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November 21, 2025

U.S. Department of Energy

1000 Independence Ave., SW

Washington, DC 20585

Re: Accelerating Speed to Power/Winning the Artificial Intelligence Race: Federal Action to Rapidly Expand Grid Capacity and Enable Electricity Demand Growth

The National Hydropower Association (NHA) appreciates the opportunity to provide input to the Department of Energy's *Accelerating Speed to Power* Request for Information. NHA is a non-profit national association dedicated to securing and promoting hydropower as a baseload and reliable source of energy. Its membership consists of more than 320 organizations, including public and investor-owned utilities, independent power producers, equipment manufacturers, and professional organizations that provide legal, environmental, and engineering services to the waterpower industry.

Hydropower, particularly pumped storage hydropower (PSH), is uniquely positioned to help DOE achieve the objectives of this initiative: expanding grid capacity, accelerating interconnection of large loads, and ensuring the reliability and affordability of power as demand from data centers and advanced manufacturing continues to rise. As such, it should be a priority for existing DOE authorities under the Loan Programs Office and the Grid Deployment Office. However, these programs have yet to be used for new hydro storage development, despite its potential for accelerating speed to power.

NHA's primary area of focus for this RFI is project development and electricity generation. Our response will address **a)** high priority geographic regions for targeted DOE investment and **b)** DOE funding, financing and technical assistance. For additional information, please see the contact below:

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1. High-Priority Geographic Areas for Targeted DOE Investment:

Pumped storage hydropower (PSH) is the nation's largest and most established form of long-duration energy storage. With just 22 gigawatts (GW) of operating capacity, PSH delivers nearly 90% of all utility-scale storage capability in the United States. As the demand for continuous, predictable electricity grows, developers and utilities alike are pursuing new pumped storage. This is especially true in Western states like Utah, Nevada, Arizona, California, Washington, Oregon, Montana, Idaho, and Colorado. In fact, of the 60 GW of pumped storage in the development pipeline today[1], 85% is located in the Western Electricity Coordinating Council (WECC) service area. Three of these projects are fully designed and licensed.[2]

Demand for electricity in the WECC is projected to grow an enormous 20.4% over the next decade, from 942 TWh in 2025 to 1,134 TWh in 2034.[3] This trend is largely driven by the power needs of data centers. At the same time, over 24 GW of baseload coal, natural gas, and nuclear are scheduled to retire.[4] To meet the needs of the artificial intelligence industry and ensure the U.S. remains a global leader, we must build new energy resources in the west. Fortunately, pumped storage hydropower is well positioned to help.

As the map below illustrates, many pumped hydro projects are located near the thousands of MWs of planned data center capacity coming online in Western cities like Phoenix, Salt Lake City, Carson City, and Portland. They are also situated near major interregional transmission infrastructure, often with direct, high voltage passage to their respective metro areas.[5] As such, these facilities are natural candidates to serve these large loads, providing the dispatchable energy storage needed to preserve 24/7 uptime. But the value of pumped storage extends far beyond just power generation. These additional contributions to the bulk electric system can unlock gigawatts of new incremental load, maximizing the efficiency of existing resources and enabling the rapid deployment of new ones. To ensure the most effective use of DOE investment, this Administration must consider pumped storage as a priority solution to accelerate speed to power in the Western U.S.

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[1] U.S. Hydropower Development Pipeline Data, 2025
https://hydrosource.ornl.gov/data/datasets/us-hydropower-development-pipeline-data-2025/
[2] Eagle Mountain, Swan Lake North, and Gordon Butte Pumped Storage
[3] Western Assessment of Resource Adequacy 2024
https://feature.wecc.org/wara/#group-section-Resource-Changes-QG2EfElxRl
[4] *Id*
[5] NHA strongly encourages DOE to visit www.hydro.org/facts to view our interactive GIS map showing the relationship between existing transmission infrastructure and proposed pumped storage projects in the WECC.

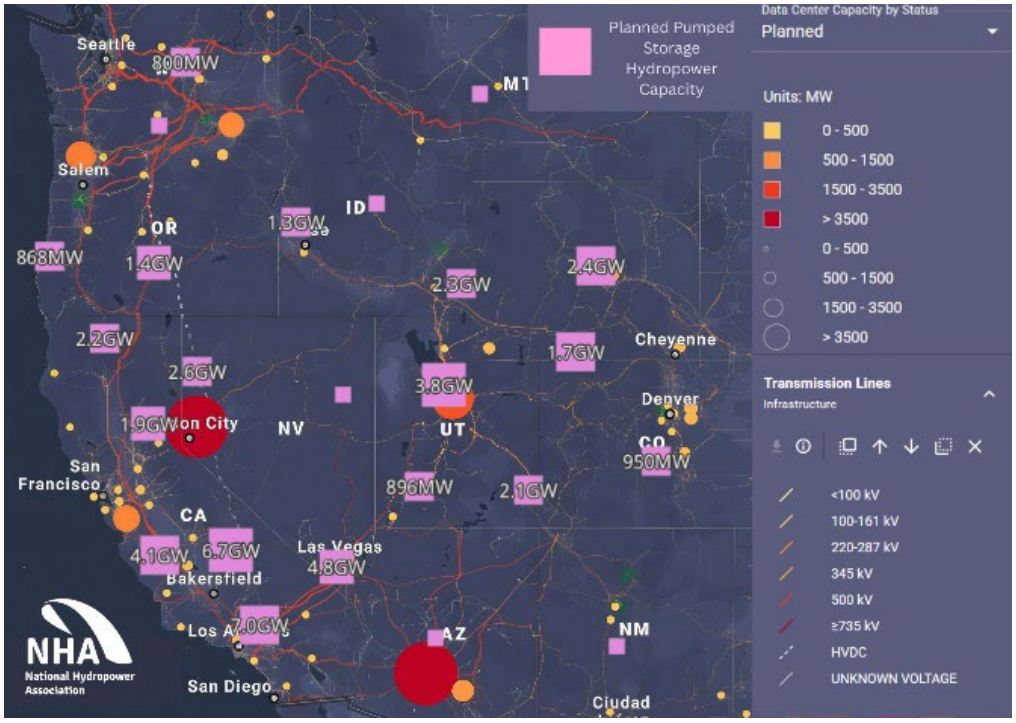


Figure 1: NREL Speed to Power Map with overlay of pumped storage development pipeline

Pumped storage provides the foundational reliability services necessary for the rapid addition of new generation and load.

Over 85% of the 172 GW of planned resource additions in the WECC are variable renewables and battery storage. This poses serious challenges for grid stability, which has long relied on synchronous, spinning mass generation to support system inertia, voltage, and frequency response. As shown in Figure 2 below, inertia in the WECC is already at an all-time low and is projected to fall even further by 2026 as conventional baseload units retire (between 2018 and 2024, there has been a decrease in inertial capability by approximately 30,000-50,000 MVA).[6] Declining reactive power margins and rising frequency volatility can damage electrical equipment and cause blackouts, as seen in Spain this past April.[7] Grid-following inverter-based resources like solar, wind, and battery storage are inherently reactive systems modeled to follow a grid's existing voltage waveform. Pumped storage, on the other hand, provides the original grid-forming physical inertia needed to maintain that foundational voltage. It can also re-energize

[6] Western Interconnect System Inertia Oct. 2025 Briefing
https://www.wecc.org/sites/default/files/documents/meeting/2025/13.%20WillisM.-%20System%20Inertia_October%20RAC%202025.pdf?utm_source=chatgpt.com
[7] Entsoe 28 April 2025 Blackout Factual Report
https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/2025/entso-e_incident_report_ES-PT_April_2025_06.pdf

the grid in the event of a total blackout. In fact, hydropower provides 40% of all black start capability across the United States, despite only being 6% of total generation.[8]

Grid interconnected large loads cannot be left vulnerable to power volatility if the United States is to onshore manufacturing and win the race to artificial general intelligence. We also cannot continue the rapacious buildout of new generation and transmission needed to enable these loads unless the basic health of the grid is secure. In the West, pumped storage is a large part of the solution. Yet none is currently under construction in the WECC, even as system inertia continues downward. This overreliance on renewables must be balanced with more conventional generation. DOE should, therefore, prioritize pumped storage as it looks to deploy capital and technical assistance towards solutions that accelerate speed to power.

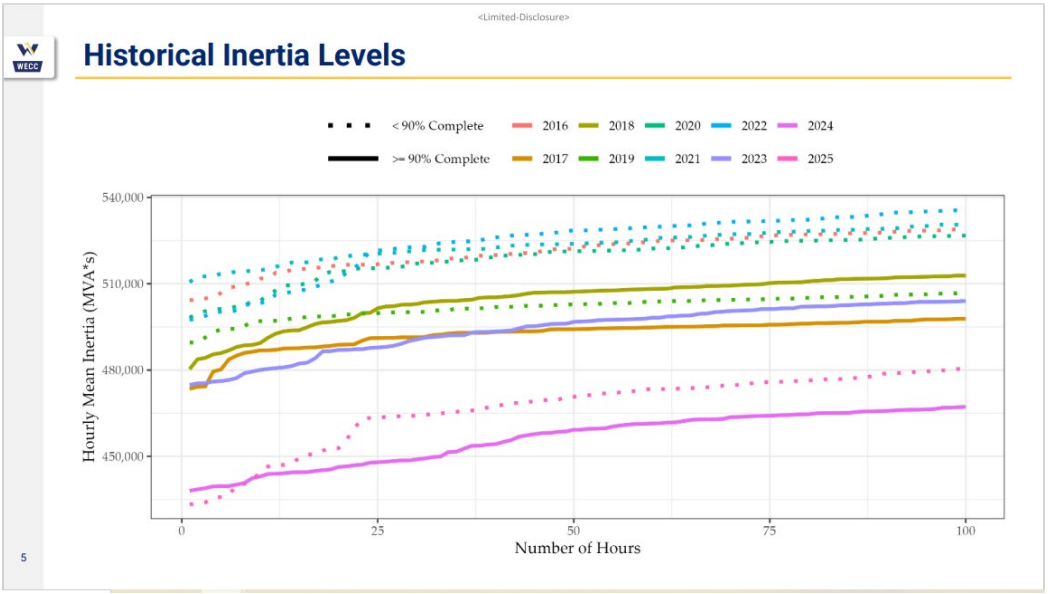


Figure 1: Historic Inertia Levels in the WECC as of 2025

Long duration pumped storage optimizes the efficiency of existing generation and new nuclear.

Pumped storage functions as both a load and a source of generation, shifting energy across long intervals and allowing other resources to operate on steadier profiles. With the ability to discharge for 8–20 hours or more, PSH converts otherwise inflexible generation into fast-responding capacity, increasing the total value delivered by those assets to large loads. This is why the technology was first developed by utilities as a complement to their baseload nuclear assets, absorbing excess generation during low-demand periods and returning it during peaks.

[8] NHA Hydro at Risk Report
https://www.hydro.org/wp-content/uploads/2024/10/NHA-HydropowerAtRisk-WhitePaper.pdf

Now, as the next generation of nuclear power comes online in the United States, pumped hydropower will be essential to maximizing its full potential. Together, advanced nuclear and pumped storage form a complementary backbone that could uphold American energy dominance for generations to come



Oconee Nuclear Station built alongside Bad Creek and Jocassee Pumped Storage Facilities in 1974[9]

The same dynamic applies to variable renewables in the WECC. Wind and solar are already producing gigawatts of energy that cannot always be used when it is generated. PSH can consume this surplus and shift it across days, enabling more effective use of the existing fleet without waiting for new generation.[10] Batteries also provide this flexibility, but are limited by short discharge windows that can only manage daily peaks. Pumped storage, on the other hand, provides the multi-day coverage needed to smooth longer weather events and extend the grid value of existing resources. As utility developers face multi-year delays and escalating cost for natural gas turbines[11], new generation must be both dispatchable and capable of optimizing the existing fleet. Pumped storage does both, leveraging each megawatt of existing nuclear, wind, and solar to its fullest potential. This, in turn, enables GWs of additional load growth.

Furthermore, the development process for pumped storage is becoming more cost-efficient and expedient. Modern civil works practices ---particularly rapidly deployable modular precast construction means and methods---compress project timelines by shifting much of the work into controlled manufacturing environments. This reduces on-site labor needs, impact of weather

[9] Oconee Nuclear Station Celebrates 40 Years of Operation
https://nuclear.duke-energy.com/2013/07/24/oconee-nuclear-station-celebrates-40-years-of-operation
[10] Storage Effectiveness in Enabling Variable Renewable Generation and Avoiding Fossil Emissions
https://docs.nrel.gov/docs/fy23osti/86751.pdf
[11] Rocky Mountain Institute Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help
https://rmi.org/gas-turbine-supply-constraints-threaten-grid-reliability-more-affordable-near-term-solutions-can-help/

delays, and overall project risk. Because civil works account for 60-70%[12] of total PSH capital costs, solutions like modular precast can significantly decrease construction field costs, borrowing/debt service costs and insurance costs, bringing facilities to PPA revenue sooner. For large PSH projects, establishing an on-site precast facility can amplify these benefits even further by allowing manufacturing to proceed in parallel with excavation, site preparation and foundation work. Overall, these innovations in civil construction help pumped storage serve new load faster than ever.

Pumped storage hydropower serves as a transmission asset to expand transfer capability without new wires.

The Western Interconnection continues to face structural transmission constraints that limit the efficient movement of energy between resource rich and load dense regions. In the WECC, the Department of Energy uses "Qualified Paths" as the primary reliability metric for these bottlenecks.[13]



Figure 2: Paths in the Western Interconnect

Under the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP), a path is designated as "Qualified" if it has operated near its rated capacity for more than 100 hours in the previous 36 months and required curtailments or other mitigation. DOE highlights four such paths—Path 66 (California–Oregon Intertie), Path 30 (TOT1A), Path 31 (TOT2A), and Path 36 (TOT3)—as chronic points of congestion constraining transfers from the Pacific Northwest toward California, Nevada, and Arizona. These corridors frequently experience unscheduled "loop flows" through neighboring paths, which occur when power cannot move freely along its scheduled route and instead diverts across adjacent transmission lines. The resulting loop flows can unintentionally load nearby interfaces, such as those through Wyoming, Colorado, and New Mexico, forcing operators to curtail scheduled power.

[12] U.S. Department of Energy Water Power Technologies Office Hydrowires Pumped Storage Hydropower FAST Commissioning Technical Analysis, July 2020, ORNL/SPR-2019/1299
[13] Department of Energy National Transmission Needs Study 2023
https://www.energy.gov/gdo/national-transmission-needs-study

This trend is further evidenced by CAISO market price data, which consistently show elevated prices along California's coastal load centers relative to inland generation hubs, indicating that transmission limits frequently prevent low-cost generation from reaching demand. During July 2024, CAISO recorded strong east–west congestion between the Desert South and coastal zones, where inland LMPs occasionally fell below zero while coastal prices remained positive or spiked above $150/MWh.[14] In such conditions, generation behind the constraint must be curtailed even as nearby demand centers pay elevated prices.

Building new transmission is a long and costly process. To keep U.S. companies ahead in the AI race, the grid needs solutions that can be deployed now. With roughly half of all congestion costs occurring in just five percent of hours[15], a more targeted, regional approach could unlock gigawatts of new incremental load without constructing new lines. Pumped storage hydropower provides that bridge. By absorbing surplus generation during periods of oversupply, PSH captures energy value that would otherwise be curtailed. When congestion stems from distance to load, it operates as a dispatchable generator—reducing dependence on constrained imports and stabilizing local supply. This dual capability allows ratepayers to save on multibillion-dollar interstate transmission projects while accelerating speed to power today.

With several fully licensed projects near Qualified paths in the WECC, and many more underway, PSH is strategically positioned to alleviate both regional and intra-state congestion. These projects demonstrate how storage can transform stranded energy into firm capacity and expand effective transfer capability without new wires, delivering immediate progress toward DOE's objectives.

2. Use of DOE Funding, Financing, and Technical Assistance

Pumped storage projects face financing and permitting challenges that have stifled development for decades, despite being a proven and valued resource for load serving entities. Under current market structures, where capacity compensation is unpredictable and ancillary services are undervalued, merchant developers struggle to secure the long-term revenue certainty needed to assure lenders that construction can proceed. Similarly, potential offtakers looking to enter bilaterial power purchase agreements (PPAs) are often hesitant to sign contracts with long lead projects if there is little confidence in future market conditions. Even for utility developers, permitting and construction risk continue to obstruct potential development. Ultimately, the industry desperately needs a first mover project to reintroduce the U.S. to pumped storage.

Strategic federal action is needed, therefore, to derisk project investment and accelerate the buildout of this essential infrastructure. Fortunately, the Department of Energy is well positioned

[14] CAISO July 2024 Summer Market Performance Report
https://www.caiso.com/documents/summer-market-performance-report-july-2024.pdf
[15] Department of Energy National Transmission Needs Study 2023

to provide this support in the form of funding, financing, and technical assistance. Focusing DOE aid on a handful of shovel-ready projects in the short term will increase the viability of the rest of the pipeline in the long term.

Generally, there are two approaches the DOE can take to support pumped storage development:

1. Prioritize the use of existing authorities to supplement gaps in available capital with federal grants, loan guarantees, and credit enhancements.

2. Work in coordination with the Federal Energy Regulatory Commission (FERC) under the Federal Power Act and the Department of Energy Organization Act to direct RTOs and ISOs to remove barriers to LDES participation in wholesale markets.

To pursue these two approaches, NHA recommends DOE take the following steps:

Use the LPO Title XVII loan guarantee authority to provide utility developers with a construction risk backstop

On October 28th, The Department of Energy issued its Energy Dominance Financing interim final rule, which revises the Title XVII loan guarantee program under section 1706 of the One Big Beautiful Bill Act. Among the most consequential changes is DOE's new definition of an eligible energy infrastructure project, which now includes resources that:

> "…support or enable the provision of known or forecastable electric supply at time intervals necessary to maintain or enhance grid reliability or other system adequacy needs.[16]"

Here, the LPO recognizes that reliability is not solely a matter of generation capacity but also of the temporal alignment between supply and demand. This means that PSH now qualifies under Title XVII not merely as an emissions-reducing asset, but as critical reliability infrastructure that supports the 24/7 availability of power demanded by data centers and industrial loads. To deliver on this clear mandate from the President and Congress, LPO must leverage their $250B in loan guarantee authority to prioritize pumped storage hydropower.

One option for LPO to support utility developers is through a construction risk backstop. In this structure, a utility develops a pumped storage project within its regulated rate base, while DOE support is used to limit ratepayer exposure and ease state commission approval. Project financing

[16] Energy Dominance Financing Amendments
https://www.federalregister.gov/documents/2025/10/28/2025-19675/energy-dominance-financing-amendments

would combine senior debt from bonds, commercial lenders, or institutional investors with an LPO loan guarantee that covers a portion of the senior debt—typically up to 80 percent—against defined construction cost overrun risks. The guarantee would activate if total costs exceed the project's P50 estimate[17] and reach an agreed upon threshold. It would apply only during the construction phase prior to commercial operation and would be sized to cover incremental overruns within a defined scenario. Funding flows would follow a layered structure: the utility would maintain a contingency reserve for moderate overruns, while the LPO backstop would supply additional liquidity if costs exceed that reserve. Any LPO disbursements would later be repaid under a negotiated cost-sharing arrangement among project stakeholders.

Use the GDO Grid Resilience and Innovation Partnerships Program (GRIP) to provide merchant developers with a post-commercial operation date (COD) revenue adjustment.

A second framework would support private developers through a post-COD revenue adjustment that operates within existing GDO grant authority. Under this structure, a developer secures a long-term revenue agreement such as a power purchase agreement, capacity contract, or tolling arrangement with a qualified offtaker. DOE, through GDO, would then offer a supplemental Revenue Adjustment Agreement in the form of a conditional grant that sits alongside the guaranteed loan. The goal is to strengthen project bankability by assuring lenders that a minimum level of operating income will be available to support debt service during the early years of operation.

The Revenue Adjustment Agreement would activate only if predefined risk events occur during construction and in early-stage commercial operation. These events would be limited to conditions that materially affect project economics and are outside the developer's control, such as differing subsurface conditions revealed late in construction, post-financial-close regulatory changes that alter design or cost, or force majeure events that disrupt early operational performance. Any claim would be validated by an independent expert, consistent with GDO's existing risk review practices. If triggered, GDO would cover a portion of the verified incremental cost through a time-bound revenue adjustment. Payments would be structured as a capacity-payment uplift or fixed annual adder tied directly to debt-service needs. The support would sunset after five to ten years, once the project reaches stable operating conditions and lenders have adequate confidence in long-term performance.

The Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Program provides broad eligibility to grid-enhancing technologies that strengthen system flexibility and resilience, including energy storage solutions. For example, in 2024, DOE committed $85.4M in cost sharing to the Virginia Department of Energy for the deployment of battery-energy storage

[17] A P50 estimate (short for *Probability 50%*) is a project cost or performance estimate that has an equal likelihood of being exceeded or undershot, typically derived from a Monte Carlo simulation

systems near the Iron Mountain data center in Northern Virginia.[18] This public private partnership represents the kind of projects DOE should be prioritizing in the AI era, where resilience of critical loads in priority industries is more important than ever. However, the GRIP program has not yet been utilized for spinning mass LDES like pumped storage, despite its proven contributions to the grid. This is a missed opportunity.

The statutory provisions governing GRIP contain no limitations on DOE structuring awards as performance-based or linking payment timing to post-COD milestones.[19] Further, merchant developers of pumped storage are already eligible under the Grid Resilience Utility and Industry Grants and Smart Grid Grants. The Trump Administration, therefore, should leverage this existing program and its $10.5B in appropriations to enable technologies that directly support speed to power, like pumped storage. This in turn would give merchant developers a viable pathway to manage early-operation revenue risk.

Use the DOE 42 U.S.C. § 7256 flexible contracting authority to establish a pilot program to provide merchant developers with floor and ceiling revenue stabilization

A third, more aggressive approach would have DOE establish a new pilot program under Section 646(f) of the Department of Energy Organization Act (42 U.S.C. § 7256(f)). Using the flexible "other transactions" authority, the DOE could test run a full floor-and-ceiling revenue stabilization structure similar to the United Kingdom's Contracts-for-Difference scheme.

Under this model, DOE would provide a defined revenue floor during the early years of operation for privately financed pumped storage projects, mitigating downside risk that otherwise limits merchant financing. In return, DOE would also share in a portion of upside revenues above an agreed-upon ceiling. This reciprocal structure would reduce federal exposure, create a natural budgetary offset, and align incentives between DOE and the developer. Operationally, DOE would execute a performance-based agreement that activates only when verified post-financial-close events materially depress revenues—such as regulatory changes or operational constraints outside the developer's control. Conversely, if market conditions yield revenues above the agreed ceiling, a share of those proceeds would flow back to DOE, supporting program sustainability. All payments would be independently validated and would sunset after a fixed term. A §646 pilot of this kind would allow DOE to test a balanced revenue-stabilization instrument that supports reliability-critical assets while offering a credible path to limit net federal cost.

[18] Building Flexible, Grid-Enhancing Data Centers in Virginia and South Carolina https://www.energy.gov/sites/default/files/2024-10/VirginiaDeptEnergy_GRIP%202_40103b_Fact_Sheet.pdf

[19] 42 U.S.C. 17386, 18711, and 18712

Encourage the FERC to direct RTOs and ISOs to remove barriers to LDES participation in wholesale markets

Private investment in long-duration storage, including LPO-backed investment, depends on predictable market revenues, and those revenues are determined by RTO and ISO rules. Today, those rules undervalue pumped storage and other LDES resources. Participation models assume short-duration, four-hour batteries and interconnection rules do not reflect the duty cycles of resources that both absorb and supply power. Further, essential services such as inertia, primary frequency response, voltage support, condensing, black-start capability, and long-duration ramping are not compensated at levels that reflect their reliability contribution. These gaps also extend to capacity accreditation models. Current approaches do not recognize discharge duration, seasonal availability, or the contribution of multi-hour storage to system adequacy, suppressing the value of LDES in capacity markets and bilateral procurements.

Given these structural barriers, federal financing alone cannot scale long-duration storage. DOE should use its authorities under the Department of Energy Organization Act[20] to encourage FERC to direct RTOs and ISOs to update their market rules. This includes revising participation models to reflect long-duration duty cycles, creating distinct products for inertia and other grid-forming capabilities, establishing capacity accreditation methods that account for duration and seasonal performance, and ensuring that controlled charging is compensated when it stabilizes system conditions.

FERC has clear authority under FPA § 206 to direct RTOs and ISOs to revise market rules when existing tariff provisions or participation models are unjust, unreasonable, or unduly discriminatory. There is also clear precedent for this type of intervention. Order 764[21] required the markets to adjust scheduling practices to accommodate variable renewable generation, and Order 841[22] required RTOs and ISOs to open their tariffs to battery storage when legacy rules shut them out. Long-duration storage faces analogous barriers today. DOE can also reinforce this process through technical assistance: national laboratory work—particularly Argonne's LDES revenue and valuation modeling—has already identified potential reforms. DOE should ensure that this research is translated into concrete recommendations and follow-through at FERC so that markets finally reflect the full reliability value of long-duration storage.

[20] 42 U.S.C. § 7173(a).
[21] FERC Order No. 764: Integration of Variable Resources https://www.ferc.gov/sites/default/files/2020-06/OrderNo.764.pdf\
[22] FERC Order No. 841: Energy Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators https://www.ferc.gov/media/order-no-841