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") hereby submits these comments to the Oregon Public Utility Commission (the "Commission") responding to the reply comments filed by Portland General Electric Company ("PGE" or the "Company") on November 5, 2019 ("Reply Comments") regarding PGE's 2019 Integrated Resource Plan ("IRP"). Swan Lake appreciates PGE's willingness to modify its procurement strategy to allow long lead time capacity resources—like pumped storage—to participate in its capacity actions, but believes PGE's modification may not adequately protect customers from future market risk and may expose them to a supply resource mix that is sub-optimal from the perspective of cost, environmental benefit and dispatchability. PGE's proposal to allow resources with long lead times to participate in its non-emitting capacity request for proposals ("Capacity RFP"), "provided that PGE is able to pair them with contract options to meet PGE's capacity needs in the interim"[1] (the "Modification") is inconsistent with its IRP modeling and may undermine PGE's ability to identify the least cost and risk option. Simply put, the Modification does not mitigate the risks associated with PGE's phased approach. As described herein, Swan Lake

[1] PGE Reply Comments at 16 (Nov. 5, 2019).

strongly believes that the better way for PGE to procure the least cost and risk capacity resources is for the Company to conduct a single RFP in 2020 for both existing and new capacity resources.

If PGE continues to hold the position that it must carry out a phased process, Swan Lake proposes that PGE either accelerate the bilateral negotiations and issue an RFP, if needed, by no later than Q3 of 2020 or seek a waiver of the Commission's competitive bidding requirements[2] to begin procurement of the long lead time resources. Swan Lake therefore asks the Commission to opine in its acknowledgement order as to whether its rules allow for a waiver and/or exception of the Competitive Bidding Rules for long lead time procurement, like the Swan Lake pumped storage project.

II. COMMENTS

As our initial comments indicate, Swan Lake has been generally supportive of PGE's approach and analysis throughout this IRP process, and we continue to believe that PGE has done a commendable job. Nevertheless, these comments are narrowly focused on a singular timing issue that continues to merit additional consideration; namely, that PGE's Action Plan featuring a staged capacity procurement strategy whereby the Company will attempt to meet its capacity needs through bilateral agreements with existing capacity resources in the region before issuing its Capacity RFP will,[3] even with the Modification, expose PGE customers to unnecessary risk that is easily avoidable should PGE simply move up the timing of the Capacity RFP.

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

[3] PGE Reply Comments at 13-16.

Swan Lake therefore reiterates its request that PGE and the Commission consider other alternatives.[4] We respectfully request the Commission clarify the applicability of its Competitive Bidding Rules to the acquisition of the Swan Lake pumped storage project. Although the Commission has not seen a request for a long-lead time resource, Swan Lake submits 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.

A. PGE's Modification Does Not Mitigate Risk for Customers

PGE's preferred portfolio calls for the acquisition of 200 MW of pumped storage in 2024 and 2025.[5] As Swan Lake pointed out in its initial comments, PGE will not be able to procure *any* pumped storage to meet its 2024-2025 capacity need unless it advances the date of the Capacity RFP, due to the long lead time requirements for pumped storage projects like Swan Lake.[6] Swan Lake detailed a number of risks associated with PGE's phased procurement approach, including the potential for overreliance on batteries[7] and the potential lack of capacity in the region.[8] As Swan Lake initially argued, holding an all encompassing RFP would both mitigate those risks and provide PGE the flexibility to test the market and avail customers of the greatest number of supply options with the most accurate and robust pricing data.[9] Given PGE's new approach to IRP modeling, the subsequent RFP process(es) may be the only way the Company can truly identify the least cost and risk resources. Swan Lake continues to believe

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

5 PGE 2019 IRP at 215 (July 19, 2019).

6 Swan Lake Opening Comments at 4 ("If unchanged, the 2021 procurement called for in the IRP would delay the Swan Lake Project until *at least* 2026, and perhaps longer"); *see also id.* at Appendix A (detailing schedule requirements for a 2025 commercial operation date at Swan Lake).

7 *Id.* at 7.

8 *Id.* at 18; *see also* Attachment A at 8 ("By 2030, the region faces a 10,000 MW need that is not adequately met by currently planned additions").

9 *Id.* at 11.

that a concurrent procurement approach will provide PGE better options for its customers when making future decisions addressing Colstrip,[10] EIM participation,[11] vehicle electrification,[12] data centers[13] and clean-energy legislation.[14]

Staff expressed similar views, noting that "the Company's capacity actions (Action Item 3), while driven by more pressing need [than PGE's renewable energy action item (Action Item 2)], are inconsistent with the reality of the resources selected in the preferred portfolio and the approach taken for Action Item 2."[15] Accordingly, Staff noted it, "finds merit in exploring how to accelerate the simultaneous evaluation of new and existing capacity resources ahead of PGE's forecasted capacity need in 2025."[16]

Staff also raised concerns about PGE's new modeling approach, along with what Staff characterized as "prioritizing near-term renewables and the potential savings they may bring, over a real need for capacity to serve load within the action plan timeframe."[17] Staff explained that it was "concerned that these deviations from the IRP's fundamental requirements could be obscuring the least cost, least risk path and harming ratepayers."[18] According to Staff:

> Pumped storage represents a unique generation product that can address both PGE and the region's capacity needs with no direct emissions. This resource could also assist with the integration of more renewables as part of a long-term decarbonization plan. **Given the potential risk that capacity from federal system hydro resources may not be available post 2025** in the same quantity as today because of additional fish recovery measures or a more lucrative California capacity market, **the timing to secure additional capacity is important**. Therefore, Staff is intrigued by [Swan Lake's] proposal that PGE conduct an "all encompassing

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10 *Id.* at 13.
11 *Id.* at 12.
12 *Id.* at 30.
13 *Id.* at 28.
14 *Id.* at 26.
15 Staff Opening Comments at 5 (Oct. 11, 2019); *see also id.* at 7 ("the IRP's approach to pumped storage does not align well with the actual process to permit and construct this long lead-time resource").
16 *Id.* at 7.
17 *Id.* at 24.
18 *Id.* at 4.

> RFP" by adjusting its Action Plan to run two RFPs simultaneously: one for renewables, the other for non-emitting capacity capable of coming online by 2025.[19]

Importantly, Staff "is intrigued by the potential of pumped storage as a zero-emission, flexible capacity resource—particularly given the region's possible capacity shortfall due to coal retirements and the West's increasing reliance on a less diversified, but also less emitting, pool of generation resources."[20] Moreover, Staff cautions that "[w]aiting until the next IRP Action Plan to explore a more holistic set of capacity options may leave PGE with less ability to avoid the addition of new fossil-fuel thermal generation in the mid-2020s, something PGE is currently saying they want to avoid."[21] Finally, Staff notes that,

> [because] contract expirations in 2025 constitute the main driver of [PGE's] capacity need, … **Staff thinks it would be more prudent for the Action Plan to place greater emphasis on not only contract renegotiations but also in steps to make PGE more resilient to capacity shortfalls such as … taking actions to better understand the financing and timing associated with new potential low-emission capacity products**, such as distribution-scale batteries and utility-scale pumped hydro."[22]

In its Reply Comments, PGE "agrees that the prospect of a regional capacity shortage in the mid-2020s is concerning and that pumped storage resources may be well-suited to meet a portion of the region's growing capacity needs" but declined to advance the date of the Capacity RFP.[23] PGE stated it would be in its customers' interests to maintain the staged procurement approach.[24] However, to allow for the opportunity for both battery storage and pumped storage to participate—without accelerating the RFP—PGE proposed a modification, namely that it

19 *Id.* at 7 (emphasis added).
20 *Id.*
21 *Id.* at 24.
22 *Id.* (emphasis added).
23 PGE Reply Comments at 15.
24 *Id.* at 14-15.

would "design the RFP to allow for new resources with long lead time to be paired with contract options that can meet capacity needs in the interim."[25]

Although PGE stated it assessed the potential benefits and the drawbacks of a concurrent RFP approach, the Reply Comments do not provide any modeling that quantifies that assessment.[26] PGE further discusses the "value of optionality" and "the risks associated with large irreversible commitments" as a reason for not adopting Swan Lake's proposal to hold an all-encompassing RFP. Yet a staged approach that effectively reduces the number of bidders, dampens competition and leaves PGE and its customers capacity-exposed in a region that nearly everyone agrees will experience substantial shortages does greater harm to supply optionality and, once carried out, will be an irreversible step in the wrong direction for customers from the perspective of cost and the achievement of public policy goals.

The Modification is a sub-optimal solution to the timing concerns raised by Swan Lake and does not mitigate the risks to customers posed by the staged process. First, it effectively does not allow pumped storage the opportunity to compete for PGE's 2024-2025 capacity need, reducing the field of potential bidders to the detriment of customers by pushing Swan Lake's earliest possible commercial operation date well beyond the pumped storage acquisition modeled in the preferred portfolio. Moreover, the Modification forces pumped storage to compete while paired with bilateral contract options that could constitute an inferior resource option for customers as compared to a stand-alone pumped storage bid. While PGE has not provided any details as to how the short-term contracts would be modeled[27] or selected in the Capacity RFP,

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25 *Id*. at 16.

26 *Id.*

27 *See* Staff Opening Comments at 38-39 ("Staff is intrigued by the introduction of the capacity fill resource to capture the uncertainties and risk surrounding its bilateral capacity contracts . . . . While Staff appreciates the Company's efforts to capture optionality in the IRP, Staff does not believe that PGE has sufficiently justified the near-term constraint on access to the capacity fill resources. Further, the 2019 IRP is unclear whether the "capacity fill" resource matches the expected costs of capacity contracts.").

the phased approach contemplates a timeline where PGE would be seeking supply resources from the market during a period when the region is forecasted to experience a growing capacity shortage, exposing PGE customers to fewer supply choices at higher costs, a condition made more acute by the likelihood that PGE will be seeking only non-emitting resources when utilities across the region will also be doing the same.[28]

PGE does not appear to believe a staged procurement strategy will limit its flexibility. For example, the Company explained that it does not believe a staged procurement strategy is mutually exclusive with participation by pumped storage resources because "new capacity resources that can come online after 2025 could still provide significant value to PGE customers."[29] PGE appears to prefer to delay the acquisition of pumped storage to loosely follow the preferred portfolio. This assumes, however, that pumped storage will eventually be available, but as these clean resources will be highly sought-after by key buyers in a capacity-short market, that may not be the case. PGE should evaluate all of the non-emitting capacity options together rather than assume that existing resources will out-perform new ones. Broadening the field of potential suppliers will help ensure PGE's customers are getting the best value.

PGE may have misunderstood the concerns expressed by Staff and Swan Lake because the Reply Comments explain that the Capacity RFP "should not be designed to specifically target pumped storage over battery storage" and expressed the Company's belief that "better outcomes can be achieved … by delaying commitments to storage technologies than by requiring commitments multiple years before battery construction would need to commence."[30] As a

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28 A December 2019 Energy+Environment Economics report, *Capacity Needs in the Pacific Northwest and California*, has been added to these comments as Attachment A.

29 PGE Reply Comments at 15-16.

30 *Id.* at 15.

threshold matter, this appears to specifically target battery storage over pumped storage. But more importantly, PGE may be undervaluing a very real, proven 100 percent clean technology that was modeled as a least cost and risk option in favor of hypothetical future cost reductions on new, emerging technologies—during a time when the Company may not have access to a robust set of capacity resource alternatives. In short, PGE may be setting itself up to be one of the last buyers in a seller's market. Given all of the risk associated with a phased capacity procurement, PGE has not adequately explained how the Modification is in the long-run public interest.

PGE may also conflate its own modeling increments with the actual flexibility offered by batteries and pumped storage. PGE states that "battery storage provides additional flexibility to right-size capacity additions over time as more information is gained about resource needs."[31] PGE does not explain how batteries can "right size" capacity additions any better than a pumped storage facility that can be contracted for in any amount PGE desires.[32]

B. The Commission Should Clarify that Procurement from the Swan Lake Project Qualifies for a Waiver and/or Exception from the Competitive Bidding Rules

In its initial comments, Swan Lake asked PGE and the Commission to consider additional alternatives to its proposal for an all encompassing RFP.[33] More specifically, Swan Lake suggested PGE could add an item to its Action Plan to commence procurement of long lead time resources in 2020 and/or seek a waiver of the Completive Bidding Rules. A Commission workshop was held on December 4, 2019, where stakeholders discussed the Commission's new rules and, among other things, how they might apply to long-lead time resources such as pumped storage.

[31] *Id*.

[32] Swan lake noted the IRP modeling appeared to require pumped storage be added in 100 MW increments and asked PGE to consider relaxing the unit constraint. Swan Lake Opening Comments at 32.

[33] *Id.* at 14-18.

As discussed in the December 4 workshop, although this may be an issue of first impression for the Commission, the Competitive Bidding Rules appear to allow for an exception and/or waiver for the procurement of the Swan Lake project due to the unusually long lead time needed for procurement. First, OAR 860-089-0010(2) allows the Commission to waive the Competitive Bidding Rules for good cause if a request is made in writing prior to or concurrent with the initiation of the resource acquisition (the "Waiver Provision"). Second, OAR 860-089-0100(3)(b) provides an exception to the Competitive Bidding Rules where there is a "time-limited opportunity to acquire a resource of unique value" for customers (the "Time-Limited Opportunity Exception"). Finally, OAR 860-089-0100(4) requires a utility seeking to acquire a resource with an exception, like the Time-Limited Opportunity Exception, to provide notice with a report to the Commission (the "Notice Provision").

As Swan Lake's initial comments detailed, pumped storage offers a unique long-duration capacity opportunity, but the timing commitments necessary to procure a pumped storage project make it ill-suited for traditional IRP processes.[34] These timing challenges provide good cause for the Commission to waive the Competitive Bidding Rules via the Waiver Provision. Swan Lake provided an Appendix detailing its project schedule, which requires a definitive power purchase agreement or ownership agreement to be in place by the end of Q3 of 2020 at the latest to achieve commercial operation to meet PGE's 2025 capacity need. Because there is a short window of opportunity to ensure pumped storage is available to meet PGE's capacity need, as modeled in the preferred portfolio, the Swan Lake project presents a time-limited opportunity under the Time-Limited Opportunity Exception. Pumped storage also offers a resource of

[34] *See id.* at 6-7 ("PGE's phased procurement plan would effectively foreclose long-duration storage projects like pumped storage from being part of PGE's near-term capacity additions.").

unique value by offering a large-scale capacity resource that is both clean and dispatchable, offering extended ramping durations and an asset life of 100 years or more.[35] As such, PGE could acquire the Swan Lake project separately from its Capacity RFP by either receiving a waiver before the acquisition or providing notice of an exception shortly after the acquisition.

We therefore ask the Commission to confirm in its acknowledgment order in this proceeding that, as discussed in the December 4 workshop, the Competitive Bidding Rules allow for an exception and/or waiver for the procurement of the Swan Lake project due to the unusually long lead time needed for procurement and unique value to the region's customers.

The Commission should also address ambiguity in its rules and confirm whether a request for waiver *before* the acquisition of the Swan Lake project would, in this case, result in acknowledgment of the resource acquisition. OAR 860-089-0010(2)(b) states, "[i]f a request for waiver is filed by an electric company after it acquires a resource, granting, if any, of the waiver request does not result in or equate to the Commission's acknowledgment of the resource acquisition." There was discussion at the December 4 workshop as to whether a request for waiver made before an acquisition would result in or equate to acknowledgment. Because Swan Lake is asking the Commission to confirm waiver and/or exception is appropriate under the rules while PGE's IRP process is still pending, we would expect that if the Commission confirms the acquisition of the Swan Lake project is eligible for waiver and/or exception, any acknowledgement of PGE's resource acquisition plan would include acknowledgement of the acquisition of the Swan Lake project outside of the Capacity RFP.

35 Typically utility resource are modeled to last for thirty or forty years.

III. CONCLUSION

For the reasons described above, Swan Lake believes the Commission should ultimately acknowledge PGE's capacity need. Swan Lake believes additional consideration is needed, however, before acknowledgement is appropriate for the phased procurement PGE is proposing for its Capacity RFP to address long lead time resources. Swan Lake looks forward to working with PGE and Staff to better understand the costs and risks associated with PGE's Modification and determining whether additional alternatives may be available.

Dated this 16th day of December,

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ATTACHMENT A

Energy+Environmental Economics Study

Capacity Needs in the Pacific Northwest and California

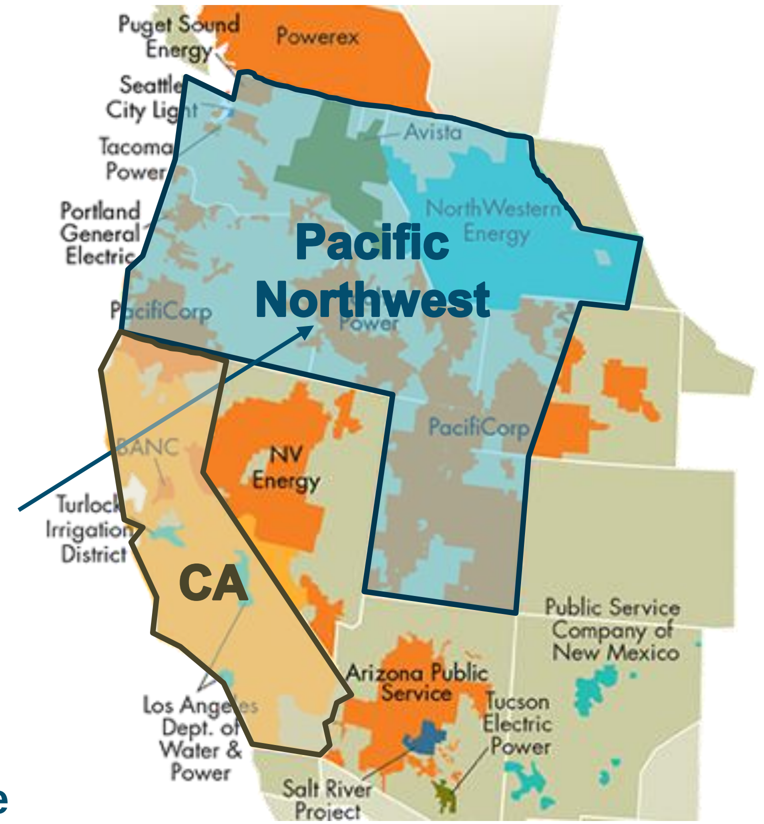
December 2019

Outline

- **Project Background**
- **Key Takeaways**
- **Pacific Northwest Analysis**
  - Key policy drivers and resource adequacy approach
  - Near-term view
  - Mid-term view
- **California Analysis**
  - Key policy drivers and resource adequacy approach
  - Near-term view
  - Forecasted oversupply available for storage charging
- **Key Terms & Abbreviations**

Project Background

+ **National Grid hired E3 to analyze and summarize a fundamentals-based view of the Pacific Northwest (PacNW) and California capacity need**
+ **Study Approach**
  - **Top down view**: Compares regional level studies on capacity need, which included updating a previous E3 study based on latest public information and comparing it against other regional studies
  - **Bottom up view**: Aggregates capacity need and planned additions from utility integrated resource plans (IRPs) across the region
  - The PacNW study region is defined as the "Greater NW," consisting of the US portion of the Northwest Power Pool, excluding Nevada
    - Other studies of regional need utilizing smaller regions are noted
+ **The views contained herein are solely those of the authors and based on public information as well as E3's analysis for its own study**



Key Takeaways

Summary of PacNW + CA Capacity Needs

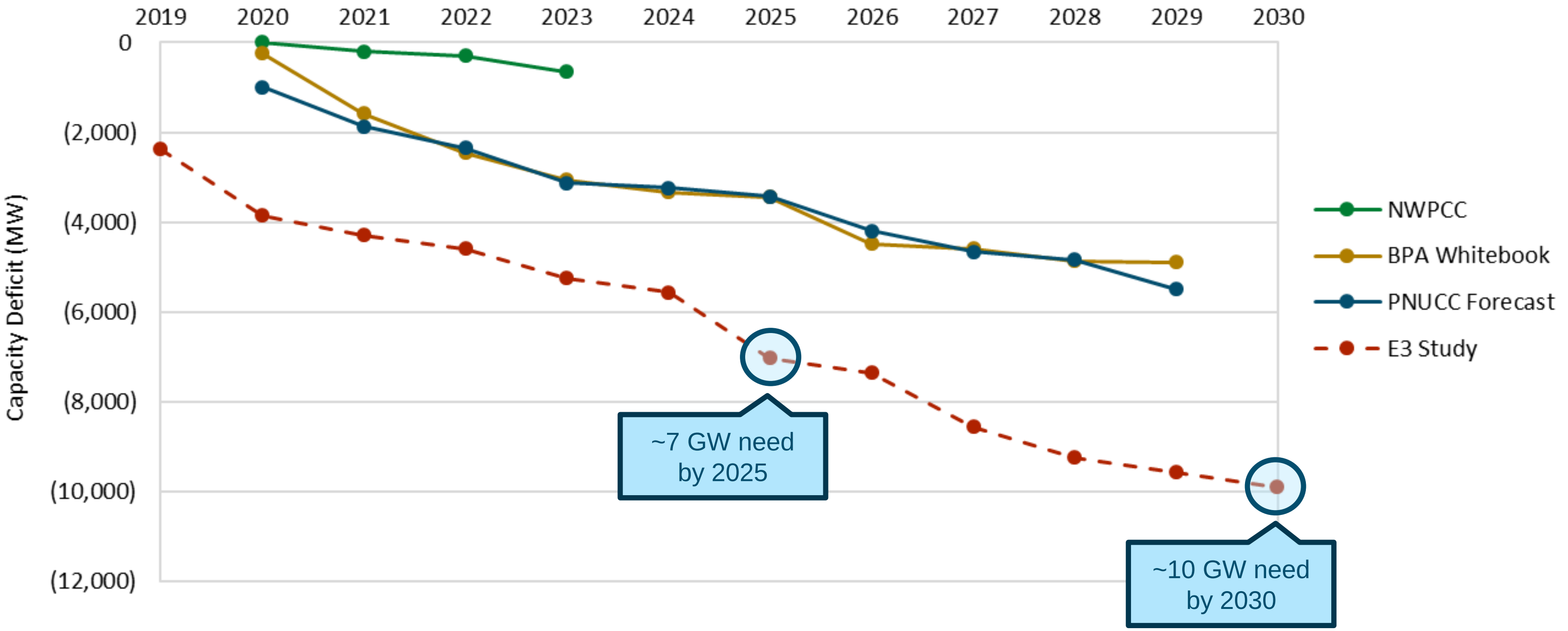
+ **Near-term (today-2025): both regions face capacity shortfalls**
+ **Mid-term (2025-2030): PacNW need grows while CA need reduced by policy/economic-driven storage additions**
+ **Long-term (2030-2050): both regions need to maintain and even increase firm dispatchable capacity to address deeply decarbonized energy sufficiency challenges**

		Near-term (today-2025)	Mid-term (2025-2030)	Long-term (2030-2050)
Pacific Northwest	Capacity Need	Immediate capacity shortfall of 0-1.2 GW, rising to 3-7 GW by 2025	Growing capacity shortfall of ~10 GW in 2030 (higher if more coal retires than currently planned for)	Capacity shortfall grows to ~20 GW by 2050, possibly even higher under high electrification scenarios
	Key Drivers	• Increasing winter and summer peak demand • Coal retirements w/ few firm replacements • Consideration of a regional RA program	• Continued load growth and coal retirements • Renewable and storage additions with diminishing capacity benefit • Additional capacity additions needed	• Energy sufficiency-based reliability planning challenge • Decarbonization policies further drive renewables/ storage; do not avoid need for firm capacity • Electrification loads could drive even higher winter peak
California	Capacity Need	Capacity shortfall by 2021-23 of 2-3 GW	Capacity balance or slight-surplus driven by maintaining existing gas fleet + policy/economic-driven storage additions	High renewable/storage capacity added, but system capacity need driven by maintaining existing dispatchable gas fleet
	Key Drivers	• Policy-driven (once-through cooling) and economic gas + nuclear retirements • Storage begins to replace new and existing gas capacity	• Relatively stable loads • High storage additions driven by RPS/GHG policy and arbitrage economics	• Energy sufficiency-based reliability planning challenge • Decarbonization policies further increase renewables/storage; do not avoid need for firm capacity • Electrification loads may increase winter and summer peak

PacNW Near to Mid-Term Capacity Need

Top-Down Forecast

+ **Multiple regional assessments point to a near-term shortfall of winter-peaking physical capacity in the Northwest region**
  - Shortfall grows to ~5,000-10,000 MW over next 10 years

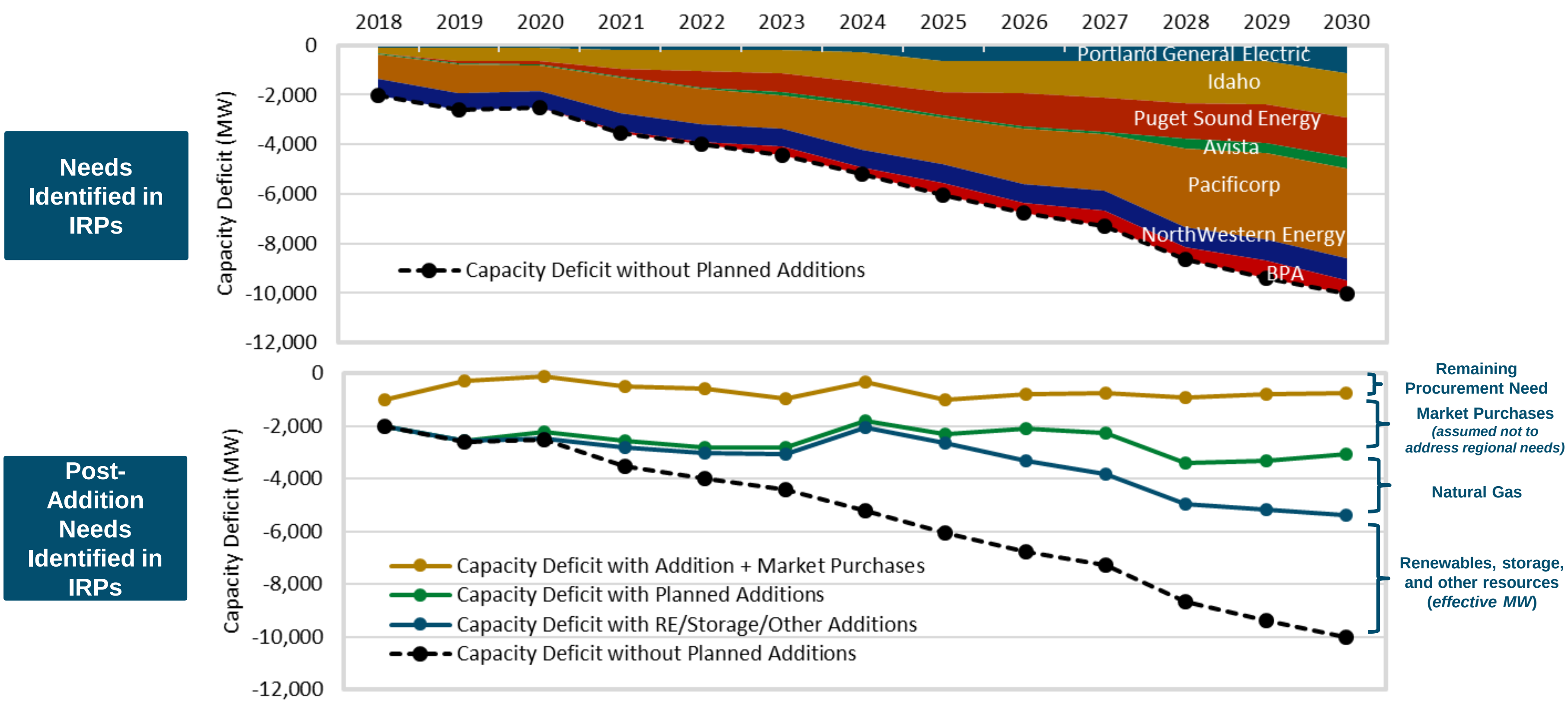


- Key differences are driven by PRM requirements, capacity counting methodologies, and resource additions (*see appendix for comparison of key assumptions*).
- E3 and NWPCC are truly "top-down" stochastic views, while PNUCC and BPA are closer to regional "bottom-up" analyses of utility IRPs.
- E3 study based on 2018 and 2030 RECAP LOLE modeling, shaped between those years based on forecasted coal-retirement schedules. This study updated previous analysis to include coal retirements from PacifiCorp's 2019 Draft IRP. E3's need does not incorporate any planned additions.

PacNW Near to Mid-Term Capacity Need
Bottom-Up Capacity Need vs. Planned Additions

+ **Through their IRPs, individual utilities have identified their capacity needs over a 20-year horizon**
  - Aggregate “bottom-up” need reaches ~10,000 MW by 2030
  - IRP planned additions do not adequately address full capacity need, leaving ~3,000 MW of additional need

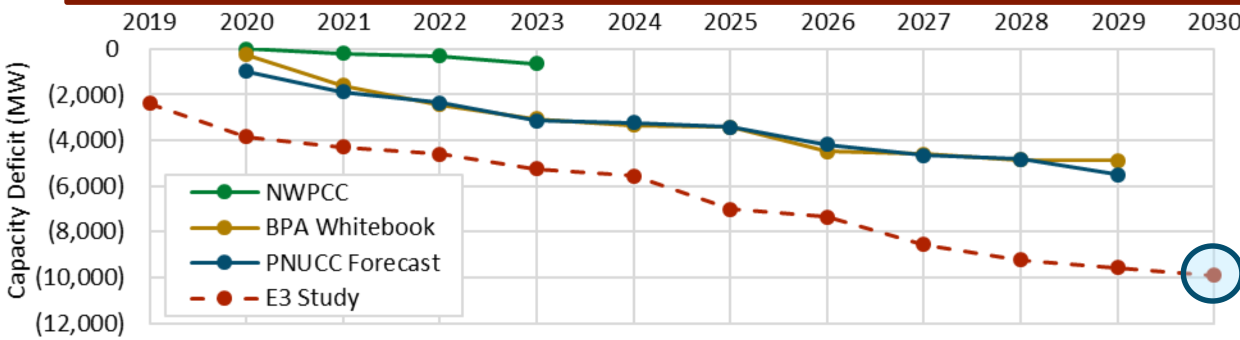
Summary of Utility IRP-based Capacity Needs



*E3 also considered Grant, Chelan, and Douglas Counties but they do not report a shortage in capacity

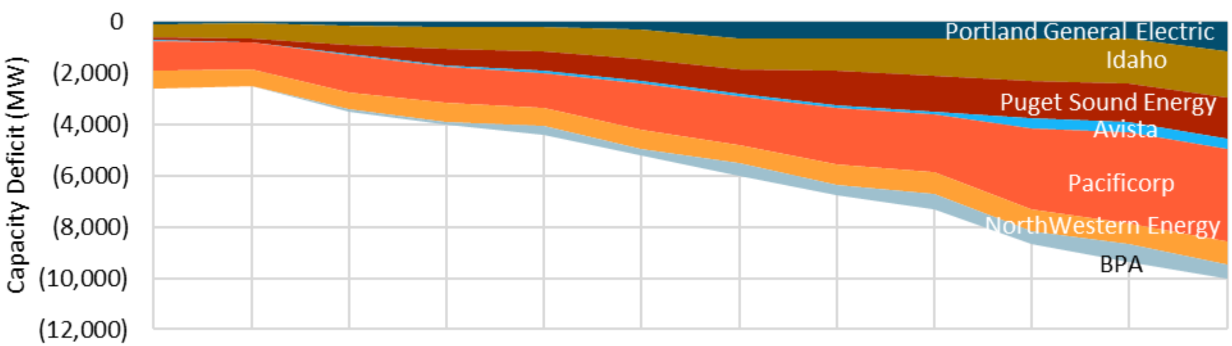
PacNW Capacity Need vs. Planned Additions

By 2030, the region faces a 10,000 MW need that is not adequately met by currently planned additions



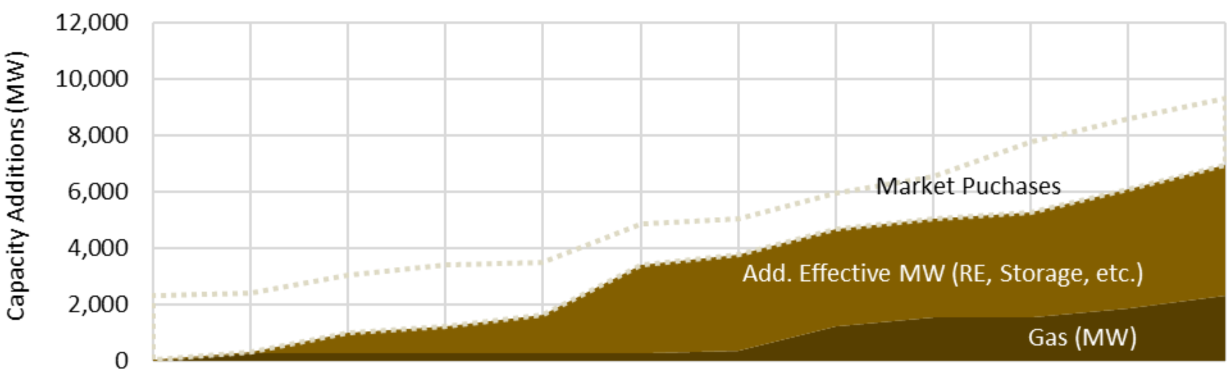
"Top-Down" Regional Assessments

5,000 – 10,000 MW capacity need by 2030



"Bottom-Up" Review of Utility IRPs

10,000 MW capacity need by 2030, before planned additions



IRP Planned Resource Additions

Only ~7,000 MW effective capacity additions…
2,300 MW of market purchases generally do not address regional need

Note: E3 top-down assessment utilizes RECAP modeling results from E3's 2019 study Resource Adequacy in the Pacific Northwest. This study further shapes the annual capacity need based on the latest proposed coal retirements schedules (as of Oct 2019). E3's capacity deficit does not include any planned additions.

Energy+Environmental Economics

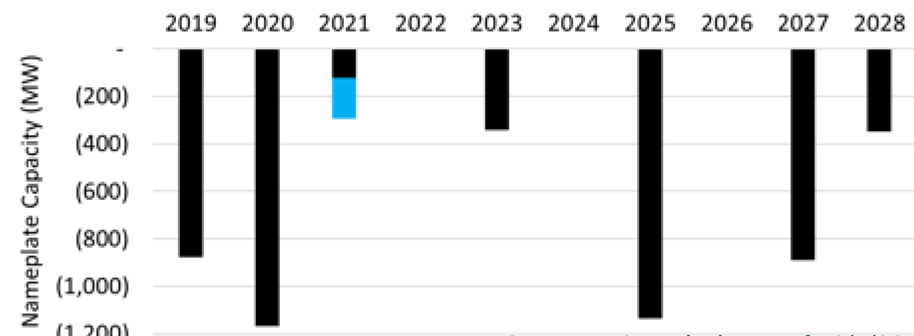
Pacific Northwest Analysis

PacNW Key Policy Drivers

+ **Coal retirements are driven by policy, planning, and politics**
  - 4.5 GW by 2030
+ **Clean energy legislation and voluntary goals are expanding**
  - WA/OR coal prohibitions
  - WA 100% carbon-free by 2045 - OR may follow
  - Idaho Power voluntary goal of 100% clean energy by 2045
+ **Economy-wide GHG reductions will drive additional impacts**
  - Electrification of transportation and building loads may significantly increase peak loads

Planned PacNW Coal Retirements

Units to Retire						
2019	2020	2021	2023	2025	2027	2028
Colstrip 1,2	Boardman	North Valmy 1	Jim Bridger 1	Centralia 2	Colstrip 3,4	Jim Bridger 2
Naughton 3	Centralia 1	Klamath Hydro		North Valmy 2	Johnston 1-4	
				Naughton 1,2		



Source: E3 analysis, as of 10/7/2019

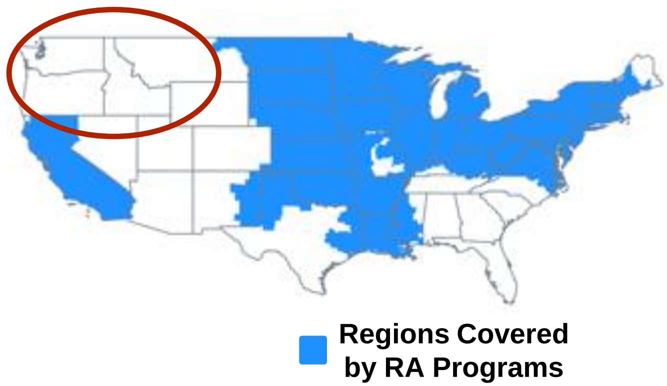
NOTE: includes coal retirements in PacifiCorp's draft 2019 IRP

	RPS or Clean Energy Standard?	Coal Prohibition?	Carbon price?	Voluntary Goals?
WA	✔ Carbon neutral by 2030, 100% by 2045	✔ Eliminate by 2025	✔ SCC in utility planning	✔ Corporations + Cities
OR	✔ 50% by 2040	✔ Eliminate by 2035	✘	✔ Utilities + Cities
ID	✘	✘	✘	✔ Idaho Power 100% by 2045
MT	✔ 15% by 2015	✘	✘	✘
UT	✔ 20% by 2025	✘	✘	✔ SLC + other cities
WY	✘	✘	✘	✘

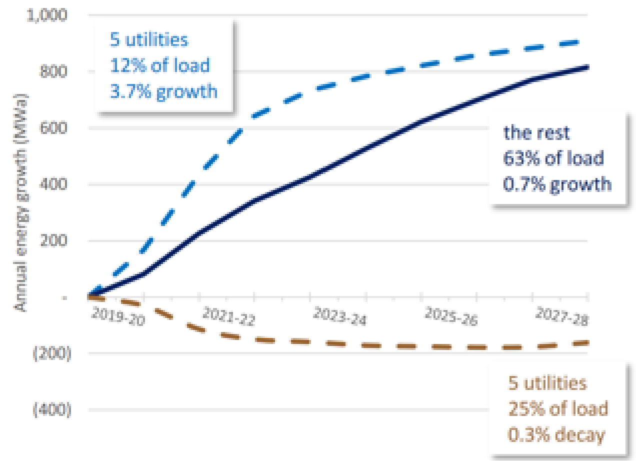
PacNW Resource Adequacy Approach

- **The Northwest has no existing regional RA program**
  - There are independent regional RA assessments (BPA, PNUCC, etc.), but no regulatory program to coordinate RA planning and procurement
- **Reliability planning done through utility IRPs**
  - Lack of consistency in assumptions (e.g. load growth, capacity contributions)
  - Lack of consistency in reliability standards (e.g. PRM vs. LOLE vs. other reliability metrics)
- **Top-down view of regional need may not match the bottom-up (IRP-based) view**
  - Reliance in IRPs on market purchases (aka front-office transactions) may lead to double counting
- **The region (led by the Northwest Power Pool) is considering developing a regional RA program**

Geographic Extent of U.S. RA Programs



Different Loads Forecast in Utility IRPs



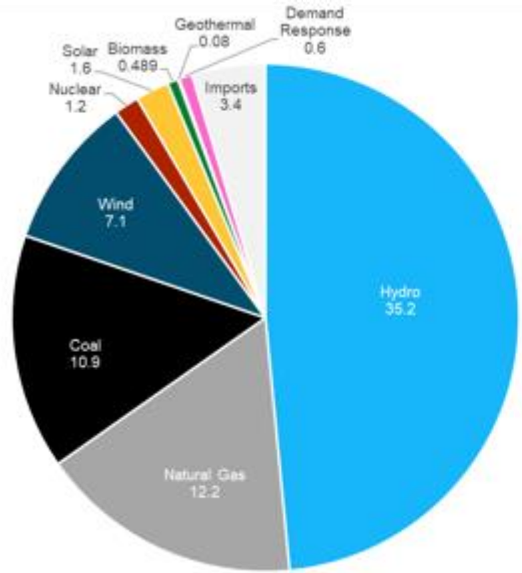
Source: PNUCC [2019 Northwest Regional Forecast]

PacNW Existing Resources
2018

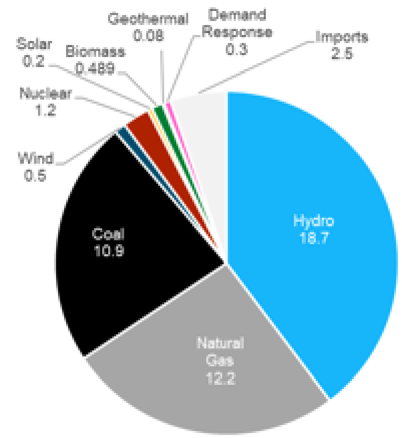
Load + Resource Balance (Greater NW = WA, OR, ID, parts of UT, WY)

Load			Load GW
Peak Load			42.1
Firm Exports			1.1
PRM (12%)			5.2
Total Requirement			**48.4**
Resources	**Nameplate GW**	**Effective %**	**Effective GW**
Coal	10.9	100%	10.9
Gas	12.2	100%	12.2
Biomass & Geothermal	0.6	100%	0.6
Nuclear	1.2	100%	1.2
Demand Response	0.6	50%	0.3
Hydro	35.2	53%	18.7
Wind	7.1	7%	0.5
Solar	1.6	12%	0.2
Storage	0	—	0
Total Internal Generation	**69.1**		**44.7**
Firm Imports	3.4	74%	2.5
Total Supply	**72.5**		**47.2**
Surplus/Deficit			
Capacity Surplus/Deficit			**-1.2**

Nameplate GW



Effective GW



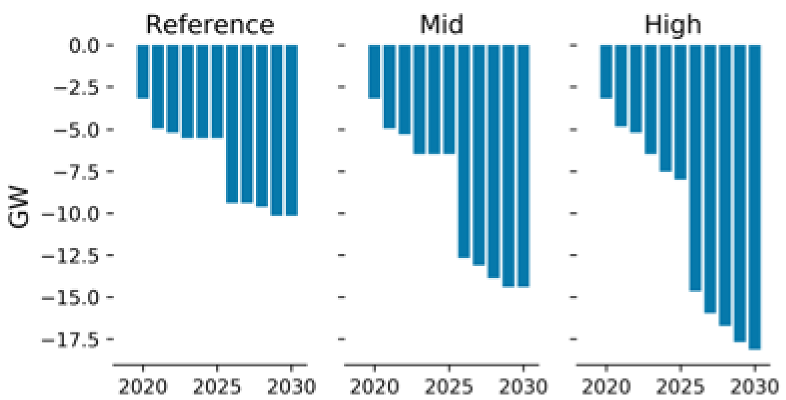
Fossil units are 1/3 of nameplate but 1/2 of effective GW

Source: E3 Resource Adequacy in the Pacific Northwest, 2019
Note: other top-down analyses (e.g. NWPCC) suggest need starting in the 2020-2021 timeframe.

PacNW Near-Term Capacity Need
Key Drivers

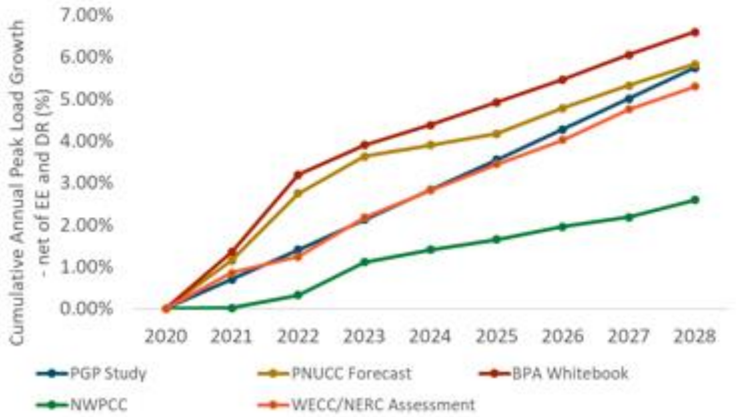
- A combination of departing industrial loads, generation additions, and sustained attention to energy efficiency left the Northwest with excess capacity for nearly two decades
- Two key drivers of the Northwest's capacity challenges have been identified in recent studies:
  1. Thermal (largely coal) resource retirements
  2. Peak load growth
- Both trends are expected to continue across the West as states and provinces continue to pursue decarbonization of both the economy and the electric supply

WECC Coal Retirement Scenarios (cumulative)



NOTE: in 2019, ~35 GW coal in WECC (11 GW in Greater NW)

NW Peak Load Growth in Recent Studies

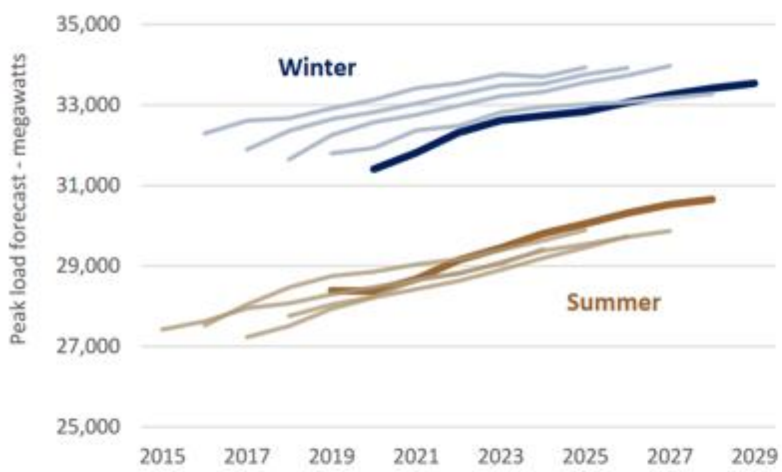


PacNW Near-Term Capacity Need
Winter vs. Summer Needs

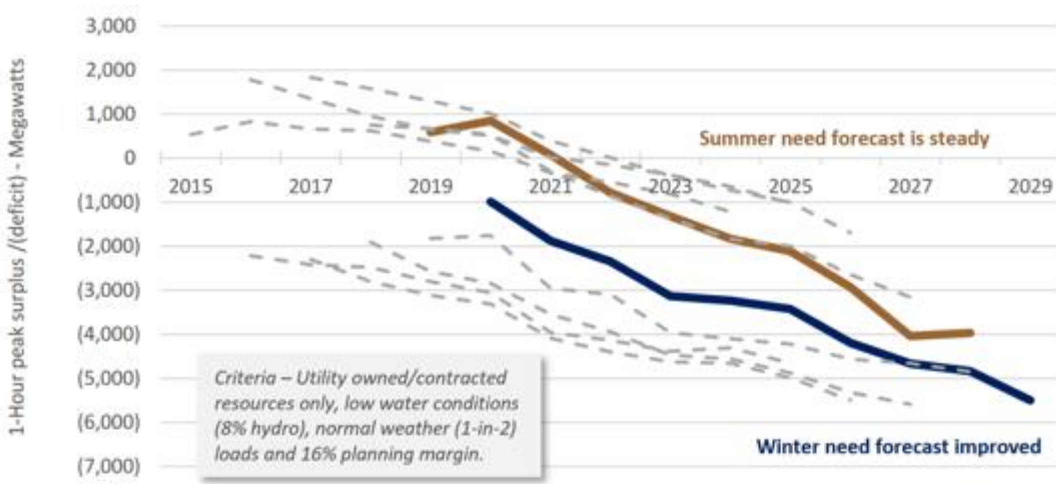
+ **PacNW is a winter peaking region***
  - Summer peak is significant and continues to climb ("dual peaking")
  - Hydro resources and imports are generally less available in summer

+ **The region faces both winter and summer load-resource balance deficits**

PNUCC Summer vs. Winter Peak Demand



PNUCC Summer vs. Winter Need Forecast



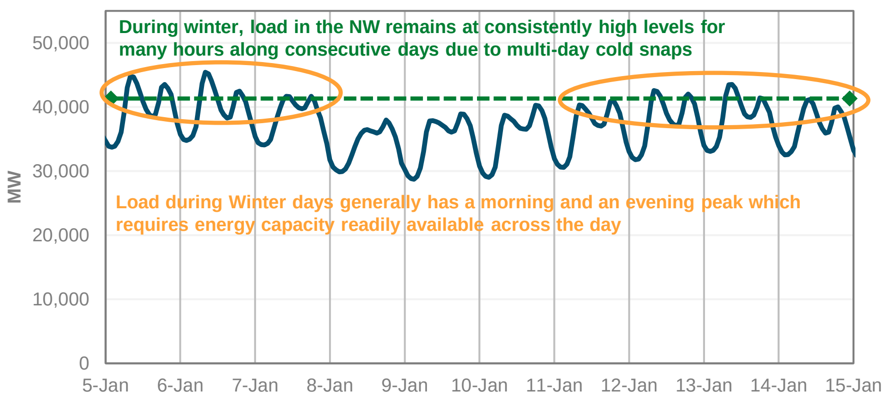
* NOTE: various definitions are used for the Northwest Region. The Northwest Power Pool ("Greater Northwest" region) exhibits a dual winter/summer peak, while the PNUCC region shown here has a stronger winter peak.

PacNW Near-Term Capacity Need

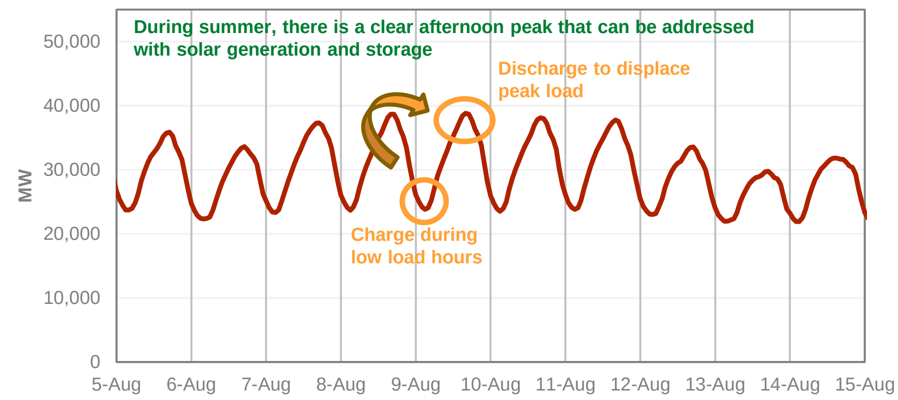
Winter vs. Summer Needs

+ **Reducing the winter peak in the NW is challenging due to its multi-day duration & daily dual-peak nature coupled with inconsistent wind and solar availability**

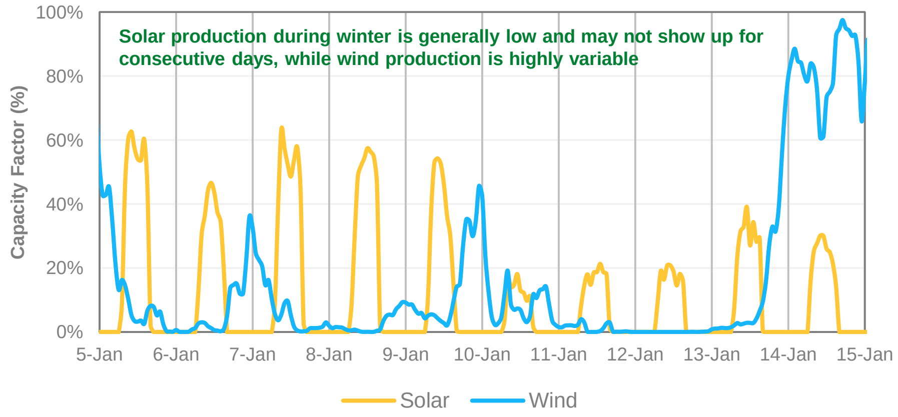
Winter Peak Load



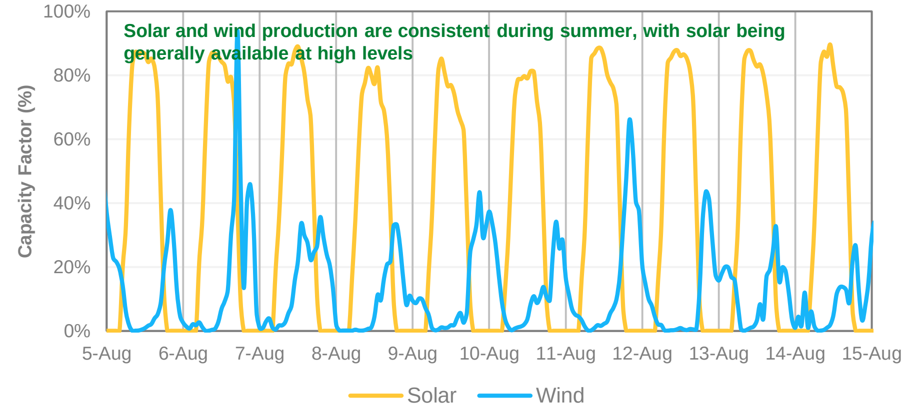
Summer Peak Load



Renewables Winter Profile

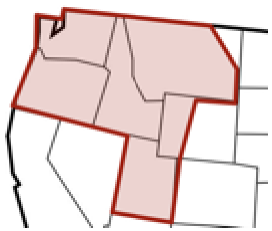


Renewables Summer Profile

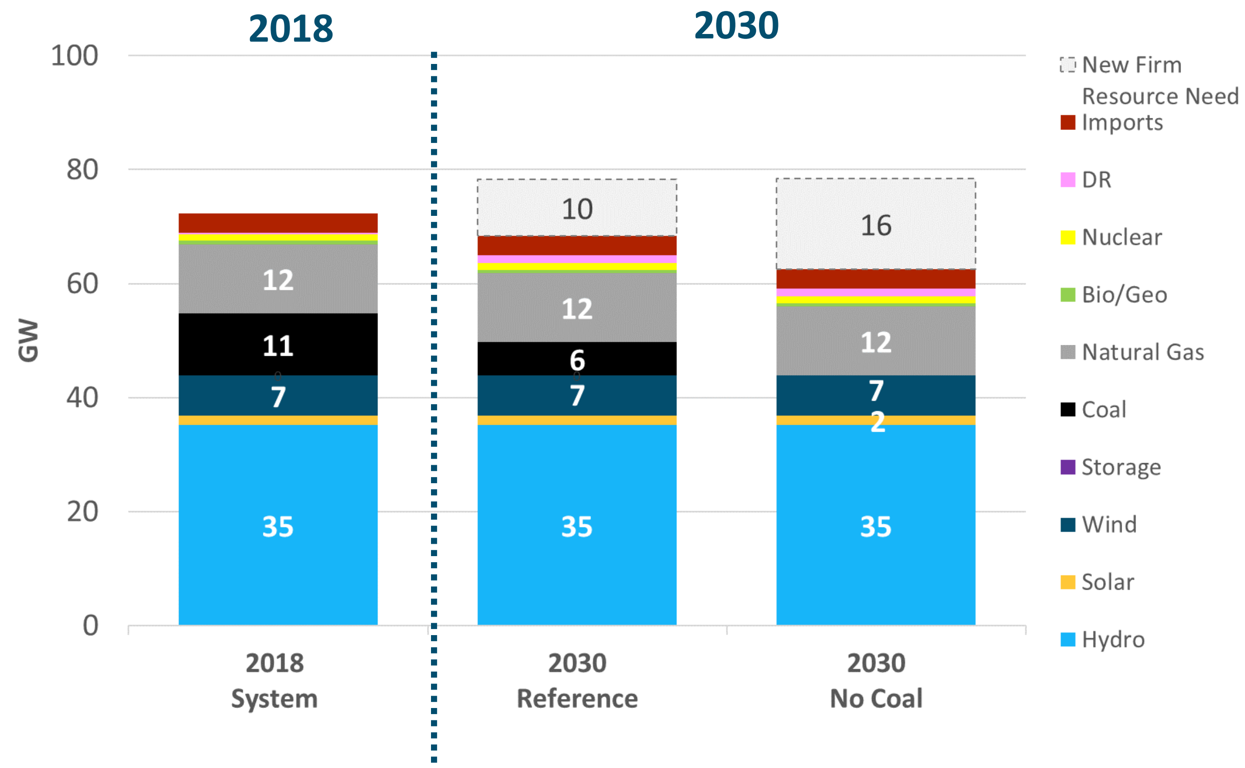


PacNW Near to Mid-Term Capacity Need

2019 E3 Study Details



- E3 2019 RA study considered Greater NW capacity needs under changing resource portfolios
- The study region consists of the U.S. portion of the Northwest Power Pool (excluding Nevada)
- Did NOT consider high electrification loads, which may further increase capacity needs



	2018	2030 Reference	2030 No Coal
Peak Demand (+ firm exports + PRM)	48 GW	53 GW	53 GW
Coal Capacity	11 GW	6 GW	0 GW
Capacity Shortfall	**1.2 GW**	**10 GW**	**16 GW**
Annual Additions ('18-'30)	n/a	~600 MW/yr	~1,300 MW/yr

By 2030, load growth + coal retirements lead to a 10-16 GW capacity need

Note: utilizes RECAP modeling results from E3's 2019 study Resource Adequacy in the Pacific Northwest, but includes the latest proposed coal retirements schedules (as of Oct 2019).

PacNW Near to Mid-Term Capacity Need
Bottom-Up Planned Additions (By Technology)

+ **Planned capacity additions reach over 13,000 MW by 2030**
  - Most new additions are wind and solar
  - Little new firm capacity online before 2025
  - Over-reliance on “market purchases” may stress the region’s available physical capacity

Planned Addition By Resource (Nameplate MW)

	2020	2025	2030
Gas	247	362	2326
Coal	0	0	0
Hydro	0	0	0
Solar	121	2951	5176
Wind	0	4068	4068
Storage	20	297	930
Others (BPA + NWE)	0	735	798
Total Planned Additional Capacity (MW)	388	8413	13298
Market Purchases	2101	1288	2332

Limited firm capacity additions before 2025

Resource types TBD

Effective capacity only ~7,000 MW*

High reliance on the market may double count physical resources

2030 “top-down” regional need vs. “bottom-up” planned additions:

9.9 GW need – 7.0 GW effective additions = 2.9 GW remaining

* Estimate of effective capacity estimated using marginal ELCCs from E3’s RECAP Study of 25% for solar, 40% for wind, 98% for storage
Note: storage’s ELCC quickly declines after the first tranche of additions

PacNW Near to Mid-Term Capacity Need
Bottom-Up Planned Additions (By Utility)

+ **Multiple utilities are planning large capacity additions to address their needs**
  - Utilities subject to strong clean energy policies may seek or require non-emitting new capacity
  - PacifiCorp has the majority of the regional capacity need / planned additions, after their planned coal retirements
+ **A PacNW regional RA program may further facilitate utility coordination needed for new large infrastructure investments in new resource adequacy capacity**

Planned Addition By Utility (Nameplate MW)	2020	2025	2030
Portland General Electric	0	805	805
Idaho	0	276	967
Puget Sound Energy	126	430	1170
Avista	15	15	360
Pacificorp	247	6153	9198
NorthWestern Energy	0	735	798
Bonneville Power Administration	0	0	0
Municipal Utilities	0	0	0
Total Planned Additional Capacity (MW)	**388**	**8413**	**13298**

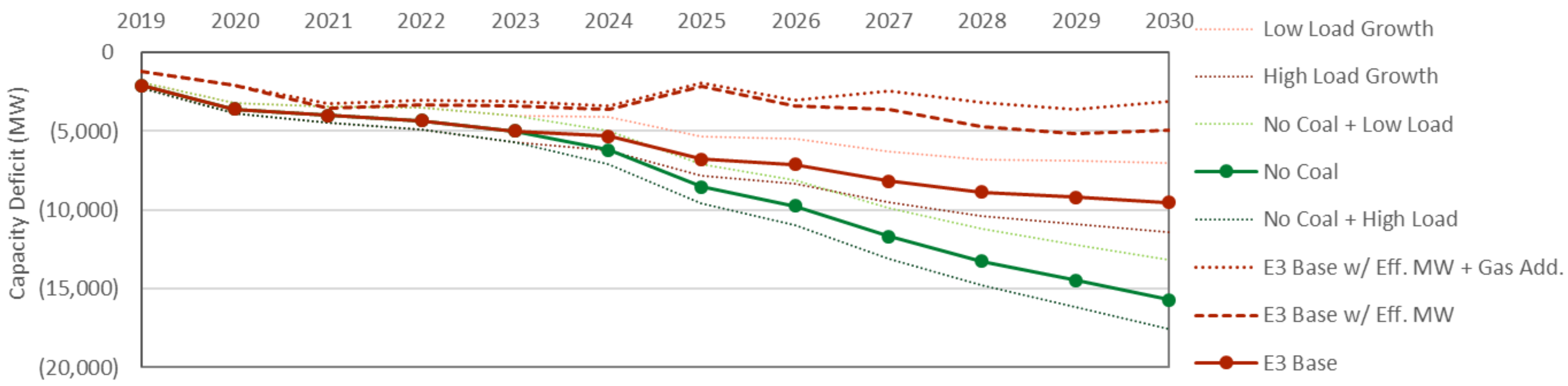
*Does not include EE and DSM

- Significant need by 2025 for utilities w/ mandatory or voluntary clean energy policies
- Market opportunity for non-emitting capacity, though some gas may be needed for reliability

PacNW Near to Mid-term Capacity Need

Top-Down Sensitivities vs. Planned Additions

+ **Top-down sensitivity scenarios were considered based on E3 study 2030 baseline**
  - Key drivers are level of coal retirements and load growth (0.4 – 1.1% / yr considered)
  - Shortfall, before planned additions, ranges from 7.4 to 15.8 GW assuming firm imports of 2.5 GW
  - Even with all planned additions from latest IRP filings, region is still ~3 GW short in 2030



Capacity Deficit Drivers

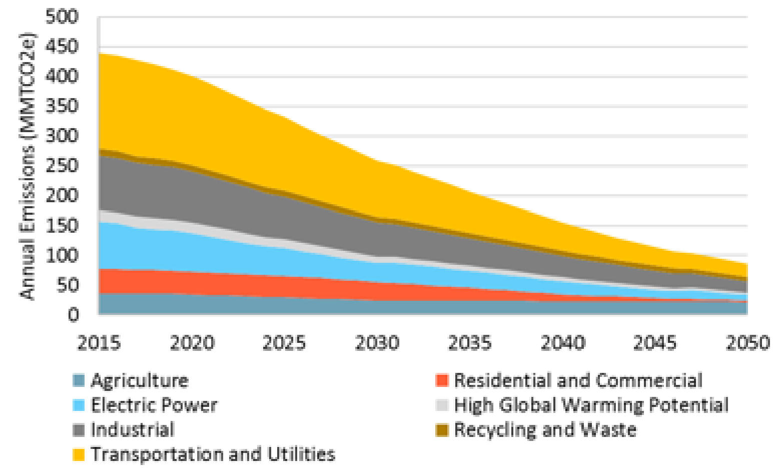
	Scenario	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load driven	Low Peak Growth (relative to base)	+196	+394	+594	+797	+1,002	+1,209	+1,418	+1,629	+1,843	+2,059	+2,277	+2,498
Load driven	**Base Peak Growth**	**-1,503**	**-1,808**	**-2,116**	**-2,427**	**-2,741**	**-3,058**	**-3,377**	**-3,699**	**-4,024**	**-4,353**	**-4,684**	**-5,018**
Load driven	High Peak Growth (relative to base)	-142	-287	-435	-585	-738	-893	-1,052	-1,213	-1,377	-1,544	-1,713	-1,886
Coal driven	**Base Schedule**	**-602**	**-1,770**	**-1,894**	**-1,894**	**-2,251**	**-2,251**	**-3,389**	**-3,389**	**-4,136**	**-4,492**	**-4,492**	**-4,492**
Coal driven	No Coal by 2030 (relative to base)	0	0	0	0	0	-884	-1,767	-2,651	-3,534	-4,418	-5,302	-6,185

California Analysis

CA Key Policy Drivers

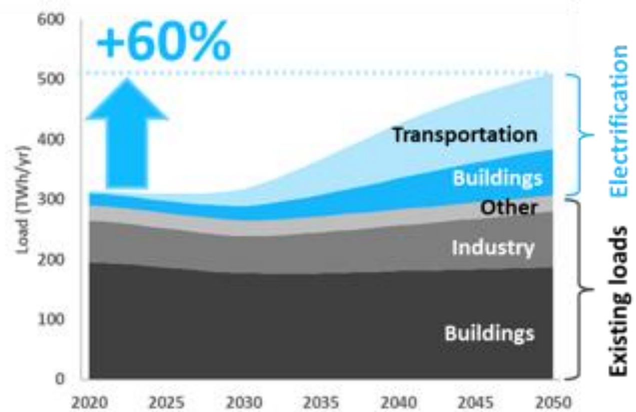
+ **Clean energy policy dominates future electric loads and generation trends**
  - SB 100 mandates 100% RPS and zero-carbon (as % of retail sales) by 2045
  - GHG targets likely to drive increasing building and transportation electric loads
+ **Retail market fragmentation continues to challenge reliability planning**
  - IOUs generally long on system and flexible RA
  - Increasing CCA and DA loads so far have not been signing long-term PPAs for stand-alone capacity resources, though renewable (i.e. solar+storage) PPAs have been signed
+ **Gas plant retirements are impacting the state's capacity needs**
  - Driven by once-through cooling policy, declining energy market revenues, and increasing competitiveness of battery storage
+ **While not officially disallowed, recent gas plant approvals have been revoked prior to construction**
  - E.g. LADWP OTC repowering, NRG's Puente and Calpine's Mission Rock plants

California GHG Emissions Reduction Targets



Source: E3 PATHWAYS analysis for 80% GHG reduction by 2050. (Note: both SB100 and GHG goals may allow small levels of emissions to remain in the electric sector by 2050.)

California Electric Loads under High Electrification

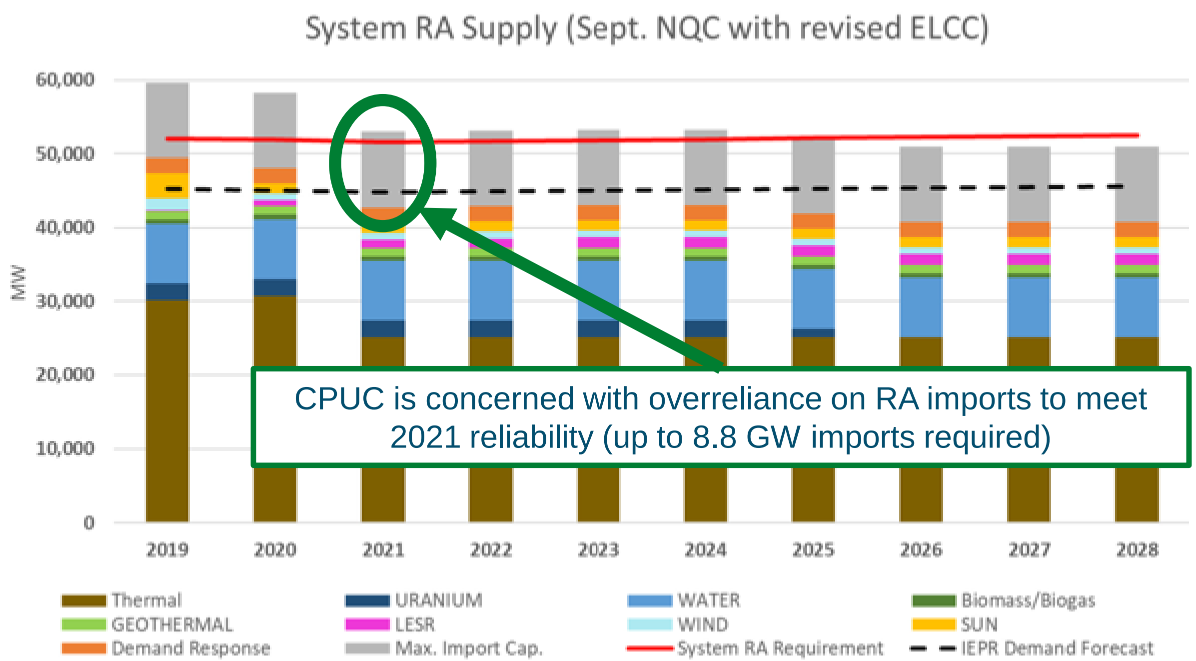


	High Electrification	
	2020	2050
Annual Energy (TWh)	315	511
Peak Load (GW)	65	93

Source: E3 PATHWAYS analysis, High Electrification Scenario.

CA Near-term Capacity Need
CPUC IRP Proceeding View

- **The CPUC's IRP proceeding has identified a tightening of the near-term CAISO capacity balance**
- **November 2019 CPUC Decision (D.19-11-016) includes a 3,300 MW capacity procurement order**
  - Also includes a delay of once-through cooling coastal plant retirements
  - New procurement via all-source solicitations; 50% online by Aug. 2021, 75% by Aug. 2022, 100% by Aug. 2023



Source: CPUC, Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues, June 20, 2019 (R.16-02-007)

CA Near-term Capacity Need

CPUC IRP Filings

- **Given California's centralized market and regulatory structure, it does not have the same distinction between top-down vs. bottom-up as the Northwest**
- **CAISO reliability needs are coordinated and planned through the CPUC's RA and IRP processes**
  - CAISO ~80% of CA load
  - All CPUC-jurisdictional LSEs and CAISO IPPs are captured through the CPUC's view of near-term capacity need
  - Municipal utilities reliability planning is coordinated with their governing boards
- **LSEs submitted IRPs through the 2018 CPUC IRP process, but IRPs did not address RA needs**

Capacity need per 2018 LSE IRP Filings

LSE	Need Year	Need Volume (MW)
PG&E	2026	n/a
SCE	n/a	n/a
SDG&E	n/a	n/a
CCAs	n/a	n/a
ESPs	n/a	n/a

IRP filings contain minimal information LSEs' capacity need

% of existing CAISO capacity included in 2018 LSE IRPs

General Type	Resource subcategory	2020	2025	2030
Thermal	CC	47%	32%	32%
	CT	62%	24%	18%
	Cogen	87%	20%	11%
	ICE	77%	77%	77%
	Steam	3%	16%	0%
Geothermal	Geothermal	70%	51%	49%
Biomass	Biomass	27%	27%	27%

Source: CPUC analysis of 2018 LSE IRP filings

CPUC analysis shows LSE IRPs do not include capacity procurement (LSEs will rely on RA market + generators will be subject to merchant status and potential retirement)

CA Near-term Capacity Need
LADWP

+ LADWP (~10% of CA-wide load)

- Last IRP (called the Strategic Long-term Resource Plan) released in 2017
  - **~5,000 MW capacity shortfall by 2030** driven by coal retirements + LA basin thermal retirements

Table 4-2. RESOURCES RECOMMENDED FOR RESOURCE ADEQUACY BY CALENDAR YEAR

Capacity (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy Efficiency	72	143	215	281	376	417	565	665	778	897	637	636	638	1084
Demand Response	68	88	125	175	225	275	325	375	425	475	500	500	500	500
New Renewable	14	94	159	201	314	205	364	511	489	546	378	386	455	796
IPP Replacement CC	0	0	0	0	0	0	0	0	553	553	553	553	553	553
Re-Powered In-Basin Thermal	0	0	0	0	0	0	0	0	310	619	619	619	929	1137
Storage	0	0	0	0	0	147	147	147	147	147	147	147	147	147
Capacity Surplus/(Shortfall)	(660)	(59)	(54)	(49)	113	260	257	113	(163)	(272)	(144)	(188)	(520)	(528)
Total Replacement	814	383	554	706	915	1044	1401	1698	2865	3510	2978	3030	3743	4746

Proposed Additions

DER + renewables

~~Fossil repower~~

Storage

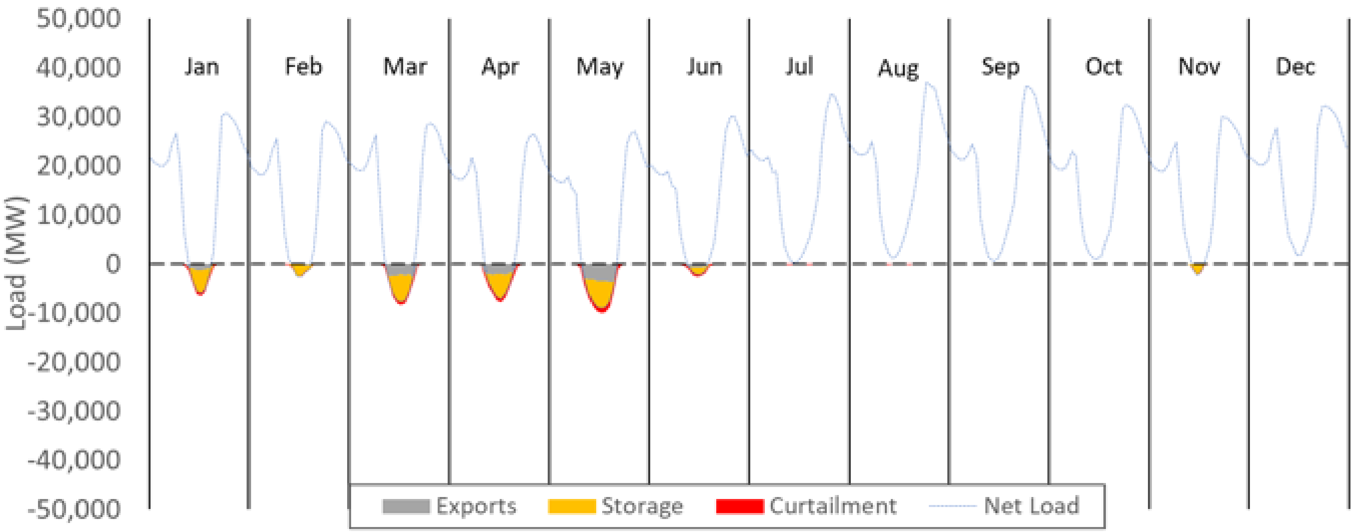
- Big changes since last IRP…
  - SB 100 + LA Mayor's even more aggressive Green New Deal (100% RPS by 2045)
  - LA Mayor's decision to NOT repower in-basin thermal (creates additional ~1,500 MW need)
  - Next IRP cycle on hold until LA completes "LA100" 100% feasibility study

CA Oversupply (2025)

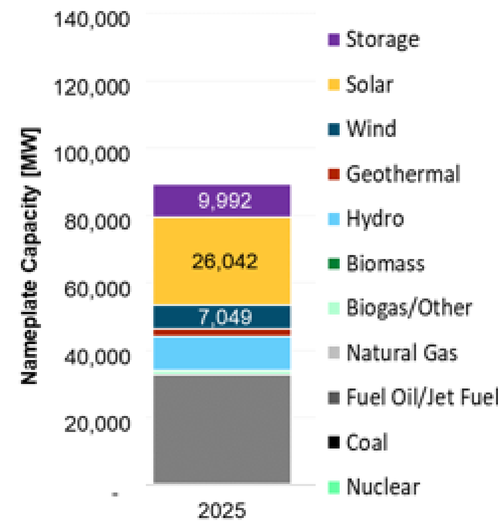
+ E3’s modeling shows midday oversupply in winter + spring months in 2025

- Excess energy will be either a) exported, b) stored, or c) curtailed

Hourly Net Load and Oversupply (monthly average)



Modeled Resource Mix



Oversupply in California in 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Avg Hours/Day	6	5	7	8	8	5	0	0	0	0	3	0	**4**
Avg Oversupply GWh/day	23	8	40	37	56	8	0	0	0	0	5	0	**15**
Total GWh/month	725	236	1,245	1,101	1,722	247	0	0	0	0	146	0	**5,421**

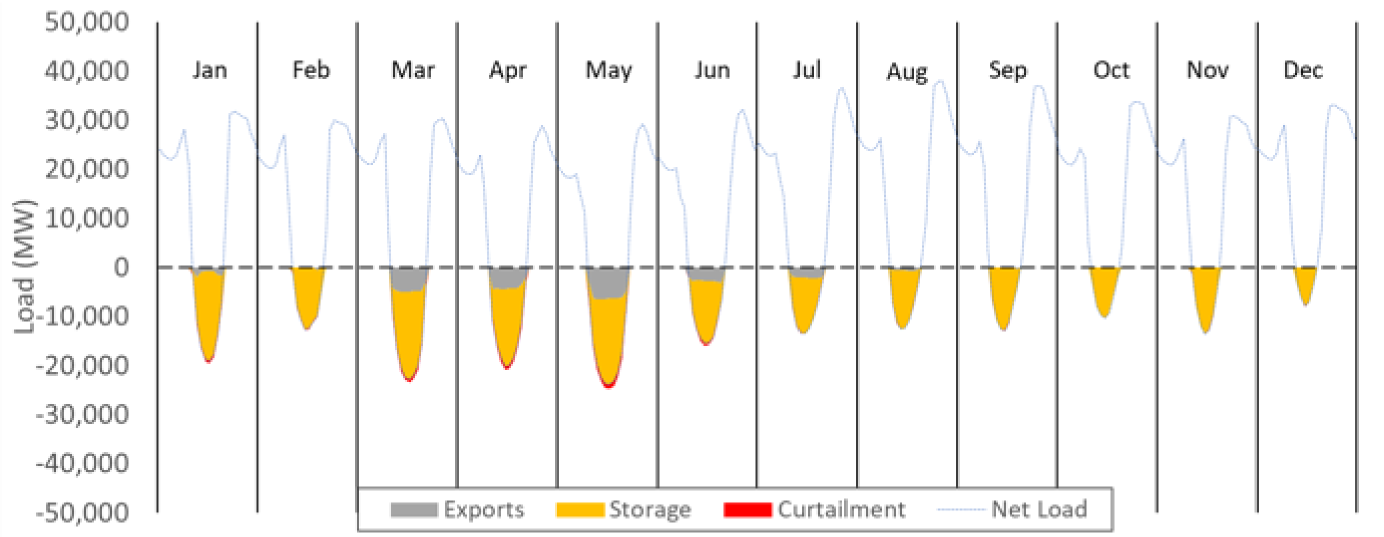
Source: E3’s Internal Price Forecasting Model

CA Oversupply (2030)

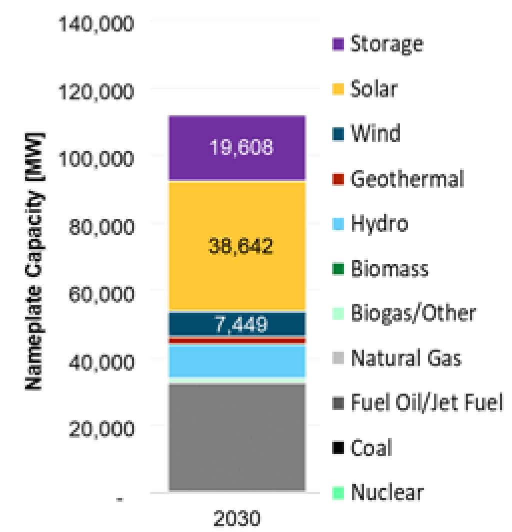
+ E3's modeling shows consistent midday oversupply conditions by 2030

- On average, CA has excess generation for multiple hours per day, every month of the year
- Energy arbitrage value drives increasing levels of storage

Hourly Net Load and Oversupply (monthly average)



Modeled Resource Mix



Oversupply in California in 2030

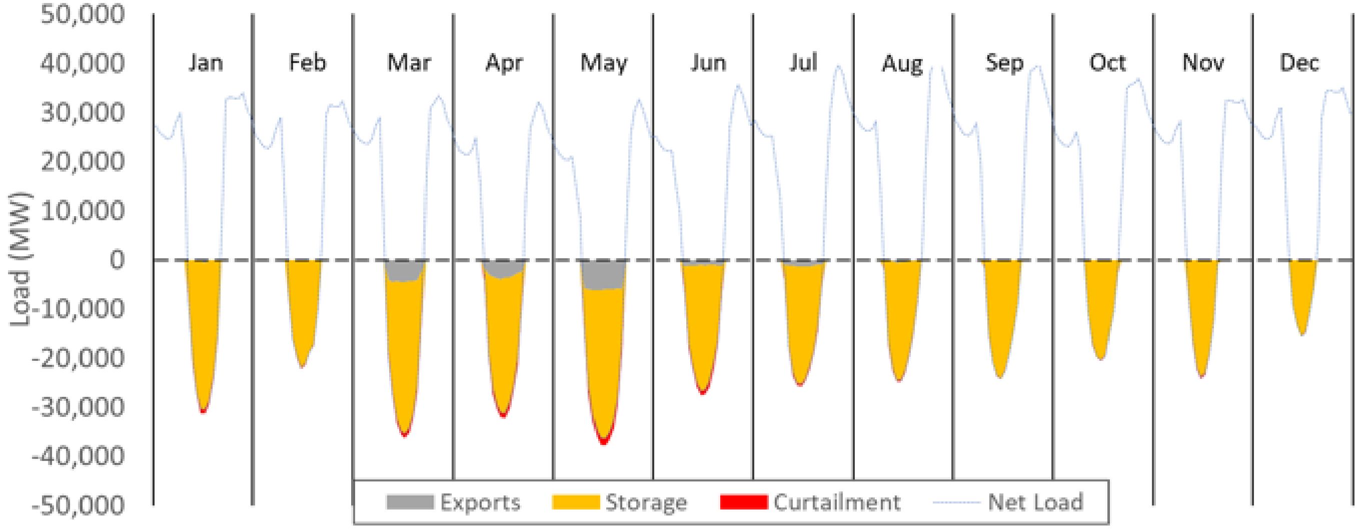
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Avg Hours/Day	8	8	9	9	10	9	8	7	7	7	7	6	**8**
Avg Oversupply GWh/day	104	70	152	133	181	100	80	66	66	49	62	28	**91**
Total GWh/month	3,237	1,962	4,715	3,977	5,612	3,014	2,485	2,042	1,968	1,513	1,854	864	**33,243**

Source: E3's Internal Price Forecasting Model

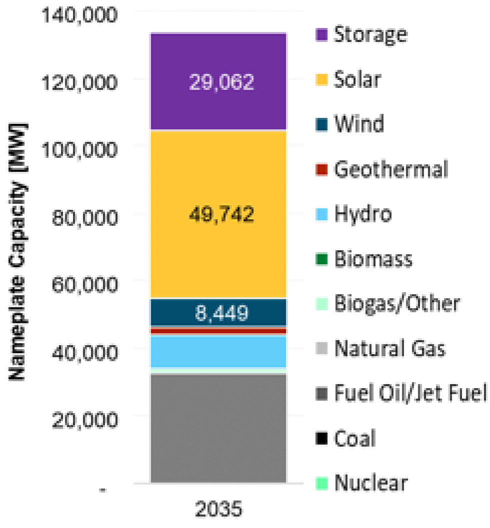
CA Oversupply (2035)

+ **E3's modeling shows consistent midday oversupply conditions by 2030**
  - On average, CA has excess generation for multiple hours per day, every month of the year
  - Storage build reaches almost 30 GW

Hourly Net Load and Oversupply (monthly average)



Modeled Resource Mix



Oversupply in California in 2035

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Avg Hours/Day	8	8	9	10	10	10	10	9	9	8	8	6	**9**
Avg Oversupply GWh/day	185	132	250	224	290	191	177	155	149	115	126	69	**172**
Total GWh/month	5,721	3,687	7,764	6,705	8,991	5,720	5,487	4,803	4,482	3,568	3,770	2,145	**62,845**

Source: E3's Internal Price Forecasting Model

Energy+Environmental Economics

Key Terms & Abbreviations

Key Terms & Abbreviations

- BPA: Bonneville Power Administration
- CAGR: Compound Annual Growth Rate
- CC: Combined Cycle Power Plant
- CCA: Community Choice Aggregator
- CP: Coincident Peak
- DER: Distributed Energy Resource
- ELCC: Effective Load Carrying Capability
- LOLE: Loss of Load Expectation
- LOLP: Loss of Load Probability
- MIC: Maximum Import Capability
- NCP: Non-Coincident Peak
- NWE: NorthWestern Energy
- NWPCC: Northwest Power and Conservation Council
- PNUCC: Pacific Northwest Utilities Conference Committee
- PRM: Planning Reserve Margin
- RECAP: E3's Renewable Energy Capacity Planning Tool (www.ethree.com/recap)
- SCC: Social Cost of Carbon

Thank You

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