Integrated Resource Planning

Roundtable 18-5

October 31, 2018

Meeting Logistics

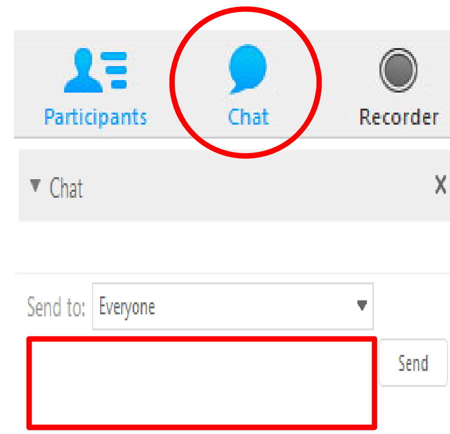
Local Participants:

- World Trade Center facility
- Wireless internet access
    - Network: 2WTC_Event
    - Password: 2WTC_Event$
- Sign-in sheets

Virtual Participants:

- Ask questions via 'chat' feature
- Meeting will stay open during breaks, but will be muted
- Electronic version of presentation: *portlandgeneral.com/irp*

>> *Integrated Resource Planning*



AGENDA

- Market Capacity Study Update
- Load Forecast Update
- Resource Need Update
- Portfolio & Scoring Update

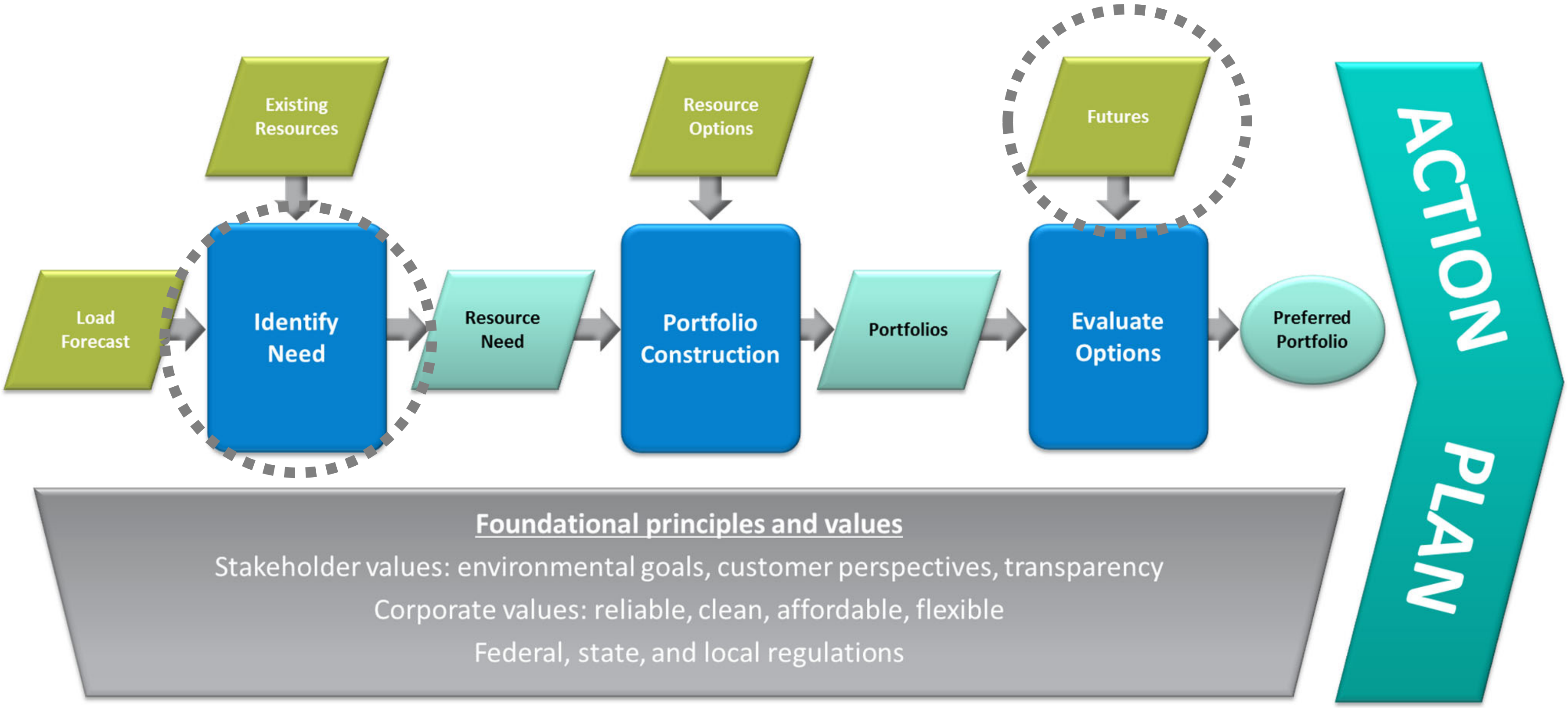
Safety Moment

Market Capacity Study

Energy + Environmental Economics (E3)

Market Capacity Study

- Directed by Order 17-386
- Informs long-term planning



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

October 31st, 2018

Nick Schlag, Director
Arne Olson, Sr. Partner
Kiran Chawla, Consultant
Manohar Mogadali, Associate

Agenda

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

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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**

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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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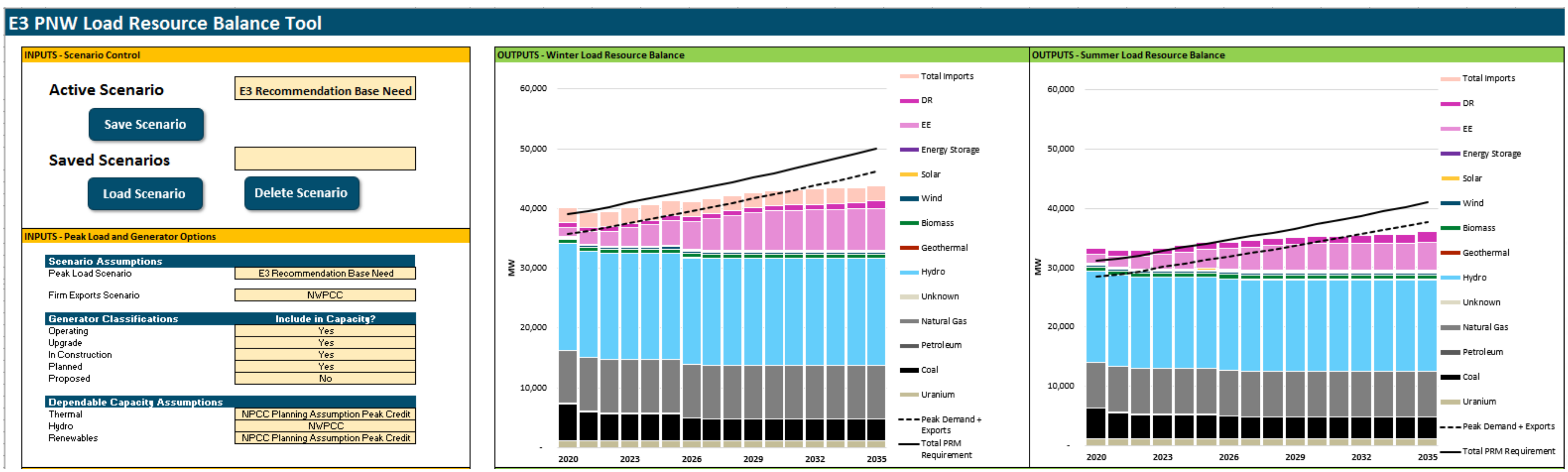
NORTHWEST CAPACITY SCENARIO MODELING TOOL

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

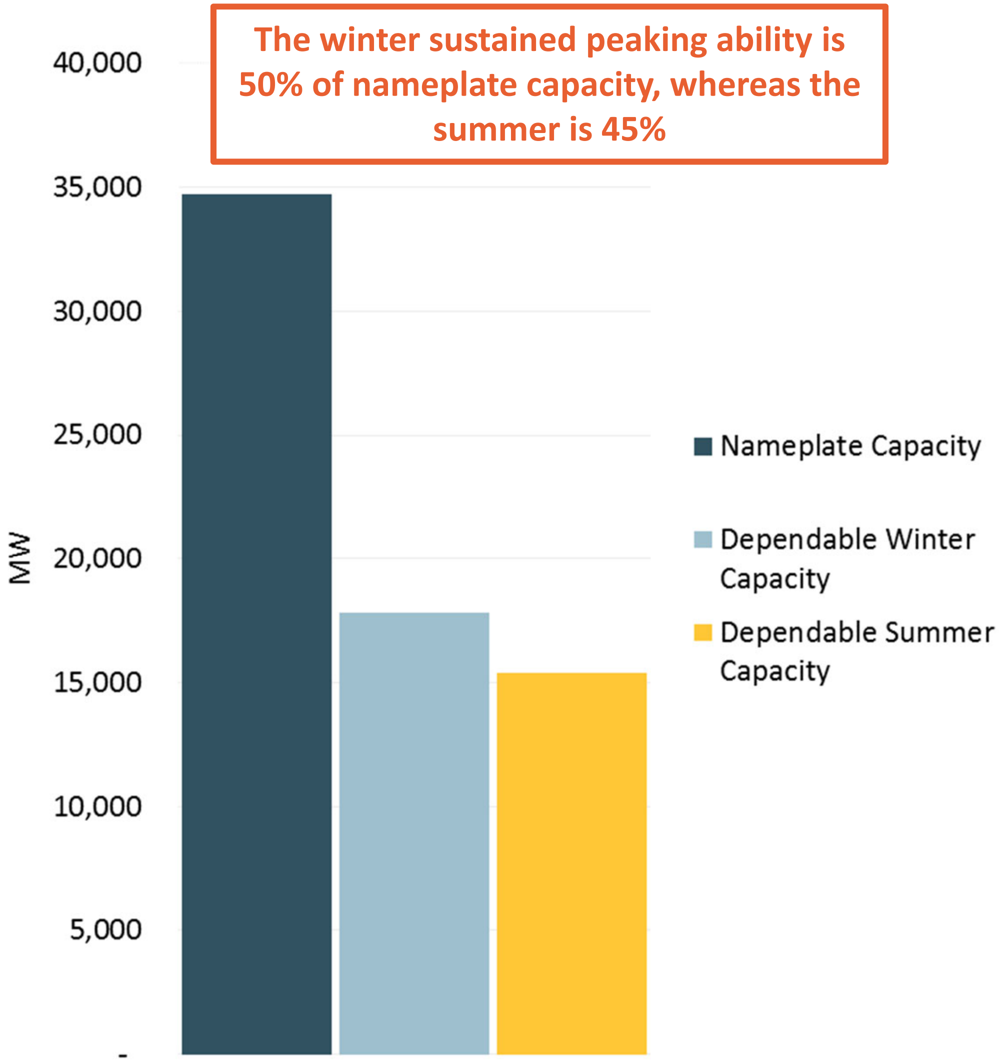
- **After calibration process, inputs & assumptions may be varied to examine alternative scenarios**

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** ☑

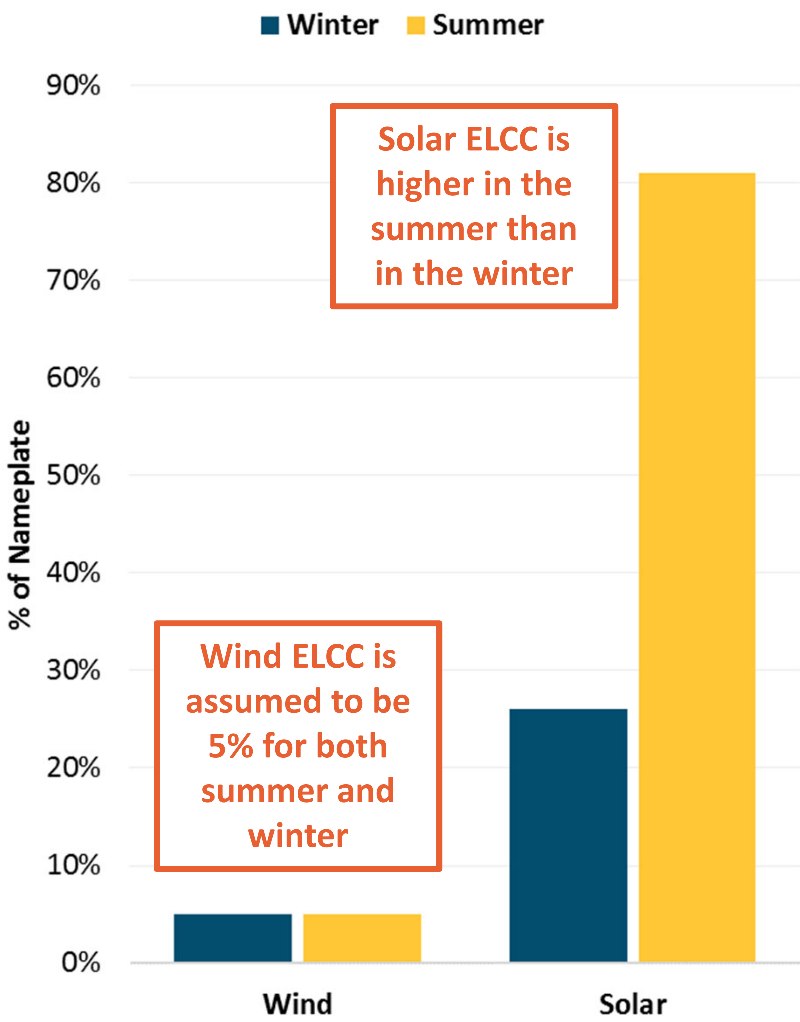
☑ **NWPCC 2023 Assessment** ☑ **NWPCC 7th Power Plan** ☑ **Calibration Parameter**

Key Assumptions for Model Calibration
Hydro Dependable Capacity



- **The 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 requirement is directly tied to conventions used to count hydro capacity

Alternative Hydro Conventions Yields Same Capacity Need

Resource	Nameplate MW	Dependable MW	Notes
Thermal	14,667	14,667	Assumed 100% availability
Hydro	34,697	21,330	Based on BPA White Book sustained peaking capability
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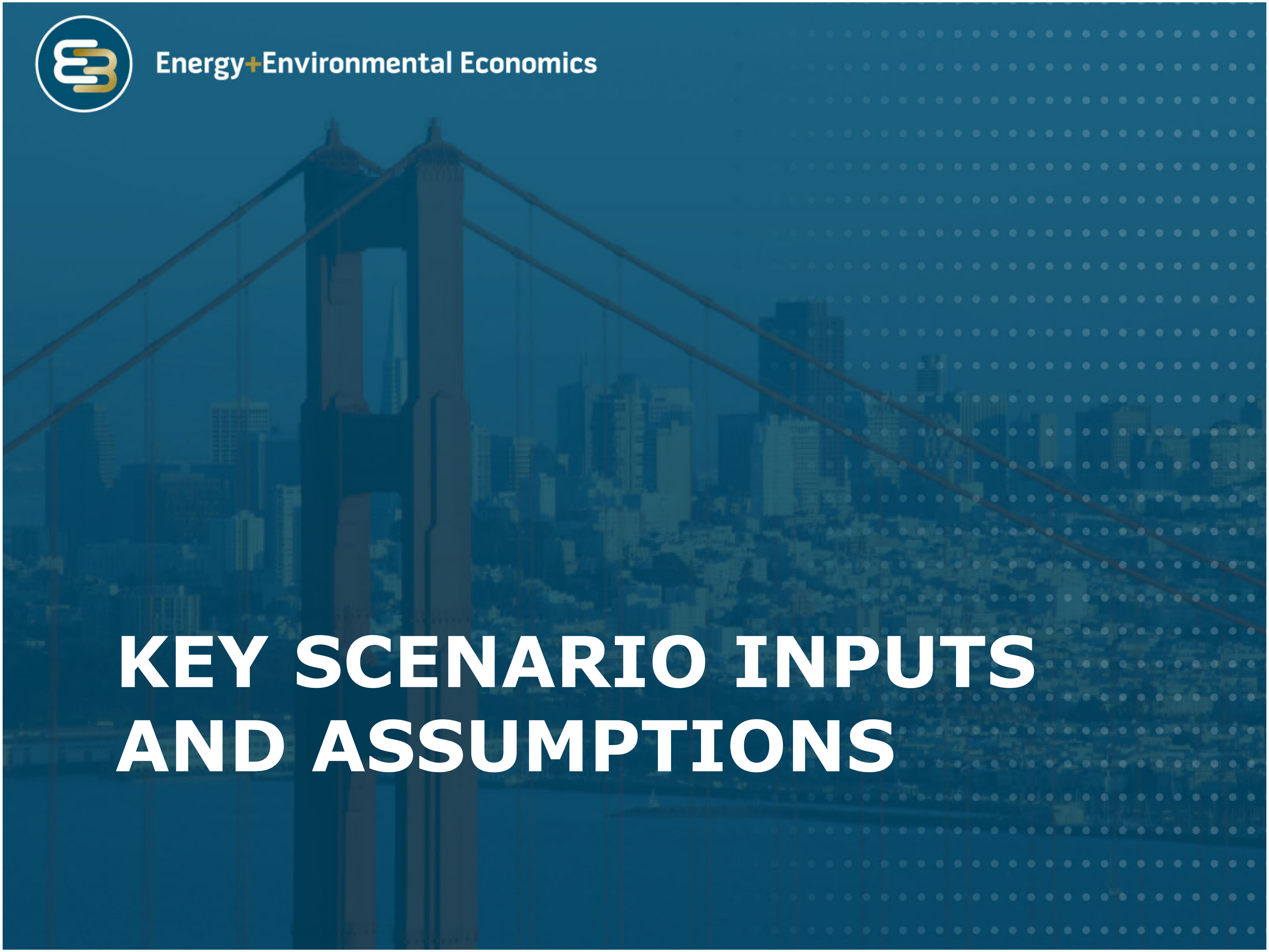
Firm Exports		462	Based on 2023 RA Assessment
Total Load		**34,532**	
Reserve Margin Need		**19%**	**Ratio between Total Resources & Total Load**

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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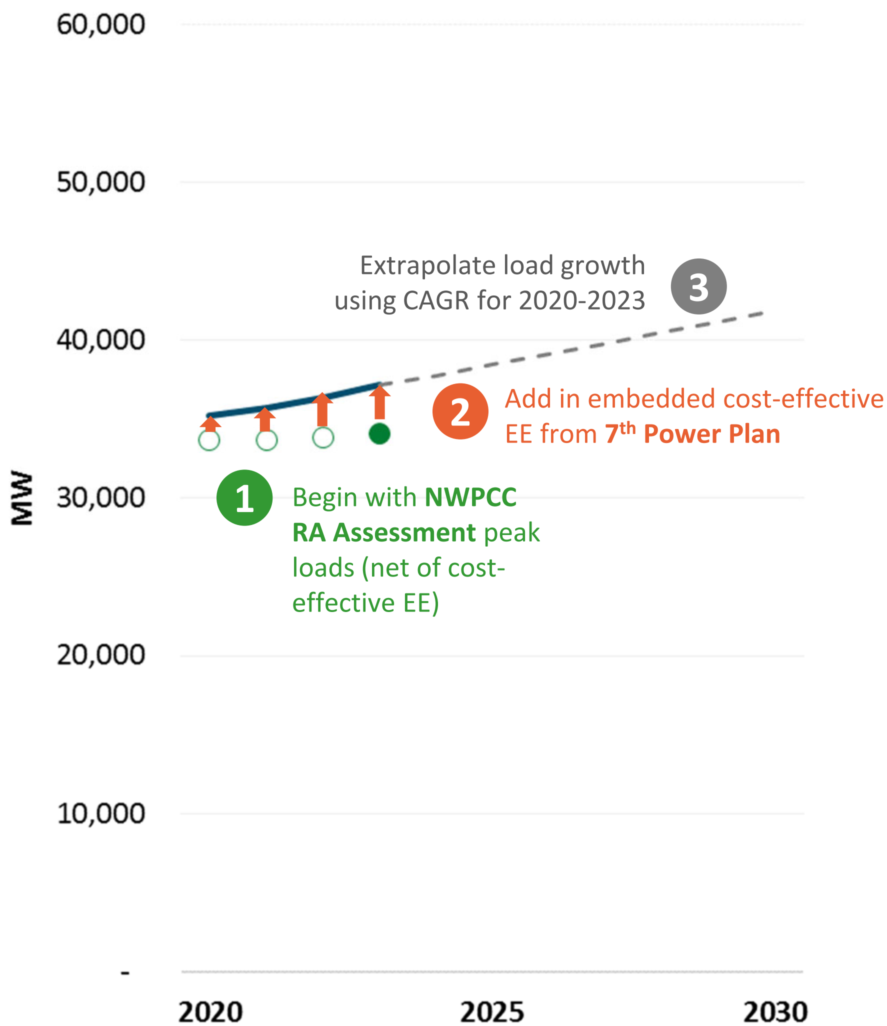
KEY SCENARIO INPUTS AND ASSUMPTIONS

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)

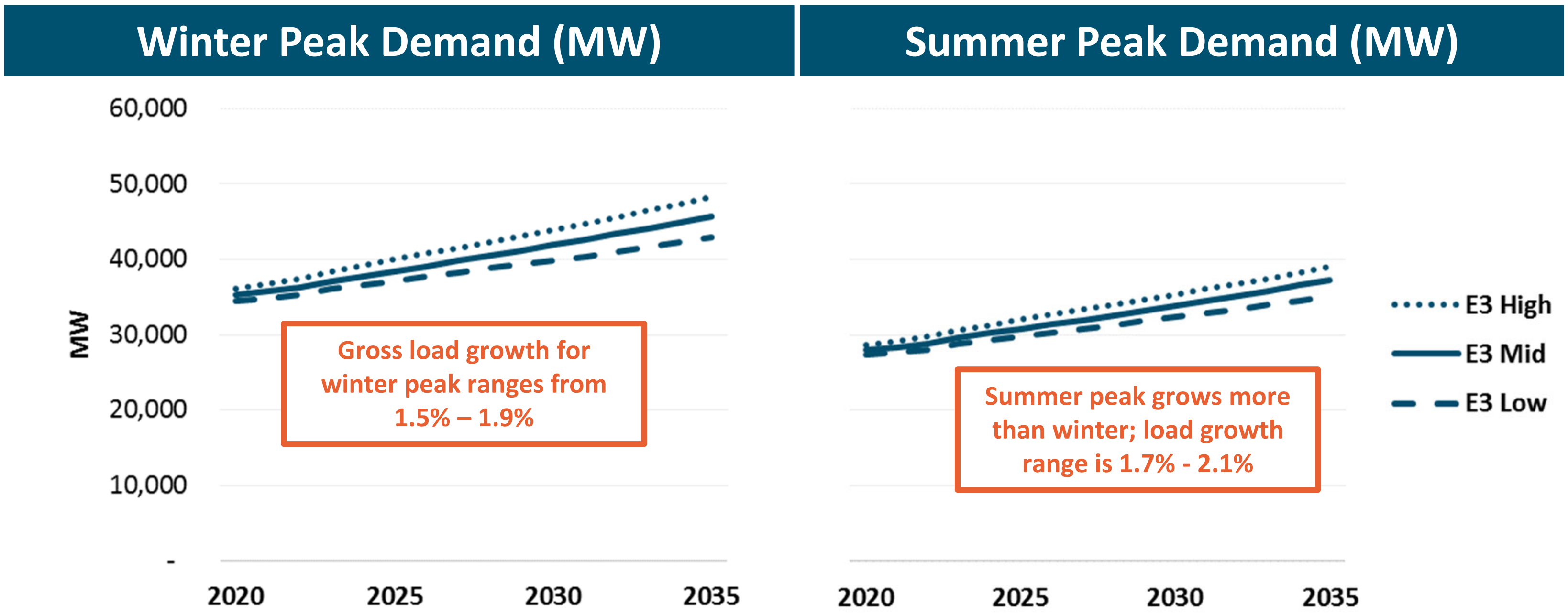
E3 Load Forecasts using NWPCC RA Assessment Loads



- **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

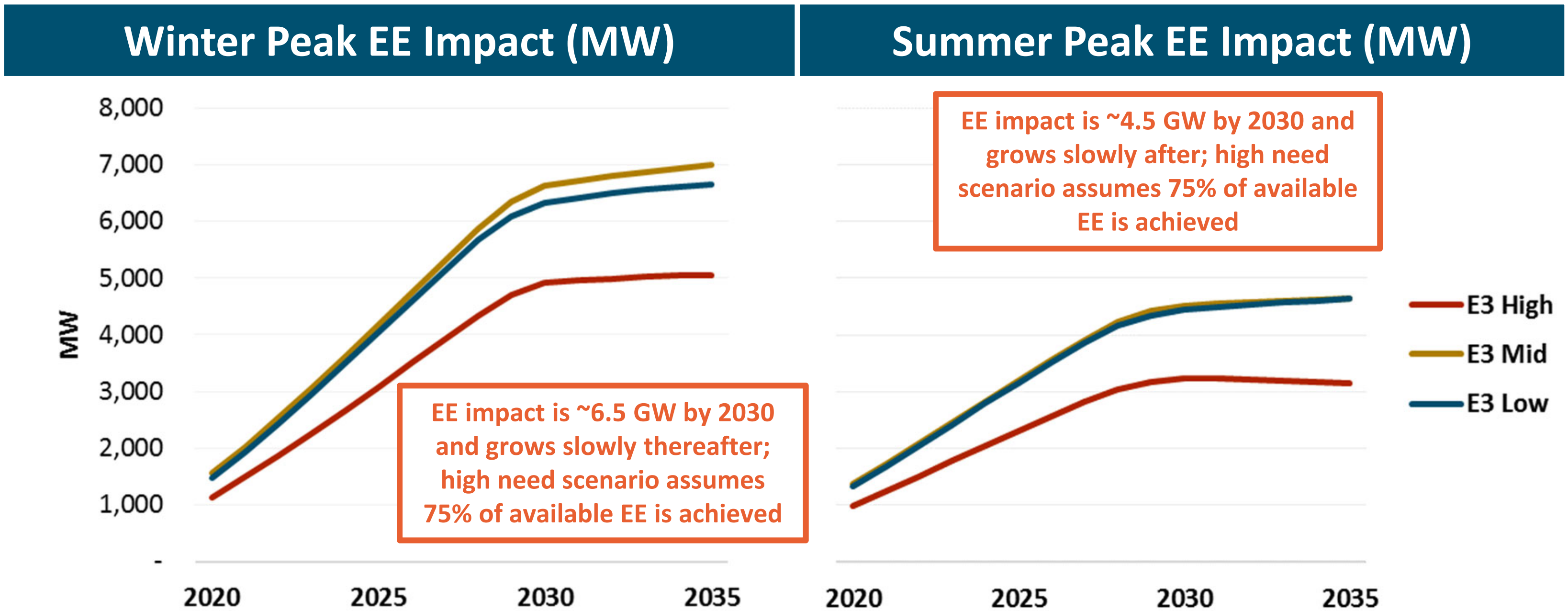
- "Mid" load forecast consistent with NWPCC RA Assessment
- "High" and "Low" forecasts reflect range of long-term growth rates considered in the NWPCC 7th Power Plan



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

Energy Efficiency

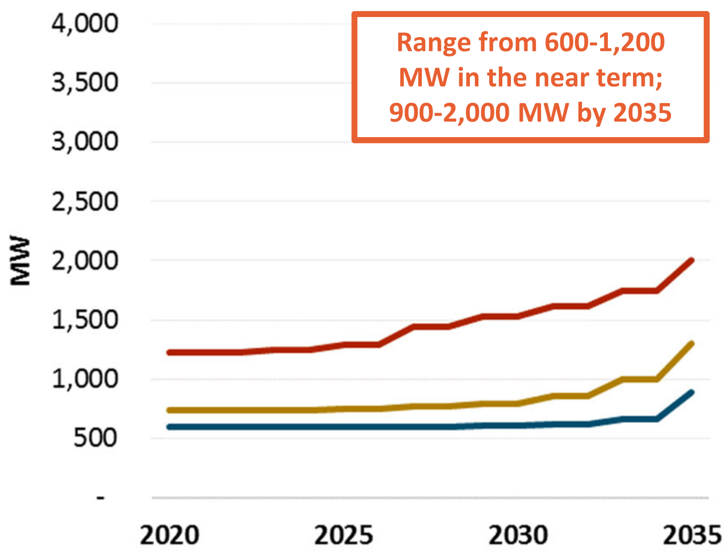
+ **NWPCC 7th Power Plan assumes lower levels of realized energy efficiency for low load and mid load forecasts; for high loads 75% of cost-effective EE is assumed to be achieved**



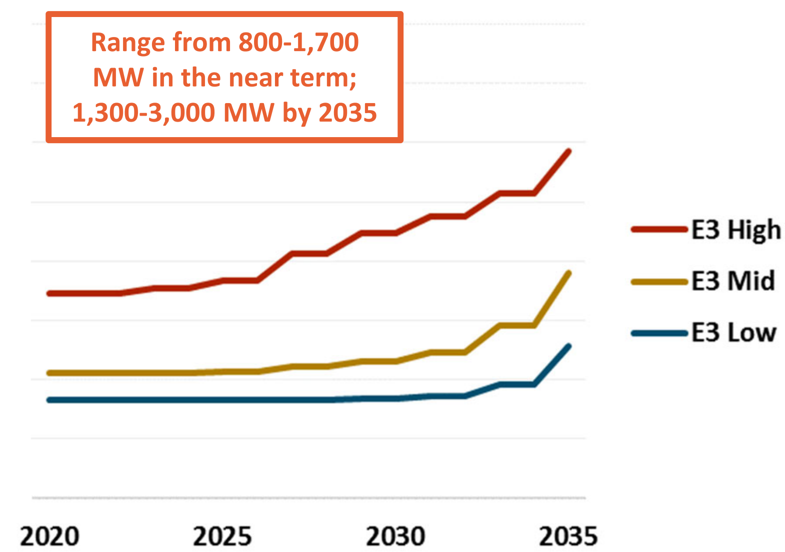
Demand Response

- 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

Winter Peak DR Impact (MW)



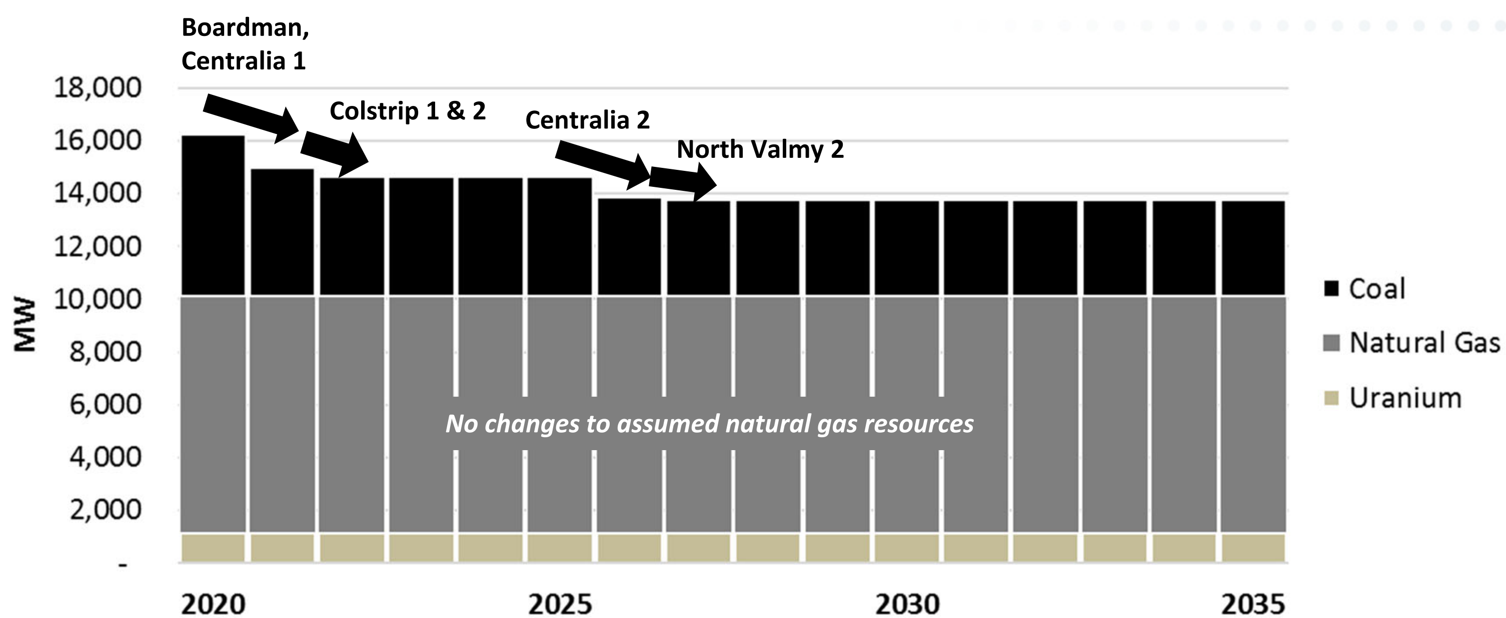
Summer Peak DR Impact (MW)



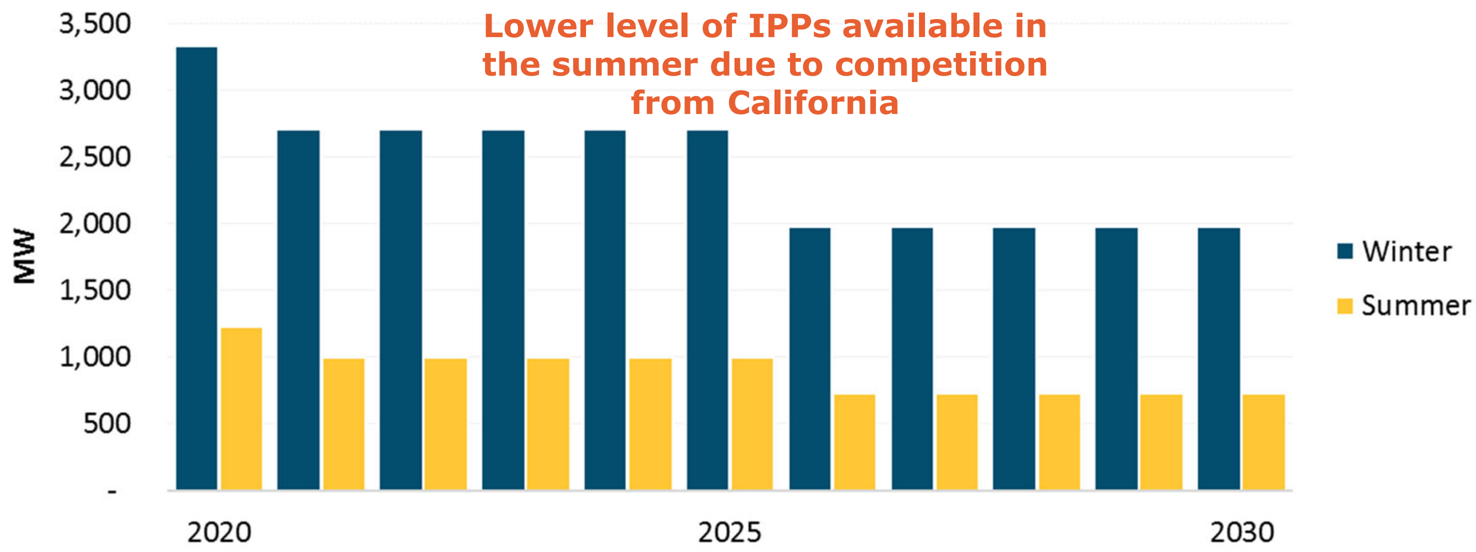
Thermal Generation Resources

- 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

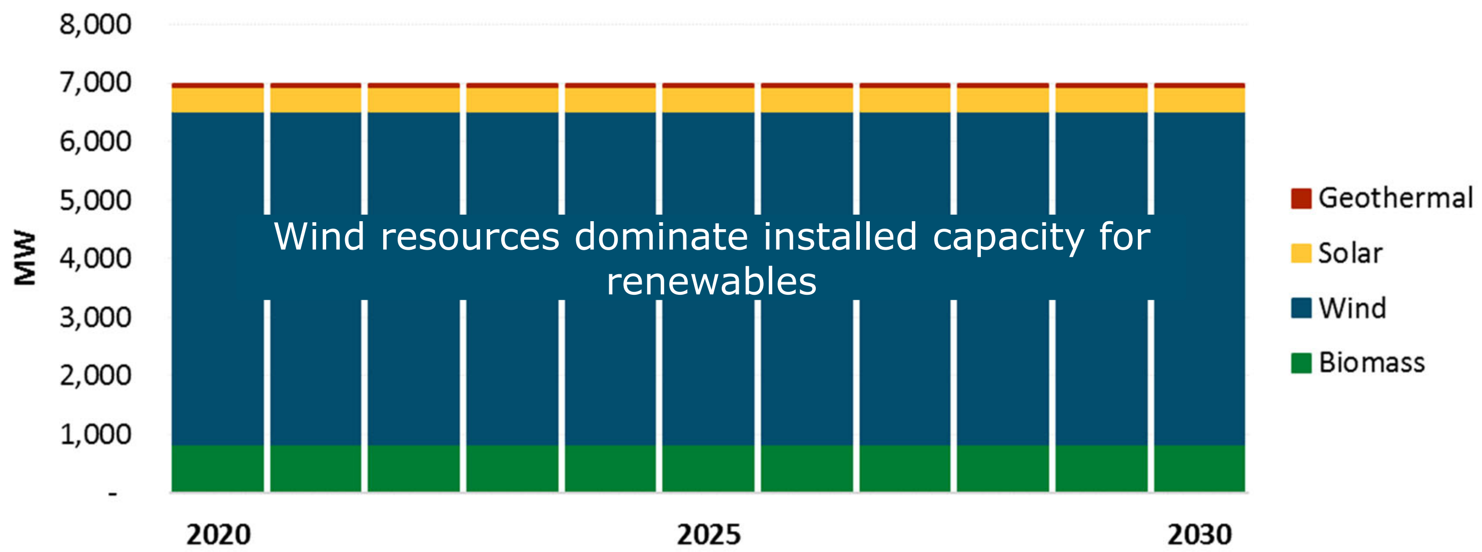


- Unknown status IPPs assumption for winter is derived using the NWPCC power plants database
- For the summer, the winter capacity is derated to account for competing demands for capacity from California, consistent with the NWPCC's approach

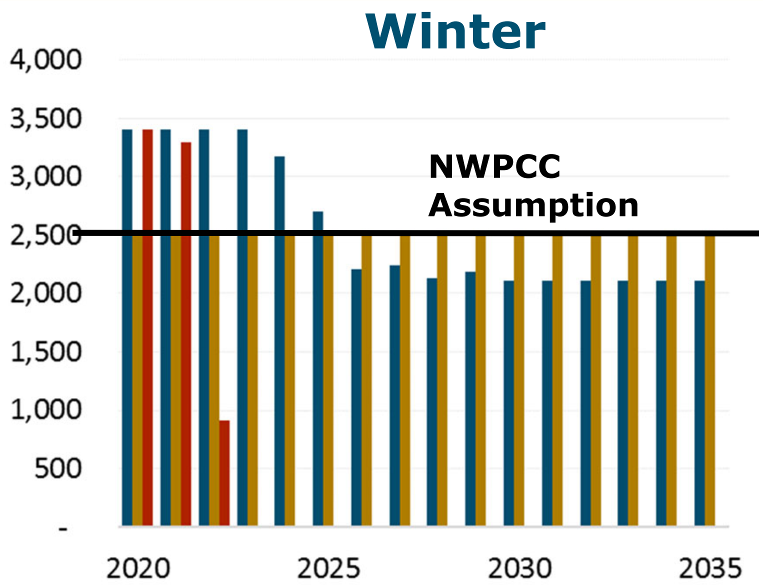
Renewable Resources

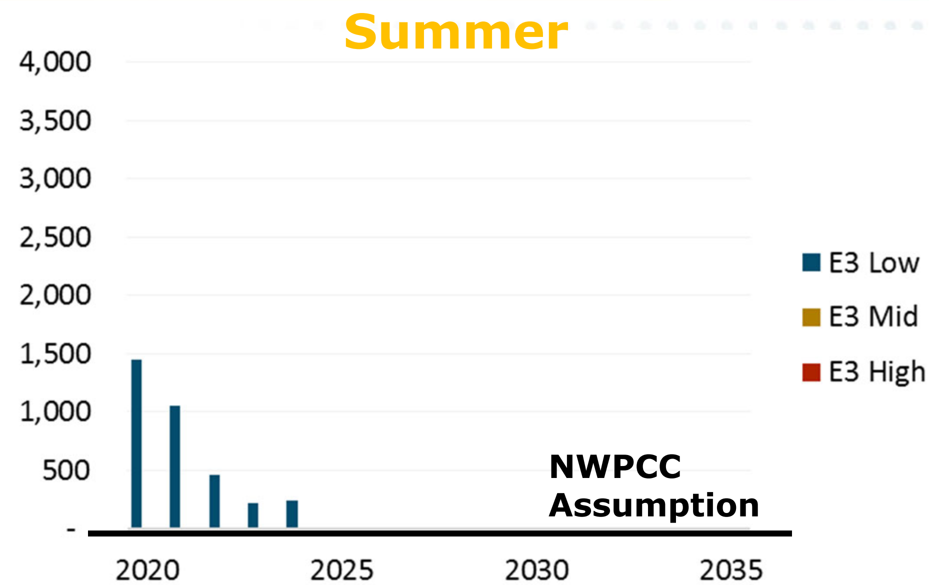
+ **Existing renewables resources are assumed to stay online through the analysis period**

Renewables Generation Installed Capacity (MW)



External Market Imports Availability
Scenario Specific





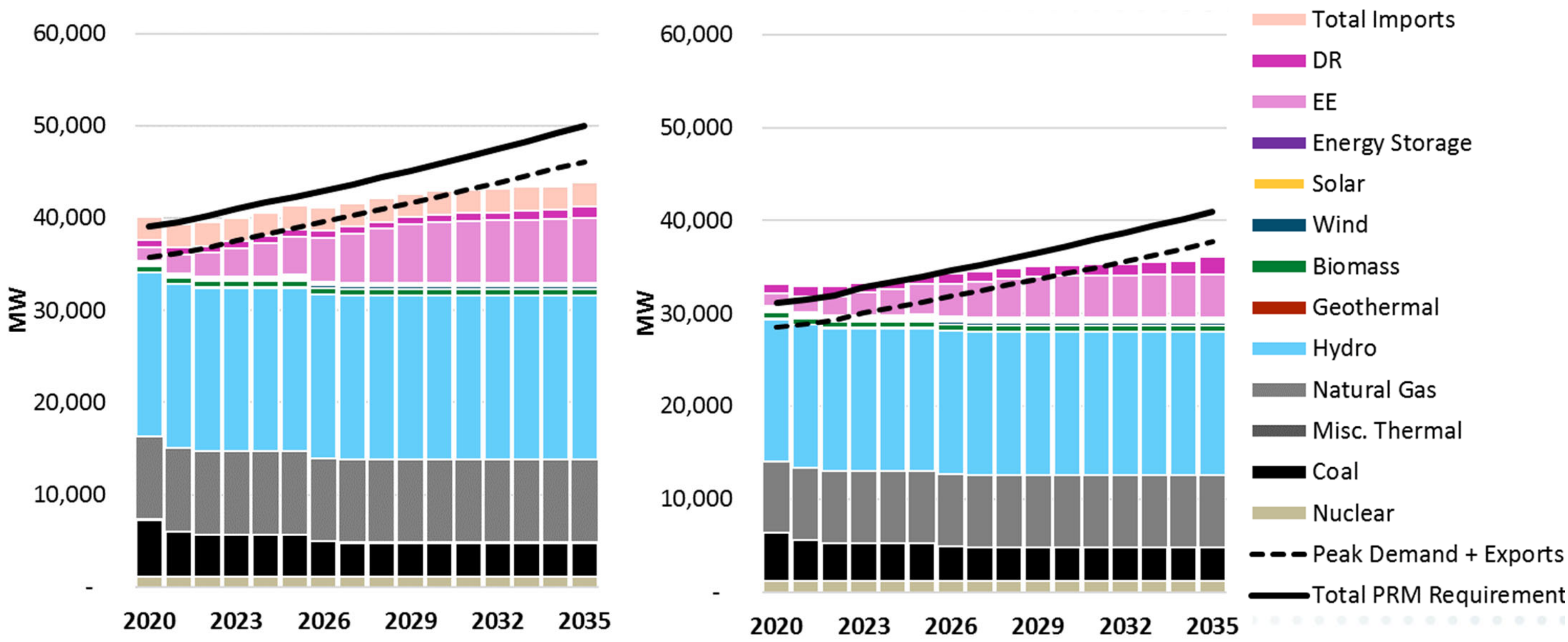
Scenario	Winter	Summer
Low Need	E3 CAISO Surplus Calculations	E3 CAISO Surplus Calculations
Base Need	NWPCC	NWPCC
High Need	E3 CAISO Surplus Calculations	E3 CAISO Surplus Calculations

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)

RESULTS

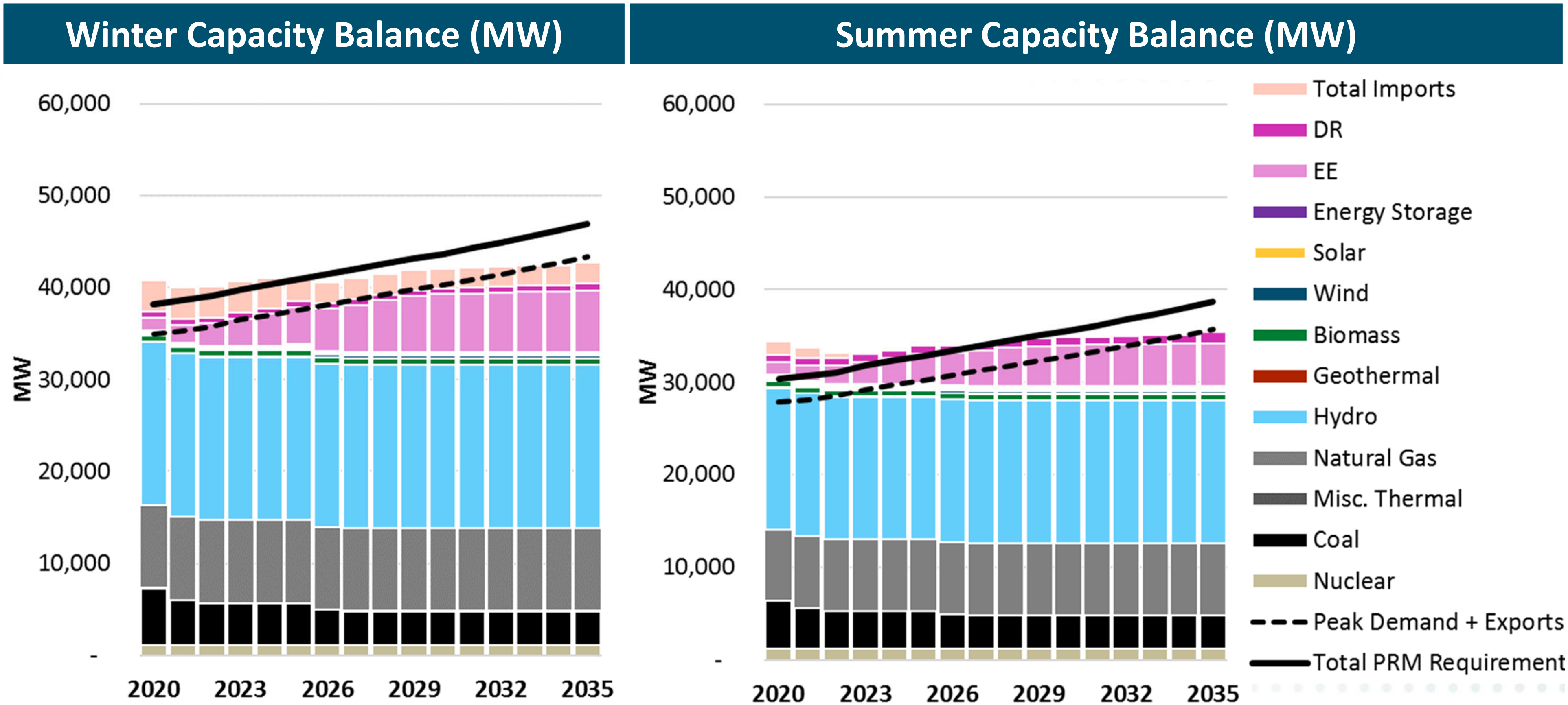
Results: Base Need Scenario

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



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

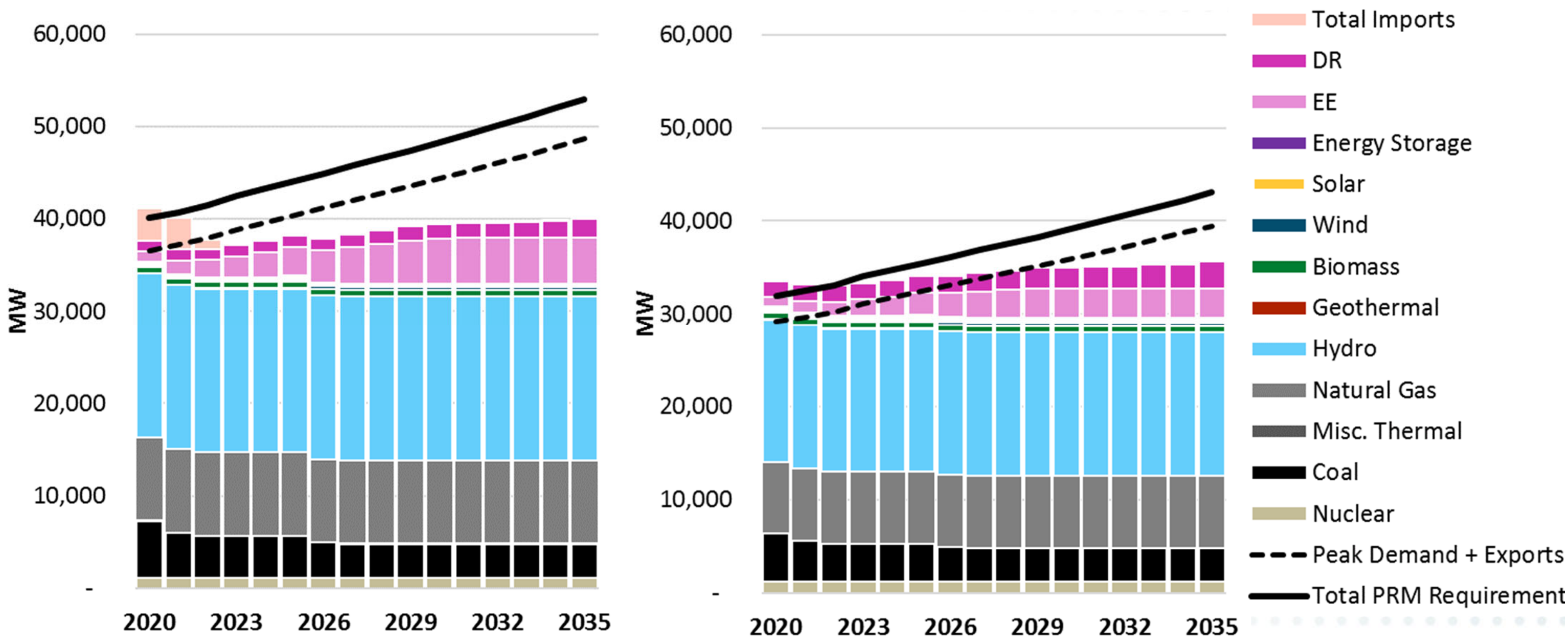
Results: Low Need Scenario



- 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

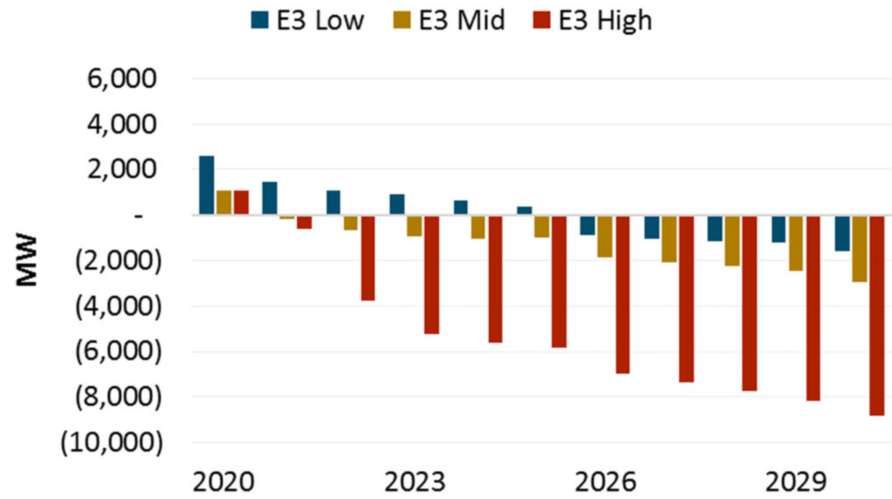
Allocating Regional Surplus to PGE

- **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

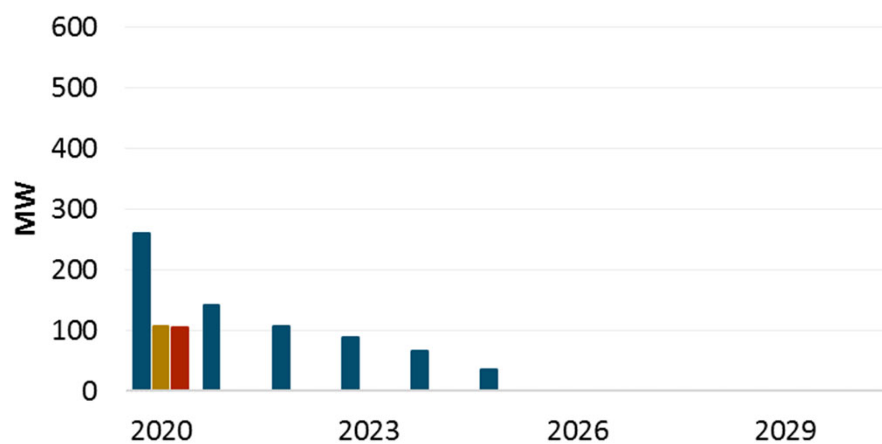
Net Capacity Position
Winter

- **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)

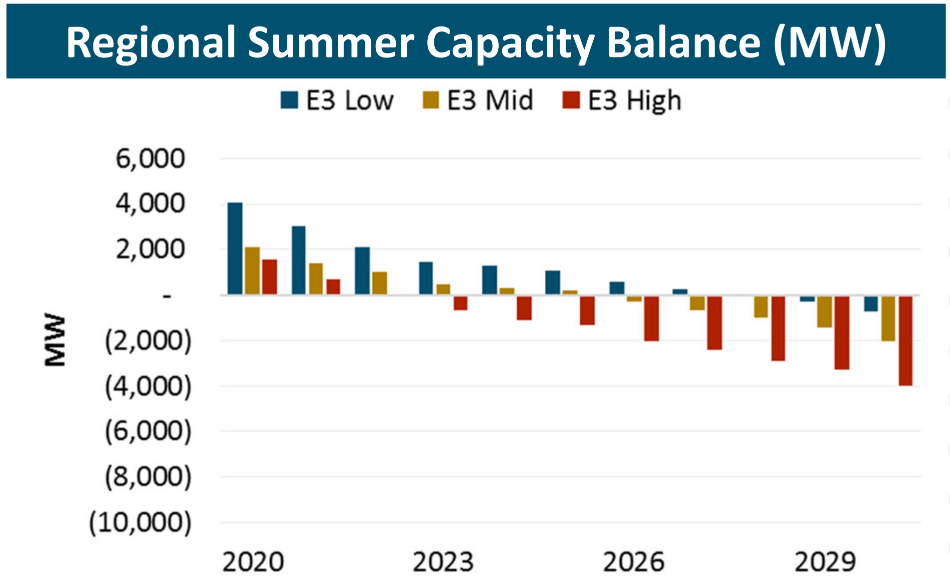


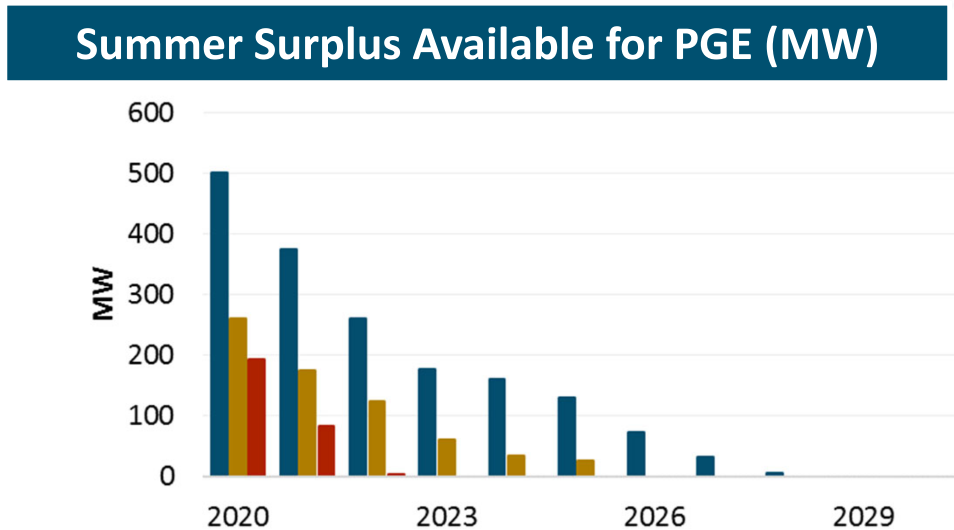
Winter Surplus Available for PGE (MW)



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**





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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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Load Forecast Methodology

Amber Riter / Alison Lucas

Review: May Technical Workshop

Topics from last workshop:

1. Load Forecast Trends and Performance
2. Load Forecast Model Study and Updates
3. Load Forecast Preliminary Results
4. Audience Questions and Feedback

Agenda for Today’s Workshop

1. Base Case Assumptions
2. Final Base Case Load Forecasts with High/Low Scenarios
    a) Residential Energy
    b) Commercial Energy
    c) Industrial Energy
    d) Peak
    e) Summary
3. Audience Questions and Feedback

Previously: Probabilistic Forecasts

PGE will run Monte Carlo simulations, combining sources of uncertainty to create confidence bands around the Base Case forecast

Uncertainty category	Definition
Model uncertainty	The standard error of the regression. By bootstrapping the residuals, the model may show skewed confidence bands, rather than a normal distribution.
Coefficient uncertainty	The standard error associated with the inclusion of the driver in the regression. During simulation runs, coefficients are randomly varied along with residuals.
Forecast uncertainty of the endogenous[1] (driver) variable	Uncertainty in the forecast of the driver. Applied in the model as a constant value or time series.
Optional pragmatic uncertainty	Broad adjustment to uncertainty level.

[1]Endogenous variables are the driver variables such as population, employment, and GDP.

Update: Probabilistic Forecasts

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Forecast uncertainty of the endogenous (driver) variable	Uncertainty in the forecast of the driver. Applied in the model as a constant value or time series.
Optional pragmatic uncertainty	Broad adjustment to uncertainty level.

Difficult to quantify. Forecast sensitivity to different driver futures considered instead with high/low scenarios.

Abstract. Instead sticking with defined categories of uncertainty.

Base Case Assumptions

Inherent assumptions in PGE’s Base Case models

- PGE’s Base Case forecast models capture trends observed over a historical period in order to make inferences for the future.
- The models assume no dramatic departure from the trends in historical customer behavior. For example, no new government policies to influence demand, notable change to nominal electricity pricing, or increase in technological innovation or funding that would affect currently observed rates of efficiency gains and appliance saturation are assumed.
- Scenario analysis conducted in other stages of the IRP are used to represent the sensitivity of the Base Case forecast to specific changes (e.g., higher levels of programmatic energy efficiency, EV penetration, rooftop PV adoption).

Base Case Assumptions

Other assumptions in PGE's Base Case models

- Normal weather assumption
  - PGE assumes a gradually warming climate in its models, based on the observed warming trend since 1975. This has HDD decreasing by 13 per year (0.3% of 15-year average) and CDD increasing by 6 per year (1.2% of 15-year average)

- DER penetration (notably electric vehicles, photovoltaic installations)
  - As of 2018,
    - PGE's system has ~75 MW AC of distributed PV capacity installed
    - PGE's service area has ~15k EVs
  - The Base Case forecast continues gradual growth of DER, as it is captured in the regression analysis.
  - More dynamic DER penetration scenarios are considered at a later stage in the IRP modeling.

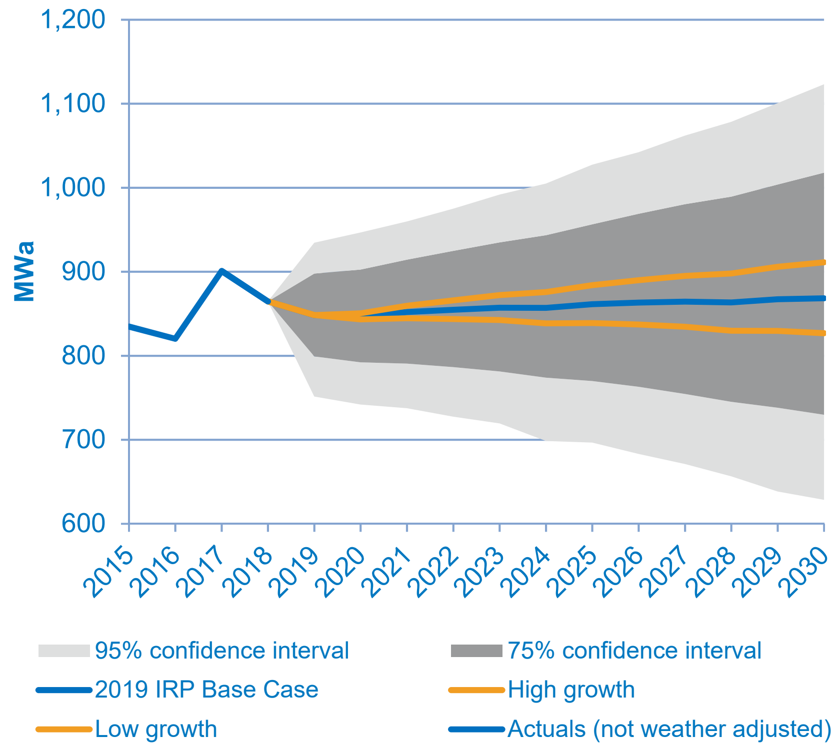
Residential Model

Forecast and high/low economic growth scenarios

Average annual growth rates, 2023 – 2050		
	Population	**Residential deliveries**
Base case	1.0%	0.2%
High growth	1.5%	0.6%
Low growth	0.5%	-0.3%

PGE used the Oregon Office of Economic Analysis's population forecast to create high and low scenarios, which are 0.5% above and below that base forecast.

Between 1990 and 2016, Oregon's annual population growth has ranged from 0.6% to 2.8% and averaged 1.4%.



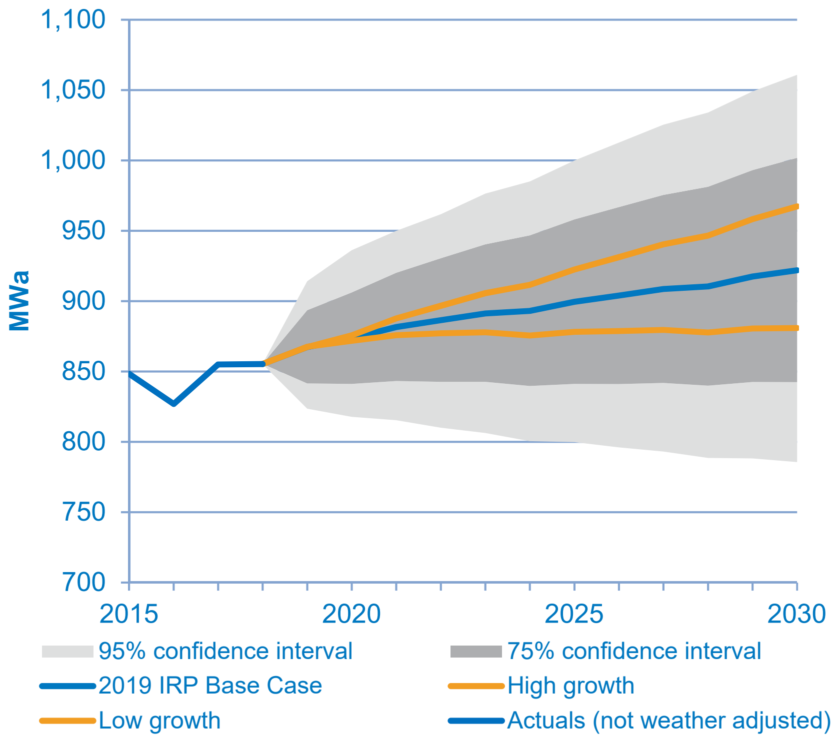
Commercial Model

Forecast and high/low economic growth scenarios

Average annual growth rates, 2023 – 2050		
	Employment	**Commercial deliveries**
Base case	0.6%	0.5%
High growth	1.2%	1.0%
Low growth	0.0%	0.1%

PGE used the Oregon Office of Economic Analysis's state total non-farm employment forecast to create high and low scenarios which are 0.6% above and below that base forecast.

Between 1990 and 2016, Oregon's annual employment growth has ranged from -6.2% to 4.2% and averaged 1.5%.



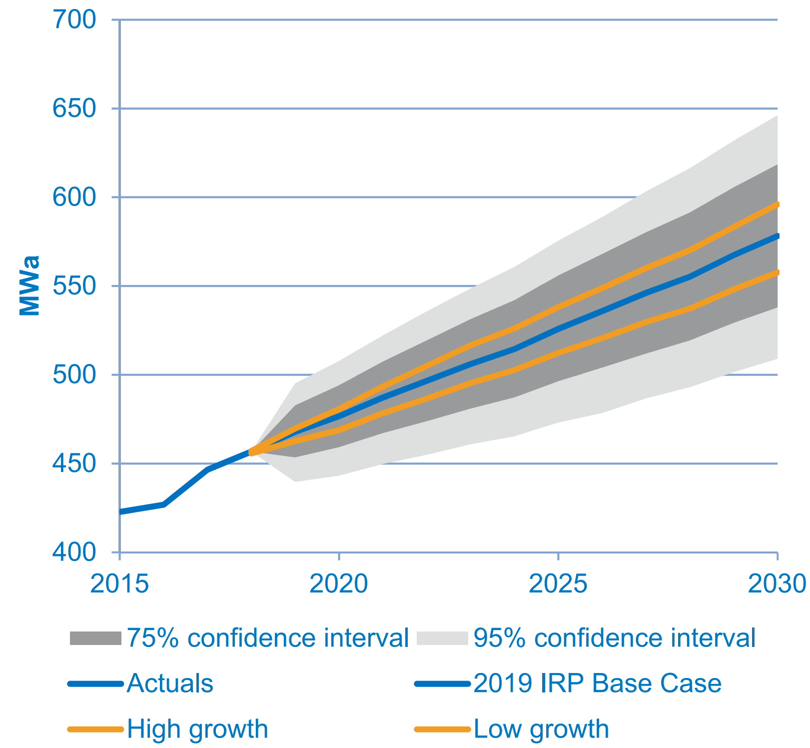
Industrial Model

Forecast and high/low economic scenarios

Average annual growth rates, 2023 – 2050		
	GDP	Industrial deliveries
Base case	1.8%	1.9%
High growth	2.2%	2.0%
Low growth	1.4%	1.7%

PGE used IHS Markit's Gross Domestic Product base, optimistic, and pessimistic forecasts to create these scenarios.

Between 1990 and 2016, US GDP growth has ranged from -2.8% to 4.7%.

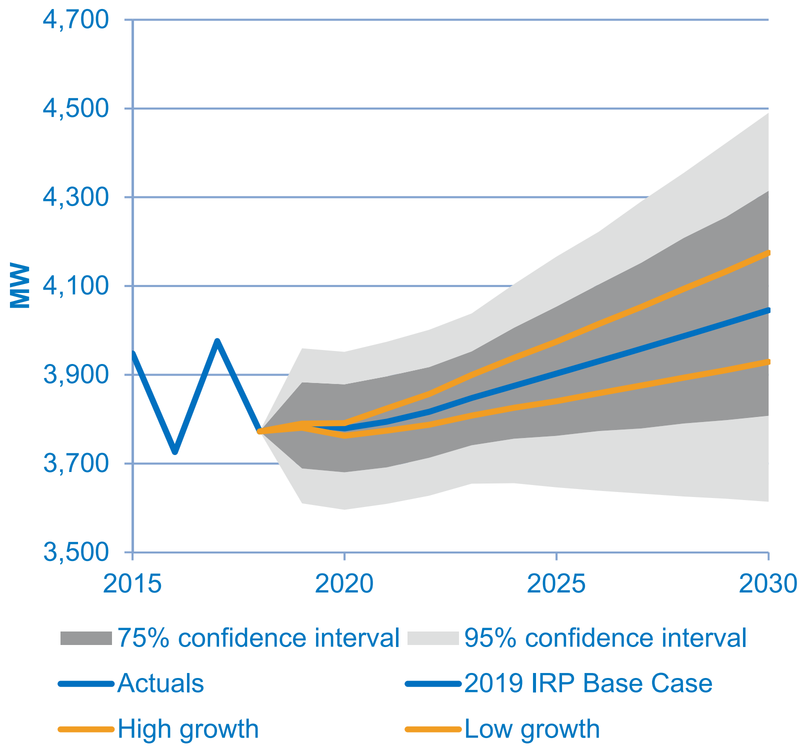


System Peak

Forecast and high/low economic scenarios

Average annual growth rates, 2023 – 2050		
	Winter Demand	**Summer Demand**
Base case	0.6%	0.8%
High growth	0.9%	1.0%
Low growth	0.2%	0.5%

Summer peak is growing at a faster rate than winter peak due to increasing use of A/Cs, winter heat gas conversion, and gradually warming temperatures.



Total System Summary

Forecast and high/low economic scenarios

Total PGE System Load Forecast [1, 2]									
	Energy Deliveries			Winter Demand			Summer Demand		
	2025 MWa	2030 MWa	AAGR[3] 2023 - 2050	2025 MW	2030 MW	AAGR[3] 2023 - 2050	2025 MW	2030 MW	AAGR[3] 2023 - 2050
Base case	2,430	2,516	0.7%	3,699	3,797	0.6%	3,903	4,045	0.8%
High growth	2,487	2,621	1.1%	3,796	3,968	0.9%	3,975	4,175	1.0%
Low growth	2,372	2,412	0.3%	3,615	3,645	0.1%	3,842	3,931	0.5%

(1) Shown inclusive of base case energy efficiency savings and Long Term Direct Access customer loads.
(2) Shown exclusive of final DER penetration forecasts.
(3) AAGR = Average Annual Growth Rate

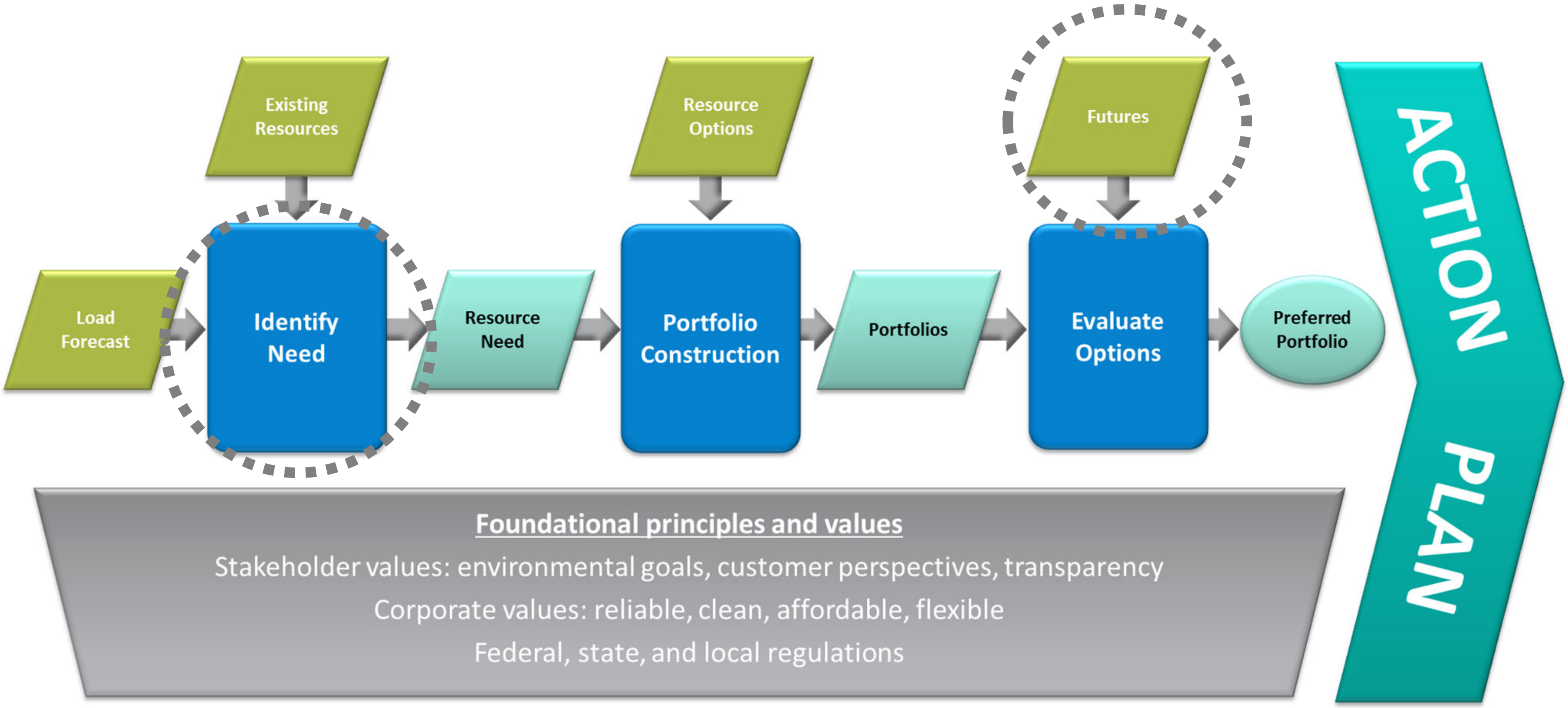
Questions? Feedback?

Email: irp@pgn.com and direct your comment to load forecasting

Resource Need Update

Kate von Reis Baron

Need Assessments



Draft Need Assessments

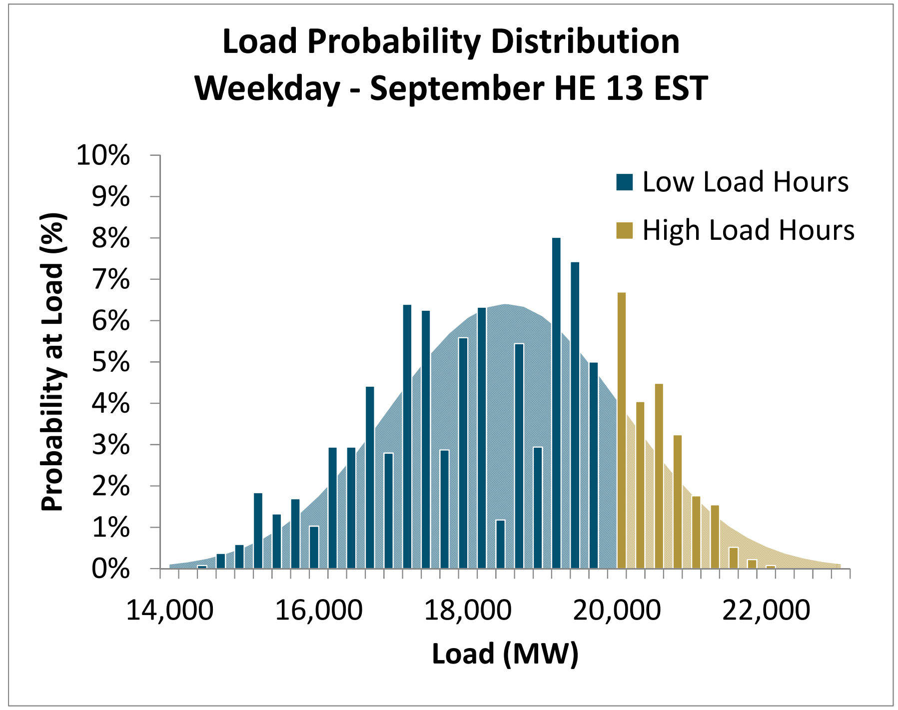
Draft analysis includes some placeholder data. Table summarizes key input status.

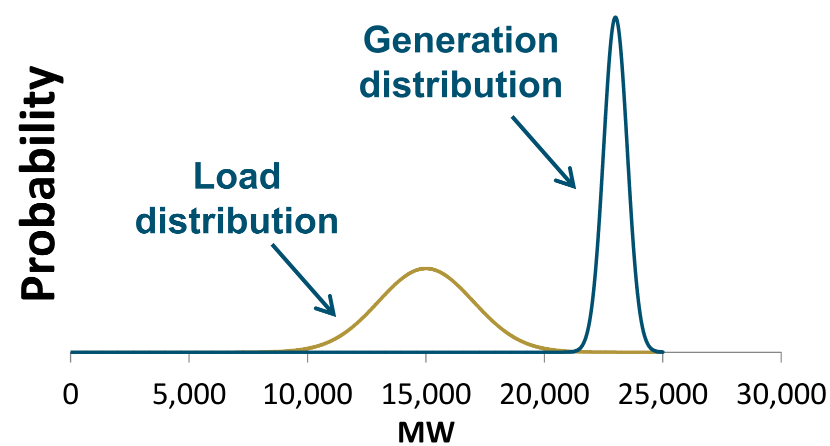
Item	Status
Load	• Final forecast, September 2018 • Pending high/low sensitivities
DER Study	• 2016 IRP assumptions • Pending base/high/low from Navigant study
Market Capacity	• Values from E3 study • Pending modeling of high/low sensitivities
Qualifying Facilities	• Snapshot and sensitivities from June 27, 2018
RFP	• Placeholder included in some views (100 MWa PNW Wind)
Existing Resources	• Pending minor updates for some resources
REC Bank	• Pending update for 2017 actuals

Capacity Need

RECAP Model

- Renewable Energy Capacity Planning model, a comprehensive open source loss of load probability (LOLP) model created by E3. Used in 2016 IRP.
- Model calculates net load distributions for each month/day-type/hour and probability distributions for non-variable resources, then calculates additional capacity needed to achieve annual reliability target.
- Annual reliability target is a loss of load expectation of 2.4 hours per year (as in the 2016 IRP).

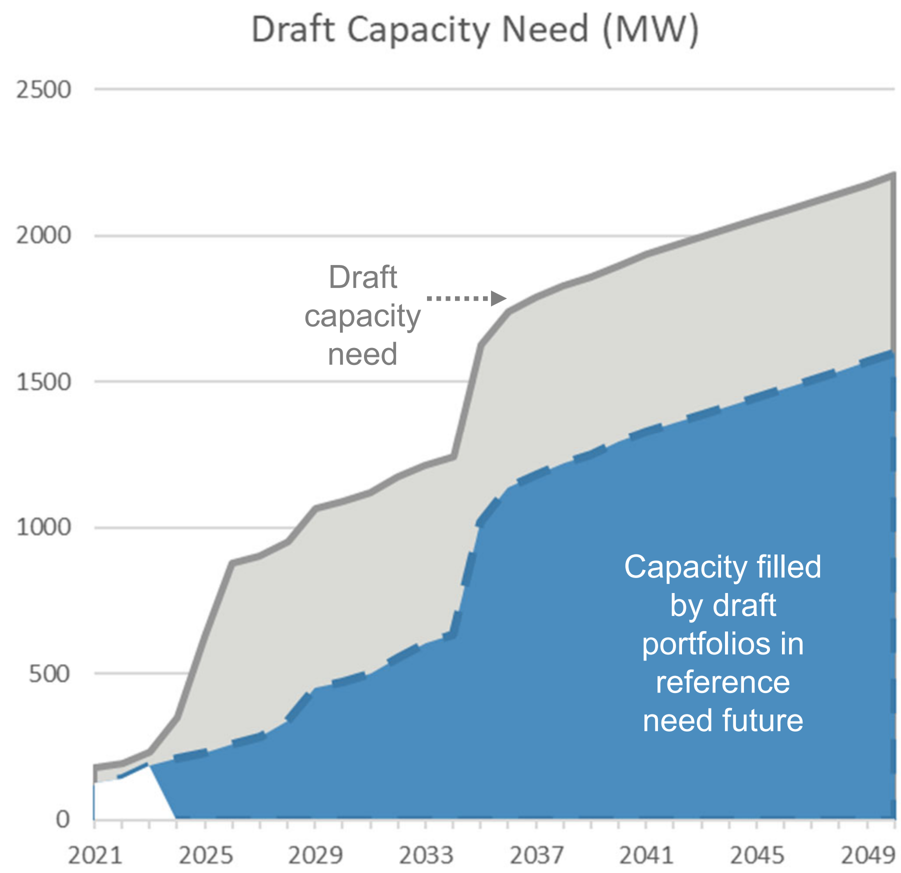




Images from E3, PGE's 2015.08.13 Public Meeting, slides 30, 32.

Capacity Need - DRAFT

- The draft capacity need begins at 178 MW in 2021, increasing to 877 MW in 2026. The increase is mainly due to contract expirations.
- Draft portfolios examine a portion of the capacity need beginning in 2024 that excludes the need associated with these contract expirations and includes a placeholder RFP resource.



Notes

1. The capacity need snapshot is a more recent vintage than the portfolio analysis in the next part of this presentation.
2. Consistent with 2016 IRP, capacity needs in the 2021-2023 time frame may be met through short- and mid-term activities.

Total LOLE

87 hrs

(target is 2.4 hrs)

Capacity Shortage

628 MW

2025 Heat Map - DRAFT

- Heat map shows seasonal and hourly characteristics of 2025 draft need.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
7	0.30	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.49
8	1.12	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	1.08
9	1.71	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	1.71
10	1.15	0.32	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.07	1.33
11	0.72	0.16	0.00	0.00	0.00	0.00	0.01	0.05	0.01	0.00	0.04	0.99
12	0.47	0.10	0.00	0.00	0.00	0.00	0.02	0.19	0.02	0.00	0.03	0.70
13	0.31	0.06	0.00	0.00	0.00	0.01	0.11	0.49	0.06	0.00	0.02	0.52
14	0.20	0.03	0.00	0.00	0.00	0.02	0.25	1.06	0.12	0.00	0.02	0.38
15	0.17	0.04	0.00	0.00	0.00	0.04	0.56	1.87	0.23	0.00	0.02	0.39
16	0.22	0.05	0.00	0.00	0.00	0.08	0.95	2.65	0.40	0.00	0.03	0.53
17	0.62	0.10	0.00	0.00	0.00	0.12	1.27	3.18	0.57	0.00	0.11	1.48
18	1.88	0.32	0.00	0.00	0.00	0.10	1.24	3.57	0.77	0.00	0.27	3.05
19	3.19	0.77	0.00	0.00	0.00	0.08	1.12	3.81	0.99	0.01	0.49	4.30
20	2.99	0.91	0.01	0.00	0.00	0.09	1.12	3.35	0.78	0.01	0.45	3.85
21	2.06	0.62	0.00	0.00	0.00	0.05	0.67	2.31	0.55	0.00	0.29	2.47
22	1.05	0.33	0.00	0.00	0.00	0.02	0.22	1.00	0.12	0.00	0.13	1.27
23	0.25	0.06	0.00	0.00	0.00	0.00	0.01	0.16	0.00	0.00	0.02	0.25
24	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.02

Physical Deficiency

2025, 83 MWa

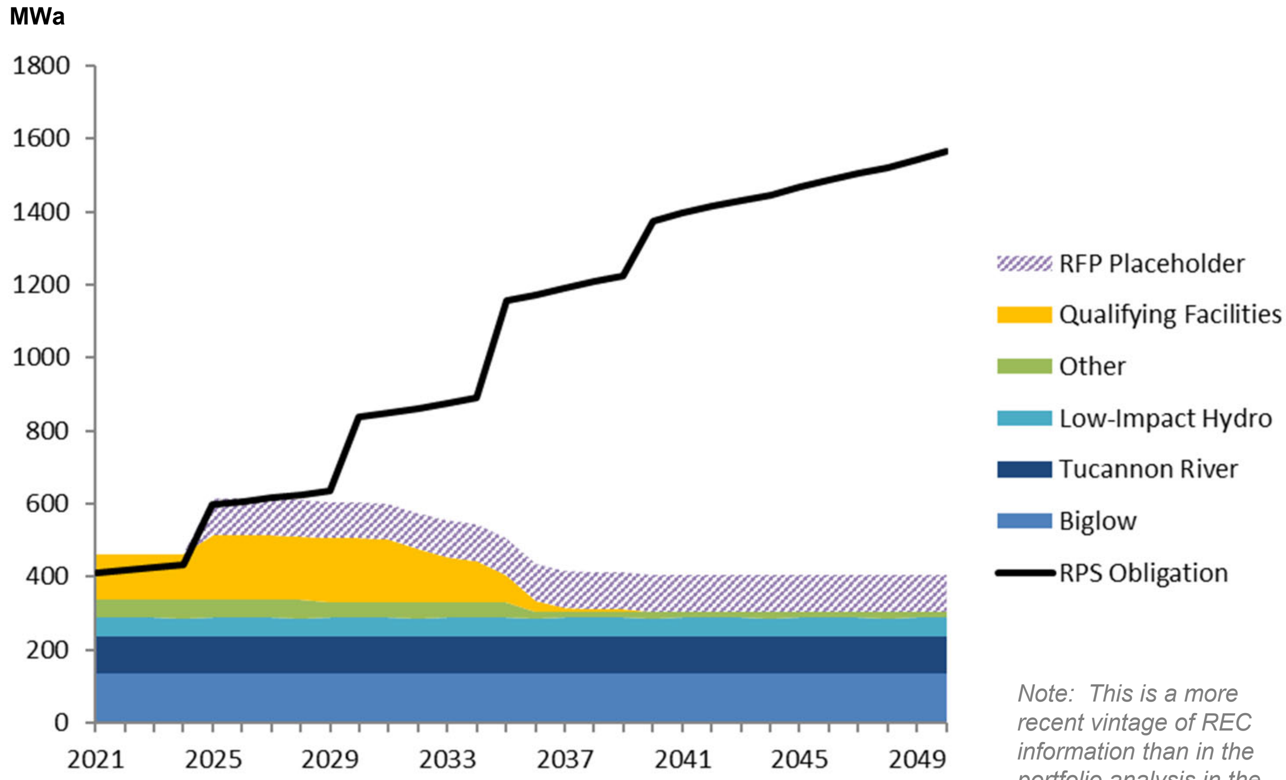
REC Bank Deficit Year

2032

422 MWa shortage in following year

RPS Need - DRAFT

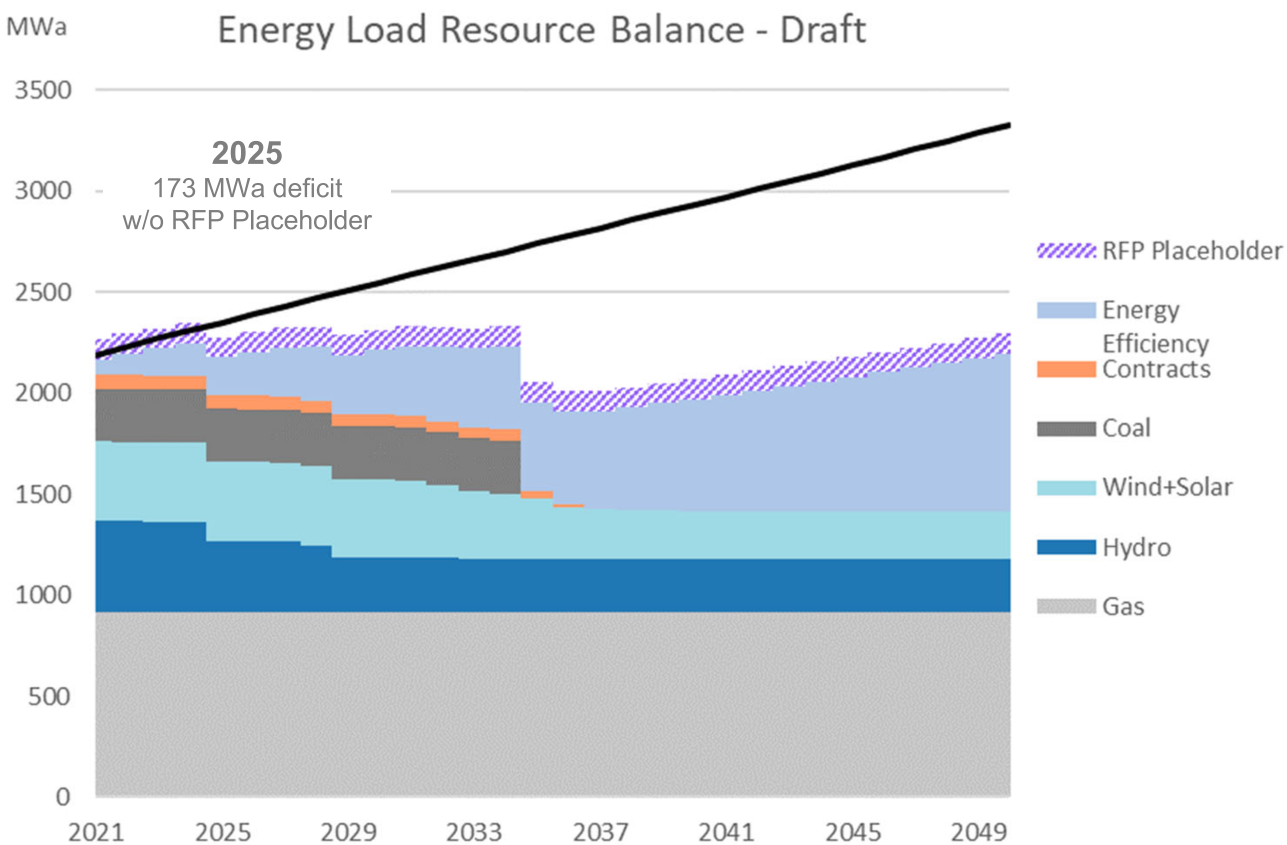
Forecast Physical REC Position



Note: This is a more recent vintage of REC information than in the portfolio analysis in the following section of this presentation.

Energy Load Resource Balance - DRAFT

- Annual energy availability (not economic dispatch)



Load
- Excludes long-term opt-outs
- Before impact of energy efficiency

Thermal
- Adjusted for maintenance and forced outage rate
- Excludes Beaver, PW2, duct firing

Sensitivities - DRAFT

Sensitivity	2025 Capacity Need MW	2025 Energy LRB Deficit MWa	2025 REC Physical Shortage MWa	REC Deficit Year	REC Shortage in following year MWa
Reference	628	173	83	2032	422
QF Executed 50%	709	258	168	2029	418
QF Proposed 50%	552	27	None	2035	783

- Reference: all executed QFs as of June 27, 2018, does not include RFP Placeholder
- QF Executed 50%: excludes 50% of QFs executed but not online
- QF Proposed 50%: include all executed QFs and 50% of proposed projects

Next Steps

1. Finalize inputs and sensitivities – updated numbers for November Roundtable
2. Capacity contribution values for new resources – draft values for November Roundtable
3. Flexibility Adequacy – ongoing modeling work, more info in an upcoming Roundtable

Stakeholder questions are welcome!

Portfolios & Scoring Update

Elaine Hart

Draft Portfolios

Included today:

- Optimized Portfolios (Cost and Carbon)
- Renewable Size + Timing Portfolios
- Renewable Resource Portfolios
- Dispatchable Resource Portfolios
- Some Stakeholder-Requested Portfolios [Staff, RNW, National Grid, ODOE]

Not included today:

- Stakeholder-Requested New Resource Portfolios
  - Co-located Renewable + Storage [RNW]
  - 8-hr Batteries [National Grid]
- Risk-Minimizing Portfolios

Draft Portfolio & Scoring Caveats

Draft analysis does not reflect pending updates, including:

Update Needed	Draft Approach
September Load Forecast	Draft analysis uses Reference June load forecast and plug data for low and high load futures
DER Study output	Draft analysis relies on 2016 IRP assumptions and PGE's Energy Storage Proposal
Market Capacity Study output	Draft analysis makes the same assumption as the 2016 IRP (200 MW in all but summer on-peak hours)
Finalized dispatch results	Draft analysis makes use of updated dispatch simulation results. Further refinements are ongoing.
Finalized flexibility analysis results	Draft analysis incorporates approximations of flexibility value for dispatchable resources, excludes variable renewable integration costs
Finalized cost and performance data	Draft analysis incorporates final renewable cost information, but relies on early draft of renewable performance data and plug numbers for low and high technology cost futures
Outcome of Renewables RFP	Draft analysis assumes a 100 MWa Gorge Wind addition in 2021, consistent with PGE's 2016 IRP Revised Renewable Action Plan

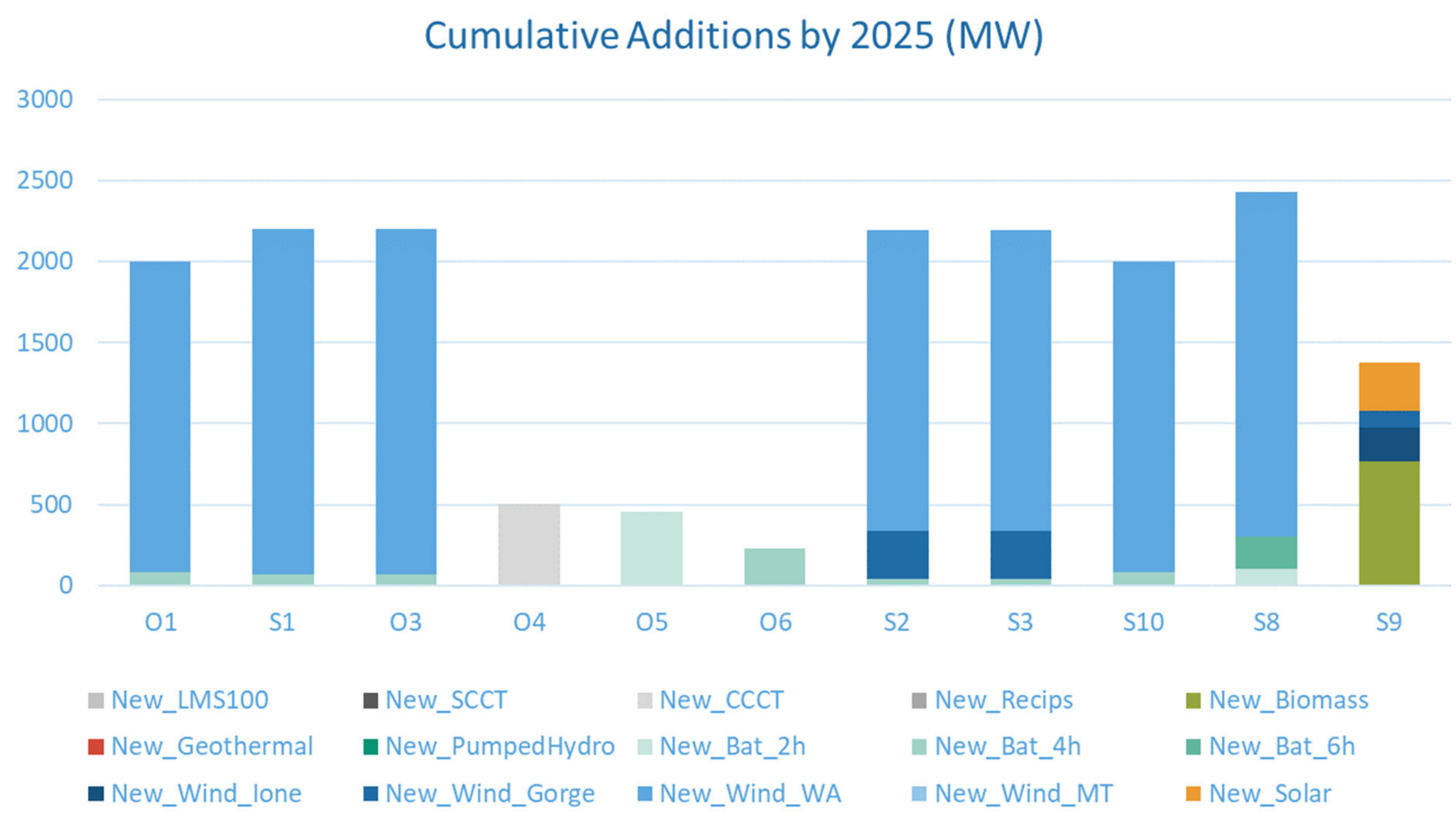
Optimized Portfolios

Draft Portfolios

Optimized Portfolios

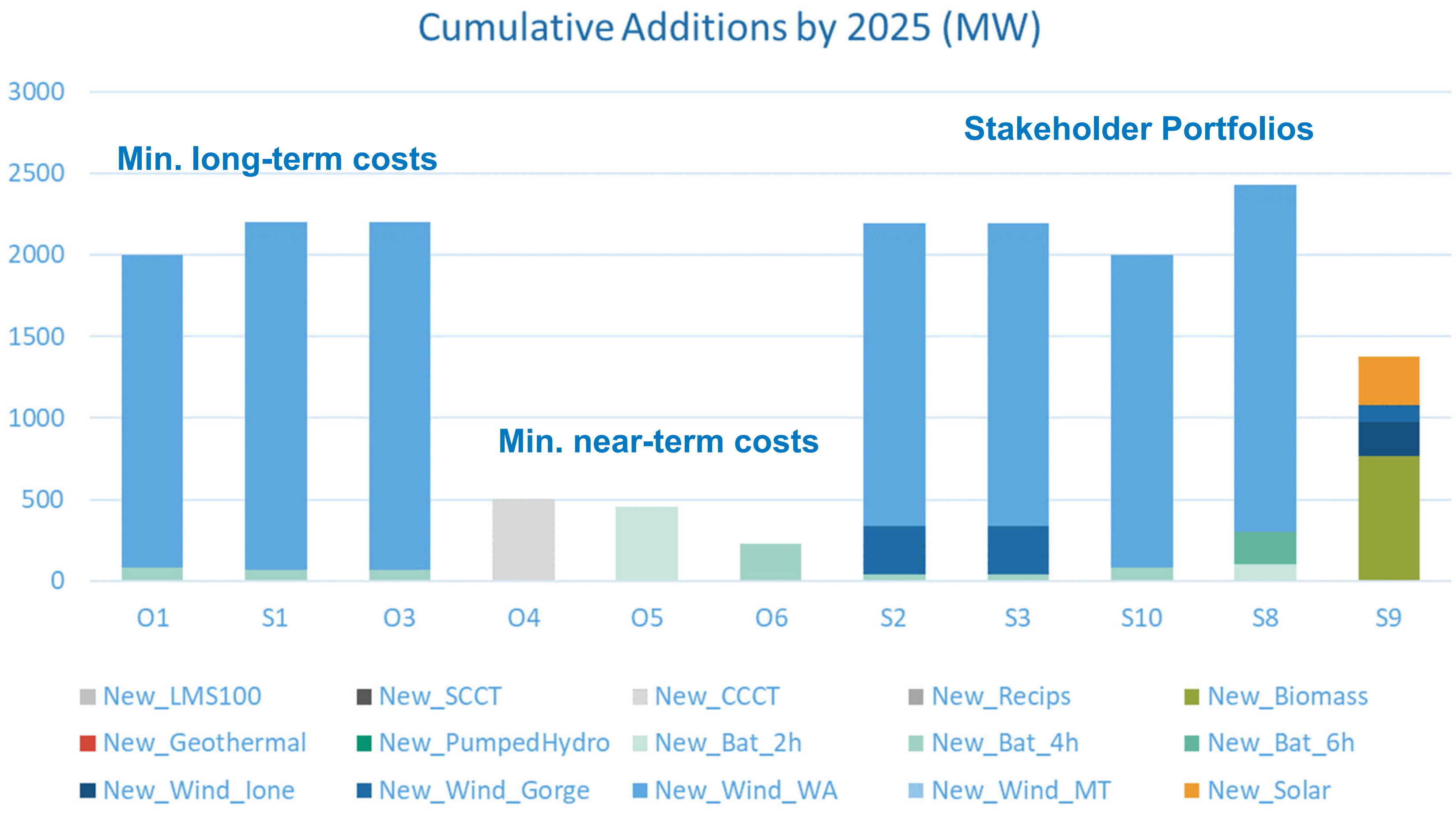
- **O1:** Minimize average long-term NPVRR across futures
- **S1:** Minimize average long-term NPVRR across futures, No Thermal [RNW]
- **O3:** Minimize Reference Case long-term NPVRR
- **O4:** Minimize average near-term NPVRR across futures
- **O5:** Minimize average near-term NPVRR across futures, No Thermal
- **O6:** Minimize Reference Case near-term NPVRR
- **S2:** Minimize Average long-term NPVRR + cumulative GHGs [RNW]
- **S3:** Minimize Average long-term NPVRR + cumulative GHGs, No Thermal [RNW]
- **S10:** Minimize average long-term NPVRR across futures, PSH unit size changed to 100 MW (PSH addition not required) [RNW, Staff, National Grid]
- **S8:** ODOE Scenario 1 [ODOE]
- **S9:** ODOE Scenario 2 [ODOE]

Draft Portfolios
Optimized Portfolios



Draft Portfolios

Optimized Portfolios



Draft Portfolios

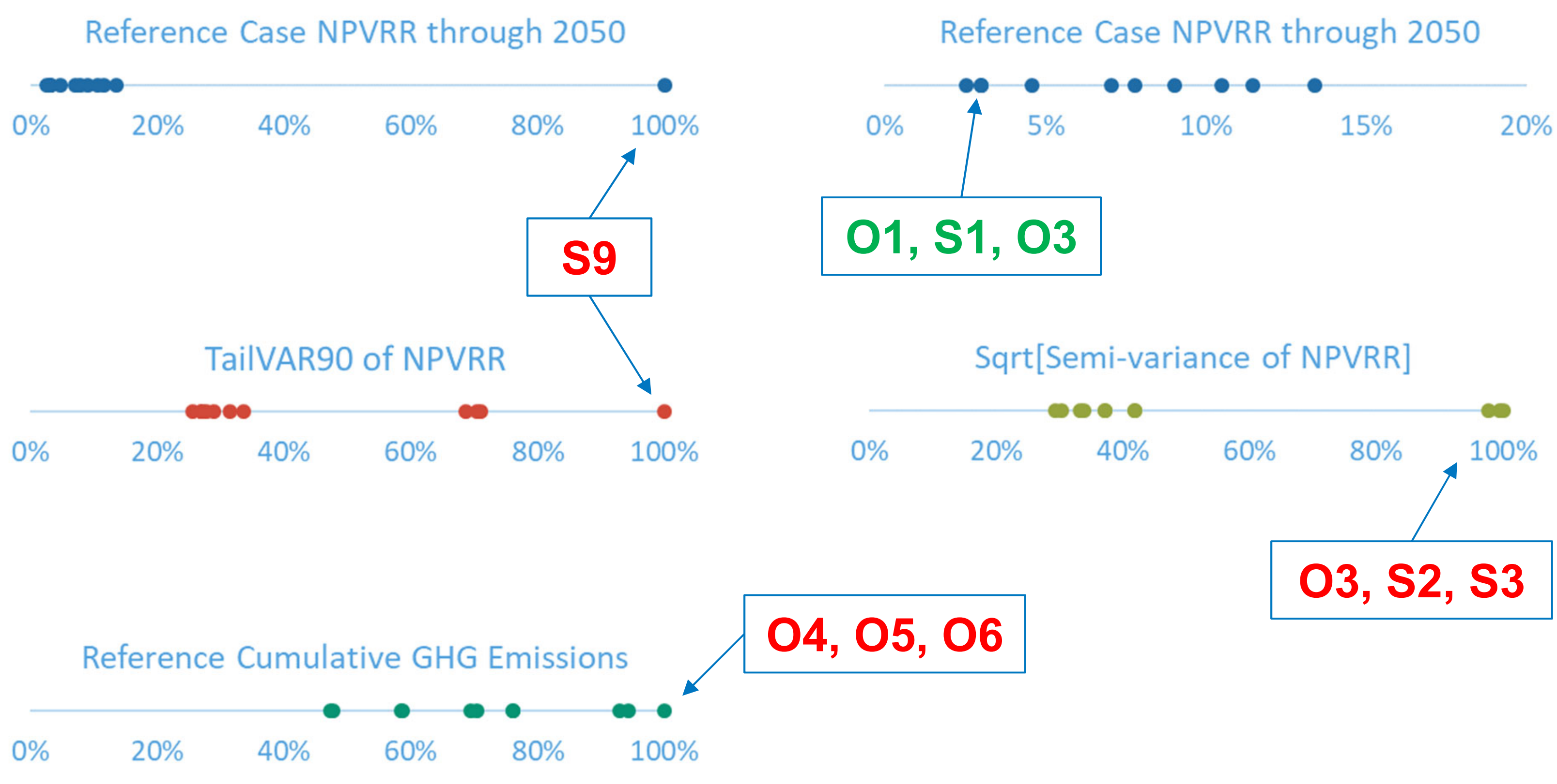
Optimized Portfolios

	O1	S1	O3	O4	O5	O6	S2	S3	S10	S8	S9
Reference Case NPVRR through 2050											
Sqrt[Semi-variance of NPVRR]											
TailVAR90 of NPVRR											

	O1	S1	O3	O4	O5	O6	S2	S3	S10	S8	S9
Average NPVRR through 2050											
Reference Case 20-yr NPVRR											
Average 20-yr NPVRR											
Reference Case NPVRR through 2025											
Average NPVRR through 2025											
Standard Deviation of NPVRR											
Reference Case Cumulative GHG Emissions											
Average Cumulative GHG Emissions											
Reference Case Cumulative NOx Emissions											
Average Cumulative NOx Emissions											
Reference Case Cumulative SO2 Emissions											
Average Cumulative SO2 Emissions											
Reference Case Cumulative PM Emissions											
Average Cumulative PM Emissions											

Draft Portfolios

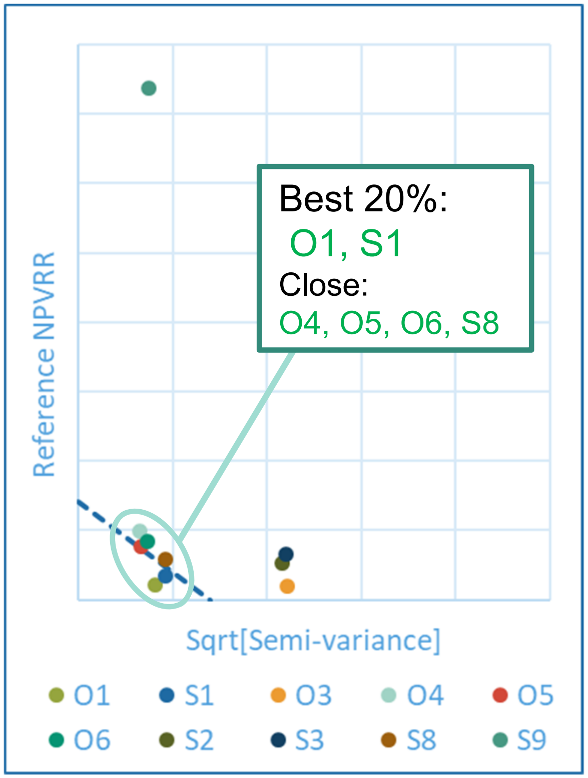
Optimized Portfolios: Data distribution by metric



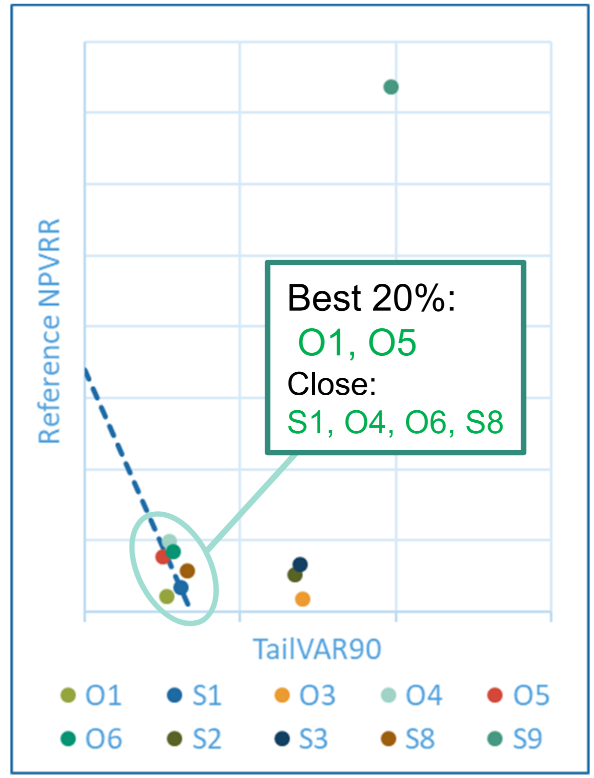
Draft Portfolios

Optimized Portfolios: Cost & Risk Scatter Plot

Reference NPVRR & Semi-variance



Reference NPVRR & TailVAR90

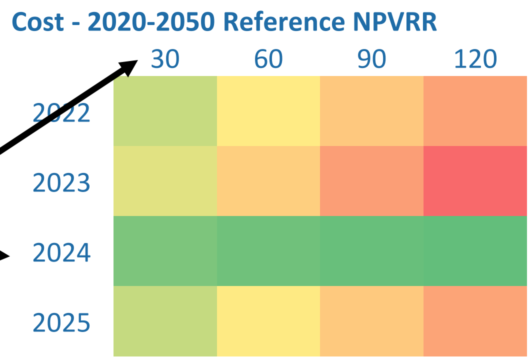


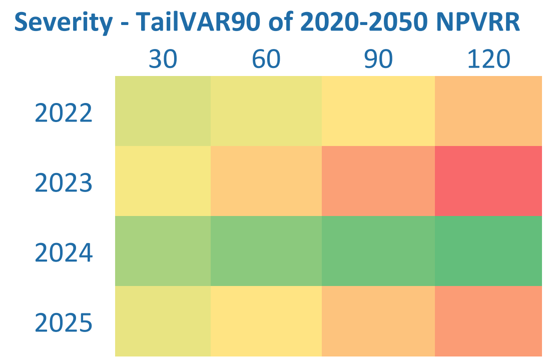
Renewable Size and Timing Portfolios

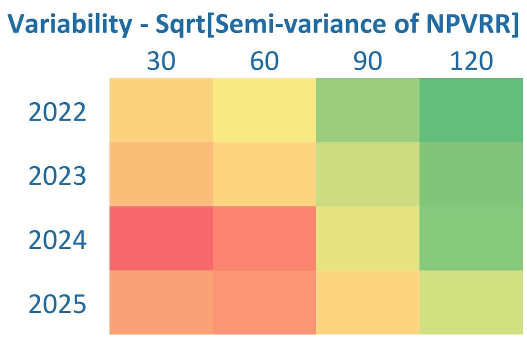
Draft Portfolios

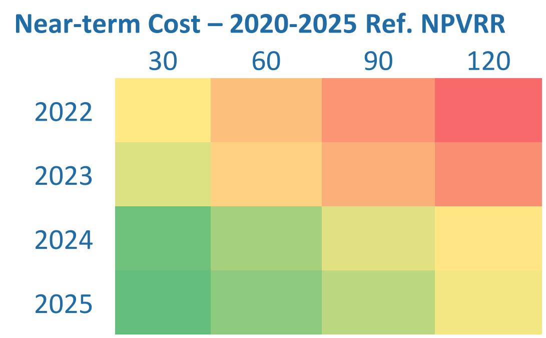
Renewable Size and Timing Portfolios

- Tests renewable resource economics as a function of both procurement size (MWa) and online date (COD)
- Draft analysis suggests:
  - 2024 COD results in lowest Cost and Severity metrics
  - Larger and earlier procurement targets reduce Variability metric
  - Smaller and later procurement targets reduce Near-term Cost









*These portfolios require a specified amount of RPS-eligible energy to be procured in a specified year, but allow for the optimal selection of the RPS-eligible resource(s) within that requirement

Draft Portfolios

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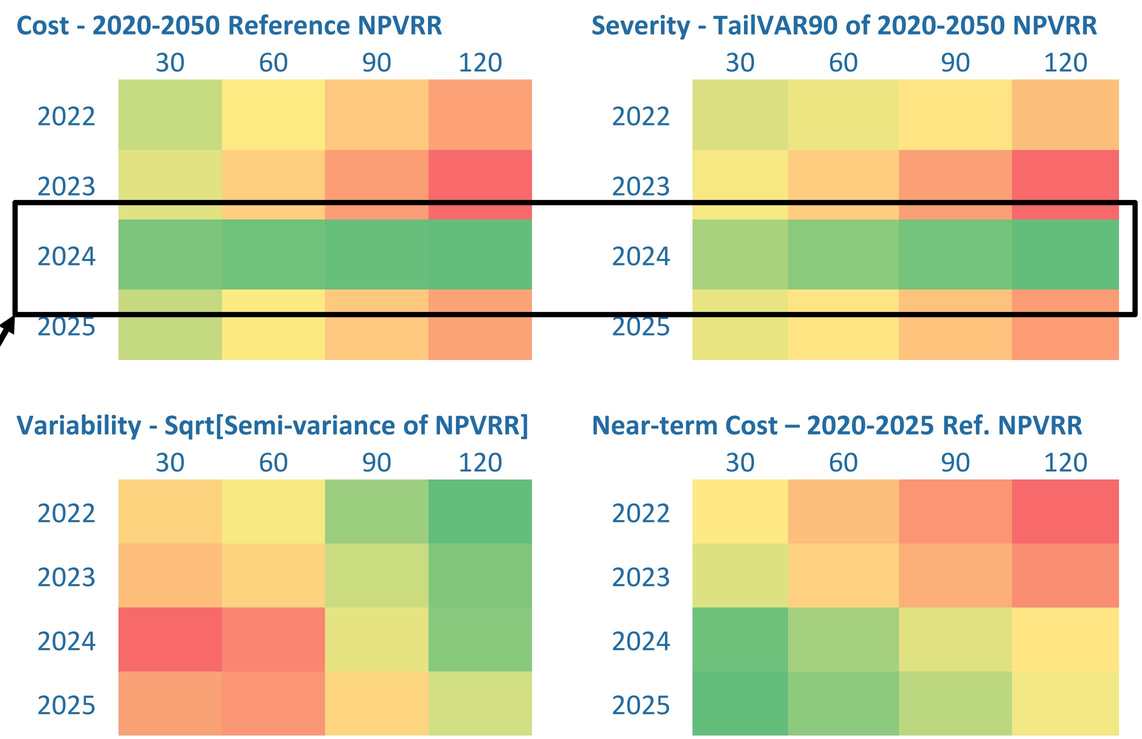

Draft Portfolios

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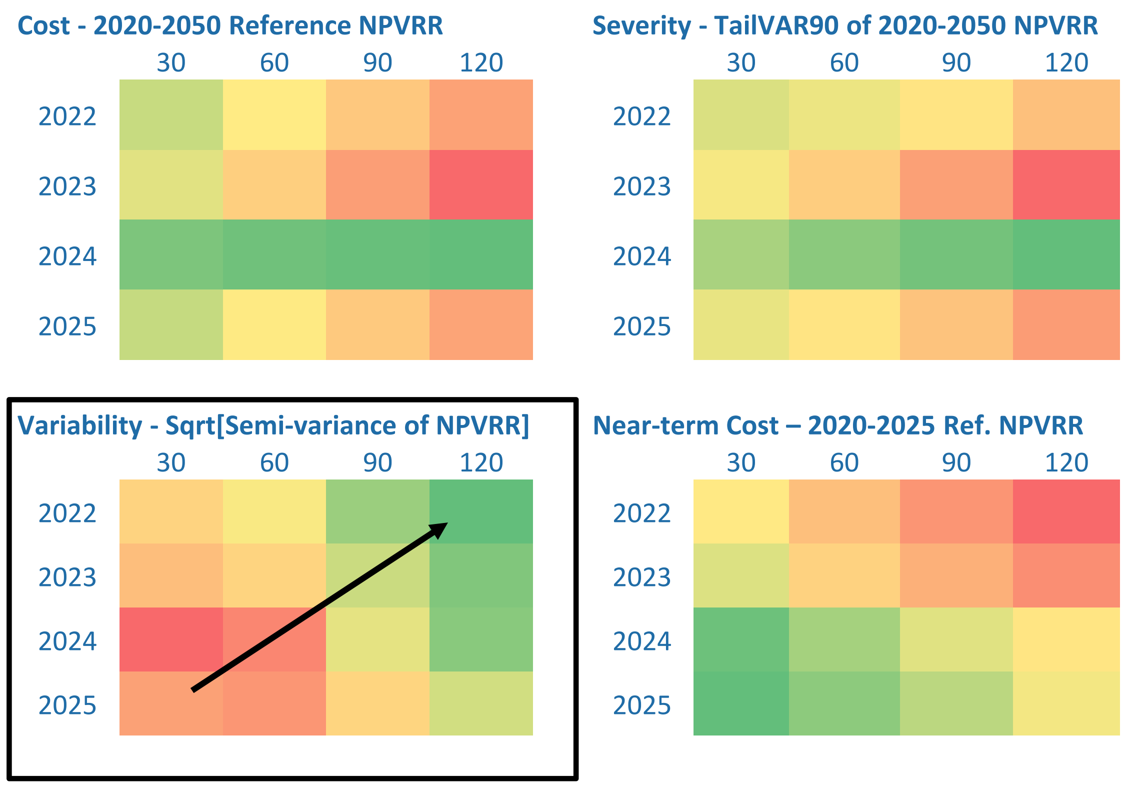

Draft Portfolios

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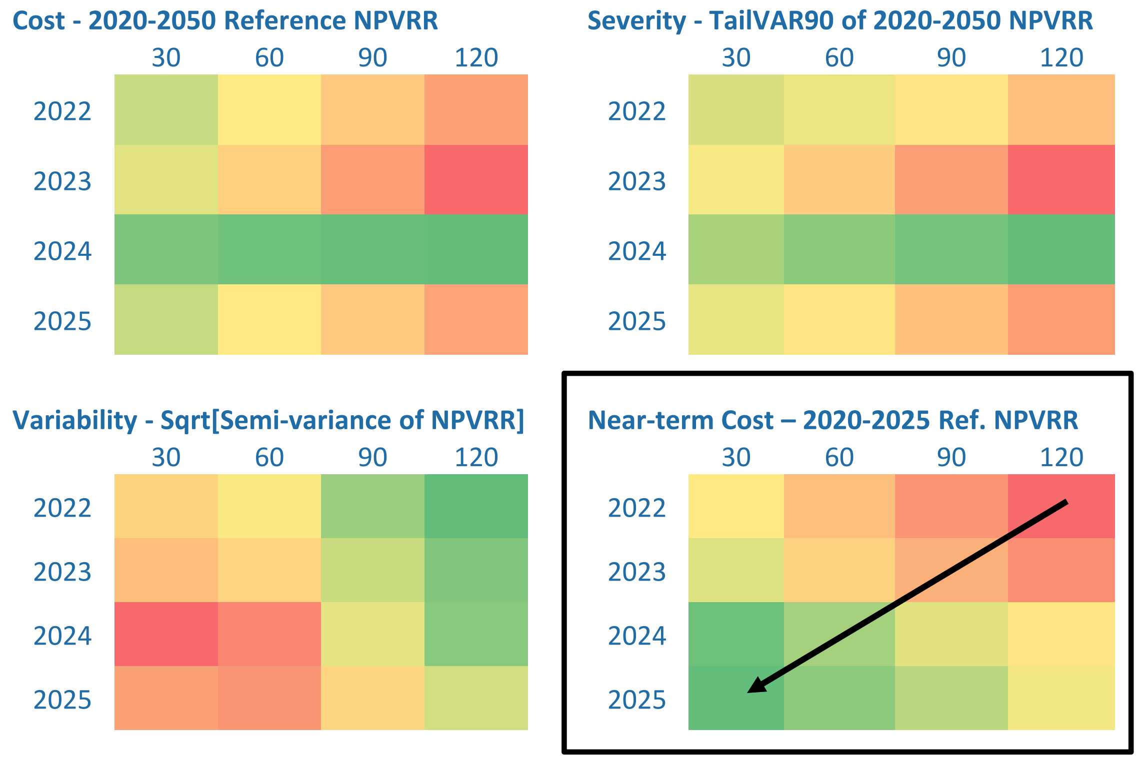
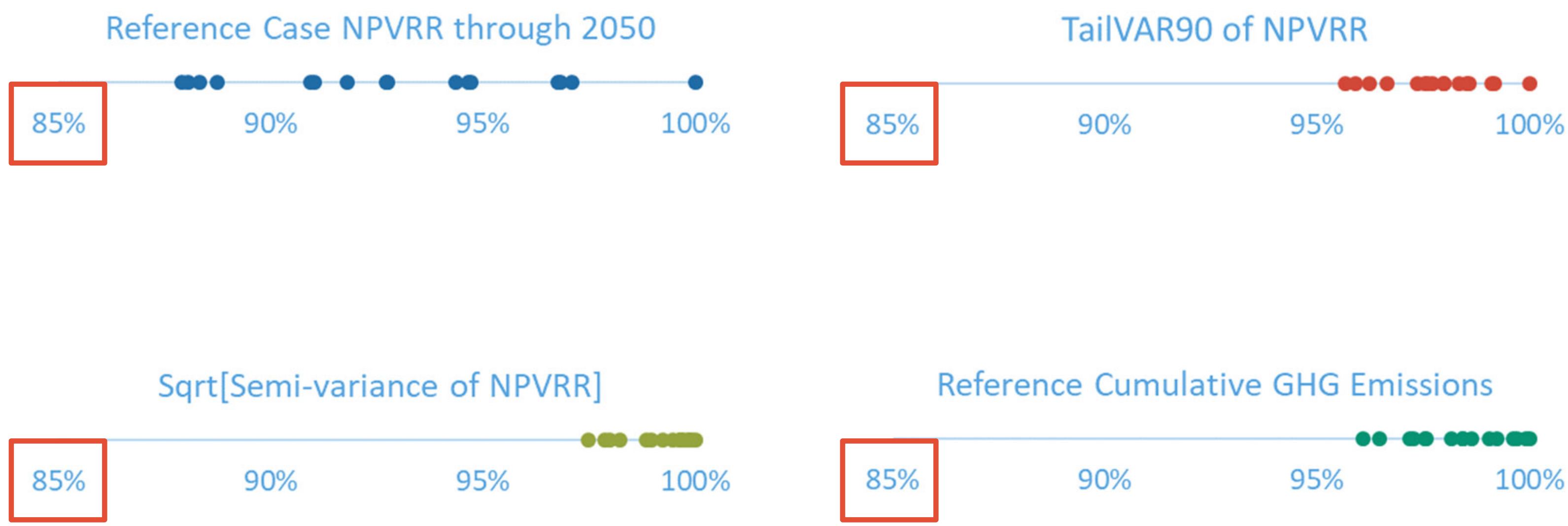


Draft Portfolios

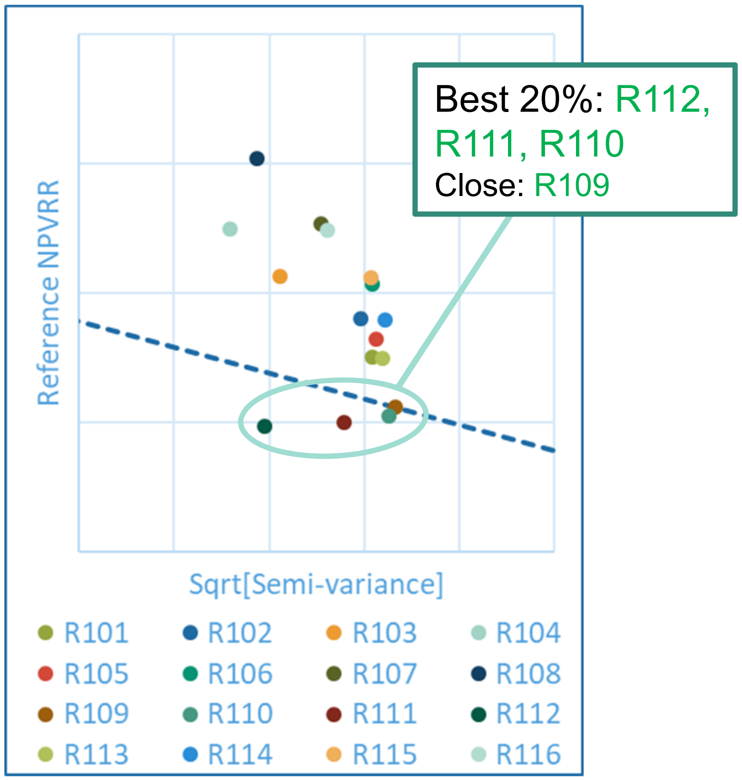
Renewable Size and Timing Portfolios: Data distribution by metric



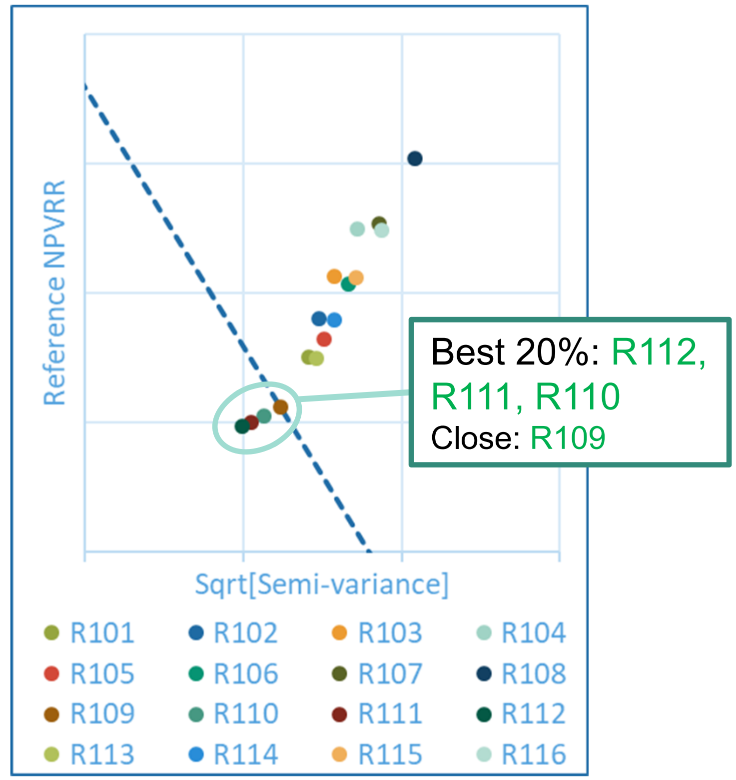
Draft Portfolios

Renewable Size and Timing Portfolios: Cost & Risk Scatter Plot

Reference NPVRR & Semi-variance



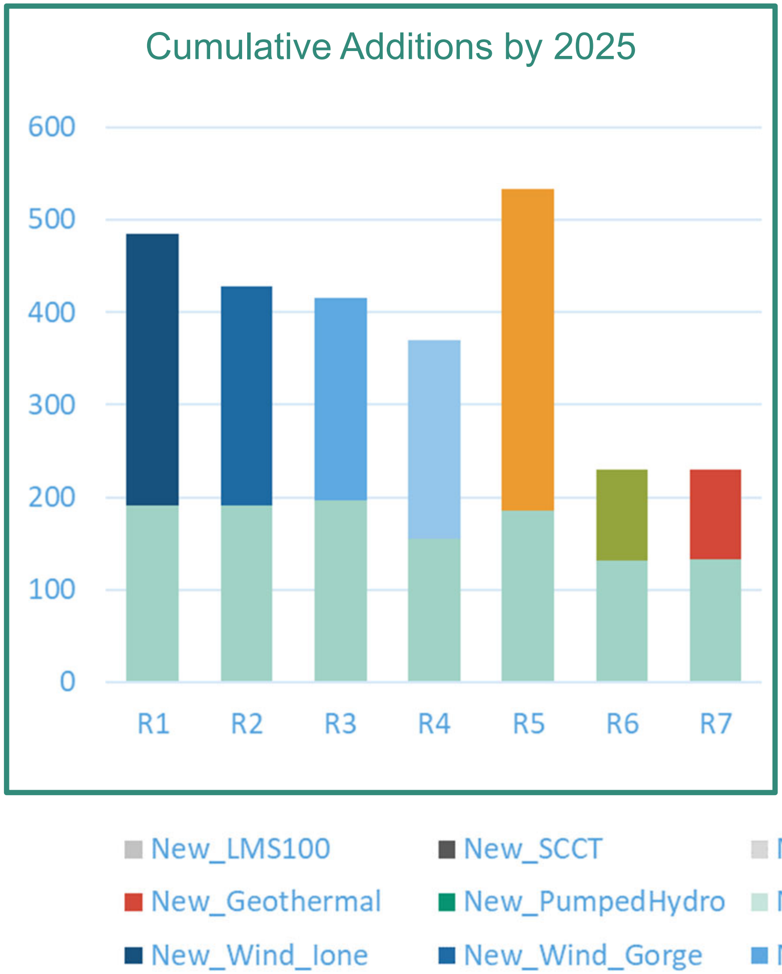
Reference NPVRR & TailVAR90



Renewable Resource Portfolios

Draft Portfolios

Renewable Resource Portfolios



90 MWa of renewables by 2025, plus 4-hr batteries for remaining capacity needs. No Thermal through 2050.

- **R1:** Ione Wind
- **R2:** Gorge Wind
- **R3:** Washington Wind
- **R4:** Montana Wind
- **R5:** Central Oregon Solar
- **R6:** Biomass
- **R7:** Geothermal

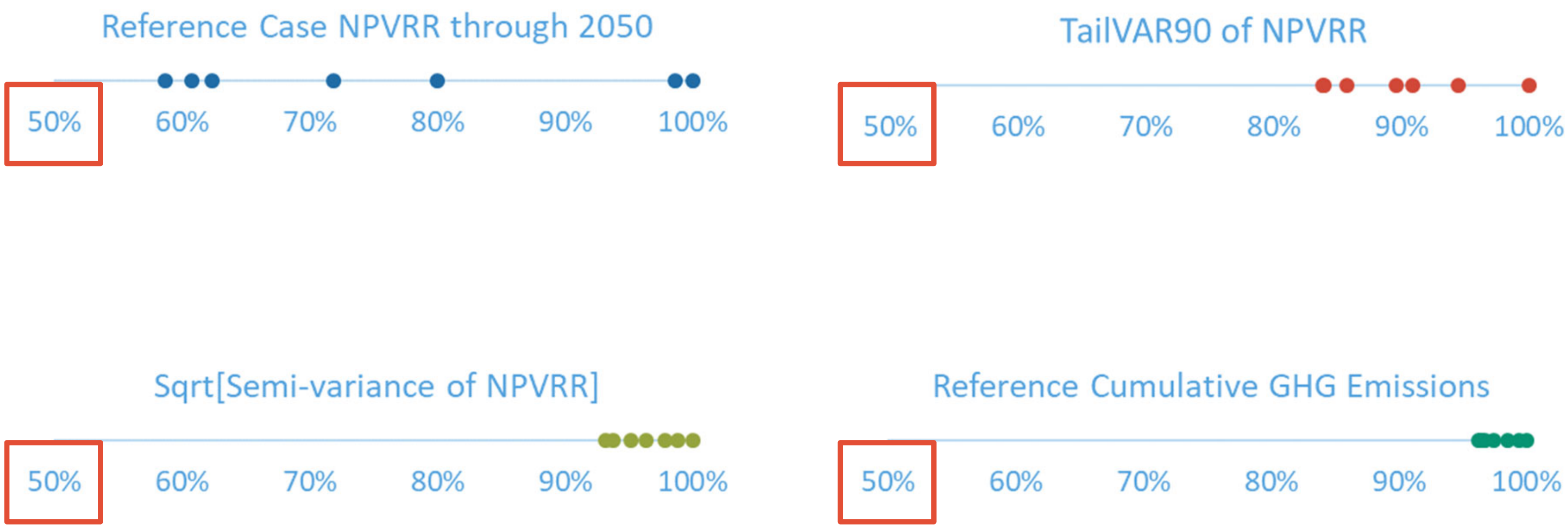
Draft Portfolios

Renewable Resource Portfolios

	R1	R2	R3	R4	R5	R6	R7
Reference Case NPVRR through 2050							
Sqrt[Semi-variance of NPVRR]							
TailVAR90 of NPVRR							
Average NPVRR through 2050							
Reference Case 20-yr NPVRR							
Average 20-yr NPVRR							
Reference Case NPVRR through 2025							
Average NPVRR through 2025							
Standard Deviation of NPVRR							
Reference Case Cumulative GHG Emissions							
Average Cumulative GHG Emissions							
Reference Case Cumulative NOx Emissions							
Average Cumulative NOx Emissions							
Reference Case Cumulative SO2 Emissions							
Average Cumulative SO2 Emissions							
Reference Case Cumulative PM Emissions							
Average Cumulative PM Emissions							

Draft Portfolios

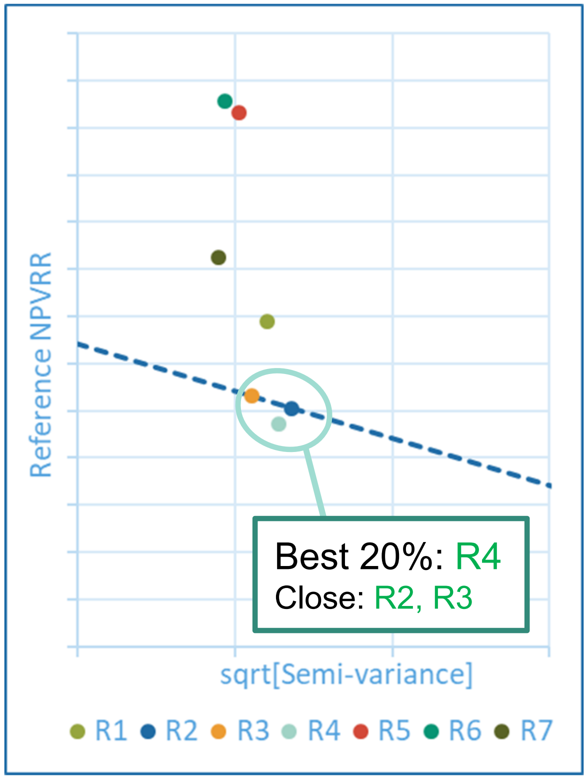
Renewable Resource Portfolios: Data distribution by metric



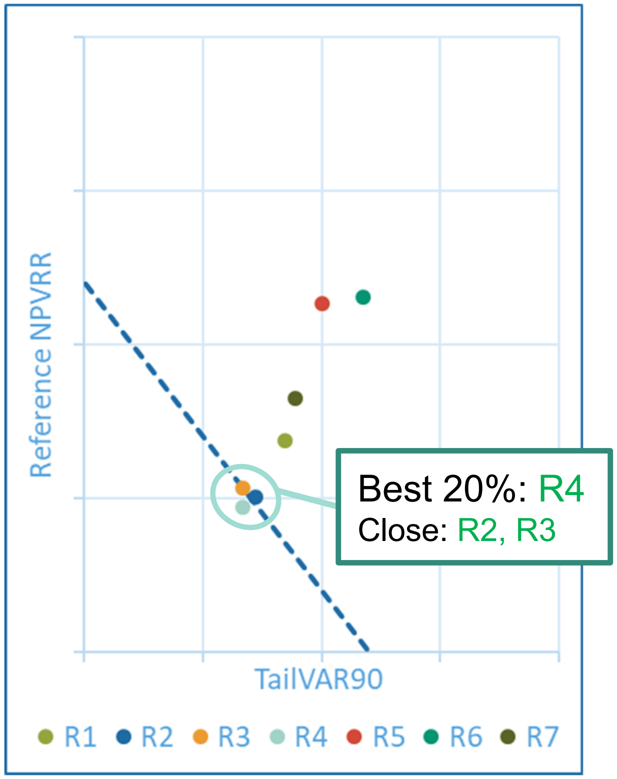
Draft Portfolios

Renewable Resource Portfolios: Cost & Risk Scatter Plot

Reference NPVRR & Semi-variance



Reference NPVRR & TailVAR90

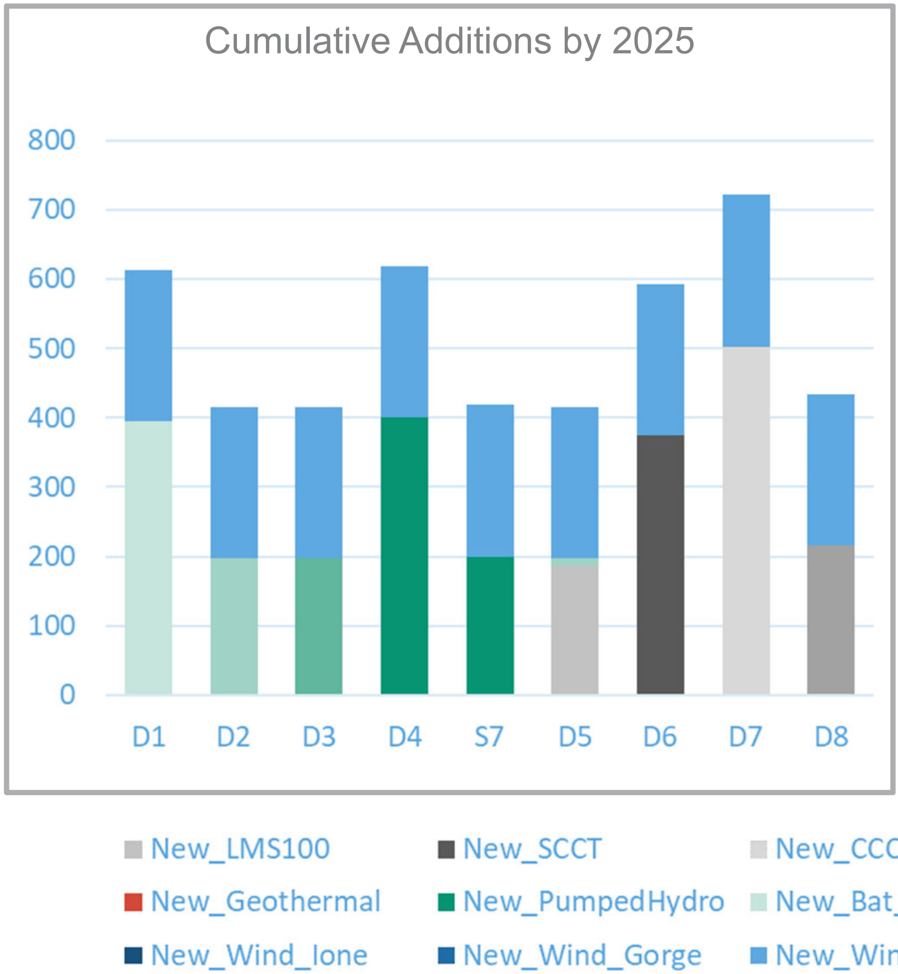


Draft – subject to change

Dispatchable Resource Portfolios

Draft Portfolios

Dispatchable Resource Portfolios



90 MWa Wind, plus 200+ MW of Dispatchable Capacity by 2025, unit sizes enforced:

- **D1:** 2hr Batteries (400 MW)
- **D2:** 4hr Batteries (200 MW)
- **D3:** 6hr Batteries (200 MW)
- **D4:** Pumped Storage (1x400 MW)
- **S7:** Pumped Storage (2x100 MW) [RNW, National Grid]
- **D5:** LMS100 (2 units)
- **D6:** SCCT (1 unit)
- **D7:** CCCT (1 unit)
- **D8:** Reciprocating Engine (12 units)

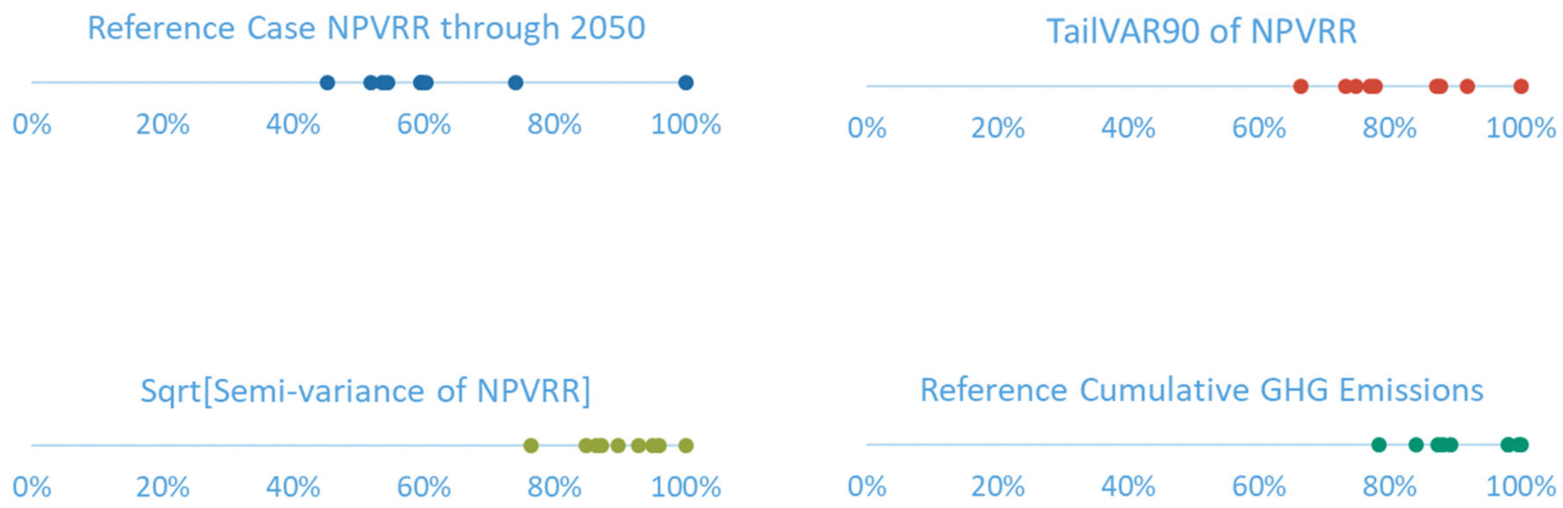
Draft Portfolios

Dispatchable Resource Portfolios

	D1	D2	D3	D4	S7	D5	D6	D7	D8
Reference Case NPVRR through 2050									
Sqrt[Semi-variance of NPVRR]									
TailVAR90 of NPVRR									
Average NPVRR through 2050									
Reference Case 20-yr NPVRR									
Average 20-yr NPVRR									
Reference Case NPVRR through 2025									
Average NPVRR through 2025									
Standard Deviation of NPVRR									
Reference Case Cumulative GHG Emissions									
Average Cumulative GHG Emissions									
Reference Case Cumulative NOx Emissions									
Average Cumulative NOx Emissions									
Reference Case Cumulative SO2 Emissions									
Average Cumulative SO2 Emissions									
Reference Case Cumulative PM Emissions									
Average Cumulative PM Emissions									

Draft Portfolios

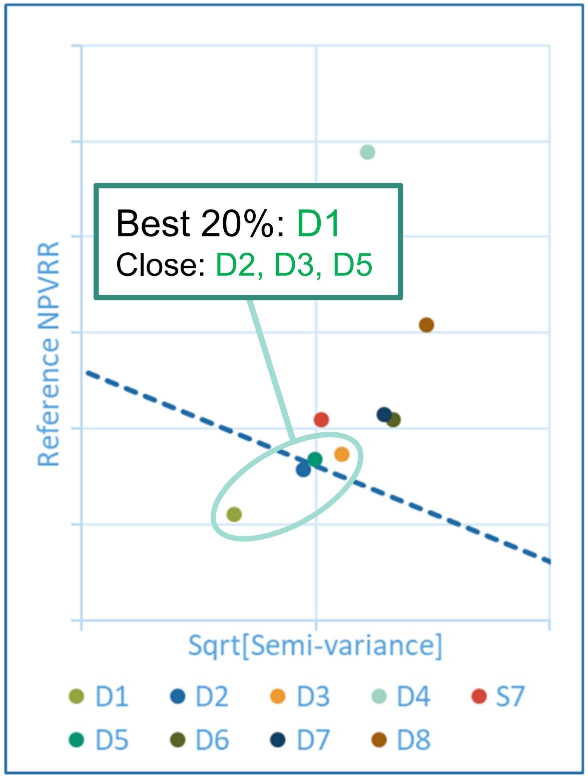
Dispatchable Resource Portfolios: Data distribution by metric



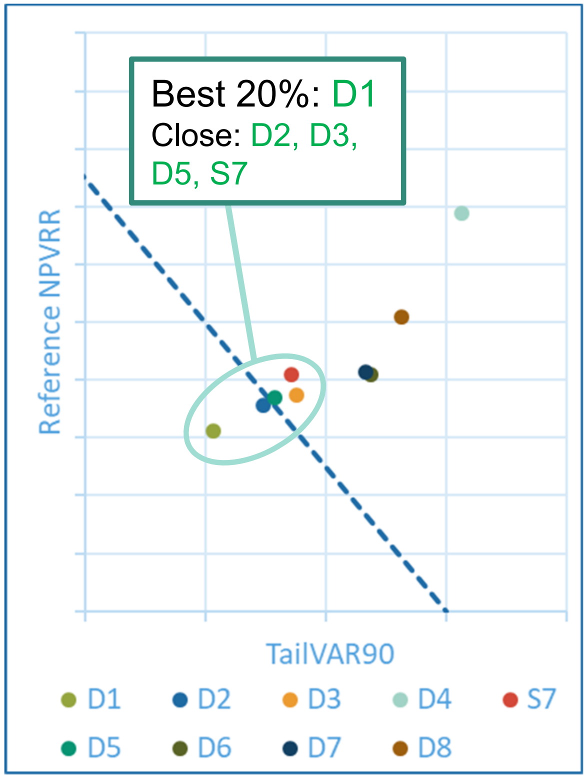
Draft Portfolios

Dispatchable Resource Portfolios: Cost & Risk Scatter Plot

Reference NPVRR & Semi-variance



Reference NPVRR & TailVAR90



RPS Glide Path Analysis

Toward a Renewable Glide Path

PGE introduced the concept of a renewable glide path in the 2016 IRP Revised Renewable Action Plan:

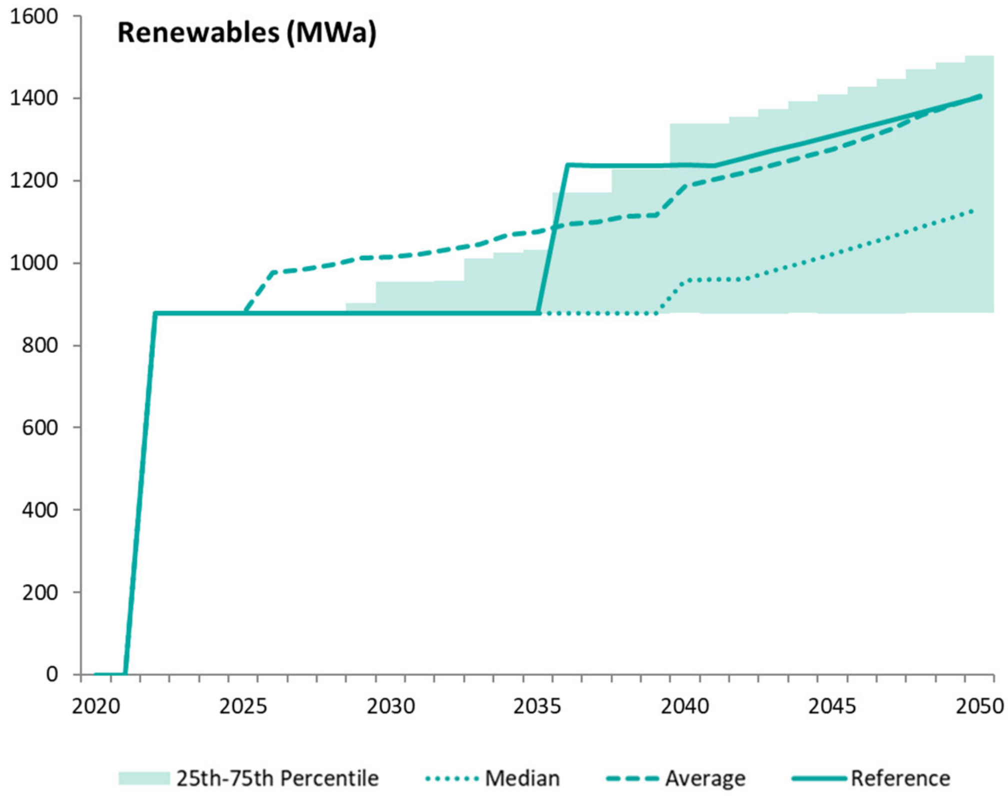
PGE: “The utility of the glide path method is to provide context for proposed near-term actions in terms of scale and long-term uncertainties.”

OPUC Order 18-044:

“Staff and many stakeholders largely agree that PGE's glide path is a good foundational analysis that allows us to conclude that a 100 MWa RFP lines up fairly well with PGE's need.”

“…PGE will use a **glide path analysis** in future IRPs and subsequent RPIPs. The glide path analysis has been a helpful foundation upon which to build and further refine an understanding of the pacing of PGE's procurement plans, showing a forecast of the company's long-term compliance strategy and the incremental steps to get there.”

Toward a Renewable Glide Path

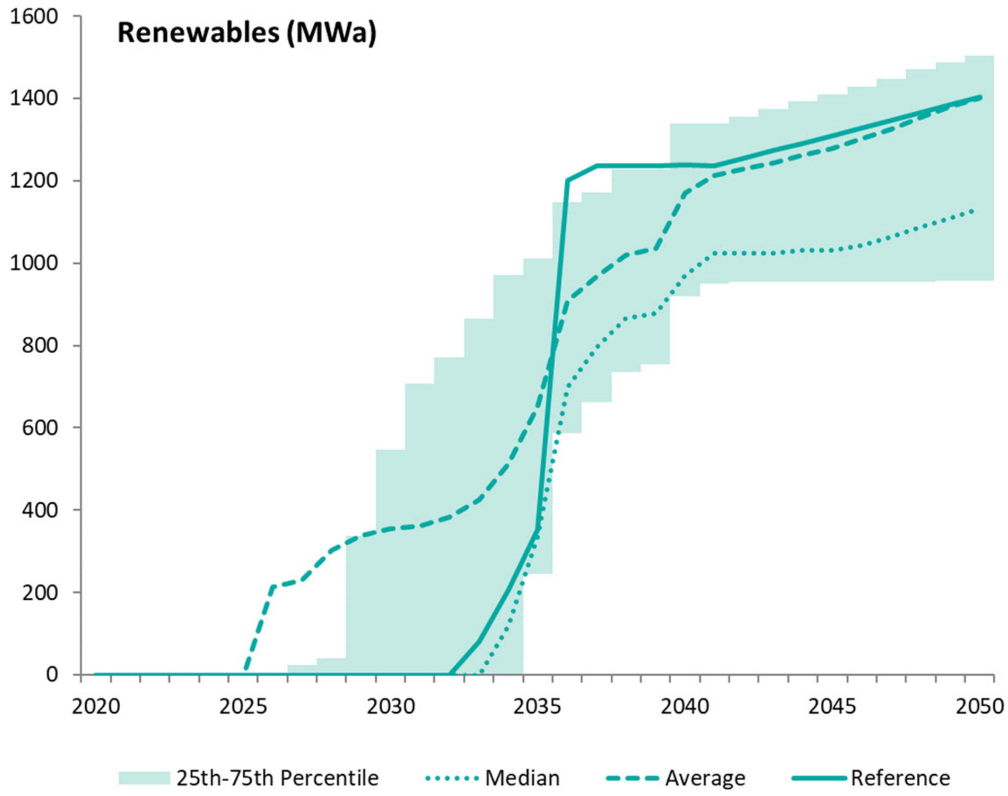


Portfolio S1

[Minimize average long-term NPVRR across futures, No Thermal]

- Very large 2022 renewable action (877MWa) defers next renewable action and results in renewable glide path that has more incremental procurement between 2035 and 2050

Toward a Renewable Glide Path

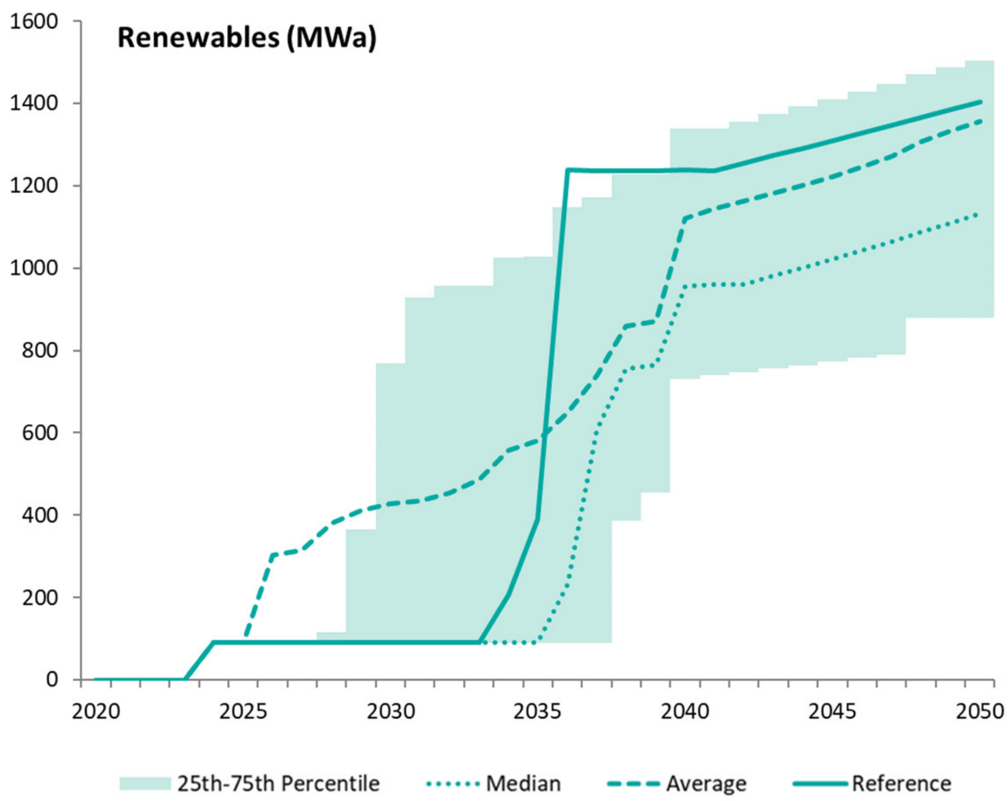


Portfolio O5

[Minimize average near-term NPVRR across futures, No Thermal]

- No renewable action through 2025 results in significant ramp up in renewable procurement between ~2030 and ~2040

Toward a Renewable Glide Path



Portfolio R111

[90 MWa of renewables in 2024, No Thermal]

- Incremental renewable action between now and 2025 defers next renewable action to late 2020s or mid 2030's, still results in significant ramp up in procurement between ~2030 and ~2040

Toward a Renewable Glide Path

Observations

- Portfolio optimization yields renewable procurement trajectory ranges that consider long-term uncertainty in RPS obligations and resource economics
- In many futures, portfolio optimization results in a brief, steep ramp up in renewable procurement sometime in the 2030s, rather than a smooth ramp up in renewables over time

Additional Investigations

- Portfolio optimization could constrain specific variables to smooth future potential renewable procurement trajectories
  - Maximum annual resource addition size
  - Maximum annual revenue requirement increase
- Hand-designed portfolios
- Stakeholder feedback?

Next Steps

Update data and refine analysis of portfolios presented today

Draft additional portfolios:

- Stakeholder-Requested New Resource Portfolios
  - Co-located Renewable + Storage [RNW]
  - 8-hr Batteries [National Grid]
- Risk-Minimizing Portfolios
- Additional requested and hand-designed portfolios

Final deadline for stakeholder requested portfolios is Friday, November 9th

Wrap up

Elaine Hart

Upcoming 2018 Roundtables

Roundtable 18-6 **Wednesday, November 28, 2018** (9:00 am - 1:00 pm PST) 2 World Trade Center, Plaza Conference 121 SW Salmon St., Portland, OR 97204	**AGENDA** ▪ Flexibility Analysis ▪ Need Update ▪ Portfolio & Scoring Update
Roundtable 18-7 Wednesday, December 19, 2018 (9:00 am - 1:00 pm PST) 2 World Trade Center, Sky Bridge A & B 121 SW Salmon St., Portland, OR 97204	AGENDA ▪ Distribution Resource Planning ▪ Transmission

https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings

Wrap Up

- Thank you for your participation today!
- Final stakeholder requested portfolios should be submitted to PGE by **November 9, 2018**
- **Questions or Feedback -** If you'd like to provide feedback on PGE's 2019 IRP or the IRP process,
  - Complete the IRP Online Form (https://www.portlandgeneral.com/forms/pge-stakeholder-feedback)
  - Email IRP@pgn.com