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U.S. Hydropower Market Report

2023 Edition

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for the U.S. Department of Energy

On the front cover: R.C. Thomas Hydroelectric Project, Polk County, Texas (image courtesy of Simpson Gumpertz & Heger). This facility, owned and operated by East Texas Electric Cooperative, added hydropower generation capability to a previously non-powered dam. It has three units with a combined generation capacity of 26.7 MW and began commercial operation in 2020.

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U.S. Hydropower Market Report

(2023 Edition)

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Highlights

U.S. Hydropower and PSH Capacity and Generation Statistics in 2022

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.[2] (Chapter 1)

- U.S. conventional hydropower capacity increased by 2.1 GW from 2010 to 2022. New project construction during that period included additions of hydropower to 32 non-powered dams (NPDs) with a combined generation capacity of 505 MW, hydropower installations at 89 conduits totaling 140 MW, and 8 new stream-reach developments (NSDs) with a combined capacity of 34 MW. The rest of the net increase (1.4 GW) resulted from capacity upgrades to existing plants. (Section 1.1)

The United States has 43 PSH plants with a combined generation capacity of 22 GW and an estimated energy storage capacity of 553 GWh.[3] Despite very strong growth in battery installations in 2020–2022, the U.S. PSH fleet continued to provide most of the utility-scale power storage capacity (70%) and energy storage capacity (96%) in 2022. (Chapter 1)

- U.S. PSH capacity increased by 1.4 GW from 2010 to 2022, of which 97% were capacity upgrades to the existing fleet. (Section 1.1)
- PSH provides longer duration storage than currently available batteries. 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. (Chapter 1)

Capital Investment in the Existing U.S. Hydropower and PSH Fleet

Multiple U.S. hydropower datasets (capacity additions, investment in refurbishments and upgrades, turbine runner installations, hydraulic turbine trade) show declines in activity in the first few years of the 2020s relative to the average for the 2010s. (Section 1.1; Section 1.3; Section 6.1; Section 6.2)

- These declines might be partially explained by COVID-19 restrictions and supply chain challenges that resulted in delays and cost increases; in the case of U.S. imports of hydraulic turbines and turbine parts, the decrease in activity starts in 2019 and was likely influenced by U.S. import tariffs.
- The hydropower incentives authorized in the Bipartisan Infrastructure Law (BIL) and the Inflation Reduction Act (IRA) tax credits are expected to stimulate investment in upgrades to the existing fleet and construction of new hydropower and 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. (Chapter 7)

1 Nameplate capacity value from ORNL Existing Hydropower Assets (EHA) Plant Database 2023, including hydropower plants in Puerto Rico.

2 eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf

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

Hydropower and PSH Relicense and License Surrender Trends

Virtually all capacity due to enter the hydropower relicensing pipeline in the past five years has done so. (Section 1.4)

- Of the 167 Federal Energy Regulatory Commission (FERC)-licensed hydropower and PSH projects due to start the relicensing process between 2018 and 2022—that is, those with licenses expiring between 2023 and 2027—155 of them (93%) have initiated the process, and they accounted for 99.9% of the capacity due to start relicensing during that period (8 GW). Of the remaining 12, 7 started the process to surrender their licenses and one requested conversion of a license into an exemption; the status of the other 4 projects was unclear at the end of 2022 based on the information on their dockets.

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. Of the 68 surrenders and terminations, 17 involve removal of a dam. (Section 1.5)

- The median authorized capacity in these licenses was 0.5 MW, but six of them had authorized capacities greater than 10 MW. The Klamath project in California (169 MW) accounts for more than half of the surrendered capacity.
- At the end of 2022, there were 18 pending surrenders (i.e., the licensees have submitted the surrender application and FERC is reviewing it) with a combined capacity of 34 MW; 4 of them propose dam removals.

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). 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. (Section 2.1)

- Fifty-six (48%) of the proposed new projects—with a combined capacity of 514 MW—already have authorization from FERC (or Reclamation). Only eight of them (14 MW) have started construction.

Ninety-six PSH projects were in the U.S. development pipeline at the end of 2022 (versus 67 at the end of 2019) with a combined power storage capacity of 91 GW. Developers have advanced beyond the feasibility evaluation stage for 10 of them. Of those 10, 3 have already been authorized by FERC but no new PSH is under construction. (Section 2.2)

- More than 80% of the proposed PSH projects have closed-loop configurations (i.e., their reservoirs are not continuously connected to a naturally flowing water feature), which allow more siting flexibility and have generally lower environmental impacts on aquatic and terrestrial resources than open-loop facilities.
- Proposed storage durations are typically 8–12 hours, but some developers are exploring longer storage durations.

Global Hydropower and PSH Construction

Although hydropower (including PSH) remains the technology with the largest share (40%) of global renewable electricity generation capacity (versus 50% in 2019), other renewable generation technologies (especially solar photovoltaics) have grown much faster in recent years. (Section 3.1)

- In the United States, hydropower (including PSH) accounted for 28% of renewable electricity generation capacity in 2022—the third largest renewable by installed capacity after wind (38%) and solar (31%).

- Almost 900 hydropower projects were under construction around the world at the end of 2022. These projects will increase global hydropower capacity by 9% (117 GW) relative to the installed capacity in 2022. Almost two-thirds of global hydropower under construction are concentrated in three regions: South Asia (32%), Africa (16%), and East Asia (16%). Only 1.5% of global hydropower capacity under construction is in North America. (Section 3.2)
- North America is the region with the greatest number of proposed PSH projects (96 in the United States and 5 in Canada), but none has reached the construction stage. Thirty-nine of the 56 PSH plants under construction globally are in East Asia (28) and Europe (11). These 56 plants will increase global PSH capacity by 38% (52 GW) relative to the 2022 installed capacity. (Section 3.2)

U.S. Hydropower and PSH Performance Metrics

The average U.S. net hydropower generation in 2020–2022 (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. (Section 5.3)

- 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%). 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.
- The median annual plant-level 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 2020–2022 averaged 35.3% versus 38.8% in the 2010s. (Section 5.4)

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). (Section 5.5)

- 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) is typically lower in the Western Electricity Coordination Council (WECC) than in other NERC regions, and the gap has widened in 2019–2021.[4]
- Both hydropower and PSH units display their highest availability factors during the summer months, suggesting that this is the season when their dispatchable capacity is most valuable.

Failures in turbine or generator components (typically in units that are beyond their expected design life) account for 69% of the potential generation lost because of 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. (Section 5.6)

- Close to 80% of the potential generation lost in 2013–2021 from forced outages related to lack of water corresponds to the WECC fleet and half of this generation loss happened in 2021.

The top 10 balancing authorities (BAs) by the average magnitude of their one-hour hydropower ramps (i.e., changes in the output of the hydropower fleet, including PSH, from one hour to the next) are in the Southeast and Northwest regions. (Section 5.7)

- The ability of the hydropower fleet to quickly adjust its output is an important attribute to help integrate increased penetrations of variable renewables in the grid.

4 There are multiple reasons to explain why the availability factor is higher than the capacity factor: (1) hydropower units do not always generate at their nameplate capacity, (2) hydropower units can be on standby—available to generate but directed to not do so by the market operator, (3) some hydropower units might, at times, act as motors rather than generators, contributing to grid stability but not producing electricity.

- The correlation between one-hour hydropower ramps and hourly changes in net load differs substantially across BAs and seasons. The higher the correlation, the more valuable the hydropower ramping is to balance the electric grid. In the 30 BAs that have more than 300 MW of installed hydropower and PSH, the season with the highest correlation between one-hour ramps and hourly change in net load in 2022 was winter for 12 BAs, summer for 8 BAs, fall for 8 BAs, and spring for the remaining 2 BAs.

U.S. Hydropower and PSH Supply Chain Challenges and Opportunities

Key challenges for the U.S. hydropower supply chain include the difficulty of domestically procuring steel castings heavier than 10 tons and stator windings for large turbine-generator units and workforce availability. (Section 6.3)

- Procurement rules for the federal hydropower fleet (Buy American Act), domestic content requirements in the Section 243 and Section 247 BIL hydropower incentives (Build America, Buy America Act), and domestic content adders in the IRA tax credits are among the federal initiatives to spur increased domestic manufacturing of hydropower components.
- The combination of an aging workforce and the difficulty of recruiting and retaining new hires for a wide array of positions including engineers, skilled trades (e.g., machinists and welders), and construction workers for jobs at remote sites results in challenges for the U.S. hydropower workforce pipeline. Expanding apprenticeship programs and developing and sharing hydropower curricula and educational resources are among the opportunities to address recruiting challenges.

Policy Developments

The BIL of 2021 and the IRA of 2022 contain significant authorizations for incentives for the U.S. hydropower fleet and industry. (Chapter 7)

- The BIL, signed into law in November 2021, includes $753 million in appropriations for incentives targeted explicitly at hydropower facilities.
    - Section 247 incentive: $553 million directed toward capital investments in existing nonfederal hydropower facilities that improve grid resilience or dam safety or those making environmental improvements.
    - Section 242 incentive: $125 million to fund nonfederal hydropower production added to a NPD or conduit, or to fund new nonfederal hydropower facilities with capacities no greater than 20 MW in areas with inadequate electric service.
    - Section 243 incentive: $75 million for funding hydroelectric efficiency improvements.
- The IRA, enacted in August 2022, includes $270 billion authorized for distribution as production tax credits (PTCs) and investment tax credits (ITCs) to support investments in clean energy out to 2032 including hydropower and, for the ITC, PSH.
    - Two important innovations for hydropower in the IRA tax credit are that (1) the PTC established parity for hydropower relative to other renewables and (2) credit recipients that are tax-exempt entities can select an elective-pay option.
    - The credit amounts are 2.75 c/kWh in 2023, to be adjusted annually by inflation, for the PTC and 30% of eligible investment costs for the ITC if the taxpayer can show that the project meets wage and apprenticeship requirements. Tax credit adders can be obtained if the project satisfies certain domestic content thresholds or is located in an energy community.

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.

- Among the proposed changes, the bill seeks to improve coordination among participants in the licensing process (with expanded authority for Tribes), ensure that license conditions are tied to project effects, and increase regulatory certainty with (1) an expedited licensing process for qualifying NPDs and closed-loop PSH projects and (2) clearer and more robust procedures for license surrenders.

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Acronyms and Nomenclature

AM	additive manufacturing
BA	balancing authority
BIL	Bipartisan Infrastructure Law
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EHA	Existing Hydropower Assets
EIA	Energy Information Administration
ELCC	effective load carrying capability
EPAct	Energy Policy Act of 2005
EQR	Electric Quarterly Report
EU	European Union
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GHG	greenhouse gas
IEA	International Energy Agency
IIJA	Infrastructure and Investment Jobs Act
IIR	Industrial Info Resources
IRA	Inflation Reduction Act
IRENA	International Renewable Energy Agency
ISO	independent system operator
ITC	investment tax credit
LBNL	Lawrence Berkeley National Laboratory
LDWP	Los Angeles Department of Water and Power
LOPP	Lease of Power Privilege
LSE	load-serving entity
MRO	Midwest Reliability Organization
NERC	North American Electric Reliability Corporation
NOI	Notice of Intent
NPCC	Northeast Power Coordinating Council
NPD	non-powered dam
NQC	net qualifying capacity
NSD	new stream-reach development
NWMT	Northwestern Corporation
ORNL	Oak Ridge National Laboratory
O&M	operations and maintenance
OEM	original equipment manufacturer
PMA	power marketing agency
PPA	power purchase agreement
PSH	pumped storage hydropower
PTC	production tax credit
PV	photovoltaic
RFC	Reliability First Corporation
RPS	renewable portfolio standard
RTO	regional transmission operator
R&U	refurbishment and upgrade
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
SWPA	Southwestern Power Administration
TRE	Texas Regional Entity
TVA	Tennessee Valley Authority
USACE	U.S. Army Corps of Engineers
WAPA	Western Area Power Administration
WAUW	Western Area Power Administration Upper Great Plains West
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WEO	World Energy Outlook
WRAP	Western Resource Adequacy Program

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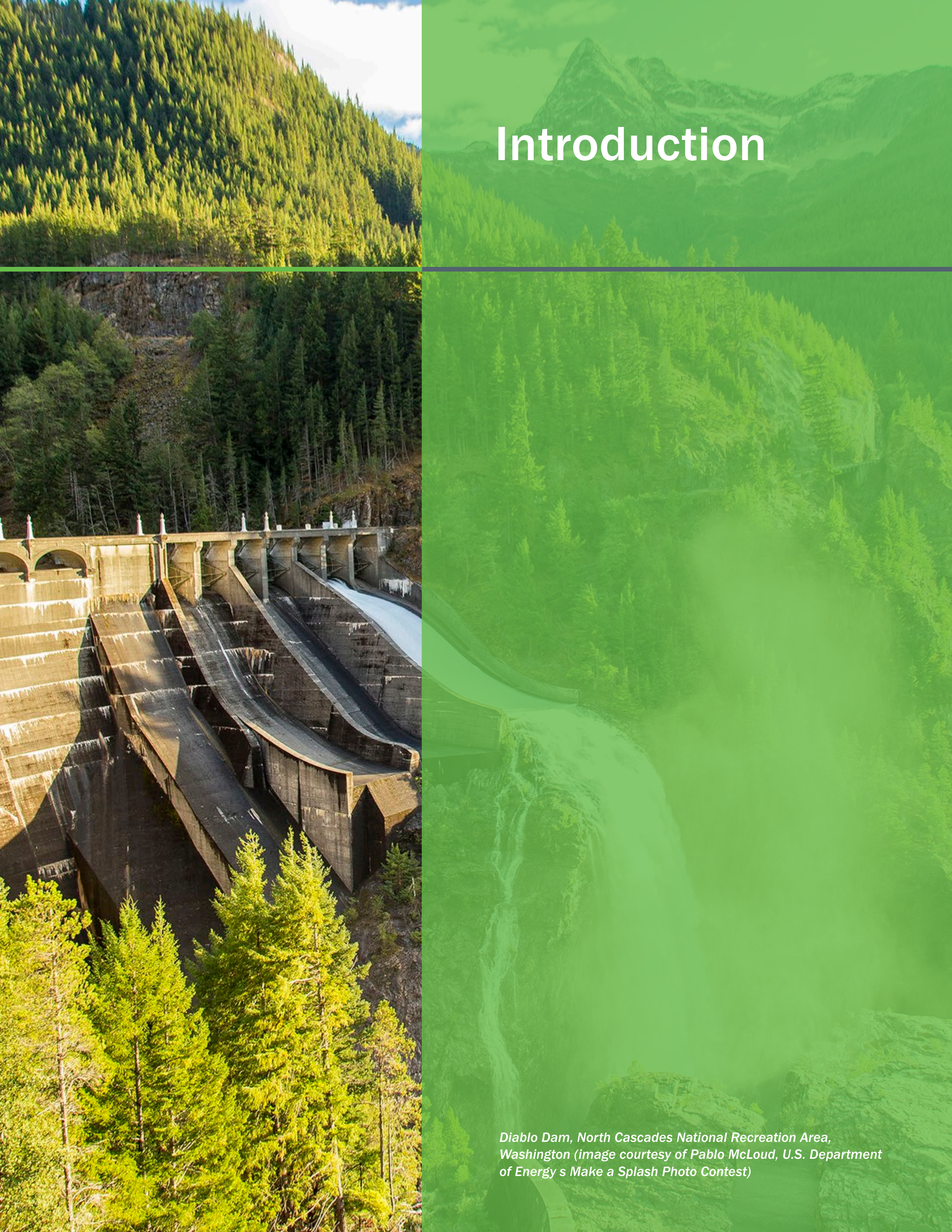
Introduction



Diablo Dam, North Cascades National Recreation Area, Washington (image courtesy of Pablo McLoud, U.S. Department of Energy s Make a Splash Photo Contest)

Introduction

This is the fourth complete edition of the U.S. Hydropower Market Report (the previous editions, published in 2015, 2018, and 2021, are available here). In intervening years between publishing the full report, updated data are also summarized and released and can be found at the Oak Ridge National Laboratory HydroSource website. This report combines data from public and commercial sources and research findings from other U.S. Department of Energy (DOE) R&D projects to provide a comprehensive picture of developments in the U.S. hydropower and pumped storage hydropower (PSH) fleet and industry trends. Prior to the first Hydropower Market Report being published, there was a noted lack of publicly available and easily accessible information about hydropower in the United States and other important trends affecting this important sector of the energy industry. New and valuable types of information are constantly being developed as part of DOE research activities and, in a rapidly evolving energy industry, it is important that these data be made available in a predictable and consistent manner for use by all different types of stakeholders and decision-makers.

This report highlights developments in 2020–2022 (the years for which new data has become available since the publication of the 2021 edition of the Hydropower Market Report) and contextualizes this information compared with evolving high-level trends over the past 10–20 years. The last year of data available varies by dataset depending on publication schedules. Apart from presenting trends over time, the report discusses differences in those trends by region, plant size, owner type, or other attributes.

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

- **Hydropower license surrenders and terminations (Section 1.5)**
- **Permitting activity trends (Section 2.4)**
- **International trends in hydraulic turbine trade (Section 3.3)**
- **Forced outage causes (Section 5.6)**

Chapter 1

Looking Back: An Overview of Changes Across the U.S. Hydropower and PSH Fleet

R.C. Thomas Hydroelectric Project, Polk County, Texas (image courtesy of Simpson Gumpertz & Heger)

Chapter 1. Looking back: An Overview of Changes Across the U.S. Hydropower and PSH Fleet

At the end of 2022, the U.S. conventional hydropower fleet included 2,252 hydropower plants with a total generating capacity of 80.58 GW.[1,2]. The U.S. hydropower fleet (excluding pumped storage hydropower [PSH]) produced 28.7% of electricity from renewables and 6.2% of all electricity in 2022.[3] In addition, the U.S. PSH fleet—43 plants with a combined generation capacity of 22 GW and an estimated energy storage capacity of 553 GWh—accounted for 70% of utility-scale power storage capacity and 96% of utility-scale energy storage capacity.[4]

This chapter describes the status of the U.S. hydropower and PSH fleets in 2022; provides an overview of changes in installed capacity; and summarizes trends in refurbishment and upgrade investments, license transfers, relicensing, and license surrenders. The chapter covers these topics for 2010–2022 with special attention to developments over the period since the publication of the last full U.S. Hydropower Market Report, 2020–2022.

Table 1 lists the top 20 states by installed hydropower and PSH capacity. For hydropower, the top three states are Washington, California, and Oregon. Together, they account for half of U.S. capacity. Sixteen states have more than 1 GW of installed hydropower capacity. PSH capacity is distributed across 18 states, with 44% concentrated in the top three (California, Virginia, and South Carolina).

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

Hydropower Capacity (MW)	
Cumulative (end of 2022)	
Washington	21,311
California	10,189
Oregon	8,457
New York	4,715
Alabama	3,109
Arizona	2,728
Idaho	2,727
Montana	2,672
Tennessee	2,504
Georgia	2,178
North Carolina	1,904
South Dakota	1,650
South Carolina	1,366
Arkansas	1,321
Kentucky	1,101
Nevada	1,057
Pennsylvania	870
Virginia	831
Oklahoma	824
Texas	738
Rest of United States	8,346

Pumped Storage Hydropower Capacity (MW)	
Cumulative (end of 2022)	
California	3,758
Virginia	3,109
South Carolina	2,849
Michigan	1,979
Massachusetts	1,768
Tennessee	1,714
Georgia	1,635
Pennsylvania	1,484
New York	1,240
Missouri	600
Colorado	508
New Jersey	453
Washington	314
Oklahoma	259
Arizona	194
North Carolina	95
Connecticut	31
Arkansas	30
Rest of United States	0

Source: ORNL Existing Hydropower Assets (EHA) Plant database 2023.

1 Nameplate capacity value from Oak Ridge National Laboratory (ORNL) **ORNL EHA Plant database 2023**, including hydropower plants in Puerto Rico.

2 A hydropower plant is a facility containing one or multiple powerhouses, each of which contain one or multiple turbine-generator units, located at the same site and using the same pool of water.

3 eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf. For hydropower percentage of all electricity, the value in 2022 was the fifth lowest since 1949 (after 2001, 2007, 2015, and 2021). For hydropower percentage of renewable electricity, 2022 was the first year below 30%.

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

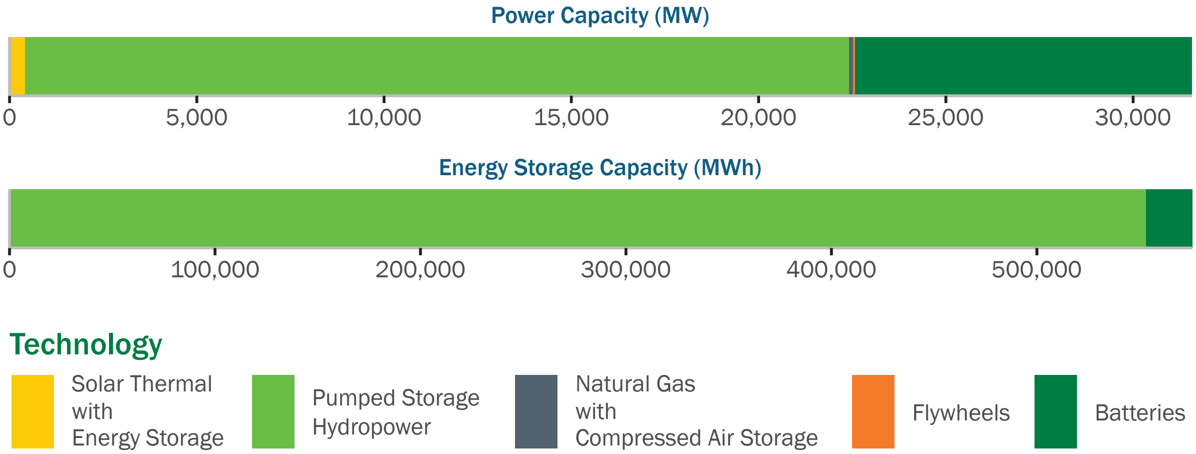


Figure 1. U.S. utility-scale electrical energy storage capacity by technology type (2022)

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

Note: 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.

Figure 1 shows that PSH remains the largest contributor to U.S. energy storage. Installed PSH capacity (22 GW) represented 70% of all utility-scale electrical storage capacity in the United States in 2022, a considerable drop relative to the 93% it represented in 2019. The rapid decrease in the PSH share of power storage capacity in the past three years is explained by the very fast growth in battery installations in 2021 and 2022. U.S. utility-scale battery capacity was 1.52 GW at the end of 2020. New battery installations added 3.4 GW in 2021 and 4.1 GW in 2022. Thus, by the end of 2022, utility-scale battery capacity reached 9 GW. More than 75% of the total U.S. battery capacity is in just two states: California (4.9 GW) and Texas (2.1 GW).

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 2 hours. The maximum duration (available at only eight installations) is 8 hours. In contrast, the estimated median storage duration of U.S. PSH plants is 12 hours.

1.1 New Project Development and Capacity Changes (2010–2022)

U.S. conventional hydropower capacity increased by 2.1 GW from 2010 to 2022. During this period, 129 new hydropower plants came online, totaling 679 MW; non-powered dam (NPD) retrofits accounted for almost 75% of this new capacity. The rest of the net increase resulted from capacity upgrades to existing plants. U.S. PSH capacity increased by 1.4 GW, of which 97% was capacity upgrades to the existing fleet.

Figure 2 displays regional changes in U.S. conventional hydropower capacity, by project type, from 2010 to 2022. Three project types—capacity additions, downrates, and retirements—involve modifications to the existing fleet. The other three correspond to new hydropower developments. NPD and conduit projects add hydropower production capabilities to existing water resource infrastructure (either to dams that previously had nonpower purposes or to conduits used for water supply or irrigation). Finally, NSD projects involve construction of hydropower facilities in river stream-reaches that had not previously been used for energy production.

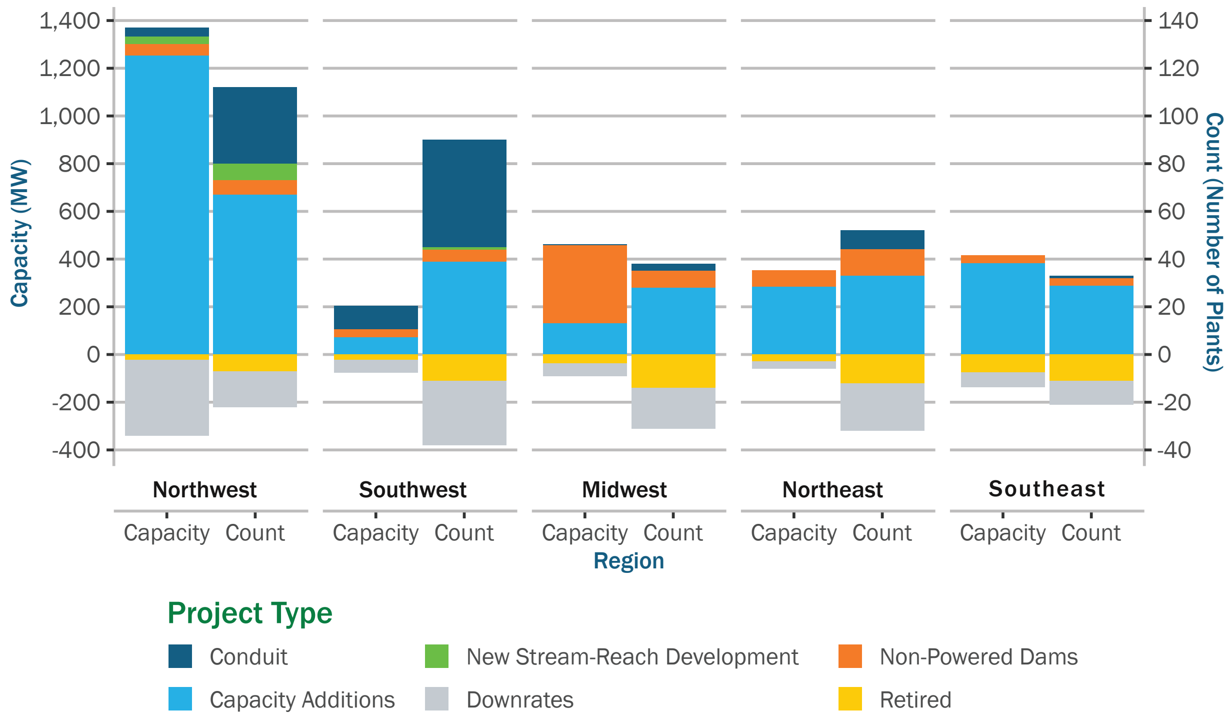


Figure 2. Hydropower capacity changes by region and type (2010–2022)

Sources: EIA Form 860 (2010–2021), EIA Form 860 2022 Early Release, ORNL 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.

For the U.S. hydropower fleet (excluding PSH), Figure 2 shows that capacity added through a combination of upgrades to existing plants and construction of new projects (2,805 MW) in 2010–2022 was greater than the capacity lost to unit downrates and plant retirements (702 MW). The resulting net increase in hydropower capacity during that period was 2,103 MW.

New project construction from 2010 to 2022 included additions of hydropower to 89 conduits (140 MW), 32 NPDs (505 MW), and 8 NSDs (34 MW). The predominant type of new hydropower development varies by region. Ninety-four percent of added capacity from NSDs is in the Northwest, 69% of capacity from conduit projects is in the Southwest, and 65% of new NPD capacity has been added to dams in the Midwest. As discussed in Chapter 2 for the U.S. hydropower development pipeline, the concentration of certain project types in specific regions is driven by availability of the required types of infrastructure (non-powered dams, conduits), as well as differences in topography and regional water use.

For the 155 plants with capacity additions, the median capacity increase is 15%. Capacity increases of that magnitude are consistent with what can be achieved through common refurbishment and upgrade (R&U) projects such as turbine runner replacement and generator rewinds.

From 2010 to 2022, 55 hydropower plants were retired, with a total capacity of 182 MW. The median capacity of these plants was 1.24 MW, and only five of them had a capacity greater than 10 MW. The region with the most retired plants during this period is the Midwest (14), followed by the Northeast (12); however, the region with the largest retired capacity (74 MW) is the Southeast.

In the first three years of the 2020s, the net change in capacity to the existing fleet (including capacity additions and unit downrates) was 92 MW; 16 new projects started operation: 10 conduits (6 MW), 4 NPDs (67 MW), and 2 NSDs (5 MW). Finally, 34 plants with a combined capacity of 39 MW were retired.

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 projects, the annual average in the 2010s was 60 MW and in 2020–2022 was 26 MW. This slowdown in capacity increases is consistent with data on refurbishment and upgrade investments shown in Section 1.2 and might be partly explained by the challenges caused by the COVID-19 restrictions and supply chain issues that resulted in delays and cost increases.[5]

Figure 2 does not include capacity changes to the PSH fleet. U.S. PSH capacity has increased from 20.5 GW in 2010 to 22 GW in 2022. As the only new PSH facility constructed in the United States during this period is Olivenhain-Hodges (42 MW), most of the capacity increase resulted from upgrades to the existing fleet. The most recent capacity changes in the U.S. PSH fleet took place in 2021. Duke Energy increased the capacity of Bad Creek, located in South Carolina, by 192 MW by upgrading two of its units while Seneca, located in Pennsylvania, reported a 57 MW downrate.

Hybrid plant configurations

Understanding the evolution in the capabilities of the U.S. hydropower fleet will increasingly require tracking the adoption of hybrid configurations. Lawrence Berkeley National Laboratory (LBNL) publishes a dataset of active and proposed U.S. hybrid plants (Bolinger et al., 2022). Hybrid plants are defined as plants where two or more generators of different technologies, or a generator and a storage device, are paired at a single interconnection point. Some hybrids are not only colocated but also co-controlled (Bolinger et al., 2022).[6] Plants that pair hydropower units with generators of different technologies have operated for decades. For instance, at the end of 2021, there were nine biomass-plus-hydro hybrids (typically at paper mills), 26 fossil-plus-hydro hybrids, and one instance of a nuclear-plus-hydro hybrid plant. Relatedly, 15 of the 43 PSH plants in the United States are also often described as hybrids because they contain a combination of conventional hydropower units and pumped storage units.

Pairings of hydropower and battery storage have been adopted with increasing frequency in recent years. 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.

The LBNL dataset lists five hydropower-battery pairings as active at the end of 2021: two in Alaska (Terror Lake Microgrid with 33.8 MW of hydropower and a 3-MW battery; Power Creek with 7.25 MW of hydropower and a 1-MW battery), two in Virginia (Buck Hydro with 8.5 MW of hydropower and a 4-MW battery system; Byllesby with 21.6 MW of hydropower and a 4-MW battery system), and one in Maine (Great Lakes Hydro with 138 MW of hydropower and a 20-MW battery system). In these five cases, the storage duration of the batteries is 1 hour or less. 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 are part of current grid interconnection queues: four of these proposals are for hydropower plants in Maine, and two more would add battery capacity to hydropower plants in Nevada. Hybridization with batteries is one of the project types eligible for the Section 247 incentive in the BIL.

Chalishazar et al. (2022) develop a case study to explore the value proposition of hydropower hybridization with batteries. Adding batteries to a hydropower system allows for discharging more energy into the grid when it is most valuable while limiting artificial fluctuations in river flow that have negative consequences on aquatic ecosystems and protecting turbine-generator units from the excess wear and tear brought about by frequent ramping and start-stop cycles. Bhatti et al. (2023) estimate that hybridization with batteries can extend the life of a hydropower unit up to 5%, which translates into economic benefits from reduced maintenance costs and deferred investment. Chapter 2 includes a description of other hybrid concepts being proposed such as PSH and solar.

5 For wind and solar, although COVID restrictions and supply chain challenges were also present in the first years of the 2020s, U.S. capacity additions were greater than in previous years. U.S. additions of utility-scale solar were greater than 10 GW each year in 2020–2022 and had never reached that value before (Feldman et al., 2023). For wind capacity, Wiser et al., (2022) report additions of 17.2 GW in 2020 and 13.4 GW in 2021 versus average annual additions of 7.2 GW in 2010–2019.

6 The dataset focuses on plants with an installed capacity of at least 1 MW.

Hydropower-to-hydrogen

Another emerging trend to optimize hydropower operations and revenue is the use of hydropower to produce hydrogen. Electrolyzers use electricity to split water into hydrogen and oxygen. Locating electrolyzers near hydropower plants provides access to the two main inputs needed (electricity and water). The resulting low-carbon hydrogen can then be used in different applications (e.g., as an input to petroleum refining operations or as a fuel for hydrogen-powered vehicles). Several hydropower-to-hydrogen projects are in operation or under development in world regions with large installed hydropower capacities (IHA, 2021).

Ongoing research is evaluating the economic and environmental impacts of coupling electrolyzers with hydropower generation plants.[7] Potential benefits include: (1) the hydropower plant owner can increase its revenue by sending the electricity to the electrolyzer rather than to the grid at times when excess renewables in the grid cause very low electricity prices, (2) hydrogen can be converted back to electricity and supplied to the grid during peak electric demand periods, (3) having two options to deliver electricity—to the grid or to the electrolyzer—can help the hydropower plant owner maintain more steady generation which helps decrease the wear and tear of hydropower units relative to modes of operation with more frequent ramping, (4) the oxygen produced by the electrolyzer as byproduct can be used to increase dissolved oxygen in a hydropower reservoir, to improve water quality. The Douglas County Public Utility District is installing a 5-MW electrolyzer near the Wells hydropower plant (774 MW) in Washington scheduled to start production in June 2024 and plans to closely couple hydropower and electrolyzer operations. In other cases, the electrolyzer and the hydropower facility are owned by different entities and proximity to hydropower is one of the factors driving the siting decision for the electrolyzer. For instance, Plug Power—a hydrogen production equipment supplier—has secured a 10-MW power allocation from New York Power Authority's Niagara Falls project (2,429 MW) for a 120-MW electrolyzer to be located near the hydropower facility.

The Section 45V Hydrogen Production Tax Credit in the IRA awards up to $3/kg of hydrogen produced with low lifecycle greenhouse gas emissions intensity. Implementation details for this tax credit, yet to be released, will determine under which conditions hydropower-based hydrogen will be eligible.[8]

7 inl.gov/water-power/national-laboratories-team-with-idaho-power-to-evaluate-hydrogen-generation-integrated-with-hydropower/

8 hydro.org/powerhouse/article/how-the-hydrogen-production-tax-credit-can-help-hydropower/

1.2 Ownership Changes (2010–2022)

The Federal Energy Regulatory Commission (FERC) approved 210 license transfers and notified the public of 109 exemption transfers from 2010 to 2022. Through these 319 transfers, 384 hydropower plants with a combined capacity of 3.8 GW and 5 PSH plants (3.3 GW) changed ownership. More than half of the plants transferred are in the Northeast.

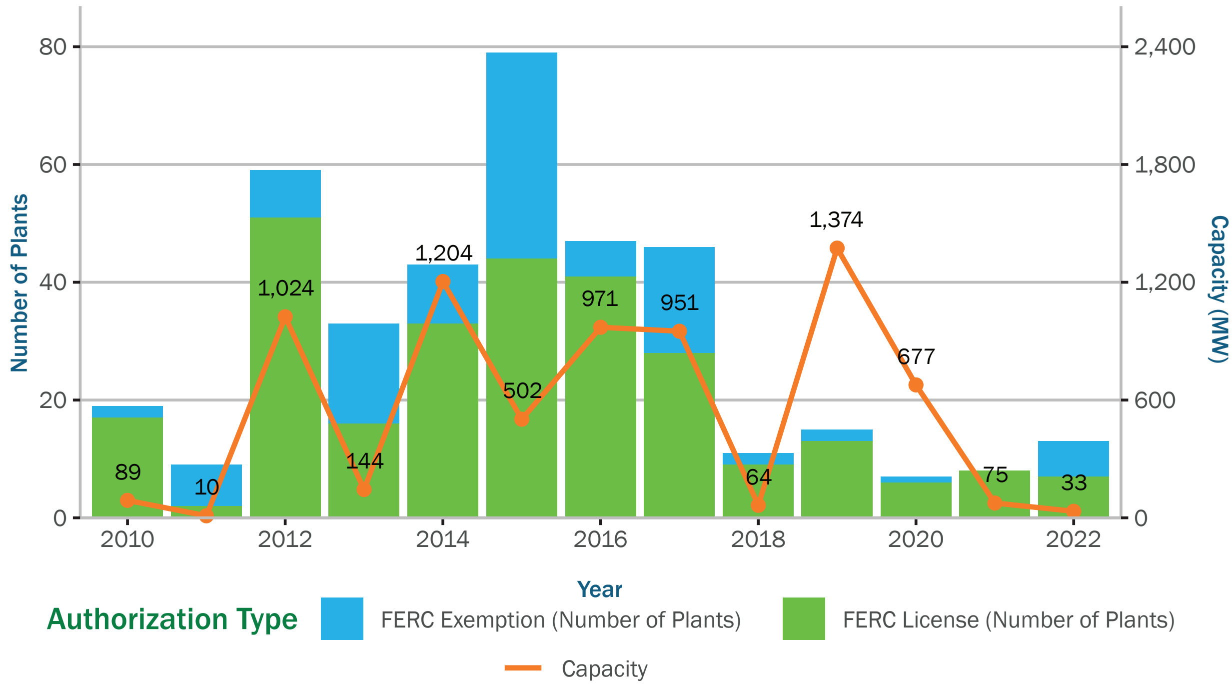


Figure 3. Hydropower and PSH ownership transfers by year and authorization type (2010–2022)

Sources: FERC eLibrary, ORNL EHA Plant database 2023.

Note: The plot includes only transfers that have already been approved by FERC.

Ownership changes of a hydropower plant licensed by FERC require the licensee to file (jointly with the prospective new owner) a transfer application. FERC's approval of the license transfer is contingent on transfer of the property title and a determination that the change of ownership is in the public interest. FERC approval is not necessary for ownership changes of hydropower plants that were authorized with FERC exemptions (instead of licenses). However, the transferors must communicate the transfers to FERC, which then issues notices of the changes to the public.

Figure 3 shows how many FERC-authorized plants and how much capacity changed ownership each year from 2010 to 2022. The pace of transfers was highest from 2012 to 2017; the annual average number of plants transferred during that period was 51. Outside of that six-year interval, less than 20 plants changed ownership each year. The total number of hydropower plants transferred in 2010–2022 was 384. Additionally, five PSH plants were among the transferred hydropower assets during this period. Because a single license can authorize multiple hydropower plants, there are more plants that change ownership (384) than there are licenses (210) and exemptions (109) transferred.

For 94% (300) of the transfers accounting for 98% of the capacity transferred, both the transferor and the transferee were private entities (e.g., investor-owned utilities, private non-utilities, power marketers, and industrial owners). A sizable fraction of these transfers change ownership among subsidiaries of the same parent company. Three transfers (5 MW) changed the ownership of plants from one public entity (e.g., cooperatives, municipalities, and irrigation districts) to another. Finally, 12 transfers (70 MW) involved a private transferor and a public transferee, and the remaining 4 (71 MW) changed the ownership of plants from public to private.

Figure 4 summarizes the regional distribution of the transfers, as well as the sizes of the plants being transferred. In all regions, most of the plants transferred are small (<= 10 MW). In total, 84% of the plants transferred had a capacity of no more than 10 MW, but they accounted for only 10% of the total transferred capacity. Fifty-three percent of the plants transferred (58% of the capacity transferred) are in the Northeast. The rest of the capacity transferred is located primarily in the Southeast and the Northwest.

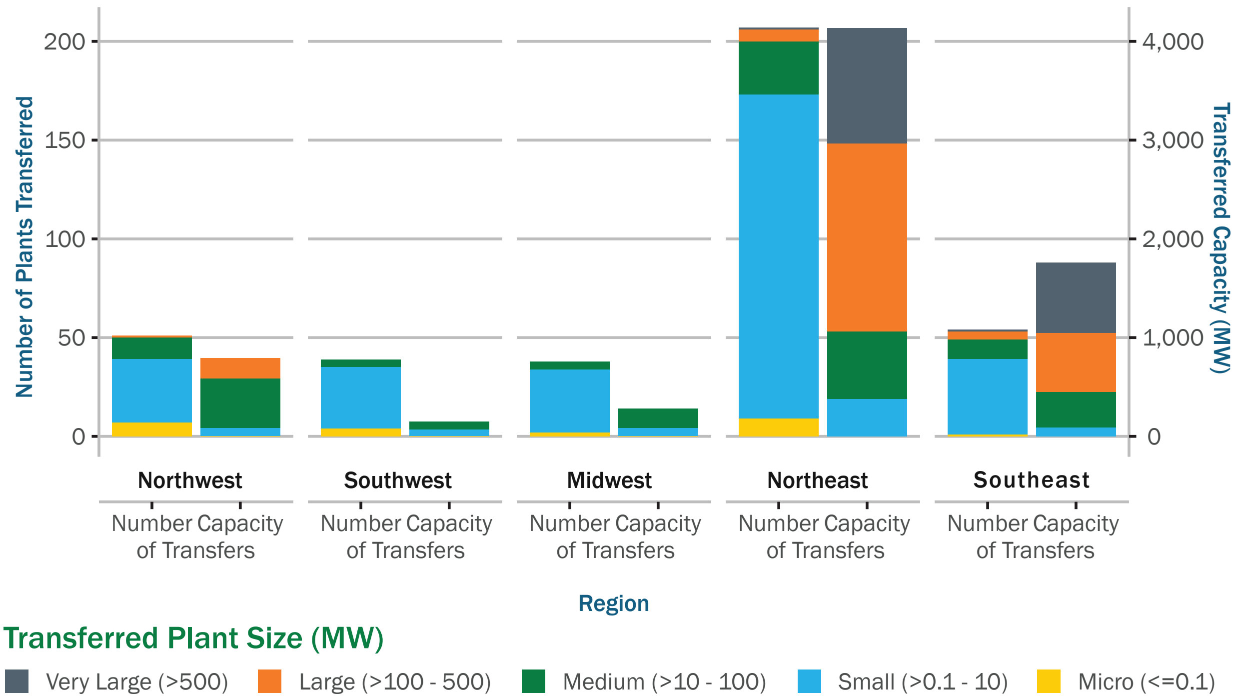


Figure 4. Hydropower and PSH ownership transfers by region and plant size category (2010–2022)

Sources: FERC eLibrary, ORNL EHA Plant database 2023.

Note: The plot includes only transfers that have already been approved by FERC.

Since publication of the previous U.S. Hydropower Market Report, which covered 2010–2019 transfers, an additional 20 licenses and 7 exemptions have been transferred, resulting in 27 hydropower plants (333 MW) and one PSH plant (Yards Creek in Pennsylvania, 453 MW) changing ownership. Of the 28 plants transferred from 2020 to 2022, 3 were in the Northwest, 6 in the Southwest, 4 in the Midwest, 8 in the Northeast, and 6 in the Southeast. Twenty-two of the 28 plants transferred during that period were small. A few entities relinquished or acquired ownership of multiple plants through transfers during this period. For instance, the City of Danville (Virginia) transferred two licenses (three plants with a total capacity of 16.35 MW) to two limited liability companies. Sappi North America, owner of multiple paper mills and hydropower plants in the Northeast, transferred four licenses that authorize the operation of four hydropower plants with a total capacity of 8.9 MW to two limited liability companies. Pacific Gas & Electric, a California investor-owned utility, transferred three licenses (and sold the underlying assets) with a total authorized capacity of 28.2 MW. One of the plants (Chili Bar) was transferred to the Sacramento Municipal Utility District based on the argument that its operation must be closely coordinated to one of the transferee's hydropower projects and that it is easier for a single licensee to operate both. The other two transferred plants have not been operational since 2017 because of damages caused by a rockslide in one case and a wildfire in the other. In both cases, the transferees plan to repair the damages and return the plants to operation. As of the end of 2022, Pacific Gas & Electric had additional license transfer applications pending FERC review.

1.3 Investment in Refurbishments and Upgrades (2010–2022)

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. Almost 85% of the tracked investment is in projects that are focused on improving the performance and extending the life of turbine-generator units. Incentive payments from the BIL might help stimulate investment in the nonfederal fleet in the upcoming years.

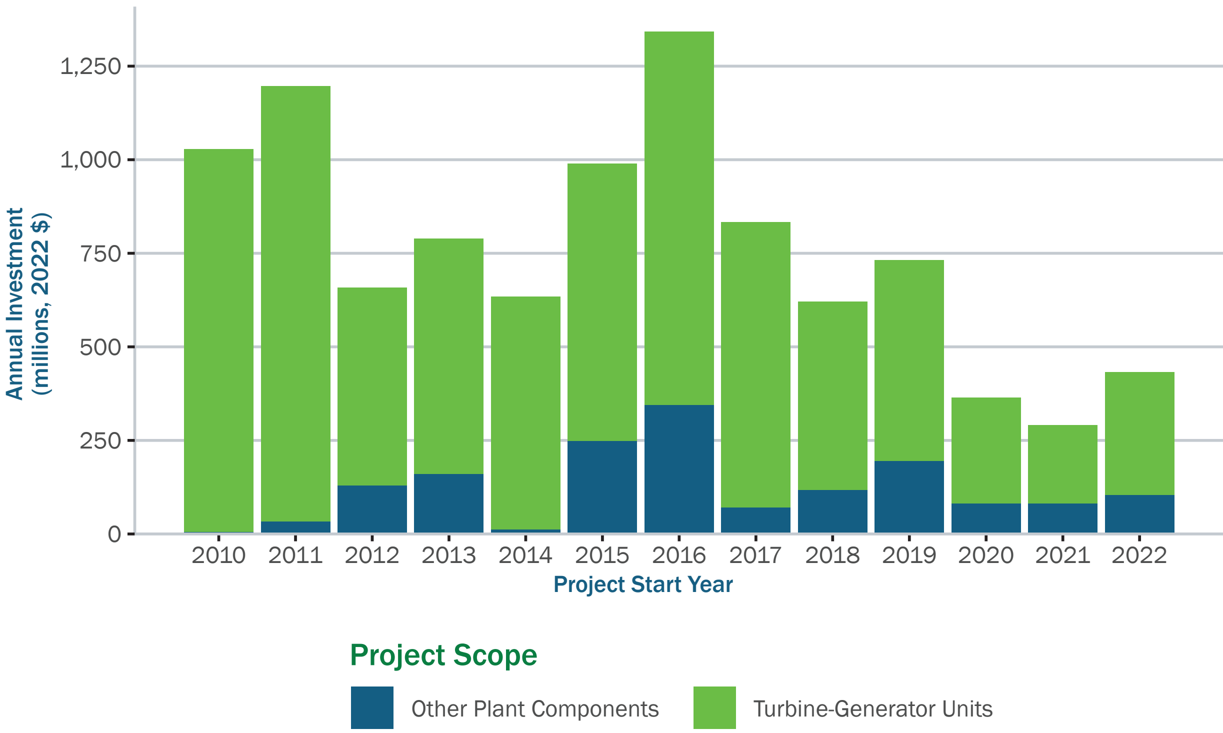


Figure 5. Expenditures on rehabilitations and upgrades of the existing hydropower and PSH fleet by project scope

Source: Industrial Info Resources (IIR).

Note: 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 category include projects for which the main item in the scope is a governor or exciter replacement or upgrade.

Since 2010, at least 168 hydropower plants and 16 PSH plants have undergone R&Us with project values greater than one million dollars. Total investment initiated from 2010 to 2022 amounted to $9.9 billion (in 2022 dollars). As of December 2022, 30 projects with a total combined value of $1.4 billion were in progress, with some of them starting as far back as 2016.

From 2020 to 2022, the annual average hydropower and PSH R&U investment was $363 million; during the 2010s, R&U investment averaged $883 million per year. A slowdown in construction activity because of the COVID-19 restrictions and related supply chain challenges could have contributed to some of the drop in investment in the first years of the 2020s.

Figure 5 shows that 84% of the R&U investment is concentrated in projects for which the scope of work focuses on turbine and/or generator components to improve their performance and extend their life. Investments in turbine-generator units can also pursue environmental benefits. Aerating runners were installed at 16 turbine-generator units, in 5 hydropower plants in the Southeast, to increase downstream oxygen levels and improve water quality.

Common types of projects involving turbine-generator units are turbine runner replacements and generator rewinds. However, projects that upgrade or replace governors or exciters are also included in the turbine-generator category. Although the governor and the exciter are not components of the turbine or generator, they support their operation.[9]

9 The governor regulates the rotational speed, power output, and system frequency of the turbine-generator units by controlling the flow of water through the opening/closing of the wicket gates. The excitation system supplies and regulates the amount of direct current needed by the generator rotor windings. (Uría-Martínez et al. 2022)

For the remaining 16% of investment shown in Figure 5, common R&U projects involve either other mechanical components (e.g., refurbishment or replacement of gates, penstocks, or cranes) or electrical plant components (e.g., replacement of transformers, switchgear replacements, and switchyard upgrades). The median value of turbine-generator R&U projects ($11 million) is substantially larger than the median value of other R&U projects ($4 million). Larger total values in 2015 and 2016 are driven by two large projects: the modernization of the fire system for one large plant and the construction of a composite seepage barrier to fortify the dam at another plant.

Figure 6 shows the share of 2010–2022 R&U investment versus the share of installed capacity (as of 2022) for the hydropower and PSH fleet segmented by region, plant type, and owner type. For each of the segments, if the dot on the plot is above the 45-degree line, the share of investment it received was higher than the share of installed capacity it represents. If the dot is below the line, the share of R&U investment directed to that segment was lower than its share of installed capacity.

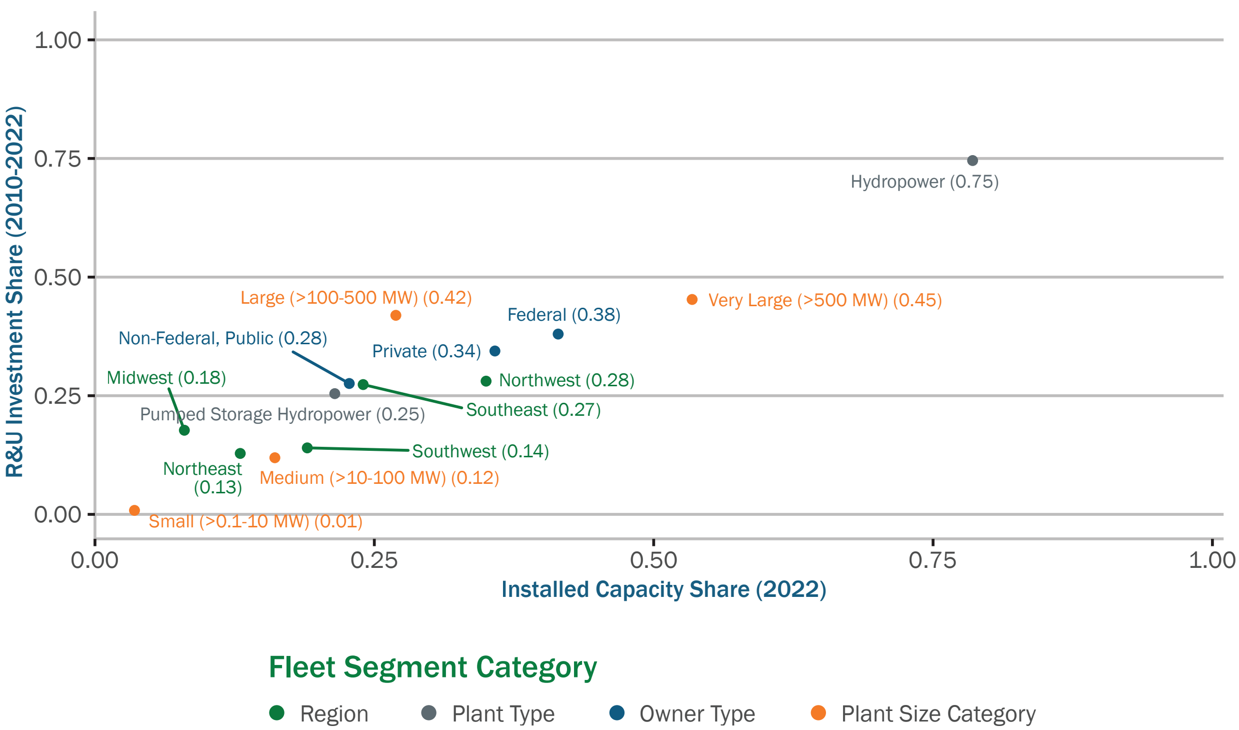


Figure 6. Share of 2010–2022 R&U investment versus share of installed capacity for various hydropower (including PSH) fleet segments

Source: IIR, ORNL EHA Plant database 2023.

Note: The IIR dataset only covers R&U projects with a value greater than $1 million and data are primarily collected from direct queries to plant owners with sizable hydropower fleets. For these reasons, coverage is incomplete for small hydropower plants. The values shown in the labels correspond to the R&U investment shares for each fleet segment.

For most segments displayed in Figure 6, the R&U investment share is close to the installed capacity share. The largest differences between share of 2010–2022 investment and share of installed capacity correspond to the segment of large plants (100–500 MW) and some of the regional segments. The R&U investment share for large plants was 42% and they represent 27% of installed capacity. For all other size categories, their R&U investment share was somewhat lower than the installed capacity share.

As for regional segments, the R&U investment share for the Midwest (0.18) is much larger than its installed capacity share (0.08). In contrast, the share of R&U investment received by the hydropower (including PSH) fleets in the Northwest (0.28) and the Southwest (0.14) was lower than the shares of capacity they represent (0.36 for the Northwest and 0.19 for the Southwest). As for the R&U investment with construction starts in 2020–2022, only 26% went to fleets in the Northwest and

Southwest, even though together they account for 55% of installed capacity. A reduction in revenues from electricity sales due to drought has likely contributed to a deferral of capital investments in the hydropower fleet in the West.

The R&U investment share for the conventional hydropower segment of the fleet was 0.75, which is lower than the installed capacity share it represents (0.79). The opposite is true for PSH. PSH plants account for a lower share of installed capacity (0.21) than the share of R&U investment they received (0.25) in 2010–2022. This can be partly explained by the age of this segment of the fleet. More than 80% of U.S. PSH installed capacity started operation between 1965 and 1985. Therefore, from 2010 to 2022, much of the PSH fleet reached the age at which a first major overhaul of the turbine-generator units is typically required. All the PSH R&U investment projects captured in Figure 6 had construction start dates earlier than 2020.

As for owner types, the segment of the fleet owned and operated by nonfederal, public entities (e.g., state agencies, municipalities, publicly owned utilities, and cooperatives) is the only one for which the share of R&U investment received in 2010–2022 (0.28) is greater than the share of installed capacity it represents (0.23). The federal fleet was relatively underinvested because its investment share (0.38) was lower than its capacity share (0.41). However, when considering only the R&U projects initiated since 2020, the federal fleet received the highest share (0.56) and the fleet segment owned by private entities (e.g., investor-owned utilities, private non-utilities, and industrial corporations) received the lowest share (0.14). Therefore, in 2020–2022, increased investment in the federal fleet has partly offset a marked decline in investment in privately owned hydropower (both conventional hydropower and PSH) plants.

Some of the incentive payments in the Bipartisan Infrastructure Law (BIL) (see Chapter 7 for details on available amounts and project eligibility details) may be used to help fund projects such as those discussed in this section. These incentives are expected to support increased R&U investment levels in the existing U.S. hydropower fleet in upcoming 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.

1.4 Relicensing Activity (2010–2022)

Virtually all capacity due to enter the relicensing pipeline from 2018 to 2022 has done so. The number of relicense applications submitted during that period (136) is more than double the number of relicenses issued (60). At the end of 2022, there were 136 pending relicenses with a combined capacity of 10.9 GW.

Hydropower and PSH projects owned by nonfederal entities typically require a FERC license as authorization for their construction and operation.[10] This initial license, known as the original license, lasts up to 50 years. Licensees need to relicense the projects to continue operating them after the original license expires. Alternatively, they can start a license surrender proceeding or, if eligible, they can request to convert their license into an exemption. Relicensing is a multiyear process that creates risks for the project owner because the terms and conditions of the new license (i.e., relicense) might require capital investments and changes in mode of operation.

Between five and five and a half years before the expiration of the current license, project licensees must submit to FERC their Notice of Intent (NOI) to relicense the project. At that point, the pre-filing period of the relicensing process starts, which involves conducting consultation with stakeholders, identifying study needs, conducting the necessary studies to evaluate environmental impacts and measures to address them, and preparing the relicense application. Then, two years before the expiration of their current license, project licensees must submit to FERC their relicense application. During the post-filing period, FERC solicits formal comment from stakeholders and prepares an environmental document. Once FERC staff make a recommendation to authorize the project, FERC issues the relicense order, which includes required actions to ensure project safety and mitigate environmental impacts. If the post-filing period extends beyond the expiration date of the previous license, FERC automatically grants annual license extensions to allow continued project operation.

10 Many small projects without significant environmental impacts are eligible to follow the exemption process instead of the licensing process. The exemption process is similar to the licensing process, but one key difference is that an exemption order is issued in perpetuity while a license order lasts up to 50 years. As of 2023, there are 624 active exemptions with a combined authorized capacity of 879 MW.

A large number of licenses have expired or will expire during the 2020s. Between 2020 and 2029, 281 licenses that authorize 12% (4.7 GW) of FERC-licensed installed hydropower capacity and 50% (9.1 GW) of FERC-licensed PSH capacity will expire. The data presented in this section is a snapshot of relicensing activity as of the end of 2022. It covers the status of licenses expiring up until the end of 2027.

Of the 167 FERC-licensed hydropower and PSH projects due to start the relicensing process between 2018 and 2022—that is, those with licenses expiring between 2023 and 2027—155 of them (93%) have initiated the process, and they accounted for 99.9% of the capacity due to start relicensing during that period (8 GW).[11] 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.

Figure 7 summarizes the trends in relicensing activities from 2010 to 2022 by showing the number of NOIs to relicense and relicense applications submitted each year, as well as the number of relicense issuances.

Figure 7. Relicensing activity trends by milestone and project type (2010–2022)

Source: FERC, ORNL EHA Plant database 2023.

11 Almost 75% of the 167 projects due to start the relicensing process between 2018 and 2022 have authorized capacities of less than 10 MW. For about half of them, this is the first relicensing period after first obtaining their original license in the 1980s. Also included among these 167 are 4 large PSH projects also being relicensed for the first time after obtaining 50-year original licenses in the 1970s.

The notable increase in the number of submitted NOIs to relicense shown in the top panel of Figure 7 from 2016 on results from the large cohort of projects with licenses that expire in the 2020s. The number of NOIs submitted in any given year is also indicative of the number of relicense application submissions to be expected three years later. For instance, in the period covered by Figure 7 the highest level of activity for NOI submissions was in 2019 and for relicense application submissions it was 2022.

The number of relicense applications submitted from 2018 to 2022 (136) is more than double the number of relicenses issued during that same period (60). The widening gap between the number of relicense applications and the number of relicense issuances since the late 2010s is indicative of a growing number of pending relicenses and a heavy workload for FERC staff.

The bottom panel of Figure 7 shows the total annual capacity for each activity milestone differentiating between hydropower and PSH. Even though 2022 had the highest number of relicense applications submitted (50) for the period shown, their combined capacity was 421 MW, meaning that most of the applications came from owners of small (<10 MW) projects. Given the much larger median size of PSH projects relative to hydropower projects, years in which one or several PSH or hybrid projects complete one of the relicensing milestones tend to correspond with the highest capacities in the bottom panel of Figure 7.

The rest of this section summarizes the characteristics of projects that got relicenses issued in 2010–2022, as well as projects that are either in the post-filing or pre-filing stages of the relicensing process as of the end of 2022.

Issued Relicenses

For the 121 relicenses issued from 2010 to 2022, the median duration of the process was 5.8 years. However, there was a wide range of durations. Ten percent of projects with the shortest relicensing durations completed the process in 4.7 years or less, and 10% of projects with the longest relicensing durations completed the process in 12 years or more.

The median relicensing duration of 5.8 years is divided evenly between the pre-filing and post-filing period.[12] The median pre-filing period was 3 years long, and the median post-filing period was 2.8 years long. The pre-filing period rarely lasts more than 3.5 years because of the established timeline for submitting the NOI to relicense (between 5.5 years and 5 years before license expiration) and the relicense application (two years before license expiration). Only 9 of the 121 issued licenses from 2010 to 2022 spent more than 3.5 years in the pre-filing period.

For the post-filing period, however, the duration range is wider. There were 28 projects with post-filing durations of two years or less and 26 projects with post-filing durations of 5 years or more. The long timelines for obtaining a Clean Water Action Section 401 certification or to complete, when needed, Endangered Species Act Section 7 consultations are two of the post-filing milestones that can considerably lengthen the post-filing period (Levine et al. 2021).

No single basic project characteristic such as project size or region determines the expected duration of the relicensing process for a specific project. Levine et al. (2021) analyze in detail the relicensing processes for 63 projects that had relicenses issued in 2005 or later and find that environmental complexity (e.g., the potential impacts to significant cultural or natural resources and the presence of endangered species or critical habitats) can be a key factor in influencing relicensing timelines.

There are some other patterns worth noting among the subsets of projects with the shortest and longest post-filing durations. Twenty of the 28 projects with post-filing durations under 2 years used the Integrated Licensing Process.[13] Sixteen of the 28 were small projects (<10 MW of installed capacity), but 4 of them were large or very large PSH or hybrid projects with capacities ranging from 259 MW to 1,785 MW. Nineteen of the 26 projects that spent more than five years in the postlicensing

12 Although the submission of the NOI to relicense marks the official start of the relicensing process, licensees will often start preparing for the process years in advance of that date.

13 The Integrated Licensing Process has been FERC's default licensing process since July 2005, but there are two other processes that the licensee can request (Alternative Licensing Process and Traditional Licensing Process). The three processes are very similar in the post-filing stage. The Integrated Licensing Process has the most predictable schedule in both the pre-filing and post-filing stages, and FERC oversees that the pre-filing schedule is met. In the Alternative Licensing Process, the licensee determines the pre-filing schedule in collaboration with stakeholders. Finally, the Traditional Licensing Process has no set timeframes. FERC especially recommends using the Integrated Licensing Process in projects with complex issues that require close coordination with stakeholders in the pre-filing stage (FERC, 2017).

period used the Traditional Licensing Process. Only one PSH project (Taum Sauk) is in the subset with post-filing durations greater than five years. There was a higher prevalence of peaking (as opposed to run-of river) projects in the subset of projects with post-filing periods greater than five years (14 out of 26) than in the subset with post-filing periods under two years (6 out of 28). The frequent flow fluctuations that result from peaking operations might translate into a higher number of environmental mitigation conditions having to be evaluated during the relicensing process and, therefore, a longer process. Finally, 13 of the 28 projects with post-filing periods longer than five years used settlement agreements (versus 7 out of 26 for the subset with post-filing periods under two years long). Settlement agreements are more often used in projects with complex issues to help resolve disputes among stakeholders. Thus, they might be interpreted as a proxy for project complexity.

For 15 of the 121 issued relicenses, the capacity authorized in the relicense is higher than in the previous license. The combined capacity additions implied by these licenses amount to 107 MW. In some cases, changes in authorized capacity result from plans by the licensee to upgrade the project facilities after the new license is issued. For instance, the Green Island Power Authority proposed increasing the capacity of the turbines in its Green Island Project and constructing a second powerhouse for a total capacity increase of 42 MW. These changes were authorized in its new license, issued in 2012. In other cases, the licensee is requesting authorization to use upgraded turbine-generator units, installed under the old license, at their full capacity. For example, Portland General Electric requested authorization for an increase in hydraulic capacity for two units in its Clackamas project for which they had upgraded the turbine runners since the facility was first licensed. The new license was issued in 2010. Another 14 relicenses approve modifications to the turbine-generator units that do not lead to capacity additions.

Projects in post-filing relicensing period as of the end of 2022 (i.e., Pending Relicenses)

At the end of 2022, there were 136 pending relicenses with a combined capacity of 10.9 GW. Of them, 1 is a 1.2 GW PSH plant (Northfield Mountain in Massachusetts), 3 are hybrid plants with a combined capacity of 1.8 GW, and 132 hydropower plants make up the remaining 7.9 GW. 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. 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.

The median time elapsed since these 136 licensees submitted their relicense applications is 1.3 years. For 29 of them, their relicenses have been pending for five or more years. These are mostly in the Northeast (7) and Southwest (19, all in California). Eighteen of the 27 are using the Integrated Licensing Process, 7 are using the Alternative Licensing Process, and the remaining 4 are using the Traditional Licensing Process.

Projects in the pre-filing relicensing period as of the end of 2022 (i.e., Pending Relicense Applications)

At the end of 2022, there were 74 projects in the pre-filing stage of the relicensing process with a combined capacity of 6.5 GW. Seventy of them are hydropower projects with a combined capacity of 1 GW. The remaining four are the largest, and they are all PSH projects. Any of those 4 projects—Rocky Mountain in Georgia (1 GW), Helms in California (1 GW), Bad Creek in South Carolina (1 GW), and Bath County in Virginia (2.5 GW)—have as much or more installed capacity than the 70 hydropower projects combined. Since three of these four large PSH plants are in the Southeast, the Southeast is the region with the most capacity (70% of the U.S. total) in the pre-filing stage of the relicensing process. By number of projects, 57% are in the Northeast region but most of them are small (<10 MW). The other three regions (Midwest, Northwest, and Southwest) all have fewer than 10 projects in the pre-filing stage of the relicensing process.

1.5 License Surrenders and Terminations (2010–2022)

From 2010 to 2022, FERC issued 68 license or exemption surrenders and terminations, with a combined capacity of 322 MW. The median capacity of these licenses was 0.5 MW. Sixteen of them (24%) will involve the removal of a dam. The two reasons most commonly cited for surrendering a license during this period were lack of economic feasibility or a decision to pursue restoration of aquatic ecosystems. Another 18 licensees have submitted surrender applications, which were under FERC review as of the end of 2022; the combined capacity authorized by those licenses is 34 MW.

The license (or exemption) surrender process requires the licensee to prepare a surrender application for FERC to review. FERC can approve or deny the request. If licensees so choose, however, they can withdraw the surrender application if they find another entity willing to take over the project. The surrender process can be long and complex, especially if it involves the removal of project facilities, in which case FERC will typically need to prepare an environmental document. Another possibility is that the licensee neglects to operate, maintain, or surrender the project, which then forces FERC to terminate the license or exemption.

Figure 8 shows the number of license (or exemption) surrender applications submitted and the number of surrenders issued by FERC for each year from 2010 to 2022.

Figure 8. License surrender activity trends by milestone and project type (2010–2022)

Source: FERC, ORNL EHA Plant database 2023.

Figure 8 shows that the number of instances of either of the milestones (surrender applications or surrender issuances) ranged from 1 to 10 per year from 2010 to 2022. Terminations are considered an implied surrender by FERC and are therefore called a surrender in the text and in the figure.

Issued Surrenders (2010–2022)

From 2010 to 2022, FERC issued 68 surrenders for licenses (and exemptions) with a combined capacity of 322 MW. The median capacity of the surrendered licenses is 0.5 MW.

By far the largest project whose license has been issued a surrender during this period is the Klamath project in California (169 MW). 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. Therefore, they do not affect total U.S. installed capacity. The other three are the Eagle and Phenix project in Georgia (28 MW), the Morris Shepard Dam project in Texas (23 MW), and Jackson Bluff in Florida (12 MW).

Twenty-eight of the 68 licenses surrendered are for projects in the Northeast. In all other regions, the number of licenses surrendered from 2010 to 2022 ranged from 6 to 14. The 68 licensees were evenly distributed between public entities (e.g., cooperatives and municipalities) and private entities (private non-utilities and industrial). Sixteen of the license surrenders will involve the removal of a dam. In cases that do not involve dam removal, the dam owner remains responsible for dam maintenance after the license is surrendered or terminated and dam safety enforcement reverts from FERC to the state dam safety office.

The median length of the surrender process (from surrender application submission to surrender issuance and not a termination) was 0.8 years. There were five projects for which the surrender process lasted 100 days or less and another five for which it lasted more than three years. One of the five projects with the longest surrender processes had the largest surrendered capacity, but the other four are less than 2 MW.

As part of the surrender application document, a licensee must state the reason for the surrender. By far the most frequent reason, cited in over half of the applications that FERC has accepted from 2010 to 2022, is economic infeasibility. Within that category, many small projects cite the need for costly repairs (caused by wear and tear of the plant components or damage from 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 other most frequent motivation to surrender a license is to pursue restoration of aquatic ecosystems. This is the reason for the surrender of the Klamath River project license, which will entail removal of four dams.[14] It is worth noting that 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.

All the terminated projects (license or exemption) had ceased operation and abandoned the project dating back as far as 1991. All terminated project dams were left in place after dam inspections showed low risk to the public and environment.

Pending Surrenders as of December 31, 2022

As of 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. The median installed capacity of these projects is 0.97 MW. Most of the pending surrenders are for projects located in the Northeast (7) or the Southwest (6). Four of the pending surrenders propose removing a dam as part of the project decommissioning plan.

For 9 of the 18 pending surrenders, the surrender application was submitted in 2021 or 2022. However, in four cases (all in the Southwest region), the surrender application was submitted in 2016 or earlier.

14 americanrivers.org/dam-removal-on-the-klamath-river/.

Chapter 2

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

Division Booster Pump Station Project, Skagit County, Washington (image courtesy of Gregg Semler, InPipe Energy)

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 as of the end of 2022. It describes the types of projects being proposed, their location, size, ownership type, and development stage. It also summarizes FERC licensing activities related to new project development in the past five years (2018–2022).

2.1 U.S. Hydropower 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.

Figure 9 shows the location, size, and type of each hydropower project in the development pipeline and summarizes the distribution of the projects along different stages of the development process. The map includes both new projects and projects with capacity additions.

For new projects, the development stages shown in Figure 9 mainly correspond to milestones in the most common federal permitting process (FERC licensing).[15],[16] The earliest public document describing a new hydropower project is typically a preliminary permit application submitted to FERC. If the preliminary permit application is being reviewed by FERC, the project is in the "Pending Preliminary Permit" stage. Once FERC issues the permit, the project is in the "Issued Preliminary Permit" stage. A preliminary permit gives priority to the permittee over other applicants to develop that project site for a four-year period. However, it does not authorize the developer to start construction. During the preliminary permit period, the permittee conducts feasibility studies and may start consulting with stakeholders to determine whether to apply for federal authorization to construct the project. Typically, only a small fraction of active preliminary permits result in successful projects. For those developers who decide to move to the next stage of the authorization process, the next steps are notifying FERC of their intention and preparing the license application. Once the license (or exemption) application has been submitted, the project is in the "Pending License" stage. During this stage, FERC reviews the application, solicits comments from stakeholders, and prepares the environmental assessment document. If FERC decides to authorize the project, it will issue a license or exemption, at which point the project reaches the "Issued License" stage. From that point until construction starts, the developer conducts a variety of preconstruction activities including obtaining additional permits, securing financing, closing offtake agreements, and completing technical designs for the project.

New hydropower development is also subject to state-level regulations and permitting (e.g., water quality certification and water rights permitting). Some of the required state permits (e.g., water quality certification) are necessary conditions for obtaining a FERC license.[17]

For capacity additions, only two stages are depicted in Figure 9: (1) those that are already in the construction stage and (2) those that are in the planning phase. For FERC-licensed facilities, the planning phase will include a process to obtain authorization from FERC for the capacity change.

15 For projects that require a lease of power privilege from the Bureau of Reclamation, equivalent milestones were identified to fit the categories shown in Figure 9, as described in the figure notes.

16 An overview of the FERC licensing process is available at ferc.gov/sites/default/files/2020-05/hydropower-primer.pdf.

17 The Regulatory and Permitting Information Desktop (RAPID) Toolkit offers an overview of hydropower regulation and permitting at both the federal and state levels (openei.org/wiki/RAPID/Hydropower/Jurisdictions).

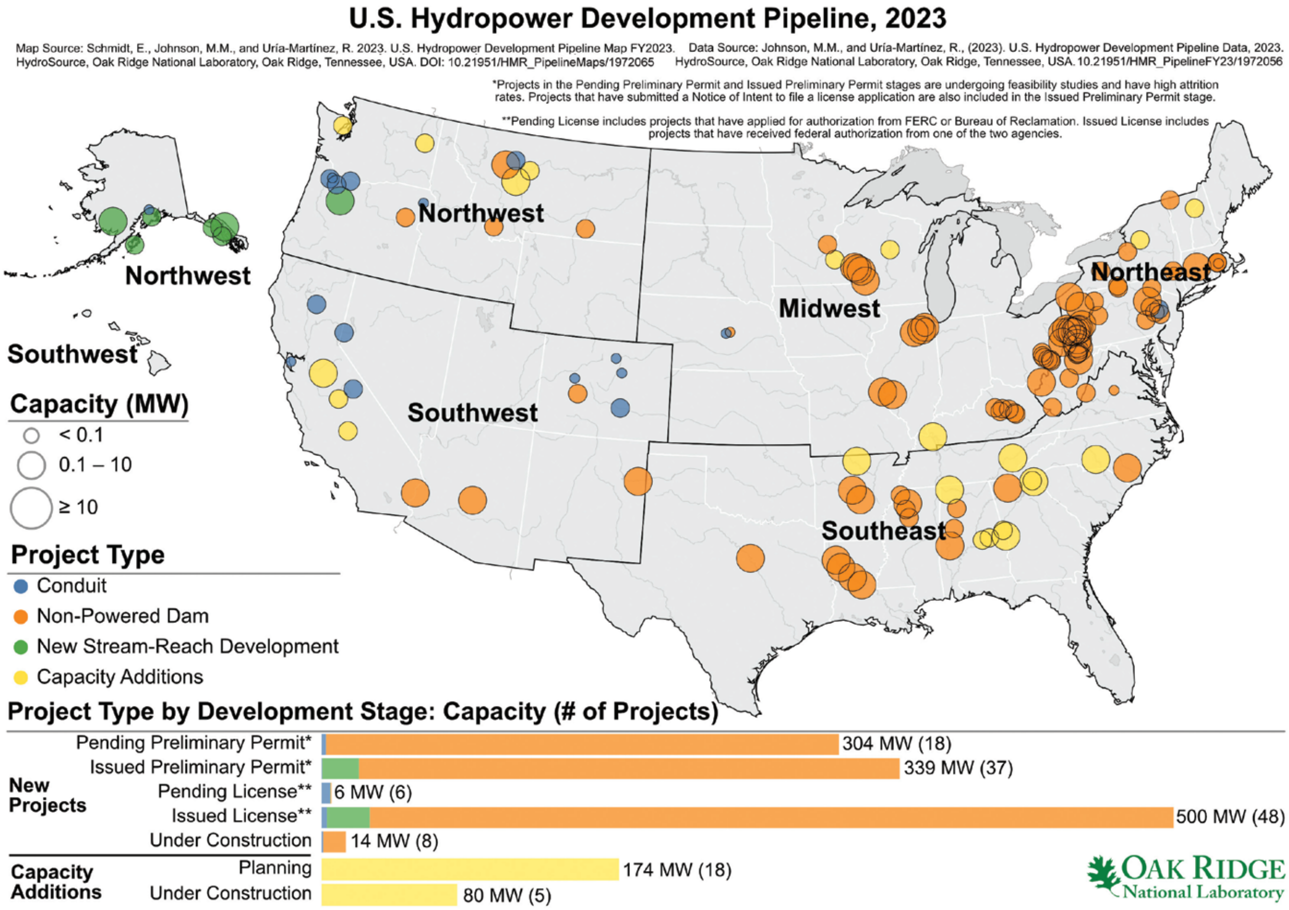


Figure 9. Hydropower project development pipeline by project type, region, size, and development stage (as of December 31, 2022)

Sources: ORNL U.S. Hydropower Development Pipeline Data 2023, FERC eLibrary, IIR.

Notes: Conduit capacities are too small to be visible on the horizontal bar plot. The capacities are 2.5 MW (Pending Preliminary Permit*), 0.365 MW (Issued Preliminary Permit*), 5 MW (Pending License**), 3.13 MW (Issued License**), and 0.89 MW (Under Construction).

*Projects in the Pending Preliminary Permit and Issued Preliminary Permit stages have high attrition rates. Pending Preliminary Permit includes projects pending a preliminary lease in the LOPP process and projects pending issuance of a FERC preliminary permit. Issued Preliminary Permit includes projects that have received a preliminary lease in the LOPP process, projects that have obtained a FERC preliminary permit, and projects with an expired preliminary permit but that for which a Notice of Intent to file a license or a draft license application has been submitted.

**Pending License includes projects for which an original FERC license or a FERC exemption has been applied for or for which a request has been made to be considered a "qualifying conduit" hydropower facility by FERC. Issued License includes projects that have been issued an original FERC license or a FERC exemption, have been approved by FERC for the qualifying conduit hydropower status, or have received a final lease contract under the LOPP process.

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). The Northeast is the region with the highest number of new project proposals (42) and the largest share of proposed new capacity (375 MW, 32% of the U.S. total), followed closely by the Southeast (360 MW across 18 new hydropower projects). The Midwest has 27 proposed projects with a combined capacity of 252 MW. Projects in the development pipeline in the Northwest and Southwest regions add up to 82 MW (18 projects) and 95 MW (12 projects), respectively.

Fifty-six (48%) of the proposed new projects—with a combined capacity of 514 MW—already have authorization from FERC (or 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.

Eighty of the 94 MW of hydropower capacity under construction at the end of 2022 corresponded to upgrades to five existing plants. The Marseilles Lock & Dam project in Illinois accounts for 10 of the 14 MW from new projects under construction. The rest is distributed between two other NPD projects in Kentucky and Rhode Island and five conduit projects in Colorado, California, and Nebraska.

Conduit projects

The development pipeline includes 17 projects that propose adding a total of 11.9 MW of new hydropower capacity to existing canals or conduits. These projects range in capacity from 2 kW to 5 MW, and their average capacity is 0.7 MW. Fifteen of them are in the Northwest and Southwest because those are the regions with the largest resource potential based on the combination of large volumes of water conveyed through conduits and suitable topography (hilly or mountainous terrain). Kao et al. (2022) assessed the U.S. resource potential for adding hydropower to conduits in the municipal, agricultural, and industrial sectors. The estimated technical capacity potential in those three sectors adds up to 1.4 GW, of which 73% was concentrated in the top 10 states. Of those 10 states, 7 are in the West (California, Colorado, Washington, Oregon, Utah, Idaho, and Wyoming) and the remaining 3 are Nebraska, New York, and Texas.

Most (13) of the conduit projects propose adding hydropower to existing pipeline infrastructure and the other 4 to canals. The proponents of conduit projects include public and private developers. Among the public developers of conduit projects, there are municipalities (seven projects), water supply or irrigation districts (three projects), and state agencies (one project). Private developers of conduit projects include limited liability companies (three projects), private individuals (two projects), and one supplier of equipment for hydropower installations in pipeline systems (one project).

Thirteen of the conduit projects that were in the development pipeline at the end of 2022 were eligible for the qualifying conduit pathway, which does not require FERC licensing.[18] Three are seeking a FERC exemption, and the other one falls under Bureau of Reclamation jurisdiction and must obtain a LOPP from that agency instead of a FERC authorization.

Non-powered dam projects

Ninety-five percent of proposed new hydropower capacity results from plans to retrofit existing dams that are currently dedicated to uses other than power generation (e.g., flood control, navigation, irrigation, water supply, and recreation). The average proposed capacity of NPD projects is 12 MW. NPD project capacities range from 0.012 to 54 MW. Forty percent (37) of the NPD projects propose adding generation capacities greater than 10 MW.

The technical potential for NPD projects is large because less than 2,500 dams of the 91,757 listed in the National Inventory of Dams have power production as one of their authorized purposes. NPD retrofit projects are largely concentrated in the Northeast, Midwest, and Southeast regions. Hadjerioua et al. (2012) performed a national NPD resource assessment that shows that those three regions contain 92 of the 100 NPDs with the largest energy potentials.

Of the 93 NPDs for which hydropower retrofits are 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. For dams owned by the Bureau of Reclamation, whether authorization to add power generation capability must be provided by the Bureau of Reclamation through the LOPP process or by FERC must be determined on a case-by-case basis.[19] Under either process, Reclamation has oversight to ensure that powering the dam will not conflict with other authorized dam purposes. For dams owned by USACE, the developer must obtain a Section 408 permit from that agency in addition to a license from FERC.[20] The Section 408 permit

18 The qualifying conduit pathway was introduced by the Hydropower Regulatory and Efficiency Act of 2013. The criteria for being deemed a qualifying conduit hydropower facility are using a nonfederally owned conduit that is operated for the distribution of water for agricultural, municipal, or industrial consumption and adding generation capacity not greater than 40 MW.

19 Information about the Bureau of Reclamation's LOPP process is available at usbr.gov/power/LOPP/index.html.

20 An overview of the Section 408 permit process is available at www.publications.usace.army.mil/Portals/76/Publications/EngineerCirculars/EC_1165-2-220.pdf?ver=2018-09-07-115729-890.

ensures that the civil works alterations required to add power generation do not harm the public interest and do not impair the ability of the dam to continue providing its other authorized purposes. Of the 24 NPD projects with issued FERC licenses proposing to add hydropower to a USACE dam, only one appears in USACE's Section 408 database as having submitted a Section 408 application.

New stream-reach development projects

Seven projects propose developing hydropower at new stream reaches. These projects are referred to as NSDs in this report, and they range in capacity from 0.14 to 19.8 MW, with an average capacity of 6.7 MW. Six of them are in Alaska, and one is in Oregon. Alaska and Oregon are among the top 10 states by NSD capacity potential identified in a national NSD resource assessment (Kao et al. 2014). The only one of the seven NSD projects that involves construction of an impoundment dam is Grant Lake in Alaska; the rest would use weirs and intake structures to divert flow towards the powerhouse.

Capacity addition projects

The 23 hydropower capacity upgrades identified as being in planning or under construction at the end of 2022 include upgrades to federal (5) and nonfederal (18) facilities. Most of the capacity additions are capacity upgrades resulting from turbine replacements and generator rewinds, but three owners plan on adding new turbine-generator units to their plants (see Figure 10). Nonfederal plants need FERC approval to increase their capacity. In 16 of the 18 nonfederal capacity addition projects, owners sought approval for the capacity changes by submitting a license (or exemption) amendment application; the others obtained approval as part of their relicensing process.[21]

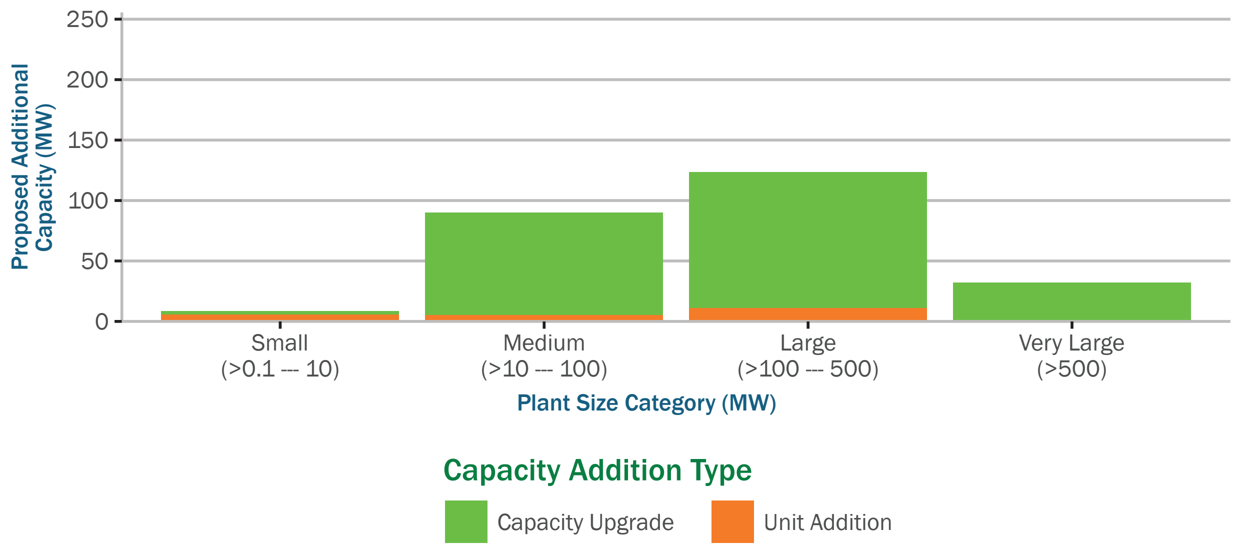


Figure 10. Proposed capacity additions to the existing hydropower fleet by plant size category and project type

Sources: FERC, IIR.

Figure 10 shows that capacity upgrades account for more than 90% of the capacity to be added to the existing U.S. hydropower fleet. On average, the 23 plants undergoing capacity upgrades will increase their capacity by 21%. For unit addition projects, the largest of the proposed additional units is 6.3 MW.

Two of the three projects that involve unit additions seek generating power from mandatory environmental flows. Minimum environmental flows are one of the most common environmental mitigation measures required in FERC licenses. Schramm et al. (2016) found that 82% of 447 U.S. hydropower plants licensed or relicensed from 1998 to 2013 were required to provide minimum flows. In cases where the required minimum flow volume (in cubic feet per second) is lower than the minimum flow

21 Levine et al. (2017) provide details on the regulatory approaches that can be followed to obtain approval for capacity changes in FERC-licensed projects.

needed by the originally installed turbines to operate, harnessing the power from environmental flows requires installation of an additional smaller turbine.[22] Production of these additional units would be eligible for Section 242 incentives in the BIL.

2.2 U.S. PSH Development Pipeline

Ninety-six PSH projects were in 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 ten of them. Of those 10, 3 have been authorized by FERC but no new PSH is under construction.

Figure 11 displays the location, size, and development stage of each PSH project (new or upgrade of an existing facility) in the development pipeline.

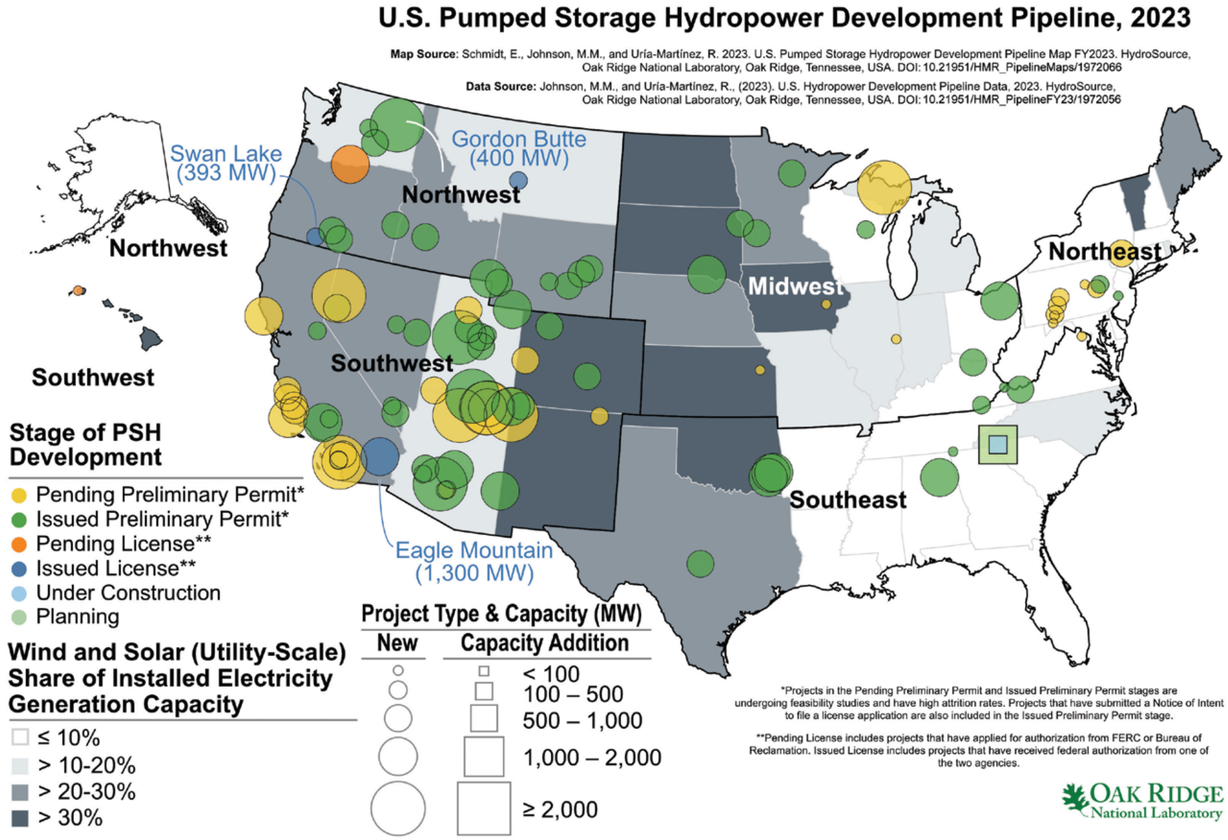


Figure 11. PSH project development pipeline by region and status in relation to state variable renewable (wind and solar) shares of electricity generation capacity

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

Notes: The Planning stage applies only to the Capacity Addition project type. Details on which projects are included in other stages are the same as for Figure 9.

Twenty-eight states have at least one PSH project in the development pipeline. California and Arizona lead with 15 and 11 projects, respectively. The 2021 share of utility-scale variable renewables (wind and solar) has limited use as a predictor of PSH project density. 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

22 Garrett et al. (2023) estimate the potential additional U.S. hydropower capacity and energy that could result from installing turbines to capture currently unexploited minimum flows. For a subset of 200 hydropower facilities with detailed historical flow data, installation of minimum flow turbines could add up to 730 MW of capacity and 1.8 TWh of energy. Based on screening criteria for the rest of the fleet, related to the ratio of nameplate capacity of the smallest turbine in a plant with respect to the capacity of the other (primary) units, total potential additional energy ranges from 12–66 TWh. That range would imply an increase in generation of 4%–24% relative to the average 2011–2021 U.S. hydropower net generation.

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 (Rosenlieb et al. 2022).[23] The high concentrations in Utah and Arizona, despite relatively low variable renewable shares in their generation mix, can be explained by a combination of having suitable sites and being an intermediate location between states with high penetration of renewables and the large loads of the West Coast. 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. The range of generation capacities is very wide (17–9,000 MW), and typical storage durations would be 8–12 hours. Some developers are exploring longer storage durations, and others are proposing hybrid projects that combine PSH with other renewables.

Proposed PSH projects have a wide range of sizes (17–9,000 MW). The Southwest has the most projects in the pipeline (48), and they have the greatest capacity on average (1,183 MW). The Northwest is second by number of projects (17), with an average capacity of 745 MW. The other three regions have similar numbers of projects in the pipeline: Midwest (12), Northeast (10), and Southeast (9). The average capacity of PSH projects proposed in the Northeast (217 MW) is much smaller than for those in the Midwest (866 MW) and Southeast (768 MW). Thirty percent of the PSH projects have generating capacities of 1 GW or more, and three projects propose capacities greater than 4 GW.[24]

For 71 of the 96 new PSH projects in the pipeline, information on proposed storage duration (i.e., the number of hours needed to empty the upper reservoir at the maximum power rating of the turbines) was included in the project descriptions offered in FERC docket documents or online articles. Proposed durations ranged from 8 to 12 hours for 66 of the projects. Therefore, the typical proposed PSH project would follow under the category of long-duration energy storage of up to 20 hours, which helps manage daily cycles of imbalance between electricity supply and demand (Twitchell et al. 2023). The PSH pipeline also includes some proposals with storage durations greater than 20 hours. For example, the draft license application for the Cat Creek Energy and Water Storage project in Idaho cites a storage duration of 120 hours, and the Beclabito Hydroelectric Energy Storage Center project in New Mexico is exploring configurations with energy storage durations of 60 hours or more.

Of the 96 new PSH projects in the pipeline, 78 are closed-loop projects. 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 concentration of closed-loop projects in the development pipeline contrasts with the characteristics of the existing U.S. PSH plants, which are all open loop. Closed-loop configurations allow more siting flexibility. Although such configurations still require sites with sufficient surface elevation difference between the upper and lower reservoirs, they do not need to be adjacent to a body of water. Another important advantage of closed-loop PSH is that its environmental impacts are generally lower.[25] Since 2019, closed-loop projects that can document low environmental impacts (i.e., little to no change to existing surface and groundwater flows and uses and no adverse effects on threatened and endangered species and their critical habitats) are eligible for a two-year FERC license process (see further discussion in Chapter 7).

For closed-loop projects, especially those in the arid portions of the West, the ability to obtain water (surface or groundwater) rights for the initial fill of the upper reservoir and to make up for evaporation and seepage losses during operations is a key step to ensure the feasibility of the project. Water rights are governed by state law. Developers apply for permits to appropriate water for the purpose of the hydropower generation in the state where the water source is located.

23 Rosenlieb et al. (2022) performed a GIS analysis to estimate the technical potential for closed-loop PSH systems in the United States. They identified 14,846 potential systems (pairings of reservoirs within a suitable distance and with sufficient elevation difference) with a total 35 TWh of energy storage potential (3.5 TW of 10-hour storage systems) after applying filters to exclude protected areas or areas with incompatible land uses. The areas with the greatest density of potential sites are the Rocky Mountains, the Cascade Range, and the Alaska Range. On the eastern half of the country, potential sites are concentrated in the Appalachian Mountains.

24 If one of these three were built, it could become the largest PSH plant in the world. The three largest PSH plants in the world as of 2022 are Fengning in China (3.6 GW), Bath County in the United States (2.9 GW), and Kannagawa in Japan (2.8 GW).

25 Saulsbury (2020) compared the potential environmental effects of open-loop and closed-loop configurations on aquatic and terrestrial resources during construction and operation and concludes that closed-loop projects typically have lower overall impacts. However, the impacts on geology and soils as well as groundwater (if that is the source of water to fill the reservoirs of the closed-loop system) can be higher for closed-loop than open-loop systems.

The three PSH projects that have already been licensed by FERC—Eagle Mountain in California, Gordon Butte in Montana, and Swan Lake in Oregon—all propose closed-loop configurations. The developers for these three PSH facilities continue to work towards compliance with their preconstruction license requirements. All three have requested extensions of their construction start deadline within the last year.[26] For Eagle Mountain and Gordon Butte, the request for extensions of the construction start deadline is at least partially connected with not having secured the rights to all the lands within the project boundary. Swan Lake did not link its extension request to any specific license requirement.

Figure 11 also shows two PSH projects in the pending license stage as of the end of 2022: Goldendale (1,200 MW, Washington) and West Kaua'i (24 MW, Hawaii).[27] They are also closed-loop projects. Five more projects (all in the West) have submitted to FERC a Notices of Intent to file final license applications: Blue Diamond (450 MW, Nevada), Cat Creek (720 MW, Idaho), Mokelumne (400 MW, California), White Pine (500 MW, Nevada), and Seminoe (972 MW, Wyoming). Three of these (Cat Creek, Mokelumne, and Seminoe) propose open-loop configurations.

The West Kaua'i Energy Project in Hawaii is a hybrid pumped storage, solar, and battery storage project. Permitting jurisdiction falls under the state of Hawaii rather than FERC. The 24-MW pumped storage portion of the project would use three existing reservoirs that are part of an irrigation system. A solar array to be built adjacent to the lower reservoir and firmed by batteries would provide all the pumping power. The project, proposed by the Kaua'i Island Utility Cooperative and AES Corporation, has been approved by the state's Public Utility Commission.

Another example of a hybrid PSH concept is the installation of floating solar photovoltaic (PV) panels on the reservoirs to reduce evaporation losses. A developer with three PSH pending preliminary permits in Arizona included this feature as part of the project description in the preliminary permit applications.

2.3 U.S. Hydropower and PSH Project Sizes and Developer Types

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. Investor-owned utilities have shown an increased interest in PSH projects in the last two years.

Figure 12 shows which combinations of project type, size category, and developer type are most common in the U.S. hydropower (including PSH) project development pipeline as of the end of 2022.

Almost 90% of PSH projects fall in the Large (>100–500 MW) or Very Large (>500 MW) size categories. The top 20 PSH projects by proposed capacity are all above 1,300 MW and 17 of them are being proposed by private non-utilities. In contrast, none of the 117 new hydropower projects have proposed capacities greater than 100 MW. The top 20 projects by proposed capacity are all NPDs or capacity additions to existing projects and range from 20 MW to 54 MW. Sixteen of them are being proposed by private non-utilities.

The bottom panel of Figure 12 shows that private non-utilities—mostly limited liability corporations as well as a few industrial corporations and educational institutions—are the most active developer type in submitting proposals for NPD (94% of projects) and PSH (82% of projects). Nonfederal public developers such as municipalities, state agencies, and irrigation districts are the promoters for 65% of the conduit projects. Federal hydropower owners exclusively focus on maintaining and upgrading the existing fleets. Investor-owned utilities also have primarily searched for opportunities to add capacity to their fleets instead of pursuing new projects. However, in the last two years, they have started submitting preliminary permit applications for PSH projects. Four investor-owned utilities (PacifiCorp, Public Service Company of Colorado, Dominion Energy, and Alabama Power Company) hold or are applying for preliminary permits to study the feasibility of PSH projects in their service areas. In addition, Duke Energy Carolinas has a 200-MW capacity addition underway in the Bad Creek PSH

26 In the case of the Eagle Mountain project, the license for which was issued in June 2014, the developer has exhausted the number of construction start deadline extensions it can obtain from FERC. In February 2023, the developer is requesting a four-year stay (i.e., a temporary suspension) of its current construction start deadline. FERC granted the stay in June 2023.

27 By April 2023, two more developers had submitted final license PSH applications to FERC: one for the White Pine PSH project (1 GW, Nevada) and one for the Seminoe PSH project (0.9 GW, Wyoming).

project in South Carolina and is studying the feasibility of further expanding the capacity of that project. An alternative option that some utilities are considering is to increase the PSH capacity in their systems by buying the power for a project already licensed through a power purchase agreement (PPA).

Although federal hydropower owners (USACE, Bureau of Reclamation, and the Tennessee Valley Authority [TVA]) are not directly pursuing new projects, both USACE and Reclamation own and operate much of the infrastructure (dams and conduits) that nonfederal developers are seeking to retrofit with hydropower. Therefore, their role in the project development pipeline is more salient than what Figure 12 might suggest. Not only do they need to approve projects that involve modifications of the infrastructure they own and operate, but they will continue to ensure that electricity production does not conflict with the other authorized purposes of the dams or conduits during the life of the power plant.

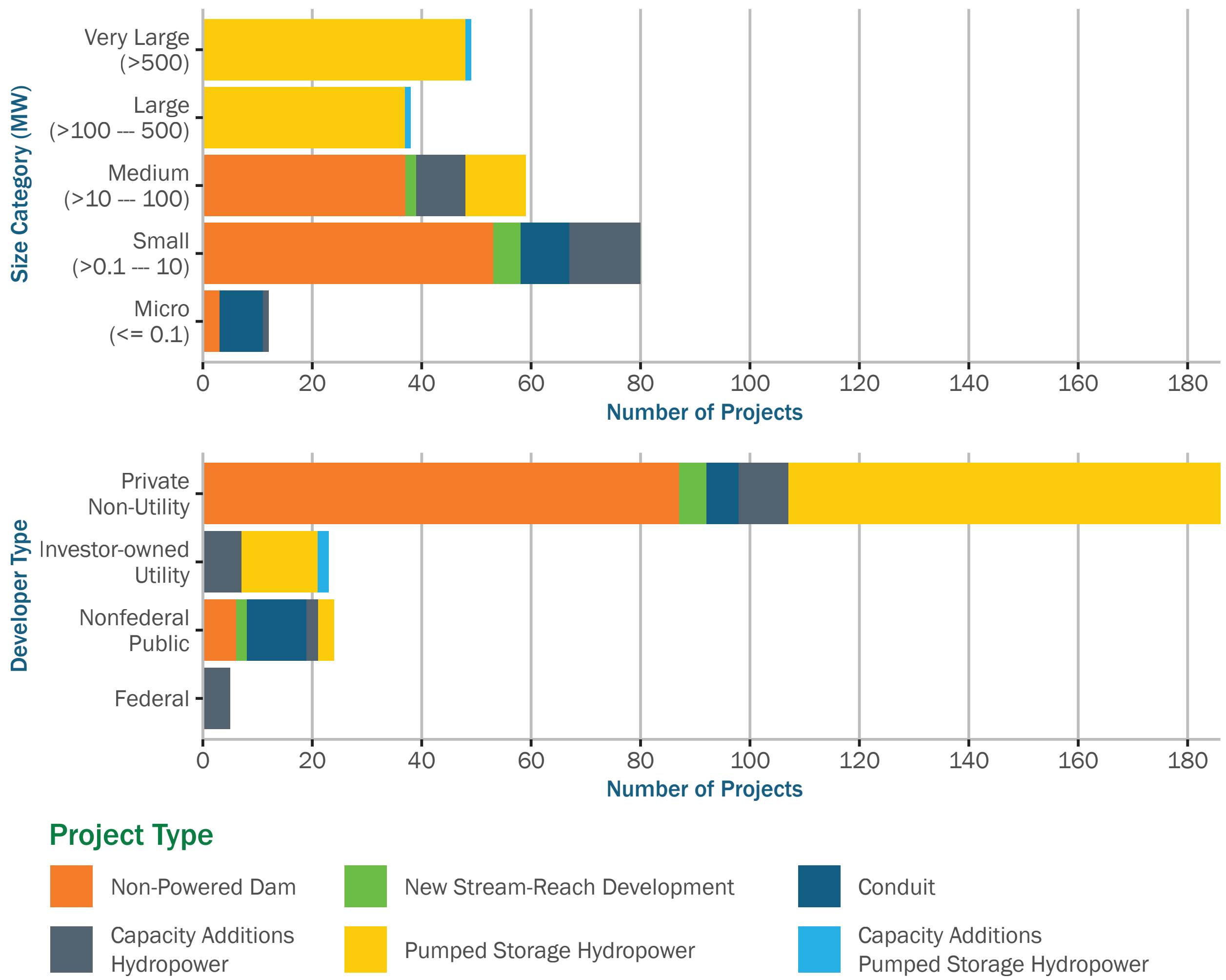


Figure 12. Hydropower and PSH project development pipeline by project type, size category, and developer type

Sources: ORNL U.S. Hydropower Development Pipeline Data 2023, FERC eLibrary, IIR.

2.4 Permitting Activity Trends

More than 90% of the 125 preliminary permits issued from 2018 to 2022 were for PSH and NPD projects (58% and 33%, respectively). The number of authorization (license or exemption) applications or issuances for those two project types was very low during this period. Eighty-four percent of issued authorizations in the past five years have been for conduit projects.

Figure 13 summarizes trends in permitting activity (by FERC and Bureau of Reclamation) in the past five years. In combination with the development pipeline snapshots in Figures 9 and 11, Figure 13 shows differences regarding typical permitting process durations for different project types.

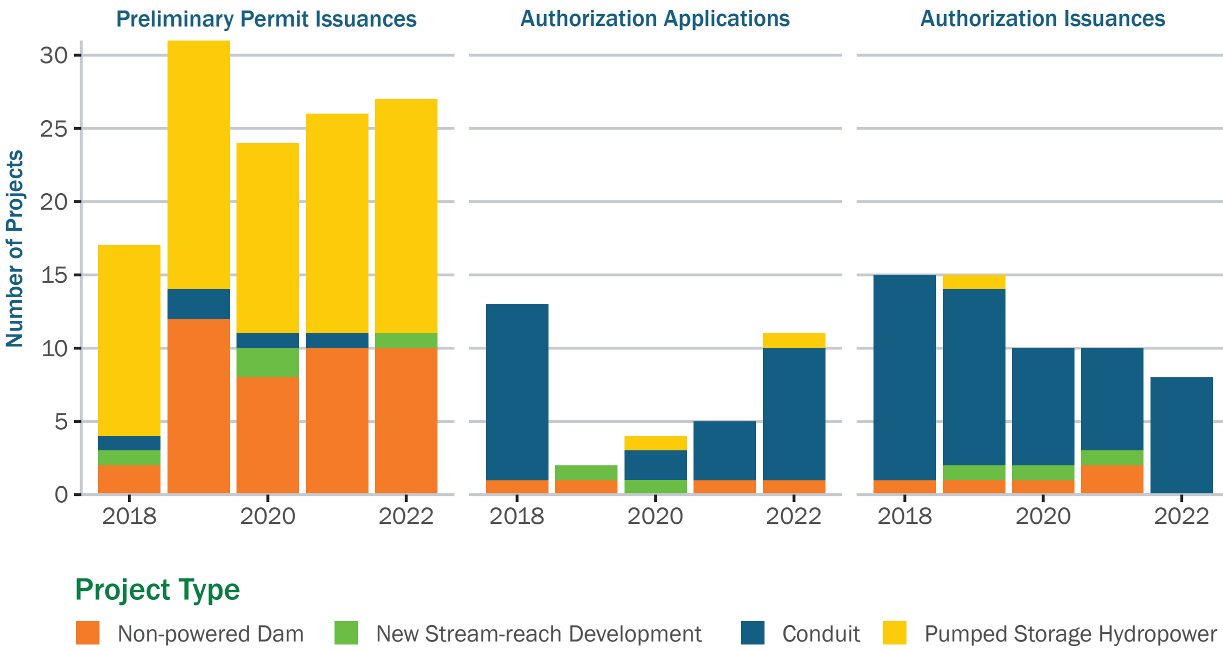


Figure 13. Permitting activity trends by project type (2018–2022)

Sources: ORNL U.S. Hydropower Development Pipeline Data 2023, FERC, Bureau of Reclamation

Notes: The Preliminary Permit Issuances panel includes preliminary permits issued by FERC and preliminary LOPPs issued by the Bureau of Reclamation. The Authorization Applications panel includes FERC license applications, FERC exemption applications, and applications for qualifying conduit status. The Authorization Issuances panel includes FERC license issuances, FERC exemption issuances, projects that were issued a qualifying conduit determination, and Bureau of Reclamation LOPP issuances.

Total activity levels are higher for preliminary permit issuances than authorization applications or issuances. The barrier of entry to obtain a preliminary permit is low and the permit grants first priority to its holder during a four-year period to decide whether to proceed to the authorization phase. On average, 25 preliminary permits (a combination of FERC preliminary permits and Reclamation preliminary LOPPs) were issued each year from 2018 to 2022.

Of the 125 preliminary permit issuances during this period, most were for PSH projects (58%) and NPDs (33%), with the rest distributed evenly between conduits and NSDs. However, for conduits seeking qualifying conduit determination from FERC, as well as some other small projects, the developer does not need, or decides not to request, a preliminary permit and the first step of the permitting process is an authorization application.

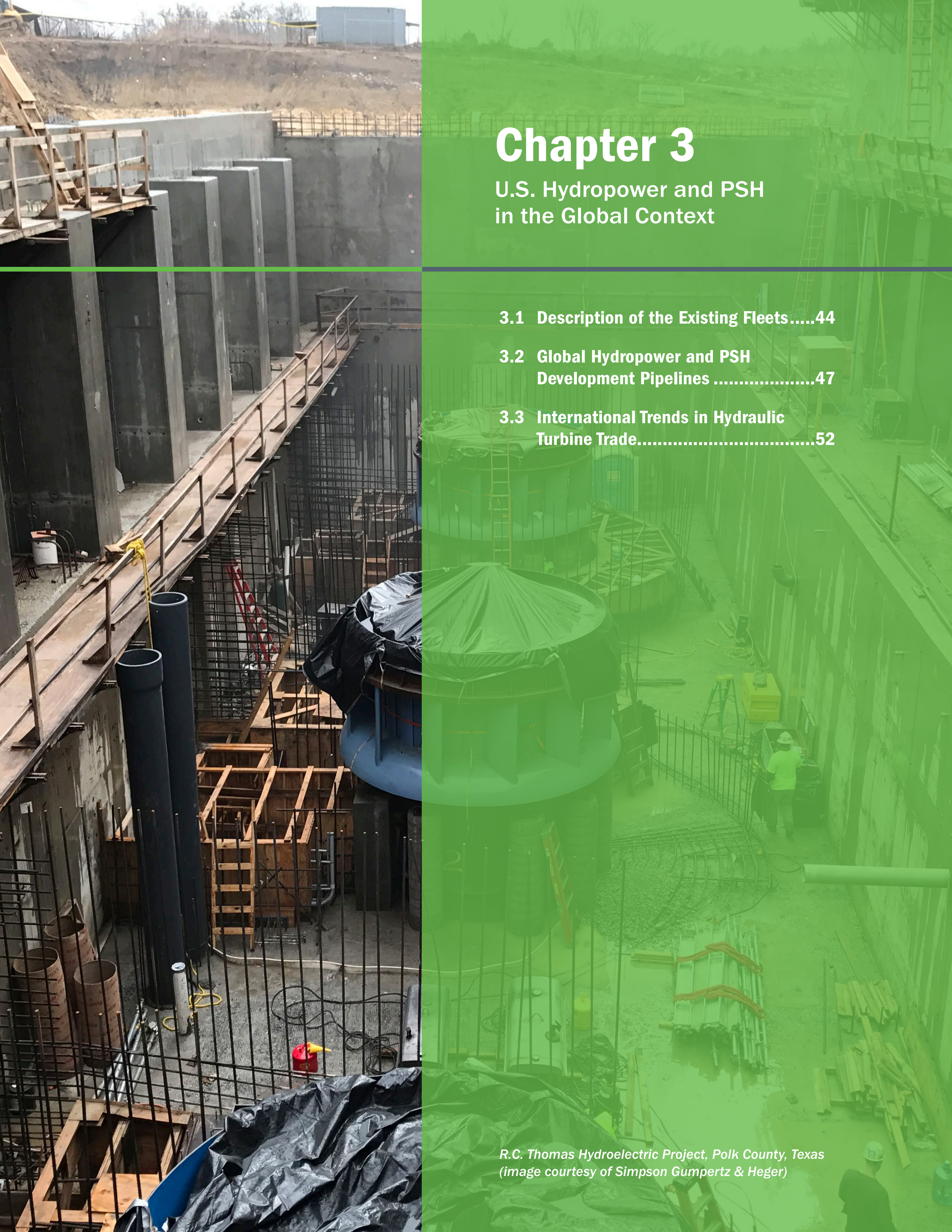
For PSH and NPD projects, there is a large drop in the number of authorization applications relative to the number of preliminary permit issuances. For a project to move from the preliminary permit stage to the submission of an authorization application, the developer must find the project to be feasible from a technical, environmental, and business case perspective. In addition, preparing a license or exemption application requires a substantial investment of money and time to complete the necessary studies.

Comparing the number of authorization issuances in the past five years for NPD projects (5) to the number of NPD projects that had authorizations at the end of 2022 (36) shows that most of the currently licensed projects to add hydropower to an NPD were authorized before 2018. Only four developers have applied for authorization for NPDs in the last five years. NPDs have long development timelines and can encounter multiple postlicensing challenges—such as long time frames to obtain additional permits, complete technical designs, and secure financing and offtake agreements—that result in long lags to reach the construction stage (Uría-Martínez et al. 2020). In some cases, the license is ultimately surrendered by the developer or cancelled by FERC if the developer fails to comply with the license terms and conditions, which include construction start deadlines.

For PSH, there is also substantial interest in holding preliminary permits and reserving the option to develop sites but, as with NPDs, it has translated in few authorization applications or issuances in the past five years. Of the three licensed, unconstructed PSH projects at the end of 2022, only one has received authorization issuance since 2018. The postlicensing challenges mentioned for NPDs also apply to PSH and might be magnified by the typical greater scale of PSH projects versus NPDs.

In contrast, conduit retrofits have much shorter development timelines. They typically are very small projects without significant environmental issues, require much less capital to be constructed than other project types, and are often developed by municipalities and water districts whose customers will be the ones using the electricity produced. In the past five years, 49 authorizations were issued for conduit projects but, as of the end of 2022, there were only 18 conduit projects in the postlicensing stage in the pipeline. Of the remaining projects, at least seven have resulted in operational projects.

Finally, NSDs are almost exclusively in Alaska and the Pacific Northwest. There is little permitting activity for this type of project at all stages.



Chapter 3

U.S. Hydropower and PSH in the Global Context

R.C. Thomas Hydroelectric Project, Polk County, Texas (image courtesy of Simpson Gumpertz & Heger)

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

This chapter describes basic attributes of the global operational hydropower and PSH fleets (regional capacities, project sizes, and ownership types), as well as the global hydropower and PSH development pipelines. Combined with the information presented for the U.S. fleet in Chapters 1 and 2, this chapter helps place the U.S. fleet and project pipeline in the global context and identifies similarities and differences relative to other world regions. The discussion centers on nine world regions: North America, Central and South America, Europe, Africa, Russia, Western and Central Asia, East Asia, and Southeast Asia and Oceania.

Additional topics covered in the chapter are the growth rate of hydropower and PSH capacity relative to other renewables, how recent hydropower growth rates compare with different scenarios of the evolution of the global electricity generation mix out to 2050, and global hydropower turbine trade trends.

3.1 Description of the Existing Fleets

As of 2022, hydropower (including PSH) remains the technology with the largest share (40%) of global renewable electricity generation capacity (versus 50% in 2019). Since 2020, PSH capacity has grown faster than conventional hydropower capacity but not as fast as other renewable generation technologies.

In 2022, global hydropower capacity reached 1,256 GW and PSH global capacity stood at 137 GW (IRENA 2023a).[28] From 2020 to 2022, the global fleet increased by 42.6 GW for hydropower and 15.9 GW for PSH (IRENA 2023a). Figure 14 displays global 2022 hydropower capacity and 2020–2022 net capacity additions to the global fleet as shares of total renewable generation capacity. It also shows the breakdown of renewable generation capacity and recent net renewable capacity additions for the countries/regions with the six largest hydropower fleets.[29]

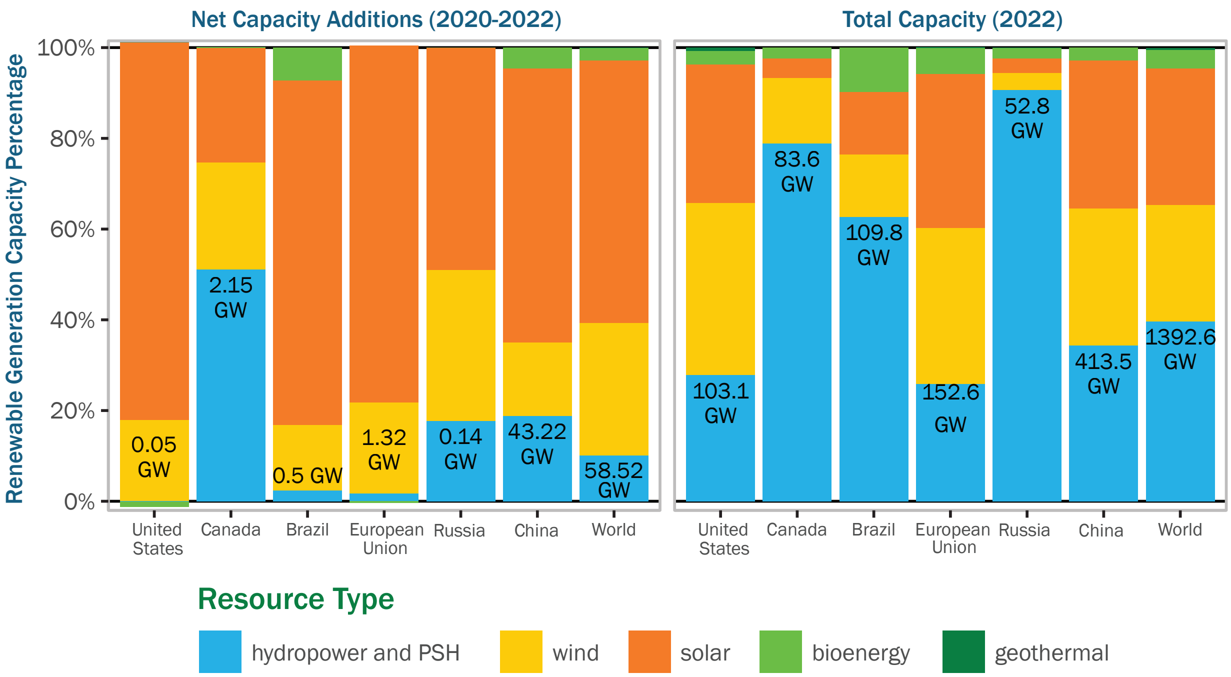


Figure 14. Renewable generation capacity mix in the countries/regions with the largest hydropower fleets

Source: IRENA Renewable Capacity Statistics 2023

28 The International Renewable Energy Agency (IRENA) counts plants with a mixture of hydropower and PSH units as conventional hydropower. IRENA does not count PSH capacity as renewable energy capacity. In this report, PSH is included in the discussion of installed renewable electricity generation capacity. In the description of the U.S. hydropower fleet in Chapter 1, the capacity of mixed projects is allocated between hydropower and PSH using unit-level data.

29 The combined fleets of the United States, Canada, Brazil, the European Union, Russia, and China account for two-thirds of global hydropower capacity (including PSH).

Note: The European Union includes EU27 countries. Labels indicate hydropower and PSH capacity. The net capacity additions bar for the United States adds up to more than 100% because the net capacity addition for bioenergy is negative. Because of differences in data coverage for new projects and capacity metric used (net summer capacity here versus nameplate capacity in Chapter 1), the capacity values reported by IRENA for the United States do not exactly match the ones reported in Chapter 1.

Globally, hydropower (including PSH) remained the renewable electricity generation technology with the largest installed capacity as of 2022. The right panel in Figure 14 shows that it accounted for 40% of global renewable generation capacity. Hydropower represents by far the largest share of renewable capacity in Canada (79%), Brazil (63%), and Russia (91%). In China, hydropower was also the renewable generation technology with the largest installed capacity in 2022, but its share (34%) was very similar to the shares of solar (33%) and wind (30%). In the United States and the European Union, wind and solar capacities were greater than hydropower and PSH capacity—wind shares were 38% for the United States and 34% for the European Union and solar shares were 30% and 34%, respectively. Hydropower was the third largest renewable in those two regions with shares of 28% in the United States and 26% in the European Union. Solar PV capacity has overtaken hydropower capacity in the United States and the European Union in the past three years.

The left panel in Figure 14 shows that both globally and in each of the countries or regions shown (except Canada) net additions of renewable generation capacity in 2020–2022 were dominated by solar PVs. A total of 333 GW of solar PV capacity has been added in the past three years, resulting in a 46% increase in global installed solar capacity. For comparison, total capacity additions of the other renewable technologies during the same period were 167 GW for wind (23% increase in global installed capacity), 59 GW for hydropower and PSH (4% increase in global installed capacity), 16 GW for bioenergy (12% increase in global installed capacity), and 460 MW for geothermal (3% increase in global installed capacity). Unlike global wind and solar fleets, which have been largely built in the past two decades, the global hydropower fleet has been developed over more than a century. In many regions, the hydropower fleet is at a mature stage consistent with slow capacity growth rates.

During the past decade (2013–2022), global hydropower capacity has increased at an average rate of 2.2% per year. For the PSH portion of the fleet, the average capacity growth rate has been 2.7%. Added global PSH capacity in 2021 (6.5 GW) and 2022 (9.3 GW) has been larger than in any other year since 2013. However, the global average growth rate masks marked differences across countries. For the six fleets shown in Figure 14, the average 2013–2022 annual hydropower capacity growth rate ranged from 4.4% for China and 2.8% for Brazil to 1.1% for Canada and less than 0.5% for the United States, European Union, and Russia. 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.

Figures 15 and 16 show the global distribution of hydropower and PSH assets. The U.S. conventional hydropower fleet accounts for ~7% of the global capacity. For PSH, the 43 plants in the United States represent 14% of global capacity. As of 2022, 83 countries had more than 1 GW of conventional hydropower. In contrast, PSH facilities are present in only 37 countries. Figure 16 shows that the PSH fleet is largely concentrated in the United States, European Union, China, and Japan. These four PSH fleets represent 80% of global capacity.

The largest owners of conventional hydropower capacity in the United States are federal agencies: USACE and the Bureau of Reclamation. In total, the federal portion of the U.S. hydropower fleet accounts for almost half of installed capacity. The salient role of public agencies in owning and operating hydropower is not unique to the United States. Of the 23 entities that own more than 10 GW of conventional hydropower—together they own ~32% of global installed capacity—only one is not at least partially owned by a national or subnational government. For PSH, the top 10 entities own more than 40% of installed global capacity and 9 of them are state owned or have a state as a major shareholder.

Figure 15. Map of operational hydropower plants by world region

Sources: Regional totals (IRENA Renewable Capacity Statistics 2023), plant-level data for the United States (ORNL EHA Plant database 2022), plant-level data for the rest of the world (GlobalData).

Notes: Regional hydropower capacity totals include the full capacity from hybrid projects containing some pumped storage units. GlobalData does not cover plants with less than 1 MW of capacity and has limited coverage of operational plants with less than 10 MW in some regions. The combined capacity of all small plants (<=10 MW) in the map is 29.8 GW. In contrast, the estimated global capacity from small plants in 2019 was 78 GW (Liu et al. 2019).

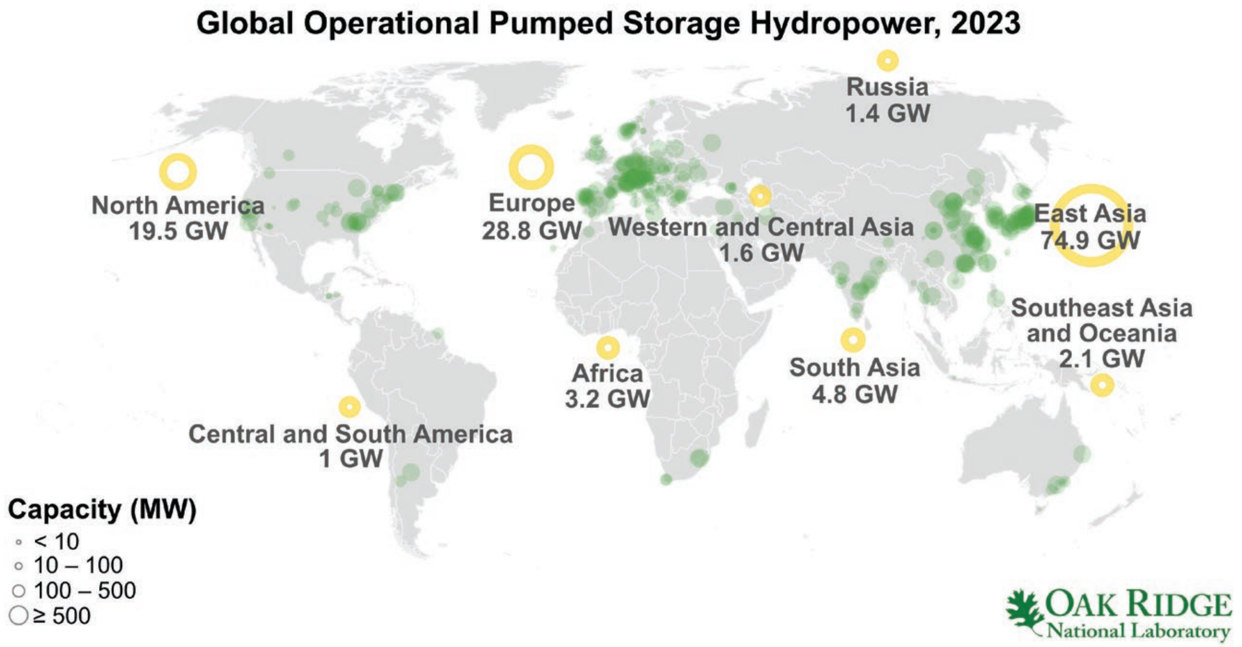


Figure 16. Map of operational PSH plants by world region

Sources: Regional totals (IRENA Renewable Capacity Statistics 2023), plant-level data for the United States (ORNL EHA Plant database 2022), plant-level data for the rest of the world (GlobalData).

Notes: Regional totals refer to pure PSH plants only; the capacity from PSH units that are part of hybrid projects is not included.

3.2 Global Hydropower and PSH Development Pipelines

As of 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.

Figure 17 shows the location of hydropower projects in the development pipeline and the shares of projects that are "under construction" versus earlier stages of "permitting and development" in each region.

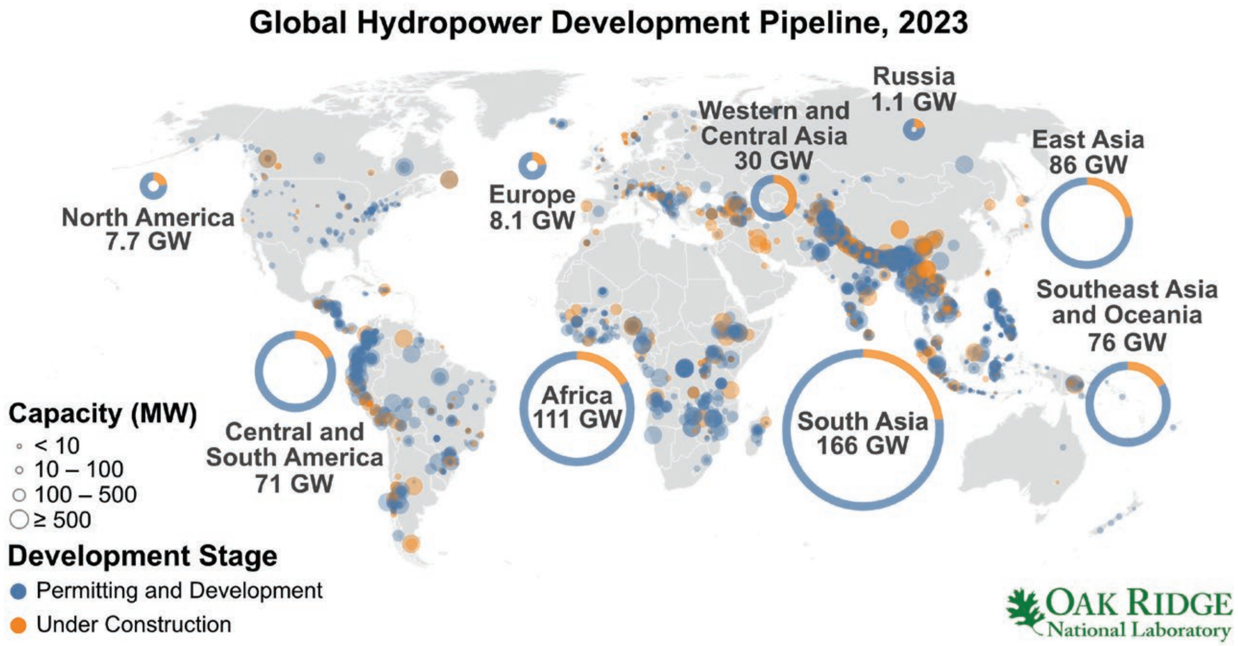


Figure 17. Map of hydropower project development pipeline by region and development stage

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.

Fifty percent of proposed hydropower capacity is in projects in South Asia (166 GW) and Africa (111 GW). East Asia has the third largest project pipeline (86 GW), and two other regions (Southeast Asia and Oceania, Central and South America) have project pipelines with more than 70 GW of proposed capacity. Western and Central Asia has 30 GW of new capacity in the pipeline. All other regions have mature hydropower fleets and project pipelines with total proposed capacities below 10 GW. North America and Europe each have ~8 GW of proposed new hydropower capacity. Finally, Russia would add more than 1 GW of new hydropower capacity if all its proposed projects were constructed.

The "permitting and development" stage covers projects with a wide range of likelihoods of proceeding to construction. This stage includes projects that have just been announced, as well as others that have completed permitting and closed financing arrangements. More than 300 GW of the proposed new capacity have an estimated construction start date in the 2020s. Western and Central Asia stands out regarding the share of proposed capacity that is under construction (40%). For the other regions, the share of proposed capacity under construction is close to 20%.

The pipeline includes 194 projects with capacities of more than 500 MW (Very Large). South Asia and Africa account for 54% of these. 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. 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.

State-owned enterprises are the most common developers of these Very Large projects. Two Chinese state-owned corporations (Power Construction Corporation of China and the China Three Gorges Corporation) are among the three entities with the largest overall proposed capacity in the global development pipeline. Power Construction Corporation of China is the developer for the Medog project in the Tibet Autonomous Region of China. This controversial mega project is at a very early stage of development, but its inclusion in China's Fourteenth Five-Year Plan is a significant signal that it might proceed forward.[30] The China Three Gorges Corporation is one of the top five conventional hydropower developers by proposed capacity in four world regions: Africa, Russia, South Asia, and Southeast Asia and Oceania. Three other state-owned enterprises (the Pakistan Water and Power Development Authority, India's NHPC Ltd, and the Ethiopian Electric Power Corporation) have more than 10 GW of conventional hydropower capacity in the development pipeline.

The only non-state-owned entity with more than 10 GW of proposed hydropower capacity as of the end of 2022 is Fortescue Metals Group Ltd., an Australian publicly traded company. Fortescue, one of the world's major iron ore producers, has announced plans for the development of Inga 4 through Inga 8 in the Democratic Republic of Congo, with a total proposed combined capacity of 34 GW. Fortescue stated that it plans to finance the project mostly out of its balance sheet and would use the power from these plants to produce and export hydrogen.

In an analysis of the clean energy investment landscape, IRENA and CPI (2023b) find that only 3% of hydropower investment committed in 2020 came from private finance—in contrast, 83% of investment committed for solar PV in that year was from private finance sources. The magnitude of the required upfront investment for hydropower along with construction risks, longer payback periods, and complexities associated with permitting and social acceptance are cited as reasons why hydropower (especially for large projects) development is not being pursued by private developers.

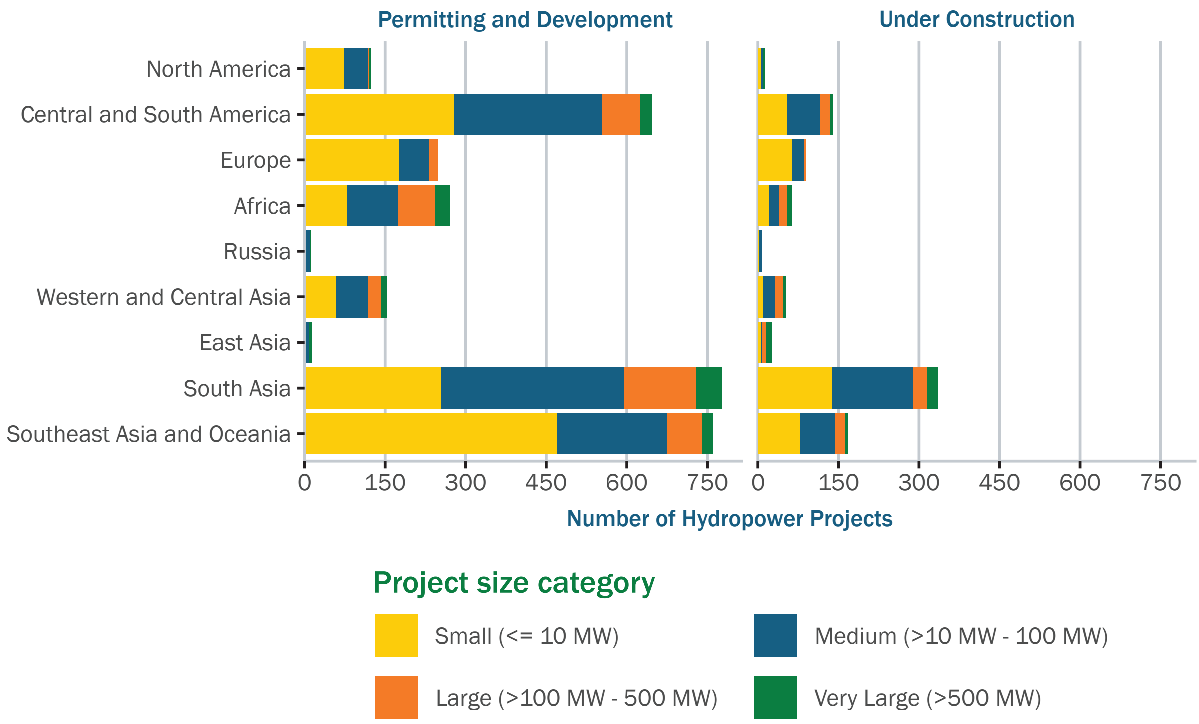


Figure 18. Global hydropower development pipeline by size category, region, and development stage

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

Figure 18 shows the distribution of the conventional hydropower project pipeline by size category, region, and development stage. Even though only 6% of all projects under construction have capacities of more than 500 MW, their combined capacity of 79 GW accounts for 67% of the total projects being constructed. South Asia has the most Very Large projects under construction.

30 thediplomat.com/2021/09/chinas-hydropower-plan-on-the-brahmaputra/.

The share of small hydropower projects (<=10 MW) is more than 50% in three regions (North America, Southeast Asia and Oceania, and Europe). The largest share of small projects is in Europe (71%). The project pipeline for East Asia does not include small hydropower projects. As mentioned in the notes to Figure 17, coverage of small hydropower projects is less complete than for large projects due to limited available information in some regions. However, for China, the lack of small hydropower projects is also a result of policy developments. In the late 2010s, the Chinese government implemented policies that led to the removal of hundreds of small hydropower plants and changes in the operations of thousands of others (e.g., by establishing minimum flow guidelines) to mitigate the adverse impacts that resulted from decades of rushed development lacking adequate assessment of environmental impacts.[31] Zhang et al. (2021) report that excessive exploitation of small hydropower resources in some parts of the country has led to dewatering of water reaches and insufficient water availability for irrigation and household use purposes during the dry spring months. In 2019, China announced it would ban the construction of small hydropower plants in regions that have an electricity surplus.[32]

As of the end of 2022, there were 363 PSH projects in the global development pipeline with a total combined capacity of 286 GW. 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%.

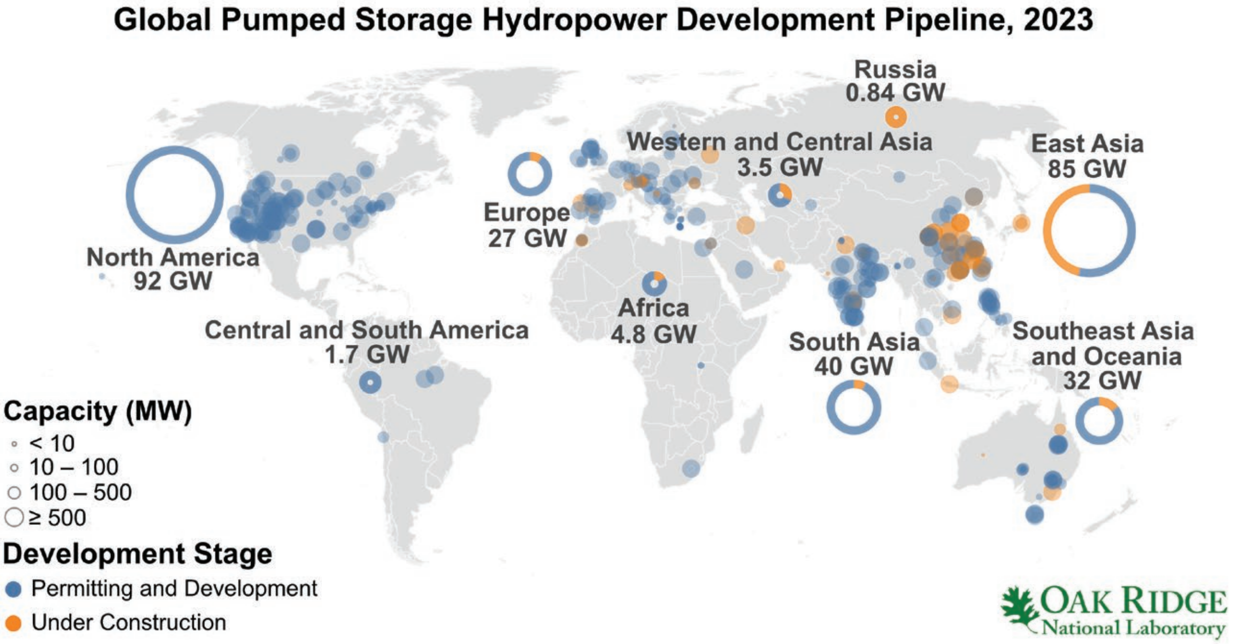


Figure 19. Map of PSH project development pipeline by region and development stage

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.

Figure 19 shows the location of PSH projects and their distribution between the "under construction" and "permitting and development" stages. North America is the region with the greatest number of PSH projects in the development pipeline (101), 5 in Canada and 96 in the United States. However, it is one of the only two world regions (along with Central and South America) where no new PSH is under construction. East Asia has almost half of its proposed PSH capacity in the "under construction" stage; for most other regions, the share of proposed capacity that has reached the construction stage is much lower.

East Asia has the second largest PSH development pipeline with a combined capacity of 85 GW followed by South Asia (40 GW), Southeast Asia and Oceania (31.5 GW) and Europe (27.4 GW). The remaining four regions (Africa, Central and South America, Russia, and West and Central Asia) all have less than 5 GW of total proposed PSH capacity.

31 sixthtone.com/news/1007533.

32 reuters.com/article/us-china-hydropower/china-to-impose-new-restrictions-on-small-hydro-plants-idUSKBN1XN0ES

Thirty-nine of the 56 PSH plants under construction are in East Asia (28) and Europe (11). The three PSH plants being constructed in Africa are in Morocco (total capacity of 775 MW). Of the 28 in East Asia, 26 are in China and the other two in Japan. Strong PSH construction activity in China is moving the country toward the PSH installed capacity objectives published by China's National Energy Administration: 62 GW in 2025 and 120 GW in 2035.[33] Of the 11 PSH plants under construction in Europe, 4 are in Austria and the remaining 7 are in Bosnia and Herzegovina, Germany, Greece, Portugal, Spain, Switzerland, and Ukraine. In South Asia there are three in India and one in Nepal. In Southeast Asia and Oceania, there are three in Australia, one in Indonesia, and two in Vietnam. Israel, Iran, and United Arab Emirates all have one PSH project under construction in the Western and Central Asia region.

Figure 20 shows the distribution of PSH project sizes by region and development stage. The median power storage capacity of projects under construction is 1,200 MW; for projects in the permitting and development stage, the median capacity is 500 MW. 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 or Small.

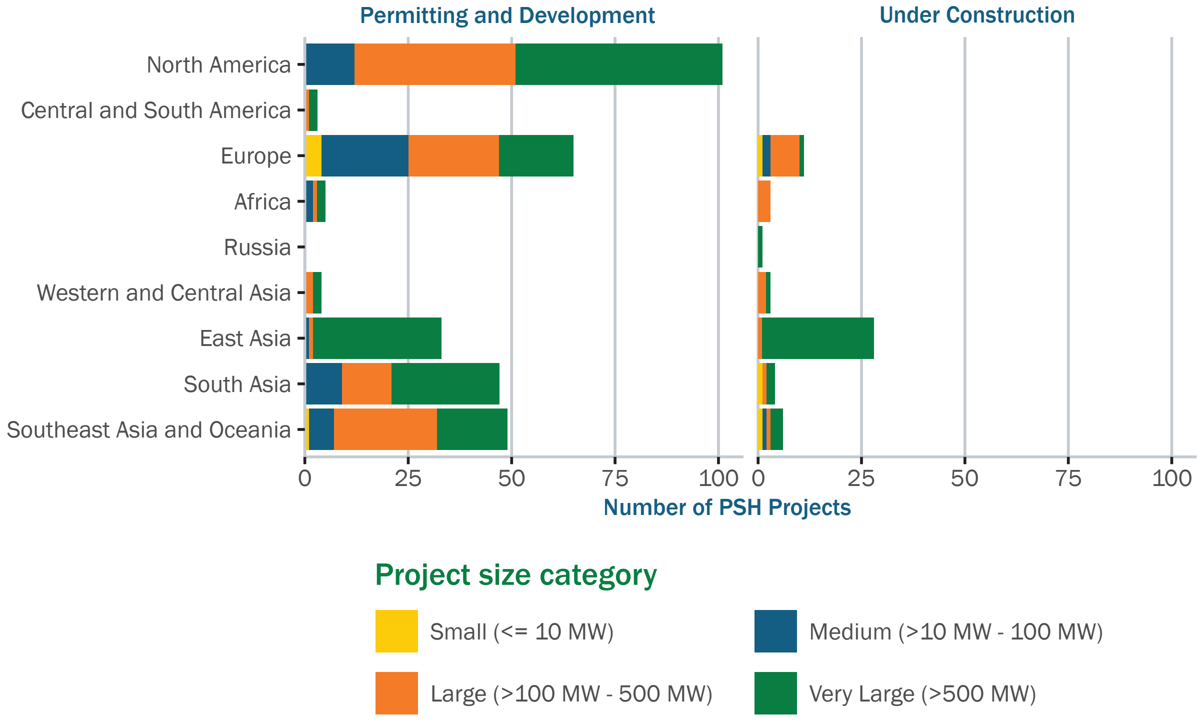


Figure 20. Global PSH development pipeline by size category, region, and development stage

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

The PSH project size distribution varies by region. The East Asia pipeline is heavily focused on Very Large projects. On the other hand, only 25% of the projects in Europe fall in the Very Large category.

Similar to the pattern observed for large hydropower plants, of the 56 PSH projects under construction, only 4 are being developed by companies that are not state-owned enterprises or at least partially owned by a national or state/provincial government. These four plants are in Germany, Portugal, Australia, and Israel. The largest of the four is Gouvaes in Portugal (660 MW).

33 hydropower.org/country-profiles/china. In 2022, China had 46 GW of pure pumped-storage plant capacity (IRENA 2023a).

HYDROPOWER IN GLOBAL ENERGY OUTLOOK SCENARIOS

The World Energy Outlook (WEO), published annually by the International Energy Agency (IEA), contains multiple scenarios on the long-run evolution of the global energy system. The IEA generates these scenarios using models of the global energy system to solve for trajectories of investment and consumption that meet projected energy demands—driven by projected trends on population and economic growth—given a set of technology, policy, and behavior assumptions. Electricity generation capacity technology mix is among the variables reported for each of the scenarios. Figure 21 shows the trajectory of globally installed hydropower capacity in scenarios from the latest installment of the WEO.

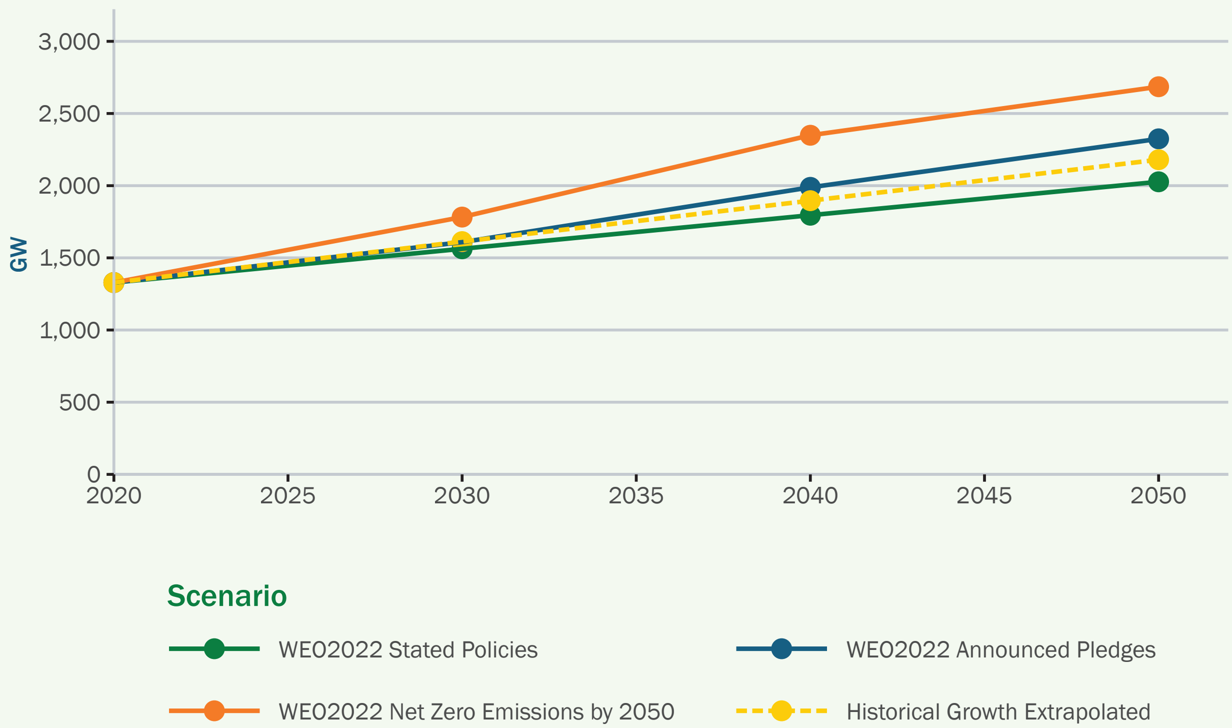


Figure 21. Global hydropower installed capacity in selected energy outlooks (2020–2050)

Sources: IEA World Energy Outlook 2022, IRENA Renewable Capacity Statistics 2023.

Global hydropower capacity (including PSH) increases in all the WEO 2022 scenarios. Another finding that is common to all WEO 2022 scenarios is that electricity use grows faster than total energy use out to 2050, because of the progressive electrification of multiple energy end uses, and that most new electricity generation capacity comes from renewables. The WEO 2022 Stated Policies scenario represents the evolution of the energy system under current policies and regulations. In the Announced Pledges scenario, countries achieve their aspirational targets regarding decarbonization and sustainable development. Finally, the Net Zero Emissions by 2050 scenario explores how the global energy system would need to evolve to achieve the goal of net zero CO2 emissions from the energy sector by 2050. Thus, differences across WEO scenarios are largely driven by the set of policies being modeled, as well as by assumptions about behavioral changes.

The global hydropower capacity trajectory under the Stated Policies scenario would result in average additions of 22 GW per year (hydropower + PSH) from 2020 to 2050. The Announced Pledges scenario results in 32 GW per year, and the Net Zero Emissions scenario would require an average of 44 GW of hydropower and PSH being added each year. Wind and solar continue to increase faster than hydropower in all the scenarios so that the share of hydropower in installed renewable electricity generation capacity decreases from 44% in 2020 to 15% (Stated Policies), 11% (Announced Pledges), and 10% (Net Zero Emissions). The WEO highlights the role of hydropower in providing flexibility and helping integrate the large amounts of wind and solar expected to come online in future decades.

One of the uses for outlooks such as the WEO is to enable the comparison of the level of investment and capacity additions needed to achieve objectives such as Net Zero Emissions to actual observed levels of activity. Divergences between modeled trajectories and recent historical trends can signal the need for further supply chain investments and policy incentives. From 2013 to 2022, IRENA (2023a) reports that the average hydropower and PSH capacity added per year was 28 GW (25 GW of conventional hydropower and 3 GW of PSH). If this average level of capacity additions is maintained (see dotted line trajectory in Figure 21), it would lead to a global capacity level by 2050 that would be higher than that projected in the WEO 2022 Stated Policies scenario—partly explained by the IEA's view that China's hydropower additions are slowing down in the 2020s relative to previous decades (IEA 2021)—but substantially lower than what would be needed to follow the WEO 2022 Announced Pledges or Net Zero scenario trajectories.

An important feature of recent global capacity additions is that they have been heavily concentrated in a few countries. As mentioned in Section 3.1, 62% of conventional hydropower capacity was added in China and Brazil, and 83% of new PSH was built in China. To move towards an energy system consistent with the Announced Pledges or Net Zero Emissions scenarios from the WEO 2022, not only must annual hydropower capacity additions be larger than what has been observed in the recent past but also they must be more geographically diverse to integrate the large foreseen deployments of wind and solar in all world regions.

3.3 International Trends in Hydraulic Turbine Trade

On average, the annual value of hydropower turbines and turbine parts traded internationally in the 2010s was $1.7 billion. Traded value declined significantly in the first two years of the 2020s, to an average of $0.9 billion. The top 10 exporters accounted for an average share of 76% of global exports in 2010–2021. The United States ranked eighth by average export value and seventh by average import value during that period.

Turbine trade statistics provide a complementary view of hydropower construction activity trends by installed capacity and help describe the global hydropower supply chain. The World Bank's World Integrated Trade Solution database contains information on the value of hydropower turbine imports and exports disaggregated by country and turbine size category (<=1 MW, >1–10 MW, >10 MW). Additionally, a fourth category of data reports the trade of turbine parts (rather than complete turbine units).

Global exports across all the categories totaled $908 million in 2021. Global exports averaged $1,707 million in 2010–2019 (in 2021 dollars). The only two years when the traded value of global turbine exports was lower than $1 billion dollars were 2020 and 2021. Additional years of data will be needed to assess the extent to which the lower traded values in 2020 and 2021 were caused by a slowdown in construction activity because of the COVID-19 pandemic.

Figure 22 shows the top 10 exporting countries in 2010–2021 (ranked by average annual export value during that period), along with the category makeup of the exports. It also displays the average aggregate exports from all other countries outside the top 10.

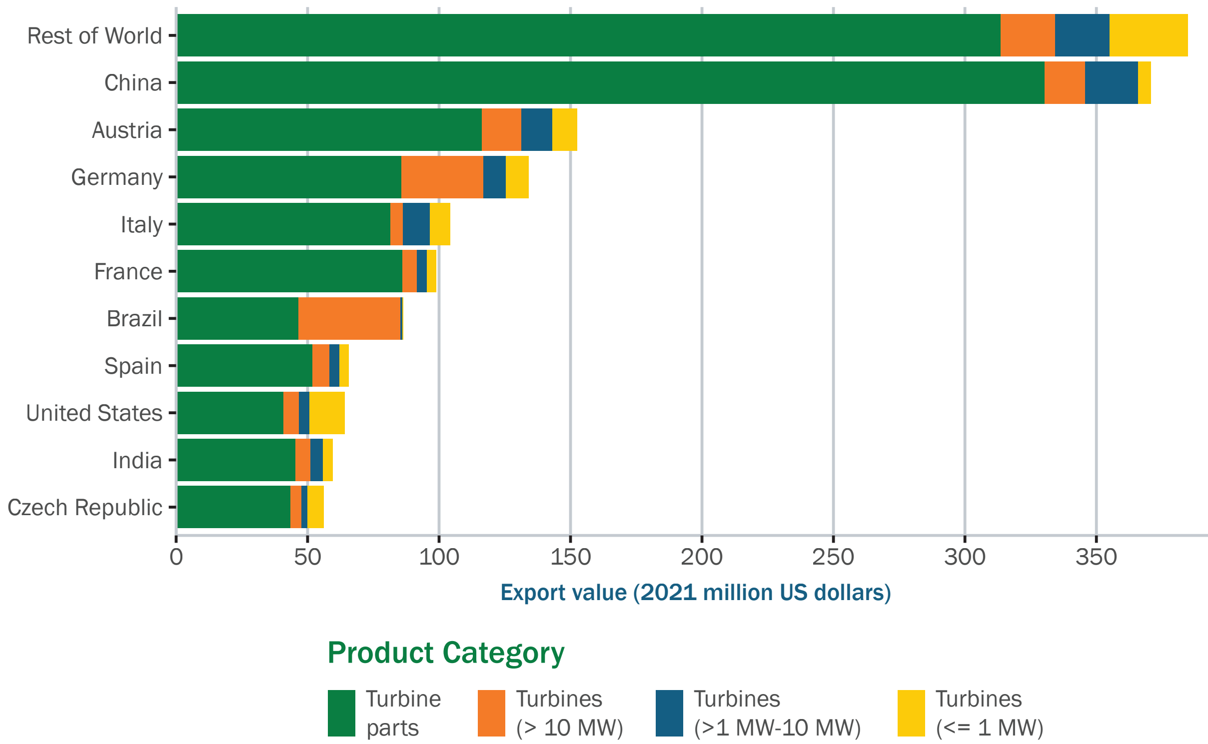


Figure 22. Average (2010–2021) export value of hydraulic turbines for top 10 countries and the rest of the world

Source: World Bank's World Integrated Trade Solution

Note: The values shown in the plot are for Harmonized System codes 841011 (Turbines; hydraulic turbines and water wheels, of a power not exceeding 1,000 kW exports by country), 841012 (Turbines; parts of hydraulic turbines and water wheels, including regulators exports by country), 841013 (Turbines; hydraulic turbines and water wheels, of a power exceeding 10,000 kW exports by country), and 841090 (Turbines; parts of hydraulic turbines and water wheels, including regulators exports by country).

The average value of exports from China ($371 million) is close to the aggregate export value from all countries not included among the top 10 exporters. Turbine parts represent more than half of the total traded value in every country. Brazil, the United States, and Germany are the only three countries where parts did not account for at least 75% of exported value. Since larger turbines should be more expensive, the fact that they represent a small fraction of the total traded value suggests that few turbine units are traded as complete units. Instead, they are traded as multiple separate components (e.g., runners and hub) that would appear in the turbine parts category.

Six of the top 10 exporters are European Union (EU) countries. 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. The large share of exports originating from the EU is consistent with large manufacturers such as Voith, Andritz, and GE Renewable Energy being headquartered in EU countries and having substantial manufacturing capabilities there.

The United States occupied the eighth spot in the top 10 ranking of exporters with an average traded value of $64 million per year. Details about the destinations of U.S. hydraulic turbine exports are presented in Chapter 6.

Exports decreased in 2020–2021 with respect to the 2010s average for all top 10 exporters. The decrease was less than 25% for the Czech Republic, India, and Austria. For the United States, Brazil, and Italy, exports decreased between 25% and 50%. The other 4 countries among the top 10 exporters (China, Germany, France, and Spain) saw the traded value of their 2020–2021 exports decrease by more than 50%.

Imports are less concentrated than exports. Only 21 countries exported more than $10 million on average in 2010–2021. In contrast, 50 countries had an average imported value of more than $10 million during that period. Figure 23 shows the average import value during 2010–2021 for the top 10 importers and the rest of the world. The list of top importers includes countries where large new hydropower plants have been constructed during this period (e.g., Turkey, Vietnam, and Pakistan) but 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 with 94% of the traded value resulting from imported turbine parts.

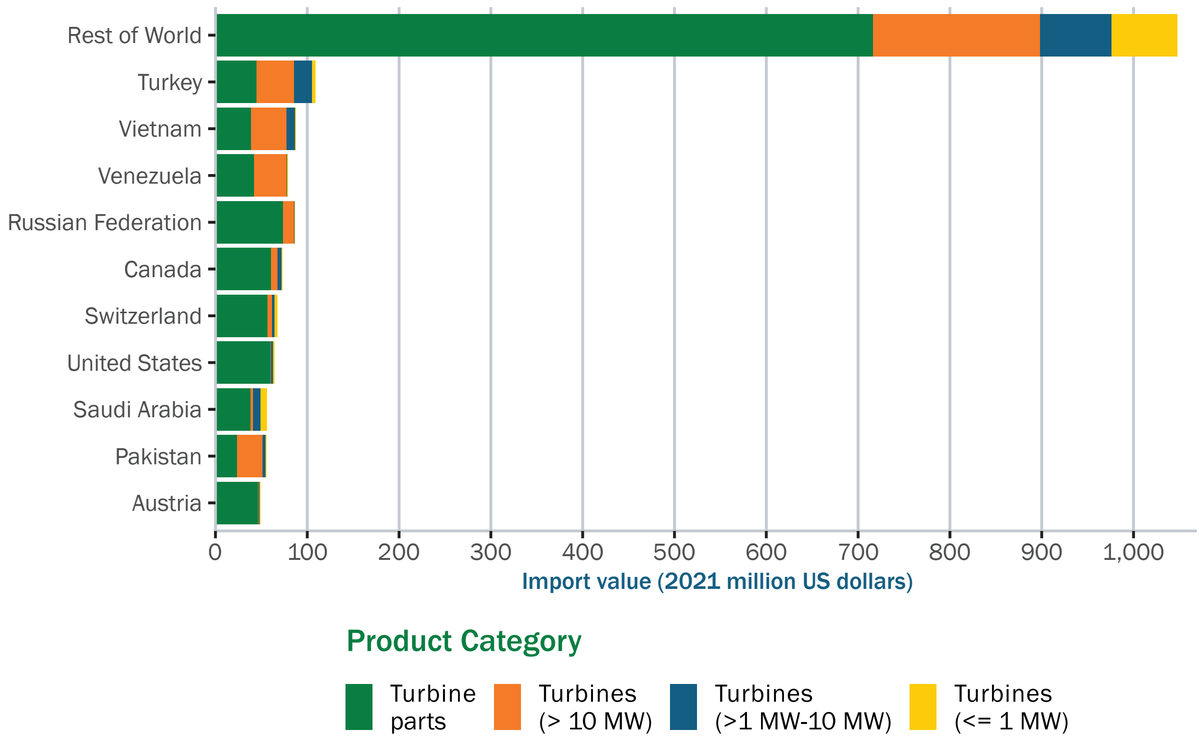


Figure 23. Average (2010–2021) import value of hydraulic turbines for top ten countries and rest of the world

Source: World Bank's World Integrated Trade Solution

Note: The values shown in the plot are for Harmonized System codes 841011 (Turbines; hydraulic turbines and water wheels, of a power not exceeding 1,000 kW imports by country), 841012 (Turbines; parts of hydraulic turbines and water wheels, including regulators imports by country), 841013 (Turbines; hydraulic turbines and water wheels, of a power exceeding 10,000 kW imports by country), and 841090 (Turbines; parts of hydraulic turbines and water wheels, including regulators imports by country).

According to all global data sources, Saudi Arabia does not have any installed hydropower capacity as of 2022. Turbines imported into that country must have been installed elsewhere.

By net export value (i.e., export value minus import value), China had the largest annual average value in 2010–2021 ($351 million). Seven EU countries, Brazil, and India completed the top 10 of next exporters. If the EU is considered as a single region (and the intraregional trade flows among EU countries are excluded), it tops the ranking of net exporters with an annual average value of $471 million in 2010–2021.

The United States and Austria are the only two countries that are part of both the top 10 exporter and top 10 importer rankings. Austria is a net exporter with an average net export value of $104 million per year. For the United States, the net trade balance is close to zero. By product category, the United States is a net importer of turbine parts (and parts account for the largest share of total hydraulic turbine trade) and a net exporter of full turbine units, especially for those with a capacity of <1 MW where the average exported value is $13 million per year and the average imported value is $1.49 million.

Chapter 4

U.S. Hydropower Prices and Revenues

Hiilangaay Hydro, Prince of Wales Island, Alaska (image courtesy of Haida Energy)

Chapter 4. U.S. Hydropower Prices and Revenues

This chapter summarizes trends in the revenue that U.S. hydropower fleet owners are receiving for the electricity they produce, as well as the capacity and grid ancillary services they provide. Hydropower is sold through a mixture of long-term power purchase agreements, 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). The marketing mechanism used in each hydropower plant largely depends on the region and owner type. The output from the federal hydropower fleet, which accounts for 7% of plants and 48% of installed hydropower capacity, is mostly marketed through long-term contracts with public utilities. Private non-utilities (also known as independent power producers) own 40% of plants and 8% of capacity. They often sign power purchase agreements with a utility but, if located in an ISO/RTO region, they can choose to bid their energy and capacity into the markets administered by those entities. Investor-owned utilities (22% of plants, 20% of installed capacity) and publicly owned utilities (31% of plants, 24% of installed capacity) may also participate in ISO/RTO markets or conduct bilateral transactions with other utilities.

4.1 Federal Hydropower Revenue

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. Sustained adverse hydrologic conditions could create upward pressure on per-unit customer rates.

The four power marketing agencies (PMAs) within the U.S. Department of Energy (DOE) market the output from federal plants owned and operated by USACE or the Bureau of Reclamation.[34] Bonneville Power Administration (BPA) markets the power from the 31 Federal Columbia River Power System hydropower plants (20,648 MW) in the Pacific Northwest, and the Western Area Power Administration (WAPA) markets the power from 57 hydropower plants (10,504 MW) located across 15 states in the West and Upper Great Plains. The Southwestern Power Administration (SWPA) markets the power from 24 hydropower plants (2,256 MW) located in Arkansas, Missouri, Oklahoma, and Texas. Finally, the Southeastern Power Administration (SEPA) markets the power from 22 hydropower plants (3,838 MW) located in six Southeastern states. The map in Figure 24 shows the geographical footprint of each PMA and the size and location of the hydropower plants whose energy and capacity they market.

34 Two of the plants whose power is marketed by the Western Area Power Administration are connected to dams along the United States-Mexico border and are operated by the International Boundary & Water Commission.

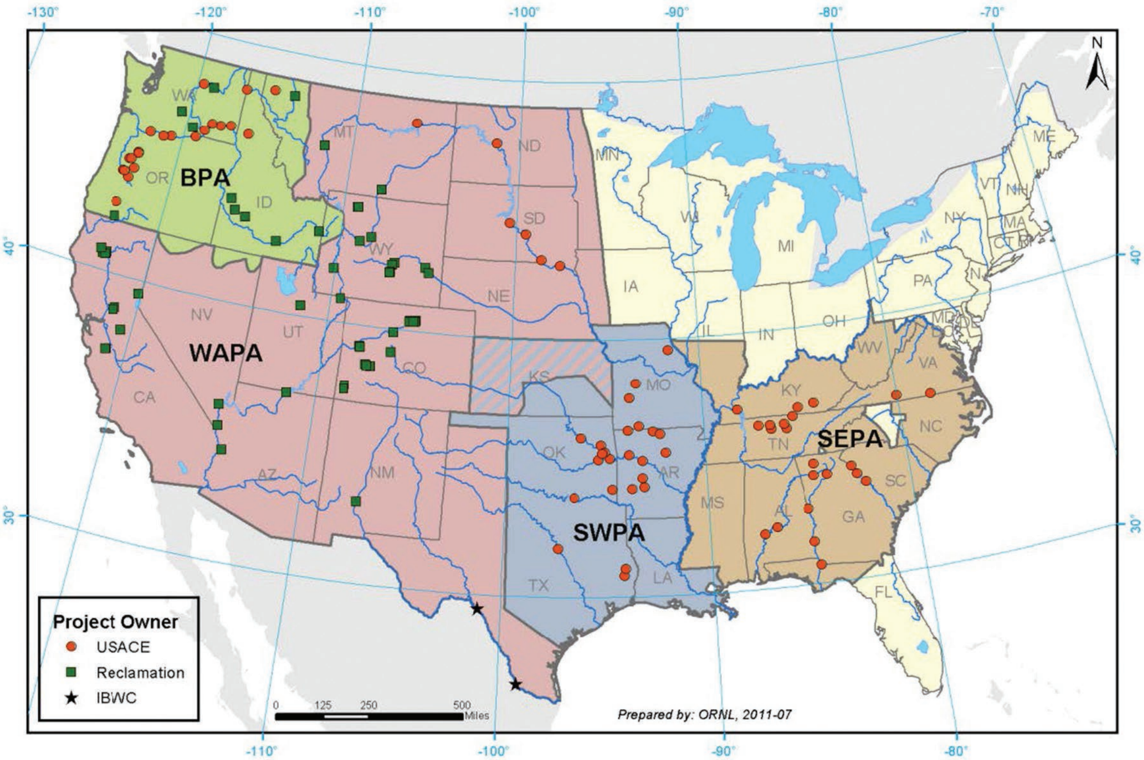


Figure 24. Federal hydropower facilities and federal power marketing regions in the United States

Source: Reprinted from Sale et al. (2012).

By statute, the PMAs market federal hydropower at cost-based rates and give priority of access to public utilities such as municipalities and cooperatives, also known as preference customers, over for-profit entities. Priority clauses were first introduced in legislation passed in the early 1900s, which called for federal hydropower assets to contribute to economic development and rural electrification and sought to prevent the formation of monopolies in the electric industry (GAO 2001).

PMAs allocate federal hydropower capacity and energy to their preference customers through long-term contracts. Periodically, the PMAs revise the rates at which these allocations are sold so that they continue to be adequate to meet their annual revenue requirement.[35]

One portion of the annual revenue requirement is an estimate of the cost of purchased power. The need for PMAs to purchase power in the wholesale market arises when the available capacity or energy produced by the federal hydropower fleet is insufficient to meet the energy delivery obligations in long-term contracts with preference customers. The PMAs pass on purchased power expenditures to their customers. Conversely, during periods when hydropower output exceeds the volumes needed to meet their contractual commitments, the PMAs can allocate the surplus power among their customers or sell it in the wholesale market. Therefore, the average price per kilowatt-hour paid by PMA customers can vary from year to year depending on available capacity and hydropower production. An additional component of PMA rates is the annual revenue requirement for the transmission necessary to deliver the energy to preference power customers.

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

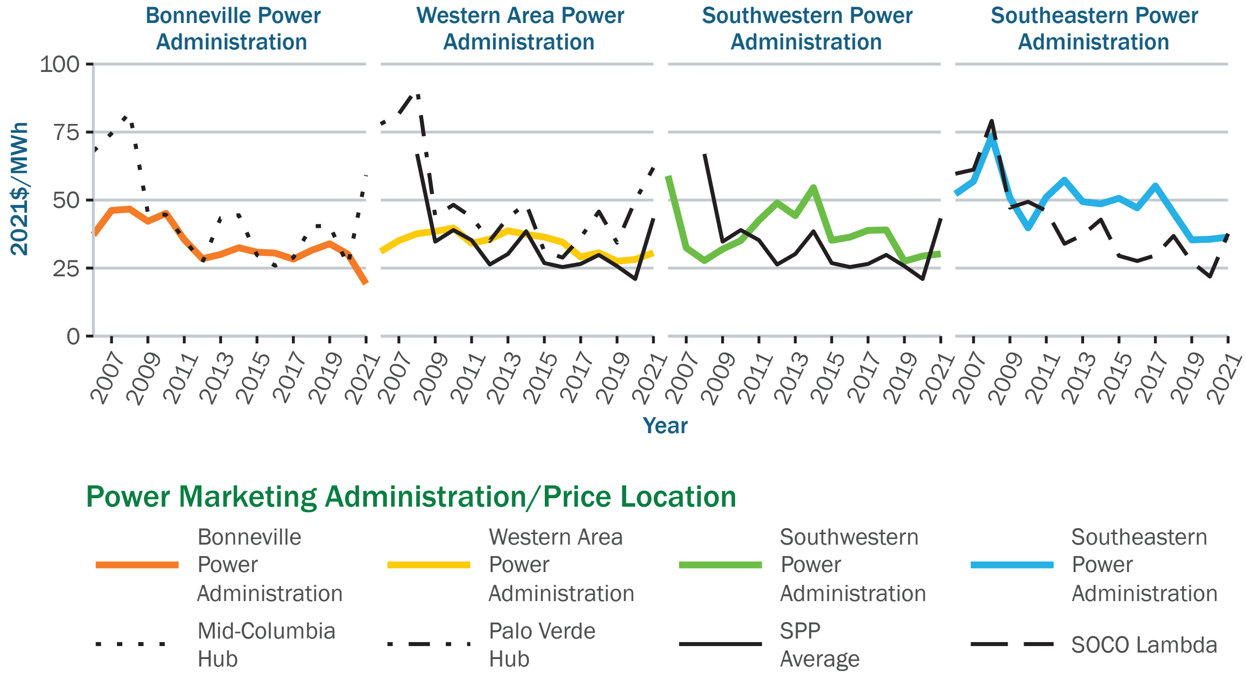


Figure 25. Average federal hydropower revenue per megawatt-hour versus average wholesale electricity prices

Sources: EIA Form 861 (2006–2021) (for federal hydropower revenue), EIA Wholesale Electricity and Natural Gas Market Data (Mid-Columbia Hub and Palo Verde Hub), Southwestern Power Pool (SPP) State of the Market reports (SPP Average), FERC Form 714 (SOCO Lambda).

Notes: The average federal revenue per megawatt-hour for each PMA is calculated as the ratio of total revenues over total sales volume. Sales and revenue data for BPA are the net of the output and sales revenue from Columbia Generating Station, a nuclear generation plant owned and operated by Energy Northwest, whose output is marketed by BPA. Mid-Columbia and Palo Verde Hub prices are daily, volume-weighted average prices across all wholesale transactions at those hubs. The SPP Average price is the day-ahead price of energy (since the start of the Integrated Marketplace in 2014, it also includes the cost of operating reserves and uplift payments). SOCO Lambda represents the average cost of operating the marginal generation unit each hour of the year in the Southern Company balancing authority.

Figure 25 shows that the average federal hydropower revenue per megawatt-hour in 2019–2021 was below the 2006–2018 average. Across the four PMAs, average revenue per megawatt-hour from 2019 to 2021 ranged from $27.75/MWh (BPA) to $35.78/MWh (SEPA). For the trading hub wholesale prices, the range for 2019–2021 was much wider—from $28.93/MWh (Soco Lambda) to $48.68/MWh (Palo Verde Hub). The average revenue per megawatt-hour for the PMAs was lower than the average wholesale price in 2019–2021, except for SEPA.

The PMA average revenue, shown in Figure 25, is a proxy for a federal hydropower price. Both the total revenue and sales numbers used to compute average revenue include output from the federal hydropower fleet and additional power purchased by PMAs in the wholesale market to fulfill the contractual obligations with their customers. Purchased power volumes are higher for dry years when hydropower generation is below average. From 2006 to 2021, the average fraction of PMA sales that came from purchased power was 17% for BPA, 23% for WAPA, 6% for SWPA, and 11% for SEPA.[36]

The average trading hub wholesale market price series, included in Figure 25, shows the cost of operating the marginal fuel source for electricity in each region. Because natural gas has been the marginal fuel in much of the country for the period shown in Figure 25, the spikes in the trading hub wholesale prices at the beginning of the period, as well as in 2014 and 2021, are correlated to spikes in natural gas prices. At times of wholesale price spikes, a contract with a PMA offers lower prices and a tool to mitigate price risk for those public utilities that make up most of the PMA customer base.

Looking at the full 2006–2021 period, the average revenue per megawatt-hour was higher and more variable from year to year for SWPA and SEPA than for BPA and WAPA. The differences in average revenue levels are partly explained by the products

36 Wholesale purchases by BPA have increased greatly in 2020 and 2021. The 2006–2019 average wholesale purchase fraction was 8%.

marketed by each PMA, which, in turn, are determined by the characteristics of each hydropower fleet. SWPA and SEPA sell firm peaking power. For instance, SWPA guarantees its customers 1,200 hours of energy per kilowatt of capacity contracted per year (3.3 hours per day if the same volume were scheduled every day). On average, the 2006–2021 capacity factor of the fleets marketed by the PMAs were 44% for BPA, 34% for WAPA, 30% for SWPA, and 26% for SEPA. Thus, SWPA and SEPA must meet their annual revenue requirement with lower average capacity factors, which, all else being equal, leads to higher prices per megawatt-hour.

Average annual prices for BPA and WAPA remained low and exhibited less variability compared with average trading hub wholesale prices from 2006 to 2021. This is because of the cost-based requirements in the PMA's long-term contracts and to the smoothing effect on costs provided by the diversity of climate regions across the various PMA marketing regions and, for WAPA, the large size of some of the hydropower storage reservoirs, which makes them capable of buffering the effects of multiyear droughts.[37]

Most of BPA's customers are full-load customers, which means that BPA covers their net load requirements. In this context, net load is the difference between electric load and supply from generation sources owned by the preference customer. WAPA's products vary across its power projects based on their different hydrologic profiles and statutory requirements ranging from firm capacity allocations in some of the projects to as-available energy in others.

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. For WAPA, the sales volume in 2020–2021 (including purchased power) was the lowest of the period shown in Figure 25 (2006–2021) and total revenue in 2020–2021 was 19% below the average total revenue in 2006–2021.[38]

Although the effects of drought on the PMA-wide average energy prices shown in Figure 25 are smoothed by the diversity of hydrologic conditions in the vast area where hydropower plants marketed by WAPA are located, it is important to note that WAPA has five distinct marketing areas defined by the hydropower projects in each region and the statutory requirements associated with marketing the energy from those specific projects. Customer rates within each distinct region are a function of the hydrologic conditions for the projects in that region, infrastructure investments, and the unique characteristics of the statutory requirements and long-term contracts under which customers receive energy from WAPA.

4.2 Hydropower Power Purchase Agreements

Within a long-term trend of declining energy prices in electricity PPAs, median hydropower PPA energy prices remained stable in the West, increased in the Midwest, and decreased in the Northeast and Southeast in 2018–2020. The typical purchase agreement structure varies by region: Midwest and Southwest had the lowest prices for their energy component, but they are also the two regions with the largest fraction of agreements that include a capacity price component.

Many private non-utility hydropower owners sell capacity and energy to a utility through a PPA. PPA terms and conditions, including prices, are typically kept private between the power producer and the utility buyer. However, large electric utilities must report purchased power volumes and expenditures as part of FERC Form 1. Thus, the FERC Form 1 dataset contains the information needed to calculate the average price paid for energy (and for capacity if it is part of the transaction) for each unique pair of utility buyer and hydropower producer.[39] The capacity component of a PPA is a fixed charge per kilowatt of capacity available over a period regardless of the number of kilowatt-hours actually generated. The energy component of a PPA is a charge per kilowatt-hour generated.

37 Turner et al. (2022) use statistical hydropower generation models to evaluate the hydropower effects of the Western droughts of the past 20 years relative to those from the twentieth century. The authors find that the diverse hydropower climate regions in the U.S. West are typically not severely affected at once by any single drought, resulting in relative stability in total hydropower generation across the region.

38 An additional factor that might have contributed to lower revenue for WAPA in 2020 is lower O&M costs for some of the hydropower plants whose power it markets. PMA's rates are cost based, and the O&M costs of hydropower plants are part of the annual revenue requirement that the rates are set to meet. Because of COVID restrictions, some Reclamation hydropower facilities delayed extraordinary maintenance activities and/or capital projects, resulting in lower total O&M costs for those facilities in 2020.

39 The dataset includes transactions between utilities and non-utilities, as well as among utilities.

To subset hydropower PPAs out of the FERC Form 1 dataset, only the data from sellers who own hydropower assets exclusively (instead of a portfolio of power plants using different fuels) are selected.[40] Using this approach, 734 unique buyer-seller pairs were identified. Of those, 134 reported PPA transactions every year from 2006 to 2020 and the rest reported transactions for only some of the years. Figure 26 compares the average energy price in the hydropower PPA subset to the energy price across all purchased power transactions in the FERC Form 1 dataset.

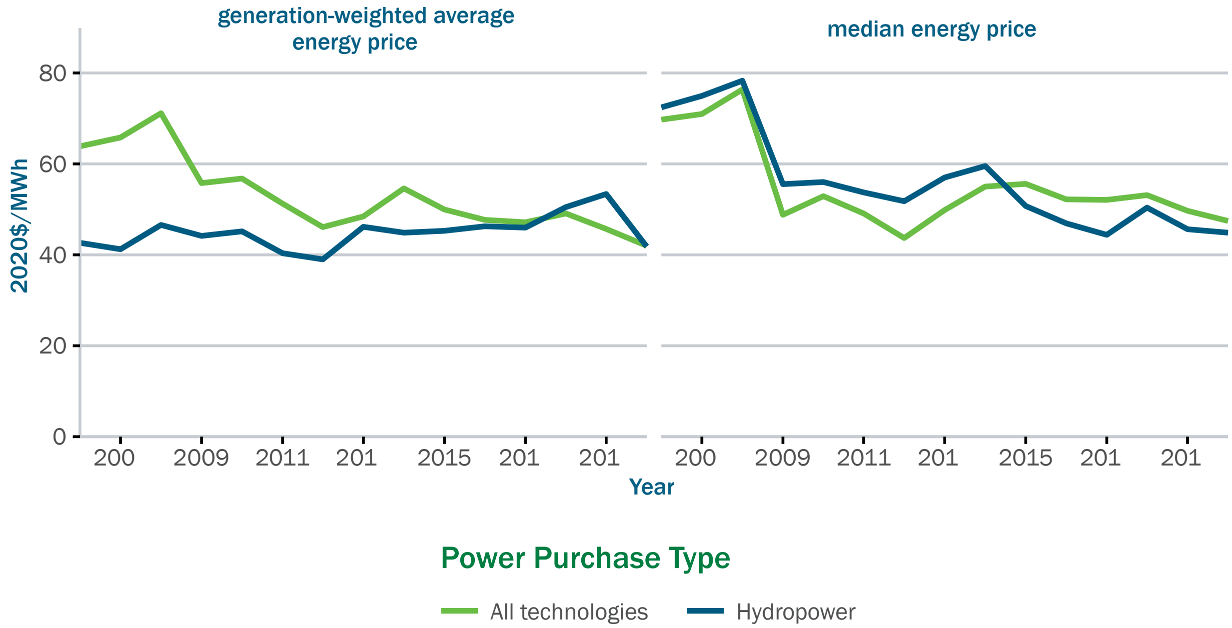


Figure 26. Median and generation-weighted average FERC Form 1 purchased power prices for hydropower versus all technologies

Source: FERC Form 1

On a generation-weighted average basis, the prices paid for hydropower were significantly lower than for all technologies combined in the late 2000s, but they converged through the 2010s. The lower price for hydropower in the initial years of the period shown in Figure 26 can be largely attributed to a few large-volume, low-price contracts between utilities in the Northwest region.

The median price (energy component) paid for hydropower has closely followed that of other technologies. The median price for hydropower transactions in 2020 was $45/MWh, and the median across all technologies was $47/MWh. In both cases, it was the second lowest price for the 2006–2020 period.[41] The low median price for 2020 is consistent with the drop in electricity prices also observed in wholesale markets that year because of the impact of the COVID-19 pandemic on electricity consumption.

The values shown in Figure 26 refer only to the energy component of PPA transactions. As of 2020, 19% of transactions involving hydropower included a capacity component. Across all technologies, the percentage of transactions including a capacity component in the price was 11%.

Figure 27 summarizes hydropower PPA energy prices (their median and their range from the 10th to the 90th percentile) at the regional level and compares them to the average wholesale electricity price for each region.

40 This approach means that not all transactions involving hydropower are captured.

41 For hydropower, the lowest median energy price in the 2006–2020 period was in 2017; for all technologies combined, the lowest median energy price was in 2012.

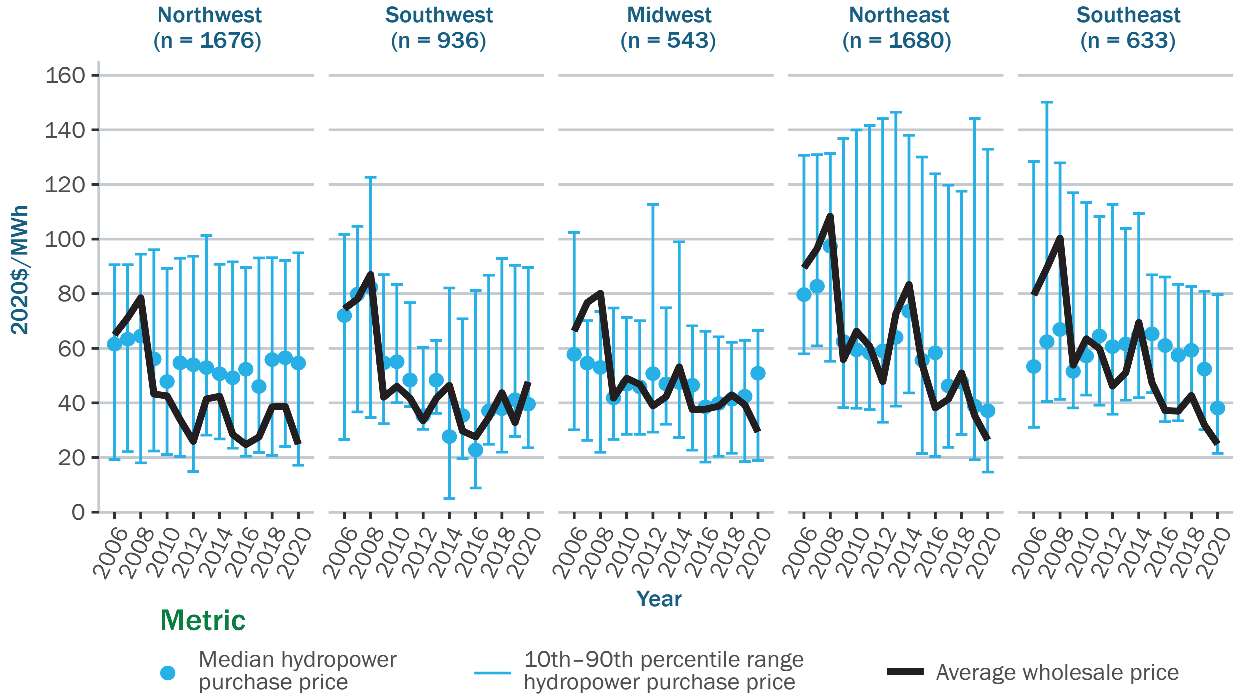


Figure 27. Energy component of the hydropower price by region and report year from power sales reported on FERC Form 1

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

Note: The n in the panel labels refers to 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 FERC Form 1 hydropower purchase price range. 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. Of the transactions, 24% include a capacity price component.

The median energy price shows a decreasing trend in every region, which is consistent with the trend in trading hub wholesale prices. On average, the lowest median prices for the energy component of hydropower purchase agreements in 2006–2020 were those in the Southwest ($47.83/MWh) and Midwest ($46.97/MWh). For the other three regions, the 2006–2020 averages of the median prices of the energy component were $54.67/MWh (Northwest), $58.43/MWh (Southeast), and $61.36/MWh (Northeast). The Northwest and Southeast are the two regions where the median hydropower price has been more consistently above the average wholesale price.

In every region and year, the energy component of hydropower purchase transactions spanned a wide range. For the Northeast region, the range became even wider in 2019–2020.[42] The year in which the purchase agreement was signed is one of the factors explaining the within-region variability. If the PPA sets a fixed price, the price will reflect the prevalent wholesale electricity price forecasts at the time the contract was signed. For instance, PPAs that were signed in 2006–2008 often reflect the view that electricity prices would remain at the high levels observed in those years. Another option is to link the purchased power price to a price index or ISO/RTO price. A high fraction of agreements setting prices linked to an index or ISO/RTO price would explain the high correlation between wholesale electricity prices and median hydropower energy prices observed in the Southwest, Midwest, and Northeast regions through the 2010s.

For the 26 PPAs where the first year of data is 2018 or later, the average price of energy ranged from $23/MWh to $80/MWh. Only 2 of these 26 agreements also included a capacity component in the price.

42 In 2019 or 2020 in the Northeast, there were 26 transactions with average energy prices above $100/MWh. These contracts do not include a capacity price component, and the sellers are all private owners of small hydropower plants. Niagara Mohawk Power Corporation is the buyer in 18 of the 26 transactions.

The fraction of transactions that include a capacity price component varies substantially by region. It is 9% in the Northwest, 18% in the Northeast, 21% in the Southeast, 34% in the Midwest, and 60% in the Southwest. The Southwest and the Midwest are also the two regions where, for the subset of transactions that include a capacity price component, the capacity charges are a higher fraction of the revenue for the plant owner. On average, capacity revenue represented 40% of total revenue in the Midwest and 31% in the Southwest. In the rest of regions, the capacity fraction of total revenue was below 20% for the small subset of transactions that did include a capacity price component.

Figure 28 summarizes the information on fraction of transactions including a capacity price component (x axis) and average capacity fraction of total revenue for the set of transactions that do have a capacity price component (y axis) by region and year.

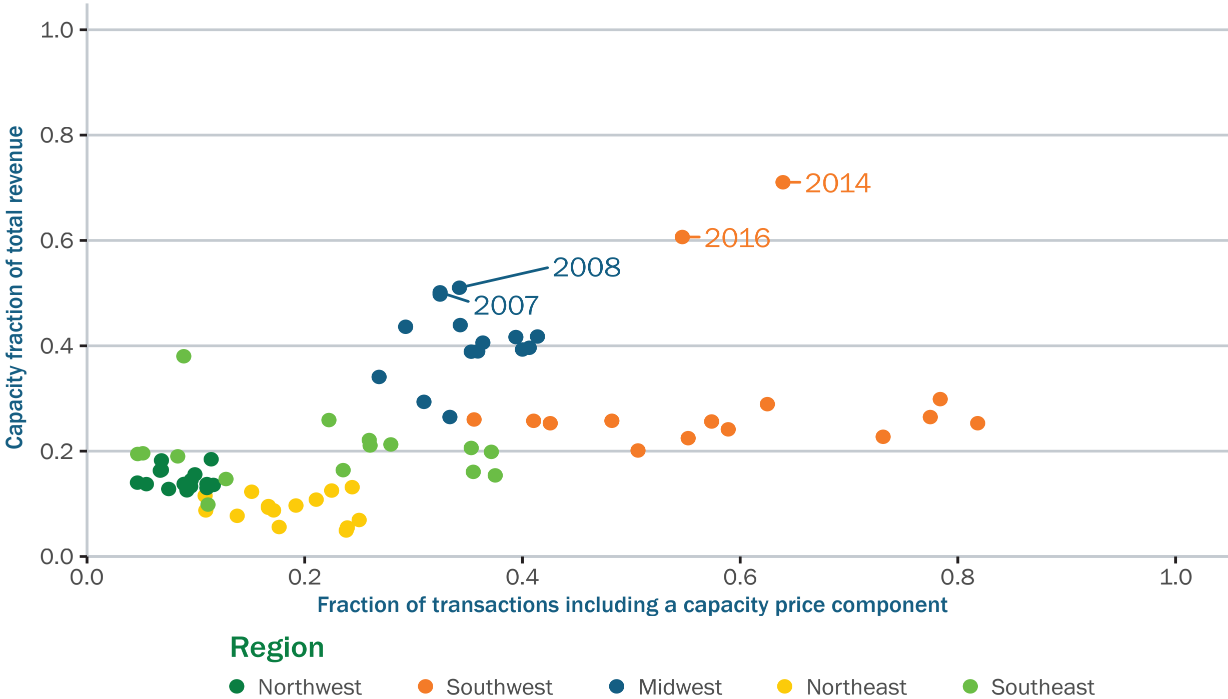


Figure 28. Frequency and magnitude of capacity price component of hydropower sales reported on FERC Form 1 by region and year

Source: FERC Form 1

Note: The year labels correspond to the years where the capacity fraction of total revenue in a region was greater than 0.5.

The Northeast and Northwest display stable fractions of transactions including a capacity price component and a stable relative magnitude of capacity revenue over total revenue. For the Southwest, the fraction of transactions including a capacity price component varies significantly from year to year, but the capacity revenue fraction is stable around 25%—except for 2014 and 2016 when the fraction was much higher.[43] In contrast, purchased power transactions reported on FERC Form 1 for the Midwest are stable regarding the fraction of transactions that contain a capacity price component, but the capacity fraction of total revenue varies widely from year to year (from 26% in 2011 to 51% in 2008). Finally, in the Southeast, 40% or less transactions included a capacity price component during this period and capacity revenue typically represented less than 25% of total revenue for the seller.

43 Fifty of the 52 purchased power transactions in the Southwest with more than 60% of total revenue corresponding to the capacity price component in 2014 and 2016 had Pacific Gas & Electric as the purchasing utility.

In the Northwest, Southwest, and Midwest, the total median revenue per megawatt-hour in 2006–2021 has been higher in PPAs that include a capacity price component. However, in the Northeast, the total median revenue per megawatt-hour has been higher for the subset of transactions in PPAs without a capacity price component. In the Southeast, PPAs with a capacity price component had higher median revenues in the first half of 2006–2021; after that, the median revenue per megawatt-hour has been the highest for short-term PPAs with energy-only prices.

4.3 Revenue Streams from Participation in ISO/RTO Markets

For hydropower plants, energy revenue is the largest component, and its magnitude is correlated with the plant's capacity factor. Capacity revenue is typically the second largest component. The amount and mix of ancillary services provided varies significantly among plants, but ancillary service revenue is typically a small component of the total revenue. The main difference for PSH plants is that energy revenue is lower (because of the low average number of hours in generation mode per day) and capacity revenue can be somewhat higher than for hydropower plants.

The previous sections in this chapter report price trends in long-term contracts for federal hydropower and revenue from hydropower purchase agreements, many of which are also long-term agreements. This section discusses the revenue streams received by plants that offer energy and ancillary services in one of the short-term (day-ahead or real-time) organized wholesale markets managed by ISOs/RTOs, as well as capacity revenue from ISO/RTOs with centralized capacity auctions.[44] The data in this section are from FERC Electric Quarterly Reports (EQRs), which contain subdaily transaction data for public utilities and nonpublic utilities that sell more than 4 million megawatt-hours per year.[45] As with other datasets that are organized at the utility level, it is challenging to extract only hydropower data. In the case of the EQRs, the approaches to identifying hydropower data involved selecting utilities that own only hydropower plants or selecting transactions with a delivery node that corresponds to a specific hydropower or PSH plant. Figures 29 and 30 show the total revenue per kilowatt that results from aggregating plant-level revenues for provision of energy, ancillary services, and capacity for the sample of hydropower and PSH plants for which FERC EQR data could be extracted based on the ownership or delivery node criteria.

44 FERC defines ancillary services as services necessary to support the transmission of electric power from seller to purchaser to maintain reliable operations of the interconnected transmission system. FERC requires transmission operators to include the following six ancillary services in their tariffs: (1) scheduling, system control, and dispatch service; (2) reactive supply and voltage control service; (3) regulation and frequency response service; (4) energy imbalance service; (5) spinning reserve service; and (6) supplemental reserve service. Definitions for each of these can be found at ferc.gov/sites/default/files/2021-09/20210907-4002_Energy and Ancillary Services Markets_2021_0.pdf.

45 Regardless of volume sold, federal and state agencies, political subdivisions, and cooperatives are excluded from the requirement to file EQRs.

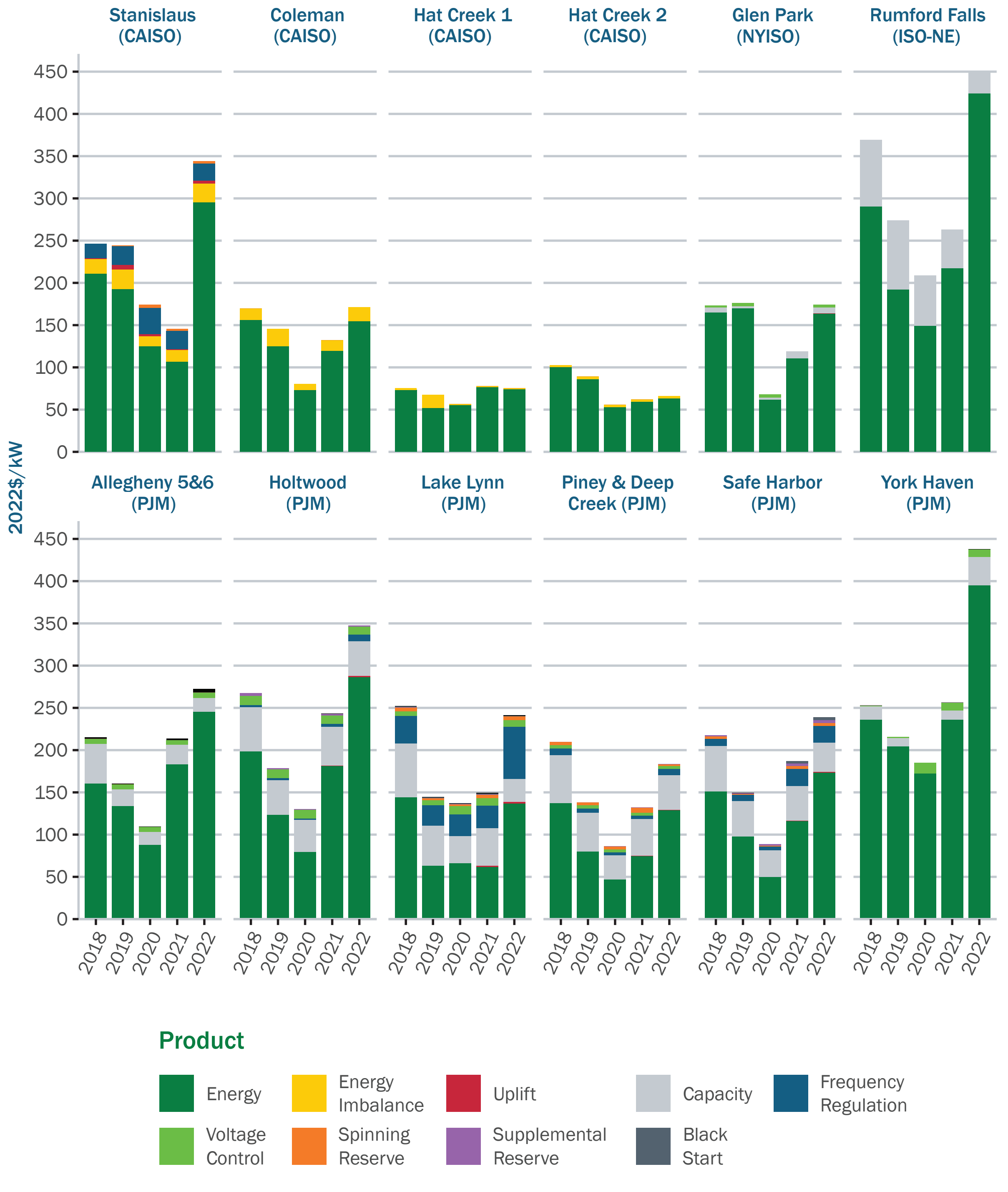


Figure 29. Annual revenue streams for a sample of hydropower plants

Source: FERC EQRs

Note: The plot includes only transactions that could be matched to specific hydropower plants. CAISO (California ISO) does not have a centralized capacity market. CAISO plant owners may trade capacity in bilateral transaction among California load-serving entities that have capacity requirements. The revenue from those bilateral capacity constraints is not included in the EQR.

Figure 29 contains revenue data for 12 hydropower plants in 4 ISO/RTOs.[46] Most of them are run-of-river plants. The only exceptions are Stanislaus (peaking plant), Coleman (peaking plant), and Lake Lynn (reregulating plant). The average total annual revenue in 2018–2022 ranged from $69/kW for Hat Creek 1 to $313/kW for Rumford Falls. This large variability is the product of multiple plant-level and market-level factors including (1) plant configuration and technical specifications of its equipment, (2) plant availability, (3) hydrology, (4) products offered by each ISO/RTO, and (5) market conditions in each ISO/RTO.

Energy revenue was typically the largest component of total revenue for this set of plants and varied substantially year to year for each plant during this period. 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 and increased sharply in 2022.

Capacity factor is an important determinant of revenue for run-of-river plants. The two plants with the highest energy revenue component in 2018–2022 (Lake Lynn and York Haven) are also the two plants with the highest average capacity factor during that period (63% and 66%, respectively). Similarly, the plants with lower average energy revenue (Hat Creek 1 and Hat Creek 2, Piney and Deep Creek) all have capacity factors below 40%. For plants with relatively low capacity factors, revenue can be boosted if generation can be timed to take place during high-price periods.

For the CAISO plants, separate reporting of the energy and energy imbalance components offers a glimpse into the fraction of energy revenue that these plants are getting in the real-time energy imbalance market versus the day-ahead energy market. For both Stanislaus and Coleman, energy imbalance revenue averaged ~10% of the total energy revenue during this five-year period. For the other two plants in CAISO, the energy imbalance revenue averaged 6% (Hat Creek 1) and 4% (Hat Creek 2). The Western Energy Imbalance market (WEIM), administered by CAISO, allows BAs outside of the CAISO footprint to participate in CAISO's real-time energy imbalance market. See textbox for a discussion of the impacts of the WEIM on hydropower operations across the West.

Capacity revenue was generally the second largest revenue component (for all the plants where capacity revenue numbers could be extracted from the EQR dataset). There are substantial differences in the average annual capacity revenue received by hydropower plants during this period across the different ISO/RTOs. The largest value was for the ISO-NE plant ($58/kW for Rumford Falls), and the lowest value was for the NYISO plant ($5.5/kW for Glen Park). Across the PJM plants, the average annual capacity revenue was within a tight range of $41–$43/kW for four of them and significantly lower for York Haven ($18/kW) and Allegheny 5&6 ($24/kW).

Load-serving entities in California must meet capacity requirements set by the California Public Utilities Commission through either self-supply or bilateral contracts. The average prices of those bilateral transactions are published annually and give an indication of the relative magnitude of capacity values in that state versus ISOs/RTOs with centralized capacity markets. The average annual capacity value in 2018–2022 was $59.5/kW.

Nine of the 12 plants in Figure 29 received uplift payments in at least some of the years in 2018–2022. Uplift payments are out-of-market payments that cover shortfalls between a supply resource's offer and the revenue earned through market clearing prices.[47] Uplift payments added up to more than $1/kW in any year only for Lake Lynn and Stanislaus (two of the three plants in this set that do not operate as run of river) and Holtwood.

Participation in ancillary service markets varied significantly from plant to plant. Stanislaus and Lake Lynn were the only two plants in this set for which ancillary service revenue averaged more than $20/kW per year. In both cases, most of the ancillary service revenue came from provision of frequency regulation, which is typically a high-value ancillary service. Four of the six PJM plants (Holtwood, Lake Lynn, Piney & Deep Creek, and Safe Harbor), as well as Stanislaus in CAISO, provided spinning reserves. Spinning reserve revenue ranged from $0 to $6/kW. All the PJM plants provide supplemental reserves, and the revenue obtained for this service ranged from $0 to $4/kW. Five of the PJM plants, as well as Glen Park in NYISO, report revenues from provision of voltage control ranging from $1/kW to $12/kW. Lake Lynn and Safe Harbor receive black start payments obtaining a revenue of $1–3/kW per year for that service.

46 Allegheny 5&6 are two plants in Pennsylvania owned by the same entity and located next to each other and are treated here as a single plant. Piney and Deep Creek are two plants owned by the same entity and operating in the PJM market and are treated here as a single plant.

47 ferc.gov/sites/default/files/2020-05/08-13-14-uplift_3.pdf.

INITIAL FINDINGS ON THE IMPACT OF CAISO'S WESTERN ENERGY IMBALANCE MARKETS ON HYDROPOWER OPERATIONS

The Western Energy Imbalance Market (WEIM) allows participation in the CAISO real-time market to balancing authorities (BAs) outside of the CAISO area. The WEIM started operations in November 2014 with only two BAs (CAISO and PacifiCorp), but participation has grown quickly. By the end of 2023, the 22 BAs to be part of the WEIM will contain 88% of WECC hydropower and PSH capacity.

The benefits of the WEIM increase with the number of participants, because the larger pool of generation resources available to resolve imbalances allows more efficient dispatch and results in lower required operating reserves. With increased participation, it becomes riskier to remain a non-participating BA because there will be very few counterparties left outside the WEIM with whom to conduct real-time bilateral trades and resolve imbalances.

Little information has been published about how participation in the WEIM changes hydropower operations and revenue. Not all the hydropower units in participating BAs bid into the WEIM (for instance, BPA joined the WEIM in 2022 with 10 of its 31 hydropower dams as participating resources and none of the hydropower resources in Salt River Project, WEIM participant since 2020, are participating resources).[48] Nonetheless, resources that do not participate might indirectly experience changes in operations as well.

Datta et al. (2022) compare operations for two hydropower plants in Portland General Electric before and after that BA joined the WEIM in 2017. They find that, after joining the WEIM, the mean hourly generation and operational range of both plants decreased by 10%–20% and the plants operated less hours close to their maximum rated capacity. These changes are likely due to CAISO's requirement for WEIM participating resources to maintain sufficient ramping capacity. Other notable changes are the increase in the number of starts per day (for one of the plants) and an increase in ramping frequency (although the ramping mileage decreased in one of the plants). The study does not indicate whether the changes in operation resulted in a higher revenue for these two plants, but it points out the need to calculate the potential costs of the new mode of operation on machine health and compare them against the monetary benefits of WEIM participation.

In 2023, CAISO published an implementation timeline for the extended day-ahead market initiative which would extend the WEIM rationale (pooling resources from a wide regional area to meet demand at a lower cost, reduce the need for curtailment of renewables, and reduce operational risk) to the day-ahead market where most electricity generation is scheduled. The go-live date for the extended day-ahead market for those BAs which decide to participate is scheduled for 2025.

The WEIM is not the only real-time balancing market in the West. SPP has managed the Western Energy Imbalance Service (WEIS) market since February 2021. The WEIS allows utilities that are not members of the SPP RTO to participate in an imbalance market that performs five-minute dispatch of all the participating resources. As of June 2023, the WEIS has 10 participants, including three of WAPA's marketing regions. Building on the WEIS, SPP is also developing a set of products (Markets +) that extend to the day-ahead market.

48 The 10 hydropower dams in BPA that are participating resources in the WEIM account for more than 80% of hydropower capacity in that BA.

Figure 30 contains the same type of data as Figure 29 for a set of PSH plants.

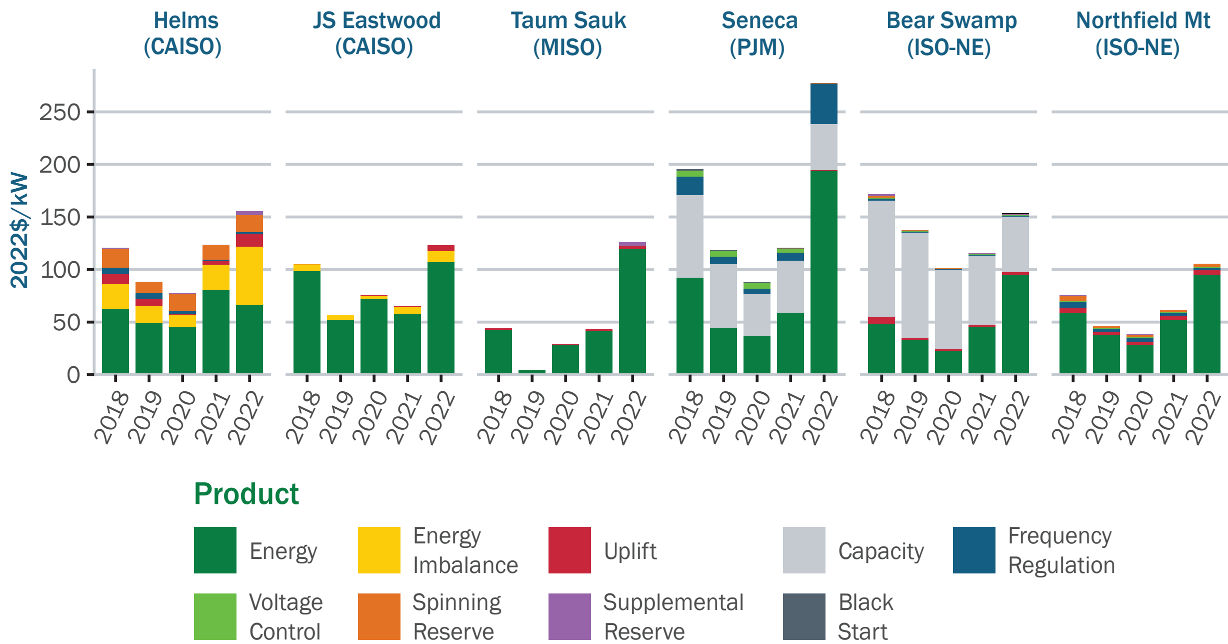


Figure 30. Annual revenue streams from participation of PSH plants in ISO/RTO markets

Source: FERC EQRs

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.

For Bear Swamp and Northfield Mountain, the two PSH plants for which plotted numbers are a better representation of total revenue because capacity revenue information is included, the average gross revenue (i.e., without netting out the cost of pumping) from participation in ISO/RTO markets was $135/kW and $160/kW, respectively, in 2018–2022.

Compared with the hydropower plants in Figure 29, the average energy revenue is lower for PSH plants and, for the PSH plants where capacity revenue data could be extracted out of the EQR dataset, capacity revenue is somewhat higher. The average annual capacity revenue in 2018–2022 was $81/kW for Bear Swamp and $55/kW for Seneca. The lower energy revenue is driven by the mode of operation of PSH plants, which generate electricity for only a few hours a day to meet peaks in net load. For example, in 2021, the gross generation from the six plants in Figure 29 was equivalent to having operated at their full nameplate generation capacity 600—1,000 hours (on average, 2–3 hours per day).

All PSH plants report uplift payments ranging from less than 1 cent/kW for Eastwood in 2018 to $9.11/kW for Helms in that same year. It was rare for uplift payments to add up to more than $5/kW-year for these plants during this period.

Capacity payments accounted for a significant share of total revenue for the two plants where plant-level information for capacity revenue could be extracted. Given that a key attribute of PSH is its availability to generate during the exact periods when it is needed, it makes sense for capacity revenue to be an essential component of the PSH revenue stack. Capacity revenue represented an average of 68% of total revenue for Bear Swamp and 44% for Seneca in 2018–2021. These large capacity shares dropped significantly in 2022 because of the large increase in energy revenue that year.

For Bear Swamp, aside from the capacity revenues from participating in the ISO-NE capacity market, the EQR data also show capacity revenue from a 100-MW long-term contract with Long Island Power Authority. That revenue averaged $13 per installed kilowatt in 2018–2020 (or $78/kW for the 100,000 kW that are part of the contract). Revenue from this contract stops being reported after April 2020. Since the plot displays revenues from participation in the ISO/RTO markets, revenue from this contract is not included.

The two CAISO facilities had similar total energy components to their revenue but have substantial differences in their revenue structure beyond that. For Helms, revenue from the real-time energy imbalance market represented an average of 30% of total energy revenues in 2018–2022; for Eastwood, the energy imbalance revenue averaged 7% of the total energy revenue. Additionally, Helms provides significantly more ancillary services than Eastwood.

All the plants shown in Figure 30, except for Eastwood, report some revenue from provision of ancillary services. Four of the six plants provided frequency regulation during this period. For Bear Swamp, revenue from that service averaged $1.2/kW-year, for Helms $3.8/kW-year, for Northfield Mountain $3.7/kW-year, and for Seneca $15.1/kW-year with revenue in 2018 and 2022 being much higher than the other three years. Seneca reports average revenue from the black start service of ~$1/kW-year. For the four plants that report providing supplemental reserves, the average annual revenue is typically less than $1/kW. Spinning reserve revenue is much higher for Helms ($14.9/kW annual average for 2018–2022) than for the rest of plants. As for voltage control, three of the plants provide it with Seneca receiving an average revenue of $4.8/kW and the two ISO-NE plants having a revenue of less than $1/kW. Just as with energy revenue, ancillary service revenue differences can be explained by differences in the number of periods in a year in which the plant provides the service, as well as the price of that product across ISO/RTOs.

Going forward, hydropower and PSH revenue structure will likely shift toward higher shares of revenue from the capacity and ancillary service markets (see textbox for a discussion of hydropower capacity revenue in different U.S. regions). On one hand, the average marginal energy price will tend to decrease in markets with high penetration of variable renewables (De Silva et al., 2022). Integrating variable renewables will also tend to increase the value of firm, dispatchable capacity and the need for ancillary services. 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. For example, CAISO, MISO, and SPP have added ramp products to their ancillary service markets to help ensure sufficient capacity is available to follow net loads in the real time (CAISO, MISO, SPP) or day-ahead (MISO, SPP) markets (FERC, 2021).

An additional source of revenue for some hydropower facilities results from the sale of renewable energy certificates (RECs). RECs are "market-based instruments that represent the property rights to the environmental, social, and other non-power attributes of renewable electricity generation".[49] RECs are created as electricity from eligible renewables enters the grid. They can be sold—most states allow producers to sell unbundled RECS, i.e., separate from electricity—by the producers and are purchased either by utilities, to demonstrate compliance with state renewable portfolio standard (RPS) programs or by other organizations that voluntarily wish to purchase renewable energy.

At the end of 2022, 29 states plus Washington D.C. had an RPS. Most RPSs restricted hydropower eligibility to generate RECs by one or more characteristics including online date (Tier I eligibility is typically restricted to facilities that started operation after the RPS was enacted), project capacity (upper limits are typically in the 30 MW or less), project type (NSD projects are typically excluded), and environmental impacts (Stori, 2020). However, as states revise their RPSs to increase their renewable energy sales or generation targets, they are rethinking hydropower eligibility rules. For instance, in 2018, the New York Public Service Commission made all hydropower projects with capacities up to 10 MW eligible for compliance with the New York RPS (previously, only those that have been built since the New York RPS was enacted were eligible).[50]

REC prices vary substantially by geography and time period. For instance, in many New England states (Connecticut, Massachusetts, Maine, New Hampshire, and Rhode Island), Class I REC prices have hovered around $40/MWh since 2020. For some states in the Mid-Atlantic/PJM region (New Jersey, Pennsylvania, Maryland, and Delaware), Tier I REC prices increased from $10/MWh in 2020 to $30/MWh at the end of 2022 (Barbose, 2023).

49 epa.gov/green-power-markets/renewable-energy-certificates-recs.

50 powermag.com/rethinking-hydropower-eligibility-for-state-renewable-incentive-programs/.

HYDROPOWER CAPACITY REVENUE

Ensuring reliable electricity supply is part of the mission of electricity system planners and operators and is implemented through resource adequacy standards. These standards have the objective of securing enough generation capacity to cover the forecasted peak load (i.e., electricity demand).

The capacity procurement mechanisms used to meet resource adequacy standards vary across U.S. regions (Bushnell et al. 2017). First, ISO/RTOs (see Figure 31) assign resource adequacy mandates to load-serving entities (LSEs). In some of these regions (CAISO and SPP), the LSEs self-supply capacity or enter bilateral contracts to meet their requirement. In others (ISO-NE, NYISO, and PJM), there are centralized capacity markets where the system operator acquires capacity through auctions and allocates the costs to the LSEs.[51] ERCOT is an exception among the ISO/RTO regions in that it has an energy-only market where supply resources receive payments only for provision of energy and ancillary services. While in other ISO/RTO regions capacity payments help plant owners recover their fixed costs. Fixed cost recovery in ERCOT is accomplished by allowing energy prices to rise far above operating costs during periods of supply scarcity. Finally, the rest of the country follows a cost-of-service regulation model where vertically integrated utilities seek approval from state public utility commissions to build a new generation plant, and, if approved, the utilities can pass through the investment and operation costs associated with the new resource to customer rates.

In the West, 20 utilities have recently signed in to participate in the Western Resource Adequacy Program (WRAP), a voluntary program that increases coordination and sets mechanisms for capacity sharing among utilities to more effectively meet the capacity needs of the region as thermal power plants retire and more renewables come online. FERC approved the WRAP in February 2023 and the participating utilities have started sharing their information regarding generation capacity and transmission available ahead of winter and summer seasons. The program sets rules for capacity accreditation of generation and storage resources. By 2028, the WRAP will enter its binding phase in which participating utilities will have to pay penalties if they do not show that they have sufficient capacity and transmission to meet the required planned reserve margin on their peak load.

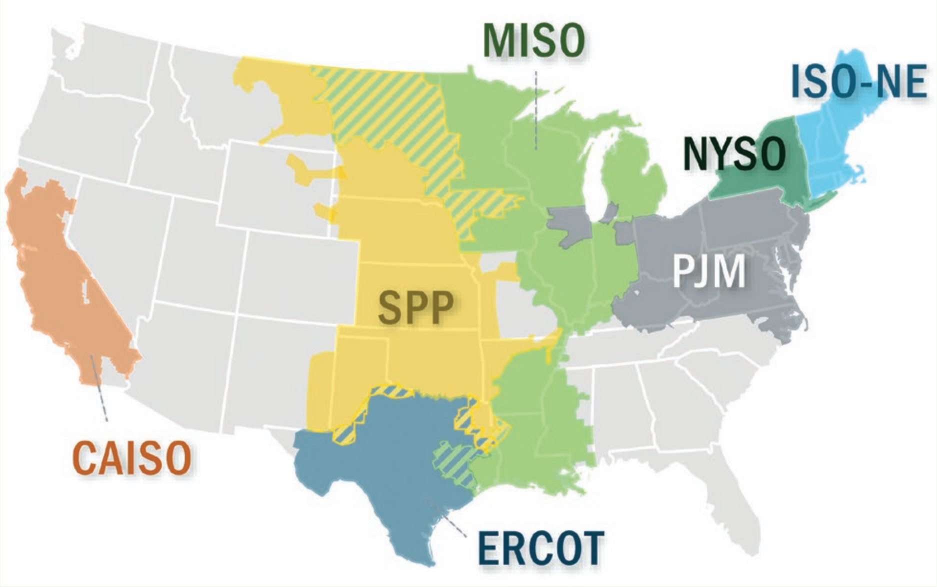


Figure 31. ISO/RTO regions

51 MISO has a hybrid system with LSE mandates and a voluntary residual capacity auction.

Figure 32 summarizes the price ranges that cleared capacity auctions in recent years in MISO, ISO-NE, NYISO, and PJM, as well as the average value of bilateral capacity trades under the California Public Utility Commission's Resource Adequacy program. For 2019–2021, the average capacity price was $65/kW in CAISO, $5/kW in MISO, $71/kW in ISO-NE, $56/kW in NYISO, and $50/kW in PJM.

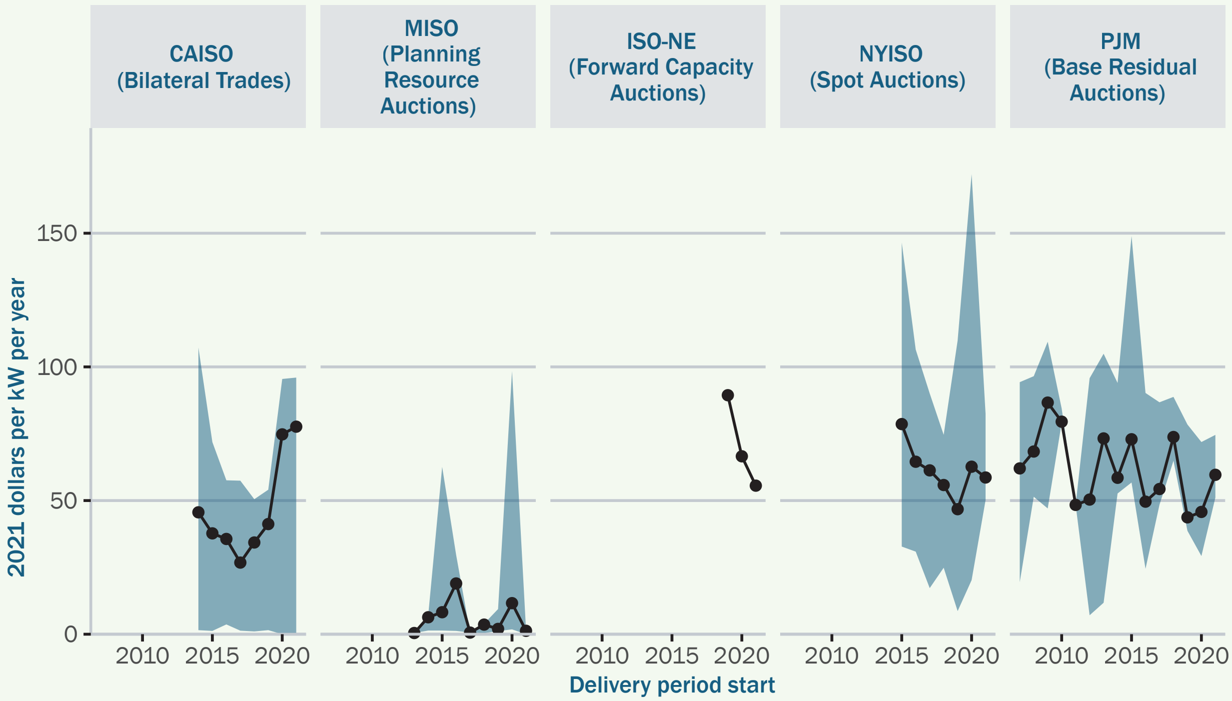


Figure 32. Capacity prices in U.S ISOs/RTOs

Source: California Public Utilities Commission (CAISO); ISO/RTO websites (MISO, ISO-NE, NYISO, PJM).

Notes: The CAISO does not operate a formal capacity market, but it has a mandatory resource adequacy requirement for load-serving entities, based on the California Public Utility Commission's Resource Adequacy framework. 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 zones. The black line and dots depict the average price across all zones. When no ribbon is shown, it is because the clearing price was the same across all zones.

Unlike energy and ancillary service prices, which are cleared at hourly or subhourly intervals, capacity prices are fixed payments whose magnitude the plant owner will know at the beginning of the year or season (depending on whether the ISO/RTO conducts annual or seasonal auctions). The capacity revenue that a hydropower or PSH plant earns by participating in one of the ISO/RTO capacity markets is the product of how much of its capacity (kW) gets accredited for capacity revenue and the capacity price ($/kW).

The capacity price differs across ISOs/RTOs (see different average levels and trends in Figure 32) and across zones within an ISO/RTO (price range enclosed by the blue ribbon in Figure 32). The fraction of capacity that gets accredited depends on the attributes of the plant and the rules for accreditation in each ISO/RTO. Given the variation in price and rules for accreditation, there can be large differences in the capacity revenue that hydropower plants are getting each year. Nonetheless, as shown in Figures 29 and 30, it can be a sizable fraction of total revenue.

Capacity accreditation rules vary across markets. Historically, accredited capacity was a function of nameplate capacity adjusted by forced outage rates and historic availability factors. In recent years, the increased penetration of variable renewables has motivated changes in accredited capacity methodologies to adequately reflect the contribution of each supply resource to reliability. PJM and CAISO are two of the ISOs/RTOs that have recently revised their capacity accreditation methodology. The WRAP also has developed methodologies to determine the capacity contribution of each generation and storage resource.

PJM has implemented a new method (Effective Load Carrying Capability, ELCC) for the first time for its 2023/2024 capacity auction. The goal of ELCC is rewarding most those resources that consistently perform well during the hours with the highest probability of supply shortage. Accredited capacity is based on a class rating and further adjusted by unit-specific performance metrics. For hydropower, the class rating is 42% for intermittent hydro (i.e., only 42% of the nameplate capacity for facilities in that class would earn capacity revenue), 96% for hydro with pondage or reservoirs. For PSH, the class rating ranges from 83% (if it offers 4 hours of storage capacity) to 100% if it offers eight or more hours of storage capacity.

For CAISO generation resources, the California Public Utilities Commission calculates accredited capacity—called net qualifying capacity (NQC) in that state—for each supply resource and month. For nondispatchable hydro, NQC is based on average production of the fleet of nondispatchable hydropower generators over a three-year period during the resource adequacy measurement hours (4:00–9:00 p.m.). For dispatchable hydro, the default method assesses NQC based on the amount of capacity bid into the market during the availability assessment hours of the previous decade and derated by capacity not bid due to lack of water. Additionally, resources with a nameplate capacity of <20 MW connected to the transmission system using the Small Generator Interconnection Procedure are not assessed for deliverability and have zero net qualifying capacity.

The WRAP uses different methods to determine the qualified capacity contribution of different generation technologies. For storage hydro (i.e., any hydropower resource with the capability to store at least one hour worth of water), the qualified capacity contribution is actual generation during the critical capacity hours (hours when the net regional capacity need is above the 95th percentile based on historic loads, energy resource performance, and interchange) of the previous 10 years plus the potential extra generation that would have been possible dispatching additional flow for generation while meeting operational constraints. For run-of-river hydro, qualified capacity contribution is the monthly average generation of the project during critical capacity hours during the previous 10 years.

4.4 Trends in Hydropower and PSH Asset Sale Prices

Based on regulatory filings and reports in the news media, 75 sale prices accounting for 4.76 GW of transferred hydropower capacity were collected. The total value of the sales in this sample is $8.6 billion (in 2022 dollars). Figure 33 shows the price per kilowatt for each transaction along with information about region and capacity sold.

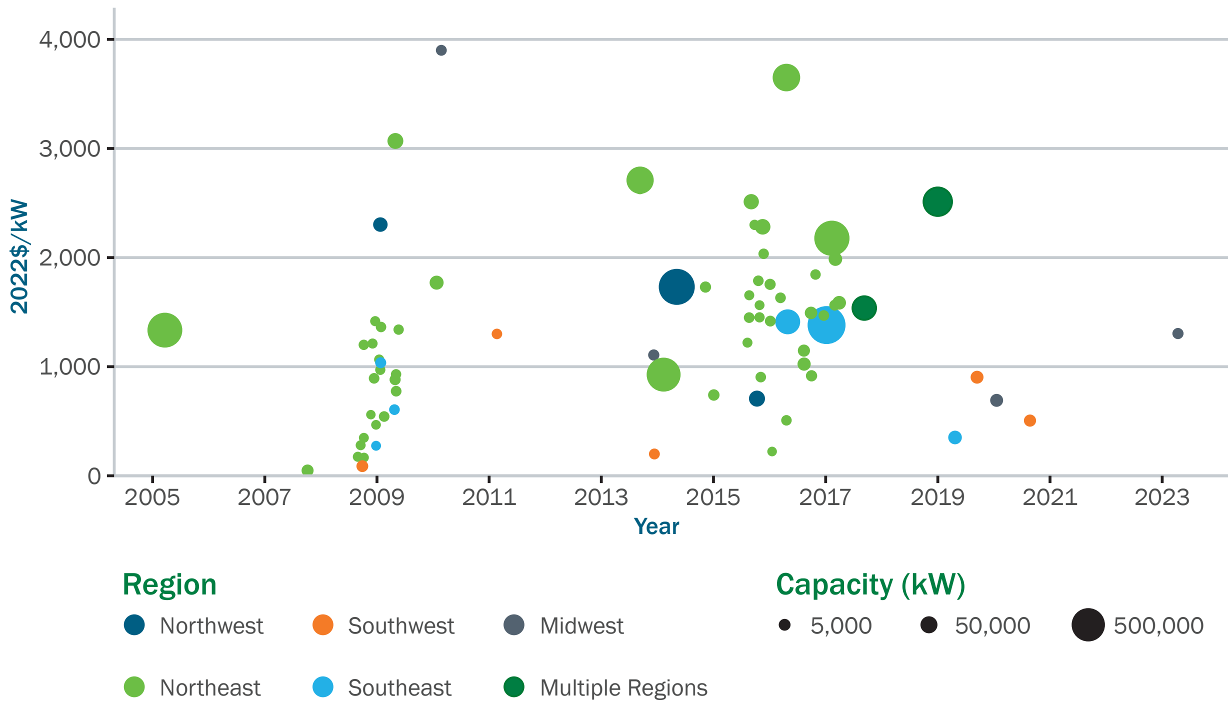


Figure 33. U.S. hydropower plant sale prices by year, capacity, and region

Source: Internet searches and regulatory filings.

Note: For transactions in which multiple plants were sold out but only the total price was reported, the price shown is the average across all capacity sold.

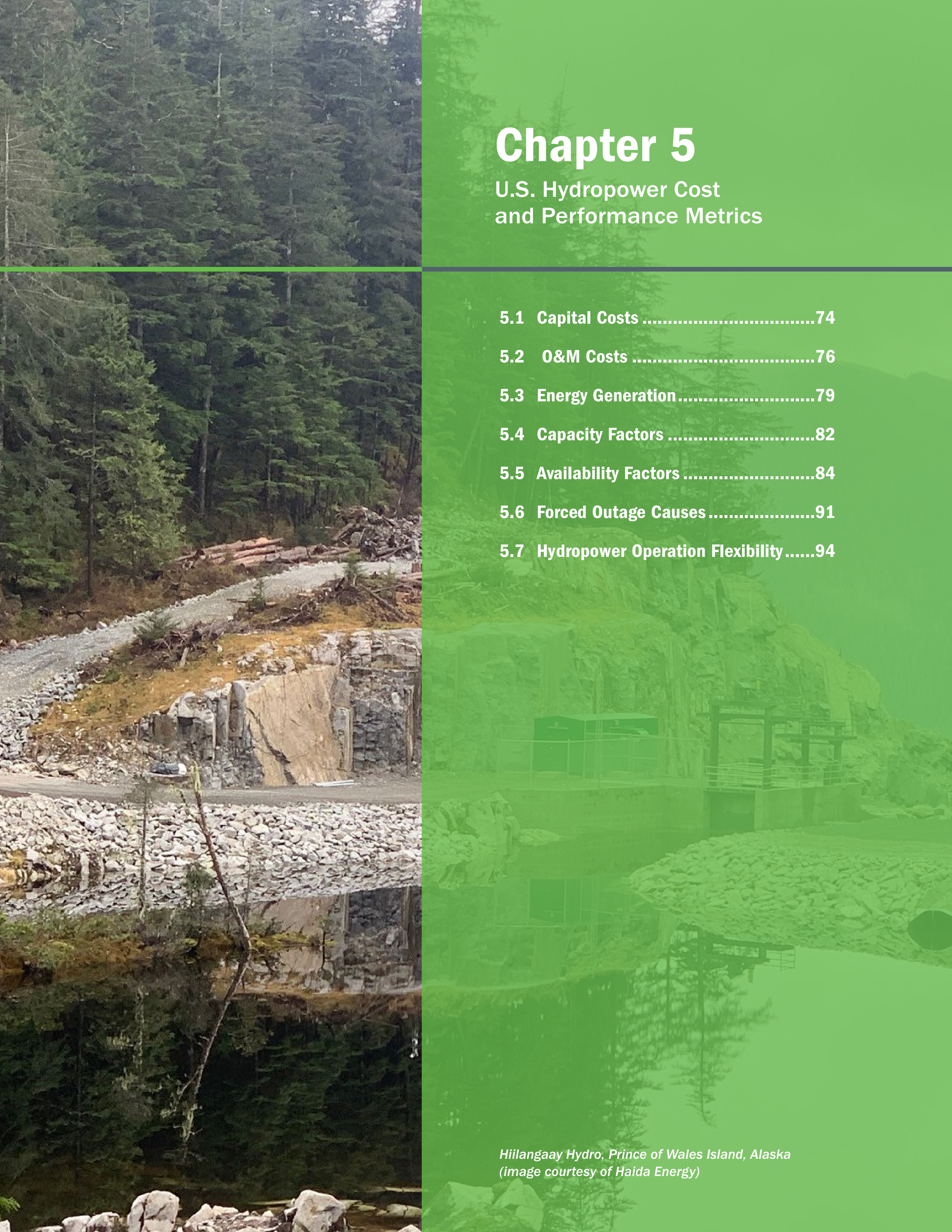
From 2020 to June 2023, five hydropower plant sale transactions have been identified. Three of these transactions involved a private seller and a public buyer and, in the other two, both the buyer and the seller were private entities. The largest of these sales, completed in February 2023, was the acquisition by HQI US Holding LLC (a wholly-owned subsidiary of Hydro Québec) of 13 hydropower plants located in Vermont, Massachusetts, and New Hampshire. This fleet, previously owned by Great River Hydro, LLC has a combined nameplate capacity of 589 MW. The transaction had an approximate value of $2 billion and also included 30,000 acres of land. Since the reported value does not include details about which portion corresponds to the hydropower facilities versus the land, it is not included in Figure 33.

Of the other four sales, two involved multiple small plants in the Midwest and the other two were individual sales for small plants in the Southwest. The price has been disclosed for three of these four transactions: the purchase of three small hydropower plants in Michigan by Hydrogen Charbone Corporation at an average price of $1,304/kW and the sales by Pacific Gas and Electric of an operational 10.4 MW plant to the Sacramento Municipal Utility District at $903/kW and an out-of-service 6.4 MW plant to Kern and Tule Hydro, LLC at $506/kW.

The full dataset shown in Figure 33 includes 75 transactions announced between January 2005 and June 2023 involving 233 hydropower plants and 1 PSH plant, for which sale prices were publicly reported. The average sale price (in 2022 dollars) is $1,304/kW, and the 10th and 90th percentiles of the price distribution were $307/kW and $2,302/kW. Seventy-six percent of the recorded transactions involved hydropower plants in the Northeast. In 87% of the transactions, both the buyer and the seller are private entities.

Chapter 5

U.S. Hydropower Cost and Performance Metrics



Hiilangaay Hydro, Prince of Wales Island, Alaska (image courtesy of Haida Energy)

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

The first part of this chapter presents data on the costs of building new hydropower projects (Section 5.1) and of operating and maintaining the existing fleet (Section 5.2). The rest of the chapter discusses performance metrics including (1) summarizing trends in hydropower generation and gross PSH generation by region; (2) combining generation and capacity data to explore capacity factor trends and ranges for different fleet segments; (3) offering information on trends and causes of outages, as well as the number of hours that hydropower and PSH plants spend in different operating statuses; and (4) providing information to illustrate hydropower's flexibility, including the number of starts and stops and summary metrics on ramping.

5.1 Capital Costs

Capacity-weighted averages for a sample of 75 U.S. hydropower projects built since 1980 were $3,955/kW for canal/conduit projects, $6,096/kW for NPD projects, and $6,621/kW for NSD projects. Five new projects starting operation since 2020 reported capital costs ranging from $5,000/kW to $10,000/kW.

Figure 34 summarizes the capital costs from construction of 75 new U.S. hydropower plants since 1980. It indicates their size as well as what type of development they entail, for example, the addition of hydropower to an existing NPD, addition of hydropower to existing conduit infrastructure (canal/conduit), or hydropower development at a previously undisturbed stream-reach.

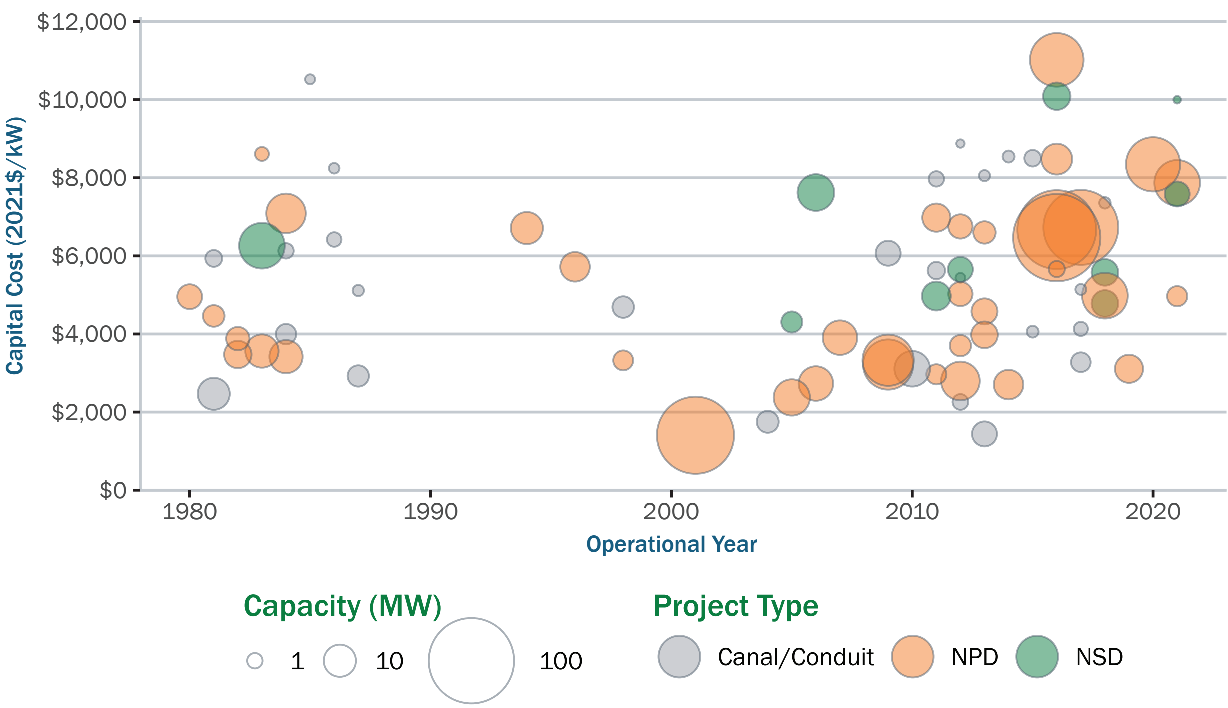


Figure 34. Cost of new hydropower development since 1980

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

Note: The U.S. Bureau of Reclamation Construction Cost Trends composite trend index was used to adjust for inflation cost data from different years. Given that the data come 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).

Capital costs vary widely across projects (even within the same project type). Eighty percent of projects had costs within the $3,000–$9,000/kW range, 15% had costs under $3,000/kW, and costs exceeded $9,000/kW for the remaining 5%. The last project in the dataset that had costs below $3,000/kW started operation in 2014. Five new projects with operation start dates in the 2020s were added to the database since the version presented in the previous edition of the U.S. Hydropower Market Report. The capital costs for those newly added projects were all in the $5,000–$10,000/kW range.

By 1980, 74 GW of conventional hydropower capacity (out of a total of 80.6 GW in operation today) had already been built. That includes the most productive sites where capital costs would be lowest because of economies of scale. Only 1 of the 75 projects in the dataset is larger than 100 MW, and 72% are less than 10 MW. Therefore, the cost data in Figure 34 are representative of a mature hydropower industry and look very different to the cost data in regions of the world that are developing very large projects.

The 75 projects in the dataset account for 13% of the capacity added from 1980. However, the 51 projects in the dataset with operational start dates of 2005 or later account for one third of projects and 84% of capacity from all new U.S. hydropower projects since that year. Since the post-2004 sample is more representative of recent development, it is explored further.

For the sample of 51 projects starting operations since 2005, the capacity-weighted mean capital cost was $3,955/kW for canal/conduit projects (16 observations with capacities ranging from 11 kW to 13 MW), $6,096/kW for NPD projects (26 observations with a capacity range from 1 to 105 MW), and $6,621/kW for NSD projects (9 observations with capacities ranging from 1.5 kW to 14 MW). The raw means were $5,617/kW for canal/conduit projects, $5,229/kW for NPD projects, and $6,733/kW for NSD. Canal/conduit projects have the lowest capacity-weighted mean relative to the raw mean, which is indicative of strong economies of scale (i.e., the capital cost per kilowatt installed decreases as project capacity increases). For NPDs, the capacity-weighted mean is higher than the raw mean because of the subset of relatively large projects above $6,000/kW since the mid-2010s. Finally, the raw and weighted means for NSD projects are almost identical because the range of capacities for NSD projects is narrow; except for a very small project (1.5 kW), the rest are in the 3–14 MW range.

More than 80% of the U.S. hydropower capacity added from new projects between 2010 and 2021 has resulted from adding hydropower to existing NPDs, and, as shown in Chapter 2, most new hydropower capacity under feasibility evaluation or already authorized with a FERC license is also for NPD projects. With only 3% of dams in the United States today having hydropower generation capability, substantial resource potential remains for NPD retrofit projects. Oladosu et al. (2021) evaluated 19 NPD sites (representative of larger clusters of sites with estimated capacity potentials greater than 0.1 MW, identified by their dam infrastructure and water resource characteristics) with capacities ranging from 200 kW to 70 MW and obtained a range of capital cost estimates from $2,200–$34,000/kW, with most sites below $12,000/kW. One of the important configuration characteristics for cost structure identified in this study is whether the NPD project is connected to a lake dam or a lock dam. Lock dams are low-head dams that have a navigation lock; lake dams tend to have relatively higher head and lower flow than lock dams and are not used for navigation purposes. Lake dams tend to have large shares of water conveyance costs, whereas lock dams typically have larger powerhouses and electromechanical equipment cost shares because of the need for large capacity turbines to make use of large flows and compensate for the low head at those sites.

5.2 O&M Costs

The costs to operate and maintain hydropower plants display strong economies of scale (i.e., the O&M cost per kilowatt decreases as plant capacity increases). As of 2020, the average O&M cost ranged from $16/kW for very large plants to $213/kW for small plants. The available dataset from FERC Form 1 lacks information about the type of plants that have made the most of the new capacity in the past three decades.

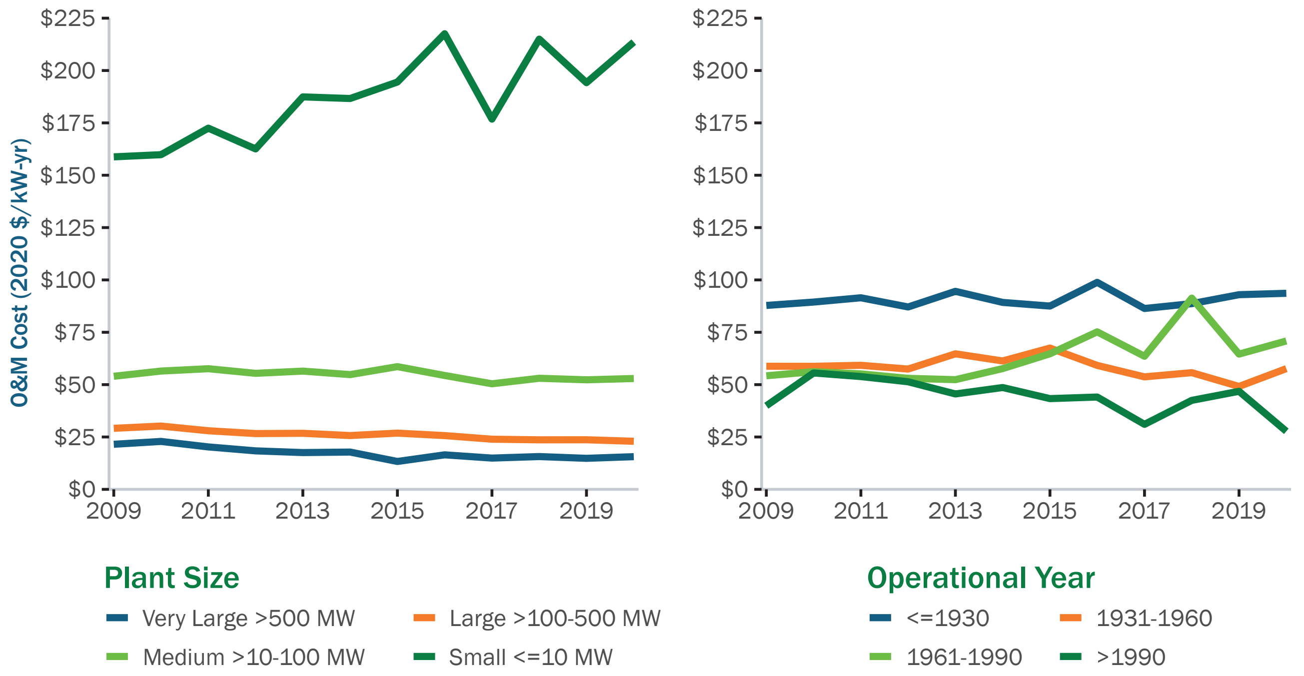


Figure 35. Trend in O&M costs per kilowatt for utility-owned hydropower and PSH plants by size category and age

Source: Oladosu and Sasthav (2022)

Note: Average number of plants by size category: 7 (Very Large), 48 (Large), 158 (Medium), 57 (Small). Average number of plants by operational year interval: 143 (<= 1930), 70 (1931–1960), 52 (1961–1990), 4 (>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.

The cost per kilowatt of operating and maintaining a hydropower plant varies significantly by size and age. By size, as of 2020, the average O&M cost ranged from $16/kW for Very Large plants to $213/kW for Small plants. The very high average cost for Small plants is largely driven by 10 plants with reported costs above $500/kW. If those are excluded, the average cost for Small plants in 2020 is $127/kW. Cost trends diverged by size during the 2009–2020 period. The average O&M cost per kilowatt in 2020 was 35% higher than in 2009 for Small plants. In contrast, the average cost declined for the other size categories. Average cost decreased by 2% for Medium plants, by 21% for Large Plants, and by 27% for Very Large plants. Since six out of the seven plants in the Very Large category are PSH, the costs for that size category are a proxy for PSH O&M costs.

The subset of plants that was commissioned by 1930 has a higher average O&M cost than any of the other newer cohorts. However, that subset also has the largest fraction of small plants (33%), which makes it difficult to disentangle the effect of size and age. The difference between the average O&M cost of plants that started operation before 1930 ($94/kW) and those that started operation after 1990 ($28/kW) was greater in 2020 than in any year of the previous decade. The data for the plants commissioned after 1990 is very limited (only four plants), and none of them are small plants.

In Figure 35, the relationship between cost and size is clearer than that between cost and age. The age variable shown here is calculated based on the commissioning year of the plant. Therefore, it contains limited information as to the age of specific plant components, such as turbine runners and generator windings, that might have been replaced since the plant started operation.

The federal agencies that own and operate almost half of the U.S. installed hydropower capacity do not file FERC Form 1. However, their O&M expenditures can be estimated from their budgets. In nominal terms, the dollar amounts appropriated to cover federal hydropower O&M expenses from multipurpose projects owned by USACE and the Bureau of Reclamation in FYs 2021–2023 stayed flat relative to those in FYs 2018–2020.[52] This means that the O&M budget for these projects has decreased in real dollar terms, adjusted for inflation.

For the USACE fleet, the average annual hydropower O&M funding in FY2021–FY2023 was $463 million ($21.15/kW) versus $471 million in FY2018–FY2020.[53] These budget numbers include the congressionally allocated percentage of costs that hydropower is required to share for project features and assets that jointly benefit all authorized purposes of the project. The budget also includes small capital expenditures for purchasing or repairing assets with a definable service life. Reclamation's annual hydropower O&M budget for FY2021–FY2023 averaged $470 million ($31.86/kW) which is the same as the FY2018–FY2020 average.[54]

The lower O&M value per kilowatt for the USACE fleet results from the median capacity of the plants in its fleet (100 MW) being larger than that for Reclamation (38 MW). Therefore, it is appropriate to compare the average expenditure per kilowatt for the USACE fleet ($21.15/kW) with the average cost for nonfederal Large projects ($22.95 in 2020) and the expenditures for the Reclamation fleet ($31.86/kW) with the costs for nonfederal Medium projects ($53/kW).

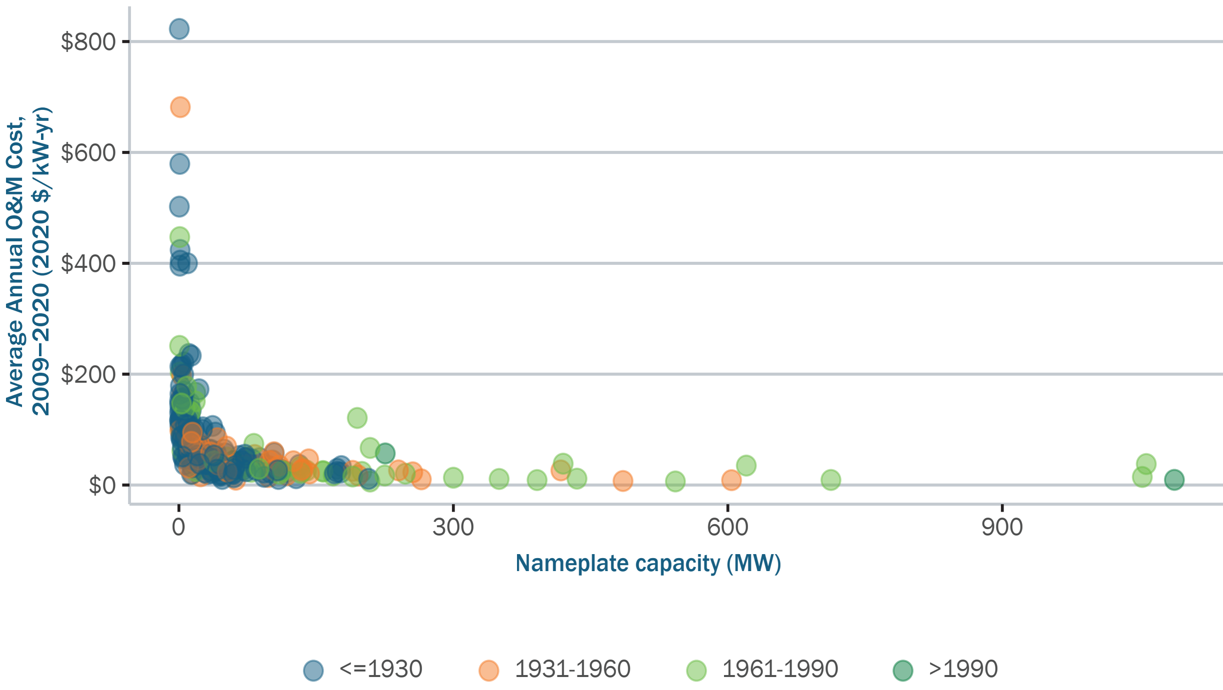


Figure 36. Plant-level average annual O&M cost by size class and age (for utility-owned plants)

Source: Oladosu and Sasthav (2022)

Note: Same notes apply as for Figure 35.

Figure 36 confirms that small, old plants tend to have the highest O&M costs, but it also shows that there is substantial variability in the annual average O&M costs from plant to plant within the same size category or age cohort. Fifty-two (75%) of the 69 plants with average O&M costs greater than $100/kW are small, and the rest, except for one Large plant, belong to the

52 For both agencies, the O&M expenses of hydropower projects marketed by BPA are covered with financing provided by that PMA instead of Congressional appropriations.

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

54 Bureau of Reclamation budgets: usbr.gov/budget.

Medium size category. Similarly, 53 (77%) of the plants with average O&M costs greater than $100/kW were commissioned before 1930, with the rest distributed among plants that started operation between 1930 and 1990.

Another indication of the strong economies of scale in the costs of operating and maintaining hydropower plants is that the plant with the highest average O&M cost ($822/kW) is also the smallest plant in the dataset (0.42 MW). All but one of the plants with average O&M costs greater than $250/kW have nameplate capacities of 1.6 MW or less.

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 are 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. The reason why small, new projects are absent from the FERC Form 1 dataset is that most of them are owned and operated by private non-utilities and public utilities that do not meet the thresholds for having to file FERC Form 1.[55]

Another O&M metric often used for comparison among technologies is O&M per unit of energy generated (i.e., in dollars per kilowatt-hour). To obtain that number, the total O&M cost is divided by the annual net generation for each plant. Given that there is a lot of variability both in total costs and capacity factors across the plants in a size category or age cohort (as well as year to year for the same plant because of hydrologic conditions and planned or unplanned outages), no clear trends emerge from averaging the plant-level data. Instead, Figure 37 displays the trend in O&M cost per kilowatt-hour at the average capacity factor for each size category during 2009–2020.

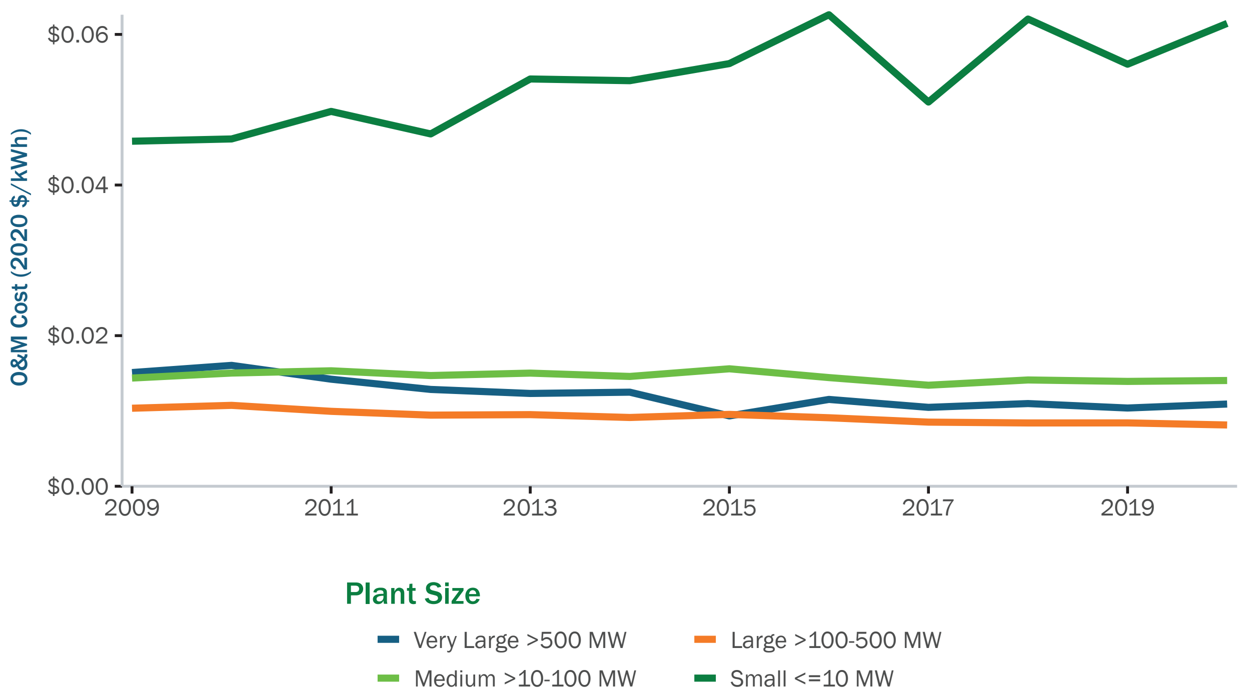


Figure 37. Trend in O&M cost per kilowatt-hour for utility-owned hydropower and PSH plants by size category (at average 2009–2020 capacity factor for each category)

Source: Oladosu and Sasthav (2022)
Note: Same notes apply as for Figure 35.

The average 2009–2020 O&M cost per kilowatt-hour was approximately 1 cent per kilowatt-hour for the Very Large and Large projects, 1.5 cents per kilowatt-hour for the Medium projects, and 5.4 cents per kilowatt-hour for Small projects. The average 2009–2020 capacity factors used in the calculation for each size category were 16% for Very Large projects, 32% for

55 To be required to file FERC Form 1, an electric utility must have, in each of the previous three calendar years, sales or transmission service that exceeds one of the following: 1 million MWh of total annual sales, 100 MWh of annual sales for resale, 500 MWh of annual power exchanges delivered, or 500 MWh of annual wheeling for others.

Large projects, 43% for Medium projects, and 40% for Small projects. The low capacity factor for the Very Large sample of plants is a consequence of six of the seven plants in that category being PSH plants. Even though they are capable of generate continuously for 8–12 hours when starting with a full upper reservoir, on average, PSH plants generate electricity just a few hours per day and have lower capacity factors than conventional hydropower plants.

5.3 Energy Generation

The average U.S. net hydropower generation in the first three years of the 2020s (266 TWh) has been 4.2% lower than the average annual generation in the previous decade (278 TWh), largely driven by extreme drought in parts of the West. Average Canadian hydropower imports in 2020–2022 were 7.6% above the annual average in the 2010s.

Average U.S. net hydropower generation in the first three years of the 2020s (266 TWh) has been lower than the average generation in the previous decade (278 TWh). A key driver of the decrease has been drought conditions in the Western regions of the country. Average Canadian imports in 2020–2022 (41 TWh) were 8% above the average in the 2010s (38 TWh). Figure 38 shows the trend in annual domestic generation and Canadian hydropower imports from 2005 to 2022.

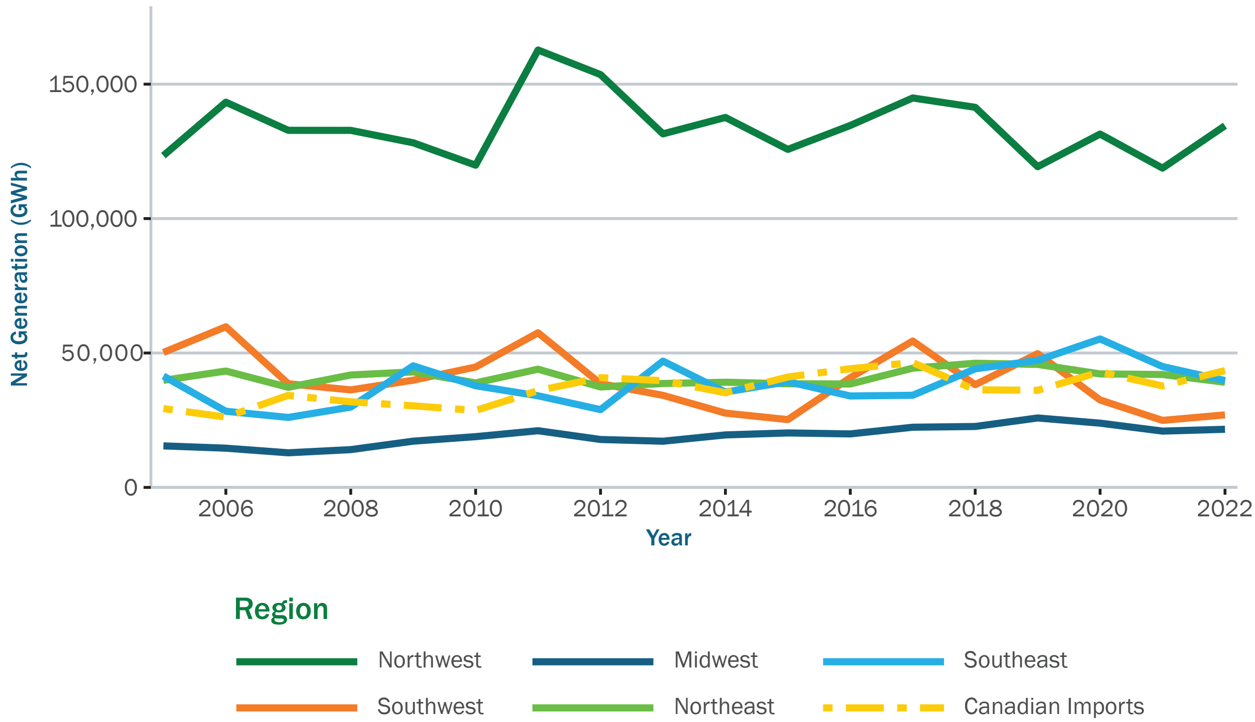


Figure 38. Annual hydropower net generation by region (2005–2022)

Source: EIA Form 923, Canada Energy Regulator.

Note: Canadian imports include only 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.

Figure 38 shows that the largest hydropower-producing region in the United States is the Northwest. With an installed capacity of 35.9 GW in 2022, its average generation from 2005 to 2022 has been 134 TWh.[56] The Southwest, Northeast, and Southeast all have been the second-largest producing region for some years in 2005–2022. The Southwest and the Southeast both have

56 Some of the hydropower generated in the Northwest is exported to British Columbia (Canada) as part of the Canadian Entitlement, which is one of the provisions from the Columbia River Treaty—an international agreement between the United States and Canada implemented in 1964 to jointly develop and operate the water resources in the Columbia River Basin for the purposes of flood control and power production. The value of the Canadian Entitlement is estimated to range from $229 million to $335 million per year (Congressional Research Service, 2023). In 2018, the United States and Canada started negotiations to modernize the Columbia River Treaty. The size of the Canadian Entitlement might be revised as part of those negotiations.

installed capacities of 15 GW, and the fleet in the Northeast adds up to 8.6 GW. The average 2005–2022 generation volumes were 40 TWh for the Southwest, 38 TWh for the Southeast, and 41 TWh for the Northeast. The Midwest, with an installed capacity of ~6 GW, has had the lowest generation every year during that period. The average generation from that region was 19 TWh per year in 2005–2022. Finally, Canadian hydropower imports averaged 37 TWh per year.

Part of the hydropower generated in the Northwest is exported to British Columbia in Canada as part of the "Canadian Entitlement," which is one of the provisions from the Columbia River Treaty—an international agreement implemented in 1964 for development and operation of the water resources in the Columbia River Basin for the purposes of flood control and power production. The value of the Canadian Entitlement is estimated to range from $229 million to $335 million per year.

The year-to-year variability of generation in each region is primarily a result of changes in available water volumes due to hydrologic conditions. The coefficients of variation in annual generation (the ratio of the standard deviation of a series over its mean) allow comparing the degree of interannual variation in generation volumes by region. The higher the coefficient of variation, the more variable the generation volume is. The Northwest and Northeast had the most stable annual generation series with coefficients of variation of 9% (Northwest) and 7% (Northeast). The Southwest region had the highest coefficient of variation during this period (27%), followed by the Southeast (20%) and Midwest (18%).

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%). The average Canadian imports in 2020–2022 were 7.6% above the average in the previous decade. The drops in the Northwest and Southwest are largely explained by drought. Changes in operations due to increased penetration of renewables may also be playing a role (e.g., see textbox in Section 4.3 for anecdotal evidence on hydropower units in the Northwest reserving more capacity for ramping, to help balance net load, after joining a regional energy imbalance market).

For the rest of the decade, changes in domestic generation volumes will mostly depend on the frequency of dry versus wet years and net changes in installed capacity. Since the Northwest and Southwest regions together account for more than 60% of U.S. hydropower capacity, hydrologic conditions there have a large weight on the national aggregate generation volumes. As for Canadian hydropower imports, an increasing trend is expected 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.

Year-to-year, hydrology also plays an important role in Canadian hydropower exports into the United States. The 12% drop in Canadian imports in 2021 with respect to 2020 was the consequence of a 48% decrease in imports from Manitoba Hydro into Minnesota. Canadian hydropower imports through that route were expected to increase in 2021 after completion of the Keeyask project (695 MW) and the Great Northern Transmission Line (883 MW of design transmission capacity) that would bring part of the flows from that project into the United States. However, Manitoba experienced the worst drought in decades in 2021 and had to instead drastically reduce exports that year.

In the Northeast, construction of the New England Clean Energy Connect—a proposed transmission line from Québec to New England with 1,200 MW of delivery capacity—restarted in 2023 after having been halted for approximately 18 months because of litigation.[57] The transmission line, proposed as the delivery route to bring hydropower (or a combination of hydropower and wind) as part of a 20-year clean energy purchase agreement between Hydro-Québec and the Central Maine Power Company with electricity distribution utilities in Massachusetts was originally scheduled to commence service in 2023.

Also bringing hydropower from Hydro-Québec to the Northeast, with New York as the destination, is the 339-mile Champlain Hudson Power Express Line, construction of which started in November 2022.[58] It will have a delivery capacity of 1,250 MW and is expected to be operational in 2026.

57 jdsupra.com/legalnews/another-legal-victory-for-new-england-5787761/.

58 chpexpress.com/news/governor-hochul-announces-start-of-construction-on-339-mile-champlain-hudson-power-express-transmission-line-to-bring-clean-energy-to-new-york-city/.

Average gross PSH generation in the first three years of the 2020s (21.3 TWh) has remained stable relative to the average annual gross generation in the previous decade (21.4 TWh). A substantial increase (19%) in gross PSH generation in the Southwest from 2020 to 2021 despite extreme drought in that region is an indication that PSH use is more closely linked to market conditions than hydrology.

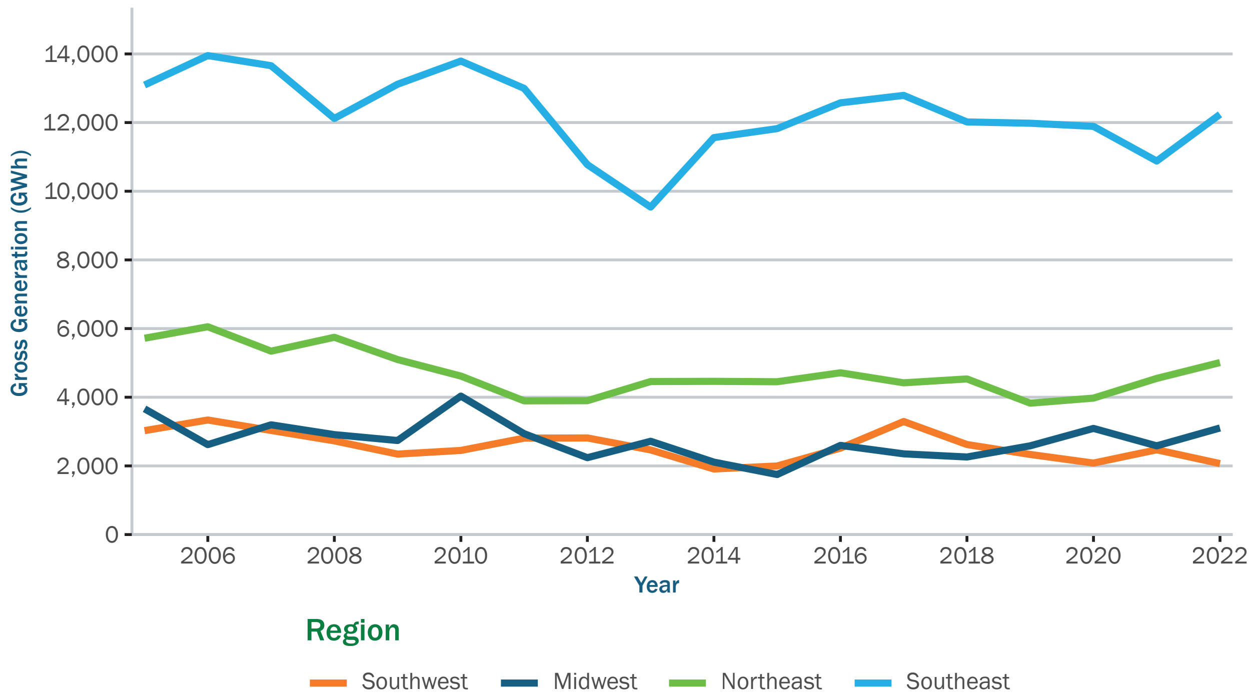


Figure 39. Annual gross PSH generation by region (2005–2022)

Source: EIA Form 923.

Note: The Northwest region was excluded because it has a very small PSH capacity.

On average, the U.S. PSH fleet has produced 22.3 TWh per year in 2005–2022 (see Figure 39). The average in the 2010s (21.4 TWh) was lower than the 2005–2009 average (24.7 TWh). The average generation in the first three years of the 2020s (21.3 TWh) has remained stable relative to the previous decade. These are gross generation numbers that do not subtract the electricity consumed during the hours in which PSH plants are in pumping mode. As any other electrical energy storage technology, PSH is a net consumer of electricity (i.e., the volume of electricity consumed in pumping mode is greater than the volume of electricity generated in generation mode).

The Southeast has the largest PSH fleet by installed capacity (9.7 GW, 44% of U.S. total) and largest average gross generation in 2005–2022 (12.3 TWh, 55% of U.S. total). The next region by installed PSH capacity is the Northeast (5 GW, 23% of U.S. total), and it produced an average of 4.7 TWh (21% of U.S. total) during this period. The Southwest has a PSH fleet with a total nameplate capacity of 4.5 GW (20% of U.S. total) and produced typically 2.6 TWh per year (12% of U.S total). Finally, 12% (2.6 GW) of PSH capacity is in the Midwest, and this region produced an average of 2.7 TWh per year (12% of U.S. total) in 2005–2022. Comparing the capacity percentages and generation percentages across regions indicates that the PSH fleet in the Southeast typically operates at the highest capacity factor and that the PSH fleet in the Southwest displays the lowest capacity factor.

One attribute of the PSH fleet in the Southwest that helps explain its lower capacity factor is that only three of the PSH plants (35% of PSH capacity) in that region are owned by investor-owned electric utilities. The rest are owned and operated by federal, state, and municipal agencies that manage water and power. PSH plants operated by these public agencies are often part of complex water supply and irrigation projects for which maximizing electricity production or revenue from the pumped storage units is not the primary purpose.

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%). From 2020 to 2021, gross PSH generation decreased by 16% in the Midwest and by 8% in the Southeast, but it increased 14% in the Northeast and 19% in the Southwest. For Helms—the largest of the three PSH plants in the Southwest owned by an investor-owned utility—gross generation was the highest during the 2005–2022 period in 2021. The PSH gross generation increase in the Southwest during an especially dry year is an indication that PSH generation is less dependent on hydrology conditions than is conventional hydropower generation. Instead, PSH use is primarily a function of market conditions such as peak net load and price levels. The Southwest fleet did not maintain a trend of increased gross generation in 2022. Except in the Southwest, PSH gross generation increased in 2022 relative to 2021—by 20% in the Midwest, by 12% in the Southeast, and by 10% in the Northeast—coinciding with a sharp increase in electricity prices connected to the spike in natural gas prices after Russia's invasion of Ukraine.[59]

Since the U.S. PSH fleet is composed of only 43 plants, the unplanned outage of one large PSH plant can result in a substantial drop in regional generation in a year. For example, the large dip in generation in the Southeast in 2012 and 2013 was largely a result of one of its PSH plants (Raccoon Mountain in Tennessee) being out of service during that period.

5.4 Capacity Factors

The median plant-level U.S. hydropower capacity factor in the first three years of the 2020s averaged 35.3% versus an average of 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 capacity factor varies significantly across regions and owner types.

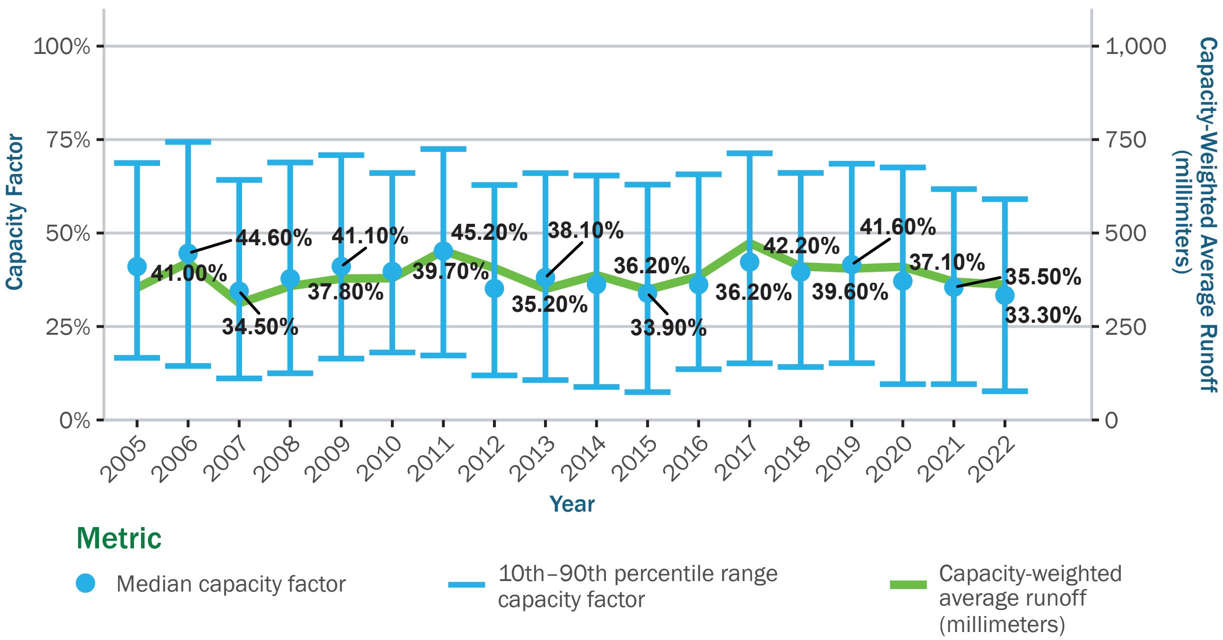


Figure 40. Plant-level distribution of hydropower capacity factors by year (2005–2022)

Sources: ORNL EHA Capacity Factor Plant Database (2005–2022), U.S. Geological Survey (USGS) WaterWatch.

Note: The capacity factor values for 2022 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 2022, respectively. The USGS HUC 2 runoff values for the last quarter of 2022 are also preliminary values. Capacity factor data include hydropower plants in the 50 U.S. states. HUC2 region runoff data excludes Alaska and Hawaii. Regional weights for capacity-weighted average runoff calculation are based on installed hydropower capacity in each HUC 2 region.

59 The 2022 average prices for representative trading hub wholesale prices in the Midwest region (Indiana Hub) and the Northeast region (NEPool Mass Hub) increased by 68% and 86%, respectively, relative to 2021 (eia.gov/electricity/wholesale/#history).

Figure 40 shows that from 2005 to 2022 the median capacity factor of the U.S. hydropower fleet ranged from 33% to 45%, without any clear trend but closely following the trajectory of capacity-weighted average runoff. The 10th–90th percentile range is very wide. As of 2022, the 10th and 90th percentiles for capacity factor were 8% and 59%. The 90th percentile capacity factor in 2022 was at its lowest level for the period shown in Figure 40.

Figure 41 shows the differences in average capacity factor values depending on the region and market type (ISO/RTO or not) where each plant operates, as well as its owner type and mode of operation.

Figure 41. Annual average hydropower capacity factor by region, mode of operation, owner type, and market type (2005–2022)

Sources: ORNL EHA Capacity Factor Plant Database (2005–2022), ORNL EHA Plant database 2023.

Note: The generation values for 2022 used to compute the capacity factors are preliminary values from EIA Form 923 2022 Early Release. The number of plants included differs across panels. The average number of plants per year is 1,351 in the Region panel, 1,350 in the Market Type panel, 906 in the Mode of Operation panel, and 1,345 in the Owner Type panel.

Hydropower plants in three of the regions (Northwest, Midwest, and Northeast) have operated with consistently higher average capacity factors than the Southwest and Southeast. The capacity factor for the hydropower fleets in the Northwest, Midwest, and Northeast was at least 40% in most years in 2005–2022 and surpassed 50% in some of those years. The region with the smallest installed capacity (Midwest) has had the highest average capacity factor every year since 2014. In contrast, the average capacity factor in the Southeast has been no greater than 40% every year. However, the plot shows a slightly increasing trend, and 2019–2022 is the only four-year continuous period in which the average capacity factor in this region has been above 35%. The Southwest presents the most variable average capacity factor ranging from 48% in 2006 to 21% in 2015; but only 4 of the 17 years shown in the plot were above 40%, and three of them were more than a decade ago.

Mode of operation information is available for approximately two-thirds of the plants included in the other three panels. The "Peaking" and "Run-of-River" classifications shown on the plot are summaries of a more detailed classification described in McManamay et al. (2016).[60] Intermediate or mixed operation modes were assigned to the most fitting of the two summary categories. The average capacity factor for the "Run-of-River" aggregate category for 2005–2022 was 42% versus 39% for the "Peaking" aggregate category. But the difference in average capacity factor narrowed during this period. In 2019 and 2020, the average capacity factor for the Peaking category was slightly higher (by less than one percentage point) than for the Run-of-River category. In 2021 and 2022, the Run-of-River average capacity factor was higher again, by less than two percentage points relative to that of the Peaking category.

The average 2005–2022 capacity factor for privately owned plants was 42% versus 36% for plants owned by federal agencies or nonfederal public entities, whose dams tend to have multiple authorized purposes with hydropower being a lower priority use relative to other purposes such as flood control, navigation, or irrigation. However, the gap between the capacity factor for the federal fleet versus the privately owned fleet has narrowed. The average capacity factor for federal plants increased continuously from 2016 to 2020. The federal fleet had the highest average capacity factor (among the three owner type segments) in 2020 but dropped by more than five percentage points in 2021 and by an additional five percentage points in 2022.

Hydropower plants operating in ISO/RTO market regions had a 41% average capacity factor from 2005 to 2022. For plants operating outside ISO/RTO regions, the average capacity factor was somewhat lower (38%). However, it is difficult to disentangle the effect of market type from that of region and owner type. For example, the federal fleet has typically had a lower capacity factor than plants with other owner types, and plants in the Southeast have a lower capacity factor than those in most other regions of the country. Both characteristics (being a federal plant and being in the Southeast) increase the likelihood of not operating in an ISO/RTO market.

5.5 Availability Factors

In 2019–2021, after more than a decade of slow but steady decrease in availability, the average availability factor was stable at 79% for small units, 83% for medium units, and 78% for large units. The average availability factor was lower in the Western Electricity Coordinating Council (WECC) than in other NERC regions every year since at least 2005, and the gap 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.

The capacity factor information presented in the previous section does not provide a full picture as to the fraction of hours per year in which hydropower and PSH units might be providing services (remunerated or not) to the electric grid. The availability factor (i.e., the percentage of hours in a year in which a turbine-generator unit is available to generate electricity or provide grid services) is a complementary metric useful to further understand trends in the performance of the U.S. hydropower and PSH fleets. Availability factor is one of the metrics reported by plant owners to the North American Electric Reliability Corporation (NERC). Figures 42 and 43 show (1) what percentage of hours different hydropower fleet segments are available, (2) breakdown of operation modes during available hours, and (3) breakdown of outage types during unavailable hours. Figure 42 segments hydropower units by unit size as either small (<=10 MW), medium (10–100 MW), or large (>100 MW). Figure 43 shows the same type of information for different NERC region groupings, distinguishing between hydropower and PSH units.

60 The subcategories summarized as Peaking are peaking, reregulating, and intermediate peaking. The subcategories summarized as Run-of-river are run-of-river, canal/conduit, run-of-river/upstream peaking, and run-of-river/peaking. Descriptions of each of the subcategories are provided in McManamay et al. (2016).

The number of units reporting to the NERC Generating Availability Data System (GADS) is not constant over time. Details about the percentage of installed units included in NERC GADS each year for each of the unit size and regional groupings are provided in an Appendix.

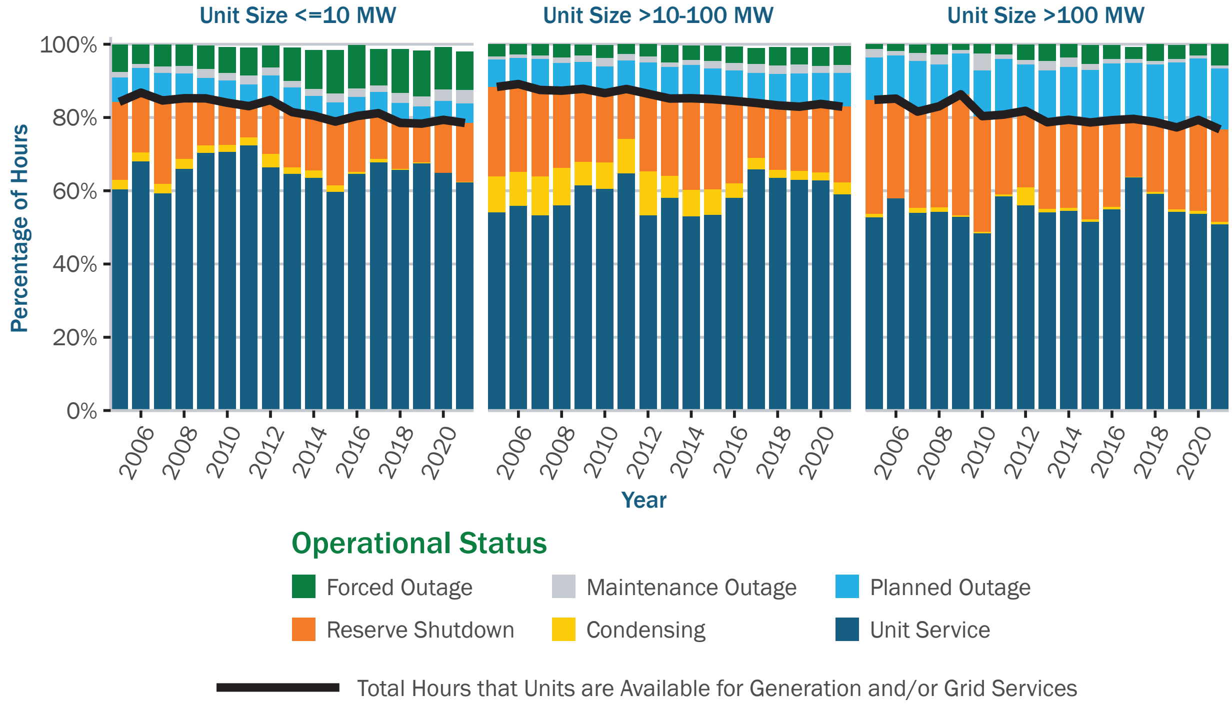


Figure 42. Hourly breakdown of hydropower operational status (average, by unit size class, for units reporting to the NERC GADS for 2005–2021

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); Condensing (units operated in synchronous condensing mode), and Unit Service Hours (number of hours synchronized to the grid).

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Figure 42 shows that availability factor has trended downward for all unit size classes during the period of analysis (2005–2021). In the three most recent years of the dataset (2019–2021), new since the previous edition of the U.S. Hydropower Market Report, the average availability factor has stabilized at 79% for small units, 83% for medium units, and 78% for large units. The distribution of unavailable hours into planned, maintenance, and forced outage hours continues to differ significantly among unit sizes, revealing differences in O&M practices. The average hours per year spent on planned outages increase with unit size (i.e., larger plants spend more time in planned outage mode), and the average hours per year spent on forced (i.e., unplanned) outages decrease with unit size (i.e., smaller plants have more forced outage hours). These two statements are not independent of each other because more frequent or longer planned outages reveal more intensive preventive maintenance and investments that, in turn, decrease the frequency and severity of forced outages. In 2019–2021, the average percentage of hours spent in forced outages was 11% for small units, 5% for medium units, and 4% for large units. Relative to the 2005–2018 averages, the average percentage of nonforced (i.e., planned plus maintenance) outage hours in 2019–2021 has been stable for small units at 8%, and increased for medium units (from 9.7% to 11%) and large units (from 15.4% to 17.8%).

In interpreting the data in Figures 42 and 43, it is important to keep in mind that the average number of hours in each outage state depends on the frequency of outages (how many units are out of service) and their duration. For instance, an average of 5% of hours in planned outage status across a fleet segment can result from many short-lived outages or a small number of long ones.

For the hours when units are available, plant owners report how many hours are spent synchronized to the grid (unit service hours), in condensing mode, or in reserve shutdown.[61] Electricity generation takes place during unit service hours, but the units can also be providing grid services during those hours as well as while in condensing mode (reactive power) or in reserve shutdown (nonspinning reserves). The closer to its maximum power rating a unit generates during all the hours in unit service mode, the closer the percentage of unit service hours will be to its capacity factor. The average percentage of hours in unit service mode in 2019–2021 was 53% for large units, 62% for medium units, and 65% for small units. For 2005–2018, the average percentage of hours in units service mode was 55% for large units, 58% for medium units, and 66% for small units. Therefore, the 2019–2021 averages were lower than those for 2005–2018 for small and large units but larger for medium units. The average availability factors are also substantially higher than the average capacity factors discussed in Section 5.4. Therefore, units are generating at partial load for a sizable fraction of the hours they are synchronized to the grid.

Since each panel of Figure 42 includes units in every U.S. region, the difference in unit service hours is not driven primarily by hydrologic conditions in any particular region. Instead, the higher fraction of hours that small units spent synchronized to the grid is consistent with a large fraction of small units being part of run-of-river plants that stay connected and generating electricity as many hours as possible. On the other end of the spectrum, it is more common for large units to instead try to optimize the timing at which they pass a limited, preset volume of stored water through the turbines over a period of time (peaking mode).

Condensing mode has been most frequent among medium units, but its frequency has decreased significantly in recent years. The percentage of hours spent by medium units in condensing mode averaged 7.4% in 2005–2018 versus 2.6% in 2019–2021. For large units, the average percentage of hours spent in condensing mode was 0.7% in 2019–2021 and 0.9% in 2005–2018. Small units averaged 0.2% of hours in condensing mode in 2019–2021 versus 2% of hours in 2005–2018.

The remaining percentages of hours not spent in one of the operational statuses already discussed are classified as reserve shutdown. During those hours, the units are turned off but available to synchronize to the grid and start generating if the electric system operator needs them in response to a contingency elsewhere in the system (e.g., forced outage, lower generation than forecasted from variable renewables). In 2019–2021, the average percentages of reserve shutdown hours were 14% for small units, 19% for medium units, and 24% for large units. In all segments, the average percentages spent in reserve shutdown in 2005–2018 (15% for small units, 21% for medium units, and 25% for large units) were higher than those for 2019–2021.

61 Units are in condensing status when they are synchronized with the grid, water is blocked and drained, and the runner is rotating through air only. While condensing, the units do not generate; they consume electricity to overcome friction and air resistance. Keeping a unit in condensing mode reduces the start and stop of machines and increases plant availability factor, and the rotating mass provides inertia to the grid minimizing frequency disturbances.

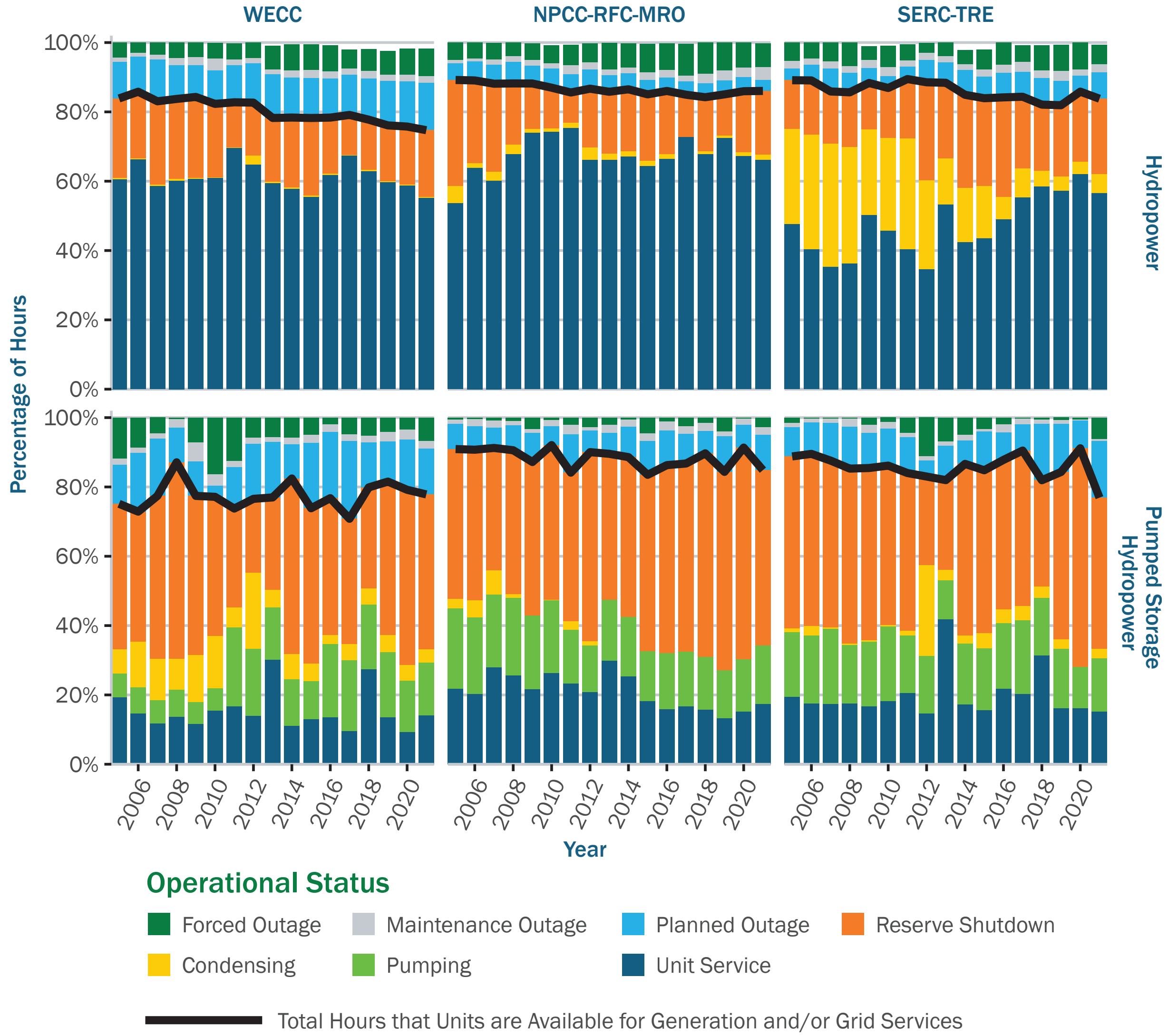

Figure 43. Hourly breakdown of hydropower and PSH operational status (average, by NERC region groupings, for units reporting to NERC GADS for 2005–2021

Source: NERC pc-GAR.

Note: Pumping hours (hours the turbine-generator operated as a pump/motor). All other operation and outage state definitions are provided in the note for Figure 42. The NERC region classification comprises six regions: 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.

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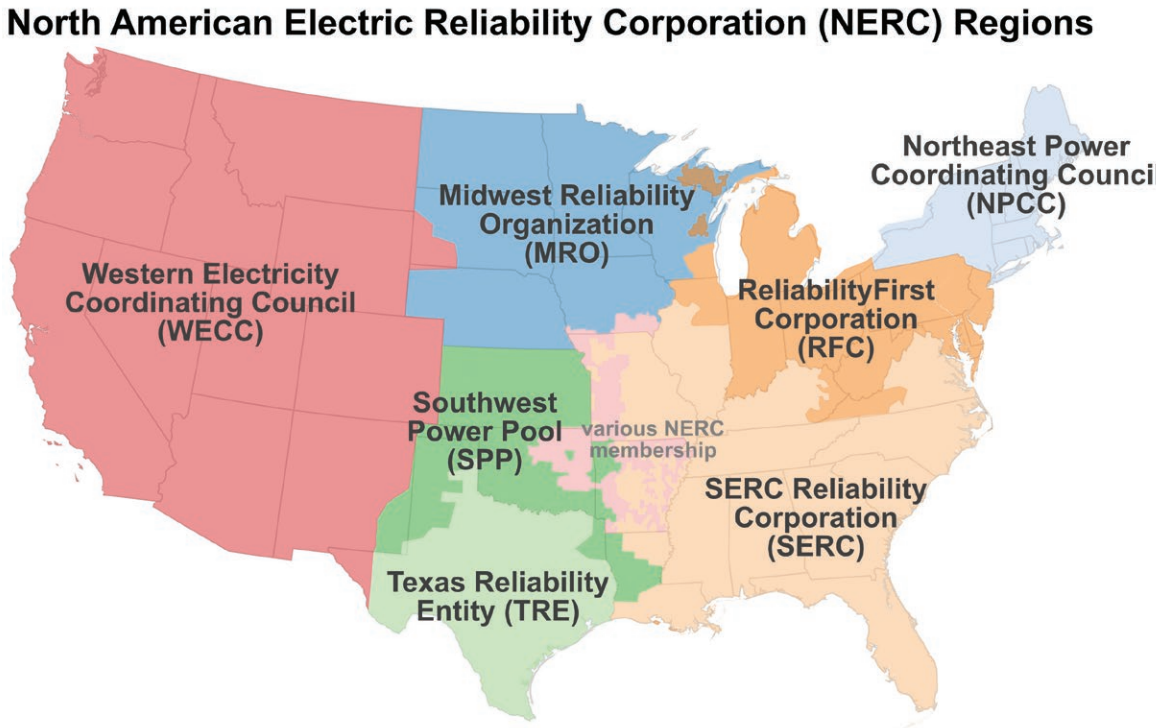

Figure 44. NERC regions

Source: atlas.eia.gov/datasets/eia::nerc-regions/explore.

The set of data used to produce the top panels in Figure 43 is the same as the one used for Figure 42, but here it is segmented by NERC regions (see Figure 44) rather than unit sizes. Additionally, the bottom panels present data for PSH units. Compared with hydropower units, PSH units spend less hours synchronized to the grid and more hours on reserve shutdown. Additionally, PSH units operate in pumping mode for a sizable fraction of hours (on average, 15% of hours in 2019–2021) to replenish their upper reservoirs.

The average availability factor for hydropower units has been lower in WECC than in the other NERC regions for every year shown in Figure 43, and the gap increased in 2019–2021. The availability factor averaged at 87% in NPCC-RFC-MRO, 86% in SERC-TRE, and 81% in WECC in 2005–2018. For 2019–2021, the averages were 86% for NPCC-RFC-MRO, 84% in SERC-TRE, and 76% in WECC. For PSH units, WECC also displays the lowest availability factor; but the value changes more abruptly from year to year rather than consistently trending downward. Moreover, the average availability factor was 80% in 2019–2021 versus an average of 77% for 2005–2018.

The average fraction of hours spent in condensing mode changes significantly across regions and for hydropower versus PSH units. However, a common trend across regions and unit types is that the average fraction of condensing hours has decreased over the period shown in Figure 43. In SERC-TRE, the hydropower units reporting to NERC had an average fraction of hours in condensing mode of 22% in 2005–2018 but only 4% in 2019–2021. Similarly, the other fleet segment with the most average hours in condensing mode (PSH units in WECC) spent an average of 4.5% hours per year in condensing mode in 2019–2021 versus 9% in 2005–2018.

Regardless of region, on average, reserve shutdown is the status of hydropower units for ~20% of hours each year. The average fraction was a bit lower in 2019–2021 than the rest of the period for NPCC-RFC-MRO (16% in 2019–2021, 18% in 2005–2018) and WECC (17% in 2019–2021, 19% in 2005–2018) and was slightly higher for SERC-TRE (21% in 2019–2021, 20% in 2005–2018). In all regions, the average time spent in reserve shutdown by PSH units was significantly higher in 2019–2021

(56% for NPCC-RFC-MRO, 46% for WECC, and 52% for SERC-TRE) than in 2005–2018 (47% for NPCC-RFC-MRO, 39% for WECC, and 43% for SERC-TRE).

For hydropower units, the average fraction of unit service hours in WECC decreased for four years in a row (from 67% in 2017 to 55% in 2021), which is consistent with the severe drought experienced in a large portion of that region for much of that period. For NPCC-RFC-MRO, unit service hours have been quite stable at ~67% for the past decade. Hydropower units in SERC-TRE have notably increased the fraction of unit service hours over the last decade as the number of hours spent on condensing mode decreased. The SERC-TRE average fraction of unit service hours in 2019–2021 was 59%. Considering the full 2005–2021 period, the average unit service fraction of hours for hydropower units is 67% in NPCC-RFC-MRO, 61% in WECC, and 48% in SERC-TRE.

PSH roundtrip efficiencies (i.e., megawatts generated per megawatt of energy used to pump water from the lower to the upper reservoir) range from 0.7 to close to 0.9 (Mongird et al. 2019). If the power rating of the PSH unit is the same in generation and pumping mode and the unit generates at its full power rating while in unit service mode, the average fraction of hours in pumping mode should be larger than the fraction of hours in generation mode by enough margin (10%–30%) to account for the roundtrip energy losses. The fact that the average fraction of hours in pumping mode is less than 10% above the average fraction of hours in unit service for 38 of the 51 combinations of year and region shown in Figure 43, suggests that the aforementioned conditions are not often met (i.e., the turbines do not generate at full power rating while in unit service mode and/or the unit has a different power rating in generating and pumping mode). Additionally, all active PSH plants have open-loop configurations. If the upper reservoir is connected to a naturally flowing water feature, it does not depend entirely on pumped water from the lower reservoir contributing to a lower number of pumping hours than would be necessary in a closed-loop plant. Furthermore, especially in WECC, many of the PSH units are part of hybrid hydropower plants with complex configurations that make the relationship between generation and pumping energy hard to track.

Figure 45 displays seasonal trends in availability factor for the subsets of the U.S. hydropower and PSH fleets reporting to NERC GADS. For hydropower units, the decreasing trend in availability factor discussed for different unit sizes in Figure 42 and for different regions in Figure 43 is also common to all seasons. For 2019–2021, it stabilized at ~76% in fall and ~80% in winter. For the other two seasons, the average availability factors in 2019–2021 were 83% (spring) and 84% (summer). The gap between the availability factor in fall and the rest of the year is largely explained by many plant owners choosing that season for planned and maintenance outages as it coincides with months of lower electricity demand and prices than summer or winter. For the converse reason of high electricity demand and prices, plant owners try to ensure maximum availability of their units in summer and winter.

For PSH units, trends in availability factor are less clear. The large drop in 2019 is likely related to the much lower number of PSH units that reported to NERC GADS during that year. Additionally, since the values in Figure 45 are capacity weighted, the 2019 drop might have been driven by extended outages of several of the largest PSH units in the dataset. The much higher availability factor for PSH in summer (90% or higher in 13 of the 17 years shown) than the rest of the year indicates that it is a priority for PSH plant owners to avoid any outages during those months because of the high revenue potential involved in helping manage summer electricity demand peaks. For the winter months, after a period of steadily increasing availability factors from 2014 (82%) to 2018 (88%), availability decreased to 85% or below every year in 2019–2021.

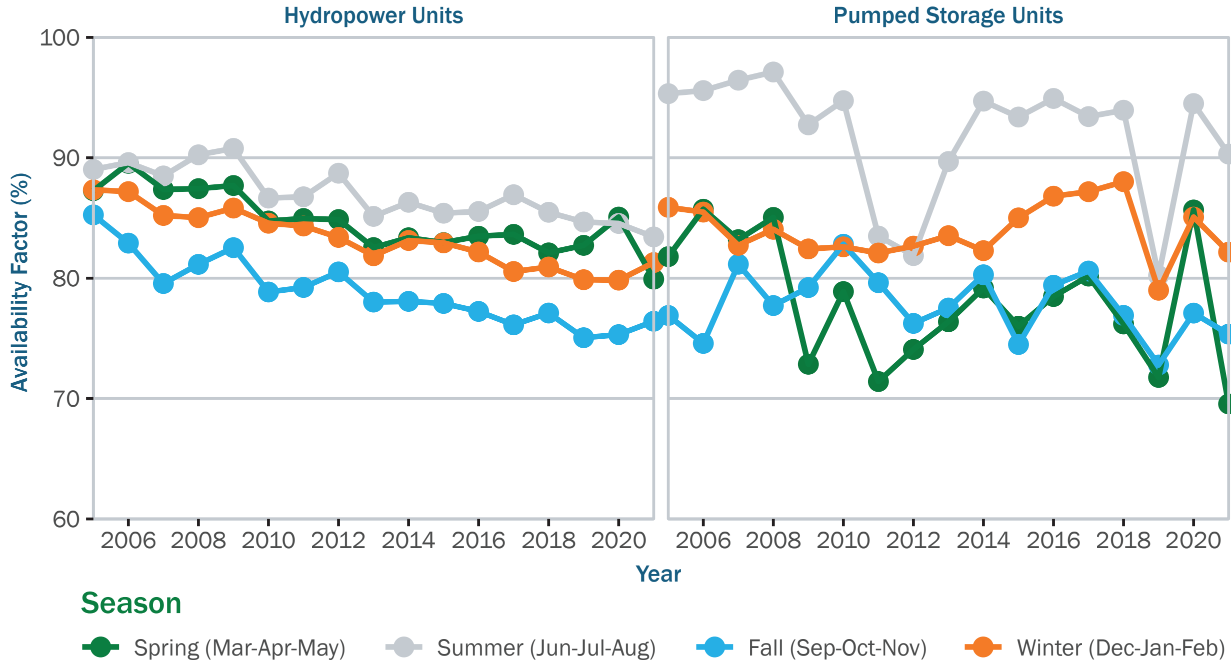

Figure 45. Capacity weighted average hydropower and PSH unit availability factor by season (for units reporting to NERC GADS in 2005–2021)

Source: NERC pc-GAR.

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5.6 Forced Outage Causes

The average percentage of hours in forced outage status per installed megawatt of hydropower and PSH in 2013–2021 ranged from 0.5% to 5.8% in the different NERC regions. 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 forced outages during that period. Failures in main transformers and lack of water are also among the top reasons for the largest (in terms of generation lost) forced outages.

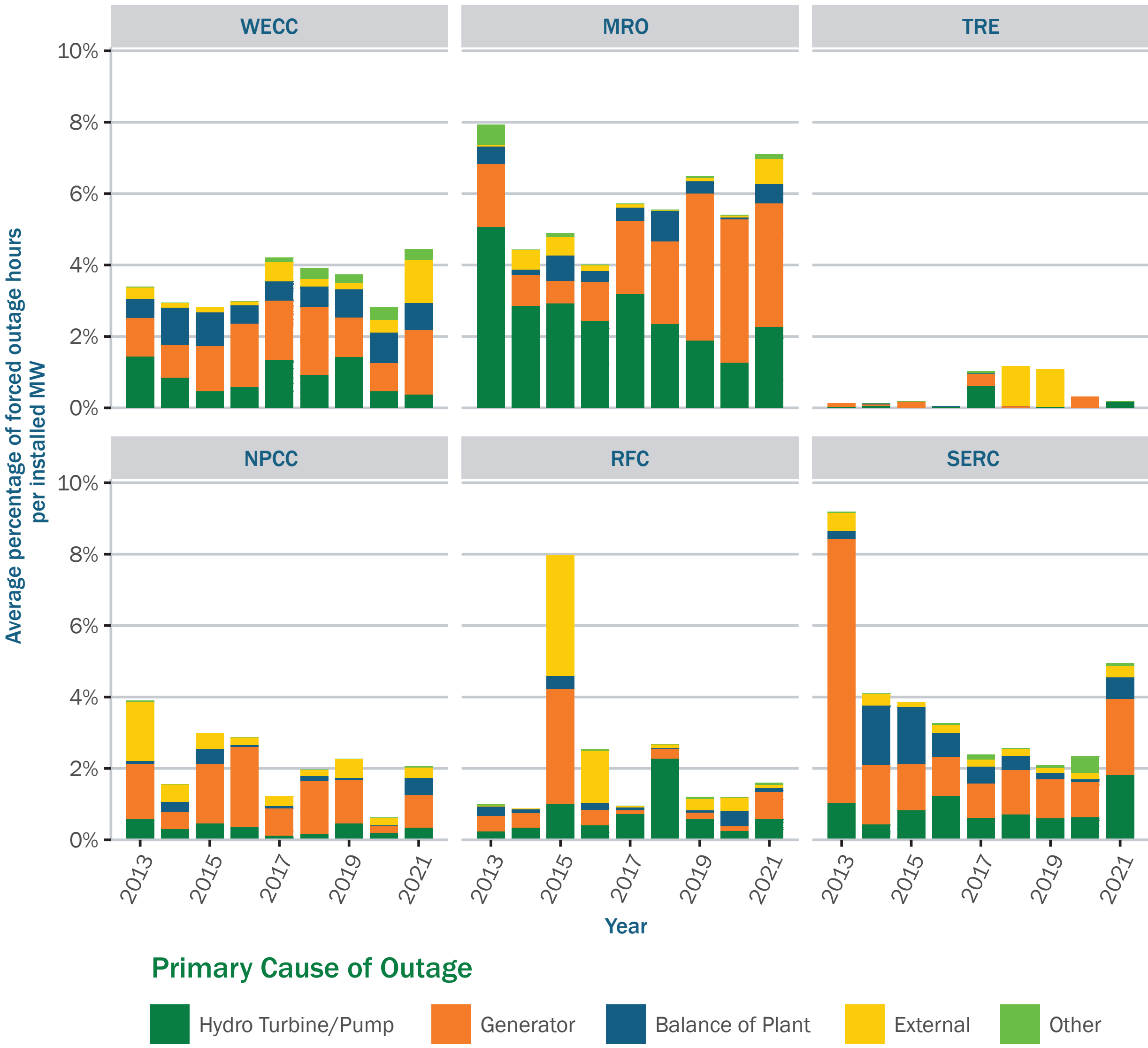

Figure 46. Average percentage of forced outage hours per installed megawatt of hydropower and PSH by year, NERC region, and primary outage cause

Source: NERC GADS Cause Code Reports, ORNL EHA Capacity Plant Database (2005–2022).

Notes: The six NERC regions 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 Electricity Reliability Council (SERC). NERC collects data on outages and other performance metrics as part of the Generating Availability Data System (GADS). Reporting to GADS is mandatory for generating units that are 20 MW or larger, but some smaller units report on a voluntary basis. The total installed capacity (hydropower + PSH) in each NERC region as of 2021—used as the denominator to compute the percentage of forced outage hours per installed MW—is 55 GW for WECC, 23 GW for SERC, 11 GW for NPCC, 7 GW for RFC, 6 GW for MRO, and 0.6 GW for TRE.

The "External" category includes outages caused by catastrophes (flood, drought, fire, lightning, earthquake, tornado, hurricane, storms) and economic reasons (lack of water, groundwater or other 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, and regulatory/safety/environmental reasons.

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." Calculating average forced outage hours per megawatt of installed capacity serves to adjust the data by the hydropower fleet size in each region. Installed hydropower and PSH capacity in 2021 ranged from 55 GW in WECC to 0.6 GW in TRE.

Forced outage hour percentages for different fleet segments are presented in Figure 42 and Figure 43. This section focuses on the causes of the forced outages. It is worth emphasizing that hydropower units are unavailable during a forced outage. This is in contrast to the reserve shutdown status discussed in Figure 42 and Figure 43 in which the units are turned off because it is not economic to generate but are available to restart as needed.

The national average number of reported forced outage events was 3,769 per year in 2013–2021. 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. Out of the potential generation lost in the 5% (1,633 events from 2013 to 2021) of forced outage events that lasted more than two weeks, 45% correspond to outages in which the primary cause relates to the generator, 25% to turbine-related outages, 18% to outages initiated from problems in the balance of plant components, 9% to external causes, and 3% to other causes.

The direction of the trend in the average percentage of forced outage hours per installed megawatt differs across regions. In WECC and MRO, the average percentage of forced outage hours increased during this period; for NPCC and SERC, it decreased. Several regions display spikes in the average percentage of forced outage hours in a few years (MRO in 2013, RFC in 2015, and SERC in 2013 and 2021). These spikes result from a small number of events that have long durations and/or affect large units.

In WECC, NPCC, and SERC, generator-related forced outages were the primary cause responsible for the largest share of forced outage hours in 2013–2021. In MRO, turbine-related forced outages accounted for the largest share of forced outages in six of the nine years shown in Figure 46. Together, forced outages where the primary cause was either the turbine or the generator accounted for 50% or more of all generation potential lost because of forced outages in 85% of the region-year combinations shown in Figure 46. Forced outages with turbine or generator-related primary causes accounted for 69% of the total potential generation lost because of forced outages in 2013–2021. Hydropower units that are 30 years old or older accounted for 73% of forced outage occurrences with a primary cause related to the turbine or the generator.

Table 2 shows the top 10 detailed cause codes by share of generation lost because of forced outages nationally in 2013–2021. Of the more than 200 cause codes included in the database, the top 10 outage causes accounted for 45.3% of all potential generation lost.

Table 2. Top 10 Forced Outage Cause Codes by Percentage of Potential Generation Lost

Forced Outage Cause Category	Forced Outage Detailed Cause Code	Percentage of Potential Generation Lost Because of Forced Outages in 2013–2021
Generator	Stator windings, bushings, and terminals	10.35%
Balance of Plant	Main transformer	7.23%
Generator	Rotor, general	5.36%
Hydro Turbine/Pump	Bearings A	4.03%
Generator	Rotor windings (including damper windings and fan blades)	3.49%
Hydro Turbine/Pump	Other turbine problems	3.28%
Generator	Generator bearings	2.97%
External	Lack of water (hydro)	2.96%
Generator	Generator bearings and lube oil system (including thrust bearings)	2.88%
Generator	Other miscellaneous generator problems	2.79%

Six of the top 10 cause codes relate to generators including problems with stator and rotor windings, generator bearings, and other rotor and miscellaneous generator problems. Among turbine-related forced outage causes, bearings are the component resulting in the largest volumes of potential generation lost. The only balance of plant component that is part of the top 10 forced outage cause codes are main transformers. Finally, among external causes, lack of water resulted in 3% of all potential generation lost because of forced outages in 2013–2021.

The significant share of generation potential lost by these 10 forced outage cause codes is because of a combination of their frequency, the capacity of the affected units, and the outage duration. The two cause codes involving generator rotors were the least frequent by number of events among the top 10 (~100 for each code in 2013–2021), but their average duration was larger than one month. The number of forced outage events caused by problems in the main transformer was 750 during this period, and their average duration was two weeks. Lack of water was the most frequent cause code among the top 10 listed in Table 2 (1,528 events in 2013–2021). The average duration of these events was six days.

Although 70% of the forced outages from lack of water are reported in the NPCC region, these events have an average duration of less than two days and account for only 16% of the national potential generation lost attributed to that cause code. Close to 80% of the potential generation lost because of forced outages related to lack of water corresponds to the WECC fleet. In WECC, the average duration of these outages is approximately one month. Fifty-two percent of the 6.4 TWh of potential generation lost in WECC for this reason over 2013–2021 corresponded to outage events in 2021.

The impact of a forced outage on the revenues of a plant owner will depend not only on the potential generation volume lost, but also on energy prices. The forced outage database contains data on the season in which each forced outage event took place. By absolute number, the share of forced outage events in 2013–2021 was 35% in summer (June–September), 24% in winter (December–February), and the remaining 41% in the off-peak season when electricity prices tend to be lowest. However, accounting for the capacity affected per event and the event duration, the highest seasonal share of potential generation lost (51%) happened in the winter months, followed by off-peak months (28%) and summer season (21%).

5.7 Hydropower Operation Flexibility

The role of dispatchable, flexible generators is crucial to maintain the supply and demand of electricity continuously balanced. With the increased penetration of variable renewables (wind and solar), the amount of hourly and subhourly supply-demand imbalances that dispatchable generators need to adjust for has increased. In general, the technical parameters of hydropower units allow highly flexible operations in terms of how fast they can start and adjust their output up or down. However, actual hydropower operations might be substantially less flexible than what is technically possible because of adverse hydrologic conditions or operational constraints. Additionally, since flexible operation increases the wear and tear on 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.

This section presents data on two flexibility-related metrics for the U.S. hydropower and PSH fleet: the amount of one-hour ramping (i.e., change in generation level from one hour to the next) and the number of start-stop cycles that hydropower turbine-generator units perform in a year.

One-hour ramping

The average observed one-hour ramps of the hydropower fleets (including PSH) are larger than those of the natural gas fleets in most BAs. The top 10 BAs by the magnitude of the average one-hour hydropower ramp are all in the Southeast and Northwest regions. Both hydropower ramping mileage and the correlation between one-hour hydropower ramps and changes in net load vary across seasons.

Figure 47 compares summary metrics (average, 10th percentile, and 90th percentile) from the one-hour ramp distributions of the hydropower and natural gas fleets—the two dispatchable generation technologies that perform much of the load following in most of the BAs—in 30 BAs with more than 300 MW of hydropower (including PSH) installed capacity. The data shown in Figure 47 is for 2022, but the takeaways have been the same each year since 2019 (the first full year of EIA Form 930 data).

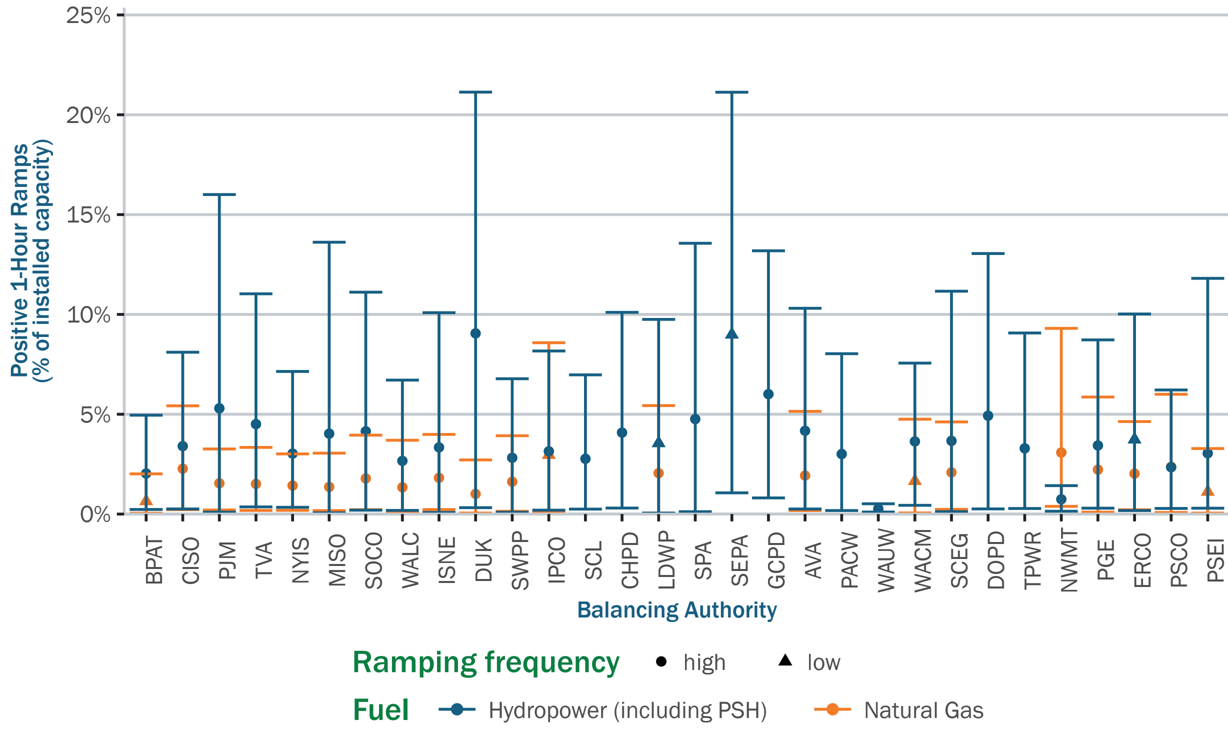

Figure 47. One-hour ramps (as a percentage of installed capacity) for hydropower (including PSH) and natural gas for selected BAs in 2022

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

Note: Only positive ramps are shown. The distribution of negative ramps mirrors that of positive ramps. 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 is provided in the Appendix. The BA acronyms used here are those used in the EIA Form 930 dataset. For some of the BAs (e.g., BPAT and CISO), these acronyms differ from the ones most commonly used (e.g., BPA for Bonneville Power Administration and CAISO for the California Independent System Operator). High-frequency ramping means that the fleet changed generation level (in any direction) from one hour to the next in at least 75% of the hours in the year.

In 28 of the 30 BAs shown in Figure 47, the average one-hour ramp per installed megawatt for the hydropower (including PSH) fleet is greater than the average one-hour ramp for the natural gas fleet. The top 10 BAs by the magnitude of the average one-hour hydropower ramp are all in the Southeast and Northwest regions. Except for ERCO (ERCOT), LDWP (Los Angeles Department of Water and Power), and SEPA, the hydropower fleet changed generation from one hour to the next in 75% or more of the hours in the year.

In half of the BAs, the 90th percentile of the one-hour ramp distribution for the hydropower fleets is 10% or higher than their installed capacity. For example, if a BA has a hydropower fleet with 1 GW of installed capacity and the 90th percentile is 10%, this means that the 10% largest one-hour (positive) ramps involved increases in generation of 100 MW or more. The 90th percentile of the one-hour ramp distributions did not reach 10% of the installed capacity for the natural gas fleets in any of the BAs shown in Figure 47.

Figure 48 shows the total (one-hour) ramping mileage by hydropower and PSH fleets in 2022 by BA and season. The mileage is calculated by adding up all the one-hour ramps (up and down, in absolute value) performed by the hydropower fleet in one BA in a year. To adjust for the size of the different fleets, the mileage number is divided by installed capacity. Ramping mileage summarizes the volume of ramping work performed by the fleet. Within a fleet, some units might have much higher or much lower mileage than the average value shown in the plot.

At the BA level, average mileage per installed megawatt is one of the metrics to gauge the level of flexibility provided by the hydropower fleet. At the unit level, mileage also matters for asset health. Large, frequent ramping can accelerate the degradation of the turbine-generator units and lead to increased capital investment needs over the life of the asset.

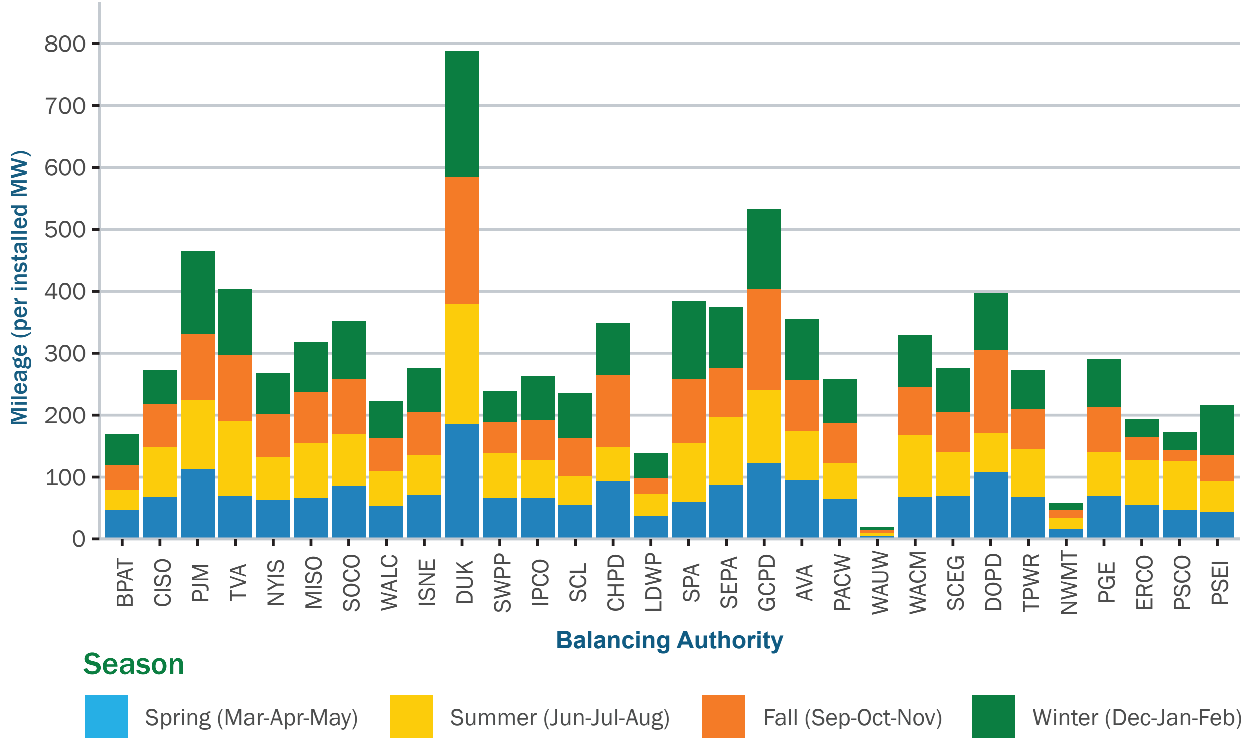

Figure 48. One-hour ramping mileage (per installed megawatt) for hydropower (including PSH) fleets in selected BAs (2022)

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 is provided in the Appendix. The BA acronyms used here are those used in the EIA Form 930 dataset. For some of the BAs (e.g., BPAT and CISO), these acronyms differ from the ones most commonly used (e.g., BPA for Bonneville Power Administration and CAISO for the California Independent System Operator).

In 20 of the 30 BAs shown in Figure 48, annual mileage from one-hour hydropower ramping ranged from between 200 and 400 MW per installed megawatt in 2022.[62] By far, the fleet in the DUK (Duke Energy Carolinas) BA performed the most ramping in 2022—mileage for this fleet has been 665 or higher every year in 2019–2022. Two-thirds of the installed capacity in that BA are highly flexible PSH facilities (Bad Creek and Jocassee in South Carolina), which helps explain the high mileage number. Two BAs—Western Area Power Administration Upper Great Plains West (WAUW) and Northwestern Corporation (NWMT)—stand out by their low mileages. In both cases, values were consistently low in 2019–2022. The NWMT fleet includes no PSH capacity, and run-of-river plants account for at least 40% of its installed capacity. The low hydropower ramping mileage in the WAUW BA is due to a very low fleet capacity factor during this period. The EIA reports an installed hydropower capacity of 969 MW in the WAUW BA in 2022, but net generation ranged from 5 to 93 MW in all hours that year. As ramps are normalized by installed capacity, even if the few units that are online ramp frequently, the ramps per installed megawatt appear very small.

62 In contrast, one-hour ramping mileage performed by the natural gas fleets in these BAs in 2022 was less than 200 per installed megawatt in all but one of the BAs. However, total mileage is larger for natural gas in those BAs where the installed capacity for natural gas is substantially larger than for hydropower. Of the 30 BAs shown in Figure 48, total mileage (without adjusting per installed capacity) was greater in 2022 for the hydropower fleet than the natural gas fleet in 16 of them, primarily in the Northwest (AVA, BPAT, CHPD, DOPD, GCPD, IPCO, PACW, SCL, and TPWR) and Southeast (DUK, SEPA, SPA, and TVA). The remaining three are WACM, WALC, and WAUW.

It would be more accurate to normalize ramps by capacity online rather than capacity installed, but information about which units operate each hour is not publicly available.

One-hour hydropower ramping mileage is not constant throughout the year. Except for the hydropower fleet in PSCO, where some of the largest units were unavailable for a large part of the year leading to unusually unequal seasonal ramping shares, the share of annual ramping in any of the BA-season combinations shown in Figure 48 ranges from 15% to 38% (if evenly distributed throughout the year, all seasonal shares would be 25%). Winter is the season with the most mileage for 15 of the 30 BAs. 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 hydropower ramping 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.

The value of the flexibility provided by hydropower depends not only on the magnitude and frequency of ramps and unit start-stops but also, crucially, on their timing. Ramping will be valuable if it happens at the time and in the direction needed to balance net load (i.e., electricity demand net of wind and solar generation). To explore how closely the changes in hydropower generation level match the changes in net load, Figure 49 shows the correlations between one-hour hydropower ramps and hourly changes in net load in 2022, by season.

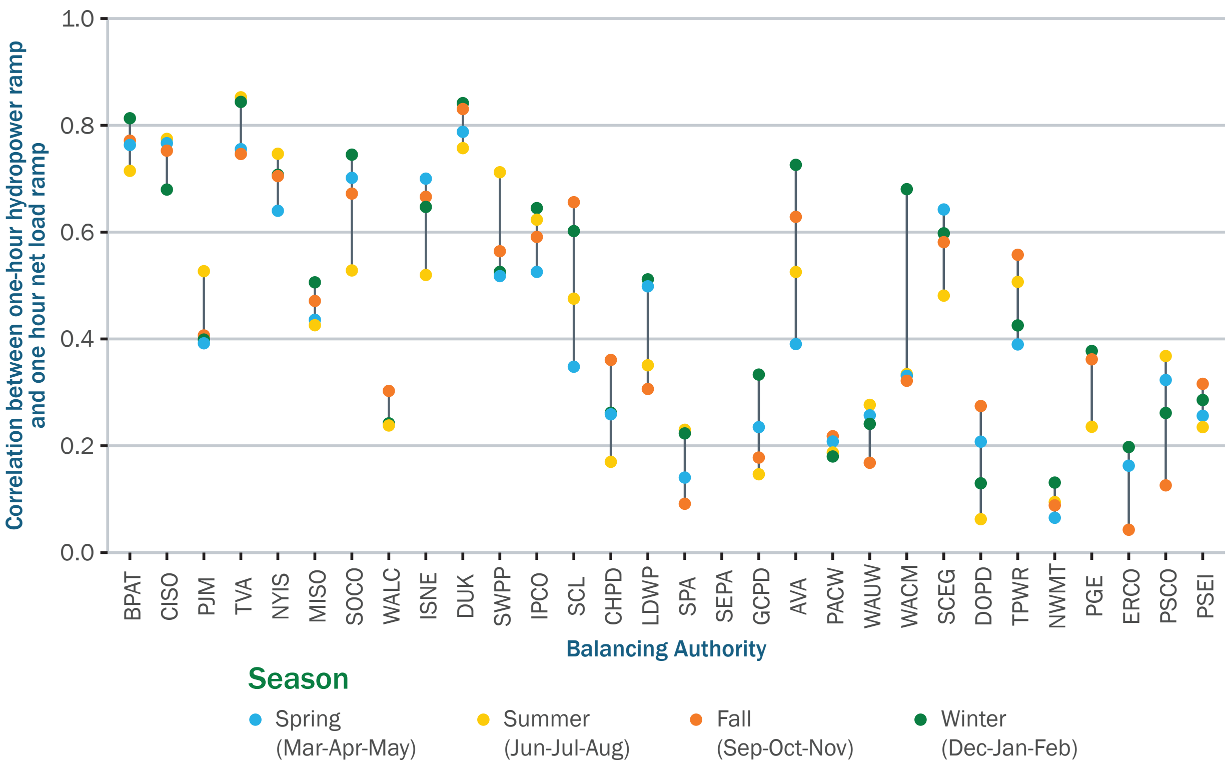

Figure 49. Correlation between one-hour hydropower (including PSH) ramps and hourly changes in net load in 2022 by BA and season.

Source: EIA Form 930.

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 is provided in the Appendix. The BA acronyms used here are those used in the EIA Form 930 dataset. For some of the BAs (e.g., BPAT and CISO), these acronyms differ from the ones most commonly used (e.g., BPA for Bonneville Power Administration and CAISO for the California Independent System Operator). No correlation is computed for SEPA because it is a generation-only BA and does not report load data to EIA Form 930. The correlation coefficients for WALC in spring, PGE in spring, and ERCO in summer are not displayed because they are not statistically significant.

Figure 49 shows a wide range of correlations across BAs and substantial variation across seasons for some BAs. The higher the correlation, the more valuable the ramping is to balance the electric grid. In ISO/RTO regions where ramping flexibility is remunerated, high correlations should translate into higher revenue for hydropower. Most of the correlations greater than 0.6 correspond to the largest fleets (the x-axis orders BAs from more to less installed hydropower and PSH capacity) such as BPAT (Bonneville Power Administration, 22 GW of installed hydropower capacity), CISO (California ISO, 8.8 GW), or TVA (Tennessee Valley Authority, 6.7 GW).[63] Even if they ramp at the optimal times, smaller fleets cannot match the magnitude of changes in BA net load.

Correlation is highest in winter for 12 of the BAs, in summer for 8 BAs (of which 4 are ISO/RTO regions), in fall for another 8 BAs, and in spring for the remaining 2 BAs. 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. For these reasons, when feasible, hydropower plant owners will be particularly attuned to electricity market signals during those seasons. However, the ability of a hydropower unit to ramp not only depends on the characteristics of the turbine but also on hydrologic conditions and operational constraints, both of which vary by season. Operational constraints might be in place to mitigate environmental impacts—like those for the hydropower fleet in the Northwest region during fish spawning season—or to ensure the dams satisfy the other purposes for which they were originally authorized (e.g. flood control and irrigation).

Unit starts

In 2019–2021, the median PSH started close to once per day (295 starts per year), the median large unit started approximately once per week (56 starts per year), the median medium unit started less than twice per month (21 starts per year), and the median small hydropower unit started less than once per month (10 starts per year). For large units and PSH units, the average number of unit starts has decreased considerably in 2019–2021 relative to 2005–2018.

Figure 50 shows the number of starts per year performed by the median plant in each hydropower unit size segment and by PSH units. For each combination of fleet segment and year, the plot also shows the 10th and 90th percentiles of the distribution of unit starts. The bottom (top) horizontal mark on the vertical bar denotes the maximum (minimum) number of unit starts performed by the 10% of units with the lowest (highest) number of unit starts.

63 For the natural gas fleets in eight of these BAs, the correlation between their hourly ramping the hourly changes in net load is greater than 0.8 in all seasons.

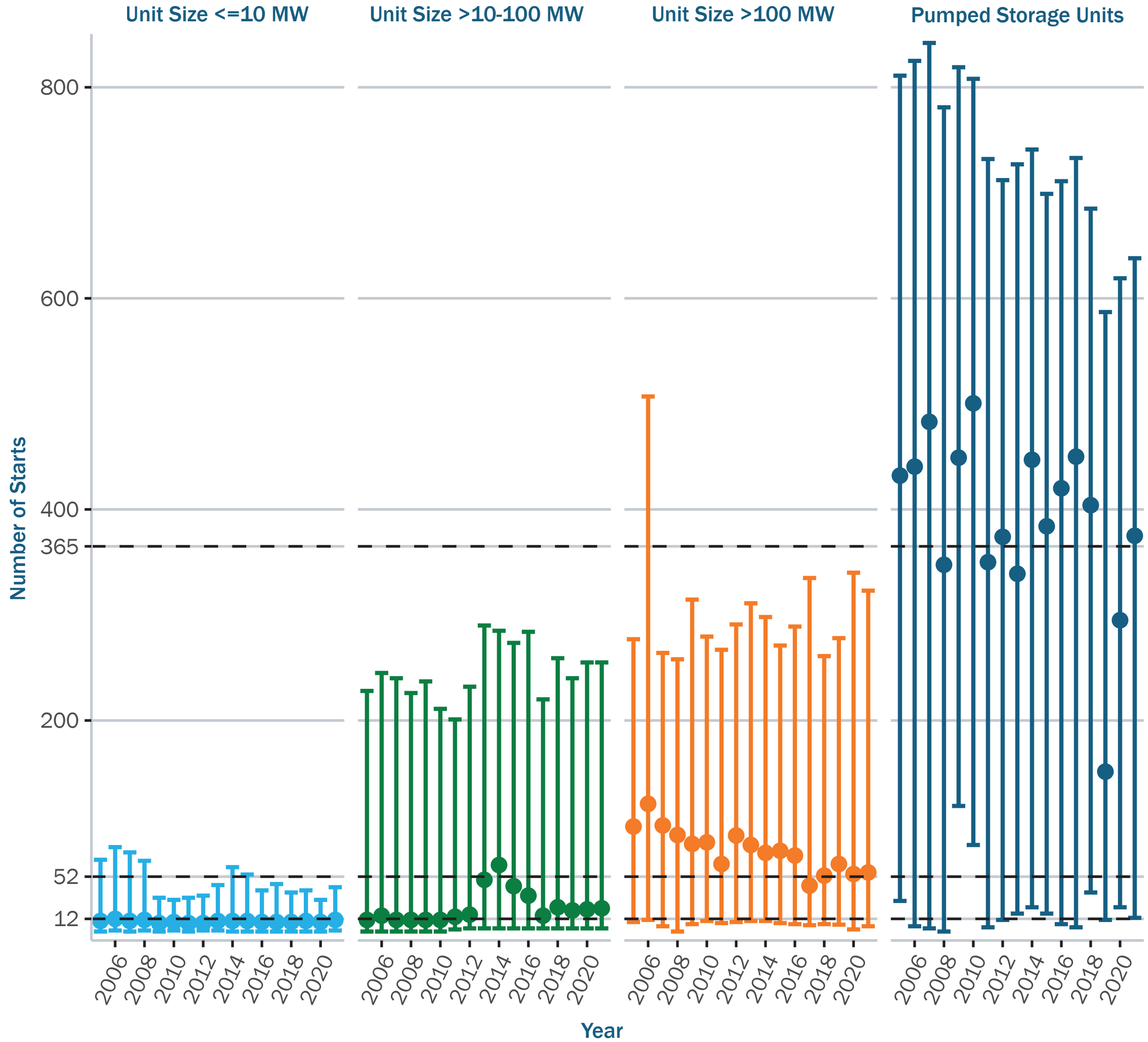

Figure 50. Hydropower and PSH unit start distributions by year, unit type, and unit size (2005–2021)

Source: NERC pc-GAR.

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In 2019–2021, the average median number of starts was 295 for PSH units, 56 for large units, 21 for medium units, and 10 for small units. Thus, the median small hydropower unit started on average less than once per month, the median medium unit started less than twice a month, the median large unit started approximately once per week, and the median PSH unit started close to once per day. These values represent an increase relative to the 2005–2018 average medians for medium units. However, for large units and PSH units, they represent substantial decreases. The very low median number of starts for PSH units in 2019 is likely related to the much lower number of PSH units that reported to NERC GADS during that year rather than an actual decline. For 2020–2021, the average median number of starts for PSH units was 335, still much lower than the average median for 2005–2018 (426).

For PSH units, the decreasing trend in unit starts is more marked for the 90th percentile than for the median. The last year in which at least one PSH unit reported more than 1,000 starts per year was 2014. The maximum number of starts reported in the most recent years were 846 (2019), 750 (2020), and 871 (2021). The very wide range in unit starts observed for PSH units shows that not all U.S. PSH facilities are equally flexible. One reason why some PSH units (or hydropower units) might report very few unit starts in a year is that they had a long outage. Other PSH units in the West are part of complex water resource projects where other purposes, such as irrigation, have a higher priority than power production; this results in patterns of operation significantly different to those in a PSH plant that times its starts and stops based on electricity market signals alone.

Chapter 6

Trends in U.S. Hydropower Supply Chain

Rock Island Dam, Chelan County, Washington (image courtesy of Karl Specht, U.S. Department of Energy s Make a Splash Photo Contest)

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

This chapter contains updated information on hydraulic turbine runner installations and U.S. trade of hydraulic turbines and other turbine parts. It also summarizes the findings from the *Hydropower: Supply Chain Deep Dive Assessment*, published in 2022 in response to Executive Order 14017, "America's Supply Chains," regarding key challenges for the U.S. hydropower supply chain and potential opportunities to address them (U.S. Whitehouse 2021, Uría-Martínez et al. 2022). Upper bound estimates of U.S. hydropower equipment demand, with a focus on turbine runners, for the next few years are also presented based on information about the U.S. hydropower project development pipeline (Chapter 2) and announced plans for hydropower R&U investments. Finally, the chapter also discusses the domestic content provisions included in the hydropower incentives from the Bipartisan Infrastructure Law and the Inflation Reduction Act tax credits.

6.1 Hydropower and PSH Turbine Runner Installations

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). Almost 75% of runners installed in 2020–2022 were for units with capacities no greater than 10 MW and were produced by at least nine different manufacturers.

In 2020–2022, the annual average hydropower capacity for which runners were installed (206 MW) was much lower than in 2007–2019 (1,256 MW).[64] The number of runners installed in 2022 was lower than each of the previous 15 years. At least 52 runners were installed in the United States (for units with a combined capacity of 617 MW) in the past three years. Seventy-three percent of them were for units with capacities of 10 MW or less. The runners for units with capacities of 10 MW or less were produced by at least nine different manufacturers. In contrast, all the installed runners in 2020–2022 for units with capacities greater than 10 MW were manufactured by three OEMs: Andritz, GE, and Voith.

Of the runners installed in 2020–2022, 60% were at new plants, but they accounted for 18% of total installed capacity. The two Kaplan units installed at the Red Rock project (55.2 MW facility rating, located in Iowa) and the three Kaplan units installed at the Lake Livingston project (26.7 MW facility rating, located in Texas) accounted for almost 75% of the 110.3 MW installed in 2020–2022 at newly constructed plants. The remaining 26 runners installed at new facilities were for units with an average capacity of 1.1 MW.

Among the runner replacements in 2020–2022 (21 runners for units with a total capacity of 506 MW), the one for a PSH unit at Cabin Creek (150 MW) in Colorado accounts for more than 25% of the replaced capacity. Additionally, there are nine units with nameplate capacities in the 20–30 MW range whose runners were also replaced in 2020–2022.

Figure 51 shows runner installations for units with a combined capacity of 17 GW in the United States from 2007 to 2022 broken down by manufacturer.

64 Throughout this section, runner refers to a turbine runner and unit refers to a turbine-generator set. The runner, a set of blades or buckets designed to capture the maximum energy from the water passing through, is a key component of a hydropower turbine. A hydropower plant might contain one or multiple units.

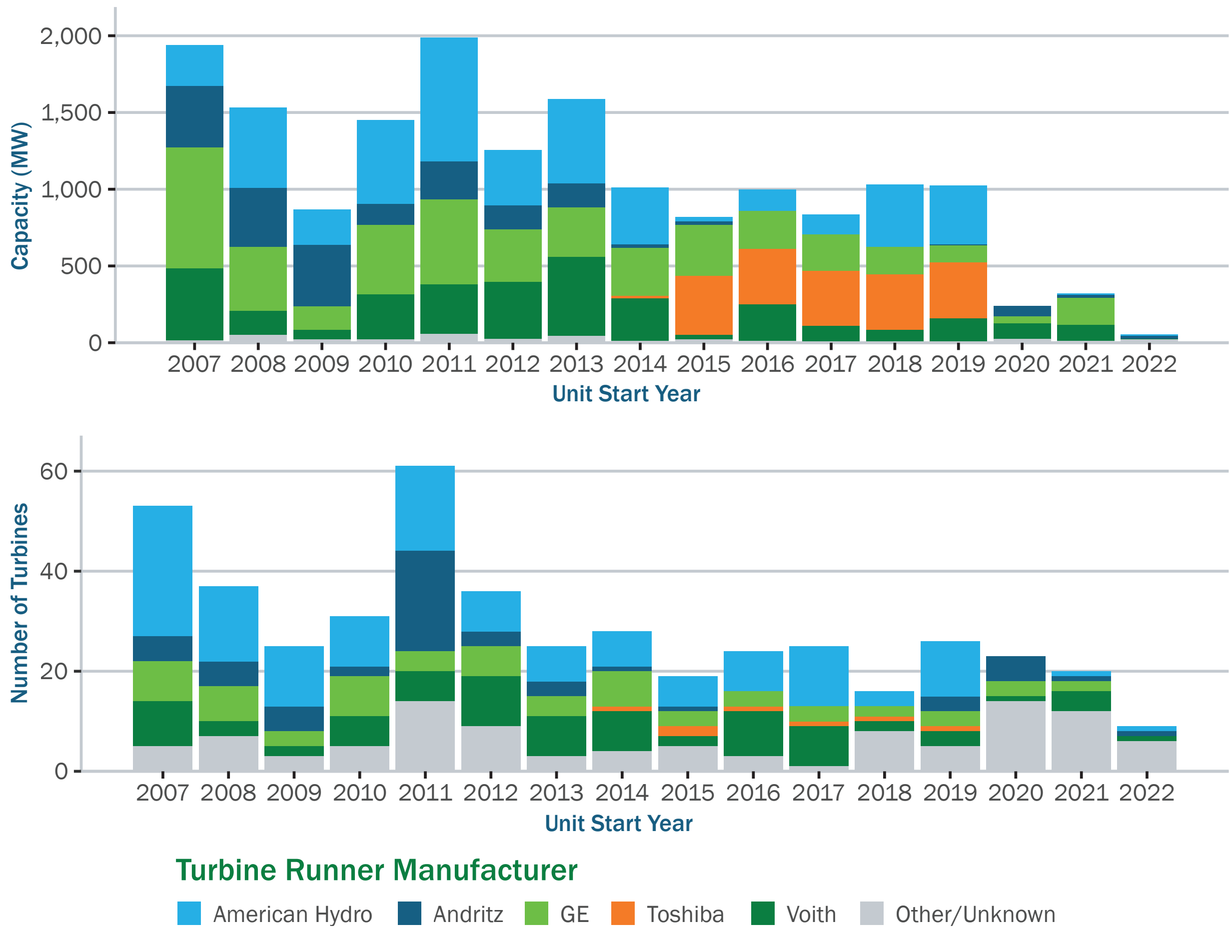


Figure 51. Annual installations of hydropower and PSH turbine runners in the United States by manufacturer

Sources: IIR, ORNL EHA Unit database 2023, personal communication with Debbie Mursch (GE).

Note: During the period shown in the plot, there have been multiple mergers and acquisitions among hydraulic turbine OEMs resulting in increased global consolidation of the industry. The manufacturers shown in the plot are the ones to which each runner is assigned based on current industry structure. For instance, GE purchased Alstom in 2015. Turbine runners manufactured by Alstom from 2007 to 2014 show up as being GE turbine runners in the plot.

The number of annual runner installations in 2007–2022 ranged from 61 in 2011 to 9 in 2022. American Hydro, Andritz, GE, Toshiba, and Voith supplied more than 70% of the runners installed in the United States since 2013, and runners manufactured by these OEMs represented 98% of installed capacity. The average capacity of the units for which these companies manufactured runners is 50 MW; the median capacity of these units is 22 MW. American Hydro manufactured 26% of the runners installed during 2013–2022, and these runners accounted for 25.5% of installed capacity. Voith, GE, and Andritz had the next largest market shares by number of runners (21% Voith, 14% GE, and 7% Andritz). The average capacity of the units for which GE manufactured the runner (65 MW) was significantly greater than for the rest of manufacturers, except Toshiba. Toshiba held a very small market share by number of runners (3%), but those seven runners represented 23% of installed capacity because they include the PSH runner replacements for Ludington's five units (362 MW each).

Three of the five major turbine manufacturers shown in Figure 51 have manufacturing facilities in the United States: Voith in York, Pennsylvania; American Hydro in York, Pennsylvania; and Andritz in Spokane, Washington. GE manufactures hydropower turbines for the North American market in Sorel-Tracy, Canada. Finally, both of Toshiba's hydraulic turbine manufacturing facilities are in Asia, one in China and the other in Japan.

The median capacity of units for the 61 runners in the “Other/Unknown” manufacturer category installed in the past decade is 0.9 MW; the average capacity is 2.6 MW. None was manufactured for units with a capacity greater than 30 MW. Fifteen different companies manufactured the 35 runners within the “Other/Unknown” category for which information was available. Some of these manufacturers are U.S. companies (e.g., Canyon Hydro, Cornell, and SOAR), and others are headquartered in Canada, Europe, or Asia. The large number of companies reflects the stronger competition that exists in the small turbine (<=30 MW) industry segment.

Figure 52 displays runner installations for units with a combined capacity of 17 GW in the United States from 2007 to 2022, differentiating installed capacity and number of runners by whether they are installations at existing facilities or at new plants.

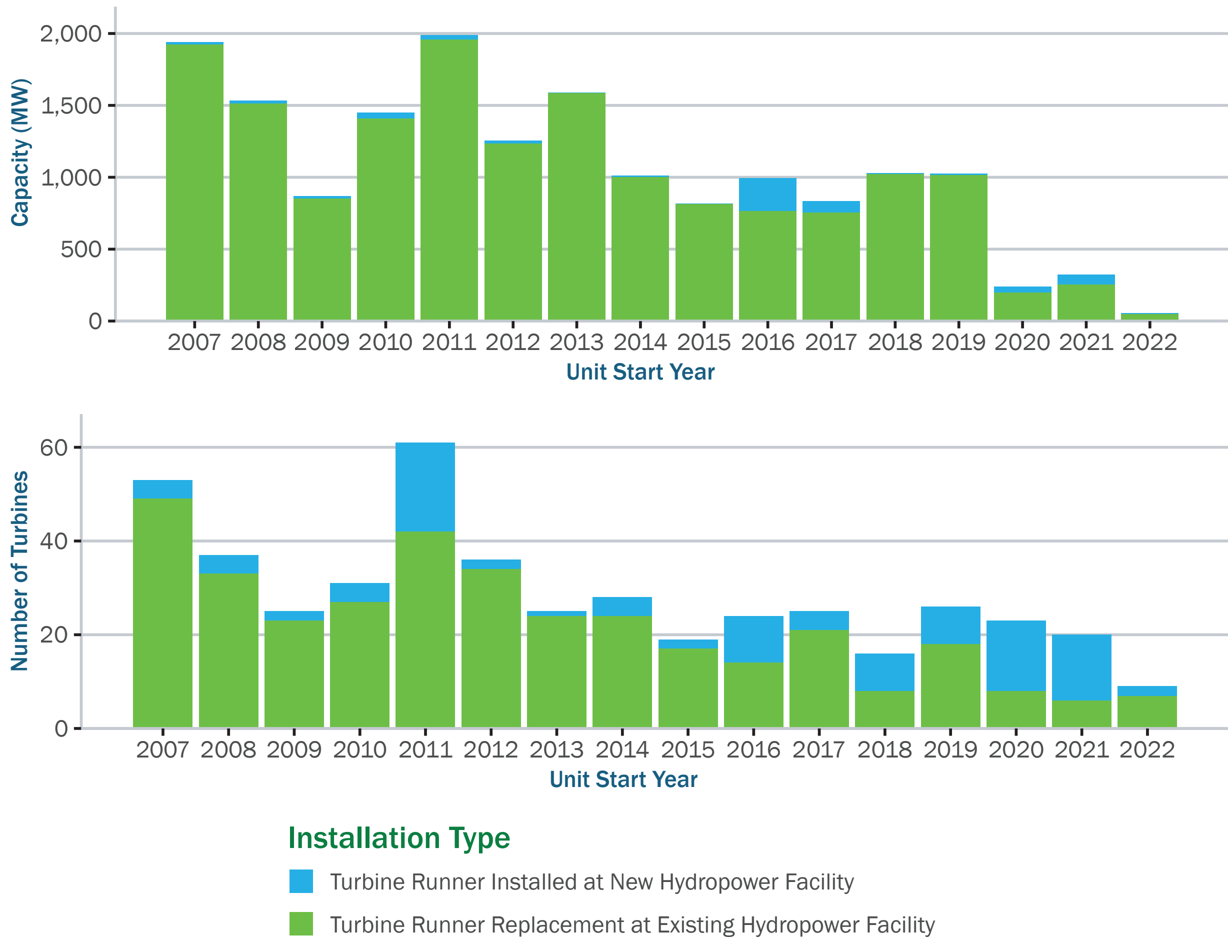


Figure 52. Annual installations of hydropower and PSH turbine runners in the United States at new versus existing facilities

Source: IIR, ORNL EHA Unit database 2023, personal communication with Debbie Mursch (GE).

Of the runners installed in the past 10 years, 68 (32%) were for newly constructed facilities, and the remaining were unit additions or replacements at existing plants. The average capacity of units for which runners were installed at new plants since 2013 was 7 MW and the median capacity was 1.1 MW. For runners installed at existing facilities, the average and median unit capacities were 50.7 MW and 18 MW, respectively.

Figure 53 shows the distribution of runner installations among the three main types of hydraulic turbines: Francis, Kaplan, and Pelton. Francis is the most common turbine type (47% of runners installed in 2013–2022), and every major turbine manufacturer installed Francis runners for the U.S. hydropower fleet during this period. American Hydro and GE manufactured the largest number of Francis runners for the U.S. market during this period (42 and 21, respectively). The second most common type of runner installed in recent years (35% of runners installed in 2013–2022) was for Kaplan turbines. Voith has captured the largest market share (50%) in runners for this turbine type. Pelton units are typically used in high-head settings, and only 15 runners have been installed since 2013 for Pelton turbines, for units with a total capacity of 126 MW.

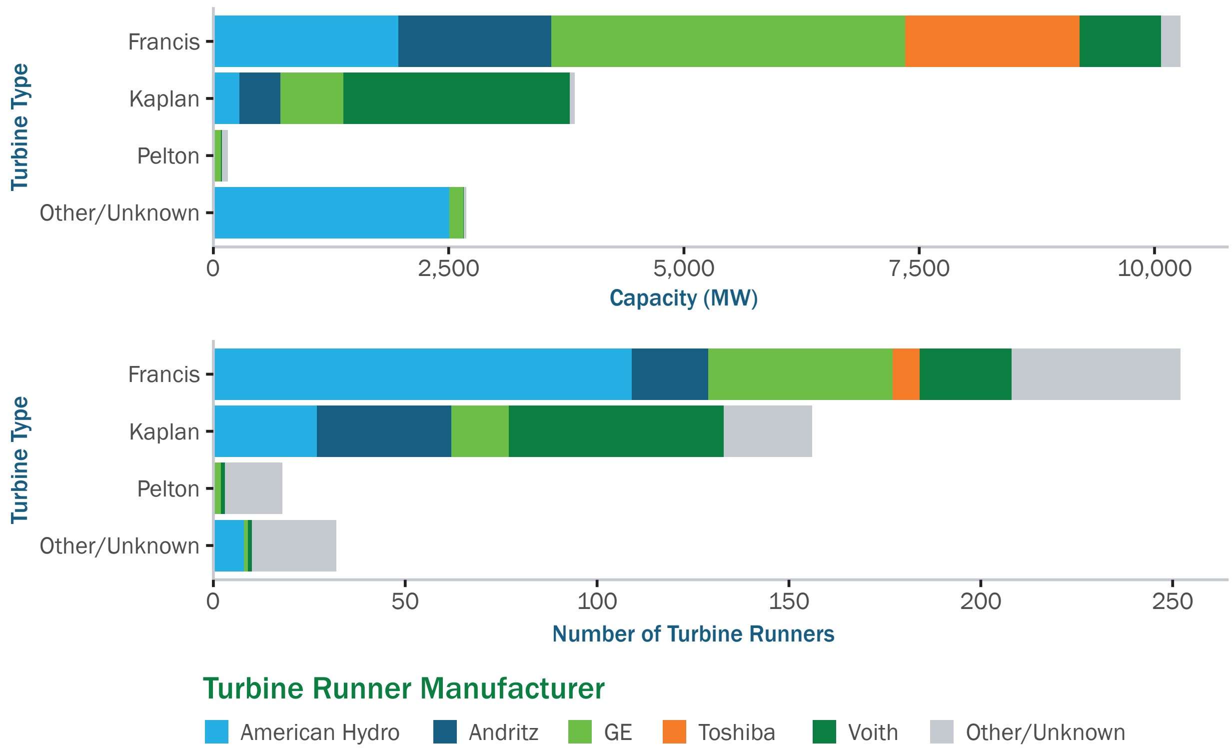


Figure 53. Installed hydropower and PSH turbine runners in the United States by turbine type and manufacturer (2007–2022)

Sources: IIR, ORNL EHA Unit database 2023, personal communication with Debbie Mursch (GE).

The distribution of turbine types installed in the past decade is significantly different for installations at new plants vs. runner replacements at existing facilities. For runner replacements, 60% of the turbines were Francis, and they represented 64% of capacity replaced. Kaplan runners also accounted for a substantial share of runner replacements (34%). For new facilities, the most common turbine type is Kaplan accounting for 86% (395 MW) of the capacity for which runners have been installed since 2013.

The reason for the large share of Kaplan units among new facilities built in the past ten years is that, by capacity, the predominant type of new hydropower project in the United States during that period is the addition of hydropower equipment to low-head (up to 20 meters) NPDs, and Kaplan is typically the selected turbine type for low-head sites.

Francis and Pelton turbines account for 6% each of the new runner installations since 2013. The average capacity of new units for which runners were installed during this period was 16 MW for Kaplan units, 2.2 MW for Pelton units, and 1.8 MW for Francis units.

6.2 Hydropower and PSH Turbine Imports/Exports

In 2020–2022, hydraulic turbine trade value for both imports and exports has been lower than the average for 1996–2019. Canada continues to be the top importer and top exporter. Contributing factors to the decrease in traded value include declines in U.S. hydropower R&U investment during the COVID-19 pandemic, supply chain challenges, and import tariffs.

Since 1996, U.S. trade balances of hydraulic turbines and turbine parts have, on average, been positive (i.e., on average, the United States has been a net exporter), but both imports and exports significantly declined in the 2020s. The average trade values (in 2022 dollars) of U.S. hydraulic turbines and turbine parts from 1996 to 2019 were $62 million for exports and $60 million for imports. In contrast, the average traded values in 2020–2022 were $32 million for exports and $39 million for imports.

In 2022, the United States saw its third largest hydraulic turbine trade deficit ($20 million) of the 1996–2022 period. Seemingly caused by the slowdown in domestic hydropower R&U investment during the pandemic, turbine import values dropped sharply in 2021 (from $47 million in 2020 to $27 million in 2021), and that was the only year in the last three years when the United States was a net exporter, with a trade balance of $10.77 million.

For the period 2020–2022, Canada and Indonesia are the only countries where the United States exported more than $10 million worth of turbines and turbine parts. Exports to those two countries accounted for almost half of all U.S. exports in those three years. Canada continues to be the country from which the United States imports the largest fraction of turbines and turbine parts (33% or $38 million in 2020–2022), followed by Brazil (17% or $20 million) and China (8% or $9 million). An additional 32% of U.S. imports ($37 million) came from Europe.

Turbines are the only piece of equipment for which the current Harmonized Tariff Schedule of the United States trade classification is granular enough to identify trade flows in the hydropower industry.[65] Some turbine-generator 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 53 because the Harmonized Tariff Schedule does not have a hydropower-specific statistical reporting number for turbine-generator sets.[66]

65 Hydraulic turbine trade data were queried through the Interactive Tariff and Trade Data website (dataweb.usitc.gov) maintained by the U.S. International Trade Commission, which compiles import and export statistics from the U.S. Department of Commerce, as well as tariff information. The values presented in Figure 54 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."

66 The U.S. International Trade Commission rejected the request for a breakout of the Harmonized Tariff Schedule codes that would allow identification of hydropower turbine-generator sets imports and exports because of low trade volumes.

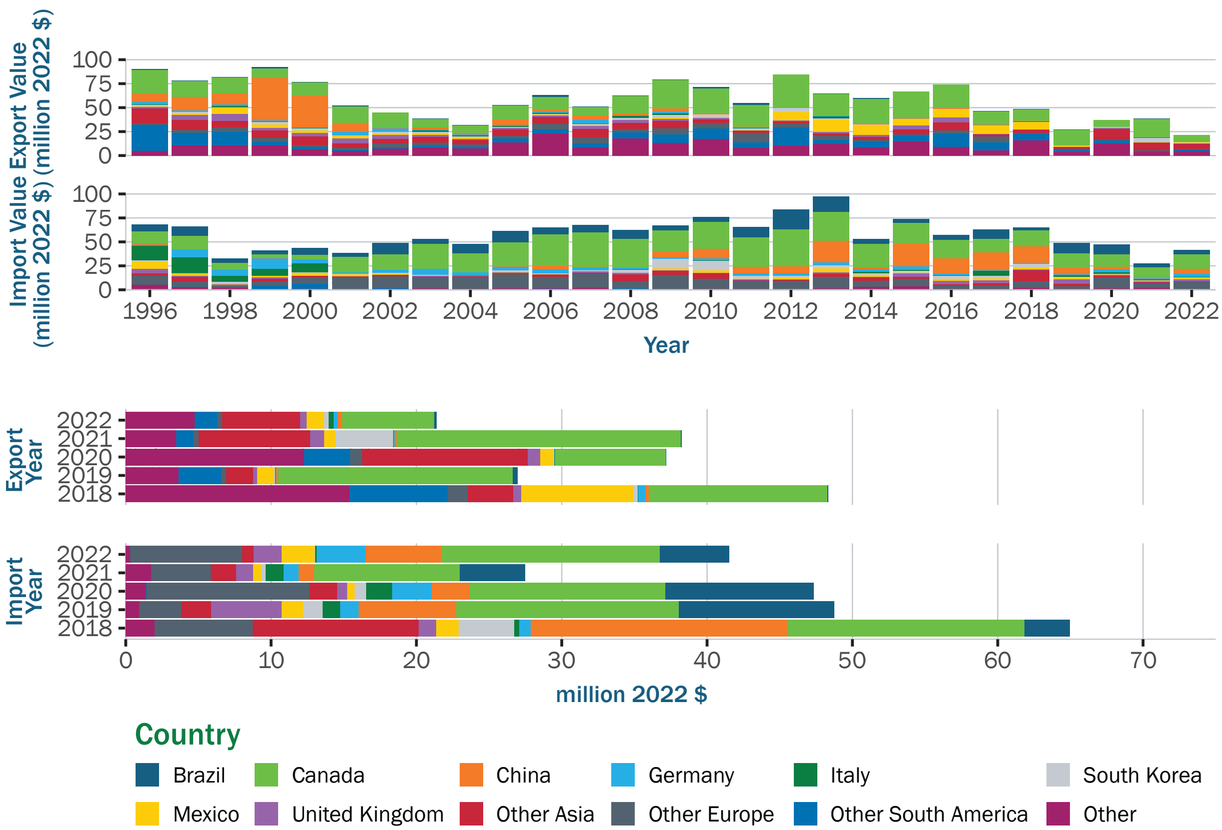


Figure 54. U.S. hydropower and PSH turbine/turbine parts import and export values by country

Source: U.S. International Trade Commission.

Figure 54 demonstrates that trade flows in 2018 were close to the average values of the past two decades, but imports and exports of hydraulic turbines and parts have experienced a strong decline since. Years 2020 and 2021 fall within the bottom five export values from 1996 to 2022. Imports in 2021 ($27.5 million) were the lowest value (1996–2022) by $5 million ($32.8 million in 1998). The value of turbine exports in 2022 ($21.4 million) was the lowest value by $5.6 million, with 2019 having the second lowest export value ($27 million).

In 2018, China was a top exporter to the United States with more than $15 million worth of turbine and turbine parts shipped to the United States in that year. Since then, that number has been reduced to less than half that each year, which is likely attributable to the 25% tariff imposed by the United States in 2018 to a list of products imported from China that included hydraulic turbines and turbine parts.[67]

The only country to consistently import ~$10 million or more is Canada. Although averages for exports to Mexico are still lower since 2018, there was a slight increase in 2022, reaching $1.2 million after two years below $1 million.

Historically, Indonesia is rarely in the top 5 hydraulic turbine trading partners with the United States, but in 2020 and 2022 it imported more than $13 million worth of U.S. hydraulic turbines and turbine parts. The last previous year when Indonesia had imported millions of dollars ($3.8 million) of U.S. hydraulic turbines and turbine parts was in 1996. The recent increase might be due to Indonesia's aggressive zero emissions initiative and billion-dollar investments already underway to build new hydropower facilities.[68]

67 In contrast to the drop in hydraulic turbine exports from China to the United States and bolstering the likelihood of U.S. import tariffs contributing to it, hydropower turbine installations in China increased substantially in 2020–2022 after five consecutive years of decline from 2015 to 2019. Hydropower (including PSH) capacity additions in China were 12.2 GW in 2020, 20.6 GW in 2021, and 22.6 GW in 2022 (IRENA, 2023a).

68 Several hydropower plants that started construction in Indonesia since 2019 purchased turbines from OEMs that have manufacturing facilities in the United States.

Apart from the tariff for Chinese turbines, the United States also imposed a tariff of 25% on most foreign steel in 2018. Since a large share of the steel castings used to manufacture U.S. hydropower turbines are foreign, these tariffs effectively increase the cost of purchasing domestically manufactured new turbines or turbine parts for U.S. plant owners.[69] The tariffs might help explain the decrease in imports shown in Figure 54 starting in 2019.

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 tariff-free metric tons per year) was also applied to steel imports from the United Kingdom. Based on interviews with turbine OEMs, steel foundries in Brazil, China, Eastern Europe, and South Korea supply most of the large steel castings for hydropower turbines (Uría-Martínez et al. 2022). Therefore, as of 2023, the tariff is only still in full force for Chinese steel.

As discussed in Chapter 3 for international turbine trade statistics, most of the U.S. imports and exports are for turbine parts rather than complete turbine units. From 1996 to 2022, 72% of the value of U.S. hydraulic turbine exports and 92% of the value of U.S. imports were for turbine parts. The following textbox on the Barkley Turbine-Generator Unit Modernization Project describes the turbine part imports for the ongoing modernization of the Barkley hydropower plant. It also highlights the complexity of the hydropower supply chain and related logistics.

69 Turbines or turbine parts imported from other countries that do not have a tariff on Chinese components might be using Chinese castings without being affected by the U.S. tariff on Chinese turbines.

HYDROPOWER SUPPLY CHAIN COMPLEXITY: BARKLEY TURBINE GENERATOR UNIT MODERNIZATION PROJECT

Modernizing the turbine-generator units in a large hydropower plant is a multiyear project with multiple phases, components sourced from multiple countries, and challenging logistics. The ongoing modernization of USACE's Barkley plant illustrates the supply chain complexity of these projects.

The Barkley plant, which came online in 1966, is on the Cumberland River in Kentucky, and it has four 32.5 MW units with Kaplan turbines. To improve unit efficiencies and plant performance, USACE initiated the design phase for the Barkley turbine replacement and generator rewind project in fiscal year 2017. USACE sent out the solicitation for bids to procure the new turbine and generator components in 2020 and awarded the contract to Andritz in September 2020. As a federal procurement contract, it is subject to Buy American Act requirements, which impose domestic content thresholds on the components and limit the list of countries from which they can be sourced.

Post-award, Andritz designed the new turbines and produced a model for hydraulic testing in its turbine test center in Austria. Once the design was approved in July 2021, manufacturing of the components for the new Kaplan units started. Andritz procured the large castings required for the turbine parts from European countries.

For the first Kaplan unit, three of the blades were manufactured in Slovenia and the other three in Italy. The turbine hub was manufactured in Spain. The turbine hub was then transported via ship to a paint shop in the United States for a special paint coating, required by USACE as part of the specifications provided in the solicitation, which will contribute to extend the life of this component. Turbine blades and hub are then transported to Andritz's machine shop and test center in Morelia, Mexico—although Andritz has a machine shop in Spokane, Washington, it cannot handle the dimensions of these units.

In Morelia, Mexico, the units will be assembled and tested for functionality to ensure there are no oil leaks (oil pressure testing). Once tested, the units will be disassembled and transported via truck from Morelia to the plant site in Kentucky. As for the generators, Andritz manufactures the coils for this project in Peterborough, Canada, and outsources the manufacturing of the laminations to a company in Europe.

At the plant site, the planned outage of the first unit being replaced is scheduled to last approximately one year. The first step is disassembly of the old unit to perform cavitation repairs before the new components are installed. The generator rewinding process typically takes 6–8 months and will be performed by specialized Andritz crews. Once the generator rewinding and core restacking are complete and the turbine components have arrived at the plant site, the assembly and installation of the new turbine will take place. The first new unit is scheduled to come online in February 2024. The other three plant units will be modernized in subsequent years.

Source: personal communication with Sam Kent (Andritz) and USACE staff.

6.3 U.S. Hydropower Supply Chain Challenges and Opportunities

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. Because of their typical unit sizes, PSH projects and some R&U projects will be the most affected by these challenges. Domestic content requirements in federal incentives and federal procurement rules try to spur increased domestic manufacturing of hydropower components.

Executive Order 14017, "America's Supply Chains," issued in February 2021, directed the Secretary of Energy to submit a report on supply chains for the energy sector industrial base that assesses risks and offers policy recommendations to strengthen them. In response to that order, DOE prepared 11 deep dive assessment reports of supply chains for different energy technologies including hydropower. For hydropower (including PSH), Uría-Martínez et al. (2022) combined data collection, expert knowledge, and 15 interviews with OEMs, plant owners, and consultants to identify supply chain challenges and opportunities to address them.

The interviews focused on hydropower-specific components that are critical to unit or plant operations: turbine, generator, governor, excitation system, switchgear, emergency closure system (gates, valves), penstock, and balance of plant. The hydropower supply chain deep dive assessment report describes the function of each of these components in a hydropower plant. It also provides details about how turbines and generators are manufactured. Other components such as transformers and pumps, which are also critical to hydropower operations, were excluded from the scope of the report because they are not unique to hydropower.

The main supply chain challenges identified are as follows:

- It is difficult to procure large steel castings (>10 tons) for turbine components from U.S. foundries. Offshoring of the large foundries that operated in the United States decades ago resulted from a combination of higher labor costs and more stringent occupational safety and environmental regulations than those in other world regions. The steel foundries from where castings are now imported are mainly in Brazil, China, Eastern Europe, and South Korea.
- Stator windings for large units (>100 MW) are very difficult to procure domestically. The special insulation requirements for these components limit the number of companies worldwide that can provide them. They are typically imported from Canada, Mexico, Brazil, and Europe.
- Workforce availability is limited for a wide array of positions in the U.S. hydropower industry including engineers, skilled trades (e.g., machinists and welders), and construction workers for jobs at remote sites. Based on a hydropower industry survey, Daw et al. (2022) report expected high retirement rates over the next 5–10 years, especially for skilled craftspeople and engineering services. Skilled craftspeople (e.g., electricians, mechanics, technicians, operators) make up the largest share of onsite workers at hydropower and PSH plants, and competition from other sectors of the economy makes attracting them to the hydropower industry difficult. For hydropower engineers, workforce development pipeline challenges are revealed by the combination of expected high retirement rates and a decrease in the number of new hires. New hires in the hydropower workforce come in with limited knowledge of the hydropower industry, and the knowledge they have is typically from prior work experiences and apprenticeships rather than academic curricula. Students have limited awareness of hydropower as a career path.
- Diversity of turbine suppliers has decreased in the last decades because of the trend of consolidation in the industry (especially for large units). The larger the unit, the smaller the number of manufacturing facilities worldwide that have the necessary tooling. As attested by the data presented in Section 6.1, diversity of suppliers is substantially greater for units with capacities below 30 MW.
- For many hydropower plant components, the supply chain is opaque. In 2021—the year when the interviews were conducted—global supply chains were experiencing long delays and escalating costs for ocean shipping. In those circumstances, plant owners expressed a willingness to pay a premium for domestic components. However,

even if a domestic supplier can be identified for the purchase of a finished component, it does not mean that all its subcomponents are manufactured domestically. Visibility into all tiers of the supply chain is needed for plant owners to develop supply chain risk mitigation strategies.

The slow pace of turbine installations and imports in 2020–2022, discussed in Sections 6.1 and 6.2, will likely create a pent-up demand for hydropower plant components later in the decade. Additionally, the new federal incentives authorized through the BIL and IRA might boost investment in existing and new (nonfederal) hydropower facilities. Lack of full guidance on implementation of these incentives may have contributed to slow investment activities in 2022 and the first half of 2023.

As discussed in Chapter 2, at the end of 2022, there were 48 hydropower projects (~100 turbine-generator units) and 3 PSH projects (11 turbine-generator units) for which federal authorization to proceed to construction has already been issued. An upper bound to demand for hydropower plant components would occur in the next few years if all these licensed projects proceeded to construction and all planned R&U activity moved forward. According to Industrial Info Resources, dozens of turbine replacement projects are planned with scheduled start dates in 2023–2027.

Different types of hydropower construction activities listed in the previous paragraph (new hydropower plants, new PSH, and R&U to existing hydropower and PSH) might be exposed to the aforementioned supply chain challenges in varying degrees. For the 48 hydropower projects that have already been licensed, only one of the proposed turbine-generator units have capacities greater than 30 MW. Therefore, almost all fall into the segment of the turbine market (<30 MW) with high supplier diversity. Nonetheless, if the required turbines have any special design features (e.g., aerating turbines or fish-friendly designs), the number of OEM options becomes more limited. Of the 90 turbine-generator units authorized in licensed NPD projects, 74 are Kaplan units. For PSH, however, the 11 units authorized in their licenses all have capacities greater or equal than 100 MW. Only the major turbine OEMs can supply them. For R&U projects, the planned units captured in the IIR database range in capacities from 0.6 to 57.5 MW. Among these units, there are 28 with capacities greater than 30 MW that would all go to R&U of units in the federal U.S. hydropower fleet.

Although the number of potential suppliers—including options with domestic manufacturing—is greater for units with capacities of less than 30 MW, steel castings of more than 10 tons might be needed for some of the units below the 30 MW threshold.[70] Apart from more than 100 turbine-generator units, if all 48 hydropower and 3 PSH licensed projects proceeded to construction within a few years, they would require all other mechanical and electrical components needed in a hydropower plant, as well as specialized construction equipment, material for the civil works, and workforce.

For large PSH units and steel castings of more than 10 tons, given that only a limited number of facilities worldwide can produce them, a combination of increased new hydropower construction activity in the United States and internationally could result in long timelines for procurement.

Uría-Martínez et al. (2022) list some opportunities to address the identified supply challenges. First, the United States is well positioned to be a global leader in advanced manufacturing for hydropower applications. 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 for 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. Musa et al. (2023) explore in depth the opportunities for AM and materials in the hydropower industry.

Second, R&U of the existing U.S. fleet (the fourth largest in the world for hydropower and third largest for PSH, but also one of the oldest in the world) offers a substantial market opportunity to attract reshoring of manufacturing for hydropower plant components that are currently hard to procure domestically. The opportunity is even bigger when the needs of the hydropower industry are combined with those of other clean energy technologies. For instance, the wind industry also faces the challenge of lack of domestic options for procurement of large steel castings. Collaboration across U.S. renewable energy

70 There is no simple correspondence between the power rating of a turbine and its dimensions or weight.

industries to identify common supply chain needs would be valuable to better present the business case for reshoring additional manufacturing operations.

Third, federal procurement rules can be leveraged to increase the domestic content requirements for manufactured components used in federal hydropower R&U projects.[71] The Buy American Act imposes domestic content thresholds for construction material—defined as articles, materials, or supplies brought to the construction site by a contractor or a subcontractor for incorporation into the building or work—in federal projects. A two-part test is used to determine whether an end product or construction material qualifies as domestic. First, the end product (e.g., a turbine) must be manufactured in the United States. Second, a certain share of the cost of its components (e.g., steel castings needed to manufacture the turbine) must be mined, produced, or manufactured in the United States. 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, gradually, to 75% by 2029.[72] 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. Above that value threshold, construction material coming from any country in the Trade Agreements Act competes on equal terms with domestic construction material.[73] For turbine parts and steel castings used in turbine manufacturing, key exclusions from the Trade Agreements Act are China and Brazil because both countries have large hydropower industries and are among the limited list of countries with steel foundries capable of producing large steel castings.

Recipients of incentives from the Bipartisan Infrastructure Law (see Chapter 7 for details about the Section 242, Section 243, and Section 247 hydropower incentives) might also be bound by domestic preference requirements. The Build America, Buy America Act was approved along with the Bipartisan Infrastructure Law. It applies to nonfederal entities (excluding for-profit entities) that are recipients of federal financial assistance programs for infrastructure.[74],[75] It requires the following domestic preferences. First, all iron and steel—from the initial melting operations to the application of coatings—used in the project must be produced in the United States. Second, all manufactured products are produced in the United States, and 55% or more of the cost of their components must be from domestic components. Third, all construction materials are manufactured in the United States. Waivers can be requested if applying the domestic preferences is inconsistent with the public interest; if the iron, steel, manufactured products, or construction materials needed are not produced in the United States in the quantities and qualities required or if their use results in a project cost increase of more than 25%.

For applicants to the Inflation Reduction Act tax credits for new hydropower and PSH facilities, domestic content requirements are not a requisite for credit eligibility but a credit adder. If the credit applicant can show that 100% of steel or iron and 40% of manufactured products used in the construction are domestic, the production tax credit is increased by 10%.

Finally, the Inflation Reduction Act also includes tax credits for investments in manufacturing facilities for clean energy technologies, including hydropower. Details about these credits are presented in Chapter 7.

For workforce challenges, Daw et al. (2022) identify the expansion of apprenticeship programs, as well as development and sharing of hydropower curricula and educational resources among the opportunities to address recruiting challenges.

71 The federal hydropower fleet has an installed capacity of 39.3 GW (48.5% of total U.S. installed capacity) and the federal PSH fleet has an installed capacity of 3.6 GW (16% of total U.S. PSH capacity) and they are not eligible for the Bipartisan Infrastructure Law incentives or the Inflation Reduction Act tax credits.

72 A fallback threshold allows products with a 55% domestic content to qualify as domestic contents until 2030 but only for construction materials and end products that do not consist wholly or predominantly of iron and steel or a combination of both. Steel is the primary material for most hydropower turbine components, which therefore cannot apply the fallback threshold.

73 A list of countries that are compliant with the Trade Agreements Act can be found at gsa.federalschedules.com/resources/taa-designated-countries/.

74 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. These types of entities own 24% (19.6 GW) of U.S. hydropower capacity and 17% (3.7 GW) of U.S. PSH capacity.

75 For-profit entities (i.e., investor-owned utilities, wholesale power marketers, industrial companies, and private non-utilities) own 27% (22.1 GW) of U.S. hydropower capacity and 67% (14.7 GW) of U.S. PSH capacity.

Chapter 7

Policy Developments

Piedmont Temporary Regulator In-Conduit Hydroelectric Project, Alameda County, California (image courtesy of Gregg Semler, InPipe Energy)

Chapter 7. Policy Developments

This chapter provides a summary of recent (since publication of the previous edition of the report in January 2021) policy developments at the federal and state level that might affect investment in and operations of the existing hydropower and PSH fleet, as well as development of new hydropower and PSH projects. It includes (1) a detailed description of the incentives relevant to hydropower and PSH contained in the Infrastructure and Investment Jobs Act (most commonly called BIL) and the IRA, (2) proposed legislation—S. 1521 *Community and Hydropower Improvement Act*—including significant reforms to the hydropower licensing process, (3) a discussion of recently passed or proposed FERC rules to improve the dam safety and financial assurance of hydropower projects, and (4) a list of 2021–2022 state-level policy updates involving requirements or targets for installation of new renewable generation or energy storage capacity.

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

The largest portion of hydropower incentives in the BIL ($553 million) is directed toward capital improvements in existing nonfederal hydropower facilities through a new incentive, codified as Section 247 of the Energy Policy Act (EPAct) of 2005. Eligible capital investments are those improving grid resilience or dam safety or those making environmental improvements. The rest of the hydropower-specific appropriations go toward funding incentives already codified in the EPAct of 2005. Those include $125 million to fund hydroelectric production incentives (Section 242 of the EPAct of 2005) and $75 million for funding hydroelectric efficiency improvement incentives (Section 243 of the EPAct of 2005). The Section 242 incentives are available for nonfederal hydropower production added to a NPD, conduit, or nonfederal hydropower facility with capacity no greater than 20 MW in areas with inadequate electric service. Existing hydropower facilities (including PSH) improving efficiency by 3% or more are eligible to apply for Section 243 incentives.[76] DOE administers the Sections 242, 243, and 247 incentives. Table 3 summarizes authorized funding, incentive amounts, and eligibility criteria for the three hydropower BIL incentives.

As of the end of June 2023, DOE was reviewing applications for the Section 242 incentives (the application period for electricity generated in 2021 and 2022 closed on May 8, 2023) and the Section 243 incentives (the application window closed on June 20, 2023). For the Section 247 incentive, the window to submit full applications is open from June 23 to October 6, 2023, only for applicants who first submitted a letter of intent by June 22.[77]

76 Efficiency is calculated as the ratio of actual power production to theoretical power production. Theoretical power production (P) is the maximum hydropower output at 100% efficiency and is calculated as $P = Q*H/11.81$, where Q is average flow (in cubic feet per second) and H is net operating head (in feet). For the pre-capital improvement efficiency, actual power production corresponds to historical data. For the post-capital improvement efficiency, actual power production is an estimate based on the turbine manufacturer's efficiency data from model tests or other resources.

77 Application guidance for Sections 242, 243, and 247 incentives is available at the DOE website.

Table 3. Eligibility Conditions and Incentive Amounts from Sections 242, 243, and 247 Incentives of the BIL.

Incentive	Authorized funding	Eligibility	Incentive amount
Hydroelectric Production Incentives (**Section 242** of the EPAct of 2005)	$125 million	*Nonfederal hydropower production added to an existing dam or conduit.* ("Added" means installing a turbine where none existed before 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 1, 2005.) *Nonfederal hydropower facility <20 MW constructed in an area with inadequate electric service.* (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: eligible facilities can apply for the incentive for a period of 10 consecutive years beginning with the first fiscal year it 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 (**Section 243** of the EPAct of 2005)	$75 million (up to 25% set aside for *small hydropower*[a])	*Capital improvements at existing (placed in service by November 15, 2021), operable hydropower facilities improving efficiency by >=3%* To apply, the project must have at least applied for the required federal, state, and/or tribal authorizations (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. In case of oversubscription, project selection based on scoring rubric provided in the DOE guidance.
Capital Improvement Incentives (NEW **Section 247** of the EPAct of 2005)	$553 million (up to 25% set aside for *small hydropower*[a])	*Capital improvements at existing (placed in service by November 15, 2021) nonfederal 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.* To apply, the project must have at least applied for the required federal, state, and/or tribal authorizations (award conditional on completion of authorizations). 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. In case of oversubscription, project selection based on scoring rubric provided in the DOE guidance.

[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] Not-for-profit applicants include states, local governments, territories, Indian Tribes, institutions of higher education, and nonprofit organizations.

The BIL also appropriates $2 million per year from 2022 to 2026 to support feasibility studies and permitting of PSH projects with more than 1,000 MW of capacity that help with integration of solar and wind energy and that could provide energy and/or grid services in more than one organized wholesale electricity market.

Additionally, hydropower dam owners might be eligible for other BIL funding directed towards dam improvements. This includes $800 million targeted toward rehabilitation of dams with high hazard potential and safety projects to maintain or upgrade dams. Hydropower dam owners could also be eligible for some of the additional $800 million authorized to fund river restoration through removal of dams and in-stream barriers with the consent of the dam owner. The funds for dam safety are administered primarily by the U.S. Department of Homeland Security through the Federal Emergency Management Agency (FEMA). The funds for dam removal are administered by multiple agencies including the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, FEMA, USACE, and the U.S. Forest Service.

The IRA became law in August 2022. Unlike the BIL, it does not contain specific appropriations for hydropower, but it includes production and investment tax credits 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 production tax credits, and the eligibility of PSH projects for the investment tax credits.

Table 4 summarizes the credit amounts and eligibility criteria for the IRA tax credits (Section 45, Section 48, Section 45Y, and Section 48E) applicable to new hydropower or PSH facilities. The 10-year horizon of tax credit support that the IRA provides is longer than what was available with the previous versions of the production and investment tax credit and is better aligned with the development timeline of hydropower projects.

Another important innovation in the application of the Inflation Reduction Act (IRA) tax credits is that credit recipients who are tax-exempt entities can select an 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 (Pisano 2022).[78] Moreover, taxpayers who have earned these credits can sell them to another entity for cash. The possibility of an elective-pay option is valuable for publicly owned hydropower developers, such as municipalities and state agencies, that are tax exempt.

For facilities placed in service from January 2022 to December 2024, the production tax credit (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 IRS for 2023 is 2.75 cents/kWh. To be eligible for this credit amount a project must satisfy wage and apprenticeship requirements.[79] Otherwise, only 20% of the credit will be received (i.e., 0.55 cents/kWh in 2023). Two of the new PTC modifications are favorable to hydropower. First, unlike in previous versions of the PTC, the IRA establishes credit parity for hydropower relative to other renewables such as wind—for hydropower facilities placed into service after December 31, 2022. Second, conduit projects (i.e., projects where pressurized water is used on a pipeline or conduit the primary use of which is the distribution of water for agricultural, municipal, or industrial consumption) with an installed capacity greater than 25 kW are now eligible for the credit.

Projects eligible for the Section 45 PTC can select to claim the Section 48 investment tax credit (ITC) instead. The IRA also includes an important modification to the Section 48 ITC. It expands eligibility to energy storage technology, including PSH, placed into service between January 2022 and December 2024. The credit 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 investment tax credit amount is 6%.

78 However, such recipients 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.

79 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.

The PTC can be increased by an additional 10% and the ITC by an additional 10 percentage points if the project meets domestic content requirements such that 100% of steel or iron and 40% of manufactured products used in its construction are produced in the United States.[80] Moreover, an additional 10% (for PTC) or 10 percentage points (for ITC) are available for projects located in an "energy community." Locations that qualify as energy communities belong in one of three categories: (1) certain brownfield sites, defined as either (a) real property the redevelopment of which might be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant or (b) certain mine-scarred land; (2) metropolitan or nonmetropolitan statistical areas with substantial fossil fuel production—0.17% or greater direct employment or 25% or greater local tax revenues related to fossil fuel extraction, processing, transport or storage—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 (or tracts directly adjoining those where the closure or retirement has taken place).[81]

For facilities to be placed in service starting in 2025, the IRA sets up new clean electricity production (Section 45Y) and investment (Section 48E) tax 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 credit is available for the first 10 years of production of the facility. Facilities that are 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. A three-year phaseout period for the credit will start either in 2032 or, if it happens later, in the year when the annual greenhouse gas emissions from U.S. electricity production drop below 25% of the emissions in 2022. 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).

The technology-neutral clean electricity investment credit (48E) is for facilities placed in service starting in 2025 and can be claimed for new generation facilities with anticipated greenhouse gas emission rates no greater than zero and any energy storage installation with a storage capacity greater than 5 kWh.[82] The credit is 30% if wage and apprenticeship requirements are met; otherwise, the facility qualifies only for a 6% credit.

The domestic content and energy community bonus credits are also applicable for the clean electricity production and investment credits. For facilities that start construction after 2026, the minimum percentage of the component cost of manufactured products that must be domestic to qualify for the bonus is 55% (rather than 40% in earlier years). The available credit for PTC, ITC, and clean electricity production or investment credit is reduced by the amount of tax-exempt bond financing used to finance the facility (up to a 15% reduction).

80 The Treasury Department published detailed guidance on the domestic content bonus for the IRA Sections 45, 48, 45Y, and 48E tax credits in May 2023.

81 In April 2023, the Treasury Department and the Internal Revenue Service released guidance with more details on eligibility for the energy community bonus. DOE has also released an energy communities mapping tool (except for the brownfield site category).

82 For qualified facilities with maximum net output no greater than 5 MW, the basis costs over which the credit can be claimed include expenditures paid for qualified interconnection property.

Table 4. IRA Tax Credits Relevant for Hydropower and PSH.

Credit	Qualified facilities/projects	Credit amount	Credit adders
PTC (Section 45)	Hydropower placed in service during the eligibility period (2022–2024), including previously excluded conduit projects >25 kW Credit eligibility for the first 10 years of production	Full amount: 1.5 c/kWh (if wage and apprenticeship requirements are met) Base amount: 0.3 c/kWh (inflation-adjusted values published annually by the IRS; the full amount for 2023 is 2.75 c/kWh)	Additional 10% credit if project meets domestic content requirements or is located in an "energy community" (these adders can be stacked)
ITC (Section 48)	Hydropower and PSH placed in service during the eligibility period (2022–2024) (Hydropower can select to claim PTC or ITC, not both)	Full amount: 30% of eligible investment costs (if wage and apprenticeship requirements are met) Base amount: 6%	Additional 10 percentage points of credit if project meets domestic content requirements or is located in an "energy community" (these adders can be stacked)
Clean Electricity Production Credit (Section 45Y)	Facilities with a greenhouse gas (GHG) emissions rate of <=0 placed in service in 2025–2032 (three-year phaseout starts in 2032 or, if it happens later, in the year when GHG emissions of U.S. electricity drop below 25% of 2022 level) Credit eligibility for the first 10 years of production	Full amount: 1.5 c/kWh (if wage and apprenticeship requirements are met) Base amount: 0.3 c/kWh (inflation-adjusted values published annually by the IRS; the full amount for 2023 is 2.75 c/kWh)	Additional 10% credit if project meets domestic content requirements or is located in an "energy community" (these adders can be stacked)
Clean Electricity Investment Credit (Section 48E)	Facilities with a GHG emissions rate of <=0 or any energy storage technology (including PSH) with a storage capacity >= 5 kWh placed in service in 2025–2032	Full amount: 30% of eligible investment costs (if wage and apprenticeship requirements are met) Base amount: 6%	Additional 10 percentage points of credit if project meets domestic content requirements or is located in an "energy community" (these adders can be stacked)

The hydropower industry is also eligible for one of the incentives in the IRA geared towards investment in domestic clean energy supply chains.

Section 13501 of the IRA extends the Section 48C qualified advanced energy property credits. Before the IRA, Section 48C credits did not apply to factories producing hydropower components; the IRA expanded the definition of eligible property to include production of components designed to produce energy from water. Factory owners can claim a 30% credit if the workers involved in the construction or upgrade of the factory are paid the equivalent of union wages and apprentices are hired for construction (unless an apprenticeship program is not available); otherwise, they will qualify for a 6% credit. Of the total $10 billion authorized for these credits, at least $4 billion must be allocated to factories located in energy communities (where a coal mine closed after December 31, 1999, or a coal-fired generation unit was retired after December 31, 2009). Initial concept papers for the first round of awards of these credits are due July 31, 2023.

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."[83]

The reform proposal is a product of the Uncommon Dialogue on Hydropower, River Restoration, and Public Safety. This initiative, started in 2018, has convened a wide range of hydropower stakeholders (owners, nongovernmental environmental organizations, Tribes, and state and federal agencies) to "advance the renewable energy and storage benefits of hydropower while enhancing the environmental and economic benefits of healthy rivers."

For improved coordination among licensing process participants, the package proposes holding consultations or technical conferences (instead of relying too heavily on written filings) at several points of the licensing process such as the development of a schedule for all federal authorizations needed by a project, development of the joint study plan and environmental assessment/environmental impact statement documents, and resolution of conflicts regarding proposed license terms.

Expansion of the authority of tribal nations in the licensing process

An important component of the proposal is its expansion of the authority of tribal nations in the licensing process. Under the current process, Tribes are represented by the U.S. Department of the Interior. The proposal shifts mandatory conditioning authority from the U. S. Department of Interior to a federally recognized Tribe for any project located on land within the boundaries of a tribal reservation. Additionally, the proposal extends authority to Tribes with treaty-protected rights to submit license recommendations to FERC for protecting and enhancing fish and wildlife resources.

Need to prove linkage between license conditions and project effects; consideration of off-site measures to mitigate project effects

The proposal requires establishing ties between license conditions and project effects, as well as a culture of "show your work," in which agencies and federally recognized Tribes with mandatory conditioning authority refer to specific sections of a study (rather than the entire study) to explain their positions and the hydrological data and models used are disclosed.[84]

Another innovation introduced by the proposal is the requirement that agencies and federally recognized Tribes with mandatory conditioning authority consider off-site measures proposed by licensing participants as potential supplements to on-site measures for mitigating project effects on fish species. Off-site measures are activities replacing or providing substitute resources or habitats at a different location than the project area.

For improved regulatory certainty, the two key proposed changes in S.1521 are an expedited licensing pathway for qualifying NPDs and closed-loop PSH projects and an update to the license surrender process.

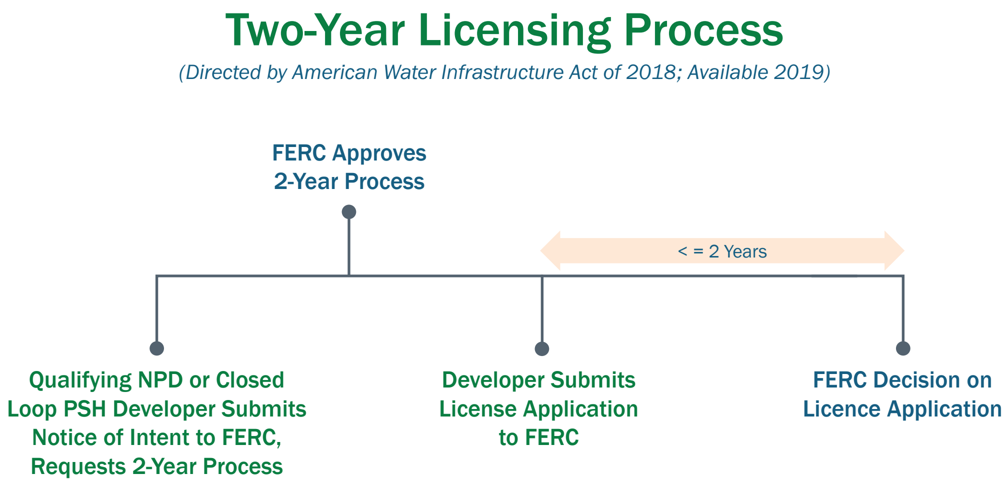
The expedited licensing process would apply to NPDs and closed-loop PSH projects with only incidental impacts to riverine systems. For NPDs, FERC would be directed to issue its final decision on a license application within two years after it determines that the proposed hydropower project qualifies 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 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 that 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).

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

84 Project effects are defined as the ongoing or foreseeable reasonable environmental effects that would not occur or would be different but for the continued O&M or new construction of the project. Foreseeable reasonable effects must not be speculative, remote, or indefinite and must be supported by monitoring, modeling, or other analysis that is generally accepted in the scientific community.

To decide which projects qualify for this expedited process, some of the criteria are common to NPDs and closed-loop PSH projects. In both cases, it must be unlikely that unusual or complex resource issues would arise during the licensing process and the information provided by the applicant in the Notice of Intent must be sufficient in detail and scope to make the determination. Additionally, for NPDs, FERC is directed to take into consideration whether the dam is expected to continue serving a public purpose for the term of the license, whether the dam has any unmitigated adverse resource effects (including lack of fish passage), whether the dam is likely to be removed during the term of a license because of environmental or dam safety considerations, and whether the licensing might improve the environmental conditions of the dam. To make a decision on whether a closed-loop PSH project would qualify for the expedited process, the project must also be unlikely to involve threatened or endangered species or their critical habitats (unless the Notice of Intent identifies measures to mitigate the potential damages), and the project must not be located on tribal land (unless the affected Tribe is one of the project developers or consents to the development).

Figure 55 summarizes the key points in the timeline of the proposed expedited licensing process and its differences relative to the two-year licensing process already available since 2019. In the two-year licensing process, directed by the America's Water Infrastructure Act of 2018, FERC shall issue its final decision within two years after the date on which the applicant submits the final license application for a qualifying NPD or closed-loop PSH project.



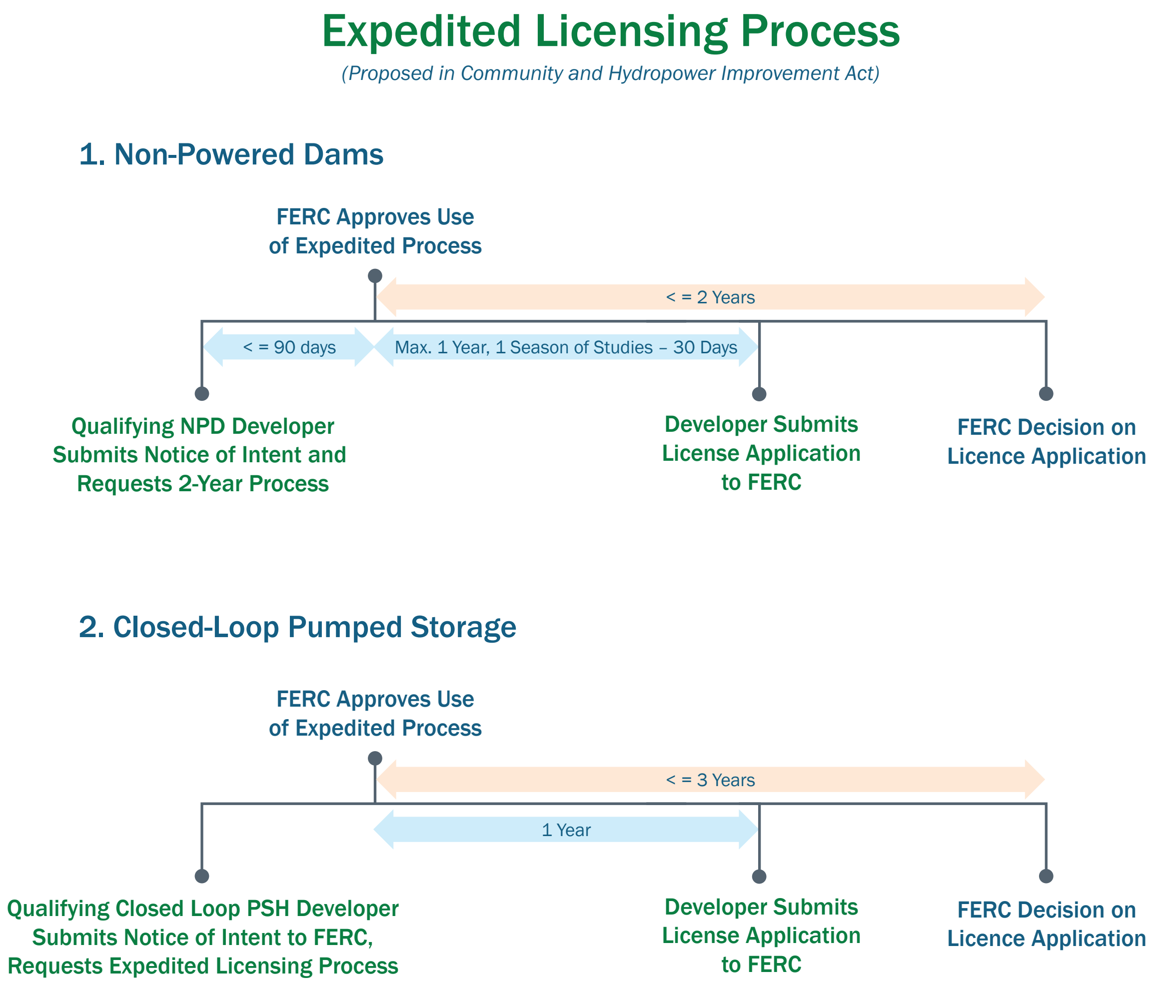


Figure 55. Differences between existing two-year licensing process and proposed expedited licensing process (for qualifying NPDs and closed-loop PSH projects).

For the projects that qualify, this expedited process would imply substantial time savings relative to the typical length of the licensing process. Levine et al. (2021) report the average length of an original hydropower license (from Notice of Intent submission to final FERC decision on the license application) to be five years for a sample of 107 hydropower projects with licenses issued after October 2005, of which a significant fraction were NPDs. For the three closed-loop PSH projects that have been issued licenses as of December 2022, the time elapsed from Notice of Intent submission to final decision on license application ranged from 3.6 years to 8.9 years. The proposed new expedited process would make the permitting timelines for hydropower more comparable with those for other renewables.

For the license surrender process, the proposal directs FERC to establish more clear and robust procedures that include timelines, provide opportunities for public participation starting early in the process, and explore opportunities to expedite the process for projects without complex environmental issues or public opposition. It also proposes that FERC should periodically compile a list of nonoperating projects and develop a plan for whether or not to restore operation for each of them.

Two recent hydropower regulatory actions by FERC (publication of updated dam safety rules and consideration of new financial assurance rules) focus on analysis and mitigation of hydropower dam risks, both physical and financial.

FERC's decision to review its dam safety program was motivated by the Oroville Dam spillways incident in California in 2017.[85] The changes are geared toward detecting similar problems in other dams before they result in safety hazards.

After a Notice of Proposed Rulemaking in July 2020, followed by a period of public comment, FERC published changes to its dam safety regulations (title 18, Code of Federal Regulations, part 12) in December 2021. The changes affect the independent consultant inspection process. The new FERC dam safety rule introduces two tiers of project safety inspections by independent consultants.[86] Until now, projects were subject to a safety inspection by independent consultants (Part 12D program) every five years. With the change in rules, the periodicity of the inspection continues to be five years. However, the scope of the inspection alternates between a periodic inspection and a more in-depth comprehensive assessment. The periodic inspection involves a review of the project's performance during the past five years combining field inspection, data analysis, and an evaluation of whether any potential failure modes are occurring. Among other additional items, the comprehensive assessment incorporates a semiquantitative risk analysis.[87],[88] The risk of each failure mode depends on the combination of its probability and its potential damage. Ranking the risk of different failure modes helps prioritize dam safety activities. The comprehensive assessment is a new process and will require learning and adaptation by project owners. Another aspect of the independent consultant review process modified with the new rule is the greater emphasis on ensuring that the independent consultant team has adequate collective expertise to evaluate each project.

Other changes to FERC dam safety regulations include codification of the existing requirement for owners of high and significant hazard dams (983 of the 1,729 hydropower dams under FERC jurisdiction are either high or significant hazard dams according to the National Inventory of Dams) to maintain an Owner's Dam Safety Program, updated public safety incident reporting requirements, and submission of a public safety plan to FERC.

The addition of a risk analysis component to the dam inspection process once per decade is a key component of the changes to the FERC dam safety rule. With the financial assurance rule that is under consideration by FERC, the agency addresses a different but related risk. The objective is avoiding situations in which insufficient funding might result in hydropower project owners not being able to comply with all the license terms, especially those related to project safety, resulting in public safety and environmental hazards. The failure of the Edenville and Sanford dams in Michigan following heavy rains in May 2020 brought this issue to the forefront as the licensee in charge of those dams failed to comply with the terms of the FERC license for years and declared bankruptcy after the incident.[89]

To address the concern that inadequate financing could result in further episodes of damage to the public and the environment (especially among nonoperational projects), FERC published a draft Notice of Inquiry in January 2021 seeking input on whether additional measures should be taken to ensure that licensees have the financial resources needed to comply with license terms through the life of the project and to respond to unanticipated events. The Notice of Inquiry requested comment on three options for financial assurance: (1) requiring licensees to obtain bonds, (2) creating an industry-wide fund or requiring licensees to have funds placed in escrow, and (3) requiring licensees to obtain insurance policies to cover costs in the event of a safety hazard. Either of these mechanisms are meant to guarantee sufficient funds for the operation, maintenance, and sufficient environmental and safety measures throughout the duration of the license. FERC held a technical conference in April 2022 to

85 Concrete and foundation erosion in the Oroville Dam main spillway, discovered during a period of record inflows in February of 2017, forced use of the emergency spillway (for the first time in its history). Erosion of the emergency spillway threatened collapse of the concrete weir and triggered an evacuation order for more than 180,000 people living downstream. Ultimately, increased flow over the main spillway lowered the water level enough to eliminate the threat of collapse and lift the evacuation order. Spillway repairs were completed in 2018.

86 Additionally, FERC staff also conduct dam safety inspections, the scope of which has not changed with the new rule.

87 Other additional components of a comprehensive assessment are spillway adequacy analysis; analysis of the potential for internal erosion or piping of embankments, foundations, and abutments; analysis of structural integrity and stability of all structures under credible loading conditions; and any other analyses of record pertaining to geology, seismicity, hydrology, hydraulics, or project safety.

88 The regional engineer may waive the risk analysis requirement of a comprehensive assessment for specific projects.

89 ferc.gov/news-events/news/ferc-terminates-licenses-michigan-hydroelectric-projects.

further discuss potential financial assurance mechanisms.[90] As of June 2023, FERC has not announced whether it will proceed with a final rule on this topic.

Since the 2021 edition of the Hydropower Market Report, seven states have increased their RPS and clean energy mandates or goals. RPSs 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 have adopted energy storage mandates and a few others are considering them. However, most energy storage mandates to date are structured such that they are strongly geared toward short-duration battery storage rather than PSH.

Seven states have increased their renewable portfolio standards or introduced clean energy mandates/goals in 2021–2022.

2021 updates:

- Delaware increased its RPS target from 28% by 2030 to 40% by 2035. Hydropower facilities with a maximum design capacity of <= 30 MW that meet appropriate environmental standards are eligible to meet the RPS objectives.
- Illinois increased its RPS target from 25% by 2026 to 50% by 2040. Hydropower facilities that do not involve the construction of new dams or significant expansion of existing dams are eligible to meet the target.
- Nebraska adopted a 100% carbon-free generation goal in 2050.
- North Carolina increased its clean energy standard target to 100% of electricity sales from carbon neutral generation by 2050 (from 12.5% sales of renewables by 2021).
- Oregon increased its clean energy standard to 100% of electricity sales from carbon-neutral generation sources by 2040.

2022 updates:

- California passed legislation that codifies the goal of 90% clean electricity by 2035.[91]
- Rhode Island passed a law requiring that 100% of the state's electricity must be offset by renewable production by 2033.[92]

With these updates, as of December 2022, 16 states (plus Washington D.C. and Puerto Rico) had 100% clean or renewable energy mandates or goals.[93] Hydropower counts toward compliance in all of them.

In 2021, legislation by Maine and Connecticut expanded the list of states with energy storage mandates (i.e., requirements for utilities to have a specified amount of energy storage capacity in their resource portfolios by a specified deadline) from seven to nine.[94] The other states with energy storage mandates are California, Oregon, New Jersey, New York, Massachusetts, Nevada, and Virginia. Maine added a target of 300 MW by the end of 2025 and 400 MW by 2030; after that, new energy storage goals will be evaluated every two years. Connecticut adopted a target of 300 MW of storage by the end of 2024 and 1,000 MW by 2030. These targets are more geared toward battery installations than long-duration storage such as PSH. Illinois, Vermont, and Michigan are also considering energy storage targets. Additionally, in April 2022, New York increased its energy storage goal from 1,500 MW by 2025 to 6,000 MW by 2030.

90 ferc.gov/news-events/events/technical-conference-financial-assurance-measures-hydroelectric-projects; natlawreview.com/article/ferc-holds-technical-conference-to-consider-financial-assurance-hydropower-projects.

91 utilitydive.com/news/california-sweeping-climate-package-carbon-neutrality-2045-clean-electricity-2035-diablo-canyon.

92 cleantechnica.com/2022/07/01/rhode-island-legislature-commits-to-100-of-states-electricity-from-renewable-sources-by-2033/.

93 The 16 states with 100% clean or renewable energy mandates or goals are California, Colorado, Connecticut, Hawaii, Maine, North Carolina, Nebraska, New Jersey, New Mexico, Nevada, New York, Oregon, Rhode Island, Virginia, Washington, and Wisconsin.

94 utilitydive.com/news/as-states-ramp-up-storage-targets-policy-maneuvering-becomes-key/618218/.

Resources

R.C. Thomas Hydroelectric Project, Polk County, Texas (image courtesy of Simpson Gumpertz & Heger)

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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 2 and Figure ES-2, 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 plant or unit generates continuously at its nameplate capacity.

Conduit – Hydropower project where hydropower 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).

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.

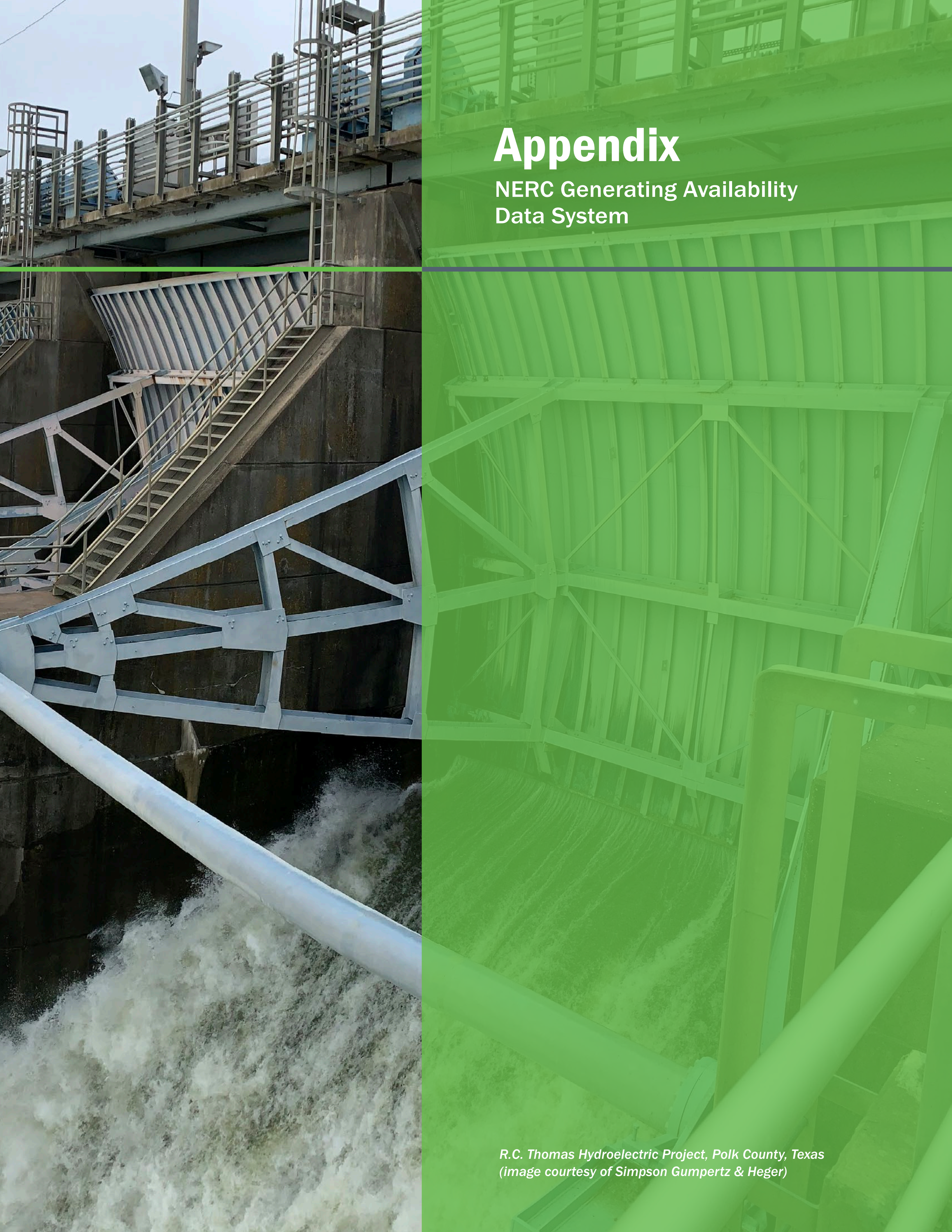
New stream-reach development – Hydropower project where hydropower generation capability is added to previously undeveloped sites and waterways.

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

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

Plant retirement – A plant retires when its owner decides to stop operating all its turbine-generator units. Depending on the cause of the retirement (e.g., accident, safety concerns, economic reasons), the retirement might be temporary or permanent.

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



Appendix

NERC Generating Availability Data System

R.C. Thomas Hydroelectric Project, Polk County, Texas (image courtesy of Simpson Gumpertz & Heger)

Appendix: NERC Generating Availability Data System

The data shown in Figures 42, 43, 45, and 50 refer to the set of plants that report to the NERC GADS each year. The dimension of that set has changed over time as NERC reporting requirements change. NERC GADS started in 1982, but reporting was voluntary until 2011. It then became mandatory for units greater than 50 MW in 2012 and for units greater than 20 MW in 2013. Despite the requirements, the set of utilities reporting after 2013 changes somewhat year to year. Figures A-1 and A-2 show the percentage of installed units covered by GADS data, accessed through pc-GAR, each year by unit size segment, unit type (hydropower versus PSH), and the various NERC region groupings considered in Figure 43. The denominator used to compute the percentages is total number of units in each of the fleet segments of interest from the EHA dataset.

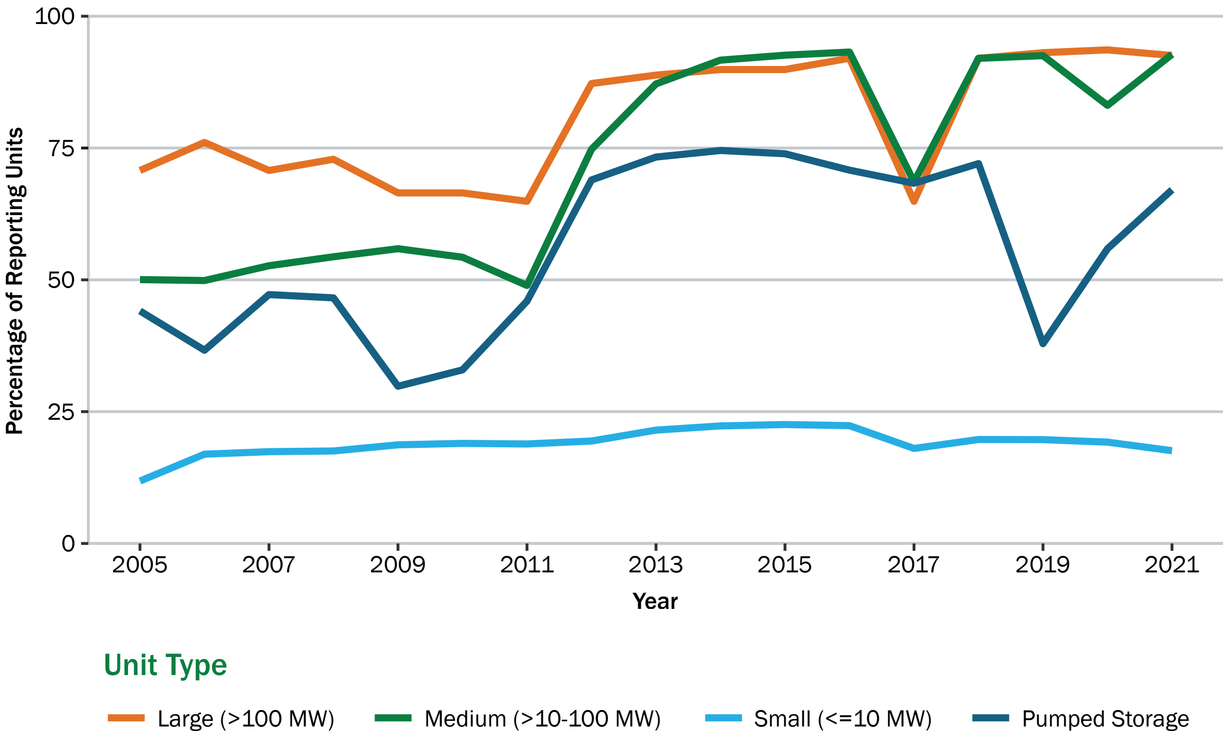


Figure A1. Percentage of units reporting to NERC GADS by type and size

Source: NERC pc-GAR, ORNL EHA Unit database 2023.

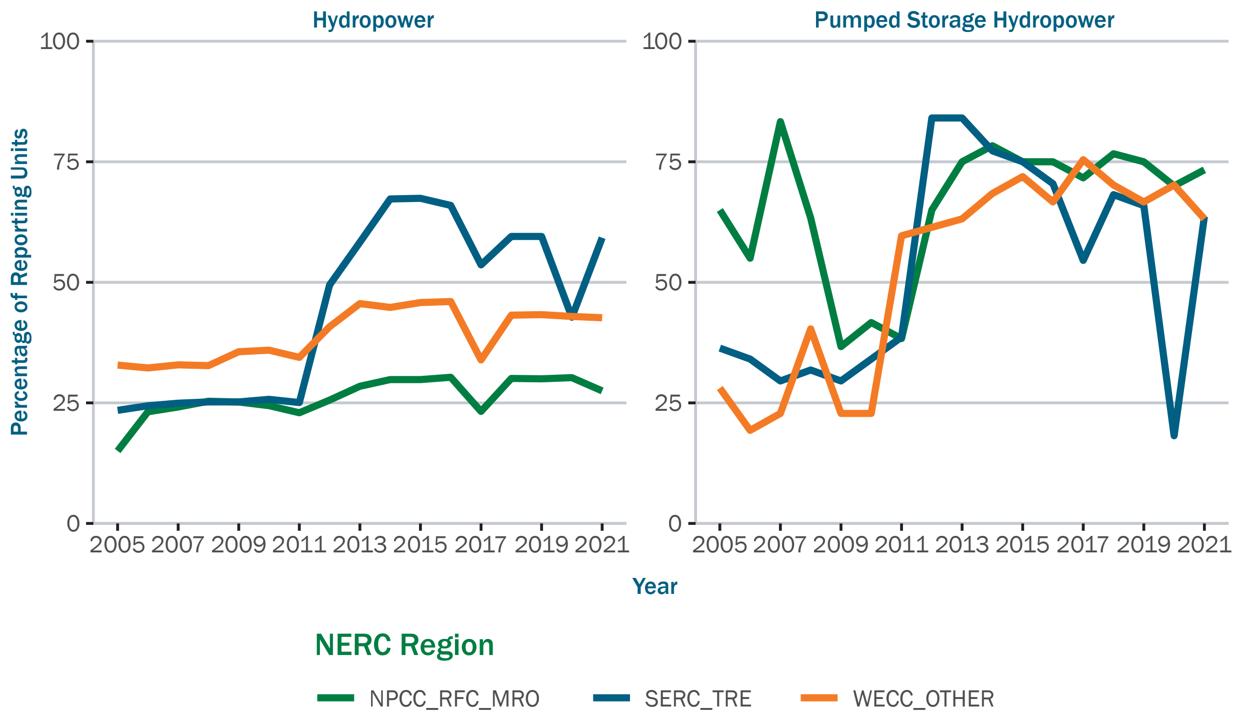


Figure A2. Percentage of units reporting to NERC GADS by type and regional grouping

Source: NERC pc-GAR, ORNL EHA Unit database 2023.

In line with NERC's evolving reporting requirements, Figures A-1 and A-2 show large increases in the percentage of large and medium units (hydropower and PSH) included in the data from 2011 on. 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 from the SERC-TRE regional grouping in 2019). Coverage of small hydropower units is much lower, less than 25%. Therefore, statements about that fleet segment in Figure 42 and Figure 50 carry less weight than those for the other unit size segments.

All the performance metrics from NERC GADS that can be accessed via the pc-GAR software are anonymized. PSH units were identified as those with nonzero pumping hours in a year. This query approach can lead to some misclassifications (e.g., PSH units that had zero pumping hours because of being out of service). However, the number of misclassified units is small and should not affect the results for the large or medium hydropower unit samples (89% of U.S. PSH units have power ratings of 10 MW or more and, if misclassified, would go into one of those two segments).

Table A1. Balancing authorities with 300 MW or more of installed hydropower and PSH capacity

BA Acronym	BA Name	NERC Region
AVA	Avista Corporation	WECC
BPAT	Bonneville Power Administration Transmission	WECC
CHPD	Public Utility District No. 1 of Chelan County	WECC
CISO	California Independent System Operator	WECC
CPLE	Duke Energy Progress East	SERC
DOPD	Public Utility District No. 1 of Douglas County	WECC
DUK	Duke Energy Carolinas	SERC
ERCO	Electric Reliability Council of Texas, Inc.	TRE
GCPD	Public Utility District No. 2 of Grant County, Washington	WECC
IPCO	Idaho Power Company	WECC
ISNE	ISO New England	NPCC
LDWP	Los Angeles Department of Water and Power	WECC
LGEE	Louisville Gas and Electric Company and Kentucky Utilities Company	SERC
MISO	Midcontinent Independent System Operator, Inc.	MRO
NYIS	New York Independent System Operator	NPCC
NWMT	NorthWestern Corporation	WECC
PACE	PacifiCorp East	WECC
PACW	PacifiCorp West	WECC
PGE	Portland General Electric Company	WECC
PJM	PJM Interconnection, LLC	RFC
PSCO	Public Service Company of Colorado	WECC
SC	South Carolina Public Service Authority	SERC
SCEG	South Carolina Electric & Gas Company	SERC
SCL	Seattle City Light	WECC
SEPA	Southeastern Power Administration	SERC
SOCO	Southern Company Services, Inc.–Trans	SERC
SPA	Southwestern Power Administration	MRO
SRP	Salt River Project Agricultural Improvement and Power District	WECC
SWPP	Southwest Power Pool	MRO
TIDC	Turlock Irrigation District	WECC
TPWR	City of Tacoma, Department of Public Utilities, Light Division	WECC
TVA	Tennessee Valley Authority	SERC
WALC	Western Area Power Administration–Desert Southwest Region	WECC
WAUW	Western Area Power Administration–Upper Great Plains West	WECC
WACM	Western Area Power Administration–Rocky Mountain Region	WECC
YAD	Alcoa Power Generating, Inc.–Yadkin Division	SERC

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Back Cover Image

R.C. Thomas Hydroelectric Project, Polk County, Texas
(image courtesy of Simpson Gumpertz & Heger).

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