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Coal Based Electricity Generation in South East Europe: A Case Study for Croatia

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ABSTRACT: In this paper, we have provided an evaluation of the techno-economic performance of a coal-fired power generation unit designed and constructed following the current best available techniques (BAT) principle and situated in South East Europe (SEE). We have provided the framework of a technical model of an ultra supercritical pulverized coal-fired power plant (USC or USCPC), conducted a detailed analysis of associated costs, presented a composite cost model and performed a sensitivity analysis to identify the main cost-drivers for this type of technology. Furthermore, a market analysis has been carried out to best determine the impact of the surrounding environment on the overall performance of the project.

Keywords: Ultra supercritical unit; South East Europe; Feasibility
JEL Classifications: L1; M3; O2

1. Introduction

Europe is one of the world's major energy consumers, but possesses limited indigenous energy resources of its own. Global geopolitical developments, global economic turbulence and sometimes extreme energy prices have, especially in recent years, caused the need to carefully examine all possible options that might influence on the economic performance of an investment in the electricity sector. Citizens and industry are reliant on energy, particularly electricity, and require it to be available at all times and at affordable prices. Over the past decade, fossil fuels, and particularly coal, have satisfied the major share of the incremental growth in primary energy demand. At the moment, fossil fuels supply around 81% of the world's primary energy. When looking at the electricity generation by fuel, fossil fuels are used to produce around two thirds of the world's electricity; coal, natural gas, and oil contribute about 41%, 22% and 5% respectively (IEA, 2012). Emissions of environmental pollutants from power plants have led to an increase in stack emissions that are causing air quality degradation. Despite emerging as an overall global issue, directly related to the quality of life, as the global demand for energy continues to grow, paired with a relative abundance of fossil fuels and the proven technologies for using them, it seems that fossil fuels will continue to be used in the future as well. Despite the fact that recent movements towards renewable energy during the past few years were made possible with the adoption of various schemes and investment incentives in several European countries, conventional technologies such as nuclear, coal and gas generation continue to form the basis of the generation mix mostly due to their reliability and lower generation costs. Although, at present, renewable energy sources represent a small share in the total energy consumption, solar and wind power plants are considered the fastest growing energy sources (de Oliveira and Fernandes, 2012). However, in a transition phase towards a sustainable worldwide energy system fossil fuels (coal in particular) should remain a significant source of energy for several decades to come (Lucquiaud et al., 2011).

Every large project requires an equivalently large investment; this is one of the main reasons that careful planning and detailed analysis of different factors influencing the financial performance of such an investment are imperative to best understand the project specifics and be able to commit to an arduous task such as constructing a large-scale power generation unit. Our paper is aimed to provide for a better perspective on the techno-economic performance of a coal-fired power generation plant situated in South East Europe. Our principal objectives in this paper are to (1) provide a detailed cost model of an USCPC power plant; (2) conduct a market analysis with sensitivity cases to determine the impact of several factors on the techno-economic performance of the investment.

The Long Run Marginal Cost (LRMC) calculated has been adapted to the surroundings of SEE. The USCPC unit is considered a part of the SEE regional electricity market (SEE REM) and the EU emission trading scheme (EU ETS). Moreover, a sensitivity analysis has been carried out to estimate the effects of potential variation of the most uncertain parameters such as the investment costs, availability and fuel and carbon costs. Technical model of the plant has been implemented into the SEE database and market analysis has been carried out based on the results gained through a number of simulations of the SEE REM. Using an extended version of the software tool, we were able to determine the influence of different external factors on the performance of the unit in study. What adds value to this type of research is the consideration of the surrounding environment of the power plant object of investment. The results here provided are a combination of a mathematical model and a simulation model and are applicable to the real electricity market with costs best representing current costs of the electricity sector.

The paper is organized as follows. In Section 2 we talk about the electricity sector and the current situation regarding coal fired electricity generation. Section 3 explains the basic technical aspects of the unit in study. Section 4 describes the project framework along with the unit's surroundings. In Section 5 we provide a cost structure of the investment. After a brief description of the software used to obtain the dispatching results and electricity prices in Section 6, a detailed market analysis paired with sensitivity cases is presented in Section 7. Section 8 brings a brief review of the conclusions.

2. Situation Regarding Coal Based Electricity Generation

In recent years, the electricity market is no longer a happy island in a sea of troubled crisis. Today, it faces a whole new panorama with extremely risky margins and closures due to lack of demand. Before us now stands a dramatic new novelty: one of the fundamental rules of energy economics was that the demand for electricity is always on the rise – it is no longer the case. Throughout global crisis and instability of the power market, coal has remained a competitive source of energy. It is particularly favoured for electricity generation by developing economies. As far as EU energy policy, the future of coal is often linked to the CO_2 market and the development of the carbon capture and storage (CCS) technology. To enable the coal industry to contribute to climate protection, modernisation of existing installations and the construction of new state-of-the-art power plants, as well as the proving of new power plant designs with efficiencies over 50 %, have to be pushed forward. Investment will be needed in both generation and network assets, including conventional power plants, renewable generation, as well as "smart" transmission and distribution grids. In order to promote these developments, policymakers should embrace incentives for energy efficiency improvements along the whole electricity supply chain.

As far as the issue of coal is concerned, it is currently the second most important primary energy source, behind oil. Coal has a rapid growth of use which has affected its international trade substantially during the years. As this growth has been considerably stronger for some regions than the others, the coal market has changed. Apart from the spike in the price of coal in 2007-2008, prices have been relatively stable and are predicted to remain so for the foreseeable future despite the growth of consumption. As for any technology choice, there are a number of pros and cons whether to invest in coal generation or not. The drawback regarding this type of technology is its highly unfavourable environmental impact. There are a number of critics claiming that coal-fired electricity generation is facing strong headwinds that will in close future lead to abandoning this type of generation in favour of environmentally more acceptable technologies. Another concern and closely related to the environmental impact is the social acceptability issue. In addition to these two issues, the unpredictable nature of the carbon market might also present a deal-breaker for this type of projects. Requirements for environmental protection and economic viability make high efficiency and operating flexibility a natural matter of course not only in the EU, but also around the world. These higher efficiencies can be achieved only along the path of higher steam temperatures and pressures. Power plants operating at supercritical steam pressure have already demonstrated their operational capabilities and high availability. The next step is achieving steam temperatures higher than 600°C, which decisively affects many aspects of the design of the power plant, especially of the boiler. Today, there are clear evidences that high efficiency USC technology is an established and available power generation technology in Europe. At present, there are a number of high efficiency USC power plants, like the one considered in this study, across Europe; Avedøre 2, Nordjylland 3, RDK 8, Maasvlakte 3, Staudinger 6 are just a few with net lower heating value (LHV) efficiencies equal or superior than 46%. High efficiency USC technology is offered by more than one technology suppliers (Hitachi, Alstom, Siemens, BWE, IHI, etc.).

Despite problems, there is a number of coal projects currently planned, in the tender process or under construction not only around the world, but also in the EU. Europe's choice today doesn't seem to be "either coal or renewables" but "coal and renewables". This can be confirmed by observing the analysis provided by the World Resources Institute (WRI). Their analysis claims there are currently 1,199 new coal-fired plants, with a total installed capacity of 1,401,278 megawatts (MW), being proposed on a global scale. These projects are spread across 59 countries. It should be noted, however, that the new rising economies of China and India together account for 76 percent of the mentioned proposed new coal power capacities (WRI, 2012). As far as Europe is concerned, it is planning to build 40GW of new coal-generation plants to replace its ageing coal fleet. In Europe today, there are over 15 GW of coal-fired generation power plants under construction, most of which are in Germany. In addition, Central/Southern Europe is planning to add another 20 GW of new coal-fired generation plants by 2020. Eastern Europe and the Balkans should contribute with an important role in the future of coal power generation is planning to build more than 10 GW of new coal-fired generations plants (Datamonitor, 2013). However, all these should be taken with a certain dose of reserve. First of all, European energy utilities are simply replacing, or planning to replace, their ageing coal-fired generation power plants with newer and higher-efficiency coal plants – not building new capacities. Secondly, the already mentioned difficulties regarding investments in coal-fired power plants proved to be too challenging for a number of projects as several of them have encountered problems that led to delays or even abandonment due to technical, legal and/or financial/economic matters. Taking everything into consideration, the future of coal based electricity generation is uncertain, but at present, it plays an important role in broadening the energy mix and providing for a safe source of supply. What might prove to be of crucial significance is the speed of technological progress of coal based technology. Work is being undertaken in EU, Japan, USA, India and China to develop high temperature (700-720˚C) and high pressure (350-375 bar) systems to increase the efficiency of generation to around 50% LHV and to reduce CO_2 emissions (Bugge et al., 2006). Commercialisation at 48% LHV efficiency might be expected around 2020. Whether this transition to high steam temperatures is economical depends not only on the choice of main steam pressure, reheat pressure and feedwater temperature, but also on the range of fuel.

3. Technical Description of the Power Plant

There are a number of factors that determine the efficiency of pulverized coal (PC) plants. The most effective means of achieving high efficiency is to use steam temperatures and pressures above the supercritical point of water, i.e. at pressures above 22.1 MPa. USC units are often defined as units with pressures above 22.1 MPa and temperatures above 600°C. State-of-the-art USC units operate with steam parameters between 25 MPa and 29 MPa, and temperatures up to 620°C (IEA, 2012). The unit in study will employ a pulverized coal fired, steam cycle based power generation technology with ultra-supercritical conditions and shall be designed for a nominal continuous ratio (NCR) in which it will work most of the lifespan. In the mentioned nominal continuous ratio, the plant shall have the best efficiency factor and be cost-effective and most profitable. The plant must be able to work in any other defined operating conditions without a drastic drop of efficiency factor and the drop of the plant cost-effectiveness. The boiler shall be designed in such a way to guarantee outlet steam temperature of 600°C on super heater and of 610°C on reheater for a load of minimum 60%.The firing system shall be designed in such a way to secure stable ignition, and fuel switching to coal dust. Net efficiency as determined by the acceptance tests must be not less than 46 per cent based on the lower heating value (LHV) of the reference coal and operating under referent climate conditions. The main technical characteristics of the power plant in study are given in the following table (Table 1).

Table 1. Technical parameters of the power plant

Thermal input	1090
Power output (net)	500 MW
Gross minimum power	280 MW
Start-up fuel	Extra light fuel oil
Fuel	Pulverized coal (PC)
Main steam pressure at steam turbine stop valves	250-300 Bar
Main steam temperature at steam turbine stop valves	≥600 °C
Hot reheat steam temperature	≥610 °C
Net efficiency (LHV)	46%
Availability	7600 h
Flexibility	on a weekly basis
Dispatch ramp rate (35-50% load)	5 MW/min
Dispatch ramp rate (50-100% load)	10 MW/min
Minimum run rate	35% or lower
Nominal system frequency	50 Hz
Nominal frequency variation	49.5/50.5 Hz
Highest/lowest frequency	47.5/51.5 Hz
Nominal voltage	400 kV
Minimum/maximum voltage	360/420 kV
Minimum/maximum voltage (at disturbance conditions)	340/460 kV

3.1. The process

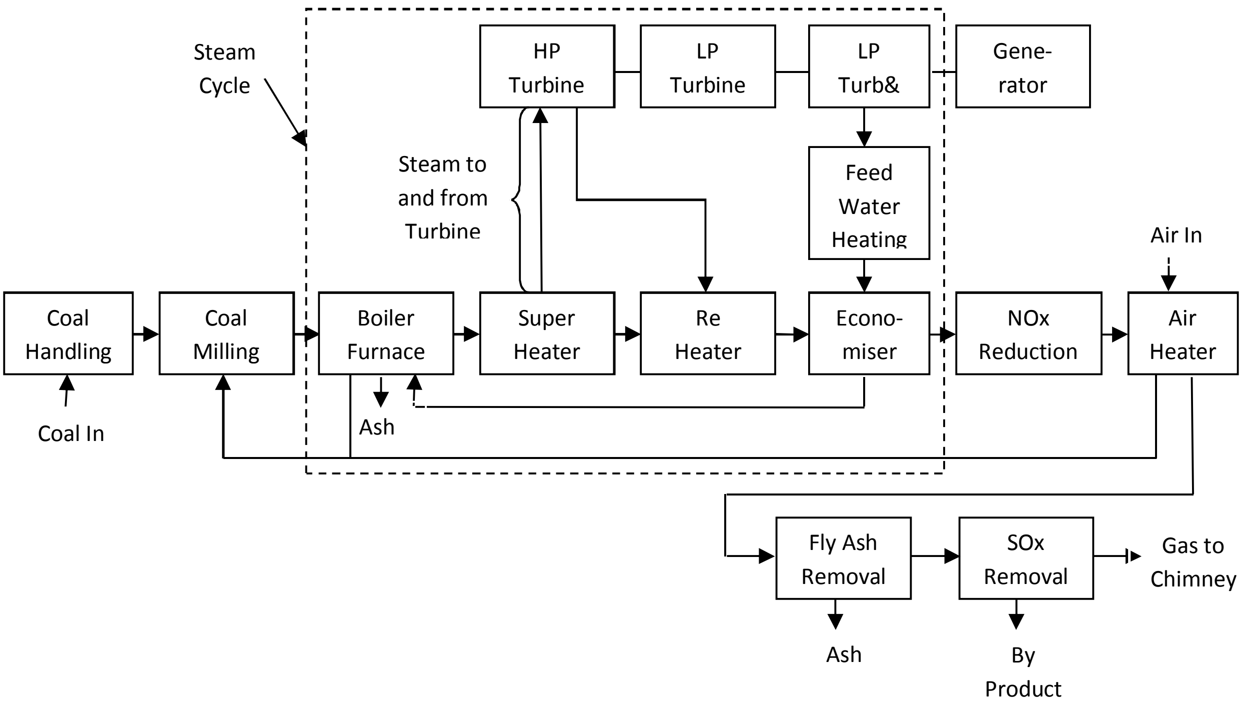
The pulverized coal and air mix prepared is blown by fans through burners into the boiler furnace. The furnace is additionally supplied with secondary hot air needed for combustion and reduction of NO_x emission. Hot flue gases from the boiler furnace are vertically transported to the boiler top. In the process, they transfer the generated heat to heaters, evaporators and steam super-heaters. From the boiler, the flue gases are conveyed into the system for removal of nitrogenous NO_x compounds. The flue gases are then cooled in a regenerative rotational air heater (RAH). RAH uses the flue gas heat to warm up fresh process air.

The boiler is of ultra-supercritical parameters (≥600°C / ≥610°C/ ≥250 bar), single reheat, once-through, sliding pressure, balanced draft, tower-type boiler designed for firing pulverized coal as the main fuel employing the extra light fuel oil firing system. Feed-water pumps shall feed the boiler with water. Burner management system (BMS) should control, protect and supervise the boiler unit. The system must ensure that the combustion in the furnace, as well as the main and auxiliary boiler equipment operation, shall be performed with maximum safety and with maximum reliability and availability, all within the plant distributed control system (DCS). Boiler island minimum load should be at 35% of nominal continuous ratio (NCR), while 100% coal fired and with sliding pressure. Up to 20% of nominal continuous ratio (NCR) boiler needs to work on extra light fuel oil (ELFO). From 20-35% of NCR boiler works on the extra light fuel oil (ELFO) and coal, and from 35% to a maximum continuous load (MCR) (103%) on coal.

The feed-water, after being heated through low pressure (LP) and high pressure (HP) preheaters, will enter the inlet chambers of the boiler water heaters to be heated to a temperature somewhat lower than the evaporation temperature. The water heater outlet chambers shall be connected to the evaporator inlet chambers. Upon leaving the evaporator, the steam shall be superheated in a multi-stage steam super heater to ≥600°C and ≥250 bar, and be conveyed to the turbine HP section. After it had done its work in HP turbine, the steam shall be returned into the boiler as cold reheated steam (MCR) to be heated (hot reheating) at ≥610 ºC, and returned into the turbine to enable expansion through the intermediate pressure – low pressure (IP-LP) part section and do the work. The boiler shall be designed so that at 60% loading it still guarantees the steam temperature at heater 600 °C and reheater of 610 ºC.

A bottom ash (slag) silo should be located in the vicinity of the boiler house, as well as the dry ash silo. They are located so as to enable simultaneous removal by conveyors to the pier for by-products and if necessary removal by trucks or conveyors to the bottom and fly ash stockyard. They also serve as a standby to each other. The power house of the unit will accommodate a three-stage steam turbine with a generator, condenser, condensate pumps, LP and HP condensate heaters, de-aerator - feed-water tank, feed-water pumps, injector vacuum pumps, auxiliary equipment for lubrication of turbine and generator bearings, process control and regulation, and protection devices. The chemical water treatment plant shall be located SI of power house together with the neutralization basins, demineralized water tank and chemicals tank. A detailed scheme of the process is presented in Figure 1.

Figure 1. The process



3.2. Referent climate conditions

Thermal power plant will be designed to operate under all climate conditions that might be encountered considering the surrounding environment. Basic referent climate conditions are defined by Table 2.

Table 2. Referent climate conditions

	Minimum	Maximum
Air temperature	-12°C	37°C
Relative humidity	12%	98%
Air pressure	932 mbar	1050 mbar
Sea temperature	10°C	22°C

3.3. Permissive emissions and by-products

According to the EU Directive 2010/75/EU emission limit values for new plants that come in operation after 7th January 2014 must be equal or lower than the values presented in Table 3.

Unit shall be equipped with all necessary equipment so that the flue gases and cooling water, wastewater and other substances released into the environment meet the strictest European regulations. All other process waste materials such as slag and ashes, and process by-products such as gypsum shall be disposed of in an environmentally acceptable manner.

Table 3. Permissive emissions

SO_2 emissions for design coal	mg/Nm³	≤150
NO_x emissions for design coal	mg/Nm³	≤150
Particulate emissions for design coal	mg/Nm³	≤10

3.4. Connection to the grid

The generators and related control plant must be designed to comply with the requirements of the Croatian Grid Code. The plant will be designed to operate on three phase 400 kV gas-insulated switchgear (GIS) and permissible generator voltage variation of at least ± 5% of nominal voltage and with an initial short-circuit current 7500 MVA (40 kA) at 400 kV. Respecting the conditions prescribed for electric grid system the generators and generator-transformer combination should be able to supply the following:

1. Maximum continuous rating at the unit power factor within the 400 kV ±10% line voltage range
2. Maximum continuous rating within the grid frequency range of 49.5 to 50.5 Hz.
3. Maximum continuous rating at the power factor of 0.85 inductive, within the line voltage range of 400 kV ±10%.
4. Maximum continuous rating at the power factor of 0.95 capacitive within the line voltage range of 400 kV ±10%.

3.5. Fuel issue

Extra light fuel oil should be used as starting fuel for the boiler unit. Good quality imported hard coal will be the main fuel. According to IEA estimates, global hard coal consumption increased by more than 70% from 3,700 million tonnes (Mt) in 2000 to 6,317 Mt in 2010 (IEA, 2011). Croatia does not produce coal and has to rely on imports. Since the price of coal is generally low, means of transportation become a much more important topic as delivery costs hold a higher percentage in the overall fuel costs than for other fossil fuels. We have, therefore, envisaged that the unit will be positioned along the coast of the Adriatic and coal will be supplied by sea. This will also facilitate an easier and more efficient solution for the units cooling system. The permissible limit values of the imported coal basic characteristics are listed in the table below (Table 4). The reference lower heating value of coal used for further analysis and calculation has been set at 26.3 GJ/t.

Table 4. Coal characteristics

Data	Units	Lower boundary	Higher boundary
Lower heating value	MJ/kg	24.0	29.3
Ash	%	8	15
Humidity content	%	6	15
Volatility	%	25	45
Sulphur	%	0.3	1.5
Nitrogen	%	1.2	1.85
Chlorine	%	0.01	0.15
Hardgrove index	HGI	45	60
Ash softening temperature	°C	1,200	1,300
Ash fusion temperature	°C	1,350	1,550

Coal transporters shall supply the coal to the boiler daily bunkers by the silo conveyor system or a direct system. The coal feeders feed coal into the coal mills located under the daily bunkers for pulverization. In the mills, coal dust will be mixed with hot and cold air blown by the primary air fans (PAF). The pulverized coal and air mix prepared in this way is blown by fans through burners into the boiler furnace. The furnace is additionally supplied with secondary hot air needed for combustion and reduction of NO_x emission. Hot flue gases from the boiler furnace are vertically transported to the boiler top. In the process, they transfer the generated heat to heaters, evaporators and steam super-heaters. From the boiler, the flue gases are conveyed into the system for removal of nitrogenous NO_x

compounds. The flue gases are then cooled in a regenerative rotational air heater (RAH). RAH uses the flue gas heat to warm up fresh process air. The coal storage shall be designed to allow mixing of different coal types to reach the specifications required to supply the plants (this refers in particular, but not exclusively, to sulphur levels).Boiler designs today usually encompass a broader range of typical coals than initially intended to provide future flexibility (MIT, 2007). Coal types with lower energy content and higher moisture content significantly affect capital cost and generating efficiency.

3.6. Quadratic hourly consumption

During operation, power plants occasionally need to adjust their power output to be able to cope with the fluctuations of the market. The efficiency in these cases does not remain constant. If a unit does not operate at nominal power, it will have a higher consumption and an accordingly lower efficiency. USC units operate at higher efficiencies and lower emissions than traditional (subcritical) coal-fired plants, producing more power from less coal and with lower emissions. The quadratic hourly consumption curve (QHCC) [Gcal/hour] is presented to best depict these fluctuations of fuel consumption. For a better understanding, the USC unit specific consumption modelled by the QHCC was compared to a quadratic curve of consumption of a unit of 35% LHV efficiency. Our analysis confirmed that the installed capacity of coal and lignite based units in the SEE region has an average efficiency of 35%. This is why, in further text, we have provided a comparison of economic performance and environmental impact between a subcritical unit of the same capacity as the reference USC unit. As it can be noticed from Figure 2, a typical subcritical system has a significantly higher fuel consumption resulting in higher operating costs and higher specific emissions. The following equation (Equation 1) expresses the consumption of fuel in the operating power range, between the minimum and the maximum operating power:

$$c = c_2 \cdot P^2 + c_1 \cdot P + c_0 \quad (1)$$

where is C = consumption (Gcal/h), C_2= coefficient of second degree (Gcal/MW^{2}h), C_1 = coefficient of first degree (Gcal/MWh), C_0= constant term (Gcal/h), P= operating power (MW).Coefficients used to describe the specific consumption curve for the two units mentioned are shown in Table 5.

Table 5. Coefficients of the specific consumption curve

Power plant	C_2	C_1	C_0
USCPC	0.000196	1.566389	102.6426
SubCPC	0.000330	2.058683	105.2233

The following figure (Figure 2) represents the two curves of specific consumption in GJ/MWh. As it can be seen, consumption depends on the output of the plant and is higher when the plant is operating at lower capacity. The importance of QHCC of a unit lies in the fact that through them, specific fuel costs and specific emission costs can be calculated. These two costs form the major part of overall variable costs by which the merit order curve (MOC) that defines units' hourly dispatch is based on Rubin et al., 2007. An independent power producer (IPP) can make a profit only when it sells its production on the market at a price higher than the mentioned variable costs. Our analysis showed that, at nominal power, the USC unit in study would consume 0.297 tonnes of coal per megawatt hour compared to 0.390 t/MWh consumed by an average subcritical unit.

3.7. CO_2 emissions

In this paragraph we present a short analysis of the correlation between specific consumption (power plant efficiency) and CO_2 emissions. As mentioned, USC units burn less coal and have lower specific emissions than typical subcritical power plants. The dependence of specific emissions on power plant efficiency is presented in Figure 3. The case considered in our study regards a new entrant USC unit with net efficiency of 46% and the 35% average efficiency of coal-fired generation in SEE. It can be seen that the USC unit would emit almost a quarter less CO_2 (0.75 tCO_2/MWh compared to 0.99 tCO_2/MWh).If we were to compare overall carbon emissions for these two types of generating capacities, the difference on an annual scale would amount to approximately 920,000 tonnes (for a presumed production of 3.8TWh).This represents a significant cut in harmful emissions greatly helping with the improvement of the environmental impact of coal based generation.

Figure 2. Specific consumption curve

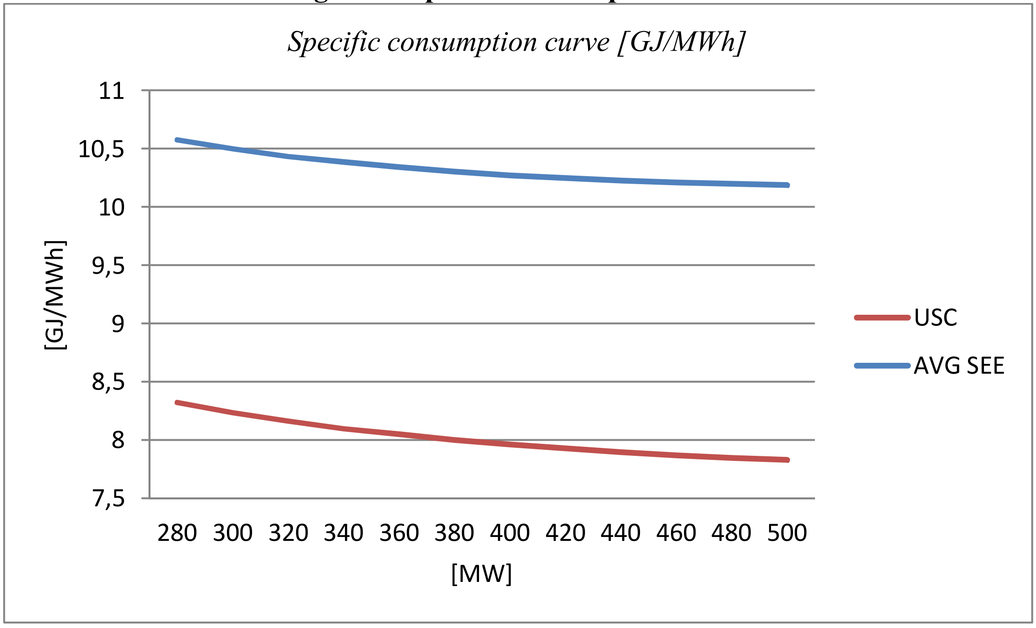
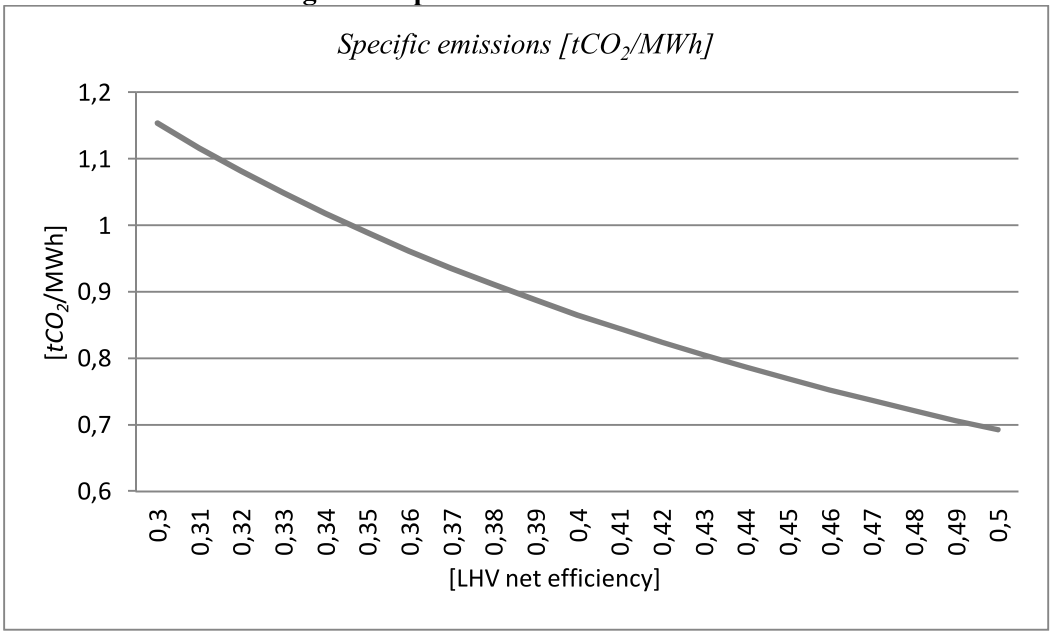


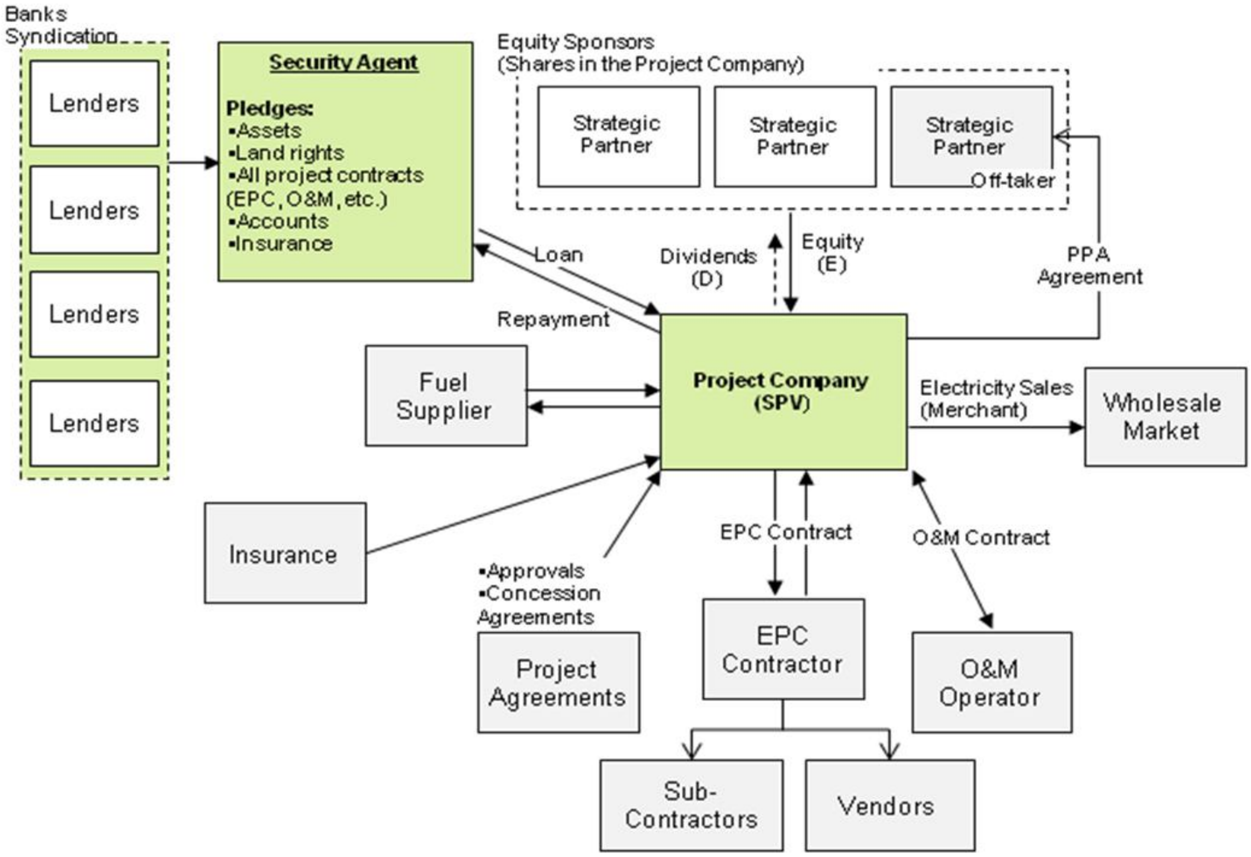
Figure 3. Specific emissions curve



4. Project Framework

A growing number of investments in the power sector are being realized by project financing arrangements. At the moment, the non-recourse project financing (NRPF) structure seems to be international best practice for the development of large scale power projects. Project financing refers to a loan which is structured to primarily rely on the project's income to repay the loaned amount. It uses project's assets as collateral in case the income is insufficient to cover the debt instalment. Lenders have no direct recourse to the project sponsors and are guaranteed only by project's assets and cash flows. This means that a utility involved in building a power plant by this structure does not hold responsibility through its own assets or, in other words, if a project (for any reason) is not able to repay its debt, the company can only lose its share of equity invested in that very project. This type of arrangement requires for the establishment of a project company, a special purpose vehicle (SPV). SPV is often formed by more than a single company. Companies having a share in the project become strategic partners. They transfer assets and involve resources as their stake in the project. This contribution creates a liability on the business in the shape of capital as the project is a separate entity from its owners. The amount of assets invested compared to the amount of debt forms the debt-to-equity ratio of the project. Figure 4 depicts the high level structure and main characteristics of an SPV. It shows the way participants are involved with the SPV as well as the main inputs of this type of structure for a thermal power plant project.

Figure 4. SPV high level structure

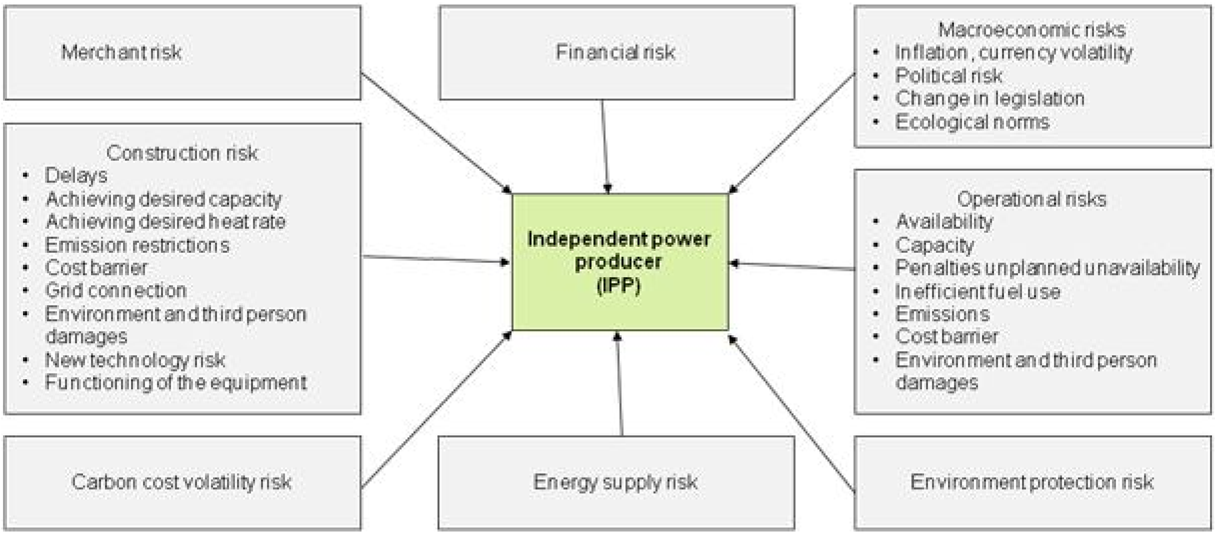


Lenders loan the necessary funds to the equity sponsors. After obtaining all the project agreements (PA), after the engineering, procurement and construction (EPC) contractor has completed the plant and after the unit has successfully passed the test phase, it can officially commence with operation– this date is called the commercial operation date (COD). From then on, the SPV functions as an IPP and sells its production on the electricity market or via bilateral agreements. SPV might sign a power purchase agreement (PPA) with an off-taker that guarantees a sale of a proportion of its production during a certain period of time (usually a couple of years) at a prearranged price. If this agreement has been signed prior to applying for a loan, it can prove to be a very valuable asset for the SPV lowering merchant risks and providing not only for a safer investment, but also a lower debt risk premium resulting in lower costs. Quality PPAs are not easily obtained, especially considering recent climate. An off-taker can be a strategic partner in the SPV or a different (independent) utility looking to cut electricity market volatility risks.

4.1. High level risk assessment

Power plant projects are dependent on a series of mandatory requirements and challenging interfaces. The main challenges are not only of technical (e.g. BAT criteria, efficiency demand), but also economical (e.g. feasibility, risk acceptability) as well as legislative (e.g. location and building permits) and regulatory (e.g. permissible emissions, ETS) nature. We have identified eight main types of risks involving thermal power plant projects: financial; construction; macroeconomic; environmental protection; carbon cost volatility; fuel cost volatility; operational; merchant. Figure 5 depicts a high level risk assessment for a coal-based IPP.

Figure 5. IPP main risks



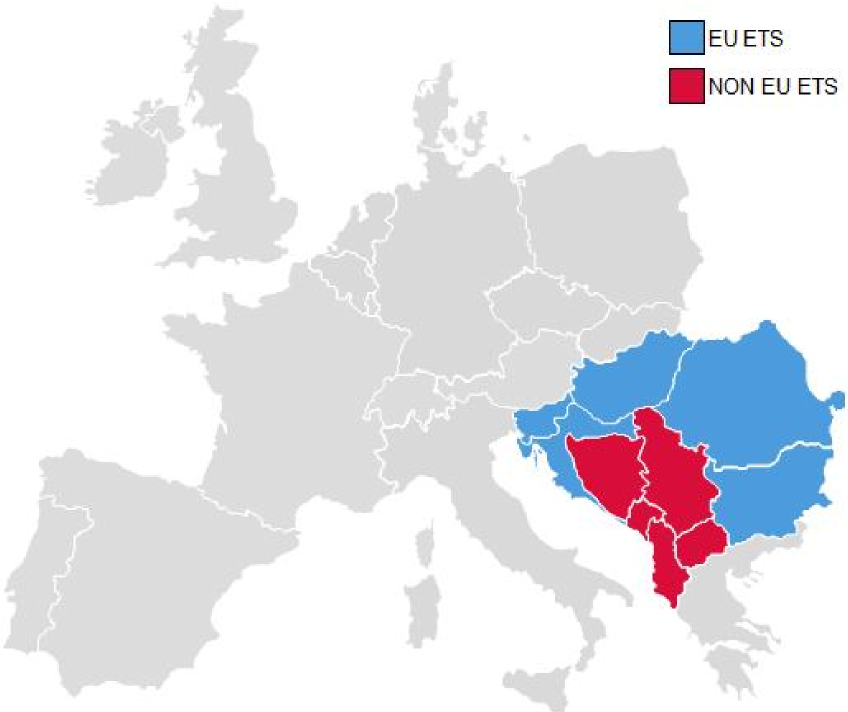
The concern for the environment caused strict and sometimes demanding restrictions that thermal units nowadays face during planning, construction and/or operation. Coal-based electricity generation, in particular, is facing problems due to its extremely negative environmental impact. One of the new risks that arose in recent years and that thermal units face is the emission trading scheme (ETS). ETS is a market-based scheme that allows parties to buy and sell permits for emissions or credits for reductions in emissions of certain pollutants. Croatia, being a part of the EU has adopted this scheme and as of 1st of January 2013, a new entrant unit based in Croatia needs to account for every tone of CO_2 emitted to the atmosphere (EC, 2009). Within the EU climate and energy package there is a legally binding overall emission reduction target of 20% by 2020 (compared to 1990 emission levels). It comes from a mutual agreement between the European Council, the European Parliament and the European Commission. EU ETS is one of the tools being used to help reduce these emissions.

4.2. Surrounding peculiarity

South East Europe is a specific region, especially when it comes to the field of the electric power sector. The SEE electricity markets are undergoing structural changes following the reforms imposed by the EU. Electricity reform in the EU has been primarily driven by two electricity directives in 1996 and 2003 (Jamasb et al., 2005). On 19th September 2007, the European Commission (EC) adopted the so called "third energy package" of legislative proposals concerning electricity and gas markets. The primary aim of reform is to improve the productive efficiency of the sector and lower costs and prices by providing for a competitive and integrated energy market that allows European consumers to choose between different suppliers and enables all suppliers to have an access to the market. Having an efficient and well-developed power sector enables growth and boosts the economy affecting the improvement of living standard of the population and development of society (Cerović et al., 2014). Best practice in regulatory reform involves three aspects: form, progress and outcome of regulation (Green et al., 2006). With the assistance of EU, the SEE countries have not only a clear reform model to follow, but also an access to technical assistance to help with the process. Because of this, SEE is and will be a test of transferability of the EU reform model within the EU as well as its transferability to a set of developing countries (Green et al., 2006; Pollitt, 2009).

We have identified two of the main difficulties for an IPP competing on the REM of SEE. Number one is concerning the SEE countries' affiliation to the EU ETS scheme. As it can be seen from Figure 6, not all countries of the region are a part of the ETS. This creates an imbalance between competitors on the market. If carbon costs rise to a certain point, they might prove to be too much of a burden for a thermal power plant competing with players with no obligations to purchase CO_2 certificates. This, potentially high imbalance between competitors on the market is a considerable risk rather unappealing for investors (Višković et al., 2014a). With a number of forecasts claiming that prices of emission unit allowances (EUA) will rise during the course of years, one must wonder whether it is a wise decision to invest in coal-fired generation when just across the border there is a number of players using similar technology (mostly lignite) and not being burdened with such heavy costs – it is certainly a risky liability to hold.

Figure 6. South East Europe countries ETS affiliation

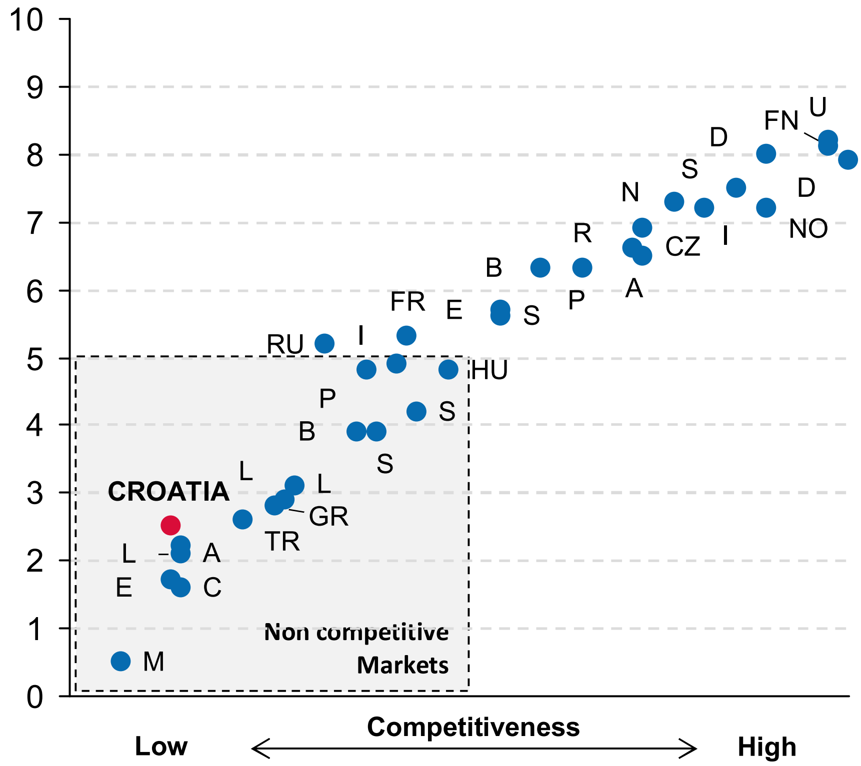


Despite its accession to the EU, Croatia is still moving slowly to fully applying the acquis communautaire in a practical manner. The unbundling process is only at the beginning as only recently a model of unbundling for transmission system operators was selected and Croatia's power exchange seems to be a long way from being operational. Despite all the problems, it is only a matter of time when all this will be sorted and Croatia will have a fully liberalised and deregulated electricity market. However, as things currently stand, the Croatian electricity market is one of the lowest competitive electricity markets in Europe (ranked 28th on 33 countries analyzed in 2013) (Datamonitor, 2013). With regard to the wholesale market structure, Croatia is a strongly concentrated market: the generation segment is entirely dominated by the country's main utility company – HEP (other players in the generation sector are TPP Plomin d.o.o. and Krško nuclear power plant (NPP) (both co-owned at 50% by HEP), which also controls 100% of electricity imports. The same situation is perceivable also in the retail-end segment of the value chain. Dominance of HEP across all segments of the value chain does not facilitate market transparency as well as access to consumer information. Current market dynamics along with the mentioned dominance mean that Croatia is perceived as a challenging market for new entrants. Figure 7 shows the results of the Datamonitor MCI index competition intensity analysis (Datamonitor, 2013). MCI is the index which measures the development of the electricity markets competitiveness, comparing between each other 34 European markets.

4.3. Croatian electricity market legal framework

Regarding the electricity sector, the framework recognises five types of activity: generation, transmission, distribution and sale of electricity and organisation of the electricity market. Generation, supply and trading on the electricity market are market activities in which price and quantity are freely negotiated. However, generation of electricity for tariff customers, transmission and distribution of electricity, electricity market organisation and supply for tariff customers all remain regulated activities. The electricity legal framework is regulated by the following three acts: Energy Act, the Energy Activities Regulations Act and the Electricity Market Act. As mentioned, there is a lot of work to be done to bring Croatia to the standards needed to attract foreign investment. At present, it is a rather unfamiliar terrain for foreign capital and the changes imposed by the EU are of great value and importance not only in improving the conditions in the electricity sector, but providing for better transparency and image. One of the key and crucial issues for foreign investors or financial institutions is the country's regulatory framework that is capable of ensuring transparency and certainty over the long run.

Figure 7. MCI score 2013 (source: Datamonitor)



4.4. Why coal in Croatia? Rationale

In order to provide development and growth of the energy potential of Croatia, replacement and modernisation of existing power plants is no longer the only solution. New power plants using modern technologies are needed to keep pace with the fast-changing and fast-evolving demands of the electricity sector and competition. The majority of existing thermal power plants in Croatia have too many years of service behind them and are unable to meet with the demands of the modern electricity market. A number of them uses obsolete technology and have far too expensive costs to be competitive on the market. Unfortunately, for the most part, it is considerably cheaper to import electricity then produce it at Croatian-based thermal units. During the new generation mix planning and designing one should take into account the diversity of energy sources and ensure not only a cheaper source of electricity, but also the security of supply at all times for the consumers. Thus, besides the construction of hydro-energy, gas, wind, solar and other facilities, the construction of coal thermal power plants is essentially needed. In addition, the development of the unit in study is in compliance with the Croatian Energy Strategy which aims at achieving security of supply & a competitive energy system. The three pillars of the Strategy are identified as security of energy supply, competitive energy system and sustainable energy sector development (OG, 2009). These objectives imply the following targets: reduce the dependency on energy imports; maintain the percentage of energy produced by large hydro power plants and renewables at 35% in 2020 (same level of today); compensate for the increase in electrical energy consumption in Croatia; compensate for the planned shutdown of plants that cannot meet emission legislation in the next years. The new production unit in study would be very important for the development of the Croatian power system as a whole. By its construction, it would be one of the most important production facilities in the Croatian power system and would have a role of a base power plant in the electrical power management and control system. According to this proposal of technical solution, the new unit has been conceived as an independent and technology-independent plant which is intended solely to generate electricity with power rating of 500 MW net (the power submitted to the grid).

4.5. Overview on the Croatian thermal generation set

When evaluating a techno-economic performance of an IPP on the electricity market it is necessary to have an extensive knowledge of its surrounding environment. For this purpose, we have made a model of the thermal generation set that represents the assumed state of the Croatian thermal sector in year 2015 (Višković et al., 2014a; Višković et al., 2014b). We have assumed that the installed capacity will amount to 2015 MW (excluding NPP Krško). Thermal power plants used in the techno-economic analysis are presented in Table 6, along with the fuel they use. Each of the units listed is described by the constraints and technical characteristics needed to successfully form the electric power system model. When comparing the thermal generation set used in the study to the current status of the thermal sector of Croatia, the main difference is in a solemn extra unit predicted to be operational by 2015 – the 230 MW combined-cycle in TE Sisak.

Table 6. Installed thermoelectric capacity in Croatia in the year 2015

Power plant	Fuel used	Installed capacity
EL-TO Zagreb	Gas	207
TE-TO Zagreb	Gas+Oil	208+120
TE-TO Osijek	Gas+Oil	22+63
KTE Jertovec	Gas+Oil	45+50
TE Sisak	Gas+Oil	230+420
TE Rijeka	Oil	320
TE Plomin	Coal	330

5. Economic Assessment

While making the assessment of the main driving parameters of the unit in study we have given particular consideration to the specifics of the surrounding environment and their influence on the costs presumed. In other words, some cost components of the long run marginal cost presented in this paper are, in a certain amount, country specific and differ from other surroundings. For a better and easier economic assessment of a power plant, we have divided all the costs that the unit might encounter into four divisions: investment, operation and maintenance (O&M), fuel and CO_2 costs.

5.1. Investment costs

Investment costs assumed for the purposes of this study include costs encountered on the project until its successful commercial operation date (COD). They comprise of capital and financing costs with a debt repayment term which was set at 15 years. We have presumed a 75:25 debt to equity ratio with a financing methodology which considers a bridge loan during the EPC period (with capitalization of interest) and a straight line repayment loan during the designated period. As far as the interest rates considered in the study, it should be noted that, as a whole, the electric utility industry's credit rating is in lower tier of the investment grade category (BBB). In addition, because IPP debt is considered risky, most private entities and lead investors tend to demand for higher interest rates. Bridge loan interest rate is set at 8.5%. We have also considered an interest rate on term loan at 6.5% and a discount rate of 8.7% – value presumed as the investor's weighted average cost of capital (WACC). Capital expenditures (CAPEX) assumed are shown in Table 7, they comprise of construction costs, costs for mechanical equipment and intangible costs. The assumed capital costs of the USCPC unit in study equal 760M€; 570 M€ of which are financed through debt and 190 M€ through equity. The specific capital cost is presumed at 1.52 M€ per megawatt of installed net output capacity.

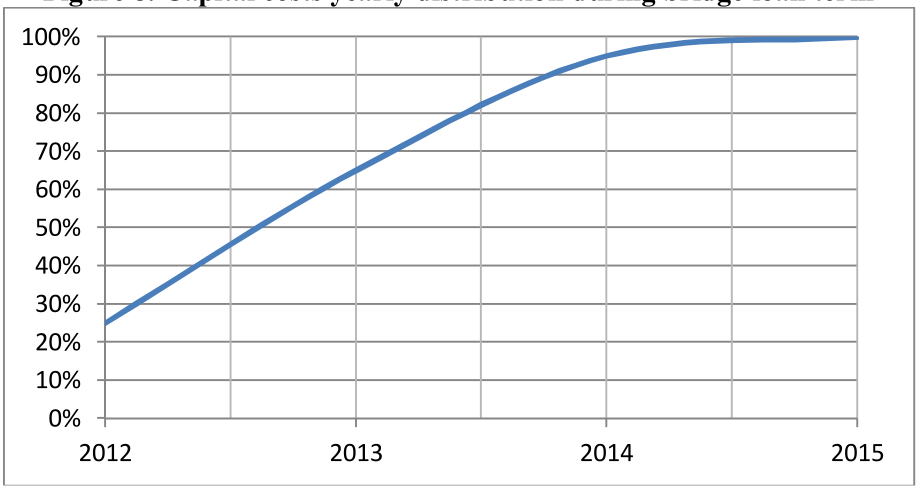
All costs of the project prior to construction are considered to be financed by equity. After completing the necessary documentation and obtaining financing the construction is able to start. The bridge loan duration is 4 years – during this period we have presumed the unit's construction, connection to the Croatian electrical grid, completion of the testing phase and a successful COD. Taking into account the bridge loan interest during the period, the yearly distribution of capital costs shown in Figure 8, as well as the financing fee considered at 2% of the overall senior debt (2% of 570 M€ = 11.4 M€), we have calculated the overall investment in the SPV to reach its maximum at 865.85

M€; 675.85 M€ of which are debt. Under the financing conditions specified in the text above, the specific investment cost equals 1.73 M€ per megawatt of installed net output capacity.

Table 7. Capital costs

	Investment [M€]
Main plant building	370
FGD system	65
Fuel supply and storage	45
Electric block & protection system	35
Cooling system	35
Electrical plant unit	25
Contingencies	25
Water system	20
Environment regulation	15
Slag and dry ash	15
Auxiliary building & plants	10
Spare parts	30
Engineering	35
Project management	20
Supervision & other expenses	15

Figure 8. Capital costs yearly distribution during bridge loan term



5.2. Operation and maintenance costs

The O&M costs presumed in this study have been considered as part of the fixed annual costs of the power plant. This is because our analysis showed that the variable part of the O&M costs does not greatly change depending on the units' predicted output and therefore does not have a significant impact on the overall costs of the IPP. As mentioned, the unit in study is predetermined to cover the base load and as such, its presumed output does not change in a significant matter. Costs of programmed and unscheduled maintenance, labour costs, taxes and assurance as well as a number of other different expenses have all been taken into consideration.

5.3. Fuel costs

As already mentioned, good quality imported hard coal has been selected as the main fuel of the unit in study. We have presumed the reference value of the cost of imported coal to be 80€/t. This value includes the cost, insurance and freight (CIF), the additional transport cost to Croatia and the Croatian excise duty of 0.3€/GJ (OG, 2013). The prices of fuel have been modelled according to the futures contracts obtained from the European energy exchange website (EEX, 2014) and team analysis. The cost of fuel oil was presumed at 9.52 €/GJ and the cost of natural gas (NG) 8.57 €/GJ – all the costs have been adapted to the Croatian surroundings. Prices in Croatia are projected to remain aligned with international prices and are forecasted stable across the years due to supply/demand balance (coal plant decommissioning in EU and US) and wide availability from different countries.

5.4. CO_2 costs

Carbon costs are the ones most difficult to predict due to the number of different unforeseeable factors that influence the formation of emission unit allowance (EUA) cost; despite that EU aims at increasing CO_2 prices, the prices' evolution remains uncertain. One EUA gives the right to emit one tonne of CO_2 in the atmosphere. As of 1st of January 2013, electricity producers based in the EU have to account for the CO_2 emissions by purchasing these rights. At the moment, the price of a tonne of CO_2 is 4.78€/tCO_2 (EEX, 2014) and seems to be inadequate to promote a more extensive use of renewable sources. However, a number of pundits are claiming that it is only a matter of time when this price will rise. For the purposes of our study, we assumed a referent cost of CO_2 to equal 10 €/tCO_2 for all the countries inside the ETS scheme (CRO; SI; HU; RO; BG). CO_2 price is a very high impact parameter for our analysis. The specific costs of CO_2 emissions can be calculated by using the specific emission coefficient for the unit considered (it equals 0.75 tCO_2/MWh for the unit in study) and multiplying it by the cost of one certificate. It can now easily be seen why the specific CO_2 cost for the referent case scenario equals 7.5 €/MWh.

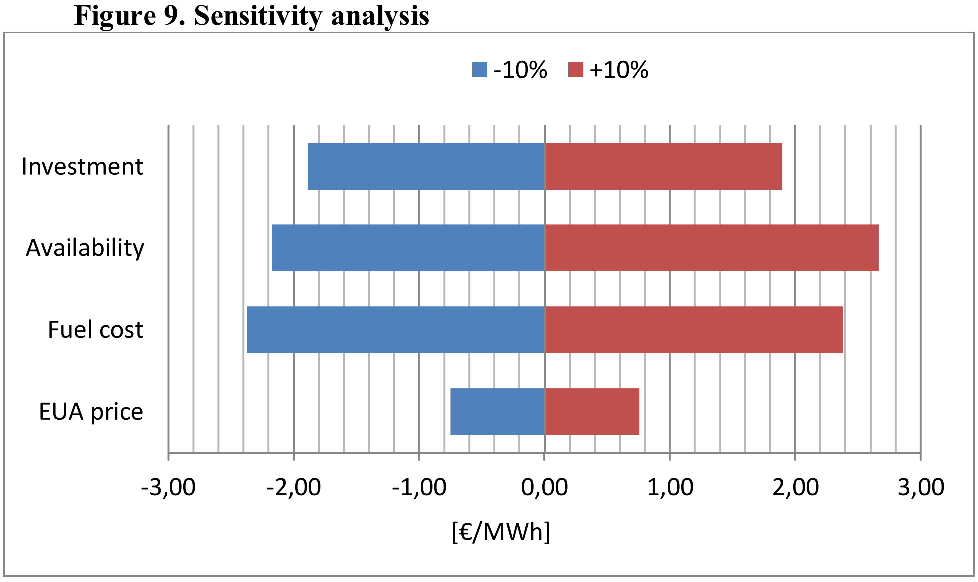
5.5. Overall long run marginal cost

Combining the four aforementioned elements we have calculated the referent overall LRMC of the unit in study. The model is used for the purposes of further analysis and is presented to enhance the understanding of costs an IPP encounters on a yearly basis. With the conditions considered, the calculated LRMC equals 55.27 €/MWh. Investment, O&M, fuel and CO_2 costs contribute with 34%, 9%, 43% and 14% respectively. Referent LRMC is shown in Table 8. It should be noted that it contains an annual investment cost of 71.87 M€; this is because it was projected on a straight line basis during the course of the debt repayment term.

5.6. Sensitivity analysis

When assessing costs, the majority of the parameters considered are affected by uncertainty. This is the reason why we have run a sensitivity analysis on some of the key factors to best determine their influence on the LRMC of the IPP in study. The two scenarios considered a 10% change in the parameters observed. The results of the sensitivity case analysis are presented in Figure 9. As it can be noticed, a 10% variation on the factors considered does not result in drastic changes in the overall LRMC. It should be noted, however, that the cost of EUA can significantly vary from the 10 €/tCO_2 considered and represents the most uncertain parameter of the cost assessment. As mentioned earlier, the current cost of an allowance is approximately 50% lower than our reference one while a number of pundits predict it will rise up to even 40 €/tCO_2 which would make a 400% increase. Taking this worst case scenario of EUA cost into consideration, we have calculated that the LRMC of the unit in study would equal 77.85 €/MWh which would represent an increase of 22.58 €/MWh.

Figure 9. Sensitivity analysis



5.7. Comparison with different types of coal based generation

We have taken into consideration the difference between the operating costs of a new entrant unit in study and a hypothetical subcritical coal based generation capacity. As mentioned earlier in the text, out analysis revealed that the average efficiency of coal based generation in the SEE region is 35%. We have assumed that the 500 MW capacity does not bare investment costs; only O&M, fuel and CO_2.Despite the considerable difference in investment costs burden, a new entrant unit has far superior specific fuel consumption making its variable costs far more favourable. Our analysis showed that a 46% efficient USCPC plant would have 24.5% lower specific consumption than an average 35% unit of the same size working at nominal rate – this results in 7.47 €/MWh difference between the specific fuel costs. Paired with lower specific emissions and accordingly lower CO_2 costs, the difference between the variable (operating) costs of the two capacities are almost 10 €/MWh for the referent case considered (10 €/tCO_2); that makes a difference of 37.4 M€ on a yearly basis excluding the O&M expenditures. After including all costs of the project, the overall difference of the two LRMC analysed equals 7.03 €/MWh.

Table 8. Referent long run marginal cost

Investment costs	Capital costs [M€]	760
	Economic time [years]	30
	Debt/equity ratio	75/25
	Bridge loan duration [years]	4
	Bridge loan interest [%]	8.5
	Debt repayment time [years]	15
	Debt interest	6.5
	Discount rate [%]	8.7
	Presumed annual working hours [h]	7600
	Presumed annual production [TWh]	3.80
	Annual investment costs [M€]	71.87
	Quote for investment costs [€/MWh]	**18.92**
Operation and Maintenance costs	Maintenance [M€/year]	15.2
	Personnel [M€/year]	1.7
	Assurance [M€/ year]	0.95
	General and administrative costs [M€/year]	0.38
	Others taxes (Amonia; Limestone; SO_2; NO_X) [M€/year]	0.95
	Annual O&M costs [M€/year]	19.18
	Quote for O&M costs [€/MWh]	**5.05**
Fuel costs	Specific consumption [t/MWh]	0.30
	Presumed coal price [€/t]	80
	Annual fuel costs [M€]	90.61
	Quote for fuel costs [€/MWh]	**23.78**
CO_2 costs	Specific emission coefficient [tCO_2/MWh]	0.75
	Estimated emissions [MtCO_2]	2.87
	EUA price [€/tCO_2]	10
	Annual CO_2 costs [M€/year]	28.69
	Quote for emission costs [€/MWh]	**7.53**
Annual total costs [M€]		**210.0**
Referent long run marginal cost (LRMC) [€/MWh]		**55.27**

6. Market Simulator

In the new framework of competitive electricity markets, all power market participants need accurate price forecasting tools (Murthy et al. 2014). The forecast of the wholesale energy prices and power units' production in the year 2015 is performed using a software tool called PROMED, a day-ahead market simulator developed by CESI. We have created an extension to this software and modified CESI's database of the region so it can best correspond to the up-to-date situation. The main goal of the market analysis is to investigate the impacts of different factors on the techno-economic performances of a new entrant IPP based on coal on the SEE REM. PROMED operates using a detailed database of the region's electricity sector. The database contains (CESI, 2009): zonal market structure and relative net transfer capacities, equivalent influence of energy exchanges between SEE regional electrical system and its neighbouring systems on an hourly basis, hourly load demand, fuel prices &emission prices, thermal generation set & thermal units constrains, hydro generation set, competitors bidding strategy on the day-ahead electricity market. Assuming full competition in all hours, the competitors' bid-up strategy is aimed to cover the estimated LRMC of power units. Electricity price forecasting is performed trough two computational steps (CESI, 2009):

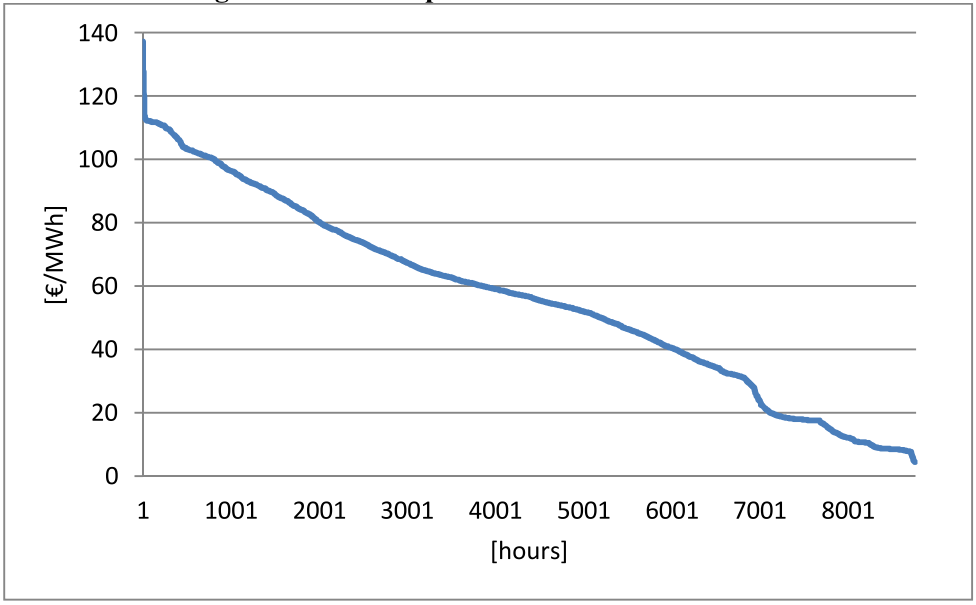
1) Unit commitment; during which the hourly merit order is formed based on the constraints of the power system.
2) Dispatching; during which the hourly production schedule of each thermal unit in coordination with the hydro dispatching is formed.

The main problem in creating a database of the region and modelling the electricity sector so it can best represent the real life situation lies in the difficulty to predict future demand. As our analysis confirmed, the global crisis significantly affected the economies of SEE countries. In the past few years, they have recorded a drop or, at best, a stagnation in the demand for electricity. We based our forecast of the future national demands on the basis of an elaboration of the historical data of the national electricity consumption published by ENTSO-E. The demand modelled represents the load to be covered by the plants that offer their electricity production in the regional system. Another important issue is the ever changing generation portfolio that requires constant monitoring and updating. Our model of the system was based on the research provided by CESI and team analysis by which the model was updated and modified.

7. Economic and Financial Assessment

Different external influences require that plant utilization factors be evaluated in the context of a network of generating plants meeting a specified (time-dependent) electricity demand (Rubin, 2007). This is the main reason why we have conducted the electricity market analysis. After building a model of the SEE electricity sector, we have made a number of simulations of the SEE REM. The goal was to simulate the situation of the electricity sector of SEE in the year 2015. The referent scenario showed a rather interesting result confirming the current troubled status of electricity generation through the use of traditional sources. Our analysis showed that the main problem of an IPP based on coal is not the obligation to purchase emission allowances (despite our predicted price of EUA being double the current value), but the overall state of the electricity sector. The mentioned stagnation/drop of consumption along with the EU support to the renewable energy sources resulted in a highly unfavourable situation of the thermal sector. The power plant in study, despite using the best available technology, having lower specific emissions and a higher efficiency than any other coal unit currently connected to the grid in SEE, did not achieve full dispatch. From the predicted maximum of 3.8 TWh, the annual production calculated amounts to 3.53 TWh – this significantly affects the profitability of the project as well as it raises another issue. Is a coal fired power plant with a 500 MW net output really needed to the Croatian electricity sector? Under current conditions and with the uncertain future of EU policies towards coal, it seems a safer investment might be in a unit of lower output. In addition, another problem regarding low consumption is its correlation to the average marginal price of electricity. Current price of electricity does not support the construction of new traditional sources of electricity generation. The following figure (Figure 10) represents the electricity price duration curve obtained from the yearly series of the hourly prices sorted in a decreasing way.

Figure 10. Market price duration curve for SEE



7.1. Overview of the Croatian electricity sector

We forecasted the electricity demand of Croatia to equal 17.8 TWh on an annual scale. Despite the decrease in consumption in year 2013, we predicted an increase in the two following years. Total production from the thermal sector equalled 8.67 TWh, 3.53 TWh of which were achieved by the unit in study and 5.14 TWh was produced by the rest of the sector. This means the new 500 MW unit would satisfy around 20% of the annual Croatian demand by producing approximately 40% of all electricity generated by the country's thermal sector.

Table 9. Croatian electricity sector basic data

	2010	2011	2012		2015 (SIM)
Load demand	17.94	17.70	17.51		17.83
Hydro	8.30	4.58	4.77		6.42
Thermal	4.78	5.17	4.69	…	8.67
Renewables	0.14	0.20	0.33		0.35
Industrial	0.03	0.03	0.09		0.1
Exchange balance	-4.67	-7.70	-7.62		-2.77

7.2. Dependence of electricity price on electricity demand

One of the general rules of supply and demand dictates lower prices at lower demand and higher prices at higher demand. Price of electricity derives from the bid-up strategy modelling: an hourly bid-up proportional to the demand level has been superimposed on the marginal cost curve of each thermal unit. The resulting price has a trend following the demand: it's high in peak load hours and lower off peak hours. The trend during the course of the referent year (2015) can be observed in Figure 11.

7.3. Economic analysis

In order to best depict the overall economic and financial performance of the investment in study, we have built a detailed model comprising of all the effective costs and profits that the IPP should encounter during the lifetime of operation of the power plant. The analysis conducted has been carried out by the year by year evaluation of the effective and present cash flow. The starting year of commercial operation is predetermined by the market simulation at 2015. For this year, the simulation provided us with two important values upon which we have based our further assessment of the performance of the project during its lifetime: unit dispatch and unit revenues. Using the technical parameters of the unit in study, we have calculated the data presented further in text. The cash flow during the first year of operation is shown in Table 10.

Figure 11. Yearly profile of the load and marginal price curve for Croatia

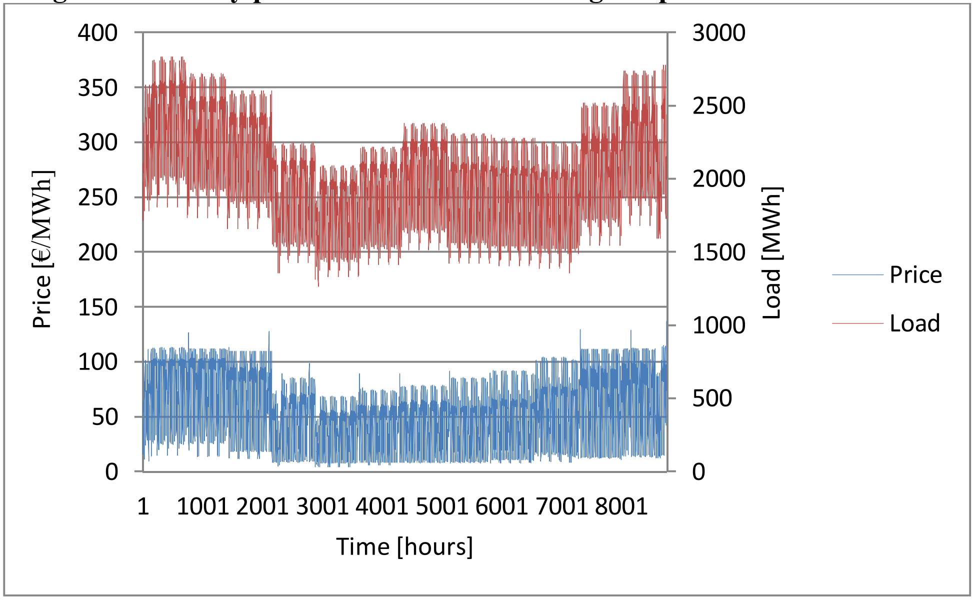
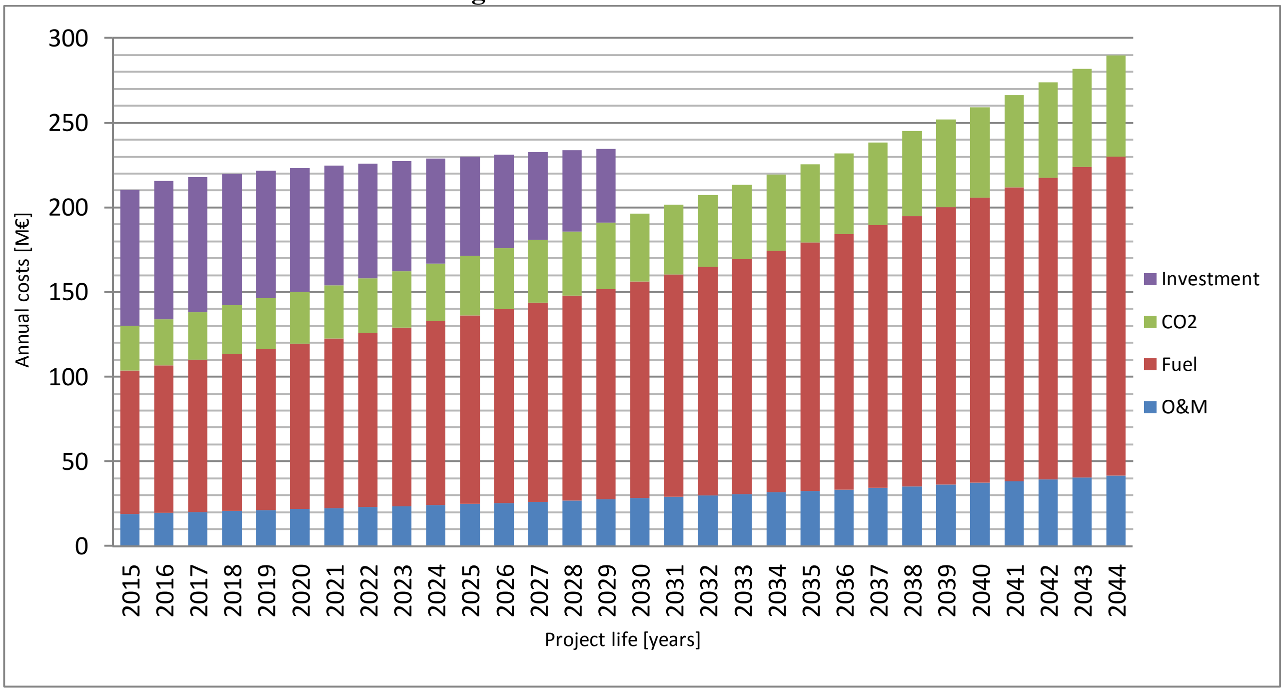


Table 10. Cash flow during referent year of operation (all values in M€)

Revenue	211.57
O&M	19.18
Fuel	84.57
CO_2	26.57
EBITDA	81.23
Amortization	39.33
EBIT	41.90
Interest	43.93
EBT	-2.02
Taxes	0.00
Net income	-2.02

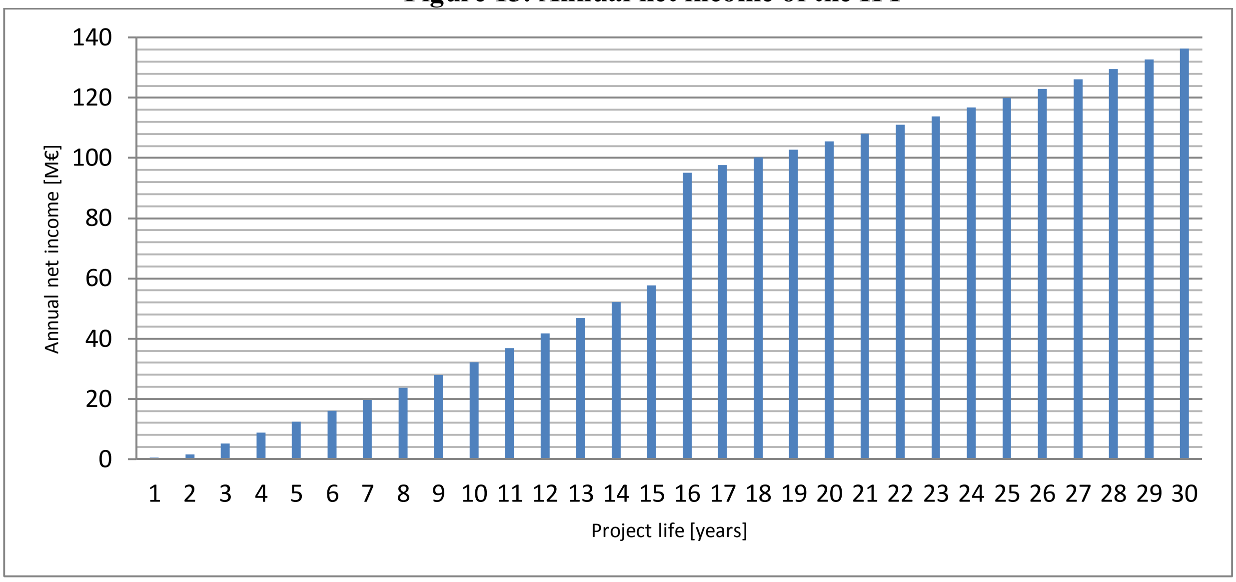
When evaluating annual costs we have taken into consideration a 0.1% per year degradation of the power plant efficiency which results in a higher specific consumption as well as higher specific emissions; both of these, in a certain amount, raise the operating costs of a unit. The fuel costs reported include start-up costs as well as the costs of higher consumption when operating at capacities below nominal. Capital costs have been considered with their financial amortization schedule with an amortization rate of 6.67% which corresponds to an amortization period of 15 years. As far as the annual O&M costs are concerned, we have considered them to be sufficient for all the planned and unplanned maintenance as well as the overhauls during the project lifetime. The components of the model have been recalculated year by year on the basis on the inflation rate provided by Global Insight. The analysis also considers all the taxes imposed with special consideration given to the Croatian company tax which, at the rate of 20%, presents the most significant burden among these duties. Figure 12 shows the annual costs of an IPP during the project lifetime.

Figure 12. Annual costs of an IPP



The IPP in study is presumed to generate revenue by selling its output on the energy exchange. Primarily, its production is used to satisfy the needs of the Croatian demand and, when possible, used for export. Its bidding strategy is aimed at covering the LRMC of the unit. Using the data from Table 10 along with necessary assumptions we built a model with the projected revenues of the project during the course of its lifetime. The revenues on an annual basis are presented in Figure 13.

Figure 13. Annual net income of the IPP



With the help of the two projections (of costs and revenues), we were able to calculate the net present value of the investment (NPV). Considering the project lifetime and the discount rate of 8.7% (investor's presumed WACC), the investment of 190 M€ would have an NPV of 138.92 M€. The internal rate of return (IRR) is the value of the discount rate that makes the net present value of all cash flows equal to zero. For the referent scenario, the IRR would equal 12.4%. We have also calculated the investment's profitability index (PI) and its payback period (PBP). Relevant parameters of the investment are presented in Table 11. It should be noted that, despite achieving a good IRR, the project should be considered a risky investment not only because of the associated risks, but also the influence of a number of unpredictable factors and the uncertainty of future EU policy and regulation regarding coal fired electricity generation. The net loss during the first year of operation should also be a sign to take greater precaution when deciding whether to invest in this type of project or not.

Table 11. Investment parameters resume

Equity	190 M€
NPV	138.92 M€
IRR	12.4 %
PI	0.731
PBP	11.16 years

7.4. Sensitivity market analysis

Because of the uncertainty regarding some of the parameters in the market analysis have conducted a sensitivity market analysis offering a more detailed perspective on the possible changes in the electricity sector that directly reflect the performance of the unit in study. We have focused on five major factors: EUA prices, fuel costs, hydrology, demand and renewables to see the strength of their impact on the performance of the project. We would like to point out that our analysis of the variations of factors focused on the boundaries of optimal and pessimal possible scenarios. It is unlikely that the parameters considered in the sensitivity analysis would remain such for a prolonged period of time (project lifetime), but the results obtained represent a valuable insight on the dynamics of the market in study.

We have covered a variation of EUA prices from 0-80 €/tCO_2 (Figure 13, cases 2-6).Our analysis showed that the IPP can bare this heavy burden (e.g. over 50 M€/annum for the 20 €/tCO_2 scenario) and still achieve profit up to a certain extent. The breakpoint occurs for prices of CO_2 higher than 30 euros per tonne. Taking into account the competition in place and the characteristics of the SEE REM, our analysis showed that prices of EUA ranging from 30-50 €/tCO_2 seem to be highly unfavourable for the IPP in study. The unit loses its place in the MOC and, along with lower dispatch, achieves an accordingly worse financial performance. For the prices above the 50 euros per tonne mark, the situation within the sector improves and the IPP is able to achieve a positive NPV despite the extreme carbon costs it faces. The main reason for this is the competition the unit faces. Firstly, it is important to note that the price of electricity on the market is formed by other thermal units. If these units have higher costs, their bidding strategy (aimed to cover these costs) will lead to the rise of the overall average marginal price of electricity (AMPE). Other coal fired units in the region have high specific emissions and are more affected by the changes in EUA prices. Due to the high efficiency of an USCPC unit and much lower specific carbon emissions, the unit in study is able to hold its position within the MOC, sell its production and still make a profit even with a cost of a tonne of CO_2 at 80 €/tCO_2. The main results of the EUA variation analysis are presented in Table 12.

Table 12. EUA prices sensitivity cases

EUA [€/tCO_2]	0	20	40	60	80
AMPE [€/MWh]	47.49	63.35	75.62	90.62	106.18
Production [GWh]	3571	3500	3236	3690	3760
Revenues [M€]	184.3	239.3	256.8	345.5	407.1
CO_2 emissions [tCO_2]	2.70	2.65	2.44	2.78	2.83
NPV [M€]	129.11	156.32	-22.43	48.81	46.64
IRR [%]	12.2	12.9	8.1	10.0	10.0

Fuel prices were analysed with four additional scenarios by changing the prices of both coal and natural gas (Figure 13, cases 7-10). Compared to the referent case, coal price was set at -20%, -10%, +10% and +20%, while the price of gas was set at +20%, +10%, -10% and -20%. The pessimistic predictions of coal prices were paired with the optimistic for gas and vice versa. We identified the fuel costs breakpoint at which the IPP is no longer able to achieve a satisfying dispatch and a positive NPV at prices of coal higher than 90 €/t and natural gas lower than 7€/GJ. This can be seen by observing case 10 of Figure 13 where we assumed 20% higher costs for coal and 20% lower for natural gas. The main results of the fuel prices variation analysis are presented in Table 13.

Table 13. Fuel prices sensitivity cases

Coal price [€/t]	64	72	88	96
NG price [€/GJ]	10.28	9.42	7.71	6.85
AMPE [€/MWh]	51.62	53.63	56.79	56.27
Production [GWh]	3576	3563	3480	2583
Revenues [M€]	199.7	206.6	215.1	149.7
CO_2 emissions [tCO_2]	2.69	2.68	2.62	1.94
NPV [M€]	138.74	88.91	127.69	-235.61
IRR [%]	12.6	11.2	12.1	-

The two scenarios observing different hydrological conditions were based on situations encountered in years 2010 and 2011 (Figure 13, cases 11-12). 2010 was a year of extremely favourable conditions resulting in a 30% higher production of the hydro sector; year 2011 was the opposite, resulting in a bit less than 30% lower production. The market analysis revealed that the variations of hydrological conditions have a great impact on the dispatching and financial results of the unit. This is emphasised because of the high share the hydro sector holds in the overall Croatian production capacity. The comparison between the two scenarios revealed an 800 GWh difference per annum in electricity production which amounts to a 334 M€ difference in the two NPVs achieved. The main results of the analysis on the influence of hydrology on the IPP are presented in Table 14.

Table 14. Hydrological conditions sensitivity cases

Hydrology	Optimal	Pessimal
AMPE [€/MWh]	52.16	55.72
Production [GWh]	2732	3534
Revenues [M€]	151.0	214.5
CO_2 emissions [tCO_2]	2.06	2.66
NPV [M€]	-173.35	160.97
IRR [%]	3.9	13.0

As mentioned earlier in the text, before, it was common to assume that the electricity demand is always on the rise (Figure 13, cases 13-14). Due to a number of reasons, this is no longer a possibility. Predicting a country's consumption has become an arduous task to undertake. It is because of the unpredictable uncertainties encountered whilst facing this type of forecasting, that the referent values from prior scenarios were altered. The variations considered were +10% for the optimistic and -10% for the pessimistic scenario. Results that were obtained showed a staggering influence of demand on the performance of the unit. A raise in the predicted demand allowed the unit not only to achieve the highest dispatch of all scenarios, but the greatest NPV as well. On the other hand, a 10% drop in demand results in the lowest possible dispatch paired with the most negative NPV of all scenarios. Between the two scenarios there is a 1660 GWh/annum and a 756M€ difference. The main results of electricity consumption sensitivity cases are presented in Table 15.

Table 15. Electricity consumption sensitivity cases

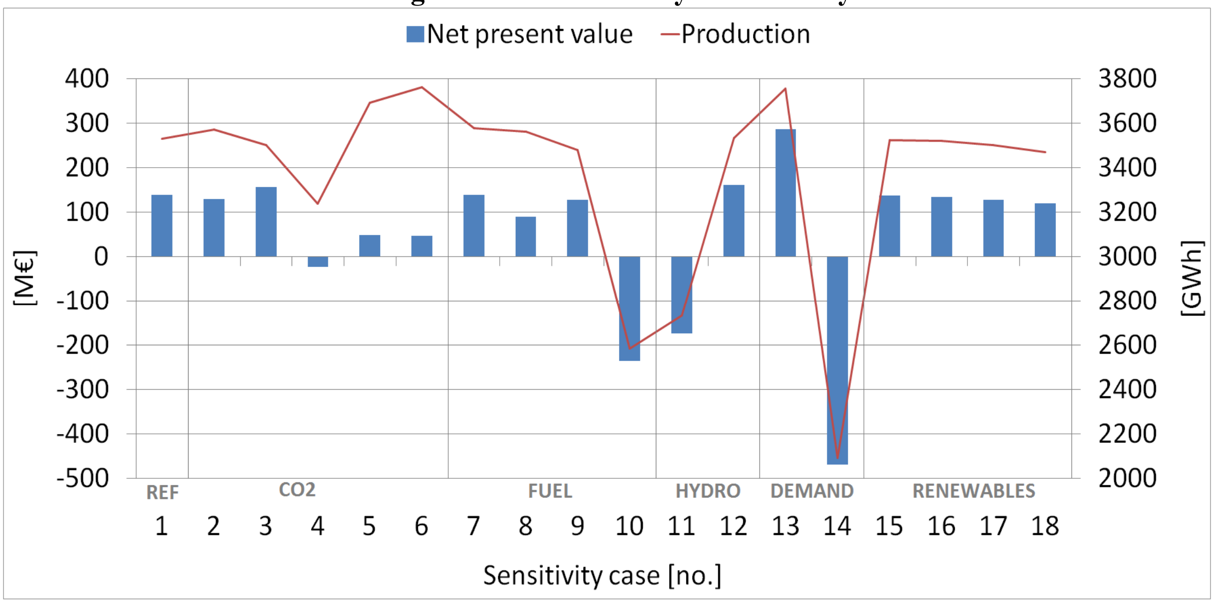
Electricity consumption [%]	-10	+10
AMPE [€/MWh]	60.45	47.41
Production [GWh]	3756	2094
Revenues [M€]	237.1	99.7
CO_2 emissions [tCO_2]	2.83	1.58
NPV [M€]	286.85	-469.34
IRR [%]	16.2	-

The last of the sensitivity cases involved the use of renewable sources (Figure 14, cases 15-18). Despite the scenarios being somewhat of a stretch considering the state of the Croatian electricity sector, they envisage the annual production of renewables in Croatia (excluding the hydro sector) to be 1000 GWh, 2000 GWh, 3000 GWh and 4000 GWh, or, in other words, 6%, 11%, 17% and 22% of the annual overall Croatian consumption respectively. Somewhat surprisingly, the IPP is not influenced by this growth and still achieves a satisfying dispatch along with a positive NPV. Partially it still serves as base load power for the Croatian system and partially it sells its production across the borders. Observing the electricity sector as a whole, it can be noticed that the most significant influence manifests in the energy exchanges. More renewables mean less imports; 3000 GWh at settings listed results in a breakpoint at which the import/export equals approximately zero. For any quote of renewables higher that this value, Croatia becomes a net exporter of electricity. The negative aspect regards the rest of the thermal sector which gradually lowers its output as it has less consumption to bid for on the market.

Table 16. Renewables production sensitivity cases

Production from renewable sources [GWh]	1000	2000	3000	4000
AMPE [€/MWh]	55.1	55	54.92	54.8
Production [GWh]	3525	3519	3501	3471
Revenues [M€]	211.1	210.7	209.7	207.6
CO_2 emissions [tCO_2]	2.65	2.65	2.64	2.61
NPV [M€]	137.44	133.80	127.50	118.89
IRR [%]	12.4	12.3	12.1	11.9

Figure 14. Market analysis sensitivity cases



7.5. Results and discussion

Primarily, we would like to advise the reader of this article to refrain from thinking that the numbers presented are "real". As detailed as the analysis, they are only of indicative nature. Just because a computer can calculate numbers to the penny does not mean that the numbers are true. The biggest pitfall of this type of analyses is a significant amount of uncertainty due to the high number of assumptions that have to be made. The uncertainties regarding these types of investments cause projects to flop in the very beginnings without reaching financial close. Financial close occurs when all the project and financing agreements have been signed and all the required conditions contained in them have been met. It enables funds to start flowing so that project implementation can actually start. Despite plans of adding new generation capacities by building new thermal units, most of the projects in EU these days are being cancelled or at best postponed mainly due to the risks and uncertainties involved. Most of the projects nowadays are being financed by financial institutions. These institutions do not to bare uncertainties and charge risk premiums to compensate for them. If they adjudge the project risks as too high, they are unwilling to finance the project. Because of these issues, IPP companies pioneered the use of the discounted cash flow (DCF) model. It was mostly used for smaller power projects. In this model, the developers attempt to fix as many costs as possible by obtaining fixed price contracts for all of the major cost contributors such as the EPC price, fuel contracts, O&M and, most preferably, a PPA. Having a quality PPA presents one of the most significant assets of an IPP as it can diminish one of the biggest risks that projects in the electricity sector face – the merchant risk. Having reduced the risks of the project, proper financing can be achieved and at a lower cost. This is a perquisite for a successful investment.

As for the IPP in study, our analysis established it as a risky investment, highly dependent on external factors that cannot be influenced. However, after observing all the scenarios, there are only four cases in which the investment achieves a negative NPV. Prices of EUA at 40 €/tCO_2, a combination of fuel prices 20% different from predicted, 30% higher hydro production and 10% lower demand are all conditions less likely to happen and the likelihood of them to be maintained through a prolonged period of time is deemed very low. Despite all the uncertainties, we consider the IPP in study a stable investment relatively resistant to external influences and likely to achieve a profit as much as any other coal fired unit in the region.

8. Conclusions

Investing in electricity generation and achieving a profit has in recent years become an increasingly difficult task. The fast changing dynamics of the electricity market paired with harsh EU policies towards fossil based electricity generation make investments in coal fired power plants extremely risky. Uncertainties inevitably raise costs and tend to postpone or even cancel a number of projects. Now more than ever, feasibility studies, market analysis, detailed risk assessments and consideration to a string of possible influencing factors are needed to understand the possibilities when investing in the thermal sector. Only carefully planned, well structured projects can obtain the necessary licenses, achieve financing and get through the construction period.

As this paper showed, it is very difficult to predict whether this type of investment will have a future; will it achieve a positive cash flow during the course of years and will it, in the end, be financially successful. Despite providing the numbers, this paper cannot give the answer whether to invest in coal based electricity generation in SEE or not. It can and it does, however, provide a clearer picture of the possible problems, risks and outcomes when investing in this type of projects.

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