Examining U.S. West Electric Reliability Challenges

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Abstract

In this paper, we examine the common set of challenges curated across integrated resource plans among a wide range of planning processes in the Western states. These challenges include: extreme climate change-induced weather events; retiring coal and gas facilities as early as possible; higher known and policy-driven electric load forecasts; new resource deployment risks; long lead times of new transmission investments; and volatility and uncertainty of market purchases of energy. These challenges and questions are not exclusive to the U.S. West, as all regions face them in some form, but the Interdependencies of the entities in the Western Interconnection merited its own examination. In future papers, a similar type of examination could be conducted for other regions, taking into account the region's specific context. Nonetheless, in understanding these challenges, it has helped frame the discussion on potential solutions, which clearly points to the need and potential of long-duration energy storage (LDES) technologies. Pumped Heat Energy Storage (PHES) stands out as one of the LDES options for its scalability, low technical risk, and ability to stabilize the grid. To realize these LDES solutions, this paper concludes with key recommendations for Western entities to: issue LDES-specific solicitations; include LDES in IRP modeling and planning; and develop procurement mechanisms seeking specific LDES attributes.

Introduction

Like the gold rush more than a hundred years ago, a new "green rush" is occurring across the Western U.S. to retire coal facilities and build new solar, wind, and energy storage.

Many Western states are moving to fully decarbonize their electric grids, adopting 100% zero-carbon electricity or net-zero requirements to be met as early as 2040 and as late as 2050.[1] As a result, many of the Western U.S. states are procuring and building renewables and storage at unprecedented levels. Going forward, utilities and load-serving entities (LSEs) are planning for record levels of these clean resources and accelerating plans to retire coal facilities in their respective Integrated Resource Plans (IRPs) to meet these renewable and greenhouse gas (GHG) emission reduction goals. This is great news for the planet as GHG emissions must be quickly and dramatically reduced in order to stem (and ideally reverse) the harmful impacts of climate change.

The electric grid Is touted as the greatest machine ever made by mankind.[2] It is also undergoing the greatest reinvention in history – through the transition from an electric grid served by mostly firm yet often inflexible fossil, nuclear, and hydro resources to one dominated by weather-dependent, intermittent renewables and energy-limited battery storage. While not without its challenges, reaching 70-80% of the electric grid served by solar, wind, and battery storage resources is largely recognized as achievable,[3] and the Western U.S. states are proceeding with procurements and new-build development accordingly. In the California Independent System Operator (CAISO), for example, an all-time record of 97% of renewables served the electric grid for an instantaneous point in time in Spring 2022.[4] Recognizing that an instantaneous point in time is not the same as serving the grid with near 100% renewables for prolonged periods and across many hours and days, let alone months, it is nonetheless a celebratory milestone, showing the way that advancing toward these decarbonization goals is within reach.

However, each of the Western states' IRPs reveal significant challenges and questions along the way. Utilities/LSEs are confronting them today and cannot defer them as a future problem. In pursuit of these decarbonization goals, some of the common electric reliability planning challenges cited in these IRPs include:

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[1] National Regulatory Research Institute's State Clean Energy Policy Tracker. Accessible here.

[2] Orf, Darren. "The Power Grid Is the Largest Machine In the World, and Our Nation's Greatest Engineering Achievement." Popular Mechanics. 8 June 2023. Accessible here.

[3] Esposito, Dan. "Studies Agree 80 Percent Clean Electricity by 2030 Would Save Lives and Create Jobs at Minimal Cost." Energy Innovation. September 2021. Accessible here.

[4] "California ISO hits all-time peak of more than 97% renewables." CAISO News Release. 14 April 2022. Accessible here.

- **Extreme climate change-induced weather events** that increase planning targets, impact the ability of a number of supply resources to perform, and pose hazard risks to electrical infrastructure;
- **Retiring coal and gas facilities as early as possible** while maintaining the incumbent resources' round-the-clock and grid stability attributes and ensuring new supply resources are built as timely replacements;
- **Higher known and policy-driven electric load forecasts** with the electrification of the transportation and building sectors, in addition to the growth of various industrial loads, including manufacturing, data centers, cannabis grow facilities, among others;
- **New resource deployment risks** (*e.g.*, supply chain constraints) with reliance on a consolidated set of technologies, namely solar PV, onshore wind, and lithium-ion battery storage;
- **Long lead times of new transmission investments** that delay the efficiencies and diversity benefits of an interconnected regional grid and connect often far-flung solar/wind resources to load centers; and
- **Volatility and uncertainty of market purchases of energy** as all utilities and LSEs in the West simultaneously face the above challenges and must plan toward their state's decarbonization goals

Given these challenges, Western utilities/LSEs face headwinds in revolutionizing the electric grid. The proverbial "building the plane as you fly it" is apt when it comes to achieving decarbonization goals while maintaining reliability across all hours and days of the year. The above challenges are compounded by the fact that these Western entities must not only plan for the immediate term (*i.e.*, next 3-5 years) but also make no-regrets decisions and/or advance procurement investments and policy reforms today to meet longer-term planning requirements and goals.

For example, even though some Western utilities have planned retirements for coal or gas facilities in the late 2020s or early 2030s, investment plans and strategies must be enacted today or in the near future to be "ready" with the emerging solutions that support the complete and reliable transition away from these fossil resources. Confronting these supposedly longer-term challenges or decisions today will avoid a persistent "whack-a-mole" and "catch-up" approach to solving for the electric grid's needs. While some Western entities are early in their journey to procuring the low-hanging fruit (solar PV, onshore wind, lithium-ion battery storage), a narrow near-term focus on procurement of these resources will only lead to untenable just-in-time procurement of the full range of clean energy technologies needed to actually reach net-zero GHG or zero-carbon electricity targets, not just get partially the way there.

To their credit, many of the IRPs reflect this fact. To retire fossil resources and still meet reliability planning requirements in the face of the above challenges, many Western entities recognize that the low-hanging fruit technologies (solar PV, onshore wind, lithium-ion battery storage) alone are insufficient, and a closer examination of various "emerging technologies" is needed, including but not limited to long-duration energy storage (LDES), floating offshore wind, hydrogen-fueled turbines, small modular nuclear, and distributed energy resource (DER) aggregations. Absent commercial deployments of these technologies by their very nature as emerging, they, however, express uncertainty on their current and long-term costs, performance capabilities, and deployment scalability, making it difficult to incorporate them into their planning models to inform procurement strategies. Despite these uncertainties, the planned retirements of many fossil assets in the West are nonetheless quickly approaching.

Amidst this uncertainty, it appears clear that Western utilities and LSEs need synchronous, low-risk, and scalable LDES options to solve the above challenges. Whether LDES is ready to address these challenges will depend on whether they can offer the following desired attributes and meet procurement requirements:

- **Matching the need and use case:** With commercially available LDES solutions that can scale durations at marginal cost, these Western entities will benefit from the ability to right-size their LDES resource to evolving needs over time, provide resiliency in the event of transmission contingencies or delays, and serve as a transmission alternative. Depending on the use case, it will be important to find LDES options that offer attractive energy-land density where land is scarce, or expensive or repowering host sites have defined footprints.
- **Like-for-like attributes:** If there are LDES solutions that provide like-for-like grid-stabilizing attributes to the incumbent fossil

resources and simultaneously support the integration of intermittent renewables, they will be able to truly achieve round-the-clock clean power across many hours, days, and seasons. Given the variability of load and renewables, load-following capabilities will become increasingly important among LDES solutions.

- **Technical viability:** By its nature as emerging, LDES technologies need to "prove out" technical viability and their spec sheets.
- **Achieving scale:** Once proven, LDES technologies will need to scale to hundreds or thousands of megawatts in the near future to meet fossil retirement timelines and achieve economies of scale and projected cost declines – a challenging chicken-or-egg problem to build up manufacturing capacity to achieve scale without the certainty for demand of any particular LDES technology.

In this paper, we examine the aforementioned common set of challenges curated across IRPs among a wide range of planning processes in the Western states. These challenges and questions are not exclusive to the U.S. West, as all regions face them in some form, but the interdependencies of the entities in the Western Interconnection merit its own examination. In future papers, a similar type of examination could be conducted for other regions, taking into account the region's specific context. Nonetheless, in understanding these challenges, it will help frame the discussion on potential solutions, which clearly points to the need and potential of LDES technologies.

While many LDES technologies address the aforementioned challenges, pumped heat energy storage (PHES) represents a great-fit LDES option for Western entities that can notably provide like-for-like attributes and meet the readiness criteria for commercial deployment. With reliance on mature, proven equipment and components and existing supply chains, PHES offers immediate scalability and lower technical risk relative to other "general" LDES technologies.

Table 1: Assessment of LDES General and PHES Against IRP Challenges and Commercial Readiness Criteria [5]

IRP Challenges	**LDES General**	**PHES**
Extreme climate change-induced weather events	●	●
Balance of retiring coal and gas facilities as early as possible	◔	◕
Higher known and policy-driven electric load forecasts	●	●
New resource deployment risks	●	●
Long lead times of new transmission investments	◑	◕
Volatility and uncertainty of market purchases for energy	◑	◑
Commercial Readiness	**LDES General**	**PHES**
Matching the need and use case	●	●
Like-for-like attributes	◑	●
Technical viability	◑	◕
Achieving scale	◑	●

To realize the emergence of LDES solutions to address these challenges, this paper concludes with recommendations on some of the overarching actions that can be taken by Western entities:

- Issue LDES-specific solicitations or specify preferences for LDES resources;
- Incorporate LDES archetypes or technologies in IRPs; and
- Develop use case-defined procurement mechanisms and replacement interconnection procedures for like-for-like capacity.

Exploring the challenges and solutions to deep or complete decarbonization

While imperfect for various reasons, IRPs are nonetheless useful and sophisticated exercises to ensure sufficient supply is available and built across a planning horizon, often 10 years but also sometimes up to 20 years into the future. Different scenarios are modeled to assess different "futures" of policies and market

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[5] In the table, ● indicates a high or very favorable score on one end and ○ indicates a lower or less favorable score on the other end. "LDES General" refers to a broad representation of many "emerging" LDES technologies available today.

conditions, along with sensitivities around the costs and resource availability and limits to capture certain uncertainties of resource options. Altogether, the IRP sheds light on how utilities and LSEs are considering policy requirements, exogenous macro conditions, and resource options, as well as providing insight into their guiding principles, preferences, and potential decision-making criteria and process for investing in new resources and infrastructure.

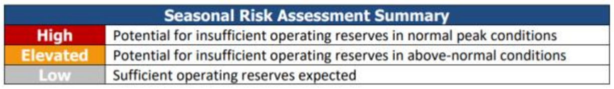
Upon review of these IRPs, the first few steps of decarbonization are portrayed as easily achievable with solar, wind, and battery storage, but it is clear that almost every Western utility and LSE is searching for solutions that are likely not yet commercially available or cost-effective to support the full or near-complete transition away from fossil resources. With limited or no options at this time, some utilities and LSEs are "buying time" and extending the life of their fossil assets with renewable fuel-capable turbines that maintain optionality in case those renewable fuel markets actually materialize as cost-effective commodities. In some cases, they are outright swapping retiring coal assets with new gas resources. At best, some of these entities are investigating emerging technologies through requests for information (RFI), at least showing their intent to find these answers.

To understand this predicament, it is helpful to better understand common challenges identified across their IRPs. In doing so, it becomes clearer that LDES resources could be that answer, particularly one that is synchronous, scalable, and has low technical risk.

Extreme climate change-induced weather events

Over the past five years, grid planners and regulators across the nation have placed their attention on the risks and threats of extreme weather, such as frequent cold snaps, heat waves, wildfires, drought, hurricanes, and snowstorms. With the frequency and severity of extreme weather events increasing due to climate change and becoming more visibly apparent, the Federal Energy Regulatory Commission (FERC) initiated two rulemakings aimed at improving the reliability of the bulk power system against the threats of extreme weather (RM22-10)[6] and aimed at gathering information on current planning practices to these ends. FERC also directed the North American Electric Reliability Corporation (NERC) develop reliability standard modifications as well.[7] Heading into Summer 2023, almost every area in the Lower 48 states faced elevated risks of supply shortages in "above-normal conditions" related to extreme heat events and wildfire risks to the transmission network (see Figure 1).

Figure 1: NERC Summer Reliability Risk Area Summary [8]



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

In the U.S. West in particular, these conditions have taken the form of extreme heat events and wildfire risks to the transmission network. For those across the West, memories are fresh from the region-wide "heat dome" that reduced the availability of sharing with neighboring states for spare capacity. Making matters worse in 2020, the abnormal humidity at the time prolonged the heat (and thus cooling loads) in normally dry desert conditions in California and the Southwest. While the industry norm is often planning toward 1-in-2, or at most, 1-in-5 load forecasts, the 2020 regional heat wave was a 1-in-30 weather event for Californians[9] and represented records for neighboring states.[10] Similarly, despite being just a 1-in-11 weather event in the Labor Day week of September 2022, California again approached the precipice of rolling outages due to

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[6] "FERC Acts to Boost Grid Reliability Against Extreme Weather Conditions under RM22-10 et al." FERC News Release. 16 June 2022. Accessible here.

[7] FERC Order No. 896. Accessible here.; *see also* FERC Order No. 897. Accessible here.

[8] NERC. 2023 State of Reliability Technical Assessment. June 2023. Accessible here.

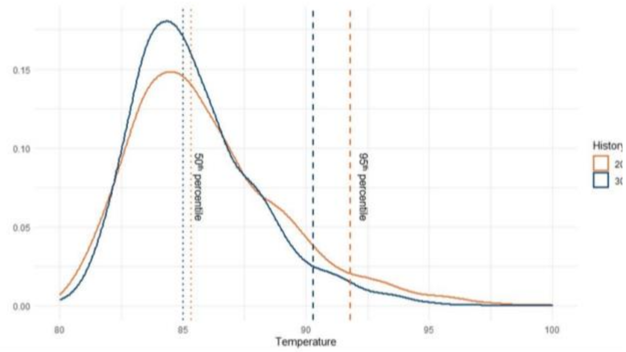
[9] *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*. CAISO, et al. 13 January 2021. Accessible here.

[10] The Southwestern Heat Storm in August 2020 led to the hottest summer on record, with over 50 days above 110 degrees. Widespread excessive heat warnings and heat advisories were issued in 12 states, including most of California, with more than 50 million people experiencing highs over 100 degrees. *See, e.g.*, "Summer 2020 ranked as one of the hottest on record for U.S." NOAA. 9 September 2020. Accessible here.

insufficient supplies and because of the sustained 10-day nature of the broiling heat wave.[11] California was spared in Summer 2023 with a mild season, but heat and temperature records were continuously broken in the Desert Southwest.[12] The Pacific Northwest similarly experienced an unprecedented maximum temperature event in June 2021,[13] and the warmest month on record in August 2022 based on average temperature.[14]

A startling illustration of the increasing nature of extreme heat events can be seen through a distribution chart that shows the probability of "long-tail" weather events is only increasing to higher extreme temperatures when focused on more recent historical data (see Figure 2). The orange line shows the distribution of peak temperatures over the past 20 years, which shows only a slightly higher increase in the frequency of "normal" (median) peak temperature days but a much higher frequency of extreme peak temperature days as compared to when looking at a 30-year historical lookback window. In other words, there is a clear trend toward more extreme conditions in recent years. One can imagine the trends to move even more rightward (*i.e.*, the 95th percentile dotted lines) when weighting more greatly the past 5-10 years or looking at rolling averages of the most recent weather years going forward.

Figure 2: CEC Distribution of 2022 Peak Temperature in CAISO [15]



In short, the extreme heat events are more frequent and prevalent than ever. For the electric grid, this translates to higher summer loads as air conditioners are run for longer periods. Even in regions where summers are typically mild and can be enjoyed without indoor air conditioning like Northern California and the Pacific Northwest, adoption of air conditioning units is increasing.[16] As cooling needs are increasing load on the one hand, the extreme heat is also stressing conventional gas generation's ability to provide capacity, with these units suffering from ambient derates and reduced efficiencies. A further stressor on the availability of supply has been the cumulative effects of reduced hydro availability for the summer as a result of dry, drought-driven winters, particularly in Northern California and the Pacific Northwest. The supply-demand balance, as a result, is stressed. Planning norms need to be updated in the face of these increasingly frequent extreme heat waves, and new resources need to be built quickly and at scale.

In addition to these extreme heat events, the general warming of the world's climate is creating drought conditions across the West that not only impact hydro availability but also lead to wildfire conditions putting transmission infrastructure at risk. The Bootleg Fire in July 2021, for instance, knocked out a key transmission corridor between California and Oregon, along with access to 5,500 MW of imported power that put California and other Desert Southwest utilities at risk of supply shortfalls.[17] Holy Cross Energy in Colorado, which has a service territory at the end of a radial transmission lines, faced similar blackout risks during the Lake Christine Fire in 2018.[18] Even where wildfire risks do not directly lead to transmission outages, the resulting smoke and ash can impact the insulating medium of transmission lines, leading to droop and

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[11] *Summer Market Performance Report: September 2022*. CAISO. 2 Nov 2022. Accessible here.

[12] "Phoenix hit 110 degrees on 54 days in 2023, setting another heat record." PBS News Hour. 10 September 2023. Accessible here.

[13] *Clean Energy Plan and Integrated Resource Plan 2023*. PGE. 30 June 2023. Accessible here; see also *Idaho Power Integrated Resource Plan*. September 2023. Accessible here.

[14] *Clean Energy Plan and Integrated Resource Plan 2023*. PGE. 30 June 2023. Accessible here.

[15] *SB 846 Diablo Canyon Extension Study*. California Energy Commission. 2 March 2023. Accessible here.

[16] Carpenter, Julia and Anthony De Leon. "Heat Waves Now Last Longer, Spurring an Air-Conditioning Boom." *The Wall Street Journal*. 13 July 2023. Accessible here.

[17] Fitzgerald Rodriguez, Joe. "Growing Oregon Wildfire Threatens California Transmission Lines, State Issues Grid Warning." KQED. 10 July 2021. Accessible here.

[18] Condon, Scott. "After Lake Christine Fire, Holy Cross Energy seeks more resilient power supply for Aspen." The Aspen Times. 20 May 2020. Accessible here.

possibly derates or trips,[19] and reduce the generation potential of solar resources.[20] Examples are numerous across the West, and all Western utilities have begun to incorporate these transmission risks into their IRPs. The Los Angeles Department of Water and Power (LADWP) represents a clear example of a utility that has incorporated transmission resiliency considerations into their planning and procurement, looking to LDES options due to the risks of wildfire-related transmission outages impacting the ability of renewable energy being imported into the major load center.[21]

The combined and multi-faceted impact of extreme heat, drought, and wildfires has created the risk of supply shortfalls. Notwithstanding efforts to build new clean resources as quickly and as much as possible, these risks have also led to a desire to hold onto the existing fossil fleet a bit longer to add further cushion against potential supply shortfalls. In California, planned retirements of Southern California once-through-cooling gas facilities were extended through 2026, despite it being planned for retirement twice in 2020 and then again in 2023,[22] at the dismay of local communities who have felt a trail of broken promises. Outside of California, many utilities are hesitant to accelerate coal retirements beyond what is required and have opted for coal-to-gas conversions until the massive amounts of procured solar, wind, and battery storage is built to address capacity needs, let alone replace existing capacity resources. As updates are made to IRP models to incorporate these various extreme weather impacts, the resolve to transition away from the current fossil fleet will be tested.

Rather than defaulting to the existing fossil fleet, many LDES technologies are commercially available today to provide significant resilient capacity, mitigating concerns that heat waves will stretch across regions and more hours of the day. If an extreme weather event calls for energy storage resources to support sustained loads during an extended heat wave, LDES can ensure capacity is available into the night or across multiple days. In the event that a wildfire occurs that knocks out a key transmission line or forces a temporary de-energization, LDES can ensure there is reserve capacity and energy to ride through these emergency periods until the transmission line is able to be restored. With these extreme weather risks growing in magnitude and frequency, LDES resources should be more deeply considered in planning and procurement processes.

Higher known and policy-driven electric load forecasts

In addition to the extreme weather-driven impacts to load, every Western entity is planning for load increases, which can be broken into two main drivers.

First, there are the known load increases from general population growth largely due to migration into their respective service territories, which are most pronounced in lower cost-of-living states such as Nevada and Arizona.[23] The more significant source of known load growth has been the new influx of manufacturing and other agricultural/industrial activities in the U.S., spurred in part by new policies (*e.g.*, legalization of cannabis), new federal industrial policy (*e.g.*, Inflation Reduction Act, CHIPS Act), and growing tech sectors (*e.g.*, AI, data centers, cryptocurrency). For example, Arizona Public Service Company (APS) refers to these as Extra High Load Factor (XHLF) customers. The major source of load growth in APS service territory during 2023-2038 was projected to be XHLF customers, whose share of total energy sales (MWh) will increase from 3% to 34% and their share of summer peak demand (MW) will increase from 2% to 21%.[24] This is consistent with the spate of news of new manufacturing facilities selecting Arizona as their destination,[25] with the headlines being semiconductors and lithium-ion batteries. As the foundation of today's Internet economy, data centers and semiconductor manufacturing are also growing in

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[19] Chen, *et al.* "Wildfire Risk Assessment of Transmission-Line Corridors Based on Naïve Bayes Network and Remote Sensing Data." Sensors (Basel). Accepted 14 January 2021. Accessible here.

[20] Cai, Mengmeng, Chin-An Lin, Vikram Ravi, Yimin Zhang, Sarah Lu, and Manajit Sengupta. 2023. *Final Technical Report: Impact of Wildfires on Solar Generation, Reserves, and Energy Prices*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-86640. Accessible here.

[21] Steinberg, Daniel, Paul Denholm, Jaquelin Cochran, Brady Cowiestoll, Jennie Jorgenson, Matt Irish, Himanshu Jain, Lily Wu, Gord Stephen, and Sarah Awara. 2021. "Chapter 6: Renewable Energy Investments and Operations." In *The Los Angeles 100% Renewable Energy Study*, edited by Jaquelin Cochran and Paul Denholm. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79444-6. Accessible here.

[22] Becker, Rachel. "Southern California's natural gas plants to stay open through 2026." Cal Matters. 15 August 2023. Accessible here.

[23] Buccholz, Katharina. "The U.S. States Losing & Gaining Population." Statista. 7 August 2023. Accessible here.

[24] APS 2023 IRP Stakeholder Meeting. 7 April 2023. Accessible here.

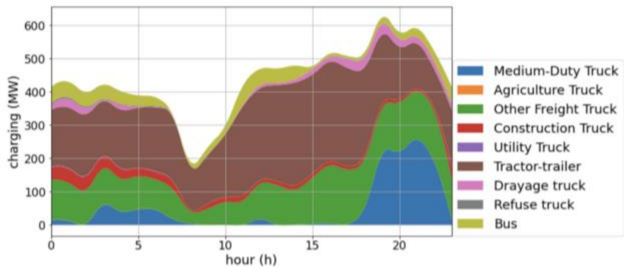
[25] "Arizona's boom in manufacturing plants." Arizona PBS. 12 December 2022. Accessible here.

prevalence in the Pacific Northwest, where lower-cost energy and abundant land has made the region an attractive site for such facilities.[26] With a growing share of XHLF or similar customers, the need for firm, baseload-like generation and storage resources are identified as needed in their respective IRPs.

Second, in addition to increases from various known industrial loads, several Western states expect to add significant electrification loads driven by policies that incentivize transportation and building electrification. These policy-driven load forecasts are most noticeable in California, where the California Air Resources Board (CARB) has adopted zero-emission regulations for not only passenger vehicles but also to medium- and heavy-duty vehicles, fleets, locomotives, off-road vehicles, and many other transportation end uses. To illustrate the level of impacts to California's distribution system alone to accommodate these electrification policies, one study found the need for up to $50 billion in traditional electricity distribution grid infrastructure investments by 2035 in "unmitigated" load scenarios.[27] One can imagine similar increases in supply capacity needs to meet this substantial forecasted demand. Similarly, policies to increase the adoption of light-duty electric vehicles and heat pumps have contributed to significant increases in load forecasts in the Pacific Northwest.[28]

Collectively, these electrification loads will require significant amounts of capacity and energy across different periods of the day. While certain electrification loads align well with mid-day energy use to take advantage of abundant solar generation (*e.g.*, workplace EV charging), much of these loads will show up overnight, even as efforts are made through program and rate design to incentivize shifting these loads away from the critical net peak hours (*i.e.*, 4-9pm). In California, overnight and high-capacity charging needs increase with electrification of medium- and heavy-duty vehicles. Just look at the load profiles of these vehicles, which typically operate during the day and recharge either regularly throughout the day or more consistently overnight.

Figure 3: CEC 2030 Statewide Load Profile of High Charging Demand Scenario [29]



Together, these known and policy-driven load increases can be best addressed through LDES solutions that support the consistent baseload energy needs of important industrial customers and the overnight charging needs of various electrification applications. Short-duration battery storage will be insufficient in this regard, unless their portfolio capacity is overbuilt at high costs. In their internal analysis, Southern California Edison Company (SCE) found results consistent with this hypothesis. Relative to the baseline requirements set by the CPUC, SCE found an incremental 600 MW of LDES by 2035 was selected by their model under more stringent GHG requirements and higher electrification forecasts.[30] Rather than replacing existing baseload fossil assets with shorter-duration batteries, these forecasted loads point to how LDES is critically needed to shift renewable energy not only for the net peak hours but also across close to 24 hours a day to support their round-the-clock power needs with fully decarbonized and reliable electricity.

<u>Replacing coal and gas facilities with clean firm resources as early as possible</u>

Coal facilities are being driven out of the U.S. West as a result of their aging nature and poor economics, combined with Environmental Protection Agency (EPA) regulations and state-level clean energy policies in place. Much of the coal facilities are planned for retirement over the next 3-4 years but some will do so as late as the first half of the 2030s.[31] However, the planned retirement of these coal assets is occurring at a

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[26] PacifiCorp 2023 IRP Public Input Meeting. 14 July 2022; see also *Clean Energy Plan and Integrated Resource Plan 2023*. PGE. 30 June 2023. Accessible here.

[27] *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*. Kevala. 9 May 2023. Accessible here.

[28] *Clean Energy Plan and Integrated Resource Plan 2023*. PGE. 30 June 2023. Accessible here; see also *PSE 2023 Electric Progress Report*. Accessible here.

[29] Crisostomo, Noel. "Medium and Heavy-Duty Vehicle Load Shapes." CEC Demand Analysis Working Group Meeting. 14 September 2021. Accessible here.

[30] *2022 Integrated Resource Plan of Southern California Edison Company (U 338-E)*. 1 November 2022. Accessible here.

[31] Roth, Sammy. "Newsletter: Here are the last coal plants clinging to life in the American West." 10 February 2022. Accessible here.

time when load is only projected to increase due to known load growth, electrification policies, and extreme weather, as discussed earlier. Despite the top-down requirements and the incentives to do so, Western entities must also keep the lights on, increasing the risk of any attempts to accelerate their retirements and to fully commit to zero-carbon generation and storage resources given their limitations as either intermittent, energy-limited, or pre-commercial technologies.[32]

Meanwhile, as more recent investments made in the 2000s, natural gas-fired facilities are likely to remain well into the 2030s – likely the last of the fossil units to retire due to their proven, flexible, and firm nature to maintain reliability until other clean firm technologies emerge and become cost competitive. In some cases, some utilities are even making new investments in gas for this very reason,[33] explaining that gas resources support diversity, reliability, and affordability objectives that must be co-optimized with decarbonization goals. By pursuing new gas turbines with hydrogen blending capability, they suggest that these new fossil investments will not be stranded assets and will advance decarbonization if the hydrogen market and technologies mature and hydrogen becomes a commercially-available commodity market, such that these gas facilities could potentially run on 100% green hydrogen fuel in the future.[34] Even in California, where almost all entities have exited their positions in coal generation, state planners have been unable to move on from three once-through-cooling gas-fired generation in Southern California (Huntington Beach, Ormond Beach, Alamitos) that were originally planned for retirement in 2020 but were extended twice, most recently until the end of 2026.[35] There are some exceptions, such as PacifiCorp, which is looking at small modular nuclear reactor (SMR) demonstration projects,[36] or California community choice aggregators (CCAs) procuring enhanced geothermal projects,[37] but beyond these few cases, most Western entities are banking on coal-to-gas conversions and new hydrogen-capable turbines as firm resource options.

In some ways, being less ambitious on minimizing coal in the portfolio mix or falling back on gas is not surprising. To date, most of the battery storage used to integrate solar and wind resources have been four or fewer hours in duration, with lithium-ion technology showing it can economically extend to eight hours of duration.[38] Yet, most probabilistic reliability modeling is consistently showing the need for firm generation capacity in light of load growth, resource retirements, limited nature of renewables and storage, and extreme weather.[39] To illustrate, take a look at the capacity need heat map in 2026 (see

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[32] SRP Integrated System Plan Advisory Group Meeting #11: ISP Analysis Key Findings. 21 April 2023. Accessible here.

[33] SRP Stakeholder Series Meeting. 16 June 2021. Accessible here; *See also* Xcel plans to convert the Pawnee Generating Station in Brush, Colorado from coal to gas, with assurances that contract terms for any hydrogen-capable resource includes the option for hydrogen.

[34] *See, e.g.*, Idaho Power plans to assess 340 MW of peaking hydrogen to replace their Bridger units in 2038 and conversion of coal to gas for the Valmy units. *Idaho Power 2023 Integrated Resource Plan*. Accessible here; *see also* PGE's 2023 CEP/IRP, explaining that almost all of PGE's existing thermal fleet is capable of combusting a blend of hydrogen or renewable natural gas.

[35] Ernst, Anne. "CEC Vote That Would Extend OTC Power Plants Gets Vocal Opposition." *California Energy Markets*. 11 August 2023. Accessible here.

[36] *PacifiCorp 2023 Integrated Resource Plan: Volume I*. 31 March 2023. Accessible here; *see also* Idaho Power, which is modeling SMR in its IRP.

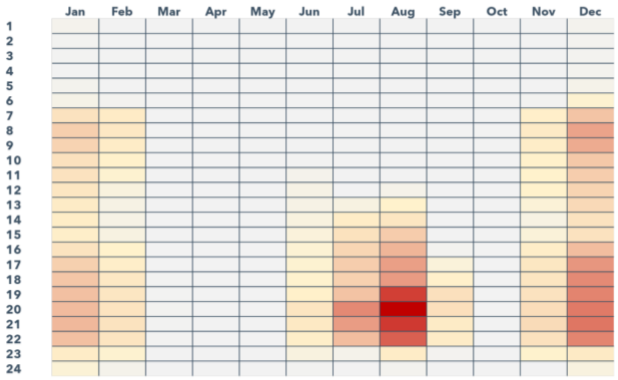
[37] "Fervo Announces 20 MW Power Purchase Agreement to Provide 24/7 Carbon-Free Geothermal Electricity to Southern California." Fervo Press Release. 10 November 2022. Accessible here.

[38] Colthorpe, Andy. "Second eight-hour lithium-ion battery system picked in California long-duration storage procurement." *Energy Storage News*. 8 March 2022. Accessible here.

[39] *See, e.g.*, E3. *Resource Adequacy in the Desert Southwest: Final Report*. February 2022. Accessible here.

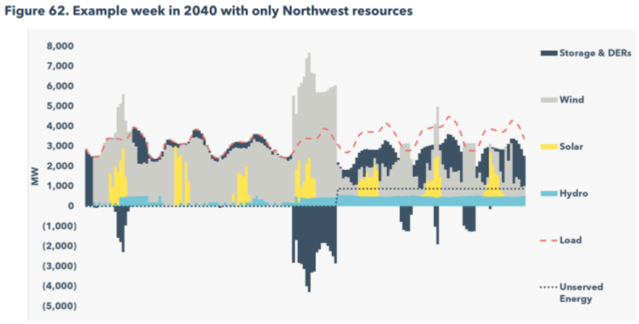
Figure 4) of Portland General Electric (PGE), which showed the most critical need for four hours of summer capacity in the net peak hours (*i.e.*, 6-10 pm in this case), but summer capacity need still stretches close to 9-10 hours. Importantly, as a dual-peaking system, the winter capacity need was estimated in the 15-16 hour range. Another utility in the Pacific Northwest, Puget Sound Energy (PSE), similarly highlighted how the majority of the lost load hours still occurred in the winter months for long-duration periods (24 hours or more).[40] Seeing these types of results would suggest that the current suite of technologies is insufficient.

Figure 4: PGE 2026 Reference Case Capacity Need Heat Map [41]



These IRPs also consistently highlighted the role of firm resources in filling the gaps during "renewable drought" events, a particular challenge for grids relying on heavy penetration levels of intermittent renewables (*i.e.*, solar and wind).[42] In the Pacific Northwest where wind is more abundant and a better fit in providing both summer and winter capacity and energy, there are multiple days of low wind generation, causing any energy stored in batteries to be exhausted and unable to recharge during this consecutive day period. This was illustrated in PGE's modeling analysis of a one-week example (see Figure 5), concluding that the lack of energy was due to a multi-day period in which both wind and solar locations in the Northwest were unproductive due to a lack of wind (reducing wind generation) and shorter winter daylight hours combined with cloud cover (reducing solar generation).

Figure 5: PGE Example Week in 2040 with Only Northwest Resources [43]



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[40] PSE 2021 Integrated Resource Plan. April 2021. Accessible here.

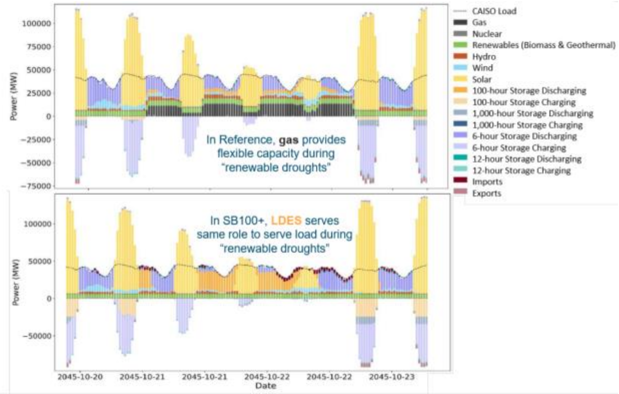
[41] *Clean Energy Plan and Integrated Resource Plan 2023*. PGE. 30 June 2023. Accessible here.

[42] "Energy droughts in wind and solar can last nearly a week." DOE/Pacific Northwest National Laboratory. 11 December 2023. Accessible here.

[43] *Clean Energy Plan and Integrated Resource Plan 2023*. PGE. 30 June 2023. Accessible here.

If unaware of scalable, low-risk, and synchronous LDES options available to address these forecasted needs, it is unsurprising that IRPs across the West are left grasping for speculative solutions. Encouragingly, several IRPs are increasingly looking at LDES solutions specifically, including in California's IRP managed by the California Public Utilities Commission (CPUC), as well as special LDES-specific modeling projects commissioned by the California Energy Commission (CEC). In the CEC's recent modeling efforts (see Figure 6), they looked specifically at how LDES of sufficient duration can allow the system to ride through "renewable droughts" and preserve system reliability.

Figure 6: CEC Modeling of Illustrative Renewable Drought Events with and without Gas and LDES [44]



The CEC's consultants showed that there is a much larger role for LDES and emerging technologies to achieve a deep decarbonization scenario, with nearly 50 GW of multi-day LDES needing to be deployed, reducing the need for solar plus storage investment by over 150 GW. In addition, the CEC's consultants found that LDES can enable cost effective in-state gas retirement – a similar finding that could be found for entities outside of California seeking to find solutions to reliability needs currently being served by coal or gas assets. Without LDES or gas capacity, the system has less backup energy that can be delivered during an unforeseen grid stress event. In other words, LDES could be the solution that many are looking for in transitioning their fossil fleet to meet decarbonization goals while meeting reliability requirements.

New resource limitations and deployment risks

All West entities are already procuring substantial amounts of solar, wind, and battery storage projects to meet state policy goals, but the pace and magnitude of building these projects will need to be sustained at unprecedented levels through 2040-2050. California, for example, has already reached 6,600 MW of battery storage in operations today,[45] but will need to annually build new solar, wind, and battery storage at that same level (around 6 GW). In total, California will need to build 48 GW of battery storage, 69 GW of utility-scale solar, and 22 GW of onshore and offshore wind by 2045.[46] Similar growth trends are expected in other Western states, most recently with Arizona publishing their latest IRPs.[47] Super charged by the tax credits made available via the Inflation Reduction Act (IRA), the procurement and deployment of these commercially-available technologies are obvious and key ingredients of taking the early steps to achieve decarbonization and reliability.

Nonetheless, over the past couple years, these technologies have faced supply chain constraints that created risks to timely deployment,[48] which is in addition to the macroeconomic factors impacting the broader economy (*e.g.*, inflation, high-interest rates). In IRP modeling, Western planners are beginning to incorporate these factors into their capacity expansion considerations (*e.g.*, maximum build rate by technology, higher cost sensitivities, deployment delay scenarios).[49]

More importantly, after some initial "tranches" of short-duration storage deployment, these IRP models are showing diminishing marginal reliability value of these technologies under deeper decarbonization scenarios. In IRP world, it is industry best practice to capture interactive effects and translate resource-specific

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[44] CEC Staff Workshop on Research to Assess Long-duration Energy Storage Deployment Scenarios. 29 March 2022. Accessible here.

[45] "California Sees Unprecedented Growth in Energy Storage, A Key Component in the State's Clean Energy Transition." CEC Immediate Release. 24 October 2023. https://www.energy.ca.gov/news/2023-10/california-sees-unprecedented-growth-energy-storage-key-component-states-clean

[46] Joint Agency Senate Bill 100 Final Report. March 2021. https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349

[47] Howland, Ethan. "Arizona Public Service, Tucson Electric expect to add 20 GW of mainly renewables, storage by 2038." Utility Dive. 2 November 2023. Accessible here.

[48] "Renewable-energy development in a net-zero world: Disrupted supply chains." McKinsey. 17 February 2023. Accessible here.

[49] *See, e.g.*, PacifiCorp IRP Public Input Meeting. 13 October 2022; *see also* CEC SB 846 Joint Reliability Planning Assessment. Accessible here.

capacity value into an equivalent "perfect capacity" (PCAP) accredited value under probabilistic modeling, commonly referred to as effective load carrying capability (ELCC) methods.[50] For energy storage resources, the ELCC value is primarily a function of modeled system load profile, available charging energy (*e.g.*, solar and wind penetration), storage duration, and penetration of other energy-limited resources (*e.g.*, 4-hour storage, demand response), which is not without complexities and limitations.[51] Yet, this ELCC modeling has generally shown that longer durations are needed from energy storage resources over time in order to more closely resemble the resource adequacy contributions of a PCAP resource.[52] While many would agree that coal or gas resources are not "perfect" resources, these results underscore how energy storage resources that can provide capacity across the entire day or across multiple days will be needed to transition away from the firm capacity currently provided by the fossil fleet. This is where LDES fits in.

Noting again that one of the key factors determining the ELCC value of any given resource is a function of their availability to meet a specific probabilistic load profile, it is helpful to take a look at how LDES fits into, generally, two categories of systems. On the one hand, there are generally summer-peaking and solar-heavy systems in California and the Desert Southwest, where some of the early results show limited differences in the capacity contributions of, say, 4- and 8-hour resources.[53] Although the ELCC results do not seem to bear it out, the Arizona utilities, for example, are seeking 10-11 hours of storage duration in their competitive solicitations, with the possibility for storage solutions with asymmetric, fast-charging capabilities.[54] With ELCC values produced for a wider range of LDES durations (*i.e.*, 10-12 hours), LDES value may be overlooked value in the Desert Southwest, at least in the IRP modeling efforts.

On the other hand, with peak capacity needs in both the summer and winter seasons, the Pacific Northwest region presents unique opportunities where LDES could squarely address grid capacity needs and synergize well with the solar and wind resources planned for development. With winter-peaking Upper Plains wind resources[55] complementing summer-peaking regional solar resources, LDES has the potential to integrate and support renewables shifting in both seasons while addressing the above-discussed renewable droughts over some multi-day periods. This stands in contrast to short-duration batteries that pare well with solar as a summer peaking resource but less so with wind. Overbuilding short-duration batteries could address both needs, but it would only serve to create excess capacity in the summer to meet winter capacity needs while not necessarily addressing the multi-day lulls in wind generation. This LDES use case is supported by ELCC modeling conducted by PGE, showing that 10-hour energy storage "holds" its capacity value in both the summer and winter seasons (see

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[50] *Redefining Resource Adequacy for Modern Power Systems: A Report of the Redefining Resource Adequacy Task Force*. Energy Systems Integration Group. 2021. Accessible here.

[51] ELCC values are influenced by modeling forward inputs and assumptions for each of these factors, which involve informed estimations and policy decisions around setting marginal versus average accreditations, the mix of portfolio mix futures, and the establishment of resource classes. ELCC outputs may also have limitations around the granularity of project-specific factors, such as specific durations, location, and innovative configurations.

[52] *See, e.g.*, "PNM 2023-2042 IRP: Siemens Market Price Outlook, Itron Load Forecast, and Pricing topics." PNM Steering Meeting #9. 15 September 2022. Accessible here.

[53] *Incremental ELCC Study for Mid-Term Reliability Procurement (January 2023 Update)*. Astrape Consulting and E3. January 2023. Accessible here.

[54] *See, e.g.*, APS 2023 All-Source RFP Appendix E. Accessible here; *see also* SRP 2023 Non-Inverter Based Energy Storage Resources RFI Appendix A. Accessible here.

[55] "Wind generation seasonal patterns vary across the United States." EIA Today in Energy. 25 February 2015. Accessible here.

Figure 7). In its Draft 2023 All-Source RFP, PGE also showed how, for the "first 100-MW tranche" of procurement of the resource type, 10-hour pumped hydro storage, as an imperfect but sufficient proxy for LDES for illustrative purposes, had ELCC values of 111% in the summer and 80% in winter, compared to 4-hour lithium-ion batteries at 69% and 44%, respectively.[56]

Figure 7: PGE Summer/Winter Storage ELCC by Storage Penetration and Duration [57]

Figure 147. Summer storage ELCC

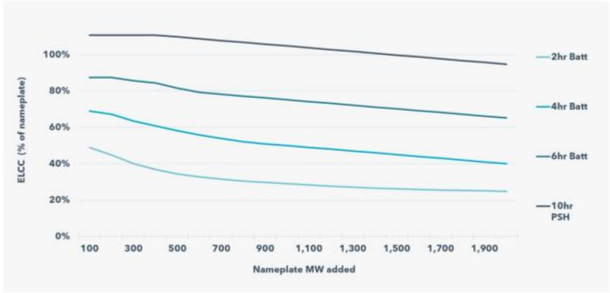
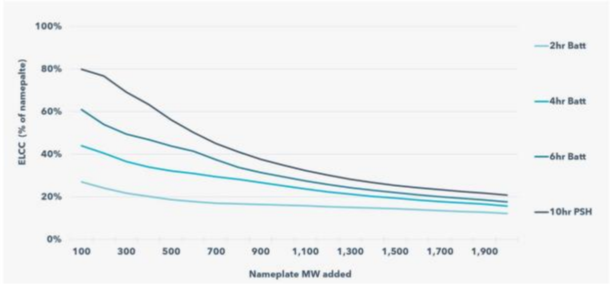


Figure 148. Winter storage ELCC



With this in mind, LDES appears to be a good-fit resource in the long-term resource procurement and capacity needs of both the Pacific Northwest and Desert Southwest for different yet consistent reasons: a flexible resource that can integrate solar and wind resources unique to their areas that also provides firm, round-the-clock reliability attributes of fossil assets. Along these lines, California was the first state to adopt LDES-specific procurement requirements for its constituent utilities and CCAs, underpinned by reliability modeling showing that 1,000 MW of LDES by 2026 is needed to replace the Diablo Canyon Nuclear Power Plant (DCPP) as a firm capacity resource, as well as due to concerns about resource diversity.[58]

Moreover, beyond capacity contribution of short-duration battery storage that declines over time, there are questions about whether the collection of inverter-based resources (IBRs), including solar PV, wind, and battery storage, are providing like-for-like reliability attributes as retiring resources. For instance, one of the key "urgent reliability" issues flagged by the Department of Energy's (DOE) Electricity Advisory

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[56] *Portland General Electric 2023 All-Source RFP – Draft*. Accessible here.

[57] *Clean Energy Plan and Integrated Resource Plan 2023*. PGE. 30 June 2023. Accessible here.

[58] *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026)*. CPUC Decision 21-06-035. 30 June 2021. Accessible here.

Committee was highlighting the "other" reliability attributes may be overlooked in current new resource procurement activities, which include but are not limited to inertia, primary frequency response (PFR), reactive power capability, ramping, regulation, energy assured resources, and black start capability.[59] With supply-side capacity shortfalls top of mind across the West due to all of the challenges discussed above, there has been little airtime or discussion of these "other" reliability attributes, particularly synchronous inertia that all systems need some minimum amount to maintain grid stability and avoid grid collapse. In retiring coal and (eventually) most if not all gas units from the existing West resource mix, these attributes will be lost and are not being replaced with the ongoing procurement of inverter-based solar PV, wind, and battery storage. Already, some early reliability issues have been identified for these IBRs, including unplanned tripping and inadequate ride-through performance.[60]

Western entities need to look closely at synchronous LDES options that can provide firm capacity across more hours, days, and seasons and offer like-for-like capacity as coal/gas resources in terms of both resource adequacy and grid stability services. Considering the deployment risks of consolidating new resource procurement into a small subset of technologies and the limitations of these resources as firm capacity, concerted efforts should be made to incorporate LDES into IRP modeling and to specifically seek out synchronous, low-risk, and scalable LDES in competitive solicitations.

Long lead times of new transmission investments

Transmission will play a major role in the clean energy future. New transmission that connects load centers with the large-scale, remote solar and wind farms will be essential in providing low-cost energy to charge the storage portfolio and support reliable capacity needs. Likewise, new transmission can relieve congestion and function as capacity-reducing investments if they connect constrained load pockets with system supply resources.

With the renewed attention on the importance of coordinated transmission planning, earnest efforts are being made to improve transmission planning to incorporate forecasts for policy-driven generation and storage identified in IRPs, as done through record approvals of such transmission projects in CAISO's most recent 2022-2023 Transmission Plan.[61] Similarly, foundations are being set for coordinated planning via an organized effort by the Western Power Pool.[62] Yet, as many in the industry are familiar, transmission development is notoriously slow and can take an estimated 12-18 years, if not more.[63]

While there is no getting around substantial transmission investment and development needed, here again is an area where LDES resources can increase transfer capability, reduce congestion, and, in some cases, serve as a transmission alternative or deferral resource. Although the frameworks to have storage operate as both a transmission and market resource have yet to be worked out, LDES at much longer durations (*e.g.*, 10-36 hours) could offer opportunities to split the energy capacity of the resource to provide day-to-day capacity and energy services and still have sufficient reserves to support transmission overloads or contingencies. At a project level, LDES could also optimize the point of interconnection, where the interconnection capacity could be economically right-sized rather than oversizing to meet instantaneous peak generation as a strategy to avoid curtailments.

Volatility and uncertainty of market purchases of energy

A final key risk and challenge area is around the volatility and uncertainty of market purchases to meet any residual energy needs on either a forward or operational basis. California utilities and CCAs are subject to resource adequacy compliance requirements to ensure sufficient capacity is bilaterally contracted to meet forecasted load, plus some planning reserve margin. Non-California utilities historically have not contracted to meet their loads, relying instead on spare

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[59] *Urgent Needs to Reliably Facilitate the Energy Transition: Recommendations for the Department of Energy*. DOE Electricity Advisory Committee. 18 October 2023. Accessible here.

[60] *2022 California Battery Energy Storage System Disturbances – California Events: March 9 and April 6, 2022 Joint NERC and WECC Staff Report*. NERC. September 2023. Accessible here.

[61] "CAISO 2022-2023 Transmission Plan approved." CAISO News Release. 18 May 2023. Accessible here.

[62] Western Transmission Expansion Coalition: Concept Paper for a West-Wide Transmission Plan. Western Power Pool. October 2023. Accessible here.

[63] Falkenburg, Nelson. "California's transmission permitting: Slowest in the West?" Clean Air Task Force. 30 May 2023. Accessible here.

energy available on the Western Interconnection. This worked when coal, gas, nuclear, and hydro resources dominated the supply mix, where these resources would inject and deliver sufficient 24x7 energy to the grid and match well with the diversity in load profiles of different service areas. Generally, market purchases represented a low-cost means to serve some portion (sometimes substantial portions) of loads across the West in lieu of more expensive long-term contracts and provided optionality to rebalance portfolios as needed in the near term.

However, this paradigm has changed with fossil fuel retirements and more energy-limited or intermittent resources across the West grid. Consequently, the availability of market purchases has been dwindling, leading to price volatility/increases for any market purchases, as well as grid reliability challenges if low availability of market capacity aligns with high loss-of-load risk hours. Further, though localized events can be weathered through external markets, region-wide events such as the 2020/2021 heat storms would stress loads and constrain supplies such that West utilities are reexamining their reliance on market purchases. Any CAISO market design changes that would curtail certain exports out of California further exacerbated these concerns. As such, many Western entities are beginning to increase their bilateral procurement for both price stability and reliability, with reductions in market purchases during risk-hour windows or eventual elimination altogether.[64]

To address the challenge of resource adequacy in the West, a large contingent of Western entities (21 participants at last count) developed the Western Resource Adequacy Program (WRAP), which will incorporate a forward showing and operational showing requirement, thereby ensuring transparency into what is truly available for regional reliability and allowing all participants to commit resources to serve their forecasted load needs. The WRAP was recently approved by FERC and will begin to take effect in 2025,[65] with much more details needing to be worked out in the interim.[66] The goal of the WRAP is to reduce overreliance on uncontracted market purchases and incentivize Western entities to bilaterally contract for some minimum quantity of resources to address their forecasted needs. The architects of the WRAP recognized that the supply mix in the U.S. West is becoming more weather-dependent, energy-limited, and/or geography-specific in their availability. Meanwhile, extreme weather events (*e.g.*, regional heat dome) create potential conditions where these supply resources may already be committed elsewhere and not broadly available to the regional market. Unlike in previous years when firm fossil resources were abundant, spare market capacity cannot be counted on during these extreme conditions.

From a general planning perspective, the WRAP represents a welcome and prudent development that will enhance the planning challenges as the Western Interconnection transitions to increasingly complementary and interdependent resources. Like other new-build supply resources, it will encourage greater procurement of LDES under long-term agreements to reduce the reliance on market purchases. With the recent history of region-wide extreme weather events, LDES offers a more compelling price and reliability hedge against West-wide scarcity events that are occurring with greater frequency and duration, not just for momentary and fleeting periods as currently served by shorter-duration storage resources.

Recommendations to realize LDES solutions

In reviewing the challenges and risks above, it becomes clear that LDES solutions are needed throughout the West to achieve decarbonization goals and targets and maintain grid reliability. The current focus on short-duration battery storage is rational in the near term, as it addresses several immediate problems. LDES solutions, however, have the ability to represent a potential solution to simultaneously address or mitigate most, if not all, of them. It stands to bear that a more cost-effective and reliable solution is to address multiple issues rather than one that solves one at a time. The optimal configuration in terms of capacity, duration, ramping capabilities, and charging speed, among others, will depend on the specific service area. The use case of LDES throughout the West appears to be one that can simultaneously provide firm capacity across many hours and days, resiliency during extreme weather

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[64] *See, e.g.*, NV Energy First Amendment to the 2021 Joint IRP. Accessible here; *see also* "PNM 2023-2042 IRP: Southwest Resource Adequacy in the Desert Southwest and Supply Resilience in Planning for PNM." PNM Steering Meeting #2. 25 May 2022. Accessible here.

[65] Order Accepting Proposed Tariff re Northwest Power Pool under ER22-2762. Accessible here.

[66] Gridlab. *Western Resource Adequacy Program: Considerations for Planners and Policymakers*. September 2022. Accessible here.

events or renewable drought, and grid stability services akin to today's conventional generation fleet.

Like other emerging technologies (*e.g.*, enhanced geothermal, SMR, CCS, green hydrogen), many LDES options are not yet commercially available or cannot be commercially scaled in a quick timeframe – a challenge for West entities that are needing to make decisions in the near term and do not have the benefit of a "wait-and-see" approach. However, LDES is an asset class encompassing many technology types, where there are some technology options today that can rise to the moment to simultaneously address all or most of the challenges/risks above and scale quickly as a low-risk LDES technology. PHES is one best-fit option that checks many of the boxes as a scalable, low-risk, and synchronous LDES technology.

As Western entities continue to grapple with the above-discussed challenges and potential solutions in their IRPs and competitive solicitations, several actions could be taken today to begin the process of bringing these solutions to fruition. Building off the current IRP efforts, Western entities can: start with solicitations targeting these resources; incorporate LDES into IRP modeling to recognize their value and use cases; and construct mechanisms and attribute-based use cases to solicit LDES resources that provide like-for-like attributes as existing fossil resources expected for retirement.

Issue LDES-specific solicitations or specify preferences for LDES resources

One of the first steps to realizing LDES solutions is to solicit these resources. While seemingly obvious, many all-source solicitations are structured around more conventional solar PV, wind, and battery storage technologies. In Malta's experience with all-source requests for proposals (RFPs), the solicitation requirements are structured around expectations, risks, and economic considerations of lithium-ion battery solutions, including requirements to provide information on degradation and fire safety, among others. Furthermore, with many LDES technology providers being young and early-stage companies, the time and resources to respond to all-source solicitations are extensive and present significant opportunity costs for companies when the prospects of success are either unknown or likely low given no intention to procure LDES resources. To the degree that utilities have existing brownfield sites available for redevelopment with LDES, it could also go a long way toward facilitating their procurement. If not yet ready for commercial procurement of LDES solutions, a preliminary step could be to issue RFIs to get a sense of the landscape of LDES options in order to inform future solicitations for these resources.

Incorporate LDES archetypes or technologies in IRPs

Before issuing an LDES-specific RFP or RFI, Western entities may need to first understand the use case of LDES resources and how they address their needs. As discussed earlier, there are interdependencies of LDES resources with renewable resources, available transmission, current and forecasted load profiles, and extreme weather-related hazards. Unless specifically modeled, it may be difficult to determine the desired attributes, such as size, duration, charging speed, ramping capabilities, and synchronous inertia. Fortunately, California regulators and planners are advanced in their incorporation of LDES technologies in their modeling, though there are many areas of improvement. In addition, other non-California utilities are beginning this journey into IRP modeling of "emerging grid solutions," including LDES technologies. Public Service Company of New Mexico (PNM), for example, issued an RFI and incorporated LDES resource types in their IRP modeling based on those responses, opting to model various LDES archetypes.[67]

Given the lack of publicly-available information on LDES technologies, Western entities should start with modeling LDES archetypes that vary in minimum duration, megawatt scalability, roundtrip efficiency, and other attributes (*e.g.*, fast charging, synchronous inertia). Alternatively, Western entities should partner with representative organizations, such as the Long-Duration Energy Storage Council, which has provided benchmark reports of a wide cross-section of LDES technologies for use in IRP modeling.[68] Either of these

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[67] PNM indicated its plans to model pumped hydro storage LDES with 85% roundtrip efficiency and 70-hour duration, as well as additions of iron-air batteries with 40% roundtrip efficiency and 100-hour duration. *See* "PNM 2023-2042 IRP: Modeling Framework and Core Scenarios, RFI Selections, Existing System, and Economic Development." PNM Public Advisory Group Meeting #14. 15 February 2023. Accessible here.

[68] The DOE, for example, consulted the LDES Council for its flagship analysis into commercializing LDES technologies to meet their Long Duration Storage Shot goals. *See, e.g.*, *Pathways to Commercial Liftoff: Long Duration Energy Storage*. DOE. March 2023. Accessible here.

actions will greatly enhance the use case definition and refine the procurement parameters for any LDES-related solicitation, in addition to building the groundswell of support from regulators and stakeholders to approve any resulting LDES contracts.

Develop use case-defined procurement mechanisms and replacement interconnection procedures for like-for-like capacity

To have greater assurances of reliability when retiring fossil resources, Western entities could more specifically analyze specific fossil facilities, with the goal of defining the attributes provided by the extant resource with an LDES resource. As detailed in the DOE EAC's report,[69] there are many reliability attributes that may not be sufficiently analyzed under the assumption that a megawatt is a megawatt. However, based on the operations of the fossil unit and the various services provided (*e.g.*, synchronous inertia, black start, grid stability), it may highlight how any resulting LDES procurement should include these other attributes or favor them in bid/proposal evaluations. Along these lines, it will be critical to assess how any LDES replacement resource will integrate with the rest of the portfolio given the synergies with renewable generation. In conducting this unit-specific analysis, it may better fine-tune the solicitation parameters to ensure critical reliability attributes are not lost and to tailor the configuration of LDES as the best-fit resources.

For synchronous and scalable LDES that provides like-for-like attributes to retiring coal resources, there may also be opportunities to leverage existing interconnection service rights, where facilities and upgrades have already been built and costs have already been paid for. For entities like PacifiCorp[70] and APS,[71] such processes are in place and have been approved by FERC, presenting a quick path to commercial operations for resources that could maximize the use of the existing interconnection as a similar asset to the one being replaced, except without the emissions.

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[69] "Urgent Needs to Reliably Facilitate the Energy Transition: Recommendations for the Department of Energy." DOE Electricity Advisory Committee. 18 October 2023. Accessible here.

[70] Order Accepting Tariff Revisions and Service Agreement, Subject to Condition re PacifiCorp under ER23-407 et al. Accessible here.

[71] Order Accepting Tariff Revisions re Arizona Public Service Company under ER23-1272. Accessible here.