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Long-Term Assessment of Load-Resource Balance in the Pacific Northwest

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Agenda

+ Study scope & overview
+ Review of existing regional studies
+ Modeling overview & approach
+ Scenario inputs & assumptions
+ Results & conclusions

STUDY SCOPE AND OVERVIEW

Project Goals

- **In 2017, the OPUC acknowledged PGE's request to conduct a study related to the treatment of existing capacity available in the market in future Integrated Resource Plans**
- **To inform the development of its 2019 Integrated Resource Plan (IRP), PGE is seeking to understand:**
  - How future changes in resources and loads in the Pacific Northwest might affect the region's overall capacity position;
  - How constraints within the region might impact the ability to deliver excess capacity in the region to PGE loads; and
  - What implications of these factors have for PGE's long-term planning assumptions of market purchases of available surplus capacity

Key Trends in the Northwest
Drivers of Capacity Need

- **The key trends shaping the Northwest power sector are:**
  - Increasing peak loads, especially in the summer
  - Coal plant retirements
  - Few thermal power plants being expected to be built in the coming years
  - Addition of new renewables
  - The high level of energy efficiency that is already achieved as well as expected to be realized by utilities

Image source: PNUCC

- **The expected capacity need is primarily driven by the retirement of almost 1,800 MW of coal over the next few years**

Project Approach

1. **Review existing studies by regional entities**
   - Northwest Power & Conservation Council (NWPCC)
   - Bonneville Power Administration (BPA)
   - Pacific Northwest Utilities Conference Committee (PNUCC)
2. **Develop a simple heuristic-based scenario tool to test impact of various assumptions on market surplus and deficit results**
   - Designed to be consistent with existing studies, but provides more flexibility for scenario analysis
3. **Use spreadsheet tool to design a range of scenarios to inform recommended assumptions for PGE 2019 IRP**

LITERATURE REVIEW

Four Existing Studies Surveyed

+ **NWPCC: Pacific Northwest Power Supply Adequacy Assessment for 2023**
  - Time horizon: 2023
  - Seasons: winter & summer
+ **NWPCC: 7th Northwest Conservation and Electric Power Plan**
  - Time horizon: 2015-2035
  - Seasons: winter & summer
+ **PNUCC: Northwest Regional Forecast of Power Loads & Resources**
  - Time horizon: 2019-2028
  - Seasons: winter & summer
+ **BPA: 2017 Pacific Northwest Loads and Resources Study (The White Book)**
  - Time horizon: 2019-2028
  - Seasons: winter only

Key Assumptions Comparison

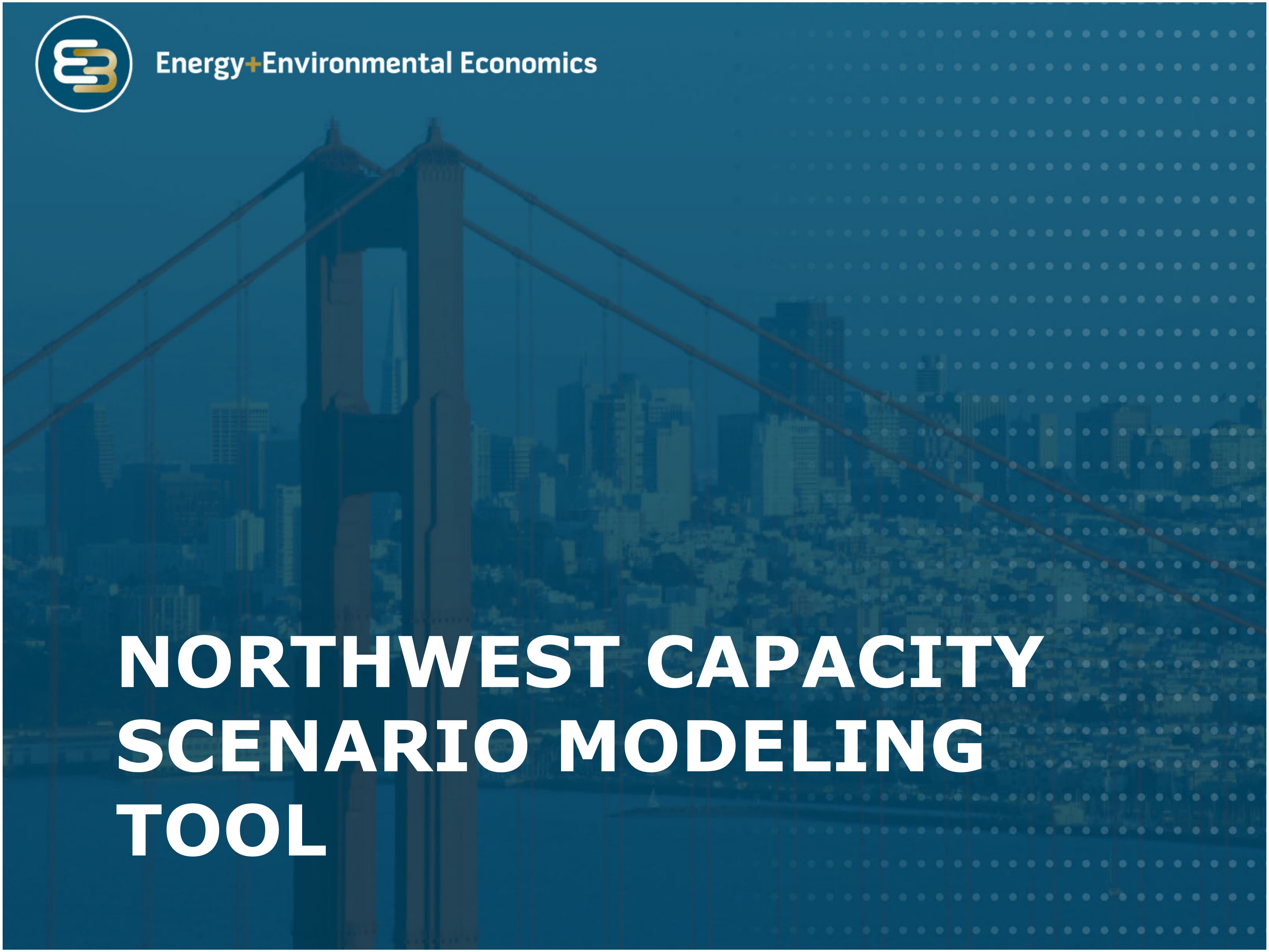
Assumption	PNUCC Study 2018	BPA Whitebook 2017	NWPCC 7th Power Plan	NWPCC 2023 Assessment
Analytical Approach	Deterministic	Deterministic	Deterministic	Stochastic
Peak Load Calculation	NCP of all participating utilities	BPA Load Forecasts	Ranges of load forecasts tested	Distribution of peak loads for 80 temperature year modeled in GENESYS
Resources	Existing and committed; IPPs not included	As per utility IRPs, IPPs included	Existing, IPPs included	Existing and planned, IPPs included
Adequacy Metric	PRM of 16%	Adjustment to available resources based on operating reserves and transmission losses	Adequacy Reserve Margin instead of PRM	LOLP
Hydro Capacity	8th percentile based on average water	BPA internal Hourly Operating and Scheduling Simulator (HOSS) model	P2.5% 10-hour sustained peaking ability	A wide range of hydro conditions modeled in GENESYS
Wind Capacity	5%	Wind capacity not counted as firm	5% for Adequacy Reserve Margin	ELCC endogenously calculated in GENESYS

Key Results of Existing Studies

- **PNUCC study shows a ~1.8 GW winter capacity in 2020, and ~0.5 GW summer capacity need starting in 2021**
  - Primarily different from BPA White Book and NWPCC in not including regional IPPs
- **BPA White Book shows a winter capacity need starting in 2021 of 1.1 GW**
  - No summer analysis provided
- **NWPCC RA assessment shows a need of 300-400 MW by 2021, with an additional 300-400 MW needed by 2022**
  - RA assessment shows need only for the winter by 2022
- **NWPCC 7th Power Plan shows a capacity need of 1 GW in 2021 for the high need scenario, and a capacity surplus of 700 MW for the low need scenario**

Summary of Literature Review

- **Under current assumptions, new capacity is required by 2021 in all studies reviewed**
  - If unknown status in-region IPP generation is not available, new capacity is required in 2019
- **PNUCC and BPA White Book use different metrics and have a different time horizon compared to NWPCC**
  - Comparing across studies is difficult due to range of approaches and time horizons
- **Key uncertainties include loads, new build expected to come online before 2021, level of DSM that is realized, contribution of unknown status IPP generation, and external market purchases**



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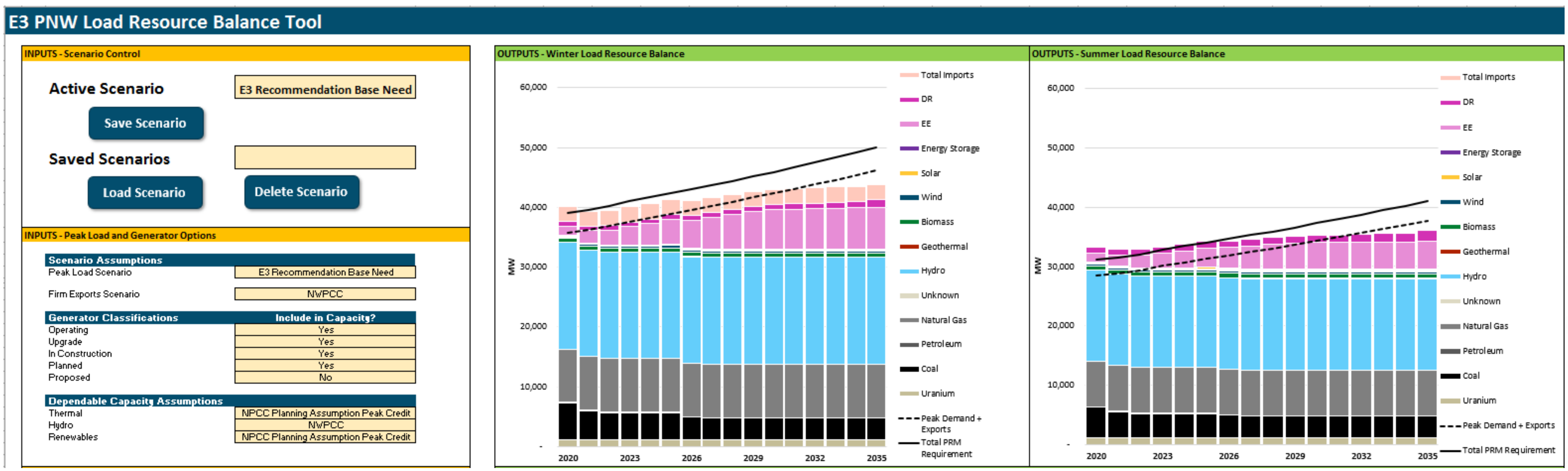
NORTHWEST CAPACITY SCENARIO MODELING TOOL

Model Overview

+ **E3 developed a spreadsheet tool to analyze expected regional net capacity position under a range of different assumptions**
+ **Model uses input assumptions from regional outlook studies**
+ **Model can be used to replicate results from studies or create custom scenarios**
    - E3 calibrated the model to align with NWPCC 2023 RA assessment



Model Overview

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- **Model can be used to replicate results from studies or create custom scenarios**
  - E3 calibrated the model to align with NWPCC 2023 RA assessment

- Calibration helps benchmark to regional outlook studies
- Using the calibrated model, additional scenarios and sensitivities not tested in the existing studies can be examined

Model Calibration
NWPCC GENESYS vs E3 Model

- **E3 used the NWPCC 2023 RA Assessment to calibrate the E3 model**
  - For calibration, assumptions are consistent with NWPCC 2023 assessment for 2023; NWPCC 7th Power Plan values are used when applicable
- **The PRM requirement assumed in E3's model is derived from the results of NWPCC's RA assessment**
  - PRM value was calculated to yield "need" results consistent with NWPCC's 2023 assessment

Category	GENESYS	E3
Approach	Stochastic	Deterministic
Adequacy Metric	LOLP	PRM
Horizon	One year snapshot	10 year outlook
Hydro	Stochastic simulation of 80+ years	Assumed contribution (%) to winter & summer peak
Renewables	Stochastic simulation of hourly renewable output	Static assumed ELCC (%)

Model Calibration

NWPCC GENESYS vs E3 Model

- **E3's capacity model uses a PRM approach that is calibrated to yield comparable results to the NWPCC 2023 Adequacy Assessment:**

1
Gather key assumptions from 2023 Adequacy Assessment
(demand forecast, installed capacity, etc.)

2
Choose capacity counting conventions for each type of resource
(firm, variable, hydro, etc.)

3
Derive PRM requirement to align timing and magnitude of "need" with 2023 Adequacy Assessment

- **After calibration process, inputs & assumptions may be varied to examine alternative scenarios**

Model Calibration
NWPCC GENESYS vs E3 Model

- Align 2023 summer and winter peak loads net of EE ☑
- Use NWPCC 2023 estimates of DR ☑
- Use NWPCC 2023 contracted non-NW imports + exports ☑
- Benchmark total thermal dependable capacity ☑
- Assume NWPCC 2023 in-region unknown status IPPs ☑
- Assume NWPCC 2023 seasonal external markets imports ☑
- Estimate renewables ELCC ☑
  - NWPCC 7th Power Plan wind ELCC; E3 estimates for solar ELCC in summer
- Estimate hydro dependable capacity ☑
  - NWPCC 7th Power Plan 10 hr sustained winter and summer peaking
- Calculate implied PRM to yield NWPCC 2023 capacity need ☑

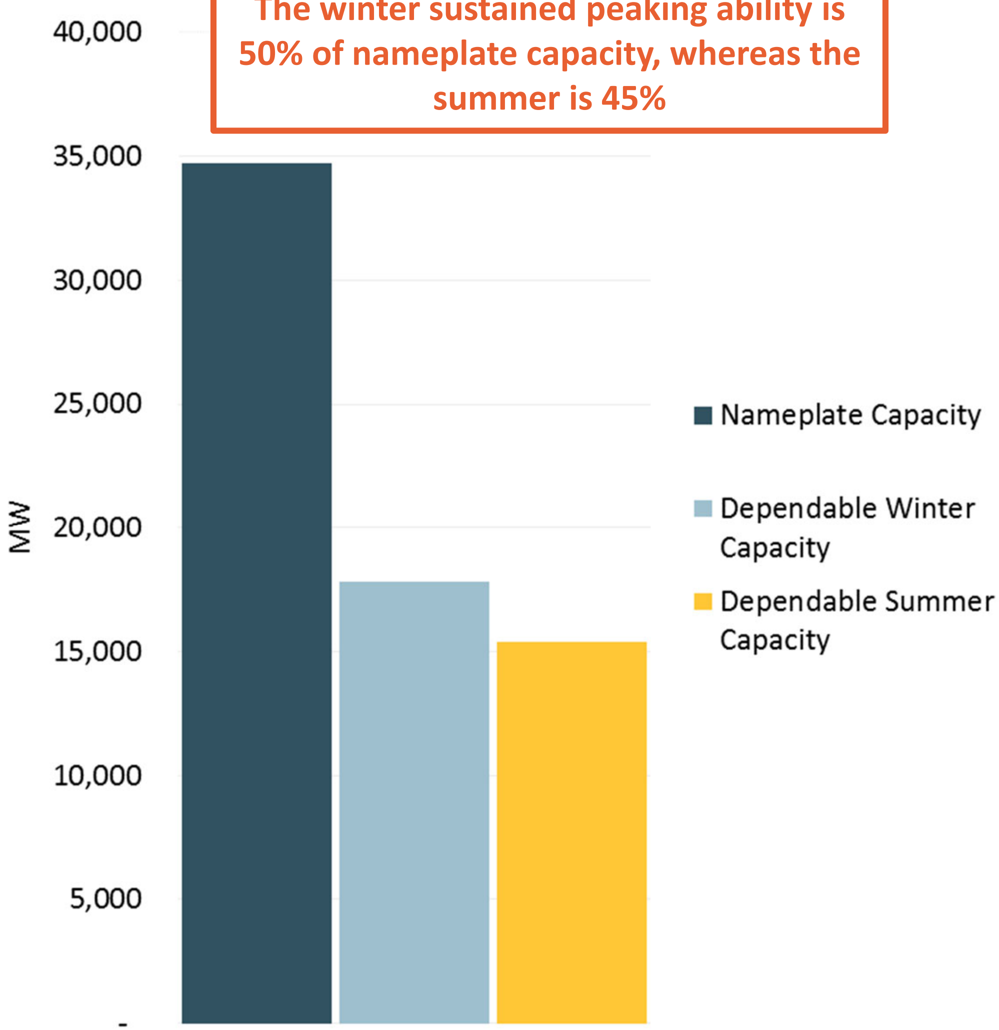
☑ NWPCC 2023 Assessment

☑ NWPCC 7th Power Plan

☑ Calibration Parameter

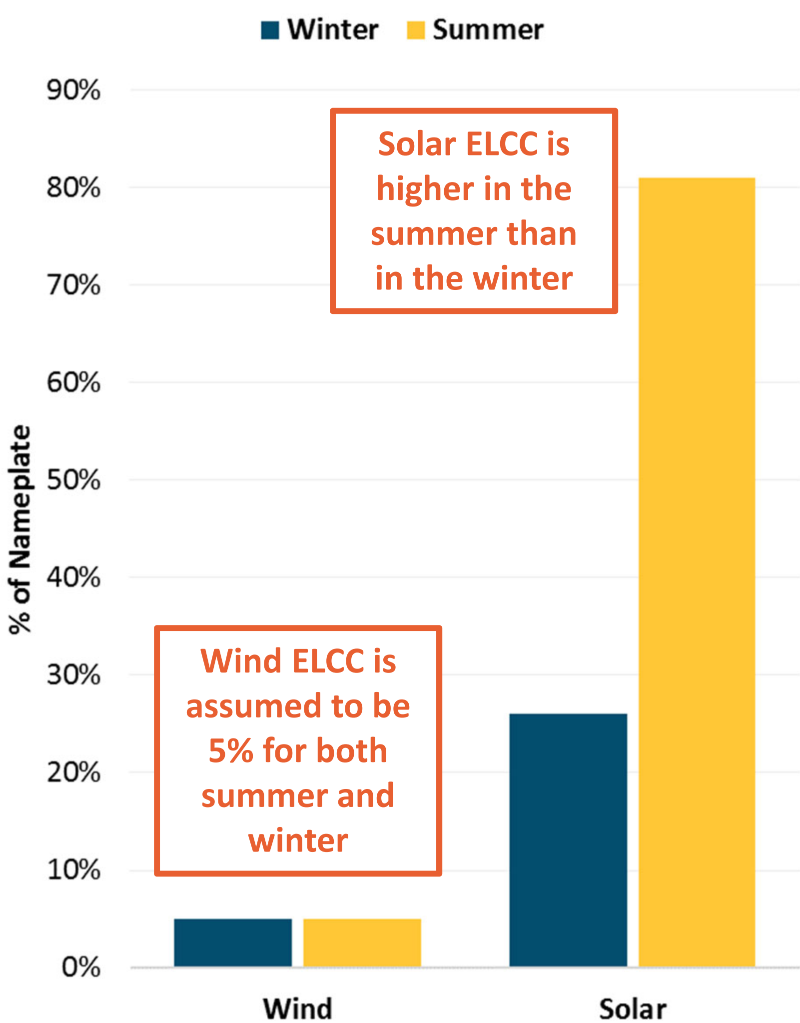
Key Assumptions for Model Calibration
Hydro Dependable Capacity

The winter sustained peaking ability is 50% of nameplate capacity, whereas the summer is 45%



- **The Pacific Northwest region has more than 34 GW of nameplate hydro capacity**
- **However, the hydro resources are limited in their ability to provide power during a sustained peak load event**
  - Hydro resources are energy limited and cannot output generation at their full nameplate capacity for multiple consecutive hours
- **To account for their energy limits, the nameplate capacity is derated to reflect the hydro fleet's sustained peaking ability**
  - Similar to assumption used by NWPCC 7th Power Plan for its system adequacy assessment
  - Use of critical water year to determine capacity credit does not imply analysis assumes critical water conditions exist

Key Assumptions for Model Calibration
Renewables ELCC



- **Due to their intermittent generation, variable renewables usually do not contribute their full nameplate capacity towards meeting system peak**
- **To estimate the contribution of renewables to system peak, effective load carrying capacity (ELCC) of renewables is used**
  - Determines renewable production as a fraction of nameplate capacity during peak load event
- **For wind and solar ELCC estimates, E3 used the NWPCC 7th Power Plan**
  - Adequacy reserve margin results for wind peaking capability
  - Associated system capacity contribution (ASCC) for seasonal solar ELCC

Derivation of a Planning Heuristic for the Northwest

Resource	Nameplate MW	Dependable MW	Notes
Thermal	14,667	14,667	Assumed 100% availability
Hydro	34,697	17,790	Based on critical water 10-hr sustained peaking capability
Solar	448	116	Assumed 26% ELCC
Wind	6,264	313	Assumed 5% ELCC
Other	1,200	784	Biomass, geothermal, energy storage
DR	740	740	Assumed 100% availability
Imports		2,565	2,500 MW from CA + 65 MW firm imports
Generic Need		700	Need identified in 2023 RA Assessment
Total Resources		**37,675**	
Loads		**Load MW**	**Notes**
1-in-2 Peak Demand		34,070	Based on 2023 RA Assessment (includes all cost-effective EE)
Firm Exports		462	Based on 2023 RA Assessment
Total Load		**34,532**	
Reserve Margin Need		**10%**	**Ratio between Total Resources & Total Load**

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Reserve Margin Need		**10%**	**Ratio between Total Resources & Total Load**

Reserve margin requirement is directly tied to conventions used to count hydro capacity

Alternative Hydro Conventions Yields Same Capacity Need

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Hydro	34,697	21,330	Based on BPA White Book sustained peaking capability
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Firm Exports		462	Based on 2023 RA Assessment
Total Load		**34,532**	
Reserve Margin Need		**19%**	**Ratio between Total Resources & Total Load**

Changing the convention used to count hydro towards the reserve margin does not change the capacity need

Summary of Model Conventions

+ **Load-resource tool estimates resulting regional capacity surplus or deficit in the Northwest for the summer and winter using implied planning reserve margin**

+ **Planning reserve margin (PRM) requirement of 10% calibrated based on MW of need in NWPCC 2023 RA Assessment**

+ **PRM calculation dependent on capacity accounting conventions in load-resource tool:**
  - Contribution of hydro towards reserve margin based on seasonal 2.5 percentile 10-hr sustained peaking capability
  - Wind and solar resource contributions based on assumed effective load carrying capability

+ **Assumptions & conventions used in this tool are derived to reflect loads & resources of the broader Northwest, but are not directly applicable to individual utilities (e.g. PGE)**

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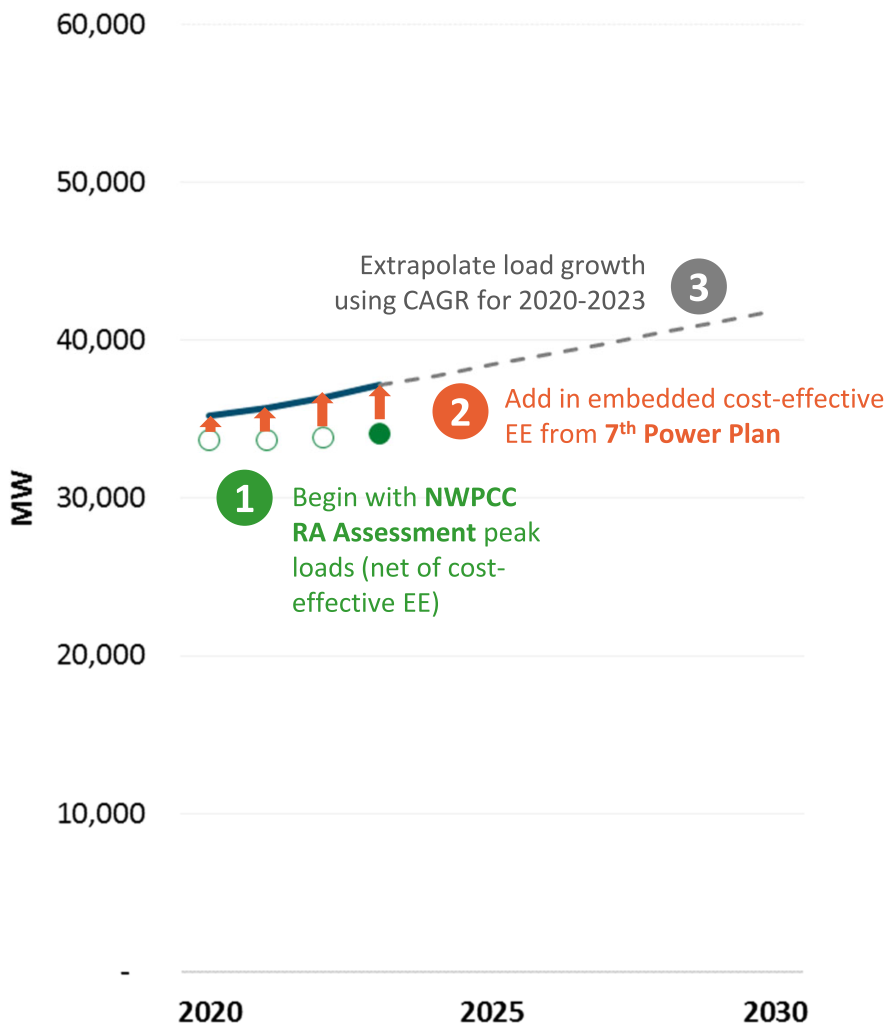
KEY SCENARIO INPUTS AND ASSUMPTIONS

Scenario Input Summary

Assumption	Low Need	Base Need	High Need
Load Forecast *(pre-EE)*	1.46%/yr (W) 1.73%/yr (S)	1.74%/yr (W) 1.92%/yr (S)	1.94%/yr (W) 2.21%/yr (S)
Energy Efficiency *(treated as a resource)*	**100%** of cost-effective EE	**100%** of cost-effective EE	**75%** of cost-effective EE
Demand Response	NWPCC Low	NWPCC Med	NWPCC High
Thermal Generation	Announced retirements		
Hydro Generation	Constant at today's levels		
Renewable Generation	Current plans		
Market Imports	3400 MW through 2023, 2100 MW by 2030 (W) 1400 MW in the near term, 0 in the long term (S)	2500 MW (W) 0 (S)	3400 MW through 2021, 0 after 2023 (W) 0 (S)

E3 Load Forecasts using NWPCC RA Assessment Loads

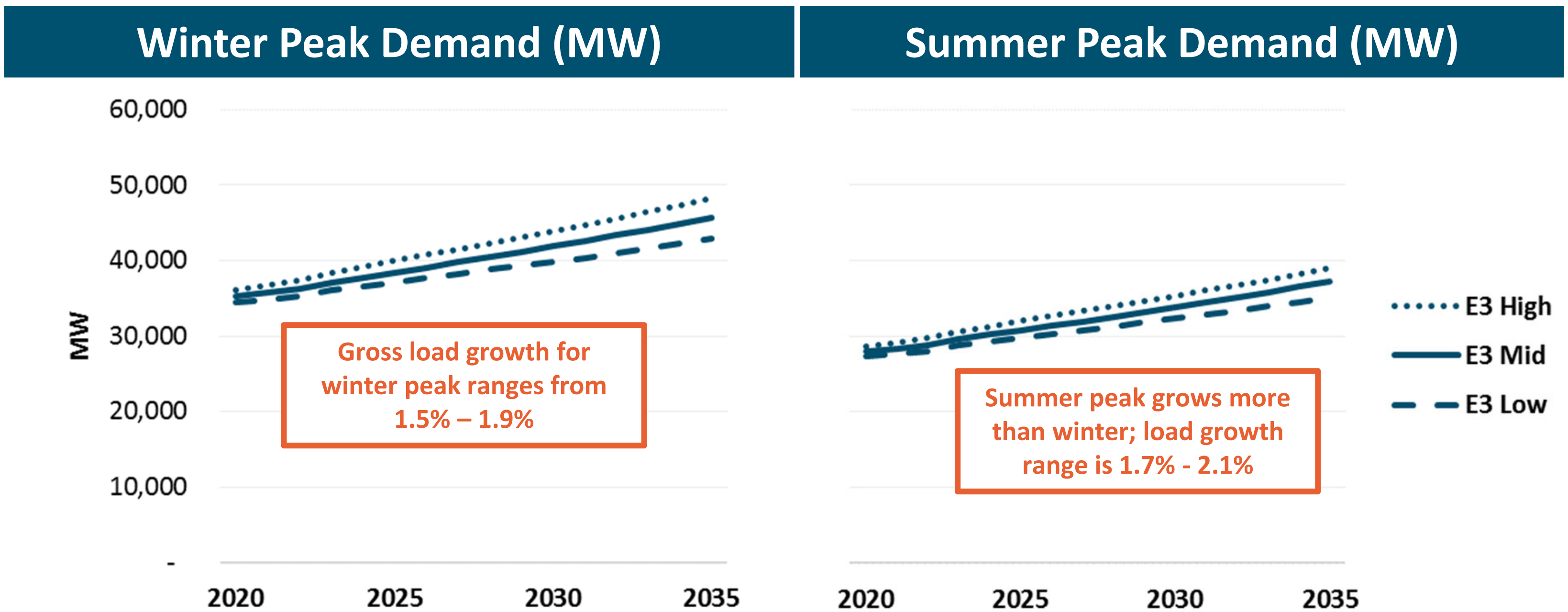


+ **NWPCC sources are used to develop a "pre-EE" demand forecast in three steps:**

1. NWPCC RA assessment peak loads net of EE for 2023 are used as a starting point
   - E3 received additional data from NWPCC for 2020-22 peak loads net of EE from their RA assessment
2. Loads before the impact of EE are backed out by adding back in the embedded cost-effective EE from NWPCC 7th Power Plan
3. The implied gross peak loads for the 2020-2023 period are used to extrapolate the gross loads post 2023

Recommended Demand Forecasts

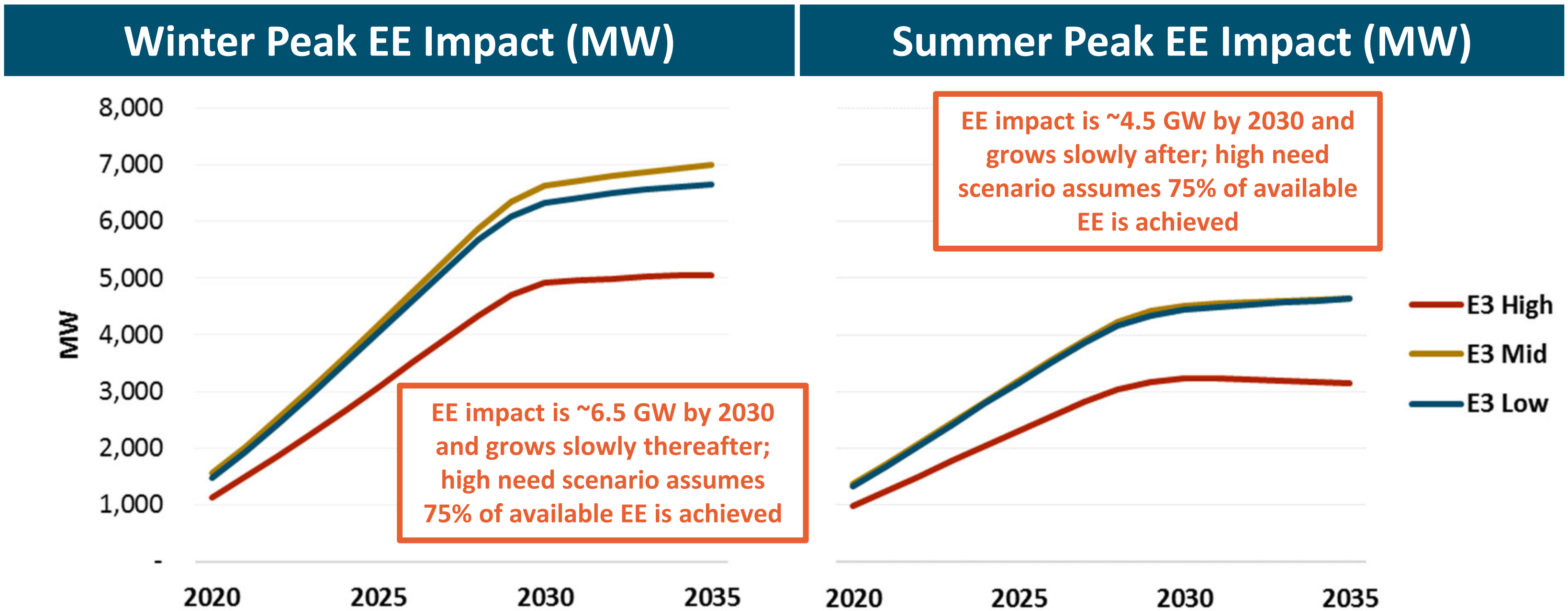
- "Mid" load forecast consistent with NWPCC RA Assessment
- "High" and "Low" forecasts reflect range of long-term growth rates considered in the NWPCC 7th Power Plan



* Note: demand forecast does not include impact of EE, which is treated as a resource

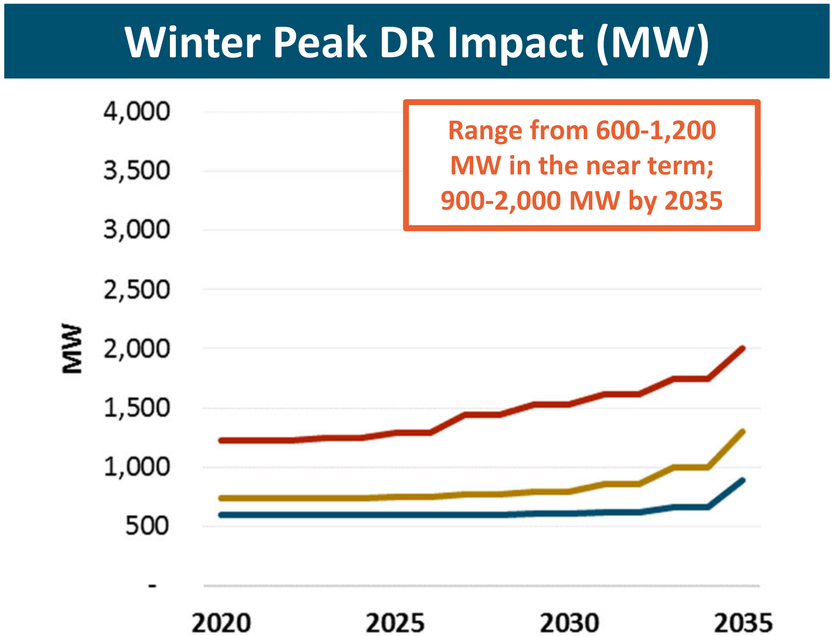
Energy Efficiency

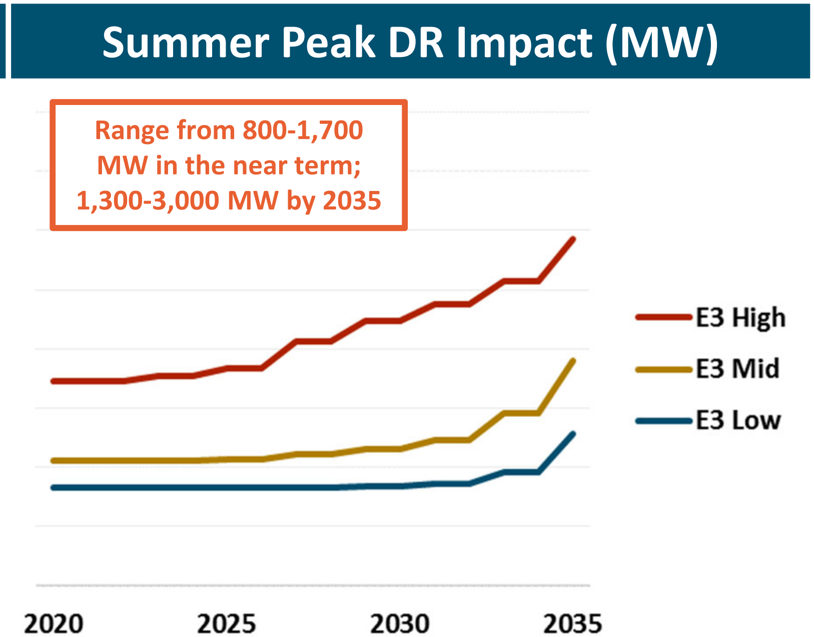
+ **NWPCC 7th Power Plan assumes lower levels of realized energy efficiency for low load and mid load forecasts; for high loads 75% of cost-effective EE is assumed to be achieved**



Demand Response

- Demand Response (DR) assumptions from NWPCC 7th Power Plan are used
- Winter DR availability is reduced to 2/3rd of that identified in the NWPCC 7th Power Plan based on RA adequacy assessment

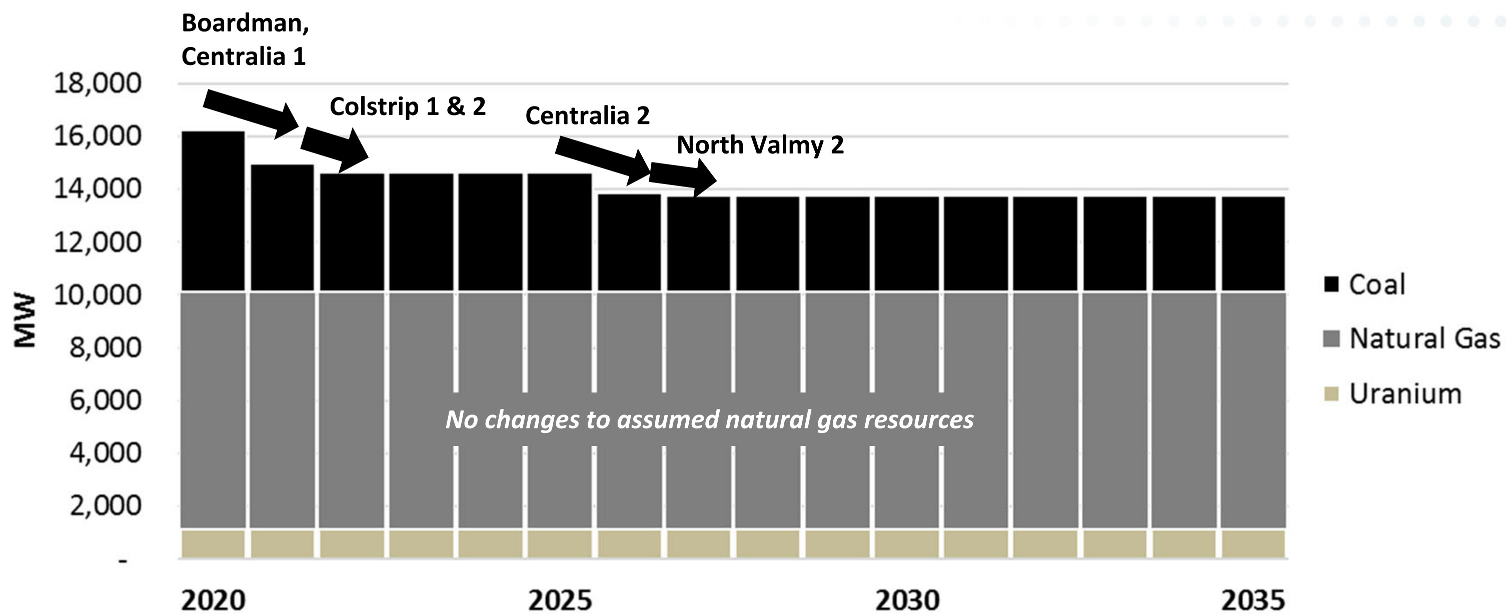




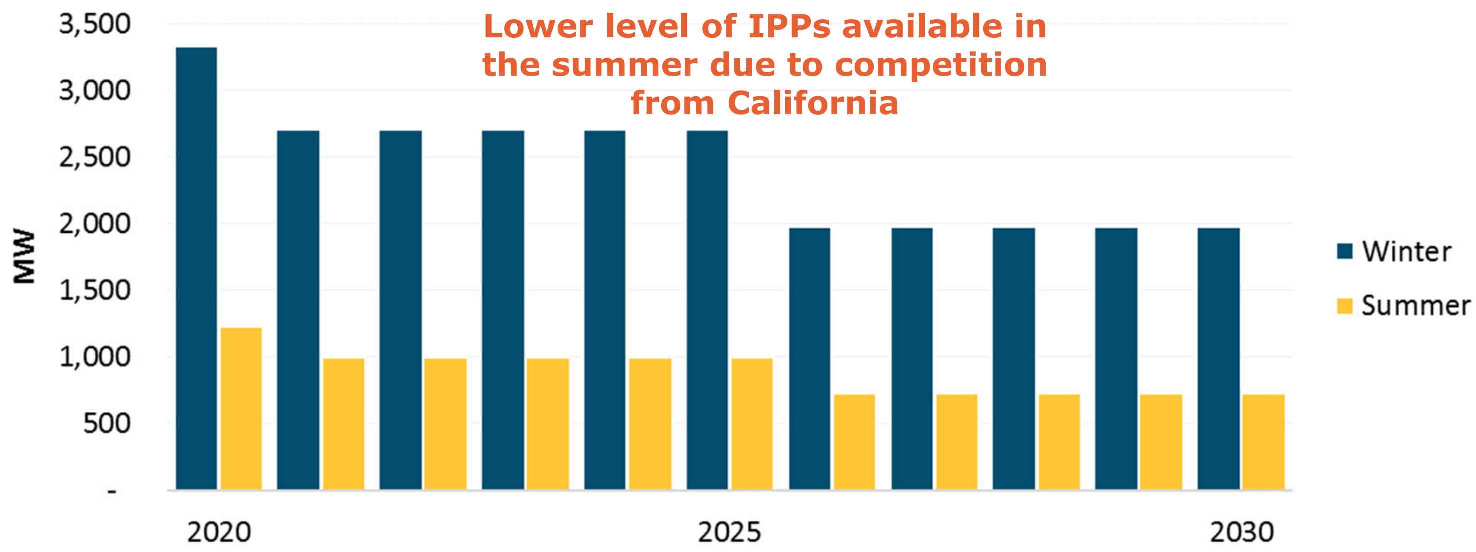
Thermal Generation Resources

- Characterization of coal & gas resources in the Northwest based on NWPCC powerplant database
- Key planned retirements based on announced retirements

Thermal Generation Installed Capacity (MW)



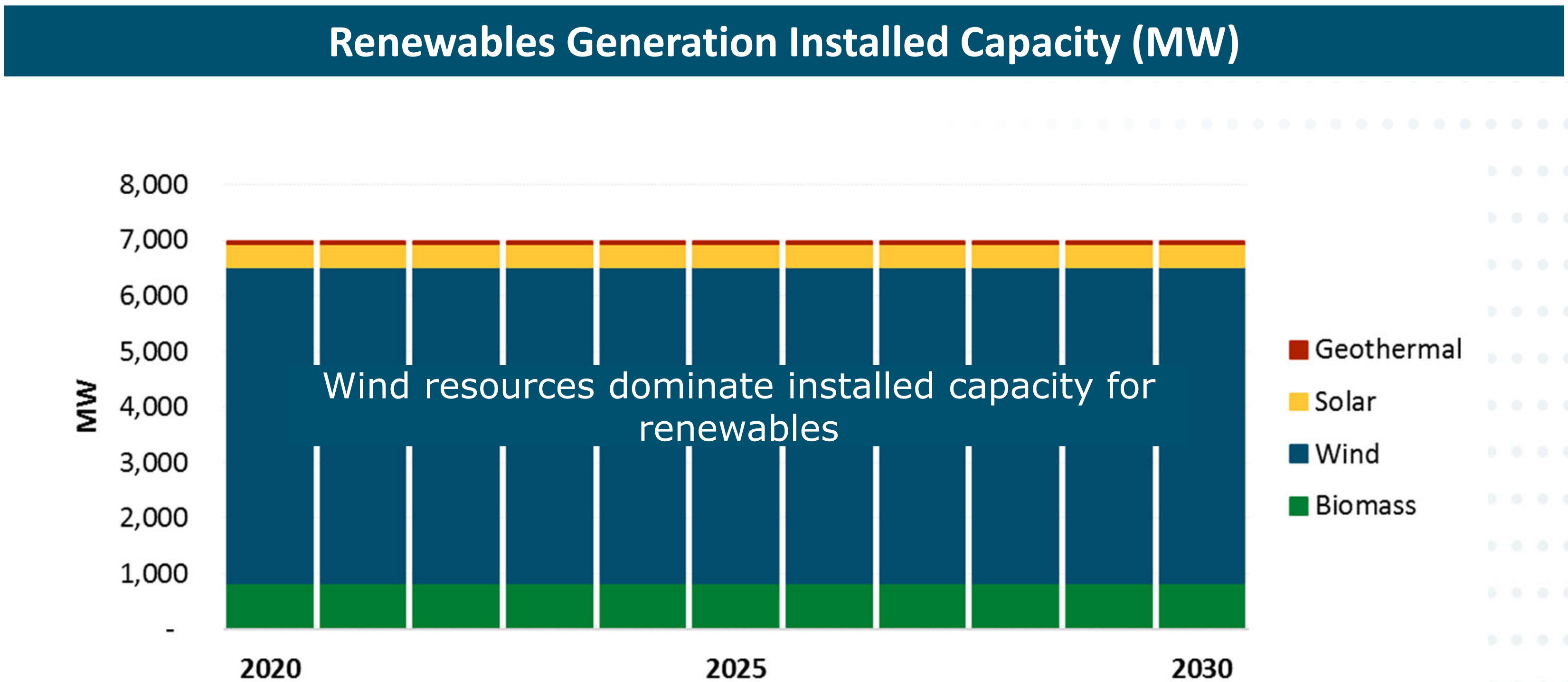
Key Assumptions for Model Calibration
IPPs Availability



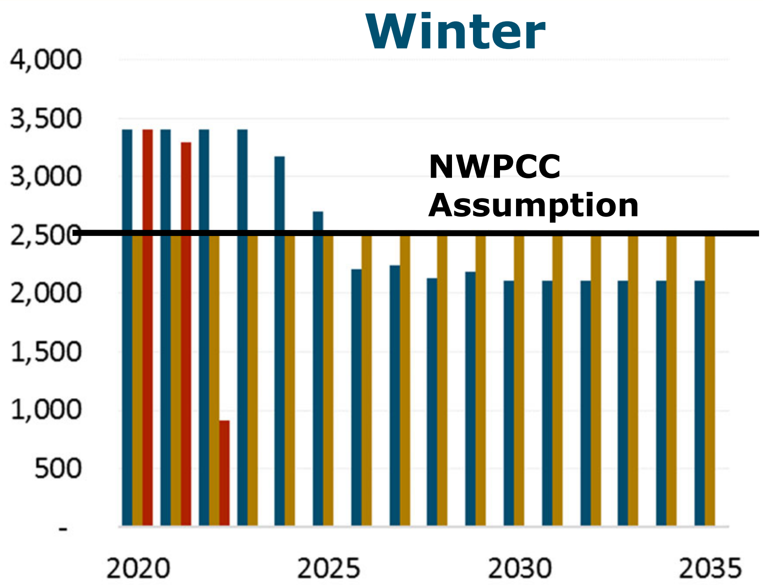
- **Unknown status IPPs assumption for winter is derived using the NWPCC power plants database**
- **For the summer, the winter capacity is derated to account for competing demands for capacity from California, consistent with the NWPCC's approach**

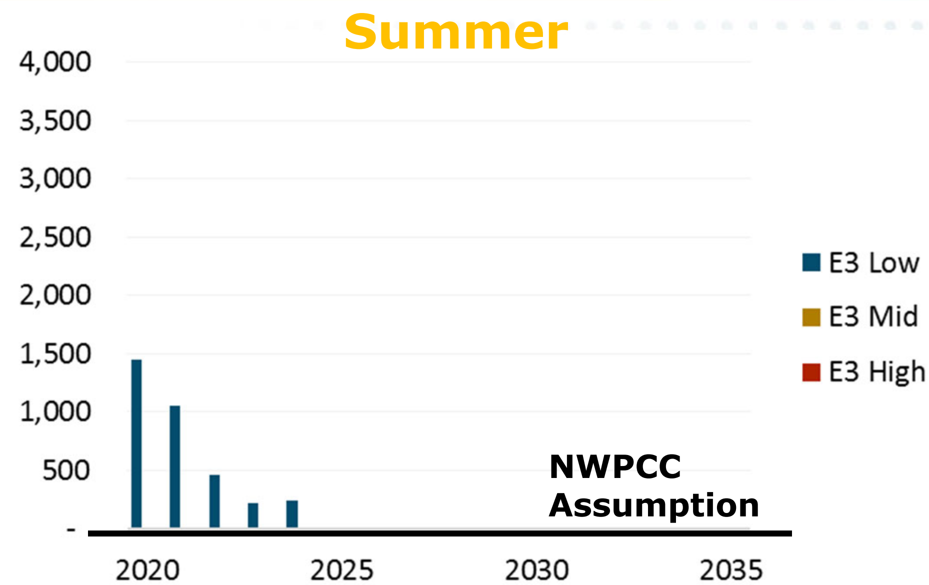
Renewable Resources

+ **Existing renewables resources are assumed to stay online through the analysis period**



External Market Imports Availability
Scenario Specific





Scenario	Winter	Summer
Low Need	E3 CAISO Surplus Calculations	E3 CAISO Surplus Calculations
Base Need	NWPCC	NWPCC
High Need	E3 CAISO Surplus Calculations	E3 CAISO Surplus Calculations

Total surplus capped at 3400 MW developed by the NWPCC as the available capacity 95% of the times (actual transfer capacity is ~4 GW from CAISO)

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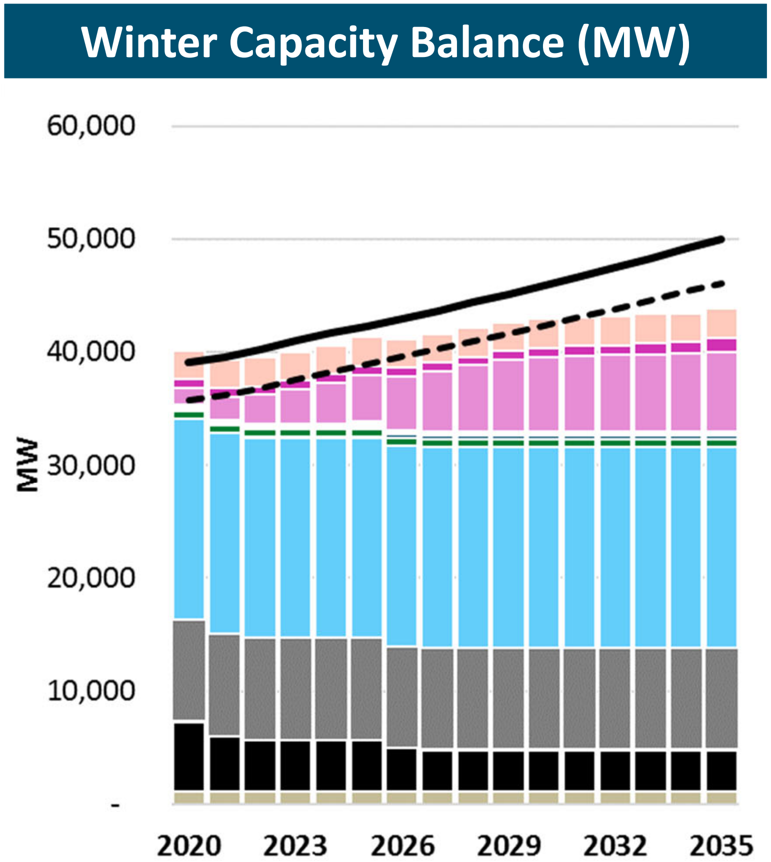
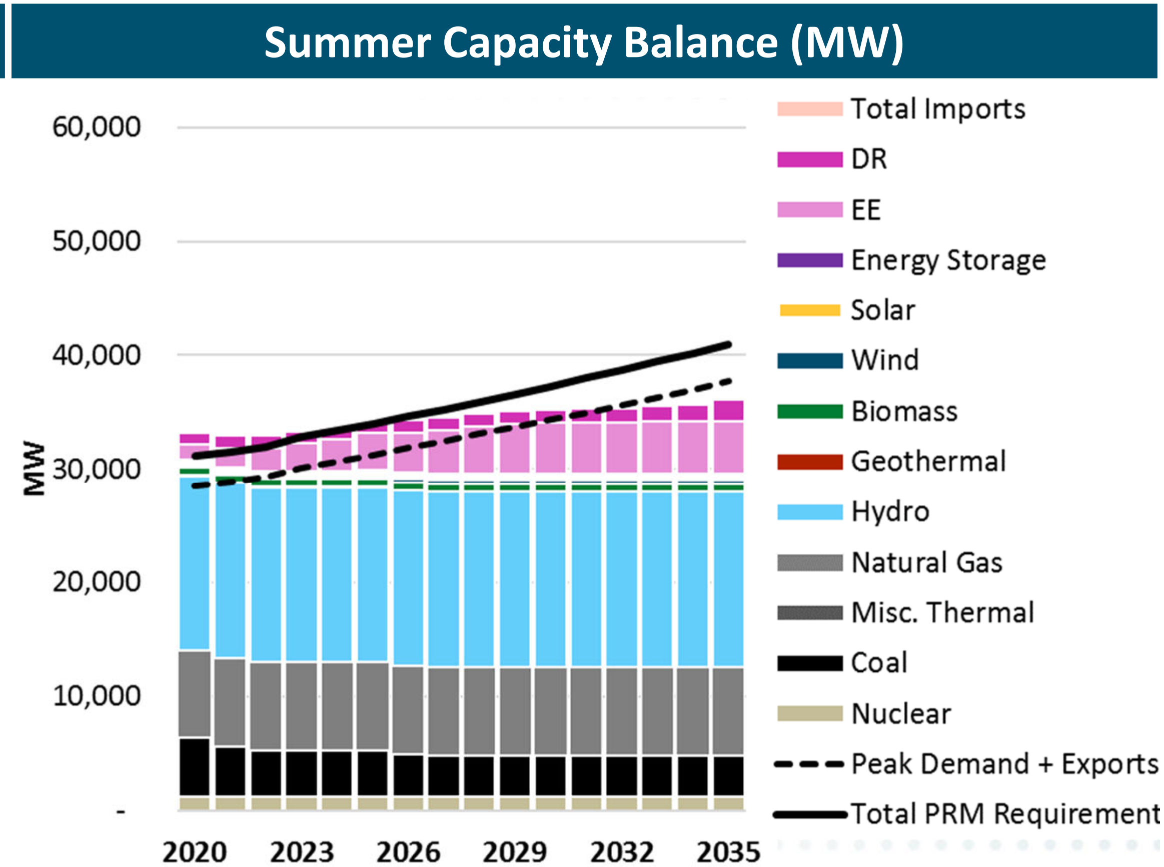
RESULTS

Results: Base Need Scenario

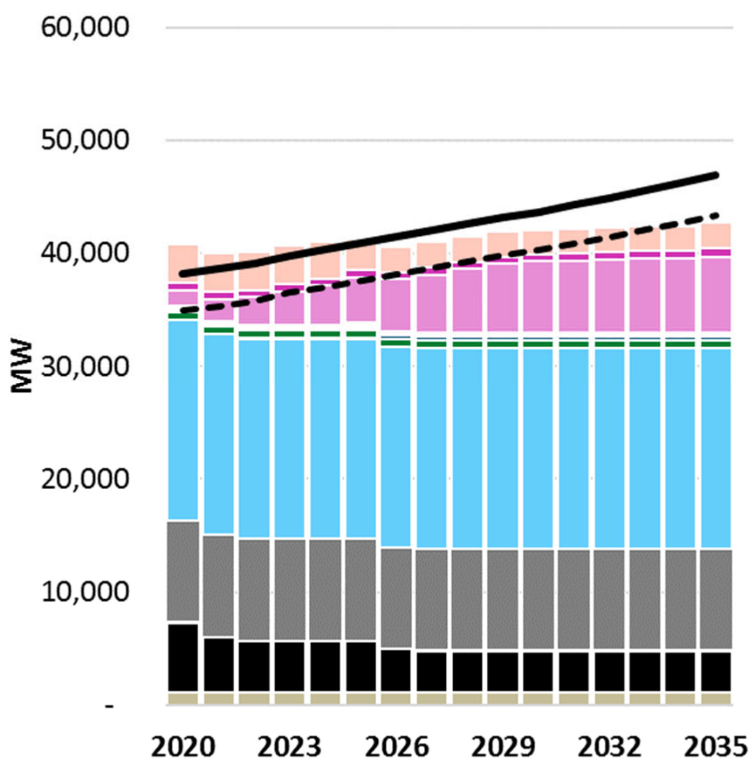


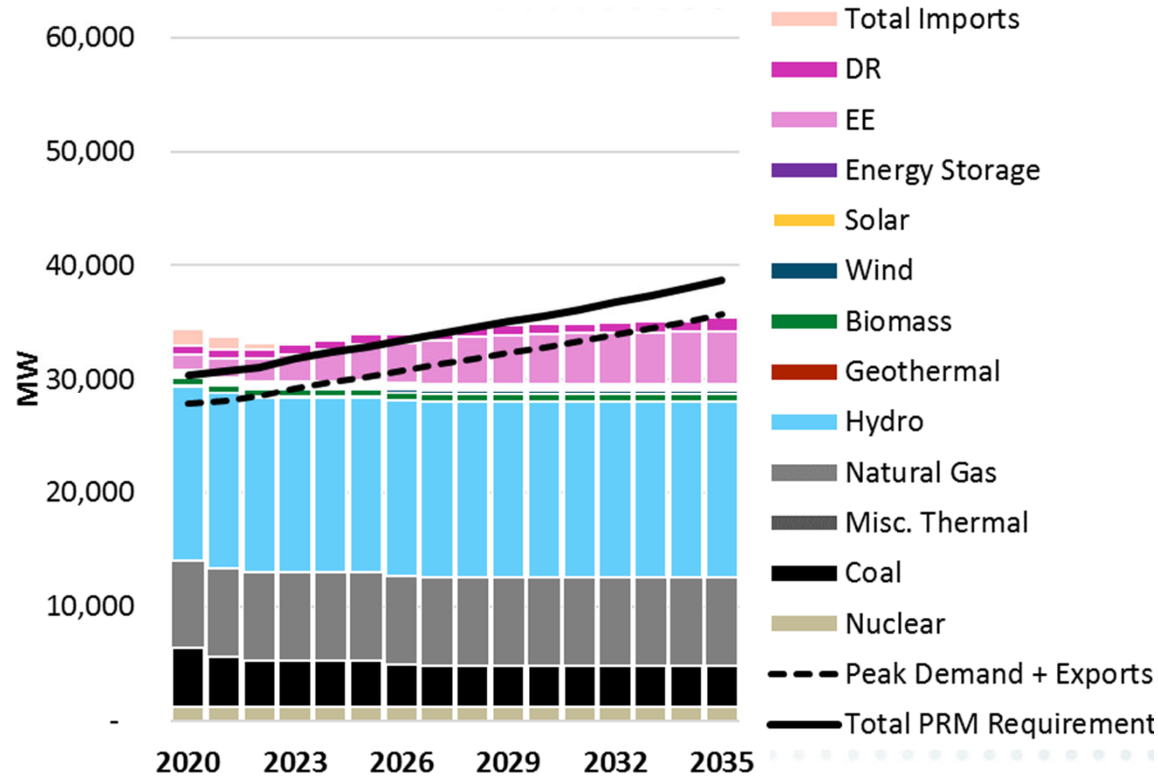


- **Winter: Capacity deficit starting in 2021**
- **Summer: Capacity deficit starting in 2026**

Results: Low Need Scenario

Winter Capacity Balance (MW)	Summer Capacity Balance (MW)

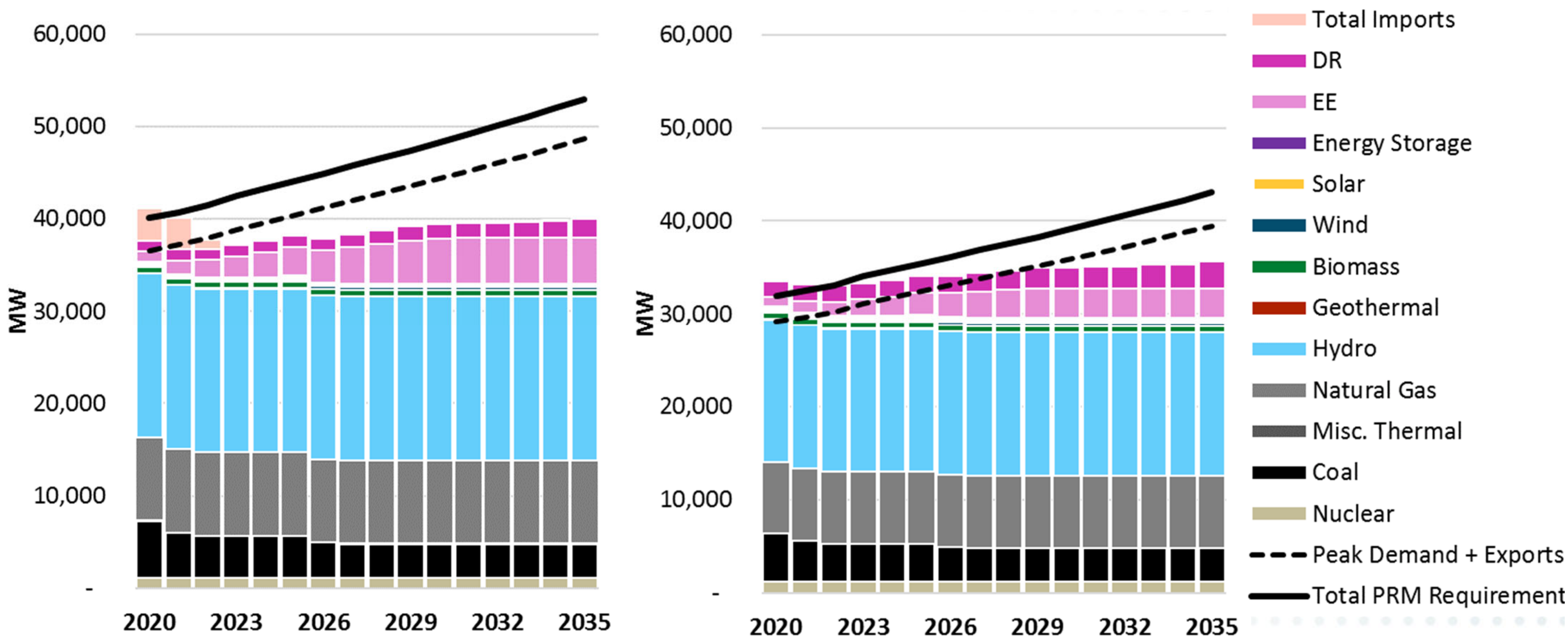




- **Winter: Capacity deficit starting in 2026**
- **Summer: Capacity deficit starting in 2029**

Results: High Need Scenario

Winter Capacity Balance (MW)	Summer Capacity Balance (MW)



- Winter: Capacity deficit starting in 2021
- Summer: Capacity deficit starting in 2023

Results Summary

- Scenarios show region will reach winter load resource balance between 2021-2026 and summer balance between 2023-2029
- Region remains tighter on capacity in the winter despite growing summer peak demands

Scenario	Winter Year of Capacity Deficit	Summer Year of Capacity Deficit
Low Need Scenario	2026	2029
Base Need Scenario	2021	2026
High Need Scenario	2021	2023

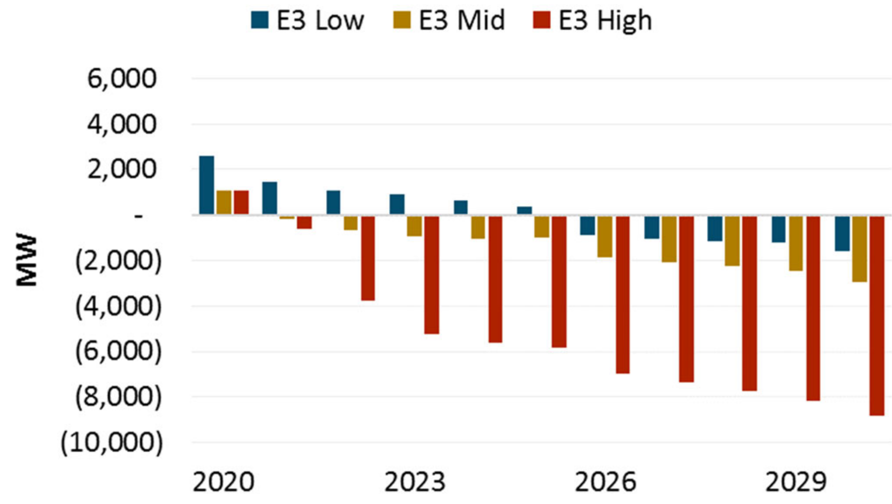
Allocating Regional Surplus to PGE

- **In years of regional capacity surplus, PGE is allocated its peak load share of the market surplus capacity**
  - In years of regional capacity deficit, no market surplus is available for PGE
- **PGE's share of market surplus is assumed to be ~10% in the winter, and ~12% in the summer**
  - Share of available surplus is calculated using the ratio between PGE winter and summer peak and the winter and summer peak for the region

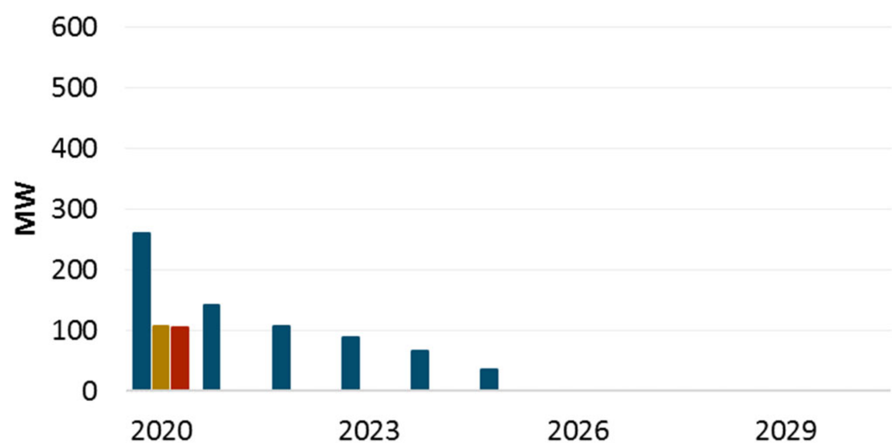
Net Capacity Position
Winter

- **Except for the Low need scenario, the region is capacity short in the winter starting in 2021**
  - No market surplus available for PGE if region is net short
- **For the Low need scenario, surplus capacity is available through 2025**

Regional Winter Capacity Balance (MW)



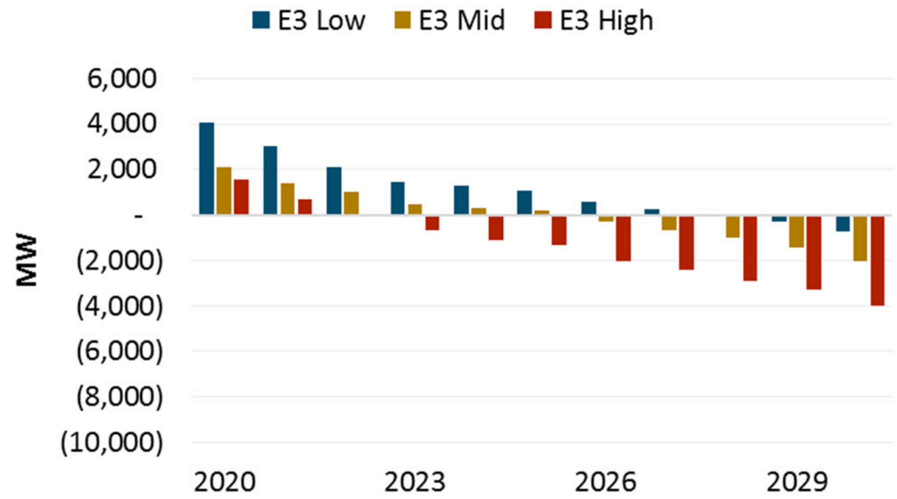
Winter Surplus Available for PGE (MW)



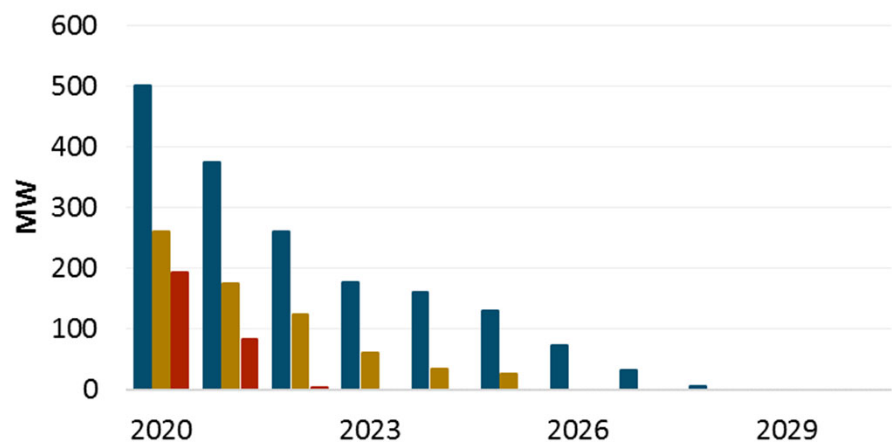
Net Capacity Position
Summer

- Region has surplus summer capacity through 2022 for all scenarios
- For the High need scenario, no market surplus capacity is available starting in 2023, whereas for the Base scenario, a small market surplus is available through 2025

Regional Summer Capacity Balance (MW)



Summer Surplus Available for PGE (MW)



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ADDITIONAL CONSIDERATIONS

Additional Considerations

- **In addition to loads, resource additions and retirements could change the net capacity position of the region**
  - Economic thermal plant retirements could result in a net short position sooner
  - New resource buildout in the near term could push out the need for capacity in the region to a later year
- **Higher level of IPP resources being contracted to in-region entities in the summer could push out need for new capacity to meet summer peak**

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Thank You!

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