FINANCING FRANCE'S NEW NUCLEAR BUILD

Designing a financing model that guarantees competitively priced electricity in France

11 February 2022

INTRODUCTION

In 2019, the 2019-2023 French energy plan (Multi Annual Energy Plan, MAEP)[1], established a working group comprising State and industry representatives, the aim of which was to investigate the option of renewing a proportion of the nation's current nuclear fleet through the construction of new nuclear installations.

On 10 February 2022, French President Emmanuel Macron announced the launch of an industrial programme to build six EPR2 reactors as part of the plan to renew the nation's current nuclear fleet. Work is also underway to research the building of eight additional reactors. The cost of the first part of the programme to build the six initial units is estimated to range between €50 and €55 billion. The goal is to have the first of these reactors operational by 2035. Several candidates for the upcoming April 2022 presidential election are proposing similar nuclear renaissance programs.

In its 'Futurs énergétiques 2050' study paper (FE2050, Future Energy 2050), RTE (Réseau de Transport d'Électricité, the French Electricity Transmission Network TSO)[2] shows that key to minimising the cost of the overall electricity system by 2050 is the renewal of part of the overall nuclear base, in addition to significant sustained investment in solar and wind energy. RTE analysed several decarbonisation scenarios for 2050 both with and without nuclear fleet renewal. The grid operator concluded that as regards continuity and quality of electricity supply, the scenarios without nuclear power plant renewal are based on significant technological and societal gambles (very ambitious deployment rates for solar and wind generation, further scope for supply and demand flexibility, price reductions). It also concluded that the cost of the French electricity system under scenarios that included the renewal of the nuclear fleet **were roughly €10 billion cheaper** than those without.[3,4]

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[1] Which in French is known as the PPE for 'Programmation pluriannuelle de l'énergie'

[2] 25 Oct 2021 https://www.rte-france.com/actualites/futurs-energetiques-neutralite-carbone-2050-principaux-enseignements

[3,4] Comparison of the N2 (~40 GW of nuclear power in 2050 comprising 16 existing and 23 new) and M23 (largescale renewable energy development especially wind power) scenarios

RTE's sensitivity analyses show that the total cost of the electricity system increases if 'the cost of financing new nuclear power is significantly higher than that of renewables.' Based on feedback from the Hinkley Point C (HPC) project in the United Kingdom (UK), the Sfen had already warned that the final production cost of electricity from a nuclear project was very sensitive to the cost of capital for the project, i.e., the rate of return required by the provider of capital to finance the project.[5] This rate can nevertheless be reduced depending on the choices made in how the project is structured and on how State policy support is tailored.

The purpose of this study note is to:

- clarify financing issues that specifically concern new nuclear projects;
- assess the different schemes that have developed in the European Union to finance new neclear reactors;
- propose various tools that facilitate minimising the cost of capital and thus the cost of electricity for the community (consumers and taxpayers).

STUDY NOTE SUMMARY

1. Beyond their capital-intensive nature, nuclear projects have particular features in terms of size and lifespan. They require substantial initial investments, with high financial costs throughout the construction period, and a return on investment for such projects is not feasible before 10 to 15 years. Energy companies operating on Europe's volatile open electricity markets can no longer carry large nuclear projects purely on their balance sheets alone. Furthermore, major projects can be subject to delays for various political and technical reasons. Nuclear project time horizons are also incompatible with the return on investment expectations of many private financial market participants.

2. Case studies of several recent projects, as well as others projects that are still under discussion, offer new solutions in terms of the feasibility of and arrangements surrounding State or public involvement. Initially, France's national nuclear fleet was based on a self-financing model before shifting to loan funding (EDF). Market conditions at that time (quasi-monopoly supplier status, pricing power) now no longer apply. The Flamanville Nuclear Power Plant 3 proved particularly challenging, with financing coming from EDF's own capital base combined with maximum market risk. Finland provides an interesting financing case, where a cooperative comprising electricity-intensive industries and local authorities come together and jointly make a long-term commitment. Hungary has secured EU approval for a low-interest State loan financing model, and the Czech Republic is also interested in implementing a such a model. Lastly, innovative financial engineering models for nuclear power are being developed in the UK that draw on schemes already in place for other infrastructure sectors (renewable energy, tunnels). The first of these for the nuclear sector was the Hinkley Point C project, and this was recently followed by the Sizewell C project.

3. The State has several levers available to lower the cost of capital and significantly reduce the final price of electricity for consumers. First, the State must ensure a stable long-term energy policy and this point is very much consistent with the principles of climate policy, of which nuclear power is one of the key levers in France. In order to ensure long-term policy stability, nuclear power must have a copper-fastened place in the European taxonomy for sustainable activities. A regulatory framework must also be put in place that allows market

[5] Sfen technical note: the cost of production of new French nuclear power, March 2018

risk to be covered by appropriate mechanisms. Lastly, intervention through direct investment or by mutualising construction risks would have a significant effect in lowering the average cost of capital. France will therefore have to be innovative, and in combining various tools, design a suitable financial engineering scheme that is fit for purpose. Accordingly, a real weighted average cost of capital (WACC) target of 4% to 5% appears to be optimal from the point of view of the community and achievable via government support so that risk can be efficiently allocated.

Acknowledgements: this note is the result of reflections from Sfen's Energy Economics and Strategy Technical Section 8. Technical Section 8 drew initially on a research project that was completed in the summer of 2020. It was undertaken by Solène Métayer, as part of an internship at the École Polytechnique. The research project allowed for a review of the economic literature, and an analysis of initial foreign case studies. The Technical Section was also able to benefit from the content of exchanges between international experts during a virtual seminar in January 2021 jointly organized by the IFNEC (International Framework for Nuclear Energy Cooperation) and the OECD Nuclear Energy Agency (OECD-NEA).

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1. Financing issues specifically associated with nuclear construction projects

In addition to the actual amount of capital allocated for a project such as for example, the construction of a nuclear facility, all capital investment decisions must take the cost of accessing that capital into account. As with most major projects, large nuclear construction projects are likely to draw on a combination of debt and equity financing. This mix will result in a cost of capital (Ed. note: the Cost of Capital concept used in this note refers to the weighted cost of capital (WACC) as detailed below). When the owners (equity investors) use their own capital funds to invest, they apply their own cost of capital to that investment. Otherwise, they resort to borrowing at market interest rates that are adjusted to account for a project-specific risk premium.

Crib note on the *discount rate and the cost of capital*

Discount rate: To make an economic trade-off between a present cost and a future cost, we use a rate that reflects the preference for the present. The **discount rate quantifies the preference** for holding a euro today compared to its worth tomorrow. In addition, a distinction is made between discounting the value from the point of view of the community, known as the **socio-economic approach**, and discounting the value from the point of view of private actors, in which case the discount rate used necessarily reflects the **cost of capital**.

Weighted average cost of capital (WACC), or cost of capital: For private actors (shareholders and creditors), the WACC is set by the financial markets when the capital is in the form of debt financing, and by the intrinsic risk of the project when the capital is in the form of equity financing. In terms of the risk-return paradigm, investors, in principle, will only take on more risk in exchange for higher expected returns. Safe investments are associated with low returns. By weighting the rates of return on the capital employed (debt and equity) for any given project (e.g., a nuclear power plant), we obtain the weighted average cost of capital (WACC). This cost of capital is strictly the same for all investments with the same risk profile. The WACC, in particular, depends on the structure of the project, the relevant regulations, etc. As we shall see, a renewable energy project, for example, currently benefits from State-guaranteed support mechanisms, and is a relatively safe investment.

Cost of capital and technology neutrality in FE2050 scenarios: In its FE2050 study, electricity grid operator RTE assumes the same cost of capital (4%) for all technologies since there is no fundamental economic reason for any differentiation. We thus cannot use different costs of capital for different technologies **without implicitly making assumptions about the policies supporting these projects going forward**. Thus, the IEA[6] has shown that the support policies accompanying the various renewable energy sectors have had a very strong impact on their effective weighted average costs of capital. As such we note that in the UK nuclear arena a new regulatory mechanism (hybrid RAB (Regulated Asset Base) model vs. the CfD model (Contract for Difference), see Chapter 2.4) means that the WACC for the Sizewell C project has been significantly lowered compared to that for the Hinkley Point C project.

[6] IEA: World Energy Outlook 2020, https://www.iea.org/reports/world-energy-outlook-2020

Any other assumption by the RTE would therefore have contained specific bias vis-à-vis nuclear power, which, currently and unlike renewable energies, does not benefit from any support policy (c.f. Flamanville case in Chapter 2.1). On the other hand, the RTE study does present variants on the cost of capital.

Socio-economic approach to the cost of capital: For State actors, and more specifically from the point of view of the community, it is much more suitable to conduct a study using a homogeneous normative approach for all investments. This amounts to selecting a unique socio-economic discount rate as defined in the 2013 France Stratégie 'Quinet 'report (independent think tank affiliated with the French Prime Minister's Office), and subsequently revised at the end of 2021 (Guesnerie report). Insofar as the investments necessary for energy transition relate to societal issues, the socio-economic approach, which includes the valuation of positive and negative externalities beyond just private sector actors does appear to be particularly relevant.

Today, investments by private investors or pension funds **in the renewable energy sector benefit from volume and sales price guarantees** for periods of 20 years and longer. These mechanisms greatly reduce the risks relative to future project revenues. These projects carry a high degree of uncertainty in terms of the development timeframes (administrative authorizations, public consultations). In contrast, the uncertainty surrounding construction periods for onshore wind and solar projects in Europe is low (around two years), as the implementation of these technologies has already reached the serial production phase. One way to reduce risk is thus for investors to lock their funds in a project only at the actual start of construction, leaving a third party project owner to finance the development until that stage.

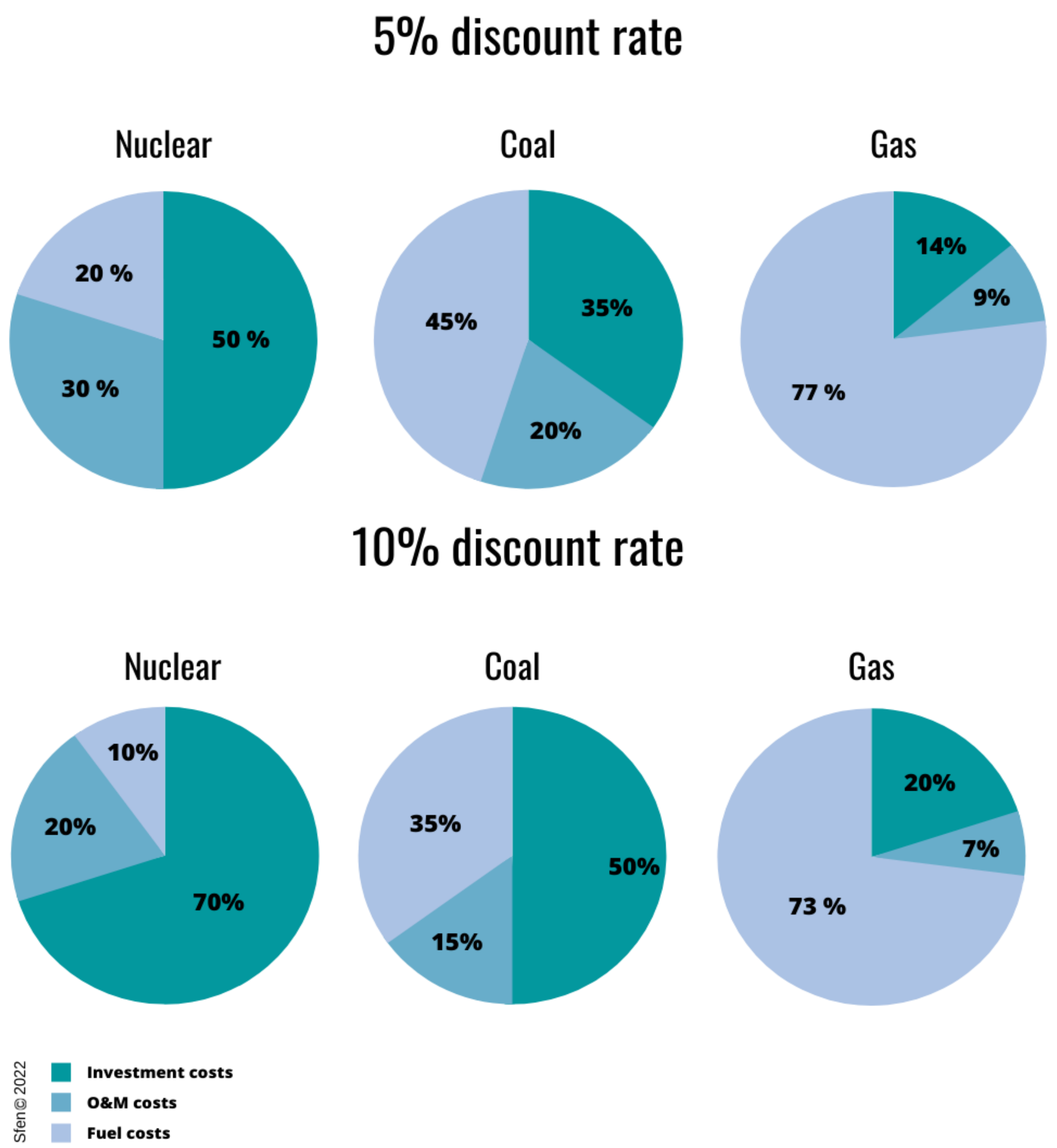
Thus, in its response to the RTE consultation of May 2021, FEE (France Énergie Éolienne), the French WindEurope association member, recommended the following discount rates be applied: **3% for onshore wind (mature), and two rates for offshore wind (fixed and floating), 5% in 2030 and 3% in 2050**. These rates attract institutional investors who are subject to very high prudential standards, in order, in particular, to safeguard their investors' funded pension amounts. Pension fund investments are highly significant: pension funds in the OECD area amounted to approximately €30 trillion in 2019.[7]

These investors tend to shy away from financing exceedingly long term uncertain projects, without very solid guarantees. This, as we shall see, is the case of nuclear power.

1.1. Nuclear projects are capital intensive

Compared to coal or gas-fired power plants (see graphs below), nuclear reactor production costs comprise a relatively low proportion of variable, fuel-related costs (10% to 20%) and a correspondingly high proportion of fixed costs, corresponding to the initial investment deployed in constructing nuclear installations as well as to ongoing operation and maintenance costs. In this way the nuclear economic model is similar to that of renewable energy, which has even lower variable costs. Both nuclear and renewable energy projects are referred to as capital-intensive projects.

[7] https://www.oecd.org/pensions/Pension-Funds-in-Figures-2020.pdf

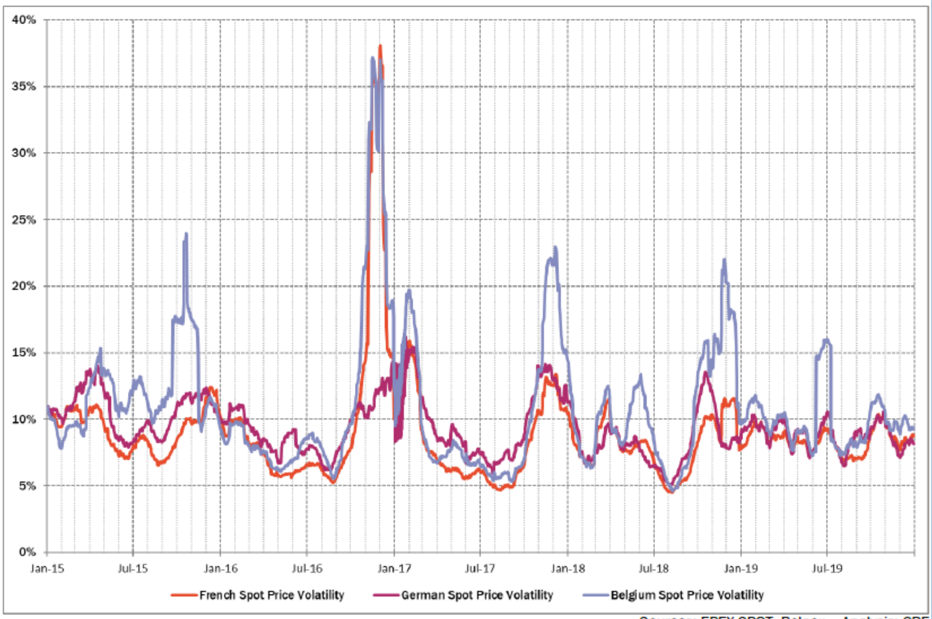


Potential investors seek answers to two questions when establishing **if wholesale electricity market revenues will be sufficient to cover the cost of the capital invested, and provide the expected return**. The first question relates to the volume of electricity that the utility will be able to sell on the market, and the second question relates to the selling price. These two uncertainties together constitute what is usually termed as *market risk*:

- **Market risk due to load factors:** The European market gives installations with the lowest marginal cost of production priority on the grid, and as such, nuclear power plants come ahead of coal & gas-fired plants, and behind renewables. As the share of variable renewables in the electricity mix grows, nuclear power must be increasingly able to smoothly adjust supply when demand is low and solar or wind generation is high (e.g., midday during the summer months). If the market can allow the community to optimise the use of a diversified energy mix, then it is the investor who consequently bears all of the risk. It should be noted that this risk is only marginally offset by the implementation of capacity mechanisms.

- **Market risk due to wholesale market prices:** In the past decade, wholesale energy prices in France have been very volatile. Over the period studied, monthly average prices have fallen to below €15/MWh in April 2020, when almost all of Europe was under its first Covid-19 lockdown arrangements, and they rose to more than €170/MWh during the autumn of 2021. For an EPR reactor producing up to 13TWh/year of electricity, a €20/MWh fall in the wholesale price represents an annualised revenue loss of €260 million.

Graph 22: Day-ahead price volatility (rolling 30-day average)



Sources: EPEX SPOT, Belpex – Analysis: CRE

1.2. Nuclear projects have unqiue size dimensions

According to a recent OECD NEA study[8], average construction costs for recent first of a kind (FOAK) third generation reactors globally range from below $3,200/kWe (Korea, China) to $8,600/kWe (France, United States).

Table 8.2: Construction costs of recent FOAK Generation III/III+ projects

Type	Country	Unit	Construction start	Initial announced construction time	Ex-post construction time	Power (MWe)	Initial announced budget (USD/kWe)	Actual construction cost (USD/kWe)
AP 1000	China	Sanmen 1, 2	2009	5	9	2 x 1 000	2 044	3 154
	United States	Vogtle 3, 4	2013	4	8/9*	2 x 1 117	4 300	8 600
APR 1400	Korea	Shin Kori 3, 4	2008	5	8/10	2 x 1 340	1 828	2 410
EPR	Finland	Olkiluoto 3	2005	5	16*	1 x 1 630	2 020	>5 723
	France	Flamanville 3	2007	5	15*	1 x 1 600	1 886	8 620
	China	Taishan 1, 2	2009	4.5	9	2 x 1 660	1 960	3 222
VVER 1200	Russia	Novovoro-nezh II-1 & 2	2008	4	8/10	2 x 1 114	2 244	**

* Estimate. ** No data available.

Notes: MWe = megawatt electrical capacity. kWe = kilowatt electrical capacity.

Source: NEA (2020).

[8] Projected costs of generating electricity, OECD-NEA December 2020

The study shows that these costs depend little on the choice of technology from among those available. Instead there are two other determining factors. The first is the socio-economic environment where the installation is being constructed. Notably both Korea and China are benefitting from ongoing nuclear programmes and the momentum associated with building their first nuclear power plants, meaning they both can taking advantage of the serial production effect. Against this backdrop, China's Funqing 5 reactor, the first realization of the Chinese Hualong-1 technology, took less than six years to build and reached criticality in December 2021.

The second factor is the size of the initial capital injection. Assuming a series cost of €4,500/MWe, which is considered to be achievable in Europe and the United States, then building 10 GW of nuclear power capability would require an initial capital injection, excluding financing costs, of around €45 billion. A Standards & Poor's study of the capitalization of European energy companies shows that none is currently in a position to carry projects of this size on their own balance sheets[9].

Top 20 European electric and multi-utilities companies by market capitalization in Q3'20

Ranking¹					Market cap as of 09/30/20 (€B)	Change in market cap from (%)²	
09/30/20	09/30/19	Industry	Company (trading symbol-exchange)	Country		06/30/20	09/30/19
1	1	Electric utilities	Enel SpA (ENEL-MIL)	Italy	75.40	-3.4	8.2
2	2	Electric utilities	Iberdrola SA (IBE-MAD)	Spain	65.58	-1.2	8.1
3	4	Electric utilities	Ørsted A/S (ORSTED-CPSE)	Denmark	49.38	14.4	37.5
4	5	Multi-utilities	National Grid PLC (NG.-LSE)	U.K.	34.49	-9.8	2.0
5	6	Electric utilities	Electricité de France SA (EDF-ENXTPA)	France	27.97	9.9	-10.6
6	3	Multi-utilities	Engie SA (ENGI-ENXTPA)	France	27.56	3.8	-23.7
7	9	Multi-utilities	E.ON SE (EOAN-XETRA)	Germany	24.58	-5.9	5.7
8	8	Multi-utilities	innogy SE (IGY-XETRA)	Germany	24.22	0.0	-2.4
9	7	Electric utilities	Endesa SA (ELE-MAD)	Spain	24.17	4.1	-5.4
10	11	Multi-utilities	RWE AG (RWE-XETRA)	Germany	21.63	13.1	22.6
11	14	Electric utilities	EDP - Energias de Portugal SA (EDP-ENXTLS)	Portugal	16.55	7.1	27.8
12	12	Electric utilities	VERBUND AG (VER-WBAG)	Austria	16.22	17.1	-7.0
13	10	Electric utilities	Fortum Oyj (FORTUM-HLSE)	Finland	15.35	2.2	-20.4
14	18	Electric utilities	EnBW Energie Baden-Württemberg AG (EBK-XETRA)	Germany	14.63	10.2	38.5
15	13	Electric utilities	SSE PLC (SSE-LSE)	U.K.	13.73	-11.4	-3.5
16	16	Electric utilities	Terna-Rete Elettrica Nazionale SpA (TRN-MIL)	Italy	12.00	-2.4	1.3
17	15	Multi-utilities	Veolia Environnement SA (VIE-ENXTPA)	France	10.21	-8.0	-20.6
18	20	Multi-utilities	Suez SA (SEV-ENXTPA)	France	9.88	51.5	10.9
19	17	Electric utilities	CEZ AS (CEZ-PSE)	Czechia	8.65	-13.6	-16.3
20	19	Electric utilities	Red Eléctrica Corporación SA (REE-MAD)	Spain	8.63	-3.6	-14.2

Industry: Electric utilities · Multi-utilities

Data compiled Oct. 5, 2020.
Analysis includes publicly traded electric utilities and multi-utilities companies headquartered in Europe. The industry is classified according to S&P Global Market Intelligence's Global Industry Classification Standard.
¹ Ranking is based on market capitalization converted to euros as of specified dates.
² Market capitalization percentage change is calculated based on the reported currency of the stock price.
Source: S&P Global Market Intelligence

The only infrastructure project currently of this magnitude in France is the **Grand-Paris Express** project, which is being steered by the Société du Grand Paris, a special purpose public body established in 2010.[10] The project includes the design and construction of four new metro/underground transport routes around the capital city, which are scheduled to start operating between 2024 and 2030. This project amounted to an investment of more than **€36 billion (in 2012)**[11], and financing is via tax revenues from the Paris region, borrowing from public investors, and fund raising on the financial markets as part of specific 'green' programs.

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[9] https://www.oecd.org/pensions/Pension-Funds-in-Figures-2020.pdf

[10] Loi 2010-597 du 3 juin 2010

[11] Société du Grand Paris : l'essentiel du Grand Paris Express

1.3. Nuclear projects have uniquely long project schedules

Prior to the start of a project comes the **preliminary phase**, during which the project owner invests, inter alia, in feasibility studies before making a decision to commit. For projects of this size, such studies can entail several hundred engineers and span several years which can translate into financially significant amounts stretching to several hundreds of millions of euros. EDF currently shoulders this burden for projects in France. At the end of January 2022 the UK government announced it would support EDF Energy develop the UK Sizewell C project in Suffolk with a £100 million investment.[12]

The first phase of the project, once the commitment decision has been made, is the development phase and in France this phase is estimated to last five years. During this time the site area has to be prepared and the studies required to complete all the regulatory steps have to be undertaken before the 'first concrete' is poured. First, the designated operator needs a few months to prepare the application request for both regulatory authorization to build a base nuclear installation (BNI) and for a construction permit. Then this phase goes through four contemporaneous activities namely final design specification, analysis of the preliminary safety report, preparation of the chosen site, and any other relevant administrative authorizations.

The second phase is the physical **construction** phase, and this starts with additional site preparation from the time the building permit is obtained. For instance, preparation for the construction of a pair of EPRs at the Penly nuclear power plant in Normandy, involves clearing brush and scrubland, reprofiling the cliff, earthworks, dyke building, and the first underground structures before the so-called first concrete stage, at which time the on-site workforce will be around 1,500[13]. After that, the site will be divided into three phases, the civil engineering phase, the assembly phase, and the overall testing phase, right up until plant start-up. The entire construction process should take between 8 and 10 years, with an average on-site workforce of 3,000, that can be expected to peak at 7,500.

The following figure summarizes the various costs investors incur during the entire life of a nuclear reactor, from the beginning of the development phase through to its dismantling. During the first 10 to 15 years, investors have to **finance development expenses**, followed by construction expenses, as well as interest repayments, depending on which scheme is chosen.[14] These expenses represent about two-thirds of the costs over the entire life cycle of the reactor, during which time the operator receives no revenue, since the reactor only produces electricity once it is commissioned. The business model is characterized by a large initial investment and operating costs that depend little on fuel costs (uranium only represents 5% of electricity production costs). However once a reactor is operational, investors enjoy a high degree of predictability over costs during the amortization period. It is worthy to note that subject to authorization, which is renewed every ten years by the relevant nuclear safety authority after the nuclear reactor site is re-examined, EPR reactors are designed to operate for at least 60 years.

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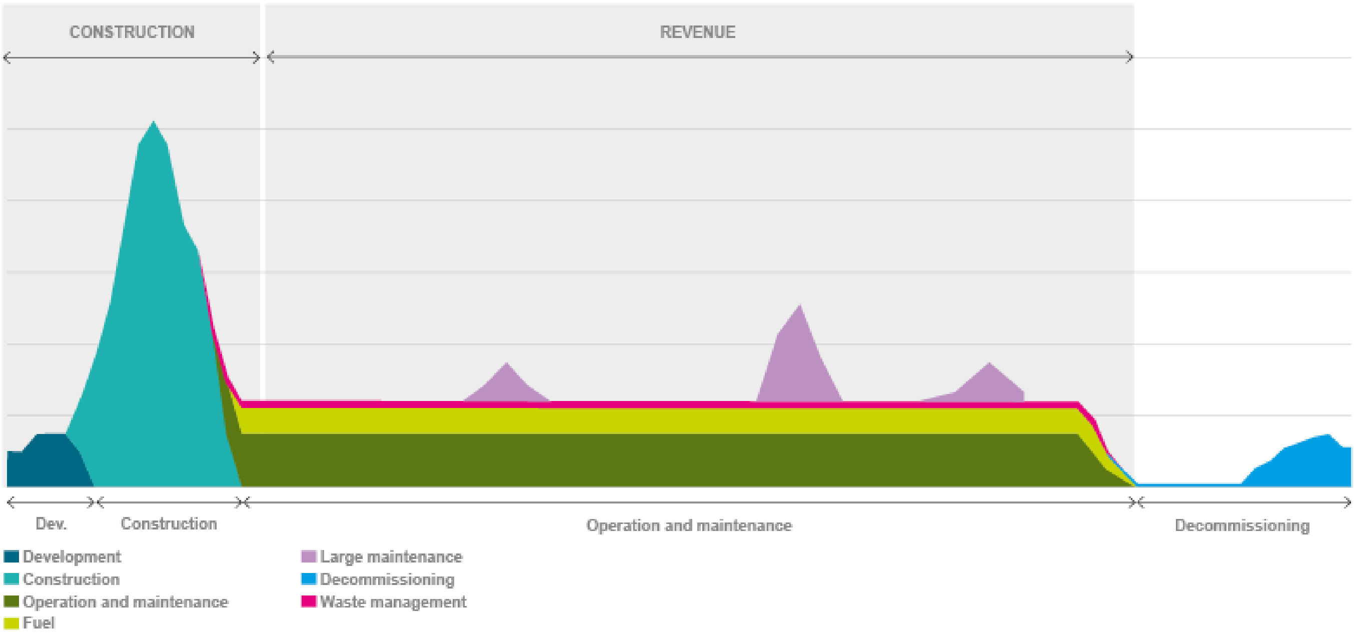
[12] https://www.gov.uk/government/news/government-readies-sizewell-c-nuclear-project-for-future-investment

[13] Sfen Webinar January 2022: https://new.sfen.org/replay/replay-session-les-etapes-jusquau-premier-beton/

[14] Interest payments relating to capital drawn for the construction phase.

Expenditure profile of a nuclear power plant
Sfen©2022



Nuclear construction phases are lengthy and subject to delays along the way and they thus present a *construction risk*, as we shall see. It should be noted that construction risk, and the associated increase in construction costs, is not an exogenous factor that cannot be influenced. Sfen has shown that this risk can be significantly reduced by setting up an appropriate industrial programme involving reactor pairs on a tailored timetable producing positive serial effects.[15] In other words, implementing an industrial programme can lower the level of construction risk and how investors perceive that risk. The cost of capital is consequently lower. Two major reasons can cause schedules to slip:

- **Political reasons**
  During their development phases and at the start of their construction phases, nuclear projects can be called into question when a change in the ruling political majority occurs. They may also suffer delays due to efforts by political opposition forces. During the development phase, a climate of political uncertainty is likely to increase the risk premium required by investors, which in turn raises the cost of capital, and ultimately inflates the price of electricity for the community. Political uncertainty is even more likely to hinder investment. An extreme case of political risk is that of the Zwentendorf nuclear power plant, located near Vienna in Austria. In 1977[16], when the plant was completed, the Austrian people, by way of a public referendum, voted by a narrow majority of 50.8% against commissioning the plant. The plant has never been put into operation. In 1978, a year after the referendum, the Austrian parliament approved legislation prohibiting the use of nuclear energy (Atomsperrgesetz).

[15] Note Sfen : Les coûts de production du nouveau nucléaire français (2018), https://new.sfen.org/note-technique/les-couts-de-production-du-nouveau-nucleaire-francais/

[16] The world's only nuclear power plant to have been completed but never put into operation, due to the outcome of a national referendum. https://www.zwentendorf.com/en/

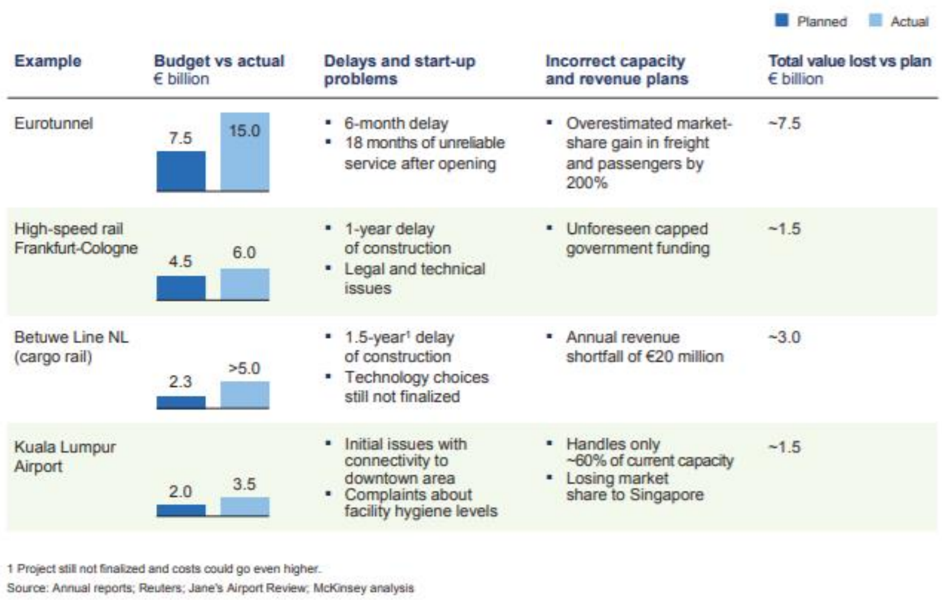
- **Technical reasons**

  Europe's first third-generation reactor construction sites (Olkiluoto 3: OL3, Flamanville 3: FLA3), known as first of a kind (FOAK) reactors were subject to delays, which directly translated into construction cost overruns. This situation is typical of large, complex infrastructure projects, such as the Channel Tunnel construction, which saw the actual cost of the project double its initial budget.

  The figure below gives an example of some major industrial project cost overruns and helps put the European OL3 and FLA3 EPR delays into perspective. We also note that these delays were exacerbated by the projects having to restart their industrial plan schedules.

  A few illustrative examples cited in a McKinsey study compare the differences between first estimate project costs and final actual costs of large complex projects.[17]

Exhibit 2 Large-scale projects face many challenges.



As stated above, the main lever to lower construction risk is the implementation of a multiple unit industrial programme that can generate a series effect. This effect can be seen at the UK Hinkley Point site in Suffolk, where the planning gains for the second unit's civil engineering element are in the order of 30%.

As part of the preparation stages for the French 2050 long term energy plan, the nuclear industry has drawn on the experience of and feedback from the Taishan, Flamanville, and Hinkley Point projects to work on several levers that can reduce construction risk. For instance the EPR2 model has been designed to offer the same safety level, but with a simpler build. Similarly in 2019, the Excel plan was launched in a bid to get the industry back to its highest level of rigour and to 'get it right first time'. This plan comprises several elements, including one on skills development and another one on new contractual schemes.

[17] Mc Kinsey 2013 « A risk management approach to a successful infrastructure project. https://www.mckinsey.com/business-functions/operations/our-insights/a-risk-management-approach-to-a-successful-infrastructure-project

In conclusion, EPR projects concentrate various types of risk and can cost several billion euros. A vicious circle can quickly develop, namely where the higher the risk perceived by investors, the higher the cost of capital, and the higher the market risk. We will see in Chapter 3 that one way to lower financing costs is to remove risks from projects and/or distribute them across several actors, for example end-consumers and/or the State.

2. Different financing schemes developed in Europe

An analysis of the financing model used for the earlier nuclear fleet, along with case studies of the financing schemes for several recent nuclear projects as well as for those currently under discussion, provide a certain number of lessons in terms of forms of State involvement, their consequences on the cost of capital and, ultimately, the actual cost of production.

2.1. France, from the initial older fleet through to Flamanville 3: two distinctly different models

2.1.1. Financing France’s earlier nuclear fleet against a backdrop of political consensus and State committment

The construction of national nuclear power plants (France, United States, Japan, etc.) was historically carried out in a very unique financing framework that was more accessible than it is today, and as such largely inimitable. *‘In the 1970s and 1980s, finance was available for a rapid and widespread expansion of nuclear capacity, even though at the time the technology was new with only a limited track record*,’ reports the OECD[18]. The first reactors in the 1960s were directly State funded in order both to demonstrate the efficiency of this new energy source, and to support related military activities (such as marine propulsion). The situation was made simpler by the fact that most utility enterprises were State-owned, and the energy issue was a direct State responsibility. ‘Electricity supply was generally seen as a natural monopoly,’ says the OECD. State utility services such as electricity could rely on guaranteed revenues to cover their costs.

Against this backdrop, French industrial companies benefitted little from a clear regulatory and financial framework with long-term visibility. Thus, the earlier traditional French nuclear programme, originally launched under the Pompidou and Giscard d'Estaing presidencies, enjoyed **real political consensus among successive governments** during the construction of the fleet’s 58 reactors. No fewer than 43 nuclear reactors were commissioned during the François Mitterrand 1981-1995 presidency.

[18] The Financing of Nuclear Power Plants - https://www.oecd-nea.org/jcms/pl_14380/the-financing-of-nuclear-power-plants?details=true

The fleet of 58 French nuclear reactors built between the early 1970s and the early 2000s went through two phases of financing: a self-financing phase prior to 1980, and a debt financing phase after 1980.

- **Pre-1980: period of self-financing**

France's fleet of 58 nuclear reactors built between the early 1970s and the early 2000s went through two financing phases: a self-financing phase prior to 1980, and a debt financing phase after 1980.

In the early 1970s, EDF was a vertically integrated State-owned company with near-monopoly status in electricity generation and supply, and it operated within a structured regulatory framework. The nuclear programme was accelerated under a programme contract, initially for the period 1970-1974 that was signed between the State and EDF as part of the 6th national economic plan.[19] Investment objectives were revised by successive amendments, reaching seven billion French francs in 1975.

The State's mission letter for EDF stipulates that in terms of tariffs, the company **will enjoy the freedom to set its tariffs** 'within the limits compatible with the government's clearly expressed desire to see the general increase in prices contained at a moderate level;' or in other words, at a level that allows it to cover its costs. As (low voltage) energy sales were growing by more than 10%, **the company was able to cover two-thirds of its investment outlays from its own resources,** and to carry out its construction programme without government assistance.

In 1970, the State's capital contribution (via the taxpayer) represented less than 10% of EDF's investment outlays (550 million French francs, vs EDF investment of more than 5.1 billion francs). A study of the programme specifies that 'the amount in current francs of external resources diminishes every year [...]; State financial disengagement became total in 1973, with EDF receiving zero public support that year: EDF sourced the two billion francs not covered by self-financing on the financial markets in two loans that were taken out without recourse to the State guarantee. It is worth noting that in 1962 and 1963, State funding contributed in the order of two billion French francs per year.'

- **Post-1980: period of debt financing**

'From 1980, **EDF was authorised to borrow up to EUR 40 billion** from commercial sources without government guarantees.'[20] While these loans weren't backed by any State guarantee, EDF secured them easily because of the company's triple AAA credit rating. The management consultancy firm Sia Partners [21] describes the system as follows: "Electricity prices were

[19] http://temis.documentation.developpement-durable.gouv.fr/pj/4439/4439_2.pdf | Un espoir pour les entreprises publiques : b| les contrats de programme : O.R.T.F., Electricité de France, S.N.C.F., 1970-1974 / c| par Philippe Comte.

[20] OCDE-AEN: The Financing of Nuclear Power Plants Dec 2009, https://www.oecd-nea.org/jcms/pl_14380/the-financing-of-nuclear-power-plants?details=true

[21] Le financement est-il devenu une limite au développement d'un projet nucléaire ?, SIA Partners, Sept 2017, https://www.sia-partners.com/fr/actualites-et-publications/de-nos-experts/le-financement-est-il-devenu-une-limite-au-developpement

determined by the cost of developing a set of power plants, to which was added a rate of return on capital (between 8% and 9%).[22] Thus, consumers bore most of the risk, while benefitting from advantageous tariffs made possible by the initial State investments."

Against the backdrop of a now open electricity market and a ratings downgrade for EDF (to BBB+ by Fitch Ratings) in January 2022, this method of debt financing cannot be replicated for today's multi-EPR program in France.

- **European energy company partcipation**

Noteworthy is the fact that during the construction of the nuclear facilities, EDF established production allocation contracts with European energy companies covering 10 production tranches.[23] The allocated share however has remained modest, at around 1.5 GW in total:

- Fessenheim 1-2: EnBW (17,5 %) et Swiss electricity group CNP which includes Alpiq, Axpo and BKW (15 %)
- Cattenom 1-2: EnBW (5 %)
- Bugey 2-3: Électricité de Laufenbourg 1 (17,5 %)
- Tricastin 1 to 4: Electrabel 2 (12,5 %)
- Chooz B1-B2: EDF Luminus, a Belgian EDF subsidiary (3,3 %)

The principle underlying the production allocation contracts was that for a given allocated production tranche, the relevant partners accessed the share of the energy to which they were entitled in return for payment of their share of the costs, including construction costs, annual operating costs, local and nuclear-specific taxes, and associated decommissioning costs. With these transactions **the energy partners shared the industrial risks with EDF during the development phase** (three FOAK reactors are involved) and assume the performance risks associated with the current operation of the power plants, although they play no operational role.

2.1.2. Financing Flamanville 3: a complicated political picture that subsequently stabilised

In 2005, as the national nuclear industry chain was re-starting in France, construction of the country's 59th nuclear reactor on the Flamanville site commenced with an FOAK EPR.

The Folz report [24] documented weak State-related strategic continuity during the genesis of the project, which was punctuated with several 'stop start' decisions. Design work for the new Franco-German reactor occurred from 1993 to 1997 only to be followed by an hiatus in activity between 1997 and 2002 due to the arrival of a new 'nuclear chilly' government. Then in 2002 a change in political majority ushered in a flurry of activity, with the national administrative Cour

[22] This cost of capital should be considered vis-à-vis the rate of inflation at the time (from 13% in 1980 to about 3% after 1985)

[23] EDF Document de référence financier 2014, https://www.edf.fr/sites/default/files/contrib/groupe-edf/espaces-dedies/espace-finance-fr/informations-financieres/informations-reglementees/document-de-reference/EDF_DDR_2014_VF.pdf

[24] JM Folz « la construction de l'EPR de Flamanville », Octobre 2019, https://www.economie.gouv.fr/rapport-epr-flamanville

des Comptes[25] report (July 2020) noting 'a burst' of decision making, as if the actors were seeking to take advantage of a window of opportunity that might close at the next election.

However, once the project got underway, and in spite of discussion and debate, successive changes in political majority have not undermined the project's integrity.

- **Own funds financing**

In 2005, an agreement was reached for the Italian utility Enel to take a 12.5% stake in the Flamanville project. The aim was to share the risks and benefits of the project, which at that time had been estimated to cost €3.3 billion. However, in 2012, following the Italian government's decision not to relaunch a national nuclear electricity power programme, Enel withdrew from the Flamanville project.

In the end, EDF financed the construction of Flamanville 3 entirely from its own funds. The company not only financed the development phase, but also all the overruns associated with the construction of an FOAK, as well as the restarting of the French nuclear industrial process, which had lain fallow for fifteen years. In January 2022 EDF re-calculated the construction costs to be €12.7 billion.[26] In July 2020 the Cour des Comptes calculated the financial interest costs at €4.22 billion, or about 30% of construction costs.

- **A project exposed to market risks**

The French Cour des Comptes calculates the production cost for the Flamanville EPR at between €110 and €120/MWh.[27] The final cost calculation is significantly higher than the initial estimate and sets a ceiling for the future cost of new FOAK nuclear power plants.

If we compare Flamanville 3 to the Saint-Brieuc wind farm (between €140 and 150€/MWh), the FOAK equivalent in offshore wind power, two points can be noted:

- Flamanville 3 production costs, even if high, remain lower than those of the wind farm, even before systems costs are taken into account. Flamanville 3 will indeed be a controllable means of production, bringing significant value to the electrical power system.
- Flamanville 3 did not benefit from a feed-in tariff for its electricity. When EDF began construction, no decision had been taken on the price to be received for the electricity produced. To this day, it is still not clear whether the electricity produced by Flamanville 3 will be sold on the volatile wholesale market, or on the basis of a fixed price.

The Cour des Comptes thus recommends 'calculating and monitoring the projected profitability of Flamanville 3 and the EPR2 reactors.' While this issue is clearly linked to cost control, it is also related to the need to be able to predict future electricity selling prices, and it must allow for adequate financing arrangements. Thus, the Cour des Comptes notes that EDF ***'will no longer be able to commit itself as it could previously without securing a guarantee over the income it will receive from the operation of its reactors.'*** EDF should therefore benefit from a system similar to the one currently in place for solar and wind energy in France, or for example at the Hinkley Point C nuclear power plant project in the United Kingdom.

[25] French administrative court charged with conducting financial and legislative audits.
[26] In 2015 constant euros.
[27] Cour des comptes « la filière EPR » July 2020, Cour des Comptes : https://www.vie-publique.fr/rapport/275117-la-filiere-epr-cour-des-comptes

2.2. Finland's Mankala model – electricity corporate cooperative

Finland's 'Mankala' principle is a cooperative model developed in the 1960s to facilitate investment in hydro, wind, and nuclear power generation capacity, i.e., investment in highly capital-intensive infrastructure. Indeed, the first infrastructure project to benefit from this co-operative model was a 25 MW hydro dam, called 'Mankala', located in the southeast of the country.

Under the Mankala principle, investors, often electro-intensive industrial and municipal power users, own a limited liability company (LLC). The LLC sells electricity to its shareholders at the cost of production, since being a co-operative enterprise the LLC does not have to make a profit. Thus, instead of sharing the financial return from the market sale of the electricity produced, investors receive the electricity directly from the plant in proportion to their financial participation in the project. The Mankala model allows investors to share the risk, thus reducing individual risk, and to benefit from long-term price stability. Today, it is Finland's dominant framework, accounting for approximately 2/5 of the country's total electricity and 2/3 of its nuclear electricity.[28]

The Olkiluoto 3 EPR (OL3), recently underway, was financed according to the Mankala principle.[29] As such it operates with a 'turnkey' delivery contract worth €2.28 billion between the operator, TVO, and the Areva-Siemens consortium. While OL3 was launched in 2005, with commissioning scheduled for 2009, it experienced delays and cost overruns, before finally reaching first criticality at the end of December 2021. The total cost of the TVO share is estimated at €5.7 billion, an amount which does not include the cost overruns borne by the consortium.[30]

The OL3 project was 75% debt financed, via issuance from TVO, its shareholders, and the French export credit agency The remaining 25% of the funding came from shareholders' own capital. While the resulting overall cost of capital is not publicly available, economic studies on nuclear power competitiveness published in Finland (Lappeenranta University) suggest an implied discount rate of 5% (Sfen, 2018) It should be noted, however, that by the nature of the contract, the shareholders were placing most of the construction risk on the Areva-Siemens consortium.

2.3. Eastern Europe: State support and European competition rules

2.3.1. The Paks 2 project in Hungary

Hungary is planning to expand its existing 2GW Paks plant located 100km south of Budapest with two Russian-built VVER-1200 reactors (1.2GW). The site is already home to four nuclear reactors operated by the State-owned power utility MVM, and it accounts for more than 50% of Hungary's electricity production. In 2014 following inter-governmental negotiations, the project, valued at €12.5 billion, was awarded to the Russian State corporation Rosatom. The two new reactors will be built and operated by a separate company, MVM Paks II, which is 100% Hungary State-owned. These reactors are intended to gradually replace the existing installations and provide additional capacity.

[28] https://www.ifnec.org/ifnec/upload/docs/application/pdf/2018-11/s3_3_fin_korteniemi.pdf
[29] https://new.sfen.org/rgn/olkiluoto-3-demarrage-premier-epr-europe/
[30] TVO_Report-of-the-Board-of-Directors-and-Financial-Statements_2020.pdf

Design and construction of the new reactors will be financed directly by the Hungarian government through MVM Paks II. Hungary has taken out a €10 billion loan from Russia, the repayment of which was originally scheduled to begin in 2026 but was recently postponed to 2031. [31] The new units will operate under **market conditions** and without any income or price setting mechanisms.[32] According Russia's Rosatom, the rate of return on capital for the project will ultimately be 3%, with an estimated final cost of electricity of less than €55/MWh.

Between 2015 and 2017 the European Commission studied the Paks II financing scheme and Hungary has made several substantial commitments to ensure that the use of public funds does not, in accordance with EU State aid rules, distort the electricity market. Thus, any potential profits made by Paks II cannot be used to reinvest in the construction or acquisition of additional electricity generation capacity. Furthermore, in order to ensure market liquidity, Paks II will sell at least 30% of its total electricity production on the energy market. Paks II will then sell the remainder of its total electricity production under objective, transparent and non-discriminatory conditions through auction mechanisms.

Hungary has **already amended its regulatory framework to allow certain works commence** as early as the beginning of 2021 (assembly base, earthworks, soil consolidation and the work pit). This provision has been put in place until the entire project receives the final go-ahead for construction to begin in 2022, with a view to commissioning around 2030.

2.3.2. The Dukovany 5 project in the Czech Republic

The Dukovany 5 project involves the construction of a 1200 MW reactor at the Dukovany site, as part of a programme to replace the nuclear reactors currently in operation.

The project will be financed in part by a government loan to the majority State-owned power company ČEZ.[33] The loan, which will come directly from State funds, is intended to cover 70% of the total cost of the plant, currently estimated at approximately €6.5 billion. ČEZ will be responsible for financing the remaining 30%. In order to ensure low-cost financing, the interest rate on the State's stake will be 0% during the construction period and 2% thereafter.

Alongside, new legislation will define a legal framework to establish a long-term guaranteed price, similar to the UK Contract for Difference (CfD) model. Depending on the duration of the guaranteed price mechanism, the production cost should come to between €48 and €70/MWh.

The European Commission must approve these plans to ensure that they comply with EU State aid rules. It should be noted that this type of scheme cannot be replicated for France, as EDF's balance sheet cannot take on any more debt, even if the lender is the French State.

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[31] Reuters, 29 April 2021, https://www.reuters.com/article/hungary-nuclearpower-russia-financing-idINL8N2MM8SW

[32] https://ec.europa.eu/competition/state_aid/cases/261529/261529_1713906_26_2.pdf

[33] Sfen RGN, Czech Republic, secured financing for the extension of the nuclear power plant in Dukovany June 2020, https://new.sfen.org/tag-rgn/republique-tcheque/

2.4. The Hinkley Point C (HPC) and Sizewell C projects: UK regulatory innovation

In 2006, the UK government began work on its long-term energy strategy, which included the development of both nuclear and renewable sources. While being one of the first countries to deregulate its electricity market, the UK also comprehensively examined the case for implementing an innovative regulatory framework. This framework was applied when launching the HPC construction project and feedback from that experience has led to the implementation of new mechanisms for the Sizewell C project.

2.4.1. Hinkley Point C (HPC)

HPC is an extension of the UK's Hinkley Point nuclear power plant. Since December 2018, two EPR-type reactors have been and currently still are under construction. Founded in 2009, the Nuclear New Build Generation Company (NNB GenCo) owns the plant and is in charge of its construction and operation. NNB GenCo is 66.5% owned by EDF, and 33.5% by China General Nuclear Power Group (CGN).

In 2008, the UK government's energy strategy was based on two principles. The first was that private investment should be the only option, with no direct government financial involvement. The second was that nuclear power should be treated no differently than other low-carbon energies.

The CfD (Contract for Difference) mechanism, which had been set up for renewable energies, was the only existing financing framework at the time, and was therefore adapted for financing nuclear projects. As discussed in Chapter 3.2, CfDs guarantee electricity producers with a fixed selling price, the Strike Price, in order to provide them with greater revenue certainty while maintaining the functioning of wholesale electricity markets.

EDF and CGN are fully financing the HPC project via equity contributions as part of a framework that includes several mechanisms including:

- a contract for difference (CfD), the Strike Price of which was set at £92.50/MWh (2012 prices), which is indexed to inflation, and the term for which is 35 years.
- loan guarantees of up to £2 billion for NNB GenCo issued bonds, should the company need the funds (which ultimately were not required)
- a payments guarantee for NNB GenCo in the event of a change in public policy that results in the plant's closure.

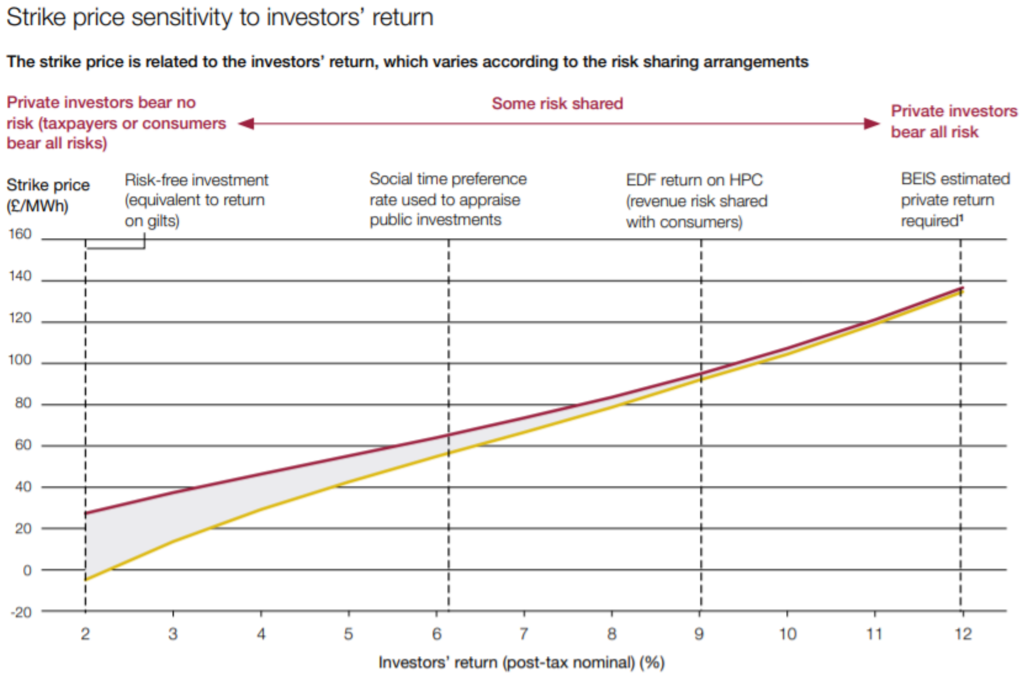
This framework, which was considered as State aid, was approved by the European Commission in October 2014. It consists of a guaranteed price (Strike Price),[34] by way of a CfD, for a period of 35 years after the plant is commissioned.

The agreement was initially criticised for resulting in an electricity price that would be 'too high'. The Strike Price negotiated by EDF was set at £92.50/MWh (2012 prices), falling to £89.50/MWh (2012 prices) if the proposed Sizewell C plant project was approved. At the time of the agreement, the Strike Price corresponded to between twice and three times European

[34] https://www.gov.uk/government/collections/hinkley-point-c

market prices. Some few years later, amid a Europe-wide crisis in the electricity markets, both spot and forward market prices reached above €100/MWh and could remain there for a long time.

Another criticism came from the UK's select committee responsible for overseeing UK government expenditures, the Public Accounts Committee (PAC). Even if the new regulatory framework allows market risks to be addressed, it still leaves most of the construction risk to be borne by industry stakeholders. In practice, this translates into a very high-risk premium, and therefore a high cost of capital, of the order of 9%. The following graph illustrates the sensitivity of the guaranteed price (Strike Price) to the cost of capital.



Sensitivity of the electricity price to the rate of return on investment (Source: UK National Audit Office)

The PAC report concludes that even if industry is committed to bearing the construction risks, and even if consumers are protected from cost overruns, **consumers could end up paying more for HPC's electricity than they would have if the government had taken a share of these risks.**[35] The issue the PAC noted surrounds securing the optimal return point for the community as a whole, by finding the right split between the consumer and the taxpayer. In this regard the Regulated Asset Base (RAB) model represents 'financial engineering' progress.

[35] https://www.bbc.com/news/business-42065837, https://publications.parliament.uk/pa/cm201719/cmselect/cmpubacc/393/39306.htm

2.4.2. Sizewell C

The UK's Sizewell C (SZC) project aims to extend the Sizewell nuclear power station that is located in the eastern region of Suffolk. The project includes the construction of two new EPR reactors that are exact replicas of the HPC project. The aim is for EDF Energy to benefit from a series effect by sharing a large proportion of the design and by taking advantage of the learning effects that were already evident with the second HPC unit. Replication benefits are expected both on the project's cost and schedule. EDF Energy submitted its application for planning permission to the UK government on 27 May 2020.

In order to learn from HPC, the UK government has been working on a new financing framework, the Regulated Asset Base (RAB) model, which draws on a widely implemented financing mechanism for largescale infrastructure projects including the Thames Tideway Tunnel (TTT) that will renovate London's sewerage system, and that began construction in 2016.

The term Regulated Asset Base (RAB) is used to define revenues the private sector is authorised to earn from investments not subject to competitive market conditions (e.g. distribution networks). Under this framework, investors' revenues based on their expenditures are periodically reviewed by an independent regulator that estimates whether capital investment expenditures (CAPEX) are consistent with previously accepted ex ante forecasts.

The RAB model lowers the cost of capital, and thus the final cost of the project to the community (consumer and taxpayer) by spreading the construction risk:

- between consumers and industry, up to a certain ceiling that is initially set beyond the estimate targeted at the time of the investment decision;
- with the State, for risk that exceeds the pe-determined ceiling; and,
- by ensuring revenue payments during the construction phase.

With the RAB model, consumers also bear the costs right from the construction phase and as a result of the associated reduction in financial interest payments are set to benefit from a significant reduction in the overall cost of production. The sharing of risk of cost overruns between investors, consumers and taxpayers operates as a second lever for reducing costs because of the lower risk premium being demanded by investors. In other words, by accepting some of the construction risks, consumers benefit from more competitive electricity prices, even in scenarios where cost overruns do materialize.

In addition to the new investment framework, on 28 October 2021 the UK government announced in its 2021 Autumn Budget and Spending Review **that it is prepared to invest 'up to £1.7 billion** (...) to enable a final investment decision on this large-scale nuclear project by the end of the parliamentary term' (Ed. note 2024).[36]

[36]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1043689/Budget_AB2021_Web_Accessible.pdf

<table>
<tr><th colspan="2"></th><th>Hinkley Point C (2018 – 2026)</th><th>Sizewell C (2022 - ?)</th><th>Dukovany5 (2029 – 2036)</th></tr>
<tr><td colspan="2">Financing model and sources</td><td>Private financing (EDF & CGN)
CfD: sale price 92.50£/MWh (inflation indexed) ; over 35 years
State guarantee for loans up to £2 billion</td><td>RAB Model
Private sector financing (including pension funds) and State participation anticipated</td><td>Majority State financed
Czech State loan for 70% of the investment cost

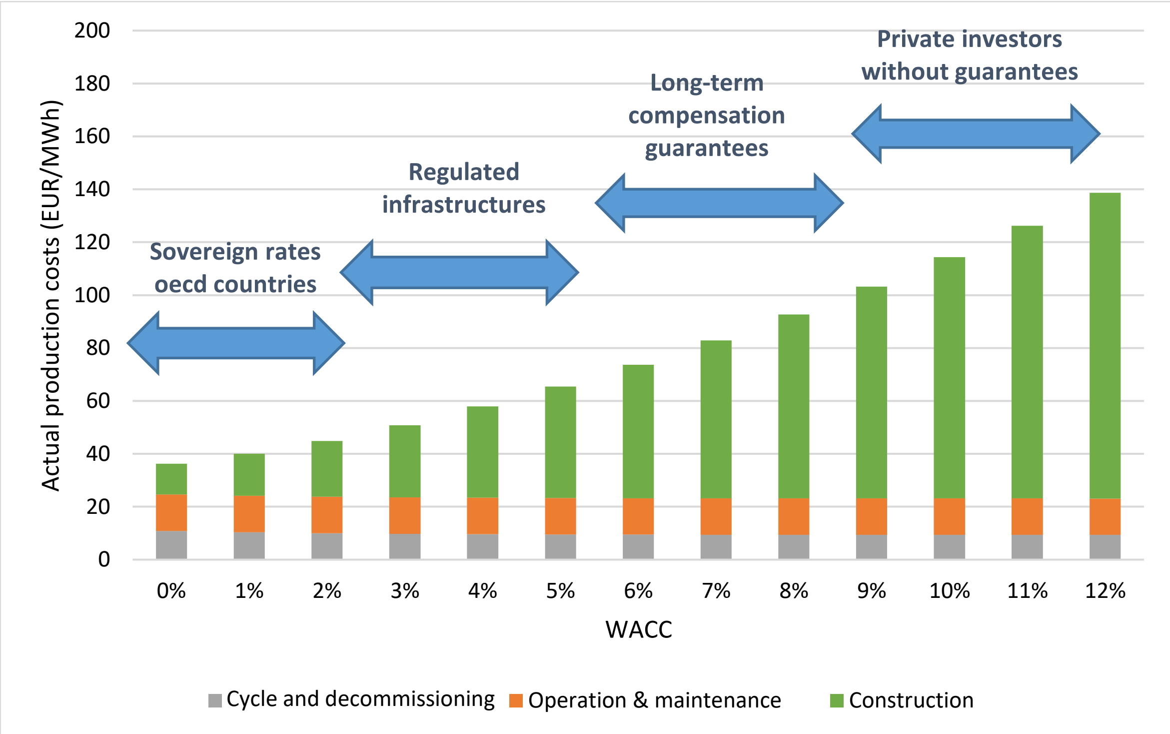
CfD type electricity purchase agreements between ČEZ and the State)</td></tr>
<tr><td rowspan="2">Risk allocation</td><td>Construction & Operating risks</td><td>Industry</td><td>Shared between investors, consumers, and the State</td><td>Unconfirmed, but expected to be borne by consumers</td></tr>
<tr><td>Market risks</td><td>Consumers</td><td>Consumers</td><td>Consumers</td></tr>
<tr><td rowspan="3">State role and involvement</td><td>Direct financial</td><td>-</td><td>Possible</td><td>State loan covering 70% of project at a very low interest rate (0% during construction phase, and 2% during the operating phase)</td></tr>
<tr><td>Indirect financial</td><td>Loan guarantees
(option not exercised by EDF)</td><td>-</td><td>-</td></tr>
<tr><td>Non-financial</td><td>Guaranteed electricity price (CfD) over 35 years</td><td>Financial guarantees covering cost ceiling overruns

Guaranteed ROI during construction and operations</td><td>Guaranteed electricity price (CfD) over 30 and 60 Years</td></tr>
<tr><td colspan="2">Discounted cost of production (EUR/MWh)</td><td>102 EUR/MWh
(92.5 £/MWh) (2012)</td><td>44-66 EUR/MWh
(40-60 £/MWh with a rate of return of between 4.5% and 5.5%)</td><td>48-70 EUR/MWh</td></tr>
</table>

3. How to effectively manage nuclear power financing costs

According to French government data provided during the RTE consultation, estimates can be calculated for the financing needs of three pairs of EPR2 reactors as part of the country's new energy plan. The cost per unit would be in the order of €8.5 to €9.0 billion, for a total cost of between €50 to €55 billion for three pairs of EPR2 (10 GW). With construction spread over 20 to 25 years, this amounts to a financing requirement of between €2 billion and €2.5 billion per year.

The cost of this programme does not appear to be a problem per se on a national scale. However, it is a problem at the more micro scale of a company such as EDF, which can no longer singly carry this type of project on its own balance sheet alone. With all the various cases studied, the State had several levers at its disposal to lower the cost of capital, which could significantly reduce the final price of electricity for consumers.



There is a strong link between the cost of capital and the price of electricity. The graph above illustrates the impact of the cost of capital on a nuclear plant's Levelized Cost of Electricity (LCOE). Thus we can see that:

- in the Hungary and Czech cases, State loan financing allows the project to benefit from sovereign rates and to provide an electricity price of below €40;
- in the UK HPC case, the long-term remuneration guarantee could not avoid a cost of capital above 9%, which resulted in a high guaranteed price;
- the UK Sizewell C plant combines several features to achieve a cost of capital in the range of 4%-5%.

While the new French energy plan was being informed, EDF had already stated that its objective was to achieve electricity production costs below €70/MWh. To this end, France must implement a scheme that allows a cost of capital of between 4% and 5%. The schemes implemented in other countries, while providing a great deal of useful information, cannot be simply replicated in France, for various reasons related, inter alia, to EDF's unique position.

France will therefore have to combine various tools to innovate and design a financial engineering scheme that suits its own unique situation. To this end, France has three types of levers available, namely political, regulatory, and direct.

- we recall that it makes rational and efficient sense for the State to contribute to the construction of new reactors, in the same way that it currently provides significant help and support for renewable energies. The level of the public discount rate to be applied to the electricity system (RTE used 4%) is very significantly lower than the cost of capital facing the energy companies (which amounts to 6%-8%, if no additional mechanism is implemented);
- nuclear power brings many positive externality effects to the country in terms of supply security, and energy independence, as well as in terms of jobs and training. Nuclear power is, in many respects, an indispensable asset for the reindustrialisation of the country.

3.1. Political levers

3.1.1. Ensuring long-term political continuity

Even if the presidential election in April 2022 affirms the intention of the energy programme, it still has to pass several important milestones before the construction permit is signed, something that cannot be expected for a further 5 years. The first concrete is currently scheduled to be poured in 2027 and the first commissioning in 2035. In terms of timings for the three pairs of EPR reactors, EDF announced it was planning for a 4-year gap between each site, and an 18-month gap between each unit on the same site, so the full programme will not be completed until 2045, i.e., 25 years from now. During this period, France will probably undergo no less than five political changes.

The programme will therefore be subject to political risk which, as we have already seen, is likely to generate additional costs. Firstly, there will be additional construction costs: the construction sites must follow a certain schedule in order to optimize the allocation of human and material resources, and to maintain skills. If work on the site halts, the immobilised resources must still be financed, and they may sometimes be permanently redeployed to other projects. However, political risk can also increase the cost of capital, as investors, if they are not confident in a country's political climate, will either demand higher premia, or may even decide not to invest.

Even if several of the presidential candidates currently include the nuclear project on their agendas, it is important to seek national consensus for it, and once launched it should be ringfenced from any potential political partisanship. History has shown that this is possible. Thus, in 1981, the French Socialist Party’s common programme, while stipulating that ‘the country's energy supply will be diversified,' specified that the nuclear programme would continue for the plants already under construction.37

Even if France no longer pursues five-year national plans, it does have the capacity to commit to long-term programmes in strategic sectors such as for instance Defence, through planning laws, and by placing long-term orders with industry. The question of France's electricity supply, as well as the entire national environmental (biodiversity) and energy transition policy (carbon neutral objective), calls for this capacity to have agency over the long term, with continuity and planning out to a 2050 horizon.

The decision to initially only build 10 GW of capacity, whereas France will certainly need between 30 GW and 50 GW of nuclear power by 2050, reflects a desire to eliminate any potential misgivings from any decisions made. In particular, it will consolidate the nuclear power option and the capacity of France, and of Europe, to build new reactors efficiently. Regardless of the future performance of alternative, renewable, and flexible energy means, the first six EPRs will occupy an established position and will contribute to the balance of the French and European electricity networks by 2040.

Public debate, an essential step from a legal point of view, must allow for discussion on these subjects, just like parliamentary debate, and the inclusion of the programme into law in 2023.

3.1.2. Securing the place of nuclear energy in the European taxonomy

In Europe, movement towards green financing aims to direct investors towards projects that help tackle climate change and adapt the economy to global warming. Green financing should eventually become the dominant form of finance in the European Union. To this end, the European Commission has implemented a taxonomy for sustainable, or 'green 'activities. This classification should enable investors to record the ecological performance of their holdings in projects as part of their extra-financial reporting. In doing so, the activities included in this taxonomy will benefit from simplified access to a broad investor base, which will automatically lower the cost of capital for projects. In addition, the taxonomy will extend beyond its initial scope and influence other major European policies, such as eligibility for European Union funds and state aid authorizations.'

The sustainable taxonomy has been designed on the basis of scientific criteria. In 2021, the European Commission's science and knowledge service, the Joint Research Centre (JRC) was mandated to conduct an in-depth study of the environmental footprint of nuclear power, and it concluded that nuclear power met all the criteria of the taxonomy. That is, it fosters at least one of the six objectives of the taxonomy (climate change mitigation, adaptation to global warming, water protection, circular economy, pollution prevention, and biodiversity protection), without negatively impacting the others. This is the 'Do No Significant Harm' or DNSH principle. The JRC report concluded that, while clearly helping combat climate change, nuclear energy also had comparable or even lower environmental impacts than other technologies included in the taxonomy.

However, the debate over whether or not nuclear power is included in the taxonomy has become political, pitting pro-nuclear EU Member States against their anti-nuclear equivalents.

[37] https://www.monde-diplomatique.fr/mav/124/A/51865

In a major step forward, on 03 February 2022 the European Commission published a proposal for a delegated act that now includes nuclear activities in the taxonomy. However, political compromise instead of scientific basis has left nuclear energy now being considered as a 'transitional energy.'

Because nuclear power is now classified as a 'transitional energy,' projects must meet a certain number of technical criteria, which may be subject to periodic changes, thus creating uncertainty for investors.

Together with its partners, France must continue to lobby the European Commission to ensure that nuclear power is fully included in the taxonomy as a sustainable energy source, in order to provide investors with long-term visibility and stability, which will help lower the cost of financing nuclear power over the long term

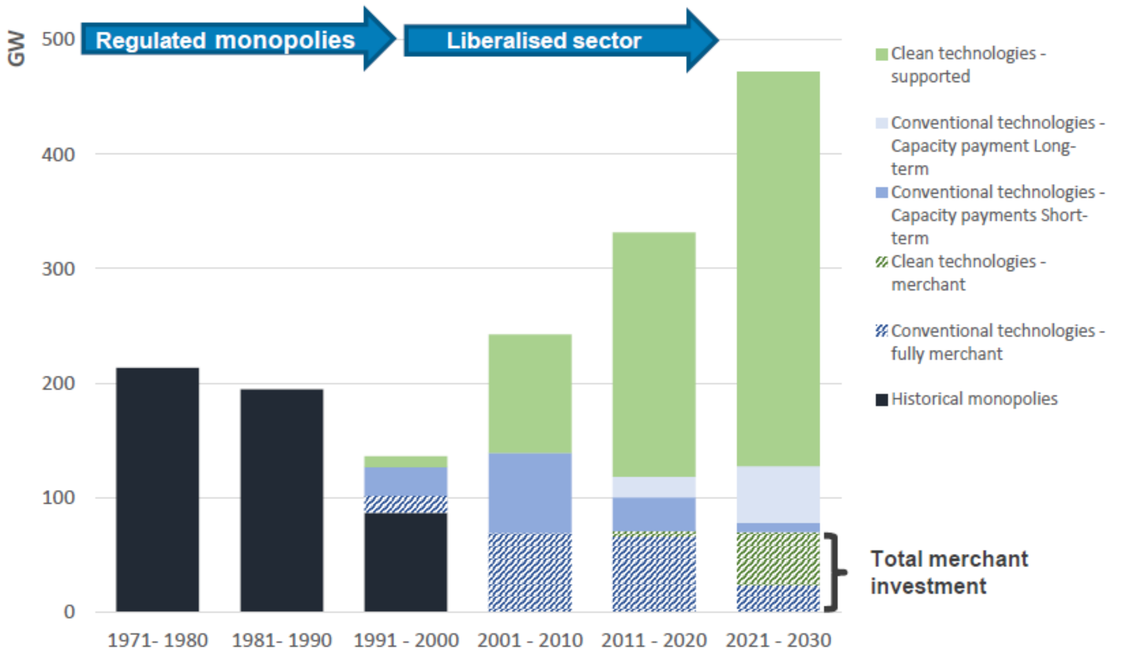
In particular, it is imperative that **nuclear projects be able to benefit from a stable technical benchmark**. According to Article 19.5 of the June 2020 Taxonomy regulation, transitional energies are subject to a review of their technical screening conditions (review clause) 'at least every three years […] in line with scientific and technological developments.' This creates damaging uncertainty in the regulatory and technological framework, not least since on average a nuclear project from the declaration of intent to its commissioning takes between 10 years and 15 years. Furthermore, since nuclear competitiveness relies on the serial construction of pairs of EPRs, it is inconceivable that each new EPR pair would be subject to different technical conditions. This would lead to instability and a lack of visibility that would run counter to long-term investment policies.

3.2. Regulatory levers

Like renewable energies, nuclear power is highly capital intensive and particularly sensitive to market risk.

A study by Compass-Lexecon[38] shows that even if during the period between 2005 and 2010 a small proportion of new investment was directed to the deregulated electricity market (primarily in the UK and in gas-fired power plants), this proportion has subsequently been tailing off. In 2020, most investments are being covered by long-term public contracts (e.g., purchase obligation contracts and Contract for Difference-CfD type contracts) or by private (non-market based) contracts (e.g., power purchase agreement-PPA).

[38] IFNEC-NEA seminar, https://www.ifnec.org/ifnec/upload/docs/application/pdf/2021-01/fabien_roques_associate_professor_dauphine_university__executive_vice_president_compass_lexecon.pdf



Commissioning of generation facilities in Europe and regulatory framework at the time of decision making
(Source: Compass-Lexecon, IFNEC-NEA seminar, 2021*)*

France must implement new remuneration mechanisms for its new nuclear programme that reduce market risk.

3.2.1. Contract for Difference (CfD)

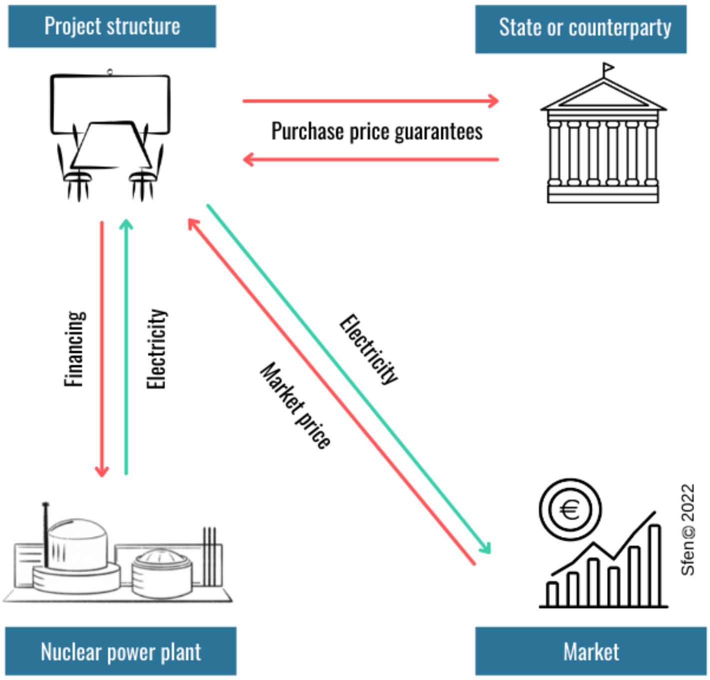
CfDs are long-term bilateral contracts between electricity producers that sell their electricity on a centralized common market platform and, most often, a third-party counterparty (generally dependent on the State).

In concrete terms, the producer is guaranteed a fixed selling price (often called the Strike Price) for all the volume produced. Two situations can then arise. First is when the market price is lower than the ‘Strike Price’, and second is when the market price is higher than the ‘Strike Price’. When the market price is below the Strike Price, the CfD commits the third-party counterparty to pay the price difference to the producer. Conversely when the market price is greater than the Strike Price the producer has to pay the surplus achieved back to the third-party counterparty. The CfD mechanism allows the State to share the risk of the price of electricity providing an insufficient income stream to repay the investment outlays over a given period.

This mechanism has the advantage of operating outside the market, and so does not introduce any exogenous disturbance to market dynamics. Ceteris paribus, the CfD mechanism does not modify the wholesale price of electricity and is thus not a factor distorting the market.

CfDs do not guarantee profitability since the Strike Price only applies to the volume sold on the markets. Furthermore, using CfDs to hedge price risk presents new risks such as margin risk (Strike Price that turns out to be too high), or relatively high management costs related to the underlying control processes (Alao and Cuffe, 2021).

Several examples of CfD contracts being used in the electricity markets exist. Noteworthy is the fact they have all been approved by the European Commission, even though they are a form of State aid. We outlined the Hinkley Point C case above where the electricity seller is the French operator EDF, and the buyer is a UK State counterparty. The figure above shows the different financial and physical flows for both cases when the (1) market price is inferior to the Strike Price, and the (2) market price exceeds the Strike Price.



Contract for Difference financing model (Source: SFEN)

3.2.2. Industrial and energy company participation

Europe's electricity market crisis in the autumn of 2021, which was linked to the increase in gas prices, has brought the question of electricity market reform back to the table.

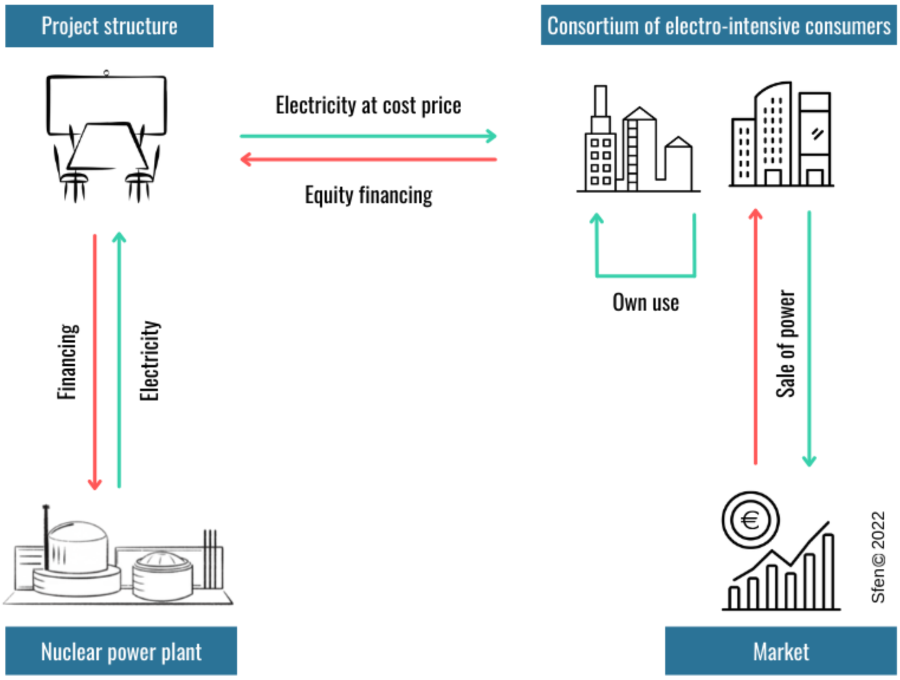
The actors most particularly affected by the crisis include:

- electricity intensive manufacturers, for which electricity can represent up to 30% of production costs;
- alternative ('non-incumbent') electricity suppliers, some of which are in financial difficulty. All of them are generally criticised for benefitting from the advantages of the incumbent nuclear fleet, via regulated access to incumbent nuclear electricity, i.e., the Arenh mechanism (Accès Régulé à l'Electricité Nucléaire Historique), without them bearing the investment costs or the operating risks.

In Chapter 2, we saw that mechanisms exist to involve these actors in nuclear investment financing. During the construction of the nuclear fleet, EDF formed partnerships with foreign energy companies, which, in exchange for sharing the construction risks and participating in the operating costs, benefit from electricity drawing rights. This is the Finnish Mankala cooperative model which allows industrialists and municipalities to benefit from drawing rights at cost price, in exchange for their investment in the construction of a reactor.

At a time when many industrial companies, such as ArcelorMittal (Steel) in Dunkirk, are going to undertake major investment plans to decarbonise their industrial processes, (for instance via green hydrogen (low-carbon electrolytic hydrogen), it is important to be able to both guarantee supply security and give them long-term visibility.

France must put in place, in agreement with the European competition authorities, a regulatory framework that meets the needs of industrial customers and alternative suppliers, while sharing part of the risk with the investor.



Energy company - industry cooperation model (Source: SFEN))

3.3. State intervention

3.3.1. The State as investor

An effective way to reduce the average cost of capital is for the State to decide to co-finance a nuclear project by investing public capital in the company that is in charge of the project.

As a reminder, the principle of the State as shareholder and as presented in the PLF 2020[39] (Budget white paper) now means implementing a more selective shareholding policy refocused around three priority areas. Firstly, strategic companies that contribute to France's sovereignty (defence and nuclear). Secondly, companies involved in public service assignments or in the national or local general interest. Thirdly and lastly, involvement in companies where systemic risk exists. Nuclear energy meets all three priorities.

This type of public investment can take the form of a **capital injection to an operator with the appropriate project management skills**, if it is intended to be public like EDF, or alternatively in a special purpose entity that owns the new reactors, and in which case the State becomes a partial owner.

[39] Referenced in the Cour des Comptes: Management of State financing operations during the Covid-19 health crisis (February 2022)/ https://www.ccomptes.fr/fr/publications/la-gestion-des-participations-financieres-de-letat-durant-la-crise-sanitaire

State intervention in the financing of a nuclear project can also take the form of **State loans extended to the operator in charge of the programme**. For France however, scope for this loan-extension option seems to be slight due to EDF's already high debt level.

State contributions to the financing of a nuclear project can be made through **tax credits during the construction phase**.

A fundamental challenge with such a scheme is to strike the right balance between :

- the appeal of significant public participation, which carries the advantage of reducing the average cost of financing; and,
- the contribution made by the operator of the current nuclear fleet, which already has the industrial skills necessary to be a competent project owner, as well as the corresponding technical and regulatory framework.

3.3.2. Sharing the construction risk

In the financing mechanism currently under discussion for the UK Sizewell C project, negotiations are underway on the question of how to share the construction risk between the project owner and the State. This risk is shared in the form of a maximum cost overrun threshold. The threshold is fixed in advance, and beyond this level the State will take over the financial responsibility for the overrun. In exchange for the cost-overrun share mechanism and because it contributes to a lower cost of capital, a CfD mechanism framework could apply that sets a lower Strike Price for the industrialist. It should be remembered that the UK National Audit Office, via its feedback on the HPC project, considers this trade-off between the taxpayer and the electricity consumer to offer a better social optimum at the community level. It is indeed via this trade-off that the community secures a minimal cost and therefore a low and maybe even the lowest price.

ANNEX

REMUNERATION ARRANGEMENTS WITHIN THE RENEWABLE ENERGY SUPPORT MECHANISMS

The law of 10 February 2000 on the modernization and development of the public electricity service introduced, among other things, a support system for electricity produced from renewable energies by way of the purchase obligation. In concrete terms, and subject to the need to preserve the proper functioning of the power networks, EDF and the non-nationalized distributors are required to enter into a contract for the purchase of electricity at a fixed price, for a maximum period of 15 years if the renewable energy producers concerned so request. The implementation of this system entails additional costs for the buyers (EDF and other distributors) which are fully compensated by a tax called the contribution to the public electricity service tax that was first levied in 2003 and that is paid by all electricity users (CSPE which stands for 'contribution au service public de l'électricité' in French).

In 2015, the law on energy transition for green growth (LTECV) reformed the financing of public service charges. This reform has two components. Firstly, public service charges are now included in the State budget. Secondly, the CSPE tax merged with the 'Taxe Intérieure sur la Consommation Finale d'Électricité' (TICFE, a domestic tax on final electricity consumption), under the name CSPE. Furthermore, under European guidelines on State aid that requires renewable energies to be progressively exposed to market competition, the 2015 LTECV introduces a fundamental overhaul of existing renewable energy support provisions. Feed-in tariffs, which had been the main support mechanism, will be progressively replaced by a so-called compensation mechanism, which is nothing more than a CfD. For the time being, support mechanisms retain the purchase obligation particularly for small renewable installations as defined in the law of 10 February 2000.

Thus currently, remuneration for renewables come under two headings:

1. With the feed-in tariff, electricity injected into the network by the eligible installations is bought back at a fixed price by EDF or the non-State-owned distributors (see above). This on-tap remuneration system is aimed in particular at low-capacity installations that are connected to the distribution network.

2. As part of the LTEVC's remuneration supplement framework, producers benefit from a CfD that allows them to benefit from a reference level of remuneration. Depending on the type of installation, this reference level is set either by the public authorities (on-tap) or through a competitive bidding process (call for tender). The remuneration supplement, which corresponds to the difference between the market price on which the renewable energy production is sold and the ex-ante fixed price level, is by definition variable. The final consumers bear the costs arising from the suppliers' obligation to pay for the renewable electricity injected into the grid.