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**Financing arrangements
and industrial
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Summary : The paper studies how the risks specific to a nuclear power investment in liberalised markets – regulatory, construction, operation and market risks – can be mitigated or transferred away from the plant investor through different contractual and organisational arrangements. It argues that at least for the first new reactors significant risk transfers onto governments, consumers, and vendors are likely to be needed to make nuclear power attractive to investors in liberalised markets. These different types of risk allocations will in turn induce different investment financing choices. Four case studies of recent new nuclear projects illustrate the alternative consistent combinations of contractual, organization, and financial arrangements for new nuclear build depending on the industrial organisation, the market position of the company and the institutional environment prevailing in different countries. The most likely financing structure will likely be based on corporate financing or some form of hybrid arrangement backed by the balance sheet of one or a consortium of large vertically integrated companies.

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1. Introduction

All the nuclear power plants operating today in liberalised markets have been developed by vertically-integrated regulated utilities. Under traditional industry and regulatory arrangements, many of the risks associated with construction costs, operating performance, fuel price changes, and other factors were borne by consumers rather than suppliers. The current context for new nuclear build is significantly different. The electricity industry structure has been transformed by gradual liberalisation in many developed and developing countries over the past 20 years. In the theoretical decentralised electricity market model, investors bear the risk of uncertainties associated with obtaining construction and operating permits, construction costs and operating performance and they also have to assume the usual volume and price risks. While many regulators favour strict unbundling between generation and transmission, as well as vertical de-integration between generation and supply, electricity reforms in most countries have not necessarily resulted in complete industry restructuring. There is a large variety of industrial structures and market rules from one country to another one. In some countries, part of the electricity price risk affecting plant investors can therefore be shifted to electricity marketers and consumers through long term contracts and/or vertical integration when regulation allows these arrangements. Depending on the proportion of the construction and operating risks which are borne by the power plant investors, they will ask for a different return on investment. This will in turn affect the financing arrangement adapted to the project, its capital cost and the relative competitiveness of nuclear compared to other technologies.

There have been few nuclear plant orders in liberalised markets over the past decade – to the exception of the Finnish and French plants under construction–, but rising fossil fuel and CO2 prices are reviving interest in nuclear power. A potential nuclear power renaissance in liberalised electricity markets will face a number of hurdles associated with the specificities of the technology and the legacy of past experiences. Nuclear power suffers indeed from some specific risks: i) the regulatory risk associated with the instability of safety regulations and design licensing; ii) the policy risk where electoral cycles could undermine the commitment to nuclear power and the development of nuclear waste disposal facilities; and iii) the construction and operation risks associated with the necessary “re-learning” of the technology. Besides, the large size of a nuclear project and the capital intensity of the technology make it relatively more sensitive to some critical market risks such as the electricity price and volume risks.

The key factor in the success of nuclear power in liberalised markets lies therefore in the ability of the power industry to engage with regulatory and safety authorities, plant vendors and consumers to allocate risks onto parties which are best able to manage them. By shifting part of the pre-construction, construction, operating, and market risks onto other parties (regulators, plant vendors, creditworthy consumers, etc.), electricity producers are in a better position to attract potential investors (lenders, etc.)

The allocation of the different construction, operating and market risks in turn influences the selection of the financial arrangements among different options. While in the past regulated utilities financed their investments using corporate financing with recourse debt and bonds, a wide range of options ranging from project finance with non-recourse debt and with high gearing to corporate and hybrid financing approaches are now available to investors in power markets (Etsy, 2004). Project

finance and hybrid financing approaches have been widely used to financing large and capital intensive infrastructure projects in the past decade. Modern project finance fits in theory perfectly well with the business model of the pure power producer, but interest in the so-called “pure merchant plant” model without long term contracts has collapsed with the bankruptcy of many merchant gas plant investments from independent producers in the US and the UK in the late 1990s. Given the risks specific to nuclear power and the alternative contractual risk allocations, it is critical to identify the possible coherent combinations of financing arrangements and industrial organisation allowing to transfer some of the risks away from the producer.

The objective of this paper is therefore to study how the risks specific to a nuclear power investment in different types of liberalised markets can be mitigated, how they can be allocated to the different stakeholders, and which financial arrangements are consistent with the alternative allocations of the construction and operating and market risks in different electricity market regimes. The paper is organised as follows. The next session details how the risks specific to nuclear power can be mitigated or transferred away from the plant investor onto other parties. The third section contrasts the different possible financing arrangements and how these are intrinsically linked to the contractual risk allocation between the different parties. The fourth section illustrates through four different case studies how different combinations of contractual and financing arrangements between the electricity producer, the plant vendor, the consumers, the public authorities and the lenders are viable depending on the local institutional and regulatory environment, the industry structure and the type of electricity reform realised in the country.

2. How can the risks specific to new nuclear build be mitigated or shifted away from the investor ?

We consider the different risks specific to nuclear build and different ways to *ex ante* mitigate them or to shift them away from the producer-investor onto another party. Although these risks are intrinsically related and partly overlap, we classify them in the following categories: regulatory and political risks, construction and operating risks, and finish by market risks (volume and price risks). It is noteworthy that some of these risks, in particular market risks, are not intrinsically related to nuclear power, but are magnified by its specific characters including the long construction lead time, the high capital intensity and the absence of correlation between nuclear operating costs and hourly electricity prices, contrary to other generation technologies such as combined cycle gas turbines (CCGTs).

2.1. Regulatory and political risks

We consider in this section risks associated to regulatory action or political choice which are exogenous and not inherent to the management of plant planning and realisation. While all power generation technologies are subject to the risk of changing regulations on environmental protection, nuclear projects face specific regulatory and political risks. In many countries, the uncertain outcome and likely complexity and length of the public inquiry add to the licensing phase uncertainties. Besides, political and regulatory requirements may change during the design and construction phase, adding to the above risks (for example, following a change in government). There are also regulatory and political risks during the operating phase (such as retroactive regulations, political phase-out decisions...).

In the past, disputes about licensing, local opposition, cooling water source, redesign requirements, quality of control, etc. have delayed construction and completion of nuclear plants in a number of countries, in particular in the USA and Germany (Bupp et Derian, 1979; Nuttall, 2005).

Political and judicial risks are related to the 'politicization' of nuclear energy and the difficulty to build a large social acceptance. Levy and Spiller (1994) highlight how the credibility and effectiveness of a regulatory framework - and hence its ability to facilitate private investment - vary with a country's political and social institutions in network industry. In this perspective, countries which want to re-open the "nuclear option", a strong political leadership is needed to reduce regulatory and licensing risks at different levels (Delmas and Heiman, 2001):

- The safety regulation, both for the certification of reactor technology and for the stabilization of safety regulation;
- The definition of a legitimate solution to the nuclear waste disposal issue;
- The stability of the legal framework on limited liabilities and insurance provision in case of nuclear accident;
- The political process for building acceptability on plant siting and nuclear waste management.

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In this perspective, governments and regulatory and safety agencies have a critical role to play in setting on clear and consistent procedures for licensing design and authorization procedures for siting. The mitigation of the key risks in the regulatory and licensing process requires smooth cooperation of regulators, utilities, and nuclear plant vendors, in ensuring respectively a smooth plant siting and licensing process, a clear design certification procedure and the stability of the safety rules.

In countries - such as the USA - where safety regulation had generated large risks on construction costs and lead-times in the past, new streamlined licensing procedures should help reduce regulatory risk, but governments might also want to provide investors with additional guarantees that they will shoulder any unforeseen costs due to regulatory changes or delays..¹ In the same perspective, it has been argued in the UK that given the long lead-time of nuclear projects it would be economically efficient that the government guarantees the State commitment in favour of the nuclear option (WNA, 2005).

2.2. Construction risks

All large-scale complex projects are characterised by above-proportional levels of completion and financial risks (Etsy, 2002). In a review of 60 large \$1-billion engineering projects, Miller and Lessard (2000) show that the critical factors of poor performance are a high proportion of public ownership due to soft budget constraint ; extra-large scale (complexity and management problems); and if they are first-of-a-kind or one-of-a-kind (lack of experience, design risks, etc.). The last two factors will be at play in nuclear projects.

¹ In the USA, a complementary guarantee against regulatory risk has been introduced in the 2005 Energy Policy Act for the first new nuclear projects. Under this scheme a standby insurance for regulatory delays is provided for the four first projects: 500 millions for the two first ones and 250 millions for the next two.

Compared to other power generation technologies, new nuclear build is characterised by long lead times (3 years for project preparation, 5 to 6 years for construction), and high front-end cash outflows (€ 4 to € 5 bn for a first-of-a-kind (FOAK) plant of 1500 MW, €3 bn for a standard plant, to compare to an investment cost of €500 millions for a large CCGT of 600 MW). It is also likely to have high cost estimation and schedule risk around the forecast baseline lead-time, based on past experience construction cost overruns. Nuclear plant construction risks are amplified by the capital intensity inherent in such large and complex projects: a construction delay of 24 months will increase the levelised cost of nuclear kWh by about 10% compared to about 3% for a gas CCGT and 7% for a coal generation plant (IEA, 2006). Besides, industrial “re-learning” associated with advanced reactor designs increases not only the construction cost, but also the construction risk for the first units. Investors will need to gain confidence in the maturing “Generation 3” evolved nuclear technologies (ABWR, EPR, AP1000, ACR, etc) proposed by nuclear plant vendors.

One critical aspect to assess project construction risk is the quality of project management – more precisely the interaction between the plant vendor, the utility, and the engineering and construction (E&C) company. Past experience shows a large difference of efficiency in project management between countries and suggests that large utilities leveraging their own engineering and procurement capacity may be in a better position to: i) limit the overall engineering costs of each project; ii) develop industrial programming and standardisation on series; and iii) maintain a bargaining power with the reactor vendor (Thomas, 1985; Zaleski, 2004). In France, EDF has been able to leverage such advantages by maintaining a large engineering department, while German utilities have been relying on the engineering services of the reactor vendors, and US utilities have historically been dependent of architect engineers such as Bechtel, Ebasco, etc. , to the exception of Duke Power and TVA.

Different solutions are possible to mitigate construction risk by spreading the risk across different parties, or to transfer part or the whole of the project risk to the plant vendor. One solution is to associate in a consortium the reactor supplier and eventually the E&C company with the investor and have the consortium collectively commit to a firm construction price contract, as presented in the Texas University study on the South Texas nuclear plant project (TIACT, 2005). Such fixed price contract would incite vendors and E&C company to control the manufacturing and engineering costs. A more direct solution is a ‘turnkey’ contract which shifts onto the vendor a substantial part of the construction risk. In the perspective of initiating a renaissance of the nuclear market, plant vendors might be more inclined to bear part of the construction risk than in the past, in order to demonstrate their evolved new designs and build confidence. For instance, AREVA carries the major part of the construction risk for the first unit of its EPR design under construction, the Finnish Olkiluoto 3 reactor with a total project fixed price of €3.2 billion.

It is however unlikely that nuclear plant vendors will accept to bear all of the construction cost risk through turnkey contracts in the future after the FOAK. Some countries might want to subsidise the first new nuclear units by shouldering part of the construction cost risks in order to fasten the re-learning process of nuclear power technologies. The re-learning cost for the first units could indeed deter investment and some argue that government support is necessary to help demonstrate the technology.

This could be justified by the social benefits that cumulative learning will help to draw in the future in terms of avoided CO₂ emissions at reasonable cost by next competitive nuclear reactors.¹

2.3. Operating and performance risks

From the perspective of a financial investor, operating, performance, design and construction risks can be regarded as layers of the same category of risks, as they represent the same underlying uncertainty about successful operation of a given technology and design, in particular when a technology has been dramatically improved.

The extent of technological uncertainty relating to the FOAK depends on whether established designs have been used, or whether relatively new designs have been put forward. At the operating stage, this may also affect technical reliability. In the case of a nuclear plant, considerable complexity and highly specific engineering both add to the problem of limited understanding of those risks by external investors. In theory, financial investors should demand a very high premium for informational asymmetry arising from limited understanding of these risks; in practice, investors may be unwilling to assume these risks at all as long as confidence has not been established in the performance of the technology. Experience of exchanges of nuclear assets on the US electricity industry between 1998 and 2001 shows that creditors did not want to assume any portion of nuclear performance risk even when there is an established track record (Esty, 2002; Scully Capital, 2002).

As a consequence, contractual arrangements have been developed in different industries to mitigate and transfer these risks away from uninformed parties. Performance risk could be allocated to the equipment vendor, e.g. through a guaranteed lifetime load factor. In the case of CCGT projects, the large vendors (General Electric, Alstom, Siemens, etc.) accept to bear the performance risk during all the lifetime of the plants. In the case of nuclear project, the Finnish contract contains provisions for the vendor AREVA, to assume part of the operating risk: the contract is based on a nominal load factor of 91% on all the lifetime of the equipment.² Based on empirical data from existing reactors, this appears as a risky bet for a FOAK reactor, and it is unlikely that the other nuclear vendors will be ready to assume such a risk in their future FOAK projects.

2.4. Market risks

Market risks are sell-side risks arising from highly fluctuating fuel, CO₂ and power prices. These market risks are not specific to nuclear projects, but the large size of nuclear plant exposes the investor to greater risks than other smaller size modular generation technologies (Gollier et al., 2006, Roques et al., 2006). Indeed, despite low capital intensity and the benefit of relatively stable net cash flows through highly

¹ In the USA for instance, the 2005 Energy Policy Act creates a federal support which includes a provision of loan guarantee for the first 6 GWe of nuclear plants ordered before a deadline, as well as a production tax credit of \$18/ MWh during eight years which is a response to these learning costs and risks for the first 6 GWe of nuclear plants ordered and commissioned before precise deadlines (NEI, 2007). It includes as well as a loan guarantee up to 80% of the investment cost if debt covers up this amount, the Department of Energy being allowed to issue this guarantee to several projects for a total budgetary envelop of \$18.8 billions.

² Personal communication with an AREVA manager.

correlated gas and power prices in many markets, market risk also exists for CCGT plant (Roques, 2008). A large number of pure CCGT producers went bust in the US in 2002-2003 when the gas price increased threefold, because they were displaced from base load to mid load. A nuclear plant is not exposed to the same "dispatchability risk" as CCGT plant, because its low variable costs makes it sure to be dispatched as a base-load generator, provided that is available. On the other hand, with a cost structure symmetrical to the one of the CCGT (60% of capital investment in total cost against 25% for the CCGT), the capital intensity of a nuclear plant makes it vulnerable to sustained periods of low electricity prices.

One additional component of price risk is the risk associated with the CO₂ price in Europe. The attractiveness of carbon free technologies such as nuclear plant for a power producer is reinforced by the additional cost placed on fossil fuel generation technologies by climate policies and CO₂ emissions pricing. But the CO₂ price risk associated either with the volatility of the European Trading Scheme allowance price in Europe, or with the uncertainty on any carbon pricing scheme in other countries discussing the introduction of such policies increases market price risks and can actually adversely affect nuclear. Because marginal plants are fossil, the power price and CO₂ price are highly correlated, which implies that fossil fuel generation which sets the power price is largely hedged against fuel and CO₂ price risk, contrary to nuclear plants. The CO₂ price risk is largely political in nature and investors find it particularly hard to appreciate and to develop hedging strategies (Grubb and Newbery, 2007).

Different options are possible for investors and producers to securitise any generation investment in electricity markets by transferring part of the market risk on to other parties, such as vertical integration, long term contracts, or the combination of horizontal integration and vertical arrangement in a consortium. Such arrangements can help to shift the market risks onto other players than the producers, in particular retailers and consumers.

Long-term contracting between new nuclear generator and large credible buyers. Intrinsically interests of generators and large wholesale buyers converge to manage their market risks (Chao, Oren and Wilson, 2008). Indeed producers and buyers have a natural incentive to insure each other against volatile spot prices on a long period. But their interests diverge on two aspects: first, producers' need for an off-take guarantee contrasts with suppliers' need of flexibility because of the variation of their loads and market shares; second, the risk of opportunistic behaviour of the buyers which are less committed to the transaction than a new generator and could be tempted to break the contract in case of market downturn. In fact, suppliers do not wish to be bound by Power Purchase Agreements (PPA) with fixed prices (or any clause of price indexation on fuel price) on a long time-span. But to commit to fixed-prices contracts, wholesale buyers (distributors, industrial consumers) must be quite sure that power prices will not drop to a low level (Neuhoff and De Vries, 2005). The recent literature studying the conditions of generation investment and vertical arrangements has shown that the needed contractual credibility could be reached if guarantees which limit opportunistic behaviour of the counterpart exist (Joskow, 2006; Michaels, 2006; Chao, Oren, Wilson, 2007; Finon, 2008). In the case of suppliers, the guarantee could result from the possibility to shift their risks on part of their customers either because they retain a large core consumer base or because they benefit of a supply franchise on the households segment.

In the case of industrial consumers, the guarantee could be common ownership of the new generation equipment in partnership with a producer in consortium. In the same perspective, CO2 price risk could be transferred onto government by long term option contracts which would be auctioned in order to guarantee minimum revenue for new non carbon capital intensive equipments, comparatively to marginal fossil fuel generation units (Newbery, 2003; Ismer & Neuhoff, 2006).

The model of generation cooperative. In some industries such as the world oil and gas industries, producers are used to jointly develop some large projects to share costs and risks. Joint interest of different stakeholders could lead to the creation of a consortium to develop a new nuclear project in order to share costs and allocate market and construction risks by mixing horizontal and vertical arrangements. Different types of consortium structure can be envisaged: a consortium of end-users and suppliers; a consortium of end-users, large suppliers and power producers; or a consortium which associates nuclear business (reactors vendors, E&C companies), end-users and power producers.¹ Arrangements would need to be organised by PPAs between the consortium and its member end-users and suppliers to securitise repayments of debt. In particular as end-users are unlikely to be as risk averse as the non-regulated suppliers and to search a high return on investment, the joint company could sell to them nuclear output at cost, plus a reasonable margin as in the Finnish EPR project. These contributions could help consolidate the transfer of the different risks organised in the different contracts and be perceived as a source of efficiency that could make the consortium structure as an attractive organisational model.²

Combination of vertical and horizontal arrangements. Partial or complete vertical integration is another option to secure investment in generation by guaranteeing off-take quantities and sales prices of the project power production and by passing the fuel risk on to the internal wholesale buyer. We consider here vertical integration between generation and supply businesses, and not between generation and regulated transmission system which is not a necessary condition, even if a number of experts could view it as a condition to insure secure cash flow for investing in highly capital intensive infrastructure in other energy network industries. When vertical integration is associated to a diversified portfolio of generation equipments, the latter gives a complementary advantage in terms of hedging to investment projects from vertically integrated companies in comparison to a merchant plant project - even backed by a long term contract with a credible party -, as pointed out by Chao, Oren, and Wilson (2008). Since they benefit from a large and diversified asset base, they are able to obtain loans under corporate financing arrangements and consequently, owing to a normal debt-equity ratio (50/50) and good ratings, save on capital costs and risk premium.

¹ The consortium of owners created to manage the new investment could take one of several forms – the simplest being a corporation, which is a distinct company created solely with the purpose of managing the project. Another possible form of a legal entity for sponsors is a general partnership, which operates as a distinct legal entity for contractual and financing purposes.

² Such consortium would also reduce the market risks. But they present different performances in terms of organisational issues to control costs and performances, financial issues and required rate of return on investment. Three consortium options for a nuclear power plant project in Texas have been compared in this sense by the University of Texas (TIACT, 2004)

But a sum of successive nuclear in an ambitious strategy might alter the credit rating of the company and its average capital cost for the large volume of capital of the company.

Companies benefiting from a diversified portfolio of generating stations can rely during low price period on “portfolio bidding”, i.e. occasionally to bid at prices below the generation cost (investment and fuel) of their capital intensive equipments. For instance, if one company adds one nuclear power station to its portfolio, it could be able to protect its investment if price decreases below the complete cost, i.e. when net cash flow could not cover annual amortization (Roques et al., 2008). Finally, integrated companies can generally leverage a large and diverse set of customer relations. This combination of advantages is likely to be critical when considering potential candidates for a new nuclear plant projects with specific market and construction risk mitigation arrangements.

3. The compatibility of contractual, organisational and financing arrangements

The different contractual and organisational arrangements detailed in the previous section have in turn an impact on the attractiveness of alternative financing structures for a nuclear plant - ranging from project financing to corporate financing and hybrid financing.

3.1. Financing arrangements for new nuclear build

In theory, there exists a large variety of financing structures that might be considered for a nuclear plant project. A precise answer as to which exact structure would be optimal is likely to involve a detailed investigation of all possible pros and cons of different designs. The financing structure will have important implications not only for the costs of financing and risk allocation, but also for rules of operation and contingent control over assets. .

The two basic types of financing are *equity* and *debt*. Equity capital acts as a buffer for absorbing variability in cash flows and is necessarily influenced by the risk profile. Considerable uncertainties associated with successful implementation of the construction phase are likely to make it difficult to raise high levels of debt for the initial part of the project without any government support if nuclear industry is in the phase of re-learning and if the future owners-operators are not backed to a parent company with a strong balance sheet. Overall, the exact level of project gearing will need to be optimised according to various considerations including the need of new capacities to follow consumption growth and equipment closures, anticipation of price spikes in relation to the competitors' technology mix on the market, anticipation of the trend of fuel price and CO2 allowance price, predicted financial characteristics of revenues, and allocation of risk between different parties.¹ Still, financing choices are not constrained to a simple dichotomy between equity and debt. Typical business financing models are now diversified and adjusted to fit particular purposes and needs of the project.

¹ White (2006) shows how the gearing ratio debt/equity for a nuclear plant is mechanically much lower than for a CCGT which has a much lower ratio fixed costs/fuel cost. While the gearing might easily reach 80% of debt for a CCGT which fixed cost is only 20-25 % of the total cost, we can calculate for the nuclear plant gearing reaches no more than 50%, given that investment cost reaches 65% of the total cost.

Although in general rather complex, project finance solutions can be value-creating and particularly applicable in situations where certain business characteristics of the project are unique and can be exploited for the mutual benefit of operators and capital providers alike.

The issue of equity investment is common to both project finance and corporate finance. In any financing structure there could be a single sponsor or a consortium of sponsors.¹ Since the participation of more than one party sponsors of the project usually involves creating a separate company with split ownership, such arrangements are more typical of project finance, although they can also be adopted in hybrid structures of corporate and project finance characteristics. While it is common for an electricity utility to be the sole sponsor of a new plant development, minority participants might co-sponsor the project, for instance through a direct equity contribution. Engineering and construction companies often participate in new, large-scale investment as sponsors. Such arrangements are usual for large-scale projects from outside the electricity sector (infrastructure, oil and gas projects), and are gaining popularity in the power generation business. Given the fact that the amount of equity required for a new nuclear plant project can be considerable, creating a broad consortium of equity holders might be critical to the success of the project (OXERA, 2003).

Candidates for sponsors include specific nuclear technology providers and others with particular interest in the nuclear sector. It could be an incentive for a reactor vendor to reduce lead-time and construction cost, in particular at the end of the construction process. Given the unique nature of this development and its potential importance for nuclear technology providers, the latter could become substantial equity holders in projects for the first one or two reactors that they would sell in order to benefit from industrial reference (OXERA, 2004).

An alternative way of their involvement in a nuclear build is the turnkey contract which allocates major part of the construction risk onto the nuclear plant vendor, an arrangement that AREVA chose for the first EPR plant under construction in Finland. It certainly helps the sponsors to obtain cheaper loans. But it is worthwhile to notice that any constructor has no interest to bear the construction risk for the next reactors. Beyond the first two reactors, it risks to meet a design mistake, which tend to be correlated across a series of new stations, and if it implies long repairs, this risk might easily bankrupt the vendor that has provided guarantees.

3.2. Corporate finance versus project finance

The two main approaches to financing the development of a nuclear plant can be referred to as *corporate finance* and *project finance*. Between the polar extremes of corporate and project finance lie a multitude of *hybrid* options.

¹ A consortium of owners created to manage the new investment could take one of several forms – the simplest being a corporation, which is a distinct company created solely with the purpose of managing the project. Another possible form of a legal entity for sponsors is a general partnership, which operates as a distinct legal entity for contractual and financing purposes.

The crucial feature of *corporate financing* is the importance of the project developer and its direct involvement in taking the risk of the project onto its own books.¹ Under such an arrangement the new asset (the power plant) remains an integral part of the sponsor's entity, and hence of the sponsor's balance sheet. Therefore, from the financial perspective, the critical aspect of corporate finance is that neither the new asset nor the liabilities to the creditors financing the new asset are legally separated from the remainder of sponsor company's assets and liabilities. Implicitly, new creditors purchase an option on cash flows from the company's other assets because managers are more likely to subsidise the new investment from other corporate assets than to risk bankruptcy of the company as a whole by defaulting on financing for the new investment. The critical point in the modern finance perspective is that corporate financing is not asset-specific but represents the sponsor company's general borrowing. It is therefore driven by the sponsor's general financing situation as its terms are based on the sponsor's credit rating and leverage in addition to pure investment factors. In the case of a new nuclear power plant, the sponsor's financial circumstances might therefore uniquely determine the terms and conditions of the new borrowing that is viewed as negative from the modern finance perspective.

The key feature of project finance is the legal separation from sponsors' other assets of what is most typically a single large asset constituting a new, self-contained, well-specified investment by the sponsor(s). The legal separation ensures that the project entity's creditors – the lenders to the independent power producer (IPP) – have no recourse to the parent. The 'project' in project finance is not simply a group of assets based on a self-contained and highly focused investment, but is also a set of contracts governing the use of that investment. These contractual arrangements can significantly alter allocations of risk among different entities involved in the project. Specifically, selected risks can be transferred away from the project finance vehicle and onto sponsors. For the construction of a new power plant, these contracts typically include: i) a construction and equipment contract with an E&C company, and several different contractors and technology providers (reactor and turbo-alternators vendors) which could include some turnkey principle; ii) a long-term fuel supply contract; iii) one or several long-term power purchase agreements with electric suppliers or large consumers at fixed price; and iv) an operating and maintenance contract. During the stage of institutional and industrial relearning of nuclear technologies, government could also assume some risks, in particular by the way of loan guarantee as is doing the US government for the first 6 GWe of plants to be ordered. In other words, project finance could be conceivable for new nuclear builds if around the special vehicle entity, PPA at fixed price, turnkey contracts and government loan guarantee are set for securing the investment; or at least two of them as in the Finnish order.

While project finance deals are characterised by a significant degree of complexity and thus high transaction costs, they have been popular for new projects in the power industry in liberalised markets in the 1990s and early years of 2000 with low capital intensive CCGT projects. However, following the bankruptcy of many IPP's CCGT merchant plants in the US after 2002 after gas price upheaval, lenders have become much more cautious and the financing of new merchant plants has dried up (Scully Capital (2002)).

¹ In the terminology of modern finance, we distinguish the following categories: the developers who promote the project, the operator, the lenders, the project sponsors i.e. the parent company in simple projects, but also eventual associates in a consortium projects as equity sponsors; and other interested parties as fuel vendors.

Most of the merchant plants installed in the US liberalised markets did not have long term off take power purchase contracts and were exposed to significant volumetric risk (Joskow, 2006; 2007; Michaels, 2006).

The key advantage of the *corporate finance* methodology is its simplicity. No special legal, financial or administrative structures are required. This is likely to diminish the transaction costs substantially in comparison with project financing. Also, since financing in the latter case is done on the basis of the existing corporate balance sheet, it can build on previous financings arranged for this entity, enjoying the same market name recognition, reputation, investor familiarity with the risks involved, and the past performance record. This explains the recent trend in the power industry to come back to corporate finance, with investment risks managed through a diversified plant portfolio and vertical integration inside a large firm.¹ Or else through such portfolio combined with a set of long term PPAs with creditworthy buyers in the case of pure producers as some examples exists in the USA (Exelon, Constellation, NRG Energy, etc.). Combination of corporate finance with vertical integration appears to be a relevant solution for financing future nuclear plants because this combination is quite well aligned of risk management requirements for a new nuclear build. Most importantly, corporate finance could be the only available option if the project is seen by the investors as too risky to be financed on a stand-alone basis (Hudson, 2002).

New *hybrid* finance arrangements have emerged in which project finance is combined with long term fixed-price/indexed-price contracts. Hybrid project financing for merchant nuclear could therefore also be envisaged under different possible schemes close to corporate financing. The first scheme is project finance with one or several long term fixed price contracts with creditworthy buyers, and a low degree of leverage of 50%; but it could eventually be increased to a level of 75-80%, with the addition of a government loan guarantee as we see as being possible for some US projects, or else with turnkey contracts and performance guarantees as it is the case for every CCGT project. The second possible scheme is a project financing structured as corporate financing, i.e. in which the power generating company is the borrower with the backing of the parent company, a corporate structure that combines a power generation company and an electric distribution company.

3.3. The impact on cost of capital

The limited leverage is an important drawback of any corporate finance funding arrangement (OXERA, 2004). Leverage in corporate financing is likely to be as low as 50%, with a substantial amount of equity required for the project. Some possible benefits of leverage, including low capital commitment and high debt tax shields, will no longer be available relative to a comparable project-finance transaction for CCGT. But this drawback needs to be nuanced in the case of a nuclear plant given that gearing in a project finance arrangement for a nuclear plant would likely reach 50% at most because of the high ratio of investment cost in the cost price.

Given the probable remaining concern for nuclear stations once first few will be built, lenders should prefer to focus not only on the risk exposure of projects, but also on financing profile of companies (size and structure of its balance sheet). Because of this concern, when equity investment in an nuclear project goes beyond 15%-20% of

¹ A portfolio theory approach can help to identify the best risk-return portfolio of power plants assets for a de-integrated producer, with the optimal share of nuclear power depending on the degree of risk aversion of the producer (Bazilian and Roques, 2008, Roques et al., 2008).

market capitalisation, they will be worried about the effect on the shareholder value. The financial equation of nuclear investment for companies of any size below a €20 billions market value is more difficult to balance. A nuclear power investment of € 2 to 3 billions would likely put stress on such company's credit rating and their stock share value. This value can be altered by the dilution of capital resulting from the need to provide about \$1 billion of equity, and by placing substantial capital investment at risk for an extended period of time.

That does not mean that WACC of large companies will not be altered if they want to build a number of nuclear plants. Each project, if they are perceived as risky, will add a small risk premium to the WACC of the companies by decrease of the credit rating, but at the end, applied to a large volume of capital, it could have an important effect. Moreover total of equity investment in several nuclear builds could at the end reach the same precautionary threshold of 15%-20% of market capitalisation (for instance €6 billions in equity for 4 plants for a market cap of €40 billions) than one nuclear build for a small company. Ownership of already amortised existing nuclear assets could enhance the credit rating of a company in the future, as the existing nuclear plants cashflows could pay for new nuclear build with good prospect on future return on equity, in particular in a probable scenario of high CO2 price.¹

However, to date, the relation between nuclear plants ownership and the companies' credit rating in the notation agencies is not obvious, as nuclear plants have for long been perceived as a source of risks for a company rather than as a potential hedge for new investment. In theory, companies with a large fleet of nuclear plants in their assets portfolio should benefit from lower correlation of their share value with the market value compared to rival electricity companies with no nuclear plant. There is yet no systematic research published on the effect of ownership of nuclear assets on the "beta" of electricity companies in Europe (Table 1).

In the US, a 2005 study by Bloomberg Financial Markets on the largest energy companies operating nuclear plants (Exelon with 17 reactors in 2005, Entergy with 10 reactors, Dominion Resources and the FPL group) shows that they have far outperformed the overall stock market performances in 2004 and 2005 (Gray, 2005).²

Table 1. Comparison of WACC (nominal after tax) and beta coefficient between some European companies in 2000

	Endesa	E.ON*	RWE	Iberdrola	Electrabel
Nuclear share in their capacity (home market)	12%	25%	14%	15%	40%
WACC	6.3%	6.2%	6.4%	6.1%	6.6%
Beta coefficient in CAPM	0.81	0.61	0.58	0.62	0.54

* Note: Average of VEBA and VIAG's WACC and in 2000 before merger.
Source: Lautier (2003) for WACC, and Verminen for beta coefficient (2000)

¹ This is one main reason for which a number of written-off nuclear plants in the US markets have been sold by regulated utilities to some merchant companies specialised in nuclear plants operation. These later companies can indeed extract greater benefit from the large margins of these nuclear plants than regulated companies with cost of service tariffs (Lacy, 2006).

² Website access to the Bloomberg study: 20057 <http://www.bloomberg.com/markets/rates/>

An interesting extension would be to compare how different institutional arrangements and nuclear assets ownership affects the “beta” of the companies market values on a wider scale including other OECD countries (Japan, South Korea in particular). One issue, however, is that many countries with nuclear plants do not operate in a market economy or have not liberalised their electricity industry (Japan and South Korea for instance have not introduced wholesale and retail competition in their electricity industries).

In sum, lenders are likely to prefer to lend money to companies with a strong rating and a large balance sheet – ideally with a large and diversified asset base and vertical integration. Corporate financing by large European companies (the so-called ‘seven sisters’ with more than € 35 billion of market capitalisation) is therefore likely to be the dominant forms of financing for new nuclear plant in Europe. But smaller-size companies are also candidates to new nuclear build in liberalized markets, in particular in the USA where the industry is more fragmented than in Europe. Some independent producers (Constellation and NRG Energy) with a balance sheet of less than € 7 billion (\$10 billion) and a not so diversified portfolio of assets have recently announced plans to build new nuclear plants in the US (Table 2).

Table 2. Market capitalisation of some large- and mid-size electricity companies in Europe and the USA in 2008 (in €billion)

Market valuation	Companies	Comments
€ 50 to 100 billion	EDF (€108 bn) ; E.ON (€ 80 bn) ; Suez-Electrabel (€52 bn)	
€ 30 to 50 billion	Iberdrola (€50 bn); RWE (€40 bn); ENEL (€40 bn); Endesa (€35 bn); Exelon (€ 35 bn).	In this range, Exelon is the sole US company.
€ 10 to 30 billion	TVA (€20 bn); FPL Group (€18.5 bn); Duke Energy (€15.2 bn); Entergy (€13 bn); Texas Utilities TXU (€15 bn); Vattenfall-Europe (€11.9 bn); Detroit Edison (€9 bn).	As TVA is a government company, its capitalisation is its balance sheet’s amount. TXU was bought by hedge funds for \$45 billions but had debt of \$25 billions.
Less than € 10 billion (Non-integrated companies)	NRG Energy (€6bn) ; Constellation (€3 bn) ; AES (€6.5 bn); Calpine (€4.8 bn); Mirant (€3.5 bn).	AES, Calpine and Mirant are not candidates to invest in nuclear plants.

Reference: Stock market quotation on mid-march 2008. Note : Exchange rate of 1.5US\$ to 1€

The impact of new nuclear build on the market value of electricity companies is difficult to assess. While during the build period the construction risk could alter the value of the company, the stable net cash flow of the new asset during the operating period could improve the company market value if the availability factor is good. Moreover, the collective perception by the financial community of nuclear assets profitability could be volatile.

But once confidence is established, asset value of existing or new nuclear units increase as shown by their increasing second hand price in the sale of nuclear assets between US electricity companies during the period 1998-2004 (Nuttall and Taylor, 2008).

4. Case studies. Alternative consistent combinations of contractual and financing arrangements for new nuclear build

When comparing different nuclear investment case studies, it is important to emphasise how the local industrial organisation and institutional environment will make some organisational and contractual arrangements more suitable in one country than another (Delmas and Heiman, 2001, Bredimas and Nuttall, 2008). Countries in which the operators remain vertically integrated between generation and supply and where nuclear option meets sufficient political legitimacy, could benefit from the better position of such companies to manage the risks specific to a nuclear power investment. Besides in some countries such as France, the slow pace of electricity market reform has been partly motivated by the objective to preserve the capacity of the incumbent company to invest in large scale and capital intensive projects such as nuclear plant (Finon and Staropoli, 2001).

In the case of new nuclear build, the local institutional environment and the industrial organisation of the power and equipment companies will therefore play a determinant role in enabling different types of risks transfers from the utility to other parties. In this section, we illustrate through 4 case studies how the local environment leads electricity companies to favour one set of organisational and contractual arrangements. Similarly, we review how the financing arrangements (corporate finance, hybrid finance, project finance) are aligned with these contractual arrangements, the specific institutional environment and the industrial structure of the electricity industry (including the size of the investor company and its vertical and horizontal integration to benefit from scale and scope economies in the management of its risks). The four case studies considered are the US nuclear merchant project of South Texas Project of the NRG Energy group, the consumers' consortium project of Okililuoto in Finland, the large size, vertical company's nuclear project of EDF's Flamanville EPR and some hypothetical projects in oligopolistic mid-size vertical company such as the UK.

4.1. The conditions of viability of a nuclear merchant plant project in liberalised US markets : The case of the South Texas project

Besides the nuclear plant orders in US states which are still regulated, some announcements of nuclear projects by non-vertically integrated producers in liberalised US markets in 2006-2007 seemed to announce the renaissance of nuclear in a "merchant" framework. The rationale to invest in nuclear build in liberalised markets lies in the opportunity to earn potentially greater revenues than under the cost of service regulation (Lacy, 2006).¹ Besides the South Texas Project (STP) that is studied next, four other projects have been announced in these liberalised markets.²

¹ "As a merchant we have to be careful, but also as a merchant the reward is at a much higher level of return compared with regulated utilities". says M. Shattuck, the Constellation chairman on September 2007 at the Merrill Lynch Power and Gas Leaders Conference in New York.

² Beside The South Texas project (STP) one can list the project of the Texas power company TXU of two APWR builds, two projects of the specialised nuclear producer Constellation-Unistar with EPR projects in Calvert Cliffs in Maryland, and the Exelon 's project in Clinton in Illinois.

The South Texas project (STP) of two ABWRs, each of 1200 MW, is promoted by an independent producer: the NRG company. NRG has been the first unregulated company to submit for one of the joint construction and operation licences (COL in September 2007). Project financing arrangement of the STP is made possible by the different Federal guarantees, which aim to alleviate the construction and regulatory risks, and also by a series of PPAs with creditworthy parties. Indeed the project will be backed by long-term fixed-price contracts with municipalities and historic suppliers.

A consortium of producer and suppliers to share costs and risks. The best way to reach this condition is to associate historic suppliers or monopolist distributors to the project inside a consortium structure. And it is possible in Texas in which there are monopoly 'islands' composed by large municipalities (Austin, CPS Energy of San Antonio, etc.) which cover 20% of the retail markets (Adib & Zarnikau, 2006).¹ The promoter of the project, NRG Energy, is an IPP company with a diversified portfolio of 23 GW in different technologies (CCGT, OCGT, coal plants and a nuclear plant) and operating on different markets (Texas, South Central, North East and outside USA in Australia and Brazil)². It creates a consortium with two monopolist municipalities with the following shares: NRG 44%, Austin Energy 16%, and CPS Energy of San Antonio 40%. The latter will contractually off-take 56% of the electricity on a cost-price basis. So risks are shared between NRG and the two municipalities, while NRG also benefits from its assets portfolio for risk management.

Mitigation of risks on construction costs and performances. Importantly the investor reduces the risks on siting and construction costs by building them on, or adjacent to, an existing nuclear site, in part because local communities already accept the plants. It also chose the General Electric ABWR technology already developed and tested in Japan and Taiwan by the GE's licensees Hitachi and Toshiba. This approach reduces both construction risk and operational risks. The experience with the previous construction of ABWRs implies that the constructor can rely on existing manufacturing lines, and thereby reduce the first-of-a-kind engineering cost, thanks to the construction partnership between General Electric and Hitachi. This cautious technological choice combined with the federal standby insurance against the regulatory risks can explain why a turnkey contract is not judged necessary.

Learning costs and risks bearing by the federal government. As mentioned above, federal support includes a production tax credit (PTC) of \$18/MWh on the first 8 years of operation allocated on the first 6 GWe of nuclear plant. It is an implicit attribution of a virtual CO2 credits in the line of the PTC attributed to renewable energy projects. It is meant to compensate the learning costs which affect FOAK projects and to enhance the financial attractiveness of such a project. However, it does not address financing challenges before and during construction. If lenders require it, securitization can turn these guaranteed revenue streams from government into lumps of capital in the special purpose vehicle of the project financing, as shown more generally by George (2007).

¹ In the US States in which electricity markets have been liberalised, there is a variety of electricity firms: historical suppliers which have retained part of their generation assets, independent producers which sell their electricity on the power exchange and bilaterally, municipal utilities which retain their legal monopolies, and new suppliers which compete with historical suppliers on specific market segments.

² NRG, 2007, "NRG Strategy: platform established for multiple growth opportunities". Web Site of NRG Energy.

Another support defined in the 2005 EPA Act allows a US Federal loan guarantee of up to 80% investment of projects of unregulated companies.¹ The bankers get guarantee to receive their payments in case the electric company defaults on a new nuclear plant developed with project finance after the commissioning of the equipment. So a large part of the learning cost and construction risks are assumed by the Federal government.

Regulatory risk bearing by federal government. All the new nuclear projects benefit from the mitigation of regulatory risks by the safety certification of Standard Plant Design, the new early site permitting process, and the new streamlined procedure of license established at the end of nineties in order to limit the cost and delays associated with licensing new commercial plants. The major part of remaining regulatory risks would be borne by federal government if the project applies for a construction and operating license (COL) before the end 2008, deadline which is defined in the Energy Policy Act of 2005 to be eligible for Federal supports. A complementary element of federal support is the limitation of regulatory risks by the Federal government by the standby insurance for regulatory delays for the four first projects (500 millions for the two first ones and 250 millions for the next two).

Market risks: Securing the investment by long term contracts. The consortium is likely to benefit from favourable financial terms because of the presence of municipal utilities which will be a proof of predictability of the customer base and stability (TIACT study, 2005). They could have the possibility to transfer risks on the local consumers via their tariffs. Moreover 75% of the NRG's energy share (44%) will be sold by long term contracts with historic suppliers in Texas.² Only the production of the remaining 400 MW will be sold into the market in order to seize opportunities to retain benefits from future carbon policies in the mid term (Crane, 2007).

A project financing. Project financing relies in theory on a set of long term contracts. But the major help in this case comes in fact from the loan guarantee for up to 80% of the project. This loan guarantee is an important subsidy as it has a double effect on the financing structure of a nuclear plant project. First it allows access to guaranteed debt, which has therefore a lower interest rate (for instance 5% instead of 8% in real terms). Second, loan guarantee being up to 80% of a project, it makes it possible to increase the leverage of the project, using up to 80% of debt as compared to 50% of debt in the case in which debt is not guaranteed. These two factors combined have a large impact on the weighted average cost of capital. It has been calculated that the effect of the federal loan guarantee on the cost is a decrease of the total cost of \$ 70/MWh by \$ 11/MWh (Deutsch et Monitz, MIT report, 2004).

Reproducibility. The South Texas Project (STP) shows that NRG is likely interested to invest in nuclear because it can shift away most of the risks onto other parties through contracting arrangements and through federal guarantees, making "merchant financing" possible in this specific institutional context. Four other companies are candidates to develop some so-called "merchant" nuclear generators

¹ The budget voted by the Congress on 17th December 2007 for loan guarantee to the set of non-carbon technologies includes an amount of \$18.4 billion for the nuclear reactors on a total of . indicatively that means that twelve \$3-billion nuclear projects with a debt ratio of 50% could be benefit from this loan guarantee

² "NRG CEO: Nuclear projects may fit merchant model best", September 2007

in liberalised US markets¹. Constellation Energy considers that in its Maryland project, “some of the output may be sold under long term contract, but (its) project could in fact be built with all the output being sold into the wholesale market”.² But it is doubtful that it succeeds without PPAs for the major part of the off-take. Some of these “merchant” projects could succeed under the same conditions as the STP, in particular the loan guarantee and the production tax credit in the terms of the 2005 EPACT, and if they could trigger interest from historic suppliers and municipalities to contract on long term because they are credible counterparties, which is a key condition to long term contracting.

Could this “merchant” model be reproduced after the suppression of the federal support? Banks will likely only agree to lend in a hybrid finance type arrangement, i.e. with the backing of power purchase agreements. There seems to be little demand for such long term power purchase agreements from “pure” suppliers, such that the most likely arrangement will involve corporate financing with vertical suppliers and with large IPPs able to contract with historic suppliers which have a stable base of customers.

4.2. The model of consumers cooperative in a decentralised market (with reference to finland)

New nuclear build can be promoted by a cooperative of large consumers and suppliers which look to manage their risks and control their cost of sourcing by installing an equipment with a production cost not exposed to risks which usually determine the electricity price volatility on a market i.e. fuel price risk, CO2 price risk or hydraulic inflow risk on hydro-dominated market. If consumers or suppliers anticipate high fossil fuel and CO2 price in the coming decades, one way to hedge such risks is to build and operate nuclear power plants. In his context we analyse the case of the Finnish nuclear project ordered by a cooperative of large consumers before drawing some general lessons on the opportunity to invest in nuclear plants in this institutional environment. The Finnish Okiluoto III project developed by an existing cooperative of consumers has three main characters: it is developed in a political environment of consensus; it is the benchmark of a consumers’ consortium project in which consumers share equally project costs and risks; and the reactor vendor assumes the construction risk via a turnkey contract. It relies typically on two contractual structures for electricity price risk and construction cost risk - a set of PPAs with the consortium members and a turnkey contract with the vendor. This type of arrangement makes possible a corporate financing approach, in which the cooperative is the borrower with the backing of the shareholding companies and the set of PPAs allows an unusual high gearing ratio of 75/25.

A consortium of consumers and suppliers. The promoter TVO, is a electricity generation cooperative of pulp and paper companies and some electricity supply companies. Indeed the cooperative is controlled at 60% by PVO, which is itself a cooperative owned by different forestry companies (42% by UPM, 16% by Stora, 42% others), and already owns and operates two nuclear reactors and a thermal

¹ In the USA five companies develop specialisation in nuclear generation with existing assets which have been sold by utilities or acquired with the help of mergers and acquisitions in the liberalised and regulated regional markets: Florida Power and Light FPL (which owns 4 reactors), Constellation (Unistar) (4 reactors in Maryland and New York), Dominion (6 reactors), which all three have experienced restructuring in their home states, Exelon (14 reactors) and Entergy (9 reactors) which both purchased a relatively large number of plants.

²“NRG CEO: Nuclear projects may fit merchant model best” , September 2007.

plant. The other shareholders are the main Finnish production and supply company Fortum (25%), a distribution company EPVO (6.6%), and the Helsinki city (8.1%).

Mitigation of political and regulatory risks. The Finnish policy and institutional environment guarantees stability of the government commitment to nuclear power and limits the political risks. The nuclear plant order signed in 2005 was preceded by a long democratic process to determine the national energy policy, the siting of the plant and the development of a nuclear waste storage facility. As for the exogenous regulatory risks, the vendor has implicitly accepted to bear it by signing up a turnkey contract without provision of revision of the price in case of unanticipated regulatory difficulties.

Reallocation of construction and performance risks on the vendor: a turnkey contract. The turnkey contract with AREVA allocates the construction risk on the reactor vendor above a cost level which includes unforeseen learning costs (€ 3,2 billion, i.e. 2000€/kW). As a consequence of the ongoing difficulties and delays in the construction of the plant, AREVA has set aside provisions of around €800 millions in 2006 and 2007 for construction delays and E&C cost increase due to safety controls. A number of reasons have been brought forward to explain the problems and delays, including the inexperience of AREVA in E&C and the specificity of the Finnish style of control of the safety criteria. Another peculiarity of the contract is that the operational risk, which is important for a FOAK project, is also completely shifted onto AREVA with penalty to be paid when performance will be lower than an average 91% load factor on 40 years.¹

Market risk: a set of power purchase agreements at cost-price. Long-term power purchase agreements with a fixed price have been signed *ex ante* with the members of the consortium for a period of 60 years, i.e. the lifetime of the reactor. What makes the PPAs an obvious solution is the fact that the purchasers are the owners of TVO. Contracts at cost-price without reference to the market price will link the cooperative with its members - the company will sell nuclear output at cost to its shareholders in proportion of shares.² The fixed price transfers the market risk onto the purchasers in the sense that they will support an opportunity cost in the case that the Nordic market price would decrease below the fixed price. But this risk appears limited given the need for new power generation capacity and the likely increase of the average Nordic power price as a result of the rising CO2 price in the European market. The associates in the cooperative will likely avoid effects of CO2 price volatility and benefit from the CO2 rent. They also free themselves from price effects of long term market power exercise by incumbent generators in terms of capacity development restrictions.³

A special type of corporate finance. The project relies on corporate financing with a very high leverage of 75-25, thanks to the double hedging of the PPAs and the turnkey contracts. This allowed the owners to finance the project with 25% of equity only and to get 75 % of the financing by loans at preferential rates : 2,6% nominal for the €1,85 bn loan from the Bayerische Landesbank during the construction before refinancing; and a credit of €0,6 billion from the French 'export' credit bank

¹ Personal communication with AREVA managers. In fact the AREVA contract with TVO being confidential, the information on this clause has never been disclosed with precision.

² Shareholders are committed to pay TVO's fixed cost regardless they take their portion of electricity produced by TVO. The variable costs are paid by the owners in accordance with the amount of electricity they have taken from TVO.

³ Interview of TVO managers in *Enjeux Les Echos*, November 2005.

COFACE. Refinancing will be made at 4,6 % after the commissioning¹. With the combination of a low debt cost, a high leverage, and a low return on equity, the project has a low WACC of about 5%. This leads according to some studies to a cost-price as low as €24 /MWh for the owner-operator (Tarjanne and Luostarinen, 2003).² This low level of cost assumes a load factor of 91%, a performance which is guaranteed by the turnkey contract with AREVA.

Reproducibility. As the turnkey contract is an essential pillar of the Finnish nuclear project, it represents a major unknown for the reproducibility of this model of generation cooperative with projects based on new technologies. Long term contracting with large consumers at cost-price appears to be the other main condition of success of the Finnish model and the cheap financial arrangement. There are a number of new projects which attempt to reproduce some of the key characters of the Finnish project. In June 2007 a consortium of Finnish industrial and energy companies named Fennovoima launched a new nuclear plant project of 1000-1800MW for a commissioning in 2016-2018.³ In April 2008 British Energy envisaged to launch a project to be developed by a consortium with several large consumers. One issue is the time period of the contractual agreement with the nuclear producer. It is unlikely to replicate this cooperative scheme composed with large consumers in globalised industries where prompt relocation could be decided, if they are not locked by a determining advantage to operate in the country such as some natural resource endowment, like forestry is in Finland for pulp and paper companies. Large industrial consumers (aluminium smelters, steelworks, etc.) are unlikely to be willing to commit to a long term power purchase agreement on a so long period as 40 to 65 years because they face potential relocation risk and market risk. Moreover, in the case of a consortium which regroups suppliers to buy electricity on a long term basis, the stability of such a consortium supposes that the regulator accepts the entente of these retail competitors for part of their procurement, which will not be possible above a certain total market share. The same restriction could occur if successive industrial projects develop on the same market, reducing the market share on which competition could exert on a short term basis.

4.3. Nuclear development by large vertically integrated firms (with reference to France)

Electricity reforms in a number of countries have not been so radical as to dramatically alter vertical and horizontal industrial structures. In many European countries, incumbent companies were allowed to retain their vertical integration between generation and supply, and were not obliged to divest some of their production units. Besides, such companies have over the years expanded abroad and have thereby generally increased their horizontal integration by mergers and acquisitions in other markets.

¹ Such low rates on loans, which have been challenged by opponents as a state aid before the European Commission, are in fact explainable by the banker 's confidence in the collaterals and in the guarantee offered by the PPAs

² A very optimistic cost-price of 16 €/kWh had been calculated in 2003 at the origin of the decision. It had been calculated with a discount rate of 3% and a load factor of 91% (University of Tampere, 2003). In the present estimation, the price reaches €25 /MWh, with a discount rate of 5%. In the two cases, the calculation supposes a very optimistic load factor of 91% guaranteed by the vendor AREVA.

³ Fennovoima regroups different industrial Finnish companies, Outokumpu, Boliden, Katterna, Rauman Energia and also E.On which is not present in Finland.

Large vertical firms which benefit from a large base of 'sticky' consumers on their home markets are in a good position to invest in large and capital intensive equipments such as nuclear plants, because their size and vertical integration makes it possible to limit market risks and lower capital cost. Large-size vertical companies are therefore generally likely to benefit from better financing conditions than mid-size vertical firms for their generation projects and a fortiori large independent producers.

Turning now to the example of EDF's EPR project, the Flamanville 3 reactor project, this project was ordered in 2006 after a long lasting political debate to prepare the industrial re-learning of the advanced PWR technology in view of the progressive replacement of the French nuclear fleet of 59 PWRs built in successive series in the 70s and 80s. The 1650 MW EPR reactor was sold by AREVA without turnkey contract, and EDF is its own E&C service provider, and bears the risks associated with the construction cost.

Mitigation of regulatory and political risks in the French environment. The French political and judicial environment allows strong governance which is reflected in the stability of the safety regulation. The recent democratic modernisation of the decision process for the siting of large industrial equipments such as nuclear plants adds some political legitimacy (Bredimas and Nuttall, 2008). That is a key advantage for limiting regulatory risks during the long lead-time of construction of a set of reactors and for guaranteeing stability for decommissioning and waste management requirements. Moreover, the combination of EDF's large engineering capacity and the French regulatory style in nuclear safety limit regulatory risks. Indeed, being its own architect-engineer, EDF avoids the potentially costly effect of an E&C company's intermediation between the electricity company and the safety authority during the plant construction which is observed in other countries (Germany, USA, etc.). Indeed given that the E&C payment is made on a cost-plus basis, there exist few incentives to balance the requirements of the safety regulator. At the end of the process, if there remain residual regulatory risks they could be borne without major problem by EDF.

Market price and CO2 price risks. EDF's position on the French power market as the historically dominant supplier with a large segment of 'sticky' consumers¹ a large set of written-off nuclear assets, a diversified portfolio of activities (generation assets, large supply business, national markets diversification, etc.) allows it to manage market risks on capital intensive nuclear investments in several advantageous ways, e.g. allocation of risk onto the consumers and portfolio management. In particular, ownership of a large fleet of written-off nuclear plants gives EDF a stable source of cash flow (Finon and Glachant, 2007). The integration of the French market with the electricity continental markets ensures that fossil fuel marginal plants set the electricity price at levels which reduce the market price risk for new nuclear plants. Ultimately in a low probability context of low gas and CO2 prices, EDF could internally subsidise the EPR investment cost recovery through the cash flows of existing nuclear plant.

¹ In 2008, the French historical company still had to sell almost all its electricity at regulated retail prices even to industrial consumers. In this context EDF bears all the nuclear investment risks. But based on the 2003 European directive requiring complete retail market opening on July 2007, EDF is likely to benefit in the future from sales at market price on the French retail market.

Control of construction cost and risks. The size of EDF and its vertical integration allow the company to bear the construction risks and not to search the protection of a turnkey contract with AREVA for the nuclear reactor. Beyond its large size, EDF benefits from the capability of its important engineering department which is the architect-engineer for the project and which gives it a strong bargaining power with the reactor vendor and the safety authority. EDF will also likely benefit from AREVA's experience with the Finnish reactor. Moreover exceptional risks (such as a giving-up of the project after dramatic problems of misconception or a political U-turn after a nuclear accident in the world) could be borne by EDF as historical precedents (such as the cost of closure of the large EDF's FBR demo plant SuperPhenix) tend to indicate.

Corporate financing. EDF has reduced the cost of the project through an association with ENEL which finances 12.5% of the investment cost.¹ EDF finances all its investment needs in corporate financing and it does so for its Flamanville 3 reactor as for a usual project. It benefits from a good credit rating, which allows it to borrow at around 5%. Financing large investment is, however, more costly for EDF than before the market reform and its partial privatization (15% of stocks are private in 2008). A governmental report places the new standard for return to equity at 13.7 % nominal (IGF-CGM, 2004). With a 50%/50% financing split, this results in a weighted average cost of capital of 9.3 % when the cost of debt is at around 5%. Because of this relatively high cost of capital, the levelised cost calculated for the Flamanville EPR (€46-48 /MWh) is much higher than the price charged to the members of Finnish TVO cooperative (€25 /MWh) calculated with a WACC of 5%, a higher level of performance, and a longer lifetime (65 years instead of 40 years).

4.4. Nuclear investment in a oligopoly of medium-size vertical companies (with reference to the UK and Eastern Europe)

Let us now consider other candidates to invest in new nuclear plants: other large size companies Suez-Electrabel, EON, RWE and ENEL on the one side, some medium size or small size companies in Eastern Europe and in US liberalised markets. Other European companies would likely benefit from their size and diversified portfolio when investing in nuclear power. Suez-Electrabel (merged with GDF) strives to install an EPR in France to be commissioned soon after 2012 and to be partner in some projects in Eastern European countries (Romania). E.ON and RWE also plan to invest in nuclear plants in Great Britain (perhaps with the Westinghouse technology AP1000) and in different Eastern European countries (Bulgaria, Romania) in association with local producers: ENEL possibly in Italy, but also in Slovakia (with Slovenske Elektrarne the historic company acquired in 2007 which has the project to achieve two VVER nuclear reactors in Mochovce for a cost of €2 billion) and in Romania.²

Given their size and portfolio of existing assets, all of these companies have the financial capabilities to develop such projects and to benefit from vertical integration

¹ ENEL will benefit from equivalent drawing rights on the reactor production by only paying variable costs afterwards.

² It is noteworthy that in 2008 Suez, RWE, ENEL compete to be partner of the state company Nuclearelectrica in the new projects of Cernavoda envisaged in Romania and that RWE and EON compete to be partner of the Bulgarian public company NEK in the project of two VVERs of Belene plant.

to control market risks. However, these possible nuclear investments differ from the French EDF model in three respects. First, the legal restriction to develop nuclear plants on their home market (respectively Belgium, Germany and Italy) constrains these companies to proceed in other markets with fewer restrictions: the necessity to act in an institutional environment less familiar to them induces some political and regulatory risks. Second, their weak engineering capability compared to EDF might prevent them from being their own architect engineer and thereby reducing investment costs. And third, these companies can shoulder less regulatory and political risks than EDF, given their less important position in their respective home markets. This explains why they mostly concentrate on partnerships with local firms.

Finally as it is widely reported in the British debate in which direct public support is denied (Nuclear White Paper, 2008) and in the rising American one (as evoked by Joskow, 2007), a clear policy should also be needed to stabilise the carbon value of a nuclear investment in a way or another. It is noteworthy that such claim has not been expressed in Finland and France when ordering the respective nuclear plants because the belief in the competitiveness of a new nuclear plant, even if CO₂ price is quite low and does not give a supplementary advantage to the nuclear project.

4.5. The selection between institutional and financing arrangements in different electricity reform context

To conclude from these four case studies, it appears that requirements for managing specific risks associated to new nuclear build in liberalised markets with new advanced LWR technologies are so important that there is a natural selection of industrial organisation and institutional arrangements by which investment in nuclear plants is made possible. In fact, poorly liberalised markets without major changes in industrial structures and with preservation of large vertical incumbents appear to be the most favourable configuration for the development of new nuclear, provided that there is no political restrictions and few regulatory risks as is the case in France and probably in Eastern European countries where nuclear power does not face too much public opposition. Re-integrated oligopolies such as the UK market come just after on the ladder of industrial structures favourable to nuclear investment. Nuclear projects will likely be promoted by energy companies first in their home market or on other markets where they have vertical subsidiaries or where they could enter in consortia with local historic companies. In such cases, corporate finance would appear as the most appropriate arrangement to benefit from the strong balance sheets of medium and large companies, and from their diversified portfolio of assets (generation plants, businesses). Consequently they benefit from moderate capital cost which helps to limit the cost-price of nuclear kWh.

In other types of industrial organization prevailing in markets which have been deeply reformed, there exist possibilities to develop nuclear projects in the contractual framework of consumers cooperative (on the model of the Finnish EPR project) or with the backing of long term contracts at fixed price with credible parties (historic suppliers, municipalities in particular) as in the South Texas Project case, using possibly some form of hybrid-project financing. Banks are reluctant to commit in project finance or hybrid finance without strong complementary guarantees at this stage of industrial re-learning: long term contracts and turnkey contract in Finland, loan guarantee, standby insurer against the regulatory risk and PPAs with credible parties in Texas.

Table 3. The different combinations of risks allocation arrangements and financing arrangements on nuclear projects in liberalised and regulated markets

Type of reforms	Decentralised market industries with IPP companies	Decentralised market industries	Liberalised industries with large vertical companies	Liberalised industries with medium-size vertical companies
Reference case	South Texas Project	Finnish plant Olkiluoto III	French EPR Flamanville 3	UK projects US project Eastern Europe projects
Allocation of construction risks	On Government <i>Standby insurance</i> <i>Governmental loan guarantee on 80%</i>	On Vendor <i>Turnkey contracts</i>	On producer	On producer consortium
Allocation of market risks on consumers	PPA with municipalities / historic suppliers	PPA with large industrial users / historic suppliers	Large base of sticky consumers	Large base of sticky consumers
Structure of financing	Project finance	Hybrid finance	Corporate finance	Corporate finance
Capital structure ratio debt/equity	70/30	75/25	50/50	50/50
WACC In nominal	9.2%*	5%	9.3 %	NA

*Assumptions: Normal financing conditions equivalent to those on coal and gas generation projects with 12% of Return on equity and 8% of interest rate on debt in nominal and after tax.

Finally, despite the difference in institutional arrangements and financing structure, the cost of capital is not so much different in the different cases unless substantial support is given for new nuclear build through risk transfers onto the government or regulator, given that gearing will likely be limited to about 50/50 in project finance projects for nuclear plants (Table 4). In the specific cases where significant risk is transferred onto governments (as during the re-learning phase in the US), there is a substantial advantage to project or hybrid financing schemes which enable higher leverage and lower the global project cost of capital. This is typically the case in the South Texas Project for which the government loan guarantee would allow to reach a high gearing of 70/30 and a WACC of 9.2%, given that financial investors will not require a risk premium.

Nevertheless a consumers' consortium with creditworthy participants is clearly the most favourable arrangement because it combines the possibility to borrow at low rates, to obtain high gearing and to make sponsors not looking for profit because they are the direct buyers of the off-take and will not participate to wholesale market, as shown by the Finnish project and its low cost of capital of 5%.

5. Conclusion

The paper discussed the conditions for the development of new nuclear projects in liberalised electricity markets based first on a theoretical categorization of the different types of risks and how these could be mitigated and/or transferred away from the investor onto other parties. We discussed in particular the different contractual and organizational arrangements that can be used to transfer the different types of risk onto the parties best able to manage these risks. Moreover, we showed that various contractual and financing arrangements can be envisaged, but that the adequate arrangements will largely depend on local specificities including the local industry structure and market reforms, the political environment, and the experience of the local utilities and safety and regulatory authorities, etc. We illustrate how these critical local factors play a large role through four case studies.

The risks specific to a nuclear power investment in liberalised markets – regulatory, construction, operation and market risks – can be mitigated or transferred away from the plant owner-operator through different institutional, contractual and organisational arrangements. We argue that in liberalised markets significant risk transfers from plant investors onto consumers, plant vendor and government are needed to make nuclear power project attractive to investors, and bankable for lenders. Based on four case studies, we show that there exists a range of alternative consistent combinations of contractual and financial arrangements for new nuclear build. The suitability of the different alternatives depends largely on factors specific to the industrial organization of the electricity market and the institutional environment which shapes the nuclear policy in one country.

In the first phase of nuclear re-learning, the likely range of viable contractual and financing arrangements appears quite limited. The most likely financing structure will be based on corporate financing or some form of hybrid arrangement backed by the balance sheet of one or a consortium of large vertically integrated companies. In the perspective of project financing of new nuclear plants in liberalised markets, the minimal conditions are loan guarantees by government, and PPAs at fixed price for almost all the offtake. Turnkey contract for the FOAK reactors could also provide a guarantee during the construction phase followed by refinancing for the plant operation phase.

During the first phase of nuclear re-learning, banks and lenders are therefore likely to favour corporate financing by firms with strong balance sheet, which are able to shoulder a great share of risks through a diversified asset portfolio and vertical integration. This implies that countries where electricity reform has been partial and which have preserved industrial champions could be the most favourable for new nuclear investment. But this does not exclude nuclear development in countries with a more fragmented industry, but more original models for risk pooling and/or risk transfer are likely to emerge in such countries, such as consortium of consumers and suppliers with original arrangements to lower the cost of capital and increase leverage as presently in Finland, or else a consortium of specialised nuclear producers (as British Energy in the UK) and large consumers.

The four case studies highlighted that there remain many critical factors specific to a country industrial and regulatory environment and its electricity reforms, such that the reproducibility of some current innovative approaches such that the consortium of industrial users in Finland or the “merchant” project in Texas backed by federal loan guarantees can be questioned. There is not a “once-for-all” contractual and

financing arrangement for investing in capital intensive equipments with risks as specific as nuclear plant in liberalised markets. The adequate combination of contractual and financing arrangements will likely be determined on case by case basis depending on the specific local industrial organization, the market position of the investing company and the institutional environment prevailing in the country.

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