BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2019 Integrated Resource Plan.	FINAL COMMENTS OF SWAN LAKE NORTH HYDRO, LLC

I. INTRODUCTION

Swan Lake North Hydro, LLC ("Swan Lake") submits these comments to the Oregon Public Utility Commission (the "Commission") responding to the recommendation from Commission staff ("Staff") in its report dated February 27, 2020 (the "Staff Report") to acknowledge in part and decline to acknowledge in part the Portland General Electric Company ("PGE" or "Company") 2019 Integrated Resource Plan ("IRP"). Swan Lake shares many of the concerns expressed by Staff in the Staff Report concerning PGE's action plan.[1] We therefore recommend that the Commission acknowledge PGE's capacity need and provide additional guidance as to how PGE should evaluate its different options for acquiring capacity to meet that need. PGE should issue one RFP and prioritize procurement for its actual need, i.e. long-term capacity, over other economic benefits.[2] Similarly, although existing resources could prove to be more cost effective, Swan Lake questions whether PGE should enter into any bilateral contracts

[1] *E.g.*, Staff Report at 36 (Feb. 27, 2020) (explaining PGE has made a reasonable case for low cost renewables to meet part of its capacity need, but has not yet demonstrated how the two separate requests for proposals ("RFP") will be optimized at a portfolio level).

[2] In addition to Staff, Citizen's Utility Board ("CUB") and Renewable Northwest ("RNW") and Alliance of Western Energy Consumers ("AWEC") also support or do not oppose conducting a concurrent RFP. *See* CUB Final Comments at 7-8 (Dec. 17, 2019); RNW Final Comments at 7 (Dec. 17, 2019); AWEC Final Comments at 8 (Dec. 17, 2019); Staff Report at 19, 21.

before receiving bids for new resources. Given the amount of uncertainty at play in recent IRPs,[3] the better approach may be to examine bids from all types of resources modeled in the preferred portfolio and then determine what best matches the action plan in terms of cost and risk to customers. On the other hand, undue delay addressing PGE's capacity need in this IRP could lead to pressure to build a new gas plant or add gas contracts in the next IRP cycle, especially if the region is bracing for troubling capacity deficits.

Due to the remaining uncertainty regarding PGE's evolving approach to procurement, Swan Lake believes it may still be necessary for PGE to seek a waiver of the Commission's competitive bidding requirements[4] to allow long lead time resources like the Swan Lake pumped storage project to meaningfully participate in PGE's procurement. As the Staff Report highlights, IRPs prioritize action within a two-to-four-year window.[5] This timing is fundamentally at odds with projects that take more than two to four years to achieve commercial operation. And despite the region's clear need for long-term capacity, it is challenging to prioritize and value long-term needs over short-term opportunities. Swan Lake therefore reiterates its request that the Commission opine in its order as to whether the Competitive Bidding Rules allow for a waiver and/or exception for long lead time resources, like the Swan Lake pumped storage project, in situations where a utility's action plan calls for a near-term acquisition of a long lead time resource, like the PGE action plan has done in this case.

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[3] Staff Report at 9 (noting the "lines blurring between opportunity and need [where] portfolio analyses is informing less of the resource strategy while the resulting RFP informs more and more").

[4] OAR Chapter 860, Division 89, Resource Procurement for Electric Companies ("Competitive Bidding Rules").

[5] Staff Report at 5 ("the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years").

II. BACKGROUND

As Swan Lake understands PGE's current action plan, the Company is proposing three potentially concurrent supply-side actions: 1) bilateral negotiations with existing capacity in the region; 2) a renewable RFP that will capture mainly economic benefits that might also result in the acquisition of some capacity; and 3) a dispatchable capacity RFP to capture any remaining capacity need after the bilateral negotiations (and potentially after the renewable RFP). PGE plans to cap the procurement from these actions at 150 MWa.

As Staff notes, "[p]arties were originally concerned that a 2023 renewable resource addition did not align with the identified 2024-2025 capacity need and the company's long energy position demonstrated in the traditional load-resource balance."[6] PGE's preferred portfolio calls for, among other things, the acquisition of 200 MW of pumped storage in 2024 and 2025 to meet its capacity need.[7] Throughout the IRP process, however, the Company has been responsive to feedback from stakeholders and open to considering modifications that mitigate risks to ratepayers. PGE has since proposed "a more fluid portfolio approach."[8] But according to Staff, "in the push to capture [economic opportunities], the Company put its actual capacity needs on a slower [procurement] track that could limit the ability to secure cost-competitive non-emitting capacity resources."[9] Consistent with information provided by PGE in the January 30, 2020 workshop in this proceeding (the "January Workshop"), the Company has issued an RFP seeking approximately 300 MW of firm capacity contracts that would run from 2021 to 2025.[10] As was noted in the January Workshop, however, PGE is uncertain it will be

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6 Staff Report at 27.
7 PGE 2019 IRP at 215 (July 19, 2019).
8 *Id.* at 17.
9 *Id.* at 9.
10 *See PGE Issues RFP Looking for Firm Capacity to Meet Looming Deficits*, CLEARING UP (Feb. 21, 2020), *available at*: https://www.newsdata.com/clearing_up/supply_and_demand/pge-issues-rfp-looking-for-firm-capacity-to-meet-looming/article_ae6482b4-54e3-11ea-a7da-cb2b1252f8d3.html.

able to secure the full amount requested, and PGE's IRP does not explain how the Company will approach its evaluation of these different capacity options in terms of cost and risk.

A. PGE Has Demonstrated a Substantial Capacity Need

PGE's updated reference case indicates that the Company will need up to 697 MW of capacity by 2025.[11] As Staff points out, roughly 350 MW of this need is driven by capacity contracts that will expire in 2024 and 2025.[12] As referenced above, PGE explained in the January Workshop that due to changing market conditions, resources with available capacity in the region had little inducement to sell at a discount, meaning PGE did not expect to secure the same kinds of capacity compared with what was available after PGE's last IRP. Regardless of the size of existing capacity PGE is able to secure in the short-term, it appears that those contracts will expire in 2025, precisely when the region is expected to be facing a substantial capacity shortage.

B. PGE's Action Plan Does Not Prioritize Capacity

Swan Lake agrees with Staff that "mid-term capacity contracts will create a longer runway to develop a portfolio of non-emitting dispatchable capacity resources without precluding opportunities to acquire new cost-effective resources that are currently available, including long lead time resources that are in the preferred portfolio."[13] But a longer runway could also just delay what currently appears to be an inevitable result. To date, PGE has prioritized an RFP that "*could* meet PGE's capacity needs, but it is unclear to what extent and how cost-effectively the resources may do so."[14] As Staff notes, "the addition of renewable

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11 PGE 2019 IRP Updated Needs Assessment at 5 (Nov. 27, 2019) (updating from 685 MW to 697 MW).
12 Staff Report at 17 (citing PGE 2019 IRP at 25).
13 *Id.* at 19.
14 *Id.* at 24 (emphasis added).

resources will have some impact on [PGE's] capacity needs, but the only characteristics that PGE is explicitly seeking through this RFP are energy and RPS eligibility."[15] Staff therefore "recommends acknowledgment that PGE has some amount of 2025 capacity need and should engage in activities designed to procure non-emitting capacity resources during the Action Plan window."[16] But Staff determined "there is still considerable risk in the Company's plan to separately and specifically seek resources attributes for which the Company does not have material near-term need."[17] To that end, Staff determined that "[i]f the Company chooses to move forward with a separate RFP, it should clearly articulate how it will consider the non-dispatchable renewable resources concurrently with dispatchable capacity so the resource additions are optimized across portfolios."[18] Swan Lake believes this is a reasonable approach for PGE's procurement.

C. PGE Should Issue One All-Source RFP Rather Than Two Separate RFPs

While Oregon's two utilities have very different systems and needs, PGE may want to consider PacifiCorp's current approach to procurement. PacifiCorp is also concluding an IRP—looking at the same capacity shortages in the region over the same time horizon—and is also preparing to issue an RFP, but PacifiCorp is seeking 4,400 MW of energy and 600 MW of storage in one single RFP.[19] Swan Lake reiterates its earlier comments urging PGE to evaluate all non-emitting capacity options together, as we continue to believe that broadening the field of potential bidders will help ensure PGE's customers are getting the best value.[20] Simply put, if

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15 *Id.*
16 *Id.* at 28.
17 *Id.* at 28-29 (highlighting the potential risk of overbuilding, near-term resource performance risk, and modeling flaws).
18 *Id.* at 30.
19 PacifiCorp's Application for Approval of 2020 All-Source Request for Proposals, Docket No. UM __, (Feb. 24, 2020).
20 Swan Lake's Final Comments at 7 (Dec. 16, 2019).

PacifiCorp can figure out the best combination of resources to acquire from a single RFP, why can't PGE?

Staff stresses the benefits in concurrent procurement, including optionality and flexibility, and found that concurrent procurement would "strike a suitable balance between the risk of inaction and risk of overbuilding."[21] Swan Lake believes this is the correct lens from which the Commission should view PGE's capacity options. To that end,

> Staff reiterates the benefit of creating a longer, more flexible runway to develop a least-cost, least-risk portfolio of non-emitting capacity resources. The asset life, operational characteristics, and ability of a utility to meet 300 – 700 MW of capacity need with current battery technology remains relatively unknown. Staff finds PGE's revised approach better reflects the reliability risks of a just-in-time capacity approach along with exposure to price and carbon risks if PGE misses its opportunity to secure cost-competitive, non-emitting resources that may be available in the near-term.[22]

Swan Lake agrees with Staff, but submits that this logic may also support an all-source RFP. The Commission should consider whether holding two potentially concurrent RFPs is comparable to an all-source RFP and whether either option may increase the risk of overbuilding renewables[23] or obfuscate the least cost and risk resources and/or transmission solutions.[24] As briefly noted above, Swan Lake is concerned that additional optimization and modeling could delay addressing PGE's capacity need in this IRP. Delaying capacity procurement may increase the likelihood of a new gas build or additional gas contracts in the next IRP cycle if the region remains unprepared for the substantial capacity deficits currently forecasted.

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[21] Staff Report at 21.

[22] *Id.*

[23] A January 2019 Energy+Environment report, *Resource Adequacy in the Pacific Northwest*, has been added to these comments as Attachment A (addressing potential to overbuild renewables).

[24] A May 2011 Transmission Utilization report, COI Utilization Report, has been added to these comments as Attachment B (discussing transmission usage on California-Oregon Intertie ("COI") and PGE's 950 MW of transmission ownership North of the California Oregon Border, which is fully subscribed on a long-term basis).

D. Waiver of the Competitive Bidding Rules May Still be Appropriate

Swan Lake reiterates that PGE and the Commission may need to consider other alternatives to address PGE's capacity need.[25] We therefore respectfully request the Commission clarify the applicability of its Competitive Bidding Rules to the acquisition of the Swan Lake pumped storage project. Swan Lake believes the waiver and exception sections in Oregon Administrative Rules ("OAR") sections 860-089-0010 and 860-089-0100 would apply to the acquisition of a long lead time resource, like pumped storage, especially in instances where a utility forecasts a near-term need from a long lead time resource.

III. CONCLUSION

For the reasons described above, Swan Lake agrees with Staff that the Commission should acknowledge PGE's capacity need. Swan Lake also believes additional guidance is needed before acknowledgement is appropriate for the potentially concurrent procurement PGE is currently proposing. Finally, Swan Lake remains concerned that long lead time resources may not be able to meaningfully participate in PGE's procurement and therefore urges the Commission to opine on situations where waiver of its Competitive Bidding Rules would be

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25 Swan Lake Opening Comments at 14-18 (Oct. 9, 2019).

appropriate to accommodate long lead time resources liked pumped storage.

Dated this 6th day of March, 2020.

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ATTACHMENT A

Energy+Environmental Economics January 2019 Report:
Resource Adequacy in the Pacific Northwest

Energy+Environmental Economics

Resource Adequacy in the Pacific Northwest

Serving Load Reliably under a Changing Resource Mix

January 2019

Arne Olson, Sr. Partner
Zach Ming, Managing Consultant

Outline

+ **Study Background & Context**
+ **Methodology & Key Inputs**
+ **Results**
  - 2018
  - 2030
  - 2050
  - Capacity contribution of wind, solar, storage and demand response
+ **Reliability Planning Practices in the Pacific Northwest**
+ **Key Findings**

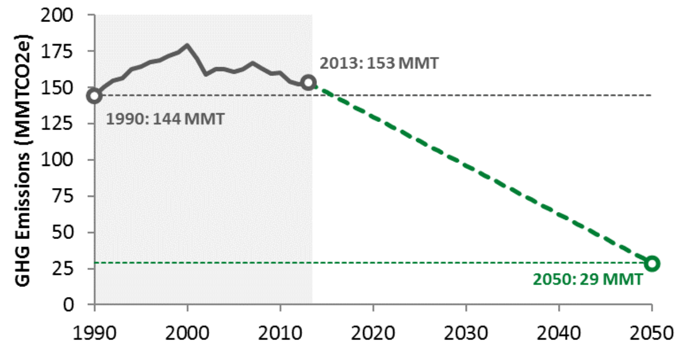
Energy+Environmental Economics

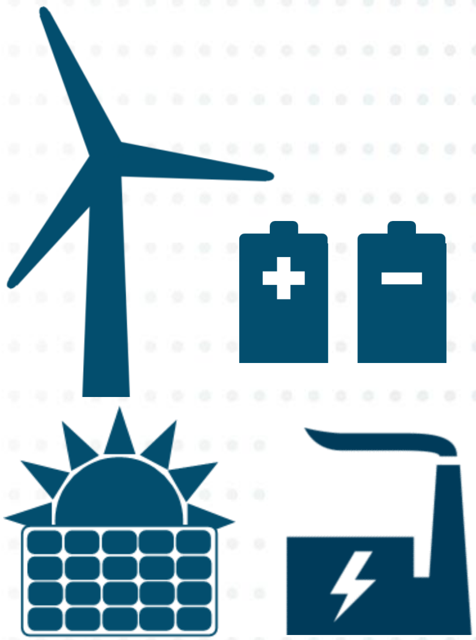
STUDY BACKGROUND & CONTEXT

About This Study

- **The Pacific Northwest is expected to undergo significant changes to its generation resource mix over the next 30 years due to changing economics and more stringent policy goals**
  - Increased penetration of wind and solar generation
  - Retirements of coal generation
  - Questions about the role of new natural gas generation
- **This raises questions about the region's ability to serve load reliably as firm generation is replaced with variable resources**
- **This study was sponsored by 13 Pacific Northwest utilities to examine Resource Adequacy under a changing resource mix**
  - How to maintain Resource Adequacy in the 2020-2030 time frame under growing loads and increasing coal retirements
  - How to maintain Resource Adequacy in the 2040-2050 time frame under stringent carbon abatement goals

Historical and Projected GHG Emissions for OR and WA





Study Sponsors

+ **This study was sponsored by Puget Sound Energy, Avista, NorthWestern Energy and the Public Generating Pool (PGP)**

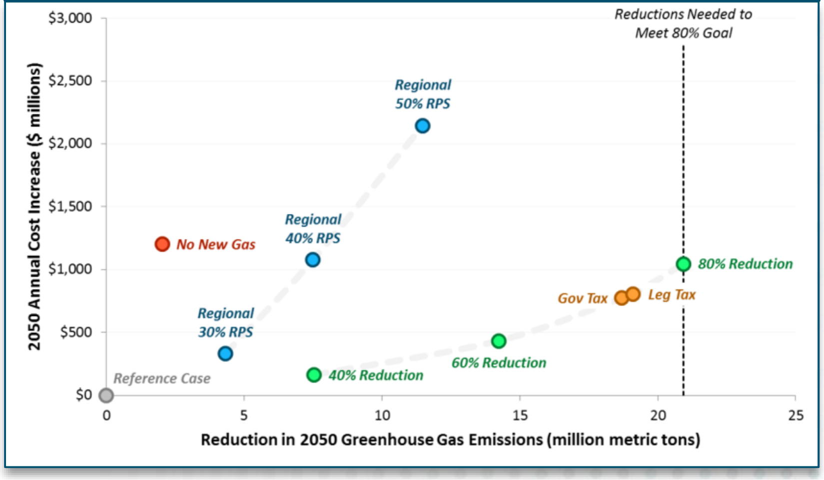
  - PGP is a trade association representing 10 consumer-owned utilities in Oregon and Washington.

E3 thanks the staff of the Northwest Power and Conservation Council for providing data and technical review

Relationship to Prior E3 Work

+ **In 2017-2018, E3 completed a series of studies for PGP and Climate Solutions to evaluate the costs of alternative electricity decarbonization strategies in Washington and Oregon**
  - The studies found that the least-cost way to reduce carbon is to replace coal with a mix of conservation, renewables and gas generation
  - Firm capacity was assumed to be needed for long-run reliability, however the study did not look at that question in depth

2017 E3-PGP Low Carbon Study



https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/

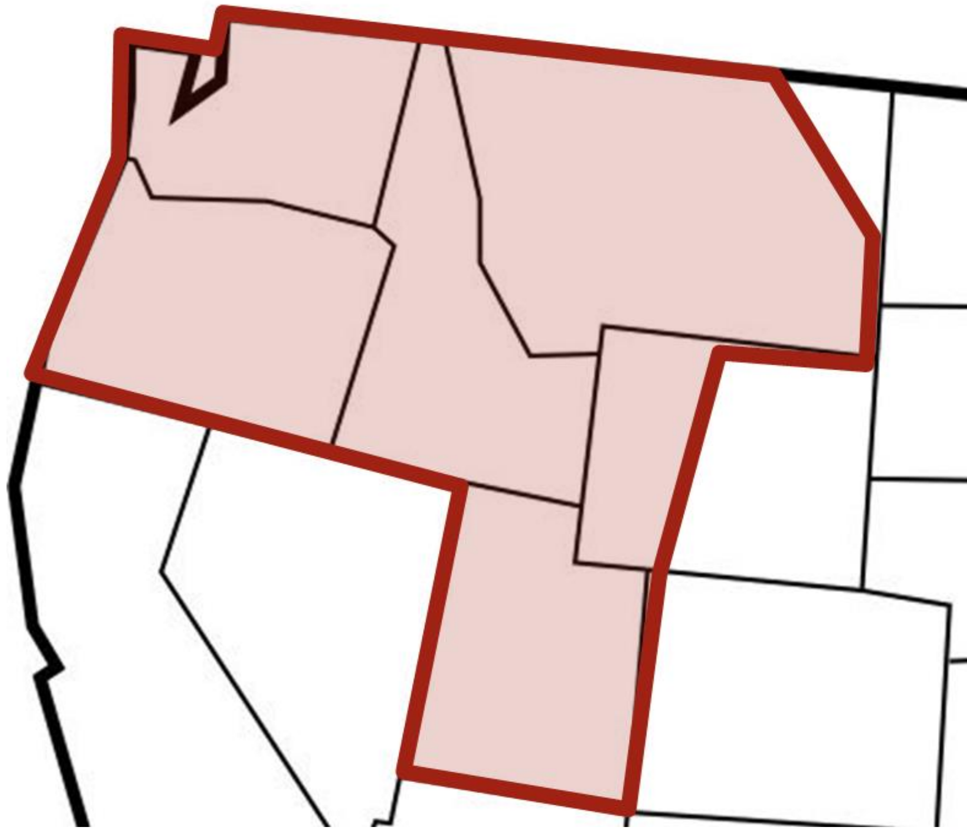
+ **This study builds on the previous analysis by focusing on long-run reliability**
  - How much capacity is needed to serve peak load under a range of conditions in the NW?
  - How much capacity can be provided by wind, solar, storage and demand response?
  - What combination of resources would be needed for reliability under low or zero carbon?
+ **The conclusions from this study broadly align with the previous results**

Long-run Reliability and Resource Adequacy

- **This study focuses on long-run (planning) reliability, a.k.a. Resource Adequacy (RA)**
  - A system is "Resource Adequate" if it has sufficient capacity to serve load across a broad range of weather conditions, subject to a long-run standard for frequency of reliability events, for example 1-day-in-10 yrs.
- **There is no mandatory or voluntary national standard for RA**
  - Each Balancing Authority establishes its own standard subject to oversight by state commissions or locally-elected boards
  - North American Electric Reliability Council (NERC) and Western Electric Coordinating Council (WECC) publish information about Resource Adequacy but have no formal governing role
- **Study uses a 1-in-10 standard of no more than 24 hours of lost load in 10 years, or no more than 2.4 hours/year**
  - This is the most common standard used across the industry

Study Region – The Greater NW

- **The study region consists of the U.S. portion of the Northwest Power Pool (excluding Nevada)**
- **It is assumed that any resource in any area can serve any need throughout the Greater NW region**
  - Study assumes no transmission constraints or transactional friction
  - Study assumes full benefits from regional load and resource diversity
  - The system as modeled is more efficient and seamless than the actual Greater NW system



Balancing Authority Areas include: Avista, Bonneville Power Administration, Chelan County PUD, Douglas County PUD, Grant County PUD, Idaho Power, NorthWestern Energy, PacifiCorp (East & West), Portland General Electric, Puget Sound Energy, Seattle City Light, Tacoma Power, Western Area Power Administration

Individual utility impacts will differ from the regional impacts

- **Cost impacts in this study are presented from a societal perspective and represent an aggregation of all costs and benefits within the Greater NW region**
  - Societal costs include all investment (i.e. "steel-in-the-ground") and operational costs (i.e. fuel and O&M) that are incurred in the region
- **Cost of decarbonization may be higher or lower for individual utilities as compared to the region as a whole**
  - Utilities with a relatively higher composition of fossil resources today are likely to bear a higher cost than utilities with a higher composition of fossil-free resources
- **Resource Adequacy needs will be different for each utility**
  - Individual systems will need a higher reserve margin than the Greater NW region due to smaller size and less diversity
  - Capacity contribution of renewables will be different for individual utilities due to differences in the timing of peak loads and renewable generation production

Energy+Environmental Economics

METHODOLOGY & KEY INPUTS

This study utilizes E3's Renewable Energy Capacity Planning (RECAP) Model

+ **Resource adequacy is a critical concern under high renewable and decarbonized systems**
  - Renewable energy availability depends on the weather
  - Storage and Demand Response availability depends on many factors
+ **RECAP evaluates adequacy through time-sequential simulations over thousands of years of plausible load, renewable, hydro, and stochastic forced outage conditions**
  - Captures thermal resource and transmission forced outages
  - Captures variable availability of renewables & correlations to load
  - Tracks hydro and storage state of charge

RECAP calculates reliability metrics for high renewable systems:

- **LOLP:** Loss of Load Probability
- **LOLE:** Loss of Load Expectation
- **EUE:** Expected Unserved Energy
- **ELCC:** Effective Load-Carrying Capability for hydro, wind, solar, storage and DR
- **PRM:** Planning Reserve Margin needed to meet specified LOLE

Information about E3's RECAP model can be found here:
https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

RECAP Methodology and Data Sources

- **RECAP calculates long-run resource availability through Monte Carlo simulation of electricity system resource availability using weather conditions from 1948-2017**
  - Each simulation begins on January 1, 1948 and runs hourly through December 31, 2017
  - Hourly electric loads for 1948-2017 are synthesized using statistical analysis of actual load shapes and weather conditions for 2014-2017
  - Hourly wind and solar generation profiles are drawn from simulations created by the National Renewable Energy Laboratory and paired with historical weather days through an E3-created day-matching algorithm
  - Annual hydro generation values are drawn randomly from 1929-2008 water years and shaped to calendar months and weeks based on the Northwest Power and Conservation Council's GENESYS model
  - Nameplate capacity and forced outage rates (FOR) for thermal generation are drawn from various sources including the GENESYS database and the Western Electric Coordinating Council's Anchor Data Set
- **RECAP calculates whether there are sufficient resources available to serve load during each hour over thousands of simulations**

RECAP evaluates the availability of energy supplies to meet loads using an 8-step calculation process

Step 1

Calculate Hourly Load

Step 2

Calculate Renewable Profiles

Step 3

Calculate Available Dispatchable Generation

Step 4

Hydro Dispatch

Step 5

Calculate Available Transmission

Step 6

Dispatch Storage

Step 7

Dispatch Demand Response

Step 8

Calculate Loss of Load

RECAP calculates a number of metrics that are useful for resource planning

- **Annual Loss of Load Probability (aLOLP) (%):** is the probability of a shortfall (load plus reserves exceed generation) in a given year
- **Annual Loss of Load Expectation (LOLE) (hrs/yr):** is total number of hours in a year wherein load plus reserves exceeds generation
- **Annual Expected Unserved Energy (EUE) (MWh/yr):** is the expected unserved load plus reserves in MWh per year
- **Effective Load Carrying Capability (ELCC) (%):** is the additional load met by an incremental generator while maintaining the same level of system reliability (used for dispatch-limited resources such as wind, solar, storage and demand response)
- **Planning Reserve Margin (PRM) (%):** is the resource margin above 1-in-2-year peak load, in %, that is required in order to maintain acceptable resource adequacy

Additional metric definitions used for scenario development

- **GHG Reduction %** is the reduction below 1990 emission levels for the study region
  - The study region emitted 60 million metric electricity sector emissions in 1990
- **CPS %** is the total quantity of GHG-free generation divided by retail electricity sales
  - "Clean Portfolio Standard" includes renewable energy plus hydro and nuclear
  - Common policy target metric, including California's SB 100
- **GHG-Free Generation %** is the total quantity of GHG-free generation, *minus* exported GHG-free generation, divided by total wholesale load
  - Assumed export capability up to 6,000 MW
- **Renewable Curtailment %** is the total quantity of wind/solar generation that is not delivered or exported divided by total wind/solar generation

RECAP vs. RESOLVE: How are the models different?

- **RESOLVE is an <u>economic model</u> that selects optimal resource portfolios that minimize costs over time**
  - Selects optimal portfolio of renewable, conventional and energy storage resources
  - Reliability is addressed through high-level assumptions about long-run reliability needs via a PRM constraint
  - Independent simulations of 40 carefully selected and weighted operating days

- **RECAP is a <u>reliability model</u> that calculates how much effective capacity is needed to meet peak loads**
  - Calculates system-wide Planning Reserve Margin and other long-run reliability statistics
  - Economics are addressed through high-level assumptions about resource cost and availability
  - Time-sequential simulations of thousands of operating years selected randomly

E3 often uses RESOLVE and RECAP in tandem to develop portfolios that are least-cost with robust long-run reliability

<u>RESOLVE</u>
Electricity Capacity Expansion

↕

<u>RECAP</u>
Electricity Resource Adequacy

Demand forecast is consistent with PGP study

- **Demand forecast is benchmarked against multiple long-term projections**
  - Both Pre- and Post-EE
- **Load profiles are held constant throughout the analysis period**
  - No assumptions about changing load shapes due to climate change
- **Electrification is only included to the extent that it is reflected in these load growth forecasts**
  - Load growth includes impact of 1.1 million electric vehicles by 2030
  - Heavy electrification of buildings, vehicles, or industry would increase RA requirements beyond what this study shows

Source	Pre EE	Post EE
PNUCC Load Fcst	1.7%	0.9%
BPA White Book	1.1%	—
NWPCC 7th Plan	0.9%	0.0%
TEPPC 2026 CC	—	1.3%
E3 Assumption	**1.3%**	**0.7%**

	2018	2030	2050
Peak Load(GW)	43	47	54
Annual Load (TWh/yr)	247	269	309

The study considers Resource Adequacy needs under multiple scenarios representing alternative resource mixes

2018-2030 Scenarios	Carbon Reduction % Below 1990[1]	GHG-Free Generation %[2]	CPS %[3]	Carbon Emissions (MMT)
2018 Case[4]	-6%	71%	75%	63
2030 Reference Case[4]	-12%	61%	65%	67
2030 Coal Retirement	30%	61%	65%	42

2050 Scenarios	Carbon Reduction % Below 1990[1]	GHG-Free Generation %[2]	CPS %[3]	Carbon Emissions (MMT)
Reference Case	16%	60%	63%	50
60% GHG Reduction	60%	80%	86%	25
80% GHG Reduction	80%	90%	100%	12
90% GHG Reduction	90%	95%	108%	6
98% GHG Reduction	98%	99%	117%	1
100% GHG Reduction	100%	100%	123%	0

[1]Greater NW Region 1990 electricity sector emissions = 60 MMT/yr
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load
[3]CPS % = renewable/hydro/nuclear generation divided by retail electricity sales
[4]2018 and 2030 cases assumes coal capacity factor of 60%

New wind and solar resources are added across a geographically diverse footprint

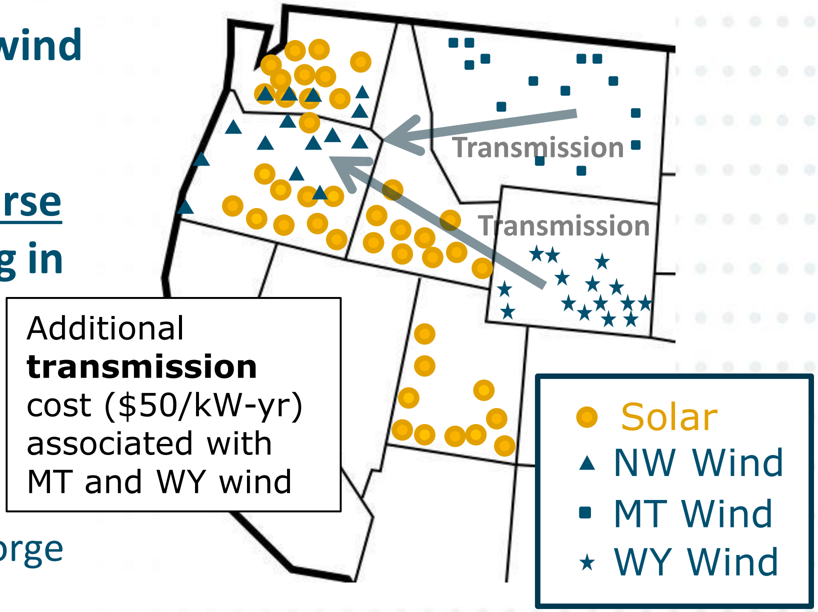
+ **The study considers additions nearly 100 GW of wind and 50 GW of solar across the six-state region**

+ **The portfolios studied are <u>significantly more diverse</u> than the renewable resources currently operating in the region**

  - Each dot in the map represents a location where wind and solar is added in the study
  - NW wind is more diverse than existing Columbia Gorge wind

+ **New renewable portfolios are within the bounds of current technical potential estimates, but are nearly an order of magnitude higher than other studies have examined**

+ **The cost of new transmission is assumed for delivery of remote wind and solar generation but siting and construction is not studied in detail**



NREL Technical Potential (GW)

State	Wind
WA	18
OR	27
CA	34
ID	18
MT	944
WY	552
UT	13
Total	**1588**

https://www.nrel.gov/docs/fy12osti/51946.pdf

Resource Cost Assumptions

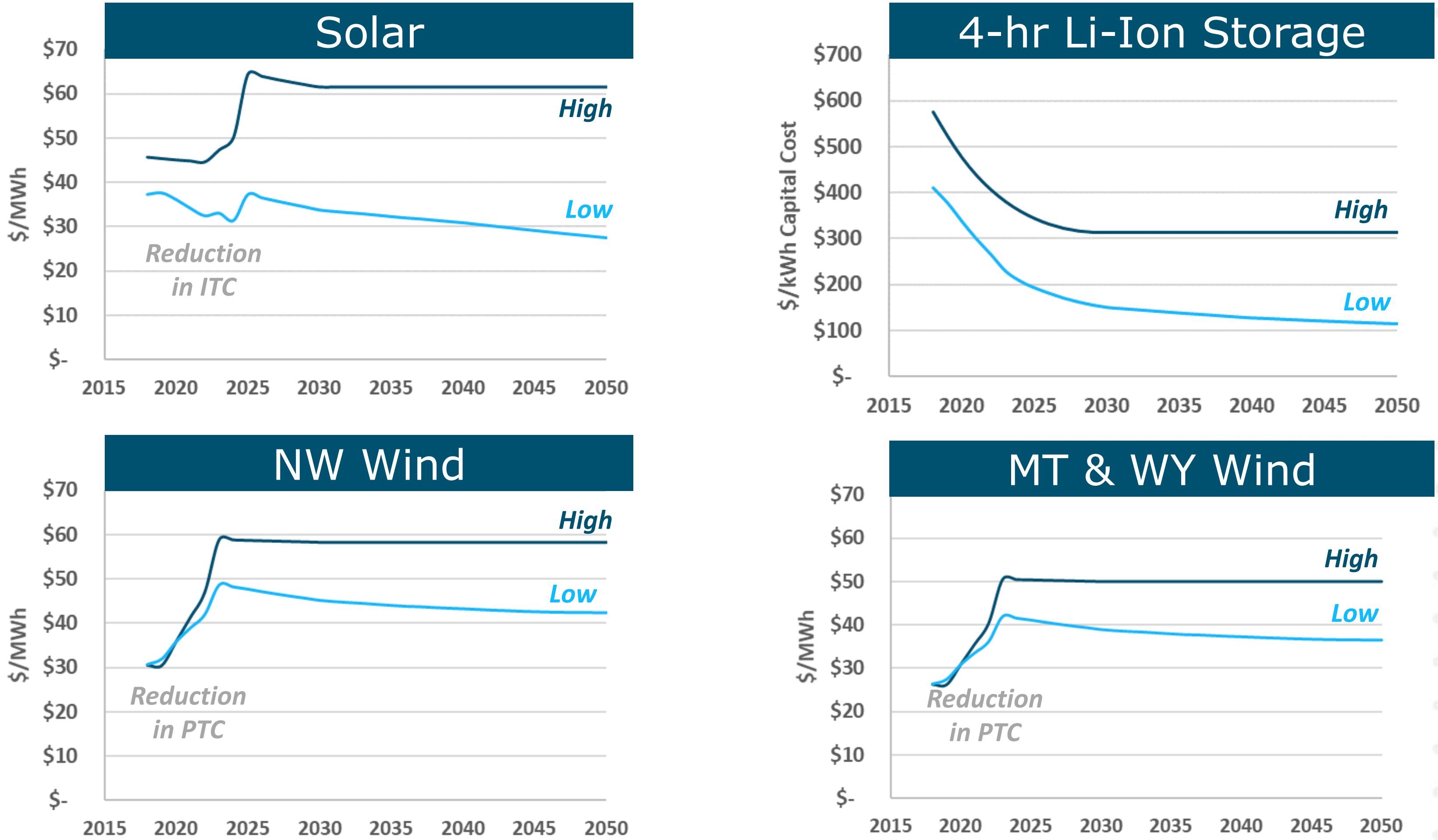
$2016

Technology	Unit	Resource Cost High	Resource Cost Low	Transmission	Notes
Solar PV	*$/MWh*	$59	$32	$8	High Source: PGP Study; Low Source: NREL 2018 ATB Mid Case; CF = 27%
NW Wind	*$/MWh*	$55	$43	$6	High Source: PGP Study; Low Source: NREL 2018 ATB Mid Case; CF = 37%
MT/WY Wind	*$/MWh*	$48	$37	$19	High Source: PGP Study; Low Source: NREL 2018 ATB Mid Case; CF = 43%
Battery - Capacity	*$/kW-yr*	$30	$5		High Source: PGP Study; Low Source: Lazard LCOS Mid Case 4.0
Battery – Energy	*$/kWh-yr*	$41	$23		High Source: PGP Study; Low Source: Lazard LCOS Mid Case 4.0
Clean Baseload	*$/MWh*	$91	$91		$800/kW-yr; Technology unspecified
Natural Gas Capacity	*$/kW-yr*	$150	$150		7,000 Btu/kWh heat rate; $5/MWh var O&M
Gas Price	*$/MMBtu*	$4	$2		Corresponds to $33/MWh and $19/MWh variable cost of natural gas (gas price * heat rate + var O&M)
Biogas Price	*$/MMBtu*	$39	$39		

Costs shown are the average cost over the 2018-2050 timeframe; trajectories in following slide

Note: RECAP is primarily a loss-of-load probability model that calculates resource *availability* over thousands of simulated years. RECAP does estimate least-cost *dispatch* and *capacity expansion* but this functionality does not involve optimization and is necessarily approximate

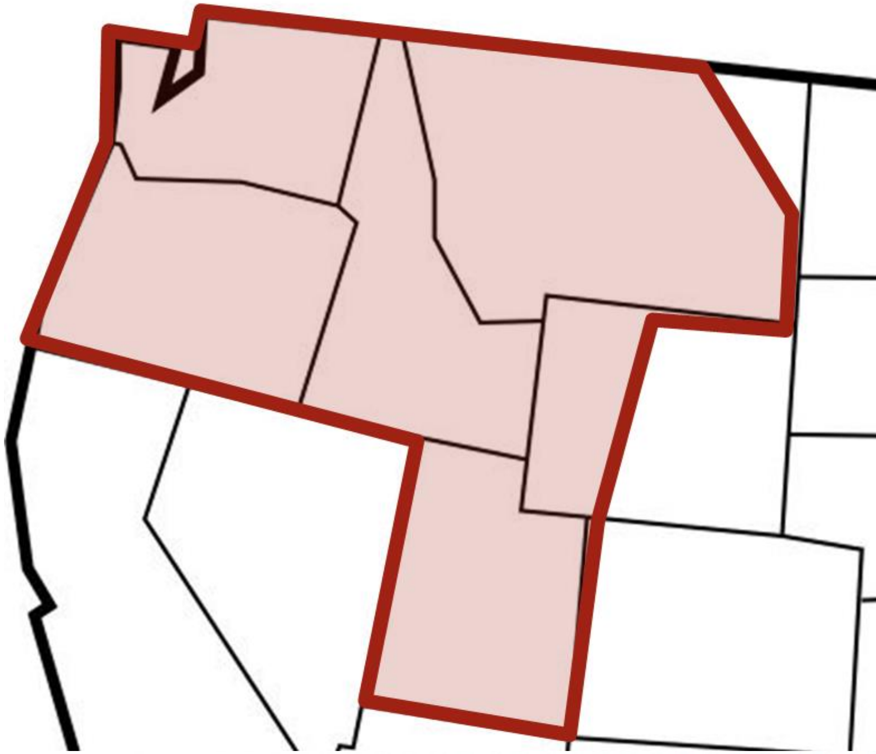
Resource Cost Assumptions



Shown in 2016 dollars

Imports/Exports

+ **Import assumptions are consistent with NWPCC GENESYS model**
  - Monthly import availability
    - 2,500 MW from Nov – Mar
    - 1,250 MW in Oct
    - Zero from Apr – Sep
  - Hourly import availability
    - 3,000 MW in Low Load Hours (HE 22 – HE 5)
  - Monthly + hourly import availabilities are additive but in any given hour total import capability is limited to 3,400 MW
+ **For 100% GHG-free scenario, no imports are assumed in order to ensure no imported GHG emissions**
+ **6,000 MW export capability in all hours**



All region outside the Greater NW region is modeled as a single 'external' zone.
MT Wind and WY Wind are included in the NW zone and not in the 'external' zone.

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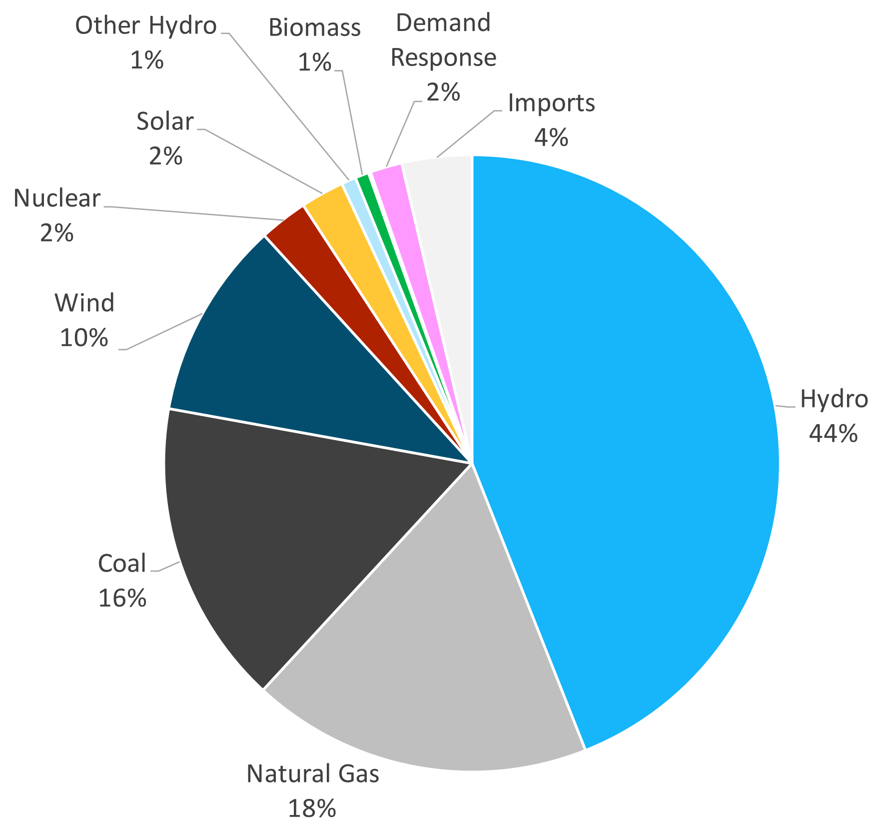
2018 RESULTS

2018 System

- **2018 Baseline system includes 24 GW of thermal generation, 35 GW of hydro generation, and 7 GW of wind generation**
  - Sources: GENESYS database for NWPCC region and TEPPC anchor dataset for other select NWPP BAAs
- **By 2023, approximately 1,800 MW of coal generation is expected to retire**
- **2018 Loads: 246 TWh/yr, 43 GW peak**

Resource	2018 Nameplate MW
Hydro[1]	34,697
Natural Gas	12,181
Coal	10,895
Wind	7,079
Nuclear	1,150
Solar	1,557
Other Hydro[2]	524
Biomass	489
Geothermal	80
Demand Response[3]	299
Imports[4]	2,500

Capacity Mix %



[1]Hydro is modeled as energy budgets for each month and does not use nameplate capacity
[2]Other hydro is hydro outside NWPCC region
[3]Demand Response: max 10 calls, each call max duration = 4 hours
[4]Imports are zero for summer months (Jun, Jul, Aug, Sep) except during off-peak hours
NOTE: Storage assumed to be insignificant in the current system

2018 system is in very tight load-resource balance

- A planning reserve margin of 12% is required to meet 1-in-10 reliability standard
- The 2018 system does not meet 1-in-10 reliability standard (2.4 hrs./yr.)
- The 2018 system does meet Northwest Power and Conservation Council standard for Annual LOLP (5%)

	Reliability Metrics
Annual LOLP	3.7%
LOLE (hrs./year)	**6.5**
EUE (MWh/year)	5,777
EUE norm (EUE/Load)	0.003%
1-in-2 Peak Load (GW)	43
Required PRM to meet 2.4 LOLE	12%
Required Firm Capacity (GW)	48

2018 Load and Resource Balance

	2018
Load (GW)	
Peak Load	43
PRM (%)	*12%*
PRM	5
Total Load Requirement	**48**

Resources / Effective Capacity (GW)		Nameplate Capacity (GW)	ELCC* (%)	Capacity Factor (%)
Coal	11			
Gas	12			
Bio/Geo	1			
Imports	3			
Nuclear	1			
DR	0.3			
Hydro	18	*35*	*53%*	*44%*
Wind	0.5	*7.1*	*7%*	*26%*
Solar	0.2	*1.6*	*12%*	*27%*
Storage	0			
Total Supply	**47**			

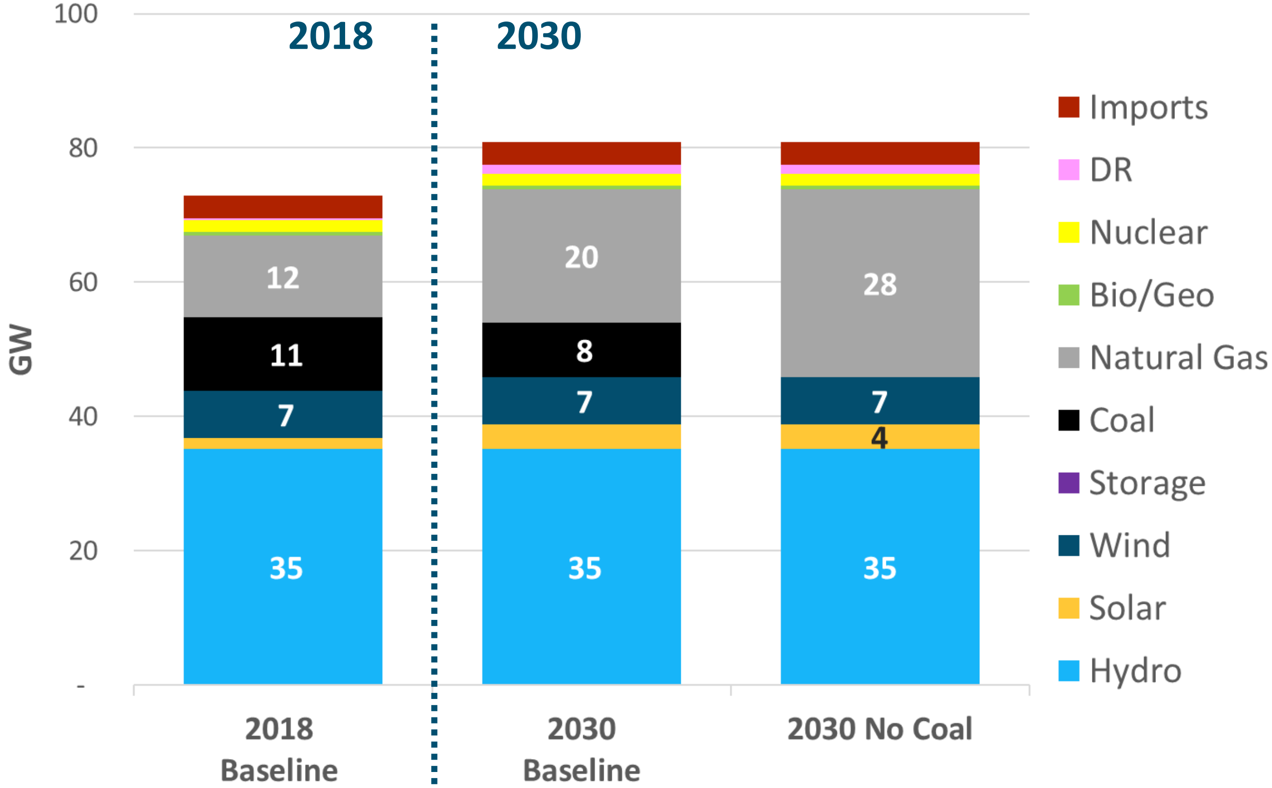
Wind and solar contribute little effective capacity with ELCC* of 7% and 12%

**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

Energy+Environmental Economics

2030 RESULTS

2030 Portfolios



GHG Free Generation (%)	61%	61%
Carbon (MMT CO2)	67	42
% GHG Reduction from 1990 Level	-12%*	31%

**Assumes 60% coal capacity factor*

5 GW net new capacity by 2030 is needed for reliability (450 MW/yr)

With planned coal retirements of 3 GW, 8 GW of new capacity by 2030 is needed (730 MW/yr)

If all coal is retired, then 16 GW new capacity is needed (1450 MW/yr)

The Northwest system will need 8 GW of new effective capacity by 2030

- The 2030 system does not meet 1-in-10 reliability standard (2.4 hrs./yr.)
- The 2030 system does not meet standard for Annual LOLP (5%)
- Load growth and planned coal retirements lead to the need for 8 GW of new effective capacity by 2030

	2030 No Net New Capacity	2030 with 5 GW Net New Capacity
Annual LOLP (%)	**48%**	2.8%
LOLE (hrs/yr)	**106**	2.4
EUE (MWh/yr)	178,889	1,191
EUE norm (EUE/load)	0.07%	0.0004%

2030 Load and Resource Balance

	2030
Load (GW)	
Peak Load (Pre-EE)	50
Peak Load (Post-EE)	47
PRM	*12%*
PRM	5
Total Load Requirement	52

Resources / Effective Capacity (GW)		Nameplate Capacity (GW)	ELCC (%)	Capacity Factor (%)
Coal	8			
Gas	20			
Bio/Geo	0.6			
Imports	2			
Nuclear	1			
DR	1.0			
Hydro	19	*35*	*56%*	*44%*
Wind	0.6	*7.1*	*9%*	*26%*
Solar	0.2	*1.6*	*14%*	*27%*
Storage	0			
Total Supply	52			

Wind and solar contribute little effective capacity with ELCC* of 9% and 14%

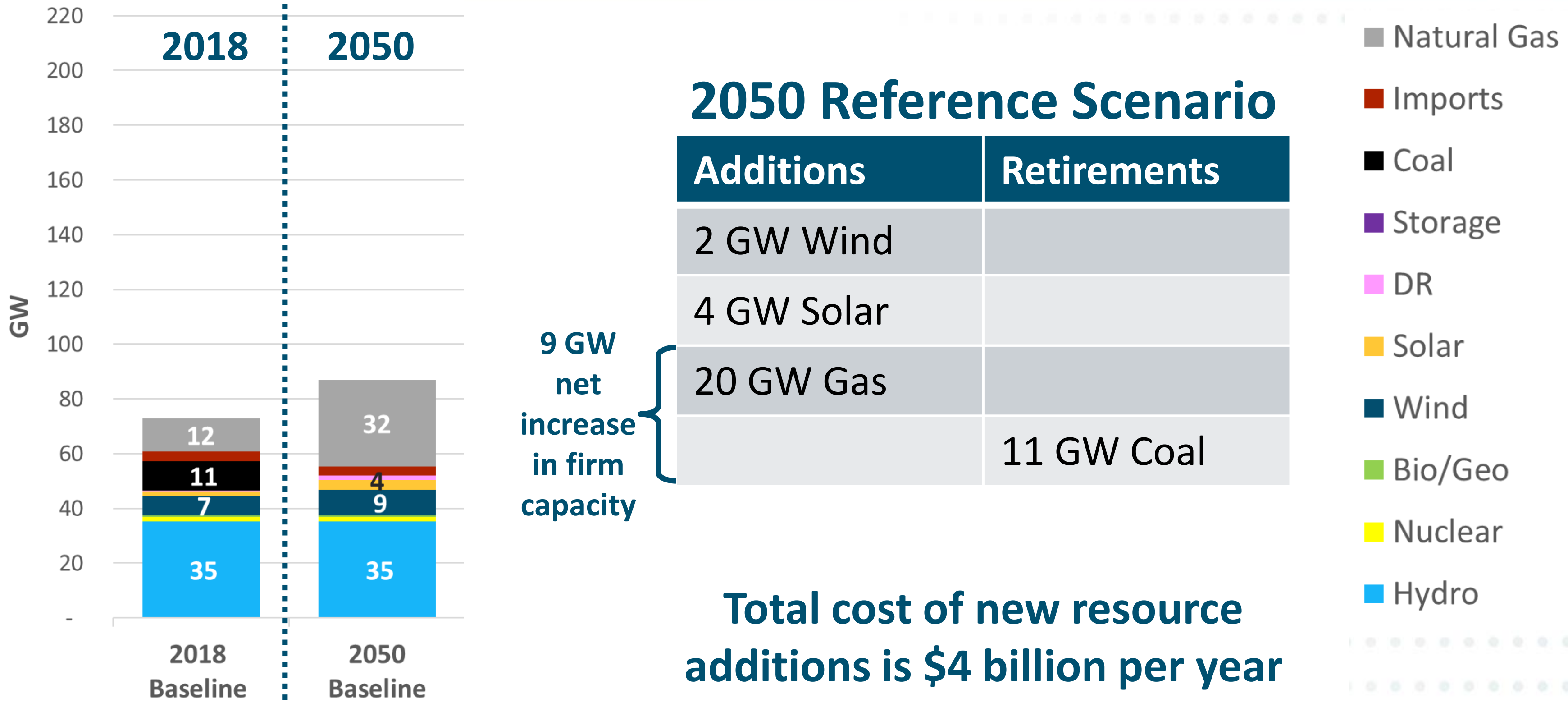
8 GW new gas capacity needed by 2030

**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

Energy+Environmental Economics

2050 RESULTS

Scenario Summary
Greater NW System in 2050



	2050 Baseline
Carbon (MMT CO2)	50
CPS (%)[1]	63%
GHG Free Generation (%)[2]	60%
Annual Renewable Curtailment (%)	Low
Annual Cost Delta ($B)	Base
Additional Cost ($/MWh)	Base
% GHG Reduction from 1990 level	16%
Gas Capacity Factor (%)	46%

2050 Reference Scenario

Additions	Retirements
2 GW Wind	
4 GW Solar	
20 GW Gas	
	11 GW Coal

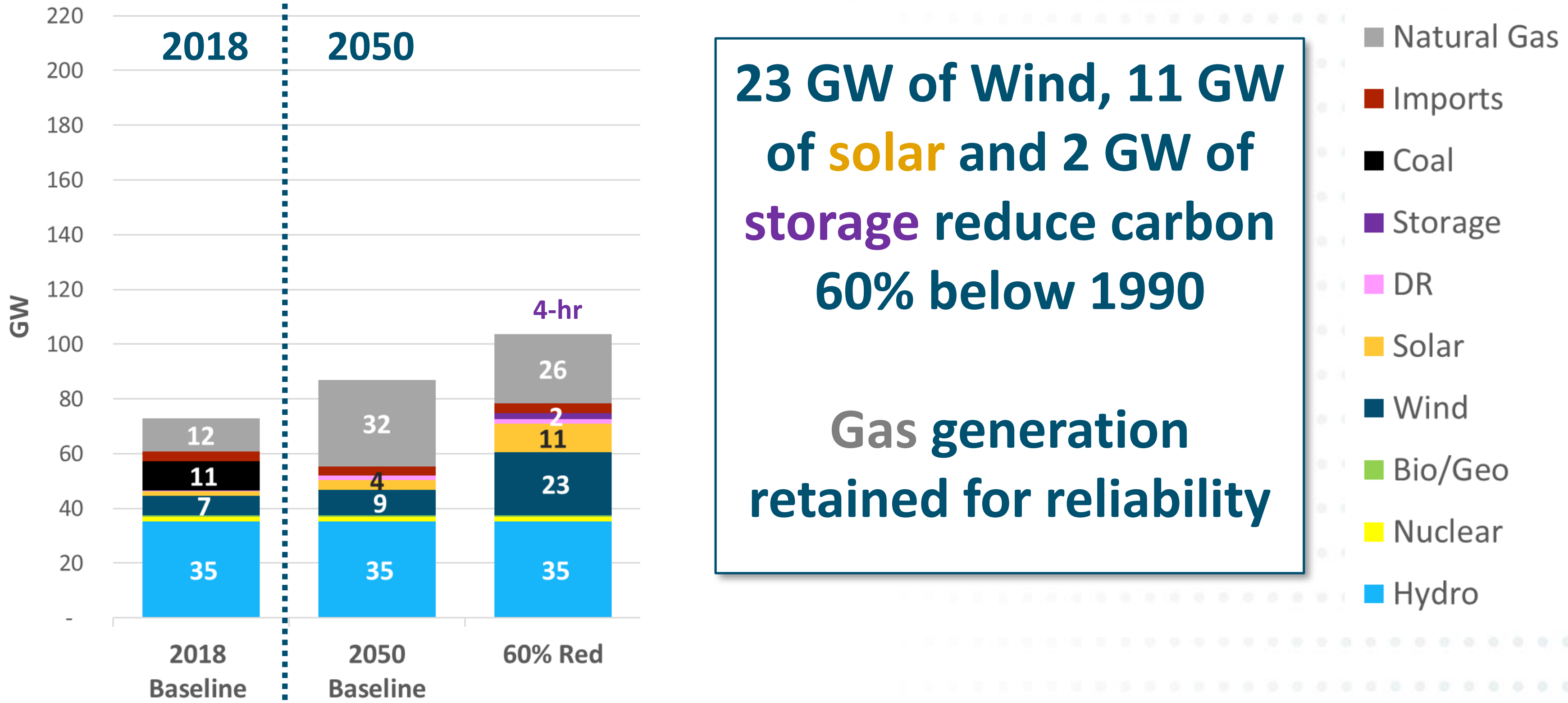
9 GW net increase in firm capacity

Total cost of new resource additions is $4 billion per year (~$30 billion investment)

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary

Greater NW System in 2050



23 GW of Wind, 11 GW of solar and 2 GW of storage reduce carbon 60% below 1990

Gas generation retained for reliability

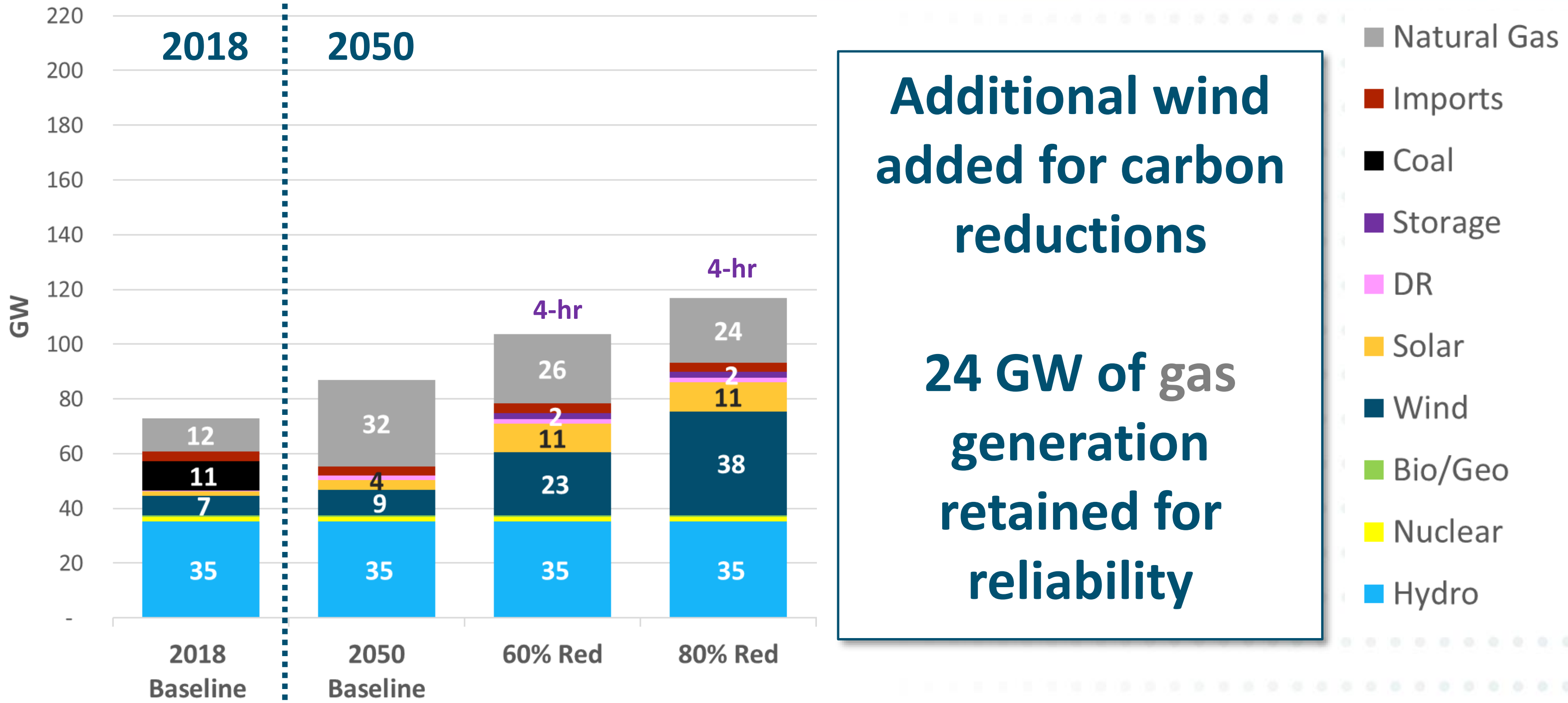
	2050 Baseline	60% Red
Carbon (MMT CO2)	50	25
CPS (%)[1]	63%	86%
GHG Free Generation (%)[2]	60%	80%
Annual Renewable Curtailment (%)	Low	Low
Annual Cost Delta ($B)	Base	$0 - $2
Additional Cost ($/MWh)	Base	$0 - $7
% GHG Reduction from 1990 level	16%	60%
Gas Capacity Factor (%)	46%	27%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary

Greater NW System in 2050



Additional wind added for carbon reductions

24 GW of gas generation retained for reliability

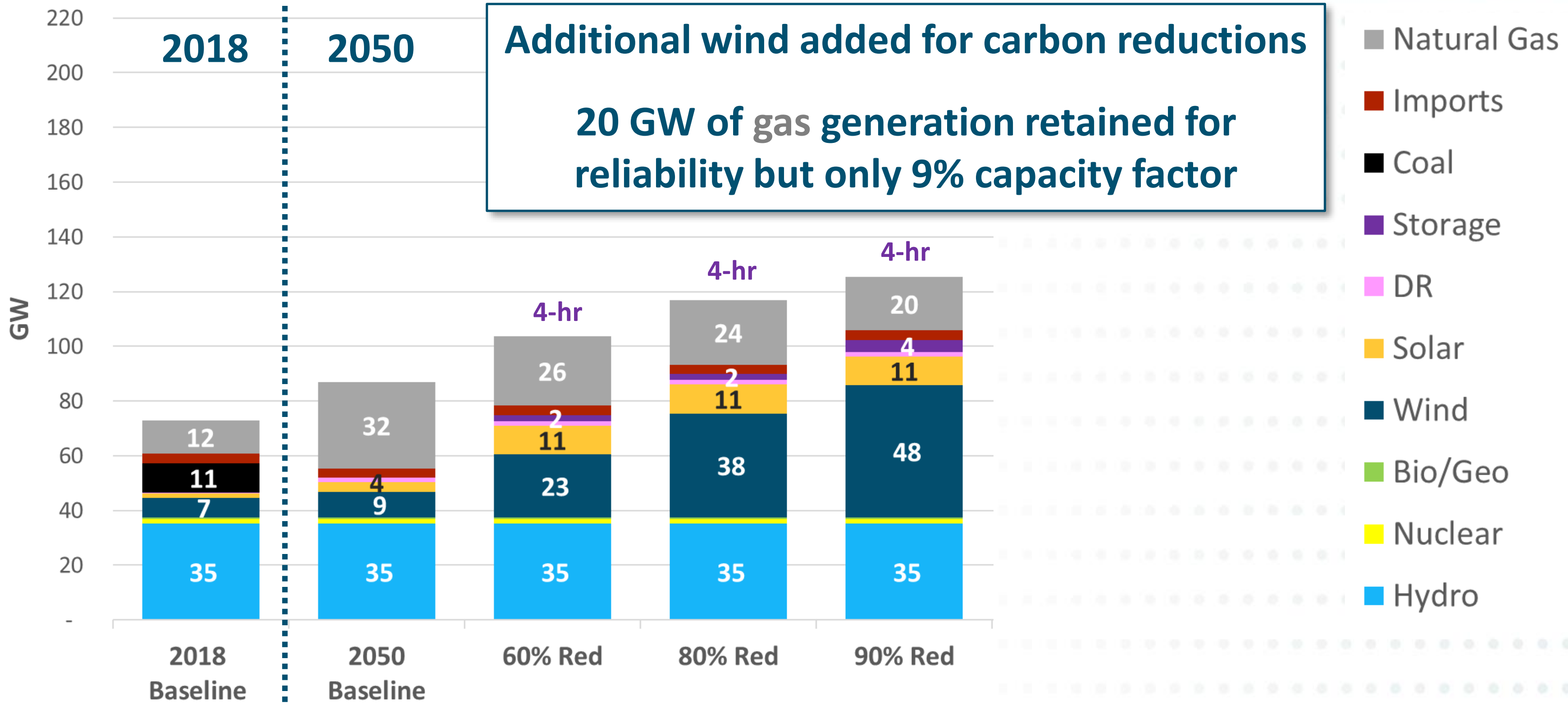
	2050 Baseline	60% Red	80% Red
Carbon (MMT CO2)	50	25	12
CPS (%)[1]	63%	86%	100%
GHG Free Generation (%)[2]	60%	80%	90%
Annual Renewable Curtailment (%)	Low	Low	4%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14
% GHG Reduction from 1990 level	16%	60%	80%
Gas Capacity Factor (%)	46%	27%	16%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary

Greater NW System in 2050



Additional wind added for carbon reductions

20 GW of gas generation retained for reliability but only 9% capacity factor

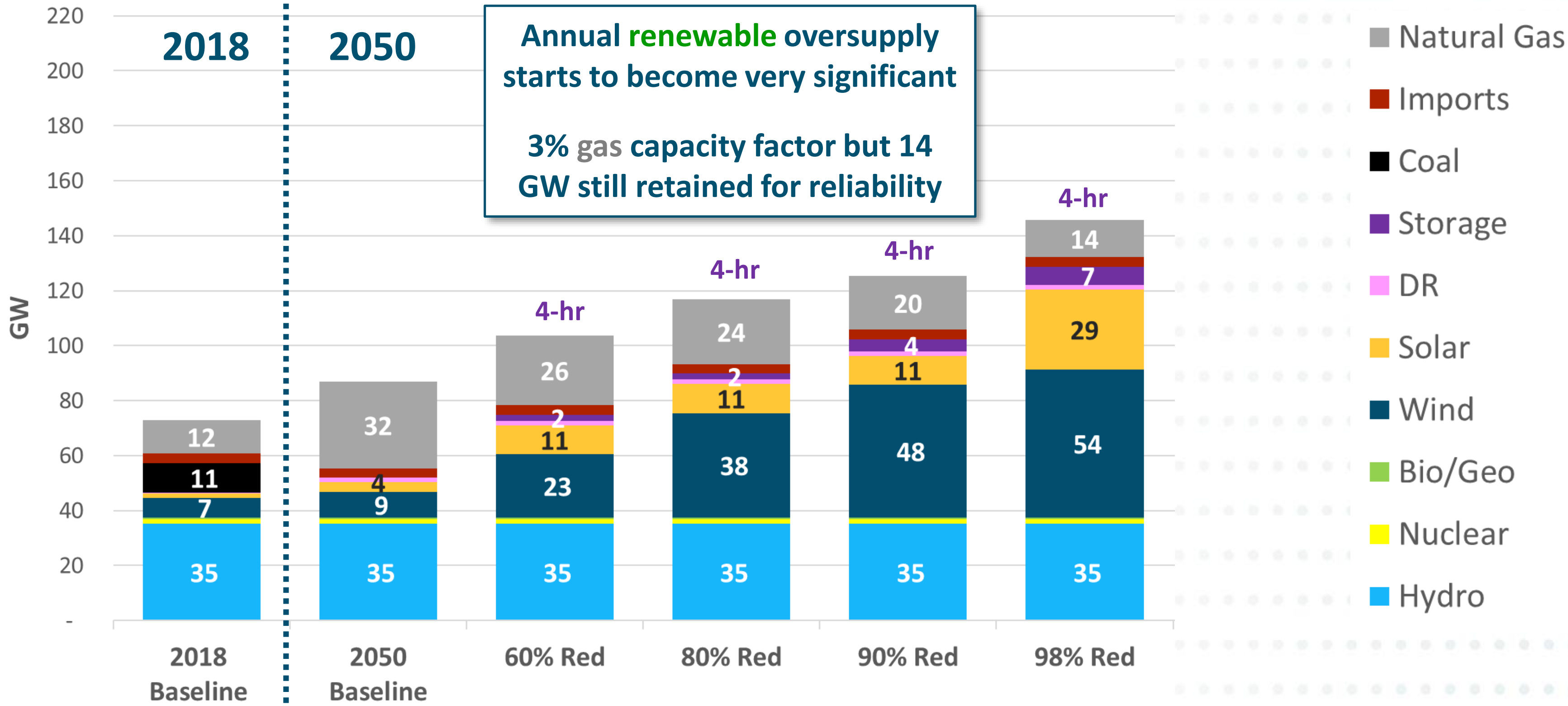
	2050 Baseline	60% Red	80% Red	90% Red
Carbon (MMT CO2)	50	25	12	6
CPS (%)[1]	63%	86%	100%	108%
GHG Free Generation (%)[2]	60%	80%	90%	95%
Annual Renewable Curtailment (%)	Low	Low	4%	10%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18
% GHG Reduction from 1990 level	16%	60%	80%	90%
Gas Capacity Factor (%)	46%	27%	16%	9%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary

Greater NW System in 2050



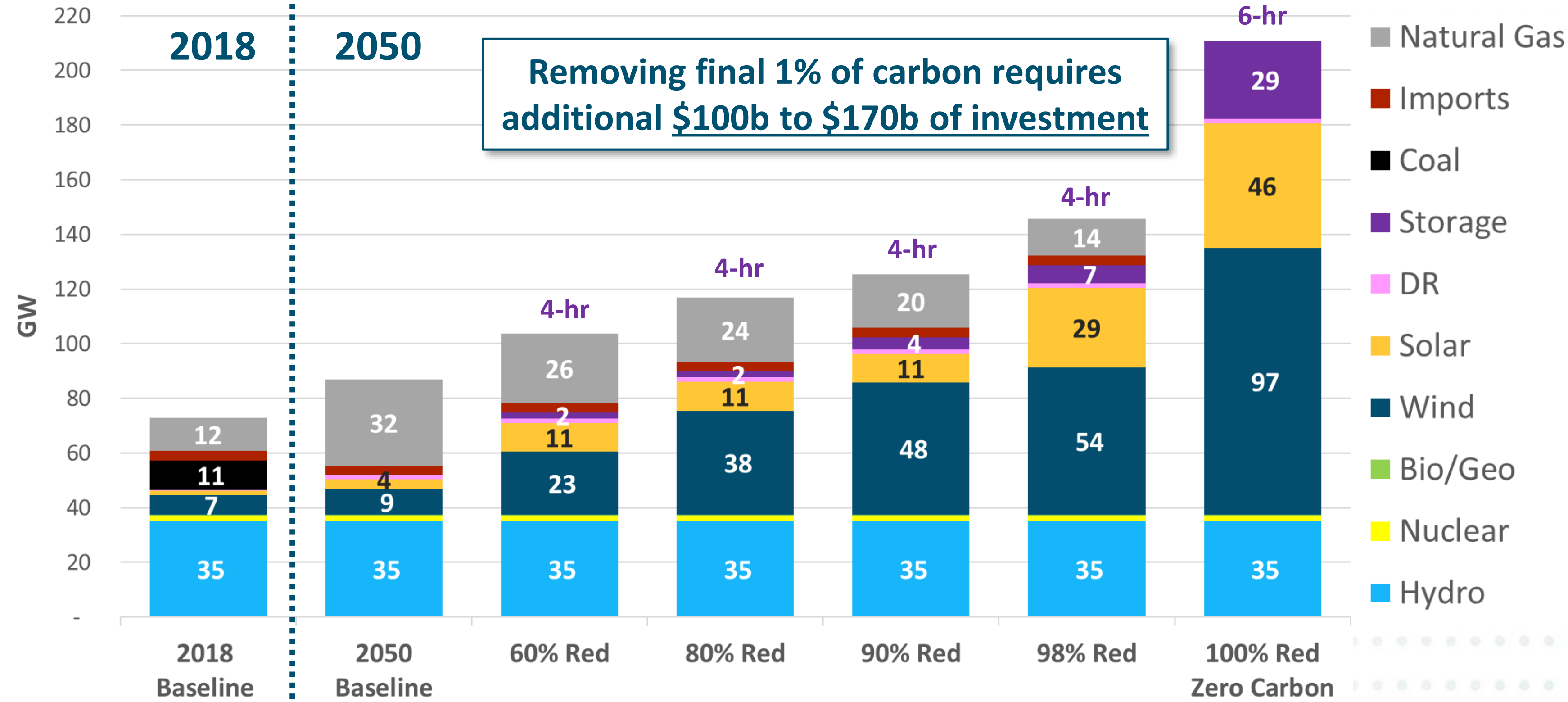
	2050 Baseline	60% Red	80% Red	90% Red	98% Red
Carbon (MMT CO2)	50	25	12	6	1
CPS (%)[1]	63%	86%	100%	108%	117%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%
Gas Capacity Factor (%)	46%	27%	16%	9%	3%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary

Greater NW System in 2050

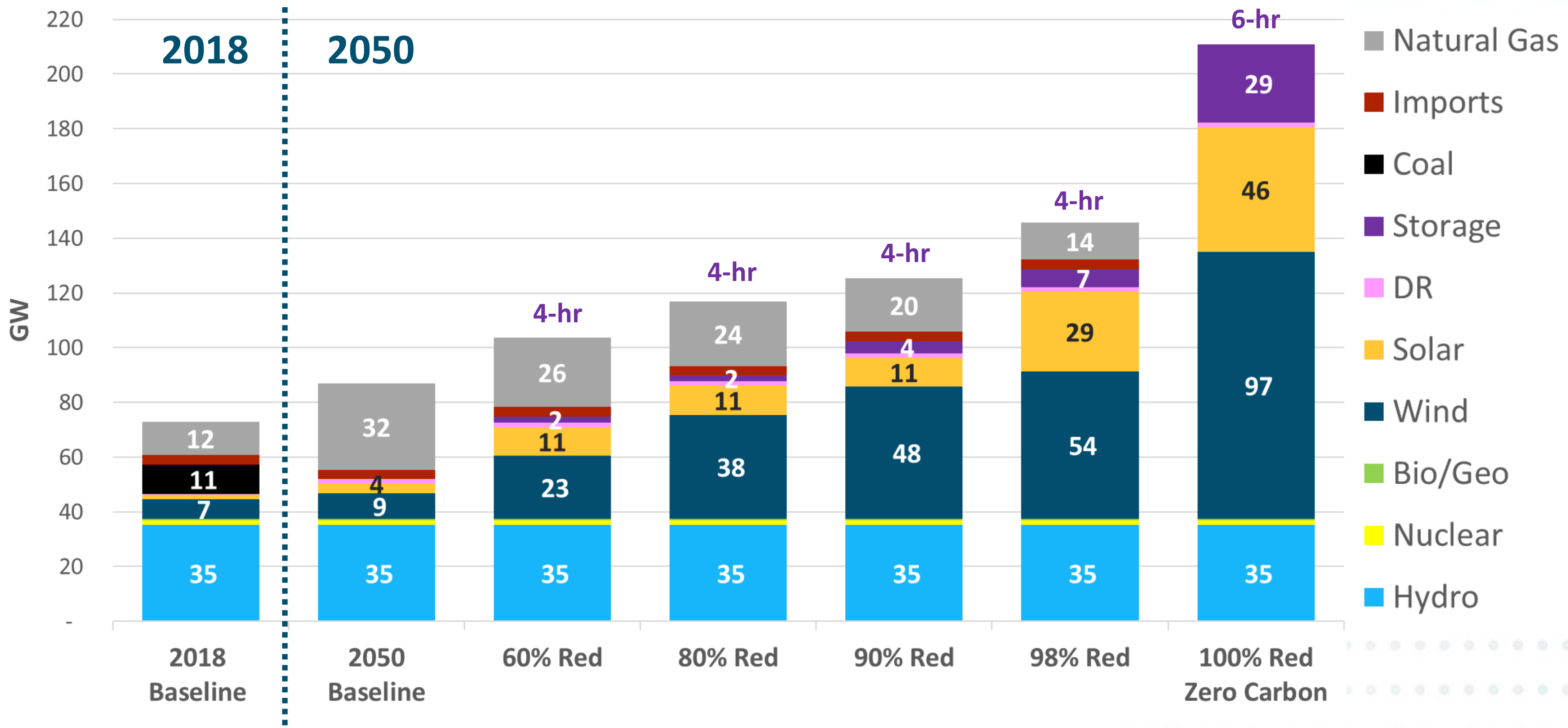


Carbon (MMT CO2)	50	25	12	6	1	-
CPS (%)[1]	63%	86%	100%	108%	117%	123%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%	100%
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28	$52 - $89
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%	100%
Gas Capacity Factor (%)	46%	27%	16%	9%	3%	0%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

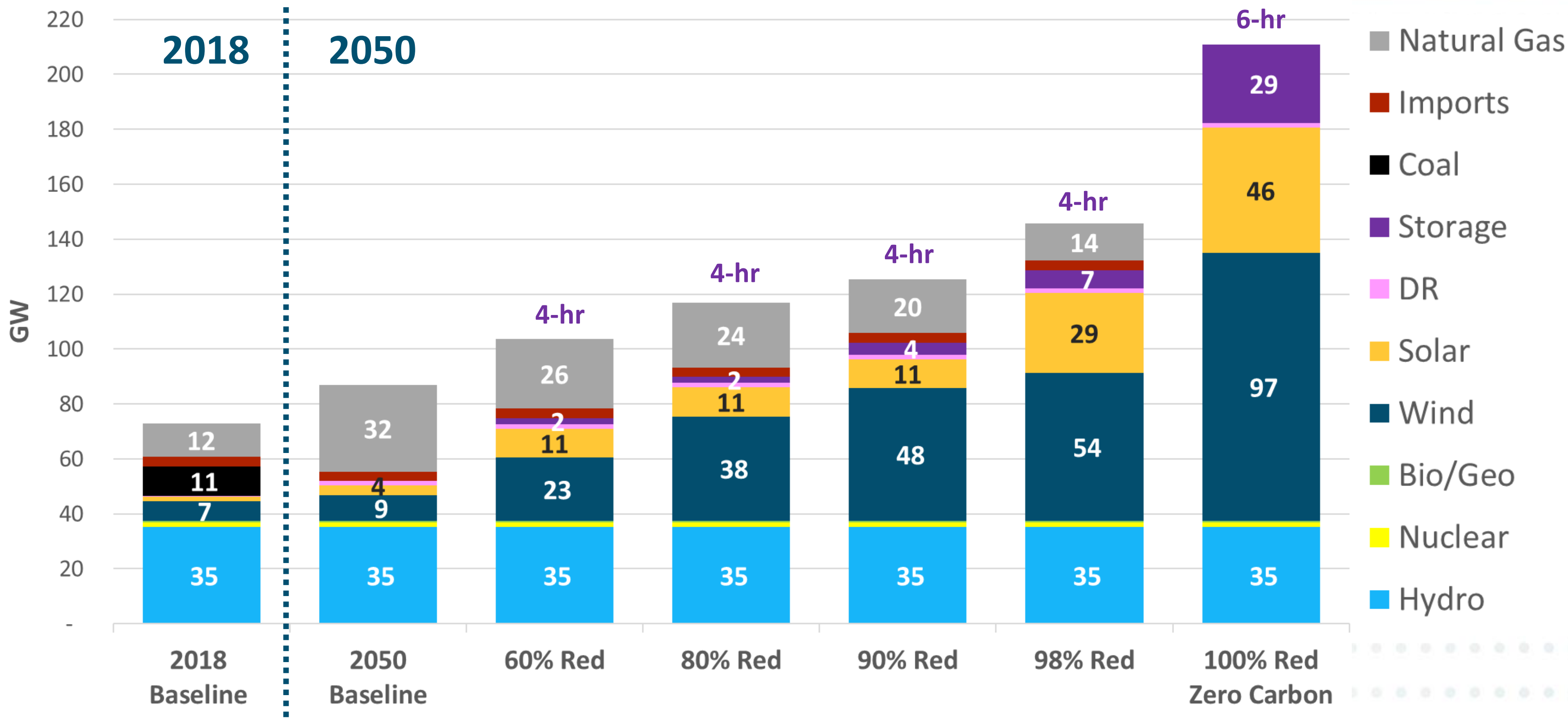
Scenario Summary
2050 Emissions Reductions



Carbon (MMT CO2)	50	25	12	6	1	-
CPS (%)[1]	63%	86%	100%	108%	117%	123%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%	100%
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%	100%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

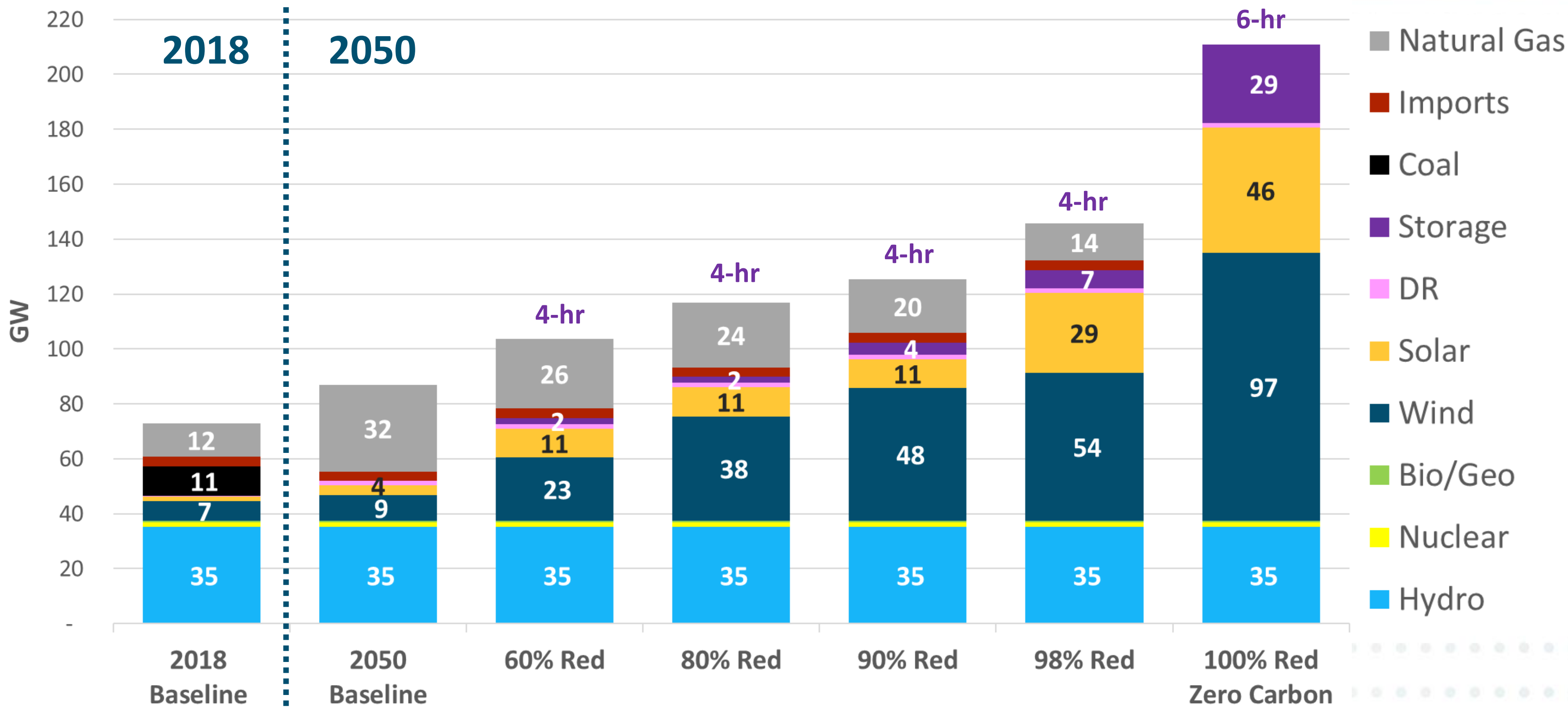
Scenario Summary
2050 Resource Use



Renewable Capacity (GW)	13	34	49	59	83	143
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Gas Capacity (GW)	32	26	24	20	14	0
Gas Capacity Factor (%)	46%	27%	16%	9%	3%	0%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

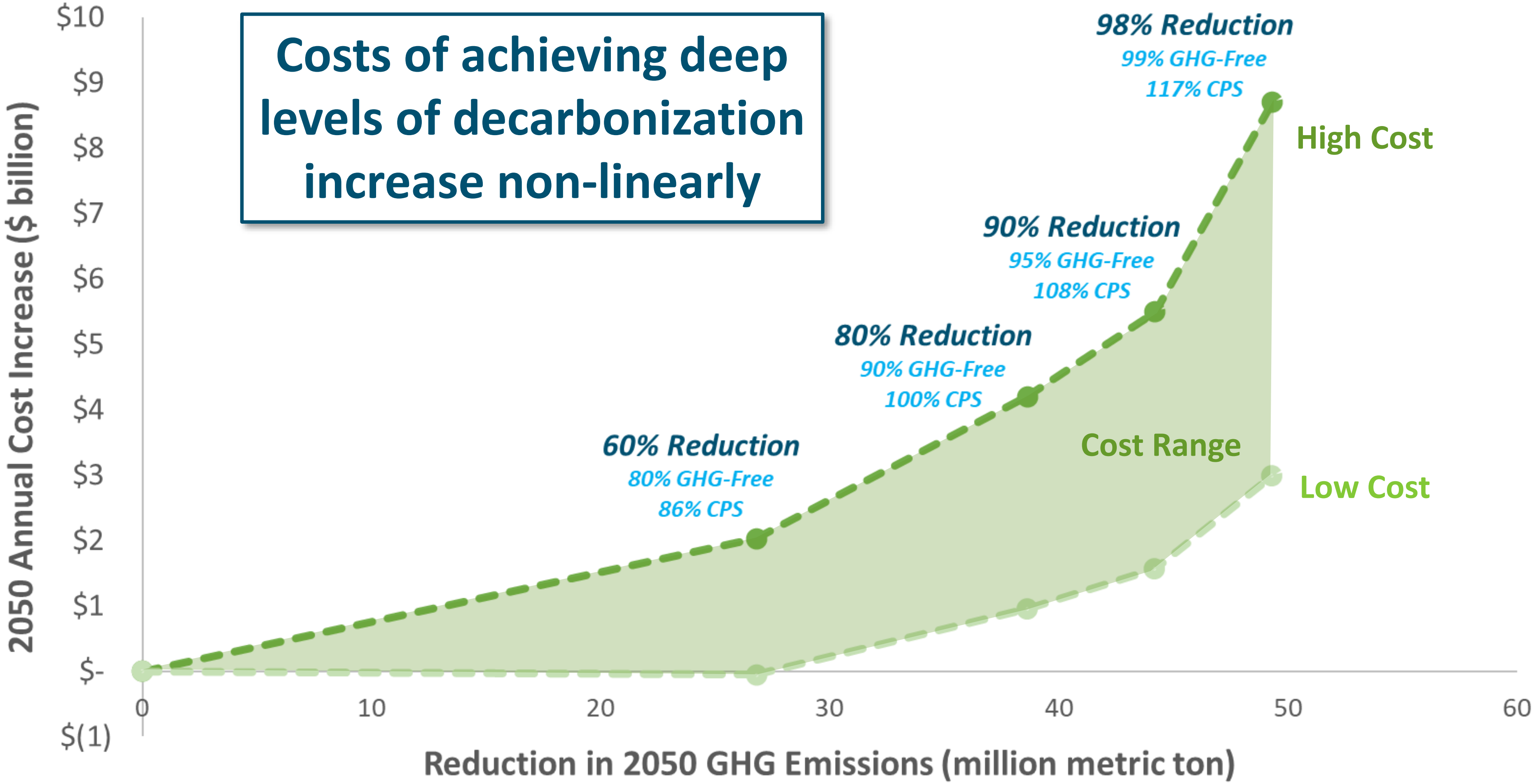
Scenario Summary
2050 Costs



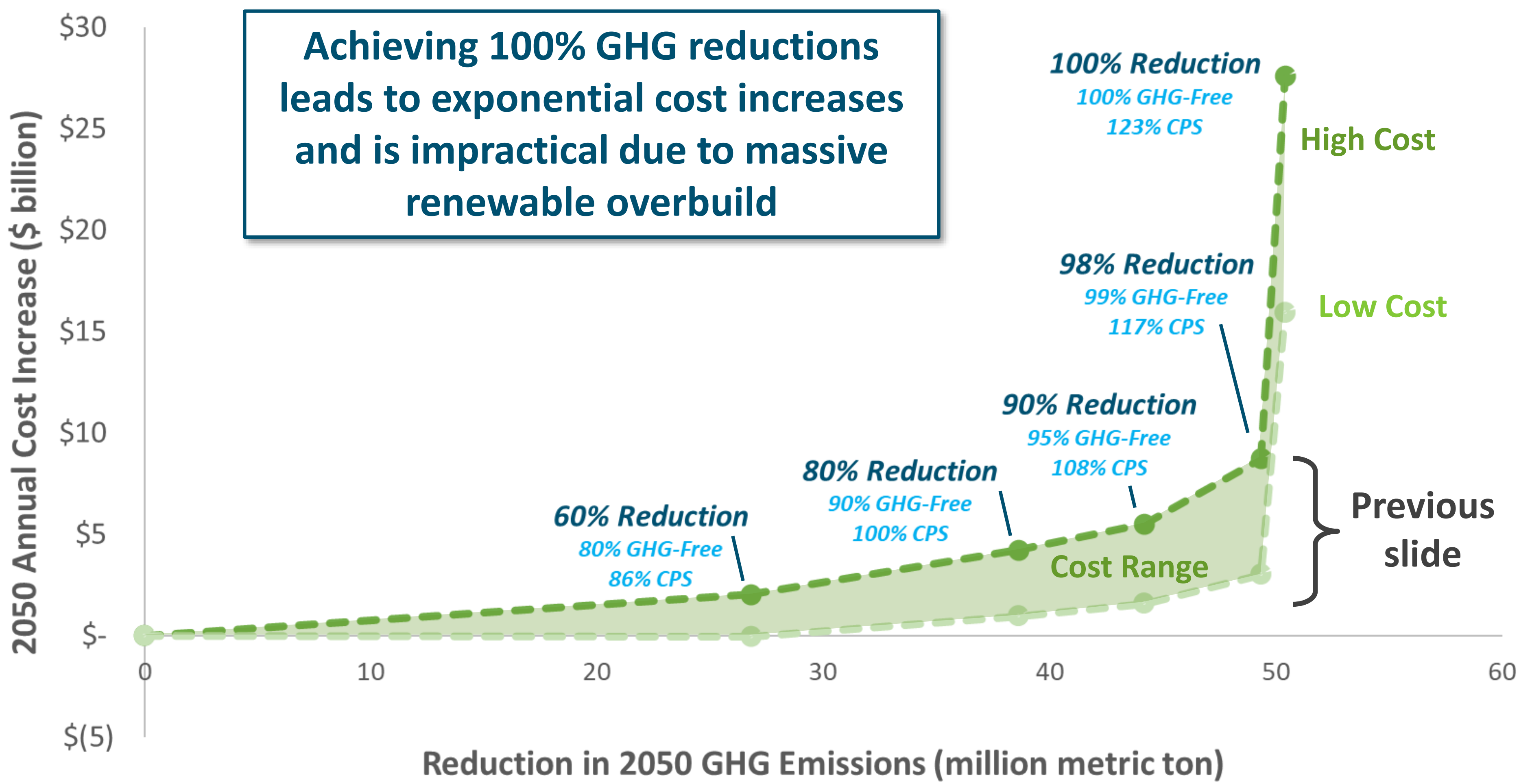
Marginal Carbon Reduction Cost ($/Metric Ton)	Base	$0 - $80	$90 - $190	$110 - $230	$310 - $700	$11,000 – $16,000
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28	$52 - $89

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Cost of GHG Reduction

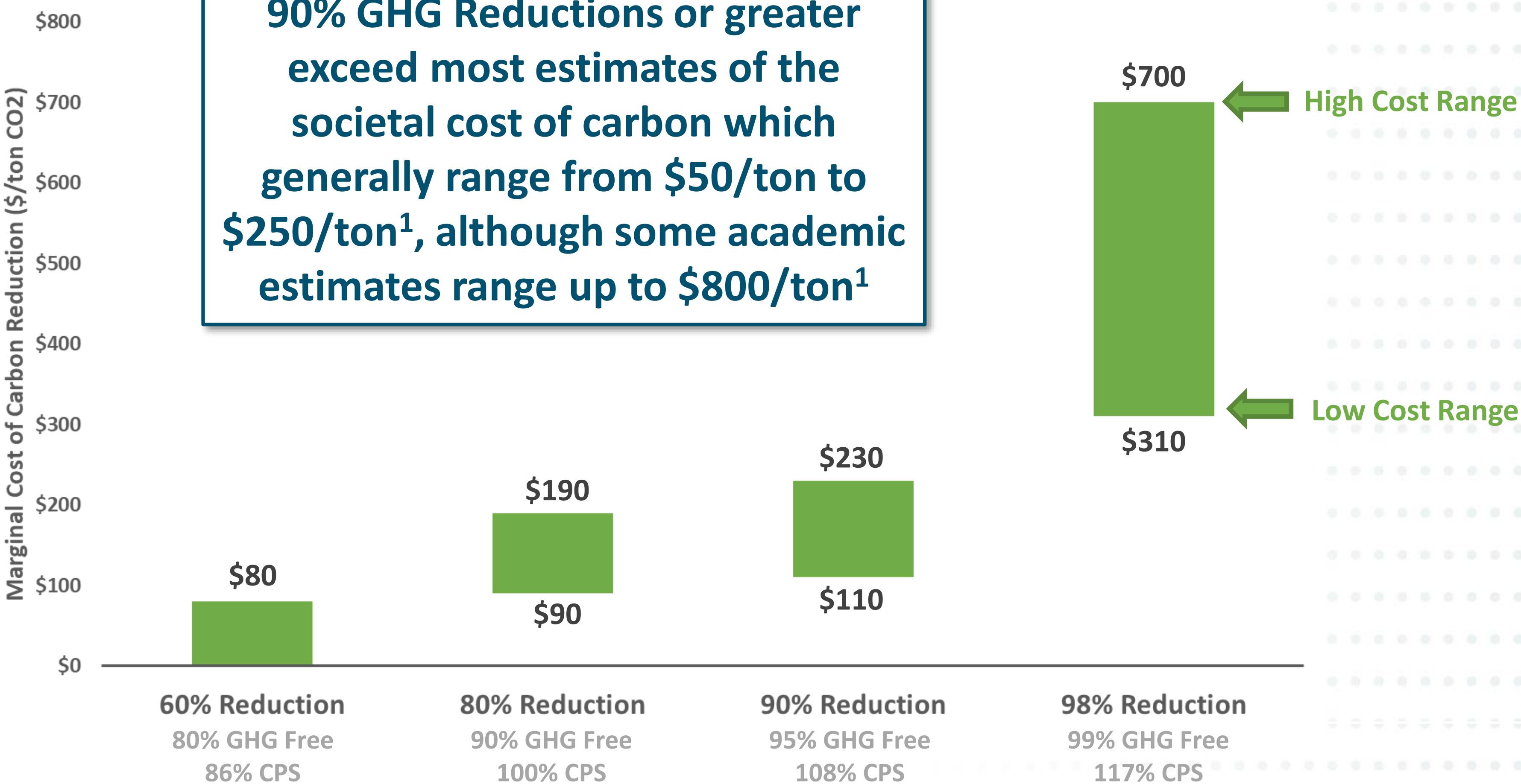


Cost of GHG Reduction



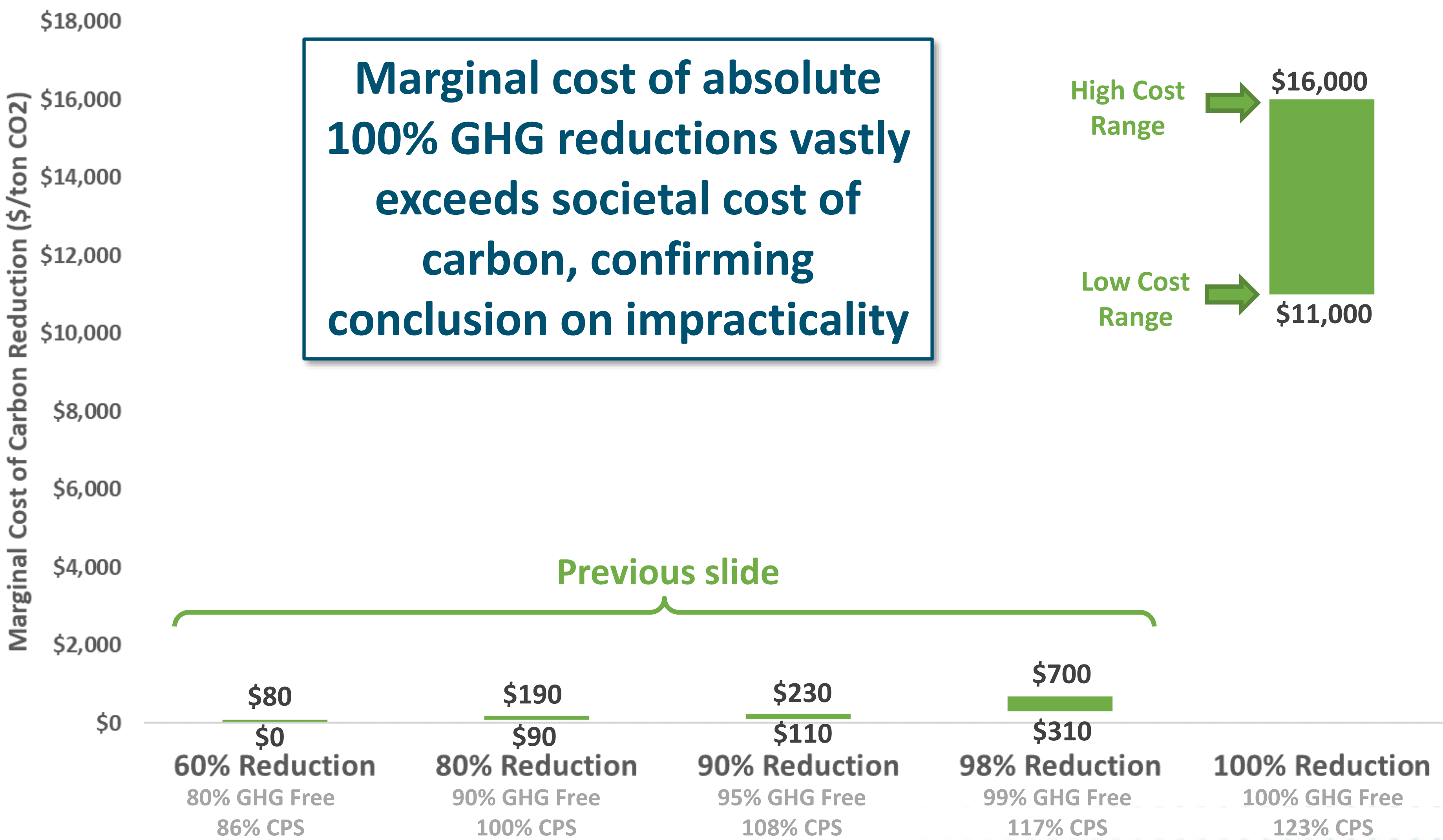
Marginal Cost of GHG Reduction

Marginal cost of CO2 reductions at 90% GHG Reductions or greater exceed most estimates of the societal cost of carbon which generally range from \$50/ton to \$250/ton[1], although some academic estimates range up to \$800/ton[1]



[1] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html; https://www.nature.com/articles/s41558-018-0282-y

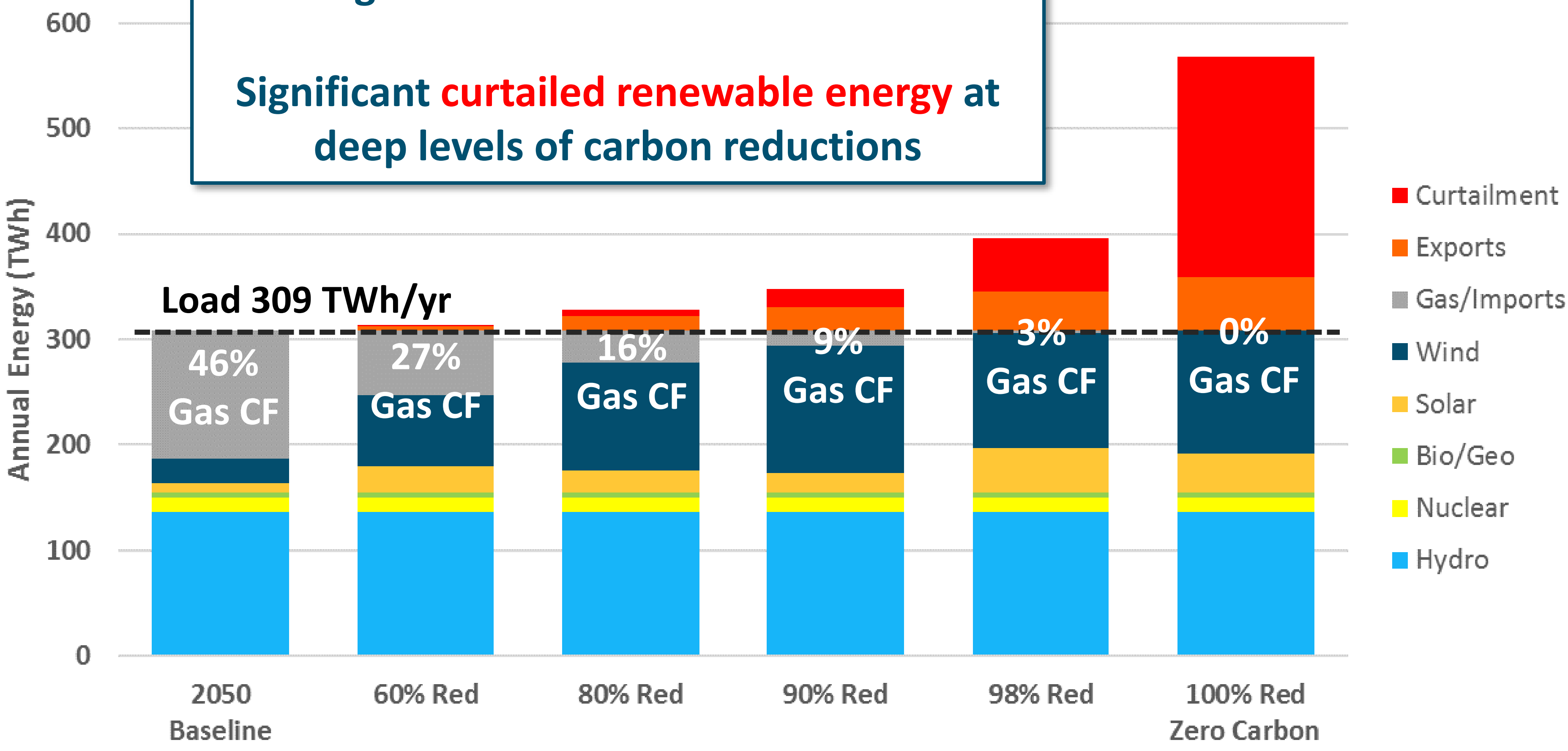
Marginal Cost of GHG Reduction



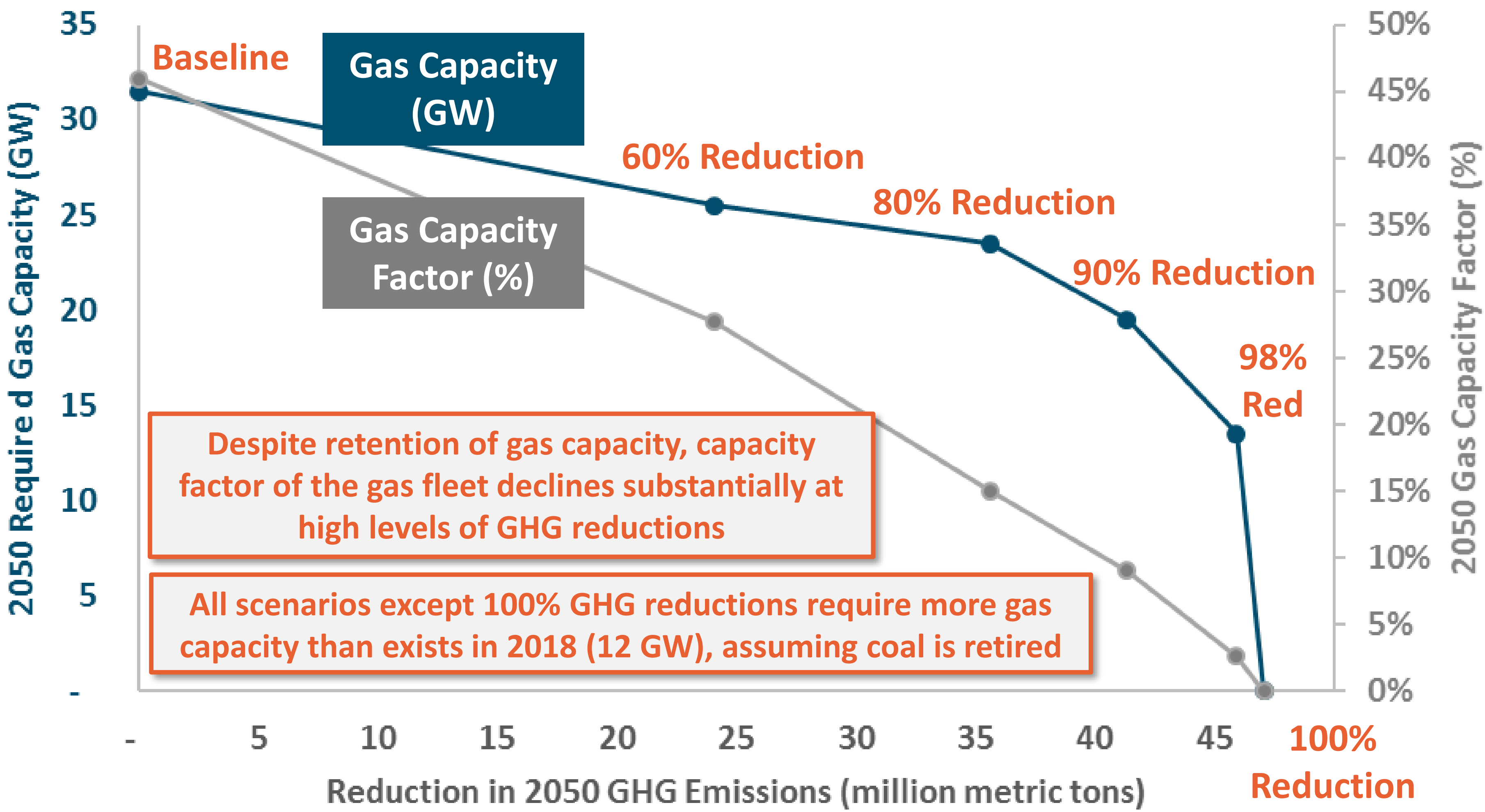
2050 Annual Energy Balance

Gas capacity factor declines significantly at higher levels of decarbonization

Significant curtailed renewable energy at deep levels of carbon reductions



Gas capacity is still needed for reliability under deep decarbonization despite lower utilization



2050 Load and Resource Balance

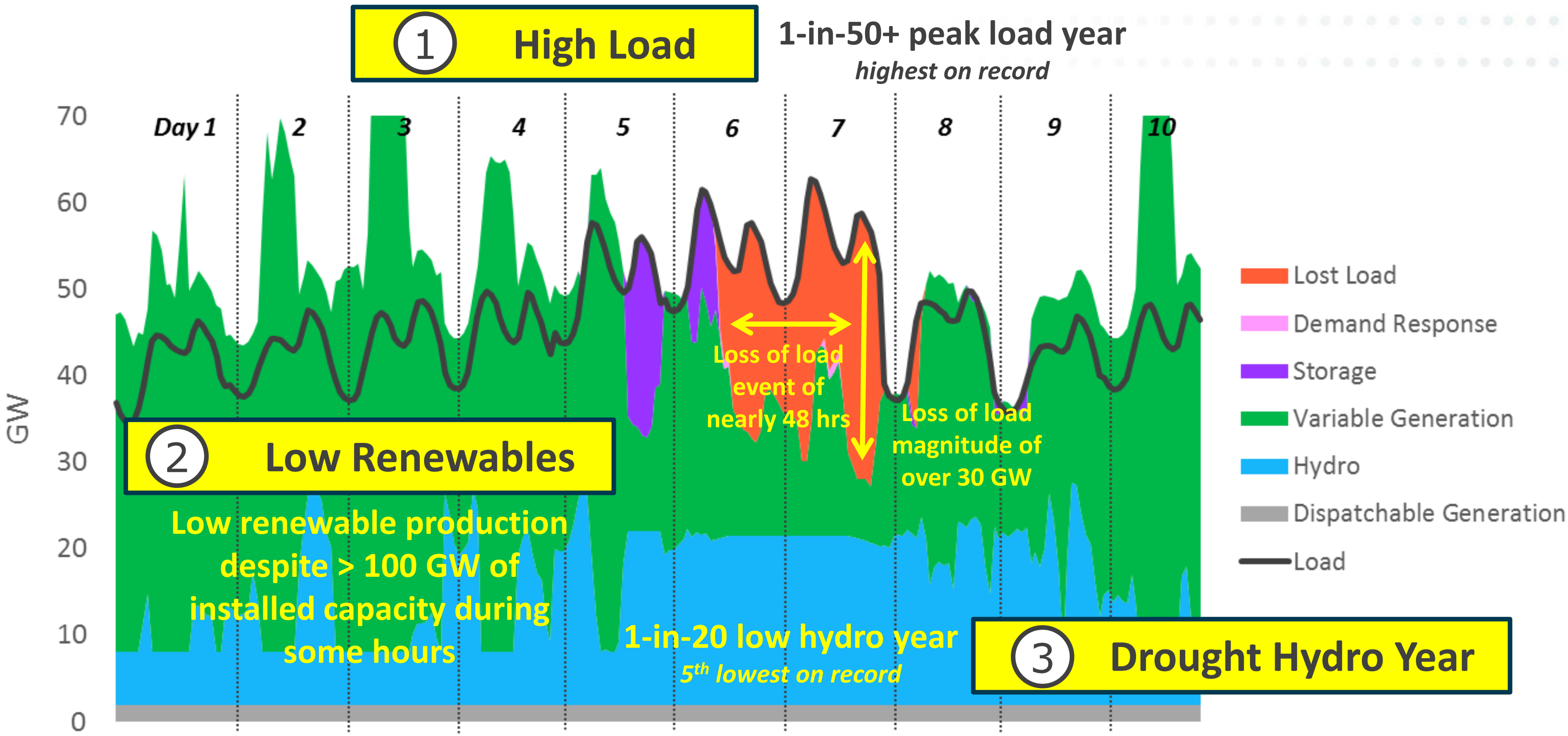
	2050		
	80% Reduction	90% Reduction	100% Reduction
Load (GW)			
Peak (Pre-EE)	65	65	65
Peak (Post-EE)	54	54	54
PRM (%)	*9%*	*9%*	*7%*
PRM	5	5	4
Total Load Requirement	59	59	57

Resources / Effective Capacity (GW)	80% Reduction	90% Reduction	100% Reduction	Nameplate Capacity (GW)			ELCC (%)			Capacity Factor (%)		
				80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.
Coal	0	0	0									
Gas	24	20	0									
Bio/Geo	0.6	0.6	0.6									
Imports	2	2	0									
Nuclear	1	1	1									
DR	1	1	1									
Hydro	20	20	20	*35*	*35*	*35*	*58%*	*58%*	*57%*	*44%*	*44%*	*44%*
Wind	7	11	21	*38*	*48*	*96*	*19%*	*22%*	*22%*	*35%*	*36%*	*37%*
Solar	2.0	2.2	7.5	*11*	*11*	*46*	*19%*	*21%*	*16%*	*27%*	*27%*	*27%*
Storage	1.6	1.8	5.8	*2.2*	*4.4*	*29*	*71%*	*41%*	*20%*	*N/A*	*N/A*	*N/A*
Total Supply	59	59	57									

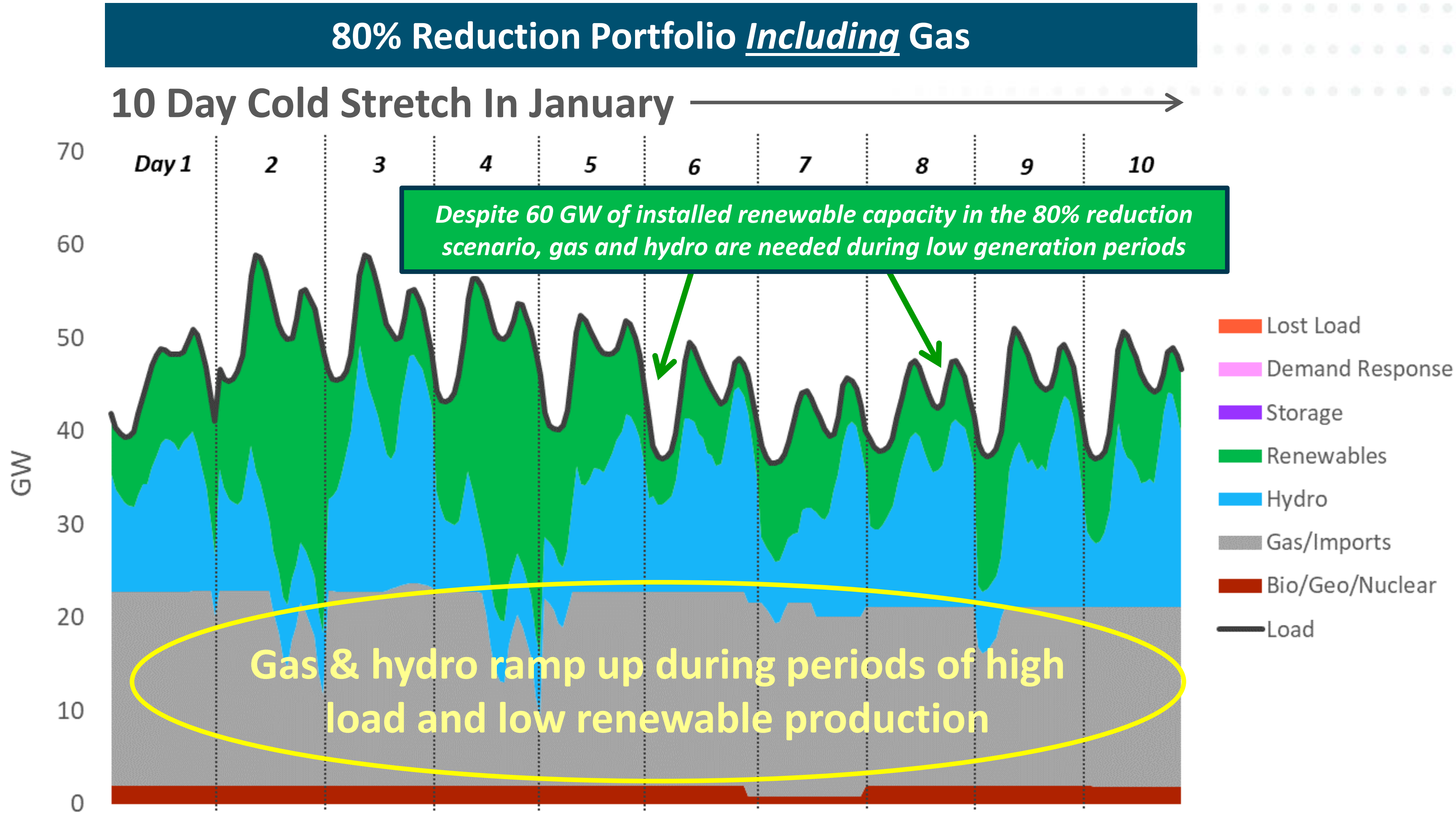
Wind ELCC* values are higher than today due to significant contribution from MT/WY wind

**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

The Stressful Tri-Fecta

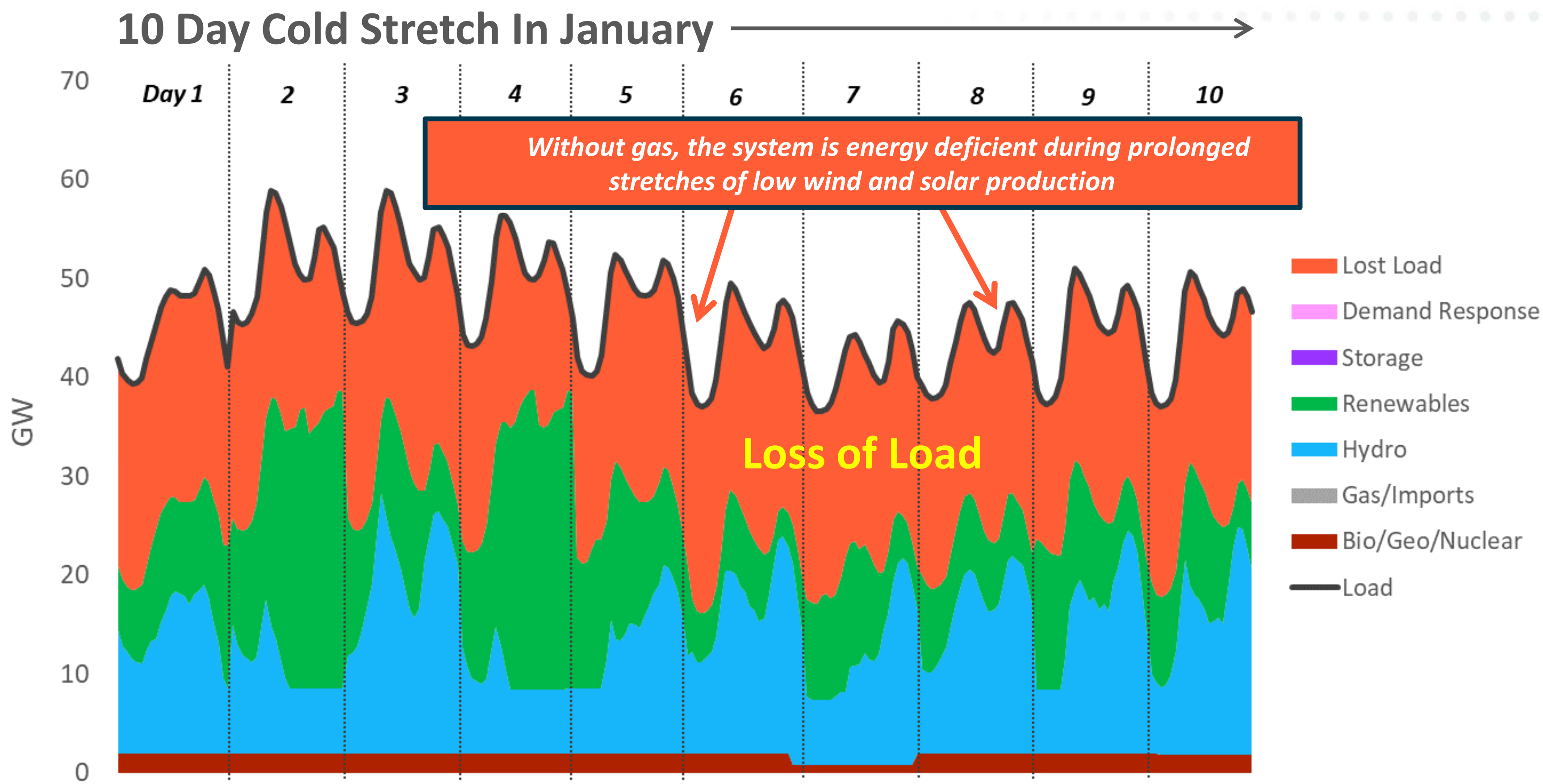


Illustrating the Need for Firm Capacity – January

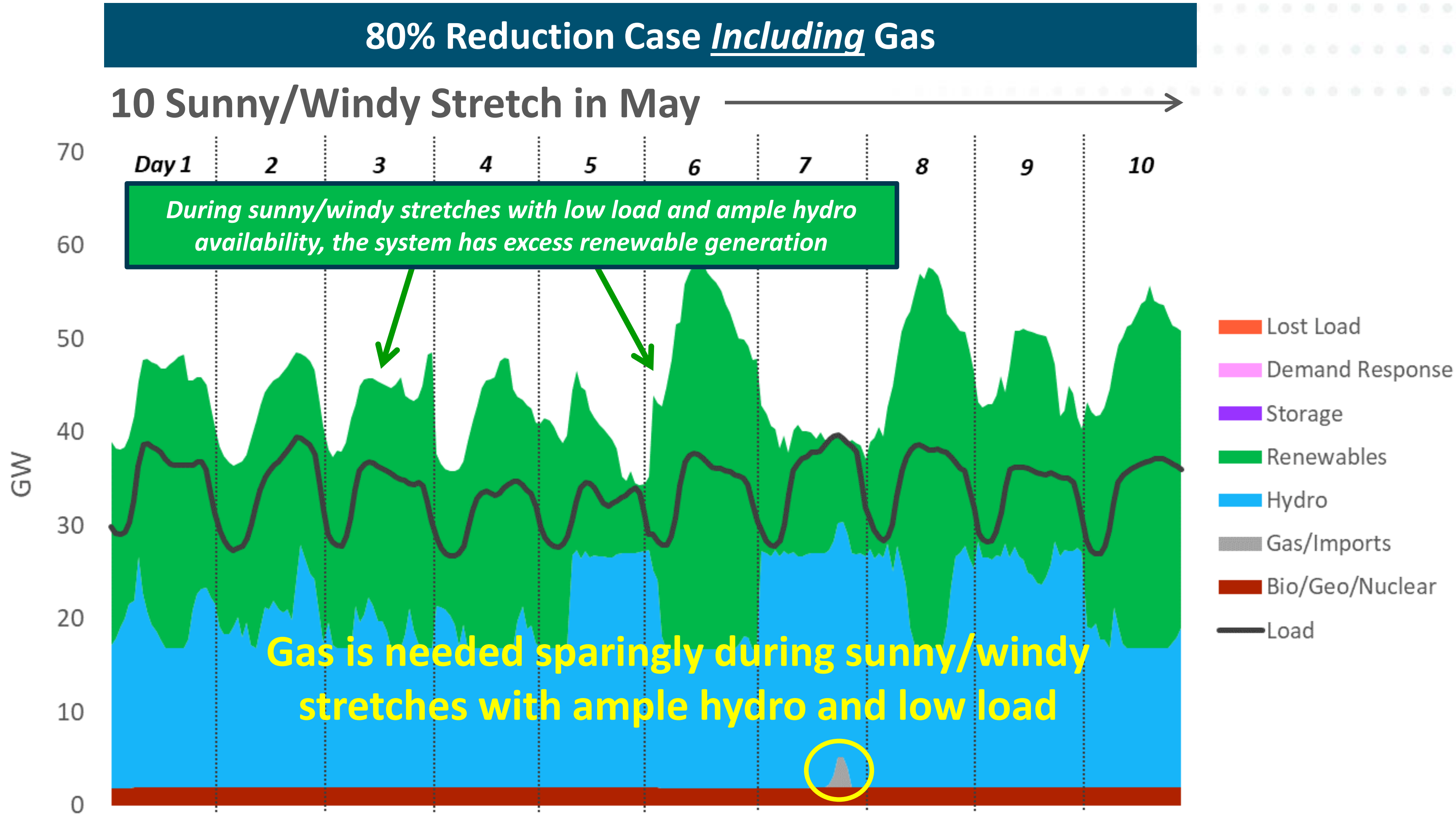


Illustrating the Need for Firm Capacity – January

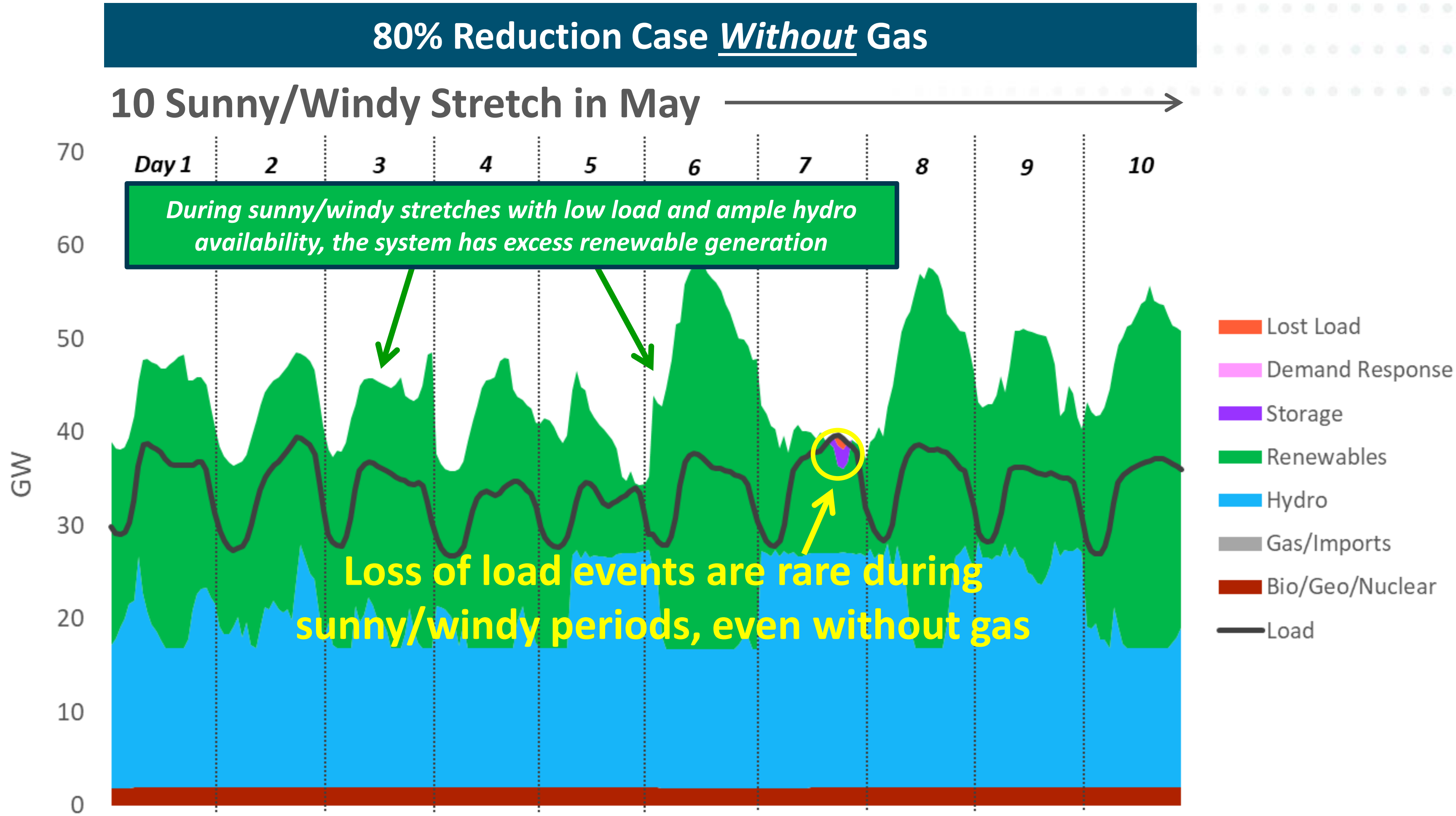
80% Reduction Case *Without* Gas



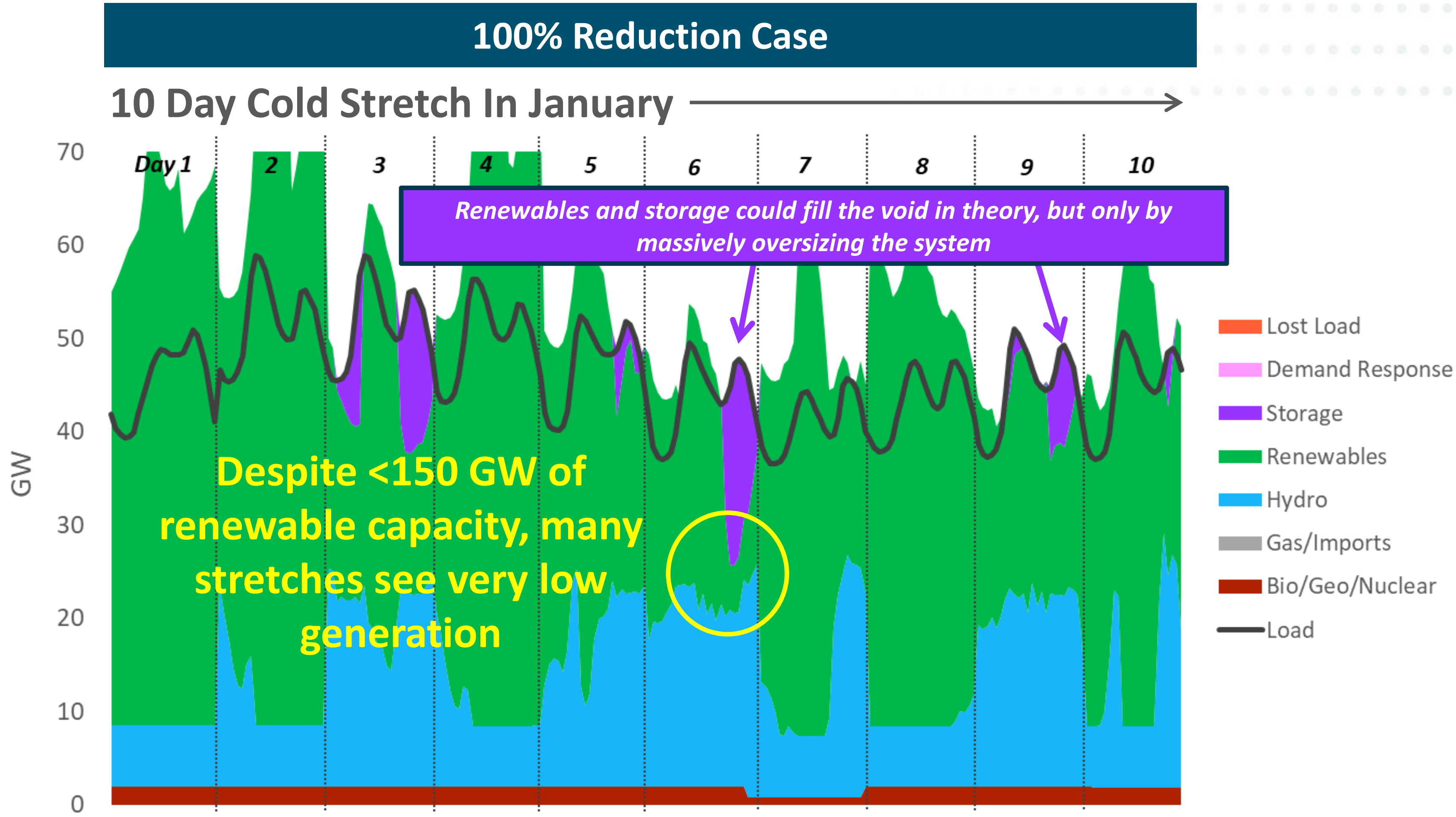
Illustrating the Need for Firm Capacity – May



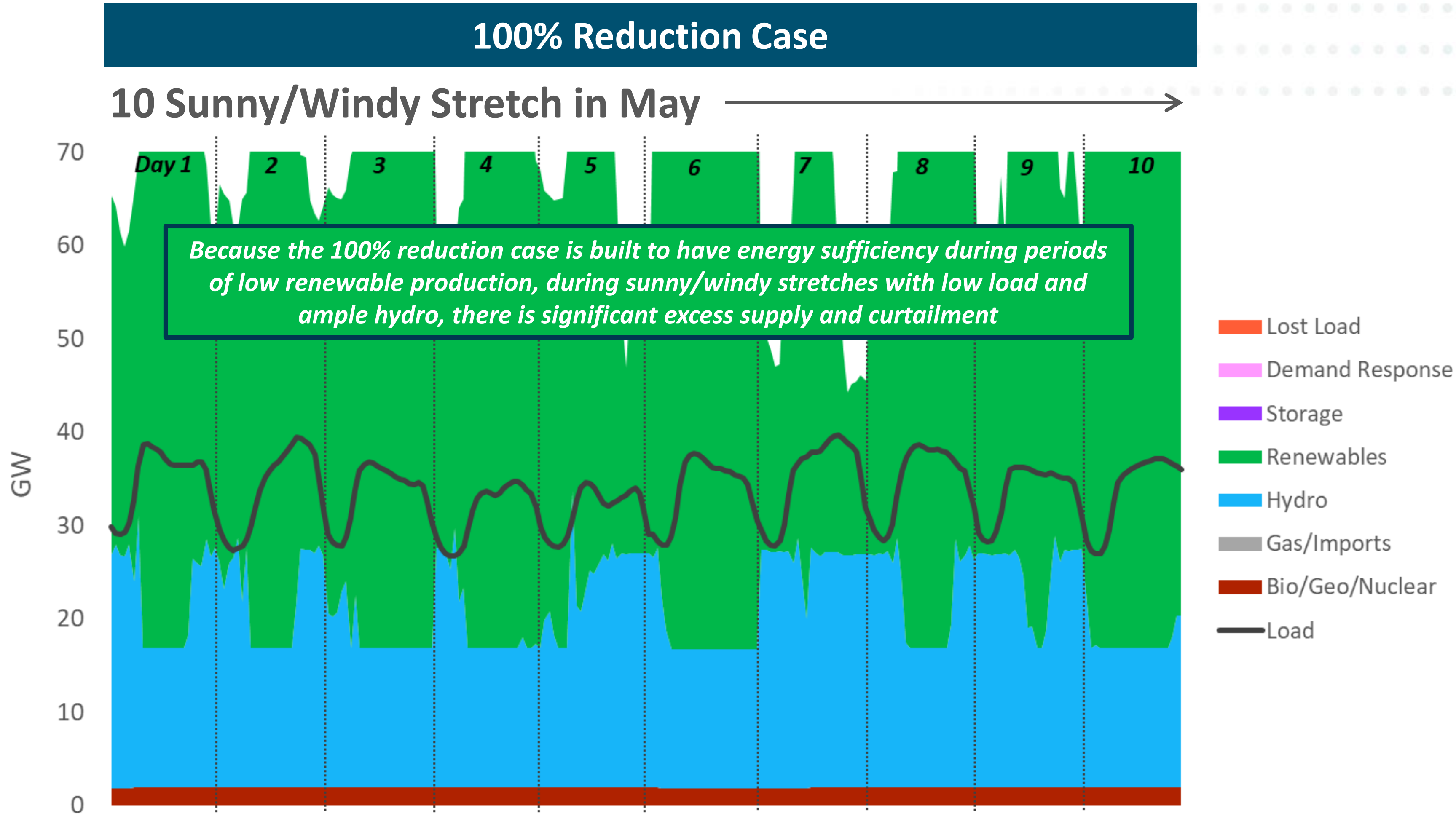
Illustrating the Need for Firm Capacity – May



Illustrating the Need for Firm Capacity – January

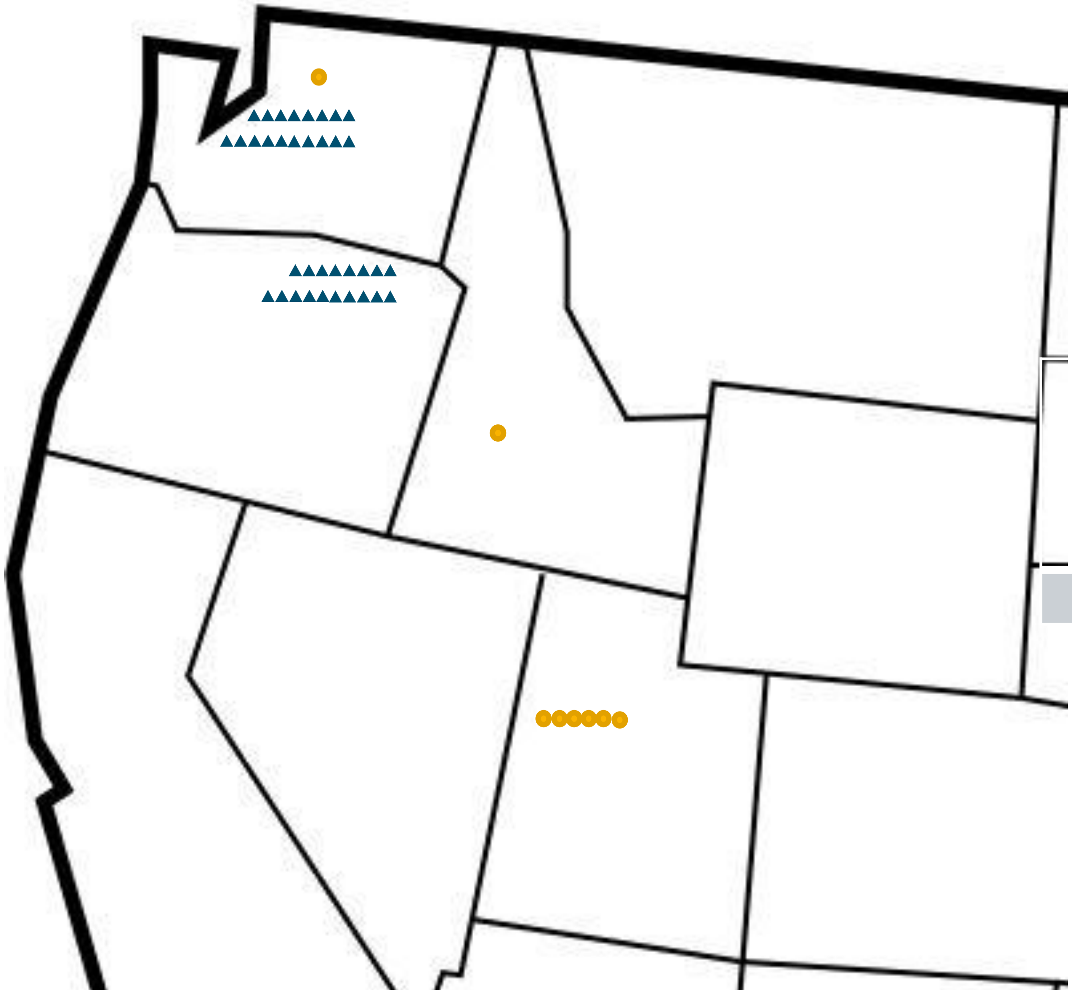


Illustrating the Need for Firm Capacity – May



Renewable Land Use

2018 Installed Renewables



Technology	Nameplate GW
● Solar	1.6
▲ NW Wind	7.1
■ MT Wind	0
★ WY Wind	2

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind – Total Land Use (thousand acres)
Today	12	19	223 – 1,052

Land use today ranges from

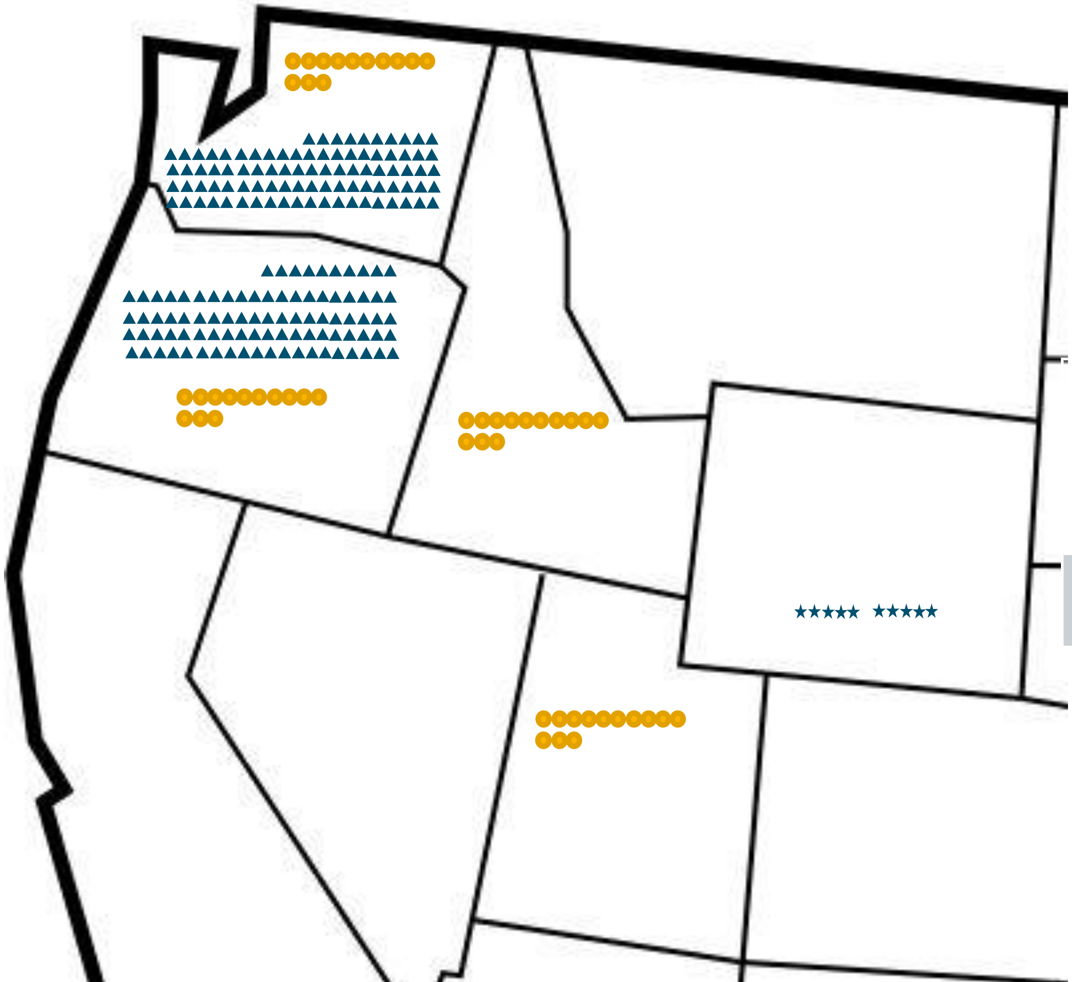
1.6 to 7.5x

the area of Portland and Seattle combined

Each point on the map indicates 200 MW. Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

Renewable Land Use
80% Reduction in 2050



Technology	Nameplate GW
● Solar	11
▲ NW Wind	36
▪ MT Wind	0
★ WY Wind	2

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind - Total Land Use (thousand acres)
80% Red	84	94	1,135 – 5,337

Land use in 80% Reduction case ranges from

8 to 37x

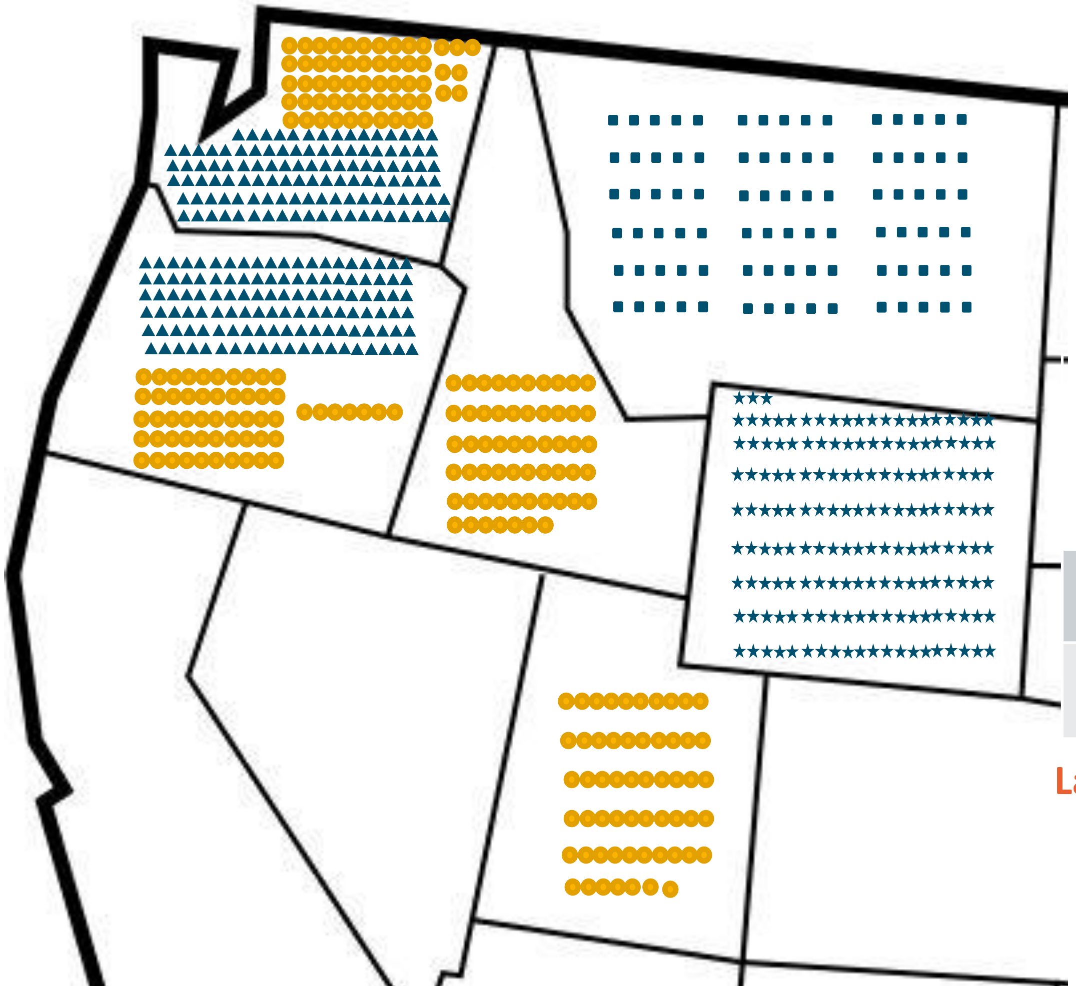
the area of Portland and Seattle combined

Each point on the map indicates 200 MW.
Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

Renewable Land Use

100% Reduction in 2050



Technology	Nameplate GW
● Solar	46
▲ NW Wind	47
▪ MT Wind	18
★ WY Wind	33

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind - Total Land Use (thousand acres)
80% Clean	84	94	1,135 – 5,337
100% Red	361	241	2,913 – 13,701

Land use in 100% Reduction case ranges from

20 to 100x

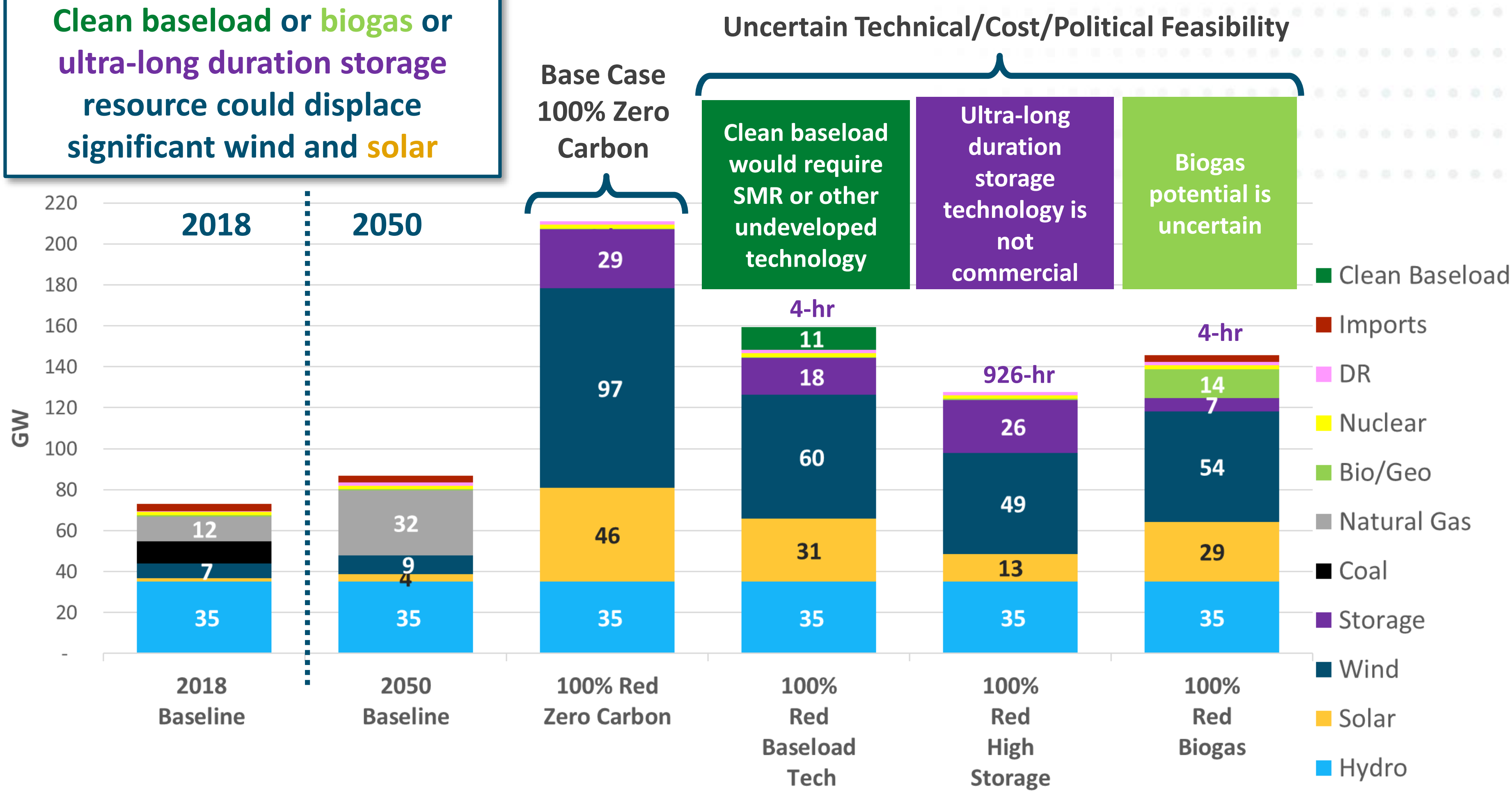
the area of Portland and Seattle combined

Each point on the map indicates 200 MW.
Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

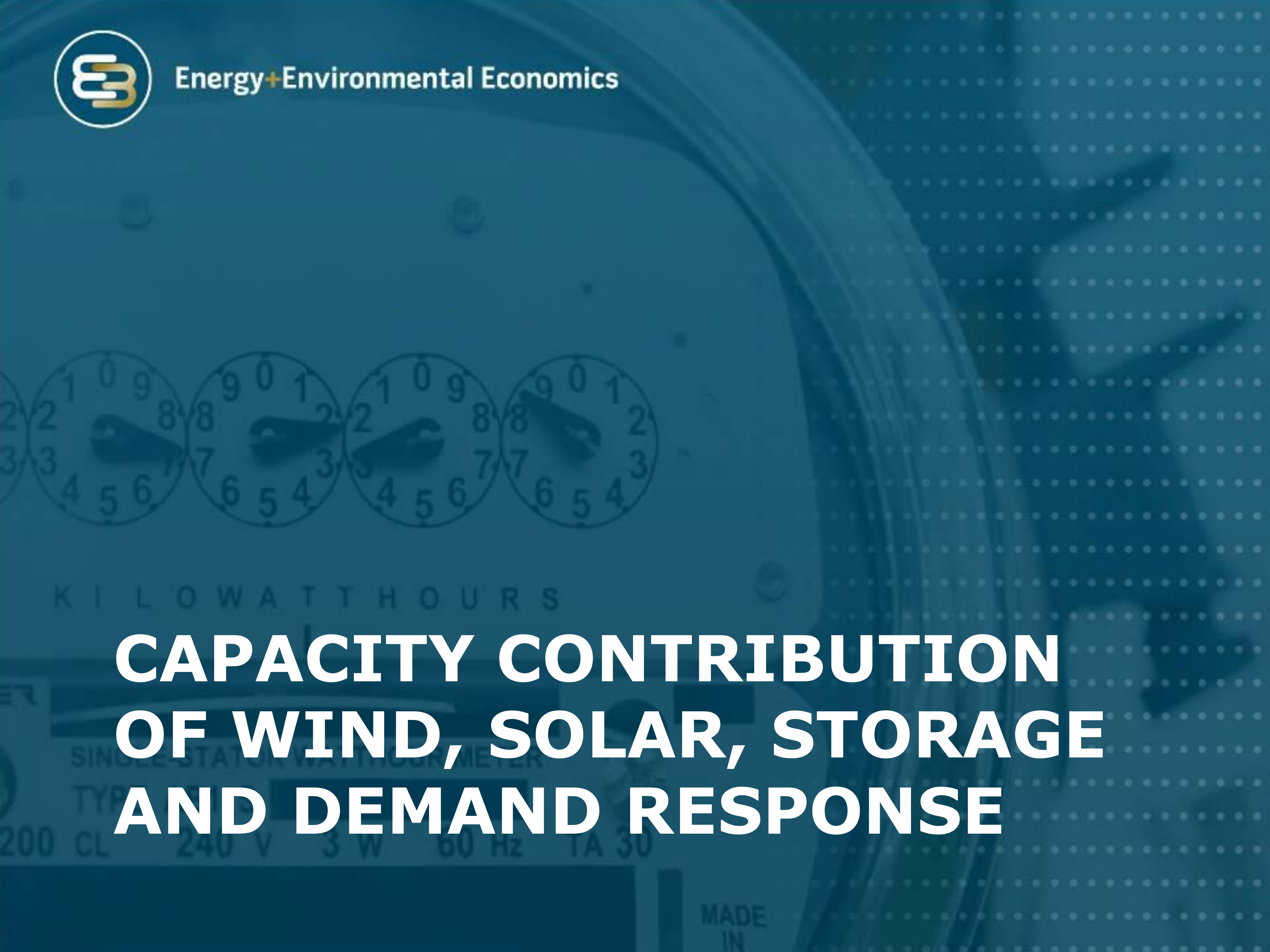
100% Reduction Portfolio Alternatives in 2050

Clean baseload or biogas or ultra-long duration storage resource could displace significant wind and solar



Carbon (MMT CO2)	50	0	0	0	0
Annual Cost Delta ($B)	Base	$16- $28	$14-$21	$550-$990	$4 - $9
Additional Cost ($/MWh)	Base	$52-$89	$46-$69	$1,800-$3,200	$14 - $30

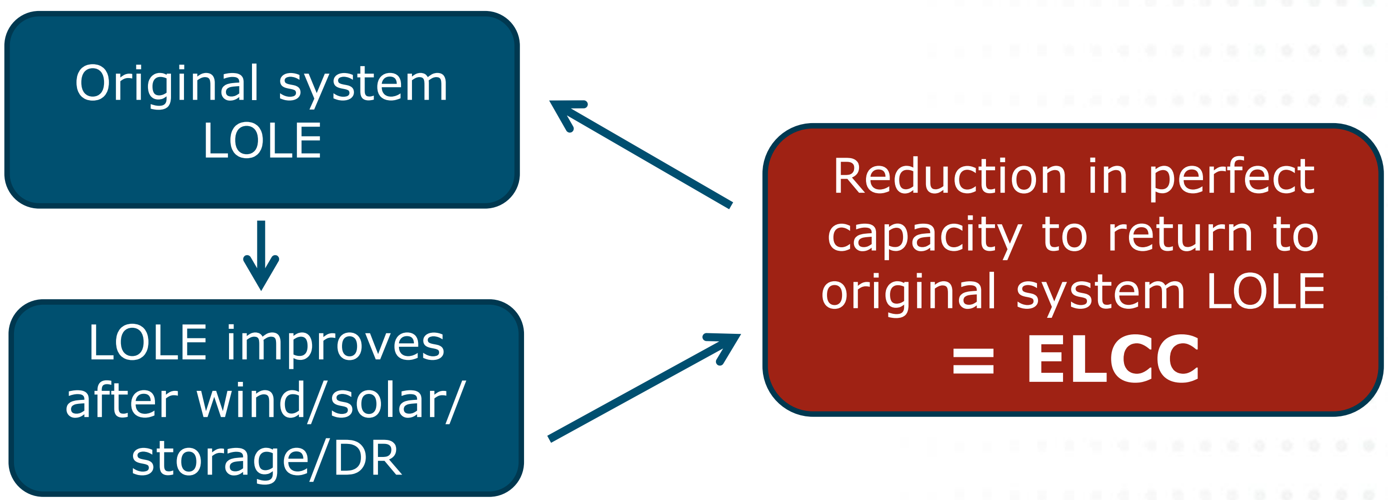
Energy+Environmental Economics



CAPACITY CONTRIBUTION OF WIND, SOLAR, STORAGE AND DEMAND RESPONSE

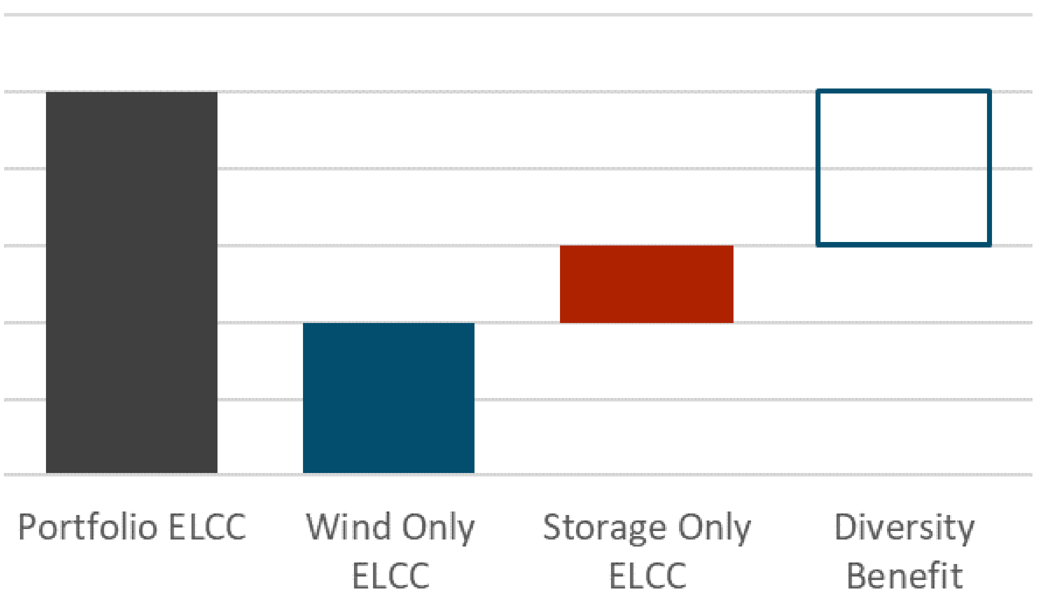
"ELCC" is used to determine effective capacity contribution from wind, solar, storage and demand response

- Effective load carrying capability (ELCC) is the quantity of 'perfect capacity' that could be replaced or avoided with dispatch-limited resources such as wind, solar, hydro, storage or demand response while providing equivalent system reliability
- The following slides present ELCC values calculated using the <u>2050 80% GHG Reduction Scenario</u> as the baseline conditions

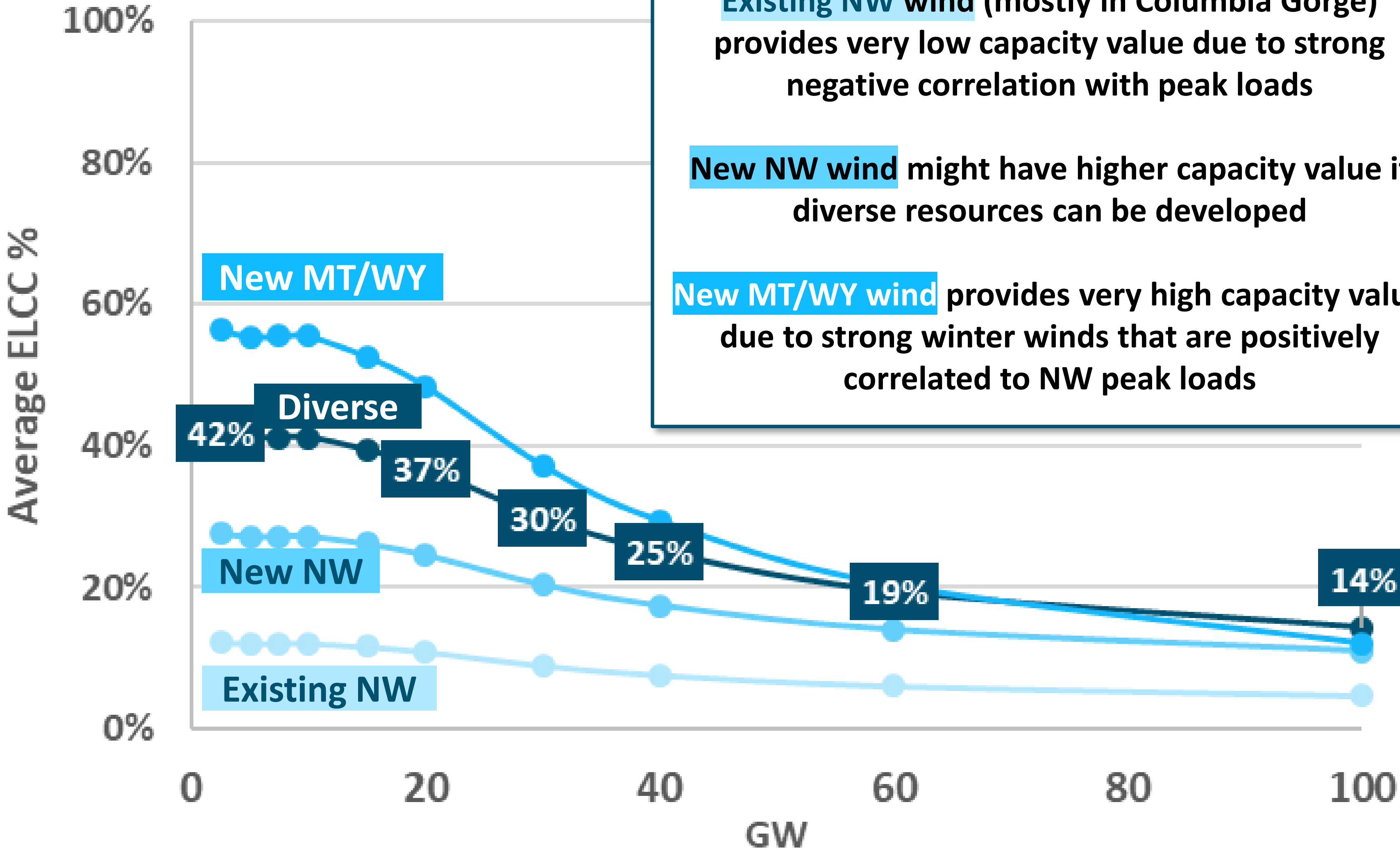


Portfolio ELCC & Diversity

- Determining the ELCC of individual resources is not straightforward due to complex interactive effects
- The ELCC of a portfolio of resources can be more than the sum of its parts if the resources are complementary, e.g., daytime solar + nighttime wind
- The incremental capacity contribution of new wind, solar and storage declines as a function of penetration



Wind ELCC varies widely by location

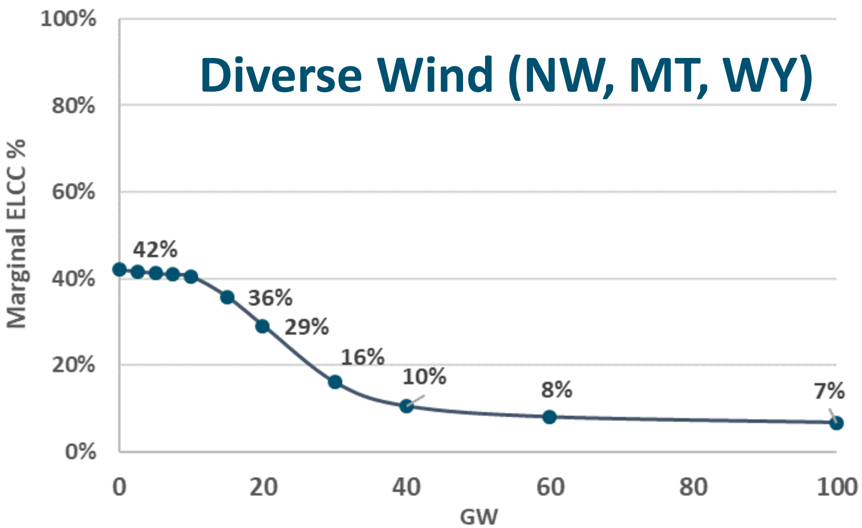


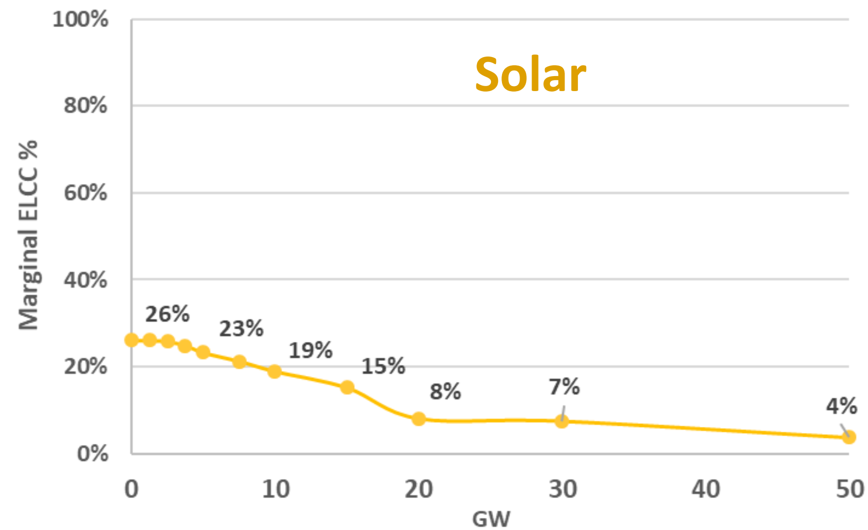
Existing NW wind (mostly in Columbia Gorge) provides very low capacity value due to strong negative correlation with peak loads

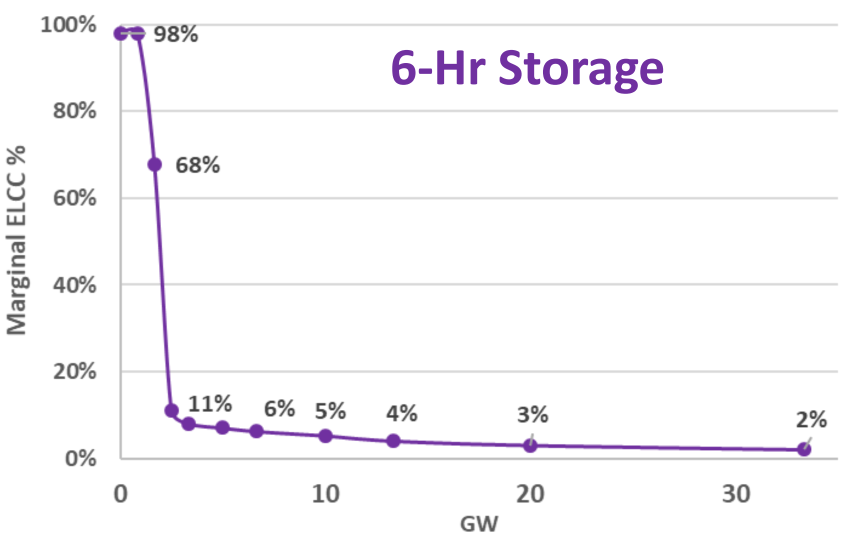
New NW wind might have higher capacity value if diverse resources can be developed

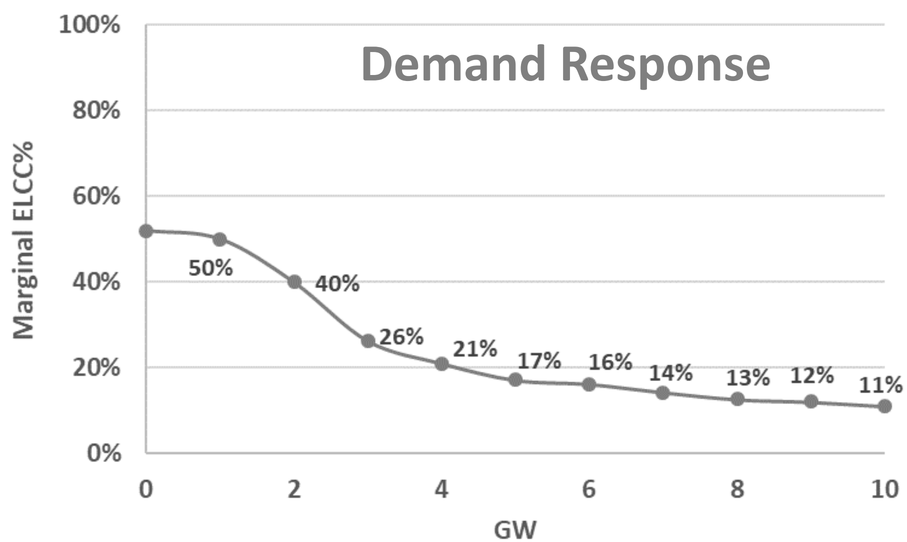
New MT/WY wind provides very high capacity value due to strong winter winds that are positively correlated to NW peak loads

Wind, solar and storage all exhibit diminishing ELCC values as more capacity is added

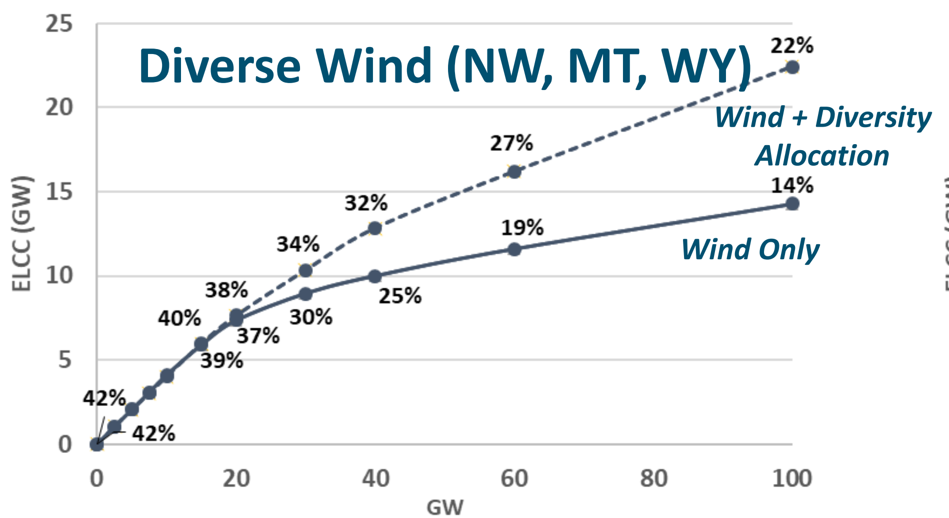


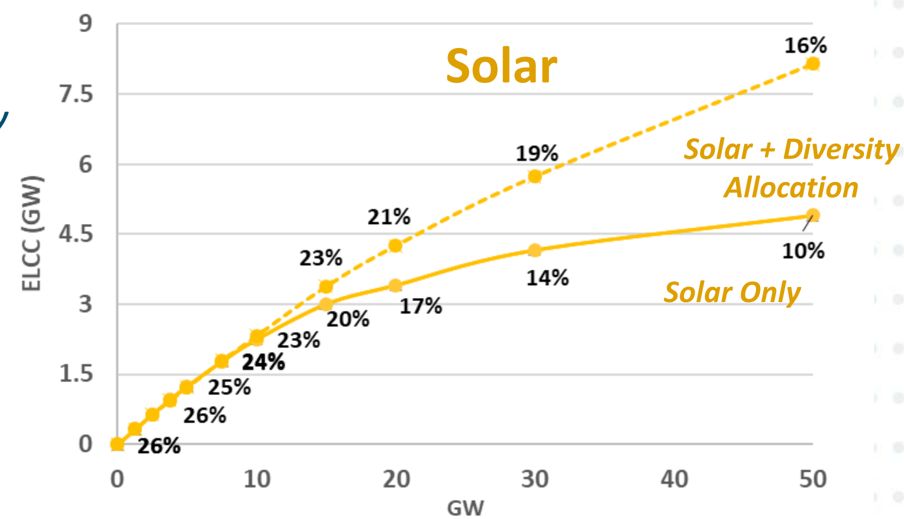


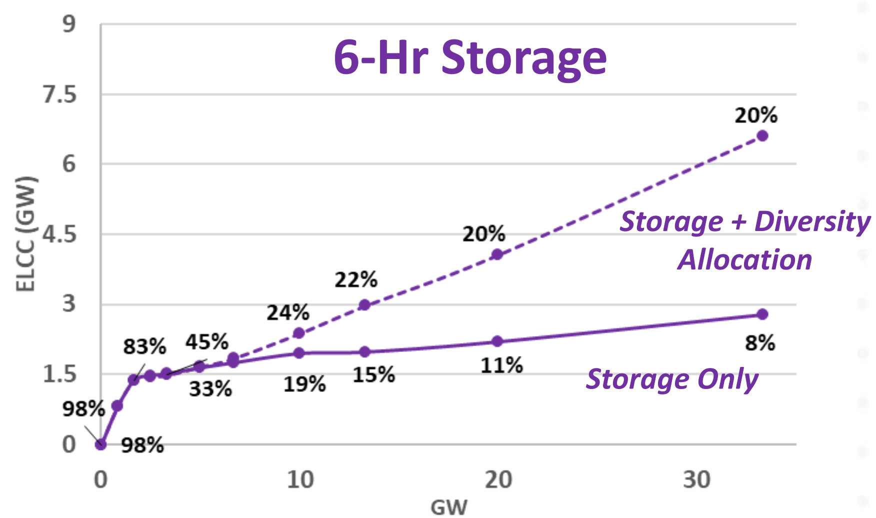




Cumulative ELCC Potential for Wind/Solar/Storage

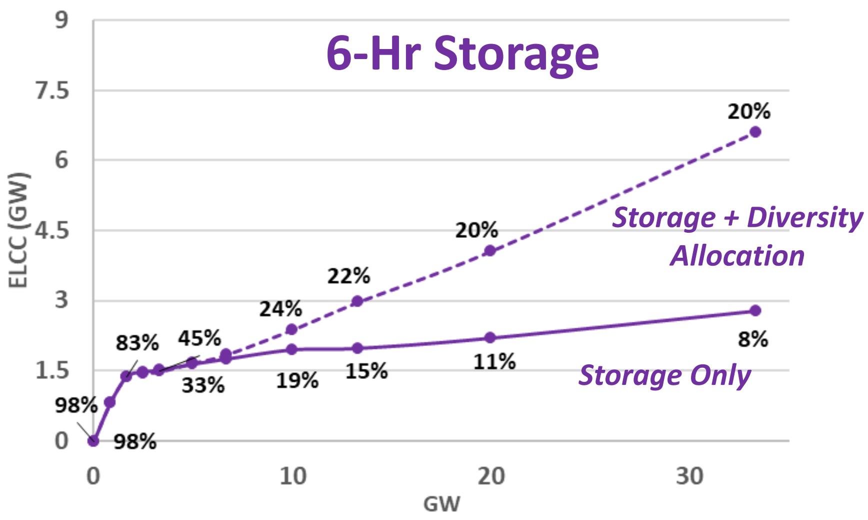


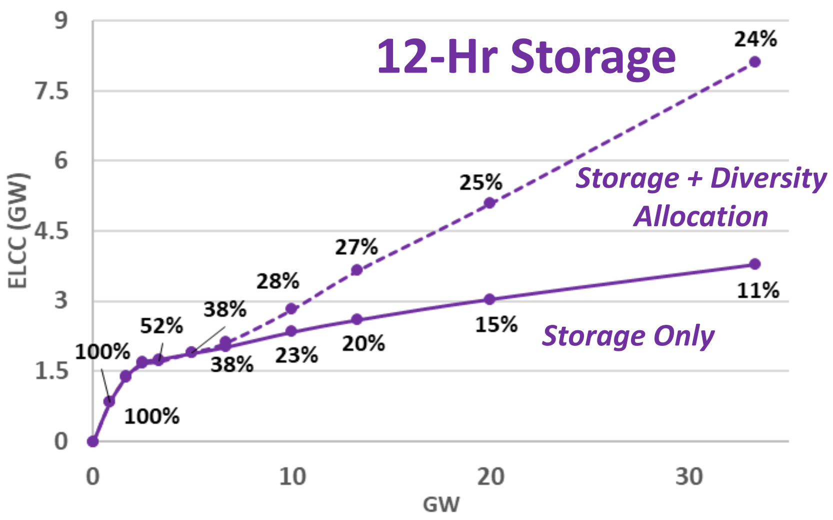




Value of Storage Duration

+ **Increasing the duration of storage provides additional ELCC capacity value, but there are still strong diminishing returns even for storage up to a duration of 12-hours**

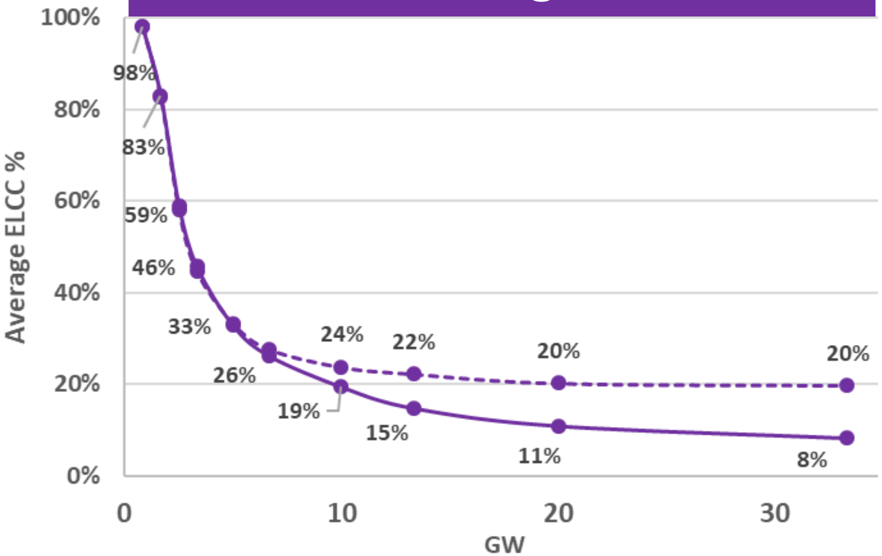




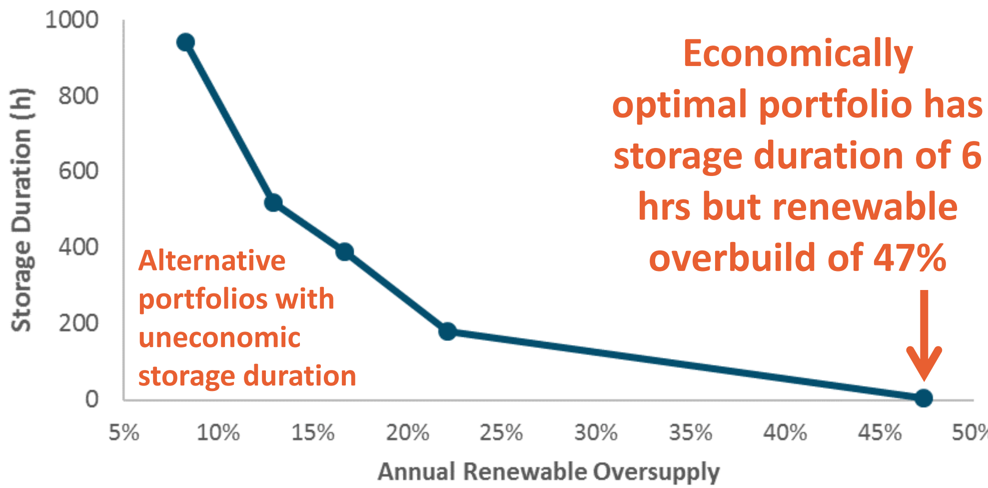
Energy storage is limited in its ability to provide firm generation

- In a high-renewable electricity system, there must be firm energy to generate during multi-day and multi-week stretches of low renewable energy production
- For storage to provide reliable capacity during these periods, it must have a fleetwide duration of 100-1000 hours
- In Current storage technology (Li-ion, flow batteries, pumped hydro), is not capable of providing this duration economically; most storage today has 1 to 10 hr duration
- Because storage does not have the required duration, a 100% zero carbon system must build twice as much renewable energy as is required on an annual basis to ensure low production periods have sufficient energy

6-Hr Storage ELCC



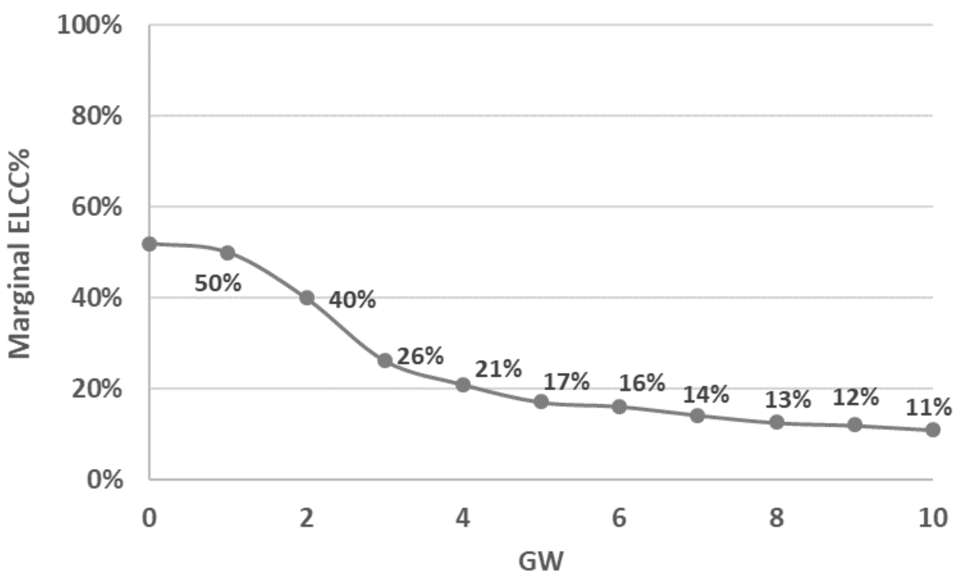
100% Zero Carbon Portfolios



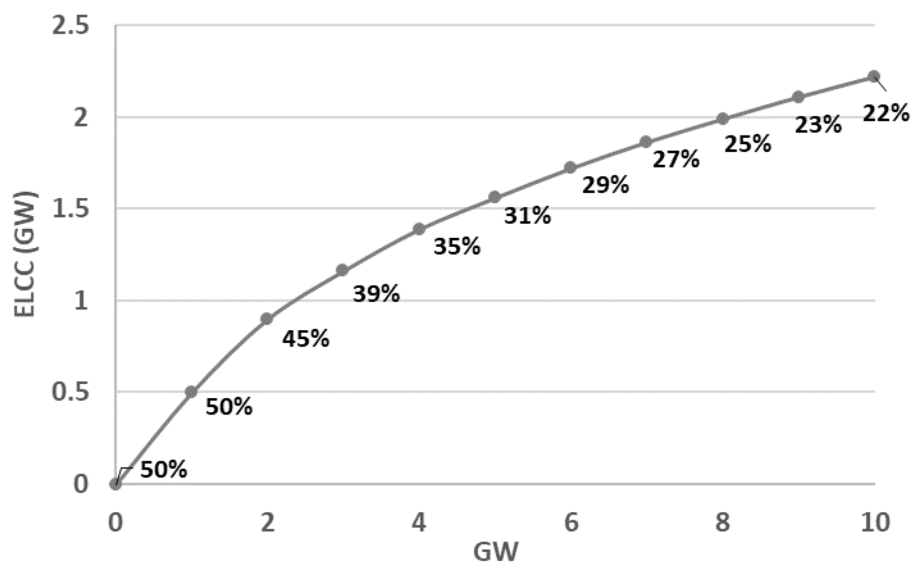
Demand response is limited in its ability to provide firm generation

+ **Demand response is capable of providing capacity for limited periods of time, making it difficult to substitute for firm generation when energy is needed for prolonged periods of time**
+ **DR assumption: 10 calls per year, 4 hours per call**
+ **Results shown for the 2050 system**

DR Marginal ELCC %



DR Cumulative ELCC MW



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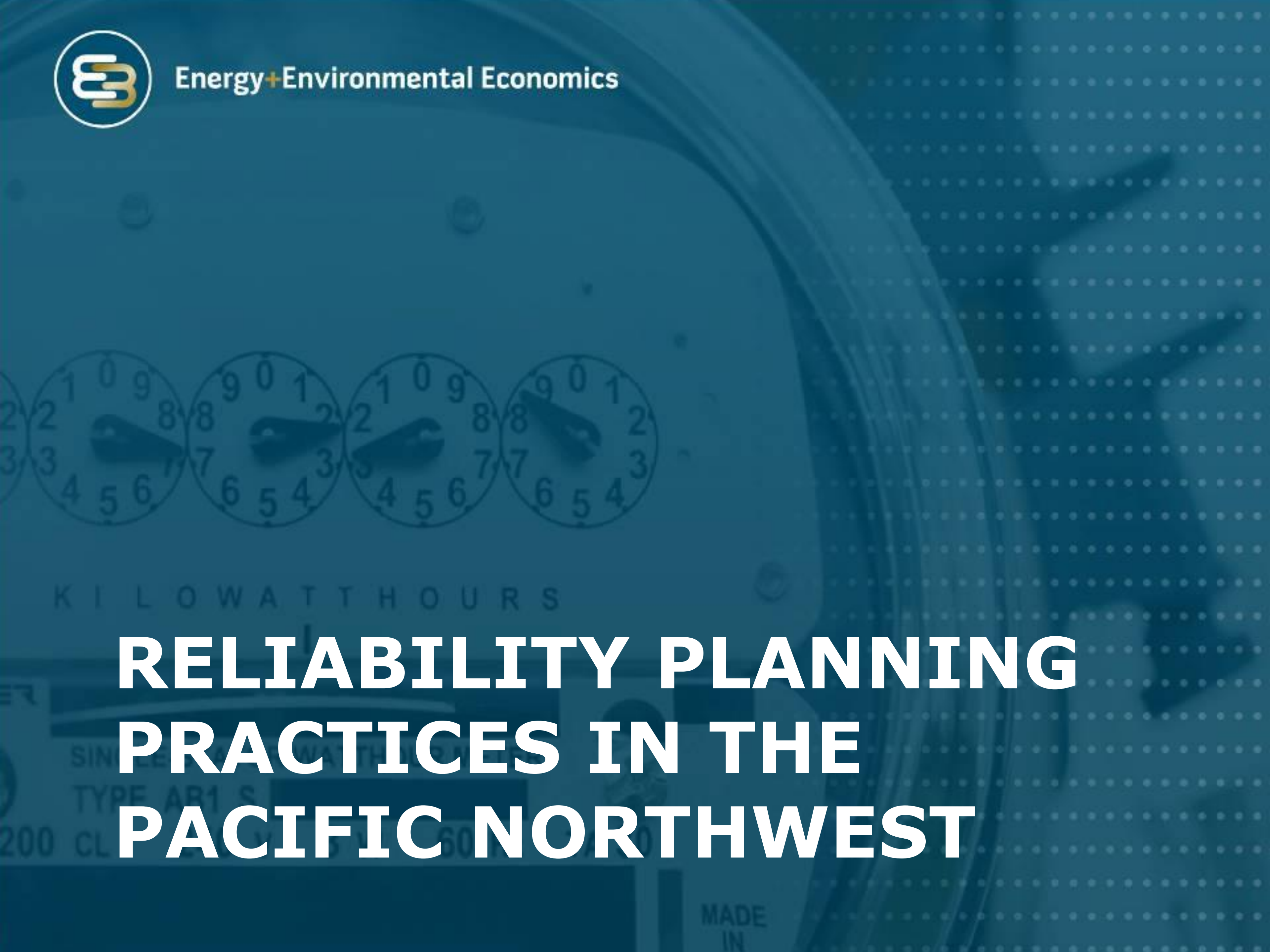

RELIABILITY PLANNING PRACTICES IN THE PACIFIC NORTHWEST

Reliability Standards

- **This study uses a reliability standard of 2.4 hrs/yr LOLE**
  - Corresponds to 1-day-in-10 year loss of load
- **The Northwest Power and Conservation Council uses a reliability standard of 5% loss of load probability (LOLP) per year**
  - Currently considering moving from an LOLP to LOLE standard
- **At high penetrations of renewable energy, loss of load events become larger in magnitude, suggesting simply measuring the hrs/yr (LOLE) of lost load may be insufficient**
- **MWh/yr of expected unserved energy (EUE) is a less common reliability metric in the industry but captures the magnitude of outages**

Exploring an EUE (MWh/yr) based reliability standard may help to more accurately characterize the reliability of a system that relies heavily on energy-limited resources (e.g. hydro, wind, solar)

Regional Planning Reserve sharing system may be beneficial

- Current planning practices in the NW do not have a centralized capacity counting mechanism
- Many LSE's rely on front-office transactions that risk double-counting available surplus generation capacity
- This analysis shows that new firm capacity is needed in the NW in the near term and significant new firm resources are needed in the long-term depending on coal retirements

The region may benefit from and should investigate a formal mechanism for sharing planning reserves to ensure resource adequacy that would both 1) standardize the attribution of capacity value across entities and 2) realize benefits of load & resource diversity among LSE's in region

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KEY FINDINGS

Key Findings (1 of 2)

1. **It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient firm capacity is available during periods of low wind, solar and hydro production**
   - Natural gas generation is the most economic source of firm capacity, and adding new gas *capacity* is not inconsistent with deep reductions in carbon emissions
   - Wind, solar, demand response and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs
   - Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) gas or coal generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas
2. **It would be extremely costly and impractical to replace all carbon-emitting firm generation capacity with solar, wind and storage, due to the very large quantities of these resources that would be required**
3. **The Northwest is anticipated to need new capacity in the near-term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements**

Key Findings (2 of 2)

4. **Current planning practices risk underinvestment in new capacity required to ensure Resource Adequacy at acceptable levels**

   - Reliance on “market purchases” or “front office transactions” reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region
   - However, because the region lacks a formal mechanism for counting physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity
   - Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory
   - The region might benefit from and should investigate a formal mechanism for sharing of planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy

The results/findings in this analysis represent the Greater NW region in aggregate, but results may differ for individual utilities

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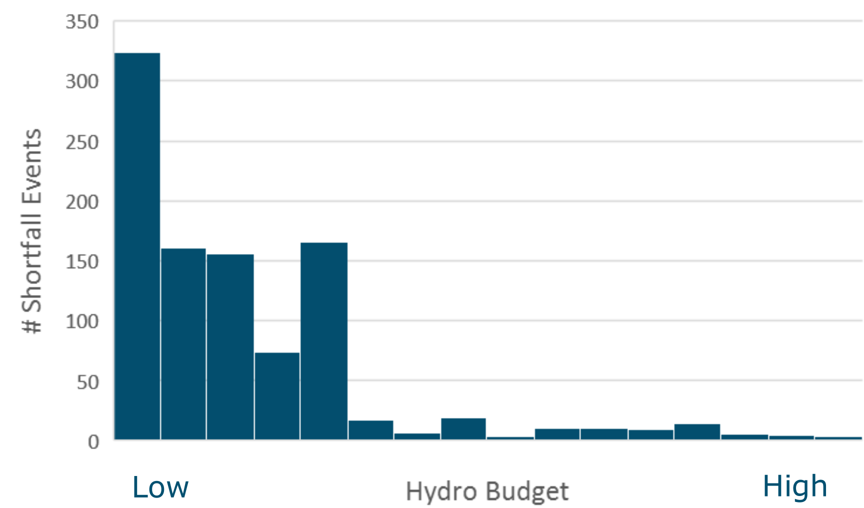
APPENDIX

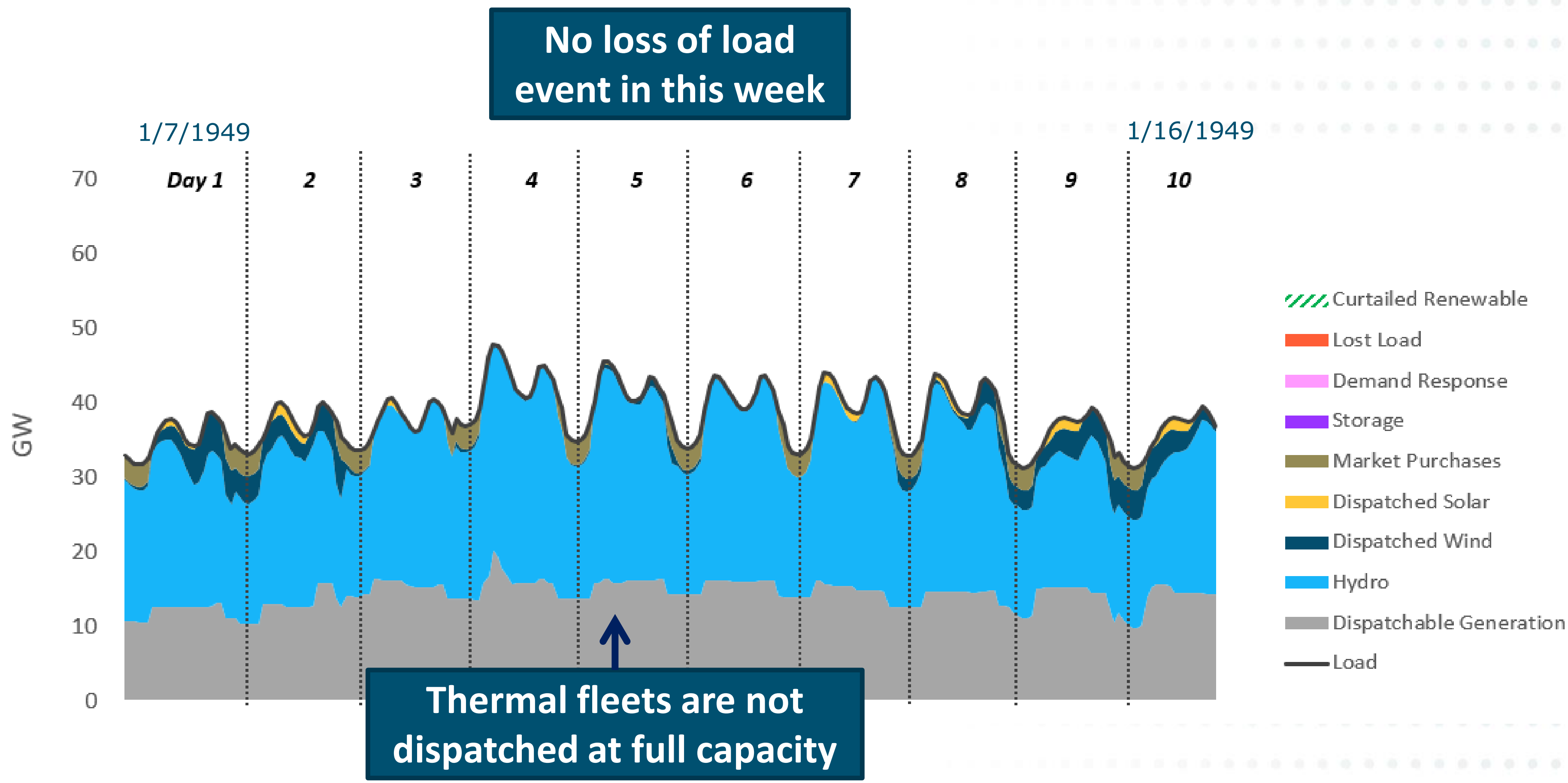
ROLE OF HYDRO IN MEETING RESOURCE ADEQUACY NEEDS

Low Hydro Years: Low Reliability

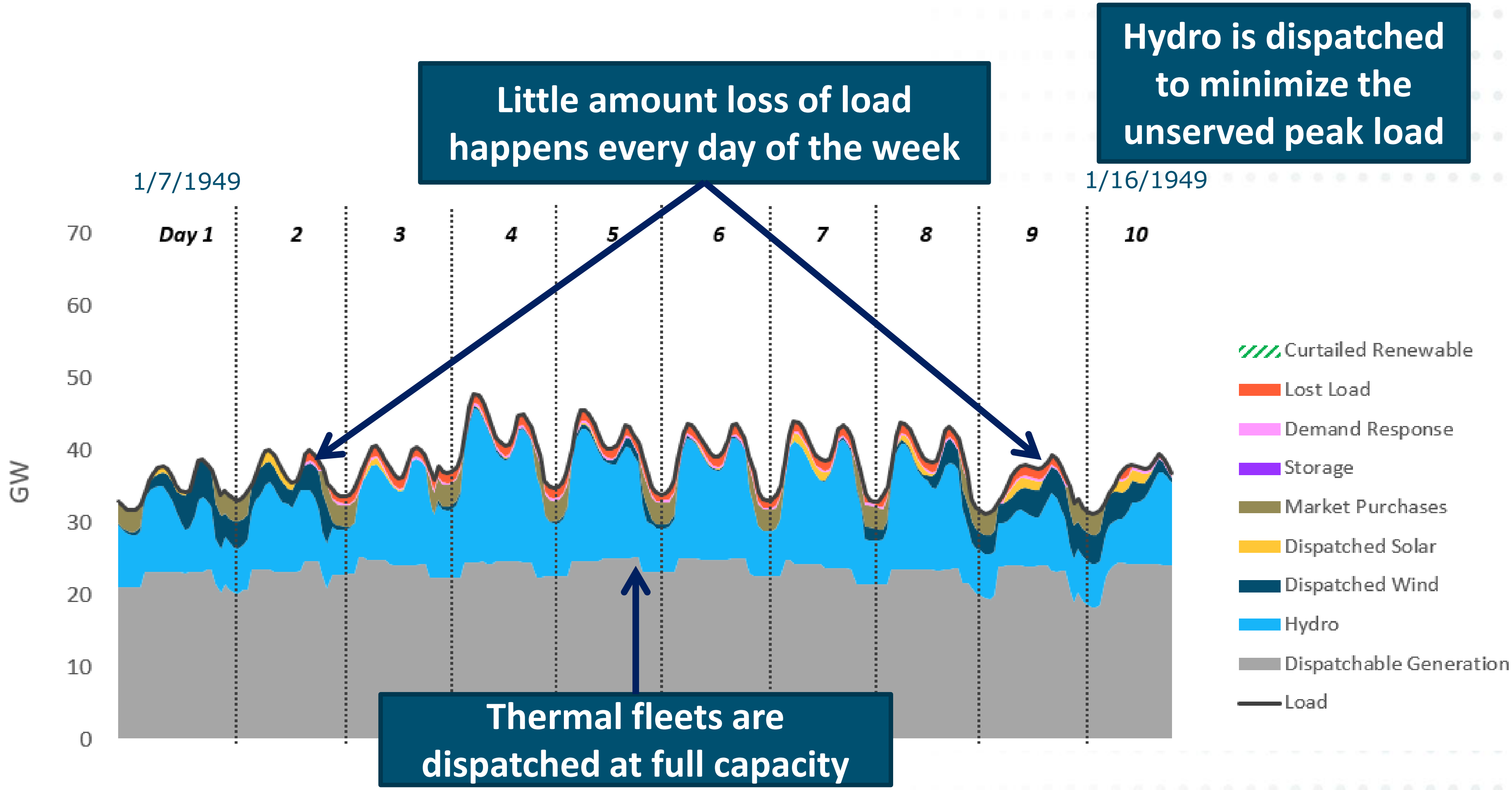
- **Most shortfall events occur during low hydro years**
  - 25% of all events occur in lowest 5 of 80 hydro years
  - 96% of all events occur in lowest 25 of 80 hydro years
- **Hydro conditions are a major factor for NW system reliability in 2018**
- **As renewable penetration increases, renewable production becomes a bigger factor for NW system reliability**
- **High correlation between shortfalls and low hydro years results in consistent values for annual LOLP using GENESYS and RECAP**



Today's System with Median Hydro

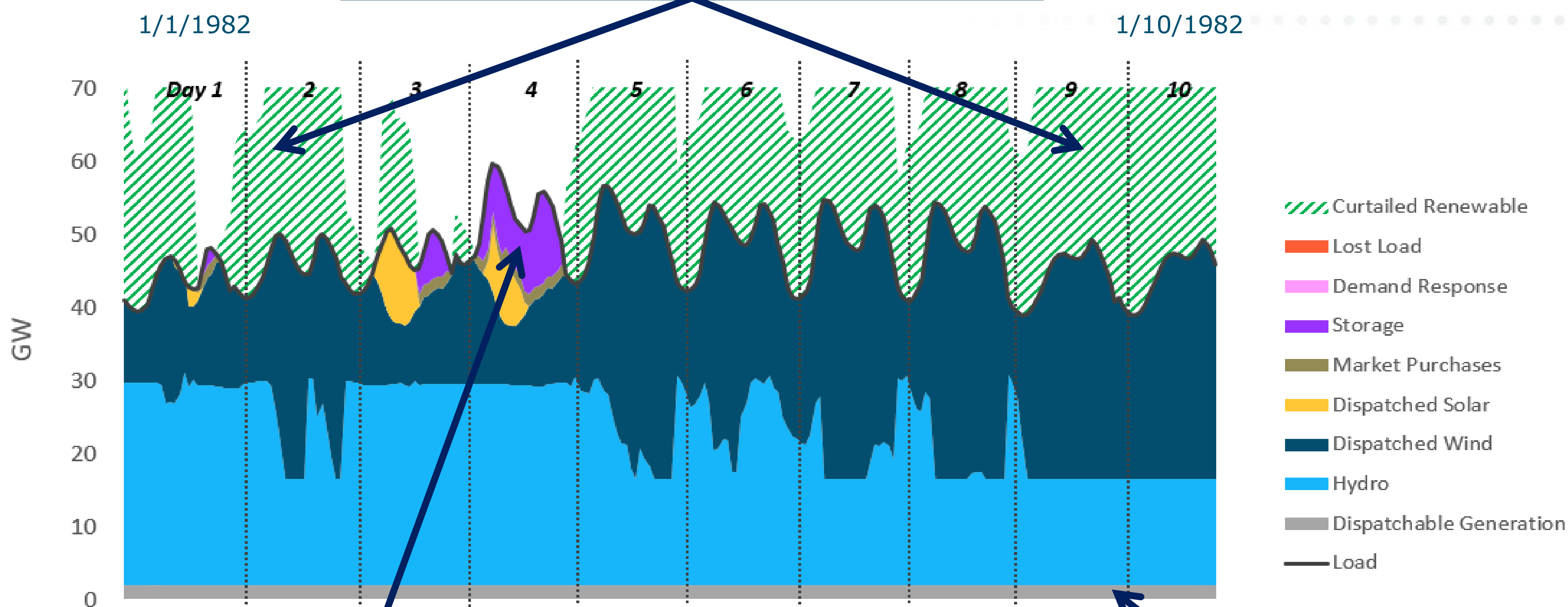


Today's System with Low Hydro



2050 System with Median Hydro

No loss of load event and with a large amount of renewable curtailment



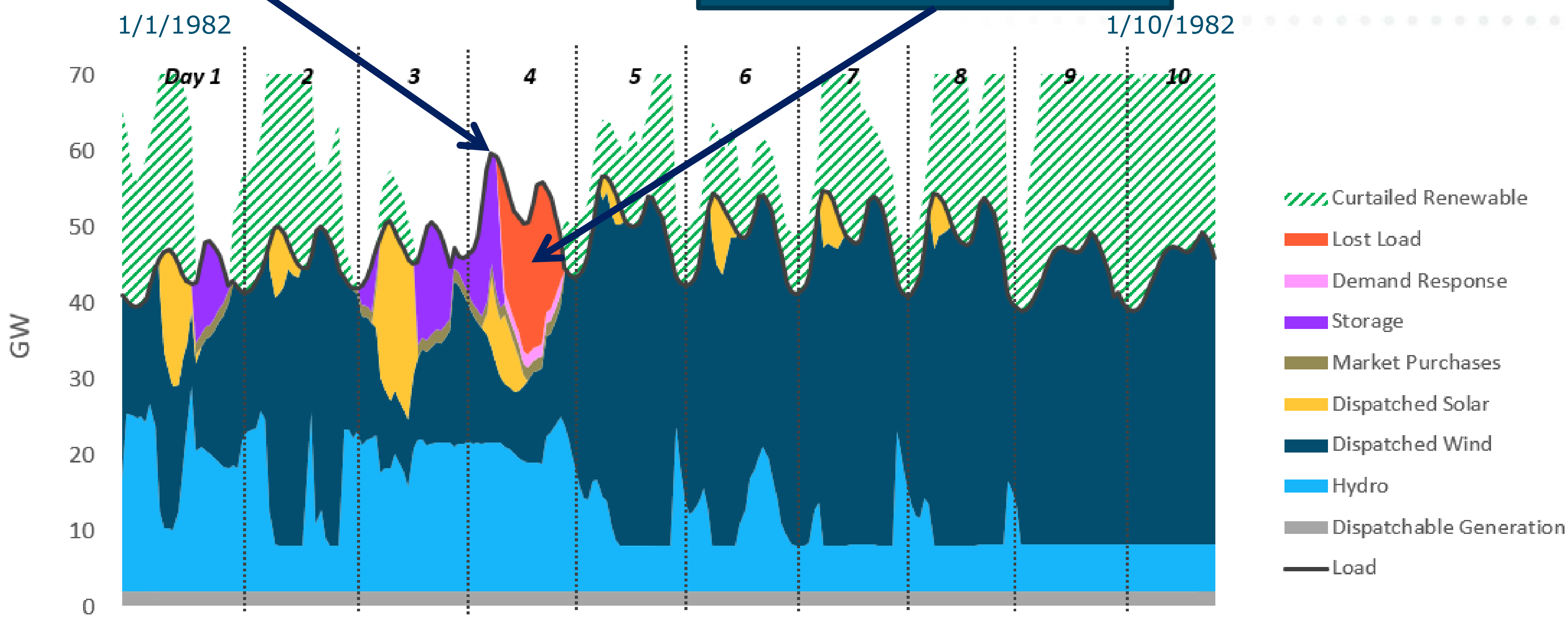
Storage is dispatched during low renewable hours

Very little dispatchable generation in 100% clean system

2050 System with Low Hydro

Storage depletes at this moment

Large amount loss of load happens on one day



Loss of load is mainly driven by low renewable generation plus drought hydro condition

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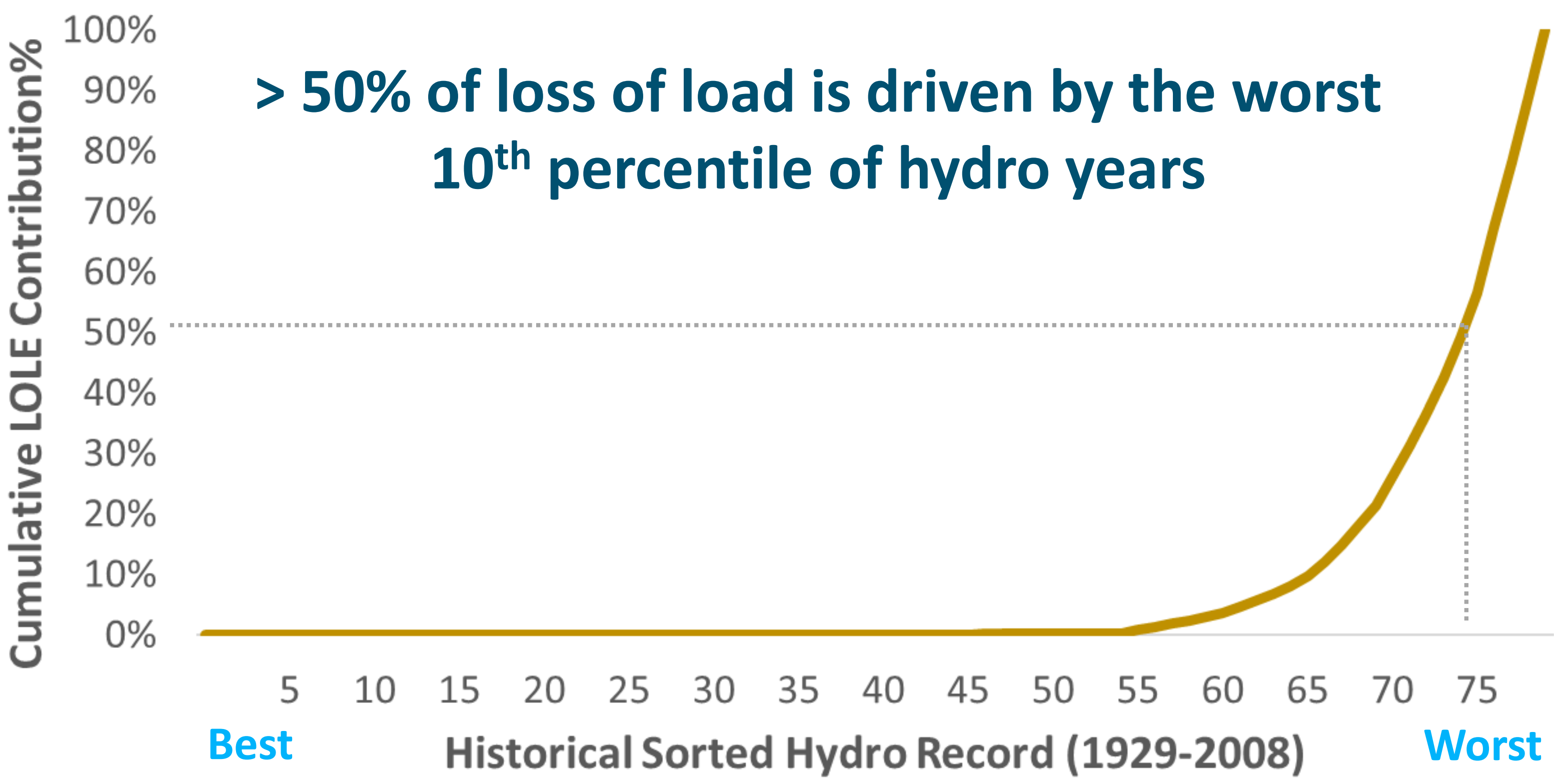
2018 Hydro Analysis

In today's system, nearly all loss of load is driven by low hydro years which is the single most variable factor in the system

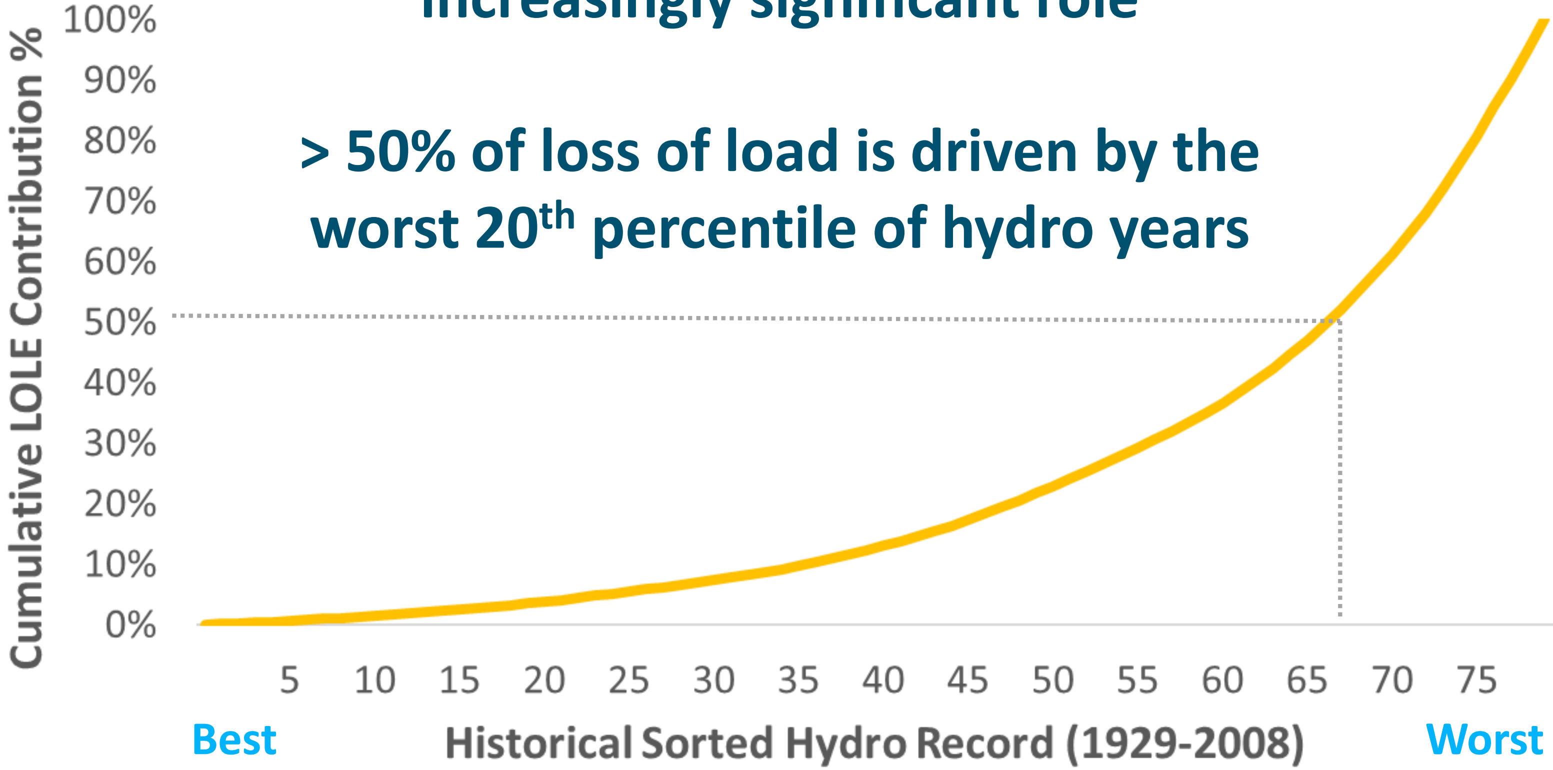
> 50% of loss of load is driven by the worst 10^{th} percentile of hydro years



2050 - 95% Clean Hydro Analysis

In a 95% clean system, hydro is still the dominant driver of loss of load, but renewable intermittency plays an increasingly significant role

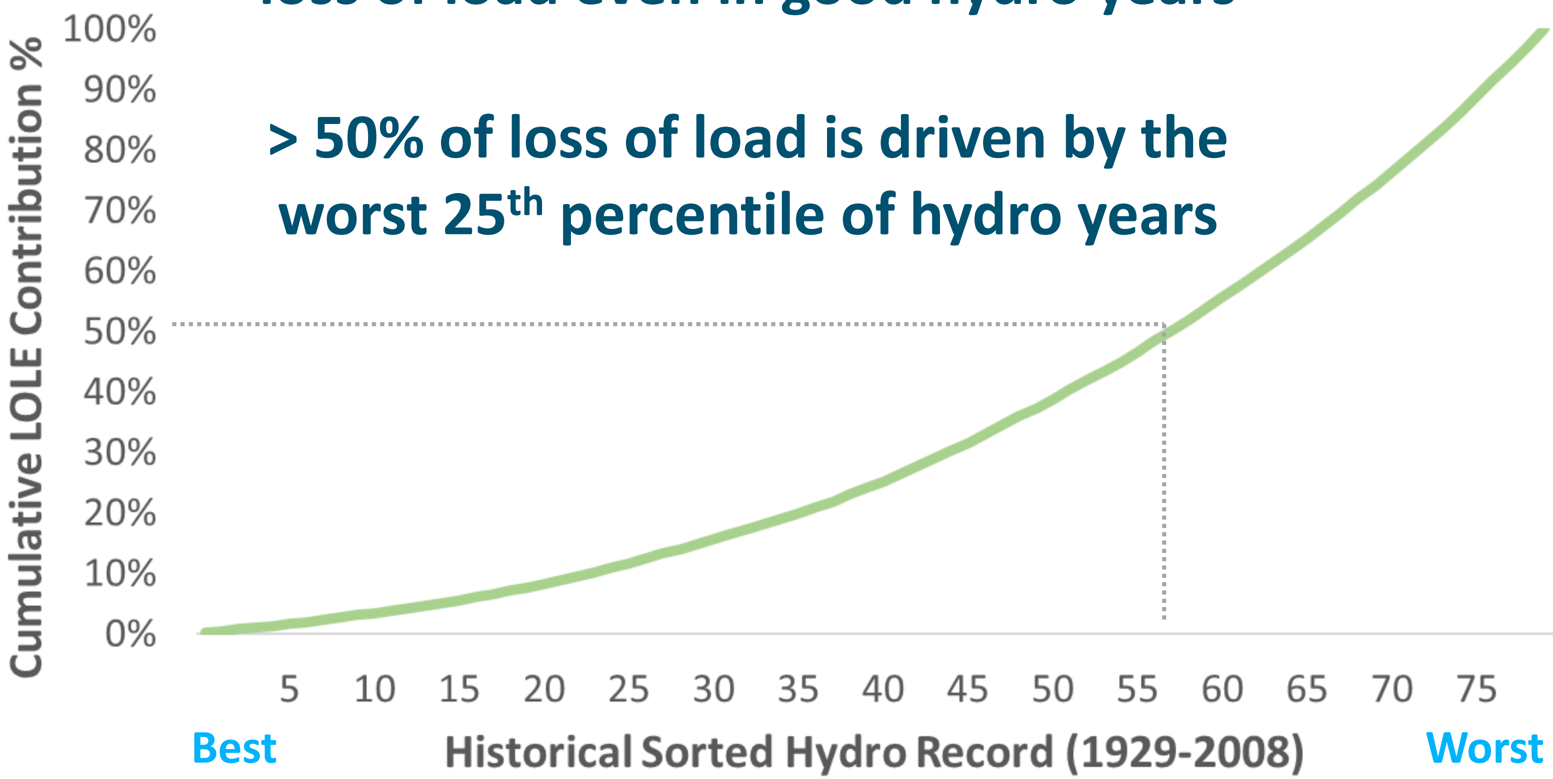
> 50% of loss of load is driven by the worst 20th percentile of hydro years



2050 - 100% Clean Hydro Analysis

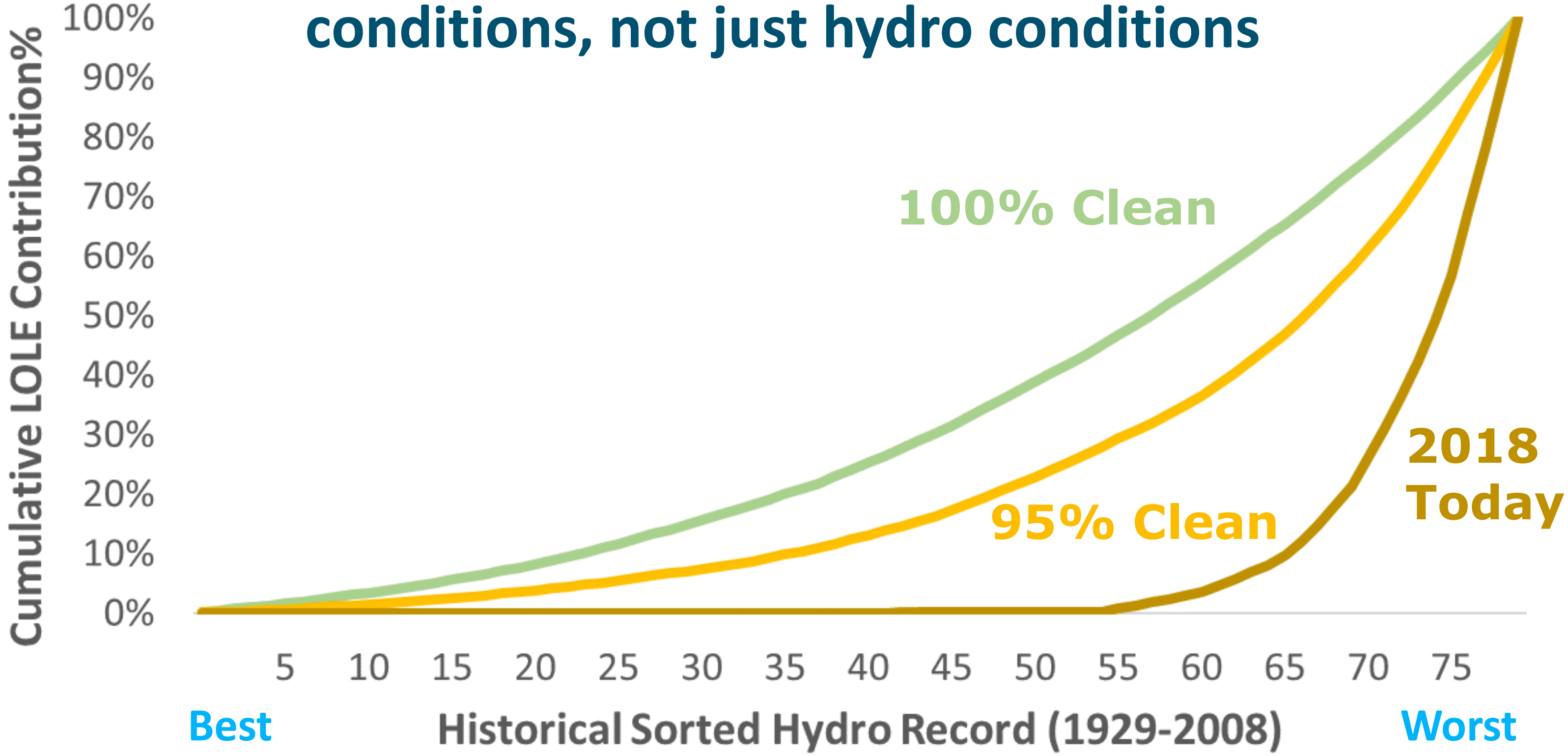
In a 100% clean system, hydro is still the dominant driver of loss of load, but low renewable events can cause loss of load even in good hydro years

> 50% of loss of load is driven by the worst 25th percentile of hydro years



Hydro Analysis

At higher % clean energy, the system becomes increasingly dependent upon renewable generation conditions, not just hydro conditions



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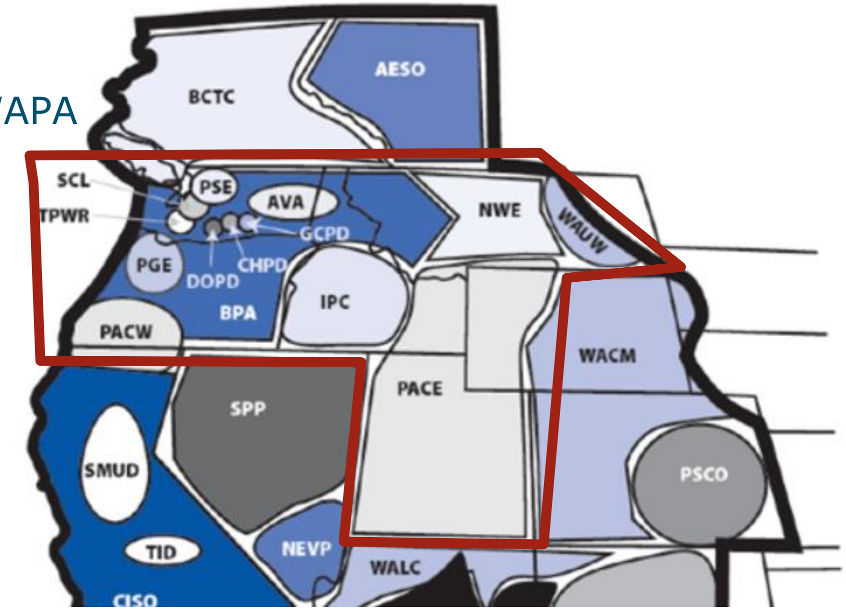
RECAP TECHNICAL DETAILS

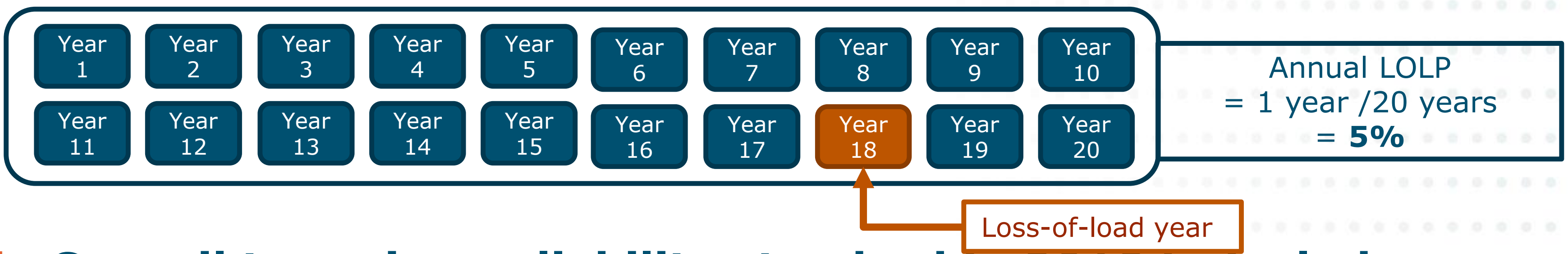
Modeling Region

- Modeling region is Northwester Power & Conservation Council + Select Northwest Power Pool load areas
- Load areas included (17)
  - AVA – Avista
  - BPAT – Bonneville
  - CHPD – Chelan
  - DOPD – Douglas
  - GCPD – Grant
  - IPFE – Idaho Power
  - IPMV – Magic Valley
  - IPTV – Treasure Valley
  - NWMT – Northwestern
  - PACE – PacifiCorp East
  - PACW – PacifiCorp West
  - PGE – Portland General
  - PSEI – Puget Sound
  - SCL – Seattle
  - TPWR – Tacoma
  - WAUW, WWA – WAPA



Reliability Metrics

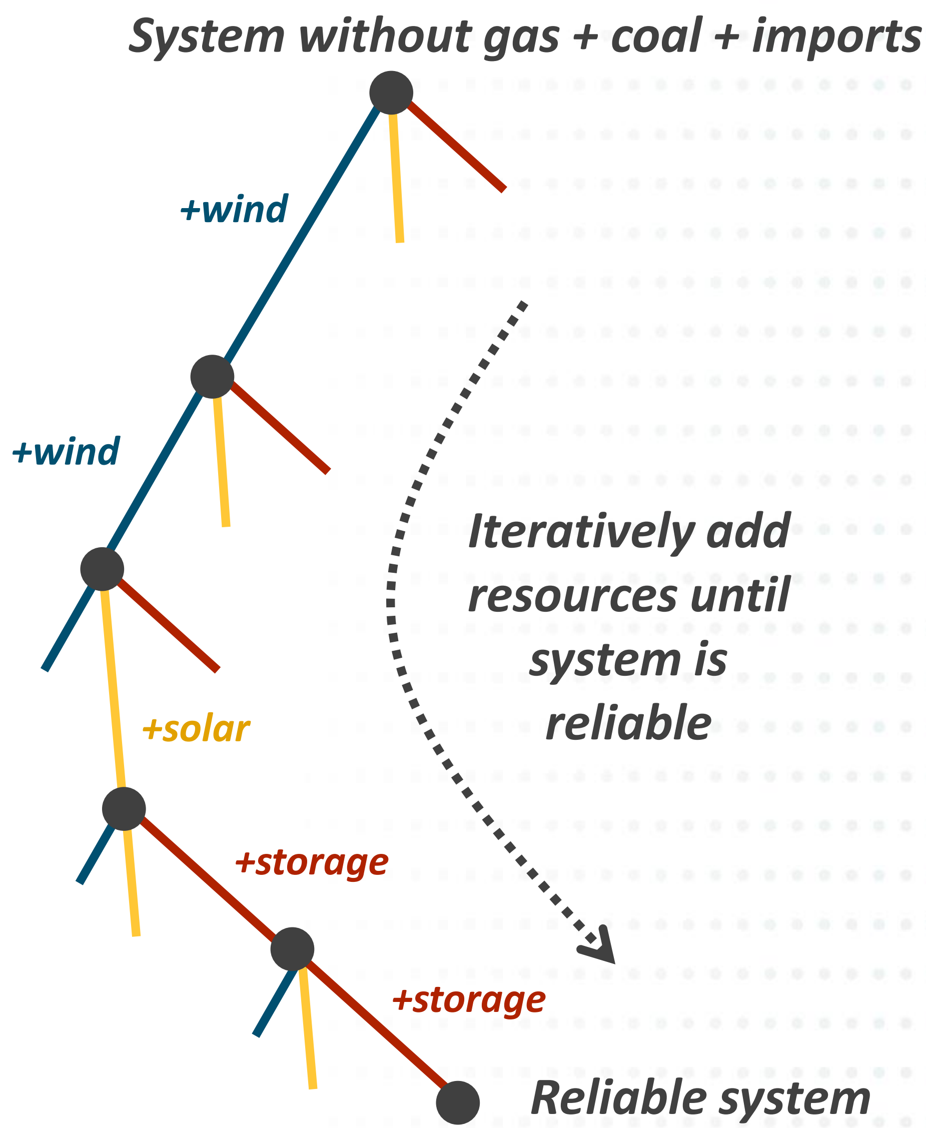
- **NWPCC has adopted a 5% annual loss of load probability (aLOLP)**
  - Every 1 in 20 years can result in a shortfall



- **Council to review reliability standard in 2018 to include seasonal adequacy targets**
- **Loss of load expectation (LOLE) measured in hrs/yr and expected unserved energy (EUE) measured in MWh/yr are other common metrics**
- **NWPCC reports LOLE and EUE, but does not have an explicit standard for these metrics**
  - 0.1 to 2.4 hrs/yr is the most common range for LOLE

Smart Search Functionality

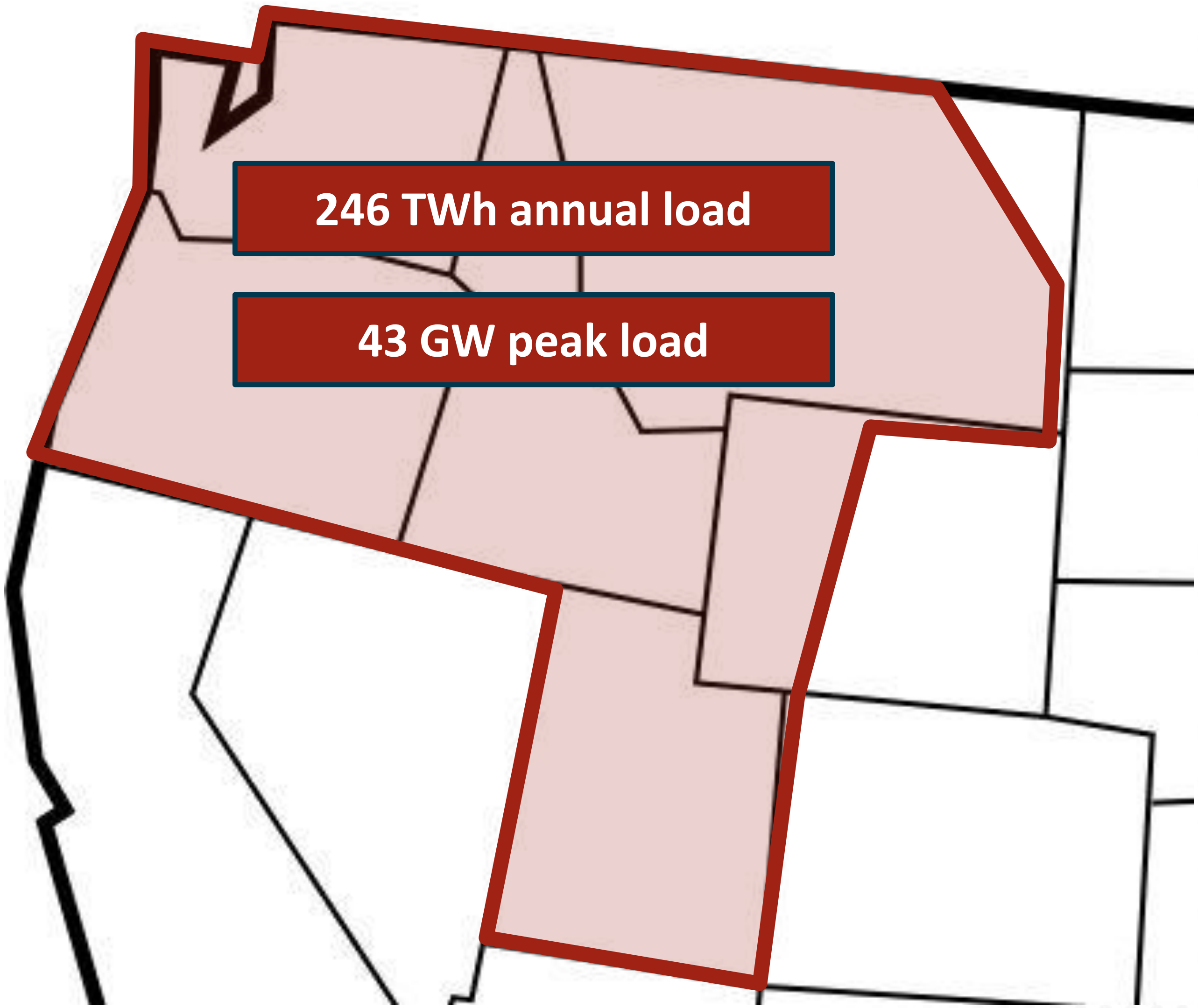
- Smart search functionality iteratively evaluates the reliability contribution of adding quantities of equal cost carbon free resources and selecting the resource with the highest contribution
- This allows the model to select a cost optimal portfolio of resources that provides adequate reliability



RECAP Data Sources

+ **Hourly load profiles**
  - NOAA weather data (1950-2017)
  - WECC hourly load data (2014-2017)
+ **Renewable generation**
  - NREL Wind Toolkit (2007-2013)
  - NREL National Solar Radiation Data Base (1998-2014)
  - NWPCC Hydro data
+ **Generating resources**
  - WECC TEPPC
  - Future portfolios will be informed by RESOLVE outputs from PGP Low Carbon study

Greater NW Region



Load

+ **Initial runs were completed using 2017 load levels**
  - Annual Load: 246 TWh
  - Median Peak Load: 42,860 MW
+ **Future load growth was assumed to be 0.7%/yr post-2023**
+ **2014-2017 WECC actual hourly load data was used to train neural network model to produce hourly loads for historical weather years**
  - BTM solar was added back to historical loads

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	28	27	26	26	26	27	29	32	33	34	33	33	32	32	31	31	31	32	34	34	33	33	31	29
Feb	26	25	25	25	25	26	28	31	32	32	32	31	31	30	29	29	29	30	31	32	32	31	30	28
Mar	24	23	23	23	24	25	28	30	30	30	30	29	29	28	28	27	27	28	28	29	29	28	27	25
Apr	22	22	21	22	22	24	27	28	28	28	28	27	27	27	26	26	26	26	27	27	28	27	25	23
May	22	21	21	21	21	22	24	26	26	27	27	27	27	27	27	27	27	27	27	27	27	27	25	23
Jun	23	22	21	21	22	22	24	26	27	27	28	28	29	29	29	29	29	29	29	29	28	28	26	24
Jul	24	23	22	22	22	23	24	26	27	28	29	30	31	31	32	32	32	32	32	31	30	30	28	26
Aug	23	22	21	21	21	22	24	25	26	27	28	29	29	30	30	31	31	31	30	30	30	28	26	24
Sep	21	20	20	20	20	22	24	25	26	26	26	27	27	27	27	27	27	28	27	28	27	26	24	22
Oct	21	21	20	20	21	23	25	26	27	27	27	27	27	26	26	26	26	27	27	28	27	26	24	22
Nov	24	23	23	23	23	24	26	28	30	30	30	29	29	28	28	28	28	29	31	30	30	29	28	26
Dec	27	26	26	26	26	27	29	31	33	33	33	32	32	31	31	31	31	33	34	34	33	33	31	29

Simulated Load

+ Neural Network Inputs

	2018	2030	2050
Median 1-in-2 Peak (GW)	43	47	54
Annual Load (TWh)	247	269	309

+ Load growth was assumed to be 0.7%/yr post-2023

+ 2014-2017 WECC actual hourly load data was used to train neural network model to produce hourly loads for historical weather years

- BTM solar was added back to historical loads

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	28	27	26	26	26	27	29	32	33	34	33	33	32	32	31	31	31	32	34	34	33	33	31	29
Feb	26	25	25	25	25	26	28	31	32	32	32	31	31	30	29	29	29	30	31	32	32	31	30	28
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Dec	27	26	26	26	26	27	29	31	33	33	33	32	32	31	31	31	31	33	34	34	33	33	31	29

Wind

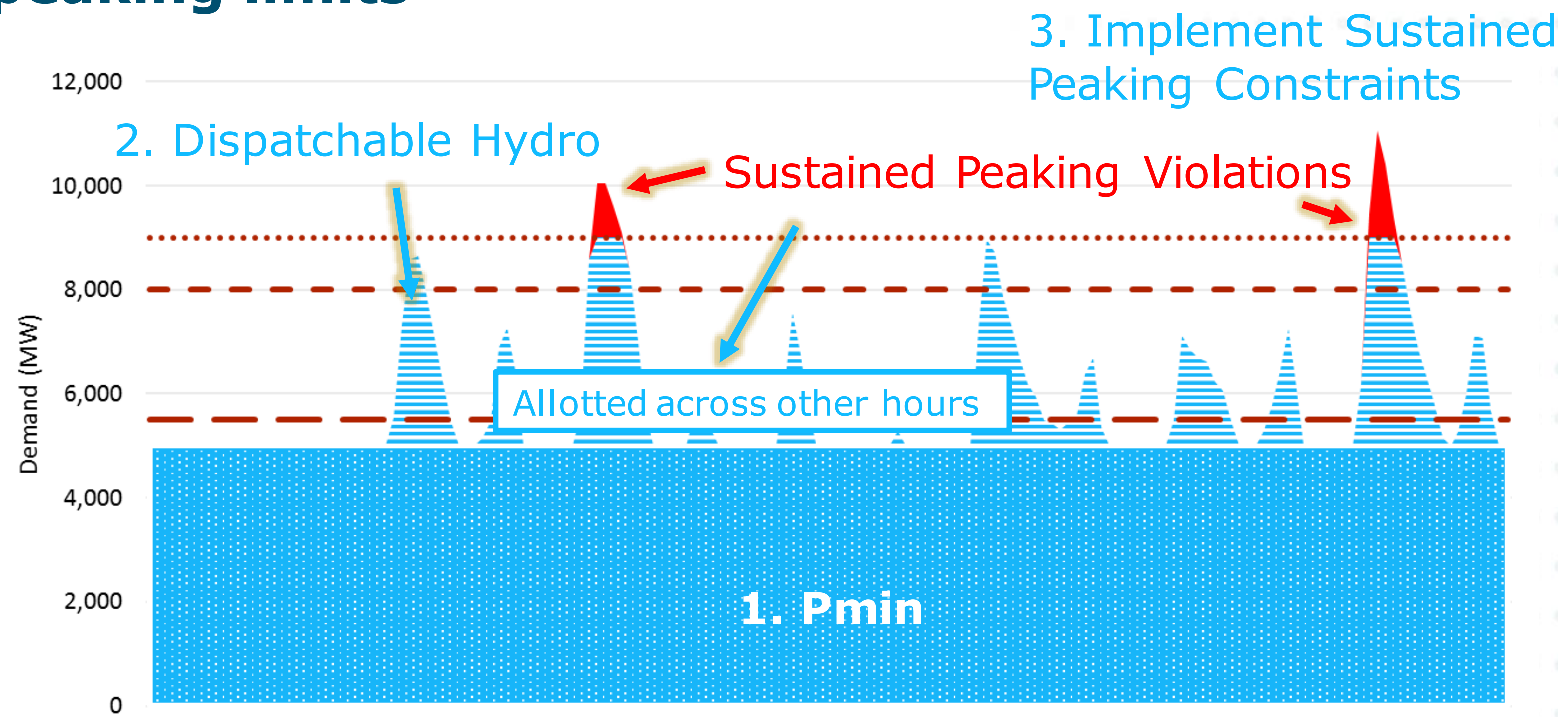
- Wind profiles are simulated output from existing and new sites based on NREL's mesoscale meteorological modeling from historical years 2007-2012

Average Wind Capacity Factor

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.34	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.31	0.3	0.3	0.3	0.31	0.31	0.32	0.33	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Feb	0.28	0.28	0.28	0.27	0.27	0.27	0.26	0.26	0.24	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.25	0.27	0.27	0.28	0.28	0.28	0.28	0.28
Mar	0.31	0.31	0.31	0.31	0.3	0.3	0.3	0.28	0.28	0.28	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.3	0.3	0.31	0.31	0.31	0.31
Apr	0.31	0.31	0.31	0.3	0.3	0.3	0.27	0.26	0.25	0.25	0.25	0.25	0.25	0.26	0.26	0.27	0.28	0.28	0.29	0.3	0.3	0.31	0.31	0.31
May	0.29	0.29	0.29	0.29	0.28	0.26	0.23	0.22	0.22	0.21	0.21	0.21	0.21	0.22	0.23	0.24	0.26	0.27	0.27	0.29	0.29	0.29	0.29	0.29
Jun	0.31	0.31	0.3	0.3	0.29	0.26	0.23	0.22	0.22	0.21	0.21	0.21	0.22	0.23	0.25	0.26	0.28	0.29	0.3	0.32	0.33	0.33	0.32	0.32
Jul	0.25	0.24	0.24	0.23	0.22	0.19	0.16	0.15	0.14	0.13	0.13	0.13	0.14	0.15	0.17	0.19	0.21	0.23	0.24	0.26	0.26	0.26	0.25	0.25
Aug	0.25	0.25	0.24	0.24	0.23	0.22	0.19	0.17	0.16	0.15	0.14	0.14	0.15	0.16	0.18	0.2	0.22	0.23	0.24	0.26	0.26	0.26	0.25	0.25
Sep	0.19	0.19	0.19	0.19	0.18	0.18	0.17	0.15	0.14	0.13	0.13	0.13	0.14	0.15	0.15	0.17	0.18	0.19	0.2	0.21	0.2	0.2	0.19	0.19
Oct	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.22	0.2	0.2	0.2	0.2	0.21	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.24	0.24	0.24	0.25
Nov	0.29	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.27	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.26	0.27	0.27	0.28	0.28	0.28	0.28	0.28
Dec	0.32	0.32	0.31	0.31	0.31	0.31	0.31	0.3	0.3	0.29	0.28	0.27	0.27	0.27	0.27	0.28	0.29	0.3	0.3	0.31	0.31	0.31	0.31	0.31

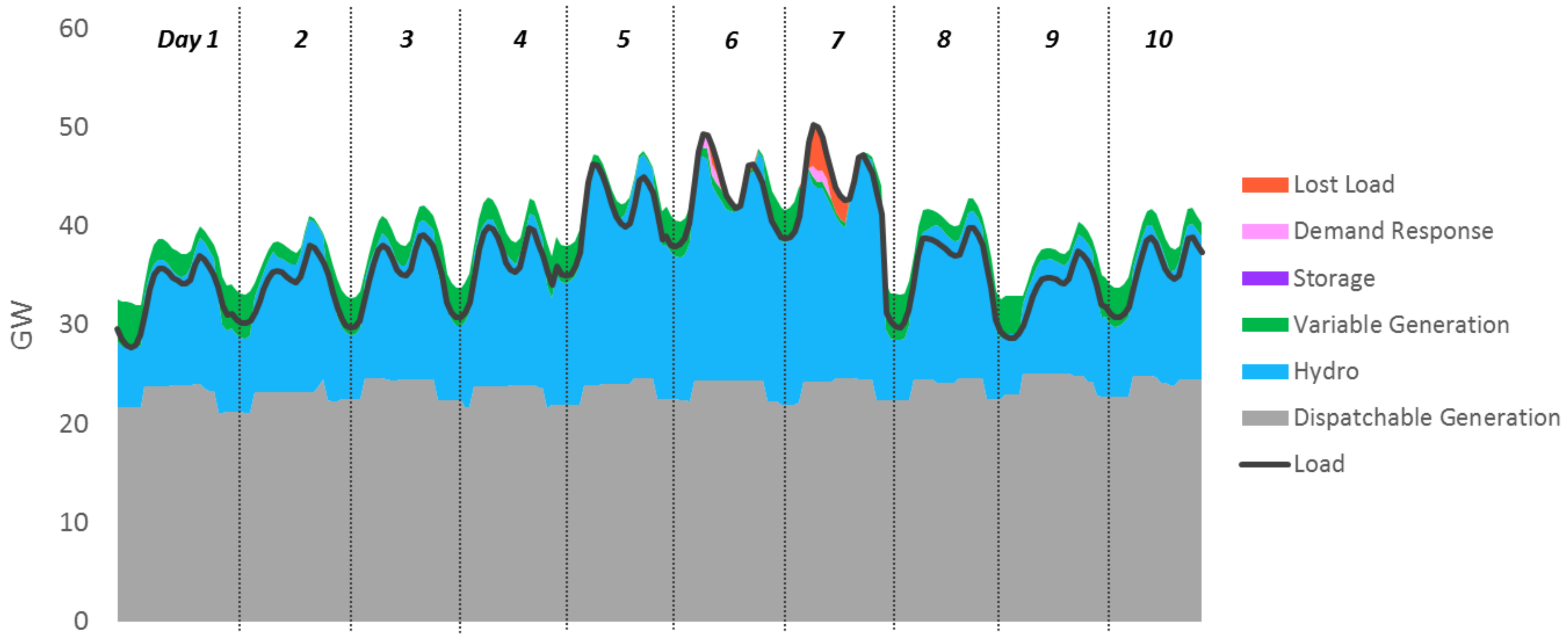
Hydro

- Hydro availability is determined randomly from historical hydro conditions (1929-2008) using data from NWPCC
- Monthly hydro budgets allocated in four weekly periods and are dispatched to meet net load subject to sustained peaking limits



2023 System: Week with Loss of Load

Highest load shortfall event: (Jan 1 – Jan 10, Temp Year: 1982)

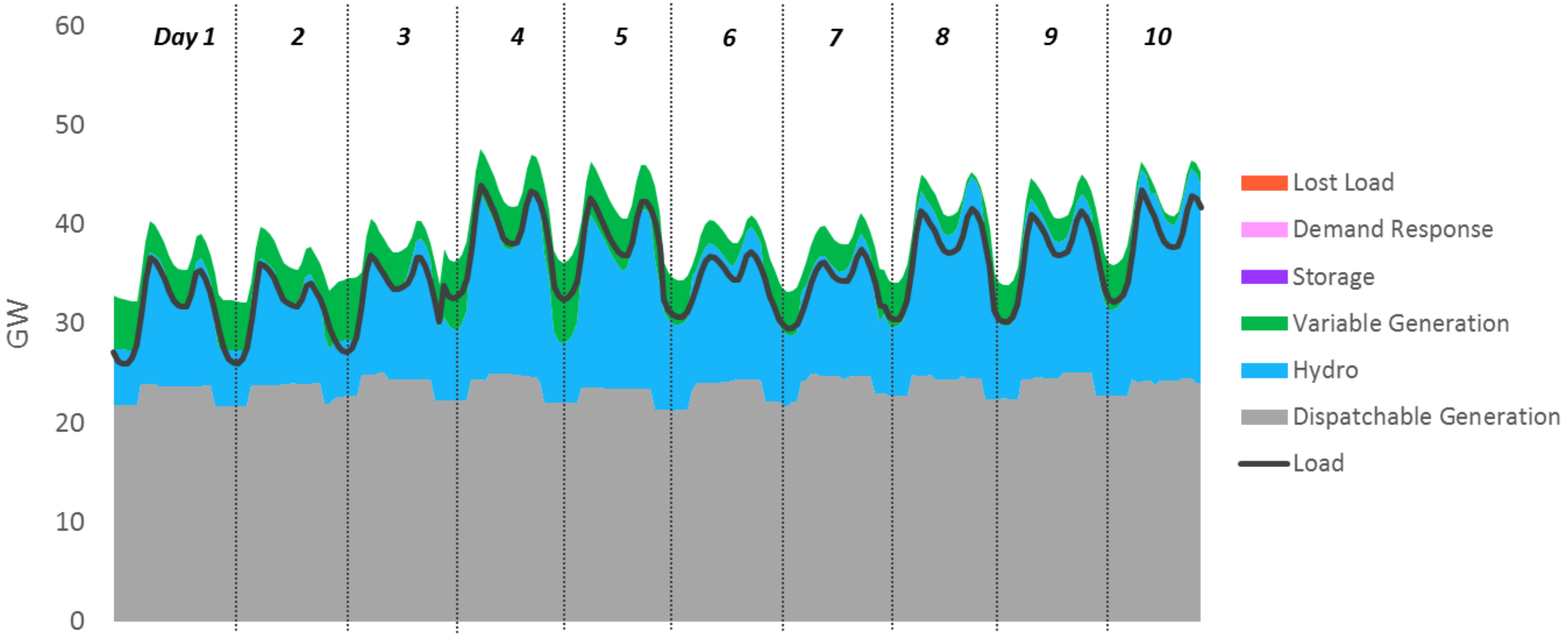


<u>Note</u>:

- Dispatchable Generation - includes thermal, geothermal, nuclear, run-of-river hydro, and imports
- Variable Generation – includes wind, solar and spot market purchases (in low-load hours)
- Hydro – includes all non-ROR hydro
- DR – 80 calls of 4 hour duration and 142.5 MW

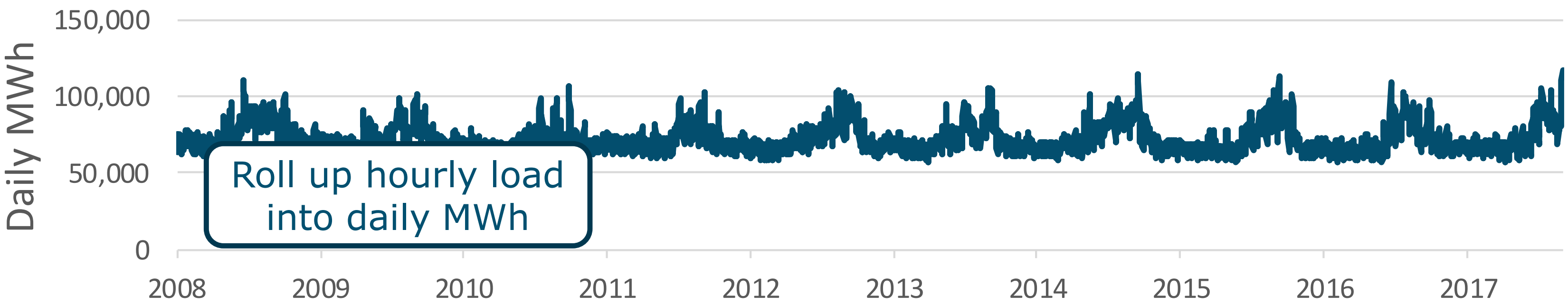
2023 System: Week with no Loss of Load

No load shortfall: (Feb 1 – Feb 10, Temp Year: 1982)



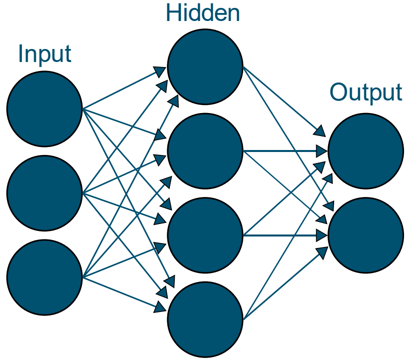
Note:
- Dispatchable Generation - includes thermal, geothermal, nuclear, run-of-river hydro, and imports
- Variable Generation – includes wind, solar and spot market purchases (in low-load hours)
- Hydro – includes all non-ROR hydro
- DR – 80 calls of 4 hour duration and 142.5 MW

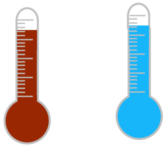
Running Neural Network Model



Roll up hourly load into daily MWh

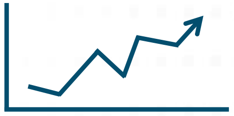
Run neural network model to establish relationship between daily gross load and the following factors





Max & Min Daily Temp

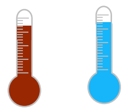
Month & Day-Type



Day Index for Economic Growth

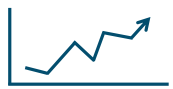
Training the Model

Use historical temperatures and calendar to 'train' NN model

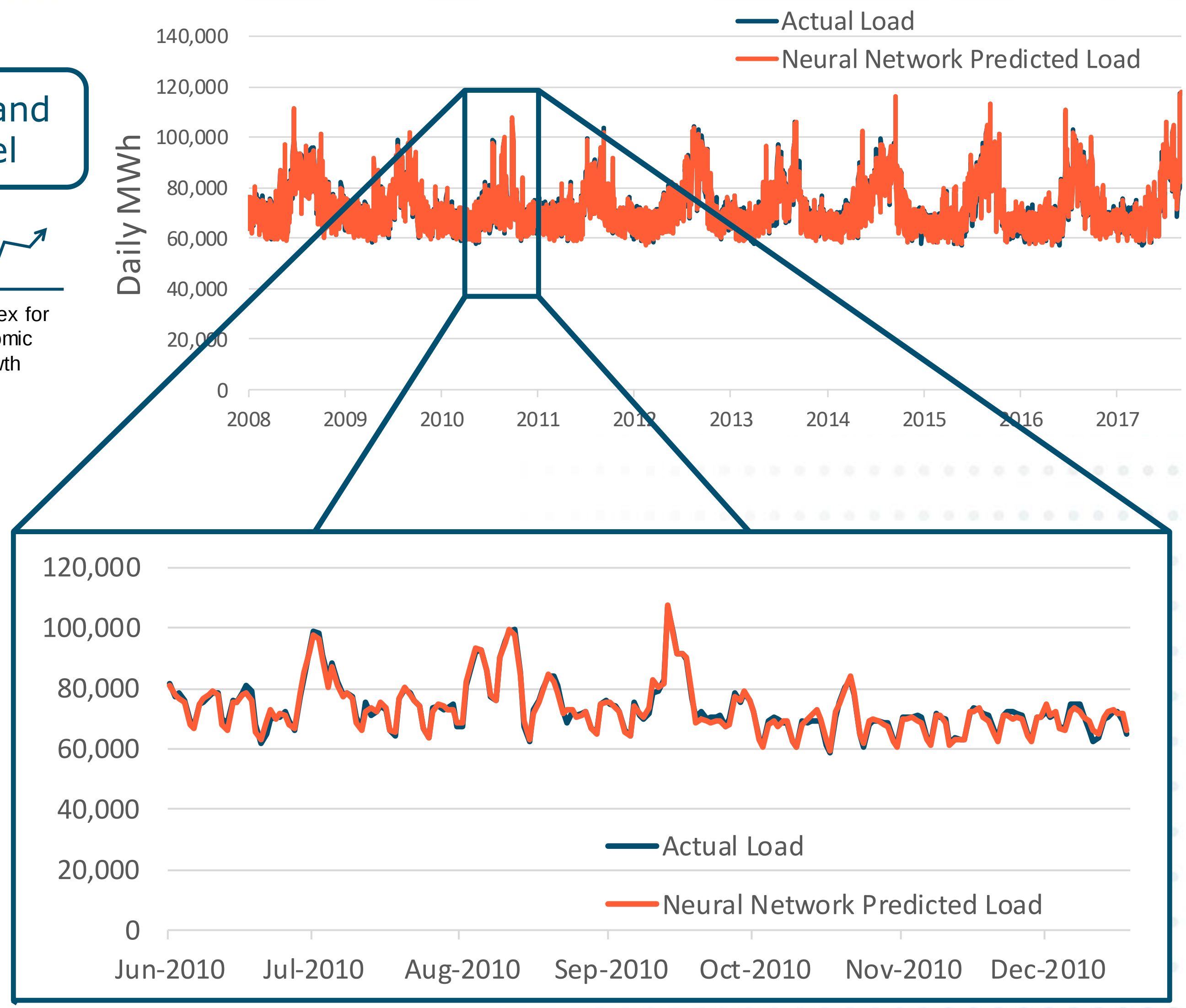


Max & Min Daily Temp

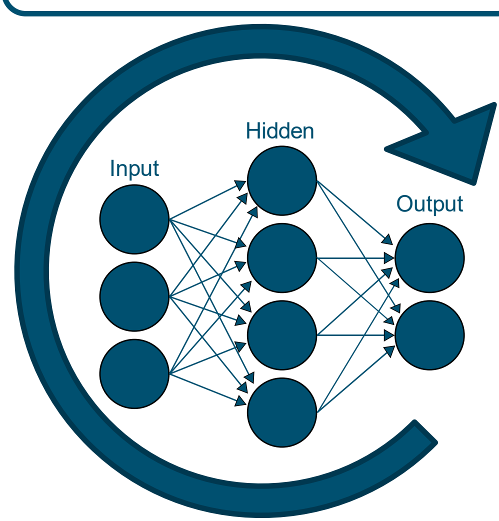
Month & Day-Type



Day Index for Economic Growth



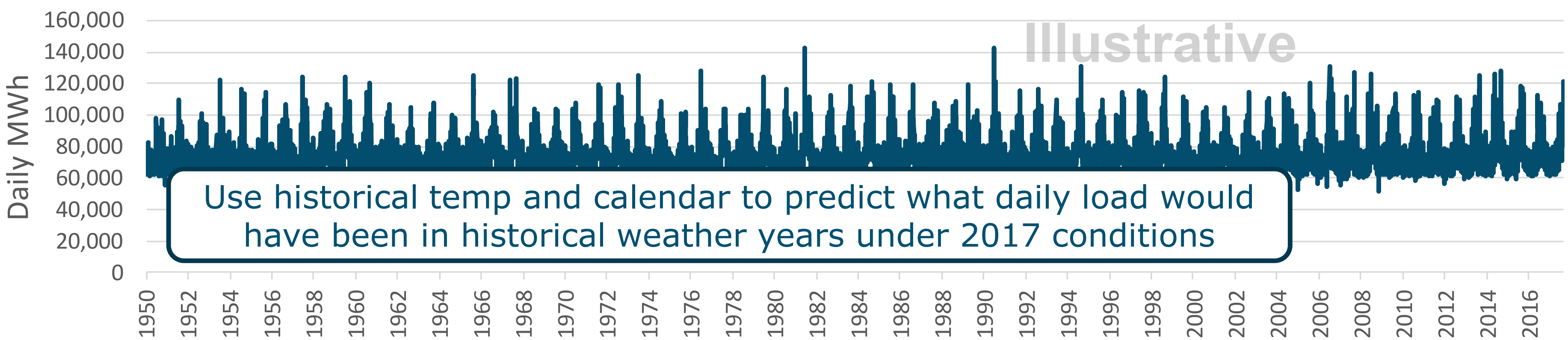
Iterate until model coefficients converge



Daily Load Simulations

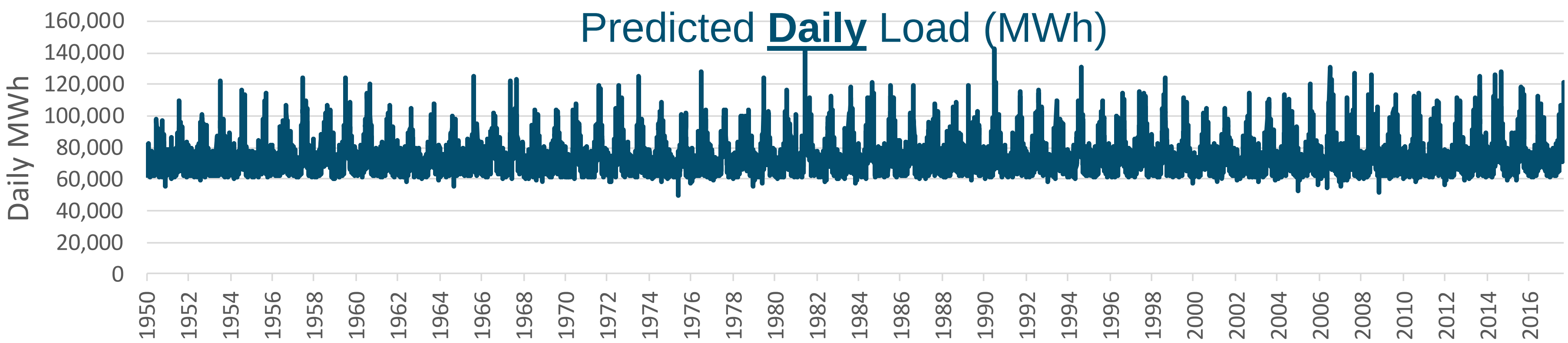
1950		2017
Jan	Historical Calendar →	Sep
Max & Min Daily Temp	Historical Temperature Record →	Max & Min Daily Temp

2017 Economic Conditions



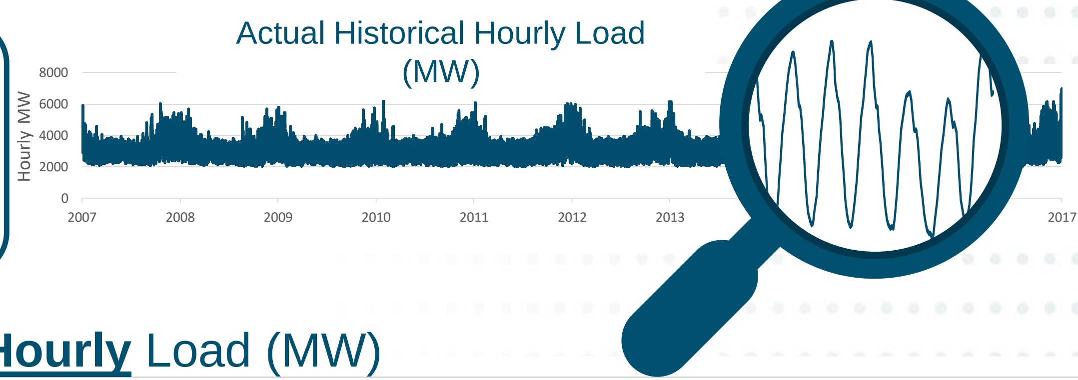
Use historical temp and calendar to predict what daily load would have been in historical weather years under 2017 conditions

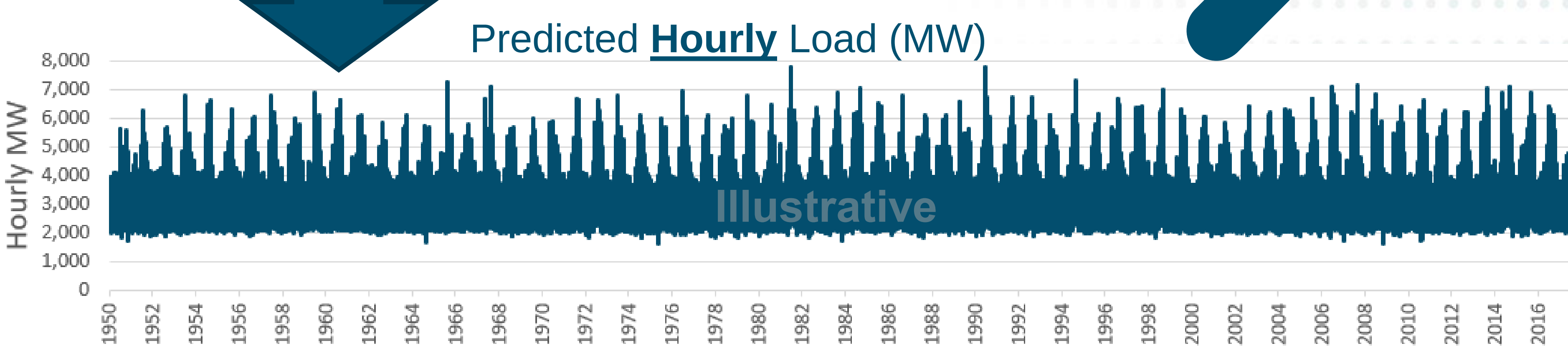
Converting Daily Energy to Hourly Load



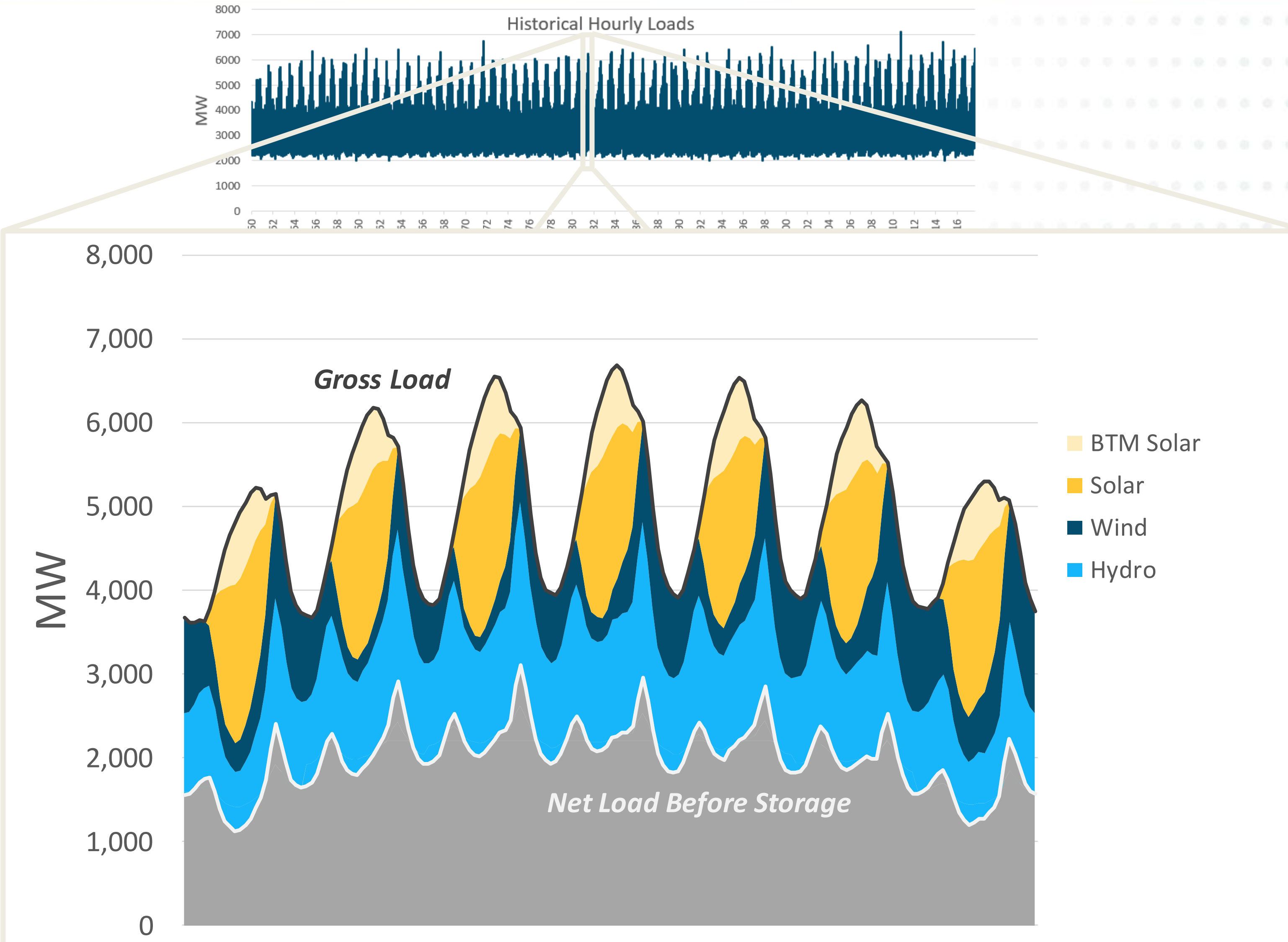
- Convert predicted daily load into hourly load by finding historical day with most similar daily load and using that hourly shape
- Constrained to search over identical day-type within +/-15 days

AUG
Weekday





Calculating Renewable Resources



Predicting Renewable Output

INPUT: example hourly historical renewable production data (solar)

1998 Jan — 2012 Dec

OUTPUT: predicted 24-hr renewable output profile for each day of historical load

1950 Jan — 2017 Sep

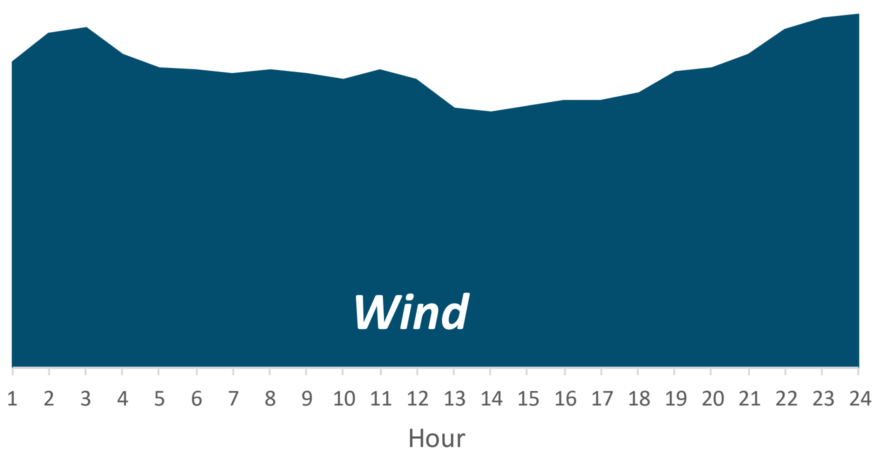
+ Renewable generation is uncertain, but its output is correlated with many factors

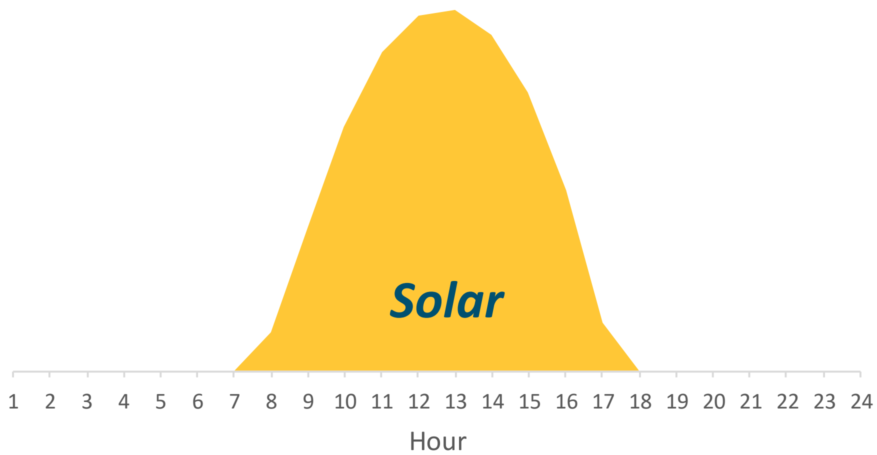
- Season
  - Eliminate all days in historical renewable production data not within +/- 15 calendar days of day trying to predict
- Load
  - High load days tend to have high solar output and can have mixed wind output
  - Calculate difference between load in day trying to predict and historical load in the renewable production data sample
- Previous day's renewable generation
  - Captures effect of a multi-day heatwave or multi-day rainstorm
  - Calculate difference between previous day's renewable generation and previous day's renewable generation in renewable production data sample

Renewable Profile Output

- Once a historical date has been randomly selected based on probability, the renewable output profiles from ***<u>that day</u>*** are used in the model

Renewable Output Profiles on Aug 12, 1973

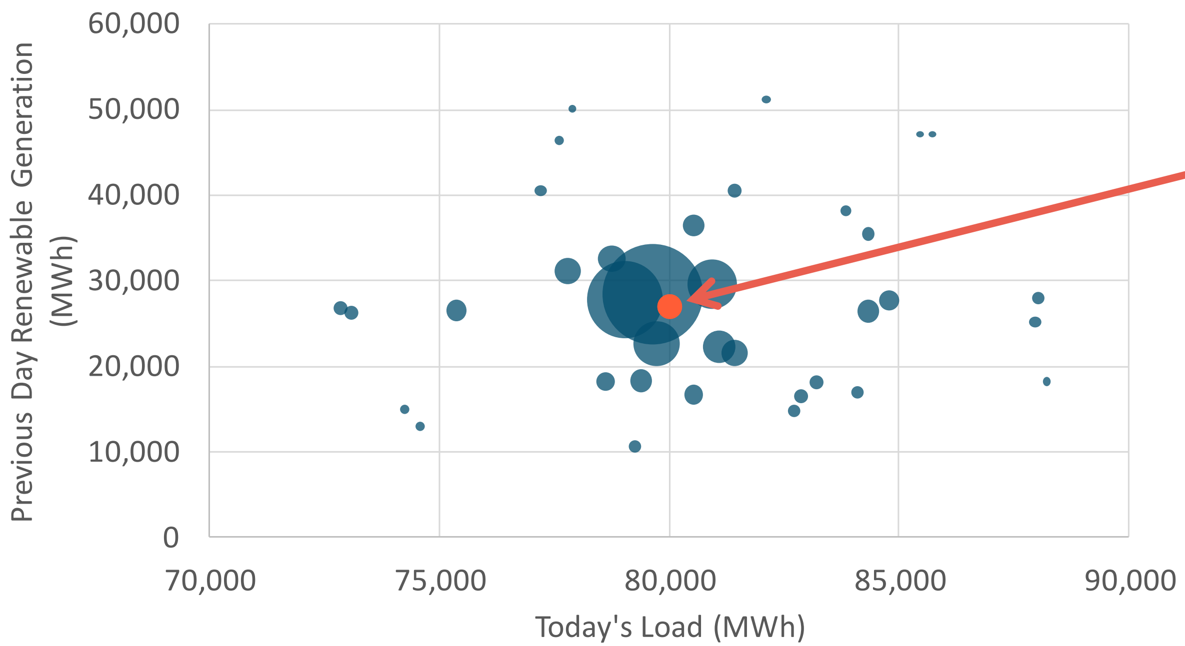




- Renewable profile development is done in aggregate for each resource type in order to capture correlation between solar generators

Predicting Renewable Output

- Each blue dot represents a day in the historical sample
- Size of the blue dot represents the probability that the model chooses that day



Aug 12, 1973	
Daily Load	80,000 MWh
Previous-Day Renewable Generation	27,000 MWh

Probability Function Choices

Inverse distance

Square inverse distance

Gaussian distance

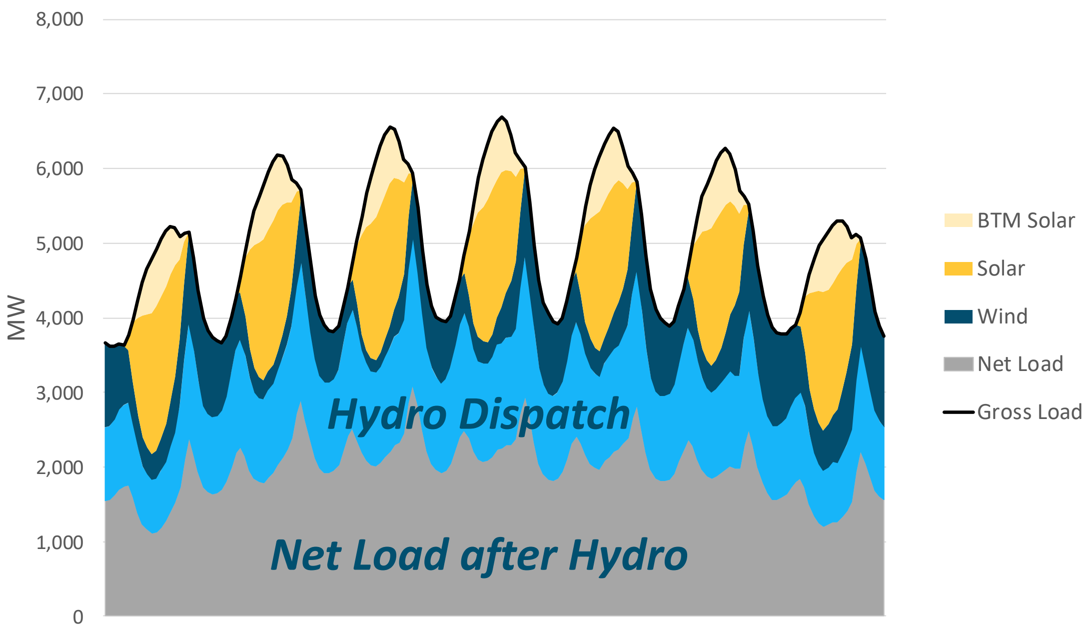
Multivariate normal

Probability of sample i being selected $= \dfrac{\dfrac{1}{Distance_i}}{\displaystyle\sum_{j=1}^{n} \dfrac{1}{Distance_j}}$

Where $\text{distance}_i = \text{abs}[\text{load}_{\text{Aug }12} - \text{load}_i]/\text{stderr}_{\text{load}} + \text{abs}[\text{renew}_{\text{Aug }12} - \text{renew}_i]/\text{stderr}_{\text{renew}}$

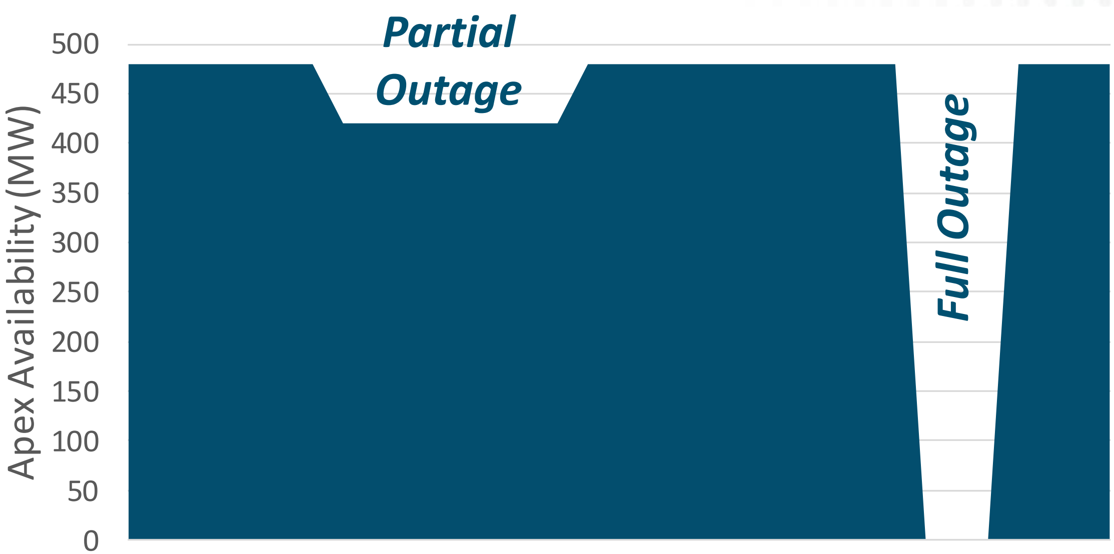
Hydro Dispatch

- **Predicted renewable generation is subtracted from gross load to yield net load for each historical day**
- **Historical hydro MWh availability is allocated to each month based on historical hydro record**
- **Hydro availability is allocated evenly across all days in the month**
- **Hydro dispatches proportionally to net load subject to Pmin and Pmax constraints**



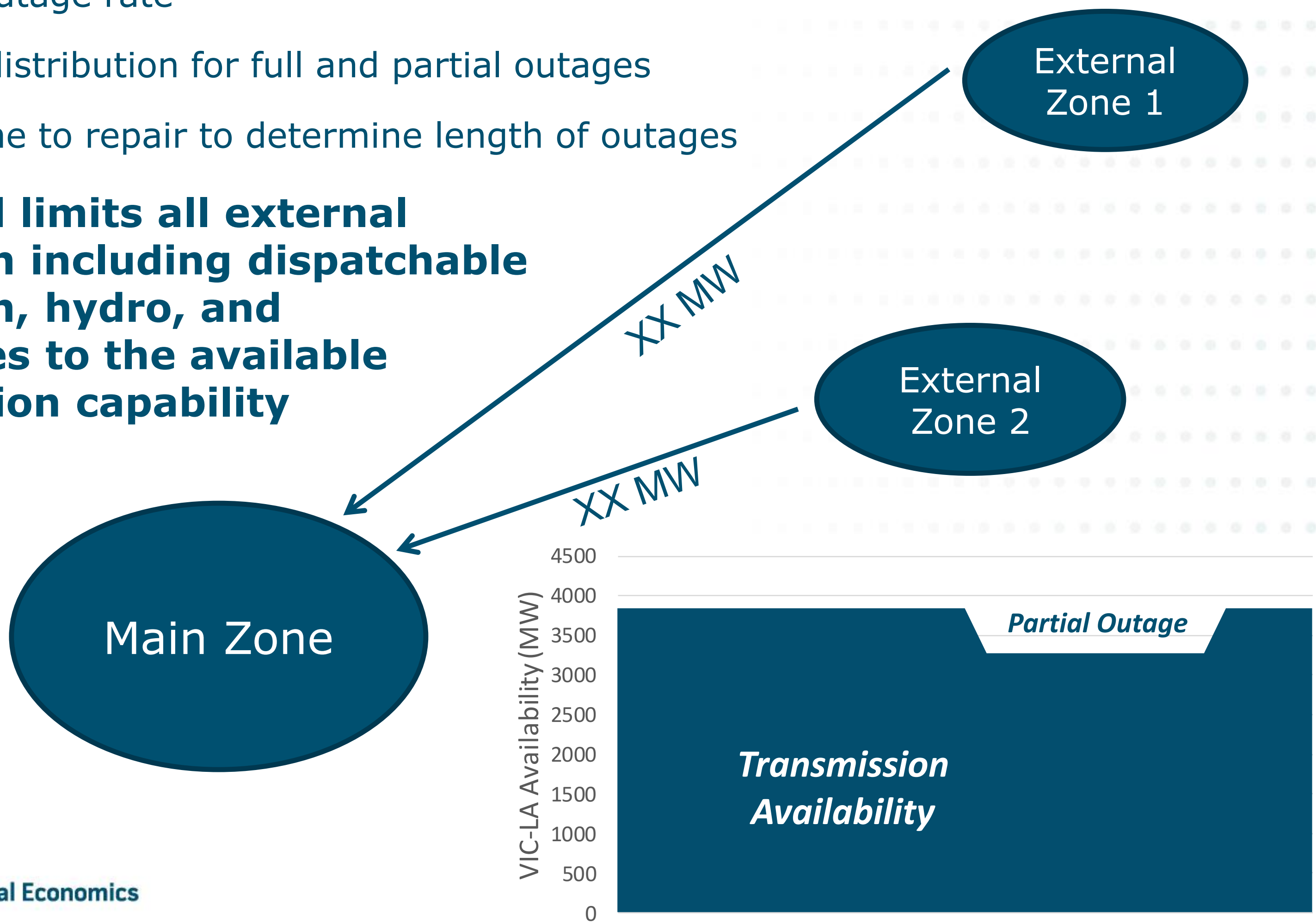
Available Generation

- For all dispatchable generation, the model uses the net dependable capacity of the generator
- Using the forced outage rate of each generator, random outages are introduced to create a stochastic set of available generators
- Outage distribution functions are used to simulate full and partial outages
- Mean time to repair functionalizes whether there are more smaller duration outages or fewer longer duration outages
- This is done independently for each generator and then summed across all generators



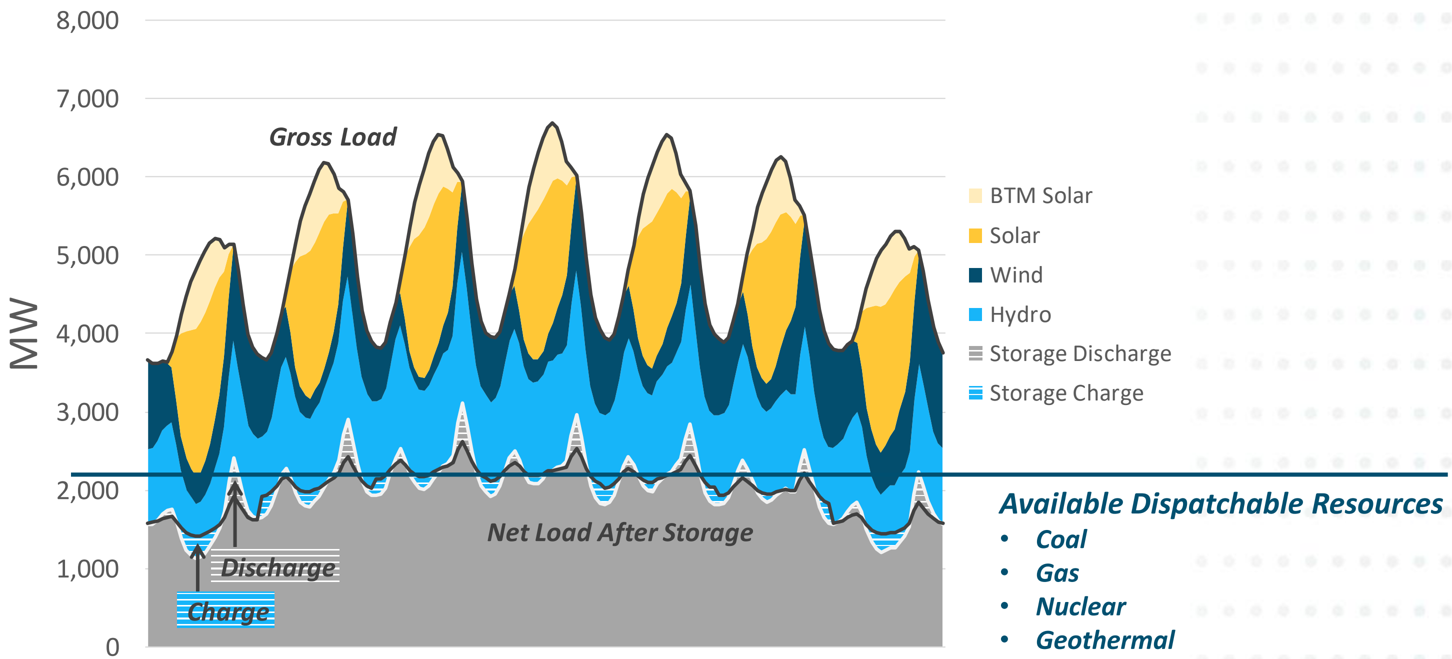
Transmission

- **The model uses identical logic as for generators to determine available capacity on each transmission 'line' into the main zone**
  - Forced outage rate
  - Outage distribution for full and partial outages
  - Mean time to repair to determine length of outages
- **The model limits all external generation including dispatchable generation, hydro, and renewables to the available transmission capability**



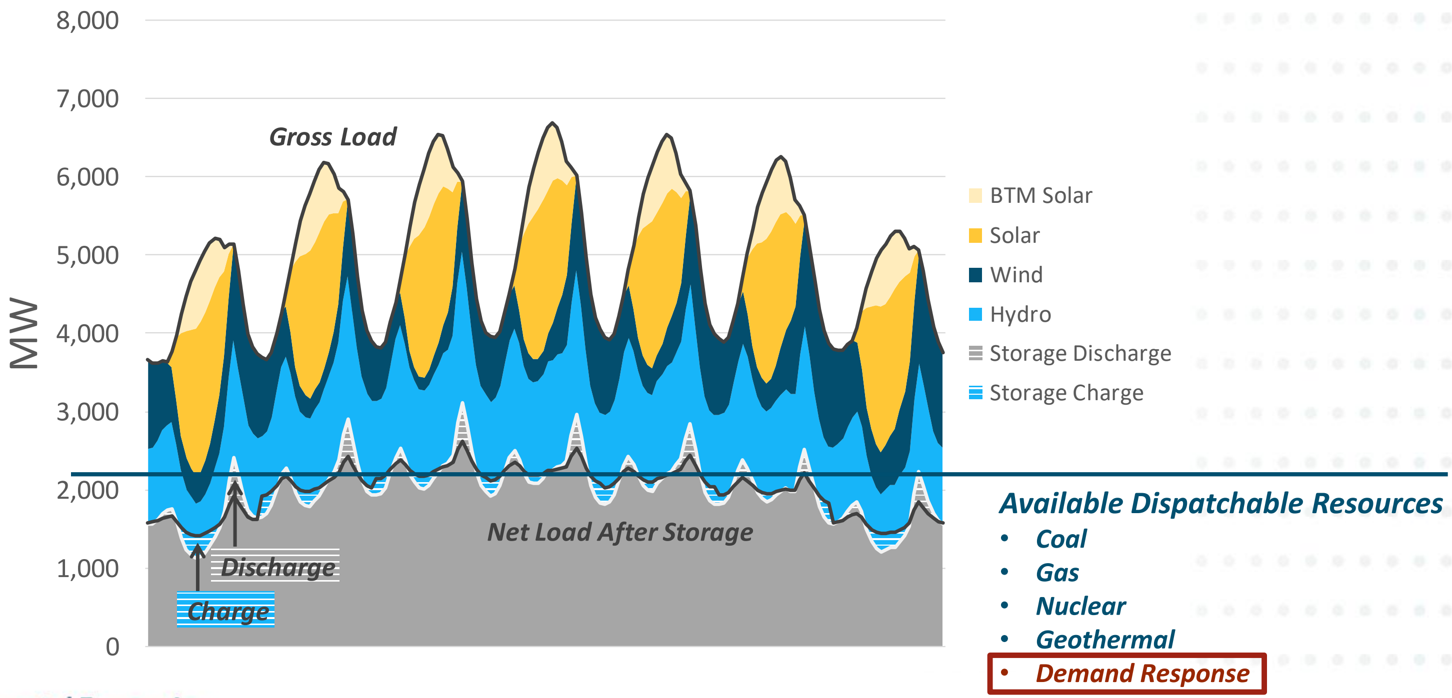
Storage

- Storage is dispatched for reliability purposes only in this model
- When net load is greater than available generation, storage always discharges if state of charge is greater than zero
- When net load is less than zero storage always charges
- When net load is greater than zero, storage charges from dispatchable generation if state of charge is below 100% (or other user specified threshold)



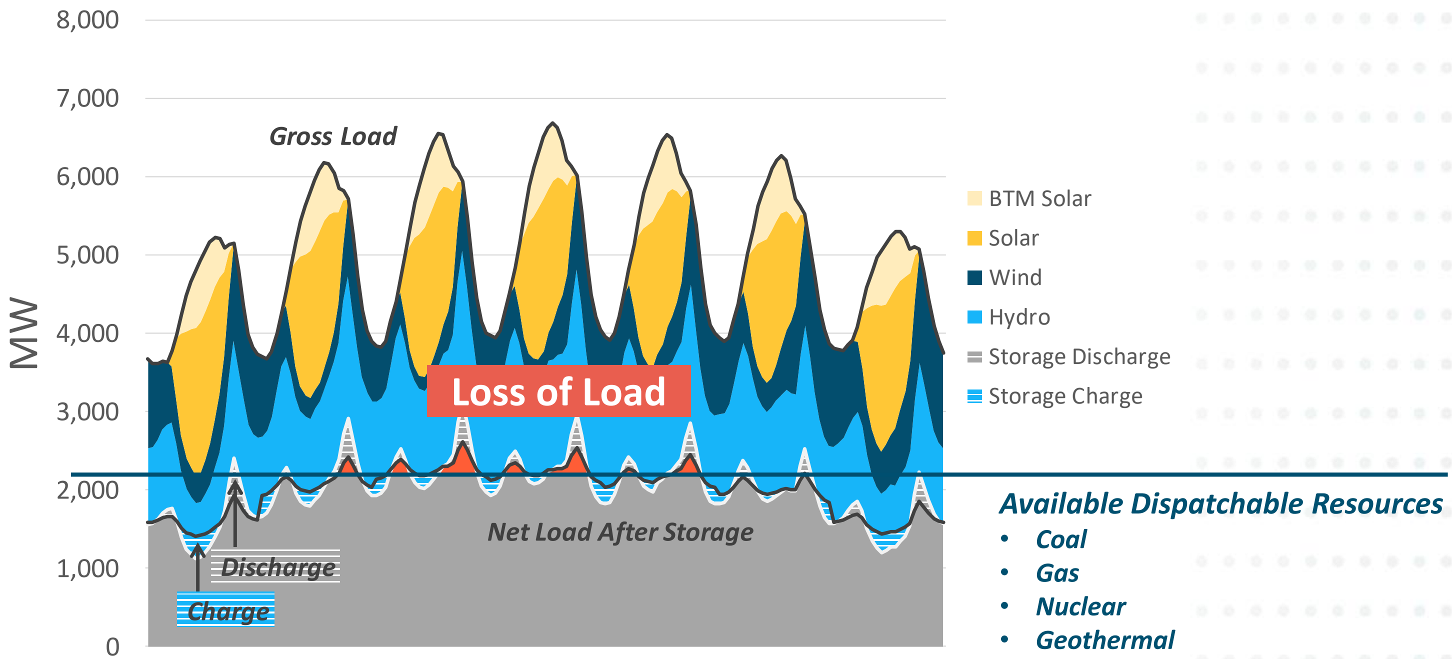
Demand Response

- Demand response is treated as the dispatchable resource of last resort – if net load after storage is greater than available dispatchable resources it is added to available resources
- Each DR resource has prescribed number of hours with a limited quantity of available calls per year



Calculating Loss of Load

- Any residual load that cannot be served from all available resource is counted as lost load
- Loss of load expectation (LOLE) is the number of hours of lost load per year



Available Dispatchable Resources

- ***Coal***
- ***Gas***
- ***Nuclear***
- ***Geothermal***
- ***Demand Response***

Energy+Environmental Economics

Thank You!

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ATTACHMENT B

Transmission Utilization Group May 2011 Report:
COI Utilization Report

Transmission Utilization Group

COI Utilization Report

May 04, 2011

Executive Summary

In 2010 the Transmission Utilization Group (TUG), composed of owners of the California-Oregon Intertie (COI), began work to determine how the COI has been utilized in the recent past. The joint effort consisted of analyzing the past five years of usage data, transmission reservation and scheduling timelines, and transmission rates associated with the COI. In addition, TUG held a public COI user group meeting to receive input as to the factors influencing COI usage and the obstacles preventing higher utilization.

Based on the analyses and observations identified below, TUG reached the following conclusions regarding the potential for increasing COI transmission availability and usage:

- Entities that need firm delivery will require new transmission capacity.
- New long term transmission capacity would allow the generators and California utilities to enter into power purchase agreements, obtain financing, and have certainty of power deliveries.
- Pacific Northwest and California entities should cooperate and consider moving forward with an Open Season process to determine the demand and interest for additional transmission.

The COI has multiple owners and parties with scheduling rights on both sides of the California Oregon Border (COB). Pacific Northwest (PNW) parties own and operate the COI north of COB and Pacific Southwest (PSW) parties own and operate the COI south of COB. The California ISO (CAISO) is the southern path operator and the Bonneville Power Administration (BPA) is the northern path operator. Three balancing authorities, CAISO, BPA and Sacramento Municipal Utility District intersect at the northern end of COI (Malin and Captain Jack substations). This regional diversity in ownership and operational differences provide market opportunities/challenges and influence the COI utilization.

The TUG analysis determined that the COI is fully subscribed on a long-term basis north of COB in the north-to-south direction and is heavily utilized during peak months. Limited amounts of short-term firm and non-firm transmission north of COB are available on a real-time basis. Specific conclusions are:

- COI utilization varies significantly year-to-year depending on seasonal and market factors. Variability in the spring hydro run-off in terms of volume, shaping, and duration, produce vastly different yearly profiles. Similarly, monthly variability in the summer months is driven by California load, i.e., higher temperatures. COI usage increased each year from 2006 to 2008. In 2009, the usage dropped back to the 2006 levels (likely driven by the recession and lower than normal hydro run-off). The body of the report analyzes details of these trends.
- Without additional transmission capacity to move energy into California during a high wind-high water event such as occurred in June 2010, generation in the Pacific Northwest, including wind resources, will have to be displaced or curtailed to maintain system reliability.
- Analysis of the five-year usage data shows that the price spread between the PNW's Mid-Columbia (Mid-C) and California's NP15 trading hubs appears to be the most significant driver for the usage of the COI. As the price spread between the two hubs increases, usage increases to the point that the COI is fully utilized.
- Historical usage is highest in the summer months when the loads in California peak, and during the spring months when high hydro runoff in the PNW make excess energy available. During the five-year period, high utilization (90 percent or higher of the scheduling limit) occurred in 30 percent of the "heavy load" hours (between hours ending 0700 and 2200) during the summer season, and 32 percent of heavy load hours during the spring high hydro runoff months.
- The COI is frequently unavailable at the full 4800 MW scheduling limit due to various system constraints over the five-year period. During the spring high hydro runoff months, the scheduling limit on the COI was often reduced due to planned maintenance outages. COI owners currently coordinate outages to generally occur in the spring because physical access is easier and to prepare the lines for the critical summer months. The COI owners should look at spreading the outages between the spring and fall, or other times of the year, to maximize the available capacity and COI utilization during the spring high hydro runoff. Other system constraints that limit the 4800 MW capacity include interaction with other WECC Paths and northern California hydro generation. BPA is undertaking system improvement projects that will boost reliability and allow more power transfers between Oregon and California.

The public meeting held with COI users was informative. Participants gave the following suggestions:

- The users agreed that utilization of the COI is very seasonal, highly dependent on factors such as weather, hydro conditions and loads within each region, and mainly driven by the price spread between the two regions, which at a minimum must cover variable costs, e.g. transmission wheeling and losses.
- COI users also indicated that the transmission resale market is improving and recommended that BPA remove its price cap for resale. BPA is actively examining how it can provide market pricing flexibility for transmission resale in a manner that will also provide a safety net for consumers. BPA has also posted its newly proposed Business Practice (BP) for customers' comments.
- Although there are some disparities between the CAISO market and PNW transmission providers' reservation and scheduling timelines, most of the users said that neither scheduling timelines nor transmission rates prevent market transactions. COI users also indicated that there is sufficient access to the COI for short term transactions.
- Some merchants expressed concern over unknown costs when doing business with the CAISO market compared to bilateral markets, although market bids can limit their cost exposure. Another observation from a merchant noted that energy prices at COB have been much closer to Mid-C prices than NP-15 prices, indicating much smaller Mid-C to COB price spreads compared to COB to NP-15 spreads. An in-depth market structure analysis would be needed if the TUG desires to further understand the relationship between the energy markets and COI utilization.
- The users requested more dynamic transfer availability between the regions (both to John Day and from John Day to COB), which may also increase the utilization of the COI. At present BPA and CAISO are evaluating the potential for intra-hour scheduling on the COI as a pilot project. The CAISO is now completing a stakeholder process to add dynamic transfers to its existing market functionality. CAISO has included a technical study concluding that the CAISO does not have limitations in its transmission capability to support dynamic transfers of intermittent resources. BPA, CAISO, and other organizations in the PNW are supporting recently initiated dynamic transfer capability studies, through the Dynamic Transfer Capability Task Force convened by the Wind Integration Study Team.
- COI users commented that more incentives are necessary (structurally) from the regulators and policy makers for delivering renewable resources to California.

- Merchants would like to use both firm and non-firm transmission equally for power purchase agreements.
- Pro-rata real-time curtailment at COI can result in further curtailments at COI, as COI OTC is reduced, and curtailments are implemented. The COI users recommend that BAs and operators should investigate changes in pro-rata tag curtailment procedures.
- COI users asked Transmission Service Providers to remain vigilant to ensure that minimal seams issues exist in the future.

Table of Contents

1. Introduction

The California-Oregon Intertie (COI) owners and operators began meeting in early 2010 to discuss alternatives for increasing the transmission availability across the California Oregon Border (COB). The goal is to access renewable resource projects in the Pacific Northwest (PNW) and deliver that energy to northern and central California. The Steering Committee, representatives of the COI owners, established the Transmission Utilization Group (TUG) whose mission was to achieve an understanding of the current utilization of the COI transmission capability and to make recommendations on how to increase the utilization if possible.

Long-term firm transmission in the North-to-South direction on the COI, north of COB, is fully subscribed. Limited amounts of short-term firm and non-firm transmission are made available on a real-time basis. TUG's work principally consisted of an analysis of the historic usage of the COI going back to 2005, collection of rate information, scheduling timelines, and information from merchants on both how they currently use the COI and possible changes that could increase the usage of the COI.

The joint TUG effort was conducted under the guidance of the Steering Committee and coordinated by the Western Area Power Administration (WAPA) with support from Bonneville Power Administration (BPA), California ISO (CAISO), BC Hydro, PacifiCorp (PAC), Portland General Electric (PGE), Pacific Gas and Electric (PG&E), Sacramento Municipal Utility District (SMUD), and Transmission Agency of Northern California (TANC).

2. COI Description

The COI consists of three jointly owned 500 kV AC lines from Oregon to northern California, which together are recognized as a Western Electric Coordinating Council (WECC) regional transmission path, identified as Path 66. This path is shown in Figure 2.1. Two lines of the COI are known as the Pacific AC Intertie (PACI), the third is the California Oregon Transmission Project (COTP).

a. PACI

The PACI is two parallel 500 kV AC lines and associated facilities that run from the Malin substation in Oregon to the Tesla substation, owned by PG&E in central California. WAPA owns the Malin-Round Mountain Line #1, and PG&E and PAC jointly own Line #2. Currently, PG&E leases 100% of PAC's Malin to Round Mountain capacity. PG&E owns both lines of the PACI from the Round Mountain to the Tesla substation.

b. COTP

The COTP is the third 500 kV AC line, that runs from the Captain Jack substation in Oregon through the SMUD Balancing Authority area to an interconnection with the PACI near Tesla. The segment of the PACI from Malin to the Round Mountain substation, together with the northern portion of the COTP, constitutes the COI.

c. Path Rating

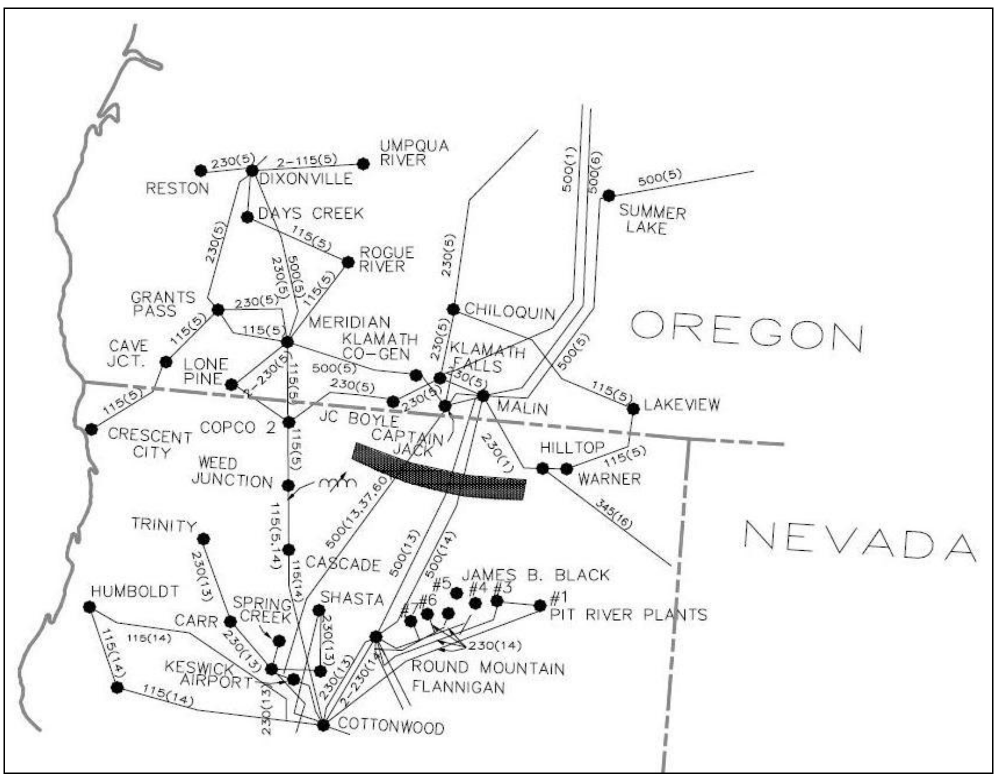
The nominal COI rating is 4,800 MW from north-to-south, and 3,675 MW from south to north. However, in addition to limitations due to outages, nomograms have been developed to identify simultaneous operating constraints between this path and other paths including:

- The Pacific DC Intertie (Path 65),
- The North of John Day (Path 73),
- Hemingway-Summer Lake (Path 75), and
- Borah West (Path 17).

Other factors that affect operating conditions are:

- Northern California hydro generation,
- Other northern California generation,
- Northern California load,
- Northwest hydro and thermal generation dispatch,
- Northwest load levels, and
- Reno-Alturas (Path 76 or NW-Sierra) flow.

Figure 2.1: The three COI lines, also known as Path 66.

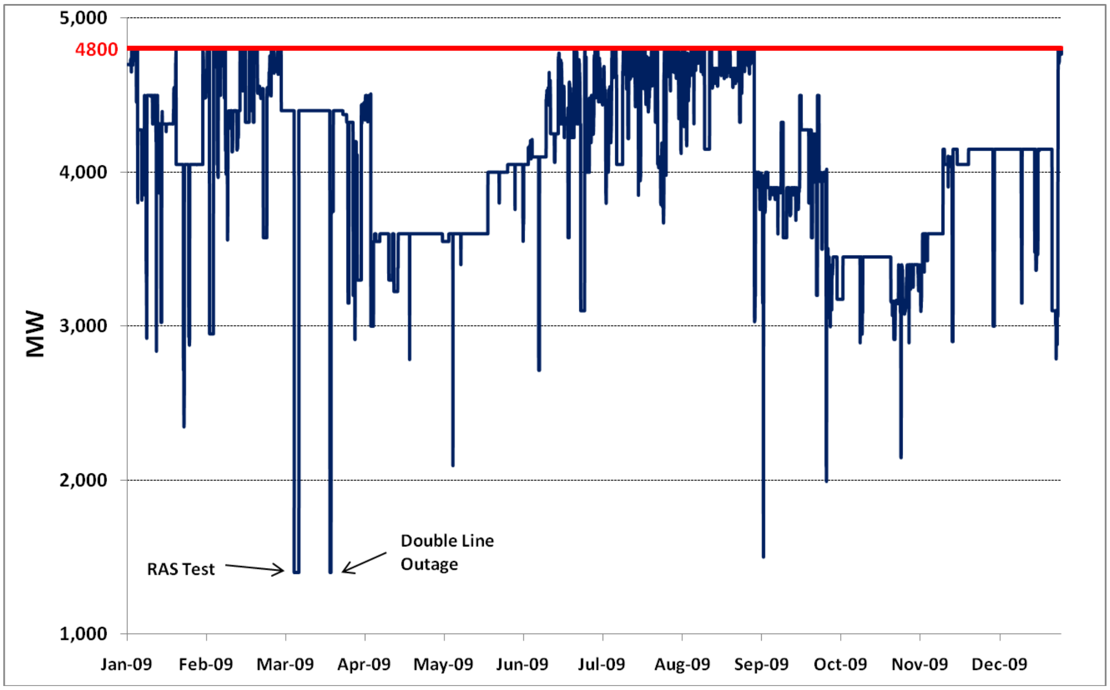


Unlike many other WECC Paths, the System Operating Limit (SOL) for COI is variable and is voltage stability limited. Even though the COI has a 4800 MW rating, it seldom has its full capability available for use (Figure 2.2).

The 4800 MW rating is highly dependent on interactions with other WECC Paths, Northern California Hydro (NCH) output, Northern California load, and also relies on a multifaceted Remedial Action Scheme (RAS) to support reliable power transfers.

The Bonneville Power Administration (BPA) is responsible for monitoring system conditions in the Northwest. The California Independent System Operator (CAISO) is responsible for monitoring system conditions in California.

Figure 2.2 – 2009 Hourly COI Limits



i. Relationship between COI and COI/NW-Sierra SOL

Although commonly referred to as simply the "COI", it is actually operated in conjunction with the parallel NW-Sierra 345 kV line[1] (WECC Path 76). Both path operators on either side of COB, CAISO and BPA, have operating procedures that reference COI as "COI/NW-Sierra" and include the following statements:

> *The COI SOL (SW section of AC Intertie) and the COI/NW-Sierra SOL (NW section of AC Intertie) will be equal. Studies have shown that 1 MW on the NW-Sierra path is approximately equal to 1 MW on the COI. Consequently, for nomogram and outage conditions, the system is always operated safely if the sum of the COI and NW-Sierra path (COI/NW-Sierra) is operated within limits defined for COI prior to energization of the NW-Sierra path.*

Since the NW-Sierra path has a maximum rating of 300 MW, the maximum capability of COI/NW-Sierra is limited to 4800 MW. Whenever the NW-Sierra path is using its full 300 MW, the COI limit maximum is reduced to 4500 MW. Conversely, when the NW-Sierra path is out of service, COI can be scheduled up to its maximum seasonal SOL of 4800 MW.

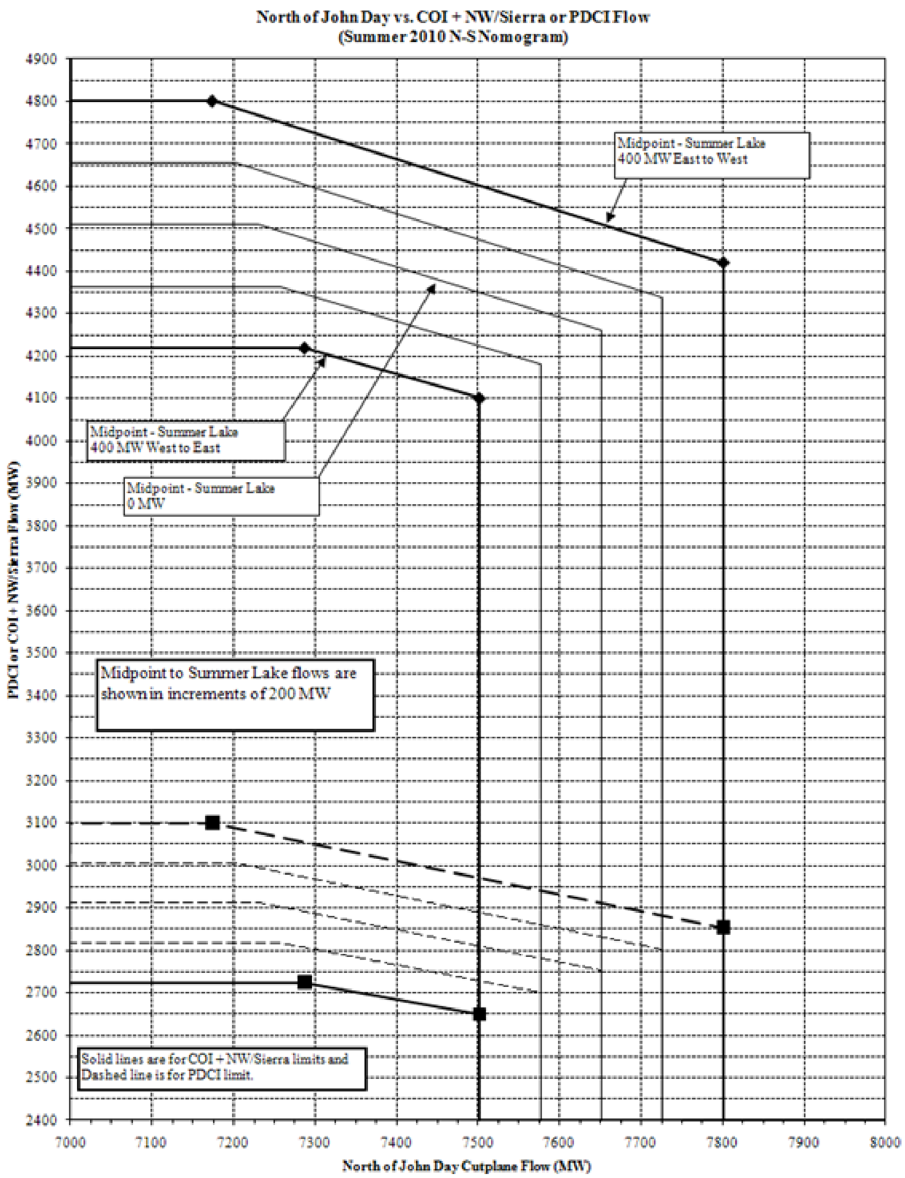
[1] Also known as the Reno- Alturas line.

ii. Hemingway - Summer Lake Flows

The COI/NW-Sierra SOL is also dependent on the actual flow from Hemingway[2], a station in Idaho, to Summer Lake, located in southern Oregon (WECC Path 75). Based on the magnitude and flow direction, the CAISO may derate the COI/NW-Sierra by up to 100 MW.

BPA also monitors the actual flow on Path 75 using the nomogram in Figure 2.3. BPA may also derate COI/NW-Sierra based on North of John Day (NJD) WECC Path 73 flow. As can be seen from the nomogram, COI/NW-Sierra cannot exceed 4225 MW when NJD reaches 7300 MW and Hemingway – Summer Lake is 400 MW west to east.

Figure 2.3: Path 75 Nomogram



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2 Previous metering point was Midpoint

iii. Northern California Hydro Generation

Northern California Hydro (NCH) is 4100 MW of generation comprised of the USBR Central Valley Project, PG&E's Pit and Feather River systems, CDWR's Hyatt Thermalito units, and the units on the South Fork of the Feather River, and the North Yuba river systems.

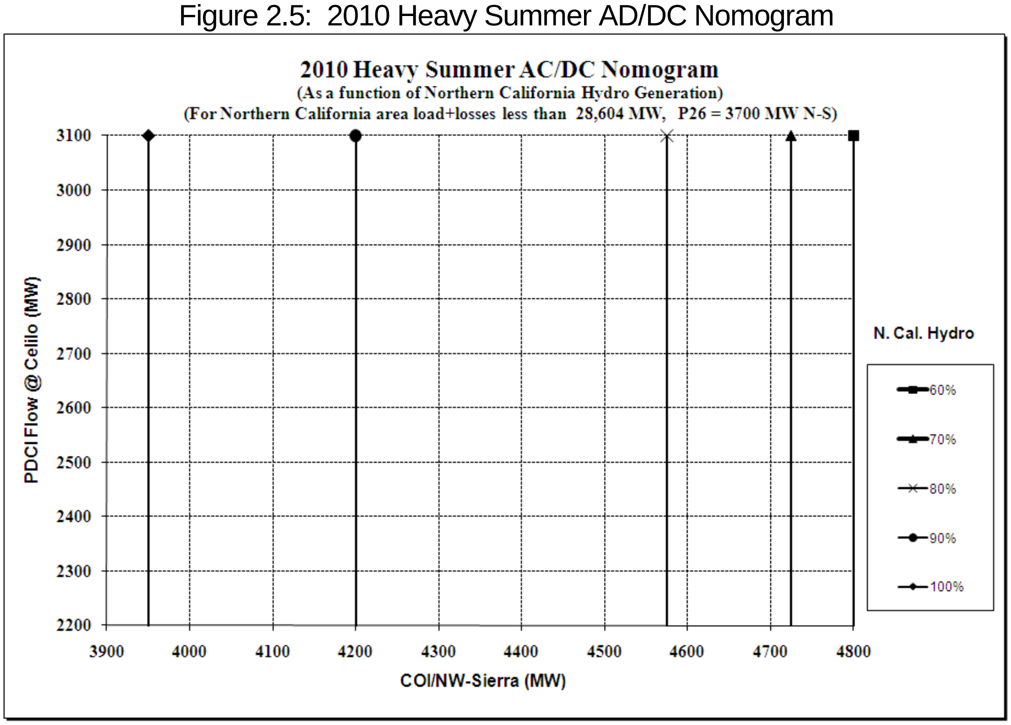
The COI/NW-Sierra capacity for 2010 summer is tabulated below and shown on the nomogram in Figure 2.4 and 2.5.

Figure 2.4: Impacts of Northern California Hydro Generation of COI Rating

N.Cal H_2O	COI / NW-Sierra
60%	4800 MW
70%	4725 MW
80%	4575 MW
90%	4200 MW
100%	3950 MW

Based on the 2010 summer nomogram, if NCH levels are forecast to be 80%, the maximum COI capability will be 4575 MW.

Figure 2.5: 2010 Heavy Summer AD/DC Nomogram



iv. Northern California Load

If Northern California Area Load (PG&E, SMUD and TID Balancing Authorities) is greater than 28,604 MW[3], the COI/NW-Sierra limit is curtailed by 15 MW for every 100 MW that Northern California area Load is expected to exceed this level.

d. COI Operation

Coordinated operation of the COI is currently accomplished through the *Owners' Coordinated Operations Agreement* (OCOA). Under the *Agreement for Use of Transmission Capacity among PG&E, PacifiCorp, Southern California Edison Company, and San Diego Gas & Electric Company*, PG&E has placed the entire eastern line under the operational control of the CAISO. This was pursuant to the Transmission Control Agreement between the CAISO and PG&E. The CAISO also manages a portion of the transmission rights on Western's facilities, and Western receives rights from Round Mountain to Tesla, pursuant to the Transmission Exchange Agreement.

Through the California-Oregon Intertie Path Operating Agreement, the CAISO is the southern path operator and BPA the Pacific Northwest (PNW) path operator. Three balancing authorities intersect at the northern end of COI (Malin and Captain Jack substations), with the BPA balancing authority area containing the lines north of Malin, the CAISO balancing authority area containing the PACI, and the SMUD balancing authority area containing COTP. Among other matters, the balancing authorities must:

- approve, validate and confirm interchange schedules,
- confirm ramping capabilities with Interchange Authorities,
- make dispatch adjustments so as not to exceed transmission facility limits,
- coordinate system restoration plans with transmission operators,
- coordinate with generators and load-serving entities within their balancing authority areas regarding their operational status, plans, and availability,
- receive real-time operating information from and provide real-time operating information to transmission operators and adjacent balancing authorities,
- implement instructions from the applicable Reliability Coordinator,
- direct resources to take action to manage congestion and ensure system balance,
- implement emergency procedures and system restoration plans, and comply with NERC reliability standards.

e. COI Improvement Project

In response to a growing demand for the COI North to South transmission capacity, BPA and the Northwest COI owners decided to undertake system improvement projects that will boost the system's overall reliability and allow more electricity to move between Oregon and California.

Although the COI is rated at 4,800 MW, it frequently is not available at its full capacity due to various conditions that constrain the system. For these reasons BPA held out a certain amount of capacity from sale in order to avoid frequent curtailments. After conducting studies on the situation, it was concluded that installing new high-voltage equipment at several critical

[3] Seasonal value; 2010 summer limit shown

bottlenecks in the transmission system would reinforce the COI so it can operate at full capacity more frequently and under a wider range of conditions.

BPA began the construction of COI reinforcement project in 2008 and it is scheduled to be completed in the late spring of 2011. The estimated cost for this project is $63.5 million and each of the COI owners in the Northwest shared a portion of the total cost, based on their percentage of ownership of the system. Subsequently, this reinforcement project allowed BPA to offer additional long-term transmission service to its customers.

3. COI Ownership and Entitlement

The COI has multiple owners and parties with scheduling rights on both sides of the California Oregon Border (COB). Pacific Northwest parties own and operate the COI north of COB and Pacific Southwest parties own and operate the COI south of COB. The COI transmission capacity in the north-to-south (N>S) direction to COB is fully subscribed on a long-term basis.

a. Ownership North of COB

The COI north of COB is shared by Facility and Capacity Owners. The Facility Owners are BPA, PAC and PGE. These parties jointly own both the physical facilities and capacity of the COI north of COB. Unlike the Facility Owners, Capacity Owners only have capacity rights on the COI. These owners include Puget Sound Energy (Puget), Seattle City Light (Seattle), Pacific Northwest Generating Cooperative (PNGC), Snohomish County PUD (Snohomish), Tacoma Power (Tacoma) and PAC. These capacity rights have been purchased from BPA's capacity share. Both Facility and Capacity Owners retain their rights to their shares for the life of the COI facilities.

Figure 3.1 below shows each party's percentage (ownership and/or capacity rights) on the COI north of COB. The BPA's share is the amount remaining after 725 MW were sold to the Capacity Owners. Each party can re-sell their firm transmission rights on a long-term or short-term basis, or a combination of both. The majority of the firm capacity that is not scheduled by firm contract holders is available for sale as non-firm hourly via BPA and other transmission provider's OASIS.

b. Ownership South of COB

Ownership of the 3,200 MW PACI lines is shared between WAPA, PG&E, and PAC (Figure 3.2). Through various agreements, control to 2,720MW of this capacity has been turned over to the CAISO for operation in CAISO-managed markets.

The 1,600 MW COTP line is owned by TANC, WAPA, Redding, San Juan and Carmichael (Figure 3.3). Control of PG&E's portion of its COTP share, 33 MW, has also been turned over to the CAISO. COTP parties can re-sell their firm transmission rights on either a long-term or short term basis, or a combination of both.

Figure 3.1 North of COB Ownership Breakdown

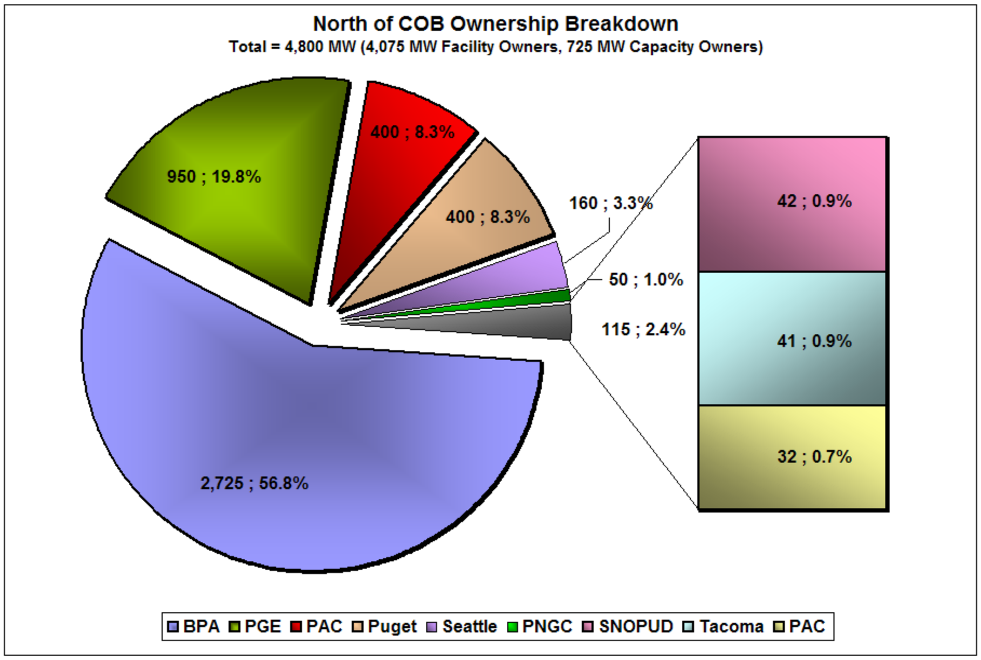


Figure 3.2 Pacific AC Intertie Scheduling Rights Breakdown

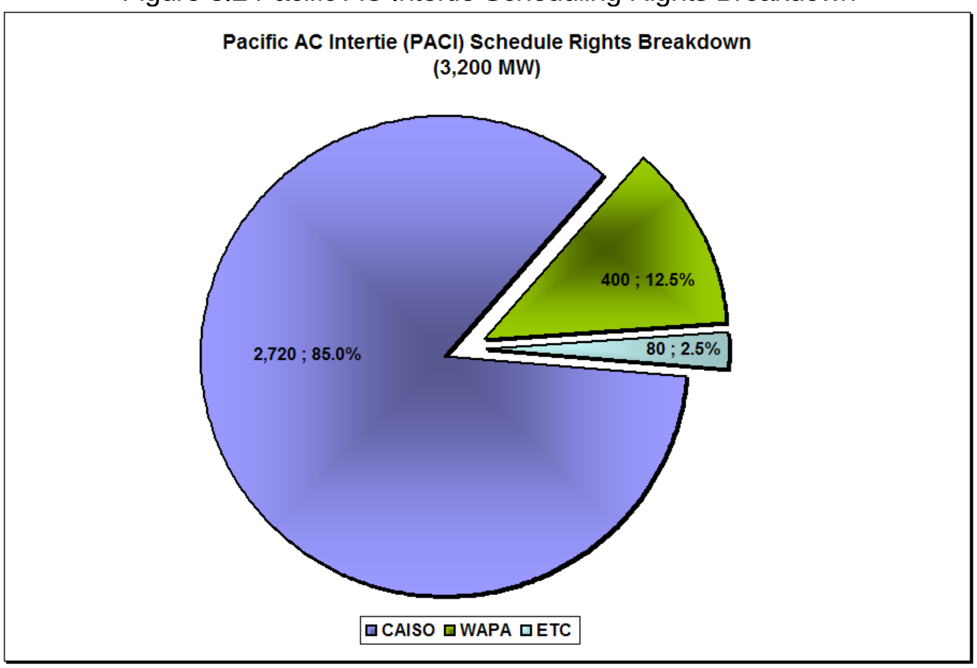
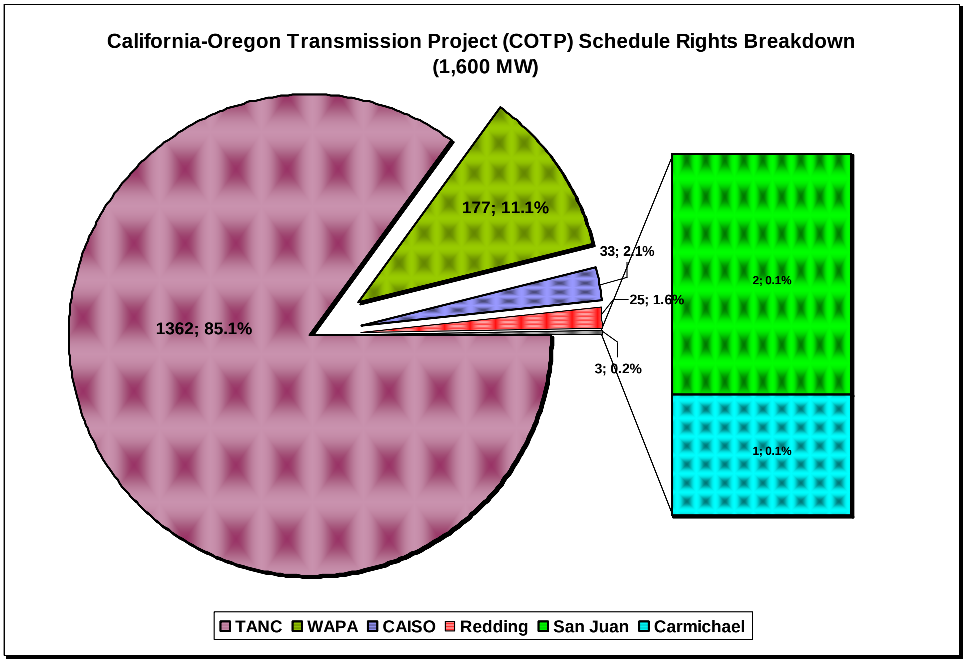


Figure 3.3 California-Oregon Scheduling Rights Project Ownership Breakdown



4. Data and Information

TUG's primary objective was to collect historical usage data and analyze the data to determine if short-term transmission is available on the COI and how to better utilize this transmission. In addition to historical usage, the TUG collected information on scheduling timelines and rates that could potentially affect COI utilization. This section describes the data and information used in the analysis in more detail. The analysis and results are discussed in Section 5.

a. Historical Usage Data

The usage data collected spans the period June 2005 through June 2010. This period should be considered to represent current COI utilization and limits and includes the effects of:

- COTP inclusion into SMUD's balancing authority,
- CAISO's Market Redesign and Technology Update (MRTU),
- additions of large wind resources in BPA's balancing authority, and
- a variety of hydro and load conditions.

The specific data components analyzed[4] and their sources consisted of:

- **Operating Transfer Capability (OTC).** Source: BPA's SCADA system. Interval: 5 minute.

[4] Data analyzed as hourly values. Some data when available in 5 minute intervals was normalized to produce hourly values.

- **Scheduling Limit.** Source: BPA’s Real Time Operations and Dispatch and Scheduling (RODS) database. Interval: Hourly. The scheduling limit reflects operational constraints on the COI for that hour.
- **COI North-to-South Limit.** Source: Derived value for the COI utilization analysis, TUG agreed to use this hourly value as a definition of limit. The value is the lower of the OTC or the Scheduling limit during that hour.
- **Scheduling Data.** Source: BPA's RODS. Interval: Hourly. The sum of the scheduling data for the PACI, COTP, Dynamic Scheduling Capacity, Reno Alturas Transmission System (RATS) Intertie schedules. The individual hourly schedules are the net of north-to-south and south-to-north schedules.
- **Dynamic Schedules.** Source: BPA's SCADA. Interval: 5 minute. The total scheduling value for dynamically scheduled generation.
- **Loop Flows.** Source: BPA's RODS**.** Interval: Hourly.
- **Metered Data.** Source: BPA's RODS. Interval: Hourly. Metered data on the COI is a measurement of the physical flows that occurred on that hour including all scheduled generation and loop flows.
- **COI North-to-South Usage.** Source: Derived. Interval: Hourly. For the purposes of the utilization analysis, North-to-South Usage is defined as the greater of the Scheduling Data or the Metered Data during each hour. Hours that have a net S-N usage are excluded in the COI utilization analysis. On all other hours S-N schedules and flows were netted against N-S information.
- **Energy Prices.** Source: Intercontinental Exchange (ICE), CAISO. Interval: Daily.
- **Load**. Source: BPA’s RODS, CAISO. Interval: Hourly. Although California load data does not include load in the SMUD control area, it gives a reasonable load shape and characteristic for the analysis.
- **Streamflows.** Source: BPA’s RODS. Interval: Hourly. Streamflow at The Dalles provides a good proxy for Northwest hydroelectric generation.

b. Scheduling Timelines

TUG gathered and compared information on the scheduling and transmission reservation timelines for each of the Transmission Service Providers (TSP) on COI including BPA, CAISO, PGE, SMUD, TANC, and WAPA.

The specific timeline and scheduling information consisted of:

- Daily and hourly requirements for firm and non-firm transmission
- Release of unused transmission (both firm and non-firm)
- E-tag submission timelines (pre-schedule and real-time submission)

c. Transmission Rates

The transmission rate information collected was limited to non-firm rates, since long-term firm service is fully subscribed.

d. Merchant Input

In conjunction with the historical data analysis, feedback was solicited from the merchant COI users regarding their experiences with the COI usage. A public meeting notice was coordinated and posted on each of the COI TSP's OASIS. In addition, a meeting notice was sent to the merchants via BPA Tech Forum. As part of these notices, a set of relevant questions relating to the COI usage was provided prior to the meeting. The merchant meeting took place on September 22, 2010 at the Portland Airport. Care was taking during the preparation and meeting to avoid potential FERC Standards of Conduct issues.

A broad based audience participated in the meeting; including representatives from merchants, regional utilities, transmission providers, NW public agencies, IOUs, wind developers, FERC, Oregon Public Utilities Commission (OPUC), and consultants representing both developers and utilities.

5. Results and Discussion

To determine historical levels of COI utilization, analysis was performed on a five year plus one month data set. The analysis indicated that there is a high level of utilization on the COI when market conditions are favorable. These periods of high utilization tend to coincide with spring months, when the Pacific Northwest (PNW) is experiencing high levels of hydroelectric run-off; and with the summer months, when California loads are high. During these seasons increasingly high price spreads between CA and the PNW strongly correlated with increased COI utilization.

The analyzed data spans the period June 1, 2005 through June 30, 2010. The data is organized and grouped in the following manner:

- HLH = Heavy Load Hour between hour ending 0700 and 2200
- LLH = Light Load Hour between hour ending 2300 and 0600
- Sundays and WECC Holidays are excluded from the 24-hour utilization profiles
- COI Reservations = Total Schedules over the AC Intertie + RATS
- COI Actual Usage = Metered flow that includes actual Dynamic Schedule flows and Loop Flows + RATS
- COI N-S Usage = Max (COI Actual Usage or COI Reservation)
- COI N-S Limit = Min (COI OTC or N-S Schedule Limit)
- COI N-S Availability = COI N-S Limit less COI N-S Usage
- Hours of net south-to-north COI flows were excluded from the data

Categories were established, with the amount of COI utilization based on the ratio of the hourly COI N-S Usage to hourly COI N-S Limit. The categories are:

- High (90% or above),
- Medium (between 50% to 90%), and
- Low (50% or below).

Finally, seasonal groupings were created and are defined as:

- Summer (California summer from July to September)
- Hydro Run-Off (Northwest hydro run-off from April to June)
- Other (from October to March)
- All (all hours, regardless of season)

a. Tabular Representation of Utilization

For each category of High, Medium, and Low utilization, the percentage of hours was determined. Figure 5.1 shows specifically the percentage of hours when High COI utilization occurred. It was found that 15% of all the hours during the study period have a High utilization rate, meaning usage at 90% of the Limit or greater. When the data is grouped by season, the hours of High utilization increase to 20% during Summer season and 26% during Hydro Run-Off periods.

Figure 5.1: Percentage of hours at High utilization

Percentage of Hours N-S COI Usage Exceeds 90% of Limit				
Seasonal Group	CA Summer	Hydro Run-Off	Other	All Hours
HLH	30%	32%	9%	20%
LLH	7%	18%	1%	7%
All Hours	20%	26%	6%	15%

Figures 5.2 and 5.3 show the average COI Usage and Limit compared against market drivers that include energy price indices, hydro generation, and regional loads. The amount of firm and non-firm transmission used during these periods is also shown. From these figures the following observations can be made:

- The average COI N-S Usage during High utilization for Summer and Hydro Run-Off periods is almost equivalent for HLH and LLH, respectively.
- The average COI Usage is highest in the Hydro Run-Off period, followed by Summer period.
- Highest COI Usage corresponds to highest NP15-MIDC price spread and CAISO load.
- The average COI N-S Limits appear to be seasonal and are lowest during High Hydro Run-off.

As the COI Usage increases, the percentage of non-firm transmission (short-term intertie sales) on the COI also increases.

Figure 5.2: Average HLH COI utilization and market factors by utilization groups.

Season Group by Month	USE > 90% of LIMIT	COI N-S Limit (MW)	COI N-S Usage (MW)	NP15-MIDC OnPk Spread ($/MWh)	NP15-MIDC OffPk Spread ($/MWh)	CAISO Load (MW)	BPA Area Load (MW)	TDA Hydro Gen (MW)	COI BPA Firm Usage (%)	COI BPA Non-Firm Usage (%)
CA Summer	90% or more Utilization	3,970	3,844	$17.09	$7.86	37,852	6,175	617	79%	21%
	50-90% Utilization	4,121	2,947	$8.34	$1.03	33,658	5,836	526	83%	17%
	50% or less Utilization	4,277	1,698	$2.49	($2.46)	29,769	5,457	471	96%	4%
CA Summer Total		**4,098**	**3,035**	**$10.14**	**$2.58**	**34,364**	**5,883**	**546**	**84%**	**16%**
Hydro Runoff	90% or more Utilization	3,751	3,595	$29.02	$20.08	31,568	6,089	1,042	83%	17%
	50-90% Utilization	3,781	2,788	$13.31	$7.46	28,356	6,003	909	86%	14%
	50% or less Utilization	3,760	1,484	$2.11	($1.75)	25,775	6,116	680	97%	3%
Hydro Runoff Total		**3,769**	**2,903**	**$17.10**	**$10.64**	**29,108**	**6,043**	**926**	**86%**	**14%**
Other	90% or more Utilization	3,347	3,159	$11.43	$3.53	29,381	6,433	912	77%	23%
	50-90% Utilization	3,841	2,610	$6.28	($0.32)	28,210	6,642	861	82%	18%
	50% or less Utilization	4,175	1,508	$1.75	($3.70)	26,838	6,764	817	93%	7%
Other Total		**3,896**	**2,331**	**$5.40**	**($0.98)**	**27,907**	**6,660**	**852**	**85%**	**15%**
All Season and Utilization Groups		**3,912**	**2,656**	**$9.66**	**$2.95**	**29,821**	**6,305**	**796**	**85%**	**15%**

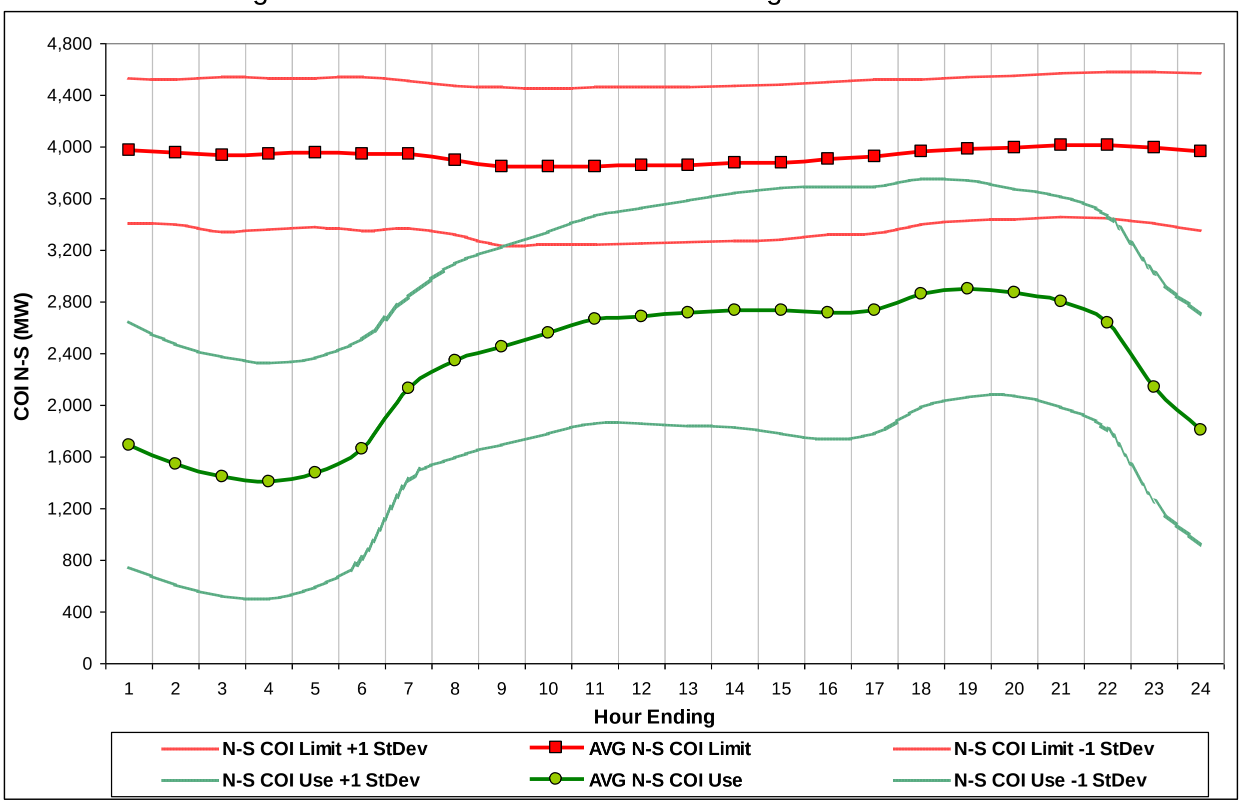
Figure 5.3: Average LLH COI utilization and market factors by utilization groups.

Season Group by Month	USE > 90% of LIMIT	COI N-S Limit (MW)	COI N-S Usage (MW)	NP15-MIDC OnPk Spread ($/MWh)	NP15-MIDC OffPk Spread ($/MWh)	CAISO Load (MW)	BPA Area Load (MW)	TDA Hydro Gen (MW)	COI BPA Firm Usage (%)	COI BPA Non-Firm Usage (%)
CA Summer	90% or more Utilization	4,012	3,903	$44.25	$30.28	31,793	5,738	645	75%	25%
	50-90% Utilization	4,166	2,745	$12.07	$4.95	29,210	5,171	469	72%	28%
	50% or less Utilization	4,188	1,331	$7.70	$0.16	24,921	4,635	406	93%	7%
CA Summer Total		**4,170**	**1,920**	**$10.08**	**$3.57**	**26,651**	**4,866**	**440**	**86%**	**14%**
Hydro Runoff	90% or more Utilization	3,797	3,638	$42.09	$32.15	25,862	5,526	1,031	86%	14%
	50-90% Utilization	3,879	2,783	$17.51	$11.42	23,272	5,021	870	84%	16%
	50% or less Utilization	3,801	1,270	$6.45	$0.78	21,683	5,100	595	96%	4%
Hydro Runoff Total		**3,841**	**2,479**	**$17.22**	**$12.17**	**23,261**	**5,136**	**816**	**88%**	**12%**
Other	90% or more Utilization	2,463	2,348	$20.47	$11.80	23,221	5,534	968	87%	13%
	50-90% Utilization	3,650	2,280	$8.43	$2.36	24,501	5,865	762	83%	17%
	50% or less Utilization	4,010	1,067	$5.14	($1.17)	22,247	5,696	627	94%	6%
Other Total		**3,940**	**1,256**	**$5.65**	**($0.51)**	**22,576**	**5,718**	**650**	**92%**	**8%**
All Season and Utilization Groups		**3,973**	**1,750**	**$9.90**	**$3.87**	**23,806**	**5,346**	**640**	**90%**	**10%**

b. Graphical Representation of Utilization

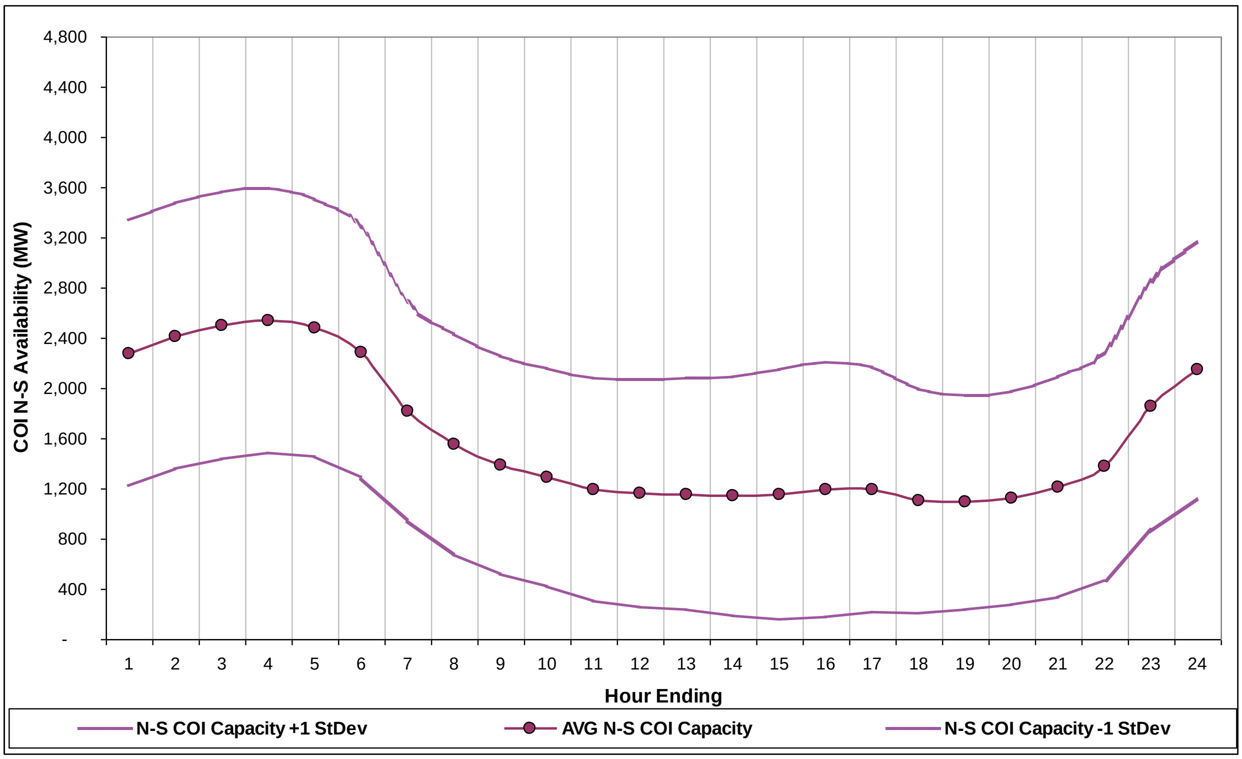
The following series of figures show the data arranged in 24-hour profiles. The average N-S COI Limit and the N-S COI Usage over 24-hours is shown in Figure 5.4. The Limit has a relatively flat profile. The Usage profile closely follows a daily load profile with morning and evening load ramps. Although there appears to be available COI Capacity on an average basis, there are a number of hours (15%) where the COI is highly utilized. In order to represent the variability of COI utilization, the standard deviation is also shown in the 24-hour profile, i.e., approximately 68% of the observations occur between the graphed upper and lower standard deviation bands. As an example, for the hour ending 12, the average Limit is 3,850 MW and 68% of the observations for the Limit occurred within a 1,200 MW band about the average. For the same hour, the average Usage is 2,690 MW and 68% of the observations for the Usage are in a 1,600 MW range about the average.

Figure 5.4: 24-Hour Profile of COI N-S Usage and Limit



The Availability, defined as the difference between Limit and Usage, is shown in Figure 5.5. Although there appears to be 1,000 MW or more "average" Availability for each hour, the data shows that within one standard deviation the Availability drops to below 500 MW for almost all of the HLH period.

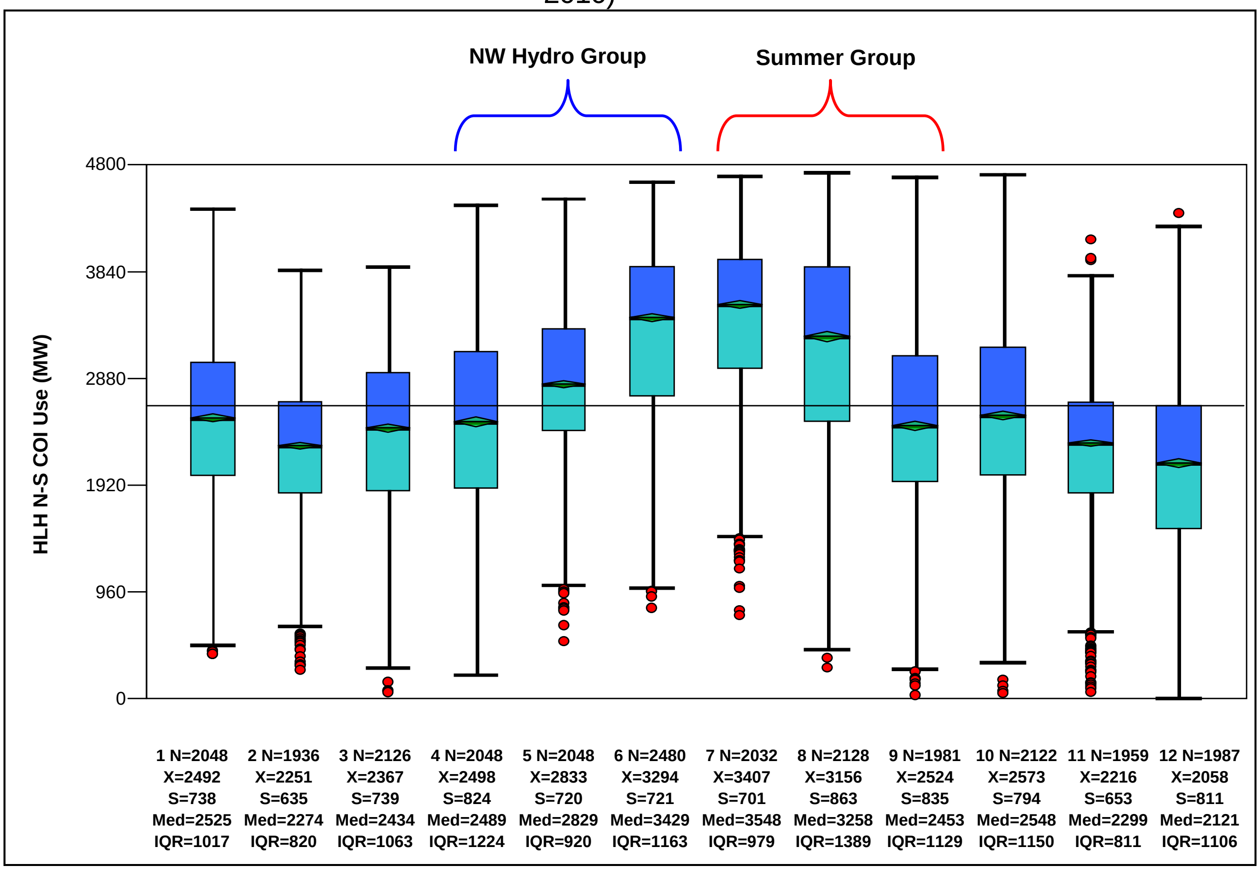
Figure 5.5: 24-Hour Profile of COI N-S Availability



c. Variability in Utilization - Drivers and Sources

In order to better understand the observed variability in COI utilization, TUG studied the seasonal patterns of COI N-S Usage. Analysis of the data, on a seasonal basis, provides a greater insight into the pattern of COI N-S utilization and the drivers that are responsible for these patterns. A box plot distributions for HLH N-S COI Usage shown in Figure 5.6, highlights the seasonal patterns.

Figure: 5.6 Box Plot of HLH COI N-S Usage by Calendar Month (June 1, 2005 – June 30, 2010)



Box and whisker Legend:

N = sample size

X = Mean/Average

S = Std. Deviation

Med = Median (50th percentile)

IQR = Inter-Quartile Range (75th less 25th percentile)

Blue box = 75th less 50th percentile

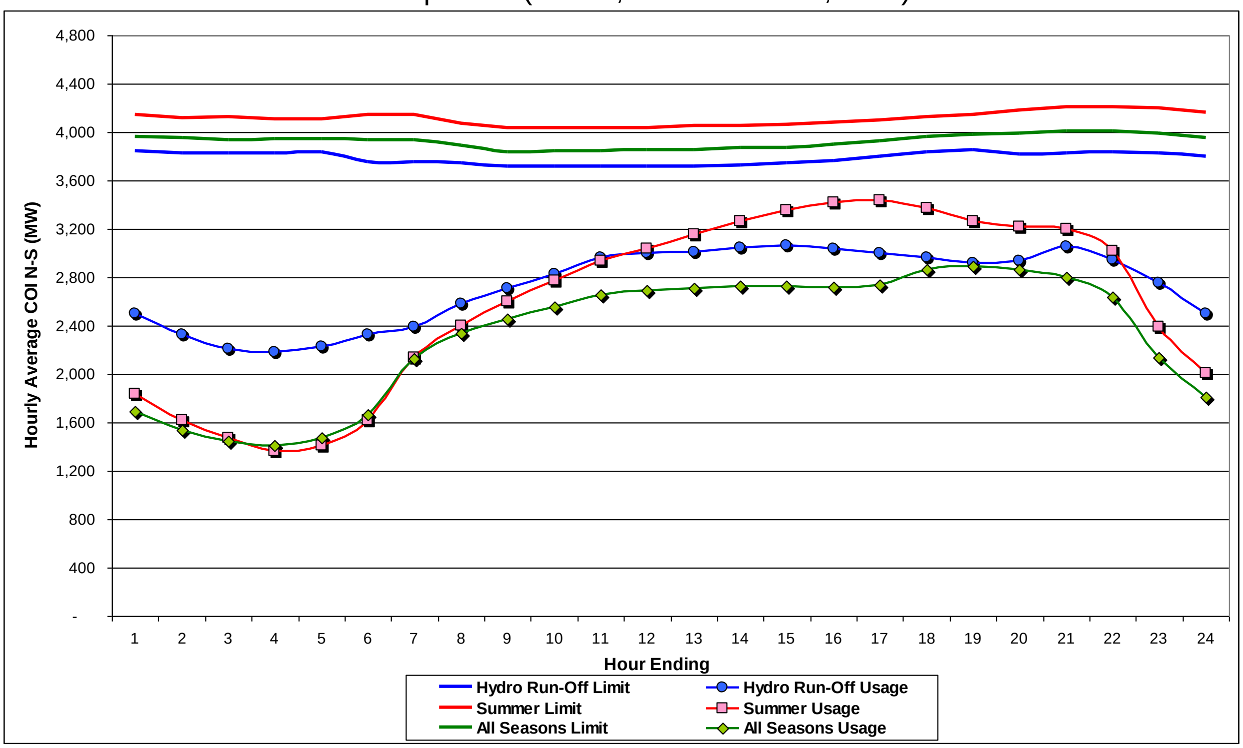
Teal box = 50th less 25th percentile

Top and bottom whiskers represent 5th and 95th percentiles.

Red dots are outliers.

Figure 5.7 shows the 24-hour profile for COI usage and COI Limits broken down by the Summer and Hydro Run-Off seasons compared to the profile of the entire study period. In Hydro Run-Off months Usage is higher than the overall average with significant LLH usage due to hydroelectric generation surplus and exports to California. Summer usage is also higher than average, particularly during heavy load hours, closely following typical summer load curves in the afternoon and evening hours. The COI Limits reflected here are the same as in Figure 5.8.

Figure 5.7: 24-Hour COI N-S Usage Profile
Seasonal Comparison (June 1, 2005 – June 30, 2010)



COI Limits also vary by season as shown in Figure 5.8. Limits are the highest during the Summer which is conducive to meeting the high usage during these months. Limits are lowest in Hydro Run-Off months, due to a combination of maintenance outages and elevated hydroelectric generation output in Northern California. Maintenance is commonly performed during this time of mild weather conditions in preparation for the heavy use summer months. During elevated levels of hydroelectric generation, COI limits must be reduced to maintain reliable operations. The reduced limit is a potential lost opportunity for additional COI usage during Hydro Run-Off.

Figure 5.8: 24-Hour COI N-S Limit Profile – Seasonal Comparison

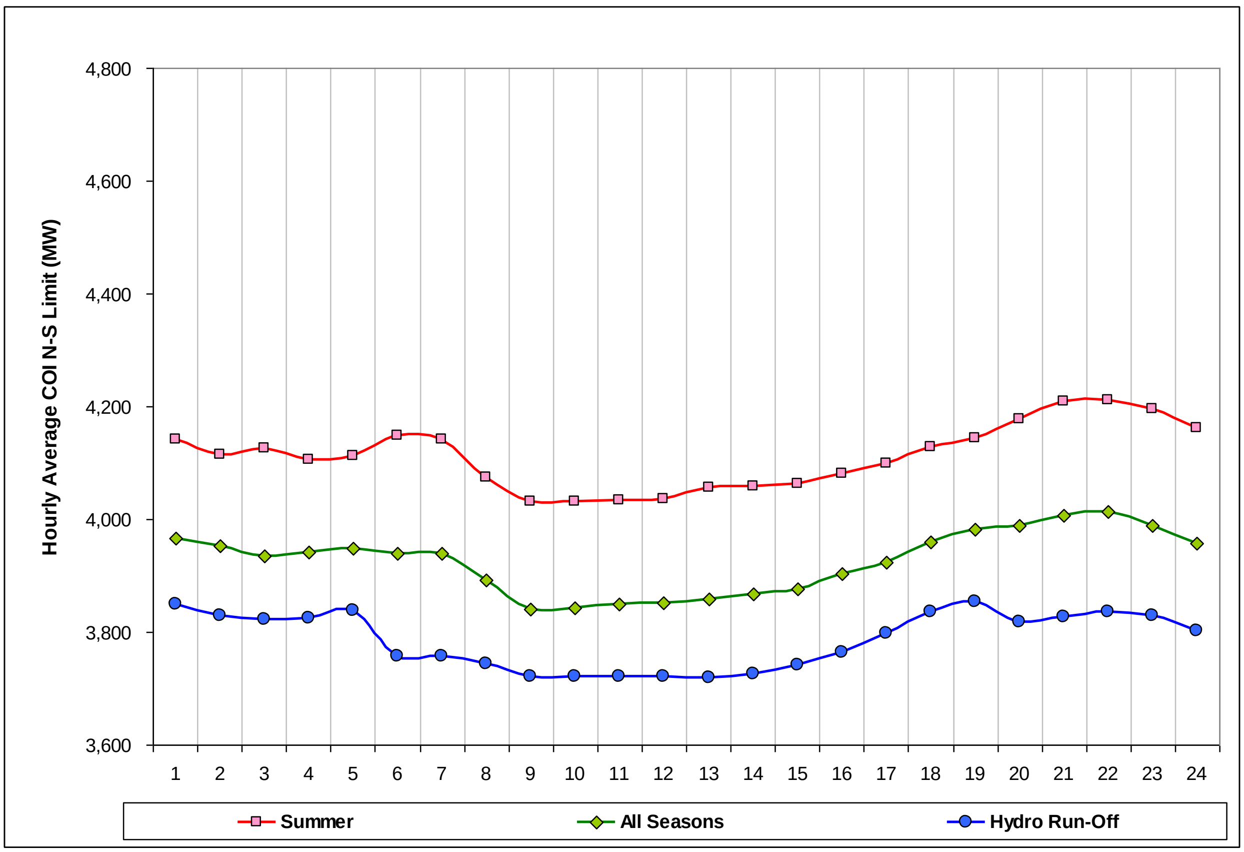
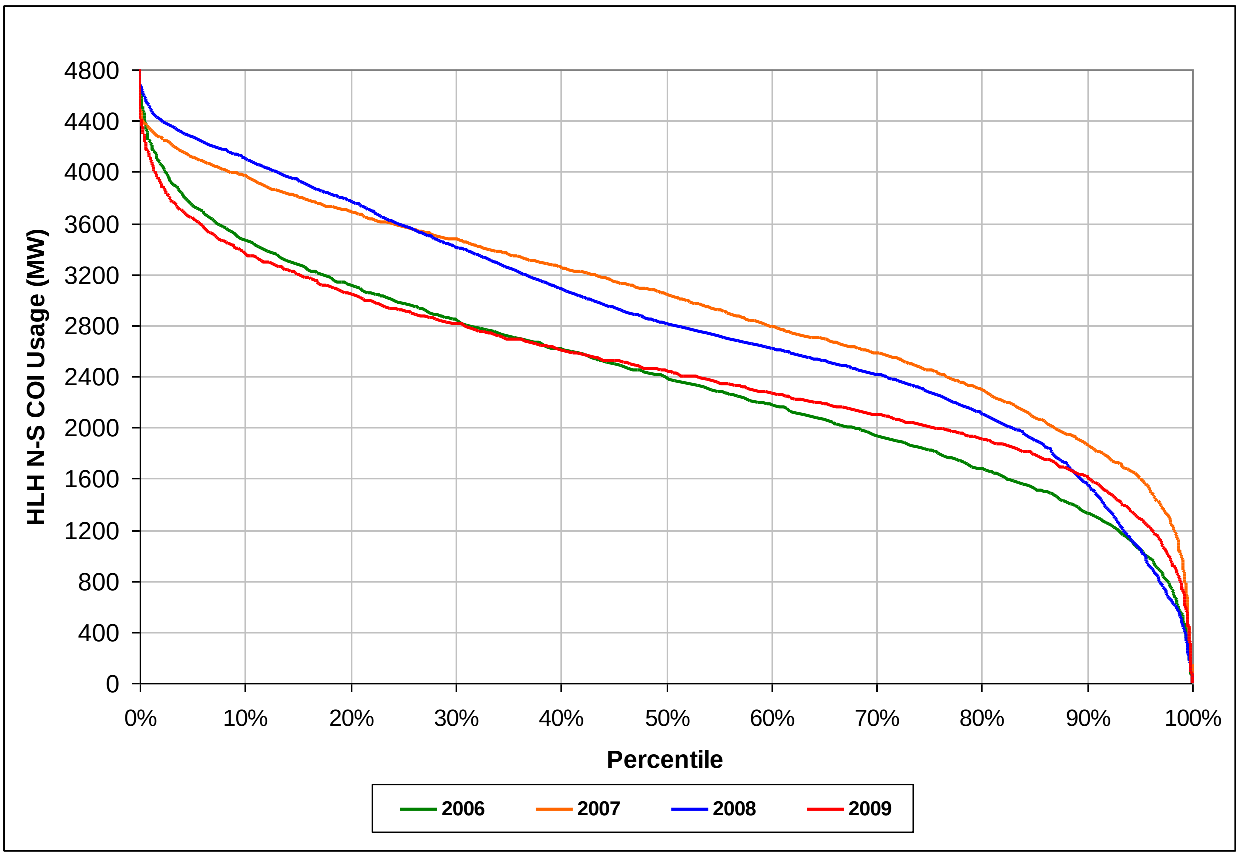


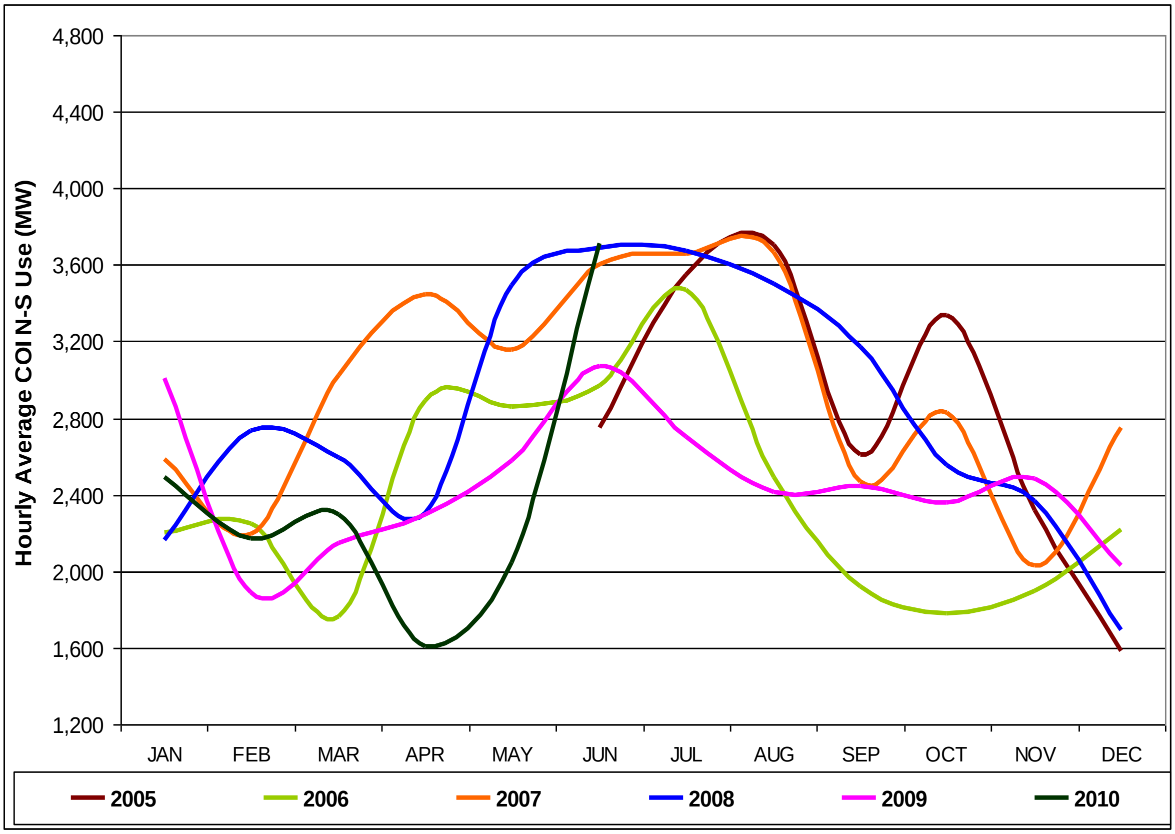
Figure 5.9 shows a cumulative probability distribution of hourly HLH COI N-S Usage over the study period. Usage generally increases each year from 2006 through 2008. In 2009 it drops to 2006 levels, likely driven by the economic recession, and lower than normal hydro run-off. The probability that HLH N-S Usage is 4,000 MW or greater is approximately 3% in 2006, 10% in 2007, 13% in 2008, but drops to 2% in 2009. In addition, the probability distribution shows the hourly observed COI usage ranging from approximately 0 MW to 4,800 MW giving an indication of the substantial variability of Usage within each year.

Figure 5.9 HLH COI N-S Use Probability Distribution



COI variability is clearly visible when looking at the yearly COI Usage profiles in Figure 5.10. This variability reflects seasonality and market factors. As an example, the hydro run-off peak is variable in terms of volume, shaping, and duration, which produces the vastly different profiles in March through June period for different years. Similarly, monthly variability in the summer months is driven by California loads, i.e. temperature.

Figure 5.10 Monthly Use Profile by Year



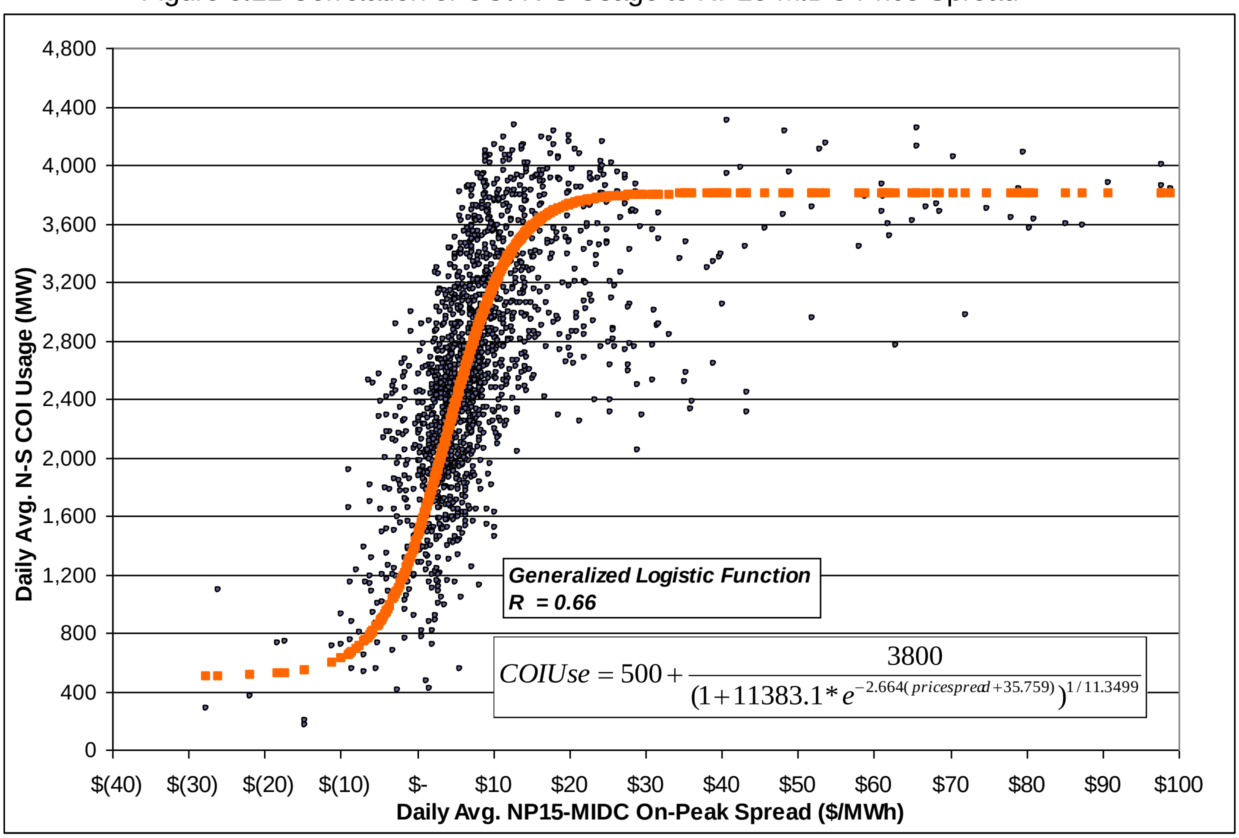
d. Quantification of Relationship to Market Drivers

A regression analysis was performed on the daily average HLH N-S COI Usage against market drivers including the NP15-MID C price spread, CAISO load, BPA load, and stream flow at The Dalles (hydro generation).

The strongest correlation is with the daily average NP15-MID C price spread and is shown in Figure 5.11. The strong relationship to Usage suggests that prices are the most significant driver of COI utilization. The historical pattern of COI usage vs. price spread closely follows an “S” curve. When the price spread is negative, i.e., below $0, the COI N-S usage follows a lower asymptote with a typical usage less than 1,500 MW. As the spread increases from $0 to $20, the usage increases rapidly to around 4,000 MW. Above approximately a price spread of $20, there appears to be less of a correlation with a higher asymptote around 4,000 MW is reached. This is most likely a result of the frequent COI derates below 4,800 MWs and the practice of some entities using their rights for reserves and emergencies as opposed to scheduling all their capacity.

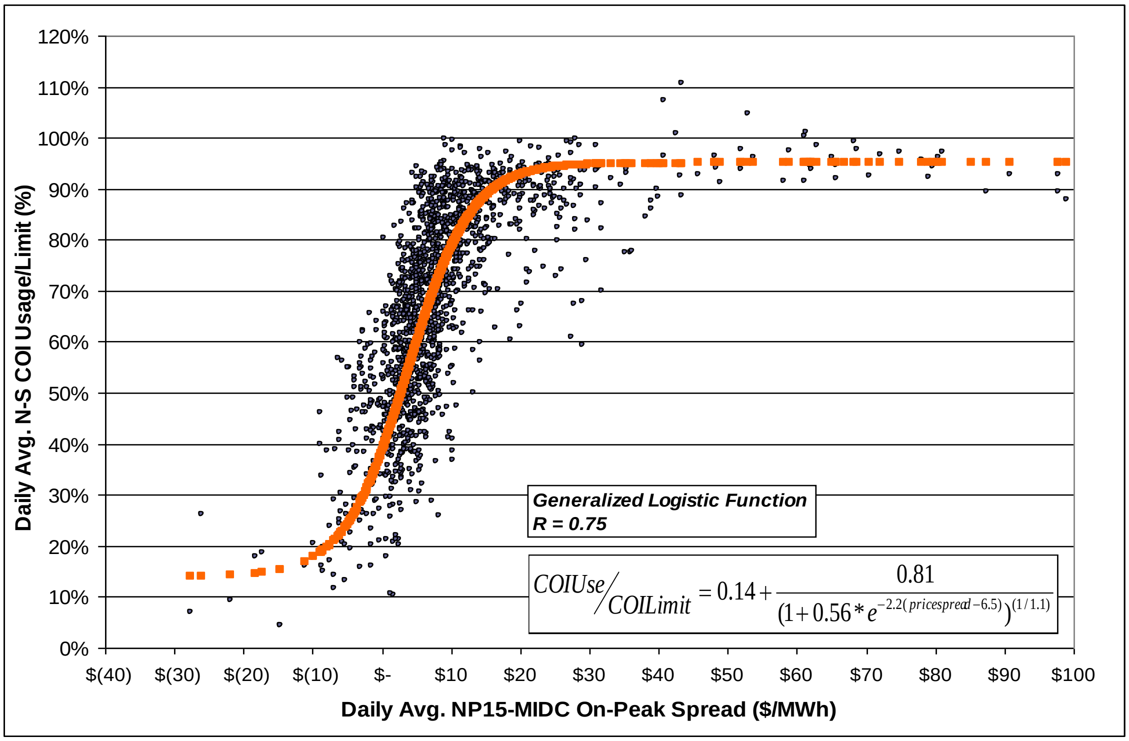
A generalized logistic function applied to the regression fit, the orange curve in Figure 5.11, results in a correlation coefficient R of 0.66. This implies that 66% of the COI usage can be described by NP15-MIDC pricing spreads. The scatter seen in the data indicates that there is variability in the relationship between COI Usage to price spread. From this it can be inferred that other factors, such as transmission congestion, regional economics, and seasonality contribute to the variability.

Figure 5.11 Correlation of COI N-S Usage to NP15-MIDC Price Spread



It is possible to account for congestion and outage impacts in the correlation analysis by normalizing the data for limited capacity availability. If the COI Usage is divided by the COI Limit the resulting data and curve fit in Figure 5.12 shows a lower variability. The correlation coefficient is higher at R equal to 0.75. This indicates that 75% of the COI utilization can be described by NP15-MIDC pricing spread when accounting for changes in the COI Limit due to transmission congestion.

Figure 5.12: Correlation of COI N-S Usage to NP15-MIDC Price Spread after data was normalized using the COI Limits.



$$\frac{COIUse}{COILimit} = 0.14 + \frac{0.81}{(1+0.56 * e^{-2.2(pricespread-6.5)})^{(1/1.1)}}$$

Regression analysis of other market factors shows lower correlation coefficients than price spread. COI N-S usage dependence on CAISO load has a linear regression fit of R = 0.53 with significant variations of COI Usage (Figure 5.13). If the analysis is performed for just the Summer data, then the variability is reduced and the correlation increases to R = 0.59 (Figure 5.14).

Alternatively, comparing the relationship of BPA Area loads with COI N-S usage results in a weak negative correlation (R = 0.21). This negative correlation is expected since an increase in BPA loads reduces COI usage as more of the PNW resources are used to serve Northwest loads. BPA loads will increase typically in cold winter months and very hot summer months.

A regression analysis was also performed on the daily average streamflow at The Dalles Dam against N-S COI usage (Figure 5.16). Streamflow at The Dalles can be used as key indicator of the Federal Columbia River Power System generation. The height of hydro run-off can occur as early as March and as late as June, so the analysis was performed during the (Apr-Jun) Hydro Run-off period. The resulting correlation coefficient is 0.48, or 48% of COI usage is described by streamflow at The Dalles. The variation of COI usage with respect to stream flow is greatly impacted by the variability of the timing and size of the run-off as well as the interaction with other market drivers.

Figure 5.13: Correlation of CAISO Load to COI N-S Usage for all data.

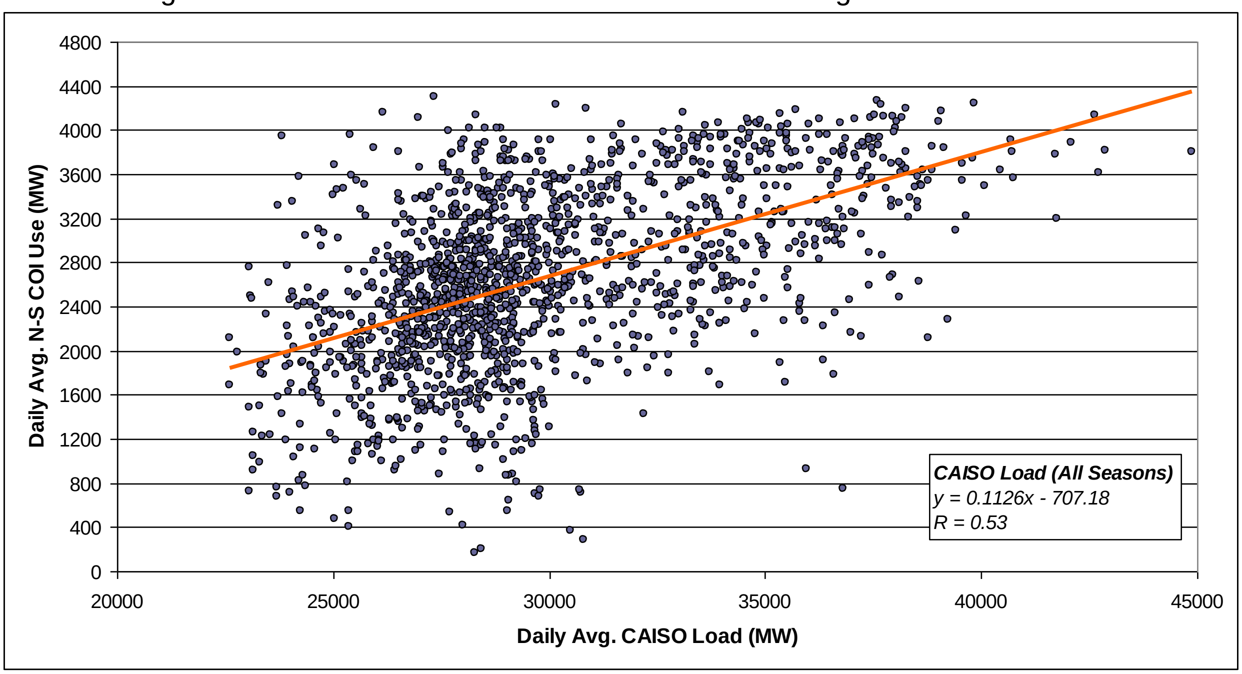


Figure 5.14: Correlation of CAISO Load to COI N-S Usage for Summer Data

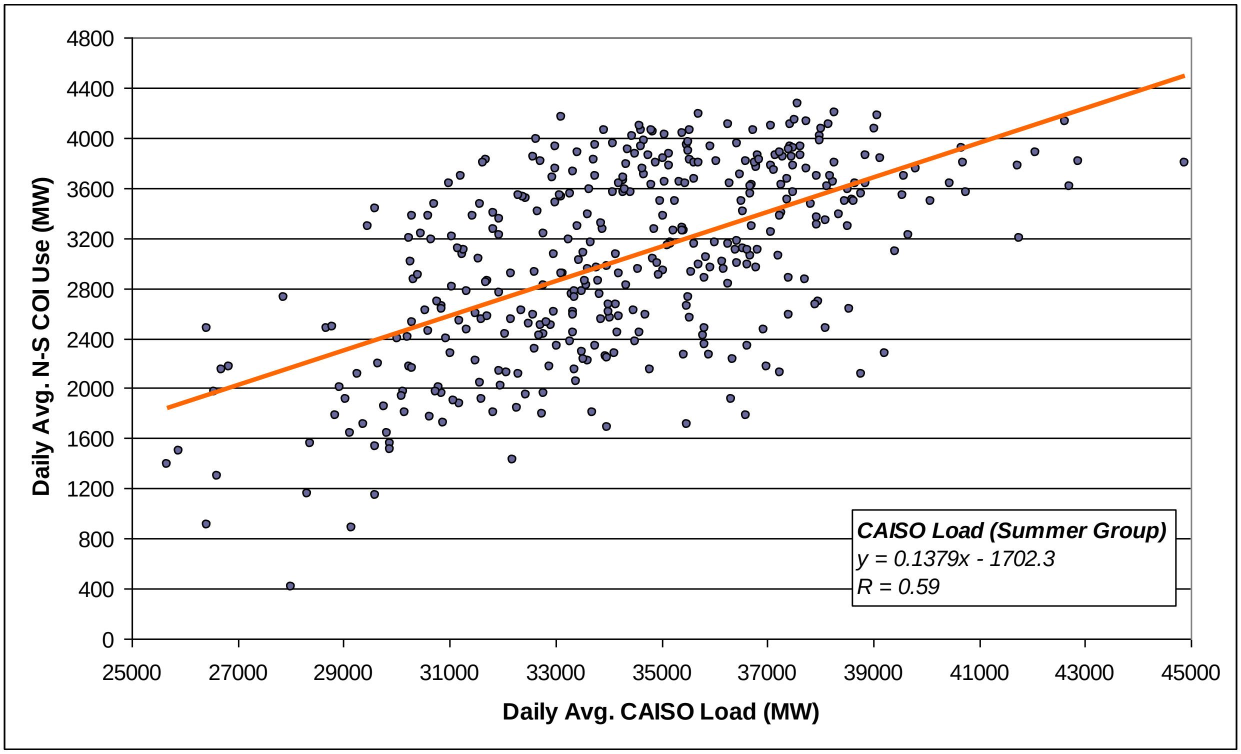


Figure 5.15: Correlation of BPA Load to COI N-S Usage

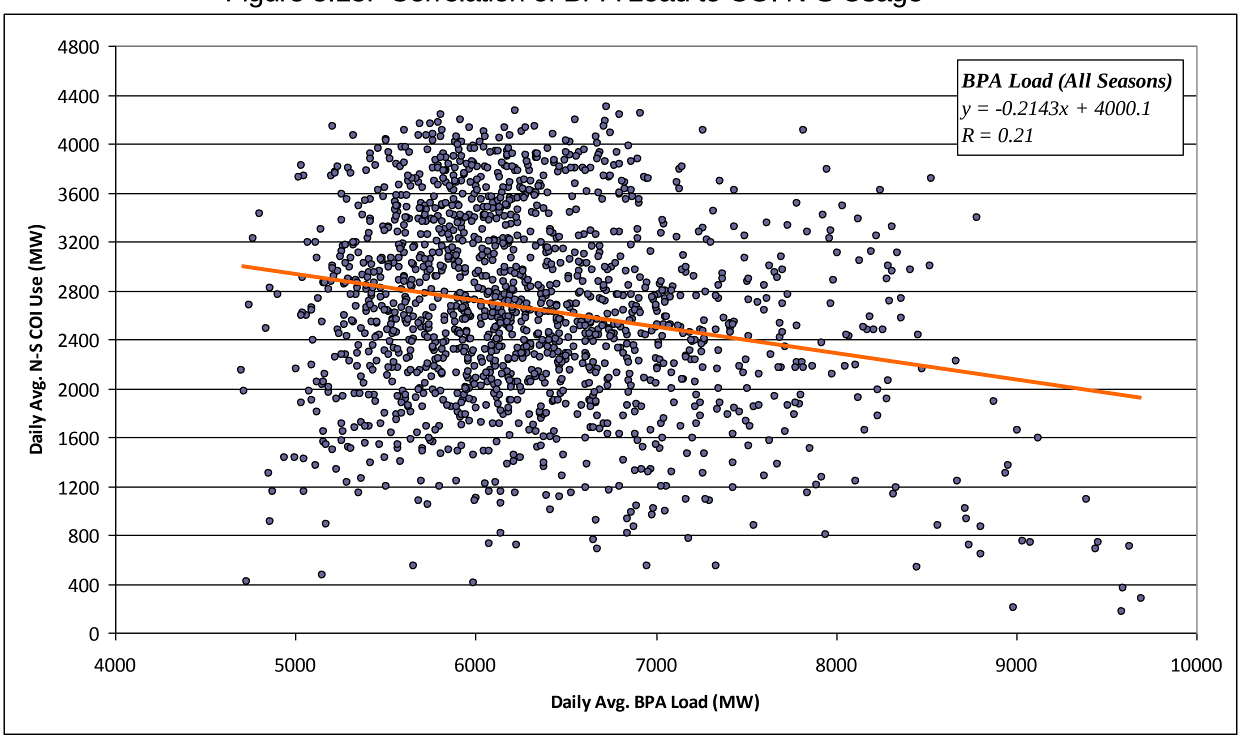
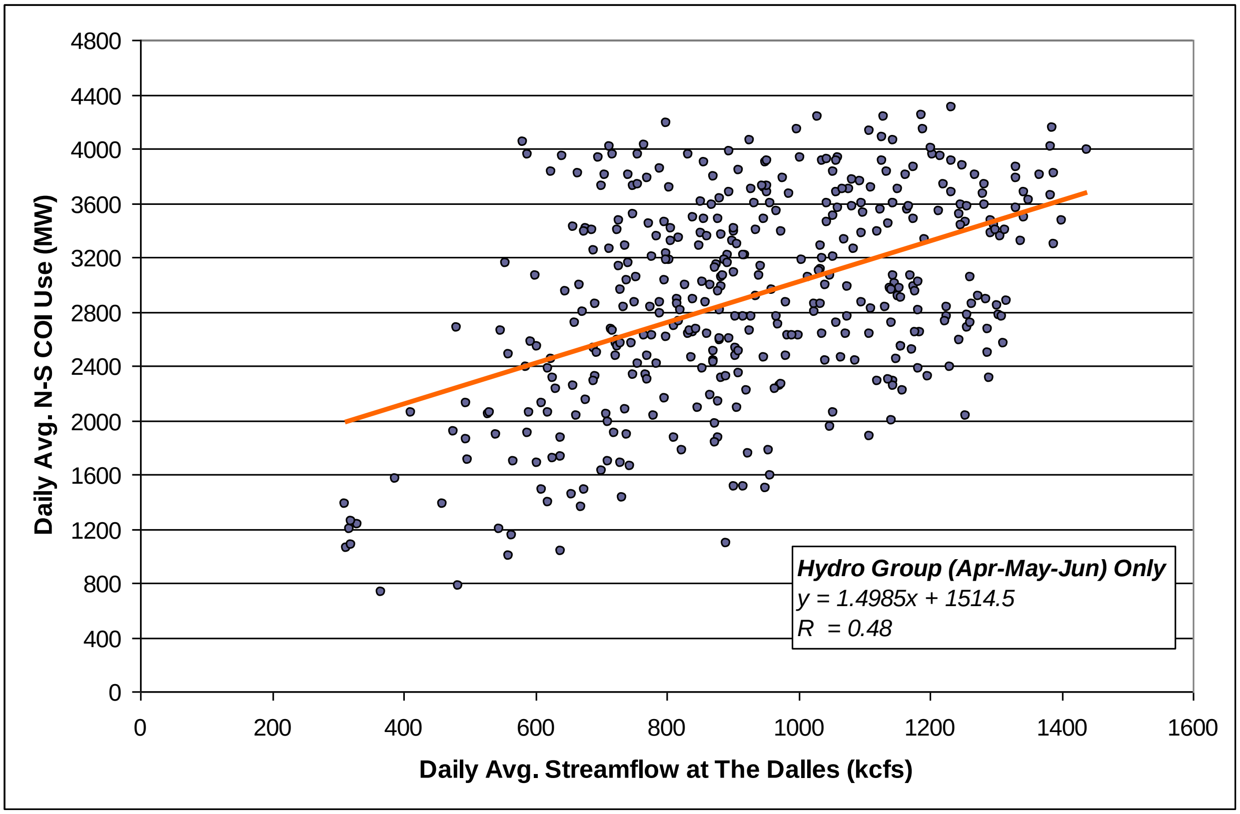


Figure 5.16 Correlation of The Dalles Streamflow to N-S COI Usage



e. Scheduling Timelines

Despite the disparities in the scheduling and transmission reservation timelines, the information gathered by TUG and feedback provided by marketers and other market entities suggests that the varying scheduling timelines do not represent a significant obstacle in utilizing COI transmission facilities.

The differences in scheduling timelines were expected to have an impact on the usage of the COI. As part of the overall process to gather and compare the scheduling and reservation timelines, specific emphasis was placed on the use of consistent terminology to ensure that any comparisons and conclusions related to the information would be appropriate and accurate. Thus, timelines were aligned based on the "top of the scheduling hour". In addition, the TUG also highlighted the scheduling and transmission reservation timelines that are associated with any applicable existing transmission contracts and grandfather agreements. Furthermore, during the merchant meeting, comments were solicited to identify any issues or concerns that may be directly related to the timelines for scheduling.

For the purpose of comparison, the scheduling and transmission reservation timeline information was compiled and summarized into two separate tables. The table in Figure 5.17 represents the "No Earlier Than" timeframe for which reservations can be made on COI transmission facilities for each TSP. The table in Figure 5.18 represents the "No Later Than" timeframe for which reservations can be made. The timelines clearly vary among the different TSPs.

Transmission Reservations

For firm transmission reservations timelines as reflected in the "No Earlier Than" category, daily reservation timelines vary from 10 AM one day prior to start of service to 1 minute prior to start of service. Hourly reservation timelines vary from 1 PM one day prior to start of service to 20 minutes prior to start of service.

For Non-Firm Transmission Reservations, Daily reservation timelines vary from 2 PM one day before the start of service to 1 minute (11:59 PM) prior to start of service. Hourly reservation timelines vary from 20 minutes to 30 minutes prior to that start of service.

i. Release of Unused Transmission

For Firm Transmission in the "No Earlier Than" category, daily timelines vary from 7 AM one day prior to the start of service to 75 minutes prior to the start of service. Hourly timelines vary from 2 PM of the pre-schedule day (one day prior to service) to 45 minutes prior to the start of service.

For Non-Firm Transmission, WAPA's Daily timeline is 2 PM one day prior to the start of service (no other Transmission Service Provider (TSP) offered Daily Non-Firm transmission). Hourly timelines for BPA and WAPA are from 20 to 30 minutes prior to start of service, respectively (No information was provided by other TSP on hourly Non-Firm).

f. Transmission Rates

Transmission rates from the TSP are tabulated in Figure 5.19. Because no long-term service is available, only non-firm short-term service rates are shown. These range from 1.30 $/MW to 17.67 $/MW, which is a significant disparity between service providers. Transmission rates affect what the necessary price spread is to incentivize COI utilization.

One difference of the CAISO's transmission service compared to other TSPs is that transmission costs are paid by the load in the form of the Transmission Access Charge (TAC). Since load pays TAC regardless of whether it is served by generation internal to the CAISO or by an import, this cost cannot be assigned to the import. There are some minimal Grid Management Charges (GMC) that are incurred when scheduling in the CAISO that add up to less than 0.1 $/MW.

The CAISO has a Locational Marginal Pricing (LMP) market and import transaction cost will occur due to the price differential between the import point and the load service point. This differential is due to congestion and losses. The differential can be a charge or a credit depending on the direction of the congestion. Many Scheduling Coordinators will have Congestion Revenue Rights (CRR) that act as a hedge against these costs. It did not appear to make sense to quantify the congestion costs or credits.

Figure 5.17

SUMMARY TEMPLATE OF THE SCHEDULING TIMELINES
FOR TRANSMISSION SERVICE PROVIDERS ON CALIFORNIA-OREGON INTERTIE FACILITIES
(Timeline - No Earlier Than)

Transmission Provider		Transmission Reservations						Release of Unused Transmission				eTag Submission Deadlines		Grandfather Agreements / Network Integration Services		Release of Transmission from Grandfather/NITS	
		Firm			Non-Firm			Firm		Non-Firm				eTag Submission Deadlines			
Name	**Timeline**	**Daily**	**Hourly**	**Preschedule Submission**	**Daily**	**Hourly**	**Preschedule Submission**	**Daily**	**Hourly**	**Daily**	**Hourly**	**Preschedule Submission**	**Real Time Submission**	**Preschedule**	**Real Time**	**Preschedule Release Time**	**Real Time Release Time**
BPA	No Earlier than	7 days before to delivery	1000 PPT of the WECC Preschedule day	Daily 1000 PPT of the WECC Preschedule day Hourly 1000 PPT of the WECC Preschedule day	N/A	1000 PPT of the WECC Preschedule day Secondary 1000 PPT of the WECC Preschedule day Emergency 20 minutes prior to the operating hour Intra 20 minutes prior to the operating hour	1000 PPT of the WECC Preschedule day Secondary 1000 PPT of the WECC Preschedule day	N/A	N/A	N/A	2200 PPT prior to start of Real-Time day. BPAT releases unscheduled transmission based on TSR reservations.	0800 PPT of the WECC Preschedule day	1800 PPT of the day prior to starting service Emergency 20 minutes prior to the scheduling hour Intra the start of the operating hour	0800 PPT of the WECC Preschedule day	1800 PPT of the day prior to starting service	N/A	2200 PPT prior to start of Real-Time day. BPAT releases unscheduled transmission based on TSR reservations.
CAISO	No Earlier than	Bid/schedules submitted up to 7 days in advance	Market awards and schedules (reservations) 13:00 pm		N/A	N/A	N/A	Bids/schedules submitted after 13:00 pm 1 day prior	Market awards and schedules (reservations) 45 minutes prior to the start of the scheduling hour	N/A	N/A	N/A	N/A		CAISO holds ETC right through HASP and TOR rights through RT. ETC rights may have T-75 or T-20 scheduling rights.	ETCs: pursuant to the rights terms and conditions. TORs and TEA: Release is not applicable as TORs are reserved until Real-Time	
PGE	No Earlier than	~4 PM PPT day before preschedule	no hourly firm product	~4 PM PPT day before preschedule	~4 PM PPT day before preschedule	12 PM PPT (Noon of the preschedule day)	12 PM PPT (Noon of the preschedule day)	7:11 AM PPT of the preschedule day	2:00 PM PPT of the preschedule day	Not Released	Not Released	N/A	N/A	N/A	N/A	2:00 PM PPT of the preschedule day	2:00 PM PPT of the preschedule day
SMUD	No Earlier than	4 days prior to service	Hourly Firm Product Not Offered	4 days prior to service	4 days prior to service	1000 PPT 1 day prior	Daily: 4 days prior to service Hourly: 1000 PPT 1 day prior	01:01 PPT Daily - Unused Firm is released as Non-Firm	Hourly Firm Product Not offered	N/A	N/A	4 days prior to service	1500 PPT WECC Preschedule Day	4 days prior to service	1500 PPT WECC Preschedule Day	18 Days prior to the beginning of the Month	01:01 PPT Daily - Unused Firm is released as Non-Firm
TANC	No Earlier than	4 days prior to service	Hourly Firm Product Not Offered	4 days prior to service	4 days prior to service	1000 PPT 1 day prior	Daily: 4 days prior to service Hourly: 1000 PPT 1 day prior	01:01 PPT Daily - Unused Firm is released as Non-Firm	Hourly Firm Product Not offered	N/A	N/A	4 days prior to service	1500 PPT WECC Preschedule Day	4 days prior to service	1500 PPT WECC Preschedule Day	18 Days prior to the beginning of the Month	01:01 PPT Daily - Unused Firm is released as Non-Firm
WAPA	No Earlier than	4 days prior to service	Hourly Firm Product Not Offered	4 days prior to service	4 days prior to service	1000 PPT 1 day prior	Daily: 4 days prior to service Hourly: 1000 PPT 1 day prior	01:01 PPT Daily - Unused Firm is released as Non-Firm	Hourly Firm Product Not offered	N/A	N/A	4 days prior to service	1500 PPT WECC Preschedule Day	4 days prior to service	1500 PPT WECC Preschedule Day	18 Days prior to the beginning of the Month	01:01 PPT Daily - Unused Firm is released as Non-Firm

Figure 5.18

SUMMARY TEMPLATE OF THE SCHEDULING TIMELINES
FOR TRANSMISSION SERVICE PROVIDERS ON CALIFORNIA-OREGON INTERTIE FACILITIES
(Timeline - No Later Than)

Transmission Provider		Transmission Reservations						Release of Unused Transmission				eTag Submission Deadlines		Grandfather Agreements / Network Integration Services		Release of Transmission from Grandfather/NITS	
		Firm			Non-Firm			Firm		Non-Firm				eTag Submission Deadlines			
Name	Timeline	Daily	Hourly	Preschedule Submission	Daily	Hourly	Preschedule Submission	Daily	Hourly	Daily	Hourly	Preschedule Submission	Real Time Submission	Preschedule	Real Time	Preschedule Release Time	Real Time Release Time
BPA	No Later than	20 minutes prior to the start of flow	20 minutes prior to the start of flow	N/A	N/A	20 minutes prior to the start of flow Secondary the end of the operating hour Emergency the end of the operating hour Intra 15 minutes into the operating hour	N/A	N/A	N/A	N/A	N/A	1500 PPT or two hours after the posted CISO preschedule market closing time; whichever time is later	20 minutes prior to the start of service Emergency the end of the operating hour Intra 15 minutes into the operating hour	1500 PPT or two hours after the posted CISO preschedule market closing time; whichever time is later	20 minutes prior to the start of service	N/A	N/A
CAISO	No Later than	Bids/schedules submitted by 10:00 am 1 day prior	Market awards and schedules (reservations) 13:00 pm 1 day prior		N/A	N/A	N/A	Bids/schedules submitted by 75 minutes prior to the start of the scheduling hour	Market awards and schedules (reservations) 45 minutes prior to the start of the scheduling hour	N/A	N/A	3:00 PM PPT 1 day prior to service	20 minutes before the start of the scheduling hour		CAISO holds ETC right through HASP and TOR rights through RT. ETC rights may have T-75 or T-20 scheduling rights.	ETCs: pursuant to the rights terms and conditions. TORs and TEA: Release is not applicable as TORs are reserved until Real-Time	
PGE	No Later than	11:59 PM PPT 1 minute prior to scheduling hour	no hourly firm product	4:00 PM PPT 1 day prior to service	11:59 PM PPT 1 minute prior to service	20 minutes before the start of scheduling hour	4:00 PM PPT 1 day prior to service	7:11 AM PPT of the preschedule day	2:00 PM PPT of the preschedule day	Not Released	Not Released	3:00 PM PPT 1 day prior to service	20 minutes before the start of scheduling hour	3:00 PM PPT 1 day prior to service	20 minutes before the start of scheduling hour	2:00 PM PPT of the preschedule day	2:00 PM PPT of the preschedule day
SMUD	No Later than	1000 PPT 1 day prior	Hourly Firm Product Not Offered	1000 PPT 1 day prior	1400 1 day prior	25 minutes prior to start of the scheduling hour	1200 1 day prior	01:01 PPT Daily - Unused Firm is released as Non-Firm	Hourly Firm Product Not offered	Not Released	Not Released	1500 PPT WECC Preschedule Day	20 Min prior to start of scheduling hour	1500 PPT WECC Preschedule Day	20 Min before the start of the scheduling hour	18 Days prior to the beginning of the Month	01:01 PPT Daily - Unused Firm is released as Non-Firm
TANC	No Later than	1000 PPT 1 day prior	Hourly Firm Product Not Offered	1000 PPT 1 day prior	1400 1 day prior	25 minutes prior to start of scheduling hour	1400 1 day prior	01:01 PPT Daily - Unused Firm is released as Non-Firm	Hourly Firm Product Not offered	Not Released	Not Released	1500 PPT WECC Preschedule Day	20 Min prior to start of scheduling hour	1500 PPT WECC Preschedule Day	20 Min before the start of the scheduling hour	18 Days prior to the beginning of the Month	01:01 PPT Daily - Unused Firm is released as Non-Firm
WAPA	No Later than	1000 PPT 1 day prior	Hourly Firm Product Not Offered	1000 PPT 1 day prior	1400 1 day prior	25 minutes prior to start of the scheduling hour	1200 1 day prior	01:01 PPT Daily - Unused Firm is released as Non-Firm	Hourly Firm Product Not offered	Not Released	Not Released	1500 PPT WECC Preschedule Day	20 Min prior to start of scheduling hour	1500 PPT WECC Preschedule Day	20 Min before the start of the scheduling hour	18 Days prior to the beginning of the Month	01:01 PPT Daily - Unused Firm is released as Non-Firm

The CAISO has a Wheeling Charge for wheel through, but because TUG was concerned with the utilization of the COI to move energy from the Northwest to California rather than through California, this cost is also not considered relevant.

Figure 5.19: Transmission rates on the COI (2010 rates on a per MW basis).

Company	**WAPA**		**SMUD**	**TANC**	**PGE**	**BPA***	
Path	COB to Tesla	COB to Tracy			John Day to COB		MID C to COB
On Peak	$1.30	$3.51	$7.56	$17.67	$1.274	$4.31	$8.62
Off Peak					$0.735		

*BPA's hourly transmission rates include two required ancillary service rates: Scheduling, System Control and Dispatch & Reactive Supply and Voltage Control from Generation Sources.

g. Discussion of Merchant Input

TUG conducted a public meeting to solicit feedback and input from COI users, principally merchants but also including regional utilities, transmission providers, PNW publics, IOUs, wind developers, FERC, OPUC, and consultants representing both developers and utilities. The meeting was held September 22, 2010 in Portland, Oregon. Participants provided responses to the following questions and provided some additional information during and after the session. In summary:

i. What factors do you consider when doing business on the COI?

Most of the Merchants agreed that utilization of the COI is very seasonal, and highly dependent on factors such as: weather, hydro conditions and loads within each region. These dependencies impact energy prices and the price spread between the two regions. Therefore, the price spread is the main driver of the COI usage and at a minimum has to cover variable costs, e.g. transmission wheeling and losses. Some merchants expressed concern over unknown cost when doing business with CAISO at COB compared to doing a bilateral business with other parties. They said some of the CAISO charges are not determined until much later, creating uncertainty, although market bids can limit their cost exposure.

ii. What Barriers Keep You from Doing COI Business?

In general there are no known market barriers in the short-term hourly market. Merchants indicated that the hourly non-firm transmission on the COI is accessible at most times.

There was misalignment of scheduling practices in the past, but this misalignment has been largely resolved over the past few years. One comment related to scheduling alignment was raised by a merchant at a different public meeting. The comment referenced minor misalignment between CAISO and the other TSPs in the hourly market. For example, CAISO requires that merchants complete hourly market transactions 75 minutes prior to the start of the hour, whereas other providers release hourly non-firm transmission 20 minutes prior to the start of the hour timeline. No barriers were identified in the day-ahead reservations or scheduling areas.

An observation was made that there are now more day-ahead markets than hourly markets. Merchants pointed out that they use COI as a relief valve by procuring more power on a day-ahead basis, then adjusting it in real-time to match the demand. Merchants indicated that PSW thermals are low cost and less flexible and that PNW hydro resources are more flexible to turn on or off.

Another observation from a merchant noted that energy prices at COB have been much closer to Mid-Columbia (Mid-C) prices than NP-15 prices, indicating much smaller Mid-C to COB price spreads compared to COB to NP-15 spreads. For the purpose of this analysis the TUG members decided to review Mid-C to NP-15 price spreads. This method was to capture the total spread for the entire length of the COI even though the transmission line and the energy markets are operated as two different zones (north and south of COB). In depth market/structure analysis will be needed if the TUG desires to further understand the relationship between the energy markets and COI utilization.

iii. What Changes Would Help You Use the COI More Efficiently?

Merchants asked that if and when a 30 min market gets underway, NW transmission providers should monitor how CAISO implements intra-hourly scheduling through the Joint Initiative to help identify and address potential seams issues.

BPA customers also raised concerns specific to BPA related to its recent reinstatement of the price cap for transmission resale. They would like to see a more robust secondary transmission market, and said that the resale will help increase COI utilization. They said that the price cap could be detrimental to the resale transmission market because it would prevent them from receiving sufficient compensation for the increased risk resulting from reducing their scheduling rights on the COI. There was one dissenting voice indicating that the price cap allows non-wind entities to be more competitive since they aren't given the advantage of the Production Tax Credit (PTC). BPA has since posted its newly proposed Business Practice (Resale of Transmission Service) for customers' comments.

Some merchants felt that the BPA's proposed Firm Contingent e-Tags for intermittent resources could be a barrier. During the spring of 2010 BPA discussed the concept of requiring the use of the Western Electricity Coordinating Council "Firm Contingent" Energy Product code on e-Tags for transmission of variable generation located in BPA's balancing authority area. This concept was discussed in response to the BPA's Dispatch Standing Order (DSO 216), which requires that intermittent resources located inside the BPA balancing authority respond when directives are given to maintain system reliability. This tagging requirement has not yet been implemented by BPA.

Some merchants also commented that BPA should continue its effort to scope, develop, and offer a Conditional Firm (CF) product on the COI, provided that such product does not undermine the rights of existing contract holders of COI capacity. There were also oppositions to this CF product development as some merchants felt that this product will negatively impact the existing firm contract holders. BPA intends to seek customer input when and if this product is developed.

iv. How do you feel about the quantity and quality of transmission available?

After looking at the 5-year data analysis, general consensus of the group was that the historical utilization of the COI looks reasonable. For most hours, on an average basis, merchants are using most of what is available during peak seasons.

Merchants indicated that there are no apparent systems issues between the transmission provider, however, they advised that all providers should remain diligent to ensure that no seams issues exist or occur in the future between the PNW/BPA and the CAISO that may limit short-term usage of the COI capacity.

Merchants requested that BPA and other TSPs coordinate to ensure that the COI OTC (or Scheduling Limit) is as high as possible.

Merchants commented that there will be a more robust secondary transmission market in the future for unused capacity on the COI. Merchants said that up until now system development has caused a delay in participation in the resale transmission market on the COI but believe that the resale market will increase over time.

Merchants also would like to have additional Dynamic Transfer Capability (DTC) both to John Day (network transmission) and from John Day to COB (COI). CAISO has 13 Dynamic Transfers on their system, with two on the COI.

v. Other Comments

One of the meeting participants said more incentives are necessary (structurally) from the regulators and policy makers for delivering renewable resources to California. Merchants would like to use both firm and non-firm transmission equally for Power Purchase Agreements (PPAs). This comment was based on some California utilities requiring only the firm transmission for their PPAs. This requirement limits interest in non-firm transmission which is often the only transmission available for sale on the COI. It would also leave renewable resources stranded in the Northwest since there is not sufficient firm transmission access to California.

Merchants pointed out that current RPS rules in California are also restricting how developers are allowed to bring in renewable resources to California. Under the proposed RPS, California utilities are allowed to separate the energy and Renewable Energy Credit (REC) for a certain percentage of their RPS requirement. These rules allow the utilities to sell the energy in the Northwest rather than wheel it to California via COI.

6. Conclusion and Recommendations

The analysis performed by the TUG showed that economics drives COI usage. As the price spread between northern California and the Mid-C hub rose, the usage increased. This occurred during summer periods when the loads in California are high, and during the high runoff period in the PNW when surplus hydro energy is available at attractive prices. Except for the high run-off period, there is adequate transmission from the PNW to northern California for short term sales, mostly transacted in the real-time market. However, the long term transmission between the regions is fully subscribed. If renewable projects are to be built in the PNW to serve the California load, additional transmission (long-term firm service) will have to be built. The PNW and California entities should investigate some type of intertie open season to determine the interest in building the necessary transmission.

Although COI utilization is high during the high runoff season in the PNW, the analysis showed that the scheduling limits are reduced during those months. The scheduling limits are often reduced due to planned maintenance outages. Typically, the high run-off months in the PNW coincide with the times when COI owners are taking transmission line or equipment maintenance outages. The outages are coordinated between the PNW and California parties generally to occur between the times the rainy season ends (so utilities can get trucks into the field) and the summer peak season begins. The COI owners should look at spreading the outages out between the spring and fall or other times of the year to maximize the available capacity during this high usage period.

The analysis also showed that there is an interest in more dynamic transfers between the regions, so that the regulating burden for the renewables can be shared between the two regions. At present BPA and CAISO are evaluating the potential for intra-hour scheduling on the COI as a pilot project. The CAISO is now completing a stakeholder process to add to its existing market functionality for dynamic transfers, which has included a technical study concluding that the CAISO does not have limitations in its transmission capability to support dynamic transfers of intermittent resources. BPA, CAISO, and other organizations in the PNW are supporting recently initiated dynamic transfer capability studies through the Dynamic Transfer Capability Task Force convened by the Wind Integration Study Team.

In summary:

- Economics / price differential drives COI usage (there is available transmission space in the real-time market).
  Recommendations: Consider a study to better understand the PNW and PSW energy market structure and in relationship (i.e. MRTU, COB, Mid-C, NP-15) to COI utilization.
- During runoff periods / summer months, utilization is very high.
  Recommendations: Consider moving maintenance outages to some other times of the year in order to maximize COI scheduling limit.
- No long-term firm transmission capacity is available.
  Recommendation: Explore possible open season to determine demand for long-term transmission service, encourage firm transmission holders for resale, and/or possible recommendation for BPA to relieve price caps.
- For short-term, no structural impediments were found (in all but a few cases).
  Recommendation: TSPs need to remain diligent to ensure that minimal seams issues exist or occur in the future.
- Pro-rata real-time curtailment at COI results in further curtailments at COI (OTC).
  Recommendation: BAs and Operators to investigate change in pro-rata tag curtailments.
- Maintenance in spring lowers the OTC level, limiting flows where biggest price differential occurs.
  Recommendation: Better regional outage coordination is needed for maximum COI utilization.
- Merchants desire for additional dynamic transfer capability.
  Recommendation: BPA/CAISO to look into the additional dynamic transfer possibility.