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Financing Nuclear Power Plants

Final Report of a Coordinated Research Project

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FINANCING NUCLEAR POWER PLANTS

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FINAL REPORT OF A COORDINATED RESEARCH PROJECT

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FOREWORD

The coordinated research project on Financing Nuclear Investments held in 2013–2016 was planned to coordinate research efforts by Member States, supported by in-house activities, in order to seek innovative ways of financing nuclear energy projects in the fast-evolving sphere of global finance. It also drew on the experience of those Member States which have recently been involved in the financing of nuclear power plants in order to identify the lessons learned with regard to sources of financing, the nature of the financing process and the barriers to financing nuclear power plants. The relative importance of different types of risk in determining financing costs was addressed, as were different models for allocating risk between stakeholders in nuclear power projects.

The focus of the coordinated research project was primarily on the specific challenges posed in financing nuclear power plants but included some assessment — for comparative purposes — of financing models and processes in the renewable and fossil energy sectors. This report summarizes the findings and results of the project. The report will be particularly valuable for those Member States with limited or no experience of financing nuclear power projects ('newcomers'), as well as States with more advanced programmes.

The IAEA officers responsible for this publication were T. Alfstad, M. Cometto, A. van Heek, M. Katsva and P. Warren of the Division of Planning, Information and Knowledge Management.

CONTENTS

1. INTRODUCTION

1.1. BACKGROUND

Financing large infrastructure projects has never been easy. The technical and managerial complexity increases with the size of a project, as well as the financial exposure and risk for investors. Nuclear power construction shares some characteristics with other large infrastructure projects but has also some specific features and risk profiles which makes investing and financing a NPP new built project more challenging. Some of these specific factors related to financing nuclear power plants (NPPs) include:

- Technical complexity of the nuclear project;
- Large size and capital intensity of a nuclear project make it sensitive to some critical market risks, such as the electricity price and volume risks (future revenue risk);
- Uncertainties regarding costs and construction time of a nuclear power project, particularly in new untested environment;
- Uncertainties related to political, regulatory and reputational risk.

Historically, large, capital intensive power projects (including nuclear) were financed with significant governmental involvement. Thus, under the former regulated utility regime and regulatory arrangements, many of the risks associated with power plant construction costs, operating performance, fuel price changes, and other factors were borne by consumers rather than investors. However, the current context for new nuclear build is significantly different. Some Member States have liberalised the electricity market to introduce competition and thus transferring most of the risk to electricity generating companies. Other Member States, which still maintain a regulated market, are now seeking alternative options with the involvement of private sector in the developing of nuclear power plants, either because the country's balance sheet would not support full government finance or imposed government policy.

1.2. OBJECTIVE

The CRP was intended to help Member States contemplating investment in nuclear energy to assess, design and negotiate cost-effective financing for such investments. More efficient financing opportunities will result in lower overall financing costs and improved economics for Member States' development of nuclear power. The report is based on the outcome of CRP meetings on "Financing Nuclear Investments" (2013–2016) as well as on training materials on financial modelling at the IAEA, and materials of an IAEA Technical Meeting "Managing the Financial Risks Associated with Nuclear New Build" (2017). The States participating in Research Coordinated Meetings (RCMs) included Bulgaria, China, Croatia, Indonesia, Jordan, Kenya, Pakistan, Uruguay and Vietnam. Three meetings were held in 2013–2016.

The main objectives of participating in the CRP were to:

- Understand the cost structure of NPP project and the sensitivity to major parameters;
- Understand the best practices for NPP financing, investment structures, contractual approaches and risk allocation options;
- Analyse the major risks and methods of their mitigation, building risk matrix and identifying risk mitigation measures for an NPP in the country;
- Develop a financial model to assess the feasibility of a NPP project using IAEA tools FINPLAN, WASP, MESSAGE, or by developing own model;
- Evaluate financial impact of indigenization/localisation.

Some countries (Croatia, Indonesia, Kenya and Uruguay) included small modular reactors (SMRs) in their analysis. SMRs can be an attractive option is some countries as they may provide some advantages compared to large reactors: (i) provide better fit with available transmission grid and power system infrastructure, (ii) have shorter construction time and lower capital requirements, (iii) have an higher predictability of construction costs due to factory fabrication (less probability of costs overrun and delays), and (iv) provide a greater flexibility to deal with lower than expected power demand.

The choice of scenarios and all technical and financial data used in the financial models were based on theoretical values and on assumptions from publicly available sources. They should not be considered as representative of country official data, assumptions or position.

All countries participating to the CRP have performed either generation cost assessment and financial modelling (supported by financial analysis and planning) and/or risk analysis. The key lessons emerged from the CRP are:

- Importance of formal financial modelling;
- Choice of assumptions in drives modelling results;
- Need for a proper risk analysis (including financial model-based sensitivity analysis).

1.3. SCOPE

The overall purpose of this publication is to present the results of the CRP on “Financing Nuclear Investments”. It is intended to contribute to the understanding of the specific challenges posed in financing nuclear power plants. Based on the experience of those Member States which have recently been involved in financing nuclear power plants, the CRP tries to identify the lessons which could be drawn with regard to sources of financing, the nature of the financing process and the barriers to financing nuclear power plants.

While electricity market conditions and the overall competitiveness of nuclear power relative to other generation sources have evolved since the completion of the CRP, the methodologies to assess the economics and financing of a nuclear project as well as the strategies to assess, mitigate and allocate the risk remain the same. Thus, the main outcomes and lessons learned from the CRP are still relevant today, few years after its completion.

The report will be particularly valuable for those Member States with limited (or non-existent) experience of financing nuclear power projects (‘newcomers’) but could also provide insights to States with more advanced programmes and for new project sponsors/operators. In particular, this report provides newcomer countries with information on financing requirements for a nuclear program, which has been identified as a key issue in the IAEA Milestone Approach (issue 3.4, funding and financing) and is an essential step in the integrated nuclear infrastructure review missions offered by the IAEA to Member States.

1.4. STRUCTURE

This report is structured in two main parts. The first part briefly introduces the most relevant financial notions and discusses the importance of financial modelling and risk analysis in project development. The second part presents the work performed and the key messages identified by the participants to this CRP. For each country it includes a description of the context for developing nuclear, presents the financial tools used and the main modelling assumptions, discuss the options/scenarios analysed and provides the main drivers for cost and risk assessment.

2. THE IMPORTANCE OF FINANCIAL MODELLING AND RISK ANALYSIS IN PROJECT DEVELOPMENT

2.1. FINANCING A NUCLEAR POWER PLANT PROJECT

2.1.1. Financing options

Two main models have been used for financing nuclear power plant: the government and corporate models. A project finance approach has been often proposed and discussed for NPP projects but never applied in practice.

The **government financing**, in which nuclear power plants are directly or indirectly financed from the governmental budget or with sovereign guaranteed loans, has been the traditional approach for financing NPP projects by state-owned utilities, and is still common in regulated markets. Example of government finance are the construction of the French nuclear fleet in the 1970–1990s by the state-owned utility EDF, the projects Qinshan 1 and 2 in China and the Barakah project in the United Arab Emirates. Government financing includes:

- Owner's resources ─ equity capital, cash flow;
- Domestic bonds issues;
- Funding from local government budget and local suppliers.

Government to government financing has recently been adopted in many new built projects, especially in countries with no or limited nuclear experience. The government of a NPP vendor provides financing (often via an intergovernmental loan and export credit agencies involvement) in order to ease the financing of a nuclear project and to provide a market for its plants. These schemes occur between governments that have close relationship and often go beyond the specific project. This type of financing has been proposed by China to Pakistan and by the Russian Federation to Bangladesh, Belarus, Egypt and India.

Under the **corporate financing** model, the investment is undertaken by a public or private company and is financed via the balance sheet with a combination of debt and equity. However, the high cost and risk involved in a new nuclear construction limit this arrangement only to large companies with strong balance sheets. Recent examples of this financing model include projects in the USA, France, Korea, Finland and China.

Vendor financing implies the involvement of the vendor company in the financing of the project via equity participation, provision of short-term loans from the company balance sheet or facilitating the credit from export credit agencies or commercial banks. Recent examples of vendor financing include some new constructions in China[1] (Daya Bay, Ling Ao, Qinshan III) and several new builds offers by the Russian Federation's company Rosatom (the project Akkuyu in Turkey or the Fennovoima project in Finland). And finally, KEPCO is a shareholder in Barakah project in UAE.

It should be noted, however, that in some cases the state has a large ownership portion of the utilities investing in nuclear power or in the vendors of nuclear technologies, which makes the distinction between corporate and governmental ownership blurred.

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[1] The largest part of the credit for the Daya Bay and Ling Ao plants is provided by French Framatome and is backed by China's Government, while most of the Qinshan 3 financing is provided by Canada's AECL.

Project finance consist in the creation by investors (parent companies) of a separate entity (special purpose vehicle — SPV) which acquires the full ownership of a project. The SPV is created as a separate company from the investors and has its own balance sheet. This allows to limit the risk taken by the parent company by ring fencing the risk of the nuclear project from the other assets of the parent company (and vice versa). On the other hand, the SPV has no other assets than its own and lenders to the SPV have recourse only to the assets and revenues of the SPV in case of financial distress. This exposes the lender to a level of risk that many potential debt holders are unwilling to accept. So far, project finance has not been applied in practice in NPP projects.

2.1.2. Types of fund

Broadly speaking, any investment project is generally funded through a combination of debt and equity. For each of these two components, there are various instruments, which have different levels of risk and expected (or required) return.

Equity holders (shareholders) invest in a company/project in return for a share of the company/project ownership and future returns. Equity investors are entitled to a participation to the profits of the company and will fully benefit from any upside of the project. On the other hand, equity holders accept a lower priority claim on the project revenues and will be repaid last in case of financial distress. Equity includes common and preferred shares, and quasi-equity instruments such as convertibles and shareholder loans. All these forms of equity are characterized by a different seniority in the claims on company's assets in case of a financial distress and therefore by a different risk (and return) profile.

Equity can be provided by:

- Local investor (projects in China, France, Republic of Korea, the Russian Federation and the United States of America);
- Foreign investor (Russian Federation's export projects, for example, in Turkey and Finland, and China's project in the United Kingdom);
- Consortium of investors (Vogtle in USA, projects in UK, Sinop in Turkey).

Debt is an obligation to repay a borrowed sum of money after a predetermined time (debt maturity) plus interest. Providers of debt capital (creditors) are entitled to the repayment of the principal plus interest, irrespective of the project profit. The debt providers have a priority claim on the project's company revenues and are generally repaid first in case of financial distress of the company. On the other hand, debt holders do not benefit from any upside from the project. The higher potential volatility of a project's future revenues (uncertainty and risk), the lower the amount of debt project lenders will be willing to lend into a project, or the higher would be the required interest. In a project company, debt is generally comprised of loans, leases, lines and letters of credit, guarantees and other forms of credit facilities.

As for equity instruments, debt instruments can be ranked in terms of seniority on claims, presence of loan's securities guarantees or other collaterals. These characteristics have a direct impact on the risk (and therefore on the cost) of debt instruments. Senior debt is debt that takes priority over other unsecured or otherwise more junior debt owed by the issuer. Subordinated debt is a debt which ranks after other debts if a company falls into liquidation or bankruptcy. Such debt is referred to as 'subordinate', because the debt providers (the lenders) have subordinate status in relation to the normal debt (e.g. Olkiluoto project in Finland). Short term commercial debt is used in most projects (e.g. Qinshan II in China).

Large financial institutions and commercial banks provide the majority of commercial debt for a nuclear project, often in conjunction with credit enhancement mechanisms such as Government guarantees and Export Credit Agencies coverage (see next section). These elements of credits enhancement are essential to reduce financial risk and thus allow the borrower to have access to more capital at a lower rate.

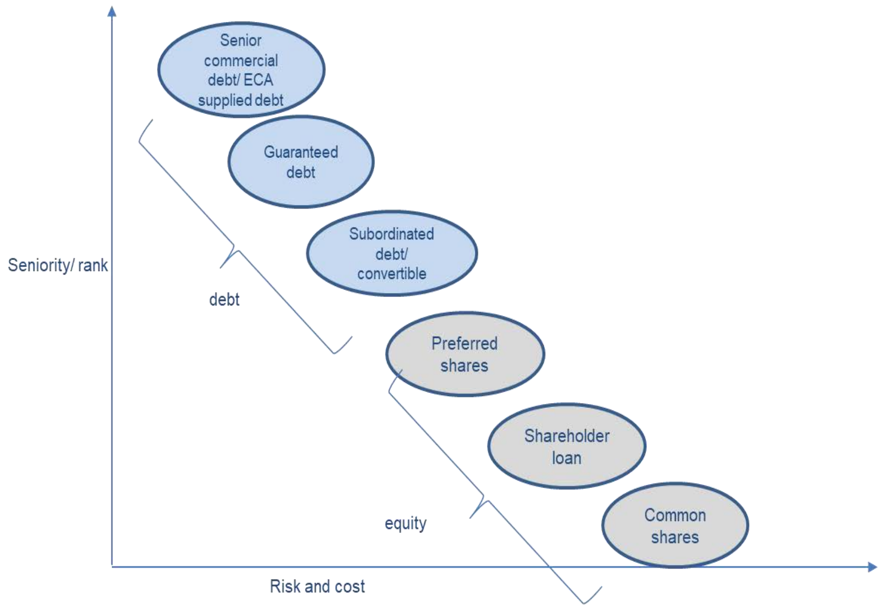

FIG. 1 Comparison of debt and equity cost and risk [1]

As a basic principle in finance, the required rate of return from an investor increases with the risk of the project. The required rate of return from an equity investor is therefore higher than that of a debt investor, as equity holders are exposed to higher risks. Similarly, the cost of financing (for both equity and debt) is higher for a riskier project than for a safer project. The project structure also has an impact on the risk of equity and debt holders[2]. A comparison of different types of equity and debt and their risk/return profile is given in Fig.1 above.

2.1.3. Credit enhancement mechanisms: governmental guarantees and ECA financing

Credit enhancement mechanisms are used in all nuclear project to reduce the risk exposure of investors, and particularly lenders, thus lowering the cost of capital and easing the financing. The process of credit enhancement is that a financially stronger party (e.g. a Government) agrees to be ultimately responsible for the liabilities of a financially weaker party (in this case the NPP project developer). If the latter defaults, its creditors will be able to recover — wholly or partially — what they are owed from the party that offered the guarantee. By reducing the risk exposure of lenders, credit enhancement allows for reducing the cost of debt, increasing the leverage of the project as well as broadening the pool of potential investors in the project. Ultimately, credit enhancement methods reduce the overall capital cost and improve significantly the economics and attractiveness of the project. This section discusses governmental guarantees and ECA financing, while next section covers the various mechanisms developed to mitigate revenue risk.

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[2] All other things being equal, a debt holder will face a higher risk in a more leveraged project (a project with a larger debt share) than in a less leveraged project, as there is less “cushion” provided by equity capital. As the risk increases with leverage, so the required rate of return from a debt holder increases as well.

Sovereign credit enhancement via governmental guarantees has been crucial for many recent projects. The host government ensures that it will be the ultimate guarantor for the liabilities of the NPP developer[3,4]. In some cases, in order to grant its credit enhancement, the host government may put additional requirements to the project developer. Examples of such mechanisms are the loan guarantees offered by the US government to the developers of the nuclear project at Vogtle, those offered by the UK for the Hinkley Point C plant (not accepted by the counterpart) as well as those used in financing the Barakah NPP in the UAE.

Sovereign credit enhancement is also important to show the commitment of the host government to the nuclear project. However, the credit enhancement mechanism is only as valuable as the perceived financial solidity of the entity (government) providing the guarantee. This can be measured by the sovereign credit rating of the host country.

Export Credit Agencies (ECA) are financial institutions (private entity or a (quasi-) governmental agencies) that provide financial services to a domestic company in order to support their activity overseas and to promote exports. The objective of an ECA is to remove some of the uncertainties and risks of political or commercial nature faced by the seller of technology when exporting, in exchange for a premium. ECA have been very important for many recent nuclear new builds: examples include the Coface (French ECA) loan for the Olkiluoto project in Finland, the loan provided by the Korean ECA for the Barakah project in the United Arab Emirates as well as the export credit given by the Russian government to build a VVER in Belarus.

Depending on the ECA, financial services provided can be:

- Direct loans with generally a medium- to long-term maturity;
- Loan guarantees;
- Cover insurances[5].

The OECD has provided a framework for the use of export credit since 1978 to ensure a level playing field and competition among OECD exporting countries (the Arrangement on Officially Supported Export Credit) [2]. This arrangement provides guidelines and terms of export credit finance: it defines the terms of a loan (drawing and repayment periods, maximal loan term, commercial interest reference rates, etc.) as well as the principles for calculating the insurance premiums. Non-OECD countries such as Russia and China are not bind by the OECD guidelines and can offer different and more attractive conditions such as longer loan maturities or more favourable interest rates.

2.1.4. Strategies and mechanisms to mitigate market risk

Nuclear power plant projects are characterised by high construction cost and long lead times, while they have low and predictable operational costs. A large proportion of lifetime generation costs of a nuclear project is therefore committed before that the plant is connected to the grid

[3] Another form of governmental credit enhancement is that the host government act (explicitly or implicitly) as a guarantor of the electricity sale agreement between the project owner and an off taker (see next Section). This can reassure the project developer and investors that the off taker will respect its contractual commitments.

[4] Note that in this context the term "liabilities" refers to the financial liabilities linked with the NPP construction and does not include the liabilities occurring in case of a nuclear accident, which are subject to different arrangements and international conventions.

[5] The main difference between a guarantee and in insurance is that with a loan guarantee the lender will be repaid in case of default of the borrower, whatever is the cause. An insurance, on the other hands, usually has a set of conditions that and clauses which must be fulfilled in order to proceed with the payment.

and starts generating electricity and revenues respectively. Capital intensive technologies[6] are particularly vulnerable to potential long term drops of the average electricity prices, and let investors significantly exposed to electricity market risk[7]. In regulated markets, where electricity tariffs are usually calculated in order to cover the lifetime generation costs of each technology, including financing costs, electricity market risk is generally limited. This is not the case in liberalised markets, where the electricity price can fluctuate depending on the laws of demand and supply. Wholesale electricity prices can be at very low levels for some prolonged periods, as experienced in many liberalised markets during the last decade. If not appropriately mitigated, long-term electricity price uncertainty is a significant risk which can hinder new investments in nuclear power plants and in other low-carbon technologies.

Different mechanisms and strategies can be implemented to secure revenues for capital intensive technologies and thus reduce the market risk for investors.

Long-term power purchase agreements (PPAs) and feed-in tariff (FIT) mechanisms are widely used tools to guarantee long-term revenues for electricity generators. Under a PPA, an electricity purchaser commits to buy the totality (or a predetermined fraction) of electricity generated by a power plant at an agreed fixed price for an extended period of time. Examples of PPA examples in nuclear are the contracts for the Barakah project in the UAE, for Akkuyu in Turkey and for the Excelsium consortium in France. The price can be fixed with time or can be adjusted for inflation. FIT have been extensively used for developing renewable projects within the European Union and in other countries. The power producers are guaranteed a fixed price for the electricity generated for a predetermined number of years, regardless of the electricity price prevailing in the markets. Often these mechanisms are coupled with a priority dispatch, which guarantees that the entire production is delivered to the market. In the early time of renewable development, the price was fixed a priory by the government or a governmental agency, but recently the target price is the result of an auction process. Overall, these mechanisms guarantee a fixed remuneration to the electricity producer and thus reduce the market risk virtually to zero.

The contract for difference (CFD) is an instrument developed in the UK to support low carbon technologies, such as nuclear and renewables, by reducing (or removing) the exposure to electricity price volatility. In a CFD, a strike price is agreed (or awarded via an auction) between the electricity producer and a counterpart, which is generally a governmental entity. The electricity producer sells the electricity in the market and receives the difference between the agreed CFD strike price and a reference price (based on market prices). If the reference price is higher than the CFD, the electricity producer pays the difference to the counterpart, otherwise it receives the difference. Even though the generating company sells electricity (and thus participates) to the market, the CFD mechanism de facto insulates the generating company from the market signals, as the combined revenues (market plus CFD compensation) are independent from the actual electricity market price. In this respect the CFD is similar to the FIT mechanism described above.

Other mechanisms are designed to complement the (uncertain) revenues from the sale of electricity to the market with another and more certain stream of revenues (a premium). These

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[6] Almost all low-carbon technologies are capital intensive: nuclear, wind, solar and hydroelectric projects are characterized by very low (or zero) fuel cost, and by low O&M costs. For all these technologies, construction costs account for more than 70% of the total lifetime costs (at a reference discount rate of 7% and above).

[7] Additional information can be found in [3].

mechanisms have the advantages to reduce the exposure to the market risk for the electricity producer whilst maintaining an effective participation into the market.

Examples of these mechanisms are the Feed in Premium (FIP) used for renewable generation technologies. The generator sells the electricity to the market and complements the revenues with a premium. The premium can be fixed or awarded via an auctioning process or by law. With a FIP, the power producer receives two complementary streams of revenues: a variable stream deriving from the sale of electricity to the market, and a fixed part via the FIP.

Other mechanisms used for nuclear project are tax incentives, such as the production tax credit used in the USA for the Vogtle project[8], the zero emission credit also awarded in some US markets to nuclear plants, or capacity payments/capacity mechanisms. Capacity mechanisms are fixed payments to power plants to reward their contribution to the power system security of supply. Generally, they are awarded to dispatchable power plants based on their ability to provide power to the grid in the most critical hours (often measured by the capacity credit).

The Regulated Asset Base model (RAB) has been recently proposed in the UK for new NPP projects. Under this mechanism, the price paid for the electricity to the generation company is set by an economic regulator based on an assumed rate of return for the investor and the effective cost of the project[9]. The RAB share some similarities with the mechanisms used to calculate the remuneration level for regulated activities (which are often natural monopoly). If correctly implemented, both investors and consumers benefit from the reduction of the market and construction risk ensured by these mechanisms.

2.1.5. Financing sources available at different project times

The level of risk in a nuclear project varies significantly with the stage on the lifetime of the plant. Risk is maximal in the first phases of a project, and then declines with the advances in the project. In case of nuclear, the level of risk drops significantly once the plant enters in commercial operation. Given this risk profile, some investors or providers of finance may be interested in participating only into certain stages of a nuclear project.

The first two stages (pre-project and pre-construction) are the riskiest. At these stages shareholder loans and equity are the most probable potential investors. At the construction stage, ECA vendor financing, commercial bank financing based by ECA and sovereign guarantees are available, as well as bilateral credits.

Owing to the high risk and uncertainty of nuclear power projects, financial investors are not likely to be involved in financing at the first two stages and at the early construction stage. At the operational stage, when the risks are much lower, the investments base is broader, and refinancing is possible. Fig. 2 provides a schematic overview of possible investor typologies at each stage of a nuclear project.

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[8] Under the Energy Policy Act of 2005, the US Government provided a production tax credit of US $18/MWh for eight years to the fist 6 GW of nuclear power constructed in the US.

[9] Some limits are put in place on the pricing mechanism to ensure the alignment of interests between the generating company and the consumer.

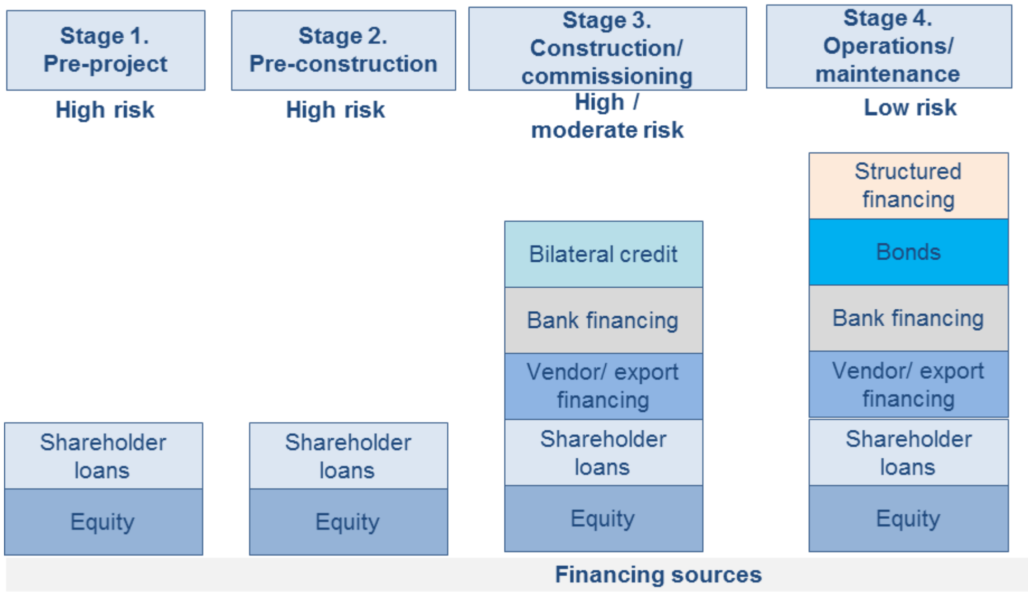

FIG. 2 Financing sources during the length of the project. Source [1]

2.2. FINANCIAL MODELLING AND RISK ANALYSIS

2.2.1. Basics of finance: time value of money and opportunity cost of capital

The time value of money refers to the concept that money available today is worth more than the same sum available in the future, owing to the capacity of money to increase through interest or revenues from an investment. It also reflects the fact that individuals generally prefer current consumption over delayed consumption, and thus value more goods available today than equivalent goods later. Owing to this effect, the money received at different times cannot be directly compared but needs to be adjusted to consider the time value of money.

Discounting is the process for determining the today's value (present value — PV) of a payoff (or a stream of payoffs) which is to be received in the future. The present value of a stream of future cash flows can be calculated using the Discounted Cash Flow (DCF) formula in Eq. (1).

$$PV = CF_0 + \sum_{t=1}^{N} \frac{CF_t}{(1+r)^t} \quad (1)$$

where the different variables indicate:
CF_t — the stream of future cash flows occurring at time t
r — the rate of return or discount factor, i.e. the reward that investors expect for delayed payment

An example of a PV calculation is provided in Fig. 3, where the green bars indicate the future cash flows for four consecutive years (starting in January 2017) and the respective present values are calculated (at January 2016).

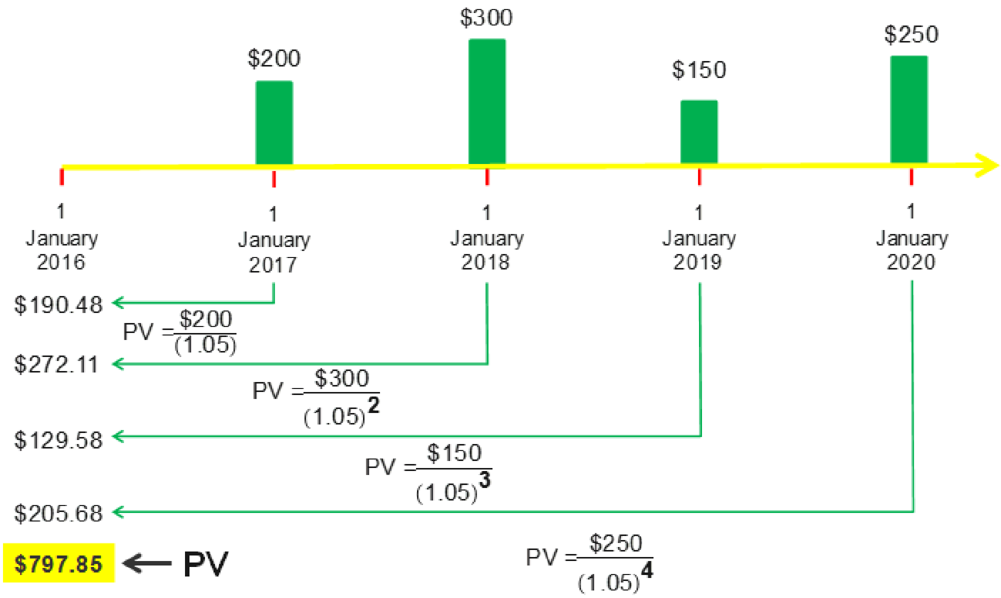

FIG. 3: Example of a calculation of the PV of future cash flow, with a discount rate of 5%

A key element in a DCF calculation, and in any investment evaluation, is the choice of the correct rate of return to be used in the discounting process. The appropriate discount rate will vary depending on the project under consideration. Intuitively, all other things being equal, a safer project is preferable to a riskier one; investors would thus require a higher rate of return for a riskier project than for a safer one. The opportunity cost of capital, also indicated as discount rate or hurdle rate, is the rate of return prevailing in capital markets for other assets with a risk profile equivalent to that of the project being evaluated.

The **Weighted Average Capital Cost** (WACC) is a measure of the cost of capital of a firm, obtained as the weighted average of the rate of return of all sources of capital (common and preferred stocks, bonds and any form of long-term debt). The WACC (i.e. the capital cost of a firm) is often used to assess any project undertaken by a company. This approach is correct only if the project evaluated has a risk closer to the average company risk. For projects that are deemed significantly riskier (or safer) than the average, the company cost of capital should be adjusted to reflect this risk difference.

The WACC can be calculated using the Equation (2).

$$WACC = \alpha_E r_E + \alpha_D r_D \cdot (1 - T_c) \qquad (2)$$

where the different variables indicate:
α_E, α_D — percentage of equity finance, percentage of debt finance
r_E, r_D — cost of equity, cost of debt
T_c — marginal corporate rate

2.2.2. Metrics for investment decision and financial analysis

In this section some of the metrics commonly used to evaluate potential investments will be introduced.

The **Net Present Value (NPV)** is used in capital budgeting to analyse the profitability of a projected investment or project. The NPV is the difference between the present value of cash inflows ("positive cashflows") and the present value of cash outflows ("negative cashflows") over the entire lifetime of a project, as shown in the Equation (3) below. It depends only on the forecasted cash flows from the project and the opportunity cost of capital.

$$NPV = CF_0 + \frac{CF_1}{(1+r)} + \frac{CF_2}{(1+r)^2} + \frac{CF_3}{(1+r)^3} + \cdots + \frac{CF_n}{(1+r)^n} = \sum_{t=0}^{n} \frac{CF_t}{(1+r)^t} \tag{3}$$

where the different variables indicate:
CF_t — cash flow in year t (net sum of positive and negative cashflows in year t)
r — discount rate.

A positive net present value indicates that the projected earnings generated by a project or investment (in present dollars) exceeds the anticipated costs (also in present dollars). Generally, an investment with a positive NPV will be profitable and would be accepted, while one with a negative NPV will result in a net loss and would be rejected.

The **internal rate of return (IRR)** is the discount rate that makes the net present value of all (e.g. positive and negative) cashflows from a particular investment or project equal to zero. It depends solely on the amount and timing of the project cash flows — see Equation (4).

$$0 = CF_0 + \frac{CF_1}{(1+IRR)} + \frac{CF_2}{(1+IRR)^2} + \frac{CF_3}{(1+IRR)^3} + \cdots + \frac{CF_n}{(1+IRR)^n} = \sum_{t=0}^{n} \frac{CF_t}{(1+IRR)^t} \tag{4}$$

where the different variables indicate:
CF_t — cash flow in year t
IRR — Internal Rate of Return

The internal rate of return of a project is typically used to evaluate the attractiveness of a project: if the IRR exceeds the investor's required rate of return, the project is desirable; if it falls below the required rate of return, the project would be rejected.

The **Modified Internal Rate of Return** (MIRR) has been defined to overcome some of the issues of the IRR metric. In particular, the IRR metric assumes that all the cash flows from a project are reinvested at the same rate of return of the project being evaluated (the IRR), which may be not realistic in practice. On the contrary, the MIRR metric assumes that all cash flows from a project are reinvested at a different rate of return (reinvestment rate) often the company cost of capital, thus better reflecting their investment potential — see Equation (5).

$$MIRR = \sqrt[n]{\frac{FV\ of\ positive\ cash\ flows\ reinvested\ at\ the\ cost\ of\ capital}{PV\ of\ negative\ cash\ flows\ reinvested\ at\ the\ financing\ cost}} - 1 \tag{5}$$

Similarly to the IRR, a project would be undertaken if the MIRR is higher than the investor's required rate of return, and would be rejected otherwise.

The **Profitability Index** (PI) is calculated as the ratio between the present value of future cash flow and the initial investment in a project — see Equation (6). The PI quantifies the amount of value created by a unit of investment and is therefore useful to rank projects. In general, a project with a PI lower than 1 would be rejected, and the projects with the highest PI would be selected. With respect of the NPV, the PI does not provide an indication of the size of actual cash flows.

$$PI = \frac{PV\ of\ future\ cash\ flows}{Initial\ Investment} = 1 + \frac{NPV}{CF_0} \tag{6}$$

The **payback period** is the length of time required to recover the cost of an investment. It is defined as the number of years before that the cumulative undiscounted cash flow equals the initial investment as shown in Equation (7). Projects are considered worthwhile investing if their payback period is less than a specified cut-off period, and projects with shorter payback periods are generally preferable to those with a longer one.

$$Payback\ Period = Full\ years\ until\ recovery + \frac{Unrecovered\ cost\ at\ the\ beginning\ of\ the\ last\ year}{Cash\ flow\ during\ the\ last\ year} \quad (7)$$

Project valuation method based on payback period have some advantages in term of simplicity of use and the ability to represent the riskiness of cash-flows. The main drawback is that, contrary to the methods described above, the payback period does not discount cash flows and therefore do not recognize the time value of money[10]. All cash flows occurring before the cutoff rate are considered with an equal weight. Also, this metric disregard all the cash flows occurring after the payback period (or the cutoff period).

2.2.3. Metrics for electricity generation cost and value analysis

This section presents some of the metrics currently used to evaluate the electricity generation costs from different technologies, as well as metrics designed to capture the value of each technology for the system.

The **Levelised Cost of Electricity (LCOE), also known as the Levelised Unit Cost of Energy (LUEC)** are standard metrics to compare the electricity generation costs of different power plants. The LCOE represent the average lifetime cost of producing a MWh of electricity, obtained by summing all the various expenses (investment, fuel, operation and maintenance, dismantling and, when appropriated, carbon emissions) over the lifetime of the power plant and dividing them by the electricity generated, after an appropriate discounting. These costs are discounted to the commercial operation of an electricity generator, as illustrated in the Equation (8) [4].

$$LCOE = P_{MWh} = \frac{\sum_t (Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t) * (1+r)^{-t}}{\sum_t MWh * (1+r)^{-t}} \quad (8)$$

where the different variables indicate:
P_{MWh} — the constant lifetime remuneration to the supplier of electricity
MW_h — the amount of electricity produced each year
$(1+r)^{-t}$ — the discount factor for year t
$Capital_t$ — total construction cost in year t
$O\&M_t$ — operations and maintenance cost in year t
$Fuel_t$ — fuel costs in year t
$Carbon_t$ — carbon costs in year t
D_t — decommissioning and waste management costs in year t

The LCOE represents the average revenue per unit of energy production that would be required by a project owner to recover all investment and operating costs. Said differently, the LCOE is the average price of electricity which equates the discounted revenues and expenditures of the

[10] The discounted payback period is sometimes used to solve this issue. This metric uses discounts cash flows to calculate the payback period, and therefore accounts properly for the time value of money. However, this metric still not account for any cashflow occurring after the payback period or the cutoff time).

plant, i.e. makes the NPV of the project equal to zero. The lower the value of LCOE, the higher is the competitiveness of a plant.

However, the LCOE is essentially a metric to calculate the cost of electricity generation and lacks representation of the value provided by each plant to the system. Therefore, the LCOE does not provide a guidance whether a power plant could be competitive in a given electricity system. A better assessment of the economic competitiveness of a power generation technology in a given system can be gained through joint consideration of the LCOE and another metric estimating the power plant value to the grid and its potential revenues for the plant owner. Examples of such metrics are the LACE, developed by the U.S. Energy Information Administration or the VALCOE, developed by the IEA.

The **Levelized Avoided Cost of Electricity (LACE)** estimates the potential revenues available to the project owner from the sale of generating electricity and capacity. It is calculated as the weighted average of the marginal cost of electricity dispatch during the periods in which the project is assumed to operate, weighted by the number of hours of assumed operation in each time period — see Equation (9). The LACE measures what would cost the grid to meet the demand that is otherwise displaced by a new generation project. These avoided costs account for both: variation in electricity demand and characteristics of the existing generation fleet. The marginal cost of meeting system planning reserves is weighted by the estimated capacity credit for each technology [5].

$$LACE = \frac{\sum_t (marginal\ generation\ price_t * dispatched\ hours_t) + (capacity\ payment * capacity\ credit)}{annual\ expected\ generation\ hours} \tag{9}$$

where the different variables indicate:
$marginal\ generation\ price_t$ — cost of serving load to meet the demand in the specified time period
$dispatched\ hours_t$ — estimated number of hours the unit is dispatched
$capacity\ payment$ — value to the system of meeting the reliability reserve margin
$capacity\ credit$ — ability of the unit to provide system reliability reserves
$annual\ expected\ generation\ hours$ — number of hours in a year that the plant is assumed to operate

The difference between the LACE and LCOE values for the candidate project provides an indication of whether or not its economic value exceeds its cost: a power plant with a LACE greater than its LCOE is financially viable and should therefore be built.

The **Value Adjusted LCOE** (VALCOE) has been developed by the IEA as an analytical metric for the capacity expansion in the World Energy Model and has been used since the 2018 edition of the Word Energy Outlook [6]. This metric adjusts the standard LCOE figure with the value of system services that each technology provides to the system — see Equation (10). These system services are categorised as energy value, flexibility value and capacity value, and varies strongly on the characteristics of the system analysed. For each of these three components, the value stream for each generating technology is compared with the system average, and the levelized cost is adjusted accordingly. A technology providing more flexibility than the average of the system, will have a negative adjustment component and thus see his VALCOE reduced (and thus becoming more competitive). An illustration of this process is provided in Fig. 4 below.

$$VALCOE_x = LCOE_x + [\bar{E} - E_x] + [\bar{C} - C_x] + [\bar{F} - F_x] \tag{10}$$

where the different variables indicate:
$VALCOE_x$ and $LCOE_x$ — value Adjusted LCOE and LCOE of the technology x
$\bar{E}, E_x$ — energy values of the system (average) and of the technology x
$\bar{C}, C_x$ — capacity values of the system (average) and of the technology x
$\bar{F}, F_x$ — flexibility values of the system (average) and of the technology x

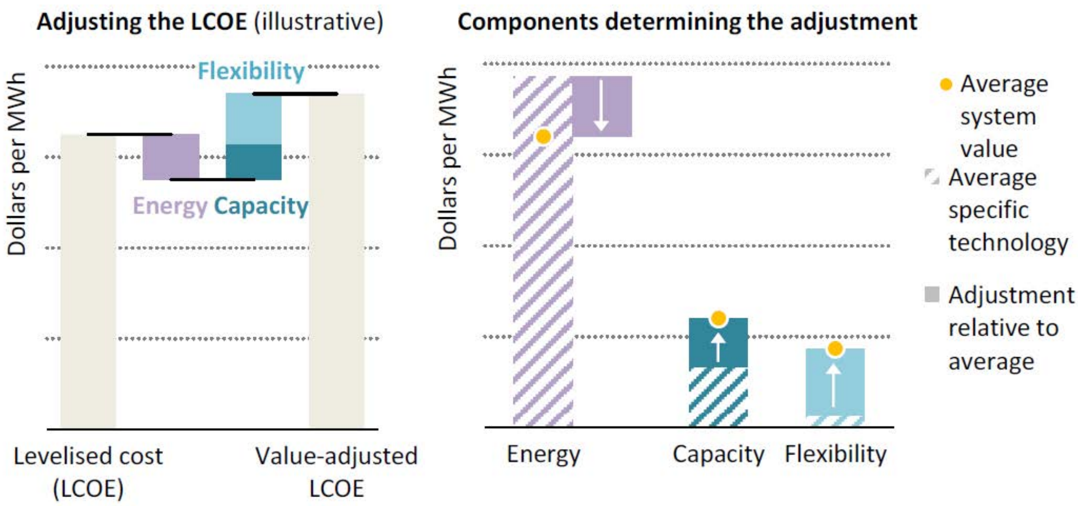

FIG. 4: Illustrative example of the VALCOE methodology [7].

The VALCOE allows for ranking technologies in a power system: the generating technology with the lowest VALCOE would have the most favorable economics and would be the preferred investment choice. However, the VALCOE itself does not provide any information whether that power plant should be built or not in that system.

2.2.4. Financial ratio and other financial measures

Many other metrics are currently used by financial analysts to assess the overall performances of a company (or a project) and to summarise its financial strength and weaknesses. These metrics are derived from the balance sheet and other financial statements of a company. In the following we will briefly describe some of the most used metrics.

Profitability ratios are a series of metrics designed to assess the ability of a company/project to generate income relative to its revenue, assets or equity over a specific period of time. The most used profitability metrics are:

- Net Profit Margin — defined as the net (i.e. after tax) profit divided by the sales (revenues);
- Return on Assets (ROA) — defined as the net profit divided by the total assets of a company;
- Return on Equity (ROE) — defined as the earnings available for equity holders divided by the total equity of a company.

Leverage ratios are metrics to assess the capital structure of a company, and to assess its ability to meet its financial obligations. Leverage ratios gives an indication of the riskiness of a company. The most used profitability metrics are:

- Debt ratio — defined as total liabilities divided by the total assets (equity plus debt);

- Debt to Equity Ratio (D/E) — defined as total liabilities divided by the total equity.

Coverage ratios are metrics to measure the ability of a company to service its existing debt, and to fulfil its obligations with its lenders. The most used profitability metrics are:

- Interest Coverage Ratio — defined as the net income divided by the interest expense;
- Debt Service Coverage Ratio (DSCR) — defined as the net income divided by the interest expense plus the interest repayment.

The **benefit cost ratio (BCR)** is used in a cost-benefit analysis to identify the relationship between the cost and benefits of a proposed project. The BCR is calculated by dividing the total discounted value of the benefits by the total discounted value of the costs. If a project has a BCR greater than one, it would generally be accepted as it provides more benefits than costs to the society. A project with a BCR lower than one would be rejected.

2.2.5. Financial modelling

Financial models are numerical tools which expresses in mathematical terms the main operational and financial characteristics of a project or a company. They are used by different stakeholders for different purposes: forecast the projected performances of a project into the future, evaluate and compare different investment opportunities, compare a business to its peers, assess the financial feasibility, bankability and investability[11] of a project and estimate the main risk factors of a project. A list of the parties interested in using a financial model, their role in a nuclear project and the metrics that can be used is provided in Table 1.

A financial model is constituted by a set of equation linking several input parameters and produces as outputs set of indicators which are used for a financial evaluation of the project. Examples of financial models are a discounted cash flow a (DCF) model, tools for sensitivity and scenario analysis, and risk assessment tools. Financial models are essentially input-output models. Inputs are assumption on technical; financial, fiscal and economic aspects that could have an impact on the financial outcomes of a project. A non-exhaustive list of possible inputs commonly used in evaluating a nuclear power project is provided below.

- Technical assumptions (plant net capacity, construction period, operational lifetime, start of construction, capacity factor, overnight cost, capital and operational expenses, fuel cost, cost for spent fuel management and decommissioning);
- Economic and fiscal assumptions (inflation, cost escalation factors, exchange rates, taxes, depreciation);
- Financial assumptions (cost of debt and equity, debt to equity ratio, WACC, upfront cost for debt-bank fee, tenor of debt);

[11] In the process of making a project attractive for investors, usually project company addresses project bankability, that means that project or proposal that has sufficient collateral, future cashflow, and high probability of success, to be acceptable to institutional lenders for financing. However, it is important to differentiate between bankability and investability. Investability is attractiveness of the project to potential investors, which includes both equity and debt investors, while bankability is only a facet of investability and includes only debt providers, whose primary interest is getting interest and principle, and who are not concerned about NPP long term performance. However, in order to get debt investors, it's essential to have strong equity investors, who are concerned about project long term performance.

- Creditors focus on what can go wrong (downside risk; measured by liquidity metrics)
- Investors focus on what can go right (upside risk; measured by equity Internal Rate of Return (IRR))

Feasibility is economic viability of the project.

- Contractual arrangements (EPC turnkey, split contract, fixed price contract or fixed price with escalation, cost based, etc.);
- Assumptions on electricity markets (liberalised or regulated market, presence of guaranteed contract such as PPA, CFD (Contract for Difference), FIT (Feed In Tariffs), or other tariffs).

TABLE 1. STAKEHOLDERS USING FINANCIAL MODELS AND THEIR OBJECTIVES

	Role	*Model use*	*Metrics used*
Initial developer	Puts together the project and provides initial equity	Testing initial economic feasibility, attracting lenders and investors; gaining political support	Same as stakeholders
Other shareholders (equity sponsors)[12]	Provide development and construction equity	Assessing overall project riskiness, equity return; Stability and predictability of revenues and cash flows, equity risk allocation, achievement of acceptable IRR and potential equity upside scenarios; Strategic investors estimate the total return of the project; Sovereign investors provide assessment of strategic importance of the investment.	Equity IRR, project IRR, payback period; ROI, ROE; Dividend profile (amounts, dividends lock up risk); Cash on cash return; Debt/equity ratio
Lenders: (banks[13], capital markets ECA)	Provides debt and credit enhancement and guarantees	Assessing overall project riskiness, return on debt Stability and predictability of revenues and cash flows, contractual structure and provisions and potential downside scenarios	Debt/equity ratio; Loan repayment profile; average loan life; Debt IRR; DSCR and other coverage ratios, ROI, Risk-adjusted ROC Debt covenants, debt margin Door-to-door tenor
Offtakers	Purchase power generated by the project	Assessing project performance output capabilities, affordability, tariff design; security of supply	LUEC/LCOE; Tariff
Guarantors	Provide backstops and credit enhancement	Assessing overall project affordability, security of supply feasibility and risk (likelihood guarantee will be called on)	IRR
Contractors and suppliers		Acceptable risk allocation to contracting parties (more risk shifted to contractors the higher the cost).	

- Sources: [1], [8], [9]

[12] EPC supplier can also be an equity holder as well as utilities (parent companies).
[13] Commercial banks and financial investors usually start participating in the project at a later stage.

The outputs are some metrics relevant for the user of the model. The key metrics include NPV, IRR, LCOE or LUEC, different ratios: solvency, liquidity, coverage, profitability, which have been discussed in the previous sections. A schematic structure of a generic financial model is provided in Fig. 5 below.

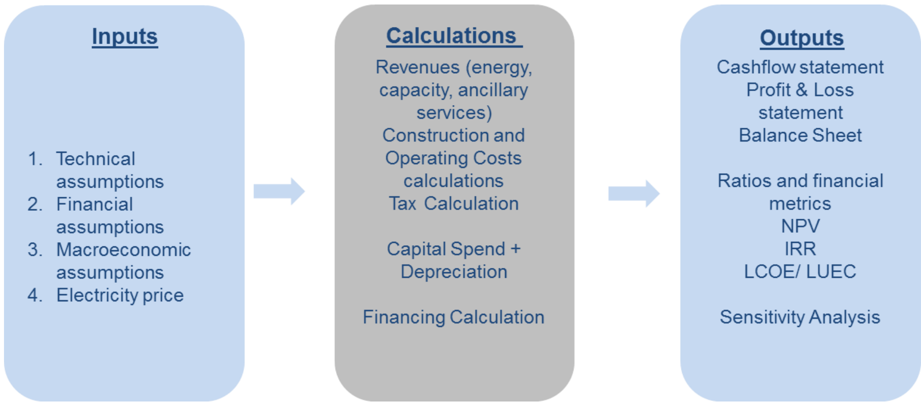

FIG. 5: Visualisation on the structure of a generic financial model

2.2.6. Sensitivity analysis

The sensitivity analysis is a technique used to determine how a variation of the underlying input parameter or variable impacts the targeted result (output) under a given set of assumptions. Sensitivity analysis is performed to identify what are the key input factors influencing an output and quantifying this impact. In practice, a sensitivity analysis is performed by changing one or several assumptions at one time and see the overall impact on the metrics of interest.

Some of the key parameters used for sensitivity analysis in a nuclear project are:

- Overnight cost (cost overrun).
- Construction time (delay in the beginning of construction and lead time overrun).
- Electricity market price, selling price or tariff (lower demand or lower market price than expected).
- Discount rate, market interest rates (investment costs higher than expected).
- Exchange rate fluctuation.
- Load factor, plant output (lower than expected).
- Operational cost (fuel cost, O&M cost and labour productivity, maintenance cost).
- Inflation and escalation costs (higher than expected).

2.2.7. Risk assessment[14]

Risk assessment aims at identifying, understanding and examining the project related factors and external events that could impact the forecasted cash flows and revenues from the project. Risk assessment is a fundamental step for all potential finance providers of any project, including NPP projects. A proper risk assessment is required by investors before deciding whether committing their capital to the project and to establish the terms, conditions and price for their investments.

[14] More information on risk assessment can be found in [10]

A risk assessment procedure involves three broad steps: i) risk identification, ii) risk analysis and measuring, and iii) development of a risk response plan, risk management and monitoring. A representation of these different stages of risk assessment is provided in Fig. 6 below.

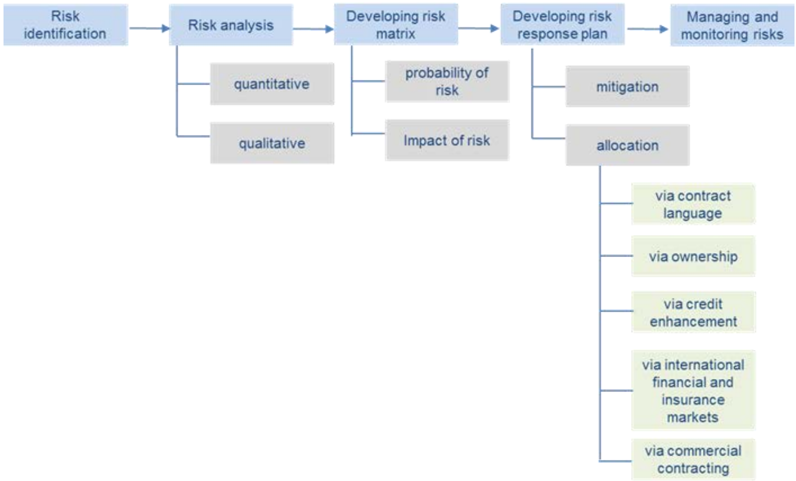

FIG. 6 Stages of risk assessment

The first phase consists of identifying and defining the various risks associated with the project to be analysed and dealt with. These risks are of different nature (technical, contractual, legal, financial, reputational, political, market related, etc.) and could appear at different phases of the project (pre-construction, construction, operation, dismantling and decommissioning) and are controllable or non-controllable by the project developer. A comprehensive list of the project risks (risk register) is created at this stage and will constitute the basis for performing the successive steps of risk assessment. A (non-exhaustive) list of NPP project risks is given in Table 2 below.

TABLE 2. RISKS IN A NUCLEAR PROJECT

	Risk	Description
Construction	Project completion	Project disruption due to financial distress arising from cost overruns, schedule delays, liquidation of project sponsors.
	Cost overruns	Cost overruns due to the imprecise estimation, high general inflation, quality defect, or schedule delays that make the project unprofitable.
	Accident or natural disaster	Accident or natural disaster that causes damage to property or injury to a person, either the Owner, contractor, or a third party.
Operation	Unexpected shutdown	Unexpected shutdown caused by error of operator, defective equipment, or non-conformance to grid and safety regulation that lowers the availability of the NPP.
	Nuclear accident	Radioactive accident that will have severe impact on environment, damage to the property of the Owner or third party, or injury to a person, the Owner, or a third party.
Market	Fluctuation of electricity markets	High initial capital cost makes NPP vulnerable to the change in the electricity market. If the PPA price is not guaranteed and the revenue decreases sharply due to the depression of market price, the Project will not be able to recover the cost and to repay the credit.
	Cost escalation	Fuel and O&M cost will be exposed to the risk of cost escalation. If inflation is greater than the cost escalation assumed in the PPA, the Project will have difficulty recovering its costs
	Default of payment under PPA	Off-taker may default in making payment under PPA due to the government instruction, financial distress.
	Surge of interest rate	Fluctuation in financial market may cause the interest rate to surge sharply
	Foreign exchange risk	The project may suffer loss in the currency conversion if the foreign exchange rate changes significantly
Financial	Credit default	Project sponsor may be unable to provide the equity investment as committed, causing the interruption of Project Company operation.
	Subsidy or incentive	Owing to the high capital cost, NPPs usually are constructed under a series of subsidies or incentives. If the subsidies or incentives are removed, the Project will have a difficult time making a profit and generating sufficient cash.
Legal and Political	Unexpected termination of PPA	PPA may be terminated by the government or legislation in the host country which makes the Project Company lose the basis for profit-making and financing.
	Change of law	Change of law such as tax law may cause an increase of cost for the NPP operation
	International relations	Nonproliferation issue making the transaction highly sensitive in international relations.

Source: Adapted from [10]

In the second phase, each of the risks previously identified is analysed individually by assessing the probability of its occurrence and the financial impacts associated with it. A risk matrix, which grades the different risks and scale their relative impacts, is developed at this stage. The risk matrix allows to identify the most critical risks, for which particular monitoring and mitigation efforts are needed.

In the last phase, the project developer defines the party (or the parties) best suited to managing each project risk during the economic life of the project, identifies the tools or contractual options to mitigate that risk and plans for an efficient risk allocation of the project between the various stakeholders.

2.3. IAEA TOOLS TO SUPPORT MEMBER COUNTRIES

The IAEA has developed a suite of analytical tools and models to support Member States in energy planning and to assist them in developing effective energy strategies. Most of the Member Countries participating to the CRP have used some of these tools, in conjunction with other tools. The following paragraphs provide a brief description of some of these tools [11].

FINPLAN (model for Financial Analysis of Electric Sector Expansion Plans) is designed to evaluate the financial implications of an expansion plan for a power generation system but can also be used for the financial analysis of a single electricity generation plant.

For the analysis of a single plant, the tool evaluates the plant's financial viability taking into account different financial sources — including export credits, commercial loans, bonds, equity and modern instruments such as swaps —, projected expenditures and revenues streams, taxes, interest rates and the weighted average capital cost. FINPLAN calculates projected cash flows, balance sheet, main financial ratios and other financial indicators (see Figure 7).

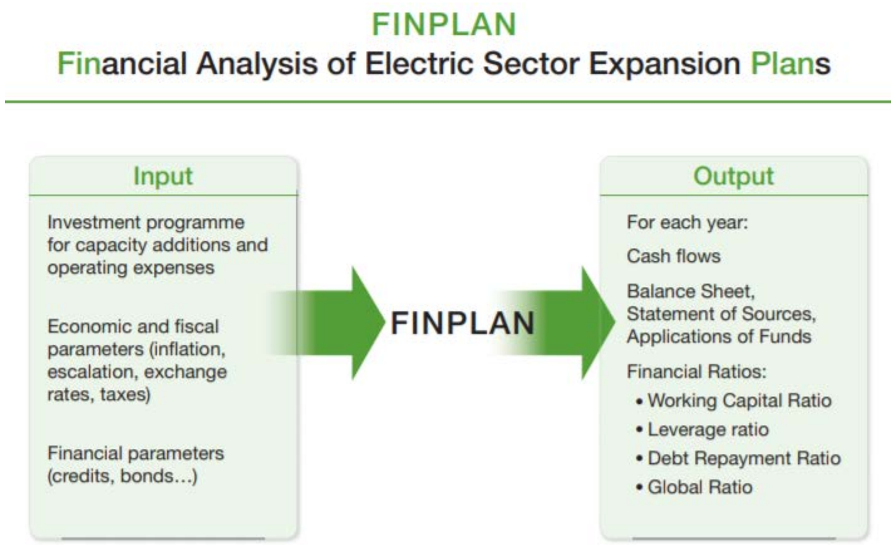

FIG. 7 Main inputs and outputs of FINPLAN

MAED (Model for Analysis of Energy Demand) evaluates future energy demand based on a set of consistent assumptions on medium to long term socioeconomic, technological and demographic developments in a country or a region. MAED provides a systematic framework to analyse different socioeconomic development policies, alternative policies for energy use, the impact of technological development and the effect of changes in the lifestyle of society.

MESSAGE (Model of Energy Supply Strategy Alternatives and their General Environmental Impacts) combines technologies and fuels to construct so-called 'energy chains', making it possible to map energy flows from resource extraction and energy conversion (supply side) to the distribution and the provision of energy services (demand side). The model can help design long term energy supply strategies or test energy policy options by analysing cost optimal energy mixes, investment needs and other costs for new infrastructure, energy supply security, energy resource utilization, rate of introduction of new technologies (technology learning) and environmental constraints. An example of the major inputs and outputs of MESSAGE is provided in the Fig. 8 below.

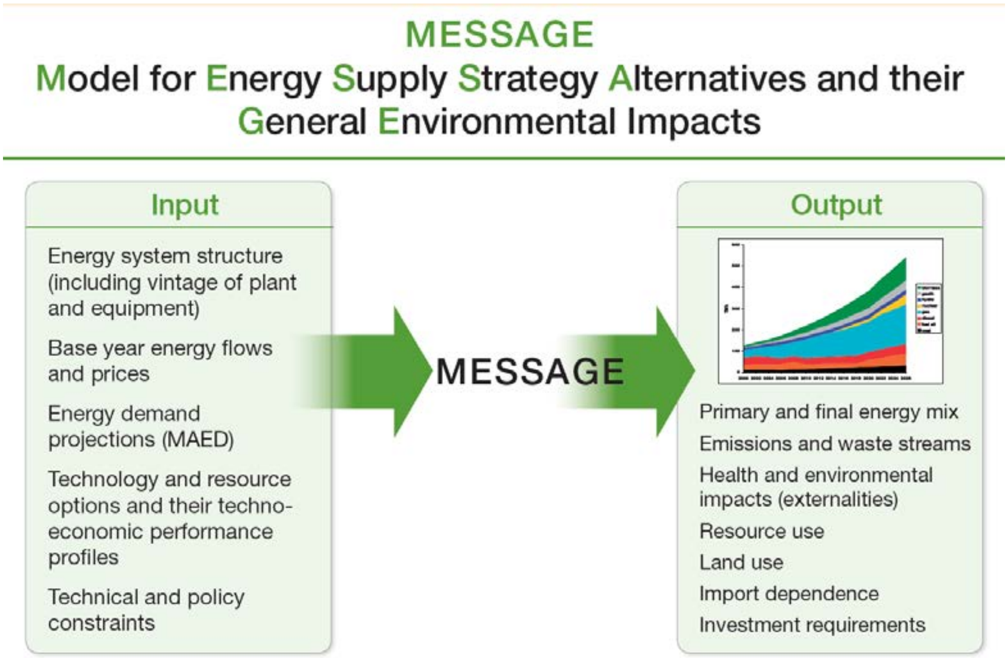

FIG. 8 Main inputs and outputs of MESSAGE.

ESST (Energy Scenarios Simulation Tool) is a tool for exploring energy system development. It allows users to assess future aggregated energy balances and provides a first screening of alternative scenarios in terms of capacity expansion, investment, carbon dioxide and other pollutants emissions. It can be used to present complex energy analysis concepts in a simple, transparent and intuitive way. Power generation expansion analysis provides basic environmental impact (emissions), investment schedule and other cost components.

WASP (Wien Automatic System Planning Package) is an effective tool for power planning in developing countries. It helps to determine 'optimal' expansion plans for power generation within constraints identified by local analysts, which may include limited fuel availability, emission restrictions and system reliability requirements, among others. WASP explores all possible sequences of capacity additions that are capable of satisfying demand while also meeting system reliability requirements. It accounts for all costs associated with existing and new generation facilities, reserve capacity and unserved electricity.

3. FINANCIAL MODELLING AND RISK ANALYSIS IN PARTICIPATING MEMBER STATES (CASE STUDIES)

The following sections present a synthesis of the work performed by each Member State participating to this CRP.

3.1. BULGARIA

3.1.1. Context

Bulgaria has a diverse energy mix that includes nuclear, thermal power plants and plants using renewables sources (hydro, wind, solar power plants and biomass). The total installed capacity of all electricity generation types is around 12.7 GW with annual gross generation of 45 TWh and gross domestic electricity consumption 37 of TWh[15]. Coal and nuclear energy produce four fifths of electricity generation (46% and 34%, respectively), while renewable sources have a share of 14%. Although Bulgaria remains a net exporter of electricity, its exports reduced significantly after the closure of four aging Kozloduy NPP (VVER–440) units in 2002 and 2006. In 2006 — the last year of operation of the two 405 MW Kozloduy reactors (units 3 and 4) — Bulgaria produced 45.8 TWh gross and exported 7.8 TWh of these (net) to Greece, Turkey, Serbia and the Former Yugoslav Republic of Macedonia.

Currently, Bulgaria has two nuclear units in operation at the Kozloduy site (units 5 and 6) for a combined capacity of 2 GW. Kozloduy NPP is the country's lowest cost electricity producer. In accordance with the national target for the long-term operation of the existing Kozloduy NPPs, a comprehensive programme for the modernization of Units 5 and 6 was carried out. A licence for operation of Unit 5 for a 10-year period was issued on 3 November 2017 and in 2019 the service life of Unit 6 has been extended by another 10 years. Government commitment to the future of nuclear energy is strong, though finance is lacking.

There are several main considerations driving the discussion of building new nuclear capacity in Bulgaria, both in terms of realistic timeframes and remaining consistent with the energy needs in the electricity generation mix. The first driver is given by the climate objectives and national commitments to the COP. The second is compliance with European energy policy targets — energy security and efficiency in the European Union, the National Energy Strategy goals, the possible removal of thermal power plants after 2030 and their eventual substitution with variable renewables. The third is the modernization of Kozloduy NPP units 5 and 6 or their decommissioning and the maintenance of a balanced energy mix.

Recent development on the power markets in the South East of Europe — limited demand growth, large construction of renewables sources, and new nuclear capacity to be built in Turkey — a need for new nuclear capacity seems unlikely before 2030. After this date, however, there may be a need for new nuclear base load capacity in the Bulgarian electricity sector, as a consequence of phasing out thermal power plants in the next two decades due to climate targets and the possible shut-down of the units 5 and 6 of Kozloduy NPP. Forecasts indicates that 2.4 GW of nuclear capacity would need to be installed and operating between 2037 and 2045.

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[15] Source: IEA Energy statistics.

The main objectives for CRP participation are to:

- Identify the most common NPP ownership structures and define the most appropriate for nuclear new build in Bulgaria;
- Identify what are the types of NPP contractual approaches as well as analysing their applicability to the context in Bulgaria;
- Investigate the conventional and alternative approaches for financing nuclear power generation project, especially in Europe;
- Build a model for financial estimation of the NPP investment;
- Investigate the nature of the uncertainties arising in the context of NPP investments;
- Develop a specific methodological approach to analyse and determine the uncertainties of the project.

3.1.2. Modelling assumptions

The information used in the research financial model for assessment of NPP investments in the Bulgarian electricity sector is based on participants' own research and assumptions and does not reflect an official position of the Bulgarian government. Many cost data used in this analysis are based on the Open Energy Information database.[16] The most important assumptions used in this research are summarised in Table 3.

Basic uncertainties in the research model are:

- Government policy in the energy sector development, in particular regarding thermal power capacities in Bulgaria and their phasing out;
- Operation life extension for units 5 & 6 after 2030 year (bearing in mind that units 3 and 4 of Kozloduy NPP were closed although they had fully implemented the modernization programme and had valid licences issued by the National Regulatory Agency);
- Expert risk estimation method.

The structuring and financing of NPP new build should comply with EU policies concerning competition and trends related to the development of a common energy union, as well as with the objectives of the Bulgarian Government. In particular, the Government of Bulgaria requires that "*Construction of new nuclear capacity* should result *in proven positive economic effect and* should occur *without request State aid*".[17]

The realization of the project new nuclear power capacity at Kozloduy NPP site is possible through attracting a strategic investor or investors. The specific amount of the percentage distribution of the share capital is a matter of negotiation. The assumption is that Kozloduy NPP keeps a 49% capital share. At present, interest in the project is being shown by Chinese companies — China General Nuclear Power Corporation (CGN) and State Nuclear Power Technology Company (SNPTC).

[16] The Open Energy Information database can be accessed at the address http://en.openei.org/apps/TCDB/
[17] Chapter XI of the Energy program of the Republic of Bulgaria for the period 2014–2018

TABLE 3. MAIN ASSUMPTIONS FOR BULGARIA KOZLODUY NPP

Project Financing	
Debt / Equity ratio	85% / 15%
Cost of debt	5.5%
Cost of equity	10%
WACC (owner)	5.7%
Tax Rate (owner)	10%
Loan origination fees	1.0%
Loan commitment fee	0.5%
Plant Development data	
Number of units	2
Cost of land	0
EPC Cost	US $2800/kW
EPC Escalation	2%
Discount date	01/01/2020
Project start date	01/01/2020
COD Unit 1	01/01/2030
COD Unit 2	01/11/2020
Plant Operations	
Starting electricity price	US $71/MWh
Escalation rate for electricity price	2%
Capacity	1000 MW/unit
Capacity factor	90%
Operating life	60 years
Fixed O&M	US $180 million/year
Variable O&M	US $2.1/MWh
Fixed and variable O&M escalation rate	2%
CapEx	US $24 million/year
CapEx escalation	2%
Annual fuel costs	US $71 million/year/unit
Fuel Cost escalation	2%
Provision for spent fuel	US $1 million/year
Decommissioning cost	US $100 million

The possible structure of the project is illustrated in the Fig. 9, and briefly described below. A special purpose vehicle (SPV) company, Kozloduy NPP New Builds (KNPP-NB), is created, with a registered capital of 35 million EUR. The SPV is fully owned by the company Kozloduy NPP (KNPP). KNPP would sign a shareholder agreement with the National Electric Company which would acquire 95% of the capital of the newly established company Kozloduy NPP – New Builds JVC. The resulting joint venture company would have a capital of 630 million EUR. At a later stage, a strategic investor with extensive experience in nuclear power projects would invest in "Kozloduy NPP – New Builds" JVC taking 51% in the company capital. The financing of the project would be realized in a debt to equity ratio 85% to 15%.

The type of contract would be *split package* — two different contracts will be signed: one for manufacturing and supply of the equipment and another with a constructing company. In the contract pricing a *hybrid approach* was used. The project company would sign contracts for fuel/raw material supplies, waste management and maintenance.

For ensuring electricity prices stability in the fully liberalized energy market — CFD are used (similar to UK model).

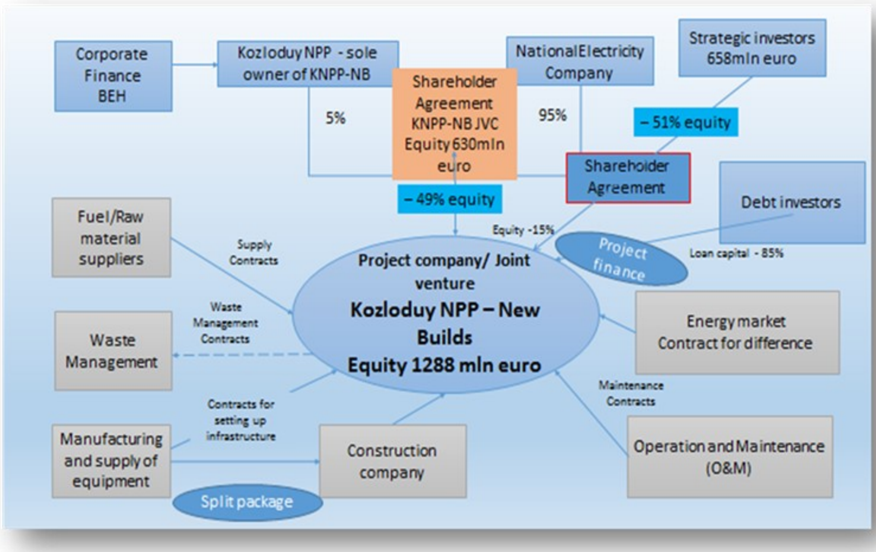

FIG. 9 Assumptions for potential Bulgaria Kozloduy NPP project structure.

3.1.3. Financial modelling

The main work performed during the CRP consisted in:

- Cost Analysis;
- Establishing a financial model for evaluating feasibility and competitiveness of the project Kozloduy Newbuild using a own model;
- Expert survey (risks assessment).

A split package type of contract is proposed — one for manufacturing and supply of the equipment and other with a construction company. In the contract pricing a hybrid approach is used.

3.1.4. Key outcomes

The main financial indicators for the proposed Kozloduy NPP project are shown in Fig. 10 below. Under the assumptions taken for this study (a strategic investor has been found, the project is financed 85/15 debt to equity), the results of the financial analysis show that a nuclear power newbuild project in the Bulgaria is financially viable. The NPV of the project is positive, the IRR of the project is above the WACC and the total return over the investment is above 10%.

FIG. 10 Main modelled financial metrics and other outcomes for proposed Kozloduy NPP.

3.1.5. Risk Analysis

In the risk evaluation of the Project, an expert estimation method and 'brainstorming' are used and the results are as follows. The main risks are:

- Financial and economic — market risks, budget overruns, lack of financing;
- Regulatory, political, legal and environmental — lack of government support;
- Construction — delays in the construction schedule;
- Nuclear fuel cycle — the absence of long-term vision/strategy for managing high radioactive waste.

Government commitment to nuclear power as a part of a national energy strategy carried out in Bulgaria can help to minimize risk, even though the strategy has not been updated since 2011. Early and firm action to put into place the legal and institutional arrangements can effectively demonstrate the strong government support for nuclear power.

Risks were ranked but not quantified, and a risk matrix has been developed.

3.2. CHINA

3.2.1. Context[18]

In 2017, electricity demand in China reached 6300 TWh, a five-fold increase compared to the levels in 2000. In 2017, the majority of electricity generation is provided by coal (about 70% of the total), while the contribution of other fossil fuels (gas and oil) is negligible. Among low-carbon sources hydroelectric power has a generation share of 17%, nuclear of 3.5%, while wind, solar and biofuels had a combined share of 7%.

The main drivers of China energy policy are to meet the growing demand and to reduce power outages, whilst reducing carbon emissions and air pollution levels due to the use of fossil fuels.

[18] Source IEA, Energy statistics, WNA Country Profiles China

In November 2014 the Premier announced that China intended about 20% of its primary energy consumption to be from non-fossil fuels by 2030, at which time it expected its peak of CO_2 emissions to occur. In the 13th Five Year Plan for power production announced by the National Energy Administration in November 2016, coal capacity will be limited to 1100 GW by 2020, by cancelling and postponing about 150 GW of projects. Gas is projected at 110 GW in 2020, hydro at 340 GW, wind at 210 GW, and solar at 110 GW (of which 60 GW of distributed PV). The objective of having a nuclear capacity of 58 GW was reiterated for 2020. Non-fossil sources would then produce 15% of electricity.

State Power Investment Corporation (SPIC) is newly established through the merger of China Power Investment Corporation and State Nuclear Power Technology Corporation in 2015. Its business covers power, coal, aluminium, logistics, finance, environmental protection, high-tech industries, etc. It invests and operates nuclear, thermal, hydro and new energy. The core business is coal. It is engaged in comprehensive energy development to facilitate the development of conventional energy with nuclear power project development; complementary to one another and is planning to achieve a breakthrough in the South Africa, Turkey and Bulgaria markets with NPP development projects, as well as to expand nuclear power development in China. Its current nuclear operation capacity is 3360 MW, and 5860 MW is under construction. By 2020, SNPTC is planning to have a nuclear capacity of 14 GW in operation by 2020, and 10 GW under construction.

The main objectives behind participating in the CRP are:

- Understand world best practices of financing nuclear power projects and develop a financial model for financing new NPPs;
- Understand the basics of capital cost evaluation methodology;
- Understand the world best practices on risks assessment for NPPs construction projects and develop a risk mitigation matrix for new NPPs.

The main work performed within the CRP includes cost assessment, financial model and risk assessment via expert survey, with a focus on investigating different financing options for nuclear new build. The research discusses the financing instruments and modes which have been used both in China (historical examples) and worldwide (including new ones) and then discuss their pros and cons. Then it analyses different scenarios for using particular financial modes, instruments and options for the new-builds in China, determining the best sources and the optimal structure. This report is of a qualitative nature with almost no quantitative analysis or in-depth modelling.

3.2.2. Financing options

China's main nuclear power financing methods were as follows:

- **Government investment.** This method mainly occurred in the early stages of nuclear power development, when governmental support was a necessity for nuclear power development. An example is the NPP of Qinshan phase I which is fully owned by China National Nuclear Corporation and was build based on a 100% government finance;

- **Issuance of Stocks and Bonds.** An example of this financing mechanism is the Qinshan NPP Phase II project. The capital for this project was jointly contributed to by many enterprises (China National Nuclear Corporation invested 50%, Zhejiang Electric Power Development Company invested 20%, Shenergy Company Limited invested 12%, Jiangsu Guoxin Investment Group Limited invested 10%, CPI Nuclear Power Co., Ltd. invested 6%

and Anhui Province Energy Group Company Limited invested 2%). Short term financing bonds were also issued to raise funds of ¥ 2 billion. The financing and operation modes have characteristics of the general engineering project investment after the implementation of "assign-change-loan" for the operational capital construction investment in China. This financing method was a method of government investment;

- **Export credit** This method was used to finance projects where a large set of equipment is imported. Examples of this approach are Daya Bay NPP and Qinshan NPP Phase III.

3.2.3. Modelling assumptions

Four financing scenarios were developed to analyse different sources of debt financing. The main characteristics of these four scenarios are provided below. Fig. 11 gives the overall financing structure modelled in this CRP.

Scenario 1: Chinese concessional buyer's credit

- Borrower : Project Company
- Lender : The Export-Import Bank of China
- Guarantor : Host government
- Loan amount : No more than 85% of the Chinese scope
- Currency : US $
- Use of the loan Payment for the EPC Contract
- Arrangement fee : To be determined
- Interest rate : Fix rate or floating rate
- Term of the loan : No more than 20 years
- Other requirements: Government to Government procedure
- Other requirements: Portion originated from China is no less than 60%

Scenario 2: Chinese buyer's credit

- Borrower: Project Company
- Lender : Chinese bank
- Guarantor : Host government or other entities acceptable
- Credit insurance Sino sure insurance
- Loan amount : No more than 85% of the Chinese scope
- Currency : US $, ¥
- Use of the loan Payment for the EPC Contract
- Arrangement fee : To be determined
- Interest rate : Fix rate or floating rate
- Premium rate: To be determined
- Term of the loan : No more than 15 years
- Other requirement: Portion originated from China is no less than 60%

Scenario 3: Chinese Commercial loan

- Borrower : Project Company
- Lender : Chinese-led international banking syndication
- Loan amount : Balance of total investment
- Currency : US $; ¥; Local
- Use of the loan Advance Payment for the EPC Contract

- Arrangement fee : To be determined
- Interest rate : Fix rate or floating rate
- Premium rate: To be determined
- Term of the loan : No more than 15 years

Scenario 4: Multisource financing versus multinational supply
Reference: China Daya Bay NPP

- Export credit from France to cover French supply of nuclear island (NI) equipment, balance of the plant (BOP) equipment, nuclear island erection, civil construction (French scope), engineering service and O&M cost;
- Export credit from UK to cover equipment, BOP equipment and technical support services;
- Export credit from USA to cover quality assurance advisor service and nuclear fuel software supply;
- Export credit from Japan to cover the architect engineer service as well as erection and commissioning support services.

Assurance/guarantee related to financing

- Inter-governmental agreement (IGA);
- Government assurance/support for project execution;
- Treasury guarantee;
- PPA guarantee;
- Repatriated in a convertible currency guarantee;
- ECA insurance.

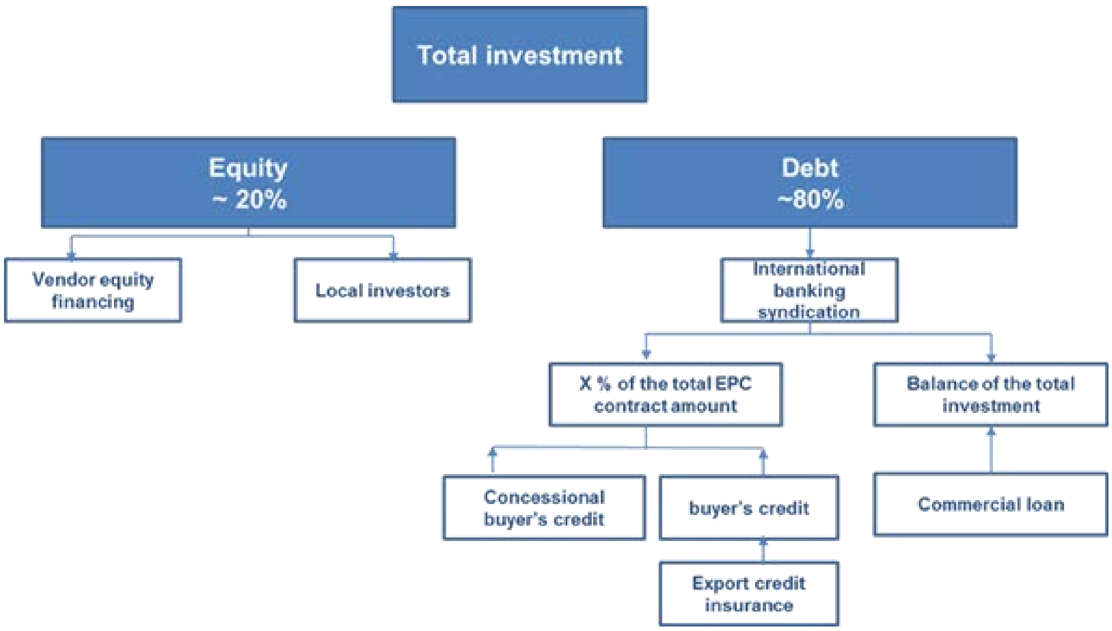

FIG. 11 China modelling and sources of financing.

An overview of the potential sources of debt financing is provided in Table 4 below.

TABLE 4. CHINA MODELLING OVERVIEW OF POTENTIAL DEBT FINANCING SOURCES

	Buyer's credit	OECD export credit	Commercial loan
Borrower	Project company	Project company	Project Company
Lender	The Export–Import Bank of China	Export–Import Bank of the USA and others	Chinese-led international banking syndication
Security Package	Host government or other acceptable entity guarantee	Host government or other acceptable entity guarantee	Same as the export credit and/or combination of project completion guarantee, shareholder's collateral of asset and/or pledge of rights, PPA guarantee. Subject to bank's evaluation
Insurance	Sino-sure insurance		Construction and operation insurance
Currency	US $	US $ or other currencies	US $
Interest rate	Fixed rate or floating rate (6-month LIBOR plus margin)	Fixed rate (CIRR) or floating rate	Fixed rate or floating rate (6-month LIBOR plus margin); higher than ECA rate
Grace period	Up to 6 months after project completion	Up to 6 months after project completion	Up to 6 months after project completion
Repayment period	Less than 15 years	Up to 18 years	Less than Export Credit Agencies

3.2.4. Modelling

The basic methodology and LCOE calculation is based on the IAEA report [12] (including cost account system but not limited to it). The DCF model is used for financial analysis as well as for sensitivity analysis. The assumptions, however, are not described in detail.

Equity

- D/E ratio: depending on the scenario, with a minimum amount of equity share;
- Diversified equity investors: SPIC, CIC, SRF etc. as potential investors;
- Amount: subject to the shareholder agreement and presence of a PPA or CFD;
- Option: equity investment with the arrangement to be repurchased by KNPP at the pre-determined point after the NPPs are put into operation, and at the price covering the cost and pre-determined return of the investment.

Debt

- Lender: syndicated loan group of Chinese first-class banks;
- Borrower: Shareholder company, or Project Company subject to security package;
- Amount: to be determined;
- Option: 100% capitalization of IDC (Interest During Construction), and part of local content (subject to content of EPC contract);
- Tenure: no less than 20 years, matching construction cycle of nuclear power project and subject to PPA/CFD and project cash flow;
- Flexible and diversified currency: EUR, US $ or ¥;

- Competitive interest rate：3M/6M LIBOR[19] (London Interbank Offered Rate) plus margin.

Bankability of the Project

The following mechanisms for credit enhancement have been considered:

- Inter-governmental Agreement (IGA)[20];
- Host government guarantee[21]: sovereign guarantee will be preferable. If interest cost could be significantly decreased;
- Guarantee from shareholder, e.g. assignment of tariff receivables under PPA, pledge over shares of the project company, security over asset of the project company, project completion guarantee etc;
- ECA insurance: Export credit insurance/overseas investment insurance provided by SINOSURE. SINOSURE may request counter guarantee in the form mentioned above;
- Supporting policies from host government: tax credit, tariff mechanism, facilitation of capital remittance.

The outcome is a financing plan, which includes evaluation of new NPP capital cost, financing cost and electricity cost to identify the potential financing sources and how to achieve the competitive financing conditions that will result in a competitive electricity cost and defines the process of planning. An example of the project cash flow is provided in Fig. 12.

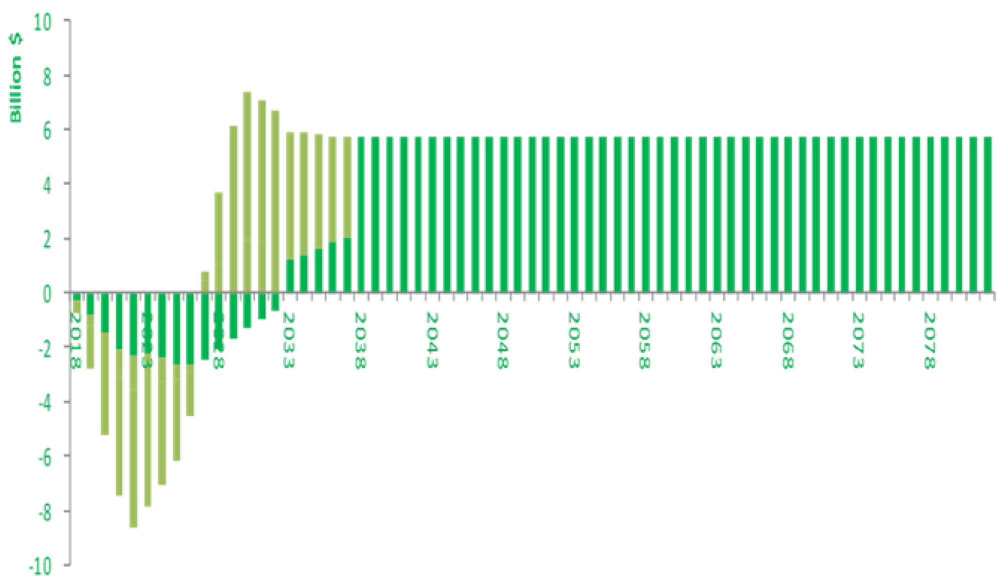

FIG. 12 China: modelling illustrations

China's nuclear power project financing mode has been developed from the highly concentrated "integration" mode of investment and financing — national financial investment financing, in

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[19] LIBOR is the average of interest rates estimated by each of the leading banks in London that it would be charged were it to borrow from other banks.

[20] A possible alternative is a government assurance/support for project execution satisfactory to the lenders.

[21] A potential alternative a guarantee provided by government-support entity acceptable to the lenders, or PPA/CFD/RGA guarantee acceptable to the lender.

the early stage of nuclear power development (Qinshan NPP Phase I), to joint venture project financing mode (Daya Bay NPP) “construct with loans, selling electricity to repay”. The next stage is development funds raised by issuing short term financing bonds in Qinshan NPP Phase II.

The diversification of the investment and financing subject is continuing, and the prototype of financing pattern is appearing. But in general, so far, the routine financing method of State equity investment and creditor right financing is still maintained.

3.2.5. Risk analysis

Risk was defined through expert survey (expert grading) and ranked. Mitigation measures and risk allocation were suggested. Sensitivity analysis has been performed and contingencies were applied. The key risks identified are:

- Short term loans for long term investment;
- Interest rate fluctuation;
- Fluctuations in exchange rates;
- Inflation;
- Project debt risk.

Finally, the sensitivity of LCOE to changes in some important parameters (capital and financing cost, capacity factor and fuel price) have been performed. Results are reported in Fig. 13 below.

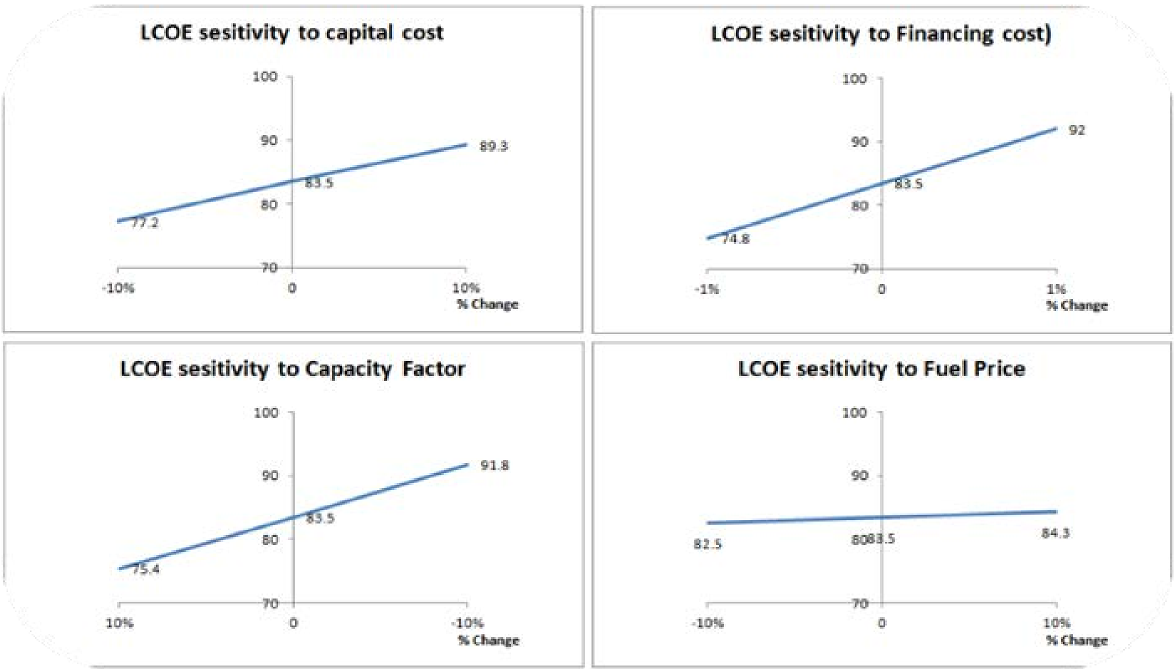

FIG. 13 China: sensitivity analysis illustration.

3.3. CROATIA

3.3.1. Context

Croatia is electricity importing country with half of electricity production coming from hydro power, 36% from thermal plants and 8% from nuclear. Although the annual energy demand increase is planned to be 3,5% (28 TWh, or 4600 MW in 2020) and it is also planned that 1.1

GW power plants will be shut down, demand increase is not the major driver behind considering or developing nuclear power. The key driver for developing nuclear power is decarbonisation.

Following 20-20-20 EU decarbonisation targets, Croatia developed national program promoting low carbon energy sources, including renewable sources and nuclear power. Low carbon sources will provide 35% of total electricity supply in all projected years (wind 1200 MW, new hydro power plants 300 MW, new small hydro power plant 100 MW). In the year 2015 it was decided by the government of the Republic of Croatia that a long-term low carbon development strategy would be prepared by year 2050. This also developed new motivation for Nuclear Power development to reduce CO_2.

The main objectives behind participating in CRP were:

- Carry out a feasibility and financial analysis for potential nuclear power plants in Croatia;
- Define financial approach most compatible with current utility and financial market conditions;
- Study how the financial risks specific to new large power plants (especially nuclear power) in liberalised markets can be mitigated and allocated to the different stakeholders, and which financial arrangements are consistent with the alternative allocations of the construction and operating risks;
- Perform feasibility analysis for SMRs.

3.3.2. Financial Modelling

The objectives of the project were achieved by using IAEA models for financial analysis and energy planning. The main tool used was FINPLAN, in order to evaluate the influence of new investment project on the balance sheet of a utility with large hydroelectric assets. WASP was used for defining future electricity productions and MESSAGE for energy supply systems and their general environmental impacts. In a second phase of the project, a own model has been developed to take into account difference in hydrological conditions during the project time. One of the objectives was the evaluation of financial risk for new thermal plant construction (including nuclear) for a company which operates in a liberalised market and with a substantial share of hydroelectrical generation.

During the first phase, models for four different technologies were developed: nuclear, Combined Cycle Gas Turbines (CCGT), coal, and solar photovoltaic (PV). For each technology, the financial results were analysed under different construction costs and electricity market conditions. The research was conducted in the following directions:

- Investment in electricity generation and the wholesale electricity market of the EU;
- Analysis of market prices on EU Power Exchanges;
- A financial model in the program FINPLAN, based on project financing model for a nuclear, coal, solar PV, and nuclear power plant project;
- Comparison of FINPLAN results for one technology to the results of a own complex financial model based on project financing model for a nuclear power plant project.

In a second phase of the project, the research focussed on the financial viability of SMRs in Croatia. SMRs can be better suited than large reactor given the forecasted very small growth of demand (driven by very strong energy efficiency policy measures) and high penetration of subsidised renewable energy sources (RES). Small and Modular Reactors (SMRs) can be built progressively as needs arise and have better features to cope with investment scenario uncertainties, making these projects easier to finance compared to large NPPs.

An SMR has competitive chances compared to larger nuclear plants primarily because:

- Lower investment costs and lower possibility of time and costs overrun;
- Modularity (power modules) which allows better time-to-market and higher flexibility to adapt to the market conditions;
- Availability of grid infrastructure;
- Attractiveness for low demand growth;
- Higher load following abilities could ease their integration with RES, which are currently the major focus in Europe.

3.3.3. Modelling assumptions and main findings

Large NPP 1000 MW

Three scenarios for a large unclear plant were investigated, covering a different range of construction costs, prevailing electricity prices, and market designs. The first scenario considers a fixed selling price and a relatively low construction cost for nuclear. The second scenario includes an higher overnight cost for the NPP, and a price for electricity sale of 45 EUR/MWh. This price is the average market price in 2014. The third scenario has the same higher construction cost and simulated that the NPP operates in the market; the quantity of electricity sold and the electricity price therefore depend on market conditions. The main assumptions and more relevant results are reported in Table 5. The electricity price indicated in the table is relative to the year 2014 and increases with inflation (assumed at 2%).

TABLE 5. MAIN PARAMETERS FOR THE THREE SCENARIOS

	Scenario 1	Scenario 2	Scenario 3
Commissioning date	2021	5000	5000
Investment (Eur/kW)	3500	5000	5000
Load factor (%)	80%	90%	–
Electricity production (TWh)	6.9	7.9	–
Electricity price (EUR_{2014}/MWh)	70	45	50

In the first scenario, the NPP project generates profit from year 2021 and shareholders get return from year 2025. In the second scenario, the project generates profit from year 2058 and shareholders get return from year 2077. In the third scenario, the project does not generate a profit and therefore the shareholders do not receive any return. Overall, large NPP projects show low competitiveness under the simulated conditions.

Results for all technologies were compared to hourly electricity market prices in 2014 on power exchanges in Hungary and Slovenia and the result is that NPP (but also all other technologies) cannot be competitive on current electricity markets.

SMR and Low Carbon Development Strategy

The NuScale reactor was taken as a reference for this study. A NuScale power plant is constituted by several units, each of them with a power of 50 MW, that can be incrementally added to match load growth up to a maximal number of 12 for a total output of 600 MW. The construction time is of 51 months from mobilisation to mechanical completion, or of 28.5 month from first concrete to mechanical completion.

Assumptions used for SMR financial modelling:

- Overall EPC Overnight Plant Costs of US $2.9 billion (data from vendor);
- Financing is 55% debt (at a rate of 5.5%) and 45% equity (at a rate of 10.0%);
- Lifetime was modelled as 40 years, compared to a technical lifetime of 60 years.

Given these assumptions, the LCOE of a NuScale plant results is in the range of US $93–106/MWh (in 2015 dollars).

The following four options were analysed for the inclusion of a NuScale SMR in "Low carbon development strategy" for Croatia and compared with the option of building a large power plant of 1 GW:

- Option 1: possibility of building one NuScale unit of 50 MW per year from 2035;
- Option 2: possibility of building two NuScale units of 50 MW per year from 2035;
- Option 3: possibility of building one NuScale unit of 50 MW per year from 2030;
- Option 4: possibility of building two NuScale units of 50 MW per year from 2030;
- Option 5: building a large NPP of 1 GW in 2034.

The analysis has been performed from 2015 to 2070. Electricity price, capacity factor of nuclear power plants and carbon emissions are calculated as an average over the period analysed. The main outcomes of this calculation are presented in Table 6.

The first preliminary analysis shows that in such a situation SMR generators would require some additional forms of remuneration, which would have to be borne by consumers or taxpayers. System average LCOE results compared with vendor calculation for NuScale LCOE US $93–106/MWh show that selling only electricity as base plant is not enough to cover all costs and that there is a need for additional revenue not only for electricity (including energy and capacity charges), but also from selling heat.

TABLE 6. MAIN CHARACTERISTICS OF THE 4 SMRS DEPLOYMENT OPTIONS

	Option 1	Option 2	Option 3	Option 4
Total number of modules	9	7	12	24
2030			1	1
2035	1	1	1	1
2036				1
2037	1			2
2038	1	2	1	2
2039	1	2	1	2
2040	1		1	2
2041	1		1	2
2042	1		1	2
2043	1		1	2
2044	1		1	2
2045		2	1	
2046			1	1
2047				1
2048				1
2049			1	1
2050				1
Average load factor	42%	42%	44%	38%
Average CO_2 Emissions (MtCO2)	1.39	1.35	1.36	1.28
Total CO_2 Emissions (Mt)	78.09	75.59	76.16	71.69
LCOE (EUR/MWh)	62.6	63.8	64.4	63.8

3.3.4. Risk analysis

The presence of uncertainties of future returns and costs are amongst the more critical factors affecting the willingness to invest.

From a strictly economic point of view, there are four main risk factors to be considered: (a) construction time, (b) investment costs, (c) variability of operating costs, and (d) market price of electricity. Most of the existing plants have been built under regulated price market, with governmental guarantees and controlled market prices, low capital costs and low investment risk. The investment risk, and the capital cost increased with deregulation of energy markets and were charged to electrical companies, penalizing capital-intensive investments projects with long time return on investment and low technological flexibility.

Sensitivity analysis has been performed. A base case and a sensitivity analysis to main parameters were performed.

3.3.5. Key outcomes

The results from all analysed cases and scenarios show that nuclear power plant of 1000 MW cannot be competitive on the Croatian (and EU) electricity market and those new different options for NPP, like SMR, would be worth investigating, as well as if nuclear can be profitable when operated at a lower capacity factor.

The competitiveness of SMRs has also been investigated in the Croatian context. The present analysis shows the economics of SMRs should improve in order to compete in energy only markets. Additional forms of remuneration may be required, such as capacity payments, compensation for load following or other system services. There is a need to develop a model for financing SMR in which income is based on energy and ancillary services. This required very detailed modelling of production on an electricity market.

3.4. INDONESIA

3.4.1. Context[22]

In the last years, electricity consumption has been steadily growing in Indonesia: in 2017 it totalled 235 TWh, a 3-fold increase compared to the consumption level in 2000. Access to electricity has also significantly improved: in 2018 98% of the population had access to electricity, compared with 67% in 2010. However, blackouts are frequent for those connected to the grid. The electricity sector has seen a significant growth of the generation capacity of power plants, transmission lines and distribution networks, but this rate of growth is not keeping pace with the increasing electricity demand. The national power utility projects that the electricity consumption will be of 457 TWh in 2025, driven by population growth, increase in the per capita consumption and development of electric intensive industries in the country. Presently, the pro capita consumption is of 900 kWh per year, well below other countries in South East Asia.

Almost 90% of the electricity is currently produced by fossil fuels: in 2017, coal produced almost 60% of the electricity, while gas about 20% and oil 7%. Other electricity sources are hydro (7%) and geothermal (5%), while other renewables (biofuels, solar PV and wind) generate less than 1% of the total. Strong reliance in fossil fuel, particularly coal, for energy and electricity production, together with emissions from deforestation and peatland fires makes the Indonesia on of the world's biggest emitters of CO_2.

Indonesia has developed ambitious long-term targets for electricity development and the government is committed to reducing carbon emissions, targeting a 29–41% reduction in CO_2 emissions by 2030 compared to the business as usual. In the National Energy Policy, the government has stated its aim to see 115 GW of installed generation capacity by 2025 and 430 GW by 2050. The share of New Renewable Energy is set to increase to 23% in 2025 and 31% in 2050. Based on Energy Law No. 30 in 1997, nuclear energy is a part of New Energy, energy that comes from new energy sources, together with wind, solar PV and other renewables.

Indonesia is planning a nuclear power programme by developing a road map for the implementation of NPPs with the involvement of national stakeholders. Both large reactors and small modular reactors are currently under consideration as possible technological options. A roadmap for the implementation of NPPs will provide details on technological aspects, fuel type, location, safety, financing and human resources readiness, along with other multi-criteria aspects.

[22] Source: IEA Energy statistics, WNA country profiles

3.4.2. The main objective behind participating in the CRP

In general, this research explores financial viability of new NPPs in Indonesia. It performs risks analysis, financial viability and investigates a financing model that may be applicable to Indonesia, considering both environment and technology conditions. This research also assesses the financial performance of a SMR project, taking into account several uncertainties that may occur in the project.

The scope of this research includes:

- Determination of technical and financial parameters for a NPP project;
- Development of spreadsheet-based cash flow models (deterministic approach);
- Integration of Monte Carlo technique into deterministic model for uncertainty/risk analysis.

3.4.3. Financial modelling

A DCF financial model, developed by State-owned electric utility company, was used for the CRP and integrated with Monte Carlo simulations. Some key variables were identified for uncertainty analysis, and their distribution functions were determined to make probabilistic simulation. Those variables are investment cost, fuel cost, capacity factor, interest rate (LIBOR rate), exchange rate, inflation rate, and the electricity sale price. Other variables, such as construction period and operation and maintenance costs, were added in the third year.

The financial performance of the project is reflected in the value of some indicators of financial feasibility; in this study NPV and IRR are used. The probabilistic analysis uses @Risk software and the Monte Carlo technique to simulate multiple sources of uncertainty as input variables and determine their impact on NPV and IRR.

Based on the simulation carried out, it was found that the selling price becomes the most critical point followed by investment cost and inflation rate.

3.4.4. Modelling assumptions

The main modelling assumptions used throughout the CRP are reported in Table 7 below.

TABLE 7. MAIN MODELLING ASSUMPTIONS

No	Parameter	Value	Reference
1	Plant capacity	2×100 MW	
2	Capacity factor	93 %	[13]
3	Yearly electricity production	1 629 GWh	
4	Fuel burn up	40.000 MWd/MTU	
5	Own needs consumption of electricity	5.5 %	
6	Base year	2013	
7	Construction period	5 years	
8	Lifetime	40 years	
9	Exchange rate	10.5 Rp/US $	www.bi.go.id
10	Discount rate	10%	
11	Debt Equity Ratio	70/30	
12	Loan portion:		
	Bank X (ECA 1)	30%	
	Bank Y (ECA 2)	30%	
	Bank Z (ECA 3)	20%	
	Bank A (Commercial bank)	20%	
13	CIRR for ECA	3.27%	CIRR OECD
14	Tax rate	25%	Act. No 36 2008
15	Inflation rate US $	1.5%	http://data.bls.gov/
16	Inflation rate domestic currency	7.9%	www.bps.go.id
17	Escalation of LUEC	2%	
18	Escalation of fuel price	0.5%	
19	Escalation of O&M cost	1.5% (US $) 7.9% (national currency)	

3.4.5. Key findings

Based on the simulation carried out, it is found that the most probable value of overnight cost is US $ 6360/kW for two SMR units of 100 MW. Three indicators of financial performance (NPV, project IRR and equity IRR) have been calculated for different scenarios. Results are given in Table 8 below.

TABLE 8. MAIN FINANCIAL INDICATORS — DETERMINISTIC RESULTS

Electricity price (US $/MWh)	Indicators of financial performance		
	NPV (US $ million)	IRR project (%)	IRR equity (%)
120	-214	8.90	11.36
130	-80	9.60	12.85
140	50	10.24	14.28
150	186	10.89	15.64
160	323	11.51	16.97
170	459	12.11	18.27

Risk (uncertainty) has been quantified by stochastic analysis. Monte Carlo simulations were performed to determine the effect of the uncertainty variables on the financial performance indicator by using @Risk software. The simulation was conducted with discount rate 10% and 1000 iterations. Main results are provided in Table 9 and in Fig. 14. The latter contains regression coefficient for each uncertainty variable. The Tornado diagram shows how the variables affect the project's financial feasibility.

TABLE 9. MAIN FINANCIAL INDICATORS — PROBABILISTIC RESULTS

Statistic	Indicators of financial performance		
	NPV (US $ million)	IRR project (%)	IRR equity (%)
Minimum	-1 000	7.11	6.18
Maximum	889	13.91	19.94
Mean	175	10.67	12.26

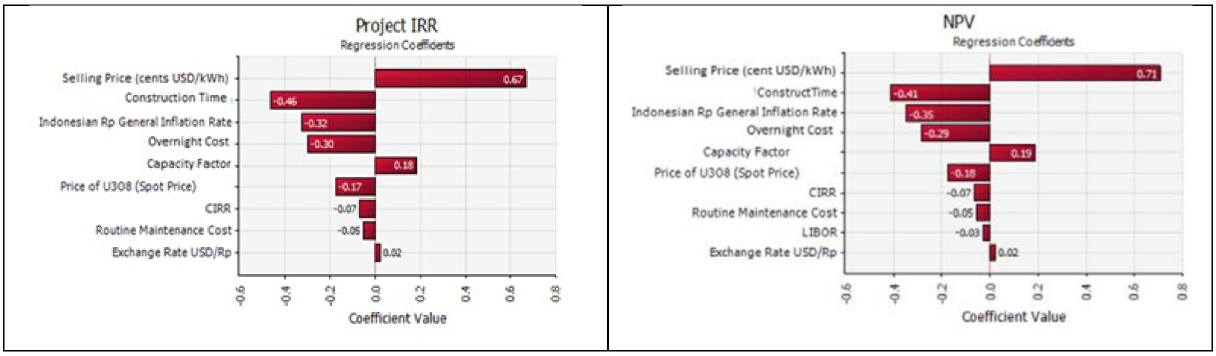

FIG. 14 Indonesia's project IRR and NPV.

The key outcomes of this study are summarised in the bullet points below:

- Electricity sale price becomes critical for a project's viability and a decision on its approval. The study results indicate that 2×100 MW SMR is feasible at the selling price of US $140 per MWh. At that price a SMR is not competitive with a coal power plant, however it is still competitive with a renewable power plant, such as a geothermal;
- The second parameter affecting the financial viability is the construction period (potential cost overruns will increase the cost);
- Investment cost has a significant impact on the cost of the project since it is a significant share of the construction cost. It should be monitored to prevent cost overrun in a project;
- Domestic currency inflation rate fluctuation is at the fourth position in the Tornado Diagram. It indicates the big challenge for the Government to stabilize the national economy so that Indonesia is not categorized as a country with high investment risk;
- Debt to equity ratio does not significantly influence the feasibility indicators of the project (NPV and IRR), as indicated by the cumulative distribution function of NPV and IRR of the project, which nearly coincide in the three scenarios.

3.5. JORDAN

3.5.1. Context[23]

Over the last decade, electricity consumption grew at an annual rate of 5% in Jordan, to reach 19.0 TWh in 2017. Per capita electricity consumption is about 1.9 MWh/year. Generation is dominated by fossil fuels, with gas and oil having the largest share (respectively 80% and 13% in 2017). The contribution of renewable sources (solar PV, wind and hydro) is increasing in the last few years, but remains limited to 1.4 TWh, i.e. about 7% of the total generation. In 2017, the total generating capacity amounts to over 3800 MW and is expected to increase to 8000 MW by 2030, when electricity consumption is projected to double.

Key energy policy objectives in Jordan are to increase energy security, lower the electricity generation cost and reduce the reliance on imported fuels; Jordan imports about 95% of its energy needs, at a cost close to the 20% of its GDP. In 2012 and 2013, natural gas supply constraints from Egypt caused a significant reduction in generation from gas plants, which previously provided most of electricity generation. In this biennium, heavy fuel oil and diesel provided the bulk of electricity generation (84% and 74%, respectively), and electricity imports grew significantly.

Jordan's Committee for Nuclear Strategy, set up in 2007, set out a programme for nuclear power to provide 30% of electricity by 2030, and to provide for electricity exports. Initial plans were to have two large power units in operation by 2025 to provide nearly half the country's electricity. However, Jordan is recently looking at the option of building SMRs, and has signed cooperation agreements with several SMR vendors.

Objectives behind participating in the CRP:

- Identifying contractual structure and ownership structures of nuclear power projects;
- Developing a financial model and carrying out financial analysis;
- Analysing the main drivers and parameters affecting the financial feasibility of a nuclear power project looking at a number of contractual and ownership structures;
- Developing a high-level risk management plan.

The research also focused on analysing the main drivers and parameters affecting the financial feasibility of a nuclear power project, looking at a number of contractual and ownership structures.

The Risk Management Section focused on risk management, presented the steps required to develop a risk management plan and discussed the methodologies of risk analysis. The research team identified and analysed the main risks related to financing a nuclear power project and proposed a mitigation plan addressing all identified risks.

A financial model was developed by an external team of consultants as an Excel model.

3.5.2. Modelling assumptions

The nuclear power plant modelled has a size of 1000 MW and an expected load factor of 90%. The project schedule consists of two years preparatory work (early works) and five years construction, for a total of 84 months. No delays have been considered in the schedule. In

[23] Source: IEA Energy statistics, WNA country profiles

addition, the project did not account for any site acquisition or identification works (site survey, site characterization and environmental impact assessment). The study considered that the site was procured and identified. The early works start with site preparation, permit acquisition, and detail design work.

With respect to the economic data of the NPP, the following assumptions have been made:

- Capital costs (CAPEX): US $5 billion or US $5000/kW. This price is the average of several prices reviewed and considered;
- O&M costs: US $135 million/year, best estimates for one reactor, including all personal and non-personal costs (except fuel — front and backend);
- Fuel cost: US $37 million/year, prices reflecting the drop in the global price of uranium as of February 2017 (source: TradeTech Long Term);
- Spent fuel management costs: US $28.5 million/year, prices reflecting the drop in the global price of uranium as of February 2017;
- Decommissioning costs: US $20 million/year, paid over the 60 years of operation with an annual escalation.

The contractual and financial assumptions used for this study are reported below:

- EPC turnkey contract;
- Project ownership and financing structure, 40/60 debt to equity ratio;
- Debt repayment: 18 years (maximum tenor as per OECD arrangement for nuclear), although longer financing tenor might be negotiated with financing institutions;
- Interest rate on debt: 3.73% (minimum CIRR for 18 years for New NPPs);
    - reference value for scenario 1 — a Government fully owned project;
    - + 100 bps for scenario 2 — joint Government and private ownership;
    - + 200 bps for scenario 3 — private ownership.
- Discount factor: For our study, WACC was used as the discount rate. For scenario 1, (7%) was the discount, scenario 2 (8%), and scenario 3 (9%). These are slightly higher than the WACC for each of the scenarios as per best practice;
- Taxes and fees: Taxes and project specific fees were disregarded from any calculation in the project. As rules and regulations differ by country, these laws are also different and incorporating them would only act as a distortion;
- Depreciation: Buildings and main equipment were calculated for the lifetime of the project equipment over 25 years, and short-lived assets at 10 years;
- Currencies: the only currency used is US $;
- Long Term Economic Parameters (Inflation/Escalation):
    - Escalation set at 3% — Again as indicative and just for this exercise. This can vary according to region, vendor and supplier;
    - Inflation is set at 2.2%, which is average 10 years (2005–2014) inflation for the USA (2.4%) and the Euro area (2%).

The model calculates LCOE, equity investment required, debt investment required, internal rate of return (IRR).

3.5.3. Financial modelling

Three main scenarios were analysed based on the public, private, and joint venture contractual options (see Table 10). As mentioned earlier, the main outcome of the financial section is to determine the most suitable/financially viable option with which to proceed.

TABLE 10. JORDAN FINANCIAL MODELLING: THREE OWNERSHIP SCENARIOS

		Ownership (%)	Required rate of return (%)	Debt rate (%)
1	Sovereign (government)	100%	9%	3.73%
	Investor (private)	0%		
2	Sovereign (government)	50%	11.1%	4.47%
	Investor (private)	50%	11.1%	4.73%
3	Sovereign (government)	0%		
	Investor (private)	100%	13.2%	5.73%

The **first scenario** illustrates a fully governmental ownership of the nuclear plant. A rate of return of 9% has been assumed in this scenario. This would make appropriating public funds for the project viable, but at the cost of a more favourable price of electricity. With full ownership, borrowing rates will most probably be more attractive than they are for private investors. There are several reasons for this, the most important being the balance sheet. CIRR is considered as acceptable for a first project which is government owned.

Government to government agreement with favourable rates, soft loans, etc. have not been considered in this exercise, and can be a major factor for large infrastructure projects moving forward, especially in developing countries.

The **second scenario** illustrates a public/private join ownership of the nuclear project. With an investor coming in, risk sharing with the government will make a good incentive and mitigate risks that are government specific. Average global country risk premium demanded as per NY Stern January 2015, was 4.2%. As the risk was split between the sovereign and the investor, a risk premium of 2.1% and a rate of return of 11.1% was chosen. This would make appropriating public funds for the project viable, and investment from the private investor viable.

With partial Government ownership, borrowing rates will most probably be more attractive than they are for full private investors. There are several reasons for this, the most important being that, as a partner, the benefits of Government can still be enjoyed, including sovereign guarantees in most cases. CIRR with 100 basis points for this scenario.

The **third scenario** illustrates a fully private ownership of the nuclear project. With full private sector ownership of the project, the investor coming in will be demanding a little more to compensate for the risk they are taking. All in average country risk premium demanded as per NY Stern January 2015 is 4.2%. Risk premium was added to the required rate of a project owned by the Government. The required rate or return would jump to 13.2%.

With no government ownership of the project, and in addition to the difficulty of procuring financing, the rates will be slightly higher. As this is a mega project, no investor will accept a premium below the norm. Projects just do not move forward. Premium has been 200 basis points over Government owned projects.

The main results of this analysis, and in particular the IRR and the electricity tariff level[24] are summarised in Table 11 below. The effect of a full Government ownership, compared with a

[24] As opposed to the LCOE, the Tariff includes the returns demanded by investors, and as such, will reflect them. As such, the results indicate that Scenario 1, a full government ownership, produces a more attractive (feasible) price of electricity.

joint venture, and with a full Buy-Own-Operate can be seen in the tariff difference. As opposed to the LCOE, the tariff includes the returns demanded by investors, and will reflect these. As such, the results indicate that Scenario 1, a full government ownership, produces a more attractive (feasible) price of electricity.

TABLE 11. REQUIRED RATE OF RETURN AND TARIFF CALCULATION (IN 2015 PRICES) FOR DIFFERENT SCENARIOS

	Required rate of return (%)	Tariff (US $\$_{2015}$/MWh)
Scenario 1	9%	86.4
Scenario 2	11.1%	103.6
Scenario 3	13.2%	123.7

Sensitivity analysis has been performed on three main factors: discount rate, delay in construction and unanticipated drop in nuclear power plant availability (load factor). Results are summarised in Table 12, Table 13 and Table 14. Higher required rates of return, lower than expected load factors and longer construction times will have an adverse effect on the levelized cost of electricity and electricity tariff.

TABLE 12. SENSITIVITY CALCULATIONS TO CONSTRUCTION DELAYS

		No delays	10% delay	20% delay
Scenario 1	LCOE (%)	Base	+4.8%	+9.6%
(7% discount rate)	Tariff (%)	Base	+5.23%	+10.3%
Scenario 2	LCOE (%)	Base	+5.12%	+10.24%
(8% discount rate)	Tariff (%)	Base	+5.29%	+10.76%
Scenario 3	LCOE (%)	Base	+5.37%	+10.74%
(9% discount rate)	Tariff (%)	Base	+6.14%	+11.03%

TABLE 13. SENSITIVITY CALCULATIONS TO DISCOUNT RATE

		5% discount rate	10% discount rate
Scenario 1 (7% discount rate)	LCOE (%)	-16.3%	+28.3%
Scenario 2 (8% discount rate)	LCOE (%)	-23.0%	+19.3%
Scenario 3 (9% discount rate)	LCOE (%)	-29.6%	+8.4%

TABLE 14. SENSITIVITY CALCULATIONS TO UNANTICIPATED DROP IN LOAD FACTOR

		90% load factor	85% load factor	80% load factor
Scenario 1	LCOE (%)	Base	+5.89%	+11.81%
(7% discount rate)	Tariff (%)	Base	+5.92%	+11.81%
Scenario 2	LCOE (%)	Base	+5.88%	+11.82%
(8% discount rate)	Tariff (%)	Base	+5.79%	+11.75%
Scenario 3	LCOE (%)	Base	+5.93%	+11.84%
(9% discount rate)	Tariff (%)	Base	+5.85%	+11.88%

3.5.4. Risk analysis

Risks were identified by expert review, ranked through qualitative review, and plan of risk mitigation has been developed. A risk matrix has been developed with risk impact, probability and mitigation. Project risks have been divided into several major groups: technical, financial, legal. The basis for splitting into these groups is the nature of risk, and the uniqueness and specificity of a nuclear project, as the type of risks change and evolve depending on the stage of the nuclear project.

3.5.5. Key findings

Compared to conventional power plants, NPPs overnight investment cost is higher (in the range of US $5000–7000 per kW). This is coupled with a required time frame of at least five years for construction completion. However, the running and fuel costs are considerably lower, and the nuclear plants operate for at least 60 years.

Owing to the fact that NPPs are quite expensive and the construction time is relatively long, financing these plants in terms of equity or debt is challenging. Main sources of financing are Governments, large utilities, ECAs, vendors and others.

For a newcomer country, the optimum contractual approach is an EPC turnkey approach. This approach minimizes risks facing the project, especially during the construction phase.

The analysis of the three scenarios modelled shows that a Governmental-owned project can attract debt at a lower rate and has a lower required rate of return than projects under a mixed public-private partnership or fully private. Thus, LCOE and the electricity tariff required are significantly lower in case of governmental owned projects: required tariff would be 43% higher for a fully private project, and 20% higher for a joint public-private project.

Nuclear power projects face a number risk that could be categorized under broad titles such as finance, regulation, technology, management, force majeure, political, environmental or others. Nevertheless, the nature and structure of the risk differs according to the stage of the project, whether planning, construction, or operation:

- Project risk management plan includes risk identification, analysis, mitigation, and allocation. Risk analysis is the process of quantitatively or qualitatively assessing and measuring risks. The analysis involves an estimation of both the uncertainty of the risk and of its impact. It includes identifying the specific risk levels by establishing the relationship between the probability of a given event and the impact of its occurrence;
- Risk analysis showed the highest risks during the planning phase are unrealistic schedule, changes in standard design due to new technical requirements, limited capabilities to finance the project, additional requirements from lenders, delay in EPC negotiation with unbalanced risks, lack of experience in licensing NPPs and lack of qualified staff;
- The top risks for a newcomer country's nuclear project are concentrated in vendor design, financing, regulatory system and licensing and EPC contract negotiation.

Risks for a conventional project could be transferred by contracting insurance companies. However, the particularity of nuclear power projects stipulates a large part of the risks should be managed by the project stakeholders. New tools have emerged to support investments in nuclear plants to manage their risks and hedge against them.

The reduction of open issues in any stage of the nuclear power project means less likelihood of mismanagement of the project, which leads to a reduction of adverse impacts with resources, cost, schedule, and other aspects of the project.

3.6. KENYA

3.6.1. Context [25]

The electricity demand in Kenia has steadily increased over the last two decades, together with the share of population with access to electricity. In 2017, electricity demand reached 8 TWh, almost three times the levels of 2000, with an annual increase rate of 6%. According to the International Energy Agency's latest data, 75% of population has access to electricity; a ten-fold increase compared with the values at the beginning of 2000. The totality of the urban population has access to electricity, while about two thirds of the rural population has access to electricity. Most of the population, particularly in rural areas, relies on traditional biomass and waste (typically consisting of wood, charcoal, manure, and crop residues) for household heating and cooking.

Electricity net generation was 11.1 TWh in 2017, of which more than 80% derived from renewable sources, mostly geothermal and hydro (4.8 and 3.2 TWh, respectively). Wind power, biofuels and solar PV combined generated about 1 TWh, i.e. 9% of the total. Power About 20% of the total generation is provided by fossil fuels (oil), with a total generation of 2.1 TWh.

The main driver behind considering nuclear power is a need for available and sustainable power to meet future demand which is expected to rise significantly with implementation of the country's industrialisation agenda. Nuclear power investment is viewed as financially viable and as providing economic benefits to the country to:

- Decrease the price of electricity;
- Support consistent growth in power demand (average 8% for the last years);
- Provide security of supply, and to reduce overreliance on hydro, which is costly to the economy due to climate changes and droughts, and expensive fossil fuels;
- Diversify the sources of power generation.

The Government of Kenya established Kenya Nuclear Electricity Board as the country's NEPIO, charged to lead the establishment of a nuclear power programme in the country. The Government has progressively maintained political commitment to the development of the programme. This has been demonstrated by annual budgetary allocation for the programme to guarantee sustained development of nuclear infrastructure as well as the recognition of international legal and safeguards obligations.

The main objectives behind participating in the CRP are:

- Analysis of optimal financing options for Kenya's NPP;
- Analysis of ownership and contractual approaches for NPP in Kenya;
- Risk analysis, categorisation and mitigation.

[25] Source: IEA Energy statistics

Risk analysis has been performed by internal experts. Risk matrixes (ranking and implications), risk mitigation and allocation measures were developed. A financial model has not been developed or used. The analysis has been mostly qualitative.

3.6.2. Considerations for the implementation of a NPP project

Implementation of a NPP project in Kenya is estimated to cost between US $4.84 billion for a 600 MW plant and US $6.22 billion for a 1000 MW plant. Below is a list of factors to be considered in choosing Kenya's NPP projects ownership and contractual approaches:

- Country's responsibilities: Alternative contracting or ownership methodologies serve to transfer some of the NPP development burden to parties outside of the host country. Kenya as the host country will however seek to retain certain core infrastructure development competencies, such as licensing and regulatory, security, safeguards, etc.
- Technical expertise. It will be important for Kenya to engage experts to assist with assessments as well as to guide the decision making, this will be critical as most of the requisite experience is not available within the country.
- Country specific conditions. Kenya will assess the underlying factors that support each of the possible structures, considering both the pros and cons of such structures, before deciding whether or not a structure is appropriate for its national situation.
- Economic and financial considerations. Various contracting and ownership approaches have varying degrees of economic and financial consequences. The approach chosen plays a key role in determination of the viability of the project or lack thereof.
- Risk sharing. Current and future market conditions, country risk factors, and the overall risk allocation mix between the developer and the country will be considered in evaluation of the optimal approach for Kenya.
- Sustainable development issues. It will be important to consider environmental factors and other considerations regarding sustainable development. This will also include nuclear specific issues, such as disposal of spent fuel and nuclear waste, as well as decommissioning.
- Availability of skilled labour. Kenya, as is the case with other countries embarking on an NPP programme, is concerned with the challenges of limited financial resources, a shortage of human resources with specific, specialized skills, the lack of technological and industrial capacity within the country as well as the lengthy development and construction periods associated with nuclear power.

3.6.3. Key findings

The key findings of the CRP are summarised in the points below:

With respect to nuclear technologies, SMRs present the most feasible option for Kenya's NPP due to the small size of the electricity grid.

Kenya may consider negotiating intergovernmental agreements inclusive of funding arrangements for the pre-construction phase of the power programme (infrastructure support) as well as financing (vendor financing through intergovernmental agreements).

Kenya will need to consider to what extent it will take ownership of the power plant. The parties to the agreements will need to agree on what stake each party will have in the power project. This could in turn impact on financing arrangements for the power project.

Most suitable contracting approach for Kenya is the turnkey contract, since it offers the following advantages:

- Better possibilities through contractual arrangements for the highest degree of integrity and homogeneity in the scope of supply and services;
- Minimum risk of cost impact;
- Reduced risk of overall schedule delays;
- Greatest opportunity to secure an attractive, large, foreign financing package;
- Utilization of standardised techniques for the whole plant;
- Maximum assistance by the supplier in meeting regulatory requirements.

For Kenya Government-to-Government Financing offers a valuable source of foreign funding and experience in the nuclear sector, as the magnitude of funds and nuclear experience is domestically unavailable. Loan Guarantees can provide cheaper interest rates for Kenya, since a guaranteed loan has lower risk, and therefore lower cost, as well as creating liquidity where it might not otherwise be present. Focus of signed Memorandum of Understandings is capacity building and technical support in upfront activities for Kenya's nuclear power programme. Vendor financing could be explored as the programme advances.

Kenya could also consider obtaining a proportion of the financing required to implement the country's nuclear power project from ECAs, despite the high costs associated with the loan guarantees that they provide.

In order to guarantee the sale of the electricity generated, a power purchase agreement will need to be negotiated prior to ground-breaking for the power project.

Kenya ought to consider engaging global consultants to assist in the pre-construction phase of the NPP project as well as managing its implementation.

3.7. PAKISTAN

3.7.1. Context[26]

Pakistan is the sixth most populous country in the world and is growing at an estimated annual rate of about 2%. Total electricity consumption was estimated at 111 TWh in 2017, about four times the levels in 1990. According to the latest International Energy Agency estimates, about 40 million people had not access to electricity in 2017, i.e. more than one fourth of the Pakistani population. Electrification rate is close to 100% in urban areas but is only slightly higher than 50% in rural areas. In 2017, more than 130 TWh of electricity were generated, mainly by fossil sources: natural gas (37.5%), oil (22.5%) and coal (8%). Hydro and nuclear generated respectively 28 and 10 TWh, i.e. about 30% of the total. Other renewables, wind, solar PV and biomass, produced less than 4 TWh, i.e. about 3% of the total.

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[26] Figures and data in this section are derived from the IAEA PRIS database, IEA Energy statistics and the WNA Country Profile for Pakistan.

Over the past years, Pakistan has experienced a major energy crisis as a result of expensive fuel sources, natural gas and electricity shortages, circular debt, and inadequate transmission and distribution systems. Electricity shortages have been hurting the social and economic backbone of the country; according to the Asian Development Bank, prolonged power shortages cut GDP by 2–3% in 2013. The electricity industry faces several problems including power line losses, high natural gas subsidies, the high cost of furnace oil used, insufficient natural gas supply and reduced load factors for gas plants. These problems have resulted in the poor financial position of generation companies and infrastructure bottlenecks, leading to widespread power shortages.

Pakistan has a relatively small nuclear power programme, with 5 units in operation for a combined capacity of about 1.4 GW. The Pakistan's first NPP, a pressurized heavy water reactor of 137 MW size, came into operation in 1972 at the Karachi site and is still in use. Then four pressurised water reactors of 300 MW each were built in Chashma between 2000 and 2017. Two additional large PWR units of about 1000 MW are under construction in Karachi (units 2 and 3); the first unit is scheduled to be commissioned in 2021 and the second in 2022. This would bring the total nuclear capacity in Pakistan to about 3.4 GW.

The Government plans to increase substantially the nuclear capacity to 8.8 GW by the year 2030. An operational nuclear capacity of 5.4 GW is still to be constructed before 2030 to meet this target. All the operational and under construction NPPs in Pakistan are funded by the Government of Pakistan and export credit agencies of the vendor countries.

The main drivers behind the development of a nuclear programme in Pakistan are energy availability, security of supply and sustainability: providing sustainable energy sources, reducing outages and bottlenecks, meeting growing demand, decreasing high reliance on oil and gas, decreasing power costs.

The main objective behind participation in the CRP are:

- Learn about sources and methods of financing currently used in the power sector as well as risk assessment methods;
- Develop an Excel financial model (based on FINPLAN) to calculate:
  - Investment, Export Credit and Equity required for nuclear programme;
  - Cost of generation;
  - Financial ratios to evaluate the financial viability of plants.
- Perform sensitivity analysis to evaluate financial impact of cost of financing, plant capacity factor and changes in fuel costs.
- Evaluate impact of increase in indigenisation in construction of plant, and sensitivity to indigenisation.

3.7.2. **Modelling assumptions**

The main modelling assumptions are reported in Table 15 below. The O&M charges and return on equity are linked with the consumer price index while the debt servicing portion of export credit is linked with the exchange rate. The EPP is recoverable as per actual expenditure paid by the generator.

TABLE 15. ASSUMPTIONS FOR PAKISTAN NPP FINANCIAL MODEL

Plant Development data	
Plant Size	1000 MW
Construction Period	7 years
Construction Starts	2018
Plant Capacity Factor	85%
Plant Life	40 years (for financial analysis)
Economic data	
Overnight Investment Cost	US $4480/kW in 2013 (mean value from [4]
Annual Phasing of Investment Cost	7%, 13%, 20%, 22%, 16%, 13%, 9%
Annual Escalation in Plant Cost	2%
Fuel Cost (Yellow Cake price of US $45.0/lb)	US $6.4 /MWh
O&M Cost [a]	US $8.0 /MWh
Project Financing	
Debt Equity Ratio	80/20
Interest Rate of Local Loan	8.0% (SBP rate + 2% spread)
Return on Equity (same as thermal plants)	16.0%
Interest During Construction	Capitalized (to be paid after commission)
Discount Rate	6.0% (State Bank of Pakistan's current discount rate) rate)
Export Credit	2.86% p.a., (CIRR for NPPs) 85% of contractor FE cost
Loan Terms	20 years (including 7 years Grace Period)

[a] including decommissioning and waste disposal costs

3.7.3. Financial modelling

An excel financial model based on FINPLAN was developed for financial analysis of new build NPPs.

The financial model consists of multiple spreadsheets:

- Inputs for all plants;
- Capital cost and financing (for individual plants);
- Debt servicing (for individual plants);
- Tariff calculations (for individual plants);
- Results (Individual as well as all plants).

The following financial indicators were developed: benefit cost ratio (BCR), NPV, IRR, payback period, DSCR.

A scenario has been analysed to assess the impact of increasing the localisation level on the total cost of the NPP project. In the "Base Case" scenario (NPP1), it has been assumed that the stakes of the foreign contractor and the owner will remain the same throughout the entire programme of all five new built NPPs. However, there is a possibility that the host country may be interested in developing its own manpower or industrial capability to gradually increase its contribution to the nuclear programme. This scenario is represented by increasing the role of the owner and gradually decreasing the role of the foreign contractor to a certain achievable level. This indigenisation effect has been mapped to the programme in financial terms and assumed to gradually rise to a certain level when, in the 5th plant, the share of the owner's contribution has increased to 40% over 12 years (from 15% in the case of the first unit). Only the shares of the owner and contractor were changed in this scenario and all other assumptions related to financing, operating cost and fuel are the same as in the Base Case. These main assumptions are described in Table 16 below.

TABLE 16. PAKISTAN NPP CASE: ASSUMPTIONS FOR ESTIMATING LOCALISATION EFFECT

	NPP 1 (Base Case)	NPP 2	NPP 3	NPP 4	NPP 5
Indigenization	15%	20%	25%	30%	40%
Share of Contractor	85%	80%	75%	70%	60%
Impact on plant cost	–	10%	10%	5%	-5%

3.7.4. Key findings

The total investment requirement of the whole nuclear power programme is estimated to be US $26.29 billion. It has been estimated that US $5.26 billion (20% of the total) will be funded through equity, an amount of US $14.76 billion (56%) will be available as export credit and the remaining amount of US $6.27 billion (24%) will be raised as debt from local banks.

The level of the electricity tariff and some financial indicators (BCR, NPV, payback period and debt services coverage ratio) have also been estimated to check the financial viability of the NPPs. Results are reported in the Table 17. As all the financial ratios are positive, so projects are financially viable on the given assumptions.

TABLE 17. FINANCIAL RATIOS FOR THE NUCLEAR POWER PROGRAMME

Financial Ratio	NPP 1	NPP 2	NPP 3	NPP 4	NPP 5
Electricity Tariff (US $/MWh)	98.9	100.6	104.0	105.7	107.5
BCR	2.09	2.09	2.10	2.10	2.10
NPV (million US $)	5377	5472	5667	5768	5870
Payback Period (years)	10.93	10.93	10.94	10.94	10.95
Debt Service Coverage Ratio	1.85	1.85	1.85	1.85	1.85

Three Sensitivity studies have been performed to test the impact of changes in some input parameters on the cost of electricity production. Sensitivity assumptions included:

- 1% increase in cost of financing (CIRR 2.9% to 3.9%, local loan 8% to 9%, ROE 16% to 17%);
- 10% reduction of the plant load factor (from 85% to 75%);
- 100% increase in fuel cost.

The results are presented in Table 18, for the five units.

TABLE 18. SENSITIVITY ANALYSIS. IMPACT OF CHANGING SOME PARAMETERS ON GENERATION COST (US $/MWH)

	NPP 1	NPP 2	NPP 3	NPP 4	NPP 5
Base Case	98.9	100.6	104.0	105.7	107.5
Increased Cost of Financing	107.6	109.5	113.2	115.2	117.1
Double Fuel Cost	104.9	106.5	109.9	111.7	113.5
Decreased Load Factor	110.2	112.0	115.9	117.9	119.9

The financial analysis of new build NPPs shows that, on the given assumptions, the projects are financially viable. The results show that the cost of generation of NPP is significantly affected by the change in capacity factor and cost of financing, whereas the change in the price of fuel has less impact on the cost of generation.

3.7.5. Impact of increase indigenisation (localisation) on cost of NPPs

Over the study period, the local contribution in the construction of NPPs has increased from 15% in the start of the programme, to 40% at the end. This increase in indigenization has been assumed to be 5% initially and 10% for the 4th and the 5th plant of the programme. According to the financial model, increasing the localisation content by 5% raises the construction cost of the initial NPPs by 10%. However, this effect tapers off for subsequent plants as the local supply chain gains more experience. The construction cost of the 4th and 5th units decreases with a 10% increase of the localisation content.[27]

The impact of increasing indigenization over the base case is negative at the start of the study period and the total investment requirement for the nuclear power programme increases from US $26.3 billion to US $28.8 billion, an increase of around 9.6%. The export credit in this case is reduced from US $14.8 billion to US $12.6 billion, a reduction of around 14% and a 9.6% increase in the equity investment from US $5.3 billion to US $5.8 billion.

Local financial institutions will have to lend 66% more investment for the indigenization plan than in the base case and will be required to provide US $10.4 billion, an increase of about US $4 billion. This large increase in local borrowing, with higher interest rates compared to foreign loans, will increase the average rate of borrowing for the projects. The increasing indigenisation results in increased capital cost and the cost of electricity generation in initial plants, which will however start gradually decreasing after the construction of some new NPPs.

3.8. URUGUAY

3.8.1. Context

The electricity sector of Uruguay has traditionally been based on domestic hydropower — with relatively low storage capacity and high hydrological conditions variability — along with thermal power (petroleum and gas) plants, and energy exchange with interconnected countries, Argentina and Brazil. Over the last 10 years, investments in energy sources such as wind power, biomass and solar power have allowed the country to cover its electricity needs almost entirely with renewable energy sources. In 2018, most electricity was generated by hydroelectric and

[27] These numbers reflect only the financial figures of indigenization whereas supplementary macroeconomic benefits such as employment, social uplift, skill development, industrial advancement etc., or burdens like cost of uplifting industry, infrastructure, etc., are not covered in these calculations.

wind power (respectively 49% and 38% of the total), while biomass and solar PV contributed to 7% and 3% of the total. Only 3% of the demand is covered by oil and gas plants. Hydropower provides a large percentage of installed power generation capacity in Uruguay. There are four hydroelectric facilities, three on the Rio Negro and one, the Salto Grande´s dam shared with Argentina, on the Uruguay River. The production from these hydropower sources is dependent on rainfall, but under normal hydrological conditions, can supply around half of Uruguay´s total annual electricity demand.

In Uruguay long term power generation expansion, developed under central planning, has three goals: national power supply security, economical convenience and sustainability, minimizing the total cost. Until now, long term power plans in Uruguay have been obtained as least-cost optimization of total power supply costs composed of: capital investment costs, fuel costs, operation and maintenance costs, investment salvage values and cost of energy not served, considering all input data in a deterministic way. National infrastructure and other pre-construction costs associated with the different power generation sources have not been included in the optimisation cost function.

Despite having defined in Uruguay an energy policy to include renewable energy sources to supply the country´s electricity demands, it is necessary to analyse regularly electricity demand and supply in the long term. Taking into account Uruguay´s electricity system size, SMRs is a power generation option to be considered as an alternative for the long term supply costs optimisation.

The main objective behind participating in the CRP

The objectives of this study are related to energy planning:

- Calculating the optimal energy mix and the cost of electricity;
- Calculating cost of NPP;
- Understanding and mitigating cost variability;
- Developing methodology to address power plans risk analysis, differentiating aspects to be treated with a deterministic approach and those with a probabilistic approach.

This study provides a method for addressing a risk analysis of an optimal power plan due to uncertainty in inputs allowing a robust assessment of Uruguay´s optimal power generation expansion strategy based on an economic approach. Separate tools have been developed to deal with some of the financial and risk assessment modelling limitations improving Uruguay´s power planning modelling.

At the beginning of this study, main objectives were analysing the power plan´s costs drivers and financial modelling limitations. As the study evolved, risks analysis became a primary focus to address enabling the development of analytical tools for considering this aspect in an economic analysis of electricity generation sources, particularly with the risk of fuel price variability and fixed costs (construction, technology and regulatory risks) of Small Modular Reactors (SMRs).

3.8.2. Energy planning modelling

WASP IV was the tool used to establish an indicative power generation expansion plan to supply the country's long term electricity demand. WASP is designed to find the economically optimal power generation expansion policy for an electricity system within user specified constraints. Additionally, to deal with some of the financial and risk assessment modelling limitations identified in WASP IV, separate tools have been developed. In some cases, recalculation of input data has been considered as a possible solution to deal with these modelling limitations. In other cases, complementing tools have been considered to expand and improve the analysis.

Some uncertain inputs associated with the construction and operation costs of the different plant types considered as new generation capacity are handled as stochastic variables and modelled through future constant annual real growth rates. These inputs, for given confidence levels, are determined through their probability distribution estimations, thus allowing a total future supply cost variability assessment. Based on risk analysis performed in this study, relevant future price uncertainties are identified.

A deterministic approach was taken in the first part of the study. Construction and technology risks are considered within capital cost rates through financial premium risks. Investment cost risk is modelled through deterministic financial premium risks above US $ risk free rate of capital cost, taking into account:

- US electricity generation industry risk;
- Country risk;
- Particular power technology risk.

A probabilistic approach was followed in the second part of the study. Future prices are handled as stochastic variables to reflect their variability with static approach. Future real prices risk is modelled through probability distributions of annual real growth rates. Thus, this project focuses on the analysis of future fuel and capital prices uncertainty in a certain period, not considering any time dependency. Fig. 15 provides a description of the approach used in this CRP.

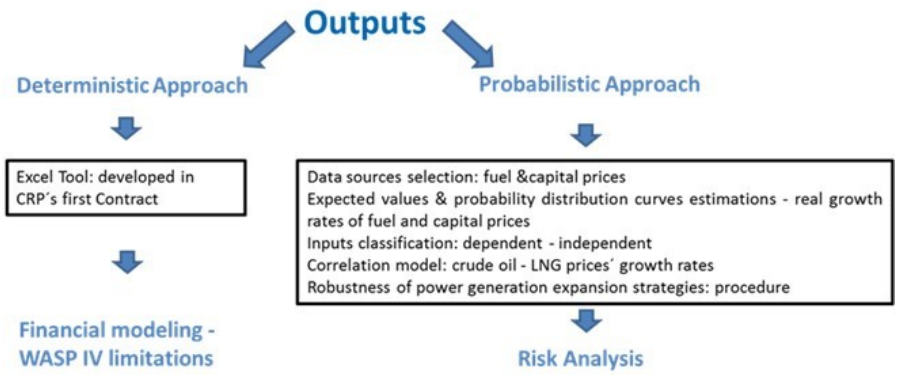

FIG. 15 Uruguay: key expected output of the modelling

Overall, there were three steps in the deterministic analysis:

- Selection of historical prices indices;
- Calculation of annual real average data;
- Calculation of best estimation of annual real growth rates of prices.

and two steps in the probabilistic analysis:

- Estimation of probability distributions;

- Calculation of mean confidence intervals.

3.8.3. Key findings

A study has been developed considering 3 technologies (CCGT, SMRs and wind power) as potential power generation options for future capacity expansion. The existing generation units composed by oil or natural gas fired power plants and renewable power plants (hydro, wind, photovoltaic and biomass) are considered as fixed inputs for optimisation. Wind energy installation has been limited to a maximum of 100 MW per year, given that this source is very competitive due to the high load factor achievable in Uruguay (40%). In the long run, CCGT and SMRs compete as optimal power plants.

Based on risk analysis performed in this study for assessing the impact of future price uncertainty, liquefied natural gas real price and capital real price growth rates variability are identified as the relevant future price uncertainties. The study therefore performs a probabilistic analysis on the real growth rates of these two variables. In case of LNG price, the values that lead to a structural change of the optimal national power plan are 0.8% and 2.86%, and in the case of capital price annual cumulative average real growth rate, the value is about 1%:

- $r_{LNG\ price} \leq 0.8\%$: the optimal expansion plan is constituted by a mix of CCGT and wind power;
- $r_{LNG\ price} > 2.86\%$: the optimal expansion plan is constituted by a mix of SMRs and wind power;
- $r_{capital\ price} \geq 1.0\%$: the optimal expansion plan is constituted by a mix of CCGT and wind power.

Whatever is the generation mix considered (a mix of CCGT and wind power, a mix of SMR and wind power or a mix of these three technologies), the cost estimates are within an acceptable confidence level for the risk factors described above. However, it is highly probable that the assumed costs of these power technologies will be relevant for the Uruguayan system.

A comparative analysis between optimal power plans in a scenario not considering prices real growth rates and a scenario considering the expected values of prices real growth rates analysed before has been made in order to assess the relevance of these inputs in the Uruguayan case. The outcomes compared are the following:

- Uruguay's optimal power plan obtained in this study for a scenario not considering uncertainties in the growth rates of prices correspond to a mix of CCGT and wind power plants;
- Considering expected real growth rates of prices, the optimal power plan remains the same until the 2040. However, from 2041 onwards, the optimal plan incorporates SMR instead of CCGT.

With regard to the cost assessment of the power system, two situations may occur:

In the first case, where different structural optimal power plans have an acceptable confidence level, the power expansion strategy to adopt would depend exclusively on the amount of relevant costs:

- If the sum of these relevant costs of all different structural optimal power plans is high enough, the cost of a power diversification strategy as a mean for risk mitigation would be too high for reasonable risk´s aversion levels. Then, the difference between the amounts of these relevant costs would determine the power specialization strategy to be adopted.

- If the sum of relevant costs is not significant, it might be more likely that there would be a willingness to accept a small costs increase to reduce risk in decision making about power expansion, therefore, in that context a diversification strategy could be an adequate risk mitigation strategy.

In the second case, where only one optimal structural power plan has an acceptable confidence level, the power expansion strategy to recommend would depend on the comparison of plan´s total costs comprising power plan´s supply costs and relevant costs that were not considered. Power specialization strategy would be determined in favour of the structural power plan whose total cost is lower.

Some dimensions that are important for analysing Uruguay´s power expansion strategy not included in the optimization process are:

- Pre-construction costs associated with different power generation sources are not included in the optimisation cost function;
- Wind energy is modelled in WASP IV as thermal unit, therefore not representing the real variability of this generation source. If that were the case, the ability of fast-cycling and rapid starting-up of CCGT would offer advantages to compensate wind fluctuations, thus increasing the economic competitiveness of this generation option;
- Socioeconomic and environmental externalities, excepting cost of energy not served, are not considered.

Because it is highly likely that these costs would be relevant for Uruguay and the benefits of diversification strategy might not be high for the Uruguayan power system, specialisation power expansion strategy seems to be a valid option for the country.

As a result of this study, from an economic and financial perspective, including risk analysis performed in this study for considering uncertainties of inputs, it cannot be asserted that there is a more convenient power expansion strategy to meet future power demand than Uruguay´s current strategy.

3.9. VIETNAM

3.9.1. Context [28]

Vietnam has experienced a significant increase in electricity demand in the last years. From 2000 to 2017, electricity demand has increased by more than eight times, with an average growth rate of 13% per year, driven by high consumption growth in the South of the country. In 2017, final consumption of electricity stood at 185 TWh and was provided mostly by hydro (45%), coal (34%) and gas power plants (21%), while wind, oil and biofuels together provided less than 1% of the total generation. The proportion of population with access to electricity has steadily increased from 2000 and has reached 100% for the first time in 2018.

In 2016, electricity demand was projected to reach 570 TWh in 2030, thus more than three times the demand level in 2015. US Energy Information Administration figures project

[28] Data based on IEA Energy statistics and WNA country profiles

Vietnam's generating capacity expanding from 42 GW in 2015 to about 135 GW in 2030. In this context of high growth of demand, Vietnam has considered establishing nuclear power generation since 1995, and firm proposals surfaced in 2006. The Russian Federation had agreed to finance and build 2400 MW of nuclear capacity from 2020. Japan had agreed similarly for another 2200 MW. Overall, nuclear power was expected to generate 32.5 TWh, i.e reaching a generation share of about 5.7%.

However, the projection for 2030 electricity demand was further reduced so that it could be met with 6 GW of coal- and gas-fired generation plus some renewables, producing about 50 TWh/year. Nuclear plans were therefore postponed. In 2020 a draft plan from the Ministry of Industry and Trade indicated that 5 GW of nuclear capacity could be built in Vietnam by 2045.

Objectives behind participating in the CRP:

- Calculate the total investment cost of a NPP project in Vietnam:
  - Developing cost components of the nuclear generation costs;
  - Understanding cost structure and comparing cost structure established by Vietnam regulatory documents to the calculation of the IAEA and other countries;
- Investigate alternative financial structures for the NPP project. Understand financial arrangements;
- Understand risk and develop a risk matrix.

3.9.2. Methodology

The cost evaluation methodology based on national legislation (construction cost law) is compared with IAEA methodology and best practices. Cost of investments is defined. Best financing practices are analysed.

Risk were assessed and ranked through expert evaluation (qualitative assessment). Ten contractors (32%), ten NPP owners (32%) and eleven consultants (36%) participated in the survey. Ordinal scales were used (ranking or a rating data that normally uses integers in ascending or descending order). The numbers assigned to the agreement or degree of influence (1, 2, 3, 4, 5) do not indicate that the interval between scales are equal, nor do they indicate absolute quantities.

3.9.3. Key findings

Cost assessment

Total investment shoud be determined by the following:

- Construction expenses are calculated according to the workload mainly based on the basic design;
- Other workloads are estimated based on the market data; equipment expenses are calculated according to quantity and categories of equipment suitable to technological design, market prices of equipment and other elements (if any);
- Expenses for compensation, support and resettlement are calculated according to the compensation, support and resettlement workload of the project and relevant state regulations;

- Project management, construction investment consultancy and other expenses are determined by making cost estimates or provisional calculations as a percentage of total construction and equipment expenses.

Potential financial arrangements on NPP construction

- Period of Loan: during construction;
- Loan interest rate and repayment term: based on Government agreement;
  - Interest rate: CIRR plus buyer premium;
  - Repayment period begins at the starting of credit and ends on the contractual date of the final repayment of principal.
- Guarantee: 100% by the Vietnamese Government.

Risk assessment

Most important finance risks identified are:

- Owner's poor management (budget and scheduling of the project);
- Ultimate cost of the plant exceeds original budget and funding expectations;
- Delay in publishing the State budget;
- Political decision associated with financial conditions;
- Lack of law system necessary for projects.

Beside finance risks, NPP projects also face many other types of risks, regarding safety, regulations, quality, etc. These risks can occur at different stages of project (decision-making stage, bidding, design, construction, commissioning, operation) and come from different partners of the project (owner, contractor or consultant).

4. CONCLUSIONS

The current report is based on the outcome of work of IAEA CRP meetings on “Financing Nuclear Investments” (2013–2016) as well as training materials for 2016–2017 financial modelling at IAEA, and materials of IAEA Technical Meeting on Managing the Financial Risks Associated with Nuclear New Build in August 2017. The countries participating in the CRP were Bulgaria, China, Croatia, Indonesia, Jordan, Kenya, Pakistan, Uruguay and Vietnam. Three meetings have been held in the period 2013–2016 within the framework of the CRP. WNA Nuclear Power country profiles (information on drivers to develop nuclear power) information is frequently used.

While modelling was not required during the CRP, many of the participants developed a financial model to assess the feasibility of NPP — using IAEA tools such as FINPLAN, WASP, MESSAGE or own models (see list below).

- Bulgaria — own model based on FINPLAN;
- China — own model;
- Croatia — FINPLAN, WASP, MESSAGE, own financial model;
- Indonesia — own financial model. Monte Carlo simulations for uncertainty evaluation;
- Jordan — own financial model developed by external experts;
- Kenya — own model;
- Pakistan — own model based on FINPLAN;
- Uruguay — WASP, own probabilistic model.

The difference between the models used by participants are driven by the objectives behind CRP participation. For Bulgaria the main research objective was to deepen the understanding of the financing mechanisms commonly used for NPP projects as well as to assess the financial feasibility and profitability of a nuclear project. For Croatia, the main objectives behind CRP participation were the analysis of the profitability of nuclear (and non-nuclear) assets in current electricity market, as well as a comparative analysis of scenarios involving large reactors and SMRs. Identifying the best energy mix (energy planning) has been the key driver for Uruguay for using WASP; however additional stochastic models have been developed for uncertainty assessment and risk quantification. The main driver for China participation was to achieve a better understanding of the financial structures and risk assessment practices to be applied to both domestic and imported designs (VVER, EPR and AP1000) using its own financial models. Indonesia focused the analysis on financial evaluation and risk assessment (using Monte Carlo tools) with a particular focus on SMRs. Pakistan has a long experience with China supported design and uses a FINPLAN based model. Jordan was at an extended stage of negotiations with Rosatom, and already had a financial model developed by external experts. Thus, while initially participants use IAEA or other models, at a later stage of project development they develop their own models. Some countries (e.g. China, Jordan, Croatia) run scenario analysis.

Among the different assumptions used by participants, the cost of equity and debt and the assumed debt to equity ratio had the largest impact on results. For example, Bulgaria used a cost of debt of 5.5% and assumed a debt to equity ratio (D/E) of 85/15, while Croatia had a cost of debt of 5.3% and a D/E ratio of 55/45; Jordan assumed a 40/60 D/E ratio and a cost of debt of 3.73%. Other technical and financial assumptions have an impact on the outcome of the models.

The main financial metrics used by participants include:

- **Cashflow metrics:** NPV, IRR, WACC.
- **Profitability metrics,** ROI, ROA, ROE. Profitability metrics used to assess a business's ability to generate earnings compared to its expenses and other relevant costs incurred during a specific period of time.
- **Revenue metrics**: Gross Revenue, EBITDA (Earnings before interest, depreciation and amortisation), cash flow available for debt service, net income, margins, etc. Revenue refers to the income business has earned from the sale of goods and services.
- **Coverage ratio** is a measure of a company's ability to meet its financial obligations. In broad terms, the higher the coverage ratio, the better the ability of the enterprise to fulfil its obligations to its lenders. The trend of coverage ratios over time is also studied by analysts and investors to ascertain the change in a company's financial position. Coverage ratios include debt service coverage ratio, minimum debt service coverage ratio, average debt service coverage ratio, loan life coverage ratio, project life coverage ratio, interest coverage ratio, debt to EBITDA ratio.

Most participants have calculated and discussed the levelized cost of electricity, the net present value of the project as well as its internal rate of return. Many countries have also run sensitivity analysis to understand which parameters or assumptions have the largest impact on financial outcomes. In particular, the LCOE is most sensitive to the cost of capital, financing cost, construction time (construction delays), capacity factor and fluctuations in the exchange rate.

Risk analysis was performed by all the participants, at least by identifying different risks and ranking them (qualitative estimation). Some participants carried on sensitivity analysis (e.g. China, Croatia, Indonesia, Jordan and Pakistan) to identify the variables that most influence the outcome, and to quantify their impact. Uruguay and Croatia performed also probabilistic analysis using Monte Carlo techniques.

APPENDIX: A SYNTHESIS OF WORK DONE DURING THE CRP

	Objective for participation	Methodology used	Key financial metrics	Key findings
Bulgaria	Identify the most common types of nuclear power plant ownership, contractual approaches and to define the most appropriate for the nuclear new build in Bulgaria; Investigate the conventional and alternative approaches for financing nuclear power generation project; Build a model for financial estimation of the nuclear power plant investment; Investigate the nature of the uncertainties arising in the context of nuclear power plants investments; Develop a specific methodological approach to analyse and determine the uncertainties of the project	Cost analysis; Financial modelling to evaluate the feasibility and competitiveness of the newbuild project at Kozloduy; Expert survey (for risk assessment). Risks were ranked but not quantified, and a risk matrix has been developed	Cost of equity 10% Cost of debt 5.5% D/E ratio 85/15 WACC 5.7% Starting electricity price US $71/MWh LCOE US $51.2/MWh ROI 10.19% IRR 8.07% NPV 5692 Min DSCR 0.78 Max DSCR 1.47	Bulgarian electricity sector will need 2400 MW installed and operating nuclear capacity in 2045 year as this nuclear capacity is going to substitute the power from units 5 and 6 of Kozloduy NPP (in case there is a decision not to extent the operation term) or phased out thermal power plants. Main assumption is the implementation of the paid Belene equipment in a new nuclear power plant at the Kozloduy site. The project is carried out based on project financing. Investment in the project will be reimbursed on the basis of future revenues from the sale of electricity without long term contracts for the purchase of electricity at the fully liberalized energy market. Contracts for difference for 35-year period, with a starting price of US $$71_{2017}$/MWh with 2% step-up can to be used to provide electricity price predictability. A split package type of contract is proposed — one for manufacturing and supply of the equipment and other with a constructing company. In the contract pricing a hybrid approach is used. On the premises that a strategic investor is found, the project is financed 85/15 debt to equity, the project is estimated to be profitable. (NPV >0, IRR> WACC, return on investment is more than 10%) The main risks identified are: • Construction (cost overruns and delays in the construction schedule) • Financial and economic (lack of financing, construction and market risk) • Regulatory, political and environmental risks • Absence of a long-term vision for the nuclear fuel cycle Project is exposed to political support, financial risk, market risk and others. One of the major risks for the project is the political risk. To minimize the risk, the government must have a commitment to nuclear power as a part of national energy strategy.

	Objective for participation	Methodology used	Key financial metrics	Key findings
China	Understand the basics of capital cost evaluation methodology. Understand world best practices of financing and develop a financial model for financing new NPPs. Understand the world best practices on risks assessment for NPPs construction projects and develop a risk mitigation matrix for new NPPs	Cost analysis Financial model Sensitivity to capital cost, financing cost, capacity factor, fuel price Risks assessment (via expert survey)	D/E ~ 80/20 LCOE IRR	The main factors affecting the LCOE of a nuclear project are capital costs, financing costs and capacity factor. The following key risks are identified, and measures for their mitigation are proposed: • Short term loans for long term investment • Interest rate fluctuation • Fluctuation in exchange • Inflation • Project debt risk

	Objective for participation	Methodology used	Key financial metrics	Key findings
Croatia	Carry out a feasibility and financial analysis for potential nuclear power plants in Croatia; Define financial approach most compatible with current utility and financial market conditions; Study how the financial risks specific to new large power plants (especially nuclear power) in liberalised markets can be mitigated and allocated to the different stakeholders, and which financial arrangements are consistent with the alternative allocations of the construction and operating risks; Perform feasibility analysis for SMRs.	Combination of financial and energy planning tools: FINPLAN, WASP, MESSAGE and own models. Risk analysis on revenues due to variability in hydroelectric generation.	For SMRs D/E ratio 55/45 LCOE of SMR 93–106 EUR/MWh	Results for all technologies were compared to hourly electricity market prices in 2014 on power exchanges in Hungary and Slovenia and the result is that NPP (but also all other technologies) cannot be competitive on current electricity markets. In Croatia, SMRs can be better suited than large reactor given the forecasted very small growth of demand and high penetration of subsidised renewable energy sources (RES): they can be built progressively as needs arise and have better features to cope with investment scenario uncertainties, making these projects easier to finance compared to large NPPs. The first preliminary analyses of SMR integration in the Croatian mix show that revenues from electricity markets would be insufficient and situation SMR generators would require some additional forms of remuneration — e. g. capacity payments and load following payments or ancillary services payments.

	Objective for participation	Methodology used	Key financial metrics	Key findings
Indonesia	Explore financial viability of new nuclear power plants in Indonesia; Determine technical and economic parameters for a NPP project; Identification of financial sources for nuclear power plants and analysis of financing schemes; Risks identification and risk analysis (construction delay, market risk, etc.) Assess the financial performance of a SMR project taking into account the uncertainties that may occur in the project.	Developing a (deterministic) financing model to assess the financial performance of the project NPV and IRRs). A Monte Carlo technique is used to propagate the uncertainty of multiple variables and to see the impact on IRR and NPV. The variables analysed are (capital cost, O&M cost, fuel cost, capacity factor, construction period, interest rate, inflation and exchange rates)	NPV, IRR and equity IRR. Sensitivity analysis to selling price of electricity, construction time, exchange rate, overnight cost	Based on the simulation carried out, it is found that most probable value of overnight cost is US $6360/kW for 2 SMR units of 100 MW each. Monte Carlo simulation was performed to determine the effect of the uncertainty variables to the financial performance indicator. The simulation was conducted with discount rate 10%. Electricity sale price becomes critical for a project's viability and a decision on its approval. The study results indicate that a SMR is feasible at the selling price of US $140 per MWh. At that price a SMR is not competitive with a coal power plant but is still competitive with a renewable power plant. The second parameter affecting the financial viability is the construction period (potential cost overruns will increase the cost); Investment cost has a significant impact on the cost of the project since it's a significant share of the construction cost. It should be monitored to prevent cost overrun in a project. Domestic currency inflation rate fluctuation is also an important factor. It indicates the big challenge for the Government to stabilize the national economy so that Indonesia is not categorized as a country with high investment risk.

	Objective for participation	Methodology used	Key financial metrics	Key findings
Jordan	Identifying contractual structure and ownership structures of nuclear power projects. Developing a financial model and carrying out financial analysis. Analysing the main drivers and parameters affecting the financial feasibility of a nuclear power project looking at a number of contractual and ownership structures. Developing a high-level risk management plan.	Financial model; Scenario analysis; Risk analysis.	D/E ratio: 40/60 Interest on debt: 3.73% (sc. 1) 4.47% (sc. 2) 5.73% (sc. 3) Discount factor: 7% (sc. 1) 8% (sc. 2) 9% (sc. 3)	Compared to conventional power plants, NPPs overnight investment cost is higher and in the range of US $5000–7000/kW. This is coupled with a required time frame of at least 5 years for construction completion. For a newcomer country, the optimum contractual approach is an EPC turkey approach. This approach minimizes risks facing the project especially during the construction phase. The analysis of the three scenarios modelled shows that a Governmental-owned project can attract debt at a lower rate and has a lower required rate of return than projects under a mixed public-private partnership or fully private. Thus, LCOE and the electricity tariff required are significantly lower in case of governmental owned projects: required tariff would be 43% higher for a fully private project, and 20% higher for a joint public-private project. Risk analysis showed the highest risks during the planning phase are unrealistic schedule, changes in standard design due to new technical requirements, limited capabilities to finance the project, additional requirements from lenders, delay in EPC negotiation with unbalanced risks, lack of experience in licensing NPPs, and lack of qualified staff. The top risks for a newcomer country's nuclear project are concentrated in vendor design, financing, regulatory system and licensing and EPC contract negotiation. The particularity of nuclear power projects makes that a large part of the risks are ultimately managed by the project stakeholders and cannot be transferred to insurance companies as in more conventional projects. However, new tools have emerged to support investors to manage their risks and hedge against them

	Objective for participation	Methodology used	Key financial metrics	Key findings
Kenya	Analysis of optimal financing options for Kenya's NPP Ownership and contractual approaches for NPP in Kenya Risk analysis, categorization and mitigation	Risk analysis, categorization and mitigation.		SMR present the most feasible option for Kenya's NPP due to small size of grid Most suitable Contracting approach — turnkey contract. Government-to-Government financing offers a valuable source of foreign funding and experience in the nuclear sector, as the magnitude of funds and nuclear experience is domestically unavailable. Loan Guarantees can provide cheaper interest rates, since a guaranteed loan has lower risk, and therefore lower cost, as well as creating liquidity where it might not otherwise be present. Vendor financing could be explored as the programme advances. Kenya should consider negotiating intergovernmental agreements inclusive of funding arrangements for the pre-construction phase of the power programme (infrastructure support) as well as financing (vendor financing through intergovernmental agreements). Kenya should determine to what extent it will take ownership of the power plant. The parties to the agreements will need to agree on what stake each party will have in the power project and this could in turn impact on financing arrangements for the power project. In order to guarantee sale of the electricity generated, a power purchase agreement will need to be negotiated prior to ground-breaking for the power project. Kenya ought to consider engaging global consultants to assist in the pre-construction phase of the NPP project as well as managing its implementation. Kenya should consider obtaining a proportion of the financing required to implement the country's nuclear power project from ECAs despite the high costs associated with the loan guarantees that they provide.

	Objective for participation	Methodology used	Key financial metrics	Key findings
Pakistan	Learn about sources of financing power sector and methods of risk assessment Develop a financial model to calculate: • Investment, Export Credit and Equity required for nuclear programme • Cost of generation • Financial ratios to evaluate the financial viability of plants Perform sensitivity analysis to evaluate financial impact of cost of financing, plant capacity factor and changes in fuel costs. Evaluate impact of increase in indigenisation in construction of plant, and sensitivity to indigenisation	Financial model (based on FINPLAN) Sensitivity analysis Impact of localisation content on electricity generation cost	D/E 80/20 ROE 16%	The total investment requirement of the whole nuclear power programme is estimated to be US $26.289 million. It has been estimated that 56% will be available as export credit, 20% will be funded through equity, and the remaining 24% will be raised from local banks. The level of the electricity tariff and some financial indicators (BCR, NPV, payback period and debt services coverage ratio) indicate that the projects are financially viable given the assumptions taken in the present study. This sensitivity analysis shows that nuclear power plants in the programme are extremely financially sensitive to any change in the cost of financing (1% higher cost of financing increases generation cost by 8.5%). These plants are also very sensitive to slight change in the plant's capacity factor (a 10% lower capacity factor increases cost of generation by 11.4%). Changes in the fuel prices has less impact on the cost of electricity generation. The increasing indigenization of the power plant results in higher construction costs and in increased capital costs (due to a lower proportion of ECA financing). This would result in increased electricity generation cost. It should be noted, however, that this analysis does not cover other supplementary macroeconomic benefits such as employment, social uplift, skill development, industrial advancement etc., or burdens like cost of uplifting industry, infrastructure, etc.

	Objective for participation	Methodology used	Key financial metrics	Key findings
Uruguay	Calculating the optimal energy mix and the cost of electricity; Calculating cost of NPP; Understanding and mitigating cost variability; Developing methodology to address power plans risk analysis, differentiating aspects to be treated with a deterministic approach and those with a probabilistic approach.	The tool used for capacity expansion is WASP IV. Separate tools have been developed to account for some of the financial and risk assessment limitations of WASP IV A deterministic approach was followed in the first part of the study: construction and technology risks are considered within capital costs rates through premium risks. A probabilistic approach was followed in the second phase of the study: future prices are handled as stochastic variables to reflect its variability with static approach. Future real prices risk is modelled through probability distributions of annual real growth rates.	Optimal mix of technologies for capacity expansion.	*Cost assessment* Liquefied natural gas real price and capital real price growth rates variability are identified as the relevant future price uncertainties. In case of LNG price, the values that lead to a structural change of the optimal national power plan are 0.8% and 2.86%, and in the case of capital price annual cumulative average real growth rate, the value is about 1%: • r_(LNG price)≤0.8%: the optimal expansion plan is constituted by a mix of CCGT and wind power; • r_(LNG price)>2.86%: the optimal expansion plan is constituted by a mix of SMRs and wind power; • r_(capital price)≥1.0%: the optimal expansion plan is constituted by a mix of CCGT and wind power. *Robustness assessment of Uruguay´s power generation expansion strategy* Whatever is the generation mix considered (a mix of CCGT and wind power, a mix of SMR and wind power or a mix of these three technologies), the cost estimates are within an acceptable confidence level for the risk factors described above. A comparative analysis between optimal power plans in a scenario not considering prices' real growth rates and a scenario considering the expected values of prices' real growth rates analysed before has been made in order to assess the relevance of these inputs in the Uruguayan case. The outcomes compared are the followings: • Uruguay´s optimal power plan obtained in this study for a scenario not considering growth rates of prices correspond to a mix of CCGT and wind power plants • Considering expected real growth rates of prices, the optimal power plan remains the same until the 2040. However, from 2041 onwards, the optimal plan incorporates SMR instead of CCGT.

	Objective for participation	Methodology used	Key financial metrics	Key findings
Vietnam	Calculate the total investment cost of a NPP project in Vietnam; Develop cost components of the nuclear generation costs; Understand the cost structure of a nuclear project Comparing the cost structure established by Vietnam regulatory documents to the calculations of the IAEA and other countries. Investigate alternative financial structures for the NPP project. Understand financial arrangements Understanding risk and developing a risk matrix.	Risk were assessed and ranked through expert evaluation (qualitative assessment).		Costs: Total investment are determined by the following: • construction expenses are calculated according to the workload mainly based on the basic design; • Other workloads as estimated based on market data; equipment expenses are calculated according to quantity and categories of equipment suitable to technological design, market prices of equipment and other elements (if any); • Expenses for compensation, support and resettlement are calculated according to the compensation, support and resettlement workload of the project and relevant state regulations; • Project management and construction investment consultancy and other expenses are determined by making cost estimates or provisional calculation as a percentage of total construction and equipment expenses Potential financial arrangements on NPP construction • Period of Loan: during construction; • Loan interest rate and repayment term: base on government' agreement; Interest rate: CIRR + Buyer Premium; Repayment period: begins at the Starting Point of Credit and ending on the contractual date of the final repayment of principle; • Guarantee: 100% guarantee by the Vietnamese government Risk assessment Most important finance risks: • Owner's poor management (budget and scheduling of the project); • Ultimate cost of the plant exceeds original budget and funding expectations; • Delay in the State Budget; • Political decision associated to financial conditions; • Lack of law system necessary for projects. Beside finance risks, NPP project also face many other types of risks, as safety, regulation, quality, etc. The risks can occur at stages of project as: decision-making stage, bidding, design, construction, commissioning, operation; and come from partners of the project: owner, contractor or consultant.

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LIST OF ABBREVIATIONS

BCR	benefit cost ratio
BOP	balance of the plant
CCGT	combined cycle gas turbines
CFD	contracts for difference
CGN	China general nuclear power group
CIRR	commercial interest reference rate
COD	commercial operation date
CRP	coordinated research project
DCF	discounted cash flow
D/E	debt equity ratio
DSCR	debt service coverage ratio
EBITDA	earnings before interest, tax, depreciation and amortisation
ECA	export credit agency
EPC[2]	engineering, procurement and construction
ESST	energy scenarios simulation tool
FINPLAN	financial analysis of electric sector expansion plans
FIP	feed in premium
FIT	feed in tariff
IDC	interest during construction
IEA	international energy agency
IRR	internal rate of return
LACE	levelized avoided cost of electricity
LCOE	levelized cost of electricity
LIBOR	London interbank offered rate
LNG	liquefied natural gas
LUEC	levelized unit electricity cost
MAED	model for analysis of energy demands
MESSAGE	model of energy supply strategy alternatives and their general environmental impacts
MIRR	modified internal rate of return
NPP	nuclear power plant
NPV	net present value
O&M	operation and maintenance
OECD	organization for economic cooperation and development
PI	profitability index
PPA	power purchase agreement
PV	present value
RAB	regulatory asset base
RES	renewable energy sources
ROA	return on assets
ROE	return on equity
SMR	small modular reactor
SPV	special purpose vehicle
SNPTC	state nuclear power technology company (China)
VALCOE	value adjusted LCOE
WACC	weighted average cost of capital
WASP	Wien automatic system planning package

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