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The Financing of Nuclear Power Plants

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1. INTRODUCTION

The increasing decarbonisation pressure together with recent energy price shocks is fuelling a revived debate on new nuclear generation capacity in many European states. In this report, we provide a synopsis of financing models currently being applied or under development for newly built nuclear power plants in Europe, catering to the special risk profile of such projects.

In February 2024, the European Commission released a recommendation for a greenhouse gas reduction target of 90% by 2040 (compared to 1990) for the European Union on the way to climate neutrality in 2050 (European Commission 2024). The power sector is expected to reach full decarbonisation by as early as 2040. [1] So-called small modular reactors (SMRs) are expected to play a role in decarbonisation by the early 2030s. A new European Industry Alliance on Small Modular Reactors has been launched alongside the aforementioned communication to accelerate this development. [2]

Also, in the British Energy Security Plan (UK Government 2023b), nuclear power plays a major role with the stated ambition to deploy 24 gigawatts (GW) by 2050 – including SMR projects, corresponding to around 25% of the projected electricity demand. On the global scale, at the COP28 in Dubai on December 2, 2023, 22 states – of which 15 are in Europe, and of those 12 are EU member states – have committed to working on tripling nuclear power capacity by 2050 compared to 2020 levels. [3]

The increasing decarbonisation pressure, together with recent energy price shocks in the wake of the COVID-19 pandemic and the war in Ukraine, is fuelling a revived debate on new nuclear generation capacity in many European states, partially driven by nuclear industry lobby organisations – be it large-capacity conventional reactors or small-capacity SMRs.

In the last two decades in Europe, only three new nuclear power plants (NPPs) went into operation while four new NPPs are currently under construction and four NPP projects are in the planning stage. Several projects, specifically in Eastern Europe, are the (planned) completion of suspended former Soviet reactor projects. While some other envisaged projects already had to be abandoned due to financial or political reasons, several countries are considering adding even more nuclear capacity. Also in light of this situation, the contested inclusion of certain nuclear-related activities in the EU taxonomy (European Commission 2022) might potentially have relevant repercussions on the financing of NPP projects.

Understanding the financing of NPP projects is therefore crucial for evaluation of the feasibility of the stated ambitions and especially the risk-sharing between the concerned parties. In this report, we provide a synopsis of financing models currently being applied or under development for newly built nuclear power plants in Europe, catering to the special risk profile of such projects, and we give an overview of current projects in Europe, Turkey and the United States, focusing on the financing models.

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[1] Albeit with the help of 10% negative emissions and carbon capture and storage technology.

[2] https://energy.ec.europa.eu/news/commission-ally-industry-small-modular-reactors-2024-02-09_en

[3] https://www.energy.gov/articles/cop28-countries-launch-declaration-triple-nuclear-energy-capacity-2050-recognizing-key

As for any investment project, the capital required to build a nuclear power plant needs to be raised. A company planning a new project could make use of its equity, that is, monetary assets it owns, and it could incur debt, that is, borrow money from a third party. Debt can come in the form of loans, where a financial institution lends money to the company against the promise of interest payments, often secured by some form of collateral, for example, the asset to be financed by the loan. In the case of default by the borrower, the lender can use the asset to settle any outstanding payments. Another option is the issuing of bonds by the company. Those can be sold (and traded) on financial markets to investors, and also promise an interest payment on the face value of the bond. In comparison to loans, bonds are usually not backed by collateral and, in case of bankruptcy, are settled only once any outstanding loan balances (except for subordinated or unsecured ones) have been paid off.

Financial institutions are only willing to issue loans and investors are only interested in buying bonds if their promised rate of return is high enough compared to the risk they entail (and other investment options in the market) – this is also called the “bankability” of a project. To organise the financing of a new nuclear power plant, it is therefore important to consider the risk profile of such a project (Section 2). Given this risk profile, several financing models are currently being used or considered in Europe. Section 3 first gives a theoretical introduction to those models, with Section 4 specifying some additional hidden costs of NPP projects often not fully accounted for in investment decisions. Section 5 then provides an overview of current projects in Europe with additional excursions to Turkey and the United States. Here, it becomes clear that NPP projects to a large extent only become bankable if a government is involved in de-risking the investment for private investors. Section 6 concludes.

2. RISK PROFILE

NPP projects exhibit a special risk profile. Empirical data suggests that these projects generally seem to have a higher risk: El Ghoul et al. (2011), for example, find that companies operating within the nuclear power industry have higher equity financing costs compared to other industries (except for the tobacco industry).

2.1. POLICY AND POLITICAL RISKS

NPPs operate in a policy environment heavily regulated on the national, but also inter-governmental levels. With constantly changing requirements for the construction and operation of NPPs and potential decisions by national governments on nuclear phase-outs or other restrictions for the nuclear industry, due notably to safety considerations, NPP projects are associated with significant **regulatory risks**.

Another aspect influencing the environment in which NPP projects are developed is **public acceptance** of the technology. This varies widely between countries, within the political spectrum, and between age groups. Also, the impact of nuclear accidents elsewhere may severely impact public perception: “A nuclear accident anywhere is a nuclear accident everywhere”, as was concluded by IAEA Director Mohamed ElBaradei in 2005. [4]

A third aspect deals with the **knowledge loss** in the nuclear industry workforce due to the small number of newly built reactors in recent years.

Lastly, there are **(geo-)political** risks, for example when foreign governments are involved in the projects, as is the case with the involvement of Russia in several aspects of some European projects. Potential exertion of political influence or sanctions may become a threat to the completion and operation of a reactor.

2.2. PROJECT RISKS

NPPs have specific project risks that differentiate them from other energy generation projects. Firstly, they require the investment of very **high upfront capital costs**, while the costs during the operational phase are comparably low. While this structure is similar to renewable energy plants such as photovoltaics and wind, the per kilowatt costs are significantly higher than for renewables [5] and the projects are usually much larger in installed capacity, at least compared to PV and onshore wind (IEA and NEA 2020).

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[4] https://www.iaea.org/newscenter/statements/enduring-lessons-chernobyl

[5] IEA and NEA (2020) list global median values for conventional nuclear at 3,370 USD/kW$_{el}$, wind offshore at 2,740 USD/kW$_{el}$, wind onshore at 1,439 USD/kW$_{el}$, and utility-scale PV at 923 USD/kW$_{el}$, while LAZARD (2023) provides ranges of 8,4750-13,925 USD/kW$_{el}$ for conventional nuclear, 3,000-5,000 USD/kW$_{el}$ for wind offshore, 1,025-1,700 USD/kW$_{el}$ for wind onshore, and 700-1,400 USD/kW$_{el}$ for utility-scale PV. SMR technologies continue to be associated with a high degree of uncertainty, but estimates look very unfavourable so far (Steigerwald et al. 2023).

Meanwhile, these high capital costs are accrued over a very **long construction period** of about eight to 16 years for recent projects (NEA 2020), during which no revenue stream is yet available. Still, already during this period, interest has to be paid on loans, the so-called interest during construction (IDC), which is often added to the loan balance. Even a small change in interest rates therefore has a substantial impact on the project costs. In contrast, for renewable installations, significantly shorter installation and commissioning lead times of between one to four years for utility-scale solar PV, one to five years for onshore wind, and two to seven years for offshore wind can be observed (IEA 2023).

Lastly, NPP projects are associated with **high risks during the construction phase** that regularly lead to time and budget overruns, as can be seen in some of the recent projects where the originally announced construction times of four to five years were vastly exceeded by a factor of two to three, and the initially announced budget by a factor of two to four (NEA 2020) (see Section 4 for details).

2.3. REVENUE RISKS

Further risks arise during the operational phase of the NPP: They are designed for a very long operating lifetime of up to 60 years compared to, for example, 25 years for solar PV and wind (IEA 2023), which also stretches out the periods for depreciation and **capital cost recovery**. Renewable projects in general also exhibit shorter payback periods, that is, the time required to fully recover the initial investment.

At the same time, it is harder to forecast the **levels of electricity market prices** over such a long period, again influencing the revenue stream and potentially increasing the financial risk of the project.

Another risk concerns the **fuel supply**, since current nuclear fuel supply chains are not adequately diversified, with 96% of uranium purchased for reactors in the EU in 2021 coming from only five sources: Niger (24%), Kazakhstan (23%), Russia (20%), Australia (16%), and Canada (14%) (NEA and IAEA 2023). Also, the Russian Rosatom operates about 20% of conversion and 46% of enrichment facilities needed in the fuel cycle (ESA 2023). Fuel fabrication itself is especially vulnerable for Rosatom's VVER reactor models since the fuel rods are widely imported from Russia, with Westinghouse currently being the only Western supplier. The prevailing situation of war and political instability influences both fuel price and potential future supply. Western states are working on a diversification strategy, which will however take time and be costly.

Other risks influencing revenue during the operational phase are fuel management, ageing problems, and accidents. NPPs can also become exposed to military risks, as could be seen in the Yugoslavian wars, but also more recently in the war in Ukraine, and potentially in the future with political tensions in the Middle East.

3. FINANCING MODELS

As for any energy infrastructure project, a number of players are involved in the planning, financing, building and operation of a nuclear power plant. Given the special risk profile of NPP projects outlined above, additional roles might come into the picture to de-risk the investment (see Figure 1). This section outlines the theoretical background of financing models, while Section 5 links the theory to current projects.

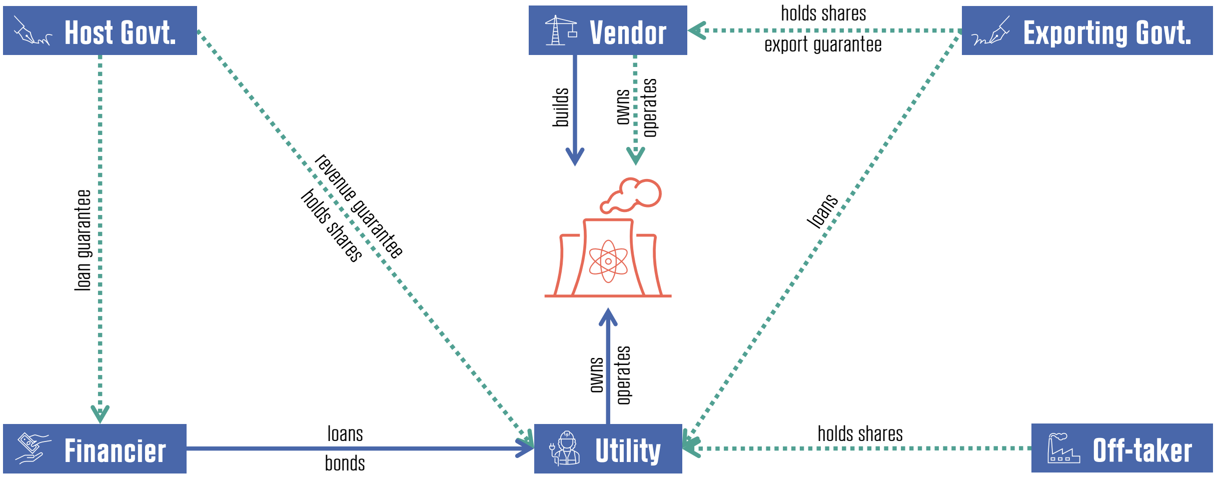

Figure 1: Schematic overview of financing models. Solid lines represent standard relationships, dashed lines optional ones.

Conventionally, a **utility company** (i.e. a producer and seller of electricity) would be planning to build a new power plant. They would decide on a make and model and subsequently order the plant from a **vendor** that would be responsible for construction. Since the utility company would not be able to pay for the project in cash, they need a **financier**, that is, an institutional investor, which could be a commercial bank or any other financial institution issuing loans or investing in company bonds, such as an insurance company or a pension fund. These three players can be found in this setting in any utility-scale energy infrastructure project.

In the case of NPPs, the following additional players might be part of the project as well, depending on the (combination of) financing models applied: An **off-taker**, that is, an entity using the electricity produced by the NPP; the so-called **host government**, that is, the government of the country in which the NPP is to be built and operated; and the **exporting government**, that is, the government of the country in which the vendor of the NPP to be constructed is located.

At the beginning of the commercial nuclear power era since the 1950s and 1960s, nuclear programmes used to be mostly national, with the vendors being under the same jurisdiction as the utility companies and therefore the host governments to support both of them. During that time, the civil nuclear programmes of the United States and the Soviet Union were developed, as well as those of France, Germany and the United Kingdom. To a limited extent, NPPs were also exported to other countries like Belgium, the Netherlands and Spain, but also outside of Europe. In recent years, some countries that previously did not have a nuclear programme (for example, Poland, Turkey, Egypt, Bangladesh, United Arab Emirates, or Saudi Arabia) or that want to restart their programmes (for example, the United Kingdom and Finland) began to plan and construct new reactors that are imported from the large vendors, mostly from Russia, South Korea, the United States, and France. The market for NPPs has therefore seen a shift from being more nationally oriented to becoming a global export market. Therefore, the interests and involvements of vendors and exporting governments have also shifted.

The following subsections describe the different financing models that are currently being applied or are anticipated to be applied in planned projects, and the roles of the introduced players within those models (IAEA 2008; NEA 2015; Pehuet Lucet 2015; IAEA 2018; Terlikowski et al. 2019; Pehuet Lucet 2019). The roles and responsibilities might shift between the planning, construction, operation and post-operation phases. In principle, most of the models could also be applied to (energy) infrastructure projects other than NPPs. For the sake of completeness, we also touch upon project financing, a model not viable for NPPs. Table 1 shows an overview of the models and their (principal) risk-bearers. In practice, several models might be used simultaneously in an NPP project.

Table 1: Overview of risk-bearers in the financing models.

Financing model	**(Principal) risk-bearer of the model**
Project financing	Not viable for NPP projects
Corporate financing	Lender via loans or bonds
Hybrid financing (Mankala)	Shareholders of the Mankala company
Vendor financing	Vendor company; if state-owned then indirectly also the owning government's taxpayers
Loan guarantees	Guaranteeing government's taxpayers (either of the home government or the exporting government)
State-owned utilities	Owning government's taxpayers (as capital stock would be increased to prevent bankruptcy)
Export guarantees	Guaranteeing government's taxpayers
Contracts for Difference (CfD)	Taxpayers (if levied via general state budget) or ratepayers (if levied via electricity rates)
Regulated Asset Base (RAB)	Ratepayers

3.1. PROJECT FINANCING

In the project finance model, a project company owning (and potentially operating) an electricity generation asset would take out loans to finance the project that are backed by the value of the asset itself (i.e. the power plant). If the company defaults, the lenders have the generation asset as collateral. Since project companies are usually set up as limited liability structures, lenders can only dispose of the assets of those companies in the event of a default. Project finance is therefore only viable for projects with an appropriate risk structure, where construction and operation costs, as well as revenues during the operation phase, are clearly predictable, as is typically the case for renewable power plants such as photovoltaic or wind. Given their risk profile, this financing model is not viable for NPP projects, since financiers would either not be willing to engage at all, or the cost of debt would rise above an economically viable level to compensate for the risks.

3.2. CORPORATE AND INVESTOR FINANCING

Utility companies can also organise the financing of an NPP project within their own balance sheet. In this case, loans taken out or bonds issued by the corporation are backed by all their assets (which could, for example, also be other power plants) and not just the NPP to be constructed itself, as in the case of project financing. This can make it more likely that a financier would be willing to lend to the utility company since the risk of default can be more balanced due to other operations generating revenue leading to a higher grade of diversification of the income stream. Given the size of an NPP investment project, only very large utilities would be able in practice to finance the project against their balance sheet.

In Finland, a special hybrid model between corporate and investor finance has developed. Named after the village *Mankala* where it was first been applied, this model is also widely used in the Finnish power sector for generation technologies other than nuclear. A number of usually industrial companies in need of power for their production get together and set up a non-profit limited liability company to construct a new power plant. The founders become the shareholders of this company and guarantee to cover all the costs of the Mankala company according to their ownership share. In return, the shareholders are guaranteed to be supplied with electricity at a price reflecting the total costs of production (cost-price model), but they also have the obligation to buy the produced electricity – both again based on their share in the Mankala company. The model can be compared to an open-season process, which is often used for decisions to invest in pipelines. The consumer of the electricity to be produced has a knowledge of their projected power demand and participates in the capacity allocation of the power plant to be built by committing to a certain number of shares in the utility company to be founded, and therefore also in the risk allocation since they have the obligation to buy electricity at cost-price. Potential cost overruns will then be covered by the final consumer. This model makes it more attractive for financiers such as institutional investors to invest in loans to the Mankala company or bonds issued by it, since the risk is again more diversified by the backing of the Mankala shareholders. This model cannot guarantee economic viability, but it is – in its pure form – a good example of risk-sharing not burdening the electricity ratepayers or taxpayers. It is, therefore, also under the discussion in countries other than Finland.

3.3. VENDOR FINANCING

With the construction of NPPs increasingly becoming an export market, new financing models supported by the reactor vendors themselves have emerged in recent years. In these models, the vendor of the plant might build and (at least in part) finance the NPP at their own risk until completion, and then transfer ownership of the plant to the utility company that ordered the plant. This is also known as the

Build-Own-Transfer (BOT) model. In the Build-Own-Operate (BOO) model, the NPP would eventually also be operated by the reactor vendor. In both cases, significant parts of the risk are covered by the vendor, making it easier for the vendor to enter new markets, especially those that might have a weak financial sector that is unable to finance a project of this size and with those risks and/or in those countries that did not previously have a nuclear industry.

3.4. DIRECT OR INDIRECT GOVERNMENT FINANCING

In several of the models mentioned so far, the host government may play a crucial role in de-risking the NPP project via direct or indirect involvement. Some more "conventional" politico-economic instruments include subsidies either via direct grants, tax breaks, or favourable loans by multi-lateral banks such as the European Bank for Reconstruction and Development (EBRD) or the European Investment Bank (EIB) [6].

One more specific option is loan guarantees by the host government for the financiers of the project. In this case, the institutional investors issuing loans to the utility company owning the NPP receive a guarantee by the host government that any outstanding debt will be covered by the state in case of default by the utility company (or in the event of other financial risks from the project). In this way, the investment becomes more attractive to the financier since the risk is significantly reduced. In return, this means that the host government takes over large parts of the financial risks associated with the project, which ultimately means that the taxpayers are exposed to those risks.

Another widespread form of host government involvement is utility companies being fully or partly state-owned. In this case, it can usually be assumed that the government, as a shareholder, would always increase the capital stock of the utility in order to save it from defaulting. The state ownership in itself therefore improves the credit rating of the utility (though remaining below the credit rating of the state itself), increasing the probability of third-party funding through loans and bonds. In return, the shareholding government profits from any dividends paid by the utility but also carries the risks of any losses. The same is true for reactor vendors that are fully or partially state-owned either due to having originally been founded by a state or by nationalisation after (looming) bankruptcy.

3.5. GOVERNMENT-TO-GOVERNMENT FINANCING

The aforementioned state-owned vendors can also be owned by an exporting government (in case the NPP is to be built in a country other than the one where the vendor is based). In this case, there are further financing models available to support the export of nuclear power technology to other countries.

A very common instrument of export support, which is widely applied across all export industries dealing with high-capital products, is export guarantees by the exporting government to an exporting company. Here, the exporting government – in the case of an NPP, the vendor's home country – de-risks the export deal by taking over some of its associated financial risks. For example, if the buyer of the NPP, that is, the utility, were default and be unable to pay for the NPP, the exporting government would step in and cover some or all of the outstanding payments.

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[6] The EIB has so far taken a cautious stand on investments in nuclear power. Still, the new president Nadia Calviño, backed by France, recently announced the expansion of its activities into the field: https://www.ft.com/content/418fbd05-b5d3-4cb3-a9e4-648b14694ec2

More directly, the exporting government could also issue loans either to the host government or the utility company ordering the NPP, thereby taking over even larger parts of the project's financial risks not only from the vendor, but also from the host government.

In both cases, the exporting country's taxpayers are ultimately exposed to the financial risks of the NPP project, in this case even in another country.

3.6. REVENUE GUARANTEES

The financing of nuclear power plants can also be de-risked by support mechanisms during the operational phase via different types of revenue guarantees for the utility company.

Comparable to the instruments already in use or proposed for the support of renewable electricity and their integration into the market, the host government might guarantee revenues from the sale of produced electricity by issuing so-called power purchase agreements (PPAs). These can be the obligation to buy the electricity produced at a certain fixed price. Here, the utility company would not be exposed to the market risk of volatile and changing electricity prices. Another approach that supports integration into the electricity market is contracts for difference (CfDs). Here, the electricity is sold at the power exchange in the host country, but the host government would pay the difference between the market price and an agreed-upon minimum price or price floor in case the market price falls below that floor price (one-sided CfD). This instrument prevents exposure of the utility to the downside risk of the market, that is, selling the produced electricity for a price below a certain revenue expectation. To minimise the costs to the host government, the CfD could be implemented as two-sided. In this case, the utility would need to repay any revenues it makes whenever the market price is higher than the agreed-upon maximum price or price ceiling/cap. In this way, gains from upside risks can be limited. Price floor and price ceiling can be identical or form a collar, that is, a price range between the price floor and price ceiling. The European Commission proposed CfDs as the go-to support instrument for low-carbon energy technologies in the EU member states (European Commission 2023).

In the United Kingdom, a model for the remuneration of nuclear power plants is currently under development under the Nuclear Energy Financing Act of 2022 (Ofgem 2023; Newbery et al. 2019). Here, a "nuclear company", that is, a company holding a license for an NPP project, can apply for a Regulated Asset Base (RAB) financing model. Similar schemes are used for other capital-intensive infrastructure projects. Usually, such financing models are applied in areas where so-called natural monopolies occur, that is, a company that has the monopoly in a certain market simply because this market can only economically support one player in a geographic area. Typically, this applies to network industries such as power grids, where there is no room for a competitor to build a parallel grid. To avoid the grid company being able to earn monopoly profits due to the absence of competition and therefore a lack of choice on the consumer side, these natural monopolies are regulated by a government authority and a cap on their profits is enforced. Several different schemes can be applied here. In the case of the RAB model, the regulator allows the utility company a certain rate of return on the invested capital – the asset base. Since this would incentivise the utility to inflate the asset base as much as possible, the regulator needs to clearly define what parts of the invested capital are eligible to enter the RAB. This is especially important in the case of cost overruns of nuclear projects to avoid an excessive de-risking of the investment. The operator of the NPP (directly or indirectly) collects the allowed revenue from all electricity suppliers in the country according to their market share in the retail market already starting in the construction period in step with the capital spent on the construction. They, in return, charge their consumers a levy on top of their electricity price. Therefore, in the RAB model, the final consumers of electricity bear a part of the financial risk of a new-built NPP. The regulator must define a financing cap for the project. In the event of cost overruns, regulation must be in place to define the risk-sharing between the utility company and the final consumers for any expenditures above the defined financing cap. By spreading the risk across many millions of households, the total investment risk decreases and with it the costs of capital, eventually also reducing the price of nuclear power for the households. This cost advantage can outweigh the downside of allocating less risk to the utility company, if the remaining risks of cost overruns are managed properly, giving the utility the right incentives.

In the United States, in some states such as New York, New Jersey, and Illinois, public utilities are mandated to purchase certain shares of nuclear power via zero-emission credits. The costs for this are passed on to the ratepayers, making them the primary risk-bearer.

4. HIDDEN COSTS

Some additional costs of NPP projects are often not fully accounted for in investment decisions. We call them "hidden" costs and they can, on the one hand, further drive the financing costs, or constitute additional risks to the NPP owner/operator or the taxpayers.

4.1. OPERATION AND MAINTENANCE

Certain revenue risks can also arise during the operational phase. The fuel supply chain and rising costs for uranium and fuel assembly can have negative effects, as mentioned above. Projects involving Russian and Chinese actors are exposed to certain political risks. One manifestation is the need to develop and certify alternative fuel rods for reactors of Soviet or Russian origin.

Another problem can be maintenance issues and problems arising from low levels and high temperatures in the cooling water supply, as observed in France in 2022 (Plackett 2022).

4.2. THIRD-PARTY LIABILITY INSURANCE

Another pool of costs that do not fully show in the price for nuclear electricity is the insurance against third-party liabilities. While nuclear power plants do need to have insurance policies, liability is usually limited, and a number of inter-governmental conventions regulate how any damages incurred above this liability limit are covered (NEA 2024). Generally, it can be stated that the taxpayers are always exposed to the residual risk.

Many European countries are parties to the 1963 Brussels Convention Supplementary to the 1960 Paris Convention ("Brussels Supplementary Convention"), for example, Belgium, Finland, France, Germany, the Netherlands, and the UK. Under this convention, operators of nuclear power plants are liable up to a certain amount, for example, EUR 1.2 billion per nuclear accident. Given the immense amount, insurance for nuclear installations cannot be provided by any single insurance firm in the market. Therefore, insurance pools were formed to disperse the risk (Faure and Fiore 2008). In Europe, those are the European Mutual Association for Nuclear Insurance (EMANI), founded in 1978, and the European Liability Insurance for the Nuclear Industry (ELINI), founded in 2002.

Any damages incurred above that insured sum or in case available funds run out have to be covered by public or international funds. In the United States, liability for nuclear damages is regulated under the Price-Anderson Act from 1958, last updated in 2005. Here, reactors must be covered by the maximum available from commercial insurance (USD 450 million) with a second insurance layer based on "retroactive premiums" only collected from all operators in the case of an accident (USD 121.3 million per reactor plus a possible surcharge) payable over many years with a maximum of USD 19 million per year. Any damages above about USD 13 billion would need to be covered by funds allotted by the U.S. Congress. In France, a comparable system allows for the backing of parts of potential claims against the balance sheets of the operators, meaning they are technically not insured.

These regulations allow the nuclear operators to pass on parts of their risks that would otherwise materialise as insurance costs to taxpayers.

There is furthermore continuous uncertainty about liability coverage – an issue that is still in development and that receives a new impetus every time there is a severe nuclear accident anywhere in the world. Both the accidents in Chornobyl and Fukushima saw substantial increases in liability and obligatory financial reserves.

4.3. DECOMMISSIONING, INTERMEDIATE AND FINAL STORAGE

At the end of its technical lifetime, a nuclear power plant needs to be decommissioned. Nuclear industry sources assume the cost to be reflected by 15% of the overnight construction costs, compared to 5% for all other technologies (IEA and NEA 2020). Due to the long lifetime of nuclear, this becomes very small in the discounted calculations of electricity generation costs. Yet there is only limited experience with decommissioning and the financing models applied differ between countries, though mostly without following the “polluter pays” principle, that is, large parts of the costs are supported by government subsidies (Wimmers et al. 2023). Decommissioning cases so far have also shown that the costs can reach the level of the initial construction costs of a reactor – and so far beyond the assumed 15% mentioned above.

Another problem is the intermediate and final storage of spent fuels and radioactive materials from decommissioning. No country operating NPPs has a final storage site available. Finland is in the process of constructing a facility planned to become operational in the coming years; other countries are still in the political decision and finding phase. This also makes the anticipated cost structures nearly impossible to forecast. In the meantime, intermediate storage sites need to be operated and maintained far beyond their originally anticipated lifetime, and financed.

5. CURRENT PROJECTS

The following section provides details on ownership and financing models of NPP projects in Europe, Turkey, and the United States. In addition, we provide a concise survey of small nuclear reactor (SMR) developments.

The main vendors for large-scale nuclear power plants are Westinghouse (U.S.), Framatome (France, formerly part of Areva and now, via EDF's 80.5% share, majority-owned by the French state – with minority shareholder Mitsubishi Heavy Industries [7]), KHNP/KEPCO (South Korea, majority-owned by the Korean state both directly (18.2%) and through the Korea Development Bank (32.9%)[8]), and Rosatom/Atomenergoprom (Russia, fully state-owned). Currently, EDF and Framatome dominate new projects in Western Europe, while Eastern Europe and Turkey are supplied by Rosatom projects. Table 2 shows the currently available credit ratings of the vendors, where available, and also of TVO, a Finnish operator. Any rating below Baa3/BBB- is considered a "non-investment grade". Several projects exhibit influences of either Russian or Chinese state-owned companies as either vendors and/or utility companies. Other companies are active in the development of so-called small modular reactors (see Section 5.11).

Table 2: Credit ratings of nuclear power companies. Source: company websites.

Long-term rating	Moody's	Standard & Poor's	Fitch	JCR	R&I
EDF (Framatome)	Baa1 stable	BBB stable	BBB+ stable	AA	AA stable
Westinghouse	B1	B	B+ stable	-	-
Rosatom (Atomenergoprom)	Ba1	BB+ negative	BBB- negative	-	-
KEPCO (KHNP)	Aa2 stable	AA stable	AA- stable	-	-
TVO	Baa3 stable	BBB- stable	BBB- stable	A+	-

Common features of recent NPP new-build projects are significant cost and budget overruns. Table 3 shows the announced and realised construction times and costs for some recent projects in Europe and the U.S., which are described in more detail below, but also in China, Russia, and Korea – countries that are frequently cited as being able to deliver projects on time and on budget. The construction start reported in this table refers to the year when the work on a given power plant was started (usually the first pouring of concrete). Before that, the building sites need to be prepared for construction, which can frequently take several years, adding to the actual construction time of an NPP.

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[7] https://www.framatome.com/fr/a-propos/gouvernance/

[8] https://home.kepco.co.kr/kepco/EN/C/htmlView/ENCCHP003.do?menuCd=EN030303

Table 3: Construction time and costs of recent NPP projects. Source: NEA 2020; IAEA 2023b – updated and expanded.

Unit	Type (country)	Construction start	Announced construction time (years)	Realised construction time (years)	Announced construction costs (USD/kW$_e$)	Realised construction costs (USD/kW$_e$)
Sanmen 1 & 2	AP 1000 (China)	2009	5	9	2,044	3,154
Vogtle 3 & 4	AP 1000 (USA)	2013	4	10/11	4,300	8,600
Saeul 1 & 2	APR 1400 (Korea)	2008/ 2009	5	8/10	1,828	2,410
Shin-Hanul 1 & 2	APR 1400 (Korea)	2012/ 2013	5	>10/>11	2,239	>6,360
Olkiluoto 3	EPR (Finland)	2005	5	17	2,020	>5,723
Flamanville 3	EPR (France)	2007	5	>17	1,886	>8,620
Taishan 1 & 2	EPR (China)	2009/ 2010	4.5	9	1,960	3,222
Hinkley Point C 1 & 2	EPR (UK)	2018/ 2019	7	>11	6,750	14,461
Novovoronezh II 1 & 2	VVER 1200 (Russia)	2008/ 2009	4	8/10	2,244	n/a
Leningrad II 1 & 2	VVER 1200 (Russia)	2008/ 2009	5/6	10/12	2,974	n/a

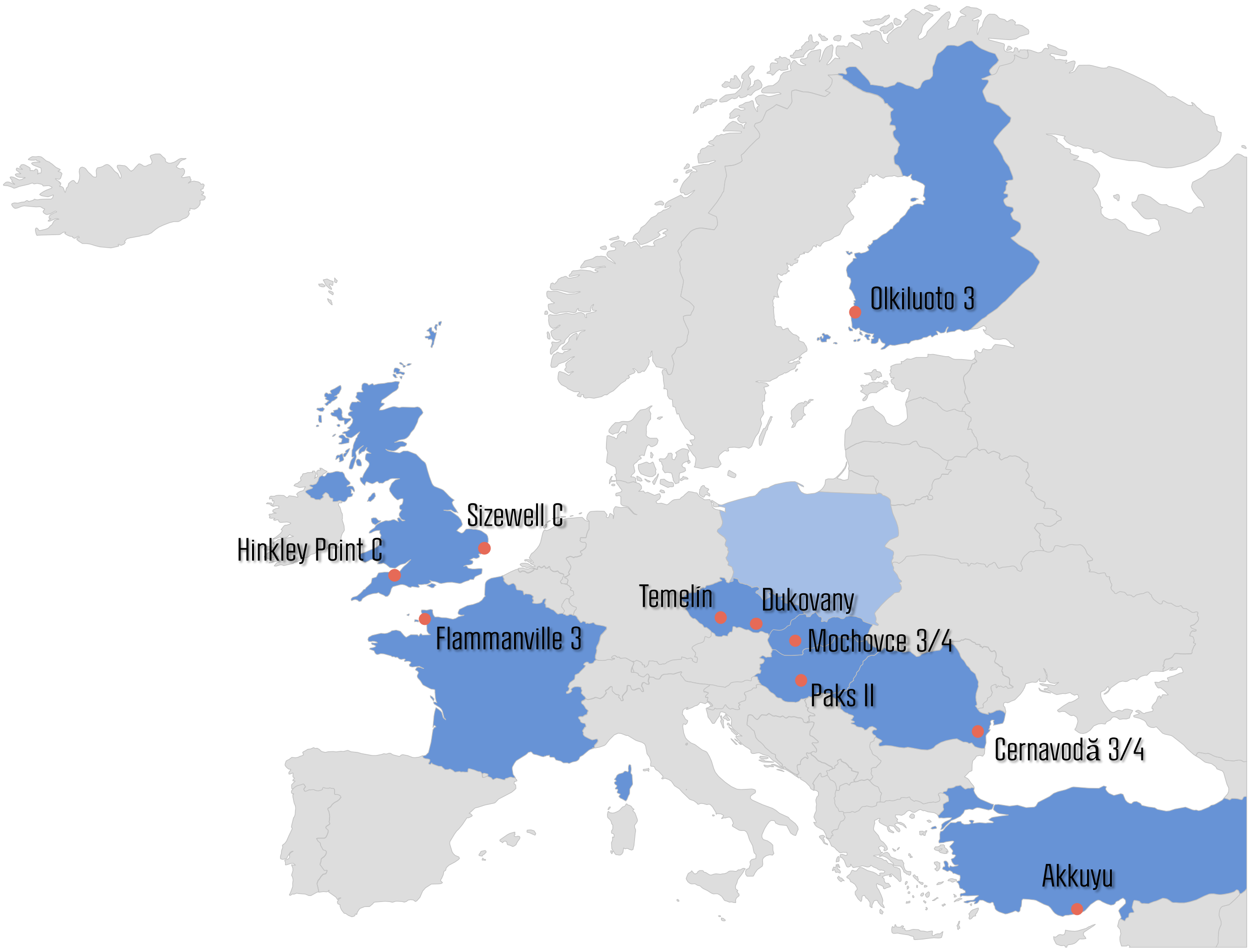

Figure 2: Recent European NPP projects and countries featured in this report. U.S. projects are not shown.

The following sections provide more details about European countries that have recently added new nuclear generation capacity or where new NPPs are under construction or planned, and what the ownership structures and financing models of these projects look like (Figure 2). In addition, Turkey and the United States are also showcased. Finally, we provide a concise survey of small nuclear reactor (SMR) developments.

5.1. FINLAND

The Finnish energy system was characterised by a high import dependency on Russia until 2022 (Proskurina 2024). Since the summer of 2022, imports from Russia consisted solely of uranium and minor amounts of liquefied natural gas (LNG) (Ministry of Economic Affairs and Employment 2023). The country operates a fleet of five nuclear reactors (two Pressurised Light-Water Moderated and Cooled Reactors (PWRs) and three Boiling Light-Water Cooled and Moderated Reactors (BWRs)) across two locations with a net capacity of 4.3 GW_{el} (IAEA 2023a). Recently, one high-capacity nuclear power plant project was terminated (Hanhikivi 1) and one went into commercial operation (Olkiluoto 3), alongside a discussion about district heating utilising so-called SMRs.

In 2022, Fennovoima terminated the engineering, procurement, and construction (EPC) contract signed in 2013 with RAOS Project from Russia for the planned Hanhikivi 1 nuclear power plant project in northern Finland. [9] The Hanhikivi project was owned during this time by Fennovoima, which is majority-owned (66%) by Voimaosakeyhtiö SF, a Finnish company with shareholders including major Finnish corporations and several local energy companies. The remaining 34% is held by RAOS Voima Oy, the Finnish subsidiary set up in 2014 by Rosatom to buy a share in the company (Thomas 2018). In this case, the vendor, owned by a foreign government, holds a minority share in the Mankala company that owns the NPP.

In 2023, the Olkiluoto-3 reactor was commissioned following a construction period of about 17.5 years. The project consists of a European Pressurised Reactor (EPR) from Framatome, owned by Teollisuuden Voima Oyj (TVO) with a net capacity of 1.6 GW_{el}. The project was also financed with the help of a cooperative Mankala investment model (Baringa 2022). In this case, major industrial electricity consumers jointly invested in the plant through their TVO joint venture, with each TVO shareholder contributing a proportion of the costs of building and operating the plant in exchange for electricity supplies, primarily for their own use (Baringa 2022). Financed with 25% equity and 75% debt, including backing from the French export credit agency Bpifrance, the project was facilitated by a fixed-price turnkey contract with Areva [10], however, construction complications stemming from underestimated risks resulted in time overruns and significant financial losses for the vendor/EPC, contributing to near bankruptcy and necessitating restructuring of Areva (Baringa 2022). Here, the Mankala model is mixed with, once again, a state-owned vendor that is itself backed by foreign government export guarantees.

5.2. UNITED KINGDOM

There are currently nine nuclear reactors (one PWR and eight Gas Cooled, Graphite Moderated Reactors (GCRs) in operation with a total net capacity of 5.8 GW_{el} in the UK (IAEA 2023a). There is currently one construction of two EPR-type reactors underway at Hinkley Point, with each reactor having a net capacity

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[9] https://www.world-nuclear-news.org/Articles/Fennovoima-cancels-Hanhikivi-1-contract-with-Russi

[10] The NPP vendor business of Areva is now Framatome, yet the risks for the Olkiluoto project remain with the residual part of Areva, now operating under the name Orano: https://www.edf.fr/en/the-edf-group/dedicated-sections/journalists/all-press-releases/signing-of-definitive-binding-agreements-for-the-sale-of-areva-np-s-activities

of 1.6 GW_{el}, and each started in 2016. The project is owned by the state-owned French EDF and Chinese CGNPG and, in the latest scenario, is expected to be in commercial use in 2031 after a total construction time (including site preparation) of probably about 15 years. CGNPG has decided not to fund any further budget overruns, leaving EDF and eventually the French government with the risk.

The country left the European Union in 2020 and since then has been looking to develop its policies to speed up its infrastructure deliveries (UK Government 2023a). In recent years, proposed NPP projects by foreign companies were cancelled due to problems finding investors [11]. In contrast, the British Energy Security Strategy set out the ambition of deploying up to 24 GW of nuclear generation capacity by 2050 – around 25% of the projected 2050 electricity demand (UK Government 2023b).

The UK government has implemented a series of regulatory, policy, and legislative initiatives aimed at facilitating new nuclear development, including the Contracts for Difference (CfD) scheme providing long-term price stability for generators, covering renewables and nuclear. The government-owned Low Carbon Contracts Company (LCCC) is entrusted with supervising these contracts awarded to private investors or generators through competitive auctions based on their bid 'strike price'. In this kind of financing model, private investors finance the development of the project, aiming to adhere to the delivery timeline to avoid penalties for non-delivery. Once commissioned, the project generates electricity and sells it at the wholesale price determined by the market. The difference between the wholesale price received and the agreed CfD strike price is made up by the LCCC, funded through a levy on electricity suppliers. In the event the wholesale price increases above the CfD strike price, the generator returns the difference to the LCCC. Hence, this is called a "two-sided CfD". These contracts ensure long-term income security for generators, thereby reducing capital costs. Additionally, the LCCC determines the levy on suppliers to fund generator payments. It also functions as a central counterparty, managing cash flows between retailers and generators. Renewable energy contracts typically last 15 years, while nuclear contracts span 35 years. After contract expiration, merchant operation incentivises power upgrades, lifetime extensions, and other improvements. (Baringa 2022)

Hinkley Point C will be remunerated via a CfD with a strike price of GBP 89.50 per MWh in 2012 prices with an inflation-correcting element. If the Sizewell C project were not to be continued, the strike price would be increased to GBP_{2012} 92.50 per MWh It was financed without direct government funding; however, this model places all construction risks on investors, and with escalating costs and delays, subsequent projects have not found any developers willing or able to secure financing post-HPC (Baringa 2022).

Subsequently, the UK government suggested developing a Regulated Asset Base (RAB) model for nuclear power, which had previously been used for other large-scale infrastructure projects such as water and electricity networks (Ofgem 2023). In September 2023, the UK government and EDF initiated an equity raise process aimed at enticing private investors to participate in the upcoming Sizewell C project. Constructive dialogues with eligible prospective investors are ongoing, with a final investment decision expected later in 2024. [12] Meanwhile, the French Finance Minister, Bruno Le Maire, has asked the British

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[11] See, for example, Hitachi's Horizon Project (https://www.pesmedia.com/hitachi-horizon-project-16092020/) or Toshiba's project in Cumbria (https://www.theguardian.com/environment/2018/nov/08/toshiba-uk-nuclear-power-plant-project-nu-gen-cumbria).

[12] https://world-nuclear-news.org/Articles/Sizewell-C-project-to-enter-construction-phase

government to take on a greater share of the cost of building new nuclear reactors, including Hinkley Point C, in the UK. [13]

5.3. FRANCE

The country operates a nuclear reactor fleet of 56 PWRs with a total net capacity of 61.3 GW_{el} (IAEA 2023a). In 1989, Framatome and Siemens began developing the European Pressurised Water Reactor (EPR), incorporating lessons from past nuclear incidents. By 2001, Areva pursued a turnkey sales strategy for the EPR, conflicting with aim of Électricité de France (EDF) to take the lead in new nuclear power. This competition led to intense rivalry and overbidding within the French nuclear sector, resulting in hasty construction launches for the first two EPRs in Finland and France. However, these projects faced technical challenges due to insufficient preparation and an underestimation of construction difficulties (Cour des comptes 2020). In France, EDF took the final investment decision for the EPR project in 2006 following public consultation and approval from the French government to build the EPR at the Flamanville site. Construction of the reactor with a net capacity of 1,630 MW_{el} started in 2007 and it is currently expected to be online in late 2024 after about 16.5 years of construction time. [14]

The French Court of Auditors estimates a substantial 3.3-fold increase in construction costs and a minimum 3.5-fold increase in commissioning time compared to initial projections, representing a notable deviation even for a "pilot" reactor in 2020. This outcome primarily stems from an initially unrealistic assessment of both construction duration and costs for the Flamanville 3 EPR (Cour des comptes 2020). In 2020, the average global reactor construction time from 1996 to 2000 was 121 months (about 10 years), the originally scheduled construction time for the Flamanville EPR was about 4.5 years – six months longer than the initial plan for the Finnish Olkiluoto 3 reactor (Cour des comptes 2020). This significant underestimation of construction time exerted immense pressure to adhere to tight delivery schedules (Cour des comptes 2020). Today, the costs are expected to rise to EUR 13.2 billion, up from the original EUR 3.3 billion. [15] The project uses a state-funded model for development of the nuclear power plant using a state-owned utility company (EDF since 2023) as the delivery arm (Baringa 2022).

In 2022, France's EDF reported record annual losses of EUR 17.9 billion, due to nuclear power reactor outages in its French fleet for maintenance and repair work. [16] Also, during those losses, the French government announced a “renaissance” for the nuclear industry, with as many as 14 new reactors under consideration, arguing that it would help to make France carbon neutral by 2050. In 2023, EDF’s bottom line bounced back to an exceptional EUR 10 billion profit, though still with a mounting debt of EUR 54.4 billion. [17]

Meanwhile, it has been decided that the price of the regulated Access to Incumbent Nuclear Electricity (*Accès Régulé à l’Electricité Nucléaire Historique*, ARENH), under which competitors can buy parts of

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[13] https://inews.co.uk/news/business/france-wants-britain-to-pay-its-fair-share-of-nuclear-power-costs-2904841

[14] https://www.edf.fr/en/the-edf-group/dedicated-sections/journalists/all-press-releases/update-on-the-flamanville-epr-0

[15] https://www.edf.fr/en/the-edf-group/dedicated-sections/journalists/all-press-releases/update-on-the-flamanville-epr-0

[16] https://www.world-nuclear-news.org/Articles/EDF-posts-record-loss-in-France-due-to-reactor-out

[17] https://www.lemonde.fr/en/economy/article/2024/02/16/edf-bounces-back-from-historic-losses-with-10-billion-profit-in-2023_6529830_19.html

EDF’s electricity production, will increase from EUR 42 per MWh to EUR 70 per MWh and the new mechanism will cover all EDF’s nuclear production. [18]

There are currently also discussions about using money that the French put into their regulated high-interest “*Livret A*" savings accounts, which until now has been used to finance social housing and municipal urban policy, for the construction of future nuclear reactors, including the EPR2. [19] *Livret A* funds are administered by the state (60%) and private banks (40%). In light of the problems of the defense industry in attracting private financing due to ESG criteria, there has now been discussion concerning allowing the use of these funds in that industry. However, this change has been stopped by the constitutional court. [20]

5.4. HUNGARY

The country operates a nuclear reactor fleet of Soviet VVER-440 pressurised and water-cooled reactors with a total net capacity of 1.9 GW_{el} (IAEA 2023a).

In the 1980s, Hungary commissioned four 440 MW_{el} reactors at the Paks site, with plans for two additional 1,000 MW_{el} units. In 2014, an agreement was signed with Rosatom for two new reactors (the so-called Paks II project) initially to be completed by 2026 but already delayed, with Russia providing 80% of the EUR 12.5 billion financing. Concerns over repayment obligations and state aid arose, but the European Commission closed the case in 2017. [21] Hungary began drawing on the Russian loan in 2017 and awarded turbine contracts to GE in 2018. The Russian state-owned Vnesheconombank (VEB), which had been financing the project, faced financial difficulties, prompting Hungary to explore alternative financing options on the open market. (Thomas 2018) So far, the financing has not changed, even though VEB has faced financial sanctions by the European Union since February 23, 2022, following the Russian attack on Ukraine.

The project owner is the Hungarian state-owned Paks II Ltd. and Rosatom is the main vendor for the reactor construction (Gizińska and Sadecki 2023). It is an example of a hybrid financing model with a state-owned utility as well as government-to-government financing via direct loans from the Russian state to the project.

In 2021, Hungary's Finance Ministry announced that the repayment of the Russian loan for the Paks II project would commence in 2031, five years later than initially agreed upon. This amendment to the intergovernmental agreement allows income generated from the new nuclear power plant to contribute to loan repayment, though pushed to periods with higher agreed interest rates. However, the amendment does not alter the interest rate tiers on the loan or the option for early repayment. [22]

Despite significant changes in the political and security landscape since the agreement's signing in January 2014, Hungary has remained committed to the project, which persists despite the annexation of Crimea by Russia in 2014 and the subsequent invasion of Ukraine in February 2022, which has not

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[18] https://www.world-nuclear-news.org/Articles/Agreement-on-post-ARENH-nuclear-electricity-pricin

[19] https://www.lesechos.fr/industrie-services/energie-environnement/exclusif-le-livret-a-en-lice-pour-financer-les-nouveaux-reacteurs-nucleaires-en-france-1904910; https://www.senat.fr/questions/base/2023/qSEQ23030470S.html

[20] https://www.lesechos.fr/finance-marches/banque-assurances/livret-a-le-conseil-constitutionnel-rejette-le-flechage-vers-la-defense-2043627

[21] http://data.europa.eu/eli/dec/2017/2112/oj

[22] https://world-nuclear-news.org/Articles/Hungary-gets-agreement-to-delay-Paks-II-loan-repay

resulted in international sanctions on the Russian nuclear sector despite appeals from Kyiv. While Hungary maintains its assertion of determination to proceed with the project alongside Rosatom, uncertainties loom over the future of its nuclear collaboration with Russia. Concurrently, Hungary is forging closer cooperation with France on the project. (Gizińska and Sadecki 2023)

5.5. POLAND

There have been ongoing discussions about nuclear energy in Poland since the 1950s, but the country still does not yet operate any NPPs of its own for commercial electricity generation (Gawlikowska-Fyk and Nowak 2014; Pistner et al. 2024).

The government's energy strategy seeks to build NPPs with a capacity of between 6 and 9 GW_{el} under the Polish Nuclear Power Programme (PNP Programme). This translates to current plans to build six reactors at two sites by 2043, with construction starting at the first site by 2026 and putting the first reactor into operation by 2033. The government foresees a strategic partnership with vendors that are yet to be selected to jointly develop, build, and operate NPPs. Under the latest published considerations a Special Purpose Vehicle (SPV) would be created by Polskie Elektrownie Jądrowe (PEJ) to build, operate, and manage an NPP. Whereas the SPV would be 100% state-owned to start with, state companies will start to divest down to a 51% remaining stake along different phases of the project with private investors gradually stepping in, providing certainty for investors, albeit at a premium as divestiture options are released closer to the commercial operation date. It has been decided to use one PWR design for all reactors to lower construction and operation costs. SMR designs were not immediately anticipated in the programme by 2020. (Ministry of Climate 2020; Ministry of Climate and Environment 2021)

The coastal Lubiatowo-Kopalino in North Poland has been selected as a site for the first three NPPs and a contract with Westinghouse together with Bechtel has been signed in 2023 to design three AP1000 reactors with a net capacity of 1.250 MW_{el} each.[23] In addition to the state-driven projects, several partly private-backed initiatives intend to build large-capacity or small-capacity reactors in the country: ZE PAK, Polska Grupa Energetyczna (PGE, majority state-owned), and KHNP (KEPCO) are assessing a possible APR1400 in Patno (central Poland).[24] KGHM Polska Miedź, a Polish minority state-owned mining company, applied for a decision-in-principle on the construction of a NuScale SMR[25], while a subsidiary of the minority state-owned refining and gas station company, Orlen, did so for GE Hitachi Nuclear Energy's BWRX-300 SMR[26].

5.6. CZECH REPUBLIC

The country operates a nuclear reactor fleet of six pressurised and water-cooled reactors (PWR) at two sites, with a total net capacity of 3.9 GW_{el} (IAEA 2023a). The nuclear sites are owned by the majority state-owned České energetické závody (ČEZ). Both reactors at Temelín are former Soviet models with construction halted (and two other reactors completely stopped) and only later completed (Axelrod 2004).

The Czech government initiated a bidding process for new reactor construction at the Dukovany and Temelín nuclear power plants, undergoing significant revisions. Initially, EDF, Korea Hydro & Nuclear

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[23] https://world-nuclear-news.org/Articles/Contract-signed-for-design-of-Polish-nuclear-power

[24] https://world-nuclear-news.org/Articles/Approval-sought-for-second-large-Polish-nuclear-po

[25] https://world-nuclear-news.org/Articles/KGHM-seeks-approval-for-SMR-project

[26] https://world-nuclear-news.org/Articles/OSGE-seeks-approval-for-SMRs-at-six-Polish-locatio

Power, and Westinghouse submitted bids for a single unit at Dukovany, with non-binding offers for additional reactors. However, a government decision prompted the expansion of the tender to include binding offers for units 5 and 6 at Dukovany and units 3 and 4 at Temelín, with the aim of clarifying costs and mitigating price escalation risks. Despite initial invitations for all technology providers to submit binding offers, Westinghouse was excluded due to non-compliance with tender requirements. Nevertheless, the tender process continues, with efforts to engage bidders who submitted binding offers. Additionally, the Czech government addressed concerns over intellectual property rights associated with the APR1400 design, requiring participants to confirm ownership of the technology offered. [27]

ČEZ embarked on a fuel supplier diversification process in 2018, resulting in contracts with Westinghouse and Framatome for the Temelín plant in 2022, and a 2023 contract with Westinghouse for Dukovany. This diversification marks a departure from previous reliance on fuel supplied by Russia's TVEL. In 2022, ČEZ also bolstered fuel reserves at nuclear power plants to enhance energy security, while adopting new fuel types conducive to longer fuel cycles, specifically 16 months at Dukovany and 18 months at Temelín. [28]

5.7. ROMANIA

The country operates a nuclear reactor fleet of two Pressurised Heavy-Water Reactors (PHWRs) with a total net capacity of 1.3 GW_{el} (IAEA 2023a).

Endeavours initiated in 2002 to restart construction of the third reactor in Cernavodă saw the establishment of EnergoNuclear in 2009 to supervise the finalisation of units 3 and 4. Initial collaborators, including GDF Suez, ČEZ, RWE Power, and Iberdrola, withdrew from the venture. Subsequently, the Romanian national nuclear company Nuclearelectrica holds 84.65% ownership in the company. The Romanian government has since been actively seeking new investors to alleviate Nuclearelectrica's share in the project. [29]

In 2013, Nuclearelectrica signed a letter of intent for the development of two units at its Cernavodă nuclear power plant with China General Nuclear (CGN). [30] In 2014, Nuclearelectrica sought a private investor for majority ownership in a joint venture to oversee the expansion of the Cernavodă nuclear plant. They offered 49% of the investment, up to EUR 2 million, to establish an independent electricity producer within two years. The investor needed to ensure compliance with Canadian Candu 6 technology and EU safety standards. Romania planned to add reactors 3 and 4 to address electricity deficits post-2020. [31]

5.8. SLOVAKIA

The country operates a nuclear reactor fleet of five pressurised water reactors (PWR) on two sites, with a total net capacity of 2.31 GW_{el} (IAEA 2023a). In 2023, the Mochovce 3 project entered commercial operation, while another reactor, Mochovce 4, at the Levice site is still under construction. Both reactor sites are owned by the minority state-owned Slovenské elektrárne a.s. (SEAS) and were originally constructed by Rosatom.

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[27] https://www.world-nuclear-news.org/Articles/EDF-and-KHNP-in-running-for-expanded-Czech-nuclear

[28] https://www.world-nuclear-news.org/Articles/CEZ-steps-up-preparations-for-arrival-of-Westingho

[29] https://www.world-nuclear-news.org/Articles/Romania-plans-Cernavoda-JV

[30] https://www.world-nuclear-news.org/Articles/Romania-signals-intent-with-China

[31] https://www.world-nuclear-news.org/Articles/Romania-plans-Cernavoda-JV

In 2020, the Italian electricity company Ente nazionale per l'energia elettrica (Enel), through its subsidiary Enel Produzione and the Czech company Energetický a Průmyslový Holding (EPH), announced additional loans for the completion of Mochovce units 3 and 4. They also revised terms for EPH's eventual buyout of Enel's stake in SEAS. This new agreement modified some terms from the 2015 contract, with Enel contributing a 66% stake in SEAS to Slovak Power Holding BV (HoldCo), later sold to EP Slovakia BV in two stages for EUR 750 million. Construction on Mochovce units 3 and 4 began in 2008, with a revised cost of about EUR 6.2 billion. Enel will provide loans of up to EUR 570 million to HoldCo for Mochovce's completion. The agreement includes an 'early call option' for EPH, with the total consideration subject to adjustments and a floor-to-cap mechanism. EPH will take over the loans if the option is exercised, starting in 2026, with the last tranche expected by 2032. [32] After encountering problems with loan financing in 2012, Enel itself financed finalisation of the construction via a general-purpose bond issued in 2015 in the U.S. – an example of balance sheet financing whereby the Mochovce projects can be “hidden” in the larger scope of Enel’s operations. [33]

5.9. TURKEY

The country is not currently operating any commercial nuclear power plants, though it is constructing its first project together with Rosatom. The Akkuyu project consists of four water-cooled VVER-1200 reactors with a capacity of 4.8 GW_{el} owned by Akkuyu Nuclear JSC, a Rosatom subsidiary.

The Akkuyu plant, located in the southern Mersin province, is Turkey's first nuclear power facility, built under a build-own-operate (BOO) model. As per the agreement, Rosatom established a project company in Turkey known as Akkuyu Nükleer. The company holds responsibilities under a long-term contract for the design, construction, maintenance, operation and decommissioning of the plant. Rosatom maintains a significant 99.2% stake in the project, with an estimated total cost of USD 20 billion. [34] It is therefore a prime example of the vendor-financed BOO model.

Once completed, the plant aims to meet 10% of Turkey's electricity needs, with all units expected to be operational by the end of 2028. Following a statement in late 2023 by Turkey's Energy Minister, Alparslan Bayraktar, the country is now in talks with Russia on a second nuclear plant, and with China for a third one – and has also held out the ambition of adding 5 GW of small modular reactor (SMR) capacity to the country's energy system by 2050. [35]

5.10. UNITED STATES

The country operates a reactor fleet of 92 nuclear power reactors (31 BWRs and 61 PWRs) with a reference capacity of 95 GW_{el}. The country has the largest number of active nuclear power plants in the world, with an average age of around 41.6 years. The oldest recorded reactor to produce electricity was commissioned on October 29, 1957, in Vallecitos, about 30 miles east of San Francisco, and the third youngest reactor was commissioned on June 3, 2016, in Tennessee between Chattanooga and Knoxville. (IAEA 2023a)

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[32] https://world-nuclear-news.org/Articles/Mochovce-new-build-project-receives-loan-boost

[33] https://www.banktrack.org/news/banktrack_welcomes_withdrawal_bank_austria_from_mochovce_nuclear_power_plant; https://www.enel.com/investors/investing/outstanding-public-bonds

[34] https://www.world-nuclear-news.org/Articles/Akkuyu-fully-operational-by-2026,-says-project

[35] https://world-nuclear-news.org/Articles/Turkey-at-important-point-in-China-nuclear-plant-t

Following a peak in new nuclear builds during the 1970s, construction projects dropped to zero in the 1980s (Thomas and Ramana 2022; IAEA 2023b). Following commencement of two construction ventures at the Summer site in 2013, subsequently cancelled in 2017, Georgia recently connected the latest two U.S. reactors to the grid (Vogtle-3 in March 2023 and Vogtle-4 in March 2024), both facing delays and cost overruns (Wealer et al. 2021; Eash-Gates et al. 2020). This project is majority-owned by Georgia Power. It uses reactor technology from Westinghouse and has been financed with the help of U.S. federal loan guarantees. No further projects are currently under construction.

Presently, 85% of operational plants have applied for licence renewals with the Nuclear Regulatory Commission (NRC). Meanwhile, the DOE's Office of Nuclear Energy notes that 13 commercial nuclear power plants in the USA have closed prematurely due to economic factors, with further closures anticipated in the coming years due to economic challenges (Pistner et al. 2024).

5.11. SMALL MODULAR REACTORS

The use of low-power reactors with a modular design is not an innovation. In the past, the first reactors used for commercial power generation had a low capacity. The deliberate design strategy was to start with lower power reactors to gain important knowledge about construction and operation before scaling up to larger capacities (Todreas 2021). The trend then has been to increase capacity to take advantage of economies of scale: the current Westinghouse reactor type AP1000 with a capacity of 1630 GW_{el} is about 280 times larger than the 1954 reactor in Obinsk with 6 GW_{el}. Today, driven by various problems such as increasing construction times and associated budget overruns or low reactor construction rates (MIT 2003; 2018; Ingersoll et al. 2020; Rothwell 2022), parts of the industry are returning to the concept of smaller-capacity reactors, of which several are to be built at one site to reduce the complexity of such a project. According to the International Atomic Energy Agency (IAEA) and the literature, these low-capacity concepts, with a capacity of around 300 MW_{el} or up to 1000 MW_{th}, are usually defined as “Small Modular Reactors” or SMRs (Pistner et al. 2021; IAEA 2021; SMR Regulators Forum 2018; Boarin et al. 2021; Steigerwald et al. 2023). However, modularity in this context is not well-defined. Also, many parts of an NPP – small- or large-capacity – are already currently produced in a modular way.

The main advertising arguments for SMRs are shorter construction times, lower costs, technological simplification, and the possibility of mass production. On the other hand, the literature suggests that the costs of this technology are quite uncertain, if not even more expensive per unit of capacity than current reactors (Mignacca and Locatelli 2020; Steigerwald et al. 2023).

According to the IAEA’s Power Reactor Information System (PRIS), there are currently very few operational low-capacity reactor projects (previously classified as "SMR" in the IAEA's Advanced Reactor Information System (ARIS)), including the KLT-40S (Russia), the EGP-6 (Russia) and the PHWR-2020 (India), with several development projects announced (IAEA 2023b; Steigerwald et al. 2023). None of them is so far being produced at any significant commercial scale, let alone in factory mass production.

The most advanced commercial project in the West to date, NuScale's collaboration with Utah Associated Municipal Power Systems (UAMPS), was cancelled in 2023 as costs continued to rise.[36] The NuScale project is one of the projects funded by the U.S. Department of Energy to achieve an initial prototype (Pistner et al. 2021). U.S. government technology funding is currently supporting further

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[36] https://www.nuscalepower.com/en/news/press-releases/2023/uamps-and-nuscale-power-agree-to-terminate-the-carbon-free-power-project

projects to reduce the risks on the way to product maturity. [37] Other European projects to build the first reactor are currently being pursued in Eastern Europe. These include concepts from GE Hitachi, Rolls Royce, and Westinghouse. [38]

In addition to the projects in Poland mentioned in Section 5.5, specifically, Romania and the U.S. agreed on nuclear cooperation in 2019. In 2023, funding of up to USD 275 million to advance the deployment of a NuScale VOYGR SMR plant in Romania was announced at the G7 leaders' summit and "multinational public-private partners" from Japan, South Korea, and the United Arab Emirates. [39] The involved partners in proposals to finance the project are the Japan Bank for International Cooperation, DS Private Equity (Korea), EXIM Bank Romania, Nuclearelectrica, Nova Power & Gas, Emirates Nuclear Energy Corporation (ENEC), DFC, and US EXIM. It is noted that ENEC's involvement was the first collaborative measure following a memorandum of understanding signed by Nuclearelectrica and ENEC. In 2024, Project Phoenix partners, an initiative launched by the U.S. government at COP28 to facilitate the financing of SMR projects abroad, conducted a field survey in Slovakia for the feasibility study on SMRs, visiting SEAS nuclear power plants and coal-fired plants. [40]

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[37] https://www.energy.gov/ne/advanced-reactor-demonstration-program

[38] https://www.world-nuclear-news.org/Articles/Six-SMR-power-plants-approved-in-Poland; https://www.neimagazine.com/news/newslatvia-and-usa-to-cooperate-on-smrs-9611089

[39] https://www.world-nuclear-news.org/Articles/NuScale-s-Romanian-SMR-plan-gets-USD275-million-bo; https://www.euronews.com/green/2023/09/11/romania-is-the-first-country-in-europe-to-get-this-new-nuclear-energy-technology

[40] https://www.world-nuclear-news.org/Articles/Slovakia-s-SMR-timescales-unveiled-as-Project-Phoe

6. CONCLUSIONS

Nuclear power plant projects with their specific risk profile largely only become bankable with governments de-risking the investment, thereby exposing taxpayers or ratepayers to the project risks.

Nuclear power plant projects carry a very specific risk profile compared to other energy infrastructure investments due to their high upfront capital requirements, long construction times, regular budget and time overruns, and certain revenue risks. From the overview of current and envisioned financing models given in this report, it can be stated that **NPP projects to a large extent only become bankable if a government is involved in de-risking the investment for private investors** – be it via loan guarantees, revenue guarantees, (partial) state ownership of vendors and utility companies, or even regulated vehicles mandating the electricity consumers to finance parts of the project development. This applies not only to large-capacity projects, but also to those small-capacity projects under discussion so far. All these options eventually involve the **exposure of taxpayers or ratepayers to the project risks**. This aspect becomes particularly important against the backdrop of rising interest rates and public budgets under scrutiny, making it harder for governments to support projects in one way or another and turning this into a specific project risk by itself. In addition, some projects are further exposed to geopolitical risks from the involvement of Russian or Chinese state-owned companies and their fuel supply (Szulecki and Overland 2023).

An additional problem is the **economic competitiveness** of NPP projects – large- or small-scale – with the alternative of systems based on renewable energy. Comparing the levelised costs of electricity (LCOEs), nuclear energy reaches around 18 US cents per kilowatt hour, much higher than solar and wind at six and five US cents per kilowatt hour, respectively (Lazard 2023). Since LCOEs cannot be directly compared due to the fluctuating nature of most renewable energy generation compared to the controllable output of nuclear generation, so-called system integration costs (such as reserve capacities, storage, and transmission) need to be taken into account as well. Yet, even doing so, the total LCOEs of renewables only roughly double compared to the numbers mentioned above. In the case of nuclear, hidden costs as detailed above are also to a large extent not included in the LCOE calculations.

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