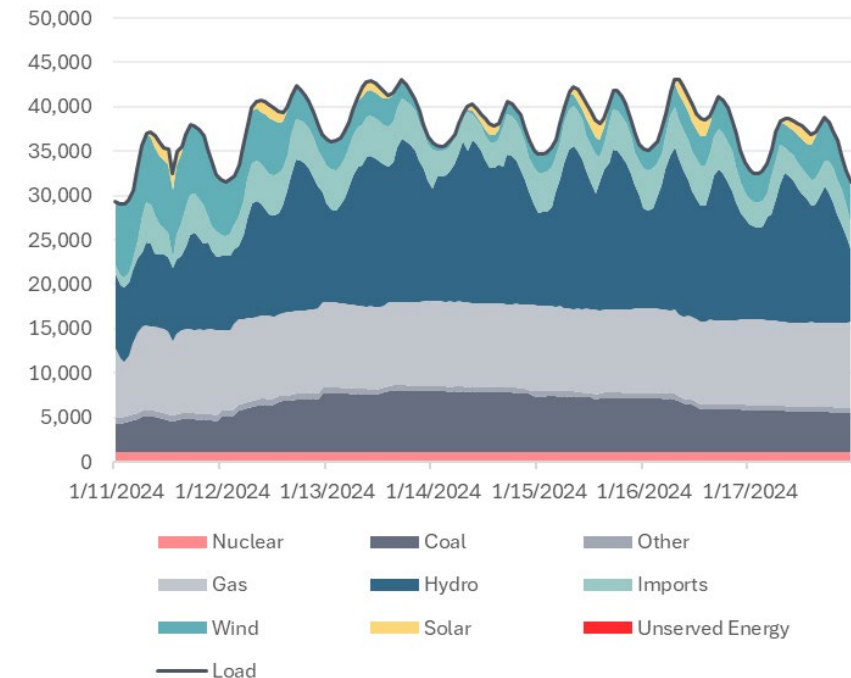
# Independent evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the **recent January 2024 winter event** might unfold if experienced in 2030 under various scenarios.

## GridPath dispatch simulation approach:

1. Developed dispatch simulation for the “Greater NW” that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
  - Resources in development
  - Emergency large load management
  - Additional proposed clean resources

Simulated dispatch in January 2024 benchmarking run

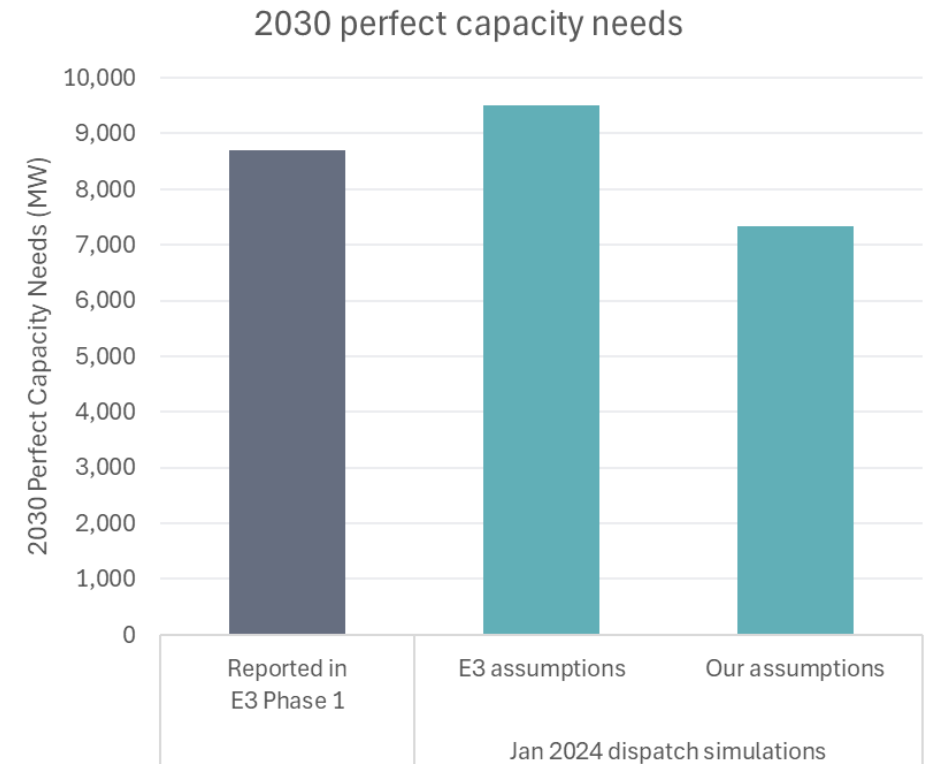


# Key assumptions

	Our analysis	E3 study
Footprint	BAs in OR, WA, ID, MT + PACE	BAs in OR, WA, ID, MT (excluding WAUW) + PACE
Hydro dispatch	<b>Optimized</b> with weekly energy budgets, minimum, maximum, and ramping constraints based on Jan 2024 hydro dispatch; unconstrained energy shifting allowed between weeks 2 & 3	Load-following heuristic with weekly budgets with up to 5% inter-week energy shifting, minimum and maximum levels based on historical min/max as a function of energy budget
Transmission constraints	2024 benchmark: <b>Constrained flows</b> between PACE and PNW based on high and low observations across January 2024 historical observations 2030 simulations: Added 1,000 MW bidirectional capacity associated with B2H by 2030 (total in 2030: -1,150 MW to +3,410 MW)	None in RA analysis (zonal results are from separate simulations, each assuming a copper plate)
Import constraints	<u>Total: 5,000 MW</u> Into PNW zone (excluding Canada): 3,000 MW Canada to PNW: 1,000 MW Into PACE: 1,000 MW	<u>Total: 3,750 MW</u>
Canadian entitlement	2024 benchmark: 660 MWa net exports into Canada across the month, but allowing Canadian storage to also support imports in any given hour 2030 simulations: Same, but net exports reduced to 590 MWa	590 MW exports to Canada in all hours, no accounting for Canadian storage or import capability from Canada
2030 baseline resource fleet	Existing based on operational resources as of January 2024 (EIA 930), in development resources based on 2024 EIA 860 Dave Johnston 3 retired <u>Coal-to-gas conversions of Centralia 2, Dave Johnston 1 &amp; 2, Naughton 1 &amp; 2</u>	Existing and in development resources based on WECC ADS Dave Johnston 3 and <u>Centralia 2 retired</u> Coal-to-gas conversions of Dave Johnston 1 & 2, Naughton 1 & 2 (however in initial need evaluation, these are retired)
2030 Load	Four load scenarios that combine different outlooks for organic load growth and data center demand, plus a load scenario that approximates E3's forecasted load growth	PATHWAYS-based bottom-up loads with adjustments and internal data center forecast

# Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
  - **E3 assumptions:** uses E3's import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
  - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas), except Centralia 2
- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
- Our dispatch analysis generally corroborates E3's findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3's projected load growth



# Alternative 2030 load scenarios

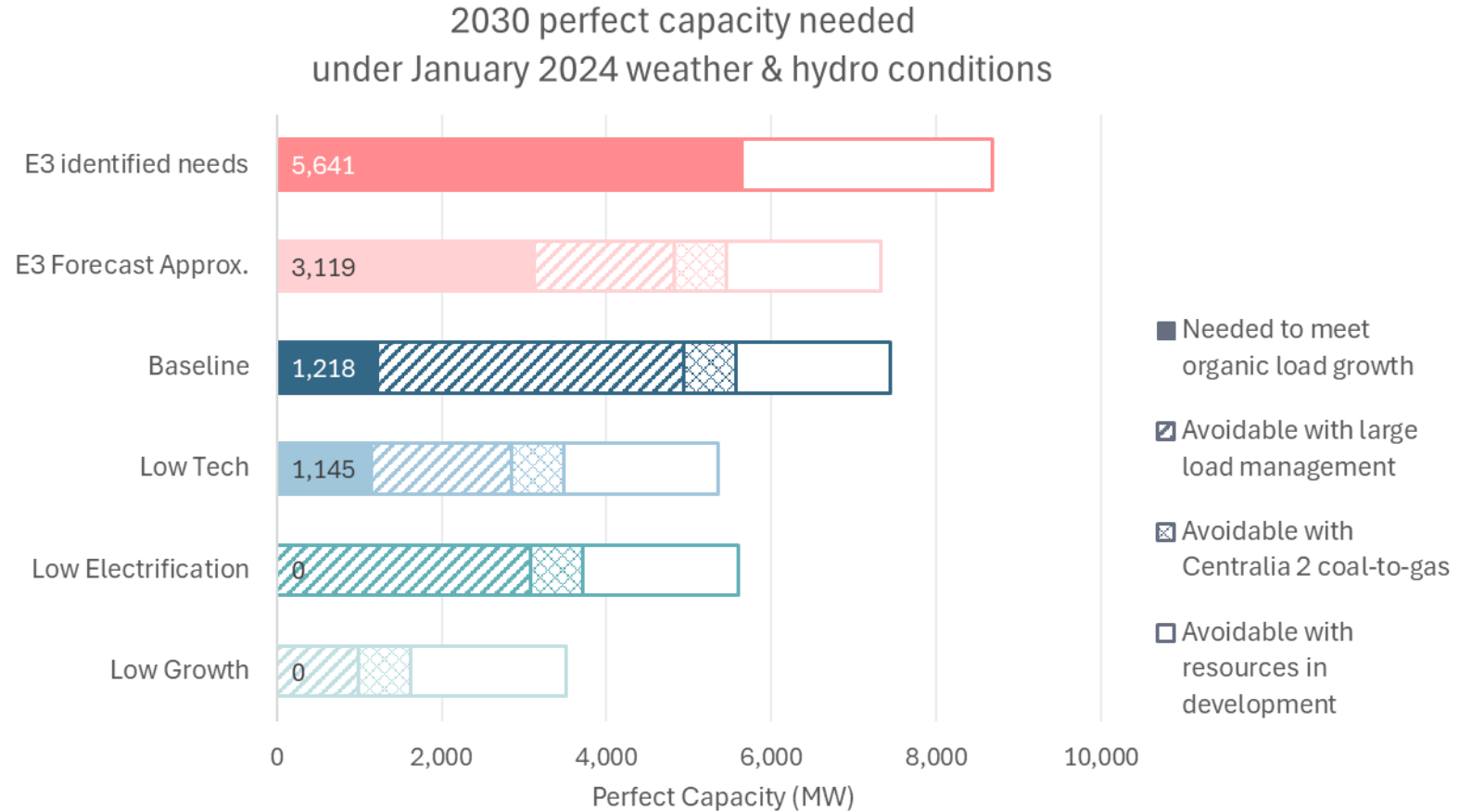
We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			1.3%

All alternative load scenarios envision accelerated load growth relative to the last 6 years

# High level findings from independent evaluation


1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios



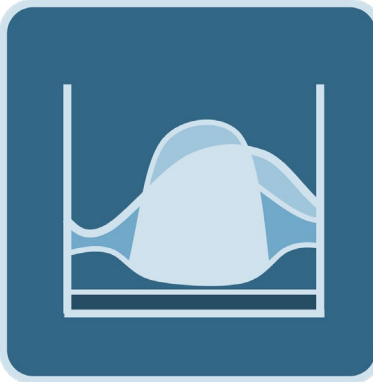

# Addressing supply shortages with new clean resources

- Next, we allowed the model to select additional resources from projects that were proposed but did not have regulatory approvals (as of December 2024) to meet demand across the January 2024 weather/hydro conditions under the Baseline Load Scenario
  - A. To meet organic load growth; and
  - B. To meet all load growth, including data center demand
- Findings are broadly indicative
  - Resource costs were high level and imprecise (i.e., these are not optimal selections)
  - Assumed proposed projects have the same hourly availability as existing projects by technology and zone (i.e., understates diversity benefits)

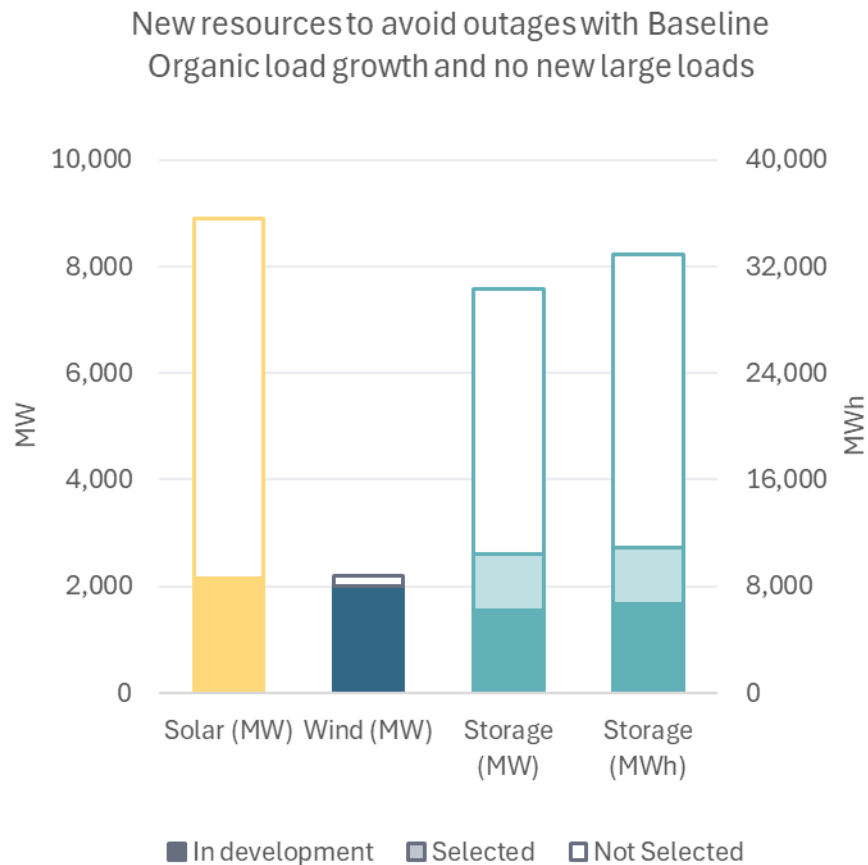
**Blended production cost/capacity expansion mode**



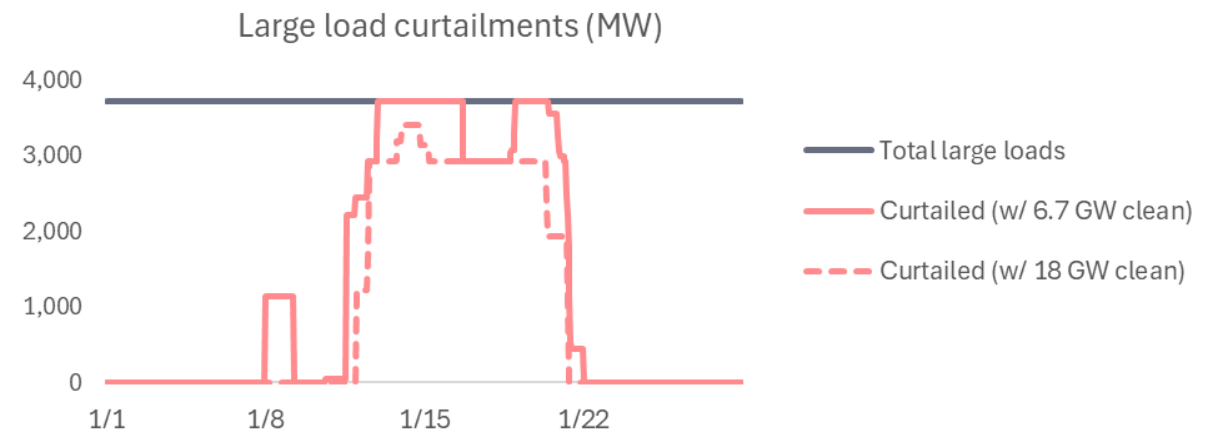
Incorporates investment variables directly into production cost problem to probe resource needs and identify potential solutions



# Clean resource additions and large load management in the Baseline scenario

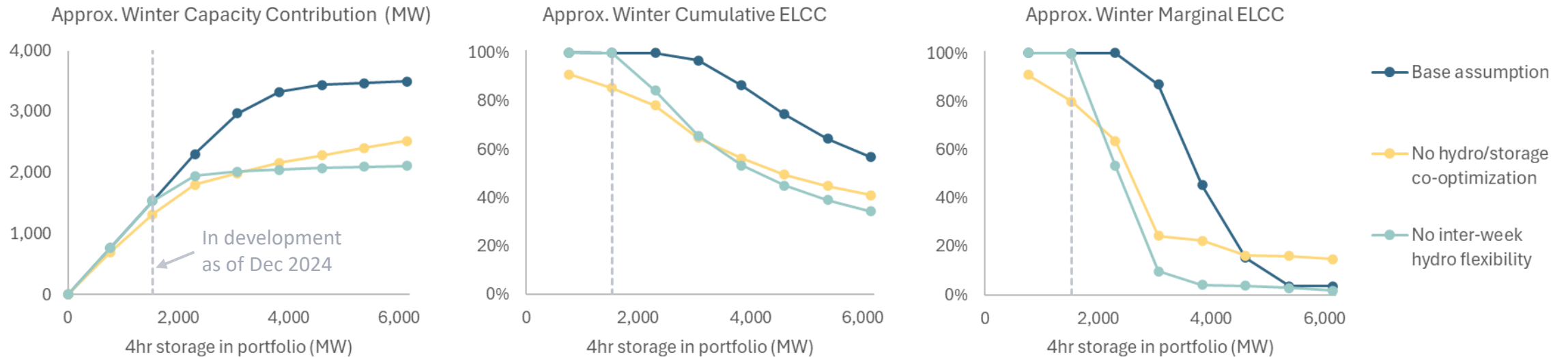


- Clean resources in development (5.7 GW) plus 1 GW of additional short duration storage were adequate to meet Baseline Organic load growth during this event
- With these additional selected resources: large loads experienced 222 hrs (9.25 days) of outages during the event
- When all proposed clean resources were included (19 GW total): large loads still experienced 168 hrs (7 days) of outages during the event



# Hydro/storage co-optimization

- Winter ELCCs for 4hr storage could depend strongly on how the hydro system is operated and modeled
- Two assumptions could lead to lower ELCCs and more rapid saturation of short duration storage than our analysis observes
  - Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
  - Load-following or net load-following hydro dispatch that is not co-optimized with battery storage dispatch

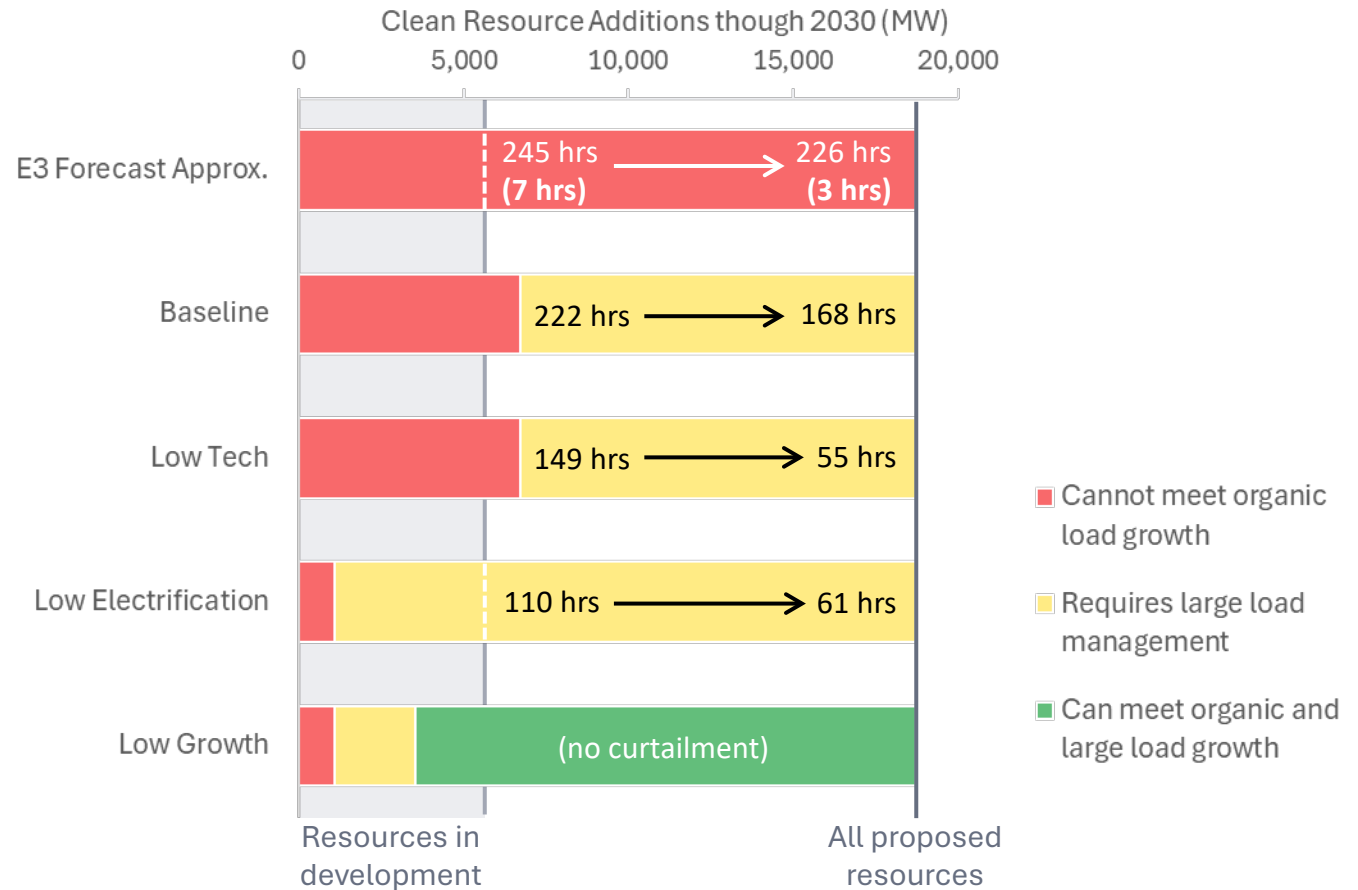


Notes:

- Approximate winter capacity contributions were calculated as the reduction in capacity need during January 2024 weather & hydro conditions under the Baseline load scenario, with wind and solar that is in development and Centralia 2 coal-to-gas conversion
- These values do not account for contributions to resource adequacy in the summer and may not be applicable to individual utilities with unique constraints
- After conducting the analysis, we found that 332 MW of batteries came online in 2024, which were not included in the baseline dispatch simulations because they were not in January 2024 EIA 930 data. This analysis suggests these additional batteries would have reduced capacity needs in all simulations by about 330 MW.

# High level findings from independent evaluation

3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events



# High level findings from independent evaluation

5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages

**Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario**  
(assuming only resources already in development come online)

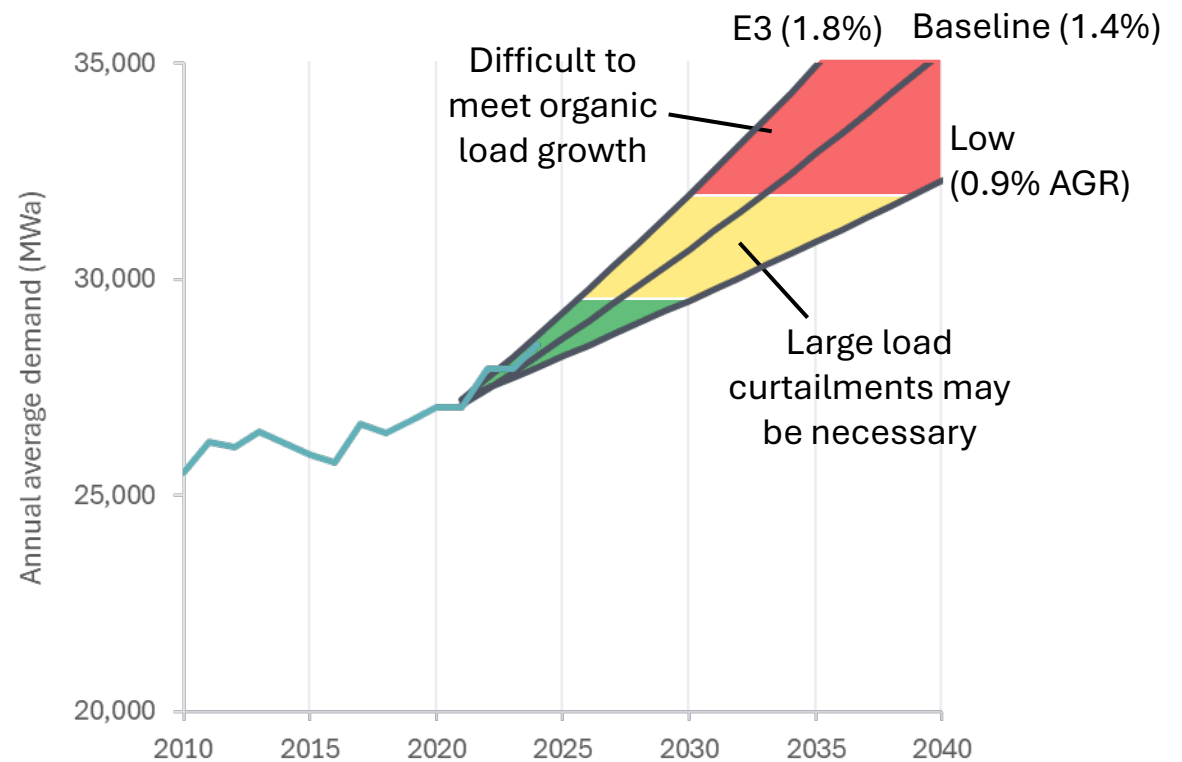
Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	19 hrs	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

# High level findings from independent evaluation

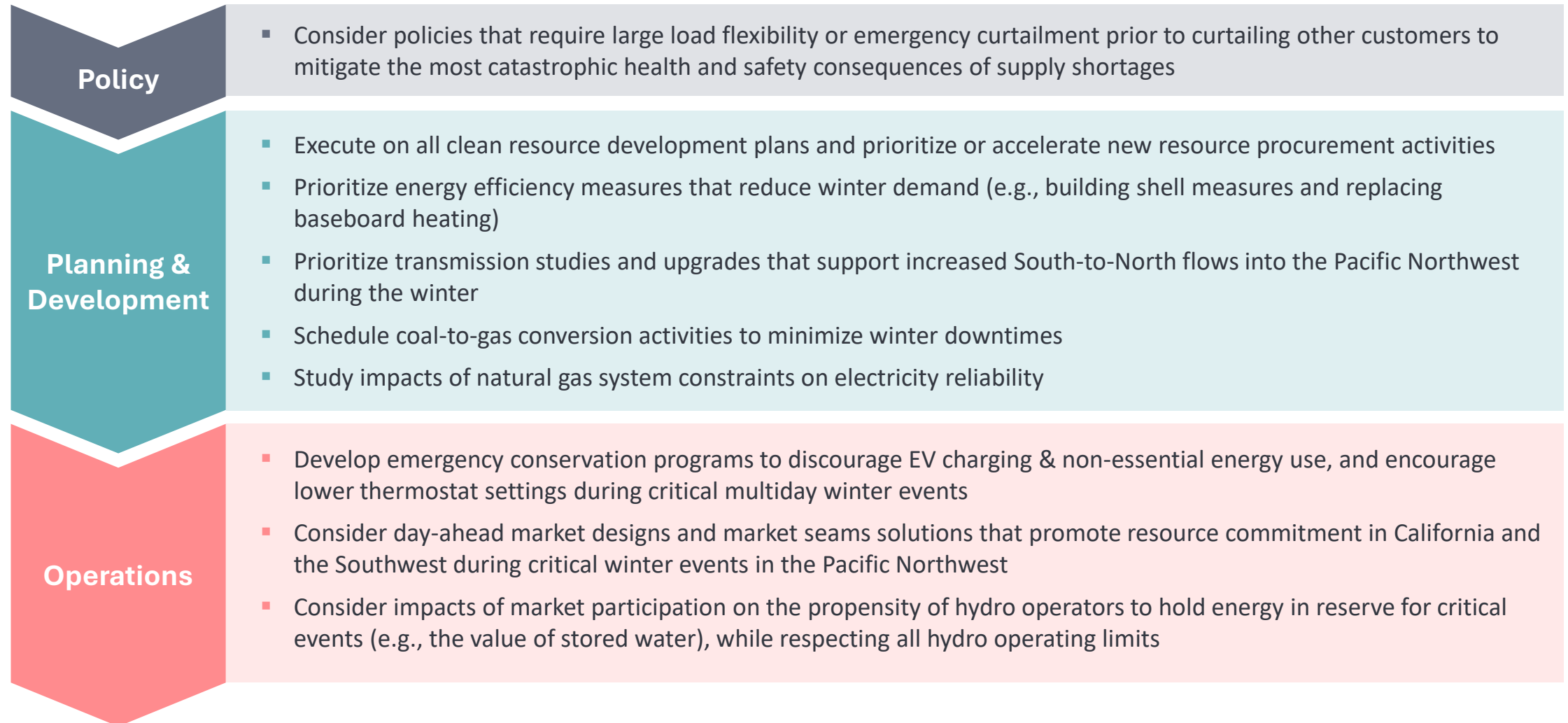
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Our recommendations focus on opportunities to push this need out in time in the interest of lowering costs and potentially leveraging new technologies

Extrapolated\* organic load growth trajectories and resource adequacy challenges



# Near-term opportunities identified to support regional RA





Cape Lookout State Park, Oregon Coast (source: [www.oregonlive.com](http://www.oregonlive.com))

## An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available



Cape Lookout State Park, Oregon Coast (source: [www.oregonlive.com](http://www.oregonlive.com))

# Thank you!

For more information, contact:  
[elaine@sylvan.energy](mailto:elaine@sylvan.energy)

**SYLVAN**  
ENERGY ANALYTICS



# Additional slides

# Finding #1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends

We estimate winter capacity needs in 2030 of 1.0 GW – 4.9 GW after accounting for coal-to-gas conversions and resources in development

		Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					Reported by E3 in Phase 1
		Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	
With no new resources		2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development		1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3’s reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3’s reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

## Finding #2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios

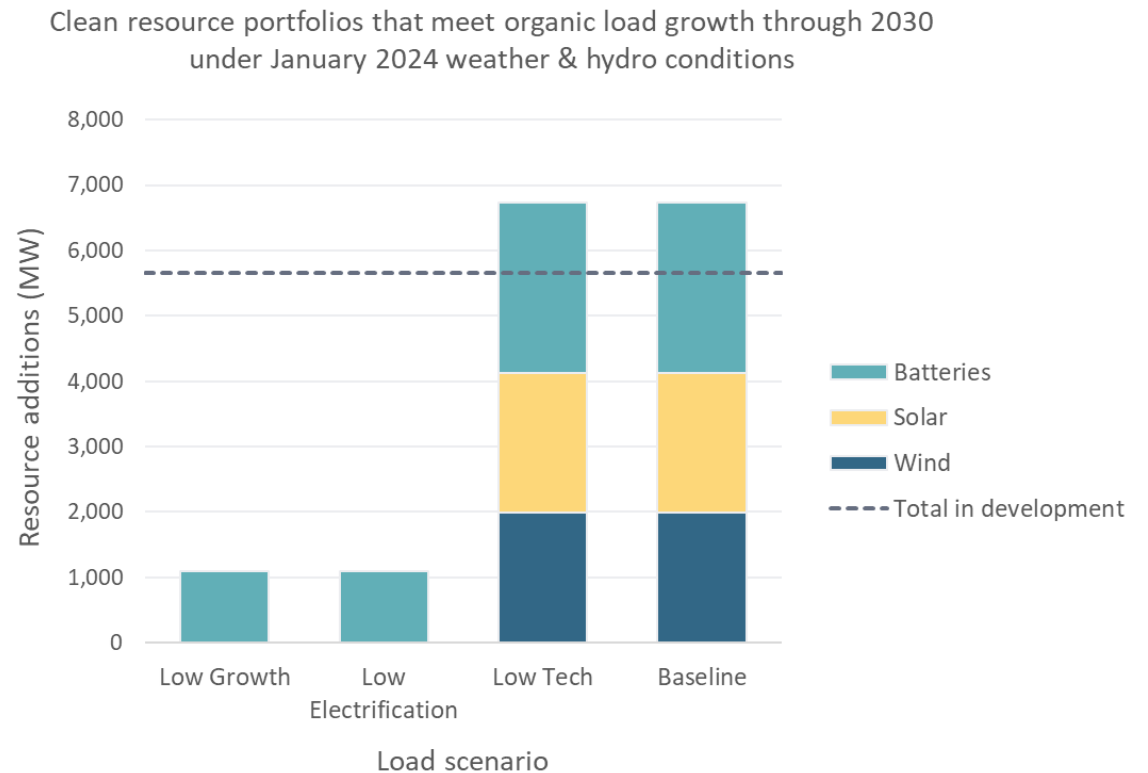
We estimate winter capacity needs in 2030 of 0.0 GW – 3.1 GW to avoid supply shortages if large loads are managed during the most critical winter weather events

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					Reported by E3 in Phase 1
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW
+ Large load flexibility	0.0 GW	0.0 GW	1.1 GW	1.2 GW	3.1 GW	NA

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

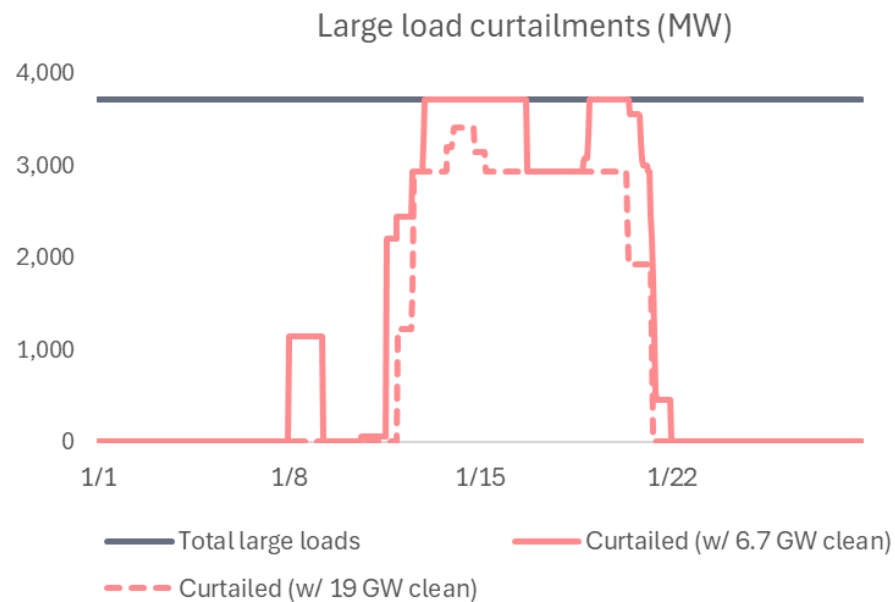
# Finding #3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest

- We estimate that less than 7 GW of new wind, solar, and batteries are adequate to avoid supply shortages among non-data center customers under January 2024 weather & hydro conditions in 2030 across our four load scenarios
- Under the E3 Load Forecast Approximation (with more electrification and fewer data centers than our load scenarios), supply shortages cannot be avoided even if all proposed clean resources (19 GW) come online by 2030



# Finding #4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events

Without these additional resources, we estimate that large load curtailments could range from 0 hours to 9 days under January 2024 weather & hydro conditions, depending on the load scenario and clean resource buildout



Load scenario	Large load curtailments in 2030 under January 2024 weather & hydro conditions
Low Growth	0 hrs
Low Electrification	2.5 - 4.6 days
Low Tech	2.3 - 6.2 days
Baseline	7.0 - 9.3 days

Note: Clean resource additions range from the greater of the resources under development and the resources needed to meet organic load growth to all proposed clean resources as of December 2024 (19 GW)

# Finding #5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages

We estimate that large load management could reduce average outages among other customers during critical winter weather conditions from 19 hours to 0.1 hours (assuming only resources already in development come online by 2030)

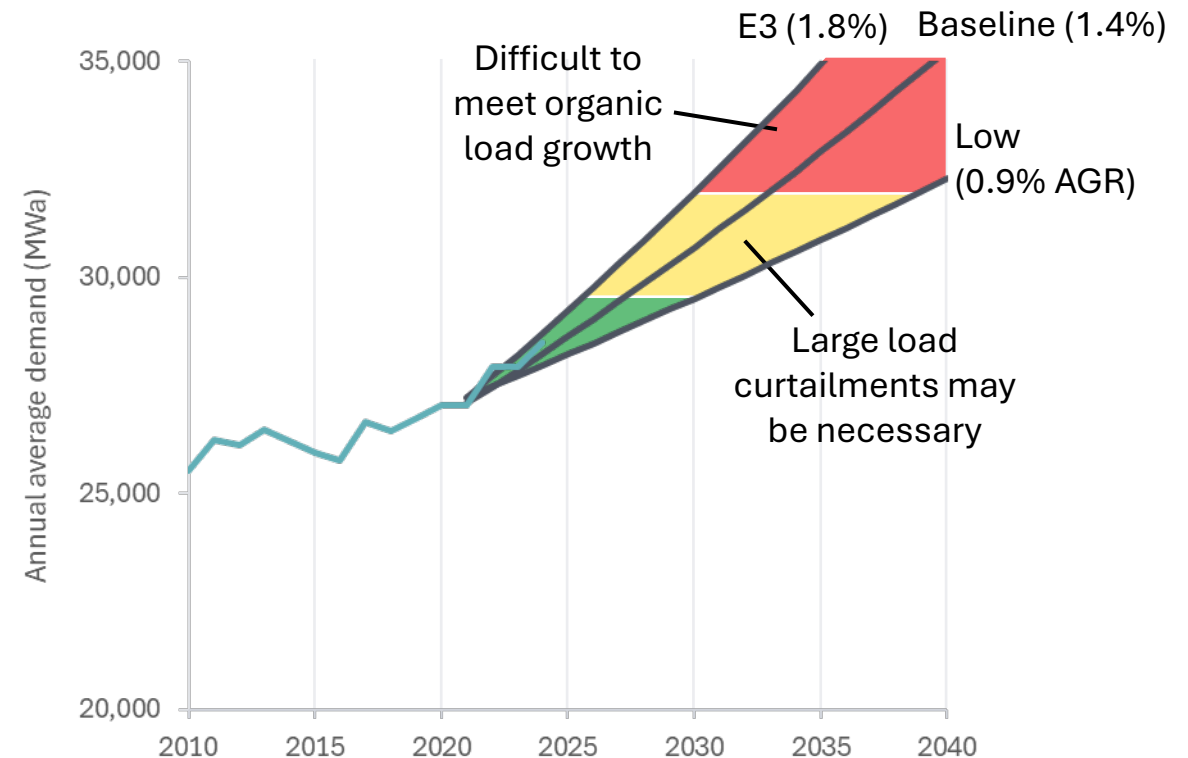
**Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario**  
(assuming only resources already in development come online)

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	19 hrs	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

# Finding #6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency)
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

Extrapolated\* organic load growth trajectories and resource adequacy challenges





# Analytical Details



# Evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

1. Developed dispatch simulation for the Pacific Northwest that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
  - Resources in development
  - Emergency large load management
  - Additional proposed clean resources

## Some technical notes

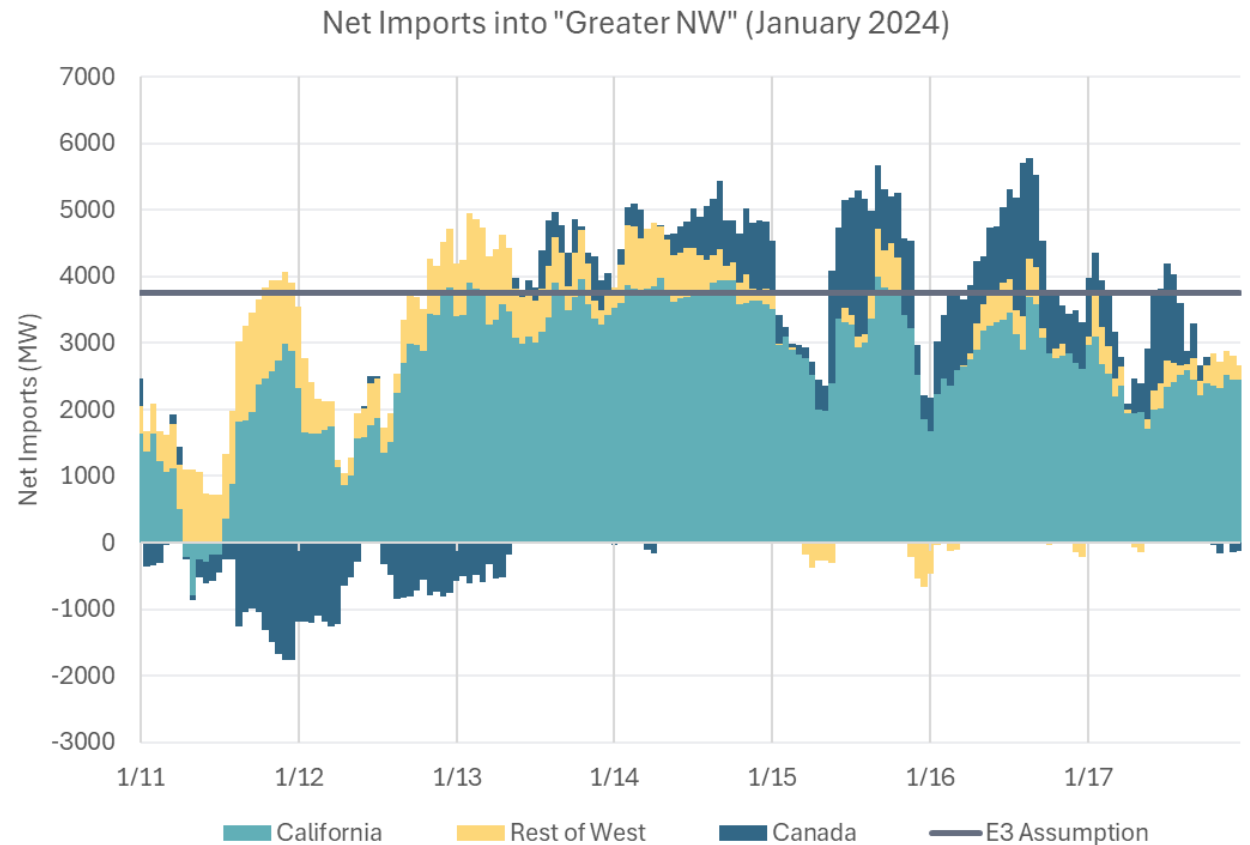
- We did not model full economics due to limited time and data availability, so results are more indicative of what the system *could* do vs. what it *would* economically do
- We have not fully reconciled our “Greater NW” footprint with E3’s due to time and data limitations. Loads and resources likely differ between the analyses and load comparisons focus on load growth rates rather than total loads to account for these differences
- Perfect capacity needs were identified by minimizing the maximum observed unserved energy across the month
- Potential customer outages were identified by equally penalizing total and maximum unserved energy to better reflect operations

# Key assumptions

	Our analysis	E3 study
Footprint	BAs in OR, WA, ID, MT + PACE	BAs in OR, WA, ID, MT (excluding WAUW) + PACE
Hydro dispatch	Optimized with weekly energy budgets, minimum, maximum, and ramping constraints based on Jan 2024 hydro dispatch; unconstrained energy shifting allowed between weeks 2 & 3	Load-following heuristic with weekly budgets with up to 5% inter-week energy shifting, minimum and maximum levels based on historical min/max as a function of energy budget
Transmission constraints	2024 benchmark: Constrained flows between PACE and PNW based on high and low observations across January 2024 historical observations 2030 simulations: Added 1,000 MW bidirectional capacity associated with B2H by 2030 (total in 2030: -1,150 MW to +3,410 MW)	None in RA analysis (zonal results are from separate simulations, each assuming a copper plate)
Import constraints	<u>Total: 5,000 MW</u> Into PNW zone (excluding Canada): 3,000 MW Canada to PNW: 1,000 MW Into PACE: 1,000 MW	<u>Total: 3,750 MW</u>
Canadian entitlement	2024 benchmark: 660 MWh net exports into Canada across the month, but allowing Canadian storage to also support imports in any given hour 2030 simulations: Same, but net exports reduced to 590 MWh	590 MW exports to Canada in all hours, no accounting for Canadian storage or import capability from Canada
2030 baseline resource fleet	Existing based on operational resources as of January 2024 (EIA 930), in development resources based on 2024 EIA 860 Dave Johnston 3 retired Coal-to-gas conversions of Centralia 2, Dave Johnston 1 & 2, Naughton 1 & 2	Existing and in development resources based on WECC ADS Dave Johnston 3 and <u>Centralia 2 retired</u> Coal-to-gas conversions of Dave Johnston 1 & 2, Naughton 1 & 2 (however in initial need evaluation, these are retired)
2030 Load	Four load scenarios that combine different outlooks for organic load growth and data center demand, plus a load scenario that approximates E3's forecasted load growth	PATHWAYS-based bottom-up loads with adjustments and internal data center forecast

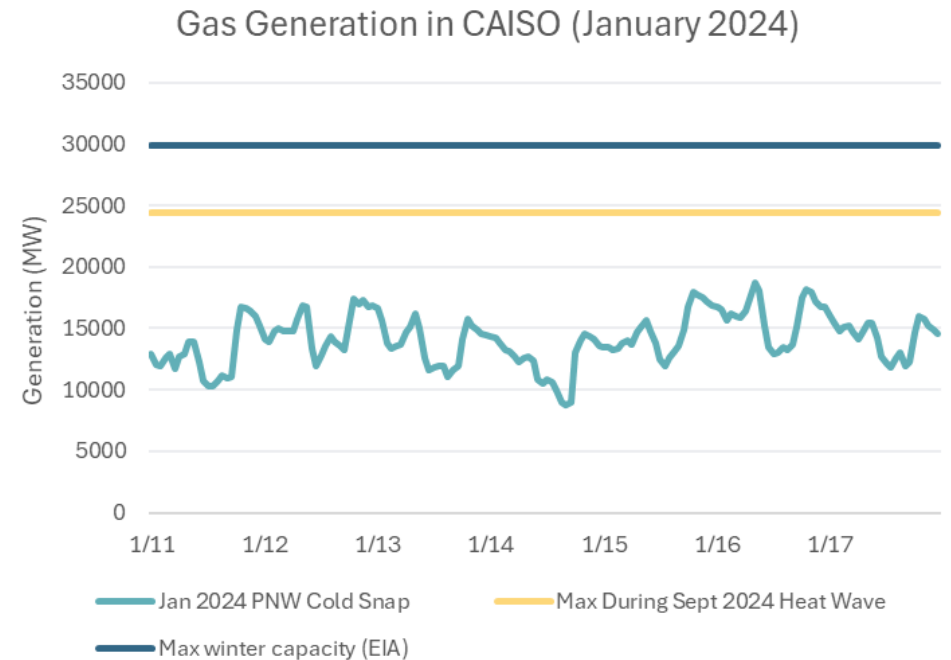
# Winter import constraints

- The E3 study assumes 3,750 MW of imports are available in all hours based on imports during the January 2024 cold event
- Net imports into the “Greater NW” exceeded 3,750 MW in 102 hours in January 2024 and exceeded 5,000 MW in the most constrained hours
- The 3,750 MW limit aligns well with imports from California during the event, but may neglect additional import capability from Canada and the rest of the West



# Transmission, not available supply, limited imports

- Much of the gas fleet in California went unused during the January 2024 event (i.e., there was not a shortage of regional generating capacity in the West)
- However, South-to-North transmission flows between California and the Pacific Northwest were constrained by operating limits
- South-to-North operating limits on COI and PDCI are tighter than North-to-South limits
  - Max N-to-S during Sept 2024 heatwave: ~5,500 MW
  - Max S-to-N during Jan 2024 cold snap: ~3,800 MW



## Near-term opportunities to support increased imports during winter events:

- Prioritize transmission studies and upgrades that support increased S-to-N flows into the PNW during the winter
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest

# Hydropower dispatch

## Study review:

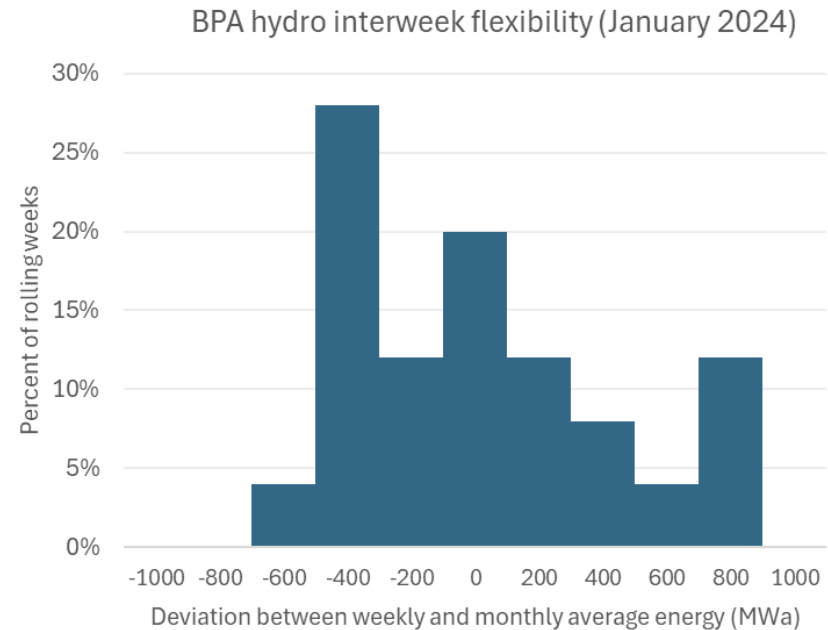
- E3 confirmed that they use a load-following heuristic to estimate hydro dispatch in each week and they allow 5% of weekly hydro energy to shift between weeks
- Heuristic dispatch may underestimate the potential of the hydro system to support resource adequacy and may overlook opportunities to co-optimize between hydro and other resources, including short-duration batteries
- Analysis into BPA hydro dispatch in January 2024 suggests that any given week could have access to as much as 880 MWa (14%) of additional hydro beyond the monthly average energy

## Outstanding substantives questions:

- How do hydro operators value stored water when dispatching their hydro fleets? Does it adequately account for the value of supporting winter reliability over longer timescales (i.e., future days, weeks, or months) or is hydro dispatch over-optimized for short-term economics?
- How will day-ahead market participation affect this tradeoff between short-term revenues and winter reliability value?

## Near-term opportunity:

- Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits



# Retirements and conversions

## Study review:

- E3 confirmed the 8,689 MW identified need assumes that coal plants retire instead of undergoing coal-to-gas conversions
  - E3 analysis suggests that capacity needs could be 850 MW smaller with coal-to-gas conversions included

## Our approach:

- Include all announced coal-to-gas conversions to avoid overstating incremental needs
  - While conducting the analysis, Transalta announced the conversion of Centralia 2 to gas. This update was incorporated into our final simulations.

## Outstanding substantive question:

- Some of PacifiCorp’s coal-to-gas conversion plans suggest winter downtimes, which may be avoidable by pushing the schedule out or accelerating it by a matter of months. How does winter reliability factor into scheduling for coal-to-gas conversions?

## Near-term opportunity:

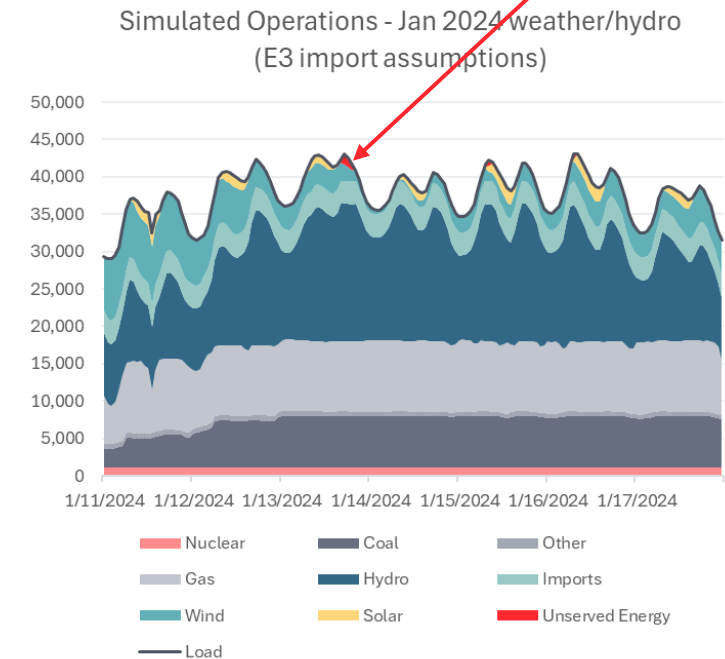
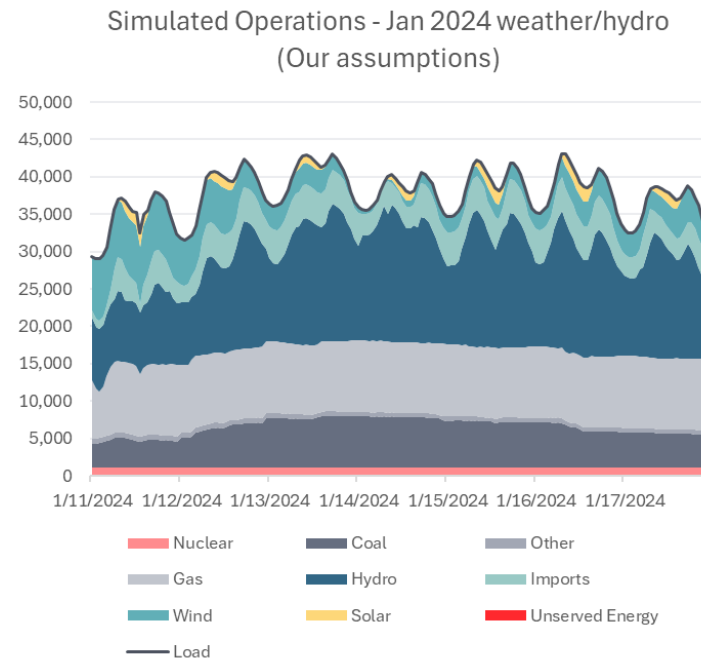
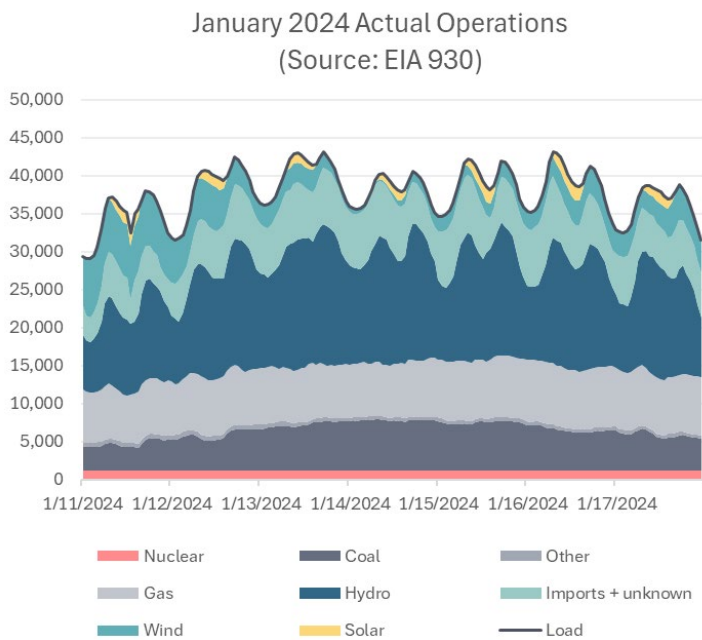
- Schedule coal-to-gas conversion activities to minimize winter downtimes

	Winter Capacity	E3 initial need evaluation	Our analysis
Dave Johnston 1	99 MW	Retired	Converted to gas
Dave Johnston 2	106 MW	Retired	Converted to gas
Dave Johnston 3	220 MW	Retired	Retired
Naughton 1	156 MW	Retired	Converted to gas
Naughton 2	201 MW	Retired	Converted to gas
Centralia 2	670 MW	Retired	Converted to gas
<b>Total retired</b>		<b>1,452 MW</b>	<b>220 MW</b>
<b>Total converted to gas</b>		<b>0 MW</b>	<b>1,232 MW</b>

# 2024 benchmarking

- Tested reasonableness of assumptions by simulating January 2024 dispatch

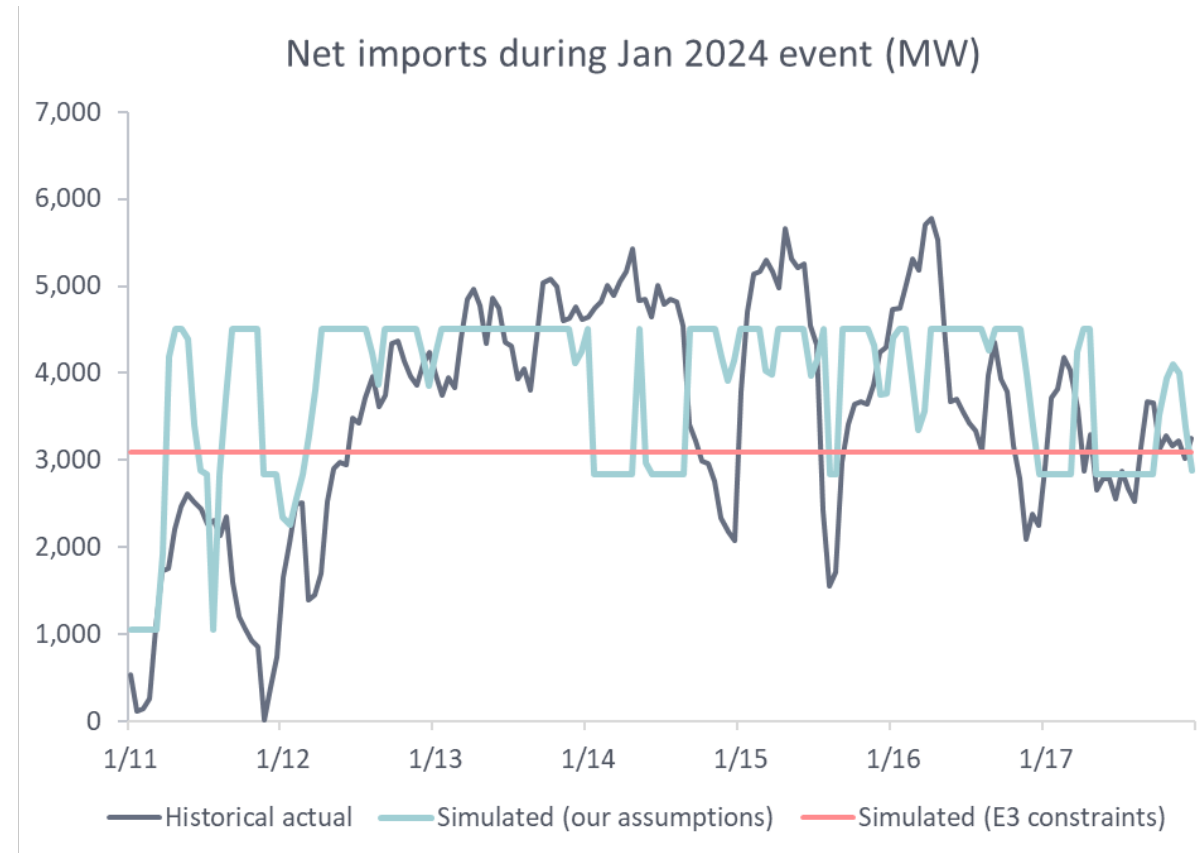
Applying E3 import constraint yields shortages in 11 hrs, up to 1,400 MW



\*Actual and simulated operations have different classifications for some resources that are interconnected to BPA, but not reported by BPA (or other BAs) in EIA 930. These resources are simulated explicitly and grouped by technology in the simulated operations plots, but fall within “Imports + unknown” in the actual operations plot (on the left)

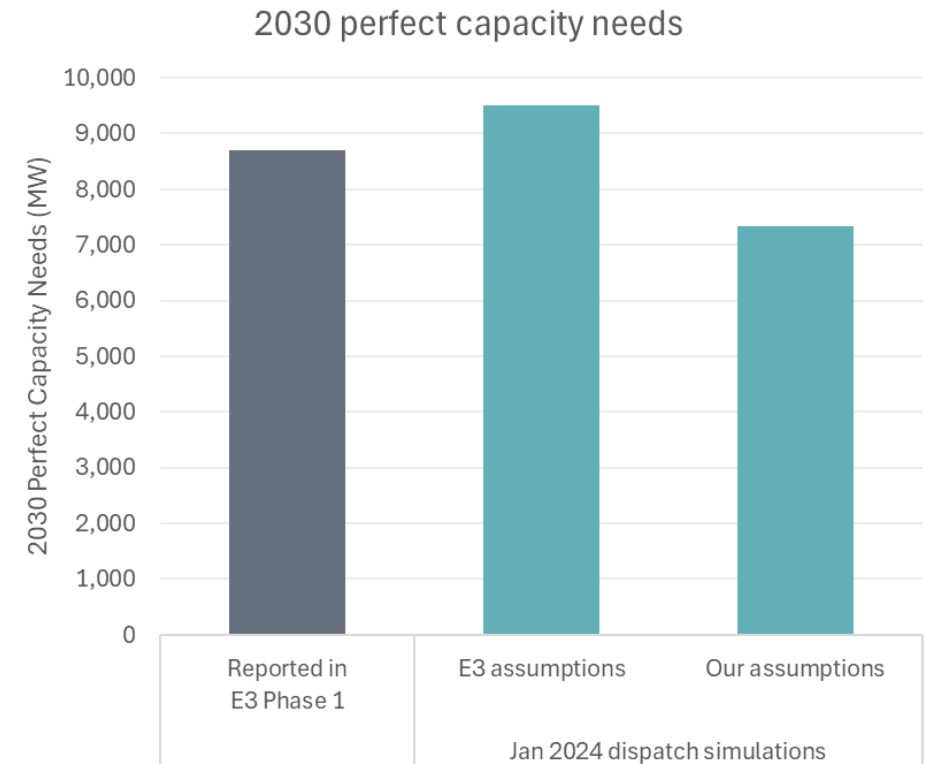
# 2024 benchmarking

- Additional imports in our assumptions are adequate to clear unserved energy in Jan 2024 benchmarking exercise
- Average net imports between 1/11 and 1/17 are similar across historical actuals and simulations:
  - Historical actuals: 3,508 MW
  - Dispatch simulation with our assumptions: 3,811 MW
  - Dispatch simulation with E3 constraints: 3,090 MW
- Reminder: simulations reflect system capability, not fully economic dispatch



# Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
  - **E3 assumptions:** uses E3’s import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
  - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas, except Centralia 2)
- Both simulations assumed loads approximately reflect E3’s forecasted load growth rates
- Our dispatch analysis generally corroborates E3’s findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3’s projected load growth



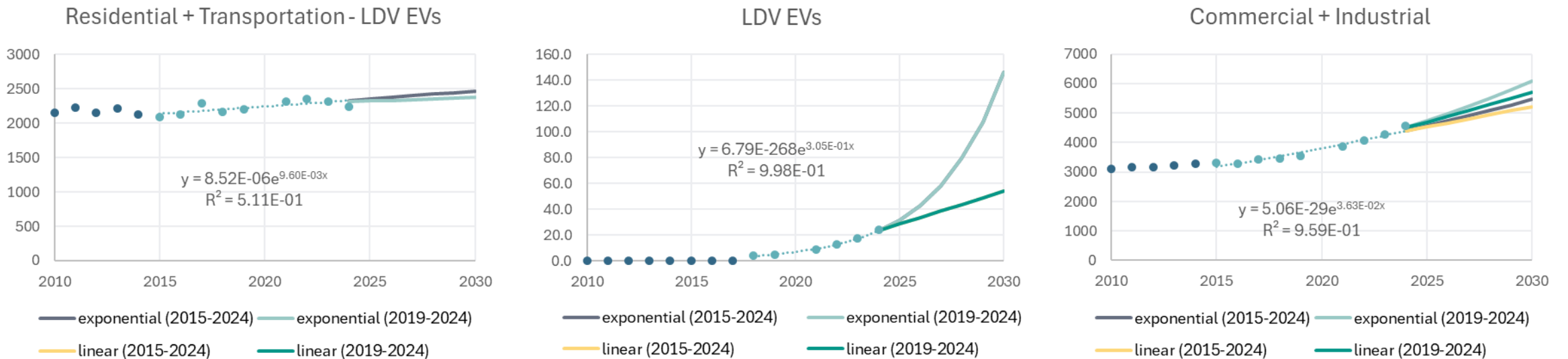
# Electricity demand scenarios for 2030

- The E3 study relies on E3's internal load forecast, which comes from their bottom-up PATHWAYS model and internal data center demand forecasts
- E3's annual energy tracks closely with PNUCC's 2025 forecast (with aligned footprints), which is based on utility forecasts and projects 3.2% annual growth
- Data centers vs. electrification
  - E3 suggests that their forecast includes higher EV and electric space heating than the PNUCC forecast, which is potentially offset by a lower data center forecast
  - PNUCC has not collected information from their members to clearly distinguish between organic load growth and data center loads
- To understand the sensitivity of 2030 resource needs to future load growth and data center flexibility, Sylvan developed additional top-down load growth scenarios from available public data

# Estimating organic load growth trends

- “Organic” load growth includes everything but new large loads (i.e., includes electrification)
- We estimated plausible ranges of sector-specific loads by fitting linear and exponential functions to recent historical sector-specific loads
- Data sources: EIA historical sales by sector and state, EIA historical LDV EV electricity consumption by state

## Example: estimation of organic load growth trends in Oregon



# Organic load growth scenarios

- **Baseline organic load growth:** upper bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
  - Falls between NWPCC “Mixed bag” and “Persistent high growth” load scenarios (excluding data center and H<sub>2</sub> demands)
- **Low organic load growth:** lower bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
  - Falls just below NWPCC “Mixed bag” load scenario (excluding data center and H<sub>2</sub> demands)
- **Note:** comparisons are high level and indicative, as footprints vary between forecasts and NWPCC loads assume fixed energy efficiency

Scenario	Average annual organic growth rate through 2030
NWPCC <sup>2</sup> “Persistent high growth”	~1.9%
E3 Forecast <sup>1</sup>	~1.8%
<b>Baseline Organic Growth</b>	<b>1.4%</b>
NWPCC <sup>2</sup> “Mixed bag”	~1.0%
<b>Low Organic Growth</b>	<b>0.9%</b>
NWPCC <sup>2</sup> “Persistent low growth”	~-0.1%

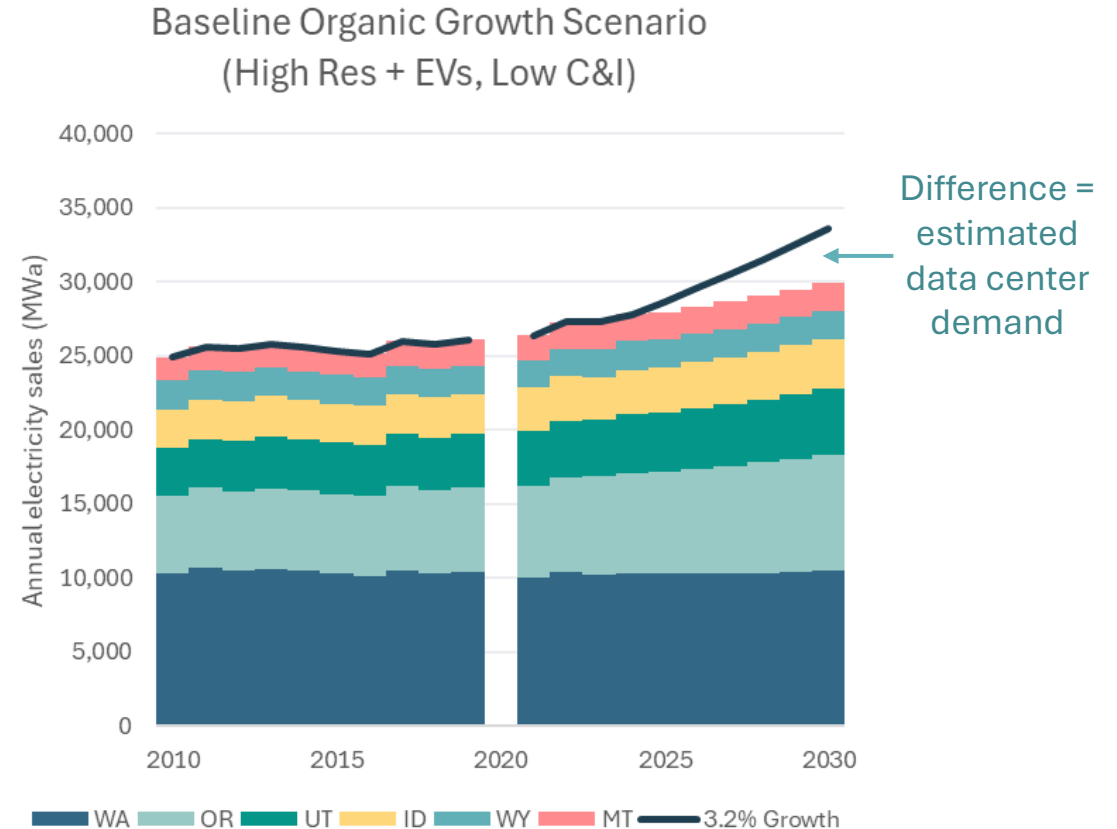
<sup>1</sup>E3 organic growth rate between 2025 and 2030 estimated by subtracting data center demand from total forecasted Greater NW demand reported on slide 24 of Phase 1 Executive Summary

<sup>2</sup>NWPCC growth rates between 2025 and 2030 estimated by subtracting data center and H<sub>2</sub> demand on slide 33 from total forecasted demand scenarios on slide 46 of the Ninth Plan Demand Forecast Part 2 ([https://www.nwcouncil.org/fs/19380/2025\\_0429\\_2.pdf](https://www.nwcouncil.org/fs/19380/2025_0429_2.pdf))

# Data center demand scenarios

- **Baseline data center demand:** estimated as the difference between the organic load growth forecast and 3.2% total load growth reported by PNUCC
  - Higher than E3 forecast, between Mid and High forecasts from the NWPCC
- **Low data center demand:** E3 data center forecast

Scenario	PNW MWa (WA, OR, ID, MT)	“Greater NW” MWa (PNW + UT + WY)
<b>Baseline Scenario</b>	<b>2,931</b>	<b>3,717</b>
<b>Low Scenario</b> (E3 Data Center forecast)	<b>1,100</b>	<b>1,700</b>
NWPCC Low Tech Load	~1,400	NA
NWPCC Mid Tech Load	~2,200	NA
NWPCC High Tech Load	~4,600	NA



# Alternative 2030 load scenarios

We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			1.3%

All alternative load scenarios envision accelerated load growth relative to the last 6 years



# Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges



# Detailed findings

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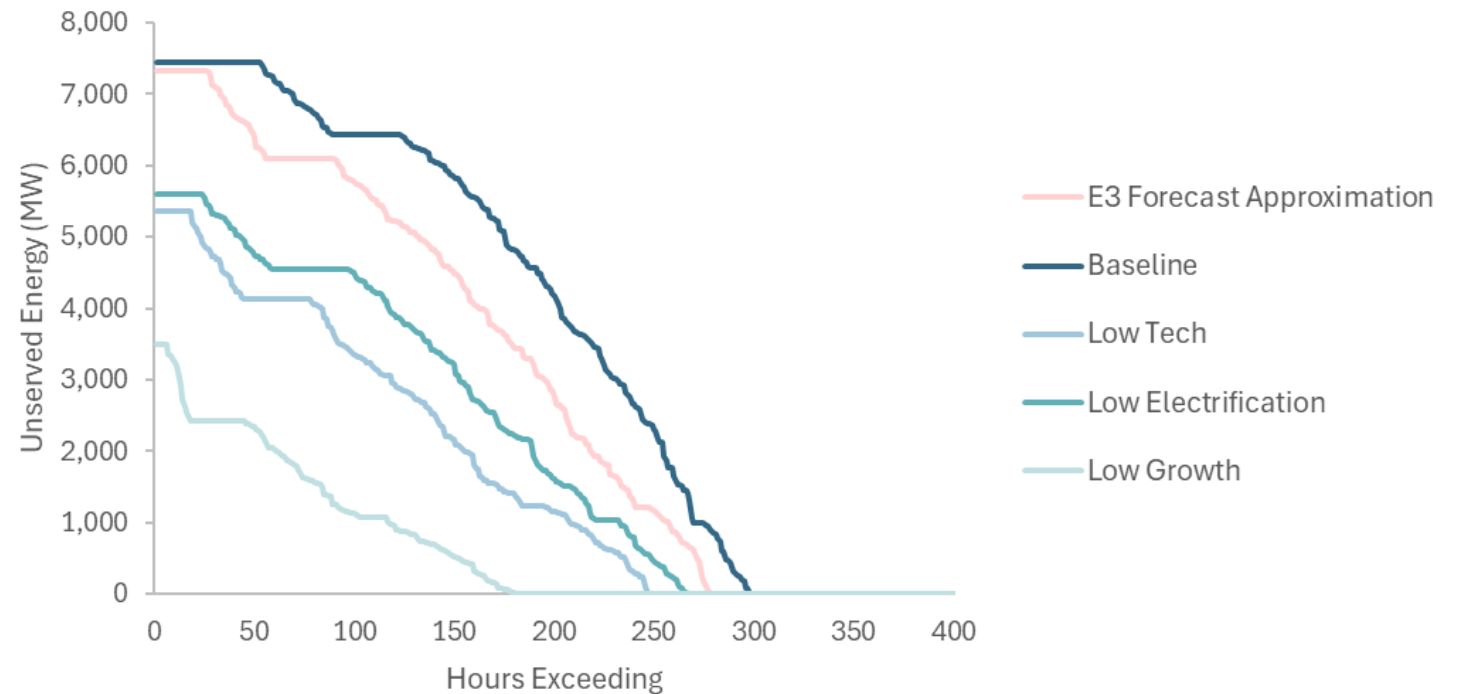
# Our findings generally corroborate E3's high level problem statement

Across all load scenarios, unserved energy is observed in large quantities and in several hours if there are no resource additions through 2030, similar to E3's findings

## Notes:

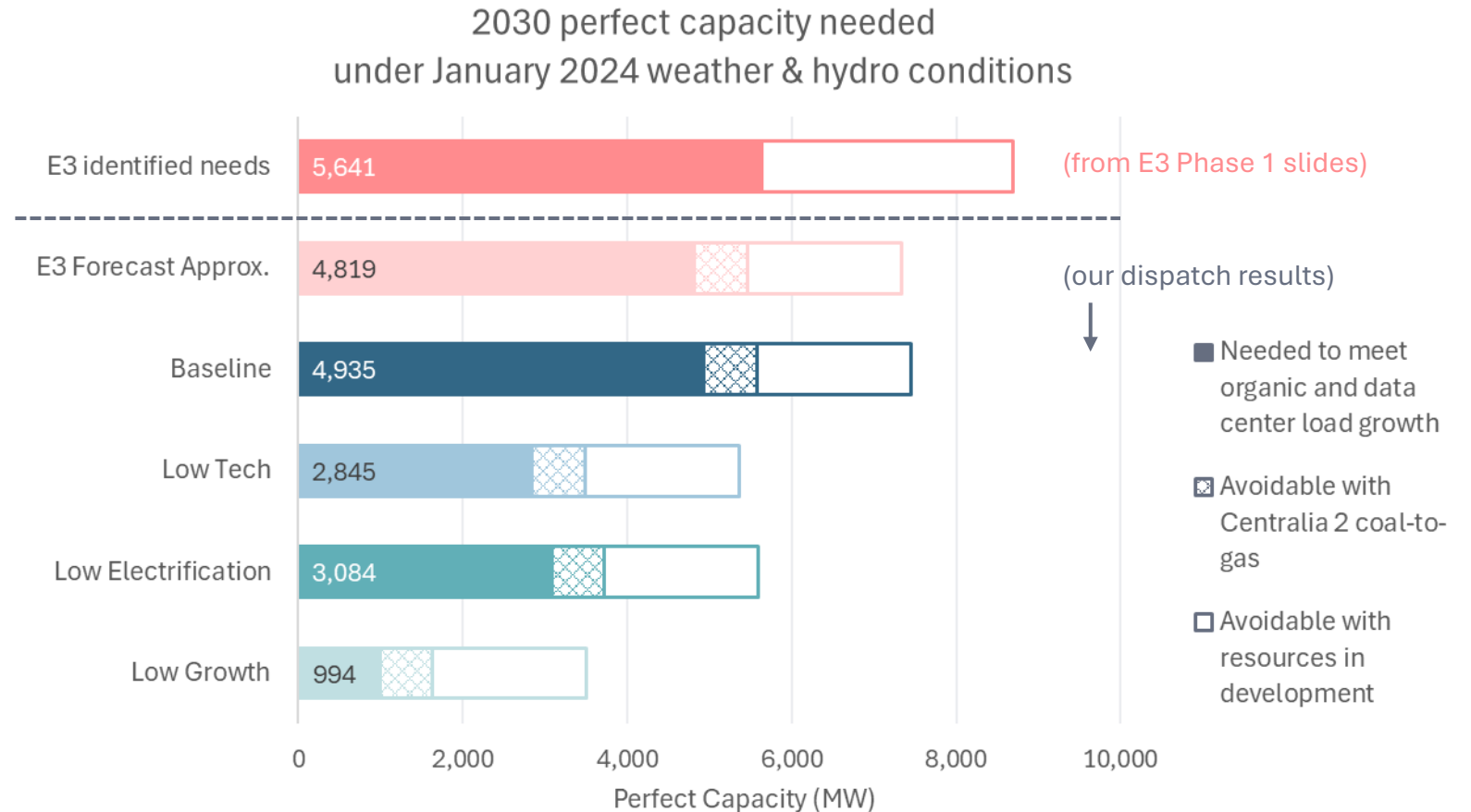
- These results are based on “operational” runs, in which both total and maximum unserved energy are penalized
- Perfect capacity needs (coming up on the next slide) are calculated by minimizing the maximum unserved energy, which can be lower than the maximum values shown on this slide

Simulated unserved energy (sorted from high to low) with no resource additions, before Centralia 2 coal-to-gas conversion



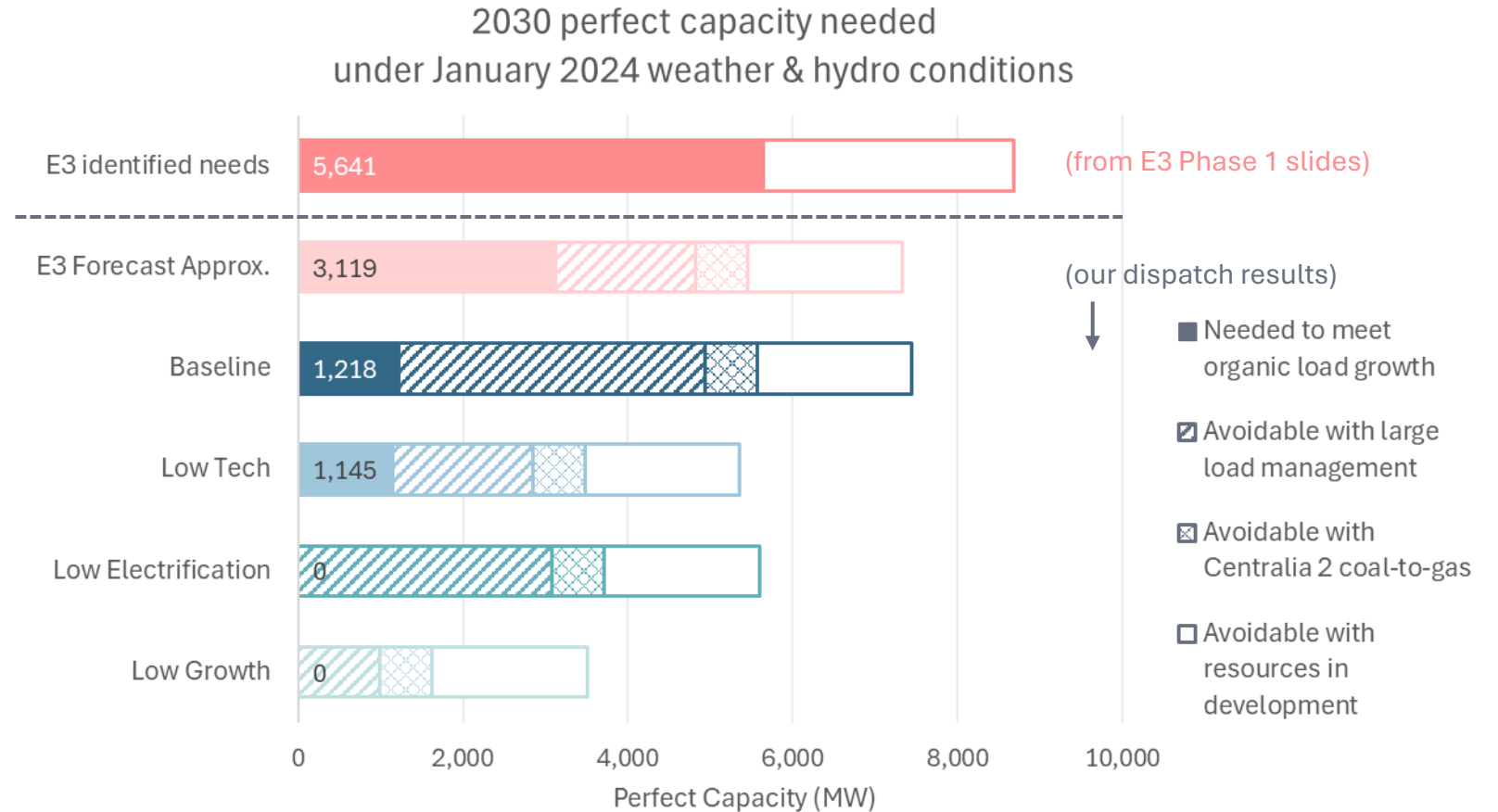
# How sensitive are 2030 resource adequacy needs to future load growth?

- No analysis can predict the future and resource needs in 2030 remain highly uncertain, due both to new large loads and electrification trends
- After accounting for resources already under construction or with regulatory approvals in place as of December 2024 according to EIA 860 (“in development”) and coal-to-gas conversion of Centralia 2, estimated remaining 2030 needs range from 1 GW to 5 GW of “perfect capacity” across load scenarios

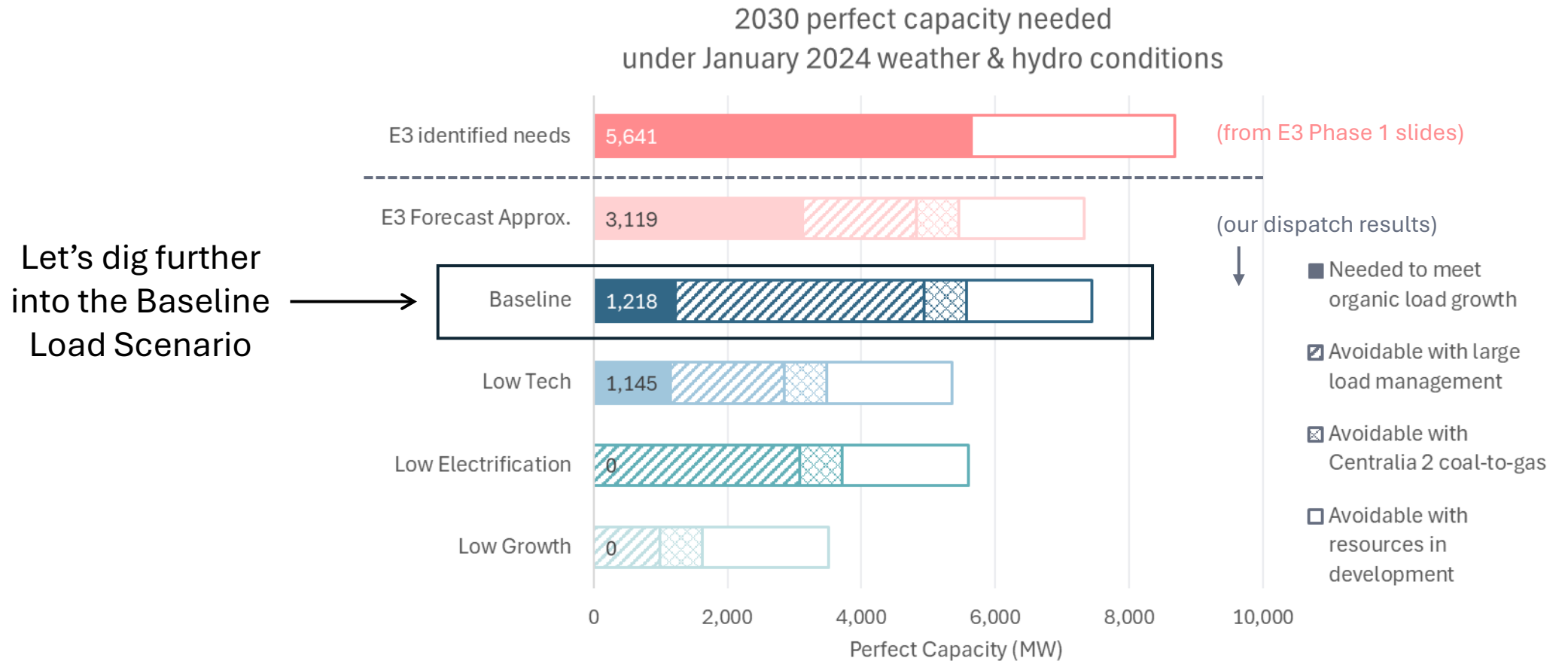


# “Connect and manage” for large loads and resource adequacy

- Large loads, which remain highly uncertain in terms of both whether they will materialize and how long they will persist on the grid, are a key driver of near-term needs
- If large loads are interconnected before adequate supply is secured, emergency large load curtailment during extreme weather could mitigate risks to other customers, similar to new requirements in Texas
- If large loads can be managed during extreme weather events, estimated remaining 2030 needs range from 0 GW to 3 GW, depending on organic load growth (including electrification)



# “Connect and manage” for large loads and resource adequacy in the Baseline Scenario



# Supply shortages from the customer's perspective

If no additional resources are secured beyond those already in development, what does the shortage under the Baseline Scenario look like from the customer perspective during this event?

Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	19 hrs	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

## Near-term opportunity:

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages
  - Could be paired with bring-your-own generation strategies
  - Could enable more rapid interconnection

\*Resources in development were either under construction or had final regulatory approvals in place as of December 2024




# Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

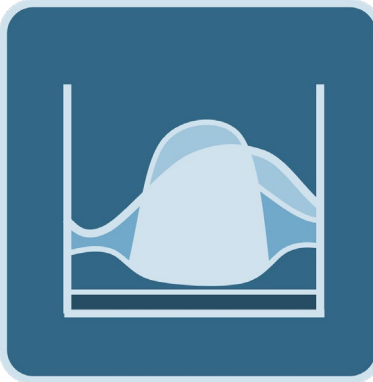

# Addressing supply shortages with new clean resources

- Next, we allowed the model to select additional resources from projects that were proposed but did not have regulatory approvals (as of December 2024) to meet demand across the January 2024 weather/hydro conditions under the Baseline Load Scenario
  - A. To meet organic load growth; and
  - B. To meet all load growth, including data center demand
- Findings are broadly indicative
  - Resource costs were high level and imprecise (i.e., these are not optimal selections)
  - Assumed proposed projects have the same hourly availability as existing projects by technology and zone (i.e., understates diversity benefits)

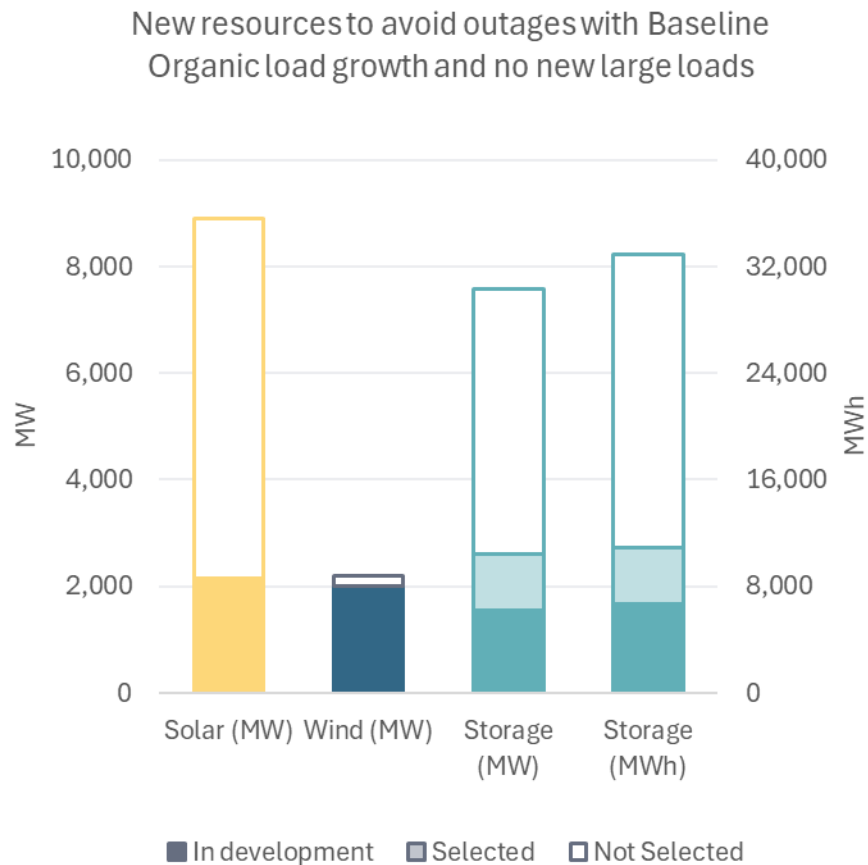
**Blended production cost/capacity expansion mode**



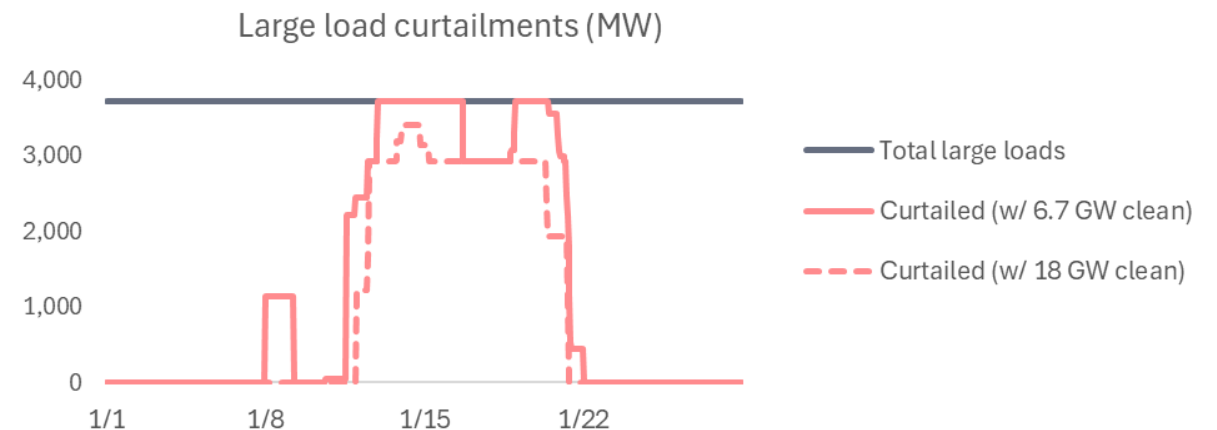
Incorporates investment variables directly into production cost problem to probe resource needs and identify potential solutions



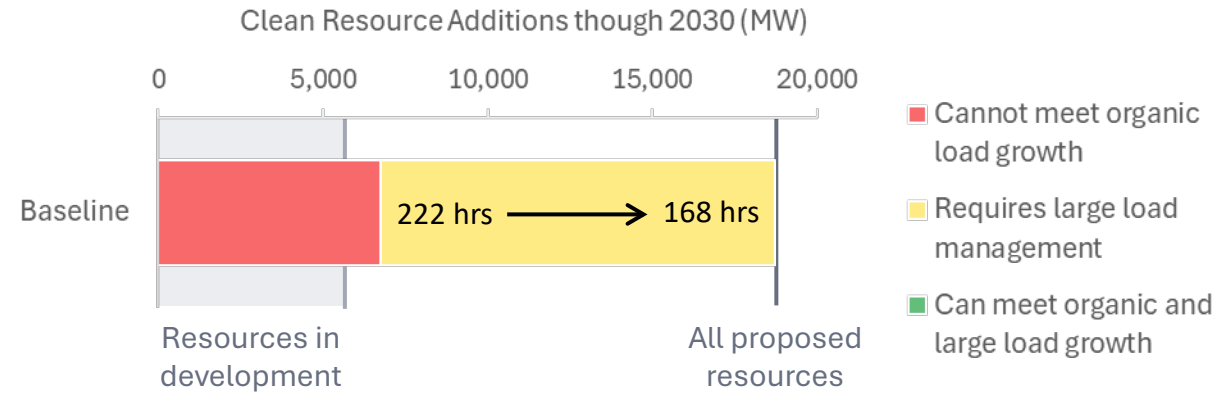
# Clean resource additions and large load management in the Baseline scenario



- Clean resources in development (5.7 GW) plus 1 GW of additional short duration storage were adequate to meet Baseline Organic load growth during this event
- With these additional selected resources: large loads experienced 222 hrs (9.25 days) of outages during the event
- When all proposed clean resources were included (19 GW total): large loads still experienced 168 hrs (7 days) of outages during the event

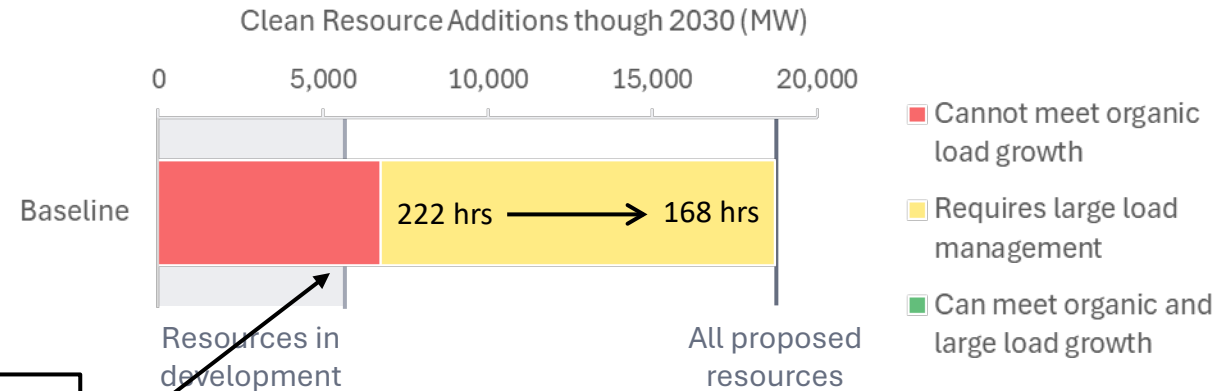


# Clean resource additions and large load management across the scenarios



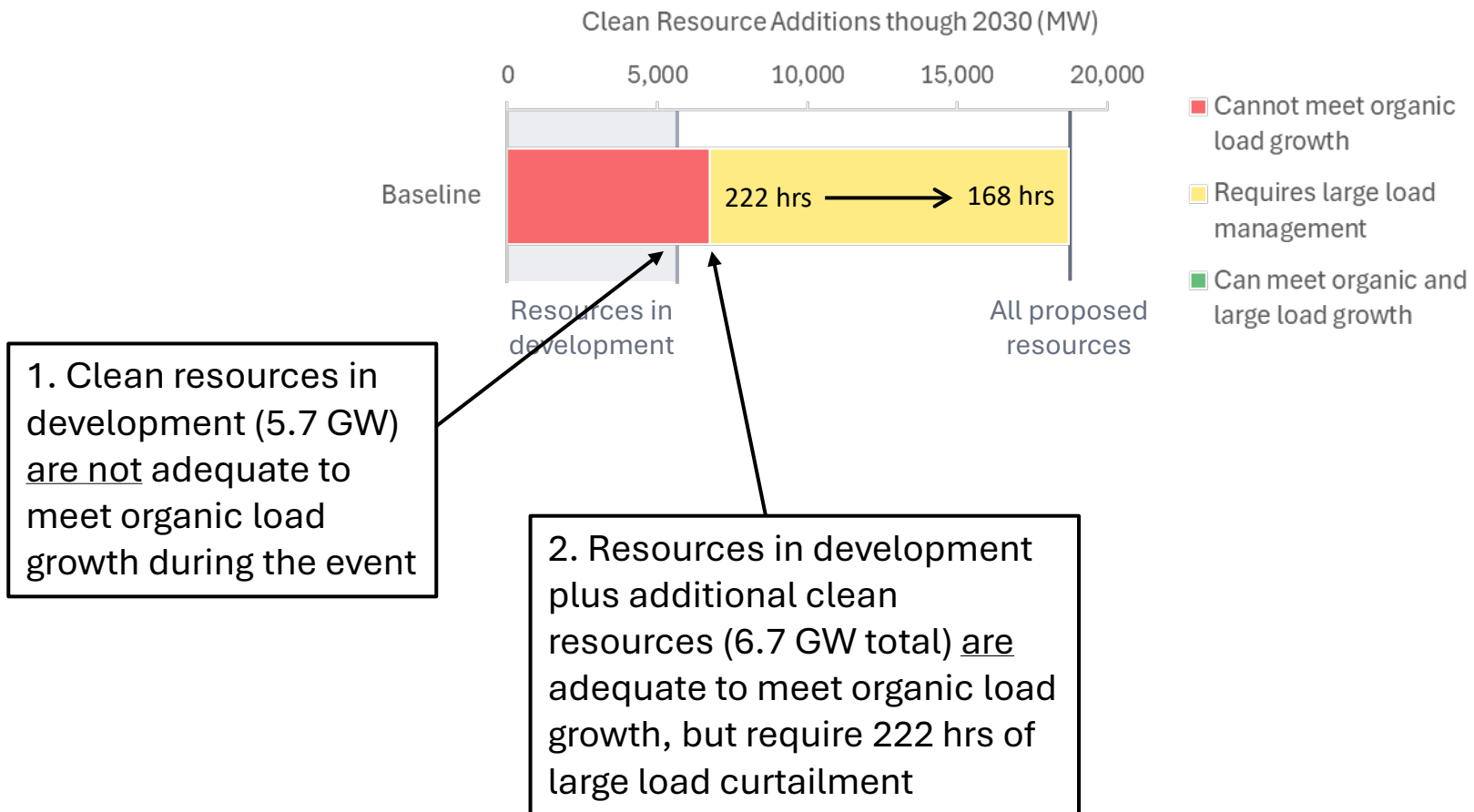
To compare across scenarios, we'll introduce a short-hand for the contributions of new clean resources toward meeting load growth and avoiding large load curtailments

# Clean resource additions and large load management across the scenarios

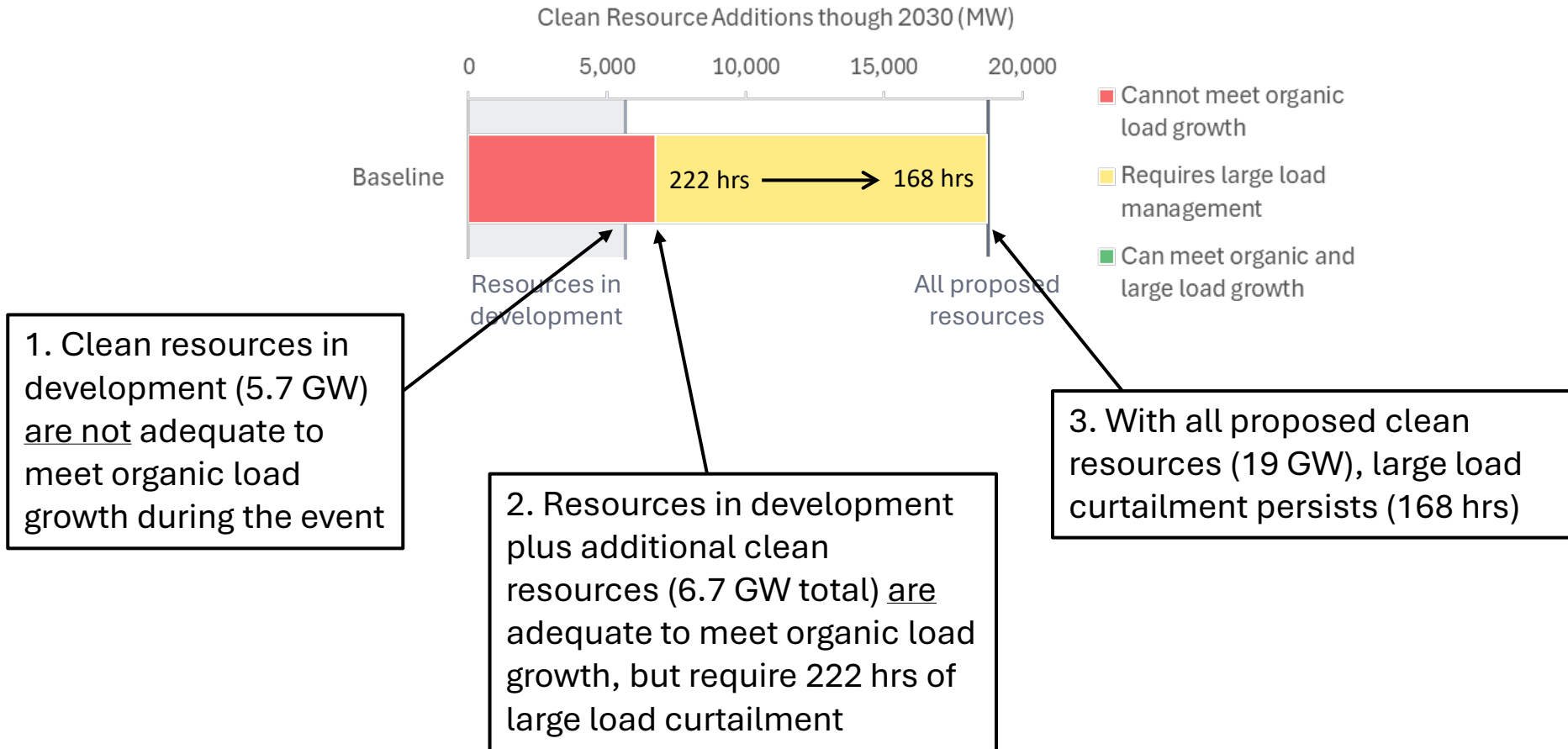


1. Clean resources in development (5.7 GW) are not adequate to meet organic load growth during the event

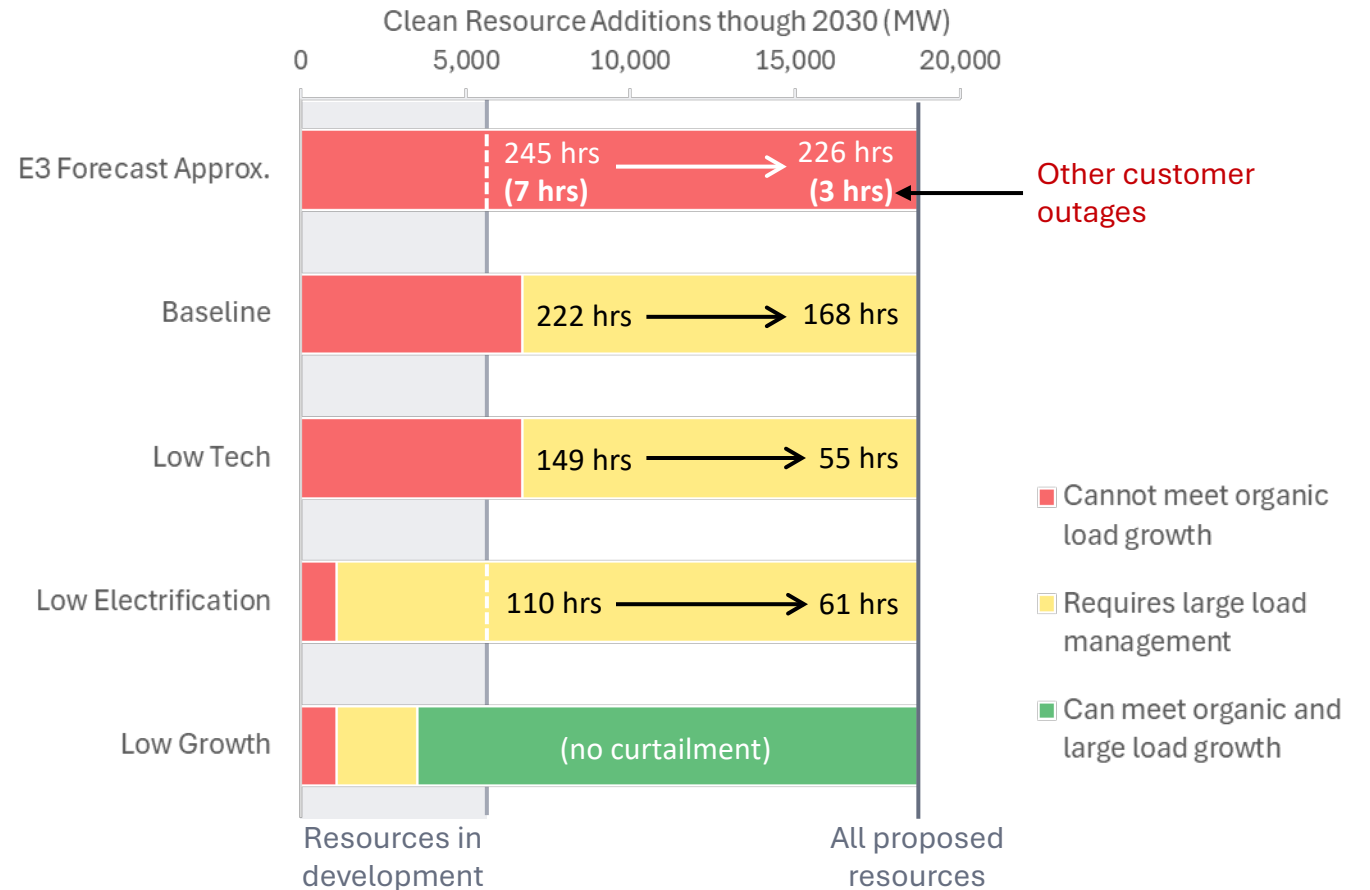
# Clean resource additions and large load management across the scenarios



# Clean resource additions and large load management across the scenarios



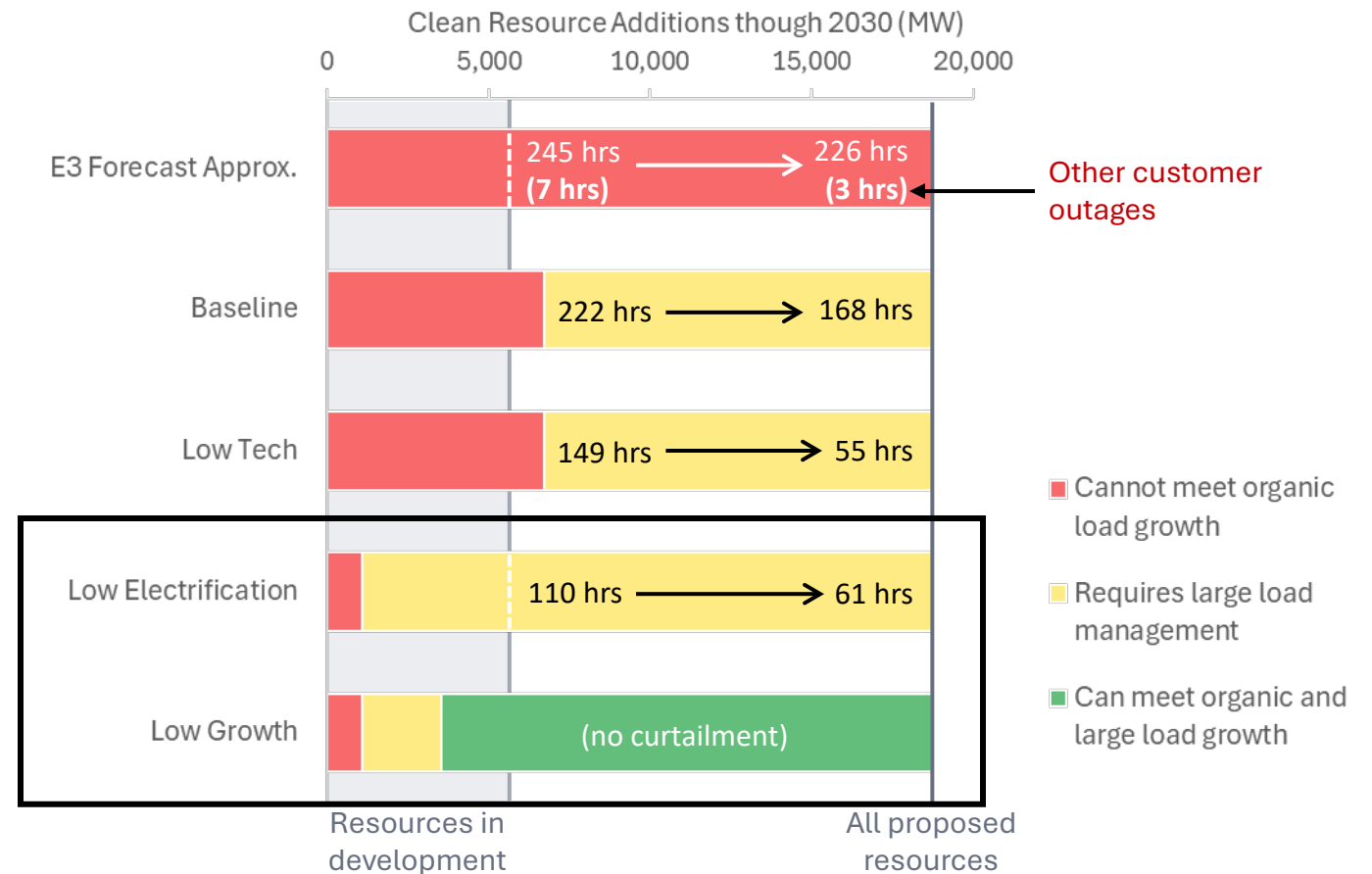
# Clean resource additions and large load management across the scenarios



# Clean resource additions and large load management across the scenarios

In scenarios without accelerated electrification (Low Electrification and Low Growth):

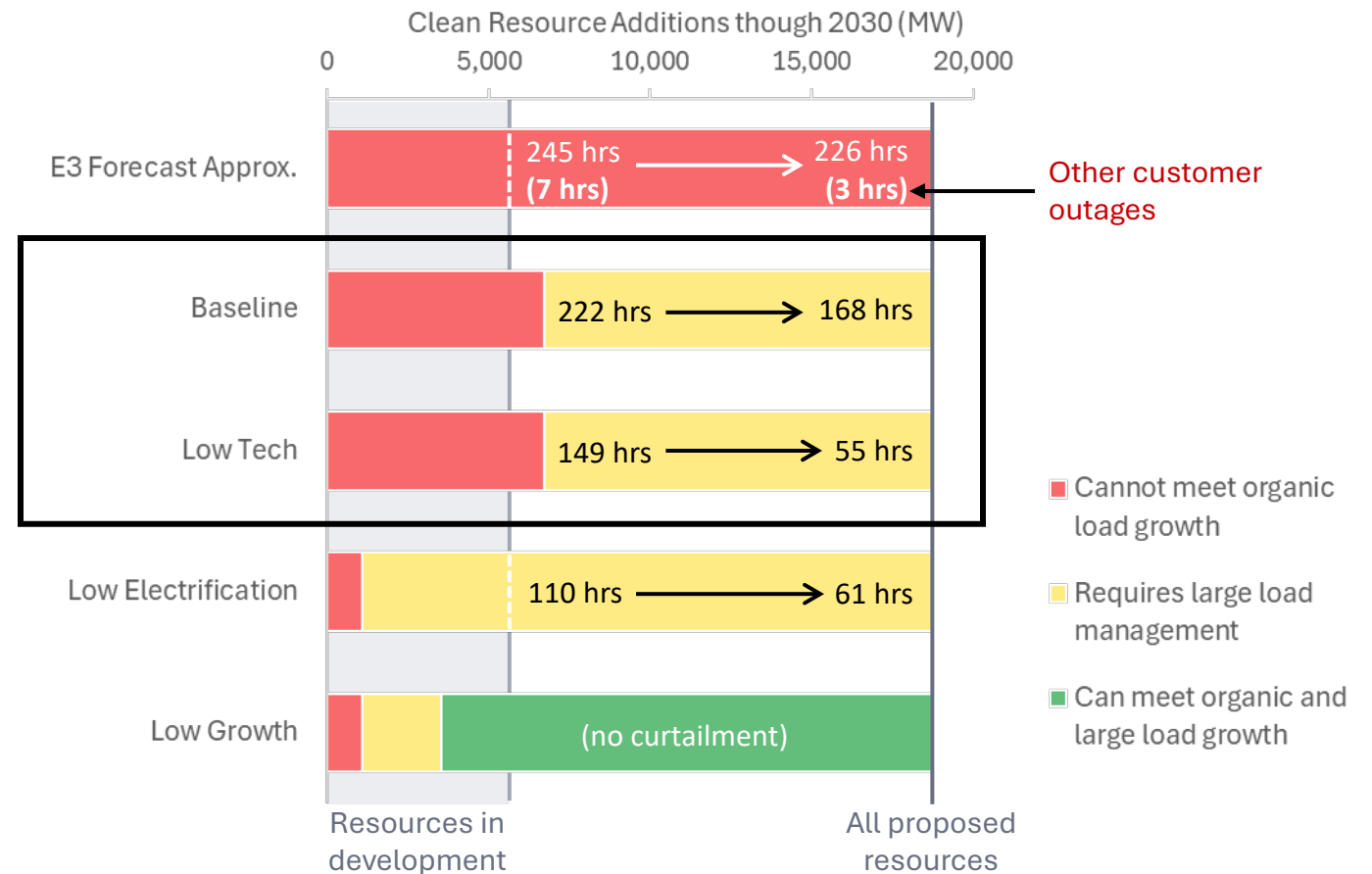
- Clean resources in development are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 0 hrs to 110 hrs)



# Clean resource additions and large load management across the scenarios

In scenarios that project 1.4% annual organic load growth (Baseline and Low Tech):

- Clean resources in development plus a relatively small amount of incremental resources are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 55 hrs to 222 hrs)



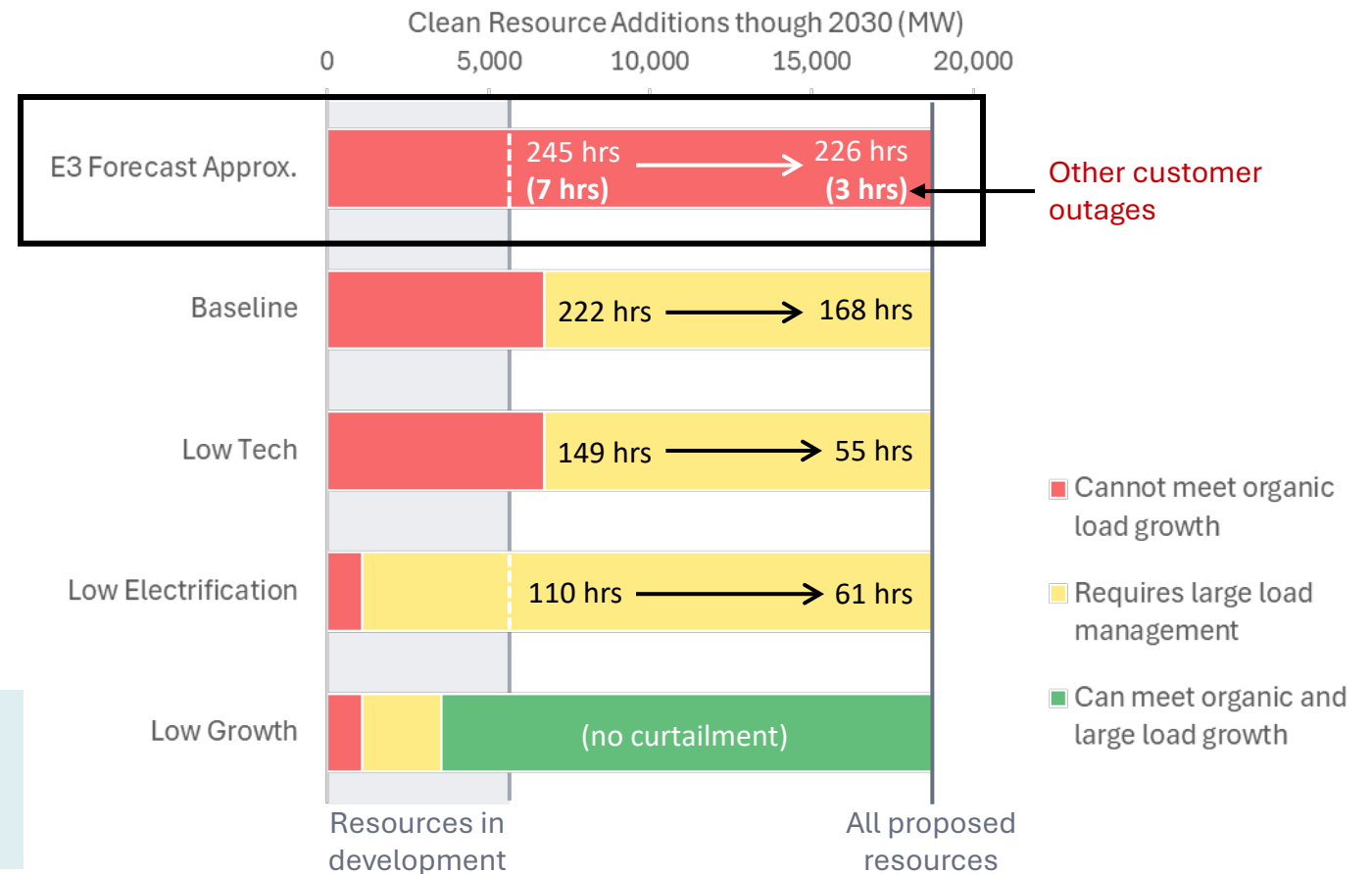
# Clean resource additions and large load management across the scenarios

Under E3's load growth scenario, which includes more rapid electrification and relatively low data center demand, the region is in a real bind!

- Resource needs to meet organic growth exceed the quantity of proposed clean projects (19 GW)
- Large load curtailments exceed 100 hrs and other customers may experience rolling brown outs even with large load curtailments unless additional resources can come online
- New gas has been discussed as a solution to this challenge, but the gas system was constrained during the January 2024 event as well

## Near-term opportunity:

- Study impacts of regional natural gas system constraints on regional electricity reliability

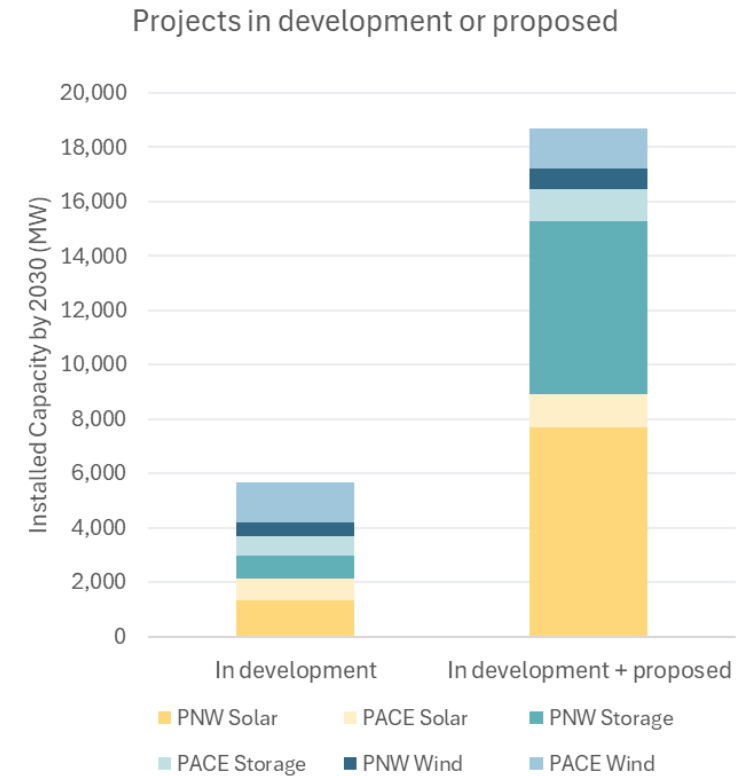


# Winter portfolio ELCCs of new clean resources

Winter portfolio ELCCs estimated by calculating avoided perfect capacity during Jan 2024 weather/hydro event (not representative of summer contributions)

Baseline Load Scenario	Installed capacity (MW)	Avoided Perfect Capacity in Jan 2024 conditions (MW)	Approx. Winter Portfolio ELCC
All clean resources in development	5,666	1,875	33%
Additional clean resources pending approvals	13,009	2,473	19%
<b>Total</b>	<b>18,675</b>	<b>4,348</b>	<b>23%</b>

(Calculated before Centralia 2 coal-to-gas conversion and large load curtailments)

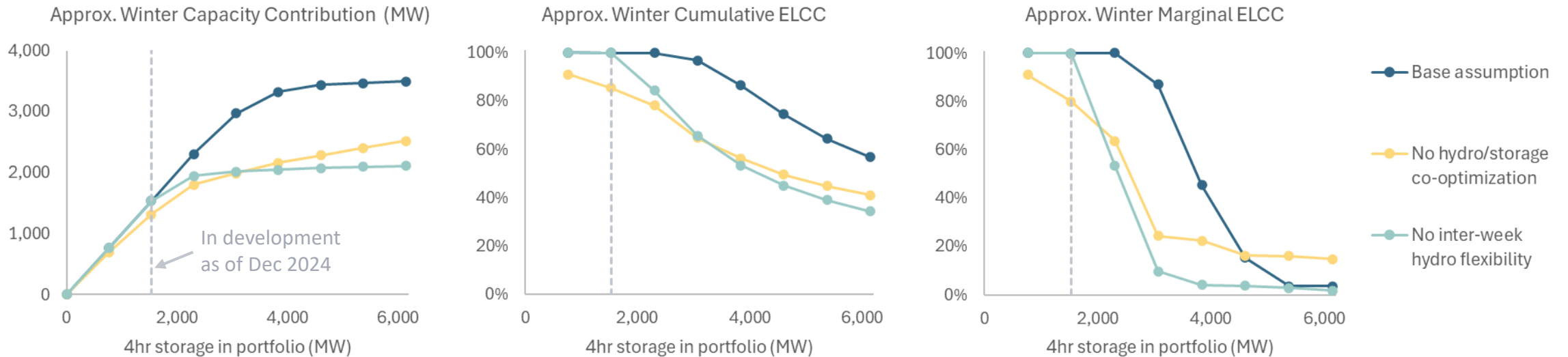


## Near-term opportunity:

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities

# Winter ELCCs of 4hr storage

- Winter ELCCs for 4hr storage could depend strongly on how the hydro system is operated and modeled
- Two assumptions could lead to lower ELCCs and more rapid saturation of short duration storage than our analysis observes
  - Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
  - Load-following or net load-following hydro dispatch that is not co-optimized with battery storage dispatch



Notes:

- Approximate winter capacity contributions were calculated as the reduction in capacity need during January 2024 weather & hydro conditions under the Baseline load scenario, with wind and solar that is in development and Centralia 2 coal-to-gas conversion
- These values do not account for contributions to resource adequacy in the summer and may not be applicable to individual utilities with unique constraints
- After conducting the analysis, we found that 332 MW of batteries came online in 2024, which were not included in the baseline dispatch simulations because they were not in January 2024 EIA 930 data. This analysis suggests these additional batteries would have reduced capacity needs in all simulations by about 330 MW.

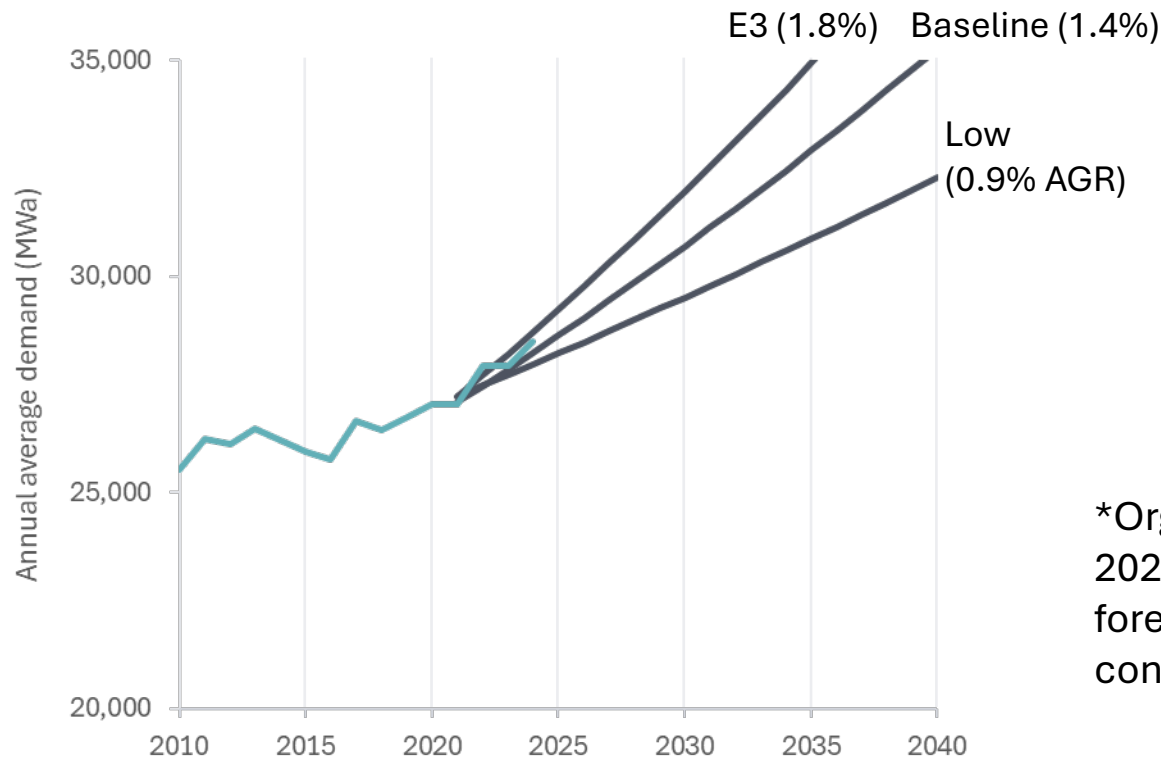


# Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

# The need for dispatchable or baseload solutions is not a question of if, but when

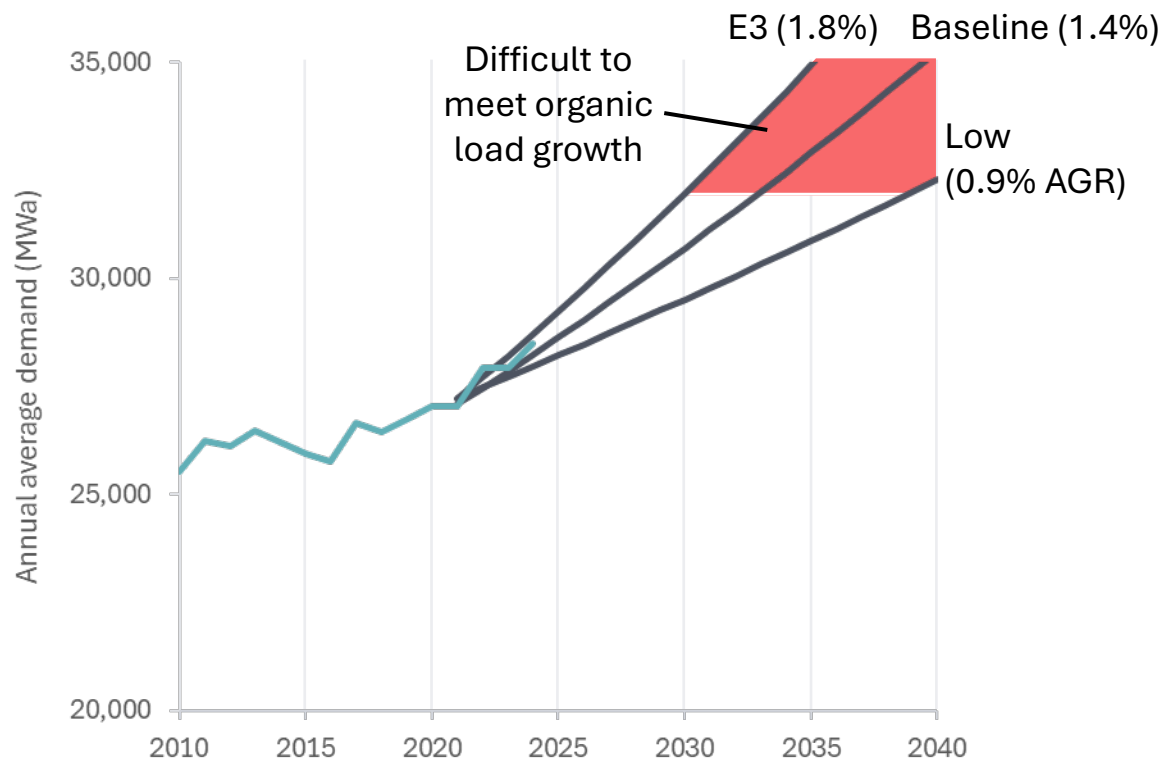
Extrapolated\* organic load growth trajectories



\*Organic load growth trajectories estimated by applying the 2025-2030 average annual organic load growth rate from each forecast to 2031-2040. This exercise is indicative and conceptual and may not align with actual load forecasts.

# The need for dispatchable or baseload solutions is not a question of if, but when

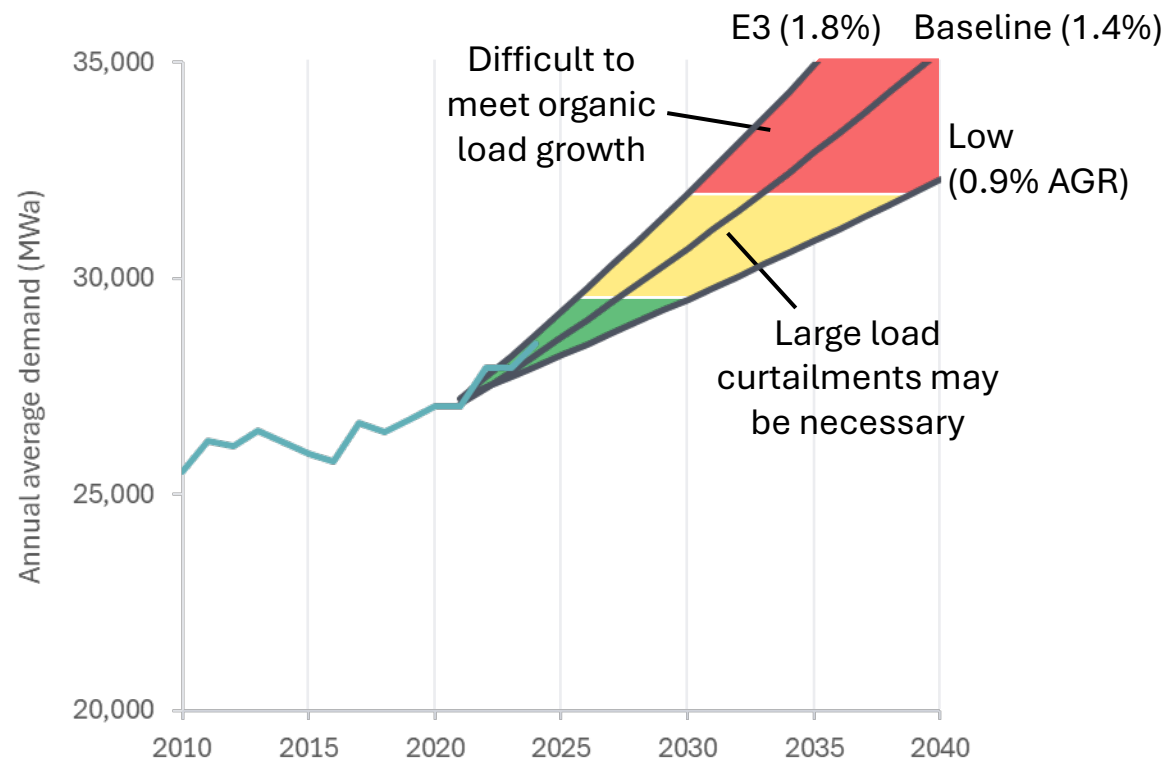
Extrapolated\* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
  - E3 Forecast: By 2030
  - Extrapolated Baseline Forecast: Roughly early 2030s
  - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

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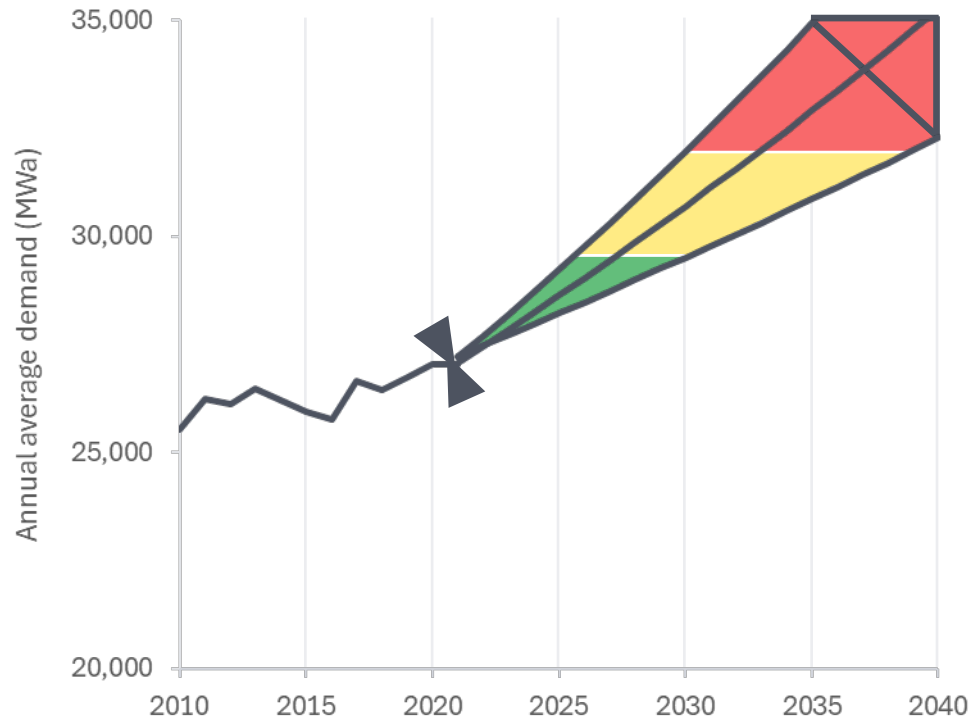
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- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution
- Large load flexibility requirements provide a crucial backstop across the scenarios

# “A kite only flies when it’s tethered”

-Victor Robert Lee



We can't control the wind (or the economy), but we have some tethers on the demand side that could buy the region some time

## Near-term opportunities:

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)



Cape Lookout State Park, Oregon Coast (source: [www.oregonlive.com](http://www.oregonlive.com))

## An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

# High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

# Near-term opportunities identified to support regional RA

