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Europe's Bid to Turn Nuclear Innovation into Industrial Capacity

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1. A nuclear revival in a changing energy system

Nuclear energy is gaining renewed ground in the energy debate, as a new set of dynamics arising from energy-security, decarbonisation and electricity-demand developments, reshaping the perception of large-scale reactor programs of the previous decades. The interest is being fueled by a convergence of forces: exponentially growing electricity demand, the growth in industrial and transport electrification, the expansion of AI technologies and data centers, growing concerns over energy security and the need to decarbonize power systems, while preserving industrial competitiveness.

The global energy system is becoming increasingly affected by the electricity sector. Over the past decade, electricity demand has grown at about twice the pace of the overall energy demand, with new loads arising from electric vehicles, cooling, data centers and artificial intelligence technologies.

This transformation is unfolding alongside the rapid integration and expansion of wind and solar in the energy systems. Renewable sources account for an important share of the power mix, but their penetration also raises concerns about the need for flexibility, storage, transmission networks, interconnections and dispatchable - available generation. Two simultaneous challenges have to be addressed by the power systems: increase the supply of clean, low-carbon electricity, by ensuring affordably as demand grows and becomes more electricity-intensive.

Nuclear power is getting attention as a policy and strategic option because of its ability to combine low lifecycle emissions, high utilisation rates, uninterrupted generation and lower exposure to volatile fossil-fuel markets.

France provides a useful illustration of how these characteristics operate within a nuclear-intensive electricity system. Nuclear generation forms a relatively stable core of the French power mix, while hydro, wind, solar and thermal generation vary more visibly over the course of the day in response to changing system conditions.

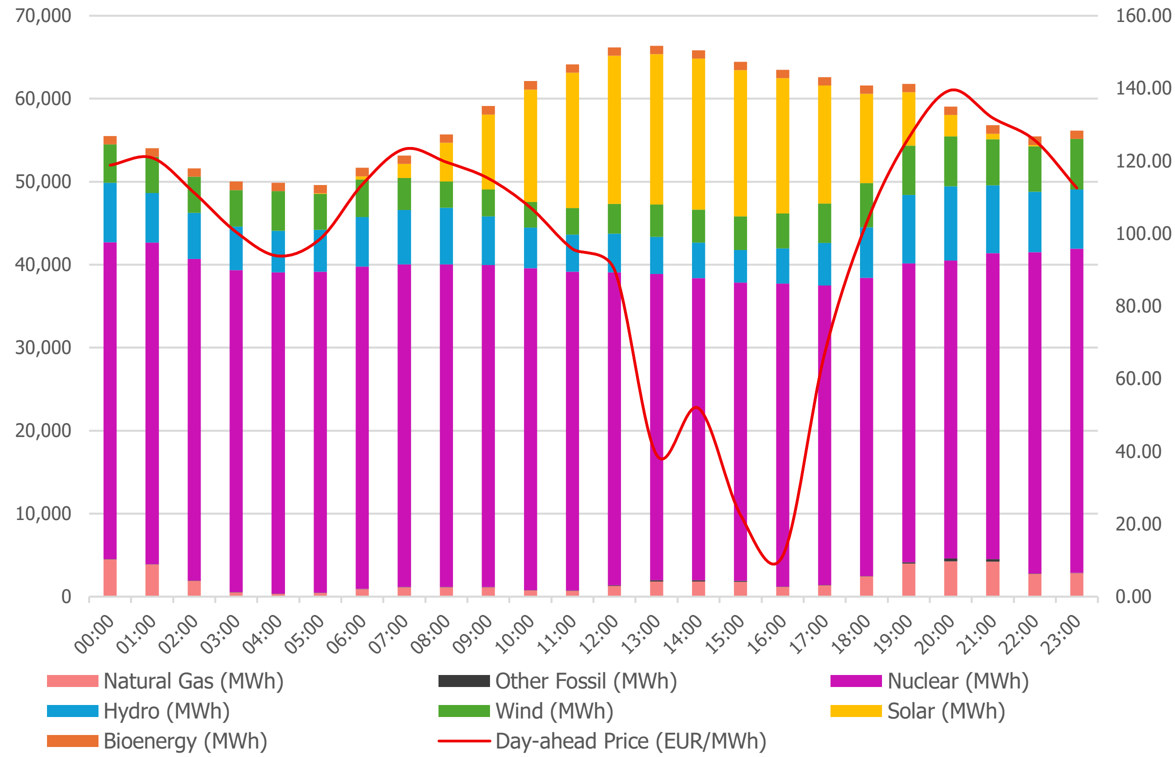

Figure 1 Hourly Electricity Generation Mix and Day-Ahead Market Prices in France, 1 July 2026, Source: RTE éCO2mix; ENTSO-E Transparency Platform

On the selected day, nuclear generation remained relatively stable compared with the stronger intraday variation observed in solar, hydro, wind and thermal generation. This does not mean that French nuclear plants operate at a constant output throughout the year, as they can adjust production in response to changing system conditions. However, Day-ahead prices fluctuate substantially, indicating that a high nuclear share does not extract the short-term wholesale price volatility factor. Prices continue to represent the interaction of demand, renewable availability, cross-border exchanges and the marginal generation in the system. Nuclear generation can therefore be faced by other dispatchable sources without, by itself, determining the market-clearing price.

In 2023, approximately 410 nuclear reactors were operating in over 30 countries around the world and providing almost 9% of global electricity generation. Nuclear was the world's second-largest source of low-emissions electricity following hydropower, producing roughly 20% more electricity than wind and 70% more than solar. Since 1971, nuclear generation is estimated to have avoided approximately 72 billion tonnes of CO_2 emissions by displacing a significant amount of fossil-fuel generation.

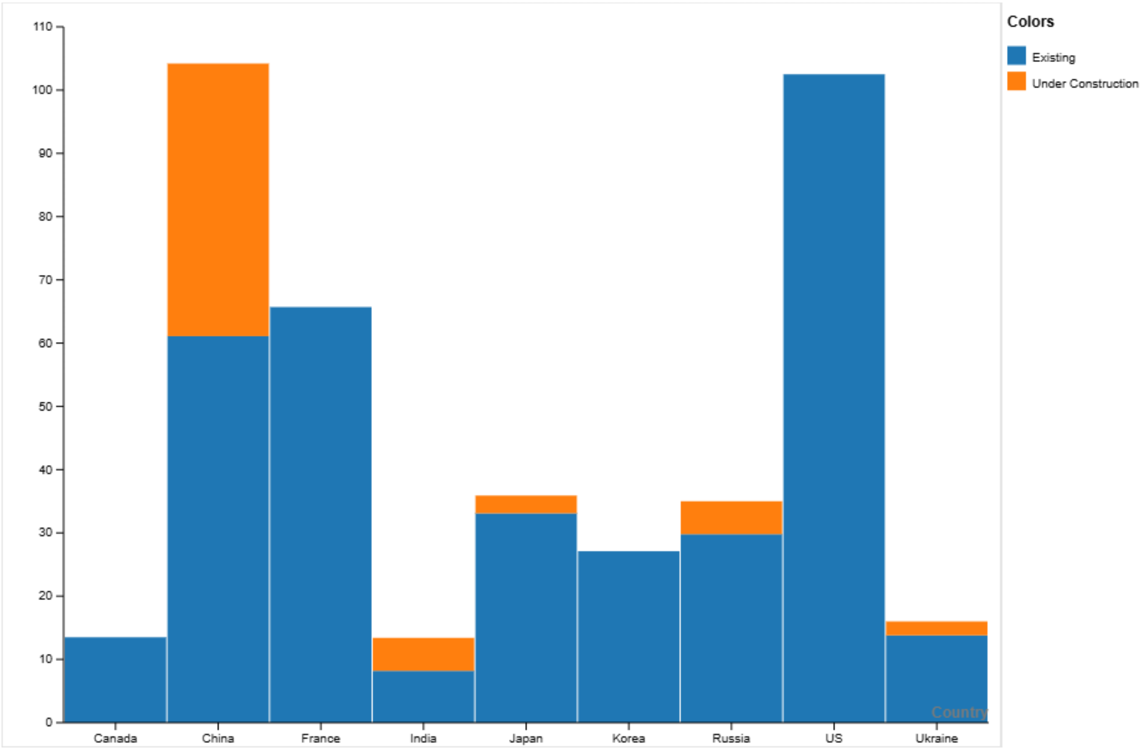

Figure 2 Nuclear Capacity in Operation and Under Construction in Selected Countries, (2025), Source: International Energy Agency

Within the EU, nuclear energy already represents a substantial part of the electricity system. At the end of 2024, 101 reactors with approximately 98 GWe of net capacity were operating across 12 Member States, while nuclear power accounted for around 23% of EU electricity generation in 2023.[1]

The sector is also experiencing a strong investment revival. Nuclear generation was expected to reach a new record in 2025, while 63 reactors representing more than 70 GW of capacity were under construction around the globe. Annual nuclear investment had already risen to more than USD 60 billion, covering both new construction and lifetime extensions projects of existing infrastructure. The United States and France retain some of the world's largest operating nuclear fleets, China stands out for the scale of its current construction pipeline, with 43.1 GW under development in addition to 61.1 GW already in operation. This contrast highlights the shift in nuclear expansion towards Asia and the growing importance of new-build activity in shaping future technological and industrial leadership.

[1] European Commision, Nuclear Illustrative Programme presented under Article 40 of the Euratom Treaty – Final (after the opinion of the EESC)

Despite the current momentum, many of the historic challenges associated with nuclear energy have not been fully resolved. Nuclear projects are still capital-intensive and require upfront capital cost, followed by a lengthy payback period. Additionally, there are also costs related to raising the required capital. Debt financing must be followed by regular payments to lenders at agreed intervals, and similarly, equity investors seek returns that compensate for the project risks. Construction delays due to political debate over the topic and cost overruns in several advanced economies have significantly weakened investor trust, while governments, associations and international bodies continue to play a central role in de-risking projects, creating predictable revenue frameworks, and risk mitigation mechanisms.

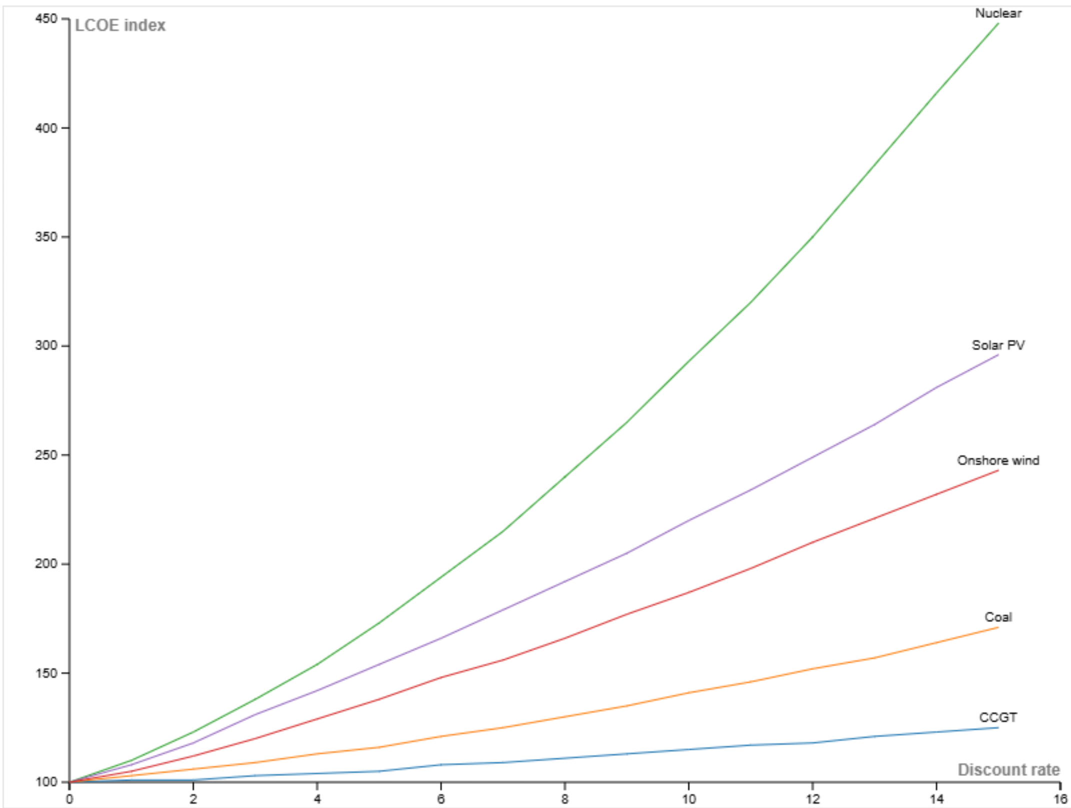

Figure 3 Effect of discount rate (%) on median LCOE (%), Source: OECD Nuclear Energy Agency & World Nuclear Association

Nuclear projects present unconventional financing models since nuclear plants require substantial upfront capital, and the revenues are not generated until the plant enters its commercial operation phase. Nuclear financing structures vary between public, hybrid arrangement and corporate structures.

Figure 4 Nuclear Project Financing Structures, Source: World Nuclear Association

Financing structures also differ based on the extent of lender recourse. Under full-recourse structures, debt repayment is supported by the sponsor's wider financial resources. Under limited- or non-recourse project structures, repayment is tied to the project's own future cash flows. Compared to RES and gas-fired projects, nuclear remains a difficult fit for conventional project-finance structures, given the high capital requirements, the risks related to the technology, the long construction horizons and the uncertainty around project completion.

Stable and predictable revenue lines are therefore important in containing or reducing financing costs. In today's liberalised electricity markets, wholesale prices can be affected by volatility and there is no guarantee that future market revenues will be sufficient to recover a large capital investment, directly affecting nuclear power. Even when a plant is economically competitive over its full operating life, uncertainty over future cash flows can increase the cost of both debt and equity and weaken the overall project bankability.

Revenue risk can be mitigated through long-term contractual market mechanisms; this could be either Power Purchase Agreements (PPAs), that provide a specific framework under which electricity is sold to buyer in a pre-defined period, or through Contracts for Difference (CfDs) by settling the difference between a predetermined strike price and the prevailing market price, reducing in that way market-price fluctuations.

The UK provides a practical example of how nuclear supporting mechanisms have evolved following the new characteristics of liberalized electricity markets. By the early 2010s, the country faced the need to replace its ageing generation capacity, preserve security of electricity supply, accelerate low-carbon investment, by limiting reliance on direct public financing for new infrastructure and drawing on private investors. The Electricity Market Reform (EMR) framework, introduced through the Energy Act 2013, responded to this investment challenge partly through Contracts for Difference (CfD). CfDs were designed to reduce generators' exposure to volatile wholesale electricity prices by providing greater certainty over future revenues and, consequently, to support investment in capital-intensive low-carbon technologies at a lower cost of capital.[2]

Hinkley Point C (HPC) was the very first new UK nuclear project designed and financed under this framework. The project was supported through a bilateral CfD with an inflation-indexed strike price of £92.50/MWh in 2012 prices for 35 years from the start of generation.

The Hinkley structure, however, made an important policy choice concerning risk allocation. The CfD was tied to electricity generation, while construction and completion risk remained with the investors, reducing the market-price and revenue risk, without removing the risk associated with financing a large capital commitment through a 5-to-8-year period. The subsequent development of the project illustrates the importance of this distinction. At the time of the 2016 investment decision, HPC was expected to cost approximately £18 billion. The project remains under construction, however, and EDF's latest estimate places the completion cost at around £35 billion in 2015 prices, with first generation from Unit 1 now expected in 2030.

The financial consequences of construction delays are also visible at system level. In the Commission's 2050 nuclear scenario, a five-year delay in planned new-build projects would reduce installed nuclear capacity in 2050 by almost 9 GWe while increasing the required investment by more than EUR 45 billion.[3]

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[2] UK Department of Energy & Climate Change (2013), *Electricity Market Reform: Delivering UK Investment*, Cm 8674.

[3] European Commission, Nuclear Illustrative Programme presented under Article 40 of the Euratom Treaty – Final (after the opinion of the EESC)

Another approach has been adopted for Sizewell C. The Nuclear Energy (Financing) Act 2022 created the regulatory basis for applying a Regulated Asset Base (RAB) model to new nuclear projects, allowing revenues to be collected during the construction phase as well. This reduces the amount of capital that must remain financed without incoming cash flows and can therefore lower accumulated financing costs. This approach includes a different allocation of risk, with consumers contributing before the plant becomes operational and consequently bearing a proportion of construction-related risk together with investors.

Sizewell C became the first project to proceed under this nuclear RAB framework, with the UK government confirming the project's Final Investment Decision in July 2025. Its economic license allows the project to recover regulated revenues through of Nuclear Regulated Asset Base (RAB) fees and incorporates incentives and penalties intended to support the whole project life-cycle from cost-efficient and timely construction, commissioning and operation. The shift from HPC to Sizewell C reflects an evolution in country's policy design regarding the energy market, towards a model that aims to reduce financing costs during construction through a broader distribution of risk.

This evolution in the structure and the models of the financing policy further highlights a broader question facing the nuclear sector: whether project risk can be reduced not only through contractual and regulatory mechanisms, but also through changes in reactor design and project scale and delivery.

This financing dimension also provides an important bridge to the current interest in Small Modular Reactors (SMRs). The renewed nuclear debate is not simply about developing a different reactor technology, but also about whether smaller unit sizes, standardized designs, modular construction and repeated deployment can reduce some of the construction and financing risks that have characterized conventional large-reactor projects.

In March 2026, the European Commission formally unveiled a strategy aimed at bringing the first European SMRs online in the early 2030s[4]. The initiative marked a notable shift in policy direction, reflecting a broader reassessment of nuclear energy's role within the European Union. After years in which energy policy focused heavily on renewables, electrification, and hydrogen, Brussels is now positioning modular nuclear technology as a complementary component of the future energy mix.

[4] Commission unveils strategy to bring Europe's first SMRs online by the early 2030s

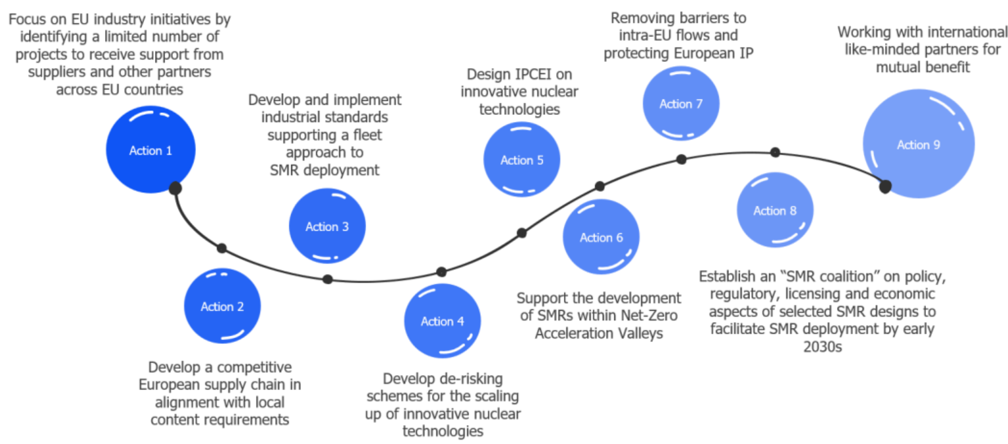


Figure 5 Strategy for the development and deployment of Small Modular Reactors (SMRs) in Europe

Among European countries, France remains the most advanced in integrating SMRs into a broader national industrial strategy.

The French government has incorporated modular nuclear technology into its "France 2030" investment plan[5], viewing SMRs as both a domestic energy asset and an export opportunity capable of reinforcing France's longstanding position within the global nuclear industry.

The centerpiece of this strategy is the NUWARD project[6], led by EDF. The reactor design consists of 2 200 MW pressurized water reactors housed within a single facility, creating a combined 400 MW plant.

Rather than pursuing an entirely novel architecture, NUWARD relies heavily on technologies derived from France's existing pressurized water reactor fleet and naval nuclear propulsion systems. This approach is intended to minimize technical and regulatory risk while accelerating deployment timelines[7].

The project is also being designed for combined heat and power applications. In addition to electricity generation, NUWARD could provide thermal energy for district heating, industrial processes, desalination, and hydrogen production.

French officials increasingly present the project as a "Pan-European" platform rather than a purely national initiative. Regulatory cooperation is already underway with countries including Finland, Sweden, Poland, Belgium, and Italy.

[5] France Publishes Energy Roadmap That Confirms Plans For Six New Nuclear Power Plants
[6] https://www.nuward.com/en
[7] Second phase of Nuward review completed

The objective is to develop licensing compatibility across multiple jurisdictions, allowing standardized reactor fleets to be deployed without substantial redesigns for each market. This approach, combining large industrial incumbents with smaller technology developers, reflects France's effort to secure leadership across multiple segments of the emerging SMR market.

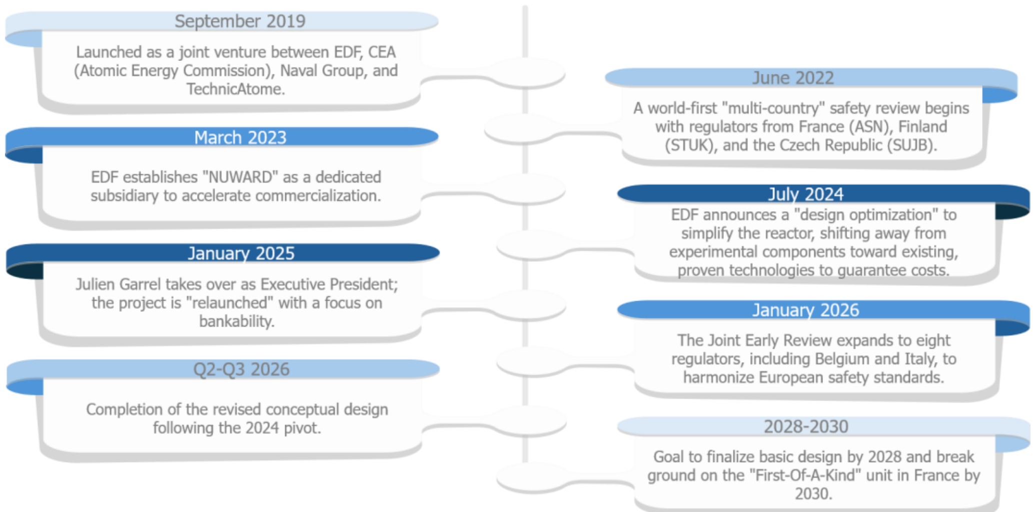
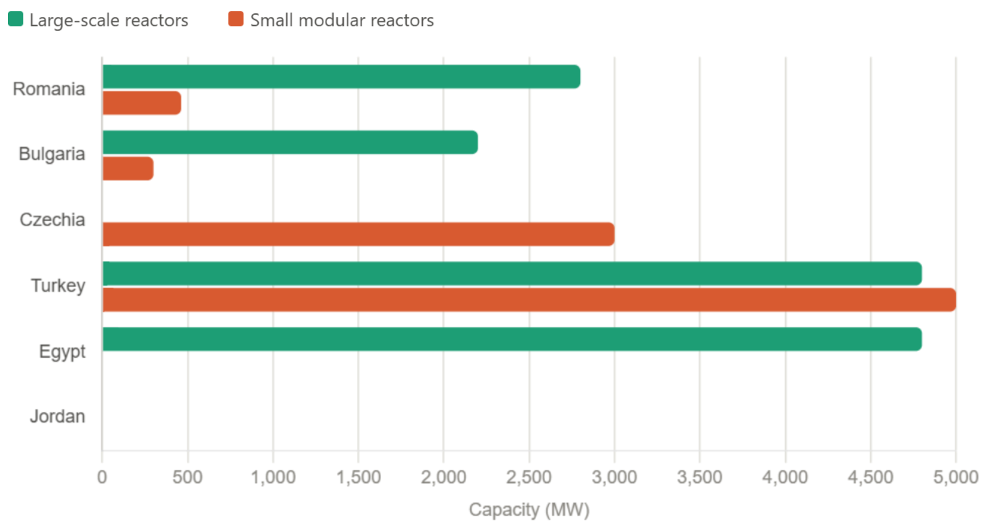


Figure 6 NUWARD project timeline

2. Small Modular Reactors: Redesigning the Nuclear Investment Model

The increased interest in SMRs is associated with the financing and delivery constraints that have historically affected conventional nuclear investment. The idea behind SMRs extends beyond reactor size and spreads to the restructure of the design, the manufacture, the financing and deployment of nuclear projects. Most of the designs currently under development range between 10 MW to 350 MW, with a diverse technology base, including encompassing light-water reactors as well as high-temperature gas-cooled, molten-salt and fast-reactor designs. Modularity is the main element of the SMR concept, allowing capacity to be installed and added progressively rather than through a single multi-gigawatt, capital intensive investment. The larger number of the diverse design of SMRs, however, also indicates that the sector commercial standardisation is required for large-scale replication. In 2024, the IAEA recorded more than 68 designs across 18 countries, while several technologies remain at conceptual, licensing or demonstration phases.



● Under construction ● Approved / contracted ● Developing ● Feasibility / target

Feasibility / target

- Bulgaria — SMR, site TBD
  BWRX-300 · ~300 MW/unit
- Turkey — National SMR programme
  Vendor TBD · 5,000 MW by 2050
- Jordan — SMR programme
  Vendor selection ongoing · 100–300 MW/unit

Developing

- Romania — Doicești SMR — Under examination
  NuScale VOYGR-6 · 462 MW
  Approval disputed — NEI, 2026
- Bulgaria — Kozloduy new build
  Westinghouse AP1000 · ~2,200 MW
- Romania — Cernavodă expansion
  CANDU · ~2,800 MW

Approved / contracted

- Czechia — Temelín + additional sites
  Rolls-Royce SMR · up to 3 GW

Under construction

- Turkey — Akkuyu
  Rosatom VVER-1200 · 4,800 MW
- Egypt — El Dabaa
  Rosatom VVER-1200 · 4,800 MW

Figure 7 Selected Nuclear and SMR Projects in Southeastern Europe and the Eastern Mediterranean, Source: IEA, The Path to a New Era for Nuclear Energy (2025) & Deon Policy Institute, Nuclear Energy the Case For Greece

The economic proposition of SMRs differs from that of conventional nuclear power plants. Whereas large reactors benefit from economies of scale, SMRs depend heavily on standardization and replication to improve economics overtime.

Early SMRs are expected to be relatively expensive, with First-of-a-Kind (FOAK) overnight capital costs ranging between USD 8,000–10,000/kW. Under assumptions of repeated manufacturing from FOAK to later units and an average learning effect of around 9.5% per unit, costs are estimated to decline by approximately 35–40%, and reaching USD 4,000–6,250/kW.[8]

From a financing perspective, conventional nuclear projects can require upfront investment exceeding USD 8-10 billion, concentrating an amount of capital and construction risk within a single asset. SMRs require lower capital commitment in absolute investment terms. For a 300 MW unit, the cost is estimated to be shaped at approximately USD 1.2–2 billion. The main financial benefit of the SMR model is therefore not necessarily a lower initial cost per megawatt, but a lower amount of capital committed at each individual investment decision.

The smaller scale of SMR projects could broaden the composition and structure of nuclear financing. Lower capital requirements at a project level may reduce the need for large consortia to distribute project risk and lower the threshold for investor participation. Construction time is also central to SMR deployment strategies assuming that greater factory fabrication, construction standardisation and simplified on-site assembly could shorten the period between licensing and operation to approximately 3-5 years, compared with 6-8 years for conventional nuclear reactors. The economic significance extends well beyond engineering. Nuclear projects are particularly exposed to financing costs because expenditure is heavily front-loaded while revenues begin only after construction and commissioning have been completed. This advantage should not, however, be interpreted as implying that early SMR projects are necessarily less sensitive to financing conditions. FOAK units may combine shorter construction schedules with relatively high capital costs per kW, leaving their Levelized Cost of Electricity (LCOE) strongly exposed to the cost of capital.

[8] Abou-Jaoude et al., 2024; Deon Policy Institute, 2026

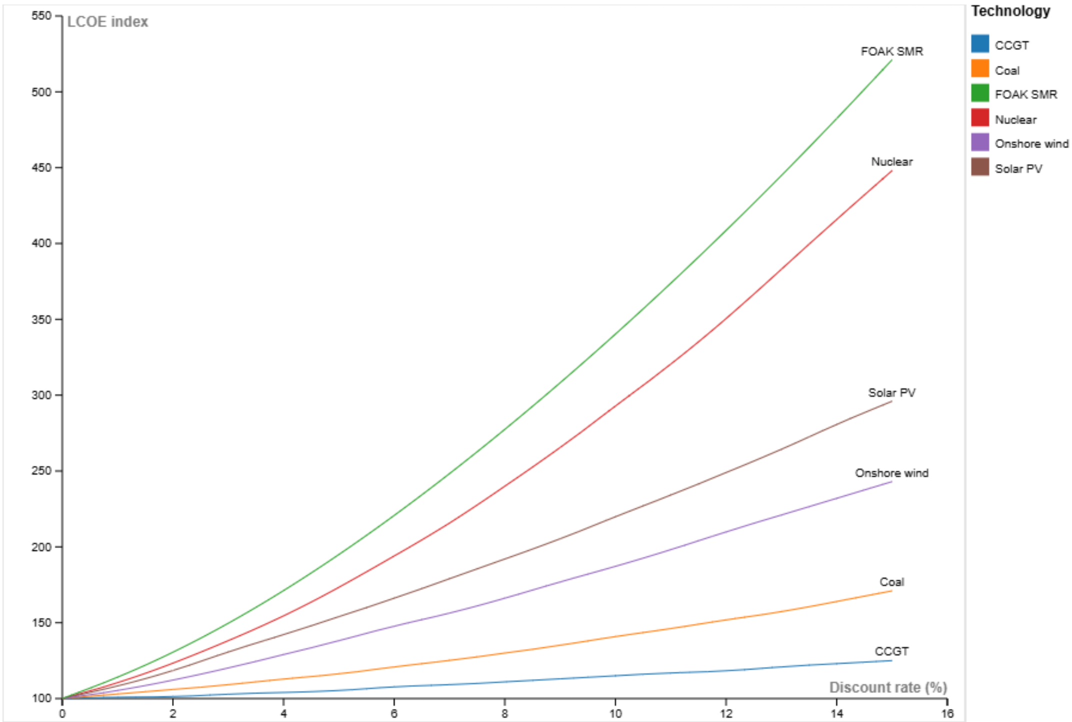


Figure 8 Effect of discount rate (%) on median LCOE (%) included the case of FOAK SMR, Source: OECD Nuclear Energy Agency & World Nuclear Association

Building on the financing dynamics illustrated in Figure 3, a scenario-based assessment of LCOE sensitivity to financing conditions was developed to include a FOAK SMR scenario**.** The model assumes a 300 MW unit, USD 9,000/kW overnight CAPEX, a five-year construction period, a 93% capacity factor and a 60-year operating life, with operating and fuel-cost assumptions. LCOE is recalculated for discount rates differing from 0% to 15% and expresses the result as an index, using the 0% discount-rate case as the baseline of 100.

Besides the fact that FOAK SMR requires a smaller overall capital investment, its LCOE is more sensitive than the conventional nuclear benchmark. While a smaller reactor reduces the total amount of capital committed to a single stage of a project, a FOAK design may still carry a higher cost per installed kilowatt. In the present scenario, the shorter construction period mitigates financing exposure but does not fully offset the effect of higher FOAK capital intensity.

The result therefore supports a more qualified interpretation of the SMR financing proposition. Smaller unit size can improve project bankability and easiness in waving financing, but lower LCOE sensitivity is not automatic. The longer-term economics of SMRs depend on whether successive deployments can achieve significant CAPEX reductions, shorten delivery timelines, while improving construction predictability as projects move from FOAK to a more mature status.

3. Greece's Nuclear Option: The Potential Role of SMRs

The potential role of nuclear energy in Greece mainly arises as an alternative, together with widen deployment of renewables, due to the rising domestic electricity demand, energy security and the broader electrification of the economy. According to Greece's NECP, electricity-related capacity requirements could increase by around 14.5 GW by 2035, reaching 42.0 GW, with transport electrification accounting for an important share.

SMRs could be particularly relevant to the country's profile, since their smaller unit size allows nuclear capacity to be deployed gradually, by following the changes in electricity demand and system requirements, compared to a conventional large-scale reactor. The Deon study estimates that a 300 MWe NOAK SMR could require approximately USD 1.2–1.9 billion of investment, compared with USD 4.5–7.5 billion for a 1,200 MWe large reactor. The main advantage is, therefore, a lower absolute investment requirement and greater flexibility in the timing and scale of deployment as the overall system evolves.[9]

The potential applications identified for Greece also extend beyond conventional electricity generation. Industrial decarbonization is another area of potential application. In 2024 Greece's energy intensive industries and activities, including cement, steel and petrochemicals, together with non-metallic mineral industries together accounted for around 9.2 TWh of final energy consumption. A significant share of that was supplied directly by fossil fuels. Advanced reactor technologies capable of supplying high-temperature process heat could therefore have a role in reducing fossil-fuel consumption in parts of Greek industry.

Maritime applications represent another area of potential contribution of nuclear energy, mainly as Trans-European Transport Network (TEN-T) ports are required to provide shore-side electricity by 2030. More specifically, the Deon Institute study identifies port electrification, nuclear-supported production of low-carbon fuels and the longer-term possibility of marine-based SMRs among the potential applications for Greece. This is especially significant given the scale of the Greek shipping industry: Greek-owned vessels account for approximately 20% of the global merchant fleet by deadweight tonnage.

For Greece, the first phase of any SMR strategy would need to focus on institutional readiness rather than reactor procurement. The country already has an independent nuclear regulator in the Greek Atomic Energy Commission (EEAE), but its current framework has not been developed around the licensing and oversight of a commercial

[9] Deon Policy Institute, Nuclear Energy the Case for Greece

nuclear power programme. A credible pathway would therefore require nuclear energy to be incorporated explicitly into long-term national energy planning, together with a substantial expansion of regulatory expertise in reactor licensing, safety assessment, safeguards and emergency preparedness. Greece could also reduce regulatory duplication by participating in the joint reviews and coordinated licensing initiatives now being promoted under the EU SMR Strategy[10], rather than developing an entirely national review process for each reactor design. In parallel, the government could undertake pre-licensing assessments of potential sites, including former lignite locations, and establish a long-term framework for spent-fuel and radioactive-waste management before any technology selection or procurement decision is made.

Given Greece's dependency on importing gas, combined with the need to improve security of supply, strengthening the case of keeping nuclear energy as an option, should be considered as a strategic alternative, rather than an immediate investment proposition.

A potential integration of an 340 – 400 MW SMR into the Greek electricity system would be expected to slightly change the generation mix by reducing the residual demand that covered by fossil-fuel. SMRs could provide a low-carbon source of electricity, while maintaining sufficient operational flexibility to adjust its output as renewable generation and electricity demand change.

The effect would differ across different system conditions. When renewables availability declines, higher SMR output could reduce the need for natural-gas-fired generation and therefore confine the power system's exposure to imported fuel prices and relevant carbon costs. By contrast, when renewable generation is abundant, system ability to exploit SMRs output depends on storage, exports, demand flexibility or reductions in other dispatchable generation.

Rather than replacing renewables or flexible generation technologies, SMRs could add to the system the potential of low-carbon capacity while reducing at the same time, rather than eliminating, reliance on natural gas. Even with SMRs in the mix, hydro, storage, interconnections and remaining thermal generation would continue to play an important role in balancing short-term variations in demand and renewable availability.

The potential contribution of SMRs to the Greek electricity system therefore extends beyond the provision of baseload electricity and includes their ability to participate in a more flexible, diversified and lower-carbon generation mix. the value of SMRs would depend increasingly on their ability to adjust generation in line with changing system

[10] https://energy.ec.europa.eu/topics/nuclear-energy/small-modular-reactors/small-modular-reactors-explained_en

requirements. The extent of these benefits would ultimately depend on the wider configuration of the electricity system, including renewable penetration, storage capacity, interconnections and the operational flexibility of both nuclear and conventional generation.