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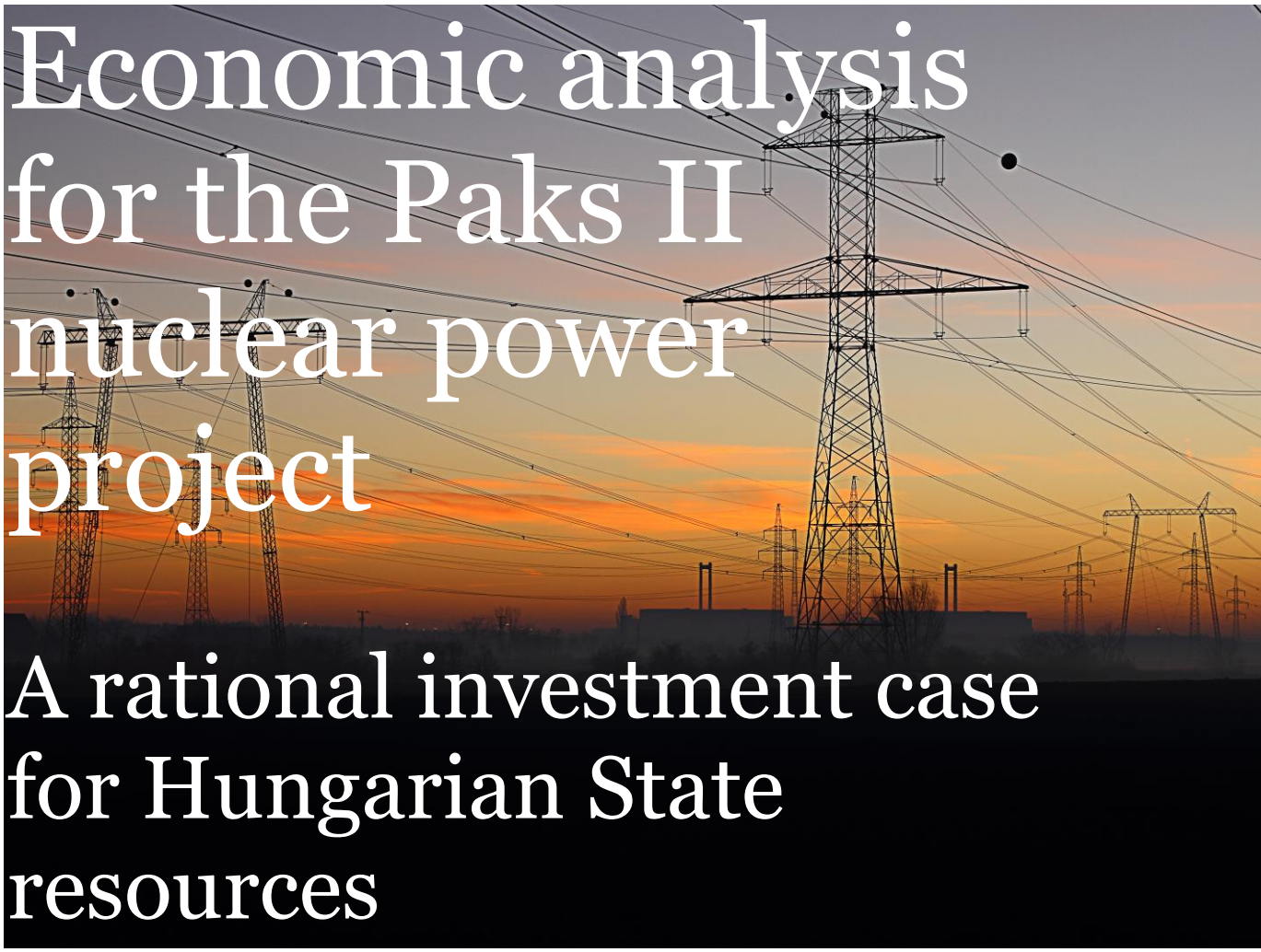

Economic analysis for the Paks II nuclear power project

A rational investment case for Hungarian State resources

September 2015

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1. Introduction

Context

The Paks II nuclear power plant ("Paks II", the "Project") envisages the creation of 2,400MW gross new nuclear power capacities utilising the Russian-made pressurised water reactor (PWR) which is one of the most advanced available nuclear technologies categorised as Generation III+. The Paks II NPP is being implemented under strict European safety requirements. When operational, the Paks II NPP would contribute to the fulfilment of the Hungarian energy policy by providing 2,400MW towards the expected c. 7,300MW[1] necessary new generation capacities required to replace retiring capacities by 2030 and to maintain adequate domestic generation capacity to satisfy domestic needs as required by the European Network of Transmission System Operators for Electricity (ENTSO-E).

This independent report has been prepared by Rothschild, with the assistance of NERA for the Prime Minister's Office of the Government of Hungary to analyse the economic prospects of Paks II utilising independent and publicly sourced information as the basis for assumptions. The calculations presented in this report are based on a financial model that generates forecast financial statements and enables the assessment of the cash flows and returns of the Project under a range of assumptions on key variables such as the project cost, power output, achieved power sales price, operational costs and costs of capital. Rothschild has provided references to information sources used but has not independently verified the publicly obtained information and the market price projections based on NERA analysis. Rothschild has also reviewed and critiqued identified publicly available independent reports which analyse the Project economics and the assumptions stated as used in those prior analyses.

Commercial and financial performance

The analysis in this report, based on the stated assumptions sourced from publicly available information, indicates that the Paks II NPP is expected to deliver equity returns to its shareholder, the Hungarian Government (the "State") (and hence Hungarian tax-payers), that are comparable to relevant project and equity return benchmarks, without the need for subsidy arrangements from either tax payers or energy consumers. This report considers the basis for each of the core assumptions relating to construction cost and schedule, operational availability, future power prices, plant life, operating period costs and eventual cost of radioactive waste disposal and plant decommissioning on which the findings of this analysis depend. The favourable anticipated financial performance is significantly due to the Paks II NPP benefiting from well negotiated contract terms: the fixed price turn-key agreement for the construction of the Paks II NPP appears competitive when compared to public information about costs of other new nuclear projects: €12.5 billion budget for 2.4GW of capacity implies €5,200/kW compared to €31.2 billion[2] for 3.2GW of capacity for the UK's Hinkley Point C project (€9,750/kW). These figures are on a nominal basis, being the nominal cost divided by the capacity, but this report

[1] MAVIR (2014): A magyar villamosenergia-rendszer közép- és hosszú távú forrásoldali kapacitásfejlesztése (Medium- and long-term development of generation assets of the Hungarian electricity system)

[2] European Commission press release (08 October 2014) - State aid: Commission concludes modified UK measures for Hinkley Point nuclear power plant are compatible with EU rules

also considers the wider overnight cost comparison methodology (i.e. on a real basis) that compares costs across projects (see section 3.1) which equally shows the relative cost competitiveness of Paks II. This analysis assumes that the parties to the EPC contract each perform their respective commitments such that the EPC contractor delivers the project within the fixed price budget that is the declared contractual intention of the parties. This analysis does not contain information sourced from the EPC contract or verification of the contract terms given the security driven confidentiality classification of the Project contracts. The economic analysis for Paks II in the context of this fixed price signed EPC contract and the financing from Russia under the financial intergovernmental agreement (Financial IGA) supports the case that Paks II, under benchmarked operational and market price assumptions, would be self-funding during the operational life of the plant without the need for any subsidies from consumers or taxpayers.

Investment rationale

The investment in the Paks II project is also strategically important. Given the near term retirement of generation capacities in Hungary, investment in new capacity projects is required in order to ensure security of supply for the future in the context of anticipated generation capacity retirement from different technologies. According to the Hungarian transmission system operator, MAVIR, 31.4% of domestic demand is currently satisfied by imports from abroad, and by 2030 more than 7GW of new capacity will need to be installed due to the closure of further generation facilities and the expected increase in peak load.

This clear requirement for investment in new power capacities and the contribution to part of this new capacity from nuclear generation is in line with Hungary's energy policy, including the preservation of nuclear power contribution to the energy mix. Nuclear energy is judged by the Hungarian Government to be the best alternative to secure the necessary base load electricity generation which provides the added advantage of reducing dependence on more expensive and price-volatile energy sources, e.g. Russian natural gas.

Independent economic analysis

The economic viability of a new nuclear power plant at Paks II has been subject to many studies and high level calculations over the years presented by industry experts, energy associations and academic researchers. Some of the research has been supportive of the viability of the Project, e.g. Dr. Aszódi's paper, "Extension of the Paks NPP – energy political, technical and economical evaluations", while others such as the analysis of Mr. Balázs Felsmann, researcher at Corvinus University of Budapest, in association with ENERGIAKLUB Climate and Energy Policy NGO Applied Communication "Can the Paks-2 nuclear power plant operate without State Aid?", have argued that the Project requires additional funding from State resources during the operational period and is not economically commercial without State support. Other independent research such as by REKK and by Mr. Balázs Romhányi do not make final conclusions on the economics but pose relevant questions, with the latter considering the costs and benefits from a State perspective rather than from a project perspective.

This paper seeks to clarify the input assumptions and bring light to the economic viability case, particularly given that older reports were not able to be conclusive on the Project economics due to lack of visibility regarding certain assumptions. Following the agreement between Hungary and the Russian Federation, a number of key input parameters became known that enable more accurate calculations, e.g. the technology for the plant is known which provides clarity on technical specifications that impact the economic assessment such as the operational life of the

plant, the capacity of the plant and the total maximum project budget of €12.5 billion (nominal terms). Using this information, as well as the wide array of public research on and benchmarking of the economic parameters of a new nuclear project, this report seeks to critically analyse the Paks II project and its economic rationale in order to provide a detailed and thorough view on the feasibility of the Project. This report will also aim to point out the areas in which the other reports diverge from benchmark assumptions or methodologies and hence the reasons for the deviation in prior published results. The analysis contained in this paper is supported by the latest published data and research from internationally reputable agencies in the power and nuclear industry, such as the International Energy Agency (IEA) and the Nuclear Energy Agency (NEA). Commentary on prior economic analysis reports is colour coded as per below:

Attila Aszódi (et al), "Extension of the Paks II NPP- energy political, technical and economical evaluations"[3]

REKK, "Nuclear Power Plant Investment Business Model and Expected Returns"[4]

Balázs Romhányi,"The PAKS II Investment Policy Implications of Budget"[5]

Balázs Felsmann, "Can the Paks-2 nuclear power plant operate without State Aid?"[6]

Significant development in nuclear technology

The current Paks I units and the proposed Paks II units are based on the same technology (pressurised water VVER reactors), but with differences in their technical specifications and design principles. While the existing units are still improved versions of the Generation II development level, the Paks II units would be Generation III+ reactors. According to the design specifications there are significant differences in the electrical capacities of the individual units; in the case of Paks II, each unit's technical capacity is 1,200MW, while the Paks I VVER-440 units continue to have a capacity of approximately 500MW, even after upgrade modifications. There is also a material difference in the planned operating lifetime (60 years for the Paks II units vs. 30 years for the Paks I units) and wider manoeuvrability, which allows the capacity of the unit to be adjusted according to demand on the grid within a certain range.

The amount of fuel required by the new units also reflects the technological improvements over the years. Instead of the previous 12-month fuel cycle (i.e. fuel would need to be reloaded every 12 months), the new units can operate on an 18-month cycle. This means that the new units require fewer shut-downs per year for fuel reloading, and so the plant is able to operate for longer each year on average and not lose production time. The power density provided by the fuel assemblies is also indicated in technical specifications as significantly higher than that of the fuel assemblies used in the VVER-440, i.e. a higher output can be achieved per unit mass of fuel material, again improving the economics of the plant. In conclusion, Paks II technical specifications indicate noteworthy advantages over the current Paks units, with increased efficiency and economic operation in addition to safety enhancements.

[3] Aszódi, Attila – Boros, Ildikó – Kovács, Arnold (2014): A paksi atomerőmű bővítésének energiapolitikai, műszaki és gazdasági kérdései, in Magyar Energetika, May 2014.

[4] REKK [Regional Centre for energy polic research] (2013): Atomerőművi beruházások üzleti modelljei és várható megtérülésük: http://www.rekk.eu/images/stories/letoltheto/rekk_atom_megterules.pdf

[5] Romhányi, Balázs (2014): A Paks II beruházás költségvetés-politikai következményei, available here: http://www.pakskontroll.hu/sites/default/files/a_paks_ii_beruhazas_koltsegvetes-politikai_kovetkezmenyei.pdf

[6] Felsmann, Balázs (2015): Működhet-e Paks II állami támogatások nélkül? Az erőműtársaság vállalatgazdasági megközelítésben, available here: http://www.pakskontroll.hu/sites/default/files/paks2_allami_tamogatas_2015jun.pdf

Affordability and safeguarding of consumer interest

Every European Union Member State is able to determine its policy for energy generation mix. Hungary, like Finland, France, Lithuania, Slovakia, Poland, Romania, Bulgaria, UK and the Czech Republic has chosen to develop new nuclear power. Globally, several other countries like Turkey, Russia, the United States, China and South Korea have decided to follow the same path. Hungary and Paks II, like projects in each of the mentioned European countries, has sought a fixed cost with a financing package that means new nuclear power can be economically constructed. The Hungarian Government has responsibly ensured that security of supply and decarbonisation are pursued while also maintaining affordability by creating a framework that avoids the need for high charges to consumers, and instead minimises costs. Hungary, like the majority of the countries listed, namely Finland, France, Turkey, Lithuania, Slovakia, Romania, Bulgaria and the Czech Republic, is pursuing a new nuclear policy without imposing on end consumers market price subsidy top up arrangements that are being introduced in the United Kingdom.

Further to projects in construction (in Finland, France and Slovakia), the Hungarian project and another VVER technology project in Finland are the most advanced pre-construction developments in Europe with already signed EPC contracts that define costs and risk allocation. Hungary has - on grounds of affordability for taxpayers and consumers - not sought to subsidise new nuclear projects on low-carbon generation arguments. On the contrary, because nuclear energy appears to be more cost competitive compared to alternative options for replacement capacity investments in Hungary, based on publicly sourced forecasts of the cost of different generation technologies, future power prices for end consumers can reasonably be expected to be lower following the building of Paks II NPP than they would otherwise be.

The State Aid rules

The European Union rules on the use of state resources categorise such state resources into those that are used on market economic investment principles and hence are within permitted state allocation decisions without the need for any further specific European Commission approvals and those that qualify as State Aid and hence require demonstration of compliance with rules on proportionality and necessity for approval. The conditions that define whether the state resources are State Aid are the (a) selective conferring of an (b) economic advantage on certain undertakings which are (c) liable to distort competition and (d) affect trade between Member States. All these criteria must be fulfilled cumulatively, not just one of those. In the case of Paks II, Hungary does not confer an “economic advantage” on Paks II NPP, as the returns on the project are exposed to the same market forces and market price uncertainties as other power generators.

The Project is not unique in that it is being implemented with the use of State resources but without market price mechanisms, on terms that require the Project’s commercial competitiveness relative to market prices - critical for public affordability and acceptability. Specific examples of projects in Member States without State Aid investigations despite use of State funds through fully or partially state owned utilities include:

- France: EDF’s 100% investment in Flamanville;
- Slovakia: Slovenske Elektrarne's investment in Mohuviche;
- Finland: Finnish municipalities shareholding in Fennovoima and Fortum’s recently announced 6.6% minority shareholding in Fennovoima;

- Romania: Nuclearelectrica's ownership of the Cernavoda project, with CGN potentially investing;
- Lithuania: VAE 34% investment in Visaginas including sunk investment to date, regional partners (Latvenergo, EestiEnergia) interest in the project;
- Bulgaria: BEH investments in Belene and considerations in Kozloduy.

Market investors or vendors co-investing are useful examples for the market investor principle and include:

- Finland: TVO's OKL3; Finnish industrial power users shareholding in Fennovoima and Rosatom 34% shareholding;
- Slovakia: Enel's investments in Slovenske Elektrarne's Mohuviche;
- Lithuania: Hitachi 20% shareholding and technology sale in Visaginas;
- Romania: CGNPC interest in Cernovoda;
- Bulgaria: Westinghouse interest in Kozloduy;

Current examples of long term capital providers considering investments in new nuclear projects that evaluate the overall full project returns rather than just the near term financial impact include the technology vendors as well as state owned utilities and industrial users. The most relevant benchmarks for Paks II NPP are the Finnish industrial power user shareholders (VSF) and the vendor shareholder (Rosatom) in Fennovoima's Hanhikivi project due to the use in that project of the same reactor technology.

Positive externalities

In cases where State Aid is identified, sovereign states can justify the use of such aid on social and economic grounds by demonstrating the proportionality of the aid used and the necessity for the aid. Considerations can then be given to external benefits in addition to the pure economic case. In the case of Hungary, in addition to the business rationale of the project for the Government as the shareholder, the project is also expected to bring significant social and economic benefits to Hungary as a nation, such as:

- Anticipated material increase in Hungary's GDP;
- Tax receipts for the Government, which can be reinvested into the economy;
- Orders for local businesses due to the intention for 40% of local content in the products and services for the development of the project as described in Hungarian-Russian intergovernmental agreement ("IGA");
- Job creation and preservation with a significant workforce to be employed at the construction site resulting into positive spill-overs to the construction service industry;
- A large-scale source of sustainable low-carbon, long-term energy supply which will contribute to a reduction in CO_2 and other pollutant gas emissions

Such positive externalities are relevant considerations for the State decision making, but have not been considered in the economic analysis contained in this paper, contrary for example to the consideration of tax revenues in the Romhányi study. These externalities can be relevant considerations in proportionality and necessity considerations in the approval of State aid cases, such as Hinkley Point C. The importance of large infrastructure projects such as nuclear new

build should not be underestimated in the current low growth environment. According to Eurelectric the nuclear industry is estimated to currently provide around 400,000 to 500,000 jobs in the European Union, directly and indirectly, with additional jobs being created for life-time extensions or new build programmes[7]. Likewise the allocation of resources to ensure cost competitive long term power production such as nuclear is critical for European economic competitiveness, without sacrificing environmental objectives - nuclear plants being the largest source of low carbon electricity in Europe[8] and indeed worldwide.

National energy policy and the right to choose energy mix

The Hungarian energy policy for 2008 - 2020 was focussed on ensuring security of supply with the aim of achieving and maintaining a balanced energy mix. In achieving these aims, the policy looked to diversify sources, maintain a sensible share of national resources and reduce Hungarian dependence on imports while remaining consistent with national climate policy. In response to these aims, the National Assembly called upon the Hungarian Government to focus on plans for new nuclear capacity. In particular, they urged the Government to consider a nuclear solution that was technically, environmentally and socially amenable to Parliament.

In accordance with the Government's objectives, the Hungarian State Privatisation and Holding Company requested that the MVM Hungarian Electricity Ltd. investigate the alternatives of the expansion of electricity production in nuclear power plants. This included the establishment of the Teller Project on 31 July 2007. Within the framework of this Project, a Feasibility Study was developed that introduced the implementation and financing of such a new nuclear power plant that could be integrated into the electricity system and could be operated in an economical, safe and environmentally-friendly way. Following this, based on the Feasibility Study prepared in 2008, the Government made a proposition to the Hungarian Parliament, in which the conceptual consent was requested from the Parliament to start the preparatory work of the implementation of new nuclear power plant units at the Paks Site. This was approved with 330 votes in favour, 6 against and 10 abstentions, on 30 March 2009. The decision was supported by previous calculations according to which the retirement of 6,000MW from the 8-9,000MW gross installed capacity was forecast due to the shutdown of the obsolete power plants, which can be partly replaced by the expansion of the Paks Nuclear Power Plant.

In 2011, the energy policy for 2008 – 2020 was repealed and the National Energy Strategy for the period up to 2030 was implemented. This strategy focusses on a "Nuclear-Coal-Green" scenario for Hungary, summarised as follows:

- The long-term preservation of nuclear energy in the energy mix;
- The maintenance of the current level of coal-based energy generation, for two reasons: (i) in energy crisis situations (e.g. price escalation of natural gas, nuclear capacities shutdown) it is the single readily available internal reserve, and (ii) preventing the final loss of a trade of value due to (i) above and with a view to maintaining the possibility of an increased share in future utilisation. The latter depends on full compliance with the committed sustainability and GHG emission criteria (full use of carbon capture and clean coal technologies);
- The linear extension of Hungary's National Renewable Energy Action Plan (NREAP) after 2020, provided that efforts should be made in order to increase the set objective for

[7] Eurelectric - Nuclear Power Plants – Tackling the Investment Dilemma

[8] Eurelectric - Nuclear Power Plants – Tackling the Investment Dilemma

renewable energy sources, depending on the capacity of the economy, system controllability and technological development.

The Government of Hungary and the Government of the Russian Federation signed an international agreement on cooperation in the peaceful use of nuclear energy, in particular on the cooperation in sustaining and extending the existing circa 2GW nuclear power generation capacity close to the City of Paks, Hungary through the development, financing, construction and commissioning of two new power units with VVER reactors (the “IGA”). The Government of Hungary and the Government of the Russian Federation signed the IGA on 14 January 2014. The Hungarian National Assembly subsequently adopted Act II of 2014 by which the IGA was incorporated into national legislation, and this Act came into effect on 12 February 2014. The Russian Federation further provided to Hungary a state credit to finance the sustaining and development of the capacity of the Paks NPP in the amount and on terms and conditions specified in a separate agreement between the Parties (the “Financial IGA”). The Russian Federation and Hungary acknowledged that performance under the IGA shall be conditional on the Financial IGA. The Financial IGA signed on 28 March 2014 between the Government of Hungary and the Government of the Russian Federation stipulated the extension of a state credit in the amount of up to €10 billion to Hungary for financing up to 80% of the Project.

Pursuant to the IGA, the Hungarian Authorized Organisation and the Russian Authorized Organisation concluded on 9 December 2014 the Implementation Agreements ("Implementation Agreements"), in particular:

- A fixed price turnkey engineering, procurement and construction contract ("EPC Contract") which came into force on 1 January 2015,
- An operation and maintenance support contract ("O&M Support Contract"), and
- An agreement on supply of nuclear fuel for the Paks NPP ("Fuel Supply Agreement").

The state level engagement for the Project is typical of nuclear projects. New nuclear projects are complex and large and they require interface between hosting state, developer, funder and technology provider. Historically, such projects have tended to be implemented in the hosting country by the nuclear industry of that state (if it had one). The presence of host state involvement highlights the important policy and safety interface and the huge investment for nuclear technology development that historically was state funded, which has meant that technology choice offerings are closely linked to finance offerings and to exporting state economic relationships with the host state. The nuclear market is a global market in which economies of scale are critical for technology and financing competitiveness, whilst host states are critical enablers for such projects. In Europe a significant number of European Member States and neighbouring countries continue to support the development of new nuclear power as part of their energy mix, which is the choice of each Member State and not a delegated power to the European Commission.

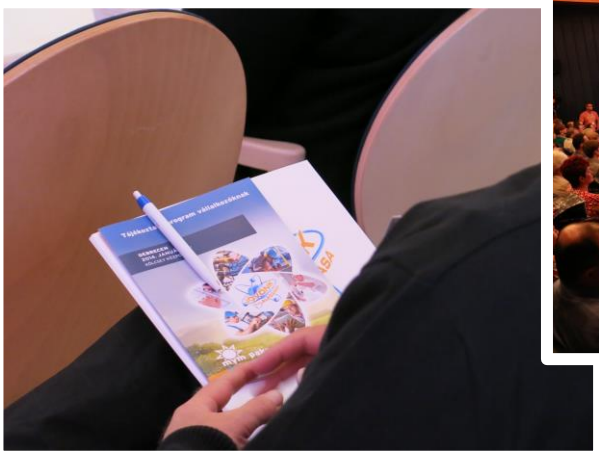
The European Commission acknowledges and supports Member States’ rights to choose to sustain nuclear capacities, as can be seen by the 2015 Management Plan for DG Energy. In order to meet its general activities, “promoting the safe and secure use of nuclear energy” is stated as one of its specific objectives. The plan provides multiple justifications for its support of nuclear energy and sets a 2020 target of “no decline of the share of nuclear gross electricity generation in 2020 with regards to 2012 baseline” which, given the near to medium term retirement of capacity, would require investment in new nuclear plants in Europe. The Plan goes on to say that “investment in nuclear energy will contribute to reduce energy dependence and is essential for the implementation of the European Energy Security Strategy.” Nuclear power

plants generate almost 30% of the electricity produced in the EU, with 130 nuclear reactors in operation in 14 EU countries. Each EU Member State decides alone whether to include nuclear power in its energy mix or not[9]. The peaceful use of nuclear energy within the EU is governed by the 1957 Euratom Treaty which established the European Atomic Energy Community (Euratom). While Euratom is a separate legal entity from the EU, it is governed by the EU's institutions. In the period 2010 – 2014 nuclear investment projects notified to the Commission under Article 41 Euratom have been disclosed as amounting to €42.3 billion; comprising €36 billion for new reactors, €3.6 billion for waste management and spent fuel disposal, €1.3 billion for power plant refurbishment, €1.2 billion for decommissioning activities, and €0.2 billion for uranium mining projects.

The Hungarian Government has sought to implement the Project in full compliance with the requirements of the European Commission, including notifying the Commission of the IGA prior to signing, notifying the Commission of the Project in accordance with Article 41 of Euratom. Further to discussions under Article 43 of Euratom, the European Commission has provided a positive opinion on the Project pursuant to the Article 41 notification. This assessment includes evaluation of the commercial viability of the project based on the notified capital costs and funding sources. Furthermore, the Euratom Supply Agency ("ESA") co-signed the Project's Fuel Supply Agreement on 20 April 2015. The Hungarian Government is still awaiting a response on its no-aid notification to the European Commission and on discussions relating to procurement matters. The analysis in this report indicates that the financial analysis of the Project, based on assumptions sourced and benchmarked from publicly available and independent sources, can substantiate reasonable return expectations comparable to relevant project and equity return benchmarks used by market participants and hence can indicate that the use of state resources is on market terms and thereby that no State Aid is applied to this Project. This is prior to any consideration of the macroeconomic rationale for supporting and permitting the use of State Aid, such as the considerations that led to the European Commission endorsing a significant State Aid package in the UK, which supports timely delivery of nuclear power generation replacement capacity.

[9] http://ec.europa.eu/energy/en/topics/nuclear-energy

2. Methodology



Public consultations and project analysis

This report analyses the Paks II economic viability on the basis of independent and publicly sourced information and assumptions. The analysis contained in this Report is supported by a financial cash flow model of the Project. The model uses assumptions which have been benchmarked to publicly available data for the plant's operational power output, nominal operational costs, capital expenditure required for the construction and development of the plant, working capital movements and corporate taxes, possible capital structure and cost of capital to arrive at an overall cost base. This is then compared for viability and profitability under different possible real power price scenarios, without reliance on any particular possible outcome of future market prices. The cash flows analysis enables the assessment of the economic performance of the Project using two methodologies.

2.1 LCOE

Discounting the costs associated with the project at an appropriate discount rate (a weighted average of the costs of the capital deployed – a WACC) in order to calculate the levelised cost of electricity ("LCOE") essentially indicates the price required for the Project to break-even, i.e. to be providing enough cash generation not only to cover all costs but also to provide a return on the invested capital which is in line with the alternative possible yields that this capital could generate from alternative investments, but no greater return than that. This approach does not require a view on the future market power prices and enables comparison across different technology options. Dr. Aszódi's paper considers the break-even cost for the Paks II plant with this methodology.

LCOE remains a transparent consensus measure of generating costs and a widely used tool for comparing the costs of different power generating technologies in modelling and policy discussions. The calculation of the LCOE is based on the equivalence of the present value of the sum of discounted revenues and the present value of the sum of discounted costs. Another way of looking at LCOE is that it is the electricity tariff with which an investor would precisely break even on the project after paying debt and equity investors, after accounting for required

rates of return to these investors. The latest published International Energy Agency (IEA) report on Projected Costs of Generating Electricity 2015 edition compares across technologies and countries using three different real discount rates: a 3% discount rate (corresponding approximately to the "social cost of capital"), a 7% discount rate (corresponding approximately to the market rate in deregulated or restructured markets), and a 10% discount rate (corresponding approximately to an investment in a high-risk environment). It should be noted that the report states the limitations of the WACC analysis and the issue of comparability of WACCs across projects[10].

The LCOE calculation begins with equation (1) expressing the equality between the present value of the sum of discounted revenues and the present value of the sum of discounted costs, including payments to capital providers. The subscript t denotes the year in which the sale of production or the cost disbursement takes place. The summation extends from the start of construction preparation to the end of dismantling, which includes the discounted value at that time of future waste management costs. All variables are real, i.e. net of inflation. On the left-hand side one finds the discounted sum of benefits and on the right-hand side the discounted sum of costs:

$$\Sigma PMWh * MWh * (1+r)^{-t} = \Sigma(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t) * (1+r)^{-t} \quad (1)$$

where the different variables indicate:

- PMWh = The constant lifetime remuneration to the supplier for electricity;
- MWh = The amount of electricity produced in MWh, assumed constant;
- $(1+r)^{-t}$ = The discount factor for year t (reflecting payments to capital);
- $Capital_t$ = Total capital construction costs in year t;
- $O\&M_t$ = Operation and maintenance costs 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.

Because PMWh is a constant over time, it can be brought out of the summation, and equation (1) can be transformed into

$$LCOE = PMWh = \frac{\Sigma(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t) * (1+r)-t}{\Sigma\ MWh\ (1+r)-t} \quad (2)$$

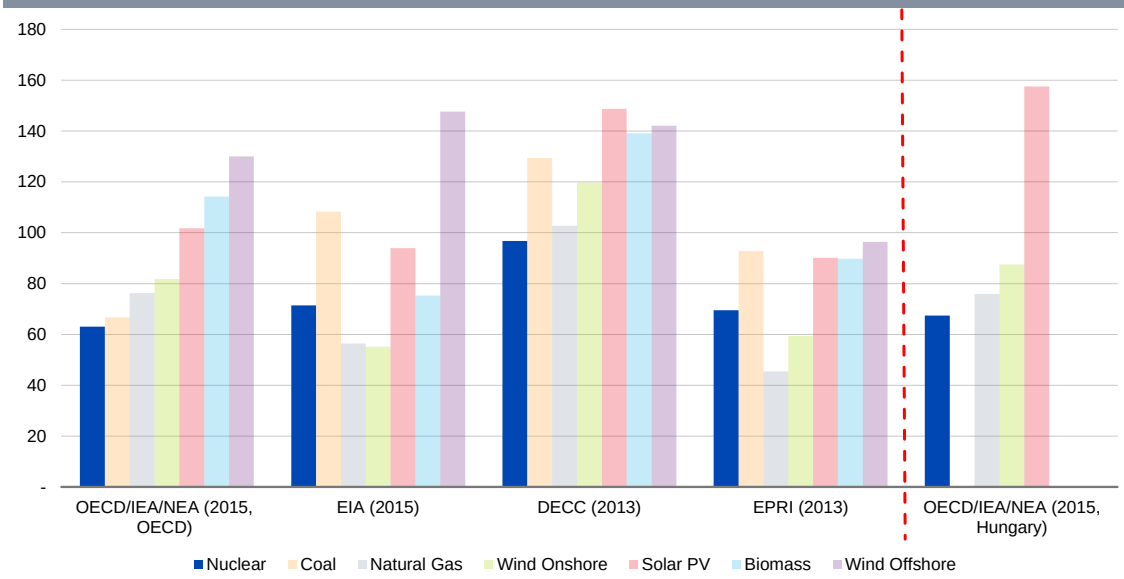
where this constant, PMWh, is defined as the levelised cost of electricity (LCOE).

Equation (2) is the formula used to calculate average lifetime levelised costs on the basis of the costs for investment, operation and maintenance, fuel, carbon emissions and decommissioning and dismantling provided by OECD member countries and selected non-member countries. It is also the formula that has been used in previous editions of reports on the cost of generating electricity, and in most studies on the topic.

[10] The report states: "Without going into the subtleties of corporate finance a real-world investor must face, one can make the following broad statements in the context of the EGC report. Such a report would need to include, among other issues, accounting conventions, tax laws, the availability of investment incentives, the structure of electricity markets and demand, etc. for one particular market and technology. It could never produce comparable results for many various technologies across many countries according to simple, harmonised assumptions."

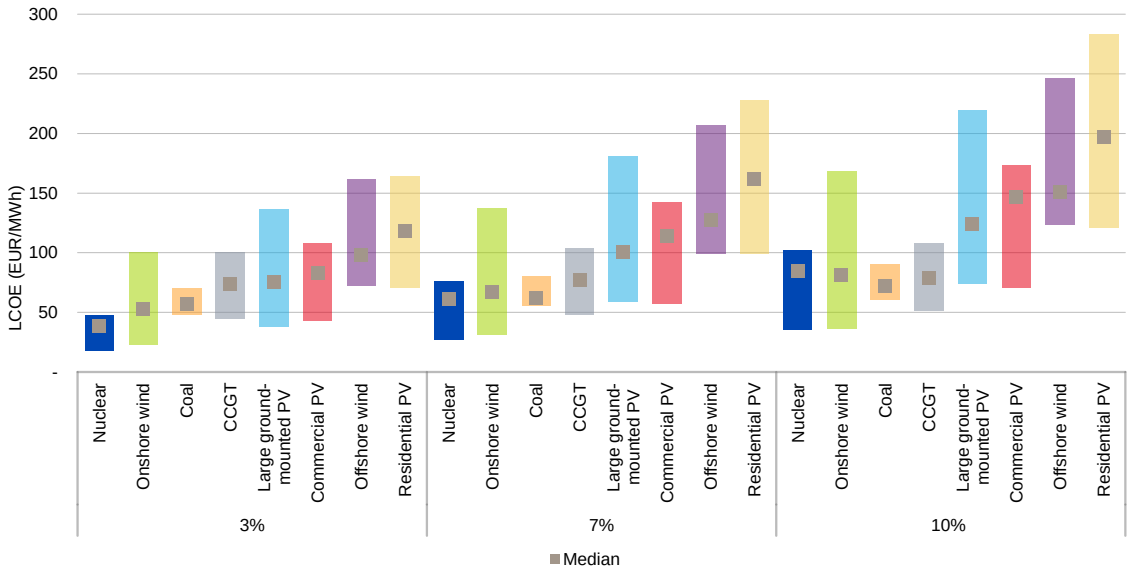
Comparing generation technologies on a LCOE basis removes the need to forecast prices which is inherently uncertain and depends on policy and subsidy developments in different countries. Figure 1 shows the estimated LCOEs for different generation technologies based on a range of sources. As can be seen from these estimates for the LCOE of different generation technologies by a number of internationally reputable sources, nuclear power appears to be a competitive source of energy, which is likely to lead to lower prices for end consumers than investments in renewable generation that require state subsidies, or more expensive conventional generation. Nuclear power also appears to be the most competitive generation type for Hungary according to the OECD / IEA / NEA analysis.

Figure 1. LCOE benchmarking (€ / MWh)



Source OECD, EIA, IEA, NEA, DECC, EPRI

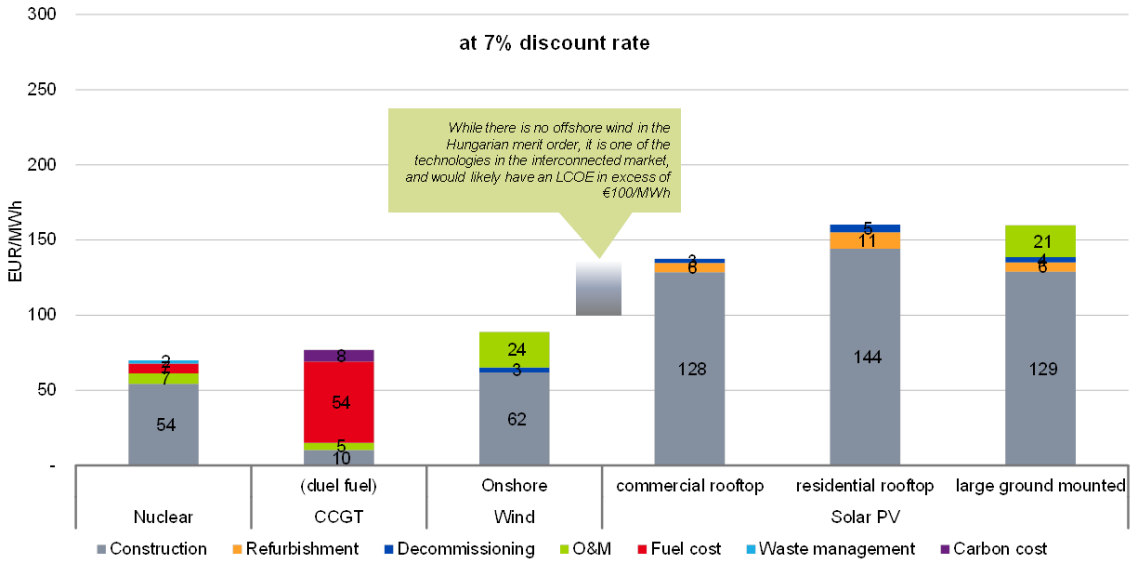
Figure 2. LCOE's for different technologies at different discount rates



Source OECD / IEA / NEA - Projected Costs of Generating Electricity (2015), CCGT stands for Combined Cycle Gas Turbines.

Figure 2 shows the LCOE's based on the OECD / IEA / NEA report for a range of technologies and at different discount rates. Compared to the conventional generation technologies, at lower discount rates, nuclear is more cost competitive, both at the 3% and the 7% level. At the 10% level, nuclear is largely in line with other conventional generation options (CCGT and coal). This dynamic is due to the discounting effect on the future cash flows. The higher the discount rate is, the lower the value of money is further in the future. This has a more pronounced effect for nuclear compared to the other generation types due to the long operational life, meaning that positive cash flows could still be earned as far as 70 years from the beginning of development. In each of the cases, this implies that investment in nuclear power is an economic resource allocation, if power prices typically settle at a cost that economically remunerates conventional generation (CCGT and coal). Relative to the renewable technologies, nuclear is calculated to have lower levelised costs at every discount rate, which makes it a prime candidate for achieving carbon emission targets. Nuclear energy is also a reliable source of baseload electricity and as such is complementary and necessary (rather than competing) for power systems that have high proportions of power generation from less reliable generation sources such as wind or solar power. Figure 3, which is based on the same source information from the OECD / IEA / NEA report, looks at Hungary in particular, and here the LCOE for nuclear generation is lower than both conventional and renewable technologies, again highlighting its competitiveness. Importantly, Figure 3 also highlights the lower exposure to fuel cost for nuclear compared to gas plants, whose cost can significantly increase if the current environment of low gas prices were to change.

Figure 3. Breakdown of LCOE cost in Hungary by generation technology



Source OECD / IEA / NEA - Projected Costs of Generating Electricity (2015)

*The base case long term LCOE forecast for Paks II NPP in the **Aszódi** Report is c. €60/MWh. This is slightly lower than the benchmarking analysis above on an absolute basis but when sensitivity ranges are considered the results are in line with the above.*

The Aszódi Report however calculates a LCOE over two periods, the initial 21 years post COD and then the last 40 years of operations with the assumption that there is an annual cost (8%) for the equity funding and an evenly spread out contribution to equity cost return. While this is meant to be illustrative, it is not a market norm, under which there is a credit order for capital

providers and equity returns are only made when the cash-flows allow. Equity is remunerated by the dividends received, which are based on distributable reserves and cash available for dividends as opposed to a fixed charge. The LCOE average is typically a measurement in the context of the entire period and the Aszódi Report therefore appears to overstate the break-even cost in the first 21 years and under state it in the subsequent 40 years.

2.2 NPV and IRR

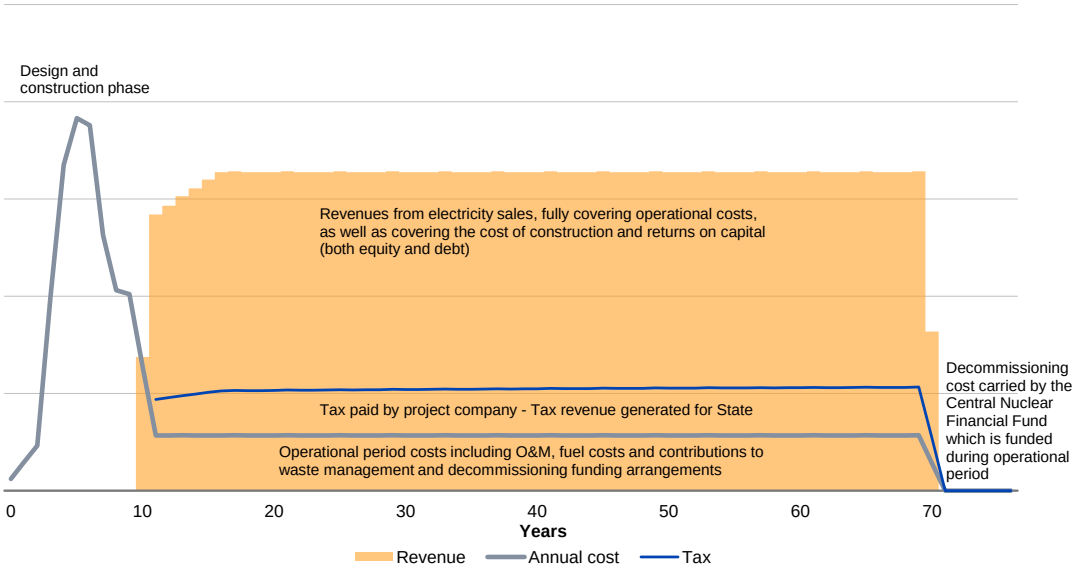
Another approach would be to consider a range of possible market price scenarios and calculate the net present value (NPV) which is today's value of future cashflows over and above payment of costs and the internal rate of return (IRR) of the project, which is the level to which those excess cashflows above the costs provide a return on the invested capital. The NPV of the project is calculated by discounting the nominal free cash flows by an appropriate discount rate (the WACC). The IRR is the discount rate that will bring a series of cash flows (positive and negative) to a NPV of zero. A project might be expected to justify investment if the IRR is equal to or greater than the WACC, or stated otherwise has a positive NPV. The equity rather than project IRR is then the return to the shareholder after any further leverage that may be available at the shareholder level. This in the case of Paks II would be the return to the Hungarian State (i.e. for taxpayers) with the benefit of the attractive loan financing conditions of the Financial IGA.

Felsmann's *report looks at the NPV and return of the project in this way. While this is a standard general methodology, upon inspection of the model several issues become apparent, including:*

- *The methodology adopted uses the Paks I 2013 actual power production, which is prorated for the Paks II units' capacity and the assumed capacity utilisation relative to the stated Paks I 2013 actual capacity utilisation. This is methodologically flawed and leads to an 81% effective average capacity utilisation being used in the model appended to the Felsmann report in the period of Paks II operations (from 2026 to 2085) compared to the 92% assumption stated in the report. It is lower than the 85% load factor stated as assumed in the few years of overlapping Paks I and Paks II operations. This has a very material impact on the overall economic evaluation.*
- *In calculating the closing balance of the Financial IGA debt, the model does not capture the first repayment making the debt balance consistently too high in every year following the year of the first repayment, thus causing an overestimation of the interest cost to the company.*
- *The model assumes additional capital injections at excessive cost of capital which are not necessary (e.g. in certain years the capital injections exceed the shortfall of free cash flow) which is contrary to normal corporate funding practice and leads to overstating the capital requirement calculations and the project costs.*

The ***REKK*** *report is also based on the NPV methodology. There do not appear to be any methodological issues with the approach taken, but the input assumptions are conservative when compared to the other publications, for example, the base case operational life of 50 years, as opposed to 60 years.*

Figure 4. Illustrative cash flows for a nuclear project



Illustrative

Figure 4 illustrates the projected cashflows for the project under the cost assumptions explored in the subsequent chapters at an indicative assumed market price in the middle of the range identified as relevant in Chapter 4, with the initial phase of construction seeing significant investment which ramps up as development begins, and ramps down into the operational period when there is a stable operational cost to run the plant, which is more than covered by the revenues earned from selling power on the market. This includes making annual payments into a fund to provide capital that is then used to fund the decommissioning of the plant.

Revenues are calculated, being the power output multiplied by the achieved market price. The power output is calculated based on the capacity and the load factor of the plant. The load factor is the ratio of the electrical energy produced by a plant and the theoretical maximum that could be produced at non-interrupted power generation, as shown in the formula below:

$$Effective\ load\ factor = \frac{Net\ electricity\ produced}{Net\ installed\ capacity\ * Time}$$

It is appropriate to assume that a nuclear plant runs at baseload (i.e. it produces power at all times, except during outages) given its low marginal costs relative to conventional generation sources, and is therefore able to achieve the baseload wholesale price.

The cash costs are then calculated and charged to the company, being operation and maintenance (O&M), fuel, waste and decommissioning funding. These costs, based on publicly benchmarked data, are input on a €/MWh basis (real 2013), inflated by the appropriate inflation index, and then multiplied by the production in each year. Working capital balances are calculated as the working capital days applied to the appropriate revenue or cost line. The working capital is split into three categories: trade receivables, inventories and trade payables. Depreciation is charged on a straight-line basis over the depreciable life of the plant. Applicable corporate taxes after utilisation of tax credits are then levied on the profit before tax. Both unlevered tax (i.e. excluding the tax shield of any interest costs at the Paks II level) and levered tax (i.e. including the tax shield of interest costs at State level) are calculated.

The Project pre-financing IRR as well as the project NPV is calculated based on the resultant Free Cash Flow to Firm (FCFF), which is: FCFF = EBITDA – Capex – change in Working capital – Unlevered Tax. To calculate the NPV of the Project, the FCFF is discounted at a post-tax, nominal discount rate. This discount rate is calculated by a fundamental WACC analysis incorporating publicly available information as shown in Chapter 6, which is then benchmarked to costs of capital implied by markets from trading valuations of listed companies that include nuclear generation portfolios, an independent estimate provided by NERA based on review and consideration of the benchmarking analysis conducted by the European Commission in the case of Hinkley Point C State Aid case review. The appropriateness of the WACC depends on the financing structure not only in the construction period but also through the operational period. The cost of capital also depends on the level of risk that the capital provider is exposed to, and hence is by definition project specific. Different discount rates and different market price conditions may lead to larger or smaller positive NPVs for different projects, which are all 'economic'. To compare projects, it is therefore more relevant to compare the rates of return or IRR – i.e. the rate at which discounting the cashflows would imply a zero NPV – and with regard to the differing risk profiles.

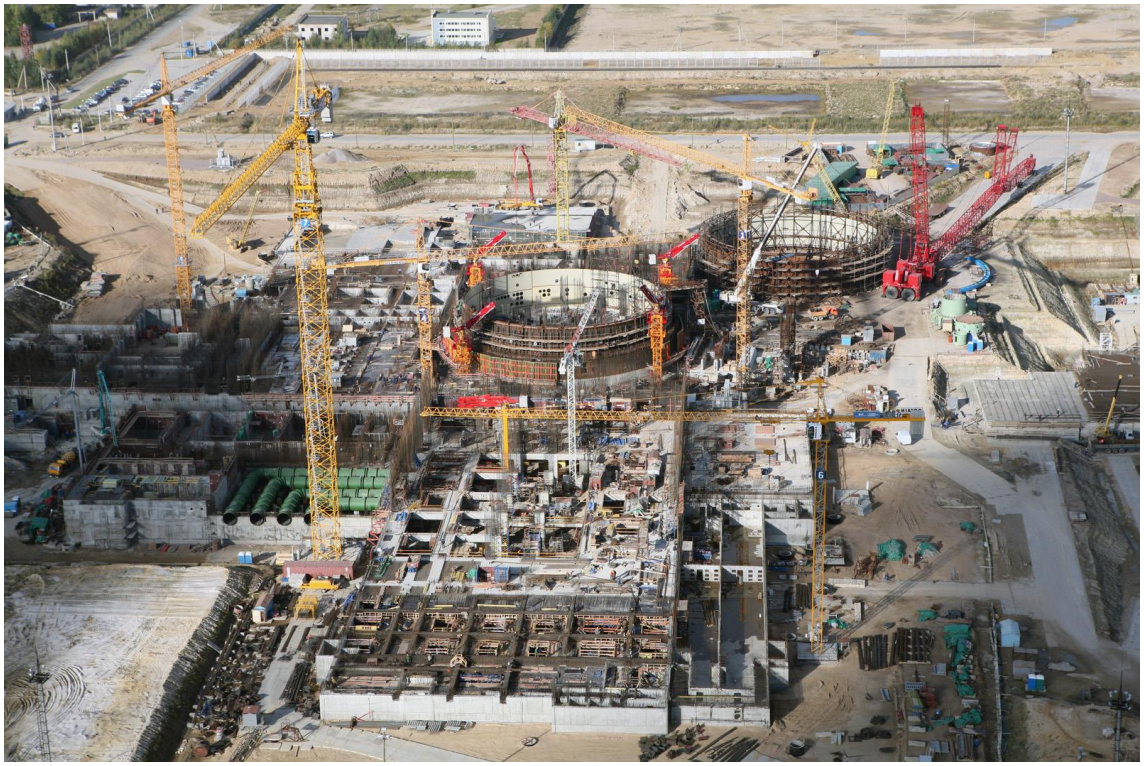
Additionally, the project has been analysed from the shareholder perspective, that of the Hungarian State which owns 100% of Paks II. The free cash flows to equity calculated by deducting the financing cash flows (debt drawdowns, repayments and interest payments) associated with the Financial IGA loan, enable the calculation of the NPV of those cashflows and the nominal equity IRR implied for the Hungarian State. It is therefore confirmed that at Hungarian State level Project payments are expected to be sufficient to meet the Hungarian State's Financial IGA obligations and provide a return on the further equity funding provided through the budget in all the evaluated scenarios. The post-financing equity IRRs at the Hungarian State level are based on the Free Cash Flow to Equity (FCFE), which is: FCFE = EBITDA – Capex – change in Working capital – Levered Tax – Cash interest – Debt Repayments + Debt Drawdowns. The dividends to be paid to the shareholder are calculated as a proportion of the last year's profit after tax, but are limited by the lower of the cash available for dividends and the retained (distributable) earnings.

Both evaluation approaches used in industry

In the utilities industry, the standard approach is to consider a range of power price and cost scenarios to judge the range of NPVs and IRRs to be expected from the project, as well as to look at the cost build up, the implied minimum remuneration of the project in downside price scenarios, and the prices at which the project is able to break-even (i.e. the LCOE). Hence, both approaches are equally suitable methods for evaluating the project and whether it is economically rational to undertake, and are in fact two representations of the same conceptual analysis.

The analysis and input assumptions for the Paks II NPP in this report are entirely based on public information inputs from industry sources including Bloomberg, DECC, EIA, EPRI, Factset, IEA, MAVIR, NEA, Platts PowerVision and REKK, with results analysed both using the LOCE and the NPV/IRR approach.

3. Construction period investment cost and risk



Visual illustration: two unit construction at Leningrad 2 (sourced from Rosatom)

3.1 Investment cost

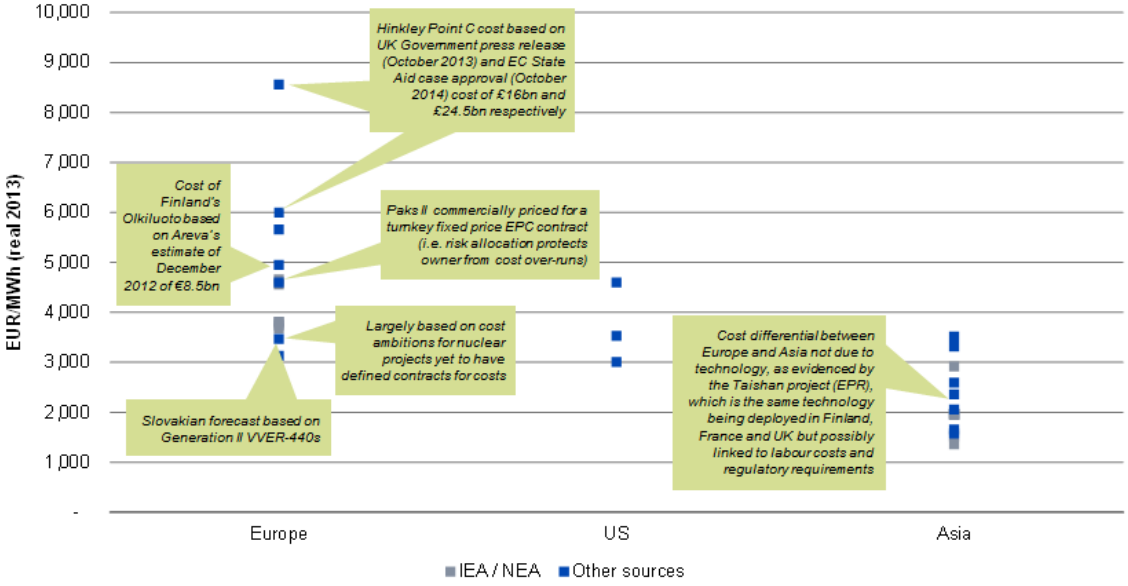
Nuclear power generation is characterised by high upfront capital costs and a long construction period, followed by a very long (60 year) operating period with low production costs when the plant can sell the power produced at prevailing market prices without setting those prices. The construction costs of nuclear power plants are unique to each technology and project. The site conditions, supply chain management, labour costs and regulatory requirements are amongst several factors that impact nuclear construction costs. In addition, the technical specifications of the nuclear plant will naturally have an impact on the cost. The Paks II project is understood to be on the basis of owner and technical specifications that seek a state-of-the-art, high-spec nuclear power plant, and incorporate the latest safety requirements post Fukushima. Such high safety specifications in the procurement would reasonably account for additional cost when compared to projects commissioned with fewer owner stated requirements or agreed prior to the safety developments post Fukushima such as some non-European projects. The total project cost for Paks II can be benchmarked on an overnight cost (i.e. real) basis against other new nuclear projects including other VVER technology project developments in Hanhikivi 1 (single unit), Belarus NPP (twin unit) and Akkuyu (four units).

The OECD / IEA / NEA report sets out the overnight costs for the various nuclear generating technologies installed in Europe and Asia and clearly identifies that even for the same technology, the cost of deployment in Europe is higher than in Asia. The OECD / IEA / NEA report lacks input data for a number of known advanced European projects. For example, in

Finland it excludes the Hanhikivi project, which is another VVER-1200 technology with a capacity of c. 1,200MW and has a signed EPC contract and in the UK, the Hinkley Point C project which is the most advanced project in the UK market and has been subject to significant cost disclosure and scrutiny due to its State Aid application and approval (total budgeted cost of €32 billion). Both are projects that are well advanced with well-defined cost bases. The information for certain projects is known to be out of date (for example there has been no updates on costs for Olkiluoto 3 since 2012). Conversely, the report includes estimates for new nuclear projects that are yet to have any cost definition (e.g. Belgium and the UK subsequent project developments that may have different economics from Hinkley Point C).

The analysis shown in Figure 5 combines the information contained in the OECD/IEA/NEA report and adds further data points from public sources, as described and disclosed in Figure 6.

Figure 5. Nuclear generating technologies



Source OECD / IEA / NEA - Projected Costs of Generating Electricity (2015), other (please refer to Figure 6)

This comparison, however, needs to be made in the context of known comparability limitations. The comparability of construction costs across projects remains a challenge, *inter alia* due to:

1. Differences in scope and risk associated with disclosed project costs, including
   a. Different levels of contingencies included within the stated 'overnight' costs;
   b. Scale differences - projects that involve two units or twin units compared to single unit plants can benefit from economies of scale in the construction period;
   c. Information may contain cost announcements made by technology vendors prior to contracting that are conditional and do not capture full local cost requirements including owner and regulatory regime specifications;
   d. Country regime differences impact risk and costs - e.g. some US states have construction period cost pass through regimes to consumers that imply a very different owner risk and hence cost profile for construction period;
2. Confidentiality limitations on verification – very few contracts are publicly disclosed.
3. Lack of consistency on nominal vs. real cost disclosures and on net vs. gross capacities used in calculations; and
4. Variation in inflation and exchange rate assumptions impacting comparability of forecast construction costs (nominal) as overnight (real today) costs.

Figure 6. Overnight cost benchmarking for Generation III/III+

	Project	Technology	Country	Year	Capacity (MW)	CoD target	Overnight costs (€/kW real 2013)
	Europe						
1	Paks II	VVER-1200	Hungary	2015	2,400	[2025-26]	4.6
2	Olkiluoto	EPR	Finland	2012	1,600	[2018]	4.9
3	Hinkley Point C	EPR	UK	2014	3,200	[2023-25]	8.6
4	Wyfla	ABWR	UK	2015	2,700	n/a	n/a
5	Oldbury	ABWR	UK	2015	2,700	n/a	n/a
6	Moorside	AP1000	UK	2015	3,400	n/a	n/a
7	Flamanville	EPR	France	2015	1,630	n/a	5.7
8	Visaginas	ABWR	Lithuania	2012	1,350	n/a	3.5
9	Belarus NPP	VVER-1200	Belarus	2014	2,400	[2018]	3.1
10	Hanhikivi	VVER-1200	Finland	2014	1,200	[2024]	4.6
	US						
11	VC Summer	AP 1000	US	2014	2,400	[2017]	3.5
12	Vogtle-3	AP 1000	US	2015	2,400	[2019]	4.6
13	Watts Bar	AP 1000	US	2015	1,150	[2016]	3.0
	Asia						
14	Taishan	EPR	China	2013	1,660	[2016]	3.3
15	Lungmen	ABWR	Taiwan	2012	2,700	[2017]	2.4
16	Sanmen	AP 1000	China	2009	2,200	[2016]	2.1
17	Shin Hanul	APR-1400	South Korea	2012	2,800	[2018]	1.6
18	UAE - Kepco	APR-1400	UAE	2015	5,600	[2017]	3.5
19	Shin Kori	APR-1400	South Korea	2014	2,800	[2016]	1.7
20	Akkuyu	VVER-1200	Turkey	2012	4,800	[2023]	2.6

Sources and methodology

1. Financial IGA for €12.5bn implied budget and technical specifications for capacity. Nominal cost deflated to 2013 real based on 2% inflation and assumed capex curve
2. Cost estimate sourced from Helsingin Sanomat - http://www.hs.fi/talous/Suomenkin+uusi+ydinvoimala+maksaa+85+miljardia+euroa/a1305627982885. 2012 estimate inflated to 2015 nominal terms at 2%, then converted to real 2013 (indexation factor of 0.9). Capacity sourced from Areva website - http://www.areva.com/EN/operations-2389/finland-olkiluoto-3.html
3. Cost estimate sourced from European Commission press release (08 October 2015) - State aid: Commission concludes modified UK measures for Hinkley Point nuclear power plant are compatible with EU rules. Nominal estimate converted to real 2013 (indexation factor of 0.9). Capacity sourced from Areva website - http://www.areva.com/EN/operations-5142/united-kingdom-two-epr-reactor-at-edf-s-hinkley-point.html
4. http://www.horizonnuclearpower.com/
5. http://www.horizonnuclearpower.com/
6. http://www.nugeneration.com/
7. Cost estimate sourced from EDF press release - https://www.edf.fr/en/edf/press_release/Flamanville-EPR-optimised-project-management-and-a-new-timetable. Nominal estimate converted to real 2013 (indexation factor of 0.9). Capacity sourced from Areva website - http://www.areva.com/EN/operations-2397/france-flamanville-3.html
8. Cost estimate sourced from the World Nuclear Association profile. 2011 estimate inflated to 2015 nominal terms at 2%, then converted to real 2013 (indexation factor of 0.9). Capacity sourced from the VAE website - http://www.vae.lt/en/project
9. Cost estimate sourced from Vnesheconombank presentation - Vnesheconombank's high-tech export support, subsidy program. 2014 estimate inflated to 2015 nominal terms at 2%, then converted to real 2013 (indexation factor of 0.9). Converted from US Dollars to Euros at 2014 average FX of 0.75. Capacity sourced from World Nuclear Association.
10. Cost estimate sourced from Rosatom presentation - Advantages of Rosatom solutions and risk management. Real 2012 estimate inflated at 2% to convert to real 2013. Capacity sourced from Fennovoima website - http://www.fennovoima.com/en/hanhikivi-1-project/plant-supplier/rosatom-s-aes-2006
11. Cost estimate from Quarterly Report to the South Carolina Office of Regulatory Staff Submitted by South Carolina Electric & Gas Company, Quarter Ending June 30, 2015 - https://www.scana.com/docs/librariesprovider15/pdfs/blra-status-reports/2015-q2-blra-report.pdf?sfvrsn=2 and Santee Cooper 2014 Annual Report https://www.santeecooper.com/pdfs/about-santee-cooper/2014ar/2014AnnualReport_FINAL.pdf; 2007 real estimates inflated at 2% to convert to real 2013. Converted from US Dollars to Euros at 2007 average FX of 0.73. Capacity sourced from World Nuclear Association
12. Cost estimate and capacity sourced from World Nuclear Association. Nominal estimate converted to real 2013 (indexation factor of 0.9); Converted from US Dollars to Euros at 2015YTD average FX of 0.90

13. Cost estimate sourced from TVA quarterly update - http://www.tva.com/power/nuclear/pdf/wb2_12th-q_summary.pdf; Nominal estimate converted to real 2013 (indexation factor of 0.9). Converted from US Dollars to Euros at 2015YTD average FX of 0.90. Capacity sourced from World Nuclear Association
14. Cost estimate sourced from Power-technology.com - http://www.power-technology.com/projects/taishan-nuclear-power-plant. 2013 estimate inflated to 2015 nominal terms at 2%, then converted to real 2013 (indexation factor of 0.9). Converted from US Dollars to Euros at 2013 average FX of 0.75. Capacity sourced from Areva website - http://www.areva.com/EN/operations-2404/china-taishan-12.html
15. Cost estimate and capacity sourced from Power-technology.com - http://www.power-technology.com/projects/lungmen. 2012 cost inflated to 2013 real terms at 2%. Converted from US Dollars to Euros at 2012 average FX of 0.78.
16. Cost estimated sourced from Xinhua - http://news.xinhuanet.com/english/2009-04/19/content_11217433.htm; 2009 cost inflated to 2013 real terms at 2%/ Converted from US Dollars to Euros at 2009 average FX of 0.72. Capacity sourced from the World Nuclear Association.
17. Cost estimate sourced from Yonhap News - http://english.yonhapnews.co.kr/business/2012/05/04/16/0501000000AEN20120504003251320F.HTML. 2012 cost inflated to 2013 real terms at 2%. Converted from US Dollars to Euros at 2012 average FX of 0.78. Capacity sourced from The Korea Hydro & Nuclear Power Co., Ltd. - http://cms.khnp.co.kr/eng/khnp-is-overview/
18. Cost estimate sourced from Bloomberg - http://www.bloomberg.com/news/articles/2015-09-03/abu-dhabi-said-to-revive-debt-plan-for-first-nuclear-power-plant-ie3wyuib. Nominal estimate converted to real 2013 (indexation factor of 0.9). Converted from US Dollars to Euros at 2015 YTD average FX of 0.90. Capacity sourced from Emirates Nuclear Energy Corporation - http://www.enec.gov.ae/our-nuclear-energy-program/prime-contractor/
19. Cost estimate and capacity sourced from World Nuclear Association. 2014 estimate inflated to 2015 nominal terms at 2%, then converted to real 2013 (indexation factor of 0.9). Converted from US Dollars to Euros at 2014 average FX of 0.75
20. Cost estimate and capacity sourced from World Nuclear Association. 2012 estimate inflated to 2015 nominal terms at 2%, then converted to real 2013 (indexation factor of 0.9). Converted from US Dollars to Euros at 2012 average FX of 0.78

The €12.5 billion (nominal) maximum budget for the Paks II NPP Project, which would typically comprise of EPC, initial fuel supply, owner costs and contingencies up to operational start up, appears on the basis of the comparison to be cost competitive for a new nuclear project in Europe in the context of risk allocation under a nominal fixed price turnkey project for 2.4GW of capacity. The €12.5 billion maximum budget does not appear to be too low or conservative based on the comparisons in Figures 5 and 6 and hence could be assumed to be a reasonable estimate, including contingencies for the cost risk taken by the EPC provider. Equally, the Paks II project does not appear to be excessively expensive, with the maximum budget being meaningfully below the Hinkley Point C project in the UK (2 units of 1600 MW each EPR reactors), which is the only advanced new nuclear development that is pre-construction in Europe for two units other than Paks II. Hinkley Point C is expected to cost £24.5 billion, or €31.2 billion, (nominal) including owner cost contingencies, c. 90% more in investment costs per unit of capacity.

*The **Felsmann** report accepts the €12.5 billion budget as an appropriate cost assumption for the analysis and as competitively priced at the current time. However it argues that the project cost of constructing a nuclear power plant in 2035 (i.e. in 20 years' time) could be lower than today. On that basis the Felsmann Report argues that the delay of the project until the 2030's should be considered as a potentially attractive alternative.*

Firstly, the arguments for cost reductions are based on generic technology assumptions, and do not appear to take into account the differences between different technologies, some of which will likely face lower reductions in cost as they are already 'next' rather than 'first of a kind'.

Further, this view ignores the capacity needs as generation capacities from other technologies are expected to retire before the decommissioning of the older Paks units. Given the fact that nuclear projects are developed over a long period of time, taking 7 to 10 years from development to operation, preparation for such projects is required well in advance. The beginning of operations for the Paks II project is expected in 2025, i.e. 10 years from now. It is prudent for the State not to allow for a potentially damaging shortage of capacity in the future.

Lastly, delaying the project would add greater uncertainty and could even increase the cost of the project. Delayed roll out of nuclear technologies when host countries already anticipate

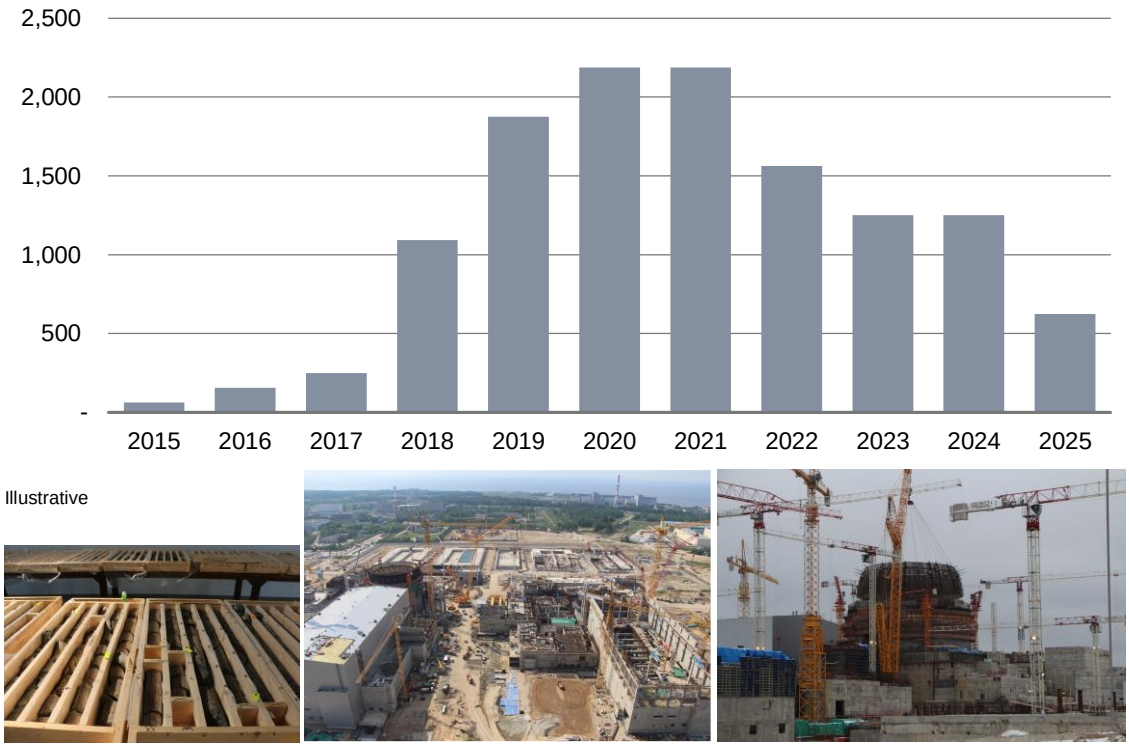
security of supply issues in the near term can lead to full cost rather than marginal cost pricing by the vendors and hence higher costs for project owners rather than lower costs over time. The owner seeking to order the new plant has lower negotiation leverage when the acuteness of the need for new capacities is notable for the seller of the reactor technology. Taking the decision to invest a decade later (yet alone two decades later) would add greater uncertainty to the project over whether terms as competitive as those already secured could be realised in the future. Greater costs arising from delayed construction rather than potential cost savings is potentially more likely if not equally conceptually feasible to envisage.

*The **Aszódi** Report prudently explores the security of supply aspects including remaining reserve capacity in Hungary in the event of a construction delay.*

3.2 Investment timetable

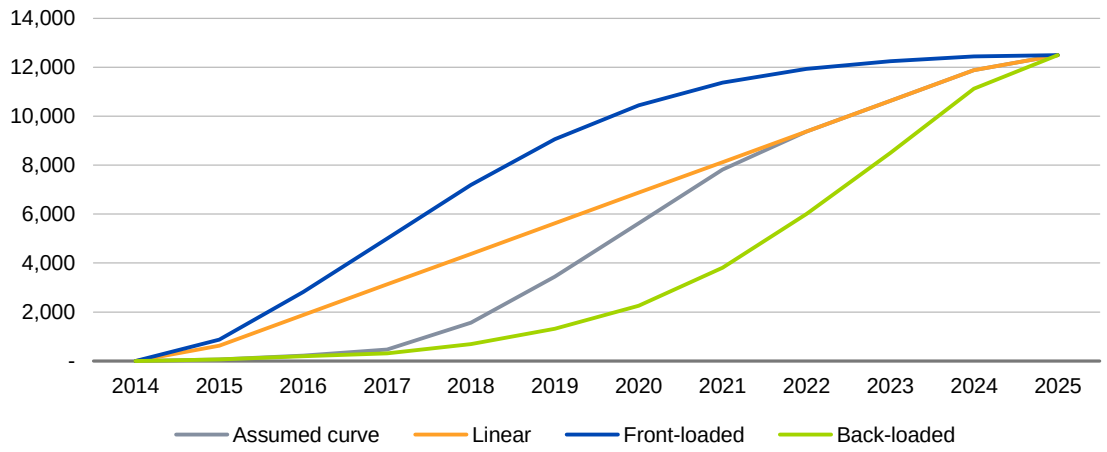
While the investment cost is one of the most important variables in determining the economic returns of the project, the cost profile also needs to be considered, both in terms of the length of the development and construction period and the allocation of cost in each year (i.e. the capex curve), both of which would typically be specified in the EPC contract. A nuclear project would typically take 7 – 10 years for development and construction, and with Paks II, it has been publicly stated that the first unit is scheduled to begin operations in 2025, with the second unit starting a year later. Given the lack of information on which to benchmark the capex curve, the assumed curve is as per Figure 7 below, with the first three years being the development period with relatively insignificant cash calls, and a ramp up of the cost as construction gets underway.

Figure 7. Assumed capex curve



Visual illustration: pictures of soil samples – part of early development work, and two unit construction site (construction shown is Leningrad 2 VVER – sourced from Rosatom)

Figure 8. Illustrative cumulative investment cost



Illustrative

Figure 8 shows different potential capex curves, ranging from a more front-loaded curve, which would be worse for returns as the cost is being brought sooner, to a back-loaded curve, in which most of the cost is incurred further out, which is beneficial for returns. The effect on returns, however, is marginal, with the worst curve for returns analysed, i.e. the front-loaded curve, only reducing the project IRR by c. 0.5 percentage points.

*The **REKK** report assumes a 12 year time period for development and construction, with 5 years being taken for pre-construction development, and 7 years for construction. This would seem to imply commercial operations beginning in 2027 rather than 2025 which is not the current schedule. However, as the original report was written in 2013, a 12 year period from that time would result in the scheduled commencement of operations, i.e. from 2025, and so it depends on the scope of the reports understanding of what the pre-construction phase consist of. Further, in REKK's 2014 update, they assume the same schedule as this report. The report also assumes that 95% of the investment cost is incurred in the 7 year construction period, which is reasonable, and also assumes that it is linear, i.e. the same cost in each year. This has a marginally positive impact on returns compared to the curve assumed in this report, as it means more of the cost is deferred to the end of the period.*

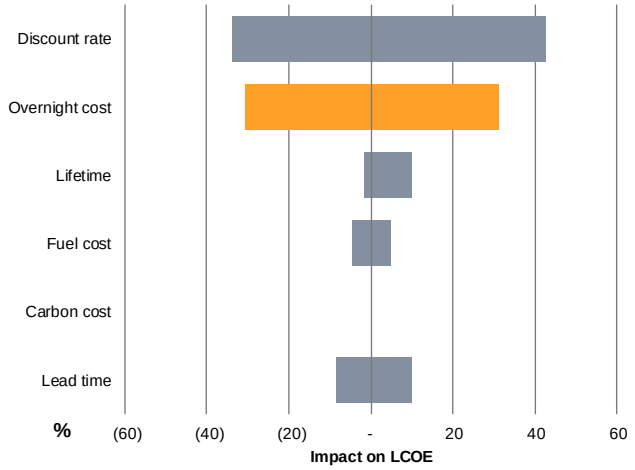
3.3 Risk allocation

Given the significant scale of investment required for nuclear projects, the economic returns of the project are heavily dependent on the cost of the project, as well as the risk of cost overrun, which can have a major negative impact. As can be seen from Figure 9 below, construction cost has a much more significant effect on the LCOE of a project (and on the IRR) than any other cost item or effect on operations. Hence, before making such a significant investment, the economic and strategic rationale of the project must be considered, in the context of the contracting and risk allocation approach that is being undertaken.

One model is a suite of contracts or an EPC contract which do not allocate contingency cost under the contract price, but require contingency funds access to be available at the owner level as the owner takes the risk on cost overruns. This is the model used by Enel for the Slovenske Elektrarne new units under construction and by EDF in Flamanville. It is worth noting that due to

the long operational period of the NPPs, even in cases of significant delays and cost over-runs in this second model the investors typically envisage prospective recovery and returns of the invested capital, explaining why investors remain committed to continue the investment to commission the units. Figure 9 below shows the sensitivity to LCOE and hence to equity return to the shareholder in an illustrative project under this contracting model. It indicates that according to the OECD / IEA / NEA study a 50% increase in overnight (real) cost would lead to approximately 30% increase in LCOE. The financial model utilised for the analysis in this report confirms the scale of impact on LCOE and indicates that this is equivalent to approximately 1 percentage point reduction in project returns. However, the degree to which this assumption can be sensitised depends on whether this contracting model is used and hence the owner is exposed to the overnight cost risk.

Figure 9. LCOE impact of sensitivities for +/-50% change in driver



Source OECD / IEA / NEA - Projected Costs of Generating Electricity (2015), discounted at median case of 7% pre tax real rate

Another model is the fixed price turn-key EPC contract, which means that the contractor takes the risk of potential additional costs of materials and does not require additional payments from the owner, unless it is the owner that changes the specifications or requires new scope. This fixed price approach means that even if the underlying costs of supplying the necessary works and services increases, it is the supplier's margins and economics that are impacted and not the project owner. This risk pass-through to the contractor is highly valuable for the owner, but also means that the contractor prices-in contingencies and hence the fixed price may be higher than it would otherwise be. Due to the very large size of the capital costs, there are very few contractors willing and able to offer such fixed price EPC contracts. This is the model used for Paks II. For the Paks II Project the maximum investment cost budget defined under the intergovernmental agreements is €12.5 billion (nominal) for the Project construction period, which is assumed to cover the construction period engineering, procurement and construction works under the EPC contract, initial fuel supply, owner costs and contingencies for Paks II NPP construction up to the date of first commercial operations (COD).

Different EPC contracts provide for different levels of risk transfer and hence it is not appropriate to assume that the presence of an EPC contract necessarily means lower cost of capital for the owner or lower level of contingency. However, assuming a large contingency in the cost and a discount rate premium can lead to double counting the level of protection for the same risk. The approach taken in this report, on the basis of the public information that the EPC contract for Paks II is fixed price and turn-key with a budget cap implicitly defined via the Financial IGA, is to

assume that the €12.5 billion budget includes a buffer for contingency and that no additional cost overrun conditions are relevant from an owner investment evaluation perspective. Nonetheless discount rate sensitivities are considered and evaluated.

*While no assumptions are made on cost overruns in the **Felsmann** report, it does state that no cost overrun is an "optimistic initial hypothesis" and "any delay or cost overruns as related to the investment may have a most negative effect on the project's being worthwhile". It should be noted that the Hungarian Government has minimised this risk - the Paks II project is being constructed under a fixed price turn-key EPC contract. This means that the cost of construction for the agreed scope is contractually fixed and not just estimated, assuming that the EPC contract parties fulfil their respective responsibilities.*

4. Operating period revenue

Visual illustration: operating NPP, tubrine hall, transmission

Revenues are calculated by multiplying the net power output by the achieved market price. The net power output is calculated based on the net capacity and the load factor of the plant. The load factor is the ratio of the net electrical energy produced by a plant and the theoretical maximum that could be produced at non-interrupted power generation, as shown in the formula below:

$$Effective\ load\ factor = \frac{Net\ electricity\ produced}{Net\ installed\ capacity\ * Time}$$

In determining plant production efficiency, three metrics are often referred to: capacity utilisation, availability and load factor. Capacity utilisation may be defined as production relative to the nameplate (gross) capacity of a given plant. Availability considers the *possible* production versus *net* capacity. Availability may be higher than load factor (production / net capacity), which includes down time for unplanned outages or curtailed load. For this reason, load factor is the most meaningful when determining cashflows, unless there is compensation for curtailment of load.

The Paks II two VVER reactors have nameplate capacity of above 1,200MW each. After deducting the reactors' self-consumption, the installed net capacity assumed is 1,180MW as stated in the IEA/NEA report. The plant is a new Generation III+ design, and as such has technical advantages over the older Paks I units, such as a 60 year design life, and a higher anticipated average load factor, with existing plants being benchmarked at 90% - 92%. It is reasonable to assume that the plant runs at baseload (i.e. it produces power at full load at all

times, except during outages), and is thereby able to achieve the prevailing baseload wholesale price. To determine the economic rationale of a nuclear power plant project it is thus appropriate to test a range of possible power price forecasts in order to test the bounds of the economic returns, especially looking to see that the project is robust even in cases involving prolonged periods of depressed market prices.

*As previously mentioned, the new Generation III+ units have been designed to have 60 year operational lives, with the potential for even longer lives if life extension programmes are undertaken. In contrast, the **REKK** Report assumes the Paks II Project has an operational lifetime of only 50 years, which is lower than the 60 year design life according to the technical specification of the plant technology. While this assumption would have a negative impact on returns, this should not be overstated, due to the discounting of the cashflows in the methodology being used. Based on the analysis in this report, decommissioning the plant 10 years earlier would only lead to a 0.1 percentage point fall in project pre-financing returns. The importance and impact of maintenance expenditure assumptions in order to achieve a 60 year operational life are considered separately in Chapter 5 below.*

4.1 Power output (load factor benchmarking)

Figure 10 provides the forecast load factor for a selection of nuclear power stations. This benchmarking focuses on the expected load factors of Generation III and III+ reactors, as to compare the Paks II units with older generation plants would be inaccurate. This is due to the greater technical specification (the shorter fuel cycle and the increased power densities of the fuel assemblies) of the plant which means that it has a different operational regime and efficiency. The benchmarking gives a range of 90% to 92% load factor, with an average of 91%. The conventional approach for calculating the load factor of a power plant is the ratio of the net electrical energy produced by a plant and the theoretical maximum that could be produced at non-interrupted power generation, as shown in the formula below:

$$Effective\ load\ factor = \frac{Net\ electricity\ produced}{Net\ installed\ capacity\ * Time}$$

Figure 10. Load factor benchmarking

Benchmark	Load factor	Source
Hinkley Point C	92%	Hinkley Point C presentation
Hinkley Point C	91%	European Commission (2014)
Hinkley Point C	90%+	EDF presentation
VVER-1200 technical parameters	90%	IAEA (2013)
St Petersburg AEP figures	90%+	Rosatom presentation
Moscow AEP figures	90%+	Rosatom presentation
Angra PWR	91%	IAEA (2015)
Average PWR technology	91%	Fortum presentation
Max	**92%**	
Min	**90%**	
Average	**91%**	

It is not appropriate to benchmark load factor to markets that have different regulatory regimes or dynamics that restrict the operational approach. For example Japanese regulation that does

not permit longer than 12 month fuel cycle means that average load factors in Japan were historically lower than elsewhere even with the same technology due to the down time required for the more frequent fuel re-loading. French load factor and availability statistics should also be treated cautiously for benchmarking. The older generation plants, in a market such as France, operate at lower load factors than they are capable of due to the uniquely high level of nuclear generation in proportion to overall supply and the relatively poor interconnectivity with the UK and Spain, which mean that the French market balancing sometimes requires the shutdown of nuclear plants (inflexibility of older nuclear technology) and hence results in lower average load factors than would otherwise be deliverable and expected. This reduction of load to enable system balancing would not be expected to be an issue for a market such as Hungary, where there is an existing high level of power system interconnection. The more appropriate peer set for Paks II would be PWR technology and Generation III or III+ nuclear power plants, as per the above table, which gives an average load factor of 91%. Moreover, the historical data from the currently operating Paks units show that the four units have an 89% - 91% capacity utilisation. Given that these units are late life and previous generation technology, the Paks II units would be expected to operate at the same, or an even better, level given the innovations and improvements in the technology.

Sensitivity analysis indicates that the returns of the project are not overly sensitive to the load factor over the operational life of the plant. For example, a 10% reduction over the life of the plant, i.e. to 82%, would only lead to a c. 0.7 percentage point reduction in returns.

*The **Aszódi** report assumes a load factor of 96%, based on the 18 month fuel cycle for the units and 24 days for fuel reloading (effectively an availability factor). The report applies downward sensitivities to load factor to 80% to test the robustness of the Project. The assumed production output in the Aszódi report from the new units (which is based on a lower net capacity of 1,100MW for each unit) is consistent with the output implied by a 90% load factor on 1,180MW net capacity per unit. The economic impact of an overlap period is also considered and it is noted that the Hungarian interconnection to neighbouring markets means that the economic impact of a period of operational overlap between Paks I and Paks II does not hinder the economic rationale of the Paks II project. This agrees with the analysis conducted in this report.*

*The **Romhányi** Report assumes a load factor of 85% for Paks II; which is conservative in relation to the benchmarking analysis conducted. Three sources are cited in support:*

a. *The factory spec of the VVER-1200 reactor which states that utilisation of 90% can be achieved.*
b. *A comparative econometric study from 2003 that examined achievable operational load of existing power plants. This study yielded an achievable utilisation of 81%.*
c. *A French study that stated average load in French nuclear power plants did not meet the expected 90% but instead didn't exceed 76%, largely due to oversupply.*

The study from 2003 is 12 years old and the technology of the plants considered is the earlier Generation II, which have lower utilisation than anticipated for Generation III+ plants such as Paks II. The study on the French nuclear market, as anticipated, indicates lower load factors due to relatively poor interconnectivity with the rest of the European market, the inflexibility of older nuclear technology and the uniquely high level of nuclear generation in proportion to overall supply profile in France, as described above. Further, the report assumes a net capacity of 1,085MW per unit, as opposed to 1,180MW, which, coupled with a low utilisation assumption, makes it extremely conservative.

*The **Felsmann** report states that 85% capacity utilisation is average and 92% is high based on benchmarking analysis of different and older nuclear technology in a different region with different regulation and market dynamics, such as the nuclear plants in France (see above for clarification of inappropriateness of benchmarking). Furthermore, the Felsmann report states that the assumed capacity utilisation is 85% in the overlap period, and 92% thereafter, whilst the actual rates being assumed in the model supporting the analysis are 76% in the overlap period and 82% in the remaining period. This significant underestimation of the power production from the plant is due to the methodology adopted whereby the Paks I 2013 actual power production is prorated for the Paks II units' capacity and the assumed capacity utilisation. The flaw in the methodology used is that the production used as the base, being Paks I's generation in 2013, does not equate to the capacity utilisation of 92% which is assumed for Paks I in that year, but rather to a significantly lower capacity utilisation, thus leading to an underestimation of the generation by the plant over the period. The effective average capacity utilisation of the Felsmann model for the period 2026-2085 is 81%, which indicates that the level of the capacity utilisation is not in line with the assumption provided in the Felsmann report, and the conclusions derived from the report with regards to the capacity utilisation are misleading.*

With regards to the overlap period, during which the Paks I and Paks II units would both be running, the Felsmann report argues that the plant would operate at lower 85% capacity utilisation. Given the level of generation capacity retiring (see next section), even before the closure of the Paks I units, and the rise in energy demand, the energy gap which would have to be filled with new capacity or import power would be greater than the new capacity from the Paks II units, and so the new units should not be assumed to cause a period of over-supply other than potentially at low demand low moments. However, given the level of interconnection in the region, the volumes produced would not be so excessive as to lead to placement issues. Rather, the 'excess' supply could be exported to the rest of the region. Even if, however, the capacity utilisation is assumed to fall during the overlap period, the sensitivity analysis described above shows that the impact on returns would be minimal.

4.2 Market price dynamics, based on NERA analysis

4.2.1 The economics of Electricity markets

Electricity markets consist of wholesale markets where producers and re-sellers and/or large consumers' trade electricity, and retail markets in which wholesale supplies are re-sold to end-consumers. In competitive electricity markets, the wholesale price provides a reference for the market value of electricity and determines the revenue received by generators for their output and the cost of electricity for re-sale to end-users.

A conventional economic framework for forecasting wholesale electricity prices involves identifying the price that achieves a market equilibrium in every trading period (usually a single hour or half-hour). For market equilibrium to be reached, the following conditions need to be met:

1. Sufficient generation is dispatched to meet prevailing levels of demand. Otherwise, the price would rise to attract more supply to the market, or to encourage consumers to curtail their demand;

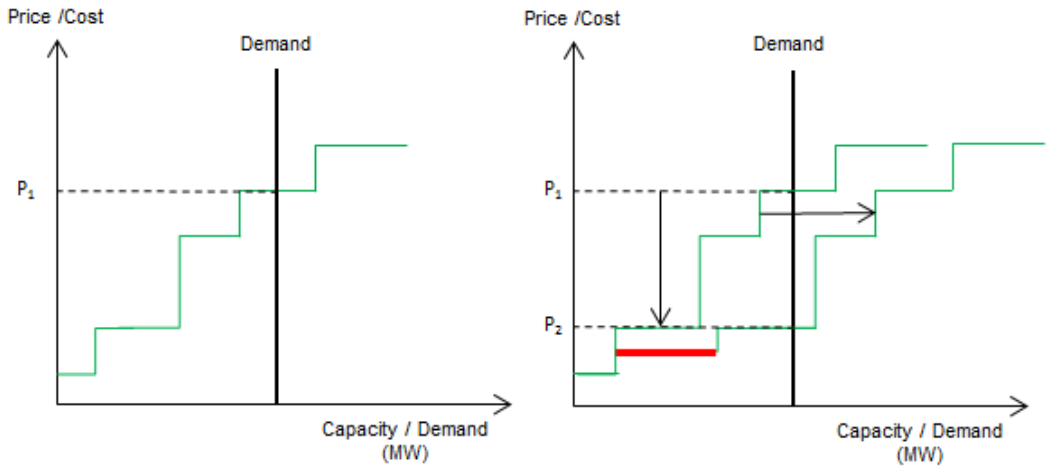
2. All generators who can profitably produce electricity at the prevailing price are doing so. Otherwise, more generators would seek to be dispatched, thus increasing supply and reducing the clearing price; and
3. Those generators that cannot profitably generate do not produce electricity. Otherwise, they would have an incentive to reduce their production, thus decreasing market supply and increasing the clearing price.

An implication of these criteria is that all generators are dispatched to meet prevailing demand in "merit order", such that the generators with the lowest variable operating costs are called upon to generate first. Then, at higher levels of demand, those with higher variable operating costs are also required to generate. And in all conditions, the market clearing price reflects the variable costs of the most expensive generator that is required to meet prevailing demand or a rationing price if demand needs to be curtailed due to inadequate supply.

Within this basic economic framework, higher levels of demand or lower levels of available generation capacity will result in higher prices, and vice versa. Accurately modelling demand and supply conditions (e.g. variations in demand by time of day, week-day or weekend-day and season, the availability of generating plants, fuel price changes etc.) is therefore key to creating credible forecasts of the evolution of wholesale market prices.

For example, as the left hand side of Figure 11 illustrates, the merit order of available generation capacity defines an upward sloping supply curve for the market (the green line). The intersection between this supply curve and the prevailing level of market demand (the black line) defines the market clearing price at a given point in time. Within this illustrative framework, if a new plant comes onto the system with a low variable cost of production and capacity illustrated by the red box on the right hand side of Figure 11, the supply curve shifts to the right. Now, the supply and demand curves intersect at a lower point on the supply curve, which reduces prices from P_1 to P_2.

Figure 11. Illustrative Merit Order, and the Effect on Price from Increasing Supply



In the long-term, prices are affected by new generators' decisions to enter the market, and existing generators' decisions to exit the market, as such decisions alter the mix of generation that is available to serve demand at any point in time:

1. Generators will decide to close plants if the market clearing price is consistently below the level that allows existing generators to earn profits above the costs they would avoid following closure (e.g. fixed operating and maintenance costs). Plant retirement decisions reduce the supply of capacity available to serve demand, and thus increase prices to a level that ensures those generators remaining in the market have an incentive to remain online.
2. Conversely, if the market clearing price is consistently at a level above the costs of new entry, new generators will be able profitably to enter the market. New plant increases supply and constrains prices to a level no higher than the costs of new entry.

Accurately modelling the dynamics of entry and exit decisions is therefore also a key element in creating credible forecasts of the evolution of wholesale market prices.

In the long-run, gradual demand growth and contractions in supply from plants retiring at the end of their economic lives mean that it is efficient to add new generation capacity to meet demand. Hence, a long-run economic equilibrium that provides generation investors with an incentive to enter the market must entail wholesale prices converging towards the cost of new entry. Specifically, wholesale market prices will tend to converge to the level that remunerates investment in the least cost mix of generation, i.e., prices will tend to converge to the average cost, or levelised cost, of the most efficient available generation, and hence estimates of levelised costs provide an indication of wholesale prices in the long-run.

Investment decisions for the deployment of capital in new generation capacity projects, including the commercial assessment of the economic viability case of the Paks II Project, therefore require the evaluation not only of the cost of the investment but also its competitiveness relative to other possible new investments which are part of the investor's view of the anticipated market development. Critical to the commercial rationale for an investment is the assumption regarding the development of market prices over the life of the plant. This is even more vital for nuclear power generation given its typical position as a price taker in the merit order, as a baseload generator and the expected long operating period.

4.2.2 Supply and demand outlook for Hungary

As discussed above, the evolution of Hungarian wholesale electricity prices depends on developments in the supply of generation capacity and the evolution of electricity demand.

The market standard methodology for forecasting power market prices is for the market price to be determined by an analysis of future anticipated demand and supply forces in the relevant market. The supply curve, as described above, is set by the merit order, which is a stack of the different generating capacities and their variable cost. The power price is set by the cost of the power plant operating at the point of the supply-demand equilibrium, i.e. the marginal producing plant in the merit order. To forecast the evolution of wholesale electricity prices in Hungary, reliable data and forecasts are needed on the development of supply and demand in Hungary and the interconnected region relevant for import pricing.

Demand outlook

The Hungarian Transmission System Operator (TSO) MAVIR, like its peers in other European markets is a useful source of independent information on the development of the electricity

system. MAVIR provides forecasts of the development of demand until 2030.[11] According to MAVIR's latest (2014) reference case projections, Hungarian annual electricity demand (measured in TWh) will rise by approximately 1% per year until 2030.[12] MAVIR forecasts that peak load will also increase by 1% per year on average, from its current level of approximately 6.7GW to 7.8GW in 2030. MAVIR also publishes forecasts for alternative scenarios. The pessimistic scenario, which assumes lower demand growth, sees peak load rising to 7.3GW in 2030, whereas the optimistic high demand growth scenario sees an increase in peak load to 8.1GW.

Eurelectric, the association of the power industry in Europe, also publishes forecasts for the evolution of electricity demand in Hungary. In its 2013 report,[13] it finds that peak demand will increase to 7GW by 2020 and 7.7GW by 2030. Eurelectric expects total electricity consumption to grow by approximately 1.2% on average to 2030 (from 2011 levels). These forecasts are very much in line with MAVIR's own expectations of the evolution of electricity demand in Hungary.

The World Energy Outlook (WEO) of the International Energy Agency (IEA) provides longer run estimates for the development of electricity demand in OECD Europe. In its "New Policies" scenario, which is its central case, it estimates that final electricity consumption will grow by an annual average of 0.7% between 2012 and 2040, and by an annual average of 0.66% between 2030 and 2040.[14] Electricity demand growth in Hungary may be stronger than the average of OECD Europe, because of the low level of electricity consumption per capita in Hungary relative to other OECD countries.[15] Therefore, electricity demand in Hungary can be expected to rise after 2030 as well as over the period to 2030.

Supply outlook

Figure 12, which is based on MAVIR's 2014 capacity forecast report,[16] shows that Hungary currently has around 9GW of installed generation capacity, consisting of around 2GW of nuclear plant, 4.5GW of gas-fired plant, 1.5GW of coal plant, and 0.5GW of oil-fired plant, with about 1GW of this capacity not actually available due to mothballing and improbable restart of these plants. The chart plots MAVIR's view of a "realistic scenario" of the evolution of installed

[11] Mavir (2014): A magyar villamosenergia-rendszer fogyasztói igényeinek előrejelzése 2014, [Electricity consumption forecast of the Hungarian electricity system, 2014, Budapest]: http://mavir.hu/documents/10258/15461/Fogyaszt%C3%A1selemz%C3%A9s_2014.pdf/5e18c6fc-7e21-4a4a-87dc-09330f20371d

[12] MAVIR assumes a higher annual growth rate of 1.3% up to 2020, which declines to an average growth rate of approximately 1% between 2020 and 2030. Total electricity consumption is expected to increase from 42.2TWh in 2013 to 50.6TW TWh in 2014. MAVIR's two alternative scenarios, with slower and faster demand growth, forecast a total demand of 47.4TWh and 52.5TWh in 2030, respectively

[13] Eurelectric – Power Statistics and Trends 2013: Full Report (2013)

[14] Annual growth rates for the alternative "450" and "Current Policies" scenarios are 0.5% and 1.1% between 2012 and 2040, and 0.6% and 1.0% between 2030 and 2040, respectively.

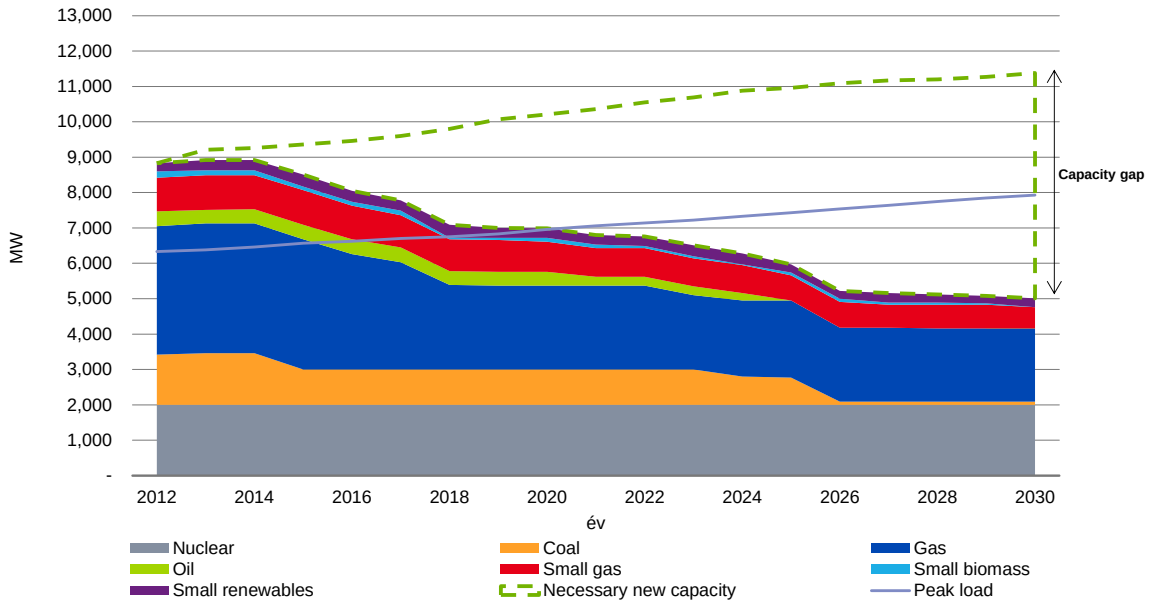
[15] A 2011 country report from the IEA presents evidence (from 2009) that Hungary's electricity consumption per capita (of 3.5MWh) is less than half the OECD average (of 7.5MWh).

[16] MAVIR (2014): A magyar villamosenergia-rendszer közép- és hosszú távú forrásoldali kapacitásfejlesztése (Medium- and long-term development of generation assets of the Hungarian electricity system): http://mavir.hu/documents/10258/15461/Forr%C3%A1selemz%C3%A9s_2014.pdf/7a379c76-a8d0-42f6-b8e6-bf8c05894a49

capacity in Hungary up to 2030, excluding the development of Paks II. Thus, the chart includes both (1) the retirement of currently generating power plants, as expected by MAVIR; and (2) those proposed investment projects in new generation plant that MAVIR realistically expects to materialise, albeit MAVIR does not spell out what these are, in the absence of Paks II.

MAVIR forecasts that almost all of the coal generation fleet will have retired by 2030, and that the installed capacity of Hungary's gas-fleet will decline by 1.5GW. Compared to its estimates of peak demand growth (discussed above), available generation capacity from domestic power producers is expected to fall below peak load by 2021. As a result, MAVIR estimates that the Hungarian market requires 3GW of additional new generation capacity by 2019, 5.5GW by 2024, and 7.3GW at the end of the forecast period in 2030, in the context of the European Network of Transmission System Operators for Electricity (ENTSO-E) objectives that each Member State should aim to maintain adequate domestic generation capacity to satisfy domestic needs. This projection is illustrated by the capacity gap area of Figure 12. It should be noted that MAVIR's projections suggest investment in new generation is required before capacity falls below peak load. This is because the demand shown excludes the energy requirements to cover electrical losses in the transmission and distribution system, some generation capacity is required to provide reserves and other ancillary services, and the installed capacity figures shown in Figure 12 include the capacity required to supply power stations' auxiliary load, and some capacity will be unavailable at peak time due to forced outages.

Figure 12. Additional capacity requirement in Hungary



Source MAVIR - A Magyar Villamosenergia-rendszer közép- és hosszú távú forrásoldali kapacitásfejlesztése (2014)

According to the forecast shown in Figure 13 from Dr ***Aszódi's*** *paper, which is broadly in line with the MAVIR forecast, the installed capacity by 2025 ought to expand to c. 10GW or more to satisfy demand*[17]*. One can see that c. 4GW capacity is expected to retire over the period, and so has to be replaced by 2025, as well as an additional 1GW of capacity to be added. Thus, the capacity required is more than double the 2.4GW to be added by the Paks II units, and so, irrespective of the Paks I units decommissioning, there is a need for further investment in generation capacity by 2025*.

Figure 13. Forecast capacity requirement

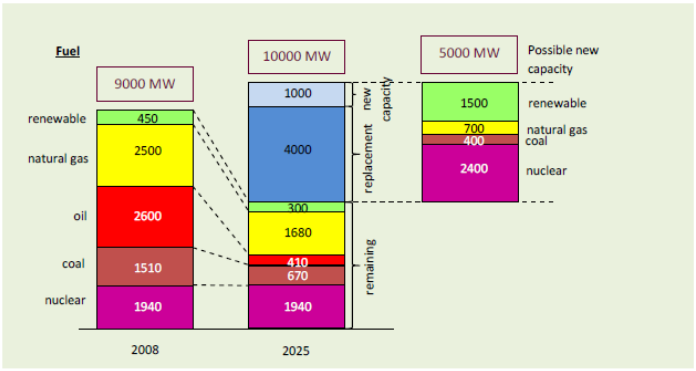


Figure 4: The expected change of the installed capacity until 2025; a possible scenario for the new capacity construction

Source Aszódi, Attila – Boros, Ildikó – Kovács, Arnold (2014): A paksi atomerőmű bővítésének energiapolitikai, műszaki és gazdasági kérdései, in Magyar Energetika, May 2014.

The considerable retirement of old facilities identified is expected to contract supply, whilst an increase in energy demand is forecast from general economic growth in the country and the rest of the region. Current local power production will therefore increasingly not satisfy the growing energy demand, and thus, Hungary will inevitably observe a gap between electricity demand and supply and increasing dependence on power imports and increasing power prices for end consumers if no new investments in power generation facilities are made.

As discussed elsewhere in this report, the Paks II project will have installed capacity of 2.4GW and is due to come on-line from 2025 in two phases. Hence, the Paks II investment will only fill part of the capacity gap identified by MAVIR. Taking Paks II into account, there would still be a remaining capacity gap of 3.1GW in 2024 and 4.9GW in 2030. In the period beyond 2030, MAVIR expects all four units at the 2GW Paks I nuclear plant to retire between 2032 and 2037 (beyond the shown time horizon), which implies a need for further investment in new generation capacity of at least 2GW over this period.

Whilst this analysis shows that peak demand is expected to exceed installed gross capacity from anytime between 2019 and 2021 onwards in the absence of new investment, MAVIR also finds an *immediate* and increasing need for investment in new generation capacity. Installed gross capacity must exceed peak demand for domestic supply to allow for electrical losses,

[17] Based on a diverse set of evidence, Dr. Aszodi forecasts growth in electricity consumption in the range of 0.5%-1.5% per annum. While this implies a high degree of uncertainty in the evolution of Hungary's electricity consumption (±50% relative to the central value of 1%), this identified range is in line with evidence from the surveyed literature.

system operating and other reserves, and the use of the generated electricity by the power plants themselves, if domestic generation is to meet domestic demand.

MAVIR's report forecasts the generation capacity existing power plants are expected to provide up to 2030. This capacity is expected to fall from 9.2GW in 2013 to 4.7GW in 2030. Despite the relatively large requirement for new generation capacity shown in Figures 12 and 13, data from Platts Powervision suggests that relatively little new capacity is actually being built, as shown in Figure 14 below.[18] Only projects that are actually "under construction" can be counted as a firm commitment to deliver new capacity, as investors in these projects are locked-in by Engineering, Procurement, and Construction (EPC) contracts, or the large amounts of capital they have committed to the project. According to Platt's data, only the 44MW, waste-to-energy plant is currently under construction in Hungary and should therefore, according industry best practice, be included in the projections of new capacity - indicating that MAVIR's "realistic view" case of the capacity requirement may understate the true requirement. Other than Paks II which has a signed EPC contract, there appear to be no other projects with signed EPC contracts to be included in this category. Investment projects "in the pipeline" in industry best practice should be considered as speculative as long as the investors have not made a firm commitment to undertake the project. While there are investor plans to build larger (gas-fired) plants in Hungary, none of these projects can be considered confirmed, as investors have not yet incurred substantial sunk costs (such as construction costs) which demonstrate commitment to undertake the project.

Figure 14. Only a Single Small Power Plant is Currently Under Construction in Hungary

Plant	Plant Type	Primary Fuel	Nameplate MW	Online Year	Status
Dunaujvaros Chp	Waste	Biomass	44	2016	Under Constr
Szeged Ccgt	CC/Cogen	Natural Gas	460	2017	Advan Develop
Szeged Ccgt	CC/Cogen	Natural Gas	460	2017	Advan Develop
Csepel III	CC/Cogen	Natural Gas	430	2018	Advan Develop
Tolna	Wind	Wind	260	2018	Early Develop
Gyor Region	Wind	Wind	300	2019	Early Develop
Szazhalombatta - Dunai Refinery	CC	Natural Gas	860	2020	Advan Develop
Almasfuzito	Coal	Coal Generic	435	2020	Proposed

Source Platts Powervision, data accurate as of September 2015

Implications for power prices

MAVIR's projections of demand growth and the retirements of existing generation capacity in Hungary suggest there is a need for 5.5GW of new generation capacity in Hungary by 2024, and 7.3GW by 2030. Even this assessment may understate the true requirement, as discussed above, and Paks II is not capable of meeting this requirement by itself – MAVIR's estimates indicate the need for significant additional capacity beyond that delivered by Paks II to ensure security of supply.

[18] The Table shows planned large projects, which are are defined as investment in power plants with a nameplate capacity above 100MW. Projects categorised by Platts as "on hold" have been excluded. In addition to large investment projects, the small project currently under construction is included in the table.

Following the framework set out above, this evidence suggests that wholesale prices in the Hungarian market will soon need to rise to a level that remunerates new investments in generation capacity in order to incentivise investors to commit capital to the sector, i.e. in the long run, when capacity is scarce, prices are expected to rise to clear the market either through incentivising new entry or otherwise by constraining demand to the available capacity. In this way, new entry costs act as a cap on long-term power prices, as any sustained price above this level would encourage new entry into the market which would reduce prices. However, the timing of the required growth in power prices to remunerate new investment will depend on the extent to which the Hungarian market can import power to meet local requirements as an alternative to developing new local generation, i.e. Hungarian power users increase their reliance on import capacities. This, in turn, depends on both the supply of available interconnection capacity to import power into Hungary, as well as the supply-demand conditions prevailing in neighbouring markets.

In the long run, when capacity is scarce, prices are expected to rise to clear the market either through incentivising new entry or otherwise by constraining demand to the available capacity. In this way, new entry costs act as a cap on long-term power prices, as any sustained price above this level would encourage new entry into the market which would reduce prices. In other words in the long run, electricity prices must rise high enough to allow new entrants to recover their levelised capital and operating costs. Thus, in the long run, electricity prices are determined by the cost of new entry, or the long run marginal cost of supply (LRMC). Prices reflect the LRMC of the cheapest generating technology (or an efficient mix of technologies that meet baseload and peak demand).[19]

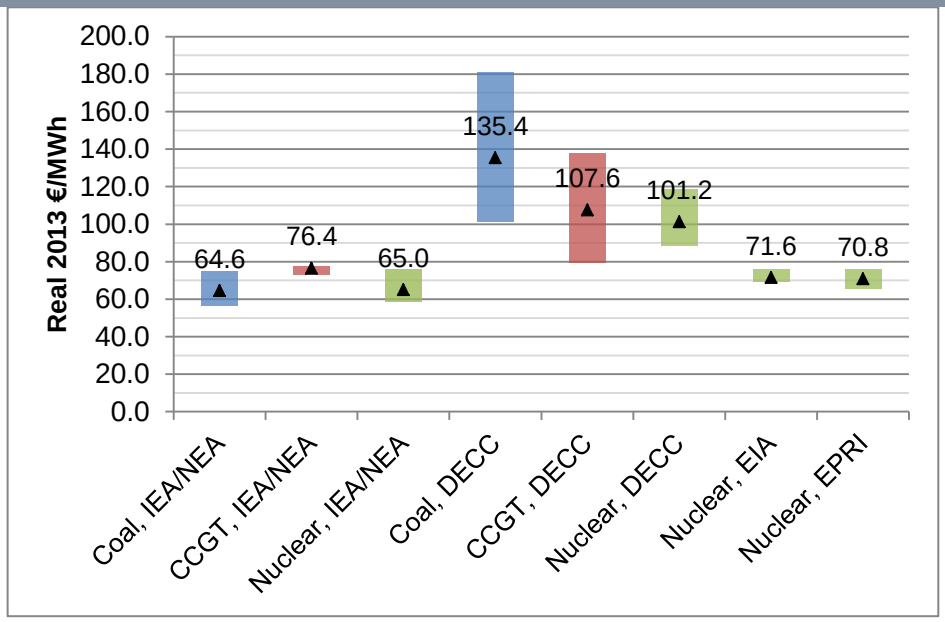
In reality, it is usually efficient for a power system to comprise a mix of power generation technologies (peaking, mid-merit and baseload plant) reflecting differences in their relative fixed and variable costs. Achieving a balance between these types of plants is important for ensuring the profile of demand that varies over the year is met as efficiently as possible. The best indicator of trends in long-run baseload market prices are the costs of generation technologies competing with nuclear plants to provide baseload supply (i.e. a plant that is expected to run in the majority of hours throughout the year). To make this cost comparison, evidence on the Levelised Cost of Energy (LCOE)[20] of alternative technologies is reviewed.

Figure 15 shows the LCOE estimates from published sources: from the UK Department of Energy and Climate Change (DECC), the US Energy Information Administration (EIA), the Electric Power Research Institute (EPRI), the International Energy Agency (IEA) and the Nuclear Energy Agency (NEA). The comparison of these published LCOE numbers helps to identify (1) a lower bound to long term electricity prices and (2) the relative competitiveness of different baseload generation technologies.

[19] Prices above the LRMC of some technologies incentivise entry of new generation capacity (of those technologies), driving down prices. Prices below the LRMC of all potential new entrants cannot be sustained in the long run, as the consequential shortfall in supply will increase prices. Thus, in the long run, prices converge to the LRMC of the cheapest generating technology, or an efficient mix of generating technologies.

[20] The LCOE is typically calculated by dividing the Net Present Value (NPV) of expected total costs of the plant over its life (including capital costs, operating and maintenance costs, fuel and CO2 costs, etc.) by the NPV of expected generation output.

Figure 15. LCOE for coal, gas and nuclear generation[21]



Source: OECD / IEA / NEA - Projected Costs of Generating Electricity (2015), DECC - Electricity Generation Costs (2013), EIA - Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook (2015), EPRI - Program on Technology Innovation: Integrated Generation Technology Options (2012)

Note: Data shown is in 2013 €/MWh. IEA/NEA forecasts apply to investments commissioning 2020, DECC forecasts apply to investments commissioning 2019. EPRI estimates are applicable to a 2025 start date, and EIA estimates apply to an online date of 2022. Only European LCOE estimates included from IEA/NEA data (both for the range ant the average of estimates).

Figure 15 shows LCOE estimates from the four sources discussed above. IEA/NEA figures show the range and average of European estimates, while DECC estimates UK-specific LCOEs. EIA and EPRI provide estimates for the levelised costs of new generation projects in the United States. There are a range of other differences between these studies which should be noted in interpreting the data. In particular:

- Figure 15 shows that the DECC study projects higher LCOEs across all technologies than the IEA/NEA study. This is primarily because the DECC study assumes a relatively high cost of CO_2 emissions of £76/tonne (€104/tonne at today's exchange rate). In contrast, the IEA/NEA report assumes a global carbon price of $30/tonne (€26/tonne at today's exchange rate). The DECC study also assumes a real Weighted Average Cost of Capital (WACC) of 10% real[22], as compared to the IEA/NEA's central assumption of 7% real.[23]

[21] The ranges capture the lowest and highest LCOE estimates for each technology. The black triangle (and the corresponding value) captures the average value of LCOE estimates for the IEA/NEA study, and 'Central Scenario' estimate for DECC data, the average estimate for EIA, and, in lieu of an average, the midpoint of the range for EPRI. For the DECC study, data for the lower cost of the two CCS technologies listed has been presented (advanced supercritical coal plants and not integrated gasification combined cycle).

[22] DECC's 10% WACC appears to be a real pre-tax WACC estimate: "In most cases, this report includes estimates using a standard 10% discount rate across all technologies, in line with the 'tradition' used in reports produced by other organisations" (p. 12). Assumptions for pre-tax real WACC are more common in the literature. Additionally, for some alternative estimates in the same report, DECC uses technology specific real pre-tax hurdle rate estimates.

- Figure 15 also shows that coal plant appears markedly more expensive, relative to CCGT and nuclear plant, in the DECC study than in the IEA/NEA study. The reason for this is that the DECC study assumes any new coal plant would be fitted with Carbon Capture and Storage (CCS) technology (consistent with UK government policy only to allow new coal plant if it is fitted with CCS), whereas the IEA/NEA study estimates the cost of a range of conventional coal-fired technologies.[24]
- Electric Power Research Institute and the US Energy Information Administration (EPRI and EIA) data shown in Figure 15 shows nuclear LCOE estimates that are consistent with the DECC and IEA/NEA estimates. The EIA estimates levelised costs of €72/MWh and EPRI estimates costs in the range of €66-76/MWh. These estimates fall towards the lower end of the range between the IEA/NEA and DECC forecasts in Figure 15. The lower values may be indicative of differences in the US regulatory regimes and hence lower cost of capital. There are other substantial differences between US and Hungarian energy markets that make comparison of LCOEs of other technologies less relevant and hence not included here. Natural gas prices in the US are much lower than in Europe, and these differences may persist even in the long run due to cost of shipping gas from North America. Low US natural gas prices imply substantially lower costs for US CCGTs than for their European counterparts, thus US sources cite lower LCOE estimates for gas CCGTs.

The differences between the studies illustrate the sensitivity of the cost comparison to differences in the assumed WACC and CO_2 prices, among other factors. However, notwithstanding these differences, the DECC and IEA/NEA studies suggest that nuclear is cost-competitive with both gas CCGT and coal plants, thus indicating that the development of new nuclear plants will tend to lead to lower prices relative to a scenario without new nuclear. The US LCOE estimates for nuclear generation further corroborate the finding that nuclear is cost-competitive in Europe with other types of conventional generation.

The figure shows that nuclear plants are cost-competitive with both gas CCGT and coal plants, i.e. nuclear-generated electricity is able to compete on costs with baseload power from other conventional technologies. In fact, nuclear generation has the lowest long run marginal cost in DECC's analysis (at just above €100/MWh). According to the EIA/NEA data, the LCOE for nuclear power can range between €28/MWh and €76/MWh, with lower estimates being for non-European OECD projects and non-OECD countries (the lowest being a nuclear project in China). In contrast, the LCOE for coal prices range from €57/MWh to €81/MWh, with the higher cost estimates coming from non-European countries[25]. The European, OECD average value of LCOE estimates for nuclear is only marginally above coal (€65.0/MWh vs. € 64.6/MWh).

Using pre-tax and post-tax discount rates in the same report would undermine consistency across estimates. Hence, is assumed that the 10% discount rate to be the hypothesised real pre-tax WACC in the DECC report.

[23] The IEA/NEA report uses internal fossil fuel price forecasts (provided by the IEA Office of the Chief Economist). According to the report, these projections are comparable to forecasts in the IEA's World Energy Outlook. DECC relies on its own 2013 fossil fuel price projections.

[24] Across each of the three technologies studied (CCGT, coal and nuclear), the IEA/NEA cost estimates for all EU countries covered by the study are taken, and the LCOE estimates shown in Figure 15 are computed from the average of these data. For those countries where the IEA/NEA study presents cost estimates for more than one coal technology, costs for that country are taken based on the average across the coal technologies shown.

[25] IEA/NEA ranges for the levelised costs of coal and nuclear in Europe are €57-75/MWh and €58-76/MWh respectively, as shown in the chart.

Overall, the EIA/NEA estimates may underestimate the LCOE of coal investments because:

- The possibility of tightening emissions control legislation over time, which has occurred in Europe in recent years, may require the coal plant to incur additional emissions abatement costs;
- Coal plant developments may run into legal challenge from environmental groups, as has occurred recently in Germany and the Netherlands; and
- The IEA/NEA study assumes no growth over time in CO_2 prices from its base assumption of $30/tonne, which may not be realistic over the life of a new coal plant, in light of the continued international efforts by governments to combat climate change.

In light of these factors, the potential for new coal developments in Hungary may be limited, so some CCGT or nuclear investments would be required. As a result, long-term power prices can be expected to need to converge to a level that remunerates investments in new CCGT and/or nuclear investments. Because both the DECC and IEA/NEA studies suggest nuclear is cost-competitive with new CCGTs, at least under their central assumptions on factors such as commodity and CO_2 prices and financing costs, allowing construction of new nuclear plant would tend to reduce power prices compared to the option of developing solely gas-fired CCGT.

Renewable sources will play an increasing role in the future, driven by ambitious government environmental targets in Hungary and Europe. Currently, renewables such as wind and solar power do not compete on costs with conventional generation, so they can only be developed economically if they receive subsidies from government.[26] Even in the long run in an unsubsidised or undistorted market, renewables (with the possible exception of hydro power) are still not forecast to be as competitive as nuclear generation. Moreover, some of the cheapest renewable energy sources, principally solar and wind, have "intermittent" production profiles, so they are not technically capable of providing baseload supply unless they are combined with extremely costly electrical storage capacity.[27] Hence they do not represent an economic alternative to sizable investment in conventional generation capacity to provide baseload supply and based on the IEA LCOE estimates would not provide a cost competitive alternative even when coupled with storage capacity solutions for the foreseeable future.

This brief review of LCOE estimates, drawn by NERA from reputable sources, indicates that nuclear is cost-competitive with alternative technologies that are capable of providing baseload energy supplies, namely gas-fired CCGTs and coal plant.

Based on the range of LCOE estimates reviewed, NERA indicates that baseload power prices in Hungary can be reasonably expected to converge to a level between €65/MWh and €108/MWh (in real 2013 prices) in the long-run, on the following rationale:

- €65/MWh is the level to which prices will converge if investment in nuclear generation is *unconstrained* (i.e. more units than Paks II are built including in the interconnected region) and the IEA/NEA's estimate of nuclear costs sets the price *or* coal generation is unconstrained (assuming environmental objectives and carbon pricing signals are set aside) and the IEA/NEA's estimate of coal generation costs sets the price; and

[26] No (or very few) investments in new solar or wind power projects have been developed in Europe without an explicit subsidy mechanism in place to support them, and there is little sign of this changing.

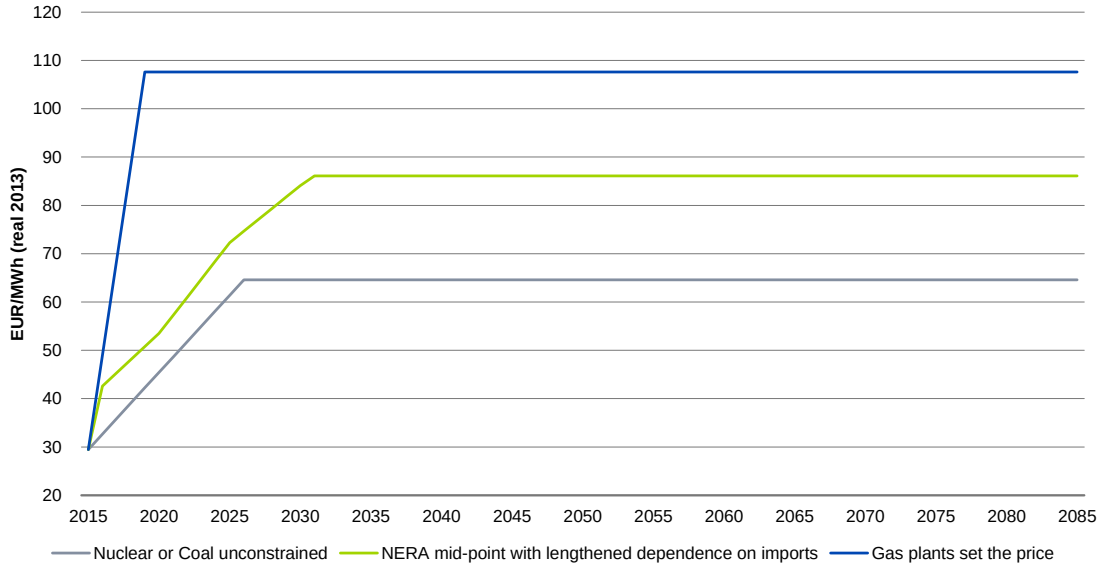
[27] Hydro power projects can in some cases be developed economically, but their feasibility depends on hydrological conditions and topography, and thus costs vary significantly on a project by project basis.

- €108/MWh is the level to which prices will converge if investment in nuclear generation is *constrained* (e.g. due to available sites) and DECC's estimate of CCGT costs sets the price.

Figure 16 presents the price boundaries implied by the analysis by NERA above for Hungarian baseload power prices, on the assumption that prices will converge gradually from their current levels to long-term equilibrium levels defined by the above range of LCOEs. This approach assumes that whatever new generation investments come onto the market are remunerated through the wholesale market:

- In the high case, prices converge to their long-term levels by 2019, the year in which supply of generation capacity in the Hungarian market falls below peak demand without new investment. In fact, evidence from MAVIR suggests that new generation capacity is required before this time.
- In the low case, prices converge to their long-term levels by 2026, the point in time at which a substantial share of the Hungarian coal fleet will retire accordingly to MAVIR. This approach assumes that the Hungarian market can fulfil the shortfall in supply highlighted by MAVIR through increased reliance on imports in the meantime[28].
- Given these long-term price levels depend on a range of assumptions, and in particular on CO_2 prices where the DECC and IEA/NEA studies both adopt relatively extreme positions on the up/downside, a central long term forecast has also been defined based on the mid-point between the high and low projections. The trajectory of convergence to this long term price assumes longer import dependence, with imports at the price levels anticipated by BMWi in the Market study scenario for Germany (see Figure 17).

Figure 16. Summary of Baseload Price Projection Based on LCOEs (€/MWh)

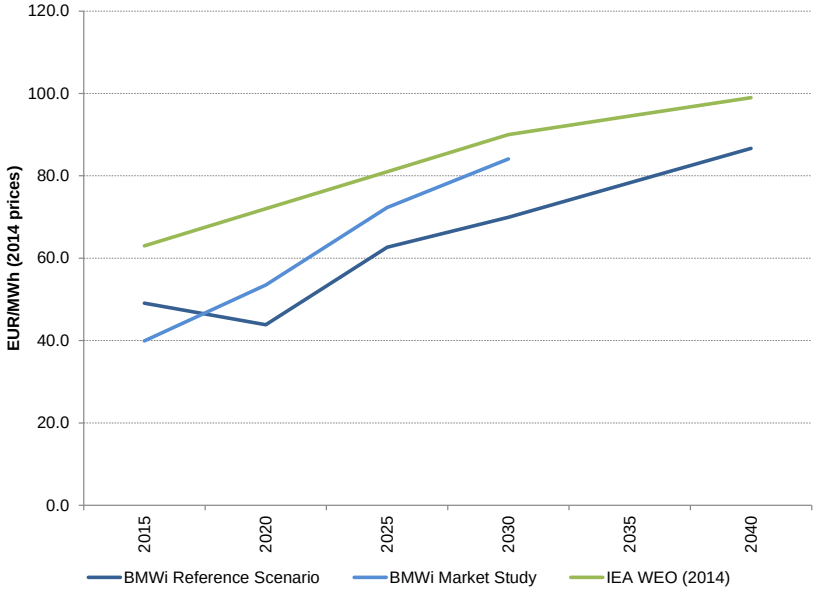


Source Historics: Bloomberg (the 2015 figure is for the year-to-date). Long-term: NERA analysis based on various sources listed above.

[28] Import prices may be above or below these price projections, based on the supply and demand conditions in neighbouring countries. Hence, Hungarian wholesale power prices may be above or below projected levels, depending on whether domestic generation or import will be the marginal source of baseload electricity in the future. In the long run however, neighbouring countries will also need to add new generation capacity to replace retiring plant. Thus, in the long run, prices will necessarily rise to levels required to encourage entry of new generation plant (both in Hungary and in neighbouring regions).

Usefully, given the significant regional interconnection, two relevant price forecasts provide a benchmark for the broader regional European market. First, two recent forecasts by the German Federal Ministry for Economic Affairs and Energy (BMWi) both forecast that power prices in Germany will increase over time, as the current overcapacity in the German market erodes. The BMWi Reference Scenario assumes that power prices will continue to drop due to increasing renewables on the system, but will increase after 2020 due to a nuclear phase-out and increasing fuel/carbon prices. The BMWi Market Study assumes that prices will increase immediately, driven mainly by growth in fuel/ETS prices.[29] The price projections from this study are shown in Figure 17 below. By 2030, these price forecasts reach a range between €70/MWh and €85/MWh, which is within the range of LCOE estimates identified above.

Figure 17. BMWi Wholesale Market Price Forecasts and IEA WEO (2014) (€/MWh)



Source BMWi

Second, the IEA 2014 World Energy Outlook states that:[30]
"*Wholesale prices and future trends vary across the European Union; on average, they are projected to increase by almost 50% over the Outlook period in the New Policies Scenario. Current wholesale price levels, of around $70/MWh, are not sufficient fully to cover the fixed costs of all power plants in the system. Reform of wholesale markets will be necessary if prices are to rise to $100/MWh in 2030 and to around $110/MWh in 2040 – the price levels that would allow for full recovery of fixed and variable costs. Such an increase would result in higher end-user prices in Europe, compared to some other countries.*"

[29] Sources: (1) Endbericht Letstudie Strommarkt, Arbeitspaket Funktionsfahrigkeit EOM & Impact-Analyse Kapazitatsmechanismen, Im Auftrag des Bundesministeriums fur Wirtshaft und Energie, 30 Juli 2014; and (2) Entwicklung der Energiemärkte – Energiereferenzprognose Projekt Nr. 57/12, Studie im Auftrag des Bundesministeriums für Wirtschaft und Technologie, Ansprechpartner, Dr. Michael Schlesinger (Prognos), PD Dr. Dietmar Lindenberger (EWI), Dr. Christian Lutz (GWS), Juni 2014.

[30] IEA World Energy Outlook, 12 November 2014, page 226.

The IEA's projection of the level of wholesale power prices necessary to remunerate investment in new generation suggests that prices will need to reach $100/MWh in 2030, or around €90/MWh at current exchange rates. Hence, this figure is well within NERA's projected range of long-term prices based on the LCOE of new generation plants.

NERA's review of these independent price forecasts for Germany (BMWi) and Europe (IEA) shown in Figure 17, indicates that wholesale prices in neighbouring and interconnected markets are also expected to rise towards new entrant cost levels over the long-run (2020s onwards), in order to incentivise new investment to meet demand growth and replace existing plant that have reached the end of their useful lives – the same trend that MAVIR is forecasting for Hungary. The range of long term wholesale prices shown in Figure 16 therefore represents a reasonable basis for assessment according to NERA for the Hungarian market in the context of the high level of interconnection.

***REKK** projects a wholesale electricity price of €90/MWh (2011 real prices) for the central, "realistic" scenario in its 2013 report. As a sensitivity check, REKK calculates with prices of €80/MWh and €100/MWh in the pessimistic and optimistic scenarios, respectively. The source of the central €90/MWh value is REKK's 2011 modelling work and report, which analysed the economic effects of the Hungarian government's proposed National Energy Strategy. In particular, the €90/MWh value came from modelling the National Energy Strategy's nuclear-coal-green scenario, which assumed the construction of a new nuclear power plant at Paks, further investment in renewables, and the establishment of one new coal plant in Hungary. The €90/MWh electricity price forecast for 2030 is the result of REKK's in-house regional electricity market model. REKK's forecast of €94.75/MWh (2013 real prices) is higher than the review of LCOE estimates implies, and in the range of wholesale price projections identified.*

***Felsmann** designs four simple market price scenarios to test how the estimated NPV of the Paks II investment varies with changes in the assumed market price:*

- *In his lowest price scenario, he assumes constant real prices that remain at the 2013 average sales price of the Paks Nuclear Power Plant of €43.39/MWh.*
- *In his second, preferred[31] scenario, he assumes a 25% increase relative to this benchmark price, i.e., a real 2013 price of €54.24/MWh will apply throughout the entire lifespan of the Paks II Nuclear Power Plant (2026-2085).*
- *In his third scenario, he assumes a 50% real price increase relative to the benchmark, to apply throughout the entire lifespan of the power plant (real 2013 price of €65.01/MWh).*
- *In his fourth and most optimistic scenario, he assumes a 75% real price increase relative to the benchmark 2013 levels (real 2013 price of €75.93/MWh).*

Felsmann refers to three studies to provide some context to the question of market price development in Hungary and to justify his choice of scenarios and his preference for the second scenario (which assumes a 25% real price increase):

- *European Commission (EC) (2014):[32] The EC forecasts annual real growth in average EU-wide electricity generation costs of 2.4% per annum during 2011-20, real reductions in*

[31] This is the assumption Felsmann uses for his Base Case scenario.

[32] European Commission - Energy prices and costs report: Commission Staff Working Document, 2014.

generation costs of 0.17% per annum during 2021-2030, and further reductions of 0.19% per annum during 2031-2050.

- *National Grid (NG) (2014)[33]: National Grid forecasts UK wholesale power prices until 2036 under three alternative scenarios (High, Base Case, and Low). Felsmann uses these estimates to derive an implied growth in real prices between minus 16% and 13%, relative to 2015 prices.*
- *EIA (2015)[34]: The EIA forecasts household and industrial power prices at four different production facilities in the United States, and, according to Felsmann, projects real price growth of 11.6% and 16% to 2020 and 2030 respectively, relative to 2013 levels.*

The sources referred to, however, are of limited relevance for determining wholesale price development in Hungary, as they are not related to the expected development of supply and demand in Hungary – which despite Hungary's relatively high interconnection capacities are still the main factors driving Hungarian wholesale electricity prices – i.e., they do not represent market clearing prices as defined in Section 4.2. The forecast electricity price growth rates from different countries or regions cannot be assumed to apply to the Hungarian market, without considering the current (and past) level of prices in (1) Hungary (2) and the region to which the estimated growth rate applies (i.e., the EU, the UK, or the US). For instance:

- *Demand and supply conditions in the Hungarian and US electricity markets are very different. Thus, EIA price growth forecasts are largely irrelevant to Hungarian energy markets. Furthermore (1) the EIA study forecasts retail and not wholesale prices (2) and that estimates are based on only four production facilities, according to Felsmann.[35]*
- *Felsmann claims the NG estimates to be nominal values, however, these figures are actually shown in real 2014 terms. Real prices are thus expected to increase in all of NG's scenarios, by 7%, 50%, and 90% until 2026 (relative to 2013), for the Low, Base Case and High price scenarios respectively (as opposed to Felsmann's numbers of minus 16%, 3%, and 13%).[36]*

The 75% price increase, i.e., a real 2013 price of €75.9/MWh evaluated by Felsmann appears on the basis of the critical review of LCOE estimates as conducted in this study, to be a possible scenario within the most likely range of future prices. Irrespective of whether the Paks II project is implemented, the Hungarian market which is interconnected to its neighbours and operating on a liberalised basis is likely to experience market prices setting by the expected LCOE of the marginal baseload plant (gas CCGTs). Depending on future CO_2 and commodity prices the price levels therefore may range between €65-108/MWh (see Figure 16), which range lies above the break-even cost (LCOE) of the Paks II plant as shown in section 6 below and hence support an economic justification for investment in the plant.

*The **Romhányi** report employs the most conservative price assumption: Romhányi assumes that prices will remain at €43/MWh (2014 real value) throughout the entire life span of the Paks*

[33] National Grid - UK Future Energy Scenarios (2014)

[34] EIA - Analysis of the Impact of the Clean Power Plan (2015)

[35] It is not clear how exactly Felsmann arrived at his estimated growth rates, based on the findings of the EIA study.

[36] Felsmann claim the DECC figures to be nominal values (they are real) and uses the wrong benchmarks to arrive at growth rate estimates. Instead of dividing the forecasted 2026 Low, Base Case, and High Price scenario prices each by the same figure (such as the actual 2013 wholesale price, or, alternatively, the 2015 Base Case price forecast), he divides each figure by a different benchmark (the 2015 price forecast for the corresponding scenario). This necessarily biases all growth rates towards zero.

II Nuclear Power Plant. The Romhányi report refers to some indicative evidence of market prices, but without demand and supply evaluation to substantiate that the current wholesale prices are just as likely to fall as to rise. This is not consistent with the aging European generation fleet and anticipated closure dates for significant capacities which support the view that future market prices depend on the LCOE of new investments rather than on the marginal cost of already amortised older facilities which are largely price setting in the current market:

- *Romhányi refers to multiple sources that predict future price increases: he cites estimates of (1) €55-60/MWh from the IEA's 2012 World Energy Outlook[37] for 2035 European wholesale power prices; (2) €90/MWh from the 2012 National Energy Strategy of the Hungarian government for 2030 wholesale power prices in Hungary; (3) a guaranteed purchase price for electricity generated by Hinkley Point of €115/MWh in the United Kingdom. All of these sources, however, indicate higher price levels than the prices assumed by Romhányi, and are supportive of the findings within this report.*

*Dr. **Aszódi** et al do not make assumptions about the development of wholesale electricity prices in Hungary, but estimate the LCOE of the Paks II Nuclear Power Plant. They find that the average LCOE of the power plant over its entire lifespan is approximately €54-55/MWh (real 2013 values). Altering some parameter assumptions, they find that all LCOE estimates fall within the range of €50/MWh to €63/MWh.*

It should be noted that while in a perfect single electricity market environment, which is a cornerstone of the common European energy policy, the supply curve would reflect the relative competitiveness of generation capacities across Member States as described above, in reality there are currently other influencing factors that impact both the demand and supply conditions such as local taxes, subsidies and policy interventions. Power prices in the EU are affected by the energy policy of each Member State. This presents a challenge to forecasting power prices, as one needs to take a view on future energy policy for interconnected Member States. This has been implicitly addressed in the analysis above by consideration of German prices. Given the European Commission's vision of investor confidence through price signals that reflect long term needs and policy objectives[38] and a single European electricity market with power generators competing on an equal footing[39] without market subsidies and distorted prices, it is reasonable to assume long term market price convergence across the EU.

Pricing scenarios for financial analysis

The analysis and benchmarking conducted above therefore indicates the following in Figure 18 as the relevant prices for analysis of the economics of construction of a new nuclear power plant in Hungary for the period from when the first Paks II unit would commission.

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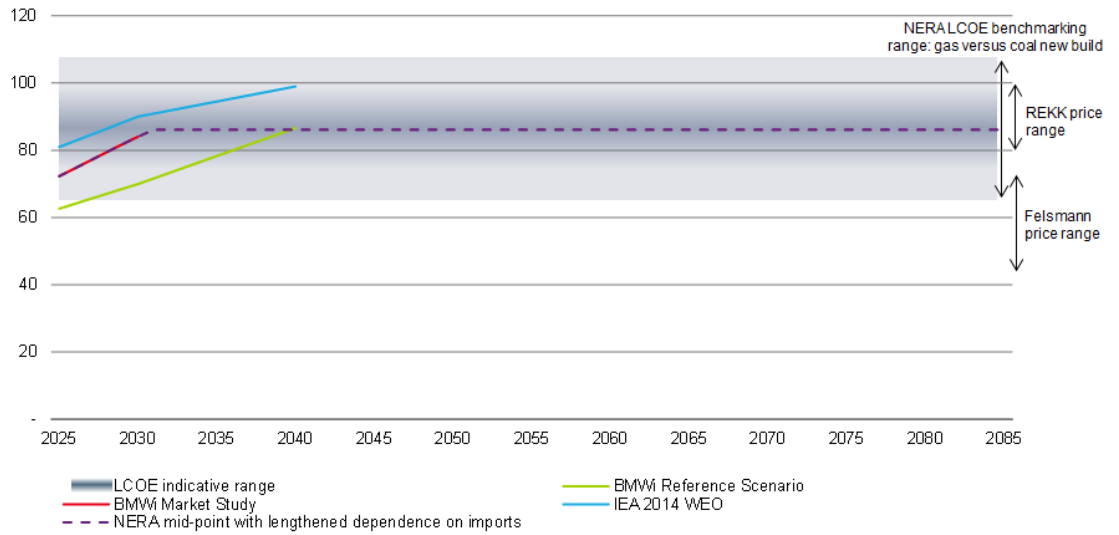
[37] In fact, the 2012 IEA WEO forecasts European wholesale electricity prices of approximately €82/MWh (2011 real prices). Romhanyi, like Felsmann, projects the price growth forecasts to current price levels, instead of using the level estimates.

[38] See COM (2015) 80 final: Energy Union Package, A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy.

[39] See SWD(2013) 439 final: European Commission guidance for the design of renewable support schemes.

Figure 18. Price projections and LCOE



If overall (rather than in any one year) the range of possible prices identified lie above the LCOE calculated for Paks II (see Chapter 7), this would indicate that Paks II is an economically viable and rational method for securing competitive and sustainable electricity supply for Hungary that is consistent with the country's energy policy, which seeks to ensure sufficient electricity generation capacity and reliable supply of electricity relative to forecast growth in the electricity demand.

5. Operating period costs

Once in the operational period, nuclear plants face low and fairly stable costs for the life of the plant, with the main components being operation and maintenance (O&M), fuel, waste and decommissioning costs. These costs, based on publicly benchmarked data, are input on a €/MWh basis (real 2013), inflated by an appropriate inflation index (assuming 2% long term inflation), and then multiplied by the production in each year. Working capital balances are calculated as the working capital days applied to the appropriate revenue or cost line, with the number of inventory days being based on the 18 month fuel cycle, while the trade receivable and trade payable days are based on benchmarking of other nuclear projects, which showed a large variation in data points. Depreciation is charged on a straight-line basis over the depreciable life of the plant. Corporate taxes are then levied on the profit before tax, taking into account tax credits accrued during the construction period that can reduce the tax payable in the initial operational period.

5.1 O&M

O&M consist of the costs required for the day-to-day operations of the plant, such as personnel, materials (other than fuel) etc., and the costs required to maintain the plant at an appropriate level. During the course of the 60 year operational life of the project, regular maintenance and upkeep will be required to ensure that the plant integrity and operational capability is preserved. Such maintenance would be performed on the components of the plant according to a schedule as prepared by the operating company. Hungary has many years of experience of managing a nuclear power station and the expertise to operate and maintain the plant appropriately.

Figure 19. O&M cost benchmarking

O&M (EUR/MWh)	Median	Source
IEA 2010 - - APR-1000**	6.7	IEA - 2010
IEA 2010 - - AP-1000**	7.0	IEA - 2010
IEA 2010 - United Sates - Advanced Gen III+**	9.7	IEA - 2010
Ristö & Kvistö 2008 O&M total	10.0	DIW - 2013
NEI 2010 O&M total	10.7	DIW - 2013
IEA 2010 O&M total	11.1	DIW - 2013
IEA 2010 - France - EPR**	12.1	IEA - 2010
CDC 2012	13.8	DIW - 2013
MacDonald 2010 O&M total	16.1	DIW - 2013
EIA 2011 total	16.4	DIW - 2013
Range lower end (Generation III)	**6.7**	
Range upper end (Generation III)	**16.4**	
Average value (Generation III)	**11.4**	

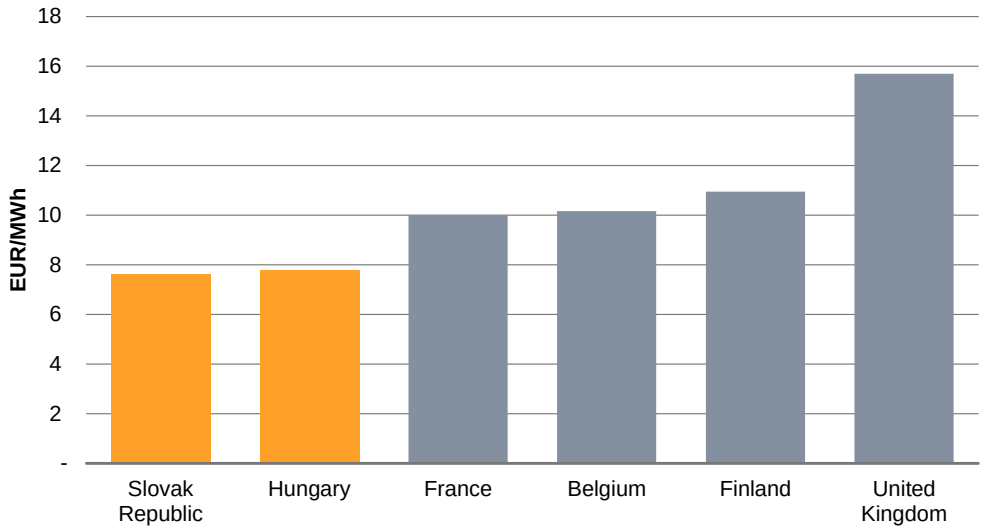
**The original amount was presented in USD. The average exchange rate for 2010 was 1.33 EUR/USD
http://x-rates.com/average/?from=USD&to=EUR&amount=1&year=2010

The appropriate source for an O&M assumption would be the Paks II project company. In the absence of public disclosure, O&M costs can be estimated based on publicly benchmarked data from reputable sources, applied on a €/MWh basis, real 2013. The O&M cost assumption from the OECD / IEA / NEA report indicates an O&M cost of €7.8/MWh for Hungarian nuclear. This is an appropriate starting assumption giving it is the most up to date benchmark, likely informed based on disclosure by the Paks II project company, and also is geographically targeted, and so

takes account of factors such as local wage costs even if cost convergence is assumed in the longer term. This assumption also falls within the range of costs anticipated for generation III and III+ reactor plants in Figure 19, based on public information studies, which range from €6.7/MWh to €16.4/MWh and depend not just on the technology specifications and operation model (e.g. length of fuel cycle and frequency of outages when maintenance staff numbers increase) but also on the local productivity and cost assumptions.

- Technological considerations: The benchmarking focuses on Generation III+ nuclear reactors, which include evolutionary, state-of-the-art design improvements. These improvements are in the areas of fuel technology, thermal efficiency, modularised construction, safety systems (especially the use of additional passive systems beside active systems), and standardised design. These advancements also have efficiency implications for operation and maintenance costs. It is therefore not appropriate to base O&M assumptions on the original Paks units. For example, while the capacity of the new plant is 400MW higher than Paks I the operational staff required for Paks II is significantly lower at 1, 000 people compared to the approximately 2,500 people required for operation of Paks I.
- Local labour market considerations: Figure 20 shows the impact of the local macroeconomic context on cost assumptions. Compared to Western European countries, which have an O&M cost of c. €10/MWh or more, the two CEE data points, which are highlighted in orange, have lower costs.

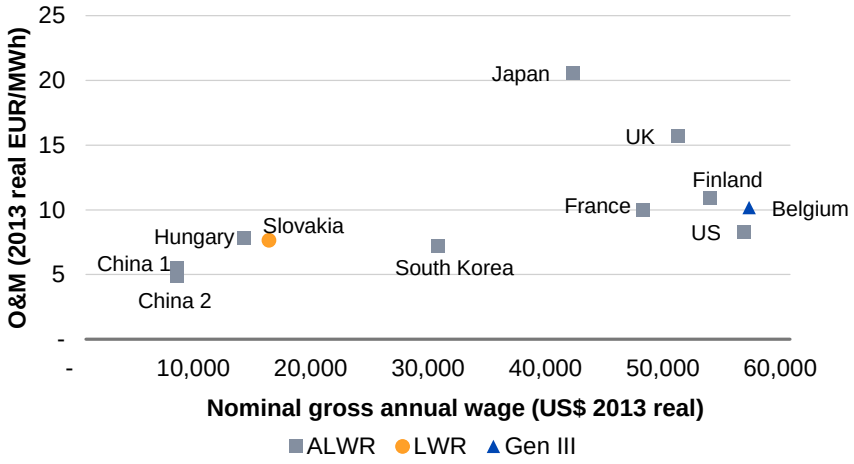
Figure 20. O&M costs (real 2013)



Source OECD / IEA / NEA - Projected Costs of Generating Electricity (2015)

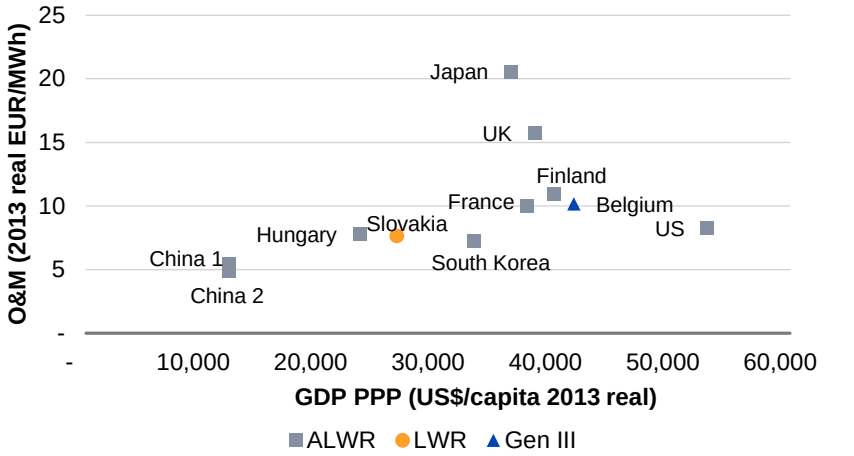
Figures 21 and 22 show the correlation between O&M costs and GDP per capita and annual wages. As would be expected, the trends show that the higher the GDP per capita or the annual wage, the higher O&M costs are. This explains the cheaper O&M costs in the CEE region given the lower wage costs and GDP. The UK is a clear outlier with high O&M costs due to local labour market dynamics.

Figure 21. O&M vs. annual wage



Source OECD, National Statistical Offices (Romania, Bulgaria), tradingeconomics.com (China); International Energy Agency and Nuclear Energy Agency, "Projected Costs of Generating Electricity 2015 Edition", 2015

Figure 22. O&M vs. GDP per capita



Source World Bank; International Energy Agency and Nuclear Energy Agency, "Projected Costs of Generating Electricity 2015 Edition", 2015

*The **Romhányi** Report assumes a staff number of up to 1,500 people, which is above the 1,000 operational specifications for the Paks II plant, implying a potentially material overstatement of the assumed O&M costs. These costs are adjusted for both inflation and productivity growth. Faster growth in Hungary's economy is assumed to be detrimental to the economics of Paks II in the modelling work, as revenues do not depend on Hungarian growth but costs rise with higher growth. A productivity growth per annum of 2% is assumed. It is rare to model costs with higher inflation than revenue, unless there is a well-established convention to do so or a contractual obligation dictating inflation terms which are not alluded to.*

*The assumptions on operational and maintenance (O&M) costs contained in the **Felsmann** analysis equate to c. €15 / MWh (real 2013). The Felsmann report bases its assumptions for O&M costs on 2013 historical data for the Paks I units rather than assumptions relevant to the technology selected for Paks II. The four reactors of Paks I were connected to the grid between 1982 and 1987, which means that the key operational figures which the Felsmann report's analysis uses is based on four, 28-33 years old, Generation II reactors, unlike the Paks II units, which will be Generation III+ reactors, with the personnel costs, which make up a significant proportion of the operating costs, simply kept at the same level as for Paks I on a real basis despite the lower operational headcount requirements for the new units and the higher power output of each unit. The €15 / MWh (real 2013) assumption is in line with higher cost countries but greater than the benchmarked country and technology specific assumption for Paks II of €8 / MWh (real 2013). Based on the analysis of this report, increasing O&M costs from €8 / MWh (real 2013) to €15 / MWh (real 2013) within the first 10 years of operations would reduce project returns by c. 0.5 percentage points. The Felsmann report assumptions include a capital cost after 30 years of operational life of 30% of the value of the machinery and equipment (i.e. 30% of €8.4 billion nominal (which equates to €2.5bn) according to their model, as opposed to 30% of the full €12.5 billion for the whole project), in addition to the cost of maintaining the unit as annual O&M expenditure, which, under this analysis, over the 30 year period would have already assumed is c. €8 billion nominal spent on maintaining the plant assets. Based on the analysis in this report, an additional €2.5bn (real 2013) of maintenance expenditure in the 40th year of plant operations would lead to less than a 0.1 percentage point fall in project pre-financing returns.*

While an important variable, even with higher O&M cost assumptions the project still remains economically viable. Should convergence of labour and other operational costs lead to O&M costs akin to those of higher cost countries and a €15/MWh (real 2013) be assumed from the start of operations, this would result in less than a c. 0.8 percentage point reduction in the project return, but would not impact overall economic viability or lead to a requirement for equity injections after the units become operational.

Life extending maintenance

The new Paks II units will be designed and constructed for 60 years operation, so no major investment requirement over and above O&M would be required in the 60 years. A well-designed and managed maintenance program will minimize the lifetime costs of the equipment, and this cost is embedded in the O&M assumption. Lifetime extension can come into consideration after 60 years, which could lead to up to an additional 20 years operation, only implementable if safety and economic rationale exist at the time. No such lifetime extensions are assumed at this stage, but it should be noted that there are a large number of utilities investing in lifetime extensions for older generation nuclear plants which is a clear indication of the competitiveness of nuclear generation, even in the current low price environment. While the capital costs of a new build are much greater than for life extension, extension does still require significant investment in the equipment as well as ensure that the plants meet current, more stringent safety requirements. Thus, the economic rationale is similar to that for a new build,

albeit on a smaller scale. Examples of lifetime extensions which have occurred / are underway include[40]:

- In the USA over 75 reactors have been granted licence renewals which extend their operating lives from the original 40 out to 60 years, and operators of most others are expected to apply for similar extensions;
- The Russian government is extending the operating lives of most of the country's reactors from their original 30 years, for 15 years, or for 25 years in the case of the newer VVER-1000 units, with significant upgrades;
- In the UK, EDF Energy is planning life extensions averaging seven years for their AGR units and announced a seven-year life extension for Hinkley Point and Hunterston in November 2012 and a five-year extension for Hartlepool in November 2013. It spent £150m to prepare Dungeness for a 10-year licence extension, to 2028, and this was agreed by ONR in mid-2014. The company confirmed it in January 2015.
- Energoatom, the state-run operator of Ukraine's nuclear units, is preparing an application to extend the life of unit 3 of the Rovno nuclear power plant, which has been in service since 1986. The planned upgrades include thermal mechanical equipment, seismicity and other monitoring systems, and a diagnostic system. For units 1 and 2, 20-year extensions were granted in 2010. In 2012, Energoatom had announced that the 11 oldest 1000MWe reactors will obtain life extensions by 2030.[41]
- Slovenia and Croatia have agreed on a 20-year life extension for the Krško nuclear power plant in Slovenia, which is jointly owned by the two countries. The agreement also covers the construction of a dry storage facility for used fuel to be financed by the shareholders. Pursuant to this agreement, the plant will be operational until 2043.[42]
- Following a power uprate of unit 4, the generating capacity of the Swedish Ringhals nuclear power plant is expected to increase by approximately 175 MWe. The uprate was approved conditional on the replacement of three steam generators, which was carried out in 2011.[43]
- The Belgian government and energy corporation Electrabel have agreed on a ten-year life extension for two units of the Doel nuclear power plant in exchange for an annual fee of €20 million ($22 million) to be paid by Electrabel from 2016 to 2025, the year until which nuclear power will have to be phased out under current Belgian law.[44]
- In Armenia, a 10-year life extension of the countries only nuclear power plant Metsamor has been ratified by the National Assembly. The Prime Minister also announced that the country will continue to develop nuclear energy in order to maintain energy security.[45]

[40] Sourced from the World Nuclear Association

[41] (World Nuclear News (2015), http://www.world-nuclear-news.org/RS-Ukraines-Energoatom-looks-head-to-Rovno-3-life-extension-19081501.html, 19 August 2015)

[42] (World Nuclear News (2015), http://www.world-nuclear-news.org/C-Partners-agree-on-life-extension-for-Krsko-2107154.html, 21 July 2015)

[43] (World Nuclear News (2015), http://www.world-nuclear-news.org/C-Uprate-approved-for-Ringhals-4-0202154.html, 2 February 2015)

[44] (World Nuclear News (2015), http://www.world-nuclear-news.org/NP-Agreement-on-extending-lives-of-Doel-units-3007155.html, 30 July 2015)

[45] (World Nuclear News (2015), http://www.world-nuclear-news.org/NN-Armenia-confirms-ongoing-role-for-nuclear-2307157.html, 23 July 2015)

5.2 Fuel, waste management and decommissioning costs

5.2.1 Fuel

Similar publicly available information benchmarking for fuel costs indicates a range of €5-7/MWh real 2013.

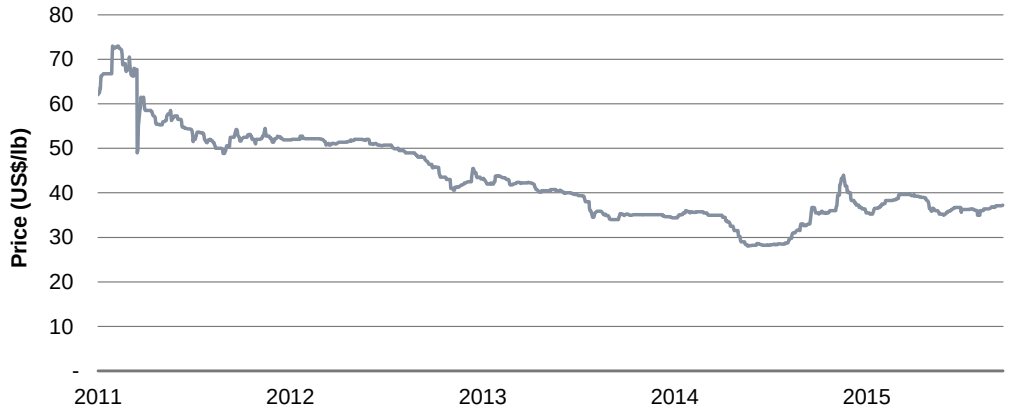
Figure 23. Fuel cost benchmarking

Fuel cost (EUR/MWh)	Median	Source
NEI 2010 Fuel	4.7	DIW - 2013
IEA 2010 fuel	7.0	DIW - 2013
MacDonald 2010 Fuel	6.0	DIW - 2013
Ristö & Kvistö 2008 Fuel	5.0	DIW - 2013
CDC 2012 fuel	5.2	DIW - 2013
Parsons Brinckerhoff 2011 Fuel*	5.8	Parsons Brickenhoff - 2011
Range lower end	4.7	
Range upper end	7.0	
Average value	5.6	

*The original amount was presented in GBP. The average exchange rate for 2011 was 0.868 EUR/GBP

However, nuclear utilities typically procure their fuel needs on a long term basis for security of supply reasons under long term confidential contracts. Given the long term nature of such contracts, there is typically a time lag between market prices and contract prices. Historical fuel costs available in benchmarking are useful, but will not capture the timing of the fuel supply contract, particularly in the low uranium price environment.

Figure 24. Historical spot uranium prices



Source Bloomberg

Thus, analysing the constituent cost components to a fuel contract can be an alternative indication of the all-in cost of fuel that could be commercially procured. First, uranium ore must be mined and processed in order to get uranium oxide, which is then converted and enriched to increase the proportion of the fissile uranium-235 isotope, before being fabricated into fuel rod assemblies, ready to be used in the reactor. Hence, the four cost component stages comprise uranium acquisition, conversion, enrichment and fuel assembly fabrication. The costs of conversion and enrichment are largely technology agnostic and have remained fairly stable. Fabrication costs will of course be specific to this project and the reactor type. There is currently only one fabricator and hence supplier for fuel for the VVER technology of Paks II Project. Assumptions for these cost components (conversion, enrichment and fabrication) can be publicly sourced from the World Nuclear Association. The remaining variable is the cost of uranium, which is available from diversified providers and for which there is a transparent reported long term forecast market price, even if most of the long term contracting arrangements remain confidential to the suppliers and procuring utilities. In the last couple of years, there has been and oversupply of uranium in the market, worsened by the closing of nuclear plants in Japan following Fukushima, which has led to declining prices. Analyst research estimates long term uranium prices at c. US$70/lb, with the recovery in prices being due to increasing demand from China and India, as well as reactor restarts in Japan, although stockpiled uranium reserves would continue to exert downward pressure on prices.

Taking all of these factors into account and the following calculation steps enables a fuel price estimation:

- First, the cost of the unprocessed kg U_3O_8, 8.9kg of which is required in order to make 1kg of UO_2 (the fuel required for the nuclear reactor) according to the World Nuclear Association, at the long run cost of US$70/lb (real 2013), which is equivalent to c. €136/kg (real 2013), from analyst research comes to a cost of c. €1,200/kg of UO_2 (real 2013).
- For the conversion, i.e. turning the uranium into pure uranium gas which can go on to be enriched, the World Nuclear Association provides an assumption of c. €10/ kg of uranium gas (real 2013), 7.5kg of which are required for 1kg of UO_2, which is equivalent to c. €75/kg of UO_2 (real 2013).
- Separative work (i.e. the process by which the natural uranium is enriched into usable fuel) is measured in separative work units (SWU), 7.3 of which is required for 1kg of UO_2 according to the World Nuclear Association. The Ux Consulting Company, which

provides forecasts of enrichment costs, estimates a long run cost of c. €73/SWU (real 2013). This implies a cost of €540/ kg of UO_2 (real 2013).

- The last stage, which is fabrication of the fuel into assembly rods which are ready for use in the reactor is estimated to cost c. €210/ kg of UO_2 (real 2013) according to the World Nuclear Association.

The above equates to a total all-in cost of uranium of c. €2,025/ kg of UO_2 (real 2013). Based on the required fuel consumption typical for the technology, and the assumed load factor in the analysis in this report, this implies a cost of c. €5/MWh (real 2013).

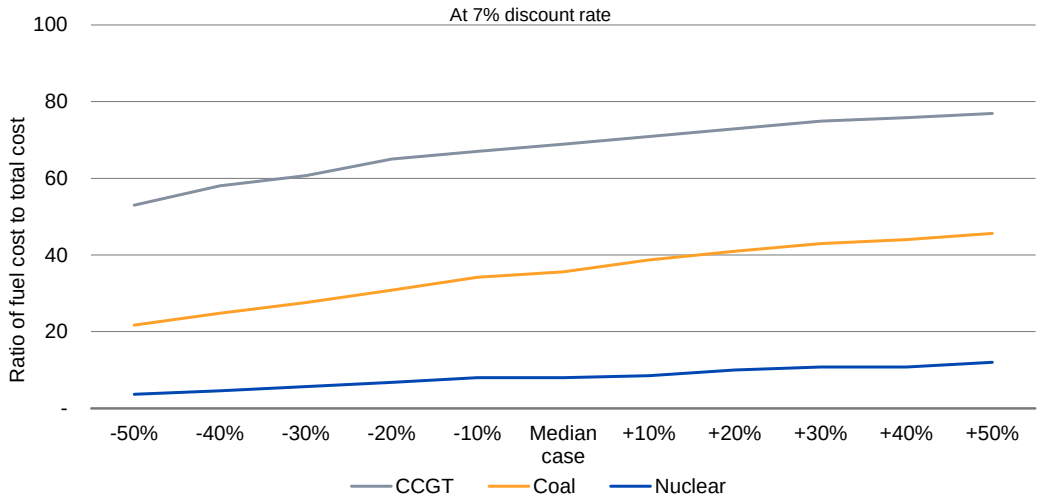
*The **REKK** report assumption for fuel costs was €8.1/MWh with maximums and minimums at ±20% respectively. This fuel cost assumption included full cycle figures, front end and back end cost considerations, e.g. processing, storage, disposal, and hence should be compared to a combined fuel and waste management cost.*

*The **Felsmann** report bases its fuel assumptions on the Paks I units' fuel cost in 2013, prorated up for Paks II's greater power generation, and this implies a cost of €4.1/MWh (real 2013), which is lower than the assumption in this report. As previously mentioned, fuel cost is dependent on the fuel supply agreement which the plants have, and there are significant differences in the fuel assemblies used by the old and new units, which could account for the difference in costs.*

*The **Aszódi** Report includes fuel costs as one of the key variable costs in the formulation of the project's LCOE. Fuel costs are set at 2 Ft / kWh (c. €7/MWh) being "based on international experience" and on a study conducted for the European Commission (2013), "Synthesis on the Economics of Nuclear Energy" which quotes nuclear fuel costs in Hungary at US$8.77/MWh (€6.6/MWh). Due to the decline in uranium prices over the past few years, higher fuel cost assumptions are to be expected, hence the apparent conservatism in the report.*

Figure 25 highlights one of the advantages of nuclear over conventional generation, which is the relative protection from commodity risk. Hydrocarbon based technologies have fuel as a majority of their operating cost, and as such, a change in the price of fuel has a significant effect on the LCOE of the plant. In contrast, given the low contribution of fuel to LCOE, nuclear plants' LCOEs are relatively insensitive to changes in fuel prices. Hence, even assuming a doubling of fuel cost (i.e. to €10/MWh) would only reduce returns by c. 0.6 percentage points.

Figure 25. Ratio of fuel costs to total LCOE for different technologies



Source OECD / IEA / NEA - Projected Costs of Generating Electricity (2015)

5.2.2 Decommissioning and waste management

In relation to decommissioning of the plant, the total associated costs are uncertain given that decommissioning will take place c.70-90 years from now and that decommissioning techniques may be refined over this period. There are various approaches commercial nuclear power plant projects use to fund decommissioning costs; typically these involve funding the expected decommissioning cost before commercial operations or funding decommissioning costs during operations. In the case of the Paks II project, waste management costs and future decommissioning costs are funded during the operation of the plant through annual payments to the Central Nuclear Financial Fund. The level of annual contribution being paid into the Central Nuclear Financial Fund to finance the waste management and decommissioning of the plant is on the basis of the relevant sections of Act CXVI of 1996 on Atomic Energy, in which the Hungarian Atomic Energy Authority was tasked by the Government to establish the Public Agency for Radioactive Waste Management, for performing tasks related to decommissioning and waste management.

In January, 2015 the Agency for Radioactive Waste Management at the request of MVM Paks II. Zrt. prepared a calculation regarding the expected yearly contributions to Central Nuclear Financial Fund (hereinafter KNPA) of Paks II.

The basis of the calculation was that the net present value of the annually paid amount during the operation and the amount of state subsidies allocated from the state budget is equal to the net present value of the expenses arising in relation to radioactive waste, spent fuel, decommissioning and the closure of the waste storage facilities taking into consideration the KNPA contributions of the operating I-IV. units (PAKS I).

The calculation method was the following:

$$NPV = F_0 + \sum_{i=0}^{n-1} \frac{B_i}{(1+d)^i} - \sum_{i=0}^{m-1} \frac{K_i}{(1+d)^i} \quad (1)$$

where:

NPV: net present value of Central Nuclear Financial Fund (NPV=0 for the whole period of Central Nuclear Financial Fund)

F_0: accumulated amount until the date of calculation

B_i: amount payable into the Central Nuclear Financial Fund in year i

K_i: amount payable from the Central Nuclear Financial Fund in year i

d: discount rate

n: period of the payments into the Fund in years

m: period of the payments from the Fund in years

Based on the calculations of the Public Agency for Radioactive Waste Management waste management and decommissioning costs to generated electricity ratios are 0.5901 HUF/kWh; 0.6951 HUF/kWh; and 0.8788 HUF/kWh (2015 real prices) by decreasing discount rates (3; 2; 1% which are the forecast Hungarian central bank's prime rate), considering a 90% load factor.

Assuming a fund growth rate (real interest of 2%) to discount back implies a 0.6951 HUF/kWh KNPA contribution, comprising waste management: 0.6061 HUF/kWh and decommissioning: 0.089 HUF/kWh. This implies a cost of €2.1/MWh or c. total funds contributed over the life of the plant for waste and decommissioning of €2.4 billion (real 2013). If the most conservative estimate is used, which would be equivalent to €2.7/MWh (real 2013), the cost would rise to €3.1 billion (real 2013) and would only lead to project returns falling by less than a 0.1 percentage point.

*The **Romhányi** report cites IAE figures of c. €2.3/MWh for decommissioning costs and assumes 485TWh in a single reactor for a full life cycle yielding a decommissioning cost of HUF576 billion (€1.86 billion) today for two reactors. At c. €500 million lower than our estimate of €2 billion, this is the most conservative estimate on a per reactor basis of the reports reviewed, and yet is still in line with the assumption utilised in this analysis. The Romhányi Report examines decommissioning costs in some detail, relative to the other reports reviewed. The report considers the effect of prevailing interest rates and their impact on the decommissioning reserve fund. A sensitivity analysis is undertaken outlining the reduction in the required contributions to meet the ultimate costs of decommissioning in higher interest rate environments.*

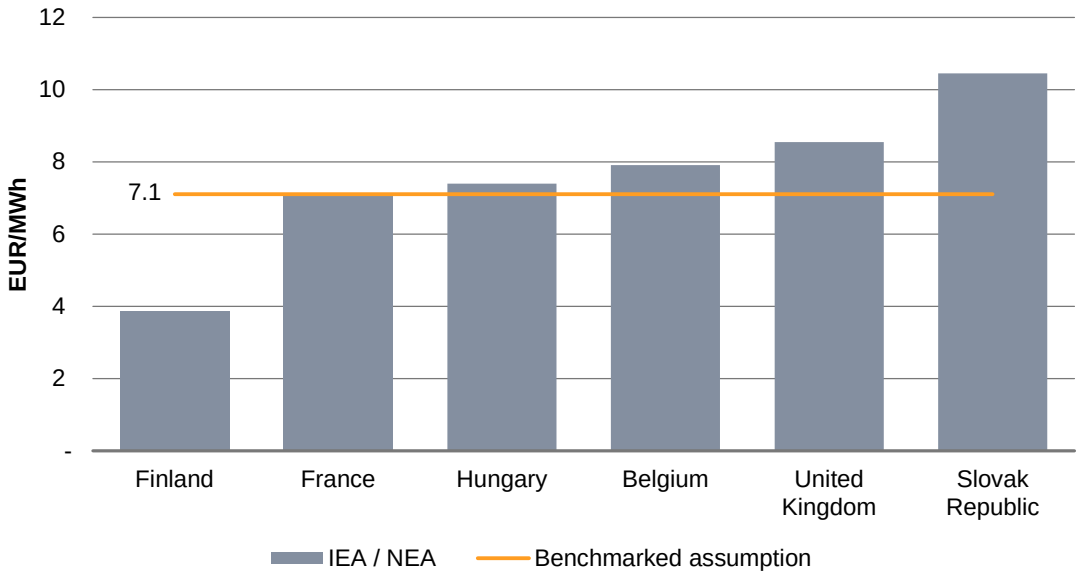
*The **REKK** report states that decommissioning is c.15% of original investment value for most plants. Furthermore, they state that the majority of closures cost between €440m and €880m in the USA. They provide an optimistic case of €465m, a pessimistic case of €865m and an average of €665m. 15% of the investment budget for the Paks II units equate to €1.9 billion, which is significantly higher than the REKK report's assumption, but significantly lower than the €2.4 billion assumption in the analysis of this report. Thus, the analysis of this report is much more conservative in relation to decommissioning costs than the REKK report.*

*The decommissioning assumption used in the **Aszódi** Report is HUF 2/KWh, which equates to over €6/MWh (real 2013). This figure originates from Section 69(1) of Central Budget of Hungary Act (Act CCXXX 2013) which dictates that the monthly contribution for the Paks I units. This cost, thus, is in relation to the older Paks units, which, being older generation units, and there being more units (although lower capacity), would be more expensive to decommission. The decommissioning assumption used in this analysis is based on the assessment of the Hungarian Central Nuclear Fund, and as such is the most up to date view of the cost.*

*Similar to the Aszódi report, the **Felsmann** analysis bases its decommissioning assumption on the Paks I units, being the contribution made in 2013, and uses the Aszódi report as a benchmark for the cost, which has been discussed above.*

5.2.3 Combined fuel, waste and decommissioning benchmarking

Figure 26. Estimated cost of fuel, waste and decommissioning for nuclear plants



Source OECD / IEA / NEA - Projected Costs of Generating Electricity (2015)

The fuel, waste and decommissioning costs have been built up from their component parts in the case of the fuel costs and forecasts from the Hungarian Nuclear Fund in the case of the waste and decommissioning costs, and come to €7.1/MWh (real 2013). This is in line with the OECD / IEA / NEA estimate of €7.4/MWh.

5.3 Depreciation

Improvements in Generation III+ reactor technology have resulted in a longer design operational life of 60 years from commissioning, with the potential to greatly exceed 60 years. The Paks II units have been designed and will be constructed in order to have a base 60 year operational life. While certain equipment will have a shorter depreciable life than the whole operating plant and will need to be replaced periodically, this would not be the case for the majority of the value of the tangible assets which are part of the core structure. The nuclear plant can be subdivided into different fixed assets, e.g. the nuclear island, turbines, equipment, etc., which would each have different depreciable lives and will be maintained according to this schedule. However, the bulk of the value will be the larger fixed assets which make up a part of the structure of the plant, as so would have the same operational life as the plant, i.e. 60 years. For this reason, it is a conventional shorthand assumption to depreciate the whole plant straight line over 60 years. In some countries, legislation has been enacted to define such 'full life' depreciation approach as an exemption from applicable more granular accounting rules.

*The **Felsmann** report assumes 2% annual depreciation for land and buildings, and 4% annual depreciation for technical equipment and machinery. This implies useful lives for the assets of 50 years and 25 years respectively. While certain equipment will have a shorter depreciable life than the whole operating plant, this would not be the case for the majority of the tangible assets, e.g. the land and nuclear island. This high depreciation charge has a significant negative impact on earnings, which leads to the significant negative retained earnings which the Felsmann report claims that the project company would have on balance sheet. As explained in the Felsmann report, negative equity on the balance sheet creates a requirement for the equity shareholders to inject more capital into the company, which negatively impacts the equity returns. Thus, this high depreciation charge is one of the causes of the negative results which the analysis in the Reports gives.*

An aggressive depreciation policy would create a tax shield for a company by reducing taxable profits without reducing the cash income of the business, which would reduce the tax owed each year. This may be rational for a privately owned entity, but given the Hungarian State ownership of the Paks II project, there is no overall state budget incentive from the owner's side to minimize the company's tax bill. Thus, a more moderate depreciation policy would be more appropriate for the company.

5.4 Tax

In addition to the main cash flows and depreciation, the remaining lines required to forecast the financial statements of the company have also been modelled. This includes tax and working capital. Tax is levied on the project company at the corporate tax rate of 19%, and is calculated both on a levered and an unlevered basis (i.e. including or excluding debt related cash flows). Operational period costs can therefore be stated at the Project Company with unlevered tax (i.e. excluding the tax shield of interest costs) and at the Hungarian State level with levered tax (i.e. including the tax shield of interest costs) due to the interest costs of the Financial IGA arising at Hungarian State level. As with most projects of this nature, during the construction and development period, when the plant is not receiving income from selling power, the company would build up tax credits, which it can utilise when operational to offset taxable income. Paks II benefits from the build-up of tax credits during the development phase, which act as a tax shield and offset profits made once in the operational period, meaning that little to no tax is paid in the early years. What this means is that in the early part of the operational period of the plant, it will have to pay less, and potentially even no, tax until all of the tax credits are used. The 'Robin Hood' tax that is levied on all energy suppliers in Hungary is assumed to be discontinued before the commercial operation of the units as it was instituted as an austerity period tax for relief to budgetary pressures and its long term continuation would lead to a disadvantageous impact for all Hungarian domestic generators vs importers. This tax is also not included in the calculation of LCOE costs in Chapter 4 above regarding prices. If the tax persists, it would either impact the LCOE and hence lead to higher domestic prices than those forecast and hence the additional cost would be at least in part mitigated by the higher prices. Should the tax persist, but assuming no increase in prices to compensate suppliers for the tax, this would have a material negative impact on project returns, leading to a fall of circa 1.5 percentage points.

*The **Romhányi** report assumes the energy suppliers' tax (the "Robin Hood" tax) would continue to be levied during the operational life of the Paks II units over and above normal corporation tax. While this has a negative impact on the economics of Paks II at a project level, as the Hungarian Government is the sole shareholder of the project, there is no value leakage from greater taxes, as it is the recipient of both dividends from the project and taxes paid by the project.*

*The **Felsmann** report assumes that the company is fully tax paying as soon as it becomes profit making and ignores the benefit which the operating company would incur from the tax credits built up over the development and construction period. It is common practice that taxable profits earned in the early years of operational period are shielded from tax charges due to these tax credits, meaning that little or no tax would be paid by the company for a period of time. This is in line with international fiscal practice for commercial entities, and is in no way a provision of State Aid. The lower taxes payable in the initial operating period mean higher earnings than represented in the Felsmann report. In the case of the Felsmann Report's financial analysis, this could save over €9 billion (nominal) for the operating company. This would reduce the equity shortfall that the Felsmann report calculates the company would face under the other conservative assumptions.*

5.5 Macroeconomic assumptions

The analysis assumes a 2% long term inflation rate over the operational life of the project, i.e. assuming a convergence to long run EU estimates. Due to the fixed nominal price of the EPC contract, it can be assumed that any cost inflation in the development and construction period relating to EPC scope would not require additional owner funding. Higher inflation levels however, if manifested in higher market power prices, could enhance project returns from higher operational period revenues. Operating period costs including fuel costs would likewise be exposed to cost inflation indices. The simplified modelling approach adopted for the purposes of this analysis does not seek to distinguish between different inflation rates.

The analysis is based in Euros and the Project is expected to be largely insensitive to foreign exchange rate fluctuations, as the construction cost maximum budget assumed is fixed in Euros, the market price is analysed in Euros given the high level of interconnection of the Hungarian power market, and a significant part of operational period expense, with the notable exception of labour costs, would be in Euros. Given that O&M costs are assumed in Euros due to the benchmarking approach taken, the analysis has been undertaken in Euros and has not required projections of foreign exchange rates.

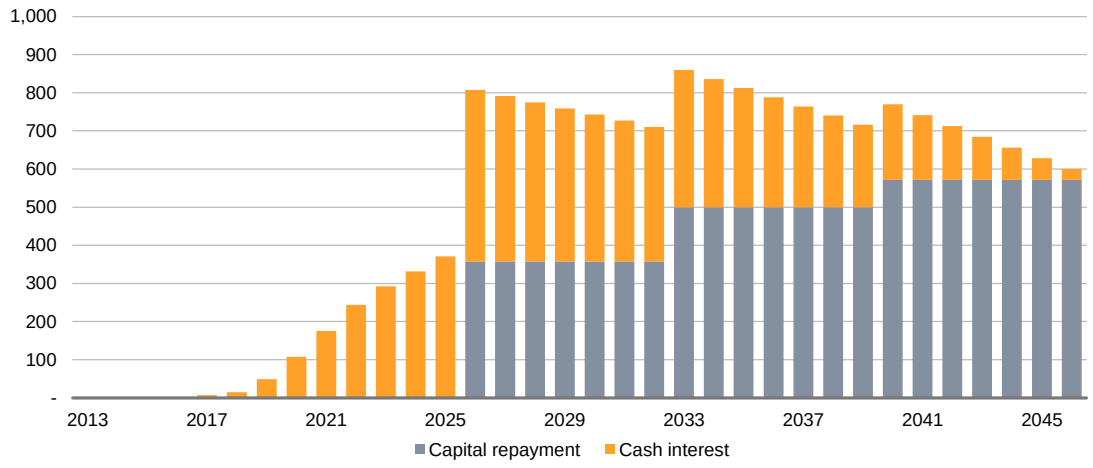
Notwithstanding the insensitivity of O&M costs to these macro assumptions, the various inflation and exchange rate assumptions used in other reports do impact the comparability of input assumptions due to the required conversion of forecast construction nominal costs to overnight (real today) costs.

6. Capital structure and cost of capital

6.1 Sources of capital

In the case of the Paks II NPP, the entire initial required capital is provided by the Hungarian State, which in turn draws for 80% of the capital needed on the intergovernmental loan provided by the Russian Federation to finance the sustaining and development of the capacity of the Paks NPP. The Financial IGA signed on 28 March 2014 stipulated the provision of state credit in the amount of up to €10 billion to Hungary for financing up to 80% of the Project. The loan has an average interest rate of c. 4.5% over the life of the loan, and has a 21 year repayment period starting from the earlier of the beginning of operations at the plant and 2026. The terms and tenor of the loan were very attractive, and the best available to Hungary at the time. The total debt service of the state credit, which is the sum of total interest and capital payments to be paid, is illustrated in the following figure based on an assumed disbursement and start of drawdown and interest payments from 1st January 2016 under the assumption that interest is not capitalised but paid during the construction period.

Figure 27. Total debt service requirements (€m nominal)



Illustrative

This structure, however, relates only to the initial capital financing. The Paks II NPP, however, will operate for 60 years and be generating cashflows that can support additional levels of debt during its operating lifetime. In order to use the cost of capital as a discount rate for cashflows throughout the life of the NPP, it is therefore necessary to determine an appropriate capital structure and cost of capital through the life of the Project including the full operational period and not just the construction period.

6.2 Weighted average cost of capital for the Paks II project

The cost of capital depends on the capital sources and on the remuneration required to compensate the providers of that capital for the risk that they are taking in supplying their capital. Debt providers typically require a lower return on their capital as they benefit from greater level of security, having first charge on the cashflows above equity holders. Equity holders, on the other hand, are paid back via dividends which are paid only where there is availability of funds and at the discretion of the company and by growth in the value of their

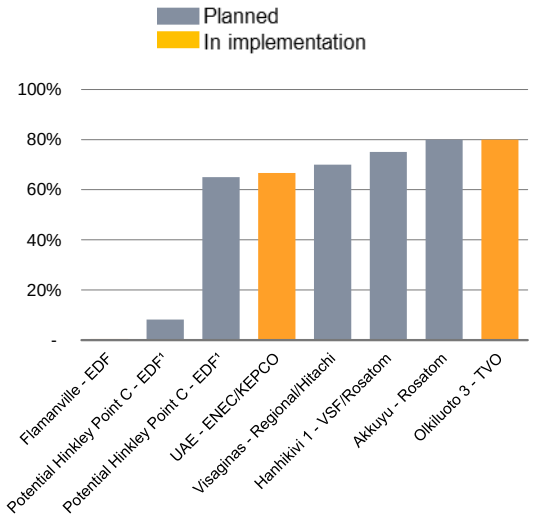
shares, which is dependent on market conditions. A fundamental WACC analysis to build up the nominal post-tax weighted average cost of capital (WACC) for Paks II is calculated below according to the methodology which states that a company's cost of capital is a weighted average of the company's debt and equity costs, where the weights are equal to the respective proportions of debt and equity financing, or algebraically:

$$WACC = \frac{E}{D+E} * R_e + \frac{D}{D+E} * R_d$$

where E and D represent the amounts of equity and debt respectively; R_e is the required return on equity, and R_d the cost of debt.

When considering the relative use of equity or debt over the life of the project, one has to consider both the construction phase and the operational phase. Assuming a conservative capital structure at Project level (i.e. no debt is raised at Paks II, just the funds from the Government of Hungary, which itself is 80% funded by the IGA) means 100% Government equity funding of the project until its commercial operations date. This would be consistent with the wide and varied structures used for financing of new nuclear power plants, where shareholder loan structures are typically used. Such shareholder loans can optimise tax shield efficiency for the project. In the case of EDF's Flamanville project, the project is being financed at the corporate level instead of the project level. Due to thin capitalisation rules, gearing (D/(D+E)) is usually not above 85%. During the operational phase, one could expect to be able to sustain a higher gearing level than during the construction phase. A 60-50% gearing during the life of the plant but maintaining a buffer of no debt prior to the end of operating life would imply a through life gearing of approximately 50-40%. This structure would be conservative compared to asset financings of over 70%. The lower gearing level assumption is bound by historic European utilities net gearing levels of c.40%, which enable utilities to maintain higher credit ratings than individual projects and maintain sufficient free cash flow generation over debt service for new investments to renew their businesses. These aspects are important for utilities valued on a perpetual dividend yield basis but less so for single asset companies that have a defined lifetime.

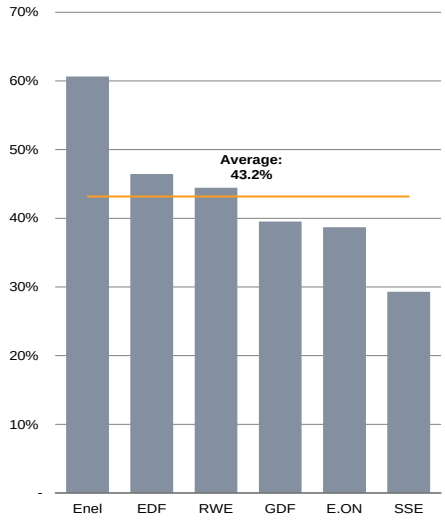
Figure 28. Nuclear projects (D/(D+E))



Source Public information

1. Range based on public announcements of Government guarantee from £2bn to £16bn

Figure 29. 5 year average gearing level of selected nuclear utilities (%)



Source Factset

Nuclear project investments present a capital allocation challenge for capital providers (shareholders or bondholders) that cannot accommodate a prolonged period without yield – the long nuclear project development and construction period in an unregulated market environment implies a long period of earnings dilution or cash flow to debt service ratio reduction that can put pressure on business rating and funding capacity. This timing impact should not be confused with the evaluation of overall investment proposition attraction, although it can be a critical hurdle for certain investors. If examined with a longer term investment horizon and on an NPV basis, nuclear investments can be attractive, with much better returns than alternative investment options, particularly in the current low growth environment.

Cost of equity

The Capital Asset Pricing Model (CAPM) can be utilised in order to estimate the cost of equity term (R_e). The CAPM is the standard theoretical framework for assessing the cost of equity in regulatory decision-making and by Competition Authorities. In setting the parameters for the CAPM, regulators and competition authorities rely on historical data, to take advantage of the large datasets of historical stock market returns and on forecasts, to take into account the direction in which macroeconomic and microeconomic variables are moving. The CAPM framework assumes that all risks are symmetric. Investors require additional remuneration for asymmetric risks where downside scenarios are not matched by upside scenarios.

The cost of equity can therefore be calculated as the sum of the risk free rate plus the country risk premium plus the business risk and any asymmetric project risk. The calculations and rationale for each of those rates is set out below:

- Risk free rate: Regulators and competition authorities typically assume that government debt is the most suitable proxy for the risk-free rate, and for a project in Europe the yield on the sovereign German Euro denominated bonds would be a suitable assumption for the risk free rate. Given the long term nature of the project the longest dated available bond is a useful proxy: In the period when the IGA and the Financial IGA were negotiated and signed (in 2014) the yield to maturity of German 30 year Bunds[46] was 2.0% (2014 average). Current rates are much lower at c.1.5% and therefore 2% likely overstates the true underlying WACC to the extent that the Project or its shareholder can refinance later post construction completion.

[46] Source - Bloomberg

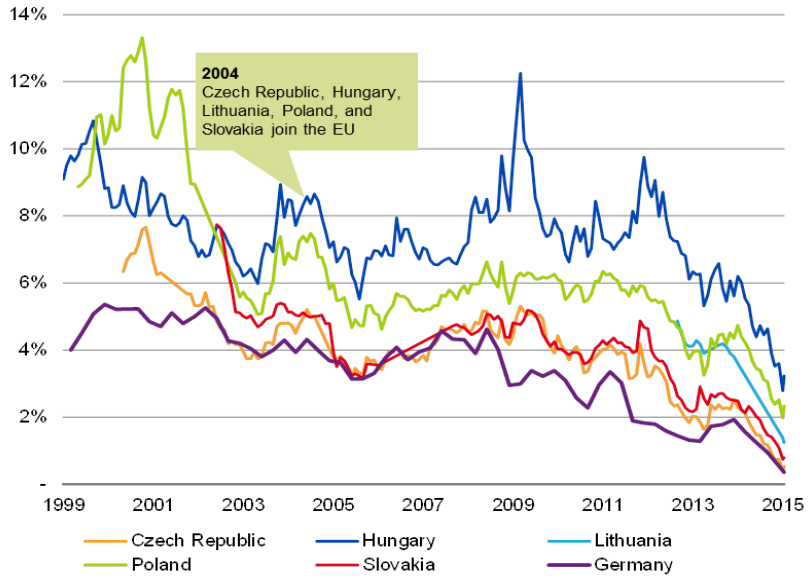
Figure 30. German 30 year bund yield (%)

Source Bloomberg

- *Underlying Bond:* The yield on sovereign German Euro-denominated bonds is a standard assumption for the risk free rate on the basis that German debt is amongst the most liquid debt in Europe with the highest credit rating. The 10 year bond yield as can be seen from Figure 31 shows steady declines since 1999.
- *Bond Tenor:* Given the long term nature of the project, the yield to maturity of German 30 year Bunds, being the longest-dated is the most appropriate tenor to use given the long operating life of the Paks II NPP.
- *Averaging Period***:** As can be seen from Figure 30, German bond yields have shown little sign of cyclicality over time. Moreover the current, general market expectation is that a low growth and low return market environment will persist for the foreseeable future. Accordingly, a short term average of the cost of debt at the time capital commitment for the project was secured provides a reasonable proxy for the risk free rate.

- Asymmetric country risk: given Hungary's rating, a premium is calculated based on the delta between Hungarian and German bond yields (of equivalent tenor).
  - Investors may demand additional remuneration for country risk. A common proxy for country risk is sovereign credit risk over and above the risk free rate. The 10 year premium for government bonds for Hungary and for other member states above the German bund shows that whilst spreads widened during the financial crisis periods, the general trend is of declining spreads reflecting increased EU integration. As can be seen in Figure 31, the difference between Hungarian and German 10 year bonds has been shrinking significantly, with a decline of c. 20% over the period in relative terms. The same holds true for other dated bonds, some deltas of which have declined even further. If a further 20% convergence is assumed before reaching steady state the current country risk premium of 2.7% would decline to 2.2% - representing a conservative long term average for the long 70 year life of the project when bearing in EU convergence targets. A range of 2.2% to 2.7% therefore seems appropriate for the calculation of equity risk.

Figure 31. 10 year Euro-denominated government bond yields[1]



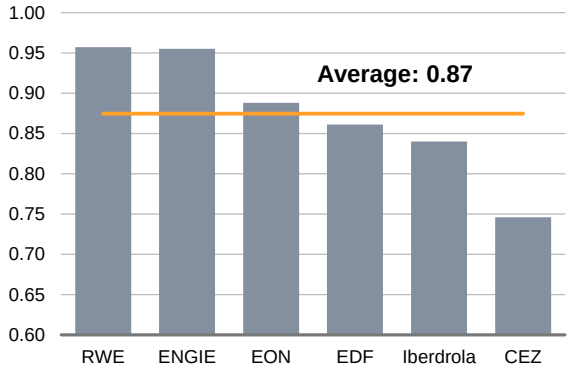
Note 1 Czech, Hungarian and Polish yields presented for local-currency denominated 10-year bond for lack of historical euro-denominated 10-year bond yield data

Source Bloomberg

- Business Risk: In the CAPM framework, business risk component of the cost of capital refers to the additional returns that investors require to invest in the business over risk free assets. Business risk is the product of two parameters that the analyst estimates separately: the Equity Risk Premium (ERP), which is the estimated difference between equity market returns and risk free returns, and the Beta (β), which is a measure of the observed volatility of the business considered relative to the overall market, such that Business Risk = β*ERP. The Business Risk thereby captures operational phase business risks, including power market price exposure, operations etc. for generation businesses that are part of the market index.
  - The Equity risk premium refers to the additional returns that equity holders require to invest in the market portfolio of equities rather than risk-free assets. In the context of the Hungarian market, the 10 year historical equity market performance relative to the risk free rate shows that the equity risk premium of the Hungarian market has a 10 year average of 4.0%[47].
  - Beta (β): In the CAPM framework, investors earn remuneration for non-diversifiable risks i.e. those risks that an investor cannot diversify by buying the market portfolio. In other words, required returns depend on the correlation, also known as the Beta, between the individual investment and the market portfolio. In principle, the Beta should be project-specific and depend on the correlation of each project's returns with the market. In practice, individual project-level returns are difficult to observe and analysts often rely on estimates based on equity holdings in comparable listed entities.

[47] Source – Absolute Strategy Research

Figure 32. European nuclear utilities equity betas



Source Bloomberg

- Power generating utilities, as comparators for Paks II, as a whole tend to have more stable returns than the market as a whole and equity Betas less than one. The higher the Beta, the higher the benchmark cost of equity. The equity betas based on NERA's analysis of the Hinkley Point comparator group used by the Commission ranged from 0.65 to 0.79[48] (see below). Figure 32 shows equity betas for utilities whose business portfolio includes meaningful exposure to existing operating nuclear power plants in Europe, which have an average beta of 0.87.
- A conservative beta of 1 or even higher at 1.1 can capture the lack of portfolio effect of a single project, implying the project is more sensitive to market price fluctuations than other operational portfolios used as benchmarks. If applied to the historical ERP, this would imply Business Risk of c.4.5. However, nuclear power plants have low variable costs and are less exposed to market price fluctuations that coal or gas plants that may need to stop operating at all rather than just receive less profits in periods of lower prices, emphasising the conservativeness of the assumption.

- Asymmetric project risks: In addition to any asymmetric country risk already reflected, there may be additional risks in construction or operation that are asymmetric and justify an additional risk premium. In the case of Paks II the downside asymmetric construction period risks of cost overruns and delays are mitigated by the fact that the EPC contract is nominal fixed price and turnkey, meaning that there is possibly an asymmetric macroeconomic *upside* as inflation in the economy can mean higher future revenues from the Project but without an increase in the fixed nominal cost of the Project.

The cost of equity based on the above therefore can be calculated to be between 8.7% and 9.2% comprising: the risk free rate of 2.0% plus the country risk premium of 2.2% to 2.7% plus the business risk and any asymmetric project risk of 4.5%.

Separately NERA examined the European Commission's ("Commission") decision on Hinkley Point C Nuclear Power Station, and where necessary, other evidence commonly employed by

[48] Generation utility subset of comparators from the Commission decision used, as deemed most appropriate for the analysis: E.ON, RWE, Centrica and GDF Suez

European Competition and Regulatory Authorities[49] and in particular drawing on the set of comparator companies that the Commission employed in determining the cost of capital for Hinkley Point. In its decision, the Commission identified a set of twenty comparators that were classified as "utility (general)". Of the set of twenty, NERA has identified four companies that own and operate generation assets rather than operating, solely or mostly, as network businesses. These are E.ON, RWE, Centrica, and GDF Suez. [50]

NERA's estimates a cost of equity between 8.5% and 9.7% for the set of EU comparators drawing on the following evidence:

- Total market return (TMR, equal to the risk free rate plus ERP): TMR estimate is based on long run historical returns to equity published by Credit Suisse Global Investment Returns Sourcebook (written by Dimson, Marsh and Staunton), a common reference point for equity market data. DMS reports a TMR for European markets over the period for which data are available (1900-2014) equal to 7% (real) or 9.5% in nominal terms (based on long-term forecasts for inflation in Hungary).
- Risk free rate: Set equal to the three month average of German government 10 year debt yield equal to 0.6%.
- ERP (equity risk premium): The forward-looking ERP is calculated as the nominal TMR minus the risk free rate, i.e. 9.0%.
- Beta: Estimated using the most recent two-year equity market data. The asset beta estimates lie in the range of 0.36 (RWE) to 0.48 (GDF SUEZ) (see table below).

	European Genco				Data source
	E.ON	**RWE**	**Centrica**	**GDF SUEZ**	
Country	Germany	Germany	UK	France	
Indices	DAX	DAX	UKX	CAC	
Equity beta	0.75	0.79	0.65	1.01	Bloomberg
Gearing	0.45	0.54	0.26	0.52	Bloomberg, 2Y average of daily gearing
Asset beta	0.41	0.36	0.48	0.48	Asset beta=Equity beta*(1-Gearing)

- CRP: Based on the difference between Hungarian and German sovereign spot yields. [51],

Cost of debt

The cost of debt is effectively the debt interest charged on debt after the tax shield effect - i.e. Debt interest rate x (1 – Tax rate) = cost of debt.

- The cost of debt for the Project (rather than for Hungary under the IGA) during the construction period is likely to be the cost of raising Euro denominated long term debt in Hungary with a premium appropriate to the project. The Hungarian government longest

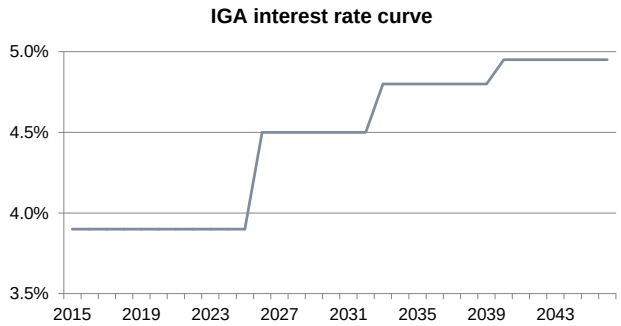
[49] European Commission (October 2014) COMMISSION DECISION of 08.10.2014 ON THE AID MEASURE SA.34947 (2013/C) (ex 2013/N) which the United Kingdom is planning to implement for Support to the Hinkley Point C Nuclear Power Station

[50] European Commission (October 2014) op. cit, Table 15, Annex A.

[51] CRP is calculated as the 3-month average of the difference between Hungary and German 10Y sovereign real yields daily data. The real yield is derived by deflating the nominal yield provided by Bloomberg with 10-year inflation forecast of the corresponding country.

dated (15 year) bond is currently trading at c. 3.9%[52] on top of which a premium would need to be added for Hungary's country risk, the longer maturity of the loan, as well as the sponsor and project risk premium. This premium for longer maturity and project risks appears to be 60 basis points as the actual project loan under the Financial IGA for 21 year repayment period is priced at an average rate of c. 4.5%.

Figure 33. Financial IGA interest rate curve



Source Russian – Hungarian Finanincing IGA

- International benchmarks for the construction period rate are few, but Scana (US utility) issued 30 year bonds priced at 4.6% which could be a proxy US benchmark for a new nuclear build, still in construction period.
- Despite these considerations the Paks II project is assumed to be equity capitalised during construction (requiring the much higher equity returns) and the cost of debt benchmarking during construction is used as a guide (or rate ceiling) to operational phase financing when project risks are further mitigated.
- Cost of debt assumptions in the operational life would be lower than during the construction period as the project risk has been largely removed, and nuclear plants are baseload, low marginal cost plants, and so have stable income streams. The cost of debt in this period can be benchmarked to European nuclear utilities corporate bonds. The longest dated corporate bonds in issue have an average yield of 3.6%. The cost of debt for the Paks II project would be at a premium to long dated bonds for utilities given their scale and the diversification of their businesses, both in terms of multiple and different technology generation plants, but also their non-generation businesses. Please refer to Figure 34, which also shows declining coupons for each issuer over the last few years.

[52] Source - Bloomberg

Figure 34. Cost of long term debt of European nuclear utilities

Company	Issue date	Bond life (years)	Quantum (EURm)	Coupon	YTM
EDF	Jan-13	Perpetual	1,250	5.4%	4.7%
EDF	Jan-13	Perpetual	1,250	4.3%	3.6%
EDF	Jan-14	Perpetual	1,000	5.0%	4.3%
EDF	Jan-14	Perpetual	1,000	4.1%	3.4%
RWE	Sep-10	Perpetual	1,750	4.6%	1.8%
RWE	Dec-12	30	100	3.5%	4.6%
RWE	Feb-13	30	150	3.6%	4.6%
GDF	Jul-13	Perpetual	750	4.8%	3.9%
GDF	Jul-13	Perpetual	600	3.9%	3.3%
GDF	Jun-14	Perpetual	1,000	3.9%	2.8%
GDF	Jun-14	Perpetual	1,000	3.0%	3.6%
CEZ	Aug-12	45	50	4.5%	3.3%
CEZ	Aug-12	45	50	4.4%	3.2%
CEZ	Sep-12	45	80	4.4%	2.9%
Average				**4.2%**	**3.6%**

Source Bloomberg

The low delta between the construction and operational period cost of debt is consistent with a significant transfer of construction period risks to the EPC provider as would be consistent with a turnkey fixed price EPC contract, leaving little project risk difference between construction and operational phases.

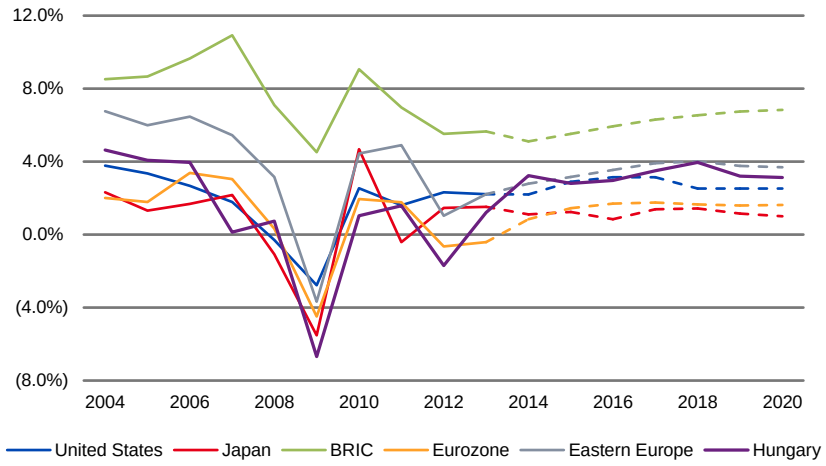
When applying the tax shield at 19.0%, being the Hungarian tax rate, the cost of debt can therefore be calculated as 4.5% x (1-19.0%) = 3.6%.

NERA benchmarked these findings to EU Comparators' cost of debt, drawing directly on the debt costs for the four comparators set out by the Commission, which lie in the range of 4.04% to 4.54%.

	European Genco				Data source
	E.ON	RWE	Centrica	GDF SUEZ	
Nominal CoD (pre-tax) %	4.04	4.54	4.44	4.44	Commission Decision for Hinkley

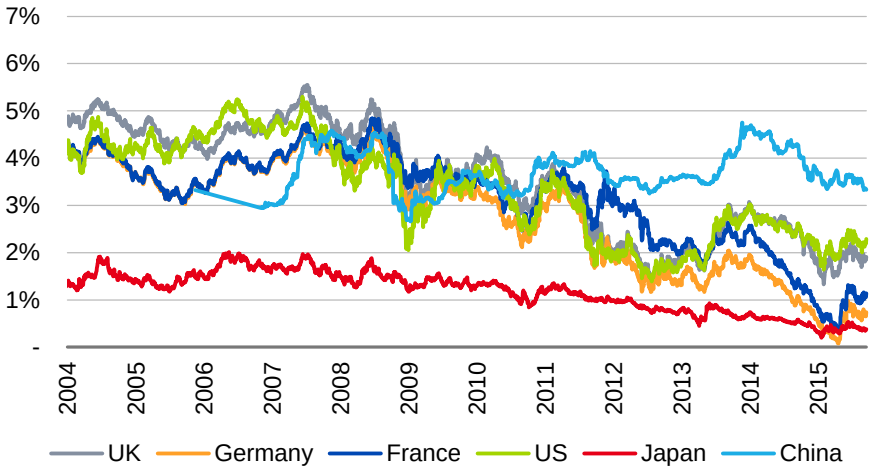
Further benchmarking can be done by reference to the macroeconomic environment, which sets the parameters for the cost of capital in the global context. Currently a low growth environment which is forecast to continue with anticipated growth rates remaining below pre-crisis levels of 2006-2007 sustains long term access to low cost debt financing for utilities. Government bond yields have also fallen significantly in recognition of the lower growth environment (in some countries to negative levels) and also due to new money injected into the global economy via the quantitative easing programs of the Federal Reserve, ECB and the Bank of England. Hoping to jump start lending and fuel the economy the Federal Reserve has injected c. US$3.5 trillion into the markets. This low growth, low return environment has meant that globally there is significant capital seeking yield assets and pushing down return expectations for higher risk assets and geographies.

Figure 35. Real GDP growth



Source IHS

Figure 36. Falling Government bond yields



Source Bloomberg

Some of this funding availability and low cost is flowing through to new nuclear projects. Examples include funds earmarked by the Russian Government in 2014 for Fennovoima project; CGN raising US$240m in 2013 at a coupon of 3.58%, having raised the same amount in the previous year at a coupon of 3.75% and Japanese Government legislative and financial support to the International Nuclear Energy Development of Japan (JINED).

Cost of debt assumptions in the operational life would be lower than during the construction period as the project risk has been largely removed, and nuclear plants are baseload, low marginal cost plants, and so have stable income streams. The cost of debt in this period can be benchmarked to European nuclear utilities corporate bonds. For example corporate bonds in issue with less than 10 years maturity indicate an average of 0.9% for Euro denominated debt.

Figure 37. Cost of short term debt of European nuclear utilities

Company	Issue date	Bond life (years)	Currency	Quantum (m)	Coupon (%)	Yield (%)
EDF	22-Jan-14	3	USD	1,000	1.2%	1.2%
EDF	22-Jan-14	3	USD	1,000	1.2%	1.2%
EDF	22-Jan-14	3	USD	750	0.7%	0.7%
EDF	22-Jan-14	3	USD	750	0.7%	0.7%
EDF	22-Jan-14	5	USD	1,250	2.2%	2.1%
EDF	22-Jan-14	5	USD	1,250	2.2%	2.0%
RWE	30-Jan-13	7	EUR	750	1.9%	1.6%
GDF	01-Jun-12	4	EUR	1,000	1.5%	0.3%
GDF	20-Jul-12	5	EUR	750	1.5%	0.3%
GDF	10-Oct-12	5	USD	750	1.6%	1.5%
GDF	10-Oct-12	5	USD	750	1.6%	1.5%
CEZ	27-May-11	5	EUR	500	3.6%	0.1%
CEZ	27-Nov-14	3	EUR	45	0.3%	0.4%
PGE	09-Jun-14	5	EUR	500	1.6%	1.3%
Enel	26-Feb-10	6	EUR	1,000	0.8%	0.3%
Enel	26-Feb-10	6	EUR	2,000	3.5%	0.3%
Enel	20-Feb-12	6	EUR	500	3.1%	0.5%
Enel	15-Oct-12	6	EUR	1,000	3.6%	0.7%
Overall average					1.8%	0.9%
Euro average					2.2%	0.5%

Source Bloomberg

*The **Felsmann** report assumes an 8% cost of debt on any short term loans required to bridge funding gaps during the operational period of the plant, but provides no justification for this assumption, which seems high.*

Firstly, the report assumes that, despite the large quantum of debt required in order to bridge the funding gap, the Paks II operating company would raise debt during the operational period through short term facilities such as a revolving credit facility, which would likely be more expensive than a term loan or issuing bond. Given the size and regularity of funding gaps assumed by the Report, this would not be the commercially rational approach to take. Rather, it would make sense to lever the company up in anticipation of the need, and thus reduce the debt service requirement.

Moreover, if the shorter dated bonds of the bonds are considered, i.e. 5 years, the average, considering both Euros and US Dollars, falls even lower to 1.5%. Please refer to the table above. Even though Paks II is a single asset company, a 500+ bps risk premium seems overly excessive.

WACC

As mentioned above, the WACC is the remuneration, according to conventional theory, required for equity and debt capital providers to accept the risk of a project, weighted by the gearing level of the project, and is calculated based on the following formula:

$$WACC = \frac{E}{D+E} * R_e + \frac{D}{D+E} * R_d$$

The bottom-up calculation of the cost of equity results in a range of 8.7% to 9.2%, which is made up of the risk free rate of 2.0% plus the country risk premium of 2.2% to 2.7% plus the business and asymmetric project risk of 4.5%. The resulting cost of debt from the benchmarking is 4.5%, which, after taking account of the 19% tax shield (being Hungary's corporate tax rate), gives a post-tax cost of debt of 3.6%. From these constituents, and based on a gearing range of 40% - 50%, the implied WACC range is:

- Nominal post-tax WACC low = (8.7% cost of equity x 50% equity) + (3.6% cost of debt with tax shield x 50% debt) = **6.2%**
- Nominal post-tax WACC high = (9.2% cost of equity x 60% equity) + (3.6% cost of debt with tax shield x 40% debt) = **7.0%**

An LCOE analysis that includes this financing cost (the WACC) can enable comparison of projects and a test for viability against anticipated market prices. However, comparing the WACC itself across different projects can be misleading as capital remuneration requirements are intrinsically linked to the risk assumed by those capital providers which differs across projects and jurisdictions and capital sources and structures used can be different.

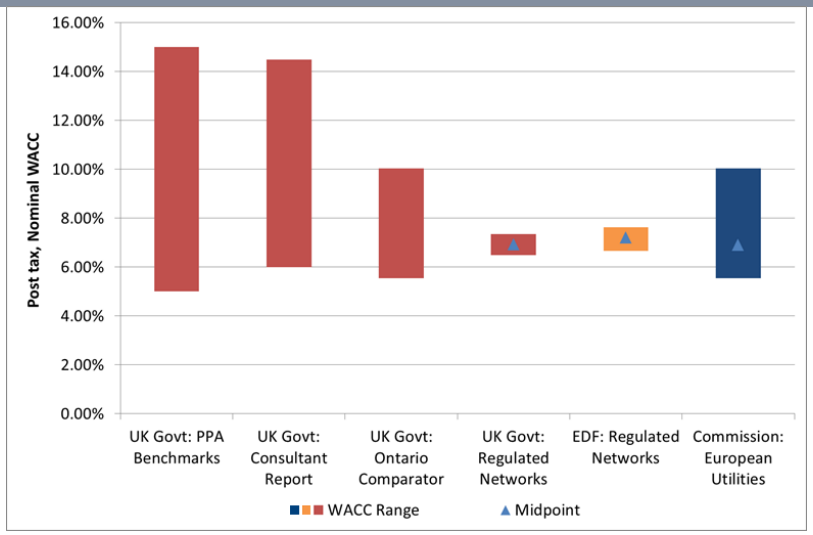
Notwithstanding this, benchmarking analysis has been conducted on cost of capital ranges. Drawing on the evidence for equity and debt costs for the European Commission's comparator companies used in the State Aid analysis for Hinkley Point C, NERA estimates a range for the cost of capital between 6.2% and 7.2% (nominal post tax), which, while based on an independent set of assumptions and analytical approach to that shown in the prior section, is fully in line with the 6.2% - 7.0% range identified as relevant for the Paks II project. Were NERA to assume the same gearing for the project as in this analysis, their implied WACC would be c.6.6%.

Figure 38. WACC benchmarking

Parameters	Definitions	Sources	Lower-bound (%)	Upper-bound (%)
Real Total Market Return	Long-run RFR plus ERP	Credit Suisse Global Investment Returns Sourcebook 2014, written by Dimson, Marsh & Staunton (Europe TMR)	7.0	7.0
Inflation	Hungary inflation forecast (2015-2024)	Consensus Economics	2.5	2.5
Nominal Total Market Return	Real total market return plus inflation	NERA calculation	9.5	9.5
Nominal Risk-free rate	3M average of Germany Gov 10Y Bond Index	Bloomberg	**0.6**	**0.6**
Nominal Equity risk premium	Nominal TMR minus nominal RFR	NERA calculation	**9.0**	**9.0**
Country risk premium	3M average of spread between German and Hungarian **real** risk-free rate	NERA calculation	**2.1**	**2.1**
Asset beta	Range of selected European Gencos asset beta	Bloomberg, NERA calculation	0.36	0.48
Gearing	Range of selected European Gencos gearing	Bloomberg, NERA calculation	0.54	0.26
Equity beta		NERA calculation	**0.79**	**0.65**
COST OF EQUITY	**Nominal RFR+Equity beta*ERP+CRP**		**9.7**	**8.5**
Nominal pre-tax cost of debt	Range of selected European Gencos cost of debt	European Commission Decision for Hinkley Point	4.0	4.5
COST OF DEBT			**4.0**	**4.5**
GEARING (1)	Range of selected European Gencos gearing	Bloomberg, NERA calculation	**0.5**	**0.3**
Nominal, vanilla WACC			**6.6**	**7.5**
Tax			0.2	0.2
Nominal, post-tax WACC			**6.2**	**7.2**

NERA collected all the cost of capital benchmarks that were considered and subsequently published as part of the Hinkley Point Decision. The graph below sets out the estimates that could be converted into a common unit (post-tax, nominal WACC). As can be seen from Figure 39, the range for each of the sources submitted spans a wide range of c. 5% - 15%. Moreover, the Commission researched its own evidence shown in blue, based on the WACC of "general utilities" in a dataset published by a US finance academic, Damodaran. The Commission's results are typically lower than those submitted by the UK government and the midpoint of the Commission's numbers is 6.9%.

Figure 39. Cost of capital benchmarks



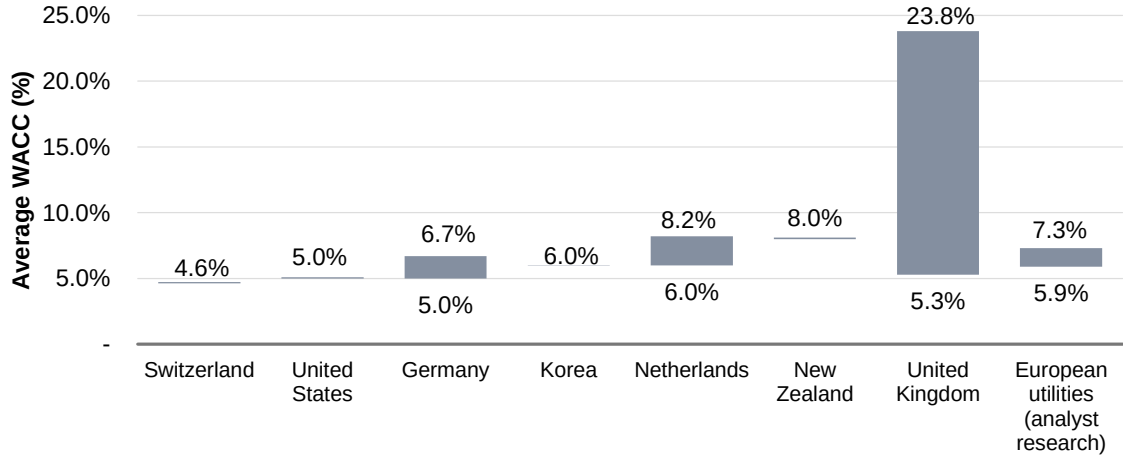
Source European Commission – Hinkley Point C decision

Notes The graph excludes two estimates which it was not possible to convert into post-tax nominal terms, both estimates of the cost of equity. The first was based on infrastructure transactions in Europe by infra-funds, giving a nominal COE of 9-16%, and the second was a COE for PPAs in Abu Dhabi of 13+%).

In the Commission Decision for the Hinkley case the finding of a market failure, as described in paragraphs 382 that merited investment aid (para 346) was based on the "lack of market-based financial instruments, as well as other types of contracts, to hedge against such substantial risk". In the case of the Paks II Project the nominal fixed price EPC contract acts as the construction risk absorbing instrument that the market failed to provide in the timetable required for the first new nuclear plant in the UK and which thereby gave rise to the first market failure identified by the European Commission in the Hinkley Point C State Aid case. The Project's EPC contract mitigation of the key risks of project delay and cost over-run is therefore a key differentiator to Hinkley Point C, which make WACC comparison inappropriate between the projects. A WACC comparison is also inappropriate as, for example, the WACC range identified for Paks II may seem low compared to WACC requirements for investments without an EPC contract framework (as discussed in Chapter 3) and yet it is higher than the 5% nominal WACC indicated by the market for a US electric utility as reported in the OECD / IEA / NEA report and in line with market implied cost of funding for European utilities. Comparing projects on WACC basis also does not capture the extent to which the project returns exceed the WACC – i.e. the extent to which a project is NPV positive, noting that a project is economically rational if the return is equal or greater than the WACC.

The questionnaire published in the OECD/ NIA/IEA report regarding required returns and costs of capital for new projects (presented in summary in Figure 40) shows the ranges and average results of a questionnaire on the cost of capital for non-regulated generation technologies in different central European countries. This indicated that the UK has a significantly higher cost of capital than the other countries and the widest range. The UK power market has faced significant changes in energy policy in the recent past, especially in relation to subsidies and support for power generators, which is leading to the addition of a regulatory risk premium being applied to the cost of capital in the UK. The magnitude of the risk is significant as has been seen by generators such as Eggborough and Drax which lost biomass subsidies they were expecting to receive, leading to material reductions in value, which may partially explain the noted premium to cost of capital compared to other parts of Europe.

Figure 40. Survey of cost of capital for generation technologies

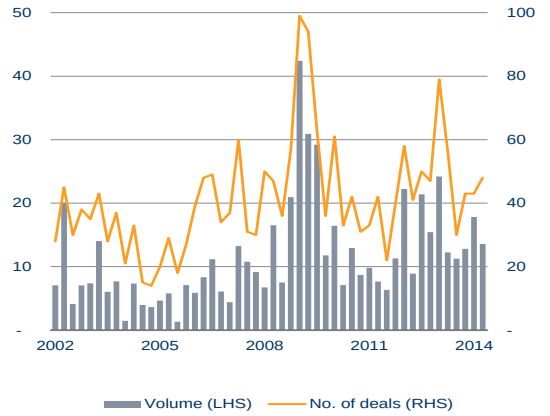


Source OECD / IEA / NEA - Projected Costs of Generating Electricity (2015)

Another useful benchmark is the WACC of the European utilities (of which the summary analyst research range is included in Figure 40), including those that own nuclear generation plants. In the existing macroeconomic environment, the utilities have been able to continue raising significant long term debt capital via bond issues at falling costs of capital together with trading

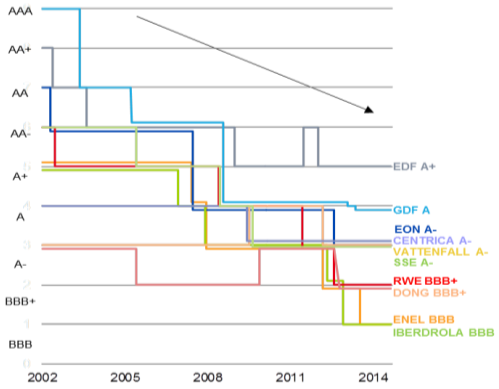
of listed shares at a growing premium to government bonds and to regulated asset values. This has been despite falling credit ratings and greater indebtedness. As utilities have access to long dated bonds with decreasing coupons, their WACCs, and thus their required rates of return, can also be assumed to be decreasing if business risk remains constant.

Figure 41. European utilities' bond issues, 2002-2014 (€ billion)



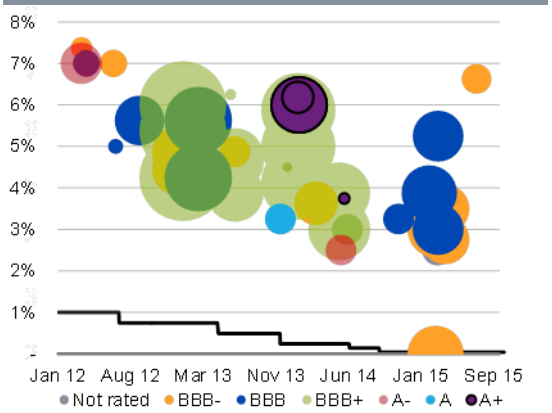
Source Dealogic

Figure 42. Credit rating evolution of European utilities, 2002-2014



Source S&P, Company information

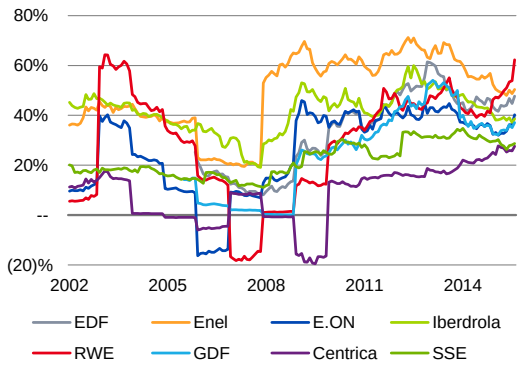
Figure 43. Corporate bonds >60 years vs ECB interest rates (%)



Source Dealogic

Note Size of dot indicates issue size. ECB refinancing rate shown as a line

Figure 44. Gearing (D/(D+E)) of European utilities(%)



Source Factset

The most significant decline in cost of issued bonds is in the longest dated bonds. The continued bond issuance by utilities has meant that gearing has remained higher and more stable.

The allowed returns in the regulated network sector tend to be lower than in the market exposed non-regulated sector due to the exposure to market price risk. Similarly the WACC for generation assets in Europe are higher than the WACC for overall utility portfolios that include regulated transmission and distribution assets. The integrated utilities and generators that do face market price risk and nuclear risk have average WACCs from 5.9% to 6.7% based on brokers' views, which is a relevant benchmark for the Paks II project given its anticipated exposure to market price risk, construction risk protections during the construction period and the majority of the investment life will occur post construction. There has been a noted reduction in allowed returns imposed by regulators on regulated assets as a reflection of the economic environment. Generation business WACCs/IRRs range from 6.5% - 8.4% for utilities with nuclear capacity in their portfolio. EU utilities with a high weighting of nuclear (EDF, E.ON, CEZ, RWE, Engie, Enel and Iberdrola) do not exhibit a risk premium compared to peers with limited or no nuclear exposure (SSE, EDP, Verbund and Gas Natural. These WACCs/IRRs are the capital costs that the utilities trading valuations and investment analysts attribute, meaning they are representative of the cost at which the utilities can raise finance for new projects, not just a reflection of the returns on capital from existing operations (hence not ex post but also ex ante). Certain brokers even provide specific indications of cost of capital assumptions for new build projects. Whilst the nuclear operating WACCs cannot be used directly to benchmark new projects where there is exposure to construction period risks, they are relevant benchmarks for the operational period and for projects where the construction cost risk has been mitigated through a fixed price turnkey contract, as is the case for Paks II.

The prior studies of Paks II also require an assumption on cost of capital to ensure full viability evaluation. Those assumptions are examined and critiqued below.

*In determining the WACC for Paks II, **REKK** considers two sources: published literature and Hungarian regulatory requirements. The report applies a geographical risk premium of 2% to the historic publications of 8% - 9% average for WACC for nuclear power plant projects. The report then applies a 2% - 3% premium to the c. 6% cost of capital outlined by the Hungarian regulator for the transmission and distribution market. This results in a WACC range assumption of 8.0 - 11.5%. The latest update of the REKK report, which aims to incorporate the terms of the Financial IGA, uses a WACC of 8% as opposed to the previously used 10% as the base case. These are real, post-tax WACCs and would need to be increased by the long term inflation assumption (2%) in order to be converted to a nominal post-tax WACC.*

The higher WACC figure may be attributed to the fact that the literature, from which the first method of WACC calculation is derived, was published from 2004 – 2012 when interest rates were higher than they are today. It is also worth noting that the source of the geographical and sector risk premium applied in each method is undisclosed.

*While methodically applying accounting rules in its financial modelling of dividends, the **Felsmann** report misses fundamental corporate finance principles on the ranking of debt and equity and rational economic behaviour. According to the model, dividends are paid whenever there are sufficient distributable reserves and a profit is made, whether or not there is a funding need, which it assumes is satisfied through very large short term expensive loans. A rational investor would not distribute dividends when there is a cash shortfall in the business, especially given the high assumed cost of debt on the funds used to fill the gap in the Felsmann report, as this would further exacerbate the shortfall. Equally, lenders would not permit such distributions to equity shareholders and simultaneous borrowing for funding shortages. More likely, dividends would be withheld until there was no funding gap and short term loans would only be utilised for*

working capital needs. In short, the methodology applied in the Felsmann report creates an additional funding cost which would not arise in any real corporate funding structure, leading to even lower free cash flow. In real corporates dividends can only be paid when the company has distributable reserves and available cash and when it would be appropriate and rational (not when it would lead to a greater necessity to borrow at a higher cost than the cost of capital just returned to shareholders through the paid dividend).

Similar to Felsmann's report, Dr. ***Aszódi's*** *cost based methodology imposes an annual requirement on the project company to remunerate equity irrespective of cash flow availability. In his report, he assumes an 8% 'interest rate' on the equity provided to the project, which is charged through the P&L on an annual basis. In other words, equity is being treated like debt and receives a fixed remuneration. While this may be true at the Hungarian Government level, should the Hungarian Government finance its equity portion through a sovereign bond, this would not be a cost at the project level. Rather, the Hungarian Government's return would be based on the dividends it receives from the project company, which would need to be sufficient to provide a market-rate of return whichever way the Hungarian Government chooses to fund its equity portion of the project. Further, the Hungarian Government 15 year bond rate is currently yielding c. 3.9% (which is the effective cost of debt), which is significantly lower than the 8% rate assumed in the Aszódi report.*

The ***Romhányi*** *report considers the project from the Hungarian Government's view point, and in stating a 7% cost for the equity portion of the project, is considering the cost of capital for the Hungarian Government, which could finance the project through the issuance of a sovereign bond. This analysis is appropriate for a fiscal review from the Hungarian State's perspective. The analysis of this report is on a project level. Furthermore, as indicated above, current State cost of debt of c. 3.9% is significantly below Romhányi's 7% assumption.*

In summary the 6.2-7.0% WACC identified should not be confused with the Government cost of funding, nor compared to the costs of capital for other projects that may have different funding structures or risk exposures. This financing cost, however, is relevant as it needs to be included in LCOE analysis so as to enable comparison of projects at LCOE level and analysis of the LCOE relative to anticipated market prices. The WACC also presents the hurdle rate that must be beaten by the anticipated project returns in an NPV/IRR analysis based on anticipated market prices. This is examined in the next and final chapter.

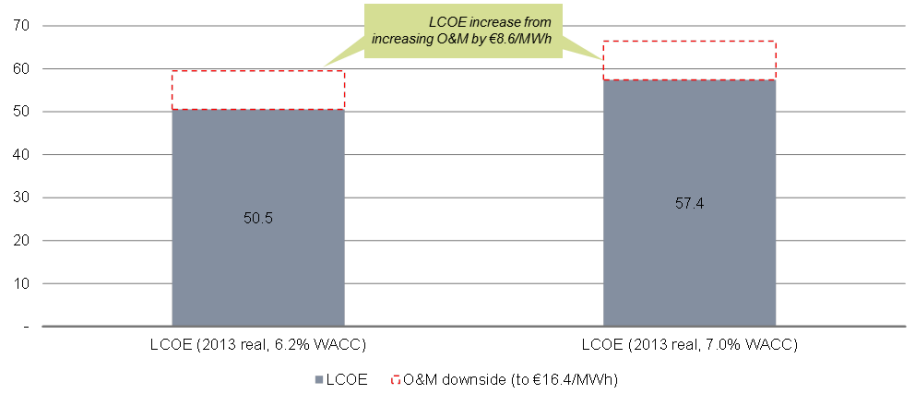
7. Summary findings

On the basis of the analysis which has been elaborated in this report, a set of assumptions, supported by publicly sourced benchmarks, have been utilised in the financial modelling used to evaluate the economic viability of the Paks II Project under a range of market price scenarios.

7.1 LCOE results

The Paks II project WACC (6.2% - 7.0% nominal cost) was calculated using a bottom up methodology in order to assess the cost of capital which would be appropriate for the project level. The WACC range sets the hurdle rate and enables project specific LCOE analysis. On the basis of the methodology described above, the financial analysis results in an LCOE for the project of €50.5 - €57.4/ MWh (2013 real) terms. Figure 46 provides an overview of the detailed results of the cash-flow based LCOE calculation:

Figure 46. Results of cash-flow based LCOE calculation



As would be expected, the capital costs makes up the majority of the LCOE. Due to the typically larger size of the units, and the high unit costs of the investment, the financing need of a nuclear power plant is larger than that of other types of power plants on the basis of other technologies.

These LOCEs compare favourably to the anticipated market prices identified in Chapter 4 and to LCOEs of other generation sources, indicating the allocation of funds to the Paks II Project would be on the expectation of commercial remuneration of allocated capital and further upside returns.

7.2 NPV / IRR results

Another way to compare across projects is to calculate the anticipated return of the project under projected price scenarios, which is equivalent to the WACC which would lead to the project being NPV neutral (i.e. a zero NPV). The potential cashflows of the Project, based on identified input assumptions sourced from a benchmarking exercise of publicly available data, reveal that the revenues received over the operational life significantly exceed the costs for the nuclear project, and ensure a return on the overall project for the capital provider. Figure 47

shows the project cashflows and indicates that based on the benchmarked assumptions, no equity injections would be required in order to finance the project after the start of operations.

Figure 47. Illustrative cumulative cash flow profile for Paks II project (€ billion)

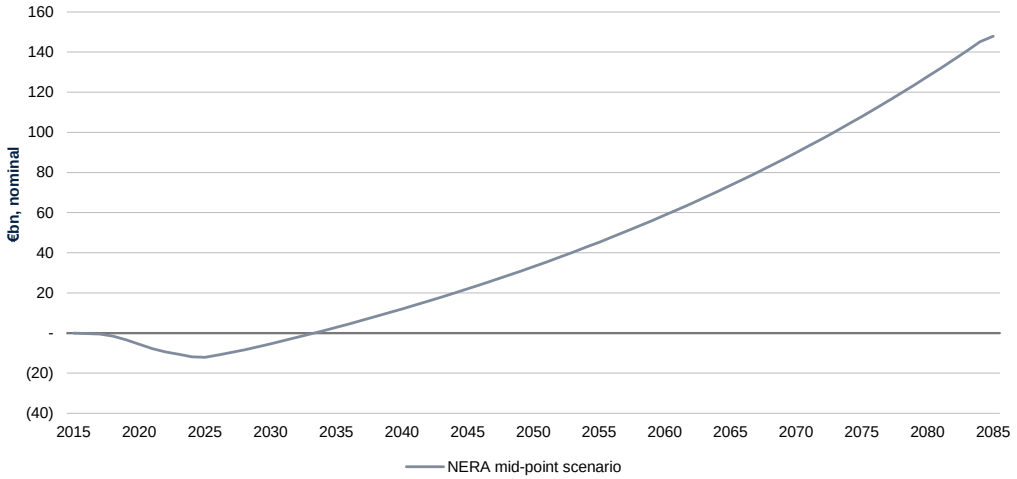
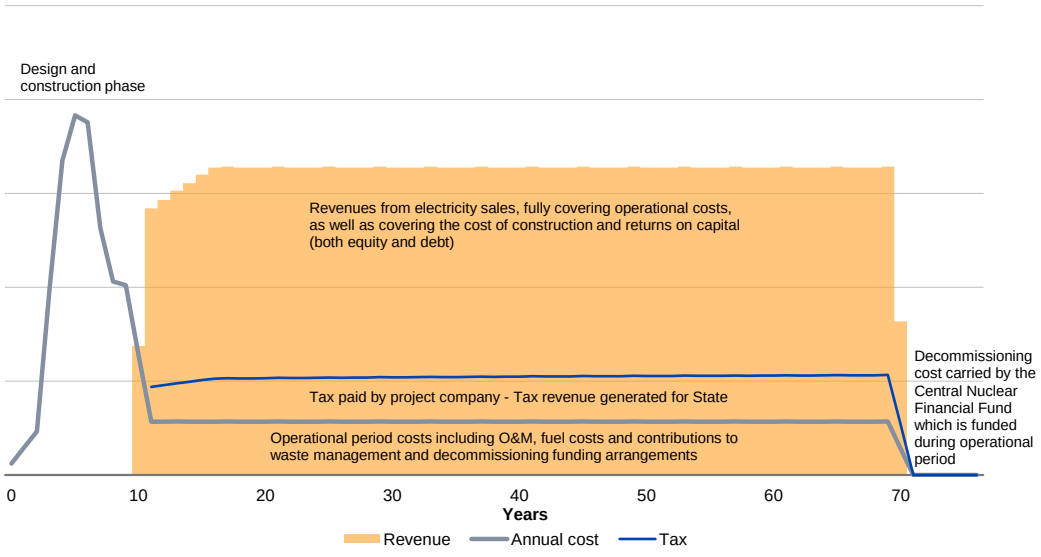


Figure 48 shows an illustrative cash flow profile range for the project based on the €12.5 billion project cost, and the mid-point curve described in Chapter 4 based on long term LCOE analysis by NERA with a long term price level of €86/MWh (real 2013). Although the shareholder will be earning dividends from COD, the breakeven point in this scenario would be in 2034 – a 9 year payback period after commercial operations commence (seen in Figure 47).

Figure 48. Illustrative cash flows for a nuclear project

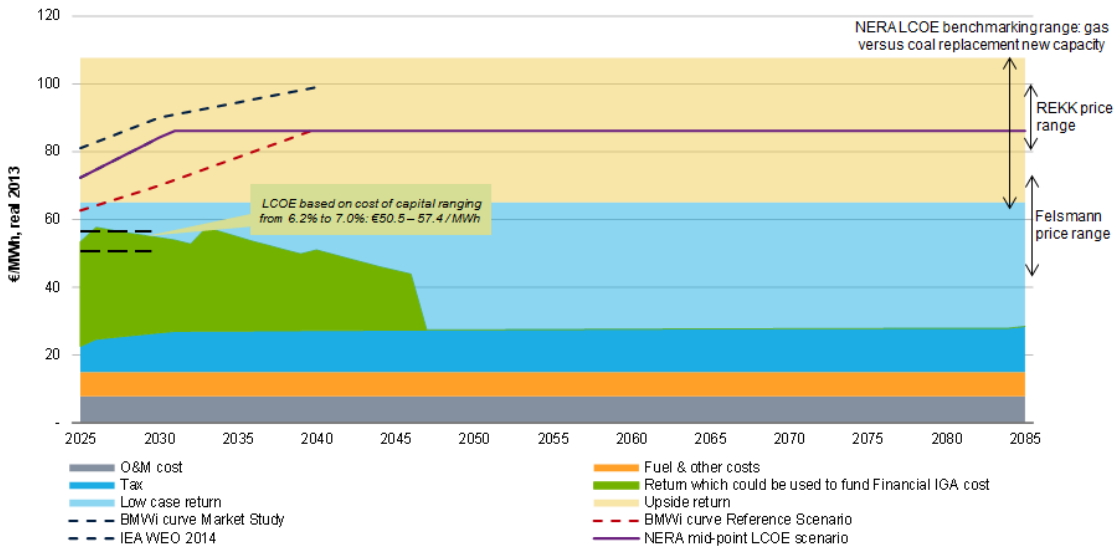


As Figure 48 illustrates, the revenues generated under the mid-point case price curve described in Chapter 4 during the operational period are anticipated to be sufficient to cover the annual costs of operations, including funding of waste management and decommissioning and the payment of taxes. The remainder of free cashflows illustrated are available to be returned to the

shareholder (the Hungarian State) to pay for the construction cost, including remunerating for the costs of using the construction period finance (i.e. a return on investment, which is greater than the cost of capital). This, as can be seen in Figure 49, is adequate to enable the State to cover the costs associated with repaying the Financial IGA (area in green) and to receive a return of its funds used with returns commensurate with typical benchmarked requirements.

Figure 49 illustrates the different cash flows which the project faces on a €/MWh real 2013 basis during the operational life of the plant. The first three shaded regions (the grey, the orange and the blue) represent the costs which the project faces, being the O&M, fuel, waste and decommissioning, and tax on an annual basis. The green shaded area represents the debt service costs to the Hungarian State in relation to the Financial IGA, which it is able to fund from the returned capital in those years and which declines as the debt is repaid over the 21 year loan life. The light blue area, which lies above all the costs, represents the minimum free cash flow which the plants generate, being the difference between the bottom end of the NERA LCOE benchmarked price range (€65/MWh real 2013) and the sum of the costs. This can also be viewed as the return to the shareholder on the project, once all cash calls are paid, over and above the payments to the shareholder that are used for the IGA debt service. The light brown area above this is the further return which the shareholder would receive if prices are higher than at the bottom end, capped by the top of the NERA LCOE benchmarked prices (€108/MWh real 2013). What Figure 49 shows is that over the operational life of the plant, based on the benchmarked prices, the plant would not only be self-funding, i.e. the revenue generated covers all costs, as well as the debt service costs, but would also provide a return to the shareholder to compensate for the initial investment. Even more, given the LCOEs for the project to generate a 6.2% - 7.0% return are below the bottom end of the range of prices, the project, in all these price scenarios, would generate a greater than 7% return, and thus would be NPV positive.

Figure 49. Illustrative commercial viability of the project (€/MWh real 2013)



The results of benchmarking the financial analysis indicate that on the range of identified possible future power prices, the project is NPV positive. The mid-point price case assumptions that relate to a long term price of €86/MWh (2013 real) described imply an IRR of 9.0-9.6%, which are in line with Hinkley Point C[53] anticipated returns (and consistent with basis of analysis being the lower cost risk profile under EPC contract) and with the OECD / IEA / NEA 7% real rate of return[54] approximation used for unregulated market risk exposed generation projects cross country comparisons. At the higher power price range of €108/MWh, which was based on DECC underlying assumptions, and is comparison consistent with the price environment relevant for Hinkley Point C, the implied project return would be nearing 12% nominal (10% real). The IRRs calculated in all of these scenarios are higher than the calculated cost of capital (WACC) range, indicating the positive expected NPV.

At Government level for shareholder equity IRR calculations it should be noted that the Paks II project, as per the Russian – Hungarian Financial IGA is to be 80% debt funded at the Government's level during construction which enhances returns further and lowers the Government level WACC. At this Government level, the equity returns implied by this analysis are consistent with the equity IRR[55] in the case of Hinkley Point's 11.0%-11.5% endorsed by the Commission and, clearly indicate commercial rather than social returns, compared to typical Government investment returns in social and economic projects of c. 3%[56]. No equity capital injections are calculated to be required in order to finance the project once the two units enter their operational period. Quite the opposite, the operating company would be able to pay dividends from 2026 or 2027, depending on the range of price assumptions.

[53] In the UK context, in the Hinkley Decision, the Commission argues that: *"Based on the available evidence and the assessment carried out, the Commission considered that the project IRR of [9.25 – 9.75] per cent post-tax nominal of the HPC project is within the range of comparable rates of return, given the assessment of risks and surrounding parameters"*

[54] 7% real market cost of capital, assumed in IEA and NEA joint report – *Projected Costs of Generating Electricity (2015),* used for market exposed, unregulated generation including new nuclear as distinct from 10% high risk scenario cost of capital applied to emerging technologies, which in the case of nuclear technology relates to *Generation IV small modular reactors (SMRs) and very high temperature reactors (VHTRs).*

[55] Calculated on assumed £16bn drawdown of available UK Government debt guarantee; implied 65% gearing

7.3 Assumptions and sensitivity

The results are driven by the benchmarked assumptions. The table below provides a summary of these assumptions, and compares them to the assumptions underlying the other analyses of the Project which have been considered in this report. It should be noted that all the assumptions are shown in Euro terms, based on current FX rates, but the analysis of each report would have its own underlying assumptions on FX rates which would affect comparability between reports.

Analysis (date)	Public information benchmarks	Aszódi (2014)	REKK (2013, updated in 2014)	Romhányi (2014)	Felsmann (2015)
Methodology	LCOE, NPV, IRR	LCOE	NPV, IRR	Fiscal	NPV
Investment	€12.5 billion, fixed price EPC contract	€12.5 billion	US$5m (€4.4m) / MW (€10 – 12.5 billion in 2014 update)	€12.5 billion	€12.5 billion, fixed price EPC contract, but large maintenance cost half way through operations
Market price	Public information and LCOE long term price formation (NERA): Long term range from €65/MWh (if coal or nuclear new capacities are built) - €108/MWh (if new gas capacities are built) (2013 real) Mid-point scenario range based on German BMWi wholesale forecasts to reaching the long term €86/MWh (2013 real) price thereafter	Cost based assessment, no view on market price; conservative demand assumptions and supply assumptions from the TSO	€80 - 100 / MWh (real 2011) Determined from the "Economic Impact Analysis of the National Energy Strategy 2030", a 2011 study by REKK	Considered on Government level €43/MWh (real 2014) market prices; €80/MWh required LCOE without tax proceeds and €40-45/MWh required LCOE with tax proceeds	Considers different scenarios with long term prices between €43 and 76/MWh, benchmarked to growth rates from publicly sourced price forecasts for UK market, US market and EU end user prices, which are largely not relevant to Hungary

Analysis (date)	Public information benchmarks	Aszódi (2014)	REKK (2013, updated in 2014)	Romhányi (2014)	Felsmann (2015)
Production	2,360MW net capacity 92% load factor	2,400MW Gross / 2,200 MW Net capacity 96% load factor	2,400MW capacity 85% load factor based on older technology	2,170MW net capacity 85% load factor based on older technology	2,400MW capacity Misrepresents capacity utilisation through non-standard methodology 76% capacity utilisation in overlap period and 82% capacity utilisation thereafter
Operational life	60 years	60 years	50 years	60 years	60 years
O & M[57]	O&M – c. €8 / MWh; +€9/MWh sensitivity to €17/MWh Fuel – c. €5 / MWh; +€2/MWh sensitivity to €7/MWh	O&M – c.€15-17 / MWh Fuel – c.€6-7 / MWh	O&M – c. €13 / MWh Fuel – c. €8. / MWh	O&M – c. €15 / MWh Fuel – c. €6 - 7 / MWh	O&M – c. €15 / MWh Fuel – c. €4 / MWh
Tax	19% corporation tax rate Includes tax credits	N/A	16% corporation tax rate	19% rate + 31% energy suppliers income tax	19% corporation tax rate Excludes tax credits
Decommissioning and waste management	Waste management and decommissioning contriubtion: €2.1 / MWh €2.4 billion, real 2013 +€1/MWh sensitivity to €3.1/MWh	Decommissioning - HUF2 / kWh (c. €6 - 7 / MWh)	Decommissioning - US$750/kW, specified as 15% the investment cost (c. €1.6 billion in total)	Decommissioning - HUF576 billion (€1.8 billion, real 2014)	€6 / MWh (based on increase of the Paks I 2013 cost)
Depreciation	100% of assets, 60 years – straight line	implied 60 years straight line	100% of assets, 50 years – straight line	90% of assets, 60 years – straight line	70% of assets, 25 years – straight line 30% of assets, 50 years – straight line

[57] Based on HUF / EUR FX rate of 311.23 and EUR / USD FX rate of 1.13 as at 20 September 2015

Analysis (date)	Public information benchmarks	Aszódi (2014)	REKK (2013, updated in 2014)	Romhányi (2014)	Felsmann (2015)
Cost of capital	6.2% - 7.0%, post-tax, nominal based on fundamental WACC analysis, but higher project returns achieved in analysed cases Hungarian State funds, including impact of Financial IGA, at shareholder level	9% implied post-tax, nominal Funded by Financial IGA and short term "money-market loan" at 8% treated as equity	8% - 11.5% post-tax, real (7% – 10% post-tax, real from 2014 update) Equivalent to c. 10% - 13.5% post-tax nominal No analysis of financing method	No mention Funded by Financial IGA and short term debt to fill funding gaps (at 7% cost of debt)	5% - 10% post-tax, real, equivalent to c. 7% - 12% post-tax nominal Funded by Financial IGA and short term debt to fill funding gaps (at 8% cost of debt)

The results of the cash flows analysis on the basis of the two methodologies used to assess the feasibility of the project, being the LCOE and NPV/IRR methodologies are also set side by side, but the ability to compare is limited unless assumptions are normalised.

Analysis (date)	Public information benchmarks	Aszódi (2014)	REKK (2013, updated in 2014)	Romhányi (2014)	Felsmann (2015)
Returns	Mid-point case range 9-9.6% nominal, 7-7.6% real; Wider market price range 8% (if coal or nuclear new builds are unconstrained) - c.12% (if gas new build replaces capacity) nominal c. 6% – 10% real; in line with public benchmark information Higher IRR for Hungarian State funds due to including impact of Financial IGA, at shareholder level	N/a – LCOE approach with implied 9% post-tax nominal return benchmark	5.2% - 12.8% real (base case: 8.7% real, implying 10.7% nominal)	N/a although indication of potential 4% real return to the Hungarian Government (assuming €80/MWh long run price)	6% nominal assuming base case capacity utilisation and 75% growth in prices scenario

*In contrast to the other reports reviewed, the **Aszódi** Report has a relatively narrow scope; focussing on the LCOE of the project in detail. On the whole, the Aszódi Report is very positive in regard to the Paks II project and although the report includes a number of relatively conservative assumptions – in comparison to the benchmarking analysis - the ultimate finding of the paper is that the project is likely to produce electricity at a competitive price for the long-term and should be constructed.*

*Extreme conservatism of the assumptions utilised in the **Felsmann** report resulted in the negative conclusions on the Paks II project. In particular, the Felsmann report provides exaggerated assumptions around O&M costs and maintenance capex, while also having methodological issues in his analysis, such as the capacity utilisation calculation, which results in losses for the project and the requirement for equity injections by the Government as the sole shareholder. Applying more robustly benchmarked assumptions leads to a very different conclusion, more closely aligned to the findings of Dr. Aszódi.*

*The **Romhányi** report focusses on the fiscal effect of the project, i.e. the project's impact on Hungarian government's budget, as opposed to the economic rationale of the project. The conclusion of the report is that the project would require an €80/MWh price in order to provide a 4% return to the Hungarian State. This is due to conservative assumptions such as the low load factor (85%) and the 31% "Robin Hood" tax. However, when also considering the tax revenues which the Government would receive from the project, the break-even price for a 4% return falls to €40-45/MWh which is in line with Romhányi's market price assumption of €43/MWh.*

*One of the main questions which the **REKK** report aims to answer is: Which factors influence return on investment for nuclear projects the most? Based on international literature, what is outlook for return on investment in a nuclear project in Hungary?*

In order to answer this question, REKK built a simple cash flow model and analysed how sensitising different variables affect the NPV and IRR. While the report accepts its own limitations due to the further analysis it would need to come to a firm conclusion, it shows a range of cases: the pessimistic case, the base or realistic case and the optimistic case, which have returns of 5.2%, 8.7% and 12.8% respectively. These are real returns, and so the range of nominal returns would be c. 7% - 15%, which, on the basis of our WACC analysis would mean that the project is NPV neutral or positive in all cases. This is in no small part due to the high market price assumptions, which are at the higher end of the LCOE benchmarked prices elaborated in Chapter 4.

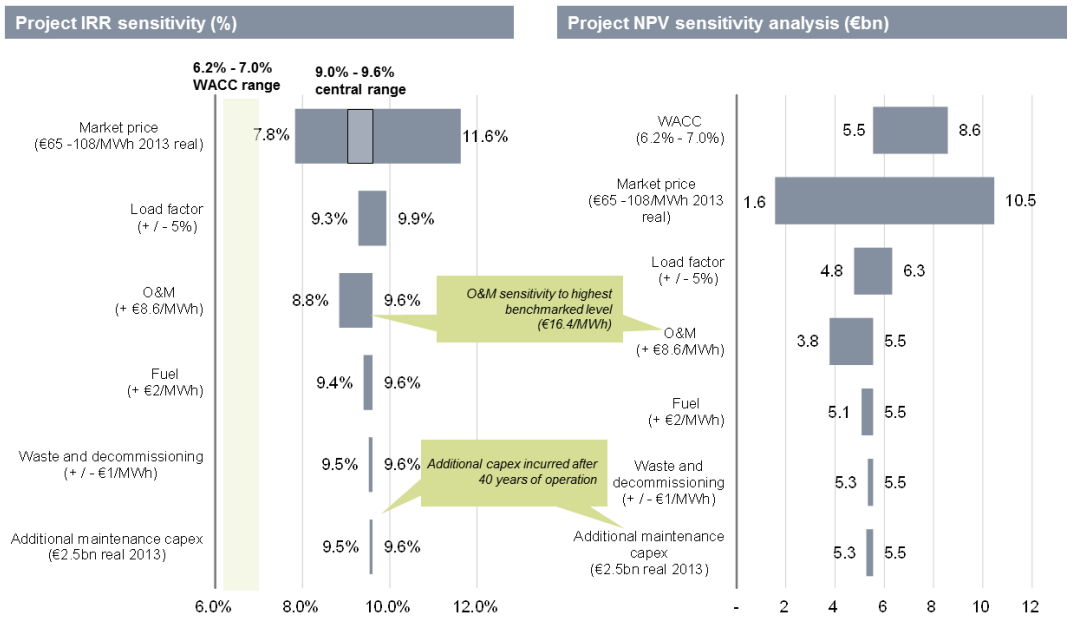
The economics analysis shows a range of project returns for Paks II during operations, in a wide range of market forecasts and sensitivity scenarios. Figure 50 show the impact of sensitising key variables on the project pre-financing IRR, as well as the project NPV at a WACC of 7%. As previously explained, due to the long operational life of the project and low operating costs, the economics of the project are relatively insensitive to cost variables during the operational life of the plant.

The entire analysis, including cost of capital and risk evaluation, is predicated on the project cost being within the €12.5 billion fixed price budget. No sensitivity has been shown on the investment cost of the project given the fixed price nominal turn-key EPC contract (including no

upside if the costs fall below the maximum €12.5 billion), which means that no additional cost overrun conditions are evaluated from an owner investment evaluation perspective.

Nonetheless discount rate sensitivities are considered and evaluated, which can accommodate any cost or capital risks not captured by the other sensitivities explicitly.

Figure 50. Sensitivity analysis



The sensitivity analysis in Figure 50 highlights that the market price is the key variable, but as can be seen in the chart to the left, even with the wide range assumed, the return is always greater than the calculated cost of capital in this analysis, implying that the project would have a positive NPV in all of the sensitivities, as shown in the chart to the right.

For the mid-point case with a long term price level of €86/MWh, as implied by the long term levelised costs analysis in published sources and the cost assumptions stated in Chapters 3 and 5, assuming a WACC of 6.2 – 7.0%, the NPV is significantly positive, with value being created by the project for the Hungarian State, and consequently the Hungarian tax-payer, ranging from €5.5 – 8.6 billion. In other words, under the assumptions in this analysis, the project could be an asset which generates material value for the Hungarian State.

7.4 Conclusion

The assumptions applied in this analysis, based on publicly available and disclosed information sources, substantiate NPV positive scenarios that could be used to substantiate a positive investment decision. The report has stated the existence of limitations to comparability and application of certain sources and assumptions, including the importance of the fixed price turn-key nature of the EPC contract for cost risk protection. The fixed price turn-key nature of the EPC contract is key to the project's economic robustness to downside scenarios and sensitivities – particularly to macroeconomic and construction period risks and to the identified appropriate cost of capital.

The project economic prospects have been evaluated by different and independent project experts. The conclusions of such studies clearly depend on the input assumptions used and this report has sought to critique those assumptions in order to clarify the foundation for the range of evaluations.

The main conclusions of the financial analysis based on public sources are summarised below:

1. The Paks II project is being implemented in accordance with the aim of liberalised and interconnected European common energy markets and contributes to the 'trilemma' objectives of enhancing security of supply, decarbonisation and maintaining affordability, without any form of revenue protection, such as the CfD provided to Hinkley Point C. Its profitability therefore depends on the market prices that emerge from the demand and supply dynamics in Hungary and the interconnected market;
2. Even in the low end of the market price range identified by NERA (€65/MWh), the operational revenues generated from the sale of the power output envisaged on benchmarked load factor assumptions can be expected to generate sufficient cash flows to cover the operational costs of running the nuclear plant, as well as contributions towards returning the invested capital. The model used indicates that under the assumptions used the plant would be profit making from the beginning of operations and would not require equity injections from the shareholder in the operational period;
3. Furthermore, the results indicate that it is reasonable to expect that the anticipated revenue over the design life of the plant covers not only the running cost of the plant during the operational period but also provides adequate cashflows for the provision of funds required for waste management and decommissioning of the plant and to return to the shareholder (the Hungarian State) the investment cost of the project together with an economic return which appears to be in line with market benchmarks for return expectations from non-regulated generation projects in other EU countries;
4. Notwithstanding that the Project is being fully funded by the Hungarian State, the anticipated remuneration of capital sources consistent with typical benchmarked market participants remuneration levels, supports the argument of absence of State Aid as defined by European Union regulations, prior to any review or consideration of additional positive externalities and social benefits that may support the application of permitted State Aid compatible with the common market principles.

The assessment based on public information sources and appropriate benchmarks indicates that the project can be reasonably expected to be economically viable, i.e. is able to fund itself once operational without the need for equity injections, and provides an equity return to the Hungarian State which is commensurate with returns required by market participants for comparable risk investment propositions.