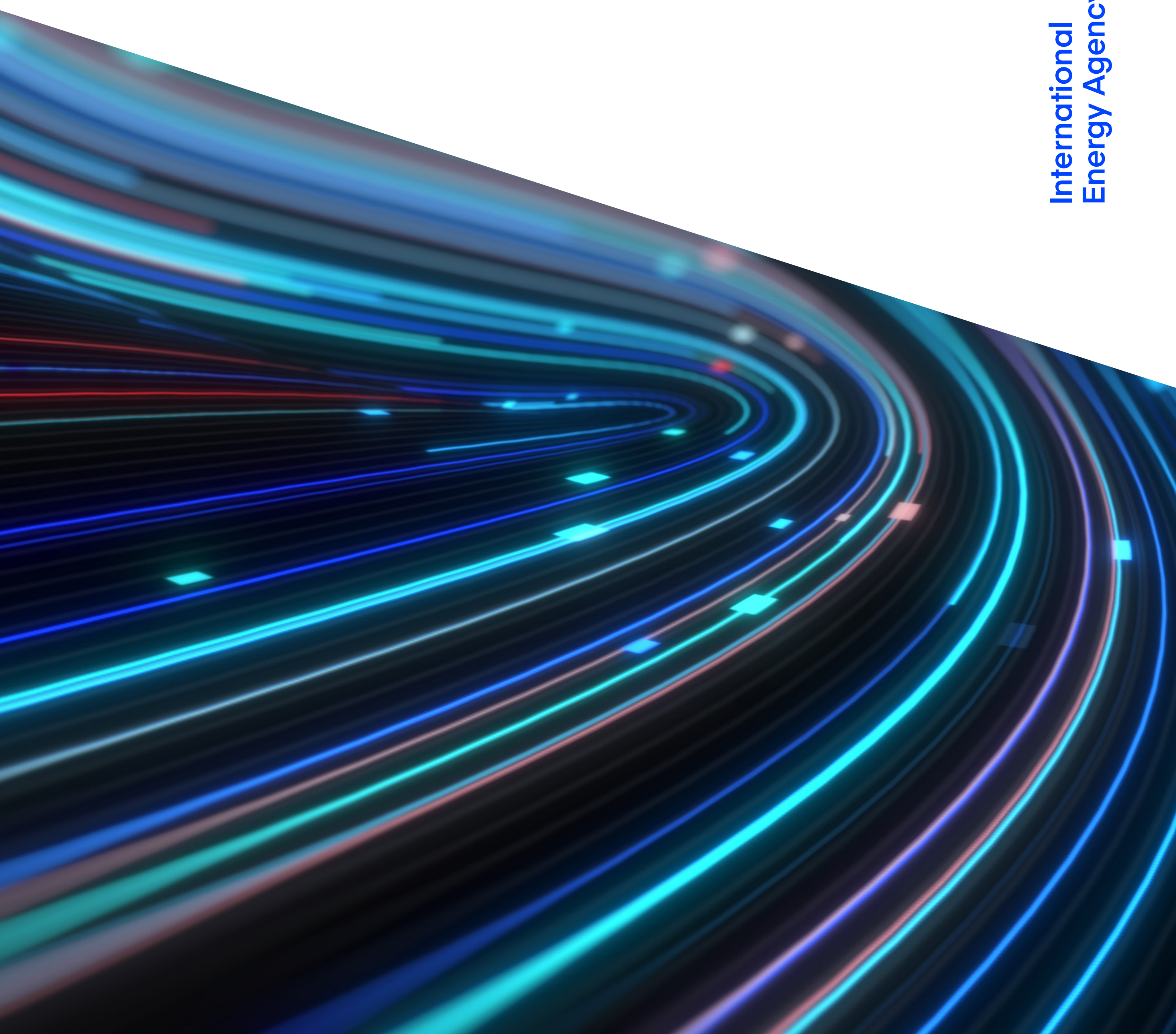
Nuclear Power and Secure Energy Transitions

From today's challenges to tomorrow's clean energy systems



International Energy Agency

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 31 member countries, 10 association countries and beyond.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Lithuania
Luxembourg
Mexico
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Republic of Türkiye
United Kingdom
United States

The European Commission also participates in the work of the IEA

IEA association countries:

Argentina
Brazil
China
Egypt
India
Indonesia
Morocco
Singapore
South Africa
Thailand

International Energy Agency
Website: www.iea.org

Abstract

Nuclear Power and Secure Energy Transitions: From Today's Challenges to Tomorrow's Clean Energy Systems is a new report by the International Energy Agency that looks at how nuclear energy could help address two major crises – energy and climate – facing the world today. Russia's invasion of Ukraine and the disruptions in global energy supplies that it has fuelled have made governments rethink their energy security strategies, putting a stronger focus on developing more diverse and domestically based supplies. For multiple governments, nuclear energy is among the options for achieving this. At the same time, many governments have in recent years stepped up their ambitions and commitments to reach net zero emissions. Nuclear Power and Secure Energy Transitions expands upon the IEA's landmark 2021 report, Net Zero by 2050: A Roadmap for the Global Energy Sector. It does so by exploring in depth nuclear power's potential role as a source of low emissions electricity that is available on demand to complement the leading role of renewables such as wind and solar in the transition to electricity systems with net zero emissions.

In this context, the report examines the difficulties facing nuclear investment, particularly in advanced economies, in the areas of cost, performance, safety and waste management. It considers the additional challenge of meeting net zero targets with less nuclear power than envisioned in the IEA Net Zero Roadmap, as well as what kind of cost targets could enable nuclear power to play a larger role in energy transitions. For countries where nuclear power is considered an acceptable part of the future energy mix, the new report identifies the potential policy, regulatory and market changes that could be implemented in order to create new investment opportunities. It also looks at the role of new technologies, particularly small modular reactors, and their potential development and deployment.

Acknowledgements, contributors and credits

The study was designed and directed by Keisuke Sadamori, Director of Energy Markets and Security.

The main authors of the study are Peter Fraser, Brent Wanner, Keith Everhart and Antoine Herzog. Luis Lopez, Zoe Hungerford, Max Schoenfisch and Yunyou Chen were the other principal contributors to this report.

Valuable comments and feedback were provided by senior management and numerous other colleagues at the IEA and, in particular, Laura Cozzi, Tim Gould, Timur Gül, Amos Bromhead, Alessandro Blasi, Alejandro Hernandez, Fengquan An, Brian Motherway, Hiroyasu Sakaguchi, Rebecca Gaghen and Nick Johnstone.

Thanks go to the IEA's Communications and Digital Office for their help in producing the final report and website materials, particularly to Jad Mouawad, Therese Walsh, Jethro Mullen, Astrid Dumond and Allison Leacu.

For their editing support, we thank Trevor Morgan (principal) and Adam Majoe (copy-editor).

Additionally, the study team benefitted from meetings with specialists, including those from the OECD Nuclear Energy Agency, and particularly Michel Berthélemy, who provided insights and helpful information. We also held useful discussions with Wei Huang, Henri Paillère and colleagues at the International Atomic Energy Agency, Sama Bilbao y León and colleagues at the World Nuclear Association, and Kirsty Gogan and Eric Ingersoll of Terrapraxis.

Special thanks go to those who were interviewed on the topic of small modular reactors, including Chris Levesque (Terrapower), Renaud Crassous (Nuward), Dominique Minière (Ontario Power Generation), Cosmin Ghita (Nuclearelectrica), John Parsons (Massachusetts Institute of Technology), Rumina Velshi (Canadian Nuclear Safety Commission), Declan Burke (Department of Business, Energy and Industrial Strategy, United Kingdom), Bruce Smith (Emirates Water and Electricity Company), Sheng Zhou (Tsinghua University), Yasuharu Kimura and Ikuo Hoshino (JGC), and Alastair Evans (Rolls-Royce).

We would also like to thank the external reviewers, including:

Daniel Balog	Ministry of Foreign Affairs, Hungary
Marco Baroni	Independent consultant

Maximilian Barth	German Corporation for International Cooperation
Jean-Paul Bouttes	Independent consultant
Diane Cameron	Nuclear Energy Agency
Juan Ignacio del Castillo Campos	Ministry of Industry, Trade and Tourism, Spain
Ewa Chmura-Golonka	Ministry of Climate and Environment, Poland
Gwangjun Choi	Ministry of Foreign Affairs, Republic of Korea
Russell Conklin	United States Department of Energy
Renaud Crassous	Électricité de France
François Dassa	Électricité de France
Jac Goodman	United States Department of Energy
Hiroyuki Goto	Nuclear Energy Agency
Volker Holubetz	Federal Ministry for Climate Action, Environment, Energy, Mobility, Innovation and Technology, Austria
Esa Hyvarinen	Fortum
Jan Horst Keppler	Nuclear Energy Agency
Ken Koyama	Institute of Energy Economics, Japan
King Lee	World Nuclear Association
François Lévêque	École Nationale Supérieure des Mines de Paris
William D. Magwood IV	Nuclear Energy Agency
Kris McCoy	Ministry of Industry, Australia
Manabu Nabashima	Ministry of Foreign Affairs, Japan
Ritika Nandekeolyar	Global Affairs Canada
David Newbery	University of Cambridge, United Kingdom
Tomasz Nowacki	Ministry of Climate and Environment, Poland
Reelika Runnel	Ministry of the Environment, Estonia
Barış Sanli	Ministry of Energy and Natural Resources, Türkiye
Antonia Vaya Soler	Nuclear Energy Agency

Markus Wrake	Energiforsk
Sheng Zhou	Tsinghua University, China

The individuals and organisations that contributed to this study are not responsible for any opinions or judgments it contains. All errors and omissions are solely the responsibility of the IEA.

Executive Summary

A new dawn for nuclear energy?

Nuclear energy can help make the energy sector's journey away from unabated fossil fuels faster and more secure. Amid today's global energy crisis, reducing reliance on imported fossil fuels has become the top energy security priority. No less important is the climate crisis: reaching net zero emissions of greenhouse gases by mid-century requires a rapid and complete decarbonisation of electricity generation and heat production. Nuclear energy, with its 413 gigawatts (GW) of capacity operating in 32 countries, contributes to both goals by avoiding 1.5 gigatonnes (Gt) of global emissions and 180 billion cubic metres (bcm) of global gas demand a year. While wind and solar PV are expected to lead the push to replace fossil fuels, they need to be complemented by dispatchable resources. As today's second largest source of low emissions power after hydropower, and with its dispatchability and growth potential, nuclear – in countries where it is accepted – can help ensure secure, diverse low emissions electricity systems.

Advanced economies have lost market leadership. Although advanced economies have nearly 70% of global nuclear capacity, investment has stalled and the latest projects have run far over budget and behind schedule. As a result, the project pipelines and preferred designs have shifted. Of the 31 reactors that began construction since the beginning of 2017, all but 4 are of Russian or Chinese design.

Restrictions on nuclear power remain in certain countries, driven by concerns about safety and waste. The 2011 accident at the Fukushima-Daiichi plant in Japan following a major earthquake undermined public trust in nuclear power, underscoring the need for robust, independent regulatory oversight. Accident risks are one of the main factors behind bans on nuclear power or policies to phase it out. While there is progress on disposing of high-level nuclear waste, with three countries having approved sites, gaining public and political acceptance has been challenging.

The policy landscape is changing, opening up opportunities for a nuclear comeback. More than 70 countries, covering three-quarters of energy-related greenhouse gas emissions, have pledged to cut their emissions to net zero. While renewables would provide the largest share of low emissions electricity and many countries either do not foresee the need or do not want a role for nuclear power, a growing number of countries have also announced plans to invest in nuclear. The United Kingdom, France, China, Poland and India have recently announced energy strategies that include substantial roles for nuclear power. The United States is investing in advanced reactor designs.

Energy security concerns and the recent surge in energy prices, notably in the wake of Russia's invasion of Ukraine, have highlighted the value of a diverse mix of non-fossil and domestic energy sources. Belgium and Korea have recently scaled back plans to phase out existing nuclear plants. The UK Energy Security Strategy includes plans for eight new large reactors. Faster restarts of Japanese nuclear reactors that have received safety approvals could free up liquefied natural gas (LNG) cargoes desperately needed in Europe or other markets in Asia.

In the decade following the 1973 oil shock, construction started on almost 170 GW of nuclear power plants. These plants still represent 40% of today's nuclear capacity. Nuclear additions in the last decade reached only 56 GW. With policy support and tight cost controls, today's energy crisis could lead to a similar revival for nuclear energy.

Achieving net zero globally will be harder without nuclear

As an established large-scale low emissions energy source, nuclear is well placed to help decarbonise electricity supply. In the IEA's Net Zero Emissions by 2050 Scenario (NZE), energy sector emissions fall by about 40% from 2020 to 2030, and then decline to zero on a net basis by 2050. While renewable sources dominate and rise to nearly 90% of electricity supply in the NZE, nuclear energy plays a significant role. This narrow but achievable pathway requires rigorous and immediate policy action by governments around the world to reshape energy systems on many fronts.

Extending nuclear plants' lifetimes is an indispensable part of a cost-effective path to net zero by 2050. About 260 GW, or 63%, of today's nuclear plants are over 30 years old and nearing the end of their initial operating licences. Despite moves in the past three years to extend the lifetimes of plants representing about 10% of the worldwide fleet, the nuclear fleet operating in advanced economies could shrink by one-third by 2030. In the NZE, the lives of over half of these plants are extended, cutting the need for other low emissions options by almost 200 GW. The capital cost for most extensions is about USD 500 to USD 1 100 per kilowatt (kW) in 2030, yielding a levelised cost of electricity generally well below USD 40 per megawatt-hour (MWh), making them competitive even with solar and wind in most regions.

Nuclear power plays a significant role in a secure global pathway to net zero. Nuclear power doubles from 413 GW in early 2022 to 812 GW in 2050 in the NZE. Annual nuclear capacity additions reach 27 GW per year in the 2030s, higher than any decade before. Even so, the global share of nuclear in total generation falls slightly to 8%. Emerging and developing economies account for more than 90% of global growth, with China set to become the leading nuclear power producer before 2030. Advanced economies collectively see a 10% increase in nuclear, as retirements are offset by new plants, mainly in the United States, France, the United Kingdom and

Canada. Annual global investment in nuclear power rises from USD 30 billion during the 2010s to over USD 100 billion by 2030 and remains above USD 80 billion to 2050.

Less nuclear power would make net zero ambitions harder and more expensive. The Low Nuclear Case variant of the NZE considers the impact of failing to accelerate nuclear construction and extend lifetimes. In this case, nuclear's share of total generation declines from 10% in 2020 to 3% in 2050. Solar and wind would need to fill the gap, pushing the frontiers of integrating high shares of variable renewables. More energy storage and fossil fuel plants fitted with carbon capture, utilisation and storage (CCUS) would be needed. As a result, the NZE's Low Nuclear Case would require USD 500 billion more investment and raise consumer electricity bills on average by USD 20 billion a year to 2050.

Nuclear has to up its game in order to play its part

The industry has to deliver projects on time and on budget to fulfil its role. This means completing nuclear projects in advanced economies at around USD 5 000/kW by 2030, compared with the reported capital costs of around USD 9 000/kW (excluding financing costs) for first-of-a kind projects. There are some proven methods to reduce costs including finalising designs before starting construction, sticking with the same design for subsequent units, and building multiple units at the same site. Stable regulatory frameworks throughout construction would also help avoid delays.

An even larger role for nuclear power will require greater declines in construction costs. Hydropower, bioenergy and fossil fuel plants equipped with CCUS are the main alternative dispatchable low emissions sources to nuclear. Each one also faces challenges to expand. Hydropower sites and sustainable bioenergy supply are limited, while there are economic, political and technical obstacles to scaling up CCUS. Where there is potential to expand these alternatives and CCUS is commercially available, the construction costs of nuclear power would need to fall to USD 2 000-3 000/kW (in 2020 dollars) to remain competitive. Depending on financing costs, this would yield a levelised cost of electricity for nuclear power of USD 40-80/MWh, including decommissioning and waste disposal. If new projects were able to achieve these costs in more markets, an even larger role for nuclear would be available.

Using electricity from nuclear to produce hydrogen and heat presents new opportunities. The rapid expansion of low emissions hydrogen is a key pillar of the NZE, with related investment rising from near zero today to USD 80 billion per year to 2040. Under the NZE's cost projections, hydrogen production via natural gas with CCUS or via electrolysis using renewables are the cheapest options. For nuclear to compete with these alternatives, investment costs would need to decrease to USD 1 000-2 000/kW. The economics would be more favourable if the nuclear reactor is co-located with a hydrogen user, avoiding transportation costs. The NZE estimates surplus nuclear electricity could be used to produce an estimated 20 million tonnes of hydrogen in 2050. There are also possibilities to co-generate heat from nuclear plants to replace district heating and other high-temperature uses, though the potential scale of this market is limited and construction costs would need to fall to USD 2 000-3 000/kW to make it competitive.

Markets need to account for added value of all services

Nuclear and other dispatchable power sources complement renewables by providing critical services to electricity systems. The predominance of wind and solar in the power mix and the end of unabated fossil generation must be complemented by a diverse mix of dispatchable generation to provide stability, short-term flexibility and adequate capacity during peak demand periods. For example, in an analysis of a carbon neutral power system in China, nuclear would provide only 10% of total electricity produced in 2060, but supply almost half the required inertia, a key component of system flexibility.

Wholesale markets should price system services to reflect their value. The need for system services such as flexibility, adequacy and stability increases sharply as the share of variable renewables increases. Electricity markets should be designed to fully value these services, not just electricity production. In addition, robust carbon pricing regimes would encourage a more decarbonised energy system at lowest cost.

Government involvement will be needed to finance new investment. Nuclear projects have long relied on state ownership or a regulated monopoly structure to guarantee revenues and reduce risk to investors because there is rarely sufficient private sector finance for such capital-intensive and long-lived assets, particularly those exposed to significant policy risk. Innovative financing mechanisms, such as the recently approved Regulated Asset Base (RAB) model by the United Kingdom, can help to secure adequate financing while assigning risks to those best situated to accept it.

Momentum behind small modular reactors is building

The challenge of net zero has stimulated a burst of development in small modular reactor technologies. In the NZE, half of the emissions reductions by 2050 come from technologies, including small modular reactors, that are not yet commercially viable. SMRs, generally defined as advanced nuclear reactors with a capacity of less than 300 MW, have strong political and institutional support, with substantial grants in the United States, and increased support in Canada, the United Kingdom and France. This support makes it possible to attract private investors, bringing new players and new supply chains to the nuclear industry.

Being smaller can help SMRs fit in. Lower capital costs, inherent safety and waste management attributes and reduced project risks may improve social acceptance and attract private investment for research and development, demonstration and development. SMRs could also reuse the sites of retired fossil fuel power plants, taking advantage of existing transmission, cooling water and skilled workforces. Other opportunities include co-location with industry to provide electricity, heat and hydrogen.

Policy and regulatory reforms are needed to stimulate investment. The successful long-term deployment of SMRs hinges on strong support from policy makers and regulators to leverage private sector investment. Adapting and streamlining licensing and regulatory frameworks to take SMR attributes into account is key. International harmonisation of licensing and definitions are essential to developing a global market. Securing private financing will require a robust and technology-neutral policy framework, including in the area of taxonomies and environmental, social and governance that will have a growing influence on financial flows.

Decisions are needed now for SMRs to play a meaningful part in energy transitions. While only a small number of units are likely to start operating this decade, with recent momentum SMRs could start playing a significant role in energy transitions in the 2030s, provided that regulatory and investment decisions are made now, and commercial viability is demonstrated. This is true both for small evolutionary reactors that could achieve economic competitiveness more readily, but also for the advanced reactor models.

Policy Recommendations

The following recommendations are directed at policy makers in countries that see a future for nuclear energy. The IEA makes no recommendations to countries that have chosen not to make use of nuclear power and fully respects their choice.

- **Extend plant lifetimes**. Authorise lifetime extensions of existing nuclear power plants so they can continue to operate for as long as safely possible.
- **Make electricity markets value dispatchable low emissions capacity**. Design electricity markets to ensure nuclear power plants are compensated in a competitive and non-discriminatory manner for the avoidance of emissions and the services they provide to maintain electricity security, including capacity availability and frequency control.
- **Create financing frameworks to support new reactors**. Set up risk management and financing frameworks to mobilise capital for new plants at an acceptable cost and with fair sharing of risks between investors and consumers.
- **Promote efficient and effective safety regulation**. Ensure that safety regulators have the resources and skills to undertake timely reviews of new projects and designs, develop harmonised safety criteria for new designs, and engage with potential developers and the public to ensure that licensing requirements are clearly communicated.
- **Implement solutions for nuclear waste disposal**. Involve citizens in prioritising approval and construction of high-level waste disposal facilities in countries that do not yet have them.
- **Accelerate the development and deployment of small modular reactors.** Identify opportunities where SMRs could be a cost-effective low emissions source of electricity, heat and hydrogen. Support investment in demonstration projects and in developing supply chains.
- **Re-evaluate plans according to performance.** Make long-term support contingent on the industry delivering safe projects on time and on budget.

Introduction

Nuclear energy could play an important role in ensuring that the energy sector's journey to net zero emissions is rapid and secure. While wind and solar PV are expected to lead the decarbonisation of the global power mix, flexible and dispatchable[1] resources will be required to complement these supplies. There are economic and technical challenges to be overcome, and not all countries will pursue nuclear energy as an option, but rising climate ambitions in many countries and today's energy crisis offer reasons to take a fresh look at what nuclear energy can deliver.

This report assesses the contribution that nuclear can make and the conditions that would need to be met for nuclear power to realise its potential in a secure and cost-effective way. It builds on the analysis in our 2019 report, Nuclear Power in a Clean Energy System, which focused on the role of nuclear power in developed economies and the prospects for lifetime extensions of existing plants – a low cost option to sustain clean electricity supply today.

Since that last report, the policy landscape has shifted in ways that favour nuclear energy. Many countries are recognising that a broad suite of low-carbon technology options will be required to meet ambitious climate policy goals. Nuclear energy also brings dividends for energy security, an important consideration at a time of heightened attention to this issue in the wake of Russia's invasion of Ukraine.

This report addresses a number of questions, including:

- What is the potential for growth in nuclear energy in those countries that decide to pursue it as part of their transition to a clean energy system?
- What is the economic value of nuclear power and what elements of market design are needed for this to be realised?
- What are the cost metrics that nuclear power needs to hit to achieve this potential?
- What other financial measures would be needed to support nuclear expansion?
- How can small modular reactors (SMRs) complement existing technologies and what measures will ensure that they are safe, economic and deployed in a timely manner for electricity generation and for the supply of heat and hydrogen?

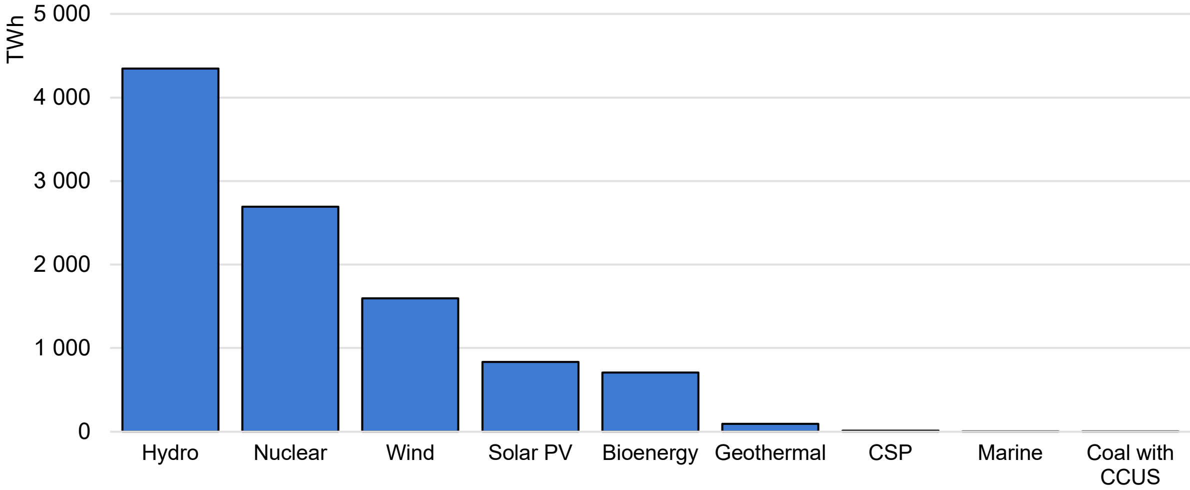
[1] Electricity that can be produced and dispatched to the system as and when required.

1. Nuclear power in the world today

Nuclear remains a leading source of clean electricity

Nuclear power made up about 10% of global electricity generation in 2020. This share has declined from 18% in the late 1990s, but nuclear is still the second-largest source of low emissions electricity (i.e. non-fossil-based) after hydroelectricity and the leading source in advanced economies.[2] In 2020, nuclear electricity still exceeded the total combined contribution of wind and solar PV generation worldwide, despite massive growth in those renewable sources. At the end of 2021, there were 439 nuclear power reactors in operation in 32 countries around the world, with a combined capacity of 413 GW. Around 270 GW of that capacity was in advanced economies.

Low emissions electricity generation by source worldwide, 2020



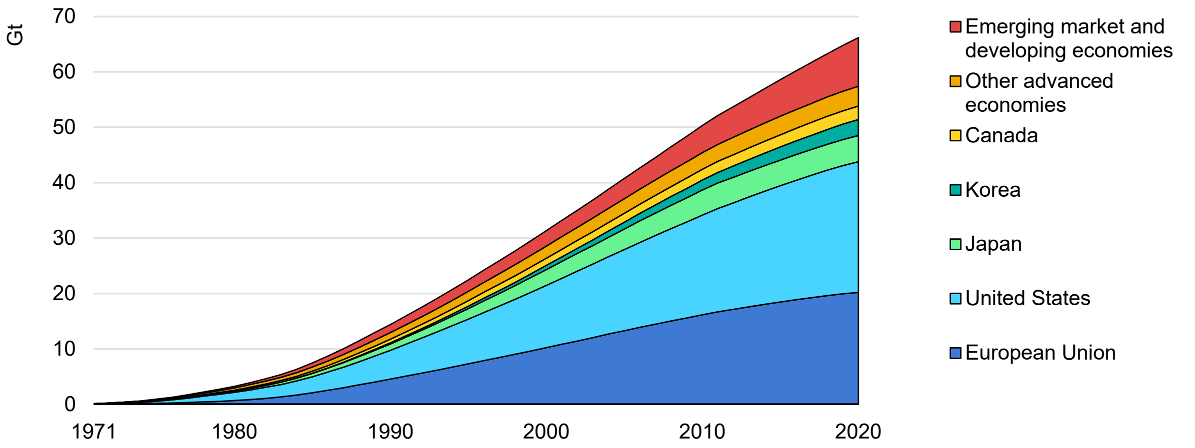
Note: CSP = concentrating solar power; CCUS = carbon capture, utilisation and storage.
Source: IEA (2021), World Energy Outlook 2021.

Nuclear power has made a major contribution to slowing the rise in global emissions of CO_2 since the 1970s. Around 66 Gt of CO_2 was avoided globally between 1971 and

[2] Australia, Canada, Chile, the 27 members of the European Union, Iceland, Israel, Japan, Korea, Mexico, New Zealand, Norway, Switzerland, Turkey, the United Kingdom and the United States.

2020.[3] Without the contribution of nuclear power, total emissions from electricity generation would have been almost 20% higher and total energy-related emissions 6% higher over that period. Advanced economies accounted for over 85% of these avoided emissions: 20 Gt, or over 40% of total emissions from electricity generation, in the European Union and 24 Gt, or 25%, in the United States. Without nuclear power, emissions from electricity generation would have been around one-quarter higher in Japan and about 50% higher in Korea and Canada.

Cumulative CO_2 emissions avoided by nuclear power by country/region

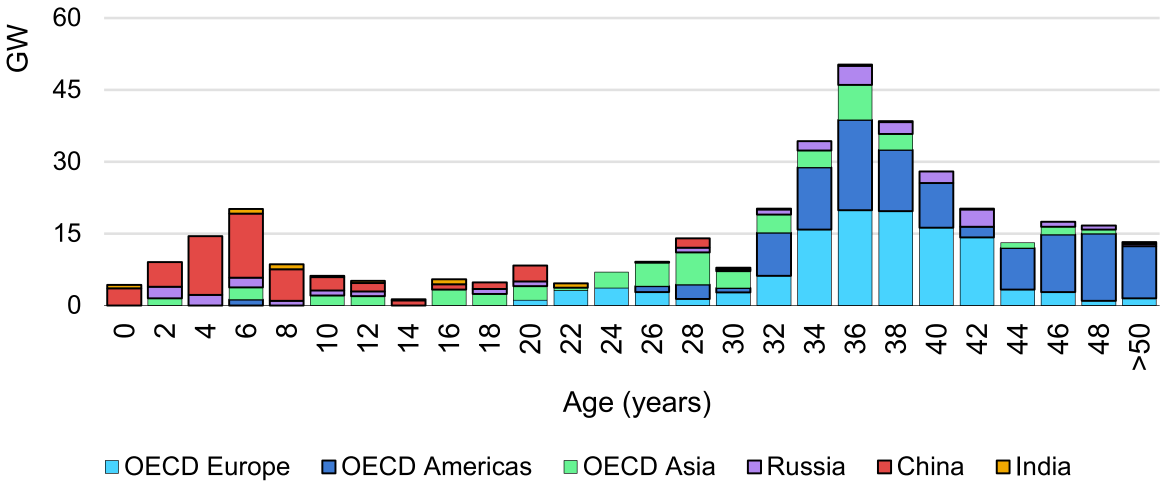


Market leadership is shifting away from advanced economies

Almost 70% of the global reactor fleet is in advanced economies, but this fleet is ageing. There are big differences in the average age of nuclear capacity across regions, ranging from just 5 years in the People's Republic of China (hereafter "China") to 15 years in India, 36 years in North America and 38 years in Europe. Market leadership has been shifting to the Russian Federation (hereafter "Russia") and China: 27 of the 31 reactors that began construction since 2017 are of Russian or Chinese design.

[3] This assumes that other sources of electricity that were expanding alongside nuclear power would have been scaled up proportionally in its place.

Age distribution of operational nuclear capacity by region, end of 2021



Note: OECD Europe includes Belgium, Czech Republic, Finland, France, Germany, Hungary, Lithuania, Netherlands, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom. OECD Americas includes Canada, Mexico and the United States. OECD Asia includes Japan and Korea.
Source: IAEA Power Reactor Information System (PRIS).

Investment in nuclear power in advanced economies has stalled over the last two decades because of high costs of new projects, long construction times, unfavourable electricity market and policy environments, and, in some countries, a lack of public confidence after the accident at the Fukushima Daiichi Nuclear Power Station. Construction of first-of-a-kind Generation III reactors[4] has been subject to delays and significant cost overruns. The competitiveness of new nuclear power plants is further undermined by the fact that most power markets still do not adequately remunerate the low emissions and dispatchable attributes of nuclear power.

Retirements of nuclear power plants are set to accelerate in the coming years, particularly in advanced economies, as existing plants reach the end of their operating licences, are forced to close due to policy-driven phase-outs or cease operation for economic reasons. Lifetime extensions will, nonetheless, slow the pace of retirements to some degree. For example, the United States has to date issued 20-year extensions of the original 40-year operating licences for 88 of the country's 93 reactors currently in operation, while 11 reactors have applied for a further 20-year extension, bringing their lifetimes to 80 years. France has developed a rolling 10-year extension programme for plants that meet safety requirements, while plants in Hungary, Finland, the Czech Republic and the United Kingdom have also recently received 20-year extensions. In total, these extensions have already prevented the closure of nearly

[4] This generation of reactors aims to enhance safety, relative to the preceding generation, by incorporating design changes that lower the risk of a severe accident and, should a severe accident occur, by using appropriate mitigation systems to limit its impact on the population and the environment.

one-quarter of total capacity that would otherwise have occurred by 2020, a share that rises to almost 40% by 2030.

Investment has started to recover, driven mainly by China and Russia

Nuclear power capacity additions dwindled during the 2000s, but are now starting to pick up, particularly in China and Russia. Capacity additions peaked in the 1980s, when 230 GW of new nuclear power plants were brought on line across the globe, primarily in Europe and North America. But new construction slowed sharply in the 1990s in the wake of the major nuclear accidents at Three Mile Island in the United States in 1979 and Chernobyl in Soviet-era Ukraine in 1986, with just 25 GW of new capacity added.

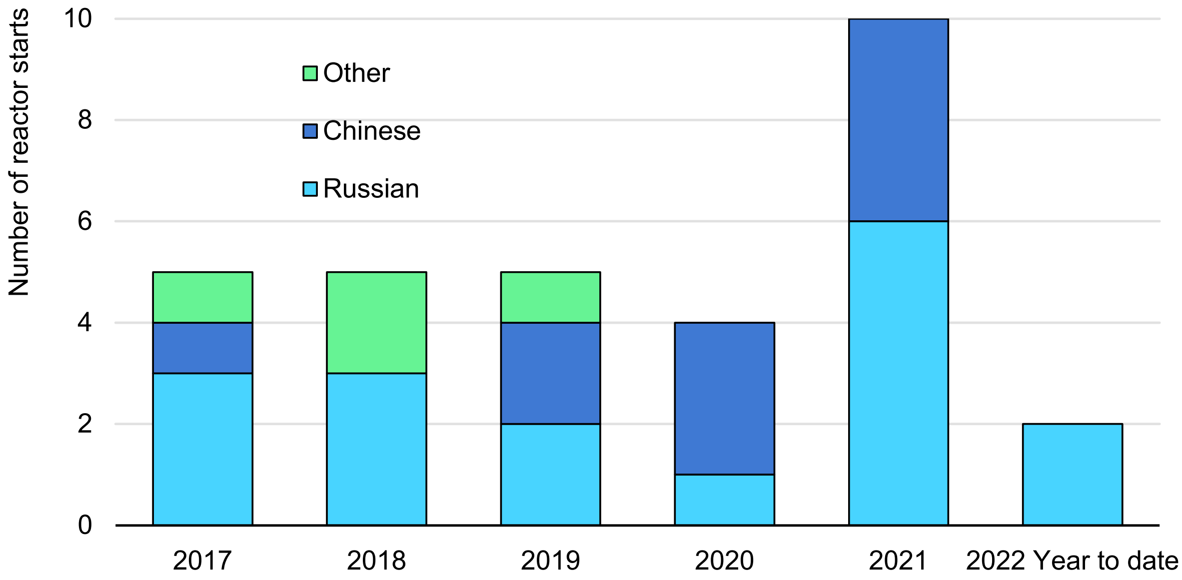
Capacity additions rebounded to 46 GW in the 2000s and 56 GW in the 2010s, despite the impact of the 2011 Fukushima Daiichi accident in Japan (much of the capacity added since then was already under construction). Another 6 GW was commissioned in 2020 and 5.6 GW in 2021. China contributed most of the capacity that came online since 2010.

2021 saw a surge in construction starts, with ten units breaking ground compared to the four to five per year that had been typical in recent years. Overall, there are 52 reactors currently under construction, totalling 54 GW of capacity. China is currently building 16.1 GW, Korea 5.6 GW, Turkey 4.4 GW, India 4.2 GW, Russia 3.8 GW, the United Kingdom 3.3 GW and other countries combined 16.6 GW.

Of the 31 reactors that commenced construction since the beginning of 2017, 27 of these are either of Russian design (17) or Chinese design (10) with two of European design under construction in the United Kingdom and two Korean-designed units in Korea. Russia dominates the export market: all ten Chinese-designed units are being built in China, only three Russian-designed units began construction in Russia, with the rest starting construction in Turkey (3), India (4), China (4), Bangladesh (2) and Iran (1).

Russia’s invasion of Ukraine raises questions about the export prospects for Russian-built nuclear plants. Finland has cancelled a contract, signed in 2013, for Rosatom to build a plant in Finland, citing delays and increased risks due to the war in Ukraine.

Nuclear power construction starts by national origin of technology, 2017-2022



Source: IAEA Power Reactor Information System (PRIS).

Net zero pledges are reviving interest in nuclear's potential

The number of countries with net zero targets has increased rapidly over the last few years. More than 70 countries, covering 76% of global energy-related CO_2 emissions, have now adopted such a pledge, covering either CO_2 or greenhouse gas emissions more broadly. This compares with only six countries at the end of 2018. In addition, more than 60 other countries have pledged to reach net zero or carbon neutrality, but without specifying a timeframe. These pledges are not yet underpinned by all the specific policies and measures that will be required for their realisation, but they are prompting deliberations on the mix of low emissions technologies, including energy efficiency, that can move countries towards these goals. Nuclear energy has been one of the beneficiaries.

Significant developments in support of nuclear power 2020-2022

Country	Policy
United States	• As part of the 2022 Civil Nuclear Credit Program, a USD 6 billion investment to help preserve the existing U.S. reactor fleet. • Allocation of USD 8 billion to demonstrate clean hydrogen hubs, including at least one hub dedicated to the production of hydrogen with nuclear energy. • Following the Advanced Reactor Demonstration Program, a total of USD 3.2 billion investment over seven years on two nuclear projects.

Country	Policy
Canada	• The 2020 SMR Action Plan lays out the steps for the deployment of SMRs. Several projects have obtained federal and provincial government funding. • Announcement of an SMR project at Darlington based on GE-Hitachi technology to be commissioned by the late 2020s.
France	• Following the France 2030 investment plan, announcement to extend the lifetime of all nuclear reactors that can be extended while ensuring safety. • Announcement of plans to build six new large reactors starting in 2028 at a cost of around EUR 50 billion, with an option to build eight more by 2050. • A EUR 1 billion investment to develop innovative reactors, including a small modular reactor by 2030.
United Kingdom	• As part of the 2022 Energy Security Strategy ambitions for eight new large reactors, as well as small modular reactors, to achieve nuclear generation capacity of 24 GW by 2050, or around 25% of the forecast electricity demand. • The Nuclear Energy (Financing) Act, enacted in 2022, made a provision for the implementation of a regulated asset base model. • In 2021 a government commitment of GBP 210 million in funding to develop an SMR, matched by GBP 250 million in private investment.
Belgium	• In March 2022, the Belgian government decided to take the necessary steps to extend the lifetime of two reactors by a decade through 2035.
Netherlands	• Discussions in 2022 on the construction of two new nuclear stations.
Poland	• The 2020 Polish Nuclear Power Programme plans the construction of large reactors with a total capacity of between 6 GW and 9 GW. • In 2022 the government agreed to the deployment of SMRs based on US technology to replace existing coal-fired co-generation plants.
Korea	• The new government elected in 2022 plans to support lifetime extensions of current facilities, restart construction at two sites, develop and enhance cooperation on SMRs, seek to build ten plants overseas by 2030.
Japan	• In 2022, the government announced it would increase energy security with a view to restart existing reactors provided they are safe.
China	• Under the 14th Five Year Plan period (2021-2025), maintain a steady pace of construction setting the goal of about 70 GW by 2025, versus 53 GW at the beginning of 2022.
India	• Start of construction of a new ten reactor fleet expected between 2023 and 2025, for a total of 9 GW. • Political steps towards the construction of six large reactors using French technology.

Renewables, particularly wind and solar PV, are typically foreseen as providing the largest sources of electricity as countries move to a net zero future. However, a growing number of countries have also announced plans to support new nuclear investment. For example, President Macron of France announced in February 2022 plans to build six new large reactors starting in 2028 at a cost of about EUR 50 billion, with an option to build eight more by 2050. The French government previously pledged EUR 1 billion to develop innovative reactors, including a small modular reactor by 2030. China plans to continue its current pace of construction of nuclear reactors in order to help meet its goal of carbon neutrality by 2060. The newly-elected President of Korea made an election pledge to reverse the country's nuclear phase-out by supporting lifetime extensions of current facilities and restarting construction at two sites while also seeking to build ten plants overseas using Korean technology by 2030.

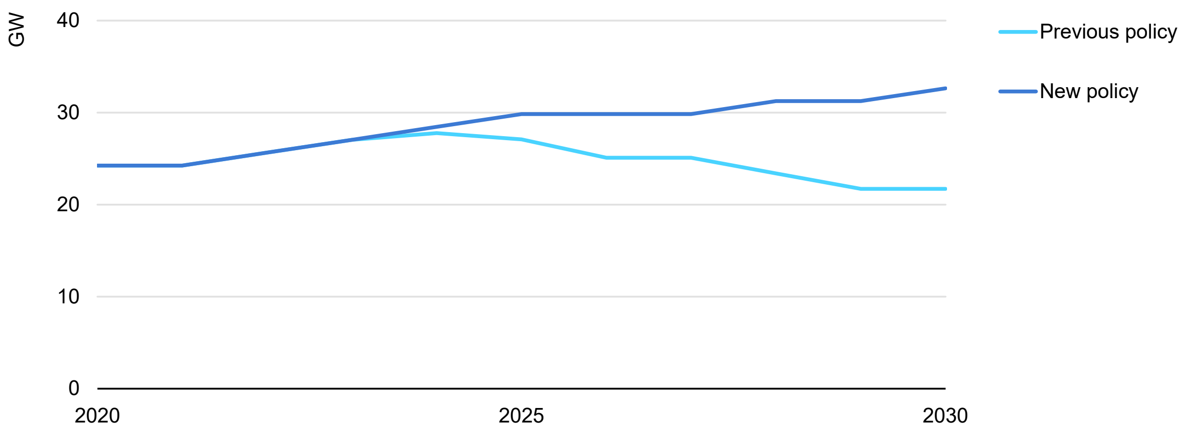
Today's focus on energy security provides an opening for nuclear

Deployment of nuclear energy increases the diversity of the energy mix, can facilitate the rise of variable renewables such as wind and solar, and also provides an opportunity – at scale – to reduce reliance on fossil fuels. The oil security crisis of the 1970s spurred the first wave of nuclear new-builds: in the decade that followed the first oil shock, construction started on almost 170 GW of nuclear power plants; these plants still represent 40% of the nuclear capacity that is operating today. If policy support is forthcoming and costs are kept under control, the renewed interest in nuclear today could point in a similar direction.

Russia's invasion of Ukraine has exacerbated the tightness that was already apparent in fuel markets around the world. This has in turn driven up electricity prices. According to the European Union Agency for the Cooperation of Energy Regulators (ACER), retail electricity prices were on average 30% higher year-on-year in February 2022, with prices increasing the most in places that depend heavily on natural gas in power generation, like Madrid, where they have risen 55%, and Rome (80%). Europe's push to diversify away from Russian supply could maintain upward pressure on fuel prices for some time to come.

Nuclear energy is one of the options that can be deployed by governments to reduce reliance on fossil fuels for the power sector, in particular for natural gas. For example, Korea's plans to lift the share of nuclear in Korea's total generation would, in our assessment, reduce natural gas use in the electricity sector by 5 bcm to 7 bcm per year within the next decade.

Impact of Korea's policy reversal on nuclear power capacity



Sources: IEA Analysis based on IEA (2021) World Energy Outlook 2021.

Many countries with nuclear reactors depend on imported uranium for fuel. However, nuclear power plants need to refuel infrequently, reducing exposure to short-term disruptions, and fuel can be stored for a few years before being used.

Challenges to an expanded role for nuclear

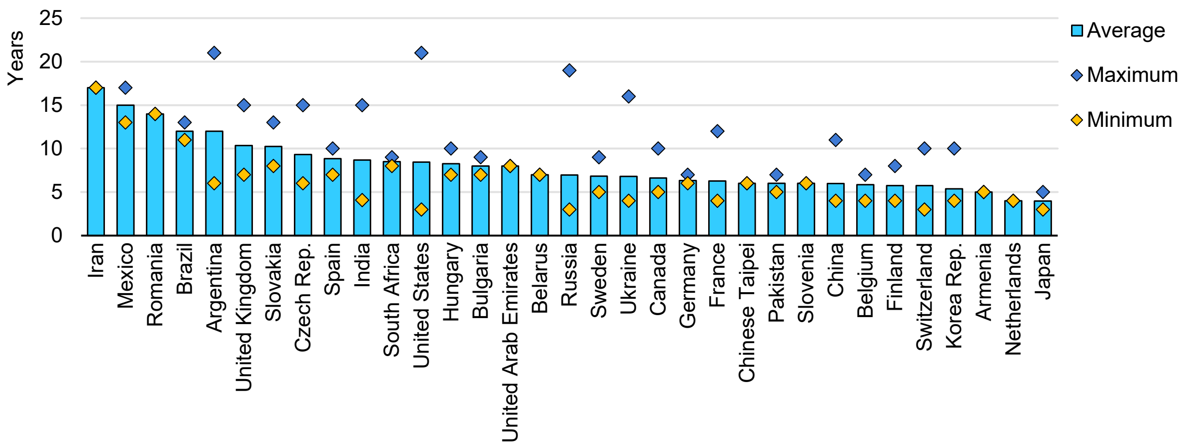
Attracting increased investment in nuclear energy will hinge on efforts to manage and allocate the risks, which include project risks, such as those related to the construction of plants and technology, political risk, regulatory risk, operational risk and market or price risk.

Conventional nuclear plants are large and highly capital-intensive, involving long lead times and complex construction works. These risks directly affect the cost of capital, and ultimately the levelised cost of electricity, by increasing the returns demanded by investors to account for them. Like other projects of similar complexity, nuclear projects can carry substantial risks of delays, particularly for first-of-a-kind units. Once built, market risks can also be substantial as these may depend on the electricity market design, which can change, or policy interventions that affect profitability. Governments have made renewed efforts to identify, mitigate and assign these risks to the various stakeholders through financing support mechanisms like direct financial support, power purchase agreements, and regulated models.

Construction costs and lead times have risen in advanced economies

Rising construction costs and lead times have plagued the nuclear industry in many countries in recent years. There is a wide variation in the average construction time for nuclear reactors across countries, historically. The nuclear reactors in operation around the world today took on average seven years to build, but 15 of them took 15 years or more, while 152 were built in five years or less. Countries with mature nuclear programmes, like the United States, Canada, France, China, Korea and Japan have generally been able to complete construction more quickly. Licensing, site selection and permitting have usually added several years to the time needed to complete each new nuclear reactor project.

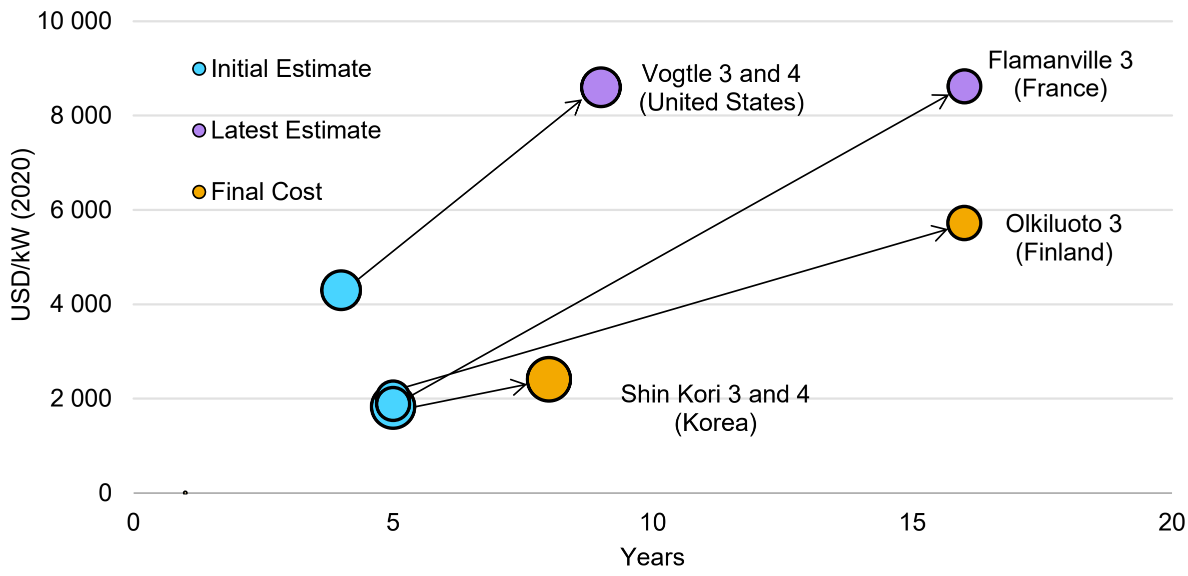
Construction times for new nuclear power plants by country, 1967-2021



Note: Excluding temporary pauses on construction activities for individual projects.
Source: : IEA analysis based on IAEA Power Reactor Information System (PRIS).

Recent nuclear power plant construction projects in Europe and the United States have experienced considerable delays and cost overruns. Vogtle Units 3 and 4 in the state of Georgia were originally projected to cost around USD 4 300/kW on an overnight basis and take four years to complete, but the most recent estimate has increased to nearly USD 9 000/kW and the units are now expected to come online only in 2023 – nine years after the start of construction. These will be the first AP1000 units built in the United States, adding to the four already in operation in China. Even in Korea, which has had relatively good construction performance, most recent units have experienced delays and cost overruns. The Shin Kori 3 and 4 pressurised water reactors, the first APR1400 designs, were commissioned in Korea in 2016 and 2019 respectively after 7.5 and 10 years of construction, compared with the 5 years they were originally expected to take.

Overnight cost and construction times for selected recent nuclear projects



Source: Nuclear Energy Agency (2020), Unlocking Reductions in the Construction Costs of Nuclear.

Similar delays and cost overruns have been experienced with the EPR, a third generation pressurised water reactor, in Europe. This is due to several factors including a low level of design maturity at the onset of construction, challenges with project management, regulatory changes during the construction period and delays in parts manufacturing in the absence of an active supply chain. The first EPR to start construction, at Olkiluoto in Finland in 2005, began producing electricity in 2022, a delay of 13 years from its original planned date. The EPR at Flamanville in France, construction of which started in 2007, has also encountered lengthy delays. It is now expected to be commissioned in 2023. Both EPRs have cost far more than originally projected. For example, the Flamanville plant is now expected to cost EUR 12.7 billion compared with an initial estimate of EUR 3.3 billion. The two EPRs built in China – Taishan 1 and 2 – have also experienced significant delays, both doubling their construction time to nine years though limiting the final construction cost to around USD 3 200/kW.

Reducing the costs of constructing new nuclear power plants and the time required to construct them, particularly in advanced economies, will be vital if nuclear power is to play its part in supporting energy transitions. The size and the complexity of constructing the civil works associated with a nuclear power plant are typically responsible for much of the delays: the nuclear "island", which is the heart of the nuclear power plant and contains the containment building, auxiliary building, and fuel handling area, usually accounts for less than 20% of the total costs.

Techniques to make it easier to construct the civil works, such as modularisation and standardisation, could reduce the cost and complexity of construction at the plant site. Experience has shown that the construction period, particularly for "first-of-a-kind" units, tends to take significantly longer than for subsequent units. Conversely, once a commitment is made to build several units of the same design, the construction period for the latter units can fall considerably. In the case of France, building the first of a kind of the N4 series required nearly 12 years, the fourth unit just over 8 years – a 30% reduction. But staying with the same design also mattered: moving from the previous series (known as P4) to N4 resulted in an increase in costs and the construction period, although the whole overnight cost of construction of the French nuclear fleet was contained at under EUR 2 000/kW for each pair of reactors,[5] thanks to a combination of factors including the series effect, an active nuclear industry and the absence of major changes in regulatory standards.

Attracting private sector financing is hard without government involvement

Due to their size and complexity, nuclear projects have historically relied upon some form of state ownership or regulated monopoly structure in order to guarantee revenues and reduce risk to investors. All the plants recently commissioned or entering the construction phase involve capacity in excess of 1 GW. Very few utility company balance sheets can support the risks associated with building and operating a fleet of such large nuclear power plants without some form of guarantee from the government. Mechanisms for policy support have included feed-in tariffs and contracts for differences.[6] Alternatively, utilities can be allowed to include nuclear facilities as part of their portfolio of regulated assets to guarantee a return on investment.

The UK government, having identified the need for new nuclear power plants as part of its future low carbon energy mix, introduced the Nuclear Energy (Financing) Act 2022 with the aim of reducing the costs that consumers would need to pay for energy from new nuclear power plants. Although many of the specific mechanisms will be spelled out in future regulations, the intent of the legislation is to provide better value for money for consumers by reducing the cost of capital for investors in new nuclear power plants. This is to be achieved through providing the owners of the project with a right to a regulated revenue stream during the construction, commissioning and operating phases of a project. Through this mechanism, consumers will begin contributing financially to a project during the construction phase and will be sharing risks with the investors associated with cost overruns. As a consequence, it is expected that projects will be able to attract capital at a much lower cost and, as regulated projects, these lower costs will ultimately feed through to the consumers. The government's impact assessment estimates costs to consumers could fall by 44% or more compared to the contract-for-difference approach that was used to finance the Hinkley Point C project.

[5] World Energy Outlook 2014, Fig. 10.6 page 367.

[6] Financial contracts-for-differences involving the payment of the difference between a fixed price and the settlement price of a commodity over a specified period.

The current market designs in most advanced economies increases price risk for investors, but reduce risk for end consumers compared with regulated markets. Electricity price volatility, caused in part by increasing shares of resources with zero marginal cost like wind and solar, but also by swings in gas prices, creates uneven and unpredictable returns for market participants unless they hedge their exposure to market prices. Hedging this exposure through long-term contracts is one solution, but it requires counterparties willing to accept prices that are high enough to ensure a return for the nuclear power operator well into the future.

Remuneration for nuclear's contribution to secure and low emissions power systems is often inadequate

Current power market designs fail to adequately remunerate two benefits of nuclear power generation. Nuclear power is a dispatchable resource that is able to generate during periods of system stress, when load is approaching the level of available supply capacity. This contributes to the secure operation of the system, avoiding costly outages that cause economic and social harm. This service could be compensated through either a separate capacity payment or through unfettered market pricing arrangements that account fully for the ability of resource to secure against shedding load, sometimes called "scarcity pricing". However, most markets today limit prices from reaching the levels associated with the value of lost load through price caps, and without a supporting capacity mechanism, deprive operators of dispatchable capacity of revenues[7].

Most power markets also fail to reward the low-carbon attributes of nuclear power. Where they exist, carbon prices rarely approach the levels needed to reach net zero emissions. For example, the most recent auction of allowances for the Regional Greenhouse Gas Initiative, which covers 11 states in the eastern United States, yielded a CO_2 price of just USD 13/t– far below the prices that are required to spur deep decarbonisation. In addition, in many countries support for clean energy production like production and investment tax credits and feed-in-tariffs excludes nuclear power from subsidies or other support mechanisms that are available to wind and solar.

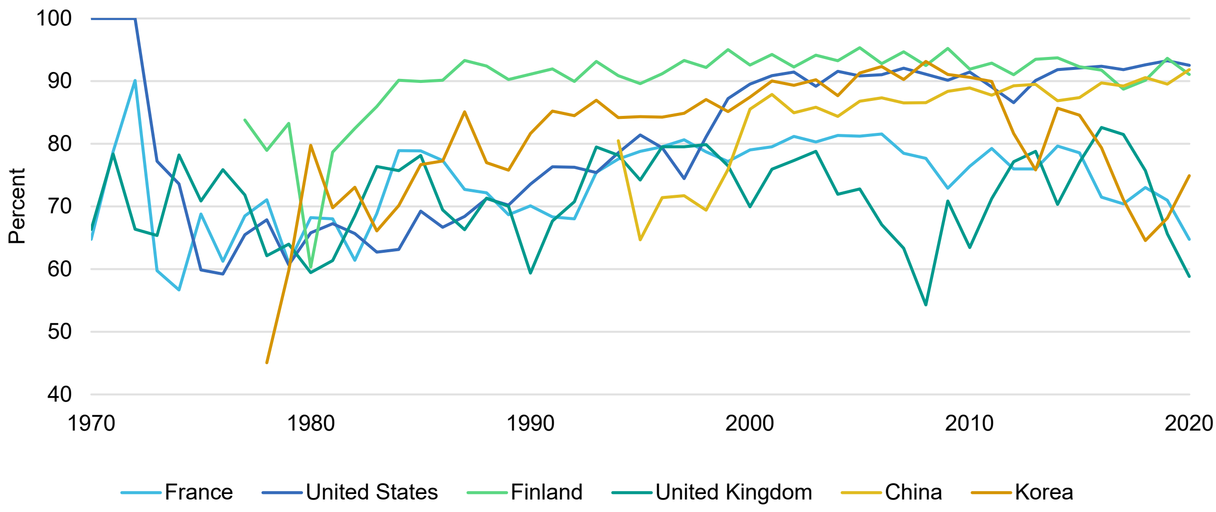
Ageing fleets require maintenance work that reduces availability

Some countries, including France, the United Kingdom and Korea, have seen the availability of their plants decline since 2015, due mainly to the need to carry out work to extend lifetimes and, in some cases, unplanned shutdowns. In France, the

[7] Governments and consumers have difficulties accepting high and unstable electricity prices. For example, Spain and Portugal recently set a price cap of EUR 50/MWh for gas in response to the recent jump in prices and some governments have called for scrapping the marginal pricing system entirely. ACER's recent assessment of the EU wholesale market concludes that the current marginal price-based market design should be retained and cautions that ill-designed interventions could endanger the benefits of market integration, which they estimate to be worth approximately EUR 34 billion per year through efficiencies gained by cross-border trading.

availability factor[8] of nuclear plants dropped to 54% in March 2022. The recent decline is due to a combination of factors, including the peak of the Grand Carénage programme, which aims to extend the operating lifetimes of most reactors beyond 40 years by means of large-scale renovation work, rescheduled maintenance outages after the Covid-19 crisis and unplanned outages to investigate signs of corrosion found in pipes in at least 9 of the country's 56 operating reactors. By contrast, in the United States, where nuclear plants have a similar age profile to those in France, the average availability factor was broadly constant until the year 2000 and has since increased, reaching 91% in 2020.

Average nuclear capacity availability by country



Source: IAEA Power Reactor Information System (PRIS).

Some countries rule out nuclear, largely due to concerns over safety and waste management

Some countries have decided to phase-out the use of nuclear power, primarily due to public concerns about safety issues (not necessarily in their own country). Public support waned in many countries after each of the three major nuclear accidents, at Three Mile Island, Chernobyl and Fukushima Daiichi. In those countries that have retained nuclear, there are strong requirements on industry to enhance safety.

The Fukushima Daiichi accident in 2011 prompted countries to re-evaluate and strengthen nuclear safety and emergency preparedness. Safety inspections or "stress tests" were carried out at existing reactors in many countries and certain types of reactors were ordered to make safety modifications. These considerations led several countries to adjust their planned use of nuclear power. Germany, which had built 36 nuclear reactors with a combined capacity of 30 GW, subsequently accelerated the phased closure of all this capacity. Most of the reactors have already shut, and the three still operating are due to close by the end of 2022. Elsewhere in Europe,

[8] The share of installed capacity that are available to generate at any given time.

Spain, Sweden and Switzerland have also announced the gradual phase-out or non-replacement of their nuclear fleets. In Japan, many of the nuclear plants that were shut after the Fukushima Daiichi accident have not yet restarted operation, and the share of electricity generation from nuclear has dropped as a result from a high of 35% in 2002 to around 5% today.

The accident at Fukushima Daiichi drew global attention to the risks and potential costs of a nuclear accident. The decision to idle or close other reactors necessitated increased thermal power generation, which led to substantial fossil-fuel import costs, contributing to a record high trade deficit, and higher CO_2 emissions.

Official investigations into the Fukushima Daiichi accident concluded that the accident could and should have been foreseen and prevented. It stressed the need to improve the competence and independence of the regulatory body. This underscores the fact that an effective regulatory framework and sound, independent regulatory oversight are prerequisites for the safe operation of a nuclear fleet and critical to establishing and maintaining public confidence in nuclear power.

The safe disposal of spent fuel and other radioactive waste material remains critical to the public acceptance of nuclear energy programmes. Spent fuel rods that have been removed from the reactor core remain highly radioactive and continue to generate large amounts of heat for decades. Public acceptance of the long-term storage of high-level waste is key. Currently, 47% of spent fuel worldwide is stored on site at nuclear power plants, usually in large concrete-lined water tanks. Few countries have developed long-term solutions for recycling and/or the geological disposal of spent fuel, mainly due to the large investments involved and hard political decisions on siting.

Timeline for deep geological nuclear waste storage facilities in selected countries

Country	Application submitted	Construction licence granted	Start of construction
Finland	2012	2015	2016
France	2021	2025(e)	2022(e)
Sweden	2011	2022(e)	Early 2023 (e)
China			2041(e)
Canada	2028(e)	2032(e)	
Switzerland	2024(e)	2031(e)	

Note: (e) = estimate.
Source: Nuclear Energy Agency (2020), Management and Disposal of High-Level Radioactive Waste: Global Progress and Solutions.

Safe decommissioning of plants must also be ensured

Decommissioning is particularly important in the case of a nuclear power plant given the need to safely manage radioactive materials. It includes all activities from shutdown and removal of fissile materials to environmental restoration of the site.

Costs depend on many factors, including the decommissioning schedule, the plant location, the arrangements for the storage and disposal of nuclear waste, the level of decontamination required, legal requirements, any cost escalation and the assumed discount rate. This range of plant-specific cost drivers and the relatively limited experience in completing decommissioning projects, albeit increasing in recent years, leave some uncertainty as to the magnitude of the expected decommissioning costs.

Most countries legally require utilities to arrange adequate funding for decommissioning activities, with regulators playing a major role in approving the mechanism to secure funding and the amount to be set aside. For a nuclear power plant built today, the decommissioning cost is assumed in our analysis to be around 15% of the plant investment cost (in real terms). When funds are collected during the operation of a nuclear power plant, these costs represent a small percentage of electricity rates. An increase in the decommissioning cost of a nuclear power plant from 15% to 25% of the investment cost, raises generating costs by just around 1%.

Russia's invasion of Ukraine could also have negative consequences

Heightened energy security concerns resulting from Russia's war in Ukraine could bolster the case for nuclear energy in some countries as they seek to reduce reliance on expensive and volatile fossil fuels and accelerate transitions. However, it could also have negative impacts. Aside from the effects on public opinion of active conflict in the vicinity of Ukraine's nuclear facilities, the conflict raises questions about Russia's future as a producer and exporter of nuclear fuel supplies.

Through the Rosatom subsidiary TVEL, Russia supplies nuclear fuel to 73 Russian-designed (VVER) reactors inside Russia and in other countries, including Ukraine, Belarus, Armenia, Bulgaria, Finland, the Czech Republic, Hungary, Slovakia, China, India and Iran, making up around 16% of the world market in 2020. CEZ, the Czech state-owned electric utility, recently announced it will obtain its fuel supplies for its Temelin nuclear power station from two western suppliers from 2024. Russia plays an even more significant role in the production of uranium fuel, accounting for 38% of uranium processing (conversion) worldwide and over 45% of fuel enrichment capacity in 2020. Much of the uranium processed and enriched by Russia is sourced from Kazakhstan, which was responsible for 41% of global uranium production in 2020. Euratom, which monitors European uranium trade, estimates that Russian companies provided about 24% of uranium conversion services and 25% of enrichment services to EU utilities in 2020. A French company, Orano, supplies the majority of enrichment services and the largest share of conversion services to those utilities, while Canada and the United States are also significant suppliers of conversion services to them.

2. The role of nuclear energy on the road to net zero emissions

Opportunities for nuclear in energy transition

There are five features of the journey to net zero emissions, common to almost all scenarios that meet exacting climate goals, that open up opportunities for nuclear energy:

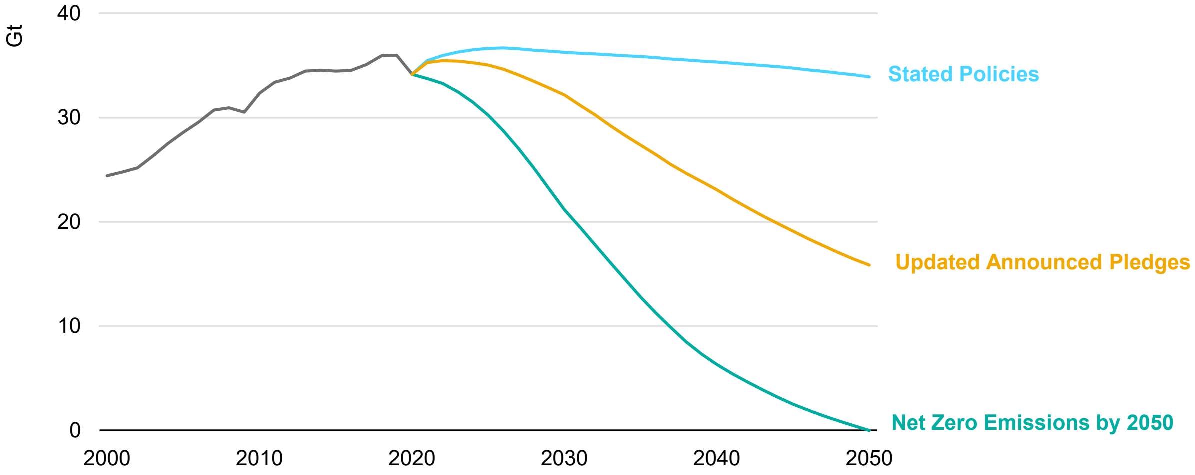
- Widespread electrification of end-uses, with electricity taking progressively higher shares of final consumption.
- Rapid growth in low emissions electricity generation.
- The need to curb emissions from heat production.
- Fast-growing demand for low emissions hydrogen.
- The continued need to support innovation, which facilitates the development of advanced nuclear technologies.

This chapter explores the contribution of nuclear energy in these areas with reference to the IEA's Net Zero Emissions by 2050 Scenario (NZE)[9], which shows what is needed for the global energy sector to achieve net-zero CO_2 emissions by 2050. Alongside corresponding reductions in GHG emissions from outside the energy sector, this is consistent with limiting the global temperature rise to 1.5 °C in 2100 without a temperature overshoot (with a 50% probability).

The global emissions pathway in the NZE represents a significant departure from a trajectory based on today's policy settings. This is described in the Stated Policies Scenario (STEPS), which takes account of policies and targets currently in place but not pledges or announcements not yet backed by implementation plans. It is also very different to that in the Updated Announced Pledges Scenario (UAPS), in which countries and companies are assumed to meet all their announced pledges to cut emissions, including those made at the 26th Conference of the Parties (COP26) in Glasgow in November 2021 and submitted as Nationally Determined Contributions (NDCs) under the Paris Agreement to the United Nations Framework Convention on Climate Change (UNFCCC), on time and in full. Global emissions plateau and decline only slightly by 2050 in the STEPS (see *World Energy Outlook 2021* for more details), which is consistent with a global temperature increase of 2.6 degrees Celsius (°C) above pre-industrial levels in 2100. Emissions fall much more in the UAPS, by around 18 Gt in 2050, consistent with a global temperature increase of 1.8 °C.

[9] The NZE is set out in detail in our landmark report, Net Zero by 2050: a Global Roadmap for the Energy Sector, released in 2021.

Global energy sector CO_2 emissions by scenario, 2000 to 2050



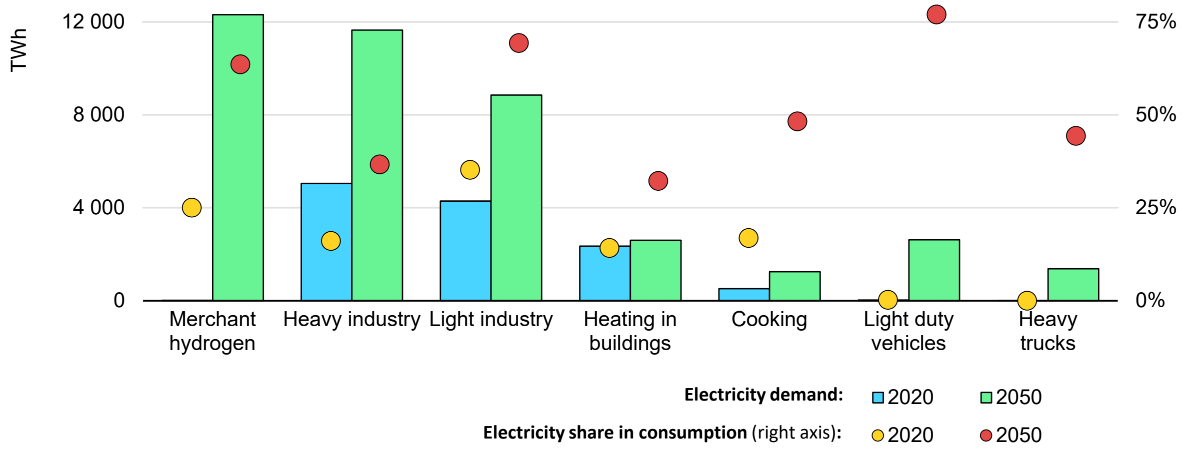
Note: Energy sector emissions includes those from the combustion of fossil fuels and industrial processes.
Sources: IEA (2021), World Energy Outlook 2021; IEA analysis based on IEA (2001), COP26 Climate Pledges Could Help Limit Global Warming to 1.8 °C, but Implementing Them Will Be the Key.

The five opportunities arising for nuclear energy in the net zero transition are characterised in the NZE in the following terms.

Electrification as a key pillar of decarbonisation

The use of electricity in place of unabated fossil fuels helps to cut global energy sector CO_2 emissions in 2050 by about 7 Gt in the NZE, accounting for 20% of the total reduction. Global electricity demand increases from about 23 000 TWh in 2020 to over 60 000 TWh in 2050, with the share of electricity in total final consumption jumping from 20% to nearly 50%. Merchant hydrogen production is the leading driver of the increase in global electricity demand, adding over 12 000 TWh – an amount greater than the total electricity demand in advanced economies today. Among end-use sectors, industry sees the largest increase in electricity consumption at almost 11 000 TWh, mainly in low and medium temperature applications, primarily in light industry. Rapid growth in the fleets of electric cars, buses and trucks pushes up global electricity use in transport by over 9 000 TWh. The rest of the increase comes from the electrification of other end-uses, including heating in buildings and cooking.

Global electricity demand and share of electricity in total energy consumption in selected applications in the Net Zero Emissions by 2050 Scenario



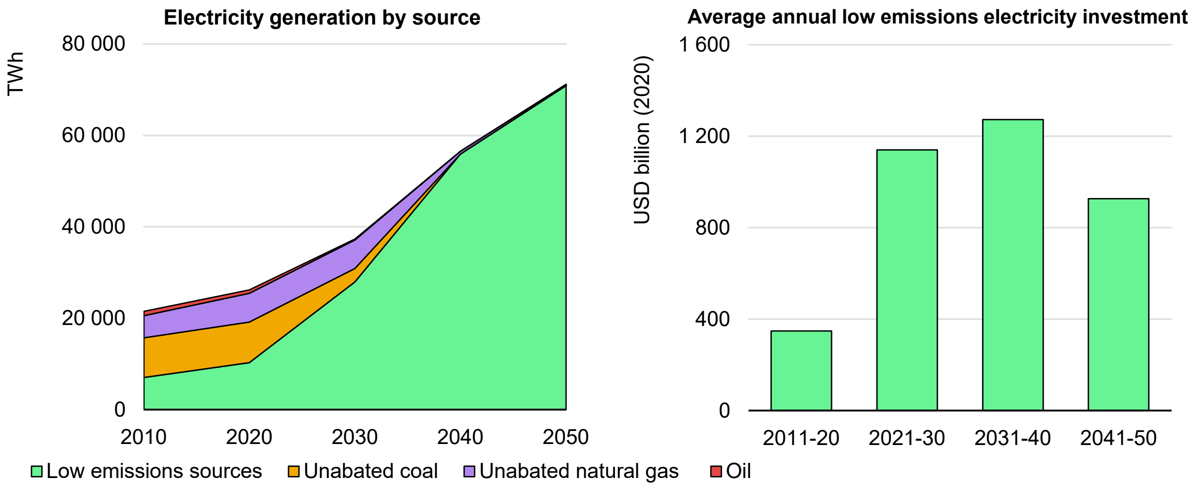
Source: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

Emerging market and developing economies (EMDEs) make up three-quarters of global electricity demand growth in the NZE, due to their more rapid growth in population, incomes and living standards. Greater reliance on electricity to meet the increase in demand for energy services causes electricity demand growth to rise from an average of 3.7% per year in 2016-2020 to 3.9% in 2021-2050. Advanced economies see a return to growth in electricity demand, having plateaued in recent years, due to more rapid electrification of end uses and the take-off of electrolytic hydrogen production.

Rapid growth in low emissions electricity generation

The rise in low emissions electricity generation in the NZE, both to meet rising electricity demand and displace unabated fossil fuels, is staggering. In 2021, unabated fossil fuels accounted for over 60% of electricity generation worldwide, led by coal (35%), natural gas (23%) and oil (3%). Hydropower was the largest low emissions source of electricity (16% of generation), followed by nuclear power (10%), wind (7%) and solar PV (4%). The power sector emitted 13.8 Gt in 2021, the most of any sector and nearly 40% of the energy-related total. The picture changes radically over the three decades to 2050 in the NZE. Global electricity generation increases two-and-a-half times over 2020-2050 to keep pace with demand. The electricity sector is the first to achieve net zero emissions, doing so by 2035 in advanced economies collectively and by 2040 worldwide. Low emissions sources expand sevenfold by 2050, an average rate of growth of about 2 000 TWh, or 7%, per year, equivalent to adding over 1 400 GW of solar PV capacity, 750 GW of wind or 280 GW of nuclear each year.

Electricity generation by source and average annual investment in low emissions sources in the Net Zero Emissions by 2050 Scenario



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

Global investment in low emissions sources of electricity surges over the current decade, reaching over USD 1.1 trillion per year on average over 2021-2030 – almost four times that in 2011-2020. The push to fully replace unabated fossil fuels in power generation by 2040 lifts the pace of investment even higher in the 2030s, signalling a huge opportunity for all low emissions sources of electricity that are commercially available and cost-competitive. Beyond 2040, investment in clean electricity falls back, with new sources needed solely to meet electricity demand growth.

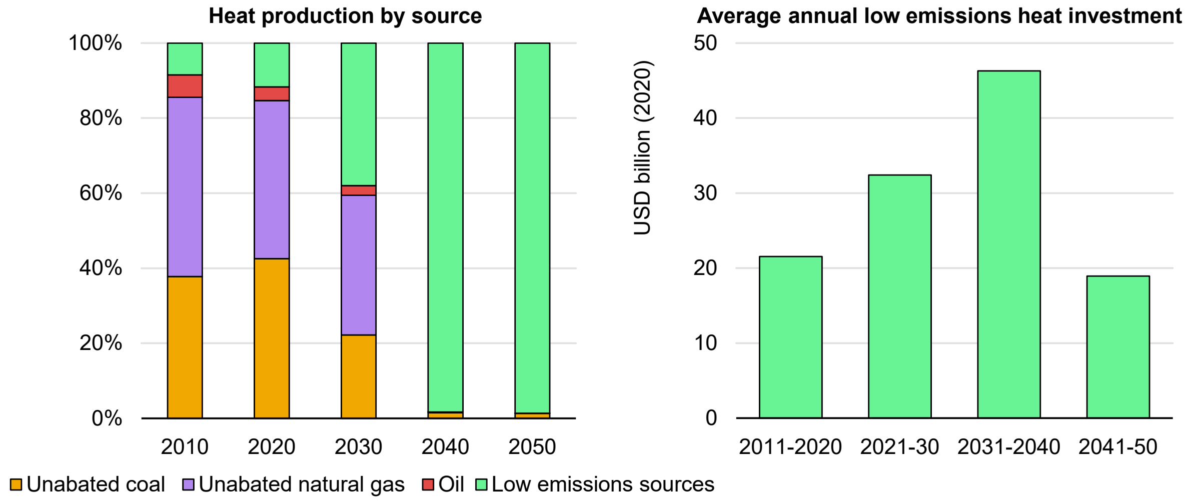
Curbing emissions from heat production

Reducing emissions from the production of commercial heat, injected into district heat networks or sold to industry, is a major task in getting to net zero. In 2021, nearly 90% of the heat sold commercially worldwide was provided by unabated fossil fuels and 75% from combined heat and power (CHP) facilities. Coal was the largest source of heat, making up 45% of the total, followed by natural gas (41%) and bioenergy (8%). Nuclear power provided just 0.1%. Global heat production emitted 1.3 Gt of CO_2 in 2021, 4% of total energy sector emissions.

Global emissions from heat production are almost entirely eliminated in the NZE thanks to a combination of lower demand due to efficiency gains and electrification in buildings and industry, and switching to low emissions energy sources. Commercial heat demand falls steadily, by 15% in 2030 and almost 60% by 2050 compared with 2020. Low emissions sources rise to close to 40% of the total heat supply in 2030 and nearly 100% in 2040. Between 2020 and 2040, the supply of low emissions heat grows by about 400 petajoules (PJ) per year, equivalent to adding 25 GW of thermal energy (GW_{th}) of new bioenergy CHP capacity, 20 GW_{th} of nuclear CHP or 18 GW_{th}

of large-scale heat pumps annually. Additions of capacity based on low emissions sources fall back sharply as they are needed solely to replace retired capacity.

Commercial heat production by source and average annual investment in low emissions sources of heat in the Net Zero Emissions by 2050 Scenario



Note: Commercial heat production includes district heating and industrial applications.
Source: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

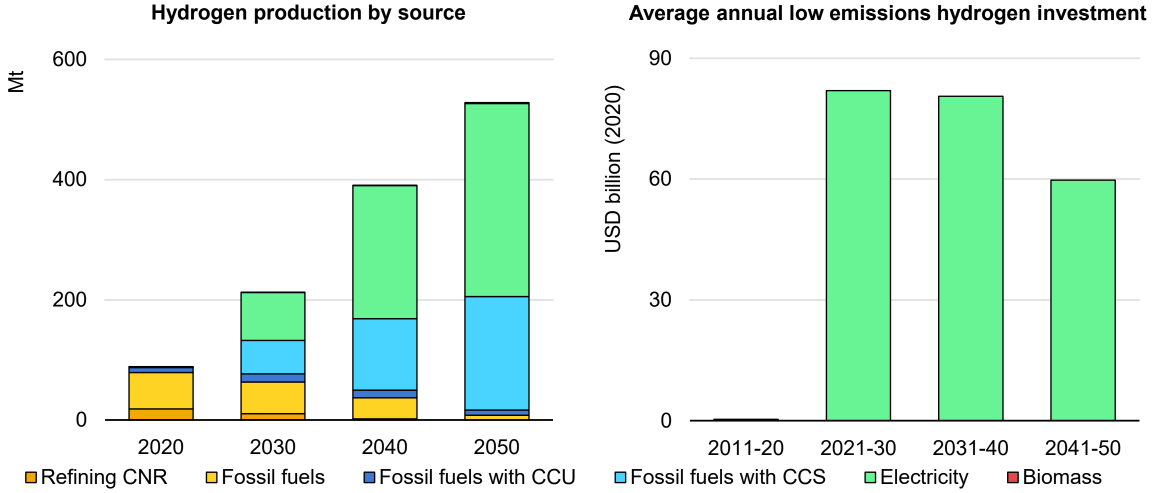
Investment in low emissions heat plants increases rapidly to 2040 in the NZE, averaging well over USD 30 billion per year in the 2020s and about USD 27 billion in the 2030s before falling back substantially. As with low emissions electricity, technologies that are already commercially available and cost-competitive account for most of this investment.

Fast-growing demand for low emissions hydrogen

Hydrogen, as an energy carrier like electricity, is expected to play a vital role in facilitating emissions reductions in all end-use sectors. In 2020, global hydrogen production was about 90 Mt, the bulk of which was produced from unabated fossil fuels and used in refining or industrial applications. Low emissions hydrogen accounted for about 10% of the total, produced almost entirely by fossil fuels with CCUS (hydrogen produced through electrolysis using renewables-based electricity is minimal as yet). Global hydrogen production emitted close to 0.9 Gt of CO_2 emissions, making up 2% of all energy sector emissions.

Global hydrogen production expands rapidly in the NZE, more than doubling to 200 Mt in 2030 and over 500 Mt in 2050. All of the increase comes from low emissions production technologies, with unabated fossil-based production falling steadily as existing plants are retired to just 25% of total hydrogen output in 2030 and under 10% in 2040. Fossil fuels with CCUS become the leading source of hydrogen in 2030 but are quickly overtaken by electrolysis. With 350 projects currently under development, electrolytic hydrogen production is about to take off, though the long term pace of expansion hinges on effective hydrogen strategies and policies. Global investment in the production of low-carbon hydrogen grows rapidly in the NZE in the medium term, averaging over USD 80 billion per year in the 2020s and 2030s, before falling back in the 2040s as net zero emissions come into sight.

Hydrogen production by source and average annual investment in low carbon sources of hydrogen in the Net Zero Emissions by 2050 Scenario



Note: CNR = catalytic naphtha reforming.
Source: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

Support for innovation

Fully half of the emissions reductions in the NZE in 2050 compared with 2020 are associated with technologies that are not yet on the market, though many are at the demonstration or prototype phases today. Innovation is needed most in long-distance transport and heavy industry, where reducing emissions with current technologies is hardest and most costly. Key areas include advanced battery designs, carbon capture in the cement industry, carbon removal technologies and large-scale electrolysers for hydrogen production, as well as advanced nuclear designs such as small modular reactors (SMRs), advanced biofuels, optimised heat pumps with storage and autonomous trucks. Accelerating innovation calls for more spending on clean energy research and development (R&D) and enhancing international cooperation and collaboration.

The role of nuclear in achieving net zero emissions by 2050

Nuclear energy is an important low emissions technology in the NZE pathway to net zero. In particular, it complements and supports the rapid growth of renewables in bringing emissions from the electricity sector worldwide down to net zero by 2040. Nuclear power contributes to the low emissions electricity supply and, as a dispatchable generating source, enhances the security of supply by providing system adequacy and flexibility. It also continues to the supply of heat for district heating networks and some industrial facilities. The projected role of nuclear, nonetheless, hinges on decisions by policymakers and companies about the pace of construction of new reactors and the duration of continued operations for existing nuclear reactors.

The projections of nuclear power and other power generation options in the scenario are based on economic analysis within the IEA's long-term energy modelling framework, which includes cost projections for each fuel, technology and region, to determine the most cost-effective pathway to net zero emissions across all sectors by 2050. The nuclear power projections also take account of technology preferences and public acceptance, including national policies in favour of or opposed to the use of nuclear power. As such, they are consistent with planned reductions and phase-outs, such as those in Germany, Belgium and Switzerland.

The NZE incorporates technology innovation with the commercialisation of some technologies currently in advanced stages of development, but does not rely on technology breakthroughs. The projected construction costs of large-scale reactors decline for designs under construction, such as the EPR, AP1000 (developed by Westinghouse, a US company) and Hualong-1 (jointly developed by the China General Nuclear Power Group and the China National Nuclear Corporation) pressurised water reactors, as experience gained in their initial deployment is applied to subsequent projects. The analysis also considers advanced designs, such as SMRs, and these are deployed in significant number in the NZE for electricity generation, particularly in advanced economies. SMRs and high-temperature gas reactors (HTGRs) could be used in other ways than simply supplying electricity to the grid, though they are not projected to be deployed on a large scale to primarily produce heat or hydrogen before 2050 due to the availability of lower cost alternatives. Nuclear fusion is not included in the NZE due to significant uncertainty about its technical and economic feasibility.

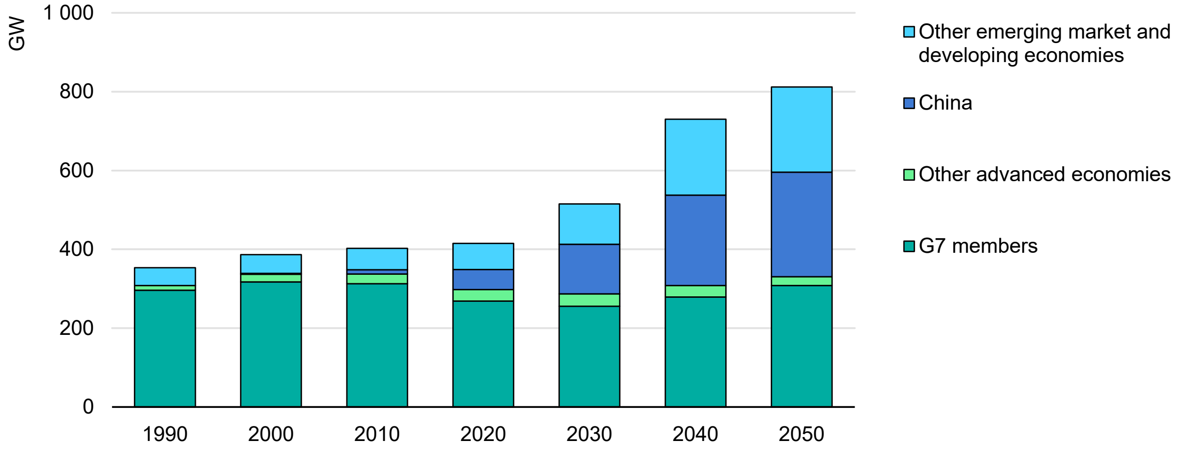
Nuclear power capacity doubles by 2050 in the NZE

Global nuclear power capacity[10] almost doubles from 413 GW at the start of 2022 to 812 GW in 2050 in the NZE, with new construction more than offsetting the

[10] All figures for nuclear capacity are presented here in gross terms before accounting for onsite electricity consumption, rather than in net terms at the point of injection into the grid.

progressive retirement of many existing plants. This represents a major acceleration compared with the last three decades, when capacity increased by about 15%, or about 60 GW. The projected expansion of nuclear power capacity is also much larger than that set to occur under current policies and regulations that have been formalised or written into law: capacity nears 530 GW in 2050 in the STEPS, 35% less than in the NZE. Without a significant change in the recent trends in nuclear power development, the path to net zero emissions would need to rely on a smaller set of low emissions technologies, reducing energy security and raising total investment costs and ultimately the cost of electricity to consumers.

Nuclear power capacity by country/region in the Net Zero Emissions by 2050 Scenario



Note: Power capacity refers to gross capacity, before accounting for onsite electricity consumption.
Sources: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector; IEA (2021), Achieving Net Zero Electricity Sectors in G7 Members.

Nuclear power undergoes strong growth in advanced economies in the NZE. These economies have long been leaders in nuclear energy technology, but a lack of new construction in recent years is already causing a contraction in capacity. Capacity shrinks by about 5% between 2020 and 2030, as new plants are unable to compensate for planned retirements of ageing reactors. A renewed construction effort leads to a rebound in capacity to 330 GW in 2050, 10% above the current level and 50% above that in the STEPS. This return to growth accelerates the decarbonisation of electricity supply, diversifies the generation mix, supports grid stability and fulfils the long-term vision of maintaining an important role for nuclear power in several advanced economies. Five of the G7 members – the United States, Canada, United Kingdom, Japan, and France – collectively continue to account for the vast majority of nuclear capacity among advanced economies. By comparison, renewables capacity in advanced economies grows fivefold over the same period in the NZE.

Nuclear capacity grows even more rapidly in emerging market and developing economies in the NZE, from less than 120 GW in 2020 to 480 GW in 2050 – about 90% of the global increase. All low emissions technologies are scaled up in these economies, including a ninefold rise in renewables capacity, in an effort to meet rising demand for electricity services from growing populations with rising incomes, while driving down emissions. China soon becomes the global leader in nuclear capacity, overtaking the United States and European Union before 2030 and is home to one-third of the global nuclear fleet by 2050. Other EMDEs accelerate the expansion of their nuclear programmes, including India, Brazil and South Africa. New nuclear power producing countries emerge in Southeast Asia, Africa and the Middle East in line with current long-term plans and announcements.

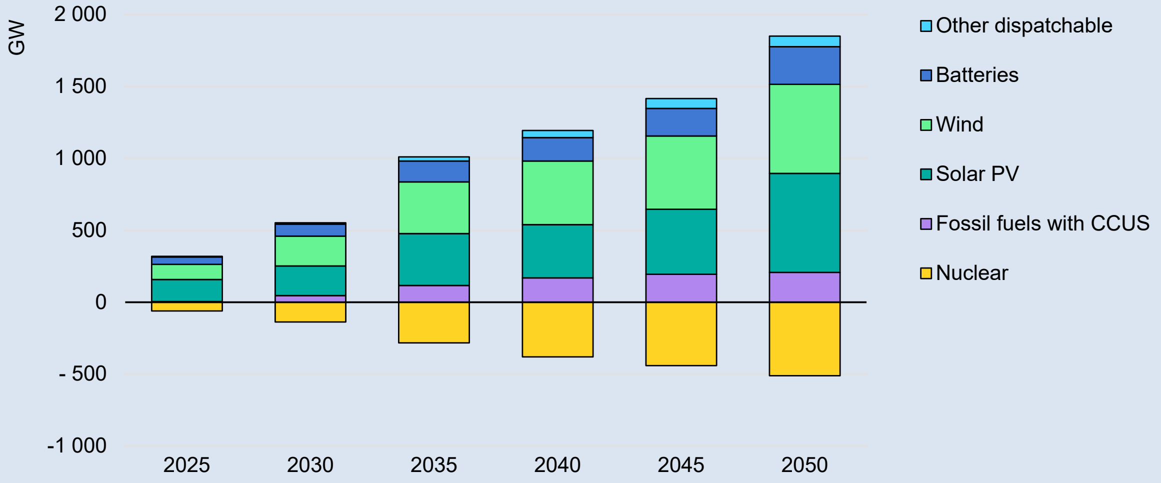
How does the path to net zero look with less nuclear?

Our Low Nuclear Case considers how the NZE might look if, instead of rising, global nuclear capacity declines from 413 GW at the start of 2022 to 310 GW in 2050. This is about 500 GW less than in the NZE. The share of nuclear in total generation would fall from 10% in 2020 to 3% in 2050. Key assumptions are as follows:

- In advanced economies, no additional lifetime extensions are granted and no new nuclear projects are started.
- In emerging market and developing economies, nuclear construction remains at the same average rate seen during 2016-2020, i.e. about 6 GW of capacity added per year to mid-century

In the Low Nuclear Case, several other low emissions sources would need to step up to decarbonise electricity by 2040 and maintain energy security. Solar PV and wind power would be the primary replacements for nuclear, with an additional 1 300 GW of combined capacity in 2050, boosting the total generating capacity by about 5% compared with the NZE (as those sources are not always fully available). This would increase the challenges associated with integrating high shares of variable renewables, which rise above 70% of total generation in many parts of the world. To maintain electricity security, far more battery storage is needed as well as fossil fuels plants with CCUS, their combined capacity increasing by 50% compared with the NZE. The capacities of other dispatchable sources of generation, including hydrogen and ammonia, also expand faster to aid grid stability and adequacy.

Change in global power capacity in the Low Nuclear Case relative to the Net Zero Emissions by 2050 Scenario



In addition to the need to integrate more renewables into electricity systems, there are three main implications of the Low Nuclear Case of the NZE:

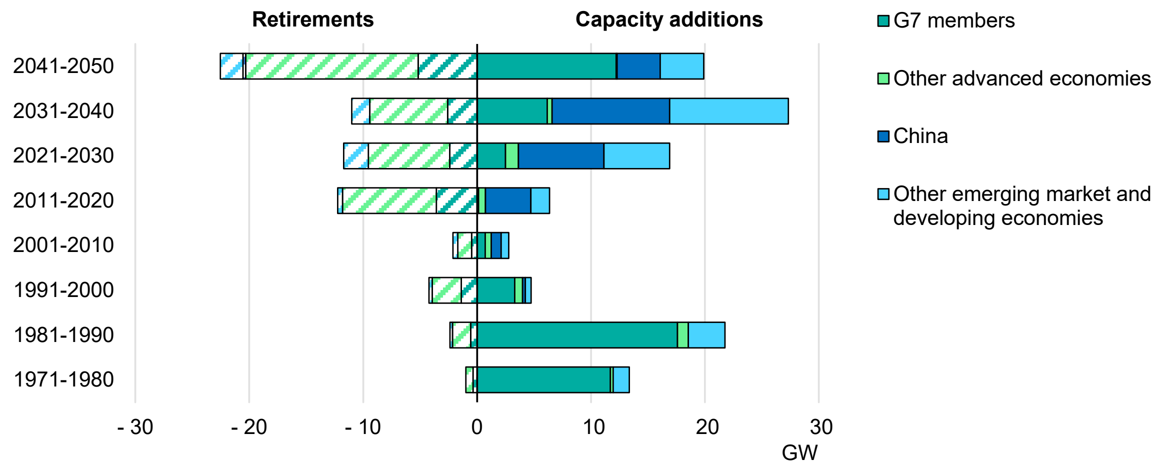
- *Higher overall costs:* Cumulative investment increases by over USD 500 billion and consumer electricity bills by almost USD 600 billion over the period to 2050. This includes the additional investment costs for power technologies, the costs of grid expansion to support additional renewables and additional fuel costs for coal and natural gas.
- *Additional strain on clean energy supply chains:* For every 1 GW reduction in nuclear capacity in the Low Nuclear Case, an additional 3.5 GW of capacity from other sources is needed, with a greater call on critical minerals for both power generation technologies and grid infrastructure.
- *Higher exposure to natural gas and coal market prices:* Coal and gas prices would be more important for consumer electricity bills, removing a degree of the shelter offered in the NZE.

New nuclear construction reaches new highs in the 2030s

Not all countries are assumed to pursue this option, but the nuclear power industry enters a new period of growth in the NZE, with a large new wave of construction of nuclear plants getting underway around the world. From 2021 to 2050, 640 GW of new nuclear capacity is brought online worldwide. An average of over 27 GW of capacity is commissioned each year in the 2030s, surpassing the average height of the previous wave of construction in the 1980s (though the record for a single year of 34 GW was set in 1984). To achieve this pace, the number of new construction starts for large-scale plants increases sharply from an average of just five per year in recent years to around twenty per year over the next decade. The pace of construction slows in the 2040s as unabated fossil fuels are largely phased-out, reducing the need for new dispatchable low emissions capacity. Despite the return to growth for the nuclear industry in the NZE, nuclear power represents just 2% of all new power capacity built over 2021-2050, with solar PV and wind power accounting for the bulk.

China remains the global leader in new nuclear construction in the NZE. It added more new nuclear capacity than any other country in each of the nine years to 2021 and this trend is projected to continue. In the period to 2040, China builds an average of 9 GW per year of nuclear capacity in the NZE, 40% of the world total. The other emerging market and developing economies combined add 8 GW per year. The combined share of China and other EMDEs in global nuclear construction falls back in the 2040s, as construction in G7 members picks up to offset a wave of retirements.

Nuclear power capacity additions and retirements in the Net Zero Emissions by 2050 Scenario by country/region and decade



Sources: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector; IEA (2021), Achieving Net Zero Electricity Sectors in G7 Members.

The shift in the centre of gravity of the nuclear energy industry to China and other emerging market and developing economies has important implications for nuclear technologies and trade. China's current nuclear development is focused mainly on large-scale reactors and domestic designs, including the successful Hualong-1 technology. China is also developing HTGRs with the aim of displacing coal-fired power and heat plants (9 GW of nuclear CHP is added in China over 2021-2050 in the NZE). The new push for nuclear energy in advanced economies is based on new domestic designs, including EPRs in Europe and SMRs in Europe and the United States. The rapid expansion of nuclear construction in emerging market and developing economies other than China would rely on importing nuclear technologies from China, Europe and the United States, creating competition among technology providers in those countries. The affordability of energy will remain of vital importance in emerging market and developing economies, providing a strong incentive for developers of advanced reactor designs to shorten construction times and minimise costs.

Nuclear lifetime extensions provide a cost-effective foundation for energy transitions

The existing fleet of nuclear power plants around the world can provide a solid foundation on which to build clean energy transitions. Yet decisions about how long to operate these plants threaten to erode that foundation. Of the 413 GW of nuclear capacity operating worldwide at the start of 2022, about 290 GW was made up of reactors in advanced economies, many of which are approaching the end of their initial operating licences. How many of these licences will be extended and for what duration remains very uncertain.

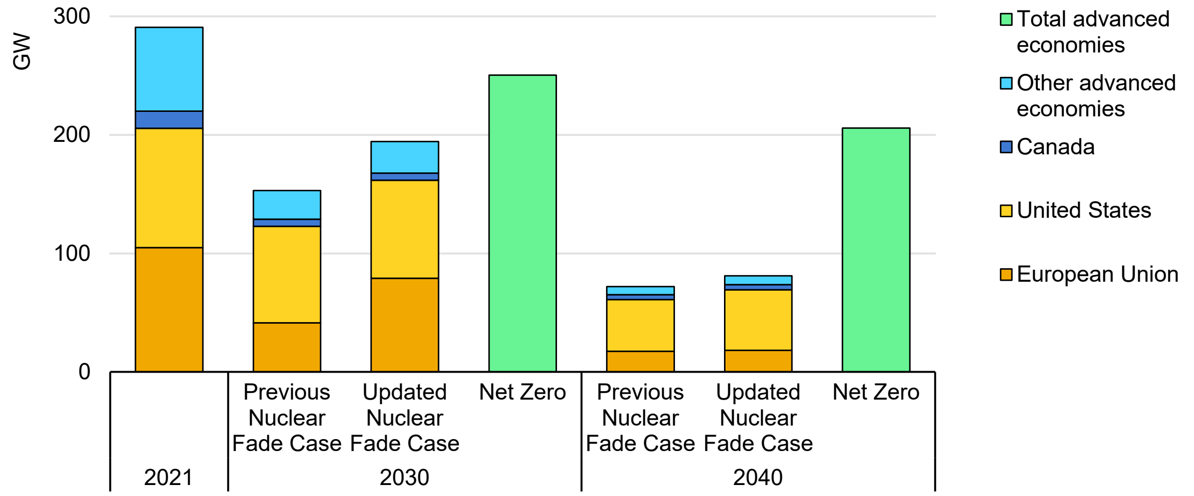
The NZE assumes that the existing fleet of nuclear power plants in advanced economies will continue to operate for as long as technically and economically possible. Unless retirements are already planned, operational lifetimes of nuclear reactors extend to 60 years in most cases and 80 years where this is already being considered, such as in the United States. As a result, the capacity of existing plants in advanced economies declines only moderately, to 250 GW in 2030 and just over 200 GW in 2040, but falls more rapidly thereafter to about 100 GW in 2050. Lifetime extensions are a very cost-effective source of low emissions electricity, estimated at less than USD 50/MWh for a 10- to 20-year extension in major markets in the 2019 IEA report, *Nuclear Power in a Clean Energy System*. With the long lead times for nuclear construction, lifetime extensions also provide time to build new nuclear plants and other low emissions sources fast enough to meet new electricity demand and displace fossil fuels.

Where the operations of reactors can be safely extended, obtaining new regulatory approvals and mobilising investment in them will be critical to maximising the overall contribution of nuclear power to the clean energy transition. A failure to do so could have far-reaching consequences.

Backing away from nuclear would reduce advanced economy nuclear capacity by 70% by 2040

In the event that no further lifetime extensions to existing nuclear reactors are granted (as well as no new investment in existing plants occurs and no new nuclear power capacity is built beyond those projects already under construction), the existing nuclear fleet in advanced economies would shrink rapidly. In an updated Nuclear Fade Case, we revisited analysis first done in *Nuclear Power in a Clean Energy System*, and found that, in these circumstances, the capacity of the existing nuclear fleet in advanced economies contracts by one-third by 2030 and over 70% by 2040, to about 80 GW. The largest declines are in the European Union and the United States, but without additional positive regulatory decisions, there are significant reductions in Japan, Canada and other advanced economies too.

Capacity of existing nuclear power capacity in advanced economies by scenario/case



Notes: Net Zero = Net Zero Emissions by 2050 Scenario. The Nuclear Fade Case assumes that no further lifetime extensions to existing nuclear reactors are granted in advanced economies. The Previous Nuclear Fade Case refers to the IEA's 2019 report (see source), which is updated here.

Sources: IEA (2019), Nuclear Power in a Clean Energy System; IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

The losses of capacity in the Updated Nuclear Fade Case are significantly smaller than in the previous version thanks to policy and regulatory decisions to extend the lifetime of over 50 GW of nuclear reactors between May 2019 and April 2022. Those decisions concern almost 20% of the nuclear fleet today in advanced economies. In the United States, an additional reactor has been granted an initial 20-year extension and six others approval for a subsequent 20-year extension since 2019. In France, regulatory approval has been granted for 32 reactors to be extended by ten years. These approvals are alongside EDF's *Grand Carénage* programme, which runs from 2014 to 2025. It involves substantial investment in enhancing reactor safety through maintenance and technical modifications, with the goal of prolonging the lifetimes of most of the fleet of 56 reactors beyond 40 years. In Japan, two additional reactors received regulatory approval to re-start since 2019.

Policy and regulatory decisions made between May 2019 and May 2022 for existing nuclear reactors by country

Country	Decision type	Comment	Capacity (GW)
France	Extension of operating licence	Thirty-two reactors (each with a capacity of about 900 MW) received regulatory approval for a 10-year extension	30.4
United States	Extension of operating licence	Initial 20-year extension granted for Seabrook 1	1.3
		Six reactors received approval for a subsequent 20-year extension	6.3
Spain	Extension of operating licence	Seven reactors approved or pending final approval for extensions of 5 to 10 years, operating up to 2035	7.4
Belgium	Extension of operations	Two reactors put forward to extend operations by 10 years to 2035	2.2
Japan	Decisions to restart reactors	Two reactors received regulatory approval to re-start	1.7
Bulgaria	Extension of operating licence	Approved extension for unit 6 of Kozloduy nuclear power plant to operate to 2029	1.0
Mexico	Extension of operating licence	Approval received for Laguna Verde Unit 1 to operate to 2050	0.8
Romania	Extension of operations	Cernavoda Unit 1 refurbishment to extend lifetime by 30 years to 2059	0.7
Total			51.8

Decisions to extend the lifetimes of nuclear reactors will have a significant impact on natural gas demand, with important implications for energy security in importing countries. Without the recent regulatory decisions, natural gas demand in advanced economies would be almost 50 bcm higher in 2030 in the NZE. Further lifetime extensions could reduce natural gas demand in advanced economies by another 70 bcm in 2030, lowering demand for LNG imports in Europe, Japan and Mexico, while making more gas available for export in the United States. There are a host of policy and regulatory decisions to be made in the near term about safety inspections and extending the operating licences of existing reactors concerning a total of 57 GW of capacity.

Pending policy and regulatory decisions on restarts or lifetime extensions by country

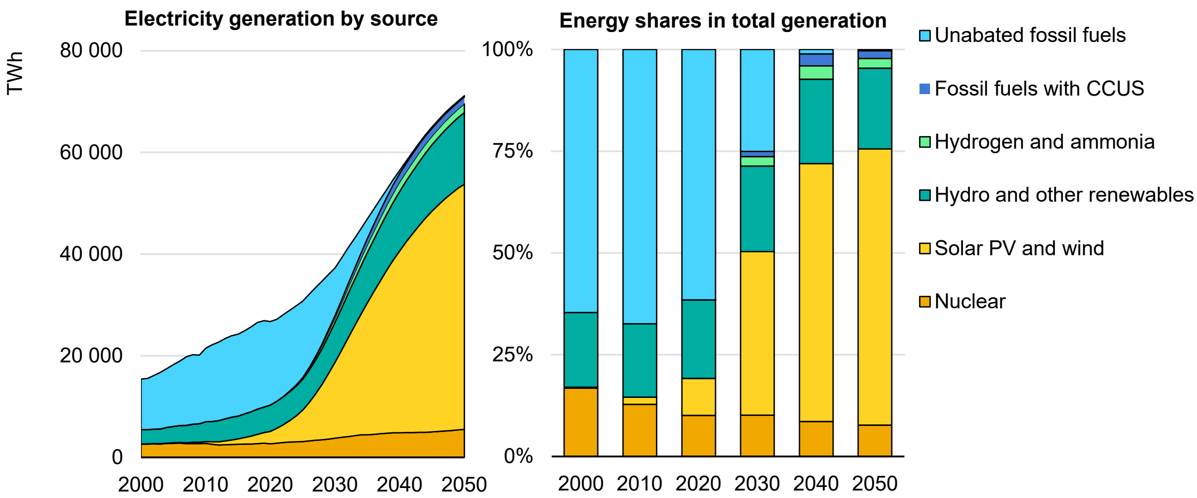
Country	Decision type	Comment	Capacity (GW)
United States	Extension of operating licence	Four operating reactors awaiting decision on initial 20-year extensions	4.9
		Applications for subsequent 20-year extensions under review for nine reactors and planned for five more by 2024	13.3

Country	Decision type	Comment	Capacity (GW)
Japan	Pending decisions to restart reactors	Ten reactors are under review to restart operations	9.0
France	Extension of operating licence	Twenty-two reactors must pass inspection before 2025 to continue operations	24.2
Korea	Extension of operating licence	Five reactors will reach the end of their licences to operate by 2026	4.8
UK	Extension of operations	20-year extension of Sizewell B to operate to 2055 under consideration	1.3
Finland	Extension of operating licence	Application for continued operations planned for two nuclear units at Loviisa plant	1.0
Mexico	Extension of operating licence	Application submitted pending for Laguna Verde Unit 2	0.8
Total			57.3

Nuclear output doubles by 2050 in the NZE, though its share of total electricity supply falls

The projected global expansion of capacity underpins a more than doubling of nuclear electricity generation from 2 690 TWh in 2020 to nearly 5 500 TWh in 2050 in the NZE. The rate of increase is nonetheless less than that of other zero carbon generating options, with nuclear power's share in total electricity generation falling from 10% to 8% over the same period. The last time that nuclear power accounted for less than 10% of total generation was in 1980. After renewables, nuclear power still becomes the largest source of electricity by 2040, surpassing that of fossil fuels equipped with CCUS, hydrogen and ammonia (also used as a means of cutting emissions from coal- and gas-fired power plants through co-firing).

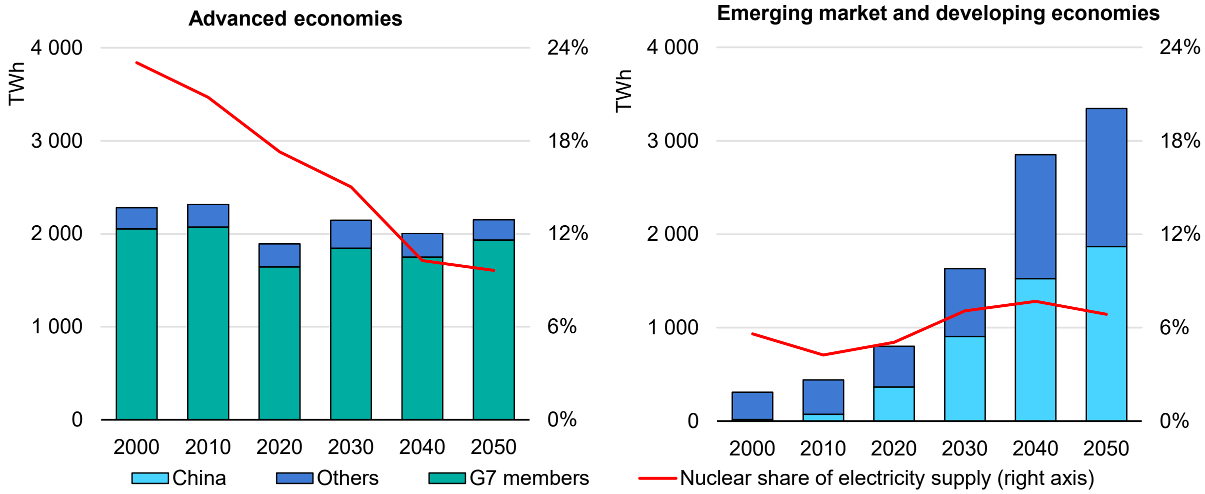
Global nuclear power generation and total generation by type of energy in the Net Zero Emissions by 2050 Scenario



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

In advanced economies, nuclear electricity generation edges up by 15% between 2020 and 2050 in the NZE. Its share of total generation falls from 18% to 10%, as total generation doubles to meet new demand from the electrification of transport, industry and heating in buildings and hydrogen production. The capacity factor – output as a share of the maximum capacity – of nuclear power in those countries rises from an average of 72% in 2020 to 85% in 2030, thanks in part to reactors being gradually restarted in Japan. In the long term, the capacity factor falls back below 80%, as the share of wind and solar PV rises and dispatchable plants need to operate flexibly more often.

Nuclear power generation and share of total generation by type of economy in the Net Zero Emissions by 2050 Scenario



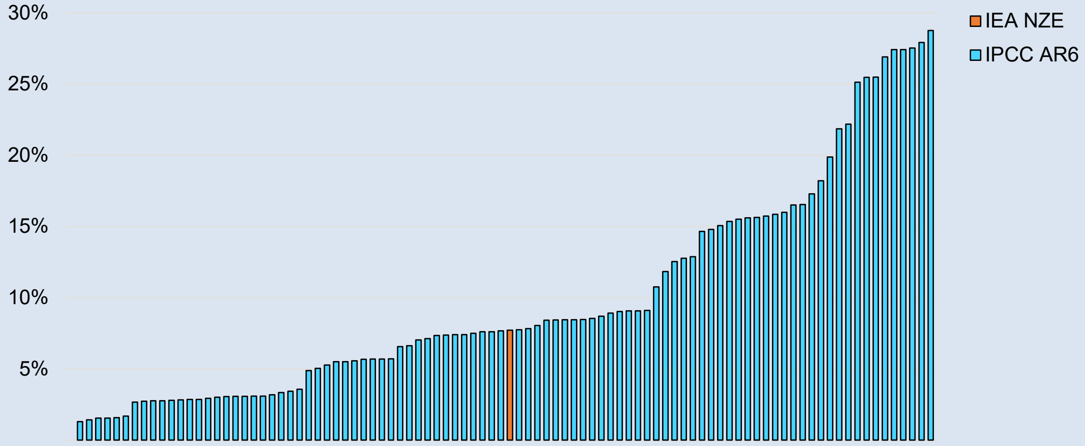
Sources: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector; IEA (2021), Achieving Net Zero Electricity Sectors in G7 Members.

In emerging market and developing economies, nuclear electricity generation increases more than fourfold over 2020-2050 in the NZE, its share of total generation rising from 5% to 7%. The share rises even more in China, from 5% to 11%, becoming the third-largest source of electricity behind wind and solar PV. In other EMDEs, the growth of nuclear power keeps pace with overall demand, with its share remaining broadly constant at about 5% through to 2050.

How does the role of nuclear in the NZE compare with other 1.5°C scenarios assessed by the IPCC?

The role of nuclear power, measured both by total nuclear power output and its share in total generation, in the NZE is broadly similar to that of the 97 scenarios assessed by the IPCC that limit warming to 1.5°C (with a greater than 50% probability) with no or limited overshoot (category C1). Nuclear power output and total generation in those scenarios varies markedly: nuclear output ranges from 1 000 TWh to 26 000 TWh in 2050, with a median value of 5 600 TWh. Nuclear's share of electricity generation in the same year ranges from 1% to 29%, with a median value of 7.6%. Generally, compared with other scenarios in the C1 category, the NZE pathway relies less on bioenergy and more on wind, solar PV and hydrogen.

Share of nuclear power in world electricity generation in the Net Zero Emissions by 2050 Scenario and comparable IPCC scenarios, 2050



Notes: NZE = Net Zero Emissions by 2050 Scenario; AR6 = IPCC's sixth assessment report.

Sources: IPCC (2022), Climate Change 2022: Mitigation of Climate Change, Working Group III Contribution to the IPCC Sixth Assessment Report; IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

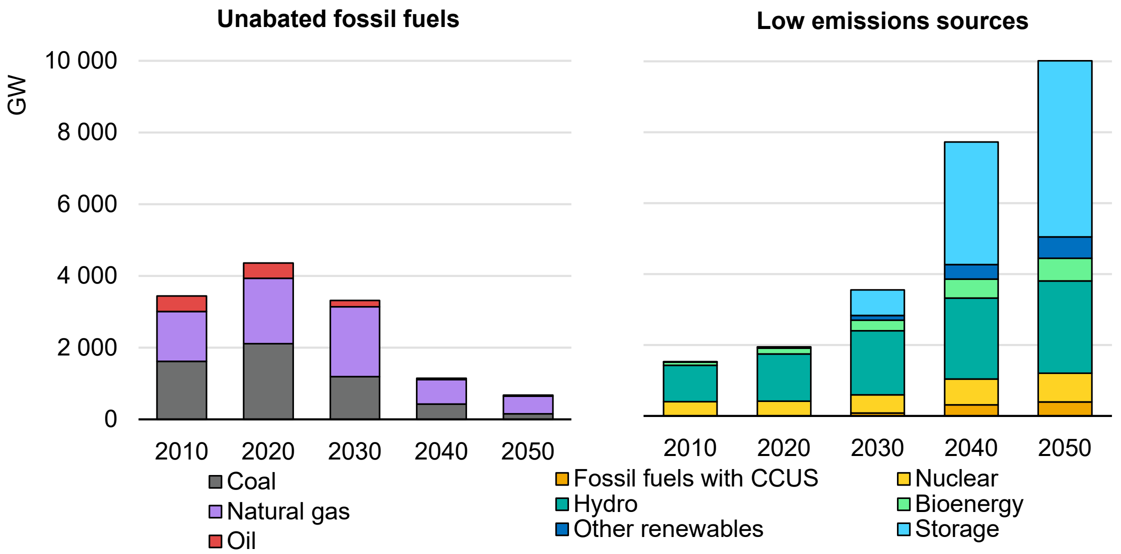
Another important comparison is the International Atomic Energy Agency (IAEA) study, Energy, Electricity and Nuclear Power Estimates for the Period up to 2050, released in 2021. It is designed to set out a "conservative but plausible" range for nuclear power development over the next three decades. In the study's high case, which takes into consideration potential policy action on climate change, though not specifically net zero emissions goals, gross nuclear power capacity reaches about 830 GW in 2050 (792 GW in net terms) – close to that in the NZE. In the study's low case, global nuclear capacity remained largely unchanged from the 2020 level of 415 GW (393 GW in net terms).

Nuclear power can make an important contribution to overall power system adequacy

Nuclear power plants have long contributed to the reliability of power systems, including through contributions to system adequacy.[11] Historically, nuclear power plants in most countries have been operational and available to generate power at least as often as all other sources of electricity, with availability factors regularly above 90%. Since the vast majority of nuclear power capacity counts towards system adequacy, its contribution to system reliability and adequacy is typically far greater than its share in total power capacity.

The share of nuclear power in total dispatchable power capacity – a metric of its contribution to system adequacy – holds steady at around 8% over 2021-2050 in the NZE. Dispatchable sources of electricity have long been the principal means of ensuring system adequacy. This remains the case in the NZE as electricity systems evolve with increased reliance on variable solar PV and wind. Unabated fossil fuels make up the majority of dispatchable capacity today, but they decline by one-quarter to 2030 in the NZE and sharply thereafter. Unabated coal-fired power is the largest dispatchable source today, but capacity in operation declines by over 40% by 2030 and approaches zero in the early 2040s. Unabated natural gas-fired power capacity remains broadly constant to 2030, buoyed by the need to compensate for the reduction in coal, but then declines rapidly in the 2030s. Oil is a relatively minor contributor today and, aside from remote locations, is phased out quickly in this scenario.

Global dispatchable power capacity by type in the Net Zero Emissions by 2050 Scenario



Note: Storage includes hydrogen, ammonia and batteries. Pumped storage is included in the hydro total. Storage is not inherently low emissions, but depends on the primary source, which is increasingly low emissions in the NZE.
Source: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

[11] Power system adequacy refers to the ability of available generators to meet electricity demand at all times.

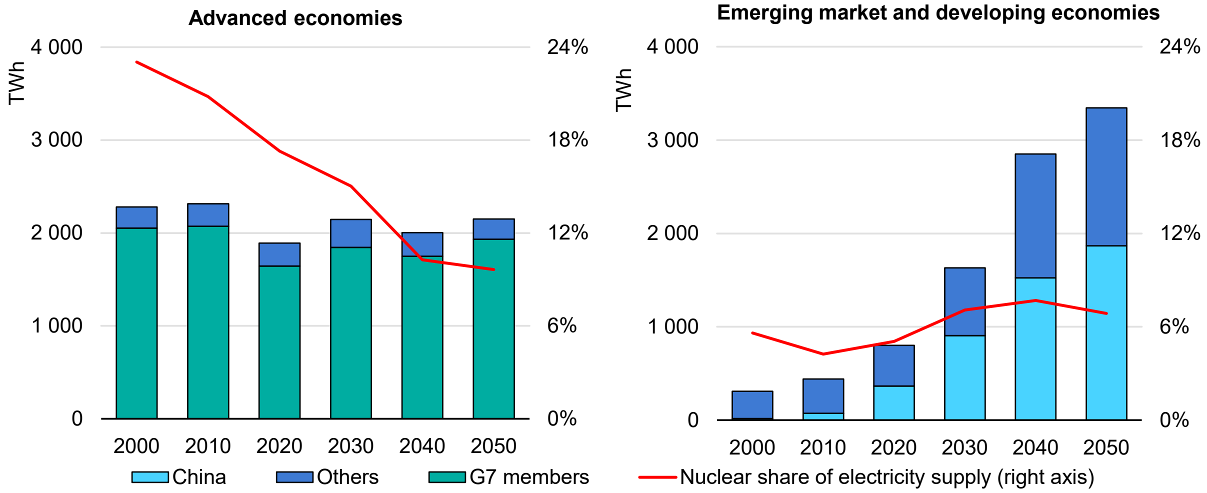
The contribution of low emissions energy sources to dispatchable generating capacity grows substantially in the NZE, with their combined capacity rising fivefold worldwide to 2050. Hydro and nuclear power have long made up the bulk of low emissions dispatchable capacity. The capacity of hydropower and other dispatchable renewables, including bioenergy, geothermal and solar thermal, more than doubles over 2021-2050, complementing the growth of non-dispatchable solar PV and wind power. Energy storage, in a variety of forms, is set for massive expansion. Batteries, hydrogen and ammonia play increasingly important roles where the fleets of coal- and gas-fired power plants are young. Fossil fuels equipped with CCUS also emerge as important contributors to system adequacy.

Nuclear also helps to meet the rapidly rising need for power system flexibility in the NZE

Electricity system flexibility – the ability of the system to reliably and cost-effectively manage the variability and uncertainty of demand and supply – is becoming increasingly central to electricity security as the share of variable renewables in generation grows. Flexibility over different timeframes, from minute-to-minute, hour-to-hour and season-to-season, is needed to ensure instantaneous stability of the power system and long-term security of supply. Hour-to-hour flexibility needs in electricity systems worldwide quadruple on average from 2020 to 2050 in the NZE – twice as much as overall electricity demand. The growing share of generation linked to weather conditions (sunshine and wind) means that other generators are called upon to change their output more often and by larger amounts. Changes in the pattern of electricity demand, which varies more within the day as a result of the increasing electrification of road transport, heating in buildings, industrial processes and the expansion of electrolytic hydrogen, also drive up flexibility needs.

The balance of solar PV and wind influences the kind of flexibility that will be needed as electricity supply is increasingly decarbonised. Solar PV output varies regularly within the day, from zero at night (without storage) rising to a peak around midday before falling back to zero. Cloud conditions add a layer of variability within the day. Short-duration flexibility, able to span a few hours or up to a day, is well adapted to this regular pattern. Emerging market and developing economies rely heavily on solar PV in the NZE, putting short-term flexibility at the heart of their energy security. Wind conditions and related power output have less regular variability across the day, but more variability from week to week and across seasons. Systems that incorporate greater wind capacity will look more to longer-duration flexibility to balance electricity supply and demand across several days or weeks. This is the case for advanced economies in the NZE, where wind remains a bigger source of generation than solar PV through to 2050.

Wind and solar PV installed capacity and shares in electricity generation by regional grouping in the Net Zero Emissions by 2050 Scenario

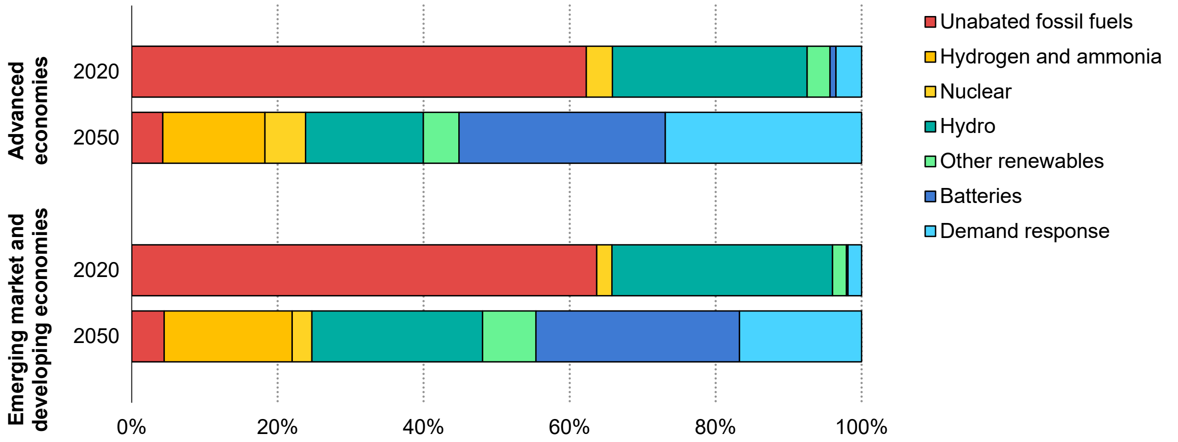


Source: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

A suite of flexibility sources, including primarily low emissions generation, is used to maintain electricity security in the NZE. Unabated fossil fuels provide over 60% of hour-to-hour power system flexibility today. Over the next decade, unabated coal-, gas- and oil-fired plants continue to provide the lion's share of flexibility, even as their shares of generation decline. Demand response, whereby consumers adjust their electricity consumption in real time in response to system needs and price incentives, and storage technologies, including batteries, become the largest sources of short-duration flexibility after 2030, making up almost half the global total by 2050. A mix of low emissions generation take the place of unabated fossil fuels. Hydropower has long been a major provider of flexibility, with reservoirs acting as large energy storage facilities. In the future, new reservoir hydro capacity is limited to a few markets due to environmental concerns and public acceptance, though pumped storage capacity continues to grow. Other dispatchable renewables, such as bioenergy and geothermal, also contribute. Low-carbon hydrogen and ammonia also contribute to seasonal storage.

Nuclear power continues to contribute to power system flexibility in the NZE. In advanced economies, its share of hour-to-hour flexibility rises from around 2% today to 5% in 2050. In emerging market and developing economies, it increases from 1% to 3%. In France, where nuclear meets the bulk of electricity generation needs, flexibility has been incorporated into reactor designs to allow some plants to ramp up and down their output quickly at short notice so as to operate in a load-following mode to align electricity supply and demand. While many countries have not regularly called on nuclear power to operate in this way to date, many reactors are able to do so with no or minimal technical modifications.

Hour-to-hour power system flexibility by source and regional grouping in the Net Zero Emissions by 2050 Scenario



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

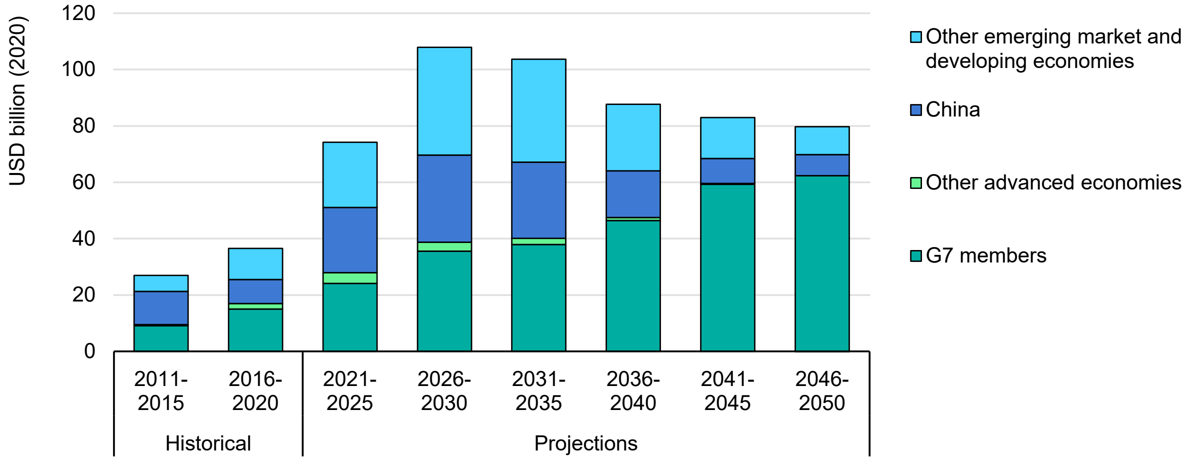
Innovation has the potential to make nuclear power more flexible. Advanced technologies, including SMRs, could open up the possibility for nuclear reactors to vary their output of electricity more readily, possibly switching to produce heat or hydrogen instead of or alongside electricity. Efforts are being made to inform policymakers and planners about the potential cost benefits of making nuclear power more flexible, such as the campaign led by the Clean Energy Ministerial.

Nuclear power investment and costs

Annual investment in nuclear power triples by 2030 in the NZE

The resurgence of nuclear power in the NZE entails a massive increase in investment in the coming decades, to build new nuclear reactors and extend the operational lifetimes of existing ones. Annual global investment in nuclear in this scenario surges to over USD 100 billion in the first half of the 2030s in the NZE – over three times the average of USD 30 billion in the 2010s. It falls steadily thereafter as the need for dispatchable low emissions generating capacity subsides, reaching around USD 70 billion in the second half of the 2040s. The investment in nuclear power over 2021-2050 accounts for less than 10% of the total for low emissions sources of electricity. By context, annual investment in renewables in this scenario rises from to USD 325 billion on average over 2016-2020 to USD 1.3 trillion in 2031-2035.

Global average annual nuclear power investment by country/regional grouping in the Net Zero Emissions by 2050 Scenario



Sources: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector; IEA (2021), Achieving Net Zero Electricity Sectors in G7 Members; IEA (2021).

The focus for nuclear investment in the NZE shifts gradually from emerging market and developing economies to advanced economies over 2021-2050. They average close to USD 50 billion per year in advanced economies, accounting for about half the global total. This is almost fourfold the average over the 2010s. These countries' investment needs are high relative to their share of global capacity due to higher construction costs and the need for large investments to extend the lifetimes of existing reactors and build new ones to offset retirements. The latter factor also explains why investment in advanced economies is skewed towards later decades. China needs to spend close to USD 20 billion per year on nuclear on average to 2050, nearly double the average over the 2010s. Other EMDEs triple investment to about USD 25 billion per year on average. In contrast to advanced economies, investment in these countries is needed more in the period to 2035.

The cost of new nuclear reactors varies widely by region

The cost of construction of new nuclear reactors – an important factor in determining relative investment in competing dispatchable generating sources – is far from uniform across the world.[12] In the NZE, it is assumed that China and India are able to build new nuclear plants at the lowest cost, at less than USD 3 000/kW, with projects completed in five to seven years. This means that a new large-scale reactor with a capacity of 1.1 GW would cost roughly USD 3 billion (in 2020 USD). Costs are assumed to remain a lot higher in the European Union and United States, though they decline progressively over the next three decades to around USD 4 500/kW. Achieving these cost reductions would require the nuclear industry to deliver projects

[12] Additional regional cost assumptions for nuclear power and other power technologies from the World Energy Outlook 2021 are freely available for download.

on time and on budget. There are some proven methods to reduce costs for subsequent investments, including beginning construction only after designs are finalised, maintaining the same design for subsequent units to achieve “nth of a kind” efficiencies and building multiple units at the same site. Innovation is also being applied to the siting process, which could shorten lengthy pre-construction periods. The nuclear construction cost assumptions apply to all sizes of reactors in our analysis.

Nuclear power construction cost assumptions for selected countries and regions in the Net Zero Emissions by 2050 Scenario (USD/kW at 2020 prices)

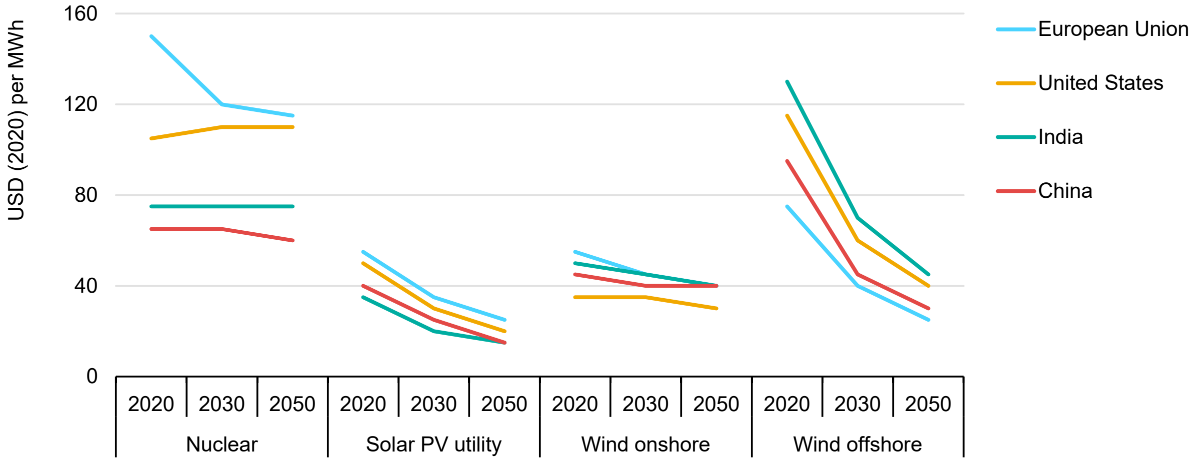
Region	2020	2030	2050
European Union	6 600	5 100	4 500
United States	5 000	4 800	4 500
India	2 800	2 800	2 800
China	2 800	2 800	2 500

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

Nuclear power must overcome economic barriers to investment

Aside from non-economic barriers such as public acceptance, the nuclear industry must overcome several economic barriers to investment for it to contribute to reaching net zero as depicted in the NZE. The primary economic barrier is cost relative to that of other low emissions energy sources. Measured by the levelised cost of electricity (LCOE) – the average cost of electricity generation for a plant over its operating lifetime – solar PV is already the cheapest new source of electricity in most markets, with costs having fallen some 85% over the past decade. Solar PV costs continue to fall in the NZE driven by massive deployment and innovation (after temporary price increases in the near term due to supply-chain disruptions). Onshore wind is the only low emissions technology that can compete with solar PV on cost, with offshore wind on track to approach the cost of onshore projects in many cases within the next few years. By 2030, the costs of solar PV and onshore wind are projected to fall to less than USD 50/MWh in most markets – well below the costs of new nuclear projects.

Levelised cost of electricity for selected technologies and countries in the Net Zero Emissions by 2050 Scenario



Note: Levelised costs for nuclear include the costs of decommissioning.
Source: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

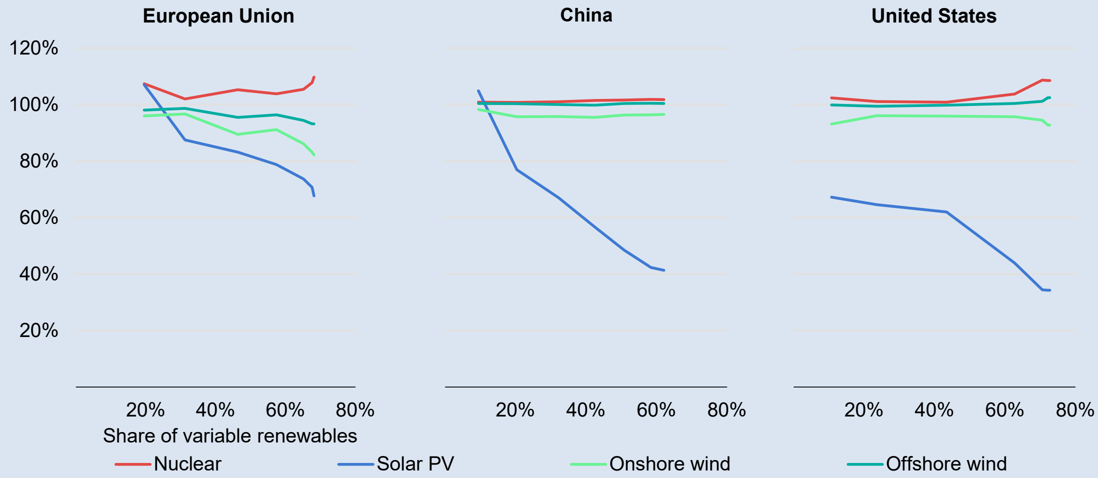
Yet, in many instances, nuclear power can still be competitive with renewables when its broader electricity system benefits are considered. The LCOE is a common metric for comparing and screening low emissions generating options but does not allow for differences in the way each technology operates, notably dispatchability. More complete metrics, such as the value-adjusted LCOE, quantify the system value of different technologies, through their contributions not only to low emissions electricity, but also to system adequacy and flexibility. The value-adjusted LCOE of wind and solar PV tends to rise as their share of total generation increases, while that of nuclear and other dispatchable generating options falls, making them more competitive and granting them a larger role in least-cost systems than the LCOE alone might indicate.

What is the value of nuclear output?

The competitiveness of nuclear in relation to other power generation technologies is determined by the value of its output as well as its cost of production. The ability of an electricity source to be available during times of highest system needs, for example, helps to raise its energy value, measured by the average wholesale price obtained for its output in a competitive market. At the same time, an abundance of output when it is not needed reduces the energy value. The energy value of a particular technology in a system depends on the pattern of demand, the mix of generating resources, fuel and CO_2 prices, and other system-specific elements.

As the share of variable renewables rises, the energy value of an additional solar PV or wind project tends to decline. The regular output pattern of solar PV means that without storage, its energy value declines the most. In our simulations of the European Union, China and the United States, each percentage point rise in the share of variable renewables in total generation reduces the energy value of solar PV by 1-2% relative to the average wholesale electricity price. The loss of value is less marked for wind: for each percentage point increase in the share of variable renewables, the energy value of onshore or offshore wind declines by just 0.3% or less. By contrast, nuclear power's energy value relative to the system average is stable or increases in these markets as the share of variable renewables rises, rewarding its dispatchability.

Energy value of low emissions electricity relative to the average wholesale electricity price with rising shares of variable renewables by technology

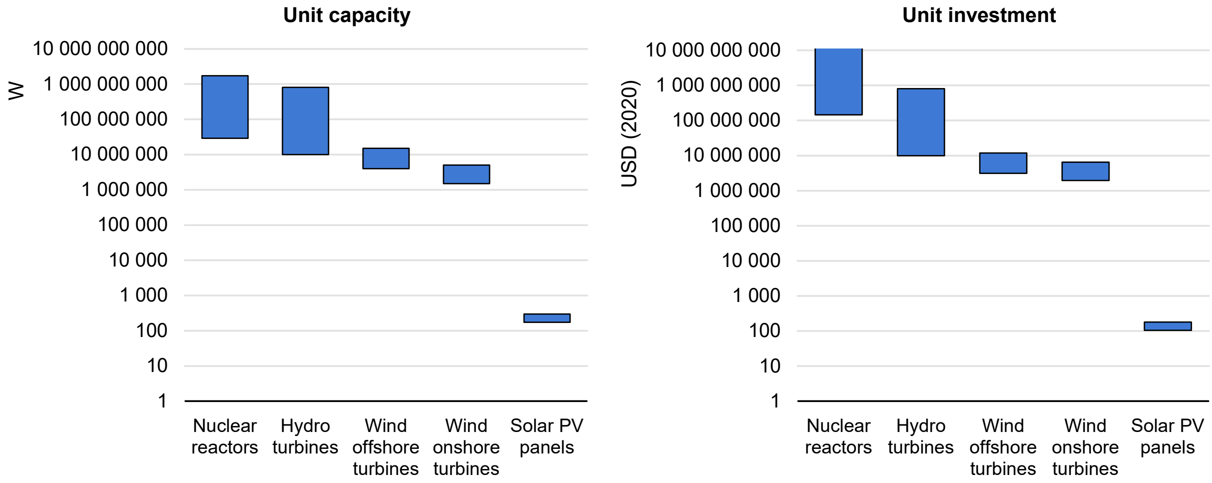


Note: Energy value is calculated as the average price per unit of output over the year, based on the simulated hourly wholesale electricity price and production profile by technology in the Sustainable Development Scenario, which achieves key energy-related United Nations Sustainable Development Goals related to universal energy access and major improvements in air quality, and reaches global net zero emissions by 2070.

Source: IEA (2021), World Energy Outlook 2021.

The relatively large size and high associated upfront costs of conventional nuclear reactors are another economic barrier. A single large-scale reactor can have the capacity to produce over 1 600 MW of power – the largest of any technology. Smaller reactors are possible, but are less able to exploit economies of scale. By comparison, hydropower has the next largest plant capacity, with individual turbines capable of producing up to about 800 MW. At the other extreme, a single solar PV panel has a capacity of 300 W in utility-scale projects and as little as 100 W in rooftop installations. The large capacity of nuclear reactors combined with their relatively high construction costs mean that the cost of a single reactor can exceed USD 10 billion in some countries – an order of magnitude greater than any other low emissions technology. Only a few companies in the world are capable of handling projects of this scale and, even for them, such projects present considerable risks in the case of delays or cost overruns. This can deter investment in a single reactor as well as the development of a series of reactors necessary to drive down the costs of new reactor designs.

Range of plant capacity and cost of selected electricity generating technologies, 2020



Note: Log scales.

In countries that plan for nuclear power to play a part in the energy transition, governments must intervene to help overcome these economic barriers. It is critical that the contributions of low emissions technologies, including nuclear power, to emissions reductions and energy security are appropriately valued. Pricing CO_2 emissions and other pollutants is the most efficient means of valuing low emissions contributions, while markets for power system services are well-suited to value contributions to electricity security. Where these are not in place, it may be necessary to intervene directly in competitive markets to incentivise private investment, or to provide price or revenue guarantees under long-term contracts to new generators as part of an overall plan for the energy sector. Government actions can also drive nuclear innovation, helping advanced designs through the various stages of development to commercialisation, for example by supporting construction of a series of reactors, for which the initial costs are likely to be high.

Advanced reactor designs, in particular SMRs, have the potential to address both the economic barriers described above, in turn making it more feasible to develop multiple projects and drive down costs. The extent to which costs can be lowered will determine the degree to which nuclear technologies are able to produce low emissions electricity, heat or hydrogen in the long term. If costs can be reduced more than assumed in the NZE relative to other low emissions technologies, the role of nuclear energy could be significantly larger than that projected.

3. The competitiveness of nuclear energy

Assessing the value of nuclear to decarbonising energy systems

Reducing emissions from power generation cost-effectively while ensuring energy security requires a market framework that adequately values both low emissions generation and the full range of electricity system services. Energy transitions require shifting away from the unabated use of coal and natural gas to a suite of low emissions technologies in the power sector. The favourable attributes of nuclear power – notably its low emissions, dispatchability and flexibility – will boost its value to electricity systems as they are progressively decarbonised. In particular, dispatchability will become increasingly valuable as variable renewables, which are not dispatchable and are less flexible than thermal generating sources, provide an increasing share of power generation. Other sources of flexibility such as hydropower or geothermal face difficulties in scalability or acceptable sites, or have yet to prove themselves commercially in the case of electrolytic hydrogen and CCUS.

For these reasons, electricity markets need to be designed to ensure that the economic value of nuclear power, alongside other low emissions technologies, is fully reflected in price signals in order to incentivise investment in a non-discriminatory manner. In the absence of good market design, governments will need to rely to a greater extent on other incentives, such as administratively defined payments, to make these investments happen, often with higher cost outcomes.

Nuclear energy can also contribute to the expansion of low emissions heat and low emissions hydrogen production. Competition between the technological options for supplying those growing markets is significantly different than in the power sector and the impact of site-specific considerations is more important for the investment decisions taken. Exploiting this potential could strengthen business cases for new reactors by increasing revenues and reducing the risk of having to curtail production in systems with high shares of variable renewables.

Electricity generation

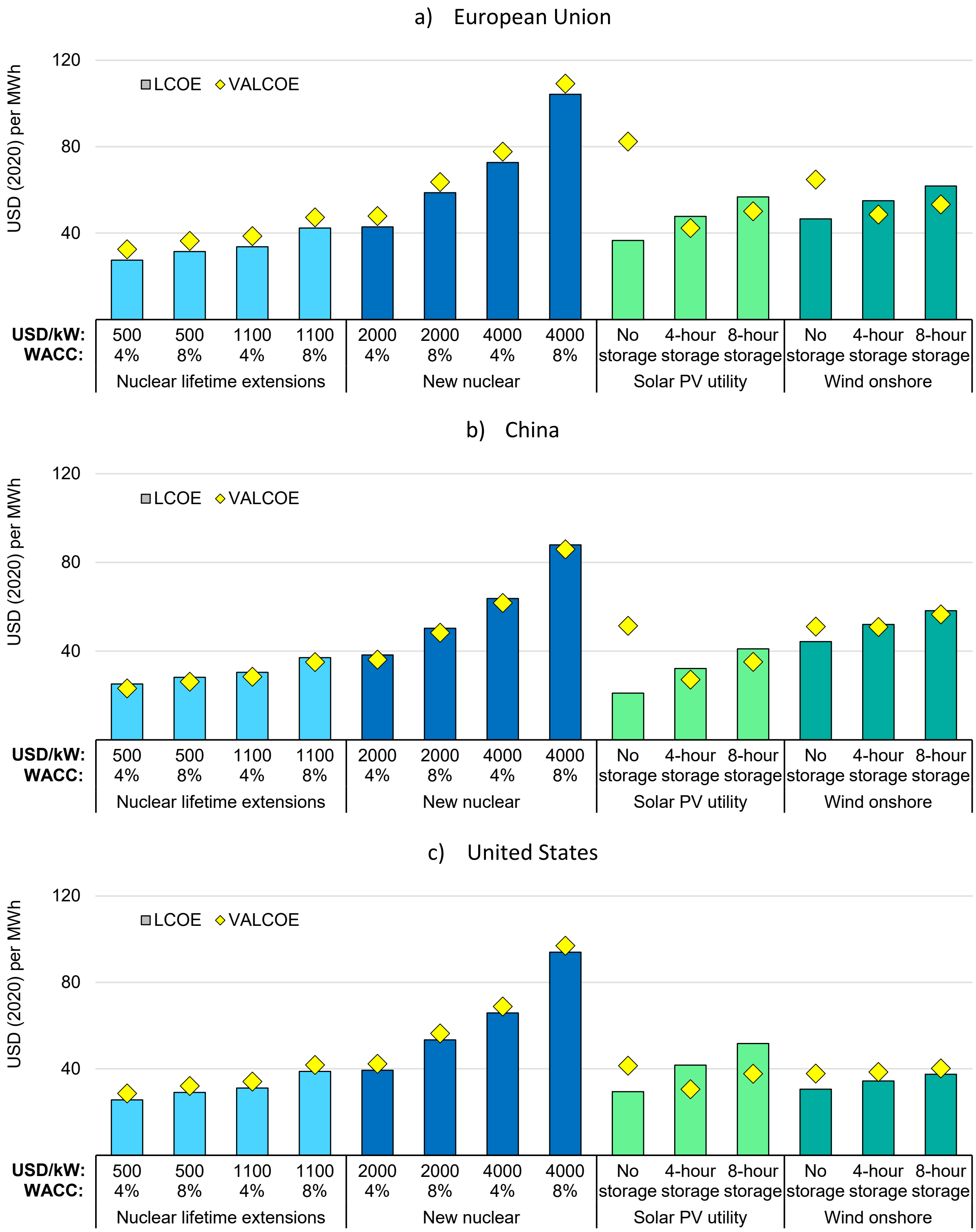
New nuclear reactor construction costs need to fall sharply to compete for more market share with solar PV and wind

The cost of building new nuclear reactors will be crucial to the future role of nuclear power in the global clean energy transition. At the cost assumptions in the NZE, nuclear plays a complementary role, contributing to system stability, expanding the suite of low emissions sources and stepping up where renewables are constrained. However, in order to compete directly with solar PV and wind power, considering both the costs and system value for each technology, the construction cost of new nuclear would need to be reduced to USD 2 000/kW (in 2020 USD) or less for capacity to be added in 2030. At this construction cost, the LCOE of nuclear power would be in the range of USD 40-60/MWh, depending mainly on the cost of financing. The lower end of that range corresponds to a weighted average cost of capital of 4%, which requires project- and technology-specific risk to be minimised or transferred to other parties. Support measures should be technology-neutral whenever acceptable and possible to ensure the most affordable energy transitions. The duration of construction and the capacity factor, which also influence the LCOE, vary by region. For example, shorter construction periods and higher projected capacity factors result in a lower LCOE in China.

Where the costs of nuclear construction are closer to USD 4 000/kW, the LCOE jumps to USD 60/MWh to USD 100/MWh, which exceeds that of solar PV and wind projects, including with storage, in most cases. The value-adjusted LCOE (VALCOE) of nuclear power is very similar to the LCOE in the European Union, China and the United States as nuclear power's contribution to low emissions electricity supply, power system adequacy and flexibility is roughly equal to the average of the entire power plant fleet.

Nuclear lifetime extensions are a competitive source of low emissions electricity, especially in Europe and the United States. The capital cost for most extension projects is in the range of USD 500/kW to USD 1 100/kW in 2030, yielding an LCOE generally below USD 40/MWh. At this cost, nuclear lifetime extensions are competitive with low cost solar PV and wind under most conditions, despite solar PV and wind power costs falling heavily. Extensions contribute to power system services to a similar degree as new projects, so there is little difference between their VALCOE and LCOE.

Levelised cost of electricity and value-adjusted levelised cost of electricity for selected generating resources in selected countries, 2030



Notes: LCOE = levelised cost of electricity; VALCOE = value-adjusted LCOE; WACC = weighted average cost of capital. VALCOE is a metric in the IEA energy modelling framework that reflects technology-specific LCOEs and contributions to system value. The size of storage is assumed to be one-quarter of that of the renewable energy project (e.g. a 100 MW solar PV array has a 25 MW battery with 4 hours or 8 hours of duration). Construction costs for solar PV and wind onshore and simulated operations are based on the Net Zero Emissions by 2050 Scenario.

Source: IEA (2021), World Energy Outlook 2021.

The competitiveness of nuclear depends also on the prospects for further reductions in the cost of generating electricity from solar PV and wind. Solar PV is the cheapest source of electricity in most regions today; it is also widely available and scalable. The LCOE of solar is projected to fall by more than 40% by 2030 in the NZE, with most utility-scale projects costing around USD 20/MWH to USD 40/MWh. However, the variable output of solar PV does not match patterns of electricity demand very well, reflected in a VALCOE that is notably higher than its LCOE. Pairing solar PV with either 4-hour or 8-hour storage makes it more competitive, with co-location offering cost advantages, with a lower VALCOE than solar PV on its own in China, the European Union and the United States.

As with solar, wind power is widely available and scalable in most markets. It is a more mature technology than solar PV, though innovations continue. As with solar PV, the LCOE of most onshore wind projects is expected to fall to USD 30/MWh to USD 70/MWh in 2030. The profile of wind output, which depends on wind conditions, are often misaligned with demand patterns, so wind's VALCOE is generally well above it's LCOE, making it less competitive than the LCOE alone would suggest. Pairing storage with onshore wind can lower the VALCOE, particularly where the share of wind in total generation is high, such as in the European Union. Non-economic factors, including the availability of suitable sites and public acceptance, will also affect their deployment.

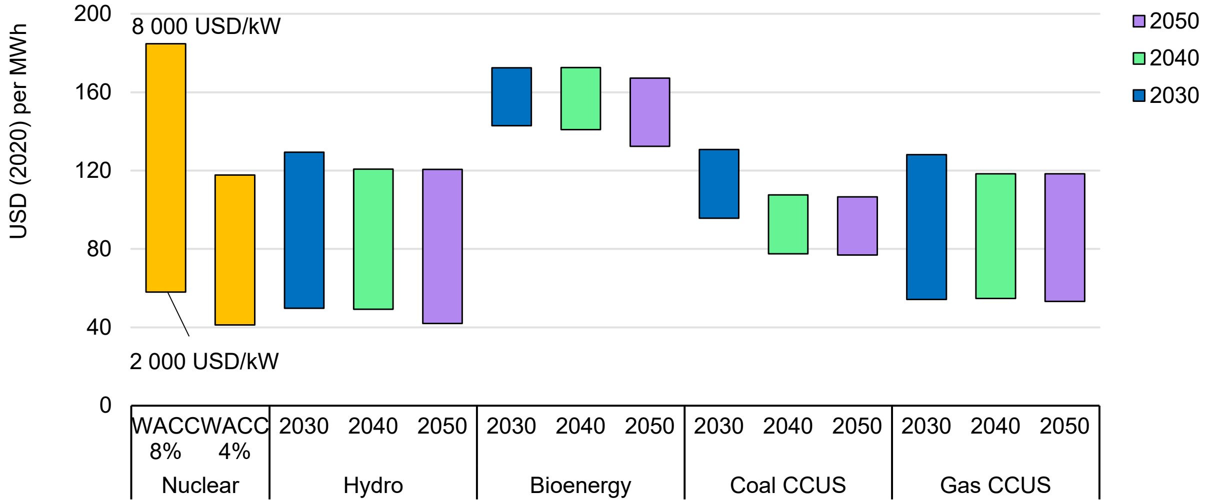
Nuclear is better able to compete with other dispatchable low emissions options

The cost of building new nuclear power plants needs to fall much less to compete with other dispatchable sources of low emissions electricity. In most places, nuclear construction costs would need to fall to USD 2 000/kW to USD 3 000/kW (in 2020 USD) to compete with other dispatchable sources, including hydropower, bioenergy and fossil fuel plants equipped with CCUS, though the potential of these alternative dispatchable sources may be limited in some regions. Depending on financing costs, this would yield a LCOE of nuclear power of USD 40/MWh to USD 80/MWh. Among these sources, the LCOE is a good measure of their competitiveness since their dispatchability and value to electricity systems are similar. While the use of fossil fuels with CCUS carries a greater risk of price volatility, falling dependence on fossil fuels across the global energy system would put downward pressure on prices in the long term.

The global potential for building more hydropower capacity, which has been a low-cost source of low emissions electricity for decades, is limited. The costs and eventual performance of hydroelectric plants depend heavily on project-specific factors. The LCOE for new projects is projected to dip to USD 40/MWh to USD 100/MWh by 2050 in the NZE, with new projects increasingly concentrated in a few regions with remaining potential and the best site conditions. Most high-quality resources developed long ago and many sites are unavailable due to environmental concerns and social impacts, with the expansion of hydropower with reservoirs limited mainly to China, Southeast Asia and Africa.

Bioenergy power plants are scalable and can be built at most sites, but are limited by relatively high costs. This is particularly the case where sustainable domestic supplies of biomass are limited and biomass pellets need to be imported, such as in Europe. As a result, the LCOE of these plants often exceeds USD 150/MWh by 2050 in the NZE. While the availability of low-cost fuel in the form of agricultural residues can greatly improve the economics of bioenergy power plants, such projects tend to be small in size and their overall contribution to electricity generation modest.

Levelised cost of electricity for selected dispatchable low emissions electricity generation sources



Notes: WACC = weighted average cost of capital. Ranges represent variations across major regions with at least 10 GW of deployment over 2020-2050 for each technology, reflecting regional construction costs, fuel prices, CO_2 prices and simulated operations in the Net Zero Emissions by 2050 Scenario.
Source: IEA (2021), World Energy Outlook 2021.

Natural gas-fired power plants equipped with CCUS have the potential to be among the cheapest dispatchable sources of low emissions electricity. An important factor is the cost of the carbon capture equipment, which has been in the development and demonstration phases for more than a decade. Full-scale commercial projects are needed urgently to drive down costs and reduce uncertainties for the technology. There are signs of progress, as policy support for the development of CCUS is expanding, for example in the United States and Canada, and the number of projects under development worldwide is increasing. A spillover benefit would be to make capture equipment available for industry in hard-to-abate applications, such as iron and steel production.

Another critical factor is the price of natural gas. Russia's invasion of Ukraine is set to maintain upward pressure on price levels for some time to come; if high prices persist, or if the carbon capture technologies were to progress only slowly, the cost of generation at gas-fired power plants with CCUS would be substantially higher, making nuclear power relatively more competitive. But if prices in some regions were to return to levels in the USD 2/mmBtu to USD 6/mmBtu range, then gas-fired power plants with CCUS could generate power at a cost of less than USD 70/MWh in 2030.

The competitiveness of coal-fired power plants equipped with CCUS versus nuclear power depends on whether those plants are new or retrofitted. New coal plants, like new nuclear ones, are relatively expensive to build but operate in most hours and provide a suite of system services. With technology improvements, the projected LCOE of new coal CCUS projects is in the range of USD 80/MWh to USD 110/MWh by 2040. Retrofitting existing plants with carbon capture equipment offers a way for some of the highest emitting power plants in the world to become low emissions sources. This could be significantly cheaper, especially for recent plants that were designed to be CCUS-ready, although CO_2 networks and storage need to be developed in parallel with individual facilities, which complicates the use of CCUS technology. An alternative is to permanently shut down existing coal plants and re-use the sites to host new nuclear projects, sized to fit the space and exploit the existing grid connection. This option has the potential to host a significant amount of new nuclear capacity, most likely in the form of small modular reactors.

Low-carbon hydrogen and ammonia, which can in principle be used as inputs to gas- and coal-fired power plants to provide dispatchable power, are essentially carriers of low emissions energy – not sources – and so are not primary competitors with nuclear power. Rather, they could complement nuclear power if they are used to produce those fuels as a way of storing electrical energy for subsequent use in meeting peak demand. Hydrogen and ammonia are not yet used on a significant scale in the power sector, and start to take off only after 2030 in the NZE. This is because the share of variable renewables reaches high levels and the seasonal variability of wind and solar PV creates new demand for flexible sources of electricity. As relatively expensive fuels (due mainly to the large energy losses in producing and using them), hydrogen and ammonia are best suited to meet peak demand needs and provide long-duration or seasonal storage. While large-scale nuclear power can also contribute to peak system needs, it is best suited to operate in baseload mode.

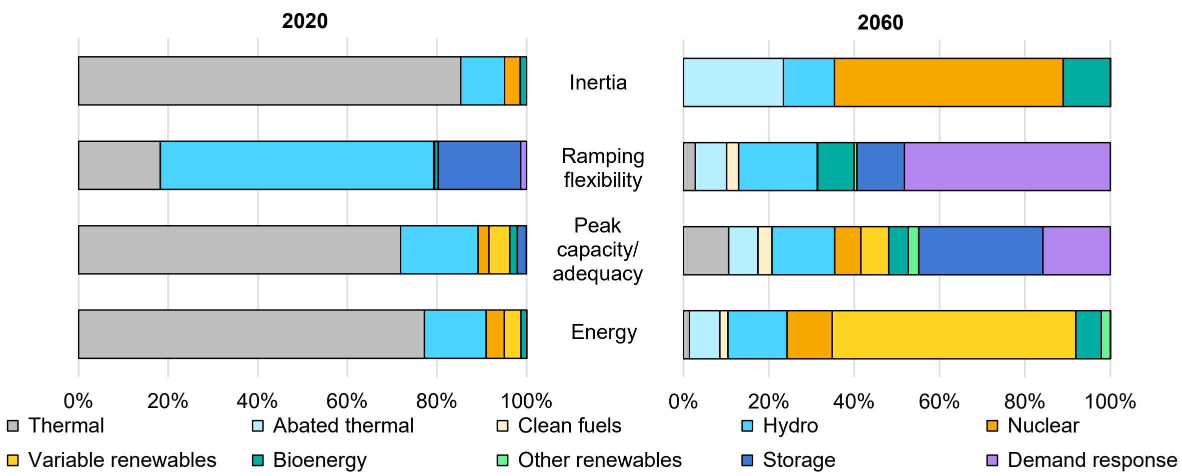
Electricity system services

Nuclear has important energy security attributes for the road to net zero

The transition to net zero emissions requires a radical change in the way various electricity system services are provided to ensure secure, flexible and stable system operation. These services include system stability, ramping and other forms of short-term flexibility, and capacity at times of peak demand, in addition to the supply of electricity itself. While variable renewables, mainly wind and solar PV, become the most cost-effective source of energy on an LCOE basis in many locations and, thus, generate most electricity in fully decarbonised systems in the NZE, other generating sources – including nuclear in some countries – are required for the secure operation of the system.

China provides an example of the role that nuclear power could play in ensuring electricity security in a decarbonised system. In September 2020, the Chinese government announced a pledge to have CO_2 emissions peak before 2030 and achieve carbon neutrality before 2060. The IEA released a report in September 2021, An Energy Sector Roadmap to Carbon Neutrality in China, presenting a scenario in which this goal is achieved, based on detailed modelling of the power and other sectors. In this scenario (which reaches net zero emissions later than in the NZE), variable renewables provide 58% of total electricity supply in 2060, up from about 4% in 2020. However, they contribute only around 8% of peak capacity. Storage, demand response, hydropower and plants with CCUS each contribute more. The share of nuclear in total generation in 2060, at around 10% in 2060, is much lower than that of variable renewables, yet nuclear contributes equally to meeting peak capacity needs. Nuclear also contributes much more to stability services, including inertia, which reaches 48% in 2060 compared with just 3% in 2020.

Contribution to electricity system services by resource in China



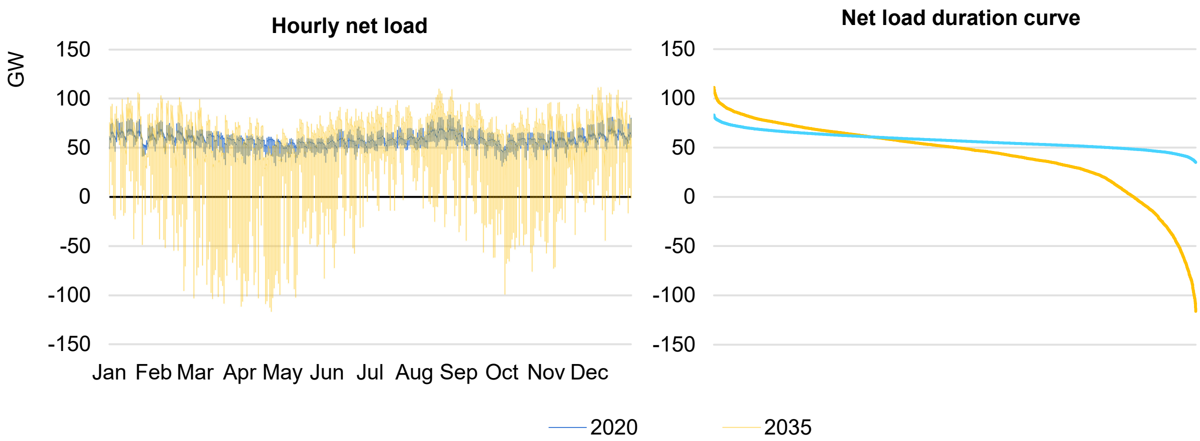
Note: Inertia is based on the contribution to inertia in the 100 lowest-inertia hours. Ramping is calculated from the contribution to the top 100 hourly ramps. Energy is total generation. These measures aim to illustrate the diverse aspects of electricity security, but do not encompass all relevant components or potential technology contributions.
Source: IEA (2021), *An Energy Sector Roadmap to Carbon Neutrality in China*

Transitions will change the optimal mix of generating resources

A major consequence of the increase in the shares of variable wind and solar energy in total power generation is an increase in the volatility in net load – total load minus wind and solar generation – over all timescales, from minutes to hours, days, weeks and seasons, as well as major changes in net load profiles. Wind and solar plants always generate when available given their extremely low operating costs. Net load represents the demand that must be met with dispatchable sources, including nuclear power, thermal plants, hydro, storage or imports from outside the system. That demand inevitably increases as more variable renewables are added to the system. Just how much in practice depends on local climatic and seasonal factors, as well as the mix of solar and wind. For example, in the summer, solar generation in some warm locations tends to coincide with electricity demand, as cooling needs peak during daylight hours, reducing net load, i.e. the generation needed from dispatchable plants. The reverse may be true in the winter, when demand may be highest in the evening after the sun has gone down.

Korea illustrates this phenomenon, which we recently highlighted in our report Reforming Korea's Electricity Market for Net Zero, by carrying out detailed power system modelling of a pathway to net zero energy-related CO_2 emissions by 2050. In that scenario, the share of variable renewables in total electricity rises from 4% in 2020 to 50% in 2035, increasing the range of hourly net load fourfold.[13] The net load duration curve – net load for each hourly period over the year ranked in descending order of magnitude – also shifts markedly. More dispatchable capacity is needed one-third of the time in 2035 compared with 2020, but none is needed about one-fifth of time.

Hourly net load and load duration curve in Korea



Note: Net load = total load minus wind and solar power generation.
Source: IEA (2021), Reforming Korea's Electricity Market for Net Zero.

As electricity systems experience increasingly pronounced hourly and sub-hourly ramps – real-time increases and decreases in electricity supply in response to

[13] Net load ranges from a minimum of -108 GW (when variable renewables output exceeds demand, resulting in potential curtailment, or disconnection from the grid) to a maximum of plus 115 GW, i.e. a range of 223 GW in 2035, compared to a range of 54 GW (32 GW to 86 GW).

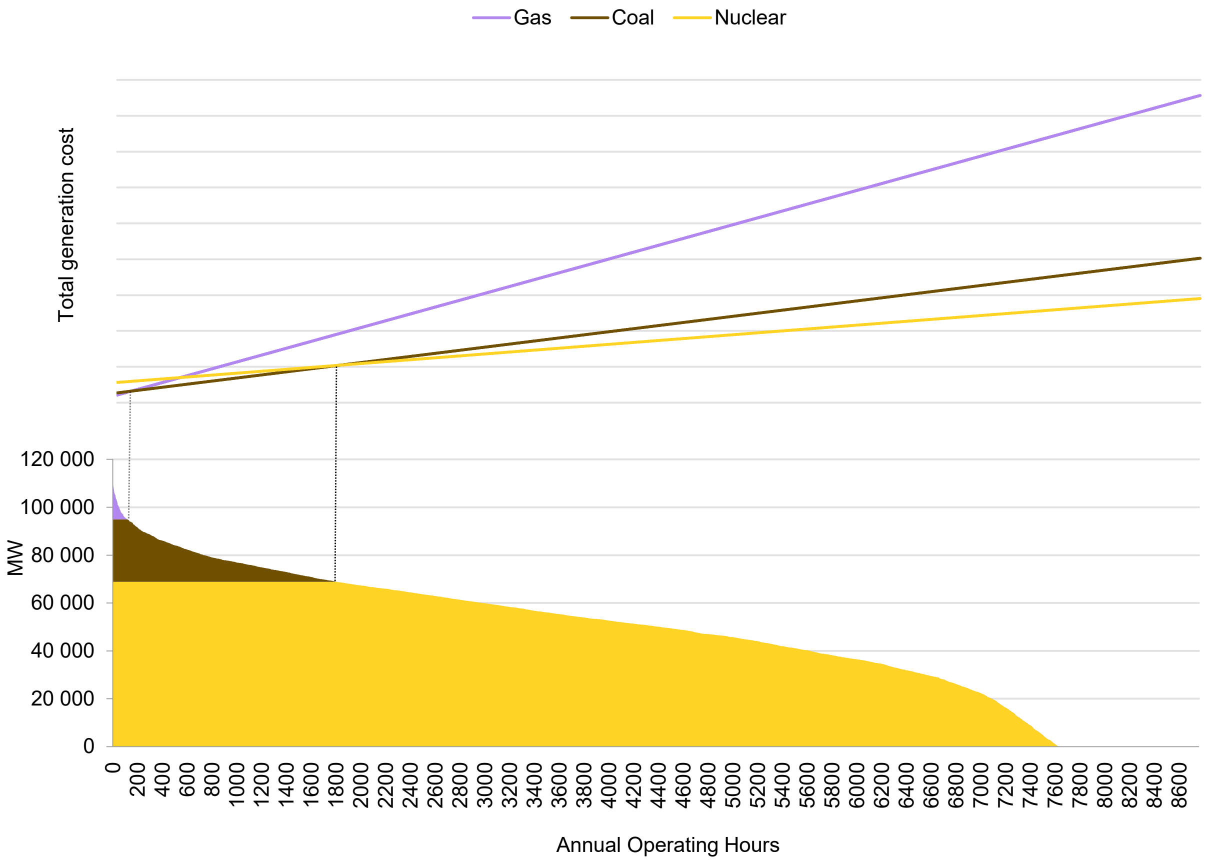
changes in load – and larger differences between minimum and maximum daily demand, the need for intraday flexibility on the supply and demand sides will grow. This flexibility can be provided by pumped storage and batteries, as well as demand response programmes, including smart vehicle charging, appliances and thermostats. The more frequent occurrence of periods during the day with very low or even zero prices, when load is met entirely by zero marginal cost renewables, will provide opportunities for energy-intensive industries that can adjust their production schedules flexibly to reduce their costs.

The optimal mix of dispatchable capacity to meet the shifting demand curve in any given system is determined by the relative cost of input fuels and the capital and operating costs of each type of plant, taking account of their capacity factors. As each generating option has a mix of fixed and variable costs, plants with high fixed costs but low operating costs operate most economically at higher capacity factors. Those with low fixed costs but high operating costs operate more economically during peak periods. In Korea, for example, net load at present is met by a mix of oil, natural gas, coal, hydro and nuclear power, in increasing order of utilisation. As the shares of wind and solar increase, the changing shape and level of the net load duration curve affect the way net load is met considerably, as the costs of low emissions dispatchable technologies fall relative to those of high-emissions sources like coal and gas.

A “screening curve” approach shows how these dispatchable generating resources complement each other in the Korean net zero scenario. The screening curve takes the total cost of a resource, including its annualised capital costs, operating and maintenance costs, and fuel costs, and finds the lowest cost solution at each capacity factor along the net load duration curve. The lowest-cost resource is then mapped onto the net load curve to determine both the amount of capacity needed and the expected total energy supplied by each resource. In the scenario, nuclear accounts for the bulk of dispatchable generation in 2035, while coal and gas are used as peaking resources.

In other systems with higher nuclear construction costs and lower coal and gas prices, the contribution of nuclear would be lower and that of coal and/or gas higher. In completely decarbonised electricity systems, peaking resources could include low-carbon fuels like electrolytic hydrogen and ammonia and the intermediate (mid-load) resource could be coal or gas plants with CCUS. The use of low carbon fuels as a potential peaking resource is explored in more detail in the IEA report, The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector.

Illustrative lowest cost dispatchable power generation mix to meet net load in Korea, 2035



Note: Net load = total load minus wind and solar power generation. The analysis assumes a 7% weighted average cost of capital.
Source: IEA (2021), Reforming Korea's Electricity Market for Net Zero. Design adapted from Baik et al (2021).

Dispatchable low emissions generation

Appropriate market design is critical to achieve a clean and secure power system transformation, at least cost

Market reforms need to value the benefits brought by nuclear power and other low-carbon and dispatchable generating options. The electricity supply industry has been liberalised or is in the process of being liberalised in most advanced economies and a growing number of emerging market and developing economies. A competitive wholesale electricity market is the central feature of a liberalised power system, aimed at sending economically efficient cost-reflective price signals while respecting physical system constraints. This requires coordinating the actions of each participant – generators that make available energy and other services to the system and wholesale buyers – in real time through bids, in which the last source of supply drawn upon in the merit order sets the price for everyone.

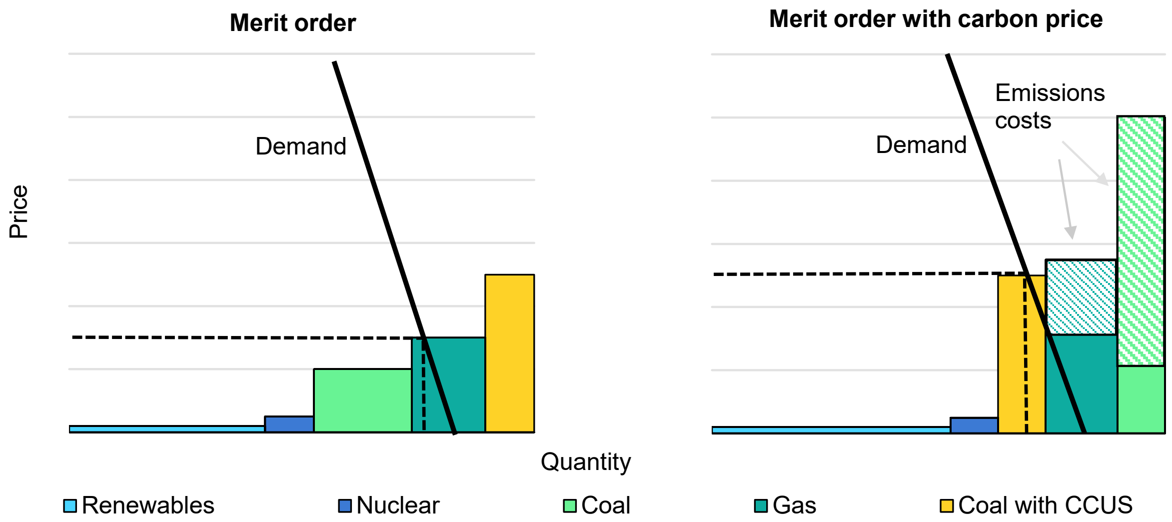
Marginal cost pricing, whereby the costliest action taken to balance the system sets the price, encourages efficient outcomes because the price reflects the aggregate supply and demand of all system actors. Each generator produces until the point at which its marginal cost is equal to the price received in the market, while customers consume electricity only when its cost is less than the value of their consumption. At the market price, no actor is enriched by changing their level of supply or demand. Dispatching power this way encourages efficient investment decisions, as the revenues earned in the wholesale market at times when market prices exceed variable operating costs allow generators to recover their investment costs and earn a rate of return.

Wholesale market prices, which can vary greatly by location and time, guide decisions by generators about operational behaviour, investment in new physical system assets and the retirements of existing assets. Expectations of spot market prices form the basis of financial instruments used to hedge price exposure or for speculation. Investment decisions need to take account of the relative merit of peaking or baseload generating capacity or storage technology (such as batteries), which is determined by the amount of price volatility in the system. For electricity retailers who buy from the wholesale market, these prices form the basis of the tariffs offered to their customers, which may include prices that vary according to time. It is, therefore, imperative that spot market prices accurately reflect both the cost of providing electricity services and the actual economic value of electricity taking account of environmental factors, including CO_2 emissions in generation.

Carbon pricing puts an explicit value on the low emissions benefits of nuclear power

In a competitive system, it is crucial that the cost of CO_2 emissions is reflected in the price of electricity generated from fossil fuels so as to favour generating options that incur little or no emissions, such as nuclear power. This encourages a more decarbonised energy system at the lowest cost. A carbon price is the principal mechanism for achieving this. Carbon pricing affects the merit order of generation, encouraging emissions-saving behaviour at any given time and location through fuel switching and the storage of renewables for later use. In principle, including a carbon price in the wholesale market price, either through an emissions trading system or carbon tax, is economically more efficient than other types of decarbonisation incentive because it targets emissions directly and does not discriminate between technologies, whether on the supply or demand side (energy efficiency and demand response), other than on the basis of CO_2 emissions.

Illustrative example of the shift in the merit order due to a carbon price



Source: IEA (2021), Korea Electricity Security Review.

Nuclear power is always behind both wind and solar PV in the merit order in wholesale markets, even with carbon pricing, as the latter has zero marginal costs. However, the introduction of carbon pricing or an increase in the CO_2 price has the effect of pushing up the cost of fossil-based generators, which raises the wholesale electricity price and increases the revenues received by nuclear plants without changing their costs. In the illustrative example, the change in the generating cost of fossil plants results in a change in the merit order and roughly doubles the marginal price. This helps to compensate for any decline in the demand for nuclear power caused by rising variable renewables capacity, which automatically pushes nuclear down the merit order.

Although carbon pricing has been introduced in the electricity and other sectors in many parts of the world, prices have often been too low to have a significant impact on investment decisions on new capacity. At present, some 45 countries and 34 subnational jurisdictions have some form of carbon pricing scheme, covering over 21% of greenhouse gas emissions. CO_2 emissions trading systems have been implemented in several electricity markets, including the European Union, a group of states in the northeastern United States and California, and China, where a national scheme was launched in 2021, immediately becoming the world's largest carbon market (by volume) covering over 4 Gt of CO_2 emissions. Until recently, carbon prices in most of these systems have been low, having only a modest impact on wholesale electricity prices. This has changed recently, with significant increases occurring in Europe, where prices surged to around EUR 100/t in early 2022, though they fell back sharply in the wake of the Russian invasion of Ukraine; permits had previously never consistently traded above EUR 30/t. Prices have also risen in the United States, though they have stagnated in China.

Carbon pricing mechanisms are implemented only in part across the United States. As a result of an expansion in variable renewables capacity and stagnating electricity demand, nuclear power plants have been coming under increasing financial pressure in some states. Since 2013, 12 nuclear plants have closed for financial reasons, and several others remain at risk of closure. Some states have adopted zero emission credits as a temporary measure to provide financial relief and support the continued operations of nuclear reactors. The credits work in a similar way to renewable obligations, which are used in some other states, providing an additional revenue source for low emissions technologies. More recently, as part of the Bipartisan Infrastructure Law of 2021, a USD 6 billion Civil Nuclear Credit Program was launched to help preserve the nuclear fleet. Under the programme, owners or operators of commercial reactors can apply for certification and competitively bid for credits to support their continued operation.

Remuneration for capacity and ancillary services

Wholesale market prices, even with high scarcity and carbon prices, may not induce adequate investment in dispatchable assets if price signals are volatile or projects are subject to other risks that are difficult to hedge, like policy risk. This may be the case for long-lived asset like nuclear power plants with large investment costs and low operating costs.

The provision of electricity system services other than the supply of energy, including capacity availability and ancillary services (a variety of operations required to maintain grid stability and security), can be incorporated into wholesale markets. This is already the case in several countries. The costs of these system services, harmonised with the energy market, need to be embedded in the marginal cost of electricity for the system to operate efficiently in a competitive market. This ensures that the prices paid for the services increase during periods of system stress, such as when shortages of reserve capacity emerge, so as to reward actions taken by market participants to relieve stress.

Capacity mechanisms, which remunerate generators for making capacity available at existing and future plant, have been adopted in several markets as a way of attracting investment in new capacity or keeping existing plants from retiring prematurely. Capacity mechanisms are common in US markets and have been introduced in some European countries, including France and the United Kingdom.

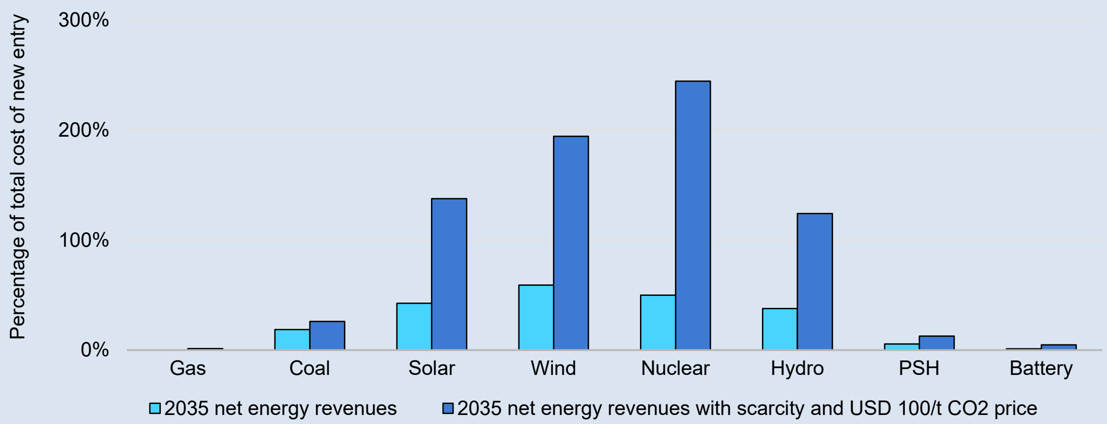
Nuclear power can benefit from these mechanisms by guaranteeing a portion of their revenues on an annual or longer basis. This can lower the cost of capital and help to make plants more financeable. But capacity mechanisms need to be designed so that they reward actual contributions to system security instead of just year-round availability. There are concerns that poorly designed mechanisms can lead to overinvestment and excessive costs and prices, especially if wholesale markets do not function well.

Adequately remunerating the provision of ancillary services can also be a means of boosting revenues to the operators of nuclear reactors, thereby increasing their profitability and the attractiveness of investing in them in the first place. Flexible nuclear power plants can typically increase or reduce power by 10% within a few minutes to control the flow of alternating current power from multiple generators through the network (frequency control) and by up to 80% within a few hours to meet load variation.

The effects of carbon pricing and capacity remuneration: a case study

Carbon pricing and capacity remuneration, either through scarcity pricing or a capacity market, can boost significantly the competitiveness of nuclear and other low emissions generating options *vis-à-vis* fossil fuel based generation. This would lower the need for out-of-market incentives, such as tax credits or feed-in tariffs, to build and operate low-carbon generation sources. In order to illustrate this, we have taken the results from the hourly model of China's electricity market based on its 2060 carbon neutrality target, in the year 2035, and tested how a CO_2 price affects the profitability of different generation types. In the absence of a CO_2 price, none of the main generation types would earn enough revenue through the energy market to support new investment. Introducing scarcity pricing and assuming a USD 100/t CO_2 price increases substantially the profitability of all low emissions generating types, making the operation and construction of new capacity more financially attractive.

Impact of CO_2 price and capacity scarcity pricing on profitability of electricity generation in China by type, 2035

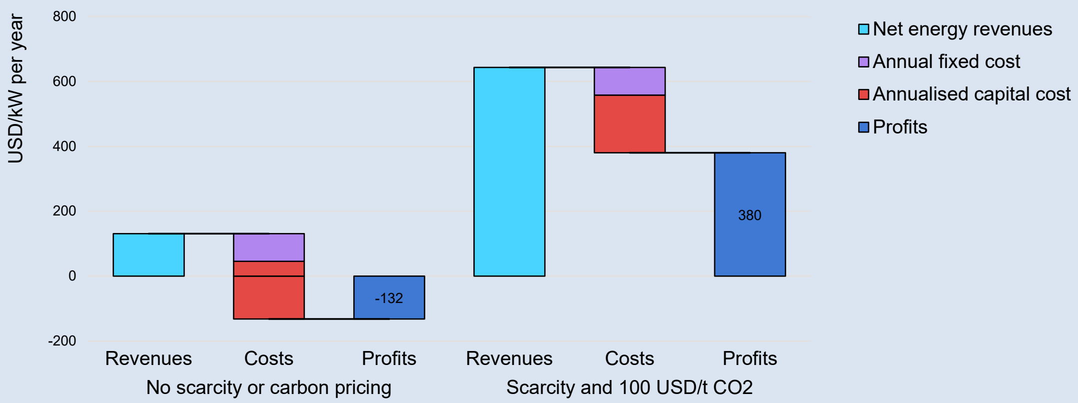


Notes: PSH = pumped storage hydropower. The comparison is between net energy revenues on the one hand and fixed operation and maintenance and annualised capital costs on the other. The weighted average cost of capital is assumed to be 7%. The analysis is based on the system reference marginal cost and scarcity pricing, with an assumed CO_2 price of USD 100/t.

Source: IEA (2021), An Energy Sector Roadmap to Carbon Neutrality in China.

Average annual revenue for nuclear power in this case study increases from USD 130/kW to USD 640/kW when scarcity pricing and a USD 100/t CO_2 price are added. This compares with an annualised cost of new capacity of USD 260/kW, of which fixed operation and maintenance make up USD 90/kW. Without scarcity pricing or a CO_2 price, revenues are high enough to cover the operating costs of existing reactors, but not to make new plants profitable.

Impact of CO2 price and capacity scarcity pricing on profitability of nuclear power plants in China, 2035



Notes: The weighted average cost of capital is assumed to be 7%, the construction cost USD 2 500/kW, construction time 7 years and technical lifetime 60 years. The analysis is based on the system reference marginal cost and scarcity pricing, with an assumed CO_2 price of USD 100/t.

Source: IEA (2021), An Energy Sector Roadmap to Carbon Neutrality in China.

Electrolytic hydrogen and heat production

This section looks at two new ways in which nuclear power *could* be used, beyond simply supplying electricity to the grid: the on-site production of low-carbon hydrogen and the large-scale supply of low emissions heat to industrial consumers and district heating networks. These applications are not deployed in the NZE on economic grounds: renewables, such as bioenergy, solar thermal or geothermal, and other low emissions energy sources may to be able to meet needs more cheaply. However, faster than expected reductions in the cost of nuclear power could in principle enable it to compete on cost, opening up new opportunities in these markets.

Today, hydrogen is an important feedstock in the chemical industry and in refineries. In the NZE, the global use of hydrogen and hydrogen-based fuels expands rapidly to reduce emissions in hard-to-abate sectors that are difficult to electrify, such as heavy industry and long-distance transport. Blending hydrogen into natural gas grids plays an increasingly important role as a means of reducing emissions in end-use sectors. It is also blended, in the form of ammonia, with coal and used in the electricity sector, though on a relatively small scale given its high cost. Global hydrogen consumption grows from roughly 90 Mt/year today to 212 Mt/year in 2030 and 390 Mt/year by 2040. The share of hydrogen that is low-carbon, i.e., produced without unabated fossil fuels, rises from 10% to 70% in 2030 and over 90% in 2040. More than half of it is produced by electrolysis, with the remainder from coal or gas with CCUS.

Nuclear-powered electrolysis could provide a source of low emissions hydrogen

Many electrolytic hydrogen projects currently under development are linked to variable renewables, either physically or through power purchase agreements. Locating an electrolyser close to the point of generation can reduce the cost of electricity through lower generation and transmission costs, as well as making it easier to verify that the hydrogen is certifiably low emissions (hydrogen produced from electricity taken from the grid is only as "low emissions" as the electricity itself). This trend accelerates in the NZE, with more than 75% of installed electrolyser capacity being linked to at least one renewable energy source by 2040.

Consideration is being given to the idea of devoting all or most of the output of a nuclear power plant to the electrolytic production of hydrogen as an alternative to renewables-based production. The key advantage of nuclear power plants is that they are dispatchable and able to operate at very high annual capacity factors, enabling a high utilisation of the electrolyser and the production of steady and adjustable streams of low-carbon hydrogen. This means that less hydrogen storage is required to smooth out daily, monthly and seasonal fluctuations in the supply of hydrogen. A stable, reliable flow of hydrogen is important to industrial users in particular for making optimal use of their production facilities.

There are currently around a dozen demonstration electrolyser projects in development with a combined capacity of 250 MW that are exploring the use of nuclear power in Canada, China, Russia, Sweden, the United Kingdom and the United States. Some commercial projects are also advancing. For example, in early 2021, the operator of the Oskarshamn-3 boiling water reactor in Sweden entered into an agreement with Linde, a chemicals company, to supply hydrogen from one of its on-site electrolysers powered directly by the plant.

Alternative technologies to produce hydrogen from nuclear energy

Most of the electrolysers in production or under construction today use conventional polymer electrolyte membrane or alkaline technologies. New electrolyser technologies that could better exploit the characteristics of nuclear power are under development. One promising technology, which could be compatible with current and advanced nuclear reactor designs, is high-temperature electrolysis based on solid electrolysis cells, which use ceramics as the electrolyte and steam for electrolysis. This technology promises electrical efficiencies of 79-84% (lower heat value), compared with 67-80% for conventional low-temperature electrolysis. Nuclear power plants could provide both the steam and the electricity necessary to drive the process.

Because of their higher efficiency, solid electrolysis cells may be a cheaper way of making hydrogen using nuclear electricity. Depending on the levelised cost of electricity of the power plant, an increase in electrolyser efficiency from 70 to 80%, for example, would reduce the levelised cost of hydrogen by USD 0.2/kg to USD 0.6/kg (in 2020 USD). However, the technology is still at the demonstration phase for large-scale applications. The biggest system in operation is smaller than 1 MW, although larger projects are currently being developed, putting the technology on the path towards commercialisation.

Advanced nuclear reactors with coolant outlet temperatures of 800 °C to 1 000 °C could become an option for the thermochemical production of hydrogen. Thermochemical cycles, such as sulphur-iodine, use high-temperature heat (greater than 950 °C) to drive a series of chemical reactions that split water into hydrogen and oxygen. The chemicals can be reused in a closed loop and water and thermal energy are the only other inputs required. Since the reactor's thermal energy is used directly, the efficiency losses associated with first converting thermal energy into electricity and then into hydrogen are avoided.

While a thermochemical cycle operating at 950 °C can reach a thermal efficiency of over 40%, the thermal efficiency of a reactor with a steam turbine turning a generator, which then supplies an electrolyser with electricity, is only around 20-30%. Using a very high-temperature reactor to drive thermochemical hydrogen production could, therefore, result in lower hydrogen production costs than if the same reactor were used to power an electrolyser. However, both very high-temperature reactors and thermochemical hydrogen production are still in an early stage of development and are unlikely to be commercially available at scale before 2030.

High temperature gas-cooled reactors could be suitable for hydrogen production. A demonstration project was connected to the grid in China in December 2021. At 750 °C, its coolant outlet temperature is high enough to support high-temperature steam electrolysis. Research is underway to boost temperatures to over 950 °C, which would allow high temperature gas-cooled reactors to be used for thermochemical hydrogen production as well. In September 2021, Tsinghua University, China National

Nuclear Corporation Limited, China Huaneng Group Limited, China Baowu Iron and Steel Group Limited and China Citic Group Limited established a technology alliance to develop and scale up HTGR-based hydrogen production, focusing on applications in the steel and chemicals sectors. In Japan, the High Temperature Engineering Test Reactor, which was shut down for safety checks following the accident at Fukushima Daiichi, resumed operations in 2021. A thermochemical hydrogen production cycle using this reactor is currently under development, with demonstration production scheduled to begin in the late 2020s.

Sources: POWER (2022), China Starts Up First Fourth-Generation Nuclear Reactor; Sato, H. (2021), Role of High Temperature Gas-cooled Reactor Technologies to Attain Carbon Neutrality, IAEA Technical Meeting on the Role of Nuclear Cogeneration Applications Towards Climate Change Mitigation, October 11-13.

The competitiveness of nuclear-based hydrogen production would require a big reduction in costs

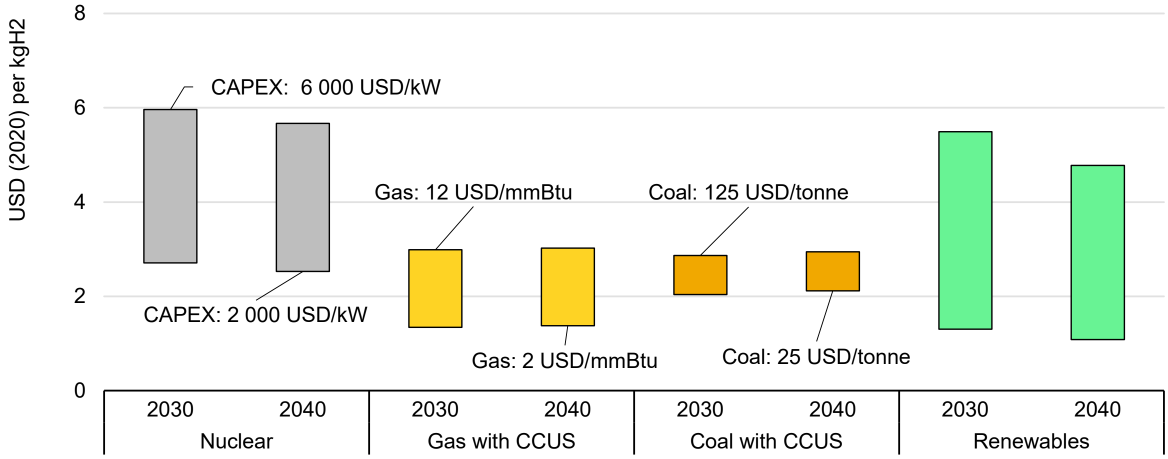
Substantial capital cost reductions relative to both renewables and fossil fuels with CCUS would be necessary for nuclear power to become a cost-competitive option for large-scale hydrogen production. The cost of producing hydrogen through electrolysis powered by a new dedicated nuclear power plant is determined mainly by the upfront cost of building the reactor, which is currently very high. The rapid rollout of renewables and electrolysers in the NZE leads to a marked decline in the capital cost of both up to 2030. This substantially reduces the levelised cost of producing hydrogen from electrolysis powered by renewable electricity, especially in regions with large renewable energy potential such as the United States, parts of western Europe, China, India, and the Middle East. In those regions, costs are projected to fall to as little as USD 1.10/kg of hydrogen (kgH_2) in 2020 USD by 2040.

In some regions, producing low-carbon hydrogen with fossil fuels – primarily natural gas and coal – in conjunction with CCUS is projected to become a viable alternative to renewables on the assumption that fossil fuel prices fall back from their current record levels. The cost of that production route is determined mostly by the price of the input fuel. At a natural gas price of USD 12/mmBtu (compared with USD 50/mmBtu at the TTF hub in the Netherlands in the first half of March 2022), the levelised cost of hydrogen produced by steam reforming natural gas with CCUS would be around USD 3/kgH2 in 2030 and 2040. Similarly, with a coal price[14] of USD 125/t (compared with over USD 360/t at the Antwerp-Rotterdam-Amsterdam hub in the first half of March 2022), the cost of producing hydrogen from coal gasification with CCUS would be around USD 2.90/kgH_2 in 2030 and 2040. In the NZE (as modelled in 2021, prior to the current energy crisis) gas prices fall back into the USD 2-6/mmBtu range in many markets, while coal prices fall to around USD 22/tonne in the United States, USD 44/t in Europe and USD 60/t in East Asia. At these fuel prices, the levelised costs of producing hydrogen are much lower, averaging USD 1.30/kgH_2-1.80/kgH_2 for gas with CCUS and USD 2.00/kgH_2-2.40/kgH_2 for coal with CCUS.

[14] Reflecting mine mouth prices plus transport and handling costs.

As things stand, new nuclear power plants as a power source for electrolysers appear unlikely to be competitive with renewables or fossil fuels with CCUS to produce hydrogen in many parts of the world. Compared with fossil fuels with CCUS, nuclear-powered electrolysis would be a competitive option only if investment costs for nuclear power plants could be reduced to below USD 2 000/kW (costs currently range from USD 2 800/kW to nearly USD 13 000/kW) and gas and coal prices were to remain above USD 9/mmBtu and USD 70/t respectively. Such a development cannot be excluded. However, to be competitive with renewable electricity in countries with a strong renewable resource, nuclear investment costs would need to fall even further, to around USD 1 000/kW in order to produce hydrogen at a cost of about USD 2/kgH_2 in 2030. In short, dedicated nuclear-based hydrogen could become a viable option only in regions with more limited renewables potential and higher costs, or if coal and gas prices remain high by historical standards.

Levelised cost of hydrogen production by energy source/technology



Notes: Levelised cost is the average net present value of the cost of producing hydrogen using renewable electricity for a plant over its operating lifetime. The cost of hydrogen production from nuclear power is for a nuclear power plant operating at an average 85% annual utilisation, with overnight investment cost (CAPEX) ranging from USD 1 000/kW to USD 6 000/kW, assuming a weighted average cost of capital of 7%, a construction time of 6 years and a depreciation period of 35 years. For the electrolyser, investment costs of USD 463/kW and an efficiency of 69% are assumed for 2030, and USD 386/kW and 72% for 2040. The depreciation period of the electrolyser is 25 years, with a lifetime of the stack (where the splitting of water into hydrogen and oxygen takes place) of 50 000 hours. The cost range for gas with CCUS is for the steam reforming of natural gas with prices between USD 2/mmBtu and USD 12/mmBtu. The cost range for coal with CCUS is for coal gasification with coal prices between USD 25/t and USD 125/t.

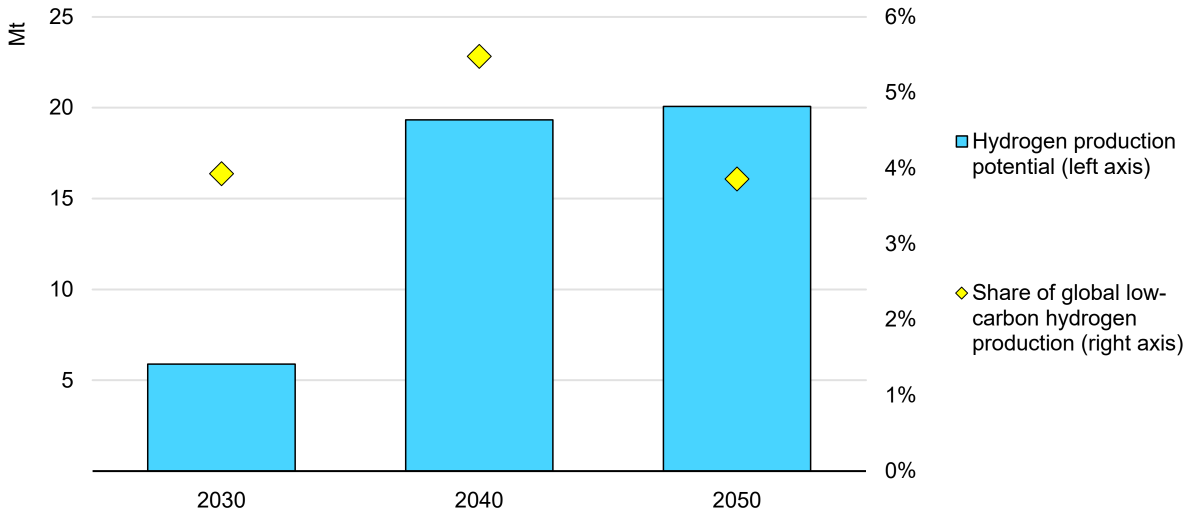
It should be emphasised that this analysis only considers production costs. It does not take into account other potential benefits that the use of nuclear power for hydrogen production may offer, such as its dispatchability and ability to produce in a constant manner, nor the drawbacks. With nuclear, large volumes of hydrogen could potentially be produced closer to where it is consumed, reducing the need for hydrogen transport and distribution infrastructure and, thus, delivery costs. Transporting hydrogen over a distance of 1 000 km by pipeline would add USD 0.40/kgH_2 to 1.80/kgH_2 to the total cost of supply, depending on the line's capacity and throughput. Maritime shipping would cost even more, at USD 1.20/kgH_2 to 1.80/kgH_2 for the same distance. Lower costs might be possible if the existing natural gas pipeline infrastructure can be converted, but this option is not available everywhere. Furthermore, compared with low-carbon hydrogen based on fossil fuels with CCUS, nuclear brings energy security benefits as it is far less vulnerable to volatile input fuel prices.

Hydrogen production could exploit surplus nuclear power

Using electrolysis to take advantage of curtailed nuclear generation and low wholesale prices during periods of low electricity demand could be a more viable option. This could raise the capacity factors of these plants and provide an additional revenue stream to their operators. In the NZE, the fast-growing shares of variable solar PV and wind in the global electricity mix, as well as the progressive electrification of energy end uses such as heating and road transport, erodes the capacity factors of baseload power generating plants, including nuclear plants, as renewables increasingly drive nuclear power down the merit order. They also increase the need for system flexibility.

Flexible hydrogen production could provide a means of exploiting underutilised capacity. In the NZE, the average capacity factor of the global fleet of nuclear power plants falls from 84% in 2030 to 76% in 2040 and 77% in 2050, while total installed capacity increases from 512 GW in 2030 to 730 GW in 2040 and 812 GW in 2050. Raising the capacity factor of the global nuclear fleet to 90% and using the additional electricity for electrolysis would theoretically allow for the production of additional low-carbon hydrogen, reaching 6 Mt (4% of total low-carbon hydrogen production) in 2030, 19 Mt (5.5%) in 2040 and 20 Mt (3.9%) in 2050. More hydrogen could be produced using the global fleet of nuclear reactors, but this would mean reducing low emissions electricity output.

Global technical hydrogen production potential from nuclear electricity generation with an increased capacity factor in the Net Zero Emissions by 2050 Scenario



Note: Hydrogen production potential assumes an increase in the capacity factor to 90% from 84% in 2030, 76% in 2040 and 77% in 2050 as projected in the Net Zero Emissions by 2050 Scenario, with all the additional output used to produce hydrogen using electrolysers.

The technical potential for producing hydrogen using nuclear power that would otherwise be curtailed is greatest for systems with high shares of nuclear in total capacity and where nuclear plants are regularly used to load-follow, such as in France. A recent study suggests that close to 70% of Europe's additional spare nuclear generation potential by 2030 would be in France alone.

The economic potential of this mode of hydrogen production is system- and market-specific: it depends on the operating profile of the nuclear power plant, the capacity factor of the electrolyser and electricity prices across the year. Where there are grid constraints, diverting electricity to a flexible on-site electrolyser could increase the flexibility of electricity systems. The optimal size of the electrolyser at each plant would be determined by the competing objectives of maximising the annual utilisation of the electrolyser and taking advantage of cheap electricity during low-price periods, as well as the operational flexibility of the power plant.

Conditions on the hydrogen side, including proximity to markets or hydrogen transport infrastructure, flexibility requirements and the cost of producing hydrogen from competing options, would also be important factors in determining the economic viability of nuclear-based hydrogen production.

Nuclear-based heat production is another possibility

Supplying heat produced in conjunction with electricity by nuclear reactors to large industrial customers (process heat) or district heating networks is another possibility. Today, the production of industrial process heat accounts for roughly two-thirds of total industrial final energy demand, slightly less than half of which is for high-temperature heat (above 400 ºC). In the NZE, demand for commercial, low emissions heat, mostly in district heating networks, grows sharply over 2021-2040, by about 400 PJ per year on average, because of the need to replace unabated fossil fuels. This requires investments averaging about USD 20 billion/year (in 2020 USD) in the 2020s and over USD 30 billion/year in the 2030s. After 2040, growth in demand for new low emissions heat is minimal as most heat is already decarbonised by then.

Although improvements in energy efficiency reduce overall heat demand in the NZE, the push to decarbonise it could present an opportunity for nuclear power plants if they can be cost-competitive. Current reactor designs are well-suited to supply large amounts of low- to medium-temperature heat to industrial consumers and district heating networks. Typically, only around one-third of the thermal energy produced by a reactor is converted into electricity, while the remainder is ejected into the environment. In a nuclear-based co-generation plant, some of that excess thermal energy is converted into useful heat through heat exchangers.

Nuclear co-generation has historically mostly been used in Europe and countries of the former Soviet Union. In Switzerland, for example, heat extracted from the Benznau and Gösgen nuclear power plants is fed into heat networks supplying factories and buildings in surrounding towns. In Russia, several nuclear power plants supply heat to municipal heating networks. More recently, nuclear co-generation has attracted significant interest in China, where many northern cities maintain extensive district heating networks based mostly on coal. The country's first large-scale nuclear co-generation project, in Haiyang in Eastern Shandong province, started up in late 2020, supplying heat extracted from two newly commissioned AP 1000 reactors to the local heat network. It provides heat to a total floor area of 4.5 million m^2, avoiding the consumption of 180 000 tonnes of coal during the winter heating period.

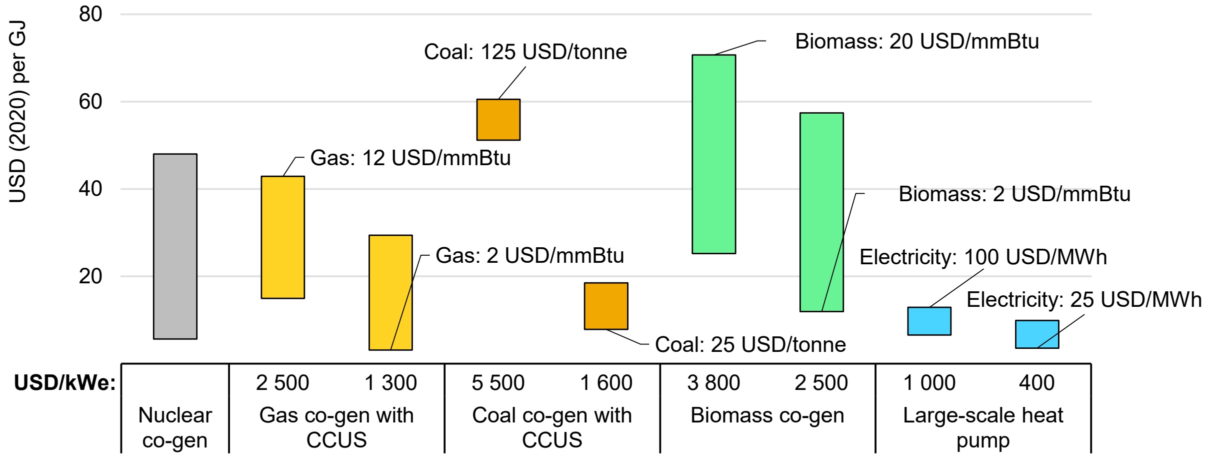
For nuclear to supply high-temperature industrial heat, advanced high-temperature reactors, such as the Chinese high temperature gas reactor, would be required. Today, high-temperature heat (above 400 ºC) is provided mostly from the combustion of fossil fuels, making it emissions-intensive. Producing high-temperature heat directly from electricity is likely to remain impractical and costly in most cases. Low emissions alternatives include coal or gas combustion with CCUS, biomass or hydrogen combustion. Some SMRs being developed now operate at much higher temperature levels than conventional large-scale reactors, allowing them to be integrated with and supply electricity and heat (and potentially low-carbon hydrogen) to industrial facilities such as chemicals, iron and steel, metals manufacturing or non-metallic minerals industries (see below).

As with electricity and hydrogen, competitive nuclear-generated heat would require a large reduction in costs

For nuclear-based co-generation to be competitive with fossil fuels in conjunction with CCUS, biomass or electric heat pumps for industrial applications and district heating, plant investment costs would generally need to be below about USD 3 000/kWe. The cost of heat produced using those alternatives is determined mainly by plant construction costs and fuel input prices. For low- to medium-temperature heat applications such as district heating, heat produced by a natural gas co-generation plant equipped with CCUS would cost more than USD 40/GJ (in 2020 USD) based on a construction cost of USD 2 500/kWe and a natural gas price of USD 12/mmBtu. Similarly, heat from a coal-fired co-generation plant with CCUS would cost up to USD 60/GJ assuming a construction cost of USD 5 500/kWe and a coal price of USD 125/tonne.

Were natural gas and coal prices to return to the long-term trajectory projected in the NZE, the cost of heat supplied by fossil fuel-based co-generation with CCUS would be much lower, ranging from less than USD 15/GJ to USD 50/GJ, with the lower end of the range representing regions with low fossil-fuel prices and plant construction costs. Biomass co-generation plants could produce heat for as little as USD 12/GJ to USD 25/GJ if cheap feedstocks, such as agricultural residue, are available locally. Large-scale heat pumps could produce heat for as little as USD 10/GJ even at comparably high average electricity prices.

Levelised cost of heat supplied to district heating networks by source

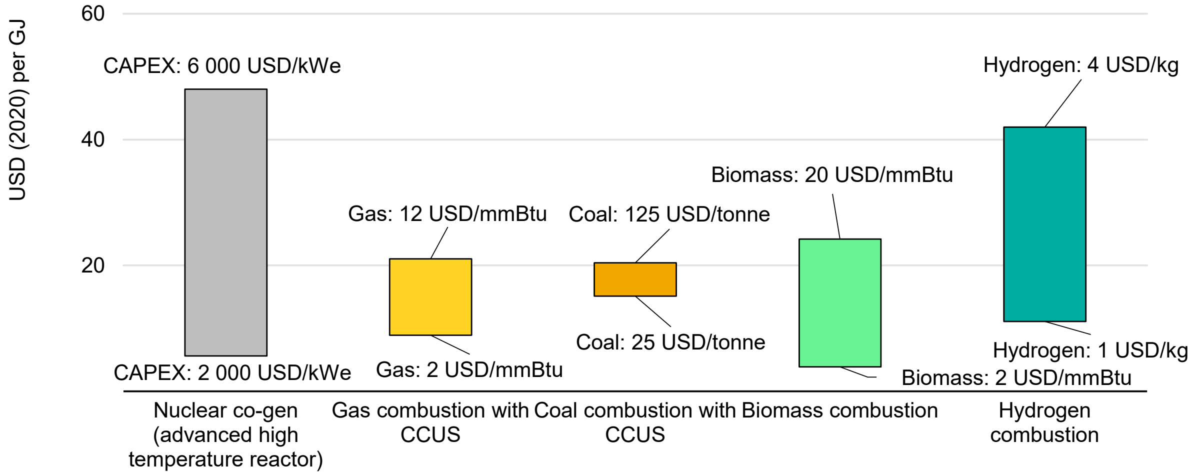


Notes: Co-gen = co-generation. The levelised cost is the average net present value of the cost of producing heat for a plant over its operating lifetime. The cost of heat production from nuclear co-generation is for units with an overnight investment cost ranging from USD 2 000/kW$_e$ to USD 6 000/kW$_e$ with a thermal efficiency of 75%, a construction time of 6 years and a depreciation period of 35 years. All co-generation plants are assumed to have a heat-to-power ratio of 1 and an annual utilisation of 75%. An average selling price of USD 70/MWh (in 2020 USD) for the electricity produced is credited against the cost of heat. A uniform weighted average cost of capital of 7% is applied to all investments. The cost range for natural gas co-generation with CCUS corresponds to gas prices of USD 2/mmBtu to USD 12/mmBtu, that for coal co-generation with CCUS to coal prices of USD 25/t to USD 125/t and that for biomass co-generation to feedstock costs of USD 2/mmBtu to USD 20/mmBtu. The assumed CCUS capture rate is 95%. A CO_2 price of USD 160/t is assumed to be levied on uncaptured emissions. The large-scale heat pump has a coefficient of performance of 3.5, and heat production costs correspond to electricity input prices of USD 20/MWh to USD 100/MWh.

As with electricity, the cost of heat produced by nuclear co-generation plants is mainly a function of the upfront investment cost of the plant. At a cost of USD 4 000/kWe, which is close to the projected global average in the NZE, low- to medium-temperature heat production costs would be around USD 25/GJ, which is above that for fossil fuels with CCUS in most regions and well above that using large-scale heat pumps. To compete with low-cost fossil fuels with CCUS and heat pumps, nuclear construction costs would have to be less than USD 3 000/kWe in most cases. Planning and construction times would also need to be reasonably short in order to limit the risk of major cost overruns. Public acceptance could be a major concern, since co-generation plants need to be sited close to population centres to minimise the losses and associated costs of transmitting heat over long distances.

For high-temperature reactors to compete with the main alternatives for the provision of high-temperature heat, heat production costs would need to fall to USD 5/GJ to USD 20/GJ, again implying that plant investment cost would need to be no higher than USD 3000/kWe. Depending on the prices of coal and natural gas, coal or gas combustion with CCUS produces heat at a cost of USD 9/GJ to USD 20/GJ, with the fossil fuel prices projected in the NZE yielding costs at the lower end of that range. Biomass combustion could be even cheaper if feedstock costs are very low, but sustainable, low-cost biomass potentials are too small for it to make a significant contribution to the global high-temperature heat supply. If low-carbon hydrogen at a cost of USD 1/kg to USD 2/kg is available, hydrogen combustion would be an economically competitive option too.

Levelised cost of high temperature heat production by source



Notes: The levelised cost is the average net present value of the cost of producing heat for a plant over its operating lifetime. The cost of heat production from nuclear co-generation is for units with an overnight investment cost (CAPEX) ranging from USD 2 000/kW$_e$ to USD 6 000/kW$_e$, a construction time of 6 years, a depreciation period of 35 years and an annual utilisation of 75%. An average selling price of USD 70/MWh (in 2020 USD) for the electricity produced is credited against the cost of heat. A uniform weighted average cost of capital of 7% is assumed for all investments. The cost range for natural gas combustion with CCUS corresponds to gas prices of USD 2/mmBtu to USD 12/mmBtu, that for coal combustion with CCUS to coal prices of USD 25/t to USD 125/t and that for biomass combustion to feedstock costs of USD 2/mmBtu to USD 20/mmBtu. The CCUS cost is assumed to be USD 70/t and the CO_2 capture rate 95%. A CO_2 price of USD 160/t is assumed to be levied on uncaptured emissions.

4. Small modular reactors

How could SMRs help energy transitions?

Our discussion in previous chapters has focused on the general opportunities and challenges facing nuclear energy in energy transitions. A doubling of nuclear power capacity by mid-century, as envisaged in the NZE, is clearly an enormous task, requiring capital spending on nuclear power of USD 2.6 trillion over 2021-50 is needed in that scenario. Much of that capital would need to be backed by governments given the investment risks associated with nuclear power projects.

Advanced reactors that are smaller in size, more affordable, easier to build and operate, and therefore easier to manage and finance are an alternative or a complement to large-scale reactors. A category of reactors, known as small modular reactors (SMRs), hold particular promise. This chapter maps out the nature of this promise, the state-of-play with SMR technology and investment, and considers some of the key uncertainties that lie ahead.

SMRs are generally defined as nuclear reactors with an electrical capacity of less than 300 MW per module, though some models under development could be larger. They include micro-modular reactors which have a capacity of less than 10 MW. The variety of designs now in development around the world, of which there are approximately 70, include different underlying technologies, including water, gas, liquid metal or molten salt cooled reactors, as well as different fuel cycles. They vary markedly according to their levels of technology and licensing readiness. None are as yet at the stage of full commercialisation.

As SMRs are smaller than existing reactor designs, the investment needs are smaller in absolute terms. They are usually designed to be factory built in modules and then transported to the site where they are to be installed. This reduces project management risk during construction, one of the most significant challenges in financing large nuclear projects. However, some designs require transport of fully fuelled cores, and the associated transport routes, security and safeguards aspects, should not be underestimated. Several SMR designs have inherent safety and waste management attributes that could support social acceptance and unlock significant private venture capital for research and development, as well as demonstration and deployment.

SMRs are designed to be deployed in series, using a global supply chain to reduce costs, as is the case for other sectors such as naval construction or aircraft manufacturing. They could be installed as single modules distributed over the whole electricity network, which could be of particular value in countries or regions with less developed networks, in remote areas or as dedicated sources of electricity, heat and/or hydrogen for cities and industrial hubs. They could also be deployed in groups of modules on single sites. SMRs may also be well-suited to replacing fossil fuel power plants, taking advantage of an existing connection to the transmission network, the availability of water for cooling and a skilled workforce.

SMRs have several technological and financial attributes that could underpin their future viability

SMRs have important attributes that could equip them well for a role in energy transitions. One of the most important is their intrinsic safety features. Lower power output and smaller reactor cores should increase the effectiveness of passive safety systems. Many SMRs include inherent safety features that all but eliminate the possibility of serious accidents. A greater reliance on passive cooling systems also enables simpler reactor designs, which should lower costs. The benefits of passive safety systems may also lead to smaller offsite emergency planning zones, which would make it easier to site plants close to population or industrial centres.

SMRs also offer a number of other technical benefits. If used to supply electricity to the grid, for example when replacing coal power plants, they would reduce the need for reinforcements to the transmission network, boosting their economic viability. This factor is set to become increasingly important as more distributed power generation grows with the increased penetration of solar PV and wind power. As with large reactors, SMRs can have different applications beyond electricity, including the production of heat and hydrogen, and the desalination of water. Due to their smaller size, SMRs may be particularly attractive for countries with smaller and less robust electricity grids, although it remains essential to have robust regulatory bodies and waste management in place. Construction times are expected to be much faster, thanks to factory fabrication and use of modular construction techniques.

Several advanced SMR designs under development also involve innovative strategies for recycling spent nuclear fuel. These strategies aim to reduce the volume and radiotoxicity of high-level waste that eventually have to be managed in deep geological repositories and the need for uranium mining for the front end of the nuclear fuel cycle. These designs could enhance nuclear energy’s contribution to long-term sustainability objectives.

SMRs could also be used to meet the need for flexibility in power generation demanded by electricity systems with high shares of wind and solar. SMRs may be well suited for flexible operation, as is already the case for some traditionally large-scale reactors, which in high renewable scenarios could improve profitability as captured electricity prices increases. In addition, flexibility could be achieved not only through load-following of electricity production, but also with flexible co-generation, for instance via hydrogen production or thermal storage.

The smaller size, shorter project lead-times and siting attributes of SMRs may make them an attractive option for private investors. The total size of the investment would be more affordable, though not necessarily cheaper on a per MW basis. Together with the lower project risks associated with shorter construction periods and factory construction, this could encourage new ways of financing new nuclear plants. SMRs also offer the advantage of scalability, enabling utilities to add capacity to the grid in smaller increments.

Status of SMR research, development and deployment

Momentum behind SMRs is picking up

The urgency of the net zero challenge, alongside heightened concerns about the security of electricity supply, is increasing the readiness of governments to consider and support technological solutions. As noted in Chapter 2, half the emissions reductions in the NZE come from technologies, like SMRs, that are not yet available commercially.

Uncertainties about when SMR technology will be ready for commercial-scale deployment at scale make it difficult to project their future role in decarbonising the energy system. In the NZE, all the world's fossil fuel plants would need to be replaced by low emissions alternatives, including nuclear power, no later than 2040. Because of the uncertainties about the technology, we do not explicitly project the contribution of SMRs in total nuclear power in this scenario. However, we do expect SMRs to account for an increasing part of new nuclear capacity additions after 2030, on the assumption that continued progress is made in developing and demonstrating the technology, and bringing down costs.

There is extremely strong political and institutional support, with government grants to R&D as well as demonstration projects having increased by an order of magnitude over the last two years in some countries and now running into the billions of USD. This is making it possible to attract large private investments, bringing new players and new approaches to developing projects into the nuclear industry. It is also seen in some countries as an opportunity to assert technological leadership.

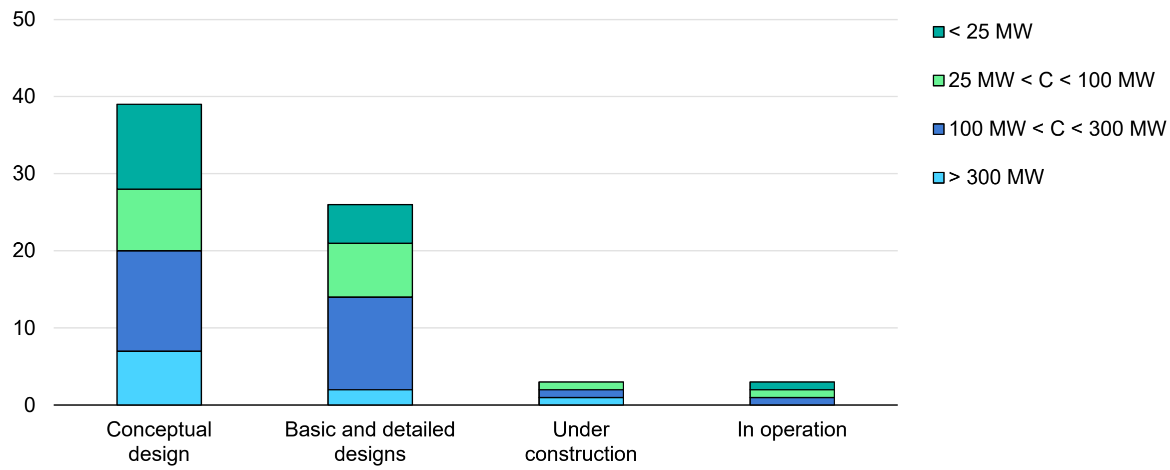
Small modular reactors under development worldwide with significant near-term milestones

Design	Net output per module	Type	Designer	Country	Status
ARC-100	100 MW electric	Sodium fast reactor	ARC Clean Energy	Canada	Demonstration project planned in New Brunswick
CAREM	25 MW electric	Pressurised water reactor	CNEA	Argentina	Under construction (Zárate)
BWRX-300	300 MW electric	Boiling water reactor	GE-Hitachi	United States / Canada	First commercial deployment announced with Ontario Power Generation (Darlington, Canada) and under discussion with Tennessee Valley Authority (Clinch River, United States)
eVinci	5 MW electric and up to 13MW thermal	Heat pipe	Westinghouse	United States / Canada	Pre-licensing application submitted in the United States in 2021
Kairos Power FHR	140 MW electric	Molten salt reactor	Kairos Power	United States	Under licensing with demonstration project planned with Oakridge National Laboratory
Micro-Modular Reactor Project	15 MW thermal	High temperature gas-cooled reactor	Global First Power / Ultra Safe Nuclear Corporation	Canada	Under licensing with demonstration project planned at Canada National Laboratories site (Chalk River)
Stable Salt Reactor – Wasteburner (SSR-W)	300 MW electric	Molten salt reactor	Moltex	Canada	Demonstration project planned in New Brunswick
NuScale SMR	50 MW electric (× 12)	Pressurised water reactor	NuScale Power	United States	Under licensing with demonstration project with Idaho National Laboratories and Utah Associated Municipal Power Systems
Natrium	345 MW electric	Sodium fast reactor	TerraPower / GE-Hitachi	United States	Demonstration project with preferred site identified at Kemmerer (Wyoming)
NUWARD	170 MW electric (x2)	Pressurised water reactor	EDF-led consortium	France	Demonstration project planned for 2030
RITM-200	55 MW electric	Pressurised water reactor	OKBM Afrikantov	Russia	First land-based version planned for 2028 in Yakutia

Design	Net output per module	Type	Designer	Country	Status
UK SMR	470 MW electric	Pressurised water reactor	Rolls-Royce led consortium	United Kingdom	Under licensing with Wylfa and Trawsfynydd identified as potential sites in the licence application
Xe-100	80 MW electric (x 4)	High Temperature gas-cooled reactor	X-energy	United States	Demonstration project with Energy Northwest (Washington)

Note: This list includes designs for which a site has been identified, a formal licence application made or that have been selected by government for near-term deployment.
Source: OECD/NEA 2022, All rights reserved.

Number of small modular reactor projects in the world by status of development



Notes: C = electrical capacity.
Source: IAEA 2022, All rights reserved.

In the **United States**, some recent major initiatives involving federal government support have made it possible to envisage a concrete push for SMRs, despite a general market context that is unfavourable to nuclear power in some states. Several sites have been selected for demonstration projects involving different reactor designs, though construction has not yet started as financing arrangements have yet to be completed. Two projects – the Kairos Power FHR and NuScale SMR – have so far reached the licensing application stage.

The federal Infrastructure Investment and Jobs Act of 2021 embraces many nuclear energy-related provisions, including funding for the US Department of Energy's Advanced Reactor Demonstration Program, which is intended to speed the demonstration of advanced reactors through cost-sharing partnerships with US industry. Under this programme, the Department of Energy has selected two reactor designs that are due to be fully operational within the next seven years and awarded

USD 160 million in initial funding to test, licence and build prototypes: TerraPower's 345 MWe Natrium plant and X-energy's 80 MWe pebble-bed unit. The Department of Energy will invest a total of USD 3.2 billion over seven years, subject to the availability of future appropriations, with these industry partners providing matching funds. Through the Office of Clean Energy Demonstrations, it has already provided USD 2.5 billion in funding for the Advanced Reactor Demonstration Program.

A range of potential applications: A focus on SMR development in Canada

Canada is at the forefront of the development of SMRs. In 2018, it developed an SMR roadmap in consultation with economic and civil society stakeholders, including several provinces, territories and power utilities, to map out the role SMRs could play in Canada's energy mix, in parallel with the introduction of regulations that have helped attract new small reactor concepts. In addition, an SMR Action Plan was released in 2020, as well as a provincial memorandum of understanding signed by Alberta, New Brunswick, Ontario and Saskatchewan, to work co-operatively to advance the development and deployment of SMRs and to encourage the federal government to provide support for SMR demonstration projects. As a result, several such projects are currently under consideration targeting the decarbonisation of hard-to-abate sectors in industry, the electrification of remote mining operations and industrial heat applications.

The roadmap identifies the potential for SMRs to meet a range of energy needs, along with opportunities for the Canadian nuclear industry to export these innovative nuclear reactor technologies. It also assesses the different reactor design characteristics, for instance reactor size or heat temperature, required for specific applications:

- *On-grid power (150 MW_e to 300 MW_e):* Replacing coal-fired power generation represents a key near-term opportunity for SMRs. A first of a kind project at an existing nuclear site at Darlington in Ontario based on the BWRX300 reactor being developed by GE-Hitachi – a US-Japanese joint venture – to be commissioned by the late 2020s has been announced. Saskatchewan is also considering on grid SMRs. The provincial power corporation in New Brunswick is also pursuing the installation of SMRs at its Point Lepreau nuclear power station site. Generation-IV technology – a set of nuclear reactor designs currently being researched by the Generation-IV International Forum – which would enable spent fuel recycling from the early 2030s is being considered for this project.
- *Extractive and heavy industries (10 MW_e to 80 MW_e):* This market segment concerns off-grid SMRs for mining, oil sands and other heavy industries, where emissions are hard to abate due to the need for high temperature heat. For many

years, extractive industries in Canada have maintained a keen interest in high-temperature SMRs to replace diesel generators.

- *Remote communities (1 MW_e to 10 MW_e):* Remote communities that currently rely primarily on off grid diesel generators for their electricity supply have been identified as a long term market opportunity for micro-modular reactors. Global First Power, a joint venture between Ontario Power Generation and USNC Power, has submitted an application to prepare a site to build a micro-modular reactor at the Atomic Energy of Canada Limited's Chalk River laboratories. This project is currently undergoing an environmental assessment.

The 2020 SMR Action Plan lays out the steps for the deployment of SMRs and envisages the first units to come online in the late 2020s. Several projects have obtained federal and provincial government funding, including the Integral Molten Salt Reactor being developed by Terrestrial Energy, the Moltex Energy molten salt SMR, the Canadian ARC-100 sodium-cooled SMR and Westinghouse's eVinci micro reactor.

China is a leader in advanced nuclear technology development. A demonstration plant with two high-temperature gas-cooled reactor pebble-bed module (HTR-PM) units – the first of their kind – at Shidao Bay was connected to the grid in 2021. China Huaneng was the lead organisation in the consortium building the units, together with China Nuclear Engineering Corporation (a subsidiary of China National Nuclear Corporation) and Tsinghua University's Institute of Nuclear and New Energy Technology, which is the nuclear R&D leader in the country. Each reactor drives a single 210 MW steam turbine, using helium gas as the primary coolant and reaching temperatures as high as 750°C. Other HTR-PM projects, at Wan'an in Fujian province, Sanmen in Zhejiang province and Bai'an in Gunagdong province, have been announced. In addition, the construction of the ACP100 SMR demonstration project on the island province of Hainan started in 2021. This multi-purpose 125 MW_e pressurised water reactor is designed for electricity production, heating, steam production or seawater desalination.

In **Russia**, Akademik Lomonosov brought the world's first floating nuclear power plant into commercial operation in May 2020 at Pevek in the Chkotka region, which comprises two 35-MW_e SMRs. In addition, Rosatom Overseas has been licensed to build the country's first onshore SMR power plant. Located in Ust-Kuyga in the Russian Far East, it will be equipped with a 55 MW_e RITM-200 SMR with the aim of producing electricity from 2028.

In **Japan**, the priority is to restart existing nuclear power plants and the construction of SMRs is not envisaged in the short term. Nevertheless, the Green Growth Strategy of the Ministry of Economy, Trade and Industry has set goals for the nuclear power sector. These include promoting the development and demonstration of fast-reactor technology for SMRs to produce hydrogen using high temperature gas reactors by 2030. This is to be achieved through international cooperation. IHI Corporation and JGC Holdings Corporation announced in 2021 that they would invest in United States based NuScale Power for overseas developments, with Japan Bank for International Cooperation also becoming involved in 2022. Others, such as Mitsubishi Heavy Industries and Hitachi are also seen closely in discussion with the Japanese government for the development of Japanese SMR technology and the sustainability and improvement of the supply chain.

In **Korea**, the recent reversal in nuclear policy by the new government led by President Yoon is expected to revive the country's nuclear industry. In 2020, the Korean government and the King Abdullah City for Atomic and Renewable Energy in Saudi Arabia updated their agreement to create a joint venture for the construction of a 100 MW_e SMR using SMART SMR technology being developed by the Korea Atomic Research Institute. Several Korean companies are also partnering with international SMR vendors.

In the **United Kingdom** the government has committed GBP 210 million in funding to develop the Rolls-Royce SMR, matched by a similar amount of private investment (by Rolls-Royce Group, BNF Resources UK Limited and Exelon Generation). The 2022 Nuclear Energy (Financing) Act establishes a new financing model for nuclear projects, known as the Regulated Asset Base. It aims to attract a wider range of private investment in both new large-scale reactors and SMRs and reduce construction costs, consumers' energy bills and reliance on overseas developers for finance. In 2022, the government published its Energy Security Strategy, which sets ambitions for eight new large reactors, as well as small modular reactors, to achieve nuclear generation capacity of 24 GW_e by 2050, or around 25% of forecast electricity demand in the United Kingdom.

In **France,** the France 2030 re-industrialisation plan, unveiled in October 2021, includes EUR 1 billion in funding for the period to 2030 for innovative designs including Generation-IV concepts and light water SMRs, such as the NUWARD SMR being developed by Électricité de France with major contributions from TechnicAtome, Naval Group, the French Alternative Energies and Atomic Energy Commission, Framatome and Tractebel. One goal is to build a first SMR unit in France by 2030.

Interest in SMRs is also growing in **Northern, Central and Eastern Europe**, where the potential market is significant, as many countries there need to replace a large amount of fossil fuel power stations and boost generating capacity to meet growing electricity demand. In several countries like the Czech Republic and Poland, there is interest in SMR technology, especially for meeting industrial heat and district heating needs. Some **emerging market and developing economies** are also developing roadmaps for SMR deployment, based on the generic IAEA roadmap, including institutional capacity-building. SMRs are more feasible for many of these countries than large-scale plants owing to grid constraint and lower initial investment costs.

SMRs are targeting some of the most difficult tasks of energy transitions

SMRs could play a role to complement variable renewables and other low emissions generating technologies in achieving net zero goals both in supplying electricity to the grid, for producing heat and hydrogen, and desalinating water. Some projects target industrial sectors where emissions are hard to abate and specific applications where other low emissions technologies are less technically or economically viable. These applications include replacing coal-fired power stations, replacing fossil fuels for producing heat in industry and district heating, and various other uses such as the production of hydrogen and hydrogen-based synthetic fuels, desalination and merchant shipping.

Replacement of coal plants to supply on-grid power

Decarbonising the power sector requires the replacement of a very large number of coal-fired power plants and retrofitting many others to capture CO_2 emissions. In countries open to nuclear power, close to 8 000 coal-fired units are shut down by 2040 in the NZE scenario, including all coal plants in advanced economies by 2030. Reusing sites for low emissions power generation such as SMRs would offer certain technical and cost advantages, including the opportunity to make use of existing onsite utilities, buildings and other facilities, the connection to the transmission network, the availability of cooling water and a skilled local workforce. There would also be substantial local economic and social benefits from maintaining local economic activity and skills.

In Europe alone (excluding countries that oppose nuclear or are phasing it out), for example, 34 GW of installed coal capacity, or 32% of the total, is made up of plants with 50 MW to 700 MW of capacity. While these coal-fired power stations could, depending on the case, be replaced by large reactors ensuring the equivalent production of electricity into the grid, SMRs with a capacity of 200 MW to 300 MW are well placed to replace some of this coal-fired capacity, depending on timing and other considerations. Various initiatives can facilitate the replacement of coal-fired plants with SMRs, such as that of TerraPraxis which aims to prepare standardised and pre-licensed designs supported by automated project development and design tools.

Replacement of fossil fuels in heavy industry, off-grid mining and district heating

Many SMR designs operate at high temperatures and could create the first real low emissions alternative to fossil-fuel co-generation of power, heat and hydrogen for industrial customers. Industries that could make commercial use of this technology include chemicals, steelmaking and ammonia. Several smaller SMRs, including reactors as small as 1 MW_e, are under development for off-grid applications, including as an alternative to diesel generators in resource extraction sites.

District heating is another potential application. Several countries and regions rely heavily on district heating from co-generation plants based on fossil fuels. Switching to biomass may be possible in some cases, but constraints on the availability or reach of sustainable biomass resources will limit the extent to which this could occur globally. If they reach commercial maturity, SMRs may be one of the few other practical solutions that can fuel low emissions district heating.

Hydrogen production, desalination and merchant shipping

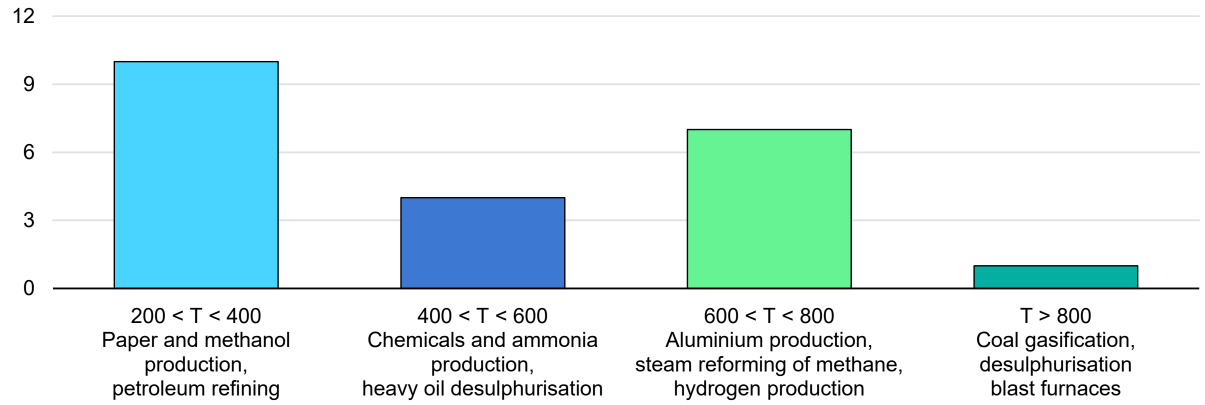
Nuclear power plants, large and small, are well suited to meet the growing demand for low-carbon hydrogen as well as hydrogen-based synthetic fuels. High temperature reactors can be coupled with either high-temperature electrolysis or thermochemical cycles to produce hydrogen. The possibility of locating SMRs near industrial hubs could boost the competitiveness of SMR-based hydrogen as this would reduce hydrogen transport and distribution costs, which can be very high.

SMRs could also be used to power desalination plants or aim to provide low emissions propulsion for maritime merchant shipping.

SMR designs vary in size and heat output according to their potential use

The SMRs being developed at present vary considerably in size, power and heat output, technology and fuel cycle, mainly according to the way they are expected to be used. Among the most mature designs, almost half involve a heat output temperature of less than 400 ºC, making them suitable for paper and methanol production and oil refining. One produces heat in excess of 800 ºC, which is required for coal gasification and iron and steel production.

Number of leading SMRs projects globally by temperature range and targeted use



Notes: T = temperature in ºC.
Source: OECD/NEA 2022, All rights reserved.

Almost half of current projects make use of Generation III technology, which aims to enhance safety by incorporating design changes that lower the risk of a severe accident and, should a severe accident occur, use appropriate mitigation systems to limit the impacts on the population and environment. These mainly take the form of light water-cooled designs, based on years of operating experience. Some concepts under construction or at a very advanced stage in the licensing process are likely to come onto the market by 2030.

The development of liquid metal cooled SMRs, molten salt cooled and gas cooled SMR designs – referred to as Generation-IV SMRs – is generally less advanced. However, these designs may prove attractive as they have the potential to reach higher temperatures to optimise co-generation and non-electric applications, as well as being compatible with the recycling of used nuclear fuel. It may take a longer time for Generation-IV models to be proven industrially, leading to the commercial deployment of a series of reactors. One of the biggest challenges, other than the technological demonstration still necessary in several cases, is establishing a sustainable fuel cycle for the reactor. Nevertheless, political leadership and significant financial support should accelerate technological advances and result in a breakthrough in the coming years.

Challenges facing SMR deployment

Cost-competitiveness is an open question, and SMR costs need to come down substantially

The cost-competitiveness of SMRs relative to other types of low emissions dispatchable power and heat generation will be crucial to the widespread deployment of the technology. How costs evolve is highly uncertain and the range of current SMR cost estimates is wide. Most of the numbers that are quoted at present are estimates produced by project developers; they have yet to be tempered by much in the way of real-life experience and so should be treated with great caution.

These estimates tend to be in the USD 45 - 110/MWh for projects in some advanced economies, depending on the degree of technology maturity and discount rate being considered (6% or 9%), while some developers aim for a range of USD 50 - 60/MWh for nth of a kind units. The costs of certifying new designs and the cost of factories yet to be built are subject to high uncertainties. Historically, economies of scale have driven an increase in the size of reactors, with current conventional large-scale designs involving more than 1 GW of electrical output capacity. In the case of SMRs, a series-construction approach is expected to be used to bring down costs. Several technical features such as design simplification, standardisation and modularisation, as well as factory fabrication, are expected to underpin this new approach. The benefits of series construction have been proven in other industries, including the shipbuilding and aircraft industries, and SMR developers are looking to make use of the lessons learned from these sectors. Observations of modularisation in some industries, including the power sector, indicate lead-time reductions of 40%, and 20% in terms of cost savings. For early SMR units, mass production may result in the amortisation of one-time costs, such as research, development, and design certification costs.

The competitiveness of SMRs should also benefit from several other features that make financing easier, notably their smaller construction cost and scalability compared with large reactors and overall easier project manageability. Investment in the development of industrial capacities is therefore a critical success factor for the long-term economic performance of SMRs. A successful pathway to competitiveness for SMRs also implies that only part of the 70 current designs under development reaches commercial maturity so as to secure a significant number of units per design as needed by economies of mass production.

The potential competitiveness of SMRs is best measured in comparison with alternative technological options for the specific applications targeted by SMRs. For instance, Canada's SMR roadmap concludes that SMRs could be a particularly attractive solution for remote regions where the alternative would be diesel powered generators. Most concepts or projects are at far too early a stage to consider developing detailed capital cost estimates, making it difficult to determine precisely which designs might prove to be the most competitive for specific applications. Moreover, for nuclear energy, the economics are only one development factor. This means that other factors, such as public acceptance related to safety features or spent fuel management, will be critical to the deployment of a particular design.

SMRs will only become economically viable once demonstration units have been successfully built and operated, and where well-defined and predictable licensing processes are in place. Some proponents expect commercial competitiveness to be considered once a few units are deployed.

Policy and regulatory support is needed to stimulate investment

The successful long-term deployment of SMRs hinges critically on strong support from policy makers and regulators for innovation and commercialisation to leverage private sector investment in R&D and developing supply chains. This support needs to go beyond funding of R&D and demonstration projects. Adapting and streamlining licensing and regulatory frameworks to take account of the unique safety features of SMRs is an important element: in most countries with nuclear energy, existing regulations have been developed for large reactors. Enhancing regulatory processes could greatly improve the future competitiveness of SMRs. International harmonisation of licensing approaches, as supported by the IAEA, could be particularly important in facilitating the emergence of a global market, which could take full advantage of the economies of scale of large-scale production of individual reactors. However, licensing would still need to comply with national and local regulatory requirements such as the environmental impact assessment or public consultation processes.

Policy makers also need to look at ways of mitigating risks for technology and project developers. As with large-scale nuclear projects, the cost of capital, which reflects risk allocation and mitigation decisions, is expected to remain a key driver of the competitiveness of SMRs. Both public and private financing will be required as SMRs move from the demonstration stage to commercial deployment. Securing private financing will be a key condition for success but will require a robust and technology-neutral policy framework, including in the area of taxonomies and environmental, social and governance that will have a growing incidence on financial flows. Some emerging market and developing economies will require the engagement of multinational financial institutions.

Regulators will also need to consider the safety and security of nuclear fuel supply, which differs considerably from that for large conventional reactors. Some SMR designs and other advanced reactors in development rely on innovative fuels, such as High Assay Low Enriched Uranium, which have few suppliers or are not yet commercially available. Existing regulations will need to be adapted to cover the specific characteristics of the supply chains for these types of fuels. Regulators and policy makers also need to keep in mind the potential implications of a very large number of small reactors being built around the world on the risks of proliferation.

The opportunities for SMRs depend on the speed of its own development, and the broader pace of transitions

The prospects for the deployment of SMRs and the degree to which they could contribute to achieving net zero goals remain uncertain. Most SMR concepts have yet to be demonstrated and new nuclear plants have typically had long lead-times. There may be significant risk of construction delays and cost-overruns for demonstration units and first-of-a-kind commercial SMRs. Indeed, the SMRs that have already been commissioned generally took a long time to build: for example, 12 years in the case of the Russian floating SMR and nine years for China's HTR-PM demonstration plant. These delays can be explained by the technological and industrial challenges that had to be overcome for these two concepts. Yet, unlike in Western countries, these reactors were built in countries with an active nuclear construction industry.

Based on recent experience, SMRs may be ready to start to play a role in decarbonising electricity supply from the mid-2030s. Within the next ten years, only a few SMR concepts are likely to approach commercial maturity. These can be classified into two categories:

- Designs resulting from proven technologies and benefitting from an existing nuclear site with requisite infrastructure. These characteristics will help to reduce the risks and costs linked to licensing, such as meeting environmental rules. For example, this could be the case for the BWRX-300 model at Darlington, Canada.

- More innovative designs, provided that they are supported by a substantial government programme. This is the case in the United States for the two advanced designs being developed by TerraPower and X-energy, which have obtained significant funding from the US Department of Energy. Such funding can help meet the large costs needed to pass the technology development and licensing stages, which represent a substantial part of the total upfront cost of the first unit. In turn, this would help to attract private finance and limit the risk for end-users.

How these developments ultimately intersect with the journey to net zero emissions depends also on the speed of these broader transitions. As noted in the opening chapter to this report, the world is not yet on track to reach net zero emissions by 2050. A scenario based on the climate pledges actually made by governments falls short of this goal, even if all of these pledges are implemented on time and in full. A scenario based on the policies that are actually in place would move the world even further away from a 1.5ºC stabilisation in rising global temperatures. The opportunities and roles open to SMRs would vary widely across these different scenarios.

In the world of the NZE, which depicts an extremely rapid transition, the number of SMRs built in the next decade will clearly fall far short of the capacity that is lost by the accelerated closure of coal-fired power plants in the NZE. This situation is especially true for advanced economies where the power generation sector reaches carbon neutrality in 2035 in this scenario (emerging market and developing economies reach that goal ten years later). Yet this does not mean that governments in advanced economies should dial back their support. In the NZE, nuclear investment needs in the G7 countries peak in the 2040s. There is, therefore, a significant opportunity for SMR designs to reach technical and commercial maturity ahead of that decade, when new capacity is most needed. This is true both for small evolutionary reactors that may be able to achieve economic competitiveness compared with other dispatchable low emissions sources, but also for the advanced reactor models that may be able to achieve a sufficient break-even point while benefiting from new attractive design features related to intrinsic improvements in terms of safety or waste production.

In a world moving rapidly towards net zero emissions, as in the NZE, there are two important windows of opportunity for SMRs:

- During the period to 2040, SMRs can contribute to the decarbonisation of the power sector. However, this will crucially depend on investment decisions made now to begin deployment at scale during the 2030s. Most early deployments are expected to be at existing power plant sites.

- Looking beyond 2040, if investment decisions are made this decade, then the period beyond 2040 would open up opportunities for large scale deployment of SMRs, including the currently less-mature reactor designs and reactors associated with spent nuclear fuel recycling strategies. These could be more widely deployed in the 2040s to supply low emissions electricity, heat and hydrogen.

IEA Publications
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/about/contact

Typeset in France by IEA- June 2022
Cover design: IEA
Photo credits: © GettyImages