



U.S. Hydropower Market Report

2026 Edition

September 2026

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*Priest Rapids Hydroelectric Project, Grant County, Washington
(image courtesy of Dave Dempsey)*

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Environmental Sciences Division

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managed by
UT-BATTELLE LLC
for the
US DEPARTMENT OF ENERGY
under contract DE-AC05-00OR22725
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ACKNOWLEDGMENTS

For their support of this project, we thank the DOE Hydropower and Hydrokinetic Office (H2O). We would like to acknowledge the input provided by Madden Sciubba, Corey Vezina, and Nicole Fitzgerald of H2O at different stages of report development.

Beyond the key Oak Ridge National Laboratory (ORNL) authors and contributors listed on the title page, others at ORNL have also supported this effort: Lora Davis (project management), Kim Askey and Galen Fader (communications). Morgan Nachman, Kelsey Rugani, and Linda Pucilowski (Kearns & West) assisted with report design and formatting.

We would also like to thank the reviewers that provided comments on an earlier draft of the 2026 edition: Shannon Ames (Low Impact Hydropower Institute), Rebecca Ellis (International Hydropower Association), Jeremy Chase-Israel (National Hydropower Association), Lindsay Aramayo (Energy Information Administration), Mark Christian (Electric Power Research Institute), Rebecca Johnson, Brent Osiek, Jennifer Henn, and Sheila Cook (Western Area Power Administration), Jeff Leahy (SMI Consulting), Carl Atkinson (Voith), Daniel Boff and Kyle DeSomber (Pacific Northwest National Laboratory), Morgan Nachman, Kelsey Rugani, and Mary Beth Day (Kearns & West).

This report was funded by the Hydropower and Hydrokinetic Office, Office of Critical Minerals and Energy Innovation of the U.S. Department of Energy under Contract No. DE-AC05-00OR22725. Any remaining errors in the document are the sole responsibility of the authors.

On the front cover: Priest Rapids Hydroelectric Project, Grant County, Washington (image courtesy of Dave Dempsey). This facility, owned and operated by PUD No. 2 of Grant County, has ten units with a combined generation capacity of 950 MW and began commercial operation in 1959.

HIGHLIGHTS

U.S. HYDROPOWER AND PUMPED STORAGE HYDROPOWER (PSH) CAPACITY AND INVESTMENT TRENDS

At the end of 2025, the U.S. hydropower fleet (excluding PSH) contained 2,258 hydropower plants with a total generating capacity of 80.55 GW.¹ The fleet produced 23.1% of all renewable electricity and 5.6% of total electricity in the United States in 2025.² (Chapter 1)

- The net capacity of the U.S. hydropower fleet increased by 2.1 GW from 2010 to 2025. This net change is a combination of 1.9 GW added to the existing fleet, 0.7 GW of capacity from new facilities (of which 94% of the capacity was from retrofits of non-powered dams (NPDs) and conduits), and 0.5 GW of capacity retirements. The three years since the previous edition of the report (2023–2025) accounted for 16% of the net capacity additions at the existing fleet, 0.4% of new project additions, and 46% of retired capacity in 2010–2025. A single project (the Klamath project) with three plants in California and one in Oregon accounts for 75% of the 217 MW of capacity retired in 2023–2025. (Section 1.1)

Forty-one PSH plants with a total nameplate generating capacity of 22.2 GW and an estimated energy storage capacity of 553 GWh accounted for 33.5% of the nameplate generating capacity and 82.1% of the energy storage capacity of utility-scale storage units in the United States. (Chapter 1)

- From 2010 to 2025, the net change in U.S. PSH nameplate generating capacity was an increase of 1.7 GW. From 2023 to 2025, 258 MW added through upgrades to existing facilities became operational and two PSH facilities in California retired (47.4 MW). (Section 1.1)
- Batteries surpassed PSH in 2024 in terms of nameplate generating capacity. By the end of 2025, 994 utility-scale batteries were in operation in the United States with total nameplate generating capacity of 43.6 GW (of which 97% are lithium-ion batteries) and energy storage capacity of 121 GWh.
- PSH continues to provide most (82%) of the energy storage capacity because of its longer storage durations (i.e., the number of hours it takes to deplete the energy stored in the unit if discharging it at its rated nameplate capacity). The median storage duration for U.S. utility-scale battery systems at their rated capacity is two hours. On the other hand, the estimated median storage duration of U.S. PSH plants at their rated capacity is ten hours. (Chapter 1 Overview)

The average annual investment in refurbishments and upgrades (R&U) to the existing U.S. hydropower and PSH fleets in 2023–2025 was \$646 million (24% lower than the 2010–2022 average in 2025 dollars). Eighty percent of the investment value corresponds to projects where the turbine-generator units are the main scope item. (Section 1.2)

- Hydropower assets in the Northwest, Midwest, and Southeast regions, large (>100 MW–500 MW) plants, and plants owned by non-federal public entities are the fleet segments that received the highest average R&U investment per kilowatt in 2010–2025. (Section 1.2)

¹ Nameplate capacity from [ORNL Existing Hydropower Assets \(EHA\) Plant Database 2026](#), including hydropower plants in Puerto Rico.

² [eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf](https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf)

HYDROPOWER AND PSH RELICENSE AND LICENSE SURRENDER TRENDS

At the end of 2025, 200 hydropower and PSH projects with a total capacity of 18.5 GW (18% of U.S. installed capacity) were in the relicensing process. (Section 1.4.1)

- The number of relicense issuances in 2025 (21) was the largest since 2005, helping to alleviate the backlog of relicense applications. (Section 1.4.2)
- The median duration of the relicensing process, from submission of the notice of intent (NOI) to relicense until relicense issuance, for 165 relicenses issued from 2010 to 2025 was six years. Typical durations were longer for large (>100MW–500MW) projects (7.5 years) than other size categories. Relicensing duration was less variable and slightly shorter (5.9 years) for projects that used the Federal Energy Regulatory Commission (FERC) Integrated Licensing Process (ILP) modality. (Section 1.4.3)

Forty projects totaling 65 MW were in the process of surrendering their licenses at the end of 2025. (Section 1.4.1)

- The annual average number of surrender applications submitted in 2023–2025 was eight (versus six from 2010 to 2022).
- The median capacity of the 40 projects in the license surrender process is 0.8 MW. The Borel project in California (12 MW) is the one license surrender with capacity greater than 10 MW. Many of the projects whose licenses are being surrendered have not generated power for years often because they are in a state of disrepair due to wear and tear of plant components or damage by a natural hazard. (Section 1.4.1)
- Median duration from surrender application submission to surrender issuance was one year. Durations were typically longer for projects in the Northwest (1.9 years) and Southwest (2.2 years) as well as those that involve dam removal (1.6 years). (Section 1.4.3)

U.S. HYDROPOWER AND PSH DEVELOPMENT PIPELINE

At the beginning of 2026, the U.S. hydropower development pipeline included 161 projects with a combined capacity of 2.06 GW. Seventy-seven percent of these projects propose construction of new facilities with a combined capacity of 1.4 GW (versus 109 proposed facilities with combined capacity of 1.1 GW one year earlier). Six of them (14 MW) were under construction and 55 were at the earliest stage of development in which feasibility is being assessed and attrition rate is very high. Moreover, the owners of 33 operational hydropower facilities are planning or constructing capacity additions totaling 669 MW. (Section 2.1)

- Most capacity additions to existing facilities result from upgrades to existing turbine-generator units. The new 259-MW unit proposed at Dworshak Dam (a 465 MW U.S. Army Corps of Engineers (USACE) hydropower plant in Idaho) accounts for 90% of planned new capacity from unit additions to existing facilities. (Section 2.1)
- For the 80 projects that obtained FERC original licenses from 2010 to 2025, the median licensing process durations were three years for conduits (seven licenses), four years for new stream-reach developments (NSD) (ten licenses), five years for NPDs (59 licenses), and six years for PSH (four licenses). Most conduit projects do not require a FERC license. Since the FERC qualifying conduit process was introduced in 2013, 175 conduit projects have used it to obtain development authorization. The median duration of that process is 0.1 years (Section 2.3).

Seventy-four PSH projects (totaling 67 GW) were in the development pipeline at the beginning of 2026. Sixty-eight of them (totaling 59 GW) were pursuing the FERC permitting process for new projects (versus 70 with total capacity of 61 GW one year earlier). Of those 68, four had already received a FERC license. Three additional new projects under consideration do not require a FERC license. Separately, owners of three existing PSH facilities plan to increase capacity by uprating existing units or adding new units. (Section 2.2)

- Almost 80% (58 of 74) of PSH projects are in the Western half of the country. The median capacity of U.S. PSH projects is 600 MW. Sixty projects propose closed-loop configurations in which the reservoirs are not continuously connected to a naturally flowing body of water. All the projects, whether greenfield developments or capacity additions, proposed by entities that already own and operate PSH capacity (Tennessee Valley Authority (TVA), Salt River Project, Duke Energy, and Pacific Gas & Electric) are among the 14 open-loop projects in the pipeline. (Section 2.2)

GLOBAL HYDROPOWER AND PSH TRENDS

In 2025, global hydropower capacity reached 1,296 GW.³ Additionally, the global PSH fleet had a capacity of 160 GW. Together, hydropower and PSH represented 14% of global generation capacity in 2025 and 15% of global electricity generated in 2024. (Section 3.1)

- From 2016 to 2025, the average annual global growth rate was 1.4% for hydropower and 3.6% for PSH; total electricity generation capacity grew at an average of 5.2% per year. (Section 3.1)
- Globally, PSH capacity in the development pipeline (628 GW) overtook hydropower capacity (431 GW) for the first time. Capacity under construction was 103 GW for hydropower (732 new facilities) and 172 GW (151 new facilities) for PSH. India has the most hydropower capacity under construction (14.3 GW) and China has the most PSH capacity under construction (149 GW). (Section 3.2)

U.S. HYDROPOWER REVENUE TRENDS

Amidst large price fluctuations in wholesale electricity markets in 2020–2024, federal hydropower remained an affordable source of energy for the utilities that have access to it. (Section 4.1)

- The average federal hydropower energy price in 2020–2024 ranged from \$33.97/MWh in the Northwest to \$44.64/MWh in the Southeast where federal hydropower is contracted as peaking power. (Section 4.1)
- Due to drought conditions, average annual energy sold from the Western portion of the federal hydropower fleet in 2020–2024 was significantly lower than in the 2010s. For the rest of the federal fleet, annual energy sales in 2020–2024 were higher on average than in the 2010s. (Section 4.1)

Most U.S. hydropower owned by non-utilities (8% of electricity produced by the hydropower fleet and 18% of electricity produced by the PSH fleet in 2025) is sold via power purchase agreements (PPAs)—with utilities or other types of offtakers—or into organized wholesale markets managed by an independent system operator (ISO) or a regional transmission organization (RTO). (Section 4.2, Section 4.3)

³ This capacity number is from the International Renewable Agency’s Renewable Energy Statistics 2026 report. It includes capacity from hybrid plants that contain a mixture of hydropower and PSH units.

- On average, the median energy price for hydropower sold to electric utilities through PPAs ranged from \$53/MWh in the Southeast to \$63/MWh in the Northwest in 2021–2024. PPA prices during that period were typically more stable than wholesale market prices in the Northwest and Southeast. For hydropower PPAs in the Southwest, Midwest, and Northeast, the median PPA price followed the wholesale price more closely. (Section 4.2)
- As corporate offtakers seek to add more dispatchable capacity to their energy portfolios, several large deals involving hydropower facilities in the Northeast and Southeast have taken place (e.g., 10-year PPA between Rye Development and Iron Mountain for up to 150 MW of hydropower capacity in Pennsylvania and West Virginia, 20-year PPA between Brookfield Renewable and Google for up to 3,000 MW of U.S. hydropower capacity—starting with contracts for two large plants in Pennsylvania). (Section 4.2)
- The average annual revenue per kilowatt of installed capacity (in 2025 dollars) in 2021–2025 for hydropower facilities selling energy into ISO/RTO markets ranged between \$101/kW in ERCOT and MISO to \$232/kW in NYISO. (Section 4.3)

U.S. HYDROPOWER AND PSH PERFORMANCE METRICS

In 2023–2025, average U.S. hydropower generation trended downwards (8% decrease relative to the 2020–2022 average and 12% decrease relative to the 2010–2019 average). U.S. hydropower generation is strongly influenced by hydrologic conditions in the Northwest region. (Section 5.3)

- On average, the median capacity factor for U.S. hydropower plants in 2023–2025 (34.2%) decreased by one percentage point relative to 2020–2022 (35.5%). Average capacity factors (not adjusted by capacity) vary significantly across regions; they ranged from 26% in the Southeast to 41% in the Midwest in 2023–2025. (Section 5.4)
- In 2023–2025, hydropower imports from Canada decreased by 55% relative to the previous three years largely due to drought conditions. Two transmission lines starting operation in 2026 (with border crossings in Maine and New York and a combined capacity of 2,450 MW) strengthen U.S. capability to import Canadian hydropower. (Section 5.3)

U.S. PSH gross generation (i.e., without accounting for energy used in pumping) increased 12% in 2023–2025 relative to the 2020–2022 average and 11% relative to the 2010–2019 average, propelled by higher output by the PSH fleets in the Northeast, Southeast, and Southwest. (Section 5.3)

- Increases in average peak/off-peak price ratios in 2023–2025 relative to previous years can help explain the increase in PSH generation for facilities participating in several ISO/RTO markets. (Section 5.3)

In 2022–2024, the average availability factor for U.S. hydropower and PSH units was 78% for small units (≤ 10 MW), 83% for medium units (>10 MW–100 MW), and 79% for large units (>100 MW). (Section 5.5)

- For large units, it has remained steady at ~80% since 2010. For small and medium units, it has trended slightly downwards (from 87% to 82% for medium units and from 84% to 75% for small units). (Section 5.5)
- Hydropower availability factor in the Western Electricity Coordinating Council (WECC) has continued to be lower than in other North American Electric Reliability Corporation (NERC) regions in 2022–2024 (76% in WECC and greater than 80% in other NERC regional groupings). (Section 5.5)

Hydropower and PSH units contribute to grid reliability by maintaining their highest availability factors in the summer months (85% for hydropower units, 92% for PSH units) which is the peak demand season in most U.S. markets.⁴ (Section 5.7)

- Hydropower and PSH displayed consistent ability to increase generation (relative to average) during the top 100 net load hours in 2021–2025. The average generation increase was greater than 20% in five of the ten balancing authorities (BAs) analyzed. BAs with high shares of peaking hydropower and PSH tend to show larger average increases. (Section 5.7)

U.S. HYDROPOWER AND PSH SUPPLY CHAIN

The U.S. hydropower supply chain includes 90 companies with domestic manufacturing locations (147 manufacturing locations in 38 states).⁵ For large or heavy components, from castings and forgings to turbine runners or generators, domestic manufacturing options are limited. (Section 6.1)

- The top ten states with the most manufacturing locations include the three states with the highest installed hydropower capacity (Washington, Oregon, and California) but also others like Texas, Ohio, and Illinois that have modest hydropower capacities but are large manufacturing hubs across industries. (Section 6.1)
- In 2020–2025, an average of 15 turbine runners were installed in the United States per year. Twenty-seven of the 31 runners with capacities greater than 10 MW were supplied by five original equipment manufacturers (OEMs). The 58 turbine runners with capacities up to 10 MW installed in that same period were manufactured by at least 14 OEMs. (Section 6.2)
- In the next decade, U.S. demand for hydropower plant components is expected to come primarily from modernization of the existing fleet which will require components for dozens of units greater than 100 MW—the ones with least domestic supply chain options. In contrast, for new facilities, the median capacity of proposed turbine-generator units is 2.4 MW. Of the 25 new units with capacities greater than 30 MW, all but one are for PSH projects. (Section 6.4)

In 2023–2025, U.S. exports of hydraulic turbines averaged \$52 million and imports averaged \$58 million. These values were 24% higher than the 2020–2022 average for exports and 31 % higher for imports. However, the 2023–2025 average values remain significantly lower than in the 2010s when both imports and exports averaged \$77 million per year. (Section 6.3)

- Eighty-seven percent of 2023–2025 turbine imports (by value) originated in Europe or the Americas. (Section 6.3)
- The United States was the fifth largest exporter of hydraulic turbines globally in 2010–2024 (when taking all European Union (EU) countries as a single bloc). (Section 3.3)

⁴ They also contribute to reliability by providing ancillary services (e.g., frequency regulation, operating reserves, contingency reserves, black start).

⁵ The U.S. hydropower supply chain has additional participants not included in this number (e.g., component suppliers with U.S. offices but no manufacturing facilities, companies that provide services to the industry)

POLICY DEVELOPMENTS

The U.S. Department of Energy (DOE) is currently processing awards for hydropower projects under three incentive programs, totaling \$591 million, to modernize and expand the U.S. hydropower fleet. (Chapter 7)

- The two incentive programs directed towards capital improvements (Section 243 and Section 247) will support at least \$1.8 billion in investments to improve efficiency, grid reliability, dam safety, and environmental performance of the hydropower fleet. (Chapter 7)
- The third program (Section 242) is a production-based incentive available during the first ten years of operation to qualified facilities placed in service by the end of Fiscal Year 2027.

Hydropower and PSH facilities placed in service from 2025 to 2032 are eligible for tax credits. (Chapter 7)

- Hydropower facilities starting operation from 2025 to 2032 are eligible for the Clean Electricity Production Credit (Section 45Y) or Clean Electricity Investment Credit (Section 48E). New PSH facilities are also eligible for the Section 48E credit. Moreover, retrofitted hydropower facilities can be eligible for the Section 45Y or Section 48E credits if they meet the “80/20 rule.” Supply chain requirements affect both eligibility for and value of these credits. (Chapter 7)

In 2025–2026, FERC took steps to streamline multiple hydropower permitting processes, including the issuance of preliminary permits, post-licensing activities involving maintenance and upgrades, and license terminations. (Chapter 7)

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LIST OF ACRONYMS

ALP	Alternative Licensing Process	NERC	North American Electric Reliability Corporation
BA	balancing authority	NHA	National Hydropower Association
CAISO	California Independent System Operator	NOI	Notice of Intent
BOR	Bureau of Reclamation	NOPR	Notice of Proposed Rulemaking
BPA	Bonneville Power Administration	NPCC	Northeast Power Coordinating Council
CE	categorical exclusion	NPD	non-powered dam
DOE	Department of Energy	NSD	new stream-reach development
EHA	Existing Hydropower Assets	NYISO	New York Independent System Operator
EIA	Energy Information Administration	O&M	operations and maintenance
ELCC	effective load carrying capability	OEM	original equipment manufacturer
ERCOT	Electric Reliability Council of Texas	PAD	Pre-Application Document
EU	European Union	PMA	power marketing administration
FEOC	foreign entity of concern	PPA	power purchase agreement
FERC	Federal Energy Regulatory Commission	PSH	pumped storage hydropower
FLA	Final License Application	RFC	Reliability First Corporation
FPV	floating photovoltaics	RTO	regional transmission organization
GADS	Generating Availability Data System	R&U	refurbishment and upgrade
H2O	Hydropower and Hydrokinetic Office	SEPA	Southeastern Power Administration
IBWC	International Boundary and Water Commission	SERC	Southeastern Electric Reliability Council
IIR	Industrial Info Resources	SPP	Southwest Power Pool
ILP	Integrated Licensing Process	SWPA	Southwestern Power Administration
IRENA	International Renewable Energy Agency	TRE	Texas Regional Entity
ISO	independent system operator	TLP	Traditional Licensing Process
ISONE	Independent System Operator – New England	TVA	Tennessee Valley Authority
LDES	long-duration energy storage	US	United States
LMP	locational marginal pricing	USACE	U.S. Army Corps of Engineers
LOPP	Lease of Power Privilege	WACM	Western Area Power Administration – Rocky Mountain Region
MISO	Midcontinent Independent System Operator	WALC	Western Area Power Administration – Desert Southwest region
MRO	Midwest Reliability Organization	WAPA	Western Area Power Administration
NEPA	National Environmental Policy Act	WECC	Western Electricity Coordinating Council

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INTRODUCTION

This is the fifth edition of the U.S. Hydropower Market Report (the previous editions were published in [2015](#), [2018](#), [2021](#), and [2023](#)). Slide decks updating a selected number of datasets from the report have been published each year since 2016. They are available at the Oak Ridge National Laboratory HydroSource website.

The 2026 report includes a combination of time series data and data snapshots. The snapshots summarize the status of selected metrics at the end of 2025 or beginning of 2026. Most time series data cover 2010–2025 with particular focus on new developments in 2023–2025 (the three new years of data since the previous edition of the report). However, for a few of the datasets, the last year of data available was 2024. Unless otherwise noted, PSH is discussed separately from hydropower throughout the document.

This report updates the datasets included in previous editions and adds the following new content:

- Relicensing and license surrender process durations (Section 1.4.3)
- FERC authorization process durations for new projects (Section 2.3)
- Contribution of hydropower and PSH to grid reliability (Section 5.7)
- U.S. hydropower supply chain manufacturing capabilities (Section 6.1)
- Potential demand for key hydropower components (Section 6.4)

CHAPTER 1. LOOKING BACK: AN OVERVIEW OF CHANGES ACROSS THE U.S. HYDROPOWER AND PSH FLEET

This chapter presents data about the status of the existing hydropower and PSH fleets including capacity changes (from new projects, capacity additions to existing plants, downrates, and retirements) and investments in R&U. It also summarizes activity related to changes in ownership (license transfers), relicenses, and license surrenders.

At the end of 2025, the U.S. hydropower fleet (excluding PSH) contained 2,258 hydropower plants with a total generating capacity of 80.55 GW. The fleet produced 23.1% of renewable electricity and 5.6% of total electricity in the United States in 2025. In addition, 41 PSH plants with a total generating capacity of 22.23 GW and an estimated energy storage capacity of 553 GWh accounted for 33.5% of nameplate generating capacity and 82.1% of energy storage capacity from U.S. utility-scale storage units (see Figure 1.⁶

Table 1 lists the top states by U.S. hydropower and PSH capacity. For hydropower, the top three states (Washington, California, Oregon) account for almost 50% of capacity. Sixteen states have more than 1 GW of hydropower. Delaware and Mississippi are the only two states that do not have any hydropower facilities. For PSH, 44.5% of capacity is in three states (California, Virginia, South Carolina). Eighteen states have at least one PSH plant.

Table 1. Top 20 States by Installed Hydropower Capacity and PSH Capacity

Hydropower capacity (MW)		Pumped Storage Hydropower Capacity (MW)	
Cumulative (end of 2025)		Cumulative (end of 2025)	
Washington	21,475	California	3,711
California	10,067	Virginia	3,109
Oregon	8,359	South Carolina	3,041
New York	4,713	Michigan	1,979
Alabama	3,109	Massachusetts	1,834
Idaho	2,729	Tennessee	1,714
Arizona	2,724	Georgia	1,635
Montana	2,692	Pennsylvania	1,484
Tennessee	2,520	New York	1,240
Georgia	2,177	Missouri	600
North Carolina	1,900	Colorado	508
South Dakota	1,650	New Jersey	453
South Carolina	1,343	Washington	314
Arkansas	1,321	Oklahoma	259
Kentucky	1,101	Arizona	194
Nevada	1,057	North Carolina	95
Pennsylvania	896	Connecticut	31
Virginia	832	Arkansas	30
Oklahoma	824	Rest of United States	0
Texas	736		
Rest of United States	8,326		

Source: Existing Hydropower Assets (EHA) Plant Database 2026

⁶ See Appendix to [2021 edition](#) of U.S. Hydropower Market Report for details on the data and approach used to estimate energy storage capacity.

The U.S. hydropower fleet includes baseload and peaking plants.

Mode of operation is an important attribute for understanding the role each hydropower plant plays in the electric system. Within the U.S. hydropower fleet, 713 plants totaling 19.2 GW are run-of-river plants that provide baseload power. These plants operate continuously for large stretches of time (provided that adequate river inflow is available), have little to no storage capacity, and offer limited flexibility to follow load. Their average capacity is 27 MW. At the other end of the spectrum of modes of operation, 261 plants with combined capacity of 26.2 GW operate in peaking mode. These plants have storage capacity and schedule their generation during periods of high demand and prices. Their average capacity is 100 MW. PSH plants also are peaking plants and can either produce (in generation mode) or consume (in pumping mode) power to balance supply and demand in the grid. They are the most flexible hydropower assets. Many other hydropower plants have intermediate modes of operation between peaking and run-of-river.

Research on hybrid configurations outlines multiple value propositions for different types of hydropower plants; hydropower owners are starting to deploy these concepts.

Gorman et al. (2025) track operational and proposed hybrid power plant installations in the United States.⁷ For run-of-river plants seeking to increase their flexibility and enhance their revenue, pairing with a battery system can be an effective solution. Adding a battery to a run-of-river plant can increase revenue by shifting a greater share of the energy generated to high-price hours and by enabling participation in markets for grid services such as frequency regulation and black-start capability. As of the end of 2024, eight hydropower-plus-battery hybrid projects were operational: three in Maine, two in Alaska, two in Virginia, and one in New Hampshire. The eight hydropower plants that have been paired with batteries range in capacities from 7.2 MW to 138 MW and operate predominantly in run-of-river mode. The batteries added to these facilities ranged in capacity from 1 MW to 20 MW and had storage durations of 1–2 hours. Three of these installations took place in 2023. One more is planned at a 6.7 MW hydropower plant in Massachusetts.

DOE has recently granted awards to two other hydropower hybridization projects involving the installation of battery systems: one for the Forks of Butte hydropower facility (14.5 MW, run-of-river plant in California) and another for Tuckertown (42 MW run-of-river plant in North Carolina).⁸ Even though most hydropower-battery hybrids in the United States to date have involved run-of-river plants, value propositions from hybridization also exist for peaking plants (Durvasulu et al., 2024). For example, a battery can reduce the number of starts and stops a peaking plant performs—by absorbing energy during periods where the market does not need the hydropower output—reducing operations and maintenance (O&M) costs and wear and tear of the turbine-generator units.⁹

Another hybrid hydropower configuration under investigation is floating photovoltaics (FPV), in which solar panel arrays are installed on hydropower reservoirs. Rosenlieb et al. (2025) estimated a technical potential of 861 GW–1042 GW for FPV on U.S. federal reservoirs. For hydropower plants, the benefits of FPV installation include a reduction in evaporation of water stored in the reservoir and increases in dissolved oxygen in the summer which can help comply with FERC license conditions. Gallego-Calderon et al. (2026) find that the capital costs of FPV are generally not competitive with land-based solar, but the business case varies geographically depending on solar irradiance and electricity prices.

⁷ The dataset includes co-located plants that pair, but control separately, two or more generators and/or storage assets at a single point of interconnection, and full hybrids where the assets are co-located and co-controlled.

⁸ renewableenergyworld.com/hydro-power/dams-civil-structures/doe-invests-almost-15m-for-hydro-grid-balancing-projects/

⁹ nnl.gov/news-media/adding-batteries-hydropower-facilities-could-increase-dam-lifespan-potential-revenue

With very fast deployment of short-duration battery storage in recent years, it becomes important to highlight the differential attributes of PSH

At the end of 2025, the U.S. had 41 PSH plants with a combined nameplate generating capacity of 22.2 GW and 994 battery storage plants totaling 43.6 GW.¹⁰ Lithium-ion batteries accounted for 97% of the capacity. Figure 1 shows the contributions of each storage technology type to nameplate generating capacity and energy storage capacity. Batteries surpassed PSH in terms of nameplate generating capacity in 2024, but PSH continues to provide most (82%) of the energy storage capacity (i.e., if all storage units were fully charged, the number of gigawatts that the battery fleet can deliver as it starts discharging is larger than the number of gigawatts the PSH fleet can deliver. However, the battery fleet will be fully discharged much faster than the PSH fleet). The median storage duration for U.S. utility-scale battery systems at their rated capacities is two hours. Less than 10% of battery installations have storage durations larger than four hours. On the other hand, the median U.S. PSH plant has ten hours of storage duration at their rated capacities and qualifies as a long-duration energy storage (LDES) asset.

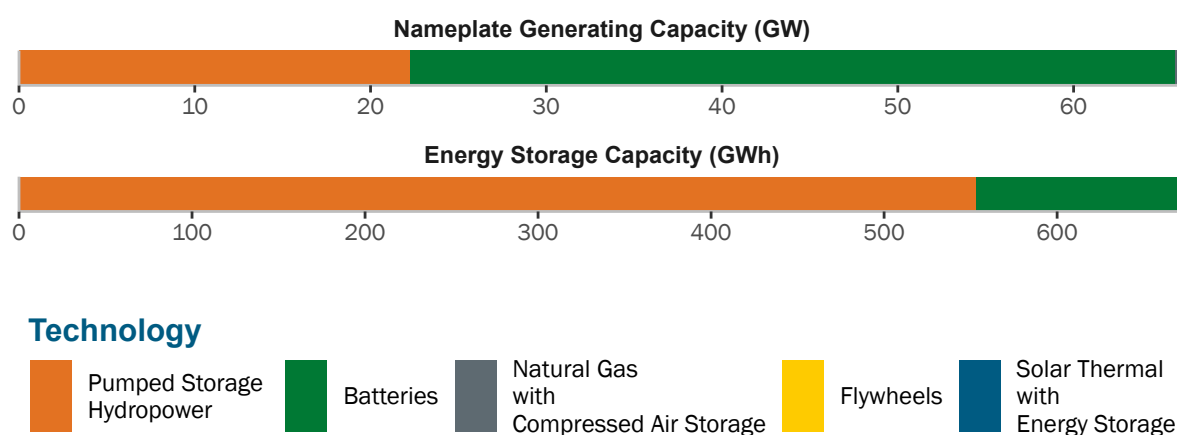


Figure 1. U.S. utility-scale electrical energy storage capacity by technology type (2025)

Source: Energy Information Administration (EIA) Form 860 Early Release (2025).

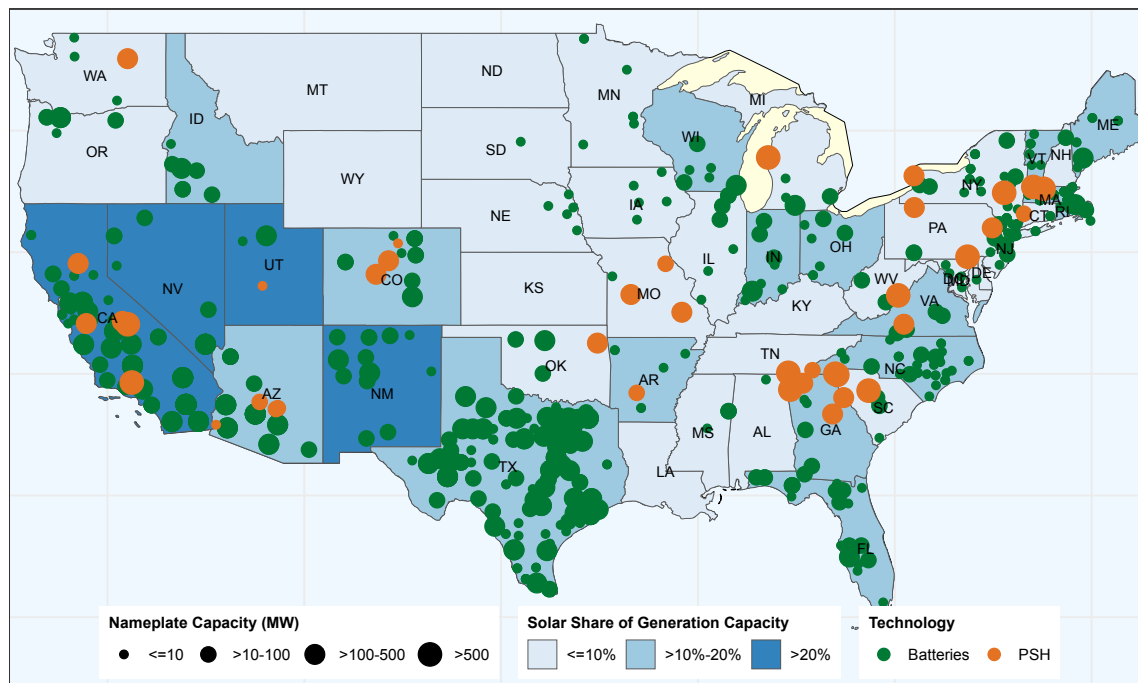
Aside from its long-duration storage capabilities, PSH has some other important differences in lifecycle performance with respect to batteries, such as longer operational life and better performance under extreme temperatures. A PSH plant can operate for more than 100 years if properly maintained (e.g., Rocky River PSH has been in operation since 1928) while batteries have an expected lifetime of approximately 20 years—influenced by the number and depth of charge/discharge cycles. Additionally, ongoing research seeks to address some of the performance issues that batteries can experience under extreme temperatures (Albeshr et al., 2023; Olis, 2021). Elevated temperatures accelerate capacity loss and battery degradation over time. Cold temperatures can decrease energy storage capacity as well as maximum charge and discharge rates. Approaches to mitigate these issues include the use of phase-change materials and active temperature control systems.

¹⁰ U.S. utility-scale storage installations also include three solar thermal facilities with energy storage (0.4 GW), five flywheels (0.05 GW), and one natural gas compressed air storage facility (0.1 GW).

LOCATION AND INSTALLATION TIMELINE OF U.S. PSH AND BATTERY STORAGE FLEETS

The two panels in Figure 2 show where U.S. PSH and utility-scale battery storage are located and when they were installed. More than 85% of U.S. PSH capacity started operation between 1960 and 1989. PSH was often developed to provide flexibility alongside baseload nuclear generation. Five states (Pennsylvania, South Carolina, Georgia, Tennessee, and Michigan) are part of both the top ten U.S. states by PSH capacity and by nuclear capacity. With its ability to quickly ramp output up or down and either generate or consume energy, PSH can convert constant output from nuclear plants into a daily generation profile that matches electricity demand more closely. In contrast, the most common use of batteries is to convert the variable output from solar plants into a smoother daily generation profile. Most batteries are in states with high penetration of solar generation. Almost 40% of battery plants are part of hybrid solar-battery installations where batteries absorb part of the solar output during late morning and early afternoon hours and release it in the evening when net load (i.e., electricity demand minus solar and wind generation) and prices are higher. Adding batteries to a solar project increases upfront capital costs, but it can improve project economics by shifting generation to higher-price hours, reducing curtailment, increasing eligibility for capacity revenues, and enabling participation in ancillary services markets.

Location of PSH and utility-scale battery storage plants (2025)



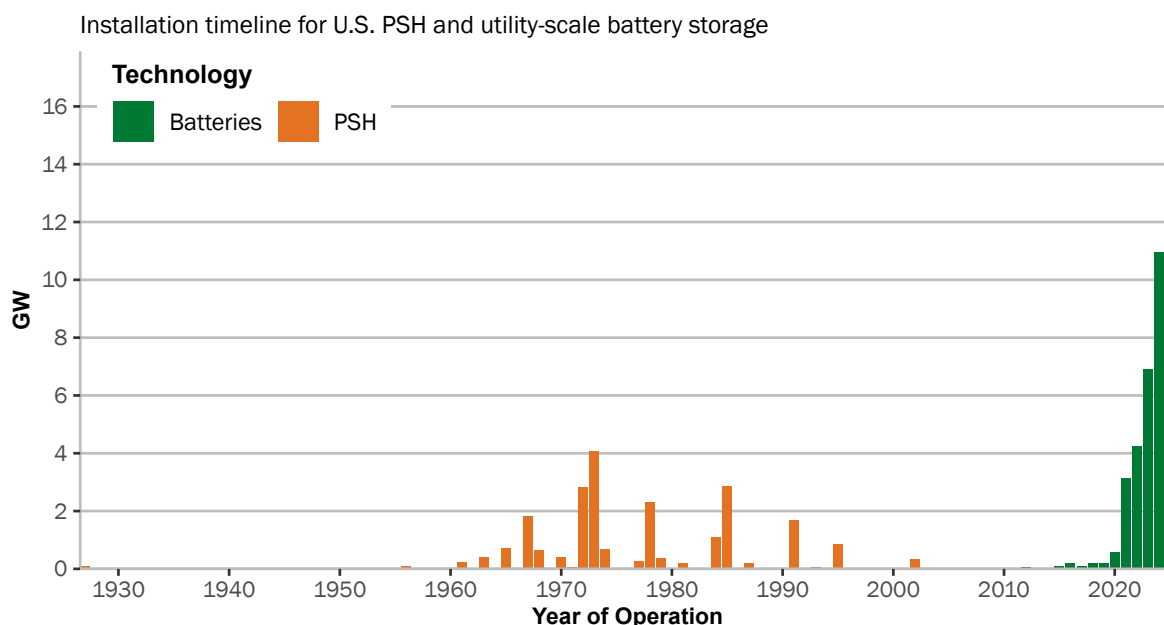


Figure 2. Location and installation timeline of U.S. PSH and battery storage

Source: Energy Information Administration (EIA) Form 860 Early Release (2025), ORNL Existing Hydropower Asset (EHA) Plant Database, 2026

Figure 2 shows that 97% of installed capacity was built in 2021–2025. The very fast growth of U.S. battery capacity in the past five years indicates that the business case for this type of asset has been attractive for developers. Continued battery pack cost reductions crucially contribute to the observed growth in installations.¹¹ For PSH, the last large-scale project came online in 2002. The larger capital outlays and longer, riskier development process needed to build new PSH require adequate remuneration of its differential performance attributes (e.g., longer storage duration, longer operational life) to incentivize new builds.

¹¹ about.bnef.com/insights/clean-transport/lithium-ion-battery-pack-prices-fall-to-108-per-kilowatt-hour-despite-rising-metal-prices-bloombergnef/

1.1 NEW PROJECT DEVELOPMENT AND CAPACITY CHANGES (2010–2025)

U.S. hydropower fleet capacity increased by 2.1 GW from 2010 to 2025. This net change is a combination of 1.9 GW added to the existing fleet, 0.7 GW of capacity from new projects, and 0.5 GW of capacity retirements. For PSH, net capacity additions to the existing fleet amounted to 1.7 GW from 2010 to 2025 all due to upgrades to plants already in operation in 2010.

Figure 3 shows the relative magnitudes (by capacity and number of plants) of the various activities resulting in capacity changes, by region. Net capacity changes to the existing fleet (combination of capacity additions and downrates) totaled 1.2 GW in the Northwest, 64 MW in the Southwest, 74 MW in the Midwest, 259 MW in the Northeast, and 334 MW in the Southeast. Relative to their total installed capacities in 2010, these changes represent increases of 3.4% for the Northwest (the region with the most installed hydropower capacity), 3.1% for the Northeast, 2.3% for the Southeast, 1.3% for the Midwest, and 0.4% for the Southwest.

Federal agencies own and operate almost 50% of the U.S. hydropower fleet, but the federal fleet accounted for 22% of capacity additions. For investor-owned utilities, the shares of capacity additions (18%) and installed capacity (19%) were very similar. The two categories of hydropower owners that represent a higher share of capacity additions than installed capacity are publicly owned utilities (37% of capacity additions versus 18% of installed capacity) and private non-utilities (21% of capacity additions versus 8% of installed capacity).

Since 2010, 161 new facilities have been added to the U.S. hydropower fleet, with a combined capacity of 712 MW. Their individual capacities ranged from less than 1 kW to 105 MW. These new facilities include retrofits of 43 NPDs and 106 conduits with total capacities of 595 MW and 80 MW, respectively. Conduit retrofits have predominantly taken place in the Southwest (50%) and Northwest (36%) because these largely arid regions have a more developed water conveyance infrastructure network than the rest of the country, built to support irrigation and connect major population centers with often distant water sources. For NPDs, the Northeast accounts for 37% of projects and the Midwest for an additional 26%. The NPDs retrofitted in the Midwest had a larger average capacity (32 MW) than those in the Northeast (4.6 MW). The remaining 12 new hydropower plants are NSDs, with a combined capacity of 36 MW, located at stream reaches without pre-existing dams. Eleven of the 12 NSD projects are in the Northwest. The types and sizes of new projects added in 2010–2025 are similar to those of projects in the development pipeline at the beginning of 2026 (see Chapter 2 for more details).

From 2010 to 2025, 139 hydropower plants with total capacity of 526 MW retired. Their capacities ranged from 18 kW to 99 MW and their median capacity was 1 MW. The Northeast experienced the highest number of retirements (26% of the U.S. total) and the Northwest had the most capacity retired (36% of the U.S. total). Facilities that operate under a FERC license or exemption need to follow the FERC license surrender process when they retire (see Section 1.4 for more details on the surrender process and the attributes of plants that have retired and surrendered their authorization to generate power in the past 15 years).

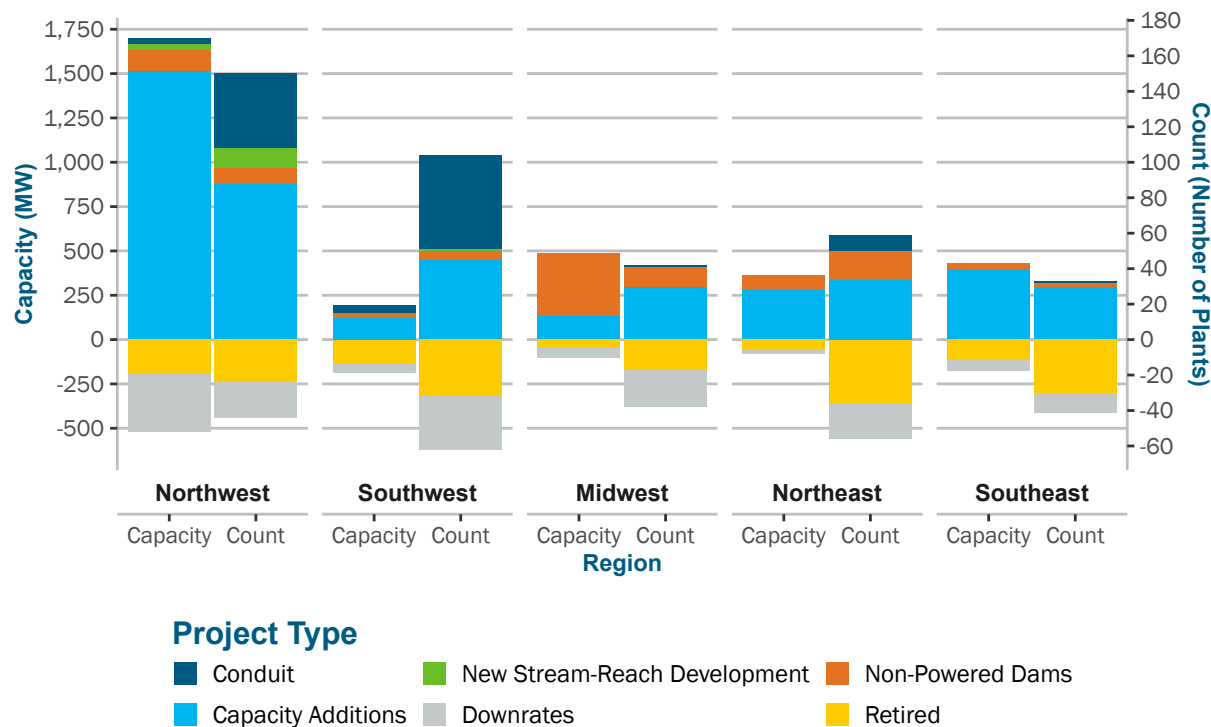


Figure 3. Hydropower capacity changes by region and type (2010–2025)

Sources: EIA Form 860 (2010–2024), EIA Form 860 Early Release (2025), ORNL EHA Plant Database 2026

Note: The regions shown in this plot are the same as for the maps in Figure 8, Figure 13, and Figure 15. Each instance of a capacity increase or decrease reported in EIA Form 860 is counted separately. Some plants reported multiple capacity changes during this period.

Activities in 2023–2025 accounted for 16% of the 2010–2025 net capacity additions at the existing fleet, 0.4% of new project additions, and 46% of retirements. Almost 75% of the capacity reported as retired in EIA Form 860 in 2023–2025 corresponds to a single FERC license (PacifiCorp’s Klamath Hydro Project) with facilities in Oregon and California. Combining all these changes, U.S. hydropower capacity increased by ~80 MW in 2023–2025.

Changes to PSH capacity are not included in Figure 3. From 2010 to 2025, the net change in U.S. PSH capacity was an increase of 1,686 MW. This net change combined capacity increases at eight existing plants (Degray in Arkansas, Castaic in California, Bear Swamp and Northfield Mountain in Massachusetts, Muddy Run in Pennsylvania, Fairfield, Jocassee, Bad Creek in South Carolina) totaling 1,772 MW, 86 MW of capacity derates at two existing plants (Seneca in Pennsylvania and Salina in Oklahoma), and retirements of two PSH plants in California: Lake Hodges (42 MW) and North Hollywood (5.4 MW). For the eight plants that upgraded their capacity during this period, the average capacity increase was 25%. Fifteen percent (258 MW) of the capacity added through upgrades to existing facilities from 2010 to 2025 became operational in 2023–2025.

1.2 INVESTMENT IN REFURBISHMENTS AND UPGRADES (2010–2025)

From 2023 to 2025, investments in R&U to the existing U.S. hydropower and PSH fleets added up to \$1.94 billion. Eighty percent of the investment value corresponds to projects where turbine-generator unit upgrades are the main scope item. Plants owned and operated by federal agencies received 45% of the tracked 2023–2025 R&U investment.

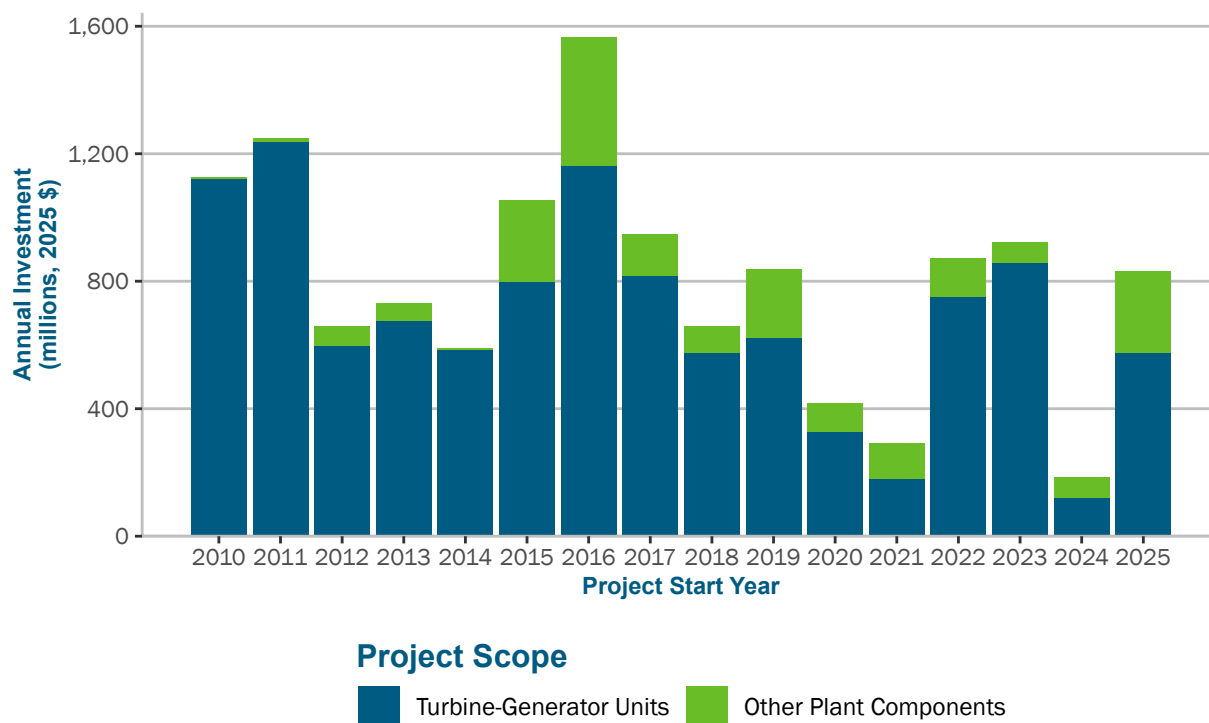


Figure 4. Expenditure on R&U of the existing hydropower and PSH fleet by project scope

Source: Industrial Info Resources (IIR)¹²

Note: IIR tracks projects with a total investment value of at least \$1 million. Total investment value includes the value of the components being refurbished or upgraded as well as associated civil work, engineering costs, labor, etc. The full value of each project is assigned to the start year, but it can take multiple years for a project to be completed. Projects in the “Turbine-Generator Units” category include projects for which the main item in the scope is a governor or exciter replacement or upgrade.

The average age of the U.S. hydropower and PSH fleets is 64 years and 54 years, respectively. To continue operating reliably, they need periodic capital investments. Figure 4 shows the trend in R&U investments from 2010 to 2025. During that period, hydropower owners invested at least \$12.9 billion in refurbishing and upgrading their generation assets (\$10.1 billion for hydropower plants and \$2.8 billion for PSH plants). Eighty-five percent of the investment went towards projects upgrading turbine-generator unit components. The 465 R&U projects included in the database helped modernize 194 hydropower plants (47% of installed capacity) and 16 PSH plants (34% of installed capacity). The average 2010–2025 R&U investment per kilowatt installed was almost identical for the hydropower and PSH segments of the fleet: \$126/kW for hydropower and \$127/kW for PSH.

¹² IIR collects data, primarily through interviews, from hydropower plant owners (municipalities, cooperatives, government agencies, investor-owned utilities, and independent power producers) with more than 5 MW of generation capacity. Project status information is updated annually.

Figure 5 compares the share of installed capacity (as of 2025) to the share of 2010–2025 R&U investment for different fleet segments (by region, plant size, plant type, or ownership type) to evaluate whether modernization efforts have been uniformly distributed. Fleet segments for which the dot on Figure 5 lies above the 45-degree line received a higher R&U investment share than the share of installed capacity they represent. The distribution of R&U investment between hydropower and PSH plants matches their capacity shares very closely. Hydropower assets in the Northwest, Midwest, and Southeast regions, large (>100 MW–500 MW) plants, and plants owned by non-federal public entities are the fleet segments receiving higher investment shares than their share of capacity. Plants in the Southwest, privately-owned plants, and small (<=10 MW), medium (10 MW–100 MW) or very large (>500 MW) plants show R&U investment shares below their capacity shares. For small plants (of which private non-utilities own a high fraction), a significant share of R&U activities may be below the \$1 million threshold captured in the IIR dataset.

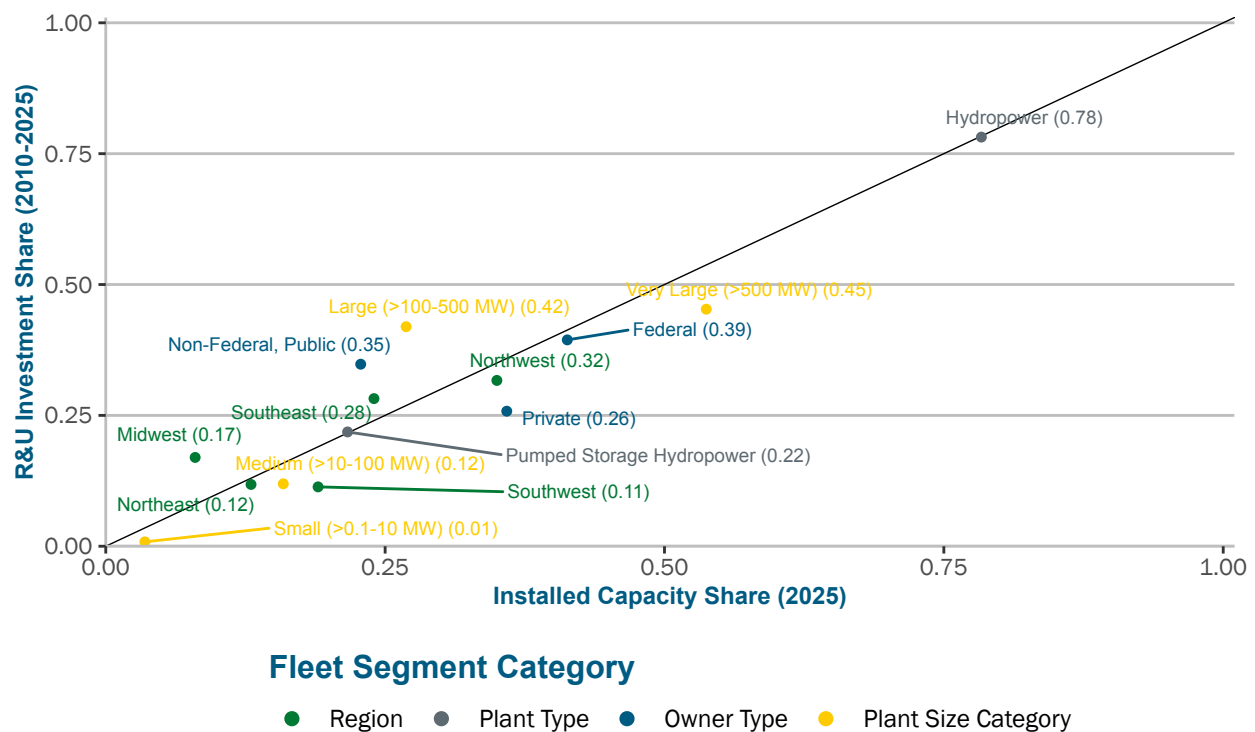


Figure 5. Share of 2010–2025 R&U investment versus share of installed capacity for various hydropower fleet segments

Source: IIR, ORNL EHA Plant Database 2026

Note: The regions shown in this plot are the same as for the maps in Figure 8, Figure 13, and Figure 15.

As shown in Figure 4, total investment value for R&U projects initiated in 2023–2025 was \$1.94 billion. For 2023 and 2025, R&U investment was close to the 2010–2025 average of \$809 million (in 2025 dollars). But R&U projects initiated in 2024 totaled \$178 million, the lowest value since at least 2010. Not only did less projects start in 2024 (17) than in the previous (23 in 2023) or following (28 in 2025) years, but their average value (\$10.9 million) was much lower (\$40.1 million in 2023, \$29.6 million in 2025).

Eighty percent of investment value from the 68 projects with start dates in 2023–2025 had turbine-generator components as their primary focus. Among those, turbine runner replacements and generator rewinds are the most common scopes of work. The remaining 20% of investment went to projects involving crane replacements or refurbishments (7 projects), spillway gate replacements (3 projects), transformer replacements (3 projects), switchgear upgrades (2 projects), controls upgrades (2 projects), valve rehabilitation (1 project), head gate replacement (1 project), penstock refurbishment (1 project), and pipe relining (1 project).

1.3 OWNERSHIP CHANGES (2010–2025)

Sixteen percent of U.S. hydropower and PSH plants accounting for 6% of installed capacity changed ownership at least once from 2010 to 2025. The average annual number of license and exemption transfers in the 2010s (36) was much higher than from 2020 to 2025 (9). Over 80% of the plants transferred are small (≤ 10 MW). More than half of the plants transferred are in the Northeast.

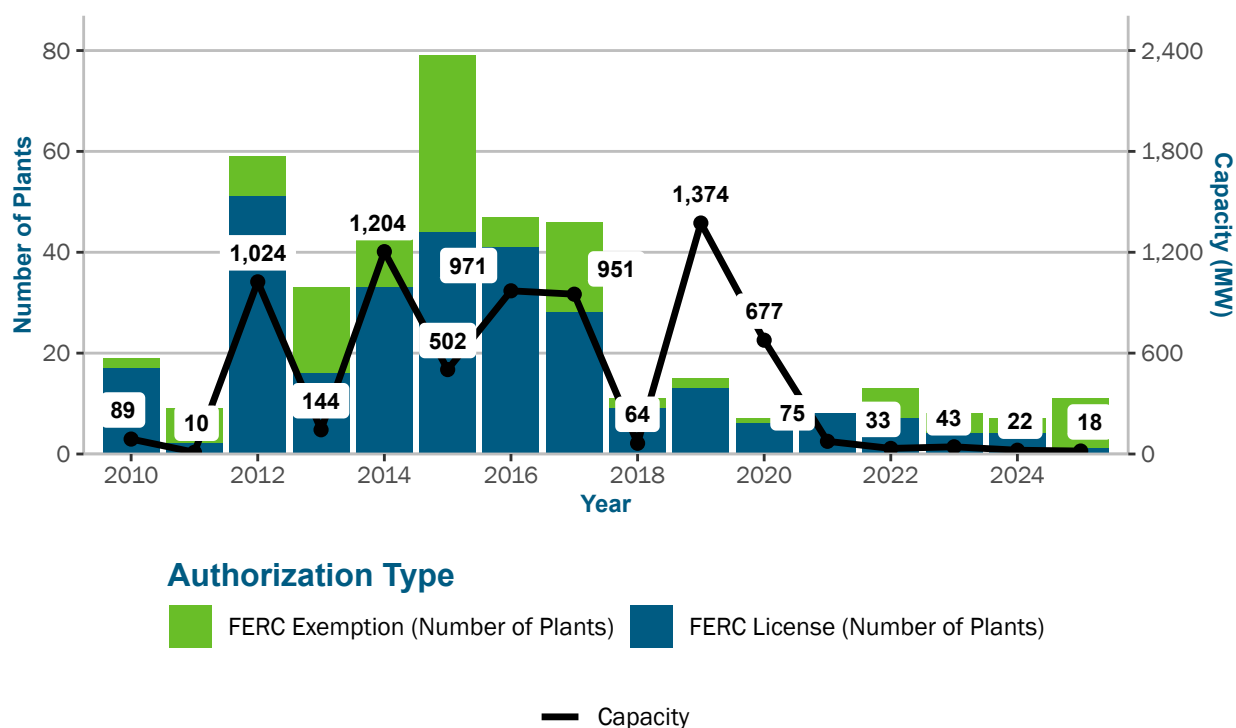


Figure 6. Hydropower and PSH ownership transfers by year and authorization type (2010–2025)

Sources: FERC, ORNL EHA Plant Database, 2025

Note: The plot includes transfers of licenses that have already been approved by FERC and transfers of exemptions notified to FERC by the exemption holders. It only includes license and exemption transfers for projects that are already operational.

Hydropower license holders must seek FERC approval to transfer the license to a different entity. For projects permitted through exemptions rather than licenses, transfers do not require FERC approval. However, the exemption holder must inform FERC of the identity and address of the transferee within 30 days of transferring the property interests.

From 2010 to 2025, FERC approved 210 license transfers involving 284 plants with a total capacity of 7 GW.¹³ Six of these license transfers corresponded to PSH projects. Additionally, 126 exemption transfers associated with 131 hydropower plants with total capacity of 207 MW have been notified to FERC.

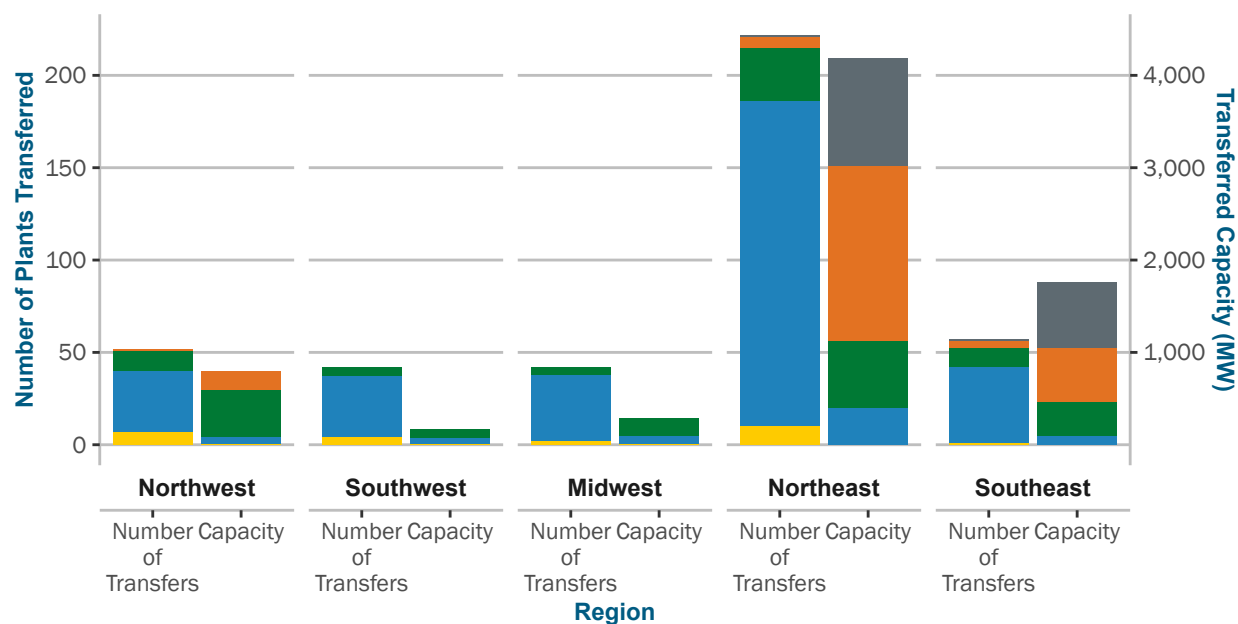
The number of transfers has been much lower in the first half of the 2020s than in the 2010s (especially among hydropower plants with more than 10 MW of capacity). Almost 75% of all the 2010–2025 transfers took place in the six-year period from 2012 to 2017. Notable portfolios transferred during that period include 18 plants (53 MW) from Central Vermont Public Service Corporation to Green Mountain Power Corporation in 2012, 11 plants (587 MW) from PPL Montana to NorthWestern Corporation in 2014, 13 plants (466 MW) from New England Power Company to USGen New England in 2016, and 7 plants (170 MW) from PacifiCorp to Klamath River Renewal Corporation in 2017.

In 94% of transfers, both the transferor and the transferee were private entities (e.g., investor-owned utilities, private non-utilities). Some of the transfers were among affiliates of the same parent company or reflected changes in corporate structure (e.g., a corporate conversion process from an incorporation to a limited liability company).

New data in Figure 6 relative to the version of this plot in the previous edition of the U.S. Hydropower Market Report covers 2023–2025. Twenty-six transfers (17 exemptions and 8 licenses one of which includes two plants) with a total capacity of 83 MW changed ownership in that period; only three of those plants have a capacity greater than 10 MW. Excluding transfers associated with corporate conversion processes or involving affiliates of the same parent company, the only company that became holder of more than one new license or exemption in 2023–2025 is Albany Engineering Corporation. It became the unique licensee for the Green Island Hydroelectric Project in New York (after having previously been a co-licensee with Green Island Power Authority) and acquired two other small hydroelectric projects in New York.

Figure 7. Hydropower and PSH ownership transfers by region and plant size category (2010–2025)” provides details about the geographical and size distribution of plants transferred from 2010 to 2025. Eighty-one percent of plants transferred had capacities less or equal than 10 MW. Fifty-four percent of plants transferred were in the Northeast. A large share of transfers in the Northeast is consistent with the Northeast also being the region with the largest share of installed capacity (44%) for the types of plants most likely to be transferred (privately-owned plants with a capacity no greater than 10 MW).

¹³ Some of the licenses were transferred multiple times from 2010 to 2025.



Transferred Plant Size (MW)

■ Very Large (>500) ■ Large (>100 - 500) ■ Medium (>10 - 100) ■ Small (>0.1 - 10) ■ Micro (<=0.1)

Figure 7. Hydropower and PSH ownership transfers by region and plant size category (2010–2025)

Sources: FERC, ORNL EHA Plant Database, 2025

Note: The regions shown in this plot are the same as for the maps in Figure 8, Figure 13, and Figure 15. The plot includes transfers of licenses that have already been approved by FERC and transfers of exemptions notified to FERC by the exemption holders. It only includes license and exemption transfers for projects that are already operational.

Details about the value of transactions accompanying license or exemption transfers in 2023–2025 were published for two of the transfers. First, the Connecticut Brownfield Land Bank paid \$1 for Kinneytown dam property and assets including the out-of-service hydropower facility. The previous owner did not have funds to undertake necessary work on the project. The new owner is developing a plan to remove the dam, which holds contaminated sediment due to decades of industrial discharges upstream, and restore the site.¹⁴ In the case of the Lower Tule project in California, Southern California Edison concluded that selling the 2.5 MW facility (not operational since 2017 due to damage to the water conveyance components of the project during a fire) at a loss was the least-cost outcome for its customers, compared to the expected repair costs to continue operating or the expected costs of decommissioning the assets. The utility conducted an auction and accepted the bid from Lower Tule Hydro, LLC which involves Southern California Edison (the seller) paying the buyer \$8.88 million. The new owner intends to restore the project to operation.

¹⁴ ctblb.org/index.php/2025/11/19/press-release-connecticut-brownfield-land-bank-acquires-kinneytown-dam-property-paving-way-for-major-river-restoration/

1.4 RELICENSES AND LICENSE SURRENDERS (2010–2025)

At the end of 2025, 200 hydropower and PSH projects (18.5 GW) accounting for 18% of U.S. installed capacity were in the relicensing process. Forty projects totaling 65 MW were in the process of surrendering their licenses.

1.4.1 Relicensing and License Surrender Pipeline

Relicensing pipeline

Forty-eight percent (47.8 GW) of U.S. hydropower capacity and 83% (18.4 GW) of U.S. PSH capacity require FERC licenses to operate. FERC licenses need to be renewed periodically (license terms are typically 30–50 years). The process that these projects follow to obtain a new license is called relicensing. Project owners that decide not to pursue relicensing have two other options: applying for a conversion from license to exemption (if eligible) or surrendering the license. For licensees that fail to take any action and are in violation of their license conditions, FERC can initiate a license termination proceeding. Both license surrenders and terminations result in projects no longer being authorized to generate hydropower.

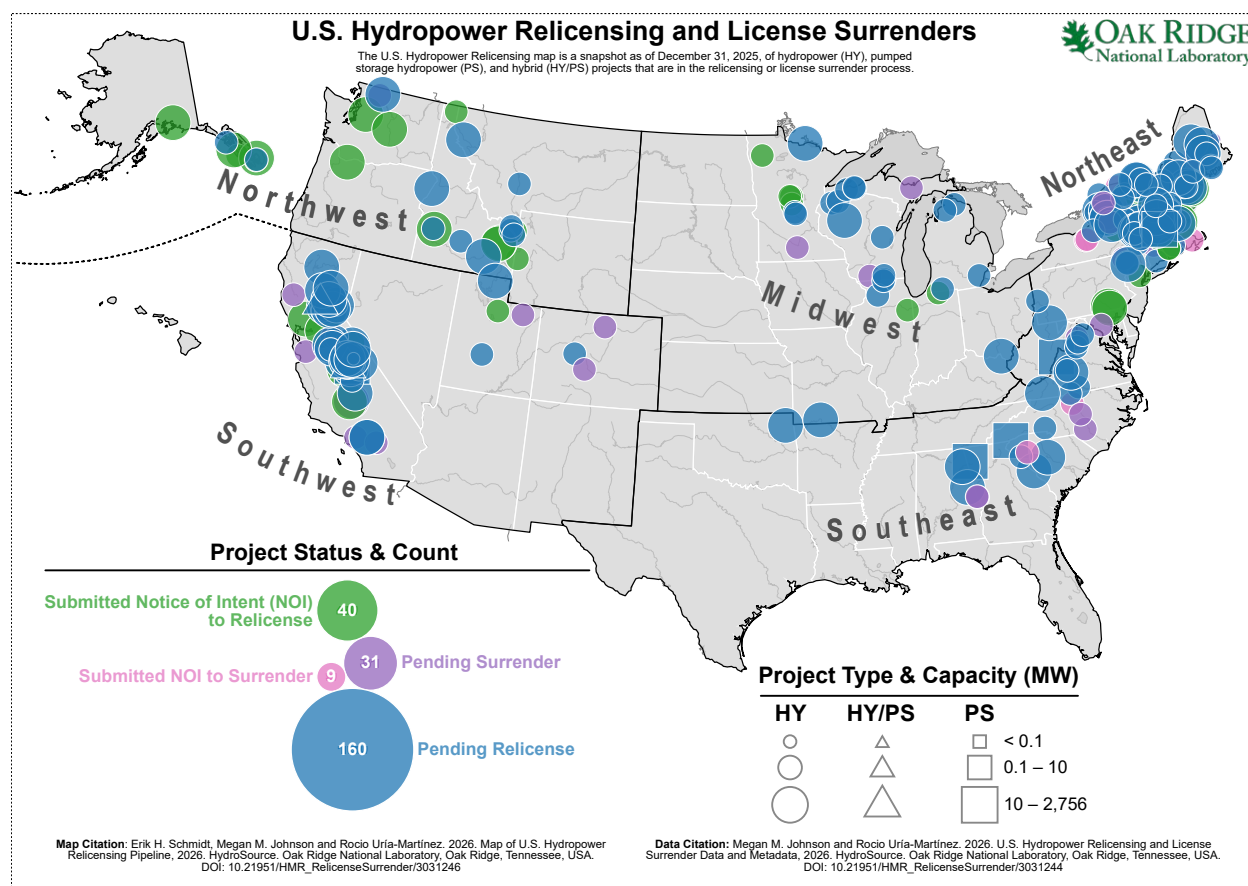


Figure 8. U.S. hydropower relicensing and license surrender pipeline (as of December 31, 2025)

Source: U.S. Hydropower Relicensing and License Surrender Dataset, 2026

Figure 8 shows that, at the end of 2025, 160 licensees with projects adding up to 16.9 GW of capacity had pending relicenses and 40 more licensees whose projects total 1.6 GW of capacity had submitted NOI to relicense and were preparing their relicense applications.

Although the Northeast is the region with the largest number of projects in the relicensing process (89), it is fourth out of the five regions in Figure 8 in relicensed capacity. This fact is consistent with the Northeast being the region with the greatest number of hydropower plants and the lowest median capacity (1.8 MW) in its hydropower fleet. The Southwest region has the most capacity being relicensed (7.08 GW across 41 projects) followed by the Southeast (6.28 GW across 18 projects). Although the Northwest is the region with the most hydropower capacity installed (36.3 GW), it ranks third in number of projects or capacity in the relicensing process in 2025. A large fraction of hydropower capacity in the Northwest (59%) does not require a FERC license because it is owned by federal agencies.

License surrender pipeline

Figure 8 also contains information about license surrenders. Licensees for 31 projects adding up to 53.4 MW have pending surrender license applications. Another nine licensees have submitted NOIs to surrender their licenses, with combined capacity of 11.4 MW. The median capacity of the 40 projects in the license surrender process is 0.8 MW. The Borel project in California (12 MW) is the only project with capacity greater than 10 MW seeking license surrender. Its license is being surrendered because the Borel Canal, required to operate the power plant, will be decommissioned as part of USACE's Isabella Dam modifications to meet current seismic standards.

The Northeast has the highest number of projects in the license surrender process (19 with a total capacity of 11.8 MW) and the Southwest has the most capacity being surrendered (33 MW distributed across 10 projects). Although license surrenders can be submitted at any point, FERC's relicensing schedule presents owners with a key decision point to evaluate whether continued operation of the project is beneficial. Not only is relicensing a costly process but meeting the conditions of a new license may require significant capital investments and changes in operations that, in some cases, render project operation not profitable.

Along with the relicenses and surrenders, six projects in Western states (Oregon, Utah, Idaho, and California) ranging in capacity from 0.115 MW to 5 MW are pursuing conversions from licenses to exemptions. For projects that are eligible, converting from a license to an exemption is an attractive option because exemptions are issued in perpetuity, reducing future regulatory burden.

1.4.2 Trends in Relicensing and License Surrender Activity (2010–2025)

In the past three years, 68 relicense applications were submitted with a combined capacity of 7.5 GW. The number of relicense issuances in 2025 (21) was the largest since 2005. Twenty-four licensees submitted surrender applications in 2023–2025 adding up to 44 MW; half of those surrenders are for projects that had not been generating power for years.

Relicensing activity

Figure 9 reports annual counts of projects (and capacity) from 2010–2025 that a) entered the pre-filing stage of the relicensing process by submitting an NOI, b) entered the post-filing stage by submitting a relicense application, c) completed relicensing after FERC issued a new license.

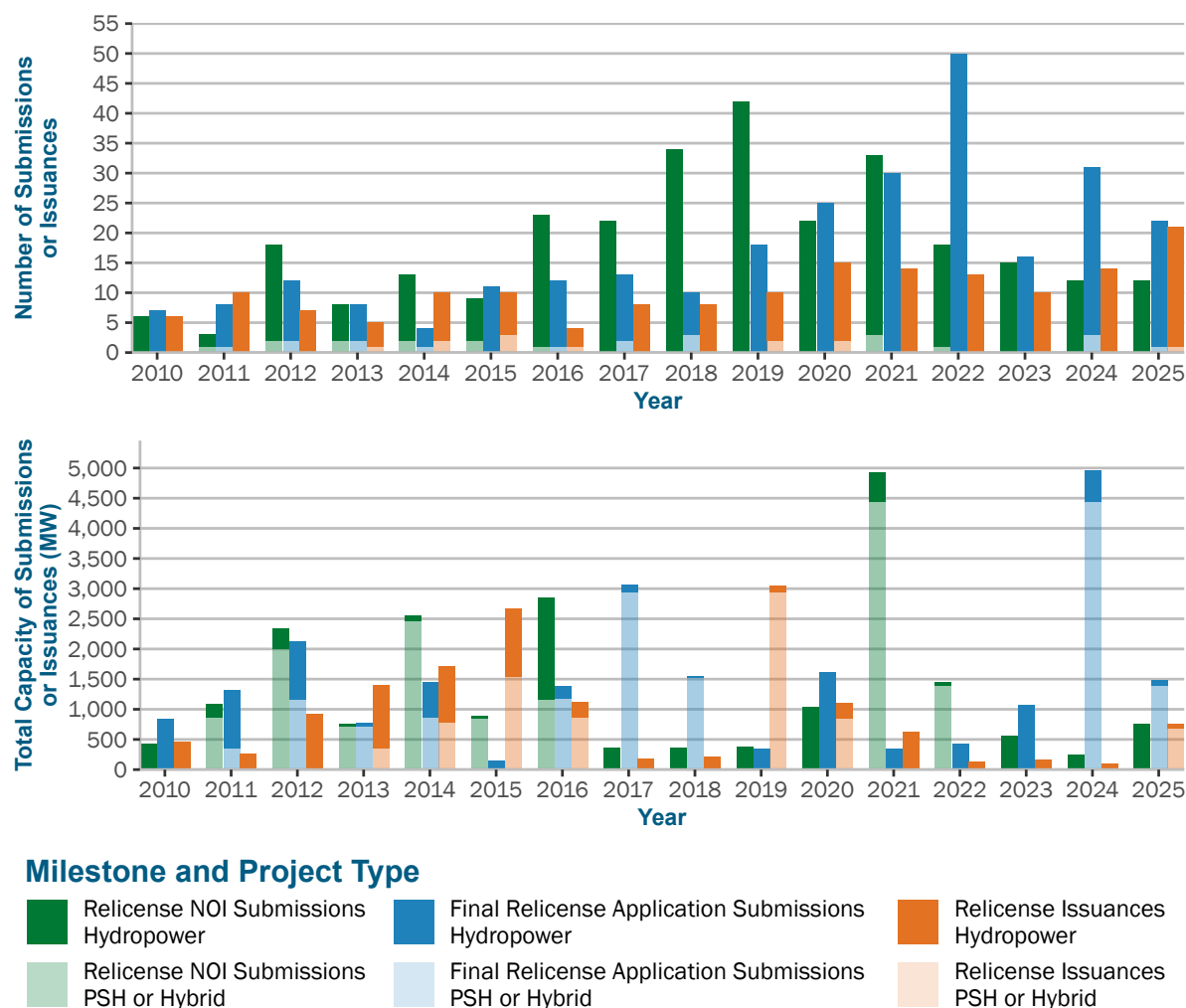


Figure 9. Relicensing activity trends by milestone and project type (2010–2025)

Source: U.S. Hydropower Relicensing and License Surrender Dataset, 2026

From 2015 onward, the number of relicense applications has been larger than the number of relicense issuances, leading to a steady accumulation of pending cases. The increase was partially mitigated in 2025 with 21 relicenses issued (the highest number of relicense issuances since 2005). The Bear Swamp PSH facility accounts for 90% of the 750 MW relicensed in 2025. The large spikes in capacity for submitted NOIs in 2021 and submitted relicense applications in 2024 are due to three PSH facilities—Bath County in Virginia (2,862 MW), Helms in California (1,053 MW), and Rocky Mountain (848 MW) in Georgia—completing those milestones in the same years.

The number of NOIs to relicense has a predictable annual upper bound determined by the relicensing schedule imposed by FERC. Licensees are required to submit an NOI to relicense (or communicate their intention to take an alternative course of action such as surrendering their license) between five and five and a half years before the existing license expires. Then, the final relicense application is due no later than two years before expiration of the current license.¹⁵ Under this schedule, 152 more licensees (3 GW of capacity), should communicate to FERC their plan to relicense, surrender, or convert to exemption by the end of the decade.

¹⁵ If a relicense has not been issued by the expiration date of the existing license, FERC issues annual licenses that allow the project to continue operating under the conditions of the existing license until the new one is issued.

License surrender activity

Figure 10 displays the annual counts and capacities of license (or exemption) surrender applications and license (or exemption) surrender issuances from 2010 to 2025. Because FERC considers license terminations as implied surrenders, terminations are also included in Figure 10.¹⁶ In 2023–2025, on average, eight project owners submitted applications to surrender their licenses (versus six in 2010–2022) and FERC issued seven license surrenders or terminations each year (versus six in 2010–2022). In total, 106 license surrenders (including terminations) were issued in 2010–2025 for projects that added up to 335 MW. Of the 106 surrendered licenses, 102 were for small hydropower plants (≤ 10 MW). Half of all hydropower capacity surrendered from 2010 to 2025 corresponds to the Klamath project in California that was issued a license surrender in 2022 and entailed removal of four dams for the purpose of aquatic restoration.¹⁷

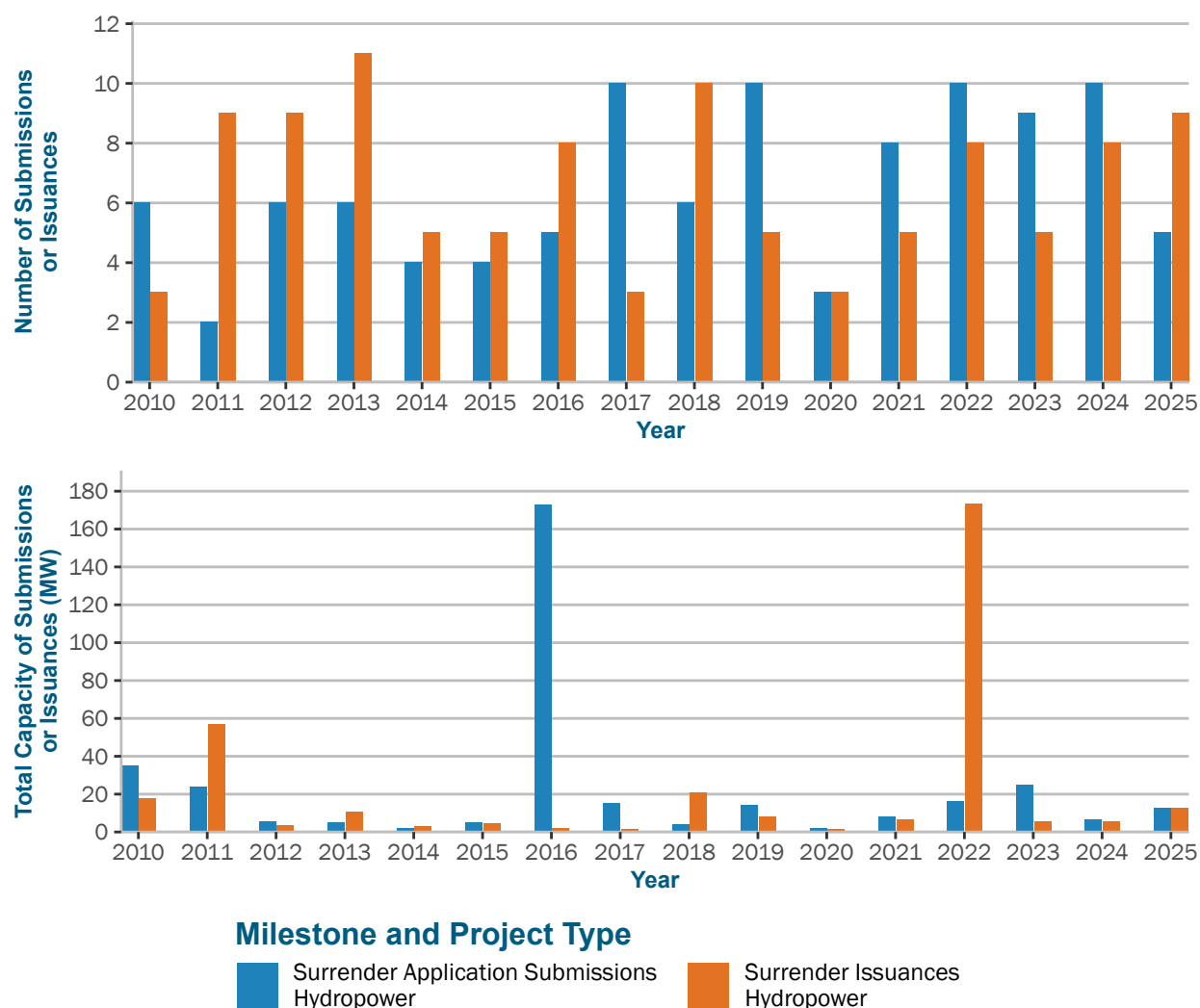


Figure 10. License surrender activity trends by milestone and project type (2010–2025)

Source: U.S. Hydropower Relicensing and License Surrender Dataset, 2026

Notes: Surrenders of licenses or exemptions for projects that were never constructed are not included.

¹⁶ FERC issued 29 license or exemption terminations from 2010 to 2025 with a total capacity of 14 MW.

¹⁷ klamathrenewal.org/the-project/

CHARACTERISTICS OF SMALL HYDROPOWER PLANTS WITH SURRENDERED LICENSES IN 2010–2025

Ninety-six percent of license surrenders issued by FERC from 2010 to 2025 were for small hydropower plants (≤ 10 MW). An analysis of the characteristics of small hydropower plants whose licenses have been recently surrendered can provide insights as to which other plants with active licenses may be considered for surrender in the future.

- Almost 75% of the small hydropower plants with surrendered licenses had capacities below 1 MW.
- Five states (California, Massachusetts, Maine, North Carolina, and Washington) accounted for 46% of the surrenders. Except for California, the share of surrenders these states represent is greater than their share of the U.S. small hydropower fleet.
- Economic infeasibility is the most frequently stated reason for surrendering a small hydropower license. However, electricity price levels do not show a strong relationship with surrendered licenses in this dataset. States with higher end-use electricity price (average across all sectors) than the U.S. average accounted for 54% of surrenders. The top three states by number of surrenders (California, Massachusetts, and Maine) all rank among the ten states with highest electricity prices. Low electricity prices may increase likelihood of license surrender when the reason is economic infeasibility of continued operation of an active plant. However, other financial reasons cited for surrenders are independent from electricity price levels such as 1) the cost of restoring to operation a plant that has sustained damage (many plants surrendering their license have not generated any power for multiple years), 2) expected costs of an upcoming relicensing process, 3) a bankruptcy filing by the plant owner.¹⁸
- Most surrendered licenses were held by private non-utilities (62%) or publicly owned utilities such as municipalities (33%). Within these ownership categories, many of the plant owners surrendering their licenses only own one hydropower project and they may not have the expertise or resources necessary to optimize project operation or fund the capital investments needed to maintain it.
- Surrendered projects span a wide range of ages. Although commissioning years are available for only 39 of the 103 surrendered projects, the partial data offer no evidence that the oldest projects are most likely to be surrendered. Commissioning years ranged from 1907 to 2014 (median commissioning year of surrendered projects was 1983).

¹⁸ The [U.S. Hydropower Relicensing and License Surrender Dataset, 2026](#) contains information about the reason for each license surrender issued since 2010.

1.4.3 Relicensing and License Surrender Process Durations

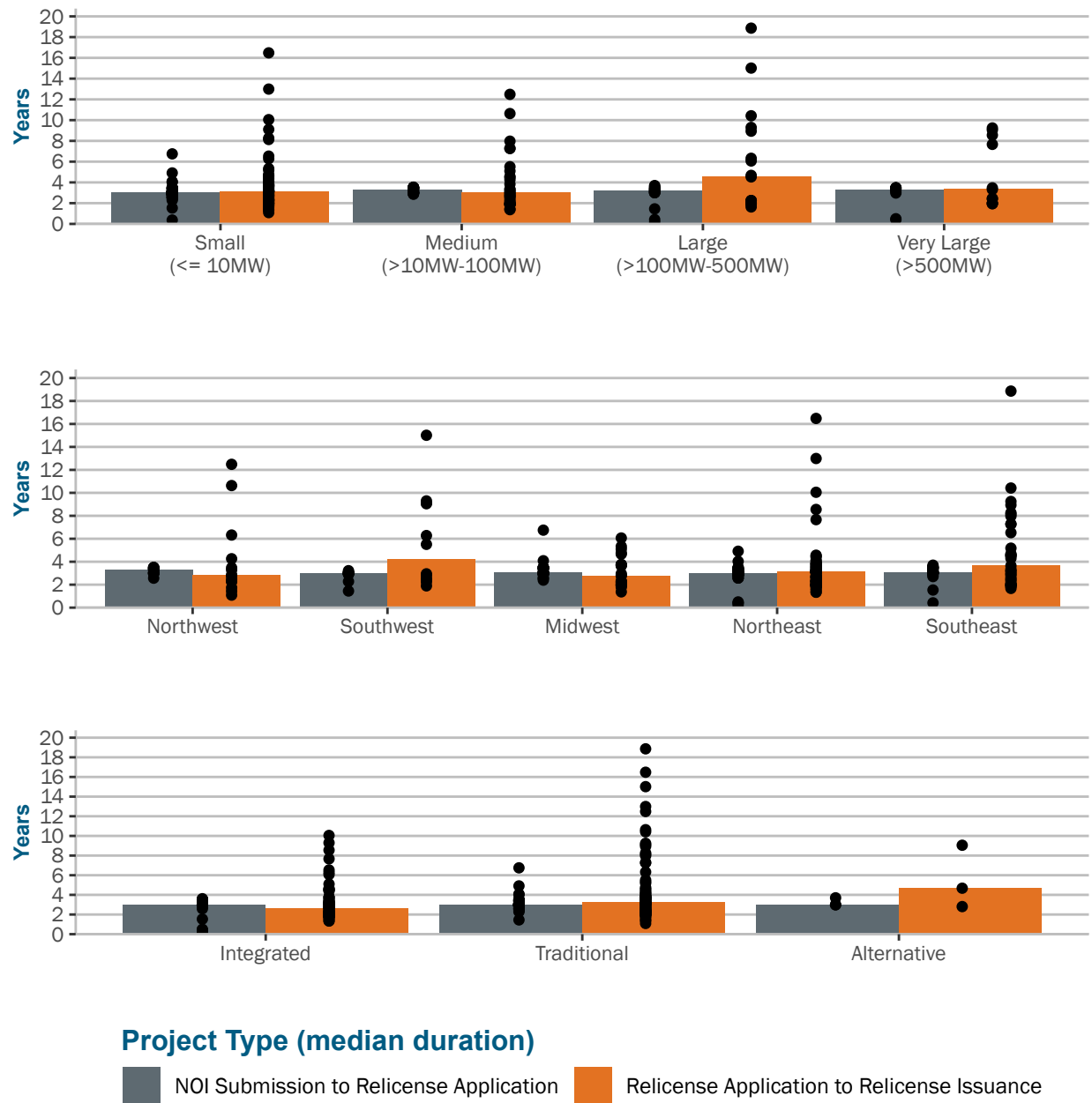
The median duration of the relicensing process for 165 relicenses issued from 2010 to 2025 was six years. Typical durations were slightly longer for Large (>100MW–500MW) than Small (<= 10 MW) projects. Relicensing duration was less variable and typically shorter for projects that used the ILP versus other process modalities.

Relicensing process duration

The relicensing process has two stages. The first, pre-filing stage, extends from the time the project owner submit a NOI and Pre Application Document (PAD) to the time they submit the Final License Application (FLA). The second, post-filing stage, includes all the activities that take place from FLA submission to relicense issuance. Notable milestones during post-filing include activities led by FERC (review of the application and preparation of the environmental document for compliance with the National Environmental Policy Act (NEPA)), consultation with state agencies regarding license conditions over which they have jurisdiction (e.g., fish passage), and activities led by the licensee such as obtaining a water quality certification from the relevant state agency or completing additional studies if required by FERC.

For the 165 projects issued a relicense between 2010 and 2025, the median duration of the pre-filing stage is three years. Only 10% of projects have pre-filing stages longer than 3.5 years. The narrow range for the duration of the pre-filing stage is driven by FERC's schedule since the NOI must be filed by 5 years before license expiration date and the license application must be filed by two years before the expiration date. The median duration of the post-filing stage is 3.1 years (average 3.88 years) with a range from 1.1 years to 18.9 years. The 10% of projects with the longest relicensing durations spent at least 7.8 years in the post-filing stage.

The height of the bars in Figure 11 correspond to the median durations of each relicensing stage segmented by project size, region, and relicensing process. The black dots show the range of durations for individual projects within each of those segments.



For most of the size, region, and process categories shown in Figure 11, the median duration of the post-filing stage of relicensing is somewhat longer than the median duration of the pre-filing stage. Across size categories, the median duration of the pre-filing stage ranged between 3.0 years for Small (≤ 10 MW) projects and 3.3 years for Medium (>10 MW–100 MW) or Very Large (>500 MW) projects. For the post-filing stage, median duration ranged from 3.0 years for Medium projects to 4.5 years for Large (>100 MW–500 MW) projects. Very Large projects are the only size category where the maximum observed duration for the post-filing stage was below ten years.

The median relicensing duration (including both stages) was longer in the Southwest (7.2 years) and the Southeast (6.7 years) than in the rest of regions (5.8 years for the Midwest, 6 years for the Northeast, 6.1 years for the Northwest). The average capacities of projects relicensed in the Southwest (118 MW), Southeast (125 MW), and Northwest (163 MW) are larger than for the Northeast (56 MW) and Midwest (98 MW) which may partly explain the regional differences in durations if size is interpreted as indicative of project complexity.

FERC offers three licensing processes: ILP, Traditional Licensing Process (TLP), or Alternative Licensing Process (ALP).¹⁹ The ILP became the default in 2005, but developers can request the use of one of the other options when they submit the NOI to file a license application. The ILP follows a more structured schedule than the other two. It also involves greater FERC engagement during the pre-filing stage to identify issues early and determine which studies are needed, helping avoid information gaps that could otherwise cause delays during the post-filing stage.

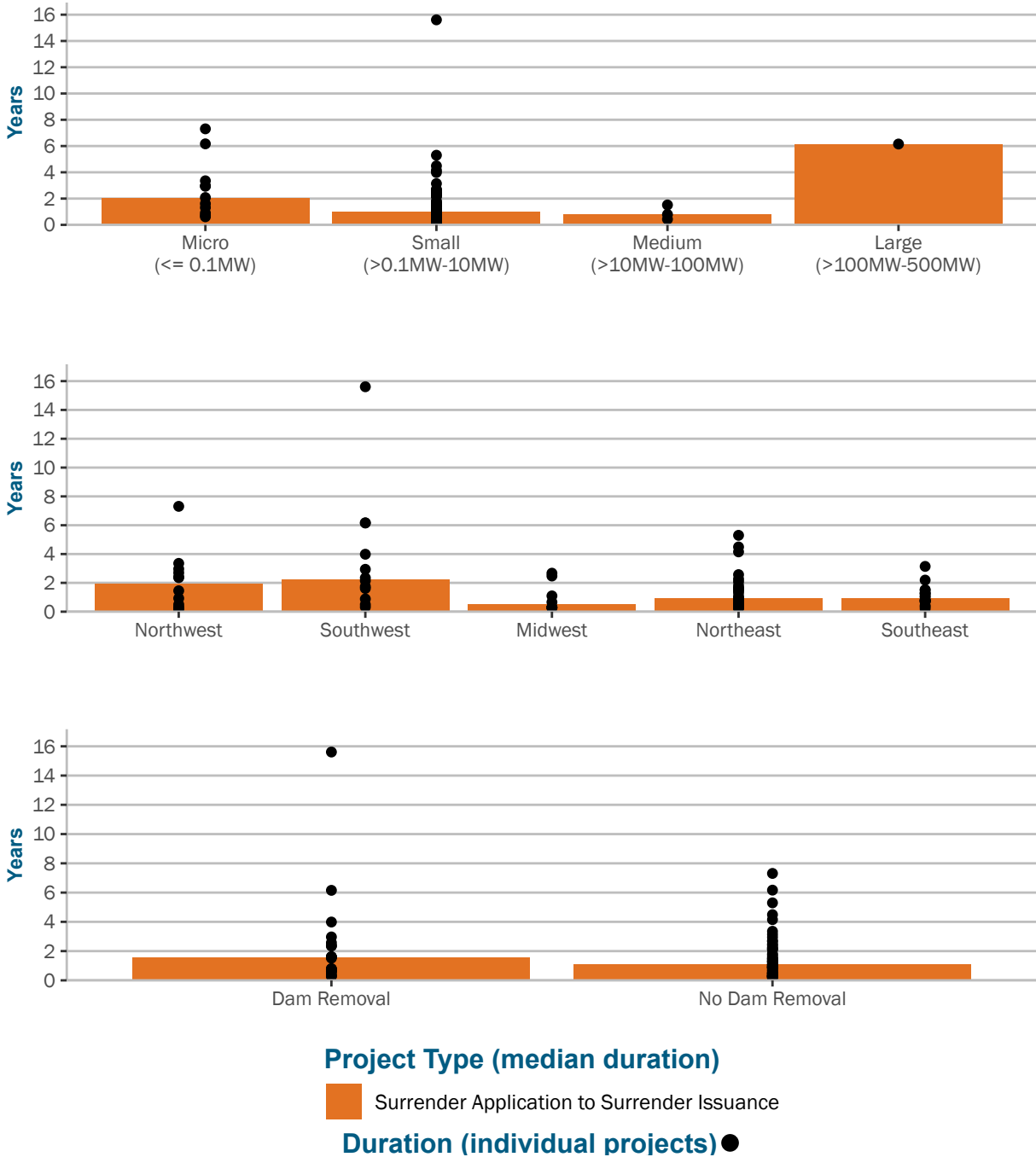
The median duration of the relicensing process for the 73 licensees that used the default ILP process was 5.9 years, 6.2 years for the 89 licensees that selected the TLP, and 8.4 years for the three instances of the ALP. The median duration of the post-filing stage is 2.7 years for the relicenses processed using the ILP, 3.3 years for the TLP, and 4.7 years for the ALP. The median duration of the pre-filing stage is the same across all three processes (3.0 years). Thus, for relicensing, the ILP meets its purpose of making post-filing stage duration more predictable by imposing a stricter schedule and more FERC participation in the pre-filing stage. Large and Very Large projects as well as projects owned and operated by investor-owned utilities used the ILP more frequently than the other two processes.

License surrender process durations

The median duration of a license surrender process (from application submission to surrender issuance) among 77 surrenders issued from 2010 to 2025 was one year. Durations were typically longer for projects in the Southwest (2.2 years) and Northwest (1.9 years) as well as those that involve dam removal (1.6 years).

Figure 12 summarizes license surrender process durations (from application submission to surrender issuance) by project size, region, and whether the surrender involves removal of a dam or not. Median surrender duration was one year, with the range of durations extending from 0.18 years (for a Micro project in the Northwest that did not require dam removal) to 15.6 years (for a Small project in the Southwest involving dam removal).

¹⁹ [ferc.gov/licensing/licensing-processes](https://www.ferc.gov/licensing/licensing-processes)



By region, surrenders issued in the Western regions (1.9 years in the Northwest and 2.2 years in the Southwest) took longer than in the rest of the country (0.9 years in the Northeast and Northwest, 0.5 years in the Midwest). Establishing a relationship between license surrender duration and project size is difficult because 80% of surrenders issued from 2010 to 2025 were for Small projects (>0.1 MW–10 MW). Median durations were longest for projects at the smallest and largest sizes, 2.1 years for 11 Micro projects (≤ 0.1 MW) and 6.2 years for the one Large project (>100 –500 MW). By comparison, the 62 Small projects and three Medium projects had much shorter median durations of one year and 0.8 years, respectively.

License surrender processes involving removal of a dam had median durations of 1.6 years compared to 1.1 years for those with no dam removal. None of the licenses surrendered in the Midwest involved dam removal which may contribute to it being the region with the lowest median surrender duration. In the Northwest, 17% of surrenders involved dam removal. In the other three regions, the proportion of surrenders in which a dam was removed was similar (50% in the Southwest, 42% in the Northeast, and 50% in the Southeast).

As part of a surrender application, the licensee typically must include 1) a decommissioning plan describing whether the project facilities will be removed, modified, or left in place, 2) a report detailing the effects of the surrender on the environment and proposing mitigation measures for those effects, 3) a schedule to complete the proposed decommissioning and mitigation actions, 4) copies of consultations with relevant federal and state agencies. The decommissioning and mitigation actions listed in the application are indicative of the complexity of the process and influence its duration. For example, the shortest surrender process captured in Figure 12 took 63 days. It was an implied surrender for the Riverdale Hydroelectric Project (1.24 MW) in Washington where FERC requested the licensee to submit the surrender application. The application did not include a decommissioning plan and FERC determined that no environmental analysis was needed because the plan was to leave the project facilities in place. The longest surrender process included in Figure 12 corresponds to the Kilarc/Cow Creek project (2.94 MW) in California. Its licensee submitted a surrender application in 2009 proposing removal of the project facilities (including multiple diversion dams) and requiring environmental analysis by FERC. Local opposition to removal of dams connected to this project, used for recreation, contributed to the long process. FERC issued the license surrender in 2024.

CHAPTER 2. LOOKING FORWARD: U.S. HYDROPOWER AND PSH DEVELOPMENT PIPELINE

This chapter presents a snapshot of the U.S. hydropower and PSH development pipeline at the beginning of 2026. It discusses key characteristics of proposed projects (new facilities and capacity additions to existing plants) including type, size, and development status. It also summarizes trends in FERC permitting activity from 2018 to 2025 and statistics about the duration of the FERC permitting process for licenses and exemptions issued from 2010 and 2025.

2.1 U.S. HYDROPOWER DEVELOPMENT PIPELINE

At the beginning of 2026, the U.S. hydropower development pipeline included 161 projects with a combined capacity of 2.06 GW. Seventy-seven percent of these projects propose construction of new facilities with a combined capacity of 1.4 GW (versus 109 proposed facilities with combined capacity of 1.1 GW one year earlier). Six of them (14 MW) were under construction and 55 were at the earliest stage of development in which feasibility is being assessed and attrition rate is very high. Moreover, the owners of 33 hydropower facilities already in operation are planning or constructing capacity additions totaling 669 MW.

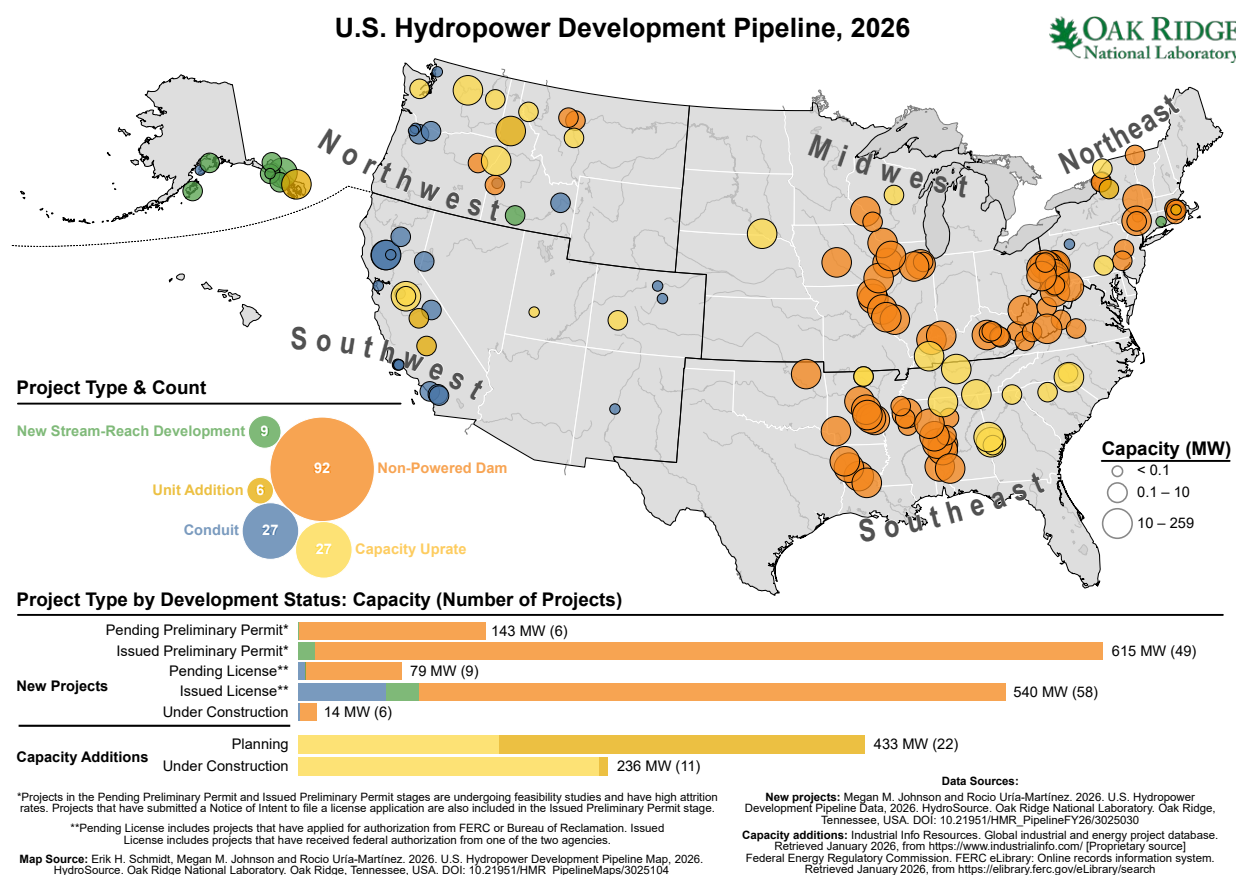


Figure 13. Hydropower project development pipeline by project type, region, size, and development stage (as of December 31, 2025)

Sources: For new projects, U.S. Hydropower Development Pipeline Data, 2026. For capacity additions, IIR (proprietary source) and FERC.

Non-powered dam projects

The median proposed capacity of the 92 NPD retrofit projects is 10 MW, and the eleven largest projects range from 30 MW to 50 MW. Twenty-one states have at least one NPD project in the development pipeline and the proposed capacity from NPD projects surpasses 100 MW in seven states (Alabama, Arkansas, Illinois, Kentucky, Louisiana, Pennsylvania, West Virginia). Federal agencies own 67 of the dams being considered for NPD projects (66 by USACE and one by the U.S. Bureau of Reclamation (BOR)); the remaining dams are owned by state agencies (nine) and by municipalities, electric utilities, or private entities. Importantly, permitting processes vary depending on who owns the dam. For instance, NPD projects on dams owned by USACE require a second federal permit (Section 408 permit from USACE), in addition to a FERC license.

At the beginning of 2026, eight NPD projects—all of them located in Pennsylvania, West Virginia or Ohio—had Section 408 permits under USACE review. Five of them are projects that already have a FERC license and the other three have submitted their license applications, but they are pending a final decision from FERC.

The Marseilles Lock & Dam (10.26 MW in Illinois) and Heidelberg (2.64 MW in Kentucky) NPD projects are under construction. Thirty-three other NPDs, with a total capacity of 448 MW, already have a federal authorization (FERC license, FERC exemption from licensing, or the U.S. BOR Lease of Power Privilege (LOPP)) and six more (74 MW) have pending license applications under review by FERC. The remaining 51 projects are at earlier development stages, during which feasibility is being assessed and final license, exemption, or LOPP applications are being prepared.

Conduit projects

Twenty-seven of the projects shown in Figure 13 would add electricity generation equipment to existing conduits.²⁰ Their combined proposed capacity is 73 MW. The median proposed capacity at these sites is 0.056 MW. Except for a project in Pennsylvania, all proposed conduit retrofit sites are in Western states, including 14 in California. Two of the California projects account for 84% of proposed capacity at all conduit sites in the development pipeline. Those two projects are being pursued by the Sites Project Authority whose primary goal is building an off-stream reservoir to store excess water during major storms and release it during dry periods. As water is released, it would pass through the proposed hydropower turbines and generate electricity helping to recover some of the energy that will be needed for pumping water into the reservoir.

Four conduit projects (all with capacities of 1 MW or less) are under construction: two in Colorado, one in California, and one in Nevada. Of the remaining 23 conduit projects, 21 already have FERC authorization and the other two have a pending FERC license or exemption in process.

Conduits are the only project category in the U.S. hydropower development pipeline for which most developers are publicly-owned utilities. Municipalities or political subdivisions (e.g., irrigation districts) own much of the U.S. conduit infrastructure and are the developers for 18 of the 27 conduit projects shown in Figure 13. For NPDs and NSDs, most developers are private non-utilities.

²⁰ A conduit is “any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity.” (18 CFR 4.30)

New stream-reach development projects

Nine NSD projects were in the development pipeline at the beginning of 2026 with total proposed capacity of 38 MW. Seven of the nine NSD projects are in Alaska with the other two in Connecticut (Quiet Woods Water Wheel, 0.003 MW) and Idaho (Molitor Hydroelectric Project, 0.714 MW). Half of the proposed NSD capacity corresponds to the Sweetheart Lake project (19.8 MW) in Alaska.

None of the NSD projects have reached the construction stage. Four Alaska projects (including Sweetheart Lake) have secured FERC licenses, the project in Connecticut has an exemption application pending, and the rest are pursuing or holding preliminary permits.

Capacity additions projects

The owners of 33 existing hydropower facilities are pursuing projects that would increase their capacities by a total of 669 MW. Figure 14 breaks down these additions by plant size category and distinguishes between increases from proposed uprates to existing turbine-generator units (383 MW) and proposed new unit additions (286 MW). Eleven of the 33 capacity addition projects are under construction and will result in 236 MW of new capacity when completed.

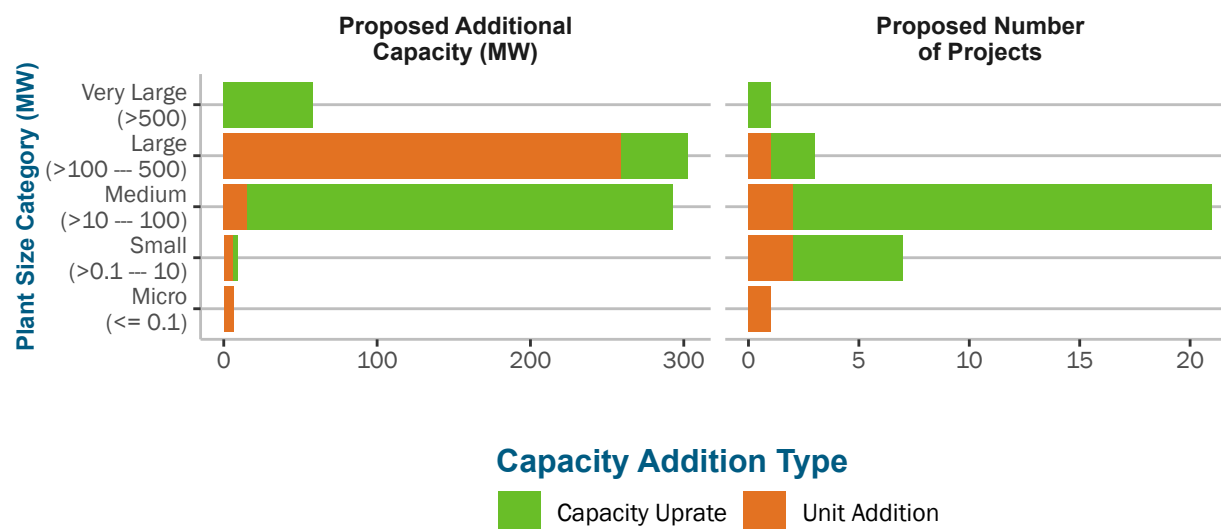


Figure 14. Proposed capacity additions to the existing hydropower fleet by plant size category and project type

Sources: IIR (proprietary source), FERC

The new 259 MW unit proposed at Dworshak Dam (a 465-MW USACE hydropower plant in Idaho) accounts for 90% of planned new capacity from unit additions to existing facilities. The Dworshak unit and a 10-MW unit proposed for Tyee Lake in Alaska are examples of facilities where the original powerhouses were built with unused turbine bays to allow for future unit additions.²¹ Two other unit addition projects propose installations of small turbines that will allow generating power from mandatory environmental flows. New units are needed to use these flows for power generation when environmental flows are below the minimum discharge (in cubic feet per second) required for the main turbine-generator units to operate.

Ten of the 33 capacity addition projects shown in Figure 13 are at federal hydropower plants. The rest are for nonfederal plants under FERC jurisdiction whose owners need to file a license amendment and

²¹ https://www.army.mil/article/288039/dworshaks_skeleton_bay_flooded_in_key_step_toward_regional_energy_growth

receive FERC approval before the capacity uprates or unit additions can proceed. For a set of 32 license amendments related to capacity upgrades issued by FERC from 2020 to 2025, the median time elapsed from amendment application submission to amendment issuance was 0.6 years and it was longer than one year in 12 instances. FERC is currently considering how to improve or streamline processes for post-licensing activities, including maintenance, repairs, and upgrades. It published a Notice of Inquiry in November 2025 seeking input from hydropower industry stakeholders on this topic (See more details in Chapter 7).

2.2 U.S. PSH DEVELOPMENT PIPELINE

Seventy-four PSH projects (totaling 67 GW) were in the development pipeline at the beginning of 2026. Sixty-eight of them (totaling 59 GW) were pursuing the FERC permitting process for new projects (versus 70 with total capacity of 61 GW one year earlier). Of those 68, four had already received a FERC license. Three additional new projects under consideration do not require a FERC license. Separately, owners of three existing PSH facilities plan to increase capacity by uprating existing units or adding new units.

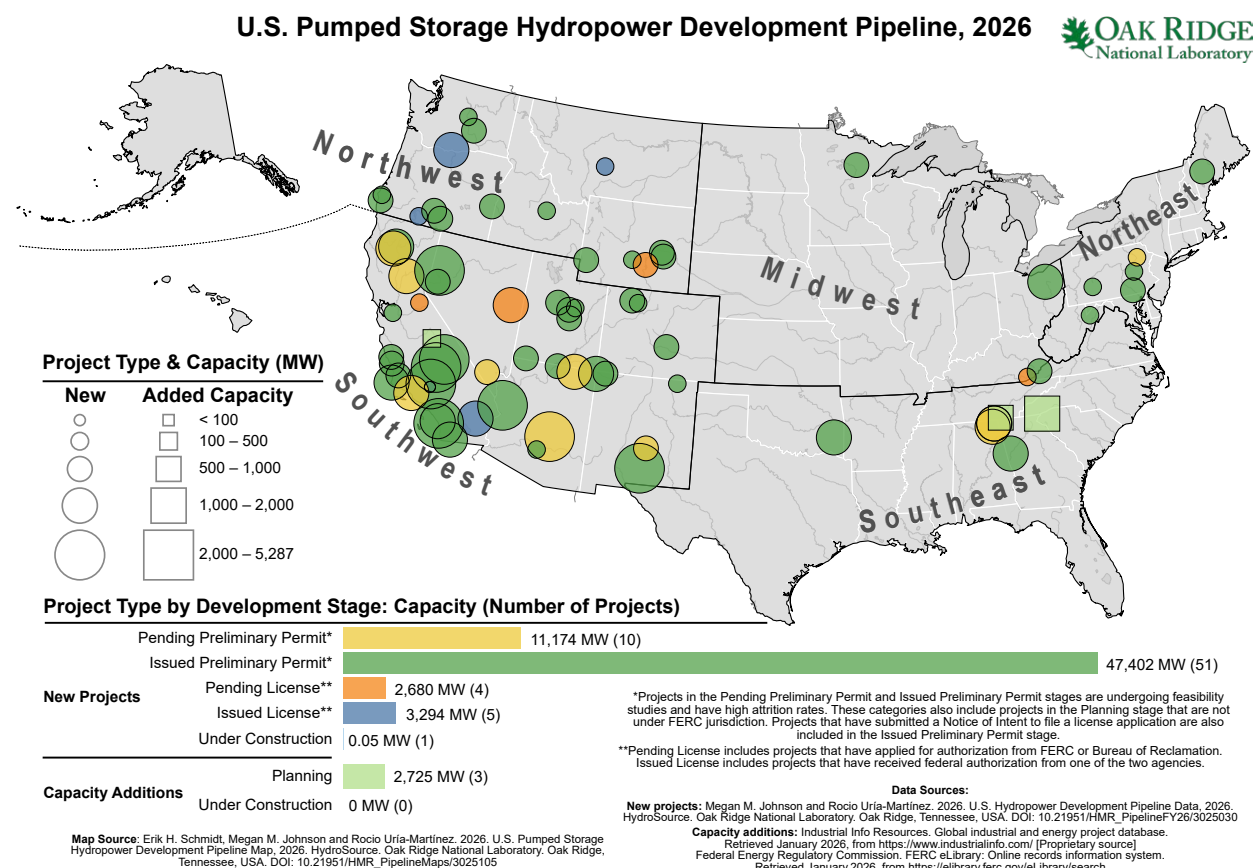


Figure 15. PSH project development pipeline by region and status

Sources: For new projects, U.S. Hydropower Development Pipeline Data, 2026. For capacity additions, IIR (proprietary source) and FERC

Note: The data in the map are a snapshot of the PSH development pipeline as of December 31 of 2025, except for inclusion of the license issuance for Goldendale which took place in January 2026.

The median proposed capacity of U.S. PSH projects is 600 MW. It includes projects ranging from 0.05 MW (Aquifer Pumped Hydro project in California) to 5,287 MW (Camp Pendleton in California).²² The PSH development pipeline is heavily concentrated in the Western half of the country with 58 of the 74 projects located in the Northwest or Southwest regions.

Fifty-eight of the 74 PSH projects in the pipeline are being proposed by private non-utilities. Unlike electric utilities, these entities would need to either enter into PPAs with for the sale of energy and other services provided by the prospective facilities or participate in one of the organized U.S. wholesale electricity markets. PacifiCorp is the only investor-owned utility proposing new PSH projects in the FERC pipeline.²³ However, other investor-owned utilities are considering an expansion to their PSH capacity by uprating their existing units (Pacific Gas & Electric for Helms in California) or adding more units (Duke Energy at Bad Creek). Two other public entities (TVA and Salt River Project) are also pursuing new PSH projects.²⁴

Sixty of the 74 projects proposed closed-loop configurations in which the reservoirs are not continuously connected to a naturally flowing body of water. Interest in closed-loop projects has grown in recent years, driven by their greater siting flexibility and their potential for lower environmental impacts. However, they tend to be more expensive because they typically require construction of two reservoirs. Moreover, securing water sources for initial fill-up of the reservoirs can be challenging. For open-loop projects that use an existing lower reservoir, environmental impacts of construction may be as low, if not lower than closed-loop (DOE, 2020). All the projects, whether greenfield developments or capacity additions, proposed by entities that already own and operate PSH capacity, including TVA, Salt River Project, Duke Energy, and Pacific Gas & Electric are among the 14 open-loop projects in the pipeline.

Four closed-loop projects already hold FERC licenses, meaning that they have completed the major federal permitting milestone. Three of these licenses have been issued seven or more years ago: Eagle Mountain in California (1,300 MW, 9–10 hours of storage duration) since 2014, Gordon Butte in Montana (400 MW, 8.5 hours of storage duration) since 2016, and Swan Lake in Oregon (365 MW, 9.5 hours of storage duration) since 2019. FERC issued the license for the Goldendale Project in Washington (1,200 MW, 12 hours of storage duration) in January 2026. Within the last year, FERC has issued license amendments for the Eagle Mountain PSH project (to reroute the transmission line that will connect it to an electric substation) and Swan Lake PSH project (to change the project design from three 131 MW variable-speed turbine-generator units to two 182.4 MW fixed-speed turbine-generator units). As for the Gordon Butte project, FERC granted its developer an extension of time (to December 2026) to complete acquisition of the land rights necessary for project construction and operation.

An additional four projects have submitted FLAs to FERC. Developers for the Seminole project in Wyoming (972 MW, 9.7 hours of storage duration) and the White Pine project in Nevada (1,000 MW, 8 hours of storage duration) submitted applications in 2023. License applications for the Mokelumne project in California (400 MW, 8 hours of storage duration) and the Lewis Ridge project in Kentucky

²² The two Aquifer Pumped Hydro projects (0.05 MW and 0.236 MW) in California are different in scale and configuration to the rest of projects in the U.S. PSH pipeline. They are research and demonstration projects to be operated for only one year. They will be operated as closed-loop systems that cycle water up and down from an underground aquifer to a surface water storage reservoir. Given their small size and location along a non-federal irrigation conduit, they followed the FERC qualifying conduit process and did not require an original FERC license.

²³ Additionally, PacifiCorp is considering licensing capacity amendments for the Cutler and Bear River projects to add PSH units under those existing licenses.

²⁴ TVA is a federal agency and therefore does not require a FERC license to construct a new project. In the case of the Salt River Pumped Storage project, a [bill](#) enacted in January 2025 designated federal land “for the development, generation, and transmission of electrical power and energy for the use and benefit of the Salt River Federal Reclamation Project” giving the U.S. BOR federal jurisdiction for approving the project and eliminating the need for a FERC license.

(308 MW, 8 hours of storage duration) were submitted in 2025. Except for the Seminole project, all these projects propose closed-loop configurations.

Some subsets of the PSH projects shown in Figure 15 are portfolios proposed by the same entity of which only one would be selected. For example, TVA is evaluating three options to expand its PSH capacity: an expansion of Raccoon Mountain in Tennessee or construction of either the Rorex Creek or Widows Creek projects in Alabama. Rorex Creek has been identified as the preferred alternative, but a final decision had not yet been made as of April 2026.

2.3 PERMITTING ACTIVITY TRENDS AND PERMITTING TIMELINES

Private developers have shown consistent, strong interest in PSH and NPD projects by seeking preliminary permits to evaluate the feasibility of specific sites and secure first priority to develop them for the duration of the permit. However, very few of those permits are moving forward to formal authorization applications. The process to permit conduit facilities is shorter than for other types of projects and they make up most of the authorization applications and issuances in recent years.

Figure 16 summarizes permitting activity by FERC and U.S. BOR for new hydropower and PSH projects from 2018 to 2025.

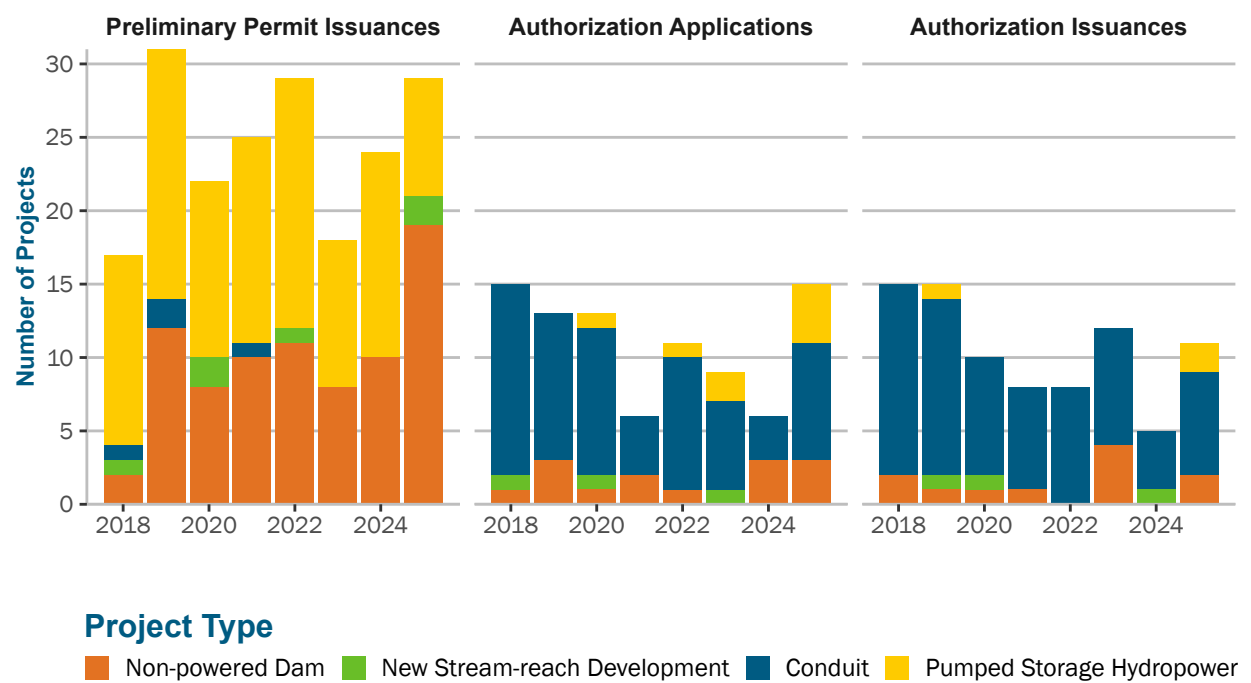


Figure 16. Permitting activity trends by project type (2018 – 2025)

Sources: U.S. Hydropower Development Pipeline Data, 2026

Notes: The Preliminary Permit Issuances category includes preliminary permits issued by FERC and preliminary leases issued by the Bureau of U.S. BOR. The Authorization Applications category includes applications to FERC for original licenses, exemptions or qualifying conduit status. The Authorization Issuances category includes issuances by FERC of original licenses, exemptions, or qualifying conduit status as well as LOPP issuances by the U.S. BOR.

From 2018 to 2025, FERC issued an average of 24 preliminary permits annually. During the same period, project developers submitted an average of 11 authorization applications per year to FERC or the U.S. BOR, and those agencies issued an average of 11 authorizations per year. For authorization applications, the volume of activity in 2025 (15 applications) was the highest since 2018 reversing the declining trend observed from 2019 to 2024.

Consistent with what Figure 13 and Figure 15 show regarding the composition of the development pipeline at the start of 2026, permitting activity for new hydropower in the U.S. is almost exclusively a combination of projects that add hydropower generation capability to existing infrastructure (NPD and conduit projects) or PSH. Very few (12) NSD projects are included in any of the permitting activity milestones shown in Figure 16.

Activity related to the U.S. BOR LOPP process from 2018 to 2025 included issuance of preliminary leases (shown as part of the Preliminary Permit Issuances category in Figure 16 for four projects (three NPDs and 1 conduit) and LOPP issuances for the same four projects plus an additional conduit project. The rest of the 367 permitting milestones shown in Figure 16 correspond to projects obtaining authorizations from FERC.

NPDs, PSH projects, and some conduit projects require an original license (or exemption from licensing) from FERC. Developers pursuing these projects typically apply for a preliminary permit as the first stage of the permitting process. A preliminary permit grants the project developer priority for developing a particular site during a four-year period. During that time, the developer conducts studies to assess the technical and economic feasibility of the project and periodically communicates its progress to FERC. The outcome from those studies informs the decision on whether to submit an authorization application (FERC license or FERC exemption). Project attrition rate at the preliminary permit stage is very high.

For conduit retrofits, many projects can apply to FERC for qualifying conduit status and do not require a FERC license or exemption.²⁵ In that case, the first step is requesting qualifying conduit determination—a step captured under the Authorization Applications category in Figure 16. FERC’s evaluation of whether a conduit can receive “qualifying conduit” determination has a much quicker turnaround than the authorization process for other types of projects. Figure 17 summarizes permitting timelines for projects that obtained qualifying conduit determination or a FERC exemption from 2010 to 2025.²⁶

²⁵ A “qualifying conduit hydropower facility” must meet the following provisions: 1) a conduit is any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption, and is not primarily for the generation of electricity, 2) the facility generates electric power using only the hydroelectric potential of a non-federally owned conduit, 3) the facility has installed capacity that does not exceed 40 MW, 4) the facility was not licensed or exempted from licensing requirements of Part I of the Federal Power Act on or before August 9, 2013.

²⁶ The qualifying conduit process became available in 2013. Conduit projects seeking FERC authorization before that followed either the FERC exemption or FERC license process.

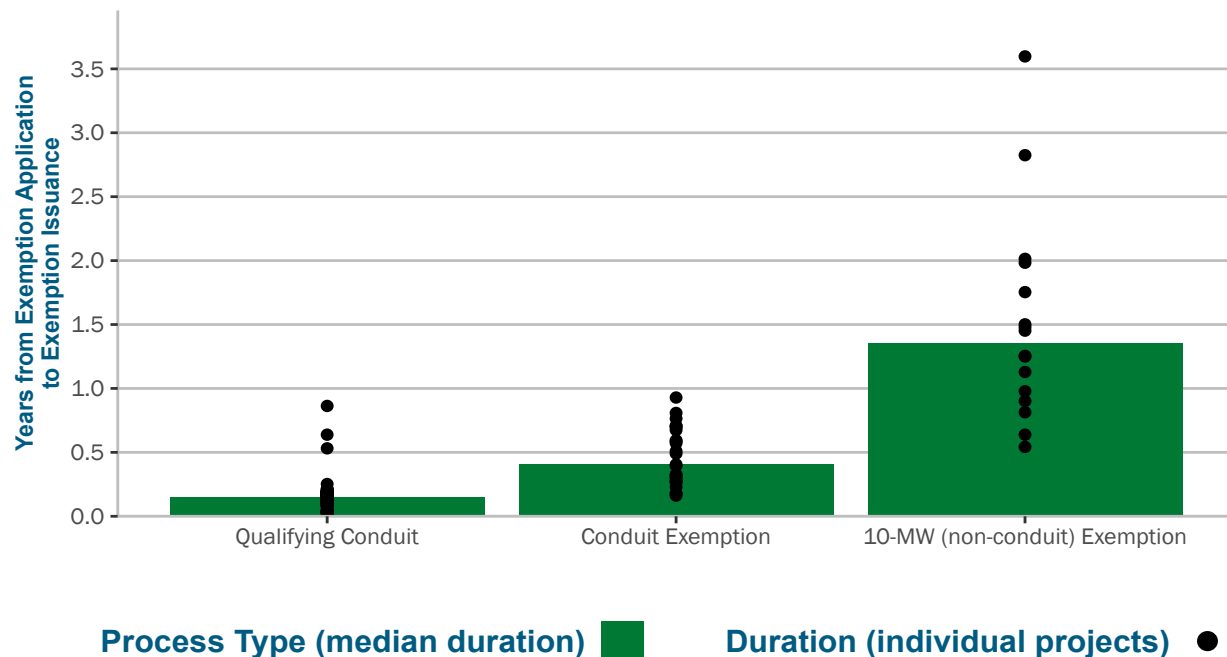


Figure 17. Duration of permitting process for projects that obtained qualifying conduit determination or a FERC exemption from 2010 to 2025

Sources: U.S. Hydropower Development Pipeline Data, 2026

The median response time by FERC for the 175 conduit projects that sought qualifying conduit determination until 2025 was 0.11 years, and the longest instance of that process took 0.86 years. FERC issues two types of exemptions from licensing: one for conduit projects that do not meet the criteria to be classified as qualifying conduits and one for other non-conduit, small (≤ 10 MW) hydropower projects. For the 25 projects in Figure 17 that used the conduit exemption process, the median time from application submission to exemption issuance was 0.4 years, and none took longer than one year. The 10-MW (non-conduit) exemption route is typically longer. The median duration from 10-MW exemption application submission to exemption issuance for the 16 projects in that process category was 1.35 years. Durations ranged from 0.54 years to 3.6 years—a much wider range than for the conduit projects. A key difference between the two exemption processes that helps explain the difference in their typical durations is that the 10-MW exemption process requires an environmental document to be prepared by FERC, but the conduit exemption process is categorically exempt from that requirement.

Figure 18 shows the median and individual durations of the two stages of the FERC licensing process for 80 projects—including conduits, NPDs, NSDs, and PSH—that obtained original licenses from 2010 to 2025. The starting point for the FERC licensing process is the submission of a NOI to submit a license application. The pre-filing stage covers the time from NOI submission to final license application submission. During this stage, project developers gather, through studies and interaction with stakeholders, all the information needed to prepare the license application. The post-filing stage covers the period from license application submission to license issuance. FERC evaluates the application and conducts the environmental review during the post-filing phase to decide whether or not to authorize the project.

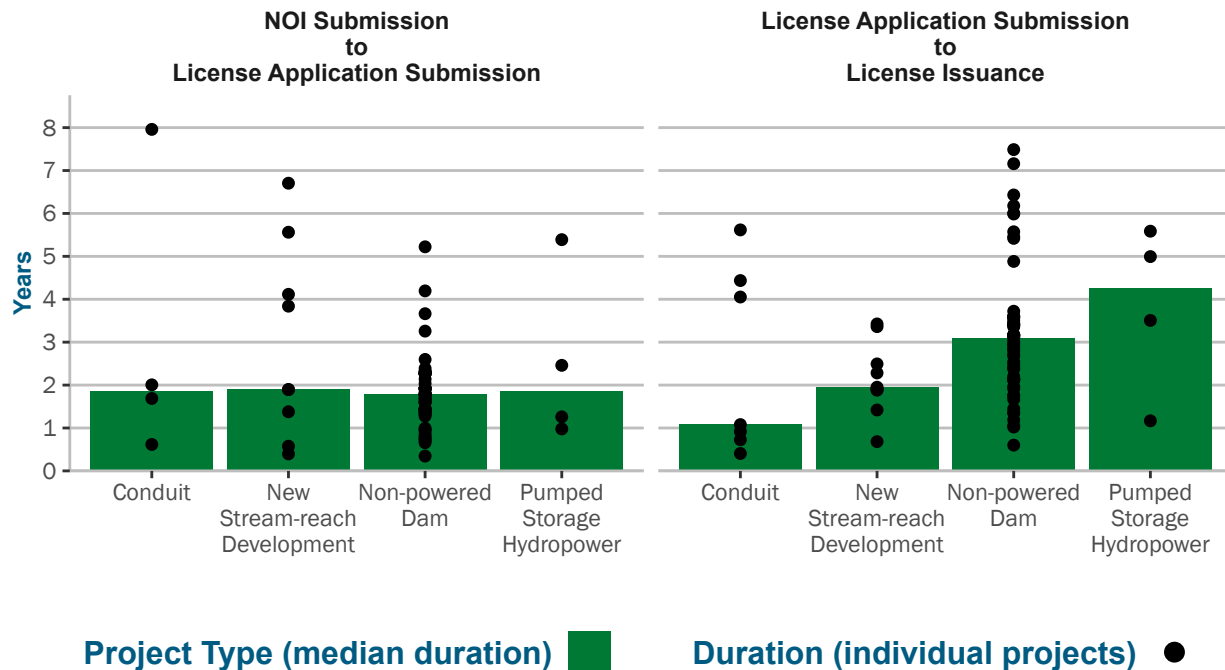


Figure 18. FERC licensing process duration for projects that obtained original licenses from 2010 to 2025

Sources: U.S. Hydropower development Pipeline Data, 2026

Figure 18 shows that the median time spent in pre-filing stage is very similar across all project types (1.8 years to 1.9 years) although there is substantial variability around that typical duration. For the post-filing stage, median durations differ considerably by project type: 1.0 years for the seven conduit projects that required a license, 2.1 years for the 10 NSD projects, 3.1 years for the 59 NPD projects, and 3.8 years for the four PSH projects. Adding up pre-filing and post-filing stage durations results in approximate median licensing process durations of three years for conduits, four years for NSD projects, five years for NPD projects, and six years for PSH.

The TLP offers more schedule flexibility during the pre-filing stage and was the most frequently selected process for original licenses issued since 2010. Sixty-five of the 80 licenses included in Figure 18 followed the TLP, 12 used the ILP, and three opted for the ALP. The median duration of the licensing process for original licenses issued between 2010 and 2025 was 6.6 years for projects using the ILP, 4.6 years for projects using the TLP, and 3.7 years for projects using the ALP. Compared with the larger set of projects using the TLP, those using the ILP typically spent more time in the pre-filing stage (2.4 years versus 1.7 years) but less time in the post-filing stage (2.8 years versus 3.1 years).

The duration of the FERC licensing process for any specific project depends on many factors. Levine et al. (2021) highlights greater environmental complexity as a key contributor to longer licensing timelines. They cite project size, presence of endangered species, long water quality certification timelines, the need for an environmental impact statement, and the use of settlement agreements as indicators of environmental complexity. With respect to size, the set of projects in Figure 18 is consistent with the idea that larger projects require longer licensing timelines. The median capacities of projects for which FERC issued original licenses from 2010 to 2025 were 0.5 MW for conduits, 3.1 MW for NSD, 5.3 MW for NPD, and 800 MWs for PSH.

CHAPTER 3. U.S. HYDROPOWER AND PSH IN THE GLOBAL CONTEXT

The United States has the fourth largest hydropower fleet and third largest PSH fleet (by individual country) in the world. This chapter provides summary statistics for the global operational fleet and the global development pipeline. It also discusses the evolution of the generation mix from 2016 to 2025 in the countries or regions with the largest hydropower fleets. Furthermore, it describes trends in global hydraulic turbine trade.

For the United States, operational plant data are from [ORNL EHA Plant Database 2026](#) and project pipeline data are from [U.S. Hydropower Development Pipeline Data, 2026](#). For the rest of the world, plant-level data for operational facilities and project-level data for the development pipeline are from a commercial database ([GlobalData](#)).²⁷

3.1 DESCRIPTION OF EXISTING FLEETS

Global hydropower capacity (including capacity from hybrid plants that contain a mixture of hydropower and PSH units) reached 1,296 GW in 2025. Additionally, the global PSH fleet had a capacity of 160 GW. Together, hydropower and PSH represented 14% of global generation capacity in 2025 and 15% of electricity generated in 2024. Over the past decade, the average annual global growth rate was 1.4% for hydropower and 3.6% for PSH; total electricity generation capacity grew at an average 5.2% per year.

Figure 19 shows the electricity generation capacity mix for the world and the six countries/regions with the largest hydropower fleets. The top six hydropower (including PSH) fleets in 2025 were those in China (448.0 GW), the European Union (154.2 GW), Brazil (110.3 GW), United States (103.1 GW), Canada (84.3 GW), and India (56.3 GW).²⁸ These six fleets account for two thirds of global hydropower capacity.

²⁷ The methodology that GlobalData uses to collect data involves a mixture of primary research (through communication with project owners, developers, contractors, and equipment suppliers) and secondary research. Information for projects in the development pipeline is updated at least annually but also dynamically based on announcements made public by project proponents.

²⁸ India became the sixth largest fleet in 2024 surpassing Russia.

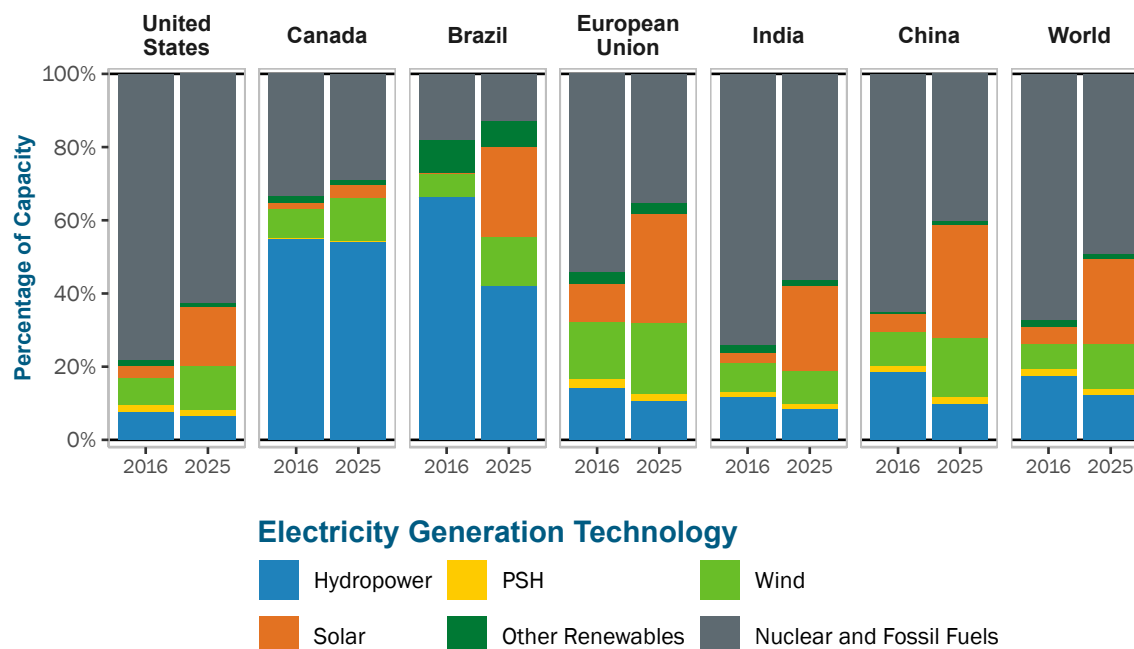


Figure 19. Electricity generation capacity mix in the countries/regions with the largest hydropower fleets (2016 and 2025)

Source: IRENA Renewable Energy Statistics 2026

Note: European Union membership changed from 2016 to 2025. The European Union grouping shown corresponds to the 27 members as of 2025.

The share of global electricity generation capacity powered by nuclear or fossil fuels decreased from 69.2% in 2016 to 50.5% in 2025. In 2016, hydropower was the largest renewable in the world and in five of the six countries/regions shown in Figure 19. By 2025, installed solar capacity had overtaken hydropower in India and both solar and wind capacity are larger than hydropower capacity in the United States, European Union, and China. Hydropower continues to account for the largest share of electricity generation capacity in Canada and Brazil.

The world hydropower and PSH shares of electricity generation capacity were 12.4% and 1.5% in 2025, respectively. Over the past decade, hydropower grew at a slower rate (1.4%) than nuclear and fossil fuels (1.6%), total (5.2%) and renewable (11.0%) electricity generation capacity. Globally, 156.9 GW of hydropower capacity became operational between 2016 and 2025. Almost half of that total corresponded to China whose fleet grew from 305 GW in 2016 to 382 GW in 2025. Of the six country/regions shown in Figure 19, the United States added the least capacity from 2015 to 2024: 0.5 GW according to International Renewable Energy Agency (IRENA) statistics. Hydropower capacity additions during that period were 6.3 GW for India, 5.0 GW for the European Union, 4.0 GW for Canada, and 3.7 GW for Brazil. Almost 43 gigawatts were added to the global PSH fleet from 2016 to 2025 of which 39 GW were in China.

The share of variable renewables (wind and solar) increased from 2016 to 2025 for all the countries/regions in Figure 19 and this increase has implications for hydropower and PSH. First, high shares of variable renewables may increase the flexibility demands on hydropower by requiring more ramping up and down to maintain supply-demand balance in the grid as wind and solar output fluctuate throughout the day. As of 2025, the variable renewable share in the global electricity generation capacity was 35% worldwide. For the six countries/regions in Figure 19, it ranged from 15% in Canada to 47% in China and 49% in the European Union. It was 28% in the United States. Although national aggregates are not ideal because each of these countries or regions contain areas with much higher penetrations than the average, U.S. hydropower owners and operators may gather valuable information from case studies

in countries with higher variable renewable penetration. Second, as the share of variable renewables increases, LDES capacity from PSH is expected to become more valuable. In 2025, China and the European Union had both the highest share of variable renewables and the highest share of PSH (1.7% for China, 1.8% for the European Union). For the United States, PSH capacity in 2025 represented 1.5% of total generation capacity.

The maps in Figure 20 and Figure 21 show the location of hydropower and PSH plants around the world. In both figures, the dots are colored by year of operation, distinguishing plants that began operating in 2015 or later from those that started before 2015. At the beginning of 2026, 82 countries had more than 1 GW of hydropower capacity and 49 countries had at least one PSH plant.

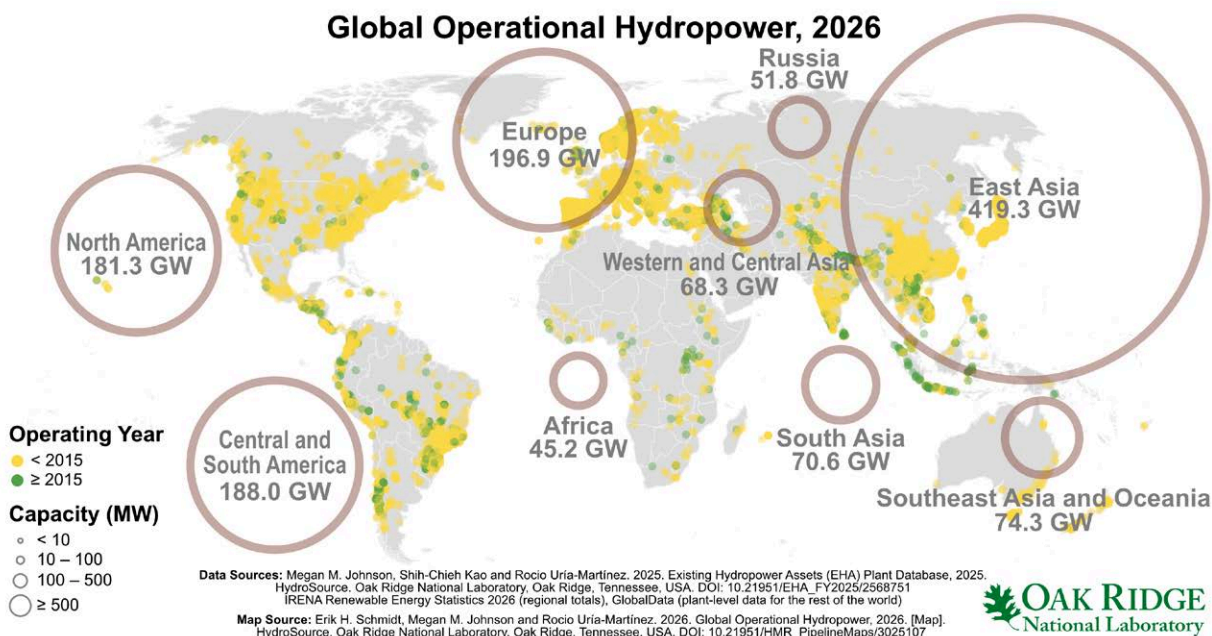


Figure 20. Map of operational hydropower plants by world region

Source: Regional totals (IRENA Renewable Energy Statistics 2026), plant-level data for the United States (ORNL EHA Plant Database 2025), plant-level data for the rest of the world (GlobalData)

The most recent additions to the hydropower global fleet (2023–2025) included 241 hydropower projects in 45 countries with a total capacity of 22.4 GW. The eight hydropower plants with capacities greater than 1 GW placed in service during the past three years are in China (4), Bhutan (1), Canada (1), India (1), and Tanzania (1).²⁹ The Julius Nyerere Hydropower Station (2,115 MW), constructed by China’s Dongfang Electric Corporation, now represents 40% of total electricity generation capacity in Tanzania and strengthens the stability of its power grid.³⁰ In Bhutan, the Punatsangchhu-II Hydropower Project (1,020 MW) increases the country’s hydroelectric capacity by 40%. It was developed under bilateral agreement with India. In Canada, the sixth unit of the Site-C project (1,100 MW) came online in August of 2025 after a decade of construction. It increases BC Hydro’s generation capacity by 8% and will help meet increased electricity demand in British Columbia.³¹

²⁹ In addition, the Grand Renaissance Dam in Ethiopia was completed in 2025 with a total capacity of 5,150 MW. Its 13 units with capacities of approximately 400 MW each have been sequentially commissioned starting in 2022.

³⁰ en.sasac.gov.cn/2025/01/06/c_18630.htm

³¹ sitecproject.com/sitec-comes-into-full-operation

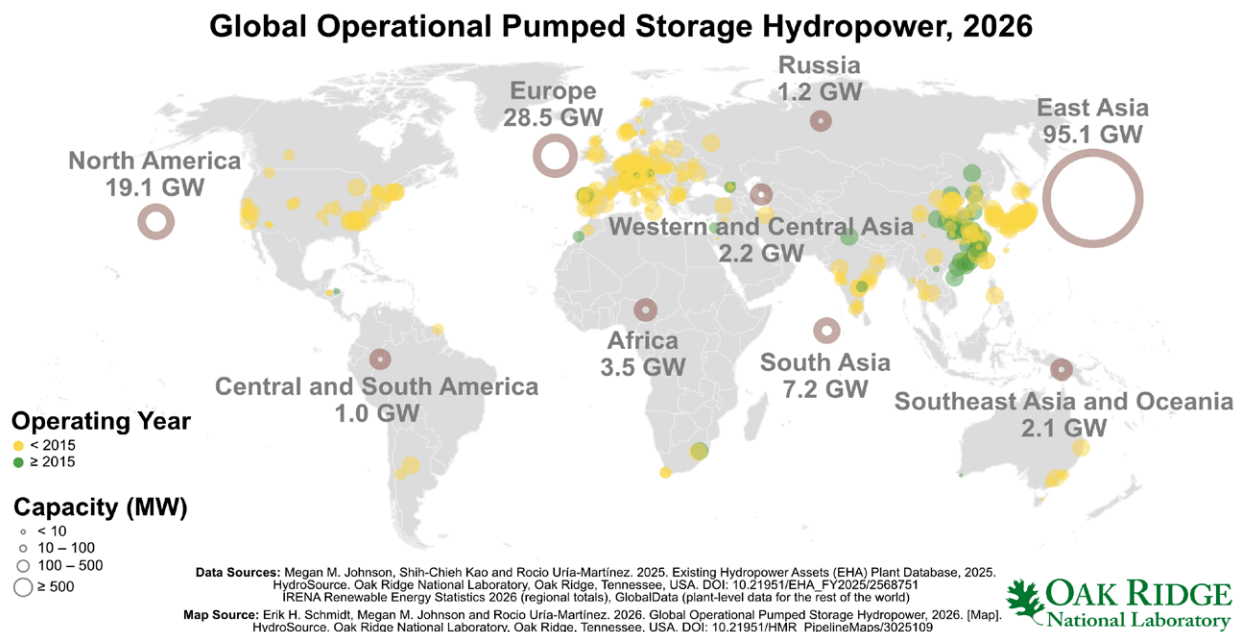


Figure 21. Map of operational PSH plants by world region

Source: Regional totals ([IRENA Renewable Energy Statistics 2026](#)), plant-level data for the United States ([ORNL EHA Plant Database 2025](#)), plant-level data for the rest of the world ([GlobalData](#))

Eighteen PSH plants became operational in six countries in 2023–2025.³² Twelve of them are in China and the rest are in Austria (2), Australia (1), India (1), Israel (1), and Morocco (1).³³ The subset of new PSH plants with capacities greater or equal than 1 GW (12) were all in China (11) or India (1).

Reasons for choosing to construct new hydropower or PSH around the world range from achieving universal electricity access targets in developing countries to improving grid stability or helping integrate variable renewables and serving expected new large loads from data centers. The resilience value of hydropower (its ability to help prevent or reduce disruption times in the electric grid caused by hazards or threats) is hard to estimate and typically not remunerated (Balducci et al., 2021). For an example of hydropower (and PSH) contribution to resilience, see textbox on the role played by hydropower in restoring power in Spain after a blackout incident in April 2025.

³² Additionally, the Hatta PSH plant in the United Arab Emirates (250 MW) started trial operations in October 2025.

³³ The Kidston PSH plant in Australia had grid connection in 2025 but its expected commissioning date is in 2026 (International Hydropower Association, 2026).

ROLE OF HYDROPOWER AND PSH DURING IBERIAN PENINSULA 2025 BLACKOUT

Shortly after 12:30 pm on April 28, 2025, the power grids of Spain and Portugal experienced a total blackout. The factual report published by the European Network of Transmission System Operators for Electricity (ENTSO-E) provides a detailed sequence of events that reveals the important role played by hydropower and PSH in trying to prevent the collapse of the grid and in the power restoration phase (ENTSO-E, 2025). The root cause of the event has been determined as a “rapid rise in system voltage and loss of voltage control on a day with multiple concurrent phenomena, accelerated by rapid generation output reductions and disconnections, leading to voltage instability and cascading disconnections in Spain” (ENTSO-E, 2026). At the time the event started, solar and wind plants were generating 63% of electricity in Spain and the number of conventional units (>30 MW) synchronized to the Spanish network was the lowest for that hour of the day up to that day in 2025. The event began as a net load increase at the distribution level, following voltage oscillations earlier that morning. This increase was likely caused either by the disconnection of small generators and/or by an actual rise in load. As grid frequency started to drop, PSH units—which were operating in pumping mode at that time of day—were disconnected to offset the lost generation. Nonetheless, more generators tripped offline, the interconnections with Morocco and France tripped due to underfrequency, and the Spain and Portugal grids went into total blackout. The restoration process involved using voltage from neighboring healthy parts of the network (Morocco and France) and re-energization of plants with black start capabilities.³⁴ Figure 22 compares the average hourly generation mix in Spain from April 1 to April 27, 2025 with the mix in April 28, before and after the outage. It illustrates that hydropower and PSH, along with combined cycle gas plants, accounted for most of the output during the restoration phase. It provides an example of the combination of hydropower attributes (black start capabilities, rapid start-up times, dispatchability, spinning masses that contribute to stabilizing grid frequency) that makes it especially valuable for grid resilience. In days with normal system conditions, solar, wind, and nuclear all account for sizable portions of total generation in Spain. However, neither nuclear nor variable renewables contributed to grid restoration throughout the afternoon and evening of April 28. The system operator did not allow wind and solar plants to start reconnecting until the grid was sufficiently stabilized (1:00 am on April 29). Similarly, nuclear plants have long and complex start-up processes and could not be brought back in until the system was restored.

³⁴ Power plants with black start capabilities are able to re-energize without relying on external power from the grid.

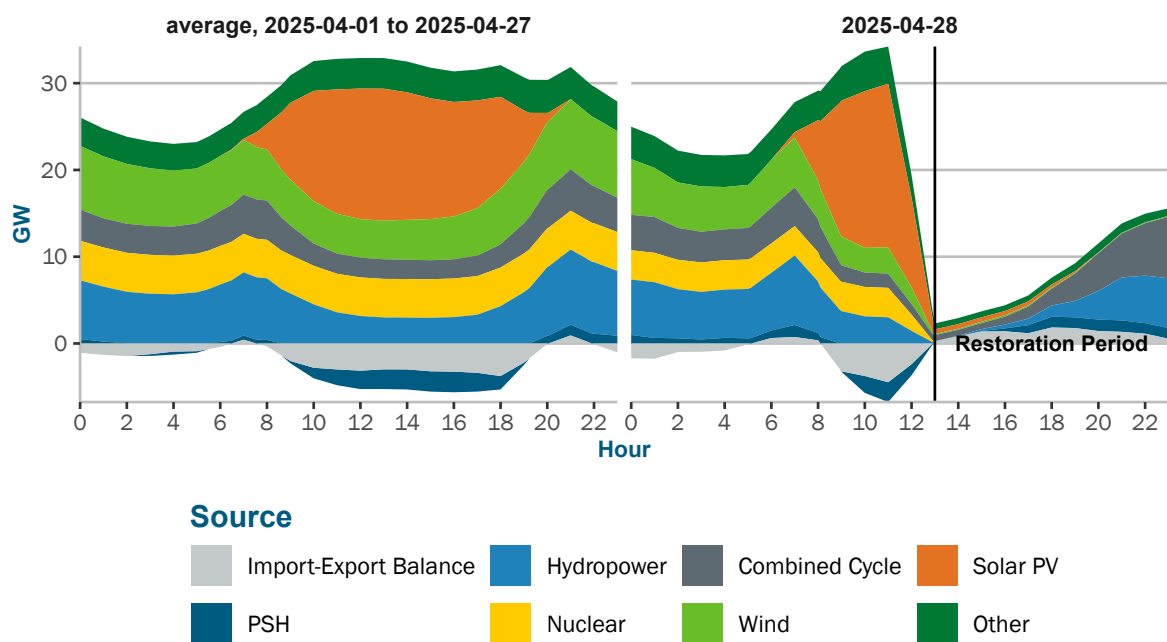


Figure 22. Electricity supply mix in Spain during the April 28, 2025 blackout, subsequent restoration period, and previous days

Source: Red Eléctrica

3.2 GLOBAL HYDROPOWER AND PSH DEVELOPMENT PIPELINES

At the beginning of 2026, 3,230 hydropower projects were in the global development pipeline with a combined capacity of 431 GW. Of those, 732 were under construction with a total capacity of 103 GW.

Figure 23 displays the regional distribution of the global hydropower development pipeline indicating the location of individual projects and the capacity breakdown between the “Permitting and Development” and “Under Construction” stages.

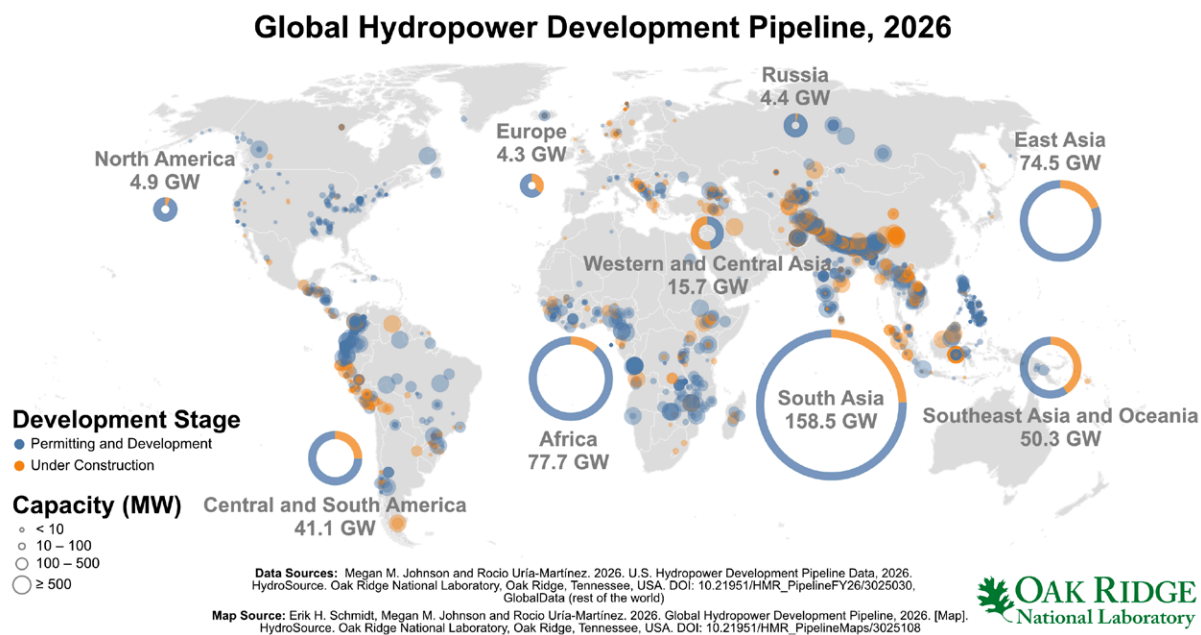


Figure 23. Map of hydropower project development pipeline by region and development stage

Sources: United States (ORNL U.S. Hydropower Development Pipeline 2026); rest of the world (GlobalData)

Notes: GlobalData does not cover projects with less than 1 MW of capacity. GlobalData reports different phases of the same overall project as different projects that may be in different development stages.

More than one third (37%) of the new hydropower capacity being developed globally is in South Asia. India accounts for 44% (70 GW) of proposed capacity in that region followed by Nepal (25%) and Pakistan (22%). Starting with the “50,000 MW Hydroelectric” initiative in 2003, the Indian government has taken multiple steps to promote hydropower development in the country. In 2019, it granted large hydropower plants the status of renewable energy (previously reserved to plants with capacities up to 25 MW) making it easier for those projects to obtain financing. It also introduced Hydro Purchase Obligations by which electric utilities are required to consume a minimum percentage of electricity from hydropower.³⁵ In October 2025, India’s power planning agency announced plans to spend \$77 billion building the transmission capacity needed to move hydropower generated in several large projects in the northeastern region of the country to where it would be consumed.³⁶

³⁵ engmag.in/hydropower-the-backbone-of-indias-renewable-energy-future/

³⁶ industrialinfo.com/iirenergy/industry-news/article/indias-77-billion-hydroelectric-transmission-masterplan--347943

Three other regions (East Asia, Africa, and Southeast Asia and Oceania) have more than 50 GW of hydropower in the pipeline. In East Asia, more than 99% of proposed capacity is in China. The countries with largest shares of proposed capacities in Africa and Southeast Asia and Oceania are Democratic Republic of the Congo (51%) and Indonesia (40%). Central and South America occupies the fifth spot in the regional ranking of proposed new capacity—41 GW of which 32% is in Colombia—and Western and Central Asia is the sixth with 16 GW of which 40% is in Kyrgyzstan. Finally, North America, Europe, and Russia each have less than 5 GW of new hydropower in the development pipeline.³⁷ For North America, 65% of proposed capacity is in Canada.

The share of capacity in each regional pipeline that has reached construction stage ranges from 3% in Russia to 54% in Western and Central Asia. South Asia also leads the ranking of hydropower construction activity both in number of plants (361) and capacity (39 GW). Other three regions (Southeast Asia and Oceania, East Asia, Central and South America) are constructing more than 10 GW of new hydropower. North America and Russia are the only two regions with less than 1 GW under construction.

Relative to three years ago, total hydropower capacity being considered for development has decreased by approximately 55 GW. More than 1,000 projects that have entered the pipeline in the past 3 years, ten have proposed capacities of more than 1 GW and they are in China, India, Indonesia, Laos, and Russia.

Figure 24 provides details about project sizes for each combination of region and development stage. Five percent of projects accounting for 68% of proposed capacity are in the Very Large category (> 500 MW). Among them, the Medog project in China is by far the largest (60,000 MW) and it was approved to proceed to construction in December 2024.³⁸ At the other end of the size distribution, 48% of projects are in the Small category (<= 10 MW) and their aggregated proposed capacity is 7.1 GW (1.6% of total proposed capacity).

³⁷ Russia is the only region for which hydropower capacity in the development pipeline has increased relative to that reported in the [2023 edition of this report](#). The increase may be related to the 17% increase target for Russia's hydropower generation in 2050 (relative to 2023) announced by the Russian Ministry of Energy in 2024 (International Hydropower Association, 2025)

³⁸ economist.com/china/2025/01/02/china-approves-the-worlds-most-expensive-infrastructure-project

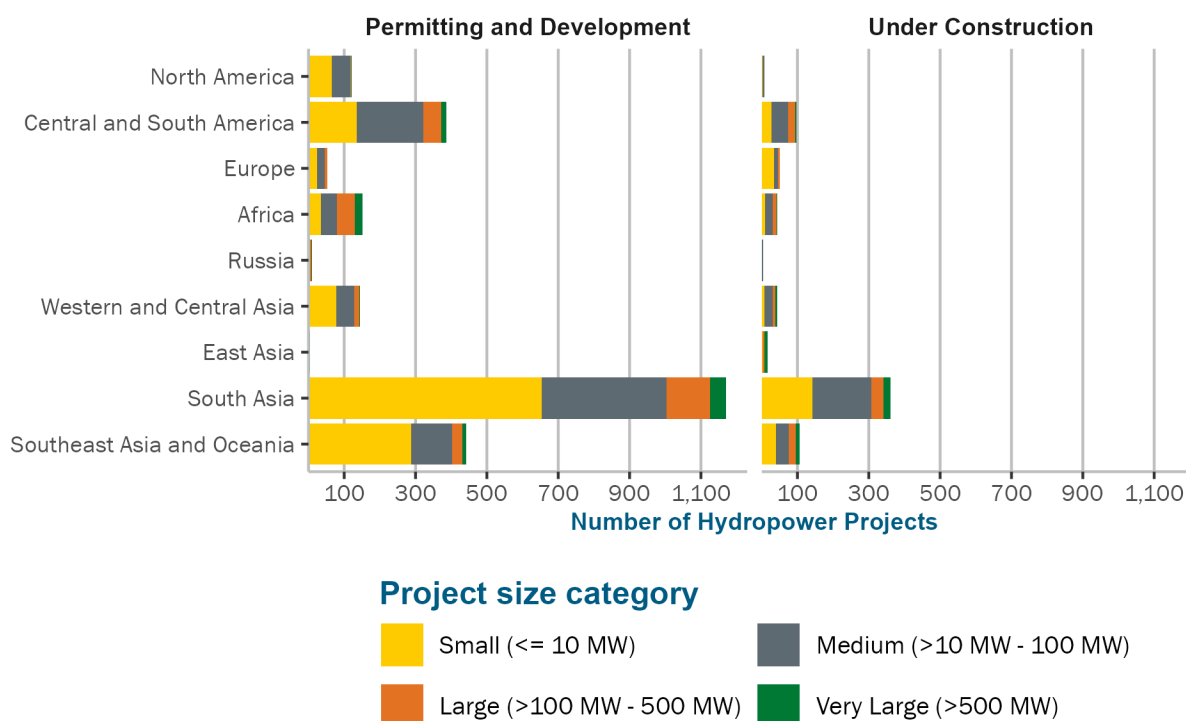


Figure 24. Global hydropower development pipeline by size category, region, and development stage

Sources: United States (ORNL U.S. Hydropower Development Pipeline 2026); rest of the world (GlobalData)

Note: GlobalData reports different phases of the same overall project as different projects that may be in different development stages.

More than 50% of proposed projects are Small (≤ 10 MW) in four of the regions: South Asia, Europe, North America, and Southeast Asia and Oceania. The share of Very Large projects is greater than 10% for three of the regional development pipelines: Africa (12%), Russia (21%), and East Asia (45%). The high percentage of projects in the Very Large category in East Asia explains why that region ranks second to last, after Russia, by number of projects in the pipeline (20) but third highest, after South Asia and Africa, by proposed capacity (74 GW).

Six hundred and twenty-three PSH projects were in the global development pipeline at the start of 2026—a 72% increase compared to three years ago. Their combined capacity was 628 GW. Almost one fourth of those projects (151) are in the construction stage—111 of them in China—and their combined capacity (172 GW) will more than double the size of the global fleet.

Previous editions of this report analyzed global development pipeline snapshots at the end of 2017, 2019, and 2022. At each of those points, proposed hydropower capacity around the world was larger than proposed PSH capacity. However, the number of PSH projects has been steadily increasing (218 at the end of 2017, 284 at the end of 2019, 363 at the end of 2022 and 623 in 2026) and the number of hydropower projects has progressively decreased (5,083 at the end of 2017, 4,545 at the end of 2019, 3,909 at the end of 2022 and 3,230 in 2026). As of 2026, proposed PSH capacity (628 GW) is now substantially larger than proposed hydropower capacity (431 GW). The same finding of larger proposed PSH capacity than hydropower capacity holds for four world regions: East Asia, Europe, North America, and South Asia.

Figure 25 illustrates the regional distribution of the global PSH development pipeline indicating both the location of individual projects and the capacity breakdown between the “Permitting and Development” and “Under Construction” stages.

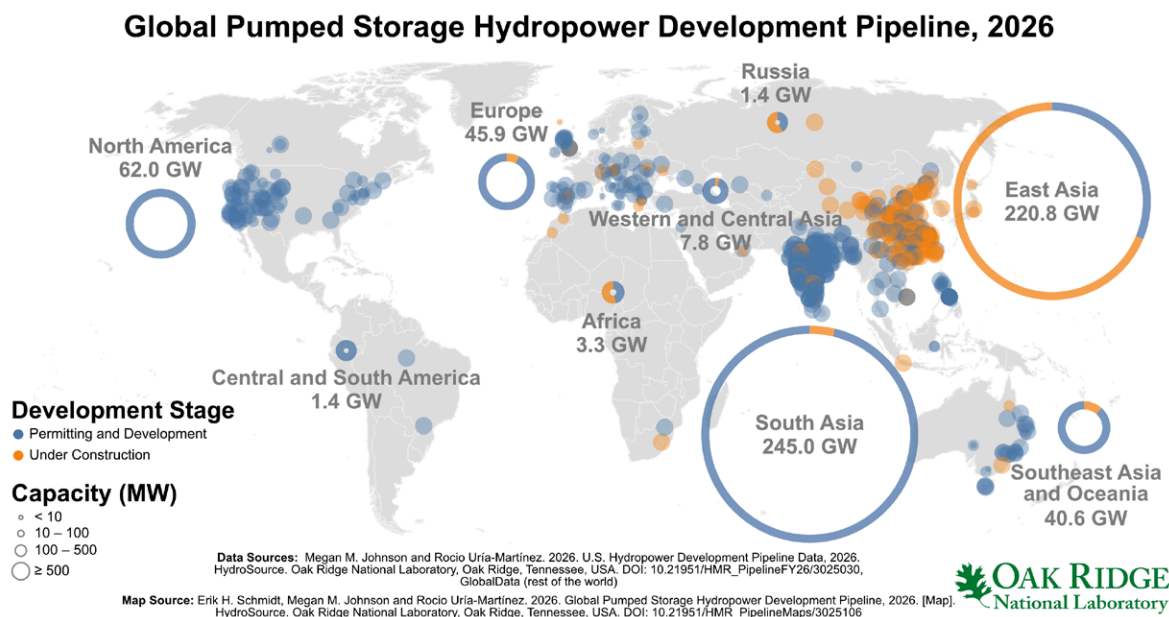


Figure 25. Map of PSH project development pipeline by region and development stage

Sources: United States (ORNL U.S. Hydropower Development Pipeline 2026); rest of the world (GlobalData)

Two regions (East Asia and South Asia) account for nearly 75% of global proposed PSH capacity. Almost all the proposed capacity in those two regions is in two countries: China (218 GW of the 221 GW in East Asia) and India (238 GW of the 245 GW in South Asia). The governments of these two countries have set ambitious goals for PSH capacity by 2035. China already has 70 GW of PSH in operation and the additional 218 GW proposed, if constructed, would bring the country close to its long-term target of 305 GW by 2035.³⁹ For India, installed PSH capacity was 7.2 GW at the end of 2025. The Indian Ministry of Power released a roadmap in January 2026 to reach 100 GW of PSH capacity by 2035–2036.⁴⁰

Three other regions (North America, Europe, and Southeast Asia and Oceania) have several dozens of PSH projects in their pipelines with total capacities ranging from 41 GW (Southeast Asia and Oceania) to 62 GW (North America). The remaining four regions have less than 10 GW of PSH considered for development. For North America, 96% of proposed PSH capacity is in the United States.

PSH construction activity is highly concentrated in East Asia with 115 projects in the Under Construction category. Of those 111 are in China, three are in Japan, and one is in South Korea. Another four regions (Africa, Europe, Southeast Asia, South Asia) have at least 1 GW of PSH that have reached construction stage. The two regions in the Americas are the only two world regions with no new PSH facilities under construction.

More than 400 PSH projects have entered the pipeline over the past 3 years. The largest among them is the Ras Al Khaimah project in the United Arab Emirates (5 GW). If built, it would become the largest PSH plant in the world and help integrate output from large solar projects in the region. Five more new projects in the United States and India have proposed capacities of 3 GW or more.

³⁹ hydropower.org/blog/pumped-storage-hydropower-series-chinas-psh-plus-model

⁴⁰ cea.nic.in/wp-content/uploads/news_live/2026/08/Roadmap_to_100_GW_of_Hydro_Pumped_Storage_Projects_3.pdf

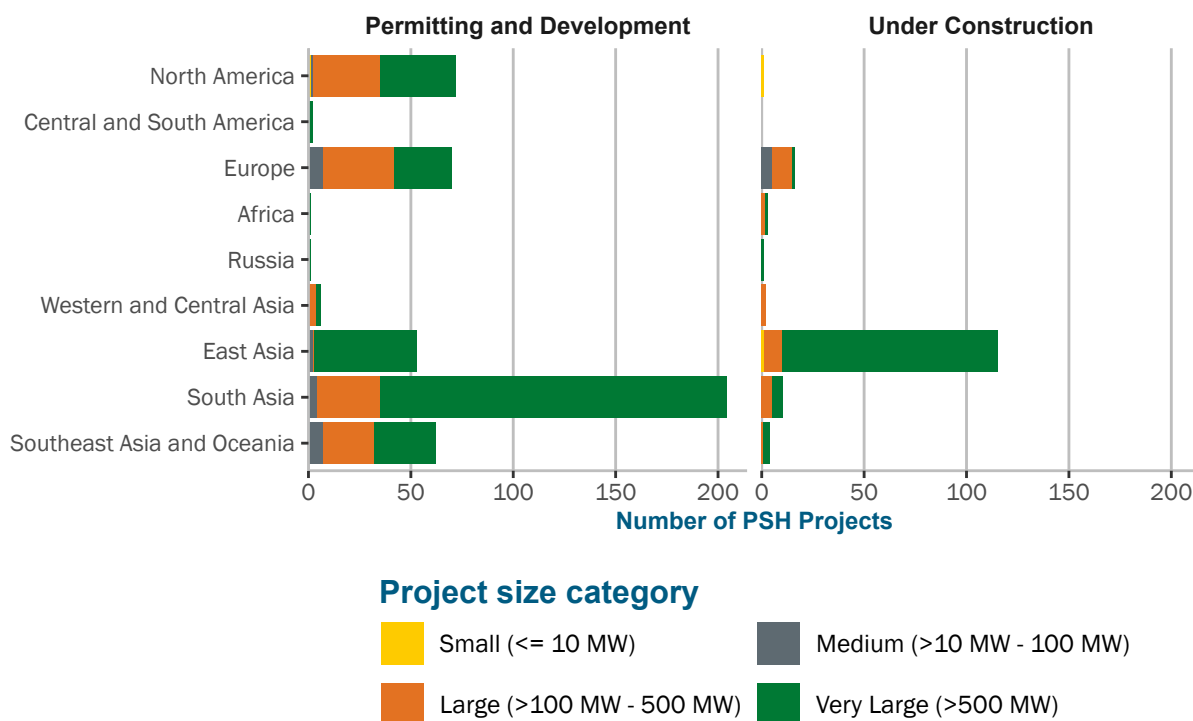


Figure 26. Global PSH development pipeline by size category, region, and development stage

Sources: United States (ORNL U.S. Hydropower Development Pipeline 2026); rest of the world (GlobalData)

Note: GlobalData reports different phases of the same overall project as different projects that may be in different development stages.

Figure 26 provides details about PSH project sizes for each combination of region and development stage. Except for two PSH projects in the United States, all other PSH projects have proposed capacities greater than 10 MW. Seventy percent of all proposed PSH projects are in the Very Large category (>500 MW). East Asia and South Asia account for 75% of them. An additional 25% of PSH projects are in the Large (>100 MW – 500 MW) category. Europe has the greatest number of projects (45) in the Large (>100 MW – 500 MW) category. Twenty-six PSH projects are in the Medium category of which Europe (12) and Southeast and Oceania (7) account for 73%.

3.3 INTERNATIONAL TRENDS IN HYDRAULIC TURBINE TRADE (2010–2024)

The annual value of global exports of hydraulic turbines and turbine parts in 2022–2024 averaged \$919 million. In 2024 dollars, this value was 50% lower than the 2010–2021 average.⁴¹ The United States was among the top ten exporters and top ten importers of hydraulic turbines and parts during the 2010–2024 period.

The global traded value of hydraulic turbines declined substantially in 2022–2024 relative to 2010–2021.⁴² The decreasing traded value is consistent with the global trend for new installed capacity. The average annual global capacity installed, including hydropower and PSH, decreased from 25 GW in 2010–2021 to 17 GW in 2022–2024. However, traded turbines do not only serve new plants but

⁴¹ In nominal dollars, the 2022–2024 average was 35.5% lower than the 2010–2021 average.

⁴² The United Nations Comtrade Database reports trade of hydraulic turbines in four accounts: 841011 (hydraulic turbines and water wheels of a power not exceeding 1,000 kW), 841012 (hydraulic turbines and water wheels of a power exceeding 1,000 kW but not exceeding 10,000 kW), 841013 (hydraulic turbines and water wheels of a power exceeding 10,000kW), and 841090 (parts of hydraulic turbines and water wheels, including regulators). Some of the hydraulic turbines and parts included in these accounts may be used in applications other than hydropower.

also refurbishments and upgrades of the existing fleet. A decline in trade value may also indicate that increasingly higher shares of hydraulic turbines are being manufactured in the same country where they are installed.

Figure 27 disaggregates global hydraulic turbine export value into the top ten countries/regions and the rest of the world. The EU27 region and China lead in hydraulic turbine exports, with annual averages of \$540 million and \$392 million, respectively.⁴³ Together they accounted for 67% of average annual export value during 2010–2024. The rest of countries in the top ten all export less than \$100 million per year. The rest of the world accounts for 8% of average annual export value. Details about the destinations of U.S. exports are presented in Chapter 6.

Turbine parts are the largest category of exports for all the countries/regions. Among exports of complete turbine units, Brazil, Japan, and the Russian Federation almost exclusively export turbines with capacities greater than 10 MW. For the U.S., more than half the annual average value from exports of complete turbine units is for the smaller category (≤ 1 MW).

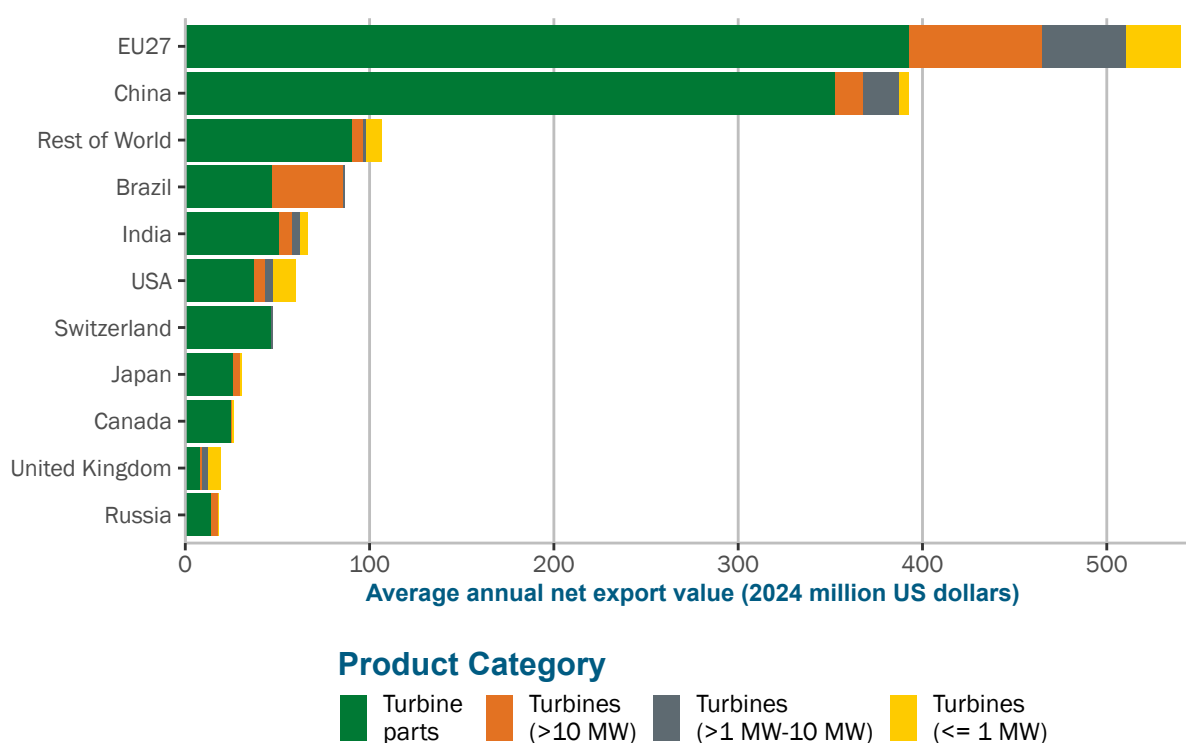


Figure 27. Average (2010–2024) annual export value of hydraulic turbines for top ten countries/regions and rest of the world

Source: United Nations COMTRADE database

Notes: The composition of EU27 has changed from 2010 to 2024. The EU27 grouping shown corresponds to membership as of 2024.

⁴³ The EU27 grouping keeps the same set of countries every year and is based on membership as of 2024. The EU27 is a large trading bloc that is more comparable to the United States than individual European countries for the purpose of the trade rankings presented in this section.

Figure 28 compares the top ten countries/regions by annual average exports of hydraulic turbines and parts to the top ten countries by installed hydropower and PSH capacity. Eight of the top ten countries/regions (EU27, China, Brazil, India, United States, Japan, Canada, and Russia) are part of both rankings. This overlap suggests that the hydraulic turbine manufacturing industry is largely located in countries with large hydropower fleets. The United States was the fifth largest exporter of hydraulic turbines and parts in 2010–2024 and has the fourth largest fleet. The European Union (EU27) and China top both rankings. Two other European countries that are not part of the European Union (Switzerland and the United Kingdom) are also among the top ten exporters despite their fleets being relatively smaller. On the other hand, some of the largest fleets (Norway, Turkey) are in countries that are not major exporters of hydraulic turbines.

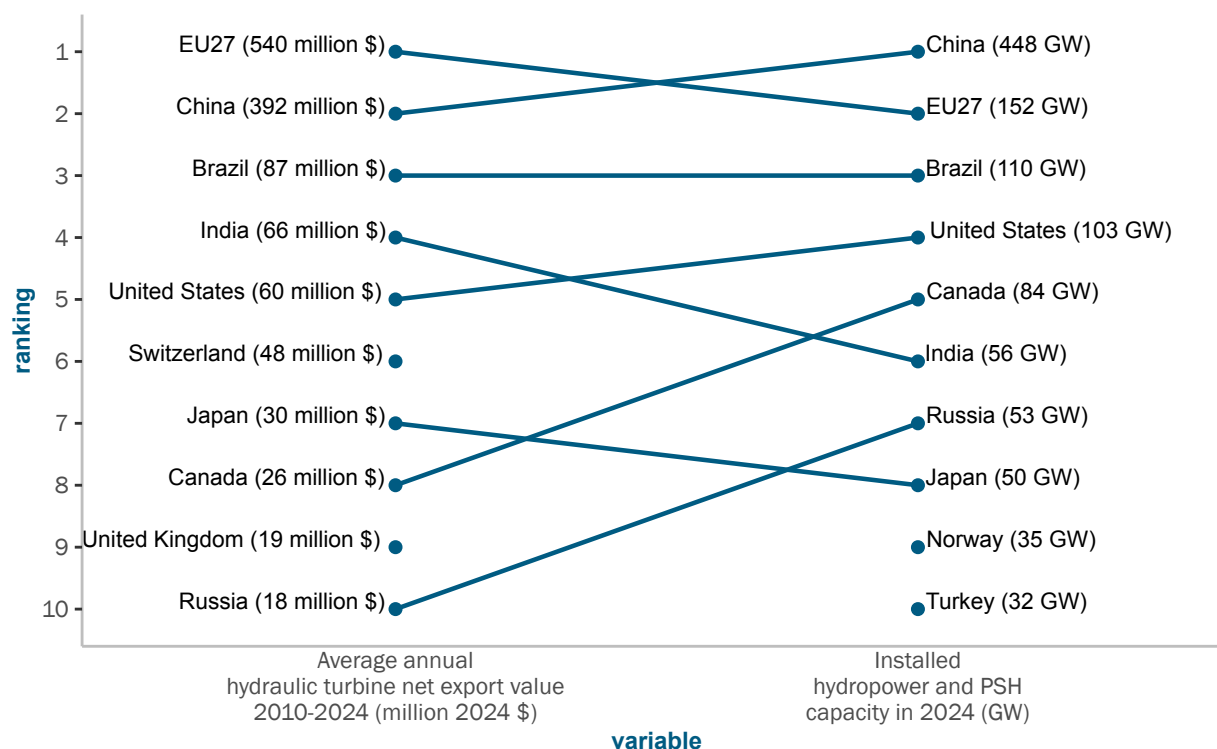


Figure 28. Top ten countries/regions by 2010–2024 hydraulic turbine exports versus top ten countries/regions by installed hydropower and PSH capacity in 2024

Sources: United Nations COMTRADE database (exports), IRENA Renewable Capacity Statistics 2025 (capacity)

Figure 27 and Figure 28 show that the top ten countries/regions, most of which have very large hydropower fleets, accounted for more than 90% of hydraulic turbine export value in 2010–2024. Import value is much less concentrated (see Figure 29). The value of hydraulic turbines imported by the top ten countries/regions represents 54% of the total. Turkey and Vietnam lead in hydraulic turbine import value in 2010–2024, with annual averages of \$102 million and \$88 million, respectively. Turkey and Vietnam, along with Pakistan, have the largest import expenditures in turbine units with capacities greater than 10 MW. Those three countries have added large amounts of hydropower capacity during this period.⁴⁴ Most other countries/regions with large hydraulic turbine import values have large and mature hydropower fleets (e.g., Russia, Canada, EU27, USA, Switzerland) and most of their import expenditures are turbine parts largely directed to refurbishing and upgrading existing hydropower plants. The United States ranked sixth (excluding Rest of World) with average annual import values of \$70 million. Details about the origin of U.S. hydraulic turbine imports are presented in Chapter 6. Saudi Arabia is part of the top

⁴⁴ From 2015 to 2024, hydropower (including PSH) capacity increased by 6.5 GW in Turkey, 7 GW in Vietnam, and 4 GW in Pakistan.

ten importers of hydraulic turbines despite having no hydropower capacity. In that case, the hydraulic turbines have different applications such as oil and gas operations.⁴⁵

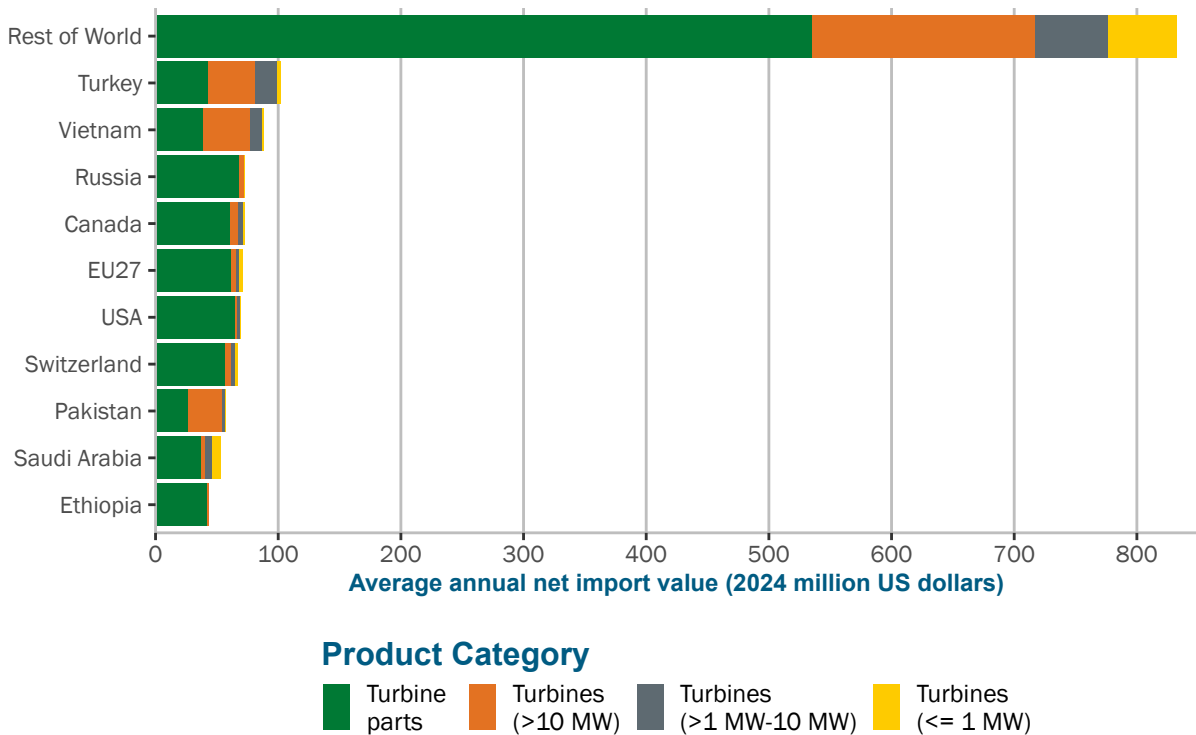


Figure 29. Average (2010–2024) annual import value of hydraulic turbines for top ten countries/regions and rest of the world

Source: United National COMTRADE database

Notes: The composition of EU27 has changed from 2010 to 2024. The EU27 grouping shown corresponds to membership as of 2024.

⁴⁵ energyrecovery.com/resources/energy-recovery-systems-in-acid-gas-recovery-plants/

CHAPTER 4. U.S. HYDROPOWER PRICES AND REVENUES

Multiple approaches are used to market the energy, capacity, and ancillary services provided by U.S. hydropower and PSH plants.⁴⁶ This chapter summarizes trends in energy and capacity revenues, which are typically the two largest revenue streams for hydropower and PSH plants. Power marketing administrations (PMAs) sell capacity and/or energy from the federal fleet, which accounts for almost 50% of installed U.S. hydropower capacity, via long-term contracts signed largely with publicly owned utilities (Section 4.1). Nonfederal fleet owners sell the energy output and other services from their plants through a mixture of bilateral transactions (among plants owned by utilities), PPAs (Section 4.2), and participation in wholesale markets managed by ISOs/RTOs (Section 4.3).

4.1 FEDERAL HYDROPOWER REVENUE

Amidst large price fluctuations in wholesale electricity markets in 2020–2024, federal hydropower remained an affordable source of energy for the utilities that have access to it. The price advantage (lower and more stable price levels) of federal hydropower versus wholesale electricity markets was salient in recent years. Due to drought conditions, average annual energy sold from the Western portion of the federal hydropower fleet in 2020–2024 was significantly lower than in the 2010s. For the rest of the federal fleet, annual energy sales in 2020–2024 were higher on average than in the 2010s.

The PMAs are the federal agencies, within the U.S. DOE, in charge of marketing the electrical output from the 132 federal hydropower plants owned and operated by the USACE, the U.S. BOR, or the International Boundary and Water Commission (IBWC). Figure 30 shows the location of federal hydropower facilities marketed by PMAs and the regions served by each of the four PMAs: Bonneville Power Administration (BPA), Western Area Power Administration (WAPA), Southwestern Power Administration (SWPA), and Southeastern Power Administration (SEPA).

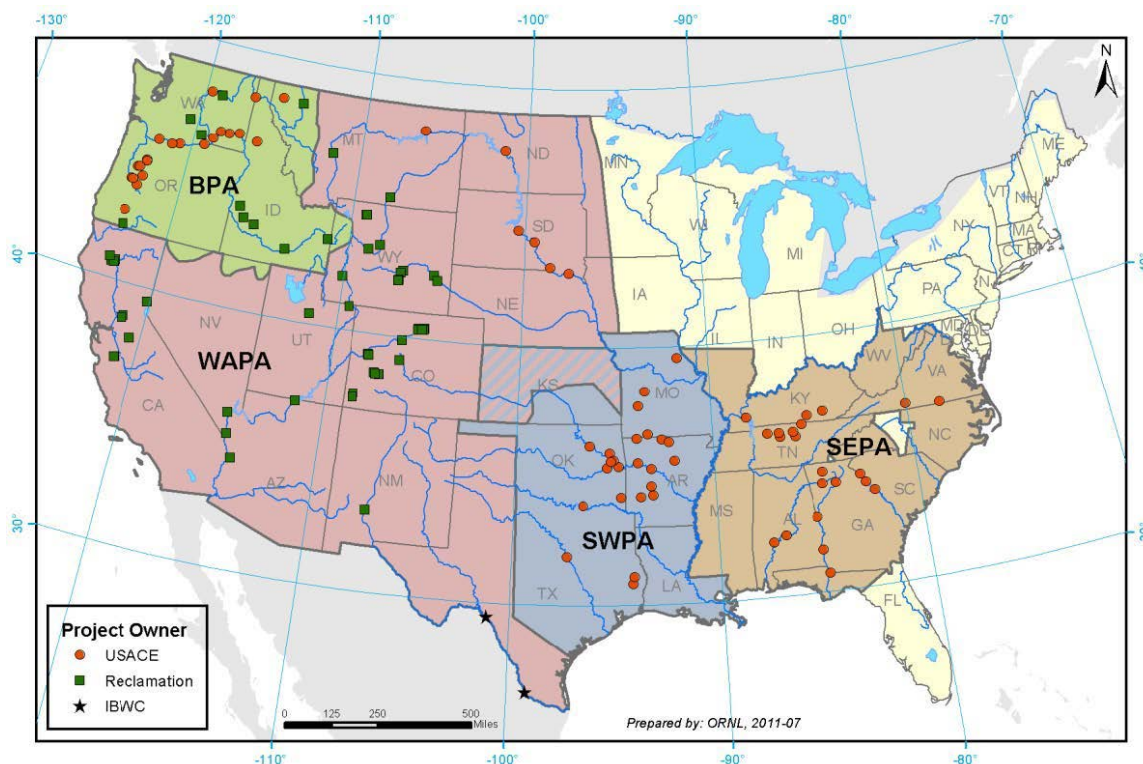


Figure 30. Federal hydropower facilities and federal power marketing regions in the United States

Source: Reprinted from Sale et al. (2012)

⁴⁶ Some hydropower plant owners can separately monetize the environmental attributes of the energy they produce.

By statute, PMAs market capacity and energy from the federal fleet at cost-based rates giving priority of access to preference customers (public utilities such as municipalities and cooperatives) over for-profit entities. Energy and/or capacity allocations to preference customers are set in long-term contracts. The rates at which energy and capacity are sold are updated more often than the energy and capacity allocations, to ensure that enough revenue will be collected each year to pay back the annual revenue requirement to the U.S. Treasury.⁴⁷ The PMAs also conduct transactions, bilaterally with utilities or in wholesale electricity markets, to balance differences between the energy produced by the federal hydropower fleet and the energy required to fulfill the allocations contracted with their customers.⁴⁸

Depending on the hydrologic conditions and operational constraints of federal hydropower plants in each region, the attributes of the allocations contracted by PMAs to preference customers vary from firm capacity and energy to as-available energy.⁴⁹ BPA differs from the rest of PMAs in that many of its preference customers purchase firm power for all their net load (i.e., total retail load minus nonfederal firm resources owned by the customer) from the PMA. SWPA markets its power as peaking power guaranteeing 1,200 hours of energy per kilowatt of capacity contracted per year—the number of hours that SWPA projects operate per year based on typical water availability.⁵⁰ Several of the smaller projects marketed by WAPA are examples of projects where the PMA does not sell firm capacity or energy but instead markets as-available energy—a percentage of available output to each customer.

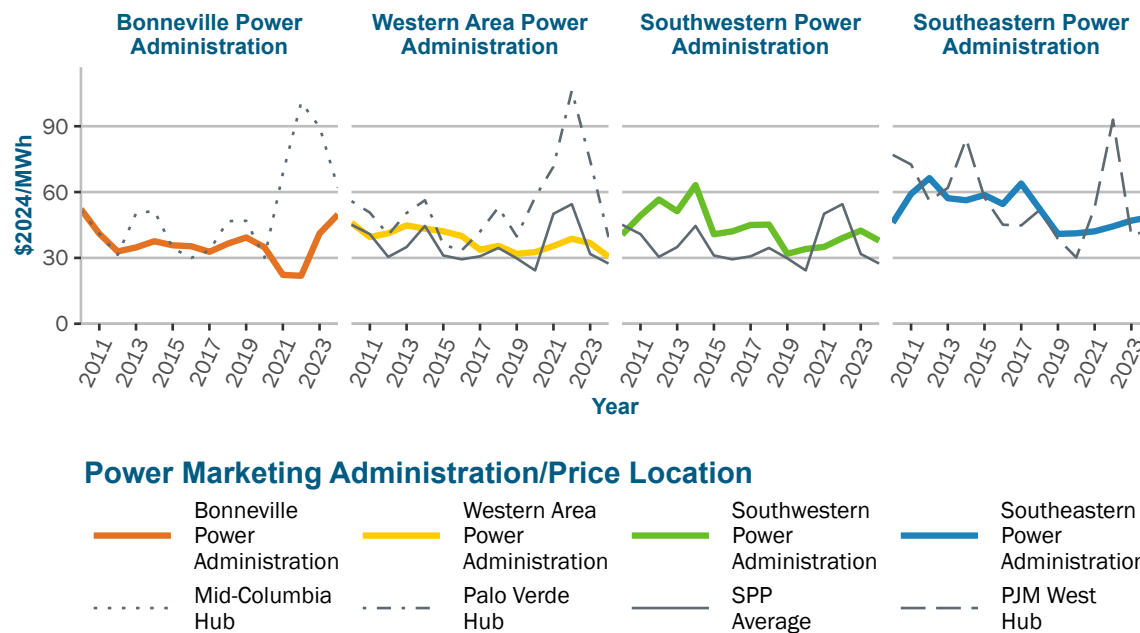


Figure 31. Average power marketing administration energy revenue per megawatt-hour versus average wholesale electricity prices

Sources: EIA Form 861 (for federal hydropower revenue and sales), EIA Wholesale Electricity and Natural Gas Market Data (Mid-Columbia Hub, Palo Verde Hub, PJM West Hub), Southwestern Power Pool (SPP) State of the Market Reports (SPP Average)

Notes: The average revenue per megawatt-hour for each PMA is calculated as the ratio of EIA 861 total revenues (resale revenues plus retail revenues) over EIA 861 total sales volume (sales for resale plus retail sales). For SWPA and SEPA, 100% of sales were for resale. For BPA, 91% or more of the total sales each year were sales for resale. For WAPA, sales for resale accounted for 82%–89% of the total. For BPA, sales and revenue exclude the portion corresponding to Columbia Generating Station, a nuclear generation plant owned and operated by Energy Northwest, whose output is marketed by BPA.

⁴⁷ The annual revenue requirement includes repayment for the initial investment in the power system, the expensed interest on the unamortized debt, the O&M costs for the hydropower function of the power system, a portion of O&M costs for other system purposes (e.g., irrigation), the cost of purchased power, and environmental project costs.

⁴⁸ Kao et al. (2022) contains more details about PMA power marketing practices.

⁴⁹ Firm capacity and energy have guaranteed availability for the customer, except for emergency conditions.

⁵⁰ The projects that SWPA markets are almost entirely dependent on rainfall and have limited reservoir storage.

Figure 31 shows the average revenue per megawatt-hour sold by the PMAs—mostly through bilateral contracts with their preference customers—each year from 2010 to 2024, compared to a representative wholesale price from the same region.^{51,52} Energy produced by the federal hydropower fleet makes up most of the PMA sales, but they may also include some energy purchased in the wholesale market. The average PMA revenue in 2020–2024 was \$33.97/MWh for BPA, \$34.83/MWh for WAPA, \$37.68/MWh for SWPA, and \$44.64/MWh for SEPA. For all PMAs, those averages were lower than the 2010–2019 average in 2024 dollars.⁵³

Higher average revenue for SWPA and SEPA results from these two PMAs marketing federal hydropower from fleets with a higher share of peaking plants that generate just a few hours each day. The power and energy allocations that SWPA and SEPA offer to their customers accordingly guarantee a maximum number of hours of energy per kilowatt of capacity contracted per year (e.g., 1,200 hours for SWPA customers). SWPA and SEPA need to make up their annual revenue requirement with lower average capacity factors than BPA or WAPA which contributes to the higher rates per MWh shown in Figure 31.⁵⁴ PMA's average revenue per megawatt-hour was typically lower—and much less variable—than wholesale price in the same regions. The average 2020–2024 wholesale price was \$70.21/MWh for the mid-Columbia Hub, \$69.84/MWh for the Palo Verde Hub, \$37.62/MWh for SPP, and \$51.83/MWh for the PJM West Hub. Wholesale electricity prices displayed very large fluctuations during those years. From an initial drop in 2020 caused by weak demand due to the COVID-19 pandemic, wholesale prices moved to a sharp peak in 2022 related to large increases in natural gas prices at the start of Russia's invasion of Ukraine. Then, they went back down to levels ranging from \$27.43/MWh for the SPP average to \$62.02/MWh for the Mid-Columbia Hub in 2024. The lower variability of federal hydropower prices is a consequence of the cost-based rates used by PMAs.

Annual variability in average revenue per megawatt-hour sold by PMAs is influenced by hydrology. Due to drought conditions, average net generation from the federal fleet in 2020–2024 was 13.7% lower for BPA than in the 2010s and 23.9% lower for WAPA. In contrast, average 2020–2024 net generation for SWPA and SEPA was 9.4% and 5.3% higher than in the 2010s, respectively. In some PMA marketing regions, rates charged to customers include adders that are applied in dry years when PMA must complement federal hydropower generation with (typically more expensive) purchased power. In contrast, in years when the federal hydropower fleet generates more than is needed to meet preference customer contract requirements, PMAs sell the surplus power to their preference customers or in the wholesale market.

To optimize surplus power revenue and minimize purchased power expenditures, BPA and WAPA have increased their participation in organized wholesale markets. WAPA's Upper Great Plains joined the SPP RTO Integrated Market with its facilities in the Eastern Interconnection in 2015. WAPA Sierra Nevada joined CAISO's Western Energy Imbalance Market in 2021 followed by BPA in 2022 and WAPA Desert Southwest in 2023. WAPA's Colorado River Storage Project, Rocky Mountain, and Upper Great Plains Western Division joined SPP's Western Energy Imbalance Service market in the Western Interconnection in 2021 and subsequently transitioned to the SPP RTO Integrated Market Expansion in the Western Interconnection in April 2026. Additionally, WAPA Sierra Nevada intends to join the CAISO Extended Day Ahead Market in 2027 and BPA announced in March 2025 that it plans to join SPP's Markets+ day-ahead market in 2028.

⁵¹ The SPP average is the average all-in price from the annual Southwest Power Pool State of the Market reports. The rest of annual wholesale prices are calculated as averages of the daily weighted (by transaction volume) average prices.

⁵² The hydropower fleet marketed by WAPA covers a very large area that extends from the Upper Great Plains to California. For that reason, two wholesale prices (SPP Average and Palo Verde Hub) are included for comparison to the average energy revenue of that PMA. The Upper Great Plains marketing region of WAPA is a market participant in SPP. The Palo Verde Hub is not far from the largest WAPA projects along the Colorado River.

⁵³ In nominal dollars, the average 2020–2024 revenue per MWh was higher than the 2010–2019 average for BPA (\$31.62 versus \$28.49) and WAPA (\$29.95 versus \$31.99) and slightly lower for SWPA (\$35.11 versus \$34.77) and SEPA (\$41.92 versus \$41.19).

⁵⁴ The average 2010–2025 capacity factors for hydropower plants whose output is marketed by the PMAs were 41% for BPA, 36% for WAPA, 31% for SWPA, and 26% for SEPA.

4.2 HYDROPOWER POWER PURCHASE AGREEMENTS

On average, the median energy price for hydropower PPAs in 2021–2024 ranged from \$53/MWh in the Southeast to \$63/MWh in the Northwest. Selling energy through PPAs has typically provided hydropower owners a more stable energy revenue in 2010–2024 than selling into the wholesale market in the Northwest and Southeast. For hydropower PPAs in the Southwest, Midwest, and Northeast, the median PPA price followed the wholesale price more closely. The number of PPAs between hydropower owners and utilities that can be identified from mandatory reporting by utilities to FERC has decreased by ~30% from 2010 to 2024.

Large utilities must report their purchased power volumes and expenditures (energy and capacity components) as part of FERC Form 1. From that information, it is possible to compute the average prices of purchased power. The capacity component of the price in a PPA is a fixed charge (\$/kilowatt) for making capacity available for generation over a certain period. The energy component is a variable charge per kilowatt-hour generated.

For each transaction, FERC Form 1 contains information about the identity of the purchasing utility and the entity that is selling the power. Only in cases where the name of the seller corresponds to a specific hydropower plant or the seller only owns hydropower plants is it possible to classify a PPA as a hydropower PPA. Based on those criteria, for purchased power transactions in 2010–2024, 617 unique buyer-seller pairs were identified. Twenty-one percent of them reported transactions every year during that period. The rest of PPAs either started or ended within that period. On average, the energy purchased through transactions in the hydropower PPAs in this dataset accounted for 6% of U.S. hydropower generation. Figure 32 compares the annual median price of hydropower PPAs to the median price across all FERC Form 1 purchased power transactions.⁵⁵ The left panel includes only the energy component of the purchased power price and the right panel includes both the energy and capacity components.

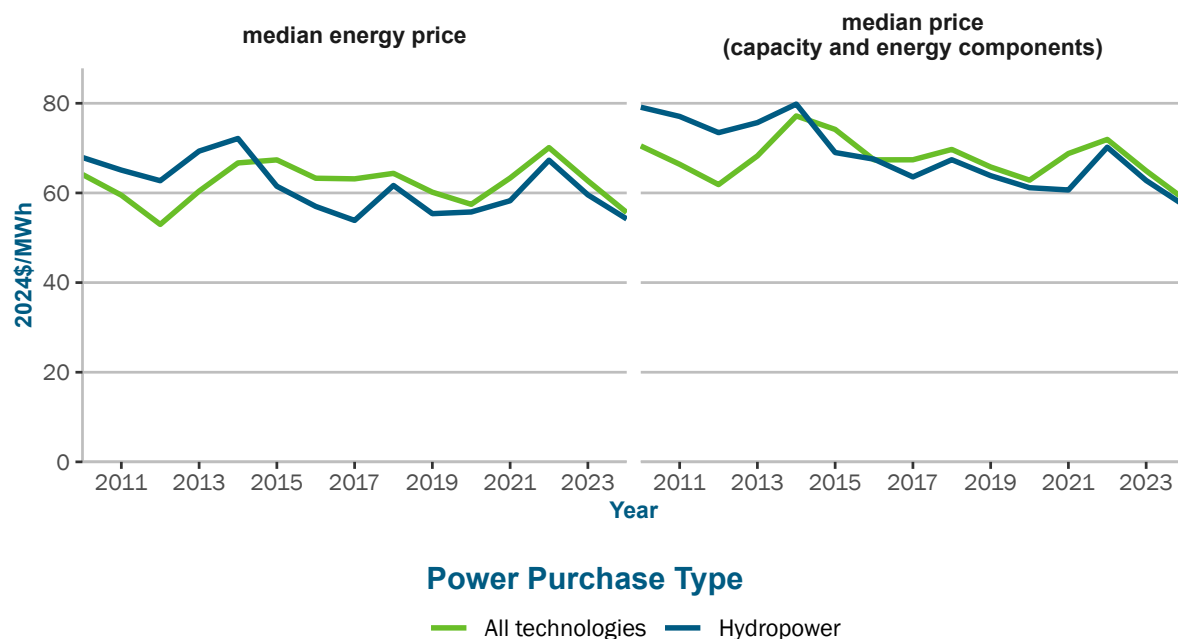


Figure 32. Median FERC Form 1 purchase power price for hydropower versus all technologies

Source: FERC Form 1

⁵⁵ Additional hydropower is likely sold in transactions where the seller owns a portfolio of generation assets some of which are hydropower. However, it is not possible to identify the hydropower share of those transactions so they are excluded from the hydropower PPA category.

At the beginning of the 2010s, the median hydropower PPA price displayed a premium over the median price across all technologies, but the sign of that differential reversed from 2015 on. From 2021 to 2024—the new years added to the FERC Form 1 dataset since the previous edition of this report—the median price paid for hydropower has been slightly below the median across all technologies. For energy price only, the average median price for hydropower in 2021–2024 was \$59.83/MWh (down from \$62.03/MWh in 2010–2020) and the average for all technologies was \$62.94/MWh (up from \$61.77/MWh in 2010–2020). With the capacity component included, the 2021–2024 average was \$62.69/MWh for hydropower and \$66.04/MWh in the full FERC Form 1 dataset.

The fraction of PPAs including a capacity component in the price is greater for hydropower (22% on average from 2010 to 2024) than across all technologies (15%). For all PPAs as well as for hydropower PPAs, the fraction of purchase power transactions including capacity prices has decreased over time. For the hydropower PPAs including a capacity component, it represented an average of 24% of total revenue per kilowatt-hour. When considering all technologies, the capacity fraction accounted for an average of 37% of total revenue for those PPAs that included it.

Figure 33 provides more details for hydropower PPAs. It shows the median energy price as well as the range between the 10th and 90th percentiles by region. It also includes average annual prices at a wholesale trading hub for each of the regions. The regional wholesale price is representative of the energy revenue the hydropower owner would have received by selling energy directly into the spot market instead of having contracted it through a PPA.

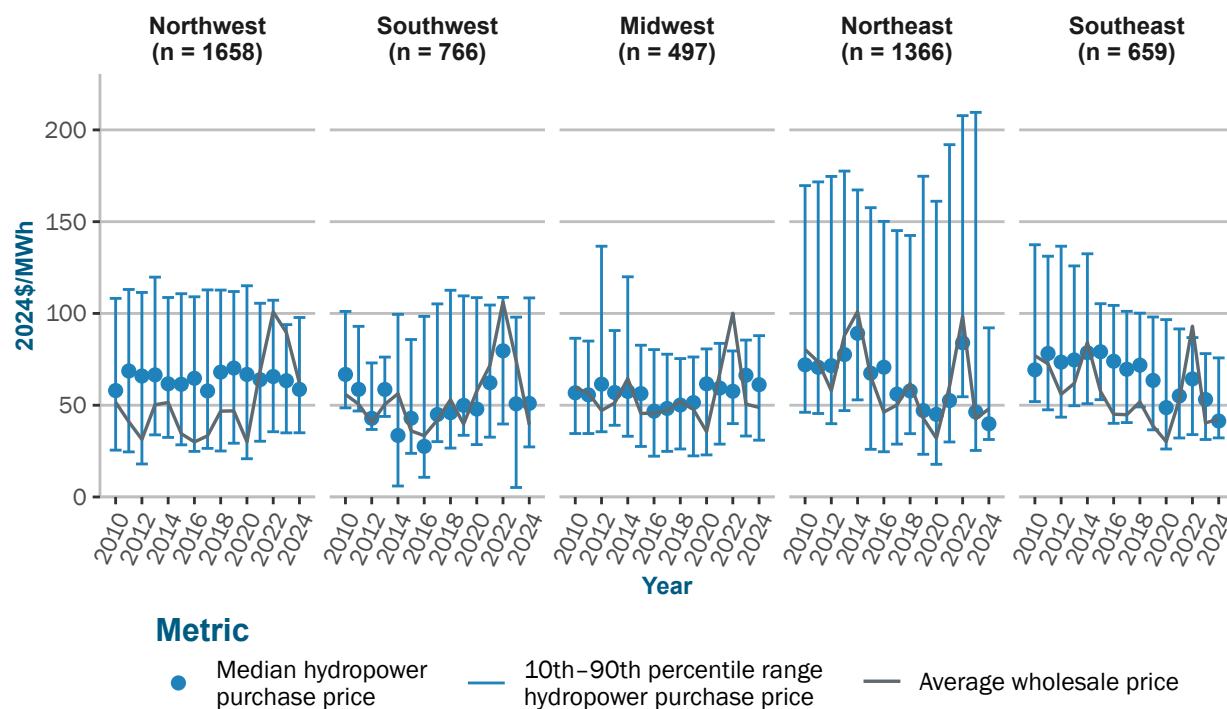


Figure 33. Energy component of the hydropower price by region and report year from power sales reported on FERC Form 1

Sources: FERC Form 1, EIA Wholesale Electricity and Natural Gas Market Data

Note: The regions shown in this plot are the same as for the maps in Figure 8, Figure 13, and Figure 15. The n in the panel labels refers to the number of observations across all years for each region. Points correspond to the median hydropower purchase price from FERC Form 1 data. Range represents the 10th to 90th percentile for hydropower purchase price. Trend lines display the average wholesale price at regional electricity trading hubs (Mid-Columbia Hub for the Northwest, Palo Verde Hub for the Southwest, Indianapolis Hub for the Midwest, Massachusetts Hub for the Northeast, and the PJM Interconnection West Hub for the Southeast). The figure displays only the energy component of prices. Twenty-two percent of the transactions summarized in the plot also had a capacity price component.

In 2021–2024, the median hydropower PPA energy price differed substantially among regions. It averaged \$62.88/MWh in the Northwest, \$60.89/MWh in the Southwest, \$61.12/MWh in the Midwest, \$55.69/MWh in the Northeast, and \$53.48/MWh in the Southeast. The Southwest and the Midwest are the only regions where the 2021–2024 average was higher than the 2010–2020 average. Selling energy through PPAs has typically provided hydropower owners a more stable energy revenue than selling into the wholesale market in the Northwest and Southeast. In those two regions, the median energy price in hydropower PPAs were higher than the wholesale price in years when the wholesale price was relatively low but some of the sudden price increase that the wholesale market offered in 2022 was not captured in PPA prices in those regions. For hydropower PPAs in the Southwest, Midwest, and Northeast, the median PPA price followed the wholesale price closely—an indication that PPA prices in those regions are typically indexed to a wholesale market price.

The Northwest displays the most stable PPA price distributions with both the median and 10th and 90th percentiles staying at similar levels in 2010–2024. Although the Northwest is also the region with the highest share of long-term (five years or longer) PPAs (72%), the long-term fraction of PPAs is similar for the Southwest (68%) and the Southeast (69%) whose median prices have been more variable over time. Therefore, the stable media prices in the Northwest points to fixed price PPAs being more common there than in other regions.

Most of the PPAs in the Southwest resulting in very low values for the 10th percentile of hydropower PPA energy prices in that region (\$5.99/MWh in 2014, \$10.71/MWh in 2016, and \$5.17/MWh in 2023) are PPAs where the capacity component accounted for most of the revenue. When considering both the capacity and energy components of prices, the 10th percentile of the price distribution for the Southwest is not below \$24/MWh in any year from 2010 to 2024.

The Northeast had been the only region where the 90th percentile energy price was greater than \$150/MWh in most years. The abrupt drop of the 90th percentile hydropower PPA energy price in the Northeast to \$92/MWh in 2024 can be traced back to renegotiation of a handful of long-term PPAs. For those few PPAs (between Niagara Mohawk Power Corporation and multiple hydropower plants in New York), the average energy prices had ranged from \$150/MWh to \$200/MWh (with zero capacity payments) until 2023. In 2024, the structure of payments under those PPAs changed to average energy prices in the \$32/MWh–\$34/MWh complemented with a capacity component of \$2/MWh–\$4/MWh.

The number of hydropower PPAs identifiable from the FERC Form 1 dataset has decreased over time: from a maximum of 395 in 2012 to a minimum of 256 in 2024. The decrease is observable in every region, but it is especially pronounced for the Southwest (from 74 PPAs in 2012 to 25 in 2024) and Northeast (from 120 PPAs in 2011 to 59 in 2024) regions. This decrease suggests that either the purchasing utilities are turning to alternative arrangements to procure the energy and capacity they need or hydropower owners are opting for non-utility counterparties or direct participation in ISO/RTO markets to market the energy and grid services from their facilities.

Because only utilities report to FERC Form 1, this dataset does not capture PPAs where the buyer is a corporate entity. No public data are available to summarize price trends in the rapidly growing segment of corporate PPAs. Corporate PPAs had initially focused on acquiring energy from new wind and solar capacity. However, technology companies are starting to seek more baseload, dispatchable capacity like that provided by hydropower to their portfolios in order to more closely match renewable energy use and renewable energy generation in their daily operations. Recent key milestones for corporate PPAs where the seller is a U.S. hydropower owner include:

- In June 2023, Rye Development signed a 10-year PPA with Iron Mountain—a storage and data center infrastructure company—for up to 150 MW of capacity from multiple hydropower facilities in Pennsylvania and West Virginia.
- In July 2025, Brookfield Renewable announced an agreement with Google to deliver up to 3,000 MW of U.S. hydroelectric capacity. The first contracts under that agreement are 20-year PPAs for Brookfield’s Holtwood (247.3 MW) and Safe Harbor (417.5 MW) facilities in Pennsylvania.

In another notable hydropower PPA signed in November 2024, TVA purchased the capacity from four Brookfield facilities in Tennessee and North Carolina: Cheoah (144 MW), Calderwood (156.6 MW), Chilhowee (49.8 MW), and Santeetlath (45 MW). This PPA has a 10-year term and is not captured in the FERC Form 1 dataset because TVA is a federal agency.

4.3 REVENUE STREAMS FROM PARTICIPATION IN ISO/RTO MARKETS

4.3.1 Energy Revenue

The average annual revenue (in 2025 dollars) for hydropower in 2021–2025 in ISO/RTO markets ranged from \$101/kW in ERCOT and MISO to \$232/kW in NYISO. In the seven ISO/RTO markets, the highest annual revenue for hydropower in that five-year period was at least 90% higher than the minimum annual revenue. The volatility of ISO/RTO prices is the main driver for the annual changes in revenue, but hydrologic conditions also play an important role.

The revenue that hydropower plant owners selling energy in ISO/RTO markets receive varies significantly from year to year and across markets. Figure 34 displays the average hydropower energy revenue per kilowatt of installed capacity if all the energy produced by the hydropower fleet in ISO/RTO balancing authorities (BAs) had been sold into the ISO/RTO wholesale markets.⁵⁶ The actual revenue of each hydropower plant in those BAs may have differed from the values shown in Figure 34. The difference depends on 1) how closely the plant matched the average generation shape of the fleet and 2) if it sold its energy through bilateral contracts or PPAs at prices that may differ from the ISO/RTO LMPs.

⁵⁶ Hourly revenue is calculated by multiplying hourly hydropower generation data from EIA Form 930 times an hourly price representative of LMPs in each ISO/RTO. Some ISO/RTOs (ERCOT, PJM, ISONE) report a summary price for their systems. For the rest of ISO/RTOs, the price used in this calculation is an average of LMPs at multiple locations (NP15, SP15, and ZP26 nodes for CAISO, North Hub and South Hub for SPP, average of eight state hub LMPs for MISO, and average of 11 zonal LMPs for NYISO). Figure 34 displays the annual sum of the hourly revenues divided by installed hydropower and PSH capacity in each ISO/RTO.

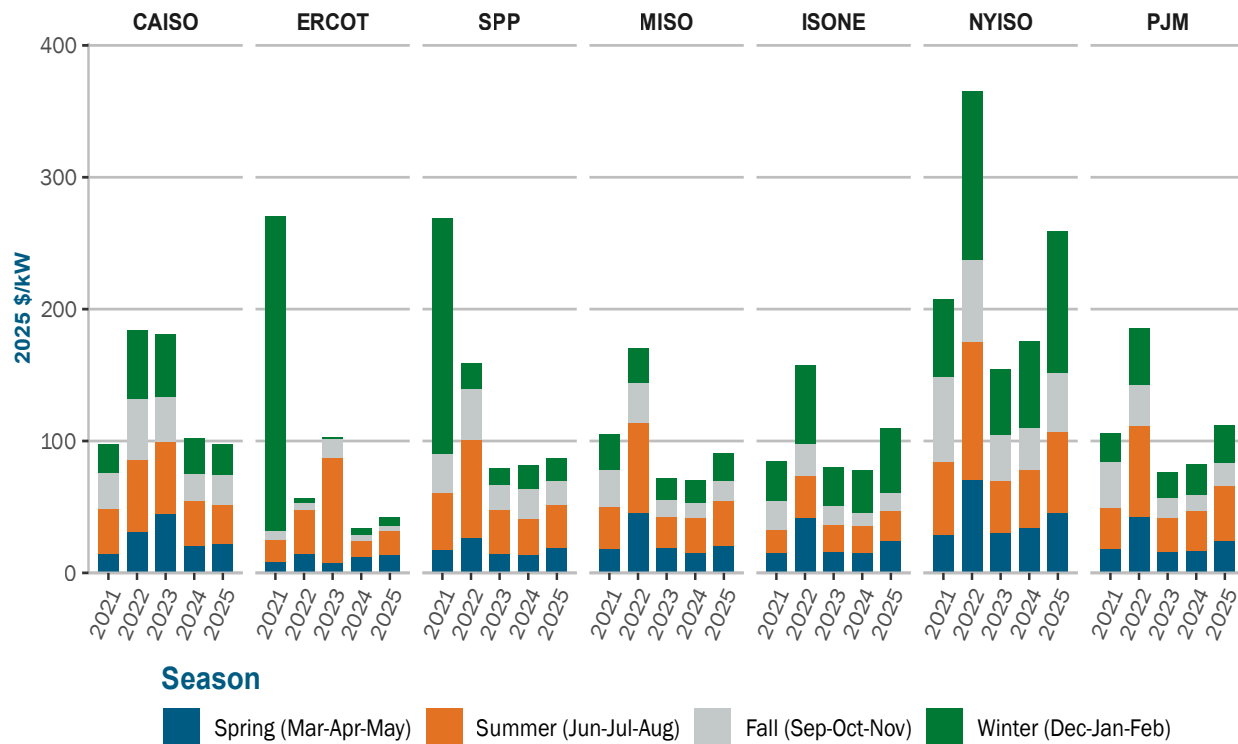


Figure 34. Average energy revenue per kilowatt of hydropower and PSH by ISO/RTO and season

Sources: EIA Form 930 (hourly generation), EIA and ISO/RTO webpages (day-ahead hourly locational marginal prices (LMPs)), EHA (hydropower and PSH capacity by year and BA). See footnote 59 for details about the LMPs used for each ISO/RTO.

Notes: The capacity and generation values used to compute the revenue shown in the plot include hydropower and PSH. For PSH, it represents gross revenue (i.e., the energy cost of pumping water is not subtracted).

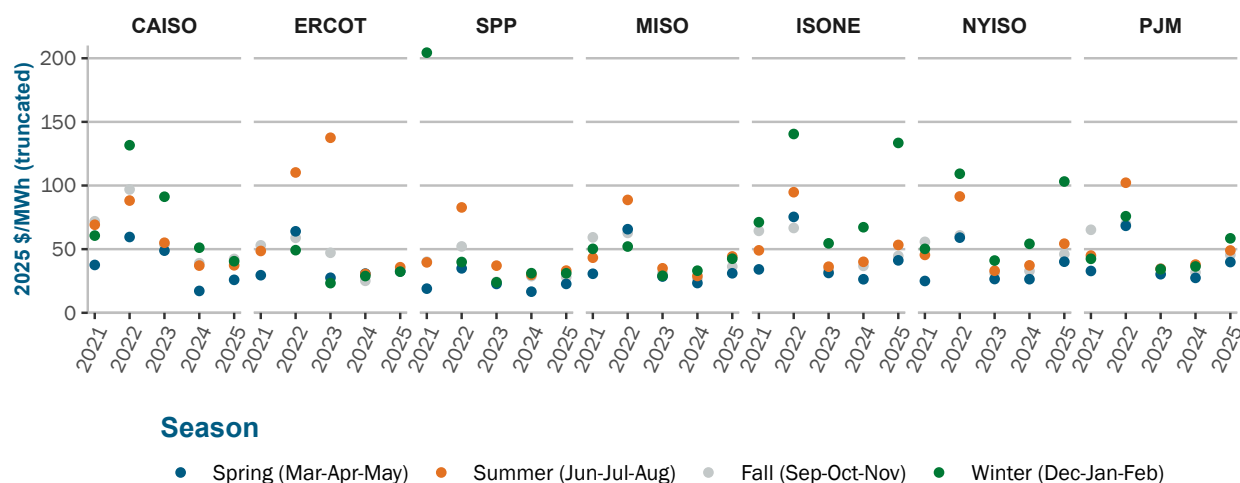


Figure 35. Average day-ahead locational marginal price by ISO/RTO and season

Sources: EIA and ISO/RTO webpages (day-ahead locational marginal prices (LMPs)). See footnote 59 for details about the LMPs used for each ISO/RTO.

Notes: The y-axis is truncated. It does not include the 2021 average winter LMP value for ERCOT (\$568/MWh).

The average annual revenue shown in Figure 34 and prices in Figure 35 depend on the market conditions (summarized by the LMP), hydropower capacity factor, and the ability of the fleet to schedule generation during hours with high prices.

The large fluctuations in annual revenue show that selling energy in ISO/RTO markets carries substantial market risk. The average energy revenue from 2021 to 2025 ranged from \$101/kW for the ERCOT and MISO fleets to \$232/kW for the NYISO fleet. As shown in Figure 35, the LMPs were similar in the ISONE and NYISO markets. The main factor driving the higher revenue in NYISO is the higher capacity factor for that fleet (50% or higher in every year from 2021 to 2025). For all other combinations of market and year, the capacity factor is 33% or lower.⁵⁷

The years of highest revenue coincide with ISO/RTO price spikes. For the ERCOT and SPP fleets, revenue was highest in 2021 driven by winter storm Uri in mid-February of that year. Prices skyrocketed during the week of the storm and resulted in average winter 2021 prices of \$568/MWh in ERCOT and \$204/MWh in SPP.⁵⁸ In both cases, the winter share of hydropower generation in 2021 was higher than in the rest of years suggesting that the hydropower fleets in those regions were able to produce more than usual during the winter storm. For the rest of ISO/RTO fleets, hydropower revenue was largest in 2022 when electricity prices increased due to the natural gas price spikes following the Russian invasion of Ukraine. The increase in average hydropower energy revenue from 2021 to 2022 in those five markets ranged from 62% in MISO to 89% in CAISO. For CAISO, the increase in hydropower revenue was also helped by a rise in capacity factor (from 15% in 2021 to 19% in 2022). Capacity factor also increased in 2022 (by less than two percentage points) in ISONE and MISO and was lower in 2022 than 2021 in NYISO and PJM.

The CAISO hydropower fleet differs from the rest of markets in maintaining high revenue in 2023. The average annual LMPs in CAISO were \$85/MWh in 2022 versus \$59/MWh in 2023 but generation was significantly higher in 2023 than 2022. The annual average capacity factor for the CAISO hydropower fleet increased from 19% in 2022 to 32% in 2023 due to improvement in drought conditions.

Summer accounts for the largest seasonal share of revenue every year in 2021–2025 for the CAISO and MISO hydropower fleets as well as for ERCOT and SPP, except in 2021 where 88% of the ERCOT hydropower revenue and 66% of the SPP hydropower revenue were attained in the winter months due to winter storm Uri. Average seasonal share of revenue for the PJM fleet is typically also highest in summer. Finally, for ISONE and NYISO, winter was the highest revenue season each of these years, except in 2021 for NYISO where highest revenue share was in the fall.

⁵⁷ Calculating capacity factor for a combined fleet of hydropower and PSH plants results in substantially lower values for fleets with a high share of PSH capacity. The formula for annual capacity factor is total generation/(total capacity * number of hours in the year). However, PSH units spend at least as many hours pumping water from the downstream to the upstream reservoir as generating. Therefore, they have very low capacity factors based on this formula.

⁵⁸ Hydropower and PSH revenue during winter storm Uri (February 13–17, 2021) accounted for 62% of the total 2021 revenue shown in Figure 34. Average energy revenue per kilowatt of hydropower and PSH by ISO/RTO and season⁷ for ERCOT and 41% for SPP.

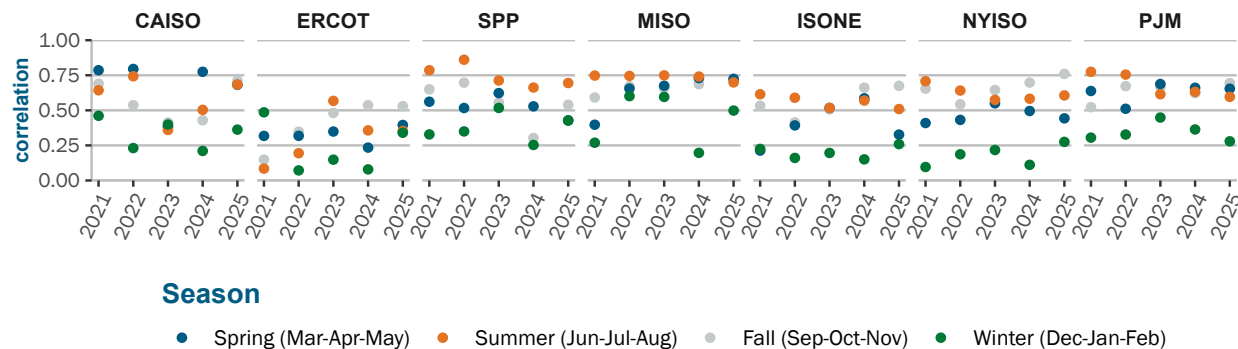


Figure 36. Correlation between hourly hydropower and PSH generation and hourly day-ahead locational marginal price, by ISO-RTO and season

Sources: EIA Form 930 (hourly generation), EIA and ISO/RTO webpages (day-ahead locational marginal prices)

Note: All the correlation coefficients shown are statistically significant at the one percent level.

Figure 36 shows that the correlations between hydropower (including PSH) generation and hourly day-ahead prices are all positive but range widely across markets, years and seasons. Sixteen of the 19 season-year-market combinations where the correlation between hydropower generation and day-ahead hourly LMPs is greater than 0.7 are in the spring or summer seasons. On the other hand, 19 of the 24 season-year-market combinations where the correlations are less than 0.3 are during the winter months. Higher correlations are indicative of the ability of the hydropower fleet to schedule more generation during hours with higher prices to maximize revenue. This ability varies across fleets depending on share of capacity operating as peaking versus run-of-river. Furthermore, the ability to follow prices is limited by operational constraints associated to non-hydropower uses of dams and required mitigation of environmental impacts.

4.3.2 Capacity Revenue

Capacity revenue can be a large share of total revenue for hydropower and PSH plants. It varies substantially year to year depending on the capacity price, which reflects the surplus or deficit of capacity to meet projected load in each region. Capacity revenue depends also on which fraction of nameplate capacity can be shown to be consistently available, especially during hours with the highest likelihood of supply shortages.

Resource adequacy is the process by which electricity planners ensure enough generation capacity is available in the system to meet projected peak demand. That process is managed differently across the seven ISO/RTOs. Four ISO/RTOs (MISO, ISO-NE, NYISO, and PJM) conduct capacity auctions. The price at which the auction clears is the capacity payment that power plant owners will receive per unit of accredited capacity. In CAISO and SPP, load-serving entities (i.e., utilities) must procure adequate capacity to meet reliability requirements and do so primarily through their own generation resources and bilateral trades. In Texas, ERCOT publishes multiple reports with information regarding projected load and generation capacity. Market participants make investment decisions based on that information as well as the expected revenues that could be achieved in that market.

Figure 37 shows trends in annual capacity revenue per kilowatt for the ISO/RTOs that conduct capacity auctions as well as for CAISO where the California Public Utilities Commission publishes summary statistics on the prices of bilateral trades conducted by utilities to meet their resource adequacy requirements. The black dots in the plot are the average capacity revenue across system subregions and the blue ribbon shows the revenue ranges. The average (in 2024 dollars) of the annual average prices for the period shown in each panel was \$13/kW-yr for MISO, \$60/kW-yr for PJM, \$68/kW-yr for ISO-NE,

\$70/kW-yr for NYISO, and \$78/kW-yr in CAISO. For CAISO, MISO, and PJM, capacity prices have been trending upward significantly in the most recent years due to increased load forecasts associated with the addition of new large loads such as data centers. For NYISO, average prices in the last three years shown in Figure 37 were in line with the rest of the period. Finally, for ISONE, average prices in 2023–2025 were less than half than the average for 2010–2022.

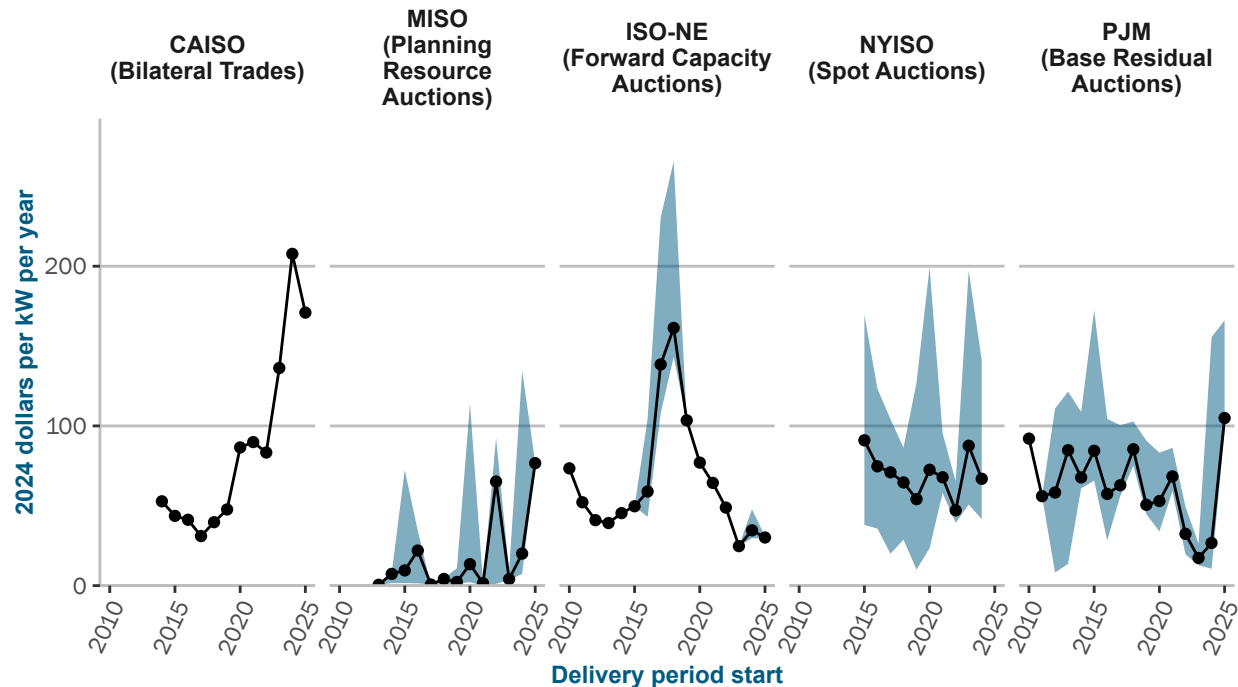


Figure 37. Capacity prices in U.S. ISOs/RTOs

Sources: California Public Utilities Commission (CAISO), ISO/RTO websites (MISO, ISO-NE), Potomac Economics (NYISO), Monitoring Analytics (PJM)

Notes: The CAISO does not conduct capacity auctions, but the California Public Utilities Commission publishes summaries of the prices of bilateral trades that the load-serving entities conduct to meet their resource adequacy requirements. The number of years shown for each ISO/RTO varies depending on data available on their websites. Missing data does not necessarily mean that there were no capacity prices in those earlier years. The blue ribbon represents the range of capacity prices across ISO/RTO subregions. The black line and dots depict the average price across all subregions. When no ribbon is shown, it is because the clearing price was the same across all subregions or, in the case of CAISO, because only one price is shown.

The subregion where a generation plant is located can matter significantly to the value of its capacity. The most recent delivery periods show large peaks in capacity prices for certain subregions, corresponding to the areas in most need of new investment. For example, the capacity price for the Dominion and Baltimore Gas & Electric subregions in PJM in the 2025 capacity auction was more than 50% higher than the average across all subregions in PJM. For the 2023 and 2024 NYISO auctions, clearing prices were much higher for the New York City zone than the rest driven by retirement of multiple generators in that subregion.

Besides ISO/RTO market and subregion, the capacity revenue that a hydropower plant receives also depends on what portion of its nameplate capacity is “accredited”. Accreditation determines the contribution of generating resources to resource adequacy. Accreditation methodologies vary across ISO/RTOs. Hydropower with storage (as well as PSH) typically has a higher fraction of its nameplate capacity accredited because it has more ability to schedule generation when needed and it is more likely to perform consistently well during the hours with the highest probability of a supply shortage.

CHAPTER 5. U.S. HYDROPOWER COST AND PERFORMANCE METRICS

This chapter presents trends for a variety of hydropower cost and performance metrics. For costs, Section 5.1 reviews capital costs of a sample of new facilities built in 2010–2025 and Section 5.2 summarizes trends in O&M costs during the same period (accounting for differences across facility sizes and vintages). Section 5.3 discusses the evolution of generation volumes by region and Section 5.4 examines the distribution of plant capacity factors. Section 5.5 provides information on availability factors, time spent on different modes of operation during available hours, and time spent in different types of outages during unavailable hours. Section 5.6 explores the causes of forced outages and their consequences in terms of lost energy. Finally, Section 5.7 discusses metrics that highlight the reliability and flexibility attributes of the U.S. hydropower and PSH fleet.

5.1 CAPITAL COSTS (2010–2025)

The capacity-weighted average capital cost for a sample of 49 projects that became operational since 2010 was \$3,316/kW for conduit retrofits, \$6,738/kW for NPD retrofits, and \$6,838/kW for NSD projects. For four small projects completing construction in 2022–2024, the cost range extends from \$1,900/kW to \$15,300/kW.

Figure 38 shows the capital cost of 49 projects that became operational from 2010 to 2024 differentiating them by project size and project type—conduit retrofit, NPD retrofit, or NSD. Their capacity-weighted average cost was \$3,316/kW for conduit retrofits (16 projects), \$6,738/kW for NPD retrofits (24 projects), and \$6,838/kW for NSD projects (9 projects).

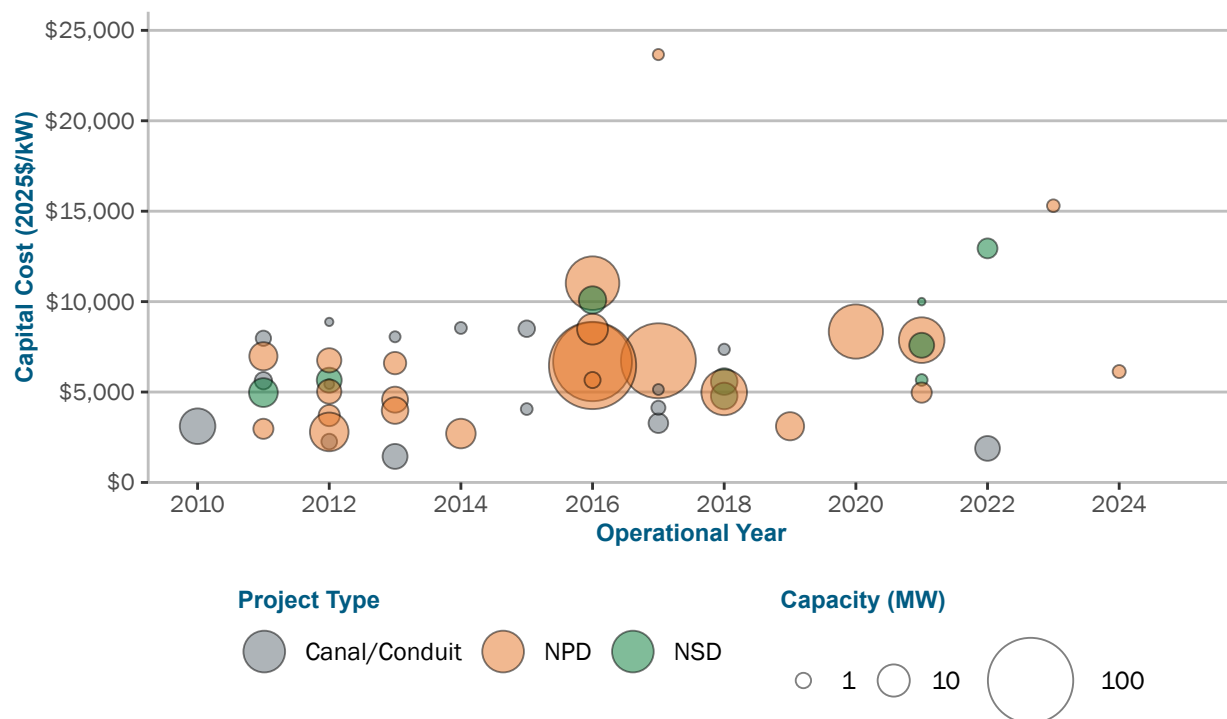


Figure 38. Cost of new hydropower development since 2010

Sources: O'Connor et al. (2015) (24 data points), IIR (4 data points), internet searches (21 data points)

Notes: The U.S. BOR Construction Cost Trends composite trend index was used to adjust for inflation. Since the data comes from multiple sources and are typically just a total project cost number, it is not possible to ensure that they all include the same components (e.g., whether the cost of licensing is included).

The dataset contains six new records for projects constructed since 2010 relative to the version used in the 2023 edition of the Hydropower Market Report. Of those six, four are projects that came online in 2022–2024 with costs ranging from \$1,900/kW (4.9 MW conduit project in Colorado) to \$15,300/kW (430 kW NPD project in Rhode Island). The two data points in Figure 38 with costs greater than \$15,000/kW are Hanover Pond Dam (220 kW NPD project in Connecticut that became operational in 2017) and Albion Dam (430 kW NPD project in Rhode Island that started operation in 2024). These are the first two commercial-scale installations of Archimedes Screw Turbines (AST) in the United States so their very high costs may relate to the use of innovative equipment. Both are also low-head sites (15.2 and 10.8 feet, respectively) which, all else equal, makes hydropower installations more expensive.⁵⁹

Eighty-one percent of projects shown in Figure 38 were small (≤ 10 MW). Within each project type, Figure 39 suggests that there is an inverse relationship between nameplate capacity and cost. However, the correlation coefficient between capital cost and size is only statistically significant for the Canal/Conduit category. The range of costs remains very wide (\$2,800/kW–\$11,000/kW) if only the nine projects with capacities greater than 10 MW are considered.

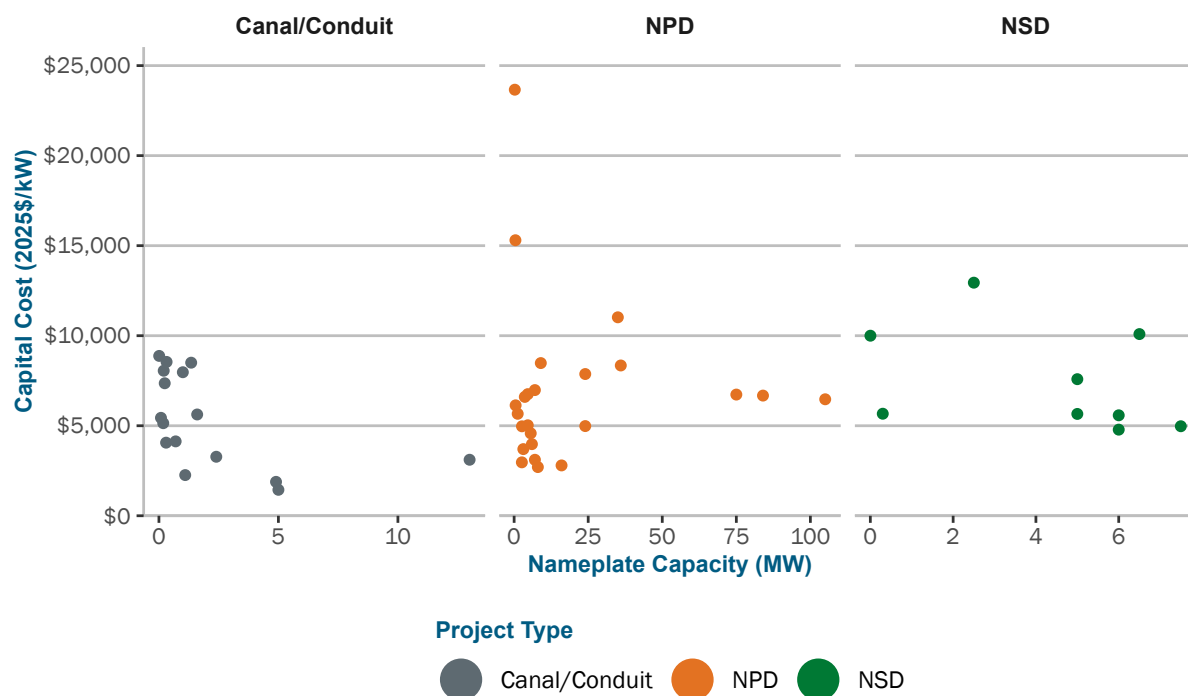


Figure 39. Relationship between capital cost and project size by project type (for sample of U.S. hydropower projects built since 2010)

Sources: O'Connor et al. (2015), IIR, internet searches

Notes: Same as Figure 38.

Project capacity is part of a set of descriptive project inputs that researchers use to generate cost estimates for new sites. For NPDs and NSDs, the National Laboratory of the Rockies Annual Technology Baseline estimates overnight capital cost for projects with different combinations of site characteristics (flow, head, water conveyance length, NPD design type (lake or lock), distance to closest

⁵⁹ To produce a given amount of power, the lower the head is, the larger the flow rate will need to be. Handling greater flow rates requires larger, more expensive turbine-generator units.

electric substation, capacity) (NREL, 2024). The estimated overnight capital costs for NPDs range from \$3,045/kW to \$20,043/kW. The estimates for NSD projects range from \$6,713/kW to \$8,546/kW.⁶⁰

5.2 O&M COSTS (2010–2024)

Hydropower O&M costs exhibit significant economies of scale (i.e., costs decrease on a per-kW basis as project size increases). Average 2021–2024 hydropower O&M costs in 2024 dollars ranged from \$19/kW for very large plants (>500 MW) to \$200/kW for small (<= 10 MW) hydropower plants. These inflation-adjusted averages were lower than the 2010–2020 annual averages for all size categories. For small hydropower plants, average wholesale electricity prices were lower than O&M costs per kilowatt-hour for some combinations of regions and years suggesting it may be challenging for them to operate profitably.

Figure 40 shows the trend in average O&M cost per kilowatt of capacity (in 2024 dollars) for utility-owned hydropower, differentiated by size category. In 2021–2024, the average O&M cost was \$200/kW for small hydropower plants (<=10 MW), \$56/kW for medium plants (>10 MW–100 MW), \$23/kW for large plants (>100 MW–500 MW), and \$19/kW for very large plants (>500 MW). Costs decreased relative to the annual 2010–2020 averages for all size categories: 7% decrease for small plants, 20% decrease for medium plants, 33% decrease for large plants, and 12% decrease for very large plants. The decrease could be partly due to increased operational efficiencies, but it also likely shows that O&M budgets have not been keeping pace with inflation.

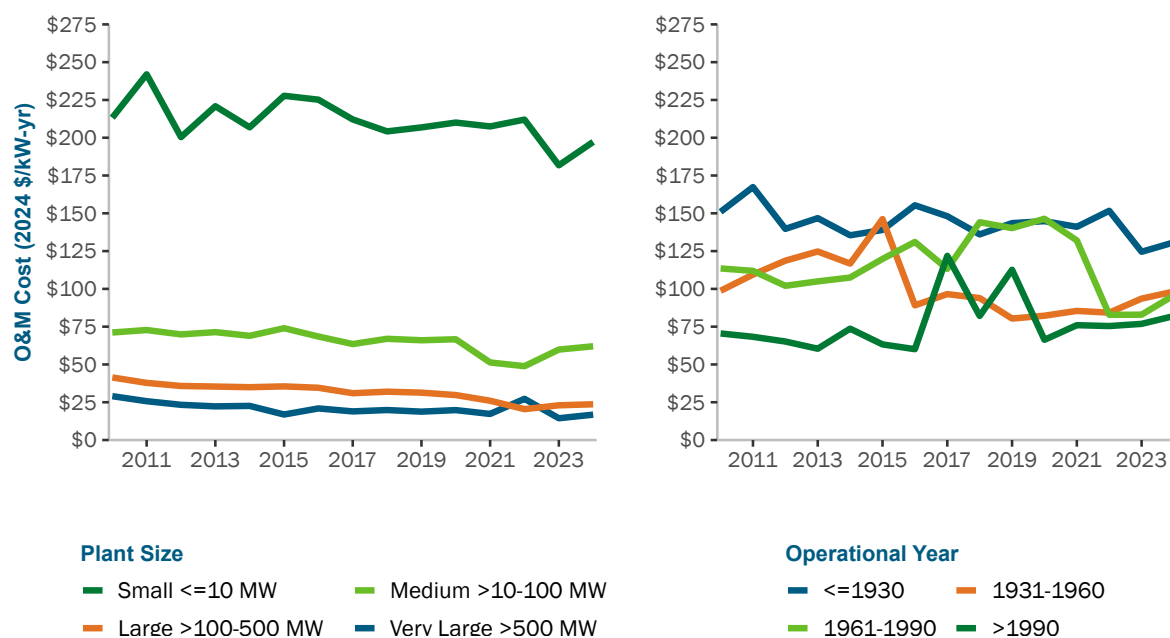


Figure 40. Trend in O&M costs per kilowatt for utility-owned hydropower and PSH plants by size category and age

Source: FERC Form 1

Notes: An updated data processing workflow corrected previous errors and identified more small hydropower plants in the FERC Form 1 database than were included in previous editions of this report. As a result, average O&M costs are not directly comparable to, and may differ from, those previously reported. The average numbers of plants in each size category are 7 (Very Large), 498 (Large), 154 (Medium), 188 (Small). The average numbers of plants in each operational year interval are 244 (<= 1930), 88 (1931–1960), 61 (1961–1990), 5 (>1990). O&M cost elements reported in FERC Form 1 are defined as “operating expenses” in FERC’s Uniform System of Accounts. They include labor, materials, and overhead associated with operation, supervisions, engineering and maintenance of the electric plant and associated structures, and rents from leased property.

⁶⁰ The dataset shown in Figure 38 and Figure 39 partially overlaps with the dataset used to estimate the equations from which these cost ranges result.

On average, the older plants have the largest O&M costs per kilowatt, and the newer plants have the smallest O&M costs per kilowatt. The average 2021–2024 O&M cost was \$137/kW for plants commissioned before 1930, \$90/kW for the ones from 1931–1960, \$98/kW for plants with operational dates in 1961–1990 and \$78/kW for plants commissioned after 1990. However, it is difficult to disentangle the effect of size and age. For plants included in FERC Form 1, the average capacity of plants commissioned after 1990 is 316 MW, 14 times greater than the average capacity of plants commissioned by 1930 (22 MW).

With strong economies of scale, even within each of the size categories shown in Figure 40, reported costs range widely, especially in the small hydropower segment. Figure 41 illustrates the cost variability within each size category by showing the median and 10th–90th percentile range in reported O&M costs.

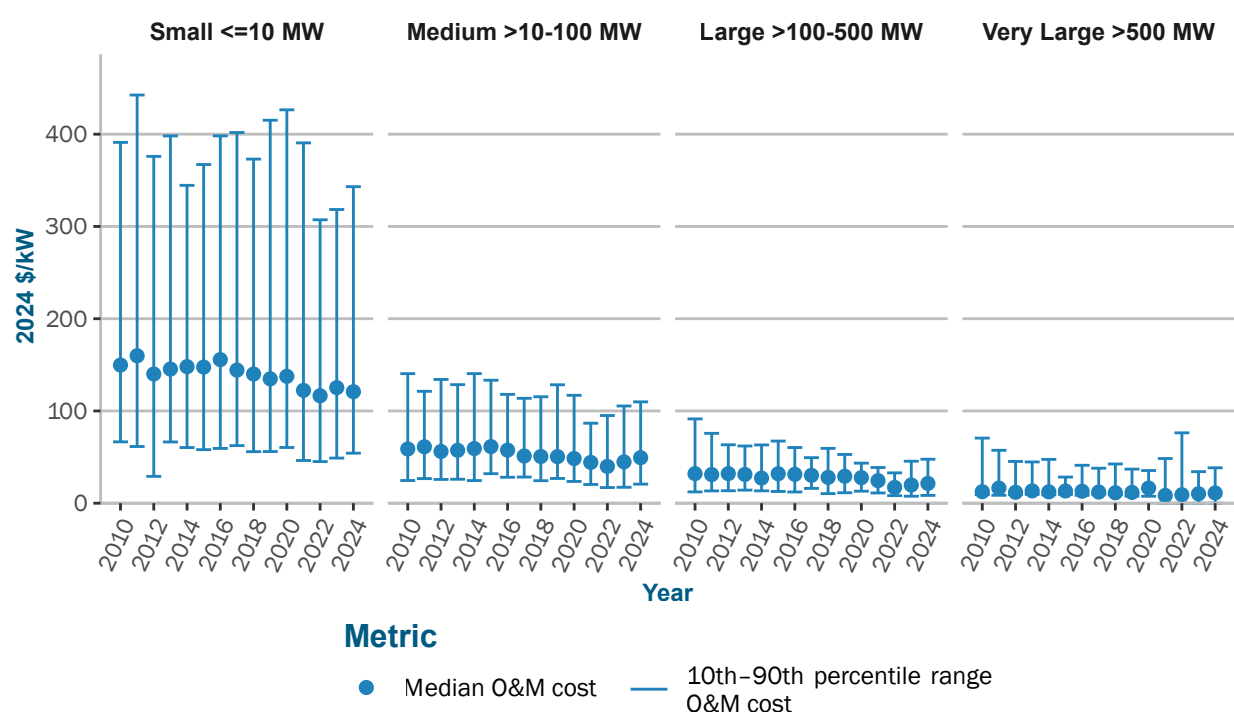


Figure 41. O&M cost (median and 10th–90th percentile ranges) by size category and year

Source: FERC Form 1

Notes: Same as for Figure 40.

An overall decreasing trend in median O&M costs as well as for the 90th percentile of the cost distribution is noticeable for all size categories. However, the 10th percentile has remained more stable. The median cost for small plants ranged between \$116/kW in 2022 and \$160/kW in 2011. The large difference between median and average for small plants—the averages ranged from \$182/kW in 2023 to \$242/kW in 2011—relates to the wide variability in O&M costs reported for this segment of the fleet. A handful of small plants with very high costs have a large influence on the average value. Among the 20 small plants with the highest average O&M costs (all with costs greater than \$400/kW per year), 18 have capacities below 2 MW. Four of the 20 (three in California and one in Colorado) had their licenses surrendered in recent years or are in the license surrender process. The 20 small plants with the lowest average O&M costs (all with costs below \$50/kW per year) all have capacities greater than 2 MW. Seventeen of them are owned by three utilities operating in the Northeast region.

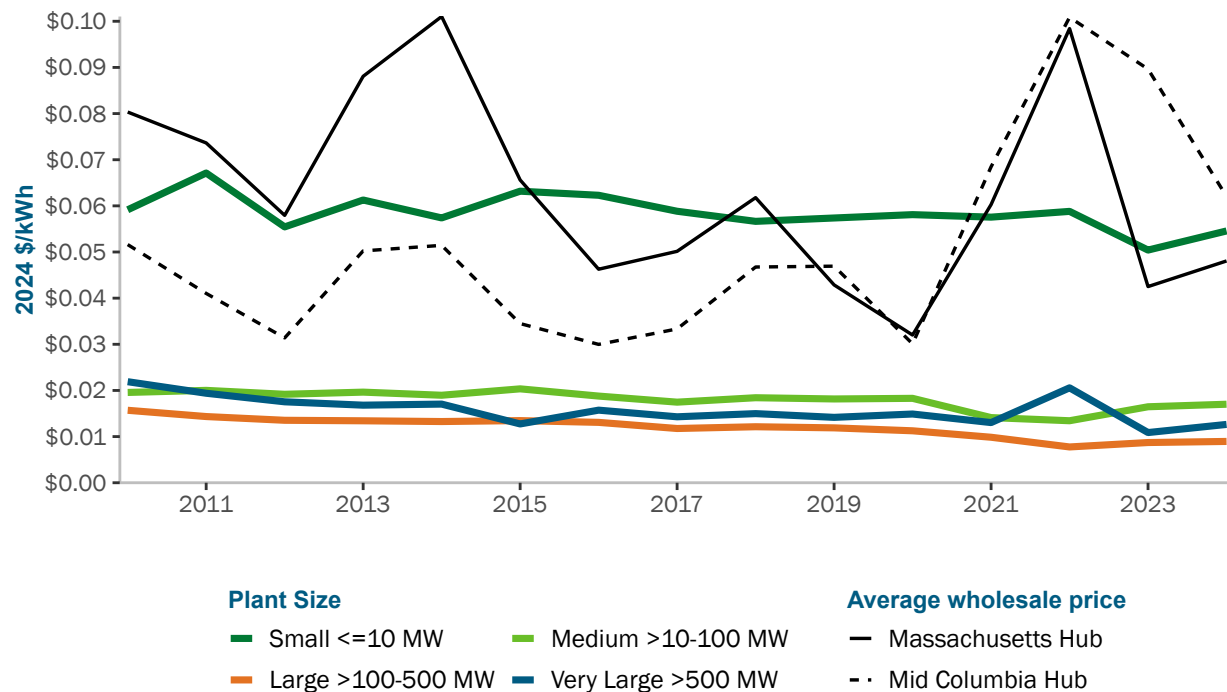


Figure 42. Trend in O&M cost per kilowatt-hour by size category (at average 2010–2024 capacity factor for each category)

Source: FERC Form 1

Notes: Same as Figure 40.

Two hydropower plants may have the same O&M costs per kilowatt of capacity and very different costs per kilowatt-hour depending on their capacity factors. To account for the differences in average capacity factors across size categories (41% for small plants, 42% for medium plants, 30% for large plants, 15% for very large plants), Figure 42 shows the trend in O&M costs per kilowatt-hour. From 2010 to 2024, O&M costs per kWh ranged from \$0.05/kWh to \$0.07/kWh for small plants and from \$0.008/kWh to \$0.02/kWh for the rest of categories. While O&M costs per unit of capacity (\$/kW) tend to be lowest for very large plants, the same pattern does not hold for O&M costs per unit of generation. Six of the seven hydropower plants in the FERC Form 1 dataset with capacities greater than 500 MW are PSH plants, which operate at very low capacity factors. As a result, their O&M costs per kilowatt-hour are higher than those of large hydropower plants.

O&M costs can be interpreted as the variable costs for hydropower generation. Electricity prices need to at least cover those costs for the hydropower plant to break even. Figure 42 includes the annual average prices for two wholesale trading hubs representative of the low end (Mid Columbia Hub in the Northwest) and high end (Massachusetts Hub in the Northeast) of U.S. regional wholesale prices. From 2010 to 2024, both wholesale prices were greater than the values needed for very large, large, and medium plants to break even. For small hydropower, the comparison between O&M costs and electricity prices suggests profitability challenges. The average wholesale prices in the Northeast and Northwest were below the average O&M cost per kilowatt-hour in six and 11 of the 15 years from 2010 to 2024, respectively.

Since only utilities file FERC Form 1, this dataset does not contain information about plants owned by private non-utilities or about the federal fleet. Three federal agencies (USACE, U.S. BOR, and TVA) own and operate almost half of U.S. hydropower capacity. USACE and U.S. BOR publish annual budgets containing the total O&M budget allocated to their hydropower fleets.

For the USACE fleet, the average annual hydropower O&M budget in FY2024–FY2026 was \$458 million (\$20.91/kW) down from an average of \$467 million in FY2018–FY2023.⁶¹ Within this aggregate number, there are differences between the O&M budget for USACE plants in the Pacific Northwest whose hydropower is marketed by Bonneville Power Administration (BPA) and the rest of USACE-owned plants. For the plants whose output is marketed by BPA, O&M expenses are covered with financing provided by the PMA. The average annual O&M budget for that subset of the USACE fleet increased from \$247 million (\$18.97/kW) in FY2018–FY2023 to \$261 million (\$20.07/kW) in FY2024–FY2026. O&M budget for the rest of the USACE fleet, allocated through Congressional appropriations, decreased from an average \$24.76/kW in FY2018–FY2023 to \$22.14/kW in FY2024–FY2026. U.S. BOR hydropower O&M budget for FY2024 was \$474 million (\$32.15/kW), almost identical to the annual average budget for FY2018–FY2023 (\$472 million).⁶² Flat budgets mean that the available funds for O&M are not being adjusted for inflation. The higher average O&M funding per kilowatt for the U.S. BOR fleet relative to the USACE fleet is consistent with the former owning plants that are on average smaller than the latter—median capacity is 100 MW for USACE plants and 38 MW for U.S. BOR plants.

5.3 ENERGY GENERATION (2010–2025)

In 2023–2025, average U.S. hydropower generation trended downwards (8% decrease relative to the 2020–2022 average and 12% decrease relative to the 2010–2019 average). U.S. hydropower generation is strongly influenced by hydrologic conditions in the Northwest region. In contrast, U.S. PSH generation increased during the most recent years (12% increase in 2023–2025 relative to the 2020–2022 average, 11% relative to the 2010–2019 average), propelled by higher output by the PSH fleets in the Northeast, Southeast, and Southwest.

The U.S. hydropower fleet generated an average of 245 TWh per year in 2023–2025. This value is 8% lower than the 2020–2022 average and 12% lower than the average during the 2010s. Figure 43 shows the trends in regional domestic hydropower generation and Canadian imports for 2010–2025. Except for the Southwest—where generation in 2023–2025 was 41% higher than in 2020–2022—all other series in Figure 43 decline from 2020–2022 to 2023–2025. For the Midwest, Northeast, and Southeast, the decrease in 2023–2025 relative to the three previous years is larger than the decrease relative to the 2010s.

⁶¹ USACE Civil Works budgets: usace.contentdm.oclc.org/digital/collection/p16021coll6/id/42

⁶² The FY2025 and FY2026 Budget Justification documents did not include tables of obligations by project function from which the hydropower O&M data were extracted in previous years.

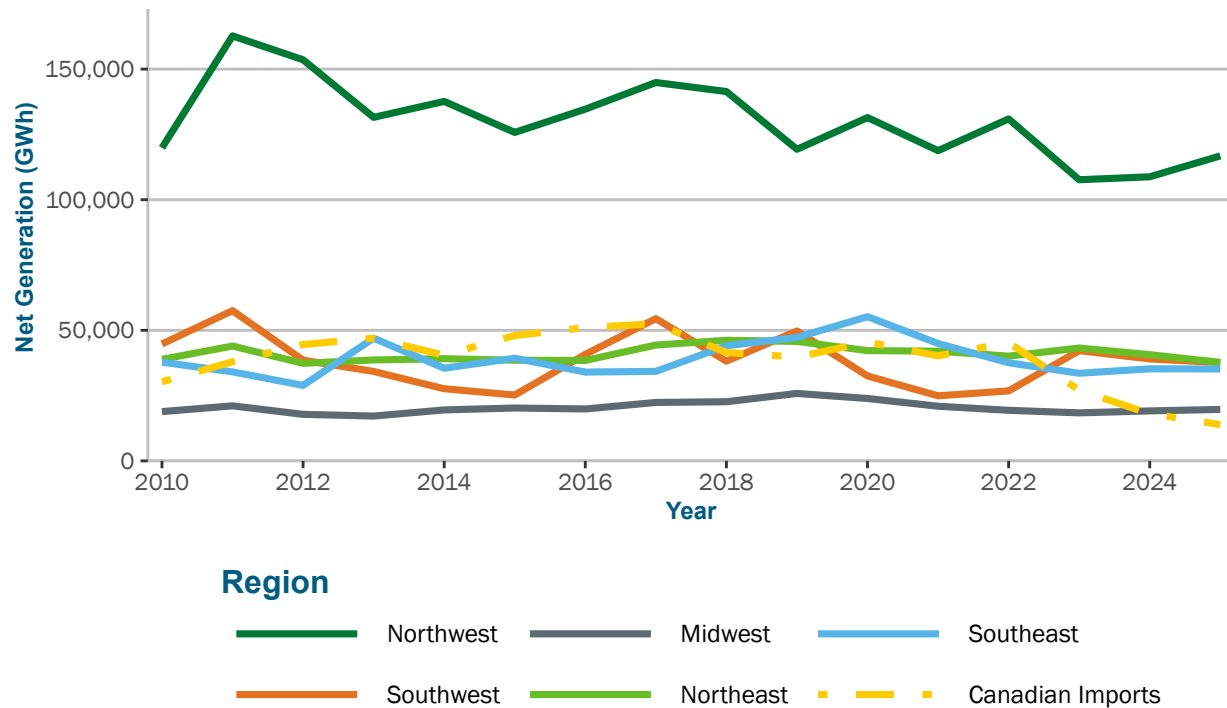


Figure 43. Annual hydropower net generation by region (2010–2025)

Source: EIA Form 923, Canada Energy Regulator

Note: The regions shown in this plot are the same as for the maps in Figure 8, Figure 13, and Figure 15. For domestic production, the values for 2025 are preliminary because they are based on data from the Early Release versions of EIA Form 923. Canadian imports include only imports from Hydro-Québec, Manitoba Hydro, and BC Hydro (directly or through their marketing subsidiaries). Since the electricity generation mix for these three companies is more than 90% hydropower, U.S. imports of electricity from these companies—which account for 49% of all U.S. imports from Canada in 2023–2025—can be classified as hydropower.

Hydropower fleet capacities (including hydropower units in plants that have a mixture of hydropower and PSH units) in 2025 were 36 GW in the Northwest (45% of U.S. total), 15 GW in the Southwest and in the Southeast (18.5% of U.S. total each), 8.6 GW in the Northeast (11% of U.S. total), and 5.8 GW in the Midwest (7% of U.S. total). The regional shares of U.S. hydropower generation in 2023–2025 were 42% for the Northwest, 15% for the Southwest, 7% for the Midwest, 15% for the Northeast, and 13% for the Southeast. The comparison of capacity and generation shares suggests that the Northeast hydropower fleet operated at the highest capacity factor and the Southeast fleet at the lowest capacity factor during this period. Differences between capacity shares and generation shares are due to differences in the predominant mode of operation (peaking vs run-of-river) of the different fleets as well as on hydrologic conditions.

Figure 43 shows that the 2023–2025 period started with very different trajectories for hydropower generation in the Northwest (18% decrease relative to 2022) versus the Southwest (57% increase relative to 2022). These differences can be traced back to hydrologic conditions in both regions.⁶³ In the Northwest, precipitation in the 2022–2023 was near normal but a heat wave in May 2023 melted the snowpack too rapidly and affected volume of water available for the summer months. In California, where two thirds of hydropower generation capacity in the Southwest region is located, snowpack in 2023 was the highest since the mid-1980s leading to a large increase in output from the hydropower fleet. Severe drought conditions in the Pacific Northwest in 2024 kept hydropower generation levels approximately flat relative to 2023. Meanwhile, generation in the Southwest decreased slightly in 2024 and 2025 without going back to the lower levels of the early 2020s. Nationally, hydropower generation

⁶³ [eia.gov/todayinenergy/detail.php?id=61645](https://www.eia.gov/todayinenergy/detail.php?id=61645)

in 2024 was the lowest in 2010–2025. The primary factor for that result was the low generation volume in the Northwest (the region with the largest installed hydropower capacity) combined with a 6% decrease in the Northeast and a 7% decrease in the Southwest relative to 2023.

Although precipitation and the resulting runoff are key drivers of hydropower generation, they do not fully explain its decreasing trend over the long run (Turner et al., 2024). For 2010–2024, Figure 47 shows a slight increase in outage hours for hydropower units with capacities below 100 MW which can explain part of the generation decrease. Figure 47 also shows that the number of hours medium units (10 MW–100 MW) and large units (> 100 MW) spent in Reserve Shutdown status has increased in recent years. These are hours in which the units are available but not connected to the grid because they are not part of the set of generating units dispatched to meet demand. Increases in outage hours and Reserve Shutdown hours are typically not connected to hydrology but also contribute to lower generation volumes.

The Canadian imports in Figure 43 only include imports from three companies whose generation mix is more than 90% hydropower (Hydro-Québec, Manitoba Hydro, BC Hydro). In 2023–2025, imports from those three entities and their marketing subsidiaries accounted for 49% of U.S. imports of Canadian electricity (down from 70% in 2010–2022). When considering all Canadian exports of electricity into the U.S. (part of which is not from hydropower plants), the average 2023–2025 volume has decreased by 39% relative to the previous three years. The percentage decrease for the three companies with very high hydropower shares was 55%. Drought conditions in Canada during this period help explain the larger decrease for the subset of Canadian imports included in Figure 43.

Recently completed and ongoing transmission line projects will strengthen the capabilities to import Canadian hydropower in future years. In January 2026, the New England Clean Energy Connect transmission line (a 145-mile high voltage direct current line with 1,200 MW transfer capability) started operation. This transmission line carries electricity produced by Hydro-Québec facilities into the U.S. Northeast via Maine. A second transmission line (Champlain Hudson Power Express) crossing the Canada-U.S. border carrying power from Hydro-Québec into New York was expected to start operating in May 2026. The NYISO highlighted the importance of the Champlain Hudson Power Express (1,250 MW of transfer capability) to maintain adequate reliability margins in its system in the next five years.⁶⁴ Also in May 2026, the U.S. DOE issued a presidential permit authorizing Basin Electric Power Cooperative to build two new transmission lines (650 MW of transfer capability) between North Dakota and the Canadian border. When constructed, this transmission line will carry electricity produced by the Manitoba Hydro fleet into the Midwest.

Figure 44 summarizes regional trends in PSH gross generation from 2010 to 2025.⁶⁵ The U.S. PSH fleet generated an average of 21.9 TWh during this period and annual output ranged from 19.2 TWh in 2013 to 24.9 TWh in 2010. Average generation in 2023–2025 increased relative to 2020–2022 in the three regions with the largest fleets: Southeast (8% increase), Northeast (25% increase), and Southwest (36% increase). As a result, U.S. PSH gross generation in the most recent three years shown in Figure 44 is 12% higher than the 2020–2022 average and 11% higher than the 2010–2019 average.

⁶⁴ [utilitydive.com/news/new-york-iso-warns-of-2026-reliability-violations-in-nyc-long-island/802699/](https://www.utilitydive.com/news/new-york-iso-warns-of-2026-reliability-violations-in-nyc-long-island/802699/)

⁶⁵ Gross generation does not account for energy consumption during pumping hours.

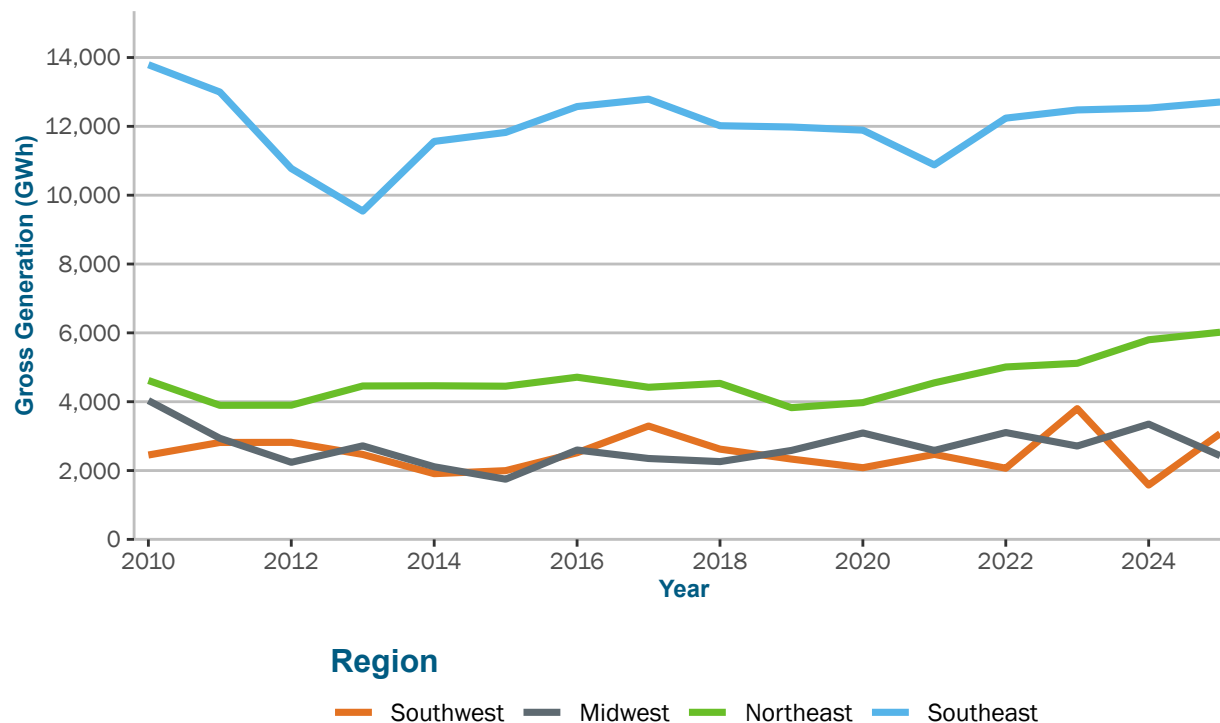


Figure 44. Annual gross PSH generation by region (2010–2025)

Source: EIA Form 923 Early Release

Note: The regions shown in this plot are the same as for the maps in Figure 8, Figure 13, and Figure 15. The Northwest region was excluded because it has a very small PSH capacity (314 MW). The values for 2025 are preliminary because they are based on data from the Early Release versions of EIA Form 923.

PSH fleet capacities (including PSH units in plants that have a mixture of hydropower and PSH units) in 2025 were 10 GW in the Southeast (44% of U.S. total each), 5 GW in the Northeast (23% of U.S. total), 4.4 GW in the Southwest (20% of U.S. total), 2.6 GW in the Midwest (12% of U.S. total), and 0.3 GW in the Northwest (1% of U.S. total). The regional shares of U.S. PSH generation in 2023–2025 were 53% for the Southeast, 23% for the Northeast, 12% for the Southwest, and 12% for the Midwest.⁶⁶ The comparison of capacity and generation shares suggests that the Southeast PSH fleet operated at the highest capacity factor and the Southwest fleet at the lowest capacity factor during this period.

As discussed for Figure 43, large year-on-year changes for regional hydropower generation are generally tied to climate variables. For PSH generation, the explanation to sudden annual changes is often tied to extended outages (planned or forced) of a few plants. The low PSH generation values for the Southeast in 2013 and 2021 match to increases in average outage hours for PSH units in the SERC balancing region (see Figure 48). Similarly, scheduled maintenance activities at Mount Elbert (Colorado) and extended outages at Helms (California) largely explain the drop in PSH generation in the Southwest in 2024.

PSH plants whose only purpose is power generation are typically very flexible assets.⁶⁷ PSH plant owners schedule generation to coincide with high-price periods. Maximizing the price differential between the hours when they consume energy for pumping water from the lower reservoir to the upper

⁶⁶ Gross generation by the only PSH units in the Northwest (part of the Grand Coulee plant) averaged 5 GWh of gross generation in 2023–2025, too small to be visible in Figure 44.

⁶⁷ In contrast, some PSH units—mostly in the West—are part of multipurpose projects where managing water for irrigation and water supply takes precedence over maximizing revenue from power sales.

reservoir and the hours when they generate and sell energy is vital for the profitability of a PSH plant. Increases in peak/off-peak price ratios tend to increase the number of hours in which it is profitable to operate. Table 2 shows the annual average peak/off peak ratio from 2021 to 2025 for the ISO/RTO markets where most PSH capacity is located. In MISO, ISONE, and PJM, the ratios have been higher in 2023–2025 than in the previous years which can help explain the increase in PSH generation shown in Figure 44. Traditionally, the peak period for electricity demand was defined as the hours from 7am to 10pm. However, in a system like CAISO with high solar penetration, that definition would result in a peak/off peak ratio smaller than one every year since 2022 because prices in the middle of the day are very low or can go even negative. Instead, the calculation for CAISO uses a reduced set of hours (4pm to 10pm) as peak and the rest of hours as off-peak. Even with the alternative definition of peak hours, the peak/off-peak ratios dropped substantially in CAISO in 2024 and 2025 and became the lowest out of all the ISO/RTOs included in Table 2 in those two years.

Table 2. Annual Average Peak/Off-Peak Ratio in Locational Marginal Prices in ISO/RTO Markets

Year	CAISO peak hours (4pm–10pm)	MISO peak hours (7am–10pm)	ISONE peak hours (7am–10pm)	NYISO peak hours (7am–10pm)	PJM peak hours (7am–10pm)
2021	1.56	1.42	1.31	1.37	1.45
2022	1.50	1.43	1.25	1.34	1.45
2023	1.60	1.54	1.33	1.36	1.57
2024	1.22	1.48	1.32	1.33	1.65
2025	1.27	1.47	1.29	1.33	1.52

Source: ISO/RTO websites

Note: ISONE and PJM report a summary hourly price for their systems. For the rest of ISO/RTOs, the hourly prices used for this calculation are an average of LMPs at multiple locations (NP15, SP15, and ZP26 nodes for CAISO, average of eight state hub LMPs for MISO, and average of 11 zonal LMPs for NYISO).

5.4 CAPACITY FACTORS (2010–2025)

On average, the median capacity factor for U.S. hydropower plants in 2023–2025 (34.2%) decreased by one percentage point relative to 2020–2022 (35.5%). Average capacity factors (not adjusted by capacity) varied significantly across regions ranging from 26% in the Southeast to 41% in the Midwest in 2023–2025.

Capacity factor measures the percentage of theoretical maximum output that a plant generated over a given period.⁶⁸ Figure 45 summarizes the distribution of annual capacity factors in the U.S. hydropower fleet from 2010 to 2025. The dots are the median capacity factor for each year, and the error bars show the range from the 10th to the 90th percentile.

⁶⁸ The theoretical maximum output would be the generation volume that results from operating the plant continuously at its nameplate capacity.

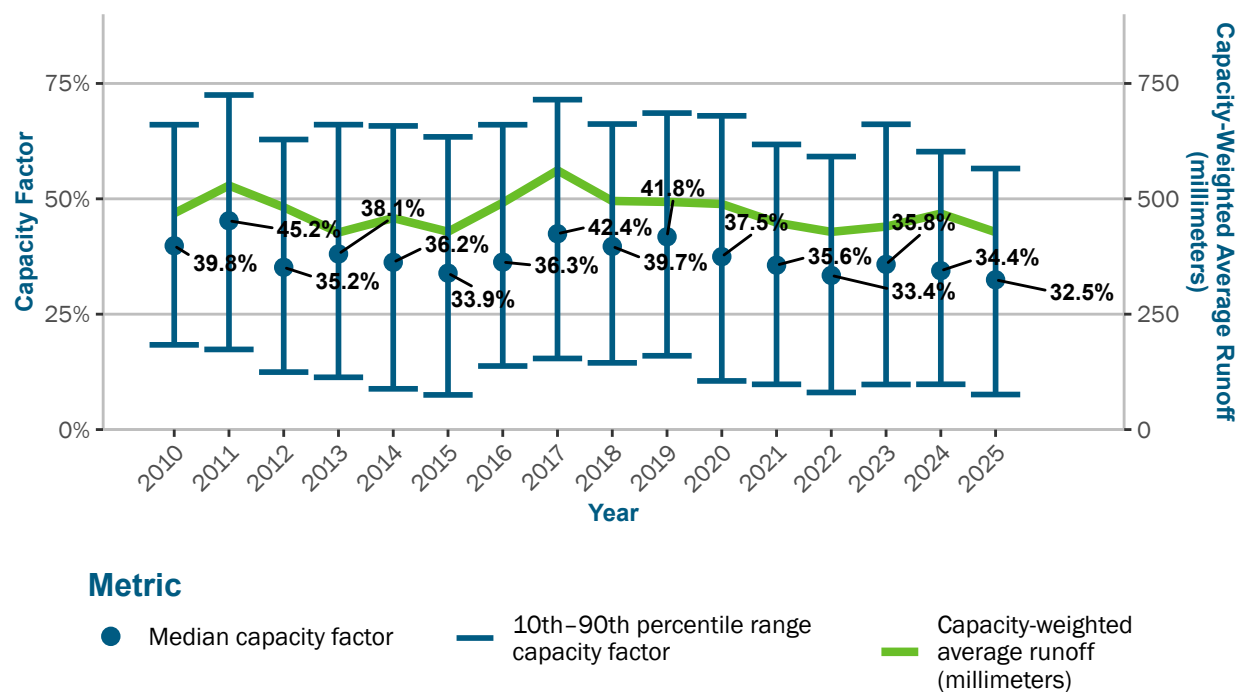


Figure 45. Plant-level distribution of hydropower capacity factors by year (2010–2025)

Sources: ORNL EHA Capacity Factor Plant Database, 2026; ORNL Dayflow

Note: Runoff data source is different from previous reports. The plot includes the capacity factors and capacity-weighted average runoff for the 50 U.S. states.

On average, the median capacity factor in 2023–2025 (34.2%) decreased by one percentage point relative to the 2020–2022 average (35.5%). Changes in median capacity factor from one year to the next do not necessarily match the direction of changes in total generation. U.S. total generation decreased from 2022 to 2023, but the median capacity factor increased. The median weighs all plants the same, but the capacity factor of large plants matters most for national generation volumes. The capacity-weighted average capacity factor in 2023 (34.9%) decreased relative to 2022 (36.7%).

The range of capacity factors across plants is very wide. The 10th percentile ranged from 8% (in 2015) to 18% (in 2010). Plants in the 10th percentile of the capacity factor distribution may be experiencing extended outages or be run-of-river plants in regions and years with extreme drought conditions. For the 90th percentile, 2025 showed the lowest value (57%) and 2011 the highest (72%). The largest plant that has consistently been part of the 10% of plants with highest capacity factors is Robert Moses (912 MW) in New York. From 2010 to 2025, it operated at an average capacity factor of 90%.

The sign and relative magnitude of annual changes in median capacity factor have generally followed those of capacity-weighted average runoff. Runoff is an estimate of the amount of water that enters river systems and can be available for hydropower generation.⁶⁹ Runoff is directly correlated with hydropower generation, particularly for run-of-river plants with no storage.

⁶⁹ It is the volume of water from precipitation (rain or snowfall) that remains after accounting for evaporation from land surfaces, transpiration from vegetation, and infiltration into soils (ca.water.usgs.gov/california-drought/california-drought-runoff.html)

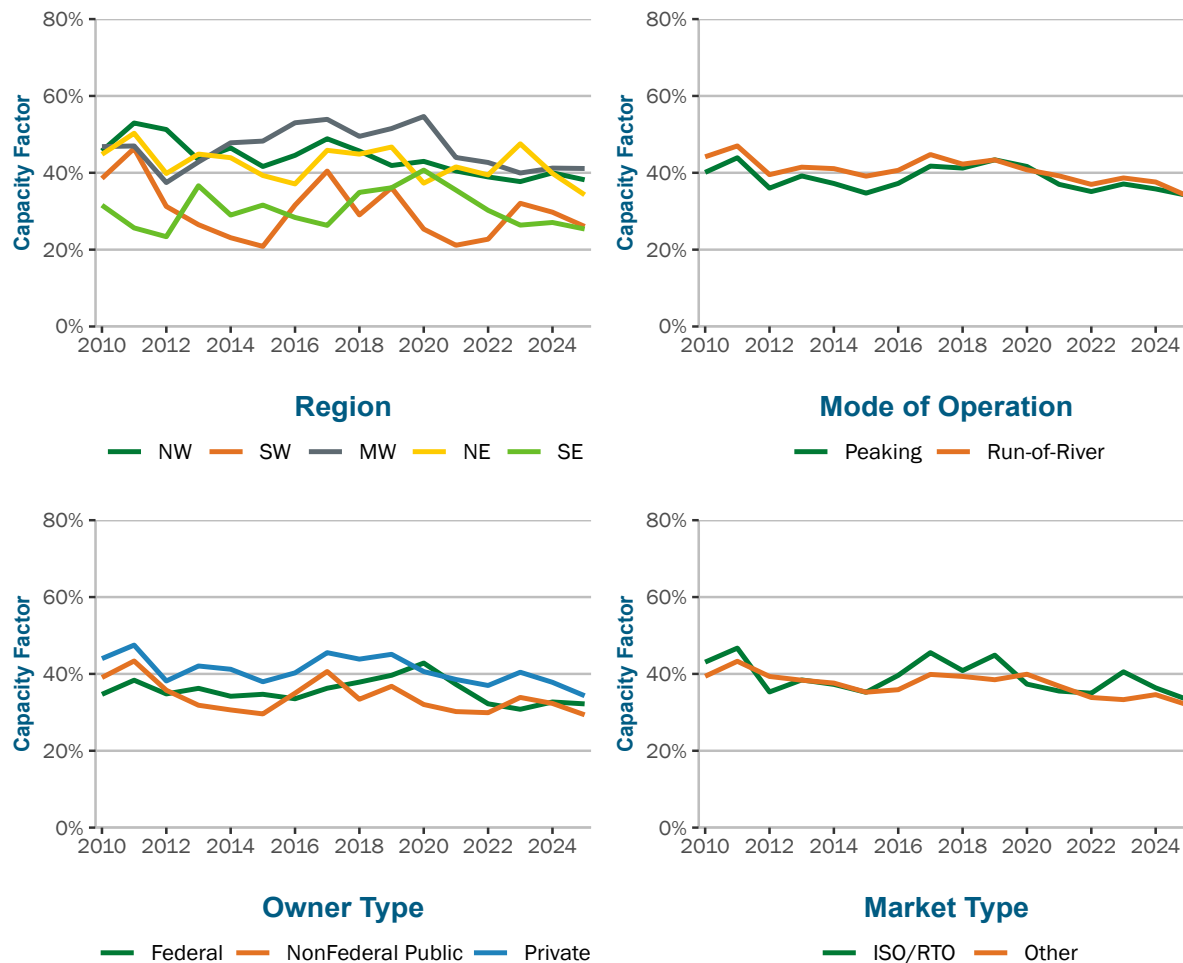


Figure 46. Annual average hydropower capacity factor by region, mode of operation, owner type, and market type

Source: ORNL EHA Capacity Factor Database, 2026; ORNL EHA Plant Database, 2026

Note: The regions shown in this plot are the same as for the maps in Figure 8, Figure 13, and Figure 15. The capacity factor values for 2025 are preliminary because they are based on plant-level capacity and generation data from the Early Release versions of EIA Form 860 and EIA Form 923, respectively.

Figure 46 shows how average capacity factor (not adjusted by capacity) trends differ for various segments of the U.S. hydropower fleet. Region is the most influential characteristic for average capacity factor trends. Average capacity factor is higher for the northern latitude U.S. regions than for the Southwest and Southeast. For the Midwest, Northeast, and Northwest, average capacity factor has been greater than 50% at least one year from 2010 to 2025 and rarely dropped below 40%. In the Southwest and Southeast, average capacity factor is lower and its range wider (from 20% to 40%). For the 2023–2025 period, average capacity factor ranged from 26% in the Southeast to 41% in the Midwest.

All regions contain a mixture of peaking and run-of-river facilities. When the fleet is segmented between those two categories, the average capacity factor is similar for both because it is averaging the regional differences.⁷⁰ From 2010 to 2017, the average capacity factor for run-of-river facilities was typically three percentage points higher than for peaking facilities, but the difference has narrowed further from 2018 and was less than one percentage point in multiple years since then. If the 90th percentiles are compared instead of the average, they are on average six percentage points higher for run-of-river plants

⁷⁰ For the operation mode categories in Figure 46, plants with Reregulating and Intermediate Peaking modes of operation are assigned to the Peaking category.

than peaking plants in 2010–2022 and seven percentage points higher in 2023–2025 (i.e., capacity factors for the 10% of run-of-river plants with highest capacity factors are greater than for the 10% of peaking plants with highest capacity factors).

By owner type, average capacity factor was highest for plants with private owners (investor-owned utilities, wholesale marketer, and private non-utilities) and lowest for plants owned by publicly owned utilities. The difference between the average capacity factors for these two fleet segments has averaged seven percentage points in 2010–2022 and six percentage points in 2023–2025. Publicly owned utilities own hydropower primarily in three regions: Northwest (9.2 GW), Southwest (4.8 GW), and Northeast (3.7 GW). The trend in average capacity factor for this segment of the fleet replicates some of the patterns for those regions (e.g., large increase in 2017). In most years from 2010 to 2025, the average capacity factor of the federal fleet has been close to that for plants owned by publicly owned utilities. Plants owned by private entities are more likely to be connected to dams where the primary or only purpose is power production, which partly explains the higher capacity factor. In contrast, hydropower plants owned by public entities are often connected to large reservoirs managed for multiple uses (e.g., flood control, irrigation, navigation) where hydropower production is not the primary purpose.

Finally, the average capacity factor has not been consistently different for hydropower plants in an ISO/RTO versus the rest of BAs. For the years when they differed, the segment of the fleet operating in an ISO/RTO displayed a higher capacity factor. One hypothesis to explore was whether hydropower plants in organized wholesale markets had higher average capacity factors in years with higher prices. In the past five years, Figure 35 shows that all ISO/RTO markets had a price spike in 2022. The average capacity factor for plants in ISO/RTO regions did not increase that year. A limitation of the classification shown in Figure 46⁷¹ is that it is based on the geographic location of the plants rather than actual participation in an ISO/RTO market.

5.5 AVAILABILITY FACTORS (2010–2024)

In 2022–2024, the availability factor for U.S. hydropower units was 78% for small units, 83% for medium units, and 79% for large units. For large units, it has remained steady at ~80% since 2010. For small and medium units, it has trended slightly downwards (from 87% to 82% for medium units and from 84% to 75% for small units). Availability factor has continued to be lower in WECC than in other regions. Both hydropower and PSH units have their highest average availability factor in the summer months (85% for hydropower units, 92% for PSH units).

For dispatchable electricity generation assets such as hydropower and PSH plants, availability factor (i.e., the percentage of hours when its turbine-generator units are available to generate power) is an important performance metric.⁷¹ When available, a hydropower unit may be synchronized to the grid generating power (unit service hours), synchronized to the grid but not generating power (condensing hours), or ready to synchronize to the grid if the system operator sends a dispatch order (reserve shutdown hours). Outages that cause units to be unavailable can be either planned or forced. Data on the fraction of hours that hydropower units spend in each of the available and unavailable operational modes provides a rich picture of hydropower operations that is an important complement to the generation and capacity factor data presented in Section 5.2 and Section 5.3.

Unlike generation data, submitted by all electricity generation plants with nameplate capacity greater than 1 megawatt to EIA at least annually and published along with plant details, data on availability factors or the breakdown of available and unavailable hours into finer subcategories are much more limited. Quarterly submissions on performance metrics to NERC were voluntary until 2011. They became mandatory for nuclear, hydropower, and fossil fuel units with nameplate capacities ≥ 50 MW in 2012 and the mandatory

⁷¹ “Dispatchability refers to the ability of a resource to turn on or off, or increase or decrease its power output, on demand during normal operating conditions”. (Sonaike et al., 2025)

reporting threshold was lowered to 20 MW for those types of units in 2013.⁷² NERC releases anonymized versions of the data provided in those submissions. Figure 61 and Figure 62 in the Appendix show the percentage of U.S. hydropower units reporting to NERC each year from 2010 to 2024. Since the wider mandatory requirements started in 2013, the average percentage of hydropower units reporting to NERC is 20% for small units (≤ 10 MW), 89% for medium units (>10 MW–100 MW), and 90% for large units (> 100 MW).

Figure 47 shows the trends in availability factor for hydropower units reporting to NERC, categorized by unit size. The average availability factor in 2022–2024 (the three new data points since the previous edition of the report) was 78% for small units, 83% for medium units, and 79% for large units. The average availability factor has remained steady at $\sim 80\%$ for large units since 2010 but decreased by three percentage points for small units and by two percentage points for medium units relative to 2010–2021.

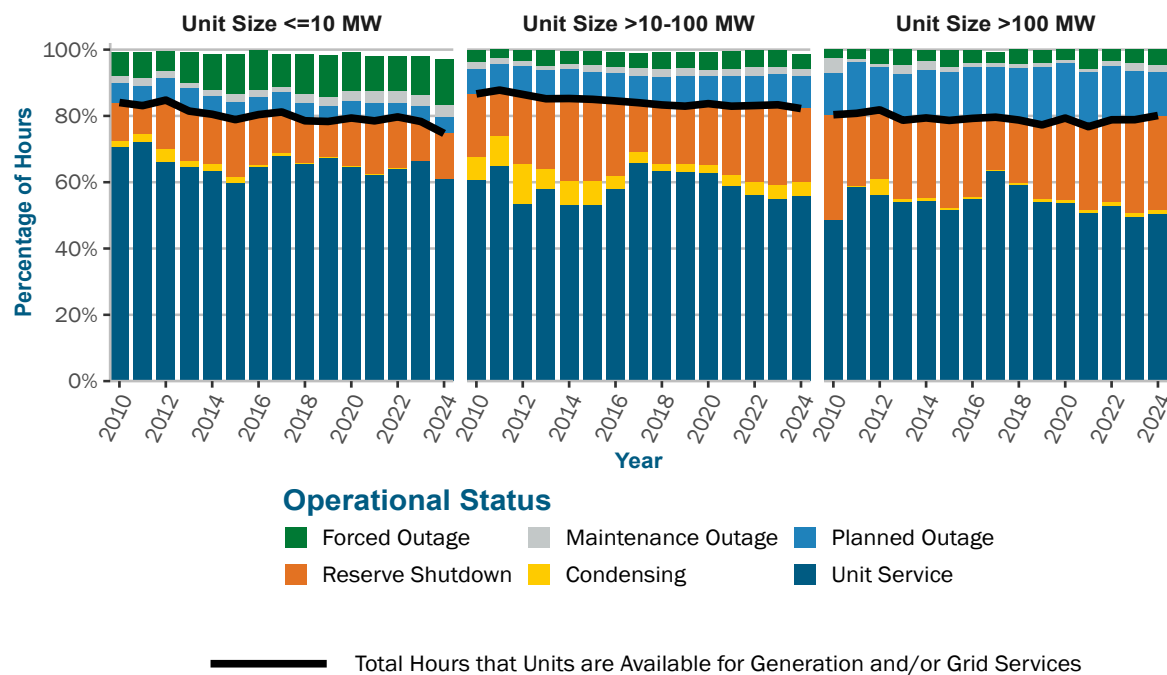


Figure 47. Hourly breakdown of hydropower operational status (average, by unit size class, for units reporting to NERC Generating Availability Data System (GADS))

Source: NERC pc-GAR

Note: Operation and outage state definitions from the NERC Glossary of Terms: Forced Outage (unplanned component failure or other conditions that require the unit to be removed from service immediately, within six hours or before the next weekend); Maintenance Outage (unit removed from service to perform work on specific components that can be deferred beyond the end of the next weekend but not until the next planned outage); Planned Outage (unit removed from service to perform work on specific components that is scheduled well in advance and has a predetermined start date and duration); Reserve Shutdown (a state in which the unit was available for service but not electrically connected to the transmission system for economic reasons); Pumping Hours (hours the turbine-generator operated as a pump/motor); Condensing (units operated in synchronous mode), and Unit Service Hours (number of hours synchronized to the grid).

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During the hours that they are available, the most typical operational status for hydropower units is Unit Service (i.e., hours in which the units are synchronized to the grid and are generating electricity). The average fraction of Unit Service hours in 2022–2024 was 64% for small units, 56% for medium units, and 51% for large units. For all size categories, the fraction of hours spent in Unit Service status

⁷² It is also mandatory for wind plants with total installed capacity ≥ 75 MW commissioned since 2005 and for solar plants commissioned since 2010 with total installed capacity ≥ 20 MW.

decreased in 2022–2024 relative to 2010–2021 (by two percentage points for small units and by four percentage points for the other two size categories). Small units tend to spend more hours generating than the other size categories because a higher share of them are run-of-river plants with limited or no storage capacity. The percentage of hours in Unit Service status is greater than the capacity factors presented in Section 5.4, indicating that units are typically not generating at their maximum rated capacity.

During hours spent in Condensing mode, hydropower units spin air and contribute inertia to the system—a non-remunerated service that nonetheless plays an important role in maintaining frequency stability. Standing in condensing mode is also a way to avoid unit restarts over short periods. Medium-sized units spent the highest average fraction of hours in Condensing mode (4% of hours in 2022–2024; 5% in 2010–2021) among all size categories. For fraction of hours spent in Condensing mode, the average is not a very informative metric. Out of the 1,053 mid-sized units reporting to NERC in 2024, 910 were not in condensing mode at all but 28 units spent more than half the hours in the year in that status.

The average percentage of hours spent in Reserve Shutdown mode (i.e., available but offline) in 2022–2024 was 14% for small units (same as in 2010–2021), 23% for medium units (up from 20% in 2010–2021), and 27% for large units (up from 23% in 2010–2021). Hydropower unit owners receive capacity payments that remunerate units for standing ready (especially during peak load periods) as they do in Reserve Shutdown mode. Additionally, hydropower units may contribute to non-spinning reserves (an ancillary service in ISO/RTO markets) while they are in that operational status. Part of the increase in reserve shutdown hours may be attributable to greater shares of variable renewable generation capacity. For instance, in regions with high shares of solar generation, high solar output around midday may cause hydropower units to shut down during hours in which they would typically have been generating until recent years.

Within the fraction of hours in which units are unavailable, the breakdown between planned and forced outages varies significantly across unit sizes. Figure 47 indicates positive correlation between the length of planned (or maintenance) outages and the size of units as well as a trade-off between number of hours spent in planned outages versus forced outages. For small units, the average percentage of hours in forced outage in 2022–2024 was 12% (up from 10% in 2010–2021). For medium units, forced outage hours averaged 5% in the three most recent years of data (up from 4% in 2010–2021). For large units, forced outage hours averaged 4% in both subperiods. Like for Condensing mode, forced outage status tends to be a rare status for most units but a few units with long-duration outages greatly influence the average. In 2024, 37 of the 173 large units reporting to NERC spent zero hours in forced outage status, the median number of forced outage hours was 18 (i.e., half the units spent less than one day offline for unforeseen reasons), and three units spent more than half the year in a forced outage.

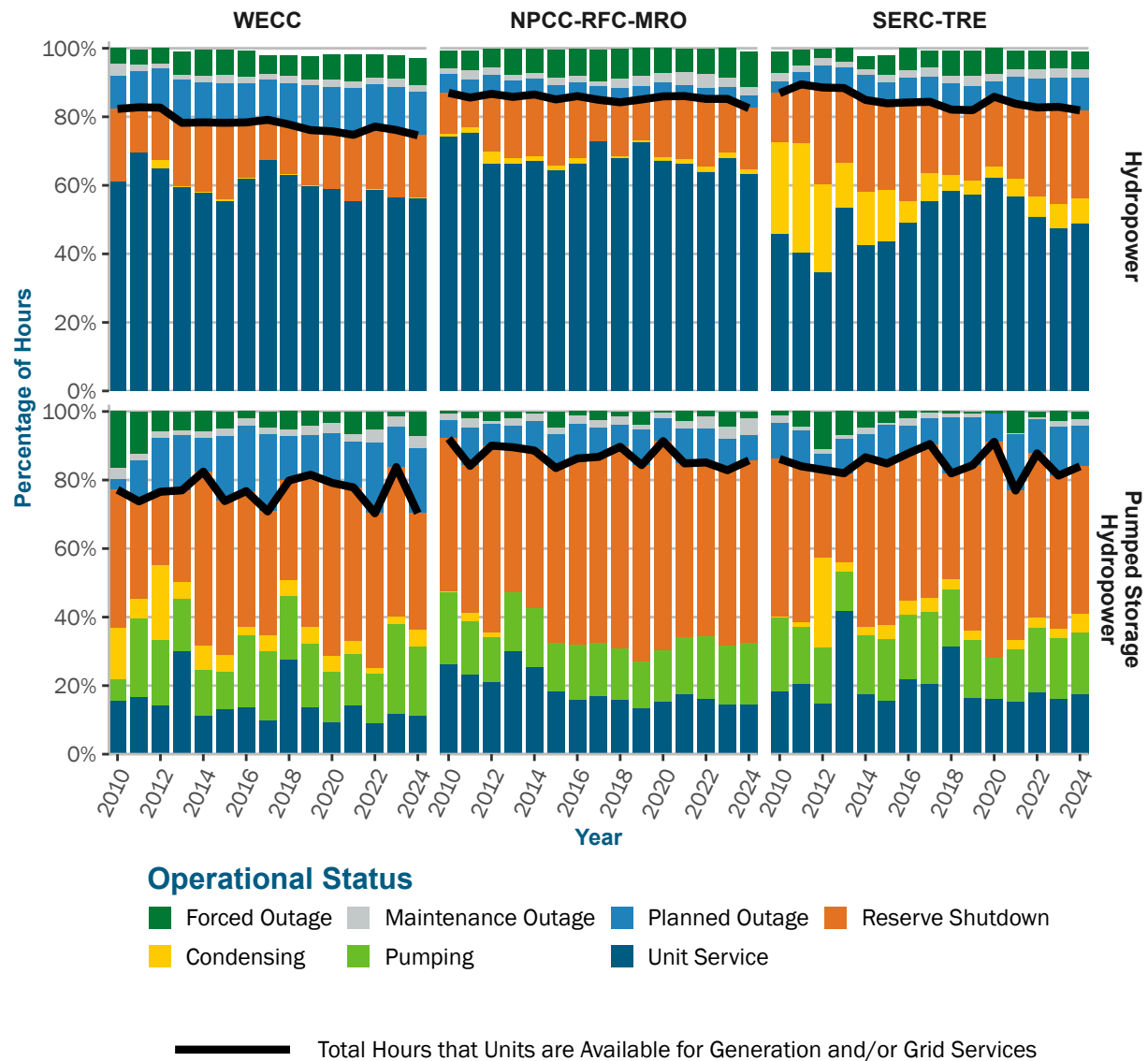


Figure 48. Hourly breakdown of hydropower and PSH operational status (average, by NERC region groupings, for units reporting to NERC GADS)

Source: NERC pc-GAR

Note: Operation and outage state definitions are provided in the note for Figure 48. The six NERC regional entities (see map in Figure 49) are: Western Electricity Coordinating Council (WECC), Midwest Reliability Organization (MRO), Texas Regional Entity (TRE), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), and Southeastern Electric Reliability Council (SERC). Data are presented for groupings of multiple regions because pc-GAR does not allow extracting data for most single regions. Data in this plot includes only units in the U.S. portion of NERC regions.

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Figure 48 organizes the information shown in Figure 47 by NERC region (see map of NERC regions in Figure 49) and unit type (hydropower versus PSH) instead of unit size. For hydropower, it illustrates significant regional differences. First, average availability factor is lower in WECC (76% in 2022–2024) than in the other two regions groupings (84% for NPCC-RFC-MRO and 82% for SERC-TRE). For all three regional groupings, average availability factor was lower in 2022–2024 than in 2010–2021 (by three percentage points in WECC and SERC-TRE, by one percentage point in NPCC-RFC-MRO). The lower availability factor of units in WECC results from longer time spent on planned outage status. On average, units in WECC spent 12% of hours in planned outages in 2022–2024 (versus 3% for NPCC-RFC-MRO and 9% for SERC-TRE). Second, units in SERC-TRE account for most of the hours in Condensing mode. Third, the average percentage of hours in Unit Service status in SERC-TRE in 2022–2024 is significantly lower (49%) than in the other regional groupings (57% for WECC and 65% for NPCC-RFC-MRO). Some of the regional findings can be traced back to differences in fleet attributes. For example, the NPCC-RFC-MRO panel looks very similar to the small units panel in Figure 1 because the average capacity of units in those regions (6 MW) is smaller than in the other groupings (19 MW for SERC-TRE, 27 MW for WECC). Additionally, SERC has a higher share of peaking units than other NERC regions. Peaking units tend to have lower capacity factors which contribute to the lower percentage of hours spent in Unit Service status in SERC-TRE relative to the other regional groupings.⁷³

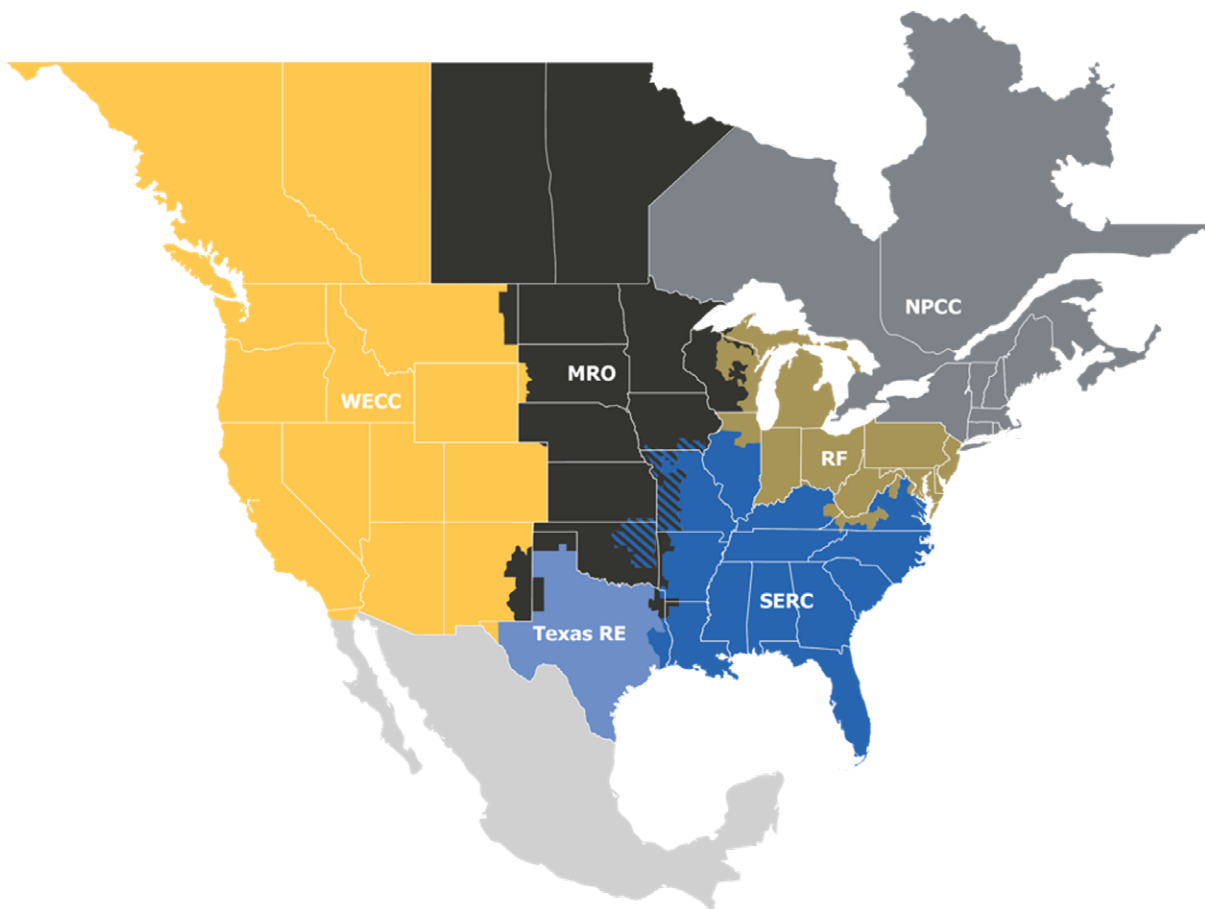


Figure 49. NERC regional entities

Source: [nerc.com/who-we-are/key-players](https://www.nerc.com/who-we-are/key-players)

⁷³ Texas has few hydropower plants. Of the 440 hydropower units in the SERC-TRE regional grouping reporting to NERC, only eight are in TRE. Splits are similar in other years. Therefore, summary values presented in Figure 48 for SERC-TRE are dominated by SERC units.

The PSH panels in Figure 48 include a seventh operational status for the hours spent in pumping mode (i.e., consuming energy to move water from the lower reservoir to the upper reservoir). The percentage of hours in Unit Service status in 2022–2024 was 11% for units in WECC (down from 16% in 2010–2021), 15% for units in NPCC-RFC-MRO regions (down from 20% in 2010–2021), and 17% for the SERC and TRE regions (down from 21% in 2010–2021). In every region, the most common operational status for PSH units is Reserve Shutdown. On average, units in NCPCC-RFC-MRO spent 52% of hours in Reserve Shutdown in 2022–2024 (up from 51% in 2010–2021). For WECC and SERC-TRE units, the average percentage of Reserve Shutdown hours in those three years were 41% (up from 38% in 2010–2021) and 45% (up from 43% in 2010–2021), respectively. PSH units are peaking units. Since they generate for a small percentage of hours in the year, it is crucial for their economic viability that they generate during high-value periods. Moreover, capacity payments rewarding PSH units for the large number of hours in which they stand ready in Reserve Shutdown status should also be an important component of total revenue for PSH.

PSH units spend on average more hours in planned outages (9% in NPCC-RFC-MRO, 12% in SERC-TRE, and 17% in WECC in 2022–2024) than hydropower units in all regions. This result is partly correlated with the larger average size of PSH units but also with their mode of operation. The much larger number of unit starts they perform per year relative to hydropower units of any size (see Section 5.7) results in cumulative wear and tear that may require more and/or longer outages to address. Standing in condensing mode (i.e., synchronized to the grid without generating power) is a way to reduce the number of starts and related wear and tear. PSH units stood in condensing mode for 3% of hours in WECC and 4% of hours in SERC-TRE regions in 2022–2024.

Figure 50 shows that the capacity-weighted average availability factor for U.S. hydropower and PSH units varies substantially across seasons. Plant owners try to maximize availability during the seasons (winter and summer) in which electricity demand and wholesale prices are highest. As a result, planned outages are typically scheduled during low demand seasons (spring and fall). Spring and fall also tend to have milder weather conditions better suited for some of the outdoors, on-site work that may need to be performed during a planned outage. Both hydropower and PSH units have consistently achieved their highest availability factors in the summer months. For PSH units, summer average availability has been 90% or greater every year since 2014; it averaged 92% in 2022–2024. For winter, the average availability factor of PSH units reached nearly 90% in 2019 but has trended downwards since then and was 81% in 2024. Planned and maintenance outages result in lower average availability factors in spring (73% in 2022–2024) and fall (75% in 2022–2024).

The main difference between the seasonal availability patterns of hydropower units relative to PSH is that their spring availability has typically been as high (or higher) than their winter availability. This is due to spring being a wet season (e.g., high runoff due to snowmelt in the Pacific Northwest) and a significant fraction of units operating in run-of-river mode with no ability to store that water for use during higher value seasons. The average 2022–2024 availability factors for hydropower units were 85% for summer, 82% for winter, 82% for spring, and 78% for fall. These four averages are very similar to the ones for 2010–2021.

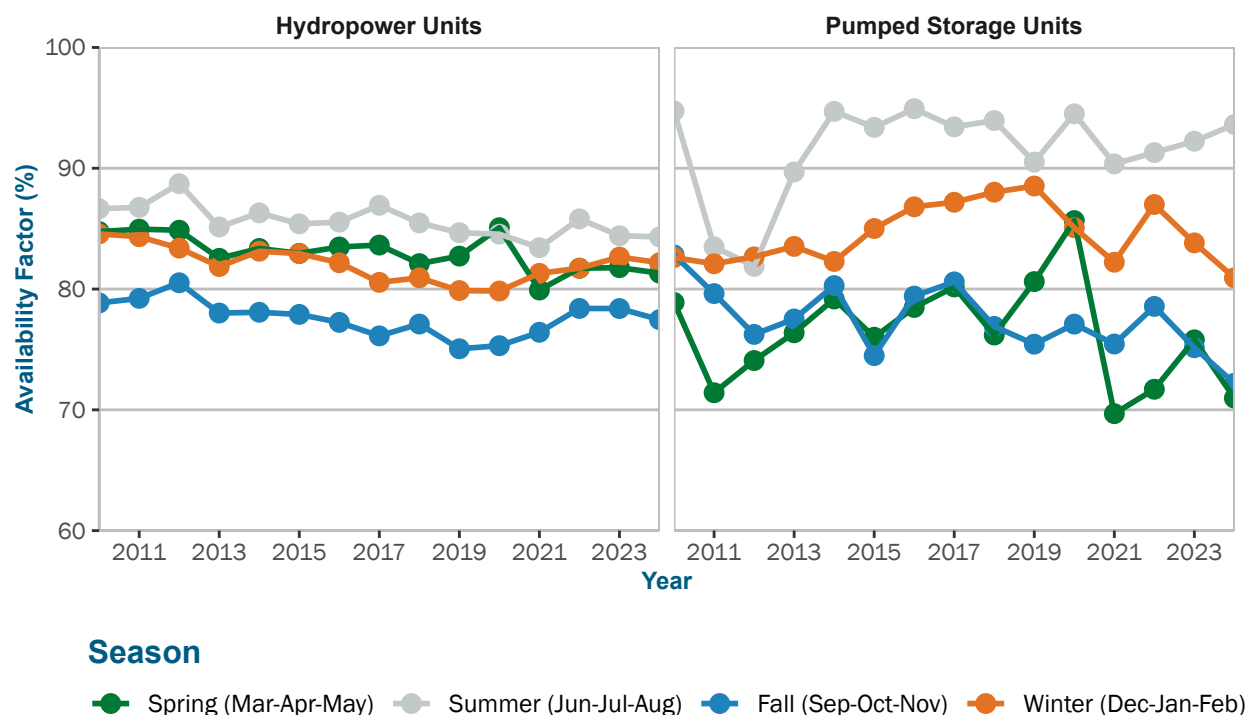


Figure 50. Capacity-weighted average hydropower and PSH unit availability factor by season (for units reporting to NERC GADS)

Source: NERC pc-GAR

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5.6 FORCED OUTAGE CAUSES (2013–2024)

Annual generation lost due to forced outages in 2022–2024 averaged 31 TWh, a 7% increase relative to the 2010–2021 average. WECC accounts for 53% of installed hydropower and PSH capacity and 66% of generation lost to forced outages in 2022–2024. Forced outages whose primary cause related to turbine or generator component failures accounted for two thirds of generation losses.

Starting in 2013, NERC publishes anonymized data on forced outage (“unplanned component failure or other conditions that require the unit to be removed from service immediately, within six hours, or before the next weekend”) events including their primary cause, the region in which they happened, the capacity of units affected, and lost electricity generation.^{74,75} The cost of a forced outage depends on how much capacity it takes offline, for how long, and in which season. Lost generation volume summarizes the first of those two factors. Figure 51 shows potential generation losses due to forced outages by NERC region and primary cause of the outage from 2013 to 2024.

⁷⁴ The dataset also includes information on unit deratings which is excluded from the analysis in this section. Generation lost due to deratings added up to 4.2 TWh in 2024.

⁷⁵ Some of the NERC regions include territory in both the United States and Canada and cause code report information does not allow to separate out only U.S. units.

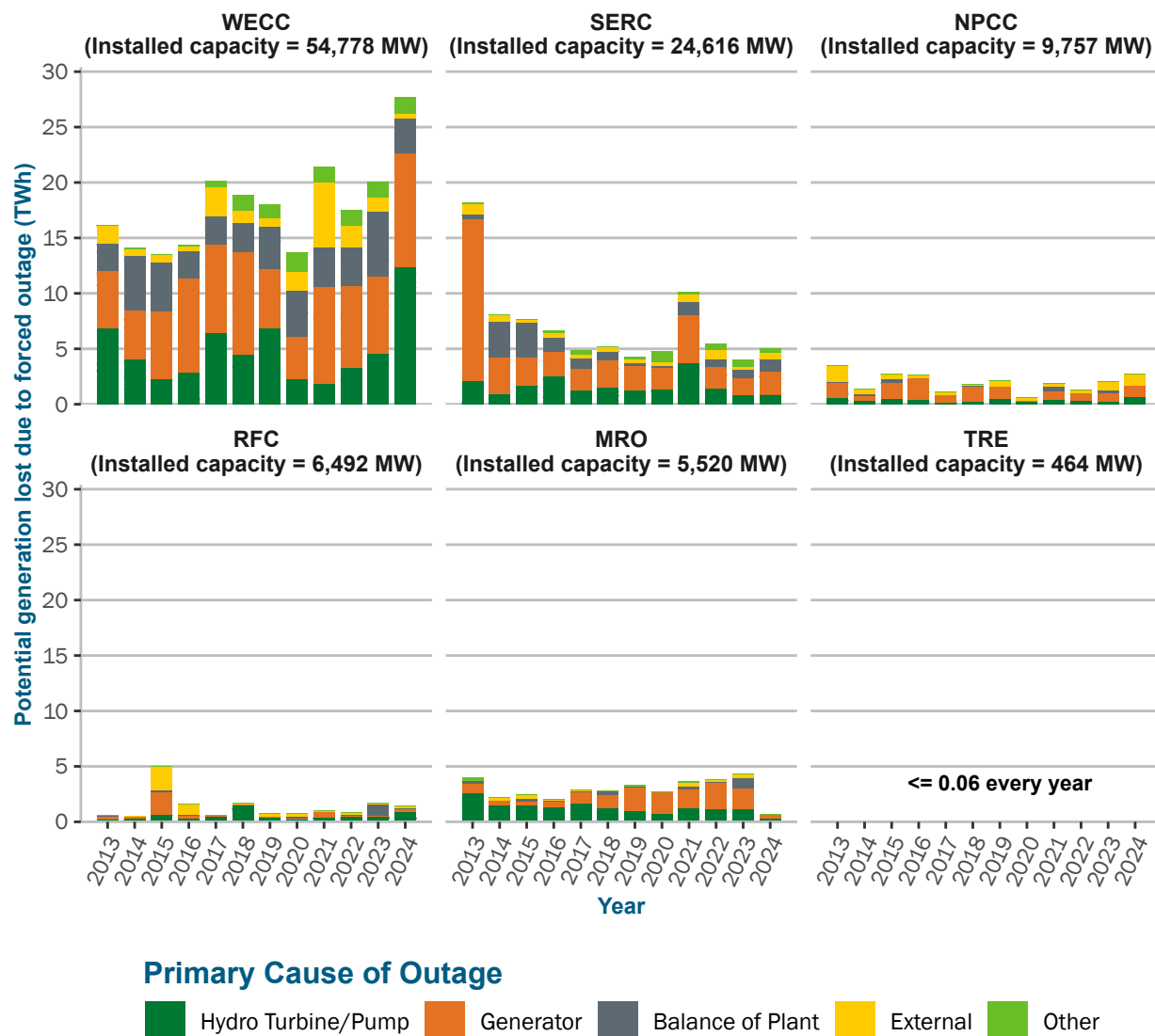


Figure 51. Potential generation lost due to forced outages by NERC region and primary cause of outage

Source: NERC GADS Cause Code Reports

Notes: The “External” category includes outages caused by natural hazards (flood, drought, fire, lightning, earthquake, tornado, hurricane, storms) or economic reasons (lack of water, water supply problems, labor strikes) as well as other miscellaneous external reasons (transmission system problems, operator training, public safety/river rescue). The “Other” category includes outages caused by performance, personnel errors, or regulatory/safety/environmental reasons.

Annual generation losses in 2022–2024 averaged 31 TWh (in U.S. and Canada), enough electricity to power approximately 2.9 million U.S. households.⁷⁶ These annual average losses represent a 7% increase relative to 2013–2021. WECC accounts for 53% of installed hydropower capacity and 66% of generation losses due to forced outages in 2022–2024. SERC ranks second in installed capacity (24%) and second in generation losses (15%). The remaining generation losses are distributed between MRO (9% of generation losses and 5% of capacity), NPCC (6% of generation losses and 9% of capacity), and RFC (4% of generation losses and 6% of capacity). Finally, the fleet at TRE represents 0.4% of installed capacity and less than 0.01% of generation losses.

⁷⁶ [eia.gov/tools/faqs/faq.php?id=97&t=3](https://www.eia.gov/tools/faqs/faq.php?id=97&t=3)

From 2013 to 2024, failures in generator components accounted on average for 42% of generation lost due to forced outages and failures in turbine components were responsible for an additional 27%. NERC offers more detailed causes within each of those categories. Failures related to stator windings and bearings entailed the greatest generation losses within the generators and turbines categories, respectively. Outages whose main cause lies in balance of plant components added up to 18% of generation losses of which 40% were related to the main transformer. Forced outages with main causes in the External category produced 10% of generation losses. Within that category, one third of generation losses arose from outages due to natural hazards (e.g., flooding, drought, hurricanes, tornadoes, fires, or storms) and another third can be traced back to outages resulting from lack of water. Eighty-nine percentage of generation lost due to outages caused by lack of water over 2013–2024 corresponded to events in two NERC regions: WECC (63%) and NPCC (26%). Finally, forced outages with causes in the “Other” category represented 4% of generation losses.

The median duration of forced outages in 2013–2024 was 4 hours (versus 6.1 hours in 2022–2024). Distinguishing by outage cause, the median duration is longest for the “Other” category (6.75 hours). For the rest of cause categories, the median duration ranged between 2 hours and 4 hours. A few long outages on large units can represent a large fraction of total generation lost. For example, multiple failures lasting one month or longer related to the bearing oil system of one or several 588-MW turbine units were responsible for the much higher volume of turbine-related generation lost in WECC in 2024 relative to the rest of years shown in Figure 5.

Forced outages are more costly to plant owners in summer or winter than the rest of the year because electricity prices are highest in those two seasons making the revenue forgone by units being unavailable also greater. In 2022–2024, the summer and winter shares of lost generation due to forced outages added up to 70%: 19% in summer (down from 21% in 2013–2021) and 51% in winter (same as in 2013–2021).. More frequent planned outages could prevent some forced outages by proactively identifying and correcting issues before they escalate into unplanned events. Even if total outage hours were unchanged, simply shifting hours from forced to planned, the cost of unavailability would likely be lower, since planned outages can be scheduled during periods of lower electricity demand and prices.

5.7 RELIABILITY AND FLEXIBILITY CONTRIBUTIONS OF HYDROPOWER AND PSH TO THE ELECTRIC SYSTEM

As discussed in Chapter 1, the mode of operation of U.S. hydropower plants varies widely, from baseload generation to peaking plants. In aggregate, the U.S. hydropower and PSH fleets contribute both reliability and flexibility to the U.S. electric grid.

Reliability contribution of U.S. hydropower and PSH

With higher availability factors than the annual average during peak demand seasons, hydropower and PSH demonstrate important contribution to grid reliability. In a set of ten U.S. BAs, hydropower and PSH displayed consistent ability to increase generation (relative to average) during the top 100 net load hours in 2021–2025. The average generation increase was greater than 20% in five of the ten BAs. BAs with high shares of peaking hydropower and PSH tend to show larger average increases.

To ensure that generation capacity is adequate to meet expected load forecasts, system operators need to translate nameplate capacity values into expected capacity available during the hours of the year when demand is expected to peak. The metric that summarizes the contribution of a given generating resource during peak hours is its effective load carrying capability (ELCC). ELCC is increasingly used in resource adequacy planning and to allocate capacity revenue in those ISO/RTOs that have capacity markets.

Figure 50 shows that hydropower and PSH maintain higher availability factors in the seasons when electricity demand typically peaks (summer and winter). The ability to maintain a high availability factor at those times is indicative of the contribution hydropower makes to reliability. Figure 52 shows how much hydropower and PSH were able to increase their generation—relative to the average for the same combination of year, season, and hour of the day to control for hydrologic conditions and demand patterns and trends—during the 100 hours with the highest net loads in 2021–2025. Net load is electricity demand minus wind and solar generation; it is the portion of demand that hydropower contributes to supply. The ten panels in Figure 52 cover the seven ISO/RTO markets in the U.S. plus four other BAs with large hydropower fleets in different regions of the country: BPA in the Northwest, TVA in the Southeast, and a hypothetical combination of the Western Area Power Administration Colorado Missouri (WACM) and Western Area Power Administration Lower Colorado (WALC) BA areas along the front range and into the Southwest.⁷⁷ Combining the data for the WACM and WALC footprints for purposes of this analysis captures the hydropower facilities along both the upper and lower Colorado River.

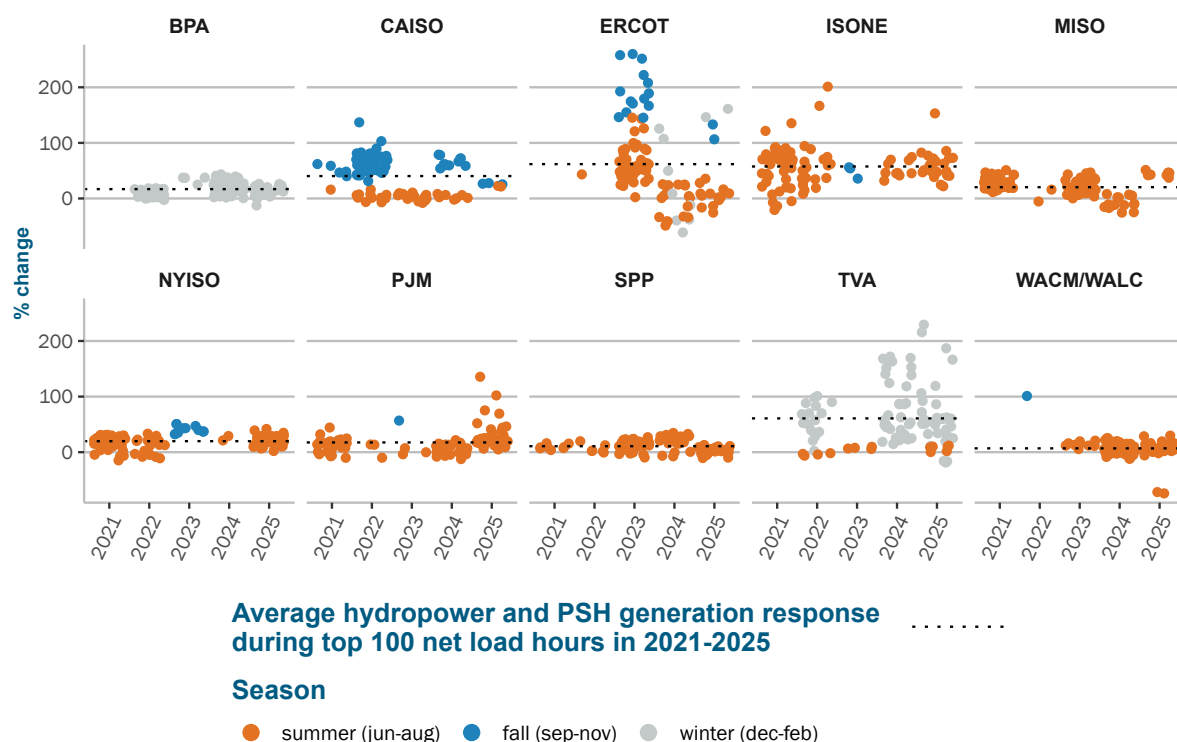


Figure 52. Percentage change in hydropower and PSH generation relative to the average during the top 100 net load hours in 2021–2025, by BA

Source: EIA Form 930

Note: A map of U.S. balancing authorities is available at eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

⁷⁷ WAPA’s Rocky Mountain and Colorado River Storage Project regions are in the footprint of what was the WACM balancing authority area. As of April 1, 2026, WACM merged with the Western Area Upper Great Plains West (WAUW) BA into the new Southwest Power Pool West BA area. WAPA’s Desert Southwest Region is in the WALC BA area, and WAPA is the BA.

For each of the footprints in the graph, Figure 52 includes 100 data points and a dotted line summarizing the average hydropower and PSH generation response across the 100 hours. The season when the highest net load hours typically take place varies by BA. It is typically winter for BPA and TVA. For the rest of BAs, the peak season is summer, defined here as June-August. A significant fraction of the top 100 net load hours took place in fall for CAISO (61%) and ERCOT (16%). All the top net load hours in the fall occur in September suggesting that, for those two BAs, September should be treated as part of the summer season. In 89.1% of the hours depicted in Figure 52, hydropower (including PSH) was able to increase its generation during the highest net load hours relative to the average for that year-season-hour combination. The average response was greater than 20% for five of the ten BAs; it ranged from 7% in WACM/WALC to 62% in ERCOT.

The generation responses summarized in Figure 52 combine reliability and flexibility attributes of each of the fleets. For a hydropower unit to increase its output at specific hours, it needs to be available and operating at less than its nameplate capacity. Fleets with a high share of hydropower plants that operate in peaking mode (as well as PSH) are likely to be able to increase their production the most relative to average values because those types of plants tend to operate at lower capacity factors than run-of-river plants during normal system conditions. For instance, 60% of hydropower in TVA operates in peaking mode and the TVA BA also has a large PSH facility (Raccoon Mountain, 1.7 GW). The average generation of the TVA fleet was 59% higher in the top 100 net load hours than the average for the same year, season, and hour of the day. In contrast, BPA has a very large fleet, but it operates more as a baseload resource under average conditions. Less than half (44%) of the BPA fleet operates in peaking or intermediate peaking mode and PSH capacity is very small (0.3 GW).⁷⁸ The average hydropower generation during the top 100 net load hours in the BPA BA was 17% higher than the average for the same year, season, and hour of the day. In the Southwest, WAPA markets hydropower from Hoover Dam (in WALC) and Glen Canyon (in WACM)—large plants that operate in intermediate peaking mode—among other hydropower plants. Even though this region of the country has experienced severe drought conditions during 2021–2025, these facilities still managed to increase their output during top net load hours in response to customer demand. The average increase in generation by the fleet in the combined WACM/WALC BA over the 100 top net load hours was 7%. In the ISONE BA, three PSH plants with combined capacity of 1.9 GW are a key factor for the large average increase in hydropower generation during top net load hours (58%). The BA with the largest PSH fleet is PJM but its average increase in hydropower generation during top net load hours is among the lowest in Figure 52 (18%). One factor explaining this result is that PSH plants in the PJM BA operate at a higher capacity factor than those in ISONE or TVA. If their utilization on a typical day is higher, they have less room to respond during top net load hours.

When calculating generation volume changes (instead of percentage changes) during the top net load hours, the largest average increase is for the BPA BA (1,403 MW) followed by TVA (1,370 MW) and CAISO (1,113 MW). ERCOT has the smallest hydropower capacity installed out of the ten BAs shown in Figure 52 (20 plants with combined capacity of 562 MW). Although hydropower generation in ERCOT during some of the top net load hours was more than 200% larger than average, it is not a very large generation increase by volume. The largest increase by the ERCOT fleet was 243 MW and the average change was 55 MW.

⁷⁸ An intermediate peaking plant stores limited amounts of water for occasional releases or moderates the intensity of peaking for hydroelectric generation (McManamay and Bevelheimer, 2016).

Extreme weather events are often connected to peak net load hours. During a five-day cold snap in the Northwest in mid-January 2024, BPA managed its resources to maximize availability during peak load hours and played a key role in maintaining grid stability throughout the event.⁷⁹ Coordinated operation of all hydropower facilities in the Federal Columbia River Power System helped deliver substantial increases in generation when it was most needed. System operators increased generation in hydropower projects in the Lower Columbia River while maintaining required water storage levels upstream for spring fish operations. In the days leading to the cold snap, BPA created storage space in the lower Columbia projects. With this strategy, they managed to provide an average of 525 MW of extra generation during the cold snap.⁸⁰

Flexibility contribution of U.S. hydropower and PSH

In 2022–2024, the median number of unit starts per year was 10 for small hydropower units, 25 for medium units, and 69 for large units. PSH units have, by far, the most unit starts (approximately one per day for the median unit). Approximately 10% of PSH units reporting to NERC average two or more starts per day.

The number of starts performed by a turbine-generator unit relates to its flexibility and mode of operation. Units in run-of-river plants typically start a few times per year and generate for long periods of time after each start. In contrast, peaking units start and stop many times and generate only a small number of hours in the year coinciding with periods of peak demand. Figure 53 shows the median number of unit starts (indicated by a dot) and the 10th–90th percentile range by unit type and size from 2010 to 2024.

⁷⁹ Forty-four of the 100 top net load hours in 2021–2025 shown in Figure 52 for BPA correspond to hours from January 12 to January 16, 2024.

⁸⁰ hydro.org/powerhouse/article/how-the-pacific-northwests-federal-hydro-system-powered-through-an-arctic-blast/?utm_medium=email&utm_source=rasa_io&utm_campaign=newsletter

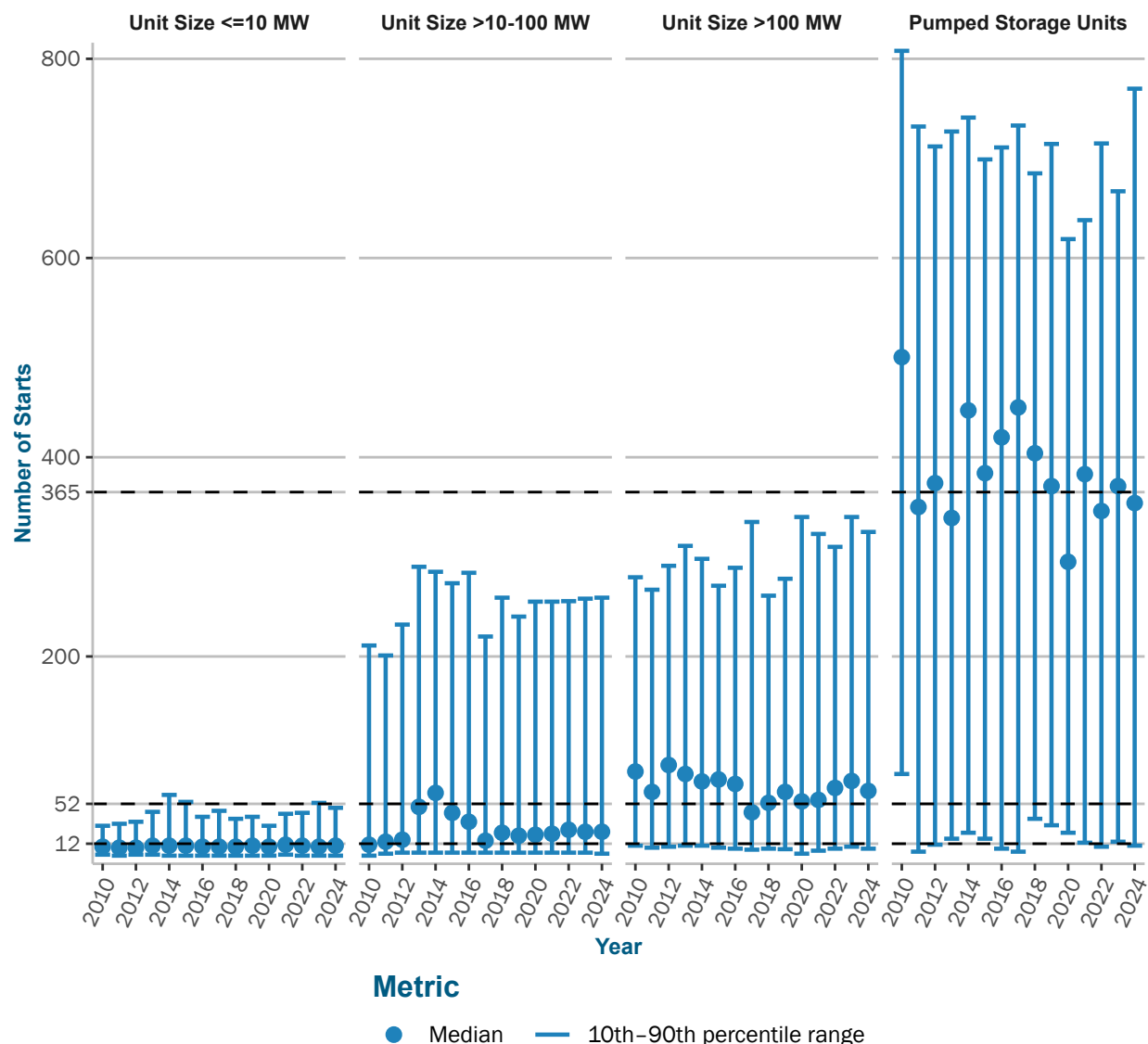


Figure 53. Hydropower and PSH unit start distributions by year, unit type, and unit size (for units reporting to NERC GADS)

Source: NERC pc-GAR

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In 2022–2024, the median number of starts for small units, which are more prevalent in run-of-river plants, was ten (i.e., less than one cycle per month). Median start frequency for small units has been steady since 2010. The ten percent of small units with the greatest number of starts cycled on and off about 52 times per year (i.e., approximately once per week). For medium (>10 MW–100 MW) and large (>100 MW) units, the range of unit starts is much wider. This indicates that these size categories contain both run-of-river and peaking units. Medium units typically started 25 times per year (i.e., approximately once every two weeks) in 2022–2024 but 10% of units in that size category started more than 250 times per year. The median number of starts for large units was 69 but 10% of large units started more than 325 times per year. PSH units differ greatly from the rest in their typical number of starts (357 per year

in 2022–2024). Ten percent of them have been starting on average twice per day (730 starts) during these years.

At the national level, no step change in number of starts is visible in the data from 2010 to 2024 despite a substantial increase in installed variable renewables capacity—from 3.5% in 2010 to 21% in 2024—that could require hydropower to make larger and more frequent output adjustments or starts and stops.⁸¹ Except for PSH units, the median U.S. number of starts in 2022–2024 has been very similar to the median number of starts in 2010–2021. For PSH units, it decreased from 393 to 357 between those two subperiods. However, the 90th percentile (i.e., the minimum number of starts for the 10% of units performing the greatest number of starts) has increased by 30 starts per year for large units and by 7 or 8 starts per year for all other unit sizes and types. Therefore, the peaking units with largest numbers of cycles have increased their number of starts even more in recent years.

⁸¹ By NERC region, variable renewable penetration in 2024 ranged from 10% in RFC to 39% in MRO.

CHAPTER 6. TRENDS IN U.S. HYDROPOWER SUPPLY CHAIN

This chapter describes the manufacturing capabilities of the U.S. hydropower supply chain and identifies components for which domestic procurement options are very limited (Section 6.1). It summarizes recent turbine runner installation activity (Section 6.2) and trends in U.S. hydraulic turbine imports and exports (Section 6.3). Finally, it offers estimates of potential turbine and generator unit demand for modernization of existing facilities and construction of new facilities over the next decade (Section 6.4).

6.1 U.S. HYDROPOWER SUPPLY CHAIN MANUFACTURING CAPABILITIES

The U.S. hydropower supply chain includes 90 companies with domestic manufacturing locations (147 manufacturing locations in 38 states). For large or heavy components, from castings and forgings to turbine runners or generators, domestic manufacturing options are limited.

Disruptions to manufacturing and logistics during the COVID-19 pandemic in the early 2020s underscored the need for improved data to better characterize the U.S. hydropower supply chain. First, project developers and facility owners lack a comprehensive, up-to-date database of U.S. hydropower manufacturing capabilities to inform procurement decisions. Second, greater visibility into the expected demand for major plant components would benefit OEMs in evaluating capacity expansion and manufacturing reshoring decisions. This section summarizes DOE activities that help address data needs identified in recent, in-depth assessments of the hydropower supply chain (Putsche et al., 2024; Uría-Martínez et al., 2022).

Manufacturing capabilities is a topic ORNL sought to address by developing a dataset of companies with domestic manufacturing facilities for production of the following hydropower plant components: castings/forgings, turbines, governors, bearings, generators, exciters, gates, penstocks, valves, trashracks, cranes/hoists, switchgears, and transformers. Figure 54 summarizes the information in the dataset.

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- For generators, company websites do not provide detailed information about the manufacturing process steps that take place domestically. A single domestic facility manufactures generator windings for units greater than 100 MW (Putsche et al., 2024).
- For transformers, 12 of the 17 locations in Figure 54 deliver transformers with ratings larger than 100 MVA.

The bespoke nature of turbine-generator units makes it difficult to determine a useful metric for manufacturing capacity (e.g., number of units they can produce in a year). Additionally, unlike for internationally traded units, no public statistics exist on quantity or value of domestic hydropower turbine manufacturing. Figure 58 in Section 6.3 shows that exported value of hydraulic turbines and parts in the 2020s is substantially lower than in the 2010s. However, without knowing how much value was directed to the domestic fleet, it is not possible to determine the evolution of utilization factor at the domestic manufacturing facilities.

6.2 U.S. HYDROPOWER AND PSH TURBINE INSTALLATIONS

On average, 15 turbine runners were installed in the United States per year in 2020–2025. This number is approximately half the 2010–2019 average and the drop is larger for turbine runners in units with capacities greater than 10 MW (16 per year in the 2010s versus five per year in 2020–2025). Of the 31 units with capacities greater than 10 MW installed in 2020–2025, 27 were supplied by five OEMs. The 58 units with capacities up to 10 MW installed in that same period were manufactured by at least 14 OEMs.

Figure 55 summarizes the trend in annual number of turbine runner installations in 2010–2025. Relative to the version of the plot in the 2023 edition of this report, it contains revisions to 2020–2022 data and three new years of data (2023–2025). Figure 55 shows a drop in installations in the 2020s. The annual average number of turbines installed in 2020–2025 (15) was almost 50% lower than for 2010–2019 (29). Average annual capacity of those new runners was 1.2 GW in the 2010s versus 0.3 GW in 2020–2025. Since the decrease in capacity is larger than the decrease in number of units, the reduction in activity has been more concentrated in runners for larger turbine-generator units (an average of five turbine runners with capacities greater than 10 MW installed per year in 2020–2025 versus 16 in 2010–2019).

The weak installation activity levels in 2023–2025 follow with a lag the decrease in R&U investment in 2020–2022 discussed in the 2023 edition of this report. That drop resulted, at least partly, from the supply chain challenges that arose during the COVID-19 pandemic. However, the drop observed in Figure 55 may also partly be a result of incomplete reporting. Hydropower plant owners are increasingly treating information about procurement decisions as strategic and signing confidentiality agreements with OEMs requiring them not to share project-level information.

The data in Figure 55 confirm that the number of OEMs procuring larger turbine runners is much lower than for smaller units. Of the 31 units with capacities greater than 10 MW installed in 2020–2025, 27 were supplied by one of the five individually-listed OEMs: American Hydro, Andritz, GE Vernova, Toshiba, and Voith.⁸² For the 58 units with capacities up to 10 MW installed in that same period, nine were supplied by one of the five OEMs, and the rest were manufactured by at least nine other OEMs or its manufacturer was unknown.

⁸² These OEMs are the top five by capacity installed in 2010–2025. Three of these OEMs (American Hydro, Andritz, Voith) have manufacturing facilities in the United States. Details on their manufacturing facilities can be found [here](#).

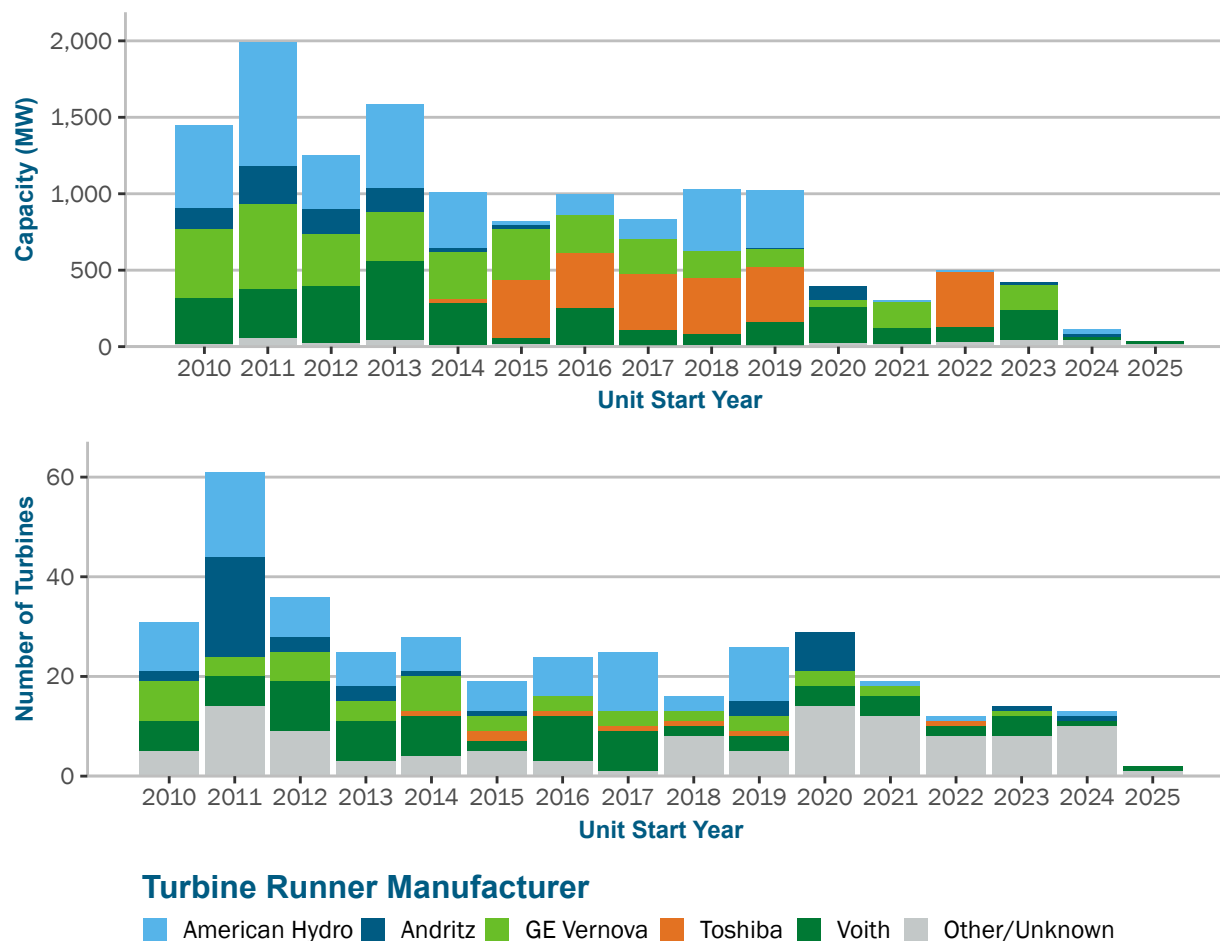


Figure 55. Annual installations of hydropower and PSH turbine runners in the United States by manufacturer

Sources: IIR, EHA Unit database 2025, personal communication with plant owners and OEMs

Note: Mergers and acquisitions have taken place during the period shown in the plot. The OEMs shown are the ones to which each runner is assigned based on current industry structure. For example, GE Vernova purchased Alstom in 2015. Turbine runners manufactured by Alstom from 2010 to 2014 show up as being GE Vernova turbine runners in the plot.

Figure 56 shows the turbine runner shares (by number of units and capacity) installed as part of R&U at existing facilities versus new projects.

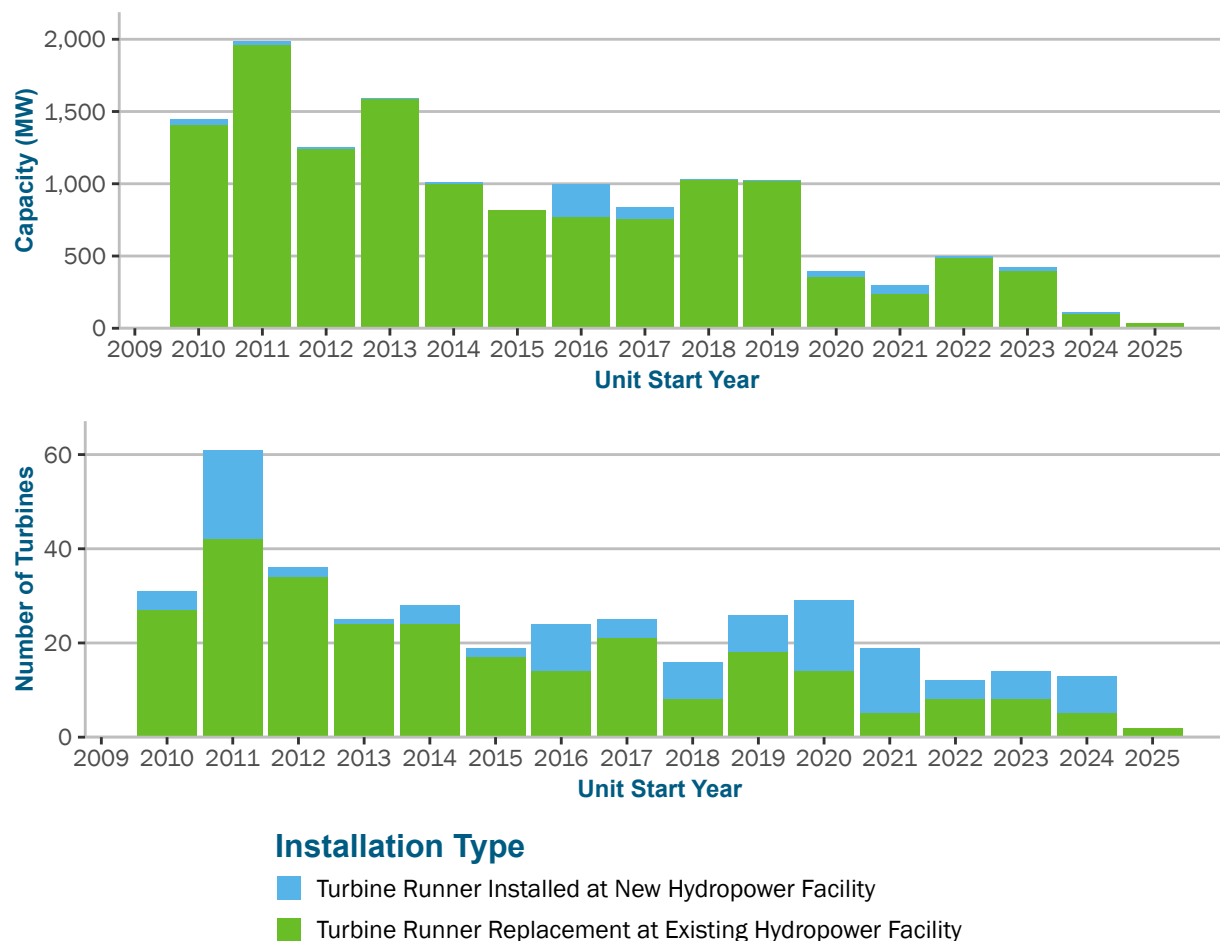


Figure 56. Annual installations of hydropower and PSH turbine runners in the United States at new versus existing facilities

Sources: IIR, EHA Unit database 2025, personal communication with plant owners and OEMs

Over 95% of the capacity of turbine runners installed from 2010 to 2025 were replacements at existing facilities. The total capacity of the 271 units installed at existing facilities is 13.1 GW. A small fraction is incremental capacity rather than a replacement unit with equal capacity as the older unit. The rest of capacity added to the U.S. hydropower fleet since 2010 is from 109 units at new facilities—mostly conduit and NPD retrofits—with a combined capacity of almost 600 MW. The capacity of units installed at new hydropower facilities ranged from 1 kW to 35 MW and their average capacity was 5.5 MW. For replacements at existing facilities, the average turbine capacity was 48.6 MW and the capacity range (0.3 MW–375 MW) was wider than for new units.

Figure 57 segments U.S. turbine runner installations by OEM and turbine type. The most common turbine runner type among units installed from 2010 to 2025 is Francis, both by number of units (183 units, 48% of the total) and capacity (4.6 GW, 55% of the total). The top five OEMs procured 76.5% of Francis runners and 100% of the 54 Francis runners with capacities greater than 30 MW. Kaplan turbine runners accounted for 34% of units installed (130) and 23% of capacity installed (3.2 GW). Voith, Andritz, American Hydro, and GE Vernova procured all the Kaplan runners with capacities greater than 30 MW (32 units). Twenty Pelton turbine runners, typically used in high-head facilities, were installed in 2010–2025. Only one of them had a capacity greater than 30 MW.

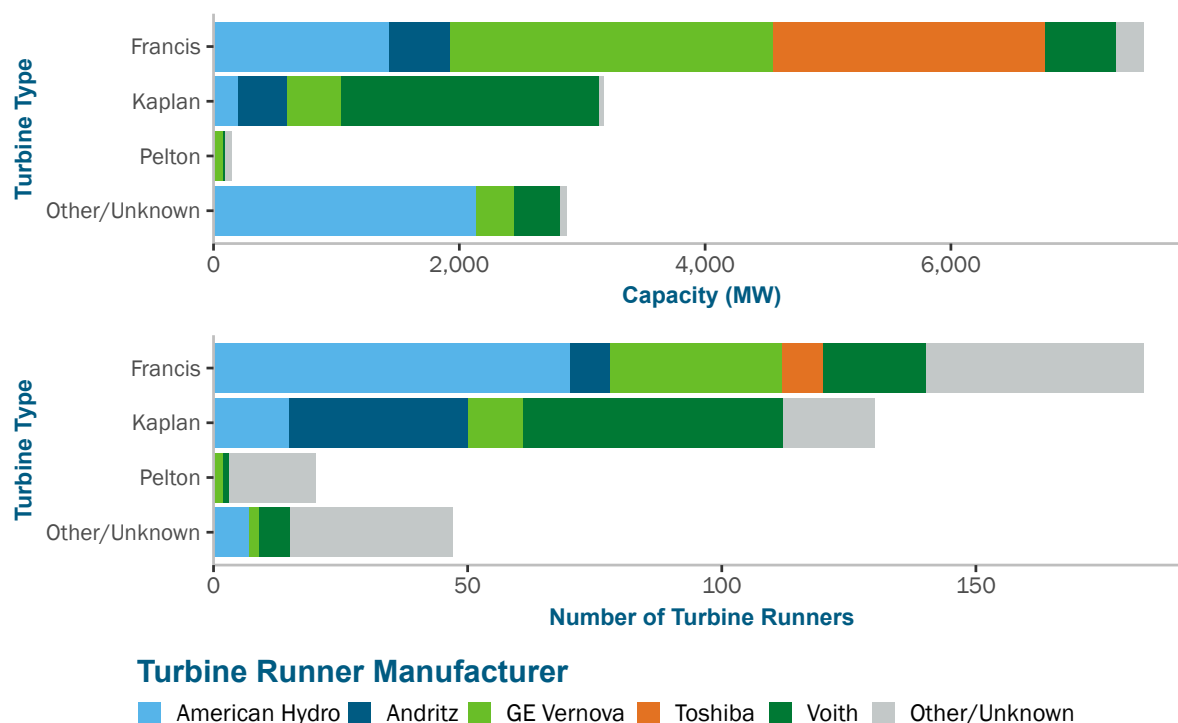


Figure 57. Installed hydropower and PSH turbine runners in the United States by turbine type and manufacturer (2010–2025)

Sources: IIR, EHA Unit database 2025, personal communication with plant owners and OEMs

Turbine runner type shares differ substantially between replacements at existing facilities and new facilities. At existing hydropower facilities, 59% of installed turbine runners installed in 2010–2025 are Francis, 32% are Kaplan, 2% are Pelton and 7% are in the “Other/Unknown” category. For new projects starting operation since 2010, 39% of units are Kaplan, 20% of units are Francis, 13% are Pelton, and 27.5% are in the “Other/Unknown” category. Kaplan turbines are commonly used in sites with low head and many of the NPDs retrofitted in the past 15 years have been low-head sites. As for the Pelton units installed at new projects, they all had capacities below 10 MW and have mostly been used in NSD projects in Alaska and the Pacific Northwest, as well as a few conduit retrofits.

6.3 U.S. HYDRAULIC TURBINE IMPORTS/EXPORTS

In 2023–2025, U.S. exports of hydraulic turbines averaged \$52 million and imports averaged \$58 million. These values were 24% higher than the 2020–2022 average for exports and 31 % higher for imports. However, the 2023–2025 average values remain significantly lower than in the 2010s when both imports and exports averaged \$77 million per year. Most of the imported turbine value in 2023–2025 originated in Europe (50%) or the Americas (37%).

Turbines are the hydropower plant component for which the U.S. Harmonized Tariff Schedule trade classification is granular enough to identify trade flows for the hydropower industry.⁸³ Turbine-generator

⁸³ Hydraulic turbine trade data were queried through the [Interactive Tariff and Trade Data website](#) maintained by the U.S. International Trade Commission. The values presented in Figure 58 are “Customs Values,” which exclude any shipping or duty costs. They include the values from Harmonized Tariff Schedule subheadings 8410.11 (hydraulic turbines with capacity less than or equal to 1 MW), 8410.12 (hydraulic turbines with capacity greater than 1 MW but less than or equal to 10 MW), 8410.13 (hydraulic turbines with capacity greater than 10 MW), and 8410.90 (hydraulic turbine parts and regulators) for “U.S. General Imports” and “U.S. Total Exports”.

sets (“water-to-wire” packages) used in small hydropower plants, as well as other products such as certain pump-turbines, are not included in Figure 58 because the Harmonized Tariff Schedule does not have a hydropower-specific statistical reporting number for turbine-generator sets.

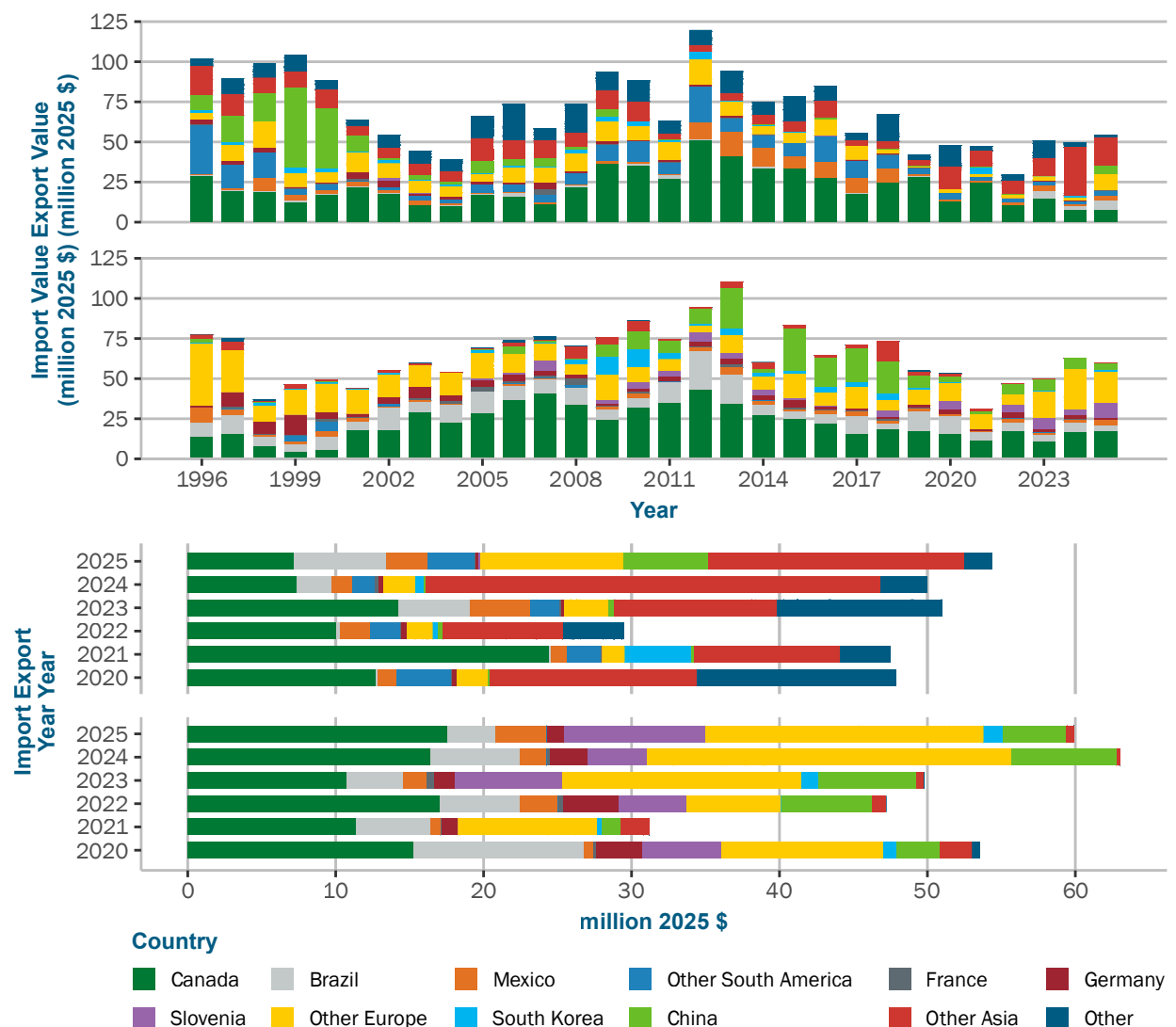


Figure 58. U.S. hydraulic turbine/turbine parts import and export values by country/region

Source: U.S. International Trade Commission (USITC)

Note: This plot incorporates revisions to official U.S. import and export statistics published by the Census Bureau impacting 2022, 2023, and 2024 records added to the USITC DataWeb in June 2025. The eight individual countries shown in the plot correspond to the top eight countries by annual average import value from 2010 to 2025.

The new data in Figure 58 relative to the version of the plot presented in the 2023 edition of the U.S. Hydropower Market Report covers 2023–2025 (in addition to data revisions for 2022 published by the U.S. International Trade Commission in 2025). From 2023 to 2025, the United States imported hydraulic turbines and parts with a total value of \$173 million and exported a total value of \$155 million. The annual average values in 2023–2025 (\$52 million for exports and \$58 million for imports) were 24% higher than in 2020–2022 for exports and 32% higher for imports. However, the 2023–2025 average values are significantly lower than in the 2010s when both imports and exports averaged \$77 million per year. Import tariffs and supply chain bottlenecks are among the reasons for the lower trade values observed in the first half of the 2020s relative to the previous decade.

Canada has been the top exporter of hydraulic turbines (by value) to the United States in 23 of the 30 years captured in Figure 58. For the remaining seven years, the top origin of U.S. hydraulic turbine imports has either been a European country (Italy in 1996, 1997, and 2000; Germany in 1999) or China (2015, 2017, 2018). Canada has also been the top destination of U.S. hydraulic turbine exports in 26 of the 30 years. For the other four years, the top destination has been either China (1999, 2000) or Qatar (2024, 2025). Since Qatar does not have any hydropower capacity operational or in development, the shipments to that country may be hydraulic turbines for use in a different industry (e.g., oil and gas).

From 2023 to 2025, the United States imported at least \$1 million in hydraulic turbines and parts from 16 countries (ten in Europe, three in the Americas, and three in Asia) and exported at least \$1 million to 12 countries (five in the Americas, three in Asia, two in Africa, and two in Europe). Out of the total U.S. imported value in hydraulic turbines and parts in 2023–2025, 37% originated in the Americas, 50% in Europe, and 13% in Asia). The import share from the Americas in the three most recent years was substantially lower than in the rest of the period shown in Figure 58 (53% in 2020–2022, 51% in 2010–2019, 53% in 1996–2009). The opposite is true for the European share which was lower in all the other subperiods (34% in 2020–2022, 20% in 2010–2019, 37% in 1996–2009) than in 2023–2025. Finally, the share of imports originating in Asia peaked in the 2010s (29%) and ranged from 8% to 13% in the other subperiods.

Most hydraulic turbine trade value takes place under the 8410.90 HTS code of “hydraulic turbine parts and regulators”. The value share of U.S. exports in that category ranged from 44% in 2020 to 92% in 2024. As for U.S imports, the share of traded value that corresponds to turbine parts ranged from 78% in 2007 to 99% in 2020.

6.4 U.S. HYDROPOWER SUPPLY CHAIN: POTENTIAL DEMAND FOR KEY COMPONENTS

In the next decade, most of the demand for U.S. hydropower plant components is expected to come from modernization of the existing fleet. If all modernization projects with planned completion dates in 2026–2035 move forward, they will require procurement for turbine-generator components for 313 units. The median capacity of these units is 45MW and 48 of them have capacities greater than 100 MW. Additionally, if all the new projects that have authorization applications (to FERC or U.S. BOR) under review, or already issued, move forward to construction in the next decade, 178 new turbine-generator units would need to be procured. The median capacity of these units is 2.4 MW. Of the 25 new units with planned capacities greater than 30 MW, all but one are for PSH projects.

Planned demand for selected hydropower plant components: fleet modernization

At the end of 2025, at least 104 hydropower plants were planning R&U or unit additions involving turbines, generators, or transformers. Planned projects at these facilities would require new components or fully new units for 232 turbines, 266 generators, and 44 transformers. Ninety-six percent of these projects have projected completion dates within the next decade. Figure 59 summarizes how many units of each component (turbine, generator, transformer) are part of the fleet modernization pipeline. The combined estimated value of the projects shown in Figure 59 is \$13.6 billion.

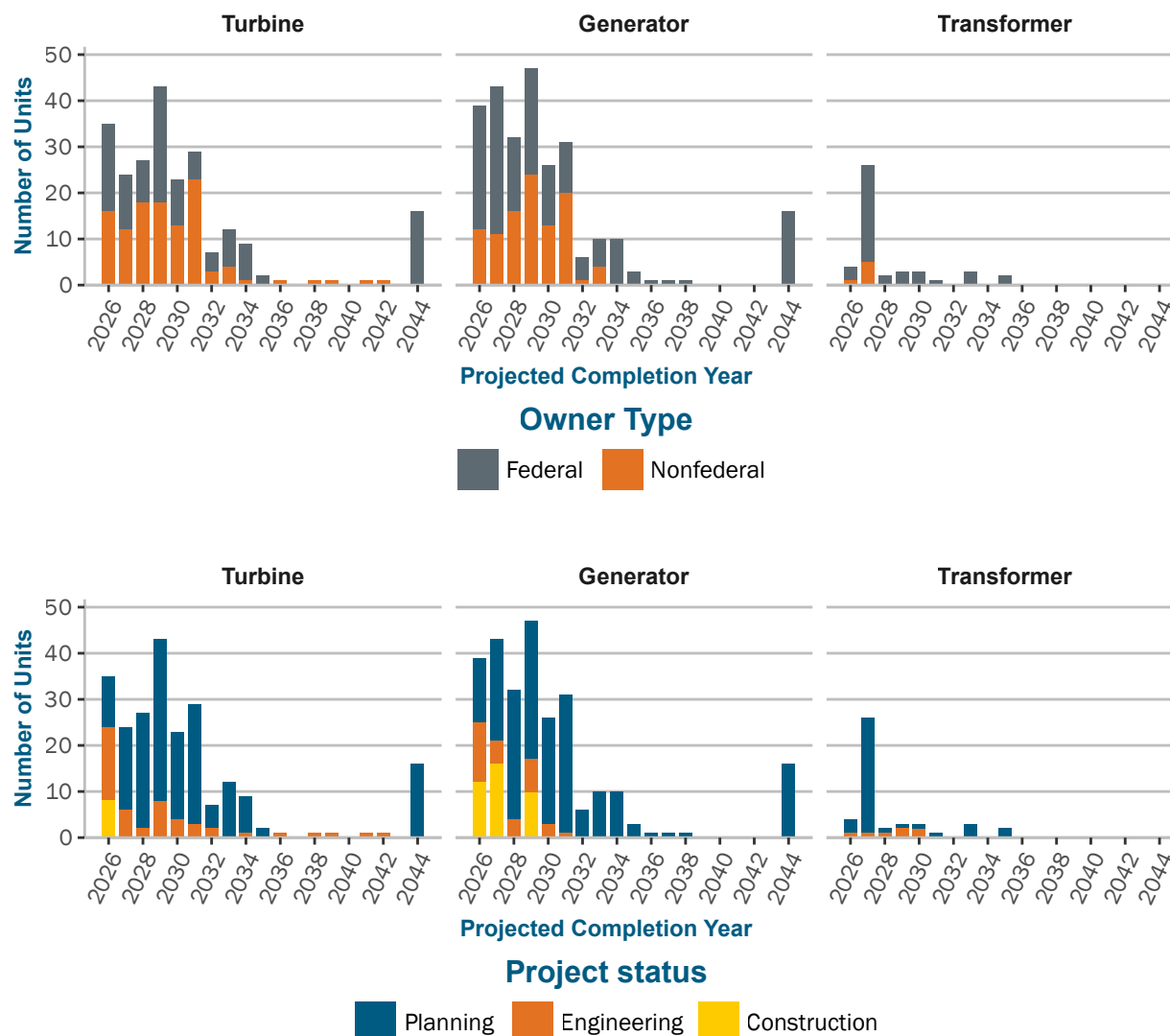


Figure 59. Projected timeline of new units or R&U for turbines, generators, and transformers in existing hydropower fleet, by ownership type and project status

Source: IIR

Note: All turbine and generator units in this dataset have rated capacities greater than or equal to 2 MW. This is partly because the dataset only tracks projects with total investment values of at least \$1 million and data are mostly collected from companies that operate hydropower plants with units of capacities higher than the 2 MW threshold.

Figure 59 shows that 51% of the turbine projects, 62% of the generator projects, and 86% of the transformer projects are for hydropower and PSH facilities owned by federal agencies. For comparison, the federal fleet represents 48% of U.S. installed hydropower capacity and 16% of PSH capacity. The share of projects that are already in the construction stage is 3% for turbines and 14% for generators. None of the transformer projects are under construction. The share of projects that are in the engineering stage is 20% for turbines, 12% for generators, and 16% for transformers. Projects in the engineering stage have typically already selected an OEM and have high probability of being completed.⁸⁴ Activities during the engineering stage include development of detailed blueprints and technical specifications, purchasing of materials and components, and site preparation. The largest share of projects in Figure 59

⁸⁴ IIR assigns a probability of completion greater than 80% to projects in the engineering stage.

are in the planning stage (76% for turbines, 73% for generators, and 84% for transformers). Activities during that stage include defining project scope, conducting preliminary design, performing market analysis, and seeking permitting and approvals.

The median capacity of the units for which turbines and/or generators are being modernized or replaced with planned completion dates in 2026–2035 is 45 MW. Sixty-nine percent of them (217 units) have rated capacities greater than 30 MW and 48 of them have capacities greater than 100 MW. Units greater than 100 MW have the most limited options for domestic manufacturing of their components (See Section 6.1). Francis is the most common turbine type among the units being modernized (71% of units), followed by Kaplan (19%) and reversible pump turbines (7%).

Comparing the number of turbine-generator units modernized from 2015 to 2024 (78) to the number of turbine-generator units covered by the projects shown in Figure 59 with expected completion in 2026–2035 (313) suggests a large increase in activity. However, as discussed above, a large fraction of these projects are not yet guaranteed to move forward within this timeframe. The number of units to be modernized in projects that are in the engineering or construction stages (i.e., those with highest probability of being completed) is 89.

Potential demand for selected hydropower plant components: new facilities

Although most hydropower plant component demand in the next decade is expected to come from modernization of the existing fleet, additional demand will also come from the development pipeline for new hydropower and PSH projects. If all the projects that a) have authorization applications under review by FERC or U.S. BOR or b) already were issued FERC or U.S. BOR authorization move forward to construction, 178 new turbine-generator units would need to be procured. The median capacity of these units is 2.4 MW. Figure 60 provides details about unit sizes by project type (NPD, NSD, conduit, or PSH). Of the 14% (25 units) with planned capacities greater than 30 MW, all but one are for PSH projects. Thus, unlike the fleet modernization projects, most of these will have access to the larger supplier diversity of the small hydropower segment of the industry.

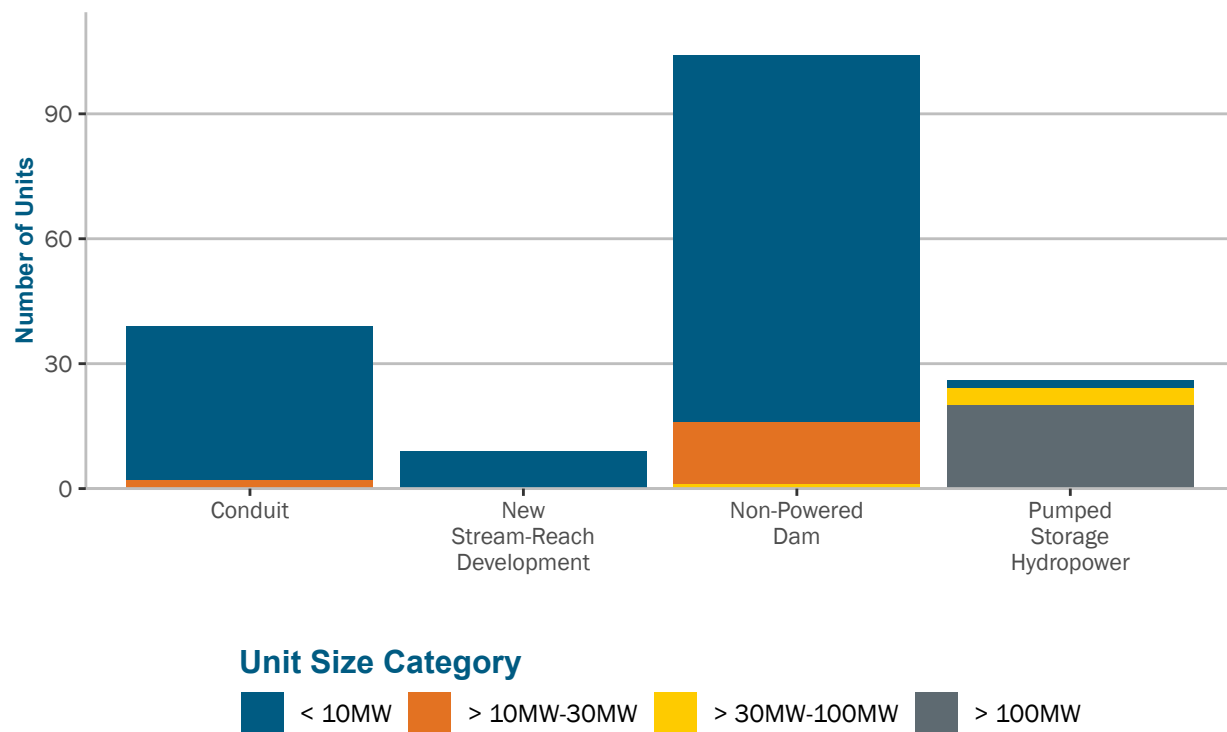


Figure 60. Distribution of turbine-generator unit sizes in hydropower and PSH projects in the development pipeline
Source: FERC

Aside from the 26 reversible pump turbines that would be needed for the ten projects with pending or issued FERC licenses, the most common type of turbine is Kaplan—typically a good match for the low-head sites in which many of the NPDs to be retrofitted are located. For conduit projects, FERC dockets mention a variety of proposed turbine types, including centrifugal, pump as turbine, Francis, and Pelton.

CHAPTER 7. POLICY DEVELOPMENTS

This chapter presents information on the status of DOE hydropower incentive programs (Section 242, Section 243, and Section 247) and technology-neutral clean electricity tax credits (Section 45Y and Section 48E) as of July 2026. It also summarizes actions initiated by FERC in 2025 and 2026 to streamline permitting processes affecting various stages of the lifecycle of a hydropower facility: preliminary permit issuance, post-licensing maintenance activities, and license terminations.

DOE is currently processing hundreds of awards for hydropower projects under three incentive programs, totaling \$591million, to modernize and expand the U.S. hydropower fleet. The two incentive programs directed towards capital improvements (Section 243 and Section 247) will support at least \$1.8 billion in investments to improve efficiency, grid reliability, dam safety, and environmental performance of the hydropower fleet. The third program (Section 242) is a production-based incentive available during the first ten years of operation to qualified facilities placed in service by the end of Fiscal Year 2027.

Table 3 contains details about the eligibility conditions and incentive amounts of the Section 242, Section 243, and Section 247 incentives program, administered by the DOE Hydropower and Hydrokinetic Office (H2O).

Table 3. Eligibility Conditions and Awarded Amounts from Hydropower Incentive Programs

Incentive	Authorized Funding/ Awarded Funding	Eligibility	Incentive Amount
Hydroelectric Production Incentive Program (Section 242 of the Epact of 2005)	Authorized funding: \$125 million Awarded funding: In October 2023, \$38 million to 66 hydropower facilities for electricity generated and sold in 2021 and 2022 (see list of projects selected) In October 2024, \$12 million to 39 hydropower facilities for electricity generated and sold in 2023 (see list of projects selected)	<i>Nonfederal hydropower production added to an existing dam or conduit.</i> (“Added” means installing a new turbine or repairing/replacing by September 30, 2027, an existing turbine that has been offline because of disrepair or dismantling for ≥ 5 consecutive years before October 2005.) <i>Nonfederal hydropower facility < 20 MW constructed in an area with inadequate electric service.</i> (i.e., not connected to regional or national grid transmission, or in the 90th percentile by electric outage frequency, or in the 90th percentile by annual average price of retail residential electricity.) Eligibility window: facility must be placed in operation by September 30, 2027. Incentive period: 10 consecutive years beginning with the fiscal year when the eligible units went into operation.	1.8 cents/kWh (as adjusted by the Internal Revenue Code of 1986) up to \$1 million per facility per year; rate adjusted downward if authorized funding is insufficient to pay all kilowatt-hours eligible at the base rate
Hydroelectric Efficiency Improvement Incentives Program (Section 243 of the Epact of 2005)	Authorized funding: \$75 million (up to 25% set aside for <i>small hydropower</i> ^a) Awarded funding (February 2024): \$71.3 million to 46 projects (see list of projects selected)	<i>Capital improvements at existing (placed in service by November 15, 2021), operable hydropower facilities improving efficiency by $\geq 3\%$</i> Award conditional on completion of authorizations. Payment after completion and verification of the efficiency increase. Build America, Buy America requirements for not-for-profit applicants ^b .	30% of total project costs not to exceed \$5 million per facility per fiscal year
Capital Improvement Incentives (NEW Section 247 of the Epact of 2005)	Authorized funding: \$553 million (up to 25% set aside for <i>small hydropower</i> ^a) Awarded funding (September 2024): \$469.8 million to 293 projects (see list of projects selected)	<i>Capital improvements at existing (placed in service by November 15, 2021) hydropower facilities for grid resilience (including the addition of energy storage in the form of reservoir capacity, PSH, and batteries), dam safety, or environmental improvements.</i> Projects should be started and completed within three years of selection for an incentive payment (unless DOE determines that a longer project period is necessary). Build America, Buy America requirements for not-for-profit applicants ^b .	30% of total project costs not to exceed \$5 million per facility per fiscal year

^a Small hydropower is defined as hydropower facilities with an installed capacity ≤ 10 MW owned by small businesses, Indian Tribes, municipalities, nonprofits, or cooperatives.

^b Build America, Buy America requirements: 1) all iron and steel used in the project must be produced domestically., 2) all manufactured products are produced in the U.S. and 55% or more of the cost of their components must be from domestic components, 3) all construction materials are manufactured domestically. Waivers can be requested if the iron and steel, manufactured products or construction materials cannot be procured domestically in the quantities or qualities necessary or if domestic procurement increases project cost by more than 25%. Not-for-profit applicants include states, local governments, territories, Indian Tribes, institutions of higher education, and nonprofit organizations.

Of the 46 projects selected for Section 243 incentives, 33 include replacements or upgrades to turbine-generator units (or their components) as part of the scope of work. The 293 projects selected for Section 247 incentives will conduct capital improvements at existing nonfederal and TVA hydropower facilities for grid resilience (84 projects), dam safety (149 projects), or environmental improvements (60 projects).

For Section 243 and Section 247 incentives, the incentive amount is 30% of total project costs. Therefore, the totals awarded (\$71.3 million for Section 243 and \$469.8 million for Section 247) will support project costs of at least \$238 million and \$1,566 million, respectively.

Section 243 incentive payments are issued after project completion, once the projects have been certified as achieving efficiency gains of at least 3%. As of May 2026, H2O has made \$4.5 million in incentive payments to the eight projects that have reached those milestones. For Section 247 payments, H2O resumed negotiations with the selectees in April 2026.

Supply chain requirements affect both eligibility for (and the value of) Section 45Y and Section 48E tax credits for new hydropower and PSH facilities. Additional guidance is needed to ease the burden of determining whether new hydropower and PSH qualify for the domestic content bonus of the credits.

Hydropower facilities placed in service from 2025 to 2032 are eligible for the Clean Electricity Production Credit (Section 45Y) or Clean Electricity Investment Credit (Section 48E). PSH facilities would also be eligible for the Section 48E credit. Moreover, retrofitted hydropower facilities can be eligible for the Section 45Y or Section 48E credits if they meet the “80/20 rule”.⁸⁵

Table 4 summarizes Section 45Y and Section 48E tax credit amounts and adders. Important features of these credits for hydropower are their direct pay (cash payment instead of credits for those credit recipients who are tax exempt entities) and transferability (credit recipients can sell all or part of their credits to a third-party) provisions.

Table 4. Tax Credits Relevant for New Hydropower or PSH Placed in Service in 2025–2032

Credit	Credit amount	Credit adders
Clean Electricity Production Credit (Section 45Y)	Full amount: 1.5 c/kWh (if wage and apprenticeship requirements are met) Base amount: 0.3 c/kWh Credit amounts are adjusted for inflation annually Credit eligibility for the first ten years of production	Additional 10% credit if project meets domestic content requirements
Clean Electricity Investment Credit (Section 48E)	Full amount: 30% of eligible investment costs (if wage and apprenticeship requirements are met) Base amount: 6%	Additional 10 percentage points of credit if the project meets domestic content requirements

Supply chain considerations matter to Section 45Y and Section 48E credit eligibility and amounts. First, OBBBA prohibits foreign entities of concern (FEOCs) and domestic entities related to them from claiming the credits. FEOCs are entities owned by, controlled by, or subject to the jurisdictions of China, Iran, Russia, or North Korea. Domestic entities are prohibited from claiming Section 45Y or Section 48E credits 1) if they have technology licensing agreements with FEOCs, 2) if they make significant payments to FEOCs, or 3) if the percentage of all manufactured products or components in the project not sourced from FEOCs is below the material assistance cost ratio. The material assistance cost ratio was 40% in 2026 for qualified energy production facilities and 55% for energy storage. It will increase five percentage points per year until 2030 (to 60% for qualified energy facilities and to 75% for energy storage facilities).

Second, meeting domestic content requirements allows credit recipients to claim the credit adders shown in Table 4. For technologies like wind, solar, and batteries that use standardized components, the U.S. Department of the Treasury guidance on the domestic content requirement includes safe harbor tables to ease the calculation and tracking burdens to the tax filers. The safe harbor tables assign a percentage of total project cost to each project component. Tax filers add up the percentages corresponding to the domestically manufactured components. If the resulting percentage is equal or greater to the required domestic cost percentage (100% for structural steel and iron, 50% of manufactured product costs for facilities starting construction in 2026 and increasing to 55% for projects starting construction in 2027 or later), they are eligible for the domestic content bonus.

⁸⁵ A qualified facility may qualify as originally placed in service even though it contains some used property provided the fair market value of the used property is not more than 20 percent of the qualified facility’s total value.

For hydropower, IRS Notice 24-41 introduced the categorization of hydropower and PSH project components as steel/iron or manufactured product (see Table 5), but the safe harbor cost percentages had not yet been published as of July 2026.

Table 5. Categorization of Hydropower and PSH Project Components for Application of Domestic Content Requirements to Obtain Domestic Content Bonus to Section 45Y and Section 48E Tax Credits

Applicable project component	Categorization
Steel or iron rebar for the reservoirs, upper and/or lower	Steel/Iron
Steel or iron rebar, plating, and piping in water conveyance (penstock piping)	Steel/Iron
Steel or iron rebar in powerhouse and foundation, spiral case, discharge ring, and draft tube	Steel/Iron
Steel or iron rebar in canals	Steel/Iron
Powerhouse structure, gates, stoplogs, screens, and embedded structure parts, foundation plates and anchors	Steel/Iron
Turbine/Pump Runner (which includes the following Manufactured Product Components, if applicable): spiral/scroll case, vanes, bottom ring, wicket gates, runner, draft tube, shaft, head cover, bearings, and flow control and isolation mechanisms)	Manufactured Product
Motor/Generator (which includes the following Manufactured Product Components, if applicable): stator, rotor, windings, poles, generator shaft, thrust bearing, brake ring/disc, guide bearings, ventilation and cooling system, and exciter)	Manufactured Product
Generator Step-Up Transformer (which includes the following Manufactured Product Components, if applicable: containment/main tank, cooling system, de-energized tap changer, load tap changer, bushings/insulators)	Manufactured Product

Source: [IRS Notice 24-41](#)

Another tax credit relevant to the hydropower industry is the Certified Qualifying Advanced Energy Project Credit (Section 48C) tax credit. Eligible projects fall into three categories: Clean Energy Manufacturing and Recycling projects, Industrial Decarbonization projects, and Critical Material projects. For eligible projects meeting the wage and apprenticeship requirements, it is a 30% tax credit on eligible capital investment costs.⁸⁶ The identity of Section 48C tax credit recipients becomes public after the final project certification process. However, recipients can choose to self-disclose before that milestone is reached. Of the \$10 billion awarded in Section 48C credits, 59 projects with total credit awards of \$3.1 billion have elected [self-disclosure](#). A few of them expand production capacity in the U.S. hydropower supply chain:

- Voith (York, Pennsylvania): New state-of-the art manufacturing equipment, including an AP 120 TM Vertical Turning Lathe and a Horizontal Boring and Milling Machine to increase production capacity, improve product quality, and enhance worker safety in the manufacturing of hydropower and PSH components (Tax credit amount: \$5,826,254)
- Eaton (Waukesha, Wisconsin): Increased manufacturing capacity of three-phase transformers (Tax credit amount: \$1,326,060)
- Prolec GE USA (Shreveport, Louisiana): New state-of-the art manufacturing equipment and a third production line to manufacture substation and pad-mount electrical transformers (Tax credit: \$7,980,000)
- Siemens Energy (Charlotte, North Carolina): New manufacturing facility for Large Power Transformers (Tax credit amount: \$18,311,501)

⁸⁶ If the wage and apprenticeship requirements are not met, the credit covers 6% of project costs.

In 2025–2026, FERC has taken steps to streamline multiple hydropower permitting processes, including the issuance of preliminary permits, post-licensing activities involving maintenance and upgrades, and license terminations.

In July 2025, FERC issued two NEPA categorical exclusions (CEs), previously established and used by the U.S. BOR, for hydropower-related activities.⁸⁷ CEs describe types of actions that do not cause significant effect on the human environment and therefore are excluded from the NEPA requirement to prepare an environmental document.⁸⁸ The Fiscal Responsibility Act of 2023 codified the practice of one federal agency (FERC in this case) adopting the CEs of another agency (U.S. BOR in this case) after consultation and analysis to determine that the types of actions to which the CEs would be applied are similar to those which the original agency intended. FERC consulted with U.S. BOR and analyzed 40 actions over the past five years that would be covered by the CEs and found that none resulted in significant effects on the human environment.

The two CEs cover the following types of actions:

- “Maintenance, rehabilitation, and replacement of existing facilities which may involve a minor change in size, location, and/or operation”
- “Minor safety of dam construction activities where the work is confined to the dam, abutment areas, or appurtenant features, and where no major change in reservoir or downstream operation is anticipated as a result of construction activities”

In October 2025, at the request of DOE, FERC issued a notice inviting comments to a proposed notice of proposed rulemaking (NPR) that would codify in FERC’s regulations that opposition from third parties such as federal land managers and Tribes is not a basis to deny an application to a preliminary permit.⁸⁹ If the NPR becomes a rule, it would reverse the policy established by FERC in 2024 to not issue preliminary permits on Tribal lands if the relevant Tribes are opposed. The National Hydropower Association, which is the U.S. hydropower industry trade association, expressed support for the NPR arguing that a preliminary permit should only be denied if there is a permanent legal barrier to licensing the project. Tribes and conservation groups submitted dozens of comments opposing the NPR as dismissive of Tribal sovereignty and ultimately wasteful of FERC’s and tribal resources because projects in Tribal land opposed by the relevant Tribes would have no realistic pathway to development.

In November 2025, FERC issued a Notice of Inquiry seeking stakeholder input on how to streamline approval for post-licensing activities (e.g., maintenance, repairs, upgrades) in hydropower projects.⁹⁰ It includes questions on 1) how to streamline approval for minor post-licensing activities that do not require a license amendment 2) whether a blanket authorization for post-licensing activities currently requiring amendments would be a good option and, if adopted, which activities it should cover. The NHA strongly recommended the adoption of a blanket authorization program and requested FERC to limit its review to actions involving “substantial alteration or addition not in conformity with the approved plans”. Several commenters recommended FERC to better define what “substantial” and “minor” alterations are. Multiple conservation groups opposed the use of blanket authorizations and argued that the classification of post-licensing activities as “substantial” or not should be based on their impacts on project operations, environmental conditions, or public uses.

⁸⁷ See FERC docket CX25-2-000 for more details on this order

⁸⁸ In 2020, the Council on Environmental Quality revised the definition of “human environment” in the context of NEPA to refer comprehensively to the natural and physical environment and the relationship of present and future generations of Americans with that environment.

⁸⁹ See FERC docket RM26-5-000 for more details on this order and public comments in response to it

⁹⁰ See FERC docket RM26-3-000 for more details on this order and stakeholder comments in response to it

In February 2026, FERC issued two orders expanding NEPA categorical exclusions. The first order is a NOPR offering justification for a NEPA CE for hydropower license and exemption terminations or revocations involving minimal ground disturbances or impacts on reservoir conditions and downstream flows.⁹¹ FERC staff reviewed all environmental documents (13 environmental assessments in total) conducted as part of implied surrender terminations and revocations proceedings since 1978. None of the documents found that the terminations or revocations significantly affected the human environment. Public comments to this NOPR include concerns that 1) this CE will become an incentive for licensees to have their licenses terminated rather than pursue a voluntary surrender that would be potentially subject to NEPA review, 2) this CE will shift the responsibility of managing the long-term consequences of leaving dams in place to state or local agencies that may have less expertise or resources to address them than FERC.

The second order issued in February 2026 adopted five existing CEs from TVA.⁹² They became effective in March 2026. As in the July 2025 order adopting CEs previously established by U.S. BOR, reaching this decision required FERC to engage in consultation with the agency that established the CE (TVA in this case) and analyze the actions over the previous five years that would have been covered by these CEs. None of the 60 actions identified as being covered by the CEs were found to have significant impacts on the human environment. The five CEs cover the following types of actions:

- TVA 16: Construction of new transmission line infrastructure, substations or interconnection facilities within limits for length (10 miles), new rights-of-way (125 acres), disturbed acreage (10 acres), and new access roads (1 mile)
- TVA 17: Routine modification, repair, and maintenance of, and minor upgrade or/and addition to, existing transmission infrastructure
- TVA 36: Routine operation, repair or in-kind replacement, and maintenance actions for existing buildings, infrastructure systems, facility grounds, public use areas, recreation sites, and operating equipment. The actions covered by this CE must not result in changes in the project design capacity, function, or operation
- TVA 37: Upgrades, uprates, and other actions that alter existing buildings, infrastructure systems, facility grounds, and plant equipment, or their function, performance, and operation. The covered actions have limits to disturbed acreage (10 acres). For modifications to water intake and outflow structures, covered actions must keep intake velocities and volumes and water effluent quality and volumes within existing permit limits
- TVA 38: Construction of new buildings and associated infrastructure within limits to disturbed acreage (10 acres of land not previously disturbed by human activity or 25 acres of previously disturbed land)

The newly established or proposed NEPA CEs for hydropower-related activities that do not cause significant effects in the human environment translate into time savings for projects seeking authorization for activities that fall under the CE. Additionally, by allowing FERC to focus its efforts on those permitting activities that may have significant effects on the environment, these CEs may shorten the time to complete those processes for the projects that need them. For the CEs adopted from U.S. BOR and TVA, if there are extraordinary circumstances by which an action falling under these categories may have significant impact on the human environment, FERC can decide not to use the CE and require NEPA review.

⁹¹ See FERC docket RM26-7-000 for more details on this order and public comments in response to it

⁹² See FERC docket CX26-1-000 for more details on this order

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GLOSSARY

Availability factor – Percentage of hours in a year in which a hydropower unit is not offline due to a planned or forced outage and is, therefore, available to operate

Capacity addition – This category, as shown in Figure 3, Figure 13, Figure 14, and Figure 15 includes additions of new turbine-generator units to existing hydropower projects as well as upgrades to existing turbine-generator units that result in an increase in unit nameplate capacity

Capacity factor – Ratio, typically expressed as percentage, between actual annual generation and maximum possible annual generation if the hydropower unit generates continuously at its nameplate capacity

Conduit retrofit – Hydropower project where electricity generation capability is added to an existing conduit (“any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity” 18 CFR 4.30)

Large (project or unit) – Project or unit with a nameplate capacity greater than 100 MW and less than or equal to 500 MW

Medium (project or unit) – Project or unit with a nameplate capacity greater than 10 MW and less than or equal to 100 MW

Micro (project or unit) – Project or unit with a nameplate capacity of less than or equal to 0.1 MW

Plant downrate – Downward adjustment to the reported (to EIA Form 860) nameplate capacity of existing turbine-generator units or situations where a plant owner decides to retire some of its turbine-generator units but continues to operate the rest

New stream-reach development – Hydropower project where hydropower generation capability is added to previously undeveloped waterways

Non-powered dam retrofit – Hydropower project where hydropower generation capability is added to an existing dam previously used solely for other purposes (e.g., flood control, navigation)

Plant refurbishment – Project that involves modifications in turbine-generator units or other hydropower plant components to extend the life of the facility and improve its performance but do not result in increased generating capacity or increased energy output

Small (project or unit) – Project or unit with a nameplate capacity greater than 0.1 MW and less than or equal to 10 MW

Unit upgrade – A hydropower unit is upgraded when some or all of its components are modified in a way that results in increased generating capacity and/or increased energy output through improved efficiency

Very Large (project or unit) – Project or unit with a nameplate capacity greater than 500 MW

APPENDIX

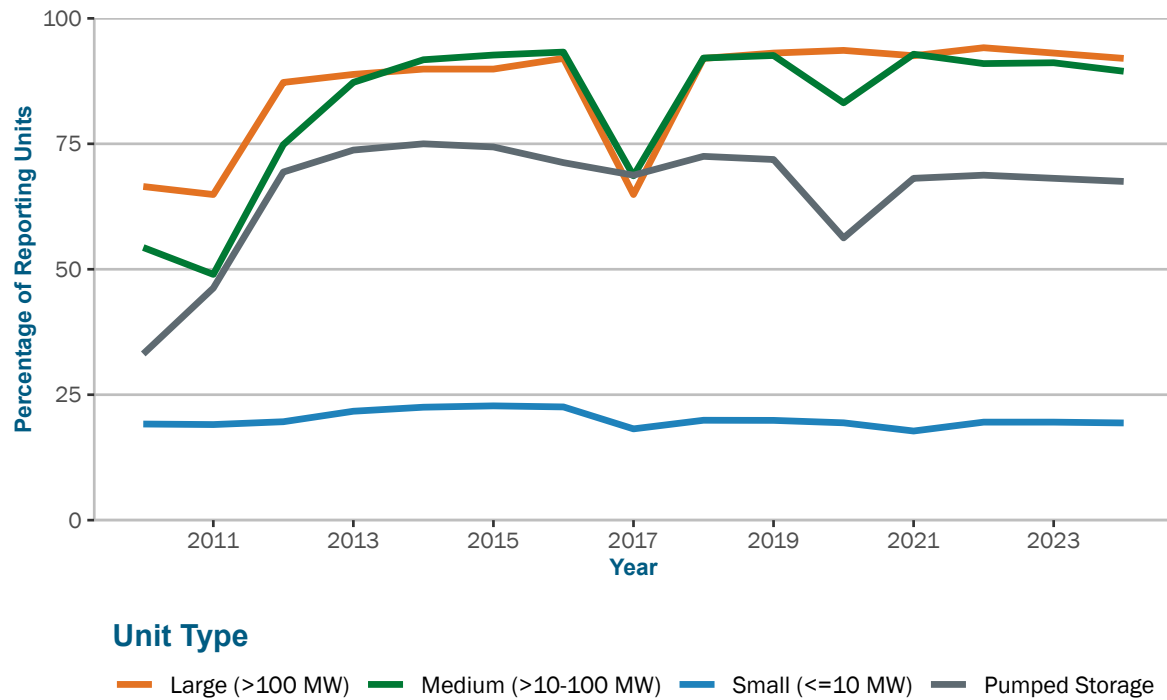


Figure 61. Percentage of hydropower units reporting to NERC GADS by type and size.

Source: NERC pc-GAR, ORNL EHA Unit Database 2025

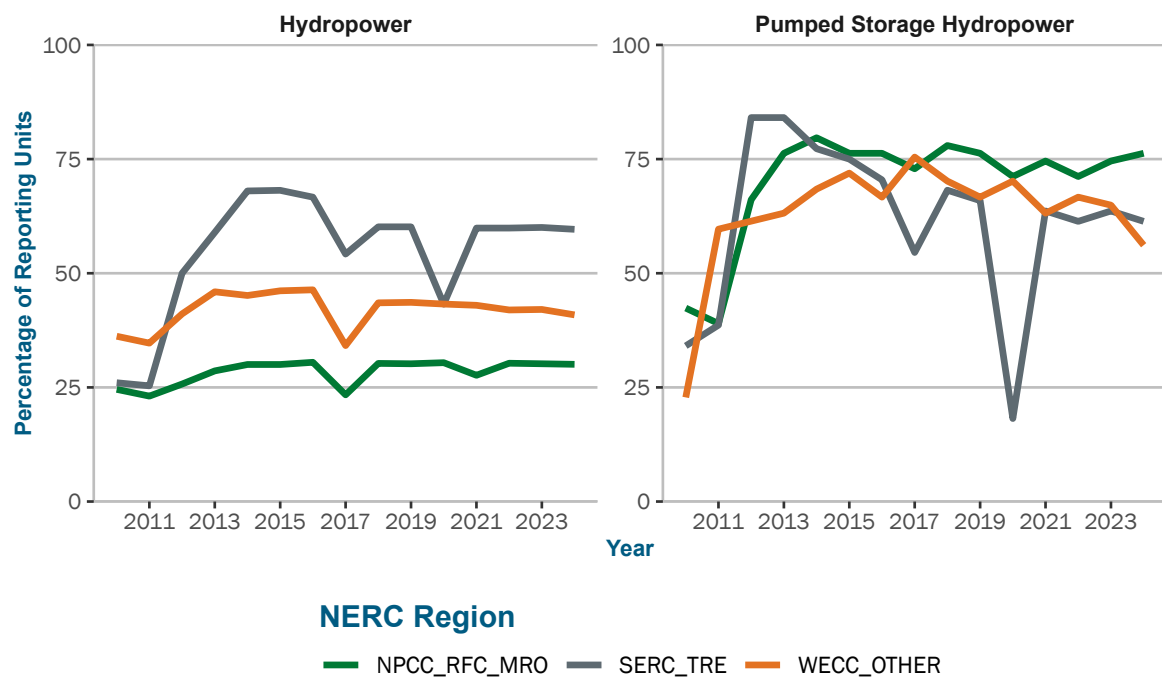


Figure 62. Percentage of units reporting to NERC GADS by type and regional grouping

Source: NERC pc-GAR, ORNL EHA Unit Database 2025

*On the back cover: Foote Hydroelectric Project, Iosco County,
Michigan (image courtesy of Leslie Cieplechowicz)*

