PGE CEP & IRP Roundtable 24-7

November 6th 2024

November 6th, 2024 – Agenda

9:00 – 9:05	Welcome | Meeting Logistics
9:05 - 9:15	CEP/IRP Update Filing Extension
9:15 – 9:45	Calpine
9:45 – 10:15	Updated Energy/Capacity Positions
10:15 – 11:00	Updated Emissions Projection
11:00 – 11:40	Transmission - Step 3 – Market Access
11:40 – 11:55	Portfolio Design
11:55 – 12:00	Closing Remarks | Next Steps

Meeting Details

1

Electronic version of presentation

https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings

2

Zoom meeting details

- Join Zoom Meeting https://us06web.zoom.us/j/9291862450?pwd=xVXQI4jIjt7FdetDzWD0G35FFvayF8.1&omn=84372774388
- Meeting ID: 929 186 2459
- Passcode: 108198

3

Participation

- Please rename yourself indicating the organization you represent if applicable.
- Use the raise the hand feature to let us know you have a question
- Unmute with microphone icon or *6

Meeting Logistics

Focus on Learning & Understanding

- There will be no chat feature during the meeting to streamline taking feedback
- Team members will take clarifying questions during the presentation, substantive questions will be saved for the end (time permitting)
- Attendees are encouraged to 'raise' their hand to ask questions

Follow Up

If we don't have time to cover all questions, we will rely on the CEP/IRP feedback form

CEP/IRP Update Filing Extension

Caroline Sherry, PGE

2023 CEP/IRP Update Extension

On October 16, 2024, PGE filed a request for an extension for the filing of the 2023 CEP/IRP Update as well as the subsequent 2026 CEP/IRP.

CEP/IRP Filing Requirements

- Annual Update Requirement: OAR 860-027-0400(11) mandates annual updates on the most recently acknowledged IRP
- Filing Requirement: OAR 860-027-0400(3) requires filing an IRP within two years of the previous acknowledgment order.
- Concurrent Filing: OAR 860-027-0400(4) mandates filing a CEP concurrently with the IRP.

2023 CEP/IRP Update

Filing Dates

- Previous: January 25, 2025
- Requested Extension: March 14, 2025

Justification:

1. Incorporate and compare preliminary 2024 emissions data, which becomes available in March 2025, with 2023 CEP/IRP forecasts.
2. Include updates from Bonneville Power Administration (BPA) on transmission infrastructure expansions.
   - BPA's 'Evolving Grid' project update provided October 17, 2024 with additional update expected December 4, 2024.

Next 2026 CEP/IRP

Filing Dates

- Previous: January 25, 2026
- Requested Extension: March 16, 2026

Justification:

1. Align the filing of the next full CEP/IRP with the extension of the CEP/IRP Update.
2. Ensure sufficient time for incorporating updates and analysis.
3. Extension will not impact PGE's ongoing procurement efforts to address capacity needs and emissions reduction targets.

Calpine – Heat Rate Call Option

Devin Mounts, PGE

Summary - Calpine

PGE has negotiated a **250 MW Heat Rate Call Option (HRCO)** with Calpine Energy Services, L.P.

Key Terms:

- Delivery of **4.5 years,** beginning July 1, 2025, through December 31, 2029
- The HRCO gives PGE the right, but not the obligation, to purchase power from Calpine at the Dispatch Costs associated with the Hermiston Power Plant
- Calpine's Hermiston Power Plant is a combined-cycle combustion turbine with a baseload capacity of 566 MW, and a peaking ability of 635 MW. PGE's contract with Calpine is backed by 250 MW from this facility

Contract Benefits

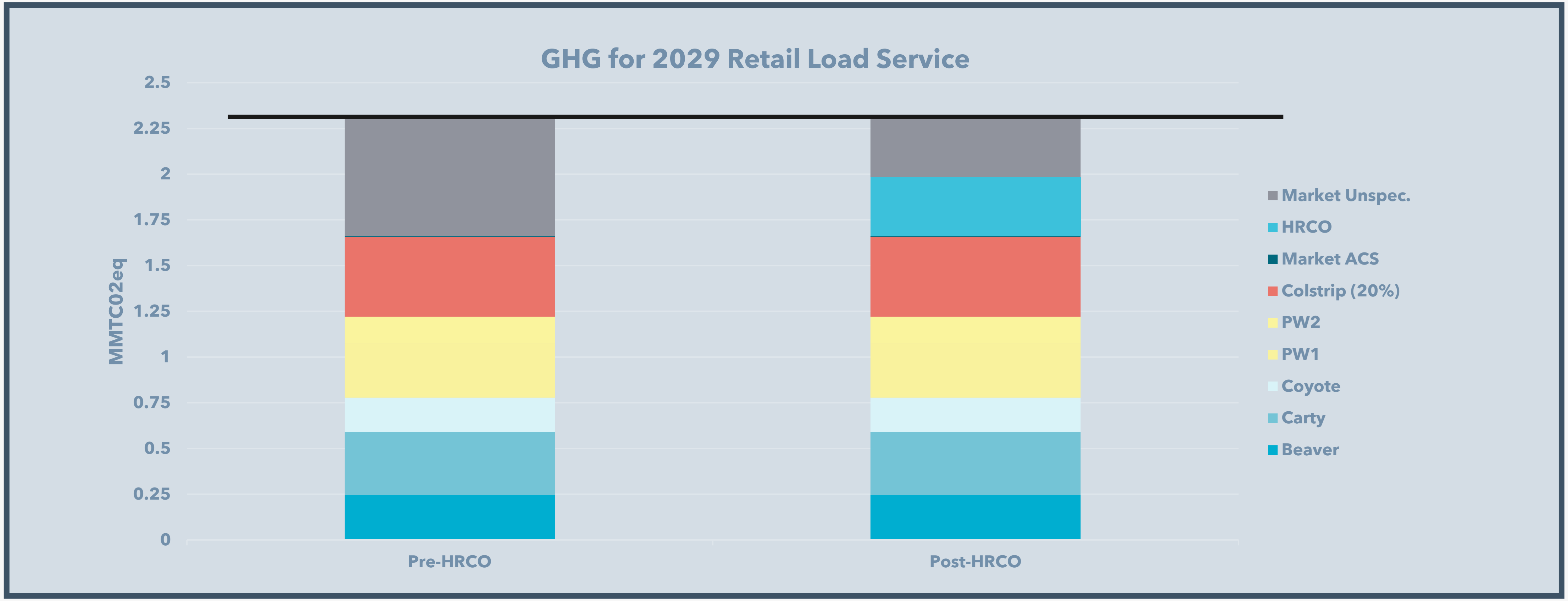
	PGE Value Streams
	Securing firm capacity from the HRCO at Hermiston Power Plant helps ensure PGE can reliably meet increasing customer load demands and capacity requirements.
	The daily call option structure of the HRCO provides valuable operational flexibility to optimize energy delivery based on system needs and arbitrage opportunities.
	Utilizing existing PGE transmission enables efficient delivery of the HRCO to PGE System.
	Hermiston Power Plant's greenhouse gas emission rate of 0.405[1] MTCO2e/MWh is 5% lower than unspecified market purchases (a mix of hydro, gas, coal, etc.) with an emissions rate of 0.428 MTCO2e/MWh.[2]

1. 2023 DEQ issued emissions factor. https://www.oregon.gov/deq/ghgp/Pages/GHG-Reporting.aspx
2. https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=1538

Emissions Impact

HRCO energy will likely reduce the need for unspecified market purchases

- The precise quantity of unspecified energy purchases reduced will be estimated in upcoming Aurora and IGHG modeling
- The 5% per-MWh decrease in emissions rate will support PGE's effort to meet the emissions reduction glidepath while increasing the quantity of energy PGE receives from its existing and contracted resources in the portfolio
- Calpine – HRCO reduces 2028 reference capacity need by an estimated 244 MW and 250 MW for summer and winter, respectively.



*Proportion of HRCO contribution is demonstrative. Actual emissions require further Aurora and IGHG modeling

Updated Energy/Capacity Positions

Rob Campbell, PGE

Devin Mounts, PGE

Defining Energy Need

Energy Need is used in portfolio analysis to determine the quantity of energy that needs to be added to PGE's portfolio in the form of new resources.

PGE determines energy need by our forecasted energy position, which is calculated using **Energy-Load Resource Balance.**

Energy-Load Resource Balance is the difference between forecasted load and the energy available from existing and contracted resources to serve load.

In past IRP's Energy-Load Resource Balance has been calculated using annual averages. Now, monthly-average calculations will be used as well.

Updating Energy Need

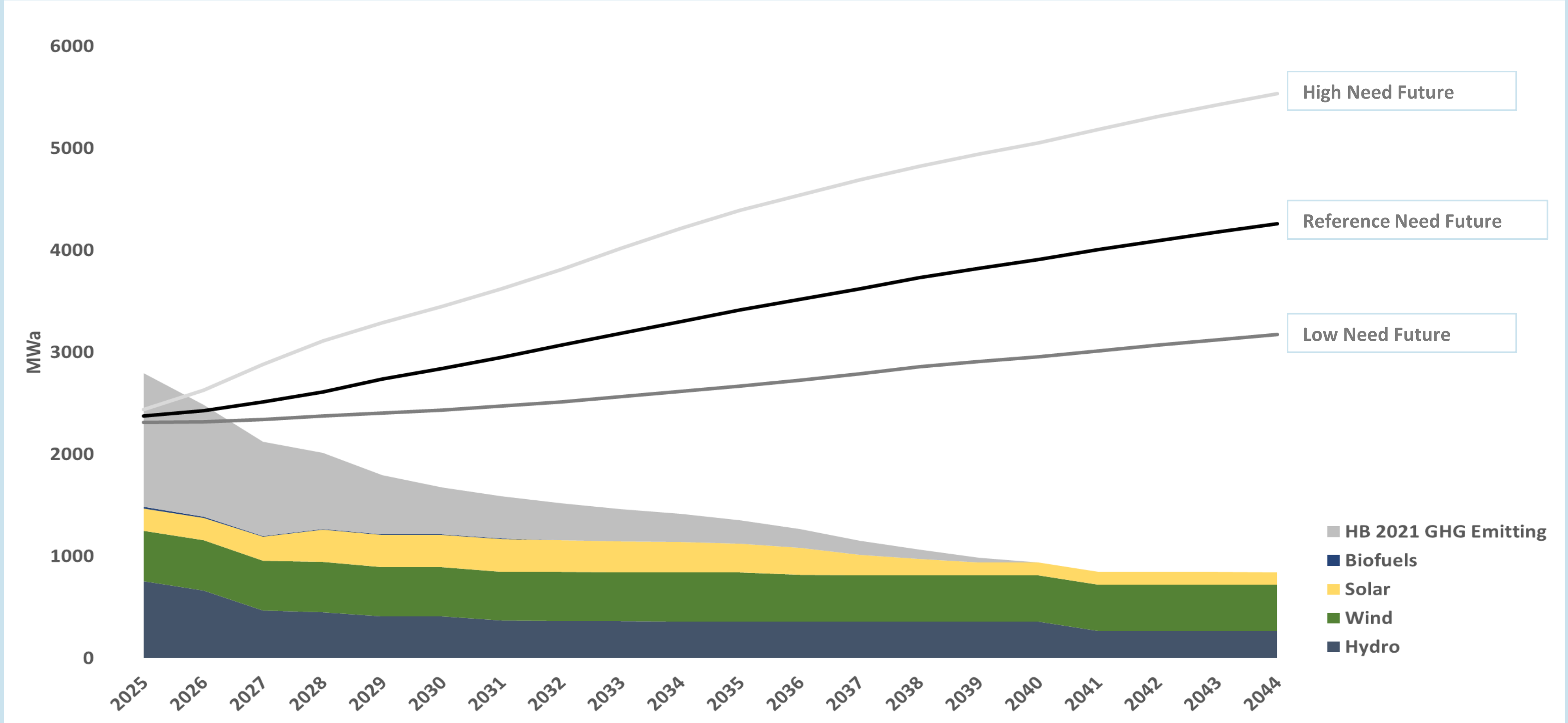
PGE updates energy need in every CEP/IRP and CEP/IRP Update as well as for some intermediate filings (i.e., 2023 Addendum).

Since the filing of the 2023 Addendum, PGE has incorporated updates to key inputs to the Energy-Load Resource Balance calculation:

1. **Load forecast** (July Roundtable)
2. **Cost-effective EE and DERs** (September and November Roundtables)
3. **Baseline portfolio which includes:**
   - QF forecast (June Roundtable)
   - 2023 RFP proxy (October Roundtable)
   - Hydro contract extension
   - Calpine HRCO contract (November Roundtable)

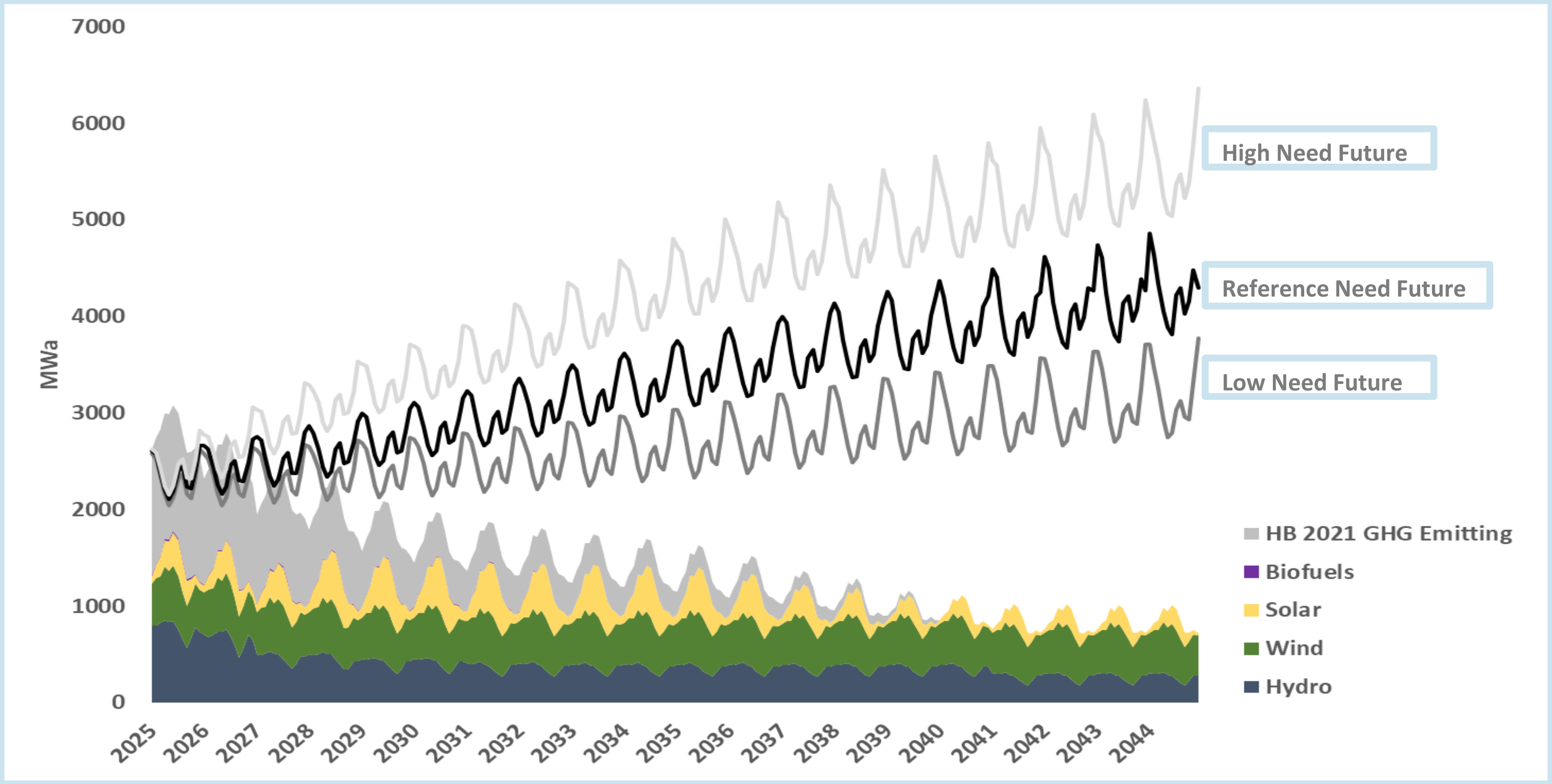
Updated Draft Annual Energy-Load Resource Balance

This graph is a depiction of system need **before** the addition of more resources.



Updated Draft Monthly Energy-Load Resource Balance

This graph is a depiction of system need **before** the addition of more resources.



Defining Capacity Need

Capacity Need is used in portfolio analysis to determine the quantity of capacity that needs to be added to PGE's portfolio to maintain a reliable system.

PGE determines capacity need through the Company's resource adequacy model Sequoia, a stochastic adequacy model which targets a seasonal adequacy level of 24 hours in 10 years (2.4 LOLH).

The seasonal **Capacity Need** is the amount of perfect capacity required to meet the 2.4 LOLH adequacy standard.

Updating Capacity Need

PGE updates capacity need in every CEP/IRP and CEP/IRP Update and for some intermediate filings (i.e., 2023 Addendum).

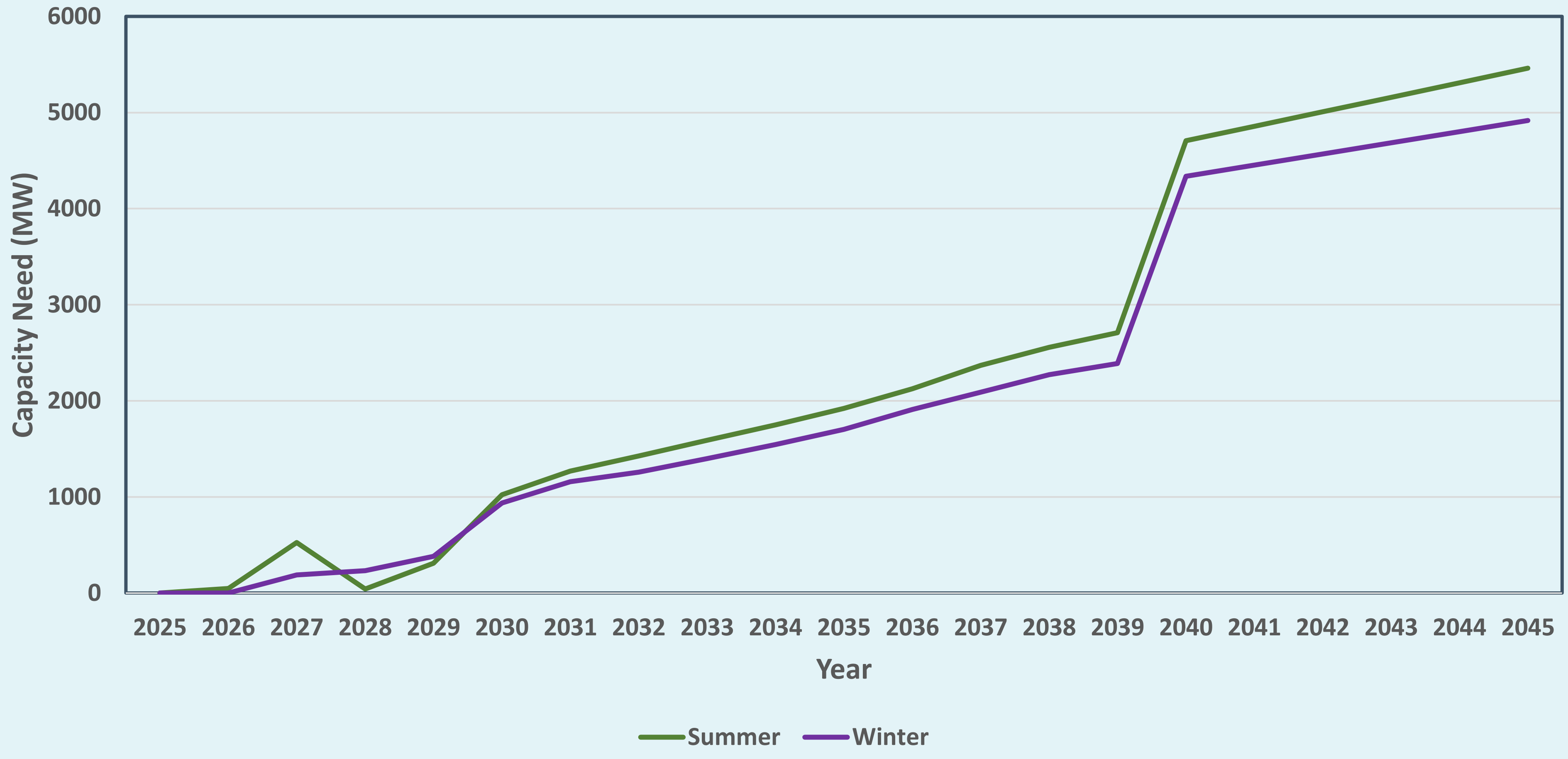
Since the filing of the 2023 Addendum, PGE has incorporated updates to Sequoia impacting the capacity need:

- **Methodological Updates, Load Forecasts, QF Forecasts** (August Roundtable)

Additional updates included:

- 2023 RFP Proxy (October Roundtable)
- DER Updates (October Roundtable)
- Hydro contract extension
- Calpine HRCO contract

Draft Capacity Need Timeline: Reference Case



Updated Emissions Projection

Seth Wiggins, PGE

The IRP is a first step in a multi-step process for traditional large generation resource acquisition

1. Integrated Resource Plan (IRP)

- Forecasts system energy & capacity needs over a 20-year horizon
- Creates a set of incremental resource additions (titled the 'Preferred Portfolio')
- Concludes with short-term Action Plan (the resources PGE will pursue over the next 2-4 years)
- Seek Commission acknowledgement

2. Request for Proposals (RFP)

- Solicits bids from developers for specified generation types
- Determines which bid(s) can meet system requirements and generation targets established in the IRP Action Plan
- Create a Final Shortlist of the best combination of bids
- Seek Commission acknowledgement of FSL

3. Resource Construction

- Commercial negotiation
- Contract execution
- Construction (typically 1.5-3 years)
- Generation resource becomes available

4. Rate Recovery Filing

- Detail PGE's specific actions to the Commission
- Establish prudency of generation financial commitments
- Begin rate recovery of those financial commitments

This traditional process takes years after an IRP is filed until new generation is available

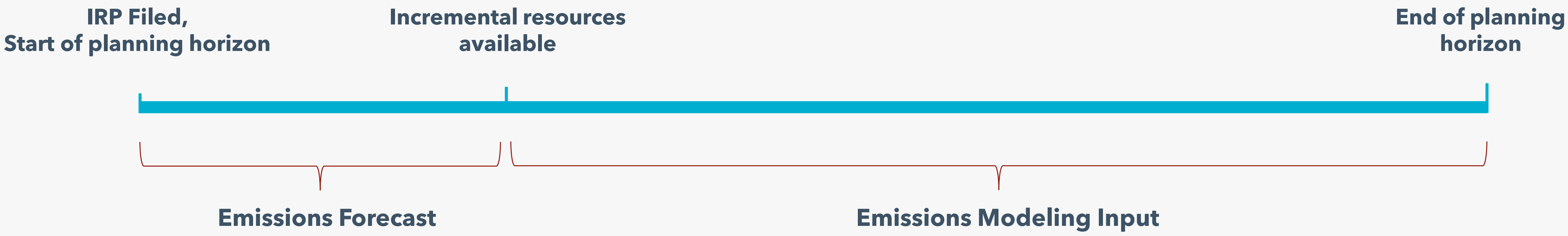
Step	Time	Cumulative Time
IRP acknowledgement	9-12 months	9-12 months
RFP acknowledgement	9-15 months	18-27 months
Commercial negotiations	3-9 months	21-39 months
Resource construction	24-36 months	45-75 months

Recently, steps have been taken aimed at reducing this time between identifying need and incremental resource generation (concurrent IRP and RFPs, UM 2348, etc.)

However, there remains a time between when an IRP is filed and when new generation resources can be available

- This time changes how we characterize emissions projections

Emissions Forecasting versus Modeling Inputs



Emissions component	Can the IRP Action Plan lead to more generation resources?	What question does this answer?
Forecast	No	What can we expect under average conditions?
Modeling Input	Yes	What quantity of emissions should we plan for?

2023 CEP/IRP Update incremental resources availability

The 2023 CEP/IRP (filed March 2023) assumed that resources could be available in 2026 (achieve a COD by December 31st, 2025)

- However, no conforming bids received in the subsequent RFP (2023 All-Source) had a COD by the start of year 2026
- Only 8 conforming bids had a COD by December 31st, 2026

Based on the bids received, it appears that the market did not support a 2025 COD

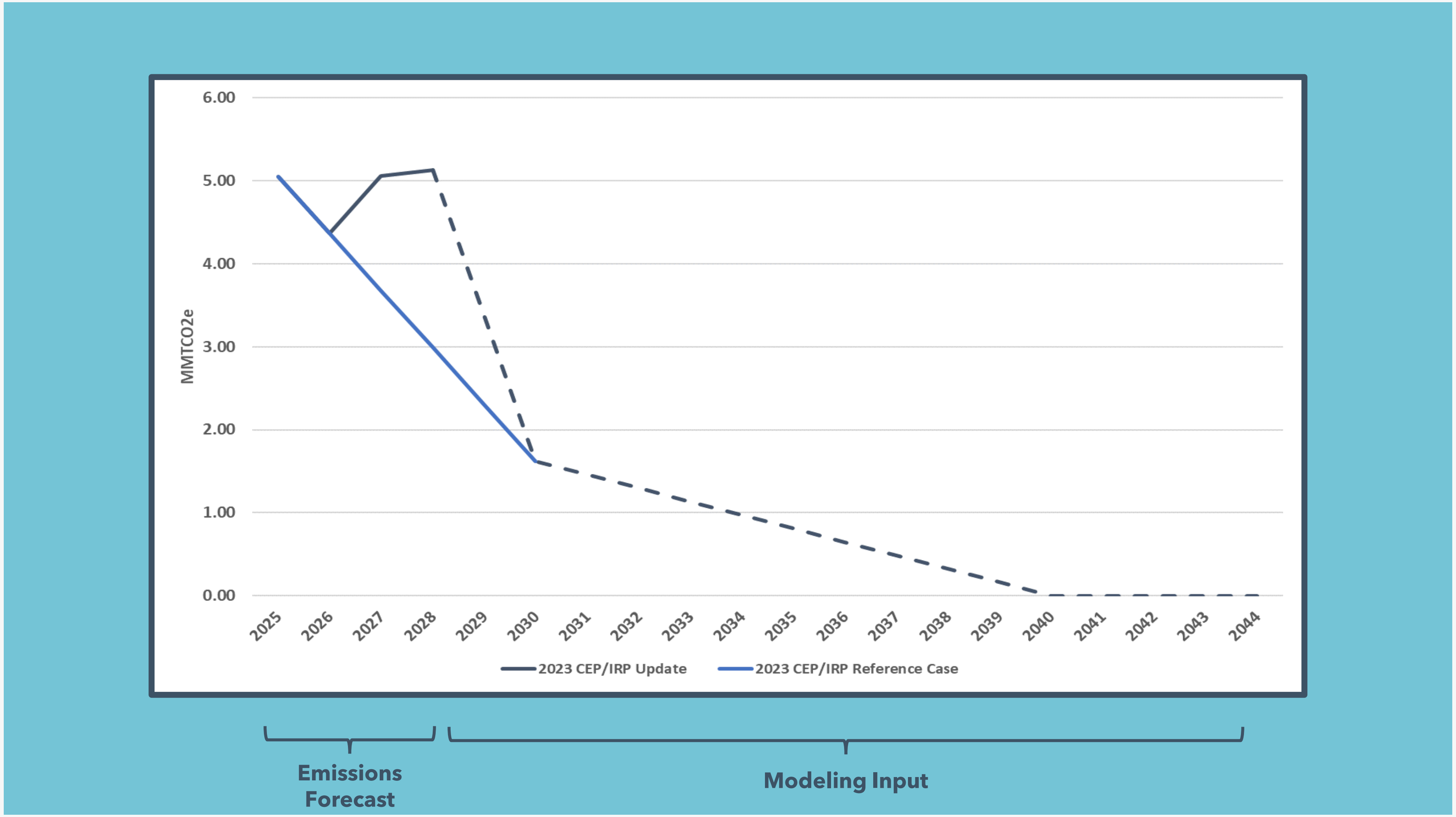
- Effectively, the 2023 CEP/IRP treated emissions in 2026-2027 as *inputs* rather than *forecasts*
- There is important load and weather uncertainty in those years, so actual emissions data might vary significantly
- However, under average expected conditions, emissions in those years are likely to be higher than what was forecasted in the 2023 CEP/IRP (due to the above lack of resource availability, the forecasted expiration of hydro contracts, and reductions in expected renewable resource procurement for calendar years 2026-2028)

The 2023 CEP/IRP Update will assume resources are available to be added in 2029 (COD by December 31st, 2028)

- Years 2025-2028 will have emission forecasts, years 2029-2044 will be modeling inputs

Hydro contract assumptions and load forecast have also been updated

Updated emissions forecast/modeling input



Transmission – Step 3 – Market Access

Seth Wiggins, PGE
EGPS

2023 CEP/IRP Transmission Modeling

PGE's geography necessitates an analysis with three components:

1. A characterization of the existing transmission system

How much transmission capacity is available to PGE today?

2. A characterization of the future transmission system

How much transmission capacity will be available to PGE when expected upgrades are made?

3. A description of actions PGE can take to increase transmission capacity for network load service

What can PGE do to bring more transmission capacity?

2023 CEP/IRP Transmission Modeling

PGE's geography necessitates an analysis with three components:

1. A characterization of the existing transmission system [Discussed at the July and October 2024 roundtables]

How much transmission capacity is available to PGE today?

2. A characterization of the future transmission system [Discussed at the September and October 2024 roundtables]

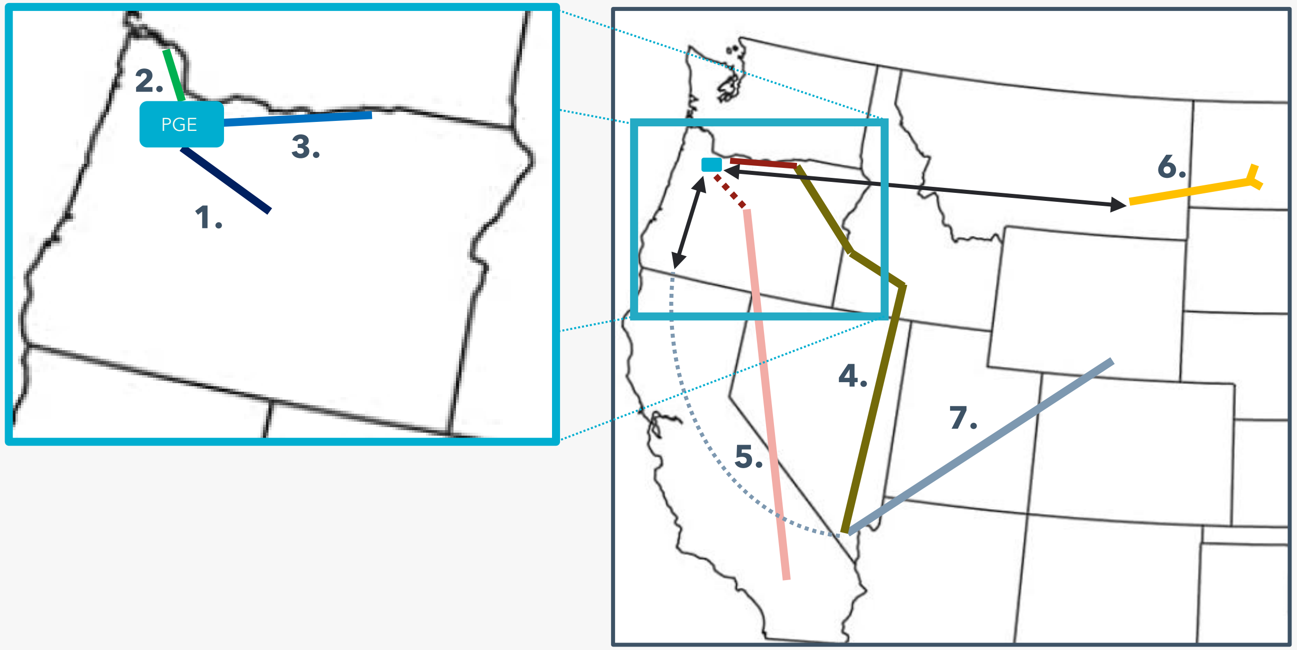
How much transmission capacity will be available to PGE when anticipated upgrades are made?

3. A description of actions PGE can take to increase transmission capacity for network load service [Discussed at the September and October 2024 roundtables and in part today]

What can PGE do to bring more transmission capacity?

2023 CEP/IRP Update Transmission Options

1.	Bethel-Round Butte
2.	Trojan-Harborton
3.	Cascade Renewable Transmission Project
4.	SWIP N + Gateway West 8 + B2H
5.	Western Bounty
6.	North Plains Connector
7.	TransWest Express



Transmission pathways and the differences in both color and patterns are described in the September Roundtable.

Each transmission option carries costs and benefits

Benefits	Example
Resource energy	Assumed MWh generation of Wyoming wind
Resource capacity contribution	Estimated Wyoming wind ELCC
Market access adequacy contribution	**Resource adequacy benefit of transmission capacity when Wyoming wind generation isn't available**
Costs	**Example**
Transmission build	Cost per mile per MW
Resource build	Wyoming wind resource cost
Market access	**Cost of market transactions that support reliability under constrained conditions**

PGE has engaged EGPS to estimate these two components

Market Liquidity Analysis for PGE

November 2024

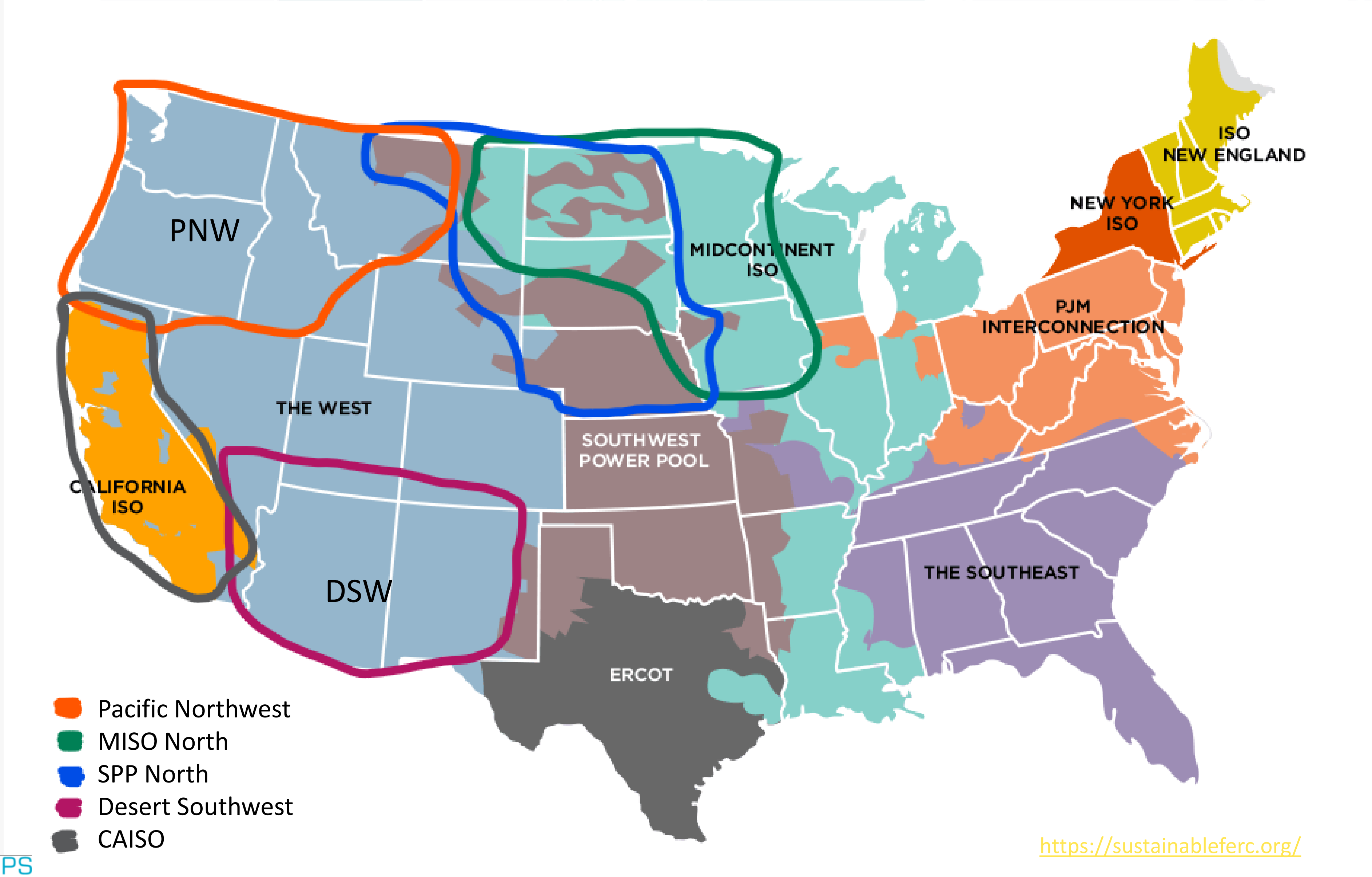
Outline

- Define vocabulary terms and geographical regions.
- Review EGPSC's mission and analytical approach.
- Review high-level conclusions and takeaways.
- Examine historical data.
- Examine forward production cost modeling results.

Vocabulary Terms

- **Pacific Northwest (PNW):** Oregon, Washington, parts of Idaho and Montana (map on next slide)
- **Desert Southwest (DSW):** Arizona, New Mexico, Nevada, parts of southern California
- **Net Load:** Load minus generation from wind and solar
- **Capacity Critical Hour (CCH):**
  - For the PNW, the 5% of hours in each year with the highest **net load**.
  - For PGE, the 5% of hours in each year with the highest **load**.
- **Implied Heat Rate:** Power price divided by gas price.
- **Net Qualifying Capacity (NQC):** Percentage of a generator's capacity that counts towards supply for the purposes of evaluating whether a region is meeting its planning reserve margin.
- **Planning Reserve Margin (PRM):** Target ratio of supply to demand in order for a region to be considered "reliable" under NERC standards.

Where Are We?



ENERGYGPS LLC

Mission and Approach

Mission	Approach
Evaluate reliability benefits to PGE of setting up an interconnection with SPP North or MISO North.	We looked at historical data in order to find the times of greatest scarcity in the PNW. We then looked at data from surrounding markets during those times, in order to see if they would have had energy available to send to the PNW.
Evaluate what it would take for the southwest region to have sufficient resources to provide imports to PGE at critical times in the future.	We used our production cost model (PCM) to calculate generator buildout for the Western US. We set rules for generator buildout: it has to keep the grid reliable, while adhering to certain policy goals such as no new thermal generation.

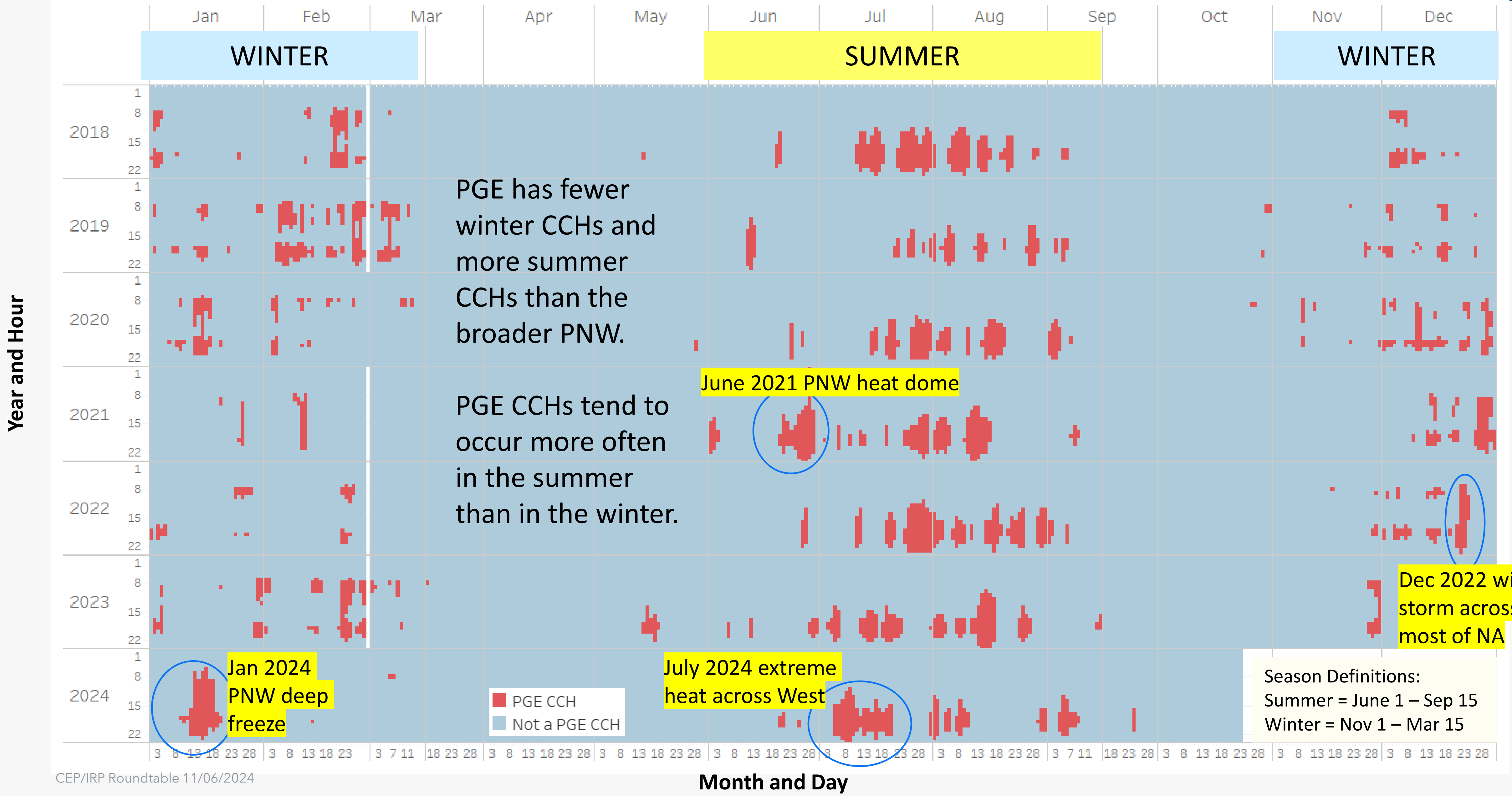
ENERGYGPS LLC

Takeaways and Conclusions

- **Conclusion #1:** If you build transmission to SPP or MISO, it is reasonable to assume that you will have access to energy and capacity during Capacity Critical Hours **in both the summer and the winter.**

- **Conclusion #2:** If you build transmission to the DSW or CAISO, it is reasonable to assume that you will have access to energy and capacity from the market during Capacity Critical Hours **in the winter.** Capacity in the summer will be less available.

When Do PGE CCHs Occur?

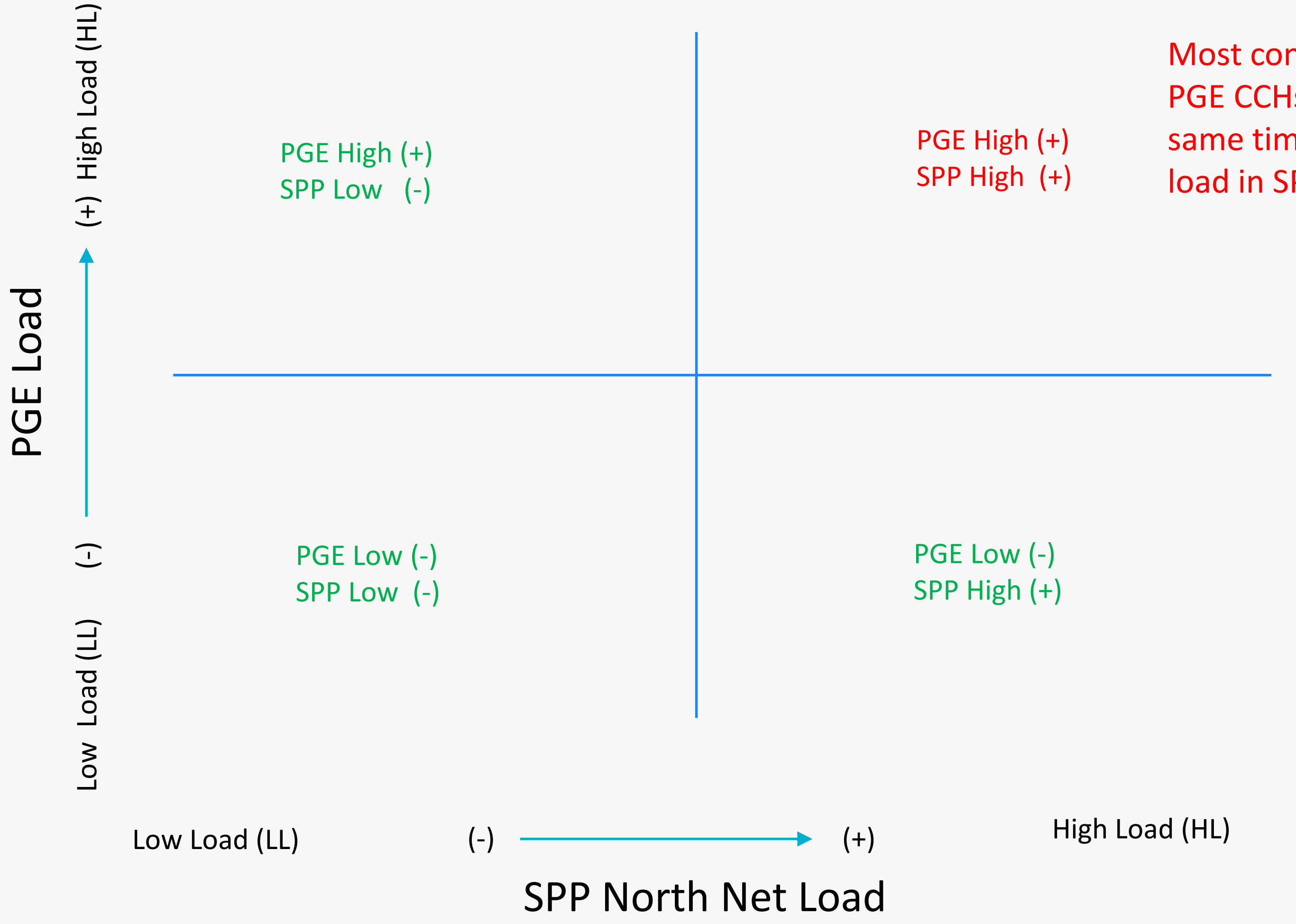


PGE has fewer winter CCHs and more summer CCHs than the broader PNW.

PGE CCHs tend to occur more often in the summer than in the winter.

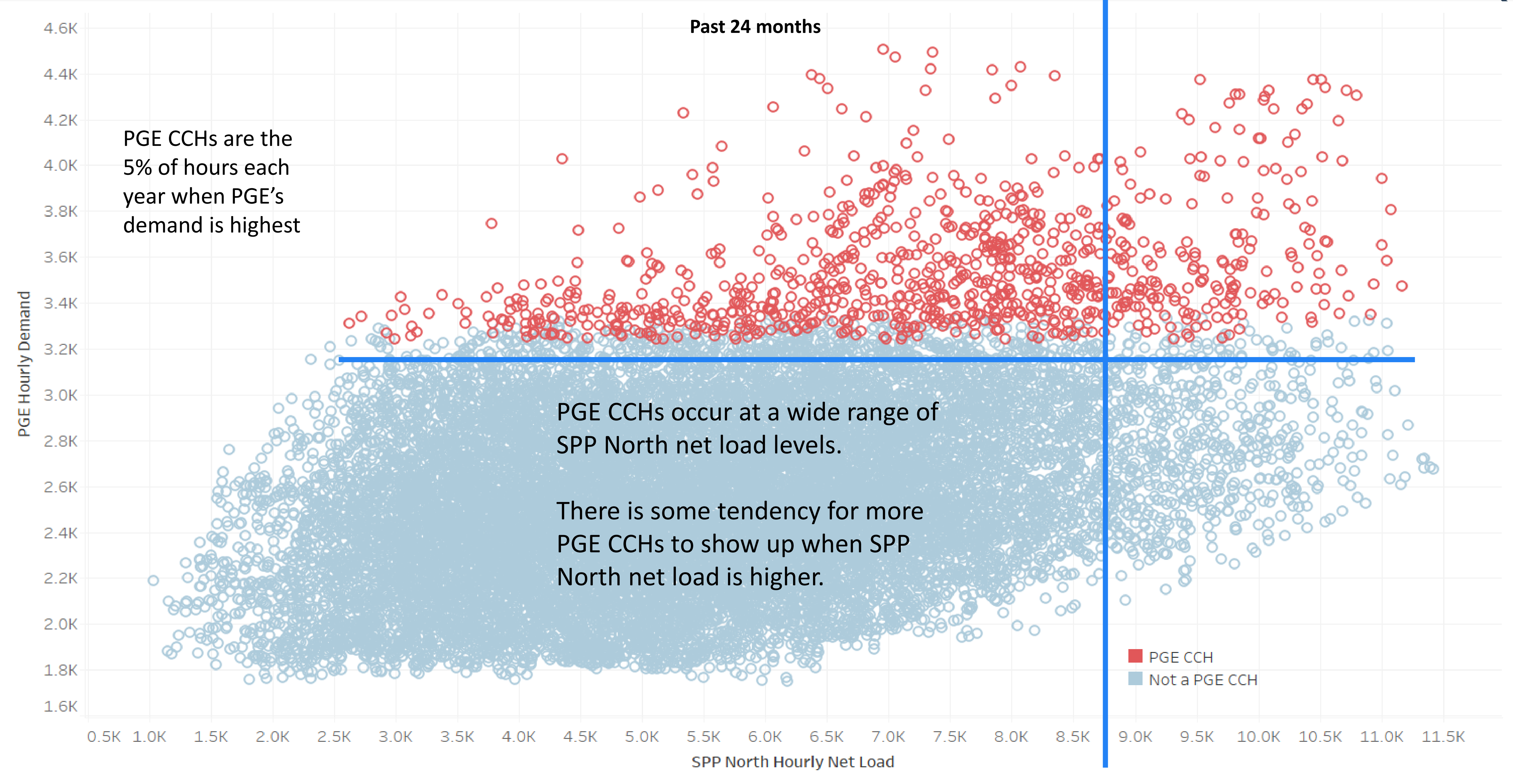
Season Definitions:
Summer = June 1 – Sep 15
Winter = Nov 1 – Mar 15

Load Relationship Scatter Plots

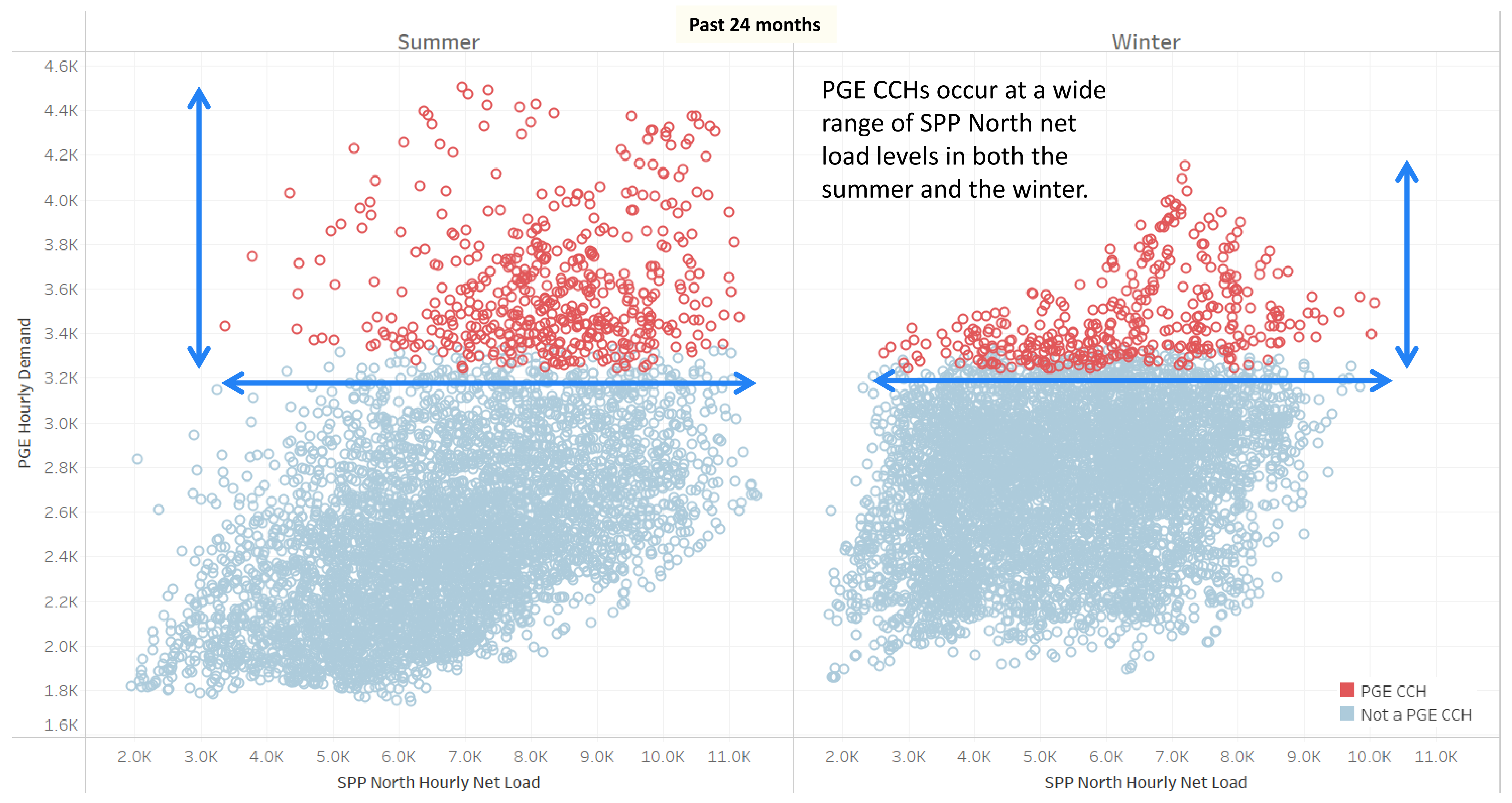


Most concerned when PGE CCHs occur at same time as high net load in SPP North

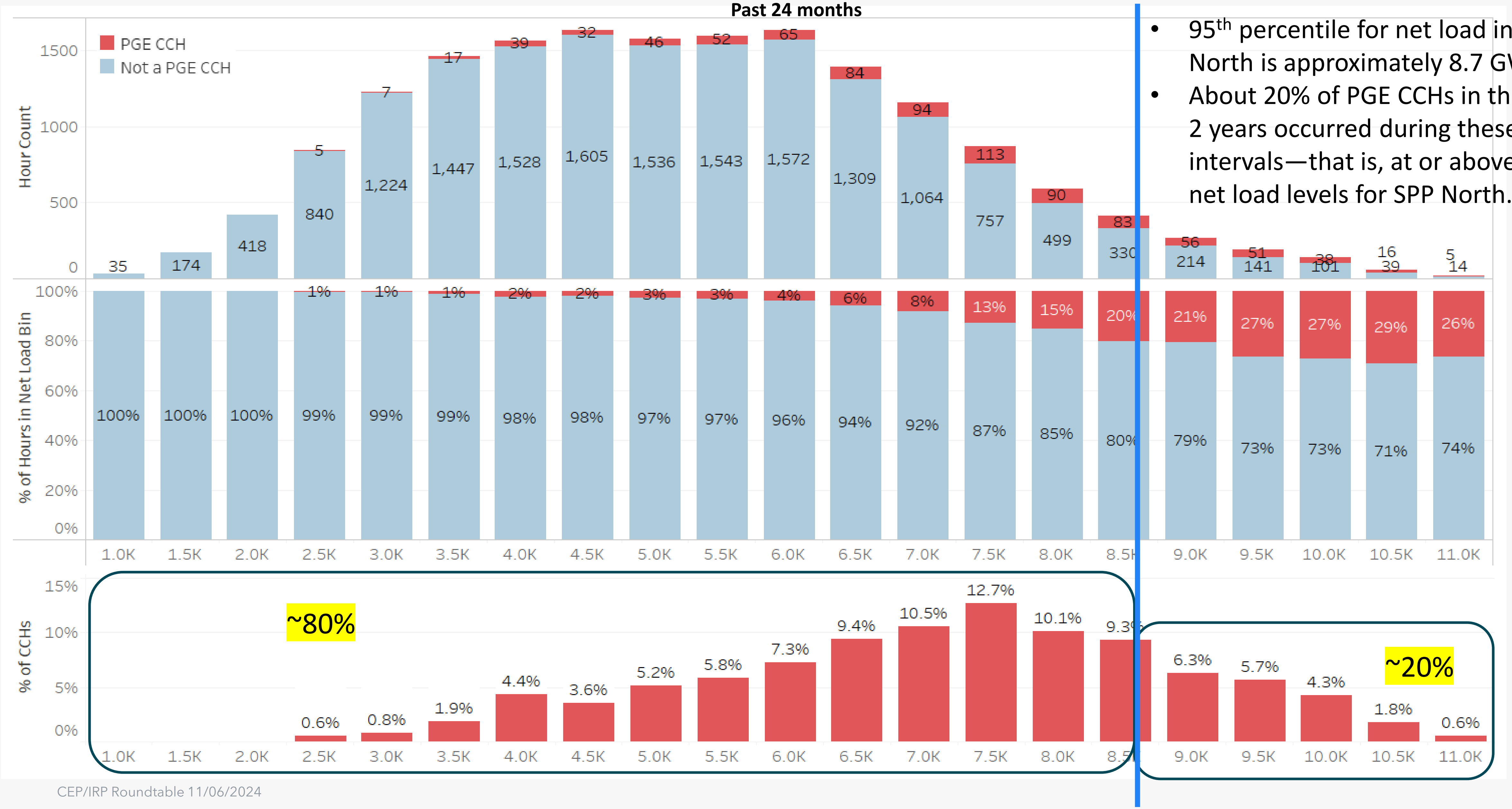
What's Happening in SPP



What's Happening in SPP – By Season

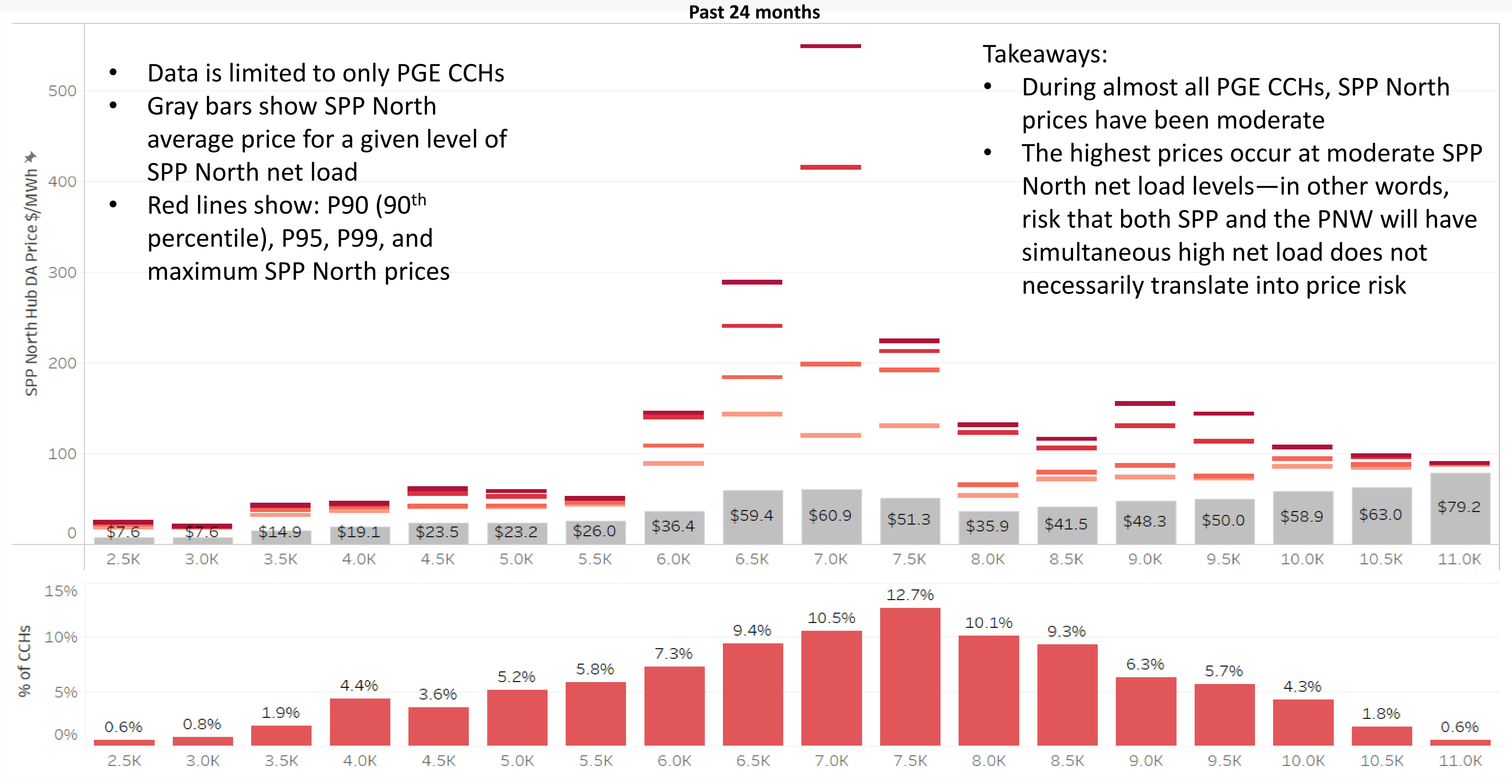


What's Happening in SPP



- 95th percentile for net load in SPP North is approximately 8.7 GW.
- About 20% of PGE CCHs in the past 2 years occurred during these intervals—that is, at or above P95 net load levels for SPP North.

What's Happening in SPP



- Data is limited to only PGE CCHs
- Gray bars show SPP North average price for a given level of SPP North net load
- Red lines show: P90 (90th percentile), P95, P99, and maximum SPP North prices

Takeaways:

- During almost all PGE CCHs, SPP North prices have been moderate
- The highest prices occur at moderate SPP North net load levels—in other words, risk that both SPP and the PNW will have simultaneous high net load does not necessarily translate into price risk

Takeaways and Conclusions

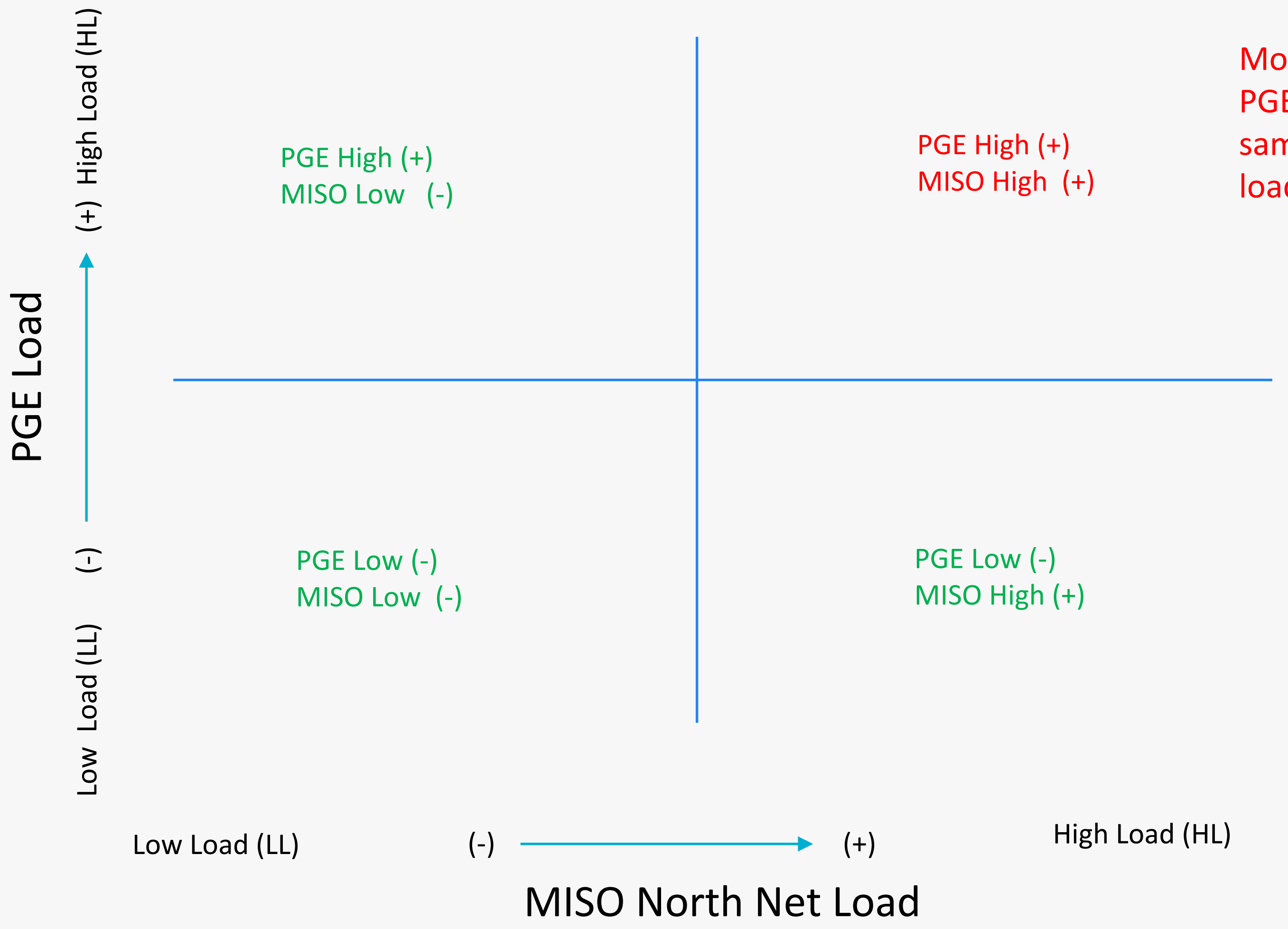
- If you build transmission to SPP, it is reasonable to assume that you will have access to energy and capacity during PGE's Capacity Critical Hours in both the summer and the winter.

- Historical data strongly indicates ample availability of supply in SPP North during ~80% of the times when demand is highest in PGE.

- Pricing in SPP when both (a) Capacity Critical Hour and (b) Top 5% of SPP Net Load Hours does not indicate acute shortage during those hours. Next steps would be to more deeply examine market conditions during these days.

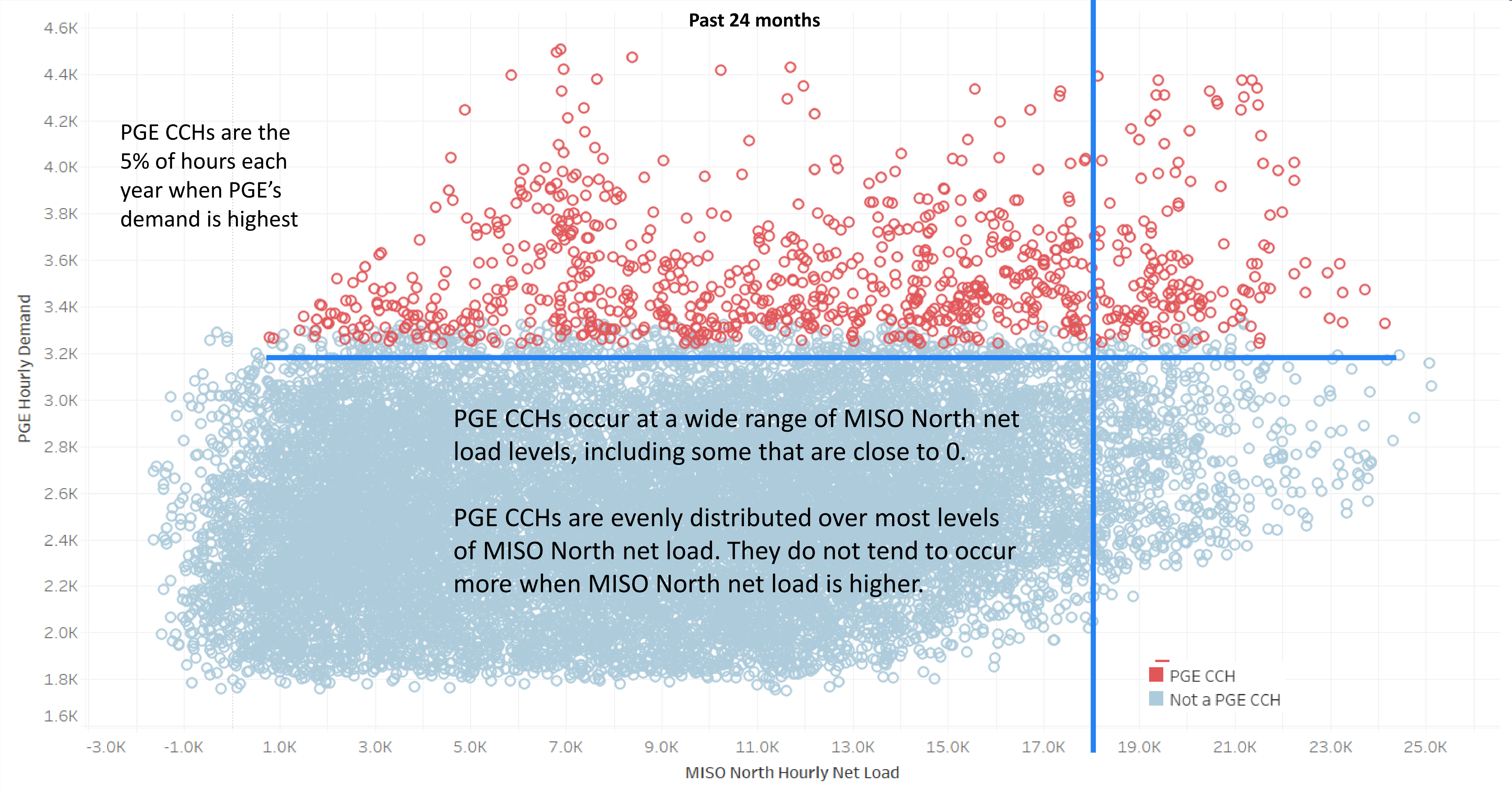
ENERGYGPS LLC

Load Relationship Scatter Plots

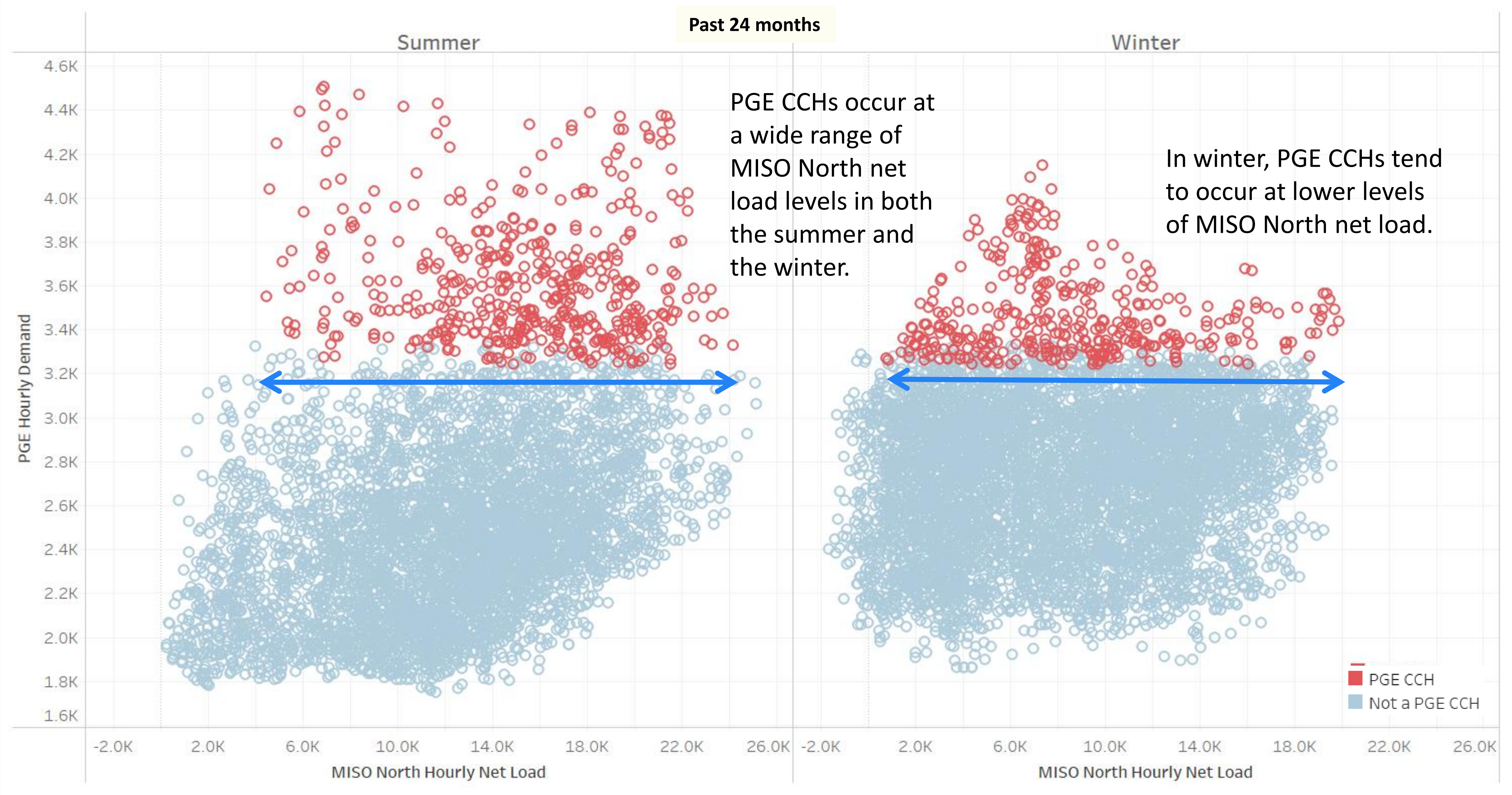


Most concerned when PGE CCHs occur at same time as high net load in MISO North

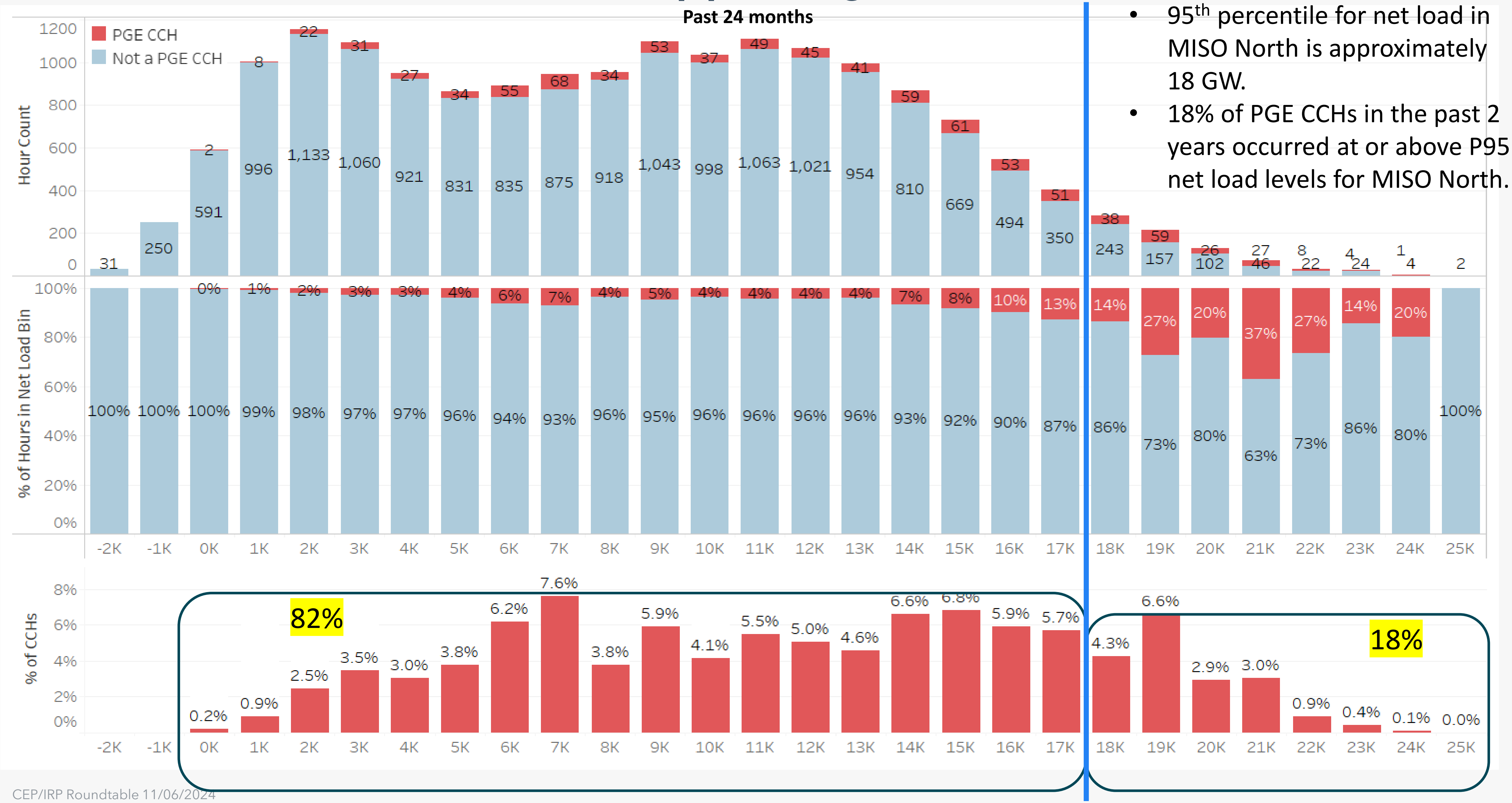
What's Happening in MISO



What's Happening in MISO – By Season



What's Happening in MISO



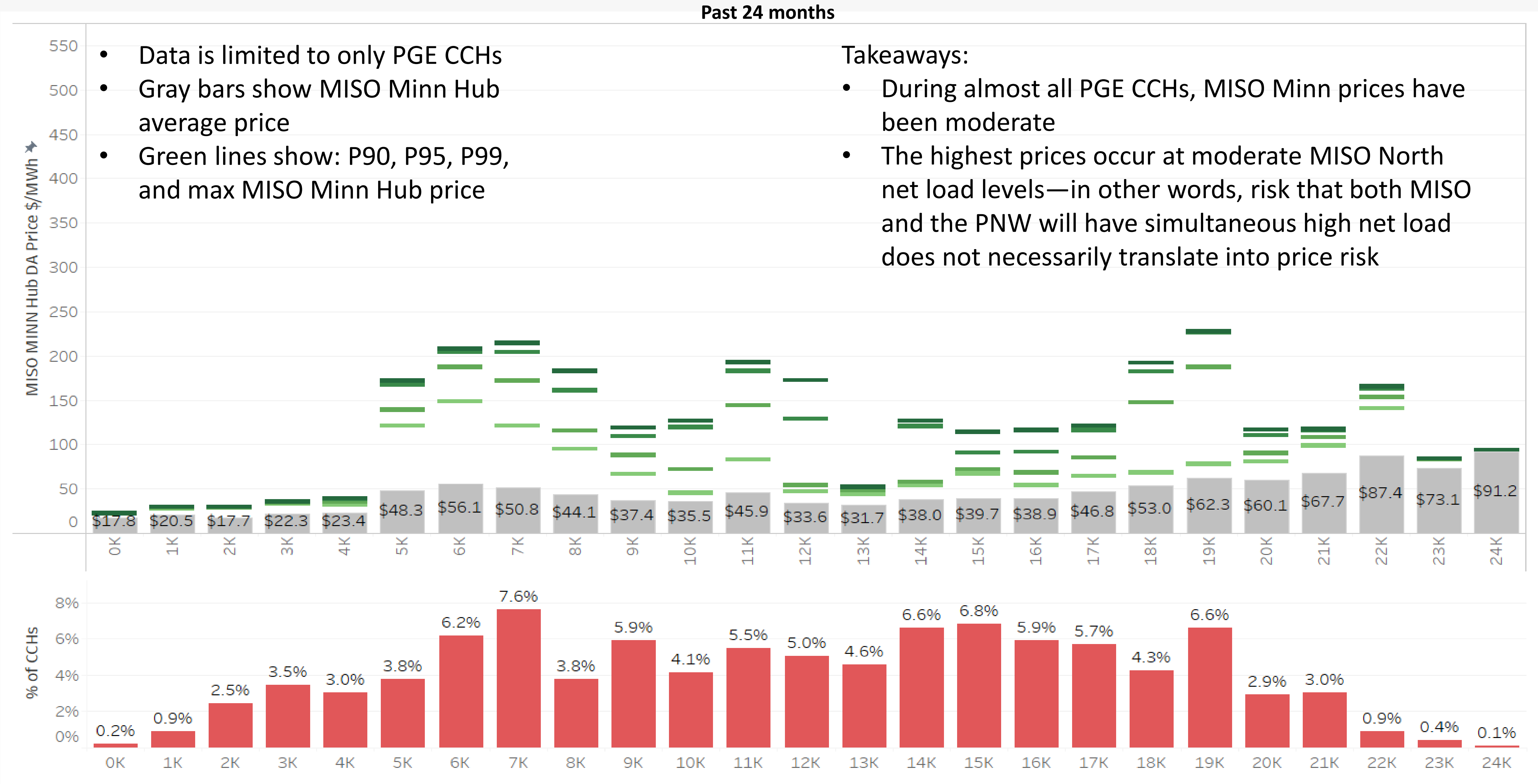
- 95th percentile for net load in MISO North is approximately 18 GW.
- 18% of PGE CCHs in the past 2 years occurred at or above P95 net load levels for MISO North.

What’s Happening in MISO

- Data is limited to only PGE CCHs
- Gray bars show MISO Minn Hub average price
- Green lines show: P90, P95, P99, and max MISO Minn Hub price

Takeaways:

- During almost all PGE CCHs, MISO Minn prices have been moderate
- The highest prices occur at moderate MISO North net load levels—in other words, risk that both MISO and the PNW will have simultaneous high net load does not necessarily translate into price risk



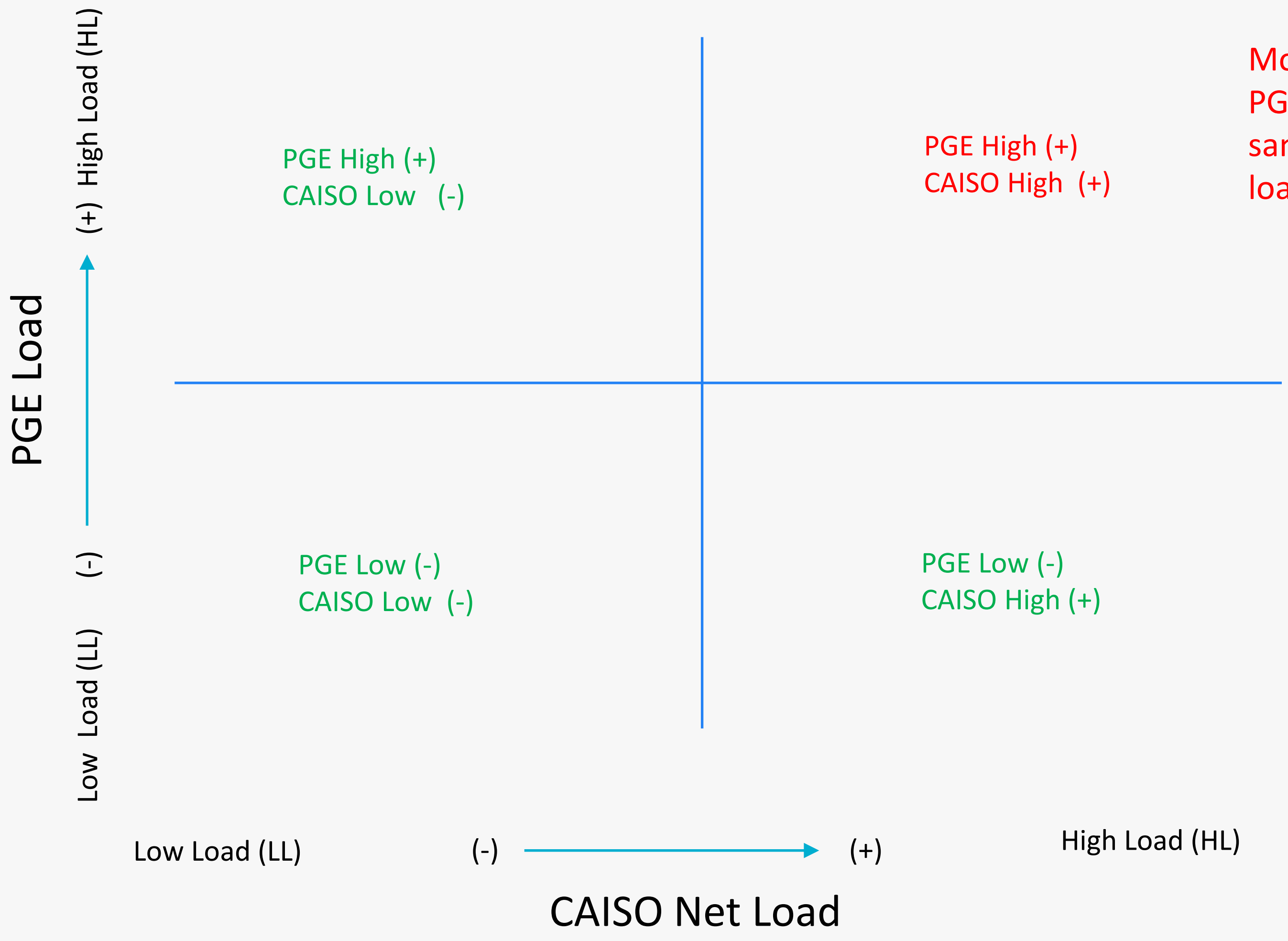
Takeaways and Conclusions

- If you build transmission to MISO, it is reasonable to assume that you will have access to energy and capacity during PGE's Capacity Critical Hours in both the summer and the winter.

- Historical data strongly indicates ample availability of supply in MISO North during ~80% of the times when demand is highest in PGE.

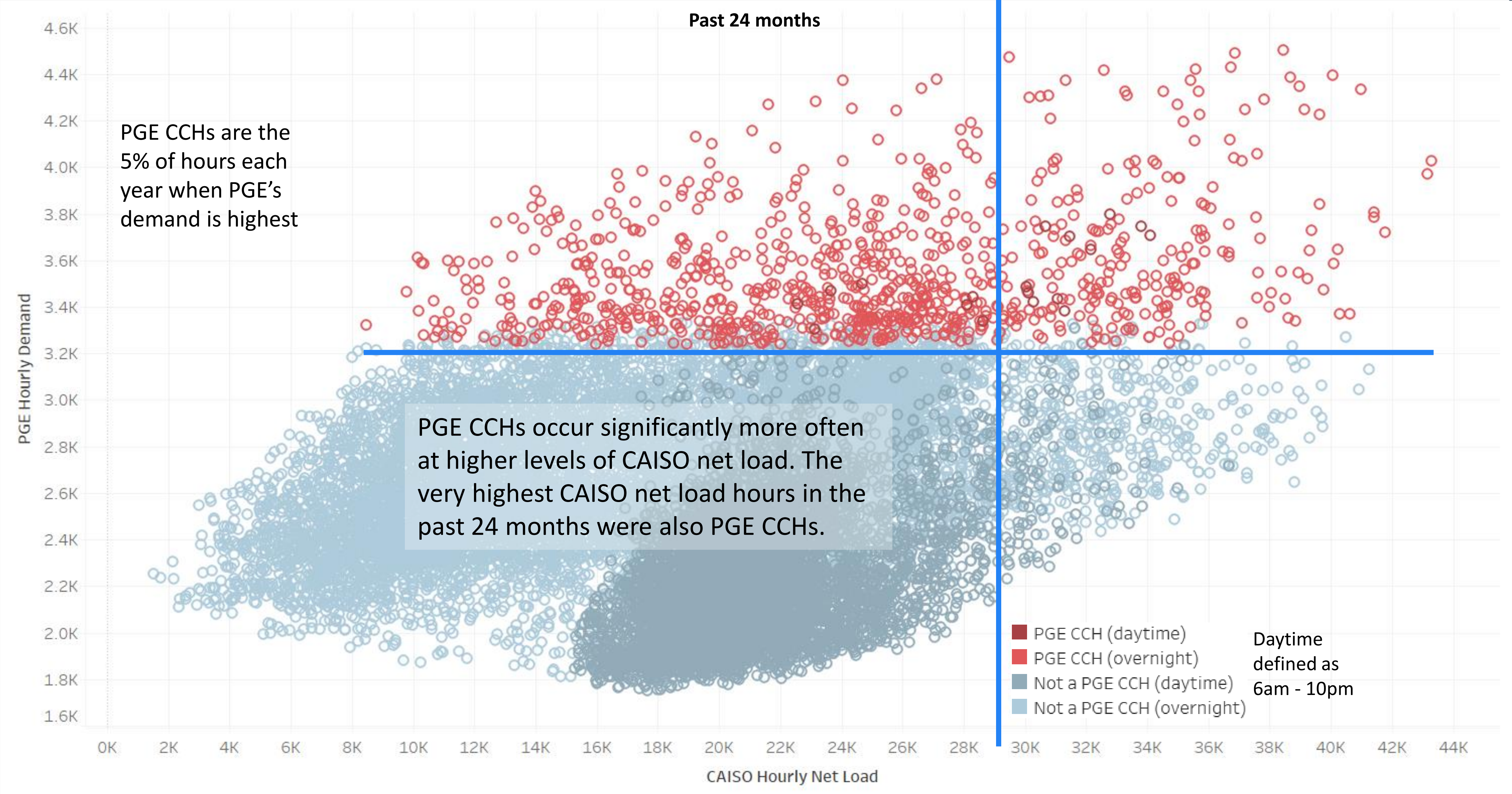
- Pricing in MISO when both (a) Capacity Critical Hour and (b) Top 5% of MISO Net Load Hours does not indicate acute shortage during those hours. Next steps would be to more deeply examine market conditions during these days.

Load Relationship Scatter Plots

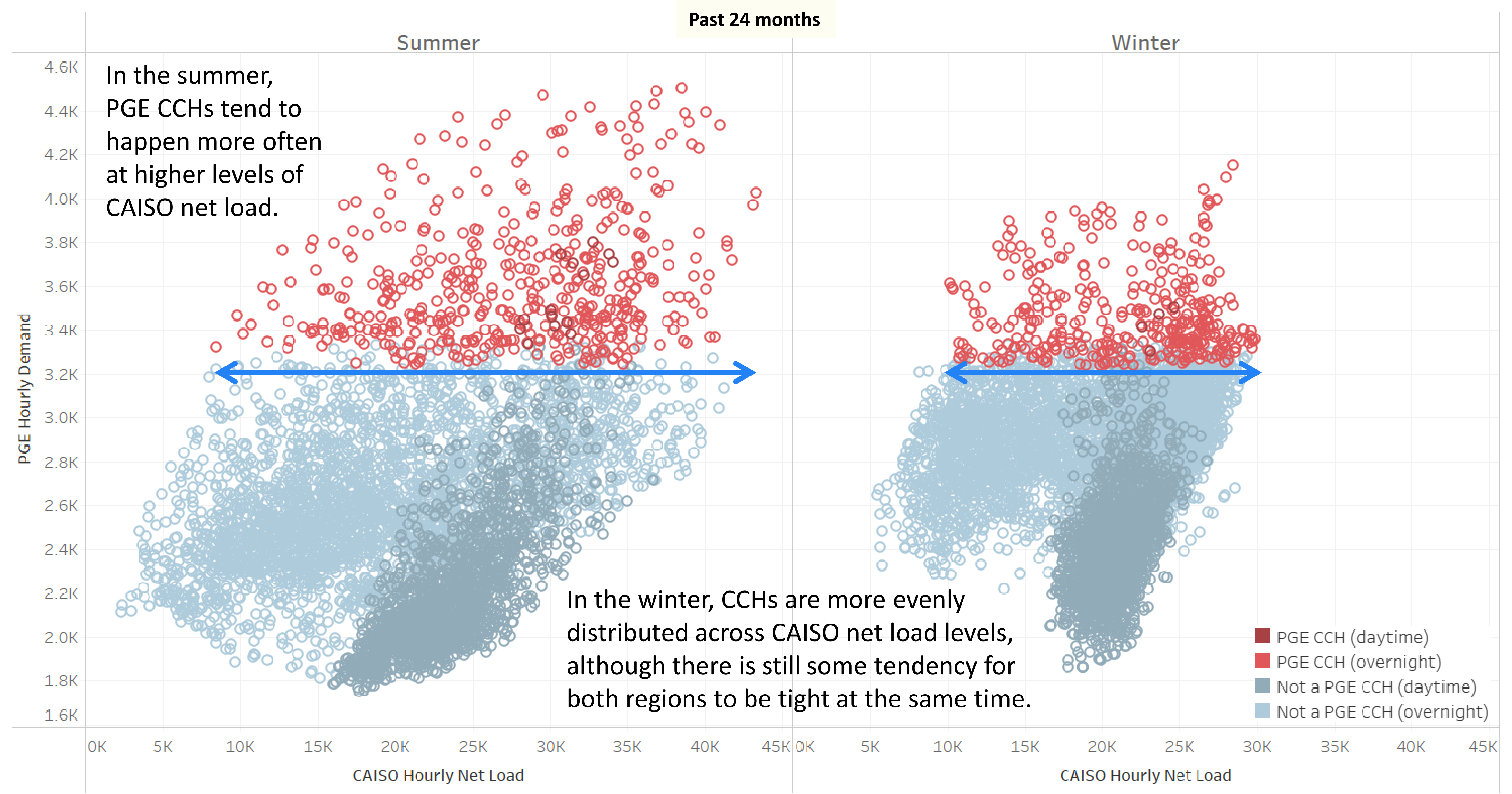


Most concerned when PGE CCHs occur at same time as high net load in CAISO

What's Happening in CAISO

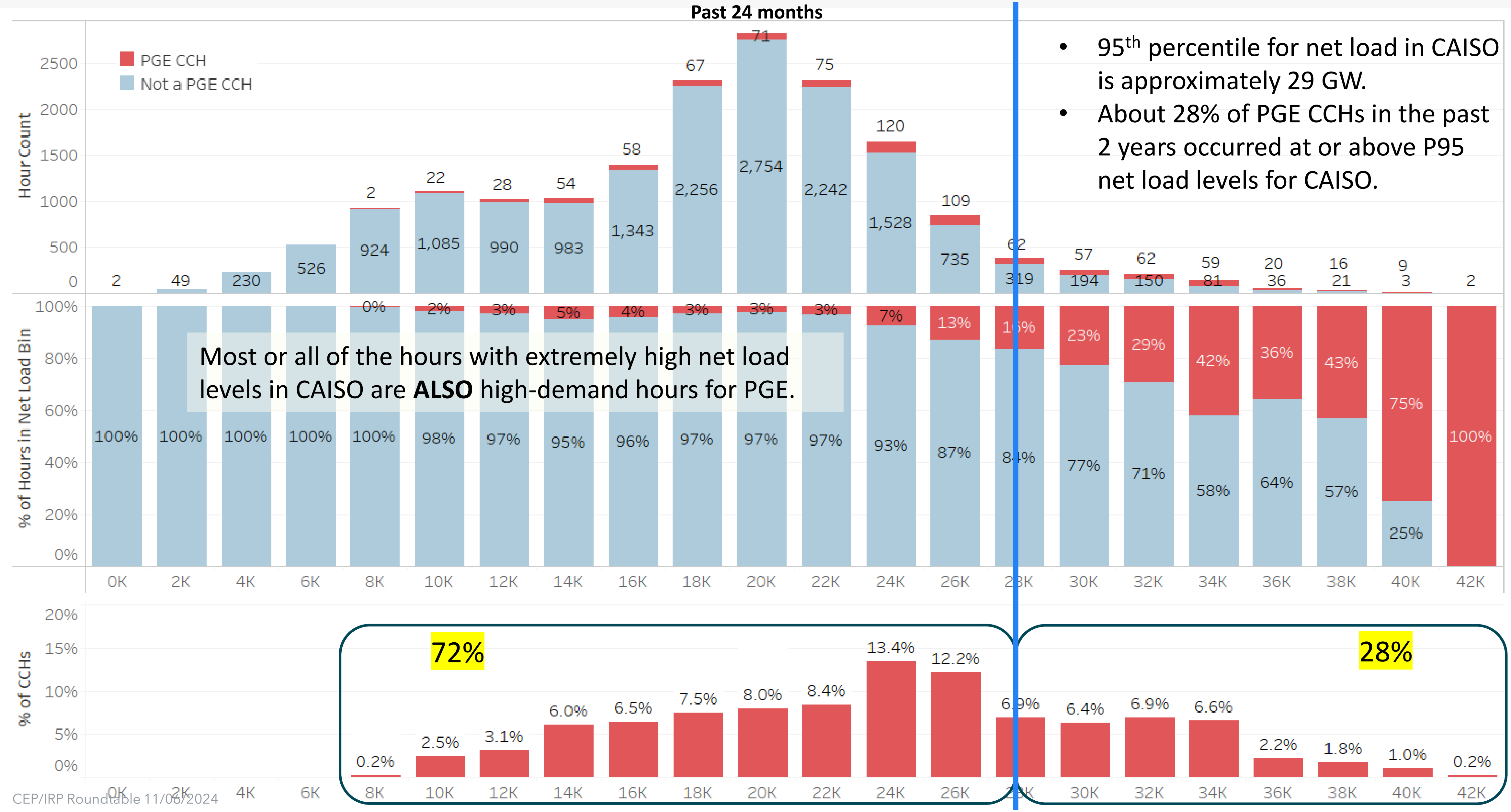


What's Happening in CAISO – By Season



CAISO

Past 24 months



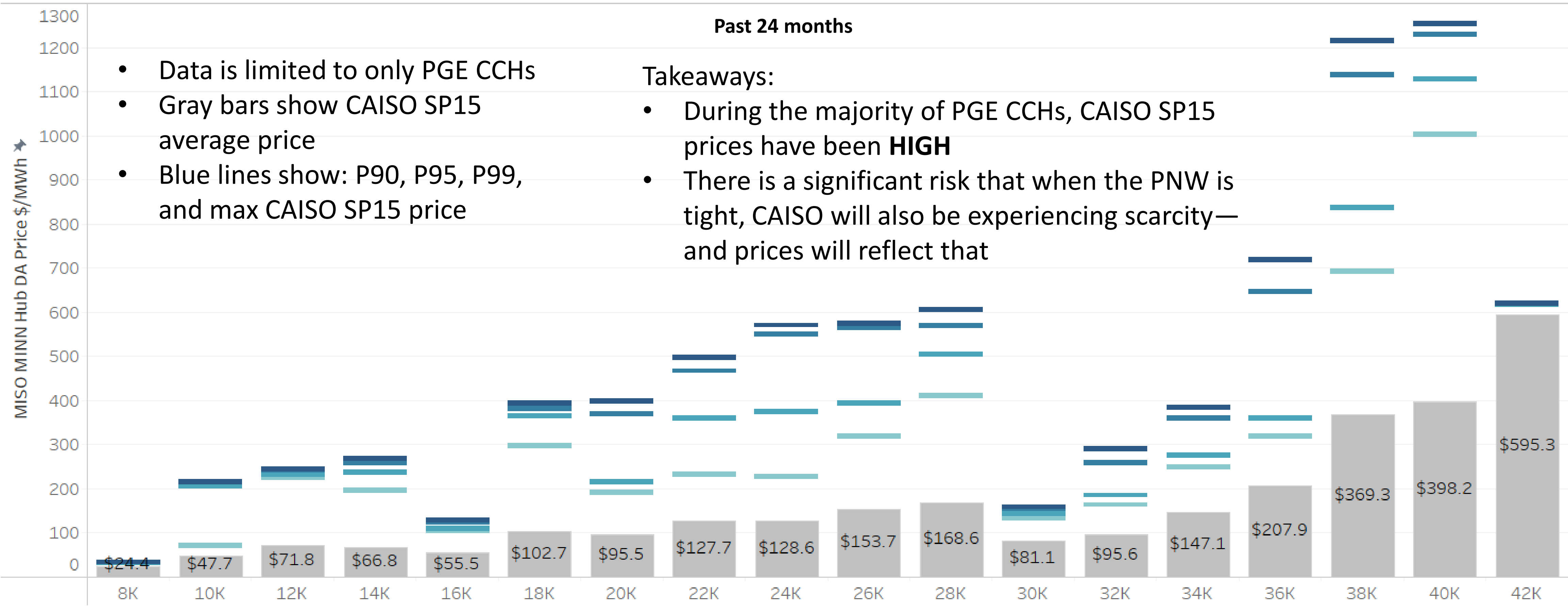
- 95th percentile for net load in CAISO is approximately 29 GW.
- About 28% of PGE CCHs in the past 2 years occurred at or above P95 net load levels for CAISO.

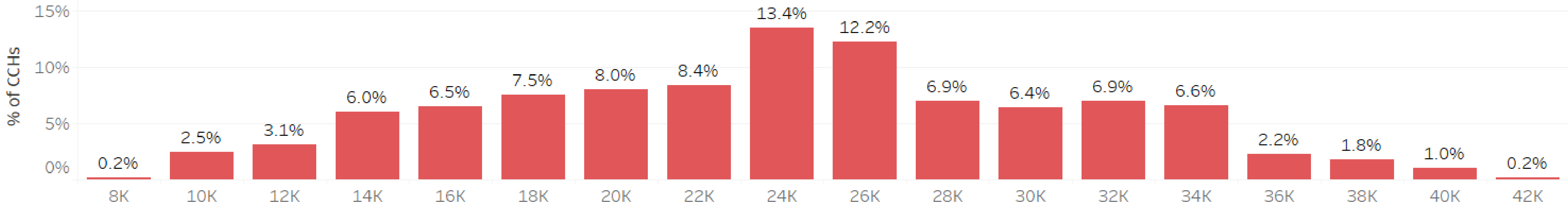
What’s Happening in CAISO

- Data is limited to only PGE CCHs
- Gray bars show CAISO SP15 average price
- Blue lines show: P90, P95, P99, and max CAISO SP15 price

Takeaways:

- During the majority of PGE CCHs, CAISO SP15 prices have been **HIGH**
- There is a significant risk that when the PNW is tight, CAISO will also be experiencing scarcity—and prices will reflect that





Takeaways and Conclusions

- If you build transmission to CAISO, it is reasonable to assume that you will have some access to energy and capacity during PGE's Capacity Critical Hours in the winter; the summer is less certain.

- Historical data indicates availability of supply in CAISO during ~70% of the times when demand is highest in PGE.

- Next steps would be to better understand what is going on during the remaining 30%.

Production Cost Model

CCH Forecast

Supply and Demand Forecast

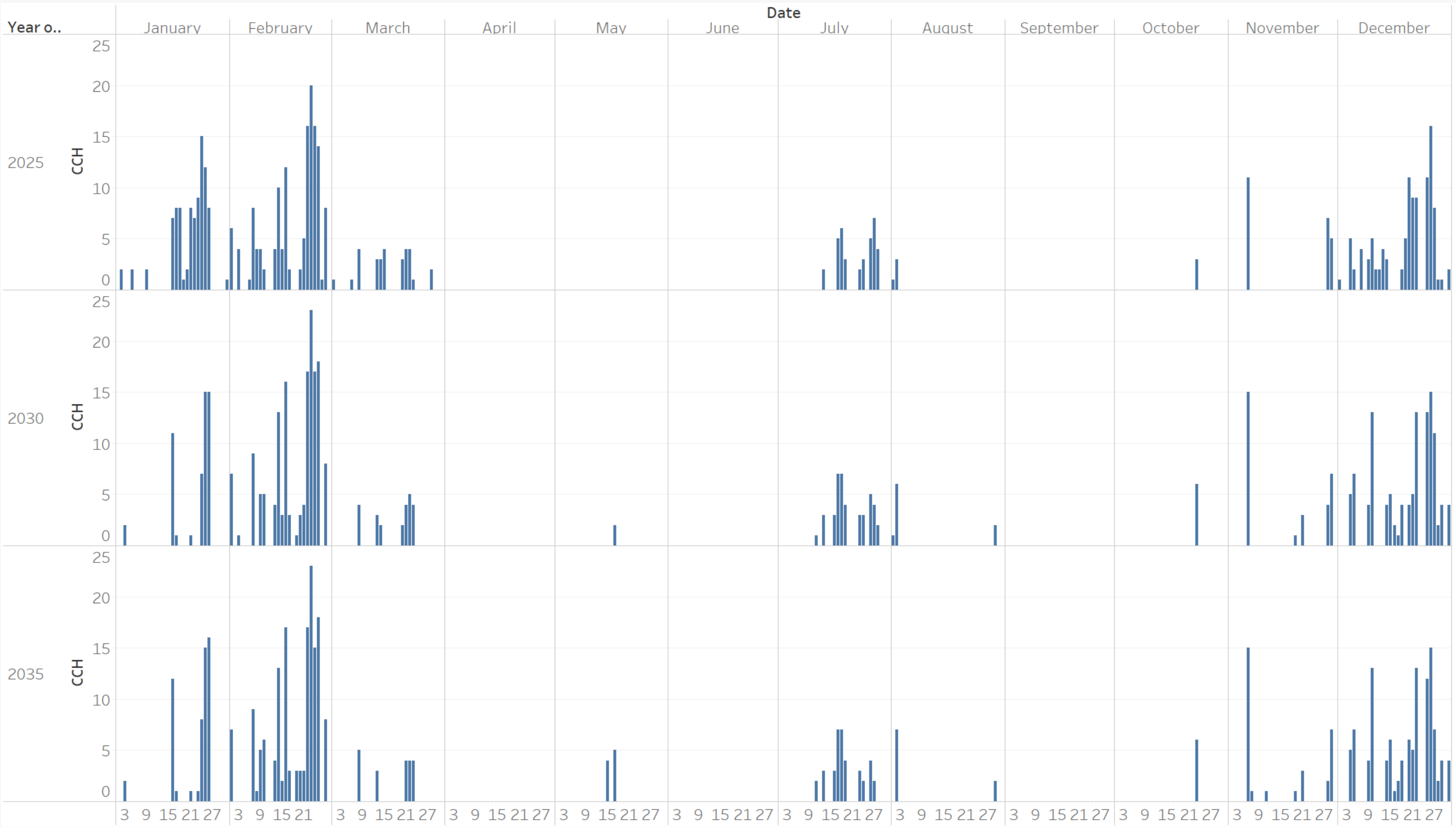
Production Cost Model Takeaways

- Production Cost Model used to forecast future CCH.
  - Forecast ran from 2025 to 2045 with hourly time steps.
  - Inputs used historical load and renewable hourly shapes with annual load growth rates applied to peak and average energy.
  - Forecasted CCH are consistent with historical observations of occurring in both winter and summer binding seasons with bias toward winter binding season.

- Production Cost Model used to estimate future export capability in CA and the DSW.
  - We forecast that by 2035 CA and the DSW will be tight (slightly below planning reserve margins) during the summer peak load month, however, will continue to be long during the winter binding season.
  - Our forecast shows up to 22.5 GW and 20 GW of available firm export capacity in CA and the DSW, respectively, in the winter binding season of 2035.

Capacity Critical Hours Forecast – Timing

- Graph shows number of CCHs during each day for 2025, 2030, 2035
- Like historical, CCHs are most common during the winter (Dec – Feb)



Capacity Critical Hours Forecast- Timing

PGE

Date

	2025												2030												2035											
Hour o..	Jan..	Febr..	Mar..	April	May	June	July	Aug..	Sep..	Oct..	Nov..	Dec..	Jan..	Febr..	Mar..	April	May	June	July	Aug..	Sep..	Oct..	Nov..	Dec..	Jan..	Febr..	Mar..	April	May	June	July	Aug..	Sep..	Oct..	Nov..	Dec..
0	0	4	0	0	0	0	0	0	0	0	0	1	2	6	0	0	0	0	0	0	0	0	0	3	2	6	0	0	0	0	0	0	0	0	1	3
1	0	3	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0
2	0	1	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0
6	0	2	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0
7	0	2	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
8	0	6	2	0	0	0	0	0	0	0	0	0	0	7	1	0	0	0	0	0	0	1	1	0	0	7	2	0	0	0	0	0	0	1	1	0
9	7	12	8	0	0	0	0	0	0	1	2	2	3	11	5	0	0	0	0	0	0	1	2	2	3	11	4	0	0	0	0	0	0	1	2	2
10	8	14	11	0	0	0	0	0	0	1	3	4	5	12	7	0	0	0	0	0	0	1	3	5	5	13	4	0	0	0	0	0	0	1	3	5
11	8	15	7	0	0	0	0	0	0	1	3	7	4	15	6	0	0	0	0	0	0	1	3	8	4	14	5	0	0	0	0	0	0	1	3	6
12	10	14	2	0	0	0	0	0	0	0	3	7	4	13	3	0	0	0	0	0	0	1	4	8	4	12	3	0	0	0	0	0	0	1	4	7
13	8	9	0	0	0	0	0	0	0	0	3	6	3	9	1	0	0	0	0	0	0	1	3	7	4	9	1	0	0	0	0	0	0	1	3	7
14	3	8	0	0	0	0	0	0	0	0	1	5	3	9	1	0	0	0	1	0	0	0	3	6	3	9	1	0	0	0	1	0	0	0	3	6
15	2	3	0	0	0	0	2	0	0	0	0	4	2	7	0	0	0	0	4	0	0	0	1	5	2	7	0	0	1	0	3	0	0	0	1	6
16	1	3	0	0	0	0	3	0	0	0	0	1	2	4	0	0	0	0	5	1	0	0	1	5	2	5	0	0	1	0	3	1	0	0	1	5
17	1	3	0	0	0	0	6	0	0	0	0	2	1	4	0	0	0	0	6	1	0	0	1	5	2	4	0	0	1	0	5	1	0	0	1	5
18	1	2	0	0	0	0	7	1	0	0	1	3	2	4	0	0	0	0	9	1	0	0	1	5	3	3	0	0	2	0	7	1	0	0	1	4
19	3	4	0	0	0	0	8	2	0	0	1	11	4	4	0	0	1	0	7	3	0	0	1	11	4	4	0	0	1	0	7	2	0	0	1	10
20	12	9	0	0	0	0	7	1	0	0	2	20	4	7	0	0	1	0	7	2	0	0	1	16	4	7	0	0	1	0	7	2	0	0	1	17
21	14	11	0	0	0	0	4	0	0	0	2	17	4	12	0	0	0	0	2	1	0	0	3	14	5	12	0	0	1	0	3	1	0	0	2	15
22	10	9	0	0	0	0	0	0	0	0	2	11	5	9	0	0	0	0	1	0	0	0	1	10	5	11	0	0	1	0	1	1	0	0	1	10
23	4	9	0	0	0	0	0	0	0	0	0	5	4	8	0	0	0	0	0	0	0	0	1	6	4	7	0	0	0	0	0	0	0	0	1	6

ENERGYGPS LLC

Annual Supply and Demand – DSW

PGE

- DSW meets **summer** requirements in 2025, becomes short in 2030, 2035
- Additions are:
  - 6.6 GW Wind
  - 12.8 GW Solar
  - 11.4 GW Storage
- This is for summer; a monthly view shows excess capacity available for export in winter

DSW	2025	2030	2035
Peak Load (MW)	**34,865**	**39,330**	**42,400**
Load (MWa)	**17,489**	**20,445**	**22,611**
Installed Capacity (MW)	**58,617**	**72,736**	**84,352**
Gas	25,099	23,662	23,917
Coal	4,952	4,049	1,225
Nuclear	3,937	3,937	3,937
Water	5,893	5,893	5,893
Wind	4,822	7,697	11,424
Solar	9,881	17,293	22,664
Storage	2,949	9,247	14,336
Geo	671	671	671
Other	412	285	285
NQC (MW)	**42,611**	**46,675**	**49,707**
Gas	23,418	22,077	22,314
Coal	4,457	3,644	1,103
Nuclear	3,858	3,858	3,858
Water	5,009	5,009	5,009
Wind	1,013	1,616	2,319
Solar	1,562	2,231	2,794
Storage	2,359	7,398	11,469
Geo	631	631	631
Other	304	210	210
Net Firm Imports (MW)	(2,000)	(2,000)	(2,000)
PRM (%)	12.1%	14.7%	14.7%
Capacity Requirement (MW) = Peak Load + PRM	39,084	45,112	48,633
Available Capacity (MW) = NQC + Net Firm Imports	40,611	44,675	47,707
Supply/Demand Balance (MW) = Available - Required Capacity (MW)	1,527	(437)	(926)
Supply/Demand Balance (%) = Balance /Requirement	3.9%	-1.0%	-1.9%
Effective PRM (%) = Available Capacity/Peak Load - 1	16.5%	13.6%	12.5%

August

ENERGYGPS LLC

2035 Monthly Supply and Demand – DSW

DSW	1	2	3	4	5	6	7	8	9	10	11	12
Peak Load (MW)	**24,861**	**25,745**	**24,747**	**27,085**	**32,935**	**36,780**	**39,832**	**42,400**	**39,055**	**30,290**	**23,086**	**24,610**
Load (MWa)	**19,902**	**19,879**	**19,488**	**19,987**	**22,258**	**25,445**	**28,985**	**30,000**	**25,028**	**20,760**	**19,172**	**20,138**
Installed Capacity (MW)	**86,043**	**86,043**	**86,043**	**86,043**	**86,043**	**84,352**	**84,352**	**84,352**	**84,352**	**86,043**	**86,043**	**86,043**
Gas	25,332	25,332	25,332	25,332	25,332	23,917	23,917	23,917	23,917	25,332	25,332	25,332
Coal	1,226	1,226	1,226	1,226	1,226	1,225	1,225	1,225	1,225	1,226	1,226	1,226
Nuclear	4,003	4,003	4,003	4,003	4,003	3,937	3,937	3,937	3,937	4,003	4,003	4,003
Water	5,893	5,893	5,893	5,893	5,893	5,893	5,893	5,893	5,893	5,893	5,893	5,893
Wind	11,424	11,424	11,424	11,424	11,424	11,424	11,424	11,424	11,424	11,424	11,424	11,424
Solar	22,665	22,665	22,665	22,665	22,665	22,664	22,664	22,664	22,664	22,665	22,665	22,665
Storage	14,336	14,336	14,336	14,336	14,336	14,336	14,336	14,336	14,336	14,336	14,336	14,336
Geo	878	878	878	878	878	671	671	671	671	878	878	878
Other	285	285	285	285	285	285	285	285	285	285	285	285
NQC (MW)	**51,288**	**51,288**	**51,288**	**51,288**	**51,288**	**49,707**	**49,707**	**49,707**	**49,707**	**51,288**	**51,288**	**51,288**
Gas	23,634	23,634	23,634	23,634	23,634	22,314	22,314	22,314	22,314	23,634	23,634	23,634
Coal	1,104	1,104	1,104	1,104	1,104	1,103	1,103	1,103	1,103	1,104	1,104	1,104
Nuclear	3,923	3,923	3,923	3,923	3,923	3,858	3,858	3,858	3,858	3,923	3,923	3,923
Water	5,009	5,009	5,009	5,009	5,009	5,009	5,009	5,009	5,009	5,009	5,009	5,009
Wind	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319
Solar	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794
Storage	11,469	11,469	11,469	11,469	11,469	11,469	11,469	11,469	11,469	11,469	11,469	11,469
Geo	825	825	825	825	825	631	631	631	631	825	825	825
Other	211	211	211	211	211	210	210	210	210	211	211	211
Net Firm Imports (MW)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)
PRM (%)	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%
Capacity Requirement (MW) = Peak Load + PRM	28,516	29,529	28,385	31,066	37,777	42,186	45,688	48,633	44,796	34,742	26,479	28,227
Available Capacity (MW) = NQC + Net Firm Imports	49,288	49,288	49,288	49,288	49,288	47,707	47,707	47,707	47,707	49,288	49,288	49,288
Supply/Demand Balance (MW) = Available - Required Capacity (MW)	20,772	19,759	20,903	18,222	11,512	5,521	2,019	(926)	2,912	14,546	22,809	21,061
Supply/Demand Balance (%) = Balance /Requirement	72.8%	66.9%	73.6%	58.7%	30.5%	13.1%	4.4%	-1.9%	6.5%	41.9%	86.1%	74.6%
Effective PRM (%) = Available Capacity/Peak Load - 1	98.3%	91.4%	99.2%	82.0%	49.7%	29.7%	19.8%	12.5%	22.2%	62.7%	113.5%	100.3%

Nearly 20 GW available capacity to export in shortest winter month; short in summer.

Takeaways and Conclusions

- Large additions of solar and storage are required to meet policy goals and maintain reliability in the DSW.

- We forecast that by 2035, the DSW will be tight during the summer, but have extra supply in the winter.

- It is reasonable to assume that the PNW will be able to obtain energy/capacity from the DSW in the winter.

- Relying on imports from the DSW in the summer would require securing resource(s) in advance.

ENERGYGPS LLC

Annual Supply and Demand – CAISO

PGE

- CAISO meets **summer** requirements in 2025 and 2030, becomes short in 2035
- Additions are:
  - 13.8 GW Wind
  - 27.3 GW Solar
  - 20.0 GW Storage
- This is for summer; a monthly view shows excess capacity available for export in winter

CISO	2025	2030	2035
Peak Load (MW)	**46,357**	**48,716**	**54,858**
Load (MWa)	**24,658**	**26,677**	**31,117**
Installed Capacity (MW)	**79,411**	**103,218**	**138,356**
Gas	26,293	26,291	26,291
Coal	57	57	57
Nuclear	2,240	-	-
Water	6,532	6,532	6,532
Wind	6,990	13,469	20,867
Solar	21,842	31,325	49,144
Storage	11,207	21,300	31,222
Geo	1,453	1,453	1,453
Other	2,796	2,792	2,790
NQC (MW)	**49,354**	**52,182**	**57,517**
Gas	25,504	25,502	25,502
Coal	51	51	51
Nuclear	2,240	-	-
Water	4,180	4,180	4,180
Wind	909	1,751	2,713
Solar	1,811	2,362	2,912
Storage	11,229	14,910	18,733
Geo	1,366	1,366	1,366
Other	2,064	2,060	2,059
Net Firm Imports (MW)	5,500	5,500	5,500
PRM (%)	17.0%	17.0%	17.0%
Capacity Requirement (MW) = Peak Load + PRM	54,237	56,997	64,184
Available Capacity (MW) = NQC + Net Firm Imports	54,854	57,682	63,017
Supply/Demand Balance (MW) = Available - Required Capacity (MW)	616	685	(1,167)
Supply/Demand Balance (%) = Balance /Requirement	1.1%	1.2%	-1.8%
Effective PRM (%) = Available Capacity/Peak Load - 1	18.3%	18.4%	14.9%

August

ENERGYGPS LLC

2035 Monthly Supply and Demand – CAISO

CISO	1	2	3	4	5	6	7	8	9	10	11	12
Peak Load (MW)	**34,714**	**34,479**	**33,851**	**35,010**	**43,256**	**48,823**	**51,299**	**54,858**	**52,756**	**42,844**	**35,326**	**35,629**
Load (MWa)	**28,901**	**28,351**	**27,914**	**27,538**	**29,327**	**32,378**	**36,480**	**37,818**	**34,320**	**31,148**	**29,130**	**29,795**
Installed Capacity (MW)	**139,591**	**139,591**	**139,591**	**139,591**	**139,591**	**138,356**	**138,356**	**138,356**	**138,356**	**139,591**	**139,591**	**139,591**
Gas	27,397	27,397	27,397	27,397	27,397	26,291	26,291	26,291	26,291	27,397	27,397	27,397
Coal	57	57	57	57	57	57	57	57	57	57	57	57
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-
Water	6,536	6,536	6,536	6,536	6,536	6,532	6,532	6,532	6,532	6,536	6,536	6,536
Wind	20,868	20,868	20,868	20,868	20,868	20,867	20,867	20,867	20,867	20,868	20,868	20,868
Solar	49,145	49,145	49,145	49,145	49,145	49,144	49,144	49,144	49,144	49,145	49,145	49,145
Storage	31,222	31,222	31,222	31,222	31,222	31,222	31,222	31,222	31,222	31,222	31,222	31,222
Geo	1,541	1,541	1,541	1,541	1,541	1,453	1,453	1,453	1,453	1,541	1,541	1,541
Other	2,826	2,826	2,826	2,826	2,826	2,790	2,790	2,790	2,790	2,826	2,826	2,826
NQC (MW)	**58,701**	**58,701**	**58,701**	**58,701**	**58,701**	**57,517**	**57,517**	**57,517**	**57,517**	**58,701**	**58,701**	**58,701**
Gas	26,575	26,575	26,575	26,575	26,575	25,502	25,502	25,502	25,502	26,575	26,575	26,575
Coal	51	51	51	51	51	51	51	51	51	51	51	51
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-
Water	4,183	4,183	4,183	4,183	4,183	4,180	4,180	4,180	4,180	4,183	4,183	4,183
Wind	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713
Solar	2,912	2,912	2,912	2,912	2,912	2,912	2,912	2,912	2,912	2,912	2,912	2,912
Storage	18,733	18,733	18,733	18,733	18,733	18,733	18,733	18,733	18,733	18,733	18,733	18,733
Geo	1,448	1,448	1,448	1,448	1,448	1,366	1,366	1,366	1,366	1,448	1,448	1,448
Other	2,086	2,086	2,086	2,086	2,086	2,059	2,059	2,059	2,059	2,086	2,086	2,086
Net Firm Imports (MW)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500
PRM (%)	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%
Capacity Requirement (MW) = Peak Load + PRM	40,616	40,340	39,606	40,962	50,610	57,123	60,020	64,184	61,725	50,127	41,331	41,686
Available Capacity (MW) = NQC + Net Firm Imports	64,201	64,201	64,201	64,201	64,201	63,017	63,017	63,017	63,017	64,201	64,201	64,201
Supply/Demand Balance (MW) = Available - Required Capacity (MW)	23,586	23,861	24,595	23,239	13,591	5,894	2,996	(1,167)	1,292	14,074	22,870	22,515
Supply/Demand Balance (%) = Balance /Requirement	58.1%	59.1%	62.1%	56.7%	26.9%	10.3%	5.0%	-1.8%	2.1%	28.1%	55.3%	54.0%
Effective PRM (%) = Available Capacity/Peak Load - 1	84.9%	86.2%	89.7%	83.4%	48.4%	29.1%	22.8%	14.9%	19.4%	49.8%	81.7%	80.2%

22.5 GW available capacity to export in shortest winter month; short in summer.

Takeaways and Conclusions

- Large additions of solar and storage are required to meet policy goals and maintain reliability in CAISO.
- We forecast that by 2035, CAISO will be tight during the summer, but have extra supply in the winter.
- It is reasonable to assume that the PNW will be able to obtain energy/capacity from CAISO in the winter.
- Relying on imports from the CAISO in the summer would require securing resource(s) in advance.

Appendix

Takeaways and Conclusions

- Interconnecting to SPP, MISO, or both would have reliability benefits for PGE.
  - Tight conditions in SPP North and MISO North have very little correlation with tight conditions in the PNW, or in PGE specifically.
  - Wind production in SPP North and MISO North has very little correlation with wind production in the PNW.
  - Furthermore, PGE is a small system relative to SPP or MISO. Adding a few hundred MW of supply to PGE's system could potentially relieve scarcity in PGE, while not making a substantial difference in SPP or MISO's demand.
- Large additions of solar and storage are required in CA and the DSW to meet current policy goals and maintain reliability.
  - We forecast that by 2035 CA and the DSW will be tight (slightly below planning reserve margins) during the summer peak load month, however, will continue to be long during the winter binding season.
  - Our forecast shows up to 22.5 GW and 20 GW of available firm export capacity in CA and the DSW, respectively, in the winter binding season of 2035.

Data Sources & Methodology Notes

PGE

- We calculated Capacity Critical Hours by looking at the 5% of hours in each year with the highest PNW net load (where net load = load less wind and solar).
- We did not consider hydro or interchange as part of the CCH calculation.
- We used four primary data sources for the historical analysis:
  - EIA Electric System Operating Data ("EIA ESOD"), which provides hourly load and generation by fuel type on a BA level (https://www.eia.gov/opendata/)
    - This data has some quality issues, including occasional days or hours that are missing or obviously wrong. We employed a few different techniques for vetting and cleaning the data, including supplementing with the data sources below.
  - CAISO load, wind, solar, transmission, and price data
    - The load is published at a CAISO system-wide level, as well as at the BA level for CAISO-adjacent BAs.
    - Wind and solar is published at a CAISO hub level.
  - MISO load, wind, solar, and price data, at a regional level (MISO North)
    - MISO publishes this data by transmission zone. The North zone includes Iowa, Minnesota, North Dakota, and parts of South Dakota and Montana.
  - SPP load, wind, solar, and price data, at a regional level for wind and solar (SPP North), and a system level for load
    - SPP publishes load by local BA. We calculate SPP North load as including the following BAs: INDN, LES, NPPD, OPPD, WAUE.
    - SPP publishes RE generation by transmission zone. We calculate SPP North wind and solar gen as including Zones 1 and 5.
- We used the EIA ESOD dataset to calculate load and net load for the PNW and DSW. We used the CAISO data to calculate load and net load for CAISO, as well as to supplement the EIA data where possible.

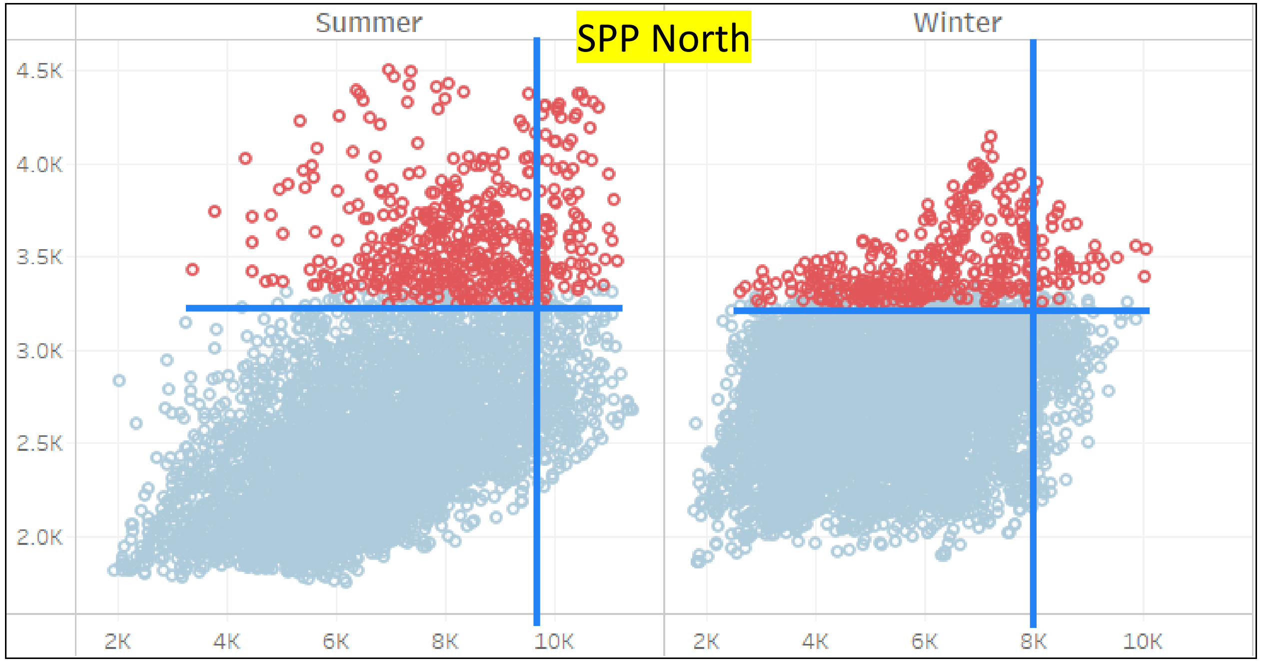
PNW BAs	DSW BAs
AVA	AZPS
AVRN	IID
BPAT	LDWP
CHPD	NEVP
DOPD	SRP
GCPD	WALC
IPCO	
NWMT	
PACW	
PGE	
PSEI	
SCL	
TPWR	

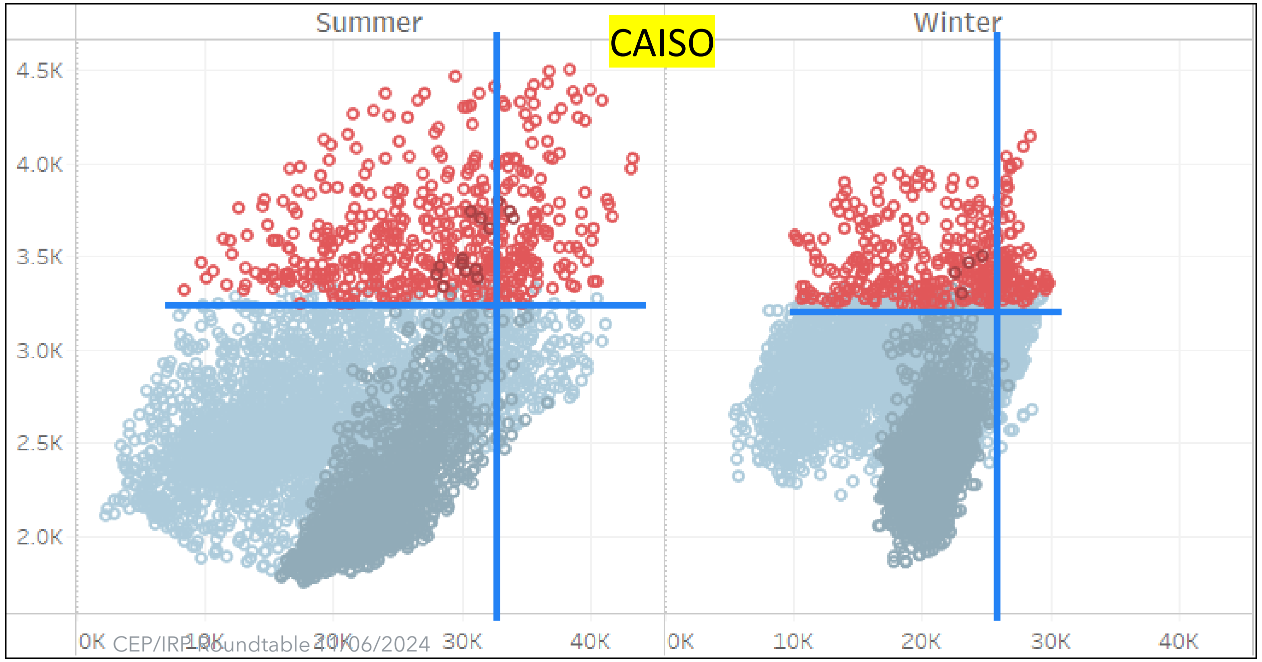
ENERGYGPS LLC

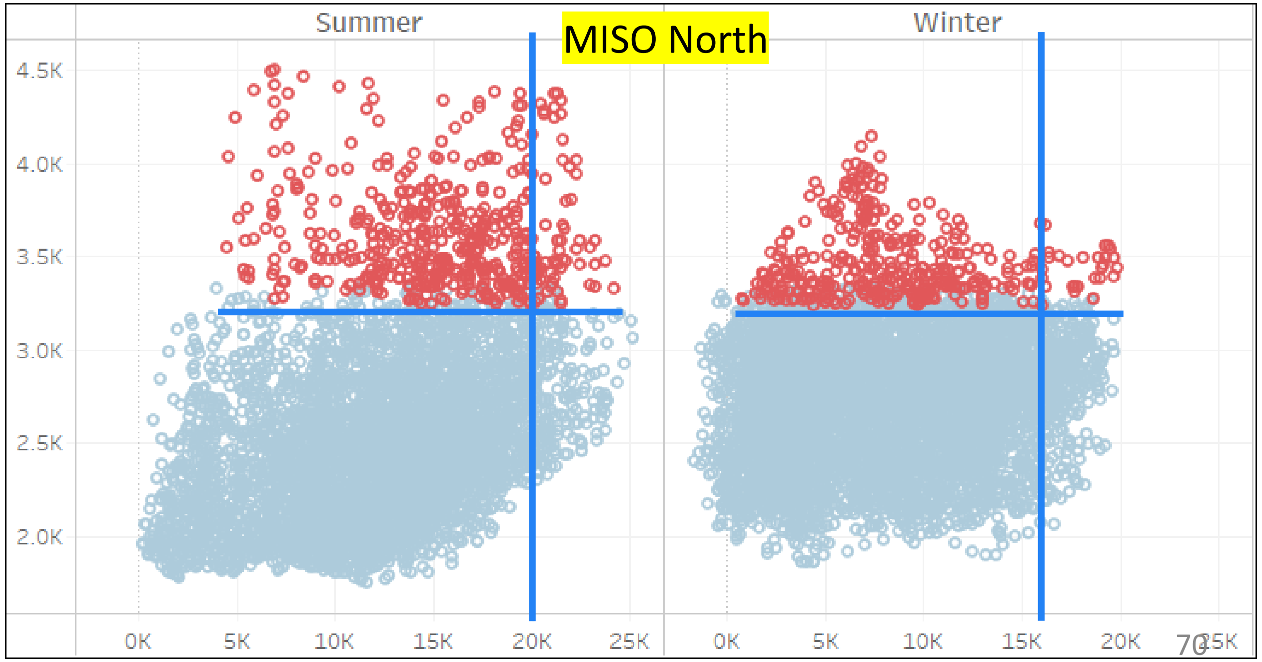
Overview

Past 24 months

- If you build transmission to SPP North, it’s reasonable to assume you can access energy/capacity during PGE CCHs in both the winter and the summer.
- If you build transmission to MISO North, it’s reasonable to assume you can access energy/capacity during PGE CCHs in both the winter and the summer.
- If you build transmission to CAISO, it’s reasonable to assume you can access energy/capacity during PGE CCHs in the winter.







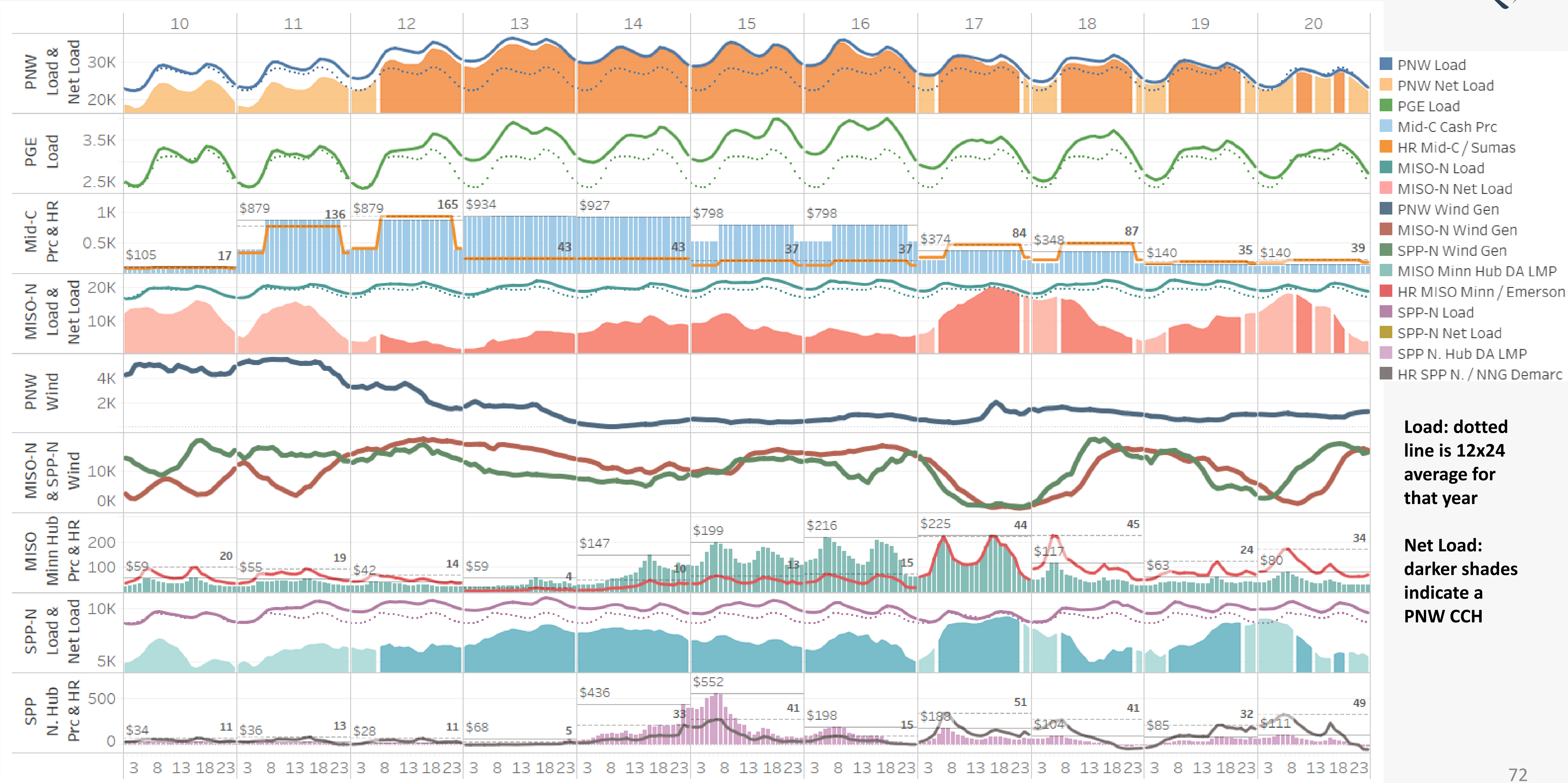
Price Conditions in Import Regions During CCHs

- Table includes 2021 – 2024 Q3, omitting Feb 2021
- Takeaways:
  - High prices (implied heat rates) at MISO and SPP are not correlated with CCHs in the PNW.
  - Average prices at MISO/SPP during PNW CCHs tend to be slightly higher than the rest of the time—but the highest prices observed in MISO/SPP do not occur during PNW CCHs.
  - The same is not necessarily true in the DSW. Prices at the Palo Verde tie point during summer PNW CCHs are substantially higher than the rest of the time.

Season / Flag CCH Hour PNW	Shoulder		Summer		Winter		All Seasons	
	No	Yes	No	Yes	No	Yes	No	Yes
Avg. PGE Load	2,337	3,051	2,492	3,798	2,648	3,252	2,486	3,410
Max. PGE Load	3,664	3,254	4,198	4,504	3,637	4,150	4,198	4,504
Avg. PNW Load	20.1K	27.8K	21.5K	29.7K	23.6K	29.4K	21,675	29,470
Avg. PNW Net Load	17.5K	26.9K	19.0K	28.2K	21.4K	28.3K	19,227	28,278
Max. PNW Load	27.9K	29.2K	30.7K	33.8K	30.8K	36.4K	30,794	36,381
Max. PNW Net Load	26.5K	28.5K	27.5K	32.4K	27.5K	35.1K	27,525	35,124
Avg. Heat Rate MISO MINN DA / Emerson	14.7	13.8	18.0	25.6	10.4	11.0	14.4	15.3
Avg. Heat Rate MISO Node DA / Emerson	10.1	9.5	13.2	21.3	10.2	11.5	11.1	14.4
Max. Heat Rate MISO MINN DA / Emerson	337.6	21.0	365.8	142.9	48.8	44.5	365.8	142.9
Max. Heat Rate MISO Node DA / Emerson	250.3	18.1	244.3	130.4	51.8	48.0	250.3	130.4
Avg. Heat Rate SPP North DA / NGPL	7.6	16.7	11.5	16.7	8.0	11.5	9.0	13.1
Avg. Heat Rate SPP Node DA / NGPL	7.6	16.7	9.9	15.1	8.5	11.8	8.6	12.8
Max. Heat Rate SPP North DA / NGPL	76.4	38.1	106.4	58.6	53.9	51.3	106.4	58.6
Max. Heat Rate SPP Node DA / NGPL	239.1	36.0	73.9	53.5	46.2	57.5	239.1	57.5
Avg. Heat Rate CAISO PV Tie DA / SoCalBorder	10.8	18.1	13.5	27.9	10.4	11.1	11.6	16.1
Avg. Heat Rate CAISO SP15 DA / SoCalCG	8.4	12.1	11.8	23.6	9.6	10.9	9.9	14.6
Max. Heat Rate CAISO PV Tie DA / SoCalBorder	104.5	40.3	210.6	332.1	47.5	34.1	210.6	332.1
Max. Heat Rate CAISO SP15 DA / SoCalCG	56.6	16.6	175.5	291.9	30.2	26.5	175.5	291.9
Avg. Heat Rate Cash MidC / Sumas	18.2	28.1	21.1	49.2	13.8	21.6	17.7	29.7
Max. Heat Rate Cash MidC / Sumas	126.2	46.8	227.1	227.1	136.2	165.2	227.1	227.1

ENERGYGPS LLC

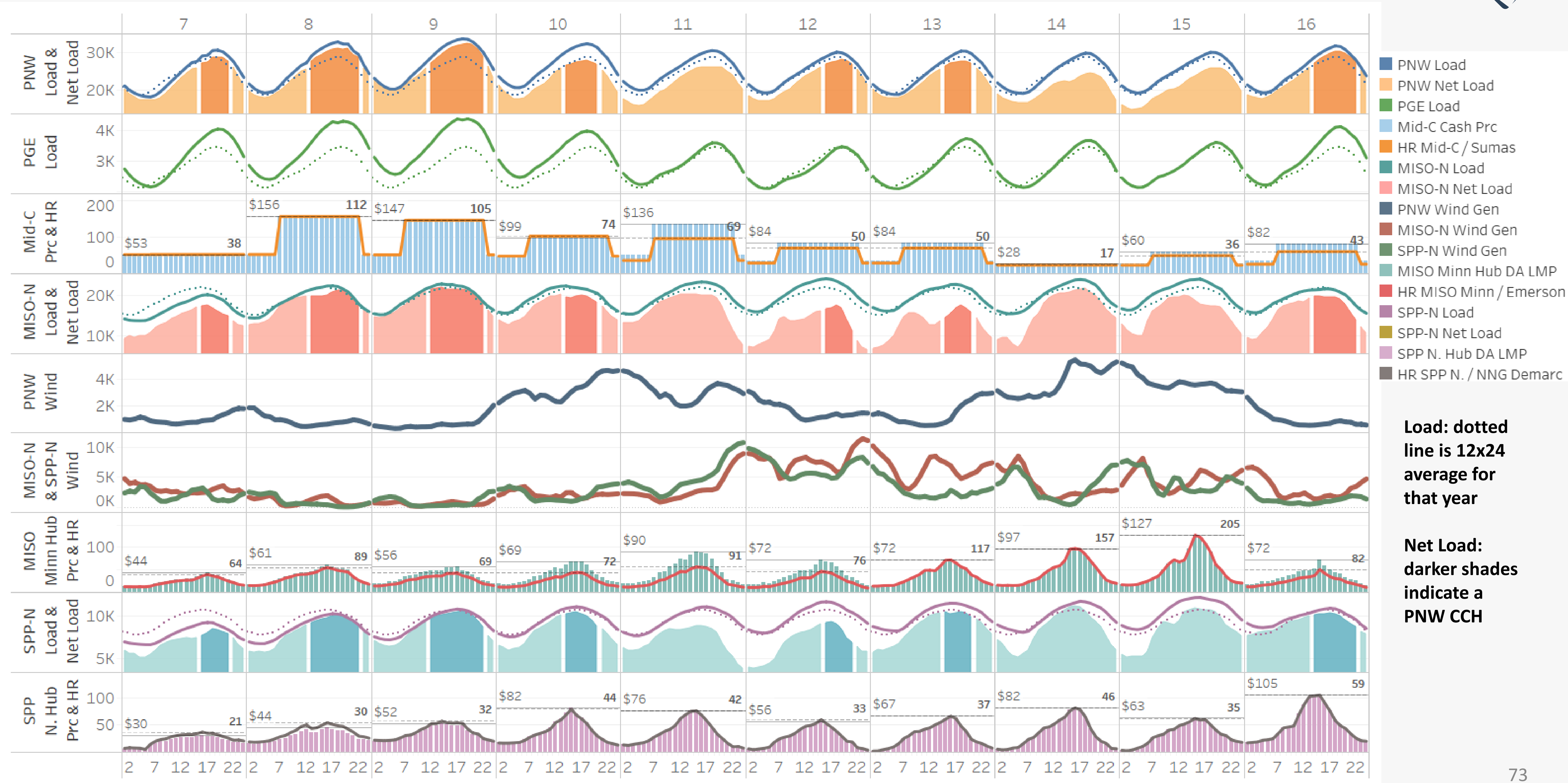
Day in the Life – January 2024



Load: dotted line is 12x24 average for that year

Net Load: darker shades indicate a PNW CCH

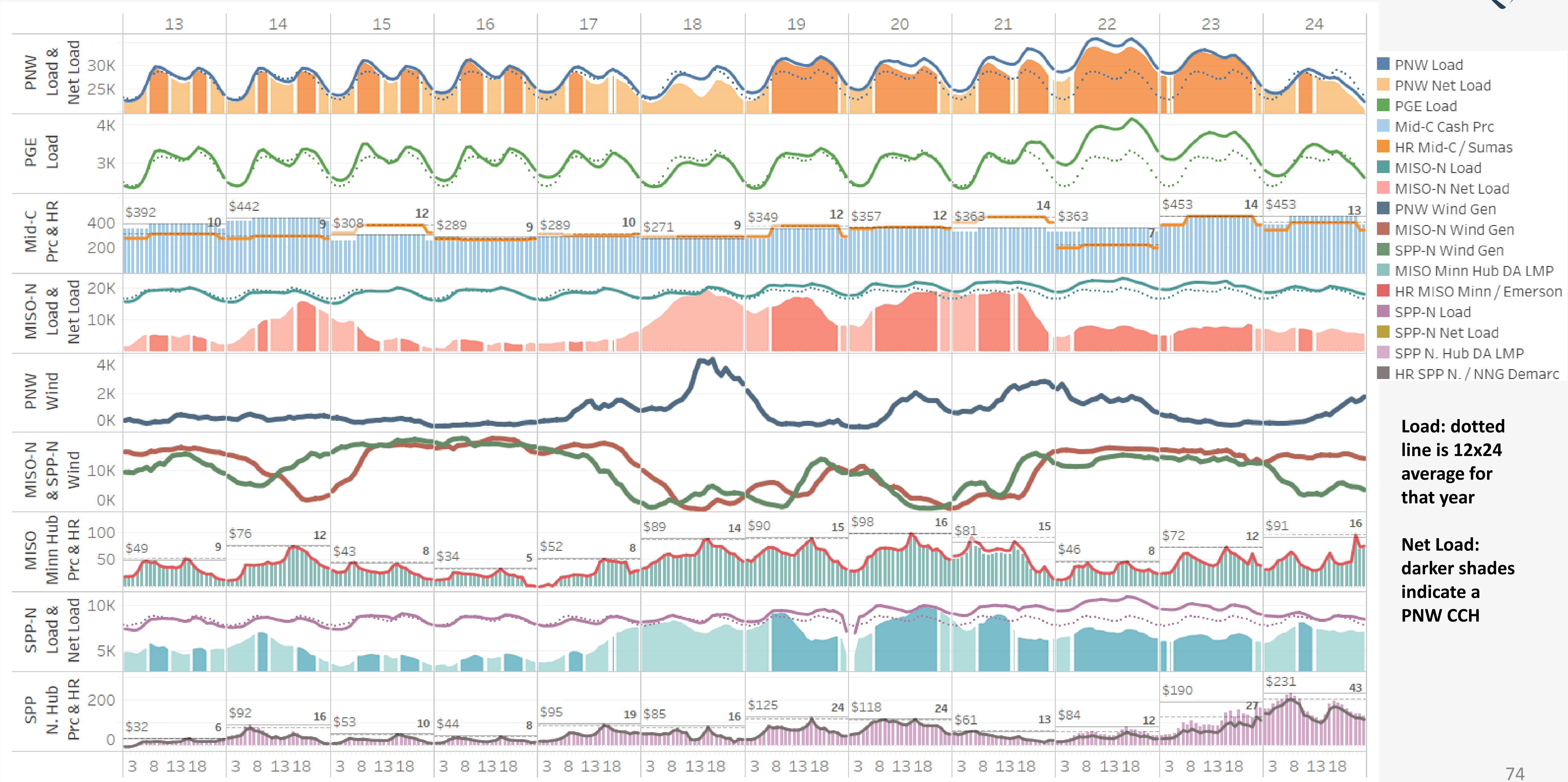
Day in the Life – July 2024



Load: dotted line is 12x24 average for that year

Net Load: darker shades indicate a PNW CCH

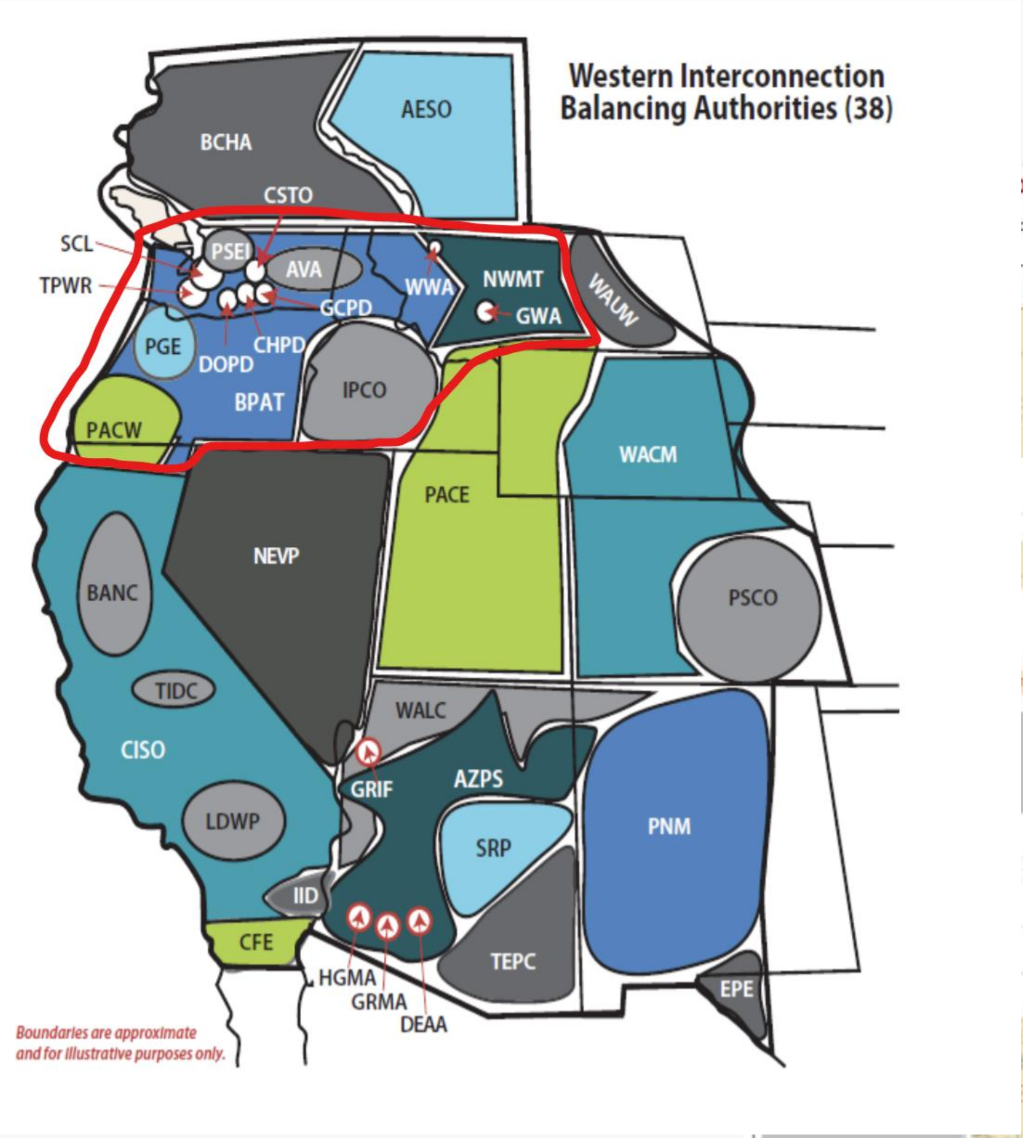
Day in the Life – December 2022



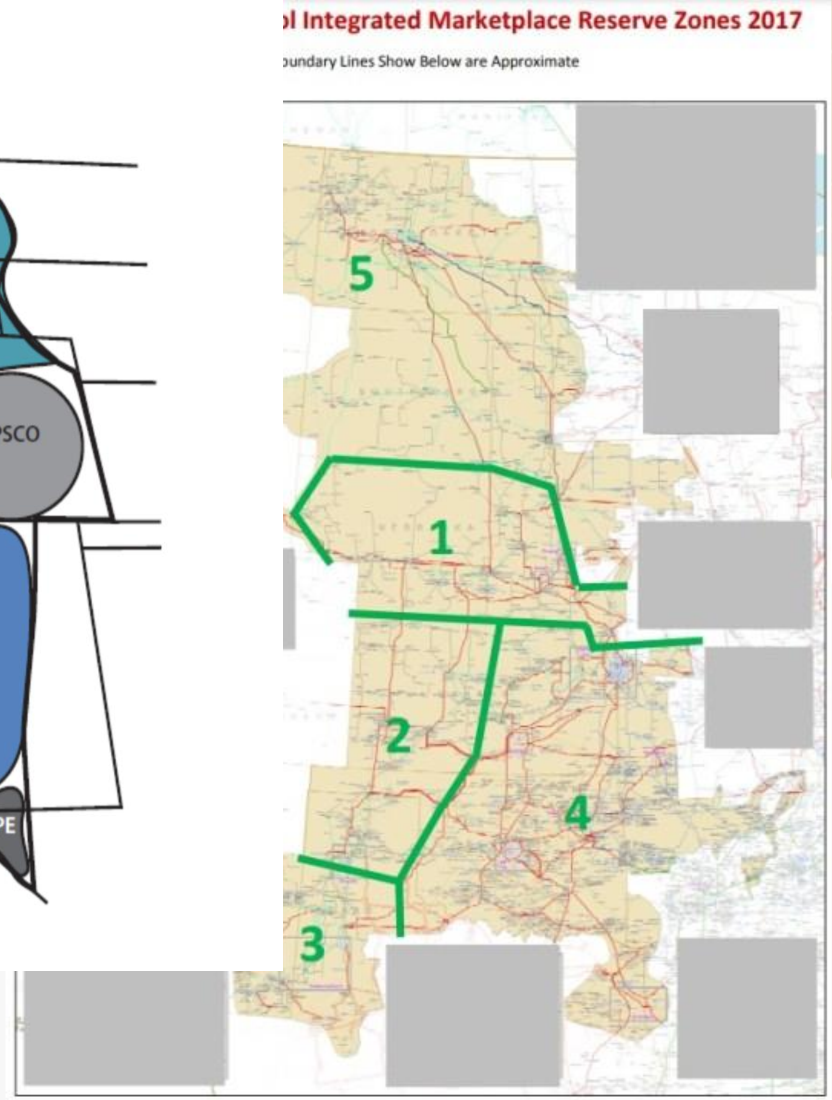
Load: dotted line is 12x24 average for that year

Net Load: darker shades indicate a PNW CCH

Where Are We?



Western Interconnection Balancing Authorities (38)
AESO
BCHA
CSTO
SCL
TPWR
PSEI
AVA
WWA
NWMT
GWA
WAUW
GCPD
CHPD
PGE
DOPD
BPAT
IPCO
PACW
WACM
PACE
NEVP
BANC
PSCO
TIDC
CISO
WALC
GRIF
AZPS
LDWP
SRP
PNM
IID
CFE
TEPC
EPE
HGMA
GRMA
DEAA
Boundaries are approximate and for illustrative purposes only.



Integrated Marketplace Reserve Zones 2017
Lines Show Below are Approximate
5
1
2
4
3

Eagan, MN
Carmel, IN
Little Rock, AR
MISO North
MISO Central
MISO South

Portfolio Design

Rob Campbell, PGE

Portfolio Analysis Plan

Focus so far

Modeling Improvements

- CBIs
- Hourly emissions
- Monthly energy need
- SSR resource

Inputs Updates*

- Load forecast
- Energy need
- Capacity need
- ELCCs
- Tx inventories and options
- Resource costs
- Price forecast
- EE and DER forecast
- Baseline portfolio

We are here

Portfolio Development

Next steps…

Analysis & Results

Preferred Portfolio

*Inputs updates are ongoing

Portfolio Analysis Overview

Portfolio analysis is conducted using PGE's optimized capacity expansion modeling tool, **ROSE-E**.

A **Portfolio** is a fixed set of resource decisions over a 20-year time horizon, designed to represent the planning environment and test key planning assumptions.

Portfolios are subject to constraints that ensure incremental resources additions are sufficient to meet energy and capacity needs and comply with regulatory requirements.

Portfolios are analyzed across a wide range of potential future conditions to capture uncertainty, each combination of which represents a specific **Scenario**.

For each Scenario, a least cost **Resource Buildout** is produced.

Portfolio Design

The **goal of portfolio analysis** is to inform the creation of a Preferred Portfolio that meets needs and complies with regulations in a way that minimizes costs and risks while incorporating realistic resource procurement constraints.

The **purpose of portfolio design** is to create a set of portfolios that allow us to gain insights on key questions of interest.

Thoughtful portfolio design:

1. Reasonably captures the realities of a complex planning environment in a simplified modeling exercise.
2. Narrows the focus of analytical effort to key questions of interest.
3. Allows the impacts of alternative decisions to be compared.

Portfolio Design in the 2023 CEP/IRP

Portfolio analysis in the 2023 CEP/IRP utilized numerous groups of portfolios to study a wide range of topics of interest.

- Transmission
- GHG glidepaths
- CBREs
- Additional EE and DR
- Optimization methods
- Emerging technologies
- Policy

Portfolios were analyzed across 351 alternative futures to address uncertainty in need, electricity prices, and technology costs.

Consistent portfolio design principles were applied across portfolios in order to isolate the impact of changes to variables of interest.

Findings from the portfolio groups were used to inform the creation of the 2023 CEP/IRP Preferred Portfolio.

Portfolio Design in the CEP/IRP Update

In the CEP/IRP Update, we plan to carry-over key design principles and insights from 2023 CEP/IRP portfolio analysis where possible and narrow the focus of portfolio design to key topics of interest.

1. Availability of transmission

Portfolios will have access to the transmission expansion/upgrade options described in the September 2024 roundtable and will be subject to varying levels of transmission capacity infusions representing BPA system upgrades.

2. Attribution of resource need by load growth sector

Portfolio results will distinguish between the resource additions associated with meeting 'organic' load and new large load.

3. Technology costs

Portfolios will be evaluated across alternative resources cost trajectory scenarios.

Questions

NEXT STEPS

A recording from today's webinar will be available on our website in one week

Upcoming Roundtable: December 4th

Distribution System Workshop: December 12th

Thank you

Contact us at
IRP.CEP@PGN.COM

An

Oregon

Oregon

Oregon

Oregon

Oregon

Oregon

kind of energy

ACRONYMS

ARIMA: autoregressive integrated moving average
ART: annual revenue-requirement tool
ATC available transfer capability
BE: Building Electrification
BPA: Bonneville Power Administration
C&I: commercial and industrial
CBI: community benefit indicators
CBIAG: community benefits and impacts advisory group
CBRE: community based renewable energy
CDD: colling degree day
CEC: California energy commission
CEP: clean energy plan
CF conditional firm
DC: direct current
DER: distributed energy resource
DR: demand response
DSP: distribution system plan
EE: energy efficiency
ELCC: effective load carrying capacity
EJ: environmental justice
ETO: energy trust of Oregon
EUI: energy use intensity
GHG: greenhouse gas
HB2021: House Bill 2021
HDD: heating degree day
HVDC: high-voltage direct current
HRCO: heat rate call option
IE: independent evaluator
IOU: investor-owned utilities
ITE: information technology equipment
ITC: investment tax credit
kW: kilowatt
LOLH: loss of load hours
LT/ST: long term/ short term
LTF long-term firm
MW: megawatt
MWa: mega watt average
NAICS: North American industry classification system
NCE: non-cost effective
NG: natural gas
NPVRR: net present value revenue requirement
OASIS Open Access Same Time Information System
ODOE: Oregon department of energy
PPA: power purchase agreement
PSH: pumped storage hydro
PUC: public utility commission
PURPA: Public Utility Regulatory Policies Act
PV: photovoltaic
REC: renewable energy credit
RLRR: low carbon price future
ROSE-E: resource option strategy engine
RPS: renewable portfolio standard
RRRR: reference case price future
RTO: regional transmission organization
SoA: South of Allston
TE: Transportation Electrification
T&D: transmission and distribution
TSR: transmission service request
TSEP: TSR study and expansion process
Tx: transmission
UPC: usage per customer
UPS: uninterruptible power supply
VER: variable energy resources
VPP: virtual power plant
WECC: western electricity coordinating council