CLEAN AIR TASK FORCE

Financing Nuclear as a Fleet

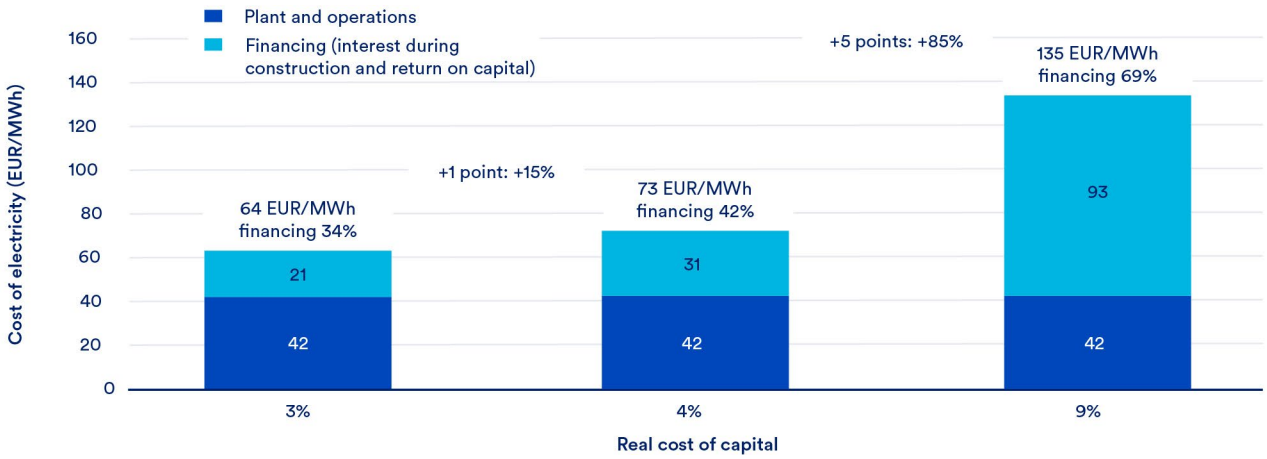
What Changes in the Cost of Capital, and What Policy Can Do About It

As European governments and utilities prepare a new generation of nuclear power plants, they should assess a choice that will shape the cost of electricity consumers pay, whether to finance them one project at a time or as committed fleets. This brief brings together the evidence on how that choice affects the cost of capital, and through it the cost of electricity, and ultimately shows that pursuing Small Modular Reactors (SMRs) as a fleet generates two distinctive benefits in comparison to an uncoordinated deployment approach. First, a fleet approach reduces the overnight costs for each unit through learning by doing and economies of series. Second, it lowers the cost of capital, because the premium lenders and investors charge on a first-of-a-kind (FOAK) unit falls as the evidence builds. A proven design, a committed programme and state support for the remaining construction risk each take part of that premium away.

Figure 1: The cost of capital and the cost of SMR electricity

Each point on the cost of capital adds 12 to 15% to the cost of electricity.

Source: CATF LCOE model on Politecnico di Milano inputs; 400 MWe unit, 60-year life, 90% load factor, real 2026 EUR.



Key Messages

- **Financing SMRs as part of a committed fleet rather than one unit at a time can cut the cost of their electricity by about 40%, from 128 €/MWh to 74 €/MWh.**[1] About 25% of that reduction comes from industrial gains and 75% from a lower weighted average cost of capital (WACC), and the two are linked. A plant that is cheaper and faster to build needs less money for fewer years, so even the industrial gain shows up mostly as lower financing costs.

- **The cost of electricity generated by nuclear reactors is highly sensitive to the cost of capital during construction.** Each percentage-point increase in the cost of capital raises the levelised cost of electricity (LCOE) by roughly 12 to 15%. This means that a 3% real cost of capital translates to an overall cost of financing accounting for about one-third of the project's LCOE. If the cost of capital rises to 9%, the project's cost of financing would account for two-thirds of LCOE.

- **Across the 18 European countries reviewed, only a handful of nuclear plants have started construction in the last two decades, and none of them in a liberalised market on private capital alone.**[2] Each had its revenue risk covered by a long-term contract, its construction risk carried on a state-owned utility's balance sheet, or both, and the ventures that had neither stalled.[3] Governments largely decide how that risk is allocated, and the allocation in turn decides what capital costs and where it comes from. A secured revenue stream alone is not enough, because the construction risk remains uncovered. At Hinkley Point C the sponsors kept that risk even with a long-term revenue contract in place, and no lender was willing to finance a plant whose cost overruns fell entirely on the borrower, and as a result the whole plant had to be financed with equity at about 9%.[4]

- **Deploying SMRs as a fleet makes each unit cheaper to build, and most of that gain reaches the cost of electricity through cheaper financing rather than through the construction saving itself.** Holding financing terms unchanged, the cost of electricity falls from 128 €/MWh to 114 €/MWh when an illustrative FOAK 400 MWe unit is compared with a unit of the same design delivered as part of a sixteen-unit programme, a reduction of about 13 €/MWh.[7] Only about 1 €/MWh of that is the lower construction cost itself. The other 12 €/MWh come from financing, because a plant that is cheaper and faster to build needs less capital for fewer years, so interest during construction and the return on capital fall before any financing term has changed.

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1 All figures in the main text use the optimistic construction cost inputs from Politecnico di Milano's study, 8,100 EUR/kW for a first 400 MWe unit, and a fleet-average cost of 7,600 EUR/kW solved so that the brief's levelised-cost model reproduces PoliMi's result for a 6.4 GWe programme. The model turns each financing case into a levelised cost of electricity over a sixty-year life; its mechanics are set out in Annex B. Footnotes give the same results on PoliMi's conservative inputs, 12,600 and 11,800 EUR/kW, on which the fleet takes the cost of electricity to 119 €/MWh from 202 €/MWh. Differences use unrounded numbers.[7,15]

2 The review covers new-build projects and financing frameworks in 18 European countries from 2005, when construction of Olkiluoto 3 began, to the frameworks announced in 2026. In liberalised markets the plants that reached construction are Olkiluoto 3 (owners' at-cost offtake and a vendor turnkey contract), Flamanville 3 (EDF's state-owned balance sheet), Hinkley Point C (35-year contract, state-owned sponsors) and Sizewell C (regulated asset base). Ostrovets, Akkuyu and Paks II were financed state to state. Mochovce 3 and 4 is the completion of units begun in the 1980s.

3 Belene in Bulgaria (cancelled 2023 after a tender with no guarantees or sales contract found no investor), Temelín 3 and 4 in Czechia (tender cancelled 2014 when the state declined a price guarantee), Bohunice in Slovakia (stalled a decade after a guaranteed price was refused), and Wylfa Newydd and Moorside in the United Kingdom (sponsors withdrew in 2020 and 2018, Hitachi even after being offered state equity, debt and a contract for difference).

4 The 9% is the expected post-tax nominal return on the Hinkley Point C project as a whole over its 60-year life, at the £18 billion cost expected when the deal was struck in 2016, as reported by the UK National Audit Office. With no debt raised, it was the cost of capital of the entire plant, not a premium on top of cheaper borrowing, and the strike price was negotiated to deliver that return on the expected cost; the overruns since then fall on the sponsors and reduce the return they actually earn. The UK government was borrowing at under 3% at the time. The Czech state loan for Dukovany carries the state's own rate plus one point, with a 2% floor, and at Sizewell C, where construction risk moved to consumers, roughly two-thirds of the capital is debt at investment-grade rates and the allowed return on the whole plant was set at 6.7% in real terms.[9,10,11,13,14]

- **A fleet can also reduce the cost of financing each unit in a pipeline.** With the plant held at its fleet-average cost, the real cost of capital falls from 7.5% to 4.1%, reducing LCOE from 114 €/MWh to 74 €/MWh.[5] The lower cost of financing is achieved in three steps:
    1. A proven design, or one that has already been built and licensed, lowers the cost of capital to about 6.45%, reducing LCOE to 101 €/MWh;
    2. A committed programme delivered via coordinated fleets lowers the cost of capital to about 5.25%, reducing LCOE to 86 €/MWh, as completion becomes more predictable, debt capacity increases, lenders gain experience and cash flows can be pooled;
    3. State absorption of the remaining construction overrun risk lowers it to 4.1%, reducing LCOE to 74 €/MWh.

- **Fleet benefits materialise over time through repetition, rather than at the outset of the first unit.** The first unit of a fleet is still a first unit, and every European nuclear project in development requires state support at the outset. While a fleet initially relies on state support, it steadily reduces that need over time as each successfully delivered unit lowers the risks the state must absorb for the next unit to be bankable.

This work identifies six actions to reduce the cost of nuclear energy deployment:

1. Enable an SMR orderbook that secures the industrial gains of repetition, because those gains reach the cost of electricity mainly as lower financing costs;
2. set up a fleet financing facility that minimises interest during construction, or defers it until the plant is operating,[6] and places with the state only the extreme construction risk, that is, overruns beyond a pre-agreed cap that no private investor will price;[7]
3. pair support with 35-to-40-year electricity price contracts;
4. phase state support out unit by unit, moving each successive unit closer to commercial terms as the track record builds;
5. write political-risk protection into the framework, compensating investors if a plant is closed for political reasons or if the law, regulation or tax treatment the plant was built under is later changed against it;
6. and grow a lending market that knows the asset, with policy banks and export credit agencies lending first and governments publishing the terms of the support they grant promptly, so that each deal informs the next.

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5 The same steps reduce LCOE from 181 to 119 €/MWh under conservative cost assumptions.

6 Two European frameworks go further and charge no interest at all during construction. The Czech state loan for Dukovany, approved by the European Commission in 2024, is interest-free until the plant operates and then carries the state's borrowing rate plus one point, with a 2% floor, repaid over 30 years. The Dutch framework announced in October 2025 for the NEO NL plants copies this structure with a 60% state loan carrying no interest during construction, repaid from generation income.[8,14]

7 At Sizewell C, consumers absorb cost overruns up to a first threshold through the regulated charge, investors and consumers share overruns above it, and the government's backstop applies only beyond a higher threshold set roughly a quarter above the base budget, with an option to discontinue the project at that point.[10,11] The Czech and Dutch frameworks reach the same result by having the state own the plant.[8,14]

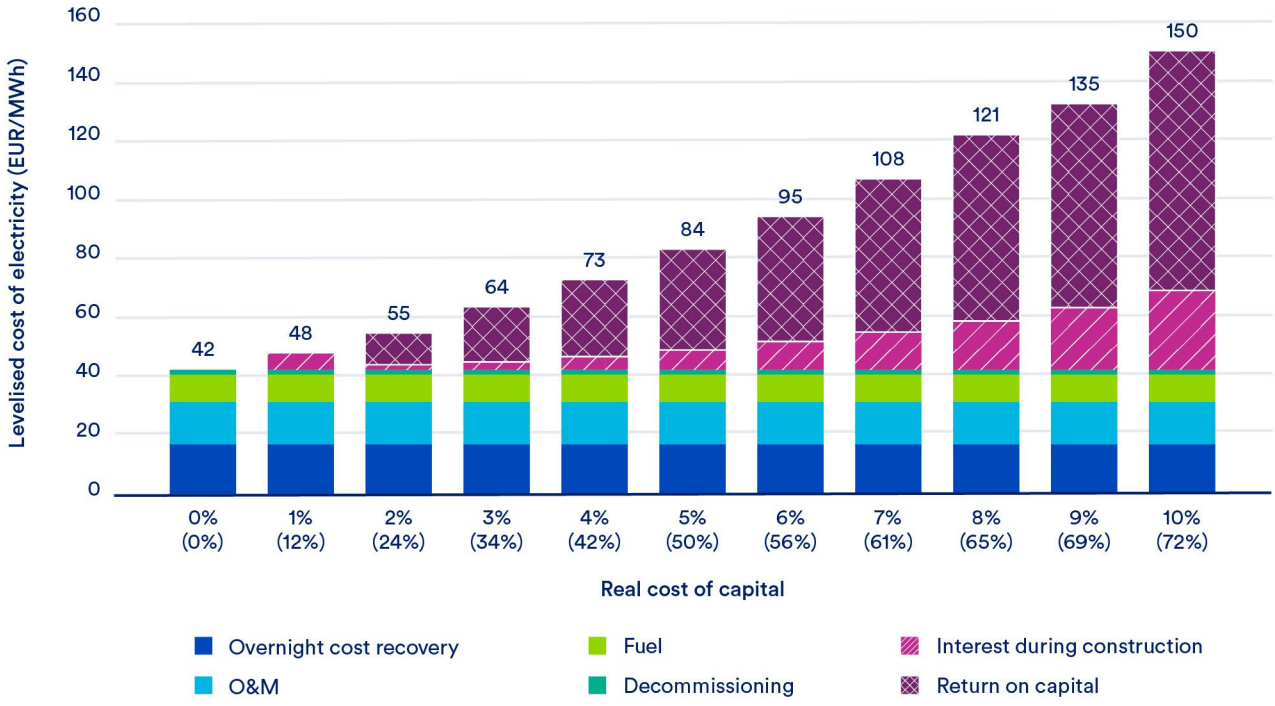
Europe's Nuclear Energy Bill Will Be Decided by the Price of Money

Europe needs more clean, firm power, and has decided nuclear will supply part of it. The European Commission projects EU nuclear capacity rising from 98 GW today to about 109 GW by 2050 and puts the investment needed at 241 billion euros.[16] The pipeline is already forming. Large reactors are under construction, contracted or in preparation in 10 countries, and behind them a broader SMR pipeline is forming, about 40 projects across 16 countries (see Annex A). Taken together, these commitments amount to a fleet. Poland alone illustrates the scale, with three large reactors in preparation, a second large plant in development, and an application for a single support contract covering the first 14 of 26 identical small reactors. Even where governments have begun to design support at programme scale, no fleet in Europe has yet been financed as a single commitment. The closest step so far is France, which in 2025 notified the European Commission of a single support package for all six units of its EPR2 programme, a state loan for 60% of the construction cost and a 40-year price contract; at the time of publication, the Commission's assessment is pending.[8,17]

Figure 2: How the Cost of Capital Builds the Cost of SMR Electricity

Each bar decomposes the levelised cost at one real cost of capital. The two hatched bands are financing, diagonal hatching for interest during construction and cross-hatching for the return on the invested capital, and the percentage in brackets under each bar is the financing share of the total. At 0% the cost falls to the physical floor of about 42 €/MWh. CATF model[15] on Politecnico di Milano inputs.[7] The plant shown is the 7,600 EUR/kW fleet-average unit used throughout this brief.

Source: CATF LCOE model on Politecnico di Milano inputs; 400 MWe unit, 60-year life, 90% load factor, real 2026 EUR.



Standalone plants are expensive, and the larger part of that expense is not the construction itself, but the cost of the capital required to finance a nuclear project. Most of the cost of nuclear electricity is committed before the first kilowatt-hour is sold. To illustrate this point, consider the following hypothetical example:

- A 400 MWe First-Of-A-Kind (FOAK) SMR unit. Assuming a base plant cost of roughly 8,100 EUR/kW (or 12,600 EUR/kW under conservative assumptions), construction spans five to ten years.[7] During those years the plant earns nothing while interest accumulates. At a 7.5% real cost of capital, a seven-year build adds about 24 €/MWh to LCOE, roughly a fifth of the total, and a five-year build about 16 €/MWh.[15] Operations, fuel and eventual decommissioning together come to roughly 26 €/MWh over a sixty-year life, or 44 €/MWh on conservative assumptions.[7,15] If capital were free, electricity from an SMR unit would therefore cost about 43 €/MWh on optimistic assumptions and 71 €/MWh on conservative cost assumptions.[15] Financing accounts for one-third of the cost of nuclear electricity at a 3% real cost of capital and for more than two-thirds at 9%, and every percentage point added to the cost of capital raises the cost of electricity from 12 to 15% (Figure 1).[1,7,15]

A standalone first unit pays all of this at the top of the range, the highest cost of capital, the longest build and the most interest. At the same time these first units are often mistakenly seen by decision makers as test cases rather than what they are, the necessarily high initial investment in a new fleet and wider industry. This raises the question of how a fleet of nuclear reactors delivered through orderbooks can change these cost outlooks.

What the Financing Record Shows: Analysis of Nuclear Financing Landscape

There is no uniform European policy approach to financing nuclear energy. A review of 18 countries found 41 distinct mechanisms in use or in legislation, from state lending and state ownership to regulated cost recovery, and each country has assembled its own combination.[8] Although the mechanisms differ in form, they address a common set of risks that dictate both the cost of capital and who is willing to provide it. Three primary risks dominate. The first is construction risk, the possibility that the plant costs more or takes longer than planned. A framework can move this risk from the investor to the state as owner, to consumers through a regulated charge, or to a vendor that accepts a fixed price. The second is market price risk, which a long-term contract or an offtake commitment removes from the investor. The third is the cost and availability of capital during construction, a risk that is most acute for a FOAK plant. All the capital must be raised before any revenue is earned, for a build that lenders cannot yet assess from experience, so project debt is scarce or expensive and interest accumulates for years. Frameworks address this by having the state, or the vendor's home state, lend or guarantee the funds at close to its own borrowing cost, by paying lenders a return while the plant is still under construction, or by relying on the sponsors' own balance sheets. A smaller number of frameworks also cover three secondary risks: political reversal, fuel supply and the back end of the fuel cycle. Table 1 sets out who carries each of these risks under the frameworks Europe has used.

Table 1: Where Europe's Nuclear Financing Mechanisms Put the Risk

Risk	The State (i.e. taxpayers, through ownership, loans, guarantees or a contract paid from the budget)	Consumers (i.e. through a regulated charge or a levy on electricity bills)	The Vendor (i.e. state-owned exporters, through a fixed-price contract and their home state's credit)	The Project Sponsors (i.e. the owners, either through a commitment to buy the output at cost or by keeping the risk)
The Three Risks Every Framework Must Answer				
Construction cost and delay	The state owns the project and absorbs overruns: Lubiatowo-Kopalino (Poland), Dukovany (Czechia), *EPR2 (France)*, *NEO NL (Netherlands)*; the state pays only for overruns above a cap: Sizewell C (UK)	Consumers pay for overruns through the regulated charge, up to a threshold and shared beyond it: Sizewell C (UK)	The vendor takes the overrun under a fixed-price turnkey contract: Olkiluoto 3 (Finland), Dukovany (Czechia, KHNP); the vendor's state owns and builds the plant: Akkuyu (Turkey); fixed-price contract financed by the vendor's home state: Ostrovets (Belarus), Paks II (Hungary)	Kept by the sponsors: Hinkley Point C (UK), Flamanville 3 (France), and Olkiluoto 3 beyond the turnkey price (Finland)
Market price	The state pays the difference between a fixed price and the market price, from the budget: Dukovany (Czechia), *EPR2 (France)*, *Lubiatowo-Kopalino (Poland)*, *Sweden*	Consumers pay the difference between a fixed price and the market price through a levy on electricity bills: Hinkley Point C (UK); consumers pay a regulated charge whatever the market price: Sizewell C (UK)	–	Owners commit to buy the output at cost: Olkiluoto 3 (Finland), Krško (Slovenia and Croatia); kept by a state-owned operator selling to the market: Paks II (Hungary), Flamanville 3 (France)
Capital cost and availability during construction	The state lends at close to its own borrowing cost: Dukovany (Czechia), *NEO NL (Netherlands)*, *Sweden's 2025 act*, *EPR2 (France)*; the state guarantees the project's debt: Lubiatowo-Kopalino (Poland); the state lends through a policy bank and holds equity: Sizewell C (UK)	Consumers pay a return from the first year of construction, so lenders are serviced before the plant earns: Sizewell C (UK)	The vendor's home state finances the build through export credit: Ostrovets (Belarus), Paks II (Hungary), Akkuyu (Turkey)	Owners' creditworthiness stands behind the company's borrowing: Olkiluoto 3 (Finland); the sponsors fund the whole build from their own balance sheets: Hinkley Point C (UK, all equity at about 9%), Flamanville 3 (France)
Secondary Risks Some Frameworks Cover				
Political reversal	The state compensates investors if a plant is closed for political reasons: *Sweden*; the state protects against changes in law: Dukovany (Czechia), Hinkley Point C and Sizewell C (UK)	–	–	Kept by the sponsors wherever no such clause exists
Fuel supply	–	–	The vendor supplies fuel for the plant's lifetime: Ostrovets (Belarus), Paks II (Hungary), Akkuyu (Turkey)	Kept by the sponsors, who buy fuel under market contracts: all other projects
Used fuel and waste	The state caps what the plant pays for waste disposal: Hinkley Point C (UK)	–	The vendor takes used fuel back to Russia for storage or reprocessing and returns the residues: Ostrovets (Belarus), Paks II (Hungary), Akkuyu (Turkey, as an option)	Kept by the sponsors, who fund provisions for disposal: Olkiluoto 3 (Finland) and most others

Mechanisms are placed by the risk they mainly address; several touch more than one. Projects in italics have a framework agreed or proposed but no closed deal. Ostrovets and Akkuyu lie outside the EU and are included as reference points for vendor-financed models. The table covers new-build frameworks only; life-extension and phase-out arrangements are excluded. Empty cells are combinations for which no European example was found.[8]

Four regularities run through Europe's financing record, and together they show that no plant has reached construction in a liberalised electricity market without either public support or its sponsors' balance sheets behind it.[8] First, no plant has been financed on private capital alone. Every plant that reached construction in a liberalised market, from Olkiluoto 3 and Flamanville 3 to Hinkley Point C, had a long-term contract securing its revenues or a state-owned utility behind it, and the ventures with neither stalled; 35 of the 41 mechanisms identified operate alongside a contract that fixes revenue.[8] Second, private capital prices the risks it keeps. At Hinkley Point C, where the sponsors kept the construction risk, no lender took part and the plant was financed entirely with equity at about 9%, despite a revenue contract.[9,13] Third, where the state lends, it lends within about a point of its own borrowing cost, over long periods, and either charges no interest during construction or defers it until the plant is operating.[9] Fourth, the only model that has succeeded without a government support scheme is the Finnish Mankala arrangement behind Olkiluoto 3, in which the plant's industrial and utility shareholders, private and public, commit in advance to buying its output at cost, so that revenue certainty comes from the owners rather than the state or consumers. As such it required no State aid clearance.[10] Every other framework has had to pass the Commission's State aid review (excluding post-Brexit Sizewell C and Flamanville 3), which can approve, reject or attach conditions.

By taking on the tail risks of construction, the state can bring in private capital that would otherwise not be willing to participate. The United Kingdom demonstrated this by financing the same reactor design twice, with the same sponsor and the same regulator, and the difference between the two deals lies in who carried the construction risk. At Hinkley Point C revenues were already secured by a 35-year contract, but the utility sponsors kept all the risk of construction going wrong and paid for the plant entirely from their balance sheets. At Sizewell C that risk moved off the sponsors, mainly to consumers, who pay a regulated charge from the first year of construction and absorb the first share of any overrun, with the state as a large shareholder and the backstop for extreme cases. With the construction risk reallocated, the source of the capital changed. Two-thirds of the financing came as debt, pension and infrastructure funds joined a European nuclear construction project for the first time, and the utility's own exposure shrank to a minority stake.[9,10,11,12]

Good evidence for what repetition does to financing comes from renewables. Between 2000 and 2017, as Germany's solar and wind fleets grew, the risk margin lenders charged fell by about 11% each time cumulative investment in the technology doubled, and the cost of capital overall fell by more than half.[11] [4] Lenders cut their margins because each round of projects gave them an actual track record of plant performance, power delivery, and cash recovery, and that track record builds fastest when projects are financed in series.[4,5] Nuclear is more complex and carries far greater construction risk than wind or solar, so the German rate cannot be applied directly. But the same pricing logic holds once a design is proven and a programme is committed, which is the starting point for the model in the next section.

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8 Ostrovets and Akkuyu, built outside liberalised markets under state-to-state arrangements, are not part of this count; they appear in Table 1 as reference points for the vendor-financed model.

9 The Czech loan for Dukovany, approved by the Commission in April 2024, is interest-free until the plant operates and then carries the state's borrowing rate plus one point, with a 2% floor, repaid over 30 years; the Dutch framework of October 2025 copies this structure with a 60% state loan carrying no interest during construction; Hungary's loan for Paks II lets interest accrue and defers repayment.[8,14]

10 The Commission examined the French export credit guarantee that covered the vendor's exposure at Olkiluoto 3 and found in September 2007 that it did not constitute State aid.[19]

11 The overall cost of capital for German renewables fell by more than half over the period, but part of that fall came from the general decline in interest rates after 2008 and is not attributable to repetition; only the fall in the risk margin is.[4]

What a Fleet Changes, and by How Much

A fleet changes two things, how much the plant costs and how much the money costs. Repetition makes each unit cheaper and faster to build, so less capital is needed for fewer years, and each delivered unit makes the next one less risky to finance. This section measures both effects on a 400 MWe unit built as part of a 6.4 GWe fleet and compares it with a single uncoordinated unit.[7,15]

The industrial part of the saving across a fleet has been quantified by Politecnico di Milano, whose model[12] isolates the cost impact of repetition while maintaining fixed financing terms. The model for this brief draws its two reference plants from that study, with the first unit built in seven years at 8,100 €/kW and the fleet-average unit built in five years at 7,600 €/kW. The ladder that follows holds those plant specifications constant and varies only how they are financed.[7,15]

Europe has not yet financed a series of standardised reactors under a multi-unit programme, so the financing savings of a fleet have to be estimated from individual projects and the literature. Therefore this study attempted to extrapolate existing evidence into what financing a fleet of nuclear reactors could look like.[2,8,15] The model starts from fifteen determinants of the cost of capital identified in the literature, listed in Table 2.[3,5,6] For each one it asks whether the determinant is present, partial or absent in four situations: a FOAK unit financed on its own, a repeat unit financed on its own, and a unit inside a committed fleet, with state absorption of construction risk as a final layer. Box 1 sets out what a committed fleet means here. Each determinant then acts on one or more of three financing variables, how much of the plant can be funded with debt, the interest charged on that debt, and the return equity investors require. The range given to each variable in each situation comes from the deals and studies referenced in the previous sections.[8,15] The result is a financing case for each situation, and with it the cost of capital that a FOAK unit, a repeat unit and a fleet unit would each face.

Box 1: Committed Fleet

A committed fleet does not require every unit to take its final investment decision at once. Each unit still decides separately. What makes a unit part of a fleet is that it belongs to an orderbook, a series of units of the same design to be built in a planned sequence, whether under one sponsor or spread across separate projects with different sponsors.

Three commitments hold the orderbook together, each made for the series rather than plant by plant. The first is a framework contract with the vendor and its supply chain, firm first units plus options, which lets them invest in capacity and crews. The second is a programme decision or act that fixes the number of units, their sites and their timetable. The third is a revenue and support framework, revenue contracts, standard lending terms and, where they apply, state loans or guarantees, set once for the series rather than negotiated unit by unit. For a national programme this can be one framework and one State aid decision. For smaller units, several sponsors or a fleet that crosses borders it is more likely to be several national frameworks working to common terms, so that a lender sees the same structure from one unit to the next (actions 1, 2 and 9).

[12] Integrated model for the Competitiveness Assessment of Small and medium-sized reactors (INCAS)

Table 2: The Fifteen Determinants of the Cost of Capital

#	Determinant of the Cost of Capital	What it Moves	How the Model Treats it from Case to Case
D1	**Country risk**	Equity return, interest	Held constant across all cases; set by the country, not by the fleet
D2	**Interest rates and capital availability**	Interest, the risk-free base	Held constant across all cases; set by macro conditions, not by the fleet
D3	**Revenue certainty**	Debt share, equity return	Supplied by the framework's long-term contract
D4	**Revenue duration and loan lengths**	Debt share, interest	Strengthens under a programme framework
D5	**On-time, on-budget completion certainty**	Equity return, debt share	Partial at the first repeat unit; full inside a fleet; transferred by the state
D6	**Policy credibility and durability**	Equity return	Strengthens with a legislated programme
D7	**State lending and guarantees**	Interest, debt share	Enters only at the state-transfer step (case 5)
D8	**Lender and investor experience**	Interest (the premium)	Improves as units are financed; the German 11% rate applies here (case 4)
D9	**Standardised, repeated deal structures**	Interest (the premium)	Improves with the fleet (case 4)
D10	**Breadth of investors competing**	Equity return, interest	Widens as the track record builds
D11	**Technology maturity**	Equity return	Switches on at the first repeat unit (case 3) and stays on
D12	**Size of each unit's capital requirement**	Equity return, debt share	Held constant. A fleet makes each reactor cheaper, but each is still a single asset costing billions
D13	**Pooling across units**	Equity return, debt share	Operating units support the financing of later ones
D14	**Sponsor's balance-sheet strength**	Debt share, equity return	Relieved by a programme vehicle or state equity
D15	**Interest during construction**	Effective interest while building	Reduced or removed by state instruments (case 5)

Adapted from the cost-of-capital literature[3] with nuclear energy-specific evidence for D5, D12, D14 and D15.[1,2,14]

Figure 3 traces the journey from a standalone FOAK unit to a state-backed fleet unit, one change at a time.

1. **Bar 1 is a FOAK unit** financed on first-unit terms at a 7.5% real cost of capital, the blended rate across debt and equity, resulting in an LCOE of 128 €/MWh.
2. **Bar 2 is a purely industrial step.** The financing terms are exactly those of bar 1, the same debt share, interest rate and equity return, but the plant is now the fleet-average unit, cheaper and faster to build because of learning, shared sites and a shorter schedule. The cost of electricity falls to 114 €/MWh. Even though no financing term has moved, most of the 13 €/MWh saving arrives through financing: the lower construction cost itself is worth only about 1 €/MWh, while the other 12 €/MWh is a smaller financing charge, because 6% less capital is raised for five years instead of seven.[15]
3. **Bar 3 is the first financing step.** The plant is the same fleet-average unit as in bar 2 and it stays that way through bars 4 and 5. Only the price of the money changes from here on. Financed now as a proven design, one already built and licensed, lenders and investors stop pricing in the technology risk of a first-of-a-kind plant (D11 in Table 2). The cost of capital falls to 6.45% and the cost of electricity to 101 €/MWh.
4. **Bar 4 is the second financing step.** The plant and the proven design are unchanged, but the unit is now financed as part of a committed fleet rather than as a standalone repeat. Lenders have a track record from the earlier units on cost, schedule and output, deal structures repeat instead of being negotiated afresh, and where units share a sponsor the ones already running stand behind the financing of the later ones (D4, D5, D8, D9, D13). As a result, lenders charge a lower margin and fund a larger share of each unit with debt. The size of the margin effect is taken from the evidence on German wind and solar, where lenders' risk margins fell by about 11% each time cumulative deployment doubled, and it is applied only from this point, once a design is proven and a programme committed.[4] The cost of capital falls to 5.25% and the cost of electricity to 86 €/MWh.
5. **Bar 5 is the third financing step.** The state absorbs the remaining construction risk and lends or guarantees at an interest rate within about a point of its own borrowing cost. The cost of capital falls to 4.1% and the cost of electricity to 74 €/MWh.[7,8,14,15]

Figure 3: The Nuclear Financing Ladder

Modelled cost of electricity from the same 400 MWe unit at five points between unit-by-unit and fleet financing, split into operations, the plant's overnight cost, the cost of debt and the cost of equity; central cases on PoliMi optimistic inputs.[7,15] Only bar 1 uses the first-of-a-kind plant (8,100 EUR/kW, seven-year build); bars 2 to 5 use the fleet-average plant (7,600 EUR/kW, five-year build) and differ only in financing. The financing charge is split between debt and equity in proportion to their weight in the cost of capital. Bars 4 and 5 are illustrative financing cases, constructed from evidence rather than observed deals.

Source: CATF LCOE model on Politecnico di Milano inputs; 400 MWe unit, 60-year life, 90% load factor, real 2026 EUR.

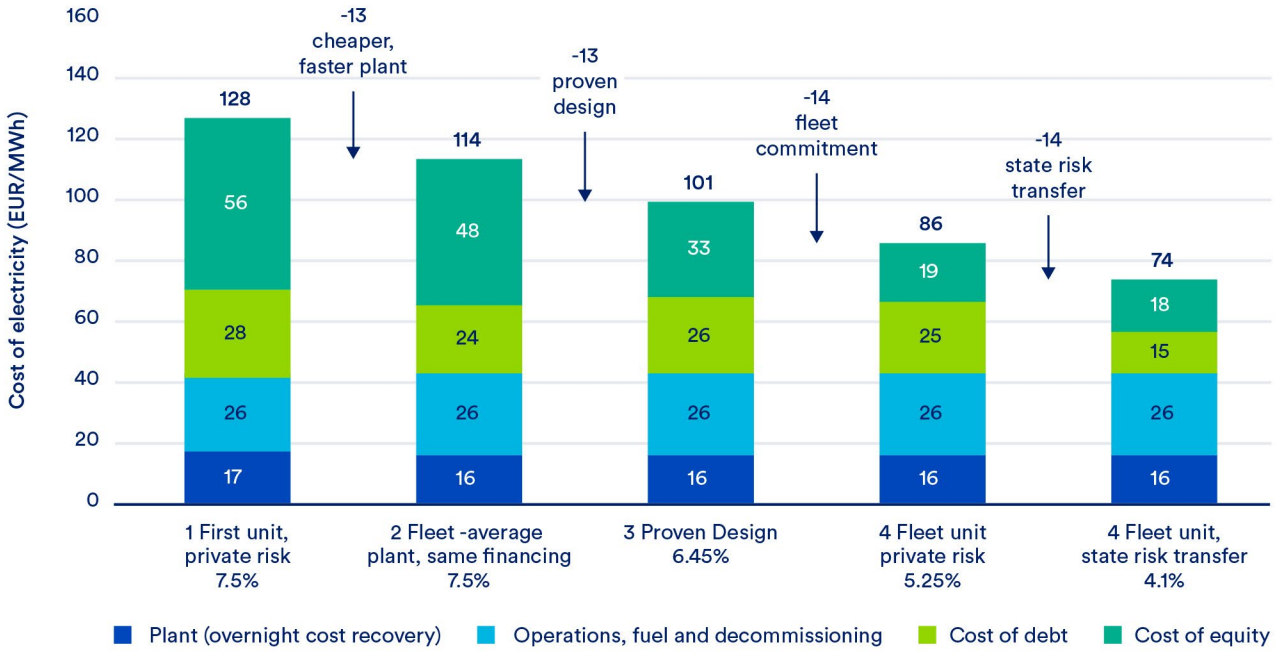


Table 3 gives each case's full ranges and its real-world anchors. The ladder is a stylised European case, with country risk and the general level of interest rates held constant (Table 2, D1 and D2), and it would look different country by country. A country that borrows more expensively starts higher on every bar and gains less from the state intervention, since the state's own borrowing cost sets the floor, but stands to gain more from the fleet steps, since there is a larger risk premium for experience to compress.

Table 3: The Four Financing Cases

Financing Case	Borrowed Share	Interest on Debt	Return on Equity	Cost of Capital	LCOE Optimistic	LCOE Conservative	Real-world Anchor
First-of-a-kind (FOAK) unit financed on its own, private risk	40–75%	5–6%	10–12%	**6.25–9.6%**	**128** (108-165)	**202** (172-260)	Hinkley Point C;[9,13] Czech nuclear premium[14]
Repeat unit financed on its own, private risk	50–70%	4.5–5.5%	8.5–10%	**5.7–7.8%**	**101** (92-118)	**160** (146-186)	Sizewell C, which lands at 104 and 165[10,11]
Fleet unit construction risk still private **ILLUSTRATIVE FINANCING CASE**	70–75%	3.5–4.5%	8–10%	**4.6–6.2%**	**86** (80-97)	**138** (127-154)	None; no such fleet in the record
Fleet unit with state risk transfer **ILLUSTRATIVE FINANCING CASE**	75–80%	2–3%	6–11%	**2.8–5.0%**	**74** (62-84)	**119** (100-134)	Dukovany;[14] Netherlands, Sweden, Poland[8]

Central values with the low to high financing range in brackets; all rates real and LCOE in €/MWh. In the first three cases the debt is commercial, export-credit and policy-bank lending on private risk and the equity is private; in the fourth the debt is lent or guaranteed by the state, and the equity range is wide because the state-transfer cases differ, from state-owned equity priced close to the state's own return to the returns granted to private investors where the state carries the construction risk. The cost of capital is the blend of the two, weighted by the borrowed share. Optimistic OCC 8,100 EUR/kW for the first unit, built in seven years, and 7,600 fleet-average thereafter, built in five; conservative OCC 12,600 and 11,800.[7] Sizewell C is shown as an anchor rather than a modelled case: its actual financing terms applied to the fleet-average plant give 104 and 165 €/MWh.[10,11] The two fleet cases are constructed from the evidence gathered for this brief rather than observed deals.[15] A first-of-a-kind unit on the state-transfer terms of the last row is discussed in the box below.

Box 2: What State Risk Transfer Buys on its Own

State support alone gets most of the way to the fleet result. A reader may ask what the state's support achieves without the fleet. The model was run for a single first-of-a-kind unit on the terms of bar 5 in Figure 2, with the state lending or guaranteeing three-quarters of the capital at close to its own borrowing cost. The unit generates at about 80 €/MWh, against 128 €/MWh for the same unit on private terms and 74 €/MWh for the fleet unit (128, 202 and 119 €/MWh on the conservative inputs). For a single plant, state support therefore delivers nearly nine-tenths of the total reduction. Most of the remaining gap is the cheaper, faster-to-build fleet-average plant, not finance. The record agrees, since the support approved for Dukovany in Czechia and Poland's first plant is of this kind.

But state support changes who carries the risk, while repetition reduces the risk itself. For the single plant, the rate is lower because the state has absorbed a risk that is no smaller than before. The model puts no value on that exposure, which stays with the state until the plant is built and the loan repaid. Repetition, by contrast, lowers the risk with or without a programme. Bar 3 takes the same plant as bar 2 and finances it as a proven design, on private terms and with no fleet behind it. Its cost of capital falls from 7.5% to 6.45%, and its cost of electricity from 114 to 101 €/MWh (181 to 160 €/MWh on the conservative inputs).

What a committed fleet adds is pace, predictability and a planned exit for the state. Outside a programme, the next unit may follow years later, with new teams, new suppliers and terms negotiated from scratch, and lenders can credit its record only once it exists. In a committed fleet, teams and supply chains carry over, and lenders price part of the coming reduction in advance, as bar 4 shows at 5.25% and 86 €/MWh. The state's support can then taper against the programme's schedule from the start. Measured in €/MWh, the fleet adds little to state support alone. Without it, however, the lower cost of capital takes longer to arrive, the state carries the risk for longer, and the whole effort ends up costlier for the state.[15]

The result carries three lessons:

- **First, most of the saving comes from the cost of capital, not the actual plant.**[13] Of the 53 €/MWh total reduction (83 €/MWh on conservative costs), about 25% comes from industrial gains and 75% from cheaper financing, and even the industrial part arrives mostly as lower financing costs. To capture the full reduction, a government therefore must help the market reach all three conditions: a proven design, a fleet programme and a state financing facility that covers the fleet.
- **Second, depending on how it is financed, the cost of electricity from a FOAK unit can land anywhere between 108 €/MWh and 165 €/MWh, a wider range than the entire distance from a repeat unit to a state-supported fleet unit.**[14] For a government preparing a first unit, the financing terms are therefore the decision with the greatest effect on the cost of electricity and developing the right financing model does more than any improvement to the plant's design or construction.
- **Third, the fleet cases should be read with caution.** No European series has yet been financed under a multi-unit programme, so their numbers are estimates built from the evidence reviewed for this brief, not observations of an actual deal. They are labelled illustrative in Table 3, and each is built from financing terms Europe has already granted or evaluated, even though no programme has yet combined them.[7,15]

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13 'Plant' here means the overnight construction cost, that is, everything it costs to build the unit if it could be built instantly and paid for without interest, covering engineering and design, equipment and materials, civil works and labour, owner's costs and contingency, as defined in Politecnico di Milano's cost inputs.[7] In the model that cost is recovered evenly over the plant's sixty-year life, which is the 'building the plant' band in Figure 2. Operating costs, O&M, fuel and decommissioning, are counted separately and are the same in every case. Everything else in the cost of electricity is financing, interest during construction and the return on the invested capital.[15]

14 Both figures are for the same 400 MWe first-of-a-kind unit, with an overnight cost of 8,100 EUR/kW and a seven-year build, on Politecnico di Milano's optimistic cost inputs. Only the financing terms differ. At the low end the unit is financed with 75% debt at 5% and equity at 10%, a real cost of capital of 6.25%, and generates at 108 €/MWh. At the high end it is financed with 40% debt at 6% and equity at 12%, a real cost of capital of 9.6%, and generates at 165 €/MWh. The range is wide because that is how widely the terms of first units have varied in practice. With no repetition behind it, a first unit carries the full construction and technology risk, and how much of that risk lenders and investors are asked to price decides whether it lands near the Sizewell C end of the range or the all-equity Hinkley Point C end. On conservative cost inputs the same range is 172 to 260 €/MWh.[7,15]

What This Means for Policy

Most of what a fleet saves comes through the cost of capital. Lenders and investors charge for the risk that a plant is not finished on time and on budget, and that risk falls each time the same design is built again. The state can secure a low cost of capital for a single plant by carrying its risk, but that does not make the risk any smaller. Without a fleet, repeat units still bring the risk down, but slowly and unevenly, as each plant's support has to be negotiated again from scratch. A committed fleet changes this. Because teams and supply chains can more easily carry over from one unit to the next, the risk falls faster and more predictably, and lenders can price that fall in advance. That lets the state carry the risk for the first units and then step back on a known schedule. Nine actions follow from this, six for national governments and three for the European Union.

For National Governments

1. **Enable an orderbook, not a demonstration.** Both the industrial saving and the financing saving depend on repetition, so the first task is to make repetition credible. Repetition pays twice: each unit costs less to build, and because less capital is committed for fewer years, the cost of financing falls before any lender changes a term. Whether the project owner is a state-owned utility, as in most of Europe, or a private developer, it will only commit to a series if the framework makes that commitment bankable. That means a common design and licensing basis, a stated pipeline of units and sites, and a revenue contract that covers the series rather than the first plant. The Politecnico di Milano modelling puts the threshold at which most of the industrial saving is realised at 5 to 8 GWe.[7]
2. **Finance the fleet through one facility, not each plant through its own deal.** The fleet cases in Figure 2 assume lenders can see and price the whole series, which requires the state's support to be set up once, at programme scale, rather than negotiated plant by plant. A fleet financing facility would fix in advance the terms on which each unit can draw state loans or guarantees, minimise interest during construction or defer it until the plant is operating, and have the state bear the remote tail risks of construction, with the whole programme notified and cleared in one State aid decision.[15] Most of this would not be new. Several of the instruments are already used in Europe's national frameworks, and the first programme-scale filings are now being tested, with France's six-unit notification under Commission review and Poland's SMR developer having asked its government for one revenue contract across 14 units.[8,17] No approved framework, however, yet fixes those terms in advance for a series of units, which is what a fleet facility would do.[16]
3. **Pair support with long-term revenue contracts.** The most recent European frameworks point that way, Hinkley Point C's contract runs 35 years, and the frameworks in Czechia, France and Poland provide for contracts of around 40 years.[8]
4. **Reduce support plant by plant and say so in advance.** The first plant needs the full financing package, but later plants should receive progressively less as completion certainty, borrowing capacity and lender experience are built up.[2,4] This can be done by tying the step-down to delivery, so that the state's share of the debt and the scope of its guarantee fall once the previous plant is completed on time and on budget. The same principle applies once a plant is operating, when a completed unit refinances at a lower rate, part of the gain should return to consumers, a rule the UK already applies at Hinkley Point C.[13]

[15] Nuclear aid is not covered by the block exemption or the energy aid guidelines, so the Commission assesses it case by case under Article 107(3)(c) TFEU, as it did for Paks II and Dukovany, and earlier for Hinkley Point C while the UK was a member state.

[16] In practice this would be a framework act rather than a project agreement. Sweden's 2025 act is the closest existing form, since it sets the terms on which any qualifying project can draw state loans, while the Czech and Dutch frameworks set similar terms for one project each. A fleet facility would set the loan rate, the guarantee terms and the risk-sharing rules for every unit in the programme before the first one is contracted, and would be notified to the Commission as one package.

5. **Make political-risk protection explicit.** Nuclear policy stability is one of the foundations that enables the fleet, which by definition is a multi-decade undertaking. Private investors need guarantees from governments to ensure these long-term investments will have an opportunity for a payoff. Europe already has working examples of such political-risk protection. The Swedish government has set up a framework that compensates investors if a plant is closed for political reasons, and the Czech and UK frameworks protect against changes in law.[8,14]
6. **Grow a nuclear-experienced lending market and keep publishing the terms of public support, consistently and promptly.** The fleet case assumes lenders who know the asset, and that pool can be built deliberately as policy banks and export credit agencies lend early and often and as standardised contracts let each deal inform the next.[4,6] What the state provides should be fully public. State aid decisions already set out how each framework works, and this brief is built on that record, but two gaps need to be closed. The first is the numbers, as for example, the Czech decision redacts the approved return and the Polish decision does not state the strike price. The second is timing, since a published decision can come out a year or more after the terms were agreed.[17] When a government grants support, it should publish the rate on the loan, the fee on the guarantee, the strike price or allowed return, and the point at which risk passes to the state, in a form that can be compared across countries. Otherwise, each government sets its support by guesswork, and nobody can tell whether financing costs are falling as the fleet builds.[5,13,14]

For the European Union

7. **Open a State aid pathway that clears a fleet facility in one decision rather than plant by plant.** The basis for it exists, since nuclear aid is assessed case by case under Article 107(3)(c) and France has notified six units in one filing. Whether the Commission will accept support set in advance for units that will get cheaper is the question its review of the French package will begin to answer.[18]
8. **Bring the European Investment Bank (EIB) in as a lender to fleet programmes, so that the facility has a large public lender in it from the start.** The EIB has begun lending to nuclear again. In July 2026 its board approved an €800 million loan for the refurbishment of Cernavodă 1 in Romania, and in September 2026 it made its first investment in small modular reactor technology, up to €40 million for Finland's Steady Energy, backed by the Commission's InvestEU programme.[18,20] This brief has not examined whether new-build lending fits its current policy or would need a new instrument, and that is a question for the Bank and the member states.
9. **Support cross-border orderbooks.** This is about demand rather than financing. The 5 to 8 GWe threshold for the industrial saving is more than most member states will order alone, so several countries committing to the same design, on a common licensing basis and a shared pipeline, is the only route to repetition for many of them.[7] Each country can still finance the units on its own territory through its own facility; it is the delivery record those shared units build, wherever they are built, that lets lenders in each country price later units as part of a fleet. Joint financing is only needed where two governments pay for one plant, as Slovenia and Croatia have at Krško, and how the Commission would clear support granted by two member states is still an open question.[19]

[17] In the Czech Dukovany decision (State aid SA.58207, Commission Decision (EU) 2025/429), the Commission approved the package on 30 April 2024, but the public text was not published in the Official Journal until 12 March 2025, with the target return on equity and WACC inputs redacted. Similarly, in Poland's Lubiatowo-Kopalino package (State aid SA.109707, approved 9 December 2025 following the opening decision in OJ C/2025/1389), the public text sets out the discounted cash flow methodology and sensitivity bands in Polish zloty but does not publish a settled strike price.

[18] See the note on the State aid procedure under action 2 above.

[19] See the note on the State aid procedure under action 2 above.

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Annex A: The European SMR Project Pipeline

The 40 small modular reactor projects in 16 European countries referred to in the text, as recorded in the CATF European SMR Project Tracker at September 2026.[8] A project is counted where a named developer or customer has announced a site, a feasibility study, a licensing step or an investment decision; vendor memoranda without a named customer are excluded. Stage is the most advanced public step reached. Most of the pipeline is at an early stage; one project has taken a final investment decision.

Country	Site	Developer or Vendor	Partner or Customer	Reactor	Stage	Target
United Kingdom	3 candidate sites	Holtec	Balfour Beatty	SMR-160	Siting, licensing or feasibility	not set
	Cottam	Holtec	EDF	SMR-300	Siting, licensing or feasibility	not set
	Hartlepool	X-energy	Centrica	Xe-100	Siting, licensing or feasibility	not set
	Wylfa, up to 3 units	Rolls-Royce SMR	Great British Energy - Nuclear	Rolls-Royce SMR	Siting, licensing or feasibility	FID 2029, mid-2030s
		GE Vernova Hitachi	Madhvani International (MISA)	BWRX-300	Early stage (MoU or study)	not set
	Llynfi, Wales	Last Energy		PWR-20	Early stage (MoU or study)	not set
Sweden	Oskarshamn	Blykalla	Uniper, OKG	SEALER-55	Siting, licensing or feasibility	2030
	Ringhals, 3 units	Rolls-Royce SMR	Vattenfall (Videberg Kraft), Industrikraft	Rolls-Royce SMR	Siting, licensing or feasibility	2030s
	Stavröd, Skåne	Blykalla	Hörby Municipality	SEALER-55	Siting, licensing or feasibility	not set
	Studsvik/Nyköping	not selected	Kärnfull Next	not selected	Siting, licensing or feasibility	not set
	Valdemarsvik	not selected	Kärnfull Next	not selected	Siting, licensing or feasibility	not set
		KHNP	Kärnfull Next	i-SMR	Early stage (MoU or study)	not set

Country	Site	Developer or Vendor	Partner or Customer	Reactor	Stage	Target
Norway	Aure & Heim	not selected	Norsk Kjernekraft	not selected	Siting, licensing or feasibility	not set
	Halden	not selected	Halden Kjernekraft AS	not selected	Siting, licensing or feasibility	not set
	Svalbard/Arctic	Blykalla	Norsk Kjernekraft	SEALER-55	Siting, licensing or feasibility	not set
		KHNP	Norsk Kjernekraft	i-SMR	Early stage (MoU or study)	not set
	Lyngdal/Farsund	not selected	Norsk Kjernekraft, TVO	not selected	Early stage (MoU or study)	not set
	Ship-propulsion study	not selected	VARD, Research Council of Norway	not selected	Early stage (MoU or study)	not set
Poland	6 approved locations	GE Vernova Hitachi	Orlen Synthos Green Energy	BWRX-300	Siting, licensing or feasibility	not set
		NuScale Power	KGHM Polska Miedź S.A.	NuScale Power Module	Early stage (MoU or study)	not set
		GE Vernova Hitachi	Samsung C&T, Synthos Green Energy	BWRX-300	Early stage (MoU or study)	not set
France	Cadarache	Calogena	CEA	CAL30	Siting, licensing or feasibility	not set
		EDF		Nuward	Early stage (MoU or study)	not set
	Cadarache	Stellaria	CEA	Alvin / MegAlvin / Stellarium	Early stage (MoU or study)	not set
Finland	Helsinki	Steady Energy	Helen	LDR-50	Early stage (MoU or study)	not set
	Kuopio	Steady Energy	Kuopion Energia	LDR-50	Early stage (MoU or study)	not set
Czechia	Dětmarovice, Tušimice, Temelín	Rolls-Royce SMR	ČEZ Group	Rolls-Royce SMR	Siting, licensing or feasibility	not set
		Rolls-Royce SMR	ÚJV Řež	Rolls-Royce SMR	Early stage (MoU or study)	not set
Hungary		Holtec	MVM	SMR-300	Early stage (MoU or study)	not set
		GE Vernova Hitachi	Hunatom, Synthos Green Energy	BWRX-300	Early stage (MoU or study)	not set
Bulgaria		NuScale Power	Kozloduy NPP – New Build Plc	NuScale Power Module	Early stage (MoU or study)	not set
		GE Vernova Hitachi	Blue Bird Energy, Synthos Green Energy	BWRX-300	Early stage (MoU or study)	not set

Country	Site	Developer or Vendor	Partner or Customer	Reactor	Stage	Target
Italy		Terra Innovatum	Uvation	SOLO Micro-Modular Reactor	Early stage (MoU or study)	not set
		EDF	Maire SpA, NextChem	Nuward	Early stage (MoU or study)	not set
Estonia		GE Vernova Hitachi	Fermi Energia	BWRX-300	Early stage (MoU or study)	not set
Lithuania	Decision by 2028	GE Vernova Hitachi	Synthos Green Energy, Altra	BWRX-300	Early stage (MoU or study)	not set
Netherlands		Hexana	Atoomcoöperatie	not selected	Early stage (MoU or study)	not set
Slovakia		GE Vernova Hitachi	Slovenské elektrárne, Synthos Green Energy	BWRX-300	Early stage (MoU or study)	not set
Romania	Doicești	NuScale Power	RoPower Nuclear S.A.	NuScale Power Module	Final investment decision	2033
Ukraine		Holtec	Energoatom	SMR-160	Early stage (MoU or study)	not set

Source: CATF European SMR Project Tracker (September 2026), compiled from company announcements, government decisions and press reports; the two Rolls-Royce SMR programmes at Wylfa and Ringhals are added from public announcements. Stage: 'Early stage' is a memorandum of understanding or study with no site named; 'Siting, licensing or feasibility' is a named site with a public siting, licensing or feasibility step; 'Final investment decision' is a committed project. Targets are the developers' stated dates.

Annex B: How the Cost of Electricity is Calculated

Every cost of electricity in this brief comes from a levelised-cost model built for the brief. This annex explains what the model does, the inputs it uses, how the financing cases were built and how its results were checked.

What the Model Does

The model takes a plant and a financing case and turns them into a levelised cost of electricity in real 2026 euros. The plant is described by its overnight construction cost, its construction period, its operating costs, its load factor and its life. The financing case is described by the share of the plant funded with debt, the real interest rate on that debt and the real return required on equity. All quantities are real and there is no tax, as in the Politecnico di Milano study the plant inputs come from.[7]

The cost of capital is the weighted average of the two sources of money. The debt share times the cost of debt, plus the equity share times the cost of equity, gives the rate at which the whole investment has to be paid for. In the central fleet case, 75% debt at 2.5% and 25% equity at 9% give 4.1%.

Interest accumulates during construction because money is spent for years before the plant earns anything. The model assumes the spend is spread evenly over the build period and compounds each year's spend from mid-year to the start of operation. At a 7.5% cost of capital this adds 30% to the overnight cost of a seven-year build and 20% to that of a five-year build, which is why the first unit's financing charge is so large.

The levelised cost is then the total investment, overnight cost plus the interest accumulated during construction, spread over sixty years of output at the cost of capital, using the standard capital recovery factor, and divided by the electricity generated each year, 7.88 MWh per kW at a 90% load factor. O&M, fuel and decommissioning are added on top.

To show where the money goes, the capital charge is split into three parts following the OECD Nuclear Energy Agency's presentation.[1] The first is recovery of the overnight cost itself, which does not depend on the cost of capital. The second is the interest accumulated during construction, recovered over the life. The third is the return on the capital invested. The last two together are the financing charge shown in the figures, and in Figure 2 it is further split between debt and equity in proportion to their weight in the cost of capital.

Inputs

Input	Optimistic	Conservative	Source
Overnight cost, first 400 MWe unit	8,100 EUR/kW	12,600 EUR/kW	Politecnico di Milano INCAS input set, as confirmed by PoliMi on 16 September 2026[7]
Overnight cost, fleet-average unit	7,600 EUR/kW	11,800 EUR/kW	Solved so that the model reproduces INCAS's 6.4 GWe programme result of 98.2 EUR/MWh at PoliMi's base financing; the conservative value is scaled by the same ratio[15]
Construction period	7 years first unit, 5 years fleet-average	same	PoliMi gives 7 years for a first unit, 6 for the second and 4.5 for later units; 5 is the programme average[7]
O&M, fuel, decommissioning	15, 9, 2 EUR/MWh	30, 12, 2 EUR/MWh	PoliMi[7]
Load factor, life	90%, 60 years	same	PoliMi[7]

The Financing Cases

No European fleet has been financed as a series, so the fleet cases cannot be read from a deal. They were built in three steps. First, each of the fifteen determinants of the cost of capital in Table 2 was assessed as present, partial or absent in four situations, a first unit financed on its own, a repeat unit financed on its own, a unit inside a committed fleet, and that unit with the state carrying the construction risk.[3,5,6] Second, each determinant was mapped to the financing variable it moves, the debt share, the interest rate or the equity return. Third, the size of each move was taken from the record. Hinkley Point C and the Czech nuclear premium set the first-unit terms, Sizewell C shows what a de-risked plant obtains, the German lending data show what experience does to margins, and the Czech, Dutch, Swedish and Polish state loans and guarantees set the state-transfer terms.[4,8,9,10,11,13,14] Each case has a low, central and high set of terms. The central values are used in the text and figures and the range is given in Table 3. The workbook lists every set with its anchor.

Case	Debt Share	Cost of Debt	Cost of Equity	Cost of Capital	LCOE Optimistic	LCOE Conservative
1 – First unit, private risk	50% (40 to 75)	5% (5 to 6)	10% (10 to 12)	7.5% (6.25 to 9.6)	128 (108 to 165)	202 (172 to 260)
2 – Fleet-average plant, same financing	50%	5%	10%	7.5%	114 (98 to 144)	181 (156 to 227)
3 – Repeat unit, proven design	60% (50 to 70)	4.75% (4.5 to 5.5)	9% (8.5 to 10)	6.45% (5.7 to 7.8)	101 (92 to 118)	160 (146 to 186)
4 – Fleet unit, private risk	75% (70 to 75)	4% (3.5 to 4.5)	9% (8 to 10)	5.25% (4.6 to 6.2)	86 (80 to 97)	138 (127 to 154)
5 – Fleet unit, state risk transfer	75% (75 to 80)	2.5% (2 to 3)	9% (6 to 11)	4.1% (2.8 to 5.0)	74 (62 to 84)	119 (100 to 134)
Comparator, first unit with state risk transfer	As case 5	As case 5	As case 5	4.1%	80 (65 to 91)	128 (105 to 145)
Anchor, Sizewell C terms on the fleet plant	65%	4.5%	10.8%	6.7%	104	165

All rates real. Cases 1 and 2 share the same financing, so the step between them is purely industrial. Cases 2 to 5 share the same plant, so each later step is purely financial. The comparator applies the case 5 terms to the first-unit plant and is discussed in the box after Table 3. The Sizewell C row applies that project's gearing cap, implied cost of debt and allowed return on equity to the fleet-average plant, as an observation rather than a modelled case.[10,11]

Checks

The model was checked in two ways. The first is against a published reference. On the Nuclear Energy Agency's standard inputs, a 4,500 USD/kW plant built in seven years, run at 85% for sixty years and financed at 9% real, the Agency reports that financing makes up 67% of the cost of electricity; the model gives 68%.[1] The second is against the Politecnico di Milano results the brief builds on. At PoliMi's own base financing, 75% debt at 5% and equity at 10%, the model gives 108 EUR/MWh for the first unit, against 113 in INCAS, so it runs about 4% low at the first-unit end. For the fleet unit it gives 98, the same as INCAS, because the fleet-average overnight cost was solved to reproduce that result.[7,15] The ladder in the brief starts at 7.5% rather than at PoliMi's 6.25% because no first unit financed on its own with private construction risk has obtained 75% debt at 5% in the European record.

What the model does not do

It does not treat construction risk as a range of outcomes. Each case has one build period and one cost, and the risk enters only through the financing terms that lenders and investors set in response to it. It prices the state's money at the state's borrowing cost and puts no value on the exposure the state takes on, so the state-transfer cases show the cost to the plant, not the cost to the public. It holds country risk and the general level of interest rates constant, so it describes a stylised European case rather than any one country. It does not model support falling from unit to unit; each case is a snapshot. And it takes the industrial saving from PoliMi's study rather than estimating it, so the size of the fleet's construction-cost benefit is theirs, not the model's.[7]