



2017 Hydropower Market Report

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On the front cover: Norris Dam, Anderson County, TN (image courtesy of Brennan Smith). Norris Dam was the first dam built by the Tennessee Valley Authority. Its construction, with flood control and hydroelectric production as primary purposes, started in 1933 and was completed in 1936. The hydropower plant at Norris Dam contains two units with combined nameplate capacity of 131.4 MW.

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Acronyms and Nomenclature

AMP	American Municipal Power	NPD	Non-powered dam
BAB	Build America Bonds	NSD	New stream-reach development
Bonneville	Bonneville Power Administration	NYISO	New York Independent System Operator
CAISO	California Independent System Operator	O&M	Operations and maintenance
CREB	Clean Renewable Energy Bond	OECD	Organization for Economic Cooperation and Development
CPI	Consumer Price Index	PMA	Power marketing administration
DSCI	Drought severity and coverage index	PJM	Pennsylvania New Jersey Maryland Interconnection, LLC
EIA	Energy Information Administration	PPA	Power purchase agreement
ERCOT	Electric Reliability Council of Texas	PSH	Pumped storage hydropower
FCRPS	Federal Columbia River Power System	PTC	Production tax credit
FERC	Federal Energy Regulatory Commission	PURPA	Public Utility Regulatory Policies Act
GADS	Generating Availability Data System	R&U	Refurbishments and upgrades
GW	gigawatt	REC	Renewable energy credit
GWh	gigawatt-hour	Reclamation	U.S. Bureau of Reclamation
HREA	Hydropower Regulatory Efficiency Act	RPS	Renewable portfolio standard
IIR	Industrial Info Resources	RTO	Regional transmission organization
IOU	Investor-owned utility	Southeastern	Southeastern Power Administration
ISO	Independent system operator	Southwestern	Southwestern Power Administration
ISONE	ISO New England	SPP	Southwest Power Pool
ITC	Investment tax credit	TVA	Tennessee Valley Authority
kW	kilowatt	USACE	U.S. Army Corps of Engineers
LOPP	Lease of power privilege	USDA	U.S. Department of Agriculture
MISO	Midcontinent Independent System Operator	USITC	U.S. International Trade Commission
MW	megawatt	Western	Western Area Power Administration
MWh	megawatt-hour		
NEPA	National Environmental Policy Act		
NERC	North American Electric Reliability Corporation		
NHAAP	National Hydropower Asset Assessment Program		

Executive Summary

The U.S. hydropower fleet represents 7% of total electricity generation installed capacity (as of the end of 2016) and produces 6.3% of electricity (2014-2016 average). In addition, 43 pumped storage hydropower (PSH) plants with a total capacity of 21.6 GW provide 95% of utility-scale electrical energy storage in the United States. The U.S. fleet is the third largest in the world for both hydropower and PSH.

U.S. hydropower capacity has increased by 2,030 MW from 2006 to 2016 bringing installed capacity to 79.99 GW across 2,241 separate plants. Of this net increase, 70% (1,435 MW) resulted from refurbishments and upgrades (R&U) to the existing fleet. Most of the 118 new hydropower plants that have started operation since 2006 involved additions of hydropower generation equipment to non-powered dams (40) or conduits (73), but five new stream-reach development (NSD) projects also started operation from 2006 to 2016—all of them in the Northwest. The median size of new plants is small (≤ 10 MW); the largest new hydropower plants coming on line over the last decade were the NPD projects developed by American Municipal Power along the Ohio River: Meldahl (105 MW), Cannelton (88 MW), Smithland (76 MW), and Willow Island (44 MW).

The addition of hydropower generation equipment to existing water resource infrastructure is also the dominant trend in planned new developments. **At the end of 2017, there are 214 projects with combined proposed capacity of 1,712 MW in the U.S. hydropower project development pipeline.** The predominant project type varies by region. Proposed developments in the Midwest, Southeast, and Northeast region are almost exclusively NPD projects. In the Southwest, most projects would add hydropower to existing conduits and irrigation canals. The Northwest has the most diverse project pipeline and contains all proposed new stream-reach developments (except for 1 in New York). Nationally, NPD projects account for 92% of proposed capacity. Thus, the success of recent initiatives to improve the efficiency of the authorization process for this type of project is crucial.

As with hydropower, substantial PSH capacity increases (2,074 MW) have been achieved since 2006 by upgrading turbine-generator units in the existing fleet; only one new PSH facility (40 MW) has started operation in that period. The lack of PSH construction in the United States contrasts with abundant PSH development around the world. Since 2006, 22 PSH facilities have been built in East Asia—mostly China—and nine in Europe. In addition, these two regions have 26 and 7 more PSH plants under construction respectively. This disparity in PSH development activity between the United States and the rest of the world could be due to differences in the authorization process and/or the available revenue streams, and deserves further analysis.

The new generation of PSH facilities being proposed in the United States are substantially different in a number of ways from the existing PSH fleet. Most of the proposed new projects are closed-loop facilities, not connected to rivers. This lowers their likely environmental impact and potentially opens up a variety of new candidate sites. They also differ in their proposed mode of operation. Much of the existing fleet was built as a complement to baseload coal or nuclear plants, and business models were mainly focused on taking advantage of price differentials between on-peak generation hours and off-peak pumping hours. However, with lower electricity prices observed for most of the last decade, such modes of operation would not lead to attractive rates of return for new projects in most locations. Instead, new PSH license applications emphasize their versatility as providers of grid services, particularly in areas of the country with ambitious RPS targets. At the end of 2017, developers were investigating PSH feasibility on 40 sites and had six pending FERC license applications. In addition, two projects (Eagle Mountain in California and Gordon Butte in Montana) have FERC licenses and could become the first large new PSH facilities in more than 20 years if they proceed to construction.

The U.S. hydropower fleet contributes to grid reliability and resilience through significant ramping capabilities and the provision of a host of grid services ranging from frequency regulation to operation reserves and black start. **Hydropower provides load following flexibility in all ISO/RTO markets;** daily patterns of hydropower generation follow electricity use patterns closely. The California market (CAISO) is the only ISO/RTO in which variable renewables have notably changed the typical daily hydropower generation profile. In CAISO, hydropower is more closely correlated with net load (i.e., load net of wind and solar generation) than with load.

Hydropower's ability to quickly adjust output up or down to follow changes in net load makes it play a key role as complement to the much larger, and also highly flexible, natural gas fleet in integrating variable renewables. The average one-hour ramp for the hydropower fleet (as a percentage of installed capacity) is greater than for natural gas in all ISO/RTOs. In addition, hydropower adjusts its output up or down by more than 5% of its installed capacity from one hour to the next more frequently than natural gas, especially in the ISO/RTOs with most PSH capacity. Nevertheless, natural gas follows net load more closely (i.e., its ramps are more highly correlated with net load than those from the hydropower fleet) likely due to the fact that its operations are not subject to the restrictions experienced by hydropower due to non-power purposes of storage reservoirs, minimum flow requirements, or water quality constraints.

U.S. hydropower R&U projects worth \$8.9 billion have started from 2007 to 2017. Based on a snapshot of active R&U projects around the world at the end of 2017, the United States has one of the highest expenditures per installed kilowatt. It also has one of the oldest fleets. Investment is not evenly distributed across the fleet. In particular, the fraction of non-PSH tracked R&U investment that corresponds to the federal fleet (39%) is significantly lower than the fraction of capacity the federal fleet represents (49%).

The scope of 80% of the tracked R&U projects includes work on turbines and generators. **At least 223 turbines units distributed across 93 plants were installed in the United States between 2007 and 2017.** It can be estimated that for at least half the turbines, machining and assembly operations were performed domestically.

Both the extent of flexible operations and the level of R&U investment are important drivers for hydropower performance trends. **U.S. hydropower availability factor—the number of hours that a hydropower unit is connected to the grid or stands ready to connect as needed—has declined over the last decade.** From 2005 to 2008, the availability ratio was 84% for large units, 85% for small units, and 88% for PSH units. The 2009-2016 average availability ratio has been 81%, 83%, and 83% for those three unit types respectively.

For small units, average forced outage hours have increased by 68% in 2013-2016 relative to 2005-2012, and the average number of planned outages has decreased by 8%. Small plants face the highest O&M costs on a per-kilowatt basis and their failure is less costly for fleet operators than that of larger units; therefore, they are low in the priority order for a fixed O&M budget that needs to cover the whole fleet. For large units (≥ 100 MW), there have been increases in both planned and forced outages. Longer or more frequent planned outages in these units are meant to prevent forced outages at times in which they would be most costly based on hydrologic or market conditions.

Accelerated wear and tear associated to the transition toward operational modes involving more frequent or pronounced ramping and unit starts or stops could also explain some of the outages for medium and large units. However, trends on this regard get lost in the national average data from NERC GADS. Case studies for facilities in parts of the country with high penetrations of variable renewables (e.g., hydropower facilities participating in the Western Energy Imbalance Market) would be valuable in illuminating the extent of changes in operation mode and associated effects on unit availability.

Except for the largest hydropower plants, operations and maintenance (O&M) costs have risen at rates higher than inflation for the last decade. Since 2007, O&M costs for hydropower projects have risen by as much as 40% compared to inflation of 16% over the same time period. These cost increases are particularly challenging for the smallest plants, which are spending much more to remain operational on a relative (\$ per kilowatt) basis than larger counterparts.

Key findings by section from this edition of the Hydropower Market Report include:

Section 1—Trends in U.S. Hydropower Development Activity

- » **The net increase in installed U.S. hydropower capacity between 2006 and 2016 has been 2,030 MW.** Of the 2,030 MW added, 70% of the capacity increases resulted from upgrades at existing facilities. Within new projects, 40 NPDs with combined capacity of 414 MW became operational during that period as well as 149 MW from 73 conduit hydropower facilities. Five new stream-reach development (NSD) projects were completed between 2006 and 2016; all of them used diversion structures and were in the Northwest, mostly in Alaska.
- » **At the end of 2017, the U.S. hydropower project development pipeline includes 214 projects with a combined capacity of 1,712 MW.** The project development pipeline as reported here includes all projects applying for FERC preliminary permits to investigate feasibility and all projects seeking or having obtained federal authorization to develop new hydropower.
- » **Almost half of the capacity (815 MW) in the hydropower development pipeline at the end of 2017 has received FERC authorization or a Lease of Power Privilege from the Bureau of Reclamation thus moving beyond the early, highest-attrition stages of development.** Most of the overall licenses pending authorization from FERC are now relicenses of existing projects.
- » **Most proposed U.S. hydropower projects are small and involve addition of hydropower generation equipment to non-powered dams (NPDs) or conduits.** Since conduits are typically very small, most proposed capacity comes from NPDs. More than half of the 129 NPDs under development are located at dams owned by the U.S. Army Corps of Engineers (USACE). Nine projects propose developing new stream-reaches and eight of them are in the Northwest region.
- » **The PSH project development pipeline includes 48 projects at the end of 2017.** Forty pumped storage hydropower (PSH) projects were at the preliminary permit stage, six are seeking authorization from the Federal Energy Regulatory Commission (FERC), and two more have a FERC license: the Eagle Mountain PSH project received its FERC license in 2014 and Gordon Butte PSH has a license since December 2016.
- » **More than 90% of proposed PSH projects are in western states or the Northeast, located in or close to states with policies requiring increases in the fraction of electricity obtained from renewables.** The plethora of PSH preliminary permit applications and license applications in these areas highlight the value of PSH for helping the integration of increasing levels of variable renewables and providing essential grid services.
- » **Although the typical size of PSH projects continues to be large, there has been an increase in smaller capacity projects being proposed in recent years.** The median size of PSH projects in the pipeline at the end of 2017 is 290 MW versus 600 MW at the end of 2014.
- » **Of the 8 PSH projects with pending or issued licenses, 7 are closed-loop projects.** Closed-loop PSH reservoirs are not located on river systems and, as a result, often have lower environmental impacts. Since location for these projects does not depend on the presence of natural water features, there is more flexibility to place them where they are most valuable for the electric grid.
- » **U.S. hydropower R&U projects worth \$8.9 billion have started between 2007 and 2017.** Federal hydropower represents 49% of U.S. hydropower capacity, but R&U investment in the federal fleet (excluding PSH projects) only represents 39% of total R&U investment.

Section 2 – U.S. Hydropower in the Global Context

- » **The United States has the third largest fleet in the world for both hydropower and PSH.** China and Brazil are the first and second country by installed hydropower capacity (304 GW and 98 GW, respectively). Japan and China are the individual countries with the two largest PSH fleets (28 GW and 27 GW, respectively); however, if European Union (EU27) countries are taken as a unit, their combined PSH fleet (47 GW) is the largest in the world.
- » **With 1,096 GW of hydropower and 153 GW of PSH installed at the end of 2016, hydropower is the largest renewable energy source and largest source of grid-scale electrical energy storage globally.** The *Central and South America* region has the highest hydropower penetration. Between 2005 and 2015, hydropower percentage in total electricity generation capacity only increased in parts of Asia; in Europe, non-hydropower renewables surpassed installed hydropower capacity during that period.
- » **Large hydropower construction has experienced a resurgence since 2000 led by Asian countries, particularly China.** For the most part, North America and Europe stopped large hydropower development (excluding PSH) decades ago and now focus on small hydropower, but a few countries in these regions—Canada, Norway, and Portugal—are still building some large projects.
- » **At the end of 2017, there were at least 700 hydropower projects and 38 PSH facilities under construction in 69 countries.** Completion of all these projects will add 161 GW and 42 GW of hydropower and PSH capacity respectively. The United States had 20 hydropower projects and no PSH under construction at the end of 2017.
- » **The United States has the 7th largest project pipeline; with most of the capacity from PSH projects in early evaluation stages, for which attrition rates are very high.** East Asia is the region with the largest fraction of its project pipeline in the *Under Construction* stage.
- » **China, India, and Brazil top the rankings of new planned hydropower capacity.** China and Brazil are developing hydropower in areas previously untapped because they are far from load centers. Thus, these projects will have to be accompanied by transmission infrastructure investments. India's hydropower project pipeline has a much larger fraction of small projects (66%) than the other two.
- » **China also leads the PSH pipeline with 111 GW proposed and a goal of 40 GW of installed PSH capacity by 2020.** China expects that increasing PSH capacity will help reduce the high levels of wind energy curtailment experienced in recent years. The United States has the second largest PSH pipeline with almost 20 GW under consideration.
- » **North America has the highest capacity-weighted average fleet age and leads the R&U investment ranking in \$ per installed kW.** Russian and European hydropower fleets are of a similar age compared to the North American fleet, but those countries are investing significantly less per kW in R&U.

Section 3 – U.S. Hydropower Price Trends

- » **Hydropower prices vary by ownership type and region depending on electric market structure.** Power marketing administrations (PMAs) market the electricity from hydropower plants owned by USACE and Reclamation—44% of installed hydropower capacity and 6% of PSH capacity—at cost-based rates. Hydropower owners participating in ISO/RTO markets—28% of installed hydropower capacity and 59% of PSH—receive the wholesale market price in each intra-hourly interval in which their bids are accepted. The rest of the fleet—28% of installed hydropower capacity and 35% of PSH capacity—is either owned by vertically-integrated utilities whose tariffs are approved by state public utility commissions (PUCs) or public utility districts, municipal utilities and independent power producers that market their power through power purchase agreements (PPA).

- » **Federal hydropower prices are lower and less variable than wholesale electricity market prices in their respective regions.** The price for energy marketed by each of Bonneville, Western, and Southwestern Power Administration (SWPA) from 2006 to 2016 averaged \$32/MWh–\$35/MWh (2016 dollars) versus \$42/MWh for the Mid-Columbia Hub. However, when considering only the post-2008 period, the average Mid-Columbia wholesale price (\$32.77/MWh) is below the average price paid by Bonneville (\$33.47/MWh) and Southwestern (\$36.42/MWh) customers. Southeastern prices were highest across the 4 PMAs in most of 2006–2016 but lower than the average PJM-West hub price. Federal hydropower prices fluctuate with hydrologic conditions due to the use of drought adders to complement base rates during dry years.
- » **Based on purchased power data reported in FERC Form 1, hydropower received higher average energy prices than the average across all technologies in 2006–2016.** The median price paid for energy produced at the small hydropower facilities that are prevalent in this dataset was \$62.8/MWh. The median price paid across all purchased power reported in FERC Form 1 in was \$52.9/MWh. However, there is substantial variability across and within regions. Purchased power prices carried the largest premium relative to the regional average wholesale electricity price in the Northwest and tracked wholesale prices closest in the Northeast region.
- » **Hundreds of hydropower plants have transferred ownership in the United States since 2004, but the private-public ownership mix has remained stable.** The pace of transfers has increased after 2011, particularly for plants with FERC exemptions rather than licenses. Transfers have been most frequent for small, privately-owned hydropower plants in the Northeast region.
- » **The average sale price for a subset of hydropower plant transfers—64 data points representing one fourth of total transferred capacity with a total sale value of \$5 billion—was \$1,072/kW, but the price range is wide.** Average sale prices do not vary significantly for projects holding FERC licenses versus exemptions.

Section 4 – U.S. Hydropower Cost and Performance Metrics

- » **The capital costs of recently developed hydropower plants remain highly variable as developers with access to low-cost, long-term financing pursue targeted opportunities at low-head NPD, small NSD and conduit projects.** Costs of recent projects vary within a range of \$2000 to \$8000 per kilowatt installed (with occasional exceptions). Much of the cost variability is due to site-specific factors such as access to existing infrastructure at NPD and conduit projects. But, at a macro scale, hydraulic head is one of the most significant cost drivers in a hydropower project all else being equal.
- » **Except for the largest hydropower plants, operations and maintenance costs have risen at rates higher than inflation for the last decade.** Since 2007, costs for hydropower projects have risen by as much as 40% compared to inflation of 16% over the same time period. These cost increases are particularly challenging for the smallest plants, which are spending much more to remain operational on a relative (\$ per kilowatt) basis than larger counterparts.
- » **Despite significant year-to-year fluctuations in regional hydropower generation correlated with hydrologic conditions, the annual U.S. hydropower generation volume has remained stable, within the 250 TWh–275 TWh range, in 2003–2016; for PSH, total gross generation displays a slight decreasing trend.** The Northwest produces approximately 50% of all hydropower and over half of PSH generation comes from the Southeast.

- » **Seasonal distribution of hydropower generation varies regionally based on hydrology and operational rules set to meet other purposes of reservoir storage space and water flows (e.g., flood control, fish passage, recreation); PSH generation correlates more closely to electricity demand than hydropower.** PSH is utilized most in the summer which coincides (except for the Northwest) with the season in which electricity use is highest. Hydropower generation typically peaks in winter or spring depending on whether most of the runoff comes from winter precipitation (Northeast and Southeast) or snowpack melt (Northwest and Southwest).
- » **Daily hydropower generation profiles in ISO/RTO markets are highly correlated with electricity use patterns; the hydropower fleet provides substantial load-following flexibility.** During fall and winter, generation from hydropower follows the early morning and mid-evening electricity demand peaks; in summer, there are sustained hydropower ramps from mid-morning to late afternoon in all ISO/RTOs, especially in CAISO, MISO, and PJM. In CAISO, solar generation profiles also influence the daily hydropower generation profile significantly.
- » **The median capacity factor—the annual generation level divided by the maximum annual generation if a hydropower unit were continuously operating at its maximum rated capacity—for the U.S. fleet has been 38.1% based on plant-level 2005–2016 data.** Hydropower capacity factors span a wide range with values outside the 25%–75% interval for 20% of the plants. Older plants have higher median capacity factors than more recent ones. The segment of the fleet owned by wholesale power marketers has the highest median, 10th, and 90th percentiles. The plants with most operational flexibility (peaking plants) tend to exhibit below-median capacity factors.
- » **For PSH, a capacity factor calculation adjusted by roundtrip efficiency indicates that the average capacity factor for PSH in the Northeast and Southeast in 2005–2016 was 36% and 44% respectively.** PSH plants that consist of a combination of conventional and reversible turbine-generator units are operated very differently and tend to have much lower capacity factors.
- » **Unit availability ratio—the number of hours that a hydropower unit is connected to the grid or stands ready to connect as needed divided by the total number of hours in a period—decreased over the last decade for all hydropower unit size categories as well as PSH units.** From 2005 to 2008, the availability ratio was 84% for large units, 85% for small units, and 88% for PSH units. The 2009–2016 average availability ratio has been 81%, 83%, and 83% for those three unit types respectively. General economic conditions played a role in reduced availability during the recession and subsequent period of weak electricity demand. A slight rebound is visible in 2012 but, after that, it has declined again except for PSH units.
- » **A tradeoff between planned and unplanned outages is visible when comparing the change in availability factor for large and small units.** For large and PSH units, planned outages accounted for approximately 80% of total outage hours in the last 4 years and the average number of forced (i.e., unplanned) outages did not surpass 450 (the equivalent of 3 weeks) any year since 2013. For small units, however, forced outages have been more than 50% of total outage hours in the last 4 years. Since O&M costs per kW installed are highest for small units and the cost of an unplanned outage is highest for larger units, plant owners tend to concentrate their O&M budgets on the latter.
- » **As a storage technology, a key PSH contribution to grid reliability stems from standing ready to be connected to the grid and meet demand peaks as they arise.** On average, PSH units spend more than 40% of hours each year in *Reserve Shutdown*—hours in which the unit is available for service but not electrically connected to the grid for economic reasons. Thus, remuneration for this and other grid services PSH provides (e.g., frequency regulation when it is electrically connected to the grid) can be a significant fraction of PSH revenue.

- » **Based on technical design parameters like ramp rates and start/stop times, hydropower and natural gas-fired generation are typically considered the most flexible generation technologies.** Based on hourly generation data from the ISO/RTOs, the average one-hour ramp (i.e., the change in the number of megawatt-hours generated by the fleet from one hour to the next) per installed megawatt is larger for hydropower than natural gas in all ISO/RTOs. One-hour ramps by the natural gas fleet follow changes in load more closely than hydropower; yet the hydropower fleet is utilized for larger one-hour ramps (as a fraction of installed capacity) than natural gas particularly in those fleets containing significant fractions of PSH units.
- » **The median number of starts per year for PSH units has been 365 (i.e., one start per day) or larger for most years since 2005; for hydropower units, the median number of starts increases with unit size.** The median average run time (i.e., number of unit service hours divided by number of starts) in 2016 was 22.4 days for small units, 4.1 days for medium units, and 2.7 days for large units.

Section 5—Trends in the U.S. Hydropower Supply Chain

- » **At least 223 turbine units distributed across 93 hydropower and PSH plants were installed in the United States between 2007 and 2017.** Their total capacity is almost 9 GW. Fifty-seven (26%) of the units were installed in new plants and the rest were either unit additions, replacements, or upgrades at existing hydropower plants.
- » **Most turbine manufacturers with significant U.S. market share have domestic manufacturing facilities.** It can be estimated that for at least half of the turbines installed in the United States in the last decade, machining and assembly operations were performed domestically.
- » **Although Francis turbines are the most common type in the existing U.S. fleet, 54% of the turbines installed at new plants during the last decade were Kaplan.** Kaplan turbines are well-suited for the low-head sites where the majority of new development has taken place.
- » **Much of U.S. hydropower turbine trade is conducted with neighboring countries; trade with Canada is strong in both directions and exports to Mexico have gone from very small to representing 10%-15% of total export value since 2012.** Over the course of the last two decades, turbine imports from European countries have decreased significantly—from 50% of turbine imports being European in 1996-2000 to less than 30% since 2006. China has stopped importing U.S. turbines and has become the source of 30% of U.S. turbine import value during the last 3 years.

Section 6—Policy and Market Drivers

- » **As of the end of 2017, there are multiple legislative proposals under consideration to modify the hydropower and PSH authorization process to reduce its length, cost, and attrition rates.** Many of these bills target various stages of the authorization process for original licenses by the project types that make up most of the U.S. project development pipeline (non-powered dams, conduits, closed-loop pumped storage) as well as for relicensing of existing projects.
- » **Federal-level incentives that helped improve project economics for hydropower developers through much of the last decade have expired.** The Renewable Electricity Tax Credit Equalization Act [H.R. 4137] proposes to restore hydropower's eligibility to federal production and investment tax credits. As of January 1, 2018, the Tax Cuts and Jobs Act ended the issuance of Clean Renewable Energy Bonds (CREB) that had been used to reduce capital costs of new hydropower projects owned by public entities.
- » **As authorized by Congress, the Department of Energy has paid \$14.1 million in incentives to developers of NPD and conduit projects under Section 242 of the Energy Policy Act of 2005 between 2014 and 2017.** This funding has gone to 63 unique projects and a total of 1.4 TWh of generation.

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- » **Renewable Energy Credit (REC) prices in states with renewable portfolio standards (RPS) that include certain types of hydropower were a major incentive for the development of eligible hydropower projects, but they have fallen substantially in recent years.** For instance, the value of Class I RECs in Massachusetts went from \$60/MWh in 2015 to \$20/MWh in 2017. Hydropower eligibility in many state RPSs is very limited and serves as a disincentive for hydropower investment.
 - » **The renegotiation of the Columbia River Treaty and multiple transmission line projects are shaping the role of Canadian hydropower in the United States for the next decades.** Any changes to the Treaty, for which renegotiation talks are expected to start in 2018, can have important consequences for the operation of the Federal Columbia River Power System (FCRPS) and Western electricity markets. The Great Northern Transmission Line in the Midwest and at least one of the transmission projects in the Northeast are likely to be constructed in the next few years and would increase in the hydropower share of the electricity generation mix in these states.

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Introduction

The 2017 Hydropower Market Report addresses the existing gap regarding publicly-available, comprehensive information on U.S. hydropower. The report is compiled from many different publicly-available datasets, and from information collected to support ongoing Department of Energy R&D projects. First published in 2015, this second edition of the report provides industry, policymakers, and other interested stakeholders with objective data and information on the distribution, characteristics, and trends of the hydropower industry in the United States. The report identifies challenges and opportunities for the existing hydropower fleet and for potential new projects to inform the policy and business decisions shaping the future of this important energy resource.



This edition of the report updates many of the core data sets presented in the 2014 Hydropower Market Report (e.g., size and characteristics of the project development pipeline, generation volumes, capacity factors, availability factors, and hydraulic turbine installations and trade), and it also includes new topics of interest identified by stakeholders to provide more context and better interpretation of development and performance trends: international hydropower development trends, purchased power prices, O&M costs, and an analysis of hourly one-hour ramp generation data to explore hydropower's contribution to load-following flexibility.

This report documents recent trends in U.S. hydropower development, refurbishment and upgrade (R&U) investments, price, cost, performance and supply chains of interest identified by stakeholders.

Section 1 summarizes capacity changes in the U.S. fleet since 2006, describes the project development pipeline as of the end of 2017, and summarizes trends in R&U activity over the last decade.

Section 2 places the U.S. hydropower fleet in the global context. It discusses the regional evolution of hydropower's fraction in the electricity generation mix in the last decade as well as the size and characteristics of new development and R&U investments in each world region.

Section 3 presents trends in U.S. hydropower prices focusing on those segments of the fleet—federal hydropower and privately-owned plants with PPAs—that receive a price that is specifically for hydropower rather than the locational marginal prices paid to all generation technologies in markets coordinated by independent system operators and regional transmission organizations (ISO/RTO).

Section 4 discusses trends in capital and operation and maintenance (O&M) costs as well as a variety of performance metrics including energy generation, capacity factor, availability factor, and number of unit starts for hydropower and pumped storage hydropower (PSH). It also explores the contributions of hydropower to load-following flexibility in ISO/RTO markets through an analysis of one-hour ramps.

Section 5 explores supply chain trends focusing on the hydropower plant component for which best data are available: turbines. The section includes data on turbine installation numbers, types, market shares by manufacturer, and import/export values.

Finally, Section 6 discusses introduced U.S. legislative changes and market developments shaping the context in which hydropower development and operation decisions are made.

Unless otherwise noted, specific numbers referring to the hydropower fleet only include the conventional hydropower segment of the fleet. PSH figures are generally presented separately throughout the report. Marine and hydrokinetic technologies (such as tidal, wave, and in-stream hydrokinetics) are not covered.

While there are no universally accepted size categories for hydropower facilities, this report uses the same size (and region) groupings as in the [2014 Hydropower Market Report](#). The size of hydropower plants and projects is classified as *Micro* (<0.5 MW), *Small* (0.5 MW-10 MW), *Medium* (10 MW-100 MW), *Large* (100 MW-500 MW) or *Very Large* (>500 MW). When discussing data for individual turbine-generator units instead of plants, a condensed size classification with just three categories is used: small (<10 MW), medium (10 MW- 100 MW), and large (>100 MW). U.S. region classification coincides with the Federal Energy Regulatory Commission (FERC) hydropower regions. A world region classification is introduced in Section 2. All references to those world regions appear italicized in the report to indicate that their boundaries in this report might not coincide with other world region classifications.

The report draws from a variety of data sources. For basic attributes of the U.S. hydropower fleet, the main source of data is Oak Ridge National Laboratory's National Hydropower Asset Assessment Program (NHAAP), a geospatial database of U.S. hydropower that includes information on existing facilities, water resource infrastructure, hydrography and environmental attributes.¹ Whenever possible, other datasets are connected to NHAAP through unique IDs assigned to each individual plant and generator in order to segment the information provided by those other datasets by size, ownership type, , and other basic plant attributes. A variety of other public datasets and documents were accessed to distil the trends discussed throughout the report. EIA Form 860, EIA Form 921, and EIA Form 861 contain key data on U.S. hydropower capacity, generation, and federal hydropower prices respectively. The FERC e-Library and Bureau of Reclamation's quarterly Renewable Energy Update are the basic sources to identify projects as they initiate the federal authorization process. Data on hydropower PPAs and O&M costs come from FERC Form 1. The Interactive Tariff and Trade Data Web from the U.S. International Trade Commission is the source for turbine import and export data. ISO/RTO websites post the data on hourly fuel mix, hourly load, and installed capacity mix used in Section 4 to describe hydropower's generation profiles and one-hour ramps in those markets. Finally, the report also contains data from two commercial databases: North American Electric Reliability Corporation (NERC) Generator Attribute Data System (GADS) for performance metrics, and Industrial Info Resources (IIR) for R&U investment data, global fleet attributes, and global fleet project development pipeline and R&U investments. Further technical details on selected report datasets are provided in the Appendix.

¹ <http://nhaap.ornl.gov/>

1. Trends in U.S. Hydropower Development Activity

1.1 U.S. Hydropower Fleet

Hydropower represents 7% of electricity generation capacity and 6.3% of electricity generation output; pumped storage hydropower provides 95% of electrical energy storage capacity.

At the end of 2016, the U.S. hydropower fleet comprised 2,241 plants with a total capacity of 79.99 GW.¹ In addition, 43 pumped storage hydropower (PSH) plants with a combined capacity of 21.6 GW provided 95% of utility-scale electrical energy storage. Based on these capacities, the United States has the third largest fleet in the world for both hydropower and PSH plants. Uriá-Martínez et al. (2015) includes maps with the locations of individual facilities and discusses fleet size and ownership distributions.² Table 1 presents the top 20 states by installed hydropower capacity and hydropower share in electricity fuel mix.

Table 1. Top 20 States by Installed Hydropower Capacity and Hydropower Percentage of In-State Generation

Hydropower capacity (MW)		Hydropower percentage of in-state generation (%)		Pumped storage hydropower capacity (MW)	
Cumulative (end of 2016)		Average (2014–2016)		Cumulative (end of 2016)	
WA	21,097	WA	68.06	CA	3,756
CA	10,332	ID	57.60	VA	3,109
OR	8,471	OR	56.72	SC	2,581
NY	4,721	SD	46.84	MI	1,979
AL	3,109	MT	36.01	TN	1,714
MT	2,638	VT	31.05	GA	1,635
ID	2,581	ME	27.35	PA	1,541
TN	2,499	AK	25.54	MA	1,540
GA	2,181	NY	19.26	NY	1,240
NV	2,096	TN	10.79	MO	600
NC	1,904	CA	10.00	CO	509
AZ	1,682	NH	6.45	NJ	453
SD	1,604	AL	6.02	WA	314
SC	1,369	AZ	5.93	OK	259
AR	1,321	ND	5.86	AZ	194
KY	990	NV	5.64	NC	95
PA	882	AR	5.51	CT	31
VA	829	MD	4.16	AR	28
OK	815	WI	3.95	UT	0.14
ME	726	KY	3.94	Remainder of United States	0
Remainder of United States	8,136	Remainder of United States	1.11	TOTAL	21,578
TOTAL	79,985	TOTAL	6.34		

¹ A plant is defined as a facility containing one or multiple powerhouses located at the same site and using the same pool of water. A hydropower project might include one or multiple plants.

² <https://www.energy.gov/eere/water/downloads/2014-hydropower-market-report>

³ PSH plants are not included.

More than a quarter of all the installed hydropower capacity in the United States is in Washington and accounts for more than two-thirds of the electricity generated in that state. Fifteen states have more than 1 GW of installed hydropower capacity, and only two—Delaware and Mississippi—have no hydropower. Hydropower represented an average of 25% or more of electricity generation from 2014 to 2016 in eight states; most of them are in the Northwest, but the list also includes Vermont, Maine, and South Dakota.

The 2014–2016 average hydropower fraction for the United States (6.34%) has declined relative to 2011–2013 (7.06%) largely because of the severe drought experienced by many Western states in those years. The hydropower fraction of in-state generation has declined in the top five states in Table 1 relative to 2011–2013. On the other hand, it has increased in Vermont (from 18.89% to 31.05%), Maine (from 25.69% to 27.35%), Alaska (from 21.45% to 25.54%), and New York (from 18.94% to 19.26%).⁴

California leads the ranking of installed PSH capacity with 3.76 GW distributed across ten plants. Nineteen states have at least one PSH plant. Of the nine states with more than 1 GW of PSH, the majority are in the Southeast or Northeast.

1.2 Capacity Changes (2006–2016)

More than 2 GW of additional hydropower have been added nationally since 2006, mostly due to refurbishments and upgrades at existing facilities and the addition of hydropower generation equipment to non-powered dams and conduits.

The net increase in hydropower capacity between 2006 and 2016 was 2,030 MW. This number combines the addition of new plants and changes in the existing fleet capacity. Figure 1 shows the regional distribution of capacity changes. New plants include new stream-reach developments (NSDs) as well as installation of hydropower units at non-powered dams (NPDs) or conduits. The three remaining categories in Figure 1 pertain to changes in the existing fleet: capacity additions, downrates—downward adjustments to the nameplate capacity reported by plant owners in EIA Form 860—and retirements.

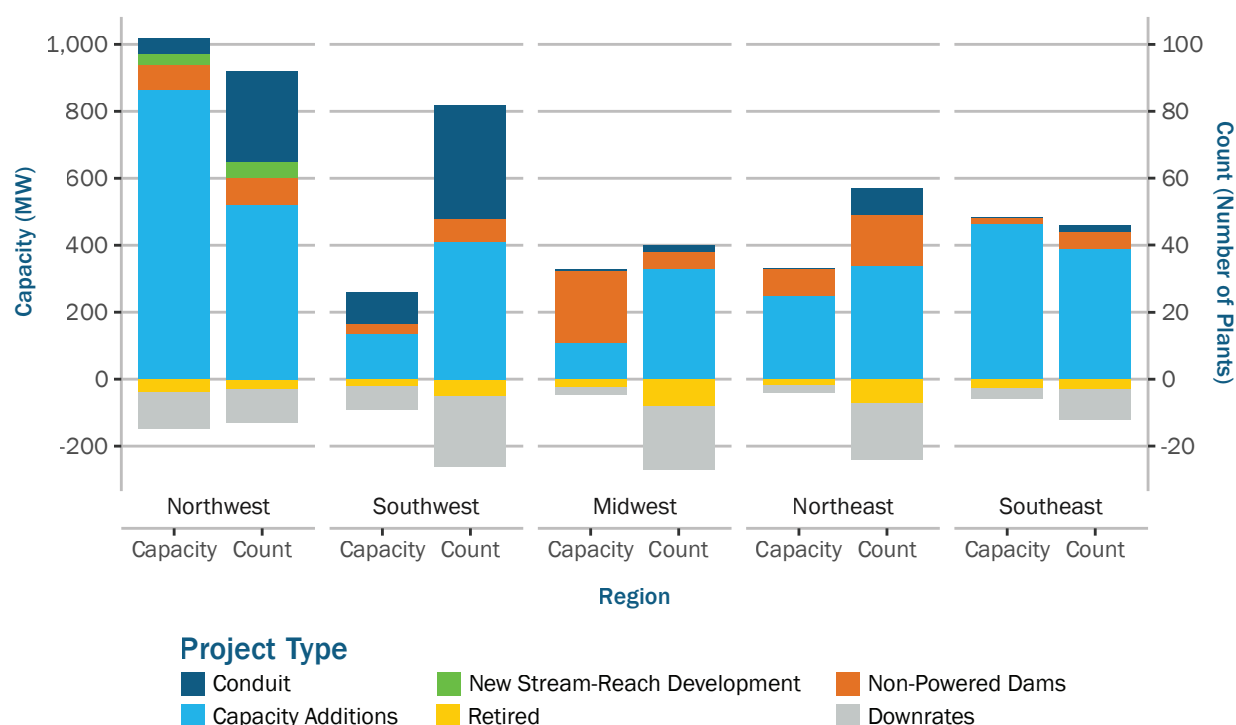


Figure 1. Hydropower capacity changes by region and type (2006–2016)

Sources: EIA Form 860, NHAAP, FERC eLibrary.

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.

⁴ In Vermont, the larger hydropower fraction reflects a reduction in in-state electricity generation (due to retirement of the 604 MW Vermont Yankee nuclear power plant in December 2014) rather than an increase in hydropower generation.

Every region experienced a net increase in hydropower capacity from 2006 to 2016. The largest net capacity increase (870 MW) took place in the Northwest, where 85% of capacity increases were from upgrades to the existing fleet. This fraction is even higher (96%) in the Southeast. Both in the Northwest and Southeast capacity increases result primarily from modernization of large plants owned by federal agencies or investor-owned utilities. The plants with largest reported increases in nameplate capacity in the Northwest from 2006 to 2016 are Portland General Electric's Round Butte and USACE's Bonneville in Oregon (126 MW and 69 MW, respectively), Avista's Noxon Rapids in Montana (103 MW), and Seattle City Light's Boundary in Washington (79 MW). In the Southeast, the largest capacity increases resulted from turbine upgrades at two USACE-owned plants: John H. Kerr in Virginia (89 MW) and Walter F. George in Georgia (38 MW); in addition, TVA's hydropower modernization program led to an additional 80 MW of generation capacity within its fleet. Most of the capacity added in the Northeast can be traced back to unit uprates in the Conowingo plant in Maryland and the addition of a new 125 MW powerhouse to the Holtwood Plant in Pennsylvania. The Midwest is the only region where the largest component of the capacity increase came from new plants rather than capacity additions at existing facilities.

Most new U.S. hydropower facilities that have started operation since 2006 resulted from adding hydropower generation equipment to existing water resource infrastructure (conduits and NPDs):

- » Between 2006 and 2016, 73 conduit hydropower facilities started operation. More than 80% of the new powered conduits are in the Northwest and Southwest, which are the two regions with the most miles of irrigation and water supply conduits. The average size of new conduit plants is 2 MW.
- » Hydropower generation with a combined capacity of 414 MW was added to 40 NPDs during the period covered in Figure 1. The three largest NPD developments are American Municipal Power (AMP) projects in the Ohio River. Meldahl (105 MW), Cannelton (88 MW), and Willow Island (44 MW) started commercial operation in 2016. The fourth AMP plant under development (Smithland, 76 MW) was completed in 2017.

Only five NSDs have become operational in 2006–2016, adding 32.5 MW to the fleet. Three of them are in Alaska, and the other two in the Pacific Northwest region: Youngs Creek in Washington and Little Wood River Ranch in Idaho. The largest is Lake Dorothy in Alaska, with a capacity of 14.30 MW. They all use relatively small diversion structures to redirect water from streams into the powerhouse.

Twenty-six plant retirements adding up to 131 MW were reported in EIA Form 860 between 2006 and 2016. At least nine of them are permanent retirements including dam removals.⁵ Other plants stopped operating for economic reasons, but they could be repowered in the future. Eight of the NPD and nine of the conduit plants included in Figure 1 correspond to facilities that were operational in the past and have been redeveloped recently. The repowered dams are all in the Northeast, and all but one of the repowered conduits are in the Northwest or Southwest. The average size of these repowered plants is 2.32 MW, and none of them is larger than 6 MW.

Approximately half of the capacity decreases classified as downrates are temporary as they correspond to units taken out of service for rehabilitation or upgrades. Downrates also include plants in which individual units are kept out of service because the investment required to make them operational after equipment failure is deemed too expensive (e.g., Kerckhoff 1 Unit 2, California). The dataset also contains at least one case in which a downrate was requested to meet the size limit for participation in a state renewable portfolio standard (RPS).⁶

Changes in PSH capacity are not included in Figure 1. The nameplate capacity of the U.S. PSH fleet increased by 10% (from 19.6 MW in 2006 to 21.64 GW in 2016), almost exclusively through upgrades to the existing fleet. The only new PSH facility that started operation during this period is Olivenhain-Hodges in Southern California (40 MW).

5 Boardman (MI), Bull Run (OR), Childs (AZ), Condit (WA), Grimh (WI), Irving (AZ), Kensico (NY), Milltown (MT), and Veazie (ME).

6 The Metropolitan Water District of Southern California amended its exemption for the Diamond Valley Lake Small Conduit Hydropower Project from 39.6 MW to 30 MW in 2009 because existing hydropower facilities above 30 MW were not eligible to receive renewable energy credits in the California RPS.

In summary, capacity change has been positive in all regions but small relative to the size of the existing fleet. Most of the capacity increases resulted from upgrades to existing facilities. New developments have mostly involved adding hydropower generation capability to existing NPD and conduits or repowering of facilities. NSDs have been very scarce and limited to the Northwest region—mostly Alaska. None of the NSDs completed during this period involved construction of a large impoundment dam.

1.3 Hydropower Project Development Pipeline (as of December 2017)

Almost every new hydropower facility in the United States requires federal authorization from either the Federal Energy Regulatory Commission (FERC) or the U.S. Bureau of Reclamation (Reclamation).⁷ This section presents information about the status of projects for which the federal permitting process with one of those agencies is ongoing or has been completed. Once a project becomes operational, it drops from the development database to be reported instead among the new plant additions (see Figure 1).

Most projects that require federal authorization fall under FERC jurisdiction.⁸ Authorization from FERC can be a license or an exemption from licensing depending on project type and size (Uriá-Martínez et al., 2015).⁹ For projects in Western states that utilize Reclamation assets, the developer needs to obtain a lease of power privilege (LOPP) from Reclamation rather than FERC authorization if the asset is a conduit or a dam authorized for federal hydropower development.

1.3.1 Hydropower Development Pipeline

At the end of 2017, the U.S. hydropower project development pipeline, excluding PSH projects, contained 214 projects with a combined capacity of 1,712 MW. The majority of projects involve the addition of hydropower generation equipment to NPDs or conduits.

The Southwest region leads the pipeline by number of projects, but they are mostly small conduit developments. Proposed new capacity is substantially higher in the Southeast and the Midwest than in the rest of the country. Figure 2 shows the number of projects and capacity by region, project type, and stage of development. It excludes projects with capacity of less than 0.1 MW. For completeness, Figure 2 also includes PSH projects. Details about the PSH project development pipeline are discussed in Section 1.3.2.

Of the projects included in Figure 2, 90% have been issued or are pursuing FERC authorization. The remaining 10% are following the Reclamation LOPP authorization process. Of those 22, 18 are conduit projects and the remaining four would add hydropower to Reclamation-owned dams. A dozen LOPP applications initiated in 2017 propose additions of turbine-generator units by the same private developer at different points of the North Unit Canal in Oregon.

7 In addition, many projects also require permits from USACE.

8 Section 23(b) of the Federal Power Act states that a hydropower project requires FERC authorization if it is located on navigable waters of the United States; if it occupies federal lands; if it uses surplus water or water power from a federal dam; or if it is located on non-navigable waters, project construction has occurred on or after August 26, 1935, and it affects foreign or interstate commerce interests, including sale of power into the interstate grid.

9 Projects eligible for an exemption from licensing are exempt from the requirements of Part I of the Federal Power Act; however, this does not mean they are altogether exempt from federal authorization. Construction and operation of projects with exemptions is subject to any terms and conditions set by federal and state resource agencies and by FERC. Unlike licenses, exemptions are issued in perpetuity but can be revoked if the mandatory terms and conditions are not met.

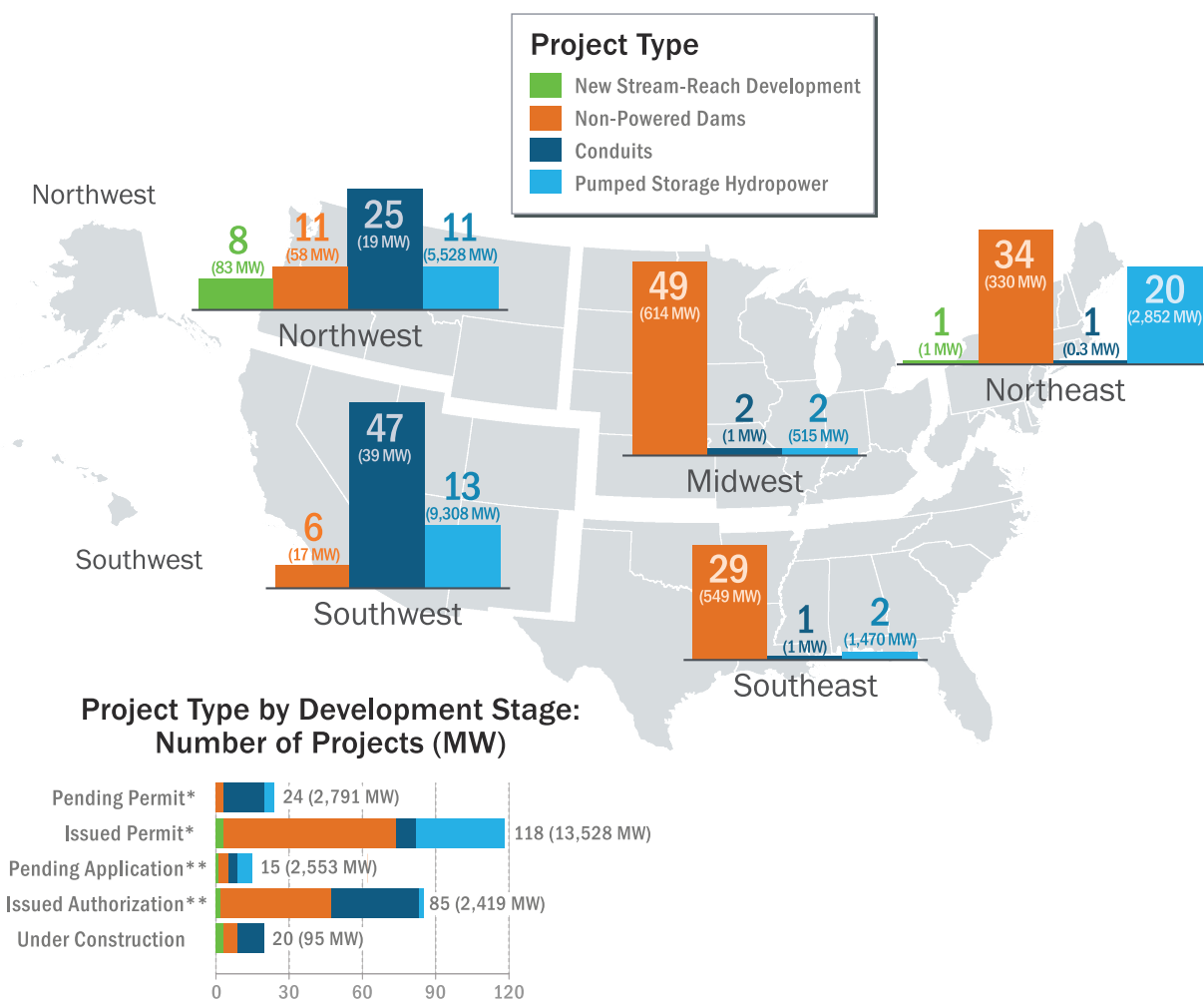


Figure 2. Hydropower project development pipeline by project type, region, and development stage (as of December 31, 2017)

Sources: FERC eLibrary, Reclamation LOPP database, web searches.

*Projects in the *Pending Permit* and *Issued Permit* stages have high attrition rates. *Pending Permit* includes projects pending a preliminary lease in the Bureau of Reclamation Lease of Power Privilege (LOPP) process and projects pending issuance of a preliminary permit. *Issued 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 have submitted a Notice of Intent to file a license or a draft license application.

***Pending Application* includes projects that have applied for an original FERC license or a FERC exemption or have requested to be considered a “qualifying conduit” hydropower facility by FERC. *Issued Authorization* includes projects that have been issued an original FERC license or FERC exemption, have been approved by FERC for “qualifying conduit” hydropower status, or that have received a final lease contract under the LOPP process.

Proposals to power existing dams currently used for other purposes account for 62% of projects and 92% of capacity in the development pipeline. Given the prevalence of this type of project, many of the recent proposed or implemented innovations in the hydropower authorization process have focused on NPDs (see insert for details). Seventy-six conduit projects adding up to 60.3 MW are also under development. Finally, the project development pipeline also includes nine NSD projects with a total capacity of 84 MW.

RECENT INITIATIVES TO IMPROVE THE FEDERAL AUTHORIZATION PROCESS FOR HYDROPOWER DEVELOPMENT AT NON-POWERED DAMS

FERC-USACE MOU on Process for Authorization of NPD Projects at USACE-Owned Dams: FERC and the U.S. Army Corps of Engineers (USACE) signed a memorandum of understanding in July 2016 that introduces a two-phased, synchronized permitting process for the various federal authorizations required for hydropower development at USACE NPDs (FERC, 2016). Both the FERC license and the Section 408 and 404 permits from USACE require environmental review under the National Environmental Policy Act (NEPA).¹⁰ In the past, the process to obtain these different authorizations has been largely sequential—the USACE permitting process was largely conducted after a FERC license had been issued—and involved duplicative information requirements. In the two-phased, synchronized process, FERC and USACE coordinate closely from the start, ensure to the extent possible that no duplicative studies are requested, and maximize the extent to which review activities and approval for the three permits occur concurrently. At the end of Phase 1, the developer receives a FERC license and USACE letters stating that the environmental review is complete or that additional information is needed. Early stage engineering design documents suffice to complete this phase. In Phase 2, USACE issues its 408 and 404 permit decisions after the developer submits the final design plans.

FERC Report on Feasibility of Two-Year Licensing Process: In May 2017, FERC published its report to Congress—requested in the Hydropower Regulatory and Efficiency Act of 2013—on the feasibility of a two-year licensing process for NPD projects and closed-loop PSH projects (FERC, 2017). The NPD project selected as pilot case for this two-year process was Lock and Dam No. 11 in Kentucky, for which FERC received a notice of intent to file a license application on May 5, 2014, and issued an original license on May 5, 2016.¹¹ Our review of FERC’s report suggests that licensing a project in two years—from notice of intent submission to license issuance—is feasible but highly dependent on the specific attributes of each project and the timely cooperation of other federal or state agencies with statutory authority in the licensing process. Achieving the expedited two-year timeline is most plausible for projects that would not alter flow regime and that have low environmental impact and limited data collection requirements. In addition, it is crucial for the project developer to consult early and often with resource agencies and other stakeholders and include negotiated environmental protection, mitigation, and enhancement (PM&E) measures in the license application.

FERC Established 40-Year License Term for New Hydropower at Non-Federal Dams: FERC set the default term for original and new hydropower licenses at nonfederal dams as 40 years.¹² Until now, the license term decision was project specific with terms ranging from 30 to 50 years. This new FERC policy, issued in October 2017, aims to reduce uncertainty for project developers and owners and increase the time for recovering the investment involved in obtaining a license.

More than half (56%) of the 129 NPDs for which hydropower additions are being pursued are owned by USACE. These projects represent 78% of all NPD capacity under development. Dams owned by state agencies account for 20% of the NPD projects and 8.5% of the capacity. Fourteen NPD projects involve dams owned by the Bureau of Reclamation. The rest of dams for which NPD development is being proposed are owned by water supply and irrigation districts, municipalities, or private owners; one is owned by TVA.

10 The Section 408 permit certifies that the addition of hydropower to a USACE-owned dam does not injure the public interest and does not conflict with the other authorized uses of the dam. The Section 404 permit provides authorization for the discharge of dredged or fill material into U.S. navigable waters at specified disposal sites.

11 Unlike typical FERC license proceedings, the project in this pilot case obtained only conditional approvals from state agencies, and some additional consultation remained to be conducted postlicensing to obtain the final approvals.

12 FERC still reserves the possibility to issue licenses with longer or shorter terms under some circumstances if (a) needed to coordinate license terms for projects located in the same river basin, (b) agreed by stakeholders under a comprehensive settlement agreement, or (c) a license applicant specifically requests a longer license term based on significant measures expected to be required under the new license or significant measures implemented during the prior license term.

Dam ownership determines the type of authorization process that a project developer must pursue. Seeking authorization for development of hydropower at USACE-owned dams involves obtaining a Section 408 permit from USACE in addition to a FERC license.¹³ Typically, the two permitting processes have been implemented sequentially, with most of the work needed for obtaining USACE permits taking place after a FERC license was issued. For the set of NPD projects using USACE-owned dams that have started construction since 2009, the median time elapsed from issuance of a FERC license to construction start has been 3.9 years.¹⁴ This is almost double the two-year period by which FERC expects developers with an issued license to start construction. If successful in shortening average permitting time, the new two-phase, synchronized process introduced in the 2016 FERC-USACE memorandum of understanding could encourage more developers to pursue NPD projects.

Of the nine NSD projects in the pipeline, seven are in two states: Washington and Alaska.¹⁵ In Washington, Public Utility District No. 1 of Snohomish County is the developer for three run-of-river projects. The Calligan Creek and Hancock Creek projects, each with a capacity of 6 MW, are under construction. For the third project (Sunset Falls, 30 MW), which submitted a draft license application in 2016, the utility district proposes a no-dam design that would minimize alteration of the flow regime and result in lower construction costs. Water would be diverted from the river to the powerhouse through an underwater intake structure—an innovative solution made possible by the water pool formed around a river bend upstream of the proposed powerhouse location.

Alaska is where most NSDs have started operation in recent years. Of the four NSD projects currently proposed in this state, only the largest (Sweetheart Lake, 19.8 MW) involves construction of an impoundment dam (280 feet long and 111 feet high). The other three projects, ranging in size from 0.262 MW to 5 MW, would use diversion structures with heights ranging from 6 feet to 20 feet. Susitna-Watana, which had been the largest project in the U.S. hydropower development pipeline in recent years, stopped pursuing a FERC license in 2017. This outcome follows a 2016 directive from Alaska's governor to abandon the project due to lack of sufficient state budget funding to complete it. To preserve the value of the licensing investment made to date, the Alaska Energy Authority continued working with FERC in 2017 to achieve the milestone of a study plan determination. Were the project to be restarted in the future with the same configuration, the developer could use that study plan to gather the pertinent information needed to file a final license application rather than having to start the process as a new project.

The hydropower development pipeline is evenly split between projects in pre- and postlicensing stages.

At the end of 2017, there were three developers with pending preliminary permit applications for hydropower projects and 71 with issued preliminary permits.¹⁶ The preliminary permit reserves the right of the permit holder to have first priority in applying for a license for the project for a three-year period while the permit holder evaluates the feasibility of the project and prepares a license application. The combined capacity of projects at these initial stages of the FERC authorization process is 46% of total capacity in the pipeline. During this early phase, the rate of attrition is very high. Based on an examination of more than 2,000 FERC dockets for new hydropower project development opened between 2000 and 2016, only 1 of every 10 projects that receives a preliminary permit proceeds to submit a license or exemption application. For the remainder, FERC sometimes cancels the permit because the developer fails to submit the required six-month progress reports or the reports indicate no progress toward a license application. In other cases, it is the developer who surrenders the permit. The most frequently stated reason for permit surrender is that project evaluation determined that the site was not economically feasible to develop.

The nine projects at the *Pending Application* stage proposed developments in one of three regions (Northwest, Southwest, or Southeast). Eight of the nine projects had a pending license application and only one had a pending exemption. The Hydropower Regulatory and Efficiency Act (HREA) of 2013 enlarged the eligible pool of projects for small hydropower

13 A section 404 permit is also needed, but it is not a requirement specific to the authorization of NPD projects at USACE-owned dams. Any project that involves a discharge of dredged or fill materials will require a Section 404 permit from USACE.

14 The set includes nine projects: Ball Mountain Dam (VT), Cannelton (KY), Dorena Lake (OR), Marseilles Lock & Dam (IL), Meldahl (OH), Red Rock (IA), Smithland (KY), Townshend (VT), Willow Island (WV).

15 The other two are the 1-MW Eagleville Project in New York and the 11-MW Whitewater Creek Project in Oregon, both of which have been issued preliminary permits.

16 For an additional seven projects with a combined capacity of 44 MW, the preliminary permit has expired, but the developer has submitted a Notice of Intent to file a license application or a draft license application indicating that they plan to move forward in the licensing process. These seven projects are included in the *Issued Permit* category discussed in this section.

exemptions by increasing the size limit from 5 to 10 MW. However, the less restrictive size limit has not prompted an increase in the number of small hydropower exemptions in the 5–10 MW range. Since August 2013, the seven small hydropower exemptions submitted have all been for projects with capacity of less than 5 MW. On the other hand, HREA also introduced a new pathway for developing projects of up to 5 MW on nonfederal conduits. Developers of these “qualifying conduit” facilities need to submit a notice of intent to FERC that contains a description of the proposed project. If within a 60-day period neither FERC nor the public contest that the proposed facility meets the eligibility criteria, the facility is determined a “qualifying conduit” and does not require any additional federal permitting from FERC.¹⁷ Since this pathway became available, FERC has issued 94 qualifying conduit determinations with a combined capacity of 32.4 MW. Based on personal communication with the developers for these projects, at least 20 are under construction or have been completed.

The ratio of projects with *Issued Authorizations* relative to projects with *Pending Applications* has risen steadily in recent years. At the end of 2015, there were 34 *Pending Applications* and 68 *Issued Authorizations*. At the end of 2017, only 9 projects were at the *Pending Application* stage and 83 had *Issued Authorizations*. Most license processing workload for FERC is now on relicenses of existing projects. There were 64 pending relicenses for hydropower projects at the end of 2017, with a total capacity of 6.4 GW. The median year in which these pending relicenses were filed is 2015. The median filing year is also 2015 for new project licenses, with the two oldest having been filed in 2011.

The 83 projects in the post-licensing *Issued Authorization* stage add up to 719 MW of capacity that could move into construction in the next few years. Forty-three of those projects received their license or exemption more than two years ago and need to obtain construction start time extensions from FERC for their development authorizations to remain valid. Construction activities associated with installation of new hydropower facilities were under way at 20 sites at the end of 2017; half of these are conduit facilities in California and Utah. The Midwest has the most capacity under construction (47 MW) distributed among two NPD projects—Red Rock in Iowa and Marseilles Lock & Dam in Illinois—and one conduit project, also in Illinois.

Small, private developments dominate the project pipeline.

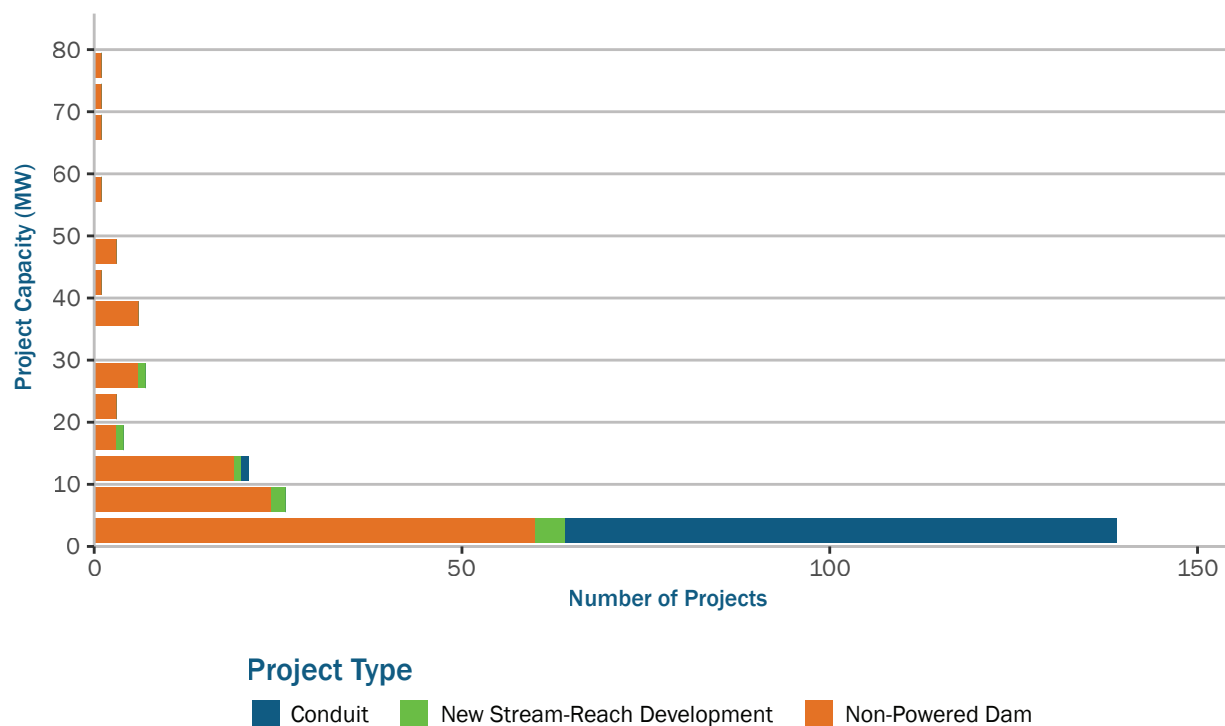


Figure 3. Hydropower project development pipeline by project type and size (as of December 31, 2017)

Sources: FERC eLibrary, Reclamation LOPP database, web searches

¹⁷ However, the facility might be subject to other applicable federal, state, and local laws and regulations.

Figure 3 shows that there are no *Large* projects (>100 MW) in the U.S. hydropower pipeline and that 77% of them are *Small* (≤ 10 MW). The median size of projects under development is less than 10 MW for the three project types: 6 MW for NPDs, 6 MW for NSDs, and 0.43 MW for conduits.

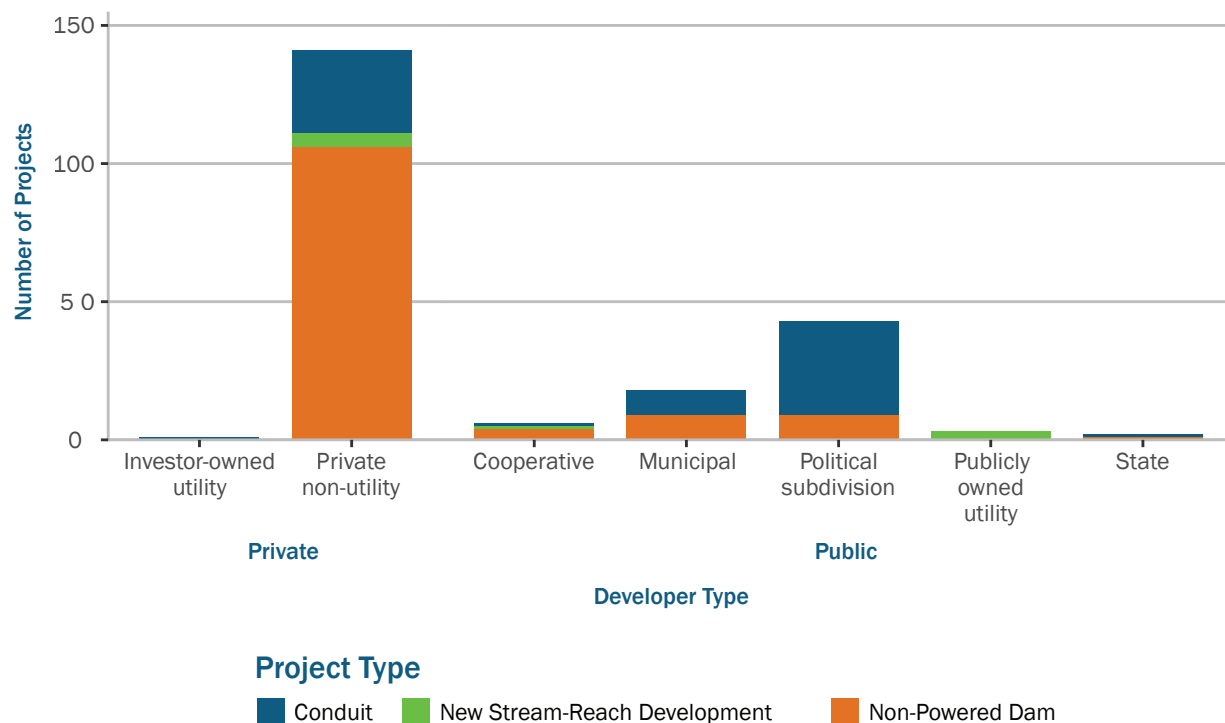


Figure 4. Hydropower project development pipeline by project type and developer type (as of December 31, 2017)

Sources: FERC eLibrary, Reclamation LOPP database, web searches

Two-thirds of all projects in the pipeline are being pursued by private developers. Conduits are the only project category more frequently developed by public entities than private developers because political subdivisions (e.g., irrigation and water supply districts) and municipalities own a significant fraction of the conduit infrastructure. Only one conduit project in California with a capacity of 0.2 MW has an investor-owned utility as a developer; for investor-owned utilities already operating hydropower plants, investing in upgrades to their existing assets is typically the preferred strategy to add megawatts of hydropower capacity to their fleets. The rest of private developers are private non-utilities. These entities sometimes specialize in getting through the permitting process with the objective to then sell the license or exemption. Otherwise, they typically need to negotiate a power purchase agreement (PPA) with a utility or industrial/corporate off-taker to obtain financing for the construction phase of the project.

1.3.2 Pumped Storage Hydropower Development Pipeline

Forty-eight PSH projects were at various stages of development in the United States at the end of 2017. The majority are closed-loop projects being pursued by private developers and located in or adjacent to states with strong RPS policies and access to competitive electricity and ancillary services markets.

Figure 5 displays the location of the 48 PSH projects in the development pipeline at the end of 2017 as well as a layer summarizing the objectives regarding penetration of renewables set by states through mandatory renewable portfolio standards or voluntary renewable portfolio goals. Penetration of renewable energy is an important consideration in selection of sites for PSH development. Figure 5 shows that most proposed PSH projects are in western or northeastern states, typically in or adjacent to states with ambitious RPS objectives. Moreover, projects in the Northeast could participate in one of the ISO/RTO markets in that region and most of the projects in the Northwest would have access to the recently created Western Energy

Imbalance Market. Access to competitive markets is an attractive feature for the private developers pursuing most new PSH projects. The size of the existing PSH fleet is inversely related with the number of proposed projects. The Northwest has the least installed PSH capacity to date (314 MW) but 11 proposed projects. In contrast, the Southeast has the largest PSH fleet (42% of total U.S. PSH capacity) but only one proposed project.

In many of the PSH preliminary permit or license application documents, developers describe their planned mode of operation as contributing to the integration of increased levels of variable renewables. The proposed mode of operation would involve producing peaking energy and supplying storage capacity to close the gaps between electricity demand and electricity supply from variable renewables throughout the day as well as providing ancillary services—spinning reserves, frequency regulation, black start, voltage support—to ensure grid reliability.

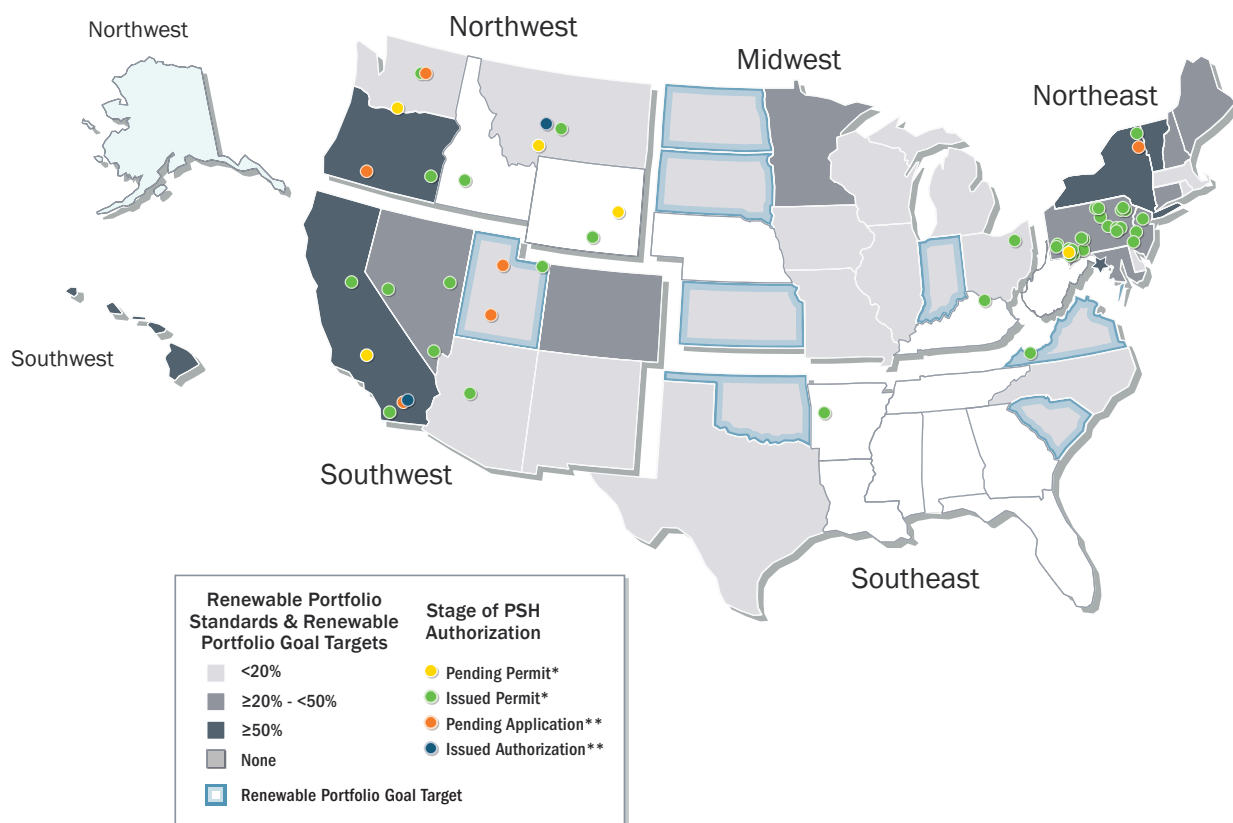


Figure 5. Pumped storage hydropower project development pipeline by region and status in relation to state-level renewable portfolio standards targets (as of December 31, 2017)

Source: FERC eLibrary

Note: This map displays the location and development status of proposed new pumped storage hydropower (PSH) projects in the United States in relation to the fraction of total generating capacity that is either wind or solar in each state. The point locations of PSH projects were derived by computing county centroids. Please note: some points overlap due to county-level aggregation.

*Projects in the Pending Permit and Issued Permit stages have high attrition rates. Pending Permit includes projects pending a preliminary lease in the Bureau of Reclamation Lease of Power Privilege (LOPP) process and projects pending issuance of a preliminary permit. Issued 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 have submitted a Notice of Intent to file a license or a draft license application.

**Pending Application includes projects that have applied for an original FERC license or FERC exemption. Issued Authorization includes projects that have been issued an original FERC license or FERC exemption or that have received a final lease contract under the LOPP process.

The PSH project development pipeline resembles that of hydropower regarding the prevalence of private developers, but they differ regarding size distribution and fraction of projects in early evaluation stage. Although the typical size of PSH projects continues to be large, it has declined in recent years. The median size of PSH projects in the pipeline at the end of 2017 is 290 MW versus 600 MW at the end of 2014. Of all these PSH projects, 83% are at the *Pending Permit* or *Issued Permit* stages versus 48% for hydropower. All but one of the 18 *Issued Permit* sites in Pennsylvania and New Jersey shown in Figure 5 are being studied by the same private developer. It is likely that the developer would ultimately only pursue one project out of the whole cluster of sites being evaluated. This portfolio approach to site evaluation allows sharing the costs of some of the necessary studies and initial stakeholder engagement among multiple sites, and it is being applied in several other hydropower project clusters.

Figure 5 indicates that there are six PSH projects with pending license applications: Battery Pearl Hill (Washington, 5 MW), Lake Elsinore (California, 500 MW), Hurricane Cliffs (Utah, 335 MW), Mineville (New York, 240 MW), Parker Knoll (Utah, 1,000 MW), and Swan Lake (Oregon, 393 MW). Except for Lake Elsinore, they are all closed-looped developments that would not be continuously connected to a naturally flowing water feature. The closed-loop configuration is being favored by regulators and developers alike because it minimizes environmental impacts on watershed ecosystems. In addition, closed-loop systems allow for more flexibility in site selection. As long as water can be piped for the initial reservoir fill and periodic refills to compensate for evaporation losses, these systems could be placed wherever appropriate topographical features can be found. On the other hand, if the chosen site involves construction of new reservoirs, the cost becomes significantly larger than if at least one of the reservoirs is already in place. Both Parker Knoll (Utah) and Swan Lake (Oregon) propose similar configurations involving newly built upper and lower reservoirs to create a closed-loop configuration and the use of a few—4 and 3 respectively—variable-speed pump-turbines.¹⁸ In contrast, the Mineville project in New York would use decommissioned subterranean mines as its reservoirs and would have 20 single-speed turbine generator units with ratings of 12 MW each.

Hurricane Cliffs PSH in Utah would be part of the Lake Powell Pipeline Project, which is a proposed 140-mile pipeline with water supply as its primary purpose. Power sales would help offset the large electricity expenditures associated with pumping water through the long conduit system envisioned in this project. Finally, the Hydro Battery Pearl Hill Project stands out due to its size—only 5 MW—and innovative design. It would use a corrugated steel tank as its upper reservoir and a floating powerhouse in the lower reservoir.

Two closed-loop projects have an issued license: Gordon Butte (400 MW) and Eagle Mountain (1,300) MW. Absaroka Energy received its license for the Gordon Butte PSH project in Montana in December 2016, 15 months after submission of its license application. The developer cites not being located on federal land and not having critical habitat or endangered species among the factors that resulted in shorter-than-average license processing timeline (Borquist et al., 2017). The other licensed project is Eagle Mountain PSH in Southern California. FERC issued the license for this project in 2014, and the developer asked for a time extension to start construction two years later as it continues to obtain all necessary permits. In 2017, the U.S. Fish and Wildlife Service issued a revised Biological Opinion analyzing the effects of the project on the desert tortoise and including recommendations and terms and conditions to reduce impacts to desert tortoise during the project construction and operation phases. Also in 2017, the Bureau of Land Management issued a Finding of No Significant Impact for the transmission line and water supply pipeline regarding the use of federal lands, but it still has to issue a Record of Decision and a Right-of-Way grant for the project to proceed.

The Sacramento Municipal Utility District also received a license for its Iowa Hill pumped storage project in 2014. However, it decided to cancel the project in 2016 because changes in cost estimates and market conditions—lower natural gas prices and slower electricity demand growth—since the project was first proposed in 2005 made it financially too risky (Hanson, 2016).

Almost two-thirds of existing U.S. PSH installed capacity was built in the late 1960s and in the 1970s. One of the main drivers for that wave of PSH construction was the need for peaking power sources to complement the fleet of baseload coal or nuclear plants also being developed at that time. The PSH plants built during that period are nearing the 50-year term on their original

¹⁸ Unlike traditional, single-speed pump-turbines, variable-speed pump-turbines can modulate power input during pumping operations which allows them to provide frequency regulation while pumping and improve turbine efficiency during partial load operation.

licenses and are in the process of applying for a relicense from FERC. Since April 2016, the owners of the Northfield Mountain PSH (Massachusetts), Ludington PSH (Michigan), and Blenheim-Gilboa PSH (New York) have filed relicense applications for these facilities.¹⁹ According to their relicense application documents, there are no plans for significant changes in the mode of operation of these facilities going forward. All three provide peaking power during the day and pump water from their lower to upper reservoirs during nights and weekends. They also provide ancillary services to the independent system operator (ISO) markets in which they participate. The continuity in proposed mode of operation by these PSH facilities suggests that the levels of variable renewables penetration in those states (5% in Michigan and New York; 4% in Massachusetts as of the end of 2016) are not yet high enough to result in market signals that would incentivize a change in operational profile. Only the license application for Northfield Mountain mentions the possibility of daytime pumping operation to absorb excess power from wind and solar were these renewables to reach higher levels of penetration in the Northeast.

1.4 Investment in Refurbishments and Upgrades

Refurbishments and upgrades worth \$800 million are initiated each year; the majority of projects include work on turbine-generator components.

With a capacity-weighted average fleet age of 56 years, the U.S. fleet requires substantial capital investments beyond routine operation and maintenance (O&M) expenditures to continue meeting performance goals regarding efficiency, flexibility, and unit availability. In addition, as noted by reviewers, the hydropower relicensing process often requires significant capital investments. For instance, mandatory investments for fish passage purposes alone can amount to several million dollars. Figure 6 offers a snapshot of recently completed and ongoing rehabilitation and upgrade (R&U) investment projects in the U.S. hydropower fleet as of the end of 2017.

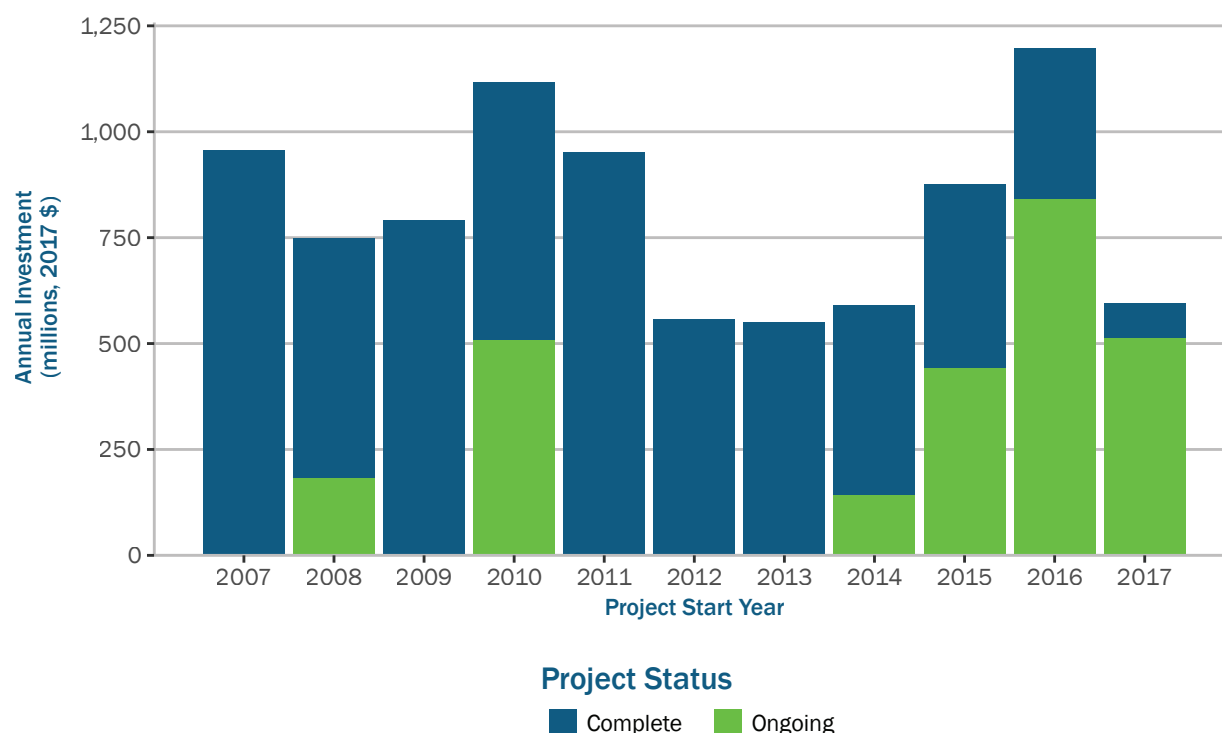


Figure 6. Expenditures on rehabilitations and upgrades of the existing hydropower fleet (as of December 31, 2017)

Source: Industrial Info Resources

Note: The full value of each project is assigned to the project start year.

¹⁹ Two hybrid plants in California that contain some PSH units also have pending FERC relicense applications.

Total tracked R&U investment in 2007–2017 is \$8.9 billion distributed across 158 hydropower plants. On average, R&U projects worth \$800 million were initiated each year. The number of R&U project starts per year has been increasing during the last decade, but the average value per project is smaller for more recent starts. The two projects still ongoing that started in 2008 and 2010 correspond to large hydropower plants in the Northwest owned by non-federal, public entities. Both projects entail refurbishment of several turbine-generator units spread out over many years.²⁰

The set of projects tracked in Figure 6 is heavily weighted towards R&U of turbines and generators. Two-thirds of the projects involve work on plant turbines and 75% on generators. Spillway gate refurbishments, transformer replacements, and control system upgrades are also part of the scope of many of these projects. Two of the four largest projects by value involve major dam repairs.

Twenty-eight plants received \$100 million or more of R&U investment and together accounted for over two-thirds of total investment. Six of those 28 plants are PSH plants. Nameplate capacity for the three PSH facilities currently applying for relicensing has increased during the last decade as a result of R&U projects that included turbine-generator unit upgrades. Overall, investment in modernization of PSH plants accounted for 22% of the total, which is in line with the fraction of capacity that PSH represents in the combined U.S. hydropower–pumped storage fleet.

Excluding pumped storage investment, tracked R&U investment in a dollar per installed kilowatt basis was highest for the Southeast and Midwest. The fraction of R&U investment for the Northwest (44%) is the same as the fraction of installed hydropower capacity it represents. The Southwest and Northeast are the two regions with the lowest investment per kilowatt.²¹

The fraction of non-PSH tracked R&U investment that corresponds to the federal fleet (39%) is significantly smaller than the fraction of installed capacity it represents (49%).

Funding sources for R&U projects at federal plants vary across the fleet (Uriá-Martínez et al., 2015). The Tennessee Valley Authority (TVA) and Bonneville Power Administration (Bonneville) have the ability to use the proceeds from electricity sales to fund capital upgrades in the facilities they own or whose power they market. For the rest of the federal fleet, the agencies in charge of marketing its power—power marketing administrations (PMAs)—send back the revenue from electricity sales to the U.S. Treasury to repay the federal investment made to construct the facilities, and the federal owners (USACE and Reclamation) submit budget requests for capital expenditures to Congress.

Section 212 of the Water Resources Development Act of 2000 authorized a complementary funding mechanism for funding capital investments at USACE-owned facilities by allowing USACE, PMAs, and their customers to enter into funding agreements whereby the PMA customers pay for nonroutine O&M investments. As such, customer-funding programs have been established in most PMA regions to provide funding for major replacements and rehabilitations at federal hydropower facilities. The widespread adoption of this funding mechanism suggests that appropriations for federal hydropower R&U have been insufficient in recent years to meet the growing R&U investment needs of this segment of the fleet. Other options that have been proposed to expand funding for federal hydropower R&U include increased budget appropriations, market-based power rates for PMA customers, and use of energy savings performance contracts (Bracmort et al., 2015).

20 For other facilities, R&U expenditures for separate turbine-generator units are reported as separate projects.

21 For the Northeast, this result is partly due to the incomplete coverage of R&U investments in small plants in the IIR database.

2. U.S. Hydropower in the Global Context

2.1 Description of the Existing Global Hydropower Fleet

2.1.1 Regional Distribution of Installed Capacity

China leads capacity additions worldwide in both hydropower and pumped storage hydropower during the last decade; the U.S. fleets are growing much more slowly.

Global installed hydropower capacity (excluding PSH) reached 1,096 GW at the end of 2016, of which an estimated 25.1 GW were added during that year (International Hydropower Association, 2017). Furthermore, 6.4 GW of pumped storage hydropower (PSH) capacity started commercial operation in 2016, bringing the total PSH capacity to 153 GW. Figure 7 displays the evolution of installed hydropower and PSH capacity between 2005 and 2016 for the six largest fleets of each type.

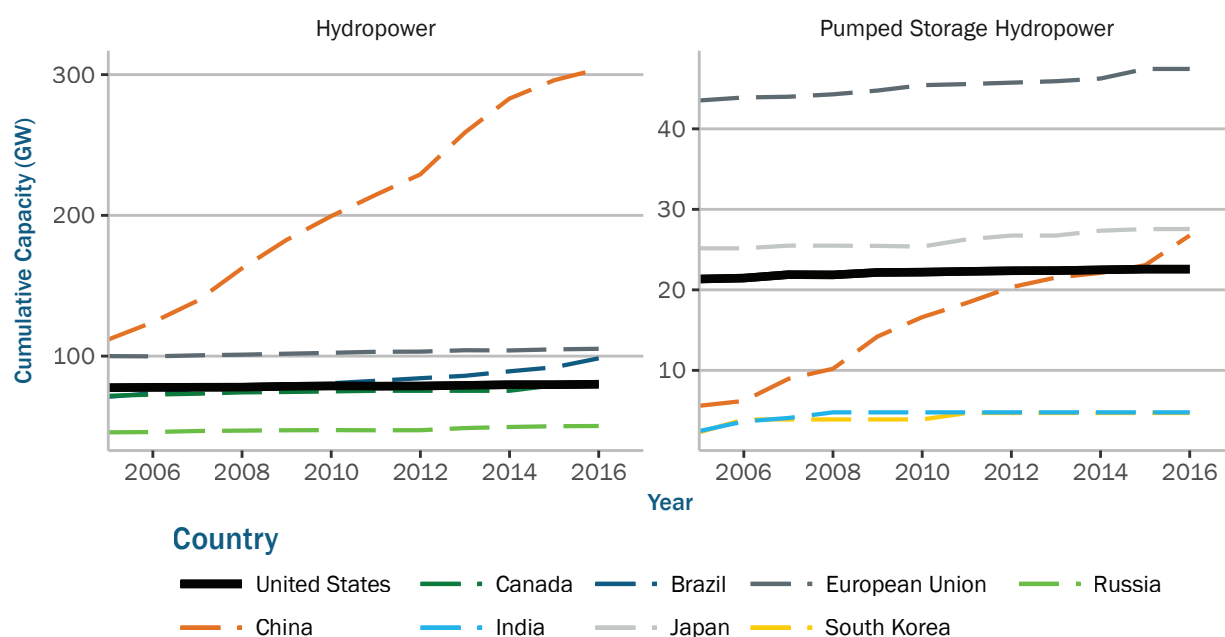


Figure 7. Evolution of installed hydropower and pumped storage hydropower capacity for the six largest fleets (2005–2016)

Sources: EIA International Energy Statistics, International Hydropower Association 2017 Hydropower Status Report, REN21 Global Status Report 2017

Note: European Union includes EU27 countries.

The U.S. fleet is one of the three fleets—along with China and the European Union—included in the top six ranking for both hydropower and PSH cumulative capacity. By the end of 2016, more than one quarter of global hydropower capacity was in China and the top six fleets accounted for 65% of global installed capacity. Japan and China are the individual countries with the two largest PSH fleets; however, if European Union countries are taken as a unit, their combined PSH fleet is the largest in the world. The number of countries that have any PSH capacity (50) is much smaller than the number of countries with hydropower (157). For instance, in the hydropower-rich region of Central and South America, only Argentina had any PSH capacity as of 2015. The top six PSH fleets included in Figure 7 represent 89% of global capacity.

Since 2005, the average annual growth rate for hydropower capacity in China has been 9.6%, dwarfing additions everywhere else. Brazil also exhibited solid growth during this period, with an average annual capacity growth rate of 3%. Capacity has remained stable in the other four largest fleets, with an average growth rate of less than 1% per year since 2005. The slowest growth corresponds to the U.S. fleet, with an annual growth rate of 0.29% during this period.

For PSH, the fleets depicted in Figure 7 can be segmented into three groups regarding their pace of growth. The strongest growth was in China, where PSH capacity has increased 16% on average per year since 2005. To achieve the goal of 40 GW of PSH capacity by 2020 set in China's 13th Five-Year Plan, double-digit growth rates will have to be maintained for the rest of the decade. South Korea and India carried out significant PSH construction in the first years of the period displayed in Figure 7, but their PSH capacity has remained stable in the most recent years. Finally, Japan, the European Union, and the United States increased their PSH capacity by less than 1% per year. When considering individual countries rather than the European Union grouping, Japan had the largest PSH fleet at the end of 2016 (27.5 GW), but it is about to be surpassed by China.

The map in Figure 8 introduces the nine world regions used to discuss various attributes of the global hydropower fleet and project development pipeline in the rest of this section. It also provides a visual summary of major hydropower clusters (e.g., southwestern China, southeastern Brazil, and the Pacific Northwest in North America).

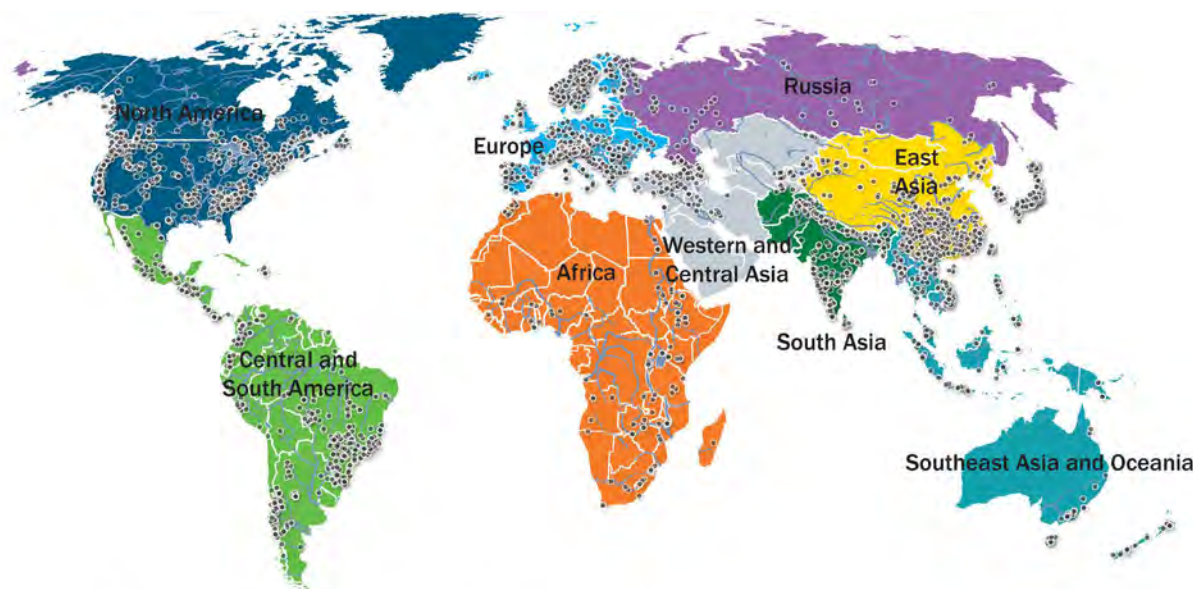


Figure 8. Map of operational hydropower plants by world region

Source: Industrial Info Resources

With major rivers often defining country borders, it is common for the development and operation of large (and typically multipurpose) hydropower projects to transcend national dimensions and require coordination between multiple countries.²² In North America, the Columbia River Treaty contains the terms of the agreement between Canada and the United States to share flood control and hydropower benefits derived from the operation of dams in the upper Columbia River basin. Similarly, the U.S. International Boundary and Water Commission owns and manages two hydropower plants near the U.S.–Mexico border as part of a treaty between the two countries. Rubio and Tafunell (2014) offer an account of multiple joint ventures between South American countries in the 1980s for the development of large hydropower projects (e.g., Itaipu between Paraguay and Brazil and Salto Grande between Uruguay and Argentina). In other cases, lack of cooperation leads to conflict surrounding hydropower developments in transnational river basins. In Asia, there is an ongoing dispute between China and India for development on the Yarlung Tsangpo river and tensions over water allocation among several Central Asian countries surround the Rogun hydropower project in Tajikistan (Hennig et al., 2013; Menga and Mirumachi, 2016).

22 The “List of international border rivers” entry in Wikipedia contains more than 100 instances in which rivers are borders between two countries, and the list is deemed incomplete.

ROLE OF PUBLIC ENTITIES IN GLOBAL HYDROPOWER DEVELOPMENT AND OWNERSHIP

From the United States and Canada to Norway, Russia, or China, a significant fraction of installed hydropower, particularly for large schemes, is owned and operated by government agencies or state-owned corporations. Public ownership is more common for hydropower than for other types of power plants because dams and reservoirs are also used for purposes such as flood control or navigation, which are typically provided by the public sector. However, ownership mixes do vary significantly across countries. In some countries (e.g., the United Kingdom and Spain), all large hydropower plants are privately owned. In contrast, only 7% of India's large hydropower capacity is privately owned. In Norway, municipalities own and operate 55% of the hydropower fleet and as much as 90% is publicly owned (Saha and Idso, 2016). The United States is among the countries with a large share of publicly owned hydropower—49% of installed capacity is owned by federal agencies, and an additional 23% of capacity is owned by state agencies, public power utilities, and cooperatives.

The public sector has played a large role—at different times in different countries—in hydropower development, but at the global scale, increased private investment has been observed in recent years (World Energy Council, 2013). Energy market privatization is enabling foreign investors to own and operate hydropower—especially small and medium plants—in countries where it was not possible before (e.g., Turkey, Nepal, India). Some recent milestones showing increased private sector involvement in hydropower development include completion of the first plant (El Quimbo) built by a private company in Colombia and the first approval in India in 2015 for a project that is 100% foreign owned (International Hydropower Association, 2016).

The role of China as a hydropower developer has changed significantly in recent years. From 1950 to 2000, Chinese hydropower development was highly dependent on foreign assistance from governments (e.g., Russia) or multilateral organizations such as the Asian Development Bank. Since 2000, China has funded many of its domestic projects and also invests heavily in hydropower development projects in neighboring countries and Africa. Norway—through its government-owned company SN Power—is another example of a country investing in hydropower development in multiple world regions.

2.1.2 Hydropower as a Fraction of Total Electricity Generation Capacity

Hydropower is the largest renewable energy source globally, but other renewables (particularly wind and solar) have grown faster than hydropower in recent years.

The 1,096 GW of hydropower in service at the end of 2016 was developed over more than 100 years. In contrast, almost 100% of global wind (487 GW) and solar (303 GW) capacity has been deployed in the last 20 years (REN21, 2017). Figure 9 shows the evolution of the hydropower fraction in the electricity generation capacity mix of each world region between 2005 and 2015.

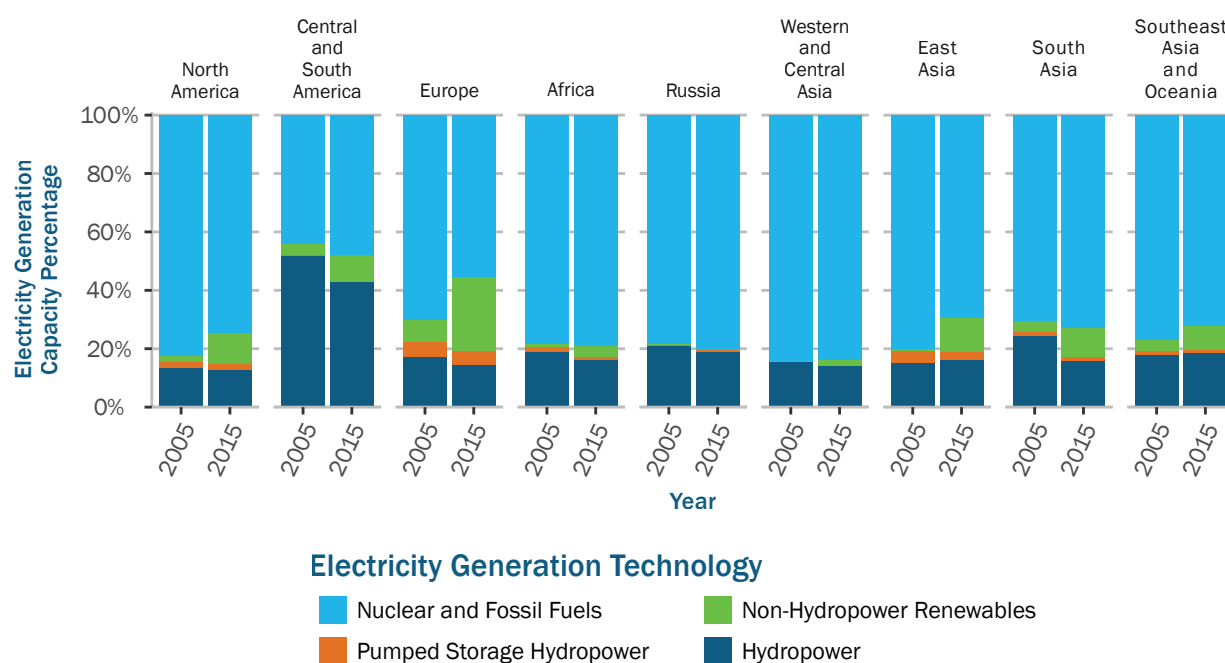


Figure 9. Electricity generation capacity mix by world region (2005 and 2015)

Source: EIA International Energy Statistics

Note: Pumped storage hydropower is included although it is a storage technology.

East Asia and *Southeast Asia and Oceania* are the only two regions where the percentage of hydropower in the electricity generation capacity mix increased from 2005 to 2015, and the percentage is projected to continue growing. The PSH capacity fraction has declined in every region except *Western and Central Asia*. On the other hand, the weight of non-hydropower renewables—mainly wind and solar—grew in the electricity fuel mix of every world region since 2005.

Hydropower represents a similar fraction—between 13% and 20%—of the electricity fuel mix in all the broad regions shown in Figure 9 except for *Central and South America*. The two regions with the largest overall share of renewables are *Central and South America* and *Europe*. In the former, most of the renewables are hydropower and approximately 50% of installed hydropower capacity is in a single country—Brazil. In Europe, non-hydropower renewables surpassed installed hydropower capacity between 2005 and 2015. Europe is also the region with the largest PSH fraction in its fuel mix; it hovered around 5% in 2015.

Fuel mix varies significantly among the individual countries making up the regional aggregates in Figure 9. In *North America*, Canada's hydropower fraction (54%) is much larger than that of the United States (7%). Canada had only 174 MW of pumped storage capacity in 2016, while the U.S. fleet surpassed 21 GW. The 2015 fraction represented by non-hydropower renewables in *North America* (11%) was very close to the hydropower fraction (13%). In the United States, wind capacity surpassed hydropower capacity in 2016.

2.1.3 Installed Hydropower Sizes

There has been a resurgence in large hydropower construction in the 2000s driven by Asia; in the United States and most other OECD countries, small hydropower dominates the new development pipeline.

There are no universally accepted size categories for hydropower facilities. The lack of consensus is especially notable regarding the limit used to categorize a hydropower plant as small. International organizations, including the International Energy Agency, European Small Hydropower Association, and United Nations Industrial Development Organization, agree in setting the upper limit to small hydropower at 10 MW. However, individual countries often use different upper bounds to define small hydropower (e.g., 50 MW in China, 30 MW in Brazil, and 25 MW in India). Liu et al. (2013) provide a detailed account of the small size definitions used in countries around the world. The size classification used throughout this report includes 5 categories: *Micro* (<0.1 MW), *Small* (0.1 MW-10 MW), *Medium* (10 MW-100 MW), *Large* (100 MW-500 MW), and *Very Large* (>500 MW).

The World Small Hydropower Report 2016 estimates global small hydropower capacity (<10 MW) to be 78 GW, representing 36% of total potential small hydropower resources (United Nations Industrial Development Organization and International Center on Small Hydropower, 2016). Existing small hydropower capacity is distributed among tens of thousands of facilities around the world. On the other end of the size spectrum, the global hydropower fleet contains more than 1,500 plants (excluding pumped storage) with a capacity above 100 MW (i.e., *Large* and *Very Large* categories). With a total capacity of 820 GW, those 1,500 plants represent 75% of total installed capacity. The world's two largest hydropower facilities are Three Gorges (22,600 MW) in China and Itaipu (14,000 MW) on the border of Brazil and Paraguay. Figure 10 shows a decadal timeline of *Large* and *Very Large* hydropower facilities.

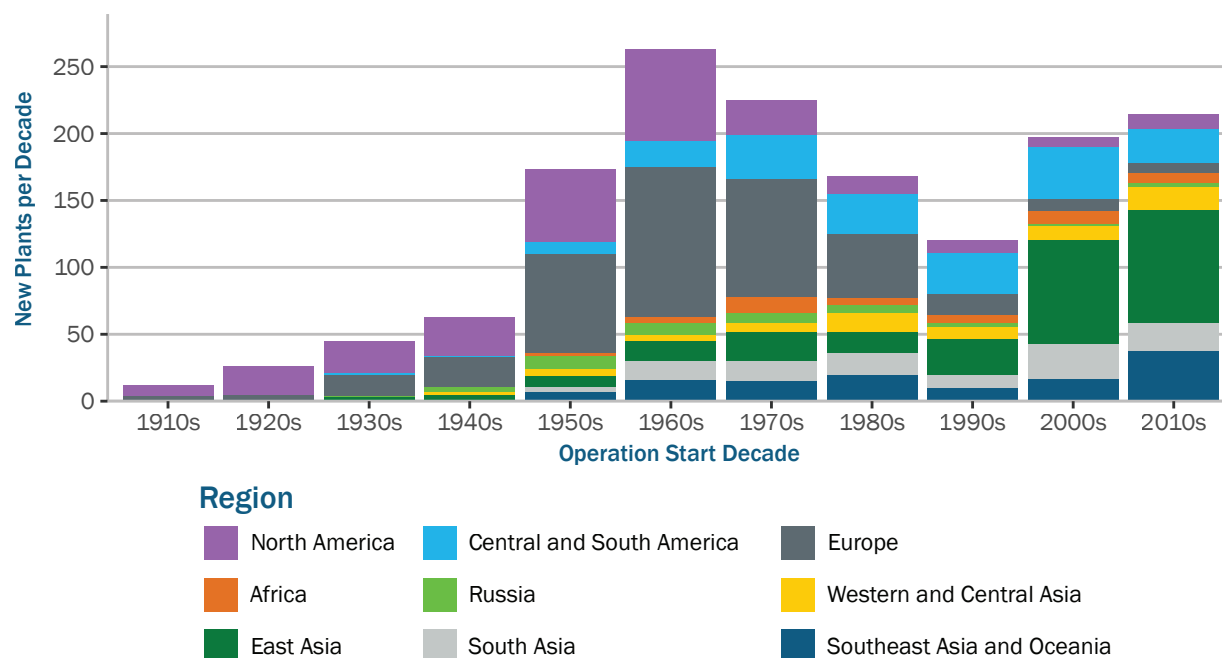


Figure 10. Timeline of construction of large and very large hydropower plants by region

Source: Industrial Info Resources

Almost 75% of all hydropower facilities (excluding PSH) with more than 100 MW of capacity are in one of four regions: *North America*, *Central and South America*, *Europe*, and *East Asia*.²³ The development timeline for this segment of the hydropower fleet differs substantially across these regions. From the 1910s to the 1940s, *North America* was the region building the most hydropower plants above 100 MW. After World War II, *Europe* ramped up development of large hydropower and added the most capacity from this size of facility from the 1950s to the 1970s. Since the 1970s, *Central and South America* has built about 30 large hydropower facilities per decade. *East Asia* and, to a lesser extent, the other Asian regions gradually increased their construction of large dams and hydropower starting in the 1960s and have dominated the development pipeline in the first two decades of this century. Even though large hydropower development is now rare in most Organization for Economic Co-operation and Development (OECD) countries, there are a few exceptions. Canada has added 16 large hydropower plants since 2000, with a total capacity greater than 6 GW. In contrast, the United States has added only one. In Europe, large hydropower projects with a total capacity of 3.1 GW have started operating in Norway and Portugal since 2000.

Globally, large hydropower plant construction peaked in the 1960s. The United States led the way in bringing the environmental impacts associated with large dam construction to the forefront. It passed legislation in the late 1960s and early 1970s that required those impacts to be studied and instructed FERC to give equal consideration to economic development and non-power impacts in permitting decisions for new hydropower projects. Acknowledgement of the environmental and social impacts of large dams gradually spread to other regions and, by the 1990s, led to multilateral banks slowing their financing of such projects. In 2000, the World Commission on Dams published a landmark report advocating the need to change the decision-making process around dam construction to include participation of all stakeholders and mitigation of negative impacts on society and the environment (World Commission on Dams, 2000). The development of *Large* and *Very Large* projects picked up again in the 2000s to address climate change and the growing energy demands of developing nations and with the increased role of the private sector and some governments—especially China—in providing financing (Moore et al., 2010). For instance, China is providing financing for the construction of multiple large hydropower dams along the Lower Mekong River in Laos, Myanmar, Thailand, and Cambodia.

Not all arguments against large hydropower are about environmental or social impacts. Project risk factors have also been raised as a reason to question large dam development. Ansar et al. (2014) compared estimated and actual costs for a set of 245 large dams built around the world and found that 75% of them incurred cost overruns and 80% experienced schedule delays. These overruns are often large enough to change the outcome of the benefit-cost evaluation that justified the project in the first place. Based on this dataset, the authors argue that smaller projects are more advisable from a risk management perspective.

Small hydropower plays an important role in the rural electrification strategies of many countries (e.g., Malawi and Colombia). A salient example is the “replace firewood with small hydropower” policy in China. From 2003 to 2013, this program resulted in 252 new small hydropower projects with a total capacity of 564 MW capable of meeting the electricity needs of 1.6 million rural residents. In addition, it is estimated that more than 6 million acres of forest area that would have otherwise been cleared for use as household energy have been protected through this policy (Kong et al., 2016).

In many highly developed countries, including the United States, new hydropower projects tend to be small because of their perceived lower environmental impact. However, small size alone does not guarantee environmentally friendly development. If the impacts of small hydro are considered on a per-kilowatt-generated basis, they can often be similar to those of large facilities, especially if multiple small hydropower units are placed along the same stream reach (Abbasi and Abbasi, 2011; Sample et al., 2015). To minimize environmental impacts, hydropower design and operation must take into account the health of the entire stream ecosystem in which it is located, and operators are increasingly being required to do so as a condition of regulatory processes.

23 Although *Europe* has the most hydropower facilities surpassing the 100 MW threshold, it ranks fourth in number of *Very Large* (>500 MW) plants and total combined capacity from *Large* and *Very Large* plants.

2.2 International Trends in Hydropower Development

At the end of 2017, there were at least 700 hydropower projects—adding up to 161 GW of capacity—under construction in 68 countries.²⁴ In addition, 355 GW of capacity distributed across 4,383 projects in 96 countries is in the earlier stages of development. As for PSH, the Industrial Info Resources (IIR) database tracks 180 projects in the permitting and development stage and 38 projects under construction with total capacities of 134 GW and 42 GW, respectively. Figure 11 summarizes the regional distribution of the combined hydropower-PSH project pipeline, distinguishing the fraction of projects in the early and advanced development stages.

2.2.1 Geographical Distribution of Hydropower Development Pipeline

East Asia has the largest hydropower and pumped storage hydropower development pipeline.

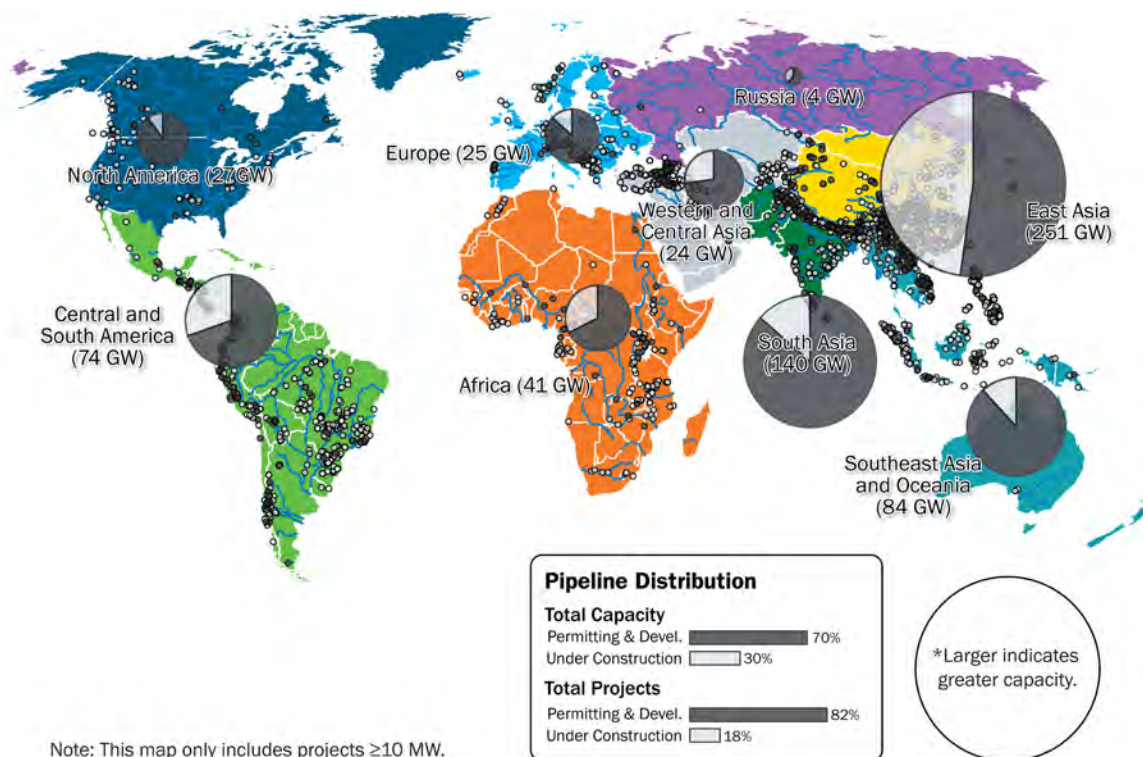


Figure 11. Map of hydropower project development pipeline by region and development stage

Source: Industrial Info Resources

Note: The *Under Construction* category includes projects that have completed the permitting process and secured financing but not yet broken ground.

A comparison of the information in Figure 11 and Figure 8 allows ascertaining the degree of overlap among regions with strong development pipelines and regions that already have large installed hydropower fleets.

- » For *North America* and *Europe*, the maps in Figures 11 and Figure 8 are consistent with the idea of mature hydropower markets with a large installed base but limited planned additional development activity. If all projects in the development pipelines for these regions were brought to completion, total capacity would increase by 14% in *Europe* and 15% in *North America*.

²⁴ The Industrial Info Resources database has comprehensive coverage of large and medium hydropower projects, but it misses part of the activity in the small hydropower segment.

- » In *Central and South America*, total capacity in the project pipeline represents a 40% increase relative to the size of the already installed fleet. The most visible difference between the locations of existing facilities and planned facilities is a pocket of projects along the Tapajós River in Northern Brazil.
- » Total capacity in the development pipeline in *Africa* more than doubles existing capacity (33 GW). Parts of Africa with almost no installed hydropower capacity have substantial development activity including Gabon, the border between Congo and Tanzania, and the Sassandra River in the Ivory Coast.
- » *East Asia* is the region with the largest total planned capacity (252 GW). Within China, much of the development planned for the upcoming years is in the Jinsha, Yalong, and Dadu rivers in the western part of the country. The western China hydropower expansion strategy includes construction of a long-distance, West-to-East transmission line to transport the energy from these new projects to major load centers in the country's eastern provinces.
- » In South Asia and Southeast Asia and Oceania, the total planned capacity is greater than the existing capacity. The ratio of proposed projects relative to installed projects appears especially large in the Philippines, Nepal, Pakistan, and Indonesia.

Table 2 lists the top 20 countries by total amount of capacity in the development pipeline, including both early and advanced development stages.

Table 2. Top 20 Countries by New Hydropower and Pumped Storage Capacity in the Development Pipeline

Country	Total Capacity – Combined (MW)	Hydropower (MW)	Pumped Storage Hydropower (MW)
China	251,520	140,120	111,400
India	65,315	61,815	3,500
Brazil	35,455	35,455	0
Pakistan	31,168	31,168	0
Nepal	25,993	25,993	0
Myanmar	25,697	25,697	0
United States	21,625	1,712	19,913
Bhutan	20,554	20,554	0
Indonesia	20,400	15,120	5,280
Philippines	18,860	7,270	11,590
Turkey	10,201	10,201	0
Ethiopia	9,202	9,202	0
Iran	8,976	7,976	1,000
Laos	8,632	8,632	0
Colombia	8,100	8,100	0
Peru	6,994	6,994	0
Argentina	6,771	6,771	0
Ecuador	6,561	6,561	0
Canada	5,859	4,359	1,500
Vietnam	5,326	4,126	1,200

Source: Industrial Info Resources, FERC eLibrary

China tops the ranking and accounts for 49% and 63% of tracked global hydropower and PSH development, respectively. Except for Brazil and the United States, all countries with more than 10 GW of hydropower in their project pipeline are in Asian regions. Multiple other countries from the Central and South America region (Ecuador, Peru, Colombia, and Argentina) are also in the top 20. Ethiopia is the only African country in Table 2, and neither Russia nor any European countries are included.

Both North American countries are part of the top 20, but their pipelines are quite different. In the United States, planned capacity is dominated by PSH projects, none of which are under construction. In contrast, hydropower projects account for 74% of total capacity under development in Canada. The percentage of projects in the *Under Construction* stage is 47% in Canada but less than 1% in the United States. The much smaller size of the PSH project pipeline in Canada (3 projects with combined capacity of 1,500 MW) versus the United States (48 projects with combined capacity of nearly 20 GW) is largely explained by the very high fraction of hydropower (60%) in Canada's electricity generation mix. Much of this hydropower is highly flexible, resulting in less overall need for additional flexibility from PSH.

East Asia is the region with the largest fraction of its project pipeline (48%) in the *Under Construction* stage. Four other regions (*Central and South America*, *Africa*, *Russia*, and *Western and Central Asia*) have one fourth or more of their planned capacity in the advanced development stage. For projects in the *Permitting and Development* stage, the expected attrition rate partly depends on details about the permitting processes used in each country. For instance, the majority of PSH projects in the United States are at a very early development stage in which project developers evaluate the project to determine whether to move forward in the permitting process. Attrition rate at that stage has been more than 90% for PSH projects whose feasibility evaluation commenced between 2000 and 2016. In other countries, projects might not be tracked until they submit the equivalent of a license or exemption application, at which point the expected attrition rate in the *Permitting and Development* stage would likely be lower.

East Asia and Europe have added gigawatts of pumped storage hydropower capacity since 2006 and are constructing many more plants; the United States has only added 1 new PSH facility since 1995 and has none under construction.

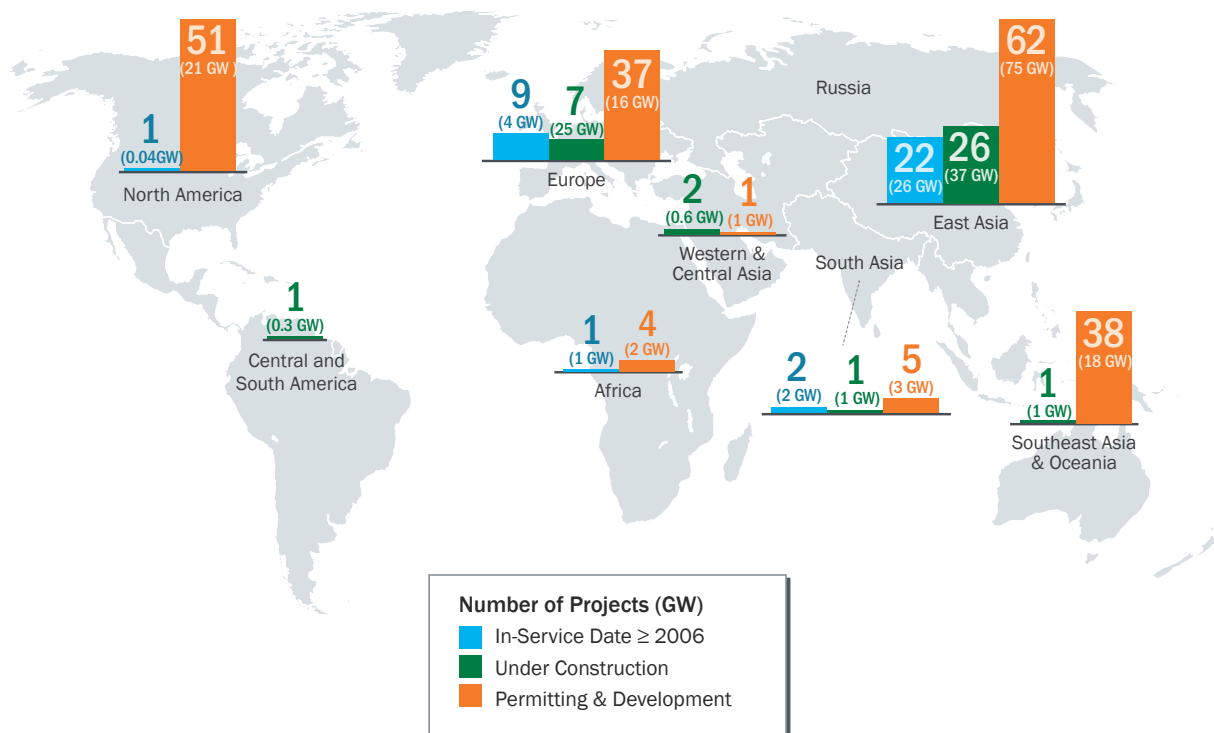


Figure 12. Pumped storage hydropower development by world region

Source: Industrial Info Resources, FERC e-Library

Trends in PSH construction over the last decade have varied significantly around the world. Figure 12 shows that Europe and East Asia have added 9 and 22 new facilities respectively since 2006. Four more PSH facilities started operation around the world in that period: two in South Asia, one in Africa, and the smallest one (Olivenhain-Hodges in Southern California) in the United States.

The regional distribution of PSH projects *Under Construction* at the end of 2017 looks very similar, with most of the activity concentrated in China and Europe. As shown in Figure 9, the percentage of non-hydropower renewables, primarily wind and solar, in the electricity generation mix of these two regions increased significantly from 2005 to 2015. PSH facilities are a good complement to wind and solar because they can respond quickly to the overall electricity supply-demand imbalances that arise as a result of sudden increases or decreases in wind and solar generation. In China, where approximately 20% of output from wind generation was curtailed in 2014, deployment of PSH plants is one of the strategies to increase the fraction of renewable energy produced that is actually consumed (International Hydropower Association, 2016; Gosens et al., 2017).

Variable renewables penetration has also increased in the United States, from 2% in 2005 to 11% in 2015, but it has not been a sufficient driver to spur new PSH development. At any point in the last decade, there have been dozen of PSH projects under consideration in the United States; however, none has yet moved into the construction phase. The disparity in PSH development activity between the United States and Europe or East Asia is striking and deserves further analysis. In China, construction of new PSH is explicitly encouraged by the government through the goal of 40 GW of PSH installed capacity by 2020 set in the 13th Five Year Plan. In Europe, gas-fired electricity generation is a less attractive means of providing the flexibility needed to integrate variable renewables than in the United States due to a lack abundant, domestic natural gas supplies.²⁵ This relative

25 <https://www.hydropworld.com/articles/print/volume-21/issue-3/feature-article/what-drives-pumped-storage-development.html>

scarcity of natural gas makes PSH particularly attractive as a provider of flexibility and grid services. A comparison of the typical length of the PSH authorization process and the available revenue streams for PSH facilities in different regions could offer additional insight as to the different trends in PSH construction.

2.2.2 Size Distribution of Hydropower Development Pipeline

South Asia has the largest project development pipeline by number of projects, but it is outpaced by East Asia in terms of planned new capacity.

Even though hydropower is a mature technology, innovation is making possible new records and types of development both in the large and small segments of the industry. For instance, the Rogun project, under construction in Tajikistan, will have the world's tallest dam (1,099 feet); and turbine manufacturers are working toward the objective of breaking the “1 GW wall,” which would mean building a turbine-generator unit capable of producing 1 GW.²⁶ In the small hydropower segment, technological innovation in turbine design (e.g., Archimedes screw turbine), site design (e.g., modularity), materials, and construction techniques is making the development of low-head sites—previously out of consideration—economically viable (Zhou and Deng, 2017).

Figure 13 summarizes the size distribution of the project development pipeline, including PSH projects. Its two panels highlight that the most frequent size categories are *Small* and *Medium*, but the fewer *Large* and *Very Large* projects account for most of the planned capacity.

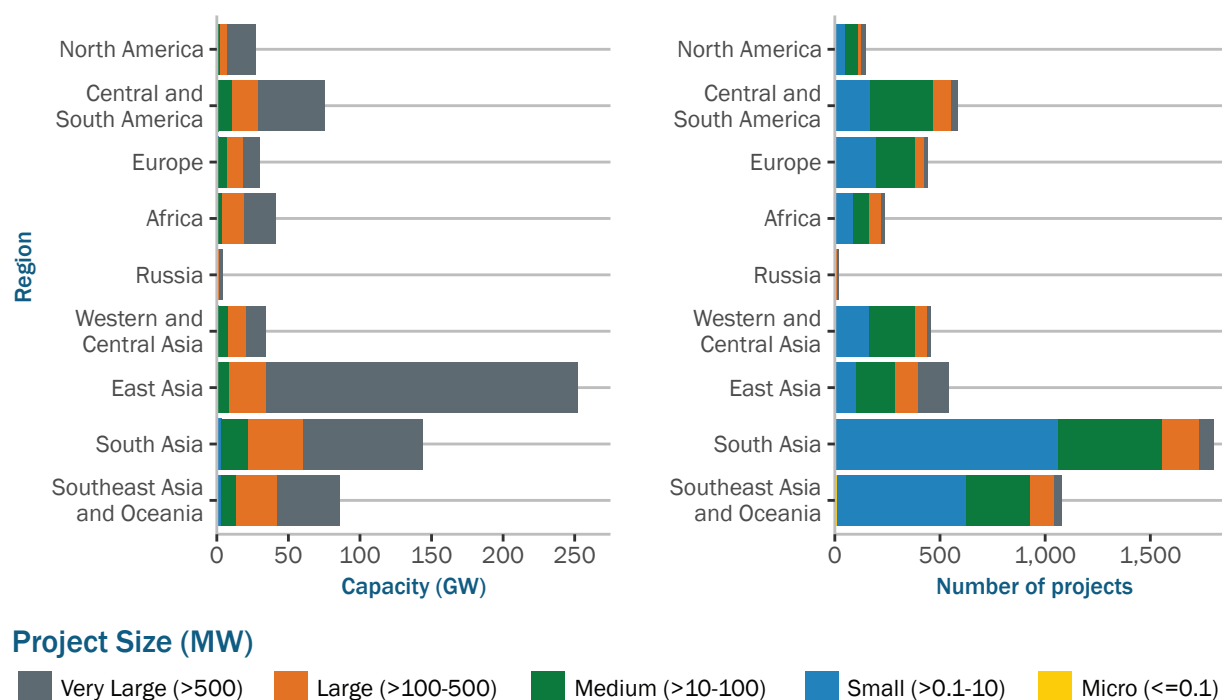


Figure 13. Tracked hydropower project development pipeline by world region and size category

Source: Industrial Info Resources

26 <http://voith.com/corp-en/industry-solutions/hydropower/large-hydro/xiluodu-china.html>.

The largest hydropower project is Belo Monte in Brazil, with two powerhouses and more than 11 GW of design capacity. Belo Monte is under construction and is slated for completion in 2019. A total of 208 projects in the pipeline are in the *Very Large* (>500 MW) category. Of those, 63—almost half in China—are under construction amounting to 121 GW.

East Asia, principally China, is the region with the most *Very Large* and *Large* projects in the pipeline. On the other hand, *South Asia*—led by India—tops the count of *Medium* and *Small* projects. The large number of small hydropower projects in India can be partly traced to a small hydropower program administered by the Ministry of New and Renewable Energy that provides financial assistance to public and private entities seeking to develop hydropower projects in that size range.²⁷

Despite the predominance of large PSH facilities, innovative PSH schemes at smaller scales are being developed around the world.

The median size of PSH projects in the development pipeline is 890 MW, and only 7% of them are below 100 MW. Reducing the cost of building storage reservoirs is crucial to making smaller PSH facilities economically viable (Witt et al., 2016). Using existing storage works (e.g., existing pools, ponds, caverns, or abandoned mine pits) is one strategy for reducing civil work costs. The Kidston PSH project in Australia (250 MW) and the Glyn Rhowny PSH in Wales (100 MW) are two examples of projects being developed at old mine sites. Legislation to promote this type of development in the United States was introduced in 2017 (H.R. 2880 *Promoting Closed-Loop Pumped Storage Hydropower Act*). Other strategies for civil work cost reductions include using floating membranes in rivers as lower reservoirs—the proposed Battery Pearl Hill PSH Project in the United States is evaluating the use of a floating membrane—and constructing the penstock in stages using a combination of conventional and alternative materials for higher and lower pressure sections.

Pilot PSH projects around the world are introducing innovative configurations, including co-location with other renewables and desalination facilities. For instance, a hybrid wind-PSH project where the foundations of the wind turbines are in the upper reservoir for the PSH unit is under construction in Southern Germany. The PSH portion of this project will have a generating capacity of 16 MW.²⁸ In Hawaii, the proposed Puu Opa PSH (8.3 MW) would pump water into its upper reservoir during day hours using solar energy.²⁹ In the island of El Hierro (Spain), a wind-PSH system started operating in 2014 that generates electricity to power not only homes and businesses but also three desalination plants. The PSH portion of the system is comprised of four units with a total installed capacity of 11.3 MW.³⁰ All these examples differ substantially from the large facilities connected to flowing rivers that make most of the existing PSH fleet in the United States and around the world.

2.3 Investment in Refurbishments and Upgrades

North America, which has the oldest hydropower fleet, is the leading region in the world investing in refurbishments and upgrades.

Figure 14 displays tracked capital investment projects started since 2015 (as well as projects with planned future start dates) targeting existing hydropower and PSH facilities in all world regions.³¹ Projects in the plant expansion category are geared towards capacity increases of existing turbine-generator units or addition of new units. Projects in the refurbishments and upgrades (R&U) category typically pursue increases in efficiency, reliability, and operating life of existing units.

27 Hydropower projects above 25 MW have not been considered renewable in India, although expanding the definition of renewable is under discussion (International Hydropower Association, 2017).

28 <http://www.mbrenewables.com/en/pilot-project/>

29 <http://www.hydroworld.com/articles/2017/11/hawaiian-cooperative-issues-request-for-qualifications-to-build-energy-project-including-pumped-storage.html>

30 <https://www.hydropower.org/blog/case-study-el-hierro-%E2%80%93-renewable-energy-for-remote-island-systems>.

31 The reason to choose 2015 as starting point is that it is the first year for which IIR provides global coverage for hydropower capital expenditure projects.

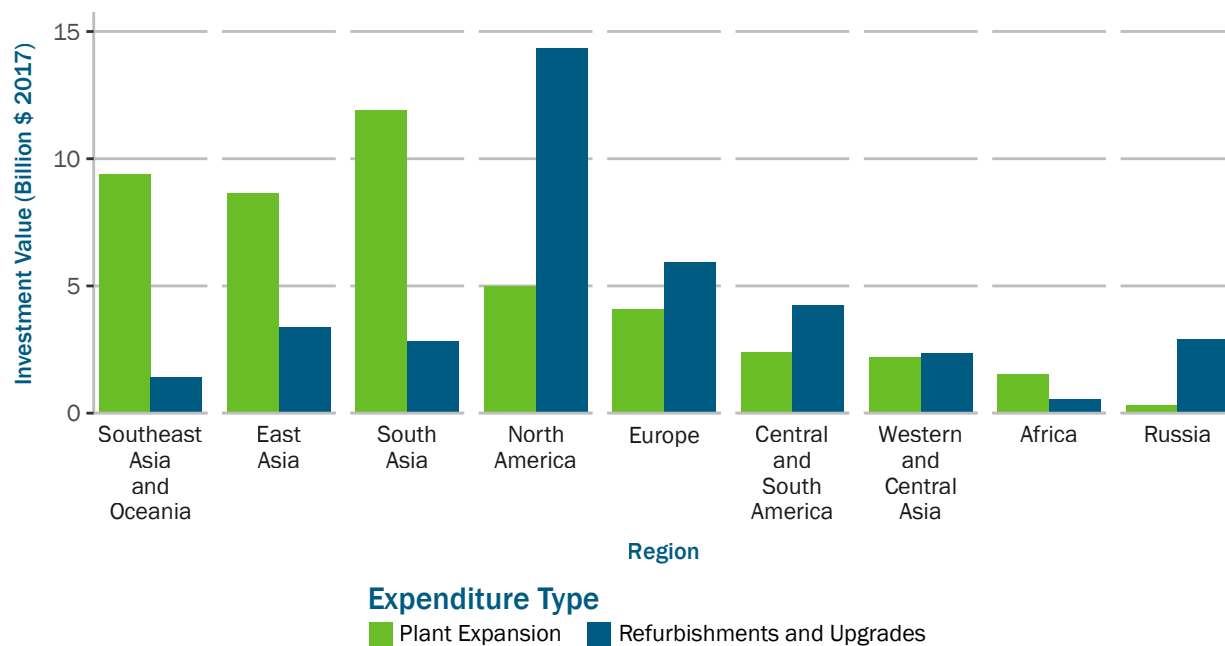


Figure 14. Expenditures on hydropower refurbishments, upgrades, and plant expansions by region

Source: Industrial Info Resources

The aggregate estimated value of all tracked projects included in Figure 14 is \$83 billion, of which 54% correspond to the plant expansion category. The region with the largest total investment is *North America* (\$19.3B). The breakdown of total investment between the two project categories varies significantly across regions. In most Asian regions, installed hydropower capacity is growing rapidly and tracked capital investment directed to existing hydropower assets goes largely toward plant expansion projects. In contrast, in *North America*, *Europe*, *Russia*, and *Central and South America*, hydropower fleets are older and the majority of the tracked projects are geared towards R&U. This is particularly true for *North America* and *Russia* where the percentages of tracked capital investment directed to R&U are 74% and 91% respectively.

Figure 15 displays tracked R&U investment in dollars per kilowatt of installed capacity in each region and it differentiates projects already ongoing or completed from those still in the planning stage.

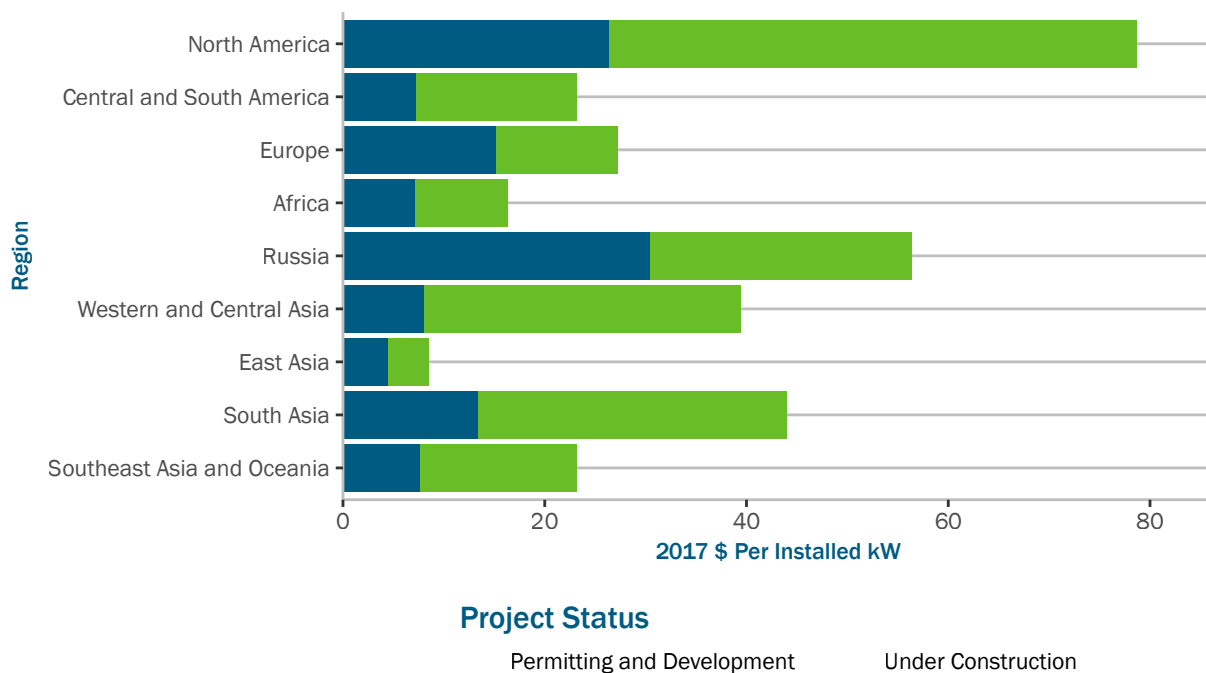


Figure 15. Expenditures on hydropower refurbishments and upgrades per kilowatt installed by world region

Source: Industrial Info Resources, EIA International Energy Statistics, International Hydropower Association 2017 Hydropower Status Report
 Note: Installed capacity data used to compute investment per kilowatt are for year 2016.

North America leads the R&U investment ranking in dollars per kilowatt with planned or ongoing projects started since 2015 amounting to an investment of \$79/kW. The fraction of projects that are *Under Construction* represents one third (\$26/kW) of the total. Details on recent R&U investments in the United States are presented in Section 1.3.

Russia and *South Asia* are second and third in the ranking of R&U expenditures per kilowatt installed. As indicated in Figure 11, *Russia* has almost no new projects planned. Thus, there seems to be a strong focus in maintaining and optimizing the existing fleet in that country. Conversely, *East Asia* has the strongest development pipeline for new projects but the lowest R&U expenditures either planned or in construction.

The average investment figures presented in Figure 15 implicitly assume that R&U investment is distributed evenly across each installed kilowatt. In reality, planned and ongoing investment are only directed toward a fraction of existing projects. For instance, tracked hydropower R&U investment in the United States is distributed across 143 plants out of more than 2,200 active U.S. hydropower plants. An alternative metric to compare R&U investment across regions that conveys the idea of R&U intensity is dollars per refurbished/upgraded kilowatt.

Figure 15 shows the relationship between R&U investment in dollars per refurbished/upgraded kilowatt and the capacity-weighted average age of the refurbished plants for world regions as well as selected individual countries.³² Age is an important attribute to take in consideration for the comparison of R&U investment levels across regions. All else equal, it should be expected that older plants would require more R&U investment per kilowatt to avoid declines in performance and reliability.

32 The calculation of capacity-weighted average relies on IIR data on individual plant capacities and operation start year. The IIR dataset has good coverage of large and medium-sized plants, but it misses a significant portion of projects in the small hydropower segment. The fraction of total capacity for which the IIR database contains plant-level design capacity values is higher than 90% in all but three regions: Europe (77%), East Asia (71%), and Western and Central Asia (61%).

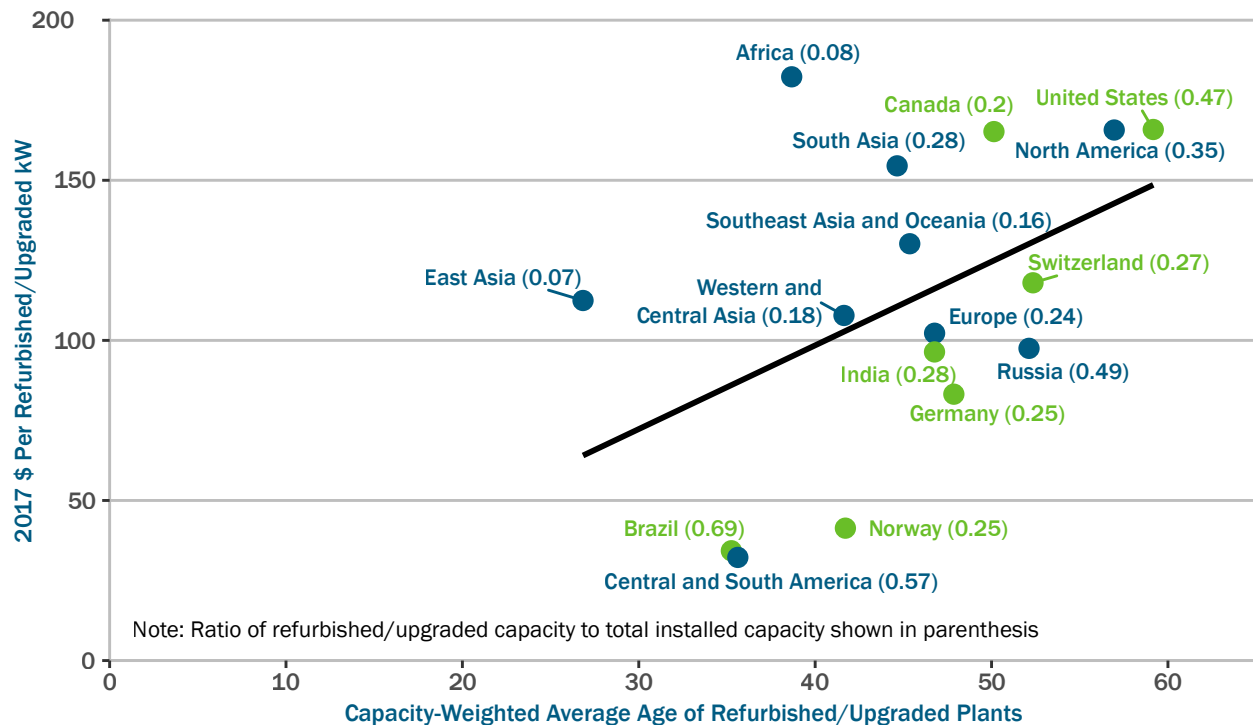


Figure 16. Expenditures on hydropower refurbishments and upgrades per kilowatt refurbished/upgraded and fleet age

Source: Industrial Info Resources, EIA International Energy Statistics, International Hydropower Association 2017 Hydropower Status Report

Figure 16 shows a positive relationship between the average age of refurbished or upgraded plants and R&U investment per refurbished kilowatt. Except in *East Asia*, the average age of plants being refurbished or upgraded is more than 30 years. On average, U.S. plants in the R&U pipeline are the oldest and are receiving the second highest investment per kilowatt (\$166/kW). Total investment value per refurbished/upgraded kilowatt is similar for the United States and Canada. Almost half of U.S. installed capacity is covered by ongoing or planned R&U projects versus 20% in Canada. Of the top 20 plants around the world by total R&U investment, 10 are in North America (seven in the United States and three in Canada).

For *Europe*, the average tracked R&U investment per refurbished/upgraded kilowatt is \$102/kW and tracked R&U projects include investment for approximately 25% of installed capacity. This percentage is fairly stable across the individual European countries included in this figure (Norway, Switzerland, Germany) even though the dollar per kilowatt metric varies significantly among them depending on the average age of the plants being refurbished or upgraded.

As shown in Figure 15, *Russia's* total R&U investment is the second largest among all world regions. However, as it is spread over a large percentage (49%) of its installed capacity, it leads to a low regional average investment per refurbished kilowatt. The lowest R&U investment intensity corresponds to *Central and South America* where a total R&U investment of \$3.3 billion is distributed among plants representing 57% of installed capacity. The highest investment per refurbished/upgraded kilowatt corresponds to *Africa*. However, this result should be interpreted with caution because the dataset only contains R&U projects for 11 plants representing 8% of total installed capacity in this region. A similarly low percentage of installed hydropower capacity (7%) is receiving or expecting to receive R&U dollars in *East Asia*.

Going forward, hydropower fleets in *Africa, Central and South America, Western and Central Asia*, and *South Asia* are about to reach the 30-year mark in terms of capacity-weighted average age. Thirty years is the approximate age at which a first round of major plant upgrades is typically needed. Thus, it is likely for global R&U expenditures to increase significantly in those regions in the near future if financing is available. Multilateral development banks are playing an important role in funding some of the R&U projects currently in the pipeline in those regions. For instance, the World Bank and the Asian Development Bank are contributing several hundred million dollars toward the modernization of major hydropower plants in Tajikistan (Western and Central Asia).^{33,34}

33 <http://projects.worldbank.org/P150816?lang=en>.

34 <https://www.adb.org/projects/46418-001/main#project-pds>.

3. U.S. Hydropower Price Trends

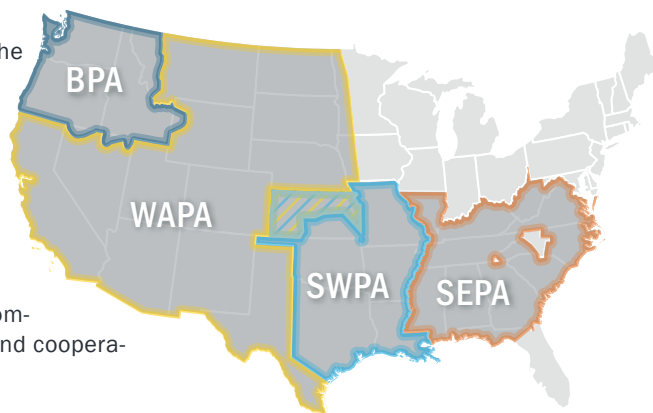
3.1 Trends in Hydropower Energy Prices

U.S. hydropower prices vary regionally and by ownership type.

For an analysis of hydropower prices, the U.S. hydropower fleet can be divided into three distinct segments that largely depend on a combination of the electricity market structure in each region and ownership type. First, power marketing administrations (PMAs)—Bonneville, Western, Southwestern, and Southeastern—market federal hydroelectric power from plants owned by USACE and Reclamation, mostly to public power utilities and cooperatives, at cost-based rates. The Tennessee Valley Authority is also a federal hydropower owner, but it markets power directly, rather than through a PMA, to customers and functions as a vertically integrated utility. Second, in regions of the country where the wholesale electricity market and transmission grid are coordinated by an independent system operator (ISO) or regional transmission organization (RTO), investor-owned utilities and wholesale power marketers submit bids for energy from their hydropower plants and receive the market equilibrium prices for their accepted bids. Third, energy from the rest of the fleet is either sold internally by vertically-integrated utilities to their customers or sold to utilities and commercial or industrial buyers through bilateral transactions or power purchase agreements (PPAs).³⁵ The maps in Figure 17 display the footprint of the PMA and ISO/RTO service areas. The footprints of PMAs and ISO/RTOs overlap in many regions of the country. Thus, it is a combination of geographical location and ownership type that determines how the electricity of a U.S. hydropower plant will be marketed.

³⁵ Some of the surplus large hydropower in the Pacific Northwest owned by public or private entities is traded at the Mid-Columbia hub, a wholesale market trading hub that is not in an ISO/RTO.

Power marketing administrations (PMAs) are federal agencies within the U.S. Department of Energy responsible for marketing the electricity generated by federal hydropower projects owned and operated by the U.S. Army Corps of Engineers, U.S. Bureau of Reclamation, and International Boundary Water Commission. PMAs sell wholesale electricity at cost-based rates to preference customers (mostly publicly-owned utilities and cooperative-owned utilities).



Independent system operators (ISOs) and regional transmission organizations (RTOs) are non-profit oversight entities, created by regional stakeholders in response to FERC Order 888 (1996) and FERC Order 2000 (1999), to coordinate competitive wholesale electricity markets and provide open access to the electric transmission grid.

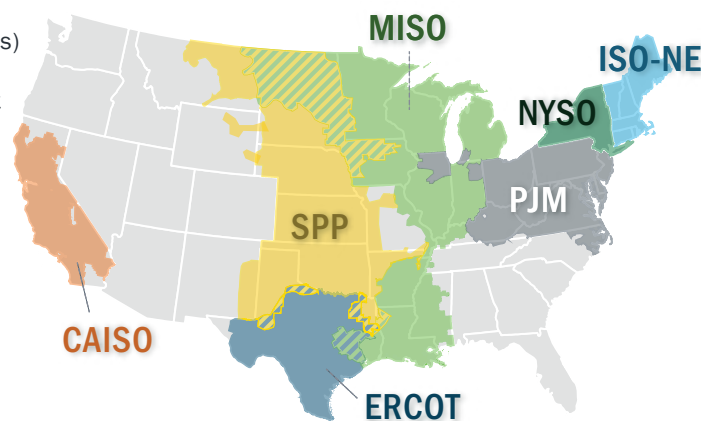


Figure 17. Footprints of power marketing administrations and independent system operators

As of 2017:

- » Electricity produced by 44% (35.2 GW) of U.S. hydropower capacity and 6% (1.3 GW) of PSH capacity is marketed by one of the four power marketing administrations (PMAs).
- » Electricity produced by 28% (22.4 GW) of U.S. hydropower capacity and 59% (12.7 GW) of PSH capacity is marketed through one of the seven organized wholesale markets administered by ISO/RTOs.
- » Electricity produced by the remaining 28% (22.4 GW) of U.S. hydropower capacity and 35% (7.6 GW) of PSH capacity is sold either internally by vertically-integrated utilities to their customers or through bilateral contracts, power purchase agreements, or transactions in wholesale market trading hubs.

Price trends for hydropower plants that generate power marketed by PMAs or sold to utilities through PPAs are discussed subsequently. In both cases, these are hydropower-specific prices and the annual averages presented are meaningful summary metrics because neither PPA prices—unless they are indexed to wholesale market prices—nor the rates at which PMAs sell power vary frequently within a year. On the other hand, in ISO/RTO markets, energy prices vary within the hour and reflect the operation cost of the marginal scheduled unit, which is rarely a hydropower unit.

This section focuses on energy prices, but that is not the only revenue stream for hydropower plants. Many also receive capacity payments and revenue from the provision of ancillary grid services such as frequency regulation and balancing reserves. In some cases, particularly for pumped storage hydropower units, these additional revenue streams can make up a significant fraction of the total annual revenue (Pérez-Díaz et al., 2015). Additionally, in states with renewable portfolio standards, electricity produced by eligible hydropower plants has attached renewable energy credits with additional value.

Further work is needed to quantify the magnitude of these other revenue streams for the U.S. hydropower fleet. On one hand, data and analysis are needed to measure the participation of hydropower in capacity and ancillary service markets in the various ISO/RTOs and hydropower's contribution to grid services in non-ISO/RTO areas. Then, the value of the services would need to be estimated based on their prices or, outside of ISO/RTO markets, based on open access transmission tariff rates for ancillary services.

3.1.1 Trends in Federal Hydropower Prices

Post-2008, federal hydropower prices do not differ significantly from average wholesale market prices in most regions.

Figure 18 displays the trends in average price per megawatt-hour received by the four PMAs for the electricity they sell. Bonneville Power Administration (Bonneville) sells the electricity produced by almost 10 GW of capacity in the 31 hydropower plants that compose the Federal Columbia River Power System (FCRPS). The footprint of the Western Area Power Administration (Western) extends over 15 states, and the electricity it markets is produced by 56 hydropower plants totaling 10.5 GW. The Southwestern Power Administration (Southwestern) markets power in 6 states from 24 hydropower plants adding up to 2.2 GW. Finally, Southeastern Power Administration (Southeastern) sells electricity from 22 U.S. Army Corp of Engineers (USACE)-owned projects with a total capacity of 4.1 GW. Because the bulk of the electricity marketed by the PMAs originates in federal hydropower plants owned by USACE and Reclamation, the PMA prices in Figure 17 can be interpreted as average hydropower prices.³⁶ As a point of comparison, the annual average wholesale electricity prices at a western and an eastern electricity trading hub—Mid-Columbia and PJM West, respectively—are also included.³⁷ Unlike the hub wholesale prices, which reflect daily supply-demand conditions, PMAs set rate schedules with the objective of covering the capital and operation and maintenance costs of the federal hydropower fleet. Those base rates are revised at intervals of one year or longer.

36 Bonneville also markets the production from a nuclear power plant (Columbia Generating Station) and Western Area Power Administration markets part of the production from a coal-fired plant (Navajo Generating Station).

37 All sales by Southeastern and Southwestern are sales for resale by public utilities. For Bonneville and Western, sales for resale represented 95% and 87%, respectively, with the rest being sold directly to retail customers. Because most sales by PMAs are at the wholesale level, they are comparable to wholesale market prices.

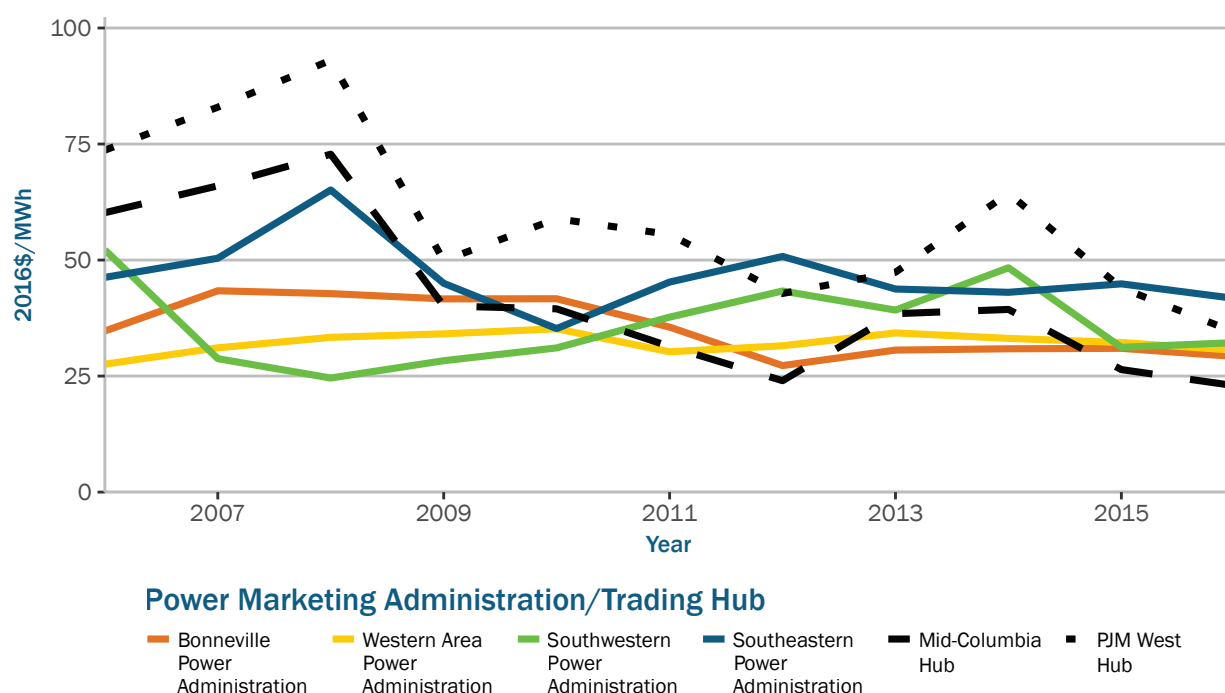


Figure 18. Average federal hydropower price versus average wholesale electricity prices at selected hubs

Sources: EIA Form 861, EIA Wholesale Electricity and Natural Gas Market Data

The average price (in 2016 dollars) across the period displayed in Figure 18 was similar for the three PMAs—Bonneville, Western, and Southwestern—responsible for marketing federal power produced west of the Mississippi River. The average price was 35\$/MWh for Bonneville, 32\$/MWh for Western, and 36\$/MWh for Southwestern. The average price in those three PMAs was lower and more stable than the average spot price in the Mid-Columbia Hub. However, when considering only the post-2008 period, the average Mid-Columbia wholesale price (\$32.77/MWh) is below the average price paid by Bonneville (\$33.47/MWh) and Southwestern (\$36.42/MWh) customers. Southeastern prices were highest across the 4 PMAs in 8 of the 11 years included in Figure 18 but lower than the average PJM-West hub price. It is important to note that the PJM-West hub is an aggregate of buses located in an area of the country, from Pennsylvania to D.C., where transmission congestion is common. Thus, the difference in average PJM-West hub prices versus average prices for Southeastern customers might be partly reflecting these transmission constraints.

Not every PMA customer pays the same price for federal hydropower. PMAs offer a variety of products differing in their duration, reliability, and flexibility attributes (Sale et al., 2012).³⁸ The average price in Figure 18 includes capacity and energy charges as well as adders applied on top of the base rate to cover the costs that PMAs incur in managing imbalances between available hydropower generation and contracted firm power volumes by their customers. For some PMA contracts, these rate adders can be substantial during drought years. Many of the price spikes in the PMA price series are related to drought events. For instance, the extreme hydrologic drought experienced by Oklahoma in 2006 is reflected in the high price for power marketed by Southwestern in that year. Because Southwestern's rates are weighted heavily on fixed capacity and firm energy, for drought years when there is little to no additional (supplemental or excess) energy provided, the price per megawatt hour is higher; conversely, in good water years when there is abundant additional energy available, the price per megawatt hour is lower. Similarly, the 2008 spike in Southeastern's prices correlates with a drought episode in that region. On the other hand, the prolonged drought experienced by many Western states in 2012–2015 does not correspond with a significant increase in Western's prices in Figure 18. There are multiple reasons for Western's price profile remaining relatively flat despite drought

38 For instance, Southwestern offers a firm energy product to their customers that guarantees delivery of 1,200 MWh per year per megawatt of capacity contracted regardless of hydrologic conditions. The price of this firm energy has averaged \$61/MWh instead of \$35/MWh. The \$35/MWh value combines firm energy and supplemental energy sales. Supplemental energy depends on hydrologic conditions and, when available, is sold for under \$10/MWh.

events. First, electricity marketed by Western is generated by clusters of hydropower projects situated in several hydrological regions. This geographical diversity smooths out the Western-wide average price. Second, some of power marketed by Western comes from hydropower plants connected to very large water reservoirs that, during an average year, hold multiple years' worth of water supplies. These reservoirs can be used to manage drought periods. Third, in regions where hydrological characteristics make water supply more difficult to forecast (e.g., the Central Valley Project in California and the Washoe Project in California/Nevada), Western sells only "as available" power. PMA customers in those regions experience hydrological risk primarily as fluctuating delivered volumes rather than price volatility.

3.1.2 Trends in Non-Federal Hydropower Purchase Prices

The average price paid by utilities for purchased hydropower has been larger than the average power purchase price across all generation technologies.

Small, nonutility hydropower owners typically sell their electricity through a PPA. The off-taker with whom they negotiate the agreements is generally an electric utility. However, in recent years, corporations looking to meet sustainability targets are playing an increasing role in buying renewable electricity through PPAs.

In many of the PPAs signed between small hydropower owners and electric utilities, prices are based on the avoided cost rates mandated by the Public Utility Regulatory Policies Act (PURPA) of 1978.³⁹ PURPA created a market for "qualifying facilities"—renewable electricity generation plants of up to 80 MW or cogeneration facilities—by requiring electric utilities to buy their power. This purchase requirement was one of the drivers for the addition of hundreds of small hydropower plants in the United States in the 1980s. The Energy Policy Act of 2005 relaxed PURPA's "must purchase" obligation by creating an exception for utilities in service areas where the qualifying facilities would have access to a competitive market. In its Order 688, the Federal Energy Regulatory Commission (FERC) determined that most of the ISOs/RTOs—MISO, PJM, ISO-NE, NYISO, and ERCOT—met the necessary criteria for utilities in their territory to claim the existence of access to a competitive market.⁴⁰ However, it also established the presumption that qualifying facilities below 20 MW do not have nondiscriminatory access even if they are in one of the ISO/RTO areas and it is up to the utilities to prove otherwise if they want to circumvent the "must purchase" obligation. Thus, since 2005, whether "must purchase" applies depends both on size and geographic location. PPAs are also negotiated for projects that do not qualify under PURPA, in which case the price can differ from the avoided cost rate. In states with renewable portfolio standards (RPS), the PPAs between obligated load-serving entities and renewable generators may be driven by state procurement policies. Procurement options for negotiating these purchase agreements include competitive solicitations, bilateral contracts, auctions, and feed-in tariffs (Kreycik et al., 2011).

Major electric utilities are required to file FERC Form 1 reports including information on the volumes of power purchased from facilities they do not own and the expenditures associated with those purchases. Power purchases reported in FERC Form 1 include data from long-term and short-term power purchases. A search of FERC Form 1 annual data on hydropower PPAs from 2006 to 2016 produced data for 2,868 hydropower energy purchases. The rest of this section focuses on a subset of 2,509 observations, from 453 buyer-seller pairs, belonging to one of two types of agreements: long-term power purchases with a duration of five or more years or nonfirm/short-duration (less than one year) power purchases.

The hydropower volumes exchanged through this subset of FERC Form 1 power purchases represent a very small percentage of total hydropower generation (typically between 3% and 5%). However, federal owners and investor-owned utilities own more than two thirds of U.S. hydropower capacity and do not sell their electricity through PPAs. A more relevant point of comparison to assess how representative the prices discussed in this section are is the total generation by the segment of the fleet whose owners—cooperatives, industrial companies, independent power producers, and some power marketers—tend to enter PPAs. The average quantity of electricity generated in 2002–2014 by that portion of the fleet was 32,534 GWh, which corresponds to 12% of the annual average U.S. hydropower production during that period. The average volume of hydropower sold through the agreements in the FERC Form 1 subset analyzed in this section represented, on average, 22% of that generation volume.

39 Avoided cost is the cost the utility would have to pay for energy, capacity, or both if it self-generated it or purchased it from an alternative source.

40 CAISO and SPP were subsequently added to the list.

Figure 19 compares the median and generation-weighted average price from hydropower purchases to the same metrics across all power purchases, regardless of technology, reported in FERC Form 1.

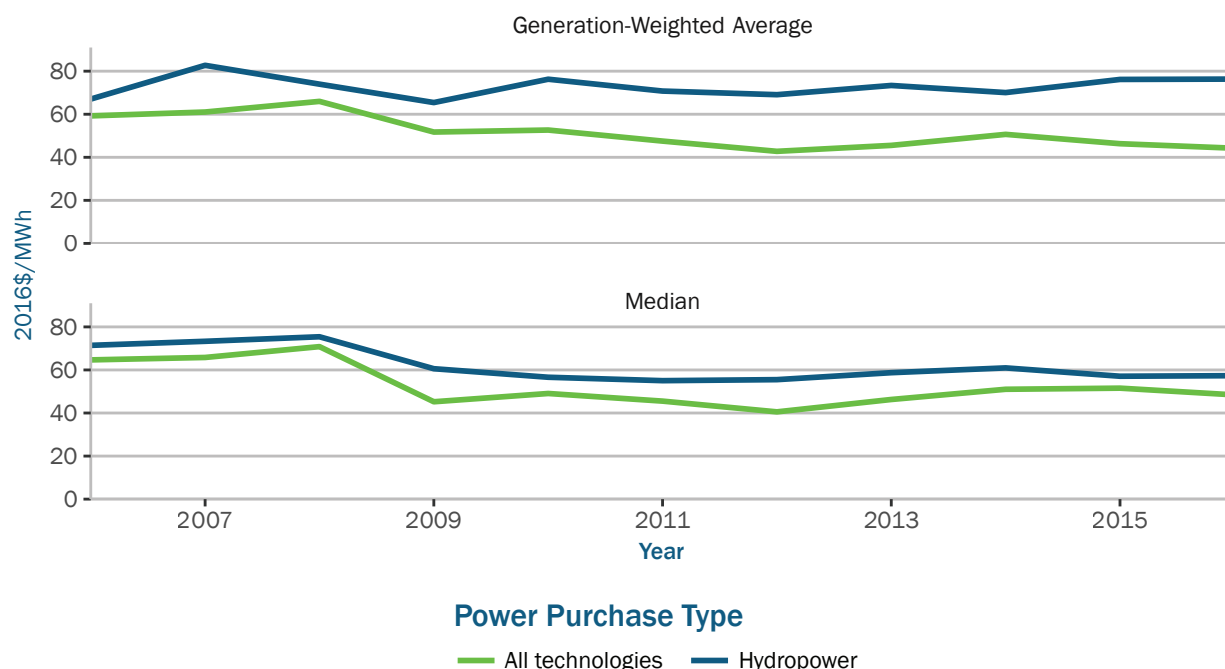


Figure 19. Median and generation-weighted average FERC Form 1 purchased power prices for hydropower versus all technologies

Source: FERC Form 1

For both summary metrics in Figure 19, the hydropower price has remained higher than the average across all technologies. The gap is larger for the generation-weighted average than for the median because there are a few hydropower purchases with large volumes being exchanged and prices above \$100/MWh. FERC Form 1 provides only the name of the buyer and the seller, so it is not always possible to identify the power plant(s) associated with each purchase. Based on the energy volumes exchanged in each transaction and assuming a 40% capacity factor, which is consistent with the U.S. hydropower fleet-wide capacity factor in recent years, the median plant size among the hydropower PPAs in FERC Form 1 would be 1.23 MW and the 25th and 75th percentiles would be 0.34 MW and 3.5 MW, respectively. Even though this calculation provides only a rough approximation to the distribution of hydropower plant sizes in the FERC Form 1 dataset, it is safe to assume that most transactions reflect power purchases from small hydropower plants. For small plants, power purchase prices will largely be based on PURPA avoided cost rates, which can vary by technology. Higher hydropower prices relative to the average for all power purchase transactions reported in FERC Form 1 might partly reflect a determination by utilities that the avoided cost from purchasing hydropower is larger than for other technologies with more limited dispatchability. However, it might also be a function of timing. Most small U.S. hydropower plants were built decades ago and locked in avoided cost rates at a time in which they were significantly higher.

Figure 20 shows the median and 10th and 90th percentile energy price received by hydropower plants whose sales are documented in FERC Form 1 for years 2006–2016.

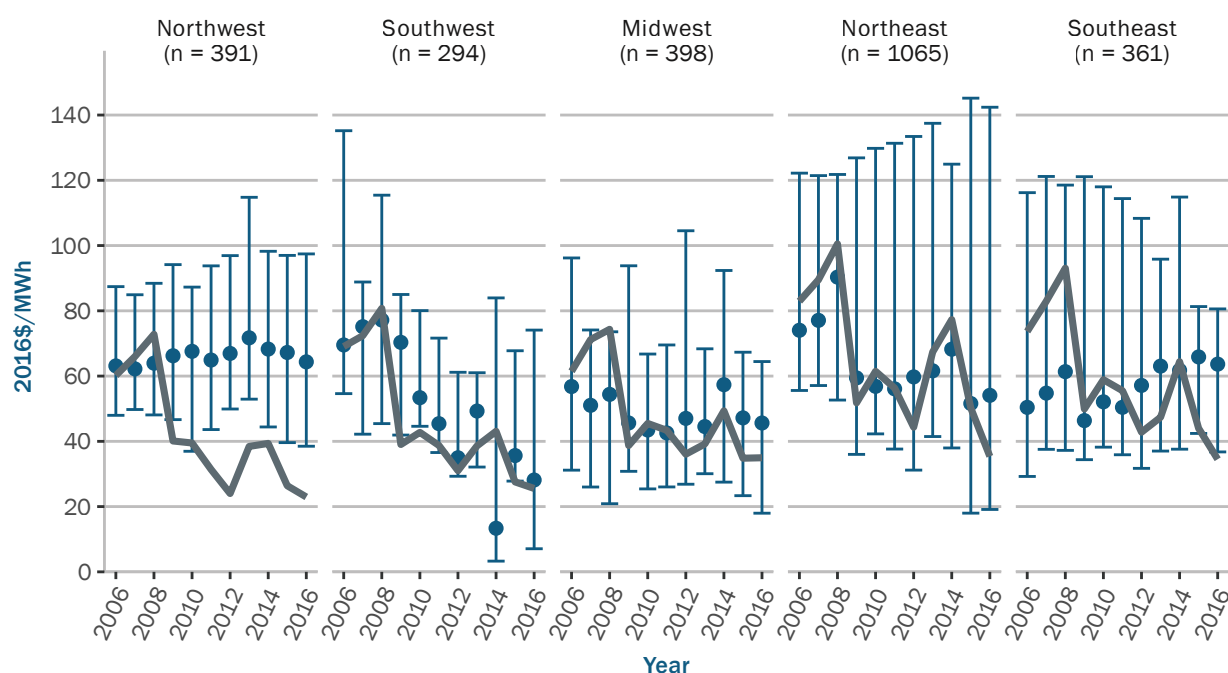


Figure 20. Hydropower price by region and report year from long-term firm power sales reported in FERC Form 1

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

Note: Points correspond to the median hydropower purchase price based on FERC Form 1 data, and the range represents the 10th–90th percentile FERC Form 1 hydropower purchase price range. Trend lines correspond to the average on-peak wholesale price at selected electricity trading hubs in each region (Mid-Columbia Hub for Northwest, Palo Verde Hub for Southwest, Indianapolis Hub for Midwest, Massachusetts Hub for Northeast, and PJM West Hub for Southeast).

The median price paid for energy produced at hydropower facilities across the country in 2006–2016 was \$62.78/MWh.

Within each region and year, there is considerable variability in hydropower prices. Variability is particularly pronounced in the Northeast where it has increased over time. In contrast, the 10th–90th percentile range has narrowed in the Southeast in recent years.

From 2006 to 2008, median hydropower purchase prices increased but stayed below average market prices in the Midwest, Northeast, and Southeast. The Northwest is the region in which hydropower prices are carrying the larger premium relative to the regional average wholesale market price. It is also the only region where the median hydropower price remained stable during the recession started in 2008. In fact, median hydropower prices in the Northwest have followed a continuous increasing trend until 2013 and declined only slightly in 2014–2016. The median hydropower price has trended downwards in the Southwest and the Northeast and upwards in the Southeast.

Divergences, sometimes large, between wholesale prices at electricity trading hubs and the hydropower prices reported in FERC Form 1 can be explained by multiple factors. First, many of the hydropower prices in Figure 20 are based on fixed prices negotiated in long-term PPAs that, by definition, do not follow the short-term fluctuations in wholesale market price. Typical durations for hydropower PPAs have historically been 15 to 20 years. Second, seasonality in hydropower generation might result in a given facility producing much of its power during a time of year when the market price is substantially above or below than the annual average. Finally, some of the agreements in the database might refer to hydropower from facilities in locations for which the selected wholesale market prices are not a good proxy.⁴¹

41 For instance, the Southeast region includes states outside of the PJM territory for which SPP or ERCOT prices could be more representative.

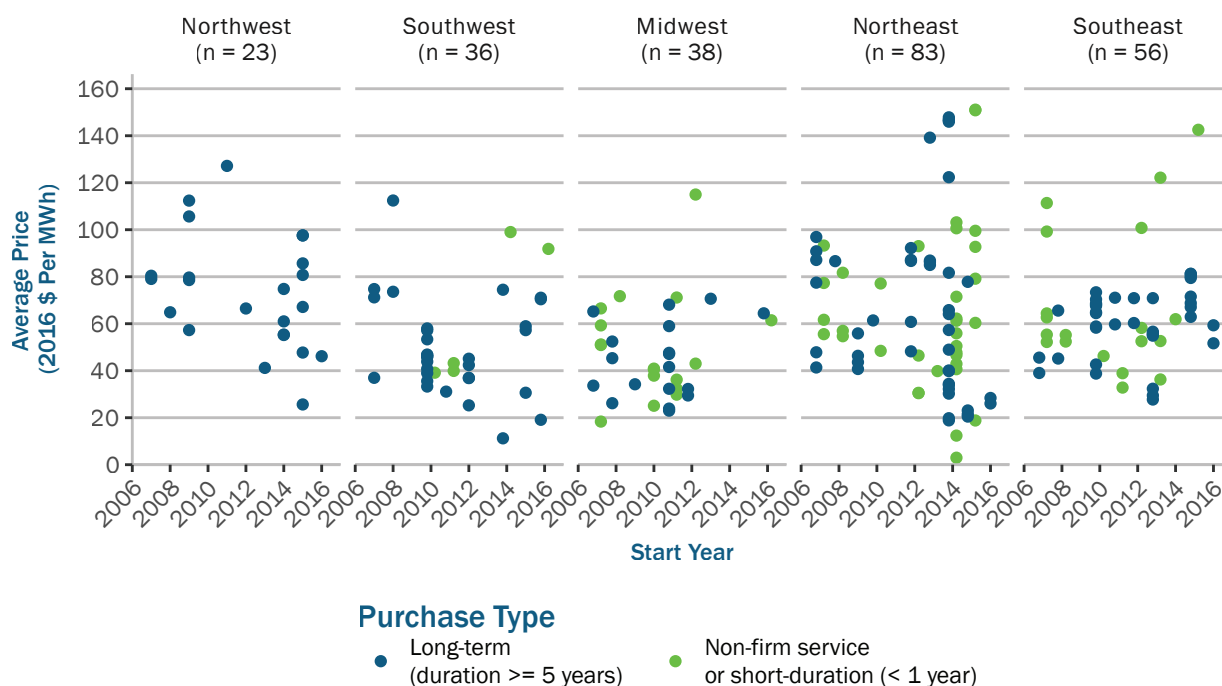


Figure 21. Average hydropower price for individual buyer-seller pairs versus start year of the purchase agreement

Source: FERC Form 1

Figure 21 shows the average price for each purchase agreement initiated after 2006 in relation to the first year in which it appears in FERC Form 1—taken here as proxy for the start year of the agreement.⁴² Market conditions at the time the agreement is being negotiated, particularly for PPAs based on long-term fixed avoided cost rates, are an important factor for the prices that will be paid throughout the life of the contract. For projects in the Northwest and Southwest, long-term purchase agreements initiated in most recent years receive lower prices. The trend is similar for the Northeast except for a very wide range of average prices in agreements initiated in the most recent years. For the Midwest, the available data sample shows very few new agreements since 2012. Contrary to what is observed for most of the rest of the country, hydropower prices negotiated as part of long-term purchases initiated in 2015 in the Southeast were high compared with most of the previous decade. For nonfirm service and short-duration power purchases, the sample size is smaller and shows no clear trends.

As indicated in Figure 20, the median hydropower purchase price in 2016 was higher than the average wholesale price in all regions. However, in much of the country, PPAs signed in recent years come with lower prices than older ones. This trend is consistent with mounting opposition from many utilities to the idea that PURPA prices should continue to be based on a long-term projection of avoided costs. They argue that the avoided cost rates required by PURPA have resulted in utilities entering into long-term contracts at prices substantially above the market price, which harms their ratepayers. FERC held a technical conference in 2016 to discuss with industry stakeholders whether changes to PURPA’s “must purchase” requirement or avoided cost rate methodology are needed given the evolution of market conditions since the last major revision of PURPA in 2005. To date, the feedback gathered by FERC through that process has not resulted in any changes to PURPA rules. Meanwhile, states are responding in a variety of ways to utilities’ proposals for changes in PURPA implementation.

- » In the Northeast, several state commissions (e.g., Connecticut, New Hampshire, and Massachusetts) have ruled that the avoided cost rate is the hourly real-time locational marginal price. This decision partly explains why the Northeast is the region where the median hydropower price has tracked the wholesale market price the closest.

⁴² 2006 is excluded because it is the start year of the dataset and we cannot discern whether PPAs with 2006 data started that year or earlier.

- » Throughout the West (Idaho, Utah, Montana, and Wyoming), public utility commissions have applied for or are considering reductions in the length of some PURPA contracts. Utilities backing these reductions argue that shorter contract lengths effectively reduce the risk involved in committing to a fixed price over the life of the contract.

For hydropower developers, entering into a long-term PPA is often a necessary condition to obtaining financing for constructing the facility. Hydropower owners of plants with FERC licenses close to expiration also consider the PPA conditions offered by utilities as important input when deciding whether making the investments necessary to pursue a relicense would be a financially sound decision. Shorter contract lengths or PPA prices tied to wholesale market prices rather than fixed would lead to revenue uncertainty and could affect the terms of financing obtained by hydropower investment projects whose owners require a PPA.

3.2 Trends in Hydropower Asset Sale Prices

Changes in ownership have taken place for hundreds of U.S. hydropower plants during the last decade; most of the transactions involve small plants and private buyers and sellers.

Figure 22 summarizes the number of transfers for projects with FERC licenses and exemptions for each year from 2004 to 2017.

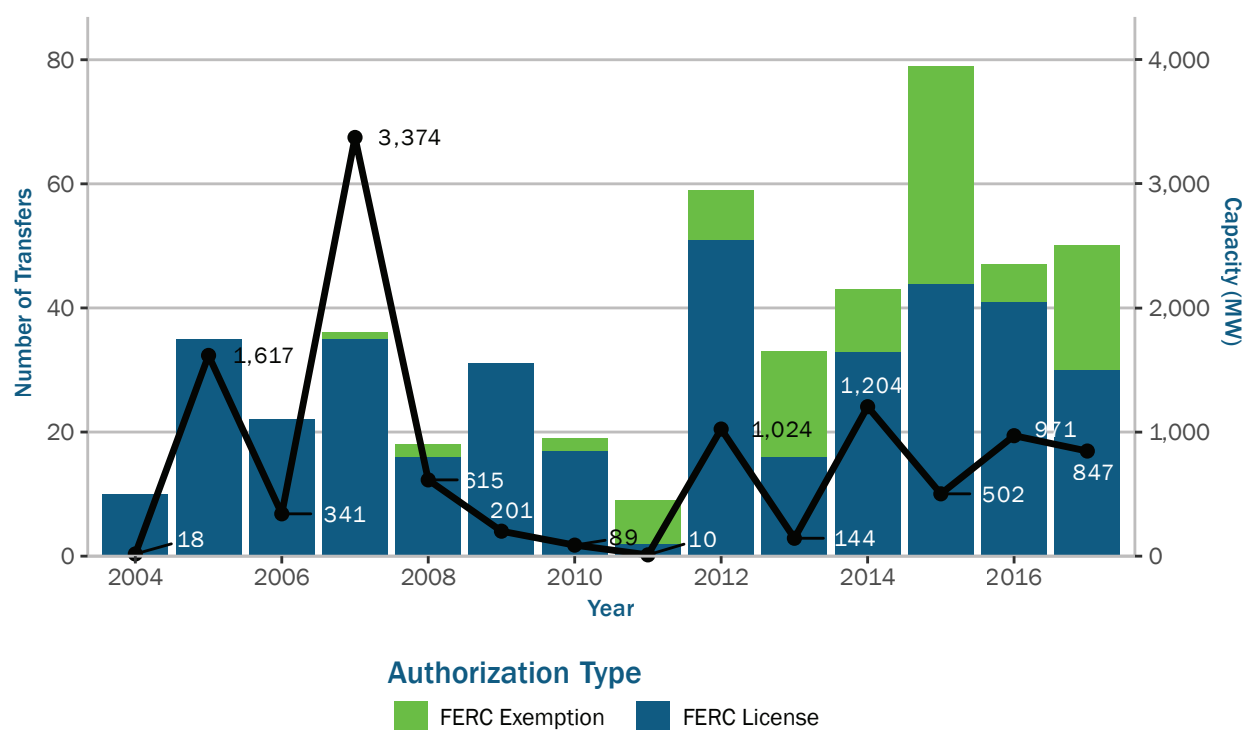


Figure 22. Hydropower ownership transfers by year and authorization type

Source: FERC e-Library, NHAAP

The total number of hydropower plant transfers between 2004 and 2017 was 491.⁴³ The pace of transfers increased after 2011, particularly for exemption-holding plants. The year with the largest number of transfers (79) in this period was 2015. However, the year in which most capacity changed ownership was 2007.⁴⁴ The dataset displayed in Figure 22 provides a continuation to Kosnik (2008), which explored data on hydropower license transfers for 1980–2003 and found two peak years with approximately 70 transfers: 1987 and 1999. The author interpreted those spikes as responses to changes in federal regulation

43 Some plants were transferred multiple times during the period of analysis (2004–2017)

44 Almost 95% of the capacity transferred in 2007 involved two entities within the same corporate structure. Duke Energy Corporation transferred 3.19 GW of hydropower capacity to Duke Energy Carolinas, LLC, in that year.

affecting hydropower relicensing: the passage of the Electric Consumers Protection Act in 1986 and FERC’s introduction of the Alternative Licensing Procedure in 1998. In contrast, no significant changes to the relicensing process have taken place in the 2010s to explain the increased transfer activity in recent years.

Most plants being transferred are operational, but a few transactions involve retired facilities that the new owners plan to repower. The dataset also contains one transfer in which the buyer is a private nonprofit corporation (Penobscot River Restoration Trust) whose mission is the removal of dams and restoration of natural river habitats.⁴⁵ Similarly, PacifiCorp and the Klamath River Renewal Corporation (KRRC) have applied to transfer the license for four hydropower developments in the Pacific Northwest to the KRRC with the objective of removing the dams in the lower part of the Klamath River, but the transfer has not yet been approved by FERC.

Despite hundreds of plants being transferred since 2004, the U.S. hydropower fleet ownership mix has not changed significantly as to its distribution between public and private entities. Table 3 segments the number and capacity of the plants transferred into four categories depending on whether the buyer and the seller are private or public entities. Most transfers have been from one private owner to another with multiple instances in which buyer and seller are different subsidiaries of the same parent company. The next, more common type of transfer involved sales by one public entity to another. A total of 16 plants were transferred from a private seller to a public buyer, and only 2 plants moved from public to private ownership. The net change in ownership type is very small: an increase of 206 MW in publicly owned capacity in 2017 relative to 2004.

Table 3. Hydropower Ownership Transfers by Ownership Type of Seller and Buyer (2004–2017)

Ownership types of seller and buyer	Number of transfers	Capacity transferred (MW)
Private to private	432	9,532
Private to public	16	246
Public to private	2	40
Public to public	41	1,139

Source: FERC eLibrary

Figure 23 provides details about the location and size of the transferred plants. The Northeast and Southeast are almost tied in terms of total capacity transferred. Within the *Large* and *Very Large* fleet segments, there were total or partial changes in ownership for 17 plants, 6 of which are pumped storage plants, but the majority (73%) of transferred plants are small. The Northeast region has the largest number of privately owned, small hydropower plants and also the largest overall number of transfers in 2004–2017. With low electricity prices and high O&M expenditures as plants age, the business case for private non-utility owners to keep a small plant becomes challenging. On the purchasing side of the hydropower asset market, a handful of companies (e.g., Ampersand Hydro, Brookfield Renewable, Cube Hydro, and Eagle Creek Renewable Energy) have built portfolios largely or exclusively populated by existing hydropower assets during this period. These companies seek to add value to the existing assets through investments to improve their efficiency and synergies in the operation and maintenance of the portfolio.

⁴⁵ It is worth noting that, despite removing two dams and decommissioning the powerhouse of a third hydropower plant, the Penobscot River Restoration Project did not decrease total electricity production in the watershed because generation increased at the remaining hydropower plants.

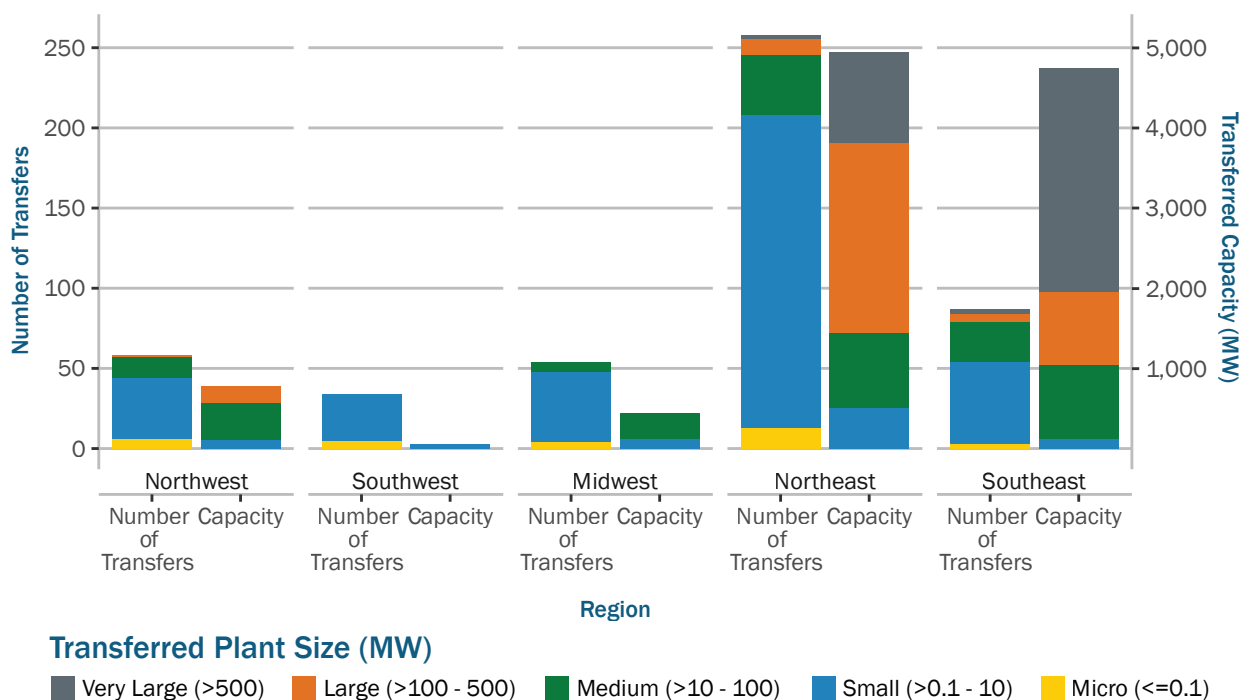


Figure 23. Region and size distribution of transferred hydropower plants between 2004 and 2017

Source: FERC e-Library, NHAAP

For a subset of the transfers, hydropower plant sale prices have been made public through media announcements and Security Exchange Commission filings. We assembled a dataset of 64 sale prices accounting for 3.7 GW of transferred capacity, which is 34% of the total capacity transferred between 2004 and 2017. The total value of the sales recorded in this sample is more than \$5 billion. The three largest transactions, two of which involved portfolios of plants, account for more than half of that total value. Mirroring the characteristics of the full set of hydropower asset transfers, most transactions for which prices were identified involved private buyers and sellers.

The average sale price per installed kilowatt was \$1,072/kW (in 2016 dollars), but there was substantial variability around that central value. The capacity-weighted average value was \$1,345/kW, suggesting that larger plants tend to be valued more. Within this sample, there is not significant variation in price for plants holding a FERC exemption versus a FERC license (\$935/kW and \$1,096/kW average prices, respectively). The average price in six transactions where the plants sold were outside of FERC jurisdiction was \$732/kW, but those tended to be very small, old plants. It is likely the combination of those attributes rather than their permitting status that resulted in the lower price. For the 38 transferred plants in this sample with FERC licenses, the median time left until expiration of the license at the time of the transaction was 16 years. Only in three cases did the sale take place with five or less years left before license expiration. Figure 24 displays the price of each tracked sale along with the years and regions in which each transaction took place.

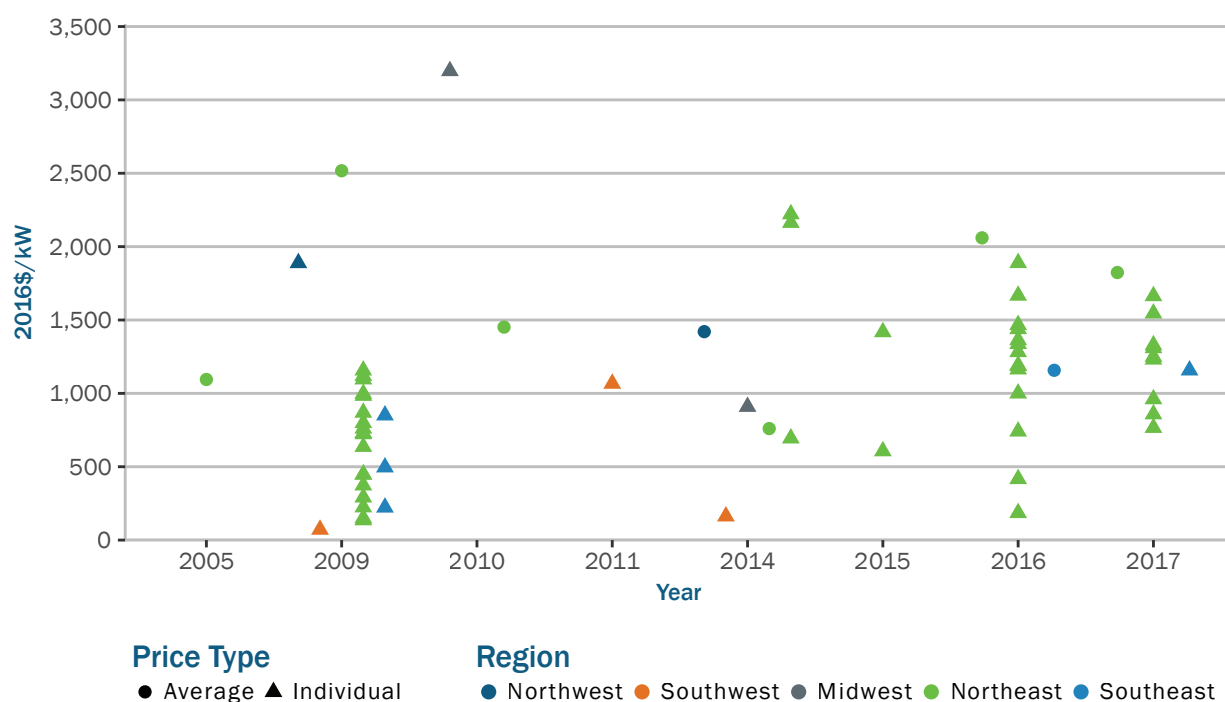


Figure 24. U.S. hydropower plant sale prices by year and region of sale

Source: Web searches and SEC filings

Note: The average price type corresponds to transactions in which multiple plants were sold but only the total price was reported

Most prices in Figure 24 correspond to hydropower plant sales in the Northeast, which, as indicated by Figure 23, is the region with the largest number of ownership transfers. The highest and lowest tracked prices corresponded to transactions in regions (i.e., the Midwest and Southwest) with much less active markets for existing hydropower assets. Several of the tracked sales in the Northeast involved multiple plants that appear as clusters of observations in Figure 24. Within those clusters there is considerable variation in the prices per kilowatt for each individual plant.

4. U.S. Hydropower Cost and Performance Metrics

4.1 Capital Costs

The capital costs of recently developed hydropower plants remain highly variable as developers with access to low-cost, long-term financing pursue targeted opportunities at low-head NPD, and small NSD and conduit projects.

As development of new hydropower projects remains slow, developers continue to pursue projects whose costs vary within a range of \$2000 to \$8000 per kilowatt (with occasional exceptions). Figure 25 tracks inflation-adjusted project costs for hydropower over the 37-year period since 1980.⁴⁶ The size of an individual project “bubble” is proportional to installed capacity. Note that gaps in the data series prior to 2010 are not indicative of stalled development in the hydropower industry, but instead reflect lapses in historical data collection—the 1980s have relatively robust coverage owing to Department of Energy’s small hydropower program efforts at the time.

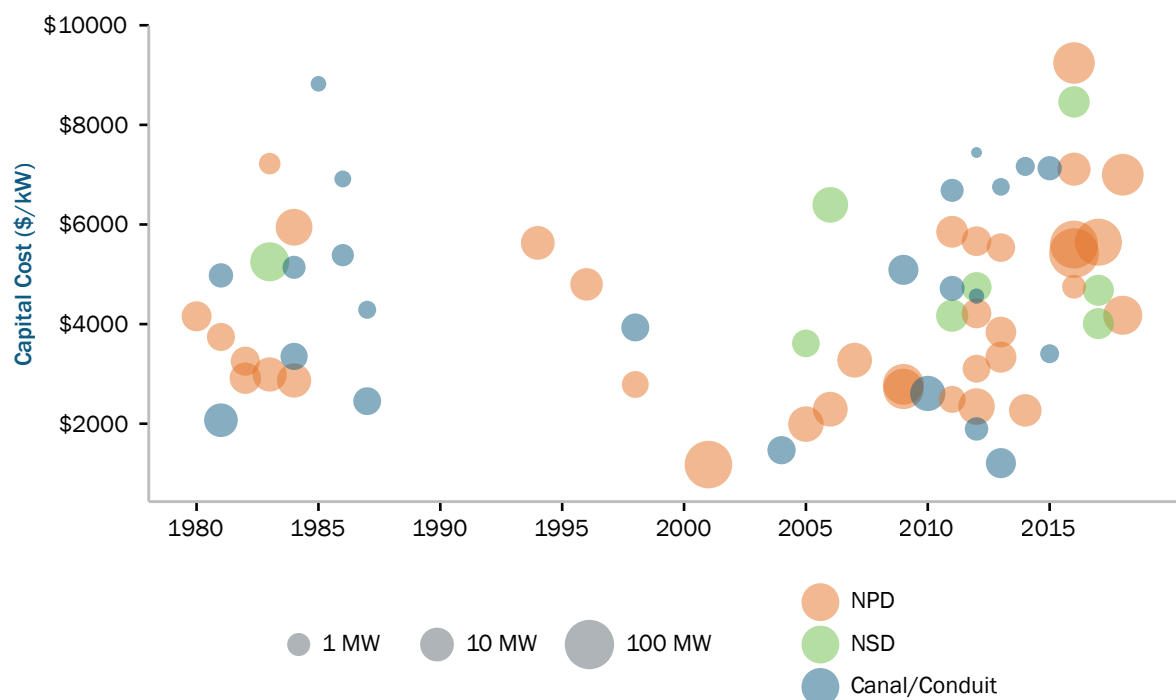


Figure 25. Cost of new hydropower development since 1980

Source: O'Connor et al. (2015), Industrial Info Resources, internet searches

Since 1980 the average NPD has cost approximately \$4,200/kW to develop, the average NSD project has cost \$5,200/kW, and the average Canal/Conduit project has cost \$4,700/kW. While there is significant variation in cost project-by-project, it is not surprising that the general range of cost for successful developments has remained relatively stable as the “best” (cheapest) projects are quickly developed and financial feasibility constrains the upper limit of what developers are willing to pay for new hydropower.

For hydropower projects, capital cost variability is driven by many factors ranging from technology selection to regional differences in market rates to cost savings possible due to existing infrastructure such as nearby interconnection opportunities.

⁴⁶ Hydropower capital costs as discussed have, to the extent possible, been quality controlled to ensure cost estimates are of equivalent scope and boundaries. Generally, these costs are inclusive of all project construction works and equipment purchases including the cost of electrical interconnection. They do not include the cost of the licensing and permitting process, nor do they include interest charges or other similar financing-related charges.

However, at a macro-scale, one of the most significant drivers of cost in a hydropower project is the available hydraulic head. All else being equal, a higher head project requires less flow to achieve the same power output as a lower head, leading to direct savings in the cost of equipment, and it reduces the size and scale of the associated civil works and water conveyance infrastructure.⁴⁷ The influence of the latter on recent projects is illustrated in Figure 26.

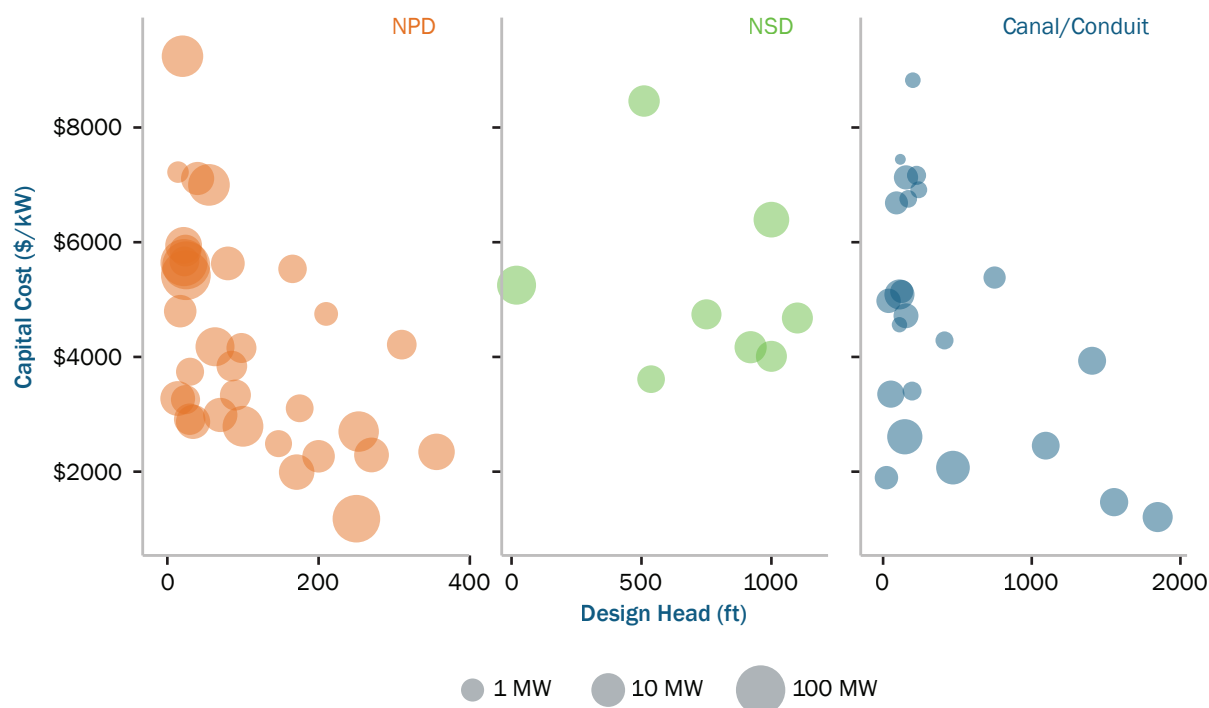


Figure 26. Relationship between capital cost and head for recent hydropower projects

Source: O'Connor et al. (2015), Industrial Info Resources, internet searches

NPD and Canal/Conduit projects exhibit strong economies of scale with respect to hydraulic head (higher heads being less expensive). Limited recent development restricts the sample size for NSD, and the significant range of development scales in terms of capacities and heads underscores the intense variability in hydropower project economics. The general focus on development of low-head resources is consistent with the bulk of remaining hydropower resources in the United States (particularly NPDs), but as is clear in Figure 24, the cost of developing these resources remains highly variable.

4.2 Operation and Maintenance Costs

Except for the largest hydropower plants, operations and maintenance costs have risen at rates higher than inflation for the last decade. These costs increases are particularly challenging for the smallest plants, which are spending much more to remain operational on a relative (\$ per kilowatt) basis than larger counterparts.

Like many aspects of hydropower, the cost of operating and maintaining (O&M) projects is highly site specific, and dependent on a variety of design, technical, and market factors. However, the single clearest source of variation in cost comes from the economies of scale with respect to the generating capacity. The larger the hydropower project, the lower it costs on a relative (\$ per kilowatt) basis to operate and maintain. Figure 27 illustrates this phenomenon by plotting the 2016 O&M costs of 451 plants as reported on FERC Form 1.

⁴⁷ In the case of the turbine runner, the higher head and lower flow rate for a given generating capacity generally means that the runner will be physically smaller, requiring less raw materials to manufacture. Higher head turbines are also usually designed to operate at a higher rotational speed, reducing the physical size of the associated generator for a given capacity.

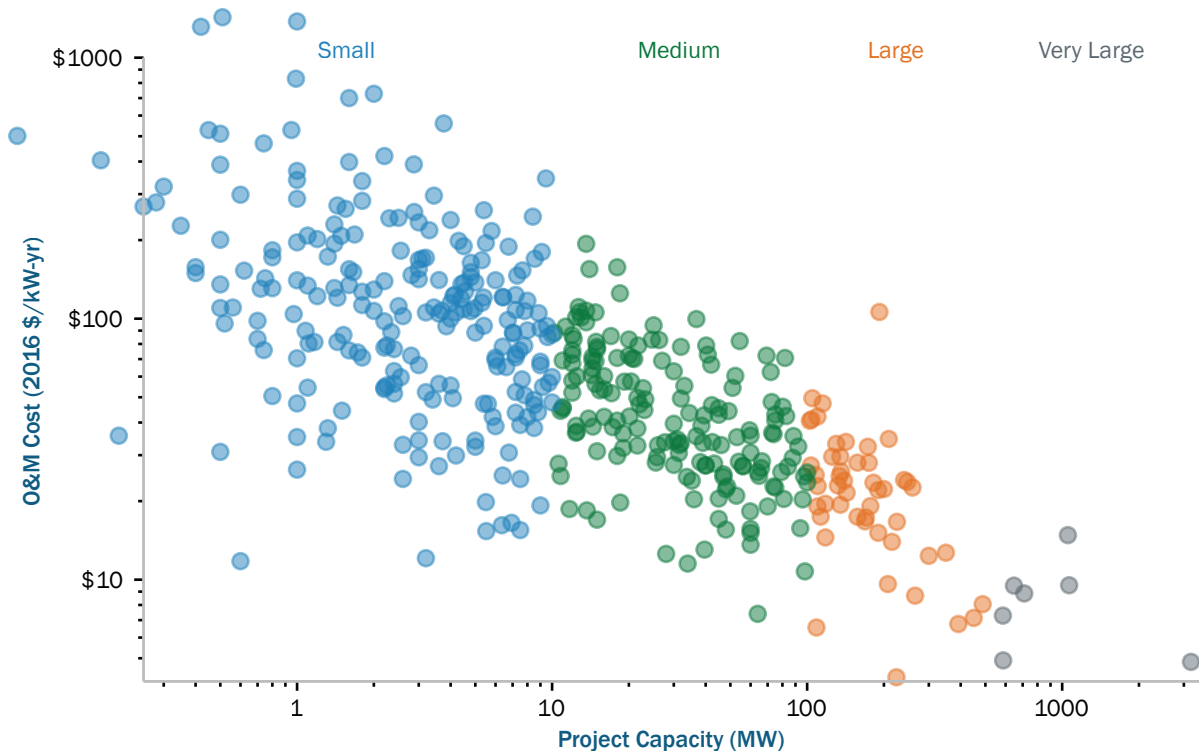


Figure 27. 2016 O&M expenditures for hydropower plants reporting on FERC Form 1

Source: FERC Form 1

Projects captured in this dataset range from very small (the 80kW Lower Paint plant) to some of the largest plants in the country (the 3.2 GW Bath County PSH plant), with an equal magnitude of variation in cost outcomes—the most expensive projects with 2016 costs well over \$1,000/kW while the least expensive at an economical \$4/kW. It is important to note that this dataset only covers a specific subset of the U.S. fleet largely—but not entirely—consisting of hydropower owned by vertically-integrated investor-owned utilities (IOUs) and municipalities. Data for *Very Large* plants is also limited as many of the largest U.S. hydropower plants are owned by USACE and Reclamation.⁴⁸ The FERC data has information for 7 plants greater than 500 MW, 6 of which are PSH. In total, the 2016 sample of 24 GW from 451 plants accounts for approximately 20% of the U.S. hydropower fleet by plant count and approximately 25% of installed capacity.

Within these plants, the largest are generally the least expensive to operate on a relative basis, and in 2016 *Very Large* plants (those with a generating capacity of greater than 500 MW) spent on average \$8/kW. At smaller sizes, O&M costs per kilowatt increase significantly. In 2016, *Large* plants (100 to 500 MW) averaged a cost of \$22/kW, *Medium* plants (10 to 100 MW) averaged \$40/kW and the smallest plants (those less than 10 MW) averaged \$113/kW.⁴⁹

To place these values in the context of electricity prices: for a hydropower project operating at a 50% capacity factor, each \$44/kW in O&M costs translates to approximately \$10/MWh or 1 cent/kWh in cost. Larger hydropower exhibits long-run O&M costs favorable to those of other electricity generation, while smaller plants are on par with technologies that are generally considered to be expensive to operate and maintain. For comparison, the U.S. Energy Information Administration estimates the fixed O&M cost for new onshore wind projects at \$47/kW, offshore wind at \$79/kW, utility-scale solar PV at \$22/kW, and advanced nuclear at \$101/kW (EIA, 2018).⁵⁰

48 The cost magnitudes and trends illustrated here are consistent with those tracked internally by utilities, such as those benchmarked in the Electric Utility Cost Group's Hydroelectric Productivity Committee.

49 In addition to size, the smaller projects are older (average year of construction: 1926) than the other size categories (1933, 1954, and 1976 for respectively larger size classes).

50 Note that these cost figures from the 2018 Annual Energy Outlook are given in 2017 dollars instead of the 2016 dollars from FERC Form 1.

Amongst the 20-25% of the hydropower fleet captured by FERC Form 1, O&M is not just highly variable plant-to-plant, but also increasing at a rate higher than inflation. Figure 28 documents trends in O&M over the last decade from 404 plants with full data records from 2007 and to 2016. The left panel shows absolute trends by size class, and the right panel contrasts growth relative to the Consumer Price Index (CPI).

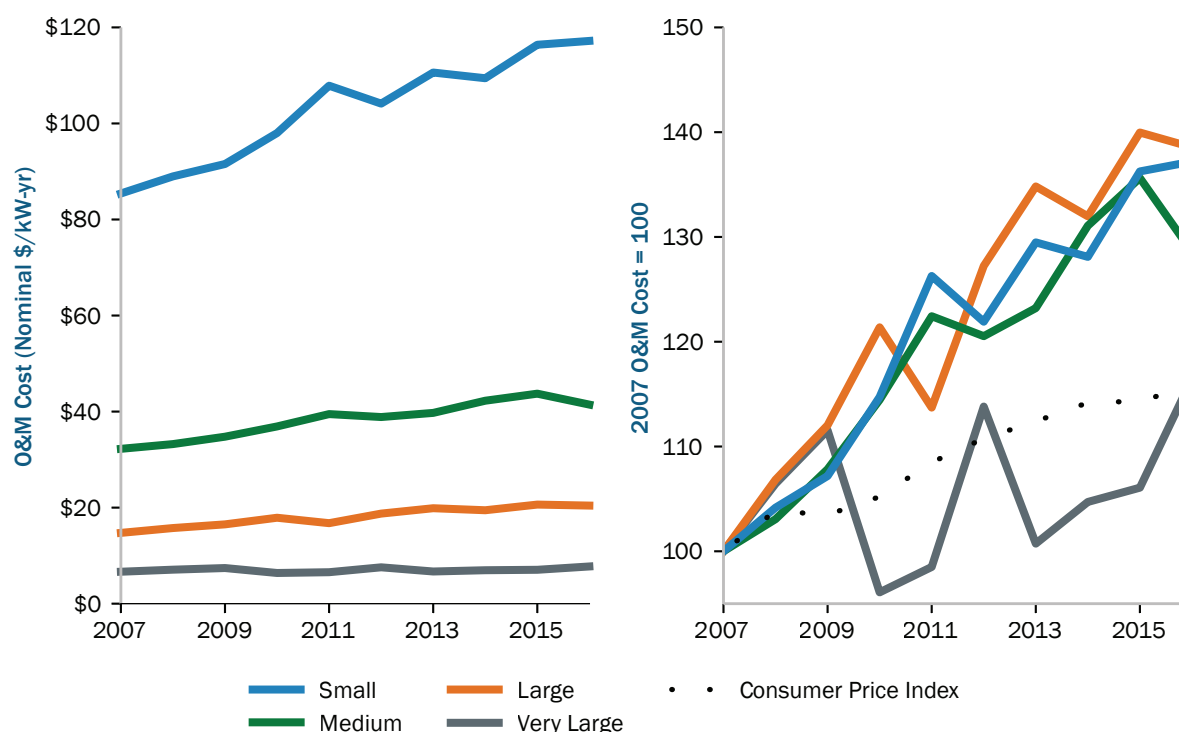


Figure 28. Trend in operations and maintenance costs for hydropower projects by size class

Source: FERC Form 1, Bureau of Labor Statistics

Small, *Medium*, and *Large* size categories have all experienced cost growth of 30-40% over the last decade—this equates to an inflation-adjusted real increase in costs of up to 20% since 2007 when evaluated relative to the CPI baseline increase of 16% over the same timeframe. Costs for all three sizes of projects appear to level-off or decrease from 2015 to 2016, but similar year-to-year volatility is common throughout the past decade. There are no definitive causes for this continual increase in real costs, but industry stakeholders have indicated that an ageing workforce, compliance with increasingly stringent regulatory requirements, and declining quality assurance (QA)/quality control (QC) could be influencing rising bottom-line O&M costs.^{51, 52}

While the cost drivers remain unclear, continuation of this longer-term upward trend (in conjunction with low electricity prices) could place significant economic pressures on the small and medium-sized plants for which O&M may already be financially challenging. While *Very Large* projects appear to have only kept pace with inflation, the sample size is small (7 projects) making it difficult to draw firm conclusions.

51 The costs of regulatory compliance do not refer solely to FERC license requirements but also to non-environmental required expenditures such as dam safety measures.

52 For a recent example in the hydropower industry trade press, see “Avoiding a Crisis in the Hydropower Industry” (Wright and Hudson, 2018).

4.3 Energy Generation

Despite significant year-to-year fluctuations at the regional level, total U.S. hydropower generation has remained stable in 2003–2016; for pumped storage hydropower, total gross generation displays a slight decreasing trend over the same period.

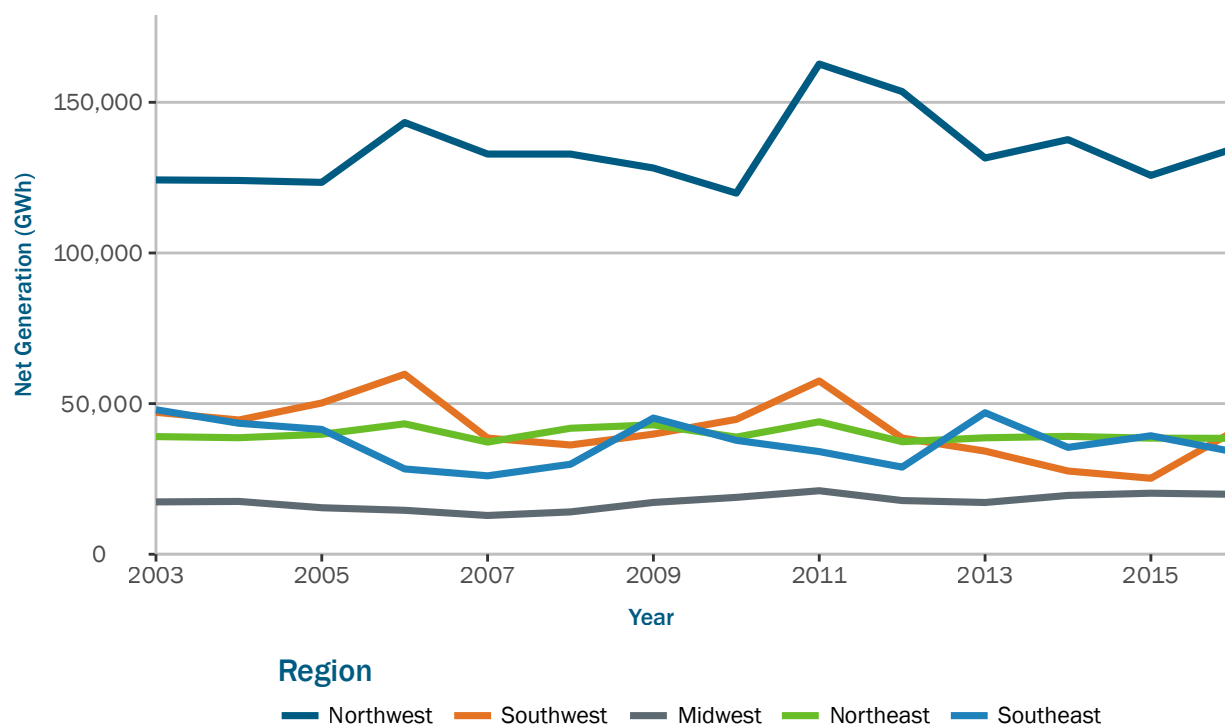


Figure 29. Annual hydropower generation by region (2003–2016)

Source: EIA Form 923

For the period displayed in Figure 29, average U.S. hydropower generation was 270,000 GWh per year. Annual generation levels ranged from 247,500 GWh in 2007 to 319,300 GWh in 2011. On average, the Northwest produced half of the U.S. hydropower each year. The Southwest, Northeast, and Southeast each accounted for approximately 15% of annual generation from 2003 to 2016. The Midwest had the lowest generation levels with an average of 17,400 GWh per year.

The peaks and troughs in each of the regional series in Figure 29 are highly correlated with wet and dry years, respectively. The coincident generation peaks in the Northwest and Southwest in 2006 and 2011 correspond to years in which the drought severity and coverage index (DSCI) was near zero in those regions.⁵³ Similarly, the sustained drop in generation in the Southwest between 2012 and 2015 corresponds to a period of high DSCI values throughout most of that region. The Southeast experienced different periods of drought, which are also reflected in its generation patterns. The two hydrological regions of South Atlantic and Tennessee—where most of the hydropower generation in the Southeast is located—had high DSCI values in 2007–2008; 2012 was also a dry year for the South Atlantic. Northeast and Midwest have more stable hydropower production volumes. In the Northeast, no year between 2003 and 2016 was dry based on DCSI values. For the Midwest, the slight dips in generation levels in 2005–2008 and 2013 coincide with drought conditions in the Missouri hydrological region where the largest hydropower facilities in the Midwest are situated.

53 <http://droughtmonitor.unl.edu/Data/Timeseries.aspx>

PSH facilities are net consumers of energy because they use more electricity for pumping water from the lower to the upper reservoir than they produce when they release water from the upper reservoir to pass through turbines and generate electricity. Figure 30 shows regional PSH gross generation (i.e., generation volume without netting out pumping energy consumed).

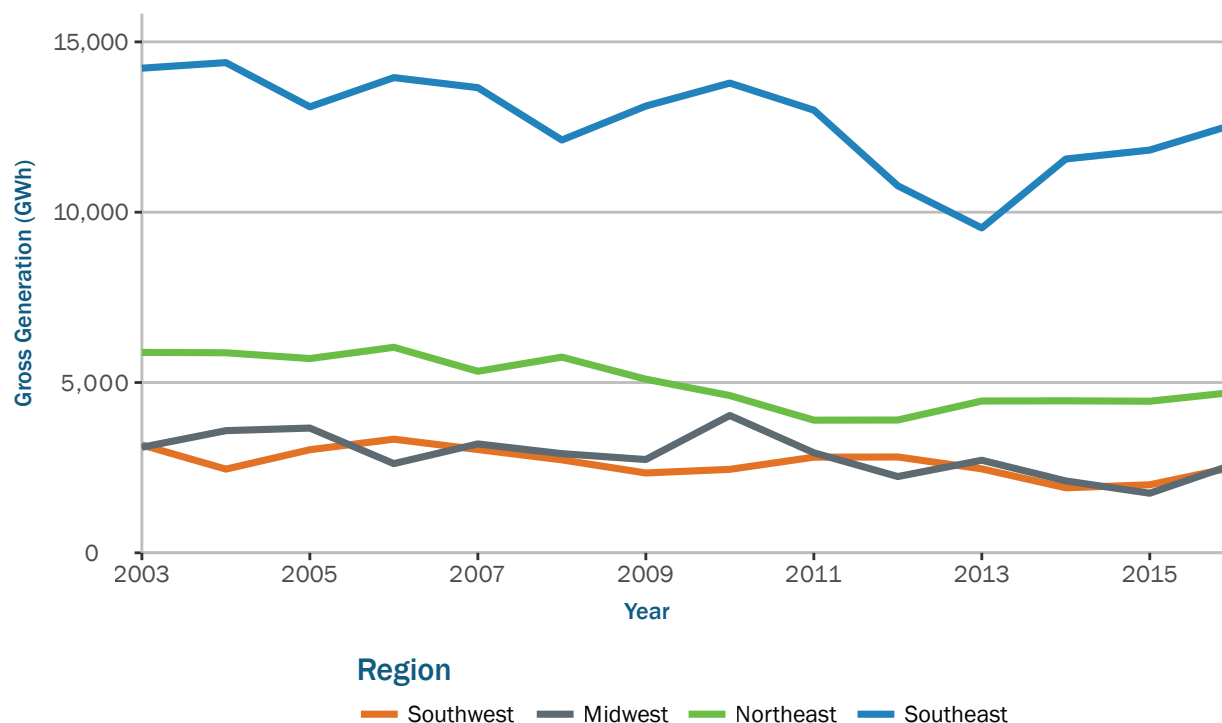


Figure 30. Annual gross pumped storage hydropower generation by region (2003–2016)

Source: EIA Form 923

Note: The Northwest region was left out because it has very small pumped storage hydropower capacity.

The Southeast has the largest installed PSH capacity and produced, on average, 54% of all the electricity output from the PSH fleet in 2003–2016. An uptick in generation is observed for all regions in 2016. However, for most of the period depicted in Figure 30, there was a slight downward trend in PSH generation. The peaks and valleys in regional generation profiles observed in Figure 29 do not always coincide with the ones for PSH. Despite all but one of the existing PSH plants being open-loop (i.e., continuously connected to a natural flowing body of water), PSH generation levels are much less determined by hydrology than are those for hydropower.

PSH operation is driven largely by electricity market conditions. For the Northeast, Figure 30 shows a clear reduction in PSH use in 2008–2011 coinciding with the economic recession during that period. The recession led to a slowdown of electricity demand growth, smaller peak electricity demands, and price declines, all of which make PSH use less profitable for facilities relying on arbitrage of peak versus off-peak price differentials as their main business model. A similar pattern of slowdown in PSH use connected to the recession of the late 2000s has been reported for several European countries (Kougias and Szabó, 2017).

Since there are no more than a handful of large PSH plants in any single region, fluctuations in regional generation are often related to planned or unplanned outages at one of them. For instance, the large drop in PSH generation in the Southeast region in 2012–2013 was partly the result of TVA’s Raccoon Mountain—the second largest PSH facility in the Southeast—being out of service for repairs during those years. Similarly, the turbine overhauls at Bath County—the largest PSH plant in the country—from 2004 to 2009 contributed to deviations from the average PSH generation levels in the Southeast during those years.

The primary drivers for seasonal distribution of hydropower generation are hydrology and multipurpose reservoir management objectives; generation from PSH correlates more closely to seasonal electricity use patterns.

The seasonal distribution of hydropower generation within a year is an important attribute to assess the value of the energy generated in each region. Ideally, more hydropower would be produced at the time of the year in which electricity demand is largest and prices are highest. However, the extent to which hydropower scheduling can be responsive to electricity market signals depends on hydrology, hydropower fleet configuration, and operation restrictions to maintain required stream flow levels and reservoir elevations. These restrictions ensure that impoundment reservoirs adequately serve the other purposes—from flood control and navigation to recreation and water quality management—they were built for and mitigate damages to fish and wildlife habitats. For hydropower facilities using diversion structures rather than impoundment reservoirs, the ability to deviate from the seasonal generation schedule dictated by runoff availability is generally limited.

Figure 31 compares the seasonal distribution of hydropower generation, PSH gross generation, and total electricity consumption for each region. It shows that seasonal PSH operations mirror electricity use patterns closely while the seasonal distribution of hydropower does not align closely with electricity use in many regions.

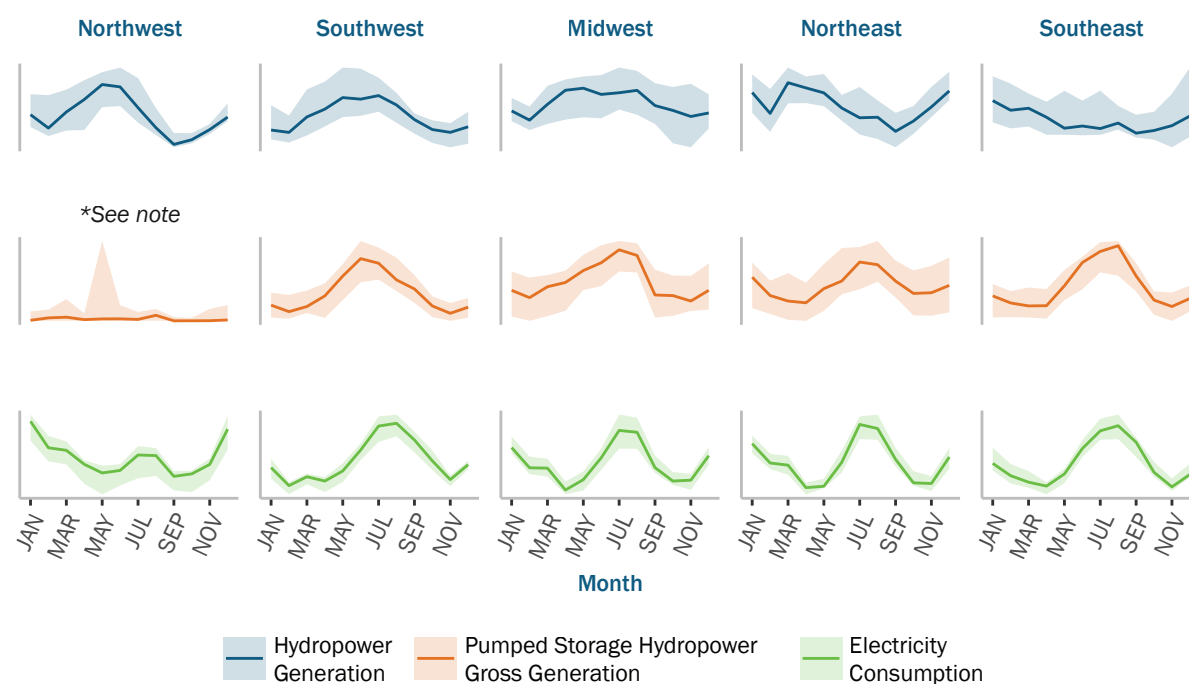


Figure 31. Seasonal profiles of hydropower generation, pumped storage hydropower gross generation, and electricity consumption by region (2003–2016)

Source: EIA Form 923

Note: The central lines depict the median levels for each variable, and the surrounding bands enclose the corresponding 10th–90th percentile intervals.

*Note: The Northwest region only has 314 MW of PSH capacity corresponding to 6 of the units of Grand Coulee. Their gross generation was extremely small (5 GWh/month on average) for most of the period depicted in the figure. However, monthly gross generation average 78 GWh in the spring of 2003 and 59 GWh in the spring of 2004 resulting in the peak observed in the figure.

PSH use is not driven by hydrology but rather is timed to coincide with periods when demand and prices are highest. Gross generation from PSH facilities is larger during the summer months in all regions which, except for the Northwest, are also the months of highest electricity consumption. Not only is total electricity consumption greater in the summer months, but, based on 2016 data reported by utilities, summer peak load is larger than winter peak load in all but the Northwest region (EIA,

2017).⁵⁴ PSH units are well suited to help meet those summer peak demands, which are largely driven by air conditioning use in hot summer afternoons. For the Northeast and Southeast regions, the seasonal pattern of generation for PSH facilities is the opposite of that for the hydropower fleet.

The Northwest, Southwest, and Midwest display hydropower generation peaks in the late spring and summer with slight variations in their timing and length. In contrast, the Northeast and Southeast hydropower fleets produce more electricity during the winter and early spring season. Typically, hydropower generation levels vary most across seasons in the Northwest and Southwest regions and are the least variable in the Northeast and Midwest.

For the Northwest, hydropower generation peaks during the snowpack melting season (April–June). The wide range of generation levels during that season across years reflects variability in snowpack timing and volume (see insert for a more detailed discussion of the variability in seasonal Federal Columbia River Power System (FCRPS) generation depending on hydrologic conditions and competing operation objectives). Spring and summer operation of the FCRPS, which accounts for 58% of installed hydropower capacity in the Northwest, is also largely driven by fish passage objectives. During the summer, some of the water that could be passed through turbines to produce electricity may instead be spilled over to help fish migrate downstream toward the ocean.⁵⁵ From September through the winter months, flood control is the primary driver of FCRPS reservoir management. Reservoir levels are drawn down to ensure enough space will be available for the winter precipitation; the released water results in increasing hydropower generation during these months. The width of the 10th–90th percentile interval narrows considerably during the winter months.

The seasonal generation profile for the Southwest is similar to that for the Northwest but somewhat smoother. Unlike the Northwest, whose reservoirs are equivalent to only a fraction of annual average runoff, the Southwest has reservoirs able to hold multiple times the average annual runoff. This larger storage capacity provides added flexibility for timing generation to coincide with the summer electricity demand peak in this region.

Hydropower plants in the Southeast produce their largest volumes of electricity in the winter and spring coinciding with the time of highest runoff in that region. Keeping reservoir levels low enough at the beginning of the flood season to accommodate the precipitation from winter storms and high enough in summer to enhance recreation opportunities are key guiding rules for the volume and timing of water releases that result in hydropower production in this region.

54 Peak load is the maximum electricity demand sustained over a specific time interval. Electricity market operators track and forecast peak loads for different seasons of the year and use them as input for decisions regarding generation capacity planning.

55 <https://www.crt2014-2024review.gov/Files/Columbia%20River%20Treaty%20Review%20-%20Fact%20Sheet%20-%20Current%20operations-%20FOR%20PRINT.PDF>.

INFLUENCE OF HYDROLOGY AND COMPETING OPERATION PURPOSES ON FEDERAL COLUMBIA RIVER POWER SYSTEM HYDROPOWER GENERATION

Figure 32 which compares 10 years (2008-2017) of generation data from the FCRPS (top panel) to flow in the Columbia River (middle panel). A third panel (bottom) captures the ability of FCRPS hydropower generation to follow fluctuations in net load (electricity demand less variable renewables), demonstrating the extent to which the additional functions provided by hydropower infrastructure can take precedence over generation flexibility.⁵⁶

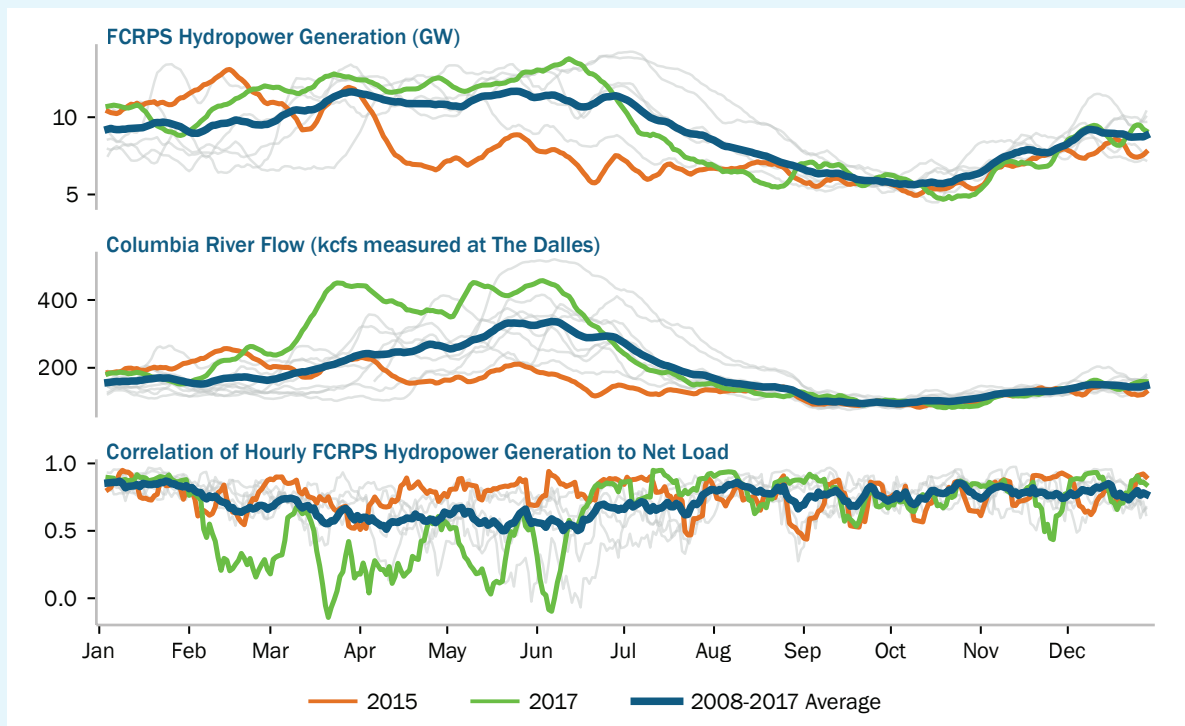


Figure 32. Generation and hourly load-following by the Federal Columbia River Power System, 2008-2017

Source: Bonneville Power Administration, USACE/USGS

Data from the years 2015 (orange) and 2017 (green) are highlighted as they present contrasting views of system-scale operations from years with substantively different hydrology. In 2015, spring snowmelt flows were far below long-term averages, adversely affecting generation from April through August. However, during this period of low flows, the FCRPS maintained the intra-day flexibility necessary to match hour-to-hour fluctuations in net load, even though overall power generation capabilities were limited by water availability and need for environmental flows. The correlation between hydropower generation and net load in the Bonneville footprint remained high (.6 to .9+), above historical norms for the same time-period.

In contrast, 2017 experienced near record-setting early spring flows, elevating hydropower production but necessitating prioritization of flood control operations to prevent property damage and loss of life. As the weather rapidly turned

⁵⁶ Note that the annual time series have been smoothed using a rolling average of one-week resolution for visual clarity. This eliminates diurnal and intra-week variation due to load following and environmental operations.

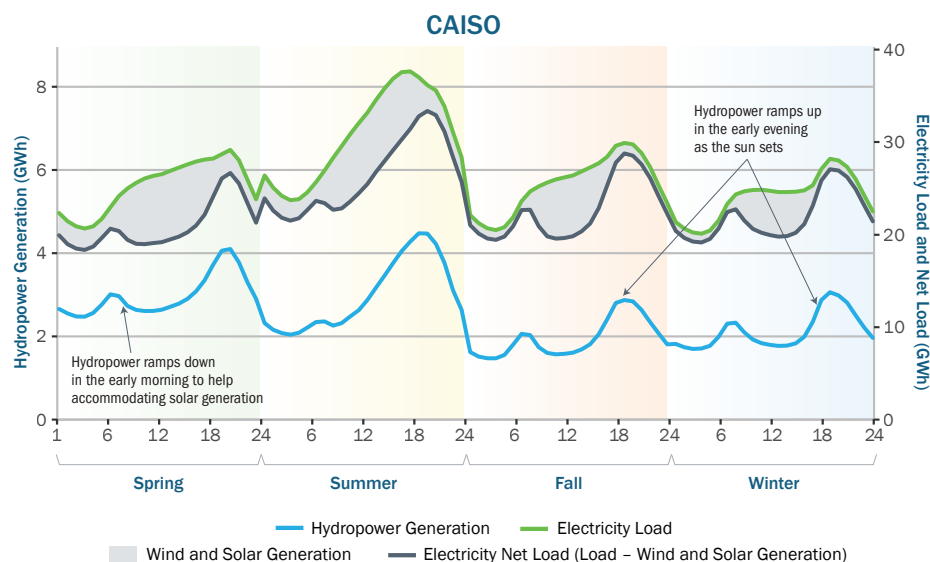
warmer (earlier snowmelt) and wetter beginning in mid-February, the Army Corps of Engineers revised reservoir elevation targets lower to accommodate evolving projections of seasonal water availability.⁵⁷ The need to strategically move water in conjunction with flood control objectives, and environmental issues associated with high total dissolved gas concentrations—harmful to fish in high concentrations—more tightly constrained the ability of the FCRPS as a whole to respond to intra-day changes in electricity demand and variable renewable generation.

Daily hydropower generation profiles in ISO/RTO markets are highly correlated with electricity use patterns; the hydropower fleet provides substantial load-following flexibility.

The annual and seasonal data presented in Figure 29 through Figure 31 are not granular enough to explore hydropower’s contribution to electric system flexibility. As shorter time intervals are considered, the fraction of hydropower facilities able to control their output increases. A substantial shift of water flows from spring to summer might require large impoundment reservoirs. However, a shift of flows from early morning to mid-afternoon is also possible for run-of-river hydropower facilities in cascaded systems with a small upstream reservoir (Huertas-Hernando et al., 2017).

For the subset of the hydropower fleet that participates in one of the ISO/RTO markets, system operators post fuel mix data hourly—and, in some cases, at 5- or 15-minute interval.⁵⁸ These data were used to produce the average daily hydropower generation profiles for each season and market. Those profiles are displayed in Figure 33 alongside electricity load and electricity net load (i.e., total load minus wind and solar generation) to explore how closely hydropower follows them on average at an hourly frequency.

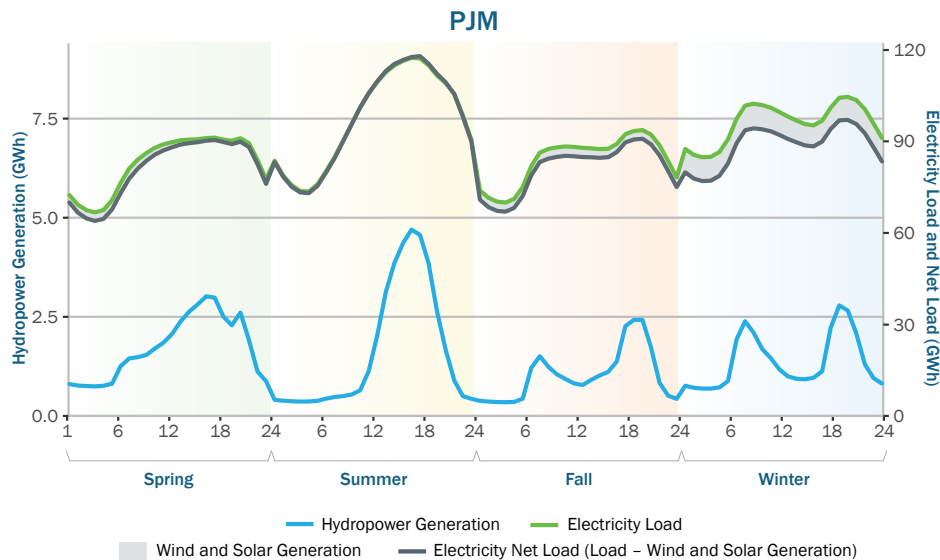
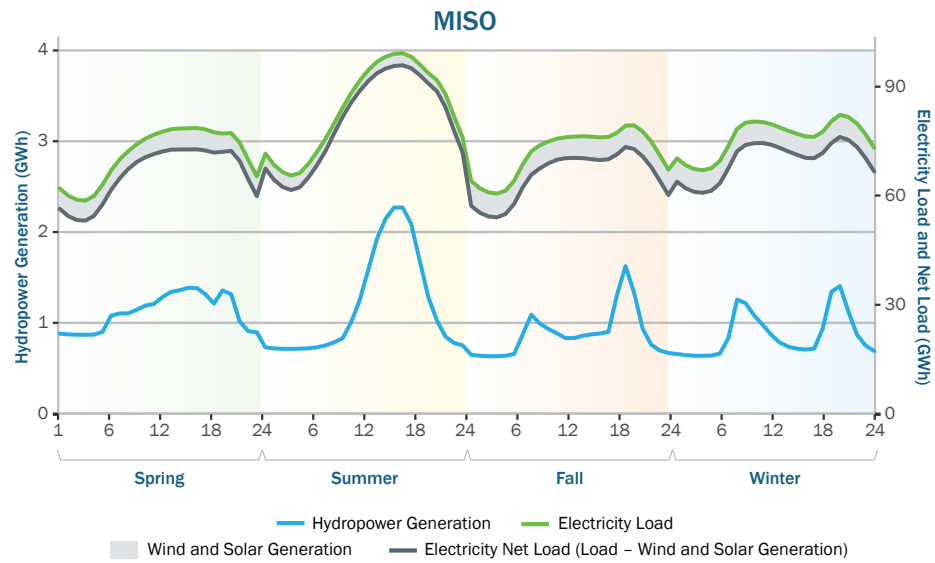
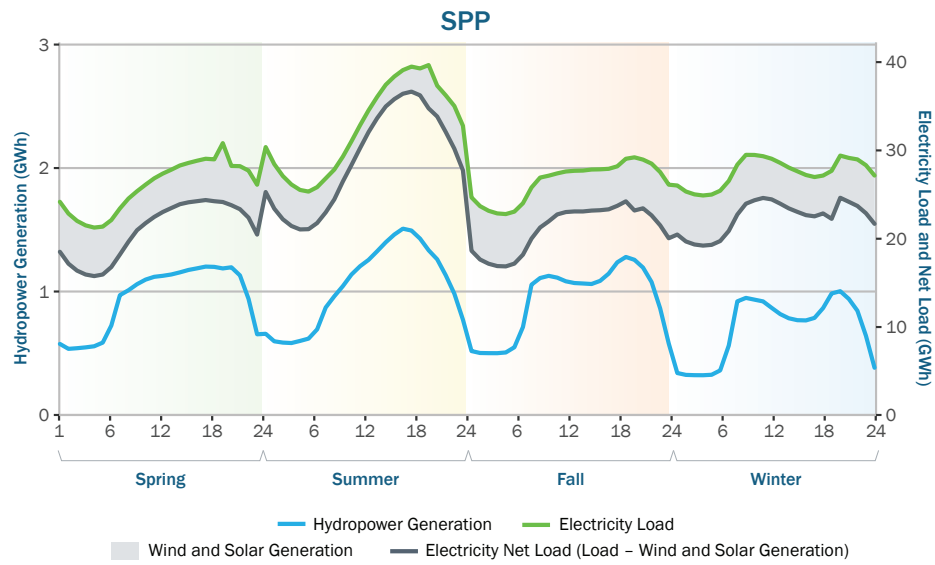
The average generation volumes in Figure 33 include hydropower generation and gross generation from PSH plants, but they do not include hydropower imports from other regions.⁵⁹ The only U.S. ISO/RTO not represented in Figure 33 is ERCOT because hydropower capacity participating in that market is very small. A map delineating the market areas managed by each ISO/RTO is presented in Section 3.1.



57 For discussion on the 2017 trajectory of water supply forecasts, weather impacts, reservoir operations and interaction with environmental objectives, see USACE’s final Seasonal Update to the 2017 annual Water Management Plan. http://pweb.crohms.org/tmt/documents/wmp/2017/Seasonal_Update/20171023_2017_WMP_SU_NWD.pdf

58 The percentage of U.S. installed capacity that participates in ISO/RTO markets is 28% for hydropower and 59% for PSH.

59 CAISO is the only ISO/RTO that reports hourly data on electricity imports, but their fuel mix cannot be determined because many imports are not resource-specific.



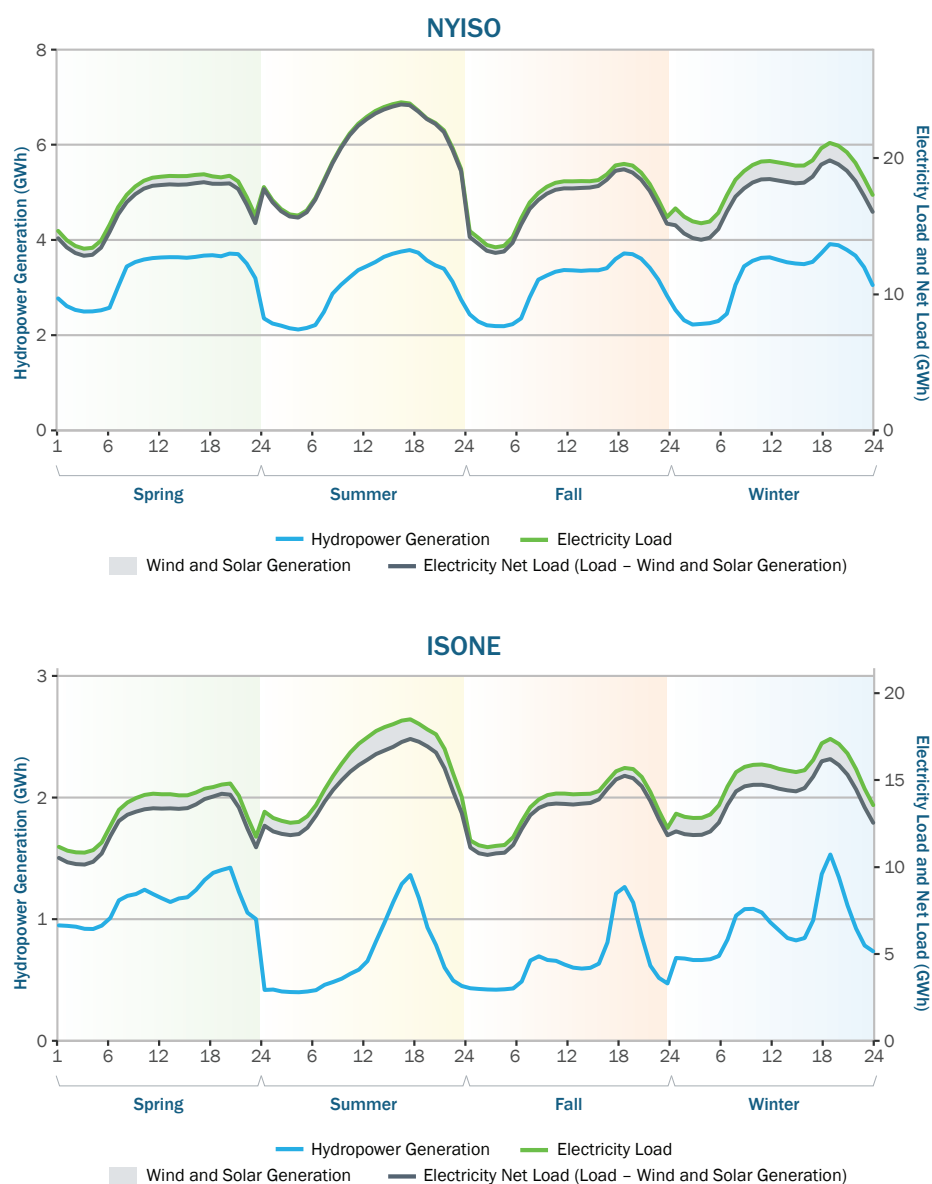


Figure 33. Average hourly hydropower and PSH generation, electricity load, and electricity net load by season and ISO/RTO region

Source: ISO/RTO websites

Note: CAISO and MISO generation profiles are based on 1/1/2014–12/31/2017 data. For other ISO/RTOs, the period represented in the plots is dictated by data availability: 5/20/2015–12/31/2017 for PJM, 1/1/2015–12/31/2017 for SPP, 8/18/2016–12/31/2017 for ISONE, and 12/09/2015–12/31/2017 for NYISO. ERCOT is excluded because hydropower generation is much lower than in the rest of ISO regions.

Figure 33 indicates that hydropower provides substantial load following flexibility in all ISO/RTOs. The average shape of hydropower generation closely resembles the electricity load profile. The average summer hydropower generation daily profile is remarkably consistent across all markets shown in Figure 33. Except in CAISO where there is a brief down-ramp to accommodate solar generation in the morning, hydropower generation ramps up continuously from the early morning to the late afternoon (4–5 pm) which, driven by air-conditioning loads, is the time of peak electricity demand in summer. In fall and winter, the typical hydropower generation profile in all markets displays two peaks correlated to electricity demand. The first peak takes place during the early morning hours. Later, in the mid-afternoon, generation ramps up again to meet the second,

larger peak around 7 p.m. For the spring season, hydropower follows a similar profile as in fall and winter in CAISO and ISONE. However, for MISO and PJM, the spring resembles the summer but with a less pronounced late-afternoon peak.

The average shape of generation from variable renewables only differs visibly from electricity load in CAISO. The divergence is associated to the large amounts of solar generation in this market. In ISO/RTOs with significant wind penetrations (MISO and SPP), the average shape of net load still is very similar to the average shape of electricity load. In CAISO, hydropower operations follow net load more closely than load. This translates in down-ramps during the early morning as solar panels start producing electricity and more pronounced upward ramps in the early evening, as the sun sets. See insert for a discussion of how the high penetrations of solar generation in CAISO have changed PSH operations in that market in recent years.

Figure 33 shows the average generation from the hydropower fleet in each market. Within each fleet, there are some plants with flatter generation profiles. Moreover, in all ISO/RTOS except for ERCOT, there is at least one PSH plant; their generation profile would also look different from the average, with just a few hours of generation per day.

In the New York market (NYISO), the average hydropower generation ramps up in the early morning but stays more stable throughout the rest of the day than in most other markets. NYISO is also the market in which hydropower represents a higher fraction of total generation. The daily profile in Figure 33 suggests that in the New York region hydropower units play a role closer to baseload than peaking in the spectrum of facility types.

Table 4. Seasonal Average Hydropower Generation Share by ISO/RTO

	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISONE
Spring	7.70%	0.10%	3.40%	1.30%	1.20%	20.90%	5.90%
Summer	11.80%	0.30%	3.60%	1.70%	1.60%	23.40%	10.60%
Fall	9.70%	0.10%	3.10%	1.50%	1.60%	17.40%	5.20%
Winter	8.80%	0.10%	2.50%	1.20%	1.00%	21.80%	7.90%

Source: ISO/RTO websites

Note: CAISO and MISO generation profiles are based on 1/1/2014–12/31/2017 data. For other ISO/RTOs, the period represented in the plots is dictated by data availability: 5/20/2015–12/31/2017 for PJM, 1/1/2015–12/31/2017 for SPP, 8/18/2016–12/31/2017 for ISONE, and 12/09/2015–12/31/2017 for NYISO.

Table 4 shows that hydropower represents only a small fraction of total generation in most ISO/RTO regions. The largest shares correspond to NYISO, CAISO, and ISONE. In the other four markets, hydropower represented less than 5% of total electricity production within the ISO/RTO footprints in every season. The weight of hydropower in the fuel mix is highest in summer for all the markets.

The percentages in Table 4 include generation by hydropower units only within the footprint of the ISO/RTO market. When combined with monthly data on Canadian hydropower imports, the percentages increase significantly for NYISO and ISONE. For NYISO, the percentage of total generation accounted for by U.S. plus Canadian hydropower ranges from 34% in summer to 43% in winter. The percentage ranges between 10% in fall and 18% in winter for ISONE. Seasonal hydropower percentages for California increase by 3% to 5% when adding Canadian hydropower imports. However, it should be noted that imports from the Northwest into California are not included in this calculation. Therefore, hydropower generation shares for California are likely underestimated. Finally, for MISO, the increase represents less than 1% in all seasons.⁶⁰

60 Data on monthly Canadian electricity imports obtained from Canada's National Energy Board Commodity Statistics (<https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx?language=english>). It is assumed that all electricity imported from Canada is hydropower. Thus, these percentages should be interpreted as upper bounds on the actual hydropower generation shares.

AN EXAMPLE OF CHANGES IN PUMPED STORAGE HYDROPOWER OPERATIONS IN MARKETS WITH HIGH PENETRATIONS OF VARIABLE RENEWABLES: THE HELMS PROJECT IN CALIFORNIA

The increased levels of generation provided by variable renewable energy resources—and particularly solar—in CAISO have resulted in new operating paradigms for PSH in that market. Figure 34 explores this change by contrasting the annual magnitude and timing of pumping operations for Pacific Gas and Electric’s Helms PSH project (top panel) with CAISO’s average net load during the last week of March (bottom panel) each year since 2012.

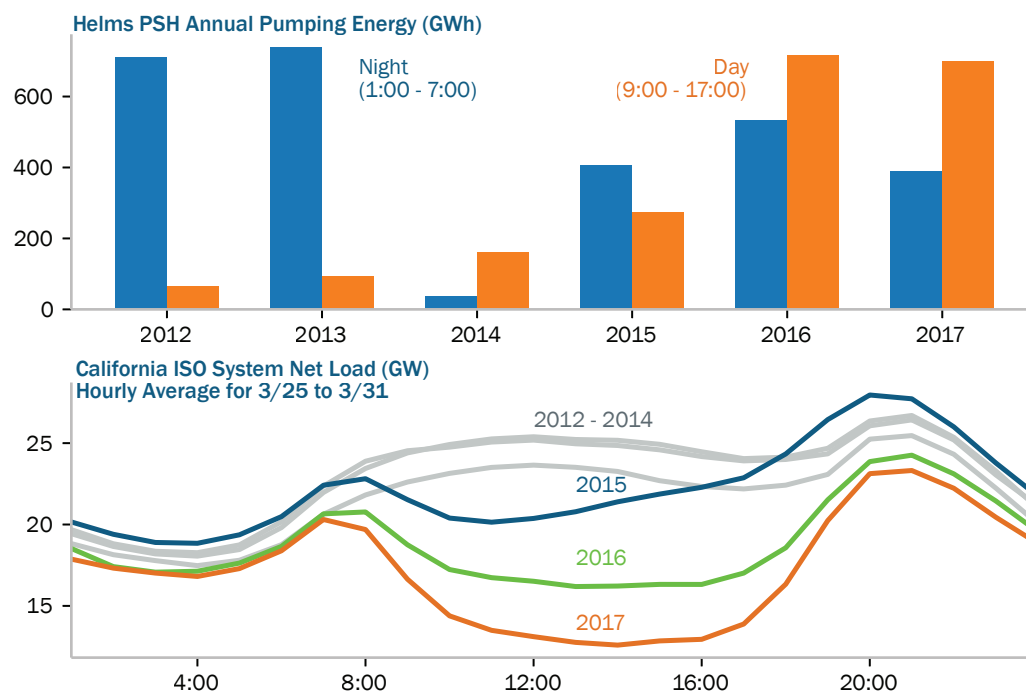


Figure 34. Annual pumping energy consumption by Helms PSH versus CAISO net load in the last week of March (2012-2017)

Source: Pacific Gas & Electric Company, California ISO

The early spring timeframe presents a unique challenge for CAISO and its participants and illustrates how high penetrations of variable renewables are causing dispatchable assets to operate in new ways. Early spring electricity demand is low due to mild temperatures, and high levels of solar photovoltaic capacity drive the need for generation even lower during midday only to fall off as the sun sets and requiring resources to rapidly ramp up to meet the combined “net” increase in demand, as residential customers return home from work in the evening, and solar generation stops.

The annual pumping patterns of the Helms project shown in Figure 34 reflect a new paradigm of low prices and potentially oversupply of electricity during daytime. Up until 2013, the bulk of pumping energy consumption at Helms took place during night hours, but the number of daytime pumping hours has steadily increased and surpassed night-time pumping in 2016 and 2017.⁶¹ The energy stored during the day is then used to meet the substantial ramping requirements now seen during the early evening hours. Continued growth in variable renewables in the California market may magnify these trends.

61 Total MWh of pumping in 2014 and 2015 was reduced due to rotor replacement projects and other planned outage work at Helms.

4.4 Capacity Factors

The median hydropower capacity factor has been 38.1% in recent years; the capacity factor range is wide and depends on hydrology, plant age, mode of operation, and ownership type.

Capacity factors indicate the percentage of hydropower generation in a period of time relative to the maximum possible generation had it worked at full capacity without interruption. Taking the average 2005–2016 capacity factor for each plant as representative of its recent performance, the median capacity factor for the U.S. fleet is 38.1%. However, values as low as 25% and as high as 75% are not exceptional. Figure 35 displays the relationship between plant-level capacity factors and four plant attributes: region, operation start decade, mode of operation, and ownership type.

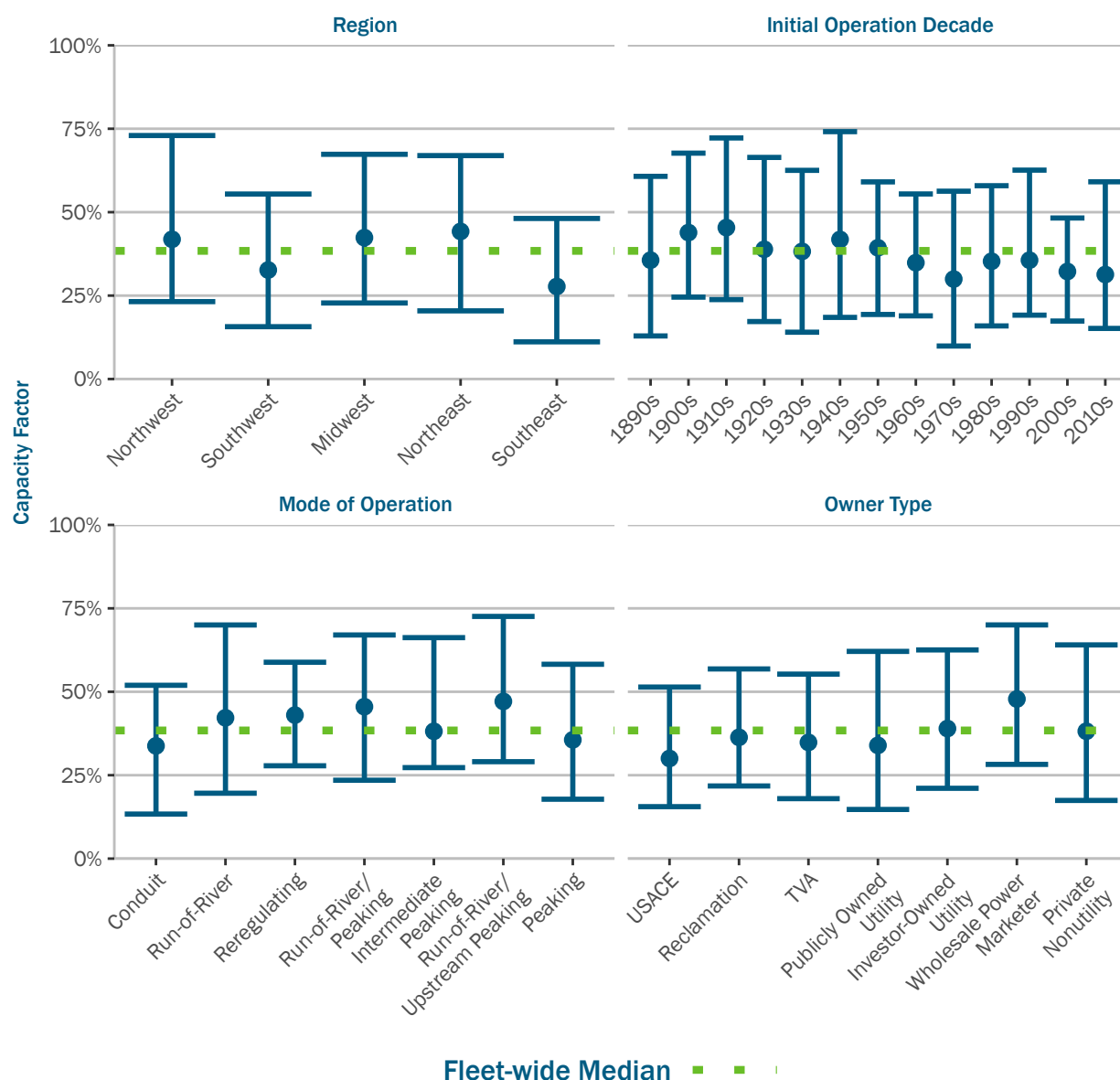


Figure 35. Plant-level distribution of capacity factors by region, operation start decade, operation mode, and owner type

Sources: EIA Form 923, EIA Form 860, and NHAAP

Note: Distributions based on average 2005–2016 plant-level capacity factors. Number of plants included in each panel varies based on data availability: region (1,499 plants), operation start decade (1,453 plants), mode of operation (978 plants), owner (1,364 plants).

Median capacity factor is substantially lower for hydropower plants in the Southwest (33%) and Southeast (28%) than in the rest of the country. For the Southwest, the low median is partly the result of the large number of conduit hydropower facilities in this region which, as seen on the mode of operation panel, tend to operate at low capacity factors. The extreme drought experienced by much of the Southwest from 2013 to 2016 also drives the lower capacity factor of plants in this region. The Southeast has the largest fraction of peaking facilities in its fleet, and those plants also display lower capacity factors than the fleet-wide median. The Midwest and Northeast have large percentages of run-of-river plants in their fleets, which tend to have high capacity factors. Median capacity factors in the Midwest and Northeast were 42% and 44% respectively.

Older plants tend to display higher median capacity factors than newer plants. The fact that plants built in the 1910s (173 observations) and the 1920s (253 observations) have median capacity factors of 45% and 39% respectively, is a testament to the potentially long operational life of hydropower plants if properly maintained. The decreasing trend in capacity factor for newer plants is even clearer for the 90th percentile: the best performers among the older facilities have significantly higher capacity factors than the best performers among plants built more recently. This direct relationship between highest capacity factors and plant age is consistent with a model of fleet buildup in which the highest quality sites were developed first.

In the panel showing capacity factor distributions by mode of operation, the modes are ordered from less to more operational flexibility.⁶² Conduit hydropower facilities are the least flexible and display a large range of capacity factors with a median of 34%. For conduits located within irrigation systems, hydropower production sometimes takes place only outside of the irrigation season which considerably reduces the hours of operation per year. The next three categories—run of river, reregulating, and run-of-river/peaking—have capacity factors above the fleet-wide median. Since these plants have limited to no ability to store water and schedule generation when it is most valuable, generating as many hours as possible is sometimes the best strategy for plant owners to maximize revenue. Figure 35 shows that the facilities with the highest flexibility (peaking facilities) tend to display capacity factors below the fleet-wide median.

The typical capacity factors for federal hydropower plants are below the fleet-wide median and their 90th percentiles are the lowest. These low capacity factors are, at least partly, caused by the multipurpose nature of the reservoirs to which the federal hydropower plants are connected. At many of these facilities, power production is the highest-ranked authorized purpose. Typical capacity factors for facilities owned by public utilities are below the fleet-wide median, but these facilities also have the widest 10th–90th percentile interval. The wide range results from conduit facilities (in western states) and run-of-river facilities being the two most common plant types owned by public utilities and from those two types of facilities having very different median capacity factors. The fleet segment owned by wholesale power marketers displays the highest median, 10th, and 90th percentile capacity factors. Unlike the federal agencies, marketers' primary focus is maximizing revenue from participation in the electricity markets. Thus, they tend to acquire plants where hydropower production is the primary if not unique purpose.

Figure 35 summarized differences in the typical capacity factor of individual plants in the U.S. hydropower fleet based on plant location, age, operation mode, and ownership type. Figure 36 complements it by showing the year-to-year variability in the plant-level distribution of capacity factors for the entire fleet.

62 McManamay and Bevelheimer (2013) provide definitions of the operational modes and details on the methodology used for site classification.

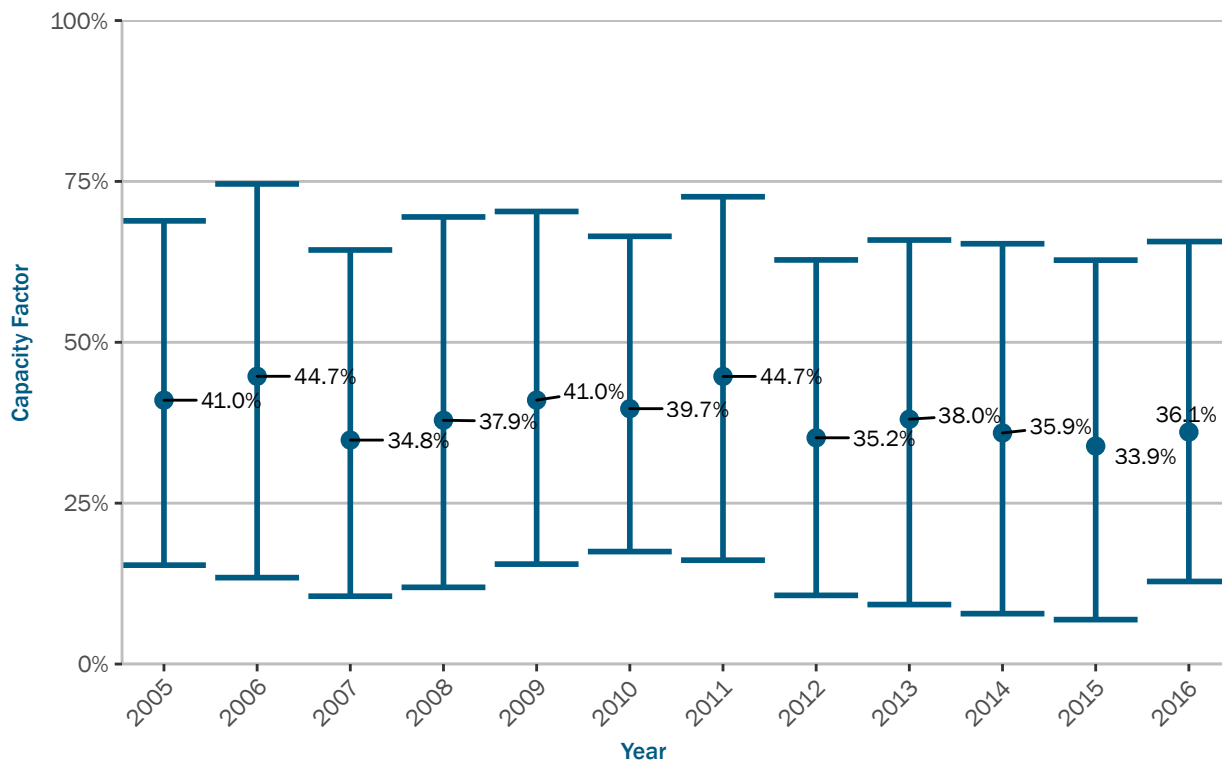


Figure 36. Plant-level distribution of capacity factors by year

Sources: EIA Form 923, EIA Form 860, and NHAAP

Interannual variability in typical capacity factor is linked to hydrologic conditions. The highest median capacity factor (44.7%) corresponds to 2006 and 2011. As previously discussed in Section 4.3, those two years were characterized by favorable hydrology in the Northwest and Southwest, which together produce about two thirds of U.S. hydropower. The lowest median capacity factor shown in Figure 36 is 33.9% in 2015, partly driven by drought conditions in much of the West in that year. The period shown in Figure 36 can be segmented into two subperiods based on the capacity factor distributions. From 2005 to 2011, there were four years with median capacity factors above 40%; since 2012, there have been none. In addition, the 90th percentile capacity factor is also lower for the 2012–2016 subperiod than for 2005–2011. Much of the most recent subperiod is affected by drought conditions in the West. Therefore, some more data points are needed to determine the importance of factors other than hydrology (e.g., increases in unplanned hydropower unit outages) as drivers of longer-run trends in capacity factors.

PSH facilities are not included in Figure 35 and Figure 36. The size of the installed PSH fleet is 27% relative to the size of the hydropower fleet. However, average PSH gross generation has typically not been more than 10% relative to hydropower generation. The lower capacity factors of the PSH fleet primarily reflect that PSH facilities are storage assets needing to spend more than one hour replenishing the water stored in the upper reservoir for each hour they spend generating at their nameplate capacity. For an average roundtrip efficiency of 75%, a PSH unit can generate at full capacity no more than 3,750 hours per year. Using 3,750 hours as the denominator for a capacity factor calculation, the median capacity factors for the PSH fleet during 2005–2016 were 44% for the Southeast, 36% for the Northeast, 23% for the Southwest, and 15% for the Midwest.

For the Midwest, the average number obscures very different values for two groups of plants. On one hand, Ludington and Taum Sauk are operated by investor-owned utilities and participate in the MISO market. They had average capacity factors of 29% and 31% respectively. On the other hand, the Harry Truman and Clarence Cannon facilities, both owned by USACE, are operated very differently. For instance, Clarence Cannon’s reversible units would be used for pumping operations only in situations where the reservoir water levels are very low and there are peaking power needs to be met (St. Louis Army Engineer District, 2004). Similarly, the Southwest fleet includes hybrid PSH plants reporting very small or zero generation volumes for some years and pure PSH plants with capacity factors more in line with those of other regions.

4.5 Availability Factors

Availability factors display a slight decreasing trend in 2005-2016 for both hydropower and pumped storage hydropower fleets. General economic conditions, O&M strategies, and changes in operation mode are among the drivers for this trend.

The generation and capacity factor discussion in previous sections focuses on the volume and timing of electricity generation. Although energy supply is the most obvious contribution to the electric grid by the hydropower fleet, it is not the only one. Hydropower plants also provide a variety of ancillary services that are vital to maintaining electric grid reliability. Provision of some ancillary services (e.g., frequency regulation) requires the unit to be electrically connected to the grid, but others (e.g., non-spinning reserves) require the unit only to be available. For this reason, unit availability is an important performance metric for hydropower plants. For the subset of plants required to report to the NERC Generation Availability Data System (GADS), a richer information set exists that provides data on availability factors at the turbine-generator unit level and a detailed hourly breakdown of the operational status of each unit (see the Appendix for a detailed description of the GADS dataset). Figures 37 and 38 summarize those data for 2005–2016 for hydropower and pumped storage units respectively.

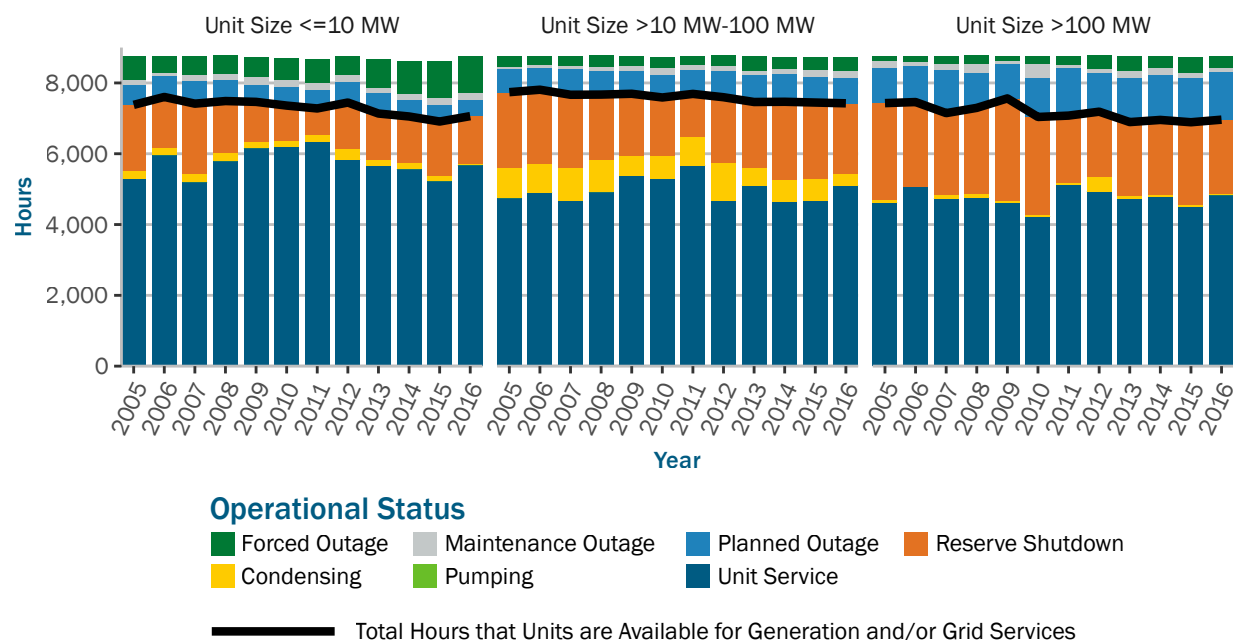


Figure 37. Average hydropower operational status (hourly breakdown by unit size classes of units reporting to NERC GADS)

Source: NERC GADS

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

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Percentage of U.S. hydropower fleet coverage for each unit size shown in the panel titles varies slightly year to year. On average, 16% of U.S. hydropower units <=10 MW, 65% of U.S. hydropower units >10 MW and <=100 MW, and 76% of U.S. hydropower units >100 MW reported data to NERC GADS in 2005-2016.

For small (≤ 10 MW) and medium (> 10 –100 MW) units, any observable trends in Figure 37 are a combination of a change in the composition of the sample over time and a change in operations of the units that have provided data to NERC every year of the analysis period.⁶³ The sample of large (> 100 MW) units has been much more stable during 2005–2016 than the other two.

Unit Service hours represent the number of hours a unit is connected to the transmission grid and able to generate power. However, being connected to the grid does not mean that the unit is generating at full capacity; part of the capacity could be set aside for providing frequency regulation or spinning reserves during those hours. Average *Unit Service* hours have declined in recent years, more clearly for small units than the other two size categories. Nevertheless, small units continue to display the highest average number of unit service hours as they include many units at run-of-river plants with very high capacity factors.

During *Condensing* hours, a unit is spinning air and acting as a motor rather than a generator. During these hours, the units provide voltage support and reactive power, which are important to grid stability (DOE, 2016). Medium units have the highest average number of condensing hours. However, operation in condensing mode is not distributed evenly among all medium-sized units. Within the medium-sized unit sample, all condensing hours are provided by approximately 25% of the units. Units in *Reserve Shutdown* cannot generate power, but they are available to connect to the grid in short notice and could be providing, and being remunerated for providing, this reserve capacity.

The sum of *Unit Service*, *Condensing*, and *Reserve Shutdown* hours make up the total number of available hours (depicted as a black line in Figure 37 and Figure 38). Available hours have steadily decreased for all the unit size categories. Medium units have been, on average, the most available in all years. From 2005 to 2008, the availability ratio was 84% for large units, 88% for medium units, and 85% for small units. The 2009–2016 average availability ratio has been 81%, 86%, and 83% for those three unit types respectively. General economic conditions played a role in reduced availability during the recession and subsequent period of weak electricity demand. A slight rebound is visible in 2012 but, after that, it has declined again. As of 2016, average available hours represented 85% of annual hours for medium units, 81% for large units, and 80% for small units.

Hours in which a unit is not available can be attributed to one of three types of outages two of which are planned and one that represents unforeseen outages caused by unit failures (*Forced Outages*). Average forced outage hours have increased over time across all unit sizes but most noticeably for small units. The average number of hours spent in one of the two types of planned outages is lower for small units than for the other two size categories. For small units, average forced outage hours have increased by 68% in 2013–2016 relative to 2005–2012, and the average number of planned outages has decreased by 8%. As discussed in Section 4.2, small plants face the highest O&M costs in a per-kilowatt basis and their failure is less costly for fleet operators than that of larger units; therefore, they are low in the priority order for a fixed O&M budget that needs to cover the whole fleet. For large units, there have been increases in both planned and forced outages. Longer or more frequent planned outages in these units are meant to prevent forced outages at times in which they would be most costly based on hydrologic or market conditions.

Accelerated wear and tear associated with the transition toward operational modes involving more frequent or pronounced ramping and unit starts or stops could also explain some of the outages for medium and large units. However, trends that could indicate this get lost in the national average data from NERC GADS. Case studies for facilities in parts of the country with high penetrations of variable renewables would be valuable in illuminating the extent of changes in operation mode and associated effects on unit availability. For example, it could be helpful to focus on data from hydropower facilities participating in the Western Energy Imbalance Market.

63 Performance data reporting to NERC GADS was voluntary until 2012. It became mandatory for units > 50 MW in 2012 and for units > 20 MW in 2013 (NERC, 2011). As a result, the number of medium-sized reporting units jumped in 2012 and 2013. For units below the 20-MW limit, reporting to NERC GADS continues to be voluntary.

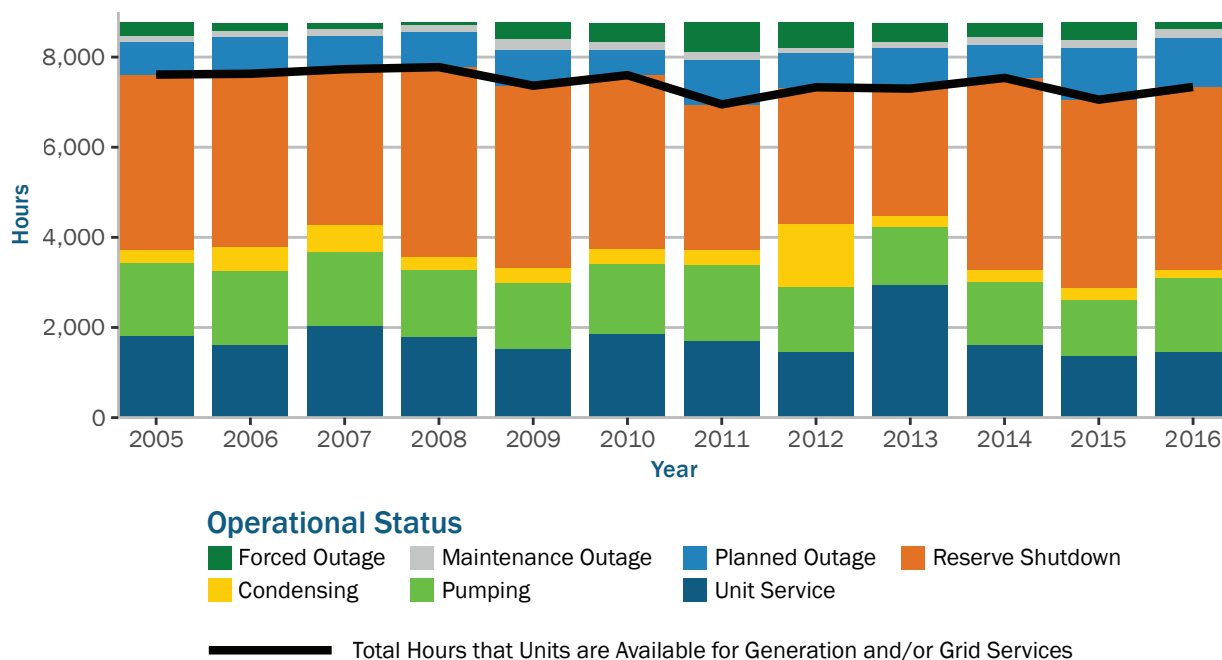


Figure 38. Average PSH operational status (hourly breakdown of units reporting to NERC GADS)

Source: NERC GADS

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

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Percentage of U.S. PSH fleet coverage in NERC GADS varies slightly year to year. On average, 53% of U.S. PSH units reported data to NERC GADS in 2005-2016.

Figure 38 summarizes the operational status breakdown for the subset of PSH units reporting to NERC GADS. On average, PSH units in this sample spent less than 50% of hours in each year generating or pumping even though those two operational statuses are the ones typically used to describe the role of PSH units in the system. The most common status is *Reserve Shutdown*. During those hours, the unit stands ready to connect to the grid to correct supply-demand imbalances. For developers seeking to build new PSH, ancillary service prices will be an important consideration for identifying economically viable projects because a large number of hours will likely be spent providing these types of services.

Average available hours declined slightly after 2008; this trend tracks the evolution of gross generation levels discussed in Figure 30. In 2016, the number of forced outage hours was lower than any other year since 2008. Average *Planned Outage* hours are similar, if a bit smaller, than for the large hydropower units in Figure 37. On average, large hydropower units have been in planned outage status for 1,000 hours or more each year (the equivalent of 42 days per year). For PSH units, the average time spent in *Planned Outage* status crossed the 1,000-hour threshold in 2015 and 2016.

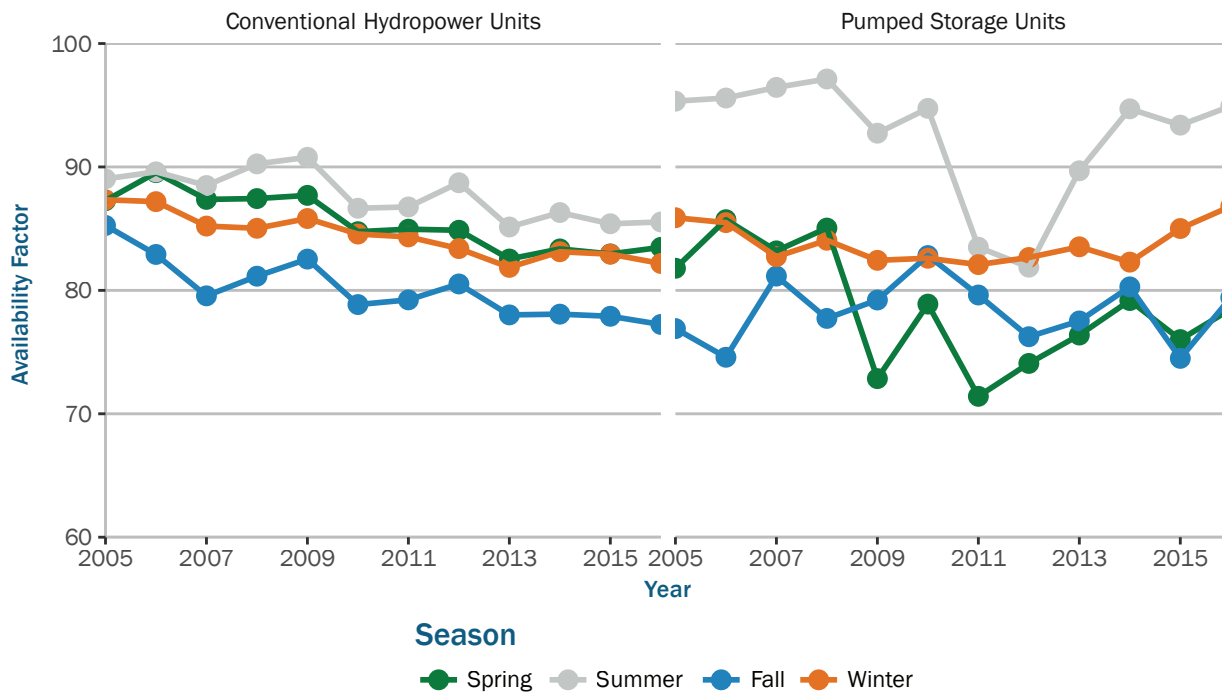


Figure 39. Capacity-weighted hydropower and PSH unit availability factor by season (for units reporting to NERC GADS)

Source: NERC GADS

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Percentage of U.S. hydropower fleet coverage for the unit types shown in the panel titles varies slightly year to year. On average, 28% of U.S. hydropower units and 53% of U.S. PSH units reported data to NERC GADS in 2005-2016.

Figure 39 presents a seasonal breakdown of availability factors for hydropower and PSH units. Availability factor is highest in the summer for both types of units. Since unavailable hours correspond most often to *Maintenance Outage* or *Planned Outage* status, the observed higher summer availability reveals that plant owners tend to schedule those outages outside of the summer season when hydropower’s contribution to meeting peak demands is highly valuable.

For hydropower units, the availability factor does not vary widely across seasons nearing an average of 85% in all seasons except for fall, when it drops to around 80%. On the other hand, the average availability factor for PSH units is noisier. The PSH availability factor in the summer typically has been around 95%. As shown in Figure 31, this is the season when PSH units generate the most energy. The drop in 2011-2013 capacity-weighted average summer availability is more indicative of a few large units being out of service for the entire year (e.g., Raccoon Mountain in 2012–2013) rather than a real drop in average availability factor across the fleet. The seasons with lowest average PSH availability factor—spring and fall—correspond to the two seasons in which electricity demand and prices tend to be lowest. The PSH availability factor is most consistent/predictable in winter when it has stayed close to 85% during the whole period included in Figure 39.

4.6 Hydropower Operation Flexibility

The electric grid needs to maintain the balance between supply and demand at all times. Maintaining this balance has become more challenging in many electricity markets in the United States and around the world over the last decade with the increased penetration of wind and solar generation capacity. Generation levels for these variable renewables are difficult to forecast and dispatch. As a result, generation units whose output can be quickly adjusted have to correct for imbalances that arise both from changes in electricity demand and supply from variable renewables. Market operators use additional mechanisms to maintain the supply-demand balance including demand-side response programs, use of storage resources, and transmission interconnections with regions whose fuel mix and electricity demand patterns are different. Flexible generation units play a large role in following the variations in net load (i.e., electric load minus generation from variable renewables). Natural gas-fired combustion turbines and combined-cycle gas turbines and hydropower—both hydropower and PSH—are typically cited as the two generation technologies providing most flexibility.

Some of the technical design parameters that make these two generation types particularly flexible are ramp rates—the number of megawatts that a generator can adjust its output up or down within a given time interval—start and stop times, and minimum generation levels. When both hydropower and natural gas are available, use of hydropower for ramping up generation will typically be cheaper because it involves no fuel cost (Cochran et al., 2014).

Within both the hydropower and natural gas fleets, there is a significant range of variation in flexibility capabilities. For hydropower, run-of-river plants typically have limited ability to frequently change its output up and down. For hydropower plants connected to larger reservoirs, the ability to respond to market signals is constrained by operational rules imposed by non-power purposes (Holttinen et al., 2013; Niu and Insley, 2013). At the high-end of the flexibility spectrum for hydropower generation would be closed-loop PSH facilities.

4.6.1 One-Hour Ramps

The average one-hour ramp per installed megawatt for the hydropower fleet is larger, but less correlated with electricity load, than the average one-hour ramp per megawatt of the other most flexible generation technology (natural gas).

Even though the potential flexibility of individual plants can be compared based on their technical design parameters and the operational constraints they face, few metrics are available to analyze the actual net contributions to flexibility by natural gas and hydropower fleets. The hourly generation data provided by ISO/RTOs can be used to explore the magnitude of fleet-wide output adjustments by hydropower and natural gas. Figure 40 displays the average and 10th–90th percentile interval one-hour ramps for hydropower and natural gas in each ISO/RTO. Installed natural gas-fired generation capacity is larger than installed hydropower capacity in all the markets. Thus, to compare the relative flexibility of these two generation types, one-hour ramps are presented as a fraction of the installed capacity for each fleet.

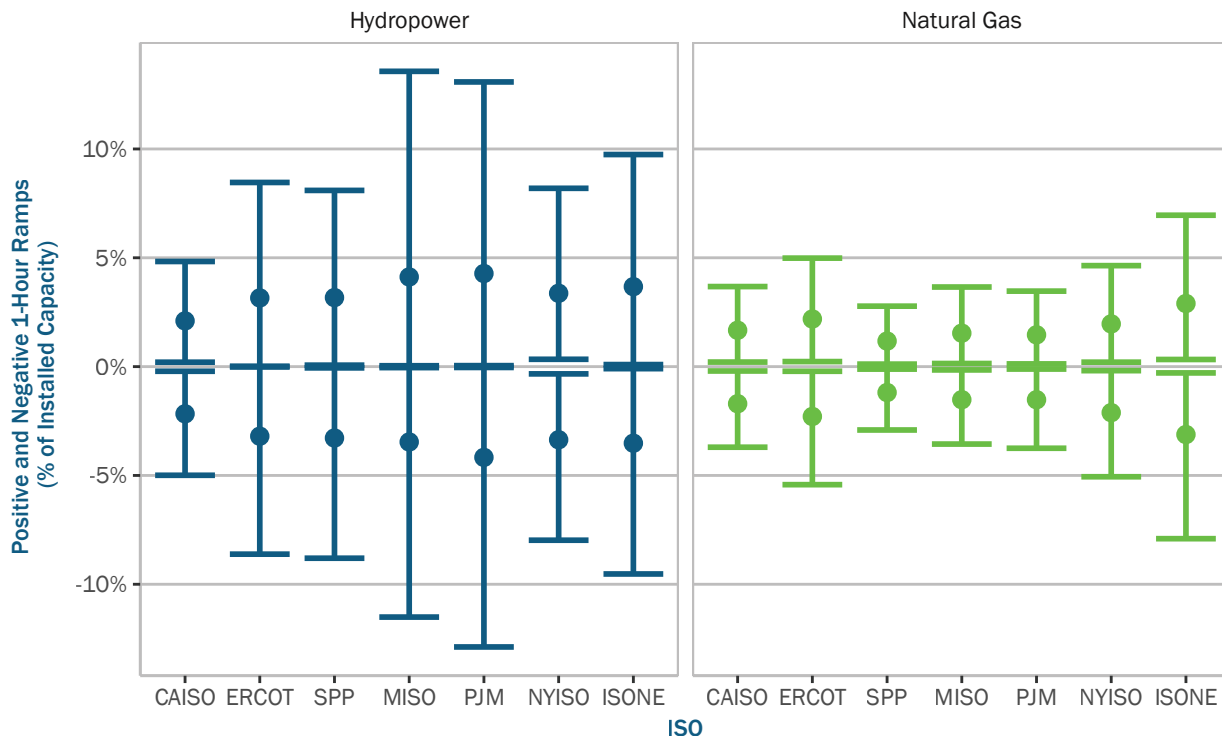


Figure 40. One-hour ramps (both positive and negative) per installed megawatt for hydropower vs. natural gas by ISO/RTO

Source: ISO/RTO websites

Note: CAISO, MISO, and ERCOT values are based on 1/1/2014–12/31/2017 data. For other ISO/RTOs, the period represented in the plots is dictated by data availability: 5/20/2015–12/31/2017 for PJM, 1/1/2015–12/31/2017 for SPP, 8/18/2016–12/31/2017 for ISONE, and 12/09/2015–12/31/2017 for NYISO.

The average one-hour ramp as a fraction of installed capacity is larger for the hydropower fleet than the natural gas fleet. This result is consistent across ramp types (positive or negative) and markets despite their being significant differences in the sizes and composition of the hydropower fleets across ISO/RTOs.⁶⁴ The width of the 10th–90th percentile interval for one-hour ramps is positively correlated with the fraction of the hydropower fleet that is PSH in each market. The three ISO/RTOs with widest 10th–90th percentile intervals for one-hour ramps are MISO, PJM, and ISONE; the fraction of PSH in their hydropower fleets is also largest among all ISOs—70% (2,418 MW), 58% (5,103 MW), and 49% (1,571 MW), respectively.

In addition, the tails of the one-hour ramp distribution are longer for hydropower than natural gas in all ISOs. As an example, Figure 41 shows the one-hour ramp distributions for the CAISO market. One-hour ramps equal to 5% or more of installed capacity are more frequent for hydropower than natural gas. Similar histogram shapes result from the data sets for the other ISOs.⁶⁵

64 For ERCOT, the ramp size was 0 in 16% of the observations. For ISONE, zero ramps accounted for 4.5% of observations. In all the other ISO/RTOs, the fraction of hours with zero hydro ramps was less than 0.5%. Thus, by excluding zero ramps from the distributions presented in Figure 40, the average size of hourly changes are somewhat overstated for ERCOT and ISONE.

65 One-hour ramp distributions normalized by installed capacity are presented in Huber et al. (2014) for wind and solar generation in multiple European countries to assess the flexibility requirements in those systems. Here, the same method is used to compare flexibility capabilities from hydropower and natural gas in the various U.S. regional electricity markets.

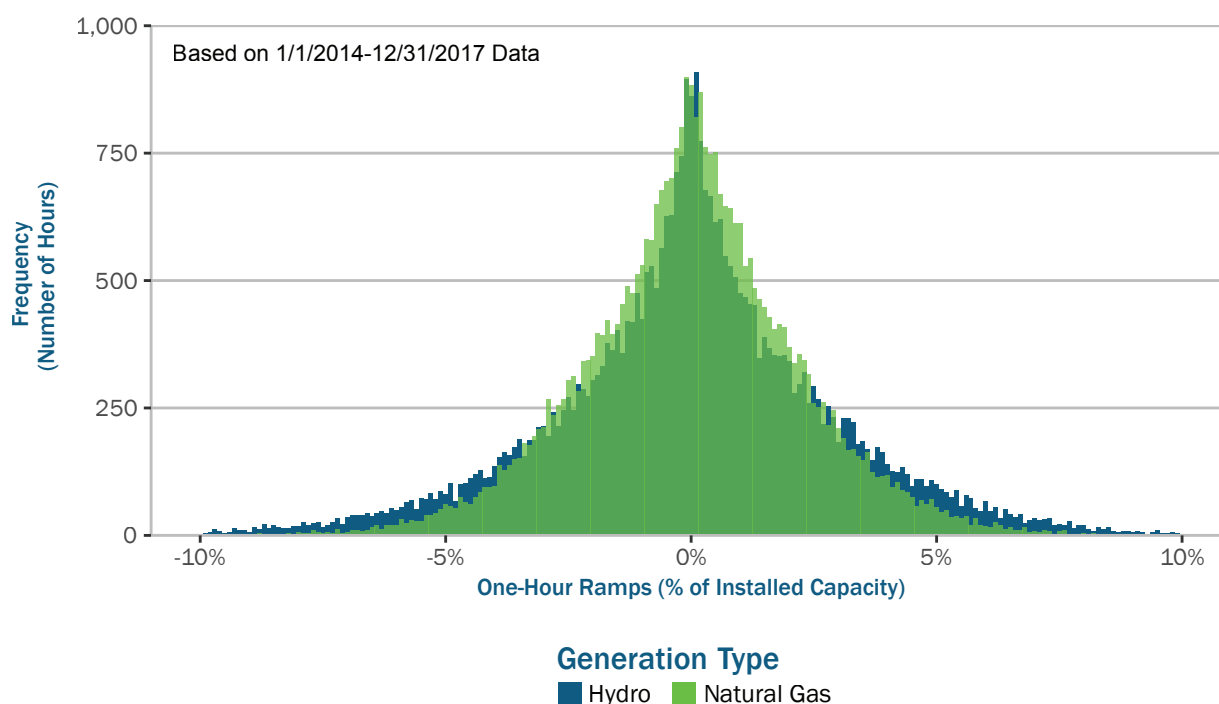


Figure 41. Distribution of positive and negative one-hour ramps for hydropower and natural gas in CAISO market

Source: CAISO website

An alternative way to summarize the information contained in the distribution of one-hour ramps is by using the concept of “mileage”.⁶⁶ Ramping mileage (for one-hour ramps) is calculated by adding up all the ramps in absolute value over a given interval—a year in this case—to obtain an aggregate measure of the ramping work performed by the fleets. The results are displayed in Table 5. To account for the difference in relative sizes of the hydropower and natural gas fleet, the mileage number is divided by installed capacity.

Table 5. Ramping Mileage (One-Hour Ramps) for Hydropower and Natural Gas per Installed Megawatt by ISO/RTO and Year

	2014		2015		2016		2017	
ISO	Hydro	Natural Gas	Hydro	Natural Gas	Hydro	Natural Gas	Hydro	Natural Gas
CAISO	NA	NA	167.49	147.79	207.23	138.57	182.92	159.60
ERCOT	144.24	207.10	170.51	193.53	308.45	194.93	*285.26	*167.63
SPP	NA	NA	284.74	92.36	254.43	112.76	264.85	105.41
MISO	344.29	113.09	232.95	132.83	362.11	150.35	376.64	139.39
PJM	NA	NA	*184.86	*66.96	366.59	125.00	396.69	144.54
NYISO	NA	NA	NA	NA	309.72	161.16	278.63	176.24
ISONE	NA	NA	NA	NA	*109.62	*95.10	301.67	264.32

Source: ISO/RTO websites

Note: CAISO, MISO, and ERCOT values are based on 1/1/2014–12/31/2017 data. For other ISO/RTOs, the period represented in the plots is dictated by data availability: 5/20/2015–12/31/2017 for PJM, 1/1/2015–12/31/2017 for SPP, 8/18/2016–12/31/2017 for ISONE, and 12/09/2015–12/31/2017 for NYISO. Values for years in which a complete set of data is not available are preceded by an asterisk.

⁶⁶ Several ISO/RTOs use the concept of mileage as part of their implementation of FERC Order 755, which requires pay-for-performance mechanisms to compensate resources providing frequency regulation (Xu et al., 2016). Under the pay-for-performance model, resources that can follow the frequency regulation signal faster and more accurately and perform more “work”—total upward and downward adjustments—over a given period must be paid more than those that respond more slowly or less accurately to the signal.

Table 5 shows that, except for ERCOT in 2014 and 2015, total annual mileage per installed megawatt is significantly larger for the hydropower fleet than for the natural gas fleet in all ISO/RTOs. The low values for ERCOT in 2014–2015 can be traced back to very low hydropower generation during part of those two years in that region. MISO and PJM markets have the largest percentage of highly flexible PSH in their fleets and the highest hydropower one-hour ramping mileages in 2016 and 2017. For the ramping mileage in Table 5 to be effective in providing flexibility to the system, it needs to happen at the times and in the directions in which load (or net load) is moving. Table 6 displays the correlations between hydropower and natural gas one-hour ramps and hourly changes in net load in each ISO/RTO.

Table 6. Correlation between One-Hour Ramps and Changes in Net Load for Hydropower and Natural Gas by ISO/RTO and Year

	2014		2015		2016		2017	
ISO	Hydro	Natural Gas	Hydro	Natural Gas	Hydro	Natural Gas	Hydro	Natural Gas
CAISO	0.77	0.88	0.79	0.91	0.83	0.88	0.79	0.87
ERCOT	0.19	0.83	0.20	0.87	0.27	0.88	*0.33	*0.86
SPP	NA	NA	0.38	0.79	0.59	0.79	0.57	0.74
MISO	NA	NA	0.40	0.91	0.43	0.91	0.39	0.84
PJM	NA	NA	*0.45	*0.80	0.48	0.79	0.50	0.82
NYISO	NA	NA	0.62	0.84	0.66	0.85	0.64	0.83
ISONE	NA	NA	NA	NA	*0.46	*0.82	0.50	0.83

Source: ISO/RTO websites

Note: CAISO, MISO, and ERCOT generation data are based on 1/1/2014–12/31/2017 data. For other ISO/RTOs, the period represented in the plots is dictated by data availability: 5/20/2015–12/31/2017 for PJM, 1/1/2015–12/31/2017 for SPP, 8/18/2016–12/31/2017 for ISONE, and 12/09/2015–12/31/2017 for NYISO. Values for years in which a complete set of data is not available are preceded by an asterisk.

Table 6 indicates that the correlation between hourly changes in generation levels and ISO net load levels is higher for natural gas in all regional markets and years. This is not surprising as many hydropower facilities face operational constraints driven by competing uses of reservoir space or water flows that affect the timing of ramps. The highest correlations between changes in hydropower generation and changes in load are seen in the CAISO and NYISO markets, the two markets with the largest shares of hydropower in their fuel mix. Conversely, the market with the lower share of hydropower generation (ERCOT) displays the lower correlation between hydropower ramps and changes in load.⁶⁷ For SPP, the correlation increases significantly in 2016 after additional balancing authorities with large installed hydropower capacity joined the SPP Integrated Market in October 2015, tripling installed hydropower capacity within the expanded market footprint.⁶⁸

In CAISO, the correlation between either hydro or natural gas hourly changes in generation and net load is significantly higher than the correlation with total load. For instance, in 2017, the correlation between hydropower one-hour ramps and hourly changes in load was 0.52 (versus 0.79 when measured relative to changes in net load). In the rest of ISOs, correlations with respect to either load or net load are very similar. This result is consistent with the data displayed in Figure 33 which shows that only in CAISO does the typical daily shape of generation from variable renewables differ considerably from the typical daily shape of electricity load.

67 Only 10 hydropower plants, with a total capacity of 530 MW, participate in the ERCOT market. Half of the capacity is owned and operated by the Lower Colorado River Authority and only generates at the request of ERCOT during power emergencies. This restricted operation helps explain why the correlation between changes in load and hydropower ramps is much lower in that market.

68 <https://www.wapa.gov/newsroom/NewsReleases/2015/Pages/spp-transition.aspx>.

In summary, the contribution to ramping flexibility from natural gas is larger than from hydropower in absolute terms because the size of the natural gas fleet is much larger. However, the average one-hour ramp size is larger for hydropower than natural gas in all ISOs/RTOs and each installed megawatt of hydropower performs, on average, a larger amount of ramping work within a year than each installed megawatt of natural gas-fired generation. One-hour ramps by the natural gas fleet follow changes in load (or net load) more closely than hydropower; yet the hydropower fleet is utilized for larger one-hour ramps as a fraction of installed capacity than natural gas. Instances of large one-hour ramps are more frequent in ISO/RTOs where a high fraction of installed hydropower is PSH. Similar analysis could be performed for shorter or longer ramps to determine how consistent the results are at different time intervals.

4.6.2 Unit Starts

Pumped storage hydropower units typically start more than once per day; for hydropower units, the median number of starts increases with unit size.

Changes in hydropower output within a short timeframe of a few seconds to a few hours are the combination of ramping by on-line turbine-generator units and full starts/stops. The time required to start or stop is another metric of flexibility at the unit level. NERC GADS information on number of starts for hydropower units is summarized in Figure 42 for three size categories of hydropower units as well as PSH units.

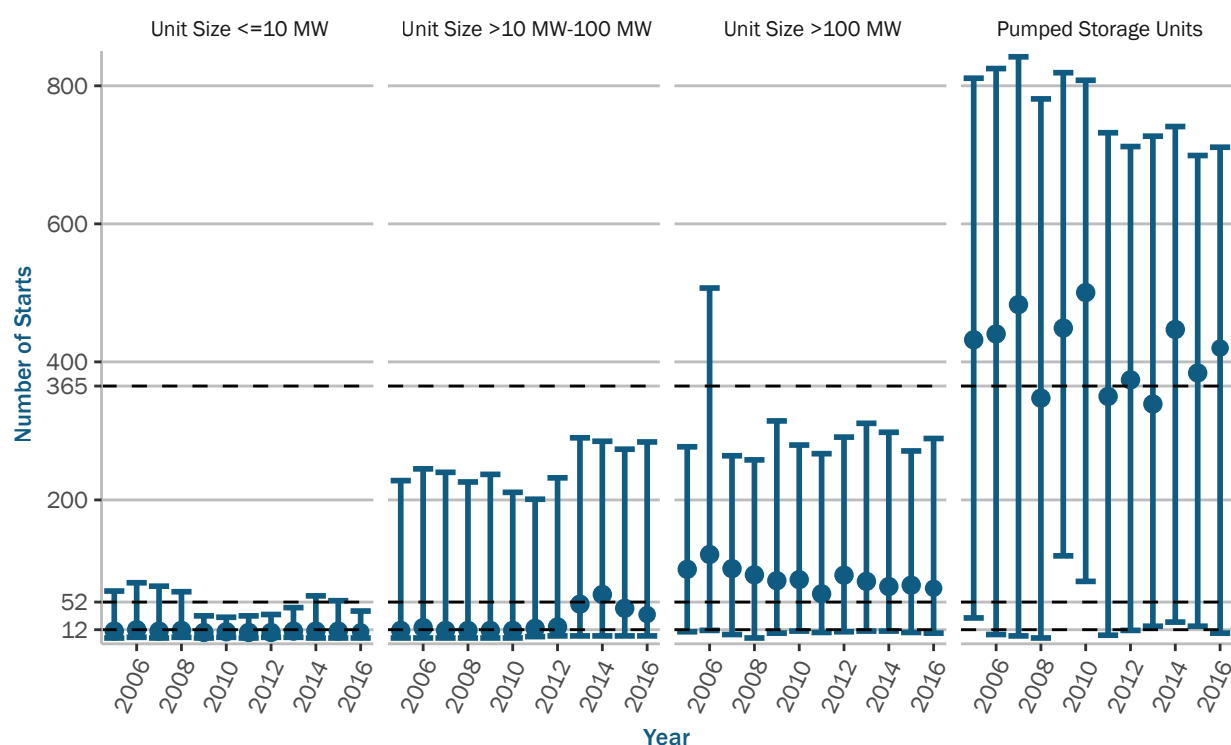


Figure 42. Unit start distributions by year, unit type, and unit size

Source: NERC GADS

Note: Percentage of U.S. hydropower fleet coverage in NERC GADS for the unit types shown in the panel titles varies slightly year to year. On average, 16% of U.S. hydropower units <=10 MW, 65% of U.S. hydropower units >10 MW and <=100 MW, 76% of U.S. hydropower units >100 MW, and 53% of U.S. PSH units reported data to NERC GADS in 2005-2016.

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Figure 42 shows starkly different distributions of number of starts for different unit types and sizes which hint at very different modes of operation across these fleet segments. For small units, the median number of unit starts ranges from 8 to 12 per year. This would be roughly equivalent to one start per month. Many small units correspond to run-of-river plants where the objective is to maximize the number of generation hours and number of starts is therefore minimized. Most but not all zero values can be justified by units being out of service for an entire year. Thus, there are a few units that were electrically connected to the grid for an entire year. Small units with more than 52 starts per year, which would be consistent with weekly operation cycles, are rare particularly in the most recent years. The small unit segment is the one for which the NERC dataset covers the lowest fraction of total population; thus, the behavior captured in Figure 42 might not be representative of the entire fleet of small units.

For medium-sized units, median unit starts increased from approximately 12 to approximately 52 around 2013. These two numbers are consistent with monthly and weekly operation cycles respectively. However, since the sample size for this size category almost doubles from 2011 to 2013, the change most likely reflects that the 144 new units added to the sample in 2013—ranging in size from 20 MW to 50 MW—start and stop more frequently than the ones included in the dataset for a longer period. The 90th percentile of unit starts is also significantly larger in the recent expanded sample of medium-sized units. Post-2012, the width of the 10th–90th percentile intervals is similar as for medium and large units. The median number of unit starts for large units decreased during the period displayed in Figure 42 from approximately 100 in 2006–2008 to 72 in 2016.

In most years between 2005 and 2016, the median number of starts for PSH units was above 365. Thus, it is not unusual for PSH units to start more than once per day. Although there is not a clear trend in the number of median unit starts for the period depicted in Figure 42, the number of starts for units on the 90th percentile of the distribution has decreased significantly over time. Thus, the most heavily used PSH units have experienced less operational cycles per year in the most recent years. This result is consistent with the decreasing trend in total PSH generation discussed in Figure 30. There are also PSH units that do not start daily. Among these, there are units undergoing long outage periods or units within complex hydropower systems operated for multiple purposes. Examples of the latter would be the Edward C. Hyatt and Thermalito plants, which contain hydropower and PSH units and are operated by the California Department of Water Resources as part of an intricate system of conduits, reservoirs, and power plants serving water supply, irrigation, and power production purposes.

Based on NERC GADS data, most of the within-day flexibility provided by hydropower comes from ramping rather than unit starts and stops. Increasing the number of starts and stops (as well as increased ramping) has a cost for the plant owner over time in the form of increased wear and tear of the unit. Therefore, adequate remuneration is required to incentivize the adoption of these more flexible modes of operation. Figure 42 shows that only PSH units start once or more per day on average. For hydropower units, there is a positive relationship between unit size and median number of unit starts. For the smaller units, operation cycles tend to be very long. In 2016, the typical average run time (i.e., *Unit Service Hours* divided by number of units starts) was 22.39 days, 4.1 days, and 2.7 days for small, medium, and large hydropower units respectively. For PSH units, the typical average run time was 3 hours in 2016. The 2016 average run time for PSH units is in line with the two previous years but lower than most years in 2006–2013.

5. Trends in U.S. Hydropower Supply Chain

The U.S. hydropower supply chain serves the needs of both existing plant owners and new developers. Given the relative sizes of the existing fleet versus the project development pipeline, most of the equipment being manufactured goes towards refurbishments and upgrades. To unlock the untapped hydropower resources at U.S. NPDs, conduits, and new stream-reaches, innovation needs to continue across all aspects of project design and implementation to improve project economics and reduce development risk.

A map containing almost 200 U.S. manufacturing facilities producing hydropower turbines, generators, transformers, penstocks, gates, and valves was presented in the first edition of this report. This section focuses on describing turbine installation trends because turbines are the components for which the most data are available. Though it is more difficult to pinpoint their locations on a map or estimate the number of hydropower industry jobs they create, engineering and consulting companies in the non-manufacturing portion of the value chain also play key roles throughout the hydropower project lifecycle. These roles range from developing early-stage design documents and conducting studies required for preparing license applications to construction, and, later on, to performing condition assessments and implementing asset management strategies.

5.1 Hydropower Turbine Installations

At least 223 hydropower turbines with a combined capacity of almost 9 GW have been installed in the United States since 2007; much of the new capacity corresponds to major R&U at existing facilities and that market segment is largely covered by three main turbine manufacturers.

Figure 43 shows hydropower turbine installations in the United States between 2007 and 2017, segmented by manufacturer. It includes turbine units at new plants, as well as major turbine refurbishments and unit additions in the existing fleet.⁶⁹ At least 223 turbine units distributed across 93 hydropower and PSH plants with a combined capacity of almost 9 GW were installed in the United States during that period.

69 The IIR dataset primarily tracks turbine refurbishments and upgrades at medium and large plants owned by federal agencies, investor-owned utilities, wholesale power marketers, and some public-owned utilities. The coverage of turbine upgrades at facilities owned by private non-utilities and new installations at small conduit projects are very limited.

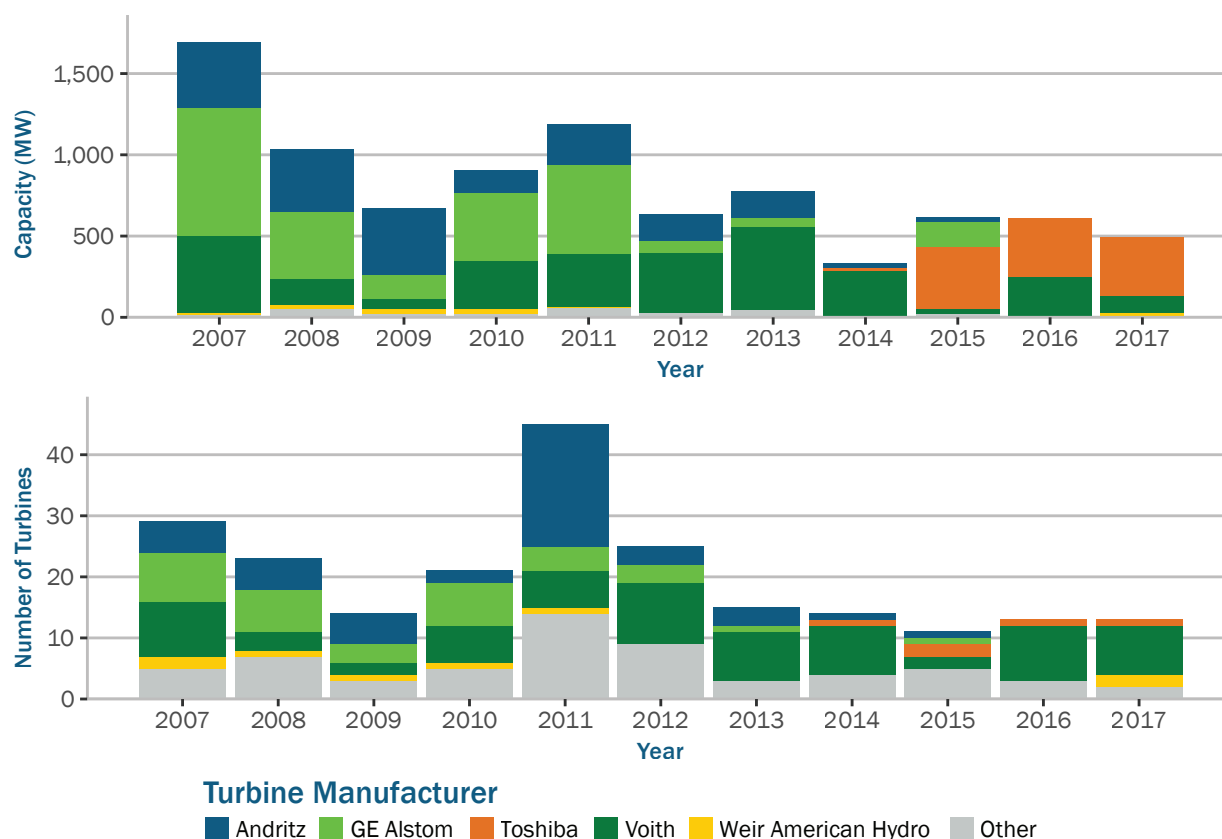


Figure 43. Annual installations of hydropower turbines in the United States by manufacturer

Source: Industrial Info Resources, NHAAP

The tracked number of turbine installations ranges from 11 in 2015 to 45 in 2011. Most of the 2011 spike in installations depicted in Figure 43 comes from two single projects with 16 and 8 units respectively. Fifty-seven (26%) of the units included in Figure 43 were installed in new plants and the rest were either unit additions, replacements, or upgrades at existing hydropower plants. The average size of the new units was 8.4 MW with none greater than 35 MW. For installations at existing facilities, average turbine capacity was 51 MW and the largest units—Ludington’s reversible pump turbines—had a 362-MW nameplate capacity.

Three turbine manufacturers—Andritz, GE Alstom, and Voith—accounted for 83% of tracked installed turbine capacity and 67% of installed units in the United States during this period. The market share of these three companies is even greater for the larger units. The companies manufactured 90% of installed units with a capacity equal or greater than 10 MW. Toshiba has a small market share by number of installations, but it shows prominently in terms of capacity in 2015–2017 because of its work on the overhaul of the large reversible pump turbines at the Ludington PSH facility.

Through a combination of mergers, acquisitions, and joint venture agreements, the global hydropower turbine industry has experienced significant consolidation during the last decade:

- » Andritz acquired VA Tech's hydropower division in 2006.⁷⁰
- » Scotland-based Weir Group acquired American Hydro in 2010. The resulting Weir American Hydro brand was purchased in June 2016 by Wärtsilä, a Finnish corporation whose presence in the hydropower supply chain had previously focused on the manufacturing of seals and bearings.⁷¹
- » GE and Alstom entered a joint venture agreement on the renewables portion of the business, including hydropower, in late 2015. At the end of 2017, Alstom announced that it will sell its stake in the joint ventures to GE.⁷²

Most turbine manufacturers with significant market share in the United States have domestic manufacturing facilities. Voith and Weir American Hydro are based in York, Pennsylvania, and Andritz has a machining facility in Spokane, Washington. All new Voith turbine runners and shafts for installation in the United States are manufactured domestically; however, the rough steel castings used as raw material are imported. As for generators, Voith sources the individual parts from third parties—domestic or foreign—and assembles them at the York facility (J. Smith, pers. comm., 2016). Similarly, Weir American Hydro machines turbine runners, turbine shafts, and draft tubes for the U.S. market domestically and procures the generators from other companies (G. Russell, pers. comm., 2016).

Alstom (now GE Alstom) concentrates the manufacturing of mechanical components for North American hydropower in Sorel-Tracy, Canada. Toshiba's two turbine manufacturing facilities are in Japan and China. Of the 60 turbine units included under the "Other" manufacturers category, approximately half were produced by smaller U.S. turbine manufacturers and the rest by Canadian, Chinese, and European companies. The next section provides detail on the import and export value trends.

Based on the location of the manufacturing facilities of each company, it can be estimated that for at least half of the turbines in Figure 43, machining and assembly operations were performed in the United States. Calculating the percentage of value added for these turbines that is generated domestically is more complicated as it would require knowing the origin of steel or other raw materials used as well as where the teams designing the units are located.

Figure 44 shows the distribution of turbine installations among the three major hydraulic turbine types: Francis, Kaplan, and Pelton. Axial flow designs such as bulb and hydro-matrix turbines are included in the Kaplan category.

70 VA Tech units included in the figures in this section are classified as Andritz units.

71 <https://www.wartsila.com/media/news/23-06-2016-wartsila-acquires-weir-american-hydro-to-strengthen-presence-in-hydro-and-industrial-services>

72 <http://www.industryweek.com/operations/alstom-selling-stakes-joint-ventures-ge>.

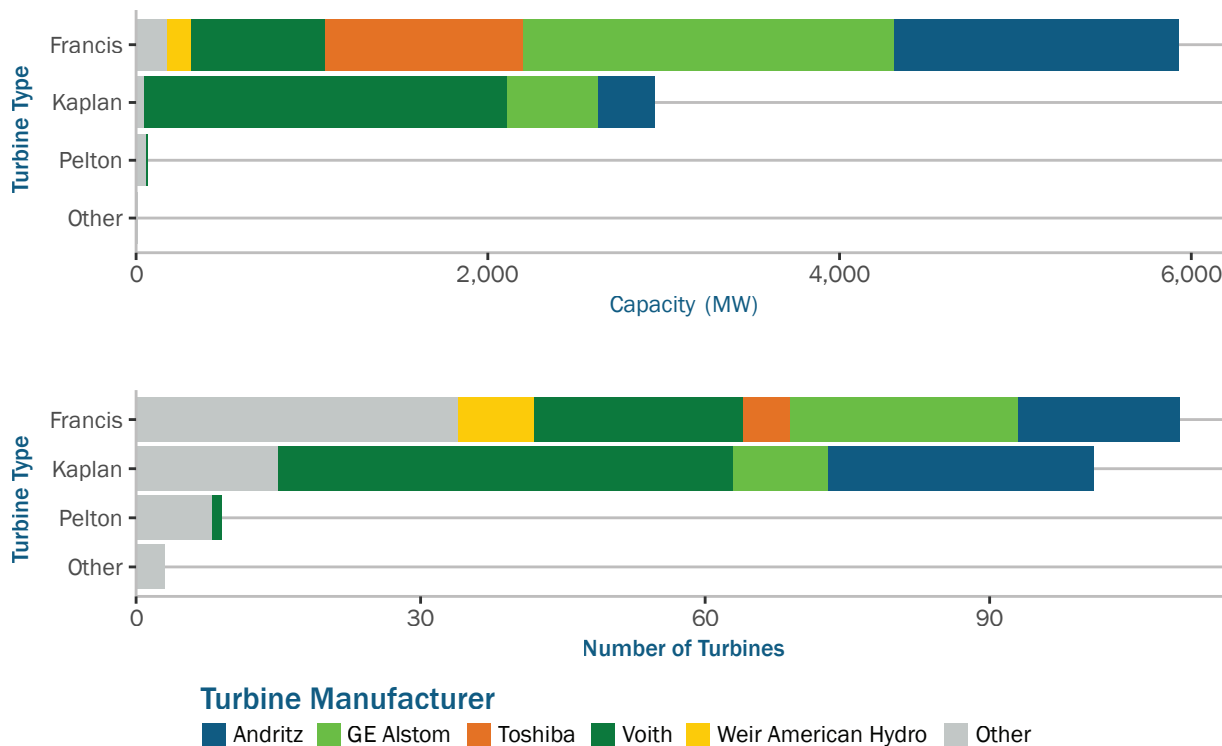


Figure 44. Installed hydropower turbines in the United States by type and manufacturer (2007–2017)

Source: Industrial Info Resources, NHAAP

All but three of the turbine installations tracked in this database belong in one of the three main turbine families. For turbines installed at existing facilities, 55% were Francis, 42% were Kaplan, and the remaining 3% were composed of Pelton units or Other turbine types. For the 57 turbines installed at new plants, Francis is no longer the most common type. Kaplan turbines, which are well-suited for low-head sites, were used in 54% of the new installations. Francis turbines account for 33% of turbines in new plants and all but one of the remaining units are Pelton.

All major manufacturers having non-negligible market shares of Francis, which remains the most common turbine type in the U.S. fleet, have domestic manufacturing facilities. The smaller Francis units tend to be manufactured by smaller manufacturers in the *Other* category. Pelton turbine installations, which have all been small units and mostly concentrated in new projects in Washington and Alaska, are also mostly manufactured by companies in the *Other* category. Thus, the bigger manufacturers appear to focus on refurbishments and upgrades of existing larger units where they see more business potential in the United States. For large units, each design is highly customized and only a handful of original equipment manufacturers have the infrastructure required to machine, assemble, and transport them. On the other hand, in the small turbine segment, the trend is toward standardization that will enable cost reductions (see insert).

INNOVATION IN SMALL HYDROPOWER PROJECT CONSTRUCTION LOGISTICS AND SUPPLY CHAIN CONFIGURATIONS

Construction logistics play a vital role in the timely and cost-efficient development of hydropower projects. Construction sequencing and logistics management are often constrained by the availability of local materials, restrictions on and difficulty of shipping equipment, and the location of equipment suppliers relative to the project site. Unpredictable climatic and environmental conditions at a site can also add risk to project development and delay construction timelines, leading to time and cost overruns. New methods are being explored to overcome these challenges and increase the predictability of development outcomes while providing positive cost impacts to project construction and equipment procurement, particularly for small projects. These methods include the use of modular prefabricated structural elements, modular equipment, and additive manufacturing.

New projects are attempting to standardize construction sequencing by breaking plants into smaller, modular, prefabricated pieces that can be transported by standard road methods and be assembled on site. Natel Energy was recently awarded a grant from the California Energy Commission to develop a standardized, modular plant design and assembly procedures that can be replicated across irrigation drops in California (Natel Energy, 2018). A major benefit of this approach is streamlining and de-risking the construction process. By manufacturing major plant components offsite in a highly regulated environment, the time and risk spent working in the river with a cofferdam, equipment, and concrete formwork might be significantly reduced.

The use of modular, standardized equipment packages at small scales could decrease costs compared with custom designed equipment and civil works solutions. Standard modular designs require few to no changes to major design features for each project, enabling design and cost efficiencies by using the same equipment across many sites. A renovation of the Bell Mill in New Hampshire is using a GoHydro standard equipment package that contains an axial-flow turbine, guide vanes, penstock, self-cleaning intake, industrial generator, shaft, bearings, and a control unit all pre-fabricated and transported to the project in a shipping box. Additional projects that could use the same modular equipment package have been identified and are under study (L. Barg, pers. Comm., 2018).

Growing interest in new materials and manufacturing techniques for hydropower applications is being spurred by rapid advancements in additive manufacturing, commonly referred to as 3D printing. Oak Ridge National Laboratory is currently partnering with Amjet Turbine Systems to demonstrate the feasibility of additive manufacturing for small, low-head turbine components (ORNL, 2017). The project is using Big Area Additive Manufacturing, a large robotic-driven deposition system that extrudes low-cost, carbon fiber-reinforced polymer to build components in layers. If proven reliable, the distributed use of 3D printing technologies has the potential to disrupt many aspects of the supply chain, from manufacturing to O&M and replacements. 3D printers could be located onsite in a powerhouse to rapidly produce low-cost replacement parts. Digital design drawings could be sent to equipment manufacturers and new replacement components printed within hours.

These small projects are helping the hydropower industry gain the important process and practical knowledge needed to consistently and cost-effectively implement prefabrication, standardization, modularity, and alternative materials at larger scales.

5.2 Hydropower Turbine Imports/Exports

The main trading partner for the United States in imports and exports of hydraulic turbines and parts is Canada; trade with Europe has declined over time. China has gone from being a net importer of U.S. turbines in the late 1990s to a net exporter of turbines to the United States in recent years.

Figure 41 presents the values of hydraulic turbines and turbine part exports and imports tracked by the U.S. Department of Commerce.⁷³ Turbines are the only component for which the current Harmonized Tariff Schedule (HTS) code classification is granular enough to identify the value of trade transactions related to hydropower. However, the trade codes that refer to hydraulic turbines do not include turbine-generator packages.⁷⁴

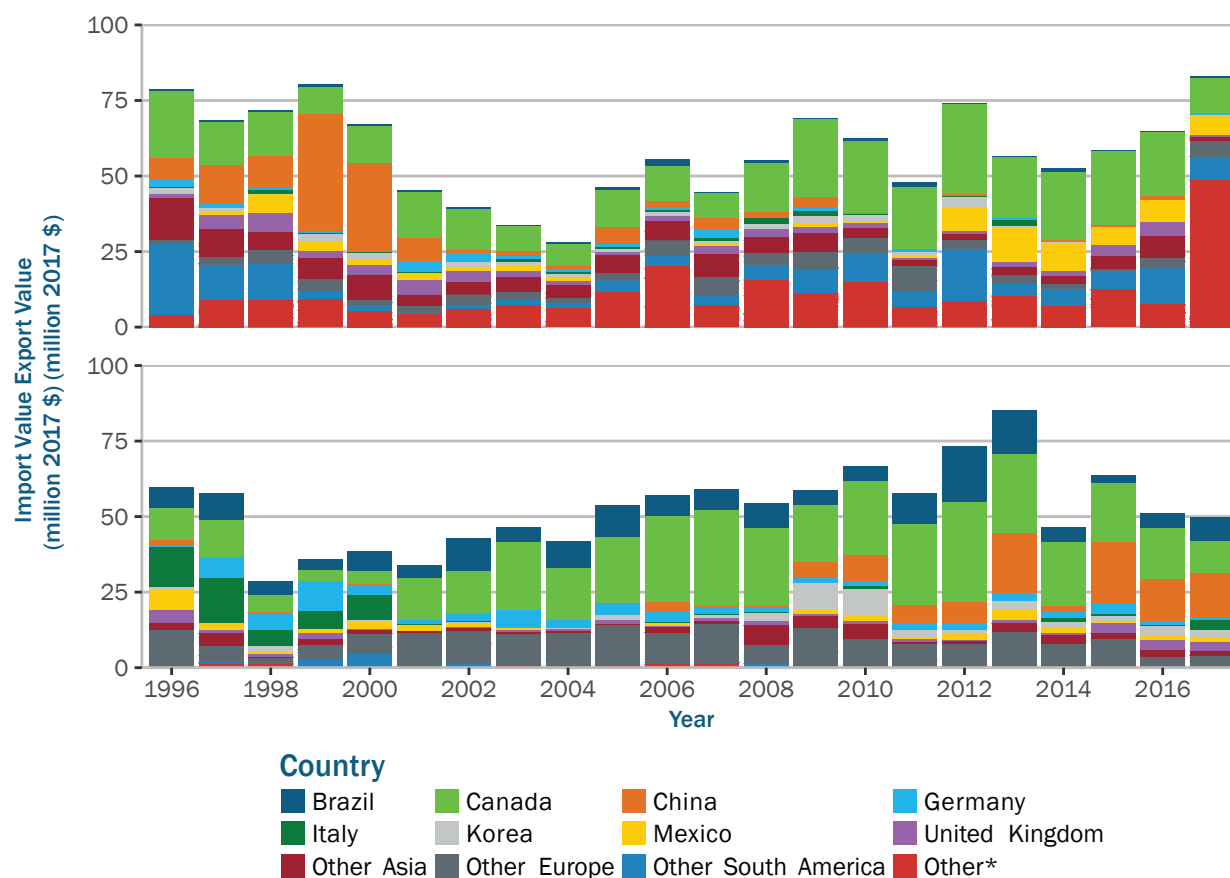


Figure 45. U.S. hydropower turbine import and export values by country

Source: U.S. International Trade Commission

Note: The 2017 data are subject to revision.

*See footnote 75 for an explanation to the large value of export to Other countries in 2017.

73 Hydraulic turbine trade data was queried through the Interactive Tariff and Trade Data Web (<https://dataweb.usitc.gov>) produced by the U.S. International Trade Commission, which compiles import, export, and tariff statistics from the U.S. Department of Commerce. The values presented in Figure 41 are "Customs Value" which excludes any shipping or duty costs. They include the values from HTS codes 8410.11 (hydraulic turbines with capacity ≤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. Domestic Exports".

74 A request for a breakout of HTS codes that would allow identification of imports and exports of hydropower turbine-generator sets was denied because of low trade volumes.

Figure 41 shows two distinct phases for the U.S. trade balance in hydropower turbines from 1996 to 2017. During the 1996 to 2004 subperiod, the United States went from net exporter to net importer of hydraulic turbines. From the low point in total trade value observed for 2004 (\$69 million), both imports and exports entered an increasing trend. Import value peaked in 2013 and was significantly lower during the remainder of the period; for exports, the general upward trend continued through 2017.⁷⁵

Transportation logistics for all but the smallest turbine units are complex and expensive. Thus, manufacturing plants—particularly for large units—are strategically located in regions with large hydropower fleets and project portfolios. Location close to waterways is also prized as it helps minimizing road transport. Because of the large size of the Canadian and U.S. hydropower fleets, multiple manufacturers have facilities near the Canada-U.S. border. As a result, a large fraction of U.S. hydropower turbine trade has its source or destination in Canada. Since 2007, with the exception of 2017, at least 30% of imports each year have come from Canada. Similarly, between 2008 and 2016, at least 30% of exports each year have gone to the Canadian market. The manufacturing plants of GE Alstom in Quebec and Canadian Hydro Components and Norcan in Ontario likely account for a significant fraction of the trade flow from Canada to the United States. The York, Pennsylvania, facilities by Voith and Weir American Hydro are among the plants that contribute to trade in the other direction.

Exports to Mexico have become a stable and significant (10%–15% of total export value) trade flow for the United States since 2012. Brazil, where Voith has manufacturing facilities, is a net exporter of turbines to the United States. However, the United States is a net exporter in its trade relationship with “Other South America” countries.

Turbine trade with Europe has changed substantially over time. From 1996 to 2000, 50% or more of all imports came from European countries—Germany, Italy, United Kingdom, and *Other Europe*. Since 2006, the import fraction from Europe has been less than 30% every year. As for exports, Europe has represented less than 20% of total value in most years of the dataset.

At the beginning of the period depicted in Figure 45, the United States was a net exporter of turbines and turbine parts to China. Then, between 2002 and 2008, trade in hydraulic turbines between the countries dwindled. Since 2009, the United States has become an importer of Chinese hydropower turbines. In 2015–2017, Chinese imports represented on average 30 % of total import value for these products.⁷⁶ U.S. exports to *Other Asia* have also declined significantly over the last 20 years as China increases its market share for turbine orders from that region.

On average, 90% of the import value captured in Figure 45 corresponds to imports of turbine parts and regulators. Rotors, stators, casings for spiral conduits, valve needles, runner hubs, and runner caps are among the components included in that category. The remainder of the import value is evenly distributed across the three turbine size categories. Turbine parts also account for almost three quarters of total export value in the last 20 years.

75 The 2017 export value is the largest for the whole 1996–2017 period. More than half of the value (\$45 million) corresponds to exports to Kuwait—a country to which exports in every other year have been two or three orders of magnitude lower. Since the 2017 numbers are provisional, this outlier trade volume with Kuwait could be an error.

76 A large portion of the 2015–2017 Chinese imports correspond to the turbine units for the Ludington PSH plant, which are being manufactured by Toshiba in China (<http://www.waterpowermagazine.com/features/featureoverhaul-at-ludington/>).

6. Policy and Market Drivers

Modifications to hydropower authorization processes intended to reduce length, cost, and attrition rates are under consideration.

Table 7 summarizes the content and status of national legislative bills introduced in 2017 proposing modifications to the hydropower federal authorization process.

Table 7. Description and Status of Bills Introduced in 2017 Related to the Hydropower Authorization Process

Bill	Objective	Status as of 12/31/2017*
H.R. 3043 (<i>Hydropower Policy Modernization Act of 2017</i>)	Modify definition of renewable energy (for the purposes of all federal programs) to include hydropower; designate FERC as leading agency in licensing process for purposes of coordinating all federal authorizations and complying with NEPA; improve the trial-type hearing process to resolve disputes about license conditions; improve study portion of licensing process through compilation of best practices and avoidance of duplicative studies; streamline process for obtaining license amendments associated with qualifying project upgrades	Passed House
H.R. 2274 (<i>Hydropower Permit Extension Act or HYPE Act</i>) and S.724	Extend maximum duration of preliminary permits (four years instead of current three-year duration with possibility of an additional four-year renewal if adequate progress is shown); extend maximum time allowed for FERC-authorized projects to start construction (up to eight years instead of current two-year period)	Passed House (H.R. 2274); Introduced in Senate (S.724)
H.R. 2872 (<i>Promoting Hydropower Development at Existing Nonpowered Dams Act</i>)	Establish an expedited licensing process for nonfederal hydropower development at non-powered dams (two years or less from license application to final license decision); identify the non-powered dams with the greatest potential for development	Passed House
H.R. 2880 (<i>Promoting Closed-Loop Pumped Storage Hydropower Act</i>)	Establish an expedited licensing process for closed-loop pumped storage projects (two years or less from license application to final license decision); explore opportunities for development of closed-loop pumped storage projects at abandoned mine sites	Passed House
S. 1029 (<i>A bill to amend the Public Regulatory Policies Act of 1978 to exempt certain small hydroelectric power projects that are applying for relicensing under the Federal Power Act from the licensing requirements of that act</i>)	Allow small projects (a) <10 MW or (b) <15 MW licensed after 1991 and not located in critical areas for Endangered Species Act (ESA) species to switch from license to exemption during the relicensing process	Introduced
H.R. 2786 (<i>To amend the Federal Power Act with respect to the criteria and process to qualify as a qualifying conduit hydropower facility</i>)	Reduce time for FERC decision in applications for qualifying conduit status (from 45 days to 30 days after public notice of developer's intent) and expand the size limit for qualifying conduits	Passed House
H.R. 1967 (<i>Bureau of Reclamation Pumped Storage Hydropower Development Act</i>)	Amend Reclamation Project Act of 1939 to authorize nonfederal pumped storage development in projects where all reservoirs are under Bureau of Reclamation jurisdiction	Passed House

*Note: At the time of publication of this report (end of April 2018), the status of these bills remain unchanged.

Several of the bills in Table 7 seek to promote the addition of hydropower to existing infrastructure—dams, conduits, or reservoirs. None of them focus on development of new stream-reaches, although H.R. 3043 (*Hydropower Policy Modernization Act of 2017*) and H.R. 2274 (*Hydropower Permit Extension Act*) would also apply to NSD projects. Several bills propose new timelines for specific stages of the authorization process. Comparing the proposed timelines to the duration of those stages in recent years serves to evaluate the significance of the changes.

- » Approximately half of all licensed projects built in recent years had to apply to FERC for an extension to the two-year deadline to start construction. This high fraction of projects requesting additional time to complete preconstruction activities suggests that the current timeline is difficult to meet and that the proposed extension in H.R. 2274 (*Hydropower Permit Extension Act*) would be valuable for developers.
- » In FERC dockets opened between 2000 and 2016, the median time elapsed from preliminary permit issuance to the next stage in the development process—submission of a notice of intent to file a license application—was 1 year. Within a given docket, the time elapsed between preliminary permit issuance and notice of intent submission was more than three years for only 2% of the sample. Thus, the current default preliminary permit duration appears to be sufficient in most cases. It is unclear that the proposed timeline extension to four years outlined in H.R. 2274 (*Hydropower Permit Extension Act*) would increase the fraction of projects advancing to a license application.
- » Out of 53 non-powered dam projects associated with FERC dockets opened between 2000 and 2016 that obtained a FERC license, the median time from license application to license issuance was two and one-half years, but it ranged widely—from half a year to seven years. The expedited licensing processes proposed in H.R. 2872 (*Promoting Hydropower Development at Existing Nonpowered Dams Act*) for nonfederal, non-powered dam developments would cap the length of this step at two years. Although it is not a large difference relative to the observed typical length, the upper bound would be helpful to developers by mitigating uncertainty about the duration of this part of the licensing process.
- » Only two closed-loop pumped storage projects have obtained an original license in the last 10 years. For the Eagle Mountain Pumped Storage project, five years elapsed between license application and license issuance. However, for the Gordon Butte Pumped Storage Project that same step took less than 15 months. Potential developers observing these disparate experiences might be dissuaded to pursue the licensing process. The availability of an expedited process that caps duration of this step at two years as offered by H.R. 2880 (*Promoting Closed-Loop Pumped Storage Hydropower Act*) could allay concerns about excessively long licensing timelines and thus encourage more license applications for this type of project.

H.R. 2872 (*Promoting Hydropower Development at Existing Nonpowered Dams Act*) and H.R. 2880 (*Promoting Closed-Loop Pumped Storage Hydropower Act*) focus on setting upper boundaries to the duration of the postfiling stage of the licensing process. The *Hydropower Policy Modernization Act of 2017* (H.R. 3043) addresses the prefilling stage, in which all studies required to prepare the license application are conducted. This bill aims to improve the efficiency of the prefilling stage by compiling and sharing best practices, avoiding duplications, and allowing watershed-wide studies to be shared by multiple projects.⁷⁷ These initiatives could ultimately translate into a shorter, less expensive license preparation phase.

Two of the bills in Table 7 (S.1029 and H.R. 3043) focus on reducing the costs of modifying or renewing a hydropower license. Original licenses are issued for a period of 30 to 50 years, and the relicensing process required to renew them is often as long and complex as the one initially undergone before project construction. Instead, exemptions from licensing are perpetual. For eligible projects choosing to make the switch from license to exemption when their original license expires, S.1029 (*A bill to amend the PURPA of 1978 to exempt certain small hydropower projects that are applying for relicensing under the Federal Power Act from the licensing requirements of that act*) would reduce lifecycle permitting costs as no further renewals would be needed once an exemption is obtained. In addition to renewing a license when it expires, project owners need to apply for license amendments when they make any significant project changes. The *Hydropower Policy Modernization Act of 2017* (H.R.

⁷⁷ Watershed-wide studies would be allowed on request only by at least two project applicants, and they could be used only by the project applicants participating in the request.

3043) seeks to streamline license amendment procedures for changes that do not cause environmental harm and that would result in project capacity or efficiency increases, improvements in project recreation services, or the protection or enhancement of natural and cultural resources.

To date, the qualifying conduit project authorization pathway introduced by the Hydropower Regulatory Efficiency Act of 2013 has mostly attracted very small projects. Out of 94 projects that received qualifying conduit determination since August 2013, only 6 have capacity greater than 1 MW. A resource assessment study might be needed to identify suitable sites beyond the 1-MW threshold that would be able to benefit from the expanded size limit for this fast authorization pathway outlined in H.R. 2786 (*to amend the Federal Power Act with respect to the criteria and process to qualify as a qualifying conduit hydropower facility*) for conduit facilities.

Federal policy incentives for new hydropower resources have changed in recent years.

Throughout much of the last decade, hydropower has been eligible for a variety of incentives at the federal level that have influenced project economics for developers and owners of qualifying facilities. However, many of the authorizations governing the eligibility for federal incentive programs, or the funding authorizations for those programs, have expired. These include the following:

- » **The Renewable Electricity Production Tax Credit (PTC) and Business Energy Investment Tax Credit (ITC).** Hydropower efficiency improvements and the addition of power at existing water resource infrastructures have historically been eligible for the PTC and ITC. Eligibility for the PTC was initially authorized by the 2005 Energy Policy Act at a rate of \$0.011/kWh—half of the same rate for wind and geothermal. In 2009, The American Reinvestment and Recovery Act (ARRA) extended the eligibility of the ITC to all facilities qualifying for the PTC, including hydropower. Both authorizations have now expired. Hydropower’s eligibility for the ITC expired for projects commencing construction after December 31, 2014, and eligibility for the PTC expired for those initiated after December 31, 2016. Subsequent legislation has extended the PTC and ITC for some non-hydropower energy sources such as wind (with a phased reduction in value), solar, and geothermal for construction starts on or before December 31, 2019. Legislation (The Renewable Electricity Tax Credit Equalization Act [H.R. 4137] introduced in October 2017) has since been proposed that would restore PTC and ITC eligibility that was lost in 2017 for hydropower and other technologies, but no law has yet been passed.

When eligibility for hydropower remained in effect, 150 projects representing 1,800 MWh per year of additional generation were certified to receive these incentive provisions (FERC, 2016b). Of those 150, 57 elected the 1603 Cash Grant provision of ARRA, receiving \$530 million in total: \$22.5 million for the powering of NPDs and \$509 million for incremental generation at existing facilities (U.S. Department of the Treasury, 2017).

- » **Support for Public Financing of Hydropower Projects.** A variety of subsidized financing instruments were available to states and municipalities that reduced the capital costs of new hydropower projects owned by public entities. The instruments used most significantly for hydropower included Build America Bonds (BABs) and Clean Renewable Energy Bonds (CREBs).

Created in the ARRA, the interest on BABs was taxable, unlike the tax-exempt bonds typically issued by public entities. To offset this taxability, the financing benefit from BABs came from a government subsidy of 35% of the interest carried by the bond, either through a direct payment to the issuer or as a refundable tax credit to the bondholder, depending on the specific type of BAB. No new BAB allocations have been made since 2010, and existing BAB payments have been subject to cuts pursuant to budget sequestration.

CREBs operate similarly to BABs (taxable with a direct payment back to the issuer) but were specifically targeted for public entities pursuing renewable energy projects. After enactment of ARRA, \$2.4 billion in CREBs were made available with targeted funding caps for municipalities, public utilities, and electric cooperatives. This funding was allocated in two rounds: the first major round in 2009 and then a supplementary round in 2015 to disburse the remainder of the original \$2.4 billion. No new allocations have been made by Congress.

Effective January 1, 2018, the *Tax Cuts and Jobs Act* bars the issuance of municipal tax credit bonds, including BABs and CREBs.

Although some incentives for hydropower development are no longer available, other federal programs are still operating.

The U.S. Department of Agriculture (USDA) administers a range of support programs targeted to support electrification, spur economic development, and mitigate high electricity costs in rural areas throughout the country (Cowan, 2016). Hydropower projects are eligible for loan or grant support under many of these programs, and as of 2017, the USDA had provided 34 projects with a total of \$165 million in loan guarantees, loan subsidies, and grants since 2004.

An additional federal incentive program that has not lapsed in recent years is the payment of awards under Section 242 of the Energy Policy Act of 2005. The Section 242 payment provides for a direct incentive payment equivalent in magnitude to the PTC (1.8 cents/kWh in 2005 indexed to inflation) up to \$750,000 per year per project to be paid to developers of non-powered dams and conduit projects for the first 10 years after development.⁷⁸ Annual payment of this incentive is contingent on congressional appropriation of funds, and although the incentive has been authorized since 2005, it has only recently been funded with appropriations given in 2014 (\$3.6 million), 2015 (\$3.9 million), 2016 (\$3.9 million), 2017 (\$6.6 million), and 2018 (\$6.6 million). From 2014 to 2017, payments were made to 63 projects on 1.4 TWh of generation. Paying up the full \$0.023/kWh authorized under Section 242 has not been possible owing to the number of eligible applicants (and magnitude of generation); payments have ranged from \$0.009 to \$0.015/kWh. An additional program under Section 243 would authorize incentive payments for efficiency improvements at existing facilities, but funding for this program has never been appropriated.

State renewable energy policies can be a significant source of value for qualifying hydropower projects.

More than half of the states (29) have Renewable Portfolio Standards (RPS) and an additional eight states have voluntary renewable portfolio goals. Some of the RPS have been a significant source of value for qualifying hydropower projects.⁷⁹ This has been particularly true for small hydropower projects in Northeastern states, with renewable energy credit (REC) prices driven by stringent qualification standards for hydropower in the Class I tier of the Massachusetts Renewable Portfolio Standard (RPS). The value of Class I RECs in Massachusetts had reached as high as \$60/MWh in 2015—a major incentive for the development of eligible hydropower projects (incremental efficiency improvements or the powering of NPD or conduits less than 30 MW). However, the value of RECs in the Massachusetts market has fallen to a low of approximately \$20/MWh in 2017 (O’Shaughnessy, 2017). Additionally, these prices are anticipated to remain low or fall in future years in the absence of additional policy intervention in the form of more stringent RPS targets (Synapse, 2017). These sustained low prices likely eliminate a regional driver of small hydropower development. However, at high enough levels of renewable growth, RPS policy could theoretically induce additional growth in PSH by creating additional system balancing needs.

Additionally, although the price of voluntarily purchased green power (such as that by corporate buyers or electric utility green power programs) has always been much lower than that in state compliance markets, its value has also fallen from highs of more than \$1/MWh to a current low of \$0.35/MWh (O’Shaughnessy, 2017).

78 At the present inflation-adjusted rate of 2.3 cents/kWh, the \$750,000 per project cap limits full incentive payments to the first ~33,000 MWh of production per year—the equivalent of generation from a 7.5 MW project with a 50% capacity factor.

79 As discussed more extensively in the Hydropower Vision (DOE, 2016) and the 2014 Hydropower Market Report (Uriá-Martínez et al., 2015), many RPS programs limit eligibility for the RPS to hydropower meeting certain criteria—such as those built after a certain date or under a specific size threshold. Generally, most hydropower in the United States is not eligible at the top tiers of state RPS programs.

Some states (e.g., Colorado and Vermont) have also implemented programs to assist small hydropower developers in navigating the permitting process by streamlining specific permitting steps (e.g., expedited water rights review process for some small conduit hydropower projects in Oregon), or providing financial incentives to small hydropower development in the form of low interest loans, grants, and feed-in tariffs (Curtis et al., 2017).

Upcoming potential changes in policies related to Canada and its hydropower resources could impact the value of U.S. hydropower for decades to come.

In the context of hydropower, the United States and Canada share more than just a political border, with boundary-spanning rivers and grid interconnections linking together the values of water and electricity for hydropower assets in both countries.

In the Pacific Northwest, hydropower operations are uniquely integrated with hydropower and water resource decisions in Canada (British Columbia) as governed by the Columbia River Treaty. The treaty was implemented in 1964 to jointly develop infrastructure and coordinate operations within the Columbia River Basin to reduce flooding and improve hydropower generation. For its role in preventing downstream flooding in the United States and coordinating water releases to optimize basin-wide electricity generation, Canada receives half of the incremental downstream power benefits created by its storage reservoirs, a provision known as the “Canadian Entitlement,” which is valued at between \$200M and \$350 million per year. The value of this entitlement is supplied by the ratepayers of Bonneville Power Administration (Bonneville) customers and the Mid-Columbia Public Utility Districts, split approximately 73% and 27%, respectively (U.S. Entity, 2013a).

The provisions of the Columbia River Treaty were set and unchanged for the first 60 years. However, on September 14, 2015, both countries became able to terminate most treaty provisions with a 10-year notice (earliest effective date September 15, 2024). While both parties desire changes to the treaty, neither has chosen to unilaterally terminate its provisions, instead choosing to begin a renegotiation process in early 2018. A key issue from the U.S. perspective—as indicated by recommendations made by Bonneville and USACE (U.S. Entity, 2013b)—is revisiting the Canadian entitlement payment, which is considered to overestimate power benefits (Kirkpatrick, 2013) as it does not take into account the operating realities of the Federal Columbia River Power system related to environmental regulation and integration of variable renewables. Treaty renegotiation could lead to entitlement payments that more closely align to the value of power from modern coordinated rivers operations.

Elsewhere in the United States, a host of electricity transmission projects that would bring additional Canadian hydropower to electricity markets in the Northeast and Midwest are at various planning stages.⁸⁰ Table 8 lists the projects that have received a DOE presidential permit—required for construction, operation, and interconnection of electric facilities crossing the U.S. border—in recent years. Presidential permits are a noteworthy milestone for a project to achieve, but authorizations from other federal and state agencies are also required before starting construction. Projects to date have all contended with some degree of opposition arising from local residents, environmental non-governmental organizations, and tribes regarding environmental impacts. To address these concerns, project developers have proposed rerouting some sections, as well as burying or submerging sections or the entire transmission line to mitigate visual impacts.

80 The Great Northern Transmission Line project is an alternating current line. The rest are direct current lines.

Table 8. Proposed Transmission Projects Crossing Canada-U.S. Border with Presidential Permits

Transmission project	Developer	Proposed route	Proposed capacity (MW)	Presidential permit issuance date
Champlain Hudson Power Express	Transmission Developers Inc.	Canada-U.S. border at Lake Champlain to New York City (333 miles)	1,000	10/06/2014
Great Northern Transmission Line	Minnesota Power	Canada-U.S. border at Roseau County, MN-Grand Rapids, MN (224 miles)	883	11/15/2016
New England Clean Power Link	Transmission Developers Inc.	Canada-U.S. border at Alburgh, VT, to Ludlow, VT (154 miles)	1,000	12/05/2016
ITC Lake Erie Connector	ITC Lake Erie Connector, LLC	Canada-U.S. border at Haldimand County, Ontario, to Erie County, PA (72 miles)	1,000	01/12/2017
Northern Pass Transmission	Eversource Energy	Canada-U.S. border near Pittsburg, NH, to Franklin, NH (192 miles)	1,090	11/16/2017

Of the projects listed in Table 8, the Great Northern Transmission Line project is the most advanced, with preconstruction activities having started in 2017. If all five projects were constructed and used at full capacity, they could bring more than 40 TWh of additional Canadian hydropower to the United States each year. This volume would represent a 60% increase relative to 2016 Canadian hydropower imports of 69.2 TWh. These additional imports require not only the construction of the transmission lines but also new Canadian large hydropower plants. For instance, electricity exports on the Great Northern Transmission Line would partly come from the 695-MW Keeyask Generation Station, and Northern Pass exports would be backed by Hydro-Quebec's Romaine Complex project: four new plants totaling 1,550 MW. Both the Keeyask Generation Station and the Romaine Complex are under construction.

In the Northeastern states, Canadian hydropower—primarily from provincially owned HydroQuebec—appears as an attractive option to help meet renewable portfolio standards while ensuring affordable energy prices. Hydropower is also viewed as a good substitute for planned retirements of nuclear plants in those states and as a complement to limit dependence on natural gas.⁸¹ Recent requests for proposals in Massachusetts and New York for large-scale renewables welcomed proposals featuring baseload power provided by hydropower on its own or in combination with solar and wind capacity. In late January 2018, Massachusetts selected Northern Pass Transmission to help the state meet its clean energy goals. However, a few days later, the New Hampshire Site Evaluation Committee denied Northern Pass a construction permit. At the time of this writing, Massachusetts announced that it would continue negotiations with Northern Pass as the transmission line developers seek a rehearing on the construction permit decision. Were those efforts unsuccessful, Massachusetts would select an alternative transmission line proposal.

In the Midwest, grid reliability, energy affordability, and fuel diversity are also underlying themes behind Minnesota Power's plan to build the Great Northern Transmission Line. Minnesota Power has entered power purchase agreements (PPAs) with Manitoba Hydro for 383 MW in the proposed transmission line. These PPAs also allow for Minnesota Power to "store" excess wind energy in Manitoba Hydro's system. During hours with high wind power production and low electricity demand in Minnesota Power's system, the new transmission line would carry electricity north, which would either be stored in Canadian pumped storage facilities or result in reduced hydropower production from Manitoba Power's reservoirs during those hours.

81 <https://www.bloomberg.com/news/articles/2017-10-13/canada-wants-to-solve-u-s-nuclear-problems-with-faraway-dams>.

Policies at the federal and state level, as well as ISO market design, are seeking to reward generators depending on their contributions to grid reliability and flexibility.

To maintain reliability, particularly in those U.S. regions with higher variable renewable penetrations, flexible resources able to quickly start, stop, and modify their output are increasingly valuable. Market operators are developing methodologies to quantify their flexibility needs and introducing products to remunerate the flexible capacity to meet those needs. For instance, in 2016, the Midwest ISO implemented a ramp product and CAISO introduced Flexible Ramp Up and Flexible Ramp Down uncertainty awards to correct for hourly generation and load forecasting errors.

Natural gas is typically the technology providing the bulk of the flexibility although, as shown in Section 4, average one-hour ramps per megawatt of installed capacity are larger for hydropower than natural gas in all ISOs/RTOs. However, some states are starting to indicate preferences toward reducing their dependence on natural gas for ramping capability and meeting peak loads. Arizona introduced the concept of a clean peak standard, although it has not yet implemented it. In an October 2017 state senate bill, California is requesting its utilities to consider the role of existing renewable generation, energy storage, energy efficiency, and distributed energy resources to meet ramping and peak power needs. For California, expanding the use of Pacific Northwest hydropower to ramp-up generation as solar output declines in the late afternoon would be one of the strategies to help meet that goal. As of the end of 2017, the Western Energy Imbalance Market (EIM) pools generation and transmission resources from six balancing authorities across the West for real-time trading of imbalances (i.e., the differences between day-ahead forecasts of electricity supply and demand and real-time needs). Through participation in the Western EIM since its launch at the end of 2014, CAISO has access to an expanded set of hydropower resources to help meet its peak power demands.

In those markets where flexibility is increasingly prized, there might be incentives to build highly flexible PSH plants, invest in other storage options, or adjust the operations of existing hydropower assets to the extent possible given the other purposes dams serve and environmental constraints. Regional differences regarding the limitation of hydropower's participation in renewable portfolio standards also continue to be an important consideration in determining which type of hydropower projects to build and where.

7. Conclusions and Further Work

Hydropower represents 7% of U.S. electricity generation capacity and produced 6.3% of electricity in the United States in 2014-2016. PSH continues to provide the bulk (95%) of electrical energy storage capacity. More than 2 GW of new capacity have been added to each of the U.S. hydropower and PSH fleets from 2006 and 2016. Both hydropower and PSH contribute to the grid not only electrons but a range of services, from frequency regulation to spinning reserves and black start, that are vital to ensure U.S. electric grid flexibility, reliability, and resilience.

From 2006 to 2016, hydropower generation capacity was added to 40 NPDs and 73 conduits. In addition, five hydropower NSDs started operation in the Northwest during that period. These 118 new projects have translated into almost 600 MW of new hydropower capacity. The range of capital costs for recently completed projects is very wide (\$2,000 to \$8,000 per kilowatt) which reveals a high degree of site-specificity to the project economics of new hydropower. On the technology front, standardization and modularity to drive down development costs is one of the central avenues of ongoing research.

Along with the projects brought to completion during the last decade, many more have been evaluated but not pursued due to unfavorable market conditions or a variety of site-specific challenges. In line with the generally lower wholesale market prices in recent years, the price that utilities are willing to pay for hydropower from new facilities developed by independent power producers has decreased in recent years relative to purchase agreements initiated a decade ago or longer. Notwithstanding that price decline in many regions, the median price paid by utilities for hydropower has remained higher than the average paid across all technologies.

Seven bills related to the hydropower authorization process were introduced in the U.S. Congress in 2017. They are largely geared towards process improvements for projects involving hydropower additions to existing NPDs and conduits, as well as closed-loop PSH projects, likely related to the fact that these are the predominant project types in the current development pipeline. An important initiative that has not involved legislative changes is the 2016 FERC-USACE MOU introducing a two-phase synchronized process to obtain the FERC license and USACE permits required for development at USACE-owned NPDs. It will likely take some years for this process to be fully implemented and operationalized within the agencies but, if successful, it could decrease the duration of the permitting process for these projects and, in turn, encourage more NPD development at USACE dams.

About 70% of total capacity increase in U.S. hydropower and 98% of capacity increase in U.S. PSH from 2006 to 2016 have resulted from investments to upgrade existing hydropower plants. Based on tracked capital expenditure projects by Industrial Info Resources, North America leads the world ranking in \$/installed kilowatt of R&U investment. The United States has ongoing or planned R&U projects for 143 plants that account for almost 50% of the total installed capacity. Despite the strong R&U investment pipeline or—since units on planned outage undergoing R&U influence average fleet availability figures—maybe partly as a result of it, average unit availability has decreased over the last decade. This trend is particularly concerning for small (<10 MW) units since their availability decrease is primarily due to an increase in unplanned outages.

A new theme in this edition of the Hydropower Market Report has been documenting hydropower flexibility. Data on one-hour ramping and correlation with net load for all ISO/RTO markets clearly indicate that hydropower provides substantial load-following flexibility. However, further data collection and analysis are needed for a comprehensive picture of the broader contribution of hydropower to grid services (e.g., frequency regulation, voltage support, spinning reserves). Grid operators are increasing their demand for these services, particularly in parts of the country with high penetration of variable renewables. However, providing them has a short-run opportunity cost for hydropower owners if capacity reserved for grid service provision could instead generate electricity at a higher price. In the long-run, provision of load following flexibility or frequency regulation, which require frequent ramping and starts/stops, accelerates the wear and tear of turbine-generator units and translates in increased O&M costs. Thus, the revenue offered for grid services should compensate those costs for hydropower operators to be willing to provide the optimal, from a grid or social perspective, level of grid services.

Based on questions arising from the analysis conducted for this report and feedback from reviewers of an initial draft of this document, the following topics arise as prime candidates for further work:

- » **Tracking the effectiveness of hydropower authorization process innovations**, particularly the implementation of the FERC-USACE MOU, by measuring changes in attrition rate and permitting process length relative to those observed in FERC dockets opened between 2000 and 2016.
- » **Evaluating the extent of hydropower participation in provision of grid services**. The technical capability by many hydropower plants and PSH to provide ancillary services is well documented. However, actual participation in ancillary services markets and fraction of total revenue that provision of those services can represent is less understood. An important element of this analysis would be data collection and analysis of ancillary service prices in ISO/RTO markets and ancillary service tariffs in other regions to assess how much variability is there in the prices of these services across the country and why.
- » **Exploring the sources of rising O&M costs** and identifying best O&M practices, particularly for the small hydropower segment that has experienced the most pronounced increased in unforced outages during the last decade. The extent to which changing O&M costs are at all related to shifting operational decisions for hydropower plants, related to increased provision of grid flexibility and reliability services, is also of interest.
- » **Identifying the reasons for the recent decline in PSH generation** shown in Figure 30. An important question to answer is whether this decline responds to a decrease in peak/off-peak price differentials in the ISO/RTO markets where many PSH plants participate or to a change in mode of operation whereby PSH owners choose to dedicate more hours/more capacity to provision of grid services. The answer could be different for different U.S. regions.
- » In-depth analysis of **relicensing trends**. Based on the expiration dates of existing licenses, FERC predicts that hundreds of hydropower plants will submit relicense applications during the next decade. Obtaining a relicense is a major milestone for existing facilities; it has implications for the timing of R&U investment decisions and it can result in new constraints that influence future mode of operation for the hydropower fleet. Thus, exploring trends in the duration and outcomes of recent relicense proceedings can produce useful information for hydropower owners seeking a relicense in the near future and other hydropower stakeholders involved in the relicensing process.

To summarize, the U.S. hydropower and PSH fleets have both experienced notable growth in the past decade, and the development pipeline of additional projects contains hundreds of projects in various stages of planning and permitting (with large amounts of PSH projects at early stages of planning being particularly significant). New data have consistently highlighted the important roles that hydropower and PSH play in grid flexibility, reliability and resilience. Significant investments are being made to upgrade and modernize existing plants, but challenges still remain for the U.S. hydropower fleet in the form of rising O&M costs and short-term declines in unit availability, likely due both to its maturity (with a capacity-weighted average plant age of 56 years) and shifting operational decisions as the grid continues to change and evolve.

In conclusion, the authors of this report would like to again thank all of the various contributors to this effort, especially the dozens of external expert reviewers whose feedback and insights on the information presented was so valuable.

Appendix: Data Sources

Industrial Info Resources

Industrial Info Resources (IIR) is a market research firm that provides data and analytics on global electricity, energy, and industrial markets.

IIR's global dataset of active hydropower plants includes 5,834 hydropower and 146 PSH plants with combined capacities of 928 GW and 96 GW respectively. Based on statistics from the Energy Information Administration combined with 2016 capacity additions compiled by the International Hydropower Association, total hydropower capacity at the end of 2016 being 1,096 GW worldwide for hydropower and 153 GW for PSH. Therefore, the IIR database covers 85% of global hydropower and 63% of global PSH capacity.

FERC Form 1

FERC Form 1 data on O&M costs correspond to account numbers 535 through 545 within the Electric Operation and Maintenance Expenses schedule.

FERC Form 1 data on purchased power agreement (PPA) prices is contained in the Purchased Power schedule.

NERC Generating Availability Data System (GADS)

The sample size for the NERC GADS dataset is not constant over time. Until 2011, hydropower plant owners were reporting to NERC on a voluntary basis. Reporting became mandatory for units greater than 50 MW in 2012 and for units greater than 20 MW in 2013. Figure 46 shows the evolution of sample size segmented by unit type and size category.

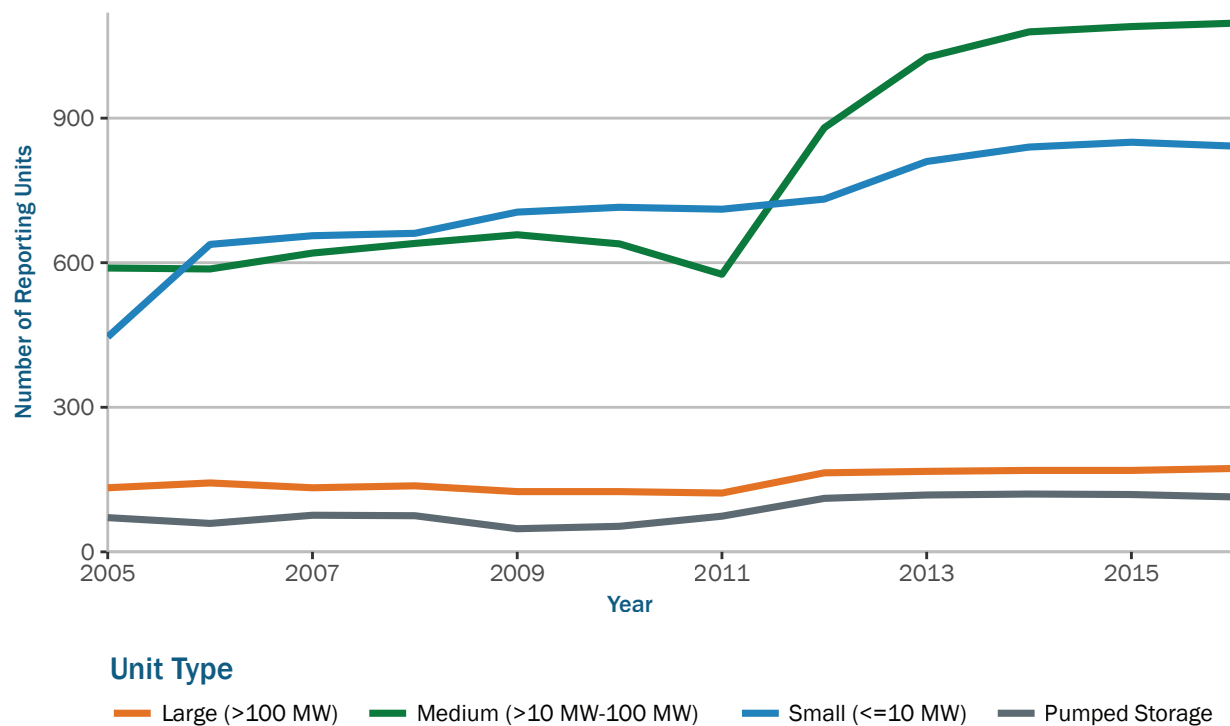


Figure 46. Number of units reporting to NERC GADS by type and size

Source: NERC Generating Availability Data System

The pc-GAR software used to query NERC GADS data is meant to keep plant names anonymous. Queries are only allowed for groups of plants large enough to preserve anonymity. For each query, it is possible to see which units are included but individual plants cannot be associated to specific unit-level results. It would require a significant amount of reverse engineering the data to identify the subset of units that have reported continuously since 2005. Since the figures presented in Section 4 are not based on a constant sample of units, keeping in mind the changes in sample composition over time is important for interpreting the trends observed in availability factors, hourly breakdown of operational status, and number of unit starts. For Medium units, changes in performance metrics in 2012–2013 are likely a result of new reporting units being different from those that have been included in the sample since 2005.

Even though pc-GAR provides an option to segment output by unit type that is meant to distinguish between regular hydropower units versus pumped storage hydropower, a considerable fraction of reporting units do not self-report themselves in either of those categories. Therefore, an alternative strategy was used to segment results by unit type. Units reporting zero pumping hours in a year are classified as regular hydropower units and units with one or more hours of pumping are classified as pumped storage units. Based on the lists of units included in the queries for the two types of units segmented based on pumping hours, a few units with zero pumping hours that are actually PSH units but were out of service are incorrectly classified. However, the number of misclassified units is small enough that it should not affect the results for the large hydropower sample.

ISO/RTO data

Three types of data were obtained from ISO/RTO websites: hourly (or intra-hourly) fuel mix, installed capacity for different generation types, and hourly load.

For those ISOs/RTOs that only post fuel mix data for intervals of less than one hour (ERCOT, ISONE, NYISO, and SPP), the one-hour ramps are computed as the change in generation from the first reported interval of hour h to the first reported interval of hour $h + 1$.

Generation capacity mix numbers vary by year or season and year depending on ISO/RTO. Reported capacity numbers include all generation units registered to participate in each of the markets. They do not account for plant outages changing actual available capacity in each period.

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Norris Dam hydropower plant, TN
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