

The Role of Nuclear in the Energy Transition: Complementary but Limited

October 2026



Energy
Transitions
Commission

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C.

ETC's commissioners come from a range of organisations – energy producers, energy intensive industries, technology providers, finance players and environmental NGOs – which operate across developed and developing countries and play different roles in the energy transition. This diversity of viewpoints informs our work: our analyses are developed with a systems perspective through extensive exchanges with experts and practitioners. The ETC is co-chaired by Lord Adair Turner and Jules Kortenhorst who work with the ETC team, led by Faustine Delasalle (Vice-Chair), Ita Kettleborough (Director), and Mike Hemsley (Deputy Director).

***The Role of Nuclear in the Energy Transition: Complementary but Limited* constitutes a collective view of the Energy Transitions Commission and was developed in consultation with ETC Members. Members of the ETC endorse the general thrust of the arguments made in this report but should not be taken as agreeing with every finding or recommendation. The institutions with which the Commissioners are affiliated have not been asked to formally endorse the report.**

The ETC Commissioners agree on the importance of reaching net-zero carbon emissions from the energy and industrial systems by mid-century and share a broad vision of how the transition can be achieved. The fact that this agreement is possible between leaders from companies and organisations with different perspectives on and interests in the energy system should give decision-makers across the world confidence that it is possible simultaneously to grow the global economy and to limit global warming to well below 2°C. Many of the key actions to achieve these goals are clear and can be pursued without delay.

This report should be cited as: ETC (2026), *The Role of Nuclear in the Energy Transition: Complementary but Limited*.

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Glossary

Additional Protocol: An IAEA safeguards mechanism, spanning over 140 states, that supplements the Nuclear Non-Proliferation Treaty by allowing more extensive inspection of civil nuclear facilities to verify the accuracy of declared activities.

Administered Tariff: A state-led nuclear financing model in which a state or state-owned enterprise funds construction and absorbs overrun risk, with revenue recovered through a fixed, government-set tariff rather than a market-based mechanism. Used in China, France, India, Russia and South Korea.

Artificial Intelligence (AI): The ability of computer systems and machines to perform tasks that typically require human intelligence. Used in this report to describe the rapid growth in electricity demand from AI data centres.

Baseload: The minimum, continuous level of electricity demand on a grid over a given period; historically used to justify a role for continuously operating generation sources such as nuclear and fossil fuels.

Boiling Water Reactor (BWR): A light water reactor design in which water boils directly in the reactor core to produce steam that drives the turbine; alongside pressurised water reactors (PWRs), one of the two dominant reactor types in today's global fleet.

Burnup rate: The thermal energy output (measured in MWd-th) produced per unit mass of nuclear fuel burned; a key measure of fuel efficiency that varies by reactor and fuel type.

Canada Deuterium Uranium reactor (CANDU): A Generation II heavy-water-moderated reactor design developed in Canada that uses natural (unenriched) uranium fuel, shifting the fuel-cycle requirement from enrichment services to heavy water production.

Capital Expenditures (CAPEX): The upfront cost of constructing or installing a piece of infrastructure or equipment.

Carbon emissions/CO₂ emissions: We use these terms to describe anthropogenic emissions of carbon dioxide in the atmosphere.

Clean electrification: The substitution of electricity for fossil fuels in end-uses such as transport, buildings, and industry, combined with the decarbonisation of electricity generation.

Combined Cycle Gas Turbine (CCGT): A gas turbine-based power generation technology that uses both a gas turbine and a steam turbine in sequence to increase efficiency.

Compressed Air Energy Storage (CAES): A method of storing energy by compressing air and releasing it to drive a turbine when electricity is needed.

Consumer Price Index (CPI): A measure of the average change in prices paid by consumers over time for goods and services.

Contract for Difference (CfD): A government policy instrument that guarantees a fixed price for electricity generation, paying the difference if market prices fall below that level and being paid back the difference if market prices are above that level (in two-way CfDs).

COP28 and the Declaration to Triple Nuclear Energy: COP28 was the 28th United Nations Climate Change Conference (Dubai, 2023), at which the Declaration to Triple Nuclear Energy was launched; it has since been endorsed by around 40 nations committing to triple global nuclear capacity by 2050.

Cost of capital: A measure of the risk associated with investments; it expresses the expected financial return, or the minimum required rate, for investing in a company or a project.

Decommissioning Expenditure (DECEX): The costs incurred at the end of a nuclear plant's operating life to safely dismantle the facility and manage resulting waste, typically funded through liability provisions set aside during operation.

Demand-side Flexibility (DSF): The ability to shift the consumption of electricity at peak times (through time-shifting usage of electricity use), offsetting new grid and generation capacity needed across the system.

Dunkelflaute: A German term (literally "dark doldrums") describing an extended period of low wind and solar output; used in the report to describe multi-day supply shortfalls, such as North Sea wind droughts, that must be covered by storage, interconnection or backup generation.

Engineering, Procurement, Construction and Installation (EPCI): The combined design, sourcing, construction and installation capabilities required to deliver a project.

European Pressurised Reactor (EPR): A Generation III+ pressurised water reactor design developed by Framatome, deployed at Olkiluoto 3 (Finland), Hinkley Point C (UK), Flamanville 3 (France) and Taishan (China).

Federal Authority for Nuclear Regulation (FANR): The single, independent nuclear regulator established by the United Arab Emirates ahead of its Barakah build programme.

Final Investment Decision (FID): The point at which a project's sponsors commit the capital required to proceed with construction.

First-of-a-Kind (FOAK): A project using a design, site or supply chain not previously built, and therefore subject to higher costs and schedule risk than a repeat, standardised "Nth-of-a-kind" (NOAK) build.

Fission: The nuclear reaction in which a heavy atomic nucleus (typically uranium-235) absorbs a neutron then splits, releasing thermal energy; the source of power in all commercially operating nuclear reactors today.



Flexible AC Transmission Systems (FACTS): Power-electronic systems used on alternating current (AC) power grids to improve control, stability, and electricity transfer capacity.

Fusion: The nuclear reaction in which two light atomic nuclei merge, releasing energy; still in early development stages.

Gas-Cooled Fast Reactor (GFR): A Generation IV fast-reactor design cooled by high-temperature gas rather than water, sodium or salt; in development since the 1970s.

Generation I–IV reactors (Gen I, Gen II, Gen III, Gen III+, Gen IV): The classification of nuclear fission reactor technology by design era and maturity. Generation I covers 1950s–60s prototypes; Generation II (from the 1970s) forms much of today's global fleet; Generation III and III+, mainly deployed from the early 2000s, add improved safety, efficiency and lifetimes; Generation IV describes advanced, largely pre-commercial designs using novel fuels and coolants.

“Green” hydrogen: Refers to hydrogen produced using electricity from low-carbon sources via electrolyzers.

Gross Value Added (GVA): An economic metric measuring the value of goods and services produced in an area, industry or sector.

High-Assay Low-Enriched Uranium (HALEU): Uranium enriched to between 5% and 20% U-235, required by most Generation IV and advanced small modular reactor designs.

High-Temperature Gas-Cooled Reactor (HTGR): A Generation IV reactor design using high-temperature gas coolant, targeting outlet temperatures of 750–950°C to enable industrial process heat and hydrogen production alongside power generation.

Hybrid cogeneration: The use of a nuclear reactor to supply both electricity and heat, for district heating, desalination or industrial process heat, from the same plant.

In-Situ Recovery (ISR): The dominant method of uranium mining, in which a mild leaching solution is injected underground, and the resulting uranium-bearing brine is pumped to the surface, avoiding conventional excavation.

Integrated Regulatory Review Service (IRRS): An IAEA peer-review mechanism that benchmarks a country's national regulatory framework for nuclear safety against IAEA standards.

International Atomic Energy Agency (IAEA): The United Nations body responsible for setting nuclear safety standards, administering non-proliferation safeguards and reviewing national regulatory frameworks.

Levelised cost of electricity (LCOE): A measure of the average net present cost of electricity generation for a generating plant over its lifetime, calculated as the ratio between all the discounted costs over the lifetime of an electricity-generating plant divided by a discounted sum of energy delivered.

Liquefied Natural Gas (LNG): Natural gas cooled to a liquid state at around –162°C for transport by ship.

Long-Duration Energy Storage (LDES): Storage technologies capable of discharging over many hours to days, used alongside nuclear and renewables to balance variable supply; the medium-long and ultra-long duration storage categories in this glossary fall under this broader term.

Low-Enriched Uranium (LEU): Uranium enriched to below 5% U-235, the standard fuel for Generation I–III+ reactors.

Medium-long duration storage: Energy storage systems designed to discharge over 8 to 50 hours.

Molten Salt Reactor (MSR): A Generation IV reactor design using molten salt as coolant, and in some designs as fuel carrier; in development since the 1960s but still pre-commercial.

Multilateral Development Bank (MDB): An international financial institution created by multiple sovereign countries to promote economic and social progress in developing nations.

National Energy System Operator (NESO): A UK-wide independent system operator responsible for planning and operating the electricity system.

National Ignition Facility (NIF): The Lawrence Livermore National Laboratory facility that in 2022 became the first to achieve fusion “scientific breakeven” ($Q>1$), releasing more thermal energy than the external energy used to trigger the reaction.

Net Zero Emissions scenario (NZE): The IEA's scenario for a global energy system reaching net-zero CO₂ emissions.

Net Zero Scenario (NZS): BNEF's scenario for a global energy system reaching net-zero emissions.

Nth-of-a-Kind (NOAK): A project built after a design has already been constructed and refined through repetition, benefiting from learning-by-doing and standardisation; contrasted with first-of-a-kind (FOAK) projects.

Nuclear Non-Proliferation Treaty (NPT): The international treaty, covering around 190 states and administered with IAEA safeguards, aimed at preventing the spread of nuclear weapons and usable material.

Nuclear Regulatory Commission (NRC): The United States' independent nuclear safety regulator.

OECD Nuclear Energy Agency (NEA): An intergovernmental agency that facilitates co-operation among countries with advanced nuclear technology infrastructures to seek excellence in nuclear safety, technology, science, environment and law.

Open Cycle Gas Turbine (OCGT): A gas turbine power plant that operates without a steam cycle, enabling fast ramping but lower efficiency.

Operational Expenditures (OPEX): Ongoing costs associated with the operation and maintenance of an asset or system.



Overnight capital expenditure (Overnight CAPEX): The cost of constructing a nuclear plant excluding financing costs, covering direct construction, equipment, services and site management; the basis on which CAPEX comparisons are typically made.

Power Purchase Agreement (PPA): A long-term contract between an electricity generator and a buyer, guaranteeing a price for the electricity produced.

Pressurised Water Reactor (PWR): A light water reactor design in which water is kept under pressure to prevent boiling in the core, with steam generated in a separate loop; the most common reactor type in the global fleet.

Nuclear weapons proliferation: The risk that civilian nuclear technology, particularly uranium enrichment and spent-fuel reprocessing, is diverted to develop nuclear weapons.

Pumped Hydro Storage: A method of storing energy by pumping water uphill to a reservoir, currently the dominant electricity storage technology globally.

Regulated Asset Base (RAB): A financing model in which investors fund construction and recover a regulated return from consumers from project inception, including during construction; adopted in the UK for the Sizewell C project.

Separative Work Unit (SWU): The standard unit for measuring uranium enrichment effort, used to size enrichment plant capacity and expansion plans.

Short-duration storage: Storage technologies designed to balance electricity supply and demand over timescales of up to 8 hours, typically batteries.

Small Modular Reactor (SMR): A nuclear reactor design with unit capacities of up to around 300 MW per unit, smaller than conventional large-scale reactors (~1,000 MW). Some SMR designs are now approaching 500 MW, beyond the original 300 MW threshold.

Sodium-Cooled Fast Reactor (SFR): A Generation IV fast-reactor design cooled by liquid sodium; in development since the 1950s but still pre-commercial, with several flagship demonstrators cancelled on cost or safety grounds.

Sunbelt and windbelt: Terms used to characterise a country's dominant renewable resource and system balancing challenge. Sunbelt countries have strong, consistent solar resource and mainly diurnal (day-to-night) balancing needs; windbelt countries rely more on wind and face larger seasonal balancing needs.

Synchronous Condenser: A rotating machine providing inertia and voltage support without generating power.

Technology Readiness Level (TRL): A 1–9 scale used to assess the maturity of a technology, from: research to Proof of Concept (TRL 1–3); Lab to Pilot Demonstration (TRL 4–6); Prototype Demonstration to FOAK / Full Commercial Deployment (TRL 7–9).

Title Transfer Facility (TTF): A virtual trading hub in the Netherlands where buyers and sellers trade natural gas, which is the main benchmark price for natural gas traded in Europe.

Tri-structural ISotropic (TRISO): A form of HALEU nuclear fuel made of tiny, highly robust uranium particles coated in protective carbon and ceramic layers.

Triuranium octoxide (U₃O₈) / yellowcake: The concentrated uranium oxide produced by mining; the first product in the nuclear fuel cycle, before conversion, enrichment and fabrication.

Ultra-long duration storage: Storage systems that discharge over durations longer than 50 hours.

Uranium dioxide (UO₂): The ceramic form into which enriched uranium is converted during fuel fabrication, pressed into pellets and loaded into fuel rods.

Uranium hexafluoride (UF₆): The gaseous compound of uranium and fluorine produced when yellowcake is converted; the feedstock used in the enrichment process.

Water-Water Energetic Reactor (VVER): A Soviet- and Russian-designed pressurised water reactor, in operation in 37 reactors globally (25 of them outside Russia).

Weighted Average Cost of Capital (WACC): The blended cost of debt and equity financing for a project; a major driver of nuclear's levelised cost given high upfront capital costs and long construction timelines.

World Nuclear Association (WNA): The World Nuclear Association is the international organization, with over 3,000 member companies across the nuclear value chain, that represents the global nuclear power industry and promotes its peaceful use.





Introduction

Clean electrification is the foundation of the transition to a global net-zero economy.¹ As the world moves towards net-zero emission energy systems, electricity demand could grow ~2–3x to 2050 and still further in subsequent decades through electrification and increasing energy access.² Most of the required additional power will come from solar and wind. Previous Energy Transitions Commission (ETC) work showed that power systems in which wind and solar account for 70% or more of generation will be able to reliably deliver electricity at costs comparable to or lower than today's fossil fuel-based power systems in most parts of the world.³

In our work to date, the ETC has always argued that existing nuclear plants should be kept operating safely for as long as possible, but we have not previously assessed the role which new nuclear plants should play alongside renewables in the development of low/zero-carbon power systems. This report assesses that role.

Nuclear power generation is a mature low-carbon technology which has been operating successfully since the 1950s. Current global installed capacity is ~380 GW, producing around 2,800 TWh per year, around 9% of global power generation. After a period of large-scale construction in the 1970s and 1980s, leading to a peak of 31 GW of new capacity coming online in 1984/85, reactor startups fell to an average of just 5 GW per year over the last 20 years.⁴ Nuclear generation has only grown by 10% since 2000, while total global power generation has increased by 2.1x.⁵ As a result, the share of nuclear in global generation has halved from its peak share of 17% in 1996 (2,400 TWh per year) to ~9% in 2025.⁶

But in the last 5–10 years, interest in the potential role of nuclear power has increased greatly. This reflects a combination of (i) increasing awareness of the future pace of electricity demand growth, which will be driven both by widespread electrification of the economy and by large new power demands (e.g., for artificial intelligence [AI] data centres); (ii) an increased focus on energy security after Russia's invasion of Ukraine in 2022 and the 2026 Strait of Hormuz energy crisis;⁷ (iii) a belief that large-scale third-generation (Gen III/III+) costs will decrease and that new reactor technologies such as small modular reactors (SMR) and fourth-generation (Gen IV) fission plants can reduce costs and shorten development timelines.

Ambition and policy support for expanding the use of nuclear power is now in place in more than 40 countries, and the Declaration to Triple Nuclear Energy, launched at COP28 in 2023, has been endorsed by around 40 nations. This originally targeted ~1,200 GW in 2050 but has since been increased to ~1,500 GW in 2050,⁸ aligned with the OECD Nuclear Energy Agency's (NEA) highest-ambition Transformative Scenario, but a significantly higher level than the ~900 GW in the OECD NEA's Ambitious Scenario and the ~1,000 GW in power system scenarios including Bloomberg New Energy Finance's (BNEF) Net Zero Scenario (NZS) and the International Energy Agency's (IEA)

1 Energy Transitions Commission (2021), *Making Clean Electrification Possible: 30 Years to Electrify the Global Economy*.

2 Systemiq analysis for the ETC (2026); BloombergNEF (2026), *New Energy Outlook 2026*; IEA (2025), *World Energy Outlook 2025*.

3 Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

4 IEA (2026), *Power Reactor Information System*.

5 Ember (2026), *Electricity Data Explorer*; Energy Institute (2025), *Statistical Review of World Energy*.

6 Institute for Global Sustainability – Visualising Energy (2024), *Electricity Generation from Nuclear Power*. Available at: <https://visualizingenergy.org/electricity-generation-from-nuclear-power> [Accessed 06 2026]; Ember (2026), *Electricity Data Explorer*. Available at: <https://ember-energy.org/data/electricity-data-explorer/?fuel=nuclear> [Accessed 06 2026].

7 Energy Transitions Commission (2026), *Lessons on Energy Security after the Hormuz Crisis: How Accelerating the Clean Energy Transition Builds Resilience Against Future Price Shocks*.

8 World Nuclear Association (2026), *World Nuclear Outlook Report 2026*



Net Zero Emissions (NZE) scenario.⁹ Reaching 1,000 GW would increase global nuclear electricity generation to 7,000–8,000 TWh per year by 2050.

In this report, we assess how large a role nuclear power could and should play in a world which needs to significantly expand total power supply while reducing carbon dioxide emissions to net-zero by mid-century. This question is hotly debated, with strong and contentious points of view on either side. Many opponents argue that nuclear power should be rejected in principle, arguing that it is unsafe, creates dangerous radioactive waste and requires too much time and investment to deploy. Conversely, many proponents of nuclear power argue that it is needed to meet the Paris Agreement to limit global average temperature to well below 2°C,¹⁰ and that it must play a major role in power decarbonisation because power systems cannot run on intermittent renewables. In this report, we therefore carefully assess six contentious arguments for and against, reaching the conclusions shown in Exhibit 0.1 and addressed directly in the executive summary, published alongside this report.

Exhibit 0.1

Six major arguments for and against nuclear and ETC conclusions

Argument	ETC assessment	Addressed in
Nuclear is unsafe, creates unmanageable waste and increases nuclear weapon proliferation risk	Other than three notable historic catastrophic incidents, nuclear has been safely operated, and can continue to operate safely under sustained regulatory oversight. It can be safely decommissioned through appropriate waste management techniques, but a small amount of highly radioactive waste will require deep burial, and public acceptance of these handling facilities in specific locations. Non-proliferation of nuclear weapons requires sustained commitments to comprehensive safeguards agreements.	Chapter 1
Nuclear is cost-competitive with clean alternatives across most geographies	New nuclear is likely to remain higher cost than clean alternatives on a power generation cost basis in most geographies, but with very large variations between countries/regions.	Chapter 1
Cost for SMRs and Gen IV will come down significantly	SMRs might reduce the cost of nuclear generation in the future, but it is currently not reasonable to assume significant cost reductions in the next decade – design consolidation and a sustained pipeline of repeat orders are needed before serial production and learning effects can bring costs down.	Chapter 1
Nuclear significantly reduces total system cost both for low operating costs & overall balancing/grid costs	Solar and wind power, which is rapidly expanding around the world, can reliably provide 70–90% of power demand at lower costs in most countries. However, integrating low shares of nuclear (e.g., 10–20% on a system basis) into power systems with renewables integration challenges can lead to lower system costs through reducing balancing, grid expansion and grid stability costs relative to counterfactual scenarios.	Chapter 3
Nuclear diversifies supply without new dependencies and geopolitical risk	Nuclear can support energy security, but concentrated supply chains for key components and fuel expose importing countries to geopolitical, cost and schedule risk, while correlated outages in standardised fleets and cooling water constraints during heatwaves can limit the resilience gain at high shares. High local content also gives nuclear greater domestic value added than renewables – though this partly reflects higher costs. Both arguments are therefore country specific.	Chapters 2 and 3

⁹ BNEF (2026), *New Energy Outlook 2026*; IEA (2025), *World Energy Outlook 2025*; OECD NEA (2026), *Nuclear Energy Outlook Global Installed Capacity to 2050 and Beyond*.

¹⁰ United Nations Climate Change (n.d.), *The Paris Agreement*. Available at: <https://unfccc.int/process-and-meetings/the-paris-agreement> [Accessed 08/2026].



Argument	ETC assessment	Addressed in
Nuclear can be developed fast enough to be a significant short-term response to rising energy demand	Countries seeking to build out power fast to meet surging demand should not disproportionately rely on nuclear given its long development timelines and supply chain ramp-up needs compared to alternatives. SMRs will not change this picture significantly in the short-term and they should not distract governments from a focus on renewable build-out.	Chapters 1, 2 and 4

These and other conclusions set out in the report lead us to the following assessment of the appropriate future role of nuclear power:

- **Nuclear capacity could increase by between 2–3x between 2025 and 2050 and continue to provide ~10% of global electricity generation, if new nuclear startups increase at a dramatic rate:** Globally, we estimate that nuclear capacity could increase ~2–3x to ~550–1,000 GW by 2050 and the ETC's estimate for a reasonable level of ambition in 2050 is ~750 GW. This represents a stretching buildout target for the industry with 15–25 GW of new nuclear capacity to be delivered per year from now to 2050 (depending on the level of life extensions achieved). This is 3–5x higher than the 5 GW per year average over the last 20 years. Meeting this step-change in development would imply capital investment of \$200 billion per year vs. around \$50 billion per year in recent years and would require effective strategies to develop policy (e.g., across permitting, licensing and decommissioning), financing and supply chains.
- **Complementary at low shares:** In many power systems, nuclear power could usefully complement the dominant role of renewables, with nuclear generation shares of up to ~20% in certain countries potentially delivering a small reduction in total system cost and providing useful diversification, even if generation costs are higher.
- **Geographically variable role:** The optimal generation share will vary greatly between countries from zero to well above the average figure to reflect differences in both (i) the quantity, mix and cost of renewable resources and (ii) capacity to deliver nuclear power at low cost.
- **Lifetime extensions should be supported where safe:** Extending typical lifetimes of the existing fleet from 60 to 80 years retains 230 GW (~1,800 TWh per year) in 2050 at relatively low cost, mainly in North America and Europe (particularly the US and France).
- **The feasible and appropriate role for nuclear power does not materially reduce the need for the massive expansion of renewables capacity** which will form the core of most future low/zero-carbon power systems. Nuclear buildout should therefore not detract from the institutional capacity needed to expand renewables and storage at the required pace to decarbonise power systems around the world.

The analysis leading to these conclusions is set out in four chapters:

1. Technologies, risks and costs of generation.
2. Delivery capabilities needed to deliver new nuclear safely, at low cost and on time.
3. Total system cost, energy security and other potential benefits.
4. Optimal nuclear development by country and globally.

1

Technologies, risks and costs of generation

There are widely divergent views on the appropriate role of nuclear power within low- or zero-carbon power systems. This reflects different assessments of new technological developments, the risks of nuclear operation and the achievable costs. In this chapter we therefore cover in turn:

- 1.1 Existing and potential new nuclear technologies: conventional large fission, Generation IV, small modular reactors (SMR) and fusion.
- 1.2 Operational risks, waste management and nuclear proliferation: significant but manageable.
- 1.3 Cost structure and variations by region: the dominant role of upfront capital and financing costs.
- 1.4 The potential cost impact of novel nuclear technologies: still unproven.
- 1.5 Overall levelised cost of nuclear electricity generation: higher than renewables in most geographies.

1.1 Existing and potential new nuclear technologies: conventional large fission, Generation IV, small modular reactors (SMR) and fusion

There are two main nuclear technology categories: fission and fusion. [Exhibit 1.1] In nuclear fission, energy is released during the splitting of atoms. Fission technology is typically segmented into technology “generations” reflecting reactor technology evolutions over time. Conventional Generation I-III nuclear fission technology has operated commercially for multiple decades (Technology Readiness Level [TRL] 9). Advanced Generation IV and SMR fission technology has been in development for decades but is still in the pre-commercial stage (TRL 2–8). Nuclear fusion releases energy when two atomic nuclei are merged, and remains in early development stages (TRL 2–5).



Only conventional large-scale fission is commercially deployed today; SMRs, advanced reactors and fusion are progressively further from deployment

Main technology	Fission			Fusion
	Conventional Large-Scale Reactors	Small Modular Reactors (SMR)	Advanced Reactors	Fusion Reactors
Generation	Gen I-III	Gen III+	Gen IV	
	 Reactor type Typically, light water reactors Typical unit size 1,000 – 1,600 MW	 Reactor type Light water reactors or advanced modular designs Typical unit size 10 – 300 MW	 Reactor type Gas, liquid metal, molten salt or supercritical water cooled Typical unit size Up to ~1,500 MW	 Reactor type Magnetic, inertial or magneto-inertial confinement Typical unit size Under ~500 MW expected initially
Key features	• Global standard since 1960s • Main reactor types are light water reactors, mainly Pressurised Water (PWR) and Boiling Water (BWR) • Incremental technology improvements since ~1970s	• Compact, factory-built modules • Limited deployment to date • Growing commercial interest due to siting flexibility but cost uncertainty remains high	• Use novel coolants (e.g., helium, liquid metal) with higher thermal efficiency and passive safety features • Decades of R&D, many designs still low TRL • Uncertain CAPEX and fuel costs	• Light atomic nuclei are joined rather than split using abundant fuel from seawater deuterium and lithium breeding. • Remains in early-stage R&D • No long-lived high-level waste
Technology readiness level	1 2 3 4 5 6 7 8 9 High (commercially deployed)	1 2 3 4 5 6 7 8 9 Low-medium (demonstration / pre-commercial)	1 2 3 4 5 6 7 8 9 Low-medium (demonstration / pre-commercial)	1 2 3 4 5 6 7 8 9 Very low (R&D / demonstration)

NOTE: These categories overlap, since many advanced designs are also SMRs, and do not include all early-stage technologies, e.g. thorium-fuelled reactor designs which can be classified as Gen II-IV. All capacities listed in electrical MW. Assumed TRL scale: TRL 1-3 = Research to Proof of Concept; TRL 4-6 = Lab to Pilot Demonstration; TRL 7-9 = Prototype Demonstration to FOAK / Full Commercial Deployment. 300 MW was the original upper limit for SMRs but some SMR designs now have larger unit capacities.

SOURCE: US DoE (2024), *Pathways to Commercial Liftoff: Advanced Nuclear*; Mycle Schneider Consulting (2025), *The World Nuclear Industry Status Report 2025*; Third Way (2024), *The Global Race for Advanced Nuclear Is On*; Nuclear Innovation Alliance (2025), *Advanced Reactor Deployment Map*; S. Wurzel (2025), *Continuing progress toward fusion energy breakeven and gain as measured against the Lawson criteria*.

All of today’s nuclear generation comes from nuclear fission reactors, almost all of which are conventional large-scale designs. Today’s fleet consists mostly of Generation II-III+ light water reactors: pressurised water reactors (PWRs) and boiling water reactors (BWRs) have been the dominant reactor type since 1970 (first Generation II, then III, then III+). Each new reactor generation has improved safety, efficiency, manufacturability and reliability.

- **Generation I** reactors were prototypes and early commercial units developed in the 1950s and 1960s.
- **Generation II** reactors, built mainly from the 1970s onwards, include PWRs, BWRs and Canada deuterium uranium (CANDU) reactors. These form the backbone of today’s global nuclear fleet and deliver the bulk of nuclear electricity in countries such as the US, France and Japan.
- **Generation III** reactors introduced improved safety features, efficiency and lifetimes (and included Advanced Boiling Water Reactors) but global deployment was limited.
- **Generation III+** reactors are commercially deployed at technology readiness level (TRL 9) and have dominated buildout since the late-2010s (e.g., Framatome’s European Pressurised Reactor [EPR], Westinghouse’s AP1000, Korea Electric Power Corporation’s APR-1400 and China National Nuclear Corporation’s HPR-1000).¹¹

¹¹ Assumed TRL scale: TRL 1-3 = Research to Proof of Concept; TRL 4-6 = Lab to Pilot Demonstration; TRL 7-9 = Prototype Demonstration to FOAK / Full Commercial Deployment. Source: Systemiq analysis for the ETC (2026); ARENA (2014), *Commercial Readiness Index for Renewable Energy Sectors*.

The fission fleet has maintained a stable capacity but a declining share in growing global generation in recent decades. Novel technologies spanning “advanced” Generation IV reactors, small modular reactors and fusion have yet to scale:

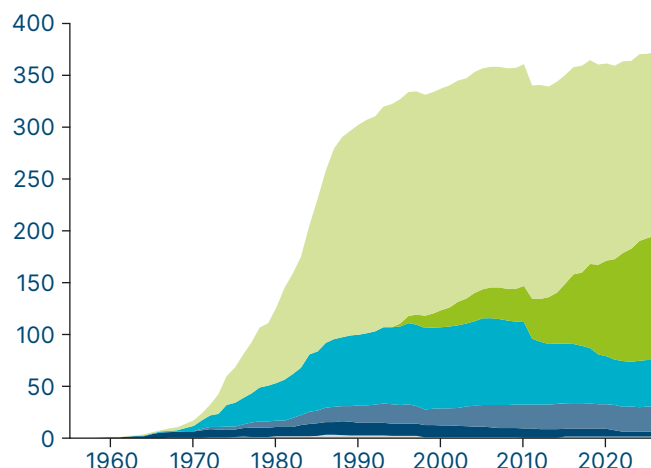
- **Conventional nuclear technology installed to date (380 GW) uses fission reactions, which has made up a stable capacity but declining share of global generation in recent decades.** Fission reaction involves splitting heavy atomic nuclei (typically U-235) to release thermal energy – typically used to produce high-pressure steam to spin turbines to generate power.¹² Today, there is around 380 GW of installed nuclear capacity globally, generating 2,800 TWh of power – a level that’s been consistent since the 2000s.¹³ As power demand has grown over the last few decades, nuclear’s contribution to global power generation has halved since its peak share of 17% in 1996 (2,400 TWh per year) to ~9% (2,800 TWh per year) in 2025.¹⁴
- **Deployment has shifted from Europe and North America to Asia:** Europe and North America dominated deployment until the Chernobyl disaster in 1986, when governments outside of Asia significantly slowed down deployment. Since then, most deployment has been in Asia. [Exhibit 1.2] The current average reactor age is 33 years globally, ranging from 20 in Asia to 41 and 44 in Western Europe and North America, respectively.¹⁵ The expected typical asset lifetime is around 60 years today, though life extensions to 80 years are being explored and, in some cases, have been undertaken.

Exhibit 1.2a

Pressurised water reactors have dominated since the 1970s; deployment peaked in the 1980s

Evolution of nuclear fleet by type over time

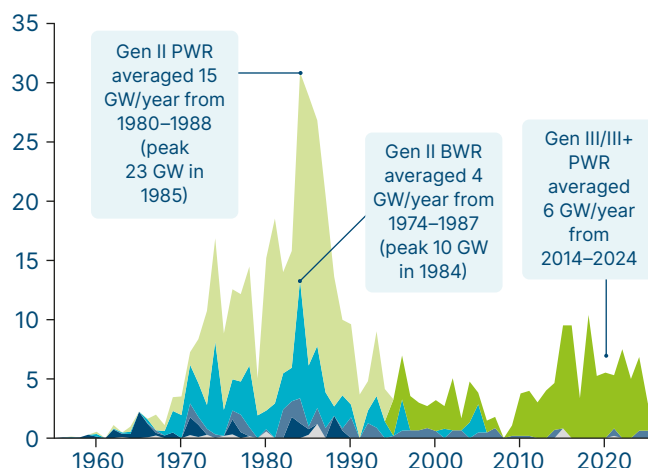
GW (operational)



■ Pressurised Water Reactor - Gen II
 ■ Pressurised Water Reactor - Gen III / III+
 ■ Boiling Water Reactor - Gen II / III
 ■ Pressurised Heavy Water Reactor - Gen II
 ■ Gas-cooled Reactor - Gen I / II
 ■ Other

Startups by type over time

GW/year (reactor start-ups)



NOTE: Breakdown for PWRs and BWRs: pre-1965 designs classified as Gen I, 1965 to 1994 designs as Gen II, 1995 to 2014 as Gen III and 2015 onwards mainly as Gen III+; advanced non-LWR designs such as FBR and HTGR are outside simple year-based generation buckets and other reactor types are predominantly Gen II. “Other” includes: Light Water Graphite Reactor; Heavy Water Light Water Reactor; Fast Breeder Reactor; High-Temperature Gas-cooled Reactor; Heavy Water Gas-cooled Reactor; Steam Generating Heavy Water Reactor.

SOURCE: Systemiq analysis for the ETC (2026); IAEA (2026), *Power Reactor Information System*.

¹² A neutron splitting a fissile nucleus releases fast neutrons and energy, which thermal reactors slow via a moderator to sustain a controlled chain reaction at criticality ($k=1$), regulated by neutron-absorbing control rods (made of boron, cadmium or hafnium). A coolant (typically water in conventional Generation I-III+ designs) removes heat from the fuel to raise steam that drives a turbine and generator, after which spent fuel – containing fission products and minor actinides – is removed for cooling and eventual storage or disposal. Source: World Nuclear Association (2026), *Physics of Nuclear Reactors*.

¹³ Institute for Global Sustainability – Visualising Energy (2024), *Electricity Generation from Nuclear Power*. Available at: <https://visualizingenergy.org/electricity-generation-from-nuclear-power> [Accessed 06 2026]; Ember (2026), *Electricity Data Explorer*. Available at: <https://ember-energy.org/data/electricity-data-explorer/?fuel=nuclear> [Accessed 06 2026].

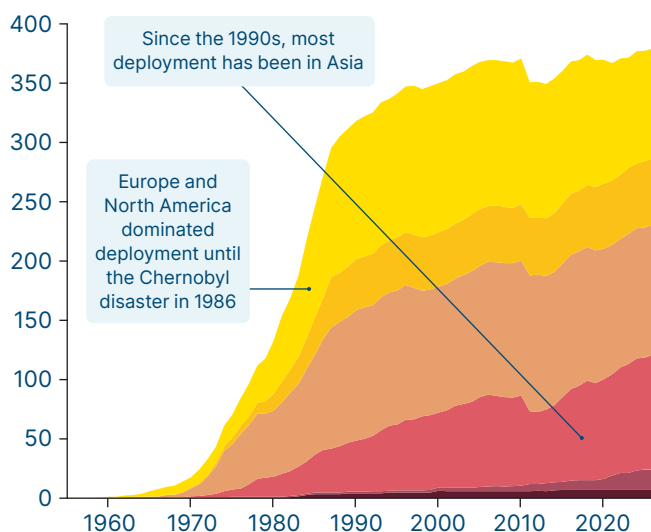
¹⁴ Institute for Global Sustainability – Visualising Energy (2024), *Electricity Generation from Nuclear Power*. Available at: <https://visualizingenergy.org/electricity-generation-from-nuclear-power> [Accessed 06 2026]; Ember (2026), *Electricity Data Explorer*. Available at: <https://ember-energy.org/data/electricity-data-explorer/?fuel=nuclear> [Accessed 06 2026].

¹⁵ Systemiq analysis for the ETC (2026); IAEA (2026), *Power Reactor Information System*.



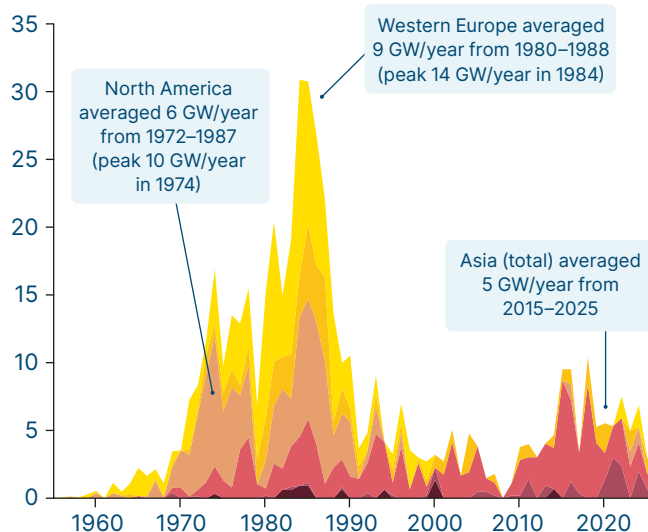
Geographic concentration of cumulative and new reactors has shifted over time

Evolution of nuclear fleet by region over time
GW (operational)



● Europe - Western ● Europe - Central and Eastern ● North America ● Asia - Far East
● Asia - Middle East and South ● Africa & Latin America

Startups by region over time
GW/year (reactor start-ups)



SOURCE: Systemiq analysis for the ETC (2026); IAEA (2026), *Power Reactor Information System*.

Fourth-generation (Gen IV) reactors are at low technological maturity (TRL 2–8) today, with first commercial deployment expected in the 2030s.¹⁶ Gen IV designs could further improve efficiency and safety through innovations in fuel (the chemical and physical form of the nuclear fuel), coolant type (the substance used to transfer heat away from the reactor core) and neutron spectrum (the level of neutron energy sustaining the fission reaction). While Gen I–III+ reactors use low-enriched uranium (LEU) fuel and are typically water-cooled, Gen IV (known as “advanced” reactors) are nuclear fission reactor technologies that use novel fuels (high-assay low-enriched uranium [HALEU]¹⁷ or conventional LEU) and novel coolants, including high-temperature gas (usually helium), metal (e.g., lead or sodium) or salt (e.g., fluoride). Reactor designs with “thermal” neutron spectra have slower speeds with moderators (typically water or graphite), while those with “fast” neutron spectra have higher neutron speeds and no moderator.¹⁸ Fast reactors typically require HALEU fuel (5–20% enriched) and sodium, chloride salt or lead coolants.¹⁹ These design changes typically increase efficiency, safety and compactness. However, Gen IV reactors are still at pre-commercial deployment stages, despite decades of research and development. First commercial deployment is expected to happen in the 2030s with leading programmes in China, Russia and the US.²⁰

Small modular reactors (SMRs) are still in early development stages (TRL 2–8) and propose to use Gen III+ or Gen IV technology at small unit sizes (typically up to 300 MW).²¹ In recent years, SMRs have seen growing commercial interest due to potential manufacturing efficiencies with smaller, more modular units and siting

16 Assumed TRL scale: TRL 1–3 = Research to Proof of Concept; TRL 4–6 = Lab to Pilot Demonstration; TRL 7–9 = Prototype Demonstration to First-of-a-kind (FOAK) / Full Commercial Deployment.

17 LEU is enriched to 5% uranium-235 (U-235) and HALEU is enriched to 5–20% U-235. World Nuclear Association (2026), *High-Assay Low-Enriched Uranium (HALEU)*. Available at: <https://world-nuclear.org/information-library/nuclear-fuel-cycle/conversion-enrichment-and-fabrication/high-assay-low-enriched-uranium-haleu> [Accessed 07 2026].

18 Thermal reactors rely on neutrons slowed – via a moderator – to below roughly 1 electron volt (eV), while fast reactors are sustained by neutrons above roughly 1 keV. Source: Nuclear Power (n.d.), *Types of Reactors*. Available at: <https://www.nuclear-power.com/nuclear-power-plant/reactor-types/> [Accessed 07 2026].

19 GEN IV International Forum (n.d.), *Generation IV Goals, Technologies and GIF R&D Roadmap*. Available at: <https://www.gen-4.org/generation-iv-criteria-and-technologies> [Accessed 07 2026].

20 US DoE (2024), *Pathways to Commercial Liftoff: Advanced Nuclear*.

21 Reactors <10 MW units can be classified as microreactors, a subset of SMRs. Source: IAEA (2023), *What are Small Modular Reactors (SMRs)?* Available at: <https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs> [Accessed 08 2026].

flexibility. None have yet completed commercial-scale deployment for grid power (with a handful of operating demonstration projects in Russia and China). The first early commercial deployment is expected to happen in 2026 through China's Linglong One project (using one 125 MW ACP100 reactor), then in 2030 through Ontario Power Generation's Darlington SMR project (using four GE-Hitachi BWRX-300 units).²² Floating SMRs – reactors built on barges or hulls in shipyards rather than on site – could push factory fabrication further and suit deployment in land-constrained coastal markets.

Thorium-fuelled reactor designs are also in early development stages: solid-fuelled Generation II-III+ heavy-water or high-temperature gas reactors are at TRL ~6–7 while Generation IV molten salt reactors are at TRL ~3–6. Thorium is more abundant than uranium but cannot sustain a chain reaction itself. Instead, it absorbs neutrons and decays into fissile uranium-233, so a reactor must be started and driven by a separate fissile fuel (uranium-235 or plutonium-239).²³ Generation IV molten salt reactors have the potential to unlock closed-cycle fuel breeding (the process of converting non-fissile thorium-232 into fissile uranium-233 inside a reactor) and recycling (extracting uranium-233 from the spent fuel to sustain continuous power generation).²⁴ This expands fuel availability and reduces long-lived waste, if paired with reprocessing and refabrication for fuel recycling.²⁵ However, feasibility is unproven as this adds cost, technical and regulatory complexity and proliferation risk.²⁶ The conventional variants of thorium reactors are closer to commercial deployment but don't offer step changes in fuel availability or waste reduction. Thorium can be used in conventional heavy-water or high-temperature gas reactors but offers limited resource or waste advantage over uranium because the bred uranium-233 is never recovered.²⁷

Fusion is at TRL 2–5 and is unlikely to commercialise at scale before 2040, though it could impact power systems in the long-term.

- **Fusion merges two light atomic cores (nuclei) into helium and releases energy in the process.**²⁸ To make this happen, confinement is needed – which requires high temperatures of ~100–150 million °C for a long period of time. There are three ways to achieve this: magnetically (strong magnetic fields hold the atomic cores in place), inertially (compressing fuel pellets, typically with lasers) or through hybrid magneto-inertial approaches.²⁹ To date, only the National Ignition Facility (NIF) at Lawrence Livermore National Laboratory has managed to release more thermal energy than the external heating energy needed to achieve fusion, meaning it reached the scientific break-even point of $Q > 1$. NIF reached a Q of 1.5 in 2022 and 4.13 in 2025, though only for a fraction of a second each time.³⁰ Separately, the Joint European Torus 2024 achieved Q of ~0.3 for ~5 seconds and non-fusing plasmas were confined for over 20 minutes in the WEST Tokamak in February 2025.³¹ [Exhibit 1.3]
- **Fusion reactions have not yet generated net electricity at a power plant level and unresolved technical and economic challenges block commercialisation:**
 - No device has maintained a stable fusion plasma over long enough durations and fuel production at scale is untested.
 - First-of-a-kind (FOAK) capital expenditure (CAPEX) is highly uncertain, estimated at between ~\$1,000–40,000 per kW (as fusion research costs have historically been poorly defined and sometimes not disclosed). Potential future cost declines could be limited by large unit sizes, high complexity and customisation needs.³²

22 Nuclear Innovation Alliance (2025), *Advanced Reactor Deployment Map*; Ontario Power Generation (2026), *Small Modular Reactors | Darlington SMR*. Available at: <https://www.opg.com/projects-services/projects/nuclear/smr/darlington-smr/> [Accessed 07 2026].

23 IAEA (2005), *Thorium Fuel Cycle – Potential Benefits and Challenges*.

24 World Nuclear Association (2025), *Molten Salt Reactors*.

25 For example, India's three-stage programme to commercialise indigenous fast breeder reactors aims to close the fuel cycle in its third stage. Source: World Nuclear Association (2025), *Nuclear Power in India*.

26 Michael Hewitt (2025), *Investment in a Nuclear Startup – Fuel Decision Tree*.

27 World Nuclear Association (2024), *Thorium*.

28 Deuterium-tritium is the leading fuel cycle because it has the highest reaction probability at the lowest achievable plasma temperature. Alternative cycles are under development, notably proton-boron-11 (e.g., TAE Technologies, HB11 Energy) and deuterium-helium-3 (e.g., Helion Energy). These are largely aneutronic, which would reduce materials degradation and activation waste and remove the need for tritium breeding, but they require plasma conditions roughly an order of magnitude more demanding than D-T and are at an earlier stage of development; helium-3 is also extremely scarce terrestrially.

29 IAEA (2010), *Nuclear Fusion Basics*.

30 Commonwealth Fusion Systems (2026), *Fourth Step on the Path to Fusion Energy: $Q > 1$* . Available at: <https://blog.cfs.energy/fourth-step-on-the-path-to-fusion-energy-q1/> [Accessed 08 2026].

31 HUN REN (2024), *Fusion Research Facility JET's Final Tritium Experiments Yield New Energy Record*. Available at: <https://www.ek.hun-ren.hu/en/2024/02/08/fusion-research-facility-jet-final-energy-record/> [Accessed 08 2026]; IRFM CEA (2025), *WEST Sets a New Plasma Duration Record*. Available at: <https://irfm.cea.fr/en/2025/02/west-sets-a-new-plasma-duration-record/> [Accessed 08 2026].

32 L. Tang (2026), *Fusion power experience rates are overestimated*.



Fusion developers are at TRL 2–5, and decades of scientific progress have not yet approached plant-level electricity

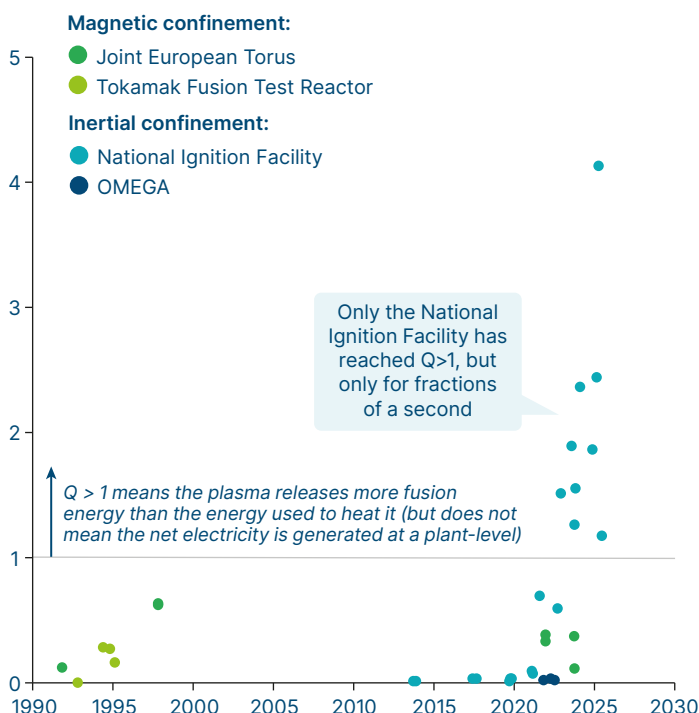
Leading fusion technology developers and estimated maturity

Technology	Leading Developers	Estimated TRL
Magnetic confinement	Commonwealth Fusion Systems	4–5
	Tokamak Energy	4–5
	Type One Energy	3–4
	BEST	4–5
Inertial confinement	Xcimer	3–4
	Marvel Fusion	3–4
	Focused Energy	2–3
Magneto-inertial	Helion	4–5
	General Fusion	4–5
	Zap Energy	4–5

0 1 2 3 4 5

The ratio of fusion power produced to the heating power put in ("Scientific Q") for experimental fusion reactors over time

Scientific Q



NOTE: BEST = Burning Plasma Experimental Superconducting Tokamak. Assumed TRL scale: TRL 1–3 = Research to Proof of Concept; TRL 4–6 = Lab to Pilot Demonstration; TRL 7–9 = Prototype Demonstration to FOAK / Full Commercial Deployment.

SOURCE: Systemiq analysis for the ETC (2026); South China Morning Post (2025), 'China speed' accelerates drive towards next step in nuclear fusion; Helion Energy (2023), *Helion-Microsoft PPA: Helion Press Release*, 10 May 2023 (50 MW, online 2028, Constellation marketer); Xcimer Energy Corporation (n.d.), *Roadmap*; General Fusion (2023), *General Fusion Announces Funding to Build New Fusion Machine Targeting Scientific Breakeven by 2026*; Physics World (2025), *General Fusion Lays Off Staff due to 'Unexpected and Urgent Financing Constraints'*; B. Levitt (2023), *The Zap Energy Approach to Commercial Fusion*; U.S. Department of Energy (2024), *Fusion Ignition and the Path to Inertial Fusion Energy*; Commonwealth Fusion Systems (2026), *Fourth step on the path to fusion energy: $Q > 1$* . Available at <https://blog.cfs.energy/fourth-step-on-the-path-to-fusion-energy-q1/> [Accessed 08 2026]; S. Wurzel (2025), *Continuing progress toward fusion energy breakeven and gain as measured against the Lawson criteria*.

1.2 Operational risks, waste management and nuclear proliferation: significant but manageable

Opponents of new nuclear development base their objections not only on its economics, but also on its operational risks, radioactive waste and potential proliferation of nuclear weapons. These risks are important and must be tightly managed, but the ETC believes they can be reduced to an acceptable level:

- Risks of operational accidents can be controlled using existing and new reactor designs, tight operational controls and strong regulation.
- Waste management issues are tractable through established methods and regulations.
- Non-proliferation of nuclear weapons is hugely important and should be ensured by conditioning new nuclear power investments on comprehensive safeguards agreements, with fuel-cycle services concentrated in existing supplier states rather than replicated nationally.

1.2.1 Reactor safety in operation

Nuclear development and operation is subject to national regulation and the International Atomic Energy Agency's (IAEA) safety standards in all countries, as set out in Section 2.1. The global civilian fleet has a strong safety record, especially with modern reactors which are engineered against operational safety risks. Public concern about reactor safety is driven by high-consequence accidents and is highest in non-nuclear countries.³³ Siting risk due to climate change is a growing concern that must be managed.

- **Accidents at Three Mile Island (1979), Chernobyl (1986) and Fukushima (2011) had severe and durable human, environmental and political consequences.** Each accident had a different cause: Three Mile Island was a technical/human error (but caused no attributable deaths and limited off-site release); Chernobyl was driven by regulatory/design shortcomings; and Fukushima was triggered by a tsunami, a natural hazard, with regulatory shortcomings compounding its impacts. Public confidence in nuclear is now stratified: greater concern is typically seen in non-nuclear countries, and it is lower in countries with established long-standing nuclear programmes and trusted regulators (e.g., France, Sweden, US, UK and South Korea). Barring these three major incidents, the strong overall safety record is largely attributable to national independent regulators, alongside rigorous, independent safety reviews led by the IAEA, which must continue to underpin new build (see Section 2.1).³⁴ Reactor designs use “defence in depth”: multiple independent layers of protection with redundant, physically separated safety systems, so that no single failure can compromise a safety function.
- **Modern Gen III+ designs (e.g., EPR, AP1000, APR-1400, HPR-1000) are engineered against the tail risks** through passive safety systems that do not require active operator intervention or external power. The specific issue at Fukushima – loss of off-site power followed by loss of backup diesel cooling after seawater inundation – would not occur in a Gen III+ plant, where passive cooling does not depend on alternating current power or active circulation.³⁵ Safe operations do often still require gravity-driven water supplies, valves, heat sinks, containment integrity or operator intervention for longer-term management. Gen IV designs extend this further through inherently negative reactivity coefficients and atmospheric-pressure operation, reducing the energy available to drive any release in a worst-case scenario.
- **A related and growing concern is climate-driven siting risk.** Most of the global operating fleet sits on coasts or major rivers for cooling-water access, and these sites face rising exposure to sea-level rise, storm surge and freshwater scarcity – linked to the coastal siting risk that Fukushima exposed. Updated IAEA siting safety standards now require explicit assessment of climate-change-adjusted flood and heat-stress envelopes over the asset lifetime; for new builds, this is increasingly reflected in elevated platform heights, dry-cooling design options and reconsideration of inland siting where transmission economics allow. Treating climate-adjusted siting as design criteria is now routine for any new build.

1.2.2 Waste management

The civilian nuclear waste management challenge is technically tractable due to low volumes of high-level waste, but it is politically and institutionally demanding and must be planned from project inception.³⁶

- **Waste is classified by its level of radioactivity: ~90% by volume is low-level, 7% intermediate-level and less than 3% is high-level. High-level waste contains 95% of the radioactive material and is the only type that requires long-term isolation.³⁷** Low-level waste arises mainly during routine reactor operation (e.g., tools and protective clothing) and is disposed of routinely via compaction or incineration followed by permanent burial in near-surface engineered concrete vaults. Intermediate level (more radioactive materials, including resins, sludges and reactor components) is mainly produced during decommissioning as reactor components are dismantled. Smaller items and non-solids are solidified in concrete or bitumen to shield their radioactivity for

33 Nuclear Energy Agency (2010), *Public Attitudes to Nuclear Power*; World Nuclear News (2025), *Poll Finds Global Public Support for Nuclear Remains High*. Available at: <https://www.world-nuclear-news.org/articles/poll-finds-global-public-support-for-nuclear-remains-high> [Accessed 06 2025].

34 Nuclear has caused 0.03 deaths per TWh, compared to coal 24.6, oil 18.4, natural gas 2.8, hydropower 1.3, wind 0.04, solar 0.02. Source: Our World in Data (2020), *Nuclear Energy*

35 IAEA (2015), *The Fukushima Daiichi Accident: Report by the Director General*.

36 This section addresses civil nuclear waste. In countries with legacy weapons programmes, notably the US and the UK, a significant share of the national radioactive waste burden and clean-up liability arises from defence activities and early dual-purpose plutonium production rather than from commercial power generation. Those legacy liabilities are managed under separate programmes and are not a consequence of new civil nuclear build. Source: U.S. Government Accountability Office (n.d.), *Nuclear Waste Disposal*. Available at: <https://www.gao.gov/nuclear-waste-disposal> [Accessed 06 2026]; Gov.UK (2023), *UK Radioactive Waste Inventory 2022*. Available at: <https://www.gov.uk/government/publications/uk-radioactive-waste-and-material-inventory-2022/uk-radioactive-waste-inventory-2022> [Accessed 06 2026].

37 World Nuclear Association (2025), *Radioactive Waste Management*.



disposal. High-level waste is generated continuously through operation as fuel is cycled out of the reactor and creates the largest disposal challenge.³⁸

- **High-level waste contains most of the total radioactivity and requires long-term isolation through deep geological disposal (or possibly fuel recycling or reprocessing in future). Local acceptance of hosting waste disposal facilities is a major barrier to high-level waste disposal programmes.** There is broad scientific and technical consensus that disposing of high-level waste in deep geological formations can safely isolate it from the biosphere for very long-time scales.³⁹ All nations with nuclear power still rely on interim storage while the first deep repositories are developed. Finland's 400m deep Onkalo facility plans to start storing waste in 2026 for up to 100,000 years,⁴⁰ Sweden's Forsmark site received construction approval in 2022 and France's Cigéo project is in the licensing stage.⁴¹

However, scaling these solutions sufficiently will rely on political will, siting consent and long-term institutional funding. A precondition to new nuclear development plans should be to establish geological repository siting, community engagement and long-term funded liability provisions, in line with global best practices.



1.2.3 Nuclear weapons proliferation risks

Proliferation, the risk of nuclear weapon development that can arise during enrichment and reprocessing, is a hugely important issue. Non-proliferation of nuclear weapons should be ensured by conditioning new nuclear power investments on comprehensive safeguards agreements, with fuel-cycle services concentrated in existing supplier states rather than replicated nationally (see Section 2.3). Novel fuels for Gen IV designs with higher enrichment than conventional fuels like HALEU raise enrichment-related proliferation risks that require careful management.

- **The primary proliferation risk from civilian nuclear lies in dual use of enrichment and reprocessing technologies, not from the reactors themselves.** Notable cases of weapons proliferation in Iran, North Korea, Israel all involve states operating outside of or in breach of IAEA safeguards, in which civilian nuclear programmes masked or accelerated weapons-grade material production.
- **Proliferation cascade risk of new countries acquiring nuclear weapons decreased significantly after the end of the Cold War in 1991. [Exhibit 1.4]** However, this trend may be reversing. The number of nuclear-armed states has never been higher, arsenals are being modernised and, in some cases, expanded and key arms control frameworks are eroding.
- **Scaling civilian nuclear fuel supply chains will require strengthened safeguards and international oversight, particularly if the use of highly enriched next-generation fuel scales.**⁴² Safeguards are designed to deter diversion of nuclear material to military applications by increasing the risk of early detection. They include the Nuclear Non-Proliferation Treaty (NPT), which includes ~190 states, under which the IAEA administers safeguards.⁴³ The IAEA also established the Additional Protocol, spanning 144 states, which involves regular inspections of civil nuclear facilities to verify the accuracy of documentation supplied, inventory checks and sampling and analysis of materials.⁴⁴

38 World Nuclear Association (2025), *Radioactive Waste Management*.

39 European Commission, Joint Research Centre (2021), *Technical Assessment of Nuclear Energy with Respect to the 'Do No Significant Harm' Criteria of Regulation (EU) 2020/852 ('Taxonomy Regulation')*.

40 IAEA (2026), *A Sustainable Solution for Spent Fuel and High Level Waste Disposal*.

41 In addition, fuel recycling (reprocessing spent fuel into mixed-oxide fuel, as practised at scale in France) could further reduce HLW volumes; however, economic viability is uncertain. Reprocessing could reduce volumes by a factor of four to five, though it adds cost and creates proliferation-sensitive material streams that require strengthened safeguards. World Nuclear Association (2024), *Processing of Used Nuclear Fuel*.

42 Our World in Data (2024), *Nuclear Weapons*.

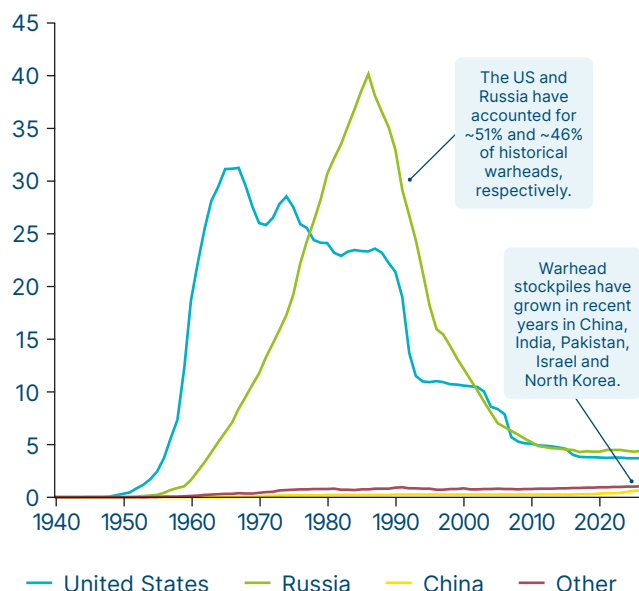
43 The main countries remaining outside the NPT are Israel, India and Pakistan. WNA (2026), *Safeguards to Prevent Nuclear Proliferation*.

44 WNA (2026), *Safeguards to Prevent Nuclear Proliferation*.

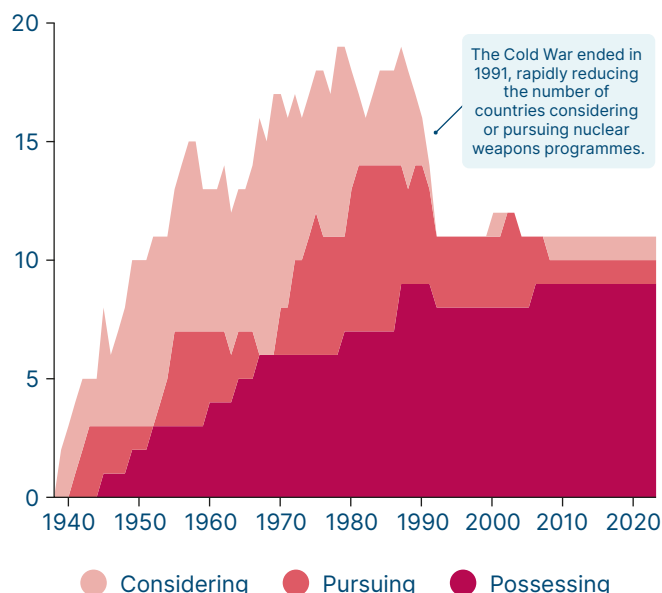
Proliferation risks require robust safeguards if nuclear scales, though fewer countries pursue weapons than during the Cold War

Estimated nuclear warhead stockpiles (a country's total inventory of assembled nuclear weapons)

Thousand warheads



Number of countries that consider, pursue or possess nuclear weapons



SOURCE: Our World in Data (2024), *Nuclear Weapons*; Our World in Data (2026), *Nuclear Weapons: Why Reducing the Risk of Nuclear War Should be a Key Concern of Our Generation* (reused with permission per CC BY 4.0); Federation of American Scientists (2026), *Status of World Nuclear Forces* (reused with permission per CC BY 4.0).

1.3 Cost structure and variations by region: the dominant role of upfront capital and financing costs

The levelised cost of electricity (LCOE) of nuclear relative to other clean power technologies is a key determinant of its relative role in a country's power system. In Section 1.5, we compare the LCOE from nuclear versus renewable sources in different countries. Renewable costs vary significantly (e.g., from \$20–200 per MWh)⁴⁵ because of differences in natural resources and local CAPEX and financing costs. LCOEs for new-build nuclear also vary significantly (e.g., \$40–190 per MWh). This is not due to technology design or fuel cost variation: technologies deployed are broadly similar around the world, and fuel costs have only a small effect on total LCOE for new-build conventional (Gen I–III+) reactors. Instead, this variation is explained by big geographical differences in i) CAPEX driven by local labour and services costs during construction (~70–80% of CAPEX); the weighted average cost of capital (WACC) which is strongly influenced by whether governments provide low-cost finance; and (iii) the speed of delivery, which compounds CAPEX and WACC. Both CAPEX and financing costs vary dramatically by region, with Europe and the US facing total CAPEX 4 to 9 times higher than in Asian countries with large-scale nuclear programmes (China, South Korea and India).

1.3.1 Nuclear LCOEs: capital expenditure and financing are the dominant drivers

The total LCOE of nuclear generation reflects the CAPEX of equipment and construction, the financing cost incurred during construction and operations, the operational expenses (OPEX) on fuel, operations and maintenance

⁴⁵ \$20–90 per MWh for onshore wind or solar, \$50–140 per MWh for offshore wind, \$30–200+ per MWh for new large hydro and \$50–100 per MWh for low-cost solar and battery projects (in the global sunbelt). Note that LCOEs are not system costs, and system costs are discussed further in Chapter 3. Source: BloombergNEF (2025), *LCOE Data Viewer*; IRENA (2026), *24/7 Renewables: The Economics of Firm Solar and Wind*.

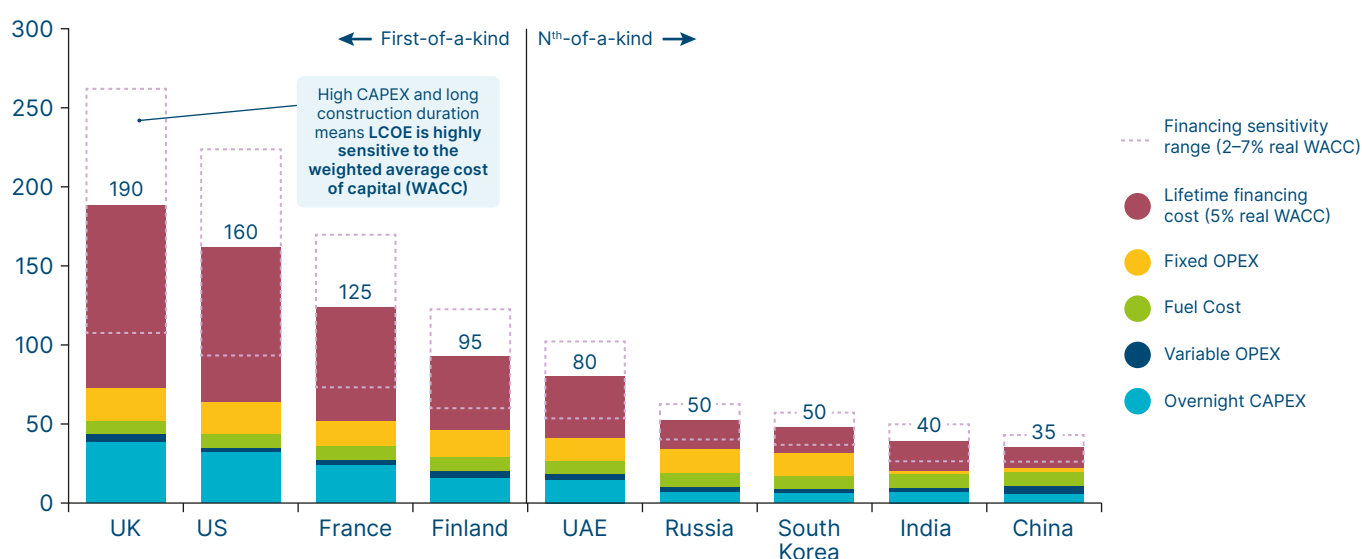
and the decommissioning expenditures (DECEX) at the end of life.⁴⁶ Lifetime extensions offer a low-cost and relatively fast (though still multi-year) opportunity to maintain operating capacity.

The large range of upfront CAPEX, project timescales and financing costs results in a wide range of LCOEs across different countries. China, South Korea and India are likely to continue to be able to deliver nuclear generation at costs below \$50 per MWh by 2035, whereas France, the UK and the US are currently unlikely to achieve costs below ~\$125 per MWh. [Exhibit 1.5]

Exhibit 1.5

Estimated LCOEs for recent projects show a clear divergence between US / Europe and the rest of the world, mainly driven by CAPEX and financing costs

Recent LCOE estimates by country with varying CAPEX, OPEX and construction duration, all else equal, Gen III / III+ \$/MWh, real 2024



NOTE: LCOE = levelised cost of electricity; CAPEX = capital expenditure; OPEX = operating expenses. 5% WACC (real) assumed for all countries as a base case, with 2% WACC representing state-backed projects and 7% WACC representing privately-funded projects. Construction duration assumed to be 10 years for US / Europe and 5 years for RoW. Interest during construction (IDC) assumed CAPEX is spent evenly over construction duration (n), so the average interest accrues at WACC for n/2 years. Fixed and variable OPEX based on BloombergNEF, ETI and INL. Fuel cost assumed to be \$8 per MWh. Total values are rounded to the nearest 5.

SOURCE: Systemiq analysis for the ETC (2026); Energy Technologies Institute (2020), *The ETI Nuclear Cost Drivers Project* (now held by Energy Systems Catapult); BloombergNEF (2026), *LCOE Data Viewer*; INL (2024), *Nuclear Energy Cost Estimates for Net Zero World Initiative*.

The levelised cost is primarily driven by CAPEX and financing costs, with fuel costs and OPEX typically accounting for 20–40% of total LCOE and DECEX ~1%.

1. Overnight CAPEX covers all physical construction costs (excluding financing) – most of which are local construction and services costs – not equipment. Historically, this has ranged between \$2,000–18,000 per kW,⁴⁷ ~15–30% of which is materials and equipment, with the rest dominated by labour and services.

⁴⁶ Typical total decommissioning (including waste disposal) costs are ~\$500–1,200 per kW spread over 15 to 20 years at the end of life. Decommissioning planning is typically embedded from project inception with funded liability provisions. The 'present value' of decommissioning and waste disposal costs is relatively low due to the long project life (60+ years), regardless of discount rate – e.g., US projects collecting \$1–2 per MWh build up sufficient funds to pay off DECEX at end-of-life. Source: World Nuclear Association (2026), *Decommissioning Nuclear Facilities*. Available at: <https://world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-waste/decommissioning-nuclear-facilities#cost-and-finance> [Accessed 08 2026].

⁴⁷ FOAK projects are at the top of the range and NOAK projects are towards the bottom. Source: Systemiq analysis for the ETC (2026); Nature (2025), *Can China Break the 'Cost Curse' of Nuclear Power?*

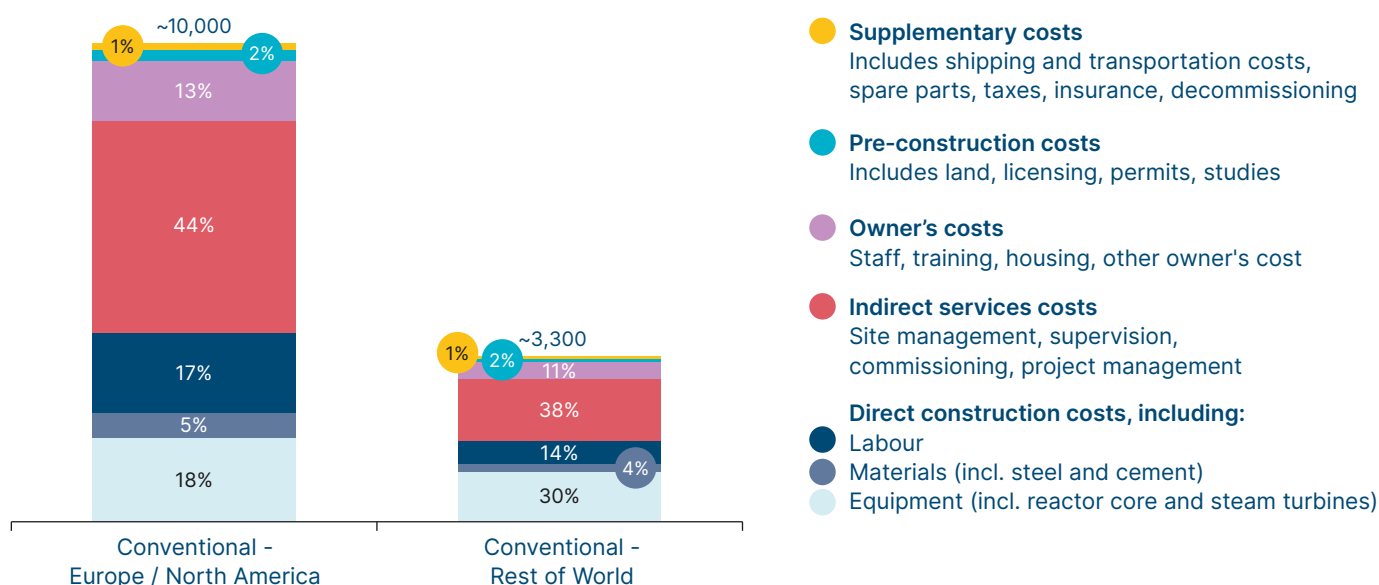


[Exhibit 1.6] Despite wide variation by region (see Section 1.3.2) and reactor type, their composition is largely consistent: ~40–50% direct construction costs (labour, materials and equipment); ~30–45% indirect services and site management; ~10% owner's costs (project management, training, commissioning, contingency); 2% pre-construction costs; and 1% supplementary costs. In contrast, life extensions typically cost ~\$500–1,100 per kW (yielding an LCOE below \$40 per MWh), well below new-build CAPEX and LCOE in all locations.^{48,49}

Exhibit 1.6

Nuclear CAPEX is mainly driven by indirect services (site management), labour and equipment costs

Conventional nuclear overnight CAPEX breakdowns for Europe/North America vs Rest of World
\$/kW, real 2024



SOURCE: Energy Technologies Institute (2020), *The ETI Nuclear Cost Drivers Project* (now held by Energy Systems Catapult)

2. Financing costs can make up to ~70% of levelised lifetime costs, but the size and relative impact vary strongly by region and depend on the project's WACC and construction timeline.⁵⁰ Financing costs are interest paid during construction and debt repayments during project operations. These are determined by the relative debt-to-equity ratio and the WACC. The WACC has a strong impact on LCOE given the dominance of CAPEX relative to OPEX and the long construction timelines. This is because capital deployed during the pre-revenue period generates no return, so interest during construction accrues and compounds on a capital balance that keeps growing until the plant earns revenue. This impact exists for all CAPEX-heavy power generation projects but is much higher for nuclear than for renewables: nuclear project development typically requires 10–25 years (6–15 years from final investment decision [FID] to commercial operation), compared to 1–4 years for onshore wind and solar (with ~1–2 years between FID and operation). [Exhibit 1.7] This makes nuclear costs uniquely sensitive to WACC, which is a key driver of the affordability of nuclear electricity. Industry estimates place the interest accumulated during construction alone at 30–45% of total project cost for FOAK projects on 12–15 year build programmes, falling to 15–25% for repeat NOAK builds completed in 7–8 years.⁵¹

48 IEA (2024), *World Energy Outlook 2024*.

49 Upgrades – physical modifications and/or recalibration that raise a reactor's licensed output – have added ~8 GWe across the US fleet since 1977 and remain a meaningful lever there (with further potential remaining), but most other major fleets (notably Sweden, Switzerland, Finland) have already largely exhausted this potential through aggressive programmes in the 2000s–2010s. Source: U.S. NRC (2022), *Background on Power Upgrades for Nuclear Plants*.

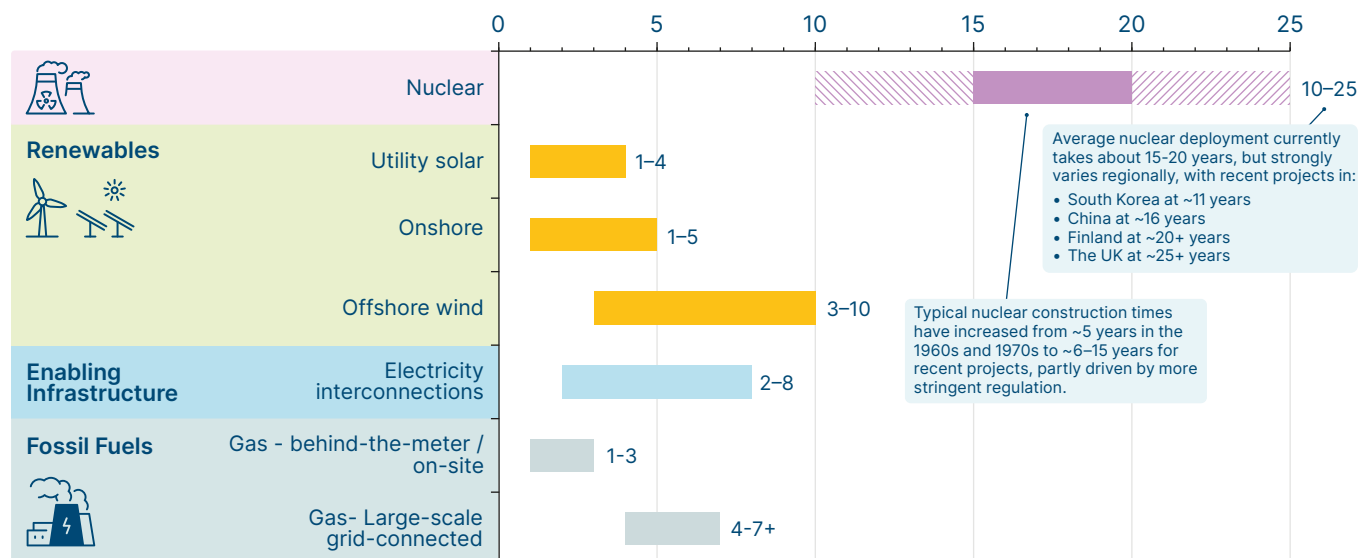
50 Systemiq analysis for the ETC (2026); Energy Technologies Institute (2020), *The ETI Nuclear Cost Drivers Project* (now held by Energy Systems Catapult).

51 World Nuclear Association (2026), *World Nuclear Investment Guide. Investment Readiness: Positioning Nuclear Projects for Faster Financing*.

Nuclear typically takes 15–20 years to deploy – significantly longer than renewables and gas which take 1–10 years

Estimated project development timelines from feasibility to commissioning, global ranges

Years



NOTE: Gas – behind-the-meter / on-site” refers to reciprocating gas engines and aeroderivatives (typically <100 MW) and “Gas – large-scale grid-connected” refers to combined-cycle gas turbines. New upstream fossil development timeframes vary by country and location. Timeframes can also vary depending on if plans are already in place.

SOURCE: Systemiq analysis for the ETC (2026) based on EIA, OTI, North Sea Link, Global Energy Monitor, Qualenergia, Iso Energy, IRENA, EA, CCC, Eurelectric, FT.

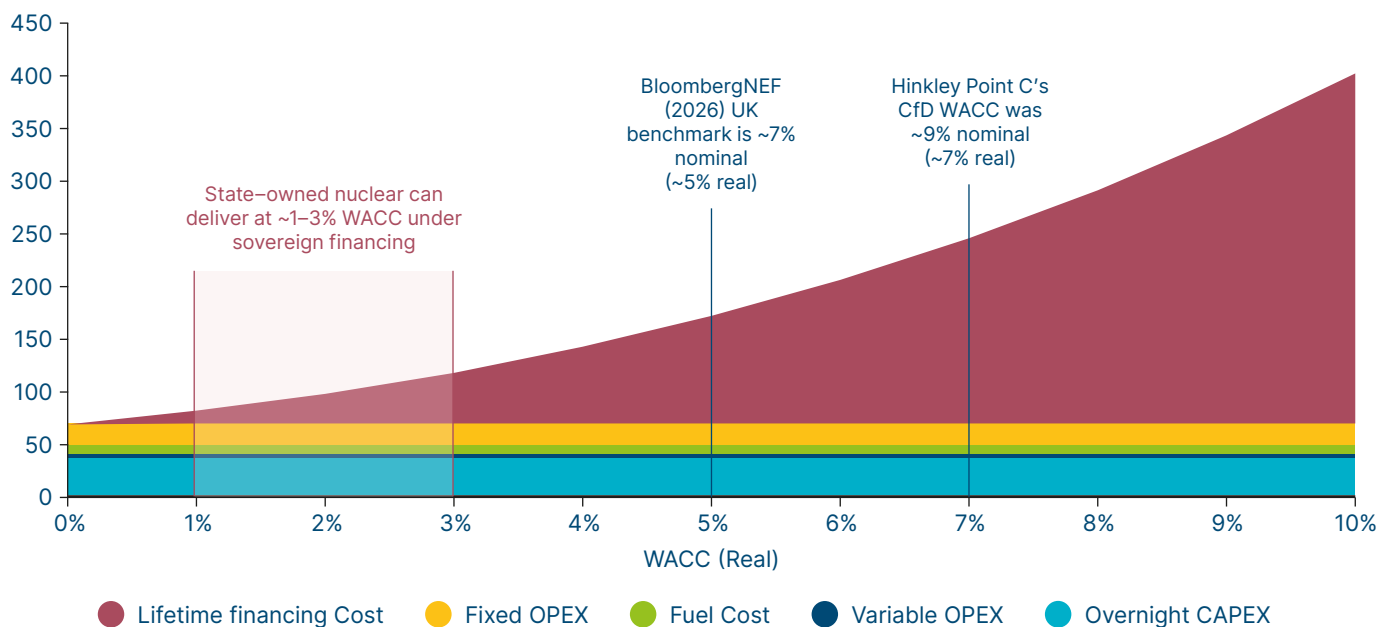
For a UK nuclear plant with high CAPEX and long construction timelines, the LCOE roughly doubles for every 4 percentage-point increase in WACC. [Exhibit 1.8] Nuclear project WACCs largely vary by country and project. This is because the WACC is shaped by 1) the local risk-free interest rate, which is driven by local macro-economic factors and 2) the project risk to financiers, which is largely shaped by what governmental risk and revenue mechanism is in place (as set out in Section 2.2). To illustrate, Chinese state-owned and financed nuclear projects with a fixed administered tariff are financed at a WACC of ~1–3%,⁵² while the predominantly privately financed UK Hinkley Point C project with a government Contract for Difference (CfD) had a WACC of ~9% nominal (~7% real). Based on this WACC, financing costs would contribute around \$190 per MWh to an LCOE of \$260 per MWh.⁵³

⁵² Guru Focus (2026), *China National Nuclear Power Co.*

⁵³ Calculated using Hinkley Point C's latest overnight CAPEX estimate of \$18,000 per kW (real 2024), a 10-year construction period, a 90% capacity factor and a 60-year operating life; 7% real WACC derived from nominal figures by converting to real terms assuming 2% CPI inflation. National Audit Office (2017), *Hinkley Point C*.

Nuclear levelised cost of energy (LCOE) roughly doubles for every four-percentage-point increase in weighted average cost of capital (WACC)

Illustrative nuclear LCOE sensitivity to WACC, based on recent UK Gen III+ nuclear costs
\$/MWh, real 2024



NOTE: CfD = Contracts for Difference, CAPEX = Capital Expenditure, OPEX = Operating Expenditure. Components shown as undiscounted lifetime totals to isolate lifetime financing cost. Overnight CAPEX is the total CAPEX excluding financing costs. Only WACC varies as a sensitivity. Modelled on overnight CAPEX of \$18,000/kW (real 2024), a 10-year construction period, a 90% capacity factor and a 60-year operating life; decommissioning costs excluded. WACC shown as pre-tax real. Nominal figures converted to real assuming 2% CPI inflation.

SOURCE: Systemiq analysis for the ETC (2026); BloombergNEF (2026), *LCOE Data Viewer*; BloombergNEF (2026), *A Costly New UK Nuclear Plant Can Still Cut Power Prices*; National Audit Office (2017), *Hinkley Point C*; INL (2024), *Nuclear Energy Cost Estimates for Net Zero World Initiative*; IEA & Nuclear Energy Agency (2020), *Projected Costs of Generating Electricity 2020*.

The strong regional WACC variation combined with the high upfront CAPEX and WACC sensitivity is important for three related points.

- **It explains most of the regional cost variation set out in Section 1.3.2 below:** differences in delivery conditions – labour productivity, construction duration, regulatory execution and cost of capital – have produced 4–9x cost divergence between recent Generation III/III+ projects.
- **It determines the impact of cost- and schedule-overruns.** Recent European and US projects at Hinkley Point C, Flamanville 3, Vogtle 3&4 and Olkiluoto 3 have seen 2–4x cost increases relative to original estimates, driven primarily by construction-duration extensions of 2–4x. These, in turn, lead to equipment and design changes and compound financing costs. State-led programmes in China and South Korea have generally kept overruns materially smaller through standardised fleet-build approaches.
- **It defines that future cost reductions must come from delivery efficiencies and financing.** Because conventional fission (Gen I–III+) is a mature technology, further potential gains from technical innovation could be limited.⁵⁴ Future cost advantages must instead come from delivery efficiencies – off-site modular construction at scale and construction productivity through fleet build approaches. Innovation in financing models, e.g., through regulated asset base (RAB) models and government risk backstops, is a key option for reducing WACC (see Chapter 2).

⁵⁴ Next-generation nuclear technologies could increase the efficiency of thermal-to-electric conversion, however, as discussed in this chapter, higher associated fuel costs are likely to outweigh these gains.

1.3.2 High regional cost variation; capital expenditure in the US and Europe is 4–9 times higher than recent Asian projects

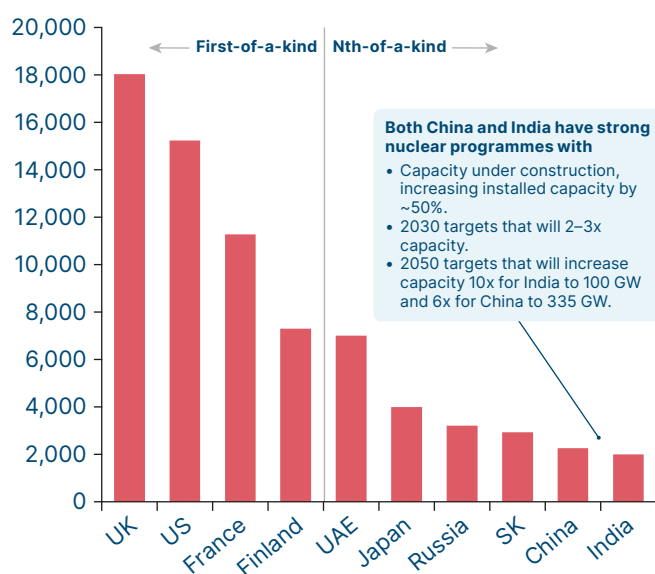
Significant overnight CAPEX variations by region have become apparent in recent decades. Nuclear CAPEX for recent builds using a similar Gen III/Gen III+ technology ranges from \$2,000–18,000 per kW around the world, with the European and North American average first-of-a-kind (FOAK) project costs around 4x the Asia average using established technology designs (“Nth-of-a-kind” – NOAK) as shown in Exhibit 1.9.

Exhibit 1.9

Nuclear CAPEX and level of overrun varies up to 9x by country, driven by local labour and material costs, regulatory architecture and design standardisation

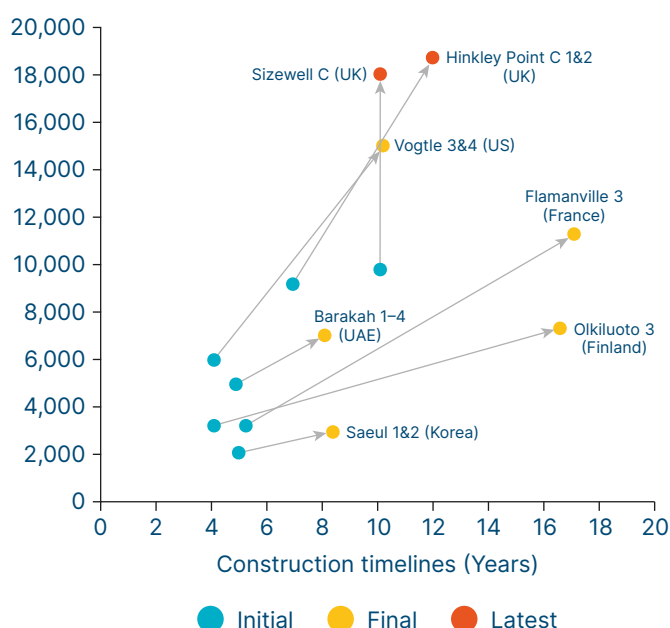
Recent Generation III overnight CAPEX estimates by country

\$/kW, real 2024



Initial and latest overnight CAPEX estimates and construction timelines

\$/kW, real 2024



NOTE: “Overnight CAPEX” refers to capital expenditure as if it were completed “overnight”, excluding all interest, financing, and inflation costs that happen during construction. Sizewell C’s latest estimate takes the midpoint from the National Audit Office’s CAPEX range.

SOURCE: IEA (2025), *The Path to a New Era for Nuclear Energy* (re-used with permission per CC BY 4.0); National Audit Office (2026), *Sizewell C*; BloombergNEF (2026), *LCOE Data Viewer*; Energy Technologies Institute (2020), *The ETI Nuclear Cost Drivers Project*; INL (2024), *Nuclear Energy Cost Estimates for Net Zero World Initiative – 2024 Update*; Financial Times (2025), *Cost of Sizewell C Nuclear Project Expected to Reach Close to £40 billion*; New Civil Engineer (2026), *Hinkley Point C’s Cost Climbs to £35 billion with Confirmation Unit 1 will Power Up in 2030*; Green Prizm (2024), *2023 Report on Chinese Nuclear Power Generation and Costs Analysis*; WNA (2026), *China – World Nuclear Outlook Report*; WNA (2026), *India – World Nuclear Outlook Report*.

The CAPEX and related WACC divergence between European/North American and Asian builds is explained by three structural cost drivers. [Exhibit 1.10] The differences are not technology-specific – the same Generation III+ designs have been deployed in both regions – but reflect choices in nuclear build-out programmes across regulatory architecture and programme commitment, as well as local labour and material markets.

One-off delivery has raised recent Western costs; programmatic approaches in Asia standardise designs and regulation, and shorten builds

Cost driver	European / North American pattern (high cost) ⁵⁵	Asian pattern (low cost)
1. Design standardisation and replication	High CAPEX driven by FOAK treatment of each project, which could decrease with fleet build pipelines. Each recent build has been largely re-engineered, forfeiting learning-by-doing across units. Even nominally identical designs are modified at site level – Hinkley Point C, despite being the same EPR design as Flamanville 3 and Taishan, has reportedly undergone ~7,000 mid-construction design changes. ⁵⁶ This raises input costs across labour, services and raw materials, compounded in some cases by high labour and services rates and local materials costs and lower labour productivity on FOAK projects. Recent projects have established supply chains and project execution models which can be replicated in future projects to reduce FOAK costs. Innovation in component fabrication – e.g., via offsite or onsite controlled environments for modular components to mitigate weather issues – could also lower CAPEX (to e.g., ~\$10,000 per kW) for future builds for standardised designs.	Low CAPEX driven by serial deployment of standardised designs across multiple units. Repetition captures learning-by-doing and supply chain efficiencies from fleet-level economies of scale. South Korea's APR-1400 and China's HPR-1000 / CAP-1000 have delivered consecutive units with falling unit cost and duration. Lower labour rates and locally priced materials compound this. Sustained government programmes mean continuity in supply chain development, resulting in higher labour productivity. This is further supported by technology exports (such as South Korea's Barakah project in the UAE, China's Karachi project in Pakistan and Russia's El Dabaa project in Egypt).
2. Regulatory architecture and standardisation	International regulatory fragmentation creates inefficient development processes. Sequential licensing across projects, with construction starting before detailed engineering is complete. About half of the ~15–20-year development time (including construction) consists of pre-development and licensing. This creates exposure to mid-construction design changes that are 5–10x more costly than the same change resolved at design stage. The Hinkley Point C ~7,000 design changes increased steel and concrete content by ~35% and ~25% respectively. UK Generic Design Assessment and US NRC Part 53 are attempting to address this by requiring greater design maturity upfront.	Standardised regulation drives efficient delivery. Parallel rather than sequential licensing, with high design maturity for repeat builds at final investment decision. Stable, long-term regulatory frameworks reduce the probability of mid-construction scope change. For example, two-thirds of China's 60 operational reactors were built in under six years, ⁵⁷ driven by centralised siting decisions, a programmatic fleet build that locks in workforce and supply chain continuity and a regulatory regime that issues construction and operating licences against a fixed reference design.
3. Financing costs and construction duration	Long delivery timelines increase CAPEX inputs and WACC; new financing models can lower WACC. Extended construction times in countries starting new reactor build programmes (e.g., 10–15 years) means input costs increase (across labour and services), alongside cost overrun risk, which also raises the WACC. Long durations also compound financing costs during construction and increase exposure to labour/materials cost inflation (e.g., driven by energy crises). New financing models, e.g., regulated asset base (RAB) models can lower WACC by shifting delivery and/or revenue risk from private investors to the state or consumers, though this creates a trade-off with risk exposure.	Proven delivery timelines mean lower CAPEX inputs, delivery risk and WACC. Shorter construction durations (e.g., 5–8 years from FID to commercial operation) reduce the amount of interest during construction. Programmatic buildout means high certainty in the long-term project pipeline, attracting low financing rates (typically government-backed).

⁵⁵ Systemiq analysis for the ETC; ETI (2020), *Nuclear Cost Drivers Project*; Fingleton (2025), *Nuclear Regulatory Review*; FT (2025), *Can the Nuclear Industry Find a Better Way to Build?*

⁵⁶ World Nuclear News (2024), *EDF Announces Hinkley Point C Delay and Rise in Project Cost*. Available at: <https://www.world-nuclear-news.org/articles/edf-announces-hinkley-point-c-delay-and-big-rise-i> [Accessed 07/2026].

⁵⁷ WNA (2026), *Nuclear Power in China*.

Historical CAPEX has shown wide programme-specific variation rather than a monotonic trend: the US costs escalated from ~\$1,400 per kW in the mid-1960s to ~\$5,000–15,000 per kW from the 1980s onwards (in 2024 prices), while French builds in the 1970s–1990s remained at ~\$2,000–4,000 per kW, before increasing to ~\$11,000 per kW for Flamanville 3. Initial Chinese projects in the 1990s were ~\$10,000 per kW which then declined to ~\$2,000–4,000 per kW from around 2005 onwards, driven by learning effects as domestic supply chain capabilities and experience increased. South Korean and Indian programmes have also remained at ~\$2,000–4,000 per kW since the late-1990s.⁵⁸

Countries which have maintained standardised, programmatic deployment of large-scale, conventional reactors in recent decades have managed to keep CAPEX at the low end of the \$2,000–18,000 per kW global range. China is the most notable example of this, accounting for 46% of global new reactor capacity since 2000.⁵⁹ South Korea, Russia and India have also delivered several projects at low cost in recent years, and have accounted for 12%, 11% and 5% of new capacity since 2000, respectively.

1.4 The potential cost impact of novel nuclear technologies, including SMRs: still unproven

New nuclear technologies might reduce the cost of nuclear generation in future, but it is currently not reasonable to assume significant cost reductions in the next decade.⁶⁰

- Small modular reactor (SMR) manufacturing and installation efficiencies may reduce costs, increase siting flexibility and unlock Gen IV technologies.
- However, the cost reduction case is still unproven for SMRs (Gen III+ and Gen IV). This means most nuclear capacity expansion in the coming decades could therefore continue to depend primarily on large-scale, conventional Gen III+ fission technology.

SMR units span a wide capacity range up to 300 MW per unit,⁶¹ which could increase siting flexibility and alignment with private funding compared to ~1,000 MW conventional large reactors; however, diseconomies of scale could limit the benefits from modularity. [Exhibit 1.11]

- **Increased siting flexibility** due to potentially lower safety stringency from smaller sizes, lower thermal inventories and passive safety features could permit smaller emergency planning zones and siting closer to demand centres. However, this has yet to be proven in practice, with many demonstration projects using brownfield nuclear/ex-fossil sites, and many regulators may still enforce the same safety conditions as applied to large reactors.
- **Closer alignment with private funding** appetite through smaller projects with lower total CAPEX than multi-GW scale projects. This opens up new sources of funders, for example, AI hyperscalers are looking to SMRs as an option to power growing data centre demand. There were 45 GW of data centre offtake agreements with SMRs by the end of 2025, with the first projects expected to enter operations around 2030.⁶²
- **However, plant-level economies of scale have pushed several leading “SMR” designs beyond the standard SMR capacity range to ~300–500 MW.** For example, GE Hitachi’s BWRX-300 is 300 MW, Westinghouse’s AP300 is ~300 MW and Rolls-Royce’s SMR is 470 MW. Higher unit sizes are typically needed to spread size-invariant fixed costs across sufficient output: regulatory compliance and safety systems, staffing and site licensing and preparation costs do not scale down proportionally with reactor capacity. Smaller units face diseconomies of scale on these cost drivers, which offsets some potential gains from more modular fabrication. SMRs are therefore typically developed as multi-unit sites to improve unit economics, so overall project capacities can be similar to large-scale reactors. This also allows early units to enter commercial operation and generate revenue ahead of full site completion, while later units are still under construction.

58 Nature (2025), *Can China Break the ‘Cost Curse’ of Nuclear Power?*

59 IAEA (2026), *Power Reactor Information System*.

60 Thorium and fusion technology could have long-term potential, but large-scale commercial deployment is unlikely before 2040. This is outlined in Section 1.1, and these technologies are not further analysed in this section.

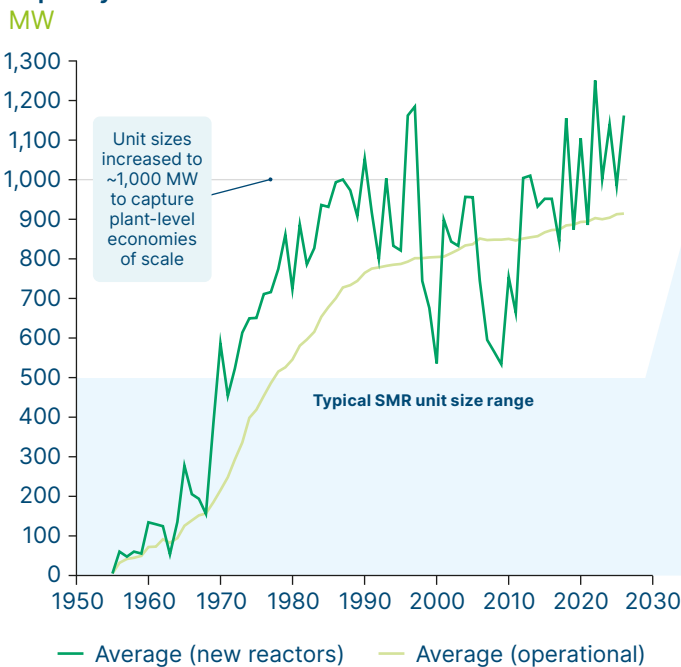
61 300 MW was the original upper limit for SMRs but some SMR designs now have larger unit capacities. Reactors <10 MW units can be classified as microreactors, a subset of SMRs. Source: IAEA (2023), *What are Small Modular Reactors (SMRs)?* Available at: <https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs> [Accessed 08 2026].

62 IEA (2026), *Key Questions on Energy and AI*.

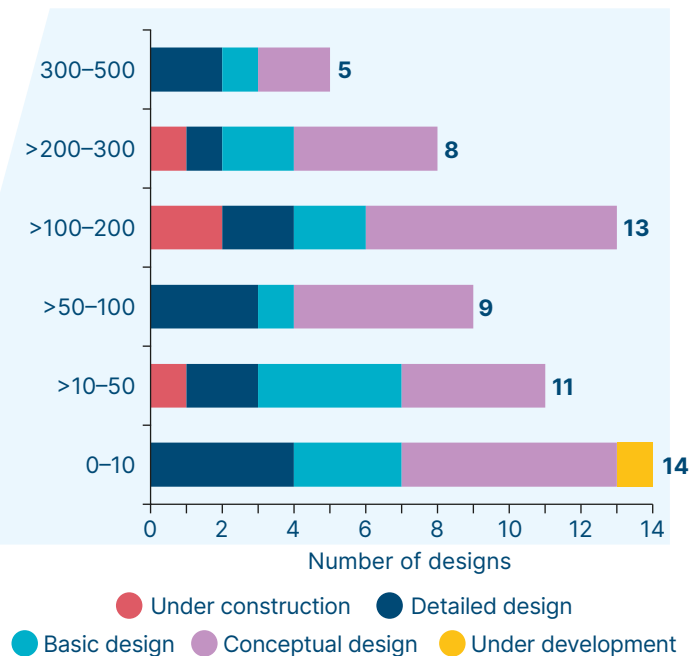


Reactor sizes have increased over time; Small modular reactors (SMR) aim to reverse this trend, but few have reached advanced stages

Global average operational and new reactor capacity over time



SMR distribution by size and maturity (2024)



SOURCE: IAEA (2026), *Power Reactor Information System*; IAEA (2024), *Small Modular Reactor Technology Catalogue 2024*.

SMRs span two technology design families with different maturity: Gen III+ and Gen IV:

- **Gen III+ SMRs are scaled-down light-water reactors using the same designs (pressurised or boiling water reactors) as the conventional fleet** (LEU fuel, water coolant, ~300°C outlet, ~50 MWd-th per kg burnup rate, ~35% thermal-to-electrical efficiency).⁶³ Gen III+ SMRs therefore use mature components and systems with thousands of reactor years of operation, but are at TRL 5–8 because no designs have been deployed commercially as an integrated system. There are several first-of-a-kind projects in construction (e.g., Linglong One in China, BWRX-300 at Darlington in Canada, targeting 2026 and 2030 operations, respectively) and prospective NuScale deployment in the US, and Rolls-Royce in the UK, Sweden and the Czech Republic. Widespread deployment is not happening yet. [Exhibit 1.12]
- **Gen IV SMRs use reactor designs that use different coolant-fuel combinations to increase safety and efficiency but also fuel costs. These technologies have been in development since the 1950s, but all have yet to commercialise.**⁶⁴ In contrast to Gen III+ designs, they remain at TRL 2–8 because there is limited operational experience of the underlying components and systems and none have been deployed commercially as an integrated system. They have not progressed beyond the demonstration stage despite decades of research and development (R&D) for many designs.
 - Fast breeder reactors have been in development since the 1970s, gas-cooled fast reactors (GFR) since the 1970s, molten salt fast reactors (MSR) since the 1960s and sodium-cooled fast reactor (SFR) since the 1950s.⁶⁵
 - Gen IV designs could also unlock new combined industrial process heat and power applications due to higher temperatures (see Section 3.3).

⁶³ Burnup rate is the thermal energy output (MWd-th) per unit mass of fuel burned; thermal-to-electrical conversion efficiency is the ratio of electrical energy output to thermal input.

⁶⁴ Gen IV designs are being developed at both SMR (e.g., X-energy's Xe-100 high-temperature gas-cooled reactor) and large-scale (e.g., Rosatom BN-1200, a sodium-cooled fast breeder reactor), though most near-term commercial focus is on SMR variants.

⁶⁵ World Nuclear Association (2025), *Generation IV Nuclear Reactors*; World Nuclear Association (2021), *Advanced Nuclear Power Reactors*; GEN IV International Forum (n.d.), *SFR Projects History - Past projects*.

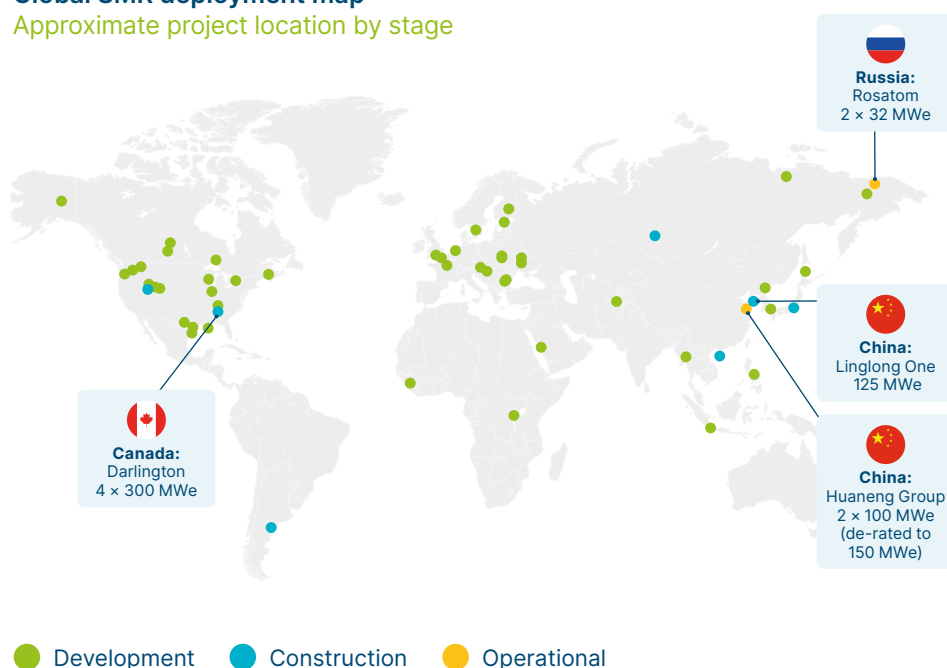
- Passive safety features use phenomena such as gravity, pressure differences or natural heat convection to ensure reactor safety without an active power input. This is a feature of several Gen IV concepts but is not unique to them – some Gen III+ SMRs (e.g., NuScale) also rely on passive cooling.⁶⁶
- Gen IV commercialisation has been held back by a combination of unresolved technical and materials challenges (e.g., fuel and structural materials capable of withstanding high temperatures and corrosive coolants over commercial lifetimes) and discontinuous R&D funding across multi-decade development timelines. Flagship demonstrators have also faced operational problems and cancellations on cost, safety or political grounds – e.g., fast reactors such as the 1.2 GW Superphénix SFR in France, the 280 MW Monju SFR in Japan and the Astrid SFR project, cancelled in 2019 despite a €651 million French government loan.⁶⁷
- The novel coolants – high-temperature gas (helium), liquid metal (sodium, lead) or molten salt rather than water – typically require HALEU fuel (5–20% enriched U-235) rather than conventional LEU (<5% enriched). This enables >40% thermal-to-electrical efficiency and burnup rates of up to 200 MWd-th per kg, but higher fuel costs per kg could outweigh efficiency gains and result in higher fuel cost per MWh (to ~\$10–60 per MWh) than conventional designs (typically ~\$5–15 per MWh). [Exhibit 1.12]
- The low TRL across these designs means component and fuel supply chains are still immature. Future costs are highly uncertain, and commercialising most Gen IV reactors will depend on demonstrated burnup rates and efficiencies and the development of sufficiently low-cost HALEU or recycled fuel production capacity – particularly across enrichment and fuel fabrication, which are the dominant cost drivers.⁶⁸ [Exhibit 1.12]

Exhibit 1.12a

Gen III+ SMRs are starting to be built in North America and Asia; Gen IV SMRs are in earlier stages of development

Global SMR deployment map

Approximate project location by stage



Siting progress, by country

Number of projects



NOTE: MoU = Memorandum of Understanding.

SOURCE: Systemiq analysis for the ETC (2026); OECD NEA (2025), *The NEA Small Modular Reactor Dashboard: Third Edition*; US DoE (2024), *Pathways to Commercial Liftoff: Advanced Nuclear*; Mycle Schneider Consulting (2024), *The World Nuclear Industry Status Report 2024*; Third Way (2024), *The Global Race for Advanced Nuclear Is On*; Nuclear Innovation Alliance (2025), *Advanced Reactor Deployment Map*. (Re-used with permission per CC BY 4.0).

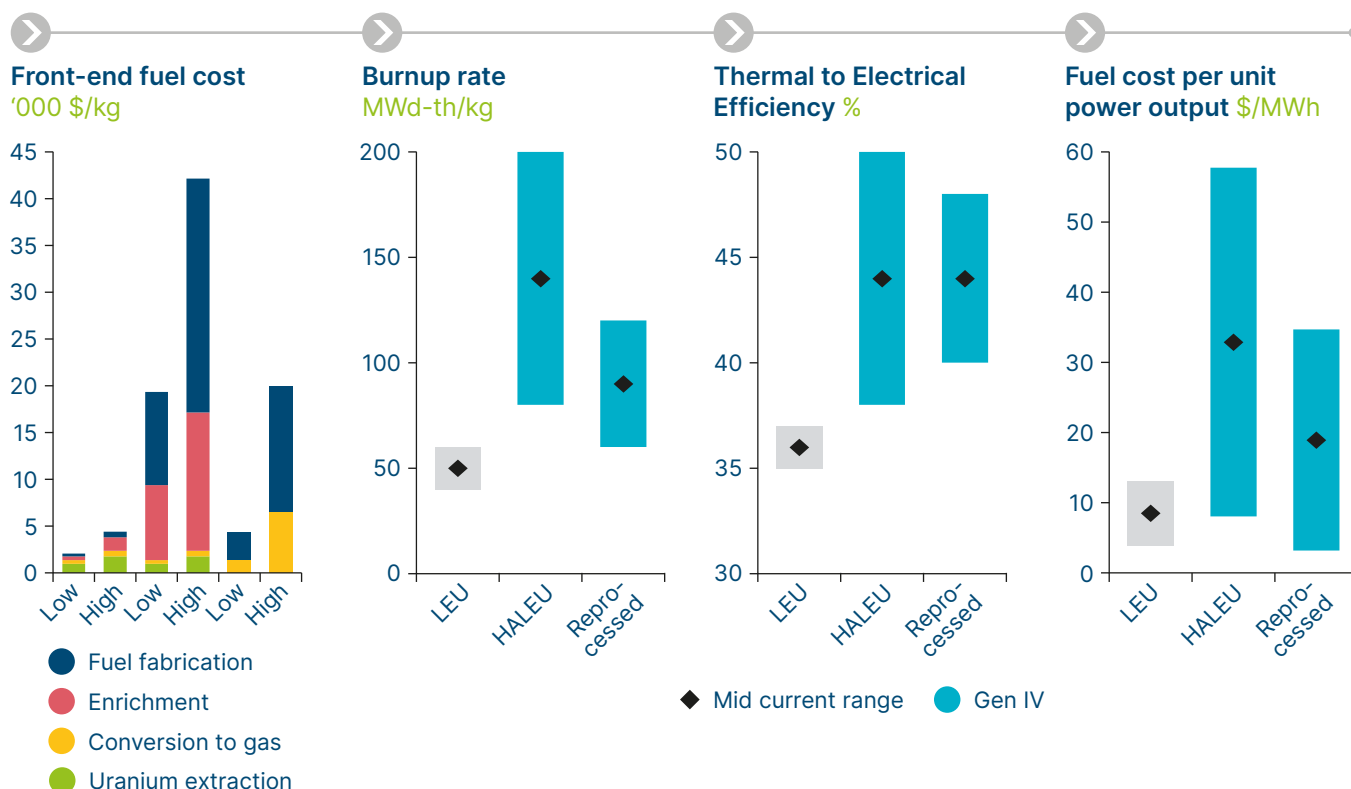
⁶⁶ Mycle Schneider Consulting (2024), *The World Nuclear Industry Status Report 2024*; Third Way (2024), *The Global Race for Advanced Nuclear Is On*; Nuclear Innovation Alliance (2025), *Advanced Reactor Deployment Map*.

⁶⁷ World Nuclear Association (2021), *Advanced Nuclear Power Reactors*; World Nuclear Association (2025), *Generation IV Nuclear Reactors*.

⁶⁸ Fuel cycle steps breakdown: Uranium extraction is the mining “yellowcake” (triuranium octoxide, U₃O₈); Conversion changes yellowcake to uranium hexafluoride (UF₆) gas; enrichment increases the Uranium-235 isotope concentration to 3–5% for LEU and up to 20% for HALEU; and fabrication reconverts the enriched UF₆ to uranium dioxide (UO₂) powder then into sealed ceramic pellets to form fuel rods and bundled into assemblies – with HALEU-based fuels (metallic or tristructural-isotropic [TRISO] forms) required for most advanced reactor and SMR designs. Refer to Section 2.3.1 for further details.

Gen IV fuel costs per MWh power delivered are set to exceed conventional costs driven by higher front-end fuel costs – despite higher efficiencies

Some Gen IV reactors use higher-enriched High-Assay Low-Enriched Uranium (HALEU) or reprocessed fuels reactors that enable higher burnup rates & use novel coolants to reach higher thermal efficiencies than conventional designs (LEU). But the front-end costs of these novel fuels are high and uncertain (due to immature supply chains) which means efficiency gains are likely offset.



NOTE: Fuel cost (\$ per MWh-e) = fuel cost (\$ per kg) ÷ [burnup (MWd-th per kg) × 24 (hours per day) × efficiency (%)], where burnup is the thermal energy released per unit mass of fuel and efficiency is the thermal-to-electrical conversion rate. A representative range of burnup and efficiency estimates was compiled for Conventional Light Water Reactors (LEU), Very High Temperature, Sodium-cooled Fast, Molten Salt Reactors (HALEU) and Lead-cooled Fast and Supercritical Water-cooled Reactors (reprocessed). LEU = Low Enriched Uranium (<5% U-235); HALEU = High-Assay Low-Enriched Uranium (5–20% U-235); reprocessed or recycled fuels include Mixed Oxide Fuel and mixed uranium-plutonium carbide. Front-end fuel costs assume uranium extraction = \$110–200 per kg; conversion costs = \$50–80 per kg; enrichment costs = \$55–200/SWU (LEU), \$200–370/SWU (HALEU); fabrication costs of \$300–600 per kg (LEU) and \$10,000–25,000 per kg (HALEU, upper bound represents TRISO). Reprocessing cost estimates are based on inflated values from OECD/NEA data.

SOURCE: Systemiq analysis for the ETC (2026) based on expert input; OECD NEA (2013), *The Economics of the Back End of the Nuclear Fuel Cycle*; Nuclear Innovation Alliance (2023), *Characterizing an Emerging Market for High-Assay, Low-Enriched Uranium Production*; WNA (2023), *Economics of Nuclear Power*; WNA (2025), *Advanced Nuclear Power Reactors*; Nuclear Energy Agency (2018), *State-of-the-Art Report on Light Water Reactor Accident-Tolerant Fuels*; GEN IV International Forum (n.d.), *Generation IV Goals, Technologies and GIF R&D Roadmap*; M. Hewitt (2025), *Investment in a Nuclear Startup – Fuel Decision Tree*.

The core economic proposition of SMR is that it can reduce CAPEX vs. conventional nuclear by replacing on-site construction with centrally manufactured standardised modules. Design consolidation and standardisation are required to deploy this modular model and unlock cost reduction. Because of the low maturity and high-cost uncertainty associated with SMRs and Gen IV reactors (SMR or large-scale), most nuclear deployment is likely to mainly be dominated by large-scale conventional reactors in the short- to medium-term.

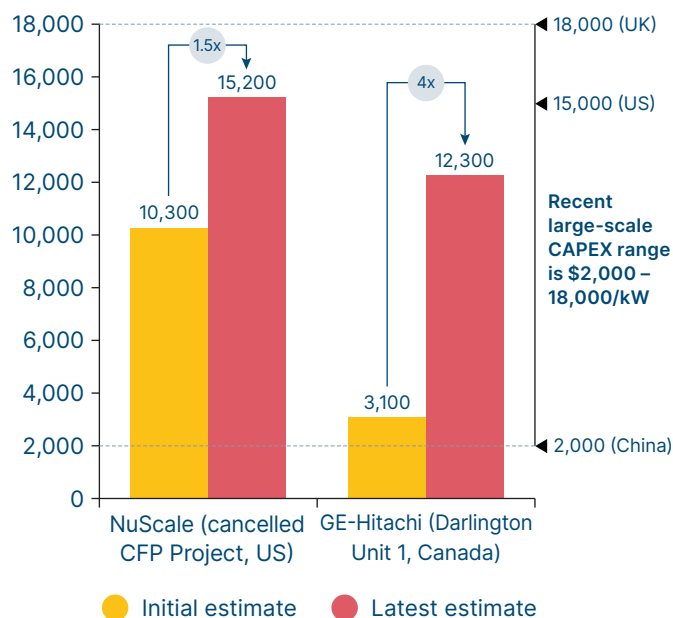
- **Current SMR overnight CAPEX and LCOE estimates far exceed those of large-scale reactors.** Exhibit 1.13 shows that CAPEX estimates of two recent Gen III+ projects are higher than those of conventional large-scale reactors in most regions – and much higher than initially expected. Using estimates for SMR fuel costs, Exhibit 1.13 gives an estimated LCOE range of ~\$140–270 per MWh for Gen III+ SMRs using LEU fuel and ~\$150–310 per MWh for Gen IV SMRs using HALEU fuel.⁶⁹ SMR projects will therefore need to undergo major cost reductions to reach affordable levels to compete with alternatives in most regions (e.g., \$90–100 per MWh – see Exhibit 1.15).

⁶⁹ CAPEX and fuel cost ranges assumed in line with Exhibit 1.12 and Exhibit 1.13, WACC of 6–8% (real) and other assumptions in line with Exhibit 1.5.

Early SMR CAPEX estimates are at the high end of recent large-scale reactors; Gen IV innovation is not expected to reduce costs in the short-term

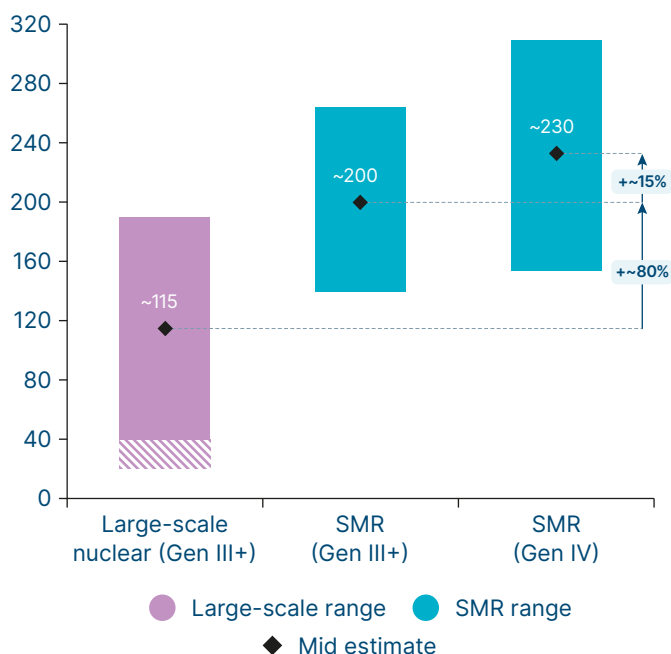
Initial and latest costs for proposed North American Gen III+ SMRs

\$/kW, real 2024



Global estimated 2025 LCOE ranges for large-scale nuclear and SMRs

\$/MWh (real 2024)



NOTE: LHS – Only all-in project cost data available, therefore, implied overnight cost derived by removing modelled financing and escalation costs, assuming a 6-year construction period at 6% WACC (NuScale) and a 5-year period at 6% WACC (GE-Hitachi), both with 2.5% annual cost escalation; NuScale's figure also nets out an assumed ~\$350 million decommissioning trust contribution. RHS assumes LEU fuel cost range for Gen III+, LEU for low Gen IV and HALEU for high Gen IV, 6–8% WACC and fixed & variable OPEX in line with large-scale reactors.

SOURCE: Systemiq analysis for the ETC (2026); IEEFA (2023), *Small Modular Reactors; Still Too Expensive, Too Slow and Too Risky*; NEA (2025), *The NEA Small Modular Reactor Dashboard: Third Edition*; World Nuclear News (2025), *Canada's First SMR Project: How is CAD20.9 Billion Cost Calculated?*; C. Keefer (2025), *Small Reactor, Big Price. The Darlington SMR is moving forward and it's expensive*; BloombergNEF (2026), *LCOE Data Viewer*.

- **Learning effects and standardisation can reduce CAPEX, in theory.** According to industry claims, the off-site modular construction model could reduce CAPEX by ~30–40% relative to traditional stick-built (i.e. constructed piece-by-piece on site) large reactors.⁷⁰ This could lower the LCOE by ~20–30% but will require: 1) standardised designs with a large project pipeline to justify investment in centralised fabrication facilities; and 2) standardisation across regulations in different countries to enable sufficient project pipelines and cross-border learning effects.
- **There are currently >70 concepts in early-stage development across different reactor designs – consolidation is needed to achieve economies of scale.** The proposal for standardised prefabricated components to be assembled on site will only work with design consolidation to unlock economies of scale, but >70 SMR concepts are currently competing for market share.⁷¹ [Exhibit 1.14] This means cumulative SMR unit volumes by reactor type will remain limited for many designs, fragmenting any potential manufacturing learning curve. Early fleet-scale orders will indicate whether that consolidation is happening: for example, Rolls-Royce in the UK, Czech Republic and Sweden; GE-Hitachi's BWRX-300 in Canada, the United States, Poland, Sweden and Estonia; and Westinghouse's AP300 in the United States, Poland, the United Kingdom and Ukraine.⁷²

⁷⁰ P.A. Wrigley (2021), *Off-site Modular Construction and Design in Nuclear Power: A Systematic Literature Review*; C.A. Lloyd (2018), *The Impact of Modularisation Strategies on Small Modular Reactor Costs*.

⁷¹ NEA (2025), *The NEA Small Modular Reactor Dashboard: Third Edition*.

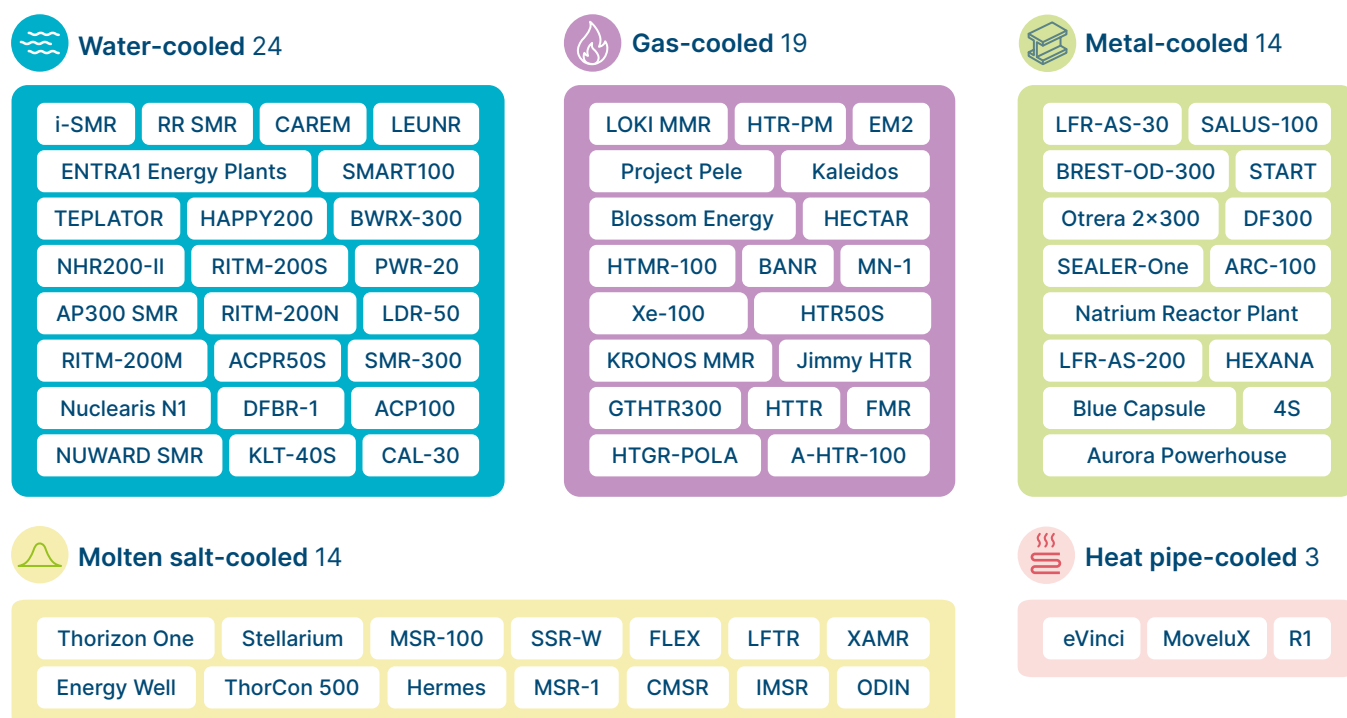
⁷² World Nuclear Association (2026), *World Nuclear Investment Guide. Nuclear Must Knows: Understanding the Nuclear Industry for Investment Decisions*.

- **High SMR buildout with standardisation across designs and international regulation could lead to learning curve reduction of around 30%.** Ambitious SMR buildout scenarios based on BNEF's Net Zero Scenario (NZS) suggest that if SMRs meet 5–10% of new nuclear buildout between 2030 and 2050, with all SMR buildout split between 10 technology providers, they will undergo three to seven doublings in units deployed per design (depending on unit capacity).⁷³ Assuming a 10% learning rate applied to ~50% of CAPEX, this could result in CAPEX reductions of ~15–30% from initial levels (of >\$10,000 per kW) by 2050.⁷⁴ This requires design consolidation and regional collaboration (particularly in Europe and North America) around a small subset of designs to achieve sufficient scale to reach the volume of repeat builds implied by manufacturer learning curves (e.g., 50+ units per design production line). Even at the top of this range, seven doublings per design are a fraction of the ~22 doublings behind the ~99.8% cost decline in solar modules since the 1970s – learning rate impacts will remain more limited for SMRs than more modular and standardised technologies like solar, batteries and wind.⁷⁵
- **Further caution on cost reduction is needed as SMRs face the same FOAK issues that affect large reactors.** The factors driving cost and schedule overruns for large-scale reactors are likely to hold for SMRs too – if not worse due to lower supply chain and regulatory framework maturity. This is illustrated by the recent North American SMR overnight CAPEX estimates that inflated from \$3,000–10,000 per kW (early projections) to \$12,000–15,000 per kW (recent estimates), driven by inflation, labour costs, interest rates and supply chain constraints.

Ultimately, SMR LCOEs could become competitive with conventional large-scale reactors once challenges around design consolidation, regulation streamlining and FOAK supply chain setup costs have been resolved, but could remain around 1.5x higher than recent Western benchmarks in the short-term. We therefore expect new nuclear capacity to mainly be large-scale Gen III+ at a global level in the next decade. Some leading SMRs could subsequently see increasing uptake in early adopter markets if costs decline, e.g., the UK, Czech Republic and Sweden (Rolls-Royce), Canada, the US, Poland, Sweden and Estonia (GE-Hitachi), and the US, Poland, the UK and Ukraine (Westinghouse).

Exhibit 1.14a

There are still >70 concepts in early-stage development across different reactor designs – consolidation is needed to achieve economies of scale



SOURCE: OECD NEA (2025), *The NEA Small Modular Reactor Dashboard: Third Edition*. (Re-used with permission per CC BY 4.0).

⁷³ BloombergNEF (2026), *New Energy Outlook*.

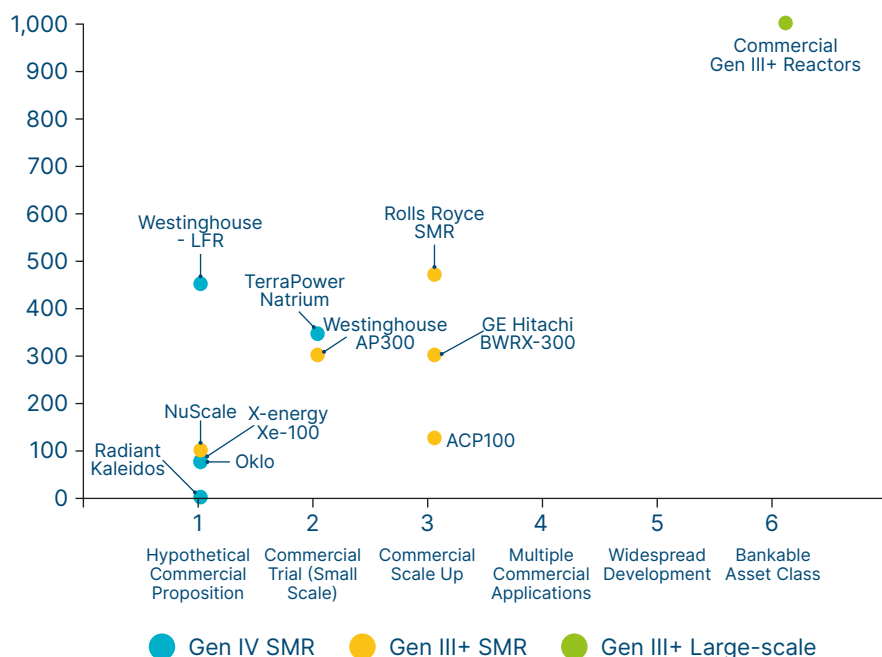
⁷⁴ Modularisation could theoretically drive learning rates of ~10% applied to ~50% of CAPEX, but actual rates are unproven.

⁷⁵ Our World in Data (2025), *Solar Photovoltaic Module Prices vs. Cumulative Capacity*.

Most SMR designs are pre-commercial scale-up; high and uncertain cost means new nuclear capacity will continue to mainly be large-scale Gen III+

Unit size and Commercial Readiness Index (CRI) of selected designs

Unit Size (MW) vs 2026 CRI



Implications for expected near-term deployment:

Large-scale Gen III+ dominate additional capacity

1. Conventional technology (Gen III+)
2. Large unit sizes (e.g., ~1,000 MW)
3. Have high project replicability

Medium role for Gen III+ SMR:

1. Conventional technology (Gen III+), doesn't rely on new supply chains
2. Larger SMR unit sizes (>100 MW)
3. Requires further standardisation and modularisation

Limited near-term deployment of Gen IV:

1. Advanced technology (Gen IV)
2. Small unit sizes (<100 MW)
3. Requires further standardisation and supply chain maturity

NOTE: CRI 1 = TRL 2–8; CRI 2 = TRL 9. Commercial Gen III+ Reactors include reactors such as AP1000, EPR, APR-1400, HPR-1000. LFR= Lead-cooled Fast Reactor.

SOURCE: Systemiq analysis for the ETC (2026); ARENA (2014), *Commercial Readiness Index for Renewable Energy Sectors*.



1.5 Overall levelised cost of nuclear electricity generation: higher than renewables in most geographies

The cost drivers set out in Section 1.3 produce a wide spread of nuclear LCOEs, from below \$50 per MWh in China, South Korea and India to above ~\$125 per MWh in France, the UK and US. The question this section addresses is how that spread compares with the renewable alternatives available in each of those geographies.

Likely future costs of renewables also vary greatly, largely due to resource variations.⁷⁶ Typical LCOEs of new large-scale nuclear and SMRs are \$40–190 per MWh and \$140–270 per MWh, respectively, compared with ~\$20–140 per MWh for solar and wind and ~\$35–220 per MWh for other renewables (geothermal and hydro). Nuclear LCOEs are higher than the typical cost for renewable generation and in many locations is also higher than the cost of “round-the-clock” renewable supply in favourable locations, for example delivered by colocated solar and battery projects. In particular, costs are likely to be lower in countries with large and consistent solar resources, and in countries where CAPEX across equipment and installation is lower (most notably China). But in most countries nuclear generation is likely to be more expensive than renewables [Exhibit 1.15]:

- In high-latitude developed countries (the global “windbelt”) where wind is the dominant renewable resource, new nuclear is likely to be more expensive than offshore wind on an LCOE-basis and significantly more expensive than onshore. In the UK, for example, 2025 strike prices for UK renewables were ~\$80 per MWh for solar, \$90 per MWh for onshore wind and \$115 per MWh for offshore wind.⁷⁷ Similarly, in the US, wind and solar generation costs are significantly below nuclear.
- In low-latitude countries in the global “sunbelt”, solar and onshore wind generation costs are likely to be significantly lower than even the low nuclear costs recently achieved in several Asian countries. Both China and India can achieve solar or wind generation LCOEs of less than \$30 per MWh in some locations. Even when storage and flexibility costs are added, the cost of providing “round-the-clock” electricity from co-located renewable sources is likely to be below the cost of nuclear electricity in sunbelt countries.⁷⁸



⁷⁶ Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

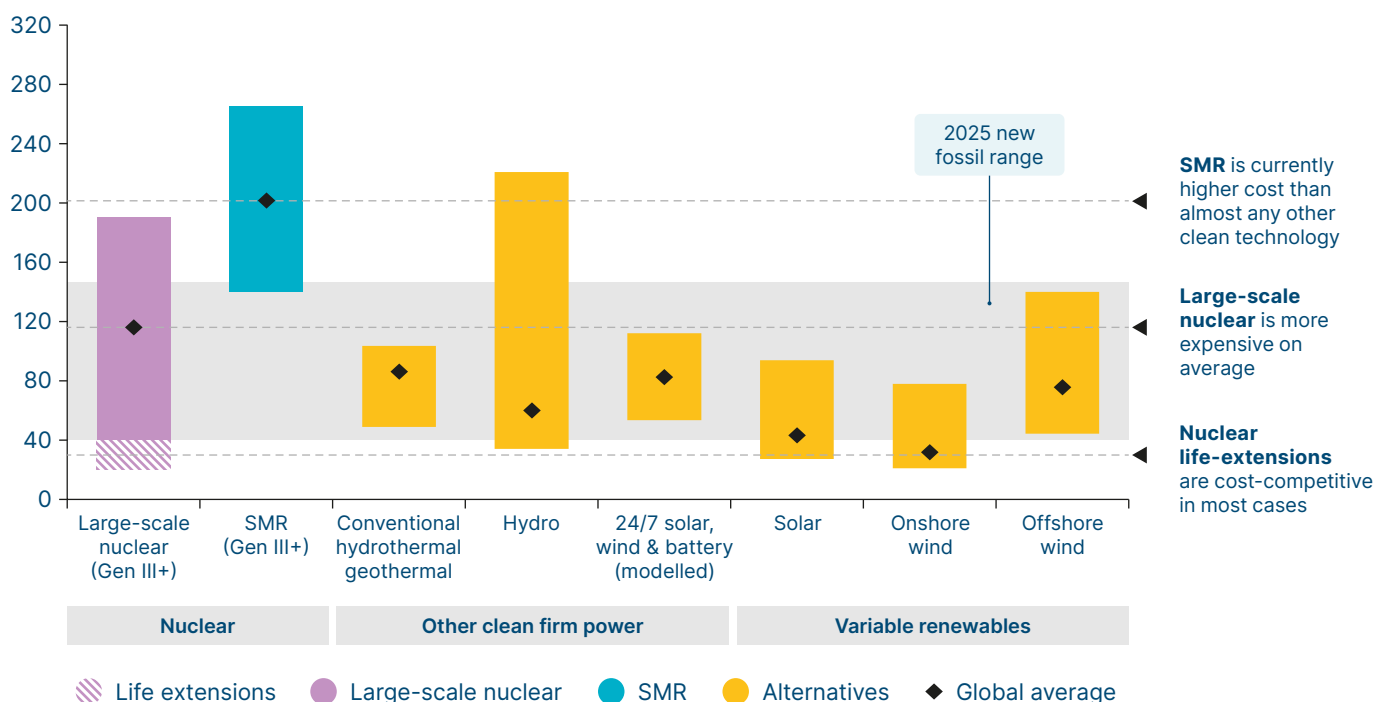
⁷⁷ Converted to real 2024 USD at the 2024 annual average GBP/USD rate of 1.278. DESNZ (2026), *Contracts for Difference (CfD) Allocation Round 7: results*.

⁷⁸ Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.



New nuclear is likely to remain higher cost than clean alternatives on an LCOE-basis in most geographies – but wide regional cost variation exists

Global levelised cost of electricity (LCOE) ranges for key clean energy technologies in 2025
\$/MWh (real 2024)



NOTE: SMR = small modular reactor. LCOE ranges are IRENA 5th to 95th percentiles and midpoints are IRENA's weighted averages, except for nuclear and 24/7 solar, wind & battery, which are the range midpoints due to limited data availability. 24/7 solar, wind & battery LCOE represents IRENA modelling for combinations of solar and batteries at 95% reliability in Sunbelt regions (IEA modelling shows that Windbelt regions could also reach this range by 2035). SMR range excludes Gen IV reactors as none have been delivered to date, therefore costs remain highly uncertain. 2025 new fossil range based on estimated ranges for newbuild coal and combined cycle gas turbines.

SOURCE: IRENA (2026), *Renewable Power Generation Costs in 2025*; IRENA (2026), *24/7 Renewables: The Economics of Firm Solar and Wind*; IEA (2024), *The Future of Geothermal Energy*; BloombergNEF (2026), *LCOE Data Viewer*; IEA (2025), *World Energy Outlook 2025*.

While nuclear LCOEs are higher than alternative generation technologies on average, LCOE comparisons across single generation technologies do not reflect the extent to which a technology can match demand 24/7. This matters as both the supply profile of renewables and the typical demand profile vary over time: neither is, nor needs to be, baseload. To better compare nuclear with renewable supply, we show modelled 24/7 solar, wind and batteries costs to reflect a baseload generation pattern. Ultimately, the system cost of matching supply to a variable load at any point in time is what matters, reflecting an optimal portfolio of diversified renewables, firm power technologies (such as nuclear), storage and flexibility combined (this is outlined in more detail in Chapter 3).

This cost advantage of renewables and storage is likely to increase over time, given the inherent characteristics of the cost trends in highly modular technologies such as solar, wind and storage technologies compared to less modular nuclear technologies. Over the last decade, renewable costs have fallen dramatically, while nuclear generation costs in many developed countries have increased. While countries such as China have managed to achieve nuclear cost reductions, they have not been at the pace achieved in either renewable generation or in battery storage. High levels of repetition through thousands of near-identical projects reinforce learning rates (~15–20% for solar, wind and lithium-ion batteries).⁷⁹ Solar and onshore wind generation in favourable locations could reach \$15 per MWh by 2035.⁸⁰ High modularity, design standardisation and short onsite construction

79 T. Kroon (2026), *An overview of prices and learning rates for Li-ion batteries*. Our World in Data (2023), *Learning curves: What does it mean for a technology to follow Wright's Law?* IRENA (2026), *Renewable Power Generation Costs in 2025*.

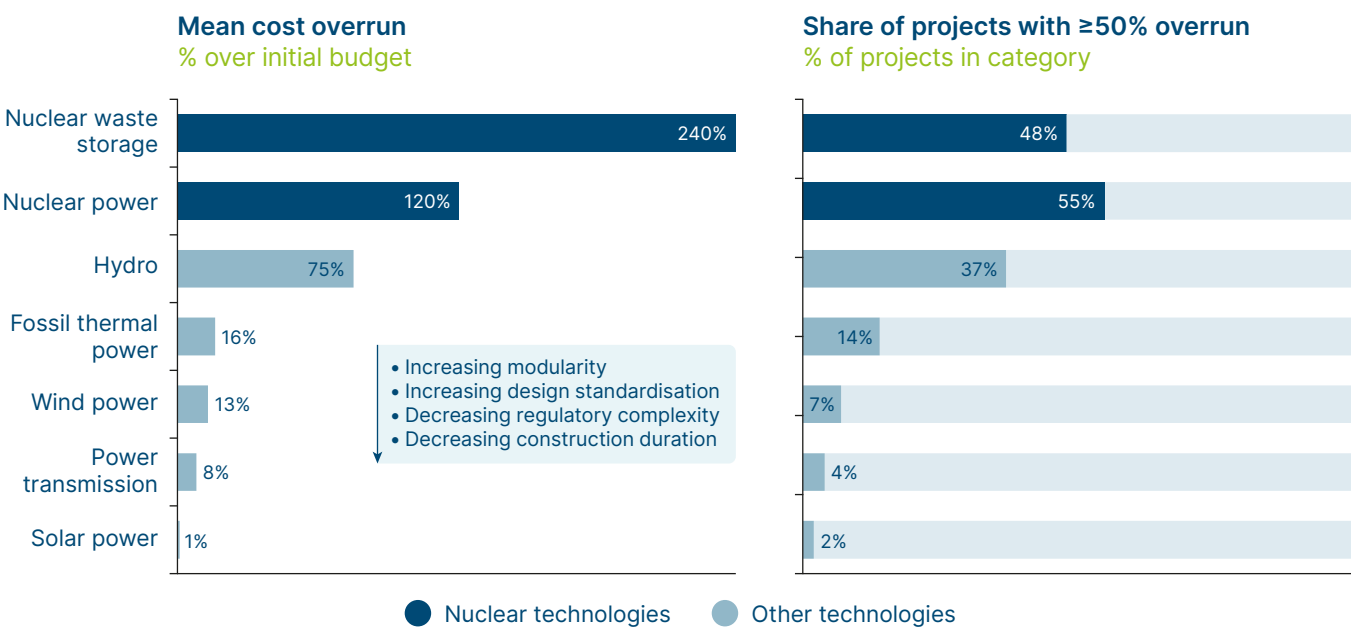
80 BloombergNEF (2026), *LCOE Data Viewer*.

durations also increase confidence in delivery costs, meaning low typical cost overruns (1% on average for solar and 13% for wind).⁸¹ [Exhibit 1.16]

Standardisation is key to cost reduction for all nuclear reactors, and SMRs could extend this through higher modularity. Both the real CAPEX per kW and real LCOE of nuclear projects in several major markets including the United States and France rose as cumulative capacity grew.⁸² As outlined in Section 1.3, this was largely driven by the lack of design standardisation, low international regulation alignment, long construction durations and high construction duration and schedule risk. This meant cost overruns of 120% on average for nuclear globally. [Exhibit 1.16] These drivers are largely a function of regulatory environment and build frequency and a sustained order book for a single standardised design would compress construction times and speed up the feedback loops to lower CAPEX. South Korea, China and India have achieved stable or falling costs by holding a single design constant across a sustained order book, which is why the case for future nuclear cost reduction requires repeat builds. SMR learning curves will rely on both standardisation and modularisation: a higher proportion of components for SMRs will be suited to modular, offsite factory fabrication, meaning that higher learning rates could be achievable than for large-scale reactors. However, as Section 1.4 described, it is unlikely that conventional or new nuclear technologies will deliver a sufficient cost reduction to reverse the inherent renewables advantage at a project level.

Exhibit 1.16

Nuclear projects face significantly higher cost overrun risk than wind and solar



NOTE: Flyvbjerg's megaproject database contains 16,000+ projects across 136 countries. Nuclear projects in China are excluded from the database due to a lack of public data.

SOURCE: Bent Flyvbjerg (2023), *How Big Things Get Done: The Surprising Factors That Determine the Fate of Every Project, from Home Renovations to Space Exploration and Everything In Between*.

81 Bent Flyvbjerg (2023), *How Big Things Get Done: The Surprising Factors That Determine the Fate of Every Project, from Home Renovations to Space Exploration and Everything In Between*.
82 J. R. Lovering (2016), *Historical construction costs of global nuclear power reactors*; S. Liu (2025), *China reins in the spiralling construction costs of nuclear power — what can other countries learn?*



2

Delivery capabilities needed to deliver new nuclear safely, at low cost and on time

As outlined in Chapter 1, the cost of new nuclear build varies greatly between countries. This variation reflects a combination of differences in:

1. **Regulatory approaches and strategy** to safely deliver projects on time and within budget.
2. **The financing cost and structure** to enable affordable buildout while managing risk distribution.
3. **The depth of existing supply chains** to efficiently deliver and operate projects.

These delivery capabilities are vital for safe, timely and low-cost development – yet today they exist in only a handful of countries, mainly those with legacy nuclear industries. The following sections address them in turn.

2.1 Regulatory approaches and strategy

The development and operation of nuclear plants is highly regulated in all countries and subject to safety standards set by and overseen by the IAEA.⁸³ This reflects the vital importance of safe management from local environmental impacts at project inception to waste fuel management and decommissioning. To design, decide, regulate, fund, insure and oversee the multi-decade programmes required for safe delivery and operations, capability is needed across independent regulators, government departments, state-owned enterprises and stewardship organisations. Countries with large existing nuclear programmes therefore typically have well-established regulatory institutions and licensing regimes which are operated by large numbers of expert staff. [Exhibit 2.1] For countries which have yet to build and operate nuclear plants, the time required to build such institutional capacity is a barrier to rapid nuclear deployment. The time and resources taken to build this capacity could divert limited resources away from more rapidly deployable clean energy options like solar and wind, ultimately slowing the pace of a country's energy transition.



83 IAEA (2022), IAEA Safety Standards Series No. SSG-76: Conduct of Operations at Nuclear Power Plants.

Fragmented oversight: a UK nuclear project engages around 20 regulatory bodies across its lifecycle, with no designated lead



Acronyms

DAC	Design Acceptance Confirmation	NESO	National Energy System Operator
DEFRA	Department for Environment, Food and Rural Affairs	NIEA	Northern Ireland Environment Agency
DESNZ	Department for Energy Security and Net Zero	NLFAB	Nuclear Liabilities Financing Assurance Board
DNSR	Defence Nuclear Safety Regulator	NRW	Natural Resources Wales
EA	Environment Agency	NWS	Nuclear Waste Services
GDA	Generic Design Assessment	Ofgem	Office of Gas and Electricity Markets
HSE	Health and Safety Executive	ONR	Office for Nuclear Regulation
IAEA	International Atomic Energy Agency	PINS	Planning Inspectorate
MHCLG	Ministry of Housing, Communities and Local Government	SEPA	Scottish Environment Protection Agency
NDA	Nuclear Decommissioning Authority	SoDA	Statement of Design Acceptability

NOTE: LLW = low-level waste; ILW = intermediate-level waste; HLW = high-level waste. The Defence Nuclear Safety Regulator (DNSR) applies where defence activities are involved, and is being merged into ONR by end-2028 following the 2025 Fingleton review.

SOURCE: Systemiq analysis for the ETC (2026); Fingleton (2025), *Nuclear Regulatory Review 2025*; UK Government (2026), *Building Our Nuclear Nation*; IAEA (2024), *Navigating Nuclear Development*; OECD NEA (2025), *UK Nuclear Legislation Profile and Primary Legislation Including the Nuclear Installations Act 1965, Energy Act 2004 and Planning Act 2008*; ONR (2017), *Licence Condition Handbook*.



Current assessments, including the IAEA's Integrated Regulatory Review Service (IRRS), suggest that high safety standards are imposed by effective regulators in most of the countries deploying new nuclear on a large scale, whether in Europe, the US and Canada, South Korea, China or India.⁸⁴ The effectiveness of regulation is demonstrated by the considerable track record of safe operation in almost all countries with nuclear power (see Section 1.2.1). However, there have been exceptions where regulatory systems did not deliver safe operation. Serious deficiencies in the enforcement of the Soviet Union's safety regulations led to the Chernobyl disaster in 1986, leading to loss of human life and ecosystem damage.

Differences in regulatory approach and overall strategy do, however, contribute to the major differences in the cost and delivery timescales of new nuclear. [Exhibit 2.2] Specifically, regulatory approaches should help enable design replication across projects, ensure project design maturity at the final investment decision and support projects to stay within schedule through the following:⁸⁵

- **Standardised design before site licensing:** Avoiding the mid-construction design changes that drove cost overruns at Hinkley Point C in the UK, Vogtle 3&4 in the US, Flamanville 3 in France and Olkiluoto 3 in Finland (see Section 1.3.2).
- **A designated lead regulator with statutory authority:** To coordinate across the multiple oversight bodies typically engaged. The UAE established the Federal Authority for Nuclear Regulation (FANR) as a single national regulator prior to its Barakah build programme, avoiding the fragmentation across ~20 bodies seen in the UK.⁸⁶
- **Parallel rather than sequential permitting:** Allowing site licensing, design certification and environmental assessments to proceed concurrently rather than as serial dependencies.
- **Stable long-term policy commitments that hold across political cycles:** Meaning pre-FID regulatory decisions remain valid through the 10–20 year delivery timeline. For example, Finland's Decision-in-Principle process requires parliamentary ratification of the government's nuclear siting decision, giving it durability beyond a single electoral cycle.⁸⁷

Differences along these dimensions help explain the major divergence of cost between nuclear programmes in China and South Korea, and those in the US and Europe (as explained in Chapter 1).

84 The IRRS provides an integrated review of any State's national, legal and governmental framework and regulatory infrastructure to evaluate alignment with IAEA safety standards. Its peer-reviewed benchmarking of national regulatory frameworks against IAEA safety standards have found China's and India's regulators to be competent and broadly aligned with international standards, comparable to reviews conducted for established Western programmes (e.g., France). Source: IAEA (n.d.), *Integrated Regulatory Review Service (IRRS)*. Available at: <<https://www.iaea.org/services/review-missions/integrated-regulatory-review-service-irrs>> [Accessed 07 2026]; IAEA (2025), *IAEA Mission Reviews China's Regulatory Framework for Nuclear Safety*. Available at: <https://www.iaea.org/newscenter/pressreleases/iaea-mission-reviews-chinas-regulatory-framework-for-nuclear-safety> [Accessed 07 2026]; IAEA (2022), *IAEA Mission Finds Solid Regulatory Arrangements in India, Notes Areas for Improvement*. Available at: <https://www.iaea.org/newscenter/pressreleases/iaea-mission-finds-solid-regulatory-arrangements-in-india-notes-areas-for-improvement> [Accessed 07 2026].

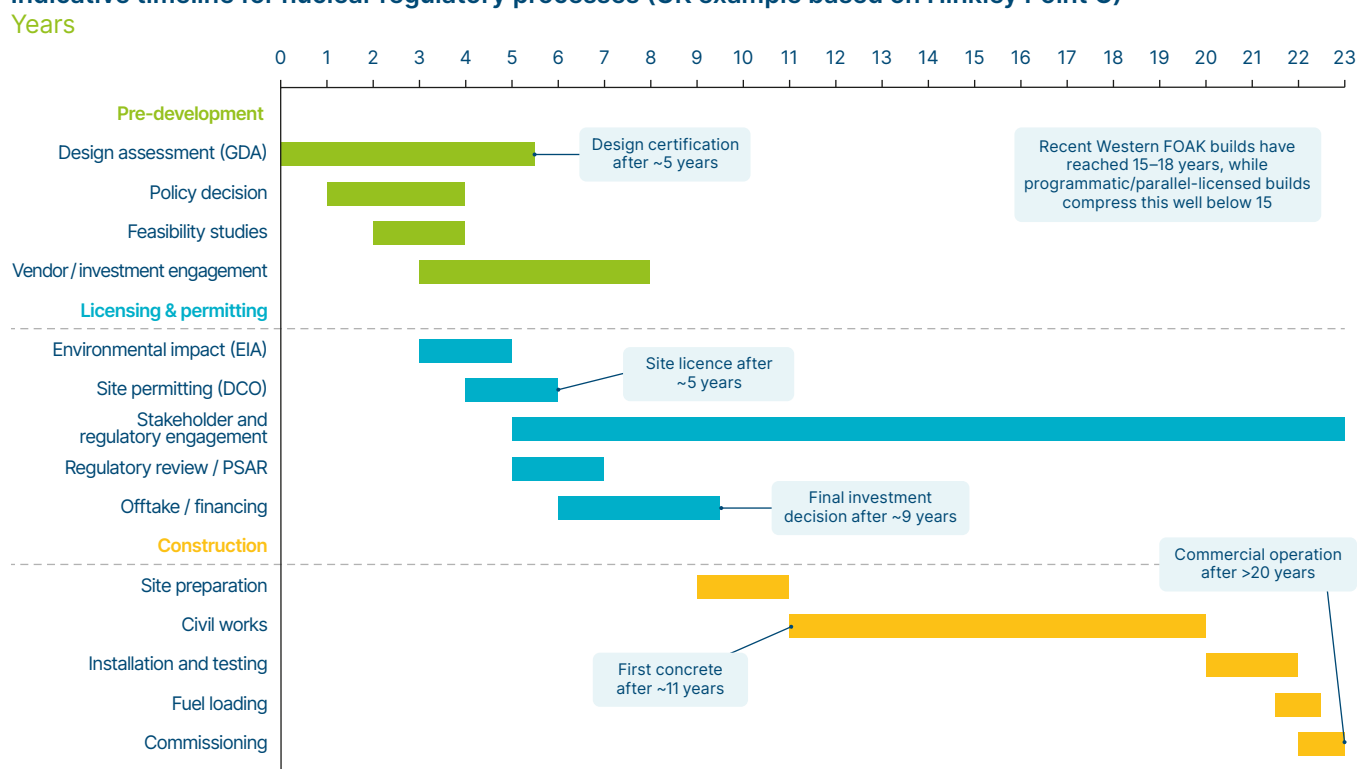
85 Fingleton (2025), *Nuclear Regulatory Review*.

86 Abu Dhabi Media Office (n.d.), *Federal Authority for Nuclear Regulation (FANR)*.

87 OECD (2001), *Stepwise Decision Making in Finland for the Disposal of Spent Nuclear Fuel*.

Nuclear pre-development, licensing & permitting and construction can take over 20 years

Indicative timeline for nuclear regulatory processes (UK example based on Hinkley Point C)



NOTE: GDA = Generic Design Assessment; DCO = Development Consent Order; EIA = Environmental Impact Assessment; PSAR = Preliminary Safety Analysis Report. "Policy decision" refers to the UK government's formal commitment to a nuclear new-build programme and the legal and planning framework that let a specific project (Hinkley Point C) proceed.

SOURCE: IAEA (2024), *Navigating Nuclear Development*; IAEA (2012), *Project Management in Nuclear Power Plant Construction: Guidelines and Experience*; UK Government (2023), *New Nuclear Power Plants: Generic Design Assessment Guidance for Requesting Parties*; General Nuclear System (2022), *The GDA Process*; N. Shykinov (2016), *Importance of Advanced Planning of Manufacturing for Nuclear Industry*.

2.2 Financing costs and revenue models: common features and national differences

Apart from supporting the development of new nuclear projects in terms of permitting, design and safety control as discussed in Section 2.1, governments often also play an instrumental role in providing financing and revenue models with the aim of reducing risk and, with that, thus financing costs. This is because the cost of capital is a key driver of the levelised cost of nuclear generation. Section 1.3.1 showed that for Western projects with high CAPEX and long construction timelines, the LCOE roughly doubles for every 4 percentage-point increase in weighted average cost of capital (WACC). In developed countries, private capital could, under some circumstances, fund nuclear construction at a WACC of around 8–10%, but at this level new nuclear is highly unlikely to be cost-competitive with a diversified 100% renewables plus storage-dominated grid.⁸⁸ This makes lowering the WACC a key priority for governments in order to deliver low-cost nuclear. However, this can also be applied to low levelised costs for other high-CAPEX, low-OPEX technologies including renewables and storage.

To lower the project risk faced by investors, governments can introduce risk and revenue frameworks that absorb construction risk and ensure stable revenues during operation. The central idea of these frameworks is that they can allocate construction, revenue and operational risk appropriately between public and private actors based

⁸⁸ Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

on who can best manage the risk. They may define who pays interest during construction, who bears overrun construction risk, who is responsible for liabilities like waste disposal, and they can create revenue stability and visibility through contracts for difference (CfD) or regulated asset base (RAB) models.

Exhibit 2.3 outlines four possible financing and revenue structures ranging from completely state-driven to fully privately funded. Across the four approaches, the administration-led option delivers the lowest cost as it leverages governmental balance sheets and associated low sovereign interest rates most (although varying by geography).

Exhibit 2.3

Nuclear financing and revenue models range from fully state-backed to privately funded

	Administered tariff (state)	Regulated Asset Base (RAB)	Government Contract for Difference (CfD)	Corporate PPA + Market revenue (merchant)
Main funding & construction risk owner	State balance sheet	Consumers (via regulation)	Contracted counterparties	Investors exposed to markets
Financing: Who pays during construction	State / state-owned enterprise (SOE)	Investors, with regulated charge to customers (including during construction)	Project developers (Private and/or State)	Private
Revenue: model during operation	Administered tariffs or state power purchase agreement (PPA)	Regulated allowed returns (including during construction)	CfD stabilises price once operating, typically for long project lifetimes	PPA stabilises price once operating then reliance on market prices
Example countries (for most new nuclear)		 Sizewell C	 Hinkley Point C	

State-backed loans / guarantees can apply to the range of revenue models

Fully privately funded projects could become viable if SMR costs decline significantly and corporates (e.g., data centres) sign PPAs

SOURCE: Systemiq analysis for the ETC (2026).

- **Administered tariff (state-led):** The state or state-owned enterprise funds construction and absorbs overrun risk; revenue is recovered through administered tariffs or state offtake agreements. This model underpins delivery in China, France, India, Russia and South Korea, and benefits from low sovereign cost of capital, with the state-owned enterprise (e.g., CGN, EDF, KEPCO, Rosatom) retaining ownership during operation.
- **Regulated asset base (RAB):** Investors fund construction with a regulated allowed return paid by consumers from project inception, including during construction; overrun risk is shared depending on contract design. The UK has adopted this model for Sizewell C, with equity shared across the UK government, EDF, Centrica, La Caisse and Amber Infrastructure.
- **Government-backed contract for difference (CfD):** Private investors fund construction; a contract for difference stabilises the price once the asset is operating, typically over long project lifetimes. Overrun risk sits primarily with the developer unless wrapped by sovereign guarantees. Hinkley Point C, Sweden's planned new build and US programmes use variants of this approach.
- **Corporate power purchase agreement (PPA):** Private capital funds construction, and revenue derives from corporate offtake combined with merchant market exposure. The developer bears full overrun risk. This model has had limited use to date, including: long-term offtake contracts for existing assets with industrial offtakers (e.g., Microsoft–Constellation 20-year deal to restart the 835 MW Three Mile Island plant, and ArcelorMittal's



Nuclear Power Production Allocation Contract with EDF in France);⁸⁹ and proposed SMR PPAs with hyperscalers are starting to emerge in the US (e.g., Google–Kairos Power, Hermes 2, a Gen IV molten-salt SMR of 50 MW initially and up to 500 MW by 2035).

Each financing option is possible, but it is notable that all nuclear projects delivered at competitive cost over the past two decades have relied on a significant role for state finance and/or state absorption of overrun risk. Some proponents of SMR projects argue they can be developed and deployed by private capital, but all current projects for large-scale nuclear plants still require a major role for government finance or other government financial support. In the Czech Republic, for instance, the first of two large new reactors to be built at Dukovany (Units 5 and 6) will be supported by Czech government loans at 0% interest rate during construction, and 1% above the Czech government's borrowing cost during operation (with a floor of 2%).⁹⁰ A 40-year CfD model will be implemented to ensure stable revenues.⁹¹

The significant role of state finance in supporting new nuclear reactor build can be justified as a route to achieving both emissions reductions and national energy security objectives. Countries considering nuclear will likely need to ensure sufficient availability of government balance sheet, vendor state loans and/or multilateral development bank (MDB) funding: newcomer markets importing delivery capabilities typically use a blended capital structure, with 10–25% of total investment from the host government, up to 30–80% from a bilateral loan from the vendor country under an intergovernmental agreement and possibly 10–20% from MDBs in future projects (e.g. the World Bank Group signalled support for financing nuclear energy projects in 2025).⁹² But it is important to note that those same emission reduction and energy security objectives could also justify state financial support to reduce the cost of capital for renewables (which, despite shorter construction timelines, are also dominated by high upfront costs and sensitive to WACC).

2.3 Existing supply chain implications for energy security and costs

New nuclear development is often proposed as a route to achieving energy security but the extent to which that argument is valid depends on both:

- **Nuclear fuel cycle security:** access to a diverse and stable supply of uranium fuel and to conversion, enrichment and fabrication capacity.
- **Domestic nuclear delivery capacity:** Countries with experience from prior nuclear deployment are in a strong position to support new build programmes. Countries without may need to depend on inward investment or imports.

These factors may also have implications for the cost and pace of nuclear new build. Globally, we expect limited supply constraints across key component manufacturing and uranium mining at the expected average build rates of ~15–30 GW per year in the medium- to long-term (Section 4.3). The potential binding constraints lie in uranium enrichment, fuel fabrication and skilled labour. For components, concentration rather than volume is a potential risk – affecting energy security and cost more than the achievable build rate.

2.3.1 Fuel supply concentration and related risks

The nuclear fuel supply cycle entails four main stages – mining, conversion, enrichment and fabrication. Supply chain capacity across each stage is currently concentrated in a small number of countries.

89 ArcelorMittal (2026), *ArcelorMittal and EDF Sign a Long-Term Contract to Secure Low-Carbon Electricity Supply*; Reuters (2024), *Microsoft May Pay Constellation Premium in Three Mile Island Power Agreement*, Jefferies says.

90 Government of the Czech Republic (2024), *The Government Has Decided on a Preferred Supplier for the New Nuclear Power Source at Dukovany*. Available at: <https://vlada.gov.cz/en/media-centrum/aktualne/the-government-has-decided-on-a-preferred-supplier-for-the-new-nuclear-power-source--negotiations-on-the-construction-of-two-units-at-dukovany-will-be-214609/> [Accessed 07 2026].

91 The government has requested these terms be extended to the second unit as part of an expanded two-unit package, currently under European Commission state-aid review. Source: World Nuclear News (2025), *EU Launches Inquiry into Czech Funding Plan for New Nuclear*. Available at: <https://www.world-nuclear-news.org/articles/eu-launches-inquiry-into-czech-new-nuclear-funding-plan> [Accessed 07 2026].

92 World Nuclear Association (2026), *World Nuclear Investment Guide. Developer and Investment Models: A Systematic Approach to Reaching Financial Close*.





1. **Uranium is mined as uranium oxide (triuranium octoxide, U_3O_8) concentrate or yellow cake. Mining is geographically concentrated today but relatively unconstrained in the long-term, with new mines and innovations set to resolve possible short-term bottlenecks.**

- **Mining is heavily concentrated: 75% of supply came from Kazakhstan, Canada and Namibia in 2024, but ample resources are available.**⁹³ Total identified resources of uranium amount to ~8 million tonnes,⁹⁴ ~130x current annual demand and ~40x 2050 net-zero demand estimates even if demand triples. Although discovering and developing a new uranium mine typically takes 10–15 years, the scale of identified resources and the price-responsiveness of supply mean upstream fuel is unlikely to be a binding bottleneck for capacity expansion to 2050.
- **Mining expansion is needed, and is progressing, driven by high uranium prices.** From around 1990–2010, the reduced pace of nuclear development after Chernobyl, together with the moderation of Cold War tensions,⁹⁵ led to less demand for newly mined output, with a significant share of demand met from secondary sources. These secondary sources are now depleted. Uranium demand is again primarily met from primary mining and higher prices are supporting new mine development (no longer suppressed by the previous stockpile drawdown), with spot prices rising from ~\$70 per kg-U from 2016–2022 to over \$200 per kg-U in 2024.⁹⁶ However, the projected pace of new mining supply coming online is insufficient for the nuclear scenarios that are envisaged; in the short-term, therefore, an accelerated ramp-up is likely to be needed. [Exhibit 2.4]
- **Uranium extraction is also becoming lower-impact and more scalable.** In-situ recovery (ISR) – injecting a mild leaching solution and harvesting the uranium-bearing brine rather than excavating ore – is the most mature low-impact method and already the dominant global production route.⁹⁷ Borehole methods such as Orano's Surface Access Borehole Resource Extraction (SABRE) make small, high-grade deposits economic with short production ramp-ups.⁹⁸ Over the very long-term, the oceans hold an effectively unlimited uranium resource with ~4.5 billion tonnes (75,000x current annual demand). The uranium price threshold required for economic viability is still uncertain and is estimated to be \$80–1,000 per kg-U depending on method and maturity;⁹⁹ therefore, it could become viable at the lower end.

⁹³ World Nuclear Association (2025), *World Uranium Mining Production*.

⁹⁴ WNA estimate using a \$260 per kgU threshold. WNA (2025), *Supply of Uranium*.

⁹⁵ Through "Megatons to Megawatts", 1993–2013, highly enriched uranium from nuclear weapons stockpiles displaced ~ 9,000 tonnes of U_3O_8 production from mines per year and met 13%–19% of demand. Source: WNA (2017), *Military Warheads as a Source of Nuclear Fuel*.

⁹⁶ WNA (2024), *Uranium Markets*.

⁹⁷ World Nuclear Association (2025), *World Uranium Mining Production*.

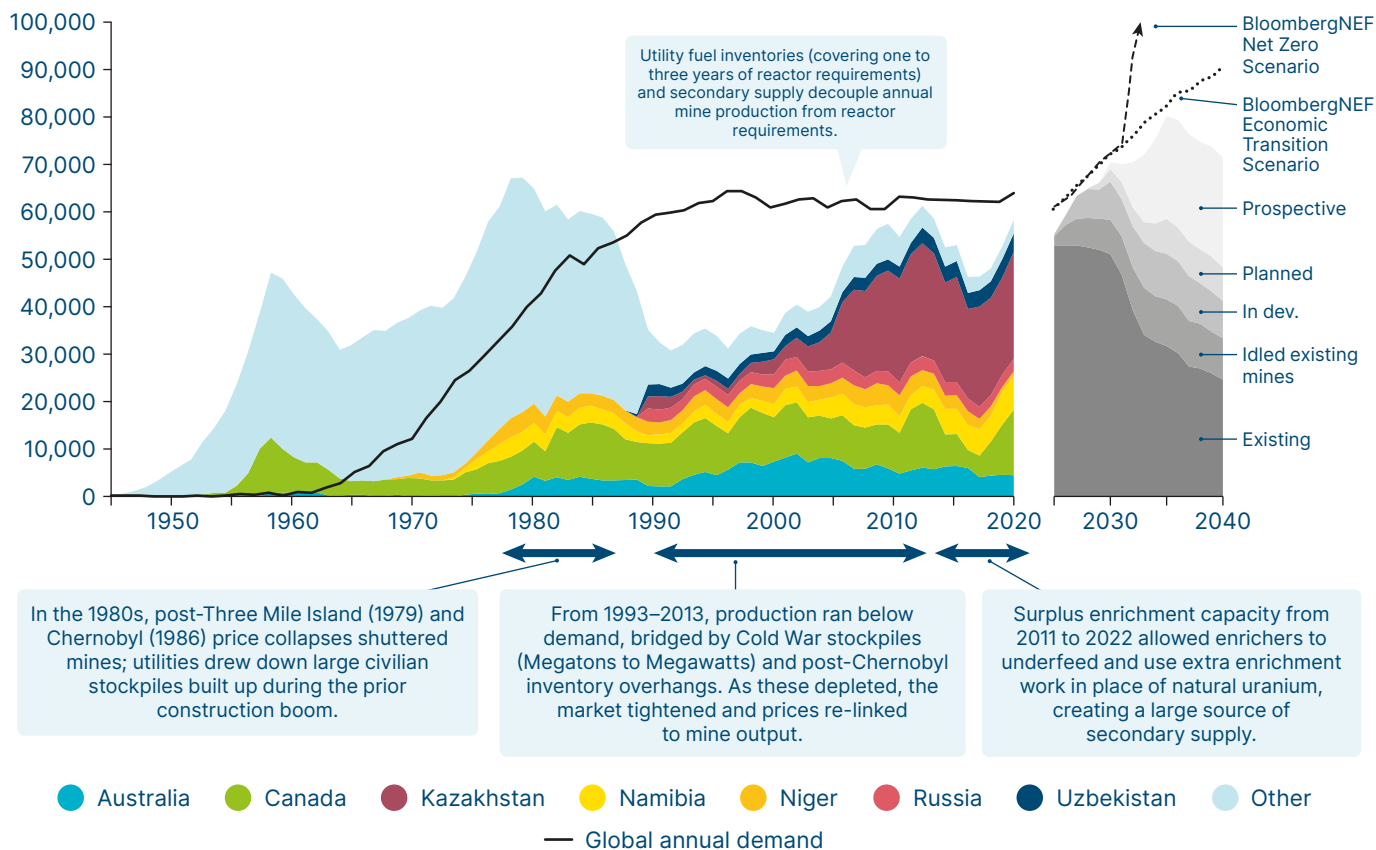
⁹⁸ SABRE has been in commercial production in Canada since 2025. Source: Orano Canada (2025), *Orano Canada and Denison Announce SABRE 1st Production at McClean Lake*. Available at: <https://www.orano.group/canada/en/news-resources/news/2025/july/orano-canada-and-denison-announce-sabre-1st-production-at-mcclean-lake> [Accessed 07 2026].

⁹⁹ H. Lindner (2015), *Review of Cost Estimates for Uranium Recovery from Seawater*; S. Wang (2025), *Bipolar Electrochemical Uranium Extraction from Seawater with Ultra-low Cell Voltage*.

90% of uranium comes from seven countries today; meeting future demand under a net zero scenario requires a significant mining ramp up

Historic world uranium production and reactor requirements, 1945–2020 (WNA)

Tonnes of uranium



NOTE: WNA data approximately extracted. "Other" includes France, South Africa, the US, Former East Germany, Czech Republic, Romania, USSR. BloombergNEF scenario natural uranium demand back-calculated using the WNA's conversion efficiency of 18.6 tU per TWh (new AP1000 or EPR, with 5% enriched fuel and 65 GWd/t burn-up).

SOURCE: World Nuclear Association (2024), *Nuclear Fuel Cycle – Uranium Markets*; World Nuclear Association (2025), *Nuclear Fuel Cycle Overview*; BloombergNEF (2026), *New Energy Outlook*.

2. Conversion of yellowcake to uranium hexafluoride (UF₆) gas is evenly split between Russia (Rosatom), France (Orano), China (CNNC), Canada (Cameco) and the US (ConverDyn). Conversion is a significant pinch point: prices have risen roughly 6–10x since the mid-2010s to near-record highs,¹⁰⁰ reflecting a structurally undersupplied Western market after decades of underinvestment. Unlike enrichment, spare licensed capacity and faster ramp times are closing the gap. China's rising share is directed mainly at domestic demand and so has little impact on importing countries, unlike Russia's incumbent position which is leading to supply security risks in importing countries – now compounded by Russian UF₆ export restrictions and Western import bans.

3. Enrichment (i.e. increasing the uranium-235 isotope concentration to the 3–5% needed for conventional reactors, excluding Canada's CANDU reactors)¹⁰¹ only has four major producers today: Rosatom; CNNC; Orano; and Urenco, a private company jointly owned by the British and Dutch states and German utilities RWE

¹⁰⁰ Nuclear Engineering International (2025), *UEC Unveils Conversion Facility Plans*. Available at: <https://www.neimagazine.com/news/uec-unveils-conversion-facility-plans/?cf-view> [Accessed 07 2026].

¹⁰¹ Conventional reactors use 3–5% low enriched uranium (LEU), while some Gen IV and advanced SMR designs require 5–20% high-assay low enriched uranium (HALEU), which currently has very limited commercial supply. Canadian CANDU reactors run on natural uranium and require no enrichment. They rely instead on heavy water as a moderator, which shifts the supply chain requirement from enrichment services to heavy water production.

and E.ON.¹⁰² Rosatom accounted for ~40% of global enrichment capacity in 2025,¹⁰³ making enrichment the main pinch point for Western nuclear fuel security. Two years after the invasion of Ukraine, Russia still supplied ~23% of EU enriched uranium demand in 2024,¹⁰⁴ with low prices continuing to make it the default choice for utilities. Near-term Western capacity is tight: Orano is expanding (Tricastin +30% by 2030; a new \$5 billion facility in Oak Ridge, Tennessee targeted for ~2032), and Urenco is adding ~1.5 million separative work units (SWU) at its UUSA (New Mexico) and Almelo (Netherlands) plants. Much of this ~5 million SWU of planned new capacity has already been pre-purchased, and the additions are not expected to be operating until after 2032. [Exhibit 2.5] New entrants are emerging with public backing: in January 2026 the US Department of Energy awarded \$900 million contracts to American Centrifuge Operating (a Centrus Energy subsidiary) and General Matter to build US HALEU enrichment capacity, though neither is expected to supply commercial volumes at scale before the 2030s.¹⁰⁵

4. Fuel fabrication reconverts the enriched UF₆ to uranium dioxide (UO₂) powder, then into sealed ceramic pellets to form fuel rods.¹⁰⁶ It is also concentrated across six dominant players, with implications that vary by reactor type. PWR and BWR markets are commercially competitive (Westinghouse, Framatome, GNF, KEPCO).¹⁰⁷ Fuel used in water-water energetic reactors (VVER) developed in the Soviet Union and then Russia is a key bottleneck: TVEL (Rosatom) supplies most of the 37 operating VVER reactors (25 of which are outside of Russia). Westinghouse Västervik (Sweden) is the only at-scale Western alternative, and Framatome's VVER fuel is 5–10 years from commercial delivery.¹⁰⁸ Switching takes 5–10 years per reactor, locking in dependency well into the 2030s – with new Rosatom VVER exports to Egypt, Turkey, Hungary, Bangladesh and India extending it further.



¹⁰² Financial Times (2026), *Fuel Shortage Threatens US Nuclear Resurgence, Warns Top Supplier*.

¹⁰³ World Nuclear Association (2025), *World Uranium Mining Production; Supply of Uranium, Conversion, Enrichment and Fuel Fabrication*.

¹⁰⁴ Financial Times (2026), *Europe Struggles to End Reliance on Russian Uranium*.

¹⁰⁵ Nuclear Newswire (2026), *DOE awards \$2.7B for HALEU and LEU enrichment*. Available at: <https://www.ans.org/news/article-7652/doe-awards-27b-for-haleu-and-leu-enrichment/> [Accessed 08 2026].

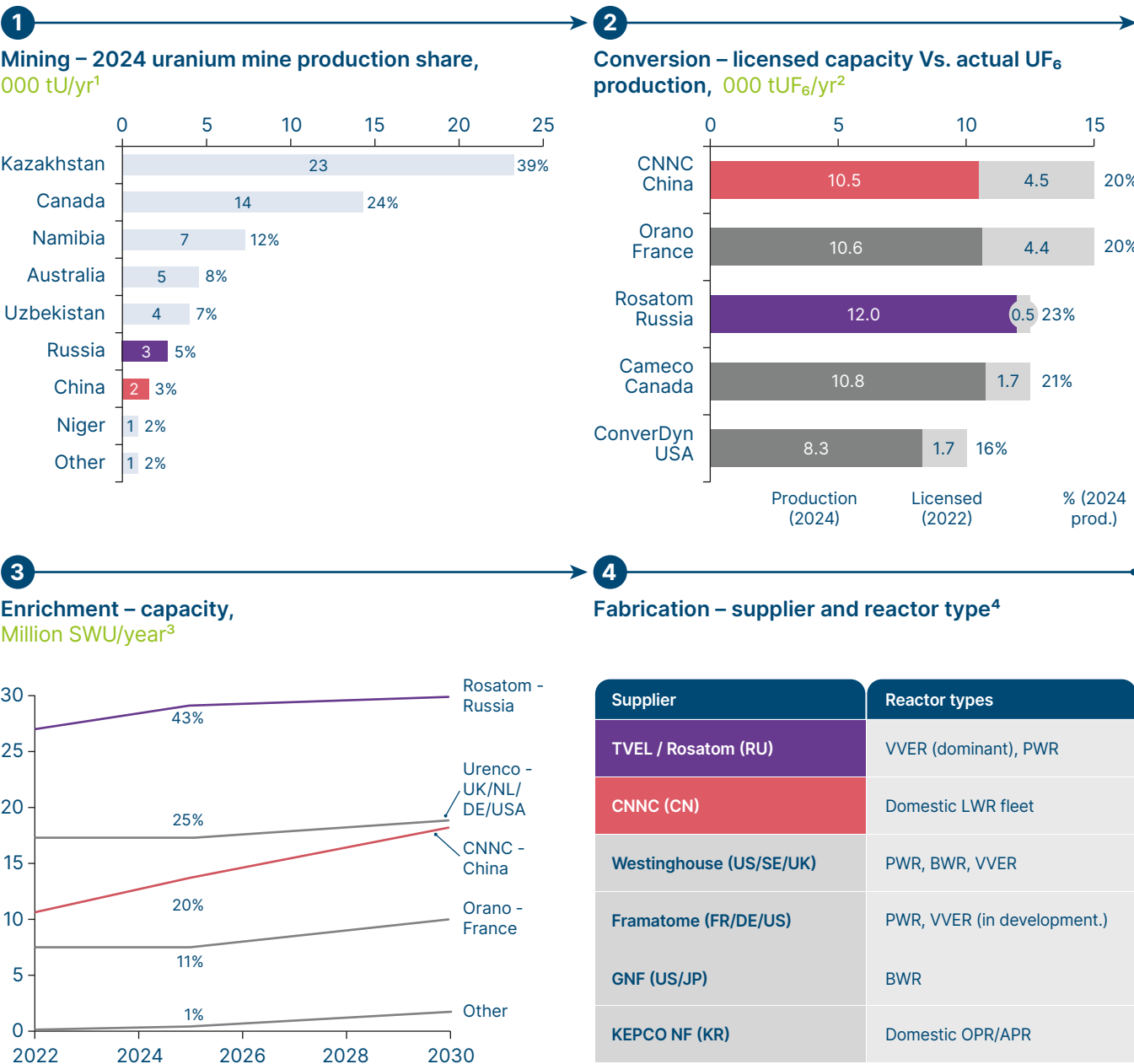
¹⁰⁶ Fuel fabrication involves converting enriched uranium into ceramic uranium dioxide (UO₂) pellets and stacked in sealed metal tubes and assembled into fuel rod bundles (fuel assemblies) for loading into the reactor core.

¹⁰⁷ World Nuclear Association (2025), *Nuclear Fuel and its Fabrication*.

¹⁰⁸ Nucnet (2024), *Hungary / Paks Signs Agreement with Framatome for Supply of VVER Nuclear Reactor Fuel*. Available at: <https://www.nucnet.org/news/paks-signs-agreement-with-framatome-for-supply-of-vver-nuclear-reactor-fuel-10-5-2024> [Accessed 07 2026]

Conventional fuel conversion and enrichment capacity is concentrated in Russia and, increasingly, China

Country / operator share of global capacity or production across the four low-enriched uranium (LEU) fuel-cycle stages



NOTE: Capacities correspond to conventional LEU ($\leq 5\%$ U-235) for LWRs and PHWRs; HALEU, MOX and military fuel cycles excluded. Conversion data shows licensed capacity bars (2022) alongside production bars (2024) due to data availability. ConverDyn 2024 figure of 8,300 t is "planned 2024 output" not actual. BWR = Boiling Water Reactor; PWR = Pressurised Water Reactor; LWR = Light Water Reactor (PWR + BWR); PHWR = Pressurised Heavy Water Reactor; VVER = Vodo-Vodyanoi Energetichesky Reaktor (Russian-design PWR); OPR = Optimised Power Reactor (Korean); APR = Advanced Power Reactor (Korean); HALEU = High-Assay Low-Enriched Uranium; MOX = Mixed Oxide fuel; SWU/year = Separative Work Units per year, the standard annual enrichment capacity unit.

SOURCE: [1] World Nuclear Association (2025), *World Uranium Mining Production*; [2] World Nuclear Association (2025), *Nuclear Fuel Report: Global Scenarios for Demand and Supply Availability 2025–2040*; Cameco (2024), *Annual Report*; Orano disclosures. [3] World Nuclear Association (2025), *Uranium Enrichment*, updated 6 June 2025; Orano press releases (2024); [4] World Nuclear Association (2025), *Nuclear Fuel and its Fabrication*.

Given the proliferation risks associated with enrichment and reprocessing capability, most countries pursuing nuclear power will rely on partnerships and long-term offtake agreements with fuel-producing countries rather than developing sovereign fuel-cycle capacity. Expanding global fuel production capacity across conversion, enrichment and fabrication capacity, maintaining strategic uranium stockpiles and diversifying supplier relationships across the full cycle should therefore be treated as prerequisites for scaling nuclear deployment.

2.3.2 Component supply chain capabilities

Manufacturing capacity in the nuclear supply chain is currently concentrated in the companies and countries which have built significant nuclear capacity in the recent past. Countries without deep existing capability will be dependent on inward investment/imports for key components and skilled labour if they seek to build new nuclear plants fast.

- **Nuclear's supply chain spans four key development stages: design, site preparation, equipment manufacturing and civil construction.** Site preparation and civil construction are inherently domestic activities, but even these are often dominated by companies from countries with large nuclear programmes. Critical equipment components include pressure vessels, steam generators, coolant pumps, turbine islands and nuclear-grade valves.
- **Heavy engineering capacity for reactor pressure vessels is concentrated in China, Russia, Japan, South Korea and France, but there is enough in aggregate to increase global build rates.** Across these countries, there is enough nominal heavy forging manufacturing capacity to produce over 40 Gen III+ reactor ~1 GW pressure vessel sets per year. This means the sector can build over 40 GW per year with 1 GW average plant sizes – well above the expected 25 GW per year build (as set out in Section 4.3). However, this capacity is highly concentrated, with around 40% of capacity in China, 25% in Russia, 20% in Japan, 10% in South Korea and 5% in France.¹⁰⁹ This means that over half currently sits in China and Russia, which may further increase as both continue to expand capacity. New capacity is also being developed in Japan, South Korea, the Czech Republic and India, where existing heavy forging capacity can pivot manufacturing facilities to nuclear products. In contrast, Gen IV plants operating at higher temperatures will require new materials, with longer lead times (e.g., 15 years) to develop.¹¹⁰
- **Manufacturing capacity for steam generators, coolant pumps, turbine islands and nuclear-grade valves is currently tighter than for pressure vessels, but capacity in these categories can ramp up with demand.** Manufacturing capacity across these components is also concentrated in a few countries, but various suppliers have announced capacity expansions.¹¹¹ Capacity can also pivot from adjacent heavy engineering: petrochemical components, shipbuilding and conventional thermal turbine islands share presses, welding and machining capability with nuclear work. Order timing and nuclear-grade qualification for pivoting industries is the main constraint for these components, rather than aggregate manufacturing capacity.
- **Supply chain capabilities depend on skilled labour, which could be a longer-term bottleneck than component fabrication.** Sufficient capacity of nuclear engineers, specialised construction crews and qualified welders can take several years to develop and typically erodes when new build programmes cease. To illustrate, France's renewed commitment to a nuclear new build programme currently entails a major programme to rebuild nuclear build skills which atrophied after the previous new build programme ended in the late-1990s.¹¹² The need to maintain a domestic nuclear skill base further emphasises the need for continuous, programmatic buildout to deliver nuclear projects effectively.
- **Countries without established domestic supply chains which seek to build significant new nuclear capacity will face a choice between importing expertise or gradually building out capabilities (and both pathways require domestic upskilling in nuclear regulation).** The quickest approach will be to rely on inward investment

109 World Nuclear Association (2026), *Heavy Manufacturing of Power Plants*. Available at: <https://world-nuclear.org/information-library/nuclear-power-reactors/other/heavy-manufacturing-of-power-plants> [Accessed 08 2026].

110 World Nuclear Association (2026), *Heavy Manufacturing of Power Plants*. Available at: <https://world-nuclear.org/information-library/nuclear-power-reactors/other/heavy-manufacturing-of-power-plants> [Accessed 08 2026].

111 World Nuclear Association (2026), *Heavy Manufacturing of Power Plants*. Available at: <https://world-nuclear.org/information-library/nuclear-power-reactors/other/heavy-manufacturing-of-power-plants> [Accessed 08 2026]; X-energy (2025), *X-energy, Doosan Enerbility Announce 16-Unit Reservation Agreement and Capacity Expansion to Support 11 GW Pipeline*. Available at: <https://x-energy.com/news/x-energy-doosan-enerbility-announce-16-unit-reservation-agreement-and-capacity-expansion-to-support-11-gw-pipeline/> [Accessed 08 2026]; EDF (2026), *EDF Subsidiary Arabelle Solutions to Build a New Heat Exchanger Factory in France*. Available at: <https://www.edf.fr/en/the-edf-group/dedicated-sections/journalists/all-press-releases/edf-subsidiary-arabelle-solutions-to-build-a-new-heat-exchanger-factory-in-france> [Accessed 08 2026]; Curtiss-Wright (2026), *Curtiss-Wright Announces \$80 Million Multi-year Investment to Expand its Operations in Cheswick, Pennsylvania*. Available at: <https://curtisswright.com/news/press-releases/news-release-details/2026/Curtiss-Wright-announces-80-million-multi-year-investment-to-expand-its-operations-in-Cheswick-Pennsylvania> [Accessed 08 2026].

112 Damona (2025), *France's Nuclear Renaissance and the Talent Imperative*.



and engineering, procurement, construction and installation (EPCI) capability imports from companies in other countries to enable rapid development. Countries which have exported full project deployment services to date are South Korea (through the Barakah project in the UAE), China (through the Karachi-2 project in Pakistan) and Russia (through the El Dabaa project in Egypt and Rooppur in Bangladesh). Importing expertise creates a long-term geopolitical dependency, from construction through to debt repayment and operation (e.g., the Rooppur nuclear plant in Bangladesh, which was financed via a Russian loan to be repaid over 20 years, following a 10-year grace period).¹¹³ A sustained gradual build-up of new build capacity would enable sovereign capabilities in the long-term but would require significant investment and delay the pace of feasible deployment. Even pathways involving skilled workforce imports require domestic upskilling in siting and licensing, construction oversight, operational safety and decommissioning and waste management.

Chapter 2 has outlined the key delivery criteria for new nuclear across regulations, financing and supply chains. Provided that these capabilities can be built to deliver nuclear cost-effectively, safely and at pace, there could be a case for nuclear deployment in many locations, even if nuclear has a higher LCOE than alternatives and time to deploy, because of the following factors outlined in Chapter 3:

1. The potential to reduce total system costs of generation, balancing and grids (Section 3.1).
2. Energy security drivers in countries with constrained renewable resource supply (Section 3.2).
3. Potential for nuclear to address heat and other off-grid applications (Section 3.3).
4. Societal benefits from the economic value added and employment impacts of nuclear projects (Section 3.4).

¹¹³ World Nuclear News (2023), *Rooppur: Bangladesh Paying Russia in Yuan to Sidestep Sanctions*. Available at: <https://www.world-nuclear-news.org/Articles/Rooppur-Bangladesh-paying-Russia-in-yuan-to-sidest> [Accessed 08 2026].



3

Total system cost, energy security and other potential benefits

Chapter 1 concluded that in most geographies, the levelised cost of new nuclear is likely to remain higher than the cost of available renewable alternatives. The size of the difference will vary significantly by country because of large variations in both renewable and achievable nuclear costs, which in turn depends on national capabilities to deliver new nuclear safely, on time and on budget (as set out in Chapter 2).

Even when new nuclear costs remain higher than clean alternatives, adding new capacity might still be justified if it delivers reductions in total system generation and grid cost, or other benefits relating to energy security, heat supply, economic growth or employment. This chapter therefore assesses four issues:

- 1. The impact of nuclear deployment on total system cost:** In many countries this could make it beneficial for nuclear to provide low shares (e.g., up to ~20%) of total electricity generation.
- 2. Limits on renewable resources and issues relating to security of supply:** This may make it optimal to deploy higher nuclear shares in some countries.
- 3. The potential economic benefit of using nuclear energy to deliver heat rather than electricity:** This can make new nuclear an economic option in specific sites co-located with heat demand.
- 4. The impact of new nuclear development on economic value added and employment:** It is important to avoid pursuing higher “gross value added” at the expense of higher prices for energy users.

3.1 Nuclear power and total system cost

As the world moves towards net-zero emission energy systems, electricity demand could grow up to ~2–3x to 2050 and still further in subsequent decades.¹¹⁴ Most of the required additional power will come from rapidly scaling and increasingly low-cost solar and wind. Analysis by ETC and others demonstrates how solar and wind can potentially reach over 60,000 TWh in a net-zero 2050 system, more than double today’s total electricity generation from all sources and >70% of global electricity generation, enabled by storage, flexibility and backup generation.¹¹⁵

Within these expanding and changing power systems, the role of nuclear will be determined by its complementarity with other generation assets, its operational flexibility, the level of baseload demand and its potential to offset balancing and grid system costs.

- **The relative role of nuclear in future power systems is defined by its complementarity with rapidly scaling, low-cost solar and wind.** The ETC’s 2025 report on power system transformations concluded that it would be technically possible to run power systems with very high shares (e.g., 90%) of variable renewables, using a combination of demand-side flexibility, batteries, long-duration storage (e.g., pumped hydro), interconnectors

¹¹⁴ Systemiq analysis for the ETC (2026); BloombergNEF (2026), *New Energy Outlook 2026*; IEA (2025), *World Energy Outlook 2025*.

¹¹⁵ Ember (2026), *Electricity Data Explorer*; Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*; BloombergNEF (2026), *New Energy Outlook 2026*.

and thermal dispatchable assets (methane-based or potentially hydrogen-based in the long-term) to balance intermittent supply and varying demand across days, weeks and seasons.¹¹⁶

- **Nuclear can operate flexibly, but flexing erodes project economics, so nuclear is poorly suited to play a flexible dispatch role.** Nuclear reactors are not generally well suited to provide a flexible response to variations in intermittent renewable supply or rapidly fluctuating demand patterns. Nuclear plants can be run on a somewhat flexible basis: modern reactors are designed for daily load cycling between 50% and 100% of rated power at ramp rates of 3% of rated power per minute or higher.¹¹⁷ However, this is significantly lower than open-cycle and closed-cycle gas turbines (~8–15% and ~2–11%, respectively).¹¹⁸ It is also usually economically inefficient to run nuclear plants flexibly, since fuel and operating costs only account for 20–40% of nuclear LCOE, so reduced output forfeits revenue with limited offsetting savings. High-capacity utilisation (typically 85%+) is required to amortise high upfront capital costs. Running at 40–60% utilisation – like some gas-fired power generation assets – effectively raises LCOE by ~1.4–2x and erodes the economic case for new nuclear.¹¹⁹ Gas plants, where ~50% of the costs are short-run operating costs, can run economically at lower utilisation. And while the French nuclear fleet has cycled daily since the 1980s and intra-day flexible generation has increasingly been deployed to respond to rising solar generation, this has tended to accelerate equipment degradation (though effects on large components typically remain within design margins).¹²⁰
- **Minimum “baseload” demand profiles could warrant some nuclear, although the need for baseload generation profiles is reducing as solar, wind and storage technologies expand.** Power systems always have a “baseload” – a continuous minimum level of demand – which is typically ~20–50% of peak demand.¹²¹ Proponents of nuclear power often argue that power systems will need a high share of baseload capacity, such as nuclear, to ensure power availability when solar and wind power are unavailable. However, baseload demand can increasingly be met with a combination of solar, wind, storage, and demand-side flexibility, reducing the role for high-utilisation assets such as nuclear. In future clean power systems, for the moments where solar, wind, other renewables (hydro, geothermal), batteries and long-duration energy storage (LDES) cannot meet demand, a limited role remains for lower-CAPEX assets such as peaking gas, biomethane or hydrogen.
- **Nuclear can reduce some system-level grid infrastructure costs, compared to renewables.** The siting of large-scale renewable assets depends on resource and space availability, which may be far from sources of demand. This is why power grids are set to expand drastically (rooftop solar avoids this but is unlikely to supply all power needs in most places). In contrast, nuclear plants, particularly SMRs, have more siting flexibility and can therefore be located relatively close to demand. This, in combination with their high locational power density and utilisation, means nuclear can reduce overall grid expansion costs as power systems decarbonise.
- **Nuclear can also reduce total system costs across balancing, curtailment and grid stability management** relative to renewable-dominated systems, all of which contribute to the total system cost paid by consumers. [Exhibit 3.1]

Exhibit 3.1 describes the different effects of nuclear relative to alternatives across generation, grid, balancing, curtailment and grid stability. Nuclear’s system value depends on the net effect of these components on total system cost.

¹¹⁶ Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*; Energy Transitions Commission (2025), *Demand side flexibility – unleashing untapped potential for clean power*.

¹¹⁷ Based on the European Utility Requirements. OECD NEA (2011), *Technical and Economic Aspects of Load Following with Nuclear Power Plants*.

¹¹⁸ IRENA (2019), *Flexibility in Conventional Power Plants, Innovation Landscape Brief*.

¹¹⁹ Systemiq analysis for the ETC (2026).

¹²⁰ Modo Energy (2025), *France's Grid is Shifting. Can Nuclear Keep Up?* Available at: <https://modoenergy.com/research/en/nuclear-flexibility-france-grid-shifting> [Accessed 06 2026]; OECD NEA (2011), *Technical and Economic Aspects of Load Following with Nuclear Power Plants*.

¹²¹ Baseload means the minimum, constant level of electricity demand required on an electrical grid over a specific period to support essential services like hospitals and continuous industrial operations.



The system value of nuclear depends on the net effect on system costs of nuclear across generation, grid build, balancing, curtailment and grid stability

System cost component	Nuclear cost impacts vs renewable-dominated system
Generation: CAPEX, OPEX, financing cost and lifetime generation, reflected in the LCOE	 Increase: Nuclear LCOE is materially higher than wind/solar (and offshore wind in land-constrained systems)
Balancing: Costs of assets to provide balancing needed to ensure supply meets demand	 Decrease at low shares: Need for dispatchable capacity reduces – particularly more expensive medium-long and ultra-long duration storage. Residual balancing still required when nuclear baseload + renewables are insufficient.
	 Increase at high shares: Balancing costs can increase at higher nuclear shares as more system flexibility (or curtailment of other assets) is needed to accommodate inflexible generation.
Supply-side curtailment: ¹²² Costs associated with curtailing generation assets for balancing and/or grid congestion management	 Increase or Decrease (depending on power mix and market design): Less need to overbuild renewables when firm nuclear is added – each nuclear GW can substitute several GW of overbuilt wind/solar capacity; however, in typical liberalised energy markets, renewables are lower on the merit order stack and benefit from priority dispatch rules, meaning that nuclear would be curtailed first, and curtailment costs could rise depending on the proportion of nuclear vs renewables in the mix.
Grid build: Additional transmission and distribution (T&D) costs to connect generation to demand	 Decrease: Lower T&D costs driven by potential brownfield/coal-site reuse, higher utilisation of connections and proximity to demand than utility-scale wind and solar. However, in many sunbelt regions, widespread expansion of behind-the-meter rooftop solar and storage could reduce the need for centralised grid and generation assets.
Grid stability: Ancillary service costs to maintain grid stability across voltage (e.g., reactive power support, voltage control) and frequency (e.g., through reserves, inertia, fast frequency response)	 Decrease: nuclear generators are synchronous machines which provide inherent inertia, fault level and reactive power, reducing the need for the synchronous condensers and Flexible AC Transmission Systems (FACTS) ¹²³ which add to system costs in high-renewables systems. Inertia is not a substitute for fast frequency response, however. Because nuclear runs at high and steady output it holds little upward headroom, so batteries or other fast-acting reserve are still required to contain and restore frequency after a loss of supply.

Our 2025 work on power systems conducted detailed modelling across four country archetypes (China, India, Spain, UK) and 30 years of bi-hourly weather data for entire years of modelled supply and demand to understand the cost of reaching fully low-carbon power systems across a range of archetypal power systems.¹²⁴ The key conclusions from this modelling were:

- **Solar and wind can technically reach ~90% generation shares of most global power systems.** Economically, overbuilt renewable capacity could meet ~60–90% of demand through naturally concurrent generation across a range of weather system archetypes.¹²⁵ The remainder can be backed up by short-duration storage (batteries, flexibility), medium- to long-duration storage (pumped hydro, compressed air, emerging electrochemical long-

¹²² Curtailment is a mechanism used to deliver balancing and congestion management, not an independent cost category. It is shown as a separate row because system-cost studies typically report curtailment as a distinct cost item.

¹²³ FACTS are advanced power electronics-based systems used to enhance the stability, controllability, and power transfer capacity of high-voltage AC electrical grids.

¹²⁴ Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

¹²⁵ The four archetypes assessed were: high-latitude windbelt systems (e.g., the UK) with low (and seasonal) solar irradiance, high wind speeds and high seasonal heating- and cooling-driven demand fluctuations; low-latitude sunbelt systems (e.g., India) with high solar irradiance, mixed wind speeds and low seasonal demand variability; mild/Mediterranean systems (e.g., Spain) with high (but seasonal) solar irradiance, relatively high wind speeds and moderate seasonal demand variability; and mixed climate systems spanning large areas (e.g., China) with high solar and wind resource in places and high seasonal heating- and cooling-driven demand fluctuations.

duration batteries) and, in windbelt climates with wind droughts which last over a week, ultra-long duration storage such as gas-fired power (fuelled by fossil methane, biomethane or hydrogen).

- **System costs for a fully low-carbon system are lower than or comparable to fossil-fuelled systems**, with higher resilience through reduced or avoided reliance on fossil imports. Our 2050 modelling showed that weighted average system costs per unit of demand in high-renewables systems could be made up of: generation costs meeting ~60–90% of demand at average costs of ~\$15–50 per MWh; short-duration storage (and demand-side flexibility) meeting ~5–40% of demand at ~\$40–80 per MWh; medium- to ultra long-duration storage (spanning LDES and gas-fired turbines for extended low-supply periods) meeting up to ~5% of demand at ~\$200–500 per MWh. Grid costs per MWh of demand are expected to rise in the short-term, as grid expansion precedes demand growth, before stabilising at ~\$10–30 per MWh in clean power systems once grid investment is spread over higher demand from electrification.¹²⁶
- **Sunbelt countries are set to have structurally lower total system costs than windbelt ones.** Steady solar output and small seasonal swings mean they mostly need to balance supply between day and night. The continuing decline in solar and battery costs enables high-availability systems in sunbelt regions by economically overbuilding solar capacity and shifting the generation using batteries.

Building on our 2025 work on renewable-dominated systems outlined above, we have modelled how increasing nuclear power into a variable renewable-dominated system changes the total system cost and composition. We have done this for two of our four climate archetypes: UK (a windbelt and high-cost nuclear archetype) and India (a sunbelt and low-cost nuclear archetype). While there is high uncertainty in long-term system modelling and this is not an exhaustive assessment of the country-specific factors that drive power system planning, this analysis allows us to draw indicative conclusions on the nuclear shares that countries with similar archetypal features should target. [Exhibit 3.2]

- **In the UK high latitude windbelt case costs are similar at 0% and 20% nuclear.** In the UK, if nuclear can be delivered at ~\$110 per MWh by 2050 (a ~40% decline from recent levels), a nuclear share of up to 20% of total electricity supply could leave UK system costs staying roughly constant compared to a 100% renewables system.¹²⁷ At this level, nuclear would reduce relatively expensive overbuilt offshore wind and ultra-long duration storage needs (in terms of capacity and generation, modelled as green hydrogen). Grid costs also decrease as nuclear substitutes offshore wind, due to higher use of brownfield sites/connections (e.g., old coal sites), higher utilisation of connections and closer proximity to demand. Combined, these system benefits might largely offset the increased generation costs. A ~20% share corresponds to ~20 GW and is aligned with the National Energy System Operator's (NESO) high-electrification 2050 scenario and is close to the UK Government's 24 GW 2050 target.¹²⁸ A nuclear share of this level also beneficially increases supply diversity, reducing risk exposure to extreme weather situations such as an extended midwinter "dunkelflaute" wind drought in the North Sea.
- **In the Indian sunbelt case, system costs are marginally lower at 10% nuclear than 0%.** This is representative of the global sunbelt where solar will be the predominant renewable resource, and where the primary balancing need is diurnal and can be met with battery storage. For India, if nuclear can continue to be delivered at the relatively low levels achieved recently (~\$40 per MWh),¹²⁹ the total system cost could fall as nuclear shares are increased from 0 to 10%. At this level, nuclear displaces low-cost solar and batteries in the system, also reducing balancing and grid costs. The 10% penetration corresponds to ~100 GW (in line with the Indian government's targeted 100 GW by 2047).¹³⁰
- **Nuclear's optimum penetration should be capped below baseload demand:** When nuclear's share is increased to ~50% in the UK scenario (40 GW) and 30% in the India scenario (~250 GW), system costs rise compared to the no/low nuclear share scenarios. Grid costs continue to decline but the impact decreases as nuclear replaces onshore renewables at higher shares (rather than offshore wind in the UK case) and also requires grid reinforcement. At shares higher than baseload demand, nuclear or other continuously operating sources face

126 Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*

127 A cost decline of ~40% from today's ~\$190 per MWh level (see Chapter 1) was assumed to capture learning curve effects and implementation of the delivery capabilities outlined in Chapter 2. Renewables LCOE assumptions: solar ~\$20/MWh, onshore wind ~\$30/MWh, offshore wind ~\$60/MWh. Source: Systemiq analysis for the ETC (2026); Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

128 NESO (2025), *Future Energy Scenarios: Pathway*; Department for Energy Security & Net Zero (2024), *Civil nuclear: roadmap to 2050*.

129 See India's recent nuclear costs in Section 1.3.2. Renewables LCOE assumptions: solar ~\$10/MWh, onshore wind ~\$30/MWh, offshore wind ~\$50/MWh. Source: Systemiq analysis for the ETC (2026); Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

130 WNA (2026), *India – World Nuclear Outlook Report*.

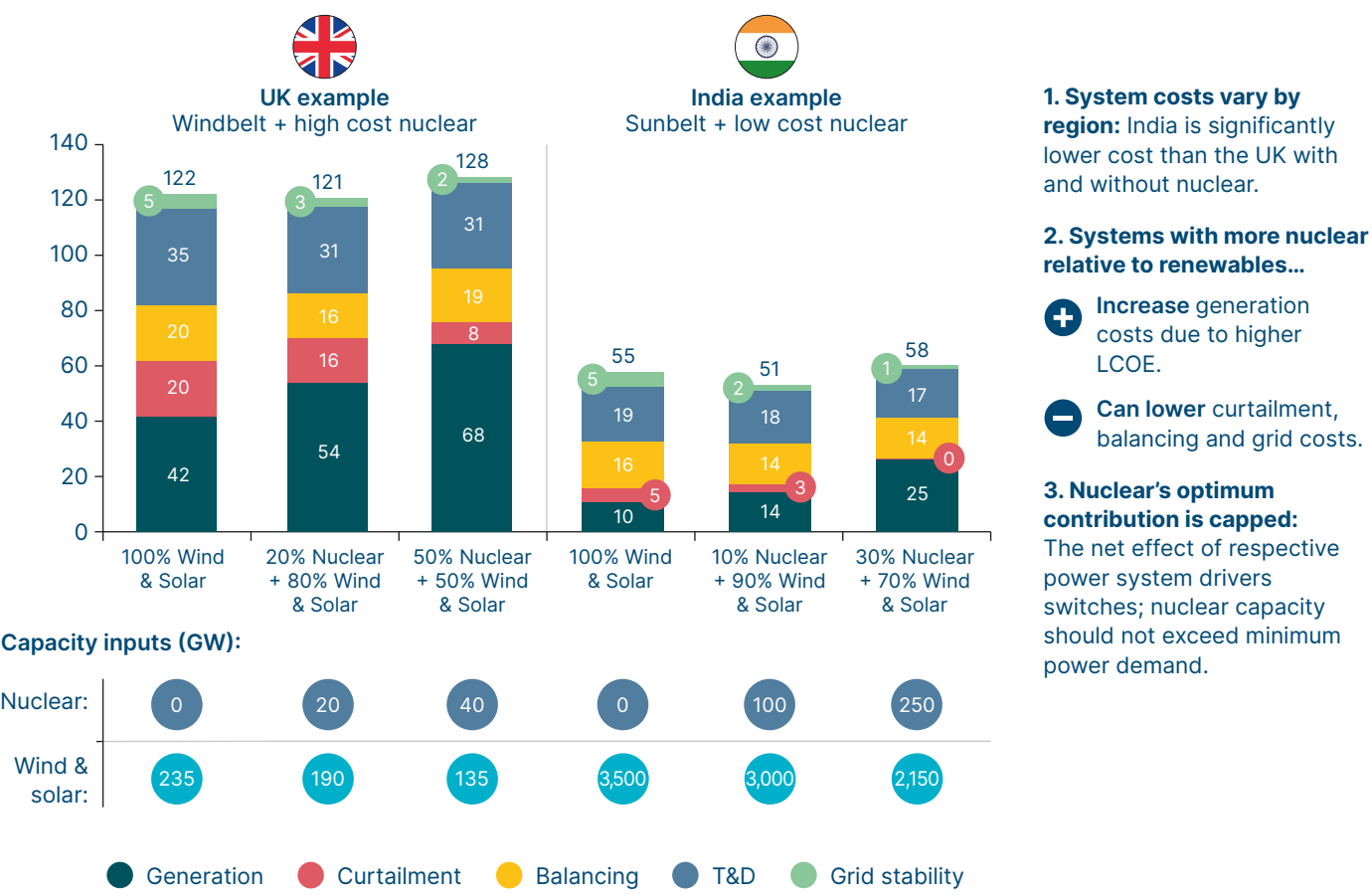


curtailment.¹³¹ Therefore, nuclear should not exceed baseload power demand minus typical renewables output (corresponding to ~20% in the UK example in Exhibit 3.2). LDES technologies could also shrink the role for baseload generation, through mechanical, thermal and electrochemical technologies that are under development with a range of maturity.¹³² Novel renewables technologies including next-generation geothermal could also decrease in cost and increase in scalability, providing an alternative clean firm power supply option in many countries.¹³³ Given nuclear development timelines of ~10–25 years, system planners will need to consider nuclear costs compared to these competing options to meet this residual demand.

Exhibit 3.2

Nuclear’s higher generation cost can be offset by balancing and grid costs in clean power systems, up to a limit

Illustrative view of components of total system cost and variation by system, UK and India case studies in 2050, \$/MWh of demand (real 2024\$)



NOTE: “20% nuclear” refers to the share of generation. India is one of a small subset of countries in the sunbelt with existing nuclear development capacity. Shares don’t scale directly due to value rounding and different levels of overbuild across scenarios. T&D = Transmission & distribution. Generation – BloombergNEF’s medium 2050 CAPEX and OPEX estimates, with capacity factor, WACC and lifetime assumptions based on ETC modelling; Curtailment – surplus electricity at the weighted average wind & solar LCOE (assuming no nuclear is curtailed); Balancing includes lithium-ion batteries for short-duration (<8h), pumped hydro for medium- to long-duration (8–20h) and green hydrogen peakers for ultra-long duration (>50h), with costs based on ETC’s 2025 power system analysis. Average T&D cost per MWh based on ETC’s 2025 power system analysis.

SOURCE: Systemiq analysis for the ETC (2025); BloombergNEF (2025), LCOE Data Viewer.

131 In some cases, the combination of domestic and interconnected baseload can be considered to account for export opportunities (e.g., in highly interconnected European countries).

132 US Department of Energy (2023), *Pathways to Commercial Liftoff: Long Duration Energy Storage*

133 Energy Transitions Commission (2026), *Beneath the Surface Geothermal’s Role in Delivering Clean Heating, Cooling and Power*

3.2 Adequacy and security of supply considerations for renewables and nuclear

The restrictions on oil and gas supply and volatility in prices which resulted from the closure of the Strait of Hormuz have illustrated the threats to energy security created by reliance on imported fossil fuels.¹³⁴ Both renewables and nuclear electricity supply can be a means to achieve greater national energy independence and security. But limited renewable resource (driven by high population density and low wind and/or solar resource) will in some cases increase the optimal role of nuclear, while risks in nuclear fuel supply must also be managed.

3.2.1 Variations in renewable resources

Across the whole world, and in most individual countries, there is easily enough solar or wind resource to deliver high shares of electricity supply, even while electricity meets a rapidly rising share of total energy requirements. Even meeting global electricity demand of 100,000 TWh per year in the second half of this century would only require solar covering under 2% of available land area.¹³⁵ However, nuclear power requires just ~1–2% of the land area per TWh per year of wind or utility-scale solar (although both can have shared land uses e.g., alongside agriculture, and solar can be on rooftops).¹³⁶

In countries with significant land constraints, limited renewable resources or favoured siting for nuclear over renewables and transmission buildout, nuclear's optimal share of electricity generation could be higher than the 20% of total generation outlined above. [Exhibit 3.3]

- **Several countries with very high population densities are unlikely to meet future electricity demand entirely from renewables.**¹³⁷ Singapore, with a population density of ~8,200 people per km² versus ~500 in India, ~150 in China and 4 in Australia,¹³⁸ is not likely to source more than a very small share of total electricity supply from either wind or solar. Countries like Bangladesh, with a high population density of ~1,400 per km² and ~60% of land used for agriculture, would only reach ~6,000 kWh of electricity per capita per year if 10% of its total land area were given over to solar panels – ~20% of per-capita consumption in highly electrified countries like Norway today.¹³⁹ This land supply constraint may be alleviated by the deployment of agrivoltaics but not entirely eliminated.¹⁴⁰ Adequate electricity supply in very high population density countries will therefore require either the import of electricity from other countries or a greater role for nuclear than applies on average across the world, provided that the delivery conditions outlined in Chapter 2 can be established.
- **A lack of renewable resources compounds land constraints in some countries.** In addition, some countries that are not land constrained have poor renewable resources. In Malaysia, land availability and moderate solar and wind resources could limit renewables scalability. Japan and South Korea are high latitude countries with relatively low average solar yield and low average onshore wind speeds. The optimal role of nuclear may therefore be higher in these countries but will also depend on the potential to build out alternative technologies – such as offshore wind and geothermal – based on country-specific assessments to establish pathways with lowest system cost and highest public support.
- **Public concerns could favour some nuclear buildout in countries with significant renewables and transmission siting constraints.**¹⁴¹ Even in countries which have plentiful domestic renewable resources, public concerns about the visual impact of wind or solar installations or new transmission lines may create local opposition to the scale of renewable development compatible with least total system cost. This is particularly

¹³⁴ Energy Transitions Commission (2026), *Lessons on Energy Security after the Hormuz Crisis: How Accelerating the Clean Energy Transition Builds Resilience Against Future Price Shocks*.

¹³⁵ Assuming 14 km² per TWh/year for utility solar PV based on NREL, 130 million km² total global land area with 30% protected for biodiversity. Source: Systemiq analysis for the ETC (2026); Shell (2026), *The 2026 Energy Security Scenarios: Challenges to the Transition*; NREL (2013), *Land-Use Requirements for Solar Power Plants in the United States*. NREL/TP-6A20-56290. Available at: <https://www.osti.gov/servlets/purl/1086349>. [Accessed 07 2026]; World Bank (2026), *World Development Indicators – Land area (sq. km)*. Available at: <https://data.worldbank.org/indicator/AG.LND.TOTL.K2> [Accessed 07 2026]; Convention on Biological Diversity (2022), *Kunming-Montreal Global Biodiversity Framework*, Target 3.

¹³⁶ Energy Transitions Commission (2023), *Material and Resource Requirements for the Energy Transition*.

¹³⁷ Countries with high population density but with reasonable coastlines could supply much of their electricity needs from offshore wind; however, this would come with the trade-off with grid and balancing costs compared to nuclear outlined in Chapter 2.

¹³⁸ Our World in Data (2025), *Population Density*, 2025. Available at: <https://ourworldindata.org/grapher/population-density>. [Accessed 07 2026].

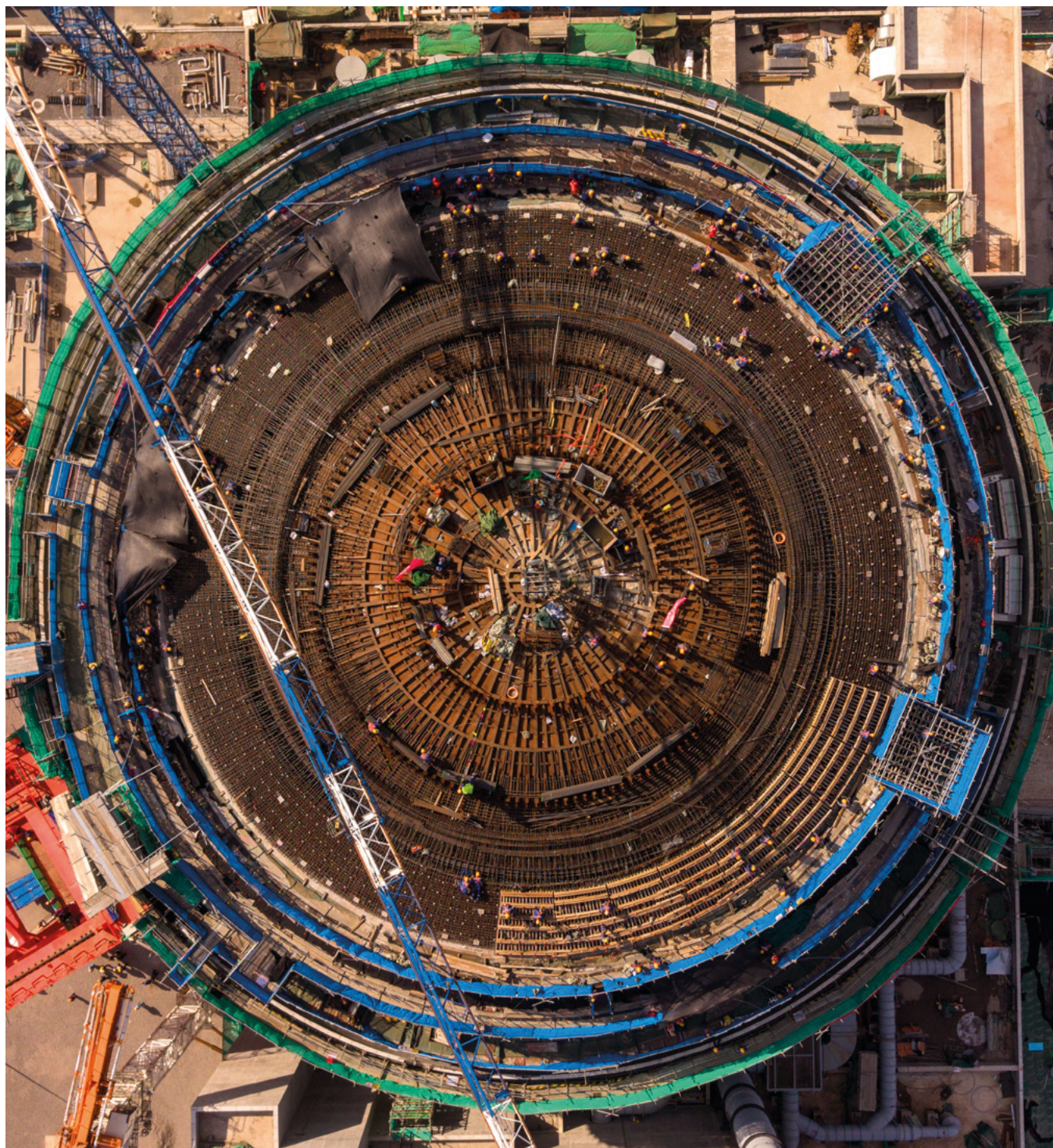
¹³⁹ Our World in Data (2025), *Population Density*, 2025. Available at: <https://ourworldindata.org/grapher/population-density> [Accessed 07 2026]; BBC (2025), *Bangladesh Country Profile*; World Bank Group (n.d.), *Arable Land (% of Land Area) – Bangladesh*; Statista (2025), *Electricity Consumption Per Capita Worldwide in 2025, by Selected Country*.

¹⁴⁰ Energy Transitions Commission (2026), *Unlocking Solar at Scale: How Agrivoltaics Overcome Land Constraints in India's Energy Transition*.

¹⁴¹ Energy Transitions Commission (2024), *Building Grids Faster: The Backbone of the Energy Transition*.



relevant in many European and North American countries (e.g., the UK, France, Germany and Northeastern US), where permitting timelines for new high-voltage lines exceed 10 years.¹⁴² A greater role for nuclear may therefore be politically preferred even if this results in slightly higher costs, as nuclear's high energy density means a single nuclear site can host several GW of capacity under one consent process, whereas an equivalent volume of renewables and associated transmission requires dispersed consent across many communities and jurisdictions. Nuclear can also use brownfield coal sites, however this needs to be weighed against the long lead times of new nuclear projects and the alternative brownfield site uses which could be delivered faster (including batteries, solar and synchronous condensers).¹⁴³

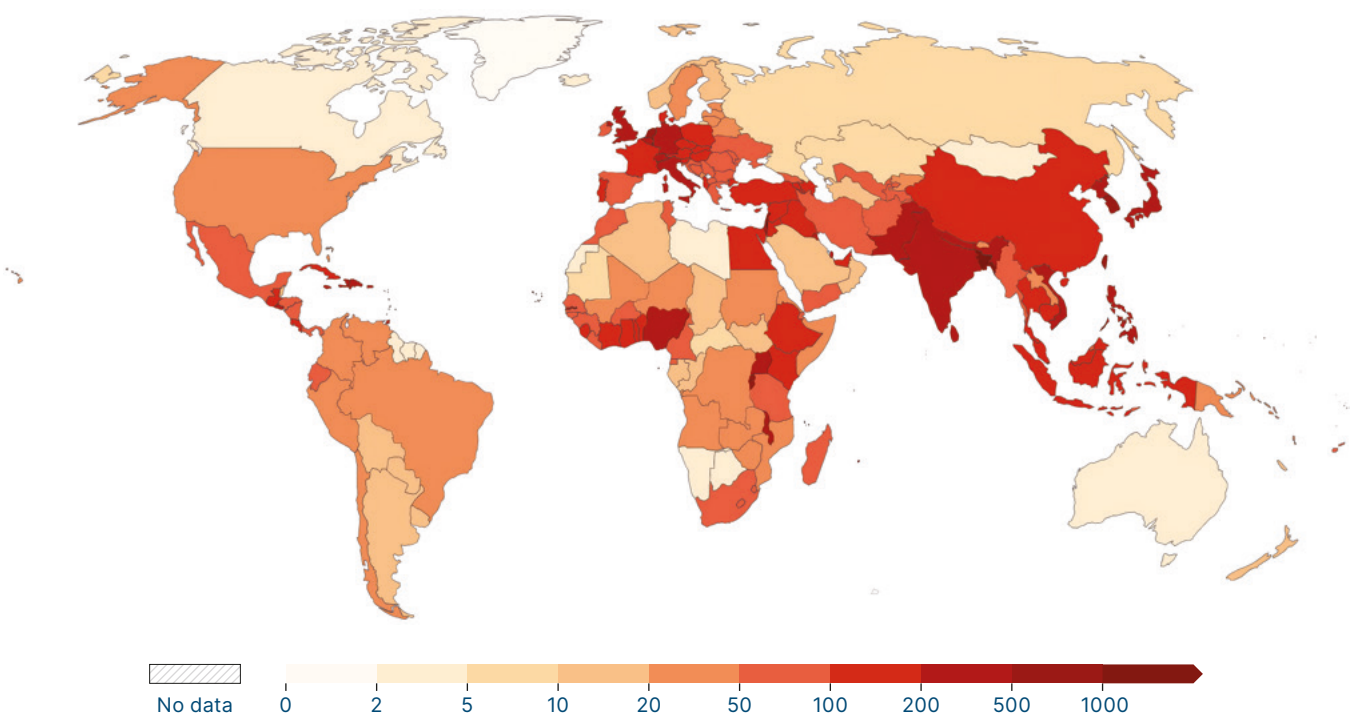


142 Energy Transitions Commission (2024), *Building Grids Faster: The Backbone of the Energy Transition*.

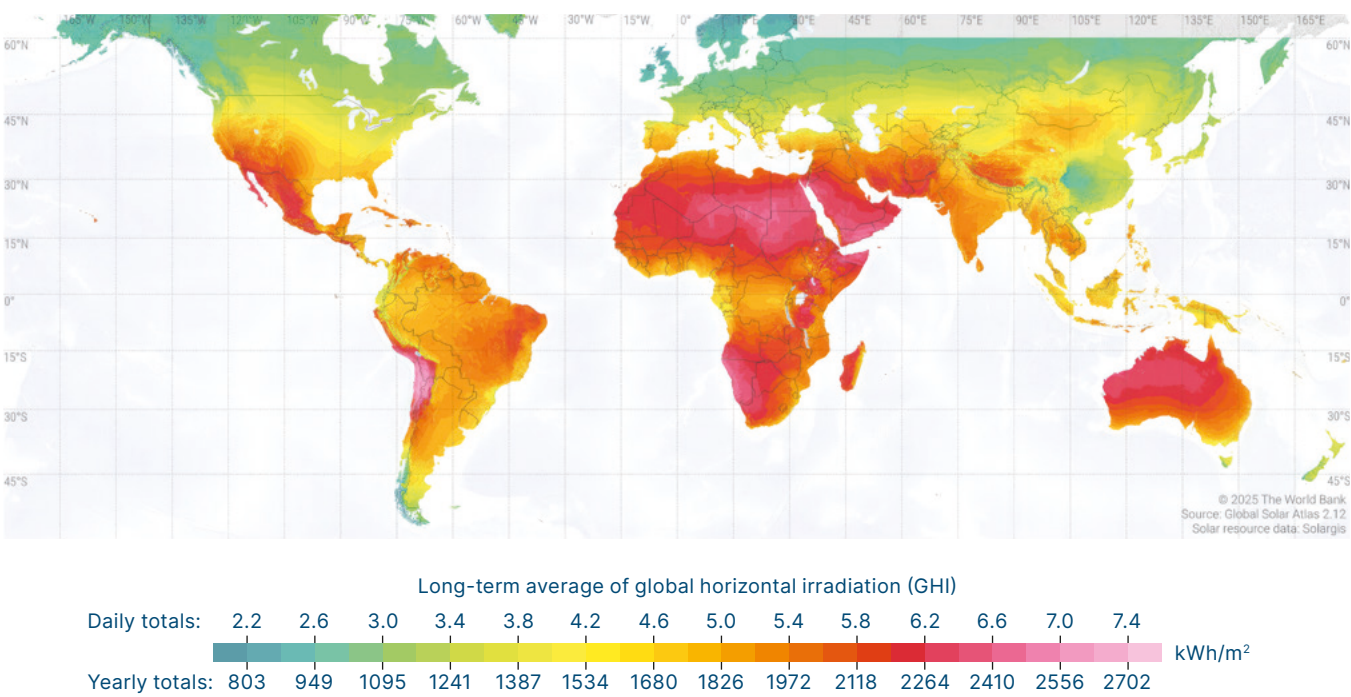
143 US DOE (2022), *Investigating Benefits and Challenges of Converting Retiring Coal Plants into Nuclear Plants*.

Nuclear’s system value is highest where land is scarce and solar and wind resources are weakest

Population density by country (Our World in Data, 2025)
people per km²

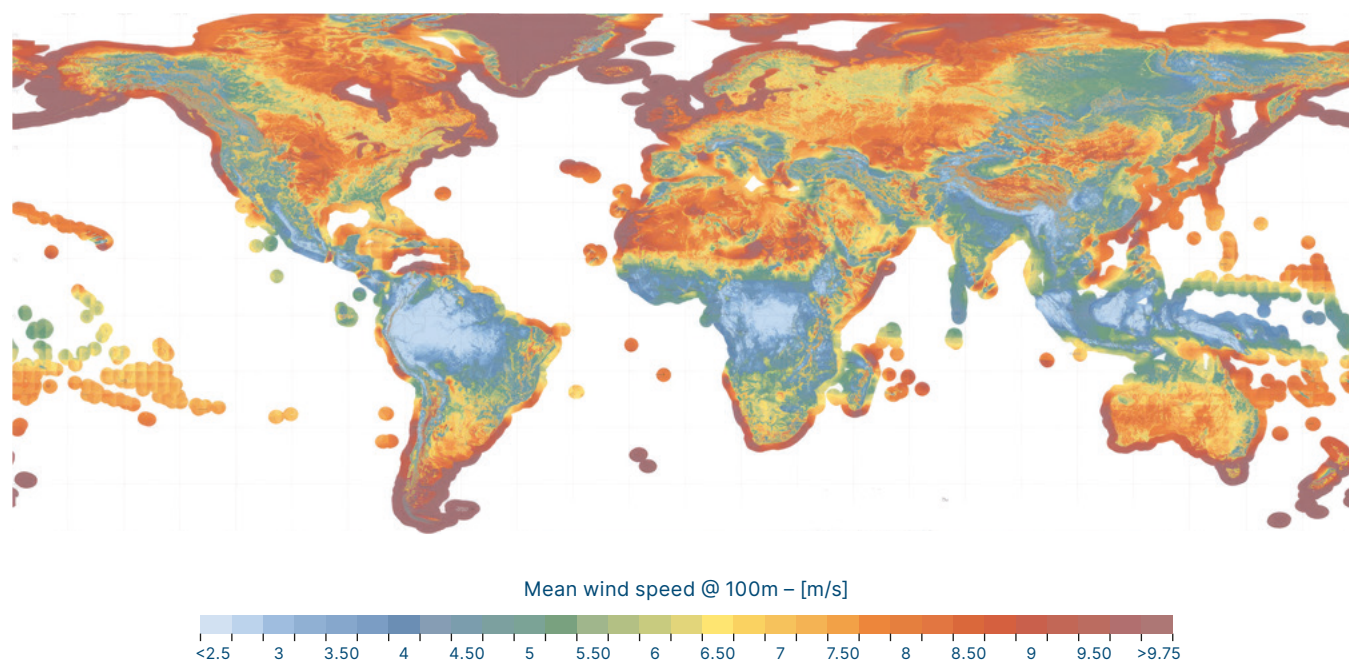


Solar global horizontal irradiation variation across the world (Global Solar Atlas)
kWh/m² (long-term yearly average)



Wind speed variation across the world (Global Wind Atlas)

m/s (mean speed 100 m above surface level)



NOTE: GHI refers to Global Horizontal Irradiance – the total amount of solar radiation received on a horizontal surface.

SOURCE: HYDE (2023); Gapminder (2022); UN WPP (2024); UN FAO (2024) – with major processing by Our World in Data, *Population Density, 2025*. Available at <https://ourworldindata.org/grapher/population-density>. The World Bank (2025), *Global Solar Atlas: Global horizontal irradiation*. Available at <https://globalsolaratlas.info/download?c=11.523088,8.613281,3>; World Bank (2023), *Global Wind Atlas*. Available at <https://globalwindatlas.info/en/>. All maps re-used with permission per CC BY 4.0.

3.2.2 Security of nuclear supply

Nuclear can contribute to energy resilience through reduced fossil-fuel import dependence. However, the extent to which nuclear adds to system resilience depends on access to fuel supply, the level of unexpected shutdowns and local climate resilience.

- **Nuclear reduces exposure to fossil fuel import disruptions that translate into near-immediate price and availability shocks.** As of July 2026, European Title Transfer Facility (TTF) gas prices stood ~77% above year-earlier levels, driven by Strait of Hormuz disruptions.¹⁴⁴ In the UK system modelled in Section 3.1, reaching 20 GW of nuclear reduces the residual gas-based backup needed in 2050 by ~20%. The absolute volume is small – residual gas in a high-renewables 2050 system meets under 3% of total annual demand – but there is strategic value in reducing the need for ultra-long duration backup in systems exposed to gas market shocks and where development of new strategic gas reserves could be avoided.
- **Fuel supply concentration limits the desirable share in many countries.** Fuel supply risks argue against high shares of nuclear generation in countries which do not control key elements of the fuel supply chain but are likely manageable at sub-20% generation shares (discussed in Section 3.1). Unlike renewables, nuclear power generation does require a fuel supply which needs to be imported in most countries. Different elements of the nuclear fuel supply chain – covering mining, conversion, enrichment and fabrication – are often concentrated in specific countries, including Russia, France, China and Canada (as outlined in Section 2.3). However, the very high energy density of nuclear fuel, combined with long refuelling cycles (typically 18–24 months), means that nuclear operators typically hold one or two years' of fuel supply on site as a strategic reserve (but can economically store up to 10 years if supply risk is a concern and the fuel can be procured). This contrasts to gas-fired generation, where piped and shipped gas flows across borders daily.

¹⁴⁴ Trading Economics (n.d.) *EU Natural Gas*. Available at: <https://tradingeconomics.com/commodity/eu-natural-gas> [Accessed 07 2026].

- **Unplanned downtime is a system-level risk in standardised fleets.** Unexpected shutdowns of very large capacity units can create significant short-term supply risk – this can be exacerbated if a large nuclear fleet contains multiple units of a similar design and advanced age. This can create a systemwide shortage such as in France in 2022, when nuclear output fell 30% below its 20-year average due to corrosion issues which caused downtime at 12 of France's 56 operating reactors (rising to 32 reactors offline at the September 2022 peak, including scheduled maintenance).¹⁴⁵ This risk could be reduced by ensuring that new nuclear fleets contain units of multiple designs, although this would come with a cost premium versus deploying one standardised design, as discussed in Chapters 1 and 2.
- **Droughts and water shortages can affect nuclear power cooling, leading to reduced output or forced shutdown.** Around 20% of nuclear reactors operating today use lakes or rivers for cooling via once-through systems. To protect local biodiversity, maximum allowable water temperature thresholds can curtail nuclear output in summer. For example, 6.2 GW, representing ~10% of capacity in France, was taken offline during the July 2026 heatwave, with shutdowns at Nogent-sur-Seine and Golfech 2 and reduced output at Saint-Alban 2 and Bugey 3.¹⁴⁶ This may argue against high nuclear shares in some countries where risks are higher and increasing as global temperatures rise. Modern designs can make nuclear power plants more resilient to heat waves and droughts, though at some added cost (e.g., using cooling towers to reduce output water temperatures or, eventually, novel Gen IV reactor designs with alternative coolants).¹⁴⁷

3.3 Nuclear for heat and off-grid applications

Nuclear reactors can supply heat alongside power. In such “hybrid cogeneration”, part of the heat released from fission drives a turbine to generate electricity and/or is extracted for other applications like industrial process heat, hydrogen production, district heating or desalination. The output temperature from the reactor determines which applications are viable. This varies by reactor type. Conventional Gen II-III+ reactors deliver steam at up to ~300°C, giving usable process steam below ~250°C, sufficient for district heating, desalination, food, pulp and paper and producing the steam for high-temperature electrolysis. Advanced Gen IV high-temperature gas-cooled reactors (HTGR) target outlet temperatures of 750–950°C, though near-term designs target 600–750°C which could deliver heat to the user at 550–700°C, enabling chemicals, refining and thermochemical hydrogen applications.¹⁴⁸

Today, a small number of operating plants (primarily in Russia, China and central and eastern Europe) provide heat for district heating. Future deployment may remain limited due to uncertain cost-competitiveness with alternatives and siting requirements.

- **Nuclear plants are unlikely to be built at scale for heat alone, because costs are unproven and they will compete with lower-cost electrification solutions.** While dedicated heat-only reactors are in development (e.g., Steady Energy's LDR-50 with 50 MW-th units producing ~150°C heat), there are currently no operating commercial-scale plants meaning that costs are highly uncertain. The OECD Nuclear Energy Agency (NEA) estimates that delivered heat from Gen IV reactors, including HTGRs, could become competitive with other low-carbon sources.¹⁴⁹ However, because heat can only cascade downwards, such reactors delivering heat at 550–700°C are likely to address the medium-temperature 250–550°C applications. This range can also be met by electric boilers, and high-temperature heat pumps at the lower end, which are likely to have lower levelised costs of heat in places with relatively low electricity prices.¹⁵⁰
- **Flexible offtakes could improve the economic case for cogeneration.** Reactors could be built to run at full output into off-grid applications including industrial heat and data centres, then curtail that flexible demand to release firm power into the grid when output from renewables is low. This would enable the high load factor needed for economic nuclear generation, while providing high system value during moments of low renewables supply.

¹⁴⁵ RTE (2023), *Annual Electricity Review 2022*; World Nuclear Association (2026), *Nuclear Power in France*.

¹⁴⁶ Y. Guénand (2024), *Climate Change Impact on Nuclear Power Outages - Part I: A Methodology to Estimate Hydro-thermic Environmental Constraints on Power Generation*; Renew Economy (2026), *Nuclear Reactors Taken Offline in France, as Extreme Heat Pushes River Temperatures into Danger Zone*.

¹⁴⁷ ECO Infos Energies Renouvelables (2026), *The Only Nuclear Power Plant in France That Cools Its River*. Available at: <https://www.les-energies-renouvelables.eu/article/actualites/energies/la-seule-centrale-nucleaire-qui-refroidit-sa-riviere-en-france-1070/> [Accessed 08 2026].

¹⁴⁸ NEA (2022), *High-Temperature Gas-Cooled Reactors and Industrial Heat Applications*.

¹⁴⁹ NEA (2022), *High-Temperature Gas-Cooled Reactors and Industrial Heat Applications*.

¹⁵⁰ Systemiq (2024), *Global opportunities for Electrothermal Energy Storage*; Fraunhofer ISI (2024), *Direct electrification of industrial process heat. An assessment of technologies, potentials and future prospects for the EU*.



- **Hybrid applications require co-location of reactors with industrial sites or heat transport from suitable sites.** Exclusion zones limit the proximity of nuclear plants to industrial clusters, meaning that co-locating reactors with industrial heat offtake is rarely practical. Heat transport economics depend on the medium: steam is expensive to move and impractical at distances beyond a few kilometres, whereas pressurised hot water at 110–130°C can move tens of kilometres with minimal heat losses.¹⁵¹

In practice, these conditions are restrictive and are likely to limit buildout targeted at non-power applications. Most large industrial clusters are far from sites where new reactors can realistically be permitted, and deployment timelines for the Gen IV high-temperature designs best suited for industrial heat applications could extend into the 2040s (see Chapter 1) – beyond the window in which most hard-to-abate sectors need to begin decarbonising at scale.¹⁵² China is a notable exception, where standardised build, state-backed financing and planned industrial co-location have enabled nuclear district heating and early hydrogen pilots at costs unlikely to be reproducible in most other markets. For these reasons, we have not carried out dedicated modelling on non-electric nuclear applications.

3.4 Economic value added and employment effects

The economic impact on domestic “value added”¹⁵³ and employment is a factor that is often used in decisions around technology deployment. Both nuclear and renewables entail relatively small employment and cost during operation and, as a result, deliver the benefit of electricity at low marginal cost. Additionally, operational efficiency improvements incorporated in new nuclear designs and ways of managing wind or solar farms are tending to reduce operations and maintenance (O&M) job requirements over time. However, both technologies require large upfront investments, which create economic activity and employment during the EPCI phases.

It is often claimed that nuclear investment will create more value added and more/higher paid jobs than renewables investment. But it is important to assess the validity of this argument carefully in terms of investment costs, level of technology-specific domestic inputs and the potential to develop them.

- **High “value added” may reflect high costs rather than economic efficiency.** If all inputs to nuclear and renewables investment were produced domestically, the fact that nuclear created higher “value added” than renewables would just be a different way of saying that it entails a higher investment cost, and thus, higher-cost electricity. And higher future electricity costs/prices could more than offset any short-term benefit of job creation during construction.
- **Local content improves the case for nuclear compared to renewables in many countries.** Only if nuclear investment entails a higher share of domestic inputs than renewables might there be an economic benefit not captured by a focus solely on total system cost. For nuclear, construction, installation and site-based services account for ~70–80% of overnight CAPEX (materials and equipment alone are only 15–30%). These activities are inherently domestic – underpinning nuclear’s high local content of up to 70% in mature industrial countries.¹⁵⁴ For solar and onshore wind, the inverse is true: manufactured equipment (solar modules, inverters, wind turbines) makes up ~60–70% of CAPEX, with domestic construction and installation only contributing 30–40%.¹⁵⁵ This equipment is a tradable good frequently imported from a concentrated set of manufacturing hubs (particularly China).
- **However, whether that on-site share is captured domestically depends on where the workforce and expertise come from, and the domestic jobs it creates are dominated by lower-skilled, lower-value activities.** High local content can entail a CAPEX penalty versus importing EPCI workforce from nuclear exporting countries. [Exhibit 3.4] New-entry countries like the UK at Hinkley Point C see construction-heavy job profiles, with limited highly skilled manufacturing content where components are imported – and even the construction and engineering effort draws heavily on imported EPCI expertise.¹⁵⁶ Importing a highly skilled EPCI workforce from

151 World Nuclear News (2023), Chinese long-distance nuclear heating project begins operation. Available at: <https://world-nuclear-news.org/articles/chinese-long-distance-nuclear-heating-project-begins-operation> [Accessed 09 2026]; CNNC (2025), Haiyang district heating network expanded. Available at: https://en.cnncc.com.cn/2025-11/28/c_11441137.htm [Accessed 09 2026]

152 ETC (2018), Mission Possible: Reaching net-zero carbon emissions from harder-to-abate sectors

153 Gross value added or GVA is an economic metric that measures the value of goods and services produced in an area, industry or sector.

154 Nuclear Engineering International (2012), *Localisation of Supply—How Can It Work?*

155 IRENA (2026), *Renewable Power Generation Costs in 2025*; NREL (2025), *Documenting 15 Years of Reductions in U.S. Solar Photovoltaic System Costs*.

156 OECD NEA & IAEA (2018), *Measuring Employment Generated by the Nuclear Power Sector*.



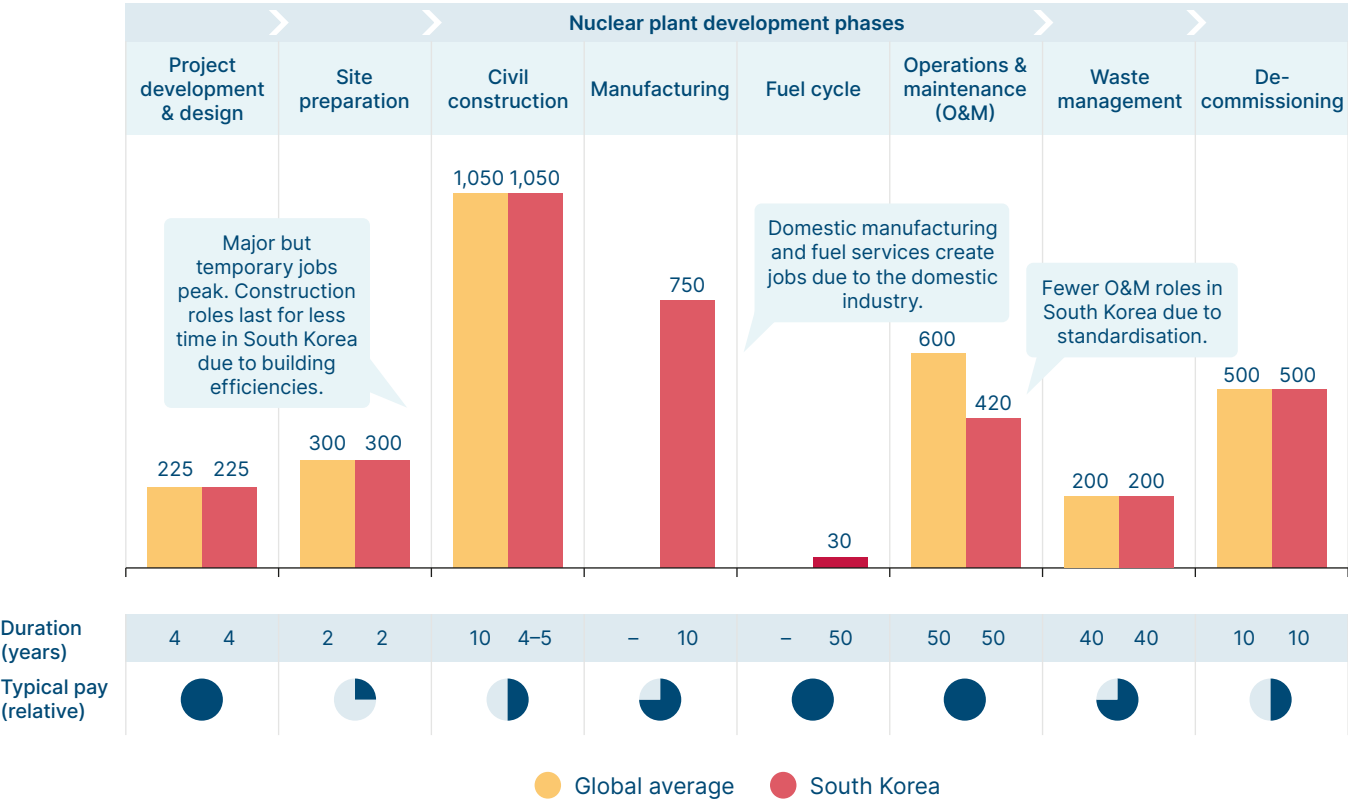
nuclear exporting countries (such as China, South Korea and Russia) is a route to decreasing the overall cost of construction and installation, although this sacrifices local content and “value added”. Nuclear’s local-content advantage is therefore not automatic: it is realised only by countries with an established domestic workforce and supply chain, whereas the equipment-heavy cost structure of renewables limits domestic capture in most countries regardless of their industrial maturity.

- **Ultimately, any economic benefit arising from a higher share of domestic production must therefore depend on the level of existing and potential new domestic nuclear.** This will be determined by whether it has or can develop supply chains to produce the specialised equipment used in nuclear plants (e.g., reactor cores), and the skilled EPCI workforce to install it, rather than simply incorporating imported equipment and expertise in domestic construction.

Exhibit 3.4

Civil construction creates most jobs, followed by O&M and decommissioning - duration may vary by project/region

Jobs by project stage for a representative 1 GW large-scale conventional Gen III+ reactor, global average and South Korea
Jobs per year per GW



SOURCE: Systemiq analysis for the ETC (2025); OECD NEA & IAEA (2018), *Measuring Employment Generated by the Nuclear Power Sector*.

Countries should assess the potential for either renewables investment or nuclear investment to foster the development of economically competitive domestic equipment supply chains as part of their industrial policy. But supply chain considerations do not provide a generally applicable reason for preferring nuclear to renewables investment.





Optimal nuclear development by country and globally

As Chapter 2 described, the ability to deliver new nuclear power cost-effectively currently differs greatly by country. Chapter 3 outlined that the system benefits of deploying nuclear will vary significantly by country, primarily due to differences in renewable resources. The question is what these two factors imply for the optimal size of nuclear capacity in a specific country – a critical question for governments and civil society as they consider building new nuclear. In this chapter, we assess in turn:

- 1. The impact of extending the operational life of existing nuclear plants.** The potential for such extensions implies that some countries with large existing nuclear fleets (e.g., France) will continue to source high shares of electricity from nuclear, whatever their new deployment strategy.
- 2. The optimal role of new nuclear development in different countries,** classifying countries into five categories from low to high potential roles.
- 3. Implications for nuclear's global role:** potentially growing ~2–3x between now and mid-century, but maintaining up to 10% of global generation in 2050. This would imply a dramatic increase in new nuclear build compared with today's levels, but would not significantly reduce the need for massive renewable deployment.
- 4. The actions required across governments and industry** to scale nuclear safely and at low cost.

4.1 Extending existing fleet lifetimes wherever possible

Extending the lifetime of our existing fleet to 80 years is a low-cost opportunity to maintain 230 GW of capacity which will otherwise retire before 2050. LCOEs of ~\$40 per MWh are lower than the total system cost of renewables in even the most favourable locations. Life extensions should therefore be pursued wherever technically feasible and safe.

- **Feasible nuclear lifetimes have increased from 40 to 60 to 80 years over the past decades.** Much of the existing nuclear fleet was built and licensed on the assumption that it would operate for around 40 years and then be decommissioned. But extensions to 60 years have become increasingly common since 2000, and extensions to 80 years are now being considered. In 2019, the US's Turkey Point Units 3 and 4 became the first plants to be approved for 80 years of operation, and 12 plants in the US now have extensions to 80 years.¹⁵⁷ Extensions to 80 years are also now being considered in numerous countries, including France, Sweden and Canada.¹⁵⁸
- **Life extensions offer a low-cost and relatively fast (though still multi-year) opportunity to maintain operating capacity.** Life extensions typically cost ~\$500–1,100 per kW vs. a range of ~\$2,000–18,000 per kW for new

¹⁵⁷ U.S. NRC (2026), *Status of Subsequent License Renewal Applications*. Available at: <https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal> [Accessed 07 2026]; Brian W. Smith (2022), *From 40 to 60 to 80 Years – What is Next for License Renewal in the USA?* Available at: <https://adamswebsearch2.nrc.gov/webSearch2/main.jsp?AccessionNumber=ML22286A004> [Accessed 07 2026].

¹⁵⁸ Montel News (2024), *French Reactors Could Run for More Than 60 Years – EDF CEO*; GRS (2026), *Nuclear Energy Worldwide 2026*; Nuclear Engineering (2025), *Life Beyond 40*.



builds.^{159,160} This implies LCOEs for maintained nuclear generation of below \$40 per MWh, which could be below the total system cost of renewables even in the most favourable renewable locations.

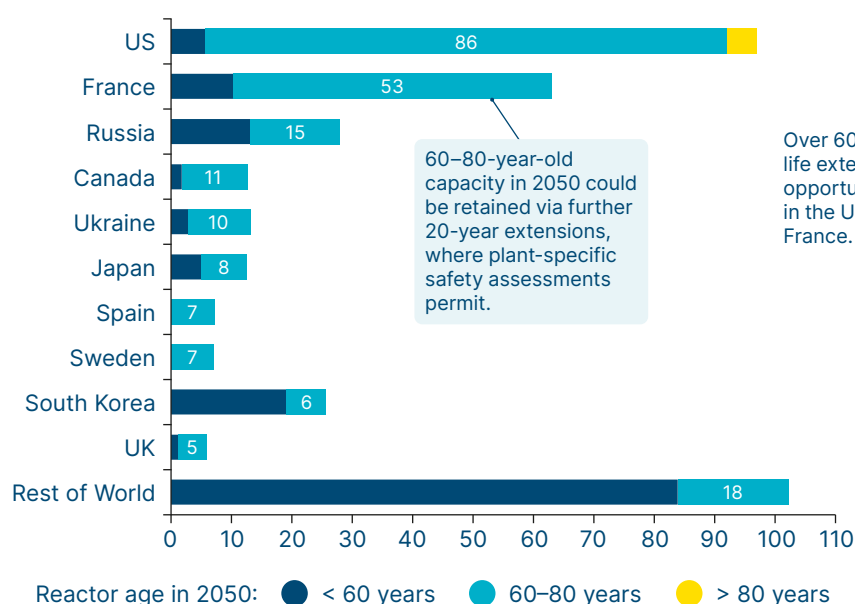
- **Lifetime extensions to 80 years could result in the retention of 230 GW of capacity, which will otherwise retire before 2050.** The current average reactor age is 33 years globally – ranging from 20 in Asia to 41 and 44 in Western Europe and North America, respectively.¹⁶¹ 60% of this retained capacity will be in the US and France, and another 28% elsewhere in Europe. [Exhibit 4.1] As a result, the total nuclear share of generation in some countries (particularly France) could remain high even if no new nuclear plants were built. However, countries which commit to significant CAPEX on life extensions will need to develop a nuclear technology delivery capability which may itself increase the feasibility and reduce the cost of new nuclear development.

Exhibit 4.1

Lifetime extensions from 60–80 years could save over 200 GW from retirement by 2050 – concentrated in the US and France

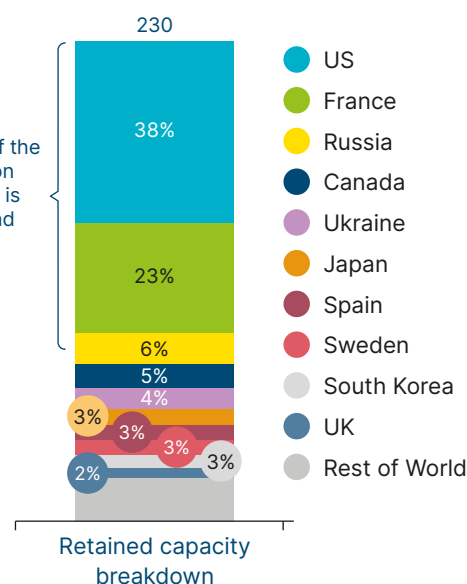
Nuclear capacity age distribution in 2050

GW



Retained capacity with 80-year life extensions

GW



SOURCE: Systemiq analysis for the ETC (2026); IAEA (2026), *Power Reactor Information System*.

4.2 Optimal new build strategies by country

Governments should critically assess the optimal role of nuclear in their country's context, accounting for its relatively high cost, long development timelines and high level of government support needed. All nuclear projects which have been delivered at competitive costs over the last few decades have relied on a combination of state-backed financing and state absorption of cost overrun risk to achieve a low WACC. Optimal national strategies for new nuclear build must therefore reflect a careful assessment of the economics vs. the renewable alternative: in many countries, state support for low-carbon power development will deliver least-cost decarbonisation if focused on renewables.

¹⁵⁹ IEA (2024), *World Energy Outlook 2024*.

¹⁶⁰ Upgrades – physical modifications and/or recalibration that raise a reactor's licensed output – have added ~8 GWe across the US fleet since 1977 and remain a meaningful lever there (with further potential remaining), but most other major fleets (notably Sweden, Switzerland, Finland) have already largely exhausted this potential through aggressive programmes in the 2000s–2010s. Source: U.S. NRC (2022), *Background on Power Upgrades for Nuclear Plants*.

¹⁶¹ IAEA (2026), *Power Reactor Information System*.



Optimal national nuclear strategies for nuclear new build will reflect:

- **Delivery capabilities.** The country's current and future potential ability to deliver new nuclear build cost-effectively. This delivery capability reflects the differences in institutional capacity, financing systems and supply chain depth, which were discussed in Chapter 2.
- **System benefits.** The power system benefits considered in Chapter 3, which are significantly determined by the scale and mix of countries' renewable resources and by the cost of achieving demand/supply balance, which is greater where countries face large seasonal as well as daily balancing needs. In addition, concentrations of high demand for continuous baseload power (e.g., for industrial or data centre electricity demand) in specific locations may create a rationale for nuclear deployment in some cases – though nuclear capacity should be sized to be below baseload demand (see Section 3.1).

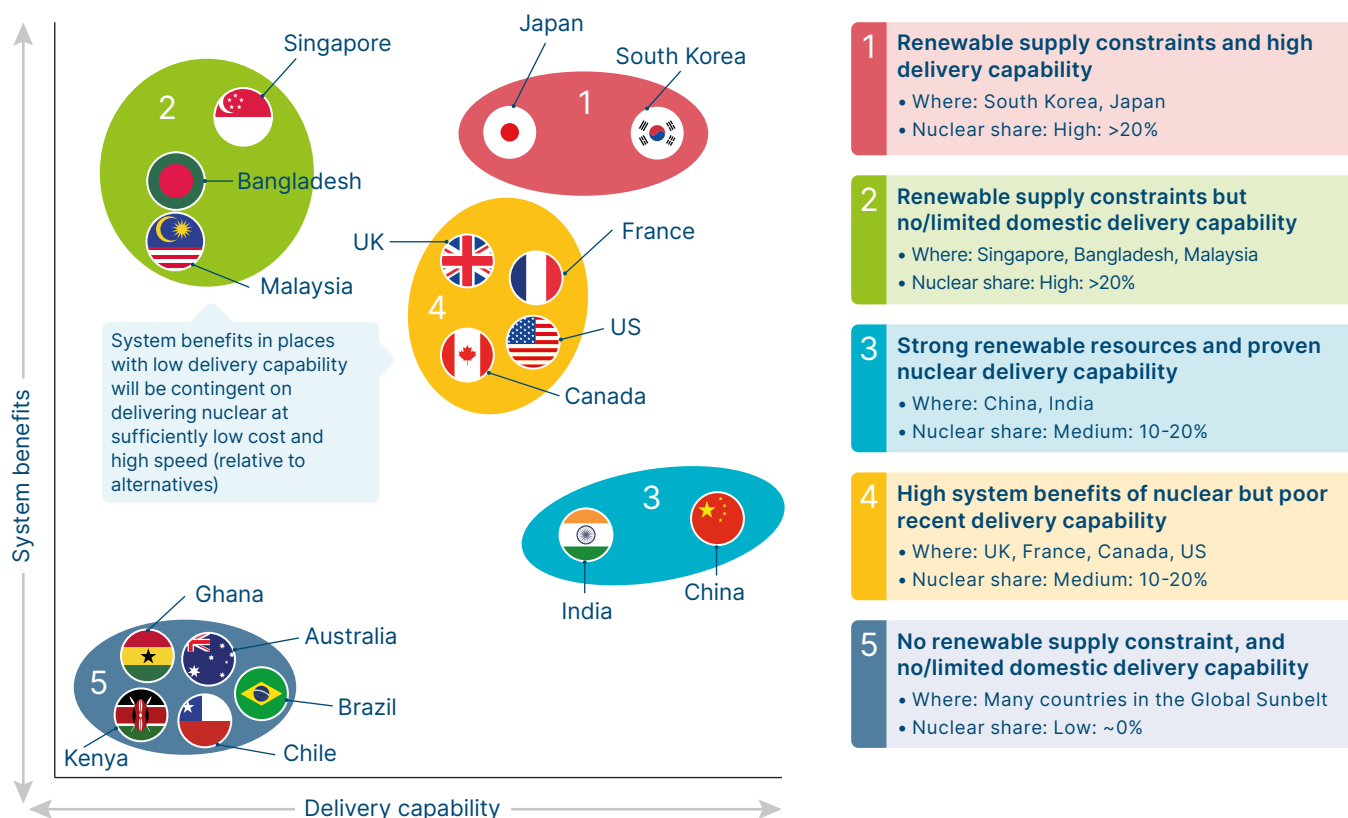
Detailed country analysis is required to assess a country's position along these two dimensions at any point in time. In Exhibit 4.2 we distinguish between five broad categories of country, and some specific country examples within those categories based on current conditions, which highlight how the two dimensions will determine optimal strategy. Countries which currently lack proven delivery capability may, in some circumstances, be able to develop it and system benefits could change over time as nuclear and alternative technologies develop.

Exhibit 4.2 sets out an illustrative assessment of countries' relative positions along the two dimensions.



Governments should critically assess the optimal role of nuclear based on its system benefits and a country's ability to deliver nuclear at low cost

Indicative assessment of relative role of nuclear for five categories of countries, based on comparable system benefits and delivery capability



NOTE: Selected countries are illustrative and not exhaustive. "Indicative nuclear share" refers to the share of nuclear in a future, clean electricity generation mix. France is an exception to the indicative nuclear share stated for Category 4 due to its high share of nuclear today; however, existing scenarios estimate that this could decline from ~70% in 2025 to 10–50% in 2050.

SOURCE: Systemiq analysis for the ETC (2026); Ember (2026), *Electricity Data Explorer*; RTE (2021) *Energy Pathways to 2050*

It suggests that country conditions and associated optimal strategy fall into five categories:

- 1. Renewable supply constraints and high delivery capability.** Japan and South Korea both face some constraints on renewable resources relative to population size. Both have delivered cost-effective nuclear build programmes in the past, with institutional capacity and relevant supply chains in place to support new nuclear build. Optimal nuclear shares are likely to be at the high end of the global range. Japan has a target to reach 20–22% by 2030, while South Korea targets ~32% by 2030 and ~36% by 2038.¹⁶²
- 2. Renewable supply constraints but no/limited domestic delivery capability.** Very high population density in Singapore (8,200 per km²) and Bangladesh (1,400 per km²) make it either impossible (in Singapore's case) or very difficult (in Bangladesh's case) to source a large share of power from renewables.¹⁶³ The optimal share of nuclear power could therefore be significantly higher than the global average. But neither country has any domestic capability to deliver nuclear power. Strategies for new nuclear development will therefore have to rely

¹⁶² World Nuclear Association (2026), *Nuclear Power in Japan*. Available at: <https://world-nuclear.org/our-association/publications/world-nuclear-outlook-report/japan---world-nuclear-outlook-report> [Accessed 07 2026]; World Nuclear Association (2026), *Nuclear Power in South Korea*. Available at: <https://world-nuclear.org/information-library/country-profiles/countries-o-s/south-korea> [Accessed 07 2026].

¹⁶³ The ability to develop Agri-PV (i.e. to install solar PV above still productive agricultural land) may, however, significantly increase Bangladesh's potential renewable resource. Source: Energy Transitions Commission (2026), *Unlocking Solar at Scale: How Agrivoltaics Overcome Land Constraints in India's Energy Transition*.

on delivery by skilled companies from overseas. For example, Russia's Rosatom built the Rooppur nuclear plant in Bangladesh, which was financed via a Russian loan.¹⁶⁴

3. Strong renewable resources and proven nuclear delivery capability. China and India both fall in this category but with important differences between them.

- **China:** With a population density of ~150 people per km² – less than half of Japan and less than a third of South Korea – and with vast low-cost renewable resources in its western and northern provinces, China could build a power system almost entirely dependent on renewables. But it also has very high electricity demand per capita (reflecting its dominant manufacturing position) and has proven ability to deliver nuclear at low LCOE (e.g., \$40 per MWh). A nuclear share of 10–20% is feasible and likely to be economic, in line with the national target of 335 GW of nuclear capacity by 2050.¹⁶⁵
- **India:** India has a population density of ~500 people per km² (over three times China's level),¹⁶⁶ but currently has lower electricity demand per capita. And due to its excellent solar resources, its primarily diurnal (day-to-night) supply/demand balancing challenge can be cost-effectively met with solar and batteries. As a result, the optimal contribution of nuclear to total system costs may be limited to 10–20% of its fast-growing electricity system, but its proven ability to deliver nuclear at low cost argues for deploying nuclear at least to this share. This is aligned with the Government of India's target of 100 GW by 2047.¹⁶⁷

4. High system benefits of nuclear but poor recent delivery capability. Higher latitude countries which have significant winter heating needs, and which will derive a large share of renewables supply from wind rather than solar, face a greater need for more expensive seasonal balancing than sunbelt countries.¹⁶⁸ Reducing the size of the seasonal balancing challenge could increase the optimal share of nuclear in windbelt countries with legacy nuclear programmes such as the UK, the US, Canada and France. But in each of these countries, recent nuclear projects have faced significant costs and time overruns. Unless costs for future projects can be significantly reduced from recent experience, the optimal share of nuclear power might be reduced to ~10%. In France, however, the large existing nuclear fleet and the government's determination to revive France's nuclear delivery capability will result in a larger share of up to ~50% in 2050.¹⁶⁹

5. No renewable constraint, and no/limited domestic delivery capability. Finally, there are many countries, often but not exclusively located in the global sunbelt, which have a combination of: (i) very large renewable resources per capita; (ii) primarily diurnal system balancing requirements; and (iii) no domestic nuclear delivery capability (across supply chains and institutional capacity). In these countries, which include most of Africa, and much of Latin America and Australia, renewables (particularly solar) and batteries will provide the fastest and cheapest option for scaling electricity supply at suitable increments to align with financing availability and system needs. In these markets, investing in nuclear concentrates scarce capital in a small number of centralised projects, committed roughly a decade before operations, during which the power system could change substantially. Developing nuclear would deliver no total system cost benefit, and would require a reliance on foreign nuclear supply chains, which would reduce energy security. Pursuing nuclear programmes in these countries would divert resources from cheaper alternatives, and nuclear shares should remain close to 0%.

4.3 Global implications: a targeted nuclear buildout in addition to (not instead of) massive renewable investment

The optimal role of nuclear will be determined by varying national circumstances, part of which will evolve over time. Defining a global target for 2050, or assessing the plausibility of global targets, may therefore not be sensible, but an indicative estimate of its scalability helps determine the potential role it can play in the context of other technologies. Our assessment of feasible buildout rates suggests that global nuclear capacity could expand ~2–3x by 2050 to 550–1,000 GW, potentially maintaining ~10% of global generation as demand also

164 World Nuclear News (2023), *Rooppur: Bangladesh paying Russia in yuan to sidestep sanctions*. Available at: <https://www.world-nuclear-news.org/Articles/Rooppur-Bangladesh-paying-Russia-in-yuan-to-sidestep-sanctions> [Accessed 08 2026].

165 World Nuclear Association (2026), *Nuclear Power in China*. Available at: <https://world-nuclear.org/information-library/country-profiles/countries-a-f/china-nuclear-power> [Accessed 07 2026].

166 Our World in Data (2025), *Population Density, 2025*. Available at: <https://ourworldindata.org/grapher/population-density>. [Accessed 07 2026].

167 World Nuclear Association (2026), *Nuclear Power in India*. Available at: <https://world-nuclear.org/information-library/country-profiles/countries-g-n/india> [Accessed 08 2026].

168 Energy Transitions Commission (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

169 RTE (2021) *Energy Pathways to 2050*.

increases 2–3x to accommodate electrification.¹⁷⁰ The ETC's estimate for a reasonable level of ambition in 2050 is ~750 GW, which represents a stretching buildout target for the industry with 15–25 GW of new nuclear capacity to be delivered per year from now to 2050 (depending on the level of life extensions achieved), concentrated in countries in categories 1–4 in Section 4.2. 1,000 GW is a likely upper bound that could result from ambitious national decisions to expand nuclear deployment. This would require a 3–6-fold increase in the pace of new nuclear build compared with the last three decades. With ambitious buildout, nuclear can therefore play a targeted but supporting role in the energy transition, alongside renewables which can ramp up to meet a large share of the remaining 90% of generation.

- **As the world electrifies – we will need a significant ramp-up in electricity generation.** Total global electricity demand could grow from today's 32,000 TWh per year in 2025 to between 55,000–80,000 TWh per year, and much higher levels by 2100.¹⁷¹ Roughly 60,000 TWh can be met by solar and wind, which could see average capacity additions of ~1,100 GW per year for solar and ~350 GW per year for wind, reaching ~30,000 GW and ~10,000 GW, respectively by 2050 (11x and 8x today's levels).¹⁷² As Chapter 3 described, the optimal generation share of nuclear in countries in categories 1–4 in Section 4.2 is likely to be ~10–20%.
- **A high ramp-up of nuclear buildout could mean ~550–1,000 GW of nuclear capacity in 2050, ~2–3x higher than the 380 GW operating in 2025.**¹⁷³ The upper end of the range is consistent with BloombergNEF's NZS, IEA's NZE and the OECD NEA's Ambitious Scenario,¹⁷⁴ but is lower than the COP28 pledge made by around 40 countries to triple nuclear capacity by 2050 to ~1,500 GW (originally ~1,200 GW). The World Nuclear Association (WNA) estimates that this target could be made up of ~400 GW of existing reactors including life extensions to 80 years, ~500 GW in construction, planned or proposed and another 560 GW based on national targets.¹⁷⁵
- **Life extensions could reduce the magnitude of the build challenge by 230 GW.** If existing plant operational lives were limited to 60 years, ~60% of existing capacity would close by 2050, with total capacity falling to ~140 GW. Life extensions to 80 years could maintain ~370 GW with no additional new build.
- **There are ~90 GW of reactors under construction and ~110 GW in the planning pipeline – meaning an additional 430–660 GW would be needed to reach 1,000 GW by 2050.** As of mid-2026, ~90 GW of nuclear capacity is under construction globally and a further ~110 GW is in planning – China accounts for around 50% of capacity under construction and 40% of planned capacity. Russia, India and South Korea also have significant build-out programmes and together make up almost half of the ex-China pipeline.¹⁷⁶ This pipeline would bring existing capacity up to ~570 GW by 2050 if fully realised and assuming life extensions to 80 years are pursued for all existing reactors. This would fall ~430 GW short of the 1,000 GW high-ambition scenario (or 660 GW with 60-year lifetimes).
- **Even with maximum life extensions and existing construction and planning, increasing capacity 2–3x means maintaining near-peak historical deployment until 2050. [Exhibit 4.3]** 550–1,000 GW of total capacity materialising by 2050 would therefore require a build rate of 15–30 GW per year on average (or 25 GW per year if maximum operating lives were kept at 60 years). This level is 3–6x the recent global average, and close to the peak of 31 GW per year achieved in 1984/85. Reaching 1,000 GW relies on higher build rates in China, India, the US, Japan, South Korea and Turkey from the mid-2030s onwards (vs. business as usual), with additional buildout in Sub-Saharan Africa.¹⁷⁷ The ETC's estimate for a reasonable level of ambition remains ~750 GW, requiring 15–25 GW per year of new build to 2050 – a 3–5x increase on the average of the last 20 years. [Exhibit 4.3]
- **Investments need to increase correspondingly – but this level does not significantly reduce the scale of investment in renewables and enabling technologies.** This scale up would imply capital investment of up to

170 Nuclear's modelled 2050 global generation share could range from ~5% with low nuclear buildout and high electrification to ~15% with high nuclear buildout and low electrification. Systemiq analysis for the ETC (2026), BloombergNEF (2026), *New Energy Outlook 2026*, IEA (2025), *World Energy Outlook 2025*

171 Ember (2026), *Electricity Data Explorer*; BloombergNEF (2026), *New Energy Outlook 2026*.

172 BloombergNEF (2026), *New Energy Outlook 2026*.

173 Systemiq analysis for the ETC (2026); IEA (2026), *Power Reactor Information System*.

174 BloombergNEF (2026), *New Energy Outlook 2026*; IEA (2025), *World Energy Outlook 2025*; OECD NEA (2026), *Nuclear Energy Outlook Global Installed Capacity to 2050 and Beyond*.

175 The 1457 GW WNA target is stated in terms of gross output, which equates to ~1,380 GW net power delivered to the grid (assuming 5% parasitic loads). Source: World Nuclear Association (2026), *World Nuclear Outlook Report 2026*

176 World Nuclear Association (2026), *World Nuclear Power Reactors & Uranium Requirements*. Available at: <https://world-nuclear.org/information-library/facts-and-figures/world-nuclear-power-reactors-and-uranium-requirements> [Accessed 07 2026].

177 BloombergNEF (2026), *New Energy Outlook 2026*.

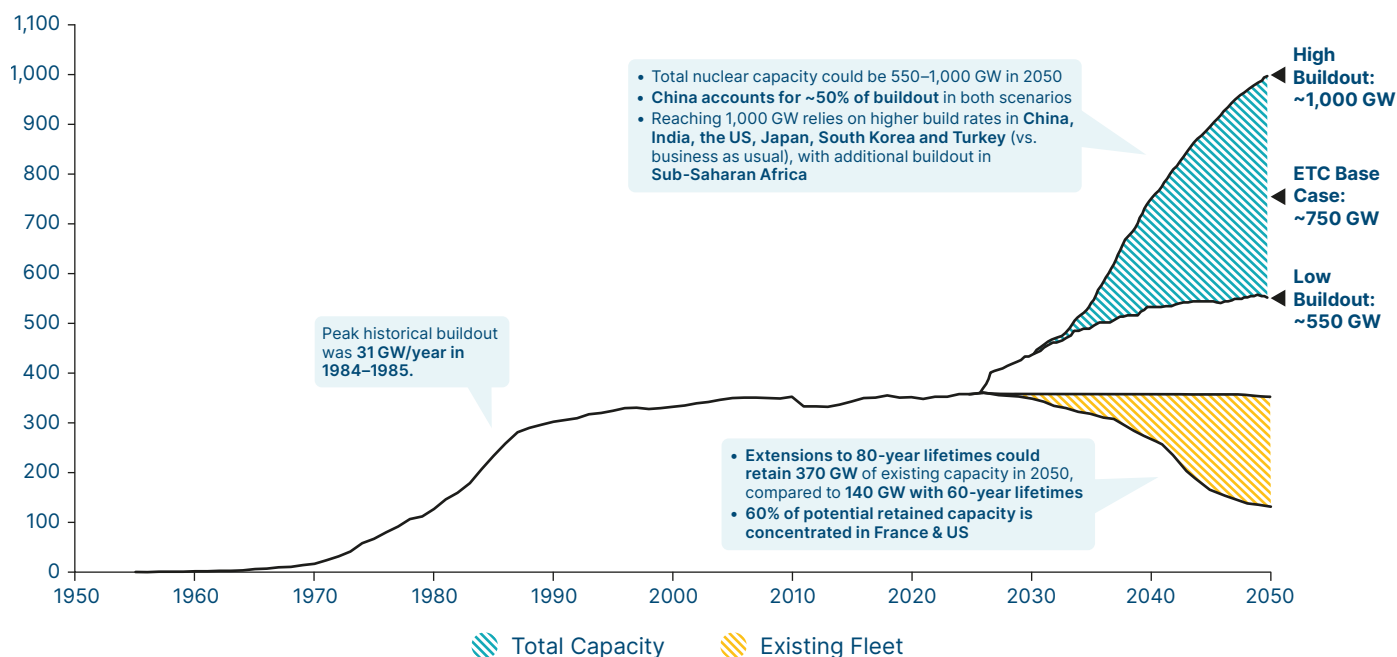


\$200 billion per year vs. around \$50 billion per year in recent years,¹⁷⁸ and would require a very large expansion of global nuclear component and fuel supply chains (both of which can scale sufficiently in the medium- to long-term, see Section 2.3), and skilled employment. While this contribution to the energy transition is useful in targeted countries, even this scale of nuclear buildout would be dwarfed by the required scale of investment in renewables to transition to low-carbon energy systems. An investment of \$200 billion per year in new nuclear build is likely to be less than 10% of the \$2,200 billion per year needed in renewables, grids and storage.¹⁷⁹

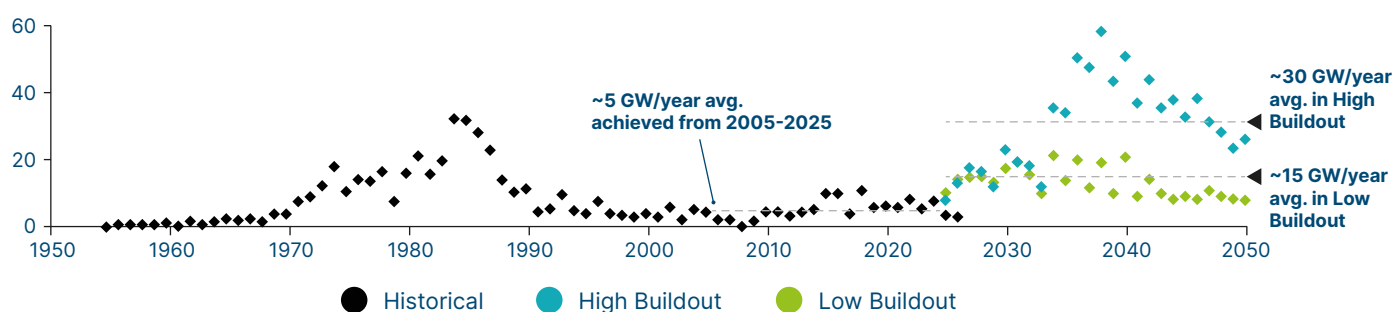
Exhibit 4.3

Increasing global capacity 2–3x by 2050 is a major build challenge; startups need to increase to close to historic peak levels, from 5 to 15–30 GW per year

Global installed nuclear capacity over time, historic trend (1955–2025) and future scenarios (2026–2050)
GW



Global annual nuclear startups over time, historic trend (1955–2025) and future scenarios (2026–2050)
GW/year



NOTE: Lower bound = BloombergNEF Economic Transition Scenario, upper bound = BloombergNEF Net Zero Scenario; Extending lifetimes to 80-yr should only be done where safety is proven; 80-yr extensions retain existing capacity by 2050 (but phases out by 2100) and with 60-yr lifetimes, existing capacity halves by 2050 (and phases out by ~2085).

SOURCE: Systemiq analysis for the ETC (2026); IAEA (2026), *Power Reactor Information System*; BloombergNEF (2026), *New Energy Outlook*.

178 Investment per year doesn't directly track capacity additions per year because CAPEX per kW is assumed to fall over the scale-up standardisation/learning effects.

179 BloombergNEF (2026), *New Energy Outlook 2026*.



4.4 Scaled nuclear delivery requires coordinated action across governments and industry

The framework in Section 4.2 determines whether and to what extent a country should deploy new nuclear. Delivering it at a competitive cost requires sustained government and industry backing.

The actions below set out what that deployment requires once the decision to deploy nuclear is made, across institutional capacity, financing structures and supply chains (established in Chapter 2). [Exhibit 4.4]

- **Institutional capacity sets the ceiling on how fast and how cheaply a country can build.** A well-resourced regulator is a precondition to new nuclear programmes, and its architecture, independence and decision-making discipline determine deliverability. Where oversight is fragmented or process-heavy, delivery costs escalate: Hinkley Point C absorbed around 7,000 design changes to satisfy British requirements, raising steel content by 35% and concrete by 25%. Key points to note include:
 - Standardisation is the key to cost reductions, but is only achievable if the regulator confines change to site-specific requirements. A fleet built on one or two licensed designs enables learning effects; a sequence of first-of-a-kind projects does not.
 - Pre-licensed siting locations and grid-aligned spatial planning can reduce development timelines that have reached up to 25 years in Western markets. This depends on integrated system planning to test nuclear against projected future firm-capacity needs, with explicit guardrails against deployment where renewables can meet demand faster and at lower cost.
 - SMR cost-competitiveness remains unproven and will also rely on standardisation; optionality can be preserved through technology-neutral aspects (e.g., sites, regulation, workforce, financing frameworks and grid planning), rather than through early commitment to a specific design.¹⁸⁰
 - Long-term waste management, including a geological disposal strategy, is also an institutional pre-requirement for new nuclear builds.
 - Nuclear liability and insurance arrangements are needed for financing, and lenders require national liability law to be in force and aligned with the international conventions.¹⁸¹
- **The financing model is decisive for cost-competitive nuclear delivery.** Financing costs can make up to ~70% of levelised lifetime nuclear generation costs so the achievable WACC decides whether a project is competitive.
- State-backed financing at low WACC cuts delivered electricity costs significantly relative to commercial finance rates, and every project delivered at competitive cost in recent decades has combined state-backed financing with state absorption of overrun risk.
- Regulated models such as RAB and revenue-stabilisation mechanisms such as CfD are key instruments to achieve this, by shifting construction and price risk off project equity, where it is most expensive.
- Decommissioning liabilities must be funded from the start of operation rather than deferred to the balance sheet of a future owner.
- Fleet-based co-investment could open a route to private participation, but only after delivery frequency has aligned construction risk with commercial investor appetite, and where the resulting financing cost still supports competitive generation.
- Secondary markets for operational assets are a further priority, allowing developers to recycle equity into successive units and institutional investors to take exposure without construction risk. Standardisation, transparent valuation and a record of predictable cashflows are required.
- **Competitive nuclear costs ultimately depend on continuity of capability, which stop-start programmes erode faster than they can be rebuilt.** Skilled welders, licensed operators and qualified suppliers can be retained by visible order books. A credible pipeline is therefore the investment precondition that allows industry to commit to training and capacity at scale, and its absence is why countries returning to nuclear after a long gap pay a

¹⁸⁰ World Nuclear Association (2026), *World Nuclear Outlook Report 2026*

¹⁸¹ World Nuclear Association (2026), *World Nuclear Investment Guide. Roadmap to Mainstream Finance: The Path to Scale Nuclear Energy*; World Nuclear Association (2026), *World Nuclear Investment Guide. Investment Readiness: Positioning Nuclear Projects for Faster Financing*.



FOAK premium on an already-mature technology. Where no domestic supply chain exists, qualified EPCI import under bilateral arrangements is the most viable route to deployment, provided it enables structured knowledge transfer. Fuel-cycle security is a near-term constraint, with enrichment capacity concentrated in Russia and China, and uranium mining concentrated in three countries. Scaling up deployment will require deliberate expansion of non-Russian conversion and enrichment capacity to diversify supply.

Exhibit 4.4

Competitive nuclear delivery depends on coordinated action across three deliverability pillars: institutional capacity, financing and supply chain

Deliverability pillar	Objective	Priority actions	Lead actor
 Institutional capacity	Make projects licensable and deliverable on time through credible, independent regulation.	- Independent, well-resourced regulator; proportionate, predictable, streamlined licensing timelines, with internationally harmonised codes and standards, with joint reviews and mutual recognition across credible regulators. - Nuclear legislation and third-party liability framework in place before vendor engagement. - Standardise on 1–2 licensed designs for fleet deployment; Preserve SMR optionality through technology-neutral enablers (sites, regulation, workforce, financing frameworks, grid planning). - Strategic siting: pre-licensed locations (including existing nuclear sites), grid-aligned planning, land-use and environmental pre-assessment, sustained public engagement through construction and operation. - Integrated system planning that tests nuclear against projected firm-capacity needs, with guardrails against deployment where cheaper alternatives can meet demand.	 Government and regulator
 Financing structures	Bring the achievable WACC into a competitive range and stabilise operating revenues.	- State-backed financing at low WACC or regulated financing models (e.g., RAB) and revenue stabilisation (e.g., CfD) with risk-sharing instruments that distribute overrun risk away from project equity, with a defined public backstop. - Nuclear included in climate and sustainable finance frameworks, assessed on technology-neutral criteria; MDB and export credit support for newcomer markets: political and sovereign risk cover. - Long-term waste management strategy, including geological disposal, and decommissioning funding from project inception. - Fleet-based co-investment in serial build once delivery frequency aligns construction risk with commercial investor appetite and secondary markets for operational assets; qualification pathways permitting industrial-grade equipment where safety allows.	 Government-led, shared with industry
 Supply chain	Sustain capability, secure the fuel cycle, and execute projects to schedule and budget.	- Credible, visible build pipelines and fleet-based serial construction, to preserve capability and capture learning-by-doing. - Design substantially complete before first concrete, with scope frozen at FID. - Owner-side programme management capability, with realistic schedules and cost estimates. - Target-cost contracts with shared overruns, so problems get solved rather than litigated. - Domestic capability development, or qualified EPCI import under bilateral arrangements, with skills training, certification and structured knowledge transfer. - Fuel-cycle security: timely uranium mine permitting, and deliberate expansion of non-Russian conversion and enrichment capacity.	 Industry-led, government-enabled

NOTE: SMR = small modular reactor; RAB = regulated asset base; CfD = contracts for difference; MDB = multi-lateral development banks; FID = final investment decision; EPCI = engineering, procurement, construction and installation.

SOURCE: Systemiq analysis for the ETC (2026).



Within this overall framework, specific challenges vary by country, with implications where system need is relatively high and domestic delivery capability is low:

- **In Category 2 countries (e.g., Singapore, Bangladesh, Malaysia) with renewable capacity constraints but no prior experience in nuclear delivery, deployment depends entirely on foreign delivery partners.** Vendor selection therefore determines not only construction cost but decades of dependency on the vendor country (for up to 80% of total project investment), a long-term energy security decision. Where fiscal headroom is limited, a single large nuclear reactor can represent a material share of both national electricity capacity and sovereign borrowing capacity, with a decade or more between financial commitment and first revenue. This megaproject risk is similar to large coal projects, and contrasts with modular renewables, where investment can be sized to available capital and returns begin accruing early. A country may therefore have a high optimal nuclear share on system-cost grounds and still be unable to bear the financing structure through which large nuclear is procured (applicable, for example, to Bangladesh but not to Singapore), and which should be assessed explicitly before commitment.
- **In Category 4 countries (e.g., the UK, France, Canada, the US) with systems integration benefits of nuclear but poor recent delivery capability,** it is essential to reduce the cost and increase the speed of nuclear deployment, to ensure that even modest levels of nuclear deployment do not increase total system cost. In the UK, for instance, this will require new approaches: stable long-term policy commitments to establish continuity in project delivery to maintain supply chain capabilities; streamlining licensing and planning, and regulations (e.g., consolidating responsibility to one lead regulator and parallel permitting); and a greater willingness to rely on already proven designs and safety regimes (e.g., via international regulation harmonisation), avoiding continuous within-project design changes.



Acknowledgements

The team that developed this report comprised:

Lord Adair Turner (Co-Chair), Jules Kortenhorst (Co-Chair), Faustine Delasalle (Vice-Chair), Ita Kettleborough (Director), Mike Hemsley (Deputy Director), Sam Wilks (lead author) with guidance from Carolien van Marwijk Kooyj and support from Shane O'Connor, Phoebe O' Hara, Stephannie Dittmar Lins, Manuela Di Biase, Apoorva Hasija, Rosalie Hunt, Elizabeth Lam, Lina Morales and Dirk Roest (SYSTEMIQ).

The team would also like to thank the ETC members and experts for their active participation:

Vivek Panda (Adani Green); Pankaj K Verma (Adani Green); Nicola Davidson (ArcelorMittal); Julia Mills (Arup); Jeremy Stain (Arup); James Butler (Ausgrid); Marie Freier (Barclays); David Hostert (BloombergNEF); Meredith Annex (BloombergNEF); Stephanie Díaz (BloombergNEF); Lu Qian (Development Research Center of the State Council); Adil Hanif (EBRD); Fu Sha (Energy Foundation China); George Wang (Envision Energy); Rebecca Collyer (European Climate Foundation); Keith Allott (European Climate Foundation); Eleonore Soubeyran (LSE); Hannah Koh (Gurin Energy); Gareth Lewis (Heathrow); Sophie Lu (HSBC); Randolph Brazier (HSBC); Kash Burchett (HSBC); Dana Cartwright (ICMM); Chris Dodwell (Impax Asset Management); Dong Wenjuan (Tsinghua University); Karan Mangotra (ISA); Andy Wiley (Just Climate); Rob Trezona (Kembara); Elisa Mele (Mundi Ventures); Nick Stansbury (LGIM); Kyllian Pather (Lombard Odier); Rachel Fletcher (Octopus Energy); Amir Hon (Petronas); Stephanie Edwards (QC Foundation); Susan Hansen (Rabobank); Sunny de Blok (Rabobank); Udit Mathur (ReNew); Greg Hopkins (RMI); Emmet Walsh (Rothschild & Co); Emmanuel Normant (Saint-Gobain); Vincent Petit (Schneider Electric); Brian Dean (SEforALL); Charlotte Brookes (Shell); Halla Al-Najjar (Shell); Jonny Clark (SLR Consulting); Tomasz Wlodarczyk (SLR Consulting); Alistair McGirr (SSE); Abhishek Goyal (Tata); Saurabh Kundu (Tata Steel); A K Saxena (TERI); Dr. Arunendra Tiwari (TERI); Rose Dortch (Transition Accelerator); Alex Kent (Transition Accelerator); Reid Detchon (UN Foundation); Mikael Nordlander (Vattenfall); Niklas Gustafsson (Volvo); Molly Walton (We Mean Business Coalition); Andrea Buetler (Worley); Nick Wayth (WRI); Karl Hausker (WRI); Sonia Brown (National Grid); Matt Phillips (PIE Climate).

The team would also like to thank the ETC's broader network of experts for their input:

Henri Paillere (IAEA); King Lee (World Nuclear Association); Deborah Ayres (IRENA); Saied Dardour (IRENA); Michael Hewitt (ULC Energy); Michael Barnard (The Future is Electric Strategy); Richard Ollington (Emys); John Fingleton (Fingleton); Josh Buckland (EDF); Steven Hargreaves (EDF); Michael Crawforth (Rolls-Royce SMR); Mycle Schneider (Mycle Schneider Consulting); Alexander Hogeveen Rutter (Third Derivative); Eddie Wu (CLP); Jonathan Tang Hung Luk (CLP); Maurits Dolmans (Copenhagen Atomics).



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