CANDOLE PARTNERS

NPP PAKS II:

ECONOMIC FEASIBILITY, IMPACT ON COMPETITION AND SUBSIDY COSTS

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This report was prepared exclusively for Greenpeace

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1. INTRODUCTION

In this study we look at the viability of the proposed Paks II nuclear power plant project (Paks II), situated in Hungary. The stated purpose of Paks II is to replace existing coal and nuclear units which are planned to be decommissioned and thus to provide security of supply for the following decades. In order to implement this project, Hungary negotiated a fixed price turn-key Engineering, Procurement, and Construction (EPC) contract with Russian company Rosatom valued at EUR 12.5 billion. This EPC contract will be financed through a financial intergovernmental agreement, in which Russia will provide 80% of the project's capex to the Hungarian State through an intergovernmental loan.

In the first part of the study we will analyse the economic viability of the project. We take into account different studies which have dealt with this matter, especially the September 2015 study "Economic analysis for the Paks II nuclear power project: A rational investment case for Hungarian State resources", carried out by Rothschild & Cie for the Hungarian Prime Minister's Office. We focus on building realistic market scenarios for the project and thus testing the sensitivity of the project results on possible market outcomes. Since the capital expenditures are fixed in the EPC contract, we focus on the sensitivity of the revenue side but take also into account possible operational expenditures of the project. On the basis of the result of our analysis, we conclude that it is unlikely that the project will achieve the returns expected by the Hungarian government.

In the second part of the study we investigate the impact of Paks II on the competition in the Hungarian wholesale electricity market. For the purpose, we identify Hungary as the relevant geographic market. We reach this conclusion following a well-established practice in competition economics, consisting of creating a correlation matrix for power prices in Central European countries, in order to verify whether the geographic market should be defined as including at least the other Central European countries with which Hungary is coupled. We find that the price correlation between Hungary and other neighbouring countries is significantly below thresholds generally considered as indicating the existence of one market including Hungary, Czech Republic, Slovakia and Romania. In fact, the only two countries from the Central European region which could be considered as one market are the Czech Republic and Slovakia.

Having established that Hungary is the relevant geographic market for competition analysis purposes we continue by calculating market concentration ratios generally used by competition departments in the EU and the US to assess market concentration. We find that the Hungarian power generation market is highly concentrated and already dominated by state-controlled companies. Going forward, we find that this dominance would further increase after the commissioning of Paks II. With the construction of Paks II, the Hungarian power generation market would look more similar to a monopolistic market than to a competitive one.

2. REMIT

We were asked by Greenpeace to evaluate the economic feasibility of Paks II and assess the impact of Paks II on competition in the Hungarian power generation market.

We build our own proprietary financial model to replicate the financial modelling undertaken by Rothschild & Cie on behalf of the Office of Hungarian Prime Minister. For the purpose of this evaluation, we use the same assumptions about investment and operating costs, financing costs and economic and technical lifetime of the proposed plant as the Rothschild study. However, this should not be understood as an endorsement of the said assumptions. On the contrary, as we note below, we believe that the Rothschild study might have underestimated the costs significantly.

We review the power price forecasts used by the Rothschild study to calculate the plant revenues. We find price expectations of the Rothschild study to be outdated and overstated, in particular given the current commodity environment and updates in commodity price forecasts. We use our own price forecasts using updated inputs from the World Energy Outlook 2015. Nevertheless, our figures remain optimistic given that these commodities are currently traded below our forecasts. Figure 8 on page 11 shows Hungarian power futures trading at lower levels than low commodity scenario forecasts in spite of the Hungarian price premium on the German power price.

We create our own price forecasting model based on the merit-order dispatch rule. To do that, we calculate variable generation costs of power plants based on of the International Energy Agency's commodity scenarios and the expected effect of the European carbon market reform. The merit order rule simulation sets power prices on the basis of variable costs of production of the last power plant that needs to be dispatched in order to satisfy demand.

We then test the robustness of Paks II returns under various commodity and operations and maintenance (O&M) costs scenarios. We conclude that Paks II is uneconomical in each of the tested scenarios and would have to be significantly subsidised by Hungarian taxpayer.

Our model shows negative Net Present Value of the project in all tested scenarios, even if these are based on the investment and operational assumptions of the Rothschild study, which we believe are somewhat aggressive. Finally, in light of submissions for the British Hinkley Point C project, in which the desired return used to set the subsidy price is set at 10%, we consider that the Rothschild study's assumption that the cost of financing would be set at 7% is quite generous and may not reflect the true cost of capital (especially equity).

In order to assess market concentration on the Hungarian power generation market, we firstly create correlation matrix of power prices in neighbouring countries. We firstly clean the data by bias introduced by common "macro" trends, such as global commodity price movements, and common seasonal elements. We find that the correlation spread of 0.38 – 0.63 is too low to indicate that Hungary would be part of a larger Central European market. The correlation threshold when two markets are considered as a single one is deemed to be 0.8 by competition authorities and academic literature.

3. ABOUT PAKS II

In 2009, the Hungarian Parliament approved a decree, aiming at building two new reactors at the nuclear power plant nearby the town of Paks, on the banks of the Danube in central Hungary. These reactors would be added to the already existing 4 VVER 440 reactors of the Paks I nuclear power plant. Paks I already covers around 50% of Hungarian electricity generation. With Paks II, the two NPPs would cover upwards of 70% of the energy production of Hungary.

The Hungarian state-owned group MVM Ltd., took the task of preparing and launching a tender to choose a supplier for the project. This tender was never launched. Instead, the Hungarian government made a direct agreement with Russia on the construction of two new units, on 14 January 2014, and, on an intergovernmental loan to finance the construction, in March 2014.

In December 2014, the Hungarian company MVM Paks II Ltd. signed the construction contract with the Russian company Nizhny Novgorod Engineering Company Atomenergoproekt (NIAEP), which used to be part of the USSR Ministry of Nuclear Power in the past, and is now an affiliated company of the state-owned Rosatom Group (which also used to be part of the USSR and later federal nuclear ministries). MVM Paks II Ltd. was originally part of the MVM Group, but has been recently brought under direct control of the Hungarian government. According to official plans, construction works should start in 2018.

According to contractual agreements, two new 1200 MW (VVER-1200/V491) units will be constructed at the site of the existing Paks I nuclear power plant, as a “turn-key solution”, with NIAEP acting as a project developer. The Russian Federation, via Vnesheconombank (the state Bank for Development and Foreign Economic Affairs (VEB)), will lend a maximum of 10 billion euro to Hungary, covering 80% of the estimated project cost, while the Hungarian state should cover the remaining 20%. Hence the overall cost of the project is estimated at EUR 12.5 billion. Nevertheless, the exact content of the intergovernmental loan contract has not been made public, and the responsibilities of the contract parties, the Hungarian and Russian states, are also unclear.

Paks II is currently being investigated by the institutions of the European Union. Following a complaint filed by Energiaklub, a Hungarian NGO, and Greenpeace, in April 2014 (plus an additional letter at the beginning of November 2015), the European Commission announced on November 23, 2015 that two investigations, respectively for illegal state aid (by DG Competition) and the violation of the EU public procurement rules (by DG Growth) would be carried out on the project.

4. ECONOMICS OF PAKS II

In this chapter we assess the economic feasibility of the expansion of NPP Paks. We assess the profitability of Paks II by means of a discounted cash flow analysis. We test the profitability of the project under various commodity and operating cost scenarios. Our base-case scenarios are based on estimates of operating data published in evaluation conducted by Rothschild & Cie ("Rothschild") for the Hungarian government in 2015. In addition, we develop scenarios based on the operating costs of EPR reactors, as estimated by the French Court of Auditors (2012, published in (Boccard, 2013)) to test the sensitivity of project returns to operating costs.

Given the wide range of estimates for investment costs and the nature of the contract between the EPC contractor (Rosatom) and the client (MVM Paks II Ltd.), which fixes the cost of the project at EUR 12.5 billion, we take into account the capital expenditure estimated by the Rothschild study. We note, however, that Rothschild's estimates are being reviewed by the European Commission: in its letter of 23 November 2015, the institution has indicated a WACC range between 8.3% and 10%. The discounted cash flow model and its inputs and outputs are all in 2014 real terms and no inflation or indexation is included.

4.1 Commodity forecasts

This section describes the source of the inputs for our proprietary discounted cash flow model, and how the scenarios (Base, Low, High) were structured. All power price forecasts are for baseload power. In addition, we discuss risks associated with revenue streams of those scenarios.

The Rothschild study works with power price forecasts developed by NERA using long term marginal cost methodology, and with forecasts developed by the German Federal Ministry of Economy (BMWi). Both forecasts are based on the commodity price forecasts of the World Energy Outlook 2013 compiled by the International Energy Agency.

We believe that the long term marginal cost methodology is not the appropriate methodology for developing power price forecasts. This methodology relies on a key assumption that, in the long run, the market must on average produce a power price which allows the construction of new power plants. This means that in addition to fuel and O&M (i.e. short term marginal) costs, the price must also allow investors to recover their investment costs, including the cost of capital.

Whilst theoretically sound, this theory is not supported by evidence from European power markets since their liberalisation. This is because once a power plant is built, it becomes sunk cost, and its operator bids only the marginal cost of power production to at least cover the costs of production. This has certainly been the case on the Central European power market, which developed significant overcapacities in the 80s and 90s prior to liberalisation and unbundling.

Furthermore, a large and growing share of Central Europe's generation capacities recover their investment cost from out-of-the-market financing mechanisms, such as subsidies by consumers (e.g. feed-in tariffs and green bonuses for renewable energy) or direct purchases by industrial and household consumers to cover their consumption. In this case, they are comparing the total price of wholesale and grid fees with the price of producing electricity 'in house' and avoiding paying the grid fees.

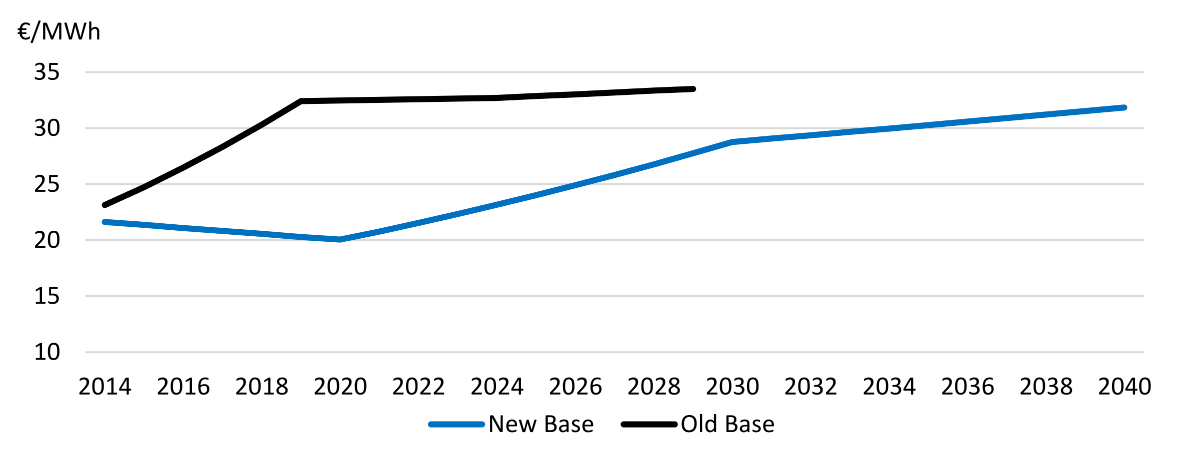
Our forecasts follow a methodology that is similar to the one used by BMWi for estimating short term marginal costs. For each year, we estimate the available power generators' marginal costs and we build a merit-order list of those generators. Generators with the lowest generation costs are dispatched first, and all generators receive the price of the last generator needed to be dispatched to meet demand – this is the so called merit-order rule. In addition, due to the European Commission's price coupling initiative (Hungary is coupled with the Czech and Slovak markets, which are in turn coupled with Germany – see www.ote.cz) and an ample interconnection capacity with the neighbouring countries, we assume Hungary will be a price-taker in the Central European coupled market dominated by Germany. Please see chapter 2 for details on regional interconnection and price dynamics.

In our opinion, the forecasts used in the Rothschild study are outdated and the forward electricity price forecasts are overstated. We updated the forecasts using the newest World Energy Outlook (WEO) 2015 (published in November 2015), and used its commodity assumptions (hard coal, gas, CO_2). Given the commodity assumptions we create electricity price forecasts. Below is the comparison of the old and the new forecasts. (Please note that the old forecasts ended in 2030.)

Figures 1, 2 and 3 below show how much market expectations have decreased since the publication of the WEO 2013 study.

Gas price assumptions of World Energy Outlook of 2013 vs 2015:

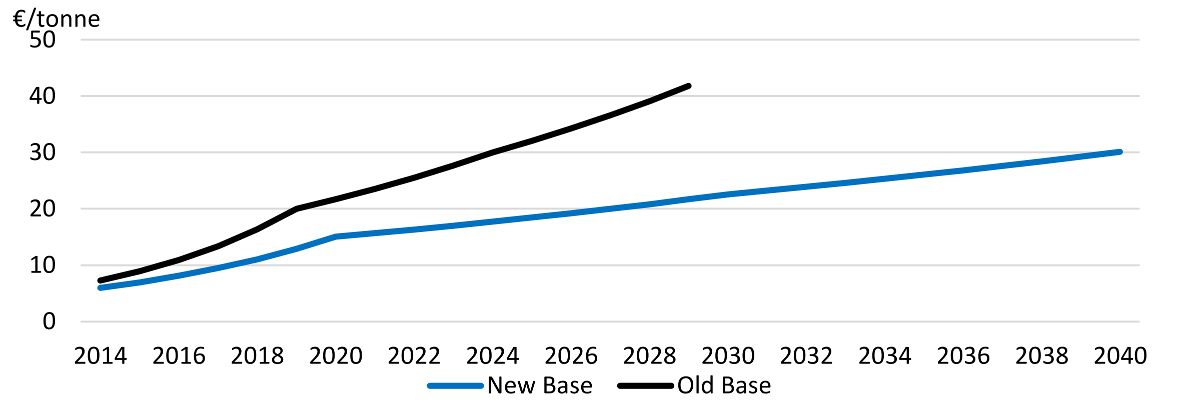
Figure 1: Gas price base assumptions old vs. new



Source: IEA (2013) & (2015), own calculations

The old and new carbon price assumptions are presented below.

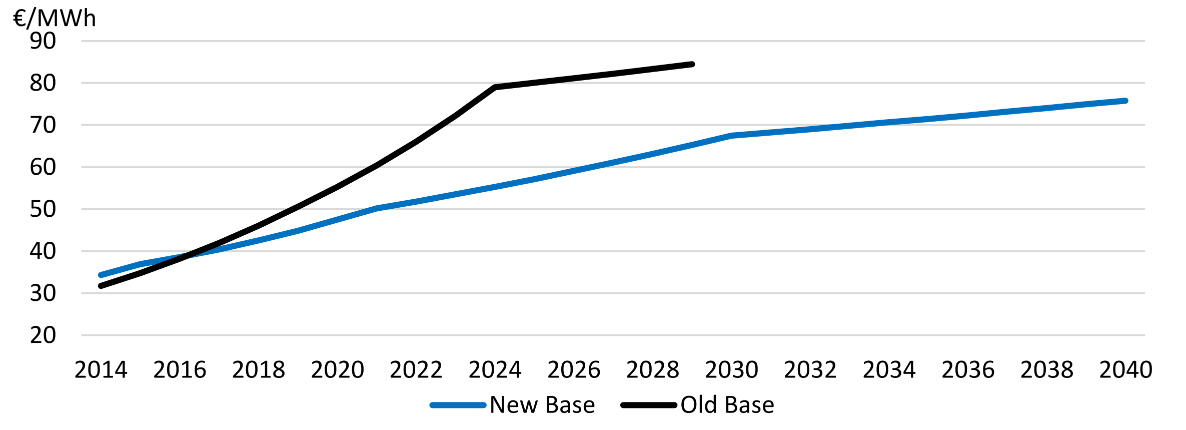
Figure 2: Carbon price base assumptions old vs. new



Source: IEA (2013) & (2015), own calculations

The old and new electricity price assumptions are presented below.

Figure 3: Electricity price base assumptions old vs. new



Source: IEA (2013) & (2015), own calculations

We calculated the new electricity price forecast (blue line in Figure 3) using the commodity assumptions from WEO 2015. There are three scenarios: Base, Low and High, which were constructed as follows:

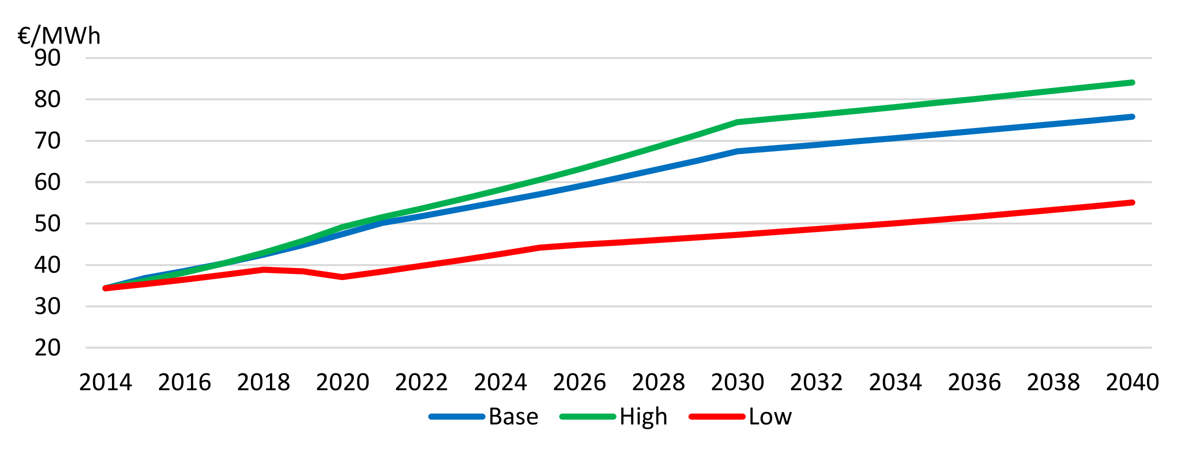
- The Base scenario in our model is based on the baseline scenario of the IEA report, called the "New Policies scenario". It assumes that all environmental policy commitments announced by EU countries, such as the greenhouse gas emission targets, are implemented.
- The High scenario is based on the "Current Policies Scenario" in the IEA report. It generally assumes that no further environmental policy commitments are made, and consequently commodity prices will grow faster than in the baseline scenario.
- The Low scenario is based on the "Low Oil Price Scenario" in the IEA report. It looks at the impact of persistently low oil and commodity prices on the energy market.

We use the commodity price assumptions directly from the IEA, however, we calculate our own electricity price forecast based on the commodity forecasts of the IEA. To do this, we make the following assumptions:

- We calculate marginal costs for producing electricity from coal and gas.
- For the base and high scenarios, we assume that because of the revival of the carbon market (Stability reserve mechanism), a gas-fired plant will be the price setting plant from 2021 onwards. Before 2021, the price setting plant is coal-fired.
- For the low scenario, we assume the price setting plant will always be either a hard coal or a gas-fired power plant, depending on which plant has lower marginal costs.
- All scenarios assume that the power generation mix is in line with the German energy policy.
- Regarding the assumption of electricity prices beyond our forecast period, we assume prices will stay constant after 2040, as this is the year with the latest inputs available.

Commodity prices remain low (especially coal) in the low scenario. As a result, electricity prices remain depressed in the low scenario. Below is the comparison of the 3 scenarios:

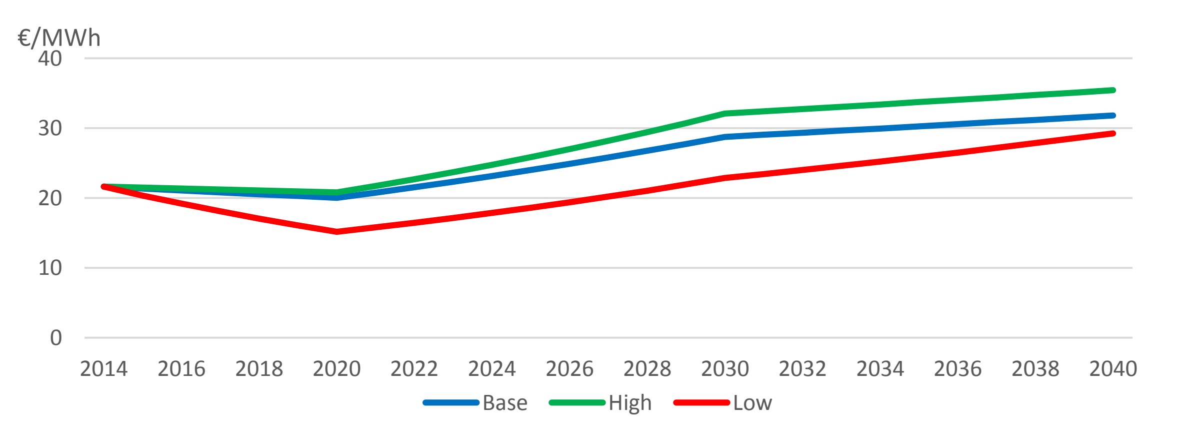
Figure 4: Electricity price base forecast



Source: IEA (2015), own calculations

Below are the forecasts of gas price in Europe, according to IEA World Energy Outlook 2015.

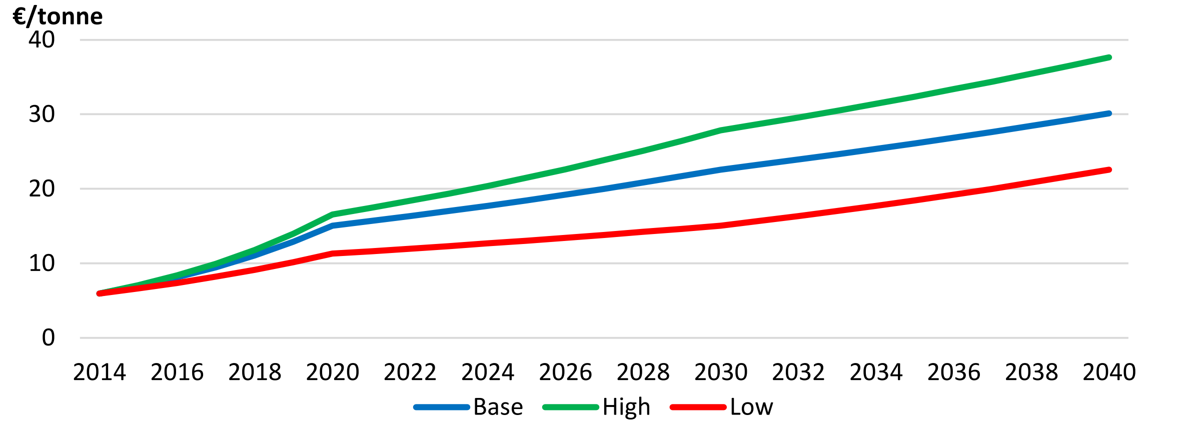
Figure 5: Gas price base assumptions



Source: IEA (2015), own calculations

Furthermore, we use three different carbon prices, whose base and high scenarios are based on the carbon assumptions in IEA World Energy Outlook 2015. The low scenario is our own, and assumes a 10-year lag in price development compared to the base scenario. The three scenarios are illustrated below.

Figure 6: Carbon price base assumption



Source: IEA (2015), own calculations

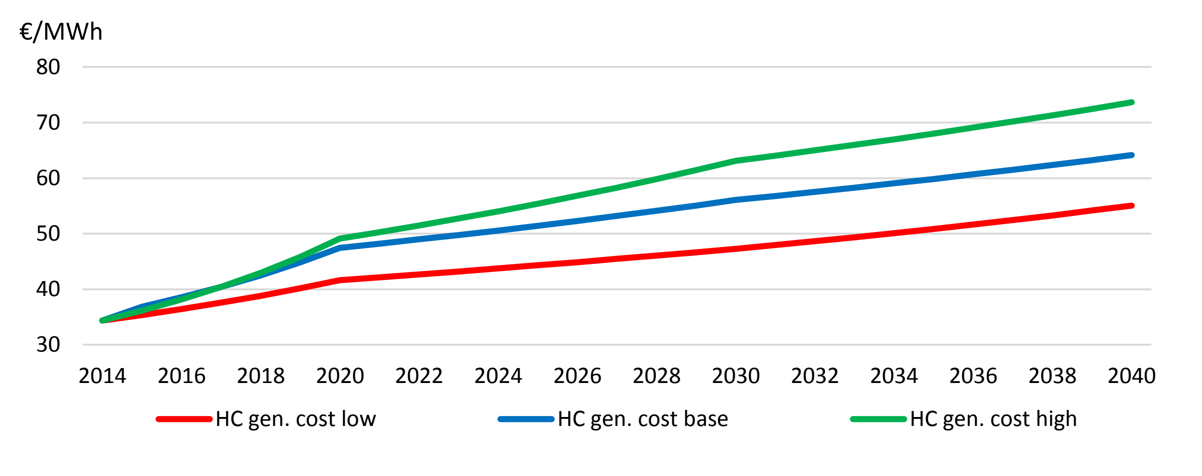
Figure 4 shows our own power price forecasts used in our financial model. Figure 5 show gas price based on IEA assumptions. Figure 6 shows carbon price based on IEA assumptions.

As mentioned above, the base and high scenarios assume that German gas fired power plants will be the marginal power plants after 2021, while the low scenario assumes the cheaper of the two fuels to be the marginal one.[1] This is because only a higher increase in the carbon price will lead to a significant increase in costs of hard coal powered generation that would make gas powered generation competitive again. This is due to the fact that hard coal emits a significantly higher amount of carbon per MWh produced than gas. In our calculations, assuming a 40% efficiency of hard coal generation and 59% efficiency of gas powered generation, we estimated that a EUR 1/tonne increase in the price of carbon will increase the price of gas powered generation by EUR 0.34/MWh and EUR 0.86/MWh for hard coal powered generation.

Below we illustrate the evolution of hard coal and gas powered generation costs based on the three carbon scenarios used.

[1] We assume the power price in Hungary will be driven by the same fundamentals as the German (and hence the continental) prices.

Figure 7: Development of hard coal powered generation cost based on carbon scenarios

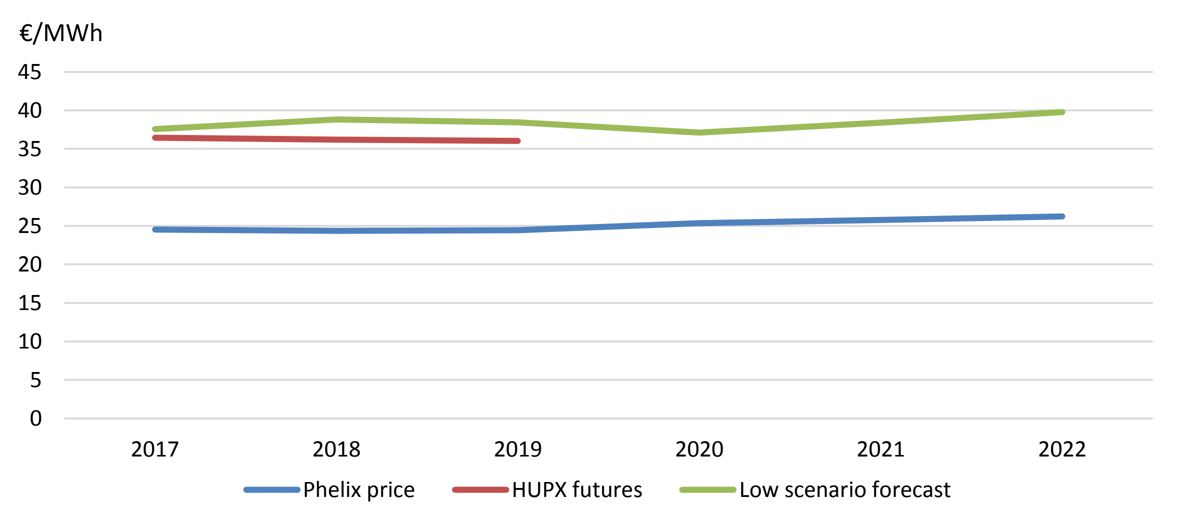


Source: IEA (2015), own calculations

Figure 7 is an example of the impact of different hard coal and carbon assumptions on the marginal costs of production on a marginal power plant, which drive the power price forecasts. These marginal costs of production are then used to forecast electricity prices in our merit-order model.

Below we compare the low scenario forecast to the future contracts currently traded (as of May 2016) on the German and Hungarian electricity exchanges. While the German-Austrian (Phelix) contract can be traded for delivery in 2022, the Hungarian contract is available for the next three years only. Currently, there is an obvious premium between the Hungarian and German-Austrian contract, which we believe will however be diminished with future interconnector developments within Europe. Nevertheless, this comparison shows that even the low scenario is relatively high compared to current market expectations.

Figure 8: Development of low scenario forecast compared to benchmark futures contracts



Source: EEX, HUPX, IEA (2015), own calculations

4.2 Investment and operating assumptions

In this chapter we outline investment and operating assumption inputs for our discounted cash flow model. As explained above, due to the high spread of investment cost assumptions and to the high sensitivity of returns to the investment cost assumptions, we decided to use the same capex assumptions as the Rothschild study.

This approach reflects the fact that the Hungary negotiated a fixed price turn-key EPC contract with Rosatom in the value of EUR 12.5 billion. Our assumed capex for the 2×1,200 MW[2] reactors is therefore EUR 5,208/kW. We assume development costs will be incurred in 2017 and 2019, with the construction starting in 2020 and ending in 2027. This assumption is conservative, given that similar projects in Europe ran into construction delays.

In theory, cost overruns and delays should be covered by Rosatom. However, in reality, Hungary may not be fully protected, as disputes about cost overruns and delays typically end up in court disputes between the contracting parties, as it happened in the case of the Olkiluoto project. (YLE, 2013)

In line with the agreement between Rosatom and Hungary, we do not assume a project financing model for the financing of NPP Paks II. We assume that the project will be funded by a combination of equity and a shareholder loan from the state. In line with the Rothschild study, and without prejudice to the reservations expressed by the European Commission in this regard, we assume a weighted average cost of capital (WACC) of 7% for the project, given that deviations from the assumed cost of capital have a material impact on the modelled return.

We assume an 80% load in the first year of operation, gradually increasing by 1% each year as plant operations become more efficient, until the load reaches 92% in 2039 and stays constant thereafter. 92% load is a benchmark for efficiently operated nuclear power plants, and it is also assumed by the Rothschild study. We assume a 60-year economic and technical lifetime of the plant, in line with the Rothschild study. Our model uses straight-line depreciation over the 60 years of the assumed economic lifetime.

We use two sources of information to establish operating and fuel costs for NPP Paks II. As stated above, we use the Rothschild study assessments as the benchmark value for our discounted cash flow model. The Rothschild study assumes ranges for fuel costs of EUR 5/MWh to EUR 7/MWh, and EUR 8/MWh to EUR 18/MWh for operations and maintenance. For the alternative scenarios, we use the French Court of Auditors' (FCA) estimates. FCA assumes fuel costs of EUR 7.3/MWh and EUR 25.3/MWh for O&M. The Rothschild study assumes EUR 2.1/MWh and EUR 3.1/MWh for decommissioning costs, while FCA assumes a EUR 1.7/MWh decommissioning cost. We develop the benchmark scenarios using EPR cost calculations as those are publicly available and verified by independent reviews like FCA.

Table 1 presents a comparison of the input parameters; Table 2 provides a summary.

[2] We use the same assumptions as Rotschild (2015), where the two Paks II VVER reactors have a nameplate capacity of above 1,200 MW each. After deducting the reactors' self-consumption, the assumed installed net capacity is 1,180 MW.

Table 1: Comparison of key input parameters of this study				
	Candole Partners	**Rothschild**	**Court of Auditors**	**Aszódi**
Capex	€ 5,208 /kW	€ 5,208 /kW	€ 5,300 /kW	€ 5,208 /kW
Fuel cost	€ 5.0-7.3/MWh	€ 5.0-7.0/MWh	€ 7.3/MWh	€ 6-7/MWh
O&M	€ 8.0-25.3/MWh	€ 8-17.0/MWh	€ 25.3/MWh	€ 15-17/MWh
Decommissioning	€ 1.7-3.0/MWh	€ 2.1-3.1/MWh	€ 1.7-3.4/MWh	€ 6-7/MWh
Load	90.7%	92.0%	85.0%	96.0%

Table 2: Summary of input parameters in this study	
Capex/kW	5,208
Lifetime	60 years
Depreciation	60 years straight line
WACC	7.0%
Fuel cost	€ 5-7.3/MWh
O&M	€ 8-25.3/MWh
Decommissioning	€ 1.7-3.0/MWh
Avg. Load	90.7%
Source: Rothschild (2015), own calculations	

4.3 Model results

This section summarises results of our modelling. We create 6 scenarios based on our commodity forecasts presented above: benchmark Base, Low and High scenarios using the cost estimates of the Rothschild study; and EPR Base, EPR Low and EPR High based on the French Court of Auditors assessment. All scenarios are **REAL** scenarios, meaning in 2014 money with no indexation for inflation. The details of each scenario are presented in the section 1.4 below.

Table 3: Summary of results						
Scenario	**Base**	**Low**	**High**	**EPR Base**	**EPR Low**	**EPR High**
IRR	**6.1%**	**4.4%**	**6.7%**	**4.4%**	**1.7%**	**5.2%**
NPV	€ -1,266m	€ -3,231m	€ -419m	€ -3,270m	€ -5,762m	€ -2,349m
Avg. revenues/MW	€ 574,600	€ 421,900	€ 645,400	€ 574,600	€ 421,900	€ 645,400
Avg. costs/MW	€ 117,300	€ 117,300	€ 117,300	€ 268,200	€ 268,200	€ 268,200
Avg. EBITDA/MW/year	€ 457,300	€ 304,600	€ 528,100	€ 306,400	€ 153,700	€ 377,200
Avg. spread	€ 55.3	€ 37.1	€ 63.5	€ 36.0	€ 17.8	€ 44.2
Source: Own calculations						

Paks II does not earn a return equal to its weighted average cost of capital (WACC) in any of the tested scenarios even using rather optimistic capex and economic lifetime estimates of the Rothschild study. The net present value (NPV) of the project is negative across all scenarios meaning that investors into the project will not be able to recover their investment over the assumed 60-year lifetime of the project. Therefore, the project is not feasible on a commercial basis and should be abandoned as it would lead to value destruction. The most severe value destruction would happen if power prices develop in line with the trajectory of the Low scenario, which seems to be the most probable scenario, based on the current pricing of futures power contracts. The results also show a big sensitivity of project returns to the assumed operations and maintenance costs.

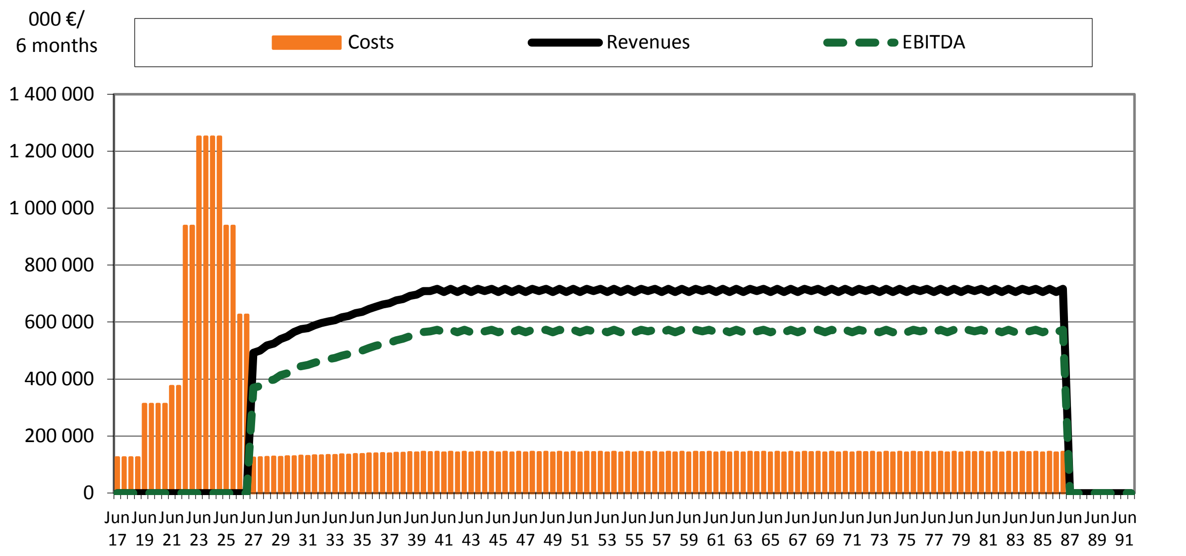
Should the project break even on an economic basis (i.e. the internal rate of return would equal the weighted average cost of capital), Hungarian consumers would have to subsidise the project by underwriting a price floor of EUR 85/MWh[3] in 2015 money in each year during the lifetime of the project, assuming the Rothschild study's O&M costs, or a staggering EUR 103/MWh assuming FCA's O&M assessment.

4.4 Discussion of the scenarios

4.4.1 Base

This section presents detailed results of the Base case scenario. Below we see the development of revenues, costs and subsequent earnings before interest, taxes, depreciation and amortisation (EBITDA) in the base scenario. Costs grow in the first years of operations because of the increase in load, on the other hand revenues grow even faster because of the load increase and electricity price increase up to 2040, when our price forecast ends. As a result, EBITDA has a growing tendency until 2040, from when onwards it is flat.

Figure 9 EBITDA Analysis[4]



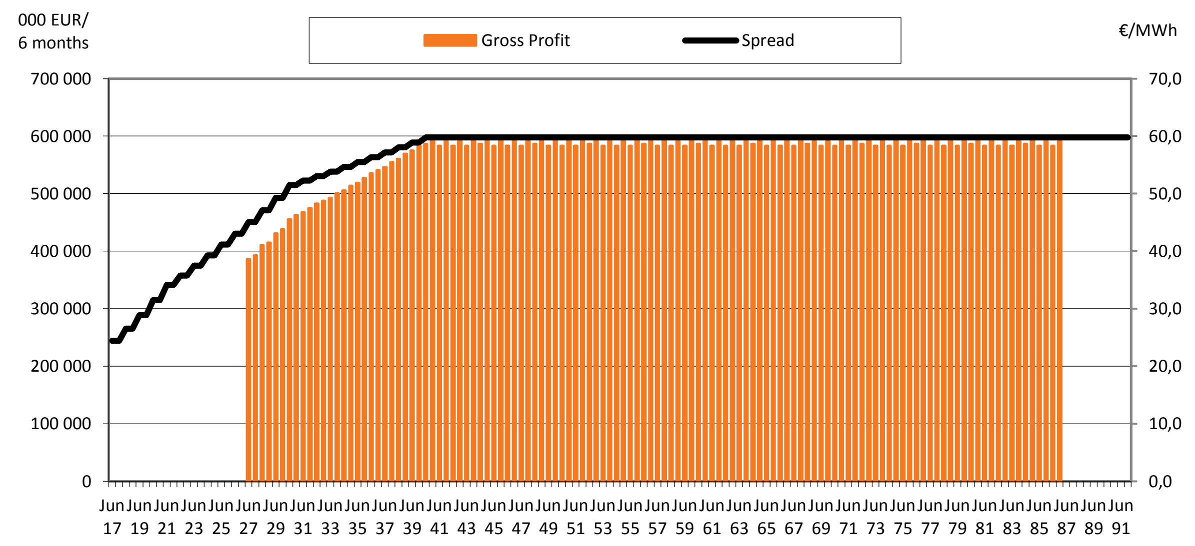
Source: Own calculations

[3] The Rothschild study calculates "Levelised Cost of Electricity" (LCOE) instead of Net Present Value. LCOE calculation typically assumes so-called "overnight investment cost" (OIC) and therefore understates the construction cost. OIC concept assumes cost as if the plant would have been built overnight and therefore excludes the cost of financing during construction and lag between expenses and revenues. Specifically, LCOE calculation in contrast to the NPV calculation does not assume that for the first 10 years the project will not make any revenues only costs (the costs being the construction and development expense of €12.5bn plus financing costs), resulting in a much lower „break even" price in the LCOE calculation.

[4] All graphs in chapter 4.4 (Figure 9-20) show data for €/6 months.

The graph below shows the development of gross profit and spread of the power plant during its lifetime. The spread is defined as the difference between the electricity price and the operational costs of the plant (fuel, O&M, decommissioning). This spread increases from around €45/MW when operations start to over EUR 60/MWh during its lifetime because of the expected increase in power prices.

Figure 10: Gross Profit & Spread

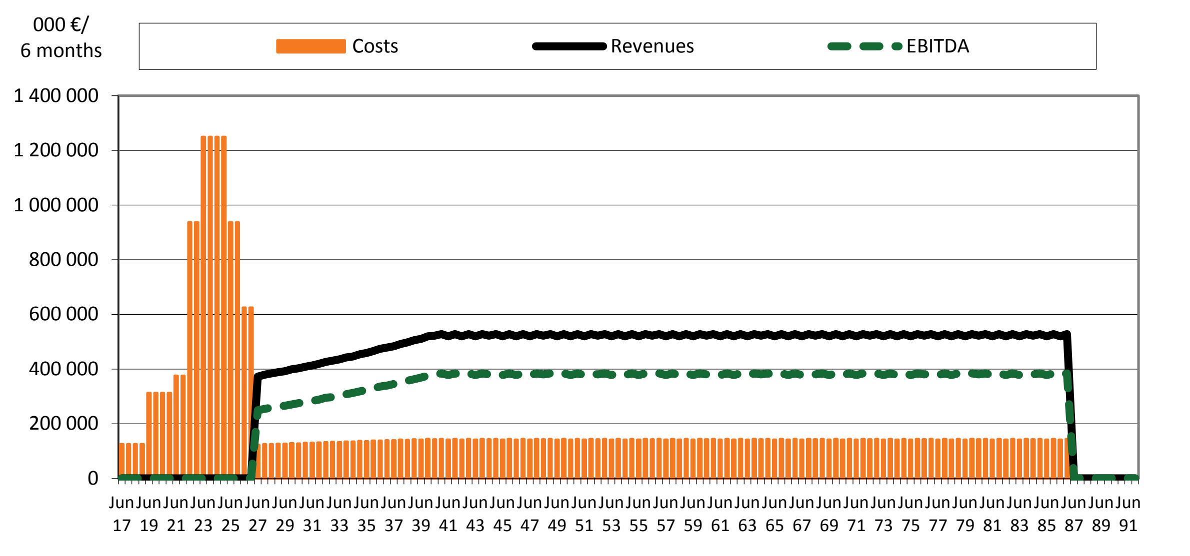


Source: Own calculations

4.4.2 Low

Below we see the development of revenues, costs and subsequent EBITDA in the low scenario. Compared to the base scenario, revenues grow slower because of a lower expected electricity price. As a result, EBITDA grows less significantly compared to the base scenario. We believe this is the most probable scenario given current pricing of power futures.

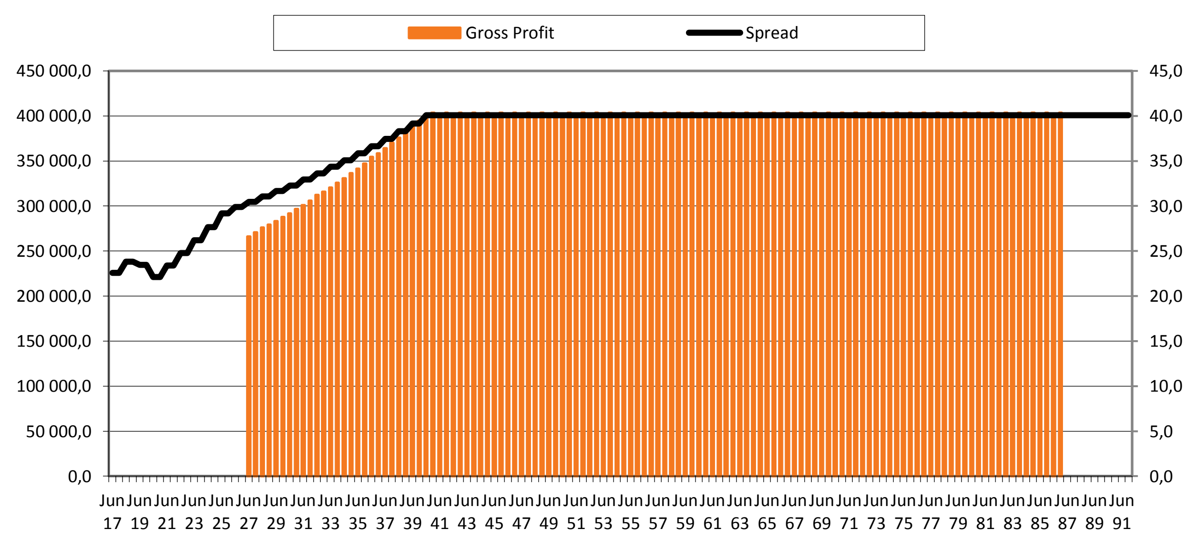
Figure 11: EBITDA Analysis



Source: Own calculations

This spread increases from around EUR 30/MWh to over EUR 40/MWh during its lifetime which is significantly below the EUR 60/MWh spread in the base scenario.

Figure 12: Gross Profit & Spread

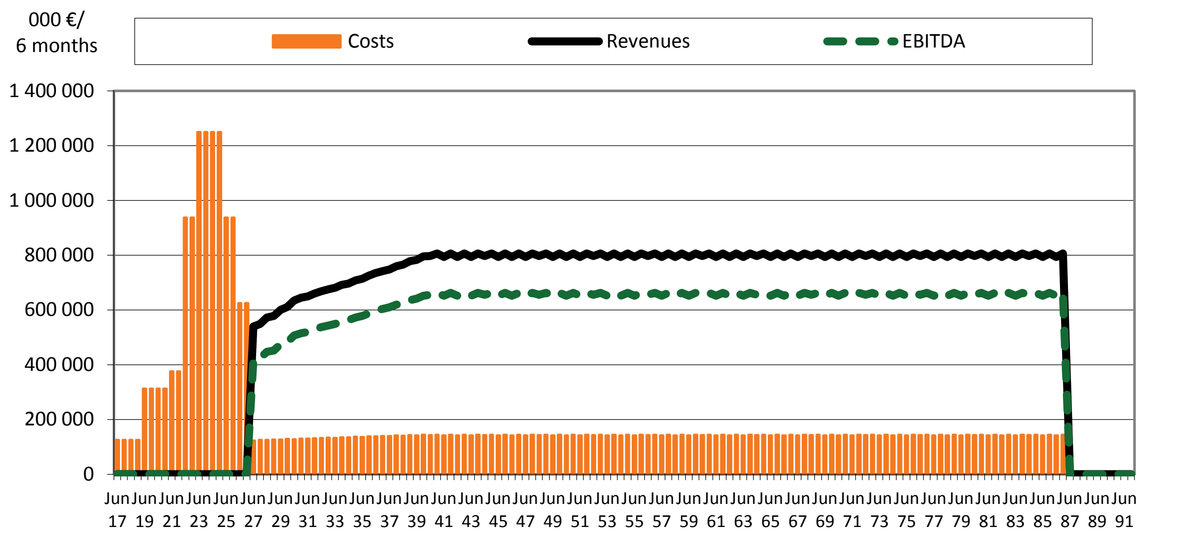


Source: Own calculations

4.4.3 High

The high scenario marks an ever higher price growth than in the base scenario, leading to a significant EBITDA growth.

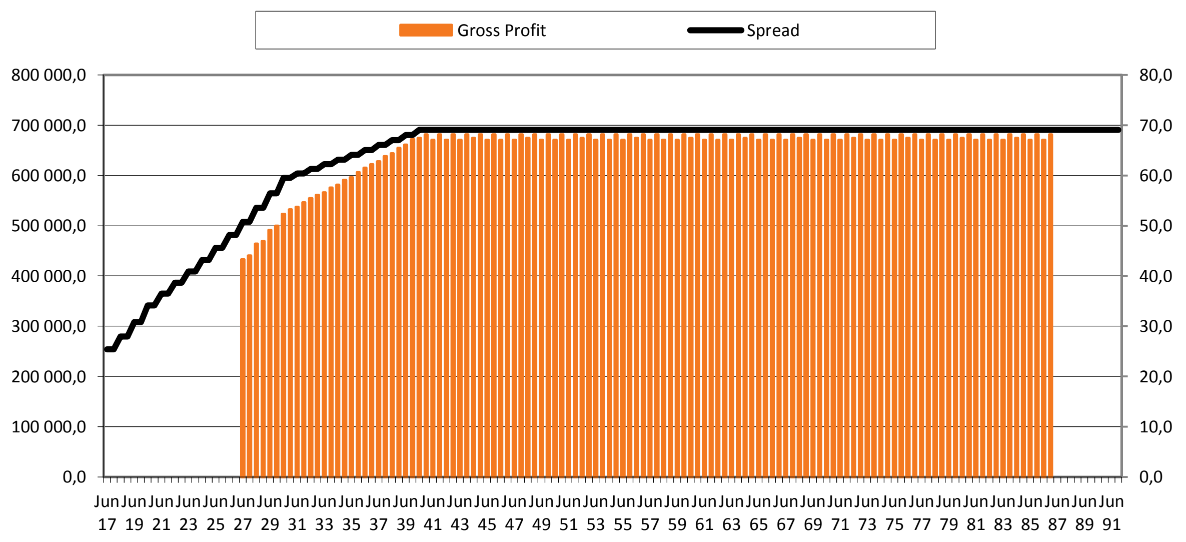
Figure 13: EBITDA Analysis



Source: Own calculations

The spread if the power plant reaches over EUR 70/MWh in the high scenario. Given the significant up-front capex even the robust gross profit development (the plant spread) is not able to amortise the investment even when other assumptions, such as ongoing O&M seem to be significantly relaxed.

Figure 14: Gross Profit & Spread

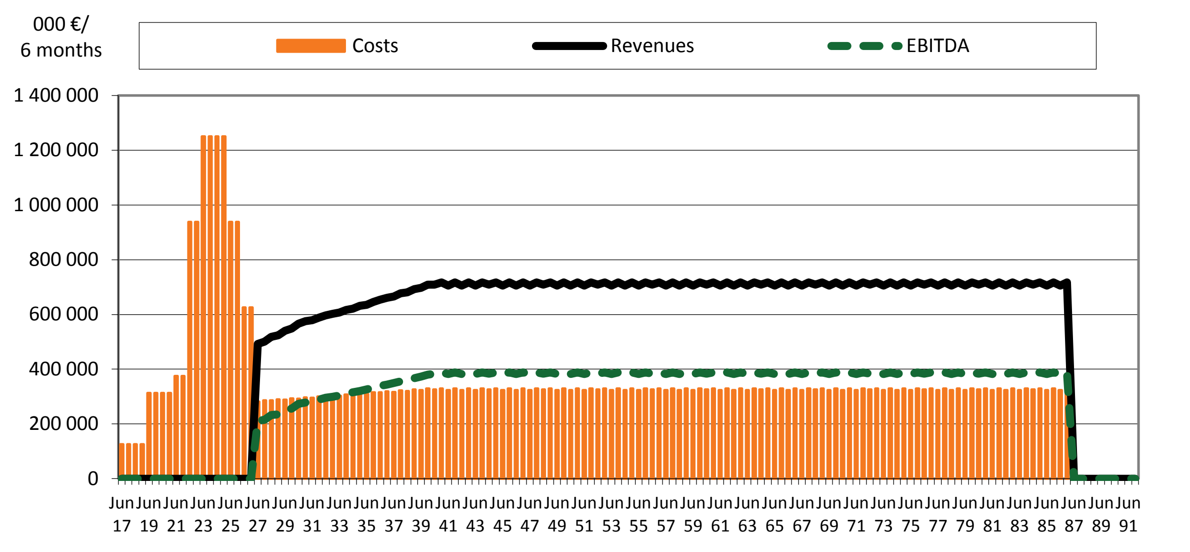


Source: Own calculations

4.4.4 EPR Base

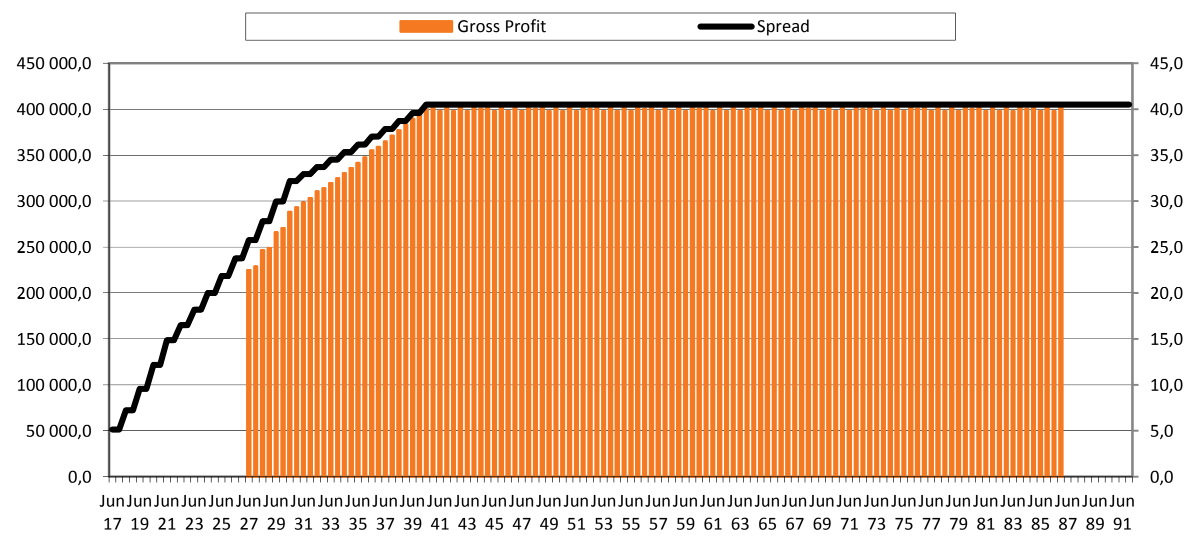
This section presents detailed results of the EPR Base case scenario. Compared to the first base scenario, the EPR base scenario has significantly higher operational costs. Costs grow in the first years of operations because of the increase in load, on the other hand revenues grow even faster because of the load increase and electricity price increase up to 2040, when our price forecast ends. As a result, EBITDA has a growing tendency until 2040, from when onwards it is flat. Similarly, the spread increase from EUR 25/MWh to EUR 40/MWh, which is much lower than EUR 60/MWh in the first base scenario.

Figure 15: EBITDA Analysis



Source: Own calculations

Figure 16: Gross Profit & Spread

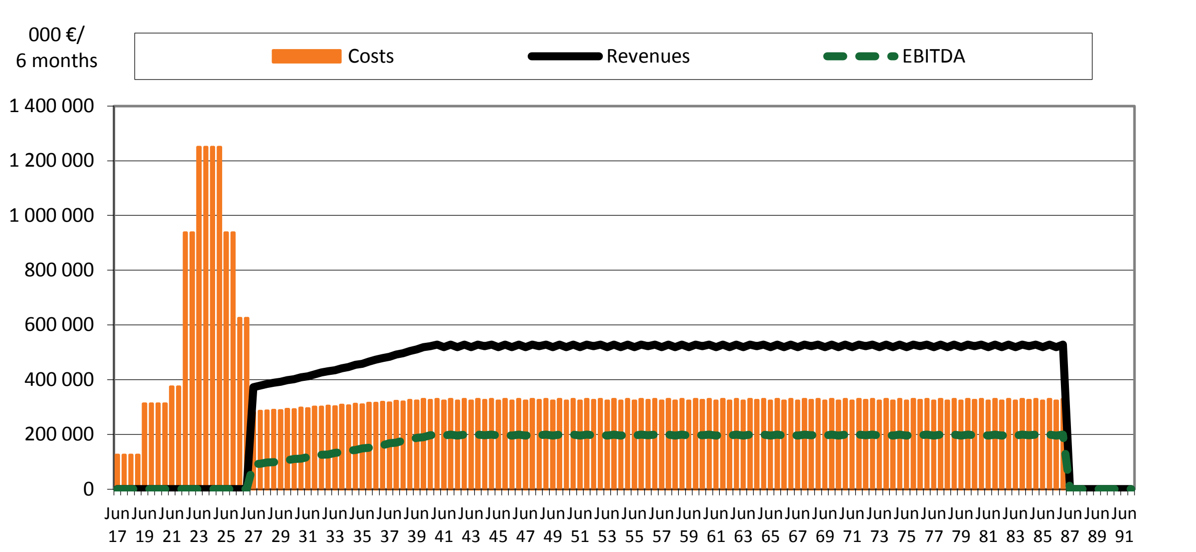


Source: Own calculations

4.4.5 EPR Low

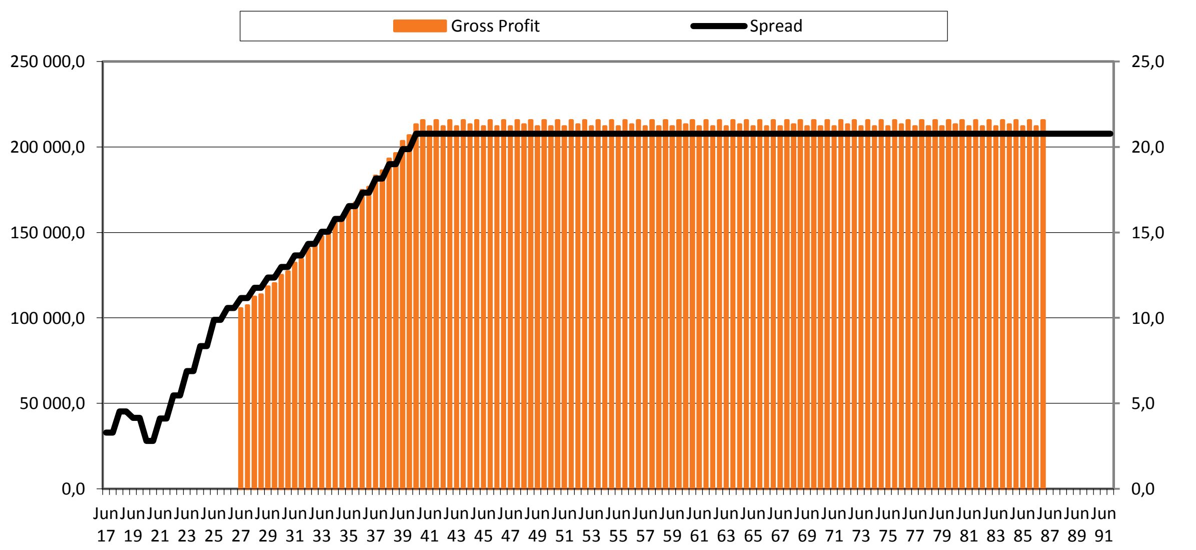
The combination of low price growth and high operational costs means that the plant achieves the lowest EBITDA of all scenarios. The highest spread achieved in this scenario is EUR 20/MWh.

Figure 17: EBITDA Analysis



Source: Own calculations

Figure 18: Gross Profit & Spread

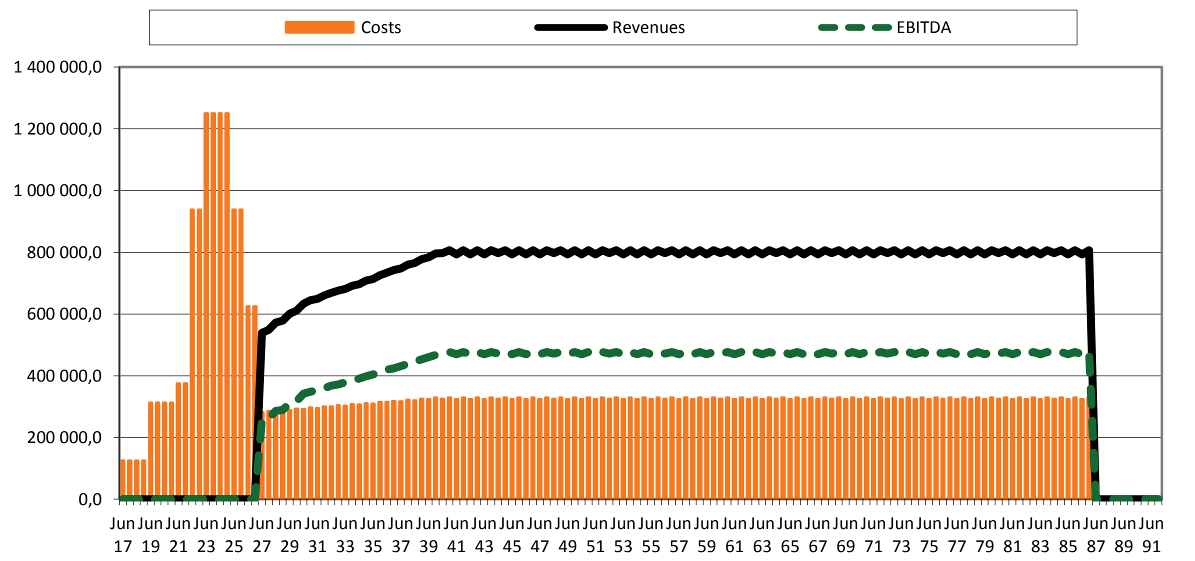


Source: Own calculations

4.4.6 EPR High

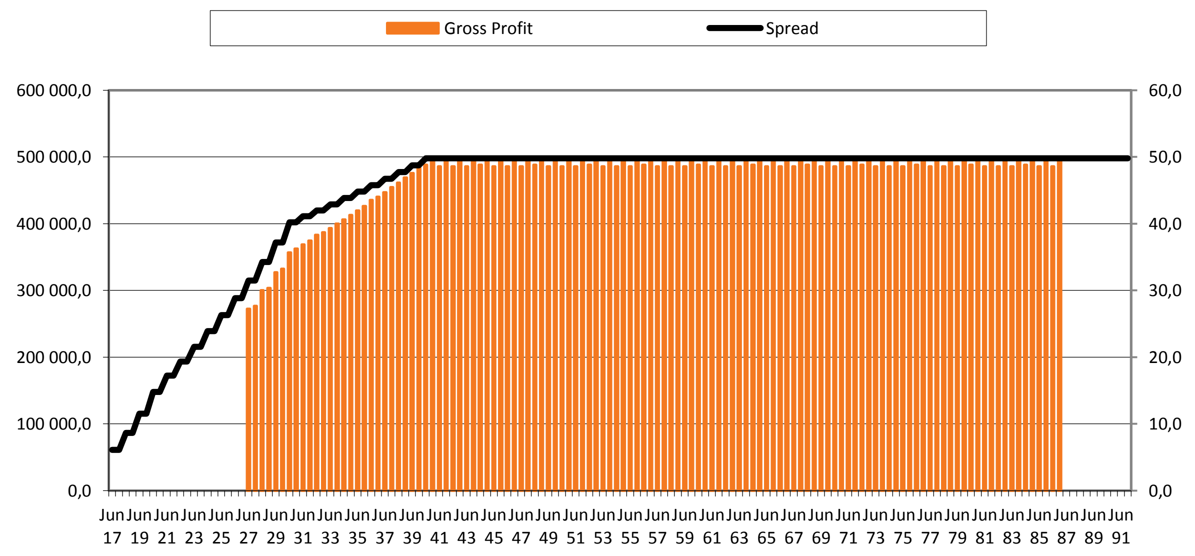
Compared to the EPR base scenario, the revenues are higher in this scenario. As a result, the spread is around EUR 10/MWh higher than in the EPR base scenario.

Figure 19: EBITDA Analysis



Source: Own calculations

Figure 20: Gross Profit & Spread



Source: Own calculations

4.5 Subsidy cost

Below we calculate the subsidy amount necessary to build and operate Paks II for each scenario, assuming the project breaks even at an IRR of 7%. We calculate the average annual subsidy by calculating the average difference between the calculated revenues in each scenario and the "optimal" revenue that would ensure IRR of 7% during the 60-year plant life. This subsidy level is calculated in real terms, at 2014 price level. In light of the negotiations for the Hinkley Point C project, we believe that expectation of 7% return is optimistic.

We believe that return expectations will move upwards closer to 10% to compensate investors for the risk of the project and may be pushed past the 10% hurdle, in order to take into account the Hungarian sovereign risk, which is significantly higher than the British sovereign risk. The amount of subsidy payable may thus increase significantly. However, in order to keep comparability with the Rothschild study we use the assumed 7% return expectation.

In a next step we calculate how much this subsidy would cost to an average Hungarian household consumer. We estimate this by taking the average annual subsidy calculated above and dividing it by Hungary's total annual consumption. In this case we take the 2014 value declared by Eurostat. Since Eurostat classifies household consumption as "Consumption Band Dc with annual consumption between 2500 and 5000 kWh", we then derive an estimate of the annual subsidy that an average Hungarian household would have to pay during the plant's 60-year operational lifetime. This household subsidy level is calculated in real terms, at 2014 price level.

Table 4: Average annual subsidy for each scenario

Scenario	**Average annual subsidy**	**Annual household subsidy (Consumption: 2,500 kWh)**	**Annual household subsidy (Consumption: 5,000 kWh)**
Base	€ 215,913,134	€ 15	€ 30
Low	€ 582,472,665	€ 41	€ 82
High	€ 45,942,501	€ 3	€ 6
EPR base	€ 553,661,249	€ 39	€ 77
EPR low	€ 920,220,780	€ 64	€ 129
EPR high	€ 383,690,616	€ 27	€ 54

5. THE IMPACT OF PAKS ON COMPETITION

In this chapter we look at the impact of the construction of Paks II on competition in the Hungarian wholesale electricity market. The aim is to calculate the current level of market concentration in the Hungarian market, and what impact the construction of Paks II will have on market concentration in the future. As a first step we define the relevant product and geographical markets. After that, on the basis of available data, we calculate market concentration values.

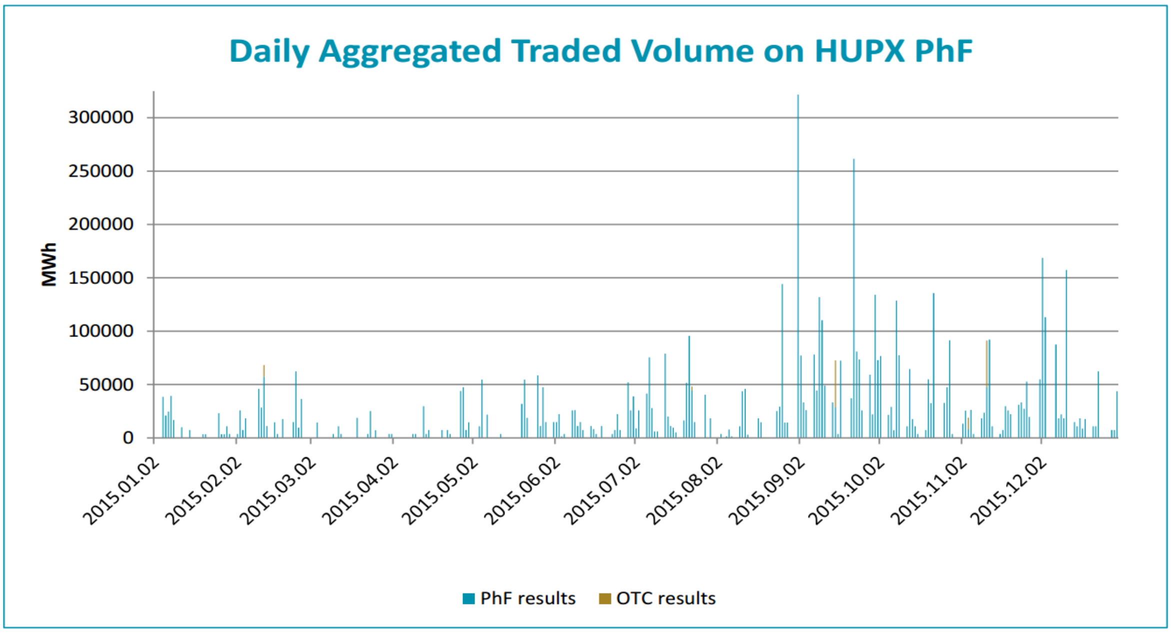
5.1 Product market definition

To see what impact the construction of Paks II will have on market concentration we must first identify the relevant product market. Paks II, like all power plants, will be selling its output on the electricity wholesale market. The electricity wholesale market is divided into many segments, including futures, day-ahead and over-the-counter ("OTC"). We use day-ahead prices for our analysis for the following three reasons.

First, the day-ahead market trades a standardised product which is comparable across borders and in time. For example, prices for OTC contracts are not easily comparable because these contracts are all different in terms of the obligations they impose on the parties.

Second, the day-ahead market is liquid and flexible, by which we mean it reacts immediately to changing market fundamentals (Zachmann, 2005). For example, the HUPX year-ahead futures market may be trading higher volume in certain hours, but there are a significant number of hours in which no transactions occur. This means its price is not representative of short run market fundamentals. For example, the chart below shows the volumes of traded physical futures on the Hungarian energy exchange.

Figure 21: Volumes of Hungarian futures traded on HUPX



Source: HUPX (2016)

Third, the day-ahead market can be defined as the marginal electricity market, the market which satisfies the residual demand. The day-ahead market is quite distinct from the OTC and year-ahead markets, from where base demand is supplied. The day-ahead market is precisely where we expect market participants to be realising their arbitrage opportunities stemming from momentary imbalances between demand and supply. In other words, in line with the Efficient Markets hypothesis, we can assume that OTC and year-ahead contract prices reflect all the market knowledge about future demand and supply conditions. If this assumption holds, arbitrage opportunities do not exist. This is because market participants act on the same information. Given that electricity is a non-storable commodity, the short-lived deviations from equilibrium (or planned) supply and demand make hourly prices very volatile and this is where arbitrage opportunities emerge. If Hungary forms one market with other countries in the region of Central Europe (dominated by Germany) arbitrage would quickly erode these deviations.

5.2 Geographical market definition and current trends

Compared to defining the product market, defining the geographic market is a more complex task. Electricity wholesale markets in Europe have undergone reforms in the recent decade with the ambition of creating a single European electricity wholesale market. One of the main tools to achieve this goal has been the unification of trading rules for national day-ahead exchanges and the implementation of implicit cross-border trading between European countries. This initiative is called market coupling. Currently Hungary's day-ahead market is coupled with Czech Republic, Slovakia, and Romania. Market coupling between the Czech and Slovak electricity wholesale markets was established in 2009, Hungary joined later in 2012, followed by Romania in 2014. The functioning of market coupling in this region, called "4M MC", is explained in the text box below.

Exhibit 1: Functioning of market coupling

The system selected to couple the national day-ahead markets of 4M MC was price coupling. This means that each market participant trades electricity in its own area. There is a power exchange in each market area. Prices and flows between the areas are set by the power exchanges of the individual market areas. Each power exchange collects the corresponding bids for their market areas and sets its own area price. When prices differ between two market areas, the power exchanges calculate the trading capacity between these areas necessary to equalise the price between them, thus creating a system price. To achieve this system price, the power exchange adds a 'price independent purchase' in the low price area, corresponding to traded volume, and a 'price independent sale' in the high price zone. As a result, the area price is lowered in the high price zone, and is increased in the low price zone, both equalling the system price. If the necessary trading capacity is higher than the interconnector capacity allows, bottlenecks are created and the markets are decoupled. Prices between the two areas will differ and there will be no system price. (OKTE, a. s., 2010)

In this chapter we will test the assumption that market coupling has worked and the 4M MC region can be defined as one relevant market. Then, we will go one step further and inquire whether the market is approaching the state of a unified European market, as this is the final goal of the initiative.

We therefore look at the price dynamics in Germany, the largest European price market and therefore possibly a price setter for the markets of other European countries.

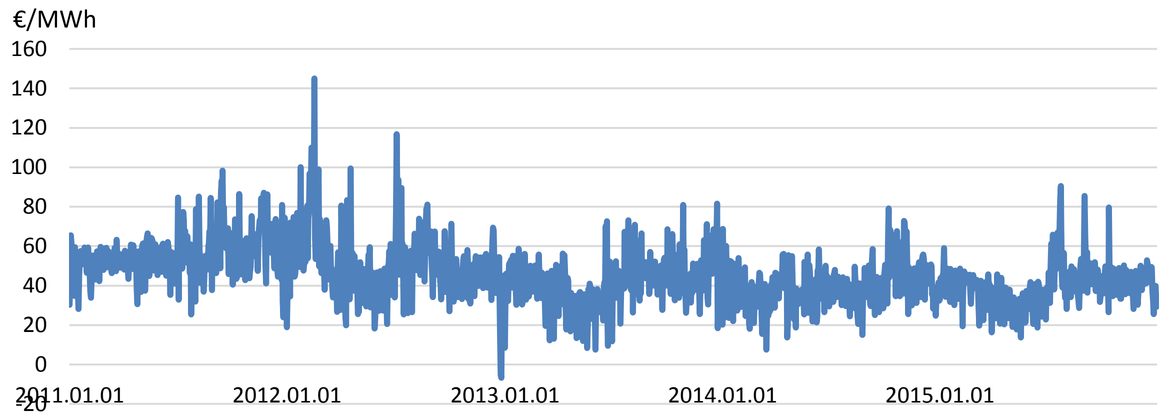
If neighbouring countries belonged to the same relevant market, electricity prices would be similar between one country and the other. In EU competition law, the relevant geographic market corresponds to an "area in which the firms concerned are involved in the supply of products and in which the conditions of competition are sufficiently homogeneous." (European Commission, 2011)

In our case we test if a firm in Hungary can increase its price without having to fear competition from neighbouring countries. If this were true, a customer could not switch to a non-Hungarian supplier when the Hungarian company increases its price significantly (Juselius & Stenbacka, 2008). Therefore, we first look at available data and at possible trends and factors to understand price dynamics in the data.

Below we show the day-ahead data we use for the analysis. We use averaged daily data from the main exchanges in the considered countries for the past 5 years (2011 to 2015). The average daily data represents base day-ahead price, which is quoted by every exchange.

Figure 22 below shows historical Hungarian day-ahead base prices for the years 2011 to 2015.

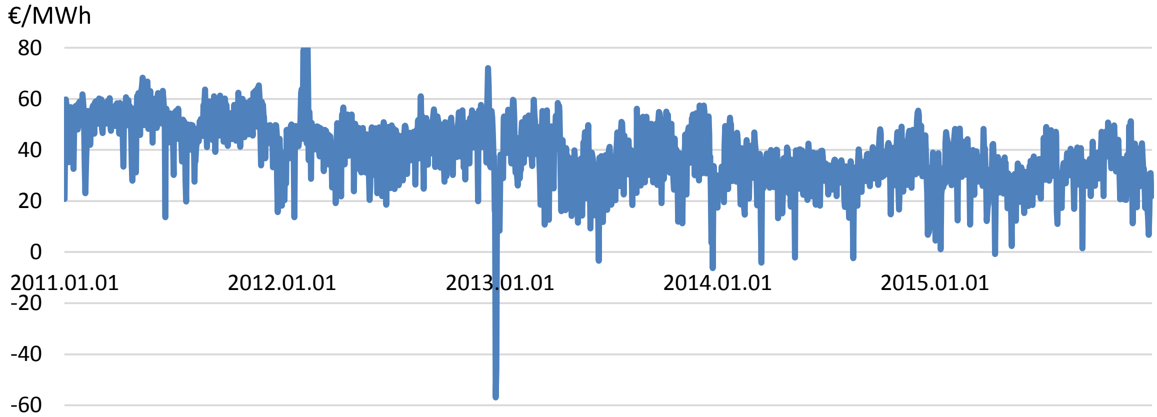
Figure 22: Hungarian day-ahead data 2011-2015



Source: HUPX (2016)

Figure 23 below shows historical German day-ahead base prices for the years 2011 to 2015.

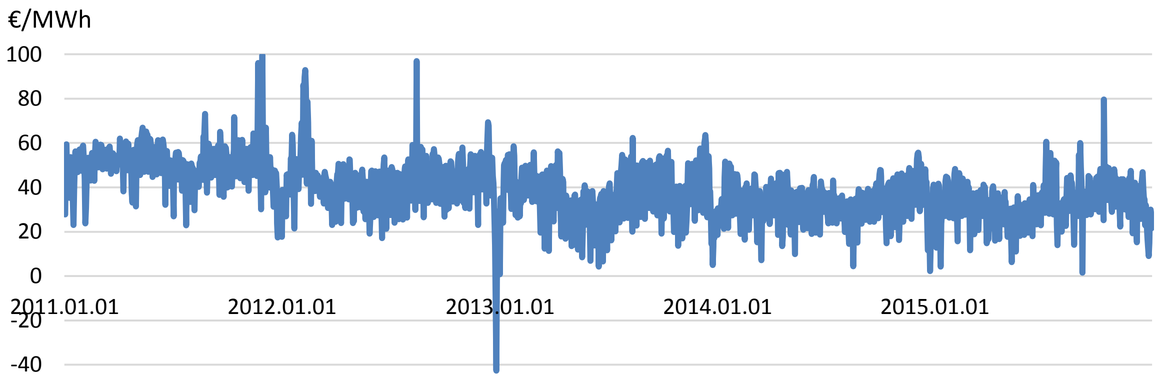
Figure 23: German day-ahead data 2011-2015



Source: EEX (2016)

Figure 24 below shows historical Slovak day-ahead base prices for the years 2011 to 2015.

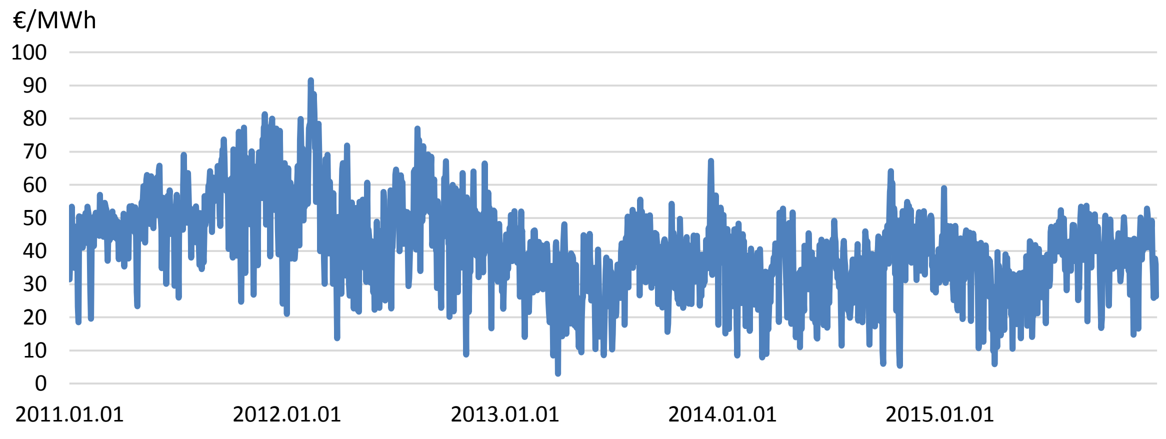
Figure 24: Slovak day-ahead data 2011-2015



Source: OKTE (2016)

Figure 25 below are the historical Romanian day-ahead base prices for the years 2011 to 2015.

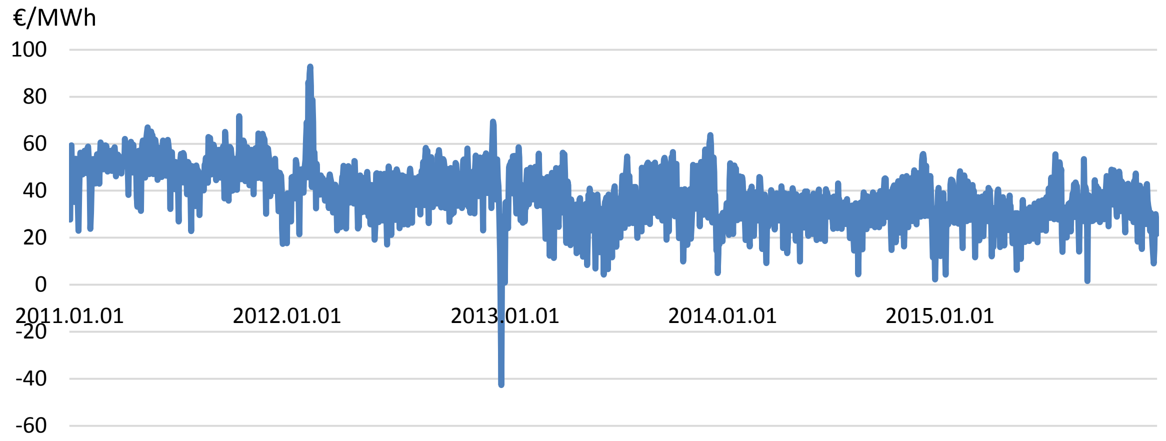
Figure 25: Romanian day-ahead data 2011-2015



Source: OPCOM (2016)

Figure 26 below shows historical Czech day-ahead base prices for the years 2011 to 2015.

Figure 26: Czech day-ahead data 2011-2015

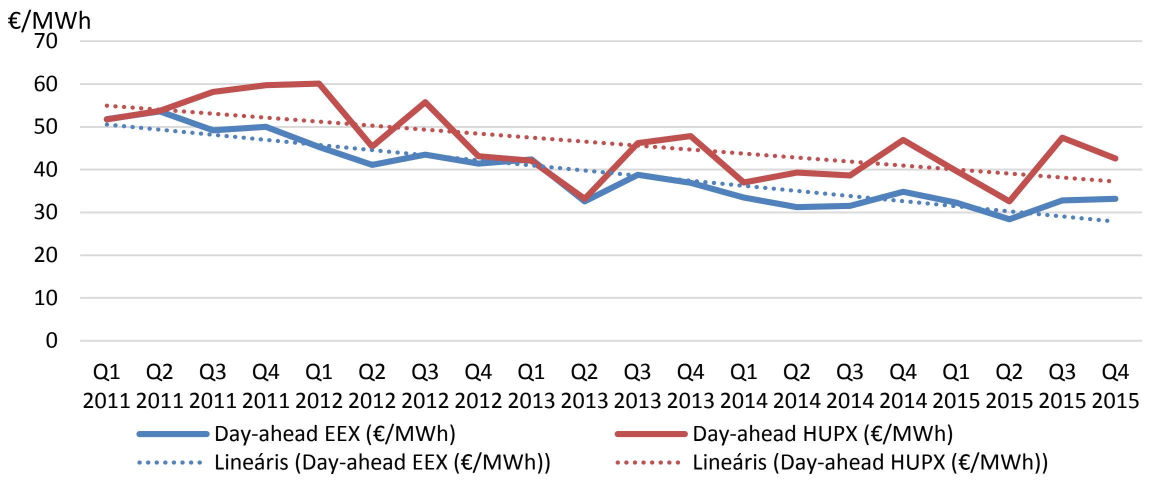


Source: OTE (2016)

At first glance, all data sets indicate a slight negative trend throughout the five years. While prices in 2011 easily hovered around EUR 60/MWh, they have declined significantly since then, averaging under EUR 40/MWh by the end of the observed period.

To emphasise this point, we look at the average quarterly prices for Germany and Hungary, which are depicted below.

Figure 27: Averaged quarterly day-ahead data 2011-2015

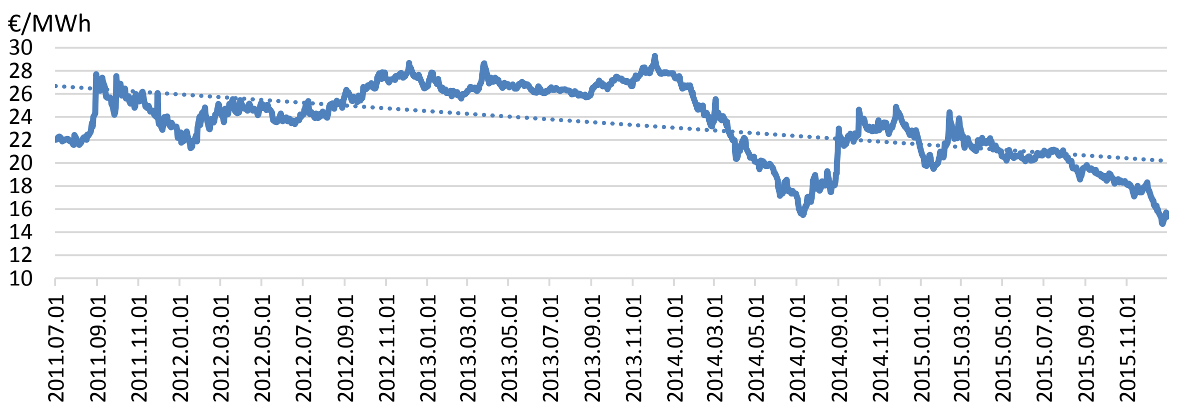


Source: EEX, HUPX (2016)

The graph indicates a trend, which has been continuing throughout the energy sector in Europe. Lower commodity prices, including gas, coal and carbon certificates and increased renewable energy has been consistently reducing the price of electricity. Gas, coal and carbon certificate prices have been reducing electricity prices because these are key inputs of marginal production costs of power plants in Europe. Because of the lower costs, plants participating on the market are bidding lower prices on the electricity market, resulting in a lower market price. The graphs below indicate the development of the prices of these key commodities in the past five years.

Below is the price of the NCG month-ahead contract for gas in Germany (Netconnect Germany). Prices of gas have remained relatively high, but slumped in 2014 and have not recovered yet. As of April 2016, certain contracts traded as low as EUR 13/MWh.

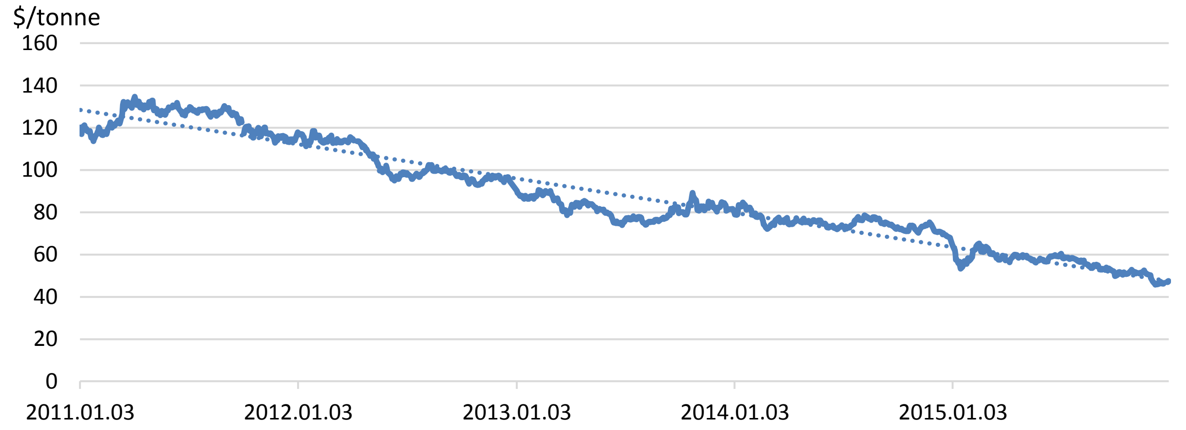
Figure 28: Daily NCG gas prices (monthly contract) 2011-2015



Source: EEX (2016)

Figure 29 below shows price of ARA month-ahead contract for hard coal (Amsterdam/Rotterdam/Antwerp). Prices have been consistently decreasing over the observed years.

Figure 29: Daily ARA hard coal prices (monthly contract) 2011-2015



Source: EEX (2016)

Figure 30 below is a depiction of carbon prices for the past five years. Prices have been in freefall because of the carbon certificates oversupply problem, but prices have been picking up since 2013 amid plans of a backloading system and Market Stability Reserve. These seem to have revived in the past two years, but as of April 2016 have declined again, trading currently at around EUR 6/tonne.

Figure 30: Daily carbon spot prices 2011–Q1 2016

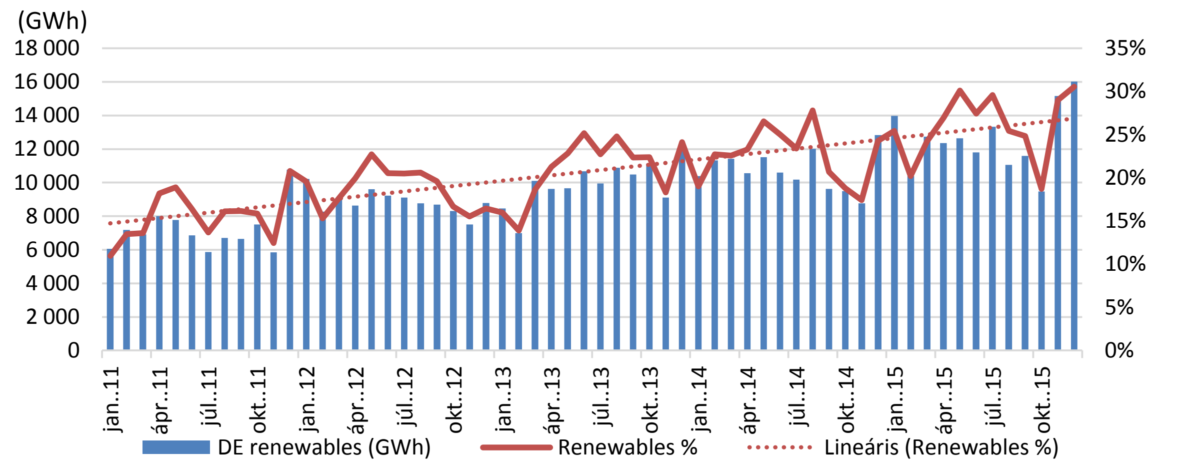
Source: EEX (2016)

Another factor that has had a strong impact on declining prices has been the increased production of renewables in the past years. Renewables' impact on wholesale market prices is twofold.

First of all, most renewable sources of energy, such a wind and PV, have low prices marginal costs, since they do not use fuel or emit carbon. As a result, they can bid low prices and are price takers of the equilibrium marginal price on the day-ahead market. Furthermore, since most renewable energy sources are currently still eligible for support programs, such as feed-in tariffs or green bonus certificates, many of these renewable producers do not participate on the free market (feed-in tariff), or can bid below their marginal prices (green certificates).

Figure 31 below depicts the development of the renewables generation in Germany in the past five years. The large increase in wind and PV capacity have increased renewables production share significantly, from around 15% in 2011 to almost 30% by the end of 2015.

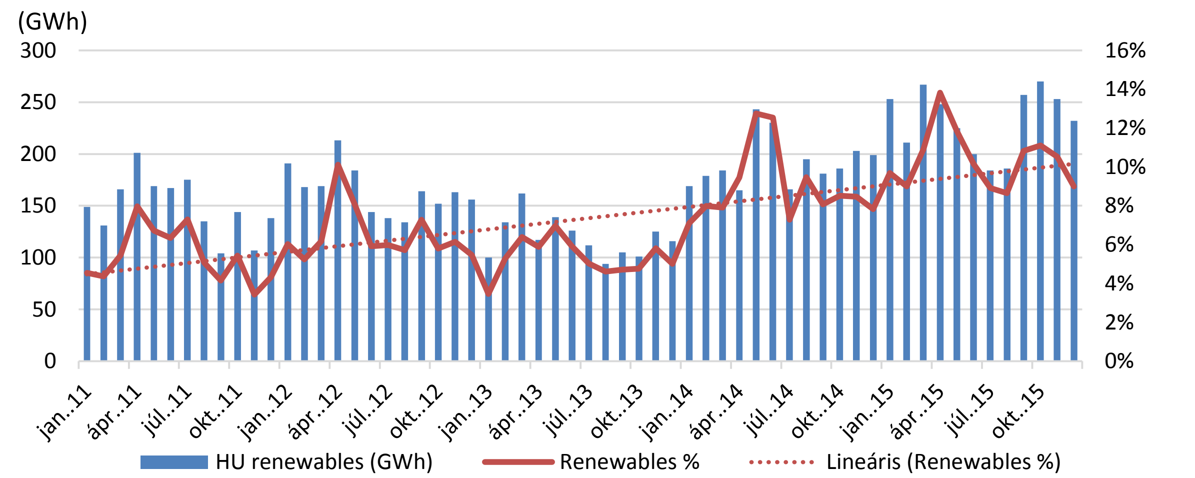
Figure 31: Renewables production and share in Germany 2011-2015



Source: ENTSO-E (2016)

The development of renewables production in Hungary has not been so substantial, but has seen and upwards trend too. In comparison to Germany which focuses on PV and wind capacity development, large share of renewables production in Hungary comes from biomass (however, a significant part of this production comes from co-firing of biomass in lignite plants). According to ENTSOE, in 2015 around 1,642 GWh of electricity from biomass were produced, in comparison to 670 GWh of wind and 13 GWh of PV production.

Figure 32: Renewables production and share in Hungary 2011-2015



Source: ENTSO-E (2016)

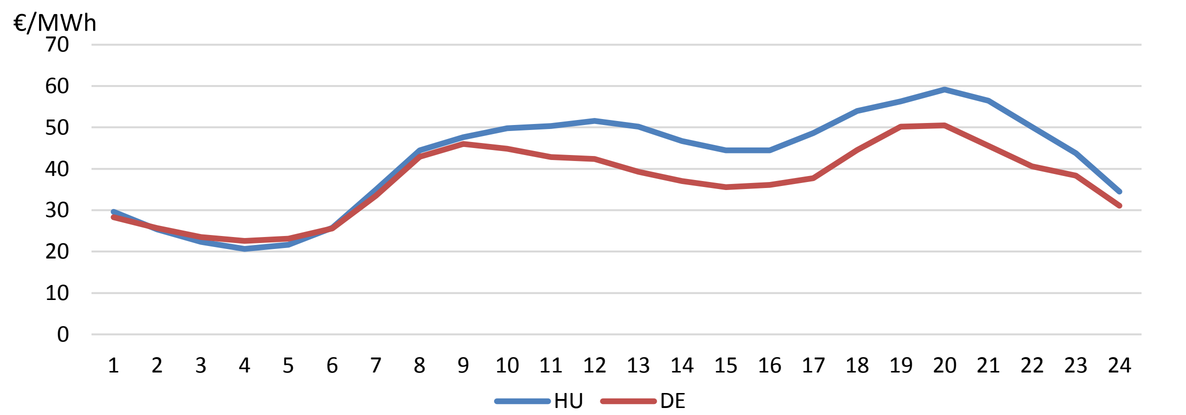
Given market coupling, and common factors influencing market fundamentals, it seems that price trends will be similar between the countries. In the next chapter, we give this assumption a closer look by looking at correlation between the different markets.

5.3 Price dynamics

If products in two geographic areas belong to the same market, their prices will be strongly correlated over time (Stigler & Sherwin, 1985). Generally, the higher the correlation between the prices in the two geographic areas, the stronger the evidence that both geographic areas belong to the same relevant market. Normally, academic literature gives a price correlation coefficient of more than 0.8 as an indication that the goods are competing in the same market (Motta, 2004). This methodology is based on the theory of arbitrage in international trade: if there is free trade, arbitrage between the areas will erode price difference, and prices in the two areas would become equal (Zachmann, 2005).

To calculate the correlation between the individual areas, we take the daily results of the day-ahead markets and calculate the correlation coefficient. Generators can bid for individual hours on the day-ahead market, but we believe it is more appropriate to use the (averaged) base price, as using individual hour data would overestimate correlation due to intraday seasonality bias. Correlation using hourly data would be high because of the similar periodicity – that is prices tend to be high during peak hours because of high demand, and low prices occur during the night (off-peak hours) because of low demand. This pattern exists in many countries irrespective of whether they belong to the same market or not. Figure 31 below shows averaged hourly day-ahead price and average hourly load values for comparison. The chart shows average hourly prices for the time period of a year (February 2013 to January 2014) for Germany and Hungary. The daily pattern is visible and similar between the countries, with Hungary having a more pronounced spread between peak and off-peak hours.

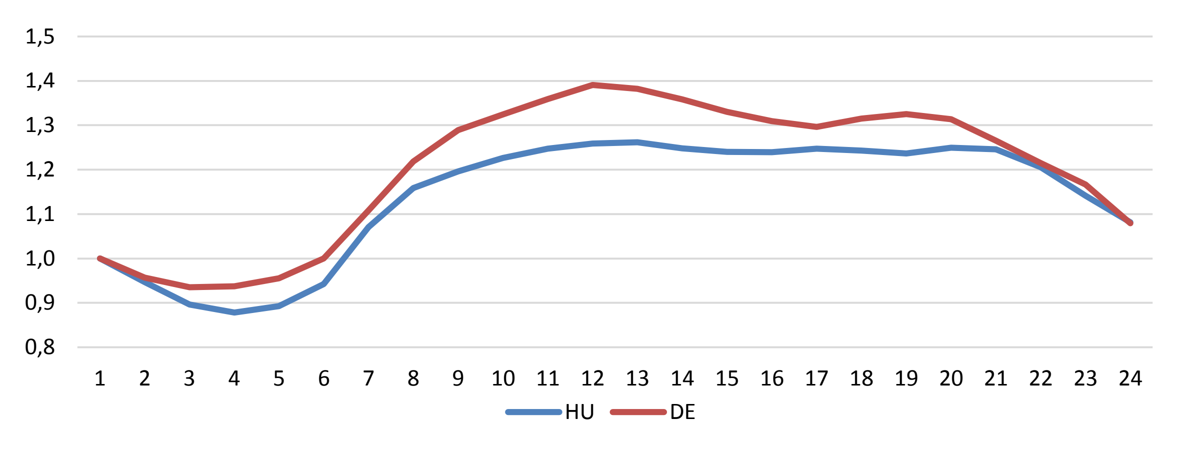
Figure 33: Average hourly prices during the time period 02/2013-01/2014



Source: EEX, HUPX (2016)

This pattern can be seen also in the load curve as shown by Figure 34 below. Here the German daily load curve is more pronounced.

Figure 34: Average load during the time period 02/2013-01/2014



Source: ENTSO-E (2016)

As a result, it is preferable to use daily values for correlation analysis, since hourly prices would overestimate the correlation between the countries due to intraday seasonal patterns shown above. We therefore calculate correlation coefficient matrix for Hungary and its neighbouring countries for the past 5 years. In addition, we calculate correlation coefficients for Czech and Slovak markets as a benchmark case to test robustness of our results. Czech and Slovak markets are widely regarded as one market for all purposes of power trading and therefore our analysis should show high correlation coefficients between the two markets. The results of this analysis are listed in the Table 5 below.

Table 5: Correlation coefficients

Year	HU-DE	HU-SK	HU-RO	CZ-SK
2011	0.51	0.56	0.64	0.94
2012	0.59	0.62	0.68	0.97
2013	0.52	0.65	0.51	0.98
2014	0.54	0.59	0.57	0.96
2015	0.53	0.66	0.70	0.93

Source: EEX, HUPX, OKTE, OPCOM, own calculations (2016)

In a next step, we remove similar weekly and holiday seasonality patterns from the data, by removing Saturdays and Sundays, and holidays. Leaving these data points in the dataset would similarly lead to overestimation of correlation. Then we calculate correlation coefficient matrix of day-ahead base prices between Central European countries and Hungary during working days. The results are presented in Table 6 below for each year in the data set.

Table 6: Correlation coefficients (excluding weekends and holidays)

Year	HU-DE	HU-SK	HU-RO	CZ-SK
2011	0.32	0.47	0.62	0.86
2012	0.46	0.49	0.63	0.93
2013	0.43	0.65	0.50	0.95
2014	0.32	0.43	0.53	0.91
2015	0.38	0.63	0.56	0.84

Source: EEX, HUPX, OKTE, OPCOM, own calculations (2016)

It is obvious from the calculations that the Hungarian market has a low correlation of day-ahead prices with its neighbors. This applies not only to the countries it is coupled with (Slovakia, Romania). It applies to Germany too, which is the largest market (price setting) in the region. The comparison with Czech Republic and Slovakia, which indicate a high correlation throughout the whole data set, puts these figures into perspective and confirms robustness of our approach.

The calculations above indicate that currently the Hungarian electricity wholesale market should be seen as a separate relevant geographic market for the purpose of evaluating the effect of the Hungarian state investment in Paks II. Despite market coupling, it seems that the Hungarian market is not integrated fully with neighbouring markets and, as a result, price differences persist. This can be caused by limited interconnector capacities, large differences in production costs or different market structures, (e.g. competitive markets vs. monopolistic market).

5.4 Current market concentration

After defining the relevant product and geographic market, we proceed by calculating market concentration in the Hungarian electricity wholesale market.

Market concentration and market power of firms can be measured using a number of methods. The assumption is that the more concentrated the market, the more likely dominant firms are capable of abusing their position. In our study, we use two measures of market concentration.

Firstly we calculate the Herfindahl Hirschman Index (HHI), which is a measure of market concentration used universally for various markets. It is the sum of the squares of individual market players. Due to the squaring of the market shares, the HHI is more sensitive to markets dominated by one or few large companies. The following table shows the classifications for the results of the HHI used by competition authorities.

Table 7: Classifications of HHI concentration levels

Scenario	Moderate Concentration	High Concentration
European Commission	>1,000	>2,000
U.S. Department of Justice	>1,500	>2,500

Source: European Commission and U.S. Department of Justice and Federal Trade Commission (2010)

The HHI was calculated by using the annual production as a measure for market share 2015. Before calculating the HHI, we cleared the data of effects of cross-ownership between companies. Regarding imports, we assume that 35% of imports are traded by MVM (State).[5] The results are listed in the following table.

Table 8: HHI level for Hungarian electricity generation sector in 2015

Country	Without imports	With imports
Hungary	3,481	2,594

Source: MAVIR, own calculations

Both values are significantly above the threshold considered to be indicative of high or moderate concentration.

[5] Since we have no 2015 values available we look at their 2014 level which was at around 40% (MVM, 2015) and 2013 level which was at 35%. (MVM, 2014) To be conservative we assume a lower value of 35%.

5.5 Future market concentration

As a next step we calculate the effect of the construction of Paks II on market concentration in the Hungarian wholesale electricity market. To do this we create two possible scenarios: in the first one Paks II does get built; in the other one, Paks II does not get built. Both scenarios are based on the National Energy Strategy 2030 by the Hungarian Ministry of National Development (Ministry of National Development, 2012). One notable difference is that we assume that the new nuclear capacity to be built will be of about 2,400 MW (this figure is consistent with the one mentioned in the Commission's letter of 23 November 2015).

It is important to note that the ownership structure is irrelevant for the assessment of market concentration, as long as there is one ultimate beneficiary owner of assets within the considered structure.

It is immaterial, for the purpose of calculating market concentration, whether Paks II will be owned by MVM or by other State-owned or controlled entities (or by the State itself). The position of the State on the Hungarian wholesale electricity market is relevant in this case: all generation facilities under State control are taken into account, unless there is evidence that they belong to separate/independent undertakings for competition purposes.

Therefore, for brevity purposes we shall refer Paks II as being a State controlled asset.

The considered scenarios are the following:[6]

1. Nuclear Scenario: assumes the construction of new reactors at Paks and the extension of the renewable energy utilisation path set in Hungary's National Renewable Energy Action Plan (NREAP).
2. Green Scenario: assumes that no new reactors will be built at Paks and the extension of the renewable energy utilisation path set in Hungary's NREAP.

We believe that these two scenarios from the National Energy Strategy are the most realistic ones. We do not believe that Hungary will be developing hard coal capacities in the future. First, financing of these projects will become harder as OECD countries have decided to limit export financing. (The Guardian, 2015) Furthermore, one of the main ambitions of the Hungarian energy strategy is to limit the import dependence of the Hungarian power sector. This would not be compatible with expanding coal capacity, and since 80% of Hungary's current coal reserves represent lower quality coal, Hungary would be dependent on the import of higher quality coal. (Euracoal, 2015) In the Nuclear scenario, around 2,400 MW of nuclear generation capacity will be built at Paks by 2030 latest. By 2040 all currently existing reactors will be decommissioned. Furthermore, all coal capacities will be shut down and replaced by renewable and natural gas capacities. These assumptions on future installed capacity in Hungary are summarised below:

[6] The Nuclear and Green scenarios are based on the scenarios of the Hungarian government's National Energy Strategy 2030, originally named as "Nuclear-Green" and "Anti-Nuclear-Green" scenarios

Table 9: Assumptions of Hungarian installed capacity in Nuclear Scenario				
Scenario	**2010**	**2030**	**2040**	**2050**
Nuclear	2,000 MW	4,400 MW	2,400 MW	2,400 MW
Coal	1,600 MW	0 MW	0 MW	0 MW
Natural gas	4,800 MW	5,600 MW	8,800 MW	10,800 MW
Renewables	600 MW	2,200 MW	3,000 MW	4,200 MW
Source: Ministry of National Development (2012)				

The Green scenario makes the same assumptions as the first scenario regard renewables and coal capacity. On the other hand, no new nuclear reactors will be built at Paks and this will be compensated by an increase in gas capacity. The assumptions on future installed capacity in this scenario are described below:

Table 10: Assumptions of Hungarian installed capacity in Green Scenario				
Scenario	**2010**	**2030**	**2040**	**2050**
Nuclear	2,000 MW	2,000 MW	0 MW	0 MW
Coal	1,600 MW	0 MW	0 MW	0 MW
Natural gas	4,800 MW	7,400 MW	10,500 MW	12,400 MW
Renewables	600 MW	2,200 MW	3,000 MW	4,200 MW
Source: Ministry of National Development (2012)				

We make further following assumptions regarding the two scenarios mentioned above:

Exhibit 2: Assumptions of scenarios

In both scenarios:

- The State retains its non-nuclear market share in the future. This means all non-nuclear operating plants retain their current market share.
- Paks expansion will have an installed capacity of 2,400 MW.
- All current operators will remain in the market and retain their market share.
- All new entrants will have a maximum market share of 1% each.
- The new installed capacity added will result in Hungary being self-sufficient and not needing imported electricity.
- Total electricity production will be capped at current production plus imports. According to MAVIR, production and imports added up to 44.75 GWh in 2015. We do not use the production figures from the energy strategy deliberately, as they assume a significant increase in electricity production. We believe this will not be the case because electricity demand has been stagnating for the past two decades.

The assumptions for the Green scenario are the same as in the previous scenario, with the following additions:

- The State will not expand Paks by another 2,400 MW. Alternatively, it will invest 1,200 MW in new gas fired capacities and another 1,200 MW into renewables.

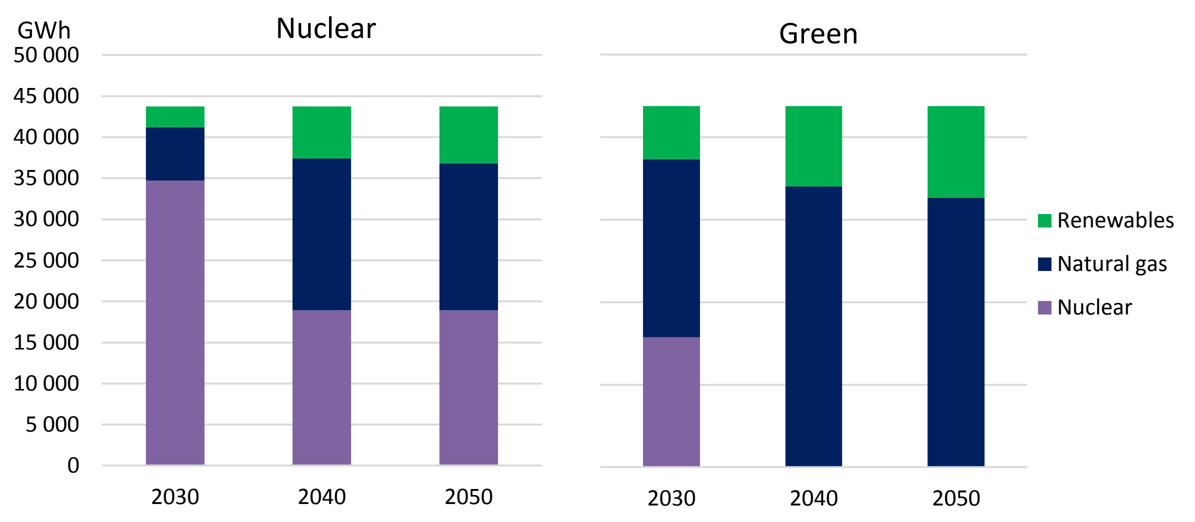
Given the assumptions above we calculate the following market concentration indexes with using HHI.

Table 11: HHI level for Hungarian electricity generation sector given two modelled scenarios			
Scenario	**2030**	**2040**	**2050**
Nuclear	6,889	2,582	2,582
Green	3,502	977	836

Source: Own calculations

It is evident from the calculations above that market concentration would be significantly higher in the Nuclear scenario. This is due to the fact that the nuclear power plants have significantly lower marginal costs than gas-fired plants and thus much higher load curves. Since all this nuclear production would belong to the State (directly or through MVM or other vehicles), the State would have a much higher market share than if it owned a corresponding amount of non-nuclear installed capacity. Figure 35 below shows the difference in generation breakdown between the two scenarios.

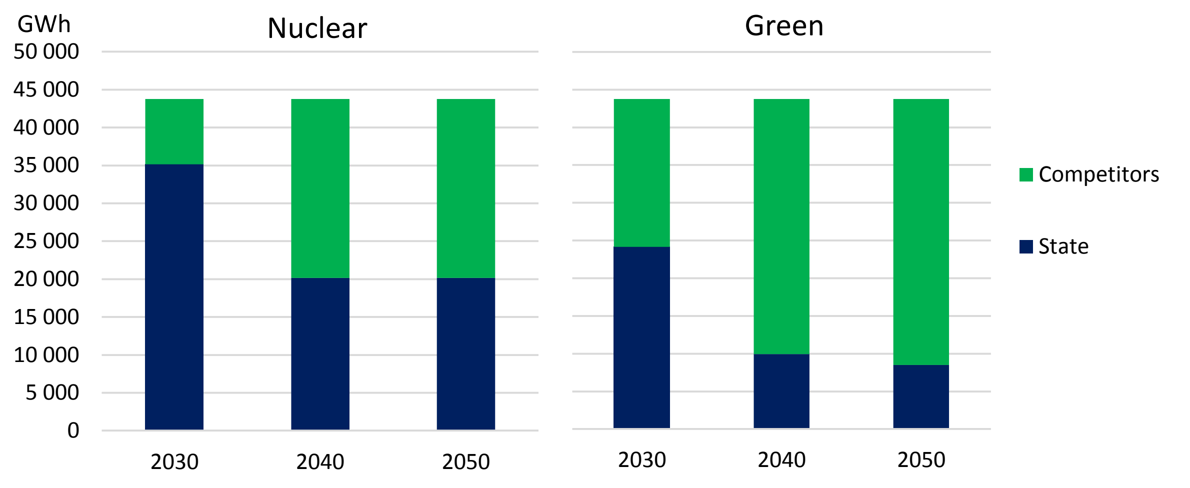
Figure 35: Generation by fuel for modelled scenarios



Source: Ministry of National Development (2012)

Figure 36 below shows the State's generation share in both scenarios. The State's market share falls significantly in the Green scenario because it has significantly lower load with its gas and renewables fleet.

Figure 36: Generation by fuel for modelled scenarios



Source: Ministry of National Development (2012)

5.6 Crowding-out effect

Crowding-out effect is a concept describing how public spending leads to decrease in private investments.

Taking into account the current and forecasted demand in the wholesale electricity market, as well as current and past government policies on electricity generation from renewables, there is a substantial risk that the proposed Paks II investment will determine a crowding-out of alternative projects in electricity generation and supply.

Economic theory states that government-funded investment may discourage the deployment of private capital making in the markets it affects, by making it unnecessary or unprofitable. In addition to the crowding out effect that is directly linked to the State funded investment, other government policies may hinder the development of alternative or competitive projects.

The study "Policy Challenges of Nuclear Reactor Construction, Cost Escalation And Crowding Out Alternatives" by Mark Cooper of Institute for Energy and Environment at Vermont Law School (2010) identifies four types of activities conducted by dominant (or state-controlled) utilities leading to crowding out of alternatives to nuclear energy:

1) Opposition to legislation promoting alternatives to nuclear power;
2) Manipulation of tariffs to undermine alternatives to nuclear power;
3) Building of large central station facilities, to dampen demand for alternatives, and/or,
4) Overstating costs of alternatives while understating the costs of nuclear (Cooper 2010, p. 38).

Cooper concludes, on the basis of extensive quantitative research, that "commitment to nuclear reactors in France and the U.S appears to have crowded out alternatives" (Cooper 2010, p. iv.). Specifically, he finds that the commitment to nuclear projects in the US and France have crowded out renewable generation. Cooper’s data show that states which have not committed to extensive nuclear projects have much better track record in renewable power and energy efficiency programs.

According to Cooper these states which had not focused on extensive nuclear programs had three times as much renewable energy and ten times as much non-hydro renewable energy in their generation mix and saved over three times as much energy. (Cooper, 2010, p. iv. – vi). The best example of this effect results from the comparison between Spain and France. Only in 2008, Spain added more wind power capacity (4,600 MW) than France had installed in total by 2007 (4,060 MW). (Cooper 2010, p. 32-33).

While committing to the development of Paks II, the Hungarian government is enacting policies discouraging investments into the renewable energy sector. These policies have the objectives, or at least the effect, of protecting the market share for the new nuclear project, independently from considerations of cost effectiveness. The government eliminated support schemes for renewables, introduced administrative and financial burdens to non-state energy investors and stopped renewable electricity tenders.

For example, in July 2010, the Hungarian government withdrew a fully prepared call for tender for wind generation (68 applications were filed in 2009, which could have led to 1118 MW of installed capacity). (Portfolio, 2010) The last time new wind capacity won on a tender was in 2006. No new tender procedure was initiated since then and no new wind capacity was built at least during the last 6 years.

In addition, the government imposed an import tax on solar panels, “claiming the move is necessary on environmental grounds”. (Parnell, 2016)

All those measures combined led to Hungary being the laggard amongst EU countries in terms of wind and solar investments. Hungary had only 329 MW of wind capacity as of the end of 2015, while Romania had 2976 MW and Austria had 2415 MW. (EWEA, 2016) Other similar sized countries (around 10 million people) had significantly more, e.g. Greece 2152 MW, Portugal 5079 MW, Belgium 2229 MW. Hungary had only 50 MW of installed solar capacity as of March 2015, with 1300 MW in Romania, 2282 MW in Czech Republic, 750 MW in Austria. (Solar Power Europe, 2015)

The above statistics indicate that the Hungarian government has been already taking steps to create demand for new nuclear power plant by discouraging alternative investments. There are serious concerns that, should the investment in Paks II be put in place, there will be little residual space for the installation of new generation capacity from renewable sources.

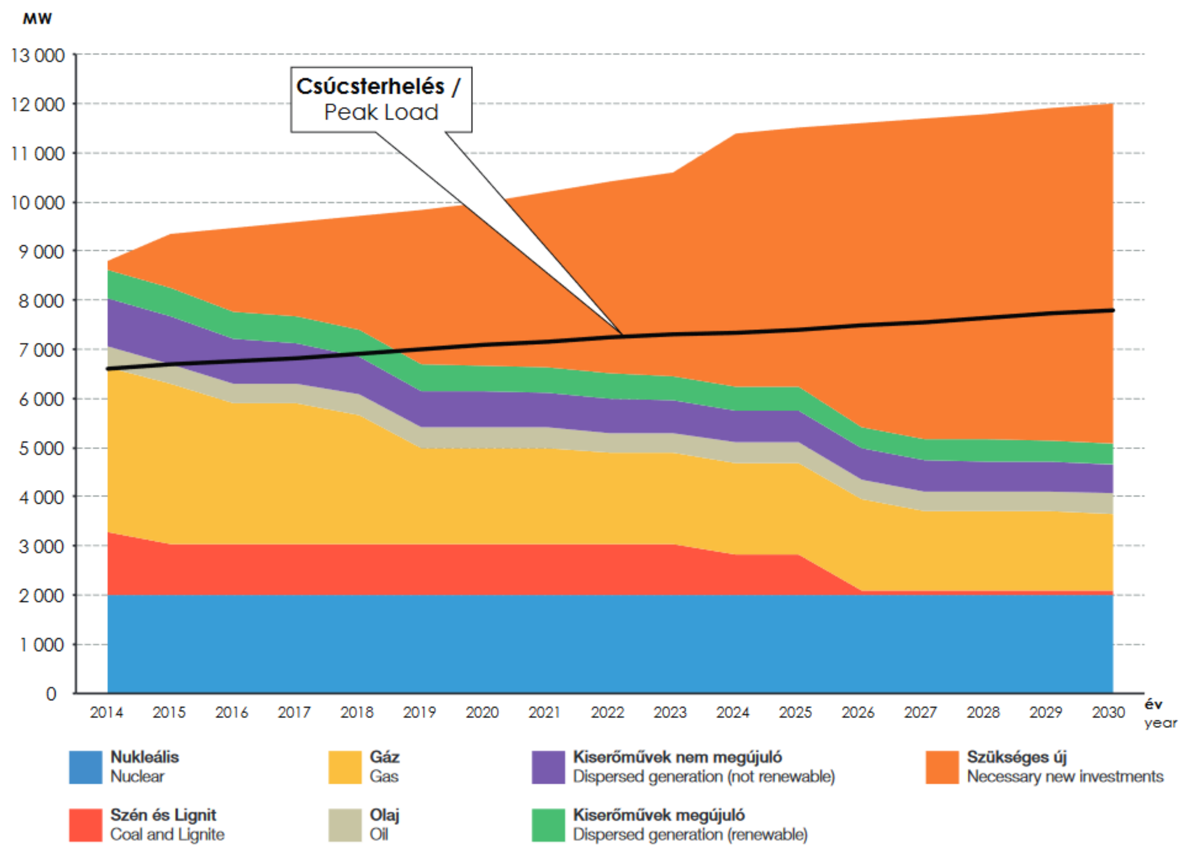
6. ALTERNATIVES TO THE PAKS EXPANSION

In the previous chapter, we argued that the construction of Paks II could increase market concentration and thus have unwanted negative consequences for competition on the Hungarian electricity wholesale market.

The government claims that investing in Paks II is necessary and justified because, due to a market failure in the electricity generation sector (the market alone does not deliver the construction of new generation capacities), Hungary is dependent on electricity imports.

According to the government, this dependency will increase in the future because obsolete power plants will get decommissioned, and no new replacements are being planned. The government considers that building new capacity will minimise Hungary's import dependency and thus address the consequences of the above mentioned market failure. This problem is depicted in the following chart by Hungarian TSO MAVIR.

Figure 37: Generation by fuel for modelled scenarios



Source: MAVIR (2015)

The Hungarian government however fails to explain how and why this alleged market failure occurs and how would a subsidy for the construction of a state-owned nuclear power plant remedy such a failure. We are not aware of any arguments being put forward by the Hungarian government to elucidate this issue.

We can only assume that, effectively, the Hungarian government intends to prevent that a large share of power consumption be covered by import.

This reasoning however is not supported by any economic theory (and is inconsistent with the very notion of an internal energy market). It is not clear why imports of cheaper electricity from other EU countries should be seen as the result of a market failure, rather than as a normal and acceptable effect of a functioning market. Indeed, the ability to buy commodity at lowest price irrespective of place of origin indicate market functioning.

The Hungarian government may also be implying that the alleged "market failure" manifests itself in decreasing power prices, which do not provide incentive to the construction of new capacity. We do not share this view. Power prices are determined by many factors, such as commodity prices, supply and demand. Recent declines in power prices indicate market reaction to low global commodity prices, strong supply of power (Europe suffers from chronic generation overcapacities) and stagnant or decreasing demand.

The recent price development is indicative of efficiently functioning markets pricing in the above parameters, rather than of a market failure. A recent study of Ecofys commissioned by the German government, which analyses the necessity of capacity mechanisms (Ecofys 2012), concurs with our arguments and rejects the hypothesis of market failure.

But even if this alleged market failure really exists as the Hungarian government asserts, the government should consider more options before committing to the Paks II project. Specifically, Hungarian government would be obliged to issue EU-wide capacity tenders which must be transparent and non-discriminatory. This means any project developer from any EU country should be able to bid for capacity which the government desires to build. Below we present the example of Germany to show how competitive auctions could deliver desired new capacity and reduce costs.

6.1 Germany

With its Energiewende, Germany has decided to phase out certain capacities, such as nuclear, and focus on the expansion of renewables generation capacity. While initially the expansion of renewable energy in Germany was supported through feed-in-tariffs, the system has been changed and priority is now given to auctions. Focus will be on onshore and offshore wind power and for large photovoltaics, both on the ground and on rooftops. On the other hand, support for hydro, small PV projects, biomass, and geothermal will still be determined by the state. This means that more than 80% of new additions to renewable capacities will come from auctions. (Amelang & Appunn, 2016)

The auction rules can differ from technology to technology, but generally the following principles apply:

- The projects applying should meet the requirements of the Federal Immission Control Act (Bundes-Immissionsschutzgesetz);
- A financial qualification requirement, such as a deposit or a guarantee may be required;
- There can be up to 3-4 rounds of auctions per year. Projects that failed in previous auctions should be able to take part in future auctions;

- Pay-as-bid pricing or uniform pricing rule should be generally applied;
- A maximum price should be set for each auction, but no floor price;
- The delay for the implementation of projects can vary by technology but should be around 24 months, and,
- Penalties for non-compliance and delays are also applied. (Klessmann et al., 2015)

The following tenders have so far occurred:

- The pilot tender took place in April 2015, when 150 MW of solar capacity were auctioned for an average price of EUR 91.7/MWh. This auction used the pay-as-bid rule;
- Another tender took place in August 2015 where 159.7 MW of solar capacity were auctioned for a clearing price of EUR 84.9/MWh. The uniform pricing rule was used;
- The third PV tender was held in December 2015, where another 204 MW of solar capacity were tendered for a clearing price of EUR 80/MWh. As in the previous tender, the uniform pricing rule was used, and,
- The latest PV tender took place in April 2016, when 128 MW of solar for a price of EUR 74.1/MWh was tendered. This is the lowest price so far. (Clean Energy Wire, 2016).

In conclusion, after twelve months of launching tenders for renewables support in Germany the tender price has decreased significantly, resulting in lower subsidy costs for consumers. Specifically, within one year, the tendering system resulted in a reduction of the tender price by almost 20%.

6.2 Comparison of costs

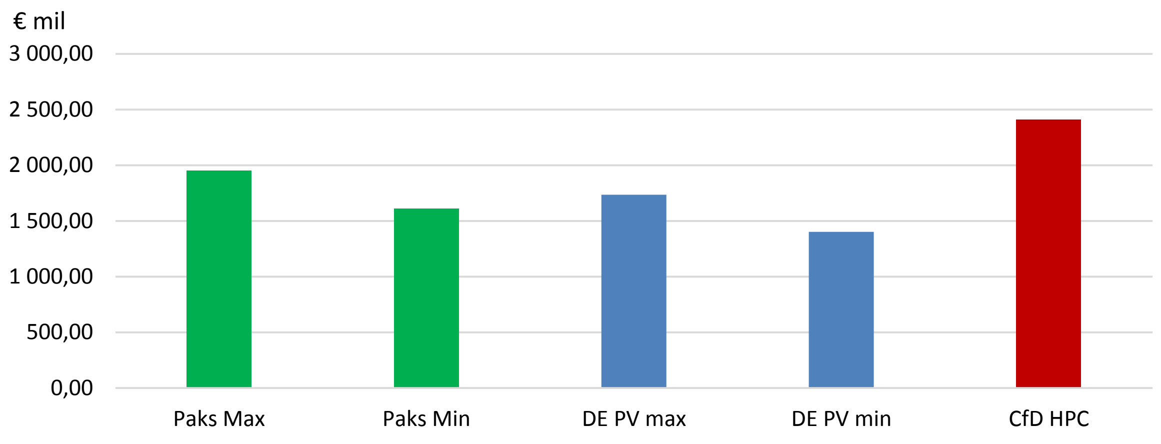
In a final step, we compare these support schemes, and how much the total costs of capacity and energy payments would apply to the final consumer. We make the following assumption of a project such as Paks II, with an installed capacity of 2,400 MW and annual production of 18,922 GWh and apply the following schemes to the project:

- Paks projects with a feed-in tariff of EUR 85/MWh, as calculated in our FM (Paks min);
- Paks projects with a feed-in tariff of EUR 103/MWh, as calculated in our FM (Paks max);
- Support scheme according to the most expensive German PV tender at EUR 91.7/MWh (DE PV max);
- Support scheme according to the latest German PV tender at EUR 74.1/MWh (DE PV min), and,
- Contract-for-difference scheme for the Hinkley Point C as approved by the UK government at £92.5/MWh or EUR 127.4/MWh (CfD HPC).

The chart below shows the cost of the different schemes given the same annual level of production, where the estimated Paks II production is taken as a reference. The table and chart below summarises the findings of these calculations.

Table 12: Assumptions of total costs of various support schemes					
Scenario	**Installed capacity (MW)**	**Production[7] (MWh)**	**Capacity price (€/MW)**	**Energy price (€/MWh)**	**Total scheme cost (€ mil)**
Paks max	2,400	18,767,494	0.00	103.00	1,933.05
Paks min	2,400	18,767,494	0.00	85.00	1,595.24
DE PV max	-	18,767,494	0	91.70	1,720.98
DE PV min	-	18,767,494	0	74.10	1,390.67
CfD HPC	-	18,767,494	0	127.44	2,391.70
Source: Own calculations					

Figure 38: Total costs of various support schemes



Source: Own calculations

[7] We use the same installed capacity as in the Rothschild report, which quotes an installed net capacity assumption of 1,180 MW as stated in an IEA/NEA report. We however cannot verify the correctness of this assumption.

7. CONCLUSIONS

In this study, we evaluated the economic feasibility of Paks II. We built our own proprietary financial model to replicate the financial modelling undertaken by Rothschild & Cie on behalf of the Office of the Hungarian Prime Minister. We used the same assumptions as the Rothschild study regarding investment costs, operations and maintenance (O&M) costs, financing costs and the economic and technical lifetime of the proposed plant in order to allow a straightforward comparison of the results of the two studies.

The objective of this study is to provide for an independent feasibility review of Paks II under various stress tests, mostly on the revenue side. To err on the conservative side, we took investment costs and cost of capital at face value. We did not challenge the investment cost value because it derives from the contract with EPC contractor Rosatom. Given inherent difficulties in assessing weighted average cost of capital for listed projects with 60 years lifetime we decided to use the estimate of WACC calculated by the Rothschild study, although we believe it is understated and does not represent the true cost of capital for power generation projects in Hungary.

We created two scenarios for O&M costs. The first tranche of scenarios assumes the lower bound of O&M and decommissioning costs estimates as used by the Rothschild study. The second tranche of scenarios is based on the assessment of O&M and decommissioning costs made by the French Court of Auditors, which we believe are more realistic. Under our stress test revenue side scenarios, Paks II does not generate a positive Net Present Value, even when assuming the lower bound of O&M cost estimates used by the Rothschild study. As we point out above, our revenue side scenarios err on the side of being conservative as even our low-case scenario trends significantly above the current pricing of power futures contracts.

We reviewed the power price forecasts used by the Rothschild study to calculate the plant revenues. We found the price expectations of the Rothschild study to be overstated, in particular given the current commodity environment. The Rothschild study uses the concept of long term marginal costs to determine future power prices. While this concept is theoretically sound, we believe that it has several significant empirical flaws and is not very helpful for modelling power markets besides academic literature.

This methodology relies on the key assumption that in the long run, the market must, on average, produce a power price which allows for the construction of new power plants: in addition to fuel, operations and maintenance (short term marginal costs), the price must also allow investors to recover their investment costs, including the cost of capital.

Second, this theory is not supported by evidence from European power markets since the market liberalisation. This is because once a power plant is built, it becomes sunk cost and its operator bids only the marginal cost of power production to at least cover the costs of production. This has certainly been the case on the Central European power market, which developed significant overcapacities in the 80s and 90s prior to liberalisation and unbundling.

Finally, a large and growing share of Central Europe's generation capacities recover their investment cost from out-of-the-market financing mechanism, such as subsidies from consumers (e.g. feed-in tariffs and green bonuses for renewable energy) or by direct purchases by industrial and household consumers to cover their consumption (in these cases the economics are based on savings compared to the grid cost of electricity).

In our view, the price expectations of the Rothschild study are outdated and overstated. We presented our own power price estimations given the commodity price assumptions of the World Energy Outlook 2015. Despite our forecasts being lower than the ones presented by Rothschild, our figures are still more bullish than current market expectations. Figure 8 on page 11 shows Hungarian power futures trading at lower levels than our low commodity scenario forecasts in spite of the Hungarian price premium on the German power price.

We created our own price forecasting model based on the merit-order dispatch rule. To do that we calculated the variable generation costs of power plants based on the commodity scenarios of International Energy Agency and on the expected effect of the European carbon market reform. The merit order rule simulation set the price according to the variable costs of production of the last power plant needed to be dispatched to satisfy given demand.

We then tested the robustness of Paks II returns under various commodity and O&M costs scenarios. Paks II does not earn return equal to its weighted average cost of capital (WACC) (even when estimated at 7%) in any of the tested scenarios. We conclude that Paks II is uneconomical in each tested scenarios and would have to be significantly subsidised by Hungarian taxpayers.

The net present value (NPV) of the project is negative across all scenarios, meaning that investors will not be able to recover their investment over the assumed 60-year lifetime of the project, despite several bullish assumptions used in the Rothschild study. In addition, we believe the assumed cost of financing at 7% is quite generous and may not reflect the true cost of capital (especially equity) in view of submissions for the Hinkley Point C project, in which the desired return used to set the subsidy price is set at 10%.

In conclusion, the project is not feasible on a commercial basis and should be abandoned as it would lead to value destruction. The most severe value destruction would happen if power prices developed in line with trajectory of the Low scenario, which seems to be the most probable scenario based on the current pricing of futures power contracts. The results also show a big sensitivity of project returns to the assumed operations and maintenance costs.

In the second part of the study, we analysed the impact of Paks II on competition on the Hungarian power market. First we found that the relevant market for assessing impact of Paks II is indeed Hungary, not a coupled CEE market (and thus even less a EU-wide market). This is evidenced by low correlations between power prices in Hungary and surrounding countries. The conclusion of the correlation analysis is that there are factors hindering a seamless trade between Hungary and neighbouring countries.

Second, we tested market concentration in the Hungarian power generation market based on scenarios with and without Paks II project. We found that Hungarian state currently has a dominant position on the Hungarian power generation market and this dominance will be even increased with the commissioning of Paks II. On the other hand, the nuclear-free scenario of the Hungarian energy policy shows low market concentration ratios, reflecting a competitive power market.

In addition, we found that Paks II will likely have a crowding-out effect on the alternatives to nuclear power generation with lower costs than Paks II. We presented the evidence of recent German renewable power auctions to illustrate how competitive process by private capital can deliver the needed generation capacity in cost-efficient way.

In conclusion, we found that the Paks II project is not economically viable without state subsidies. The subsidy will have an incentive effect as the project would not have happened in its absence. However, we believe that this incentive does not meet the proportionality principle since the electricity demand in Hungary could be met at a lower cost by electricity imports or other solutions, such as investment into energy efficiency measures or renewable energy.

In addition, we noted that the Hungarian government fails to present any evidence of market failure which Paks II should address. One could only assume that by market failure, the Hungarian government means recent decreases in power prices. In our view there is no deterministic link between low commodity prices and market failures. On the contrary: we believe that the current situation shows that the markets function well as commodity prices reacted to the oversupply of power and gas, the low carbon prices and the stagnant demand.

Finally, we found that Paks II project has a potential to distort competition on the Hungarian market as it would petrify the current situation with the dominant market power of state-controlled generation companies. This is evidenced by market concentration measures significantly above any thresholds considered for competitive markets by competition authorities.

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