Evaluating Hydrogen for Long Duration Energy Storage

Costs, Risks, and Equity Considerations

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About this Report

This report, prepared by Clean Energy Group (CEG) with support from Maria Roumpani of Current Energy Group, examines the cost competitiveness of hydrogen, particularly hydrogen power plants, compared to other long-duration storage technologies. In addition to an analysis of hydrogen's cost competitiveness, the report delves into the unique equity and environmental harms hydrogen production and use can generate compared to other long-duration storage technologies.

This report is produced through CEG's Hydrogen Information and Public Education (HIPE) initiative, which aims to equip local advocates, regulators, and policymakers with evidence-based information to understand and critically evaluate hydrogen project proposals in their communities. To learn more about HIPE and access additional informational resources on hydrogen production and use, visit www.cleanegroup.org/initiatives/hydrogen.

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EXECUTIVE SUMMARY

Utilities are facing unprecedented challenges in maintaining reliability as the electric grid incorporates more solar and wind generation and energy demand continues to grow. While new renewable energy generation can be built to meet demand, energy storage resources, particularly long duration energy storage (LDES), will be necessary to maintain a balanced and reliable grid. Many industry groups and utilities are using the increasing need for electricity to justify the buildout of new fossil-fuel power plants, under the assumption that the plants will eventually be converted to combust hydrogen. Additionally, some states are beginning to explore hydrogen as a long duration energy storage resource to store and release energy over extended periods of time.

This analysis examines the cost competitiveness of hydrogen, particularly hydrogen power plants, compared to other long-duration storage technologies. The analysis finds that due to the operational characteristics of hydrogen power plants, as well as the inefficiencies of hydrogen production and use, hydrogen power plants are not cost-competitive with other long-term duration storage resources, although they do have some advantages for seasonal storage. It is unlikely, however, that most regions will need seasonal storage resources in the next decade, making the current buildout of hydrogen-capable power plants premature, risking continued reliance on fossil fuels, and burdening ratepayers with unnecessary expenses.

There are additional infrastructure, environmental, and safety considerations that make hydrogen a less competitive option for LDES. These concerns include the lack of widely available, inexpensive, green hydrogen; the energy intensity of electrolysis for green hydrogen production; the indirect global warming potential of hydrogen; the lack of available geologic storage for hydrogen; and the expense of hydrogen infrastructure buildout. There are also equity considerations, including hydrogen's high nitrogen oxide emissions when combusted; risks to ratepayers due to the uncertainty and potential high costs of hydrogen buildout; and increased water consumption considerations.

Based on these considerations as well as cost projections and uncertainties, this analysis finds that hydrogen is not a suitable technology to meet near-term energy reliability needs and may not prove to be cost-competitive with other storage technologies for multi-day or even seasonal storage. Utilities, states, and policymakers should consider lower cost and lower risk storage alternatives, particularly as seasonal storage is unlikely to be needed in the next decade.

INTRODUCTION

The electric grid is experiencing major changes in both the composition of energy generation assets and increasing demand. With more renewable energy resources coming online, widespread electrification, and the growth of energy-intensive sectors like data centers and manufacturing, utilities are facing an unprecedented challenge. The Energy Information Administration (EIA) reports that after two decades of relatively flat consumption, energy demand in the United States grew by 2 percent in 2024, a trend it expects will continue in 2025 and 2026, with power demand expected to reach 4,163 billion kilowatt-hours (kWh) this year.[1] While new renewable generation is being built to meet this demand—the electric power sector is expected to add 48 gigawatts (GW) of utility-scale solar capacity in the next two years—energy storage resources, both hourly and long duration energy storage (LDES), will be necessary to maintain a balanced grid.[2] Shorter duration storage technologies, such as four-hour lithium-ion batteries, are already in widespread use and have proven their effectiveness and reliability when it comes to short-term, peak-demand, energy needs that would have previously been met by fossil-fuel peaker power plants.[3]

Energy demand in the United States grew by 2 percent in 2024, a trend it expects will continue in 2025 and 2026, with power demand expected to reach 4,163 billion kilowatt-hours (kWh) this year.

However, as more short-duration energy storage comes online and the remaining demand peaks grow flatter and longer in duration, longer durations of storage will be needed to ensure continued grid reliability. As a reflection of this, several states have set LDES procurement targets as part of their long-term energy system planning. California, one of the earliest states to adopt energy storage procurement targets, set an additional procurement target in 2024 for 2 GW of LDES, including 1 GW of medium duration storage (MDES), defined as 12+ hours, and 1 GW of multi-day storage.[4] Also in 2024, New York established a new roadmap to meet the state's energy storage procurement target of 6 GW by 2030, forecasting a need for 4 GW

1. U.S. EIA. "Short Term Energy Outlook - January 2025." U.S. Energy Information Administration, January 14, 2025. https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf.
2. Id.
3. Strategen Consulting on behalf of the PEAK Coalition. *The Fossil Fuel End Game: A Frontline Vision to Retire New York City's Peaker Plants by 2030.* The PEAK Coalition, March 2021. https://www.cleanegroup.org/wp-content/uploads/Fossil-Fuel-End-Game.pdf.
4. Tym, Olivia. "Table of State Energy Storage Targets and Progress." *Clean Energy States Alliance* (webpage), November 2024. https://www.cesa.org/projects/energy-storage-policy-for-states/table-of-state-targets.

of longer-duration storage (defined as 8+ hours) to be deployed by 2035.[5] Massachusetts' energy storage target of 5 GW by 2030 includes a goal of 3.5 GW of MDES (defined as 4 to 10 hours), and 750 megawatts (MW) of LDES (defined as 10 to 24 hours).

While there is a growing focus on MDES and LDES technologies to meet reliability needs, industry groups such as the North American Electric Reliability Corporation (NERC) have stated that new gas generation is the only way to meet the demands of facilities like data centers, which require high amounts of energy around the clock.[6] Many utilities in tech-heavy areas are using these concerns to justify the buildout new gas generation, despite critiques from advocates that argue that these energy demand projections may be overblown.[7] Dominion Energy in Virginia, for example, has proposed the build out of 5.9 GW of new fossil-fuel generation in a recent Integrated Resource Plan (IRP). In the IRP, Dominion states "As demand increases, gas-fired resources bridge the gap, allowing time for new generation technologies, such as...LDES, to continue being researched, developed, piloted, and ultimately deployed."[8]

Within this context, hydrogen use for LDES has been proposed to support arguments for building new gas generation, under the assumption that these gas plants will eventually be converted to combust hydrogen fuel, rather than eventually becoming stranded assets. Several natural gas plants have announced plans to convert their facilities to produce and/or cofire hydrogen, including Duke Energy's DeBary peaker power plant in Florida and the Los Angeles Department of Water and Power's Scattergood peaker power plant.[9,10]

Because hydrogen does not produce carbon dioxide (CO_2) when combusted, can be produced using renewable energy, and can then be stored seemingly indefinitely, there is understandable interest in hydrogen for LDES. However, it is important to investigate the underlying assumptions supporting this interest and objectively compare hydrogen's potential as an LDES technology in terms of cost,

Unlike other LDES technologies such as iron-air batteries or compressed-air energy storage, hydrogen can be used to justify the continued use of polluting fossil-fuel power plants.

5. Tym, Olivia. "Playing The Long Game: Why States Are Turning Their Attention to Long-Duration Energy Storage." *Clean Energy States Alliance* (blog), October 24, 2024. https://www.cesa.org/playing-the-long-game-states-long-duration-es.
6. North American Electric Reliability Corp. *NERC Long Term Reliability Assessment 2024*. December 17, 2024.https://www.nerc.com/pa/RAPA/ra/Reliability percent20Assessments percent20DL/NERC_Long percent20Term percent20Reliability percent20Assessment_2024.pdf.
7. St. John, Jeff. "More Demand, More Gas: Inside the Southeast's Dirty Power Push." Canary Media. April 11, 2024. https://www.canarymedia.com/articles/utilities/more-demand-more-gas-inside-the-southeasts-dirty-power-push.
8. Dominion Energy Virginia. *Virginia Electric and Power Company's Report of Its 2024 Integrated Resource Plan*. October 15, 2024. https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/irp/2024-irp-w_o-appendices.pdf?rev=c03a36c512024003ae9606a6b6a239f3.
9. Duke Energy. "Duke Energy Announces Plans to Build and Operate the Nation's First System Capable of Producing, Storing and Combusting 100 percent Green Hydrogen in a Combustion Turbine in Florida," October 27, 2023. https://news.duke-energy.com/releases/duke-energy-announces-plans-to-build-and-operate-the-nations-first-system-capable-of-producing-storing-and-combusting-100-green-hydrogen-in-a-combustion-turbine-in-florida.
10. Los Angeles Department of Water and Power. "Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project," October 31, 2024. https://www.ladwp.com/community/construction-projects/west-la/scattergood-generating-station-units-1-and-2-green-hydrogen-ready-modernization-project.

duration, and associated environmental, public health, and ratepayer impacts. This is particularly important because, unlike other LDES technologies such as iron-air batteries or compressed-air energy storage, hydrogen can be used to justify the continued use of polluting fossil-fuel power plants under the assumption that they will eventually be converted to combust 100 percent hydrogen. Given this high potential for extended harm, this report seeks to evaluate hydrogen in terms of its market readiness, capacity, and levelized cost of storage (LCOS) compared to other LDES technologies, while also providing an equity framework in which to assess the systemic implications of hydrogen infrastructure buildout.

Methodology

Given the significant amount of uncertainty that surrounds LDES costs, this report reviewed several recent publications, including the Advanced Technology Baseline (ATB) from the National Renewable Energy Laboratory (NREL),[11] the Energy Storage Cost and Performance Database from the Pacific Northwest National Laboratory (PNNL),[12] utility filings,[13] and other publications, including Form Energy's analysis of different LDES resources, "Modeling Multi-Day Energy Storage in New York."[14]

It is important to note that the levelized cost of storage (LCOS) calculation is sensitive to capacity factor assumptions. In other words, LCOS can vary significantly depending on whether the asset is highly utilized (resulting in a high capacity factor) or not. However, the capacity factor is not a characteristic of the technology, but rather a function of the storage asset's economics and how those compare to the overall system in which the assets operate. Consequently, the capacity factor cannot be confidently projected and, for this reason, the analysis presents results assuming two different levels of capacity factor for each LDES technology examined:

- A capacity factor of 10 percent, mimicking an LDES asset operating as a peaker power plant
- The maximum capacity factor that the storage asset can achieve if it were to operate all the time, taking into consideration its charging time and the maximum number of cycles allowed

The cost of electricity for charging all storage assets is assumed to be $30/MWh (escalating at the inflation rate each year). This value reflects the lowest estimate for

11. Stehly et al. "Advanced Technology Baseline." National Renewable Energy Laboratory, 2024. https://atb.nrel.gov/electricity/2024/data.
12. Sprenkle, Vincent, and Paul Spitsen. "Energy Storage Cost and Performance Database." Pacific Northwest National Laboratory. Pacific Northwest National Laboratory, 2024. https://www.pnnl.gov/projects/esgc-cost-performance.
13. For example, PacifiCorp's supply resource cost assumptions as presented in the August 2024 public input meeting for the 2025 Integrated Resource Plan. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/PacifiCorp_2025_IRP_PIM_August_14-15_2024.pdf.
14. Levi, Patricia, Rachel Wilson, Jason Houck, Scott Burger, and Aditya Choukulkar. "Modeling Multi-Day Energy Storage in New York." Form Energy, August 2023. https://formenergy.com/wp-content/uploads/2023/09/Form-Modeling-Multi-Day-Energy-Storage-in-NY-whitepaper-8.8.23.pdf.

the levelized cost of wind according to the 2024 Advanced Technology Baseline (inflated to 2030 dollars). Under the assumption of higher electricity costs, all technology LCOS estimates would increase but not in a uniform way. Technologies with lower roundtrip efficiency (less energy out for the same input of energy), such as hydrogen storage technologies, would experience a significantly higher increase as they require larger amounts of electricity to be able to dispatch at the same levels as LDES technologies with higher roundtrip efficiencies. For example, a $20/megawatt-hour (MWh) increase in the assumed cost of electricity would result in an LCOS increase of approximately $50/MWh for a compressed-air energy storage (CAES) system, but twice that ($100/MWh) for a hydrogen combustion turbine because of hydrogen's significantly lower roundtrip efficiency.

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The cost of hydrogen is assumed to be $4.3/kilogram (kg) prior to applying the 45V Clean Production Tax Credit (45V) of the Inflation Reduction Act (IRA), which reduces the prices of qualifying hydrogen by up to $3/kg for the first ten years.[15] All hydrogen in this analysis is presumed to be hydrogen produced via electrolysis using renewable energy, also known as green hydrogen. In a decarbonized grid, green hydrogen, as opposed to hydrogen made using fossil fuels, either alone (known as grey hydrogen) or paired with carbon capture and storage (known as blue hydrogen), would provide the most value as seasonal storage, as the hydrogen could be produced using excess renewable capacity and then stored for utilization during months with lower renewable generation. Additional information on the assumptions can be found in the Technical Appendix (p. 32).

15. The price of hydrogen in this analysis follows closely the assumptions outlined in the Electrolysis Techno-Economic Analysis (v2.2.0) of the Electric Power Research Institute, assuming an average value between the tool's "Lower Range Capex and Fixed Opex" and "Lower Range Capex and Fixed Opex" cases for 2030. The calculator is available at: https://lcri-tools.epri.com/tea-electrolysis/calculator. Furthermore, it is assumed that electricity is supplied at $30/MWh, consistent with the inputs for all other LDES technologies' LCOS assessment. Additional information can be found in the Technical Appendix.

DEFINING LONG DURATION ENERGY STORAGE

A common way to classify different storage types is by the duration of dispatch, i.e., the length of time that a storage system can deliver power at its maximum discharge rate, typically expressed in hours. A NREL literature review on LDES found a wide range of durations being used to define long-duration storage as opposed to medium- or short-duration storage, with some studies using thresholds as short as four hours to as long as seasonal duration.[16] The US Department of Energy classifies energy storage into four groups based on their dispatch duration:

- **Short Duration:** Shifting power by less than 10 hours, primarily in the range of zero to four hours. Lithium-ion batteries are the most common form of short duration storage, although other technologies, such as pumped storage hydropower, can also be used in this range.

- **Inter-day Duration:** Shifting power by 10–36 hours, also known as medium-duration storage (MDES). This group includes almost all mechanical storage technologies and some electrochemical technologies such as flow batteries. These technologies primarily serve a diurnal market need by shifting excess power produced at one point in a day to another point within the same or next day.

- **Multi-day or multi-week LDES:** Shifting power by 36–160+ hours. This group includes many thermal and electrochemical technologies. It fills a market and end-use customer need where there may be an extended shortfall of power, such as multiple days of low wind and solar output or during multi-day blackouts that could occur several times per year. Multi-day or week-long LDES can also be used to address curtailment needs during periods of overproduction for renewables.

- **Seasonal Duration:** Shifting energy for an extended period, mostly over several months, such as summer to winter. Seasonal duration technologies are generally fuel-based, such as hydrogen or natural gas paired with carbon capture.

The distinction between medium duration (10+ hour) and long duration (multi-day to seasonal) is important to consider when weighing different LDES and MDES technologies. This report will focus on energy storage technologies with inter-day, multi-day,

16. Denholm, Paul, Wesley Cole, A. Will Frazier, Kara Podkaminer, and Nate Blair. 2021. The Challenge of Defining Long Duration Energy Storage. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-80583. https://www.nrel.gov/docs/fy22osti/80583.pdf.

multi-week, and seasonal dispatch durations, which include both MDES and LDES technologies, as this threshold seems to align with the greatest number of studies.[17,18] As seen in California, New York, and Massachusetts, MDES technologies that can provide incremental increases in duration over standard short-duration storage will be needed in the next five to 10 years.[19] Longer duration technologies, particularly seasonal storage, will likely not be needed until there is a more fully decarbonized electric grid.

MDES technologies that can provide incremental increases in duration over standard short-duration storage will be needed in the next five to 10 years. Longer duration technologies will likely not be needed until there is a more fully decarbonized electric grid.

Hydrogen as an LDES resource is often discussed in the context of seasonal storage, as green hydrogen could theoretically be produced during the summer months using excess solar capacity, for example, and then deployed either in fuel cells or power plants during the winter months when solar production is lower. However, this use case is unlikely to be needed in the next decade and, as will be discussed later in this report, other LDES technologies may be able to meet this need at a lower cost. Despite this, hydrogen-capable gas plants are being built now, with the risk of becoming costly stranded assets that unnecessarily extend a utility's reliance on fossil-fuel infrastructure.

Types of LDES Technologies

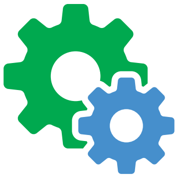
From a technological perspective, LDES solutions can be sorted into four main types: mechanical, thermal, electrochemical, and chemical.

Chemical energy storage involves creating low-carbon fuel. The primary solution in this category is hydrogen which can be produced through electrolysis or by reforming fossil fuels. Other chemical solutions include ammonia and methane. These fuels are created using electricity, can be stored for large periods of time, and then used to drive a power turbine or fuel cell. Chemical LDES systems generally experience low roundtrip efficiencies. Proposed applications are large scale and while their duration is not constrained if there are no fuel supply limitations, such a limitation could be imposed by the amount of fuel that can be feasibly and economically stored onsite.

17. "Achieving the Promise of Low-Cost Long Duration Energy Storage." U.S. Department of Energy Office of Electricity (OE), June 2024. https://www.energy.gov/sites/default/files/2024-08/Achieving percent20the percent20Promise percent20of percent20Low-Cost percent20Long percent20Duration percent20Energy percent20Storage_FINAL_08052024.pdf.

18. Scott, Katheryn, Stephen Hendrickson, Nicole Ryan, Andrew Dawson, Kenneth Kort, Jill Capotosto, Benjamin Shrager, et al. "Pathways to Commercial Liftoff: Long Duration Energy Storage." Pathways to Commercial Liftoff. U.S. Department of Energy, March 2023. https://liftoff.energy.gov/long-duration-energy-storage.

19. Tym. "Table of State Energy Storage Targets and Progress."



Mechanical energy storage systems harness kinetic or potential energy to store and release energy. They release electricity to drive mechanical components and processes to generate high-exergy material or flows. Mechanical energy storage systems can store energy for long periods of time with minimal energy loss and then be used to generate electricity. The most widespread and mature mechanical storage technology is pumped hydropower electricity storage (PHES). Other technologies in this category include the following:

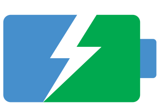
- compressed air energy storage (CAES)
- liquid air energy storage (LAES)
- flywheel energy storage (FES)
- pumped thermal (or heat) energy storage (PTES)
- gravity energy storage (GES)

Additionally, there are other emerging technologies. Most mechanical energy storage solutions offer very high energy capacity and power densities, making them appropriate for large-scale and long-term electricity storage.

Thermal energy storage systems store and release energy in the form of thermal energy. There are three types of thermal LDES:

- Sensible heat (increasing the temperature of a solid or liquid medium)
- Latent heat (changing the phase of a material)
- Thermochemical heat (endothermic and exothermic reactions)

Thermal storage technologies may also be able to provide co-benefits if waste heat is leveraged in sector-coupling applications, such as industrial processes. Many thermal LDES solutions are modular, have a small footprint, and experience no degradation. Thermal LDES systems have low marginal costs of energy but are also characterized by lower roundtrip efficiency values compared to electrochemical and mechanical solutions.



Electrochemical energy storage systems use reversible chemical reactions to store energy. Batteries fall within this category, including aqueous-electrolyte flow batteries, metal-anode batteries, and hybrid flow batteries. Electrochemical energy solutions are characterized by modular and scalable designs and generally have a small installation footprint without significant siting limitations. They have a wide range of durations, spanning from sub-hourly intervals to multi-day use cases. Electrochemical storage solutions usually have quick response times; they offer a lot of operational flexibility but are subject to cycling limitations. LDES electrochemical solutions use low-cost raw materials, such as zinc and iron, so the resulting storage systems can have low marginal costs of energy and consequently long duration.

LEVELIZED COST OF STORAGE

Much like conventional generation, energy storage can provide several fundamental services to the electric grid ranging from customer benefits, such as electric bill savings and backup power, to transmission and distribution system services. Response times, siting and sizing constraints, and cost-effectiveness considerations might make some solutions better suited for certain systems or use cases. For example, mechanical LDES technologies, such as pumped hydro, typically have a large geographic footprint, so they are less likely to be sited at a grid location for distribution investment deferral, or for any behind-the-meter applications. However, a 10-hour battery could deliver this service or be used by a large energy customer to manage their electricity expenses or serve as backup power. While it is difficult to fully compare all LDES technologies without these additional contextual considerations, this report examines how these technologies compare in their ability to provide two fundamental grid services: resource adequacy and energy arbitrage.

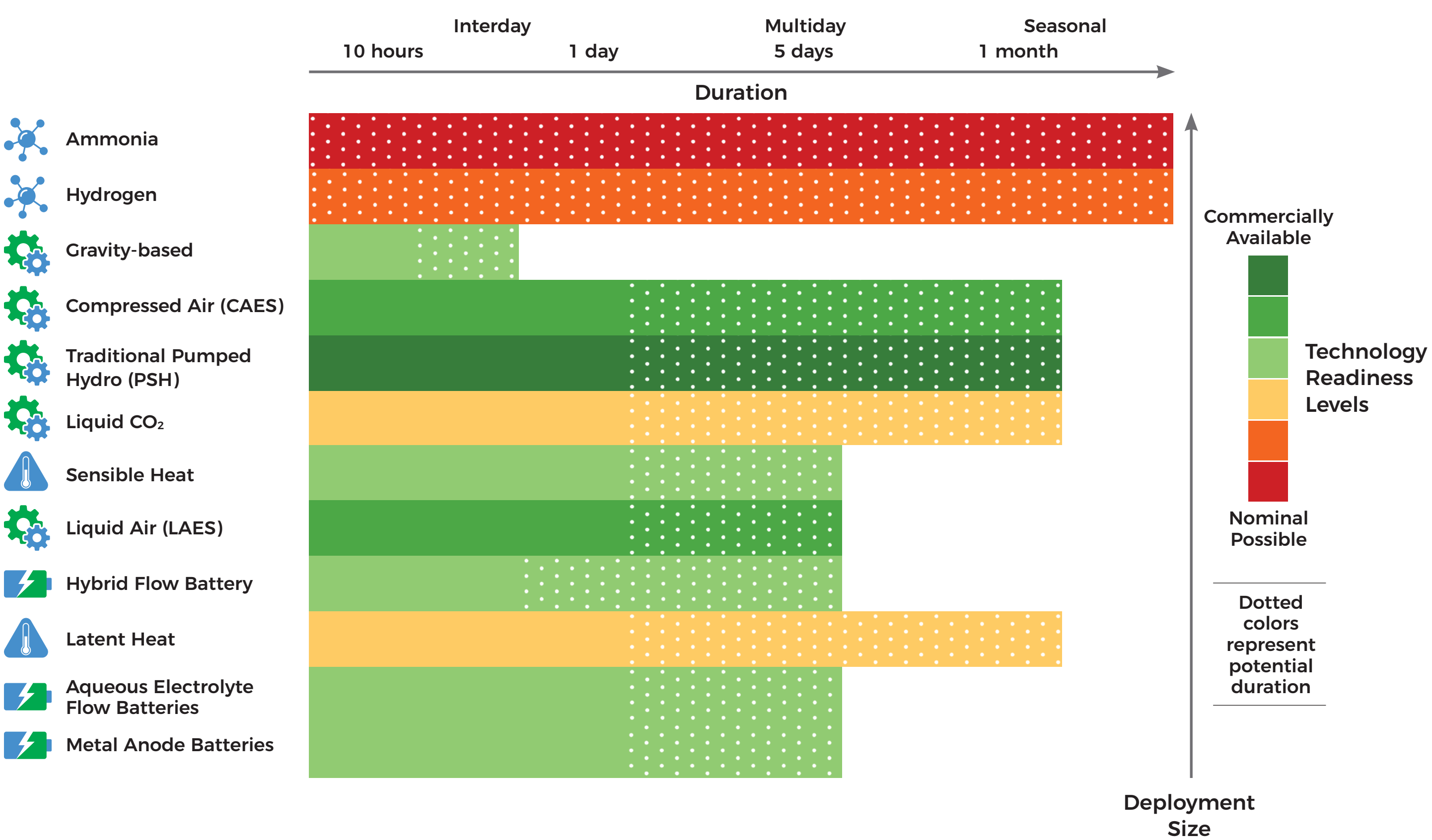
Resource adequacy (RA) is the ability of the electric grid to satisfy the end-user's power demand at any time. Resource adequacy is designed to ensure that the power system has sufficient resource capacity available to provide energy at any time, even in the case of major infrastructure disruptions (e.g., an outage at a generation unit or a disconnection of a power line) and/or intermittent generation from renewable energy sources. Instead of investing in new peaking generation (usually gas turbines) to meet demand during peak electricity-consumption hours, grid operators and utilities can invest in energy storage to incrementally defer or reduce the need for new generation capacity and minimize the risk of overinvestment in that area. Although short-duration storage systems can provide firm capacity for resource adequacy, in systems with higher deployment of energy storage and renewable energy, longer-duration storage solutions are needed to manage increasingly longer-duration peak demand events.

Energy Arbitrage is broadly defined as shifting generation from low-cost, low-demand periods to high-cost, high-demand periods. This avoids curtailment during times when electricity is generated in excess of demand and, more importantly, avoids investing in and/or operating higher-cost resources at times when demand is higher than generation.

For the provision of these services, this comparative analysis of LDES technologies focuses on the levelized cost of storage (LCOS). LCOS represents a cost per unit of discharge energy throughput ($/MWh) metric that can be used to compare different storage technologies on a more equal footing than comparing their installed costs per unit of rated energy. Different systems have a different calendar life, cycle life, depth of discharge (DOD) limitations, and operations and maintenance (O&M) costs, and may require various capital expenditures over time in the form of augmentations, replacements, and major overhauls.

Figure 1 provides a comparative analysis of several different chemical, mechanical, thermal, and electrochemical energy storage technologies. The comparative market readiness of each technology is shown, alongside several different durations. While many technologies have a reduced technology readiness level past 24 hours of storage, several, such as compressed air and pumped hydro, show high levels of readiness even at longer durations. In comparison, ammonia and hydrogen, two fuel-based storage technologies, have limited readiness, mostly due to the minimal deployment and high costs of these technologies currently.

FIGURE 1: **Energy Storage Technologies: Technology, Duration, Size, and Technology Readiness**



Different chemical, mechanical, thermal, and electrochemical energy storage technologies are compared in terms of their market readiness, as well as their ability to provide storage for different durations.

Source: Maria Roumpani, Current Energy Group

HYDROGEN POWER PLANTS AS LDES

Unlike most other energy storage technologies covered in this analysis, hydrogen fuel cannot be directly discharged to provide electricity. While the fuel itself can be stored indefinitely, it must be run through a fuel cell or combusted in a turbine to provide electricity. This impacts hydrogen's LCOS in two ways:

- The multiple energy conversions and subsequent losses (renewable electricity converted into hydrogen, which is then converted back into electricity) mean that hydrogen has a very low roundtrip efficiency compared to other storage technologies that can store and discharge electricity directly. These inefficiencies have an impact on the overall fuel cost, which is an important input to the LCOS calculation. (See Technical Appendix, p. 32.)

- In addition to fuel cost, there are capital and operating costs associated with both fuel cells and combustion turbines. Fuel cells, while suitable for smaller scale power needs, become more expensive if greater power output is needed, such as for a utility-scale installation.[20] Hydrogen-capable **combined cycle (CC)** units and **combustion turbines (CT)** have high capital and operating costs but can provide a greater power output for lower cost compared to fuel cells. This analysis looks at the LCOS of both hydrogen fuel cells and hydrogen power plants.

Despite cost, regulatory uncertainties, and other drawbacks, utilities in at least 18 states are developing "hydrogen-ready" CC units or CTs.[21] Due to the inefficiencies associated with hydrogen production and the high operating costs of power plants, hydrogen use in power plants does not make sense for day-to-day generation, where zero- or lower-margin resources such as wind and solar, as well as shorter duration batteries, can meet demand.[22] In an LDES context, the power plants could be used to combust hydrogen produced during times of high renewable energy output and then stored for periods of low output. It does not make sense to operate

Despite cost, regulatory uncertainties, and other drawbacks, utilities in at least 18 states are developing "hydrogen-ready" CC units or CTs.

20. Electric Power Research Institute. "An Introduction to Low-Carbon Fuels," December 31, 2020.

21. Wamsted, Dennis. "Hydrogen: Not a Solution for Gas-Fired Turbines." Institute for Energy Economics and Financial Analysis, August 1, 2024. https://ieefa.org/resources/hydrogen-not-solution-gas-fired-turbines.

22. Esposito, Dan. "Hydrogen Policy's Narrow Path: Delusions and Solutions." Energy Innovation, August 27, 2024. https://energyinnovation.org/report/hydrogen-policys-narrow-path-delusions-and-solutions.

hydrogen power plants for long periods of time due to the high cost and high energy demand of producing hydrogen fuel.[23]

To assess the cost of hydrogen power plants versus other LDES technologies, this analysis calculates the LCOS for these plants by using recent data from analysis conducted by the utility PacifiCorp, which is based on NREL ATB data.[24] These inputs are listed below in Table 1. It should be noted that hydrogen's cost of storage can vary depending on siting considerations. While there is a lower marginal cost to store hydrogen in large underground caverns, the availability of suitable geologic formations is limited to specific regions. More expensive aboveground storage will be necessary for most power plant locations. Both types of storage are included in this analysis.

The CC and CT capital cost estimates include a 15 percent incremental cost above typical natural gas turbines to capture the cost of installing turbines that can burn

TABLE 1: **Inputs for LCOS analysis**[25,26]

Technology	Capacity (MW)	Duration (hours)	Lifetime (years)	Roundtrip Efficiency (%)	CapEx ($/kW)	CapEx ($/kWh)	VOM ($/MWh)	FOM ($/kW-yr)	Demolition Cost ($/kW)
Lithium-Ion (8hr, 200MW)	200	8	20	85%	$3,533	$442		$81.44	$46.19
Gravity Battery	1000	8	50	83%	$3,224	$403		$90.92	$0.34
Adiabatic CAES	500	8	30	69%	$2,178	$272	$1.12	$11.00	$49.31
Iron-Air	200	100	20	43%	$11,656	$117		$21.04	$171.06
Pumped hydro	400	10	100	80%	$3,840	$384	$0.58	$20.20	$191.98
Pumped Thermal Energy Storage	100	10	60	55%	$6,174	$617	$0.70	$2.00	$60.00
Pumped Thermal Energy Storage	50	24	60	55%	$11,525	$480	$0.70	$1.00	$60.00
SCCT Frame 100% hydrogen burning, storage cavern (24 hours)	233	24	40	25%	$1,788	$74	$9.34	$35.12	$28.95
SCCT Frame 100% hydrogen burningstorage tanks (24 hours)	233	24	40	25%	$2,287	$95	$9.48	$40.78	$28.95
CCCT 2x1 100% hydrogen burning, storage cavern (24 hours)	1227	24	40	40%	$1,998	$83	$3.05	$42.38	$28.67
CCCT 2x1 100% hydrogen burning, storage tanks (24 hours)	1227	24	40	40%	$2,497	$104	$3.19	$48.04	$28.67

Source: PacificCorp, based on NREL ATB data.
(Note: VOM is defined as Varied Operations and Maintenance, and FOM is defined as Fixed Operations and Maintenance.)

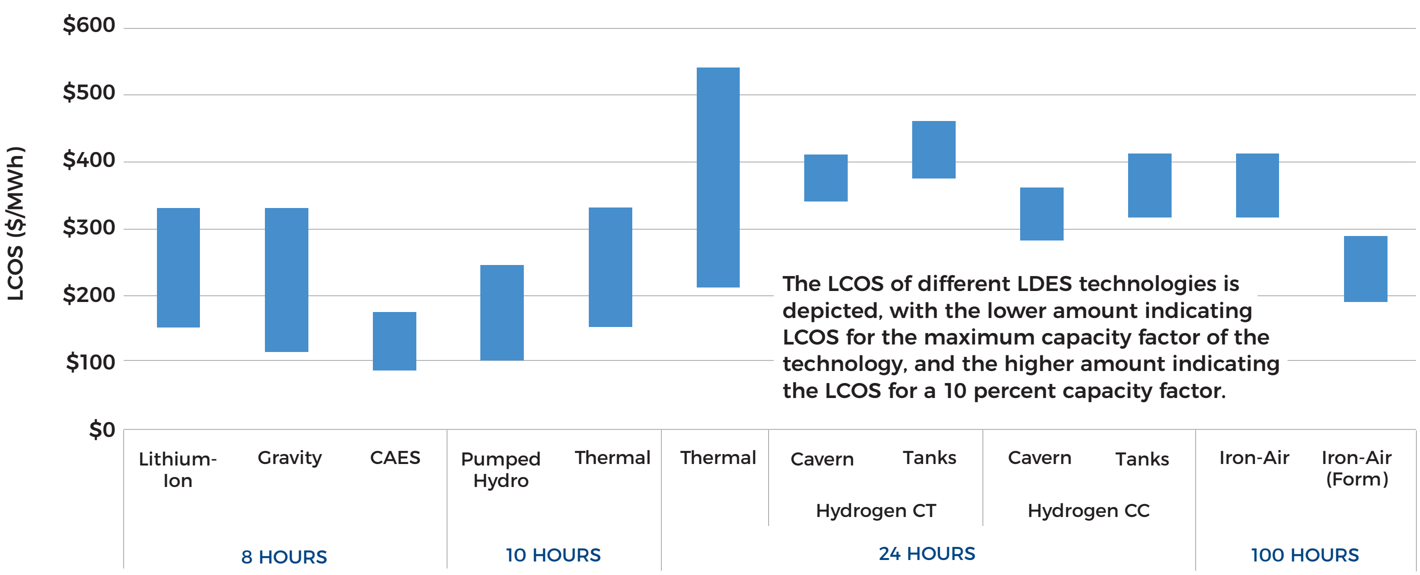
23. "Levelized Cost of Energy 2024." Lazard, June 2024. https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf.
24. Stehly et al.
25. It is worth noting that Form Energy is developing an iron-air multi-day energy storage solution that assumes a significantly lower capital cost ($2,150/kW) that would also significantly lower its estimated LCOS. See Table B1 in "Modeling Multi-Day Energy Storage in New York: Storage Portfolios that Can Enable a Reliable, Zero Carbon Grid." https://formenergy.com/wp-content/uploads/2023/09/Form-Modeling-Multi-Day-Energy-Storage-in-NY-whitepaper-8.8.23.pdf.
26. The roundtrip efficiency for the hydrogen resources includes both the electrolyzer and turbine efficiencies assuming a Stack Power Consumption of 50 kWh/kg and heat rates of 9,717 btu/kWh and 6,122 btu/kWh for the CC and CT units respectively.

100 percent hydrogen. The capital cost also includes the cost of storing the fuel onsite for 24 hours ($212/kW for underground caverns and $711/kW for aboveground tanks).[27]

Table 1 provides capital cost estimates in $/kW and $/kWh. Although CC and CT units seem to be lower cost, it is important to note that additional capital expenses to produce hydrogen in the first place are not captured in this table, but are reflected in the price of hydrogen, which is an input of the LCOS estimates listed below in Figure 2. The LCOS estimates assume a federal investment tax credit (ITC) of 30 percent for the LDES technologies (but not for the CC and CT units, which do include the 45V credit in the hydrogen price). Given the significant discrepancy between PacifiCorp's and From Energy's capital cost estimates for iron-air batteries, the graph includes the LCOS of the technology as calculated with both PacifiCorp and Form Energy estimates. Figure 2 shows the LCOS for various LDES technologies based on maximum capacity factor (the lower LCOS estimate), and a 10 percent capacity factor (high LCOS estimate).

As shown in Figure 2, capacity factor is a critical assumption for LCOS calculations. The LCOS of all storage technologies varies significantly depending on capacity factors, and capacity factors can be influenced by LDES technology characteristics. In the case of hydrogen CC and CT units, the assets are not operating for fuel production, which

FIGURE 2: **Levelized Cost of Storage (LCOS) estimates for different LDES options based on maximum and 10 percent capacity factors**



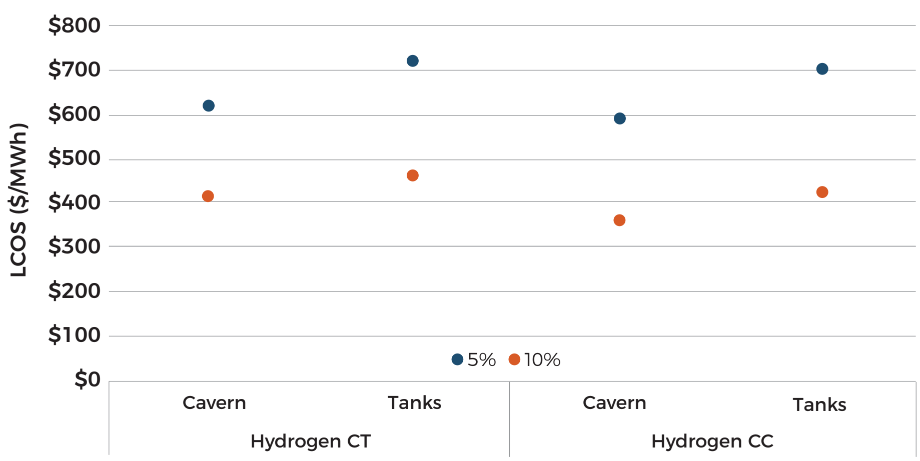
Source: Pacific Northwest National Laboratory (PNNL)

27. The LCOS analysis was also conducted for CC and CT assets, assuming the capital cost was reflected in the hydrogen price (not the plant capital expenditures): a distribution cost adder of $0.20-$0.50/kg and storage costs of $0.80–$1/kg for tanks, and $0.05-$0.15/kg for a cavern based on Figures 5 and 6 of the US Department of Energy "Pathways to Commercial Liftoff: Clean Hydrogen" report. The LCOS results were comparable to the ones presented in Figure 3. https://www.energy.gov/lpo/articles/us-department-energy-releases-updated-report-pathways-commercial-liftoff-clean.

would be analogous to the charging of a battery system. This means that assuming indefinite amounts of fuel, the units could be operating at a high-capacity factor, while technologies like batteries and pumped hydro can only discharge at capacity factors of less than 50 percent, as they need to be charged after delivering energy. However, in an LDES context, hydrogen CC and CT units are expected to operate as peaking power plants, which typically have very low capacity factors, with an average capacity factor of 5 percent.[28] Figure 3 shows how the LCOS of hydrogen units can vary based on a 5 percent and 10 percent capacity factor. Assuming a 5 percent capacity factor, which many peaking resources have today, would result in an LCOS increase of approximately $200/MWh, resulting in a minimum LCOS of about $600/MWh.

As seen in Figure 2, hydrogen power plants, when operating at maximum capacity factor (which is unlikely given the operational limitations discussed earlier in this section) have an LCOS that is not competitive with thermal LDES also operating at its maximum capacity factor, although the LCOS is more favorable compared to thermal when looking at a 10 percent capacity factor. When looking at longer durations, iron-air batteries can potentially outperform hydrogen power plants, although there is a wide range of LCOS estimates for iron-air batteries. Similarly, pumped hydro and thermal both outperform hydrogen in the MDES category (10 hours). This is particularly relevant for energy system planning in the next 10 years, when MDES resources will be much more critical for grid balancing and reliability, as opposed to the 24+ range where hydrogen and other longer-duration technologies may be more cost-effective to address future grid reliability needs.

FIGURE 3: **LCOS estimates for hydrogen LDES options under different capacity factor assumptions**



For hydrogen CTs and CC units, reducing the capacity factor from 10 percent to 5 percent, which is a typical capacity factor for peaking units, results in a corresponding increase in the LCOS of approximately $200/MWh.

Source: PacificCorp, based on NREL ATB data

28. Clean Energy Group and Strategen. "The Peaker Problem: An Overview of Peaker Power Plant Facts and Impacts in Boston, Philadelphia, and Detroit," July 22, 2022. https://www.cleanegroup.org/wp-content/uploads/The-Peaker-Problem.pdf.

Hydrogen Price Sensitivity

An important input for determining the LCOS of both the hydrogen CT and CC units is the assumed price of hydrogen. This analysis assumes that green hydrogen would be the fuel used for the CT and CC units as part of a decarbonized electric grid. The 45V Clean Production Tax Credit provides a credit of up to $3.00 per kilogram of qualified clean hydrogen produced during a given year. The US Treasury Department released final guidance regarding 45V in January 2025.[29] To qualify for the highest tier of the credit, the hydrogen must be produced with greenhouse gas emissions of 0.45 kg carbon dioxide equivalent (CO_2e) per kilogram of hydrogen or less. The guidance also requires that hydrogen facilities must be paired with new clean energy generation (incrementality); that hydrogen production energy use must be matched with clean energy generation on an annual basis, shifting to hourly matching beginning in 2030 (temporal matching); and that the clean energy resources must be located within the same transmission region as the hydrogen production facility (deliverability).[30] The results in Figures 2 and 3 assume a price of $4.3/kg, with a 45V tax credit of $3/kg for the first ten years.[31]

The 45V requirements are necessary for mitigating demand from grid-connected electrolyzers that could subsequently require dirtier forms of generation to come online.[32] While not included in this analysis, it is possible that the 45V requirements could have an impact on overall hydrogen cost. An input into the calculation of the hydrogen price in this analysis, besides the initial capital expense for the electrolyzer, is the price of electricity and the capacity factor of the electrolyzer.

In this analysis, it is assumed that electricity to power electrolysis is supplied at $30/MWh, consistent with the inputs for all other LDES technology LCOS assessments. In some analyses, it has been assumed that the electricity used for electrolysis will be free, as the hydrogen is produced from electricity generated by renewable energy that would otherwise be curtailed. At the same time, these analyses often assume that the electrolyzers will be operating nearly continuously to minimize efficiency losses. Under the 45V requirements, these assumptions are incompatible, as electrolyzer production must be matched by hourly dedicated renewable energy

Even if hydrogen fuel prices were lower—whether due to higher electrolyzer capacity factors, lower capital expenses, or lower electricity costs—if the hydrogen is being combusted in a peaker plant, the LCOS would still be high, surpassing most of the other LDES technologies.

29. Federal Register. "Credit for Production of Clean Hydrogen and Energy Credit," January 10, 2025. https://www.federalregister.gov/documents/2025/01/10/2024-31513/credit-for-production-of-clean-hydrogen-and-energy-credit.
30. Ibid.
31. Electric Power Research Institute. Electrolysis Techno-Economic Analysis v2.2.0, November 3, 2024. https://apps.epri.com/lcri-electrolysis-tea/en/capex-rates.html. The price of hydrogen in this analysis assumes an average value between the tool's "Lower Range Capex and Fixed Opex" and "Higher Range Capex and Fixed Opex" cases for 2030.
32. Ricks, Wilson, Qingyu Xu, and Jesse D Jenkins. "Minimizing Emissions from Grid-Based Hydrogen Production in the United States." *Environmental Research Letters* 18, no. 1 (January 6, 2023): 014025. https://doi.org/10.1088/1748-9326/acacb5.

generation or by stored renewable energy from a connected battery storage resource. In this scenario, it is possible that the electricity cost could be higher than $30/MWh, in which case the LCOS would increase.

Even if hydrogen fuel prices were lower—whether due to higher electrolyzer capacity factors, lower capital expenses, or lower electricity costs—if the hydrogen is being combusted in a peaker plant, the LCOS would still be high, surpassing most of the other LDES technologies presented in Figure 2. Table 2 includes the results of sensitivity analysis to determine the impact of hydrogen prices on the LCOS for hydrogen-capable CC units and CTs, based on geologic (cavern) storage and storage in above-ground tanks.

TABLE 2: **Sensitivity results for the LCOS (MWh) for different hydrogen price assumptions**

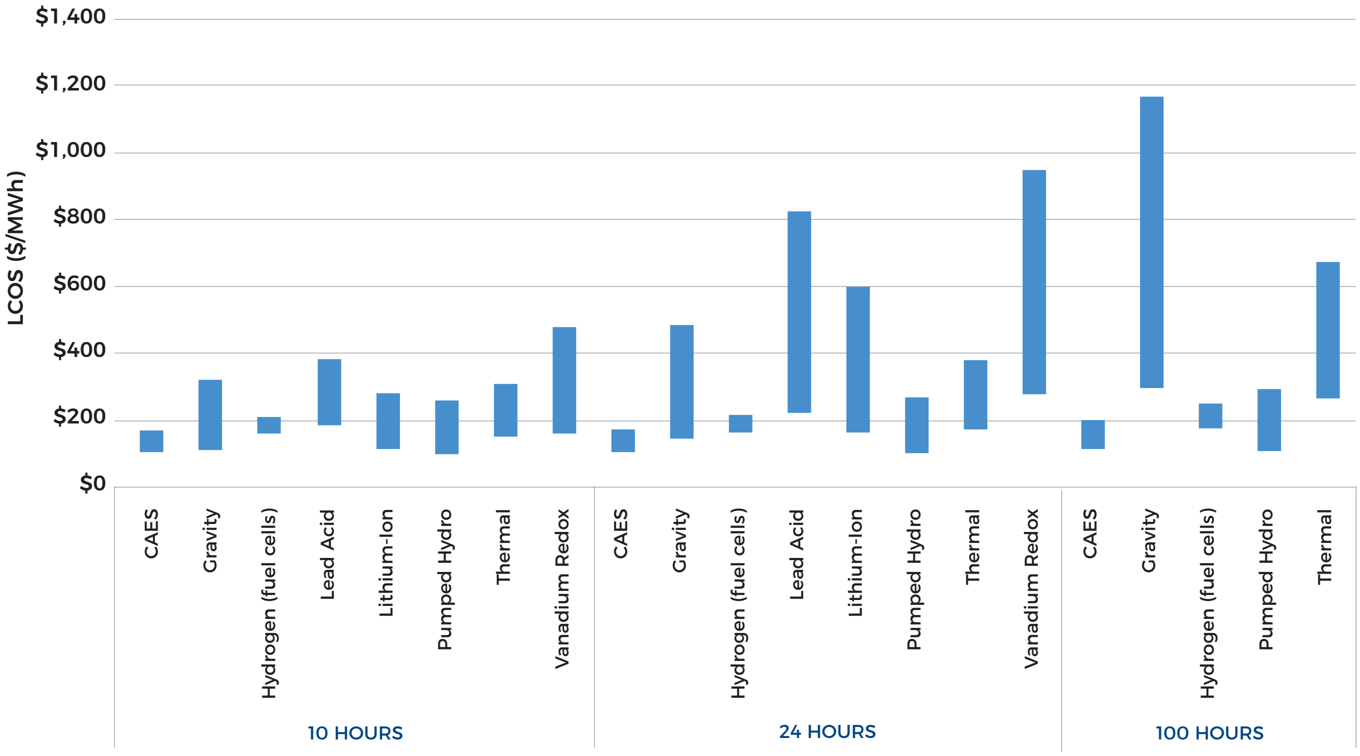
H_2 price ($kg)	CT, cavern	CT, tanks	CC, cavern	CC, tanks
0	221	273	242	294
1	301	353	292	344
2	382	433	343	395
3	462	514	394	445
4	542	594	444	496
5	623	674	495	547

Source: PacificCorp, based on NREL ATB data.

HYDROGEN FUEL CELLS AS LDES

Stored hydrogen can also power fuel cells to generate electricity. Using PNNL's capital cost projections and an LCOS model developed for this report, hydrogen-powered fuel cells were compared to different storage technologies, as shown in Figure 4.[33] As in Figure 2, the lower range LCOS represents the maximum capacity factor the storage asset could achieve, and the upper LCOS estimate represents a 10 percent capacity factor.

FIGURE 4: **LCOS of different LDES technologies using PNNL cost estimates**



The LCOS of different LDES technologies, based on PNNL estimates. The lower range represents LCOS at maximum capacity factor, while the higher range represents LCOS at a 10 percent capacity factor.

Source: PNNL

33. PNNL's capital cost projects do not include the Investment Tax Credit (ITC), which if assumed could reduce the capital cost by 30 percent or more. The ITC is not included in the hydrogen price assumption, although the 45V credit is.

Compressed air energy storage and pumped hydro technologies present the lowest LCOS across all duration categories. Gravity storage also exhibits the potential for a low LCOS for 10-hour duration storage. Lithium-ion battery technologies are excluded from the longer duration categories, as their costs scale with duration, and thus represent expensive options for longer durations. In comparison, increasing the duration of technologies like CAES, hydrogen fuel cells, and pumped hydro is only reliant on how much air, hydrogen, or water can be stored in a cavern or reservoir, so these technologies have more favorable economics for longer durations, as storing incremental energy in such a structure does not significantly increase costs.

For MDES, lithium-ion batteries, CAES, pumped hydro, and gravity storage all have the potential to be more cost-competitive than hydrogen fuel cells, though lithium-ion batteries, pumped hydro, and gravity storage become less competitive at lower capacity factors. It is worth noting that, unlike hydrogen peaker plants, hydrogen fuel cells are not as sensitive to changes in capacity factor.

For a seasonal storage use case, in which hydrogen is produced during periods of excess renewable generation and is only needed for short durations during seasonal periods of reduced generation, a hydrogen fuel cell may be a better option than a hydrogen peaker plant. However, this is only true for use cases in which a lower power capacity is needed. While hydrogen fuel cells are cost competitive across durations due to the low cost of storing incremental energy, there are additional costs when looking at scaling power capacity. The amount of power produced by a fuel cell depends on several factors, including fuel cell type, cell size, temperature at which it operates, and pressure at which the gases are supplied to the cell. A single fuel cell produces less than 1.16 volts—barely enough electricity for even the smallest applications. To increase the amount of electricity generated, individual fuel cells are combined in series into a fuel cell "stack." A typical fuel cell stack may consist of hundreds of fuel cells.[34] For larger applications, such as a utility-scale peaker power plant, the costs of scaling fuel cells may be prohibitive. For this reason, fuel cells are often considered for lower power capacity, higher duration applications, such as heavy-duty vehicles or short-haul air transport flights.

For a seasonal storage use case, a hydrogen fuel cell may be a better option than a hydrogen peaker plant. However, this is only true for use cases in which a lower power capacity is needed. While hydrogen fuel cells are cost competitive across durations due to the low cost of storing incremental energy, there are additional costs when looking at scaling power capacity.

34. U.S. Department of Energy. "Fuel Cells." Energy.gov, December 2024. https://www.energy.gov/eere/fuelcells/fuel-cells.

CONSIDERATIONS BEYOND COST

As seen in this analysis, hydrogen is rarely competitive with other LDES technologies in terms of LCOS, particularly when it is combusted in a power plant. A hydrogen combustion turbine (CT) operating at 10 percent capacity has an LCOS of $410/MWh, nearly double that of a hydrogen fuel cell operating at the same capacity factor. Both hydrogen fuel cells and power plants have a higher LCOS than many other LDES and MDES technologies. While most LDES technologies, including large-scale hydrogen fuel cells and power plants, are still in the initial stages of market readiness, there are additional associated costs and potential harms associated with green hydrogen production and use that cast further doubt on the suitability of hydrogen as a viable LDES solution.

Many of the costs and harms related to hydrogen production and use cannot be addressed through technological improvements over time. When evaluating hydrogen assets for LDES use, it is important to consider the supply chain network required, and the tradeoffs and implications associated with it. The impacts of hydrogen's production and end uses can have an outsized impact on the surrounding environment and nearby communities, and it is important that these impacts are accurately modeled in resource planning processes. In contrast, most competing LDES technologies do not carry anywhere near the same level of known harms as hydrogen production.

Many of the costs and harms related to hydrogen production and use cannot be addressed through technological improvements over time. The impacts of hydrogen's production and end uses can have an outsized impact on the surrounding environment and nearby communities, and it is important that these impacts are accurately modeled in resource planning processes.

Infrastructure and Planning Considerations

AVAILABILITY

Utilities will often model hydrogen as readily available and in most cases at low prices, assuming widely available and cheap renewable electricity.[35] However, for green hydrogen to be available at any price point, there must be sufficient renewable generation dedicated to electrolytic load, which would require a significant buildout of renewable

35. SoCalGas. "Clean Fuels Reliability Analysis," June 12, 2024. https://www.socalgas.com/sustainability/innovation-center.

energy assets in addition to the renewable energy needed to directly decarbonize the power generation sector. It is contradictory to assume that green hydrogen will be widely available in the near term when there is not yet enough renewable energy capacity to fully decarbonize the grid.

As of 2023, global green hydrogen production represented less than 1 percent of global hydrogen production. Green hydrogen also remains up to six times more expensive than hydrogen produced with fossil fuels.

As of 2023, global green hydrogen production represented less than 1 percent of global hydrogen production. Green hydrogen also remains up to six times more expensive than hydrogen produced with fossil fuels.[36] While it is possible that the price of green hydrogen will come down, it is unlikely to become cost-competitive with hydrogen produced with fossil fuels in the next five to ten years. This is particularly important to consider when evaluating proposals to build hydrogen power plants now, on the basis that they will eventually be needed for seasonal combustion of stored hydrogen. Without widely available, inexpensive, green hydrogen, these plants will likely be combusting fossil fuels or a blend of fossil fuels and fossil-fuel-based hydrogen. As a ready supply of inexpensive green hydrogen will not be available in the next decade, a buildout of "hydrogen-ready" power plants runs of the risk of unnecessarily extending a reliance on fossil fuel infrastructure.

PRODUCTION TRADEOFFS

Electrolysis to produce green hydrogen is an energy intensive and inefficient process, with efficiencies for most electrolyzers ranging from 60 percent to 81 percent depending on the technology.[37] Building out a green hydrogen production system will result in a huge amount of new energy demand. For context, to replace all of the grey hydrogen (i.e., hydrogen that is produced by methane reforming from natural gas) currently in use today would require 3,600 terawatt hours of annual energy demand, equivalent to the total annual electricity production of the European Union.[38] A single 290-MW turbine, operating at a 10 percent capacity factor, running on 100 percent green hydrogen, would require an average of 8,500 MWh of renewable energy a day, equivalent to the energy consumption of nearly 300,000 US households.[39]

This surge in demand is part of the reasoning for the Treasury's 45V incrementality, temporal matching, and deliverability requirements. Without these safeguards in place, electrolytic hydrogen production has the potential to divert renewable energy resources away from directly decarbonizing grid emissions, which could result in the utilization of dirtier forms of energy production such as oil- and gas-powered peaker power plants,

36. International Energy Agency. "Global Hydrogen Review 2024." IEA, October 2024. https://iea.blob.core.windows.net/assets/89c1e382-dc59-46ca-aa47-9f7d41531ab5/GlobalHydrogenReview2024.pdf.

37. International Energy Agency. "The Future of Hydrogen." International Energy Agency, June 14, 2019. https://www.iea.org/reports/the-future-of-hydrogen.

38. Ibid.

39. GE Vernova. "Hydrogen Calculator: Fuel Costs and Savings," 2019. https://www.gevernova.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines/hydrogen-calculator. Calculations based on a 7HA.01 290-MW turbine configured as a 1x1 combined cycle plant with a 10 percent capacity factor. Energy demand calculation based on 2,150 operating hours per year. Average U.S. household energy consumption based on U.S. EIA Residential Energy Consumption Survey, 2015.

and increase overall power system emissions.[40] When evaluating the use of green hydrogen for long- or medium-duration storage, utilities, state policymakers, and public utility commissions must consider and plan for the accompanying growth in electricity demand for hydrogen production, and in particular how this may impact and potentially jeopardize decarbonization efforts.

FUEL STORAGE

The LCOS in this analysis was calculated using figures for both hydrogen stored in large-scale geologic formations, such as an underground cavern, and hydrogen stored in above ground tanks. Hydrogen, alongside technologies like CAES and pumped hydro, does have some cost advantages in terms of duration since its duration is only limited by how much space is available to safely store it once it has been produced. There is a low additional cost to storing greater amounts of hydrogen in a large cavern, compared to LDES technologies such as electrochemical batteries. While this feature may make hydrogen a suitable candidate for multi-day duration storage, particularly in the 100+ hour range, the challenges associated with underground storage must be considered as well.

A survey of existing underground gas storage facilities in the US has found that these facilities are only suitable to store a blend of up to 20 percent hydrogen and natural gas. A full conversion of underground gas storage facilities to store 100 percent hydrogen would reduce the collective energy storage of the facilities by 75 percent due to hydrogen's lower energy density.[41] While existing underground gas storage facilities may be capable transitioning to 100 percent hydrogen storage, it should be noted that existing pipeline infrastructure used to transport natural gas to and from the facility may not be suitable for hydrogen, as discussed below. Utilities must consider the costs of either 1) converting an existing underground gas storage facility for hydrogen storage, including the costs of upgrading surrounding pipeline infrastructure, 2) siting a new underground storage facility, or 3) storing large amounts of hydrogen in more expensive above-ground storage tanks.

A full conversion of underground gas storage facilities to store 100 percent hydrogen would reduce the collective energy storage of the facilities by 75 percent due to hydrogen's lower energy density.

TRANSPORT

Unless hydrogen is produced, stored, and utilized onsite, it will likely need to be transported from the production facility to the storage facility, and possibly from the storage facility to the generation facility. The costs and risks associated with this transport must be factored into the assessment of hydrogen for LDES. Hydrogen cannot be safely run through most existing gas pipeline infrastructure, either alone or blended with natural gas.

40. Ricks, Wilson, Qingyu Xu, and Jesse D Jenkins.

41. Lackey, Greg, Gerad M. Freeman, Thomas A. Buscheck, Foad Haeri, Joshua A. White, Nicolas Huerta, and Angela Goodman. "Characterizing Hydrogen Storage Potential in U.S. Underground Gas Storage Facilities." Geophysical Research Letters 50, no. 3 (2023): e2022GL101420. https://doi.org/10.1029/2022GL101420.

Most large diameter natural gas pipelines in the US are comprised primarily of steel. When hydrogen encounters steel, it will diffuse into the alloy and combine with carbon to form tiny pockets of methane. This methane does not diffuse out of the metal and cracks the steel. This process, called hydrogen embrittlement, lowers steel's resistance to fracture and can exacerbate existing flaws.[42] Iron pipelines are also susceptible to hydrogen embrittlement, and as these pipelines tend to be older, the impacts can be even worse.[43] Plastic pipelines are not susceptible to hydrogen embrittlement, but hydrogen can permeate through the material at a rate six to seven times higher than methane, increasing the risk of hydrogen accumulating and igniting outside the pipeline.[44]

Pipelines that are newly constructed solely for hydrogen transmission and distribution must be thicker in diameter than most natural gas pipelines and will require significant capital investment, costing approximately $1 million per mile.

Due to these issues, pipelines that are newly constructed solely for hydrogen transmission and distribution must be thicker in diameter than most natural gas pipelines and will require significant capital investment, costing approximately $1 million per mile.[45] Transporting the hydrogen from the production facility to the storage site via alternative methods, such as tanker trucks, may be a lower-cost alternative to building new pipeline infrastructure. However, in an LDES context, utilities should consider how quickly hydrogen can be transported from its storage location to the power generation facility, and how this may impact the resource's ability to respond quickly to grid service needs and the implications of this on grid reliability.

Equity and Environmental Considerations

AIR POLLUTANT EMISSIONS

One of the most relevant concerns for hydrogen use in an LDES context is the public health impact of hydrogen combustion, particularly as most hydrogen power plants are expected to operate as peakers. When combusted, hydrogen produces six times as much nitrogen oxide (NOx) as methane.[46] NOx pollution is a public health hazard that does significant damage to the respiratory system over time. Many frontline communities located near existing peaker power plants have developed serious health disparities due to overexposure to NOx.

42. Raju, Arun SK, and Alfredo Martinez-Morales. "Hydrogen Blending Impacts Study." Prepared for California Public Utilities ommission, July 18, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.pdf.
43. Kuprewicz, Richard. "Safety of Hydrogen Transportation by Gas Pipelines." Prepared for Pipeline Safety Trust, November 28, 2022. https://pstrust.org/wp-content/uploads/2022/11/11-28-22-Final-Accufacts-Hydrogen-Pipeline-Report.pdf.
44. Islam, Aminul, Tahrim Alam, Nathan Sheibley, Kara Edmonson, David Burns, and Manuel Hernandez. "Hydrogen Blending in Natural Gas Pipelines: A Comprehensive Review of Material Compatibility and Safety Considerations." International Journal of Hydrogen Energy 93 (December 3, 2024): 1429–61. https://doi.org/10.1016/j.ijhydene.2024.10.384.
45. Bouwkamp, Nico et al. "Hydrogen Delivery Technical Team Roadmap." U.S. DRIVE Partnership, July 11, 2017. https://www.energy.gov/eere/vehicles/articles/us-drive-hydrogen-delivery-technical-team-roadmap.
46. Cellek, Mehmet Salih, and Ali Pınarbaşı. "Investigations on Performance and Emission Characteristics of an Industrial Low Swirl Burner While Burning Natural Gas, Methane, Hydrogen-Enriched Natural Gas and Hydrogen as Fuels." International Journal of Hydrogen Energy 43, no. 2 (January 11, 2018): 1194–1207. https://doi.org/10.1016/j.ijhydene.2017.05.107.

Currently, most retrofitted or new hydrogen-capable turbines can combust up to 50 percent hydrogen blended with natural gas with NOx emissions similar to that of a newer natural gas plant.[47] It should be noted that peaker plants can have higher NOx emissions due in part to the nature of their operations, which require frequent start-up and shut-down. During periods of start-up and shut-down, emissions are unabated, meaning that communities living near hydrogen peakers would be exposed to extremely high levels of NOx.[48] Given that peaker plants are disproportionately sited in low-income communities and communities of color, there are serious equity implications to siting additional sources of heavy NOx pollution in communities that have already borne a disproportionate air pollution and public health burden.[49]

When considering proposals to retrofit existing peakers or build new hydrogen-capable peakers for long-duration storage, public utility commissions and state review boards should heavily consider the public health implications of such an asset, particularly if there are non-combustion alternatives that could provide the same service. If hydrogen must be used, such as for seasonal storage purposes, it should be run through a fuel cell, as this process does not produce the same NOx impact.

GLOBAL WARMING IMPACTS

While hydrogen does not produce CO_2 when burned or run through a fuel cell, when leaked into the atmosphere, it causes atmospheric chemical reactions that are associated with four main climate impacts: 1) it extends the lifetime of methane in the atmosphere; 2) it increases the production of ozone; 3) it increases the production of stratospheric water; and 4) it alters the production of certain aerosols. Due to these atmospheric effects, hydrogen is estimated to have a global warming potential nearly 12 times that of CO_2 over 100 years after release. In the first 20 years of its atmospheric lifetime, hydrogen contributes to 35 times the climate warming impact of CO_2. In fact, hydrogen's global warming potential is so powerful that reducing its manmade presence in the atmosphere could tangibly slow down global warming in the next 20 years.[50]

Hydrogen's indirect global warming impacts are particularly concerning since, due to its small molecular size and low density, hydrogen gas is very prone to leakage. The increased use of hydrogen for LDES, including production, transport, and storage, will inevitably lead to more leakage.

The indirect global warming impact of hydrogen is so powerful that unless leaks are kept to a minimum, the increased use of hydrogen in the power generation sector, even if it is green hydrogen replacing fossil fuels, could negate any climate benefits.

47. Walton, Rod. "Hydrogen Substitution for Natural Gas in Turbines: Opportunities, Issues, and Challenges." Power Engineering (blog), June 18, 2021. https://www.power-eng.com/gas/turbines/hydrogen-substitution-for-natural-gas-in-turbines-opportunities-issues-and-challenges.
48. Robbins, Shelley Hudson. "The Peaker Problem." Clean Energy Group, July 27, 2022. https://www.cleanegroup.org/wp-content/uploads/The-Peaker-Problem.pdf.
49. Morgan, Eva. "New Power Plant Data Show Another Year of Racial and Economic Inequities." Clean Energy Group, February 27, 2025. https://www.cleanegroup.org/new-power-plant-data-inequities.
50. Sand, Maria, Ragnhild Bieltvedt Skeie, Marit Sandstad, Srinath Krishnan, Gunnar Myhre, Hannah Bryant, Richard Derwent, et al. "A Multi-Model Assessment of the Global Warming Potential of Hydrogen." Communications Earth & Environment 4, no. 1 (June 7, 2023): 203. https://doi.org/10.1038/s43247-023-00857-8.

The indirect global warming impact of hydrogen is so powerful that unless leaks are kept to a minimum, the increased use of hydrogen in the power generation sector, even if it is green hydrogen replacing fossil fuels, could negate any climate benefits.[51] Hydrogen's intensive indirect global warming impact, given the production, transport, and storage impacts that would result from its use for long-duration storage, likely will make hydrogen a poor choice for LDES compared to other technologies.

The average green hydrogen plant will withdraw 45.1 million gallons of water to produce 11,000 metric tons of hydrogen a year. Only 18.7 million gallons of that water can be recycled, as the rest is broken down in the production process.

WATER IMPACTS

Most types of zero- or low-carbon hydrogen production are very water intensive. The average green hydrogen plant will withdraw 45.1 million gallons of water to produce 11,000 metric tons of hydrogen a year. Only 18.7 million gallons of that water can be recycled, as the rest is broken down in the production process.[52] A 290-MW turbine operating at 10 percent capacity factor, running on 100 percent green hydrogen, would require 118,003 gallons of water a day, equivalent to the daily water usage of nearly 1,500 US households.[53] This intensive water use is of particular concern in areas already experiencing water scarcity. More than half of planned and operational green and blue hydrogen production capacity in the US are located in medium to highly water-stressed regions.[54]

These environmental impacts are compounded if the hydrogen is combusted in a power plant, as hydrogen combustion can increase the water use by the plant itself. In one pilot project in which a blend of hydrogen and natural gas was combusted in a peaker power plant, the plant had to increase water injection at a linear rate to the percentage of hydrogen being blended to keep NOx emissions within regulatory limits, nearly doubling its water use.[55] Using hydrogen in a fuel cell can mitigate some of the water use impacts of its production, as the end byproduct is water, but there will still be conversion losses. In water-stressed regions, the production tradeoffs of hydrogen for LDES should be considered in comparison to other less water-intensive technologies.

51. Bertagni, Matteo B., Stephen W. Pacala, Fabien Paulot, and Amilcare Porporato. "Risk of the Hydrogen Economy for Atmospheric Methane." Nature Communications 13, no. 1 (December 13, 2022): 7706. https://doi.org/10.1038/s41467-022-35419-7.

52. Elgowainy, Amgad. "Analysis of Water Consumption and Regional Water Stress Associated with Clean Hydrogen Production," 2023. https://www.energy.gov/sites/default/files/2023-11/1-05-water-consumption-elgowainy.pdf.

53. GE Vernova. "Hydrogen Calculator: Fuel Costs and Savings," 2019. https://www.gevernova.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines/hydrogen-calculator; calculations based on a 290 MW 7HA.01 turbine configured as a 1x1 combined cycle plant with a 10 percent capacity factor. Average U.S. household water usage estimates based on USGS Estimated use of water in the United States in 2015,

54. International Energy Agency. "Hydrogen Production and Infrastructure Projects Database." IEA. Accessed February 21, 2025. https://www.iea.org/data-and-statistics/data-product/hydrogen-production-and-infrastructure-projects-database.

55. "Hydrogen Cofiring Demonstration at New York Power Authority's Brentwood Site: GE LM6000 Gas Turbine." Technical Brief. 2022 LCRI-PG LCRI Program. EPRI, September 15, 2022. https://www.epri.com/research/products/000000003002025166.

RECOMMENDATIONS FOR HYDROGEN AS LDES

Energy storage technologies ranging from short duration to seasonal solutions will undeniably be an important part of the decarbonized grid. To enable such solutions, a change in assumptions will be needed in terms of energy resource planning. Utilities value dispatchable generation and are inclined to keep investing in gas turbines under the premise that they can at some point be converted to low-carbon, fully dispatchable generation, such as through combusting hydrogen. However, this entails significant risks if the analysis does not fully account for the future costs associated with plant conversion, as well as overinvestment in infrastructure that might become stranded for economic or policy reasons, or the greater potential for harm to nearby populations and the environment.

Hydrogen combustion in power plants is not the most cost-competitive option for longer duration storage needs. While hydrogen becomes more cost competitive for longer-duration applications, it is unlikely that the electric grid will need these sorts of longer duration assets in the next 10 years.

As detailed in this analysis, hydrogen, particularly hydrogen combustion in power plants, is not the most cost-competitive option for longer duration storage needs. While hydrogen becomes more cost competitive for longer-duration applications, it is unlikely that the electric grid will need these types of longer duration assets in the next 10 years. In addition, hydrogen production and use carry several environmental, economic, and public health risks that other promising storage technologies do not. When evaluating proposals for the buildout of hydrogen assets to meet grid reliability needs, state policymakers and public utilities commissions should account for the following considerations.

Consider the Reliability Need

Utilities must address electric system reliability across a broad spectrum of timeframes, from quick-response frequency and voltage regulation to multi-hour spikes in demand and seasonal variations. Different energy storage technologies may be better suited and more cost-effective to meet these varying reliability needs. As discussed in this report, a wide range of technologies can meet medium-duration needs in the 10+ hour duration period. Some states and utilities have already identified the near-term need for MDES, and many others will need 10+ hour storage within the next ten years, whereas the timing of multi-day and seasonal storage needs are still largely unknown.

Compared to other LDES technologies, hydrogen is not well-suited to address medium-duration reliability needs and is largely untested as a longer-duration energy storage resource (see Figure 1, p. 13). Widescale hydrogen production only makes economic sense in a largely decarbonized grid with significant excess renewable capacity, and even then, other storage technologies may remain more cost competitive due to the high operating costs of hydrogen peakers.

Consider Technology-Specific Risks

In addition to examining the expected cost of resources, utilities should also evaluate the risks associated with specific technologies. Even if one technology has the potential to be the least-cost storage option in a snapshot in time, cost projections can be very sensitive to market, technological, and policy conditions that are outside of a utility's control. When cost projections include multiple significant uncertainties, such as assumptions related to the cost of hydrogen production, transport, and power plant operations, the technology cannot be considered part of a least-cost, least-risk approach. Uncertain investments could lock ratepayers into a system that might become very expensive. The buildout of hydrogen pipelines, storage infrastructure, and power plants will require greater capital investment due to infrastructure requirements and carry additional risks for ratepayers, particularly low-income ratepayers who already struggle under a disproportionate energy burden.[56] These costs need to be accurately modeled, particularly for technologies like hydrogen, which require significant investments in both production and transmission infrastructure. On the other hand, many LDES options, such as iron-air batteries, are both modular and scalable, reducing the risk of overcommitting capital and creating greater flexibility in resource choice.

Consider Environmental and Equity Costs

While all LDES technologies carry costs and risks related to their production and utilization, hydrogen carries significant equity and environmental costs.

While all LDES technologies carry costs and risks related to their production and utilization, hydrogen carries significant equity and environmental costs. These considerations should not be secondary to other resource planning criteria, particularly since there are multiple technologies which can meet a similar need at lower environmental and equity cost. Some criteria to consider include the following:

- **Siting:** Hydrogen production facilities and hydrogen power plants carry a greater risk of displacing communities, particularly low-income communities, which are disproportionately displaced by large-scale infrastructure projects.[57] In addition to displacement risks, hydrogen production's

56. Ayala, Roxana, and Amanda Dewey. "Data Update: City Energy Burdens. How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burdens across the U.S." ACEEE, September 11, 2024. https://www.aceee.org/policy-brief/2024/09/data-update-city-energy-burdens.

57. Rosignoli, Francesca. "Linking Energy Poverty, Environmental Justice and Forced Displacement: Controversies and Ways Forward." In Legal Challenges at the End of the Fossil Fuel Era: Shaping a Just and Clean Energy Transition, edited by Daniel Iglesias Márquez, Clara Esteve-Jordà, and Beatriz Felipe Pérez, 99–117. Cham: Springer Nature Switzerland, 2024. https://doi.org/10.1007/978-3-031-61766-9_5.

heavy water use can have devastating consequences in areas already experiencing water scarcity. The effects of this can be mitigated by prioritizing low-impact projects and accounting for cumulative land-use and water-use impacts on marginalized communities in resource planning processes.

- **Emissions:** Hydrogen power plants pose a strong emissions risk for nearby communities due to high NOx emissions. This is particularly true for hydrogen power plants operating as peakers, which can have higher NOx emissions due to operational characteristics and tend to be disproportionately sited in low-income communities and communities of color.[58] The effect of this increased air pollution burden, which also increases local health impacts, should be heavily considered when comparing hydrogen power plants to other LDES technologies, many of which do not have an emissions risk.
- **Decarbonization Potential:** The worth of LDES technologies is in the value they can provide to a decarbonized grid. Each technology's impact on demand will have varying consequences to renewable resource adequacy. States with renewable energy deployment and/or decarbonization goals should push utilities to accurately account for the impact of increased electricity demand due to hydrogen production, as well as the impact of increased hydrogen leakage and subsequent global warming impact.

58. Morgan.

CONCLUSION

Utilities are facing unprecedent challenges in the shift toward an electric grid increasingly powered by solar and wind, particularly as electricity demand continues to grow. While renewable energy, short-duration energy storage, and demand management are vital components for balancing a more decarbonized grid, LDES assets will play a key role in ensuring that grid decarbonization, paired with unparalleled demand growth, can be met without a continuing reliance on fossil fuel infrastructure. However, these technologies are not created equal, and it is imperative that public utility commissions and state policymakers push for resource planning that accurately evaluates the full cost of these technologies and does not lock in assets that may harm decarbonization goals and pose a greater risk to marginalized populations.

Many utilities and independent power producers are eager to continue building new gas generation under the assumption that LDES technologies are not yet market-ready and the false narrative that these power plants can easily be converted to carbon-free hydrogen combustion in the future. Rather than defaulting to modeling technologies like hydrogen that are aligned with the existing gas distribution model, utility commissions and states must require that utilities accurately consider the costs associated with utilizing high-risk LDES solutions, particularly when there are other technologies that can provide similar services with a smaller footprint, less risk and cost uncertainty, and greater potential for public benefits and scalability.

While renewable energy, short-duration energy storage, and demand management are vital components for balancing a more decarbonized grid, LDES assets will play a key role in ensuring that grid decarbonization, paired with unparalleled demand growth, can be met without a continuing reliance on fossil fuel infrastructure.

TECHNICAL APPENDIX

The table below lists all of the costs and figures that were utilized in levelied cost of storage (LCOS) calculations in this report. Figures came from an analysis conducted by the utility PacifiCorp (denoted as PAC), the National Renewable Energy Laboratory's Advanced Technology Baseline (denoted as ATB), the Energy Storage Cost and Performance Database from the Pacific Northwest National Laboratory (denoted as PNNL), and Form Energy's analysis of different long-duration energy storage resources, “Modeling Multi-Day Energy Storage in New York" (denoted as Form).

TABLE APP1: **LCOS Calculation Inputs**

Technology	Capacity (MW)	Duration (hours)	Lifetime (years)	Roundtrip Efficiency (%)	CapEx ($/kW)	VOM ($/MWh)	FOM ($/kW-yr)	Demolition Cost	Depth of Discharge (%)	Max Cycles per year	Heat Rate (btu/kWh)	H_2	H_2 Storage Cost
Lithium Ion (4hr, 200MW)-PAC	200	4	20	85%	1,943		45.24	25.66	80%	365			
Lithium Ion (8hr, 200MW)-PAC	200	8	20	85%	3,533		81.44	46.19	80%	365			
Lithium Ion (4hr, 1000MW)-PAC	1000	4	20	85%	1,849		43.09	25.66	80%	365			
Lithium Ion (8hr, 1,000MW)-PAC	1,000	8	20	85%	3,370		77.57	46.19	80%	365			
Gravity Battery (4hr, 1000 MW)-PAC	1,000	4	50	83%	2,167		50.51	0.19	80%	1,000			
Gravity Battery (8hr, 1,000 MW)-PAC	1,000	8	50	83%	3,224		90.92	0.34	80%	1,000			
Adiabatic CAES (8hr, 500MW)-PAC	500	8	30	69%	2,178	1.12	11	49.31	80%	1,000			
Iron Air (100hr, 200MW)-PAC	200	100	20	43%	11,656		21.04	171.06	80%	1,000			
Pumped hydro (4hr, 400MW)-PAC	400	4	100	80%	312	0.58	20.2	156.47	80%	1,000			
Pumped hydro (10hr, 400MW)-PAC	400	10	100	80%	3,840	0.58	20.2	191.98	80%	1,000			
Pumped Thermal Energy Storage (10hr, 100MW)-PAC	100	10	60	55%	6174	0.7	2	60	80%	1,000			
Pumped Thermal Energy Storage (24hr, 50MW)-PAC	50	24	60	55%	11,525	0.7	1	60	80%	1,000			
Lithium Ion (4hr, 60MW)-NREL ATB-2024	60	4	15	85%	2,036.325		46.48692	25.66	80%	365			

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TABLE APP1: **LCOS Calculation Inputs** (CONTINUED)

Technology	Capacity (MW)	Duration (hours)	Lifetime (years)	Roundtrip Efficiency (%)	CapEx ($/kW)	VOM ($/MWh)	FOM ($/kW-yr)	Demolition Cost	Depth of Discharge (%)	Max Cycles per year	Heat Rate (btu/kWh)	H_2	H_2 Storage Cost
Lithium Ion (6hr, 60MW)-NREL ATB-2024	60	6	15	85%	2,811.168		65.17511	46.19	80%	365			
Lithium Ion (8hr, 60MW)-NREL ATB-2024	60	8	15	85%	3,586.012		83.86331	25.66	80%	365			
Lithium Ion (10hr, 60MW)-NREL ATB-2024	60	10	15	85%	4,360.855		102.5515	46.19	80%	365			
Lithium Ion (4hr, 60MW)-NREL ATB-2030	60	4	15	85%	1,768.287		39.60275	25.66	80%	365			
Lithium Ion (6hr, 60MW)-NRE L ATB-2030	60	6	15	85%	2,388.869		54.57035	46.19	80%	365			
Lithium Ion (8hr, 60MW)-NREL ATB-2030	60	8	15	85%	3,009.45		69.53795	25.66	80%	365			
Lithium Ion (10hr, 60MW)-NREL ATB-2030	60	10	15	85%	3,630.031		84.50556	46.19	80%	365			
PSH (10hr, 100MW)-PNNL-2023	100	10	60	80%	2,786.84		27.21		80%	1,000			
CAES (10hr, 100MW)-PNNL-2023	100	10	60	55%	1,125.33		15.43		80%	1,000			
Gravity (10hr, 100MW)-PNNL-2023	100	10	49	83%	4,549.24		26.22		80%	1,000			
Thermal (10hr, 100MW)-PNNL-2023	100	10	34	48%	3,024.95		37.26		80%	1,000			
Lithium Ion (10hr, 100MW)-PNNL-2023	100	10	16	83%	3,490.67		9.87	2.65	80%	365			
Lead Acid (10hr, 100MW)-PNNL-2023	100	10	14	77%	3,992.50		10.17	18.76	58%	365			
Vanadium Redox (10hr, 100MW)-PNNL-2023	100	10	12	65%	4,462.31	1.4	11.39	25.11	80%	1,000			
Hydrogen (10hr, 100MW)-PNNL-2023	100	10	30	31%	2,953.69		23.21		80%	1,000			
PSH (24hr, 100MW)-PNNL-2023	100	24	60	80%	2,950.29		27.21		80%	1,000			
CAES (24hr, 100MW)-PNNL-2023	100	24	60	55%	1,207.53		14.88		80%	1,000			
Gravity (24hr, 100MW)-PNNL-2023	100	24	49	83%	7,601.06		34.37		80%	1,000			
Thermal (24hr, 100MW)-PNNL-2023	100	24	34	48%	4,053.94		47.69		80%	1,000			
Lithium Ion (24hr, 100MW)-PNNL-2023	100	24	16	83%	8,120.59		21.98	2.65	80%	365			
Lead Acid (24hr, 100MW)-PNNL-2023	100	24	14	77%	9,190.10		22.44	17.02	58%	365			

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TABLE APP1: **LCOS Calculation Inputs** (CONTINUED)

Technology	Capacity (MW)	Duration (hours)	Lifetime (years)	Roundtrip Efficiency (%)	CapEx ($/kW)	VOM ($/MWh)	FOM ($/kW-yr)	Demolition Cost	Depth of Discharge (%)	Max Cycles per year	Heat Rate (btu/kWh)	H_2	H_2 Storage Cost
Vanadium Redox (24hr, 100MW)-PNNL-2023	100	24	12	65%	9,469.28	1.26	29.33	21.68	80%	1,000			
Hydrogen (24hr, 100MW)-PNNL-2023	100	24	30	31%	3,033.37		23.9		80%	1,000			
PSH (10hr, 100MW)-PNNL-2030	100	10	60	80%	2,786.84		27.21		80%	1,000			
CAES (10hr, 100MW)-PNNL-2030	100	10	60	0.55	1125.33		15.43		0.8	1000			
Gravity (10hr, 100MW)-PNNL-2030	100	10	49	83%	4,032.74		23.6		80%	1,000			
Thermal (10hr, 100MW)-PNNL-2030	100	10	34	48%	2,812.94		34.12		80%	1,000			
Lithium Ion (10hr, 100MW)-PNNL-2030	100	10	16	83%	2690		9.87	2.65	80%	365			
Lead Acid (10hr, 100MW)-PNNL-2030	100	10	14	77%	3,563.37		10.17	12.73	58%	365			
Vanadium Redox (10hr, 100MW)-PNNL-2030	100	10	12	65%	4,093.61	1.79	9.95	21.62	80%	1,000			
Hydrogen (10hr, 100MW)-PNNL-2030	100	10	30	31%	1,014.56		14.3		80%	1,000			
PSH (24hr, 100MW)-PNNL-2030	100	24	60	80%	2,950.29		27.21		80%	1,000			
CAES (24hr, 100MW)-PNNL-2030	100	24	60	55%	1,207.53		14.88		80%	1,000			
Gravity (24hr, 100MW)-PNNL-2030	100	24	49	83%	6,622.34		30.93		80%	1,000			
Thermal (24hr, 100MW)-PNNL-2030	100	24	34	48%	3,717.02		43.73		80%	1,000			
Lithium Ion (24hr, 100MW)-PNNL-2030	100	24	16	83%	6,253.84		21.98	2.65	80%	365			
Lead Acid (24hr, 100MW)-PNNL-2030	100	24	14	77%	8,238.19		22.44	11.38	58%	365			
Vanadium Redox (24hr, 100MW)-PNNL-2030	100	24	12	65%	8,642.21	0.97	20.15	18.69	80%	1,000			
Hydrogen (24hr, 100MW)-PNNL-2030	100	24	30	31%	1,094.24		15		80%	1,000			
PSH (100hr, 100MW)-PNNL-2023	100	100	60	80%	3,415.97		27.21		80%	1,000			
CAES (100hr, 100MW)-PNNL-2023	100	100	60	55%	1,637.13		16.5		80%	1,000			
Gravity (100hr, 100MW)-PNNL-2023	100	100	49	83%	20,172.34		78.6		80%	1,000			
Thermal (100hr, 100MW)-PNNL-2023	100	100	34	48%	8,088.29		102.08		80%	1,000			
Lithium Ion (100hr, 100MW)-PNNL-2023	100	100	16	83%	32,913.67		85.98	2.65	80%	365			

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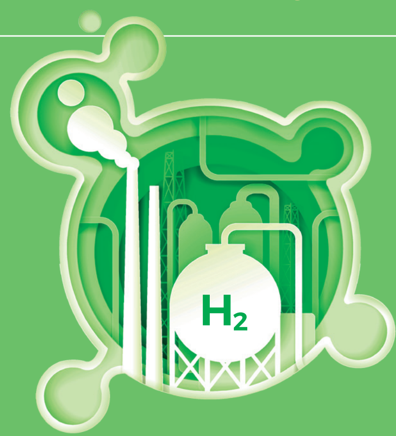
TABLE APP1: **LCOS Calculation Inputs** (CONTINUED)

Technology	Capacity (MW)	Duration (hours)	Lifetime (years)	Roundtrip Efficiency (%)	CapEx ($/kW)	VOM ($/MWh)	FOM ($/kW-yr)	Demolition Cost	Depth of Discharge (%)	Max Cycles per year	Heat Rate (btu/kWh)	H_2	H_2 Storage Cost
Lead Acid (100hr, 100MW)-PNNL-2023	100	100	14	77%	36,641.1		87.28	15.75	58%	365			
Vanadium Redox (100hr, 100MW)-PNNL-2023	100	100	12	65%	36,568.08	1.19	88.57	19.82	80%	1,000			
Hydrogen (100hr, 100MW)-PNNL-2023	100	100	30	31%	3,446.69		27.47		80%	1,000			
PSH (100hr, 100MW)-PNNL-2030	100	100	60	80%	3,415.97		27.21		80%	1,000			
CAES (100hr, 100MW)-PNNL-2030	100	100	60	55%	1,637.13		16.5		80%	1,000			
Gravity (100hr, 100MW)-PNNL-2030	100	100	49	83%	17,295.34		70.74		80%	1,000			
Thermal (100hr, 100MW)-PNNL-2030	100	100	34	48%	7,208.23		93.99		80%	1,000			
Lithium Ion (100hr, 100MW)-PNNL-2030	100	100	16	83%	25,377.6		85.98	2.65	80%	365			
Lead Acid (100hr, 100MW)-PNNL-2030	100	100	14	77%	32,725.67		87.28	10.44	58%	365			
Vanadium Redox (100hr, 100MW)-PNNL-2030	100	100	12	65%	33,472.48	0.92	75.55	17.08	80%	1,000			
Hydrogen (100hr, 100MW)-PNNL-2030	100	100	30	31%	1507.53		18.56		80%	1,000			
SCCT Frame 100% hydrogen burning, storage cavern (24 hours, 233MW)-PAC	233	24	40		1,787.5	9.3425	35.12	28.9495	100%	5,000	9,717	1	0
SCCT Frame 100% hydrogen burning, storage tanks (24 hours, 233MW)-PAC	233	24	40		2,286.5	9.4825	40.78	28.9495	100%	5,000	9,717	1	0
CCCT 2x1 100% hydrogen burning, storage cavern (24 hours, 1227MW)-PAC	1,227	24	40		1,997.95	3.052	42.38	28.6735	100%	5,000	6,122	1	0
CCCT 2x1 100% hydrogen burning, storage tanks (24 hours, 1227MW)-PAC	1,227	24	40		2,496.95	3.192	48.04	28.6735	100%	5,000	6,122	1	0
SCCT Frame-cavern-PAC	233	24	40		1,780.144	9.35101352	33.68521	33.68521	100%	5,000	9,717	1	0.45
SCCT Frame-tanks-PAC	1,227	24	40		1,780.144	9.35101352	33.68521	33.68521	100%	5,000	9717	1	1.25
CCCT-cavern-PAC	233	24	40		1,966.262	2.748712908	42.84758	42.84758	100%	5,000	6,363	1	0.45
CCCT-tanks-PAC	1,227	24	40		1,966.262	2.748712908	42.84758	42.84758	100%	50,00	6,363	1	1.25
Iron Air (100hr, 200MW)-Form	200	100	20	43%	2150		17.5	171.06	80%	1000			

Evaluating Hydrogen for Long-Duration Energy Storage

Costs, Risks, and Equity Considerations



Clean Energy Group (CEG) is a leading national nonprofit advocacy organization dedicated to advancing innovative technical, economic, and policy solutions that ensure equitable participation in the clean energy transition.

Clean hydrogen continues to receive interest from utilities and policymakers as a potential decarbonization tool. However, hydrogen production and use can have severe impacts on the environment, public health and safety, and ratepayer costs. CEG's Hydrogen Information and Public Education (HIPE) initiative provides evidence-based information and research on hydrogen's potential harms, equipping community advocates, policymakers, and regulators with the knowledge they need to critically evaluate hydrogen project proposals.

To learn more about HIPE and access additional resources on hydrogen, visit *www.cleanegroup.org/initiatives/hydrogen*.

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