U.S. Hydropower Market Report (2023 edition)

Introduction

- This is the fourth complete edition of the U.S. Hydropower Market Report. The report (and previous editions) are available at: https://www.energy.gov/eere/water/hydropower-market-reports.
- A data workbook containing the data shown in the report plots is available at https://hydrosource.ornl.gov/datasets
- This edition focuses on updated data from 2020–2022 (the years for which data has become available since the publication of the last full report) and contextualizes this information compared to evolving high-level trends over the past 10–20 years.
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Outline

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- **Chapter 2.** U.S. Hydropower and PSH Development Pipeline
- **Chapter 3.** U.S. Hydropower and PSH in the Global Context
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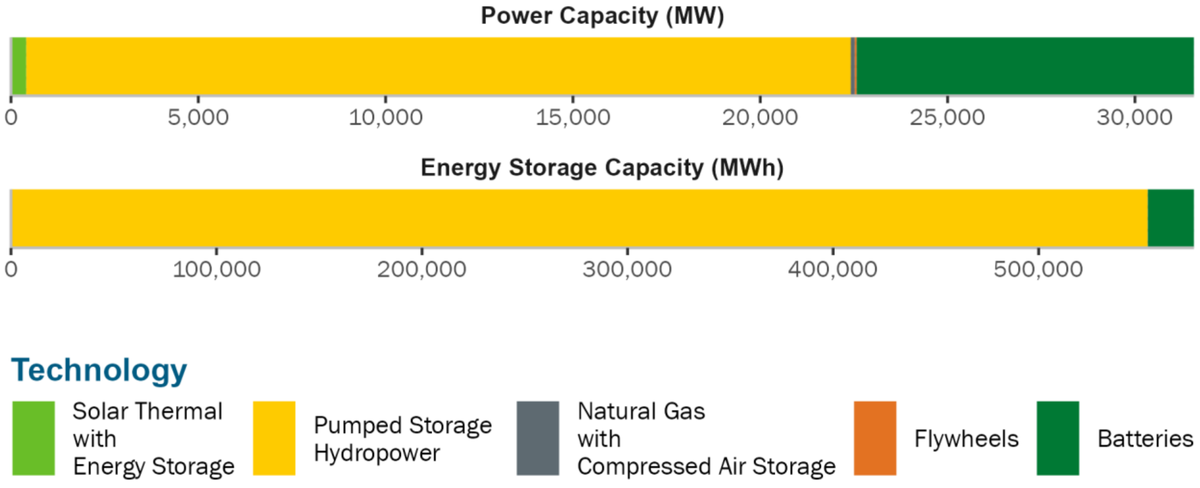
Summary metrics describing U.S. hydropower and pumped storage hydropower (PSH) fleet capabilities in 2022

- The U.S. hydropower fleet includes 2,252 plants with a total generating capacity of 80.92 GW.
  - It produced 28.7% of electricity from renewables and 6.2% of all electricity in 2022.
    - Renewable electricity share is progressively declining because of faster growth of wind and solar capacities.
    - Total electricity share ranged 6%–8% in the past two decades depending on hydrologic conditions.

- The U.S. PSH fleet has 43 plants with a combined capacity of 22 GW and an estimated energy storage capacity of 553 GWh.
  - It accounted for 70% of utility-scale power storage capacity (GW) and 96% of utility-scale energy storage capacity (GWh) in 2022.
    - Substantial drop in share of power storage capacity relative to 2019 (93%) due to very rapid growth in utility-scale battery installations in the 2020s.
    - Much slower decrease in energy storage capacity because the typical storage duration for PSH plant is longer than for batteries.

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

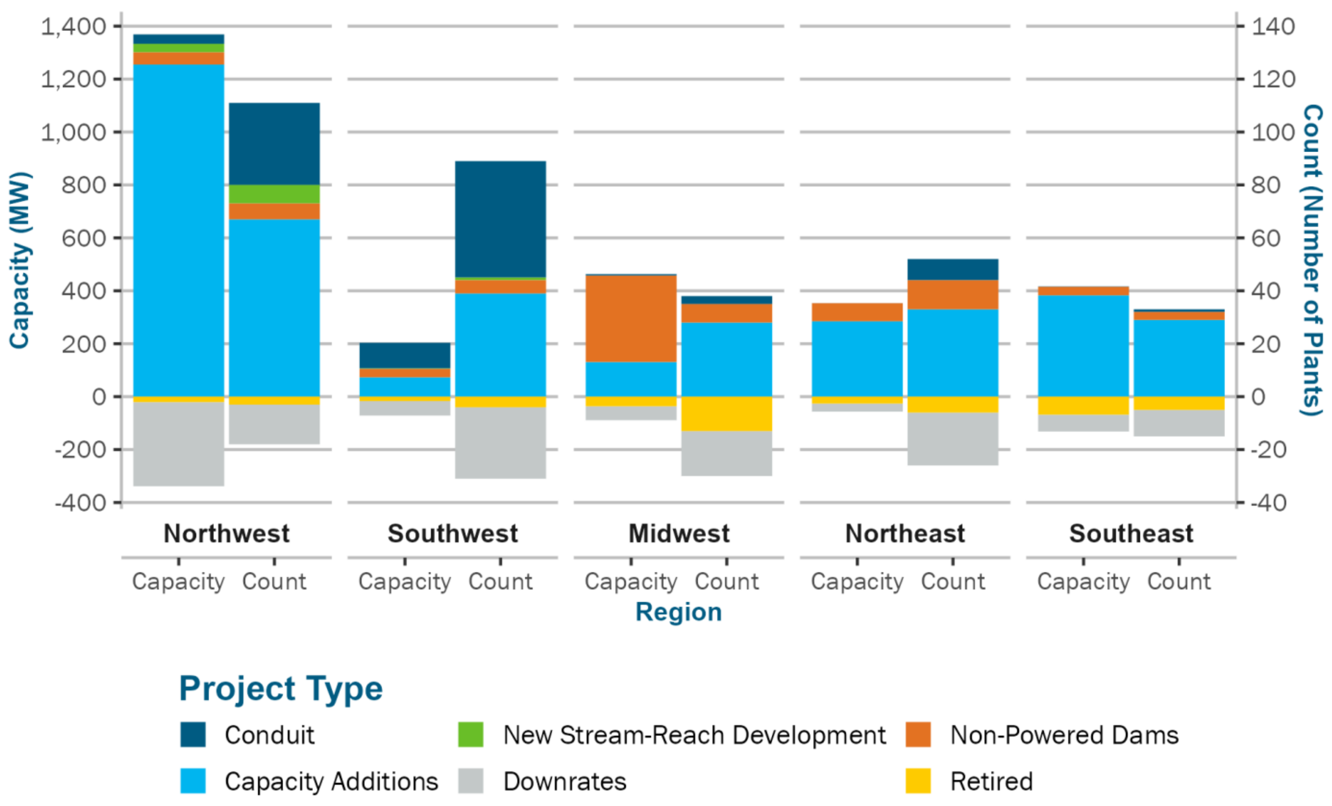


Sources: Energy Information Administration (EIA) Form 860 Early Release (2022)

Chapter 1: An Overview of Changes Across the U.S. Hydropower and PSH Fleet (2010–2022)

The net increase in U.S. hydropower capacity from 2010 to 2022 was 2.1 GW from a combination of upgrades to existing plants (1.6 GW), new projects (0.7 GW), and retirements (-0.2 GW); PSH capacity increased by 1.4 GW of which 97% resulted from upgrades to the existing fleet.

Hydropower capacity changes by region and type



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

- New project construction included:
  - 32 non-powered dam projects (505 MW; of which 65% is in the Midwest)
  - 89 conduit projects (140 MW; of which 69% is in the Southwest)
  - 8 new stream-reach developments (34 MW; of which 94% is in the Northwest)
- For the 155 plants with capacity additions, the median capacity increase is 15%.
- To date, the pace of capacity increases in the 2020s has slowed down relative to the previous decade.
  - Partly explained by COVID-19 restrictions and supply chain challenges

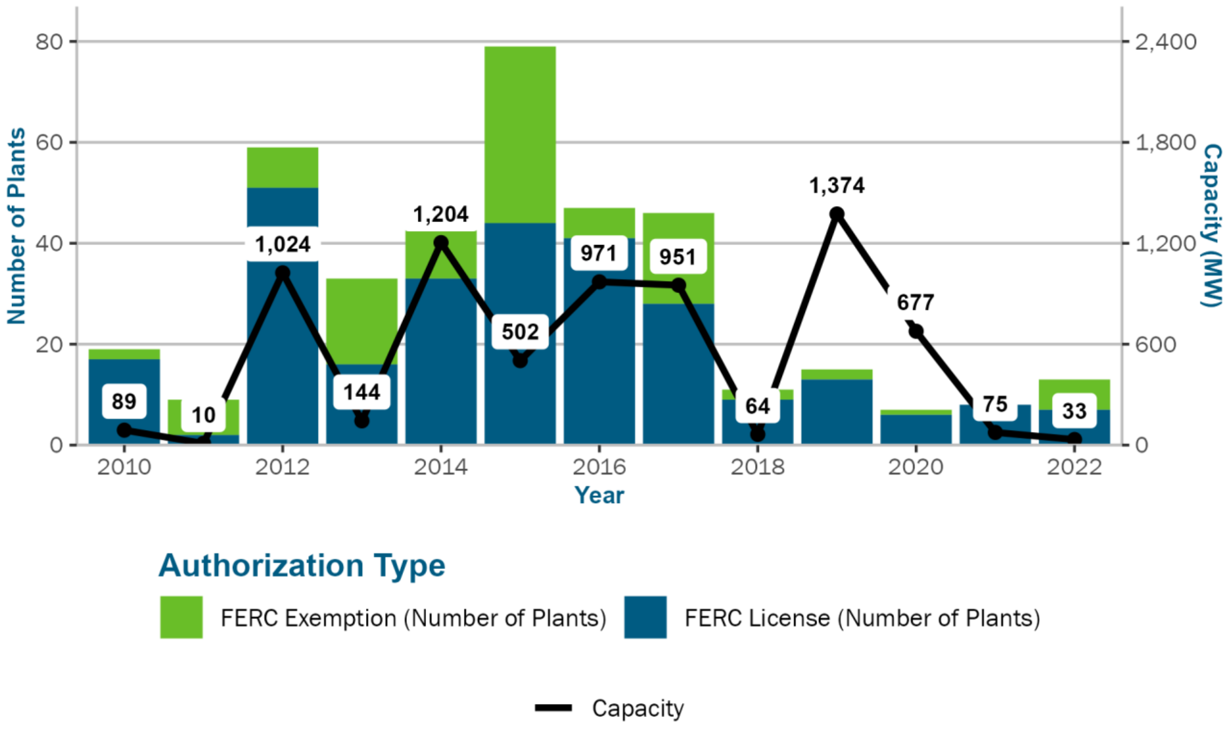
	Annual average (2010–2019)	Annual average (2020–2022)
Capacity additions to existing fleet	193 MW	66 MW
Capacity from new facilities	60 MW	26 MW

Aside: Hybrid plant configurations

- Understanding the evolution of the capabilities of the U.S. hydropower fleet will increasingly require tracking the adoption of hybrid configurations.
  - Lawrence Berkely Lab publishes a dataset of active and proposed U.S. hybrid plants.
- Hybrid plants: *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 co-located but also co-controlled* (Bolinger et al., 2022).
- Pairings of hydropower and battery storage are being adopted with increased frequency in recent years.
  - Five active hybrid plants of this type at the end of 2021 (the storage duration of the batteries is <= 1 hour in all of them):
    - 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),
    - one in Maine (Great Lakes Hydro with 138 MW of hydropower and a 20-MW battery system)
  - Plans to add battery capacity to six active hydropower plants have been entered into grid interconnection queues.
    - four in Maine and two in Nevada

From 2010 to 2022, 384 hydropower plants with a combined capacity of 3.8 GW and 5 PSH plants (3.3 GW) changed ownership through 319 license and exemption transfers.

Hydropower and PSH ownership transfers by year and authorization type

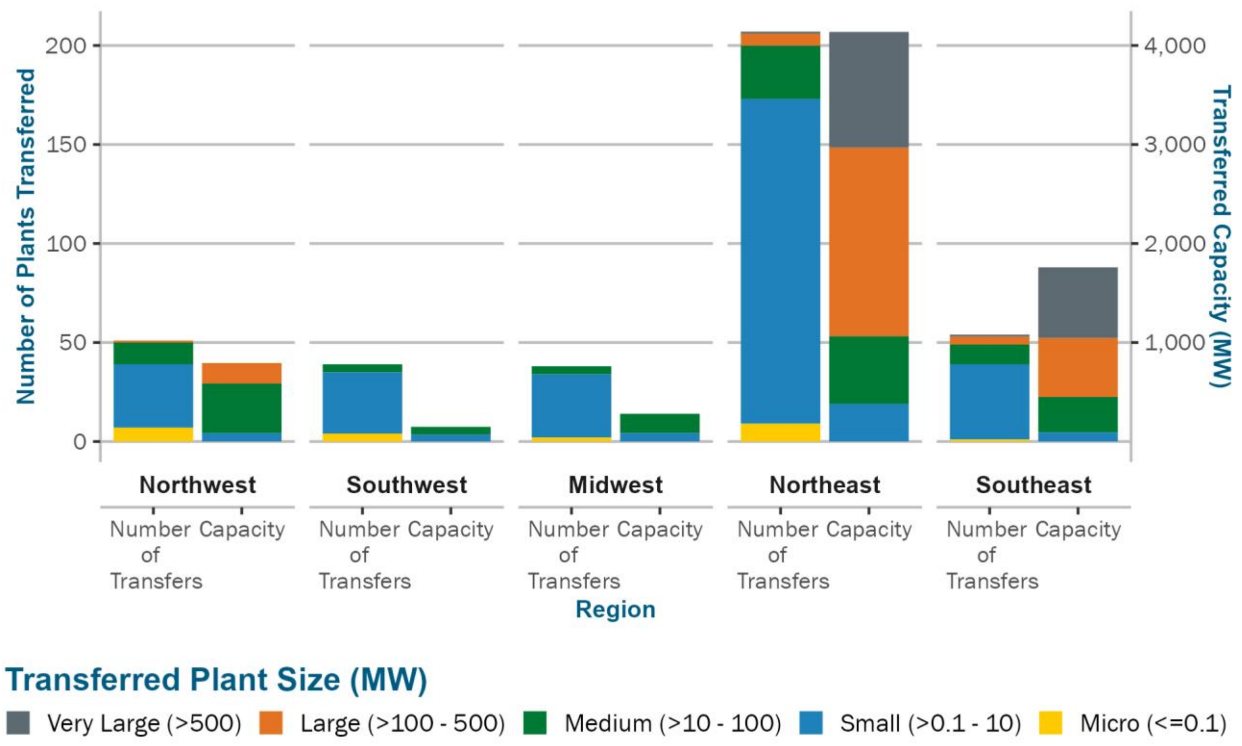


Sources: FERC eLibrary, ORNL EHA Plant database 2023

- Since 2018, less than 20 hydropower plants were transferred each year; the average number of plants transferred in 2012–2017 was 51 per year.
- License/exemption transfers by transferor and transferee type (public or private):
  - Private to Private: 300 plants (6.9 GW)
  - Private to Public: 12 plants (70 MW)
  - Public to Private: 4 plants (71 MW)
  - Public to Public: 3 (5 MW)
- In 2020–2022, 27 hydropower plants (333 MW) and 1 PSH plant (453 MW) have changed ownership.
  - City of Danville (VA) transferred three hydropower plants to two limited liability companies (LLCs).
  - Sappi North America transferred four hydropower plants to two LLCs.
  - Pacific Gas & Electric transferred one plant to the Sacramento Municipal Utility District and two plants damaged by natural hazards to private companies that plan to repair them.

Eighty-four percent of the plants transferred are small, but they account for only 10% of transferred capacity; more than half of the plants transferred are in the Northeast.

Hydropower and PSH ownership transfers by region and plant size category

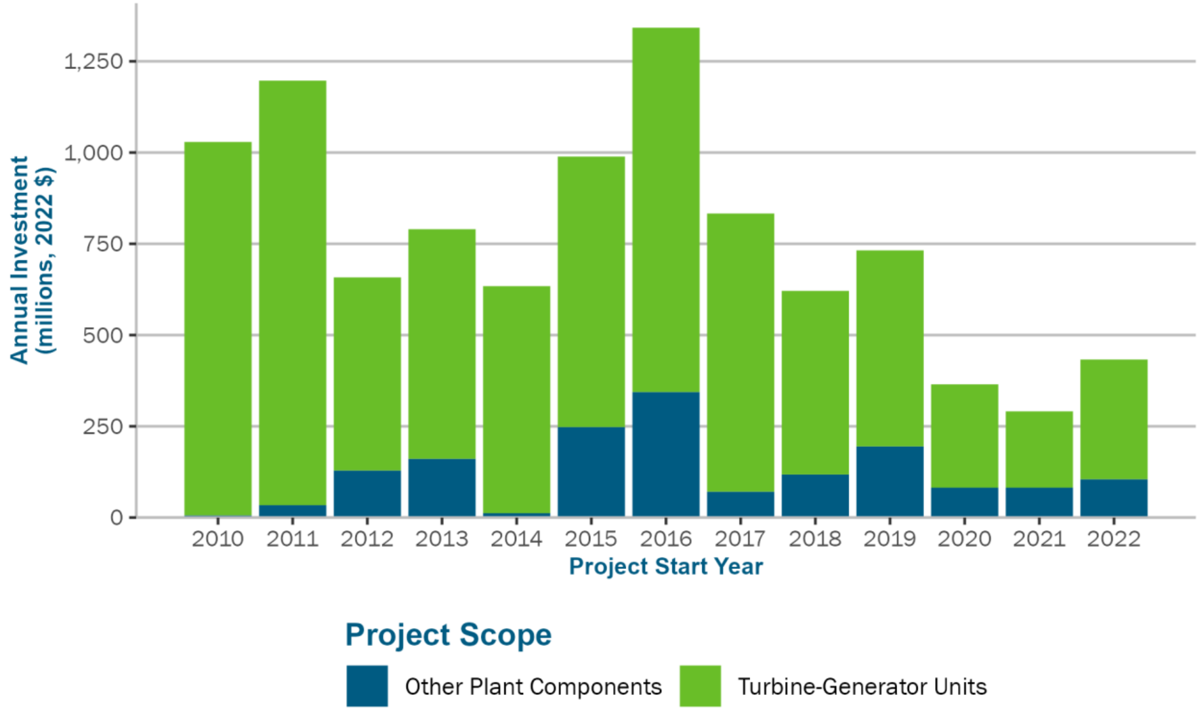


Sources: FERC eLibrary, ORNL EHA Plant database 2023

- Regional distribution of plant transfers:
  - Northwest: 51 (793 MW)
  - Southwest: 39 (149 MW)
  - Midwest: 38 (280 MW)
  - Northeast: 207 (4,137 MW)
  - Southeast: 54 (1,760 MW)
- Plant transfers by size category:
  - Micro: 23 (0.88 MW)
  - Small: 297 (708 MW)
  - Medium: 56 (1,817 MW)
  - Large: 11 (2,710 MW)
  - Very Large: 2 (1,881 MW)
    - The only two plants in this category are both PSH: Northfield Mountain (MA) and Bath County (VA)

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.

Expenditures on refurbishments and upgrades of the existing hydropower and PSH fleet by project scope

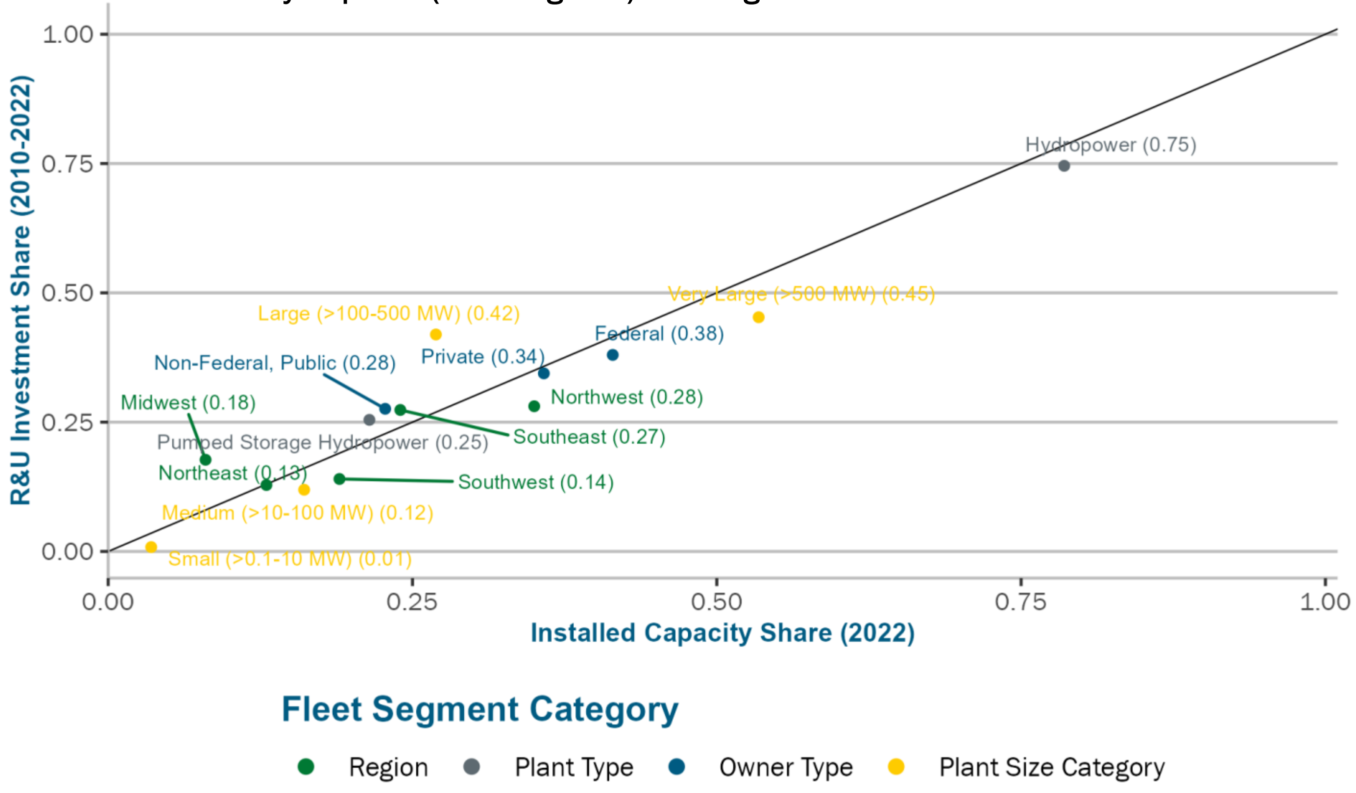


Sources: Industrial Info Resources (IIR)

- Since 2010, at least 168 hydropower plants and 16 PSH plants have undergone refurbishments and upgrades (R&U) with project values greater than one million dollars.
- Investment initiated from 2010 to 2022 totaled $9.9 billion (in 2022 dollars).
- Almost 85% of the R&U investment went to projects focused on turbine and/or generator components (e.g., turbine runner replacements, generator rewinds).
  - The rest involve other mechanical (e.g., gates, penstocks, cranes) or electrical (transformers, switchgear) components.
- The COVID-19 pandemic and related supply chain challenges may explain some of the drop in investment in the first years of the 2020s.
- Incentive payments from the Bipartisan Infrastructure Law are expected to stimulate hydropower R&U investment in coming years.

The hydropower and PSH fleets in the Northwest and Southwest regions have received a significantly lower share of R&U investment in 2010–2022 than the share of U.S installed capacity they represent.

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



Sources: IIR, ORNL EHA Plant database 2023

- There are significant differences between regional distribution of installed capacity and regional share of 2010–2022 investment.
  - Midwest: 18% of R&U investment; 8% of capacity
  - Northwest: 28% of R&U investment; 36% of capacity
  - Southwest: 14% of R&U investment; 19% of capacity
- Average R&U investment per kilowatt of installed capacity was higher for PSH ($115/kW) than for conventional hydropower plants ($91/kW).
- Non-federal, public entities (e.g., state agencies, municipalities, cooperatives) are the owner type with the highest average R&U investment per kW installed; the lowest investment per kW was for the federal fleet.
  - However, for R&U projects initiated since 2020, the federal fleet received the highest share (56%).

For the 121 relicenses issued from 2010 to 2022, the median duration of the process was 5.8 years. However, there is a wide range of durations.

Relicensing process FERC filing deadlines

5.5–5YEARS BEFORE EXPIRATION: TIME WINDOW TO SUBMIT ***NOTICE OF INTENT (NOI) TO RELICENSE***

2 YEARS BEFORE EXPIRATION DATE: DEADLINE TO SUBMIT ***FINAL APPLICATION FOR NEW LICENSE***

EXPIRATION DATE OF EXISTING LICENSE

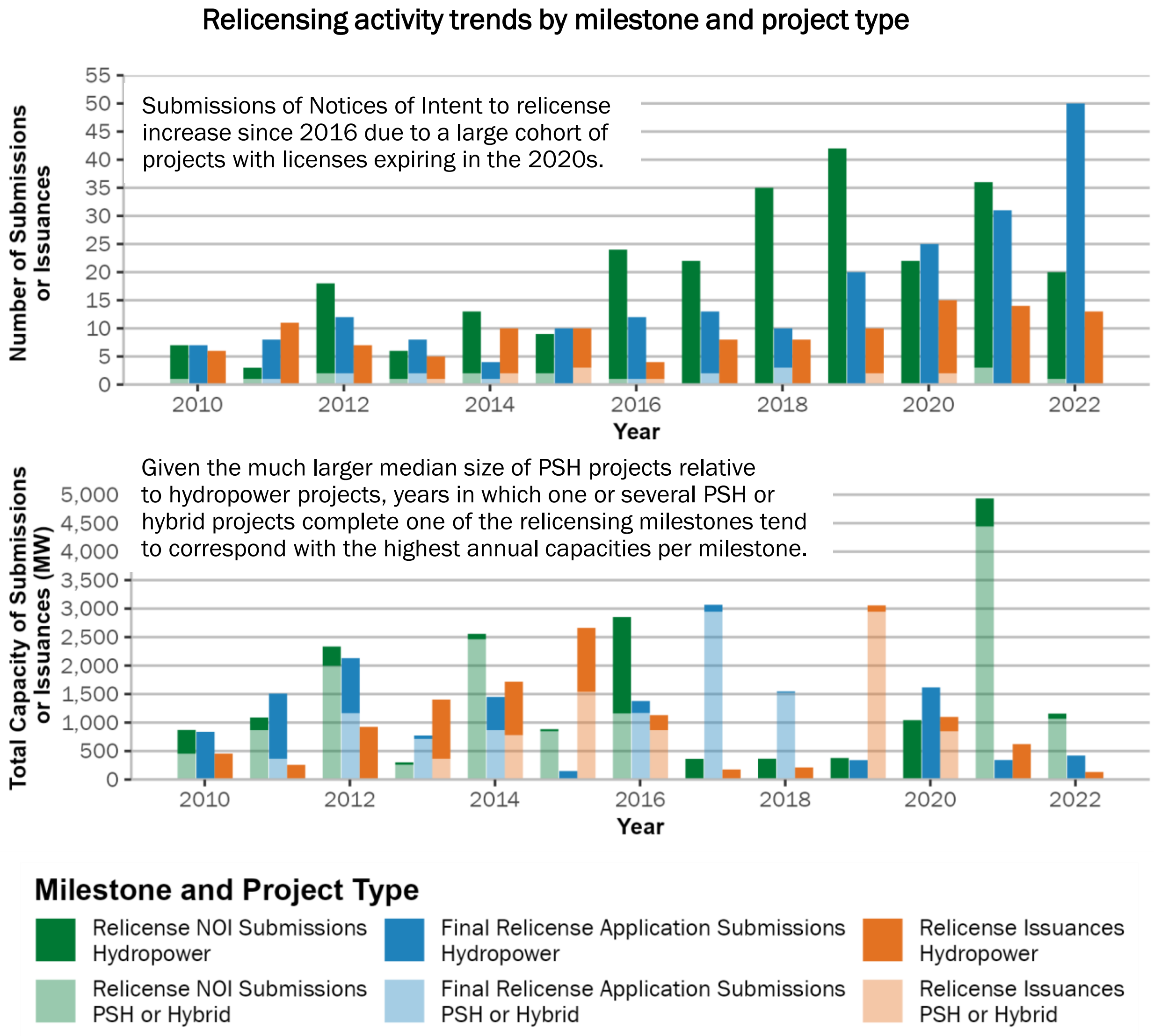
Relicensing process stages

PRE-FILING STAGE:
From NOI submission to final relicense application submission

POST-FILING STAGE:
From relicense application submission to relicense issuance
- If post-filing stage has not concluded by the expiration date of the existing license, FERC grants annual license extensions to allow continued project operation.

- The 10% of projects with the shortest relicensing durations completed the process in 4.7 years or less.
- The 10% of projects with the longest relicensing durations completed the process in 12 years or more.
- Environmental complexity can be a key factor in influencing relicensing timelines (Levine et al., 2021).
- Duration of the post-filing stage is much more variable than duration of the pre-filing stage.
  - 28 projects had post-filing durations of less than 2 years: 20 of the 28 used the Integrated Licensing Process; 16 of the 28 had authorized capacities of less than 10 MW.
  - 26 projects had post-filing durations of more than 5 years: 19 of the 26 used the Traditional Licensing Process.
  - Higher prevalence of peaking plants and use of settlements among projects with long post-filing durations than projects with post-filing durations of less than 2 years.
- For 15 of the 121 issued relicenses, the capacity authorized in the relicense is higher than in the previous license.

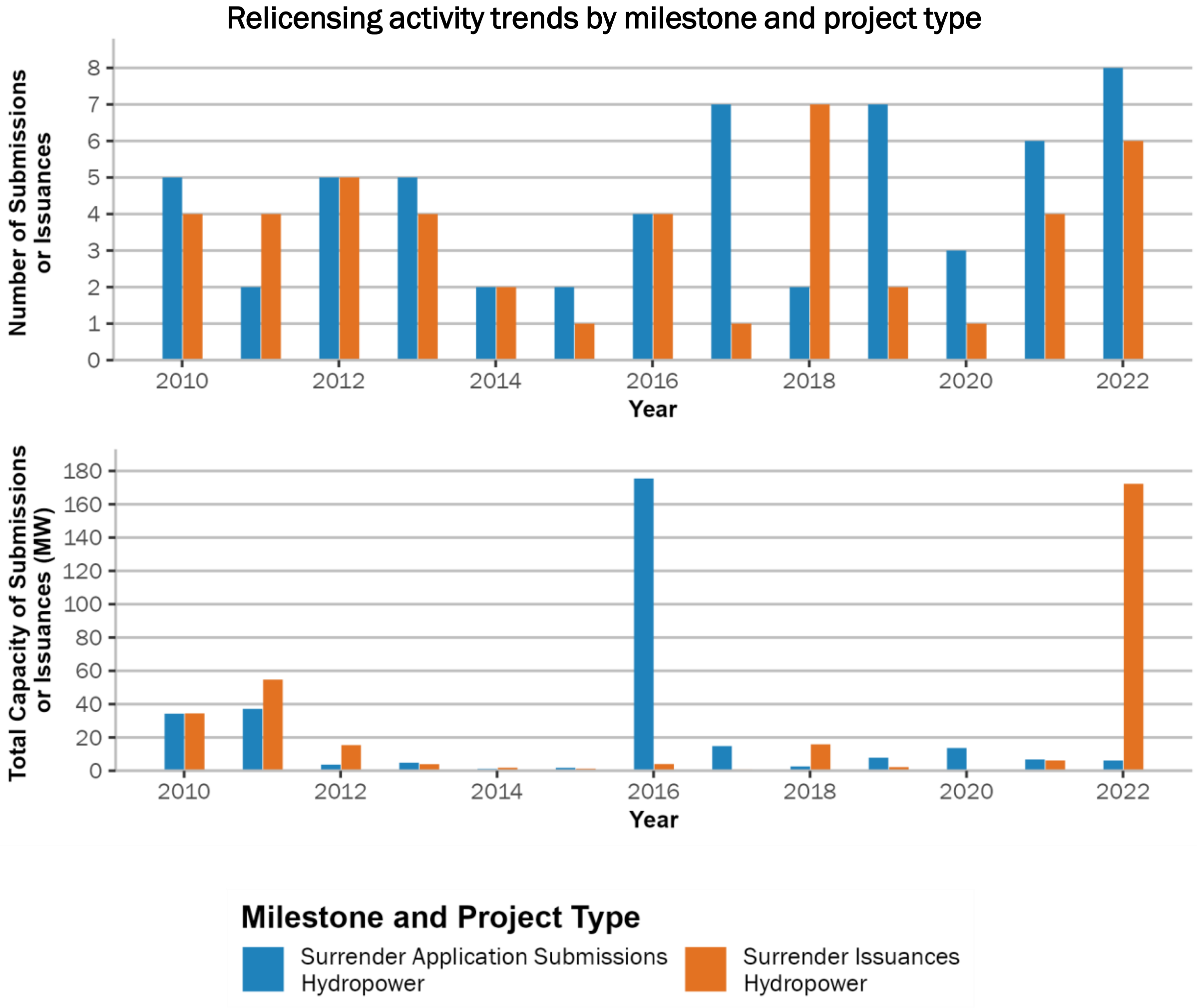
Virtually all capacity due to enter the relicensing pipeline from 2018 to 2022 has done so.



Sources: FERC, ORNL EHA Plant database 2023.

- Of the 167 hydropower and PSH projects due to start relicensing from 2018 to 2022, 155 of them did (8 GW, 99.9% of to-be-relicensed capacity).
  - Licensees for 7 small projects totaling 7 MW notified FERC of their intention to surrender the license instead of renewing it.
- The number of relicense application submissions from 2018 to 2022 (136) is more than double the number of relicenses issued during that same period (60) → increase in the number of pending relicenses.
- At the end of 2022, there were:
  - 136 projects (132 hydropower + 1 PSH + 3 hybrids) in relicensing post-filing stage: 10.9 GW
    - More than 50% were in the Northeast region, but they represented 21% of capacity.
  - 74 projects (70 hydropower + 4 PSH) in relicensing pre-filing stage: 6.5 GW
    - 57% were in the Northeast region, but the Southeast accounted for 70% of the capacity because 3 of the 4 PSH projects are there.

FERC issued 68 license or exemption surrenders and terminations in 2010–2022, with a combined capacity of 322 MW. At the end of 2022, 18 projects (34 MW) had pending surrender applications.



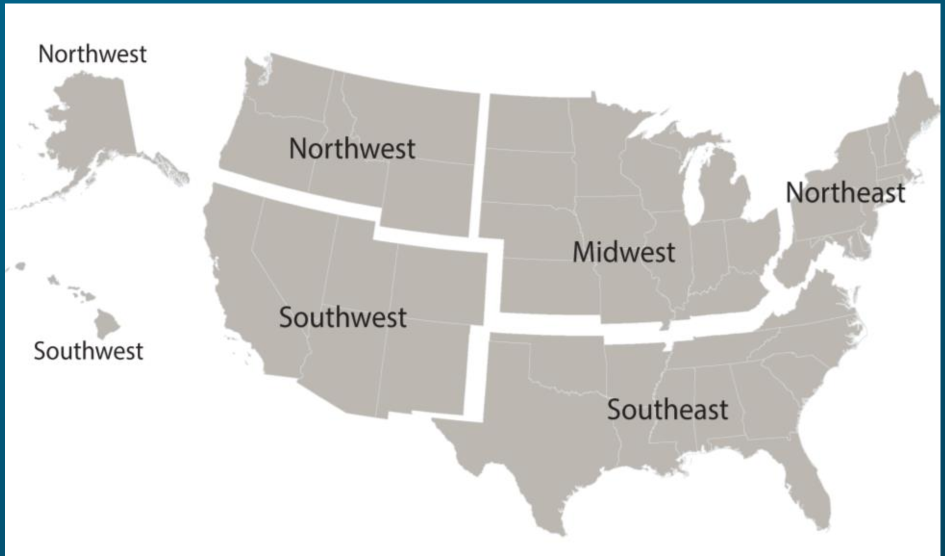
Sources: FERC, ORNL EHA Plant database 2023

- Surrenders/terminations revoke the authorization to generate power.
- The median capacity of the licenses surrendered was 0.5 MW; six surrendered licenses had capacities > 10 MW.
  - By far the largest surrendered license is the Klamath project in California (169 MW).
- Sixteen of the licenses surrendered involve the removal of a dam.
- Lack of economic feasibility or a decision to pursue restoration of aquatic ecosystems are the two reasons most commonly cited for surrendering a license.
- The median length of the surrender process (from surrender application submission to surrender issuance) was 0.8 years.
  - There were 5 surrenders with process durations longer than 3 years and 5 with durations of less than 100 days.

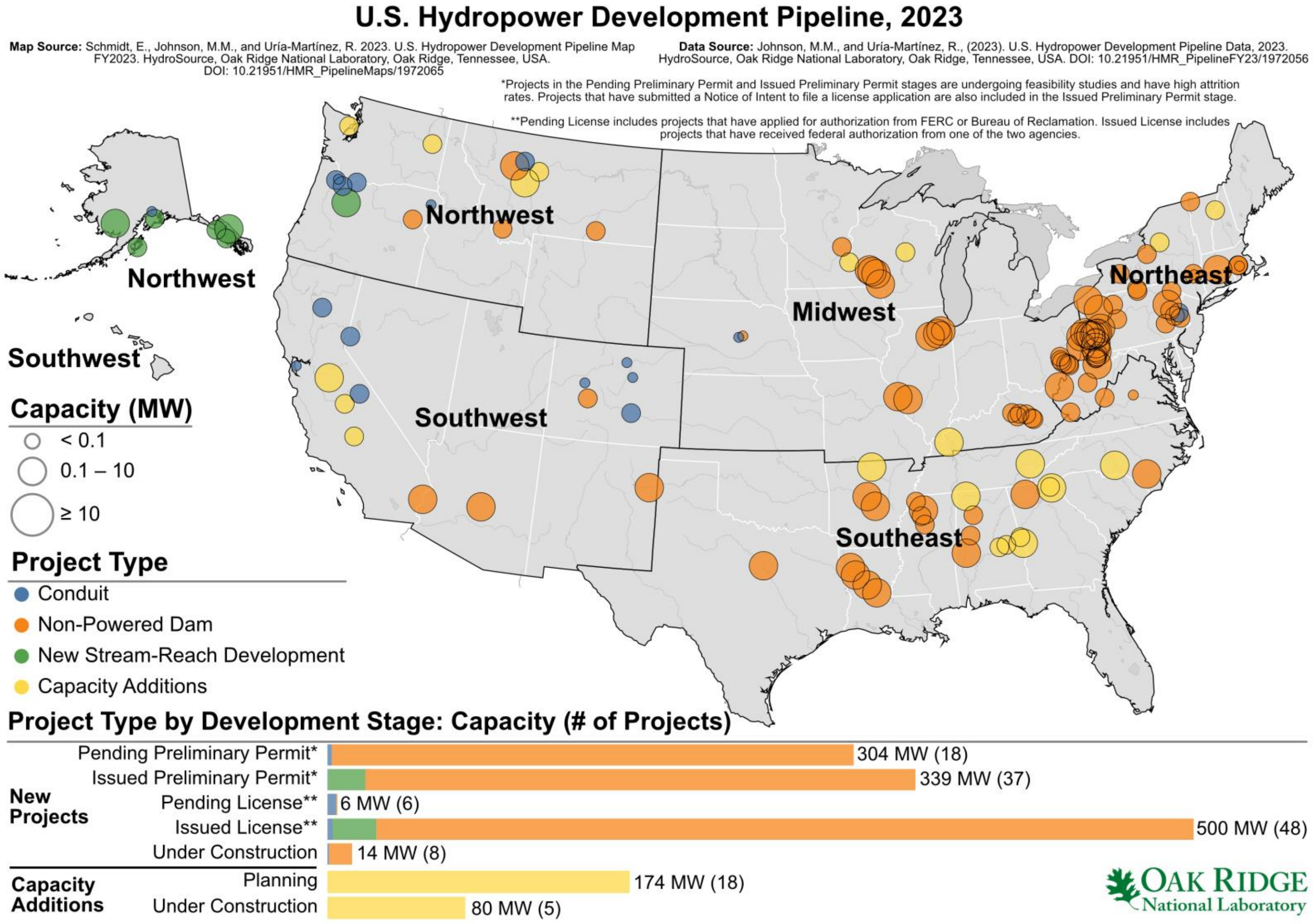
Chapter 2: U.S. Hydropower and PSH Development Pipeline

2.1 U.S. Hydropower Development Pipeline
2.2 U.S. PSH Development Pipeline
2.3 U.S. Hydropower and PSH Project Sizes and Developer Types
2.4 Permitting Activity Trends

U.S. Hydropower Market Report Regions



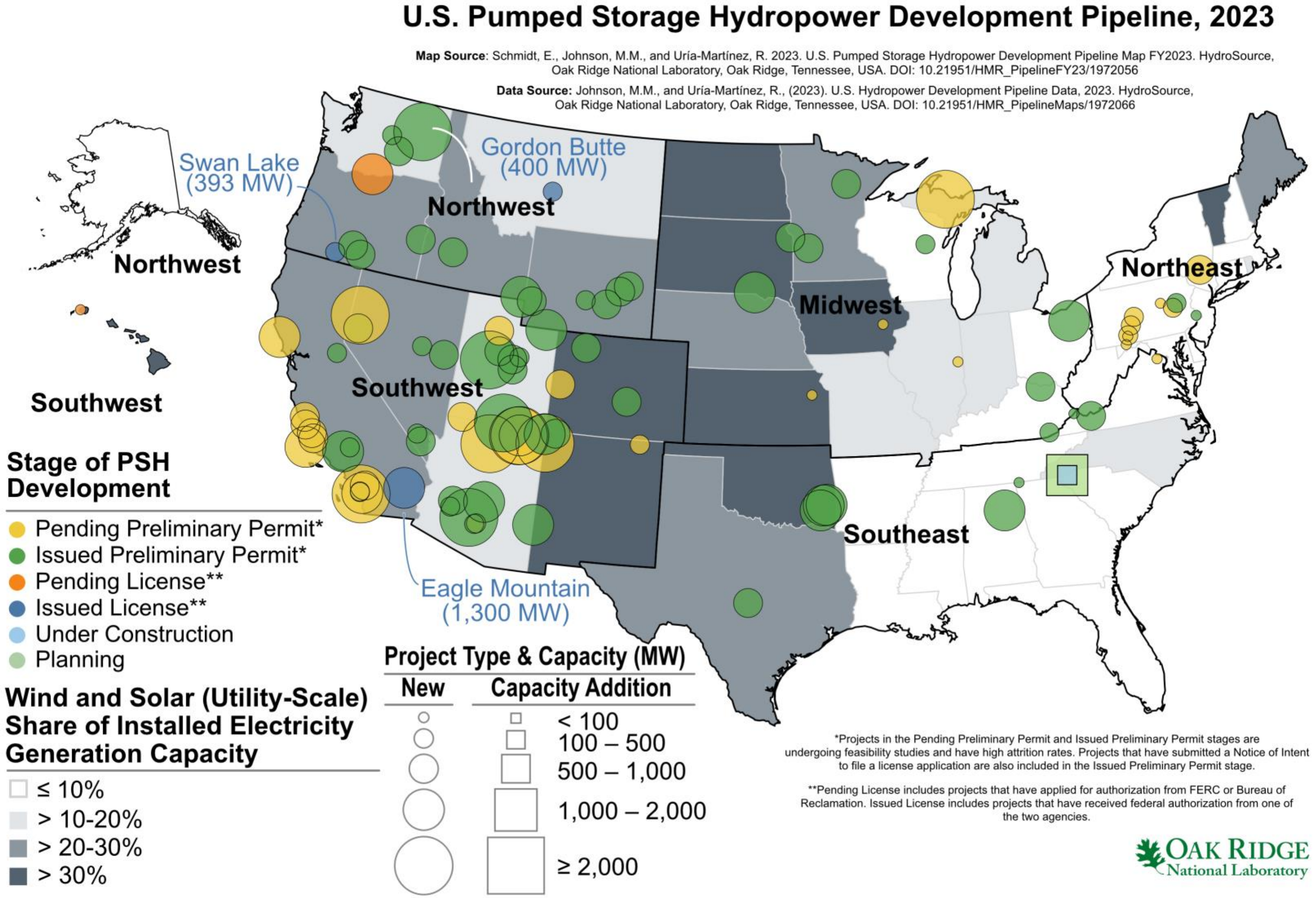
At the end of 2022, there were 117 hydropower projects (1.2 GW) in the development pipeline; additionally, 23 existing projects looking to increase the capacity of the fleet by 254 MW.



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

- Non-powered dam (NPD) retrofits account for 95% of the proposed new capacity.
- The seven new stream-reach developments (NSD) proposed are all in the Northwest.
  - Only one would involve building an impoundment dam.
- Almost half of the projects in the pipeline (56) have already received federal authorization; eight of them have reached the construction stage.
- Most (20) of the capacity additions result from upgrades to existing turbine-generator units.
  - Of the three capacity additions resulting from new units, two seek generating power from mandatory environmental flows.

Ninety-six PSH projects were on the development pipeline at the end of 2022 with a combined storage power capacity of 89 GW; capacity additions for 1.9 GW are also in planning or construction.



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

- The Northwest and Southwest regions have the highest concentrations of PSH project proposals.
- The share of utility-scale variable renewables (wind + solar) has limited use as a predictor of where the highest concentrations of PSH projects are found.
  - Siting decisions are highly dependent on topographic conditions.
  - Recent closed-loop hydropower resource assessment showed that the areas with the highest density of suitable sites are the Rocky Mountains, the Cascade Range, and the Alaska Range (Rosenlieb et al., 2022),

Ten of the proposed PSH projects (all in the West) have moved beyond the feasibility evaluation stage. Three of them are already licensed but none have reached construction stage.

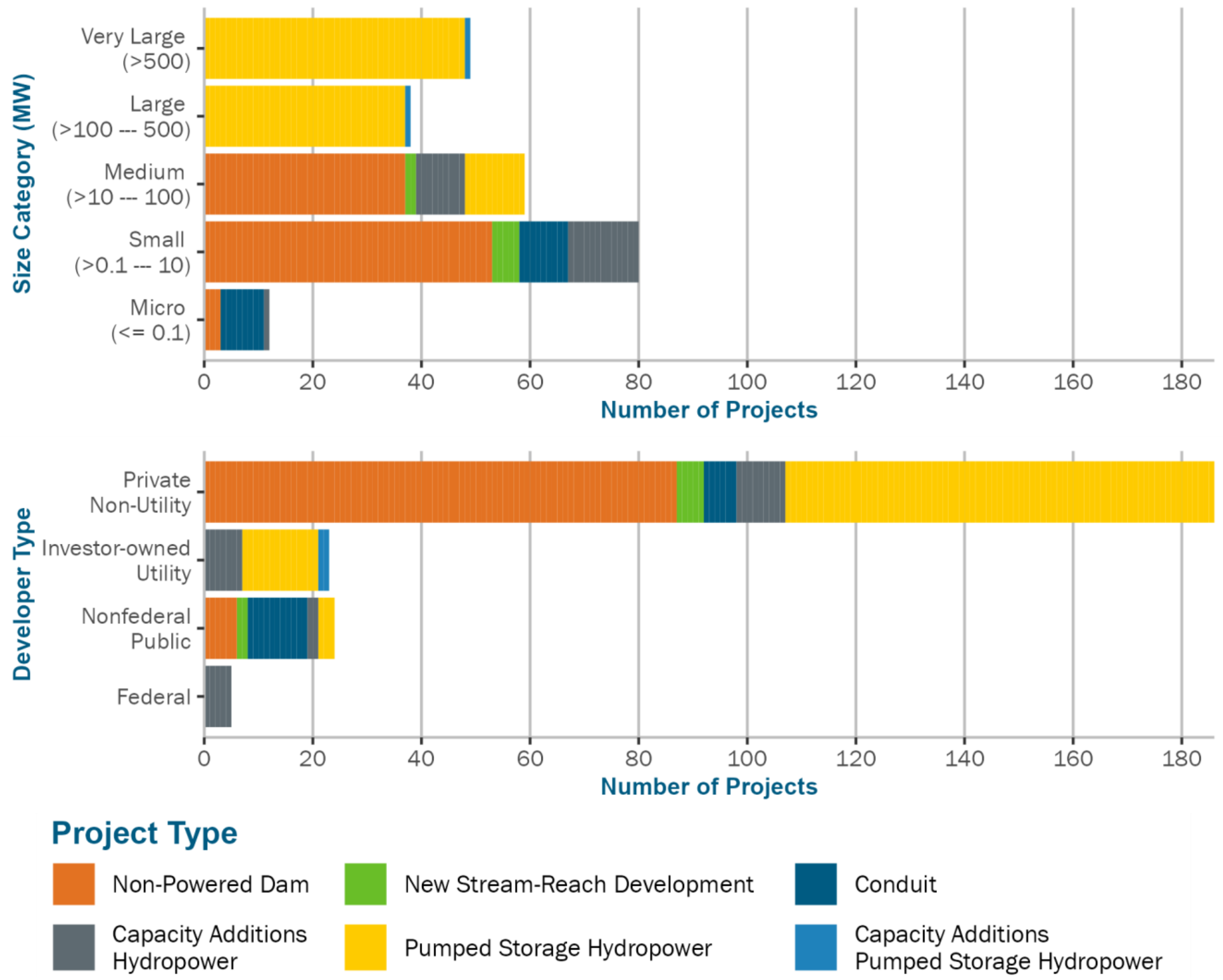
FERC docket	Project Name	Capacity (MW)	State	Configuration	Status (as of 12/31/2022)
P-13123	Eagle Mountain	1,300	CA	Closed-Loop	Issued License
P-13642	Gordon Butte	400	MT	Closed-Loop	Issued License
P-13318	Swan Lake	393	OR	Closed-Loop	Issued License
P-14861	Goldendale	1,200	WA	Closed-Loop	Pending License
NA	West Kaua'i	24	HI	Closed-Loop	Pending Authorization
P-14804	Blue Diamond	450	NV	Closed-Loop	Submitted NOI to file final license application
P-14655	Cat Creek	720	ID	Open-Loop	Submitted NOI to file final license application
P-14851	White Pine	500	NV	Closed-Loop	Submitted NOI to file final license application
P-14796	Mokelumne	400	CA	Open-Loop	Submitted NOI to file final license application
P-14787	Seminoe	700	WY	Open-Loop	Submitted NOI to file final license application

More than 80% of the proposed PSH projects have closed-loop configurations. The range of generation capacities proposed is very wide (17 MW–9,000 MW) and typical storage durations would be 8–12 hours.

- None of the existing U.S. PSH plants are closed-loop, but most of the proposed new PSH projects are.
  - Advantages of closed-loop configuration:
    - Greater siting flexibility
    - Typically lower overall environmental impacts (Saulsbury, 2020)
  - Potential challenges of closed-loop configuration:
    - Securing water permits for initial fill and subsequent make-up of water losses due to evaporation and seepage
    - Can be more expensive (if it involves construction of the two reservoirs)
- Some PSH developers are exploring ultra-long duration energy storage configurations (storage durations of days or weeks instead of hours).
- Several developers include hybrid features in their PSH project descriptions (e.g., construction of solar panel arrays as source of pumping power; installation of floating solar PV panels on reservoirs to reduce evaporation water losses).

Except for PSH and some capacity upgrades, there are no Large (>100 MW) projects in the pipeline. The most active type of developer for new projects are private non-utilities.

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

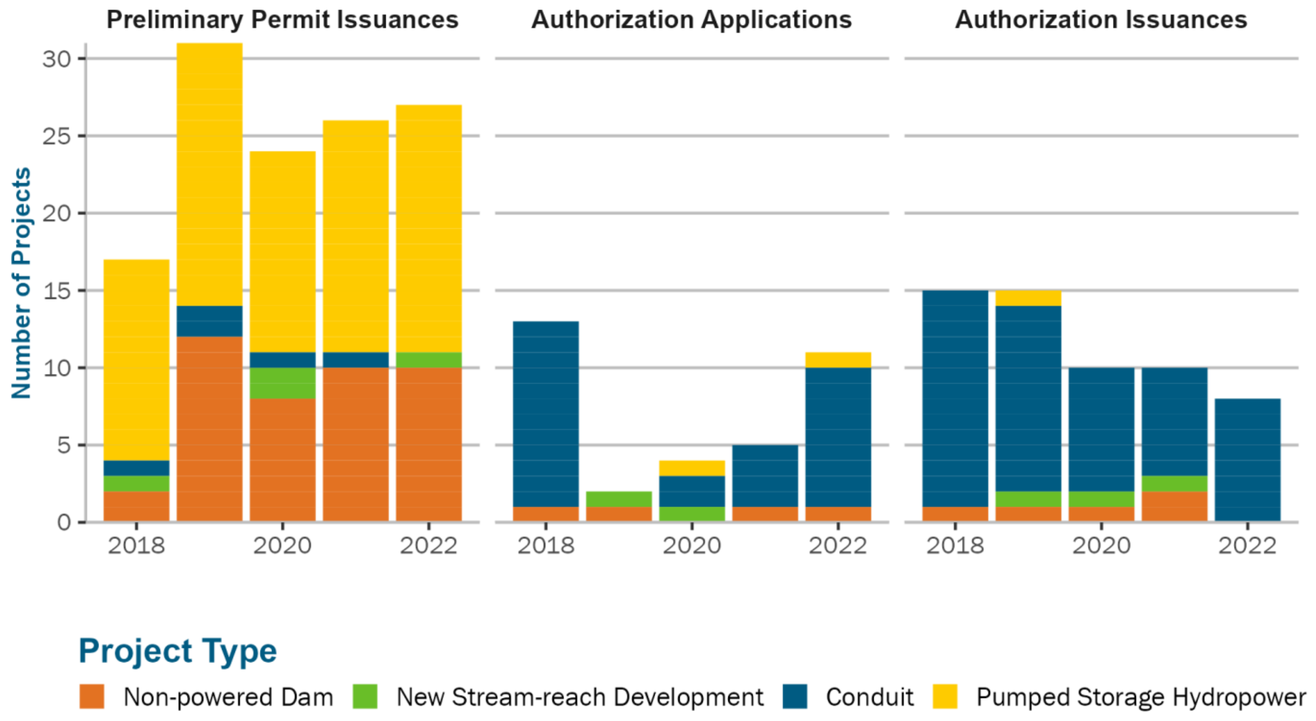


Sources: ORNL U.S. Hydropower Development Pipeline Data 2023. FERC eLibrary, IIR.

- Proposed project types vary by owner/developer types.
  - Federal owners focus on maintaining and upgrading existing fleets.
    - However, they own most of the infrastructure (dams and conduits) that nonfederal developers are proposing to retrofit with hydropower.
  - Investor-owned utilities (IOUs) have also primarily pursued capacity additions of their hydropower fleets but, in the last two years, they have started showing interest in developing new PSH projects.
    - Four IOUs have PSH projects in the development pipeline.

From 2018 to 2022, an average of 25 preliminary permits were issued each year. More than 90% were for NPDs and PSH projects. Eighty-four percent of issued authorizations in the past five years have been for conduit projects.

Permitting activity trends by project type (2018–2022)



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

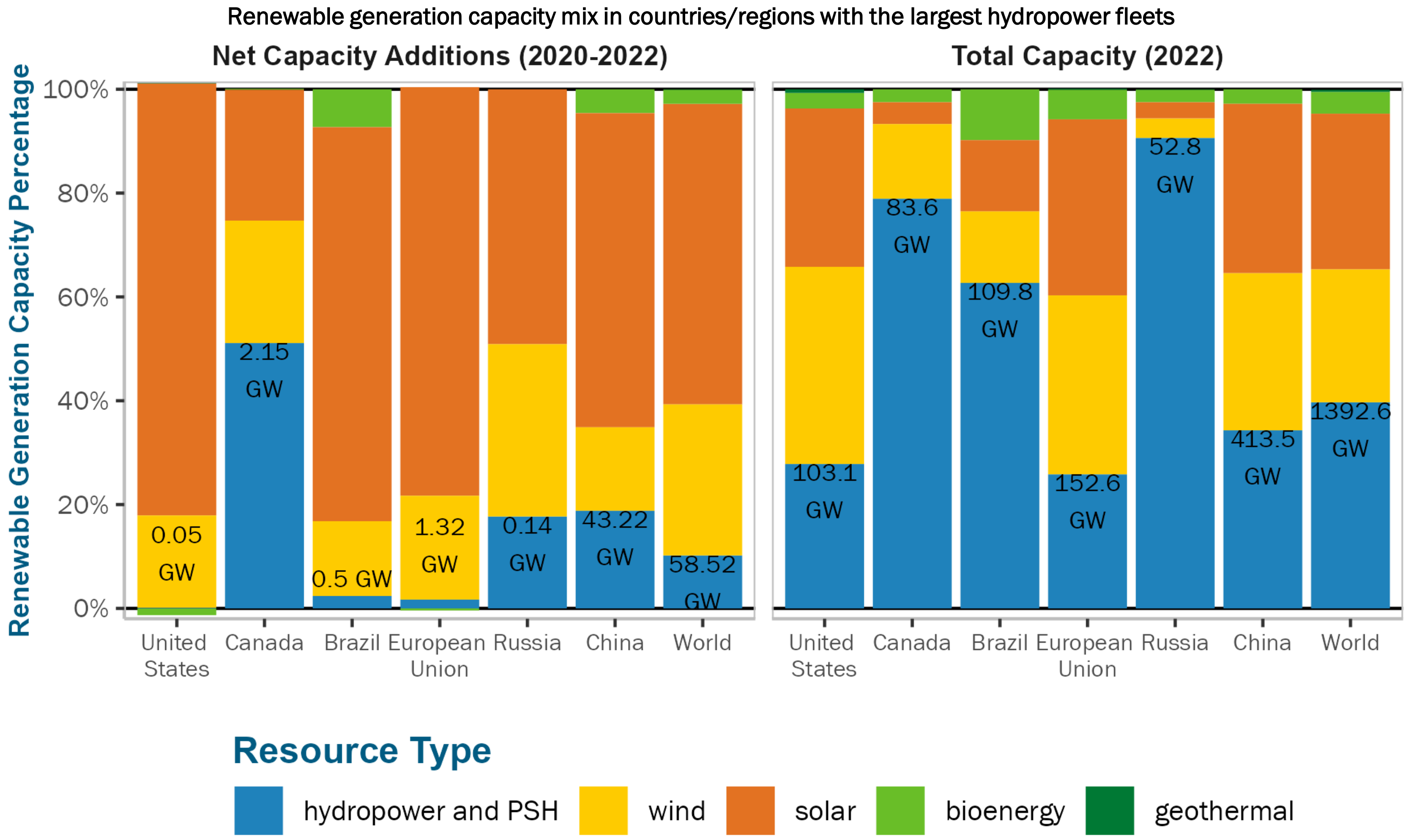
Notes:
The *Preliminary Permit Issuances* panel includes issued preliminary permits by FERC and LOPPs issued by the Bureau of Reclamation. The *Authorization Applications* panel includes FERC license applications, FERC exemption applications, and applications for qualifying conduit status. The *Authorization Issuances* panel includes FERC license issuances, FERC exemption issuances, projects that were issued a qualifying conduit determination, and Bureau of Reclamation LOPP issuances.
For many conduit projects, the first step of the permitting process is an authorization application.

- For PSH and NPDs, the number of authorization applications is much lower than the number of preliminary permit issuances.
  - High attrition rates during the feasibility evaluation stage.
- Conduit retrofits typically have much shorter development timelines. Forty-nine authorizations were issued in 2018–2022 but, at the end of 2022, there were only 18 conduit projects in post-licensing stage.
  - Of the remaining projects, at least seven have become operational.

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

3.1 Description of the existing fleets
3.2 Global hydropower and PSH development pipelines
3.3 International trends in hydraulic turbine trade

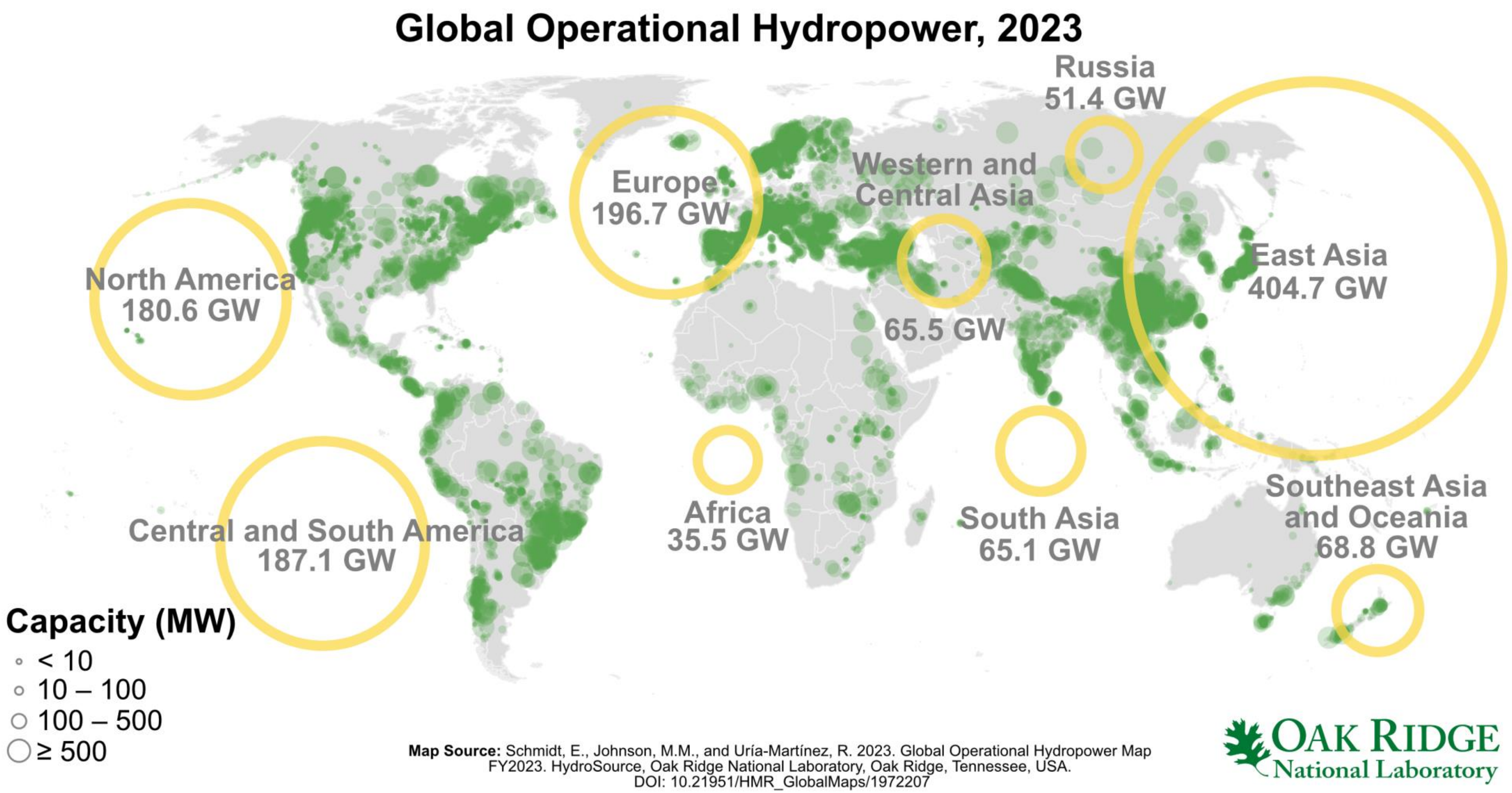
Hydropower remains the technology with the largest share of global renewable generation capacity (40%), but other renewables are growing at a much faster rate.



Source: IRENA Renewable Capacity Statistics 2023
Notes: IRENA counts the full capacity of hybrid plants as conventional hydropower. Capacity labels on the plot indicate hydropower and PSH capacity. The six countries/regions shown have the largest hydropower + PSH fleets in the world.

- In 2020–2022, 59 GW of new hydropower (including 16 GW of PSH) have been added globally.
  - More than 50% of the global capacity additions of hydropower + PSH in 2020–2022 have been in China; for PSH, China's share was 83%.
- Global net renewable capacity additions in 2020–2022 have been dominated by solar PV.
- During the past decade (2013–2022), global hydropower capacity has increased at an average rate of 2.2%; for PSH, the average growth rate was 2.7%.

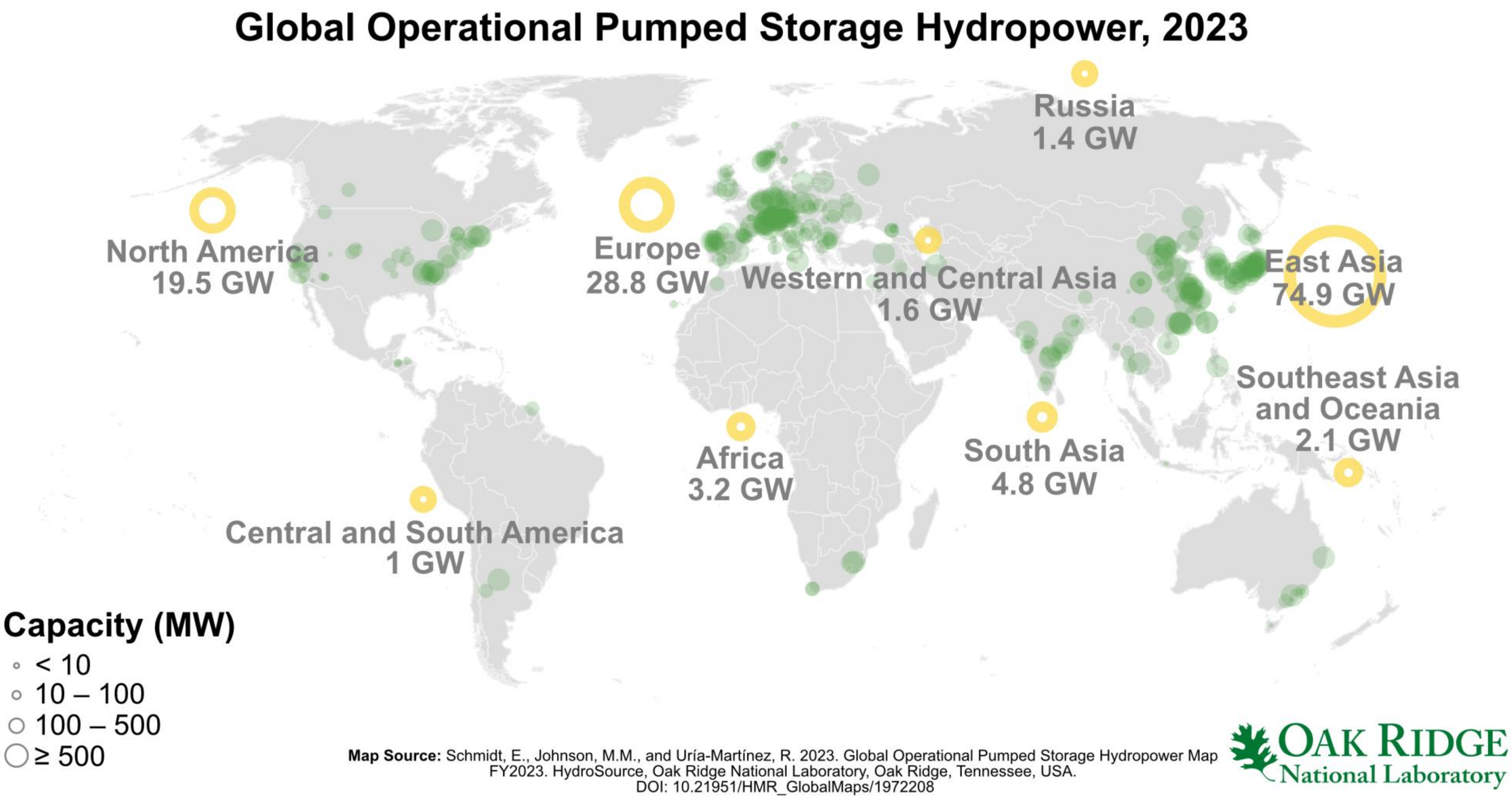
Almost one third of global conventional hydropower capacity is in East Asia; the United States fleet represents 7% of global capacity.



- 83 countries had more than 1GW of conventional hydropower in 2022.
- Of the 23 entities that own more than 10 GW of conventional hydropower (together they own 32% of global installed capacity), 22 are at least partially owned by a national or subnational government.

Sources: Regional totals (IRENA), plant-level data for the United States (ORNL EHA Plant database 2023), plant-level data for rest of world (GlobalData).
Notes: Regional totals include the full capacity from projects that have a mixture of conventional and PSH units.

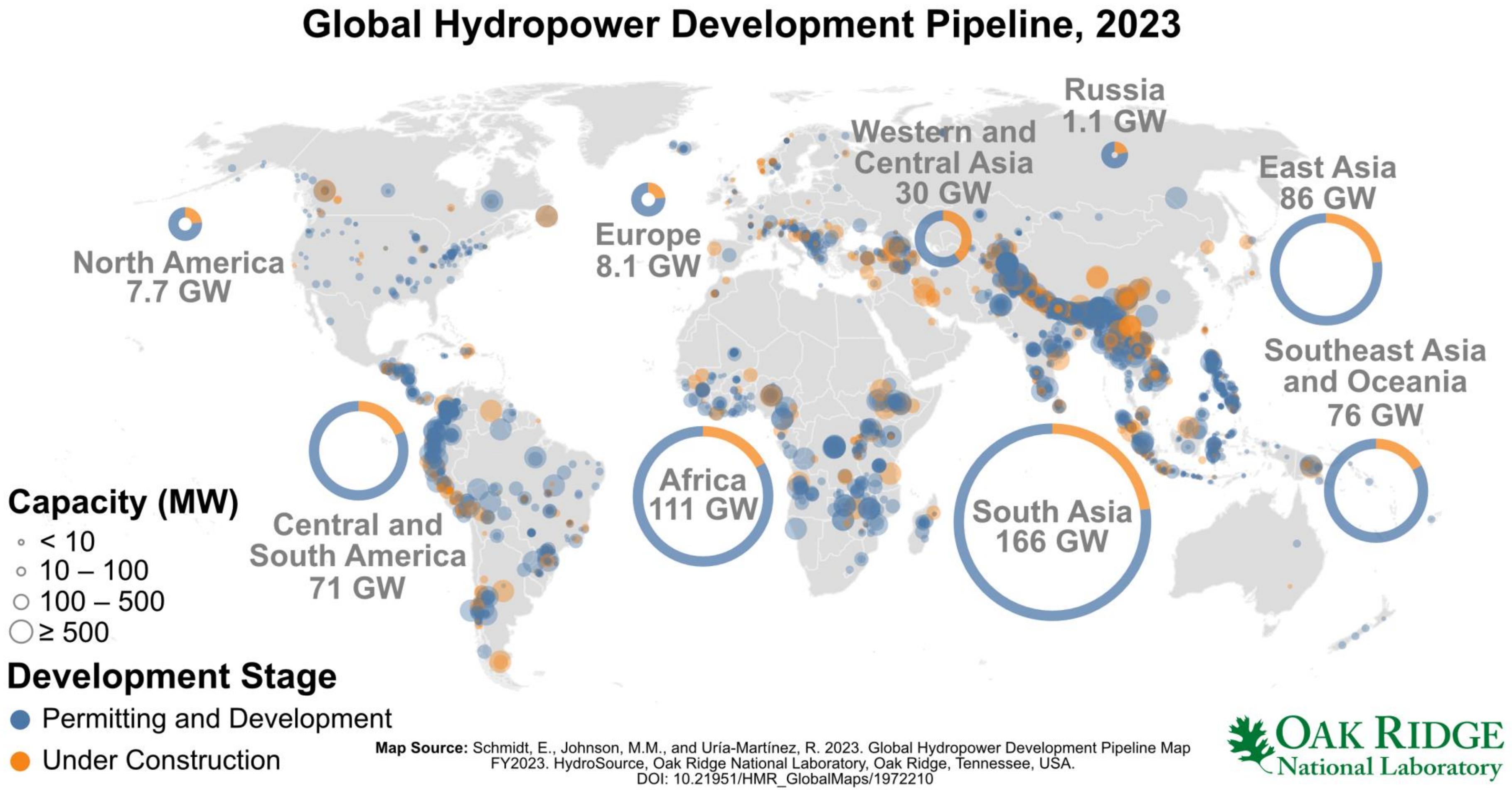
More than half of global PSH capacity is in East Asia; the United States fleet represents 14% of global capacity.



- Only 37 countries have PSH capacity as of 2022.
- The PSH fleets of the United States, European Union, China, and Japan account for 80% of global capacity.
- Nine of the top ten entities by PSH capacity are state-owned or have a state as major shareholder.

Sources: Regional totals (IRENA), plant-level data for the United States (ORNL EHA Plant database 2023), plant-level data for rest of world (GlobalData).
Notes: Regional totals only include pure PSH plants; the capacity from PSH units that are part of a hybrid project is not included.

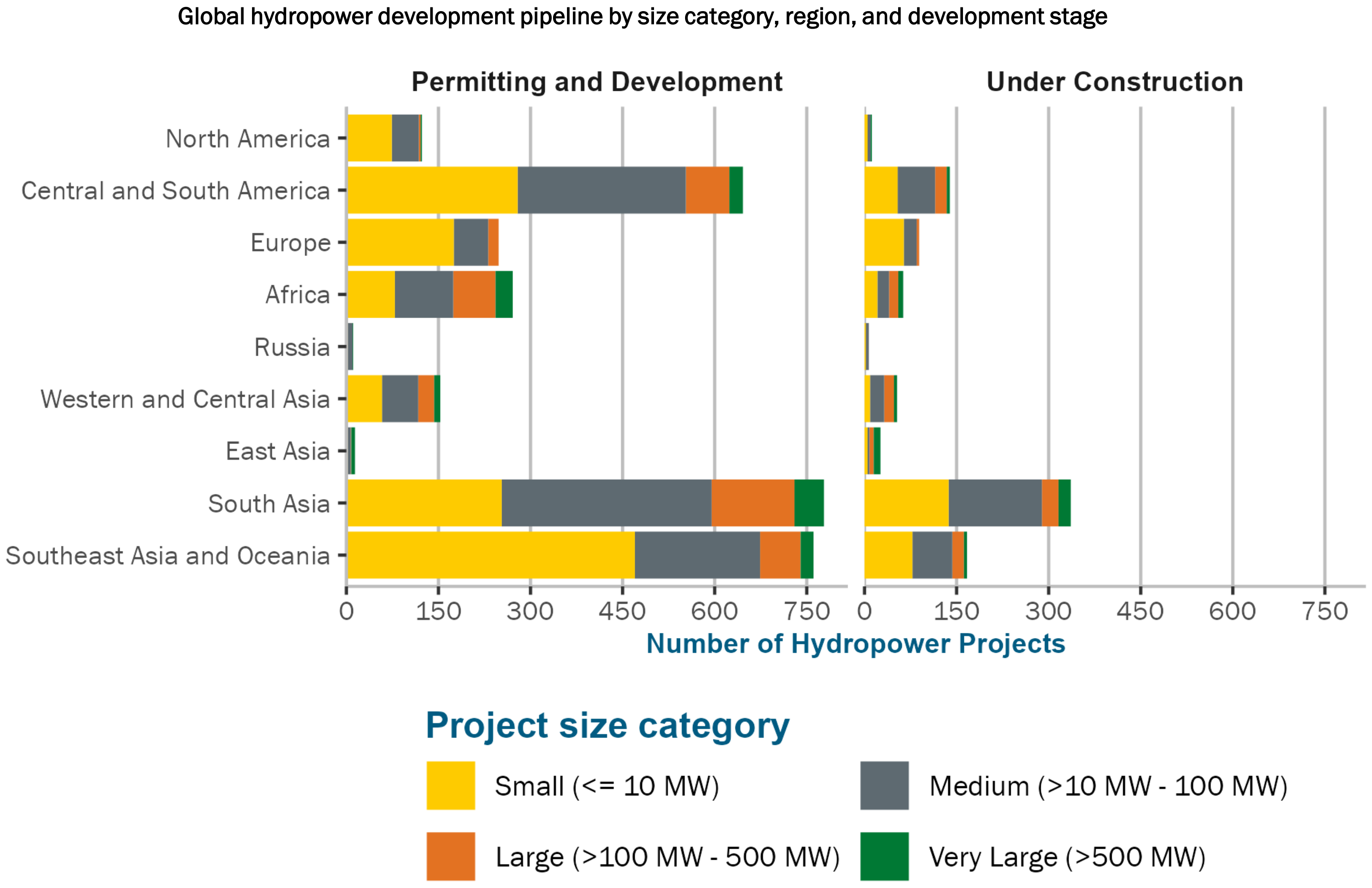
At the end of 2022, there were almost 4,000 hydropower projects in the global development pipeline (557 GW). Almost 25% of the projects are under construction and will add 117 GW to the global fleet.



- Half of the proposed capacity is in projects in South Asia (166 GW) and Africa (111 GW).
- Most regions have ~20% of proposed capacity under construction.
- The pipeline includes 193 projects with capacities greater than 500 MW.
  - Four of them are in North America (all in Canada).

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

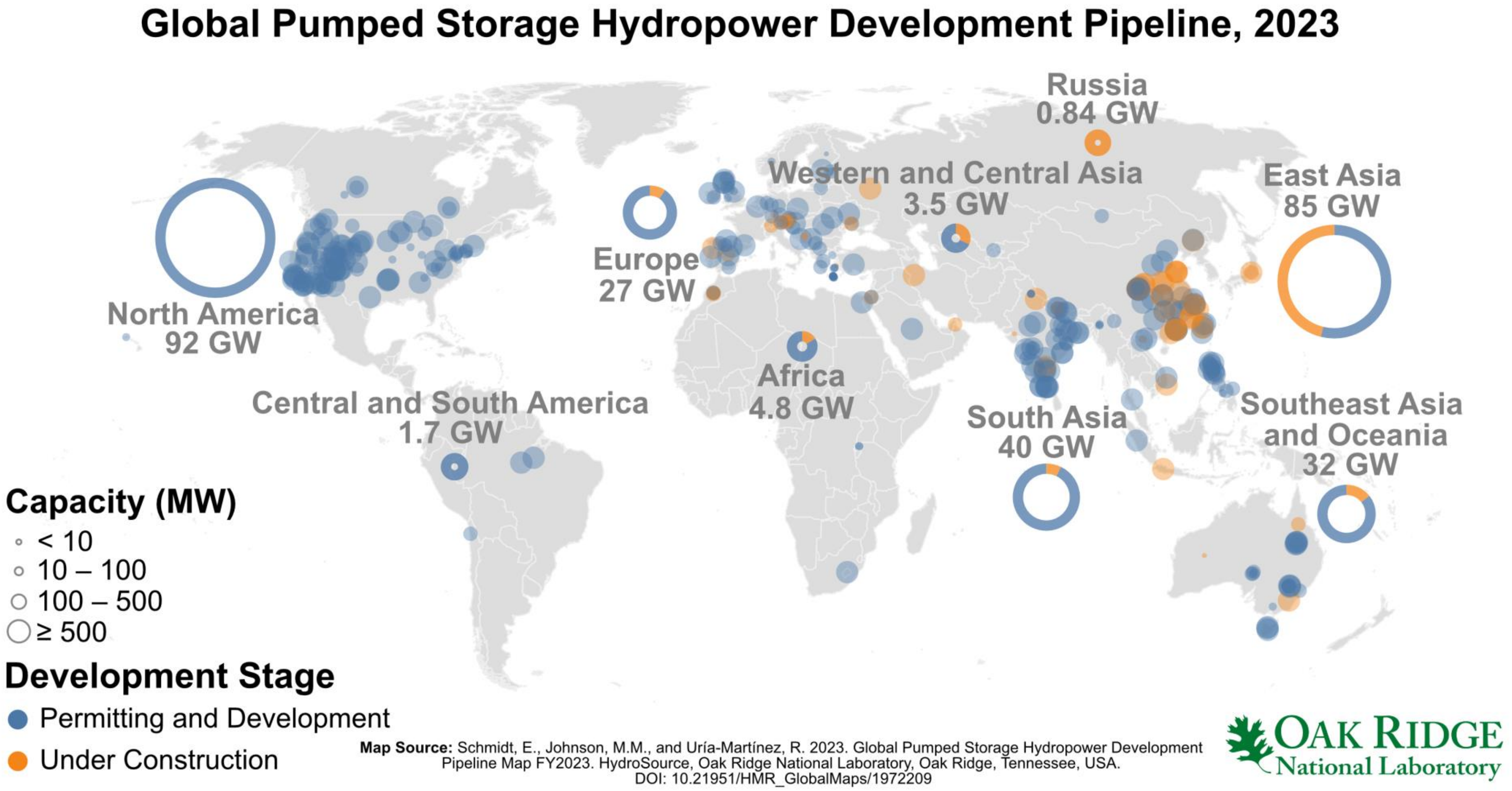
Only 6% of hydropower projects being constructed around the world are Very Large (> 500 MW) but they account for 67% of capacity under construction.



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

- The share of small hydropower projects is greater than 50% in 3 regions (North America, Southeast Asia and Oceania, and Europe).
- South Asia has the most Very Large hydropower projects under construction.
- Lack of small hydropower projects in East Asia partly explained by recent restrictions imposed by China on small hydropower development.
  - To mitigate the environmental impacts resulting from decades of rushed development and insufficient project reviews, hundreds of small hydropower plants in China are being removed and thousands are being required to change their operations.

At the end of 2022, there were 363 PSH projects (286 GW) in the global development pipeline. Of these, 56 are under construction and will add 52 GW to the global fleet.

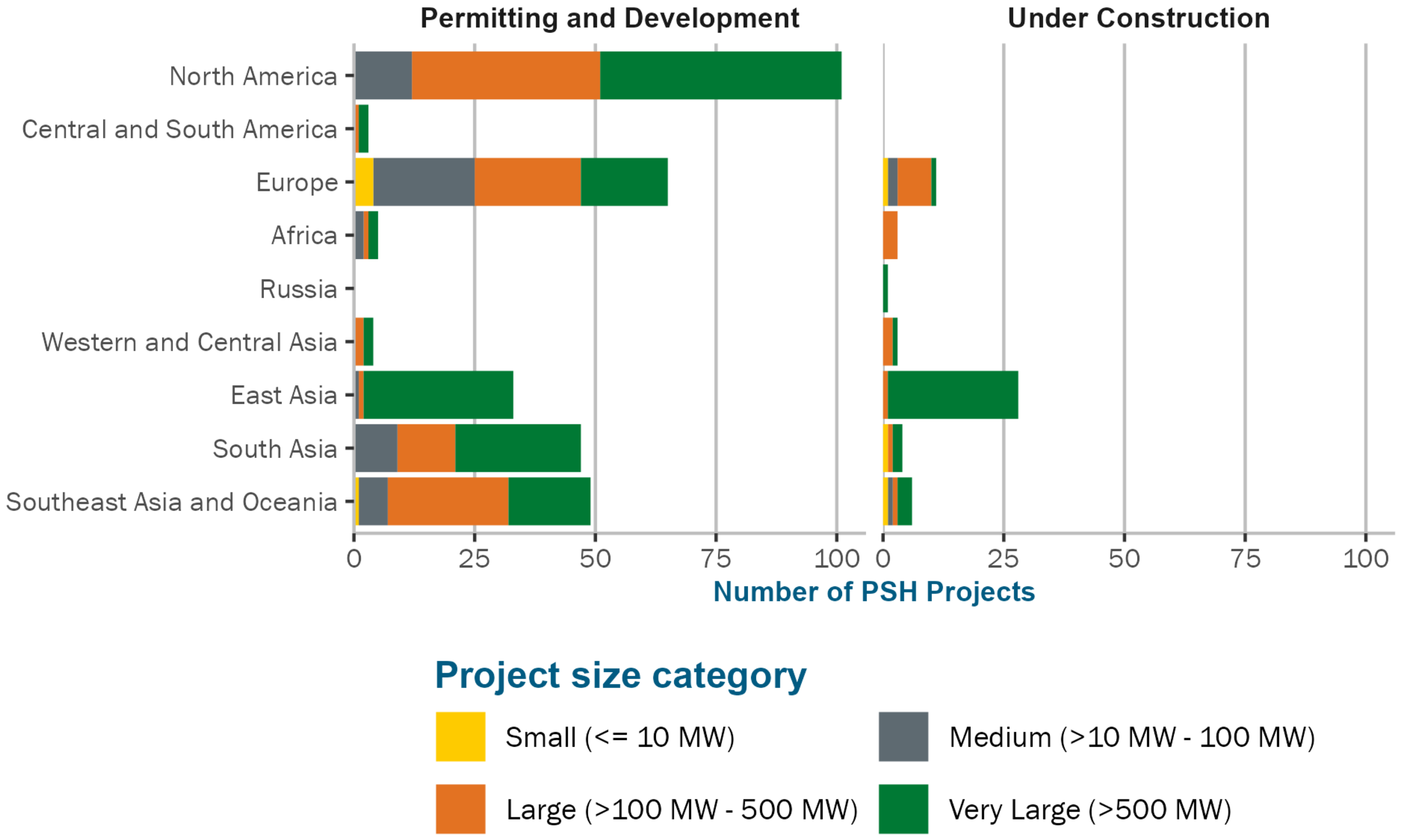


Sources: United States (ORNL U.S. Hydropower Development Pipeline Data 2023), rest of world (GlobalData).

- North America has the largest number of PSH projects in the development pipeline (101), but it is also one of the only two world regions where no new PSH is under construction.
- Seventy percent of the PSH plants being constructed are in East Asia (28 plants) and Europe (11 plants).
  - The developers for 52 of them are state-owned enterprises or at least partially owned by a national or subnational government.

The PSH project size distribution varies by region; the East Asia pipeline is heavily focused on Very Large (> 500 MW) projects. For Europe, only 25% of the projects are above that capacity threshold.

Global PSH development pipeline by size category, region, and development stage

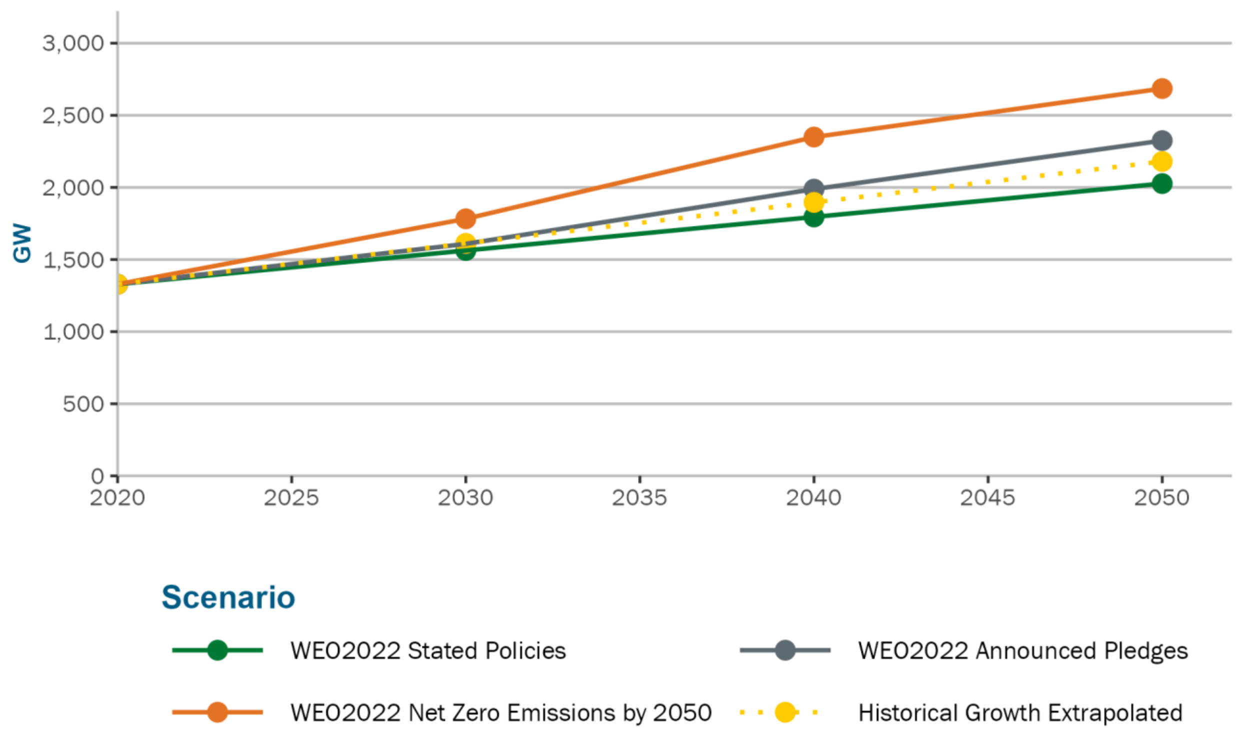


- The median power storage capacity of projects under construction is 1,200 MW; for those in earlier stages of development the median capacity is 500 MW.
- Three Chinese projects (2,400 MW each) are the three largest currently under construction.

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

Global average annual hydropower and PSH capacity additions must increase substantially relative to recent years to reach the capacity levels needed in a Net Zero emissions by 2050 scenario.

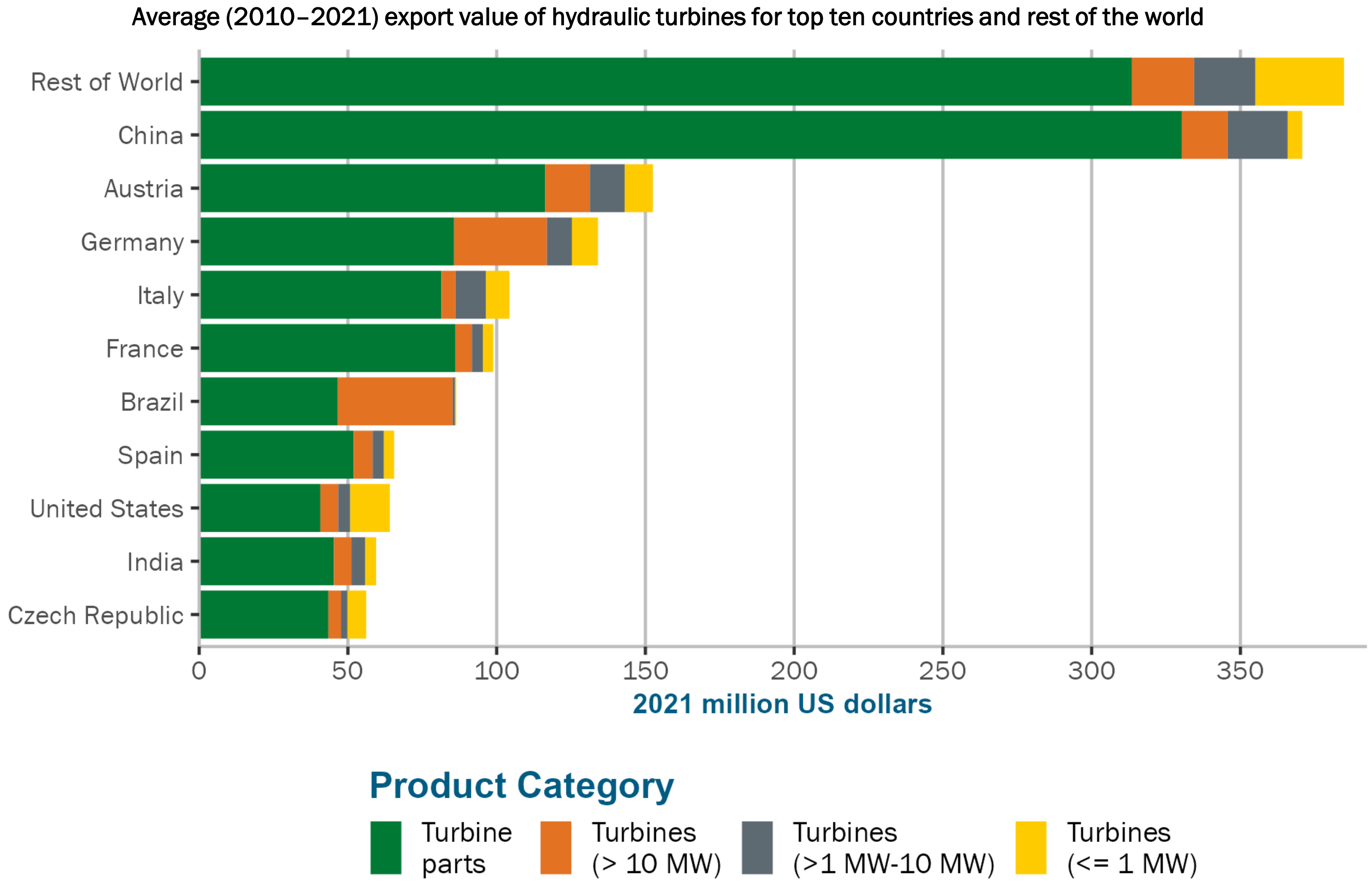
Global hydropower installed capacity in selected energy outlooks (2020–2050)



Sources: IEA World Energy Outlook (WEO) 2022; IRENA Renewable Capacity Statistics 2023.

- IEA generates scenarios using models of the global energy system to solve for trajectories of investment that meet projected energy demands given a set of technologies, policies, and behavior assumptions.
- Average annual hydropower + PSH capacity additions in different scenarios:
  - 22 GW (*Stated Policies* scenario)
  - 32 GW (Announced Pledges scenario)
  - 44 GW (*Net Zero Emissions* scenario)
  - The *Historical Growth Extrapolated* scenario extrapolates average 2013–2022 annual capacity additions (28 GW).

The average annual value of hydropower turbines (mostly parts) traded internationally in the 2010s were $1.7 billion. The United States ranked eighth by average export value during this period.

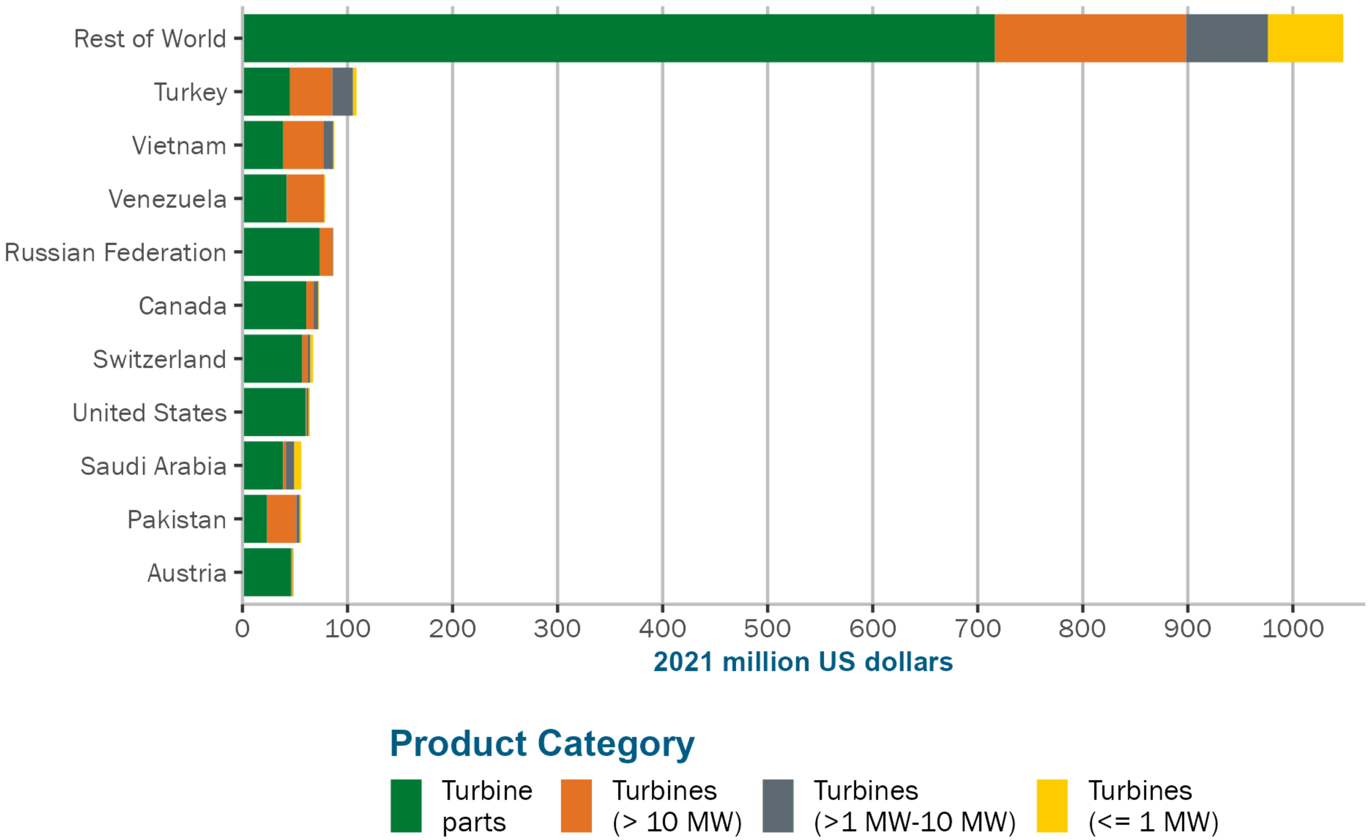


Source: World Bank's World Integrated Trade System.

- The top ten exporters accounted for an average share of global exports of 76% in 2010–2021.
  - China was the top global exporter.
  - Six of the top ten exporters are EU countries.
- Turbine parts represent 75% or more of exported value for seven of the top ten exporters.
- Since large turbines have higher price tags, the fact that large turbine units represent a small share of total trade value means that they are traded as multiple separate components (e.g., runners, hub) reported in the turbine parts category.

The United States ranked seventh by average import value in 2010–2022.

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



Source: World Bank's World Integrated Trade System.
Note: 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.

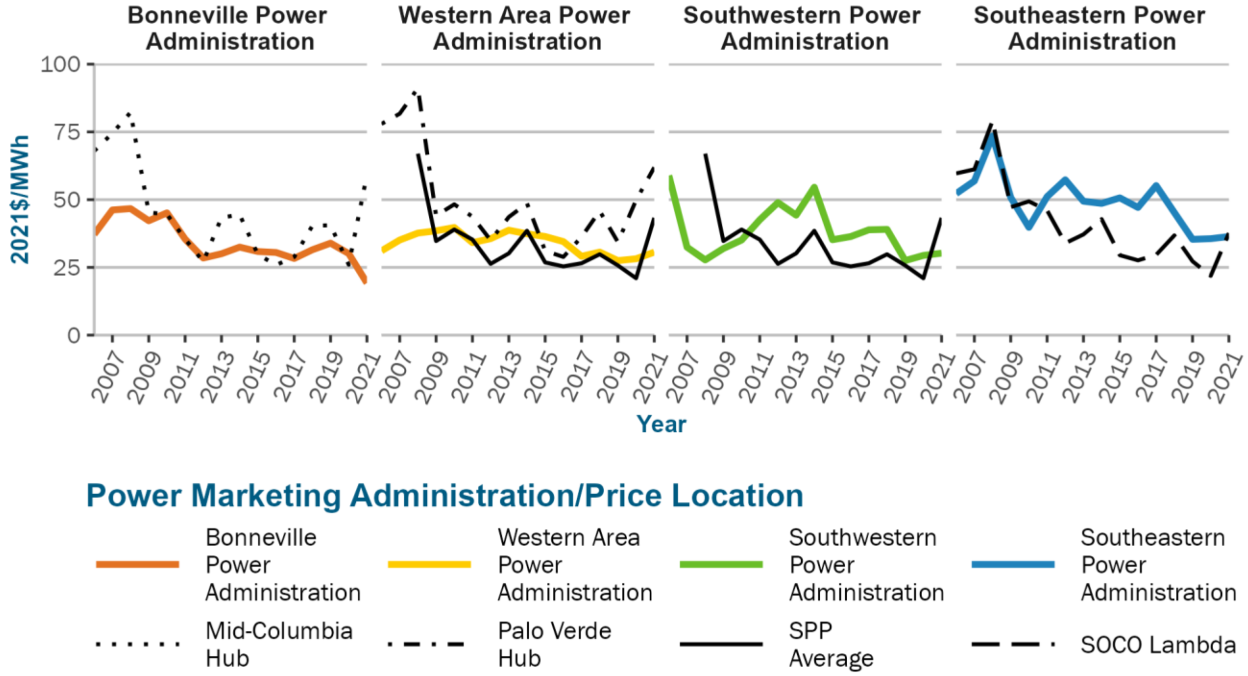
- Imports are less concentrated than exports.
  - In 2010–2021, only 21 countries exported more than \$10 million per year; 50 countries imported more than \$10 million per year.
- The list of top importers includes:
  - countries where large new hydropower is being developed (e.g., Turkey, Vietnam, Pakistan)
  - countries with mature fleets (e.g. United States, Canada, Russia) where a large share of imports are used to refurbish and upgrade existing plants.
- The United States and Austria are the only two countries that are part of both the top ten exporter and top ten importer rankings.
  - The United States is a net importer of turbine parts and net exporter of full turbine units, especially those with capacity < 1 MW.

Chapter 4: U.S. Hydropower Prices and Revenues

4.1 Federal Hydropower Revenue
4.2 Hydropower Purchase Agreements
4.3 Revenue Streams from Participation in ISO/RTO Markets
4.4 Trends in Hydropower and PSH Asset Sale Prices

From 2019–2021, most federal hydropower was marketed at rates similar to or below wholesale electricity prices.

Average federal hydropower revenue (proxy) versus average wholesale electricity prices



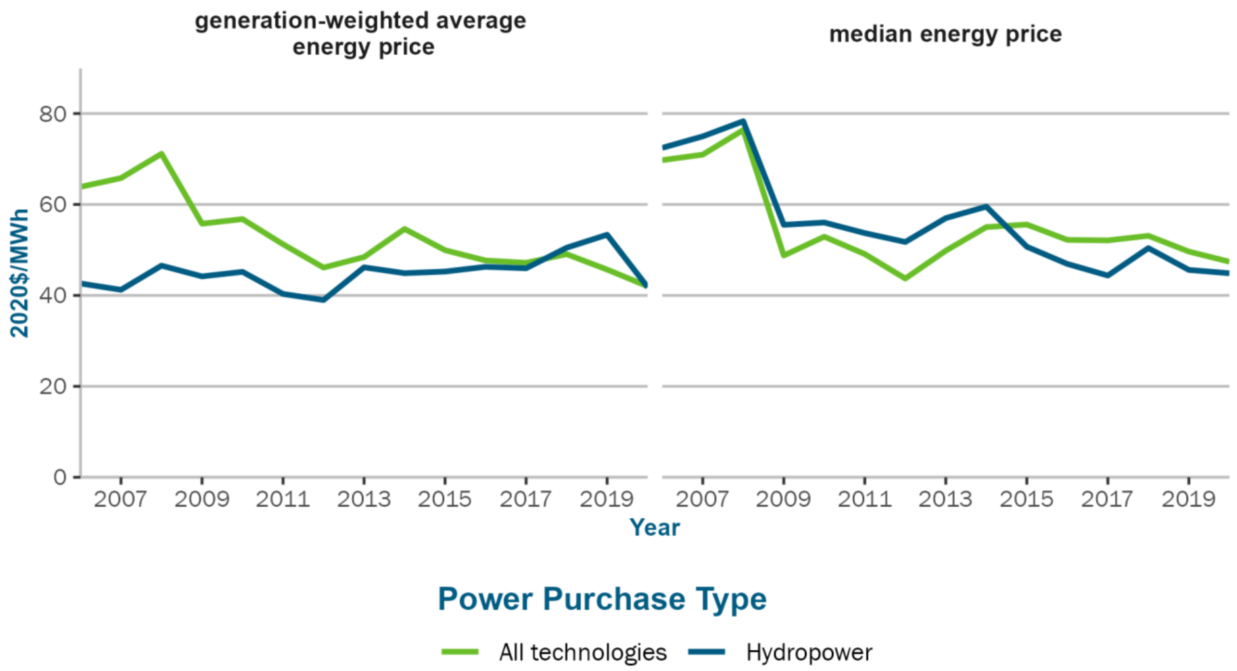
Sources: EIA Form 861 (for federal hydropower revenue), EIA Wholesale Electricity and Natural Gas Market Data (Mid-Columbia Hub and Palo Verde Hub), SPP State of the Market reports (SPP Average), FERC Form 714 (SOCO Lambda).

*Wholesale purchases by BPA experienced a strong increase in 2020 and 2021. The 2006–2019 average fraction was 8%.

- PMA revenue per MWh = Total revenue ($)/total sales (MWh)
  - The revenue and sales numbers include PMA sales of power purchased in the market as complement to the output from the federal hydropower fleet.
  - From 2006 to 2021, the average fraction of PMA sales that came from purchased power was 17% for Bonneville*, 23% for Western, 6% for Southwestern, 11% for Southeastern.
- The 2006–2021 revenue per MWh was higher on average and more variable for Southwestern and Southeastern than the other PMAs.
  - The difference in levels partly explained by Southwestern/Southeastern selling peaking power.
  - The stability of Western's average revenue is linked to geographical diversity and to its fleet containing some very large storage reservoirs capable of buffering the effects of multiyear droughts.

The median price (energy component) paid for hydropower has closely followed that of other technologies.

Median and generation-weighted average FERC Form 1 purchased power prices



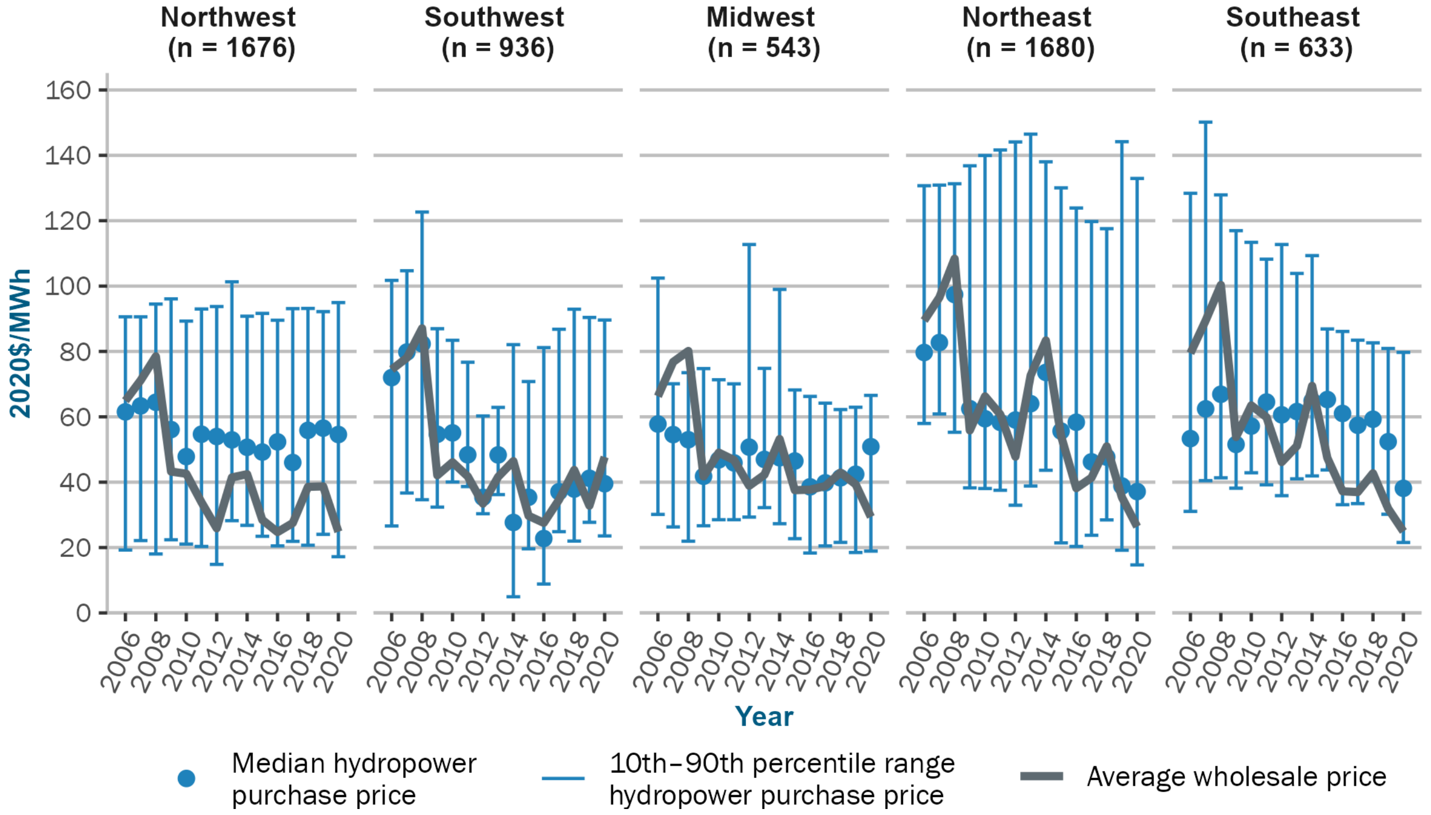
Source: FERC Form 1

Note: To subset hydropower PPAs out of the FERC Form 1 dataset, only those sellers that can be identified as owning only hydropower assets are used. Using this approach, 734 unique buyer-seller pairs were identified. Most pairs are a transaction between a utility buyer and a private non-utility hydropower owner but, for some of the pairs both the buyer and the seller are utilities.

- The median hydropower purchase price in 2020 was $45/MWh.
  - The dataset contains a mixture of prices from long-term contracts signed years ago (at fixed prices or indexed to a wholesale price)and newer contracts.
    - The mixture of contract lengths and price setting mechanisms determines how closely these median prices follow wholesale market trends.
- On a generation-weighted average basis, the prices paid for hydropower were lower than for other technologies in the late 2000s, but they have converged through the 2010s.
- The plot only shows the energy component of prices. As of 2020, 19% of hydropower purchases included a capacity component in the price.

The median energy price shows a decreasing trend in every region. On average, the lowest median prices in 2006–2020 were in the Midwest and Southwest and the highest in the Northwest and Northeast.

Hydropower price by region and report year from power sales reported to FERC Form 1



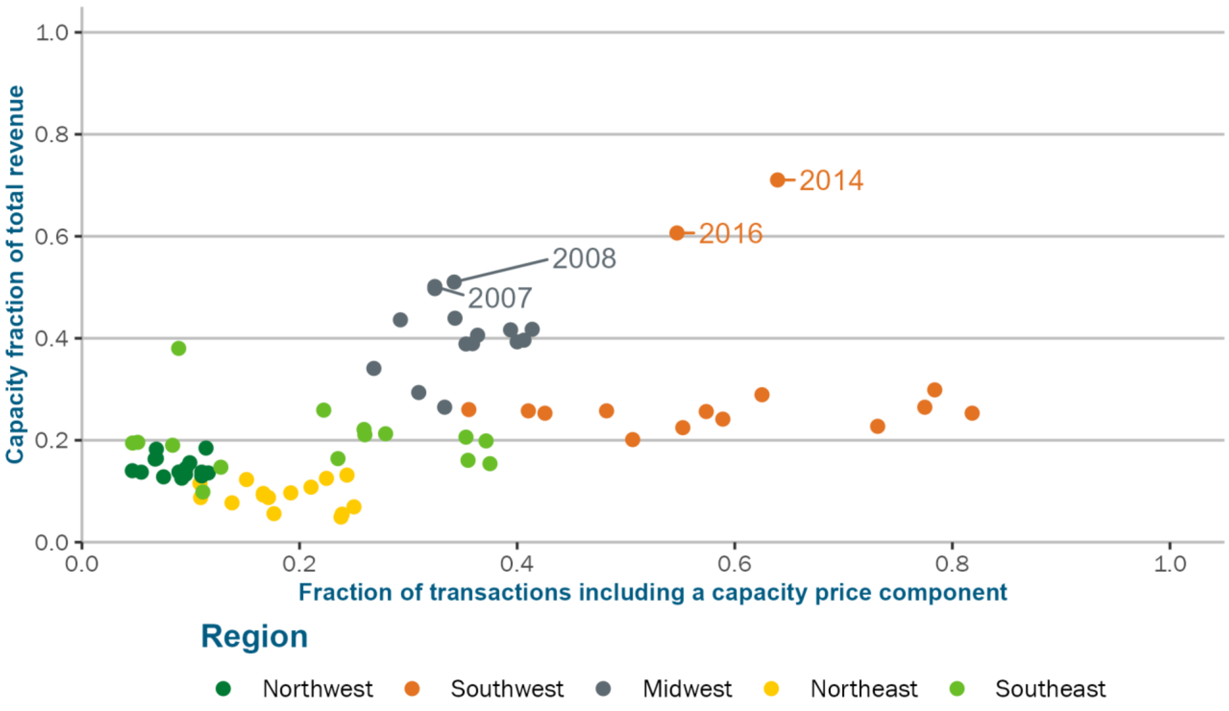
Source: FERC Form 1, EIA Wholesale Electricity and Natural Gas Market Data

Notes: 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 prices. 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.

- Prices spanned wide ranges in every region.
  - Year in which the purchase agreement was signed is one of the factors explaining the variability.
  - For the Northeast region, the range became even wider in 2019–2020 due to a few transactions with very high prices.
- For the 26 purchase agreements where the first year of data is 2018 or later, the average price of energy ranged from $23/MWh to $80/MWh.

The fraction of transactions that include a capacity price component varies substantially by region.

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



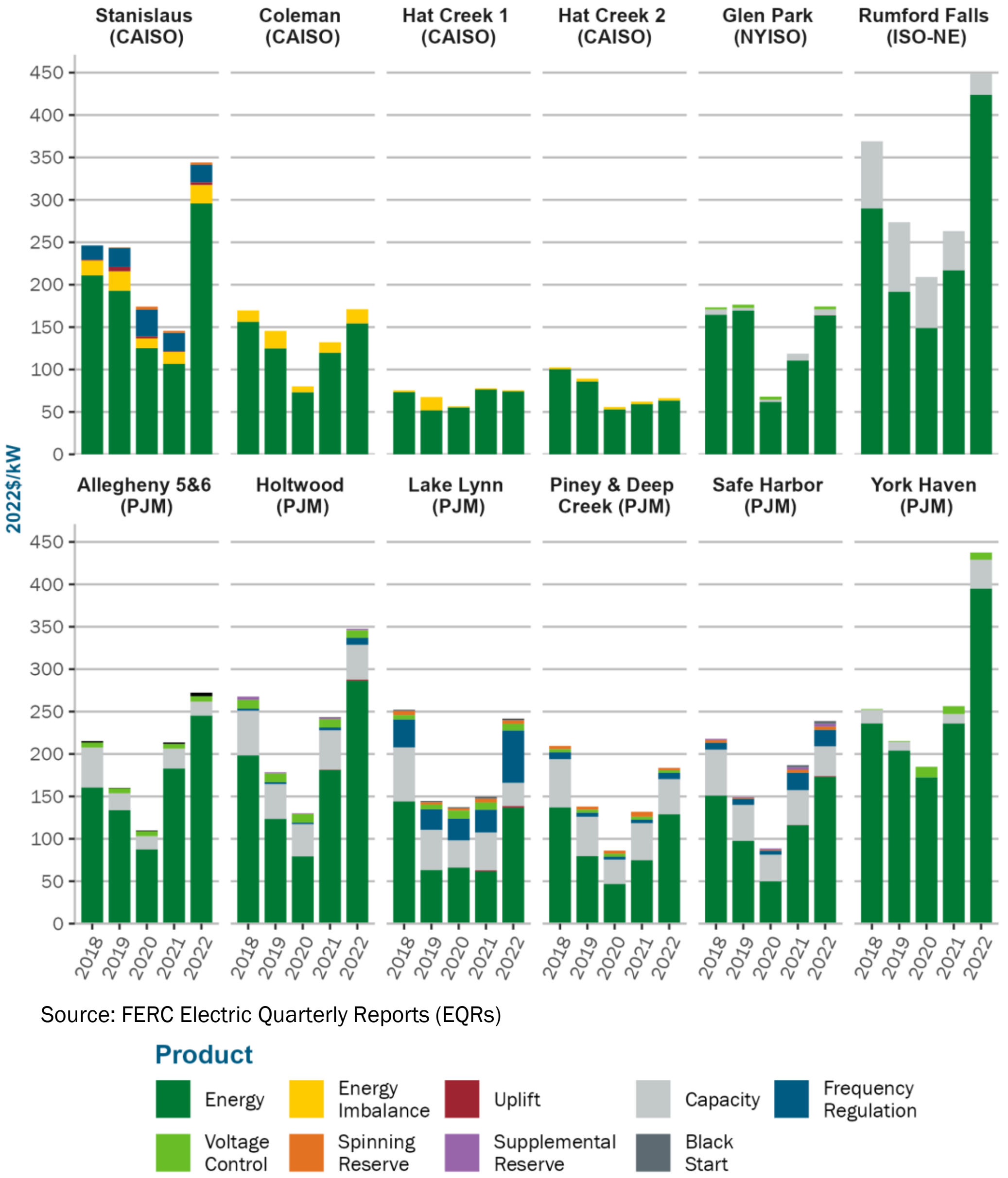
Source: FERC Form 1

- Capacity payments in PPAs reward the generating resource for being *available* to meet peak demand.
- The two regions with the larger fraction of transactions including a capacity price component are the Southwest (60%) and the Midwest (34%).
- The Southwest and the Midwest are also the two regions where capacity charges (in those transactions that include it) are a higher fraction of total revenue.
  - On average, capacity revenue was 40% of total revenue in the Midwest and 31% in the Southwest.
  - In the rest of regions, capacity revenue was below 20% of total revenue.

Energy revenue is typically the largest component of total revenue for a subset of plants where most operate as run-of-river.

- There are substantial differences in energy revenue for hydropower plants participating in the same ISO
  - Plants with higher revenue per kW have high capacity factors or generate during peak periods.
- Capacity revenue tends to be more stable year to year than energy revenue.
- Ancillary service revenue averaged more than $20/kW per year for two of the plants.
  - In both cases, most of the revenue is from provision of frequency regulation.
- Going forward, revenue structure is expected to shift to larger ancillary service and capacity revenue shares.

Annual revenue streams for a sample of hydropower plants

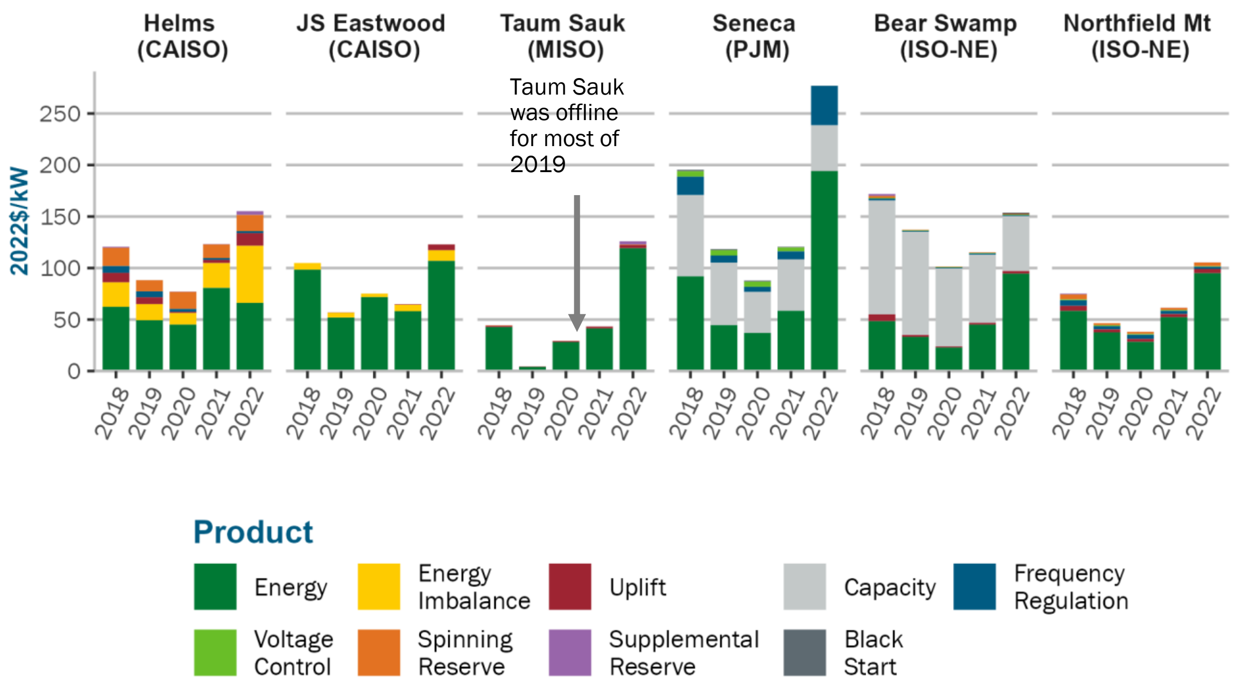


Source: FERC Electric Quarterly Reports (EQRs)

Note: The plot only includes transactions that could be matched to specific hydropower plants. Not being able to extract capacity revenue data from the FERC EQRs does not necessarily mean that the plant did not receive any capacity revenue.

Energy revenue trends (2018–2022) for PSH have been similar across ISOs, the amount and mix of ancillary services provided varies across facilities, and capacity payments accounted for over half of total revenue in some cases.

Annual gross revenue streams from participation of selected PSH plants in ISO/RTOs

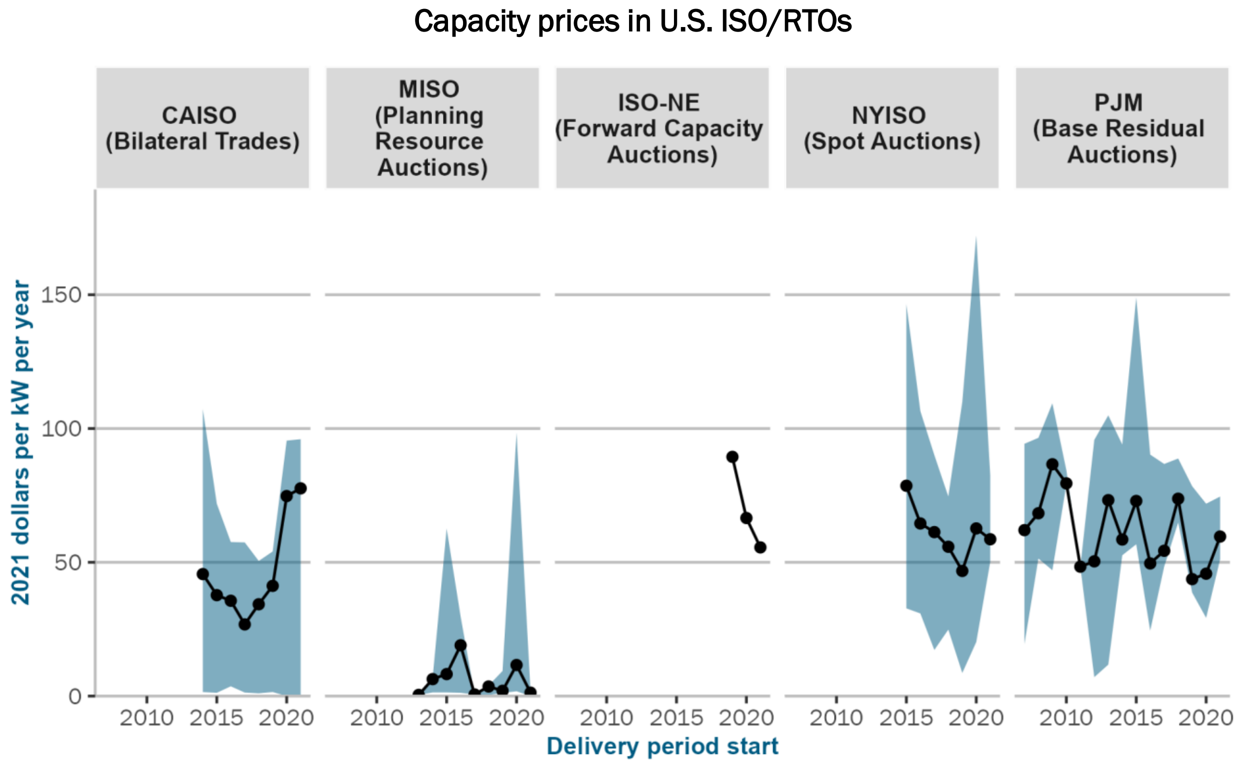


Sources: FERC Electric Quarterly Reports (EQR)

Note: The plot shows gross revenue (i.e., the cost of pumping is not netted out). The plot only includes transactions that could be matched to a PSH plant. Capacity revenue in the EQR is 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.

- Energy revenue was lowest in 2020 (except for Eastwood); a consequence of the drop in electricity prices and demand caused by the COVID-19 pandemic.
- Capacity payments are a key component of the revenue stack of PSH plants.
  - Capacity revenue represented an average of 68% of total revenue for Bear Swamp and 44% for Seneca in 2018–2021.
- Ancillary services revenue averaged $1/kW for Taum Sauk, $3/kW for Bear Swamp, $7.5/kW for Northfield Mountain, $20/kW for Helms (largely from provision of spinning reserve), and $20/kW for Seneca (mostly from provision of frequency regulation).

Capacity prices vary significantly year to year, and they are generally higher in ISOs with mandatory, centralized capacity.



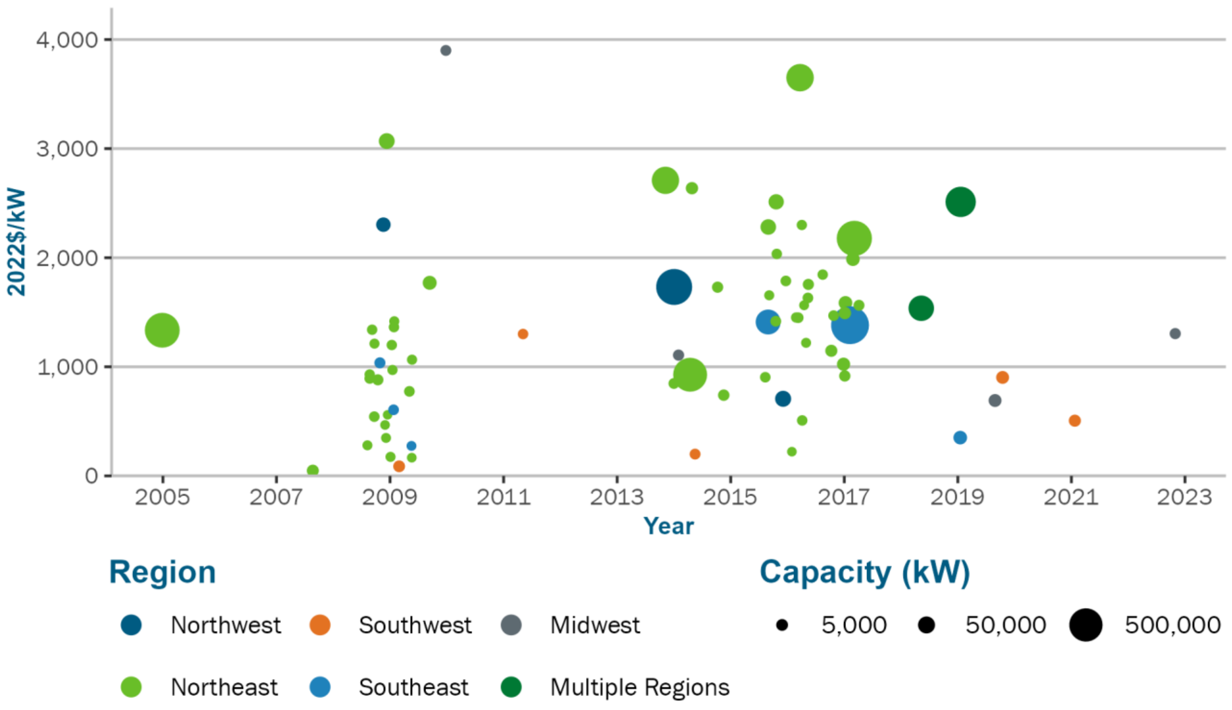
Sources: California Public Utilities Commission (CAISO); ISO/RTO websites (MISO, ISO-NE, NYISO, PJM).

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.

- The ranges in prices within an ISO/RTO in a single year reflect value of capacity in different zones.
  - Higher end of the range correspond to zones facing transmission congestion issues.
- Capacity revenue for each individual hydropower plant also depends on what percentage of its nameplate capacity is accredited for reliability purposes.
  - Traditionally, accredited capacity was nameplate capacity adjusted by forced outage rates and historic availability factors.
  - Increased penetration of variable renewables has motivated changes in accredited capacity methodologies to adequately reflect the contribution of each supply resource to reliability (e.g., PJM's implementation of the Effective Load Carrying Capability) method.
  - Hydropower with pondage and PSH have a higher fraction of their capacity accredited than nondispatchable hydropower.

Four recent (2020–2023) hydropower plant sales for which the price was publicly disclosed had an average price of $851/kW, substantially lower than the average observed in sales since 2005 ($1,304/kW).

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

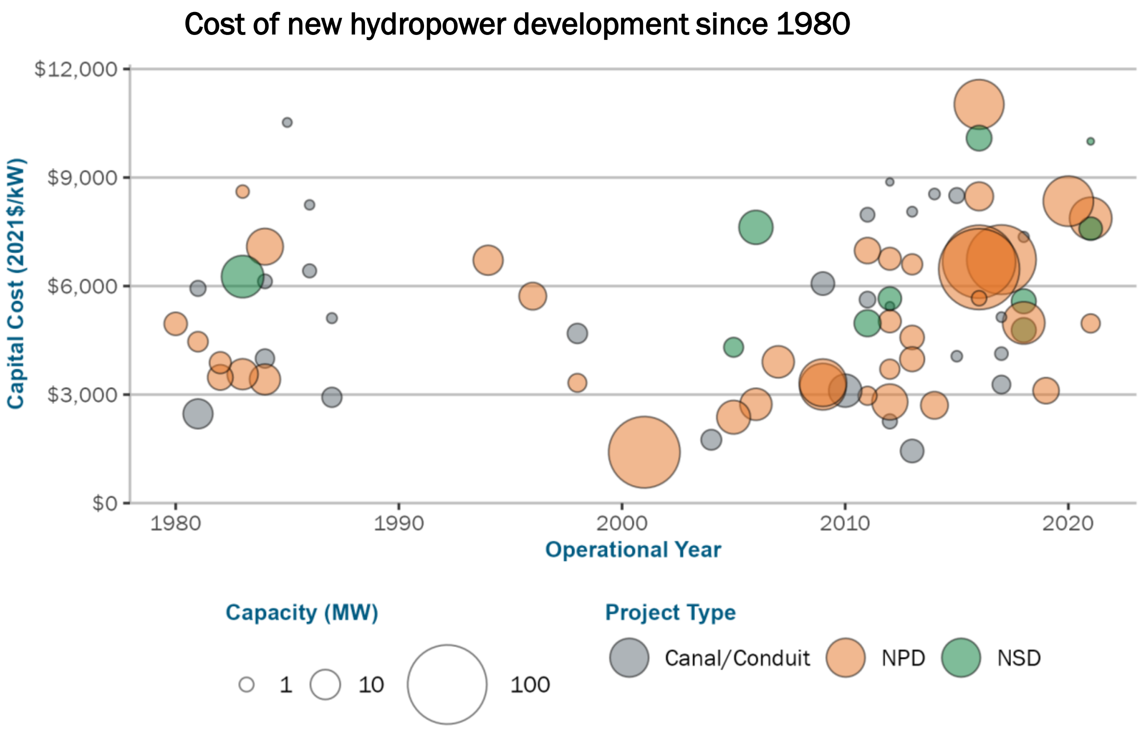


Sources: Internet searches and regulatory filings.
Note: For transactions in which multiple plants were sold but only the total price was reported, the price shown is the average across all capacity sold.

- Recent transactions:
  - Acquisition of 13 hydropower plants in the Northeast (589 MW) by HQI US Holding LLC, a subsidiary of Hydro Quebec.
    - The transaction had an approximate value of $2 billion, including the hydropower assets and 30,000 acres of land.
  - Hydrogen Charbone purchased three small hydropower plants in Michigan at an average price of $1,300/kW.
  - Pacific Gas & Electric sold an operational 10.4 MW plant to Sacramento Municipal Utility District ($903/kW).
  - Pacific Gas & Electric sold an out-of-service 6.4 MW plant to Kern and Tule Hydro, LLC ($506/kW).

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

Five new projects starting operation since 2020 reported capital costs ranging from $5,000/kW to $10,000/kW.

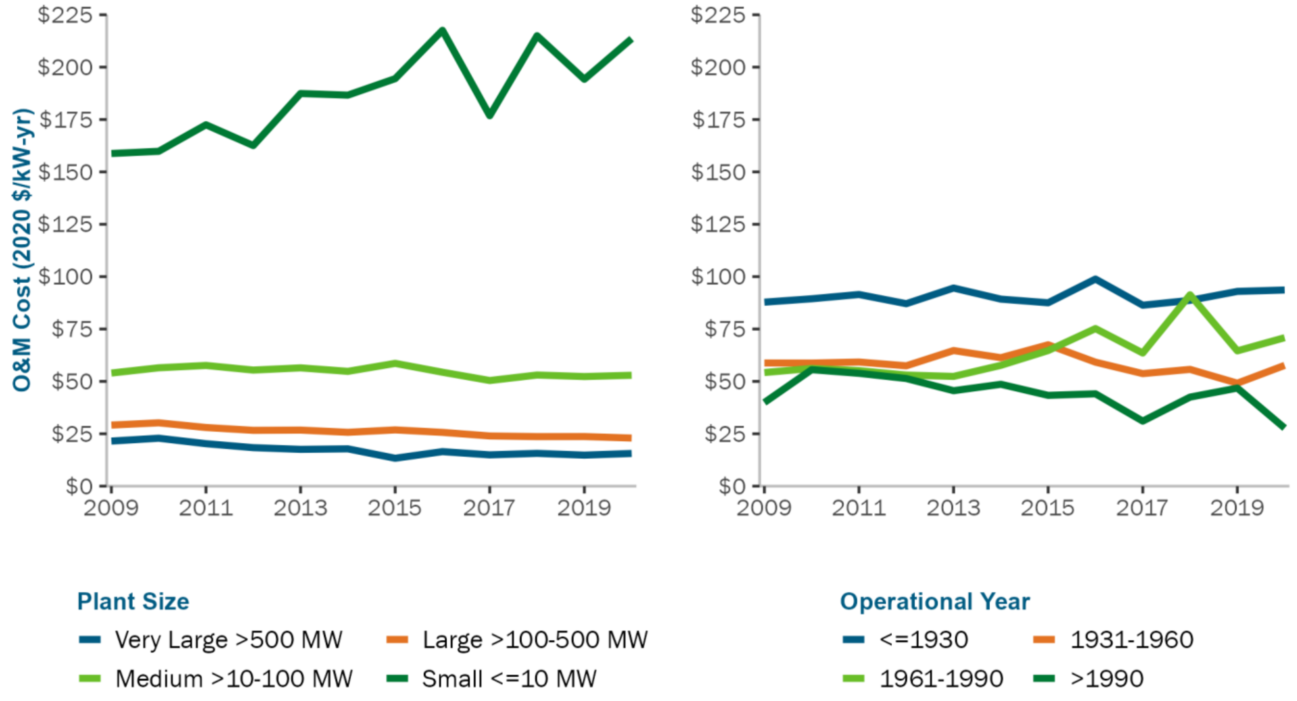


Sources: O'Connor (2015), IIR, and internet searches
Note: The U.S. Bureau of Reclamation Construction Cost Trends composite trend index was used to adjust for inflation cost data from different years.

- Capacity-weighted mean cost for projects constructed since 2005:
  - Canal/Conduit: $3,955/kW (16 projects)
  - NPD: $6,096/kW (26 projects)
  - NSD: $6,621/kW (9 projects)

Hydropower operations and maintenance (O&M) cost displays strong economies of scale (i.e., the cost per kilowatt decreases as plant capacity increases).

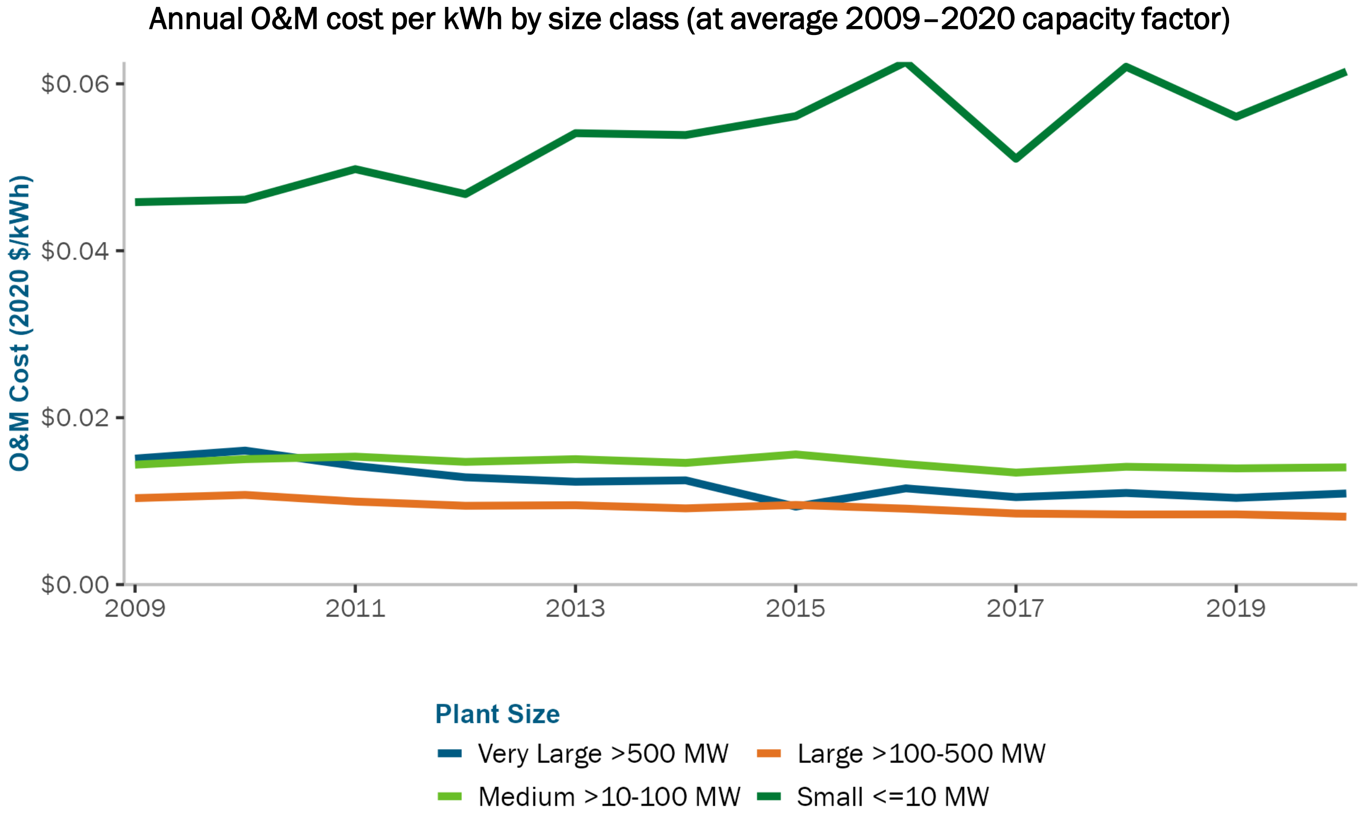
Trends in O&M costs for utility-owned hydropower and PSH projects by size category and age



Source: Oladosu & 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).

- In 2020, the average O&M cost ranged from $16/kW for Very Large (>500 MW) plants to $213/kW for Small (<=10 MW) plants.
  - There is substantial variability in annual average O&M costs within the same size category, especially among small plants.
- The relationship between cost and size is clearer than the relationship between cost and age.
  - Operational year for the plant contains limited information about the actual age of different plant components.
  - The FERC Form 1 dataset does not contain any information on small hydropower plants built after 1990 because they are mostly owned by small utilities or non-utilities not required to file that form.

Using average capacity factor for each of the hydropower size classes, the average 2009–2020 O&M cost per unit of electricity generated was ~$0.05 for the small plants and ranged from $0.01 to $0.015 for the other size categories.

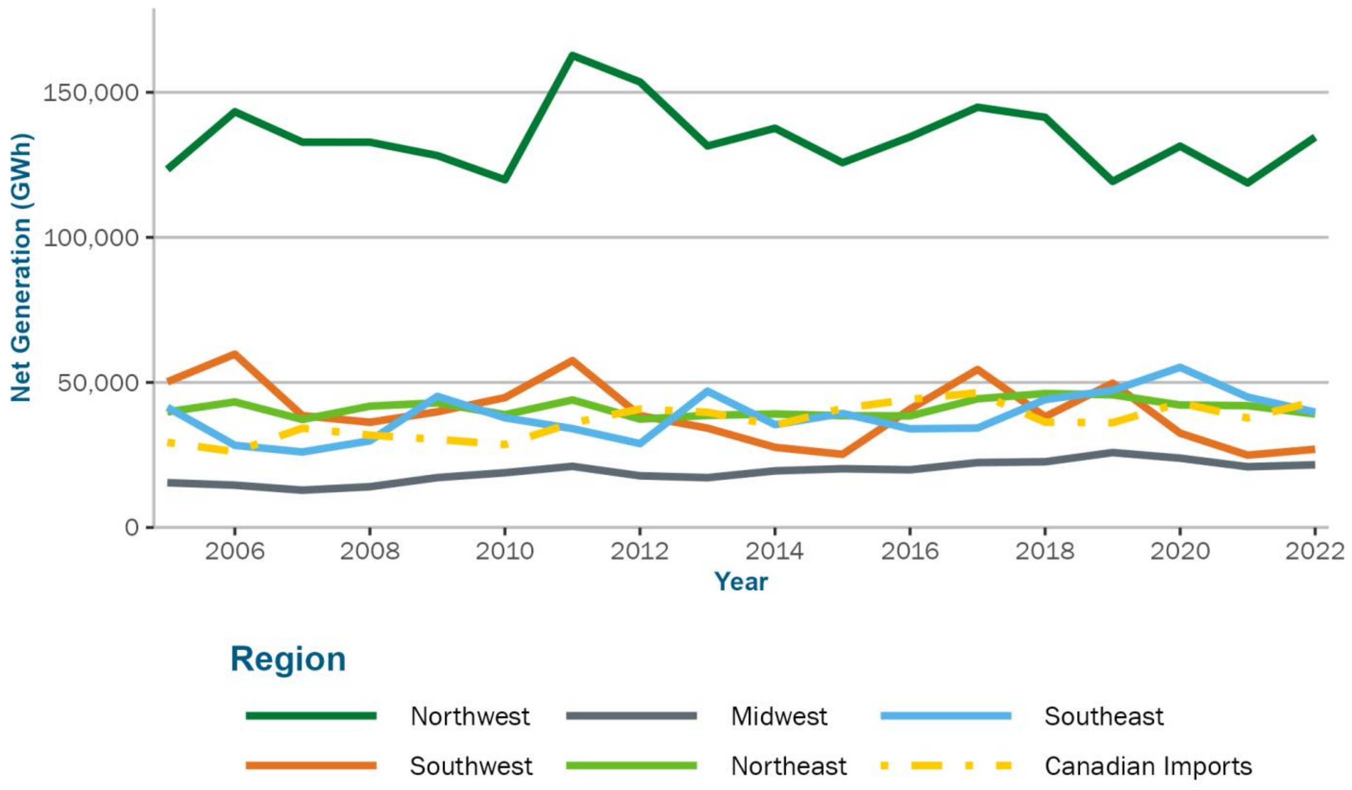


- O&M cost per kilowatt-hour is highly dependent on capacity factor.
- Calculating O&M cost per kWh at the average capacity factor for each size class provides more informative numbers than averaging out the costs per kWh reported by each plant.

Source: Oladosu & Sasthav (2022)
Note: The dataset includes both hydropower and PSH plants. The average capacity factors used for the calculation are: 16% (Very Large), 32% (Large), 43% (Medium), 40% (Small). Most PSH plants fall under the Very Large category and their capacity factors are much lower than for a conventional hydropower plant leading to the low average capacity factor for that size class.

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 drought conditions in the West.

Annual hydropower net generation by region

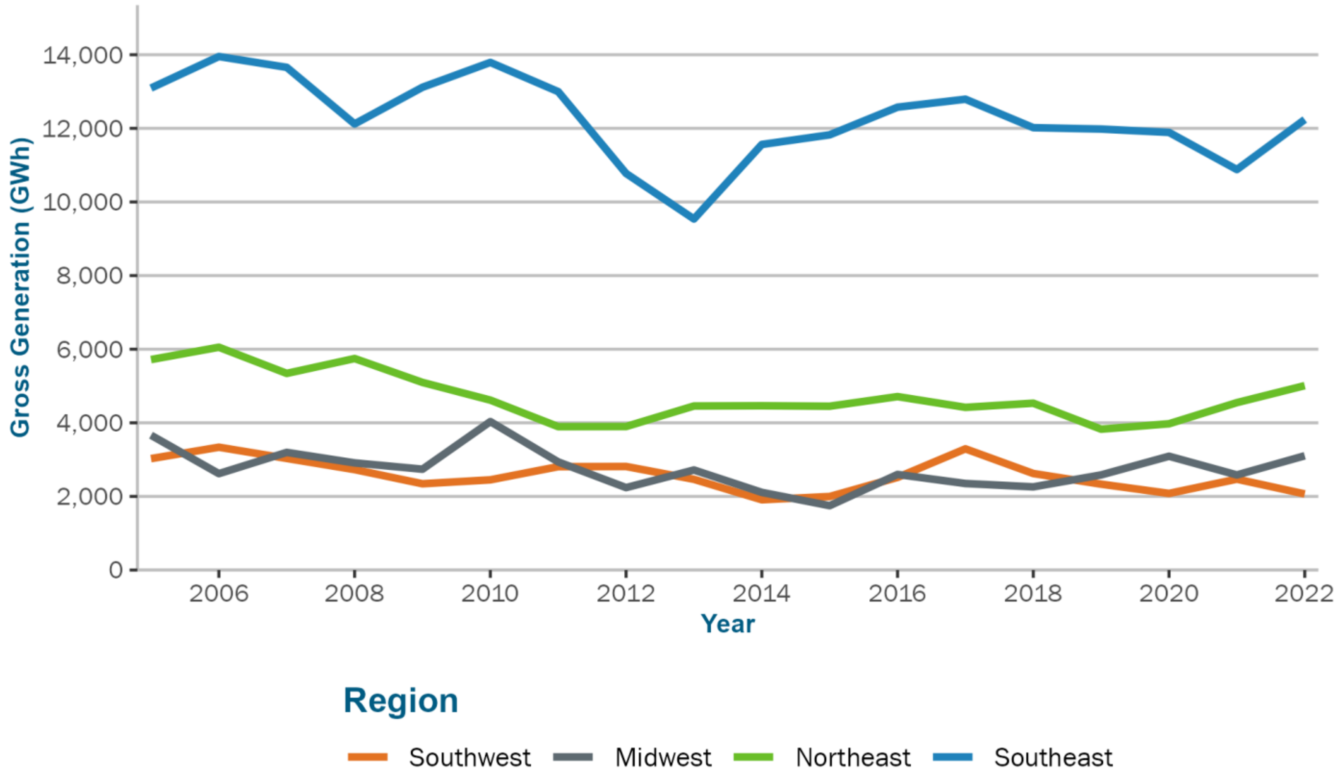


Sources: EIA Form 923, Canada Energy Regulator.
Note: Canadian imports only include imports from Hydro-Québec , Manitoba Hydro, and BC Hydro.

- The Northwest has the largest hydropower fleet by installed capacity (35.9 GW) and largest average net generation in 2005–2022 (134 TWh).
- Average regional net generation in 2020–2022 was above average in the 2010s in the Southeast (+22%) and the Midwest (+7.8%) and below average in the Northeast (-0.5%), Northwest (-6.5%), and Southwest (-31.6%).
  - The large drop in the Southwest is due to the severe drought experienced by that region.
- Average Canadian imports in 2020–2022 were 7.6% above the average in the 2010s.

Average gross PSH generation in the first three years of the 2020s (21.3 TWh) has remained stable relative to the annual average gross generation in the previous decade (21.4 TWh).

Annual gross PSH generation by region

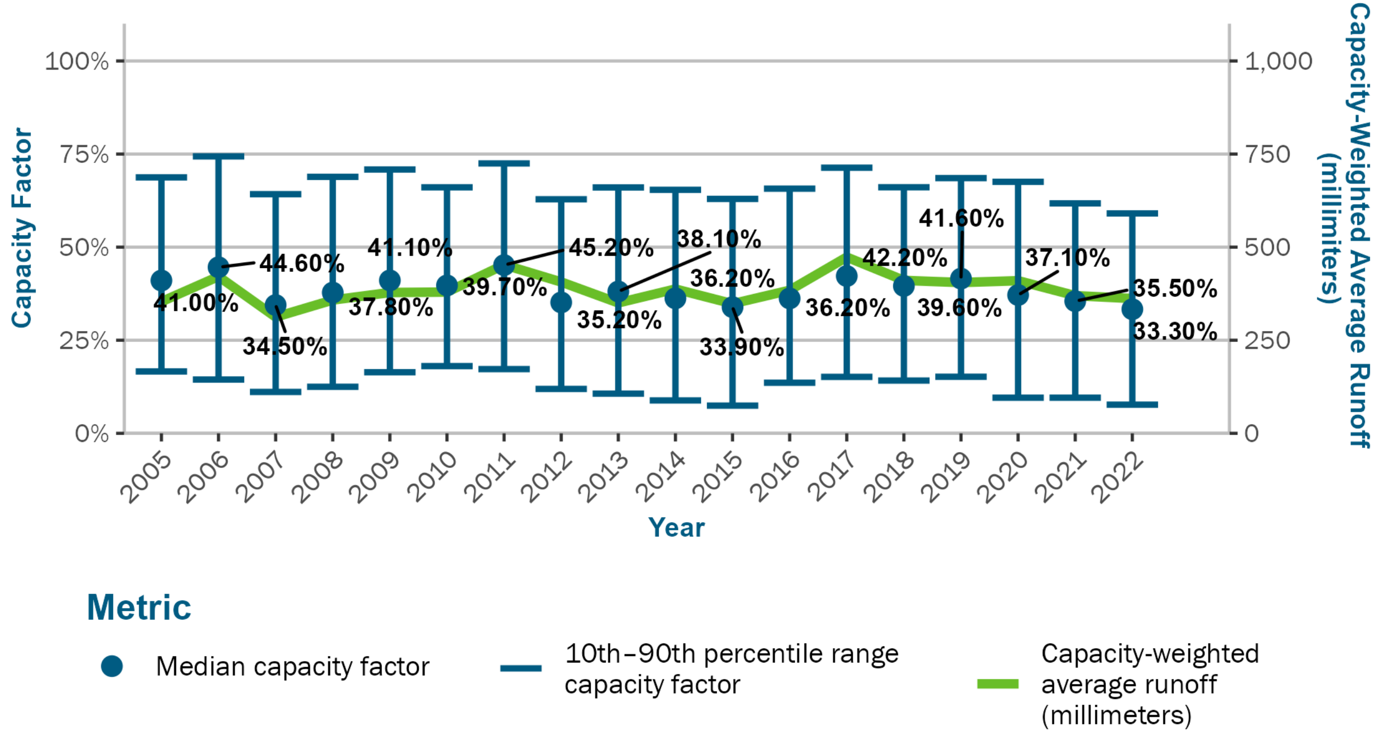


- The Southeast has the largest PSH fleet by installed capacity (9.7 GW) and largest average gross generation in 2005–2022: 12.3 TWh.
- Average regional gross PSH generation in 2020–2022 was above the average in the 2010s in the Midwest (+14.4%) and the Northeast (+4.2%) and below in the Southeast (-2.6%) and the Southwest (-12.5%).
- A substantial increase (19%) in gross PSH generation in the Southwest from 2020 to 2021 despite extreme drought is an indication that PSH use is more closely linked to market conditions than hydrology.

Source: EIA Form 923.
Note: The Northwest region was excluded because it has very little PSH capacity.

The median capacity factor in the first three years of the 2020s averaged 35.3% versus an average of 38.8% in the 2010s.

Plant-level distribution of hydropower capacity factors by year



Sources: ORNL EHA Capacity Factor Plant database 2023, 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. The USGS runoff values for the last quarter of 2022 are also preliminary values.

- From 2005 to 2022, the median hydropower capacity factor has ranged from 33% to 45%, without clear trend but closely following the trajectory of capacity-weighted average runoff.
- The 10th–90th percentile range is always very wide indicating a variety of operation modes/availabilities across the fleet.
- The 90th percentile capacity factor in 2022 was the lowest since at least 2005.

There are significant differences in hydropower capacity factors across regions and owner types.

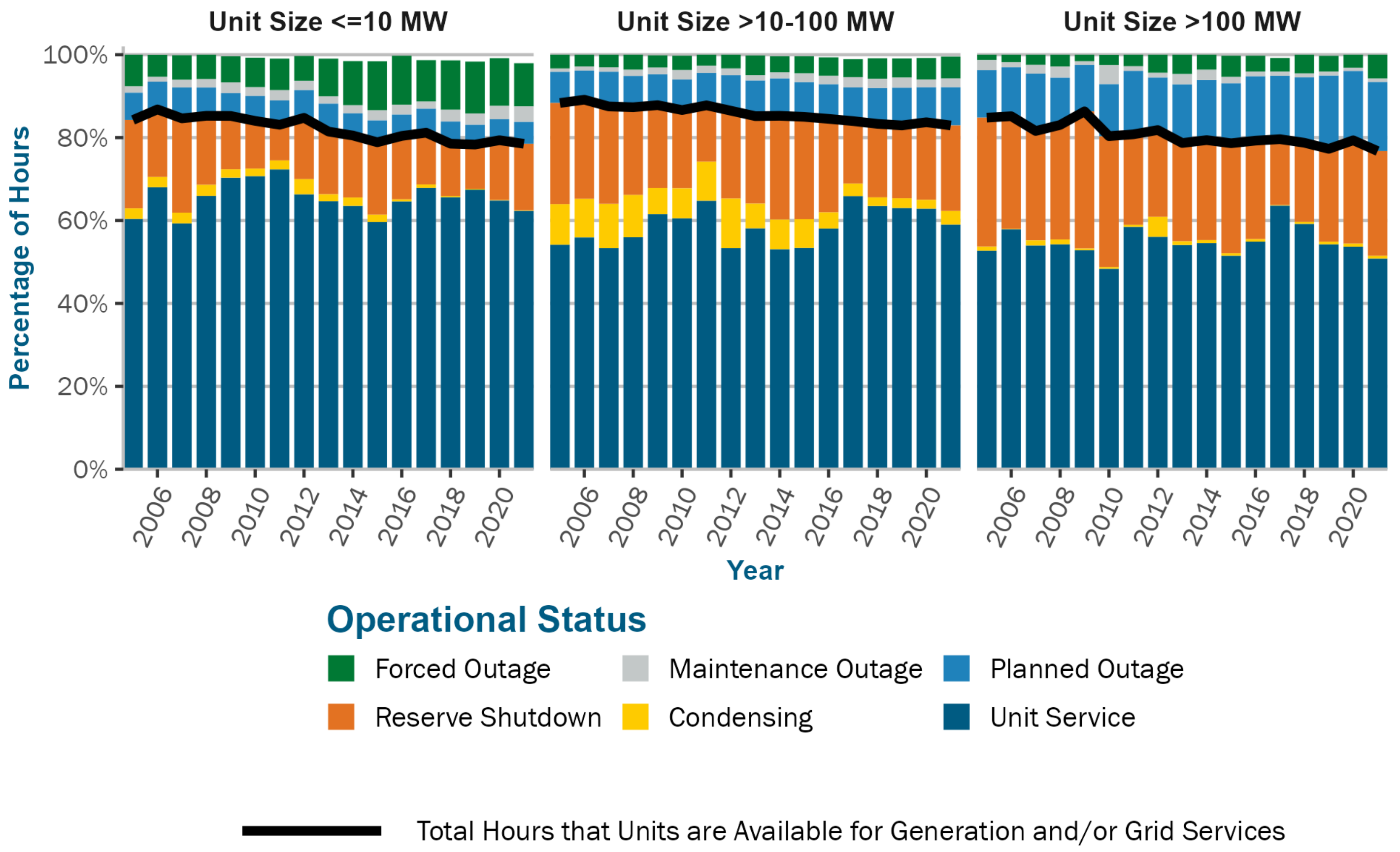
Annual average hydropower capacity factor by region, mode of operation, owner type, and market type

Sources: ORNL EHA Capacity Factor Plant database 2023, ORNL EHA Plant database 2023.
Note: The number of plants included differs across panels. The average number of plants 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 the Northwest, Midwest, and Northeast operate with consistently higher average capacity factors (typically >40%) than the Southwest and Southeast.
- The gap between average capacity factors of peaking and run-of-river plants has become increasingly narrow: as of 2022, peaking (35.1%) and run-of-river (36.7%).
  - The peaking and run-of-river categories shown in the plot are summary aggregates that include intermediate/mixed mode of operation as described in McManamay et al. (2016).
- The capacity factor of the federal fleet increased steadily from 2016 to 2020 but declined substantially in 2021 and 2022.
- The capacity factor gap by market type continued to be very narrow in 2022: ISO/RTO (35.0%) and other (33.5%).

In 2019–2021, after more than a decade of slow but steady decrease, the annual average availability factor has been stable at around 80%.

Hourly breakdown of hydropower operational status by unit size class



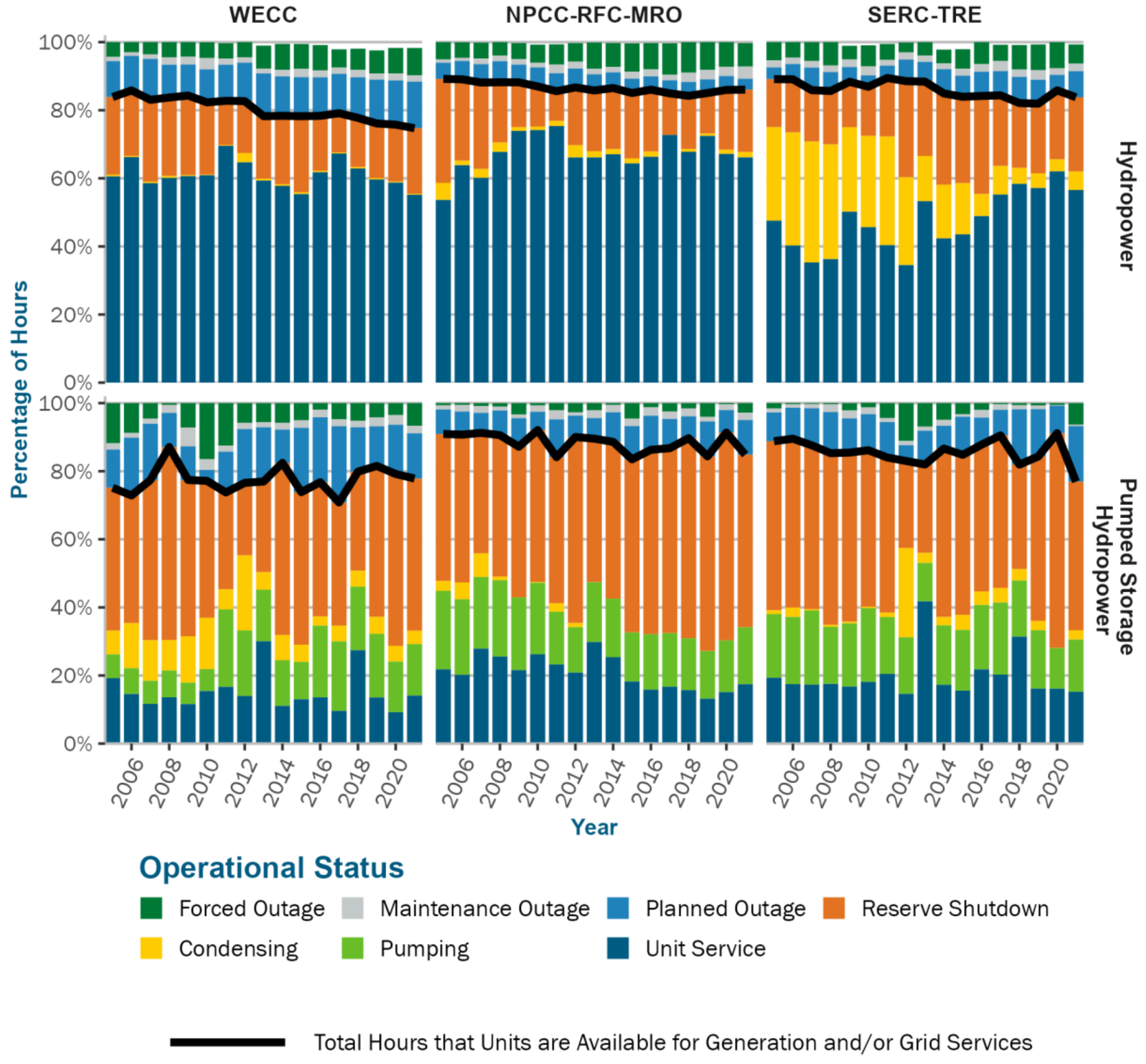
Sources: NERC pc-GAR

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

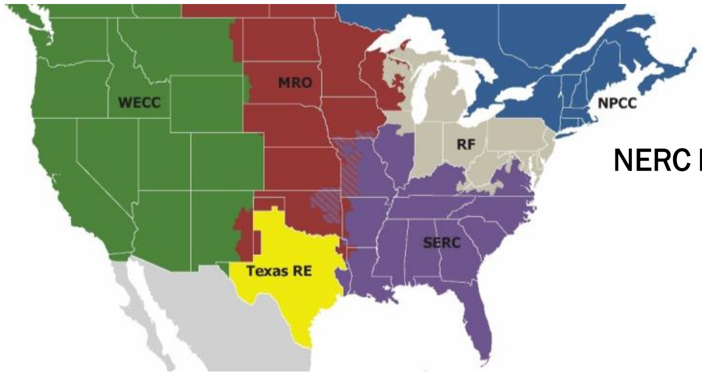
- By unit size class, the average availability factor in 2019–2021 ranged from 78% (large units) to 83% (medium units).
- Hydropower units generate electricity during unit service hours but can provide grid services during all their available hours.
- The average percentage of hours in unit service mode in 2019–2021 was 53% for large units, 62% for medium units, and 65% for small units.
- For all unit size classes, the average fractions of hours spent in condensing and reserve shutdown modes have decreased in 2019–2021 relative to 2005–2018.
- Comparing the breakdown of unavailable hours for small versus large hydropower units reveals a tradeoff between average fraction of hours spent in planned versus forced outages.

The average availability factor has been lower in WECC than in other NERC regions every year since at least 2005 and the gap has widened in 2019–2021.

Hourly breakdown of hydropower and PSH operational status by NERC region groupings



Source: NERC pc-GAR

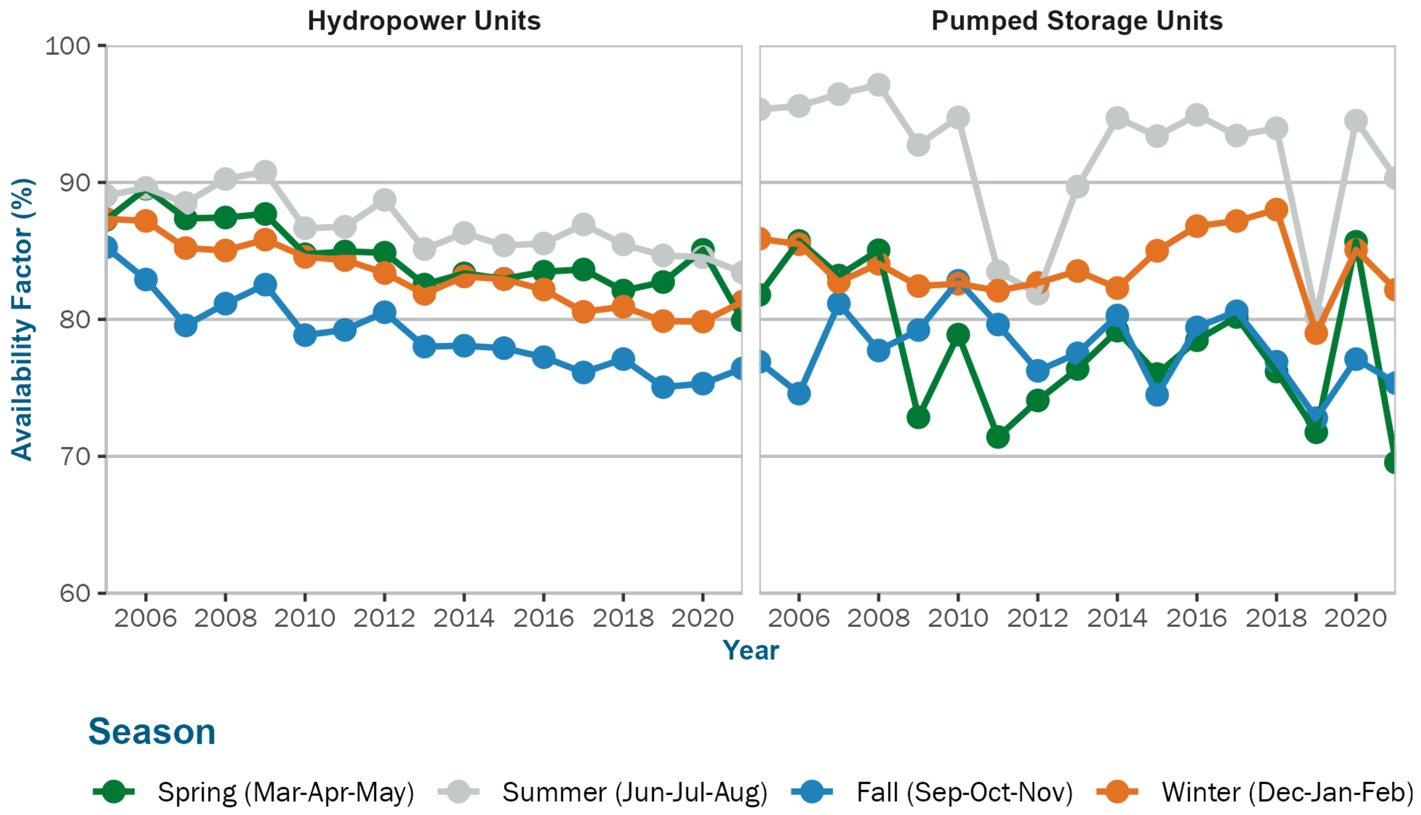


NERC Regions

- The average fraction of unit service hours for hydropower units in WECC decreased from 67% in 2017 to 55% in 2021 which is consistent with the severe drought experienced in a large portion of the region for much of that period.
- Compared to hydropower units, PSH units in every region spent less hours in unit service mode and more hours in reserve shutdown mode. Additionally, PSH units operate in pumping mode for a sizable fraction of the time (15% on average in 2019–2021) to replenish their upper reservoirs.

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.

Capacity-weighted hydropower and PSH unit availability factor by season

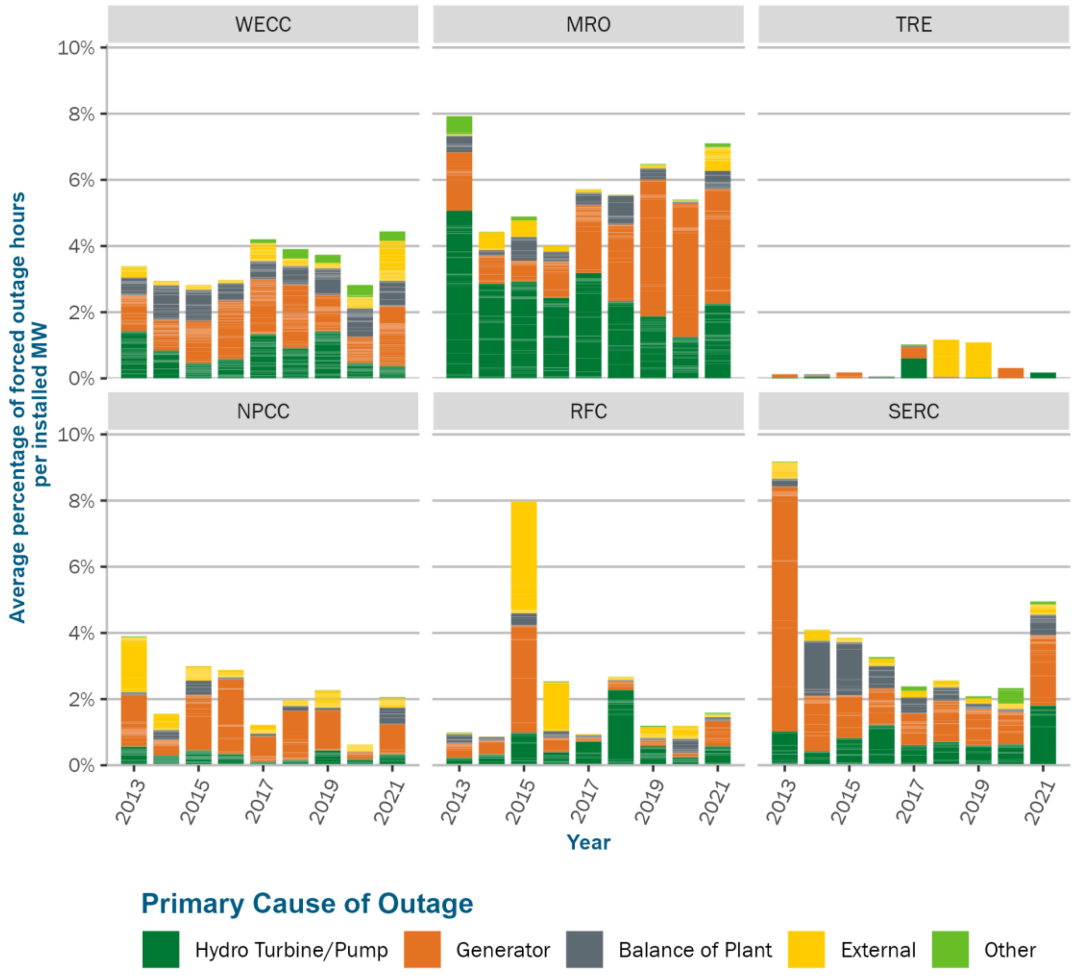


Sources: NERC pc-GAR

- For hydropower units, the decreasing trend in availability factor (AF) since the mid 2000s is common to all seasons.
  - For 2019–2021, AF has stabilized at 76% in fall, 80% in winter, 83% in spring, and 84% in summer.
  - AF being lowest in fall is largely explained by plant owners scheduling planned and maintenance outages during those months (due to electricity demand and prices being relatively low in that season).
- For PSH units, AF trends are less clear.
  - AF in summer has been in the 90%–95% range in most years showing that it is a priority for PSH plant owners to avoid outages during that season (because of large electricity demand peaks that PSH units are well suited to help manage).
  - The large drop in 2019 is likely related to the much lower number of PSH units that reported to NERC GADS that year.

The average percentage of hours in forced outage status per installed megawatt of hydropower & PSH in 2013–2021 ranged 0.5%–5.8% across NERC regions.

Average percentage of hours of forced outage per installed MW of hydropower and PSH by year, NERC region, and primary outage cause

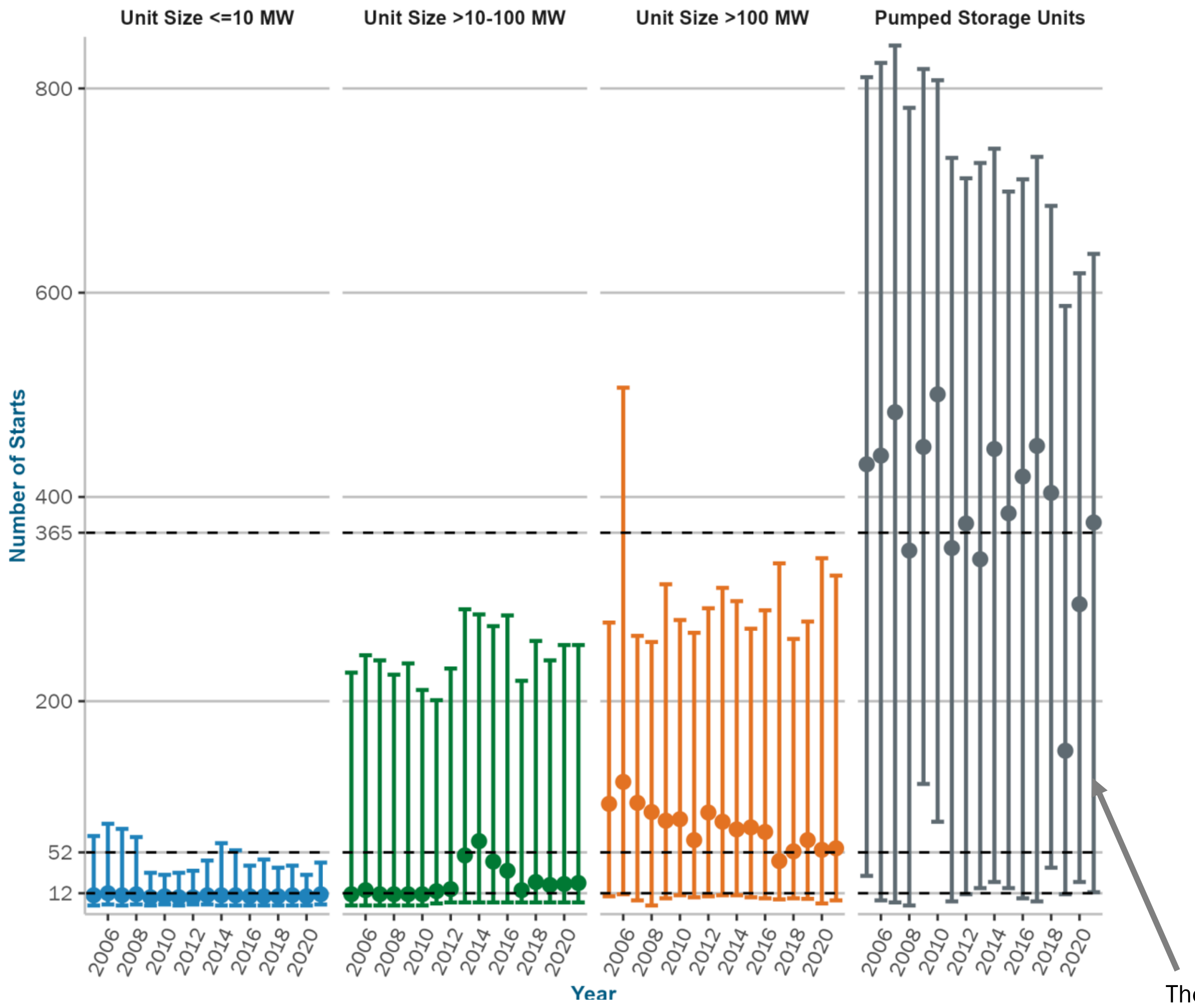


- The national average number of forced outage events reported was 3,769 per year in 2013–2021.
  - 75% of them lasted less than one day.
  - Only 5% lasted more than two weeks, but they accounted for 98% of potential generation lost.
- Failures in turbine or generator components (typically in units that are beyond their expected design life) accounted for 69% of the potential generation loss due to forced outages.
- Failures in main transformers (Balance of Plant category) and lack of water (External category) are also among the top reasons for the largest forced outages (in terms of generation lost).
  - Almost 80% of the potential generation lost due to forced outages related to lack of water were in WECC.
    - The average duration of these outages was 1 month.
    - Of the 6.4 TWh of potential generation lost in WECC for this reason in 2013–2021, 52% corresponded to outage events in 2021.

Sources: NERC GADS Cause Code Reports, ORNL EHA Capacity Plant database 2023
Note: The "**External**" category includes outages caused by catastrophes and economic reasons as well as other miscellaneous external reasons. The "**Other**" category includes outages caused by performance, personnel errors, and regulatory/safety/environmental reasons.

The average 2019–2021 median number of starts remained stable for small units, increased for medium units, and decreased for large and PSH units relative to 2005–2018.

Hydropower and PSH unit start distributions per year, unit type, and unit size



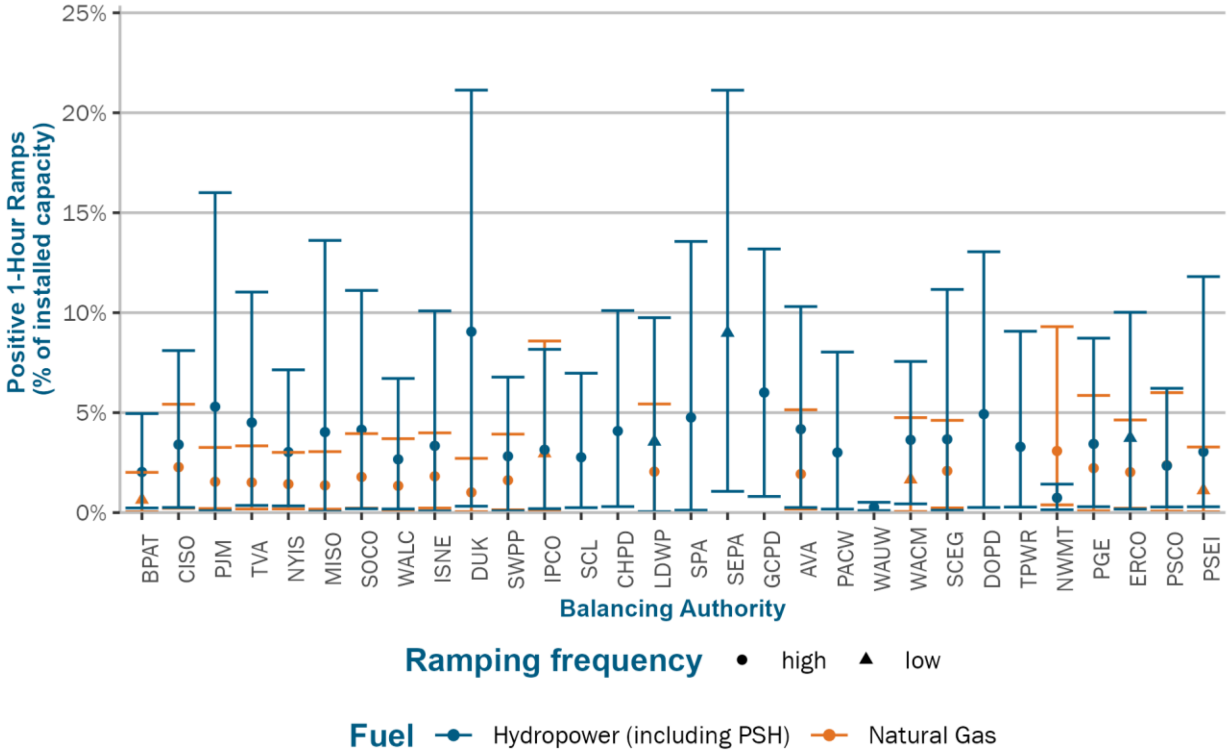
- The number of starts a hydropower unit performs per year is one measure of its level of flexibility.
- In 2019–2021, the average median number of starts was 295 for PSH units (most flexible), 56 for large units, 21 for medium units, and 10 for small units (least flexible).
- For PSH units, the decreasing trend in unit starts is more pronounced 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; in 2021, the maximum number of starts reported was 871.
- The very wide range of unit starts reported for PSH indicates that not all U.S. PSH facilities are equally flexible.

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 on that year.

Sources: NERC pc-GAR

The average observed one-hour ramps for the hydropower (including PSH) fleet is greater than the average one-hour ramp for the natural gas fleet in most balancing authorities.

One-hour ramps (as a percentage of installed capacity) for hydropower (including PSH) and natural gas for selected balancing authorities in 2022

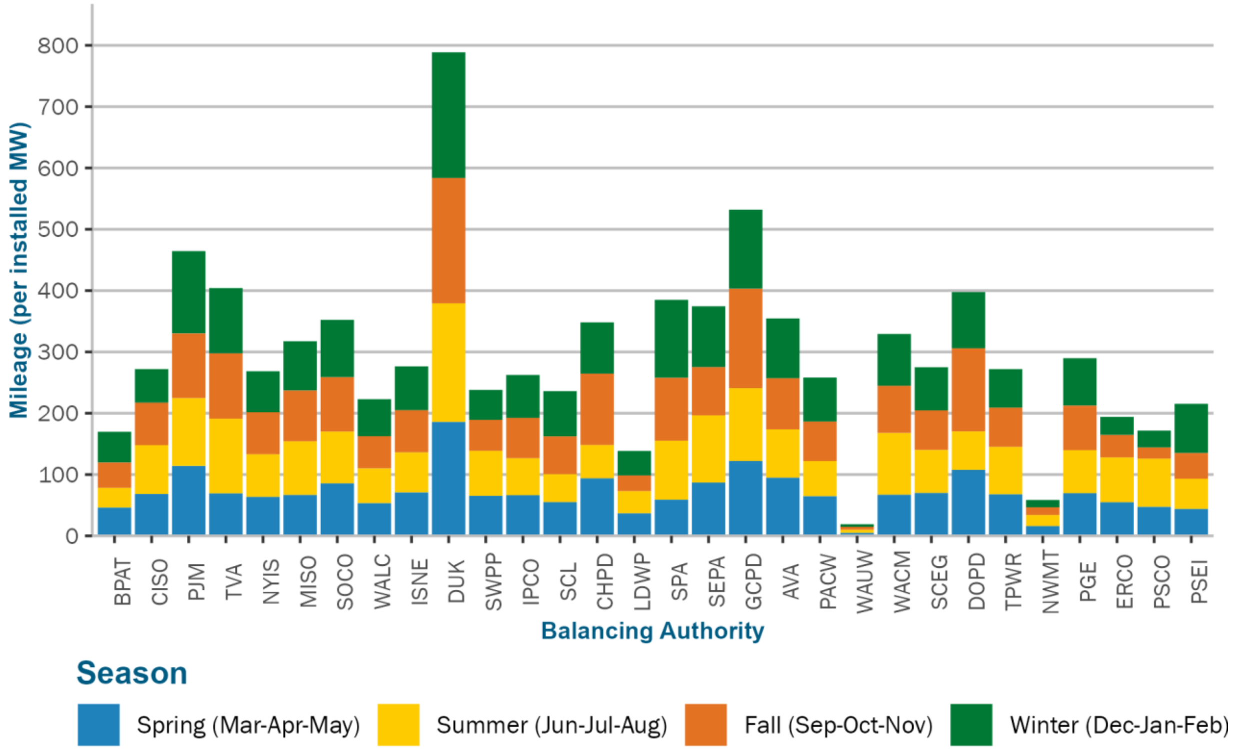


Sources: EIA Form 930, EIA Form 860 2022 Early Release
Note: Only positive ramps are shown. The distribution of negative ramps mirrors that of positive ramps. The BAs are ordered from most (BPAT) to least (PSEI) installed hydropower and PSH capacity in 2022. BAs with less than 300 MW of installed hydropower 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 and installed hydropower capacity in each BA is provided in the report Appendix. High-frequency ramping means that the fleet changed generation level (in any direction) from one hour to the next in at least 75% of hours in the year.

- Hydropower and natural gas are the two dispatchable generation technologies that perform much of the load following in most balancing authorities (BAs).
- The top ten BAs by the magnitude of the average one-hour hydropower ramp are all in the Southeast (DUK, SEPA, PJM, SPA, TVA, SOCO) or Northwest (GCPD, DOPD, AVA, CHPD) regions.
- 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.
  - The 90th percentile of the one-hour ramp distribution for the natural gas fleets is below 10% in all BAs.

The amount of one-hour hydropower ramping (summarized as mileage per installed megawatt) is not constant throughout the year; the season with the most mileage varies across balancing authorities.

One-hour ramping mileage (per installed MW) for hydropower (including PSH) fleets in selected balancing authorities (2022)

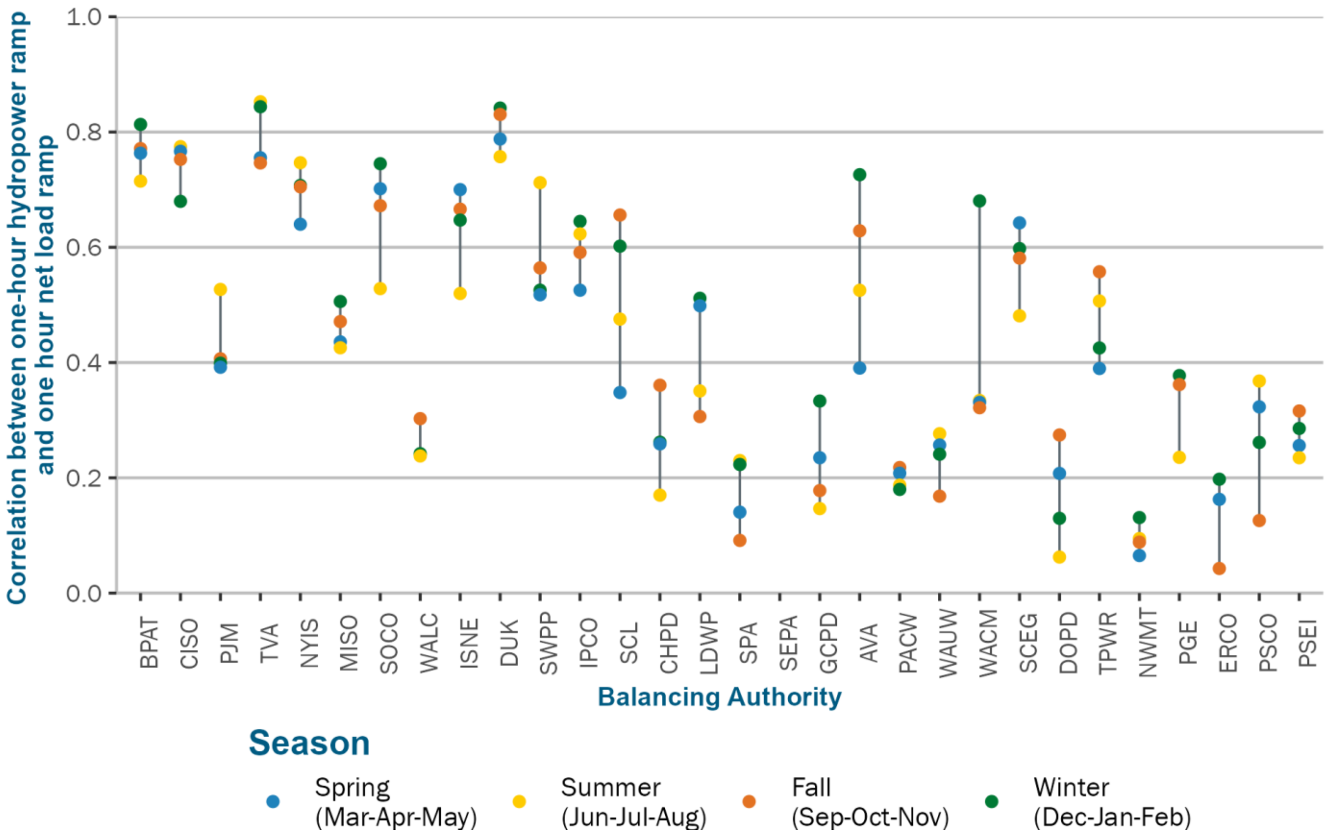


Sources: EIA Form 930, EIA Form 860 2022 Early Release.
Note: The BAs are ordered from most (BPAT) to least (PSEI) installed hydropower and PSH capacity in 2022. BAs with less than 300 MW of installed hydropower and PSH capacity or with generation values greater than what would be feasible given the installed capacity are excluded. A list of BA names to match the acronyms and installed hydropower capacity in each BA is provided in the report Appendix.

- One-hour ramping mileage ranged from 200 and 400 MW per installed MW in 2022 in most BAs.
- By far, the hydropower fleet in DUK (Duke Energy Carolinas) performed the most ramping in 2022.
  - Two thirds of installed hydro capacity in that BA are two highly flexible PSH facilities.
- The hydropower fleets in WAPA Upper Great Plains West (WAUW) and Northwestern Corporation(NWMT) had the lowest ramping mileages.
  - For WAUW, the low mileage is due to the very low capacity factor reported for the hydropower fleet.
  - In NWMT, at least 40% of installed hydropower capacity is run-of-river.
- Seasons with highest mileage: winter (15 BAs), summer (12 BAs), fall (3 BAs).
  - BAs with highest mileage in summer include most of the ISO/RTOs (NYISO, MISO, CAISO, SPP, ERCOT).
  - In most of the BAs in the Northwest, the lowest seasonal share of mileage, happened in summer.

Correlation between one-hour hydropower ramps and hourly changes in net load varies widely across balancing authorities; it also varies across seasons depending on hydrologic conditions and operational constraints.

Correlation between one-hour hydropower (including PSH) ramps and hourly changes in net load in 2022, by balancing authority and season.



Sources: 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 and installed hydropower capacity in each BA is provided in the report Appendix. No correlation is computed for SEPA because it is a generation-only BA and does not report load data to EIA Form 930.

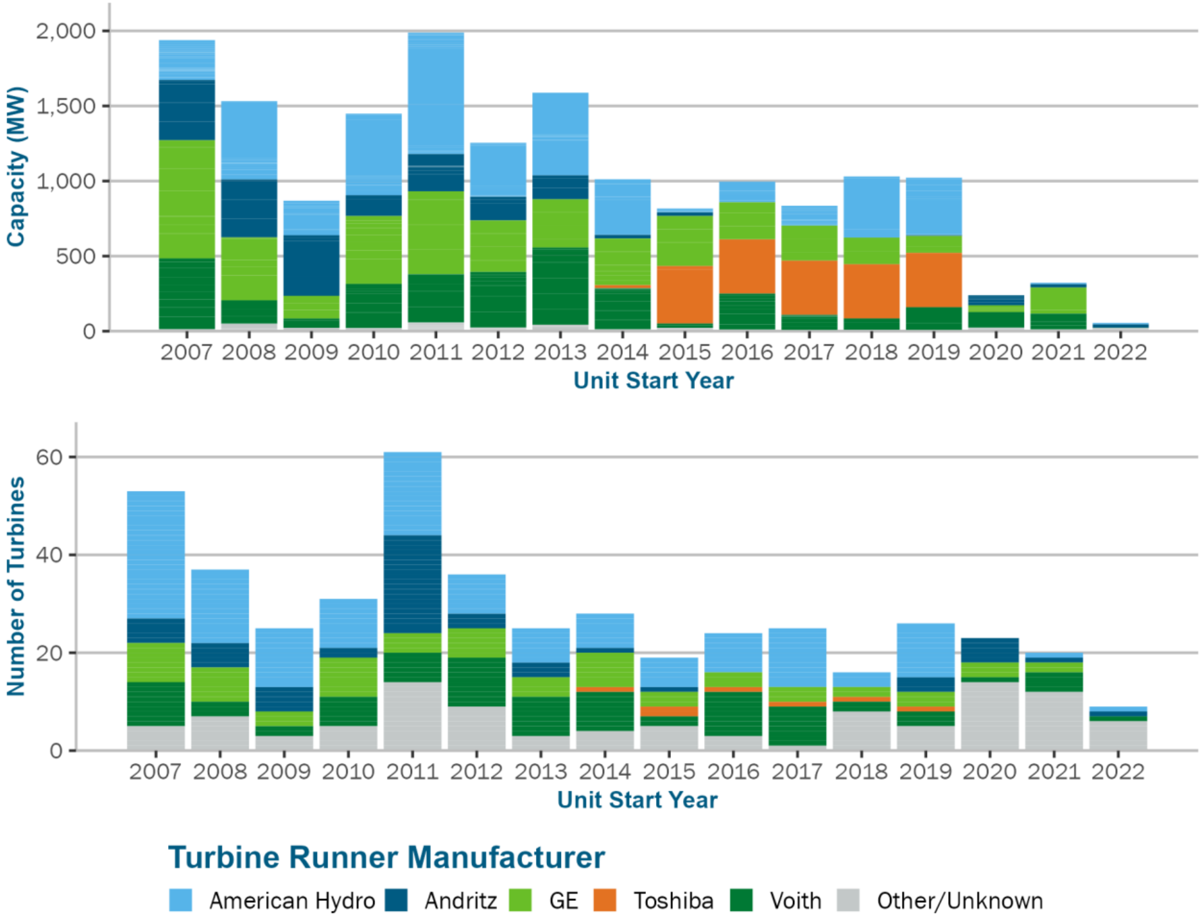
- Most of the correlations greater than 0.6 correspond to large fleets such as those of BPAT (Bonneville Power Administration; 22 GW), CAISO (California ISO; 8.8 GW), and TVA (Tennessee Valley Authority; 6.7 GW).
- Correlation is highest in winter for 12 of the BAs, 8 in summer, 8 in fall, and the remaining 2 in spring.
  - Seasonal variability in ramping patterns is related to:
    - hydrologic conditions
    - operational constraints
      - to mitigate environmental impacts
      - to ensure the dams continue to satisfy their other authorized purposes (e.g., flood control, irrigation)

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

6.1 Hydropower and PSH Turbine Installations
6.2 Hydropower and PSH Turbine Imports/Exports
6.3 Supply chain challenges and opportunities

Annual average hydropower capacity for which runners were installed in 2020–2022 (206 MW) was much lower than in 2007–2019 (1,256 MW).

Annual installations of hydropower and PSH turbine runners in the U.S. by manufacturer

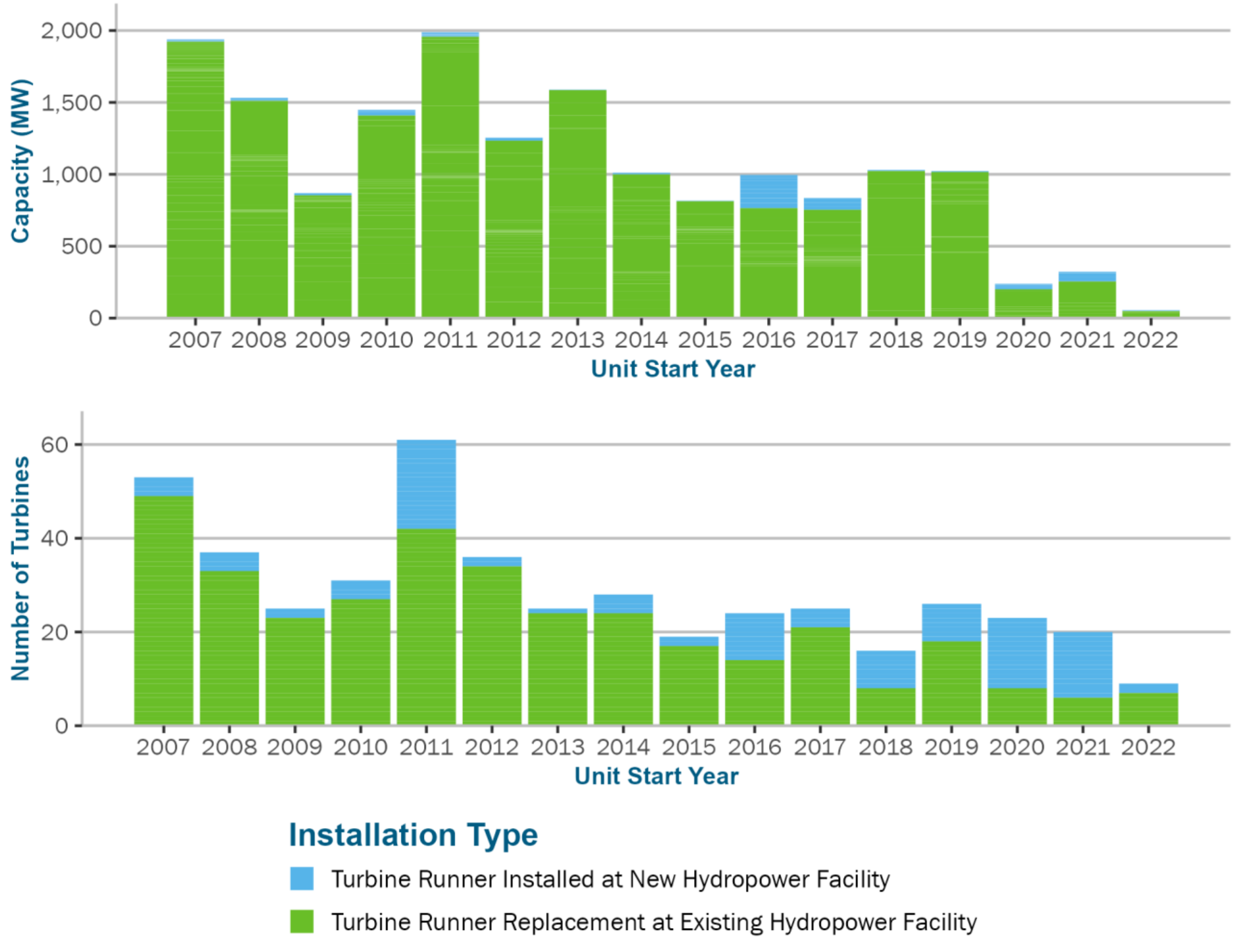


Sources: IIR, ORNL EHA Unit dataset 2023, personal communication with Debbie Mursch (GE)

- At least 52 turbine units were installed in the United States (617 MW) in 2020–2022.
  - 31 were installations at new facilities; they accounted for 18% of total installed capacity.
    - The units at Red Rock (55.2 MW) and Lake Livingston (26.7 MW) accounted for almost 75% of the capacity installed at new plants.
  - Among the 21 turbine runner replacements (506 MW), one PSH unit for Cabin Creek (CO) accounts for more than 25% of capacity.
- Five original equipment manufacturers (OEMs) supplied more than 70% of runners installed in 2013–2022 (98% of capacity).
  - Median capacity of units for which these companies supplied runners: 22 MW.
  - American Hydro, Andritz, and Voith have manufacturing facilities in the United States.
- Fifteen different companies manufactured the 61 units with “Other/Unknown” manufacturer.
  - Median capacity of units for which these companies supplied runners: 0.9 MW.

Two thirds of runner installations in the past 10 years have been replacements at existing units.

Annual installations of hydropower and PSH turbine runners in the U.S. at new versus existing facilities

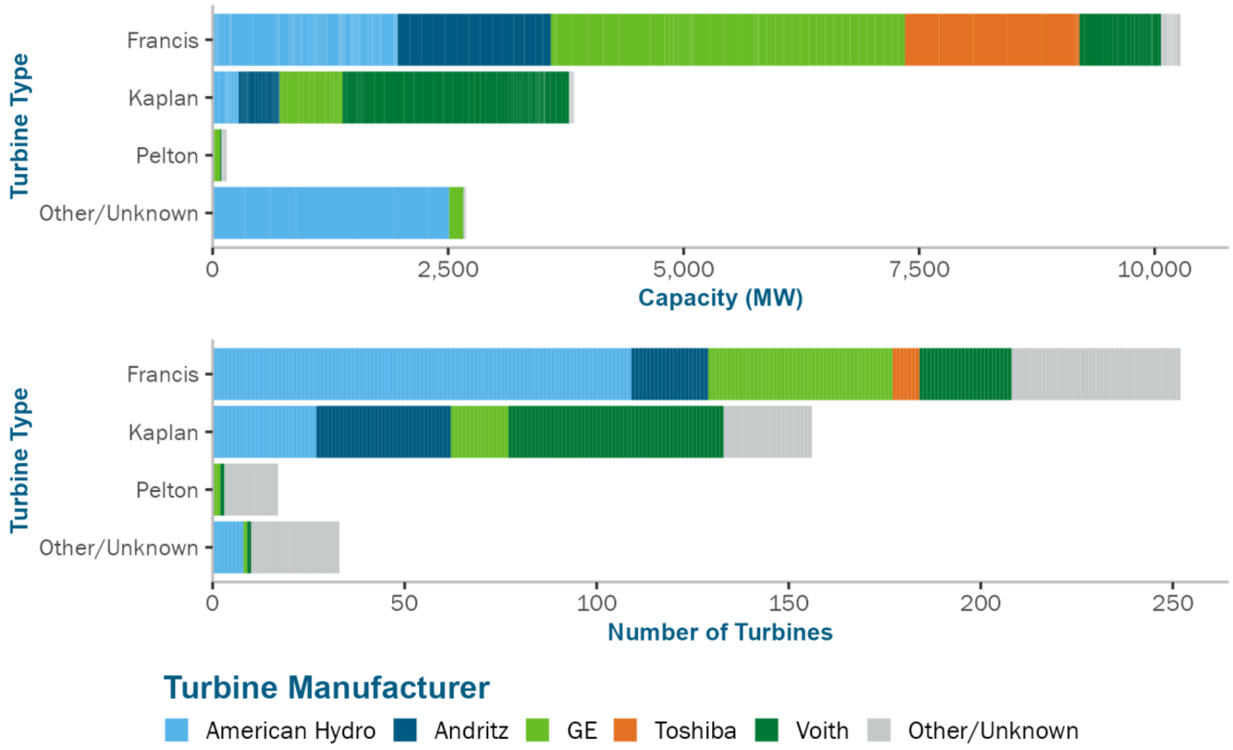


- The average capacity of units for which runners were installed at new plants since 2013 was 7 MW and the median capacity was 1.1 MW.
- For runners installed at existing facilities, the average unit capacity was 50.7 MW and the median capacity was 18 MW.

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

Almost half of all turbine runners installed in the past decade were Francis; however, at new facilities, Kaplan units accounted for 86% of installed capacity.

Installed hydropower and PSH turbines in the United States by type and manufacturer (2007–2022)

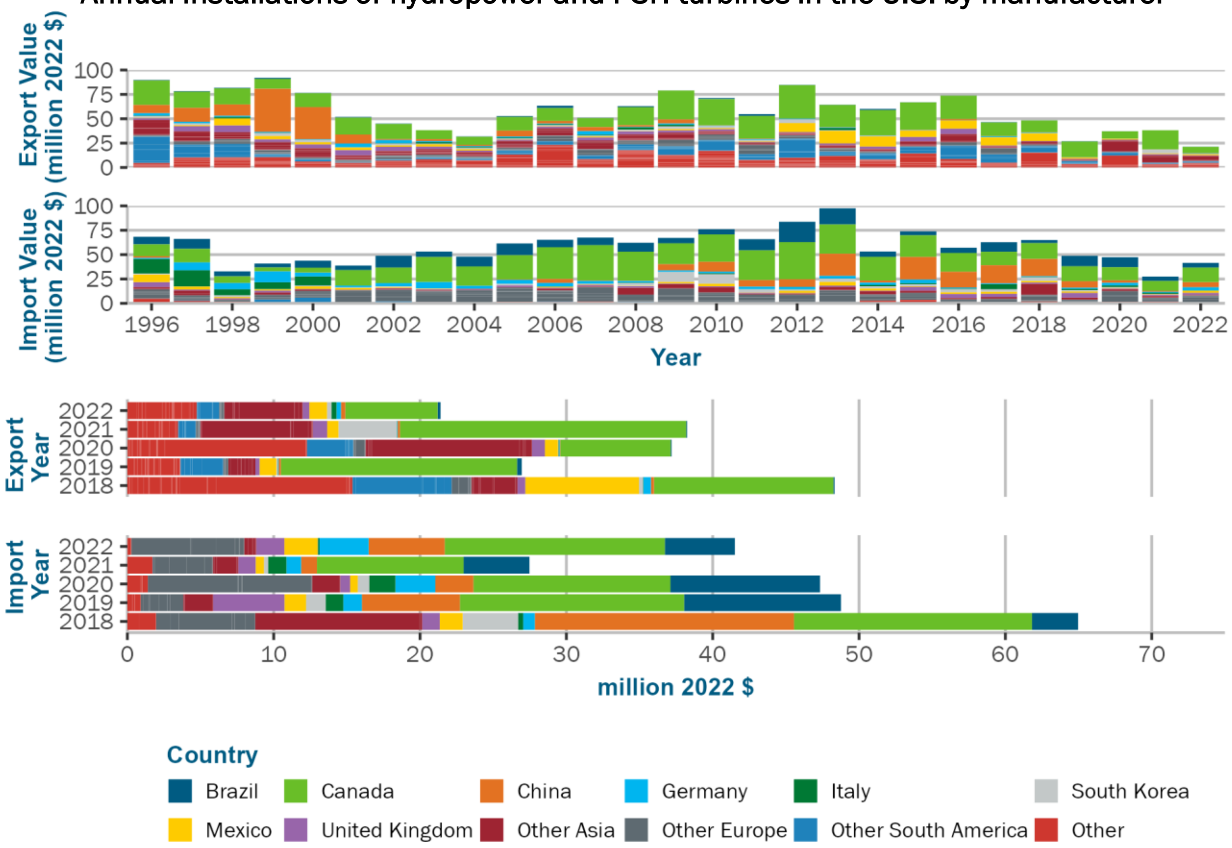


Sources: IIR, ORNL EHA Unit dataset 2023, personal communication with Debbie Mursch (GE)

- In 2013–2022:
  - 47% of units installed were Francis.
    - American Hydro and GE were the two companies that manufactured the largest number of Francis turbines.
  - 35% of units installed were Kaplan.
    - Voith captured the largest market share (45%) for this turbine type.
    - Among installations at new facilities, Kaplan represented 86% of installed capacity (mostly at low-head non-powered dam retrofit projects).
  - 7% of units installed were Pelton (used in high-head hydropower sites).

In 2020–2022, U.S. hydraulic turbine trade value has been lower than the average for 1996–2019 for both imports and exports. Canada continues to be the top exporter and importer.

Annual Installations of hydropower and PSH turbines in the U.S. by manufacturer



Source: U.S. International Trade Commission
Note: Hydraulic turbine trade data were queried through the Interactive Tariff and Trade Data Web (https://dataweb.usitc.gov). The values presented in Figure 58 are "Customs Value," which exclude any shipping or duty costs. They include the values from Harmonized Tariff Schedule (HTS) 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." Some turbine-generator sets ("water-to-wire" packages) used in small hydropower plants are not included in the plot because the HTS does not have a hydropower-specific statistical reporting number for turbine-generator sets.

- Average trade values of hydraulic turbines and turbine parts:
  - 2020–2022: $62 million (exports), $60 million (imports).
  - 1996–2019: $32 million (exports), $39 million (imports).
- Import value in 2021 was the lowest since at least 1996.
- Top U.S. export destinations (2020–2022): Canada (34%) and Indonesia (14%).
- Top U.S. import origins (2020–2022): Canada (33%), Brazil (17%), China (8%)
  - Imports from all European countries combined accounted for 32% of total U.S. imports.
- Decrease in traded value started in 2019; the year after 25% tariffs on Chinese turbines and most foreign steel were imposed.
  - By 2023, the tariffs on foreign steel have been lifted (or replaced by tariff-rate quotas) for the countries where most large steel castings for U.S. hydropower turbines originate (except China).

Executive Order 14017 "America's Supply Chains" directed the Secretary of Energy to submit a report on supply chains for the energy sector industrial base.

- The Hydropower Supply Chain Deep Dive Assessment (2022) is one of 11 reports produced by DOE to comply with the E.O. 14017. It identified U.S. hydropower supply chain challenges and opportunities.

- Key challenges:
  - Large steel castings (>10 tons) are very difficult to procure domestically.
    - Large castings are imported mainly from Brazil, China, Eastern Europe, and South Korea.
  - Stator windings from large units (>100 MW) are very difficult to procure domestically.
    - Typically imported from Canada, Mexico, Brazil, and Europe.
  - Limited hydropower workforce availability
    - Difficult to hire skilled tradesmen (e.g., machinists, welders), engineers, construction workers for jobs at remote sites.

- Opportunities:
  - Additive manufacturing is well suited to produce custom parts with complex geometries and may offer an alternative to produce domestically some of the components that currently have to be imported.
    - Some turbine OEMs already use additive manufacturing to produce small components as well as molds and castings.
  - Refurbishing and upgrading the U.S. hydropower and PSH fleets offers a large market opportunity to companies considering reshoring manufacturing operations.
  - Federal procurement rules can be leveraged to increase the domestic content of hydropower plant components used in R&U projects for the federal fleet.
    - For Buy American Act domestic content requirements to be widely applicable in federal hydropower R&U projects, the current value threshold ($7,032,000) would have to be raised.

Domestic content requirements in federal incentives and federal procurement rules try to spur increased domestic manufacturing of hydropower components.

- *Buy American Act* sets domestic content requirements for federal procurement.
- Non-federal entities receiving incentives from the Bipartisan Infrastructure Law (Section 242, Section 243, Section 247) are also bound by the domestic preference requirements set in the *Build America, Buy America Act.*
  - Non-federal entities include States, local governments, territories, Indian tribes, Institutions of Higher Education, and nonprofit organizations.
  - For-profit organizations are excluded from the requirements.
- The Inflation Reduction Act (IRA) tax credits for new hydropower and PSH facilities (Section 45, Section 48, Section 45Y, Section 48E) include domestic content bonuses; for tax-exempt entities requesting the elective pay option, domestic content thresholds are required.
- Section 48C qualified advanced energy property credits extended by the IRA apply to investment in factories to produce hydropower components.
  - Factory owners may claim the full credit of 30% if wage and apprenticeship requirements are met (6% otherwise).
  - Of the total $10 billion authorized in the IRA for these credits, at least $4 billion must be allocated to factories located in energy communities.

Chapter 7: Policy Developments

Federal Laws

1. Bipartisan Infrastructure Law of 2021
2. Inflation Reduction Act of 2022
3. Proposed changes to permitting process (S.1521)

Federal regulations

1. FERC dam safety rule
2. FERC financial assurance measures (under consideration)

State-level policy

1. Updates to Renewable Portfolio Standards (RPS), Clean Energy Mandate/Goals, Energy Storage Mandates

Hydropower incentives in the Bipartisan Infrastructure Law

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.** **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 a) electric outage frequency, or b) retail residential electricity price.) 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 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). 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, selection based on ranking of total efficiency improvements.
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 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 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, selection based on ranking of benefits provided.

[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.

Relevant incentives in the Inflation Reduction Act

Credit	Qualified facilities/projects	Credit amount	Credit adders
Production Tax Credit (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)
Investment Tax Credit (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)

Notes:

- Recipients of Section 45, Section 48, Section 45Y, or Section 48E that 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).
- Locations that qualify as **energy communities:** (1) certain brownfield sites, (2) statistical areas with substantial fossil fuel production and unemployment rates higher than the national average, (3) Census tracts where a coal mine was closed after 12/31/1999 or a coal-fired unit was retired since 12/31/2009 (or tracts directly adjoining those were the closure or retirement took place).

The *Community and Hydropower Improvement Act* (S.1521) contains a licensing reform proposal.

- Introduced in the Senate in May 2023; developed by a coalition of representatives of the hydropower industry, environmental organizations, and Tribes.

Key proposal points:

- Proposes **expedited licensing for qualifying NPD and closed-loop PSH projects**
  - FERC shall issue its final decision on a license application within 2 years (for NPDs) or 3 years (for closed-loop PSHs) after it determines a proposed facility qualifies for the expedited process.
    - FERC must determine if a project qualifies within 90 days of submission of the Notice of Intent to file a license application.

- Directs FERC to improve **clarity and predictability of the license surrender process**
  - Set timelines and provide opportunities for public participation throughout the process

- Expands the **authority of tribal nations in the licensing process**
  - Shifts mandatory conditioning authority from the Department of interior (traditionally acting as trustee to the Tribes) to a Tribe for any project on a tribal reservation

- Requires proving the **linkage between license conditions and project effects**
  - Project effects are the ongoing or foreseeable reasonable environmental effects that would not occur or be different but for the continued operation or new construction of the project.

- Requires agencies and Tribes with mandatory conditioning authority to 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.

Recent FERC regulatory actions focus on the analysis and mitigation of hydropower dam risks (physical and financial).

- Publication of updated dam safety rules in December 2021
  - It introduces two tiers of project safety inspections by independent consultants.
  - The periodicity of the inspection continues to be 5 years, but it alternates in scope between a periodic inspection and a new, more in-depth <u>comprehensive assessment including a semiquantitative risk analysis</u>.
    - The comprehensive assessment is a new process and will require learning and adaptation by project owners.
  - Greater emphasis on ensuring that the independent consultant team has <u>adequate collective expertise</u> to evaluate each project.

- Inquiry into the need for new financial assurance rules
  - The objective is <u>avoiding situations where insufficient funding might result in hydropower project owners not being able to comply with all the license terms resulting in public safety and environmental hazards</u>.
  - FERC published a draft Notice of Inquiry in January 2021 seeking input on whether additional financial measures are needed and requesting comment on three options:
    - Requiring licensees to obtain bonds
    - Creating an industry-wide fund or requiring licensees to have funds placed in escrow
    - Requiring licensees to obtain insurance policies to cover costs in the event of a safety hazard
  - FERC held a technical conference in April 2022 to further discuss this topic and has not made any further announcements.

In 2021–2022, seven states have increased their RPS and clean energy mandates/goals. Two more states have adopted energy storage mandates.

RPS updates:

- *Delaware*: from 28% by 2030 to 40% by 2035.
- *Illinois*: from 25% by 2026 to 50% by 2040.

Clean energy mandates/goal updates:

- *Nebraska*: 100% carbon-free generation goal in 2050
- *North Carolina*: 100% of electricity sales from carbon neutral generation by 2050
- *California*: 90% clean electricity by 2035
- *Rhode Island*: 100% of electricity must be offset by renewable production by 2033
- *Oregon*: 100% of electricity sales from carbon-neutral generation sources by 2040

RPSs often have restrictions on the types of hydropower projects that count toward compliance: all hydropower typically counts towards clean energy mandates/goals.

Energy storage mandate (requirements for utilities to have a specified amount of energy storage capacity in their resource portfolios by a specified deadline) updates:

- *Maine*: target of 300 MW by the end of 2025 and 400 MW by the end of 2030
- *Connecticut*: target of 300 MW by the end of 2024 and 1,000 MW by 2030
- Illinois, Vermont, and Michigan are also considering energy storage targets.

These targets are more geared toward battery installations than long-duration storage such as PSH.

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