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WATER POWER TECHNOLOGIES OFFICE

U.S. Hydropower Market Report

2023 Edition, Executive Summary

Prepared for
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Prepared by
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37831
Managed by UT-Battelle, LLC
for the U.S. Department of Energy

U.S. Hydropower Market Report (2023 edition)

Executive Summary

Chapter 1. Looking Backward: An Overview of Changes Across the U.S. Hydropower and Pumped Storage Hydropower (PSH) Fleet

The U.S. conventional hydropower fleet includes 2,252 hydropower plants with a total generating capacity of 80.58 GW.[1] The U.S. hydropower fleet produced 28.7% of electricity from renewables and 6.2% of all electricity in 2022.

U.S. conventional hydropower capacity increased by 2.1 GW from 2010 to 2022. One hundred and twenty-nine new hydropower plants came online during this period totaling 679 MW. The rest of the net increase (1.4 GW) resulted from capacity upgrades to existing plants (see Figure 1).

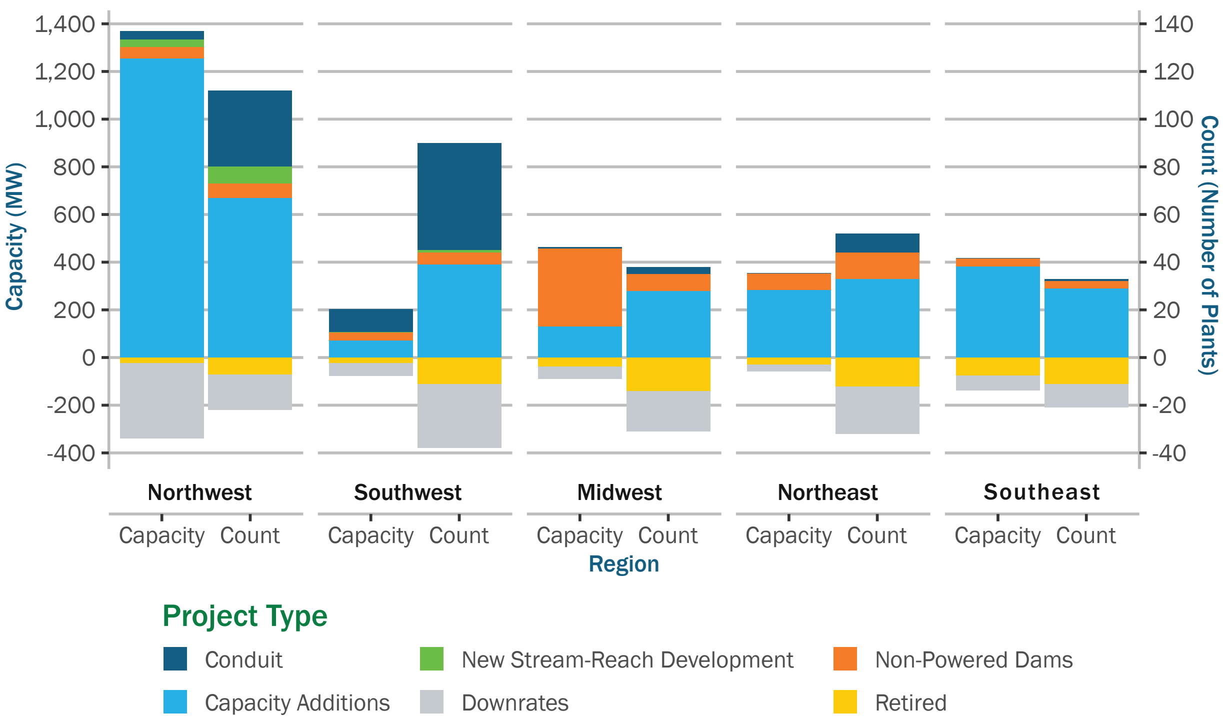

Figure 1. Hydropower capacity changes by region and type (2010–2022)

Sources: EIA Form 860 (2010–2021), EIA Form 860 2022 Early Release, ORNL Existing Hydropower Assets (EHA) Plant database 2023.

Note: 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.

New project construction from 2010 to 2022 included additions of hydropower to 32 non-powered dams (NPDs) with combined capacity of 505 MW, hydropower installations at 89 conduits (140 MW), and eight new stream-reach developments (NSDs) with combined capacity of 34 MW.

To date, the pace of capacity increases in the 2020s has slowed down relative to the previous decade. The average capacity additions per year in 2010–2019 were 193 MW/year versus 66 MW/year in 2020–2022. As for capacity added from new

1 A hydropower plant is a facility containing one or multiple powerhouses located at the same site and using the same pool of water.

projects, the annual average in the 2010s was 60 MW and in 2020–2022 was 26 MW. The slowdown in capacity additions in 2020–2022 may be partly explained by COVID-19 restrictions and supply chain challenges that resulted in delays and cost increases. The hydropower incentives authorized in the Bipartisan Infrastructure Law (BIL) as well as the Inflation Reduction Act (IRA) tax credits are expected to stimulate investment in the existing U.S. hydropower fleet and construction of new nonfederal hydropower and pumped storage hydropower (PSH) projects in the coming years. However, they may have contributed to the decline in activity in 2021–2022 because of plant owners waiting for full guidance on the implementation of these incentives (e.g., which types of projects would qualify, details on wage, apprenticeship, and domestic content requirements) to make any new capital investment decisions.

Batteries added to run-of-river projects may allow the resulting hybrid projects to provide new services to the grid, increase their revenue, and extend their operational life. At least 11 hydropower plants in the United States have added or are planning to add battery capacity to their facilities, the first ever and likely a trend for hydropower in the future.

Integrating batteries in a hydropower plant that has little or no water storage, typically a small run-of-river plant, allows the plant owner to access new revenue streams by providing peaking power or ancillary services such as frequency regulation or black start. The ability of more hydropower units to provide those services is also beneficial for the grid as it can help manage the increased variability in net load resulting from further growth in wind, solar, and distributed energy resources. Five of these hybrid facilities were active at the end of 2021: two in Alaska, two in Virginia, and one in Maine. Four out of these five battery systems were installed in the past five years. Additionally, plans to add battery capacity to six existing hydropower plants in Maine (4) and Nevada (2) are part of current grid interconnection queues. Hybridization with batteries is one of the project types eligible for the Section 247 incentive in the BIL.

PSH is an essential resource to support variable renewables (wind and solar), far greater than batteries because of the significant capacity already installed and the longer duration storage available in PSH v. batteries. The U.S. PSH fleet accounted for 70% of utility-scale power storage capacity and 96% of utility-scale energy storage capacity in 2022 (see Figure 2).[2] Overall, U.S. PSH capacity increased by 1.4 GW from 2010 to 2022 of which 97% were capacity upgrades to the existing fleet.

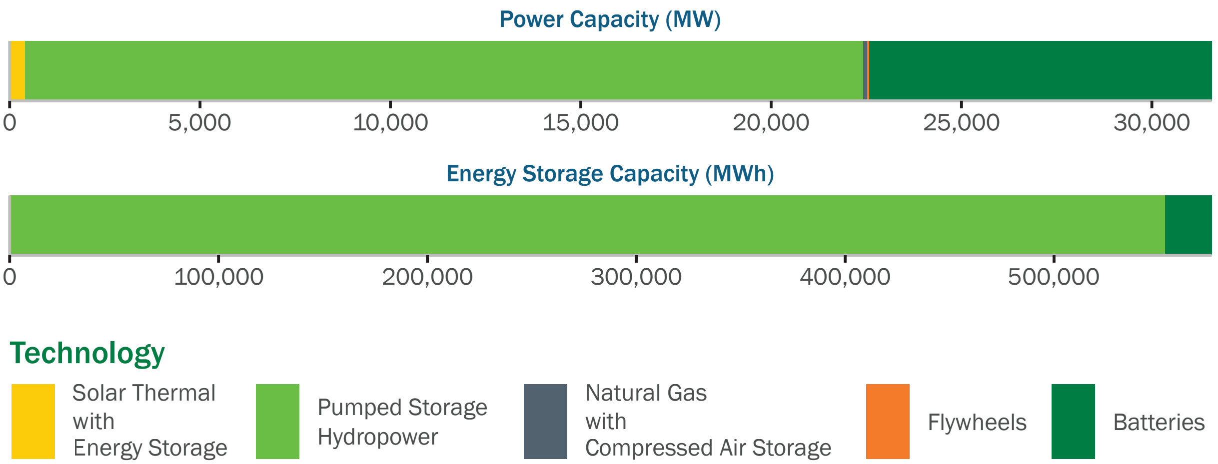

Figure 2. U.S. Utility-scale electrical energy storage capacity by technology type (2022).

Source: Energy Information Administration (EIA) Form 860 Early Release (2022).

2 Power storage capacity is the maximum amount of power (in megawatts) that the storage resource could generate for an instant. Energy storage capacity is the maximum amount of energy (in megawatt hours) that the storage resource would produce in going from a full upper reservoir (in the case of PSH) or full charge (in the case of a battery) to empty.

The United States has 43 PSH plants with a combined capacity of 22 GW and an estimated energy storage capacity of 553 GWh.[3] Installed PSH capacity (22 GW) represented 70 percent of all utility-scale electrical storage capacity in the United States in 2022, a drop relative to the 93 percent it represented in 2019. The rapid decrease in the PSH share of power storage capacity in the past two years is explained by the very fast growth in installed battery capacity—from 1.52 GW in 2020 to 9 GW by the end of 2022.

In terms of energy storage capabilities, PSH accounts for 96% of the U.S. total because the typical storage duration of a PSH plant—the number of hours it takes to empty the upper reservoir if the turbines operate continuously at their maximum power rating—is greater than the typical storage duration for a battery. For the 445 utility-scale battery installations in the United States, the median storage duration is two hours. In contrast, the estimated median storage duration of U.S. PSH plants is 12 hours.

The 2020–2022 annual average investment in refurbishing and upgrading the U.S. hydropower and PSH fleets was $363 million, less than half the annual average for 2010–2019 ($883 million per year).

Almost 85% of the tracked investment is in projects that seek improving the performance and extending the life of turbine-generator units. The likely reasons for this decline are similar to those mentioned for capacity additions (i.e., COVID-19 restrictions, supply chain challenges, and waiting for full guidance on the implementation details of the BIL incentives and IRA tax credits). Incentive payments from the BIL (Section 243 and Section 247) will help stimulate investment in the existing fleet in the upcoming years.

Virtually all capacity due to enter the hydropower relicensing pipeline in the past five years has done so.

Of the 167 Federal Energy Regulatory Commission (FERC)-licensed hydropower and PSH projects due to start the relicensing process between 2018 and 2022, 155 of them (93%) have initiated the process. These projects account for 99.9% of the total capacity due to start relicensing during this period (8 GW). Of the remaining 12 licenses, 7 with a combined authorized capacity of 7 MW are being surrendered and another licensee (0.8 MW) requested a conversion of a license into an exemption. The status of the other four licenses, with a combined capacity of 0.6 MW, was unclear at the end of 2022 based on the information on their dockets.

The number of relicense applications submitted from 2018 to 2022 (136) is more than double the number of relicenses issued (60) during the same period. At the end of 2022, there were 136 pending relicenses with a combined capacity of 10.9 GW.[4] More than 50% of the pending relicenses (71) are in the Northeast region, but they represent 21% of the capacity in this stage of the relicensing process, i.e., the projects in the Northeast tend to be smaller than those in other parts of the country. The Southwest has the highest share of capacity with pending relicenses (50%), distributed among 28 projects. The other three regions (Northwest, Midwest, and Southeast) represent 16%, 1%, and 12% of capacity respectively, and all have less than 20 projects with pending relicenses.

Relicensing timelines vary widely. For relicenses issued from 2010 to 2022, the median duration of the process was 5.8 years. The 10 percent of projects with the shortest relicensing durations completed the process in 4.7 years or less and the 10 percent of projects with the longest relicensing durations completed the process in 12 years or more. The environmental complexity of a project can be a key factor in influencing relicensing timelines.

From 2010 to 2022, FERC issued 68 hydropower license or exemption surrenders and terminations, with a combined capacity of 322 MW. As a result of the surrender or termination process, these 68 projects are no longer authorized to generate power. Most of these projects are small—with a median capacity of 0.5 MW—and 24% of them (16) involve a dam removal.

By far the largest project whose license has been issued a surrender during this period is the Klamath project in California (169 MW) which will entail removal of four dams. Only five other surrender issuances were for licenses with authorized capacities greater than 10 MW. Two of them are licenses granted in the 1980s that never proceeded to construction.

3 See Appendix to 2021 U.S. Hydropower Market Report for details on the data sources and approach used to estimate energy storage capacity.

4 A project is categorized as having a pending relicense if it is in the post-filing period of the relicensing process in which the licensee has already filed the final relicense application.

Lack of economic feasibility or a decision to pursue restoration of aquatic ecosystems were the two reasons more commonly cited for surrendering a license during this period.

Multiple small projects cite the need for costly repairs (due to wear and tear of the equipment or damage caused by natural hazards such as fires or flooding) as a key issue making the project economically unattractive. Five licensees explicitly cite the cost and risk of their upcoming relicensing process as the trigger to surrender the license. The decision to abandon hydropower production in favor of ecosystem restoration is often, at least partially, connected to an economic analysis where the required investments (e.g., in connection to a relicensing process) to mitigate the environmental impacts of the hydropower project are too high compared with the power production benefits.

At the end of 2022, there were 18 projects with pending surrenders (i.e., the licensees have submitted the surrender application and FERC is reviewing it) with a combined capacity of 34 MW and median installed capacity of 0.97 MW. Most of these projects are in the Northeast (7) and Southwest (6). Four of the pending surrenders propose removing a dam as part of their project decommissioning plan.

Chapter 2. Looking Forward: U.S. Hydropower and PSH Development Pipeline

At the end of 2022, the U.S. hydropower development pipeline included projects to construct 117 new facilities with a combined capacity of 1.2 GW (versus plans for 217 new facilities with a total proposed capacity of 1.49 GW at the end of 2019); only 8 of them are under construction. NPD retrofits accounted for 95% of the proposed new capacity. In addition to the projects to construct new facilities, 23 active upgrade projects would increase the capacity of the existing fleet by 254 MW (See Figure 3).

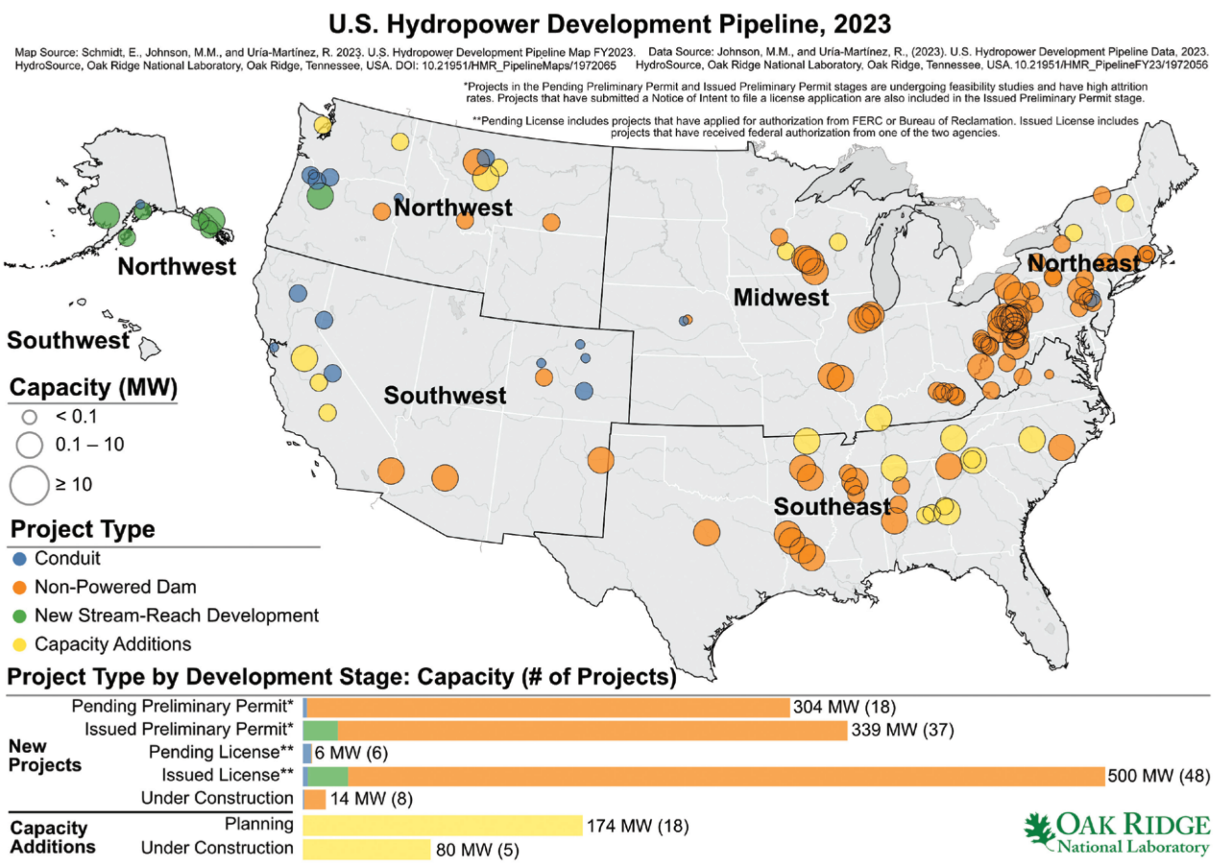

Figure 3. Hydropower project development pipeline by project type, region, size, and development stage (as of December 31, 2022).

Sources: ORNL U.S. Hydropower Development Pipeline Data 2023, FERC eLibrary, Industrial Info Resources (IIR).

Twenty-nine states have at least one new hydropower project in the pipeline. Pennsylvania stands out as the state with the most proposed new hydropower projects (26) of which 25 are NPD projects.

Fifty-six (48%) of the proposed new projects—with a combined capacity of 514 MW—already have authorization from FERC or the U.S. Bureau of Reclamation (Reclamation). Only eight of them (14 MW) have started construction. Six of the yet unauthorized projects have already submitted a final license or exemption application. The remainder include 37 projects (339 MW) with issued preliminary permits and 18 projects (304 MW) with pending preliminary permit applications. Projects with pending or issued preliminary permits are undergoing feasibility studies and typically have high attrition rates with only a small fraction proceeding to seek a FERC license.

Of the 93 NPDs for which adding hydropower is proposed, 65 are owned by the U.S. Army Corps of Engineers (USACE), 5 by Reclamation, and the remaining mostly by states. Who owns the dam matters for NPD permitting because it might result in federal permitting requirements either different from, or in addition to, a FERC license.

Most of the 23 proposed capacity additions to the existing fleet are capacity upgrades resulting from turbine replacements and generator rewinds, but three owners plan on adding new turbine-generator units to their plants. Two of the three projects that involve unit additions seek generating power from mandatory environmental flows.[5] Production from these additional units would be eligible for Section 242 incentives of the BIL which might result in increased number of installations.

The number of projects in the PSH development pipeline has increased by 43 percent in 2022 versus 2019. Ninety-six PSH projects were on the development pipeline at the end of 2022 (versus 67 at the end of 2019) with a combined storage power capacity of 91 GW. Developers have advanced beyond the feasibility evaluation stage for 10 of them. Of those 10, three have already been authorized by FERC but no new PSH is under construction (See Figure 4).

5 In cases where the required minimum flow volume (in cubic feet per second) is lower than the minimum flow needed by the originally installed turbines to operate, harnessing the power from environmental flows requires installation of an additional smaller turbine.

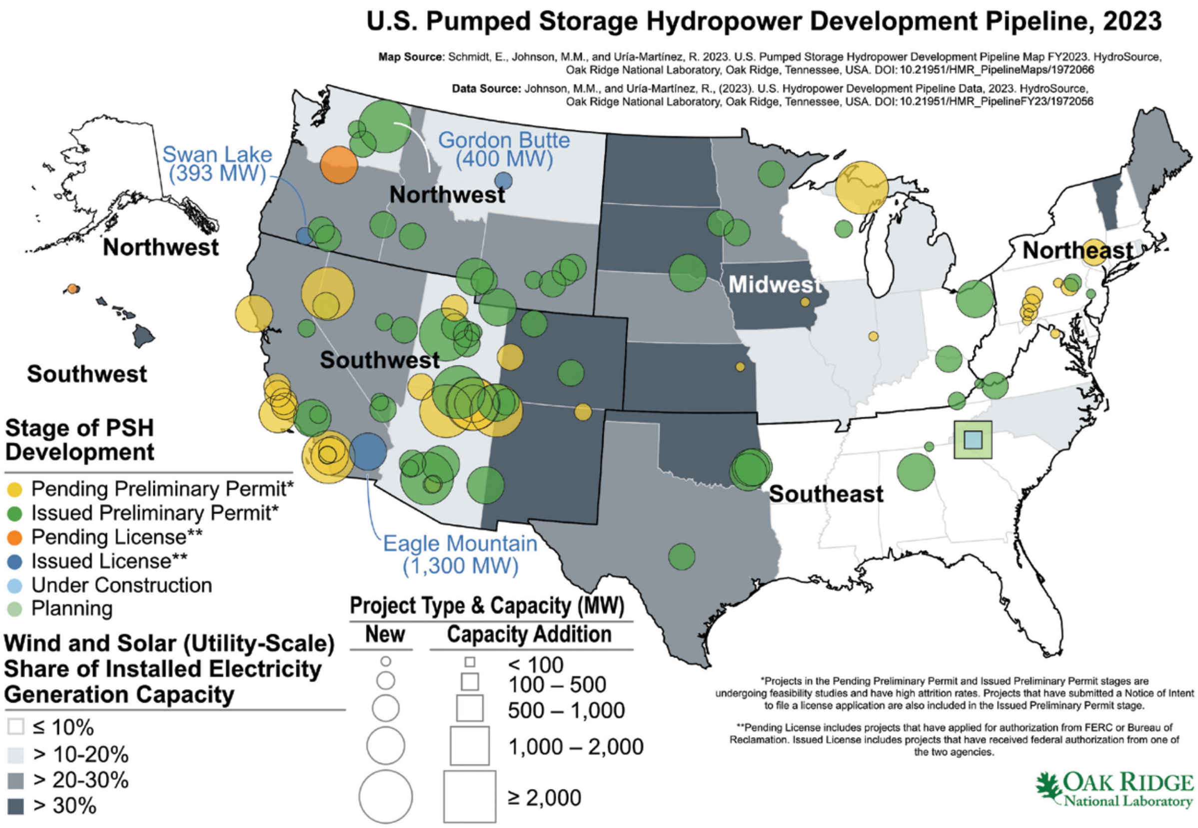

Figure 4. PSH project development pipeline by region and status in relation to state variable renewable (wind and solar) shares of electricity generation capacity.

Sources: ORNL U.S. Hydropower Development Pipeline Data 2023, FERC eLibrary, IIR, EIA Form 860 (2021).

Twenty-eight states have at least one PSH project in the development pipeline. The top five states by number of PSH projects (California, Arizona, Utah, Pennsylvania, and Nevada) do not include any of the eight states with variable renewable (wind plus solar) shares greater than 30% of their in-state electricity generation capacity. Siting decisions are highly dependent on topographic conditions, and the Great Plains—where many of the wind-rich states are located—do not have many well-suited sites for PSH development. Along with topography, other factors important to PSH siting decisions include proximity to transmission capacity, ability to secure the necessary water rights, and ease of access to the project site.

More than 80% of the proposed PSH projects have closed-loop configurations.

In a closed-loop PSH plant, the reservoirs are not continuously connected to a naturally flowing water feature such as a river or lake. The high percentage of proposed PSH projects that are closed-loop contrasts with the characteristics of the existing U.S. PSH plants, which are all open loop. Closed-loop configurations allow more siting flexibility and their environmental impacts on aquatic and terrestrial resources are generally lower than those of open-loop facilities (Saulsbury, 2020).

The range of proposed PSH generation capacities is very wide (17–9,000 MW), and proposed storage durations are typically 8–12 hours.

Some developers are exploring longer storage durations, and others are proposing hybrid projects that combine PSH with other renewables (e.g., floating solar photovoltaic (PV) panels on reservoirs in three projects in Arizona to reduce evaporation losses and a 24-MW PSH project in Hawaii where solar PV firmed by batteries would provide all the pumping power).

Except for PSH (new and capacity upgrades), all other hydropower projects in the U.S. development pipeline fall in the small (<=10 MW) or medium (>10–100 MW) size categories. The most active type of developer for new projects are private non-utilities. They account for 94% of NPD projects and 82% of PSH projects. Investor-owned utilities have shown an increased interest in PSH projects in the last two years.

Chapter 3. U.S. Hydropower in the Global Context

Although hydropower (including PSH) remains the technology with the largest share (40%) of global renewable electricity generation (versus 50% in 2019), other renewable generation technologies (especially solar PV) are growing much faster in recent years.

In 2022, global hydropower capacity reached 1,256 GW, and PSH global capacity stood at 137 GW (IRENA 2023a). From 2020 to 2022, the global fleet increased by 42.6 GW for hydropower and 15.9 GW for PSH (IRENA 2023a).

During the past decade (2013–2022), global hydropower capacity has increased at an average rate of 2.2%. For the PSH portion of the fleet, the average capacity growth rate has been 2.7%. More than half (52%) of the hydropower and PSH capacity added globally since 2013 is in China, with an additional 10% in Brazil. For PSH, 83% of new global capacity commissioned from 2013 to 2022 is in China.

At the end of 2022, there were 3,909 hydropower projects in the global development pipeline with a combined total capacity of 557 GW. Almost one-quarter of the projects are under construction and will add 117 GW to the global fleet—a 9% increase in global capacity relative to what was installed as of 2022 (see Figure 5).

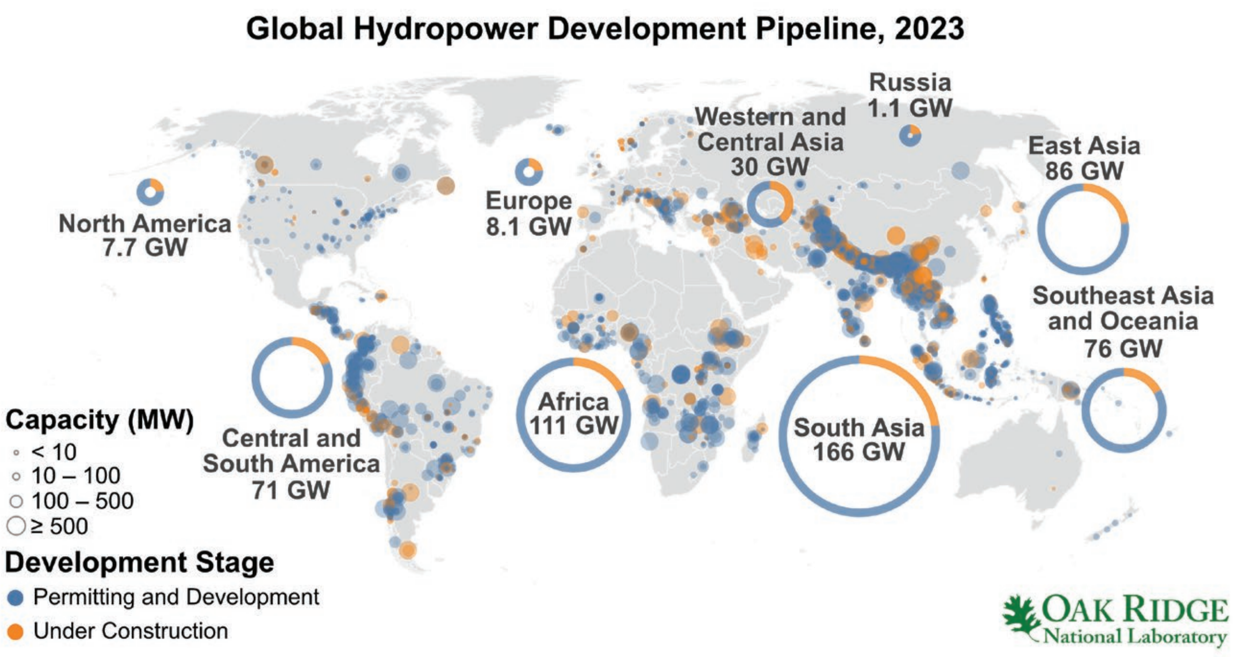

Figure 5. Map of hydropower project development pipeline by region and development stage

Sources: United States (ORNL U.S. Hydropower Development Pipeline Data 2023); rest of the world (GlobalData).

Notes: GlobalData does not cover projects with less than 1 MW of capacity and has limited coverage of projects with less than 10 MW in some regions.

Half of the proposed hydropower capacity is in projects in South Asia (166 GW) and Africa (111 GW). The largest project in the overall pipeline—Medog (60,000 MW)—is in China, and the largest project under construction—Grand Renaissance (4,775 MW) —is in Ethiopia. The pipeline includes 194 Very Large (> 500 MW) projects, typically developed by state-owned enterprises. North America has four Very Large hydropower projects in the pipeline—all of them in Canada—and Europe is the only region that has no projects above the 500 MW capacity threshold.

As of the end of 2022, there were 363 PSH projects in the global development pipeline with a total combined capacity of 286 GW (see Figure 6). Of these, 56 are under construction with a total rated power capacity of 52 GW. The new capacity from these projects under construction will increase the capacity of the global fleet by 38%.

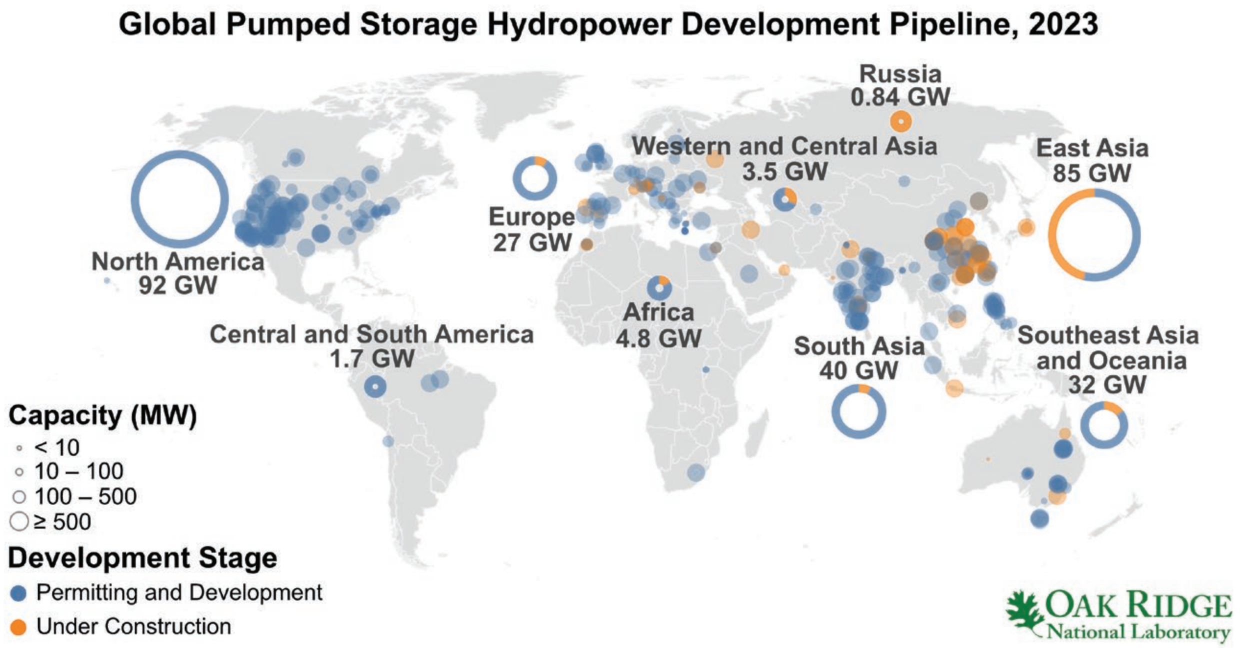

Figure 6. Map of PSH project development pipeline by region and development stage

Sources: United States (ORNL U.S. Hydropower Development Pipeline Data 2023); rest of the world (GlobalData).

Notes: GlobalData does not cover plants with less than 1 MW of capacity.

North America is the region with the greatest number of PSH projects in the development pipeline (101), 96 in the United States and five in Canada. However, it is one of only two world regions where no new PSH is under construction. Thirty-nine of the 56 PSH plants under construction are in East Asia (28) and Europe (11).

More than 60% (35) of the 56 PSH projects under construction are in the Very Large category (>500 MW). The largest PSH projects under construction are three projects in China with 2,400 MW each. The only other construction project with a capacity equal to or more than 2,000 MW is Snowy 2.0 in Australia. Of the additional 18 construction projects, 15 are in the Large category (>100–500 MW) and three are either Medium (>10–100 MW) or Small (<10 MW).

In the 2010s, the average annual value of hydropower turbines and turbine parts traded internationally was $1.7 billion. Traded value declined significantly in the first two years of the 2020s, to an average of $0.9 billion.

The United States occupied the eighth spot in the top 10 ranking of exporters in 2010–2021 with an average traded value of $64 million per year. China has been the largest exporter of hydraulic turbines and turbine parts during this period with average annual exports of $371 million. If the exports of individual EU countries are taken together, the EU becomes the top exporter in 2010–2021 with an annual average of $543 million and accounting for 32% of global exports.

During this period, the list of top importers includes countries where large new hydropower plants have been constructed (e.g., Turkey, Vietnam, and Pakistan), and also countries with mature fleets (e.g., the United States, Canada, and Russia) where a large share of imports are used for refurbishing and upgrading turbines at existing plants. The United States ranked seventh by average imported value during this period.

Chapter 4. U.S. Hydropower Prices and Revenues

Hydropower plants provide energy, capacity, and grid services. Depending on region and owner type, these products and services may be sold through long-term contracts or power purchase agreements (PPAs), short-term bilateral transactions, or bids into the day-ahead or real-time wholesale markets managed by independent system operators (ISOs) and regional transmission operators (RTOs). Additionally, some hydropower plants also sell renewable energy certificates in either mandatory compliance markets connected to a state-level renewable portfolio standard or voluntary, green power markets.

In 2019–2021, most federal hydropower was marketed at rates similar to or below wholesale electricity prices. Severe drought conditions in most of the Southwest in 2020–2021 did not result in large changes in average revenue per megawatt-hour for the power marketing administration that markets federal hydropower in that region because of the long-term nature of its contracts with customers. However, its total revenue was 20% lower than the 2010–2018 average because of lower sale volumes.

The four power marketing administrations (PMAs) within the U.S. Department of Energy—Bonneville Power Administration (BPA), Southeastern Power Administration (SEPA), Southwestern Power Administration (SWPA), and Western Area Power Administration (WAPA)—market the output from the federal hydropower fleet. Across the four PMAs, average revenue per megawatt-hour from 2019 to 2021 ranged from $27.75/MWh (BPA) to $35.78/MWh (SEPA). The average revenue per megawatt-hour for the PMAs was lower than the average wholesale price in 2019–2021, except for SEPA.

The impact of the acute droughts experienced in the Southwest over the past 20 years is not apparent on the average revenue per kilowatt-hour for WAPA, but it is visible when looking at volumes sold and total revenue. The effects of the drought on a PMA-wide average energy price are smoothed by the diversity of hydrologic conditions in the vast area where hydropower plants marketed by WAPA are located. Another factor that contributes to smoothing out the effects of drought on WAPA's average revenue is the large size of some of its hydropower storage reservoirs, which makes them capable of buffering the effects of multiyear droughts.

For nonfederal plants selling their electricity through PPAs, the national median energy price for hydropower purchased power transactions in 2020 was $45/MWh.

It was the second lowest price for the 2006–2020 period (after $44/MWh in 2017). The low median price for 2020 is consistent with the drop in electricity prices observed in wholesale markets that year because of the effect of the COVID-19 pandemic on electricity consumption. The range of hydropower PPA prices is wide. For 26 PPAs where the first year of data is 2018 or later, the average price of energy ranged from $23/MWh to $80/MWh.

As of 2020, 19% of PPA transactions involving hydropower included a capacity component in the price (a fixed charge per kilowatt of capacity available over a period regardless of the number of kilowatt-hours actually generated). But there is substantial regional variation in the fraction of hydropower PPAs that include a capacity component: from 9% in the Northwest to 60% in the Southwest.

Detailed revenue data—disaggregated into energy, ancillary services, and capacity—for a set of hydropower plants participating in ISO/RTOs show that energy revenue is typically the largest component of total revenue for hydropower plants, followed by capacity revenue. The amount and mix of ancillary services provided varies significantly among plants, but ancillary service revenue makes up a small share of the total revenue.

Since energy revenue is the dominant component, the overall pattern of total revenue (decreasing from 2018 to 2020 and bouncing back in 2021 and 2022) roughly follows the trends in ISO/RTO energy prices during the 2018–2022 period, which also were the lowest in 2020 because of the effect of the COVID-19 pandemic on electricity demand and increased sharply in 2022 in connection with a spike in natural gas prices after Russia's invasion of Ukraine.

The main difference in the revenue composition of PSH plants versus conventional hydropower plants is that energy revenue per kilowatt of installed capacity per year is lower than for hydropower (because of the low average number of hours in generation mode per day) and capacity revenue is as high or higher than energy revenue in some cases.[6] Ancillary services revenue was no greater than 25% of total revenue for any of the PSH plants in the sample from the past five years (see Figure 8).

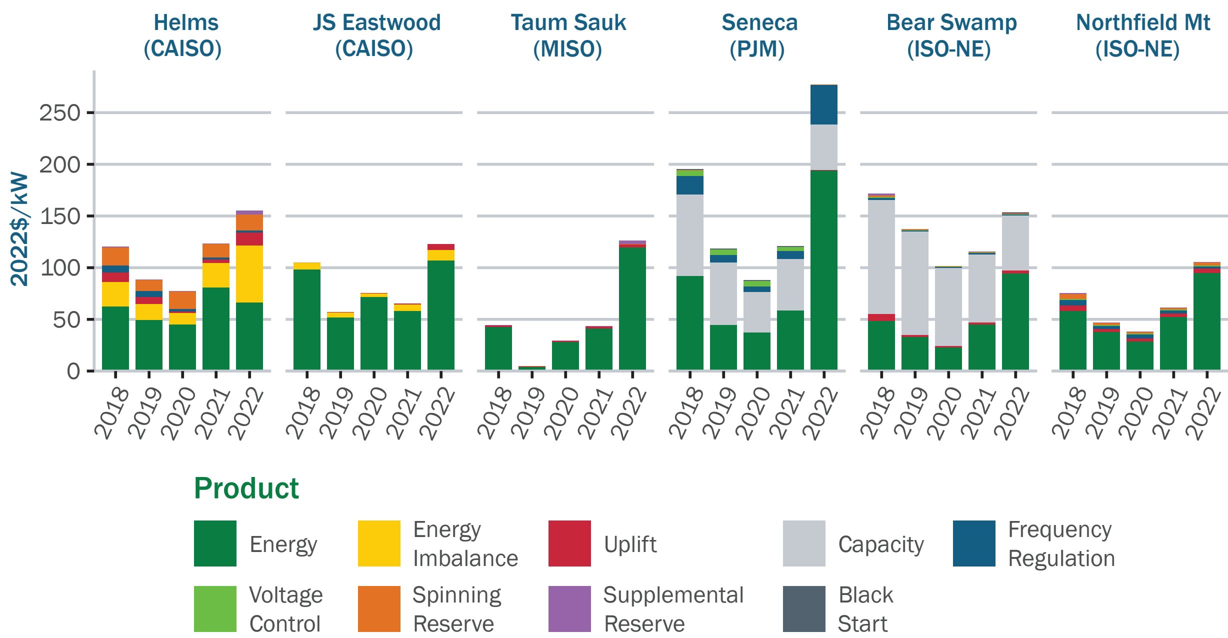

Figure 7. Annual revenue streams from participation of PSH plants in ISO/RTO markets

Source: FERC Electric Quarterly Reports (EQR)

Note: Taum Sauk was offline for most of 2019. The plot shows gross revenue (i.e., the cost of pumping is not netted out). The plot includes only transactions that could be matched to a PSH plant. Capacity revenue and black start revenue data in the EQR are presented at the company or zone level and cannot be traced back to specific delivery nodes/plants. Seneca is the only plant owned by Seneca Generation, LLC, and Bear Swamp is the only plant owned by Bear Swamp Power Company, LLC, so the company-level capacity revenue data is equal to the plant-level capacity revenue data in those two cases. For the other plants, relevant capacity revenue data could not be extracted from the EQRs, but that does not mean that capacity revenue was zero for those plants.

Going forward, hydropower and PSH revenue composition will likely shift toward higher shares of revenue from the capacity and ancillary service markets. In regions with high penetration of variable renewables, the average marginal energy price will tend to decrease while the value of firm, dispatchable capacity and the need for ancillary services will increase (De Silva et al., 2022).

In recent years, the increased penetration of variable renewables has motivated changes in accredited capacity methodologies (i.e., the rules to determine which fraction of the generation capacity of each resource counts toward resource adequacy requirements and can receive a capacity payment) to adequately reflect the contribution of each supply resource to reliability. Using historical data, the revised methodologies consider how well each resource typically performs during the hours of the year with the highest probability of supply shortage. Thus, hydropower plants with reservoirs that have been consistently available during those critical periods will have a higher fraction of their capacity accredited than wind, solar, or nondispatchable hydropower plants.

Apart from the traditional set of ancillary services (e.g., frequency regulation, spinning and supplemental reserves), flexibility services such as ramping are becoming increasingly necessary for system operators. As a result, ISO/RTOs have adopted or are planning energy and ancillary service markets reforms geared towards incentivizing generators to provide the needed level of operational flexibility (FERC, 2021).

6 For instance, the 2021 gross generation for the six PSH plants shown in Figure 7 was equivalent to having operated at their nameplate capacity 600–1,000 hours (on average, 2–3 hours per day).

Chapter 5. U.S. Hydropower Cost and Performance Metrics

The costs to operate and maintain hydropower plants display strong economies of scale (i.e., the operations and maintenance (O&M) cost per kilowatt decreases as plant capacity increases). As of 2020, the average O&M cost for the nonfederal fleet was $16/kW for Very Large plants (>500 MW), $23/kW for Large plants (>100 MW–500 MW), $53/kW for Medium plants (>10 MW–100 MW), and $213/kW for Small plants (<=10 MW).

As for the federal fleet, the average annual hydropower O&M cost in FY2021–FY2023 was $21.15/kW for the plants owned by USACE and $31.86/kW for the plants owned by the Bureau of Reclamation. The lower O&M value per kW for the USACE fleet is because those plants are larger. The median capacity of the USACE fleet is 100 MW and the median capacity for the Reclamation fleet is 38 MW.

Between 2009–2020, the average O&M cost per kilowatt-hour for the nonfederal fleet was approximately 1 cent per kilowatt-hour for the Very large and Large plants, 1.5 cents per kilowatt-hour for the Medium plants, and 5.4 cents per kilowatt-hour for Small plants.

Publicly available hydropower O&M data (from FERC Form 1) lacks information about the type of plants that make most of the new capacity in the past three decades.

An important limitation of the FERC Form 1 O&M cost dataset is that it includes very few plants constructed after 1990 and none of them are small plants. Since 86% of new hydropower plants in the United States with an operation start date later than 1990 have been small, the FERC Form 1 data does not provide any information about the typical cost of operating and maintaining most of the plants under 30 years of age.[7]

In 2020–2022, the average U.S. net hydropower generation (266 TWh) was 4.2% lower than the average annual generation in the previous decade (278 TWh), largely driven by extreme drought in parts of the West.

The average regional net generation in 2020–2022 was above the average in the 2010s in the Southeast (22%) and the Midwest (7.8%) and below in the Northeast (-0.5%), the Northwest (-6.5%), and the Southwest (-31.6%) (see Figure 9). Drought largely explains the generation decreases in the Northwest and the Southwest; changes in operations due to increased penetration of renewables could also be playing a role.

Relatedly, the median U.S. hydropower capacity factor (i.e., the ratio, typically expressed as percentage, between actual annual generation and maximum possible annual generation if the plant generates continuously at its nameplate capacity) in the first three years of the 2020s averaged 35.3% versus 38.8% in the 2010s. From 2005 to 2022, the median capacity factor ranged from 33% to 45% without a clear trend but closely following the trajectory of capacity-weighted average runoff.

Average Canadian hydropower imports in 2020–2022 (41 TWh) were 7.6% above the average in the 2010s (38 TWh). Canadian imports are expected to increase in the coming years based on purchase agreements signed between Canadian companies and U.S. utilities and backed by the construction of new, large hydropower projects in Canada and new transmission lines.

7 The reason why small, newer projects are absent from the FERC Form 1 dataset is that most of them are owned and operated by entities not required to file FERC Form 1 (private non-utilities or public utilities that do not reach the electricity sales volume thresholds for having to file Form 1).

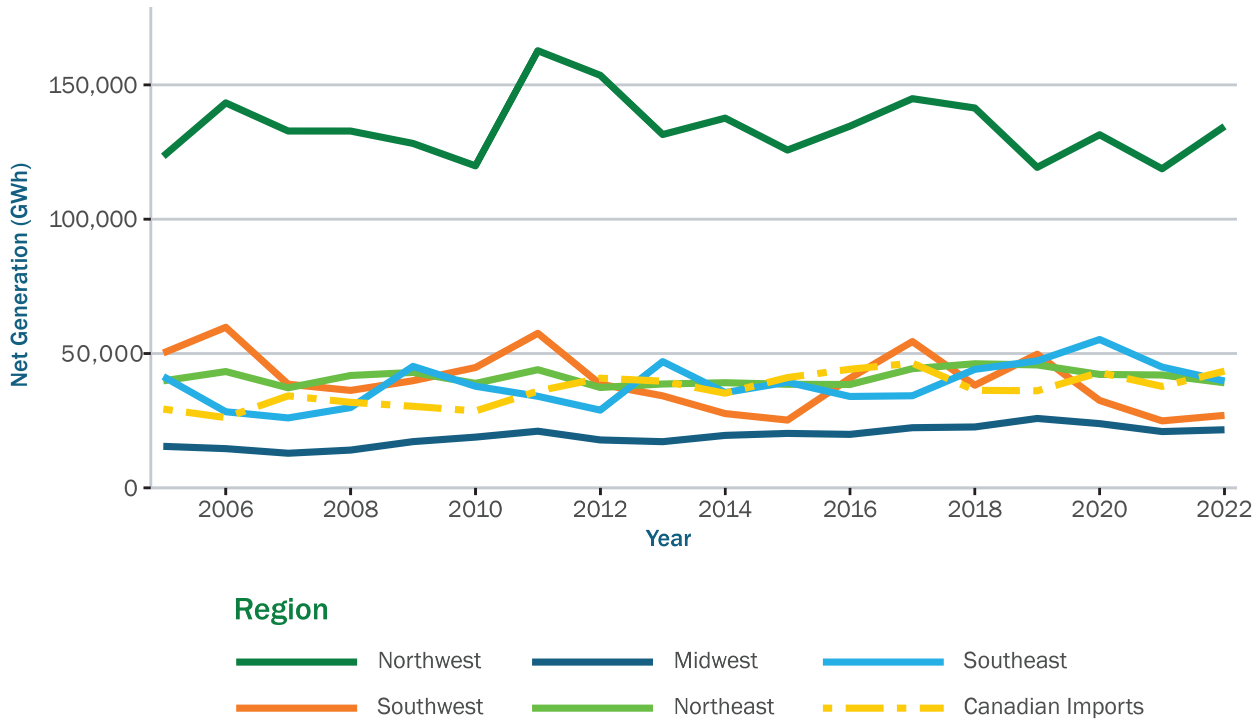

Figure 8. Annual hydropower net generation by region (2005–2021)

Source: EIA Form 923, Canada Energy Regulator.

Note: Canadian imports only include imports from Hydro-Québec, Manitoba Hydro, and BC Hydro. Since the electricity generation mix for these three companies is more than 90% hydropower, U.S. imports from these companies which account for approximately two thirds of all U.S. imports from Canada, can be classified as hydropower. Generation series for U.S. regions are only in-state generation and do not include imports.

A substantial increase (19%) in gross PSH generation in the Southwest in 2021 despite extreme drought in that region is an indication that PSH utilization is more closely linked to market conditions than hydrology.

At the national level, average gross PSH generation in the first three years of the 2020s (21.3 TWh) has remained stable relative to the average gross generation in the previous decade (21.4 TWh). Average regional gross PSH generation in 2020–2022 was above the average in the 2010s in the Midwest (14.4%) and the Northeast (4.2%) and below in the Southeast (-2.6%) and the Southwest (-12.5%).

In 2019–2021, after more than a decade of slow but steady decrease, the average availability factor has been stable at 79% for small units (<=10 MW), 83% for medium-sized units (10–100 MW), and 78% for large units (>100 MW).8

The average availability factor (i.e., the percentage of hours in a year in which a hydropower unit is not offline because of a planned or forced outage and is, therefore, available to operate) has been lower in the Western Electricity Coordination Council (WECC) than in other North American Electric Reliability Corporation (NERC) regions every year since at least 2005, and the gap has widened in 2019–2021.

Both hydropower and PSH units display their highest availability factors during the summer months indicating that this is the season when their dispatchable capacity is most valuable.

8 These averages are calculated using NERC Generation Availability Data System (GADS) data. For large and medium hydropower units, 75% or more of all installed units in the United States have been part of the NERC GADS dataset for almost every year in the past decade. For PSH units, more than 50% of the fleet has been included since 2012 (except for a large drop in reporting in 2019). Coverage of small hydropower units is much lower, less than 25%.

Failures in turbine or generator components (typically in units that are beyond their expected design life) account for 69% of the potential generation lost due to U.S. hydropower and PSH forced outages in 2013–2021. Failures in main transformers and lack of water are also among the top reasons for the largest (in terms of generation lost) forced outages.

NERC defines forced outages as "unplanned component failure or other conditions that require the unit to be removed from service immediately, within six hours, or before the next weekend". From 2013 to 2021, the national average number of forced outage events reported was 3,769 per year. Three quarters of them lasted less than one day. Only 5% lasted more than two weeks, but they were responsible for almost 98% of potential generation lost.

The WECC fleet accounted for close to 80% of the potential generation lost due to forced outages related to lack of water. The average duration of these outages was approximately one month. Fifty-two percent of the 6.4 TWh of potential generation lost in WECC for this reason corresponded to outage events in 2021.

The role of dispatchable, flexible generators is crucial to maintain the supply and demand of electricity continuously balanced. In general, the technical parameters of hydropower units allow highly flexible operations in terms of how fast they can start and ramp (i.e., adjust their output). However, actual hydropower operations may be substantially less flexible than what is technically possible due to adverse hydrologic conditions or operational constraints. Additionally, since flexible operation increases the wear and tear of hydropower turbines, how flexibly plant owners operate will depend on whether the flexibility is remunerated and, if it is, on whether the extra revenue they can get from the market by increasing their ramping or number of start-stop cycles is sufficient to compensate for the wear and tear on equipment.

The top 10 balancing authorities (BAs) by the magnitude of their average one-hour hydropower ramps (i.e., changes in output from one hour to the next) are in the Southeast and Northwest regions. Hydropower ramping mileage and the correlation between one-hour hydropower ramps and changes in net load vary across seasons.

Hydropower ramping mileage is calculated by adding up the one-hour ramps (up and down, in absolute value) performed by the hydropower fleet in one BA in a year. Winter is the season with the most mileage for 15 of the 30 BAs where there are at least 300 MW of installed hydropower and PSH (see Figure 9). For 12 other BAs, the highest share of mileage took place in summer, with the remaining three BAs having the largest share of hydropower ramping mileage in fall. Most of the ISO/RTO regions (NYISO, MISO, CAISO, SPP, and ERCOT) are among the 12 BAs with the most mileage during the summer season. In contrast, in most of the BAs in the Northwest, summer is the season with the lowest seasonal share of hydropower ramping mileage.

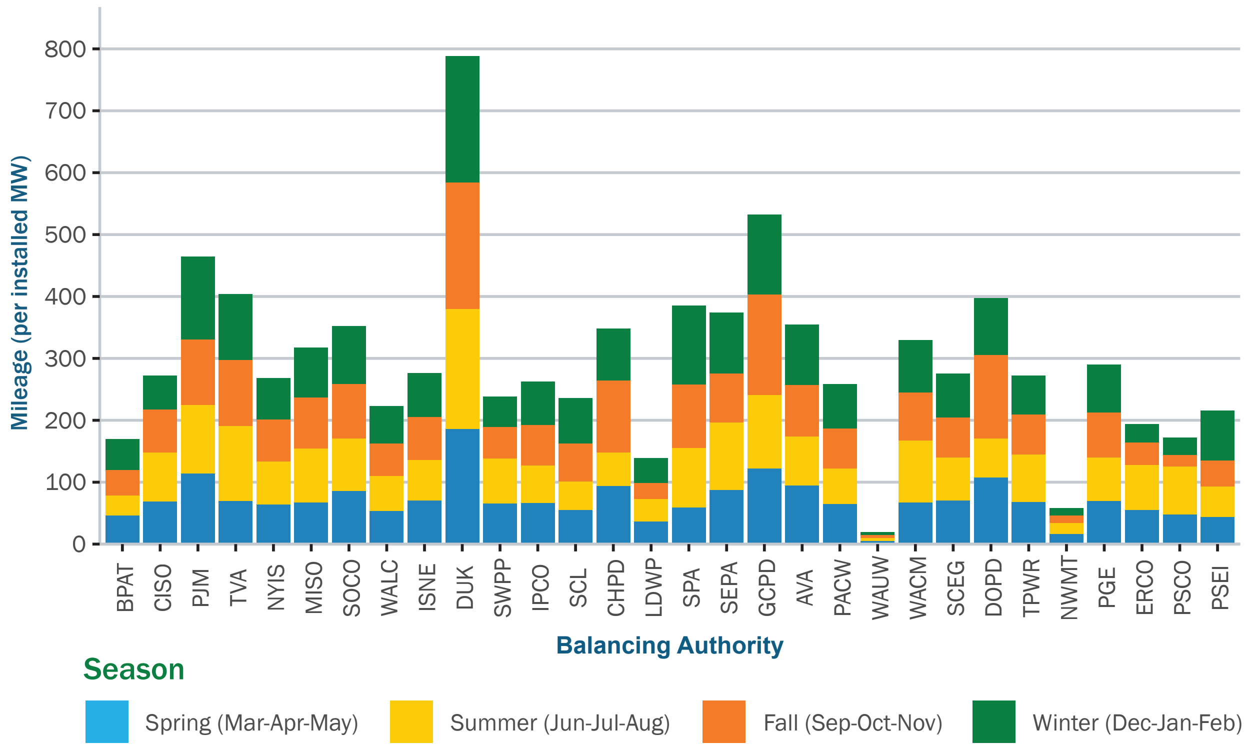

Figure 9. One-hour ramping mileage (per installed MW) for hydropower (including PSH) fleets in selected BAs (2022)

Source: EIA Form 930, EIA Form 860 2022 Early Release

Note: The BAs are ordered from most (BPAT) to least (PSEI) installed hydropower and PSH capacity in 2022. BAs with less than 300 MW of installed hydropower and PSH capacity or with generation values greater than what would be feasible given the installed capacity are excluded. A list of BA names to match the acronyms can be found at eia.gov/electricity/gridmonitor/about. The BA acronyms used here are those used in the EIA Form 930 dataset.

Winter and summer are the peak seasons for electricity demand in which electricity prices tend to be higher and the need for load following is greater. Therefore, when feasible, hydropower plant owners will be particularly attuned to electricity market signals during those seasons. Correlation between one-hour ramps and hourly changes in net load is highest in winter for 12 of the BAs, in summer for eight BAs (of which four are ISO/RTO regions), in fall for eight BAs, and in spring for the remaining two BAs.

The number of unit starts is another measure of operational flexibility. In 2019–2021, the median small hydropower unit started less than once per month (10 starts per year), the median medium unit started less than twice per month (21 starts per year), the median large unit started approximately once per week (56 starts per year), and the median PSH started close to once per day (295 starts per year). The lower numbers of unit starts for small and medium units are consistent with run-of-river operations and high capacity factors. For large units and PSH units, the most flexible units based on their number of unit starts, the average number of unit starts decreased considerably in 2019–2021 relative to 2005–2018.

Chapter 6. Trends in U.S. Hydropower Supply Chain

Annual average hydropower capacity for which runners were installed in 2020–2022 (206 MW), including runner installations at new units and replacements at existing units, was much lower than in 2007–2019 (1,256 MW).

At least 52 turbine units were installed in the United States (617 MW of combined capacity) in 2020–2022. Seventy-three percent of them had capacities of 10 MW or less. The subset with capacities of 10 MW or less were produced by at least nine different manufacturers. In contrast, all the installed units in this period with capacities greater than 10 MW were manufactured by three original equipment manufacturers (OEMs): Andritz, GE, and Voith.

In 2020–2022, U.S. hydraulic turbine trade value ($32 million for exports; $39 million for imports) has been lower than the average for 1996–2019 ($62 million for exports; $60 million for imports). Canada continues to be the top hydraulic turbine importer and exporter for the United States.

The drop in trade value started in 2019 suggesting that it is partly related to import tariffs announced in 2018. The import tariffs imposed by the United States in 2018 included a 25% tariff on Chinese turbines and a 25% tariff on most foreign steel. Since a large share of the steel castings used to manufacture U.S. hydropower turbines are foreign, the steel tariffs effectively increased the cost of purchasing new turbines or turbine parts for U.S. plant owners.

Since the tariffs were first imposed in March 2018, tariff exemptions have been negotiated with Brazil, South Korea, Argentina, Australia, Mexico, and Canada. For the European Union, a tariff-rate quota system replaced the steel tariffs starting in 2022. With the new system, the European Union can export 3.3 million tons of steel per year without tariffs. In June 2022, a tariff-rate quota system (0.5 million metric tons tariff-free per year) was also applied to steel imports from the United Kingdom.

Based on 15 interviews conducted with hydropower industry participants in 2021, key challenges faced by the U.S. hydropower supply chain include difficulties domestically procuring steel castings heavier than 10 tons and stator windings for very large turbine-generator units, as well as workforce availability.

Different types of hydropower construction activities (new hydropower plants, new PSH, or refurbishments and upgrades (R&U) to existing hydropower and PSH) might be exposed to the supply chain challenges listed above to varying degrees. Due to their typical unit sizes, PSH projects and some R&U projects will likely be the most affected.

Additive manufacturing (AM)—a modality of advanced manufacturing for hydropower alongside novel machining and casting processes, advanced materials, and novel coating processes—is well suited to produce custom parts with complex geometries and could offer an alternative to produce domestically some of the components that currently have to be imported. Some turbine OEMs are already using AM for smaller components or to produce molds for castings. However, new AM machine designs are needed to build the largest components which are also the ones where domestic procurement is the hardest.

Federal incentives and federal procurement rules try to spur increased domestic manufacturing of hydropower components.

The Buy American Act imposes domestic content thresholds for federal projects. With the amendments to the Buy American Act that entered into force in October 2022, the domestic component cost threshold increases from 55% to 60% and then to 75% gradually by 2029. However, the applicability to the hydropower industry is limited because the Buy American Act restrictions do not apply to contracts whose value is above $7,032,000 and a large share of federal hydropower R&U projects have higher values.

Non-federal entities (excluding for-profit entities) that are recipients of federal financial assistance programs for infrastructure—such as the Section 242, Section 243, and Section 247 hydropower incentives from the BIL—are also bound by domestic preference requirements. The Build America, Buy America Act, approved along with the BIL, outlines those requirements.[9]

9 In the context of the Build America, Buy America Act, nonfederal entities include states, local governments, territories, Indian tribes, institutions of higher education, and nonprofit organizations.

For the IRA tax credits for new hydropower and PSH facilities, domestic content requirements are not a requisite (except for entities requesting the elective-pay option) for credit eligibility, but are a credit adder. If the taxpayer can show that 100% of steel or iron and 40% of manufactured products used in the construction are domestic, the production tax credit (PTC) is increased by 10% or the investment tax credit (ITC) is increased by 10 percentage points.

Finally, the IRA also includes tax credits for investments in manufacturing facilities for clean energy technologies, including hydropower.

Chapter 7. Policy Developments

The BIL, signed into law in November 2021, includes $753 million in appropriations for incentives targeted explicitly at hydropower facilities:

A new incentive (codified as Section 247 of the Energy Policy Act (EPAct) of 2005) for capital investments in existing nonfederal hydropower facilities that will improve grid resilience, improve dam safety, or make environmental improvements is authorized with $553 million of funding.

Section 242 incentives (authorized for an additional $125 million) are available for non-federal hydropower production added to an NPD, conduit, or non-federal hydropower facility with capacity less or equal to 20 MW in areas with inadequate electric service.

Section 243 incentives (codified in EPAct of 2005 but never funded until now) for funding hydroelectric efficiency improvement incentives is authorized with $75 million. Existing hydropower facilities (including PSH) improving efficiency by 3% or more are eligible to apply for Section 243 incentives.

The IRA became law in August 2022. Unlike the BIL, it does not contain specific appropriations for hydropower, but it includes PTCs and ITCs through 2032 that incentivize investment in clean energy (including hydropower and PSH). Unlike previous versions of renewable energy tax credits, hydropower is eligible for the same IRA tax credit amount as other renewables. Other important innovations in the IRA tax credits for hydropower include the availability of an elective-pay option for tax-exempt developers, the eligibility of conduit projects (>25 kW) for the PTCs, and the eligibility of PSH projects for the ITCs.

For facilities placed in service from January 2022 to December 2024, the PTC extends and modifies the technology-specific Section 45 PTC that was first enacted in 1992 and extended multiple times. The credit amount stated in the IRA text is 1.5 cents/kWh, but the applicable value for each year will be adjusted for inflation (relative to calendar year 1992). The inflation-adjusted value published by the Internal Revenue Service for 2023 is 2.75 cents/kWh. To be eligible for this credit amount a project must satisfy wage and apprenticeship requirements.[10] Otherwise, only 20% of the credit will be received (i.e., 0.55 cents/kWh in 2023). Projects eligible for the Section 45 PTC can select to claim the Section 48 ITC instead. The ITC amount is 30% of the cost of the eligible energy property for projects that satisfy the wage and apprenticeship requirements. For projects that do not meet those requirements, the ITC amount is 6%.

Projects that meet domestic content requirements (100% of steel or iron and 40% of manufactured products used in its construction are produced in the US) or are located in an energy community are eligible for an adder of 10% to their PTC or 10 percentage points to their ITC. Locations that qualify as energy communities belong in one of three categories: (1) brownfield sites; (2) metropolitan or nonmetropolitan statistical areas with substantial fossil fuel production and unemployment rates higher than the national average; and (3) Census tracts where a coal mine was closed after December 31, 1999, or a coal-fired electric generating unit was retired since December 31, 2009.

10 The wage requirement is for any laborers and mechanics employed in the construction of the facility and its alteration or repair within its first 10 years of operation to be paid wages at rates no less than the prevailing rates for similar activities in that locality. The apprenticeship requirement is a minimum percentage of labor hours in the construction, alteration, or repair of the facility to be performed by individuals in a registered apprenticeship program. The minimum percentage is 12.5% for work initiated in 2023 and 15% for work initiated in 2024 or later. There is a "good faith" exception for the apprenticeship requirement if the taxpayer makes a request for qualified apprentices from a registered program and then receives a negative answer or no answer in more than five business days.

For facilities placed in service starting in 2025, the IRA sets up new clean electricity production (Section 45Y) and investment (Section 48E) credits. Qualified facilities for the clean electricity production credit are those for technologies, including hydropower, with a greenhouse gas emissions rate not greater than zero. The tax credit is available for the first 10 years of production of the facility. Facilities that were already operational before 2025 can apply for credit for any additional production due to capacity additions or installations of new units during the credit eligibility period. The amount of the credit is 1.5 cents per kWh (to be adjusted annually for inflation; 2.75 cents/kWh in 2023) if wage and apprenticeship requirements are met; otherwise, the credit is 0.3 cents (0.55 cents/kWh in 2023). Taxpayers eligible for the Section 45Y production credit can choose between it or the Section 48E investment credits. Since they are net consumers instead of net producers of electricity, PSH facilities placed in service starting in 2025 only are eligible for the Section 48E investment credits. The ITC is 30% of the eligible project costs if wage and apprenticeship requirements are met; otherwise, the facility qualifies only for a 6% credit. The domestic content and energy community bonus credits described above for the 2022–2024 PTC/ITC are also applicable for the clean electricity production and investment credits.

For both the 2022–2024 extensions of the traditional PTC/ITC and the clean energy production and investment credits, credit recipients that are tax-exempt entities can select a elective-pay option (i.e., to receive a cash payment equal to the amount of credits they would otherwise receive) as long as they satisfy wage and domestic content requirements.[11] The possibility of a direct pay option is valuable for publicly-owned hydropower developers, such as municipalities and state agencies, that are tax exempt.

The Community and Hydropower Improvement Act (S. 1521), introduced in the Senate in May 2023, contains a licensing reform proposal developed by a coalition of representatives of the hydropower industry, environmental organizations, and Tribes. The reform seeks to "streamline the permitting and licensing process, increase tribal engagement and oversight, expedite low impact projects, promote healthy habitat, and coordinate federal decision making."[12]

For advancing low impact projects, the bill proposes an expedited licensing pathway for qualifying non-powered dams (NPDs) and closed-loop PSH projects. The expedited licensing process would apply to NPDs and closed-loop PSH projects with only incidental impacts to riverine systems. For NPDs, FERC would be directed to issue its final decision on a license application within two years after it determines that the proposed project qualifies for the expedited process. Such determination must happen within 90 days of the filing of a Notice of Intent to submit a license application. The expedited process also requires that the applicant for a qualifying NPD submits its final license application by the later of two dates: (1) 30 days after the close of a single season of studies conducted in support of the application or (2) one year after FERC's determination that the facility is qualified. The only differences in the case of qualifying closed-loop PSH projects are that (1) FERC shall issue its final decision on a license application within three years (rather than two for NPDs) of the determination that the project qualifies for the expedited process and (2) the applicant must submit the final license application no later than one year after FERC's determination (rather than having a choice of two dates).[13]

The proposal components directed to streamline licensing procedures also include a request for FERC to establish more clear and robust procedures for license surrenders by setting timelines (with an eye toward expediting the process for projects without complex environmental issues or public opposition) and providing opportunities for public participation.

11 However, they are exempt from the domestic content requirements if complying with them would increase project costs by 25% or there are not sufficient domestic components available of the required quality.

12 daines.senate.gov/wp-content/uploads/2023/05/Community-and-Hydropower-Improvement-Act-One-Pager.pdf.

13 This proposed expedited process differs from the two-year licensing process already available since 2019, directed by the America's Water Infrastructure Act of 2018, where FERC shall issue its final decision within two years after the date in which the applicant submits the final license application for either qualifying NPDs or closed-loop PSHs.

At the state level, since the 2021 edition of the Hydropower Market Report, seven states have increased their renewable portfolio standards (DE, IL) or clean energy mandates or goals (NE, NC, OR, CA, RI).

Renewable portfolio standards often have restrictions on the types of hydropower projects that count toward compliance; all hydropower typically counts towards a clean energy goal or mandate.

Additionally, two more states (ME and CT) have adopted energy storage mandates and a few others (IL, VT, MI) are considering them.

To date, most storage mandates are structured such that they are strongly geared toward short-duration, battery storage rather than PSH.

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R.C. Thomas Hydroelectric Project, Polk County, Texas
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