International Energy Agency

Hydropower Special Market Report

Analysis and forecast to 2030

INTERNATIONAL ENERGY AGENCY

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Revised version, July 2021. Information notice found at: www.iea.org/corrections

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Abstract

The first ever IEA market report dedicated to hydropower highlights the economic and policy environment for hydropower development, addresses the challenges it faces, and offers recommendations to accelerate growth and maintain the existing infrastructure. This report presents ten-year capacity and generation forecasts for reservoir, run-of-river and pumped storage projects across the globe, based on bottom-up country and project-level monitoring.

Foreword

A little over two years ago, at the 7th World Hydropower Congress in Paris, I underscored the huge untapped potential of hydropower – the world's largest source of clean and flexible electricity generation – particularly in emerging and developing economies. I said then that the voice of hydropower was not being heard loudly enough, and I promised that the IEA would be a strong voice for the hydropower community, notably by making hydropower the focus of our *Renewables 2020* market report.

We did not know then that a global pandemic in early 2020 would deliver a shock of historic proportions to our societies and economies. Today, I'm proud that despite the disruptions we faced in 2020, we are now delivering on our promise of two years ago with this *Hydropower Special Market Report*. And I thoroughly believe it is worth the wait. This special report is the world's first study to provide detailed global forecasts to 2030 for the three main types of hydropower: reservoir, run-of-river and pumped storage facilities.

The report shows that some things have not changed with the Covid-19 crisis. It finds that there is still a huge amount of hydropower potential worldwide that remains untapped despite being economically viable. This potential is particularly strong in emerging economies and developing economies, where demand for new energy supplies continues to expand rapidly and many people still lack access to reliable energy services. If it is developed sustainably, hydropower can bring major benefits to energy systems in many countries.

The report's forecast unfortunately shows that, based on today's policy settings, the growth of hydropower globally is set to slow this decade. This is something the world can ill afford. As our report highlights, hydropower is the forgotten giant of low-carbon electricity; it produces more of it than any other source worldwide. And hydropower's critical contribution clean energy transitions is not limited to the huge amounts of renewable electricity it produces – its capabilities for providing flexibility and storage for electricity systems are also unmatched, making it a natural enabler for integrating greater amounts of wind and solar power.

This rare combination of attributes cannot be ignored. The IEA's recent *Net Zero by 2050: A Roadmap for the Global Energy Sector* makes it clear that the 2020s have to be the decade of massive deployment of all clean and efficient energy technologies if the world is to have a chance of limiting global warming to 1.5 °C.

Hydropower is unquestionably one of those technologies, but governments must devote significant policy attention to enabling it to overcome some of the major difficulties it currently faces. And all hydropower projects need to meet high standards for sustainability to ensure the energy and climate benefits they can bring are not undermined by negative environmental and social side effects.

The gap between rhetoric and action remains a major issue today. Despite encouraging pledges by more and more governments to reach net-zero emissions by mid-century, climate ambitions are not yet backed up by credible policies to drive down emissions. One concrete step governments can take to start closing this gap is to put hydropower squarely back on the energy and climate policy agenda. That is one of seven priority areas for action set out in this report, which I hope will prove useful for policy makers seeking to build a clean and secure energy future.

Finally, I would like to thank Heymi Bahar and the team of IEA colleagues who have worked extremely hard, with the support of Paolo Frankl, to fulfil the promise I made to the hydropower community in May 2019.

Dr Fatih Birol

Executive Director

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Acknowledgements, contributors and credits

This study was prepared by the Renewable Energy Division in the Directorate of Energy Markets and Security. Heymi Bahar was the project manager and directed the report. He designed and co-ordinated the study along with Yasmina Abdelilah, who also led the analytical framework.

The report benefited from analysis, drafting and input from multiple colleagues. The authors of the report were, Yasmina Abdelilah, Heymi Bahar, François Briens, Piotr Bojek, Trevor Criswell, Kartik Veerakumar and Grecia Rodríguez who was also responsible for data management. The report also benefited from analysis, data and input from Chenlu Cheng, Andrea Dertinger and Kazuhiro Kurumi.

Craig Hart and Peerapat Vithayasrichareon from the IEA Renewables Integration and Secure Electricity (RISE) Unit contributed to the analysis and drafting on flexibility. Jinsun Lim and Luca Lo Re from the Energy and Environment Division conducted the analysis and drafted the section on the impact of climate change on hydropower generation.

Paolo Frankl, Head of the Renewable Energy Division, provided strategic guidance and significant input to this work. Valuable comments, feedback and guidance were provided by other senior management and numerous other colleagues within the IEA, in particular, Keisuke Sadamori, Laura Cozzi, Laszlo Varro and Peter Fraser.

Other IEA colleagues who have made important contributions to this work include:

Lucila Arboleya Sarazola, Praveen Bains, Davide d’Ambrosio, Pablo Gonzalez, Shai Hassid, César Alejandro Hernández Alva, Randi Kristiansen, Ryszard Pospiech and Brent Wanner.

Timely data from the IEA Energy Data Centre were fundamental to the report, with particular assistance provided by Mathilde Daugy, Julia Guyon, Nick Johnstone, Samantha Mead, Julian Prime, Céline Rouquette, Roberta Quadrelli and Aloys Nghiem and the data science team for their work on scrappers.

This work benefited from extensive review and comments from the IEA Standing Group on Long-Term Co-operation, IEA Renewable Energy Working Party, members of the Renewable Industry Advisory Board (RIAB) and experts from IEA partner countries and other international institutions. The work also benefited from feedback by the IEA Committee on Energy Research and Technology.

Special thanks go to the IEA Hydropower Technology Collaboration Programme, and the International Hydropower Association for their valuable guidance on the design process and extensive review comments.

Valuable input was provided by Alex Beckitt, Niels Nielson, and Atle Harby (IEA Technology Collaboration Program on Hydropower), Alex Campbell, Joao Costa, Samuel Law, David Samuel, and Nicholas Troja (International Hydropower Association), Angela Africano (GE Renewables), and Richard Taylor (RMT Renewables Consulting Ltd).

Many experts from outside of the IEA provided valuable input and reviewed this report. They include:

Countries

Canada (Natural Resources Canada), China (Energy Research Institute – ERI), European Union (European Commission – DG Energy), Japan (METI, Institute of Energy Economics), Norway (Ministry of Petroleum and Energy), Switzerland (Federal Office of Energy), Turkey (Ministry of Energy), United States (Department of Energy) and Zambia (Ministry of Energy).

Other organisations

Andritz, Australian National University, BBK, École polytechnique fédérale de Lausanne (EPFL), Électricité de France (EDF), Electric Power Development Company (JPOWER), Electric Power Research Institute (EPRI), ENI, European Renewable Energy Foundation (EREF), Eurelectric, General Electric Renewables (GE Renewables), Hydro Tasmania, Hydropower Europe, Iberdrola, International Finance Corporation (IFC), International Hydropower Association (IHA), International Renewable Energy Agency (IRENA), KfW Development Bank, Latvenergo, Learning Hydro, Limak Holding- Energy, McWilliams Energy, National Hydropower Association (NHA), National Renewable Energy Laboratory (NREL), Oak Ridge National University, Renewables Consulting, REN21, Rio de Janeiro State University (UERJ), RMT Renewables Consulting Ltd, RWE, United Nations Industrial Development Organization (UNIDO), University of Cambridge, Verbund Hydro Power, Vestas Wind Systems, Vienna Technical University, Voith, World Bank and Cedric Philibert.

The authors would also like to thank Kristine Douaud for skilfully editing the manuscript and the IEA Communication and Digital Office, in particular, Jad Mouawad, Head of CDO, and Jon Custer, Astrid Dumond, Merve Erdem, Christopher Gully, Jethro Mullen, Julie Puech, Magda Sanocka, Rob Stone, Therese Walsh, and Wonjik Yan for their assistance. In addition, Ivo Letra from the Office of Management and Administration supported data management.

Questions or comments?

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Executive summary

Hydropower is the forgotten giant of low-carbon electricity

Hydropower is the backbone of low-carbon electricity generation, providing almost half of it worldwide today. Hydropower's contribution is 55% higher than nuclear's and larger than that of all other renewables combined, including wind, solar PV, bioenergy and geothermal. In 2020, hydropower supplied one sixth of global electricity generation, the third-largest source after coal and natural gas. Over the last 20 years, hydropower's total capacity rose 70% globally, but its share of total generation stayed stable due to the growth of wind, solar PV, coal and natural gas.

Emerging and developing economies have led global hydropower growth since the 1970s, mainly through public sector investments in large plants. Today, hydropower meets the majority of electricity demand in 28 emerging and developing economies, which have a total population of 800 million. In those countries, it has provided a cost-effective way to expand electricity access. In advanced economies, however, the share of hydropower in electricity generation has been declining and plants are ageing. In North America, the average hydropower plant is nearly 50 years old; in Europe, the average is 45 years old. These ageing fleets – which have provided affordable and reliable renewable electricity on demand for decades – are in need of modernisation to ensure they can contribute to electricity security in a sustainable manner for decades to come.

Hydropower plants also make a major contribution to the flexibility and security of electricity systems. Many hydropower plants can ramp their electricity generation up and down very rapidly compared with other power plants such as nuclear, coal and natural gas – and hydropower plants can also be stopped and restarted relatively smoothly. This high degree of flexibility enables them to adjust quickly to shifts in demand and to compensate for fluctuations in supply from other electricity sources. This makes hydropower a compelling option to support the rapid deployment and secure integration into electricity systems of solar PV and wind, whose electricity production can vary depending on factors like the weather and the time of day or year. With its ability to supply large amounts of low-carbon electricity on demand, hydropower is a key asset for building secure and clean electricity systems. Today, hydropower plants account for almost 30% of the world's capacity for flexible electricity supply, but they have the potential to provide even more.

Strong sustainability standards are vital to unlock hydropower's huge potential

Globally, around half of hydropower's economically viable potential is untapped. The potential is particularly high in emerging economies and developing economies, reaching almost 60%. Over the life cycle of a power plant, hydropower offers some of the lowest greenhouse gas emissions per unit of energy generated – as well as multiple environmental benefits.

Governments have an important role in ensuring hydropower's potential is realised sustainably. Robust sustainability standards and measures are needed to increase investor confidence and gain public acceptance. Today, environmental assessments of hydropower plants can be very long, costly and risky, which can deter investment. Therefore, hydropower projects need to meet clear and widely accepted sustainability standards in order to make them viable. Ensuring that hydropower projects adhere to strict guidelines and best practices can minimise sustainability risks while maximising social, economic and environmental advantages. This approach also reduces lead times for projects.

Better visibility on revenues is key to attract investment at scale

Policy measures that provide more certainty on future revenues can reduce investment risks and ensure the economic viability of hydropower projects. Since the 1950s, more than 90% of hydropower plants have been developed under conditions providing revenue certainty through power purchase guarantees or long-term contracts. This has happened in both vertically integrated and liberalised electricity markets. Today, challenges concerning complex permitting procedures, environmental and social acceptance, and long construction periods can lead to higher investment risks. In advanced economies, the business case for hydropower plants has deteriorated due to declining electricity prices and lack of long-term revenue certainty. Long-term visibility on revenues, especially for large-scale hydropower projects with long lead times, reduces financing costs significantly and increases project viability, thereby facilitating investment. This is particularly important when the private sector is involved.

Without major policy changes, global hydropower expansion is expected to slow down this decade

Global hydropower capacity is set to increase by 17%, or 230 GW, between 2021 and 2030. However, net capacity additions over this period are forecast to decrease by 23% compared with the previous decade. The contraction results from slowdowns in the development of projects in the People's Republic of China ("China"), Latin America and Europe. However, increasing growth in Asia Pacific, Africa and the Middle East partly offsets these declines.

The IEA is providing the world's first detailed forecasts to 2030 for three types of hydropower: reservoir, run-of-river and pumped storage plants. Reservoir hydropower plants, including dams that enable the storage of water for many months, account for half of net hydropower additions through 2030 in our forecast. Cost-effective electricity access, cross-border export opportunities and multipurpose use of dams are the main drivers of the expansion of reservoir projects. Pumped storage hydropower plants store electricity by pumping water up from a lower reservoir to an upper reservoir and then releasing it through turbines when power is needed. They represent 30% of net hydropower additions through 2030 in our forecast. The increasing need in many markets for system flexibility and storage to facilitate the integration of larger shares of variable renewables drives record growth of pumped storage projects between 2021 and 2030. Run-of-river hydropower – which generates electricity through natural water flow with limited storage capability – remains the smallest growth segment because it includes many small-scale projects below 10 MW.

China is set to remain the single largest hydropower market through 2030, accounting for 40% of global capacity growth in our forecast. However, China's share of global hydropower additions has been declining since its peak of almost 60% between 2001 and 2010. China's pace of hydropower development has slowed due to growing concerns over environmental impacts and the decreasing availability of economically attractive sites for large projects. In India, the world's second-largest growth market, new long-term targets and financial incentives are expected to unlock a large pipeline of previously stalled projects.

Growing electricity demand and export opportunities are driving faster hydropower expansion in Southeast Asia and Africa. The Lao People's Democratic Republic ("Lao PDR") and Nepal are developing projects for exporting electricity. Sub-Saharan Africa is expected to record the third-largest growth in hydropower capacity over the next decade, owing to large untapped potential and the need to increase electricity access at a low cost. Hydropower development in

Brazil, which has historically driven the expansion of capacity in Latin America, has slowed because of the limited availability of economically viable sites, the need for diversification, and environmental concerns. Going forward, Colombia and Argentina are set to lead hydropower growth in Latin America. Turkey's hydropower development, which already has strong momentum, is expected to drive the largest expansion in capacity in Europe over the coming years. And in North America, electricity export opportunities are set to spur moves to realise some of Canada's untapped hydropower potential.

Chinese investment accounts for most hydropower growth in emerging and developing economies

Over half of all new hydropower projects in sub-Saharan Africa, Southeast Asia and Latin America through 2030 are set to be either built, financed, partially financed or owned by Chinese firms. China's role in hydropower development is largest in sub-Saharan Africa, where it is expected to be involved in nearly 70% of new capacity between now and 2030. This includes the largest hydropower project currently under construction on the continent, the Grand Ethiopian Renaissance Dam. In Asia, excluding India, nearly 45% of all hydropower plant capacity that is set to be built through 2030 involves a Chinese company. Pakistan and Lao PDR are expected to see the largest Chinese contributions in the form of financing or construction. In Latin America, over 40% of hydropower expansion is forecast to have Chinese involvement, including notable investments in Argentina, Colombia and Peru.

More broadly, over 75% of new hydropower capacity worldwide through 2030 is expected to come in the form of large-scale projects in Asia and Africa commissioned by state-owned enterprises. In vertically integrated and single-buyer markets – in China and Africa, for example – the role of the public sector remains dominant. In Latin America and Europe, some countries provide support policies like auctions and feed-in tariffs (FiTs) that lead to higher shares of private sector investment in hydropower plants.

The modernisation of ageing hydropower plants is necessary to maintain reliable and flexible power supplies

Between now and 2030, USD 127 billion – or almost one-quarter of global hydropower investment – will be spent on modernising ageing plants, mostly in advanced economies. Work on existing infrastructure – such as the replacement, upgrade or addition of turbines – will account for almost 45% of all hydropower capacity installed globally over the period. In North America and Europe, modernisation work on exisiting plants is forecast to account for almost 90% of total hydropower investment this decade. Overall, this spending on modernising plants helps global hydropower investment to remain stable compared with last decade.

However, projected spending on existing plants is not enough to meet the global hydropower fleet's modernisation needs. By 2030, more than 20% of the global fleet's generating units are expected to be more than 55 years old, the age at which major electromechanical equipment will need to be replaced. This offers an excellent opportunity to increase the flexbility capabilities of ageing plants. The modernisation of all ageing plants worldwide would require USD 300 billion of investment between now and 2030 – more than double the amount we currently expect to be spent on this. The limited visibility on long-term revenues and the major investments needed to replace equipment can make it difficult to secure the necessary financing. The contractual arrangments and ownership model of each hydropower plant will be key factors in determining whether and when modernising the plant is bankable.

Hydropower's flexibility is critical for integrating rising levels of wind and solar PV in electricity systems

The flexibility and storage capabilities of reservoir plants and pumped storage hydropower facilities are unmatched by any other technology. Higher shares of variable renewables will transform electricity systems and raise flexibility needs. With low operational costs and large storage capacities, existing reservoir hydropower plants are the most affordable source of flexibility today. For the first time, the IEA has estimated the enormous energy value of water stored behind hydropower dams worldwide. The reservoirs of all existing conventional hydropower plants combined can store a total of 1 500 terawatt-hours (TWh) of electrical energy in one full cycle – the equivalent of almost half of the European Union's current annual electricity demand. This is about 170 times more energy than the global fleet of pumped storage hydropower plants can hold today – and almost 2 200 times more than all battery capacity, including electric vehicles.

Pumped storage hydropower plants will remain a key source of electricity storage capacity alongside batteries. Global pumped storage capacity from new projects is expected to increase by 7% to 9 TWh by 2030. With this growth, pumped storage capacity will remain significantly higher than the storage capacity of batteries, despite battery storage (including electric vehicles) expanding more than tenfold by 2030. In addition to new pumped storage projects, an additional 3.3 TWh of storage capability is set to come from adding pumping capabilities to existing plants.

Developing a business case for pumped storage plants remains very challenging. Pumped storage and battery technologies are increasingly complementary in future power systems. Each offers cost-effective storage solutions for different timescales. However, as pumped storage plants are larger and more capital-intensive, investment in them is viewed as riskier than battery projects and is not always adequately remunerated. The economic attractiveness of new pumped storage investments is weakened by a lack of long-term remuneration schemes, low prices for flexbility services, and uncertainty over electricity prices and market conditions.

Despite strong drivers, several barriers are hampering faster deployment of hydropower

New hydropower plants can provide a critical source of cost-effective and flexible low-carbon electricity. Prior to the massive cost declines of solar PV and wind, hydropower was the most competitive renewable electricity source globally for decades. Compared with other renewable options and fossil fuels, developing new large-scale hydropower plants remains attractive in many developing and emerging economies in Asia, Africa and Latin America where there is still significant untapped hydropower potential to supply flexible electricity and meet increasing demand. New pumped hydropower projects offer the lowest-cost electricity storage option. Greater electricity storage is a key element for ensuring electricity security and a reliable and cost-effective integration of growing levels of solar PV and wind.

However, the hydropower sector has a number of challenges that hamper faster deployment. New hydropower projects often face long lead times, lengthy permitting processes, high costs and risks from environmental assessments, and opposition from local communities. These pressures result in higher investment risks and financing costs compared with other power generation and storage technologies, thereby discouraging investors. In emerging and developing economies, where the largest untapped potential for new hydropower lies, the attractiveness of hydropower investments is impacted by economic risks, concerns about the financial health of utilities and policy uncertainties. In advanced economies, current market designs often do not support the business case for pumped storage plants, and there is a lack of incentives to modernise ageing fleets.

Policy support remains limited, with less than 30 countries targeting hydropower. The public sector owns and operates 70% of all hydropower capacity installed globally between 2000 and 2020. Historically, its extensive involvement in developing hydropower plants has ensured adequate remuneration and profitability in the context of long-term energy planning. Today, when the private sector is involved, well-designed government policies are crucial for reducing risks related to permitting, construction and environmental and social acceptance challenges. Beyond electricity supply, hydropower infrastructure enables multiple benefits for managing water resources needed for critical public services such as such as irrigation, flood prevention and water supplies. Acknowledging these advantages and attributing monetary value to them can significantly enhance the business case for hydropower.

Stronger policy attention and greater ambition for hydropower is needed to meet net-zero emissions goals

If governments address the hurdles to faster deployment appropriately, global hydropower capacity additions could be 40% higher through 2030, according to the accelerated case we developed for this report. In emerging and developing economies, faster growth would be possible with increased access to concessional financing and the introduction of innovative business models such as public-private partnerships that allocate risk to the appropriate stakeholder. In addition, faster growth could be possible if project delays due to environmental and social concerns are kept at a minimum through streamlining approval processes, notably in Asia and Latin America. In advanced economies, modifying market designs or introducing policies that provide revenue certainty could boost growth for pumped storage projects. All of these efforts to accelerate deployment would still need to be carried out in a manner that maintains high sustainability standards.

Reaching net-zero emissions by 2050 worldwide calls for a huge increase in hydropower ambitions. Our accelerated case provides an outlook for faster hydropower expansion based mostly on implementation improvements. But to put the world on a pathway to net zero by 2050, as set out in the IEA's recent *Global Roadmap to Net Zero by 2050*, governments would need to raise their hydropower ambitions drastically. In fact, the expansion of global hydropower capacity through 2030 would need to be 45% higher than in our accelerated case. A much stronger and all-encompassing policy approach would be required.

The IEA's 7 priority areas for governments to accelerate hydropower growth

1) Move hydropower up the energy and climate policy agenda
2) Enforce robust sustainability standards for all hydropower development with streamlined rules and regulations
3) Recognise the critical role of hydropower for electricity security and reflect its value through remuneration mechanisms
4) Maximise the flexibility capabilities of existing hydropower plants through measures to incentivise their modernisation
5) Support the expansion of pumped storage hydropower
6) Mobilise affordable financing for sustainable hydropower development in developing economies
7) Take steps to ensure to price in the value of the multiple public benefits provided by hydropower plants

Introduction

Hydropower Special Market Report 2021 is part of the *Renewable Energy Market Report* series. This special report describes the economic and policy environment for hydropower development, addresses the challenges it faces, and offers recommendations to accelerate growth and maintain existing infrastructure.

It also presents ten-year capacity and generation forecasts for reservoir, run-of-river and pumped-storage projects based on bottom-up country- and project-level monitoring. However, as technical and engineering analyses fall outside the scope of this study, hydropower technology specifications are not included.

The Hydropower Special Market Report 2021 comprises four chapters:

Hydropower today provides a summary overview of hydropower's place in the global power generation landscape and outlines fleet dynamics, ownership profiles and contributions to energy markets.

Business case for hydropower describes cost structures and competitiveness, policy and investment drivers, and challenges associated with hydropower development.

Hydropower outlook offers a bottom-up, plant-by-plant forecast of capacity additions and generation by country/region for 2021-2030, based on analysis of policy drivers and installation type (reservoir, run-of-river and pumped-storage plants). This chapter also covers investment trends and evaluates the potential impacts of climate change on hydropower generation in the long term.

Special focus: Flexibility and storage is dedicated to evaluating and understanding how the storage capabilities of hydropower technologies can help accommodate rising shares of variable renewable energy in evolving energy markets.

Policy recommendations proposes seven policy priorities to accelerate hydropower deployment.

An online data-visualisation tool also accompanies this report, allowing users to access historic and forecast capacity and generation data by country and region.

This visualisation tool can be accessed at:
https://www.iea.org/articles/hydropower-data-explorer.

Chapter 1 - Hydropower today

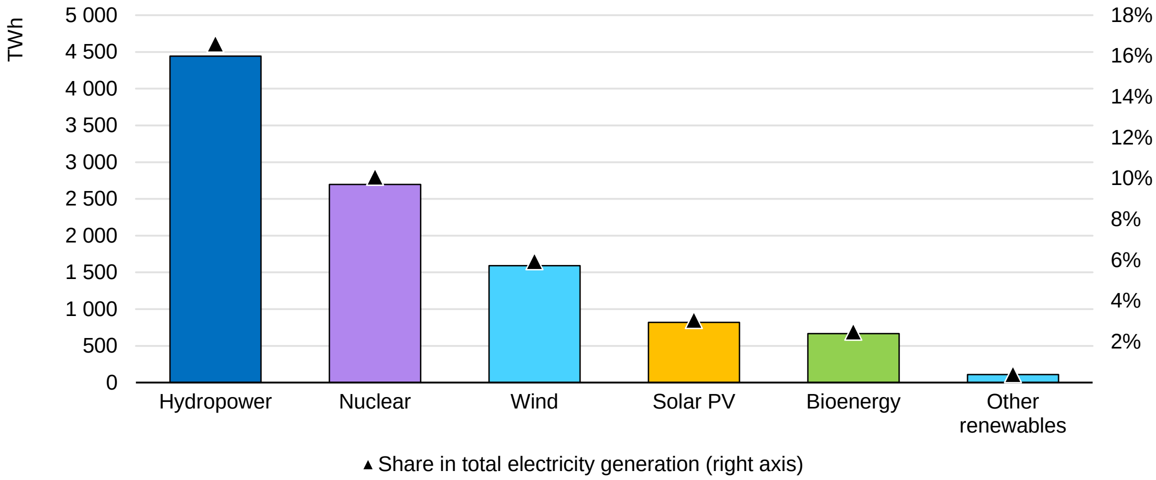
Hydropower is the largest source of low-carbon electricity

Providing one sixth of global electricity generation in 2020 (following coal and natural gas), at almost 4 500 TWh – 55% more than nuclear – hydropower technologies are the world's main source of low-carbon electricity, producing more than all other renewables-based generation combined.

Hydropower plants range in size from less than 1 MW to 22 500 MW (the world's largest plant, the Republic of China's ["China"] Three Gorges Dam). Micro-hydro power applications are mostly located in developing regions of Africa and Asia to help meet basic electricity needs and are not usually connected to the grid.

Although hydropower accounted for 17-19% of global electricity generation in the 1990s, this share has fallen slightly since the early 2000s to around 17% due to increasing amounts of wind and solar capacity and the growth of natural gas-based power generation.

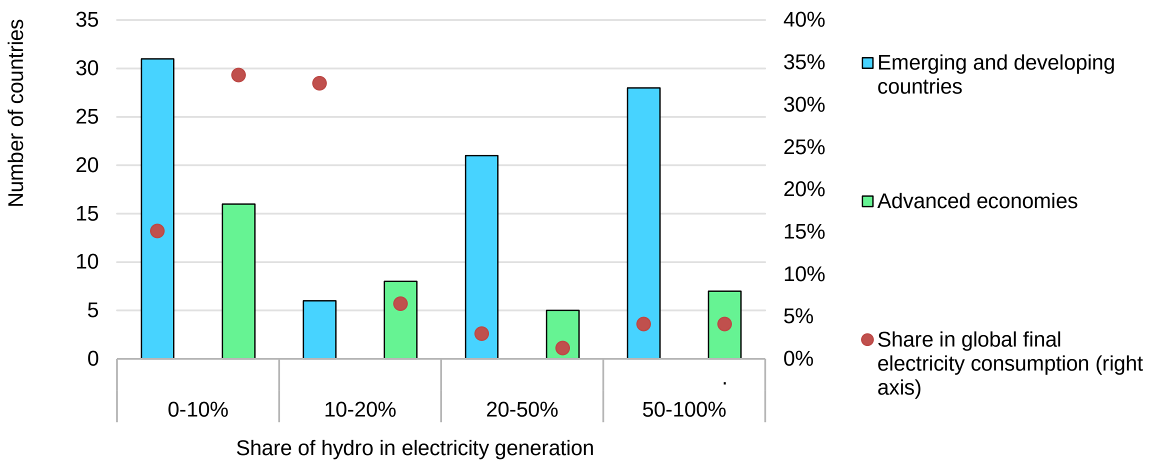
Figure 1.1 Low-carbon electricity generation by technology and shares in global electricity supply, 2020



Hydro is the backbone of many advanced, developing and emerging economies' electricity systems

In 35 countries around the world, hydropower supplies more than 50% of electricity generation. Of these 35 countries, 28 are emerging and developing economies with a total population of 800 million and rely on hydropower to cost-effectively provide most of the electricity. Realising untapped hydro potential remains a key policy priority to expand electricity access and meet growing demand in developing African and Asian countries. In the advanced economies of Norway, Canada, Switzerland and Austria, hydropower has provided the majority of power supply for decades.

Figure 1.2 Number of countries per share of hydropower in domestic electricity generation mix, 2018



Notes: Advanced economies include OECD countries, Bulgaria, Croatia, Cyprus, Malta and Romania. Emerging and developing countries include all other countries not included in the advanced economies regional grouping.
Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey shall preserve its position concerning the "Cyprus issue".
Note by all the European Union member states of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

Emerging economies and developing countries have led hydropower growth since the 1970s

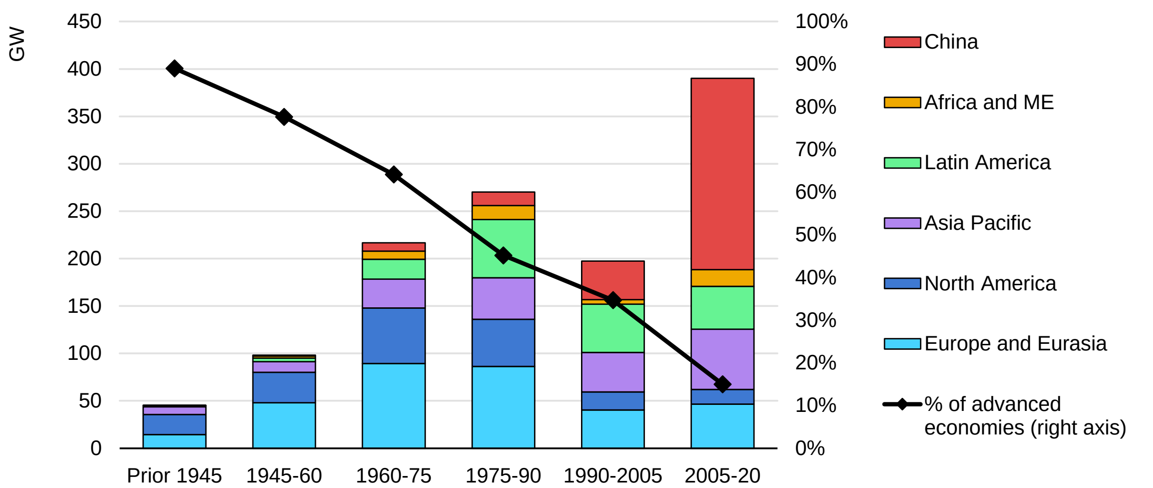
Hydropower generation is the world's oldest form of electricity production, with the United States and the United Kingdom installing the first hydropower plants in the late 19th century. Hydropower capacity (including pumped-hydro storage plants) has since risen to almost 1 350 GW in 2020, accounting for 18% of all installed power capacity globally.

Rapid economic growth and industrial development in advanced economies[1] – mostly in North America, Europe, Japan and Australia – drove hydropower capacity expansion until 1975. During this period, governments situated heavy industries adjacent to hydropower plants to optimise resources and minimise transmission costs. The Russian Federation ("Russia") and Brazil also adopted hydropower early, taking advantage of their abundant resources to cost-effectively increase electrification.

During 1975-1990, however, emerging and developing economies in Asia and Latin America increased their shares in global hydropower expansion while the share of additions in advanced economies fell below 50% for the first time. This geographical shift has persisted since 1990, with 85% of new hydro plants being constructed in emerging and developing countries in the last fifteen years. In this period, China's leadership in the hydropower market has been remarkable, with it alone responsible for 50% of global gross capacity expansion.

Outside of China, new hydropower capacity has been added in India, Brazil and some large Southeast Asian economies (mostly since 2005), while the development of large reservoir plants supports electrification in sub-Saharan Africa. In addition to providing electricity, large hydropower projects have been considered integral to regional economic development and irrigation policies in many developing countries. China has had the largest hydropower fleet in the world since 2005, followed by Brazil, the United States, Canada, Russia, Japan and India.

Figure 1.3 Hydropower gross capacity additions by region



Notes: ME = Middle East. "Advanced economies" refers to OECD member countries and non-OECD EU member states.

[1] OECD members and non-OECD EU countries.

Hydropower plants are ageing

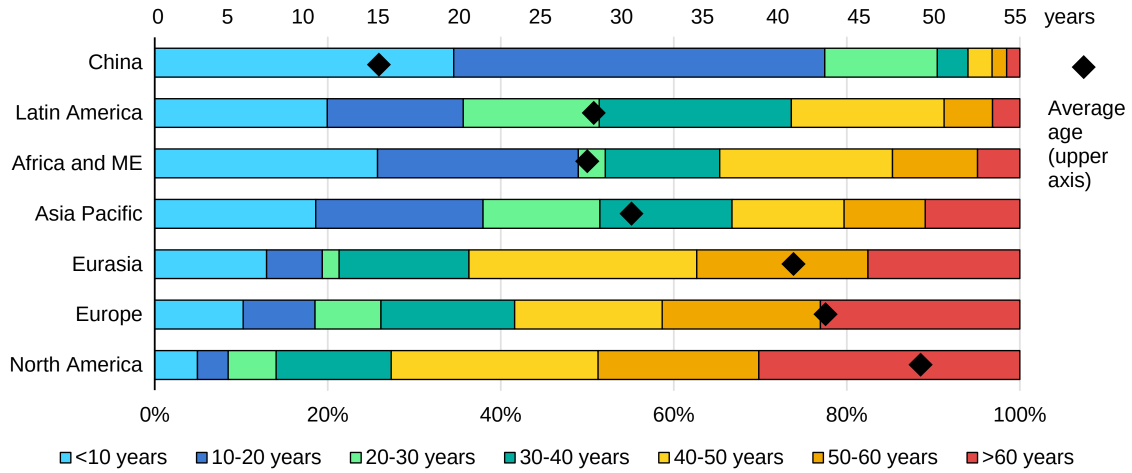
With hydropower fleets in many advanced economies dating to the large construction wave of the 1960s to the 1980s, almost 40% (476 GW) of the global fleet is at least 40 years old (today, the average age of the global fleet is 32). Regional disparities are significant, however, with North America having the oldest fleets (50 years) and China the youngest (15 years). While nearly 70% of plants in North America are 40 or more years old, in Europe and Eurasia (mainly Russia) this number is slightly lower at around 60%.

When hydropower plants are between 45 and 60 years old, major refurbishment investments are required to modernise them, improving their performance and increasing their flexibility. In countries where ageing plants provide the majority of renewable electricity, these investments are particularly important to maintain or increase output (usually by 5-10%).

In addition to renewing major equipment such as turbines and generators, investing in modernisation and digitalisation can significantly increase plant flexibility; make the plant safer; and resolve environmental and social problems such as inadequate drought management and flood control, depending on the country's regulations.

In liberalised markets, however, the type and amount of investment depends on whether developers receive enough revenue and remuneration to justify additional capital expenditures, and whether the operational losses expected during the outage/renovation period are acceptable. Advance planning is crucial for hydropower plant refurbishment, as waterflows – in addition to environmental and water regulations – may have changed since the plant first became operational and may not allow the plant to operate at historical levels.

Figure 1.4 Age profile of installed hydropower capacity, 2020



Note: ME = Middle East.

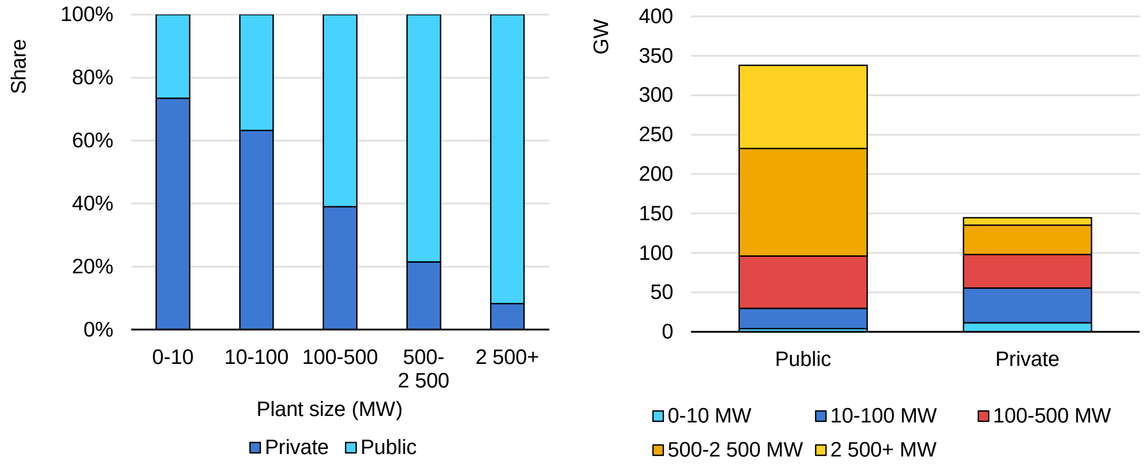
Outside of China, younger Latin American, Asia Pacific and African fleets will also require additional investment in plant refurbishment and modernisation in the next decade. Despite being young, several large-scale hydro plants in Africa and developing countries in Asia have been operating below their optimal performance level due to a lack of regular maintenance. Some plants in these regions may therefore require major refurbishment before they reach 40 years of age.

Hydropower ownership profile depends on plant size

Of the more than 10 000 new hydropower plants commissioned worldwide since 2000, nearly 70% are owned and operated by the private sector. Yet, the public sector owns over 70% of installed capacity (nearly 340 GW). There is a clear correlation between plant size and ownership profile: the larger a project's capacity, the more likely it is to be developed or sponsored by a government or government-owned utility.

Large hydropower projects require hundreds of millions to billions of dollars in investment, as well as long development periods that might not correspond with private sector expectations for returns. Local opposition and social acceptance concerns, in addition to regulatory challenges such as lengthy and complex permitting processes, can also raise project risk considerably. Furthermore, some multipurpose projects are designed to assist with flood management or be used for recreation, navigation or irrigation, which are water use and conservation areas usually managed by public authorities.

Figure 1.5 Share of ownership by plant size (left) and plant size by sector (right), 2000-2020



Source: Based on IEA (2021a), *World Energy Investment 2021*.

Private sector investment in projects of more than 500 MW occur in markets with strong policy schemes to de-risk large investments. In developing and emerging economies, public-private partnerships that can reduce project risk and make affordable financing more readily available can also stimulate large-scale plant development. In liberalised electricity markets, private businesses and investor-owned utilities own and operate multiple large-scale pumped-storage plants, as they can take advantage of arbitrage opportunities.

For small plants of less than 10 MW, private sector ownership is nearly 75%. The lower investment requirements of small plants compared with larger installations enable a greater number of companies to invest in hydropower projects. Policy mechanisms such as auctions and feed-in tariffs also encourage investment in small plants by guaranteeing a stable revenue stream and helping eliminate off-taker risk. In developing countries, governments are promoting private sector investment in small and micro plants to increase energy access and electrification.

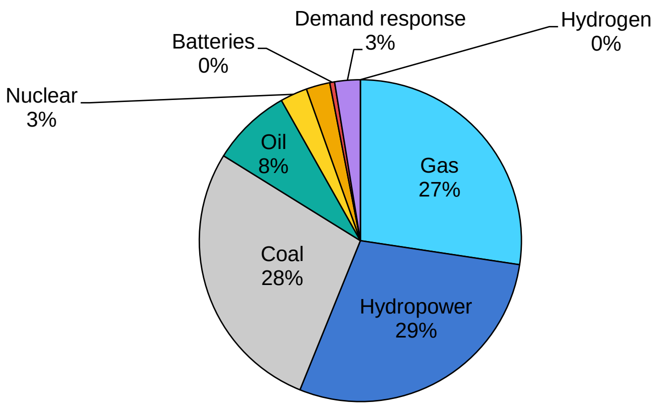
Hydropower plants are a primary contributor to system flexibility

As variable wind and solar PV installations become more widespread, power system flexibility is increasingly important. Dispatchable power plants are essential to electricity system security, and flexible generation sources have always been relied on to balance hourly, daily, monthly and seasonal demand changes – even before variable renewable technologies began generating power in unpredictable weather conditions to meet fluctuating demand.

Hydropower plants – including reservoir, run-of-river and pumped-storage – contribute to almost all grid services and provide flexible generation ranging from sub-seconds (inertia, fast-frequency response, etc.) to months and long-term storage at the same time.

Many hydropower plants can ramp up and down very rapidly and be restarted and re-stopped relatively smoothly. These characteristics make reservoir and pumped-storage plants, and to some extent run-of-river units, extremely valuable for electricity security and flexibility today. Hydropower plants currently make up almost 30% of global flexible supply capacity based on hour-to-hour ramping needs, similar to the capabilities of coal- and natural gas-fired plants.[2]

Figure 1.6 Global electricity system flexibility by source, 2020



Source: IEA (2021b), *Net Zero by 2050: A Roadmap for the Global Energy Sector*.

Reservoir hydropower plants are usually the most cost-effective option to provide supply-side flexibility in many power systems owing to their very low marginal costs and unmatched energy storage capability (see Chapter 4 for further analysis of reservoir plant capabilities). Nevertheless, their contribution to flexibility is subject to seasonal water availability and droughts, which severely limit their capabilities. Today, pumped-storage hydropower plants provide almost 85% of the world's total installed electricity storage capacity of 190 GW, and they can serve as a demand-side response resource in pumping mode.

[2] Although electricity system flexibility is quantified here by hour-to-hour ramping needs, this is only one aspect of flexibility, which also involves more instantaneous actions to maintain frequency and other ancillary services.

Chapter 2 - Business case for hydropower

Investment costs

Lower labour costs and economically viable sites attract new hydropower development in emerging markets and developing countries

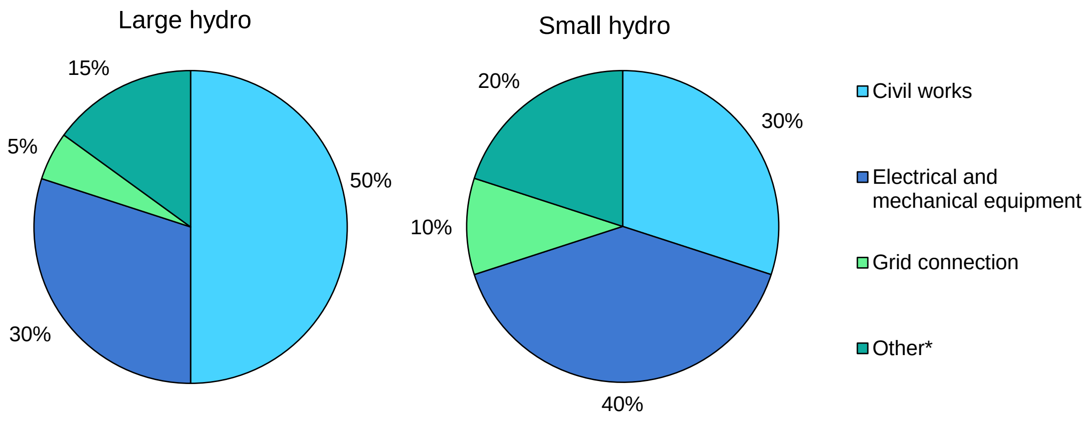
Hydropower is a mature technology with a wide-ranging cost structure that varies according to a plant's size, characteristics and location. The largest portion of a hydropower project's costs (particularly for large reservoir plants) usually goes towards intensive civil works, including earthworks, tunnelling and dam and powerhouse construction. The second-largest share of expenditures is typically for all the electro-mechanical equipment, including turbines, generators and all auxiliary systems. Many of these components are very costly because they need to be site-specific and usually cannot be mass-produced.

Although technological advances have made hydropower generation more efficient and flexible, average investment costs have largely remained unchanged in recent years and opportunities for significant cuts in the near future appear to be limited. Ongoing research and development programmes do, however, promise some cost improvements in the long term.

Access road and transmission line construction and reinforcement may also be responsible for a large portion of overall hydropower investment costs, especially for projects developed in remote locations. Furthermore, in most countries hydropower projects are subject to very rigorous and lengthy permitting processes that often take up to several years. Developing the necessary analyses, conducting scrupulous environmental impact assessments and introducing extensive environmental compensatory measures also add to the final cost.

Another important factor is the duration of the construction process, which may range from five to ten years and is often prone to delays. Such prolonged project development results in additional costs for workforce maintenance, construction management and capital engagement, common to all types of large infrastructure projects.

Figure 2.1 Typical investment cost allocation for large and small hydropower plants



* Includes planning, project development, environmental assessment, permitting, land acquisition, and social and environmental impact mitigation costs.

Notes: Small hydro = installed capacity of less than 10 MW. Large hydro = installed capacity equal to or greater than 10 MW.

Sources: Based on IRENA, World Bank and Oak Ridge National Laboratory data.

Hydropower installation costs are highly project-specific because they are determined by local hydrological conditions, terrain, geology, ecosystems and infrastructure, as well as by the purpose of the plant and its desired performance. Civil works are the primary cost component in most large-scale hydro projects, but large projects also tend to have lower overall costs per MW of installed capacity thanks to the economies of scale that can be realised. For smaller run-of-river (RoR) projects, electromechanical equipment usually accounts for the greatest share of total costs.

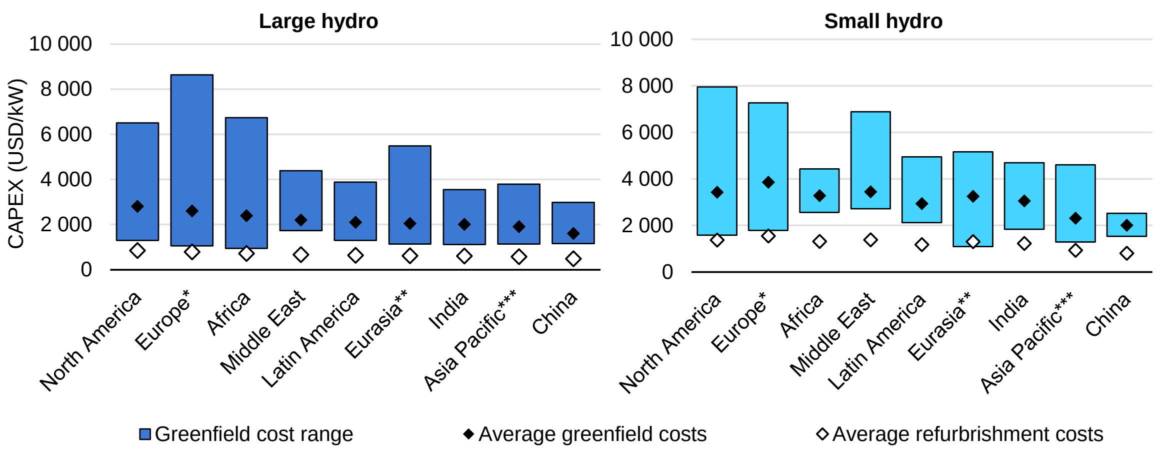
Apart from greenfield developments, an important category of hydropower investment is projects that use parts of established water management infrastructure (e.g. existing reservoirs, non-powered dams and conduits) and brownfield projects that expand operational power plants or replace their equipment. The cost of these developments is typically up to 70% lower than for new ones, as spending goes mainly towards replacing or adding electromechanical equipment.

Although total greenfield hydropower investment costs are generally between USD 1 200/kW and USD 4 500/kW,[1] the range is in fact much wider, spanning from less than USD 1 000/kW for very large plants to USD 10 000/kW for small-scale projects.

India, China and the rest of the Asia Pacific region have the lowest overall hydropower investment costs. Low labour and construction material costs reduce civil works spending in emerging economies, but other important factors are the availability of economically viable sites in suitable and easy-to-access locations, as well as relatively streamlined permitting processes.

In recent years, however, total hydropower investment costs in the Asia Pacific region have risen, especially in China, mainly due to rising labour and permitting costs, depletion of the most economical sites for large projects, and higher compensation for population displacement. Judging from projects under construction and planned, hydropower investment costs for projects to be commissioned during 2021-2030 are expected to increase 15% in China and by almost 10% in the rest of Asia Pacific.

Figure 2.2 Average overnight investment costs for greenfield and refurbished hydropower projects by region/country, 2020



*Excluding Turkey. **Including Turkey. ***Excluding China and India.
Notes: Small hydro = installed capacity of less than 10 MW. Large hydro = installed capacity equal to or greater than 10 MW.
Sources: Based on IRENA, BNEF, World Bank and Oak Ridge National Laboratory data.

Europe and North America have the highest hydropower investment costs because of relatively high labour costs, fewer undeveloped economical sites and

[1] Based on IRENA and World Bank assessments, previous IEA reports and additional research.

steep fees to mitigate impacts on the environment and existing infrastructure. In Africa, the key cost challenges are underdeveloped transport infrastructure and insufficient power transmission systems. Simply reaching the construction sites with heavy equipment and connecting hydropower plants to the grid require considerable investment.

Generation costs and competitiveness

Financing costs and capacity factors are the primary determinants of hydropower generation costs

Capital costs usually make-up 80-90% of hydropower's levelised cost of energy (LCOE), similar to other renewable energy technologies that do not require fuel inputs. Operations and maintenance (O&M) account for the remainder, which on average amounts to about 2% of the initial investment cost annually but can vary considerably among countries and individual plants. Project development costs and expected returns on investment, expressed as the weighted average cost of capital (WACC), are therefore major factors in determining hydropower generation costs.

For instance, a WACC increase of one percentage point results in 7-14% higher hydropower generation costs for a typical greenfield project.[2] The WACC, an expression of perceived investor risk and return expectations, depends on multiple factors, including overall macroeconomic and technology-specific conditions. For hydropower projects, risks associated with policy and regulatory environments, social acceptance, remuneration certainty, the financial health of off-takers and future water availability can all affect WACC rates.

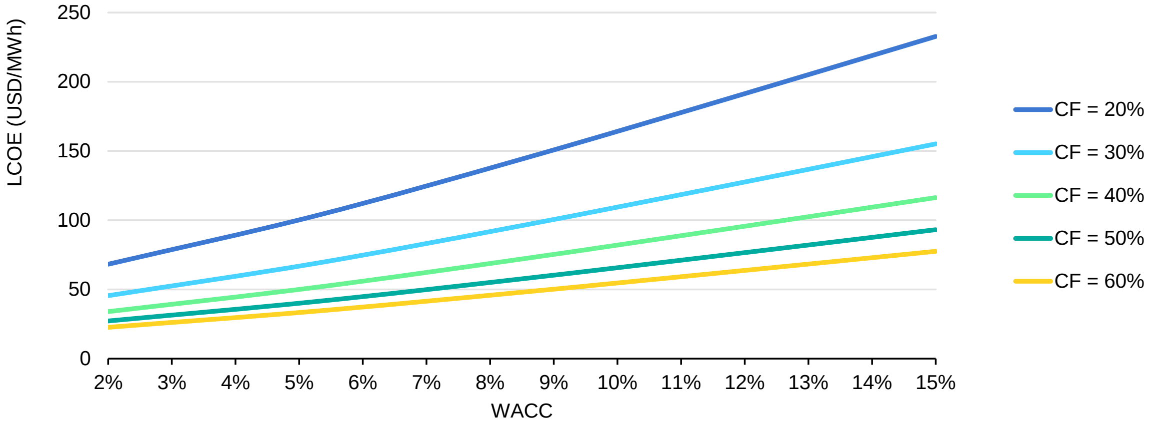
Government policies to de-risk investment – such as state guarantees, long-term contracts and other measures to raise remuneration certainty – could decrease project risk. Reducing financing costs through policy measures is important to ensure the competitiveness of hydropower generation, especially in developing countries where high macroeconomic risks result in elevated financing costs.

While hydropower plants can operate for 50-60 years without major refurbishment, civil infrastructure has a lifespan of more than 100 years with timely maintenance and periodic overhauls. Although hydropower projects can promise stable returns for a very long time, large projects require significant upfront capital, which may not suit many investors. Thus, using policy measures and the assistance of public

[2] Depending on the relative WACC change created by the one-percentage-point increase.

and multilateral banks to secure financing with payback periods better matched to the hydropower risk and return profile could be an important enabler of hydropower deployment.

Figure 2.3 Sensitivity analysis of LCOE of a typical new hydropower investment with overnight capital costs of USD 2 000/kW



Notes: LCOE = levelised cost of energy. WACC = weighted average cost of capital. CF = capacity factor. Assumptions include CAPEX of USD 2 000/kW; 50-year project lifetime; O&M costs equal to 2% of CAPEX annually; and a 5-year construction period.

The capacity factor (CF),[3] which is also a key determinant of hydropower generation costs, depends upon the type and purpose of the plant as well as local hydrological conditions. Reservoir plants are usually fitted with relatively high capacity that cannot run at full power throughout the year using only natural inflows. Such plants can supply high capacity during peak electricity demand periods to take advantage of higher prices in liberalised markets thanks to their energy storage capability, resulting in an average yearly CF of 20% to 40%.

Because RoR plants have very limited storage capabilities, their capacity is typically adjusted to maximise the use of available natural inflows throughout the year. The average yearly CF of RoR plants, which depends largely on the magnitude of seasonal inflow variations and the purpose of the plant (baseload vs peak generation), usually ranges from 30% to 60%.[4] Long-term changes in water levels and seasonal patterns of water inflow (e.g. due to climate change) can

[3] The CF is the ratio of a plant's actual yearly power generation to its total theoretically possible generation with 100% utilisation of installed capacity throughout the year.

[4] Like investment costs, CFs vary widely among plants and it is not uncommon for them to fall significantly outside the ranges presented.

significantly affect the number of operational hours, creating a revenue risk for investors (see Chapter 3 for more on the climate change impact on hydropower generation).

New and refurbished hydropower plants provide the world's most cost-effective, dispatchable low-carbon electricity

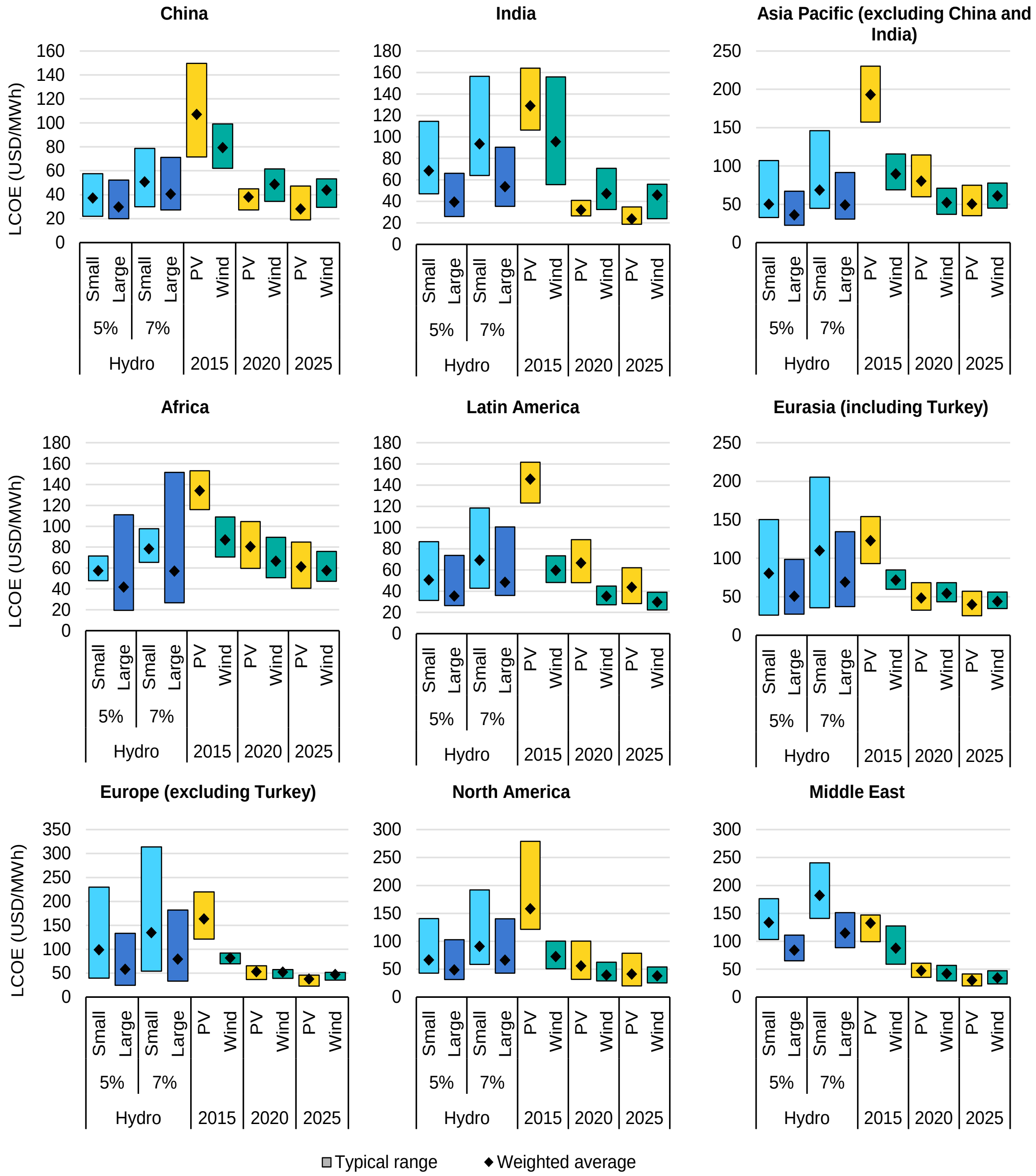
Hydropower projects have been the most competitive renewable electricity option in both advanced and developing countries for decades. Even despite rapidly falling solar PV and wind generation costs in recent years, new large-scale hydropower plants remain attractive in many developing and emerging countries in the Asia Pacific region, Africa and Latin America.

However, because hydropower projects entail longer lead times and greater risk than wind and PV developments, they usually have a higher WACC. De-risking measures that reduce the WACC (to as low as 5%) could continue to make hydropower costs competitive with wind and solar PV in many emerging economies and developing countries.

Simply comparing the generation cost of hydropower with that of variable technologies fails to appreciate the value of the much-needed dispatchable and flexible electricity that both small and large hydro plants provide. Although the flexibility offered by hydropower installations (especially reservoir plants) increases the value of the electricity generated, this is not factored into LCOE calculations (see Chapter 4 for detailed information on hydropower and system flexibility).

Generation cost comparisons also ignore the complexity of hydropower investment decisions and the risk profiles associated with large-scale project development. New hydropower projects have much longer lead times, lifetimes and usually higher social acceptance risks, than wind and solar PV developments. Therefore, even though hydropower might be the most affordable renewable electricity and may offer many additional benefits in certain locations, other technologies are often developed in its place because of the many non-economic barriers.

Figure 2.4 Average LCOE of new greenfield hydropower plants at 5% and 7% WACC (real), onshore wind and utility-scale PV, by region



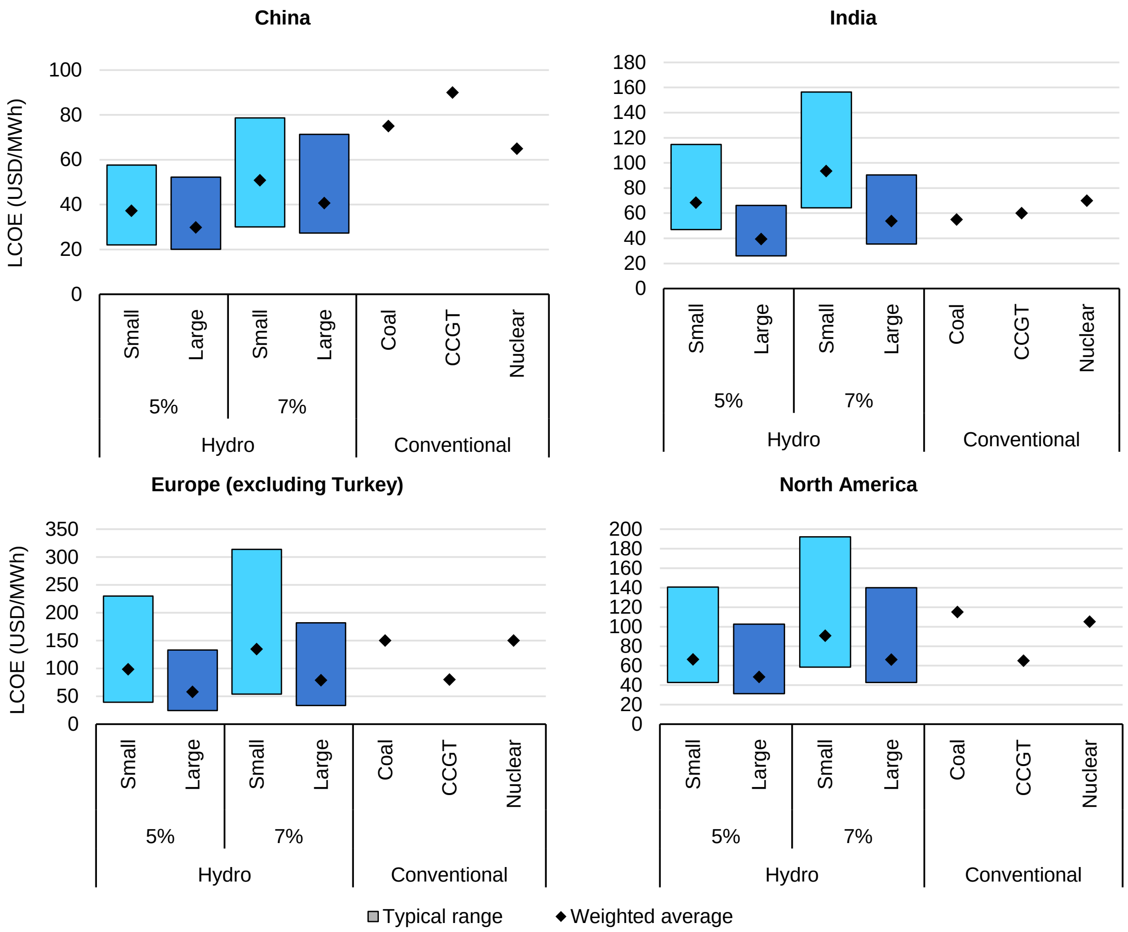
Notes: LCOE calculations based on country or regional assumptions of CF, CAPEX, OPEX and WACC. Hydropower WACC assumptions based on universal levels of 5% and 7% (real terms), PV and wind WACCs on country levels. Economic lifetimes of PV and wind assumed to be 25 years; 40 years for hydropower. Small hydro = installed capacity of less than 10 MW. Large hydro = installed capacity equal to or greater than 10 MW.
Sources: Based on IRENA, BNEF, World Bank and Oak Ridge National Laboratory data.

For most developing African and Asia Pacific countries with weak grid infrastructure and limited access to electricity, grid-connected variable renewables can increase system integration challenges despite their cost-competitiveness. Thus, developing available hydropower sites can be the most cost-effective low-carbon electricity option to expand electricity access, improve power supply quality and increase flexibility. In addition to being part of the energy system, hydropower dams can support economic development by providing irrigation, flood control and recreation resources.

In emerging economies with growing power demand, deep decarbonisation targets and untapped water resource development potential, large new hydropower plants are often the lowest-cost dispatchable and flexible low-carbon option. In China and India, for instance, reservoir and pumped-storage hydropower projects are facilitating the integration of rapidly expanding variable renewables considerably.

In Europe and North America, hydropower generation costs can be comparable with (or lower than) electricity production from other flexibility-enhancing options such as combined-cycle gas turbines and coal-fired and nuclear plants. Although most of the economical sites for large projects have already been developed, new small hydro plants can also provide an important source of low-carbon generation while enabling the integration of additional PV and wind capacity.

Figure 2.5 Average LCOE of greenfield hydropower plants at 5% and 7% WACC (real terms), coal-fired, combined-cycle gas turbine (CCGT) and nuclear plants, by region

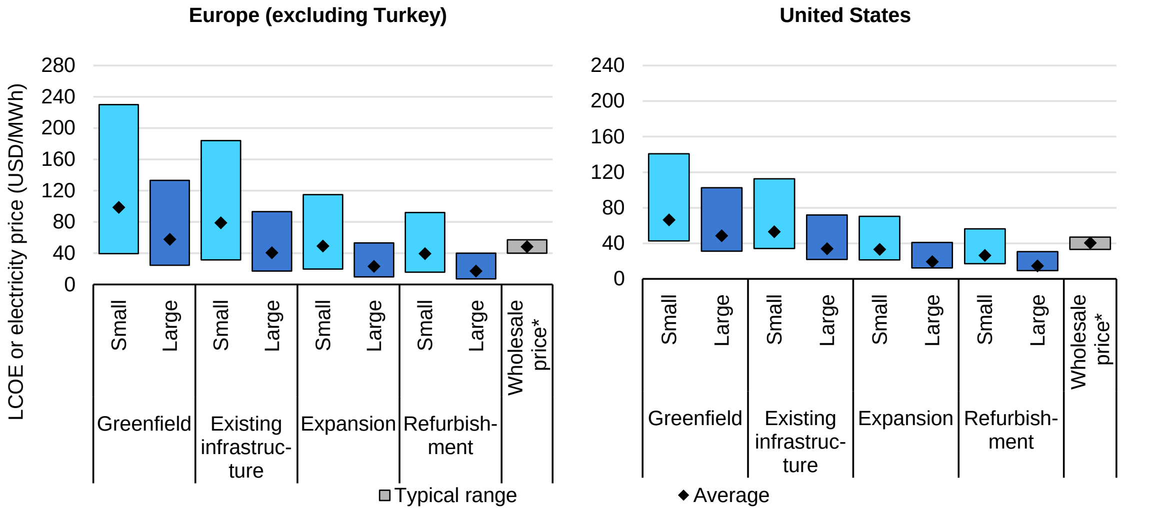


Notes: LCOE calculations based on country or regional assumptions of CF, CAPEX, OPEX and WACC. Hydropower WACC assumptions based on universal levels of 5% and 7% (real terms), coal, CCGT and nuclear WACCs on country levels of 7% for developed economies and 8% for developing and emerging. CF for coal plants assumed at 40-60%, for CCGT 40-50% and for nuclear 75-90%. Small hydro = installed capacity of less than 10 MW. Large hydro = installed capacity equal to or greater than 10 MW.

Sources: Based on IRENA, BNEF, World Bank and Oak Ridge National Laboratory data.

Electricity generation costs for brownfield hydropower projects that use existing infrastructure, expand or improve established plants, or replace ageing equipment, are lower than for greenfield developments because spending on civil works, permitting and environmental impact mitigation has already occurred. In fact, such projects can offer some of the lowest-cost electricity of all technologies (often well below most countries' average wholesale prices), especially large projects. Improvements can also increase a plant's generation flexibility and enable it to provide various ancillary services to tap into additional revenue. Brownfield investments are therefore expected to be an increasingly important element in European and North American hydropower markets.

Figure 2.6 Average LCOE of hydropower investments in Europe and North America and average wholesale electricity prices



*For Europe: minimum, maximum and average yearly wholesale EU electricity price for 2016-2019; for the United States: minimum, maximum and average yearly all-in electricity price from CAISO, PJM and ERCOT for 2016-2019.

Notes: Existing infrastructure refers to projects that are not yet powered but have some portion of civil works already in place, including non-powered dams, conduits, municipal water facilities and reservoirs (either natural or man-made). Small hydro = installed capacity of less than 10 MW. Large hydro = installed capacity equal to or greater than 10 MW. LCOE calculated at 5% WACC.

Long-term contracts and policy support

Long-term power purchase contracts ensure economic viability and make the hydropower business case tenable

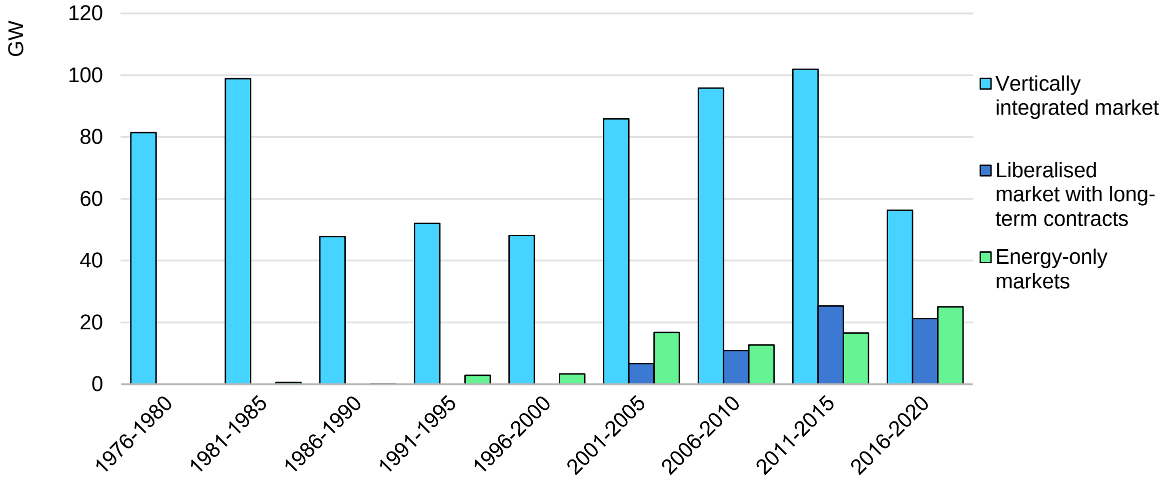
Without long-term contracts, the business case for capital-intensive hydropower projects is weak because of their protracted lead times (5-15 years) and the infrastructure's long technical lifetime (up to 100 years). Since the 1950s, more than 90% of hydropower plants have been developed under conditions of remuneration certainty, ensured either through power purchase guarantees in vertically integrated markets or the availability of long-term power purchase agreements in liberalised electricity markets.

The assurance of long-term remuneration, especially for large-scale hydropower projects, reduces financing costs significantly and makes the business case much stronger. Since electricity market liberalisation began in the 1980s,[5] more than

[5] Chile's electricity market was the first to be liberalised in 1983. Currently, 68 markets are partially or fully liberalised.

80% of new hydropower capacity additions globally have been in vertically integrated markets in which governments ensure long-term remuneration, mostly in the ASEAN region and China.

Figure 2.7 Gross hydropower capacity additions by market type, 1976-2020



Note: Includes pumped-storage capacity. Energy-only markets refer to liberalised markets without long-term contracts.
Source: Based on S&P Global Platts (2020), World Electric Power Plants Database.

Hydropower development in recently liberalised (or partially liberalised) markets still depends heavily on fixed-price remuneration where available. Brazil, Russia and Turkey alone, which have retained mechanisms for long-term hydropower contracts, are responsible for over 45% of new hydropower capacity additions in liberalised markets. Price certainty – provided through auctions, bilateral agreements and feed-in tariffs (FiTs) – has enabled large-scale hydropower development in these countries.

Europe and Latin America account for more than 65% of hydropower deployment in energy-only markets. Over 23 GW of new capacity have been brought online in Europe since its countries introduced energy-only markets, with Norway responsible for one-quarter of the region's energy-only market development. Pumped-storage projects account for nearly 35% of hydropower capacity in Europe since market liberalisation, as the business case for these plants has been based mainly on energy arbitrage and ancillary services.

However, these opportunities – especially energy arbitrage – have become less lucrative because the differential between peak and off-peak prices has decreased significantly as demand growth has waned owing to greater energy efficiency and higher shares of zero-marginal-cost renewables (especially solar) in daytime generation. This trend may reverse in the medium to long term, as more balancing will be needed in markets that have increasing shares of variable renewable energy, leading to surplus electricity production – in particular during the daytime in systems dominated by solar PV.

Policy support for hydropower remains limited

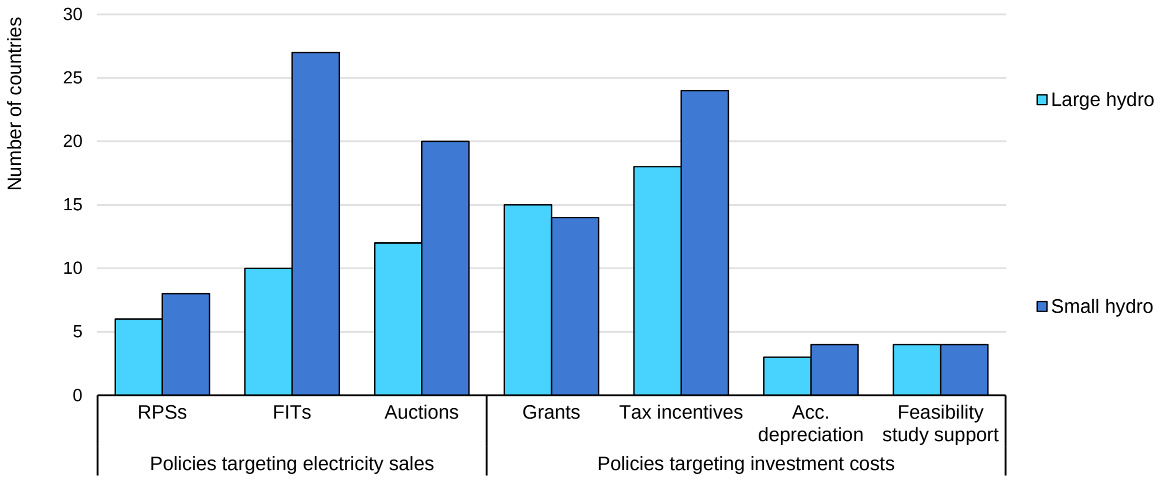
Globally, deployment targets and policy incentives have been key drivers of renewable energy deployment, especially solar and wind technologies. Hydropower is recognised as renewable energy in most countries, and India and Malaysia have recently credited it as such and have begun to provide additional support to the sector.

Specific targets that include hydropower in long-term power planning have enabled hydropower development in many countries. Such targets or long-term power planning are currently in place in approximately 40 countries – most prominently developing ones in which vertically integrated utilities manage power plant expansions through long-term planning, usually long-term concessions.

Historically, the public sector's extensive involvement in developing hydropower plants through long-term power purchase contracts did not require specific additional policies to foster deployment. However, these policies are crucial to reduce project risk when the private sector is involved, as important permitting, construction, environmental and social acceptance issues challenge hydropower developments worldwide.

Overall, the number of countries implementing policies for hydropower remains low compared with wind and solar PV. Most government support for small hydropower plants (below 30 MW) is currently offered in the form of long-term contracts through FiTs, auctions and/or tax incentives and grants. For the private sector, which is responsible for three-quarters of small hydro development, these policies provide stable remuneration to reduce project risk and offer incentives that bring down the high upfront costs. Fifteen to 25 countries worldwide, predominantly in Asia, Europe and North America, provide such policies (FiTs being the most popular, followed by tax incentives) to stimulate small project deployment where economic potential remains.

Figure 2.8 Number of countries with greenfield hydropower policies by project size and policy type



Notes: RPS = renewable purchase standard. FiT = feed-in tariff. Acc. Depreciation = accelerated depreciation. Classification of large hydro based on country-specific definitions.

Policies targeting investment costs are distributed roughly equally between large and small hydropower. Tax incentives, mostly in Asia and Africa, are the most prominent scheme, followed by investment grants that help ease the high investment cost burden. Some countries, mainly in South America and some developed economies such as Canada, Australia and Japan, offer other support schemes such as accelerated depreciation and grants that cover part of the cost of feasibility studies.

While an increasing number of countries are interested in storage technologies to support the integration of variable renewables, only five to six (India, China, some US states, Spain, Portugal, France and Viet Nam) have targets for battery or pumped storage hydro (PSH) development. For example, India conducted a successful energy storage auction in which both batteries and PSH plants received contracts, while China has PSH targets with a special pricing mechanism.

Challenges

Non-economic barriers must be lifted to enable greenfield development and fleet refurbishment

In many countries, hydropower is the most affordable dispatchable and flexible low-carbon electricity generation technology, but non-economic barriers often impede project development.

In the case of greenfield projects, lengthy permitting processes in addition to the high costs and risks of environmental assessments and local opposition often discourage investors. Even once a permit has been secured, the construction phase can be long and prone to delays due to unexpected complications such as lengthy litigation or unforeseen civil works difficulties, which can lead to additional costs. Furthermore, the long economic lifetime of hydropower projects makes it difficult to forecast not only future market conditions and regulatory and policy developments but also variations in water availability and climate change impacts, all of which can influence the overall profitability of the investment.

For brownfield developments and refurbishments, many market and regulatory barriers often discourage plant operators from investing, despite the cost-competitiveness of projects and ample refurbishment and uprate potential. The main barriers are long and complicated licence and concession renewal processes; uncertainty over water regulations; changes to environmental restrictions; and a lack of visibility over future market conditions and revenues.

Table 2.1 The impact of major economic and non-economic challenges on hydropower development

Challenge	Greenfield	Brownfield / refurbishment
Long duration and uncertainty of environmental permitting process	🔴	🟡
Local opposition	🔴	🟡
Uncertainty over future support policies	🔴	🟡
Uncertainty over future electricity prices	🔴	🔴
High cost and short payback periods of financing instruments	🔴	🟡
Long project development lead times	🟡	🟢
High cost and long duration of feasibility studies	🟡	🟢
Water regulation uncertainties and environmental constraints	🟡	🟡
Insufficient remuneration for auxiliary power system services	🟡	🟡
Insufficient remuneration for non-energy services (e.g. flood control, irrigation)	🟡	🟡
High off-taker risk	🟡	🟢
High concession fees and taxes	🟡	🟢
Power transmission system connection difficulties	🟡	🟢

Challenge	Greenfield	Brownfield / refurbishment
High water royalty costs	🟢	🟢
Ageing hydropower-expert workforce	🟢	🟢
High uncertainty over concession renewal process	N/A	🔴
Uncertainty regarding climate change impact on local hydrological conditions	🟡	🟡
International conflicts over water management	🟡	🟢

🔴 high impact 🟡 moderate impact 🟢 low impact

In addition to generating electricity, hydropower plants provide numerous power system flexibility services, including energy storage, frequency control and black-start capabilities, which are crucial for power supply quality and security (see Chapter 4 on flexibility). These services are often inadequately remunerated in many countries, which discourages investments in flexibility and prevents full utilisation of hydropower capabilities.

Hydropower's multiple benefits are often not properly valuated

A dam can serve as a resource for multiple purposes simultaneously: agricultural irrigation; drinking water supply; transport and navigation; flood control; strategic water storage; recreation and tourism; aquaculture; and electricity generation. Considering that dams have a long lifespan, the project development period is extensive and upfront investment requirements are high, the economic and social benefits offered by these multiple purposes should be better integrated into investment decisions and long-term energy planning.

Unfortunately, a key challenge to multipurpose dam development is that the economic value of the variety of services dams can provide is not always recognised or consistently appraised. While assigning economic value to electricity generation is fairly straightforward, quantifying the worth of other purposes such as flood control and recreation is more difficult.

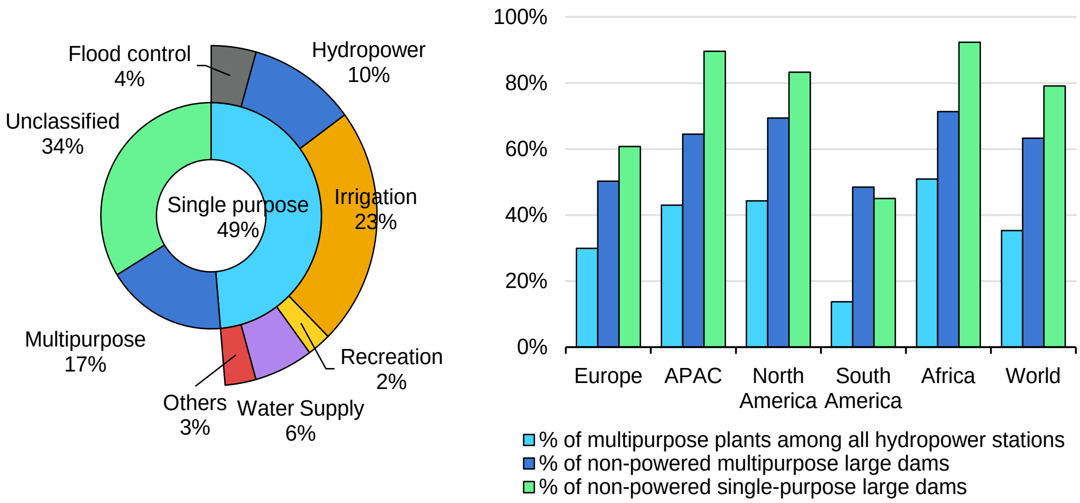
Around 58 000 large dams have been installed worldwide,[6] but due to a lack of data only 38 000 have been categorised as either one- or multiple-purpose. Of the

[6] Based on the International Commission on Large Dams (ICOLD) *World Register of Dams*, which has categorised large dams according to their purpose. It defines a large dam as having a height of at least of 15 m above its foundation or more than 5 m with a capacity of at least 3 million m^3.

large dams that have been categorised, almost three-quarters were designed and constructed for a single purpose – irrigation being the main one, followed by hydropower production, water supply and flood control.

Globally, nearly 40% of hydropower dams also provide multiple non-energy services, including flood control and irrigation. While these services are vital to the livelihoods of millions of people, their value usually remains unrecognised by power markets and authorities even though power plant operators incur additional costs to provide them. Although hydropower dams initially designed for a single purpose could eventually offer additional services, managing them can be a challenge because the valuation of secondary services was not covered in the dam's original design.

Figure 2.9 Large dams by purpose (left), and shares of hydropower and non-powered dams by region and globally (right)



Notes: Pie chart covers 57 985 dams. Of the 19 564 dams not categorised due to lack of data, 18 591 are in China. APAC = Asia Pacific, excluding China.
Source: Based on ICOLD (2021), *World Register of Dams* (database).

In Africa and the Asia Pacific region, where the agriculture sector contributes significantly to local economies, over 40% of hydro dams have multiple purposes, mostly combining power generation with irrigation, water supply and flood control. North America is another region with a relatively high share of multipurpose hydro dams resulting from the co-operation between US federal agencies and state governments to manage floods, improve inland navigation and irrigation in the early 20th century.

Conversely, the share of multipurpose hydropower dams remains low in Europe and Latin America compared with other regions. In principle, the potential to add electricity generation capabilities to existing multi- or single-purpose dams offers new opportunities, especially in European and North American countries that have already developed most of their untapped economical potential.

Developing multipurpose dams is challenging, however, because their various uses – e.g. power generation, water supply and environmental services – can conflict. While the public sector is usually responsible for providing water supplies and environmental services, both the public and private sectors develop and operate hydropower plants. The greatest challenges in developing multipurpose hydropower dams are managing ownership by different stakeholders, water-use prioritisation and remuneration mechanisms. Therefore, the complexity of ownership structures and differences between the private and public sectors, as well as risk allocation of dam investments, continue to inhibit multipurpose dam expansion.

Robust sustainability standards and measures are needed to strengthen the hydropower business case

Although hydropower installations offer many environmental benefits – some of the lowest lifecycle GHG emissions per unit of energy generated; flood control; and irrigation – the numerous sustainability concerns could outweigh the positive aspects.

Therefore, to make hydropower projects both viable and beneficial, developers strive to meet widely accepted, robust sustainability criteria to engage impacted communities and address environmental concerns. Ensuring that hydropower projects adhere to guidelines and best practices can both minimise sustainability risks and maximise their social, economic and environmental advantages.

Hydropower sustainability concerns can fall into two main categories: socio-economic and environmental. Although each category's challenges are distinct, they are also intertwined, so assessments of both socio-economic and environmental impacts are carried out together.

Socio-economic concerns range from immediate to long-term implications. Because hydropower developments can displace local populations and rising water levels affect existing infrastructure, strict consultation and agreement with local communities is necessary to ensure equitable compensation for disrupted populations. Furthermore, the construction phase creates a local boom/bust economic cycle that must be addressed by the developer prior to construction, and the increase in noise and traffic in a project's vicinity is also a concern.

Environmental issues associated with hydropower are generally complex. Dams can hinder the free flow of water, creating artificial ponds or lakes that alter water volumes and levels, and a plant's operational cycles can change water temperature, chemistry and quality. All of this could disrupt natural sediment distribution, disturbing animal migration, damaging local habitats and ecosystems and affecting biodiversity. Furthermore, methane emissions from vegetation decaying in and around reservoir projects could affect GHG emissions and carbon cycling.

Developers should utilise the mitigation hierarchy when planning projects to reduce the possibility of adverse effects. They should first attempt to avoid injurious environmental and social impacts, but when avoidance and minimisation are impracticable, developers should mitigate and compensate for impacts as much as possible. Sustainability effects that cannot be avoided or minimised completely can be mitigated and compensated for with technical solutions, operations and infrastructure, such as environmental flows, fishways, advanced turbine technologies and purposefully designed habitats.

Addressing the numerous concerns associated with hydropower requires a holistic approach that analyses a project's entire lifecycle. Hydropower developers, along with governments, international organisations and banks, have recognised the need to address sustainability concerns when implementing new hydropower projects and have therefore created standards to help guide sustainable development.

The Hydropower Sustainability Assessment Council's Hydropower Sustainability Tools cover socio-environmental, technical and financial topics and evaluate processes and outcomes that constitute good international industry practice. Three of the tools developed by the Council are the Hydropower Sustainability Assessment Protocol, which can be used to assess the four parts of a project's lifecycle (early stage, preparation, implementation and operation); the Hydropower Sustainability Guidelines, which describe best practices in sustainable hydropower development; and the Hydropower Environmental, Social and Governance Gap Analysis Tool that helps developers understand and assess project development in accordance with the best sustainability practices.

In addition, the IEA *Hydropower Technology Roadmap* offers guidance and examples for (among other areas) inventory planning for a series of projects. The Climate Bond Initiative also sets standards, such as upper limits on GHG emissions intensity for new hydropower developments and those completed before 2020 to help them qualify for refurbishment financing.[7]

Other resources address specific hydropower sustainability issues such as water-flow levels and biodiversity. The World Bank Group and International Finance Corporation's *Environmental Flows for Hydropower Projects* provides guidance on river ecosystems, including waterflows and nutrient dispersion. The IHA's recently published *Hydropower Biodiversity and Invasive Species* complements the Hydropower Sustainability Tools and helps developers avoid or mitigate project impacts on biodiversity.

To address emissions from reservoirs, the IEA Technology Co-operation Programme on Hydropower has developed *Guidelines for the Quantitative Analysis of Net GHG Emissions from Reservoirs* to help developers manage the carbon balance, while the IHA's G-res tool also provides a way to measure and report a reservoir's GHG emissions. These guidelines, used in the Climate Bond Initiative's hydropower bond criteria, provide guidance on measuring, analysing, modelling, managing and mitigating emissions from freshwater reservoirs.

Regionally, individual countries have also been addressing sustainability concerns associated with hydropower. In the United States, Stanford University's Uncommon Dialogue brought together hydropower industry representatives and conservation and environmental organisations to create a joint framework to rehabilitate current powered and non-powered dams and to develop new closed-loop pumped-storage hydropower projects.

Meanwhile, Brazil has developed the *Metodologia para o desenvolvimento e implantação de projetos de usinas hidrelétricas sob o conceito de usinas-plataforma* [Proposition of Methodology for the Development and Implementation of Hydropower Plant Projects under the Concept of Platform Plants], commonly referred to as the Platform Hydropower Plant. It provides a framework to develop projects in ecologically sensitive and remote areas, minimise their construction footprint and avoid permanent settlements around dams while also recovering forests and other affected areas.

While these tools combined cannot alone ensure complete sustainability, taking a systematic approach to address sustainability concerns and engage stakeholders early in the process can help meet and mitigate challenges as well as increase investor confidence, maximising a project's benefits. Furthermore, even though

[7] The Climate Bond Initiative also requires that hydropower developers carry out site-specific assessments using the Hydropower Sustainability ESG Gap Analysis Tool to comply with adaptation and resilience criteria.

international standards have been developed, country-level policies and regulations ultimately guide hydropower development, and the criteria may not necessarily conform to international best practices and guidelines. Countries should always design and implement policies according to the highest sustainability standards developed jointly by national and international stakeholders.

One example of a recent project that strove to achieve maximum sustainability is the Reventazon Hydroelectric Project in Costa Rica. Completed in 2016, the project met or exceeded all good-practice standards outlined in the Hydropower Sustainability Assessment Protocol while also employing the river-offset approach.[8] While not all impacts were completely mitigated, affected people were compensated and this project demonstrates how hydropower can be developed more sustainably and responsibly. Twenty-one projects have been reviewed by the Hydropower Sustainability Assessment Protocol, and their assessments are available for public review.

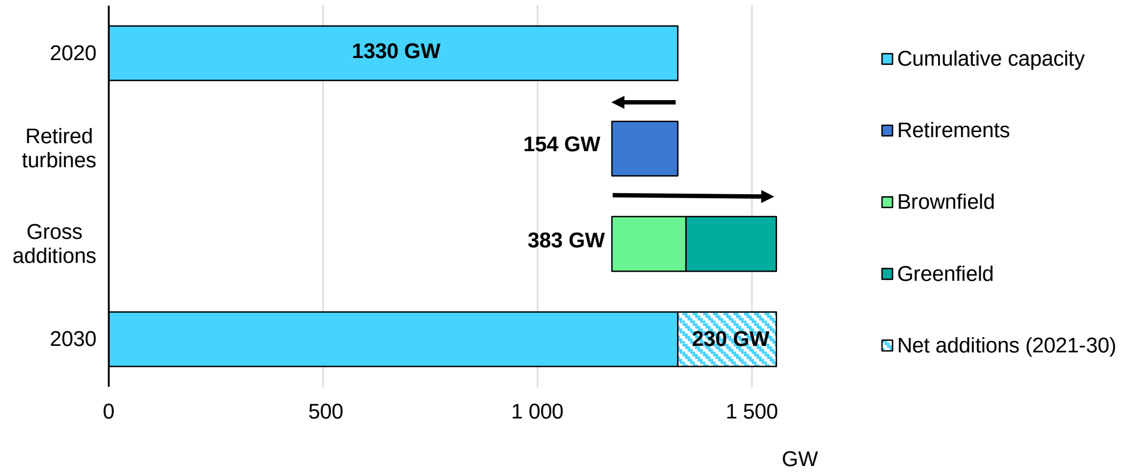
[8]The river-offset approach is a hydro project planning mechanism designed to protect free-flowing rivers, improve water quality and habitats, compensate for the loss of critical habitats and create a biological corridor.

Chapter 3 - Hydropower outlook

Global forecast additions: Main case

Global cumulative hydropower capacity is expected to expand from about 1 330 GW in 2020 to just over 1 555 GW by 2030 – a 17% (230-GW) increase. However, the increase in total capacity of new hydropower turbine installations will be greater (383 GW), split between greenfield projects (new power plants) and brownfield activities (turbine replacements or uprates, or additions of new turbines to existing plants or to non-powered infrastructure). The amount of capacity to be retired over the forecast period (154 GW) accounts for the difference between net and gross capacity additions.

Figure 3.1 Global hydropower capacity forecast, retirements, and gross and net additions, 2020 and 2030



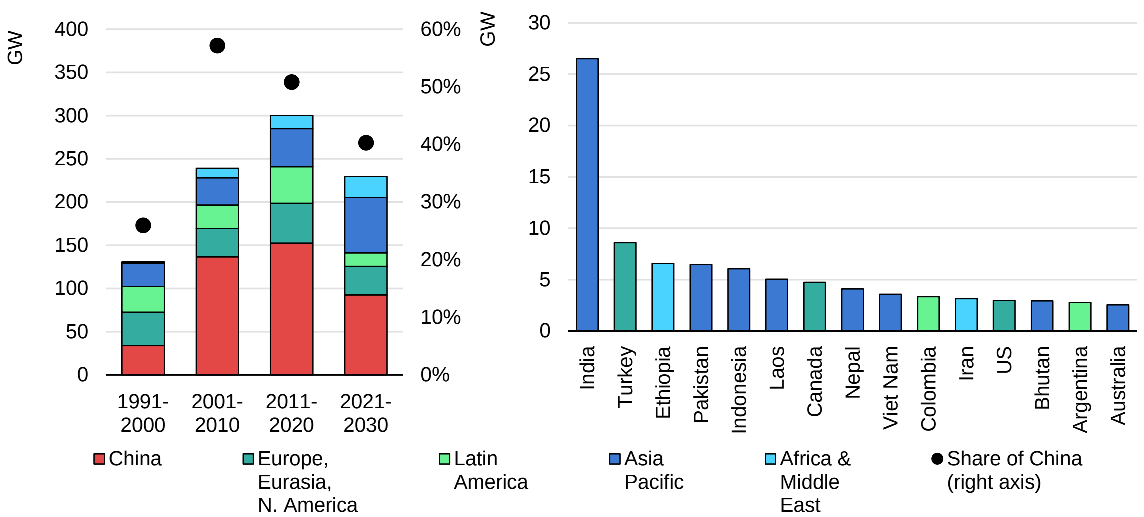
Following the deployment surge of the last three decades, global net hydropower capacity additions are expected to be 23% lower in 2021-2030 than in 2010-2020. This contraction results from development slowdowns in China, Latin America and Europe, even though increasing growth in the Asia Pacific region, Africa and the Middle East partly offsets these declines.

China continues to lead net capacity growth, accounting for 40% of expansion during 2021-2030, although its share has been declining since its peak in

2001-2010. China's development has slowed due to growing concerns over environmental impacts and the decreasing availability of economically attractive sites.

In India, the world's second-largest growth market, development of a large pipeline of stalled projects is expected to resume owing to new long-term targets and financial support to meet rising power demand. Fast-growing electricity demand and regional trade also drive hydropower development in Southeast Asia, where countries such as Laos and Nepal are developing energy-export projects. Untapped potential and the need to increase electricity access affordably underpin hydropower development in sub-Saharan Africa, the third-largest region for growth over the next decade.

Figure 3.2 Global net hydropower capacity additions by region, 1991-2030 (left) and by leading countries, 2021-2030 (right)



Note: Because of its large size, China's growth is illustrated in the left graph but excluded from the right one, which covers leading countries.

Expansion in Latin America has historically been almost entirely in Brazil, but a reduction in undeveloped economical sites as well as concerns over droughts and environmental impacts have stimulated interest in diversification and slowed hydropower development. Colombia and Argentina are therefore expected to lead future growth in Latin America.

Turkey's continuous hydropower expansion accounts for most of Europe's growth, while in North America electricity export opportunities prompt the development of untapped potential in Canada. Outside of these two markets, the main drivers for growth in these regions are renewable energy targets and rising system flexibility needs, but environmental regulations and permitting complications are key constraints to hydropower expansion. Development is therefore shifting towards projects for which permit obtention is simpler, such as plant expansions and upgrades, or projects that use non-powered dams or pre-existing reservoirs. Fleet modernisation is also a key development activity in Europe and North America.

Reservoir plants

For the first time, the IEA has devised detailed forecasts for three types of hydropower installations: reservoir, run-of-river and pumped-storage hydropower (PSH). Our forecast expects overall hydropower capacity to expand faster in the first five years of the forecast period (2021-2025) than in the second half (2026-2030) owing to the pace of reservoir project development, which accounts for over 55% of total growth.

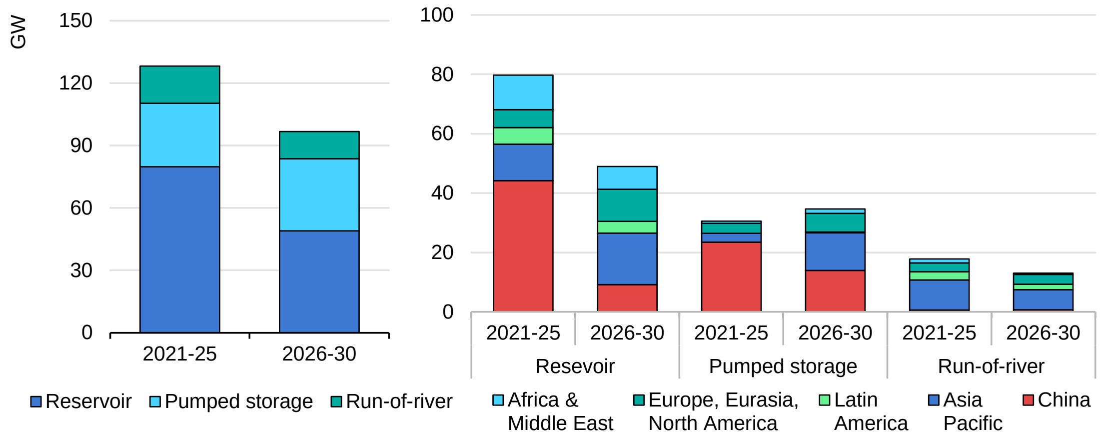
Two exceptionally large reservoir plants (Wudongde [10 GW] and Baihetan [16 GW]) currently under development influence the global reservoir expansion trend. The first 6 GW from these two plants were commissioned prior to 2021 and the remaining 20 GW are expected to become operational between 2021 and 2025. Apart from these two mega plants, global growth remains relatively stable in the second half of the decade compared with the first, with PSH projects offsetting declines in other reservoir projects and run-of-river plants.

The development of large reservoir projects in India and other emerging economies during 2026-2030 offsets the slowdown in China. Meeting fast-growing power demand in the Asia Pacific region and giving more people access to electricity in sub-Saharan Africa are key reasons to develop reservoir projects in these regions.

Cross-border power trade is another catalyst, particularly in Southeast Asia and in Latin America and sub-Saharan Africa through binational or joint government-owned projects. The multiple-purpose use of dams for flood management, irrigation, and potable water supply also spurs developments in these regions.

Conversely, North America, Europe and Eurasia account for only 13% of global reservoir expansion in the next decade because the number of available economically viable sites is shrinking, and social acceptance and permitting issues are creating challenges. Canada and Turkey lead greenfield expansion in this group of regions, with smaller capacity additions coming from plant refurbishments in other countries.

Figure 3.3 Net hydropower capacity additions by technology segment globally (left) and by region (right), 2021-2030



Pumped-storage plants

PSH projects are forecast to make up almost 30% (65 GW) of global hydropower capacity expansion during 2021-2030 – the highest decadal growth in the history of PSH development and almost double the previous record of 34 GW during 1971-1980. The main drivers are the need for increased system flexibility and greater storage requirements in several regions.

While the majority of development will be greenfield projects in emerging economies, at least 7% of PSH capacity additions will utilise existing infrastructure (old mines and natural reservoirs) or add pumping capabilities to operational reservoir plants. These projects tend to have lower investment costs, and it is usually easier to obtain permits for them than for greenfield facilities.

China, which accounts for over half of global PSH deployment, will commission most of its plants in the first five years of the forecast period. Growth is stimulated by the government's long-term PSH targets and the desire to reduce variable renewable energy (VRE) curtailment. State-owned enterprises are expected to develop over 95% of China's PSH expansion.

After 2025, PSH expansion extends beyond China as projects currently in the early stages of development become operational. The second-largest region of PSH growth is Asia Pacific, followed by Europe, North America, Eurasia and the Middle East and North Africa. Although the primary PSH investment driver in all these areas is the need for greater system flexibility, each region's plant type, ownership and business model choices differ.

In the United States, Australia and Europe, PSH expansion is needed to integrate the rising VRE shares stipulated by long-term targets. A large portion of growth is expected to consist of greenfield closed-loop[1] projects and developments that use existing infrastructure (for which permits should be easier to obtain than for greenfield open-loop plants[2]).

The main forecast uncertainty is the economic attractiveness of PSH plants. Narrowing peak and off-peak price spreads, high grid fees and inadequate remuneration for ancillary services make the business case for PSH less attractive in the absence of instruments to provide long-term revenue certainty.

In Asia Pacific (excluding Australia), system flexibility is needed to integrate VRE; to accommodate changing demand profiles resulting from rising electrification needs (Indonesia and Viet Nam); and to avoid curtailment where there are grid constraints, or supplement generation from less-flexible assets such as coal (India).

The strength of the business case in these markets will depend largely on the involvement of state-owned utilities, as minimising system costs rather than maximising plant profits is the main goal. However, economic viability will still depend on the cost advantage of PSH over other technologies (e.g. batteries and open-cycle gas turbines [OCGTs]) to provide the short- and medium-term balancing and ancillary services needed for the specific load profiles of these markets.

Rising shares of solar PV in Israel and the United Arab Emirates, as well as of wind in Morocco, Egypt and Iran, are prompting PSH development in the Middle East and North Africa. Except for Israel, PSH expansion will be undertaken mainly by government-owned utilities and will depend considerably on the engineering, procurement and construction companies' pace of contracting and construction, as well as on network expansion plans. The forecast for Israel carries higher uncertainty, as private investors still need to reach financial close.

Run-of-river plants

Run-of-river projects[3] are expected to make up the smallest segment of the hydropower market over the next ten years, partly because they tend to be smaller

[1] Closed-loop projects do not have natural inflow to either reservoir.
[2] Open-loop projects have natural inflow to one or both reservoirs.
[3] Run-of-river projects have less than 24 hours of storage. See Annex 1 for further information on definitions and methodology.

in size than reservoir and PSH plants. Most of the capacity increases will be in Asia and Latin America, where larger run-of-river projects dominate expansion in 2021-2025.

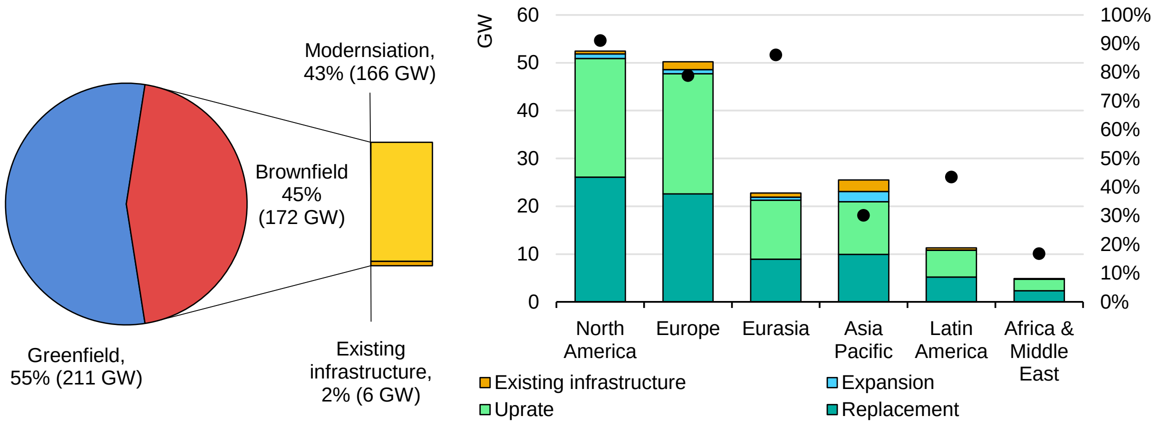
However, concerns over how changing precipitation patterns will affect generation pose a downside risk for projects in Latin America. Smaller plants can still receive financial support through investment grants or feed-in tariffs (FiTs) in some countries in North America and Europe, and the permit process could be easier in markets that consider them less environmentally impactful than large projects.

Greenfield and brownfield forecast

Between 2021 and 2030, new hydropower turbine installations, also referred to as gross capacity additions, are expected to reach more than 380 GW. Slightly over half of these additions will be from greenfield projects, constructed on completely undeveloped land with no pre-existing infrastructure or civil works.

Almost all this development (87%) will be in China, the Asia Pacific region, sub-Saharan Africa and Latin America, where there are still areas with suitable topography for economically viable sites. As these regions have relatively young hydropower fleets, new project development makes up almost all the turbines commissioned there.

Figure 3.4 Gross capacity additions by project type globally (left) and by region for brownfield projects only (right), 2021-2030



Note: *Existing infrastructure* refers to projects that are not yet powered but have some portion of civil works in place. This includes non-powered dams, conduits, municipal water facilities and reservoirs (either natural or manmade).

Brownfield projects are expected to make up a substantial part of new capacity additions over the forecast period, accounting for 45% of new turbine installations globally. However, their importance is much greater in mature hydropower markets where greenfield project potential is limited. In North America, Eurasia and Europe, brownfield projects constitute 85% of their combined growth due to the need to modernise ageing fleets and the limitation on locations for economically attractive and permittable new greenfield projects.

Brownfield projects can be divided into two categories: modernisation of existing plants (expected to be the majority of project activity) and the addition of turbines to non-powered infrastructure. In the latter, generating units are installed on some form of pre-existing structure such as dams, conduits, municipal water infrastructure or natural or man-made reservoirs.

Because some civil works are already in place, capital costs tend to be lower than for greenfield projects and permits are easier to acquire, which makes them attractive in regions where permitting new projects is a challenge (e.g. Europe, North America and Australia). Therefore, most global hydropower expansion involving pre-existing infrastructure consists of converting old coal mines to PSH plants in Australia, powering non-powered dams in the United States and using pre-existing reservoirs for PSH development in Europe.

Over 43% of the world's new hydropower additions are expected to come from modernisation of the existing fleet through turbine replacements, uprating or plant expansion (increasing the power of existing plants by adding turbines). Most projects are expected to be replacements and uprates of ageing turbines reaching the end of their lifetime in the world's oldest hydropower fleets, which are in Europe (43 years old) and North America (50 years old). The main goals of modernisation are to restore a plant's original performance; ensure its availability; adapt it to changing hydrological conditions; and improve its flexibility.

However, several uncertainties surrounding investment decisions affect the forecast for replacements and uprates. The first is the age at which the plant owner decides to replace the old turbine with a newer one. While this is partially dictated by a turbine's technical lifetime (which can range from 40 to 75 years), it can also be influenced by the amount of time remaining on any contractual arrangements, which is project-specific.

A second source of uncertainty is the business model for new investments. Limited visibility over long-term remuneration is a source of risk for a high-capex investment such as turbine replacement, and it can make it difficult to access financing. A plant's contractual arrangements and ownership model are therefore key factors in determining whether (and when) plant modernisation will be bankable.

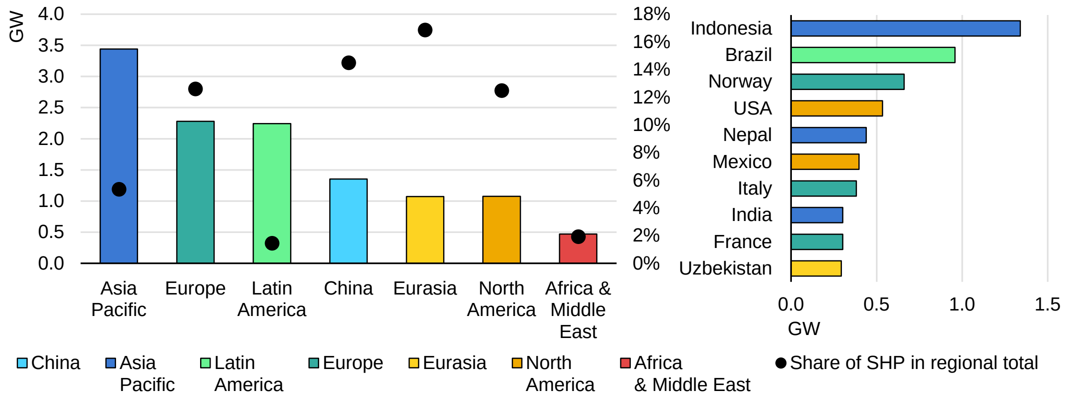
Finally, uncertainty also stems from not knowing whether the turbine will be replaced at the same rated power or a higher one (known as uprating). This decision will depend on the plant's technical limitations and specific waterflow.

Because of these uncertainties, it is forecast that 160 GW will be added through replacements and uprates. In addition to announced modernisation activities, this assumes that 40% of the capacity turning 55 years old during the forecast period will be either replaced or uprated by 7.5%. However, should the business case for modernisation be more attractive and there be greater potential to increase turbine size, this number could be more than twice as high (i.e. almost 400 GW).

Small hydropower

Small projects (plants of less than 10 MW[4]) are forecast to account for 5% (11 GW) of global hydropower expansion between 2021 and 2030. Yet this is far less than the remaining untapped potential, estimated at 66% (50 GW) (UNIDO 2019). The expansion trends by region/country are slightly different compared to large projects as the viable untapped potential varies and is more widely spread. In addition, there are various support mechanisms in place for small hydropower, in some cases easier permitting than larger projects, and a higher share of private and local ownership. For these reasons, small hydropower makes up a larger share of the hydropower growth in Latin America, Europe, Eurasia and North America than in other regions.

Figure 3.5 Net small-hydropower capacity additions by region (left) and leading countries (excluding China) (right), 2021-2030



Note: SHP = small hydropower.

[4] Small hydropower plants are defined as having less than 10 MW of capacity, in accordance with UNIDO (2019), *World Small Hydropower Development Report 2019*.

China continues to lead small hydropower deployment. With large hydropower development scaling down, small hydropower is expected to become more important to reach hydropower and renewable energy goals. The region with the greatest increase will be the Asia Pacific, where forecast growth is based on untapped potential and rural electrification from a mixture of development by state-owned utilities and independent power producers (IPPs).

Europe, the world's second-largest regional market, is led by Norway, which has supported small hydropower development through a green certificate programme since 2012. Although the certificate scheme ended in 2020, the forecast expects the business case for small hydropower projects to remain strong despite a lack of support, mainly because Norway's system services and good interconnections allow it to export power.

The next-largest markets – Italy and France – also have support schemes dedicated to small hydro in the form of FiTs, and both Russia's and Uzbekistan's major utilities support new and uprated small hydropower in Eurasia. In North America, growth in United States comes mainly from the redevelopment of non-powered dams (which is easier to obtain permits for), while Mexico has earmarked small run-of-river plants in its development plan.

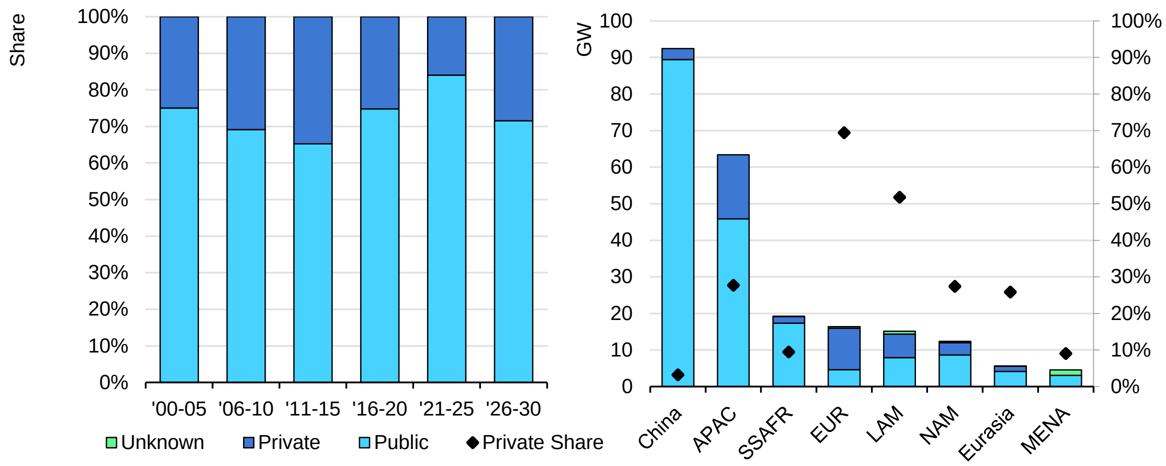
Small hydropower expansion in Latin America is led by Brazil, which supports small hydropower through dedicated auctions to diversify development away from large hydropower.

Public sector investment will continue to drive global hydropower expansion

During 2021-2030, over 75% of new hydropower capacity will be installed by utilities or developers that are entirely or majority state-owned, with the highest public sector shares realised in the first five years of the forecast period as large-scale projects are commissioned in Asia and Africa. Public sector involvement remains most significant in vertically integrated and single-buyer markets such as those found in China and Africa.

In Latin America and Europe, some countries provide support policies such as auctions and FiTs, leading to higher shares of private sector investment in hydropower plants.

Figure 3.6 Shares of public and private hydropower deployment, 2000-2030 (left) and forecast share by region, 2021-2030 (right)



Notes: *Public* refers to companies wholly or majority owned by governments and may include government-owned utilities and/or development firms. APAC = Asia Pacific. SSAFR = sub-Saharan Africa. LAM = Latin America. EUR = Europe. NAM = North America. MENA = Middle East and North Africa.
Source: Based on IEA (2021a), World Energy Investment 2021.

For small hydropower projects of 10 MW or less, by contrast, the private sector is to be responsible for over 65% of global deployment over the next decade. European countries currently have the largest shares of privately owned capacity. Over 80% of small hydropower plants in Europe were built by private firms during 2011-2020 and nearly 70% of PSH hydropower plants are privately owned. High shares of private ownership in Europe continue throughout the forecast period, with private developers (mostly in Turkey) contributing nearly 70% of capacity additions.

Latin American markets have historically been stimulated by public sector investment, especially in Brazil. However, as auction schemes and bilateral contracts overtake traditional government-backed development, more private developers are investing in these markets and building new plants and capacity than in the past.

The regions that account for the majority of capacity additions through 2030 (China, Asia Pacific and sub-Saharan Africa) are dominated by public sector investment, with most projects being over 250 MW. State sponsorship of large projects facilitates development by providing co-ordination across multiple state agencies and alleviating some of the risk associated with the myriad obstacles engendered by large projects, such as water rights/access and resettlement.

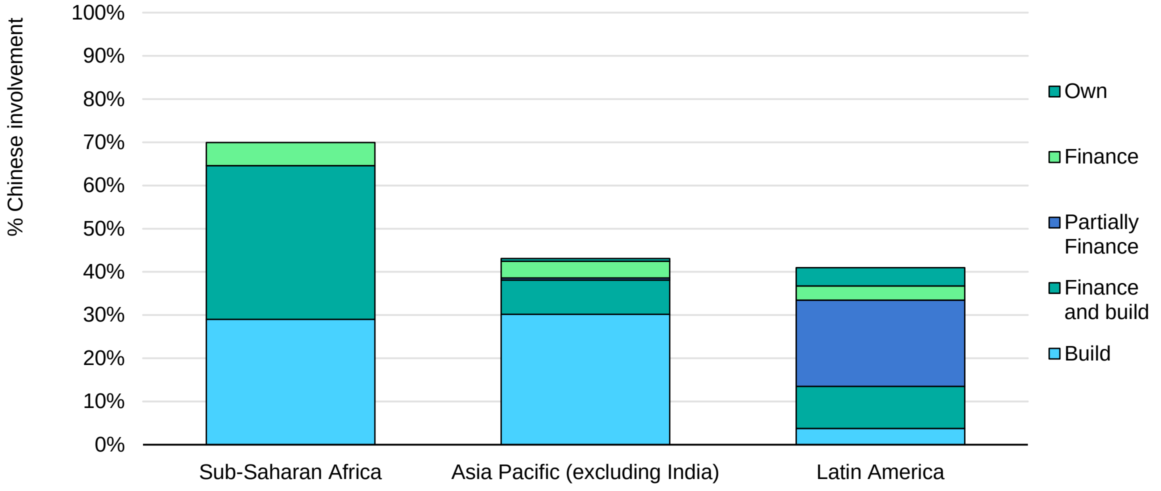
China's involvement in hydropower development is critical for emerging and developing economies

Foreign governments and corporations invest in hydropower projects by providing affordable financing and/or technical or construction expertise, or direct ownership. China is increasingly involved in hydropower projects in developing regions. China builds them through construction contracts (the "build" component of the figure below); finances them by providing the majority of financing ("finance"); partially finances them by providing financing as part of a larger funding group ("partially finance"); or owns them through direct ownership of the project or the company building the project ("own").

Over half of all new hydropower project capacity larger than 30 MW expected to come online in sub-Saharan Africa, Asia Pacific (excluding India) and Latin America during 2021-2030 will be built, financed, or partially financed or owned by Chinese firms (mostly state-owned enterprises). The Belt and Road Initiative, a Chinese government programme to develop infrastructure in developing and emerging economies, has enabled many of these projects, especially in the Asia Pacific region and Latin America.

Chinese hydropower firms have the technical expertise to help build, own and operate large projects owing to their experience developing large dams over the last two decades. The cost-competitiveness of these firms, coupled with aggressive project timelines to increase electricity access, are attractive for countries with budget sensitivity and tight schedules.

Figure 3.7 China's role in owning, constructing, developing and financing hydropower project capacity, 2021-2030



China's role in hydropower development is most significant in sub-Saharan Africa, with nearly 70% of new capacity fully or partially owned, built and/or financed by China. This includes the largest hydropower project currently under construction in the continent, the Grand Ethiopian Renaissance Dam, which is being partially financed and built by a consortium of Chinese companies.

In the Asia Pacific region excluding India (where China's involvement is very limited), nearly 45% of all hydropower plant capacity involves a Chinese company, with Pakistan and Laos receiving the largest contributions in the form of financing or construction. In Latin America, over 40% (5 GW) of new capacity has Chinese involvement, highlighted by investments in Argentina, Colombia and Peru (over 2.4 GW of this capacity is only partially financed by China). China Yangtze Power's 2020 acquisition of the Peruvian utility Luz del Sur is an additional example of Chinese investment through direct ownership of large-scale projects.

Regional outlooks

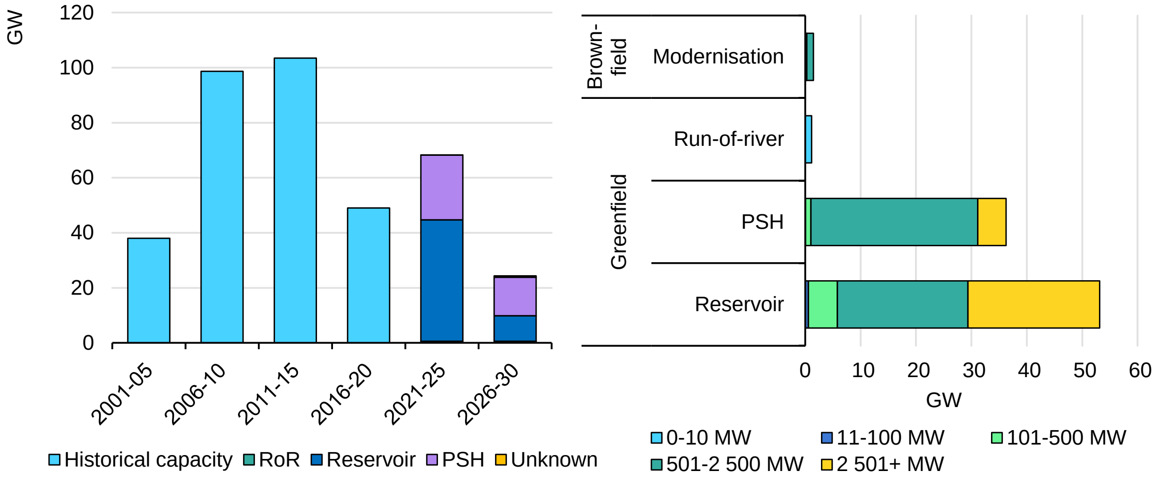
China

Hydropower capacity in China is expected to increase 93 GW by 2030, accounting for 40% of global net additions. Because of the need to meet capacity targets and the availability of long-term power purchase agreements (PPAs) for large hydropower plants at provincial electricity prices, large reservoir plants and PSH facilities larger than 500 MW will continue to dominate China's capacity additions in the next decade. Meanwhile, the deployment of small hydropower plants (below 50 MW) is expected to remain limited and will depend upon forthcoming government decisions because of possible negative environmental impacts and growing sustainability issues.

China's 2015-2020 hydropower expansion is half what it was in 2010-2015, as many of the most cost-effective sites for large-scale plants have already been exploited. While there is still economic potential for further hydropower development in China, investment costs have been rising because access to new sites is difficult and social acceptance challenges have increased.

Hydropower additions are expected to be slightly higher during 2021-2025 than in the last five years, mainly because the Wudongde and Baihetan mega reservoir projects are set to be commissioned by 2023 with a combined final capacity of 26 GW.

Figure 3.8 China hydropower capacity additions by application, 2000-2030 (left) and by size, 2021-2030 (right)



Notes: RoR = run-of-river. PSH = pumped-storage hydropower. In the right graph, the run-of-river, PSH and reservoir bars represent greenfield projects. Brownfield run-of-river, PSH and reservoir projects are included in modernisation.

During 2025-2030, PSH plants dominate hydropower growth in China for the first time. The Chinese government announced a target of reaching peak emissions by 2030 as part of its 2060 carbon-neutrality target, which will require faster deployment of wind and solar PV installations and increase the need for additional flexibility and storage that PSH plants can provide.

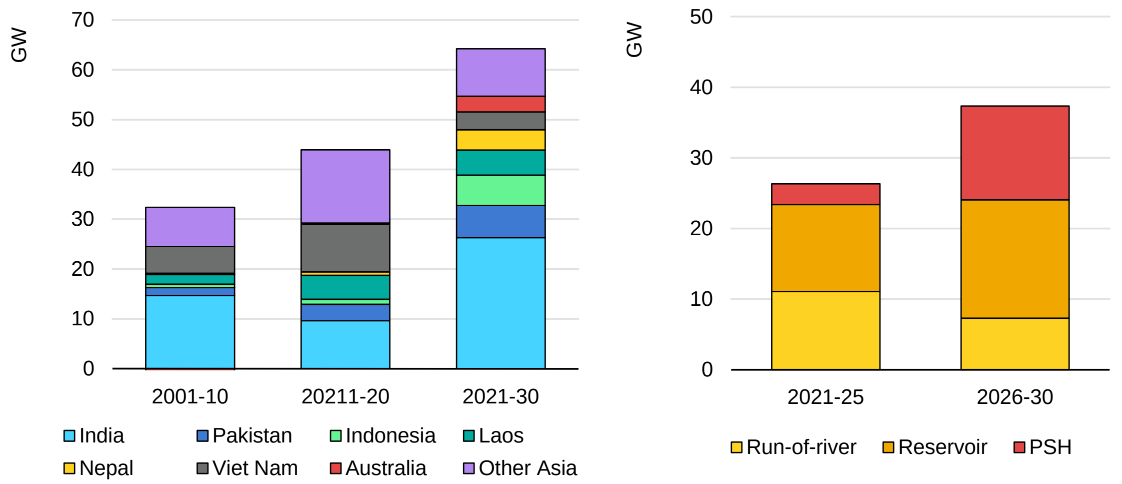
Historically, the main challenge preventing PSH deployment was uncertainty over the availability of revenue schemes. Despite the pricing mechanisms introduced in 2014 to provide remuneration for both energy and capacity, the implementation of these tariffs at the provincial level remained low. However, pricing policy changes of April 2021 are expected to improve capacity and energy remuneration for PSH plants and encourage further deployment.

Asia Pacific

The Asia Pacific region excluding China is forecast to add over 64 GW of new hydropower capacity during 2021-2030, an acceleration from the last two decades. However, because the region is made up of a large number of countries, all with varying population sizes, market structures and ownership profiles, drivers for hydropower expansion vary significantly across the Asia pacific region.

India and Pakistan together account for half of the region's expansion in the next decade, propelled by fast-growing power demand and untapped potential. Large reservoir projects dominate hydropower deployment in Pakistan, where development goals are to meet power supply gaps, reduce import dependency and tackle water shortages at the same time.

Figure 3.9 Asia Pacific net hydropower capacity additions by key countries (left) and segment (right)



Notes: Other Asia comprises Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia, Japan, North Korea, South Korea, Malaysia, Mongolia, Myanmar, New Zealand, Papua New Guinea, the Philippines, Singapore, Sri Lanka, Chinese Taipei and Thailand. PSH = pumped-storage hydropower.

India alone is responsible for over 40% (26 GW) of the region's 2021-2030 expansion, spurred by new long-term targets (30 GW by 2030) and increased policy support. In 2019, the government classified both conventional hydropower and PSH projects greater than 25 MW as a renewable energy source, making hydropower eligible for renewables-only financial support (e.g. more affordable financing and eligibility for the green certificate programme).

The government introduced a specific purchase obligation for hydropower, similar to that for solar PV, to stimulate demand and facilitate PPAs between developers and distribution companies. Financial support such as grants for enabling infrastructure and flood control, and policies enabling cross-border trade among India's states, also support hydropower development. In addition, regulations for timely dispute resolution are addressing land-access and permitting challenges, enabling the development of large-scale projects in line with the government's new target.

Outside of India, electricity export opportunities and cross-border trade continue to motivate construction of large-scale reservoir projects. Such projects are built through public-private partnerships such as the build-own-operate-transfer (BOOT) scheme, developed mainly by independent power producers.

For instance, Laos, which is already the region's largest hydropower exporter, aims to export a total of 20 GW of electricity by 2030 to become the "battery of Southeast Asia". It is therefore expected to develop around 5 GW of capacity, mainly through joint ventures and IPPs that use the BOOT mechanism. Furthermore, Laos and Viet Nam are signing bilateral agreements with Thailand and Cambodia (like Nepal and Bhutan with India) to export hydroelectricity.

To meet rising system flexibility needs, PSH accounts for one-quarter of Asia Pacific hydropower capacity expansion over the forecast period, with most projects becoming operational over 2026-2030. India leads regional growth, with its PSH fleet almost tripling by 2030 to accommodate growing solar PV capacity (which is expected to account for almost one-third of India's cumulative installed power capacity by 2030).

Fast-growing solar PV expansion also underpins the PSH forecast for Australia, the region's second-largest market, with 3 GW of PSH expected to become operational between 2021 and 2030, supported by government funding for feasibility studies.

In Viet Nam and Indonesia, changing demand patterns resulting from economic development (e.g. increased energy demand for space cooling), and the deployment of distributed solar, will require more system flexibility that could be met by PSH. For example, Viet Nam is expected to add 4.5 GW of solar PV and wind capacity by 2025, and the commissioning of the Bac Ai PSH plant (1.2 GW) by 2029 will bolster the nation's generating capacity to cover an increasing peak load.

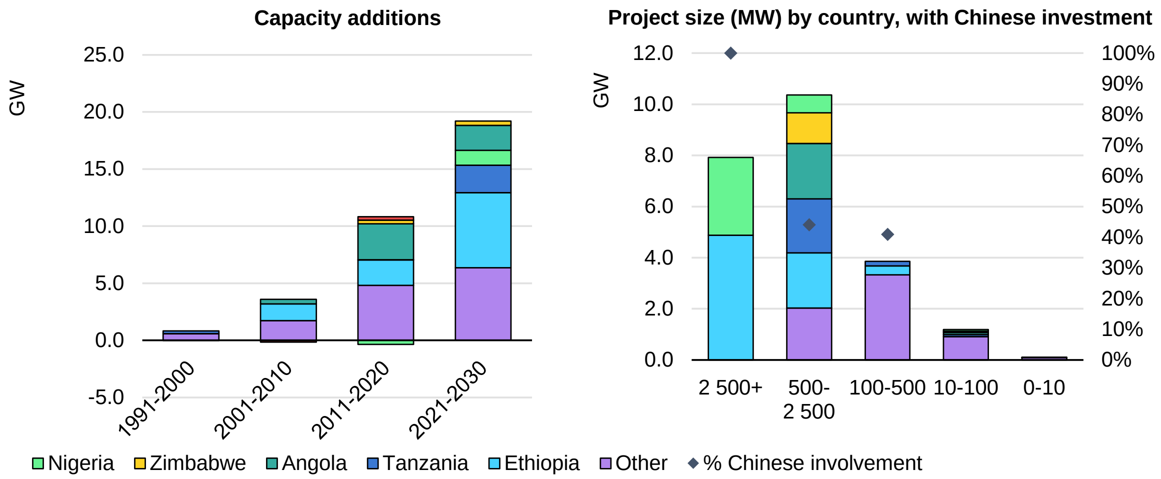
Sub-Saharan Africa

Sub-Saharan Africa is set to add over 19 GW of new hydropower capacity, almost doubling the region's cumulative installed total and making it the world's third-largest market for new capacity during the forecast period. More than half of the new capacity is expected by 2025.

Many countries in the region have much untapped economic potential, making large-scale hydropower one of the most affordable sources of electricity generation to increase energy access. Over 75% of new hydropower capacity additions will be in countries where less than half of the population has access to electricity. These installations will mostly be dual-purpose reservoir projects for irrigation or flood control in addition to power generation.

Given the high macroeconomic risks, potentially less-than-ideal location of plants and electrification policies, the majority of new plants will be developed by either governments or publicly owned utilities, with a focus on projects of at least 500 MW of installed capacity. The Chinese government or Chinese-owned firms are involved in nearly 70% of the forecast capacity through project ownership, financing or construction contracts. Projects can also provide a source of additional revenue by producing power that can be exported to a regional power grid or to other countries through agreements.

Figure 3.10 Sub-Saharan Africa hydropower capacity additions by size in selected countries, 2021-2030



Four countries contribute over 60% of sub-Saharan Africa's forecast capacity additions. The full or partial commissioning of two major dams in **Ethiopia** (totalling over 6 GW) represents more than 30% of the region's total additions. The Grand Ethiopian Renaissance Dam, currently under construction with a planned capacity of nearly 5 GW, will be the largest hydropower plant in Africa when commissioned. Project development has had some challenges, however, due to high investment costs and its location along the Nile River, which has led to regional disagreements over the pace of reservoir-filling. Outside of Ethiopia, state-owned enterprises are developing four large projects totalling over 5.5 GW in **Tanzania**, **Nigeria** and **Angola**.

Countries that enable IPPs to develop hydropower projects have a higher number of small hydropower installations, especially **Cameroon**, **Kenya** and **Uganda**, where developers can sign long-term PPAs with utilities, resulting in more small-scale projects of various sizes. Small-scale installations in these countries can supply power to areas with limited access to the national grid. As small hydropower projects have shorter development and construction times than larger ones, they can provide electricity access in places where it is urgently needed.

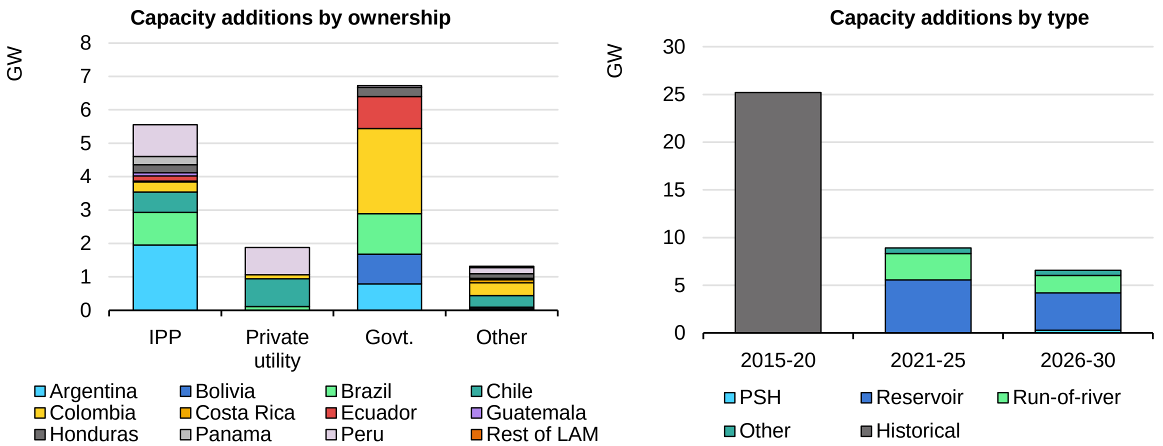
Macroeconomic challenges such as political uncertainty, currency volatility and/or high levels of debt and off-taker risks result in high financing costs that weaken the viability of large-scale hydropower projects in Africa. Gaining social acceptance (for both large and small projects) also continues to be a challenge, leading to delays and increased project risk.

The timely deployment of hydropower projects depends strongly on the implementation of de-risking measures and recognition of how dams can contribute to climate-change adaptation. Public-private partnerships and development bank financing will be critical to future development, to allocate project tasks and risks to those parties best suited to execute and mitigate them.

Latin America

Latin America's capacity is expected to increase almost 15.5 GW (over 8%) by 2030, almost entirely from greenfield projects. Nevertheless, expansion during 2021-2025 is over 35% lower than in the previous five-year period (25 GW), with further slowdown expected by 2030. This is mainly due to Brazil adding only 2.3 GW of new capacity during the forecast period, 92% less than in the last decade. Outside of Brazil, hydropower growth in other countries (led by Argentina and Colombia) is slightly above the historical trend, but not enough to offset the overall regional slowdown.

Figure 3.11 Latin America hydropower forecast summary



Notes: IPP = independent power producer. LAM = Latin America. PSH = pumped-storage hydropower.

In Latin America, rising electricity demand, untapped economic potential, long-term government planning and supportive policies for large and small plants drive hydropower growth. The need for system flexibility and dispatchable renewable energy also spurs hydropower development as VRE deployment in the region rises. However, the investor profiles of hydropower plants vary drastically depending on the policy approach.

Over 2021-2030, more private sector than government investment is anticipated, including from IPPs and privately owned utilities. In Argentina, the region's largest growth market, the government performs feasibility and environmental studies and then tenders out projects to IPPs. Auctions with long-term contracts also stimulate private sector investment in Latin America.

Although Brazil has implemented competitive tenders for both large- and small-scale projects in the past, its approach to hydropower development has shifted. As many remaining large-scale projects would have to be developed in ecologically sensitive areas, more small-scale installations will be deployed though auctions instead, and the robust deregulated market allows for bilateral agreements between developers and third parties.

In addition, the Peruvian government has auctioned over 560 MW of projects (each with a capacity of 20 MW or less), of which over 50% are already in operation (IHA, 2017). Chile is developing the region's only PSH plant, Espejo de Tarapacá, during the forecast period as part of a 600-MW solar PV and 300-MW PSH hybrid project.

Conversely, in Colombia, Ecuador and Bolivia, government-owned utilities continue to develop, own and operate large hydropower projects. In Ecuador, for instance, the government included additional hydropower development in its long-term planning, with surplus electricity exports cited as the main driver. Meanwhile, Colombia is bringing online its largest hydropower project, Hidroituango, which will inject an additional 2.4 GW into the system.

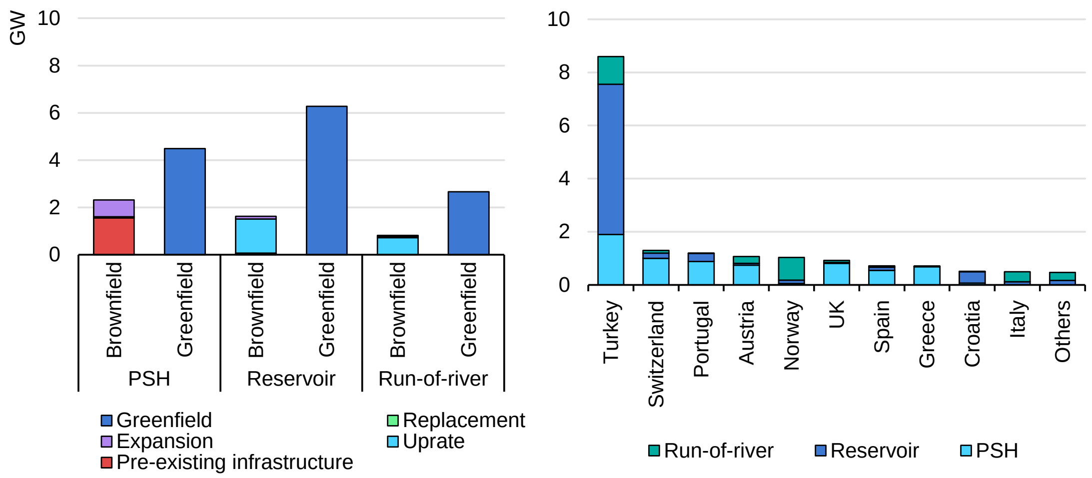
Addressing environmental concerns and social opposition is essential for the development of reservoir and large run-of-river projects in Latin America. The forecast mostly includes projects that have closed financing and are under construction, but it also encompasses some that have acquired permits or are planned, depending on individual country and project circumstances. However, the commissioning of these projects remains a forecast uncertainty because of various social, environmental and economic challenges. High investment costs, long lead times and diversification efforts may also result in lower-than-expected growth in Latin America.

Europe

Europe's hydropower capacity is forecast to increase 8% (+18 GW) over 2021-2030. Growth is led by reservoir installations almost exclusively from greenfield projects in Turkey, which account for over 70% of Europe's reservoir expansion. Turkey's main impetus for growth is its hydropower target (34 GW by 2023), supported by FiTs for both large and small projects. Private investment, mostly for projects of 100-500 MW, is expected to support over 70% of the increase.

Outside of Turkey, new reservoir projects in Europe are expected to be restricted to Portugal and Croatia, as obtaining permits for new installations is challenging and economic potential is limited. Any additional reservoir capacity expansion will be mostly from expanding or uprating existing ageing plants in Norway, Romania, Switzerland, Austria and Poland.

Figure 3.12 Europe net hydropower capacity additions, 2021-2030



Note: PSH = pumped-storage hydropower.

The second-largest source of growth is PSH expansion, which will provide the system flexibility needed to integrate rising VRE shares, accounting for more than one-third of Europe's net hydropower increase. Adding pumping capabilities to existing infrastructure is a key PSH development trend in Europe and makes up one-fifth of PSH expansion. These types of plants tend to cost less and are easier to acquire permits for because of pre-existing infrastructure such as natural reservoirs and the conversion of reservoir hydropower to mixed-usage plants.

Turkey is forecast to install its first PSH units by 2030 where flexibility is needed to accommodate rising shares of carbon-free generation while Switzerland is forecast to complete one large single plant (1 GW) currently under construction.

Growth is also expected from projects under development in Portugal and Spain, as both aim to increase their PSH capacity by a combined 6 GW during 2020-2030 to meet the renewable energy targets set out in their national energy and climate plans.

However, financing for planned PSH projects is key forecast uncertainty. Limited opportunities for arbitrage on wholesale electricity markets and low remuneration for ancillary services weaken the business case for PSH in the absence of long-term revenue guarantees.

Additional greenfield capacity is expected to come from smaller run-of-river projects owing to attractive economics in Norway and FiTs for small installations in Italy, Austria and Poland. Whether these support mechanisms are sufficient to attract new investment is nevertheless a forecast uncertainty. Lower wholesale electricity prices and water royalties may make the business case for new developments less attractive, and the impacts of water regulation on new investment decisions may challenge faster growth.

North America

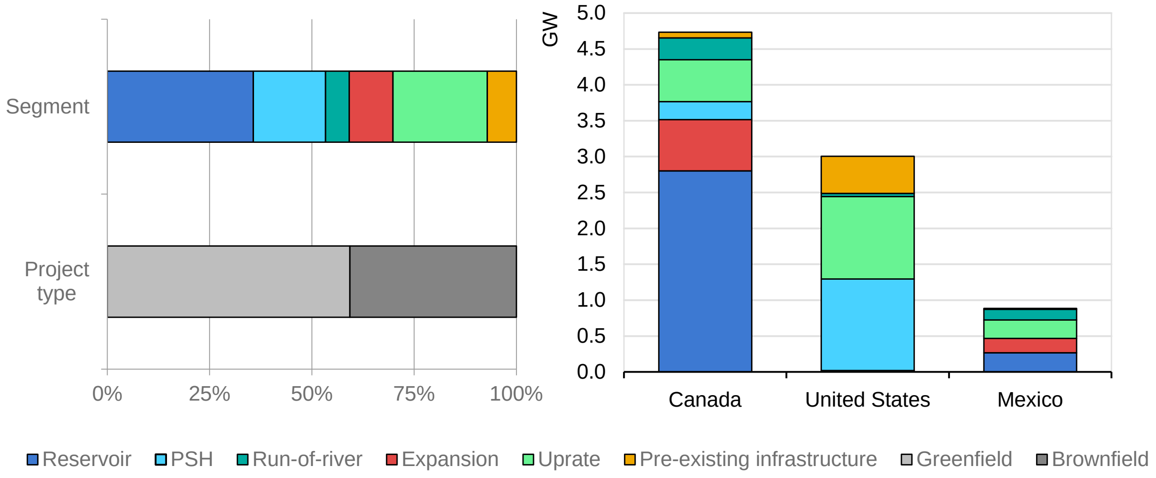
North America's hydropower capacity is expected to increase 8.6 GW during 2021-2030, led by Canada and followed by the United States and Mexico. New large reservoir projects in Canada and PSH projects in the United States make up the majority of the region's greenfield capacity additions.

Compared with other regions, North America has a larger share (40%) of net brownfield capacity additions made up of plant modernisations and the addition of capacity to pre-existing, previously non-powered infrastructure. The main impetus for these projects is the ageing of the region's fleet (averaging 50 years old), in addition to strict environmental regulations in some jurisdictions limiting new developments that substantially alter existing topography.

Most hydropower expansion in Canada will consist of new large-reservoir projects (60%), half from just three very large plants of more than 500 MW each. Growth drivers include provincial climate targets; anticipated new power demand (in British Colombia); and the potential (in Manitoba) to export energy to the United States to supply renewable electricity for state-level targets (i.e. renewable portfolio standards [RPSs]). However, cost overruns and commissioning delays have already hindered progress on several large projects.

An additional 30% of net growth is to come from modernisation, mostly by uprating the capacity of existing plants. Underpinning these projects is the need for long-term reliability and baseload power generation in anticipation of coal fleet retirements, as well as rising shares of wind energy in both Canada and the United States. Diversification away from costly fossil fuels also spurs the construction of small run-of-river plants in First Nations communities where hydropower is displacing more expensive diesel-fired generation.

Figure 3.13 North America net hydropower capacity additions, 2021-2030



Note: PSH = pumped-storage hydropower.

Conversely, the main sources of new hydropower capacity in the United States are new PSH plants and the addition of power to pre-existing infrastructure such as dams and conduits. Almost 3 GW of both segments have been licensed or have qualified as exempt from licensing under a new regulation designed to expedite the permitting process for low-environmental-impact projects (Oakridge, 2021).

In 2018, the maximum response time for license applications for closed-loop PSH and non-powered dams was limited to two years, and additional regulatory amendments to extend preliminary permits and construction timelines should also facilitate deployment.

PSH development, accounting for 43% of growth, is triggered by the need for greater system flexibility in the north-western United States to integrate rising VRE shares mandated by RPSs. Meanwhile, national FiTs support new capacity added to existing water infrastructure is supported by national feed-in tariffs for projects as existing dams. Outside of these two segments, net growth is also expected to come from uprating of older plants. Limited growth is expected for new reservoir or run-of-river projects given the environmental restrictions on new greenfield projects and the limited eligibility to qualify for certificates under state-level RPS (DOE, 2021).

Over half of Mexico's net hydropower capacity additions will be from modernisations (i.e. plant expansions and uprates) and run-of-river projects. New reservoir capacity comes from just one plant under construction, as concerns over the environmental impacts of larger plants and of droughts on current generating capacity have caused the government to limit construction of new reservoir capacity.

Mexico's latest expansion plans therefore focus on modernising its ageing fleet and building run-of-river installations. However, the economic attractiveness of investing in modernisation is a forecast uncertainty, and the prospect of having less water available for power generation due to lower precipitation and agricultural competition for water use is also a threat. The risk of inefficient reservoir management is an additional consideration.

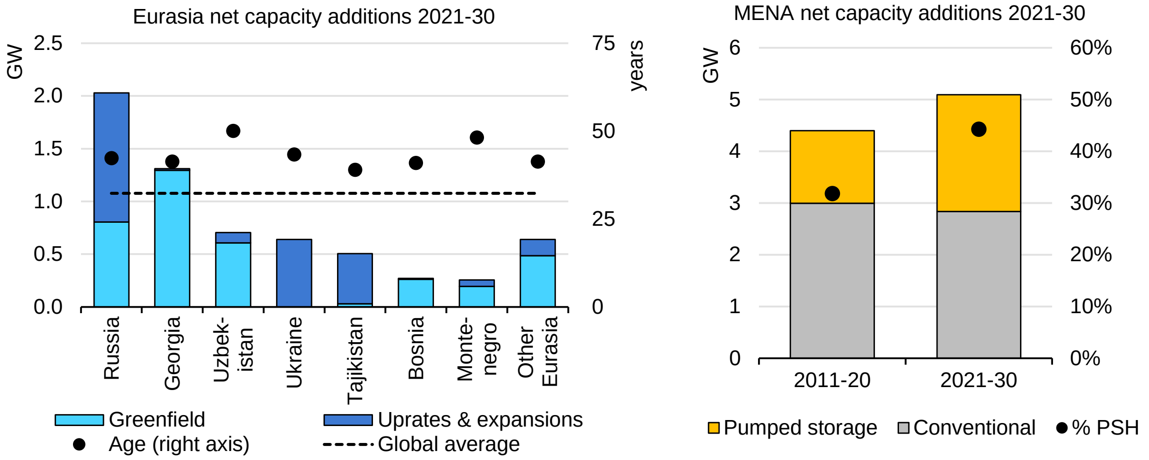
Rest of world

Hydropower capacity in Eurasia is forecast to increase 7% (6.4 GW) between 2021 and 2030. Russia, the region's leader in cumulative capacity, is the largest source of growth (30%), followed by Georgia, Uzbekistan, Ukraine, Tajikistan, Bosnia and Montenegro.

One of the region's most notable trends is the large share of overall net hydropower capacity growth contributed by new capacity from existing projects. During 2021-2030, Eurasia will have the one of the world's largest share of net capacity additions from uprates and expansions to modernise ageing plants.

In fact, as the average fleet age in the region's leading growth markets is 40-50 years, uprates and expansions will make up around 30% of its net capacity additions over the forecast period, led by Russia, Ukraine and Tajikistan. The main drivers for modernisation are to restore the performance of ageing plants, maintain their availability and improve system flexibility.

Figure 3.14 Net hydropower capacity additions in Eurasia (left) and in the Middle East and North Africa (right), 2021-2030



Notes: MENA = Middle East and North Africa. PSH = pumped-storage hydropower. The average age of the hydropower fleet in Tajikistan excludes the first two units (600 MW each) of the Rogun power plant, which were commissioned in 2018 and 2019.

Greenfield projects provide the majority of net hydropower capacity additions, but they are more prominent in some countries than in others. Some economies are developing new projects to meet fast-growing domestic power demand and reduce reliance on imported fuels (Georgia), while others are striving to improve electricity access for rural communities (Russia and Uzbekistan) and meet renewable energy targets and climate goals (Energy Community countries). The pace of development will depend on how quickly transmission grids and interconnections can be strengthened and expanded.

In the Middle East and North Africa (MENA), net hydropower capacity additions are expected to be 15% higher in 2021-2030 than in the previous decade, owing to stronger pumped-storage hydropower (PSH) development in Morocco, Egypt, the United Arab Emirates, Israel and Iran. In most of these markets, the need for greater system flexibility to accommodate increasing solar PV penetration is the main driver for growth.

PSH plants are therefore expected to account for almost 45% of the MENA region's hydropower deployment, up from just 30% in 2011-2020. Remaining conventional hydropower additions will come mostly from large reservoir projects in Iran.

Accelerated case

In the accelerated-case forecast, almost 90 GW (40% more) more hydropower capacity is possible than in the main case between 2021 and 2030. The accelerated case assumes actions taken in the immediate future to address some of the policy, regulatory, market and administrative challenges could result in faster development of the current project pipeline.

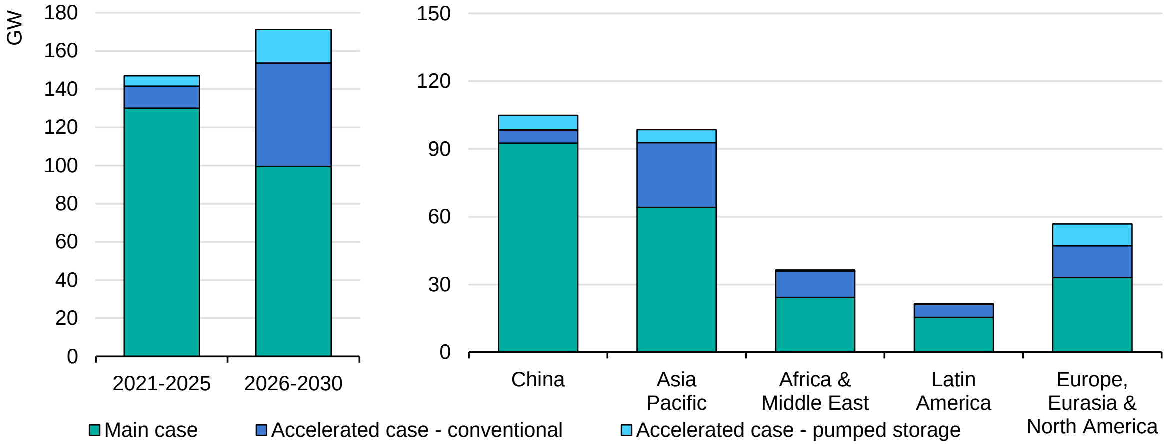
The impact of these actions on the forecast before 2025, however, will be limited, given the the long lead times of hydropower projects. Only 11% more growth than in the main case is expected if construction times are shorter and project delays kept to a minimum over 2021-25. The greatest upside potential is in the second half of the forecast period, when actions taken prior to 2025 can help spur the construction of projects that are currently in the early development stages and vulnerable to key forecast uncertainties.

Beyond 2025, growth could be 40% higher if permitting processes were expedited and made more affordable, and financing was secured for approved projects. The potential for additional accelerated-case expansion depends largely on the extent to which plants currently at the licensing and permitting stage can economically complete the environmental impact assessments required in order to be fully licensed.

Many projects have preliminary licences to assess feasibility, but the costs and time required to carry out environmental assessments and meet regulations can challenge a project’s bankability. Support to minimise project costs (e.g. funding for feasibility studies) and shorter wait times for licensing would therefore accelerate growth.

Addressing the environmental and social concerns of some projects delayed in the Asia Pacific region and Latin America, as well as gaining public acceptance, would also result in higher growth. In Europe and North America, streamlining permitting procedures and introducing regulations to simplify the approval process would boost expansion.

Figure 3.15 Net additions in the main and accelerated cases globally, 2021-2025 and 2026-2030 (left) and by region, 2021-2030 (right)



In emerging economies, financing large infrastructure projects remains a challenge for many cash-strapped state utilities/governments. In some countries, the Covid-19 pandemic has exacerbated this problem by reducing power demand and therefore utility revenues, raising questions about the need for previously planned hydropower projects and their affordability. Additional growth under these circumstances will depend on power demand rebounds, increased access to concessional financing, and the introduction of innovative business models such as public-private partnerships that allocate risk to the appropriate stakeholder.

The slow pace of regional interconnection also poses a downside forecast risk to projects for which the business case depends strongly on export revenues. Accelerating the construction of transmission lines would therefore raise the economic viability of some planned projects.

In liberalised markets, the absence of long-term contracts and revenue guarantees for PSH and refurbishment projects makes it difficult to secure financing. Modifying market designs with products or introducing policies that provide certainty could boost growth for projects in the prefinancing stage.

As approximately 40% of accelerated-case potential for Europe, North America and Eurasia is based on PSH, having a sound business case at the earliest stages of development could help ensure project deployment. For small hydropower, longer loan payback periods and greater support would also accelerate expansion.

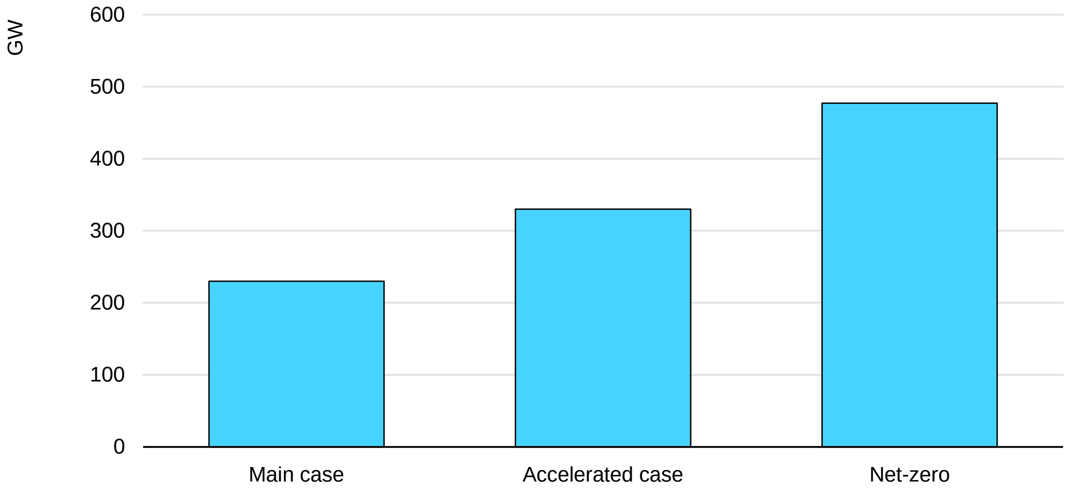
Is hydropower growth on track with the IEA's global energy roadmap, *Net Zero by 2050*?

While our accelerated case provides an outlook for faster hydropower expansion based mostly on better policy, regulatory, market design and administrative conditions, it will be necessary to raise hydropower ambitions drastically to reach the *Net Zero by 2050* level. In fact, hydropower capacity expansion by 2030 would need to be 45% higher than in our accelerated case.

Globally, around half of conventional hydropower's economic potential remains unrealised, mostly in Asia, Africa and Latin America. With robust implementation of internationally accepted sustainability rules, further acceleration of hydropower deployment is possible – but only with increased policy attention and action in the next few years.

In the IEA's world of net-zero emissions, hydropower is the backbone of global electricity security and the most cost-effective, dispatchable and flexible low-carbon electricity technology option to integrate VRE shares of almost 70% by 2050.

Figure 3.16 Net hydropower capacity growth in main case, accelerated case and IEA net-zero roadmap, 2021-2030



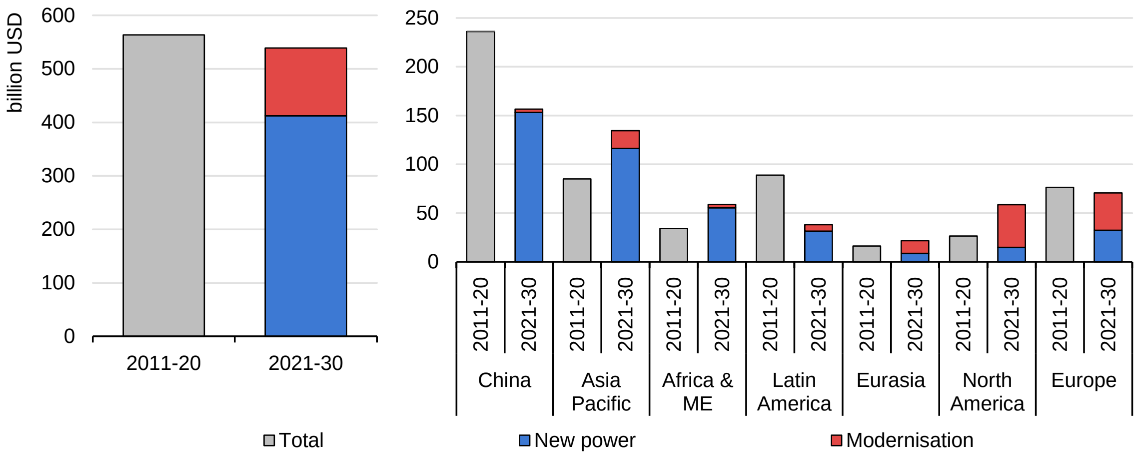
Source: IEA (2021b), *Net Zero by 2050: A Roadmap for the Global Energy Sector*.

Investment trends

Global investment in hydropower capacity over the course of 2021-2030 is expected to total USD 540 billion, relatively in line with spending in the previous decade. But stable spending does not equate to stable capacity growth. The investment level is similar only because higher spending on modernising existing plants in mature markets offsets lower investment in new power plants in younger markets such as those in Asia and Latin America.

Investment in greenfield hydropower projects slows in the top three markets – China, Brazil and Turkey – which together accounted for 60% of the previous decade's growth. The only two regions where spending on new power plants is forecast to increase are Asia Pacific (led by India) and sub-Saharan Africa, owing to the need for cost-effective power generation to expand electrification.

Figure 3.17 Hydropower capacity investment globally (left) and by region (right), 2011-2020 and 2021-2030

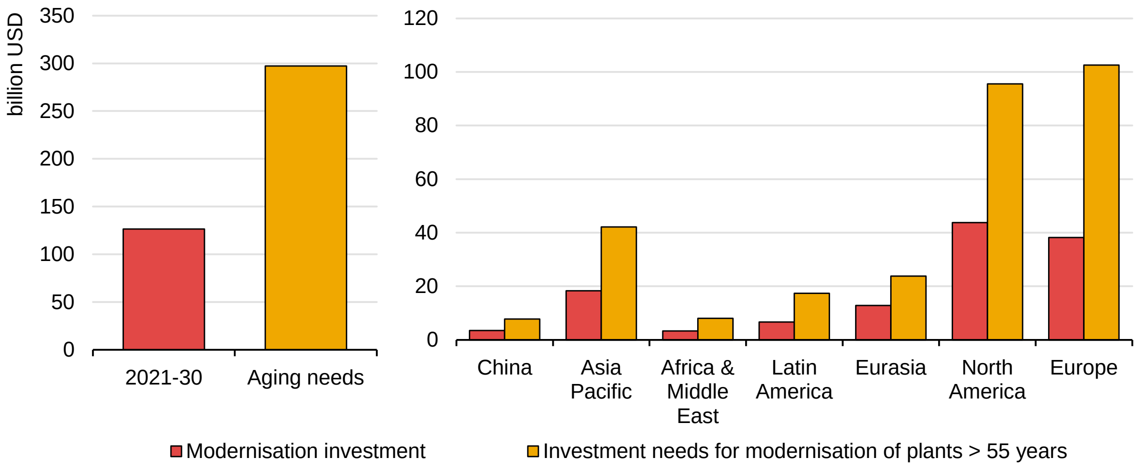


Notes: ME = Middle East.

Almost one-quarter of global hydropower investment during 2021-2030 is expected to go towards modernising existing fleets through turbine replacements, uprates and capacity expansions. The aim of these investments is to extend a plant's lifetime, restore its initial performance and improve its flexibility.

The overwhelming majority of global spending on modernisation (75%) will be in North America, Europe and Eurasia, where most of the world's ageing capacity is located. By 2030, almost half of the hydropower fleets in these regions will be more than 55 years old, the age at which the first major electromechanical investments are required to recover or improve performance. Most investment in these markets will therefore be used to restore performance to maintain availability, and to adapt the plant to operating conditions that may have changed since the plant was built.

Figure 3.18 Actual vs required investment in modernisation globally (left) and by region (right), 2021-2030



Notes: Ageing needs and investment needs for modernisation refer to the replacement of major electromechanical equipment after 55 years and do not account for major modernisation activities outside of turbine and generator replacements.

Spending on plant modernisation is less than half of what is needed

Planned and announced modernisation projects are estimated to cost a total of USD 127 billion by 2030 – only 43% of the investment actually needed to maintain the performance of the existing fleet's installed capacity. By 2030, more than 20% of the global fleet's generating units will be more than 55 years old and requiring major electromechanical equipment replacements.

Investments totalling approximately USD 300 billion will be required to replace turbines reaching the end of their lifespan, a necessary step to maintain plant availability and restore performance to original levels. But costs could be much higher if additional investments beyond turbine replacement are included, for example to upgrade civil works, other electromechanical equipment (gates, penstocks, valves, etc.) and auxiliary machinery.

Additional modernisation investments can involve conversions to automated controls, remote monitoring and predictive maintenance. Refurbishment needs will also be dictated by increasing plant flexibility, changing hydrology patterns and, in some cases, new environmental and dam safety regulations.

Two-thirds of global hydropower refurbishment investments are needed for ageing fleets in Europe (average age 48) and North America (average age 56). However, due to a lack of confidence in the business case for refurbishment in these regions, the main case sees only 41% of modernisation investment needed being spent.

In addition to declining wholesale prices in some markets, uncertainty over concession renewal procedures reduces the long-term visibility needed to incentivise high-capex investments. Other challenges include obtaining permits under new environmental, water and dam safety regulations instated after commissioning dates.

In emerging economies, investment needs may be even greater as a result of poor operations and maintenance practices that can cause plants to require replacement parts in less than 55 years.

Generation

Recent trends

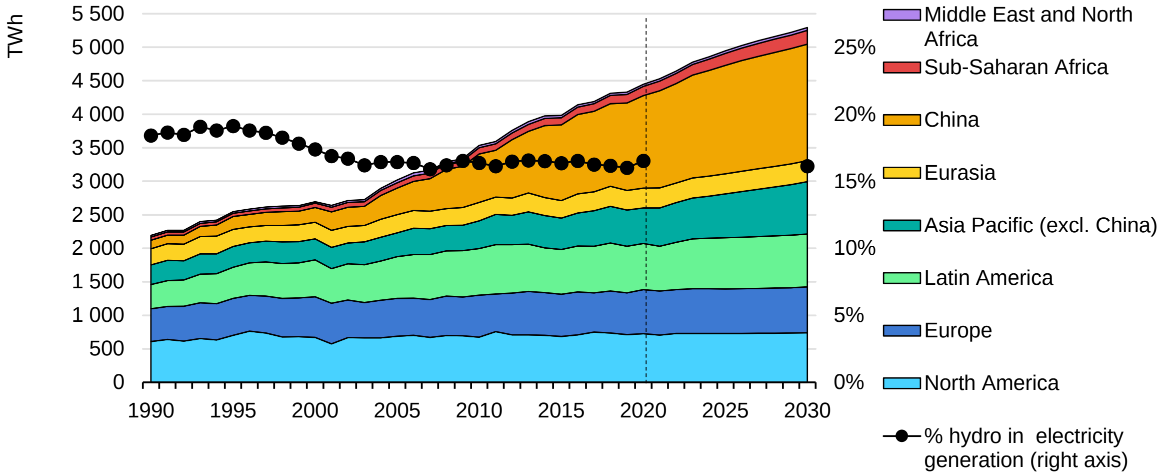
Global gross annual hydropower generation, including from PSH,[5] has doubled over the past three decades to reach almost 4 500 TWh in 2020, putting hydropower far ahead of nuclear energy as the largest source of low-carbon electricity.

China played a leading role in this growth, being the largest single-country producer from 2004 and accounting for two-thirds of the global increase since 2005. Between 2000 and 2020, China's hydropower generation expanded sixfold – in proportion to the country's total electricity generation – while its share in global hydropower output rose from 8% to 31%.

Brazil and India were the second- and third-largest national contributors to growth during this period, while North America and Europe, which together accounted for almost half of global hydropower generation in 2000, represented just 7% of the global increase.

[5] From an energy system perspective, PSH is primarily a form of storage, and in terms of hydropower output a distinction should be made between gross and net generation (to account for energy consumed for pumping). However, limited availability of turbine-level data and the diversity and complexity of plant configurations (e.g. open loops, hybrid plants) make it difficult to estimate net generation, so this section discusses gross PSH generation only.

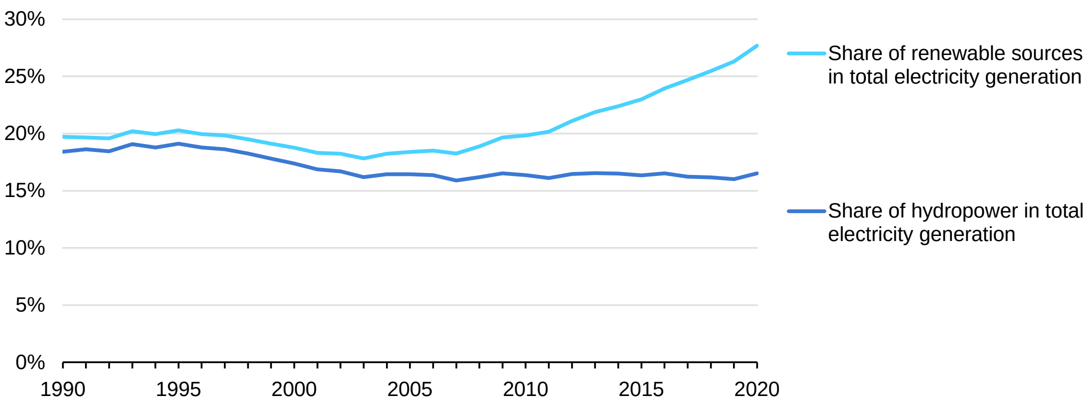
Figure 3.19 Gross hydropower generation by region, and share of hydro in global electricity generation, 1990-2030



Sources: Based on IEA (2020a), World Energy Statistics and Balances 2020 (database); IEA (2021c), Global Energy Review 2021; IEA (2020b), World Energy Outlook 2020.

At the global scale, the share of hydropower in total electricity generation has remained relatively flat at around 16% for the past 15 years. However, with the recent expansion of wind and solar PV installations, its share in global renewables-based electricity generation fell from 92% in 2005 to 61% in 2020.

Figure 3.20 Shares of hydropower and total renewable sources in global electricity generation, 1990-2020

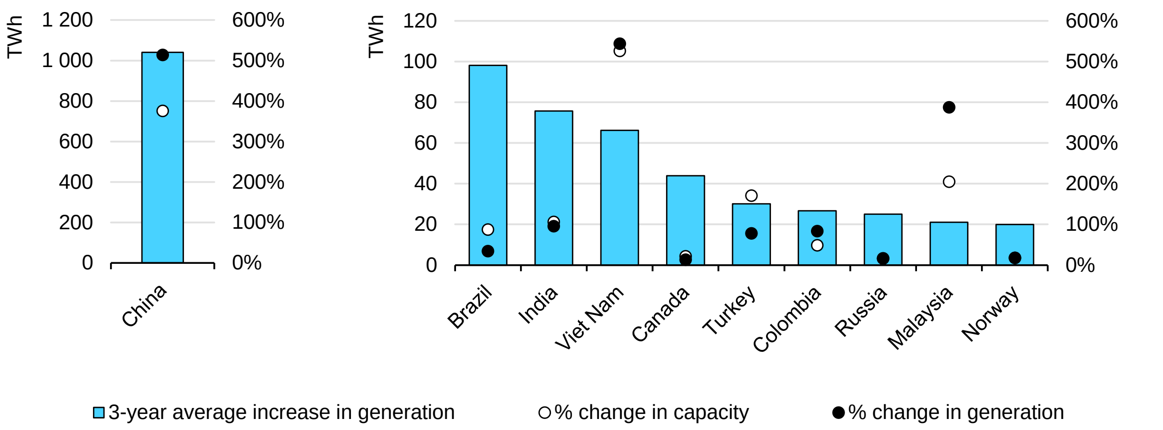


Sources: Based on IEA (2020a), World Energy Statistics and Balances 2020 (database); IEA (2021c), Global Energy Review 2021.

In 2020, Brazil was the largest hydroelectricity producer after China, followed by Canada. Despite having less installed capacity, Canada outperformed the United States thanks to a higher overall capacity factor. Together, these four countries accounted for 55% of global hydropower generation.

PSH represented 12% of global installed hydropower capacity but accounted for only 2.6% of total gross hydro generation in 2019. China and the United States together contributed 46% of global gross PSH output, while Japan, Germany, South Africa and France together generated another 20%.

Figure 3.21 Gross hydropower generation and capacity growth among top ten countries with largest increases, 2000-2019



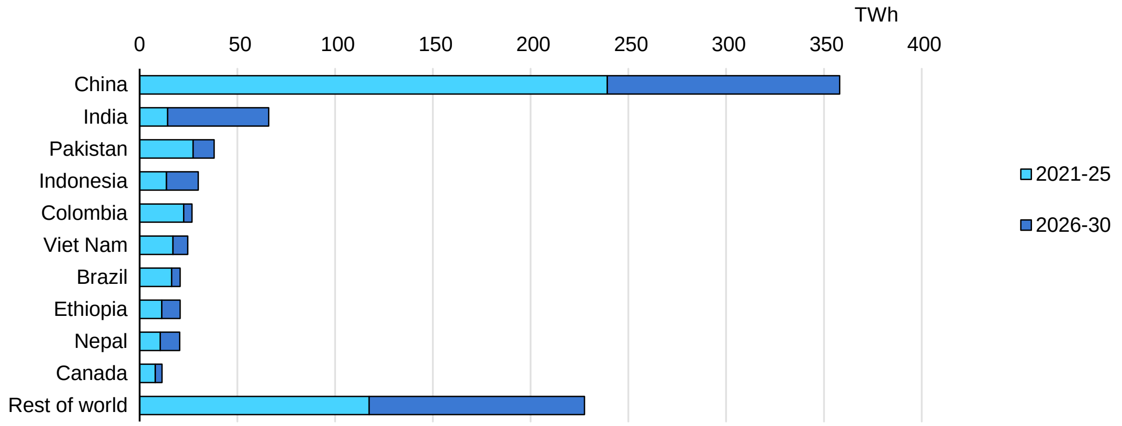
Note: Generation can increase more quickly or slowly than installed capacity, depending on changes in the capacity factor of existing plants and on capacity factors of new assets in comparison with the existing fleet.
Source: Based on IEA (2020a), *World Energy Statistics and Balances 2020* (database).

Outlook to 2030

Global hydropower generation is projected to expand 19% over 2021-2030

During 2021-2030, annual gross hydropower generation is expected to increase by almost 850 TWh (+19%) globally, with China alone accounting for more than 42% of this growth and India, Indonesia, Pakistan, Viet Nam and Brazil together contributing another 21%. PSH, which makes up one-third of projected capacity additions, contributes 7% of the anticipated increase in global gross hydropower generation by 2030.

Figure 3.22 Main-case increases in annual gross hydropower generation among top ten countries with largest growth, 2021-2025 and 2026-2030



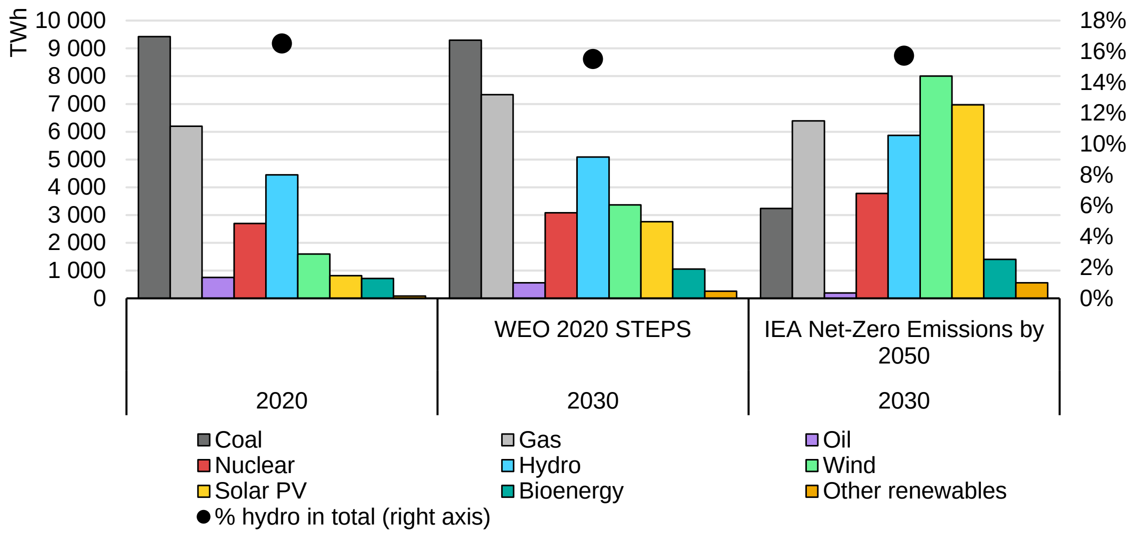
Hydropower will likely remain the largest low-carbon source of electricity generation globally over the next decade

In the IEA Stated Policies Scenario (STEPS),[6] hydropower is expected to retain its place as the primary low-carbon-electricity source globally during the next decade, with its share in total electricity generation falling just slightly to 15.5% by 2030. It is expected to account for 41% of global renewable electricity generation in 2030, down from 61% in 2020, owing to the rapid uptake of wind- and PV-based generation.

Alternately, under the IEA Net-Zero Emissions (NZE) scenario, hydropower generation increases by one-third between 2020 and 2050. On this pathway, hydropower still represents nearly 16% of total electricity generation by 2050, making it the fourth-largest electricity source after solar PV, wind and gas.

[6] STEPS reflects the impact of existing policy frameworks and today's announced policy intentions. According to STEPS projections, the world is not on course to achieve the UN Sustainable Development Goals (SDGs) most closely related to energy: to achieve universal access to energy (SDG 7), to reduce the severe health impacts of air pollution (part of SDG 3) and to tackle climate change (SDG 13). The NZE scenario aims to outline one possible transformation pathway for the global energy system, showing how the global energy sector can change course to reach net carbon neutrality by 2050 and deliver on these three SDGs simultaneously. For more details, see: https://www.iea.org/reports/net-zero-by-2050.

Figure 3.23 Global electricity generation by source in STEPS and Net-Zero Emissions by 2050, 2020-2030



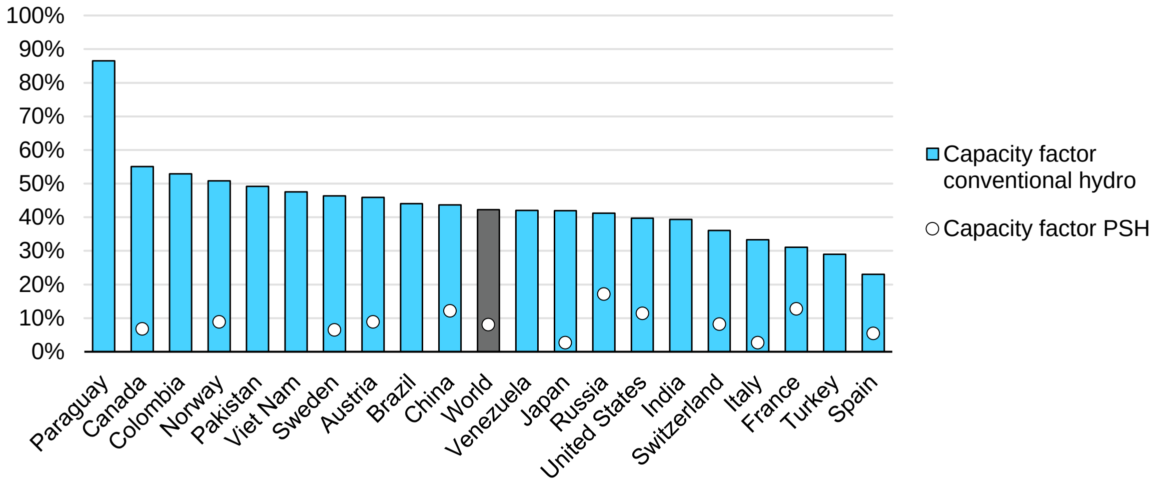
Notes: STEPS = Stated Policies Scenario. SDS = Sustainable Development Scenario.
Source: IEA (2020b), World Energy Outlook 2020.

Future hydropower generation is subject to uncertainties

Capacity factors vary over time and across installations according to hydrological patterns and plant type and purposes

Annual hydropower capacity factors vary significantly across the global hydro fleet, with most conventional projects falling within the 25-80% range (IRENA, 2020). A plant's capacity factor is determined by hydrological conditions; market and policy circumstances; and a number of plant-level variables including type (run-of-river, reservoir or PSH), designed purpose and mode of operation (peak or baseload generation, or frequency response), resource quality, outage schedules (planned or unplanned), minimum ecological flow requirements and multiple-usage constraints.

Figure 3.24 Average overall and PSH-specific hydropower capacity factors, world and top 20 generating countries, 2015-2019



Note: PSH = pumped-storage hydropower.
Source: Based on IEA (2020a), *World Energy Statistics and Balances 2020* (database).

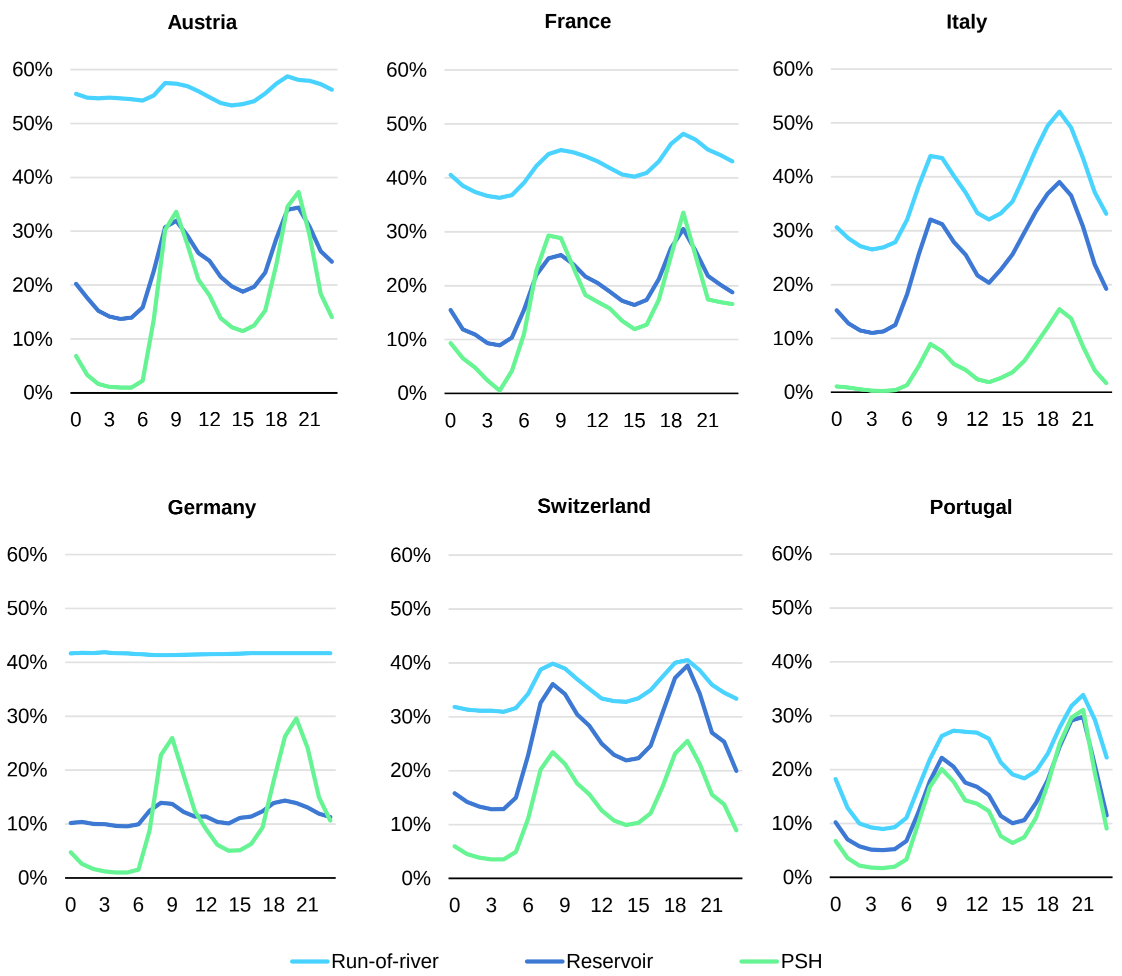
Hydropower plants designed for baseload generation – as is the case for many run-of-river plants – have among the highest capacity factors, while installations for peak generation can have capacity factors as low as 10-15%. Schemes optimised for financial return generally have above-average capacity factors, while PSH plants, which are increasingly used for flexibility services and frequency response, have particularly low generation capacity factors (8% on average globally in 2019[7]). Older PSH plants also often have higher round-trip losses, meaning that a larger electricity price gap between pumping and generation is required for economic profitability, reducing operation opportunities.

The multipurpose nature of certain dams and reservoirs can also restrict their generation, as hydropower might be given lower priority than other purposes such as flood control, irrigation, recreation or navigation. In such cases, generation patterns will reflect the water-release profile of the primary purposes (e.g. seasonal for irrigation, stable across the year for water supply, etc.). In some regions such as the United States, having multipurpose dams mostly under public sector management can therefore explain differences in average capacity factors between the public and the private segments of the hydropower fleet (US DOE et al., 2021).

[7] Because of pumping operations and cycle efficiency, the maximum theoretical capacity factor for closed-loop PSH plants is around 44% for generation.

Since in some cases there are several options for how a hydropower site can be designed (i.e. the site's specific characteristics do not automatically dictate a particular purpose and operating scheme), capacity factors for the new fleet segment will depend on the country's hydropower and grid flexibility strategies. With VRE shares becoming larger, future hydropower projects may be increasingly dedicated to balancing and flexibility services, possibly resulting in lower average capacity factors.

Figure 3.25 Annual average run-of-river, reservoir and PSH generation capacity factors for one day in selected countries, 2019



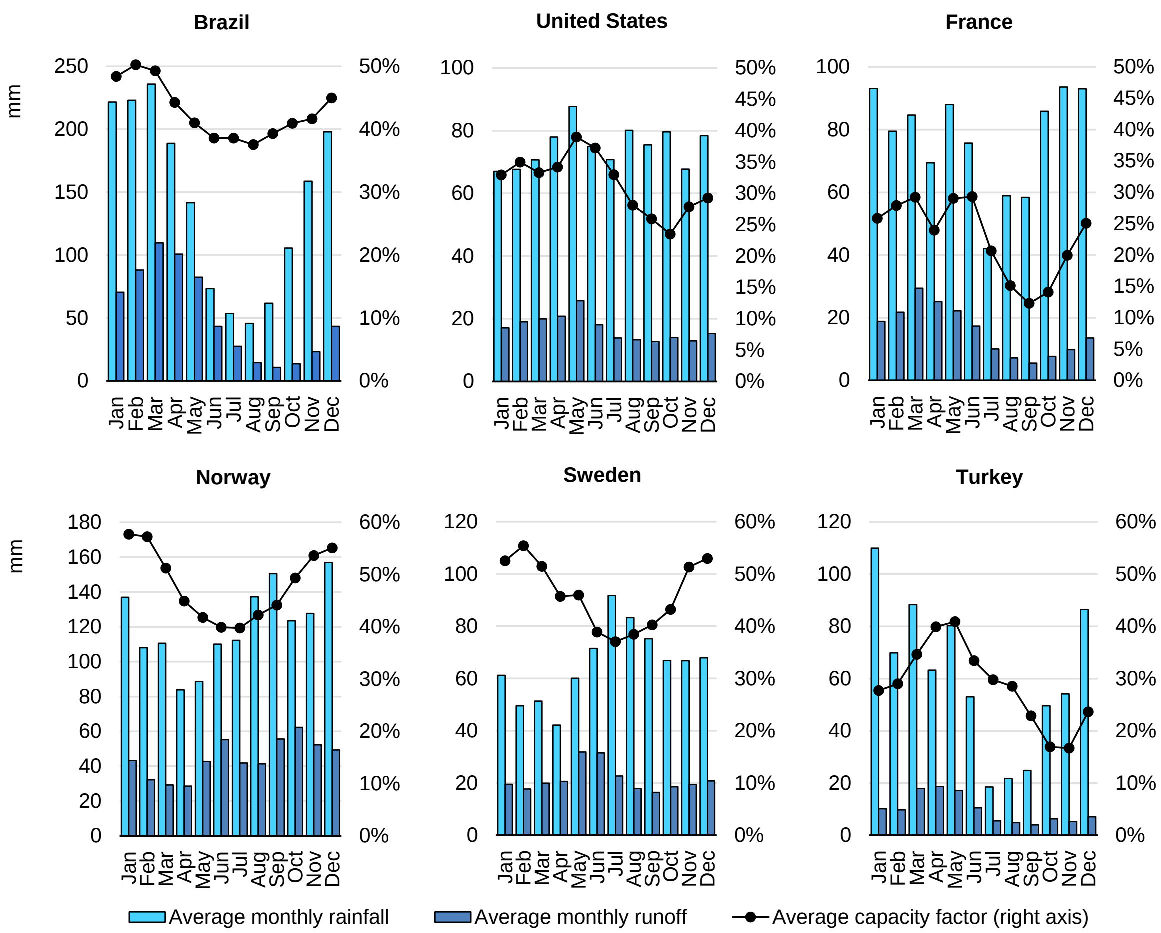
Note: PSH = pumped-storage hydropower.
Source: Based on ENTSO-E (2021), *Transparency Platform* (database).

Hydropower generation has a strong seasonality component

While hydropower is generally a dispatchable source of electricity, generation is constrained by hydrological conditions, particularly water runoff patterns (among other factors). These are largely determined by rainfall and, in river basins subject to snow accumulation and melting, temperature patterns.

Annual hydrological fluctuations can translate into seasonal hydropower operation patterns. This is particularly true for run-of-river plants. In contrast, seasonal storage capability allows the operations of some reservoir plants to be decorrelated from hydrological cycles, either partially or totally (typically when storage capacity exceeds 30-50% of annual waterflow).

Figure 3.26 Average monthly rainfall, runoff and hydropower capacity factors for selected countries, 2015-2020 and 2017-2020



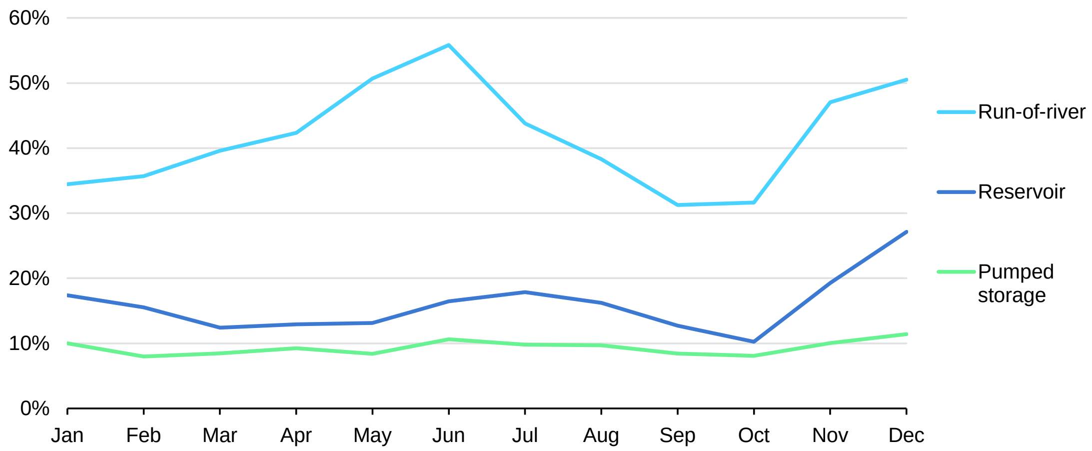
Notes: Rainfall and runoff correspond to average values from 2015 to 2020. Capacity factors correspond to average values from 2017 to 2020, except for the United States, for which it corresponds to average values from 2019 to 2020.

Sources: Based on climate data from World Bank Group (2021), CCKP; electricity generation data from ENTSO-E (2021), *Transparency Platform* (database); ONS, *Load and Generation Data* (database); EIA, *Electricity Data Browser* (database); EPIAS (2021), *Transparency Platform* (database).

Consequently, generation correlates more strongly with seasonal runoff patterns in countries that have large run-of-river shares, such as France (68% of hydropower generation in 2019), Austria (74%) and Italy (75%), than in those such as Norway and Switzerland, where reservoir and PSH together account for more than half of annual hydropower output.

Where PSH and reservoir installations dominate hydropower generation, seasonality can also stem from electricity demand patterns. This is the case in Norway, for instance, where the capacity factor is highest during the winter months when widespread electric heating in buildings boosts electricity demand.

Figure 3.27 Average monthly capacity factor by plant type, selected European countries, 2019



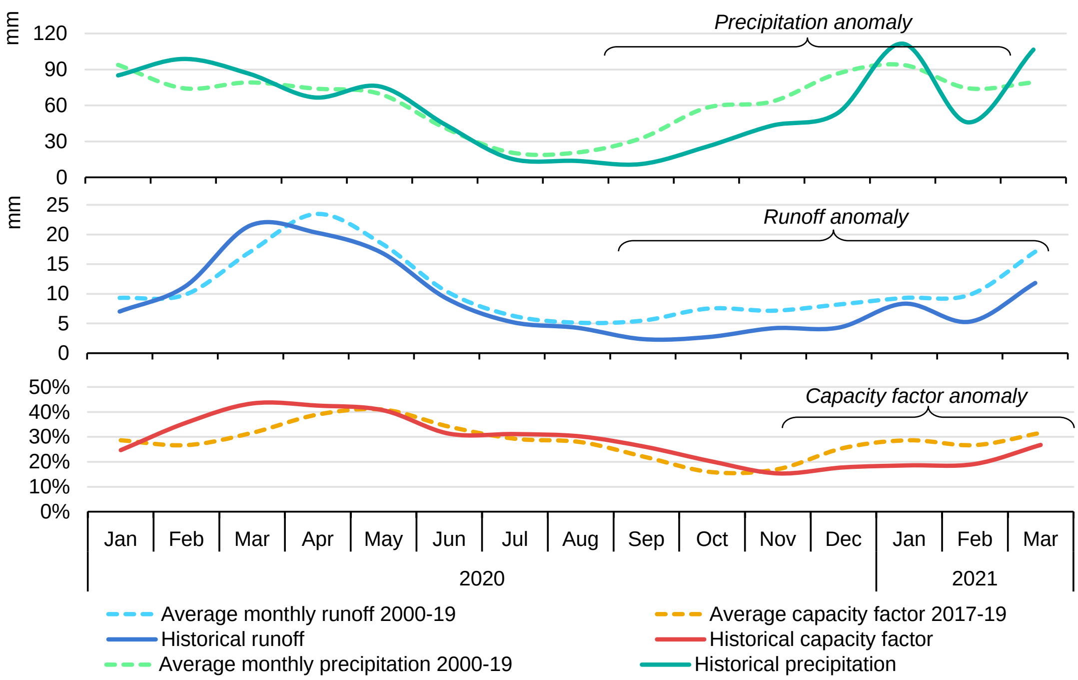
Note: Covers the aggregate of Austria, France, Germany, Italy, Portugal, Spain and Switzerland.
Source: Based on ENTSO-E (2021), *Transparency Platform* (database).

Hydropower generation is sensitive to extreme hydrological events

Hydropower's dependence on runoff patterns also means that generation is sensitive to extreme climatic and hydrological events, with both heavy precipitation and droughts affecting operations. While high precipitation can boost output, a plant's flood control capabilities may be prioritised and limit generation flexibility. Excessive river flows can also overload storage facilities and flood small plants or compromise operations.

Meanwhile, prolonged drought can significantly reduce hydropower generation (although sensitivity varies by plant). One recent example is Turkey's generation during a severe drought in 2020-2021: following historically low precipitation during the second half of 2020, hydropower capacity factors were about 30% below the monthly averages of December 2020 to February 2021. Another example involves the iconic Hoover Dam in the United States, for which capacity was down 25% in June 2021 due to a drought that affected the southwestern part of the country and reduced the Lake Mead reservoir level to a record low (USAToday, 2021).

Figure 3.28 Sensitivity of hydropower capacity factors to precipitation and runoff levels, Turkey, 2020-2021



Sources: Based on generation data from EPIAS (2021), *Transparency Platform* (database); IEA and CMCC (2020), *Weather for Energy Tracker*.

Heavy reliance on hydropower for electricity in drought-prone regions can also create energy security issues. In Eastern and Southern Africa, for instance, most projects are concentrated in the same river basins, hence subject to similar hydrological conditions and simultaneously vulnerable to drought (Conway et al., 2017).

Harmonised flooding and drought management protocols, established in concert with all water users, are crucial to ensure the co-ordinated action of operators located in the same river basin. Expanding storage capacity and capital investment in specific equipment (e.g. wide-head turbines) can also improve resilience and optimise hydropower operations during extreme hydrological events (US DOE et al., 2021). Additionally, public utilities can avail of risk-mitigation instruments (e.g. insurance schemes) to protect themselves from the financial risks of hydrological deficits.

Climate change impact on hydropower generation beyond 2030

Climate change already affects rainfall patterns and the frequency and severity of extreme events in various regions of the world. Although dams can help mitigate weather impacts through drought management and flood control, hydropower's dependence on hydrological conditions also implies vulnerability of generation to climate change.

The projected effects of climate change on hydropower generation vary across plants and countries, with increases in some regions and drops in others. In addition to impacts on generation, greater flood discharges could be another challenge for some installations, requiring significant investments to increase dam spillway capacity.

Europe's precipitation and runoff patterns are already changing, with the north generally wetter and the south generally drier in recent decades. Climate change is expected to deepen these trends, with seasonal differences becoming more marked over time (EEA, 2019). Adverse impacts on hydropower generation are expected in southern European countries such as Turkey, Italy, Portugal and Spain, while consequences for northern countries are more mixed.

In northern Europe, greater water availability in the medium term may boost hydropower generation, but higher river flows also pose operational challenges and can reduce storage capacity in the longer term by increasing sediment transport. In the long term, glacial retreat caused by rising average temperatures (e.g. in the Alps) is projected to result in lower streamflow in the spring and summer.

Recent prospective modelling for the United States suggests that, by 2050, climate change is likely to cause earlier snowmelt and affect runoff seasonality with higher winter and spring flows and less runoff in the summer and fall (ORNL, 2016). The relatively large storage capacities of many federal plants are expected to provide a buffer and mitigate the impact on annual generation patterns, but climate change is also likely to exacerbate stress on ecosystems and between competing water uses. This could mean greater water management constraints for multipurpose installations, rendering hydropower generation less flexible.

Anticipating climate change-induced challenges to hydropower operation is critical to effectively plan regional hydropower development and adapt operating rules.

Based on plant-level data and integrated modelling, the IEA has thoroughly explored the possible long-term impacts of climate change on hydropower capacity factors in Asia, Latin America and Africa.

Asia

The implications of climate change for hydropower generation are likely to vary across Asia's subregions. Three climate scenarios were modelled, ranging from below 2°C of global warming to above 4°C by 2100. Assessment results suggest that, depending on the scenario, capacity factors in Southeast Asian countries around the Mekong River basin (Cambodia, Lao PDR, Myanmar, Thailand and Viet Nam) are likely to fall 4-8% during 2060-2099 compared with the baseline period of 1970-2000.

At the same time, hydropower capacity factors in Southeast Asia's island countries (Indonesia, Malaysia and the Philippines) are projected to stay comparatively stable (from -2% to +1%) during the same period. In South Asian countries including India, Pakistan and Sri Lanka, hydropower capacity factors are likely to decrease by 4-7% in 2060-2099, while among their Himalayan neighbours (Bhutan and Nepal) they may not change significantly.

Higher GHG emissions are expected to widen the gap between Asia's subregions. Assuming global warming of more than 4°C by the end of the century, hydropower capacity factors in Southeast Asian countries around the Mekong River basin could fall by 8%, while they would increase slightly from the baseline in Southeast Asia's island countries in 2060-2099.

Assuming global warming of less than 2°C by 2100 (the Paris Agreement goal), the difference between these two subregions would be smaller: the hydropower capacity factor of Mekong basin countries would fall by 6%, and it would also decrease slightly (-2%) in Southeast Asia's island countries.

Latin America

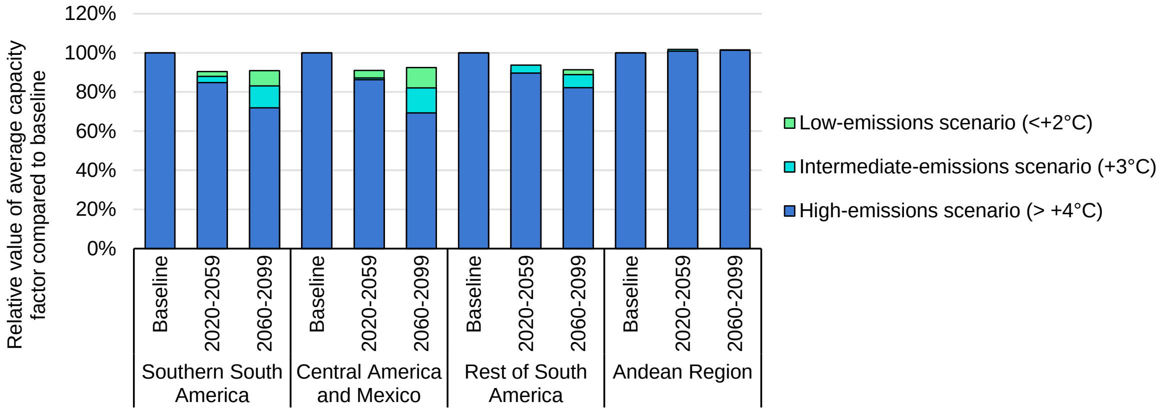
Climate change is posing an increasing challenge to Latin American hydropower, which makes up roughly 45% of the region's electricity generation. From now until the end of the century, hydropower capacity factors in Latin America are projected to decrease in all climate scenarios. In Argentina, Chile, Costa Rica, Guatemala, Mexico and Panama in particular, capacity factors are shown to fall consistently due to a decline in mean precipitation and runoff.

Higher GHG concentrations may lead to a starker decrease in hydropower capacity factors in the region. In a scenario in which continuously increasing emissions provoke a global temperature rise of more than 4°C in 2080-2100 compared with pre-industrial times, the regional mean hydropower capacity factor decreases more sharply (17.4% lower in 2060-2099 than in 1970-2000) than in a low-emissions scenario (-7.5%).

Meanwhile, in Andean countries along the northwest coast of South America (Colombia, Ecuador and Peru), a slight increase in hydropower capacity factors is projected owing to notable increases in rainfall along their coastlines. Even in a high-GHG-emissions scenario, total hydropower generation in the Andean region is expected to remain stable, although a potential increase in extreme weather events may put stress on hydropower operations.

It should be noted, however, that such a high temperature increase could entail other consequences of far greater significance – not only for hydropower operations, but for energy systems at large.[8]

Figure 3.29 Hydropower capacity factor evolution in Latin America, 2020-2099



Note: The high-emissions scenario assumes a global temperature rise of over 4°C in 2080-2100 compared with pre-industrial times while the low-emissions scenario assumes that the average global temperature will rise by less than 2°C.
Source: IEA (2020c), Climate Impacts on Latin American Hydropower.

Africa

African hydropower is also likely to be affected by climate change. For this region, the modelling exercise covered over 50% of total installed capacity and two

[8] Climate change can impair the operation of transmission lines (e.g. during heat waves), reduce water availability for the cooling of thermal plants, and hinder inland navigation and the shipping of fuels, among other effects. More fundamentally, the social and economic impacts of climate change, albeit difficult to quantify, could include a substantial transformation of energy needs, which would challenge energy system operations at large.

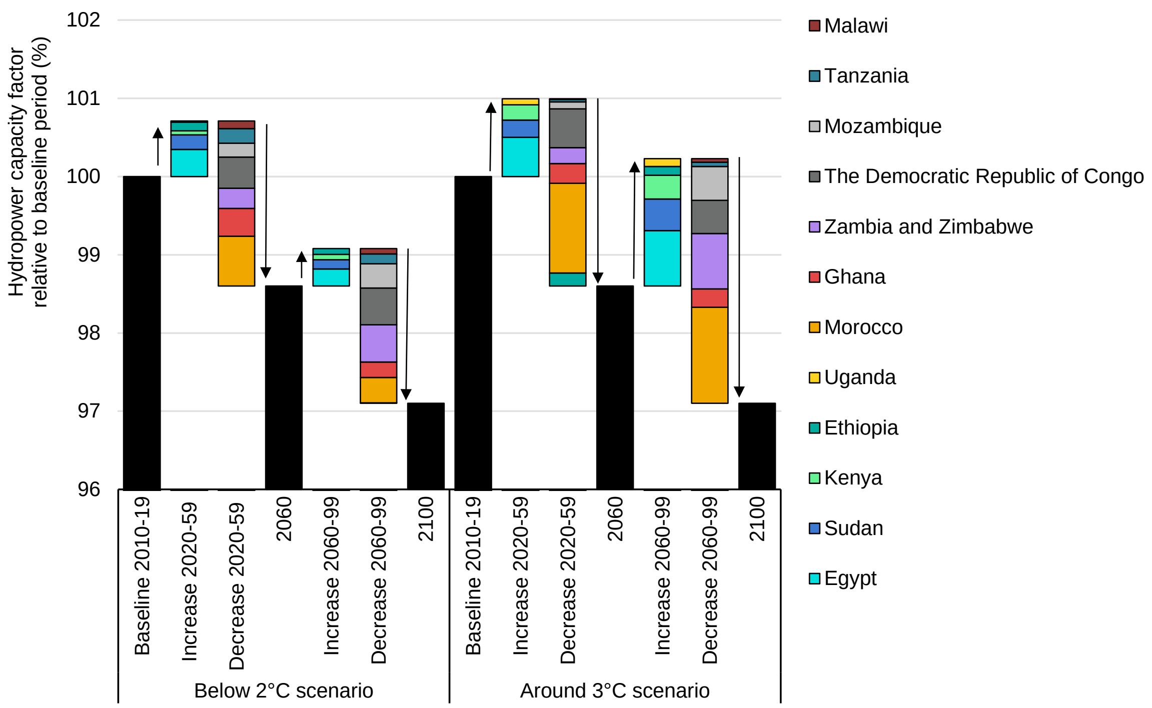
scenarios were assessed: one assuming global warming below 2 °C and the other assuming 3 °C warming.

In both scenarios, the regional mean hydropower capacity factor is projected to decrease from now until the end of the century, falling to 3% lower in 2060-2099 than in 2010-2019 due to climate change.

Country-specific data show significant spatial variations in climate change impacts. For instance, the hydropower capacity factor in Morocco is projected to decrease by around 10% while it increases by 2% around the Nile basin under a scenario that assumes global warming of less than 2 °C by 2100.

Spatial variations in hydropower generation are also likely to be stronger with higher GHG emissions. Under a higher-emissions scenario that assumes global warming of around 3 °C by 2100, Morocco's hydropower capacity factor is projected to drop considerably in 2060-2099, to 36% below the 2010-2019 level, while in East African countries around the Nile basin it is expected to increase by 7%.

Figure 3.30 Hydropower capacity factor evolution in Africa, 2020-2099



Source: IEA (2020d), Climate Impacts on African Hydropower.

Chapter 4 - Special focus: Flexibility and storage

Hydropower is currently the only low-carbon electricity-generating technology that can provide system flexibility within a range of sub-seconds to hours while also cost-effectively storing energy for days to months. As the share of variable renewable energy (VRE) increases in many markets and more synchronous thermal generation is retired, the flexibility and storage capabilities of reservoir plants, pumped-storage hydropower (PSH) units and, to some extent, run-of-river installations will be increasingly needed to reliably and cost-effectively integrate wind and solar PV generation into power systems.

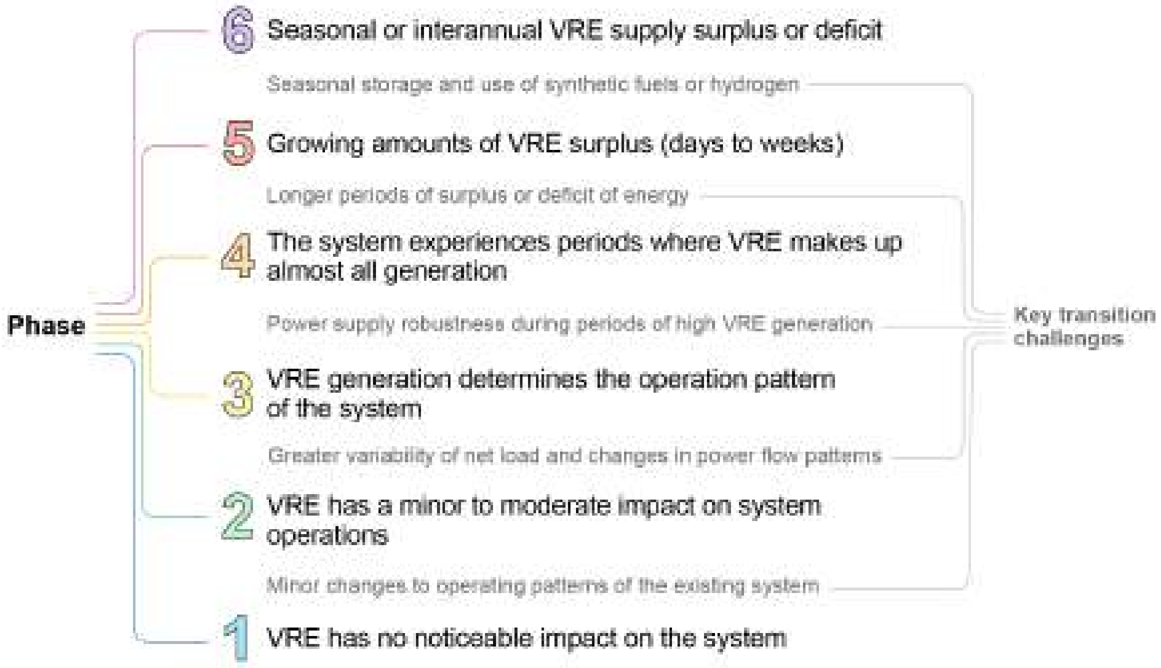
Higher VRE shares transform power systems and raise flexibility needs

The annual share of VRE (particularly wind and solar PV) in total global electricity generation is expected to increase from 9% in 2020 to 15% in 2025. This global average is deceiving, however, as it does not reflect the wide variations in VRE shares among countries. In 2020, most of the countries included less than 5% VRE, while only two (Denmark and Lithuania) had a share of more than 50%. Nevertheless, the number of countries with annual shares of 40% and higher is expected to increase from 3 to 12 by 2025.

System integration challenges are determined mainly by the portion of VRE in the generation mix, and the amount and type of flexibility resources present in the power system. The four main categories of flexibility resources are: flexible power plants (both conventional and renewable); electricity networks; energy storage; and distributed energy resources (including demand response).

The IEA assessment framework divides VRE integration into six phases. In Phase 1, VRE has no noticeable impact on countries or power systems at the system level. While 84 countries were at Phase 1 in 2020, it is expected that only 50 will still be at this stage in 2025. At Phase 2, integration challenges begin to emerge. Differences between total electricity demand and net load become noticeable, but VRE shares of 5-10% have only a minor impact on the system as a whole.

Figure 4.1 Key characteristics and challenges of system integration phases



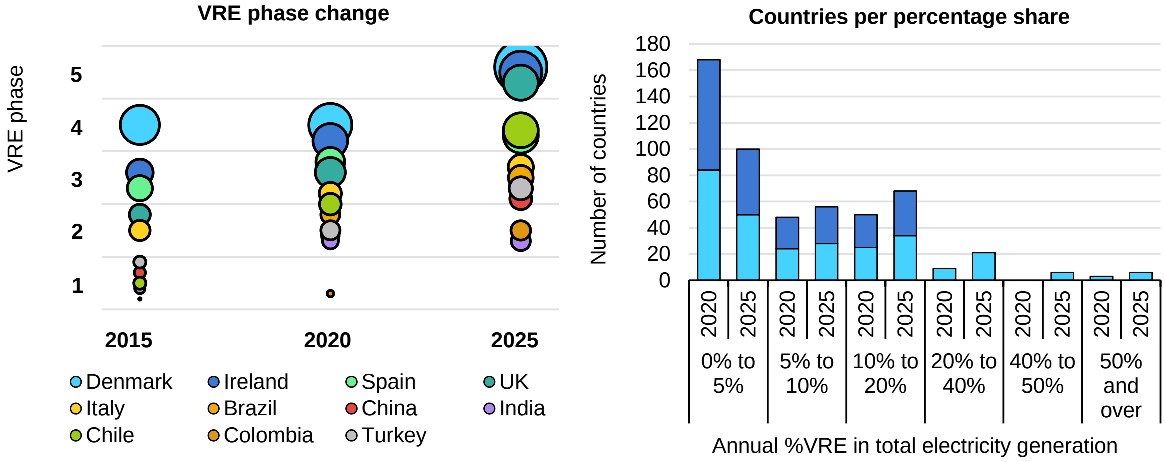
Source: IEA (2021d), Secure Energy Transitions in the Power Sector.

From Phase 3 (annual VRE generation of 15-30%) and beyond, VRE determines the whole power system's operating patterns, and additional flexibility options are needed. Only six countries are currently in Phase 4, in which VRE makes up all (or almost all) generation during certain periods.[1] No country has yet reached Phases 5 or 6, characterised by increasing VRE surpluses and deficits in relation to total electricity demand (days to weeks for Phase 5) and by seasonal or interannual imbalances (Phase 6).

As VRE shares expand and countries enter the next phase, integration challenges increase and policy priorities must be revised to ensure secure and cost-effective system integration of VRE. For instance, while Brazil's VRE share was below 5% in 2015 (Phase 1), the country has boosted VRE uptake enough to change phases every five years and is set to reach Phase 3 by 2025. By that time, the United Kingdom, Ireland and Denmark are forecast to be in Phase 5, while over 20 other countries worldwide are expected to have annual VRE shares of 20-40%.

[1] Some sub-national power systems are also in Phase 4, e.g. South Australia and California.

Figure 4.2 Evolution of countries' VRE integration phases



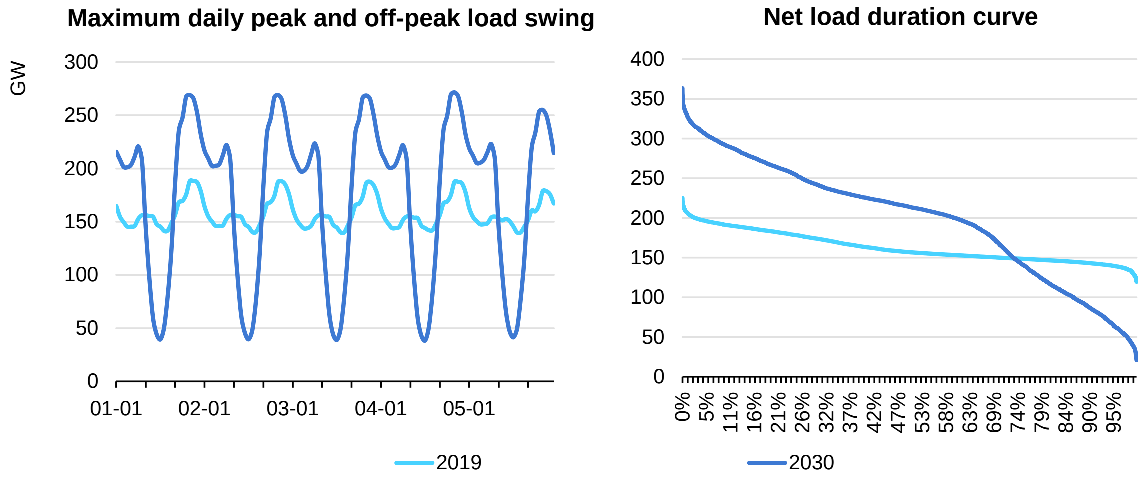
Note: Bubble size reflects the share of VRE in total electricity generation.

Power systems are already able to respond to the variability of wind and solar PV generation across different timescales, and to deal with demand volatility and recovery from unexpected outages. However, as VRE shares increase, residual loads will become more volatile,[2] gaps between peak and minimum net demand will be larger, and ramp-up and -down requirements to adjust to peak and off-peak demand will be steeper.

For instance, India's share of wind and solar PV is expected to increase from 7% in 2019 to almost 25% in 2030 (IEA, 2021), which will transform its power system profoundly and create significantly higher ramping needs (i.e. five times greater than in 2020). In absolute terms, maximum hourly ramps could climb from 16 GW (7% of daily peak net load) to 68 GW (19% of daily peak net load), and maximum 3-hour ramps could increase from 40 GW (18% of daily peak net load) to 342 GW (40% of daily peak net load). Achieving such considerable load changes will require that conventional power plants ramp generation up and down much more quickly and intensively than in the past, and eventually start up and shut down more often.

[2] Residual load is the total load minus what is generated at no marginal cost, such as VRE (e.g. wind and solar).

Figure 4.3 India load swings and load duration curves, 1-5 January 2019 and 2030 (according to the WEO STEPS scenario)



Notes: WEO STEPS = *World Energy Outlook* Stated Policies Scenario. The net load duration curve represents the net demand profile of the entire year from highest value to lowest, with the x axis representing the number of periods in the year in which net demand exceeds that value.
Source: IEA forthcoming, India Regional Model.

As VRE levels increase, an electricity system's technical, market, regulatory and institutional frameworks must be updated to ensure that flexibility is sufficient to maintain security of supply. As power system flexibility is required across a range of timescales, various flexibility hardware and operational solutions offer timescale-specific capabilities. Timescales range from sub-seconds for system stability issues to months/years for seasonal and interannual demand and generation variability (see examples in the table below).

Figure 4.4 Issues arising at different flexibility timescales and VRE integration phases

Issues seen at different flexibility timescales

Subseconds → Seconds → Minutes → Hours → Days → Months → Years

Issue addressed	System stability	Short-term frequency control	Changes in supply/demand; system regulation	Generation dispatch and operation scheduling	Scheduled maintenance; longer periods of surplus/deficit	Seasonal and interannual variable generation and demand
Example problem	Withstanding large disturbances such as losing a large power plant	Random fluctuations in power demand	Increasing demand following sunrise or rising net load at sunset	Decide how many thermal plants should remain connected to the system	Hydropower availability during wet and dry seasons	
Relevant integration phase	Phase 4	Phase 2 and 3		Phase 3 and 4	Phase 4 and 5	Phase 5 and 6

Source: IEA (2021d), Secure Energy Transitions in the Power Sector

How can hydropower technologies accommodate increasing flexibility requirements?

Although hydropower is a key contributor to flexible generation and storage, its flexibility contribution varies according to turbine type, plant design (operational mode) and installation (reservoir, run-of-river or PSH).

Run-of-river: Seasonal generation and relatively limited flexibility characteristics

Run-of-river plants are one of the least flexible hydropower technologies, as their turbine output depends on seasonal river flows and they have little or no storage (many have just a small amount of pondage, i.e. storage capacity for daily flow regulation). These plants therefore provide relatively stable generation that varies according to seasonal changes in waterflow.

As a synchronous generator, a run-of-river plant offers important system services such as frequency response, but its ability to provide other benefits such as intraday balancing (by spilling water to curtail generation) and ramping and reserve capabilities is limited. Having pondage capacity allows a plant to regulate daily generation, enabling it to provide intraday supply-demand balancing and to concentrate generation during peak periods to reinforce system adequacy. Some run-of-river plants may also be regulated by upstream lakes, allowing them to behave more like reservoir hydropower plants.

Reservoir: Flexible key to electricity security

A reservoir hydropower installation consists of one or many turbines connected to one or several reservoirs, permitting the regulation of power generation thanks to the synchronous inertia of rotating turbines, frequency control from sub-seconds to minutes, and system balancing for hours, days and even months. A plant's long-term storage capabilities usually depend on the size of the reservoir, the amount of installed capacity and downstream-related environmental and socio-economic regulations (regarding irrigation, etc.), which often specify minimum river system waterflows.

In addition to offering the flexibility of a run-of-river plant, reservoir installations allow for inter-day and seasonal balancing by shifting energy contributions to periods of higher system demand and/or lower VRE generation. Subject to design provisions, reservoir hydro can also provide important system services such as black-start, ramping and regulation capabilities. Depending what type of turbine it has, a plant may also be able to improve system inertia and fault levels while it is not generating electricity but instead operating in synchronous condenser mode and producing or absorbing reactive power.

PSH: Giant flexible electricity storage

PSH technologies provide energy storage by drawing power from the grid to pump water from lower to higher reservoirs during periods of low demand and then using that water for generation when power demand is high.

Plants have two main configurations:

- **Closed-loop or off-stream,** wherein the two reservoirs are disconnected from any river system and therefore lack natural flow.
- **Open-loop or pump-back,** wherein one or both are connected to a river system and have some natural flow.

Design is largely determined by a site's topology, which dictate a plant's configuration, reservoir size and allowable reservoir-level variation (the latter two influence how long a plant can store energy). The storage duration of these plants (generally ranging from 5 to 175 hours[3]) allows energy to be shifted across multiple days to provide both inter- and intraday flexibility. Some installations, such as cascading systems that link two or more large reservoirs, and PSH units included in traditional reservoir plants, offer even greater storage capacity.

PSH has traditionally been used to compensate for relatively inflexible thermal generation by pumping water during the night and on weekends to permit generation during peak periods. Now, however, PSH cycling frequency is increasing with multiple pumping/generating switches during the day as VRE deployment accelerates. Like reservoir installations, PSH plants can provide critical services such as power system inertia, frequency response and grid regulation to reinforce system strength and, depending on their design, can have black-start capability and operate in synchronous condenser mode.

[3] Our PSH database indicates that over 80% of historical projects have had between 5 and 175 hours of storage. More storage hours are possible, mostly in mixed plants in which multiple turbines generate power and one or several of these turbines has pumping capabilities using the same upper reservoir.

Table 4.1 Energy capabilities and system support provided by different hydropower technologies and applications

Energy capabilities	Reservoir	Pumped storage	Run-of-river
Inertial response	🟢	🟢	🟢
Voltage support	🟢	🟢	🟢
System strength	🟢	🟢	🟢
Black-start capabilities*	🟢	🟡	🟡
Fast start	🟢	🟢	🟢
Ramping capability	🟢	🟢	🟡
Scheduling adequacy	🟢	🟡	🟡
Intraday flexibility	🟢	🟢	🟡
Inter-day flexibility	🟢	🟢	🔴
Demand-side response	🔴	🟢	🔴
Baseload power generation	🟢	🟡	🟢
Daily storage of water	🟢	🟢	🟡
Seasonal storage of water	🟢	🟡	🔴

🔴 low or no capability 🟡 moderate capability 🟢 high capability

*Black-start capabilities depend on special plant features.

Notes: This indicative assessment includes hydropower energy and system support capabilities. Values may differ from plant to plant.

Source: Based on IEA Hydro TCP (2021e), Valuing Flexibility in Evolving Electricity Markets: Current Status and Future Outlook for Hydropower.

How does hydropower compare with other technologies?

A power plant’s flexibility depends on its ability to adjust its power output (ramp rate), its range of operations (minimum load) and the amount of time required to reach stable operations after starting (start-up time). Start-up time, minimum load and average ramp rate are three key indicators (among others) used to assess the flexibility of traditional power plants. According to these indicators, hydropower is one of the most flexible power-generating technologies.

Table 4.2 Flexibility capabilities of typical thermal and hydropower plants

Plant type	Hydropower	OCGT	CCGT	Hard coal
Start-up time (cold start for thermal)	< 5-20 mins	5-10 mins	120-240 mins	300-600 mins
Minimum load (% of Pnom)	35-45%	40-50%	40-50%	25-40%
Average ramp rate (% of Pnom/min)	80-100%	8-12%	2-4%	1-4%

Notes: OCGT = open-cycle gas turbine. CCGT = combined-cycle gas turbine. Pnom = nominal power. Technically, some hydropower turbines can operate at lower minimum loads than those indicated (as low as 20%), but operators prefer not to run them below 35% of Pnom as this may shorten the turbine's lifetime.

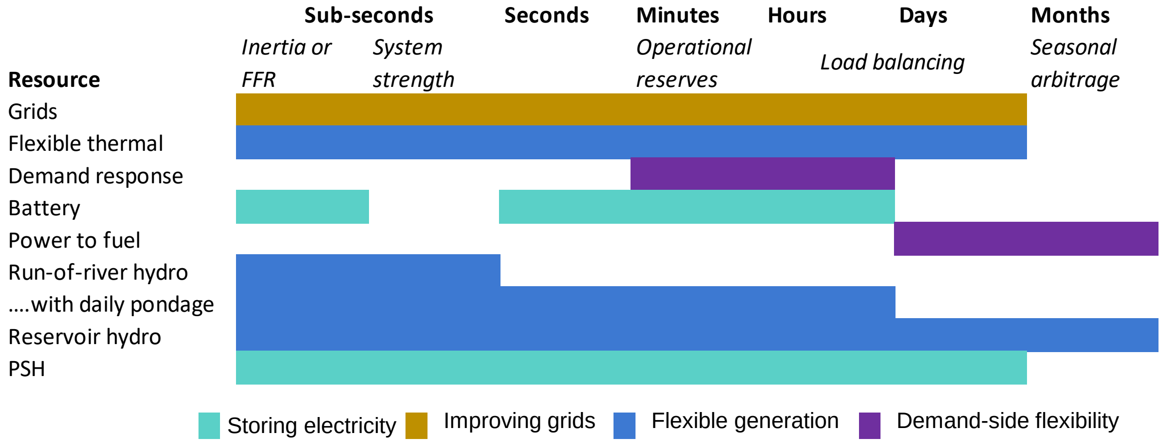
Sources: IEA (2017), Energy Technology Perspectives 2017; NREL (2012), Power Plant Cycling Costs 2012; Gonzalez-Salazar et al. (2018), "Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables"; Siemens (2017), Flexibility of Coal and Gas Fired Power Plants; Agora Energiewende (2017), Flexibility in Thermal Power Plants.

Hydropower plants can start up in 2 to 20 minutes, significantly more quickly than combined-cycle gas turbines (CCGTs) and coal-fired facilities that require up to several hours to become fully operational from a cold start. Most hydropower plants can operate at minimum loads of 35-45%, similar to dispatchable fossil fuel options. However, reservoir, PSH and, to some extent, run-of-river hydropower units have by far the fastest average ramp rate compared with gas- and coal-fired plants. Because of their higher ramp rates, hydropower plants can quickly alter their production to accommodate system needs.

Hydropower plants' flexibility capabilities make them well-suited to supply a broad range of the system services required for stable power system operations across various time scales. Newer solutions such as battery storage, demand-side response, increased sectoral coupling, power-to-fuel technologies and more interconnected and innovative grids can also aid VRE integration, but many of these are still at early development stages and their cost is relatively high.

While many technologies are competing to provide relatively short-term flexibility from seconds to hours, only a handful can meet longer-term needs. Apart from hydropower, only fuels such as hydrogen or hydrogen-based fuels produced with power-to-fuel technologies (such as electrolysers) can provide seasonal storage – at a higher cost and lower return efficiency.

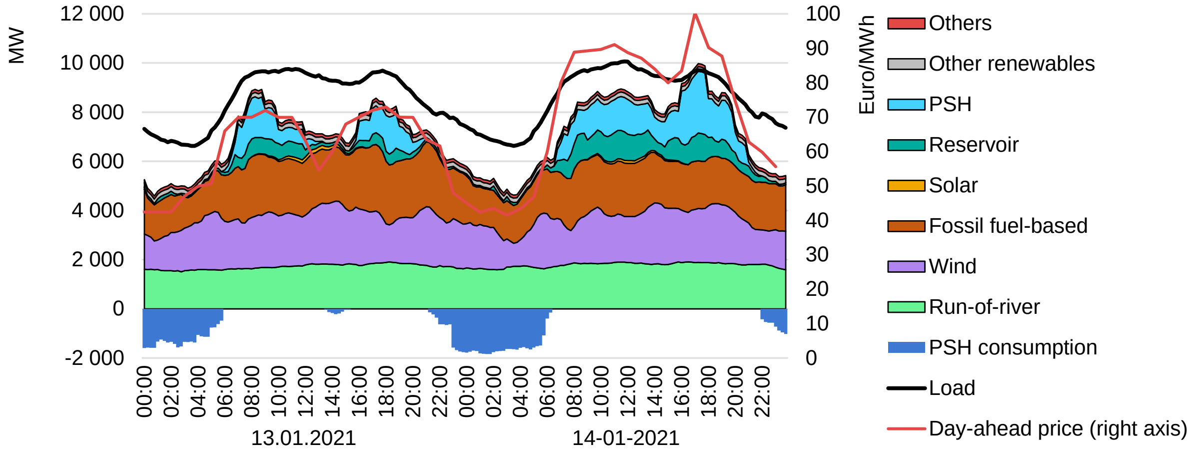
Figure 4.5 Flexibility capabilities of hydropower vs. other technologies



A portfolio of hydropower plants offering complementary services can efficiently integrate large VRE shares

Different types of hydropower technologies offering different services can work together to allow significant VRE shares to enter the energy system. Austria, for instance, regularly uses various types of hydropower plants in its electricity generation mix to integrate high VRE shares. Although wind fuels just over 10% of the country's annual electricity generation, its sub-hourly penetration can reach almost 46% during windy hours in the winter, requiring that different types of hydro plants play unique roles. For instance, on 13-14 January 2021, when wind power made up 40% of the generation mix, both PSH and reservoir facilities were used flexibly to meet peak demand. PSH plants ramped up power generation from 0 to 1 373 MW in just over one hour, bringing online over a quarter of the country's total installed PSH capacity.

Figure 4.6 **Austria hourly electricity dispatch, 13-14 January 2021**



Source: ENTSO-E (2020), *Transparency Platform* (database).

Despite declining arbitrage opportunities in Austria, PSH plants usually follow price signals for generation and pumping (as shown in the figure). Abundant night-time wind generation in the winter, along with low demand, pushes wholesale electricity prices down and increases opportunities to pump water into the upper PSH reservoirs.

What is the storage capability of hydropower plants?

Reservoir hydropower plants provide energy storage capabilities unmatched by any other low-carbon technology

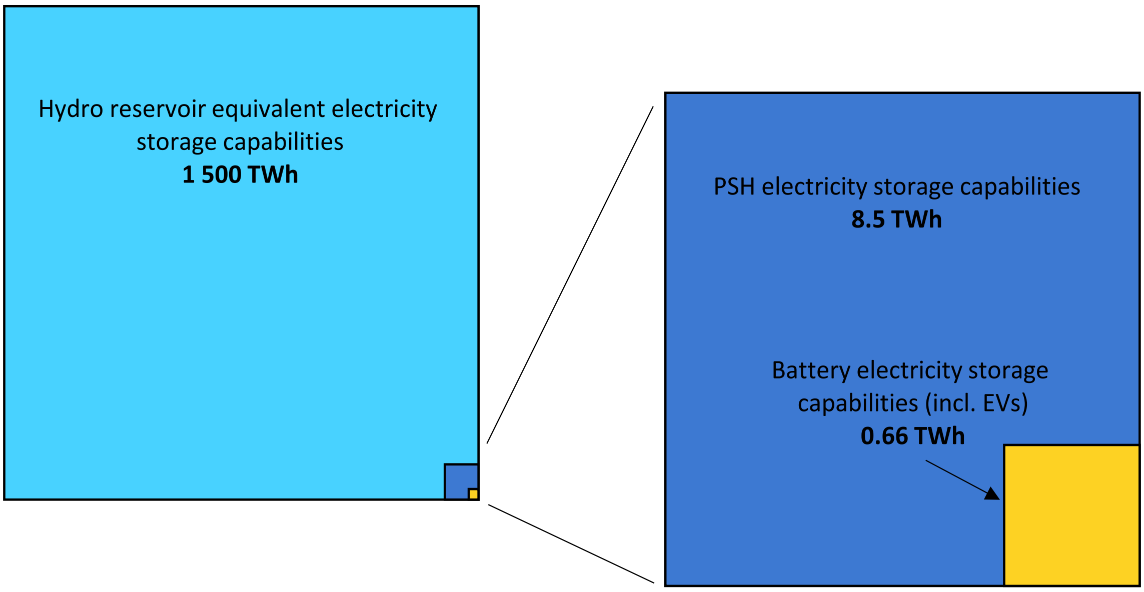
Reservoir hydropower plants are mostly designed to maximise electricity generation based on water availability (energy sales account for the bulk of their annual revenue). However, they can also respond quickly to changes in demand and supply, and to variations in wind- and solar PV-based generation thanks to their vast energy storage capabilities. In liberalised markets, electricity market design, contract arrangements, grid codes and the price of energy services (including ancillary services) determine the value of water stored in reservoirs and how it is dispatched.

For the first time, the IEA has estimated the enormous energy value of water stored behind powered dams globally. Reservoirs of existing conventional hydropower plants can store up to the equivalent of 1 500 TWh of dispatchable electrical energy. This is about 170 times more than the global fleet of PSH plants and almost 2 200 times more than all existing batteries in stationary applications and EVs combined. This makes reservoir hydropower plants by far the largest low-carbon energy storage resource on the planet, capable of stocking the equivalent of 20 days of current average global electricity generation.

Calculations of storage potential are based on the International Commission on Large Dams' database of existing dams and reservoirs, country-level storage data and IEA research. Energy storage capability calculations depend on the energy potential of water that can be used for power generation stored behind each dam.

Factors include the average head of the dam, energy conversion efficiency (assumed at 90%) and estimates of the live part of a reservoir's volume that can be used for electricity generation (typically 50-60% of nominal maximum volume). Calculations assume that reservoirs are filled to their maximum nominal level. For multiple hydropower plants on the same river, potential energy was calculated for the entire cascade, assuming that water from upstream reservoirs can be used several times to generate electricity before being discharged to the sea or ocean.

Figure 4.7 Global energy and electricity storage capabilities by technology, 2020

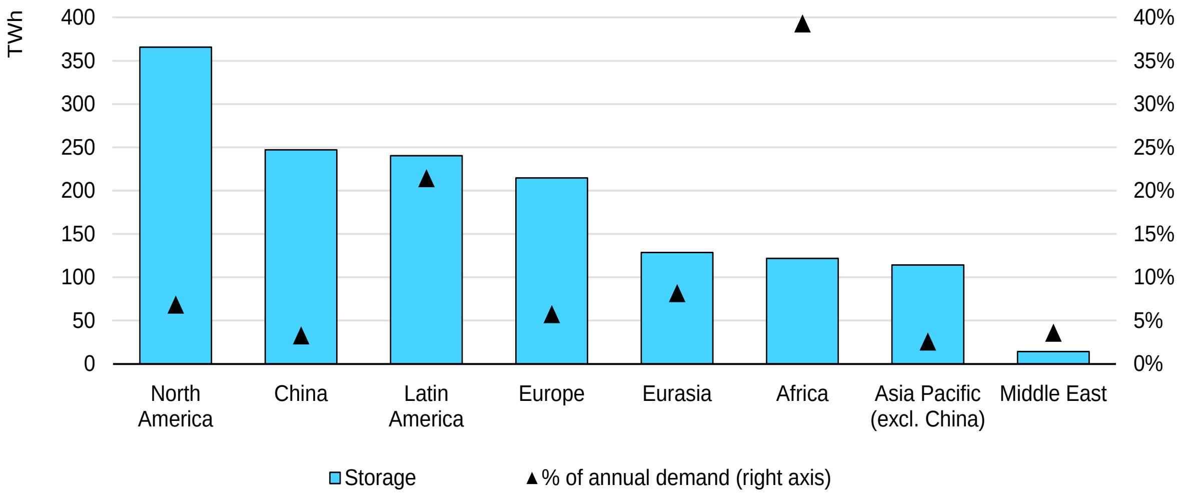


Notes: PSH = pumped-storage hydropower. EV = electric vehicle.
Source: Based on International Commission on Large Dams, ENTSO-E and national transmission system operator data.

North America has the greatest storage capabilities (370 TWh), mainly owing to Canada's large reservoirs that serve hydro plant cascades on the La Grande and Manicouagan rivers. China holds second place, with its largest storage cascades on the Yellow and Jinsha rivers. Latin America has similar capacity, the majority of which is in Brazil's Tocantins, São Francisco and Rio Grande cascades.

Norway and Sweden account for more than half of Europe's 215 TWh of energy stored in reservoirs. Eurasia, Africa and the APAC region each have an estimated hydro reservoir storage capability of about 120 TWh, with high concentrations in Russia (the Angara and Yenisei cascades), India and Ghana (the Volta cascade). Estimated potential in the Middle East is only about 15 TWh due to a paucity of hydrological resources, with Iran having the most storage.

Figure 4.8 Total energy storage capabilities of hydro reservoirs in relation to annual electricity demand by region, 2020



Source: Based on International Commission on Large Dams, ENTSO-E and national transmission system operator data.

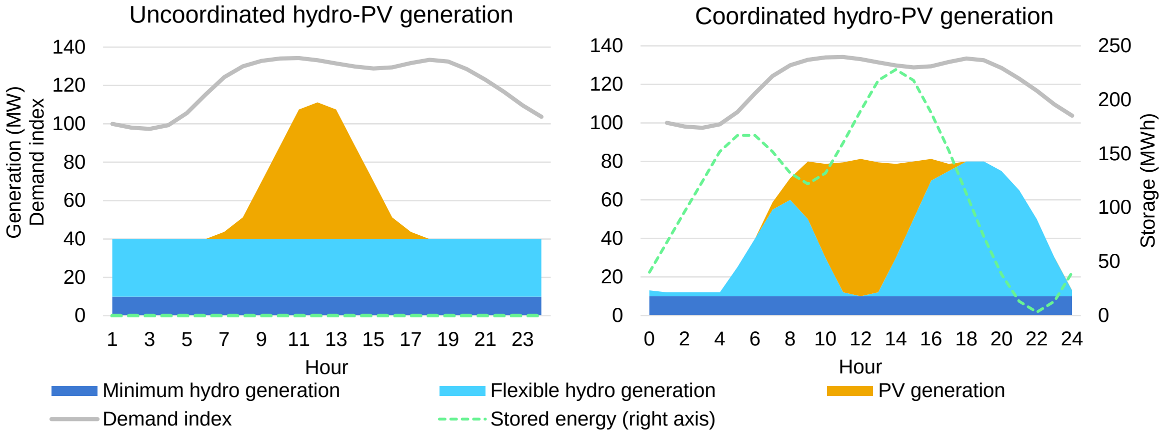
Because their storage capabilities can make it easier to integrate VRE into power systems, reservoir hydro plants are an important flexibility resource. IEA analysis indicates that a 100-MW reservoir hydropower plant with several hours of full-capacity storage capability could significantly mitigate the main integration challenges of 100 MW of PV. The plant's power generation could be reduced to a minimum[4] during maximum PV generation periods as well as during the night, and energy stored by withholding generation could be used to ramp up capacity in the morning and during evening peak-demand hours when PV generation is low.

In this theoretical case, only several hours of reservoir storage would be required to align the PV-hydro generation profile much more closely with demand than

[4] The minimum level required for environmental reasons is assumed to be 10% of installed capacity, or operation of one 20-MW turbine at 50% capacity, presuming that the 100-MW hydropower plant has five 20-MW turbines.

uncoordinated generation from PV and hydro, reducing the need for costly morning and evening ramp-ups that are often powered by gas-fired generators. While such a drastic change in the hydropower plant's generation profile may result in higher revenues because the plant can take advantage of peak prices, the greater frequency of turbine stops and starts can increase maintenance costs and eventually shorten turbine lifetime.

Figure 4.9 Theoretical intraday generation profiles of uncoordinated and co-ordinated operation of 100 MW of reservoir hydro with several hours of storage and 100 MW of PV

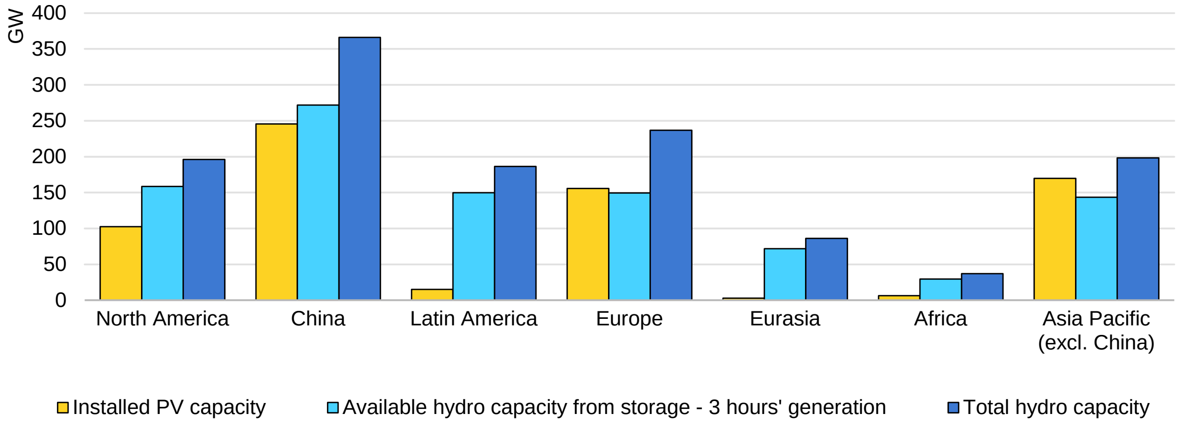


Notes: Average capacity factor of reservoir hydro plant for one day assumed to be 40%. In both examples, total daily generation from the PV and hydro plants remains the same. In demand index, 100 equals to electricity demand in the first hour of the day.

Analysis shows that reservoir hydro capacity capable of storing several hours of generation could be adequate to significantly reduce the challenges of integrating China's, North America's and Europe's current PV capacity into their power systems. In Latin America, Eurasia and Africa, reservoir hydro can provide support for much higher PV capacity than that which is currently installed, while in the Asia Pacific region, PV capacity has already surpassed reservoir flexibility capabilities.

It is important to note that hydro reservoirs provide this type of very valuable flexibility in integration phases 1-4. As soon as VRE generation exceeds demand and creates surplus electricity (e.g. at midday during the summer or on a windy and sunny weekend in the spring), the surplus must be stored by complementary plants (e.g. PSH or battery) to avoid curtailment.

Figure 4.10 Total installed hydro and PV capacity and achievable power generation from energy stored in reservoirs assuming 3 hours of continuous operation, by region, 2020



Note: Analysis assumes three hours of continuous operation.
Source: Based on International Commission on Large Dams, ENTSO-E and national transmission system operator data.

The largest reservoir systems can provide flexibility and generation-shifting options not only on an intraday basis but also weekly, monthly or even seasonally. Hydropower is currently the only economically feasible technology with such capabilities, and demand for these services is expected to grow considerably as VRE shares increase. In fact, hydro reservoirs in Norway and Sweden are already very important flexibility assets for the European power system, helping to balance swings in wind and PV generation on the continent, especially in Denmark and Germany.

The reservoir storage capabilities presented above reflect the ideal technical electricity generation potential of water stored by powered dams around the world, but reservoirs should not be treated as giant batteries with full capacity available at all times. Many constraints limit the use of reservoirs, including changes in hydrological conditions, environmental restrictions, and the multiple purposes reservoirs serve, such as irrigation, flood control and water supply.

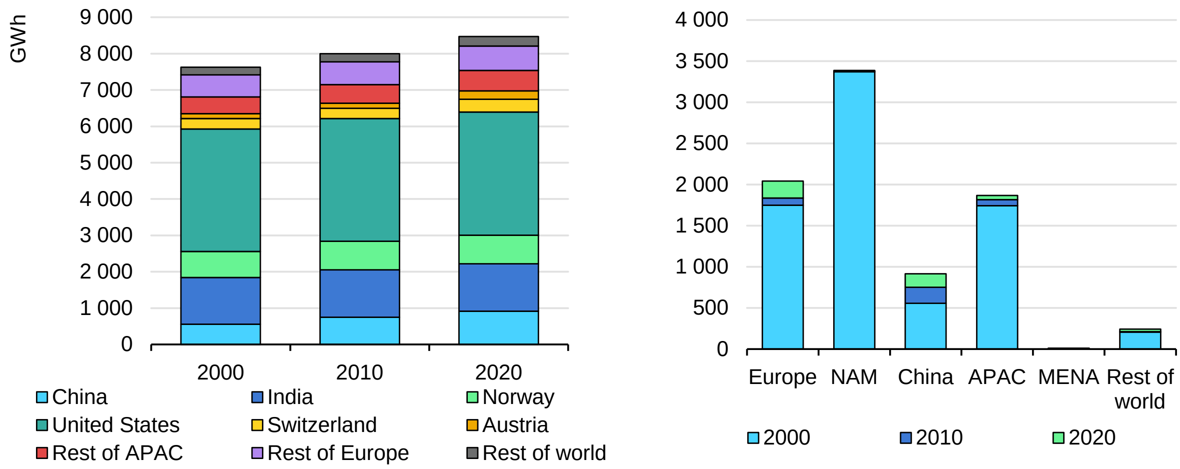
The complicated nature of hydrological systems, the uniqueness of each reservoir, and changes in actual available reservoir volumes due to sedimentation, make storage estimations particularly complicated, so modelled values should be treated as a wide approximation. Nevertheless, even given this high degree of uncertainty, projections and actual power system operation patterns prove that the energy storage and flexibility capabilities of reservoir hydro plants cannot be matched by any other technology available today or in the near future.

Electricity storage capabilities of PSH plants today and in 2030

Excluding the energy storage capabilities of traditional reservoir hydropower installations described above, PSH plants account for over 90% of total electricity storage today, with batteries and other technologies providing the remainder. Their storage capability rose 11% in the past two decades to almost 8 500 GWh in 2020.

The United States has the world's greatest PSH storage potential, followed by India. China, Norway and Korea led expansion in PSH storage during 2000-2010, and the leaders in 2010-2020 were China, Austria and Switzerland, which were together responsible for almost 70% of all additional storage in that decade. Recent large-scale storage expansions have been spurred by the need to increase flexibility and address VRE integration challenges.

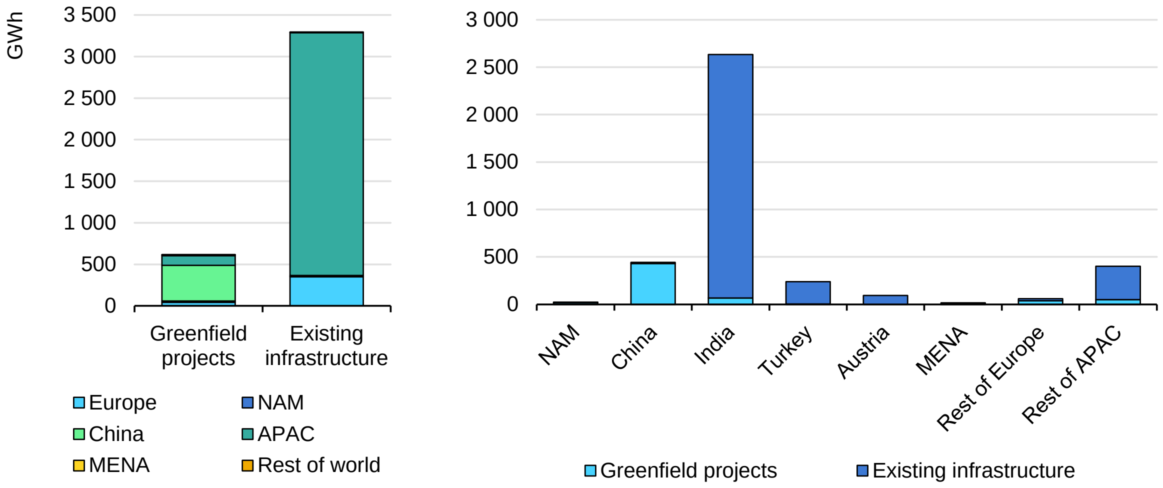
Figure 4.11 Electricity storage capability of PSH plants, 2000-2020



Notes: APAC = Asia Pacific region excluding China. MENA = Middle East and North Africa.
Sources: Based on International Hydropower Association data from Pumped Storage Tracking Tool (database) and IEA storage calculation methodology, https://professional.hydropower.org/page/map-pumped-storage-tracking-tool

Our forecast expects global PSH storage capacity from greenfield projects to increase 7% (618 GWh) by 2030. With this growth, PSH will remain the largest electricity storage technology, with more than 9000 GWh, despite significant expansion of battery storage (including EVs) from 650 GWh today to over 3 800 GWh in 2030 (WEO, 2021). China will lead expansion with new infrastructure in provinces such as Inner Mongolia and Hebei to balance growing VRE generation and help decrease curtailment.

Figure 4.12 Increase in storage capability of PSH plants by 2030

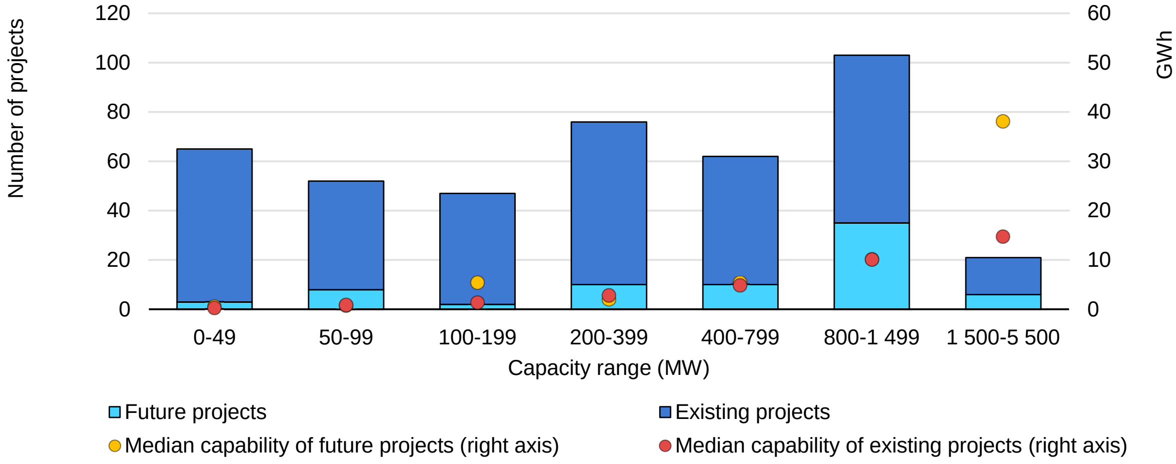


Notes: NAM = North America. APAC = Asia Pacific region. MENA = Middle East and North Africa.

Thanks to technical advances, pumping turbines can be installed in more diverse geographical conditions and offer a wider range of unit capacities. Projects using existing infrastructure (such as natural lakes and established reservoirs) can provide additional flexibility (most projects of this type build onto conventional reservoir hydropower plants to add PSH units). Our forecast expects an additional 3 300 GWh of storage capability to come from projects using existing infrastructure, with India accounting for almost 80% owing to projects such as the Tehri PSH plant, a 1-GW storage facility of the Tehri Hydro Complex.

The majority of PSH projects are designed to provide daily balancing but have considerably greater storage capabilities. While the storage capability of most plants is below 100 GWh, the largest projects are connected to significant reservoirs that could provide 100 GWh to over 1 800 GWh of storage, but these plants make up only a small portion of the fleet.

Figure 4.13 **PSH storage capacity of existing and forecast plants, by generation capacity range**



Sources: IEA pumped storage database, International Hydropower Association data from Pumped Storage Tracking Tool (database) and IEA storage calculation methodology, https://professional.hydropower.org/page/map-pumped-storage-tracking-tool

In 2020, existing plants averaged 24 GWh of storage with an average capacity of 452 MW. However, plants becoming operational in the next decade will have higher average installed capacity (880 MW) and storage (53 GWh).

Storage capability numbers for PSH depict the potential electricity that could be generated by each plant if their respective reservoirs are entirely discharged. However, PSH plants are mostly utilised for system balancing (releasing water from the reservoir to generate electricity in times of high demand and pumping water back up at times of surplus electricity in the system), and this way of operating results in low capacity factors (between 2% and 20%). In 2020, electricity generated from PSH globally reached almost 115 TWh.

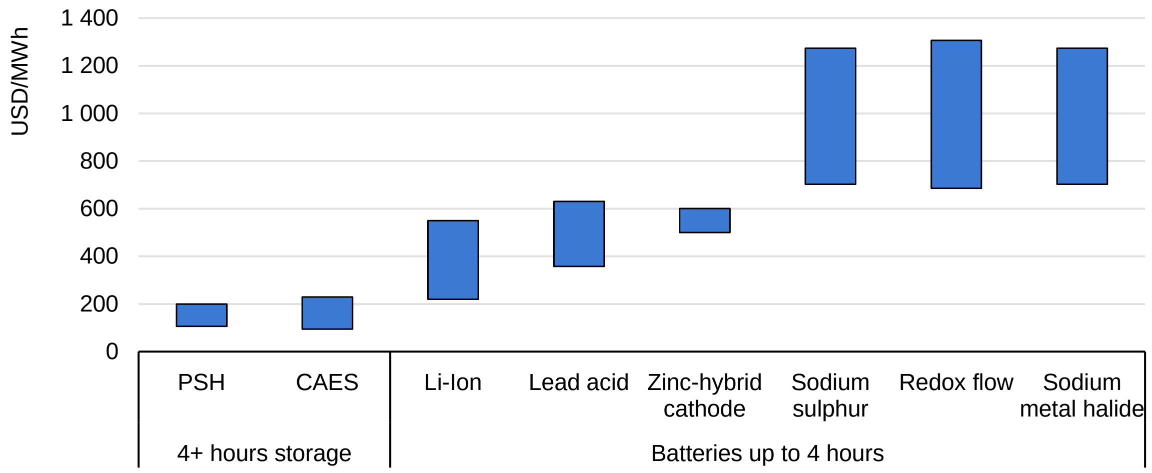
Is hydropower a cost-effective technology to provide flexibility and storage?

Hydropower is the least expensive large-scale energy storage technology today

With low operational costs because they do not require fuel, existing reservoir hydropower plants are the least costly source of energy storage in many markets. However, developers face a trade-off, having to choose either to maximise revenue through electricity generation or to use storage capabilities to provide flexibility and ancillary services.

For electricity storage, PSH is the least expensive large-scale option on a levelised cost basis compared with batteries and other technologies such as compressed air, hydrogen and flywheel energy storage. While batteries can be more cost-effective for storing small amounts of energy for a short time at high power levels, PSH is more economical for storing and releasing larger amounts of energy.

Figure 4.14 Levelised cost of energy for storage technologies, 2020



Notes: PSH = pumped-storage hydropower. CAES = compressed-air energy storage. Costs for relevant technologies are for one cycle per day.

PSH's role in providing flexibility is changing rapidly

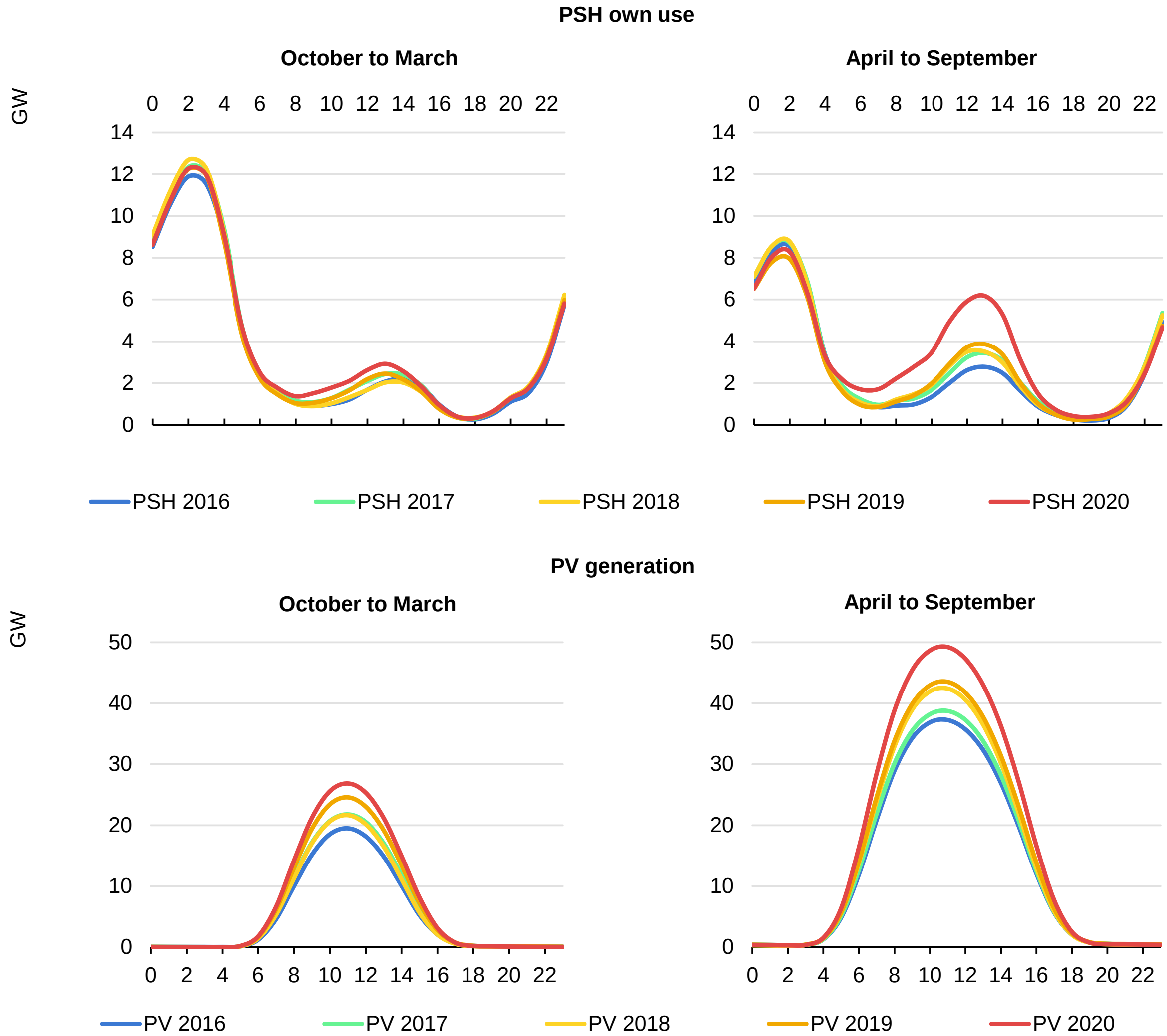
Historically, PSH plants were built in the 1970s and 1980s to store energy from baseload nuclear and coal-fired plants that could not reduce supply drastically or cost-effectively in periods of low electricity demand. As PSH plants provide flexibility by pumping water at night and generating electricity during the day to meet demand fluctuations and peaking needs, their capacity factors are relatively low, ranging from 4% to 15% in most parts of the world.

Despite their low capacity factors, PSH plants are considered valuable because they avoid the use of more expensive and carbon-intensive options such as gas and oil turbines during peak demand periods, and they enable efficient nuclear and coal plant operations.

In energy-only markets, the business case for most PSH plants focuses on arbitrage activities in the absence of long-term contracts. PSH plants have historically pumped water during the night and generated electricity during the day when prices were relatively high. However, the price differential between peak and off-peak hours has narrowed significantly in recent years, partly due to growing shares of solar PV affecting the operation of PSH plants.

In some European balancing areas, solar PV generation during the day has pushed prices close to zero over multiple hours in the summer months. As a result, the daytime pumping activity of Europe's PSH plants in the summer of 2020 more than doubled the 2015 and 2016 rates. At the same time, while PSH plants help meet peak demand in Europe and balance VRE generation, their revenues are declining due to lower electricity prices, making it more difficult to develop a strong business case for new PSH plants in energy-only markets.

Figure 4.15 Average winter and summer 24-hour PSH energy consumption (own use) and solar PV generation, aggregates of selected ENTSO-E countries, 2016-2020



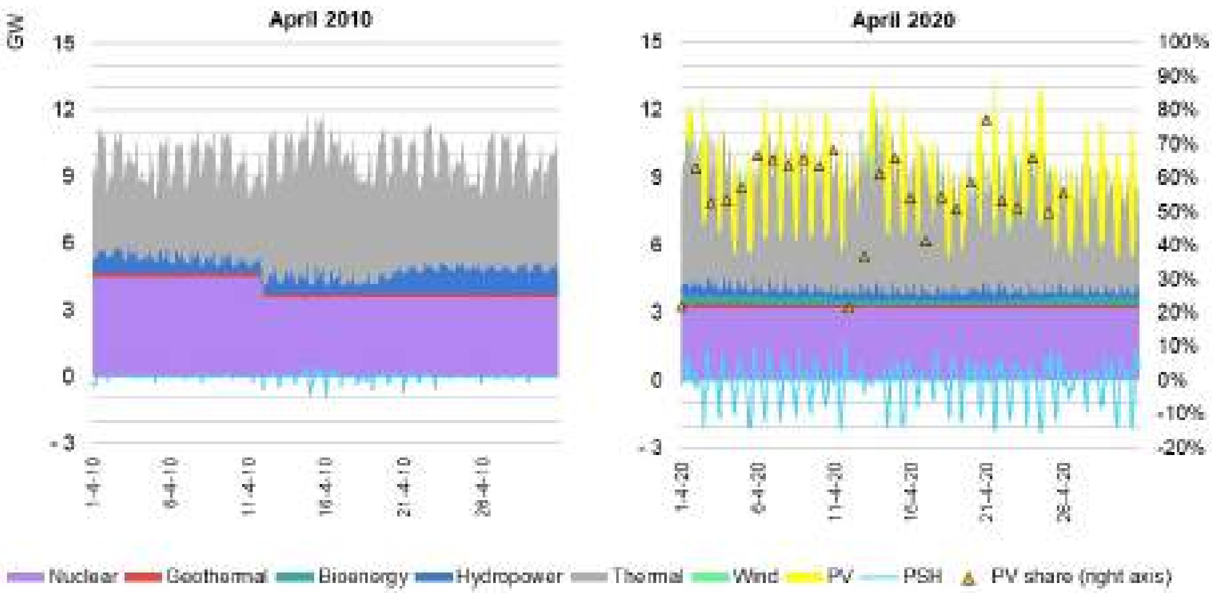
Note: Covers the aggregate of Austria, Belgium, the Czech Republic, France, Germany, Italy, Lithuania, Portugal, Slovakia and Spain.
Source: Based on ENTSO-E data.

The role of hydropower in balancing PV-based generation has also changed in Kyushu, Japan – more than in Europe. Kyushu's solar PV capacity increased from 0.6 GW in 2010 to over 10 GW in 2020, and today solar PV accounts for one-third of Kyushu's installed capacity, contributing 60-85% of hourly electricity generation in certain months. With limited interconnection with other grid areas in Japan, PSH plants (along with other hydropower units) have become more important in integrating PV generation and reducing curtailment.

The operation of PSH plants in Kyushu has therefore changed drastically in the past decade. The number of plants operating during the day has increased thirtyfold since 2012, and their generation and pumping volumes have expanded tenfold as they absorb excess PV generation by pumping during the day and discharging at night to meet peak demand.

In order to ensure electricity security, Japanese TSOs follow a priority dispatch rule that calls for the curtailing of fossil fuel-fired plants and the pumping of excess VRE generation first, then the curtailing of hydropower last. Reservoir plants ramp up and down more frequently, providing the flexibility necessary for cost-effective integration.

Figure 4.16 Kyushu (Japan) hourly electricity generation, April 2010 and 2020



Source: Based on Kyushu Electric Power Company data.

Batteries are expected to close the cost gap with PSH in the next decade, but future power systems need both

At USD 300/kWh in 2020, the capital cost of a stationary battery storage system with four hours of storage had fallen to half of what it was in 2016.[5] As a result, utility-scale battery storage plants have emerged as an option to provide short-term balancing services for wind and solar PV plants in energy-only markets that have growing VRE shares.

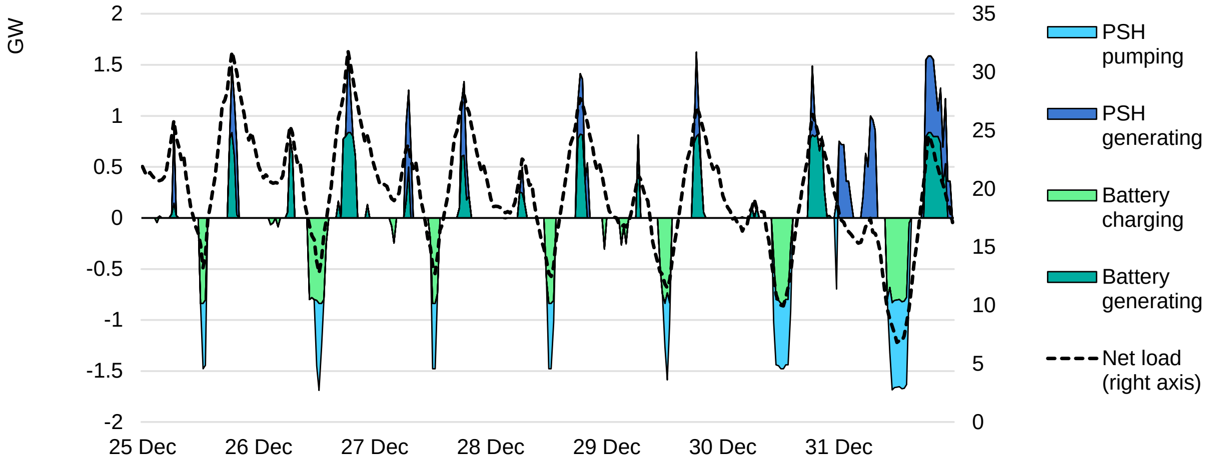
As PSH is a mature technology, its levelised generation costs are expected to remain stable throughout the upcoming decade while battery costs plummet, partly because EV deployment. Nevertheless, future power systems will need both PSH and battery storage.

While batteries are expected to meet flexibility requirements on a very short-term timescale, PSH plants will be required to provide longer-term storage (4 hours or more), especially considering growing PV supply as compared with demand during the day. PSH and battery technologies will therefore complement one another in future power systems by each offering cost-effective storage solutions for different timeframes.

The IEA's recent *Thailand Power System Flexibility Study* demonstrates the synergies between PSH and batteries by modelling the operation of Thailand's power system in 2030 with a 15% share of VRE generation. One scenario that explores the impact of deploying an 800-MW utility-scale battery installation alongside the existing 1 200-MW PSH plant shows that both plants operate together to shift demand from peak net load periods to off-peak hours. Both storage facilities are powered mainly by solar generation, and during periods of very low demand especially, both technologies work together to provide higher pumping/charging capacity owing to greater arbitrage opportunities.

[5] https://www.nrel.gov/docs/fy20osti/75385.pdf

Figure 4.17 Thailand PSH and battery operations, 25-31 December 2030

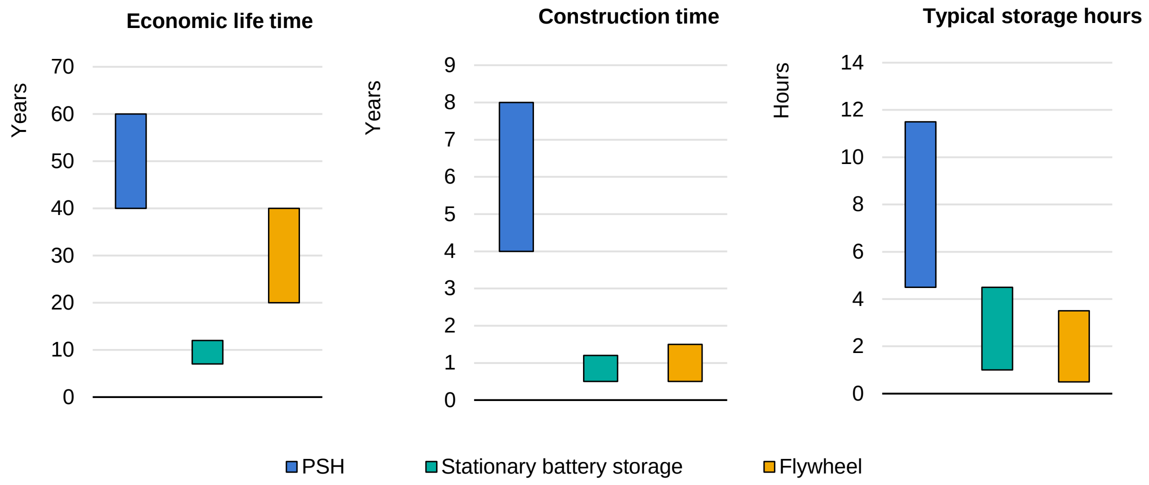


Source: IEA (2021f), Based on Thailand Power System Flexibility Study.

Despite their similar functions and contribution to VRE integration, the factors that influence the financial decision to build PSH or battery installations are very different. PSH plants have an economic lifetime of 40-60 years and can easily operate for longer with proper maintenance. Therefore, uncertainty over electricity prices and market conditions in energy-only markets makes developing a business case for PSH plants with long-term investment cycles very challenging, despite their cost-competitiveness with other storage technologies.

On the other hand, the relatively short economic lifetime of about ten years for batteries promises a faster return on investments. From a system perspective, however, with current technology, battery systems need to be replaced more frequently to maintain their contribution to the system.

Figure 4.18 Economic lifespan, construction time and storage period of selected technologies



Note: PSH = pumped-storage hydropower.

Furthermore, as PSH is a proven and mature technology, its technology risks are minimal, but development and construction challenges are significantly higher than for other technologies, which weakens its investment viability. Plus, the construction time for PSH plants can range from four to eight years, in addition to the two to five needed prior to construction to complete permitting and environmental assessment procedures.

In contrast, permitting and construction of a large-scale battery storage system can be completed in less than 12 months. And although the generation costs of flywheel technology are significantly higher than those of either batteries or PSH installations, flywheel facilities are being built for frequency regulation in the United States and Canada because they can be installed quickly and have a relatively long economic lifetime.

Are hydropower's flexibility and reliability services adequately remunerated?

Hydropower's technical capabilities for providing flexibility are unmatched. In most energy-only and vertically integrated electricity markets, hydropower plants receive remuneration for offering balancing and ancillary services such as reserve regulation and fast frequency response for primary and secondary frequency regulation.

European countries and most US grid areas employ market-based mechanisms to remunerate energy services on a daily or weekly basis. Long-term contracts and interconnection agreements are also used to compensate hydro plants for flexibility services, mostly in vertically integrated markets such as Quebec and in those that have initiated market products (like in Brazil and Japan).

Hydropower plants play a key role in providing energy services in the shortest possible amount of time (sub-seconds to seconds) to provide inertia, reactive power and voltage control. However, procurement and compensation of these services remains inadequate. Nordic countries, Ireland and the United Kingdom are among the few countries that provide market-based remuneration for services catering to the shortest response timescale.

Table 4.3 Hydropower contribution and remuneration for multiple grid services

Country	Sub-seconds to seconds Inertia, voltage control, reactive power, etc.		1-5 minutes Primary and secondary frequency regulation		15 minutes to 1 hour Regulating reserves	
	Hydro role	Remuneration	Hydro role	Remuneration	Hydro role	Remuneration
Austria	🟢	🔴	🟢	🟢	🟢	🟢
Czech Republic	🟡	🔴	🟡	🟢	🟢	🟢
Germany	🟢	🔴	🟢	🟢	🟢	🟢
Belgium	🟢	🔴	🟢	🟢	🟢	🟢
Italy	🟢	🔴	🟢	🟢	🟢	🟢
France	🟢	🔴	🟢	🟢	🟢	🟢
India	🟢	🔴	🟢	🟡	🟢	🟢
Turkey	🟢	🔴	🟢	🟡	🟢	🟢
China	🟢	🔴	🟢	🟡	🟢	🟢
US - CAISO	🟢	🔴	🟢	🟢	🟢	🟢
US - PJM	🟢	🔴	🟢	🟢	🟢	🟢
US - ERCOT	🟢	🔴	🟢	🟢	🟢	🟢
US - MISO	🟢	🔴	🟢	🟢	🟢	🟢

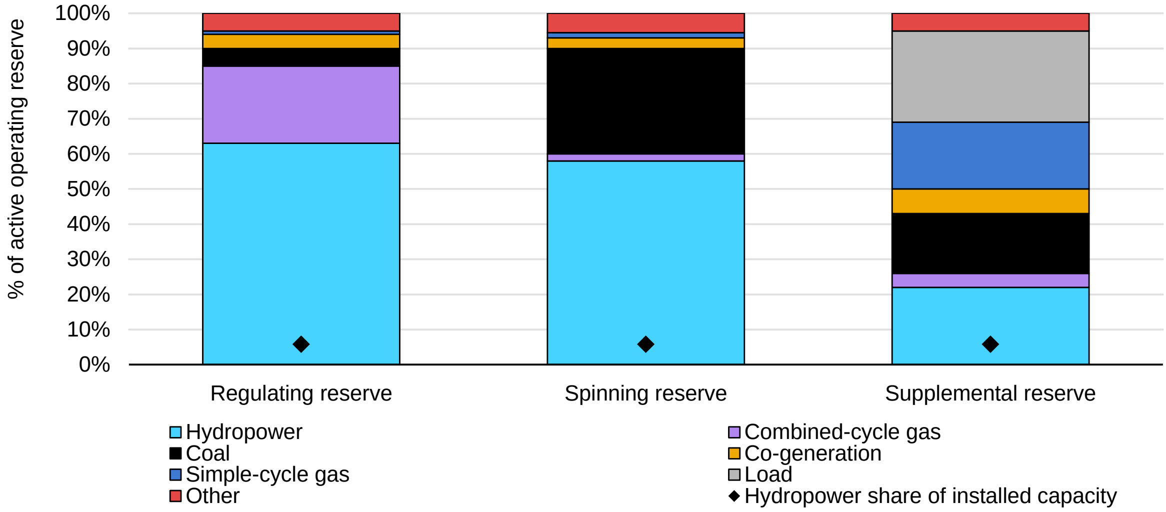
Country	Sub-seconds to seconds Inertia, voltage control, reactive power, etc.		1-5 minutes Primary and secondary frequency regulation		15 minutes to 1 hour Regulating reserves	
	Hydro role	Remunera-tion	Hydro role	Remunera-tion	Hydro role	Remunera-tion
Australia	🟢	🟡	🟢	🟢	🟢	🟢
Colombia	🟢	🟡	🟢	🟡	🟢	🟢
Switzerland	🟢	🟡	🟢	🟡	🟢	🟢
Canada - Quebec	🟢	🟡	🟢	🟡	🟢	🟢
Canada - Alberta	🟢	🟢	🟢	🟢	🟢	🟢
Japan	🟢	🟡	🟢	🟡	🟢	🟢
Ireland	🟢	🟢	🟢	🟢	🟢	🟢
Finland	🟢	🟢	🟢	🟢	🟢	🟢
Norway	🟢	🟢	🟢	🟢	🟢	🟢
Sweden	🟢	🟢	🟢	🟢	🟢	🟢
United Kingdom	🟢	🟢	🟢	🟢	🟢	🟢

Note: For hydro role, 🟢 high capability; 🟡 moderate capability; 🔴 low or no capability. For remuneration, 🟢 services remunerated; 🟡 services partially remunerated; 🔴 services not remunerated.

Source: Based on IEA Hydro TCP (2021), Valuing Flexibility in Evolving Electricity Markets: Current Status and Future Outlook for Hydropower.

When remuneration is provided, hydropower plants with low operational costs can be the most cost-effective technology offering ancillary services for system security and adequacy at the shortest timescales. In Alberta, Canada, hydropower was the largest contributor to the active operating reserve market in 2019, even though it made up only 6% of the province's installed capacity. Generators bid to provide regulating, spinning and supplemental reserves to the active and standby reserve markets, with the equilibrium active reserve price being the average of the marginal offer price and the bid ceiling. Despite their very small installed capacity, reservoir hydropower plants consistently bid the lowest prices to provide active reserve services.

Figure 4.19 **Alberta, Canada market shares of active operating reserves by technology, 2019**



Note: Co-generation refers to the combined production of heat and power.
Source: Based on AESO (2020), *AESO 2019 Annual Market Statistics*.

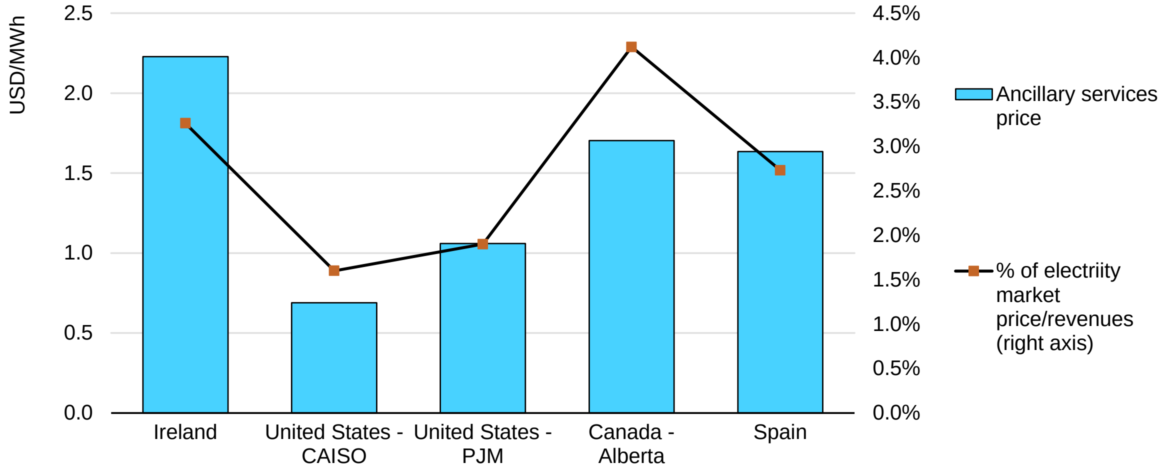
Remuneration for flexibility remains low, but long-term contracts can stimulate new investment

Energy sales continue to be the primary source of revenue for hydropower plants operating in liberalised electricity markets. Power plant ancillary services revenues range from 1% to 5% of their electricity market revenues. Although many power plants, including hydropower, gain additional revenues by offering ancillary services that provide flexibility, average remuneration is USD 0.5-2.5/MWh – significantly lower than the average daily electricity price of USD 25-60/MWh in many wholesale markets.

Furthermore, the pricing of ancillary services and the quantity delivered do not correlate with the amount of VRE penetration in a given energy system. In Alberta, for example, revenues from ancillary services totalled 4.5% of electricity market earnings in 2019 – higher than in California (under CAISO), where VRE shares are significantly larger.

Transmission system and energy market operators procure many ancillary services the day ahead or the same day, usually through competitive processes. For an existing hydropower fleet, it is mostly PSH and reservoir facilities that gain revenues from ancillary services, depending on hydrological conditions and the price of energy. Although hydropower plants have the technical ability to provide many flexibility services, facility operators must assess the trade-off between changing operations to offer ancillary services and selling bulk energy on the market.

Figure 4.20 Ancillary services prices and shares in overall wholesale price formation, 2019/20



Source: Based on AESO (2020), *AESO 2019 Annual Market Statistics*; CAISO (2020), *2019 Annual Report on Market Issues & Performance*; REE (2020), *Ancillary Services and International Exchanges Preliminary Report 2019*; PJM (2020), State of the Market 2019; EIRGRID (2020), *Ancillary Services Statement of Payments and Charges*

In addition to selling energy and ancillary services, hydropower plants can take advantage of capacity markets in which system operators provide remuneration for the on-demand availability of installed capacity. Reservoir and PSH plants are usually eligible to bid in short-term capacity markets, and in many countries these markets provide one-year contracts with delivery one to three years after award of the contract. In some markets, these contracts can provide up to 50% of a fleet's revenue. For instance, the one PSH plant in the US PJM balancing area has received 40-50% of its annual revenue from capacity markets since 2014.

Table 4.4 Short- and long-term remuneration of capacity in selected countries

Country	Short-term remuneration	Long-term remuneration
United Kingdom	1 year	15 years
Belgium	1 year	15 years
Italy	1 year	15 years*
Ireland	1 year	10 years
France	1 year	7 years

Country	Short-term remuneration	Long-term remuneration
Israel	🔴	🟢 18-20 years
US - CAISO	🟢 1 year	🔴
US - PJM	🟢 1 year	🔴
US - ERCOT	🟢 1 year	🔴
US - MISO	🟢 1 year	🔴
Australia	🟢 1 year	🔴
Colombia	🟢 1 year	🟡

🟢 available 🟡 partially available through other types of contracts 🔴 unavailable

*Contracts of up to 15 years are available upon bidder request.

In some regions, capacity markets provide long-term remuneration for new capacity and modernisation of projects. In the United Kingdom, Belgium and Italy, capacity auctions can award contracts of up to 15 years in addition to short-term remuneration, while Ireland offers 10-year contracts and France's are for 7 years. Considering that plants have an economic lifetime of 40-60 years and the development process is lengthy, long-term remuneration schemes can stimulate new PSH projects in liberalised electricity markets. However, relatively short contract delivery times (2-5 years) usually do not permit new PSH projects to be operational on time.

Storage or hybrid (renewables plus storage) auctions that provide long-term revenue visibility could also provide an incentive for new PSH or reservoir projects. In India, for instance, the government awarded 1 200 MW of renewables and storage in a tender that included 900 MW of pumped storage, offering a weighted average price of USD 57/MWh (INR 4.04/kWh) and a peak tariff of USD 86/MWh (INR 6.12/kWh), and 300 MW of battery storage at USD 60.2/MWh (INR 4.3/KWh) and USD 96/MWh (INR 6.85/kWh).

Chapter 5 - Policy recommendations

Hydropower is currently the world's preeminent low-carbon electricity technology. Nevertheless, policy attention remains limited, even though hydropower technologies contribute significant renewable electricity generation and system flexibility, and provide multiple critical services (e.g. irrigation and flood management) for millions of people.

Hydropower continues to play a key role in all IEA long-term decarbonisation scenarios (i.e. the Sustainable Development Scenario and the Net-Zero Emissions by 2050 Scenario) with substantial increases in capacity and generation. A number of significant challenges hamper faster hydropower deployment, however, and it is not easy to secure the investments necessary to ensure the proper functioning and availability of ageing assets that are crucial for electricity security.

According to our forecast to 2030, hydropower development is not on track with the IEA's long-term sustainability scenarios, indicating that policy and regulatory challenges need to be addressed rapidly. Achieving the goals of the IEA's *Net Zero by 2050* roadmap, which targets massive variable renewable energy (VRE) expansion, would require substantially stronger government ambition. Doubling global capacity by 2050 would be necessary for hydropower technologies to provide dispatchable low-carbon electricity at the same time as offering flexibility services to securely integrate very high VRE shares.

Move hydropower up the energy and climate policy agenda

Public sector involvement has been critical for hydropower expansion. However, renewable energy policy attention in the past two decades has focused primarily on increasing wind and solar PV technology expansion (and lowering its cost), mainly through support schemes such as deployment targets, financial incentives and long-term power purchase contracts.

Today, more than 100 countries have introduced short- and long-term targets and financial incentives for wind and solar PV, but fewer than 30 have policies targeting new and existing hydropower plants. As hydropower projects have longer pre-development, construction and operational timelines than other renewable energy technologies, investment risks are higher, requiring specific policy instruments and incentives as well as a longer-term policy perspective and vision.

Policy priority

Sustainably developed hydropower plants need to be recognised as renewable energy sources. Governments should include large and small hydropower in their long-term deployment targets, energy plans and renewable energy incentive schemes, on a par with variable renewables.

Enforce robust sustainability standards for all hydropower development with streamlined rules and regulations

Sustainability must be central to any hydropower development, large or small, but standards and implementation rules vary significantly among countries. In some economies, meeting them may take up to a decade and compliance may also incur significant expenditures, discouraging investment.

Multiple robust, internationally agreed sustainability standards have, however, been developed by national and multinational organisations according to best practices. If developed sustainably, hydropower plants offer net environmental, social and economic benefits.

Policy priorities

Environmental and sustainability regulations for new and existing hydropower projects need to be streamlined to provide developers with clear rules and reasonable implementation timelines, without compromising stringency.

To win public acceptance and raise investor confidence in new projects, governments should facilitate fact-based dialogue between local communities and investors in the very early-stages and maintain engagement at all phases of project development by prioritising the mitigation of negative social and environmental impacts. Those that cannot be mitigated should be minimised or compensated for.

For existing hydropower plants, governments should implement evolving sustainability standards. In some cases, however, complying with new standards may require additional investment by developers or cause revenue loss if less water is available for electricity generation. Policies to facilitate financing and compensate for possible economic losses should therefore be devised to help developers meet new sustainability standards. It may be best to implement new standards when major plant modernisation is taking place.

Recognise the critical role of hydropower for electricity security and reflect its value through remuneration mechanisms

During the world's transition to clean energy, hydropower installations could be crucial to electricity security, as they can produce large amounts of low-carbon electricity, guarantee capacity availability with fast ramp-up and -down rates, and provide ancillary services – including inertia – to ensure system stability.

However, the full value of hydropower's benefits for power systems and electricity security are rarely reflected in market designs or regulations. At the same time, hydropower operations are exposed to weather variations and the potential impacts of climate change, so specific instruments are required to address hydrological risks in the longer term.

Policy priorities

Policy makers should assess and recognise the full electricity security and system stability value of hydropower and should translate these benefits into remuneration schemes that make new projects and modernisation activities bankable.

For new projects especially, governments may provide a blend of economic instruments that both lower pre-development and construction risk and offer long-term revenue certainty. Depending on specific power system characteristics, feed-in tariffs (FiTs), PPAs or contracts for availability (capacity) could be most appropriate, and auctions could also be instituted to foster hybrid projects that provide dispatchable power (e.g. solar/wind + hydropower). Remuneration schemes will have to be designed carefully to allocate hydrological risks equitably among economic actors.

Maximise the flexibility capabilities of existing hydropower plants through measures to incentivise their modernisation

Hydropower plants are one of the largest contributors to power system flexibility today. Reservoir facilities offer flexible, low-carbon electricity in quantities unmatched by any other technology, to provide flexibility and system services across a wide range of timescales.

Given global long-term climate change goals and declining fossil fuel use in electricity generation, hydropower is the most cost-effective, dispatchable low-carbon technology with remaining untapped potential. Refurbishing and modernising ageing assets can greatly increase power system flexibility to help countries reach long-term climate goals. However, in some places market and regulatory frameworks for flexibility services remain underdeveloped, while in others remuneration is either inadequate or unpredictable. This may not incentivise additional investment to make existing plants more flexible.

Policy priorities

Governments should better recognise the value of dispatchable renewable energy and encourage modernisation and refurbishment investments, for instance through loan guarantees or by providing long-term revenue certainty.

In wholesale electricity markets, trading balancing products at shorter timescales would recompense hydropower's flexibility services more fairly. Hydropower plants could also be awarded additional remuneration for providing inertia and fast-frequency-response services.

In developing countries, the performance of many hydropower plants is less than optimal due to lack of maintenance. Fostering the refurbishment and modernisation of these plants is critical to derive the utmost benefit from the many services they offer.

Support the expansion of pumped storage hydropower

The need for long-term energy storage (i.e. of more than 4 hours) is becoming greater as larger VRE shares enter the energy system. At high shares of VRE – particularly from solar PV – midday surpluses of renewable electricity become systematic, requiring storage to avoid significant curtailment.

Despite recent reductions in battery costs, pumped-storage hydropower (PSH) is still the most cost-effective long-term electricity storage option. In fact, future power systems will need both: batteries for short-term storage (of less than 4 hours), and PSH for its long-term capabilities. The additional advantage of PSH plants is that they can provide almost all system services while ensuring electricity security and grid stability.

However, the business case for PSH plants, which is based on taking advantage of energy arbitrage opportunities, has deteriorated in energy-only markets, so prospects for new plants are limited. Long lead times, project risks associated with permitting, and the absence of long-term revenue visibility have stalled PSH deployment in countries with ambitious long-term decarbonisation targets.

Most current PSH development is therefore in vertically integrated markets where governments see PSH as a strategic asset for secure and cost-effective power system operations, and as a means to avoid inefficient curtailment of surplus renewable electricity generation.

Policy priorities

Governments should consider PSH plants as an integral part of their long-term strategic energy plans, aligned with wind and solar PV capacity expansion. Policy makers should identify suitable undeveloped sites and choose installations that would have the least environmental impact, for example closed-loop systems and the adding on of PSH capabilities to existing infrastructure such as abandoned mines, natural reservoirs and established reservoir plants. It is also essential to clarify the regulatory environment for storage by standardising definitions and eliminating double grid tariffs.

In energy-only markets, governments could provide long-term revenue visibility for PSH plants through contracts that value long-term storage. Measures and incentives that support pre-feasibility studies could help identify suitable sites and reduce investment costs for developers.

In vertically integrated markets, governments could integrate existing and planned PSH plants into ongoing electricity market reforms.

Mobilise affordable financing for sustainable hydropower development in developing economies

Most untapped hydropower potential is in developing countries across Africa, Asia and Latin America. In these economies, hydropower installations are a cost-effective option not only to generate electricity but to expand electricity energy access, promote economic development and provide water for irrigation and drinking.

However, access to affordable financing for large-scale hydropower projects continues to be limited by macroeconomic risks and policy uncertainties. In addition, the poor financial health of off-takers in many developing countries increases project risk, weakening the bankability of hydropower projects and deterring foreign direct investment.

Policy priorities

Governments, international financial institutions and development agencies should support public-private partnerships and mobilise low-cost capital to de-risk hydropower projects in developing countries.

Take steps to ensure to price in the value of the multiple public benefits provided by hydropower plants

In addition to generating electricity, hydropower plants benefit society. Reservoir installations can provide essential water services such as irrigation, flood management and potable water supply. Sustainably developed dam infrastructure also offers critical protection against the long-term effects of climate change (such as droughts) and can increase energy system resiliency.

Regrettably, the economic value of these multiple benefits is rarely evaluated quantitatively.

Policy priorities

Governments should develop metrics to assess the multipurpose value of hydropower dams and recognise the net economic and social benefits of water management services to local communities.

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Revised version, July 2021. Information notice found at: www.iea.org/corrections

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Typeset in France by IEA - June 2021
Cover design: IEA
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